A

Major Project Report on

WELL TESTING & INTERPRETATION

BY

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CERTIFICATE

This is to certify that the work contained in this thesis titled "**Well Testing & Interpretation**" has been carried out by *Udaya Nanda Saikia,Nadeem Alam Khan and Deepesh Dhoundiyal* under our supervision and has not been submitted elsewhere for a degree.

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Last but not the least I would extend our heartiest thanks to my parents who always kept me on our toes. At the end I would like to thank one and all who have been directly or indirectly involved in this project. Their help and co-operation will not be forgotten

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Contents

CHAPTER 6 PRESSURE ANALYSIS IN INJECTION WELLS

CHAPTER 7 EFFECT OF RSERVOIR HETEROGNEITIES ON PRESSURE BEHAVIOR

CHAPTER 8 MATHEMATICAL ANALYSIS OF WELL TESTING METHODS

NOMENCLATURE

I. **A**= drainage area of well, sq ft

II. **b**= intercept at **delt** = 0 of logP vs delt psi.

III. **B**= formation volume factor

IV. **C**= compressibility, psi^{-1}

V. $\mathbf{C_f}$ = effective formation compressibility, psi^{-1}

VI. $\mathbf{C_t}$ = total compressibility

VII. **D** = non-darcy flow constant, $(B/D)^{-1}$

VIII. **h**= formation thickness, ft

IX. **i**= injection rate (B/D) at surface conditions

X. **I**= injectivity index, B/D-psi

XI. **J**= productivity index, B/D-psi

XII. **k**= formation permeability, md

XIII. **m**= absolute value of the slope of linear portion of PBU curve (psi/logcycle)

XIV. **M**= mobility ratio

XV. $\mathbf{P_e}$= external boundary pressure, psi

XVI. $\mathbf{P_i}$= initial reservoir pressure, psi

XVII. $\mathbf{P_{iw}}$= bottomhole injection well pressure

XVIII. $\mathbf{P_{wf}}$= bottomhole flowing pressure

XIX. **P_{1hr}**=pressure read from the linear portion of PBU curve at 1-hour closed in time, psi.

XX. **P*=** pressure obtained when linear portion of PBU curve is extrapolated to t+delT/delT=1.

XXI. **P** = average pressure , psi

XXII. **$P^{\wedge}$** = P_w at semi-steady state, psi

XXIII. Δp_{skin}=pressure drop in "skin" region near the wellbore, psi

XXIV. **q**= production rate of well, B/D at surface conditions.

XXV. **r_D**= dimensionless radius, r/r_w

XXVI. **r_e** = external boundary radius, ft

XXVII. **R_s**= gas solubility

XXVIII. **S**= skin factor

XXIX. **S'**= apparent skin factor, dimensionless

XXX. **S**= saturation, fraction of pore space

XXXI. **T**= flowing time, hours

XXXII. del**T=** closed-in time

XXXIII. **W_i** = cumulative water injection

XXXIV. **Z**= gas deviation factor

XXXV. γ= ratio of total compressibility in oil bank to total compressibility in water bank.

XXXVI. γ= Eulers constant, value is 1.78

XXXVII. μ = viscosity, cp

XXXVIII. Φ= porosity, fraction

Special Function:

$$-Ei(-x) = \int_{x}^{\infty} \frac{e^{-s}}{s}\, ds$$

Subscripts used:

O,w,g = oil, water, gas; w also refers to well when used with p and r.

Os,ws,gs = oil, water, gas at standard conditions

Or, gr,= oil and gas at residual conditions

Sc= standard conditions

i= initial

INTRODUCTION:

The testing of wells plays an important role in the development of the reservoir. After the drilling of a well it is desired to find out if it produces oil, gas or water and what rate. The purpose of testing is to obtain certain information about the fluid properties and the reservoir characteristics and to generate the relevant data to be used in the Reservoir Engg Calculations. The information is obtained through the visual observations, surface measurement, interpreting the well test data

LITERATURE SURVEY (an overview of various tests & their objectives)

Description of a Well Test:

During a well test, a transient pressure response is created by a temporary change ir production rate. The well response is usually monitored during a relatively short perioc of time compared to the life of the reservoir, depending upon the test objectives. Foı well evaluation, tests are frequently achieved in less than two days. In the case o reservoir limit testing, several months of pressure data may be needed.

In most cases, the flow rate is measured at *surface* while the pressure is recorded *down-hole*. Before opening, the initial pressure p_i is constant and uniform in the reservoir During the flowing period, the *drawdown* pressure response Δp is defined as follows:

$$\Delta p = p_i - p(t)$$

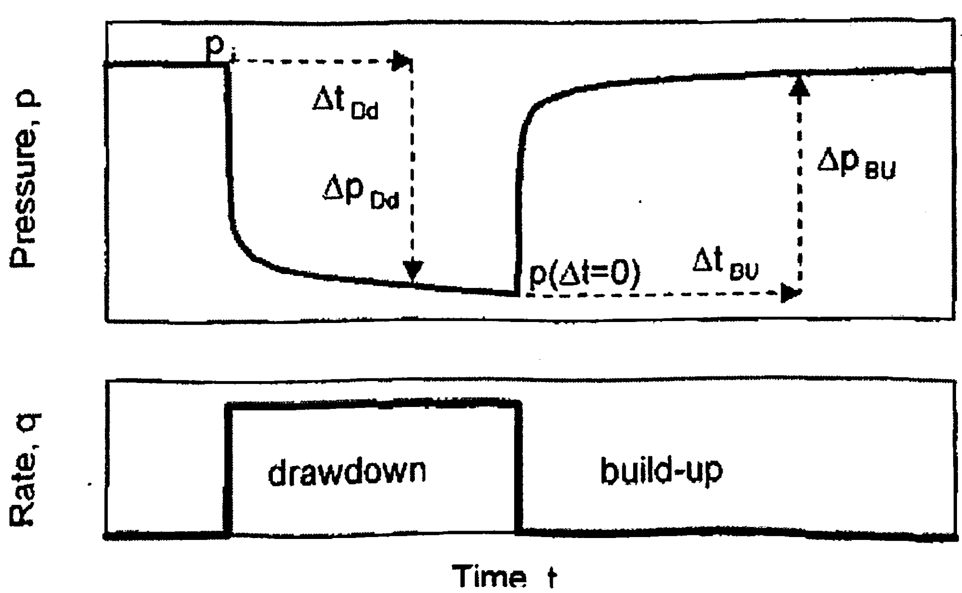


Fig:1.1. **Drawdown and Buildup sequence**

When the well is shut-in, the *build-up* pressure change Δp is estimated from the last flowing pressure $p(\Delta t{=}0)$:

$$\Delta p = p(t) - p(\Delta t = 0) \tag{1.2}$$

The pressure response is analyzed versus the *elapsed time* Δt since the start of the period (time of opening or shut-in).

Well Test Objectives

Well test analysis provides information on the reservoir and on the well. Geological, geophysical and petrophysical information is used where possible in conjunction with the well test information to build a reservoir model for prediction of the field behavior and fluid recovery for different operating scenarios. The quality of the communication between the well and the reservoir indicates the possibility to improve the well productivity. Usually, the test objectives can be summarized as follows:

Exploration well: On initial wells, well testing is used to confirm the exploration hypothesis and to establish a first production forecast: nature and rate of produced fluids, initial pressure and well and reservoir properties. Tests may be limited to drill stem testing only.

Appraisal well: The previous well and reservoir description can be refined by testing appraisal wells to confirm well productivity, reservoir heterogeneities and boundaries, drive mechanisms etc. Bottom hole fluid samples are taken for PVT laboratory analysis. Longer duration testing (production testing) is usually carried out.

Development well: On producing wells, periodic tests are made to adjust the reservoir description and to evaluate the need for well treatment, such as work-over, perforation strategy or completion design, to maximize the well's production life. Communication between wells (interference testing), monitoring of the average reservoir pressure are some usual objectives of development well testing.

Information obtained from the well testing

Well test responses characterize the ability of the fluid to flow through the reservoir and to the well. Tests provide a description of the reservoir in *dynamic conditions*, as opposed to geological and log data. As the investigated reservoir volume is relatively large, the estimated parameters are *average* values. From pressure curve analysis, it is possible to determine the following properties:

Reservoir description:

- Permeability (horizontal k and vertical k_V),
- Reservoir heterogeneities (natural fractures, layering, change of characteristics),
- Boundaries (distance, size and shape),
- Pressures (initial p_i and average $\bar{p}$).

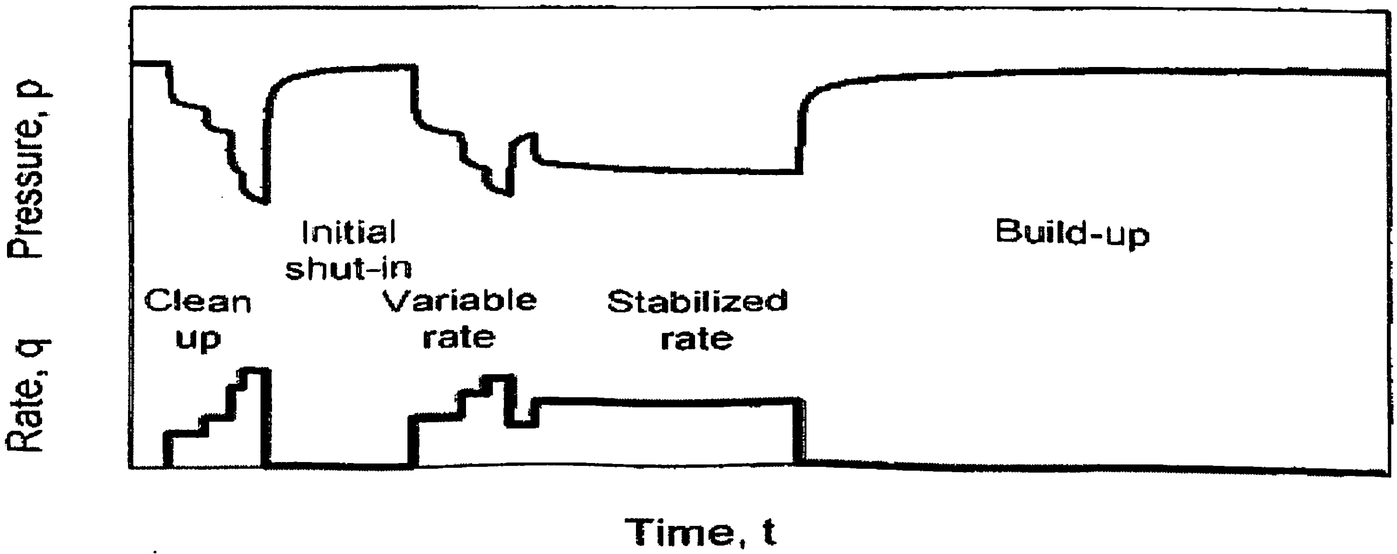
Well description:

- Production potential (productivity index PI and skin factor S),
- Well geometry.

By comparing the result of routine tests, changes of productivity and rate of decrease of the average reservoir pressure can be established.

Test Procedure

Fig:1.2-Typical test sequence (Oil Well)



Drawdown test: the flowing bottom hole pressure is used for analysis. Ideally, the well should be producing at constant rate but in practice, this is difficult to achieve and drawdown pressure data is erratic. The analysis of flowing periods (drawdown) is frequently difficult and inaccurate.

Build-up test: the increase of bottom hole pressure after shut-in is used for analysis. Before the build-up test, the well must have been flowing long enough to reach stabilized rate. During shut-in periods, the flow rate is accurately controlled (zero). It is for this reason build up tests should be performed.

Injection test / fall-off test: when fluid is injected into the reservoir, the bottom hole pressure increases and, after shut-in, it drops during the fall-off period. The properties of the injected fluid are in general different from that of the reservoir fluid, interpretation of injection and fall-off tests requires more attention to detail than for producers.

Interference test and pulse testing: the bottom hole pressure is monitored in a shut-in observation well some distance away from the producer. Interference tests are designed to evaluate communication between wells. With pulse tests, the active well is produced with a series of short flow / shut-in periods and the resulting pressure oscillations in the observation well are analyzed.

Gas well test: specific testing methods are used to evaluate the deliverability of gas wells (Absolute Open Flow Potential, AOFP) and the possibility of non-Darcy flow condition (rate dependent skin factor S'). The usual procedures are Back Pressure test (Flow after Flow), Isochronal and Modified Isochronal tests.

In Figure 1.2, the typical test sequence of an exploration oil well is presented. Initially, the well is cleaned up by producing at different rates, until the fluid produced at surface corresponds to the reservoir fluid. The well is then shut-in to run the down hole pressure gauges, and reopened for the main flow. The flow rate is controlled by producing through a calibrated orifice on the choke manifold. Several choke diameters are frequently used, until stabilized flowing conditions are reached. After some flow time at a constant rate, the well is shut-in for the final build-up test.

Our project begins with a discussion of basic equations that describe the unsteady-state flow of fluids in porous media. It then moves into the discussions of pressure buildup tests; pressure drawdown test; other flow test; type curve analysis; gas well test; interference and pulse test; and drillstem and wireline formation tests. Basic equations and examples use engineering units.

Productivity Vs Descriptive Testing

- Productivity testing of the well is conducted to
    - Identify produced fluids and determine their respective volume ratios.
    - Measure reservoir pressure and temperature.
    - Obtain samples suitable for PVT analysis.
    - Determine well deliverability.
    - Evaluate completion efficiency.
    - Characterize well damage.
    - Evaluate workover or stimulation treatment.

- Descriptive tests seek to;
    - Evaluate reservoir parameters.
    - Characterize reservoir heterogeneities.
    - Assess reservoir extent and geometry.
    - Determine hydraulic communication between wells.

Whatever the objectives, well test data are essential for the analysis and improvement of reservoir performance and for reliable predictions. These, in turn are vital to optimizing reservoir development and efficient management of the asset. Well testing technology is evolving rapidly. Integration with data from other reservoir related disciplines, constant evolution of interactive software for transient analysis, improvements in downhole sensors and better control of the downhole environment have all dramatically increased the importance and capabilities of well.

What is Productivity Test?

Productivity well testing, the simplest form of testing, provides identification of productive fluids, the collection of representative samples and determination of reservoir deliverability. Formation fluid samples are used for PVT analysis, which reveals how hydrocarbon phases coexist at different pressures and temperatures. PVT analysis also provides fluid physical properties required for well test analysis and fluid flow simulation. Reservoir deliverability is a key concern for commercial exploitation. Estimating a reservoir's productivity requires relating flow rates to drawdown pressures. This can be achieved by flowing the well at several flow rates (different choke sizes) and measuring the stabilized bottomhole pressure and temperature prior to changing the choke. The plot of flow data verses drawdown pressure is known as the inflow performance relationship (IPR). For monophasic oil conditions, the IPR is a straight line whose intersection with the vertical axis yields the static reservoir pressure. The inverse of the slope represents the productivity index of the well. The IPR is governed by properties of the rock-fluid system and near wellbore conditions. Examples of IPR curves for low and high productivity are shown in **figure-1**. Changing in flow rate and pressure are also shown The steeper line corresponds to poor productivity, which could be caused either by poor formation flow properties(low mobility-thickness product) or by damage caused while drilling or completing the well (high skin factor).

Figure-2.1

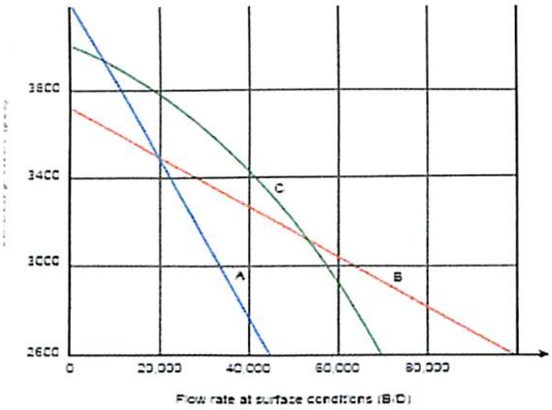
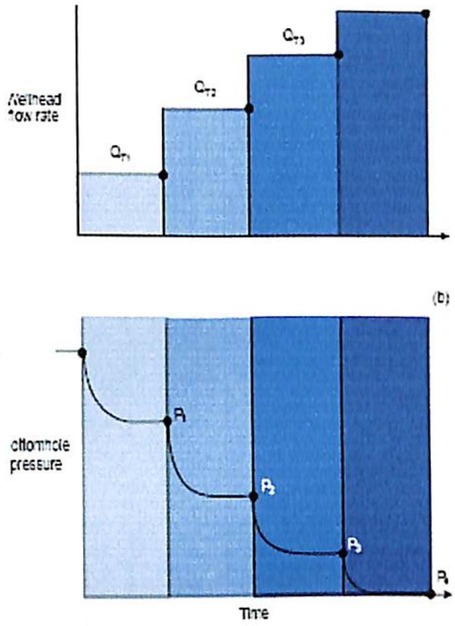


Figure-2.2



As in the **figure-2.1** IPR curves show **a) low & b) high productivity.** For gas wells, IPR curves exhibit certain curvature **(c) due to extra inertial and turbulent flow effects in the vicinity of the wellbore and changes of gas properties with pressure.** Oil wells flowing below the bubble point also display similar curvature, but these are due to changes in relative permeability created by variations in saturation distributions.

On the other hand as shown in the **figure 2.2-** relationship between the flow rate and the drawdown pressure for estimating the reservoir characteristics.

What is Descriptive Well Testing?

Estimation of the formation's flow capacity, characterization of wellbore damage and evaluation of a work over or stimulation treatment all require a transient test because a stabilized test is unable to provide unique values for mobility-thickness and skin. Transient tests are performed by introducing abrupt changes in surface production rates and recording the associated changes in bottomhole pressure. Production changes, carried out during a transient well test, induce pressure disturbances in the wellbore and surrounding rock. These pressure disturbances travel into the formation and are affected in various ways by rock features. For example, a pressure disturbance will have difficulty entering a tight reservoir zone, but will pass unhindered through an area of high permeability. It may diminish or even vanish upon entering a gas cap. Therefore, a record of wellbore pressure response over time produces a curve whose shape is defined by the reservoir's unique characteristics.

Unlocking the information contained in pressure transient curves is the fundamental objective of well test interpretation.

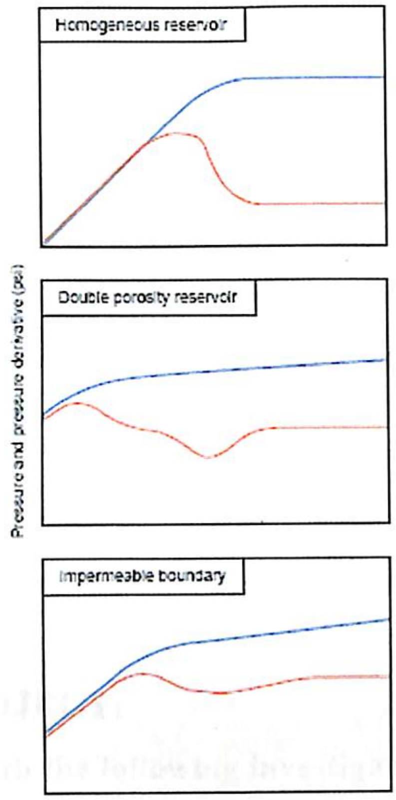


Figure:2.3

The above three plots are showing the behavior pressure transient tests for the various reservoir conditions viz; homogeneous, double porosity reservoir and impermeability reservoir. The blue curve represents the pressure pulses with respect to time; the red curve represents the derivative of pressure w.r.t. time vs. time.

Stages of Well Testing: The testing of well is carried out in the initial stage in exploratory well and periodically in the development wells. The major well tests carried out at initial and the production stage are given below:

Initial Stage

- Drill Stem Test (DST)
- Production tests &
- Repeat Formation Test.

Production Stage

- Injection-test
- Fall off test
- Well interference test
- Slug test
- Multirate flow test
- Production Logging test etc

The tests carried out at the initial stage are important to know the content of the fluid in the reservoir and the pressure in the reservoir. The tests carried at the production stage are for the Reservoir Engg calculations.

OBJECTIVES OF OUR PROJECT:

The present project will deal with the following investigation:

1) To study the drill stem testing (both open hole & cased hole testing)
2) Study of Repeat Formation Testing & its limitations
3) Transient test or Fluid flow study under Unsteady State conditions
4) Pressure build up test in Oil and Gas wells both
5) Effect of reservoir heterogeneity on Pressure build up
6) Multiple rate flow test analysis
7) To study well interference analysis, pulse testing and Injectivity test
8) Mathematical analysis of the well testing techniques
9) Analysis of the practical fields test data by ***FEKETE*** software and their comparison

DRILL STEM TESTING

The measurement and analysis of DST hel the engineer to estimate economically the reservoir arameters rior to well completion.The roerly run and interreted DST may yield more information by sending less money as comared to to the cost of the tolls and running it. It can be run either in oen hole or cased hole drilling.

Open Hole DST

1. Tests possible productive zones as penetratedby drill . This type of test is usually conducted in conjunction with mud logging and or coning programme.

2. Tests possible productive zones after drilling through to grater deth or total depth. To test in this fashion , it is necessary to use staddle packer or to set successive cement lugs to isolate the intervals.

   Cased hole DST

   DST is conducted in cased holes on intervals decided for perforations in the casing. Casing must be cemented and set prior to testing. It is useful in the following cases

   1. For cement squeeze perforations
   2. To locate leakage in the casing
   3. To ascertain the success of cement squeeze job
   4. To remove differentially stick drill pipes

The DST can be conducted in the exploratory or wild cat wells , delineation or development wells.

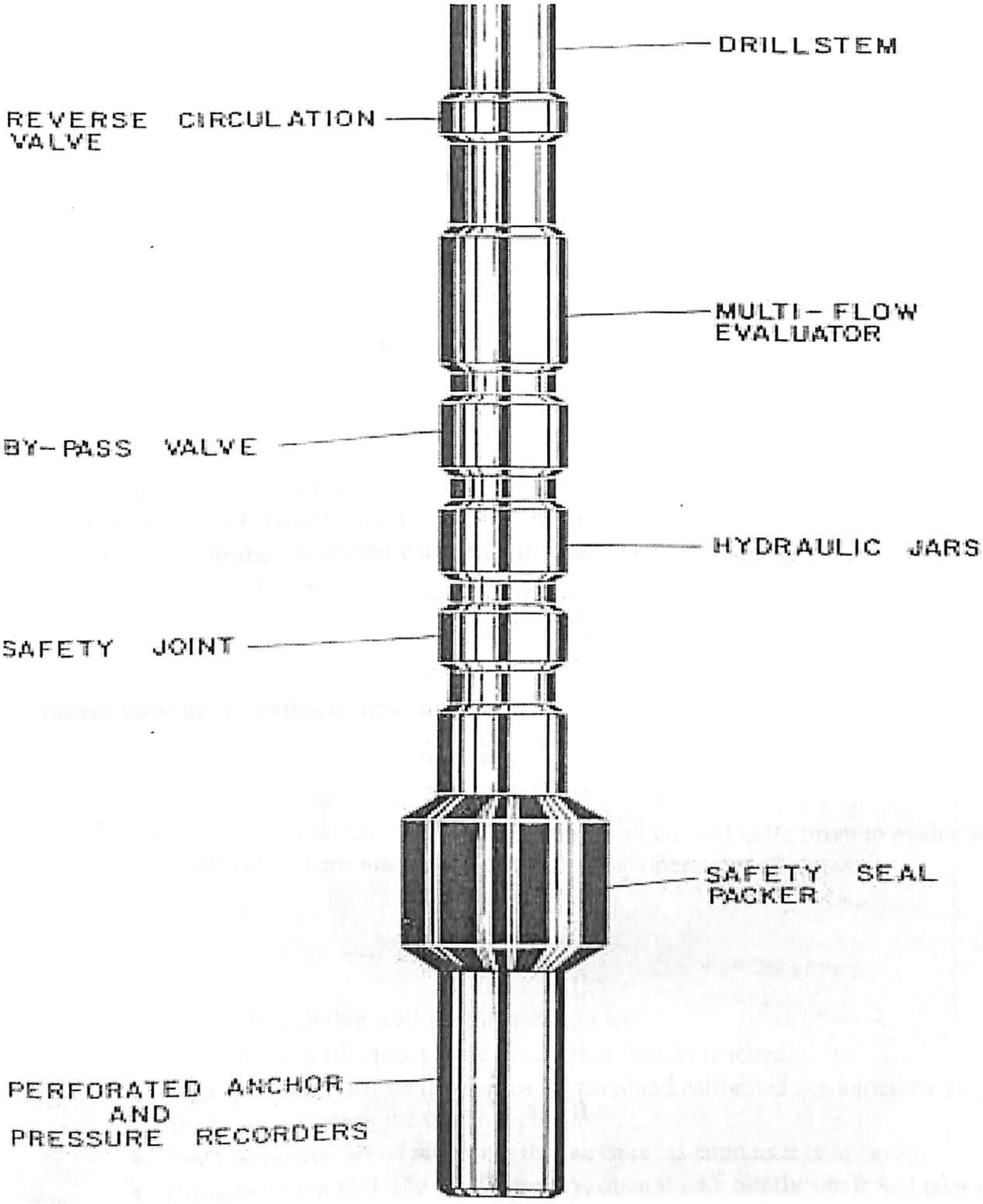


Fig:2.4 Schematic diagram of a currently using DST tool

REPEAT FORMATION TESTS

This technique is designed to

1. Measure formation pressure and
2. Collection formation fluid sample

It can b set any number of times at different zones unlike the DST

Limitations

- It is used in only open holes
- Hole size lies between 6 inches to 14.75 inches
- Maximum formation pressure s twenty thousand sig.

