IDENTIFICATION OF WELL PROBLEMS USING WELL TESTING

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CERTIFICATION

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DEDICATION

This work is dedicated to God Almighty, the most beneficial, the most merciful, the provider of wisdom, knowledge and understanding whose infinite mercy and grace has brought me this far.

This project is also dedicated to my parents, friends and well-wishers who worked painstakingly and tirelessly in imbibing spiritual, moral and financial support throughout my duration in school.

ABSTRACT

Well testing involves carrying out investigation to ascertain the condition of a well which is intended for further production. These tests are carried out at various stages of life of the well to detect well problems which affect the productivity of a well. It simply involves measuring the parameter affecting a well and how these parameters changes with time. This is then used to predict the future performance of the well and how to best enhanced such performance.

It is pertinent to carry out test on well for efficient management of the well and to be able to make better decisions as regards field operations. Several well problems such as damaged permeability, skin effect, coning problem, reduction in pressure, etc. affect the productivity of a well.

The research work was carried out to determine the problems associated with a well whose history was given. The given well data was used with mathematical models to detect the state or condition of the well. Several factors affecting the life of the well were computed and these were used to improve the productivity of well

From analysis of the well test data, it was seen that the well had impairment which was due to reduced permeability and thus, required stimulation for improved recovery of the hydrocarbons present. Also, there was high sand and water production which also reduced the productivity of the well. Matrix acidizing and hydraulic fracturing are two suitable stimulation methods suitable for improving the well recovery.

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NOMENCLATURE

Ct=Total compressibility psi-1 (kpa-1)

FE=Flow efficiency (dimensionless)

Net formation thickness, ft, (m)

J=Productivity index, Stb/psi

K=Reservoir rock permeability

M=absolute value of slope of middle time line in psi/cycle

β=Formation volume factor

P*=MTR pressure trend extrapolated to infinite shut-in time, psi

βo=Oil formation volume factor

C= compressibility, psi

Kv=Vertical permeability

Kh=Horizontal permeability

Hp=height of perforation

Ht=Top of perforation

Pi=Original reservoir pressure, psi(kpa)

Pwf=flowing bottom hole pressure

Pws=Shut-in bottom hole pressure psi (kpa)

P1hr=Pressure at 1hour shut-in (or flow) time on middle-time line (or its extrapolation) psi (kpa)

Q=flow rate, STB/D

r=distance from center of wellbore, ft9m0

re=External drainage radius, ft (m)

r_i=Radius of investigation ft

r_w=Wellbore radius ft(m)

S=skin factor, dimensionless

T=elapsed time, hours

μ=Viscosity, cp

μ_o=Oil viscosity, cp

Ø= Porosity of reservoir rock, dimensionless

CHAPTER ONE

INTRODUCTION

In the petroleum industry, a well test is the execution of a set of planned data acquisition activities to broaden the knowledge and understanding of hydrocarbons properties and characteristics of the underground reservoir where hydrocarbons are trapped

In the production of oil and gas from the reservoir to the well and to the surface, it is required to carry out tests to broaden the knowledge and understanding of hydrocarbon properties and characteristics of the underground reservoir where the hydrocarbon is trapped. These tests are carried out at all stages in the life of oil and gas fields, from exploration through development, production and injection. The tests are aimed at identifying the reservoir's capacity to produce hydrocarbon, such as oil and natural gas. The various data gathered during the test period include volumetric flow rate for optimum production and the pressures (reservoir pressure, bottom-hole pressure, and wellhead pressure) observed in the well. Well test can be surface or subsurface testing and each type has its own objectives

A properly designed, executed and analyzed well test provide useful information about formation permeability, reservoir pressure history, extent of wellbore damage and stimulation, reservoir boundaries and heterogeneities etc.

The results of well test analysis is used to make the best possible decision to optimally and efficiently produce from the well. Result from flow rate data and gas oil ratio data, for instance, can be used to determine the main type of fluid to be produced (a result showing a high gas oil ratio for a well is likely to produce mainly gas from the well) from the reservoir). Possible recovery process can also be determined from the results from well tests. These recovery process might have to be changed during the course of production as the pressure in the reservoir declines.

A well is said to have problem if its behavior deviates from the normal production pattern. Typical well problems for producing wells include low productivity, low reservoir pressure, formation damage and skin value, high viscosity oil, wellbore and tubing plugging, high gas- oil ratio etc. Hence, well testing is therefore one of the economic source of valuable information about reservoir properties such as porosity, permeability, fluid viscosity, reservoir limit, drainage volume and vertical permeability orientation etc.

1.1 TYPES OF WELL TESTING

Generally, well testing can be divided into three types viz:

- Pressure transient test
- Periodic productive test
- Deliverability test

PRESSURE TRANSIENT TEST: This is a means of assessing reservoir performance by measuring flow rates and pressures under a range of flowing conditions and then applying the data to a mathematical model. During the flow period, the pressure at the formation is monitored over time. Classification of pressure transient test includes pressure drawdown test, pressure build-up test, injectivity test, inference test, fall off test etc. These tests require higher degree of sophistication and are used to determine formation damage or stimulation related to reservoir parameters such as permeability, porosity, pressure, volume etc.

PERIODIC PRODUCTIVE WELL TEST: This is a routine test carried out to physically measure oil, gas and water produced by a particular well under normal producing conditions. It helps to determine the daily production of oil, water and gas. This information serves as an aid in well and reservoir operations and also in meeting legal and regulatory requirements.

DELIVERABILITY PRODUCTIVITY TESTS: This is an intensive oil and gas well test which involves the physical or empirical determination of fluid flow rate versus bottom hole pressure drawdown with a limited number of measurements in order to determine the capability of the well under various degree of pressure drawdown. This test is usually carried out on a newly completed well. Results may be used to set allowable production and in the selection of artificial lift system and production facilities. Classification of deliverability tests include Inflow performance relationship (IPR) test, flow after flow test, isochronal test, Potential test etc.

1.2 AIMS/OBJECTIVES:

- To study the various types of well tests carried out in the oil industry and how they can be used in identifying well problems.
- To analyze well test data gotten from literature in order to determine its reservoir characteristics by the application of well test knowledge.
- To make conclusions on the state of the well on the basis of data analysis and give possible recommendations.

1.3 SCOPE AND LIMITATIONS

The scope of this project is limited to the data of a particular well test that was derived from literature which would be used for determining problems and evaluating well productivity.

1.4 METHODOLOGY

- Literature review of textbooks, journals, articles etc., and surfing the internet for necessary information.
- Obtaining well test data from literature and carrying out analysis with the aid of mathematical calculations and graphical plots to evaluate the well problems.

CHAPTER TWO

LITERATURE REVIEW

Oil well testing is a branch of reservoir engineering. It is one of the most powerful tools available for determining reservoir characteristics. Generally, a well test is a period of time during which the rate and/or pressure of a well is recorded to estimate well or reservoir properties to prove reservoir productivity or to obtain general reservoir management data. It involves producing a well at constant rate or series of rates, some of which may be zero (well closed in) while simultaneously taking a continuous recording of the changing pressure in the wellbore using some of the pressure measuring devices. Well test information is second only to production data in importance for the prudent management of oil or gas reservoir. As such, well testing is an integral part of the overall production and depletion strategy of a reservoir. The interpretation of pressure data recorded during a well test has been used for many years to evaluate the reservoir characteristics. Static reservoir pressure measured in shut-in wells is used to predict reserves in place through material balance calculations. Transient pressure analysis provides a description of the reservoir flowing behavior. Many methods have been proposed for interpretation of transient tests but the best known and most widely used is Horner's. More recently, type curves which indicate the pressure response of flowing wells under a variety of well and reservoir configurations were introduced. Recently, the quality of well test interpretations has improved because of the availability of accurate pressure data (from electronic pressure gauges) and the development of new software for computer aided analysis. Reasons for carrying out well testing may include:

a) To see if the well will flow or not
b) To see what fluid a well will produce
c) To see if the well would flow naturally or to be pumped to the surface
d) To see what rates of flow were possible
e) To see if communication exists between different wells
f) To determine reservoir and flowing pressure
g) To determine reservoir parameters
h) To determine no flow boundaries if they exist

2.1 DIVISION OF WELL TESTING

Well testing can be divided into two viz:

a. Surface well testing: This technique helps assess the true reservoir potential at full scale under dynamic conditions. It validates well performance during cleanup and commissioning and provides reservoir monitoring for better field management.
b. Sub-surface well testing/Downhole Reservoir Testing: subsurface well testing helps gather critical data (from downhole temperature data to reservoir samples) which

provides a full view into reservoir permeability, skin, initial pressure, and more, enabling better decision making.

2.2 OBJECTIVES OF SURFACE WELL TESTING

i. To determine the productivity or producing ability of a hydrocarbon bearing formation
ii. To establish the well completion method
iii. To determine the need to stimulate the producing formation
iv. To establish actual well producing rates
v. To establish Inflow Performance Relationship (IPR) or the relationship between the producing rates and varying bottom hole pressure
vi. To determine Gas-Oil ratio

2.3 OBJECTIVES OF SUB-SURFACE WELL TESTING

i. To establish the reservoir permeability and reservoir porosity
ii. The reservoir flowing and static pressures
iii. The reservoir fluid viscosity
iv. Skin effect or degree of well damage
v. The reservoir limit

2.4 OTHER REASONS FOR WELL TESTING

Other reasons or objectives of well testing can be categorized into the following:

2.4.1 LEGAL CONSIDERATIONS

1. Tests data are necessary for the establishment of production rates by state conservation commissions and regulatory bodies in order to avoid waste.
2. Test data used for the allocation of oil production between fields and wells within individual fields.
3. Taxes such as direct taxes on production and mineral and property taxes based on value are levied on oil and gas production.
4. Test data are needed for the proper development and management of oil and gas reserves
5. Gas-oil rate and water-oil rate penalties are determined by well test.

