WELL TESTING (PP 512)

SUBJECT:

ANALYSIS AND DESIGN OF WELL DELIVERABILITY TESTS

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Design of Transient Test

13.1 Introduction

Each transient-test analysis technique described in this monograph requires specific test data. Complete and adequate data are essential for satisfactory transient- test results. Thus. an important part of preparation for a transient well test is deciding which data are needed and how they will be obtained. This chapter discusses the design of transient tests. from the choice of test type to determining data required. and describes characteristics of suitable equipment.

The first step in designing a transient test is to choose the appropriate test' for the existing situation: buildup. drawdown. multiple rate. interference. etc. When we desire specific information about a reservoir (for example. an indication of a mobility change or a boundary). test design is critical since many things can mask the response we seek. or can cause a response that is misleading because it merely resembles the behavior expected. (Sections 7.5. 10.1 through 10.7. and 11.2 through 11.4 illustrate a variety of situations that have similar test responses.) Once the test is chosen. the test duration and expected pressure response should be estimated so appropriate pressure-measuring equipment may be used. We also must decide what other data are required. determine how those data will be obtained. and consider how the testing plan will fit into the work schedules of the individuals who will perform the test. Occasionally. this part of test design indicates that a different kind of test than originally chosen should be used. If that happens, the entire design process is repeated.

Test design should minimize problems such as those caused by excessive wellbore storage. unintentional variation in rates. rate changes in nearby wells. etc. This chapter presents a broad approach to test design. emphasizing general design concepts rather than details. The design material in this chapter is limited to conventional transient testing. Pulse test design is discussed in Sections 9.3 and 10.8.

A discussion of pressure- and rate-measuring instruments indicates the kinds of instruments available. and what factors should be considered in instrument choice. We make no attempt to consider all available instruments nor to evaluate the relative merits of the instruments considered.

13.2 Choice of Test Type

When deciding what kind of transient well test to use. The foremost considerations are the type and status of the well: injection or production. active or shut-in. We may choose a single-well or a multiple-well test. depending on what we wish to learn about the reservoir.

When planning a production-well transient test. the engineer can choose between drawdown, buildup, and multiple-rate testing. He also must determine how he will make pressure measurements in artificially lifted wells. It is particularly difficult to measure down-hole pressure in rod pumped wells unless the well is equipped with a permanent bottom-hole pressure gauge. Although it is possible to run some pressure gauges in the tubing-casing annulus, that can be risky and, generally. is not recommended. Pulling the pump and then running the pressure gauge seldom solves the problem; when the pump is

pulled. the fluid in the tubing is dumped in the hole, creating an injection transient. It. is possible to pull the pump. run the gauge in tubing below the pump. rerun the pump. continue production for several days. and then test. That approach requires a gauge with a long time span; it also involves considerable expense for the necessary well-service work. One common way to obtain pressure buildup data in a rod-pumped well completed without a packer is to measure the fluid level in the tubing-casing annulus with an acoustic sounder. Pressure measurement in flowing wells. in gas-lift wells, and in some wells with hydraulic or submersible electric pumps is not so difficult. But even in those situations. mechanical problems such as gas-lift valves that open suddenly during pressure-buildup surveys must be considered and avoided in test design.

The composition and rate of the fluid produced is important. since multiple-phase effects may be significant. The system may have to be treated as an oil well or as a gas well. depending on the gas-liquid ratio. As indicated in Section 2.6. phase segregation in the tubing string may create anomalies that make analysis difficult or impossible. Such anomalies should be anticipated and avoided, if possible.

Test duration may be a problem in producing wells; generally. one does not like to shut in a producing well for a long time since delayed production can be a major cost in a test. Deferred income often may be reduced by using a two-rate test.

The choice of-test type is less complicated for injection wells than for production wells - because the difficulties associated with artificial lift are not present. Normally, an injectivity test or falloff test will provide usable results. The pressure falloff is preferred. since it is easier to perform than an injectivity test and since minor rate variations have less influence on falloff-test response. It is good practice to run an injectivity test after the falloff test. since the cost is low and additional information may be obtained, Injection wells that take fluid on vacuum are difficult to test because of high wellbore storage coefficients associated with the free liquid level in the injection string. Usually, it is advisable to test such wells by increasing the injection rate enough to obtain wellhead pressure and then performing either an injectivity test at high rate or a two-rate injection test with positive wellhead pressure maintained during both rates. Changing wellbore storage (Section 11,2) tends to be more of a problem in injection wells than in production wells.