Pressure buildup & transient test in oil wells

The transient test or unsteady state flow test is carried out in a well quite often to evaluate certain parameters. The following steps are carried out during the operations.

- Select the suitable well for the transient test.
- Flow the well till steady stare production flow is reached.
- Shut in the well lowered the already rearedand calibrated manometerin the well through the tubing to reach the target depth
- The manometer starts recording the pressure as soon as it is lowered.
- Bring the manometer to the laboratory, open it take out the chart and take the readings.
- Lot P_{ws} vs t on semi log paper

Pressure build up equation can be given by:

$$P_{ws}= P_i -162.6quB_o/kh*\log(t+del\ t/del\ t)$$

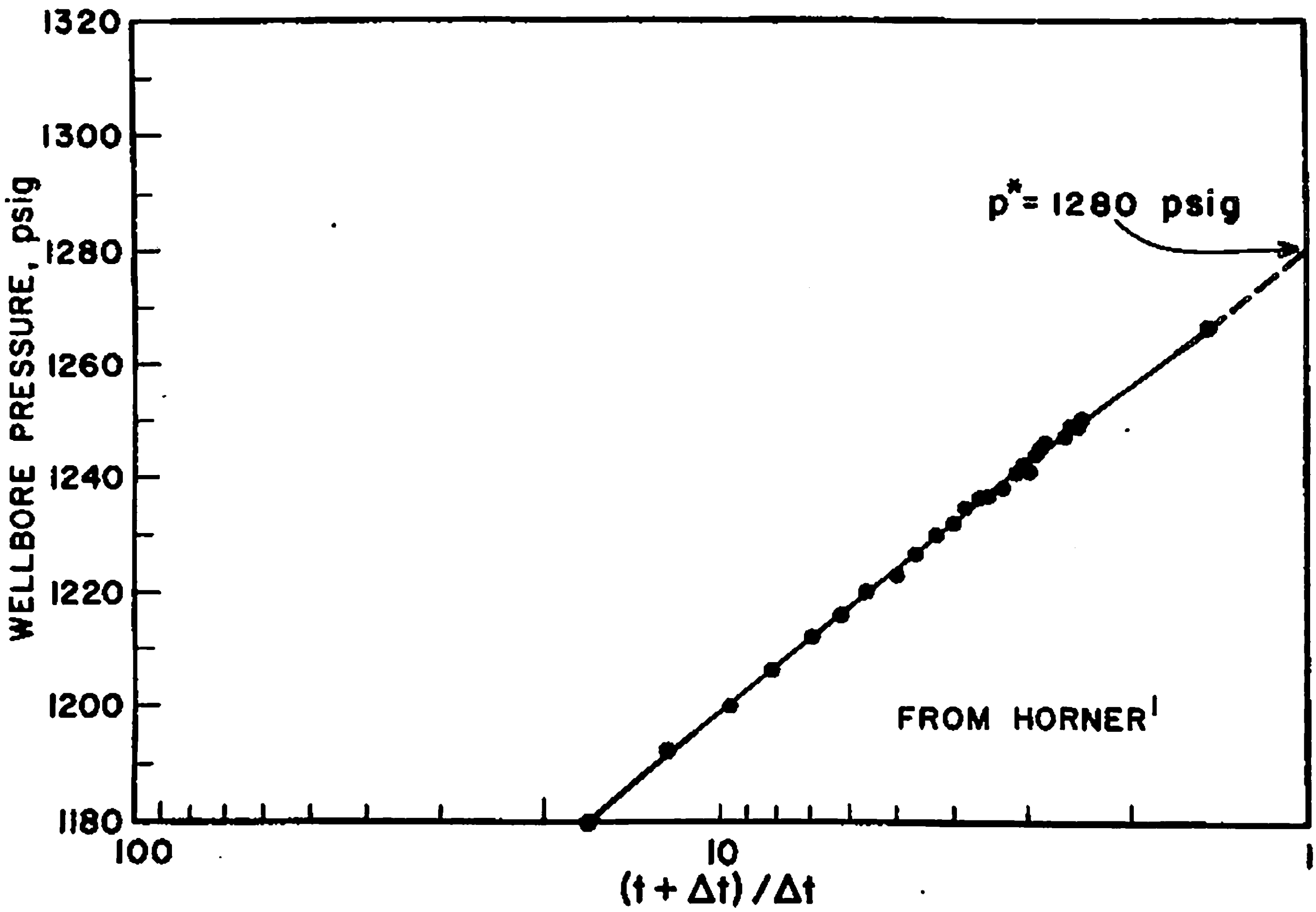


Fig: 3.1. Pressure buildup curve

The lot should be straight as per the theory but in actual practice it is curvy in nature. The curve has got three different arts

1. Initial stage this gets affected by the wellbore conditions.
2. The middle art of the curve gives the drainage effect
3. The last art gives the effect of the boundary

For our purpose part 1 is selected and the slope of this line is found. & from that the reservoir parameters are calculated.

Pressure drawdown test

Pressure drawdown test is the inverse of the pressure build up test. Here the pressure is measured by allowing the well to flow instead of shutting the well till semi steady state condition is achieved. All the relevant parameters such as hydraulic transmissibility, capacity, mobility, permeability, skin factor etc as determined from the pressure build up test can also be determined from the pressure drawdown test. The plot P_{ws} vs t is prepared . The curve can be divided into three parts:

- Portion of drawdown curve amenable to analyze by the transient method
- Portion that signifies the late transient test and
- Portion of curve by semi steady state method.

Circumstances of the PDD test

1. Sometimes it becomes difficult to interrupt PBU or there is doubt in the parameters as calculated by the PBU test. Then PDD test is performed to confirm the values of PBU
2. Due to commitment of the production targets, it may not be desirable to close the well for carrying out the test. In that sense PDD test is carried out.
3. In well in a newly discovered area

Advantages and Disadvantages of PBU & PDD test

In PDD test the production from the well is not interrupted & moreover can also determine the pore volume that is very useful in exploratory well. But the demerit is that the well should be flowed for longer time till semi steady state is reached otherwise the question is asked 'Has semi steady state condition is reached...?'

The shape of the pressure build up curve may change due to

- Presence of fault or interface or pinch out
- Multilayered reservoir
- Lateral change in hydraulic diffusivity
- Naturally or hydraulic fractured reservoir
- Non symmetric drainage area
- Pressure dependent rock properties etc..

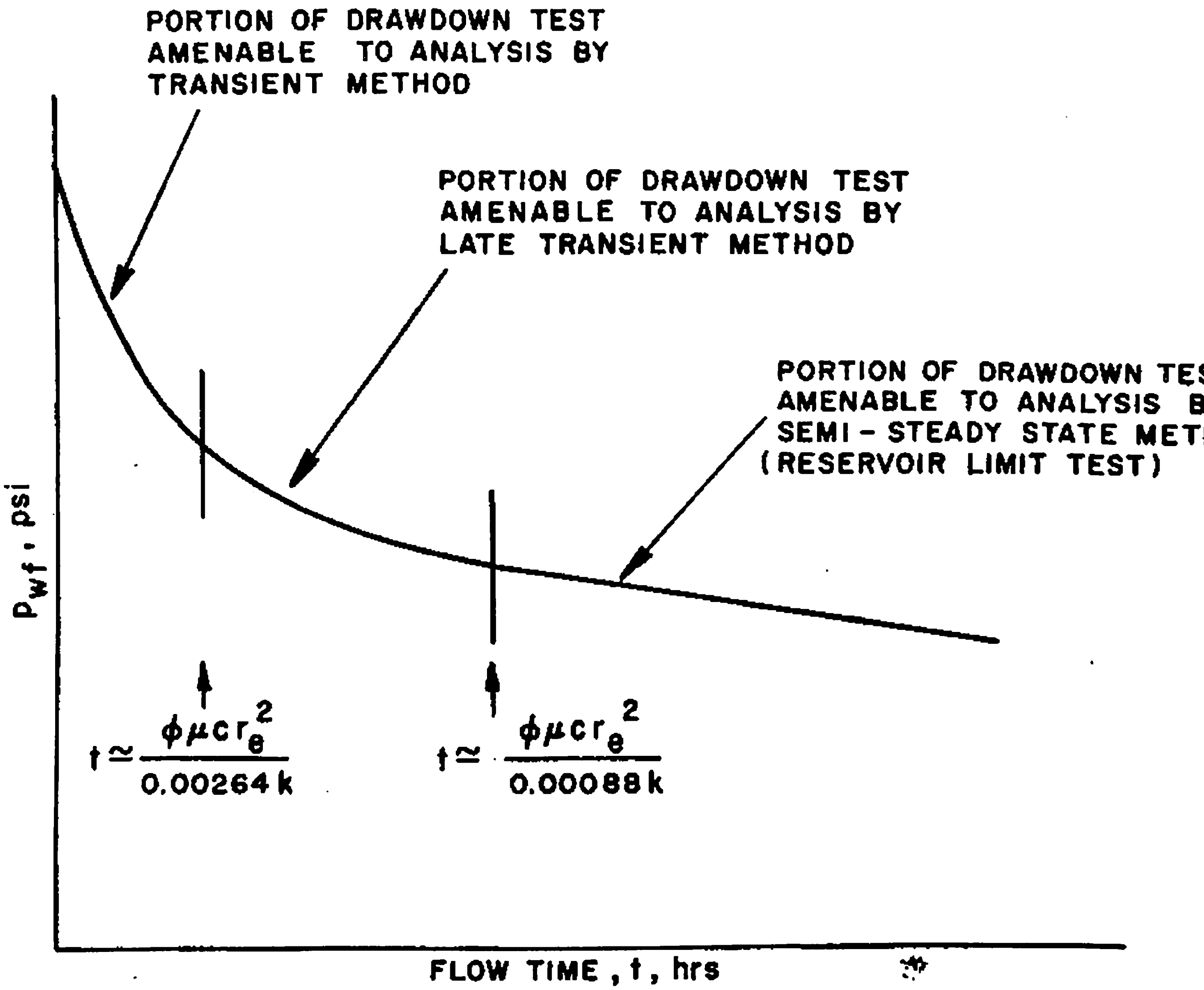


Fig:3.2. Pressure drawdown curve showing time ranges for which various analysis methods are applicable

Pressure Drawdown equation is given by:

$P_{wf} = P_i - 162.6quB_o/kh*[\log(kt/phiucr_w^2 - 3.23 + .87s)$

Multiple flow rate test

In PBU and PDD test flow rate is need to be constant. But, sometimes flow rate may vary with time and it might be the requirement of a regulatory body to test the well with various flow rates.

The multirate flow test is particularly useful where either operationally or economically it is not feasible to shut in the well for pressure build up or allow the well to flow to equalize the pressure. The purpose of the multirate flow test is to estimate\

- Capacity of the formation
- Skin factor
- Reservoir pressure

This multirate flow test is useful in oil wells as well as in gas wells. The **Back pressure** test in gas well falls in this category.

General flow equation for the multirate flow test:

$$\frac{p_i - p_{wf}}{q_n} = \frac{162.6\mu B}{kh} \sum_{j=1}^{n} \left[\frac{\Delta q_j}{q_n} \log (t - t_{j-1})\right] + \frac{162.6\mu B}{kh}\left[\log \frac{k}{\phi \mu c r_w^2} - 3.23 + 0.87s\right]$$

From the above equation it is seen that during the nth period of constant rate $t_{n-1}<t$ if we plot

$$\frac{p_i - p_{wf}}{q_n} \text{ vs } \sum_{j=1}^{n} \frac{\Delta q_j}{q_n} \log (t - t_{j-1}),$$

we should obtain a straight line of slope $m' = \dfrac{162.6\mu B}{kh}$

and intercept $b' = \dfrac{162.6\mu B}{kh}\left[\log\dfrac{k}{\phi\mu c r_w^2} - 3.23 + 0.87s\right.$

From these values we can determine the kh produc and skin factor from

$$kh = \frac{162.6\mu B}{m'} \quad , \quad . \quad . \quad . \quad . \quad . \quad . \quad . \quad . \quad (6.6)$$

and

$$s = 1.151 \left[\frac{b'}{m'} - \log\frac{k}{\phi\mu c r_w^2} + 3.23\right] \quad . \quad . \quad . \quad (6.7)$$

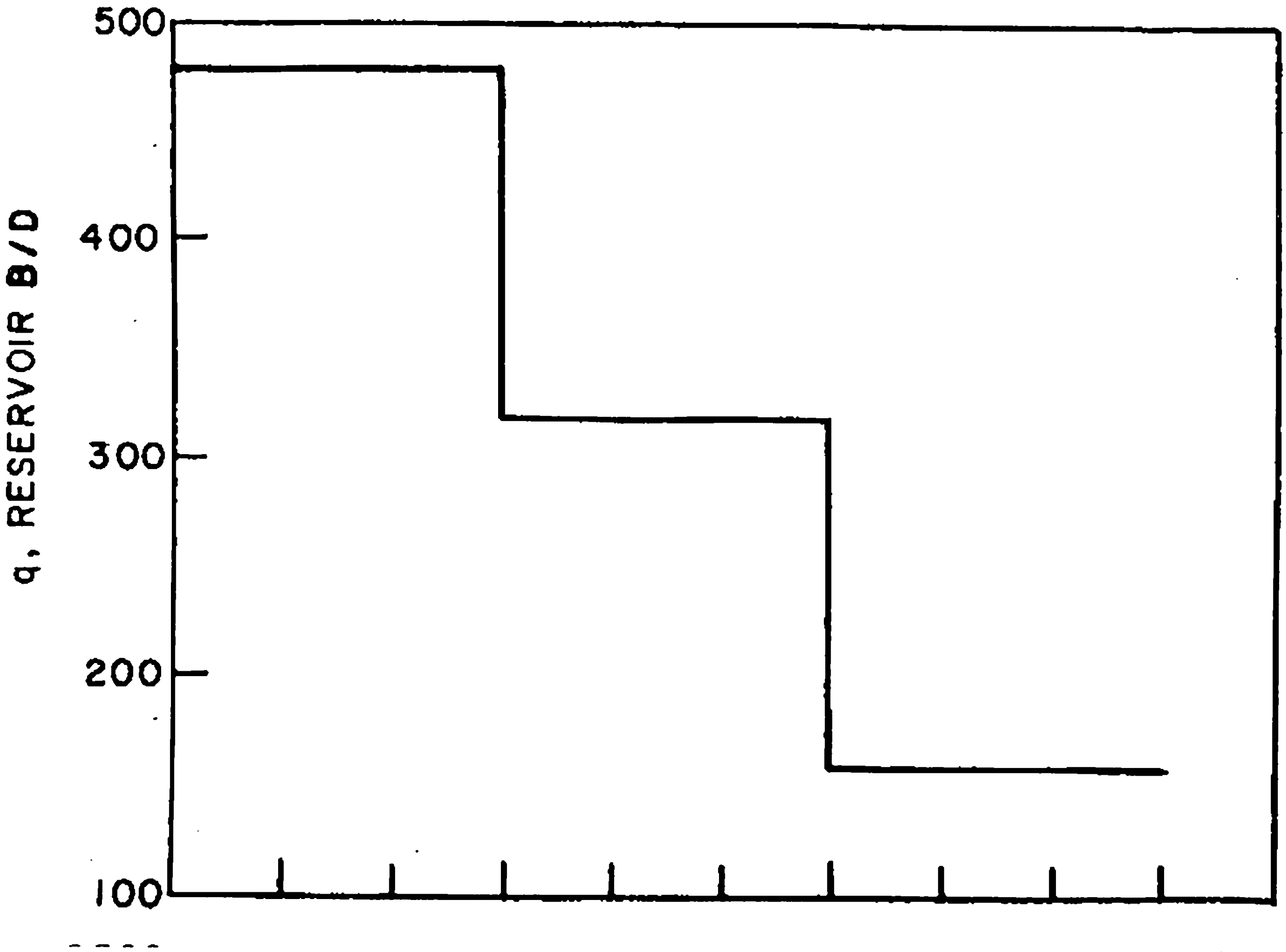


Fig.3.3. Multirate flow test analysis

Two rate flow test Analysis:

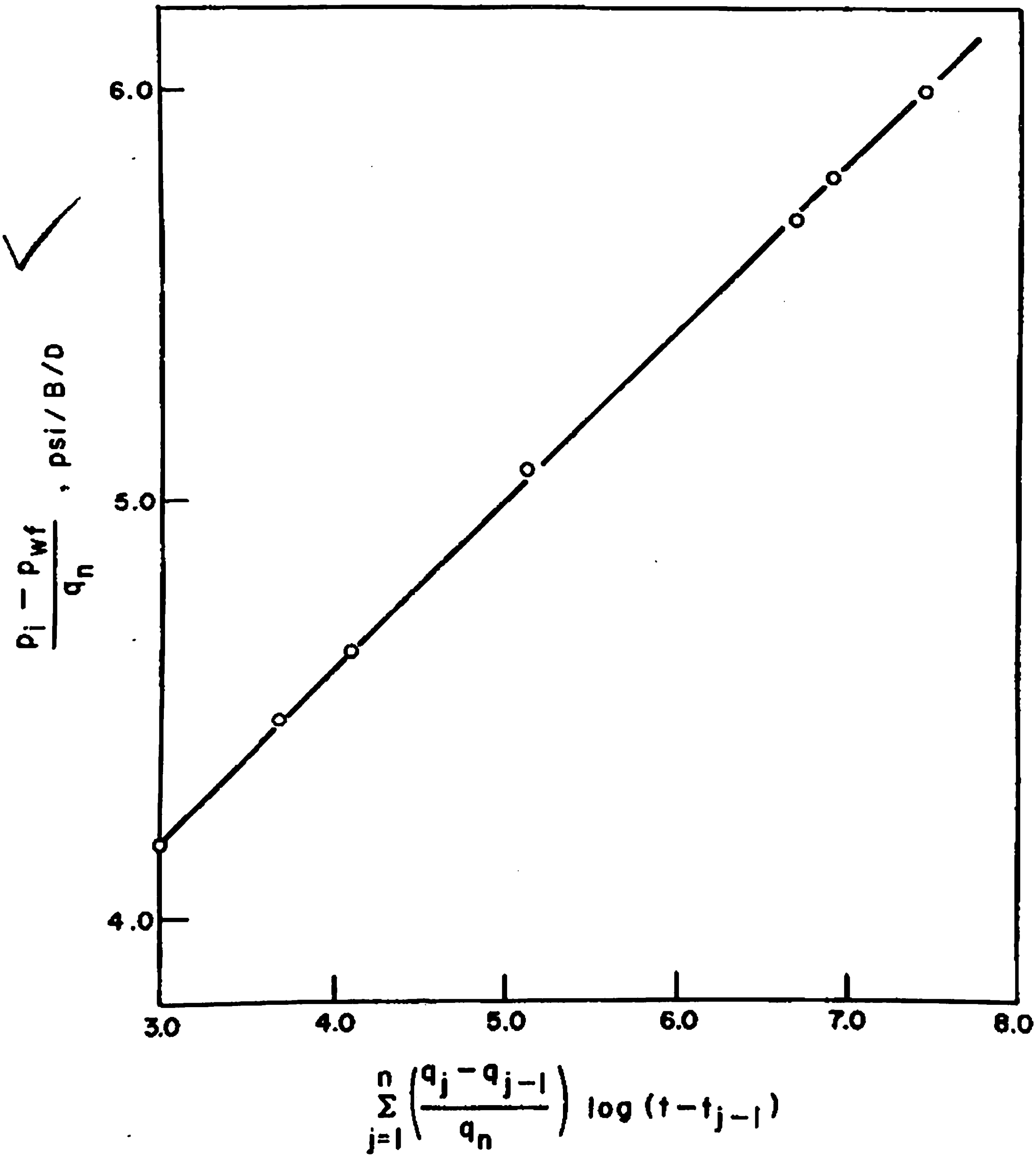


Fig: 3.4. Multiple-rate basic test plot

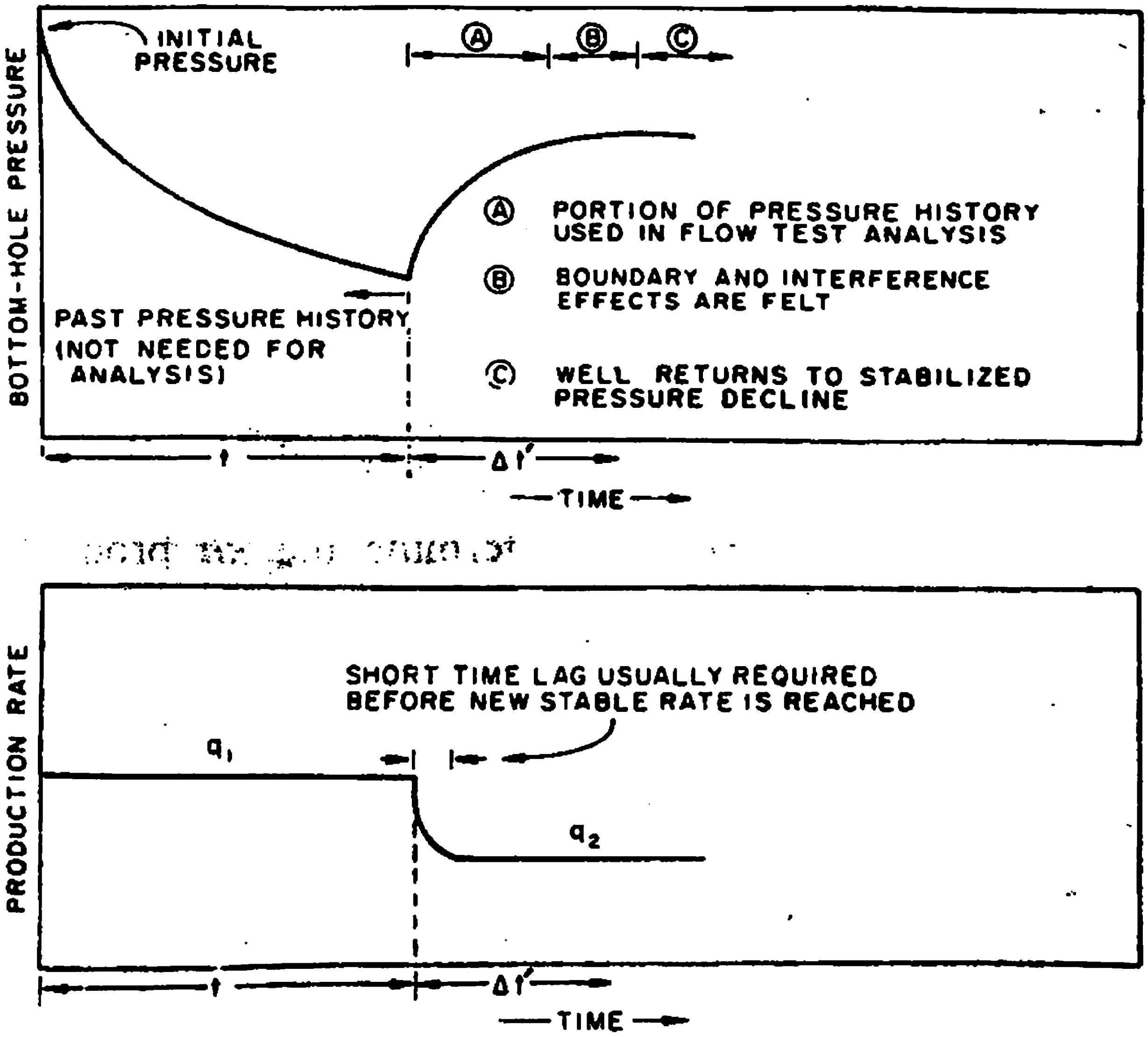


Fig:3.5 Schematic figure for the production rate and pressure performance for the two rate flow test method.