2.4.2 ECONOMIC CONSIDERATIONS

1. Maximum daily income can be achieved from an accurate well test data reflecting the producing capabilities of each well or field.
2. Production supervisors make constant use of well test data in planning and scheduling remedial or workover jobs.
3. The petroleum engineer depends largely upon well test data for the effective utilization of pipelines, water disposal facilities, pump sizing, production tubing and well equipment.

4. Field personnel need to know the potential and performance of individual well in order to make rate adjustments from time to time to meet allowable control and optimum use of handling and processing equipment.
5. Test data are needed by personnel for trouble shooting. For example, if gas/oil or oil/water production suddenly changes.
6. Test data are used in recognition of reservoir drive mechanisms and to initiate programmers that offer them.

2.5 CLASSIFICATION OF WELL TESTING

Well testing is classified into 3 main parts viz:

a) Periodic production test
b) Production or Deliverability test
c) Pressure transient tests

2.5.1 PERIODIC PRODUCTIVITY TEST

The features of these test include:

1. They are run routinely to physically measure gas, oil and water produced from a well under normal producing conditions.
2. Provide physical evidence of well conditions
3. Unexpected changes such as extraneous water or gas production may signal well or reservoir problems
4. Abnormal production declines may mean artificial lift problems, sand fill up, scale etc.
5. To help the operators/engineers to maintain accurate production records of each well
6. It helps the field engineers to analyze well problems and predict future performance of the well.
7. Measure reservoir pressure and temperature.
8. Obtain samples suitable for PVT analysis.
9. Evaluate completion efficiency.

2.5.2 PRODUCTION OR DELIVERABILITY TEST

A productivity or deliverability test is a test to predict the absolute open flow potential (AOFP) of a well and its deliverability potential under various pipeline back pressures. A deliverability relationship is needed because a gas well may not be producing to capacity. It permits prediction of what the well should produce at other pressure drawdown. The main types of deliverability tests used today are:

1. Flow after flow test
2. Inflow performance relationship test
3. Potential test
4. Productivity index test
5. Single point test

2.5.2.1 FLOW AFTER FLOW TEST

This test requires a static reservoir pressure and stabilization of 3 to 4 flow rates. This method is very useful for reservoir producing below the bubble point where mathematical model is impractical. In this case, a well is allowed to flow at a selected constant rate until pressure is stabilized i.e. pseudo steady state is reached. The stabilized rate and pressure are recorded. The rate is then changed and the well flows until the pressure stabilizes again at the new rate and the process is repeated for 3 to 4 rates. This test provides good radius of investigation but often results in a lengthy test, resulting in excessive flaring of gas. For this reason, this test is best for use in high permeability reservoirs that stabilize quickly otherwise, serious consideration should be given to the testing in-line

2.5.2.2 ISOCHRONAL TEST

This test requires a static reservoir pressure, a flow period of fixed duration followed by shut-in until pressure stabilizes again. The objective of this test is to obtain data to establish a stabilized deliverability curve for a gas well without flowing the well for sufficiently long to achieve stabilized conditions ($r_i \geq r_e$) at each rate. This sequence of flow and build up to stabilize pressure is repeated with only the final flow rate required to stabilize. This test is still quite lengthy and again best suited to high permeability reservoirs. In an Isochronal test, the production time is not equal to build up time because you have to wait for different rate for the well build up to maximum.

2.5.2.3 MODIFIED ISOCHRONAL TEST

This test requires a static reservoir pressure, then flows and shut in periods of equal duration. This is the best isochronal test because the well does not build up to the maximum pressure and thus, it is not time consuming. The production and build up time are equal. This method was developed for testing tight reservoirs but it is often used today on high volume, tubing restricted and or partially penetrated wells with fair to good permeability.

2.5.2.4 SINGLE-POINT TEST

This test requires a stabilized rate and flowing pressure measured before the well is shut in and built up to a stabilized reservoir pressure. The test is widely used for deliverability tests where the turbulence factor is known, usually for subsequent tests on a well, for initial tests in a relatively mature pool or where deliverability may be poor or flow conditions are predetermined by pipeline or plant restrictions.

2.5.2.5 PRODUCTIVITY INDEX TEST

This is the simplest form of deliverability test. It involves the measurement of shut in and bottom hole pressure and at one stabilized producing condition, measurement of the flowing bottom hole pressure and at corresponding rates of liquids produced to the surface with this, it is possible to know at what reduced flowing bottom hole pressure will flow rate peak. Productivity index is defined as the ratio of production rate (q) to the pressure drawdown ($P_r - P_{wf}$). The difference between the reservoir pressure and the bottom hole flowing pressure is called pressure drawdown. Productivity index can be expressed mathematically as:

$$PI = \frac{pr}{(pr - pwf)}$$

Where PI = Total liquid (stb/day)

Pr= reservoir pressure (psi)

Pr─Pwf= pressure drawdown (psi)

2.5.2.6 INFLOW PERFORMANCE RELATIONSHIP (IPR) TEST

The inflow performance relationship or IPR is defined as the functional relationship between the production rate and the bottom hole flowing pressure. This is a tedious concept of productivity index that attempts to represent the inflow performance of a well as a straight line function of the pwf against q. This should in effect consist of PI test of several production rates in order to provide a better representation of the time when IPR of the well will reach maximum.

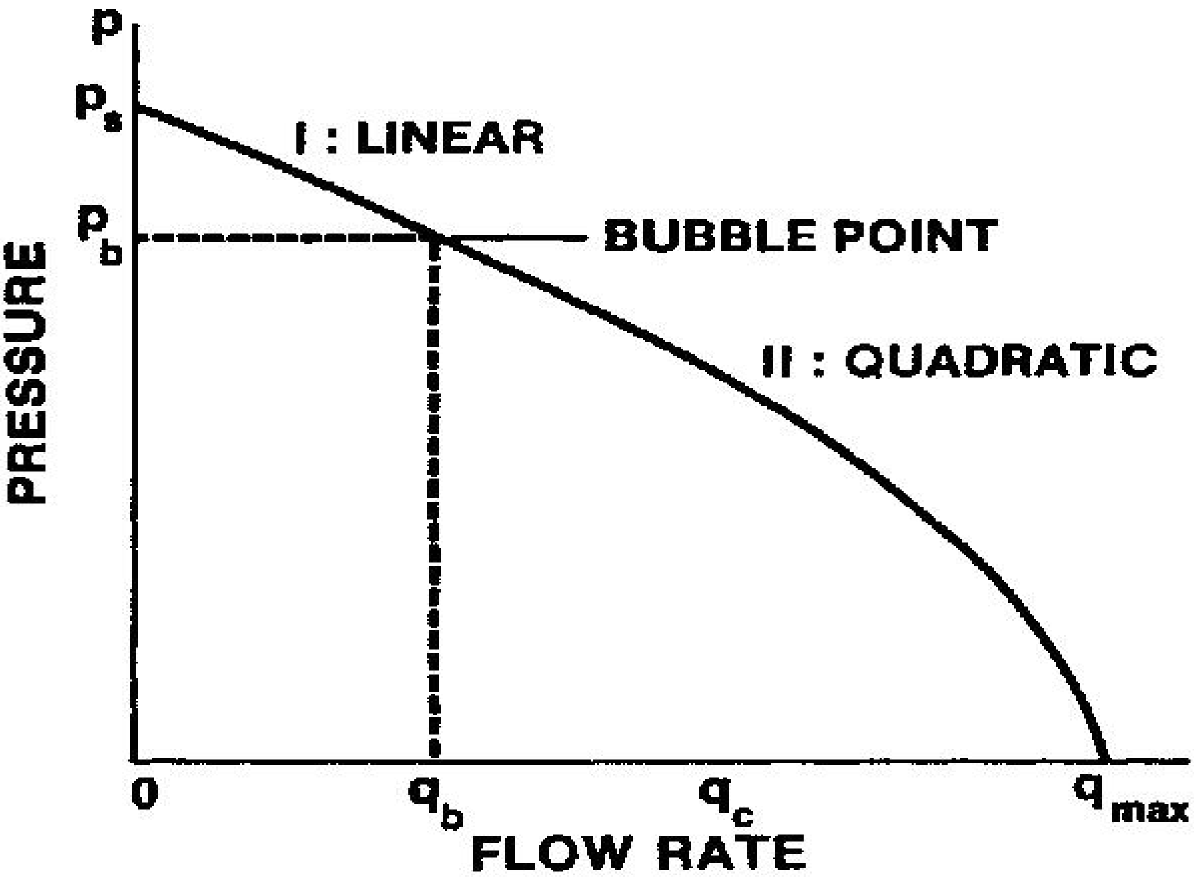

Fig 2.1: Basic shape of IPR curve (for a solution-gas drive reservoir in this case)

Where P_s = maximum reservoir pressure

P_b = bubble point pressure

q_{max} = maximum flow rate

q_b = flow rate at bubble point pressure

2.5.2.7 POTENTIAL TEST

This type of test determines the amount of oil and gas a particular well will produce under specific condition and time. It helps to know the production allowable for the operators to flow. It may be ordered by government (DPR) to determine the production rate between operator and government.