Ideally. pressures should be recorded continuously during a transient test. Best results are obtained when the bottom-hole pressure is measured, although surface pressure often can be converted to bottom-hole values if adequate information is available about the

wellbore system. If possible. one should avoid changing pressure gauges during the test because of offsets that usually occur when a gauge is changed - even when the same gauge is removed and rerun with a new chart. Remember, we are often concerned with relatively subtle pressure trends in transient pressure analyses. It is often possible to avoid changing charts in a gauge and still get good short-time and long-time data by running two gauges in tandem with different-speed clocks.

It is usually beneficial to record bottom-hole, tubing-head, and casing-head pressures during a well test. That combination of data can provide information about wellbore effects – such as fluid redistribution; wellbore storage, and leaking packers or tubing -and may allow analysis of a test that could not be analyzed adequately based on bottom-hole pressure data alone. Such surface pressure data may be valuable in verifying correct operation of the down-hole pressure gauge.

Some well tests may require bottom-hole shut-in; some may even require extra packers or drillstem test equipment. Such requirements must be considered in the test design so that all important data are obtained.

13.3 Design Calculations

There are three general approaches to designing a transient well test:

1. Estimate the complete expected pressure response using assumed formation properties.'

2. Estimate key factors in test response, such as the end of wellbore storage effects, the end of the semilog straight line, the semilog straight-line slope, and the general magnitude of the pressure response.

3. Just-run the test without design calculations.

Option 3 is generally a poor one except in wells or reservoirs that have been tested frequently enough so their behavior is well known. Estimating the entire pressure response for a test can be a time-consuming task and may require computer assistance. (In complex situations, the subsequent analysis also may require the use of a computer.) Nevertheless, in some cases that is the only reliable way to design a test. To estimate pressure response for relatively simple systems. we use superposition and Eq. 2.2:

$$p_{wf} = p_i - 141.2 \frac{\mu q \beta}{kh} \left| p_D(t_D, r_D, \ldots) + s \right| \quad (1)$$

For complex systems, or to reduce the labor required for test design, we normally use a computer to estimate expected pressure response. Once the pressure response has been estimated, the data may be analyzed by normal methods determine potential analysis problems. Example 13.2 illustrates that approach.

In most transient well tests, we need not know the complete pressure response for design purposes. It is normally sufficient to estimate the beginning time of the correct semilog straight line by using Eq. 2,21,

$$t > \frac{(200{,}000+12{,}000\ s)C}{(kh/\mu)} \qquad (2a)$$

for pressure drawdown or injectivity, or Eq. 2.22,

$$\Delta t > \frac{170{,}000\ C\ e^{0.14s}}{(kh/\mu)} \qquad (2b)$$

for falloff or buildup. The wellbore storage coefficient, C, estimated from completion details using me technique Section 2.6. Formation kh/μ. and skin factor must be assumed to use Eq. 13.2. If $s < 0$, we recommend using s = 0 in Eqs. 13.2a and 13.2b to get conservative results.

The next step is to estimate the end time of the semilog straight line. For drawdown and injectivity tests, we estimate the time when the system no longer acts infinite, using Eq.2.8:

$$t \equiv \frac{\phi\mu c_t A(t_{DA})_{eia}}{0.0002637k} \qquad (3a)$$

t_{DA} at the end of the infinite-acting period is taken from "Use Infinite System Solution Less Than 1% Error for t_{DA}<", column de la Tabla 1.2. The end of the semilog straight line for buildup and falloff tests may be estimated from Eq.5.16:

$$\Delta t = \frac{\phi\mu c_t A(\Delta t_{DA})_{esl}}{0.0002637k} \qquad (3b)$$

$(\Delta t_{DA})_{esl}$, is from Fig. 5.6 or Fig. 5.7.

Finally, the slope of the semilog straight line is estimated from

$$m = \pm\ 162.6\ \frac{\mu q \beta}{kh} \qquad (4)$$

where the sign used depends on the test type. It may be necessary to consider the general pressure-level decline in developed reservoirs when computing m. See Sections 3.4, 4.5, and 5.3 to determine how that would be done.

Once the slope is estimated, the pressure change c between two times on the semilog straight line, *t* I an be estimated from

$$\Delta p = \pm m \log(t_2/t_1) \qquad (5)$$

Again, the sign chosen depends on test type. The pressure instrument chosen must be sensitive enough to detect the expected pressure change during the test period. The normal skin equation for the test used may be used to estimate P_{lhr} (after assuming an s value and a value for bottom-hole pressure at the start of the test); thus, we may estimate the pressure at any time on the semilog straight line by appropriate application of Eq. 13.5. The range of the pressure instrument used must be chosen so that the pressure can be measured with acceptable accuracy but without exceeding the instrument upper pressure limit.