SOME RESTRICTIONS IN TWO-RATE FLOW TEST METHOD

As a final note of our discussion we would like to emphasize that in planning and execution two-rate flow tests, one needs to have an idea of flow characteristics of the well. If the field personnel is not familiar with the behavior of the well, it is advisable to observe the flowing behavior of the well at two or three different flow rates to obtain the general impression of its performance characteristics. By obtaining such observations in advance one is able to make a better choice of flow rates to be used during the flow test. A basic requirement of the two-rate flow procedure is that the well flow without surging or heading at each rate

Well Interference analysis

Why Interference of wells...????

Each well has its own drainage area. Of two wells are in the same drainage area then they start draining oil/gas of other wells, this is then called the interference of the wells as the one well may drain out the oil/gas of the other well. This is then assessed when one well is closed (known as the observation well) and the other wells surrounding the well are put on production, the pressure is measured in the first well. If drop in pressure is observed in the well then the wells are confirmed to be in the same drainage area. Thus the test has following main purposes:

- To determine the connectivity of the reservoir
- To determine directional reservoir flow pattern
- To obtain the quantitative estimation of the porosity that can't be determined from the PBU test

Equations for Pressure Interference

$$p_{ws} = p^* - 162.6 \frac{q\mu B}{kh} \log\left(\frac{t+\Delta t}{\Delta t}\right) + 70.6 \frac{q\mu B}{kh} \left[\sum_{j=1}^{NW} \frac{q_j}{q}\left\{ Ei\left(\frac{-\phi\mu c a_j^2}{0.00105k\,(t_j+\Delta t_j)}\right) - Ei\left(\frac{-\phi\mu c a_j^2}{0.00105 k t_j}\right)\right\}\right] \quad . \quad . \quad . \quad (7.1)^*$$

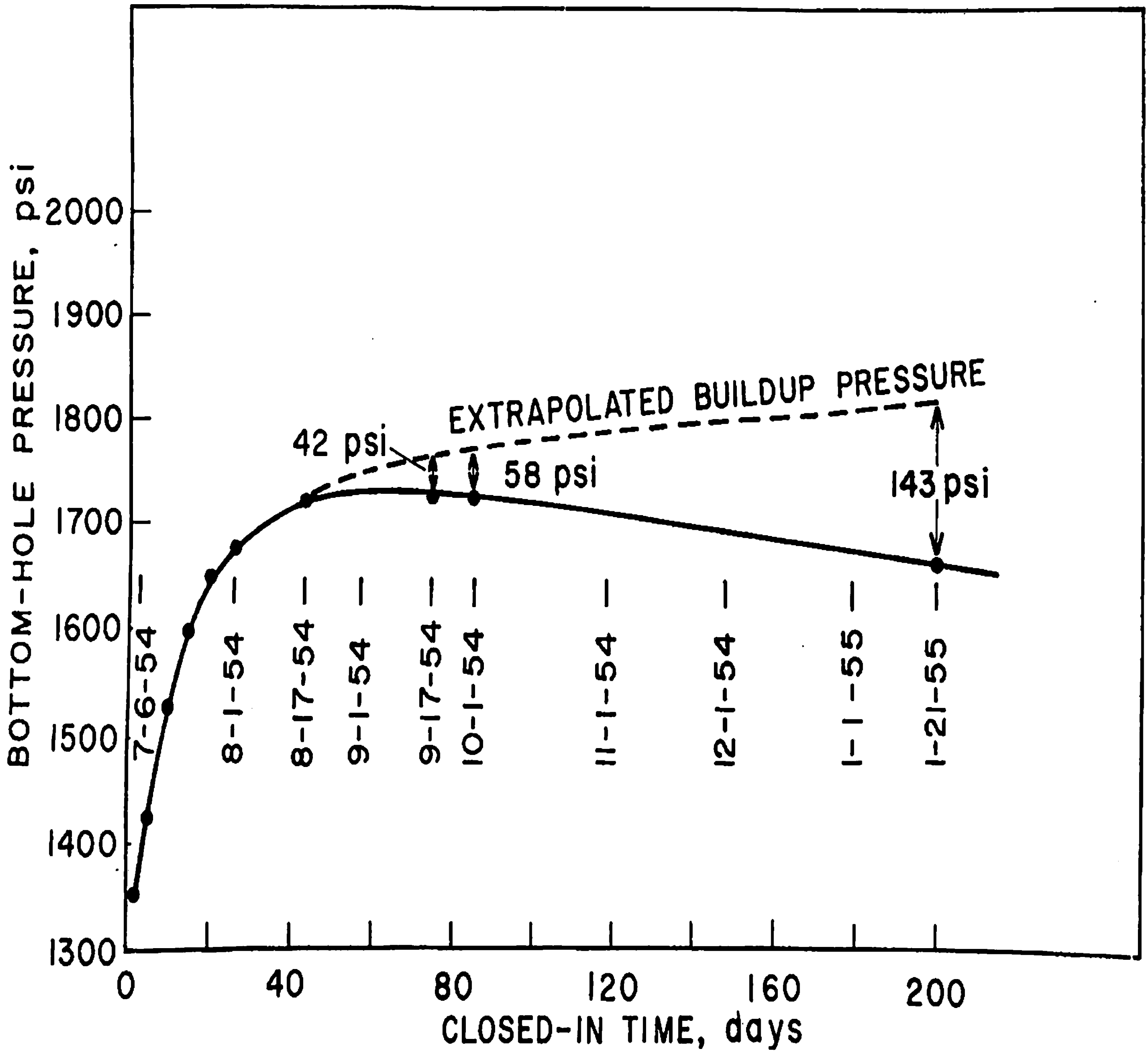
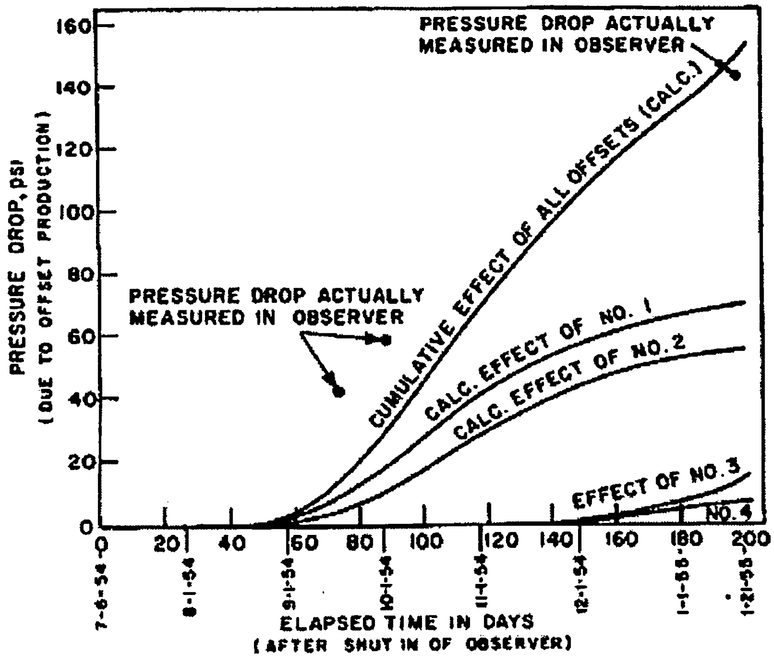


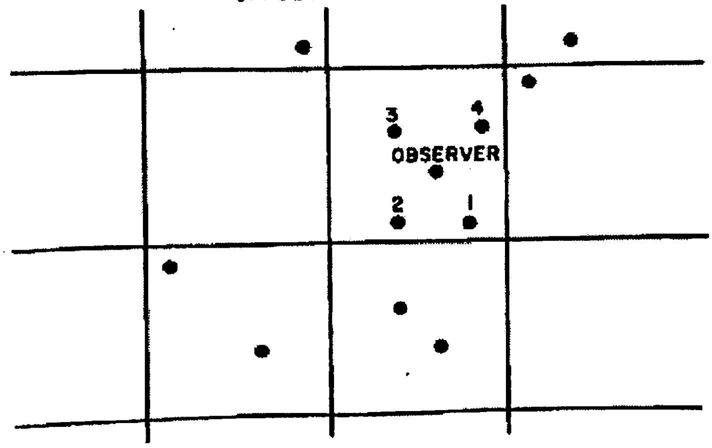
Fig:3.6. Interference test in the low permeability reservoir

LEAST SQUARE METHOD

This is a more precise method for the estimation of diffusivity is the Least square method. To use this method first measure P_{ext}-P_{obs} for each data point . Call the total pressure dropcaused by all thewells at the observer delP_{cal} (delP_{ext}-delP_{cal})^2 for each measured point. Plot a curve of $\sum(P_{obs}-P_{cal})^2$ Vs diffusivity . The value of diffusivity which gives a minimum in this curveis the keast square choice for diffusivity value.



OFFSET WELL PATTERN



OTHER METHODS FOR COMPUTING INTERFERENCE

A noval method of interference determination by ***"Pulse Testing"*** has been developed by Johnson et al. In this method a production well near the observation well is alternately produced and then closed alternatively to give a series of pressure pulses. The pulses are detected at the observation well by a very accurate (.0001 psi) pressure gauge. Use of this pressure gauge allows the interference pressure pulses to be detected much more rapidly than with normally used helical Bourdon-tube gauge. A potentially more powerful method than any of the foregoing is that of the general simulation on a digital computer.

PRESSURE ANALYZIZ IN INJECION WELLS

Injectivity test/Pressure Fall -off test:

It is of considerable interest and importance to be able to determine the characteristics of the reservoir in an area surrounding a water injection well. If we can determine early in life of an injection well that there is an appreciable "skin effect", remedial measures can be started before full scale pattern flood begins. Similarly, if we can show that a gradual buildup of skin effect is occurring with time , we can take measures to free the water of plugging material. Determination of static pressure in a water injection well may show that the water is entering a thief zone and not the desired reservoir. Finally, determination of k of sand around an injection well will allow estimation of the future relation between injection pressure and rate.

In water injection wells, it is natural to attempt to determine formation properties by closing the well and using familiar pressure buildup methods. The basic assumption for this method are same as that for pressure buildup theory. The reservoir is assumed to be homogeneous, of constant thickness and to contain a single fluid of small and constant compressibility. Prior to shut-in water is injected at constant rate through a well which completely penetrates the formation. The pressure is assumed to be constant at a radius r from the well, as will be discussed below:

For this case pressure behavior is described by the following equation

$$p_{ws} = p_e + \frac{i\mu}{4\pi kh} \ln\left(\frac{t+\Delta t}{\Delta t}\right) + \text{constant.}$$

Thus, the slope of the fall-off curve may be interpreted in terms of kh exactly in the same in PBU. The skin effect and well damage can be obtained in the same way as for the PBU.

Unit Mobility Ratio

Prior to reservoir fill-up, the oil and water banks may be idealized as shown in the followoing figure. The fluid distribution is also shown:

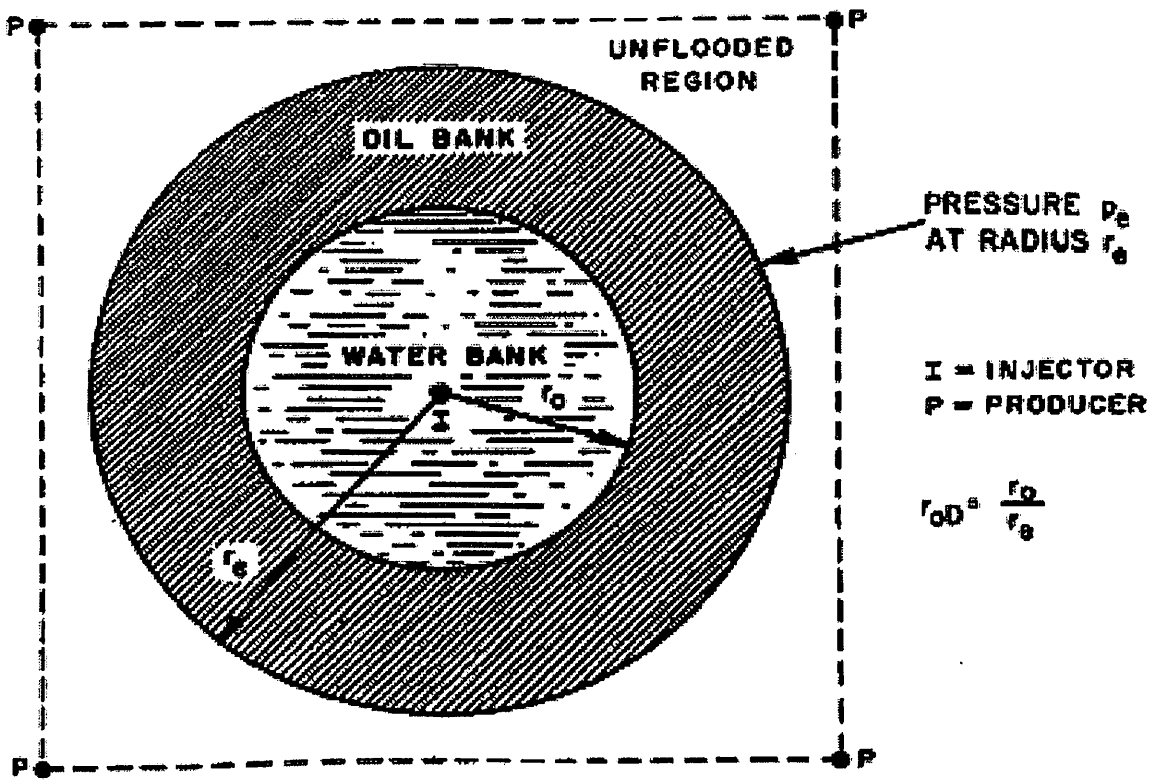


Fig: 3.7. **Oil and Water Bank**

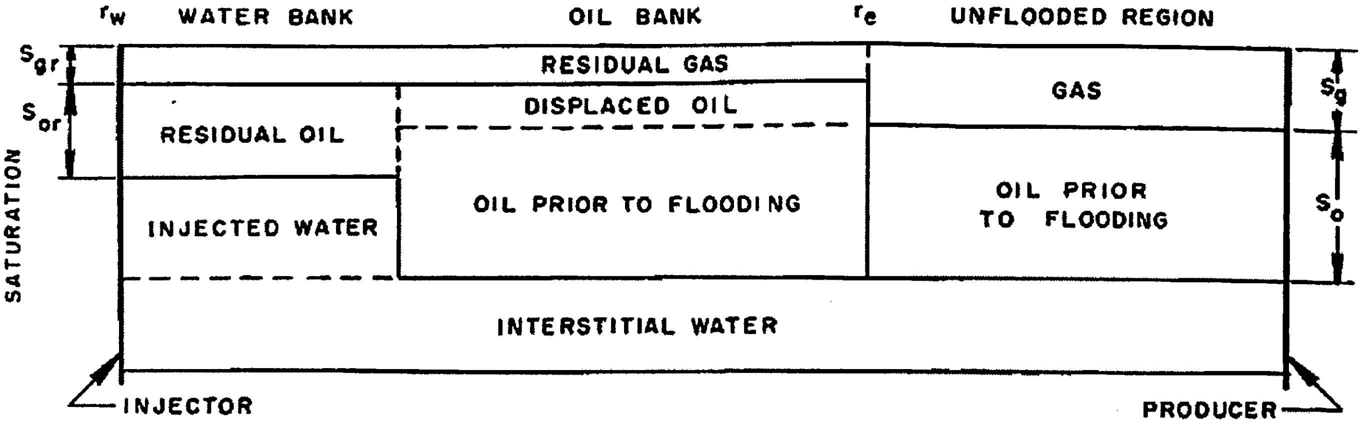


Fig: 3.8. Fluid saturation profile in the reservoir

A mathematical solution for the pressure behavior in this case was developed by the Hazebroke et al. They show that even in the presence of gas saturation one can still use the single fluid method just discussed provided that oil and water have about the same properties. But, the one difficulty in this conventional method is that of finding the correct straight line portion of the fall-off curve. For this reason it is difficult to know whether the correct slope and correct extrapolation to P^* have been used. The wellbore will be full of liquid at the time of injection is stopped at the surface. The surface pressure will often bleed off in a few minutes; but since the wellbore is still full injection will continue at a reduced rate. Until this rate falls to a new value no straight –line pressure fall-off section will be observed.

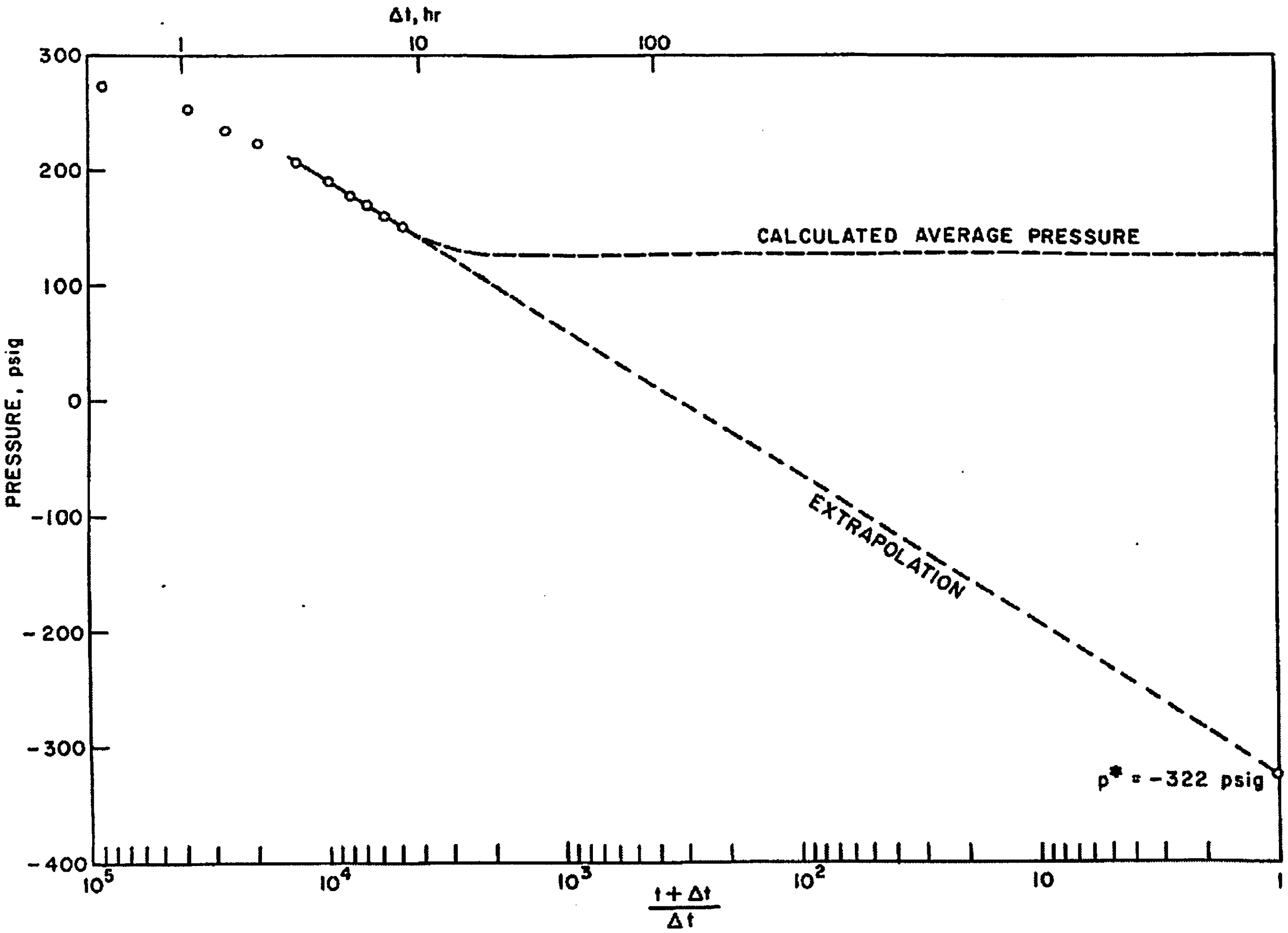


Fig:3.9. PRESSURE FALL-OFF CURVE

To overcome this difficulty with finding the straight line portion a new method was developed by Hazbroek et al. For this fluid banks and saturation shown in the above figures. Two possibilities were considered. For case A, the surface pressure decreases slowly and the well stays filled up to the top for considerable closed in time. This happens when the reservoir pressure is high After- flow into the formation in those case small since it results only from expansion of fluid in the well as the pressure decreases. For case B, the surface pressure drops to zero at a short time after closing in, after which the liquid level in the well starts to sink. In this case the volume of inflow into the formation at any time is equal to the volume of the the wellbore column between the top of the well and the liquid level at the time of interest. For both the conditions it was found that the injection well closed –in pressure is given by the following equation

$$p_{ws} = p_e + b_1 e^{-\beta_1 \Delta t}$$

Two –Rate Injection Test Analysis

As might be expeted, a procedure similar to the two-rate flow tst method can also be used for analysis of fluid injection wells. This procedure has an advantage over the conventional fall-off methods for cases in which the surface pressure falls to zero after cessation of injection. To obtain pressure data after closing such wells, a bottomhole pressure bomb must be run. With the two rate procedure, a pressure generally persists throughout the two-rate transient injection test.

THEORY:

We begin by making the same asuumtions for the unit mobility ratio cylindrical case.From the results of Hazebroek, Rainbow and Matthews and Muskat, it can be shown that the pressure behavior of the well at time ***del T*** after the change in injection rate is given by the following equation:

$$\log\left(p_{iw} - \left\{\bar{p} + \frac{i_2}{i_1}[p_w - \bar{p}]\right\}\right) = \log\frac{181.2\,(i_1 - i_2)\,\mu}{kh} - 0.000664\,\frac{k\Delta t'}{\phi\mu c r_e^2}, \quad . \quad . \quad (8.12)$$

Where P_{iw}= injection well pressure after change in rate.
P_w = injection well pressure at the time of change in rate.