2.6 PRESSURE TRANSIENT TEST

These tests provide a means of assessing reservoir performance by measuring flow rates and pressures under a range of flowing conditions and then applying the data to a mathematical model. Transient well tests measure changes in reservoir pressure associated with changes in well rate. During the flow period, the pressure of the formation is monitored over time. These tests are used to determine formation damage or stimulation related to an individual well or reservoir parameter such as permeability, porosity, pressure, volume and heterogeneity. It is also used to determine gas well deliverability.

2.7 CLASSIFICATION OF PRESSURE TRANSIENT TEST

Pressure transient tests are classified as follows:

a) Pressure drawdown test
b) Pressure buildup test
c) Injectivity test
d) Fall off test
e) Interference test
f) Multiple rate test
g) Drill stem test
h) Wireline formation test
i) Pulse test

2.7.1 PRESSURE DRAWDOWN TEST

A drawdown test is simply a series of bottom hole pressure measurements made during a period of flow at constant production rate. Usually, the equipment is first set into the well and the well is closed prior to the flow test for a period of time sufficient to allow the pressure to stabilize throughout the formation i.e. to reach static pressure. Drawdown test is suitable in new wells because the reservoir still has a uniform pressure and production is not lost during test though it is difficult to maintain production rate. The consideration for having this test is simply when there are some uncertainties in buildup interpretations. Therefore, analysis from drawdown test can be used for comparative analysis.

2.7.2 PRESSURE BUILD-UP TEST

Pressure build-up testing is the most familiar transient well testing technique which has been used extensively in the petroleum industry. In this test, the rate in the tested well is stabilized for several days, that is, to maintain the rate approximately constant. The pressure measuring device is then placed as near the perforations as possible several hours before shut-in. The device should record for at least 15 minutes prior to shut-in. The well is then shut in and pressure is allowed to build up. Buildup test is started right after *tp* (which is representing the duration of production i.e time of production) with zero production by shutting-in the well at the wellhead. The rate at which pressure builds up with time reflects the formation properties. The primary purpose of performing a build-up test is to determine the wellbore damage (skin) and reservoir permeability. However, during the course of build-up, it is possible to encounter reservoir boundaries. If all the reservoir's boundaries are contacted during the build-up, the size of the reservoir can also be determined. A method to analyze the pressure response of buildup test is using Horner method (1951). It is a semilog plot of shut-in pressure *pws* versus horner time $(tp+\Delta t)/\Delta t$ as illustrated below. This plot creates a straight-line which represents the transient flow during the middle-time of the test. Different behavior regions during buildup test are shown below. Middle-time region indicates that the pressure transient has spread away from the wellbore into the formation. Slope of the straight-line *m* is a tool to predict reservoir permeability by using below formula

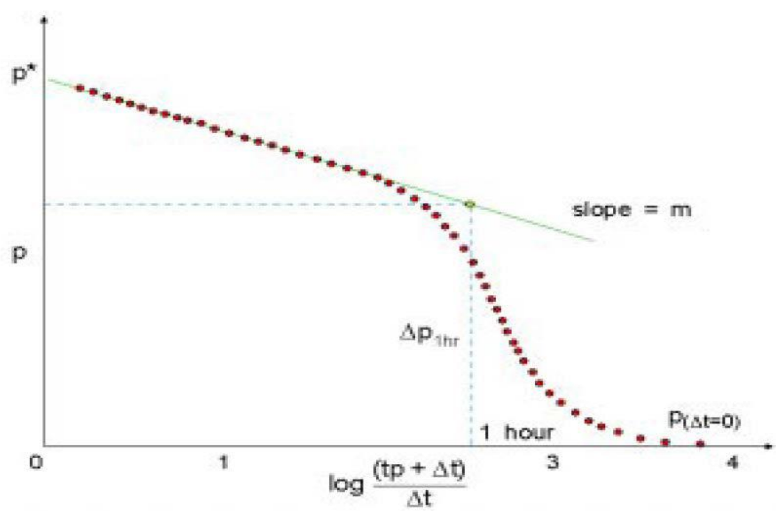

Fig 2.2 Horner's plot for build up analysis

The nonlinear part of the curve on Figure indicates the effect of after flow or wellbore storage. Skin factor may also cause the early-time deviation which can be positive or negative. Positive skin can be formed due to wellbore damage, otherwise a negative skin indicates stimulation (fracturing, acidizing, etc). This shape is formed at the beginning of the curve which means that a pressure transient is spreading around the formation nearest the wellbore.

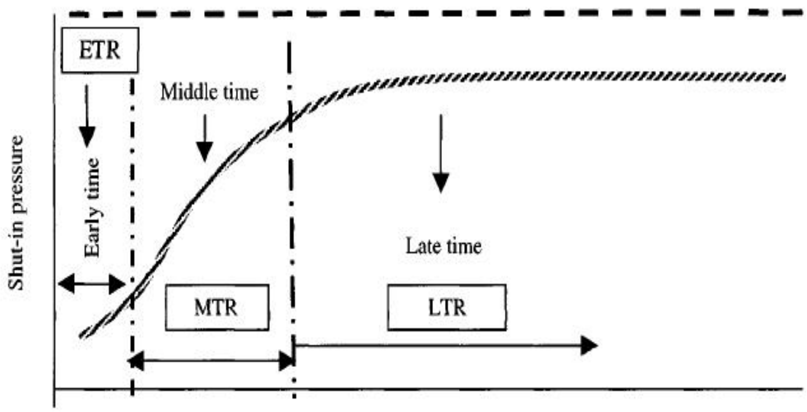

Fig 2.3 Behavior of static pressure on shut in well

2.7.3 INJECTIVITY TEST

This is a well testing technique conducted upon completions of a well. Water is pumped into the well at a constant rate until a stable pressure is reached then the pump is turned off and the rate at which pressure decreases is measured. An injectivity test is conceptually identical to a drawdown test except that flow is into the wellbore rather than out of the wellbore. Injection rate can often be controlled more easily than production rate however, analysis of the test result is the same as the original reservoir fluids. The purpose of the injectivity test is to get an indication of the total permeability of the well. The injectivity test will provide the well with an injectivity index rating, which is usually a reliable indicator of well performance.

The procedure lowering a pressure element into the well and setting it at some depth, preferably at or near a major permeable zone. Once the pressure element is in place, water is pumped into the well at three or four different pumping rates. The first pumping rate is the lowest and each successive pumping rate is higher. The first pumping rate is initiated and held at a constant rate until the well pressure stabilizes. Once the well pressure stabilizes the next pumping rate is initiated and held constant until the pressure in the well stabilizes again. This process is repeated for three or four pumping rates. When the well pressure has stabilized after the highest pumping rate, the pump is turned off and the well is allowed to return to its natural pressure. The well pressure versus time is recorded during the entire process. This procedure may be repeated numerous times with the pressure element at different depths for each test.

A very good practice is to conduct injectivity test before the removal of the drill rig equipment, so that the drill pump can be used for the injectivity test.

Though the injectivity test is a good indicator of well productivity, a major pitfall is that the injectivity index is not always proportional to the productivity index, and therefore the predictions are not always accurate.

2.7.4 FALL OFF TEST

A pressure fall-off test consists of fluid injected into a well at a constant rate for a period of time followed by shut-in of the well and monitoring the pressure decline. A fall off test measures the pressure decline subsequent to the closure of an injection. It is conceptually identical to build up test as with injectivity test. Fall off test interpretation is more difficult if the injected fluid is different from the original reservoir fluid. The pressure profile takes the same shape as the drawdown test.

2.7.5 INTERFERENCE TEST

Sometimes, we are concerned about large scale reservoir property trends. We can monitor the pressure changes at one well (the observation well) due to flowrate changes at another well (the active well). This can give improved estimates of directional permeability and reservoir storativity. Reservoir properties are characterized over a greater length scale than single well test pressure changes. Interference test can be used regardless of the type of change induced at the active well. Interference tests are particularly useful where there is some uncertainty in the geology between two wells, such as the conductivity of a fault, fracture corridors in naturally fractured media, or other sources of significant heterogeneity. The test is carried out between two wells, one being the active (producing) well and the other one is the observation well. In the active well, single or multiple drawdown tests and a subsequent buildup test are performed while the observation well is shut-in for the duration of the test. When combined with conventional single-well testing, this can be used to improve the understanding of the reservoir layering, fracture orientation and the location of barriers to the flow.