Test design also may be important in reservoir limit testing - if it is possible to estimate reservoir parameters well enough to make the design calculations. When that can be done, the time to the start of the straight line on a plot of pressure vs time (arithmetic or linear coordinates) is estimated from:

$$t_{pss} \equiv \frac{\phi \mu c_t A (t_{DA})_{pss}}{0.0002637k} \qquad (6)$$

where $(t_{DA})_{pss}$. Is taken from the "Exact for t_{DA}>", column of Table C.1. By using Eq. 13.6. even when estimates of reservoir parameters are incorrect by a factor of 2 to 3, it is possible to get a reasonable idea of the time to the beginning of analyzable data for a

reservoir limit test. In many cases, that time may be impractically long, indicating the inadvisability of attempting to run the test. The slope of the straightline portion of the Cartesian pressure-time plot is estimated from Eq. 3.33:

$$m^* = -\frac{0.2395\, q\beta}{\phi c_t h A} \qquad (7)$$

The slope estimate may be used to indicate the sensitivity required of the pressure gauge and to get an idea of how long the test need be run after the straight-line portion starts. Pressure levels generally will be below the initial pressure, so it usually suffices to choose a gauge with a maximum range equivalent to initial reservoir pressure. If there has been a substantial pressure decline, then a lower-range gauge would be sufficient; but reservoir limit testing is not necessarily applicable to wells that have experienced much pressure decline, unless they have been shut in long enough to stabilize at average reservoir pressure.

When designing an interference test, it is best to estimate the pressure response at the observation well as a function of time. That may be done by using Eq. 13.1 with *PD* taken from Fig. C.2 (Eq, 2.5a) or Fig. C.12. Such design is particularly important because observation-well response may be small and may occur only after a long time. For a reservoir with several noncommunicating layers. the most rapid response generally will

be associated with the most permeable layer. This lime of response can be much shorter than the lime corresponding to the average permeability. In such cases, we recommend that interference-test design and analysis be backed up with a reservoir simulator, since little has been published about pressure behavior away from the active well in such layered systems.

Example 1 Pressure-Buildup Design

We wish to run a pressure buildup test in a well in an undersaturated reservoir developed on 40-acre spacing. The field is suspected to be operating at pseudosteady-state conditions; that suspicion is confinned later in the example. The well is currently producing 132 BOPD and 23 BWPD at a bottom-hole pressure of about 2,450 psi. Known data from production operations, laboratory tests, and log analyses are:

q_o= 132 BOPD; q_w= 23 BWPD; μ_o= 2.30 cp ; μ_w= 0 .94 cp; c_o= 14.6 x10^{-6}; c_w= 3.2x10^{-6}; c_f= 3.4 x10^{-6}; β_o= 1.21 RB/STB; β_w= 1.0 RB/STB; A=40 acres =1742,400 ft^2; h=63'; ϕ=16.3%; r_w=0.26'; depth =3,600'; tubing =2 $^3/_8$" OD ; V_u=.00387 bl/pie. Estimated data are P= 2,450 psi k = 135 md; s=2.

Based on observed flow rates, known fluid properties, and relative permeability data, we estimate

S_w= 0.29; S_o= 0.71 ; k_{rw}= 0.02 y k_{ro}= 0.2.

Thus, composite properties may be estimated. Using Eq. 2.38,

$c_t = c_oS_o + c_wS_w + c_gS_g + c_f$=

c_t = (14.6x.71+3.2x.29+3.4)10^{-6}

c_t= 14.7 x10^{-6} al reservorio.

for *the* reservoir.

To estimate *c,* for *the* wellbore, we weight the compressibilities by the relative volume of well bore fluids,

$q_t\beta_t$ = 132x1.21 + 23x1.00 = 182.7

so

$$c_{twb}=c_o\frac{q_o\beta_o}{q_t\beta_t}+c_w\frac{q_w\beta_w}{q_t\beta_t}$$

c_{twb}= 13.2x10^{-6} for the wellbore.

We also must estimate total mobility of the fluids flowing in the formation using Eq. 2.37:

$k/\mu)_T$= k(0.2/2.3 +0.02/0.94)= 0.11 k

The semilog straight line will be bounded on the low-time end by wellbore storage effects and on the upper end as indicated by Eq. 13.3b. To estimate the start of the semilog

straight line. we determine *the* wellbore storage coefficient for the liquid-filled wellbore. We use the compressibility estimated above for the wellbore and the total mobility based on, an estimated permeability of 135 md. Then we use Eq. 13.2b for pressure buildup with an estimated s = 2.0. First we compute the wellbore storage coefficient from Eq. 2. 17:

$C = 0.00387 \times 3000 \times 13.2 \times 10^{-6}$

$C = 1.84 \times 10^{-4}$ bl/psi.