We see from the equation that if we plot $\log\left(p_{iw} - \left\{\bar{p} + \frac{i_2}{i_1}[p_w - \bar{p}]\right\}\right)$ vs $\Delta t'$ the plot should be linear; and from the intercept value we find

$$kh = \frac{181.2\,(i_1 - i_2)\,\mu}{b}$$

Value of the skin factor is determined by the following equation:

$$s = \frac{p_w - \bar{p}}{141.2 \frac{i_1 \mu}{kh}} - \ln \frac{r_e}{r_w} \quad . \quad . \quad .$$

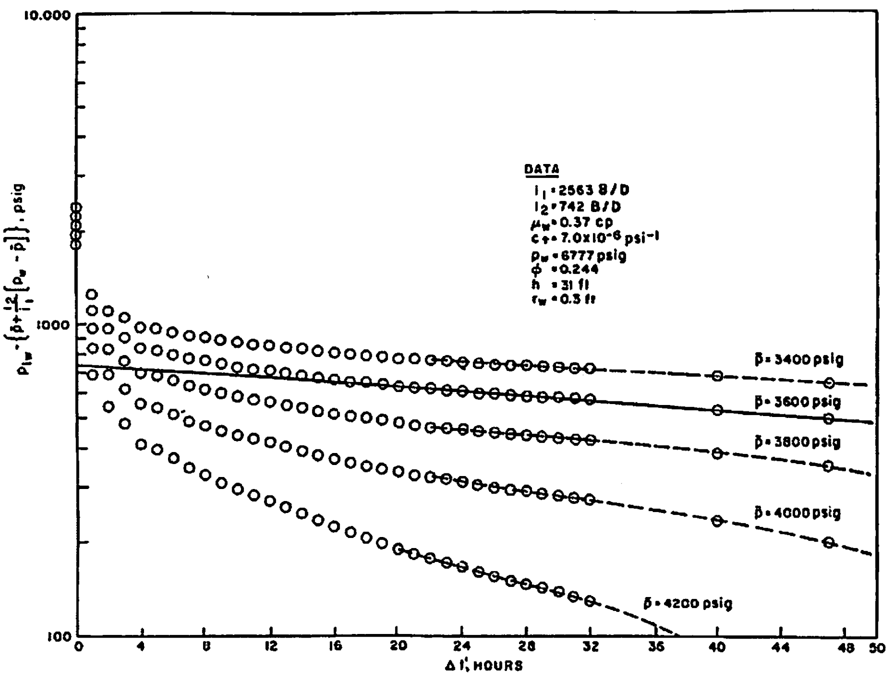


Fig:3.10*Two –Rate Injection test Analysis*

Gas Injection Wells

There is a modification in these wells. The modification consists in determining and using the formation volume factor B, the quantity which is neglected in the case of water injection because it was close to unity. The value of B is determined at the arithmetic average of the pressure P^* and P_w. The best recourse for gas reservoir is probably as follows:

1.For gas injection in miscible projects, apply unit mobility ratio. In using this method choose area A as the area of the injected gas bank. In doing so expansion of the solvent and oil out side the gas. This is justifiable because of the much higher compressibility of gas.

2.For gas injection into the oil reservoir, non- miscible case, apply the same method modified for the two phase flow in applying this case , it will be necessary to calculate total mobility and total compressibility. Total compressilibility C_t may be calculated as follows:

$$(k/\mu)_t = k_o/\mu_o + k_g/\mu_g .$$

Effect Of Reservoir Heterogeneities on Pressure Behavior

1.Pressure behavior near faults and other impermeable barriers

The pressure behavior of a well near a fault or other flow barrier in an infinite reservoir is presented by Horner. The pressure behavior in this case is explained by the **"method of images".** In this formulation, the effect of a fault is simulated by assuming the presence of a another identical well producing at a symmetrical position across the fault and then removing the fault. The image will interact with the real well so that no flow occurs across the fault. The resulting pressure drop in the real well due to its own production and the interference drop from the image well add together to simulate correctly the pressure behavior of the real well as though it were in the proximity of the fault.

Mathematically, if a well is located at a distance d from the fault, then its pressure behavior during flow at a constant rate is given by the following equation:

$$p_{wf} = p_i + \frac{q\mu}{4\pi kh}\left[Ei\left(-\frac{\phi\mu c r_w^2}{4kt}\right) + Ei\left(-\frac{\phi\mu c d^2}{kt}\right) + 2s\right] \quad . \; . \; .$$

The PBU in ideal case can be obtained by employing the following equation:

$$p_{ws} = p_i + \frac{q\mu}{4\pi kh}\left[Ei\left(-\frac{\phi\mu c r_w^2}{4k\,(t+\Delta t)}\right) - Ei\left(-\frac{\phi\mu c r_w^2}{4k\Delta t}\right) + Ei\left(-\frac{\phi\mu c d^2}{k(t+\Delta t)}\right) - Ei\left(-\frac{\phi\mu c d^2}{k\Delta t}\right)\right] \quad . \; . \; . \; . \; . \quad (10.2)$$

For **t** becomes sufficiently large, the above equation becomes

$$p_{ws} = p_i - \frac{q\mu}{4\pi kh}\left[\ln\frac{t+\Delta t}{\Delta t} - Ei\left(-\frac{\phi\mu c d^2}{k(t+\Delta t)}\right) + Ei\left(-\frac{\phi\mu c d^2}{k\Delta t}\right)\right] \quad . \; . \; . \; . \; . \; . \quad (10.3)$$

$$p_{ws} = p_i - \frac{q\mu}{4\pi kh}\left[\ln\frac{t+\Delta t}{\Delta t} - Ei\left(-\frac{\phi\mu c d^2}{kt}\right)\right] \quad \ldots\ldots\ldots\ldots (10.4)$$

for very small value of **d**

This equation tells us that the slope of the normal pressure build up plot will be unchanged for the early part of the pressure buildup.

As del **t** becomes large the equation becomes

$$p_{ws} = p_i - \frac{q\mu}{2\pi kh}\ln\frac{t+\Delta t}{\Delta t}$$

From this equation we see that the slope of the second part(late time) of the buildup curve is exactly double that of the early part. Also, the late time portion of the curve must be used to obtain the extrapolated pressure. The doubling of the slope is the differentiation of the pressure behavior of a well near fault. A theoretical example of a pressure buildup in well located near a fault is shown as follows:

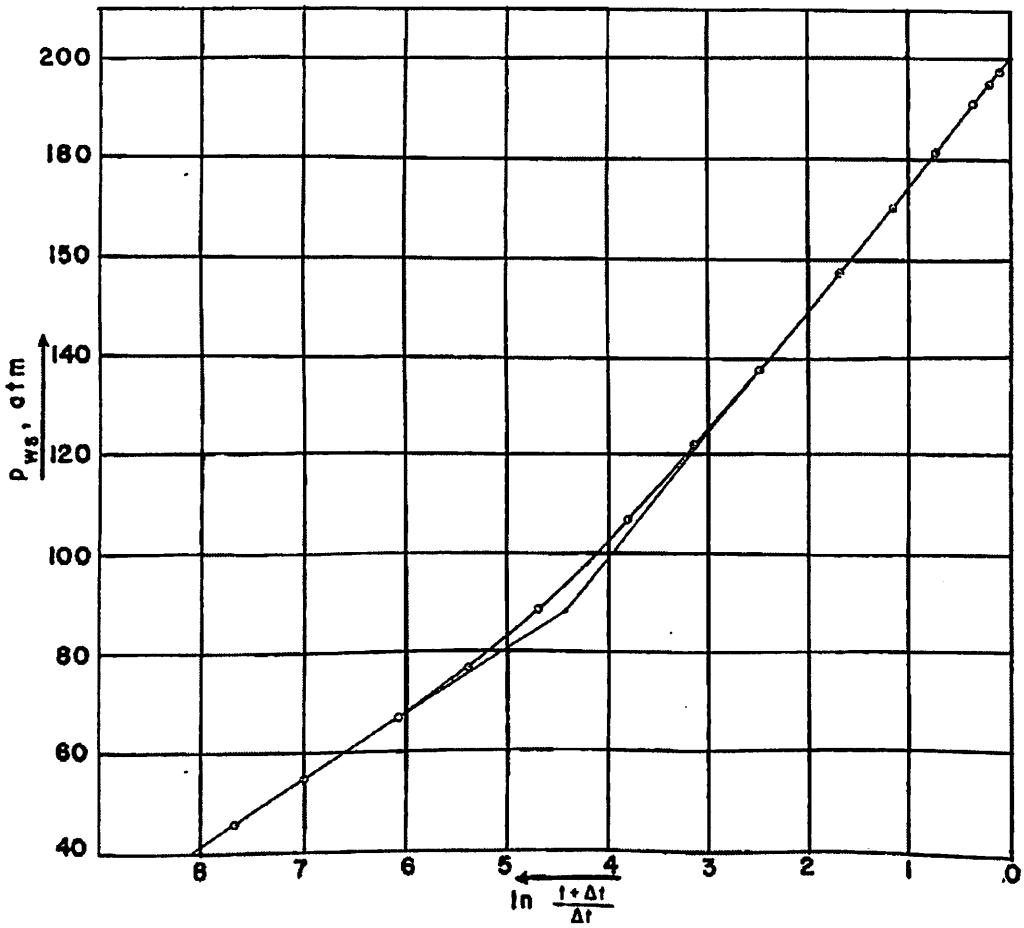


Fig:4.1. Pressure behavior in presence of fault

2. Pressure behavior in layered reservoir

In reservoirs composed of stratified layers, the most important question is whether there is significant interlayer pressure and fluid communication or lack of it. If unrestricted interlayer crossflow can occur, the reservoir behavior will be analogous to that of a single layer reservoir having the average properties of the layered system. If the discrete reservoir layers communicate only by means of a common wellbore, then they will perform in a much different manner.

The performance of bounded reservoirs composed of stratified layers was investigated theoretically for the crossflow case. Each layer was assumed to be homogeneous and isotropic but of different porosity and permeability. It is imimportant to realize that a constant producing rate from each, layer is not assumed. Rather the total rate is assumed constant. This means, then that differential depletion between the layers can cause their respective producing rate to vary semi-steady state conditions are attained. During the early time at which drainage boundary effects have not been felt, the pressure behavior at the well in the two-layer case is given by :

$$\frac{p_i - p_{wf}}{\dfrac{q_t\mu}{4\pi(kh)_t}} = \ln t - \ln \gamma$$

$$- \frac{k_1h_1 \ln \dfrac{\phi_1\mu c r_w^2}{4k_1} + k_2h_2 \ln \dfrac{\phi_2\mu c r_w^2}{4k_2}}{(kh)_t}$$

Where $(kh)_t = k_1h_1 + k_2h_2$,

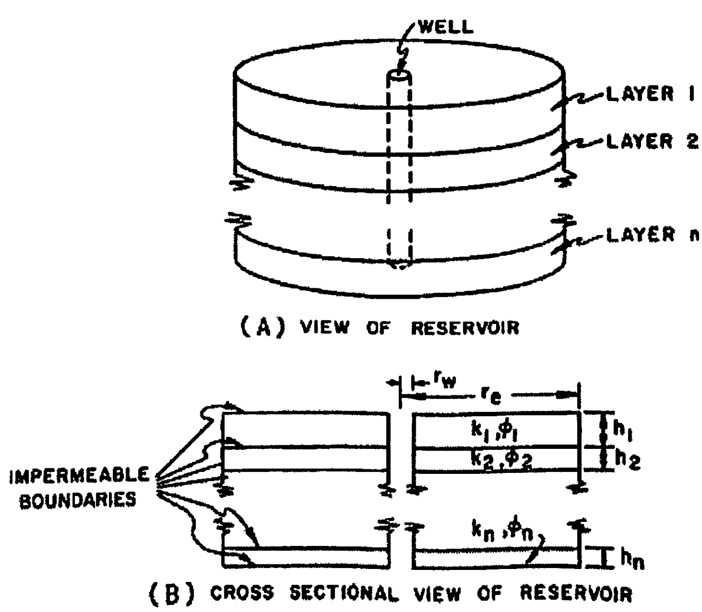
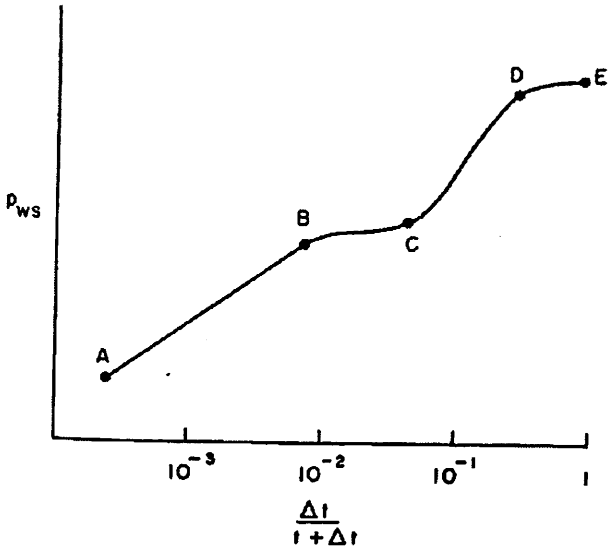
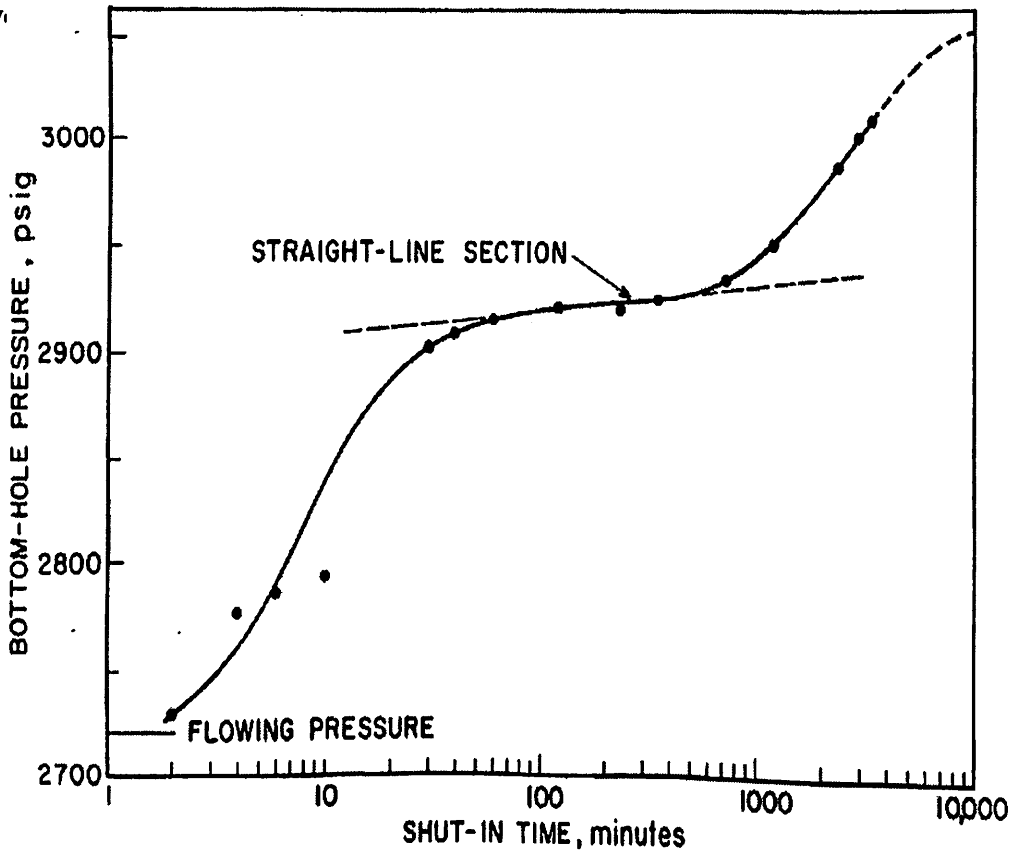


Fig:4.2. Various view of the Reservoir



As shown in the above figure is the theoretical pressure build up curve for a two layer reservoir. As in a single-layer reservoir there is an initial straight-line Section AB. After the straight line portion, the buildup curve off(BC). This leveling off corresponds in a single layers reservoir to the pressure's having almost reached it as average value. However, in a two-layer reservoir the pressure again rises (CD), and then finally levels off at the average pressure(DE). The rise in the portion CD is due to the repressurizing of the more depleted, more permeable layer by the less depleted and less permeable layer. The Section (BC) may have a slope only slightly less than of Section (AB), and thus the two sections may be indistinguishable in some practical situations as shown in the following figure. The slope of the straight line portion of the curve is used to calculate the value of $(kh)_t$. It is obvious that the curv



In case of ***Cross-flow*** situation the pressure behavior of the well is given by the following equation:

$$p_{wf} = p_i - \frac{162.6q\mu B}{(kh)_t}\left[\log \frac{(kh)_t\, t}{(\phi h)_t \mu c r_w^2} - 3.23\right]$$

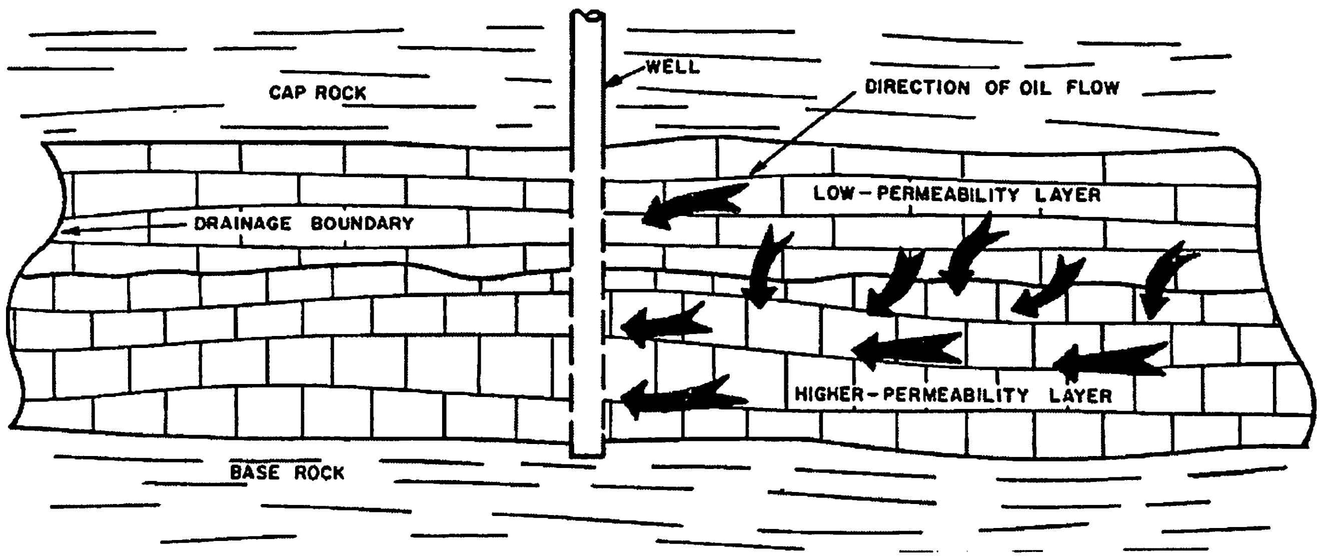


Fig: 4.2. Crossflow situation in a reservoir

From the difference between pressure behavior with and without crossflow,it is sometimes possible to infer the presence or absence of crossflow. If the well flows, one should be able to detect crossflow either from pressure drawdown or from the pressure build up tests.

3. Pressure Behavior in Naturally Fractured Formations

The idealization of a heterogeneous porous medium which was used by Warren and Root is shown . The primary porosity system is homogeneous and isotropic, and is contained within an array of identical parallelopipeds. All of the secondary porosity is contained within an orthogonal system of continuous, uniform fractures of uniform permeability. Flow can occur in the fracture system only. It is also assumed that semi-steady state flow occurs on a local basis between the primary and secondary systems i.e.; flow between the two systems at any point propotionalto the pressure difference between the two systems at that point.

The mathematical solution presented by Warren and Root for the case of pressure behavior at constant flow rate will not be repeated here. Rather, we shall present some results from numerical evaluation of the solution. All the results shown are for the infinite reservoir case and are described bt two basic parameters:

$$\omega = \phi_2 c_2 / (\phi_1 c_1 + \phi_2 c_2)$$

and

$$\lambda = \alpha k_1 r_w^2 / \bar{k}_2 \ ,$$

where c_1 = total compressibility, primary system,

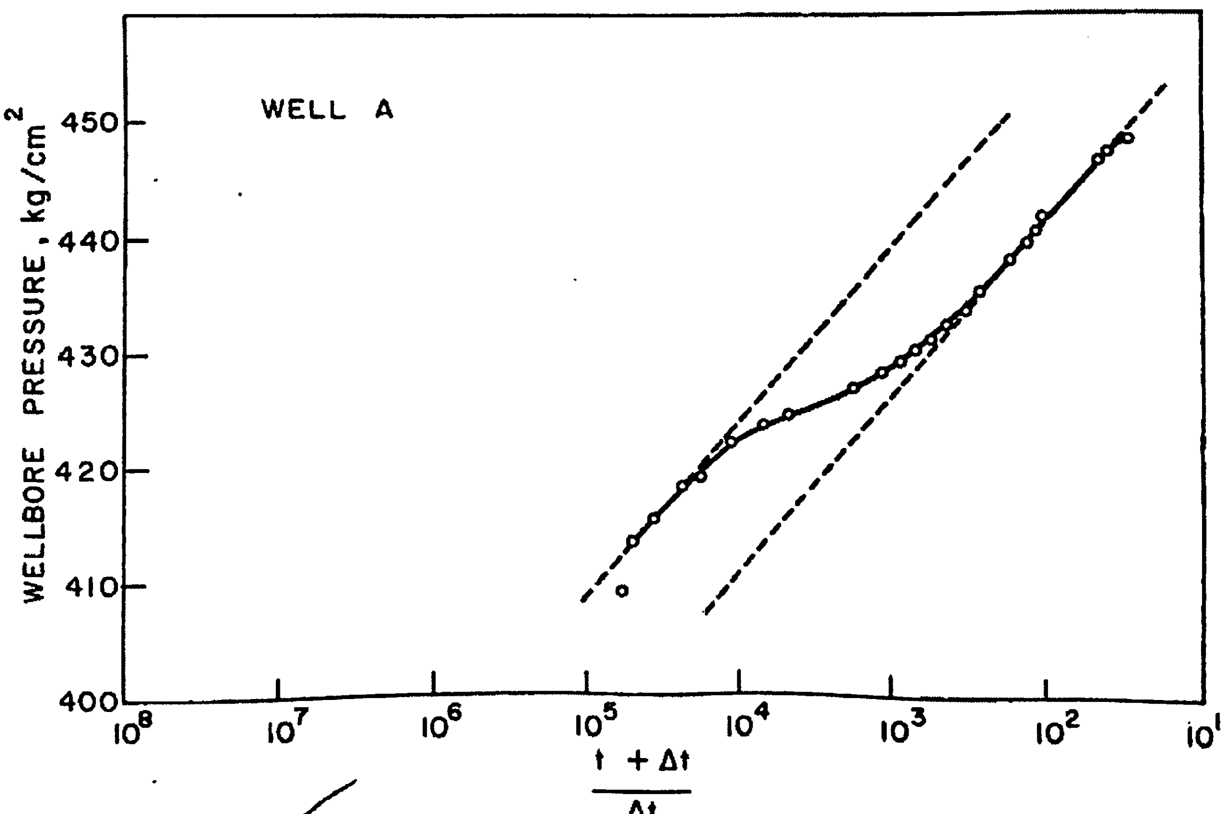
c_2 = total compressibility, secondary system,

k_1 = matrix permeability,

$\bar{k}_2$ = effective permeability, fractures, and

α = shape factor controlling flow between two systems.

A field example of a build up curve from a fractured reservoir displaying the parallel sections is shown on the figure below:



It should be noted that pressure behavior in naturally fractured reservoirs is similar to that obtained in layered reservoirs with no crossflow. In fact, in any reservoir system with two predominant rock types, the pressure buildup behavior is similar t that of the following figure. The geometry of the fractured system, the permeability involved and the pore volume of each rock type combine to yield system which are far too complex for precise analysis with presently known techniques. There may be a future for probabilistic reservoir models in aiding description and analysis of these complicated systems.