2.7.6 MULTIPLE RATE TEST

These are pressure transient tests which can be applied to several well flow situations and they account for variable rate history. These tests are conducted at a series of different flow rates for the purpose of determining well deliverability, typically in gas wells where non-Darcy flow near the well results in a rate-dependent skin effect. The advantages of this test include

i. No problem with variable rate test
ii. No loss of production
iii. Reduced wellbore storage and phase and phase segregation effect thus providing a good result where build up or drawdown test fails (Wells having altered permeability near the wellbore due to damage especially when the damage is not concentrated in a very thin skin at the sand face). The disadvantage can be seen in the fact that rate fluctuations are difficult to measure, especially on a continuous basis

2.7.7 DRILL STEM TEST

Drill Stem Testing (DST) is a procedure to determine the potential productivity, pressure, permeability, or extent of an oil or gas reservoir before the permanent completion equipment is installed. Drill stem testing is essentially a flow test which is performed on isolated formations of interest to determine the fluids present and the rate at which they can be produced. In newly developed reservoirs or in high risk developments, it may be worthwhile to test the well before completing it or installing full-fledged production facilities. This is usually done with a drilling rig on site and the string through which the well is produced is controlled by the drilling rig thus, it is often known as drill stem test. This is done to determine production characteristics of a specific zone of pressure survey to be made and the well killed prior to abandonment or permanent completion. Analysis of drill stem test provides useful information to help evaluate:

a) Productivity of the zone
b) The well completion practices
c) The extent of formation damage
d) The need for stimulation of the zone
e) Actual well producing rate
f) Radius of investigation
g) Average effective permeability which may be better than core permeability
h) Barriers, permeability changes, and fluid contacts

Primary functions of DST

a) Isolate the target zone
b) Control the flow of the well
c) Conduct the fluid to the surface
d) Obtain downhole formation
e) Evaluate the reservoir potential productivity

2.7.7.1 DRILL STEM TESTING TOOLS AND TECHNIQUE

Most drill stem testing tools include two or more clocks driven bourdon recording pressure gauges or two packers and a set of flow valves. The tools are opened and closed by manipulation of the drill pipe. The DST is run while values are manipulated. Depending on the type of test and wellbore conditions there are a number of different tools that are staked over one another to get the desired result. These tools include:

- Reverse Circulation valve: just below the drill pipes there is a mechanically activated valve that provides communication between Drill Pipe and Annulus. Its purpose is to circulate out any produced hydrocarbons after the test is complete by pumping drilling mud down the annulus and then up to the drill pipe.
- Multi-flow evaluator: it contains a sample chamber and a valve that can be opened and closed multiple times during the test to allow flow when required and stop it as well whenever needed.
- Master Valve: below the sampler there is a master valve that is designed to open and close just once during the test. It activates with a delay of 5 minutes after the command is send to it working as a master control valve for the test.
- Bypass Valve: this valve allows the drilling mud already present in the wellbore to pass out the annulus from the inside of DST assembly below it while tripping in to avoid swabbing. The same application is used to avoid surging
- Hydraulic Jar: this is an optional component of DST stem. Basically, it is a hydraulic jack that gives an upward shock to free a stuck pipe (if any)
- Slip Joint: in case the hydraulic is unable to free a stuck pipe then we have no option left than to leave the components blow slip joint in the well bore and retrieve out the filled sampler. Slip joint is an anti-threaded sub that screws open to retrieve out the above free components.
- Packers: it is used to isolate the Annulus from the test zone

- Perforated anchor: it provides a base support on the bottom of the hole for the packer to be activated by weight as well as perforations to allow the flow. It is also mounted by outside pressure recorders.

2.7.7.2 DRILL STEM TESTING OPERATION

In a standard drill stem test, the initial flow period is usually shut for 5 to 10 minutes. The idea is simply to release the high hydrostatic mud pressure. The initial shut in period should be sufficiently long to allow the measured pressure to approach stabilized formation pressure. Experience indicates that 1 hour is usually required for initial shut in period. The second flow period should be long enough to allow flow stabilization.

2.7.8 PULSE TEST

This is another form of multiple well test which involves more than one well. A pulse test is a modification of standard interference testing that is designed to assist in identification of the signal produced by the stimulus. The test is carried out between two wells, one of which is an observation well and the other well is subjected to a series of injection or production "pulses" followed by shut-in. A pulse test provides equivalent data by using short rate pulses (with smaller observed pressure changes). The process generates an identifiable pressure pattern, which can be detected by the observation well and can be isolated from the general field pressure trends. Following parameters such as hydraulic diffusivity, transmissibility and formation storage can be estimated. Pulse test values are much less affected by boundary conditions such as faults and acquifers than are interference test values. Analysis technique is more complicated and usually requires a computer. Other advantages, in comparison to interference testing can include:

1. Only two wells are involved in the test at a time, and the other wells in the field can continue injection/production
2. The test time for determining formation properties is much shorter than for conventional interference testing
3. There is a basis (as in conventional interference testing) for determining storage (fc_th), diffusivity (k/fmc_t) and interval transmissibility (kh/m)
4. Since an identifiable pressure pattern is used, there is more certainty for discriminating noise.
5. Wells other than the observation wells do not need to be monitored.

The diagram below illustrates pulse test for two well system. These show a producing well that is pulsing. Although the time and shut in time are equal in the figure below, pulse test can be done with unequal shut in time.

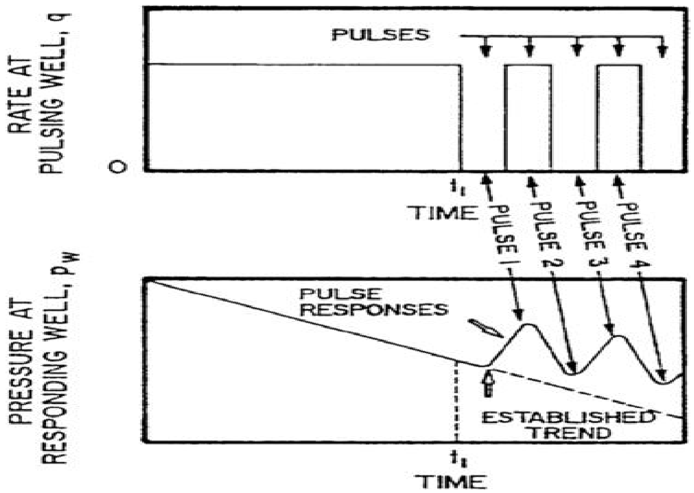

Fig 2.4 Schematic illustration of rate (pulse) history and pressure response for a pulse test

2.8 FLOWING GRADIENT (FG) AND STATIC GRADIENT (SG) SURVEY

The flowing gradient and static gradient tests are auxiliary surveys that complement bottom hole pressure tests.

2.8.1 FLOWING GRADIENT (FG)

This involves measuring flowing pressure at different depths in the well while the well is flowing. Result of this test is used for gas lift optimization. The figure below show cases where the flowing pressure measured along the transverse of the well reveals example of optimized and non-optimized gas lifting. The flowing gradient survey provides flowing pressure which can be used to determine the appropriate correlation for modelling flow along the wellbore. In all cases during the flowing gradient survey, the depth where pressure is measured is important.

2.8.2 STATIC GRADIENT (SG)

In static gradient, pressure at different depth in the well is measured while the well is shut in. Usually before a static gradient is run, the well must have been shut in for some time to allow the pressure to stabilize. At every static gradient, the gauges must be left for a minimum of 15 minutes so that pressure will be steady. Static gradient survey is used to determine the fluid distribution in the wellbore. This information is required for pressure correction and locating the depth of operating gas lift valves. The basis for determining fluid gradients using static gradients survey is that gradients depends on density of the fluid.

2.9 BASIS OF WELL TESTING

Understanding and correctly analyzing well test data requires understanding physical process involved in fluid flow processes, the effect of reservoir geometry and heterogeneity.

2.9.1 RESERVOIR ENVIRONMENT

i. Reservoir starting pressure (0.433 psi/ft)
ii. Hydrostatic pressure: this is the pressure acting against the formation pressure i.e. the pressure exerted by the mud column.

iii. Flowing well pressure: this is the pressure that drives the reservoir fluid to the surface. It is the pressure measured when the well is flowing (Pwf)
iv. Differential pressure (p) is the difference between the reservoir pressure and flowing bottom hole pressure.

The reservoir as a model is divided into 3 regions under physical and mathematical terminologies:

Table 2.1: Principal Reservoir regions

PHYSICAL TERMINOLOGY	MATHEMATICAL TERMINOLOGY
Region 1: The wellbore and near wellbore region	The inner boundary condition
Region 2: The reservoir beyond the wellbore	The basic model
Region 3: The pressure and flow conditions at the outer extent of the well drainage area	The outer boundary condition

2.9.2 THE INNER BOUNDARY CONDITION

The conditions around the inner boundary are

a) Wellbore storage
b) Skin effect
c) Induced fracture

2.9.2.1 WELLBORE STORAGE

Wellbore storage is after flow of fluids into the wellbore after the well is shut-in at the well head. It also occurs in the early life of a well when the fluid produced does not come immediately from the reservoir but it is the fluid stored in the wellbore thus, there is a delay in time before the reservoir flowrate equals surface production. During wellbore storage, reservoir effects are distorted, making it impossible to quantify well properties such as permeability, skin and P*. Wellbore storage effect lasts until pressure is equalized between the wellbore and formation. The duration of wellbore storage is primarily dependent on three factors viz: the wellbore volume, the formation permeability and fluid compressibility. Larger volumes, lower permeability and larger compressibility (gas wells) increase the duration of wellbore storage. The wellbore storage phase is a problem during well test interpretation because it pollutes the transient phase from which useful information about the reservoir can be obtained.

2.9.2.2 SKIN EFFECT

Pressure drop during flow resulting from damage to the formation is caused by invasion of drilling fluid, formation of mud cake, cement and insufficient perforation density. Skin is the term used to refer to the damage or stimulation that exists near the wellbore. The condition of near wellbore region is critical in production of crude oil. Skin effect is generally used to characterize this region. At steady state condition, skin effect results in a pressure drop for flow of crude oil through the wellbore region. In general, any phenomenon that causes a distortion of the flow lines would result in a positive value for the skin factor. Positive skin effect can be created by mechanical causes such as partial completion. Any phenomenon which can decrease the permeability of the reservoir around the wellbore can increase skin effect. A negative skin effect denotes that the pressure drop in the near-wellbore zone is less than it would have been from normal undisturbed reservoir mechanisms. Negative skin effect is usually due to acid fracturing or hydraulic fracturing which increases the permeability. Production rate increases if skin effect decreases.

