ESTABLISHING DESIGN CRITERIA FOR PRESSURE BUILDUP TESTS

Scott M. Frailey, Texas Tech University
Aaron E. Pierce, Aaron E. Pierce & Associates
Gary E. Crawford, BP Exploration (Houston), Inc.

Abstract

The designs of pressure buildup tests are of equal importance to the analysis of the measured rate, pressure, and time data. Buildup analysis techniques are the focus of many texts, journal articles, and short courses, while discussions of the design of these tests are minimal. Many tests are unsuccessful as a result of poor or little design effort and inadequate instructions concerning field data acquisition .

An effective design not only maximizes the chances of a successful test, but also eliminates unnecessary testing. For example, a design recommendation may be not to conduct the test because the results cannot meet the desired objectives.

This paper discusses criteria vital to an effective buildup design to insure the successful measurement of rate and pressure data. Factors which must be considered include: identifying test objectives, establishing the optimal rate and duration of the drawdown period, and determining the length of the shut-in period.

Introduction

Many pressure buildup tests are conducted without a proper design or they are improperly executed in the field. Consequently, an analysis is impossible; i.e., the test results do not meet the set objectives. Unfortunately, this is not discovered until after the data are acquired and the person conducting the analysis cannot adequately analyze the data. At this point the data are sent to a consultant or a service company to attempt to salvage the recorded data. Usually, the consultant will determine an error in the design and cannot solve the problem, but only recommends what to do differently next time.

Poor planning is the most frequent cause for an unsuccessful buildup test. Lengthy shut-in periods are undesirable due to costs and lost daily production, so the well test is run in as short a time as possible. In other instances, buildup tests may be run routinely for 8, 12, or 24 hours without any planning or consideration for the test objective. Invariably, this causes tests to cease before any analyzable data are recorded. Phenomena that cause a delay in the measurement of analyzable transient data are typically wellbore effects. These include fluid segregation, mechanical failures, and wellbore storage. Outer boundary effects must be considered also. The onset of the influence of a geologic boundary or interference from another well creates a pressure response in the test well that masks a portion of the transient data.

Together, wellbore effects and boundary effects may dominate the reservoir response rendering the test useless. Use of well testing computer software or simulation may provide some conclusions from this poorly acquired data; however, confidence in the results are much less. Commercially available software can provide design criteria for simple or complicated combinations of wellbore and reservoir heterogeneities.

The detriments of a failed buildup are:

- deferred production
- incurred service company expenses
- generated misconceptions that pressure testing does not work
- unresolved original test objective

Sufficient consideration should be given to the design of a well test as is given to its analysis. The primary source of design criteria is from previous buildup tests conducted in the field or, preferably, in the zone to be tested. However, it is not sufficient to identify what was done before, but to find out what worked before.

The major components of a pressure buildup design are to:

- identify test objectives
- collect reservoir, well, and fluid property data
- design drawdown and buildup periods to meet stated objectives
- condition the test well
- acquire pressure and rate data in the field

Once the test objectives are determined, design a buildup to meet these objectives. If it cannot, then do not conduct the test. If it can, the next step is to prepare the test well. Selection of the flow rate and pressure recording equipment and its location during the test and stabilization of the flow rate prior to shut-in are criteria necessary for the well preparation. In addition to flow rate and pressure, rock and fluid properties, well rate history, geological description, and completion information are required.

Well Test Objectives

A buildup contributes to formation evaluation, reservoir characterization, measurement of the near-wellbore condition, pressure maintenance, and surveillance. Make certain the required information is determinable through a pressure buildup test. Other alternatives, such as radioactive tracers, open-hole or cased hole well logging, production testing, or static measurements may meet the objectives more accurately and cost effectively. Table 1 lists several buildup objectives, the data required, and analysis considerations or reasons lengthy tests may be required.

In the area of formation evaluation, effective horizontal and vertical permeability can be quantitatively measured. Well testing can assist in the determination of natural fractures and lateral changes in mobility in the reservoir. Accurate permeability is vital to almost any prediction of production and design of secondary or tertiary recovery. During the discovery of the well, the results of a buildup (possibly from a drill stem test) contribute to the decision to run casing.