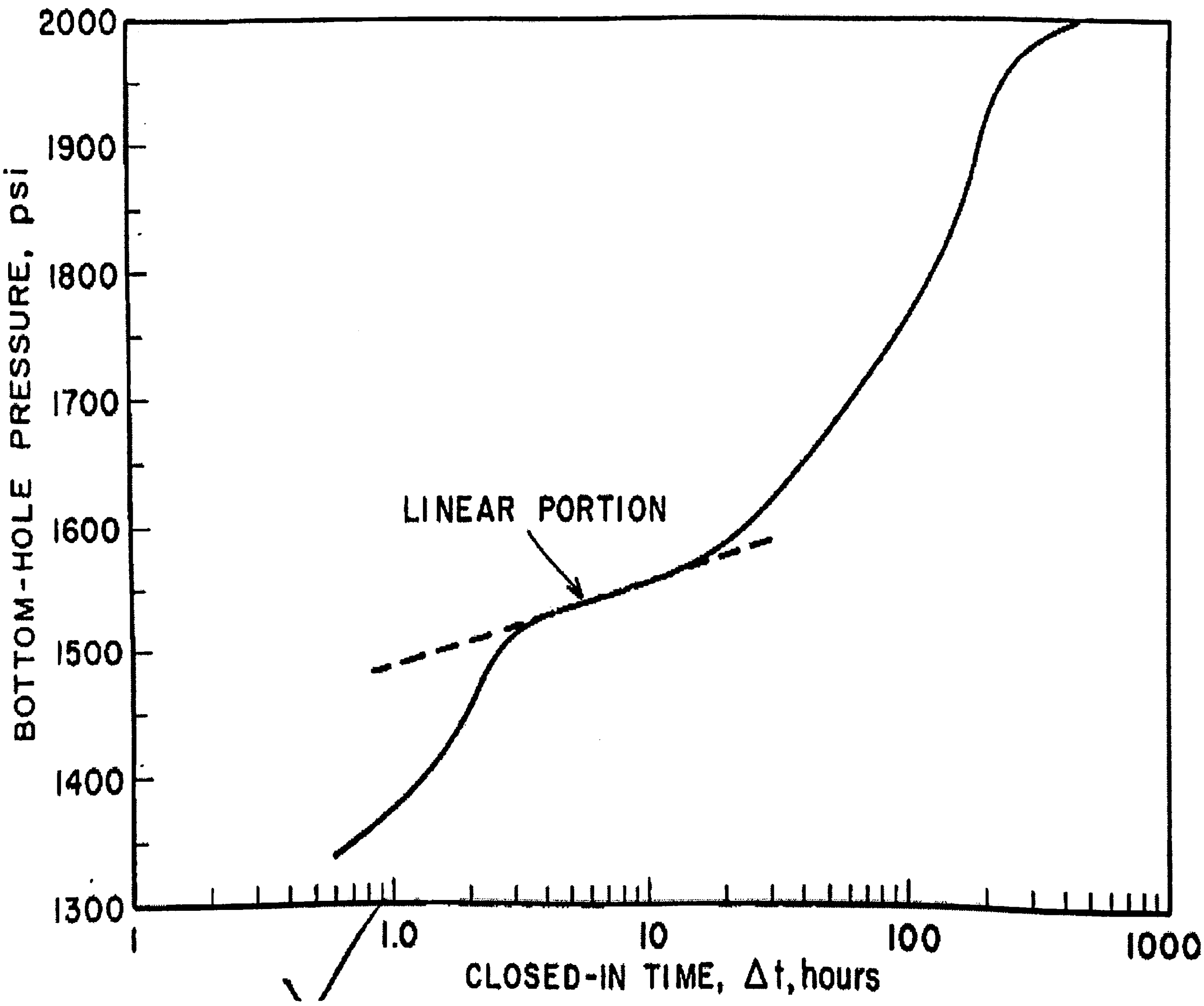


Fig:4.3. Build up in a fissured limestone

4.**Pressure Behavior in Non-symmetrical Drainage Areas**

Pressure behavior in non-symmetrical drainage area was studied by Matthews, Brons and Hazebroek. By employing the method of images to calculate reservoir pressure behavior for a large number of different reservoir shapes theses authors have established that the pressure drop for any reservoir shape and all but very early times is given by the following equation:

$$p_i - p_{wf} = \frac{q\mu}{4\pi kh}\left[\ln\frac{kt}{\phi\mu cA} + 4\pi\frac{kt}{\phi\mu cA} - F\left(\frac{kt}{\phi\mu cA}\right) + \ln\frac{A}{r_w^2} + 0.809 + 2s\right], \qquad (10.18)$$

where A is the area of drainage and $F\left(\frac{kt}{\phi\mu cA}\right)$ is a shape-dependent time function given by

$$F\left(\frac{kt}{\phi\mu cA}\right) = \frac{p^* - \bar{p}}{\frac{q\mu}{4\pi kh}},$$

Where

Brons and Miller have shown for the semisteady state conditions that

$$F\left(\frac{kt}{\phi\mu cA}\right) = \ln\frac{C_A kt}{\phi\mu cA}$$

Where C_A is a shape dependent constant whose value has been tabulated.

Combination of the above equations yields following expression for the semisteady state condition

$$p_i - p_{wf} = \frac{q\mu}{4\pi kh}\left[4\pi\frac{kt}{\phi\mu cA} - \ln C_A + \ln\frac{A}{r_w^2}\right.$$

$$\left. + 0.809 + 2s\right] \quad . \ . \ .. \ . \ . \quad (10.20)$$

If we note that

$$p_i - \bar{p} = \frac{qt}{\phi chA},$$

Then the above equation becomes

$$\bar{p} - p_{wf} = \frac{q\mu}{4\pi kh}\left[\ln\frac{A}{C_A r_w^2} + 0.809 + 2s\right] \quad . \ . \ . \ . \ . \ . \ . \ . \ . \quad (1$$

MATHEMATICAL ANALYSIS OF THE WELL TESTING METHODS

Calculation For the Pressure Build Up Analysis

Reservoir above bubble point

Test Data:

Test Date	**January 4, 1951**
Producing Formation	**Dolomite**
Hole Size (inches)	**4¾**
Cum. Prod. N_p (bbl)	**142,010**
Stabilized Daily Prod. q (bbl)	**250**
Effective Prod. Life t (hr) $=24\ N_p/q$	**13,630**

Company	**Shell**
Lease	**Lend**
Well No.	**1**
Field	**Center**
State	**Texas**

Solution: Refer to the figure shown below:

I. Calculation of kh (md-ft) and k (md):

$$kh = \frac{162.6\, q\mu B}{m}\ ;\ k = \frac{kh}{h}.$$

h 69.0 ft

q 250 B/D

μ 0.80 cp

B 1.136

m 70 psi/cycle

$$kh = \frac{162.6 \times (250) \times (0.80) \times (1.136)}{(70)} = \underline{527.7} \text{ md-ft};\quad k = \frac{(527.7)}{(69)} = \underline{7.65} \text{ md}.$$

II. Calculation of Skin Effect, s; and Pressure Loss Due to Skin, Δp_{skin} (psi):

$$s = 1.151\left[\frac{p_{1\,hr} - p_{wf}}{m} - \log\left(\frac{k}{\phi \mu c r_w^2}\right) + 3.23\right].$$

$$\Delta p_{skin} = (m) \times 0.87\,(s).$$

k 7.65 md

ϕ 0.039

μ 0.80 cp

c 17×10^{-6} psi^{-1}

r_w 2.375/12 ft

$p_{1\,hr}$ 4,295 psig

p_{wf} 3,534 psig

m 70 psi/cycle

$$s = 1.151\left[\frac{(4{,}295) - (3{,}534)}{(70)} - \log\frac{(7.65)(144)}{(0.039)(0.80)(0.000017)(5.64)} + 3.23\right] = \underline{6.37}\ .$$

$$\Delta p_{skin} = (70) \times 0.87\,(6.37) = \underline{388} \text{ psi}.$$

III. Calculation of Productivity Index (B/D-psi) and Flow Efficiency:

$$J_{(actual)} = \frac{q}{p^* - p_{wf}}$$

$$J_{(ideal)} = \frac{q}{(p^* - p_{wf}) - \Delta p_{skin}}$$

Δp_{skin} 388 psi

q 250 B/D

p^* 4,585 psig

p_{wf} 3,534 psig

$$J_{(actual)} = \frac{(250)}{(4{,}585) - (3{,}534)} = \underline{0.238} \text{ B/D-psi}.$$

$$J_{(ideal)} = \frac{(250)}{(1{,}051) - (388)} = \underline{0.377} \text{ B/D-psi}.$$

$$\text{Flow Efficiency} = \frac{J_{(actual)}}{J_{(ideal)}} = \frac{0.238}{0.377} = \underline{0.631}.$$

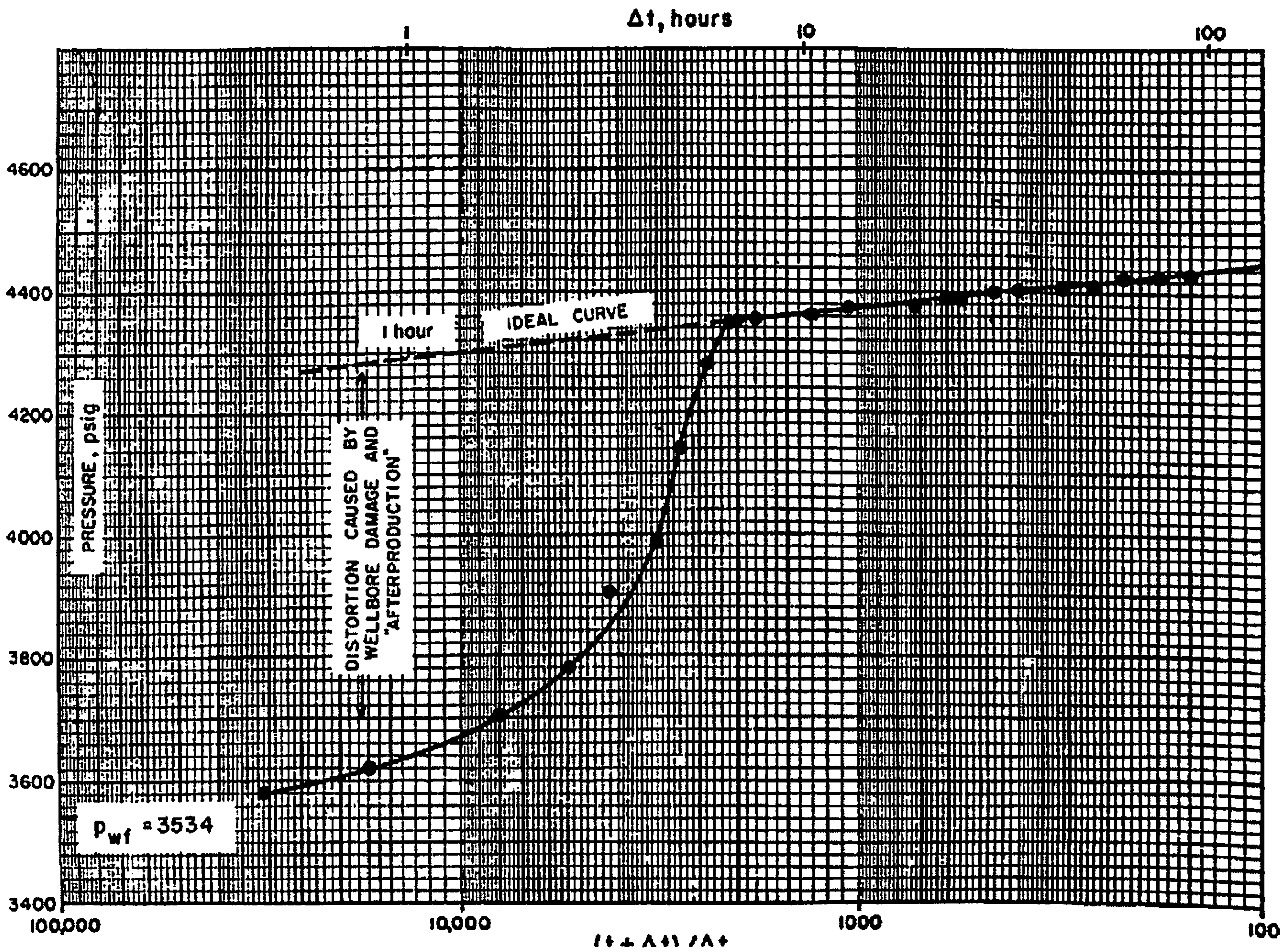


Fig:5.1. Effect of skin on the PBU curve

Compressibility is obtained from

$$c_t = S_o c_o + S_w c_w + c_f = 0.85(11 \times 10^{-6}) + 0.15(3 \times 10^{-6}) + 7.2 \times 10^{-6} = 17 \times 10^{-6}.$$

p^* is obtained by extrapolating two cycles to the right on

$$p^* = 4{,}445 + 2m = 4{,}445 + 2(70) = 4{,}585 \text{ psig.}$$

Reservoir Below Bubble Point

Test Data:

Company	Shell
Lease	Weller
Well No.	4
Field	Edd
State	California

Test Date April 1, 1956

Producing Formation Sandstone

Hole Size (inches) 12

Cum. Prod. N_p (bbl) 33,300

Stabilized Daily Prod. q (bbl) 924 oil, 15.38 MMcf gas (2.740 MM bbl gas)

Effective Prod. Life t (hr) $= 24N_p/q$ 865

Calculations:

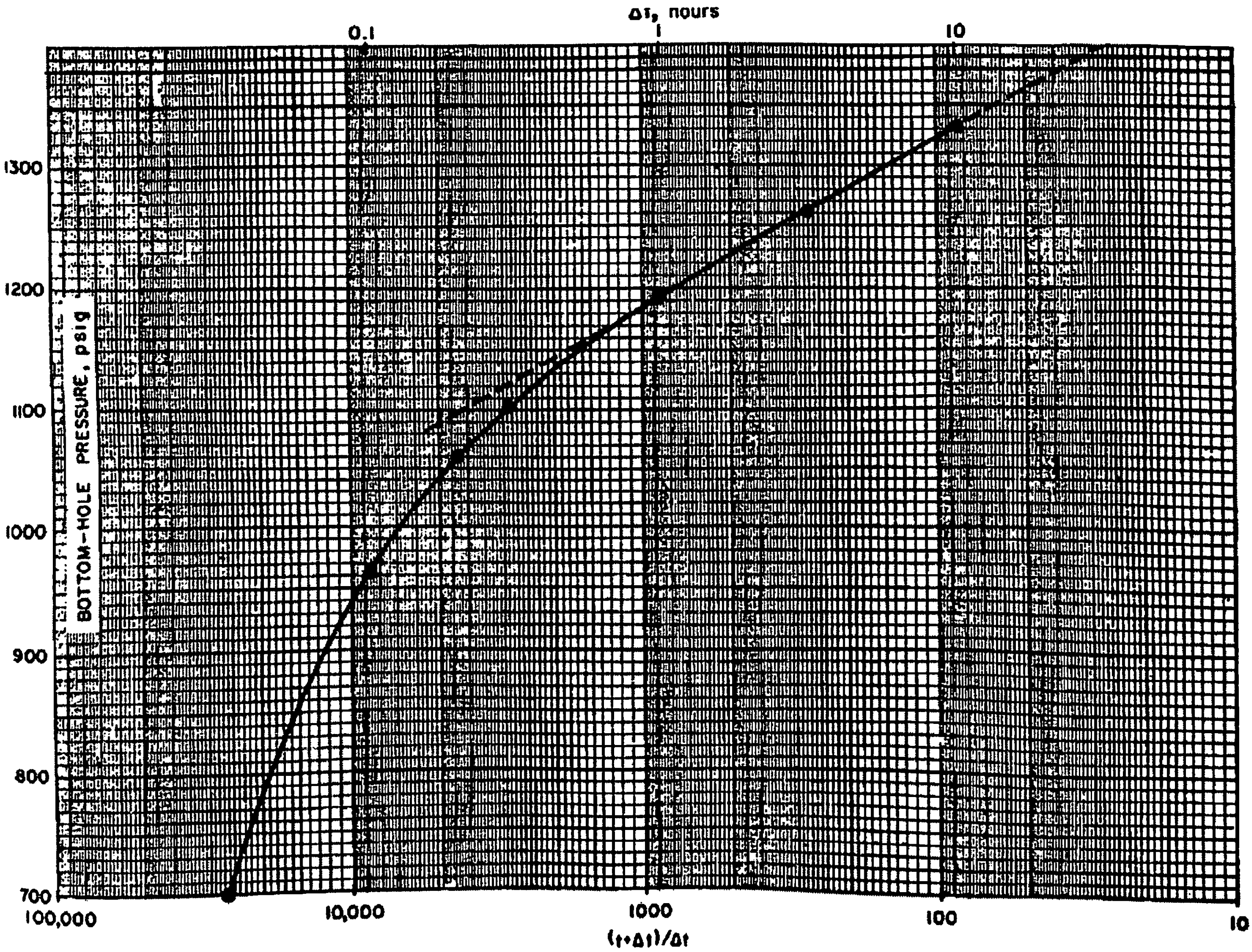


Fig:5.2.Build up curve for reservoir below bubble point

Refer to the figure:5.2 for flowing of both oil and gas

I. Calculation of kh (md-ft) and k (md):

$$kh = \frac{162.6\, q\mu B}{m};\ k = \frac{kh}{h}.$$

h	20	ft
q	924	B/D

B_g	12.9×10^{-3}	bbl/bbl
R_s	298 ft³/bbl or 53.1	bbl/bbl
μ_o	0.675	cp
B_o	1.227	
m	135	psi/cycle

$$kh = \frac{162.6 \times (924) \times (0.675) \times (1.227)}{(135)} = \underline{922} \text{ md-ft};\ k = \frac{(922)}{(20)} = \underline{46.1} \text{ md.}$$

II. Calculation of Skin Effect, s; and Pressure Loss Due to Skin, Δp_{skin} (psi):

$$s = 1.151\left[\frac{p_{1\,hr} - p_{wf}}{m} - \log\left(\frac{k}{\phi\mu c r_w^2}\right) + 3.23\right].$$

$$\Delta p_{skin} = (m) \times 0.87\,(s).$$

k/μ	2,159	md/cp
ϕ	0.15	
c	0.000376	psi⁻¹

r_w	6/12	ft
$p_{1\,hr}$	1,195	psig
p_{wf}	240	psig
m	135	psi/cycle

$$s = 1.151\left[\frac{(1{,}195) - (240)}{(135)} - \log \frac{(2{,}159)\,(144)}{(0.15)\,(0.000376)\,(36)} + 3.23\right] = \underline{2.43.}$$

$$\Delta p_{skin} = (135) \times 0.87\,(2.43) = \underline{285} \text{ psi.}$$

III. Calculation of Productivity Index (B/D-psi) and Flow Efficiency:

$$J_{(actual)} = \frac{q}{p^* - p_{wf}}.$$

$$J_{(ideal)} = \frac{q}{(p^* - p_{wf}) - \Delta p_{skin}}.$$

Δp_{skin}	285	psi
q	924	B/D

p^*	1,590	psig
p_{wf}	240	psig

$$J_{(actual)} = \frac{(924)}{(1{,}590) - (240)} = \underline{0.684} \text{ B/D-psi.}$$

$$J_{(ideal)} = \frac{(924)}{(1{,}350) - (285)} = \underline{0.868} \text{ B/D-psi.}$$

$$\text{Flow Efficiency} = \frac{J_{(actual)}}{J_{(ideal)}} = \frac{0.684}{0.868} = \underline{0.788.}$$

For Gas Wells

Test Data:

Company	Shell
Lease	Orr
Well No.	3
Field	Left
State	Texas

Test Date November 16, 1956
Producing Formation Sandstone
Hole Size (inches) 7
Cum. Prod. N_p(bbl) 1.138×10^9 (6,390 MMcf)
Stabilized Daily Prod. q (bbl) 536,900 (3.01 MMcf/D)
Effective Prod. Life t (hr) $= 24N_p/q$ 50.8×10^8

Calculations involved:

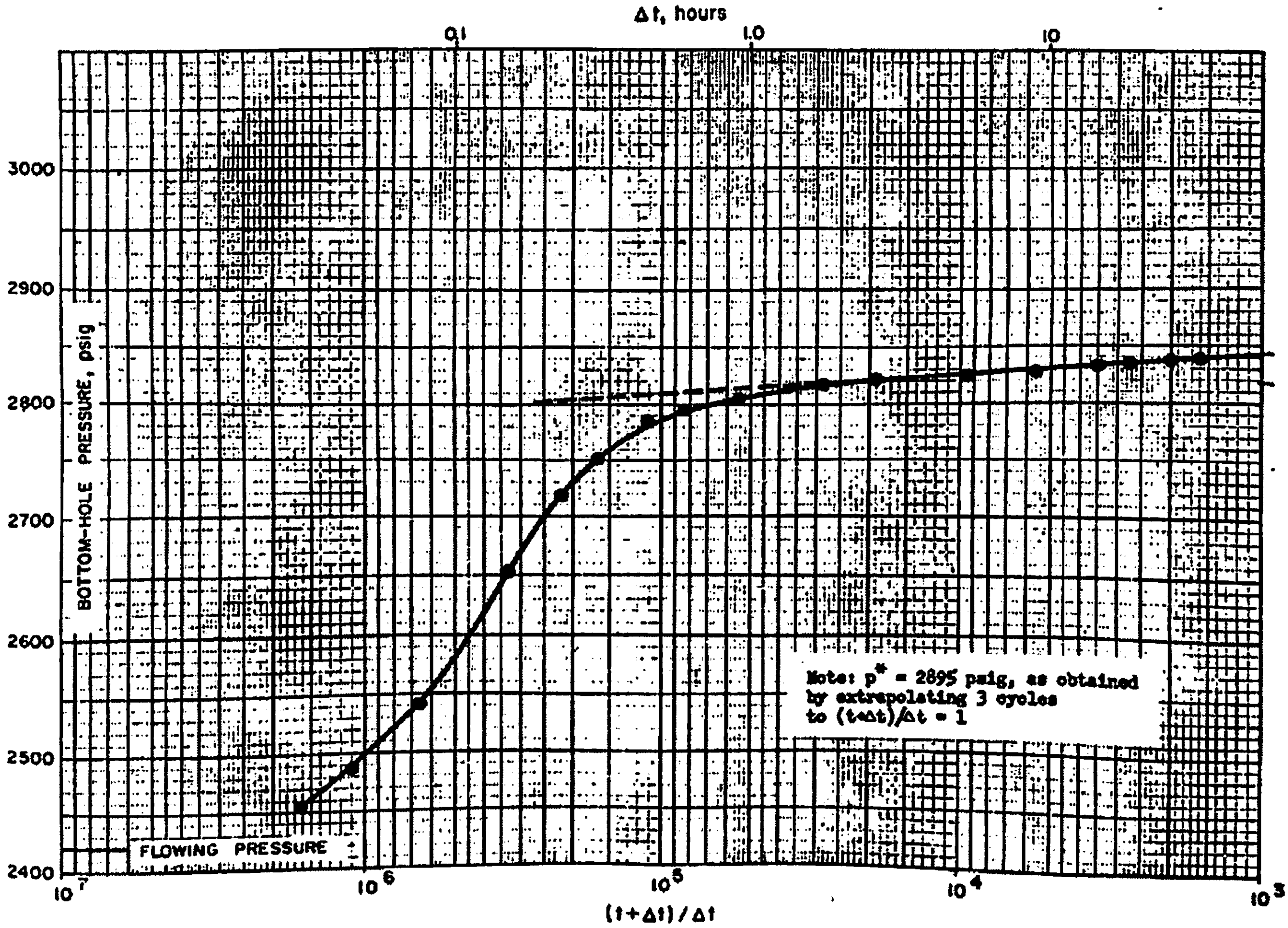


Fig:5.3. Build up curve for the gas well

Refer to the above figure shown:

I. Calculation of kh (md-ft) and k (md):

$$kh = \frac{162.6\, q\mu B}{m}\ ; \quad k = \frac{kh}{h}.$$

h	84	ft
q	536,900	B/D
μ_g	0.0201	cp
B_g	0.00563	cu ft/cu
m	17	psi/cycl

$$kh = \frac{162.6 \times (536{,}900) \times (0.0201) \times (0.00563)}{(17)} = \underline{581} \text{ md-ft}; \ k = \frac{(581)}{(84)} = \underline{6.92} \text{ md.}$$

II. Calculation of Skin Effect, s; and Pressure Loss Due to Skin, Δp_{skin} (psi):

$$s = 1.151\left[\frac{p_{1\,hr} - p_{wf}}{m} - \log\left(\frac{k}{\phi\mu c r_w^2}\right) + 3.23\right].$$

$$\Delta p_{skin} = (m) \times 0.87\,(s).$$

k	6.92	md
ϕ	0.16	
μ	0.0201	cp
c	0.000254	psi^{-1}
r_w	3.5/12	ft
$p_{1\,hr}$	2,815	psig
p_{wf}	2,422	psig
m	17	psi/cycl

$$s = 1.151\left[\frac{(2{,}815) - (2{,}422)}{(17)} - \log\frac{(6.92)\,(144)}{(0.16)\,(0.0201)\,(0.000254)\,(12.25)} + 3.23\right] = \underline{21.12}.$$

$$\Delta p_{skin} = (17) \times 0.87\,(21.12) = \underline{312} \text{ psi.}$$

III. Calculation of Productivity Index (B/D-psi) and Flow Efficiency:

$$J_{(actual)} = \frac{q}{p^* - p_{wf}} \qquad J_{(ideal)} = \frac{q}{(p^* - p_{wf}) - \Delta p_{skin}}$$

Δp_{skin}	312	psi
q	536,900	B/D
p^*	2,895	psig
p_{wf}	2,422	psig

$$J_{(actual)} = \frac{(536{,}900)}{(2{,}895) - (2{,}422)} = \underline{1{,}135} \text{ B/D-psi.}$$

$$J_{(ideal)} = \frac{(536{,}900)}{(473) - (312)} = \underline{3{,}335} \text{ B/D-psi.}$$

$$\text{Flow Efficiency} = \frac{J_{(actual)}}{J_{(ideal)}} = \frac{1{,}135}{3{,}335} = \underline{0.340.}$$

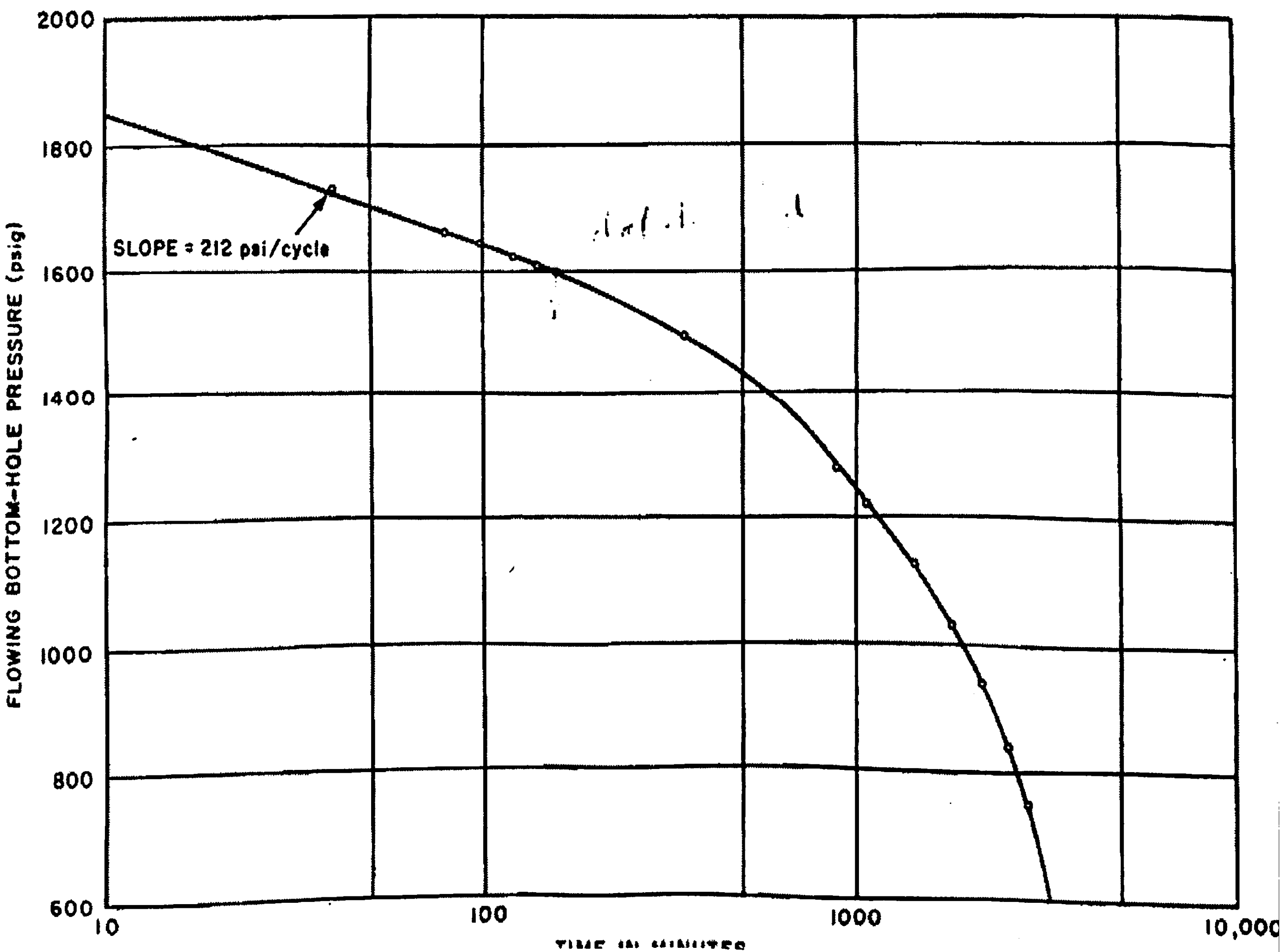
Calculations For the Pressure Drawdown Analysis

The pressure data were obtained from a 50-hrs drawdown test in a well in a Denver Basin reservoir. The test data are as follows:

$q = 800$ STB/D, $\mu = 1.0$ cp, $\phi = 0.1$', $h = 8$ ft, $r_w = 0.33$ ft, $p_i = 1{,}895$ psig, $c_t = 17.7 \times 10^{-6}$ vol/vol/psi, $B_o = 1.25$, and $S_w = 0.35$.

Transient Analysis

As shown in the figure is a plot of measured flowing BHP vs Logt from a flow time of 10 minutes onwards during the transient period are linear on this plot. Deviation from the straight line to signal the end of the transient period occurred at a time of about 2 hours. The slope during the transient period is 212psi/cycle. Calculations are follows:



Refer to the above figure shown:

$$kh = \frac{162.6\, q\mu B}{m},$$

$$kh = \frac{162.6 \times 800 \times 1.0 \times 1.25}{212},$$

$$kh = 767 \text{ md-ft},$$

$$k = 96 \text{ md}.$$

$$s = 1.15\left[\frac{p_i - p_{1\,hr}}{m} - \log\frac{k}{\phi\mu c r_w^2} + 3.23\right],$$

$$s = 1.15\left[\frac{1{,}895 - 1{,}690}{212} - \log\frac{96}{0.14 \times 1.0 \times 17.7 \times 10^{-6} \times 0.11} + 3.23\right],$$

$$s = -5.0.$$

Late Transient Analysis

The plot of log($P_{wf} - \hat{P}$) vs t, which is thw basis of the late transient analysis method, is presented in the figure shown below. From the linear plot of p vs t , it is appeared that semi-steady atate might have been reached at t~10 to 15 hours. By the trial and error method it was established that p^=1460 psig gave a reasonable straight line period of the data. The intercept and slope values are respectively, b=320 psig and $\beta = 1/7.4\ hr^{-1}$

$$kh = \frac{118.6\, q\mu B}{b},$$

$$kh = \frac{118.6 \times 800 \times 1.0 \times 1.25}{320},$$

$$kh = 371 \text{ md-ft},$$

$$k = 46.4 \text{ md}.$$

$$V_p = 0.1115\, \frac{qB}{\beta bc},$$

$$V_p = 0.1115 \times \frac{800 \times 1.25}{\frac{1}{7.4} \times 320 \times 17.7 \times 10^{-6}},$$

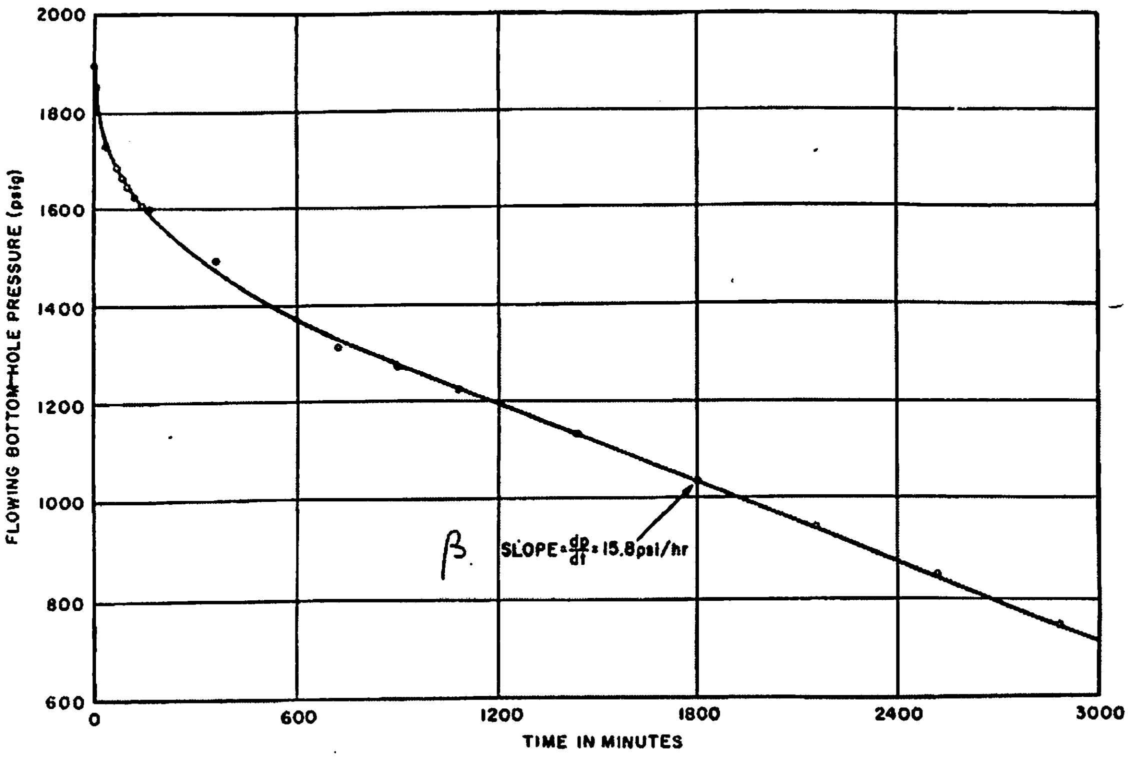
$$V_p = 0.146 \times 10^{6} \text{ reservoir bbl}.$$

This reservoir volume amounts to an equivalent drainage radius of 482ft, or ~17acres.

$$s = 0.84\left[\frac{\bar{p} - \hat{p}}{b}\right] - \ln\frac{r_e}{r_w} + \frac{3}{4},$$

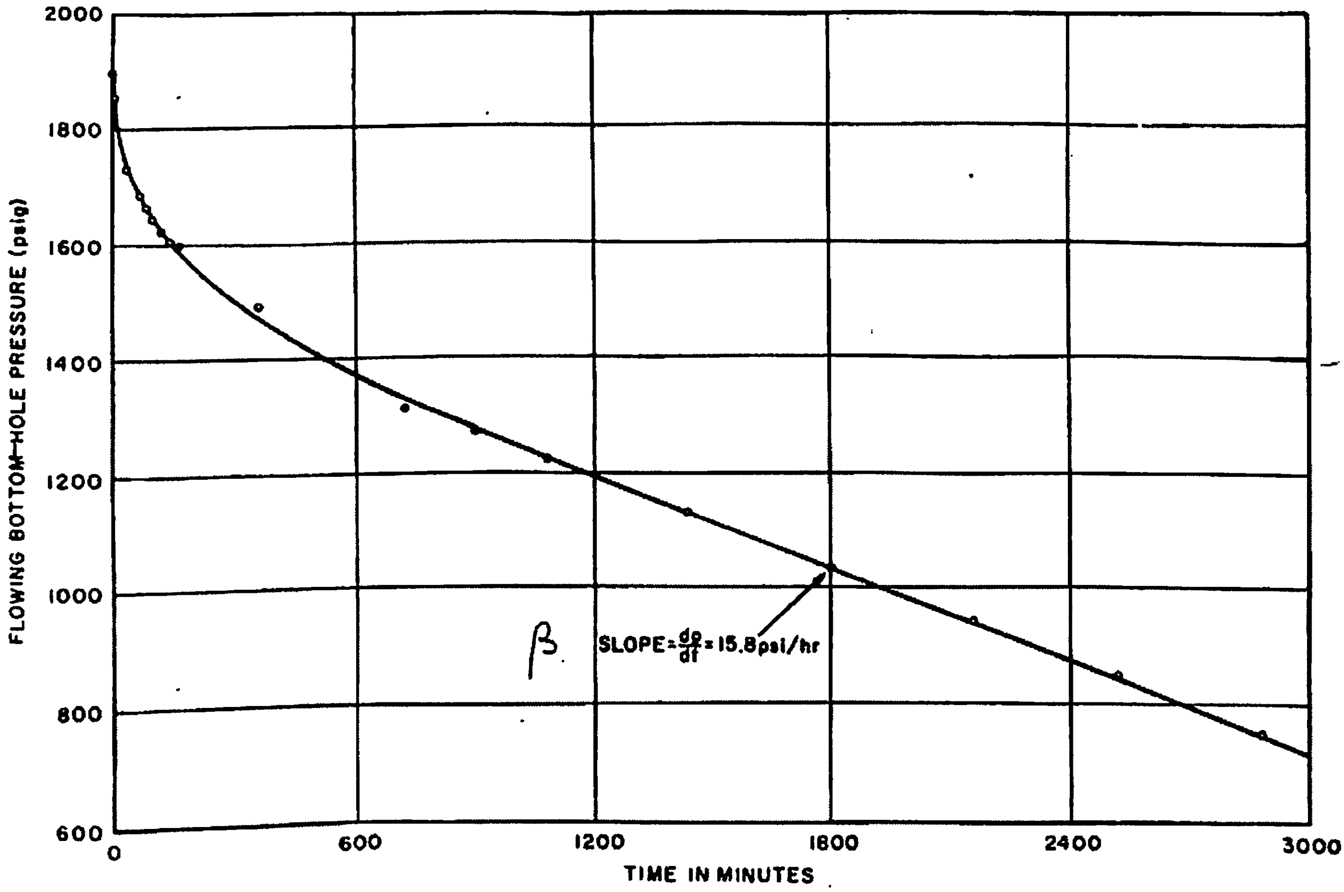
$$s = 0.84\left[\frac{1{,}895 - 1{,}460}{320}\right] - \ln\frac{482}{0.33} + 0.75,$$

$$s = -5.4.$$



The values of **kh** and **S** obtained from the transient and late transient analysis are different. This probably is caused by the fact that the well was given a hydraulic fracture treatment on completion. Since the theory for transient analysis assumes radial flow, the kh value derived from a transient analysis will be high. As flow time proceeds, the radial flow in the region away from the fracture becomes dominant and late transient analysis which is also based on radial flow theory more nearly represents the true values of the reservoir parameters. Thus, in the fractured wells we believe that the late transient results are probably more representative.

Semi-Steady State Analysis



The linear plot of P_{wf} vs **t** is found in the above figure. This plot appears to be linear for times greater than15 hours. From the slope of the plot we find the reservoir pore volume as follows:

$$V_p = 0.0418 \frac{qB}{\beta_L c},$$

$$V_p = 0.0418 \times \frac{800 \times 1.25}{15.8 \times 17.7 \times 10^{-6}},$$

$$V_p = 0.149 \times 10^6 \text{ reservoir bbl.}$$

Calculations for Multiple Rate flow test Analysis

Two-Rate Flow Test:

Test Data:

$q_1 = 107$ STB/D	$p_w = 3118$ psig
$q_2 = 46$ STB/D	$h = 59$ ft
$c_t = 9.32 \times 10^{-5}$ psi^{-1}	$r_w = 0.2$ ft
$\mu = 0.6$ cp	$B = 1.5$
$\phi = 0.06$	$N_p = 26{,}400$ STB

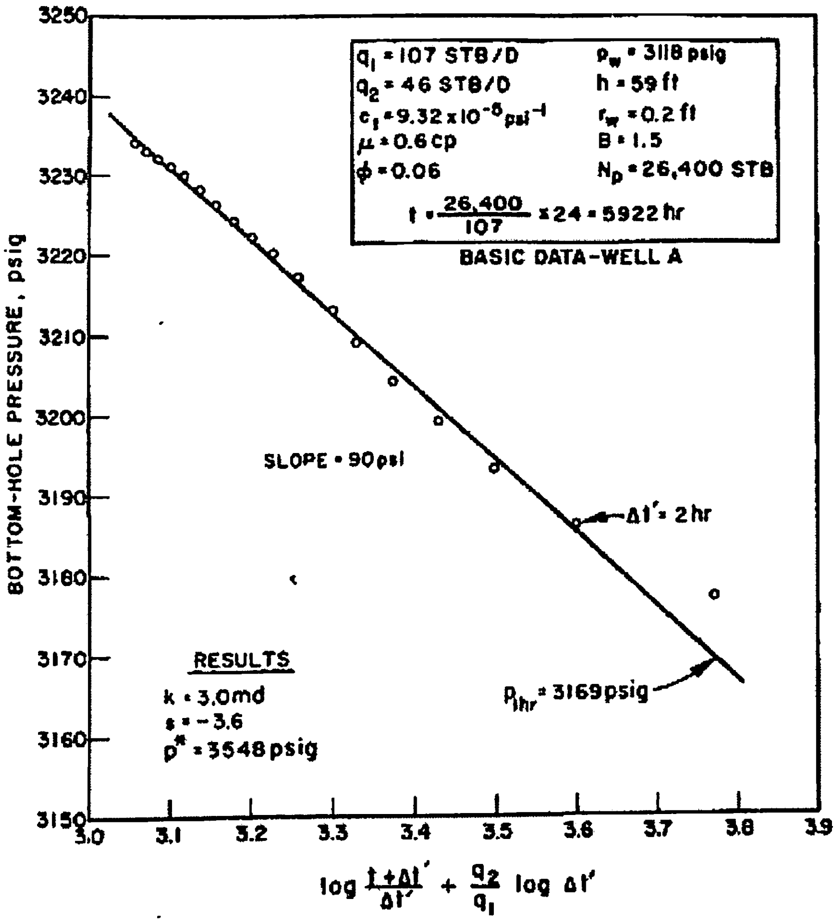
$$t = \frac{26{,}400}{107} \times 24 = 5922 \text{ hr}$$

From the basic flow test plot of p_{wf} vs $\{\log[(t+\Delta t')/\Delta t'] + (q_2/q_1)\log \Delta t'\}$, the value of m is 90 psig/cycle. Thus, from Eq. 6.9 of the text,

$$kh = \frac{162.6\, q_1 \mu B}{m},$$

$$kh = \frac{(162.6)\ (107)\ (0.6)\ (1.5)}{90},$$

The next step is the analysis procedure in the determination of the skin factor S. for this pytpose the following equation is used:



$$s = 1.151\left[\left(\frac{q_1}{q_1 - q_2}\right)\left(\frac{p_{1\,hr} - p_w}{m}\right) - \log\frac{k}{\phi\mu c r_w^2} + 3.23\right],$$

$$s = 1.151\left[\left(\frac{107}{107-46}\right)\left(\frac{3{,}169 - 3{,}118}{90}\right) - \log\frac{3}{(0.06)(0.6)(9.32\times10^{-5})(0.04)} + 3.23\right],$$

$$s = -3.6\,.$$

Calculation of P*

We use the following equation:

$$p^* = p_w + m\left[\log \frac{kt}{\phi \mu c r_w^2} - 3.23 + 0.87s\right],$$

$$p^* = 3{,}118 +$$

$$(90)\left[\log \frac{(3)\ (5{,}922)}{(0.06)\ (0.6)\ (9.32 \times 10^{-5})\ (0.04)} - 3.23 + (0.87)\ (-3.6)\right],$$

$$p^* = 3{,}548 \text{ psig}.$$

Multipoint Open Flow Potential Test

In this case the well is a gas producer in the Morrow-Chester sandstone in the Anadarko basin of Oklahoma. The data were obtained on a four point OFPT run upon completion of the well. The Test data are as follows:

$$r_w = 0.23 \text{ ft},$$
$$\phi = 0.16,$$
$$S_w = 0.20,$$
$$h = 40 \text{ ft},$$
$$\mu_g = 0.017 \text{ cp},$$
$$c_t = 6.89 \times 10^{-4} \text{ psi}^{-1},$$
$$B_g = 8.28 \times 10^{-3} \text{ cu ft/cu ft},$$
$$\text{gas gravity} = 0.7.$$

From the plot we have m= .02904, b=.00625. From the equation: $k_g h = \dfrac{28{,}958 \mu_g B_g}{m'}$

$$k_g h = \frac{(28{,}958)\ (0.017)\ (8.28 \times 10^{-3})}{0.02904},$$

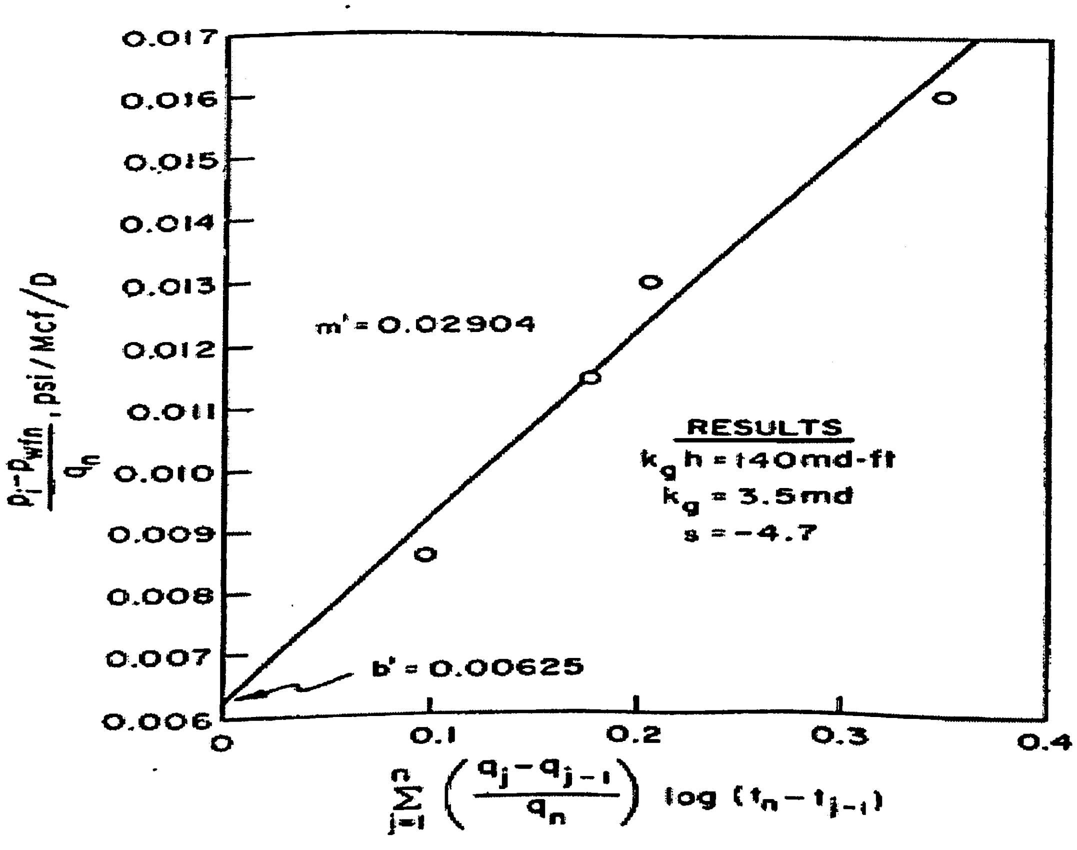
$$k_g h = 140 \text{ md-ft},$$

$$k_g = 3.5 \text{ md}.$$

$$s = 1.151 \left[\frac{b'}{m'} - \log \frac{k_g}{\phi \mu_g c_t r_w^2} + 3.23\right],$$

$$s = 1.151 \left[\frac{0.00625}{0.02904} - \log \frac{3.5}{(0.16)\ (0.017)\ (6.89 \times 10^{-4})\ (0.052)} + 3.23\right],$$

$$s = -4.7 .$$



Calculations For the Injection Well Analysis

Pressure Fall-off Analysis (Refer to figure shown below:)