2.9.2.3 INDUCED FRACTURE

Human activities around the wellbore can cause induced fracture. If a well is fractured (induced fracture), the flow pattern in the fracture into the wellbore will be bilinear, linear into the fracture and linear within the fracture. After producing for some time, the pressure transient shape begins to become radial (pseudo-radial flow period).

2.9.3 CONDITION AROUND REGION 2

There are basically two types of reservoir viz:

a) Homogenous reservoir
b) Heterogenous reservoir

2.9.3.1 HOMOGENOUS RESERVOIR

This is a reservoir that has identical property throughout e.g. porosity and permeability.

2.9.3.2 HETEROGENOUS RESERVOIR

This reservoir may be classified into two major types such as Double porosity reservoir and Double permeability reservoir. Double porosity reservoir consists of two homogenous porous media of distinct porosity and permeability that interact with one medium, producing fluid into the well while the other acts as a source. Double permeability reservoir consists of two homogenous media with each medium producing fluid into the wellbore.

2.9.4 OUTER BOUNDARY CONDITION

Due to the pressure flow in the reservoir, the infinite acting reservoir is a reservoir that has a large extent of fluid communication and a large drainage area while in a finite acting reservoir, the fluid volume communicating with the well is limited because of fault and constant pressure value.

2.9.5 TRANSIENT STATE PHASE

This state phase occurs when the well is not influenced by the nature of the reservoir. This is the most important phase because the reservoir parameter such as permeability and skin are deduced from pressure-time data obtained during this phase is the part not polluted by the wellbore storage phase. Due to the usefulness of this phase, the following guidelines must be followed during test:

i. Design and run test so that not all part of the transient state will be polluted by the wellbore storage phase.
ii. Test duration must reach transient state before test is stopped.

The duration of transient state is affected by the following:

i. Permeability of the formation: The higher the permeability, the shorter the duration of the transient phase. Thus, the well with higher permeability will have short transient state. This imposed a problem during interpretation stage because transient state duration could be easily marred by the wellbore storage phase.
ii. Location of test well: The location of test well with respect to reservoir boundary affect the duration of transient state well that are closer to the boundary will have shorter transient period compared to the well that are farther from the boundary

2.10 RESERVOIR BOUNDARY RESPONSE

There are different types of reservoir boundary responses:

i. Close boundaries: When a reservoir is closed on all sides, the pressure transient will be transmitted outwards until it reaches all sides after which reservoir depletion will enter a pseudo state making the pressure in the reservoir to decline at the same rate everywhere in the reservoir.
ii. Fault boundary: Fault boundary usually act as impermeable barriers and therefore, the pressure response of a well closed to a single linear fault can begin to look like the response of a closed reservoir. However, the response is different since the wells response is only one boundary instead of being completely closed on all sides thus, no pseudo steady state. The well will see itself in the minor and the net later time response will be like that of two identical wells. In Horner's plot, the original infinite acting response will undergo a doubling in slope at the time the boundary effect is felt.
iii. Constant pressure boundaries: When the reservoir is supported by fluid encroachment due to natural influx from an aquifer or gas cap or by fluid injection when a constant pressure may be present, such a boundary may completely enclose the well or may be an open boundary to one side of the well, the effect of any constant pressure as the boundary, for circular constant pressure boundary with the well at the center, the wellbore pressure response will depart from semi log straight line and achieve a steady state.

2.11 FLOW REGIMES

There are three types of flow regimes namely:

a) Steady state flow
b) Unsteady state flow
c) Pseudo steady state

2.11.1 STEADY STATE FLOW

Steady state exists in a flow system when there is no change in density at any position within the reservoir as a function of time. The system has the following characteristics:

i. There is no change in pressure at any position in the reservoir.
ii. No material accumulation at any point in the reservoir system.
iii. The mass flowrate into the reservoir equals mass flowrate out of the reservoir.
iv. Pressure and rate distribution throughout the reservoir are independent of time.
v. Steady state condition is closely approximated by a reservoir under strong water drive, a large gas cap or secondary recovery on a regular pattern basis and pressure maintenance by gas injection up dip.

2.11.2. UNSTEADY STATE FLOW

This flow occurs when rate and pressure changes with time or when pressure changes with time.

2.11.3 PSEUDO STEADY STATE FLOW

This occurs when a reservoir is produced at a constant rate for a long enough period of time so that the entire drainage area of the reservoir is affected by pressure disturbance. Its characteristics include:

i. There is a constant change of pressure with time at all radii
ii. There is parallel pressure distributions and corresponding constant rate distributions
iii. Pressure becomes relatively constant at each radius

2.12 DIAGNOSTIC ANALYSIS

The buildup is divided into three time regions– early, middle, and late time. The middle time represents radial flow and it is not until middle time is reached that the permeability can be determined. The permeability is calculated from the slope of the semi-log straight line, from the vertical location of the flat portion of the derivative. These two answers should be the same. The skin is calculated from the "p curve. In Figure3, the larger the separation between the curves in the middle time region, the more positive is the skin. Early time represents the wellbore and the near wellbore properties (effects of damage, acidizing, or hydraulic fracture). It is often associated with a (log-log) straight line of fixed slope. A slope equal to "one" means "wellbore storage," and during that period, nothing can be learned about the reservoir because the wellbore is still filling up. A slope of "half" typically means linear flow as a result of a hydraulic fracture. From this straight line, the fracture length or fracture effectiveness can be calculated if the permeability is known. The period after middle time is known as late time, and it reflects the effect of the reservoir boundaries and heterogeneities. It is from this region that the reservoir shape can be determined. A straight line of slope approximately "half" would indicate a long, narrow reservoir. A straight line slope approximately "one" could imply a low permeability reservoir surrounding the region investigated during middle time. If the derivative trends downward during the late time period, it could indicate an improvement in permeability (actually mobility) away from the well. If this downward curvature is severe, it might be indicative of a depleting reservoir. The average reservoir pressure (Pr) is obtained by extrapolating the semi-log straight line to infinite shut-in time (=1 on the Horner plot). This extrapolation is called p* and it is used, along with an assumed reservoir shape and size, to calculate the average reservoir pressure. For short flow durations, for example in a DST or in the initial test of a well, the correction from P* to Pr is negligible, and P* does equal Pr.

2.13 DIFFICULTIES ENCOUNTERED WHILE PERFORMING WELL TESTING

2.13.1 PERIODIC CHANGE OF FLOWRATE AND PRESSURE

This can result in accumulation effect or wellbore storage will occur. This problem can be solved by increasing the production rate to draw the accumulation in the tubing.

2.13.2 STABILIZATION PERIOD

In some wells, it is not easy to obtain the nature of flow in the reservoir and well or the location of the equipment.

2.13.3 FLUID SLUGGING INTO THE SEPERATION EQUIPMENT

This occurs if there is a long flowline with chokes at the well head. This can cause erratic production rate or a short increased back pressure.

2.13.4 FORMATION OF HYDRATE

In the system of flowlines, it may be difficult to obtain a good result. This is solved by changing the equipment or installation of heater treated up stream of the high pressure separator or use of low temperature separator. Glycol or alcohol can be injected into the flowing system or bottom hole choke can be installed in the well.

2.14 WELL PROBLEMS

A well is said to have problem when its behavior deviates from the normal production pattern. Well problem analysis involves the determination of such abnormal behavior. In order to understand well's abnormality, it is necessary to know what exactly constitutes normal behavior such as:

i. The amount of gas or oil produced.
ii. The gas oil ratio(GOR)
iii. The water cut
iv. The rate of injection (for gas injection wells)

To analyze well problems, the study can be reservoir area or on well basis. However, before studying an individual well, it should be ascertained that it is not reservoir problem that the problem actually exists. The following are typical well problems for producing wells:

a) Low productivity
b) Water-gas coning
c) Near wellbore restrictions: which includes partial penetration, scales and precipitate formation, formation of emulsions, etc.

d) Liquid loading
e) High GOR
f) Low reservoir permeability
g) Low reservoir pressure
h) Formation damage and skin value
i) Wellbore and tubing plugging
j) High viscosity oil
k) Excessive back pressure on the formation
l) Inadequate gas lift
m) Gas problem in oil wells
n) For injection wells, the problem may be low volume of fluid, high injection pressure, mechanical problem.

2.14.1 LOW PRODUCTIVITY

Many reasons can be deduced for low production rate. The question to be answered is which of the reasons is actually responsible? The likely cause of low or limited production rate are as follows:

a) Low reservoir permeability
b) Low reservoir pressure
c) Formation damage and skin value
d) Wellbore or tubing plugging
e) High viscosity oil
f) Excessive back pressure on formation
g) Inadequate gas lift system
h) Mechanical problem

2.14.2 WATER-GAS CONING

This is the encroachment of gas from the gas cap and water from the water acquifer into the oil producing zone. Water and gas coning is a serious problem in many reservoirs with wells producing from an oil zone underlying a gas cap, overlying an acquifer or both. Coning occurs in a well on production, when the water or gas zone moves up towards the wellbore in the form of a cone. Eventually, the water or gass breaks through into the well and water from the acquifer and/or gas from the gas cap is produced along with oil. The water or gas production increases progressively after breakthrough time and may reduce significantly the crude oil production.