Identifying naturally occurring fractures in a reservoir is crucial during field development, including infill well locations, and selection of wells to convert to injection. Additionally, if an aquifer is present, producing at too high rates may cause the water to move more readily through the fractures. This action bypasses the oil in the matrix blocks, the predominant source of the oil. These features occur early in a buildup test and may be dominated by wellbore effects; a downhole shut-in device may be necessary.

Locating lateral changes in mobility using buildups establishes distances to gas caps and water aquifers. In waterflood patterns a lateral mobility change reflects a flood front. However, a buildup may not identify these features if the reservoir "acts" homogeneously. For example, in a waterflood area where the water mobility is approximately equal to the oil mobility, a buildup test will not reflect the flood front.

In order to optimize reservoir development, buildups are used as an integral part of reservoir characterization. Lateral communication of a zone between wells, permeability anisotropy, fault location and relative degree of sealing, and the location and nature of fluid contacts can be concluded from correctly designed pressure buildup tests. All of these characteristics directly impact reserve calculations, number and location of development wells, and well completion requirements.

Evaluation of the near-wellbore condition is based on the skin factor. A buildup is used to identify the presence or absence of near-wellbore damage. This evaluation would determine if the well is a candidate for a stimulation. To measure the effectiveness of a stimulation treatment, a post-treatment buildup is run and a comparison of the pre- and post-treatment buildup skin factor is conducted. This is for either an acidization or hydraulic fracture treatment. Design of a hydraulically fractured well deviates slightly from a well treated with acid; this aspect is discussed in the section "Well Preparation". In the case of injection wells, changes in total fluid mobility before and after a miscible injectant (MI) slug are measured with a buildup. Results from a pre- and post-MI injection may explain an increase or decrease in injectivity. (Note a buildup conducted in an injection well is more commonly called a pressure falloff test. The design of injection wells are slightly different and are not discussed in this paper.)

For damage deeper into the formation than conventionally considered as skin damage (> 1 ft), a buildup is used to determine lateral changes in effective permeability. Examples of deep damage are relative permeability effects such as gas or water coning, precipitation of solids from water or oil, and fines migration.

To adhere to pressure maintenance and surveillance guidelines set forth by company development strategies or government regulations, a buildup is effective in monitoring localized or regional pressure decline. Average pressure in the drainage area of the well is obtainable by the Matthews, Brons, and Hazebroek or Dietz methods. Heterogeneities can cause incorrect calculations of average pressure using these methods. Well testing software may be required. Calculating reserves, identifying poorly drained regions of the reservoir, arresting declining pressure, remaining above bubble point pressure for reservoirs planned for waterflooding, and insuring pressure remains above the minimum miscible pressure (MMP) for reservoirs planned for MI are a few applications necessitating pressure monitoring.

Reservoir and Well Data

History of the well is very important. This includes the rate history ,completion records, and type of artificial lift. The production rates are necessary to determine the type of analysis to conduct. Always include downtime when the well is shut in. Report oil, water, and gas rates.

Completion records consist of wellbore radius, open or cased hole, perforated intervals, and if the well was partially completed into the formation to be tested. The type of artificial lift is important primarily if the test data has mechanical noise. For example, gas-lift mandrels may open during a buildup, allowing additional gas to enter the tubing or oil to enter the annulus during the test. As a result, a large pressure surge will occur, possibly causing the test to fail. Often, wellhead tubing and casing pressures are requested to aid in this troubleshooting process of identifying these types of pressure anomalies. A downhole shut-in is almost mandatory for buildup tests in wells with gas lift.

Fluid properties required are the formation volume factor, viscosity, and compressibility of the fluids in the reservoir. If lab derived fluid properties are not available, there are many reliable correlations available in the literature. Necessary rock properties are porosity, water saturation, formation compressibility, and thickness. Sources of the rock properties are listed below.

Property	Core Analysis	Well Logging	Correlations
Porosity	Y	Y	N
Water Saturation	Y	Y	N
Formation Compressibility	Y	N	Y
Thickness	Y	Y	N

Earlougher, Appendix D, offers a summary of correlations pertinent to buildup design and analysis.

A wellbore diagram with depths, tubulars, and workover history completes the design data requirements.

Well Preparation

After a buildup is determined the most feasible means of meeting the objective, the well must be prepared for the test. The major criteria are measuring flow rate data prior to shut-in, type of shut-in, length of shut-in, pressure gauge location, and gauge selection.