Test Data:

Test Date: October 30, 1964
Producing Formation: Sandstone
Hole Size (inches): 8.5
Cum. Inj., W_i (bbl): 2,380,000
Stabilized Daily Inj., i (bbl): 1,426
Effective Prod. Life t (hr) $= 24\, W_i/i$: 40,100

Company: Shell
Lease: Zipper
Well No.: 4
Field: Bent
State: Illinois

I. Calculation of kh (md-ft) and k (md); k is permeability to water, k_w:

$$kh = \frac{162.6\, i\mu B}{m}; \qquad k = \frac{kh}{h}.$$

h	49	ft
i	1,426	B/D
μ	0.6	cp (Fig. G.4)
B	1.0	
m	130	psi/cycle

$$kh = \frac{162.6 \times (1{,}426) \times (0.6) \times (1.0)}{(130)} = \underline{1{,}070} \text{ md-ft}; \quad k = \frac{(1{,}070)}{(49)} = \underline{21.8} \text{ md} = k_w.$$

II. Calculation of Skin Effect, s; and Pressure Loss Due to Skin, Δp_{skin} (psi):

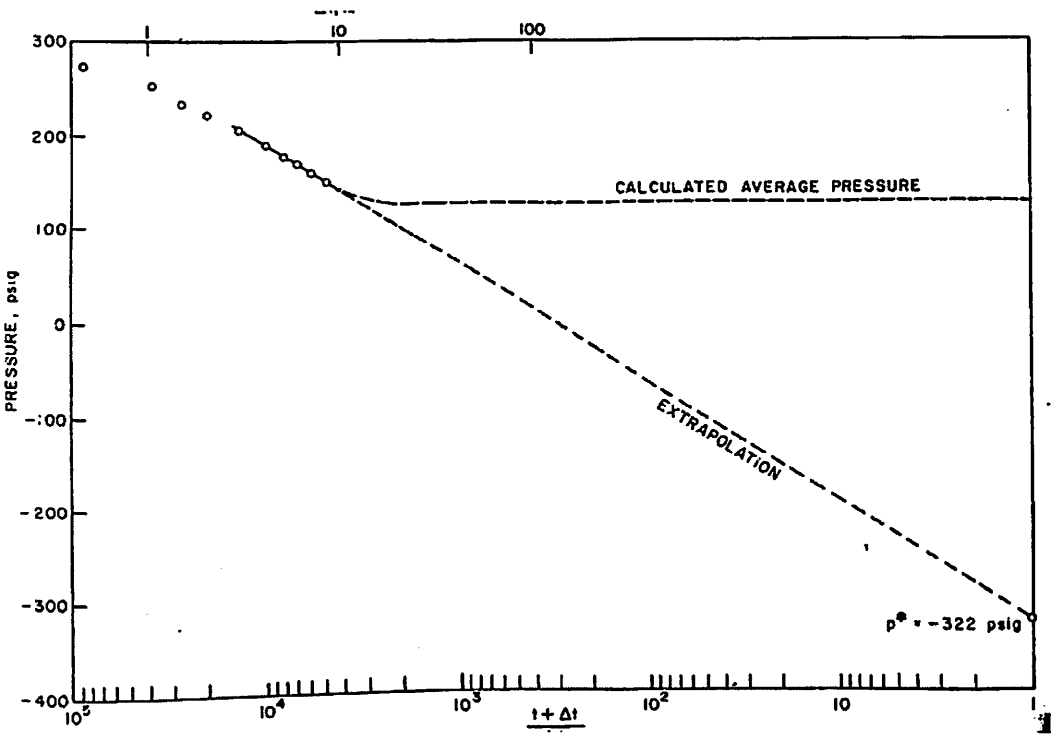
$$s = 1.151\left[\frac{p_w - p_{1\,hr}}{m} - \log\left(\frac{k}{\phi\mu c r_w^2}\right) + 3.23\right].$$

$$\Delta p_{skin} = m \times 0.87\, s.$$

k	21.8	md
ϕ	0.16	
μ	0.6	cp
c	7.0×10^{-6}	psi^{-1}
r_w	4.25/12	ft
$p_{1\,hr}$	273	psig
p_w	525	psig
m	130	psi/cycle

$$s = 1.151\left[\frac{(525) - (273)}{(130)} - \log\frac{(21.8)\,(144)}{(0.16)\,(0.6)\,(7.0 \times 10^{-6})\,(18.1)} + 3.23\right] = \underline{-3.73}.$$

$$\Delta p_{skin} = (130) \times 0.87\,(-3.73) = -\underline{421} \text{ psi (well had been fractured).}$$



III. Calculation of Injectivity Index (B/D-psi) and Flow Efficiency:

$$I_{(actual)} = \frac{i}{p_w - \bar{p}}$$

$$I_{(ideal)} = \frac{i}{(p_w - \bar{p}) - \Delta p_{skin}}$$

Δp_{skin} ____ −421 ____ psi

i ____ 1,426 ____ B/D

$\bar{p}$ ____ 125 ____ psig

p_w ____ 525 ____ psig

$$I_{(actual)} = \frac{(1{,}426)}{(525) - (125)} = \underline{3.56} \text{ B/D-psi.}$$

$$I_{(ideal)} = \frac{(1{,}426)}{(400) - (-421)} = \underline{1.73} \text{ B/D-psi.}$$

$$\text{Flow Efficiency} = \frac{I_{(actual)}}{I_{(ideal)}} = \frac{3.56}{1.73} = \underline{2.06.}$$

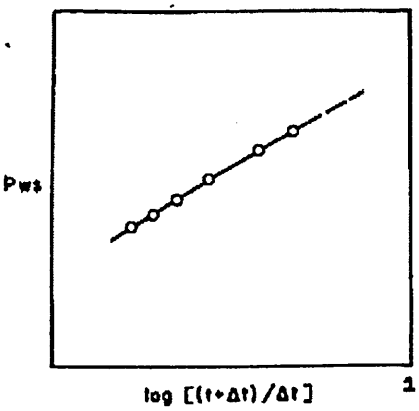
Assuming $S_o = .20$, $S_g = 0$ in the swept zone, we have

$C = C_t = S_oC_o + S_wC_w + C_f$

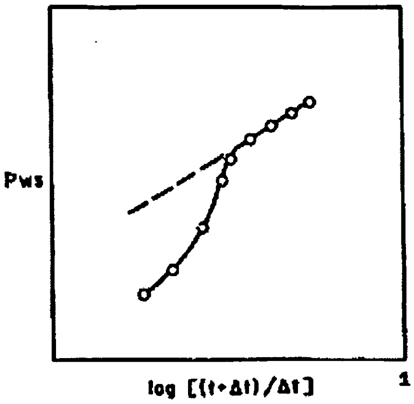
$= 0.20\,(3 \times 10^{-6}) + 0.80\,(3 \times 10^{-6}) + 4.0 \times 10^{-6},$

$= 7.0 \times 10^{-6}\ \text{psi}^{-1}.$

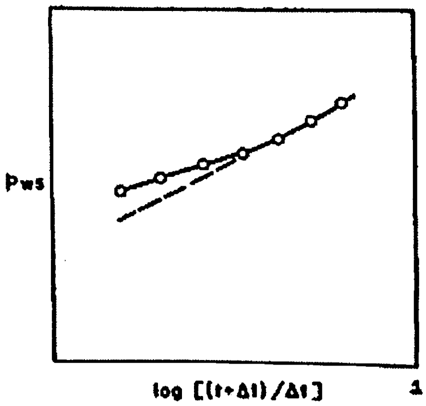
Qualitative Interpretation of Build-up Curves



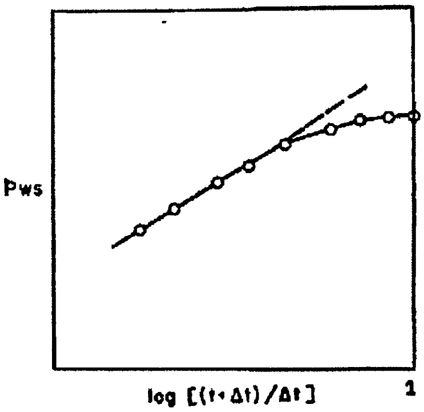
IDEAL - Sec. 3.1



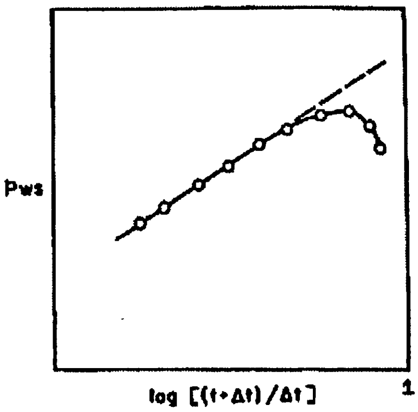
SKIN AND/OR WELL FILLUP - Sec. 3.2, 3.6



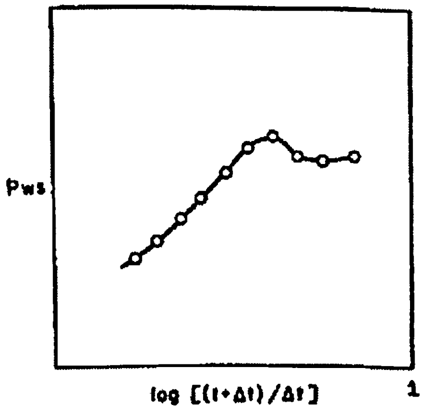
DEEP PENETRATING HYDRAULIC FRACTURE - Sec. 10.5



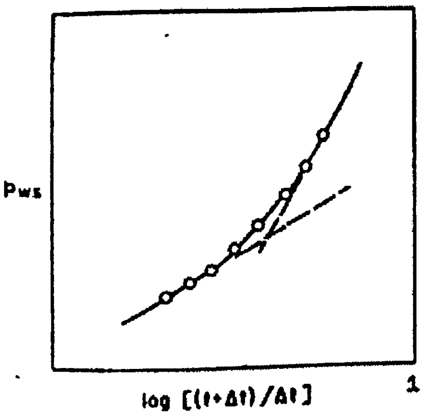
BOUNDARY (one well in a bounded reservoir) - Sec. 3.3



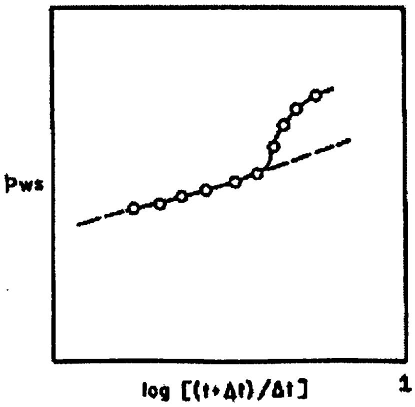
INTERFERENCE (multiple wells in a bounded reservoir) - Sec. 7.2



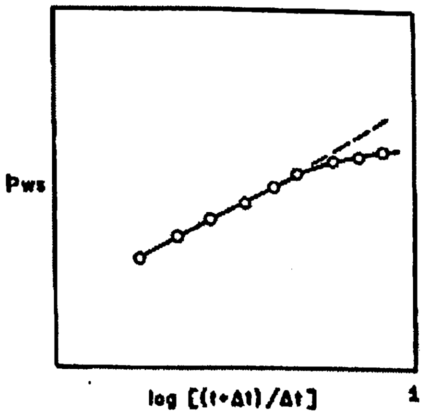
PHASE SEPARATION IN TUBING - Sec. 3.6



FAULT OR NEARBY BOUNDARY - Sec. 10.1



STRATIFIED LAYERS OR FRACTURES WITH TIGHT MATRIX -



LATERAL INCREASE IN MOBILITY - Sec. 10.2

ANALYSIS OF TEST DATA BY *FEKETE* SOFTWARE

The following data for gas well testing have been collected from ONGC

CUMMU TIME (hrs)	MEASURED PRESSURE (psia)
0	2948.51
0.2666666667	2948.58
0.5333333332	2948.6
0.7833333333	2948.6
1.05	2948.57
1.316666667	2948.57
1.583333333	2948.59
1.85	2948.59
2.116666667	2948.6
2.383333333	2948.58
2.65	2948.54
2.916666667	2948.58
3.183333333	2948.59
3.45	2948.56
3.716666667	2948.6
3.983333333	2948.6
4.25	2948.6
4.516666667	2948.55
4.783333333	2948.58
5.05	2948.6
5.3	2948.61
5.566666666	2948.56
5.816666667	2948.62
6.083333333	2948.61
6.35	2948.57
6.616666667	2948.59
6.883333333	2948.6
7.15	2948.57
7.416666667	2948.58
7.683333333	2948.55
7.95	2948.59
8.216666667	2948.55
8.483333333	2948.58
8.75	2948.59
9.016666667	2948.57
9.266666667	2948.64
9.533333333	2948.65

WELL DATA

h	8.5 ft
Φ	22
S_o	65
S_w	0
S_g	35
C_f	3.5e-06 1/psi
C_t	1.91e-04 1/psi
R_w	.300 ft

Radial Analysis

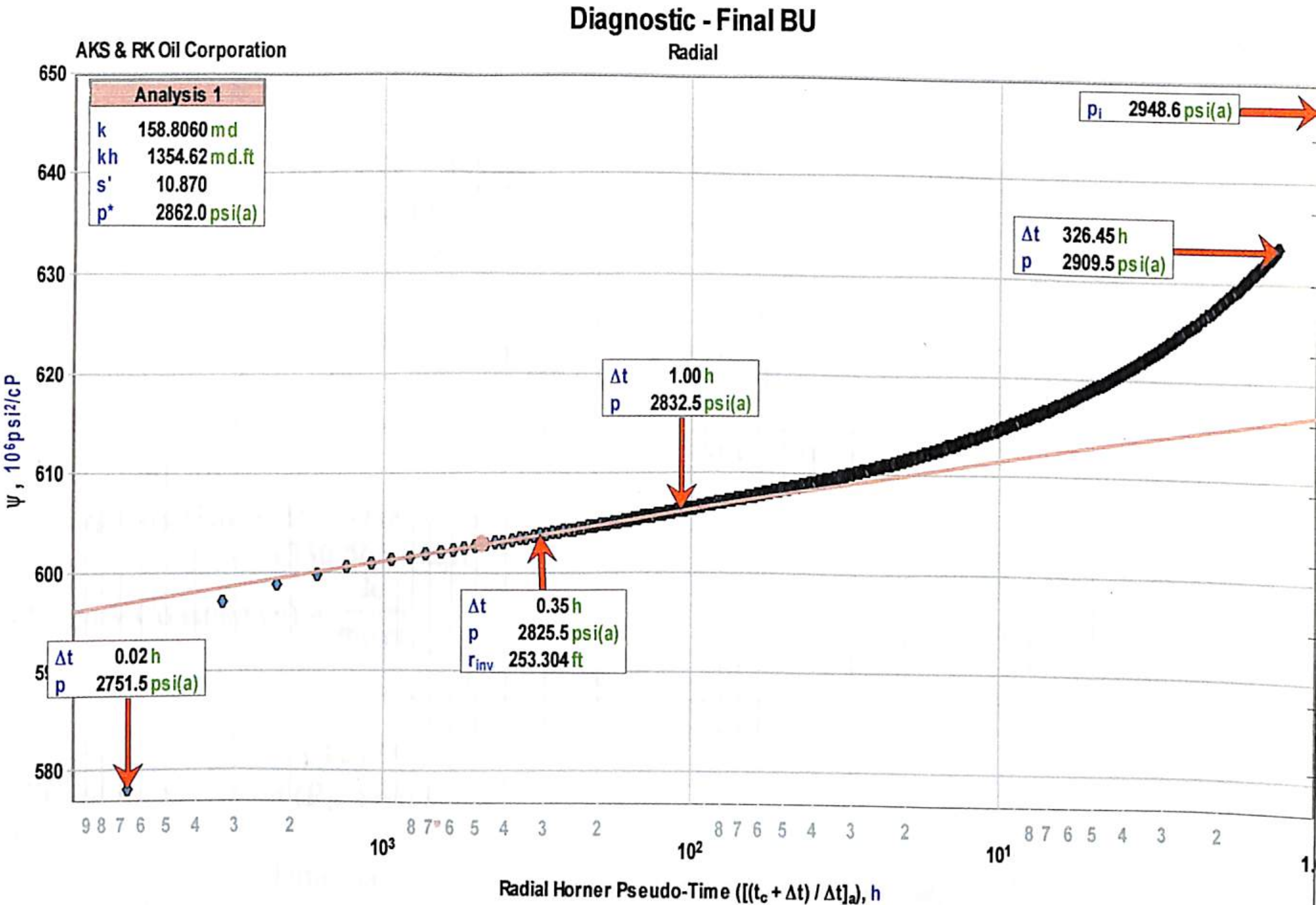
The constant rate solution for analyzing radial flow data is:

$$\Psi_i - \Psi_{wf}(t) = 1.632 \times 10^6 \frac{q_g T}{kh}\left[\log \frac{k t_a}{\phi \mu_{gi} c_{ti} r_w^2} - 3.23 + .87 s'\right]$$

Or

$$\Psi_i - \Psi_{wf}(t) = 1.632 \times 10^6 \frac{q_g T}{kh} \log(t_a) + 1.632 \times 10^6 \frac{q_g T}{kh}\left[\log \frac{k t_a}{\phi \mu_{gi} c_{ti} r_w^2} - 3.23 + .87 s'\right]$$

Plot Ψ_{wf} vs. Radial pseudo time ($\sum \Delta t_a$) on semi-log paper



By Software:

K=158.8060 md

S'=0.805

Kh=1354.62 md.ft

P*=2862.3 psia

Gas mobility=7.8×10^3 md/cp

Manually:

Slope of line (m) = $\frac{611.672-606.526}{\log(100)-\log(10)}$

=5.146

Permeability:

$$K = 1.632 \times 10^6 \frac{q_g T}{mh}$$

$$=1.632x10^6 \frac{6.867x10^{-6}x612.6}{5.146x8.53}$$

=156.69 md

Skin factor:

$$s' = 1.151 \left[\frac{\Psi_{1\,hr} - \Psi_{wf\,0}}{m} - log \frac{k}{\emptyset \mu_{gi}\, c_{ti}\, r_w^2} + 3.23\right]$$

$$=1.151\left[\frac{606.358-571}{5.146} - \log\frac{156.69}{0.22x0.0205x1.91x10^{-4}x0.3^2} + 3.23\right]$$

=0.795

Flow Capacity (Kh) = 156.69x8.53 md.ft

= 1336.565 md.ft

Diffusivity Constant (η) = $\frac{k}{\Phi \mu c_t}$

$$=\frac{156.69x10^{-3}}{0.22x0.0205x1.91x10^{-4}x14.696}$$

=12377.47cm^2/sec

Radius of investigation (R_{inv}) =1.49$\sqrt{\eta T}$

Where

T=Total Shut-in Time,sec

=486.35 hr

=1750860 sec

R_{inv} = 1.49$\sqrt{12377.47x1750860}$

=2193.45 m

= 7196.358 ft

Flow Efficiency:

$$FE= \frac{PI_{actual}}{PI_{ideal}} = \frac{ln(7196.358/0.3)}{ln(7196.358/0.3)+0.795}$$

=0.926

Gas Mobility $\left(\frac{k_g}{\mu_g}\right) = \frac{156.69}{0.0205}$

=7.643x10^3 md/cp

Linear Channel Analysis

Linear Channel flow is a flow regime which exists in long, narrow reservoirs. It occurs in the transition between the middle time region and the late time region, when the radius of investigation has reached the two closest parallel boundaries. The purpose of analyzing linear channel flow data is to determine the channel width, W.

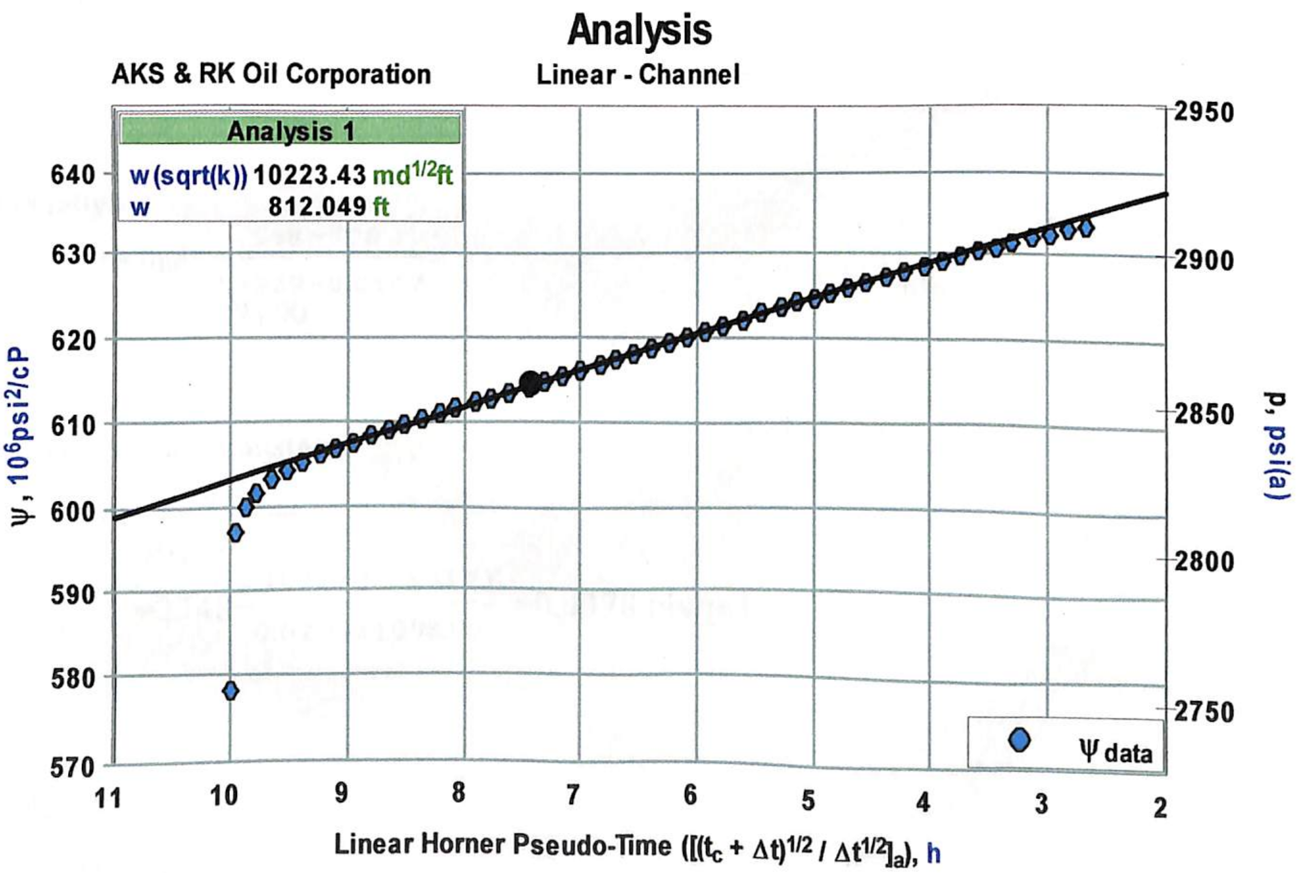
The constant rate solution:

$$\Psi_{wf} = \Psi_i - 8.157 \times 10^4 \frac{q_g T}{wh} \frac{\sqrt{t_a}}{\sqrt{k \emptyset \mu_{gi} c_{ti}}}$$

By Software:

$W\sqrt{k} = 10223.43\ \text{md}^{1/2}.\text{ft}$

W=812.049 md



Manually:

Slope of the line (m) = $\frac{629.05-611.842}{8-4}$

= 4.302

Channel Width:

$$W\sqrt{k} = 8.157 \times 10^4 \frac{q_g T}{slope.h} \frac{1}{\sqrt{\emptyset \mu_{gi} c_{ti}}}$$

$$=8.157x10^4 \frac{6.867x10^{-6}x612.6}{4.302x8.53} \frac{1}{\sqrt{0.22x0.0205x1.91x10^{-4}}}$$

= 10076.439 md$^{1/2}$.ft

From Radial flow analysis

K=156.69 md

Channel width (W) = $\frac{W\sqrt{k}}{\sqrt{k}}$ = 804.98 ft

After Flow Analysis

The purpose of analyzing after flow data is to determine the wellbore storage constant Cs.