The main factors affecting the water and/or gas coning tendency are the density difference between oil and gas or oil and water, the viscosity of water or gas, formation permeability, pressure drawdown, flow rate, etc.

Coning by water and/or gas can be reduced by:

i. Decreasing the well production rate
ii. Improving the productivity of the well

iii. Using horizontal instead of vertical wells to produce the formation
iv. Recompleting the well at a different elevation to increase the distance between the gas-oil or water-oil contact and the perforated interval
v. Performing an infill drilling

Effects of Coning

i. Reduction in oil production rates (water and gas have much higher mobility than oil)
ii. Corrosion of production facilities
iii. Loss of gas cap drive
iv. Loss in water drive

2.14.3 NEAR WELLBORE RESTRICTIONS

Restrictions can occur in the formation or within the wellbore that can cause a decrease in oil or gas production. These restrictions are a result of changes in the formation or fluid properties around the wellbore, chemical reactions within the formation or the wellbore, mechanical problems, or inadequate completion techniques.

i. **Partial penetration**: this occur if only a portion of the productive formation has been drilled or perforated. Gas or oil that is flowing from the reservoir to this limited area will cause large pressure gradient near the wellbore. Fluid flow within the pores may also reach turbulent velocity, thus generating additional pressure drop and reducing the productivity of the well. Studies on partial penetration have concluded that the effects are similar to skin damage around the wellbore (that is, an altered permeability that is lower than the reservoir permeability). To overcome these effects, the well must be deepened to expose all of the productive interval or more perforations must be added to expose additional reservoir to flow
ii. **Scales and precipitates:** plugged or inadequate perforations have the same effect as partial penetration; that is, reservoir fluids are restricted from flowing into the wellbore. Perforations can become plugged with scale or other solid particles that are precipitated from formation fluids. As these fluids are produced, equilibrium conditions of pressure and temperature become altered (especially near the wellbore) causing precipitation of these particles. Some precipitates can form when incompatible fluids come in contact downhole. Workover and completion fluids should be tested with formation fluids for compatibility. Precipitates can also occur in a formation after an acid treatment.

The most common types of scales are calcium carbonate and calcium sulphate (gypsum).c Sodium chloride (salt), Sulphur, and other minerals can also be precipitated under certain conditions. The formation of these scales or solids can be minimized or prevented through the use of chemical inhibitors, provided the produced fluids are analyzed ahead of time. If not, it may be necessary to perform a workover to clean out the well.

iii. **Paraffin or asphaltenes:** some oils can precipitate appreciable amounts of paraffin or asphaltenes as the temperature and pressure are reduced in the near wellbore region. Most often these deposits form near the surface where the temperature is lowest. However, there have been many confirmed cases of paraffin buildup near the perforations. Removal of these deposits can be accomplished with heated oil or chemical solvents.

iv. **Emulsions:** emulsions can also form in or around the wellbore and may create a block that restricts or completely cuts off production from the reservoir. An emulsion is simply a mixture of one liquid (the discontinuous phase) that is dispersed within another liquid (the continuous phase) and is likely to be formed when oil and water are mixed. Stable emulsions are the most likely to block production and are also the most difficult to remove. For an emulsion to become stable, an emulsifying agent (fine particles and/or surfactants) must be present. Although surfactants can cause emulsions, other surfactants at the proper concentrations can break emulsions. Also, special de-emulsifier agents are available to remove emulsion blocks.

v. **Formation collapse:** this usually occur in loosely consolidated or weakly cemented formations. It is due to the severe pressure drop that occurs around a wellbore which cause the formation to collapse. When this occurs, the pore structure is altered and the permeability is reduced, causing skin damage around the wellbore. To prevent this, a small hydraulic fracture treatment can be performed early in the life of the well. The fracture treatment will help minimize the pressure gradients and reduce the chance of formation collapse around the wellbore.

As the pressure is depleted throughout the reservoir, the overburden pressure caused by the overlying rock tends to compress the formation. This overburden pressure can also alter the pore structure

2.14.4 LIQUID LOADING

Liquid that enters the wellbore at the bottom of the hole can only flow the surface if the difference in pressure between the bottom and the top of the well is greater than the hydrostatic pressure of the fluid column, plus any friction that occurs as a result of flow up the tubing. If the pressure is not sufficient, the fluid will remain static in the wellbore. This is referred to as liquid loading. If gas is primarily being produced, water flowing from the formation, or condensed within the tubing, can also accumulate in the wellbore if the gas is not flowing at sufficient velocity to lift the water from the well. Accumulation of this static fluid column can impose an additional backpressure on the formation that can significantly reduce the productivity of the well or can actually “kill” the well so that it does not flow at all.

When liquid loading occurs, it may be necessary to change the wellbore configuration or to install artificial lift equipment. For example, the size of the tubing affects the velocity of the fluid flowing up the well. If smaller tubing is used, the velocity of the fluid will be greater because of the smaller cross-sectional area.

2.14.5 LOW RESERVOIR PERMEABILITY

Low reservoir permeability may be an overall reservoir characteristic or it may be limited to a specific area. In a low permeability reservoir, well productivity declines rapidly as fluids near the wellbore are produced, production test and pressure buildup test may be used in differentiating between low permeability and formation damage.

2.14.6 LOW RESERVOIR PRESSURE

If reservoir pressure measurements have been carried out on a routine basis, reservoir pressure history should be well documented. The next step is to consider the dominant reservoir drive in a particular reservoir and how this drive mechanism is associated with the apparent problem being investigated.

2.14.7 FORMATION DAMAGE AND SKIN VALUE

This is the partial or complete plugging of the near wellbore area which which reduces the original permeability of the formation.

2.14.7.1 THE CONCEPT OF DAMAGE ZONE AROUND THE WELLBORE

The causes of formation damage are as follows:

- Drilling: A situation when wrong drilling practices are carried out.
- Cementing: A situation where wrong or incomplete cementing job is done.
- Perforating: A situation where perforation is either too high to the gas cap or too low to the water zone.
- Completion and workover operations.
- Gravel packing.
- Production at high rates that exert drag on the walls of the formation.
- Injection operation perhaps with fluid that is not compatible with the formation.

Generally, formation damage can be characterized by the following causes:

- Migration of fines (based on nature of injection fluid, type and compatibility with formation).
- Swelling clay
- Scale deposits (based on nature of injection fluid, type and compatibility with formation).
- Organic deposits (based on nature of injection fluid, type and compatibility with formation).
- Induced solids.
- Induced kill fluids.
- Induced precipitates.

Correct identification is critical to successful removal of the damage or other impairment. It requires more than little experience and a thorough knowledge of field operations. Formation damage is totally unacceptable to production engineers because it restricts the flowrate into the wellbore. To improve the flowrate, the damage has to be removed or at least reduced ie permeability near the wellbore must be increased. Formation damage is quantified by a dimensionless factor called skin factor (simply skin). Pressure transient tests help to estimate the magnitude of the damage.

2.16. DESCRIPTION OF TERMS

- SKIN DUE TO PARTIAL PENETRATION: When a well does not fully penetrate the formation, or the perforations do not open up the whole formation, the reservoir fluid has to flow vertically with the flow lines converging near the penetrated area at the wellbore. The convergence of the flow lines near the wellbore cause an additional pressure drop near the wellbore, an effect similar to that caused by wellbore damage. The effects of partial penetration are accounted for by treating it as a skin effect called skin due to partial penetration (spp). This skin is always positive and typically varies from 0 to 30. It is a function of the height of the perforated interval (hp), the distance from the top of the zone to the top of the perforations (htop), and the horizontal to vertical permeability ratio (kh/kv). The height of perforations or perforated interval (hp) is that portion of the net pay (h) that is open to flow into the wellbore either through partial penetration of the wellbore, or incomplete perforation. Normally, in order to maximize production, the entire net pay (h) is open to flow into the wellbore (fully penetrated, hp = h). In some cases, it is necessary to perforate so only a portion of the net pay (h) is open to the wellbore in order to minimize coning effects. This perforated interval is judiciously placed a certain distance from the top of the zone to the top of the perforations (htop).The perforated interval has a maximum value dependent on the net pay (h) and the net wellbore inclination (s) . Top of Zone to Top of Perforations (htop) In a partially penetrated well is the distance from the top of the zone to the top of perforations. When a formation is only partially penetrated, the location of the perforated interval has an effect on the skin due to partial penetration (spp). Thus we could have the same net pay (h) and the same perforated intervals, but because these perforated intervals are located at different locations they will have different skin effects due to partial penetration. The horizontal-to-vertical permeability ratio represents the contrast in permeability between the horizontal and vertical planes within a formation (anisotropic permeability). This ratio is applicable when dealing with partially penetrated or horizontal wells and directly affects the skin due to partial penetration (spp). It typically ranges in value from 0.1 to 1000. For example, in a well with partial penetration the fluid has to travel vertically because the whole of the net pay (h) is not open to the wellbore as shown below. This vertical component of flow calls into play the vertical permeability, in addition to the horizontal permeability. A large horizontal-to-vertical permeability ratio implies a relatively low vertical permeability, which creates a larger pressure drop near the wellbore due to the vertical component of flow. Thus, this increase in pressure drop near the wellbore is represented as an increase in the skin due to partial penetration (spp).