Accurate rate measurements are imperative. Any error in rate directly impacts the permeability and skin estimated from a buildup test. Also, the well can not be produced at rates high enough for free gas to evolve in the reservoir; i.e. the bottom hole flowing pressure must be greater than the bubble point pressure of the oil.

A stabilized rate (+/- 10% of previous rate) prior to shut-in is almost mandatory. This includes gas-oil ratio (GOR), also. If a stabilized rate cannot be maintained, the well is not ready to be tested. The only exception is if the magnitude of the rate fluctuations and the time they occurred are recorded.

The shut-in time of the well is limited to 1 1/2 times the production time. In other words, for shut-in times greater than 1 1/2 times the production time before shut-in, incorrect pressure data are obtained and lead to faulty results.

Often a well must be shut in to run the pressure recording assembly downhole. If this occurs, the well must be produced again to the same stabilized rate and GOR. The subsequent flow period must be 2-3 times the brief shut-in time. After this flow period, the well is shut in for the buildup. The well definitely must be produced following the placement of the tool assembly. If 2-3 times this shut-in period is unreasonable or unattainable, then accurate flow rates and the time they occur must be recorded and incorporated into the analysis.

After the schedule of production and shut-in periods are selected, the means of measuring rate is required. Plans should be made to measure the rates accurately with a temporary or test separator or a spinner log. Accurate flow rates are as important as the measurement of the pressures to quantify the reservoir parameters. Allocated production rates are used if measured rates are unavailable, but are not desirable because rate is directly related to permeability. Moreover, a 20% error in the rate translates to a 20% error in the permeability calculated from a buildup. Also, some spinner logs do not perform at low rates and with multiple production phases.

A well can be shut in either at the surface or downhole near the formation being tested. The simplest, cheapest, and safest shut-in is at the surface. The well is always shut in as close to the wellhead as possible, preferably at the wing valve. A remote surface shut-in is highly discouraged. While surface shut-in has the aforementioned advantages, a lengthy test time may be required to measure the necessary data to analyze the buildup. Consequently, a downhole shut-in is used when a surface shut-in prolongs the measurement of transient pressure data.

The choice of surface or downhole shut-in is governed by the volume and type of fluids in the wellbore. The worse situation is when the fluid level in the wellbore is rising (or falling in the case of a falloff). This occurs during a shut-in period for most all wells that are not producing to the surface. To calculate the time at which the wellbore ceases to dominate the measured pressure for a rising (or falling) liquid level

$$\Delta t > \frac{170{,}000 C_S \, e^{0.14 s}}{(kh / \mu)} \qquad (1)$$

where, C_S is the storage coefficient calculated from

$$C_S = \frac{\text{tubing capacity, bbl/ft}}{\text{density gradient, psi/ft}} \qquad (2)$$

for a rising or falling liquid level, or

$$C_s = c\,V_w \qquad (3)$$

for a liquid filled wellbore. The latter definition of C_s is used for downhole shut-in; V_w represents the volume of fluid below the shut-off device and top of the zone being tested. Use a skin (s) factor equal to 0 if it is suspected of being <0 [Earlougher].

If the well is hydraulically fractured, the transient data occurs later. The start of transient data is at

$$\Delta t = \frac{11{,}376.6\phi\mu c_t x_f^2}{k} \qquad (4)$$

where x_f is the half-length of the fracture.

Using equations 1 (or 4) an estimate of the start of transient data is made. Because well test analysis primarily studies pressure versus the logarithm of shut-in time, the test only needs to be run 1/2 - 1 logarithm (log) cycle longer than the time from equation 1. A 1/2 log cycle corresponds to a factor of approximately 3.16 and a full log cycle corresponds to a factor of 10. As an example, if the end of storage from equation 1 was 12 hours. Then for an additional 1/2 log cycle, the end of the test would be 37.9 hours (12 hours · 3.16). So to measure 1/2 log cycle of transient data, the well would have to be shut in for about 38 hours.

Using downhole shut-in, equation 1 would yield 2 hours. Using the 1/2 cycle rule, the well would only have to be shut in for 6.32 hours (2 hours · 3.16). An entire log cycle would only require a shut-in of 20 hours (2 hours · 10), nearly half of the time using surface shut-in. Economics and confidence in reservoir properties used in the test design determine the duration of the buildup.