Constant Rate Solution:

$$\Delta\Psi = 2348 \frac{qTt_a}{\mu_{ti} C_s}$$

Manually:

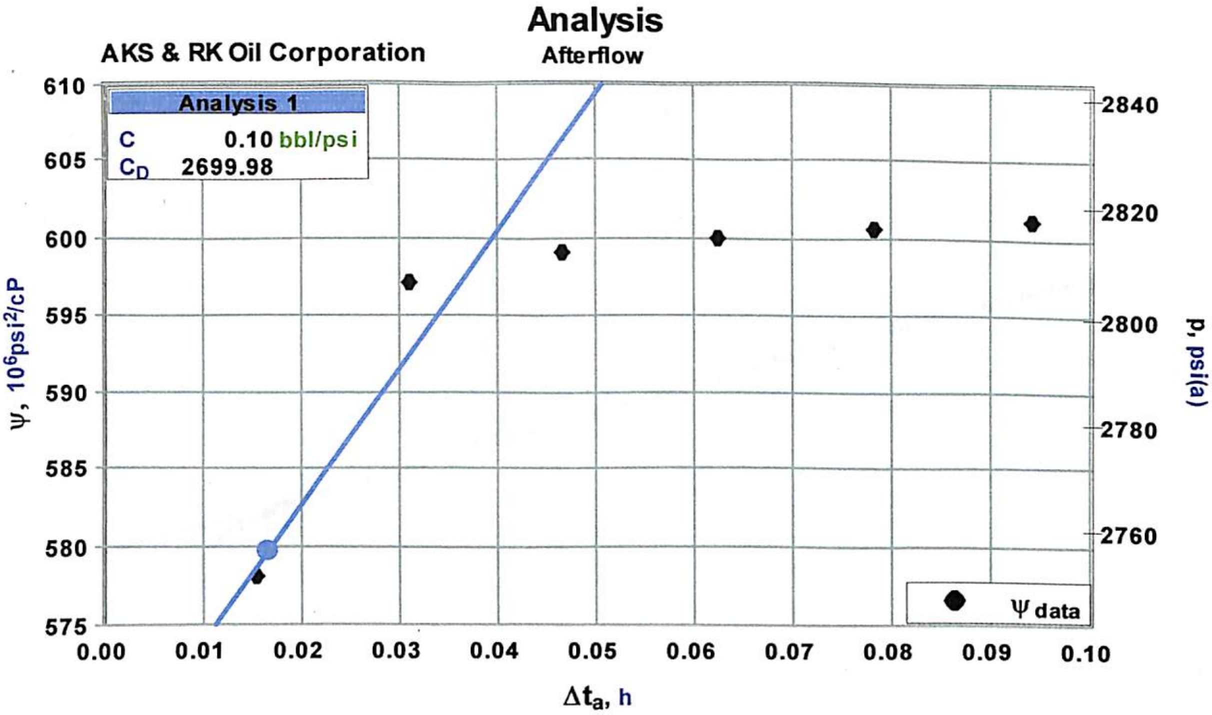
Slope of the line= $\frac{598-578}{0.0329-0.0147}$

=1098.90

Wellbore Storage Constant:

$$c_s = 2348 \frac{qT}{\mu_{ti} .slope}$$

$$=2348 \frac{6.857x10^{-6}x612.6}{0.0205x1098.90} = 0.4378 \text{ bbl/psi}$$



By Software:
Wellbore storage constant(C) = 0.1 bbl/psia

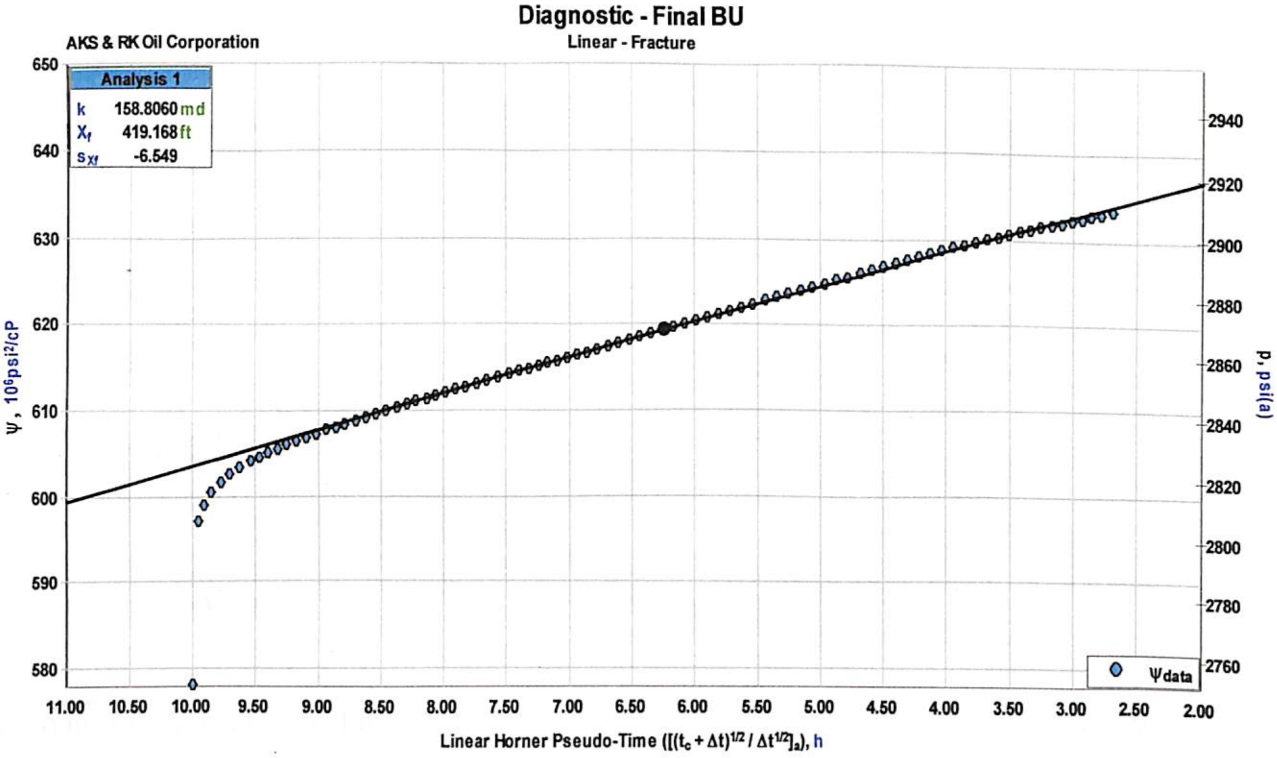
Linear Fracture Analysis:

Linear fracture flow is one of the flow regimes that can exist when a well has been hydraulically fractured. The purpose of analyzing linear fracture flow data is to determine the fracture half-length , X_f

Constant Rate Solution

$$\Psi_{wf} = \Psi_i - 40.785x10^3 \frac{q_g T}{h x_f} \frac{\sqrt{t_a}}{\sqrt{k \emptyset \mu_{gi} \, c_{ti}}}$$

Plot Ψ vs. $\sqrt{(t_{ca} + \Delta t_a)} - \sqrt{\Delta t_a}$



By Software:

$x_f = 419.168$ ft

$S_{Xf} = -6.549$

Manually:

$$\text{Slope of line (m)} = \frac{628.618-611.963}{8-4}$$

$=4.1637$

Fracture Half-Length:

$$x_f\sqrt{k} = 40.785x10^3 \frac{q_g T}{Slope.h\sqrt{\emptyset\mu_{gi}\, c_{ti}}}$$

$$= 40.785x10^3 \frac{6.857x10^{-6}x612.6}{4.1637x8.53\sqrt{0.22x0.0205x1.91x10^{-4}}}$$

$=5197.74$ ft.md$^{1/2}$

The permeability can be obtained from the radial flow regime analysis or estimated from core data or other tests. Fracture half length can be found by

$$x_f = \frac{x_f\sqrt{k}}{\sqrt{k}}$$

$$= \frac{5197.74}{\sqrt{156.69}}$$

$=415.234$ ft

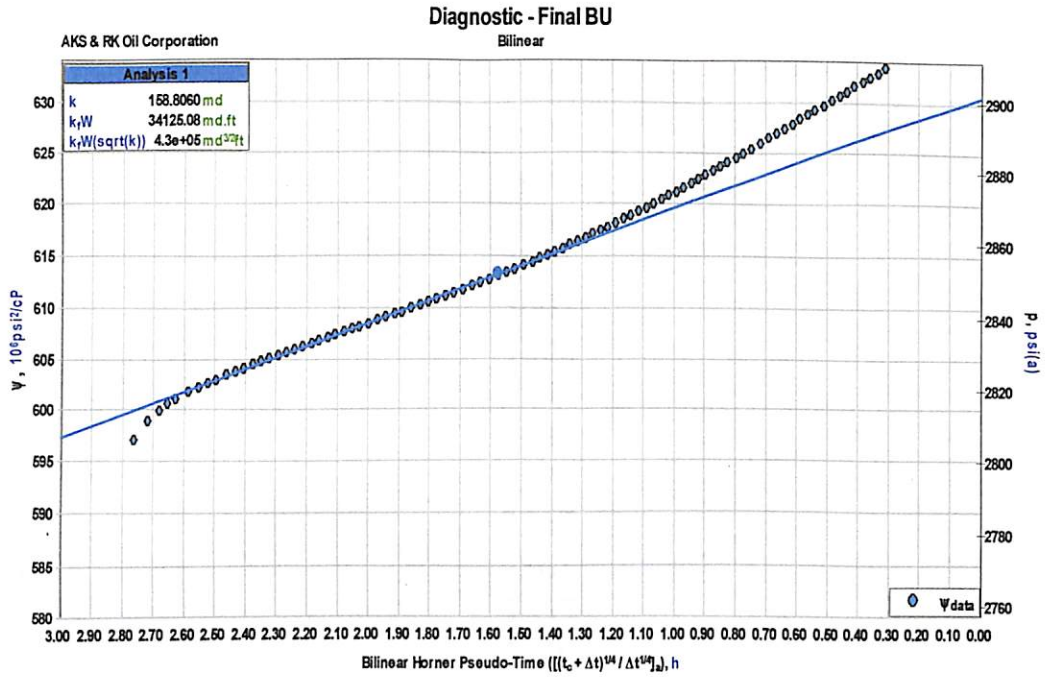
Bilinear Analysis

The purpose of analyzing bilinear flow data is to determine the fracture conductivity, $x_f w_f$

Constant Rate Solution

$$\Psi_{wf} = \Psi_i - 4.43x10^3 \frac{q_g T}{h\sqrt{k_f w_f}} \frac{\sqrt[4]{t_a}}{\sqrt[4]{k\Phi\mu_{gi}c_{ti}}}$$

Plot Ψ vs. $\sqrt[4]{(t_{ca}+\Delta t_a)} - \sqrt[4]{\Delta t_a}$



By Software:

$k_f w_f$= 34125.08 md.ft

Manually:

Slope of the line (m) = $\frac{614.054-602.963}{2.5-1.5}$

=11.091

Fracture Conductivity:

The slope of this line is used to calculate conductivity, $k_f W_f$.

$$\sqrt{k_f W_f} = 4.43x10^5 \frac{q_g T}{\text{Slope.}h\sqrt[4]{k\Phi \mu_{gi} c_{ti}}}$$

$$=4.43x10^5 \frac{6.857x10^{-6}x612.6}{11.091x8.53\sqrt[4]{156.69x0.22x0.0205x1.91x10^{-4}}}$$

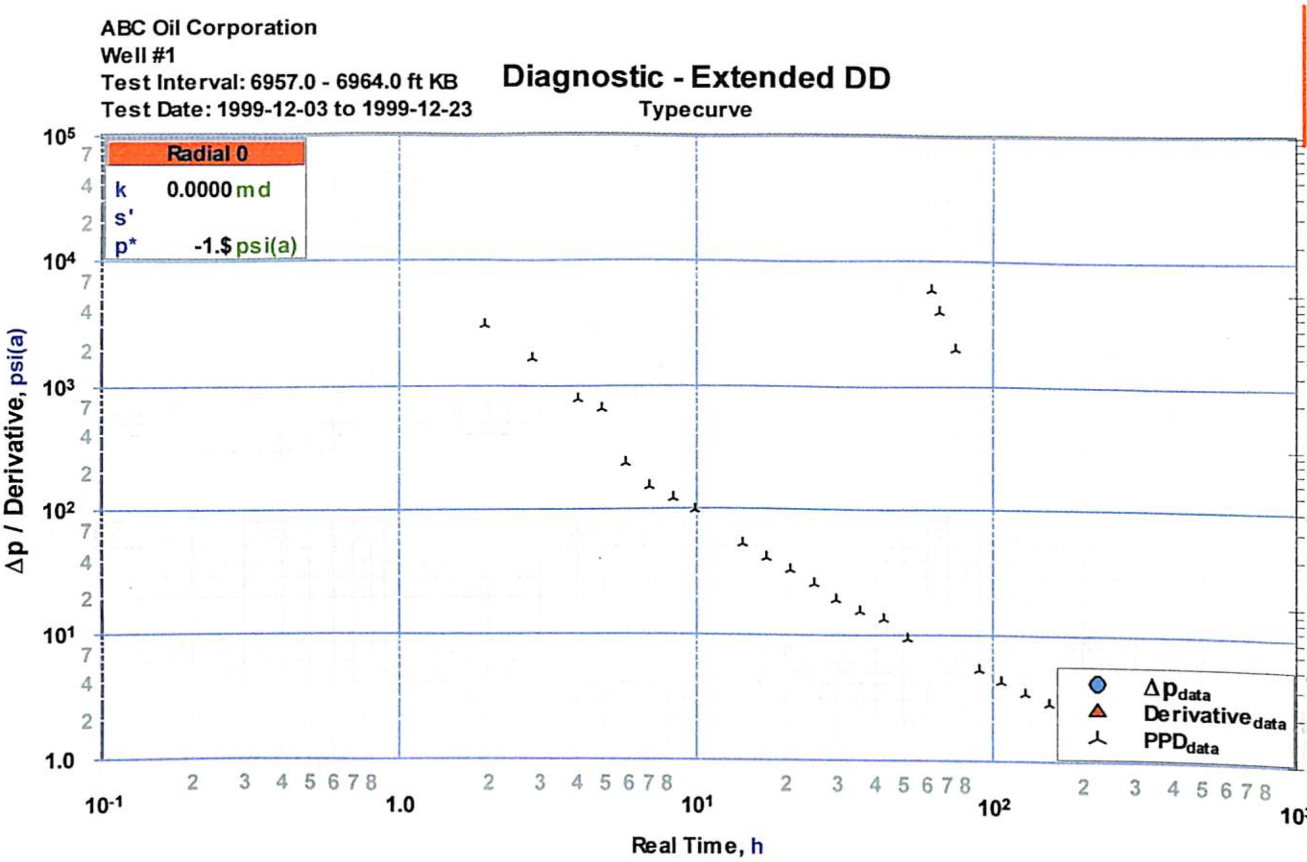
= 182.487 $md^{1/2}.ft^{1/2}$

Fracture conductivity

$k_f W_f$ =33301.566 md-.ft

Pressure Drawdown analysis

Cumm.time(hrs)	Pressure(psia)
0	4412
0.12	3812
1.94	3699
2.79	3653
4.01	3636
4.82	3616
5.78	3607
6.94	3600
8.32	3593
9.99	3586
14.4	3573
17.3	3567
20.7	3561
24.9	3555
29.8	3549
35.8	3544
43	3537
51.5	3532
61.8	3526
65.81	2948
74.2	3521
89.1	3515
107	3509
128	3503
154	3497
185	3490
222	3481
266	3472
319	3460
383	3446
460	3429



By manual calculations

Slope(m)= 70 psi/cycle

Thus permeability of the formation is given by:

$$k = 162.6 \frac{qB\mu}{mh}$$

$$= \frac{(162.6)(250)(1.136)(0.8)}{(70)(69)}$$

$$= 7.65 \text{ md.}$$

We next calculate the skin factor

$$s = 1.151\left[\frac{p_i - p_{1\,hr}}{m} - \log\left(\frac{k}{\phi\mu c_t r_w^2}\right) + 3.23\right]$$

$$= 1.151\left[\frac{4,412 - 3,652}{70}\right.$$

$$\left. - \log\frac{(1.442 \times 10^7)}{(0.198)^2} + 3.23\right]$$

$$= 6.37.$$

Radius of investigation(r_i)

$$r_i = \sqrt{\frac{kt}{948\ \phi\mu c_t}}$$

$$= \sqrt{(1.521 \times 10^4)(12)}$$

$$= 427\ \text{ft}.$$

By software

k=7.50 md
s= 6.20
r_i = 415 ft

Other Considerations in Well Tests

It is necessary to obtain the BHP prior to buildup in order to calculate the skin effect. This requires that pressure bomb be introduced into a flowing well. In general, this can be accomplished without difficulty. However, if a well is subjected to paraffin deposition, the paraffin should be cut before the bomb is introduced to eliminate the possible difficulty in insertion and possible hang-up. Sinker bars will sometimes be required to lower the bomb into a flowing well.

In some cases information on **p, kh** and skin will be desired from a well which has been closed in for some time. In such cases it is usually better first to measure the BHP over a period of , say, 24 hours to make sure the pressure is constant or is changing only very slowly. Then a pressure drawdown test should be conducted and interpreted.. This procedure will give the required information much faster than will a stabilized flow period and a subsequent buildup.

For wells producing by continuous gas lift, the production rate will usually be steady and there will bw no particular problem of measurement or interpretation. These wells often will be producing at high water cut, and it will be necessary to include water in calculation of total compressibility and total mobility. Wells on intermittent gas lift do not give a steady flowing pressure. A average value is usually satisfactory for calculating the skin effect, however. Buildup pressures are usually smooth and satisfactory on these wells.

Measuring Instruments

- Wireline Gauges.
- Permanently installed surface recording- instrument.
- Surface recording instruments run on conductor cable.

CONCLUSIONS

Current Problems and Areas for Further Investigations

1. **Reservoir Heterogeneities:** It is noted from our discussion that the heterogeneous reservoirs situations has been studied under highly idealizes pressure behavior. Thus far, we have been limited in our ability to describe reservoir heterogeneity in a rigorous manner. Hopefully, through geologic studies of various depositional units and the development of faster computers with larger memories, we may be able to study more realistic situations. For example; how will the pressure behave in a well which is completed in highly shaly, lagoon type sand traversed by a stream –channel deposit. Studies of pressure behavior based on more realistic geologic situations are a must. Also the influence of multiphase flow is important.

   Thus, we need further studies aimed at improving our ability to detect fluid contacts in more realistic geometries. Also, more rigorous treatment of hydraulically fractured wells should be encouraged. Therefore, the checkout of results obtained from mathematical investigations by comparison with field behavior should become more of a routine matter.

2. **Pumping Wells:** We can do reasonably a good job in the pressure analysis of the wells produced by artificial lift by Permanently installed surface recording pressure gauges. But, in the more common cases the equipment is not so violable, hence the value of the our present techniques is reduced. For instances, if we run a pressure build up in a pumping well, then we usually must a pull the rods before we can begin pressure measurement. In doing so, we miss the important early-time portion of the buildup and we cannot determine the skin effect with much precision.

3. **Rigorous treatment of Borehole Effects:** The borehole flow and reservoir flow need to be combined to produce better interpretation theory. Reservoir mechanics and vertical lift performance are complextly interrelated and together constitute the overall system in which we seek to operate. Perhaps it is too much to hope that eventually a suite of testing techniques for producing wells could be developed which are as our present bottom-hole pressure based methods and which employ only surface measurement of pressure. One can point to measure pressure analysis fall-off method to contend that successful combination of wellbore and reservoir flow might lead to surface based measurement and analysis theories.

Value of Pressure Analysis Method to Petroleum Industry

There are some methods attempted to assess the value of present pressure analysis methods by which we may be able to make an educated guess at whether further work is worthwhile. The cost of a transient pressure test may range from $200 to $300 for a 48 hours pressure buildup to as much as $5000 to $ 10000 for extended reservoir limit tests. These costs are simply average costs and can vary appreciably depending on operating conditions. Do we get money's worth from such tests? Even considering the fact that there will be an occasional test which fails to meet its objectives, we believe the answer is yes. For purpose of discussion, consider the case of a well which has been completed but the productivity is not as high as was anticipated. Should we spend, say, $10,000 for a stimulation treatment, or is the formation permeability so low that this is the controlling factor and a treatment to remove a "skin" would be of no value? This is clearly the case where a transient pressure test and analysis can provide the answer, and most operators would be willing to spend several hundreds dollars to obtain the needed information.

Another way of attempting to assess the value of pressure analysis to the industry is to ask whether or alternatives exist for characterizing a reservoir. As we see it, pressure analysis techniques are an indispensable part of the package of tools which the engineer must use to describe and characterize the reservoir system. Without an efficient set of the pressure analysis techniques, we do not believe it is possible to achieve the goal of optimization of the economic recovery of the hydrocarbons from a reservoir.

Thus, the conclusion is that the theory and practice of the transient pressure testing techniques is in good shape, with the exception of the uniqueness problem associated with heterogeneous reservoirs may be viewed by some as an inconsistent statement. Once could argue that all reservoir heterogeneous to a degree and therefore all transient pressure test results are non- unique. Transient pressure data must because with geological and petro physical data, in an integral approach to the reservoir characteristics. In a word, Testing of the well is necessary to keep the well healthy and productive The tests carried out at the initial stage are important to know the content of the fluid in the reservoir and the pressure in the reservoir. The tests carried at the production stage are for the Reservoir Engg calculations. We caution that pressure analysis technique must be used objectively and in conjunction with all available reservoir information. Our goal is optimization of recovery through characterization of the reservoir system.

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