- RADIUS OF INVESTIGATION: Radius of investigation represents how far into the reservoir the transient effects have traveled. A pressure transient is created when a disturbance such as a change in rate occurs at a well. As time progresses, the pressure transient advances further and further into the reservoir. This concept is not theoretically rigorous, but is adequate for practical purposes. Theoretically, when a pressure disturbance is initiated at the well, it will have an immediate effect, however minimal, at all points in the reservoir. At a certain distance from the well, however, the effect of the disturbance will be so small as to be unmeasurable. The furthest distance at which the effect is detectable is called the radius of investigation. There is a time *t* when the pressure disturbance reaches the distance (radius of investigation).
- STIMULATION: Oil well stimulation is the general term describing a variety of operations performed on a well to improve its productivity.it can be conducted on old wells and new wells alike; and it can be designed for remedial purposes or for enhanced production. Its main two types of operations are matrix acidization and hydraulic fracturing. Matrix acidization involves the placement of acid within the wellbore at rates and pressures designed to attack an impediment to production without fracturing or damaging the reservoir (typically, hydrofluoric acid is used for sandstone/silica-based problems, and hydrochloric acid or acetic acid is used for limestone/carbonate-based problems). Hydraulic fracturing, which includes acid fracturing, involves the injection of a variety of fluids and other materials into the well at rates that actually cause the cracking or fracturing of the reservoir formation.

CHAPTER THREE

3.1 WELL HISTORY

The given well is one obtained from literature. It is stated to be an onshore oil and gas field located in north central of a Delta basin. The field was discovered in 1974. The well was drilled in 1980 and flowed at a rate of 1673bbls/day. It is being operated by Midwestern Oil and gas although, the field was originally permitted to Elf Petroleum Nigeria. The well was drilled to a depth of 9560ft.The well experienced high sand and water production. The Well was closed in 1996.

3.2 PRODUCTION DATA TABLE FOR WELL

Table 3.1Production data Table for well

DATE	BEAN /64	BS&W	THP(psig)	GOR(scf/bopd)
03/81	28	0	400	680
07/81	24	0	570	661
01/82	20	0	490	473
06/82	20	0	500	426
11/82	16	0	550	397
05/83	16	0.75	700	411
11/83	10	2	600	312
04/84	8	2.16	500	312
11/84	8	2.28	550	494
05/85	10	2.56	550	421
12/85	-	-	-	-
11/86	-	-	-	-
03/87	24	4.92	600	559
09/87	20	6.84	700	661
04/89	20	9.45	450	820
11/89	16	10.45	320	473
01/90	20	4.12	175	661
09/90	24	2.05	240	661
05/91	36	0.75	420	900
12/91	20	0.10	420	473
06/92	16	0.86	350	300
01/93	8	2.56	300	208
11/93	8	4.35	250	285
03/94	8	5.62	350	209
06/95	20	6.94	400	384
04/96	20	8.56	600	450

3.3 PRESSURE VERSUS TIME READING FOR WELL

Table 3.2Pressure versus time reading for Well

Δt(hr)	Pws(psig)	(Tp+Δt) /Δt	Δp(pws-pwf)psig
0.0	1850.25	-	-
0.02	1880	360	29.75
0.028	1892	280	41.75
0.037	1907	220	56.75
0.045	1920	180	69.75
0.05	1935	150	84.75
0.06	1950	130	99.75
0.068	1962	118	111.75
0.08	1975	100	124.75
0.088	1987	92	136.75
0.101	2000	80	149.75
1.127	2020	64	169.75
0.163	2027	50	176.76
0.205	2030	40	179.75
0.24	2032	34	181.75
0.276	2033	30	182.75
0.36	2035	23	184.75
0.4	2037	21	186.75
0.47	2038	18	187.75
1.6	2047	6	196.75
2	2050	5	199.75
2.58	2051	4.1	200.75
6.67	2057	2.2	206.75
10	2060	1.8	209.75
11.43	2061	1.7	210.75