The decision to use surface or downhole shut-in depends on the time to the end of wellbore storage, the occurrence of wellbore phase segregation, and the proximity of reservoir heterogeneities. If the minimum shut-in time, using surface shut-in is acceptable (38 hours for this example), then downhole shut-in is not an option. The exception is when early time data are desired; e.g., the bilinear or linear flow period occurs in fractured wells very early in a buildup and may not be measured with surface shut-in. Other features that warrant downhole shut-in are partial penetration, phase segregation, dual porosity, and gas lifted wells. If the wellbore storage is too lengthy and downhole shut-in is not acceptable, the buildup should be planned during a period when the well is shut in for some other reason such as a temporary facility or pipeline shut-down.

Because the logarithm of time is used in pressure transient analysis, "another hour or two of shut-in" most likely will not benefit the analysis. When considering additional shut-in time, use the factor 1.56 or a quarter of a log cycle as the minimum extra shut-in time. For example if the well has been shut in for 24 hours, and transient data has not been measured yet, another few hours will not help the analysis. The well would have to be shut in for 37.4 hours (1.56 · 24 hours) for the pressure data to benefit the analysis.

Another important calculation is to check the radius of investigation (r_{inv}) of the designed buildup:

$$r_{inv} = \left(\frac{4k\Delta t}{\phi\mu c_t}\right)^{0.5} \qquad (5)$$

Equation 5 can be used to determine the reservoir volume influencing the planned buildup test.

The pressures necessary for correctly analyzing a buildup must be obtained at or very near the zone to be tested. If pressure is measured uphole or at the surface, then these pressures must be corrected to bottom-hole conditions adjacent to the formation tested. The correction is made using the density of the fluid in the wellbore. In the presence of multiple phases or gas, this correction is prone to error and dependent on correlations. For deep, hot gas wells (due to temperature changes during the shut-in) and most multiphase production wells, pressure must be measured very near the formation. Consequently, surface measured pressures work best on water wells (injectors) or oil wells with very low GOR. Always locate the gauges as close to the test zone as possible.

The location of the pressure gauges is dependent on the selection of the tubulars and the artificial lift chosen. Most pressure gauge assemblies have self-contained recording capabilities or the data are transmitted to the surface. Self-contained recording assemblies are run in on slick-line and placed on a landing nipple if present. If not, the slick line can be left on location for the duration of the test, with the gauge hanging freely. When using this type of pressure gauge always run two gauges in tandem to reduce the risk of a single gauge failure.

Gauges with surface readout capabilities are run in on E-line. This will allow real-time analysis of the pressure data, and the gauge can be pulled out of the hole immediately when sufficient data are acquired. It is more expensive to have the service company on location during the test, but the well is usually returned to production earlier. Also, during real time analysis, the test will not be stopped prematurely. If surface readout is chosen, the tool is hung freely in the hole for the duration of the test. No landing nipple is required.

The previous discussion of locating the gauge is for all types of artificial lift except rod pumps. Due to the rods in the tubing, a pressure assembly cannot be run in. Optional testing procedures include fluid level measurements in the annular area between the casing and the tubing, pulling the rods and pump and running pressure gauges below the pump, and installing permanent gauges to the pump.

Pulling the rods is expensive and time consuming. The well must be produced, after the gauges are in place. As a result the gauge selected must have very long recording capabilities. The disadvantage of permanent gauges is the cost. Additionally, an electrical line to transmit the recorded information is run on the outside of the tubing and is easily damaged if the tubing is rotated.

For the selection of pressure gauges to be used, contact local service companies. Criteria to consider during the pressure gauge screening process are maximum temperature and pressure, required accuracy and resolution, sensitivity to temperature changes, and longevity of tool batteries.

Conclusions

The value of a pressure buildup test is enhanced by proper pre-test planning, test design, and data collection. There is much more involved with pressure buildup tests than just the pressure data.

Well conditioning including rate stabilization, rate measurement, and gauge placement play key rolls in obtaining valid results from a pressure buildup test. The rate information is equally as important as the pressure. Short shut-in times must be accounted for and if a shut-in occurs while running the tool in the well, a flow period must follow prior to the shut-in for the buildup. The length of the flow period must be at least twice the shut-in time. The flow rate should be returned to the pre-shut-in rate.