BUILDUP WELL TEST RESULTS

CLIENT: MIDWESTERN OIL AND GAS COMPANY

DATE: JUNE 1990

PRODUCTION TIME: 8 hrs

PRODUCTION RATE: 150bopd

3.4 BHP Graph of Pws versus Δt

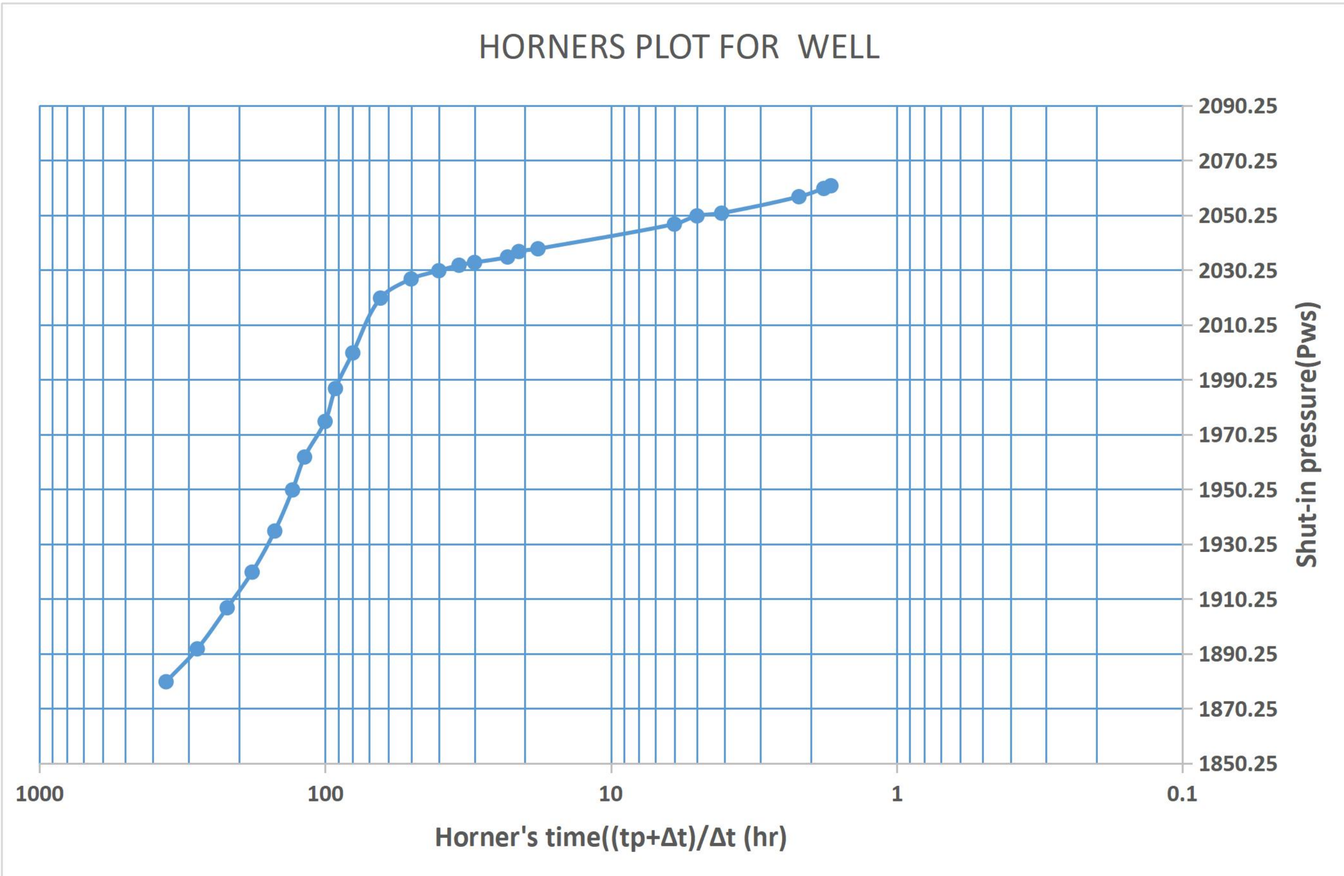

Fig 3.1 HORNER'S DIAGNOSTIC PLOT FOR WELL

3.5 The Graph of log Δp versus Δt

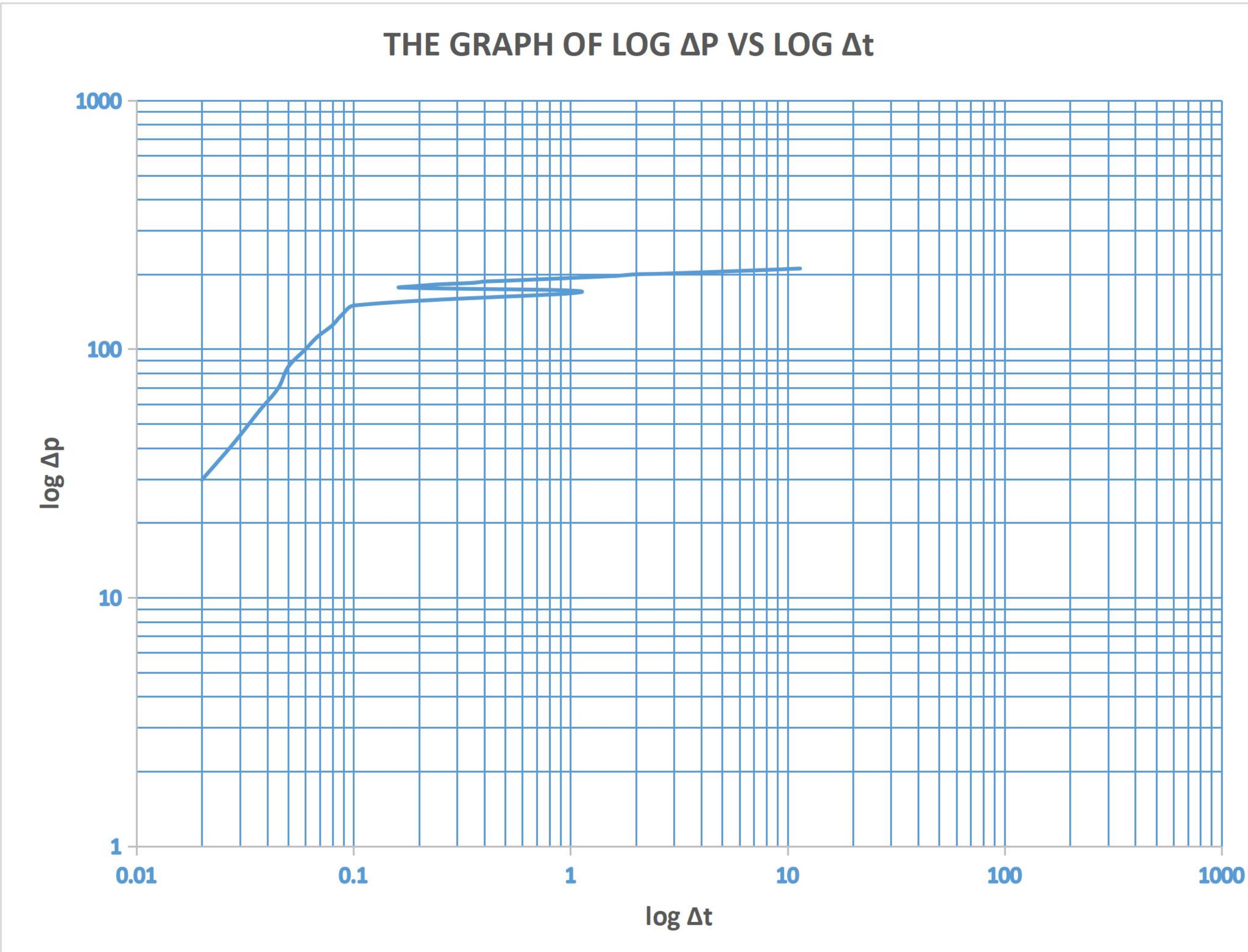

Fig 3.2THE GRAPH OF LOG ΔP VS LOG Δt

PARAMETER FOR BHP ANALYSIS

Q=150bbl/day

μ_o=1.80cp

β_o=1.15rb/stb

Ct=1.8×10^{-5}

Rw= 0.40

Ø =27

H=65ft

3.6 DATA FROM THE BHP GRAPH OF WELL

P*=2065

Pwf=1850.25

P1hr=2045

Slope (m)= $\frac{P^* - P1hr}{\log 1 - \log 0.1}$

m= $\frac{2065 - 2045}{1}$

m= 20psi/cycle

PERMEABILITY, K

K= $\frac{162.6qub}{mh}$

K= $\frac{162.6 \times 150 \times 1.80 \times 1.15}{20 \times 65}$

K=38.8md

TOTAL SKIN St

St= $[\frac{2045 - 1850.25}{65} - \log(\frac{k}{\mu ctrw2})$ +3.23]

PRESSURE DROP DUE TO SKIN

P= $\frac{141.2 q\mu\beta s}{kh}$

P= $\frac{141.2 \times 150 \times 1.8 \times 1.15 \times 8.66}{38.8 \times 65}$

P=150.55

FLOW EFFICIENCY

FE= $\frac{pr - pwf - \Delta p}{pr - pwf}$

FE= $\frac{2065 - 1850.25 - 150.55}{2065 - 1850.25}$

FE= 0.3

PSEUDO SKIN (SKIN DUE TO PARTIAL PERFORATION)

Sp=$[\frac{h}{hp} - 1][\ln(\frac{h}{rw}\sqrt{\frac{kh}{kv}}) - 2]$

$[\frac{65}{31} - 1][\ln(\frac{65}{0.4}\sqrt{\frac{kh}{kv}}) - 2]$

Assuming $= \frac{kh}{kv}$ =1

$(1.097 \times 5.09) - 2$

$=3.58$

DAMAGE SKIN (Sd)

Sd=$\frac{hp}{ht}(st - sp)$

Sd=$\frac{31}{62}(8.66 - 3.58)$

TRANSMISSIBILITY

Transmissibility= $\frac{kh}{\mu}$

$= \frac{38.8 \times 65}{1.8}$

PRODUCTIVITY INDEX

PI= $\frac{q}{pr - pwf - \Delta ps}$

$= \frac{150}{2065 - 1850.25 - 150.55}$

=2.34bopd/psi

DAMAGE RATIO

D.R= $\frac{1}{FE}$

$=\frac{1}{0.3}$

=3.3

R-FACTOR

R-factor $=\frac{\Delta ps}{pr - pwf}$

$= \frac{150.55}{2065 - 1850.25}$

=0.7

DAMAGE FACTOR

D.F=1─F.E

= 1─0.3

=0.7

RADIUS OF INVESTIGATION

Ri= $\frac{kt}{948 \mu ct}$

$=[\frac{kt}{948 \times 1.8 \times 0.27 \times 1.8 \times 10 - 5}]0.5$

=193.46ft

RATE AFTER SKIN IS REMOVED

Q= q × $\frac{p1hr - pwf}{p* - pwf - \Delta ps}$

=150 × $\frac{2045 - 1850.25}{2065 - 1850.25 - 150.55}$

=455.02bopd

EFFECTIVE WELLBORE RADIUS (Rwa)

$Rwa = rwe^{-s}$

$= 0.4 \times e^{-8.66}$

$= 6.94 \times 10^{-5}$

POTENTIAL PRODUCTION RATE WITHOUT SKIN

$Q = \frac{150}{0.3}$

$= 500$ bopd

Table 3.4 SUMMARY OF PARAMETERS CALCULATED FROM BHP DATA

PARAMETERS	VALUES AND UNITS
Permeability(k)	38.8 md
Total skin(St)	8.66
Pseudo skin(Sp)	3.61
Damage skin(Sd)	2.54
Pressure drop due to skin	150.55
Productivity index	2.34bopd/psi
Damage ratio(D.R)	3.3
Flow efficiency(F.E)	0.3
Damage factor	0.7
Radius of investigation	193.46ft
R-factor	0.7
Transmissibility	1401.1bblmdft/cp
Potential production rate without skin	500 bopd
Rate after skin is removed	455.02b0pd
Effective wellbore radius(Rwa)	6.94×10^{-5}

CHAPTER FOUR

DATA ANALYSIS AND INTERPRETATION

4.1 PRODUCTION DATA ANALYSIS

From the production data of the well, the production started in march 1981 at a rate of 1673 bopd and choke size of 28/64. With time, the production rate kept decreasing with increasing BS&W. Gravel packing was done to curb the sand production. As a result, the production rate increased gradually. With further production, the rate reduced with increasing BS&W until the well was shut in.

4.2 ANALYSIS OF BHP DATA

The BHP survey was carried out on June 1990.The well was produced for 8hrs before it was shut in. The data obtained are analyzed as follows:

PERMEABILITY(K)

The permeability was found to be 38.8md. This reduced permeability is indicative of damage caused during drilling and completion process. This could be as a result of migration of fine particles which could block the pore spaces. It could also be caused during the perforation process.

TOTAL SKIN(St)

The total skin is calculated as 8.66. It is greater than 1 and positive. This indicates that there is damage in the near the wellbore region.

FLOW EFFICIENCY (FE)

The flow efficiency is lesser than 1 which is indicative of formation damage

PRESSURE DROP DUE TO TOTAL SKIN (∆P)

With the well producing at a drawdown of 214.75, a pressure drop of 150.55psi of the total drawdown occurs across the altered zone. If the damage is removed, the well could produce more fluid with the same drawdown or alternatively, could produce the same at a much smaller drawdown.

SKIN DUE TO PARTIAL PERFORATION (3.61)

The value of this skin is positive, indicating that there was damage due to insufficient or improper perforation during completion process.

DAMAGE SKIN

The damage skin was 2.54, a positive value indicating that there was formation damage as a result of the drilling operations.

R-FACTOR

When the R-factor is lesser than 0.6, the well does not require stimulation but when it is greater than 0.6, it requires stimulation. Since the calculated value was greater than 0.6, the well requires stimulation.

RATE AFTER SKIN IS REMOVED

After skin is removed, the average production rate increased from 150bopd to 455.02bopd

CHAPTER FIVE

CONCLUSION AND RECOMMENDATION

5.1 CONCLUSION

From the analysis carried out on well, it was discovered that there was formation damage which has made the permeability inadequate to allow the well to produce at rates high enough for the timely recovery of investment in drilling and completing the well. Also, the high sand and water production is detrimental to high productivity.

5.2 RECOMMENDATION

- The formation damage should be removed or repaired. This requires a damage removal technique which is usually matrix acidizing but may occasionally involve hydraulic fracturing
- As for the sand production, the wellbore should be cleaned out and the gravel pack re-installed such that it has high integrity.
- The excessive water production can be curbed by squeezing off the perforations and re-perforating at a suitable upper interval.

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