The test must last long enough to overcome wellbore storage effects. If downhole shut-in is used instead of surface shut-in, significant reduction in test time is realized. However, there are additional costs of using downhole shut-in and the possibility of not retrieving the tools. The test duration must be at least 3 to 10 times longer than the end of wellbore storage effects.

Computer software is available for design and analysis of buildup and other types of pressure tests for the simplest to the most complex wellbore and reservoir combinations. In some instances only software can provide adequate design and analysis.

After the buildup analysis is completed, with or without positive results, study the test design used. Identify underdesign and overdesign problems; e.g. was the well shut in too long or not long enough. Use this information in the design for the subsequent buildups in this area.

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Nomenclature

A	Drainage area, sq. feet
c	Total wellbore fluid compressibility, 1/psi
C_s	Storage coefficient, bbl/psi
c_t	Total system compressibility, 1/psi
h	Net pay, feet
k	Permeability, millidarcy
s	Skin factor, dimensionless
Δt	Shut-in time, hours
t	Time, hours
V_w	Wellbore volume, barrel
x_f	Fracture half-length, feet

Subscript

pss	Pseudo-steady state

Greek Symbols

$\emptyset$	Porosity, fraction
μ	Viscosity, centipoise

Table 1
Buildup Objectives

Objective	Required Measured Data	Special Considerations*
Permeability	Rate, viscosity, formation volume factor, net pay.	The slope of the transient data from a Horner plot is required. Rate data is directly related to permeability and must be measured with accuracy equal to the pressure measurements.
Skin Factor	Permeability, porosity, viscosity, wellbore radius, fluid saturations, fluid and formation compressibility, last flowing pressure.	The slope of the transient data from a Horner plot is required.
Average Pressure	See permeability and skin, drainage area and shape and the location of the well within the drainage area.	The data listed are for the Matthew, Brons, Hazebroek method. The slope of the transient data from a Horner plot is required. This slope is extrapolated to infinite shut-in time.
Flow Efficiency	Average pressure, last flowing pressure before buildup test, skin factor.	The slope of the transient data from a Horner plot is required.
Fracture Half-Length	Rate, formation volume factor, net pay, porosity, fluid saturations, fluid and formation compressibility,	The slope of the transient data from a Horner plot and from a square root of time plot is required. This necessitates very early and late time data . Wellbore effects must be minimal in order to measure the fracture pressure response and find a slope on the square root of time plot. Due to the fracture effect, radial flow is delayed (slope from Horner plot) and a longer shut-in time is essential.
Distance to a Fault	Permeability, porosity, viscosity, fluid saturations, fluid and formation compressibility.	The measurement of the fault on a Horner plot is imperative. A doubling of slope indicates the presence of a fault. Other features may approximately double the slope. Consider other information to confirm the possibility of a fault.
Vertical Permeability	Porosity, viscosity, fluid saturations, fluid and formation compressibility, net pay.	Computer analysis most likely required. Measurement of two Horner straight lines. The first is very early, requiring minimal wellbore effects. The second depends on the ratio of the perforated interval to the net pay thickness and the vertical permeability
Dual Porosity	Calculations can be done, but more important to identify the existence of phenomena.	Horner plot has two parallel straight lines. First line may be masked by wellbore effects. Computer analysis most effective. Minimal wellbore storage required.
Mobility Changes	Permeability, porosity, viscosity, fluid saturations, fluid and formation compressibility.	The measurement of the mobility change on a Horner plot is required. The slope will either increase if the mobility decreases or the slope decreases if the mobility increases. Other features may exhibit similar features. Consider other information to confirm the possibility a mobility change.
Evaluate Fracture Treatments	See permeability and skin factor.	Conduct buildup before and after stimulation. The pre-frac buildup should be immediately before the stimulation. The post-frac buildup should be immediately following a flow period, allowing the well to cleanup before the test.
Injectivity / Productivity	See permeability, skin factor, and average pressure.	Compare buildup results over various production or injection periods. Example pre- and post-MI injection falloffs can be used to monitor injectivity changes

* Horner plot is listed as the necessary analysis. Today, the derivative plot (log-log) is the most commonly used, especially to identify transient data. A superposition plot is also applicable if rates before shut-in are changing.