Then we apply Eq. 13.2b:

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

$$\Delta t > \frac{170{,}000 \times 1.84 \times 10^{-4} \times e^{0.14 \times 2}}{0.11 \times 135 \times 63}$$

$\Delta t > 0.0044$ hours = 2.6 minutes.
This indicates that wellbore storage should not be a problem.

We may now check the assertion that the well was producing at pseudosteady state. For a square system with a well in the center, $(t_{DA})_{pss} = 0.1$.. Using Eq. 2.24,

$$t_{pss} \equiv \frac{\phi \mu c_t A (t_{DA})_{pss}}{0.0002637k}$$

$$t_{pss} \equiv \frac{0.163 \times 14.7 \times 10^{-6} \times 1'742{,}400 \times 0.1}{0.0002637 \times 0.11 \times 135}$$

$t_{pss} \approx 107$ hours ≈ 4.5 days

Since the well has been operating for many weeks, it can be treated like it is operating at pseudosteady state.

To estimate the end of the semilog straight line, we use Eq. 13.3b and the appropriate figure from Chapter 5. Since the reservoir is producing at pseudosteady state, we assume that the pattern is a closed square with the well in the center. We use $t_{pDA} \approx 0.1$ (see Sections 5.2, 6.3, and Table C.1) and Curve 1 of Figs. 5.6 and 5.7. From Fig. 5.6 $(\Delta t_{DA})_{esl} \approx 0.013$ - for a Horner plot, and from Fig. 5.7 $(\Delta t_{DA})_{esl} \approx 0.0038$ for a Miller-Dyes-Hutchinson plot. Then, applying Eq. 13.3b,

$$\Delta t = \frac{\phi \mu c t A (\Delta t_{DA})_{esl}}{0.0002637k} = 1070 (\Delta t_{DA})_{esl}$$

The semilog straight line should end at about at = (1,070)(0.013) = 14 hours for the Homer plot, and

Δt=1070x0.0038 = 4.1 hours

for the Miller-Dyes-Hutchinson graph. These times are probably conservative since the other wells will not be shut in, and thus, the shut-in well will not really be at the center of a closed 40-acre square. Nevertheless, the Horner plot should have a longer semilog straight line.

We estimate the slope of the semilog straight line from Eq. 13.4:

$$m = 162.6 \frac{\mu q \beta}{kh} = 162.6 \frac{182.7}{0.11 x 135 x 63}$$

m= 31.8 psi/cycle.

The relatively small m value indicates a slowly increasing pressure so we need a sensitive pressure gauge. We might consider stabilizing the well at a higher production rate before the buildup test to create a larger pressure response.

We may estimate the pressure level expected during the buildup *test.* A simple way to do that is to solve the skin factor equation. Eq. 5.7. for p_{1hr} We may then use p_{1hr} and m to estimate the pressure at later times. Rearranging Eq.5.7,

$$p_{1hr} = p_{wf} + m \left[\log\left(\frac{k}{\phi \mu c_t r_w^2}\right) - 3.23 + 0.86859s\right]$$

$$p_{1hr} = 2600 + 27.6s$$

Then the pressure at any time on the semilog straight line can be estimated using Eq. 13.5:

$$p(\Delta t) \approx 2{,}600 + 27.6s + 31.8 \log \Delta t.$$

If we expect s = 2 and a 24-hour test, $p \approx$ 2,700 psi: The pressure gauge we choose probably should be in the 3,300-psi range and still be capable of detecting a 30-psi change over a period of several hours.

The average pressure to be' expected likewise can be estimated by the Dietz method, using C_A = 30.88 for the square drainage area. The time when the semilog straight line should reach p_s is given by Eq. 6.7a:

$\phi c_t A$

$$(\Delta t)_{ps} = \frac{\quad}{0.0002637\lambda C_A} = = 34.5 \text{ hours.}$$

Using the equation above,

p_s= 2,600 + 27.6x2+ 31.8 log(34.5) ≈ 2,704 psi.

Since the reservoir pressure is declining, we may have to consider that decline in the analysis, as indicated in Section 5.3. Nevertheless, the information estimated in this example indicates correct times; the pressure changes are in addition to the established trend at the well before testing. It would be worthwhile to try to measure that trend before doing the test, so it could be included in the analysis if necessary.

The pressure decline before shut-in may be estimated from Eq. 13.7:

$$m^* = -\frac{0.2395\, q\beta}{\phi c_t h A} = -\frac{0.2395\text{x}182.7}{0.163\text{x}14.7\text{x}10^{-6}\text{x}63\text{x}1742400}$$

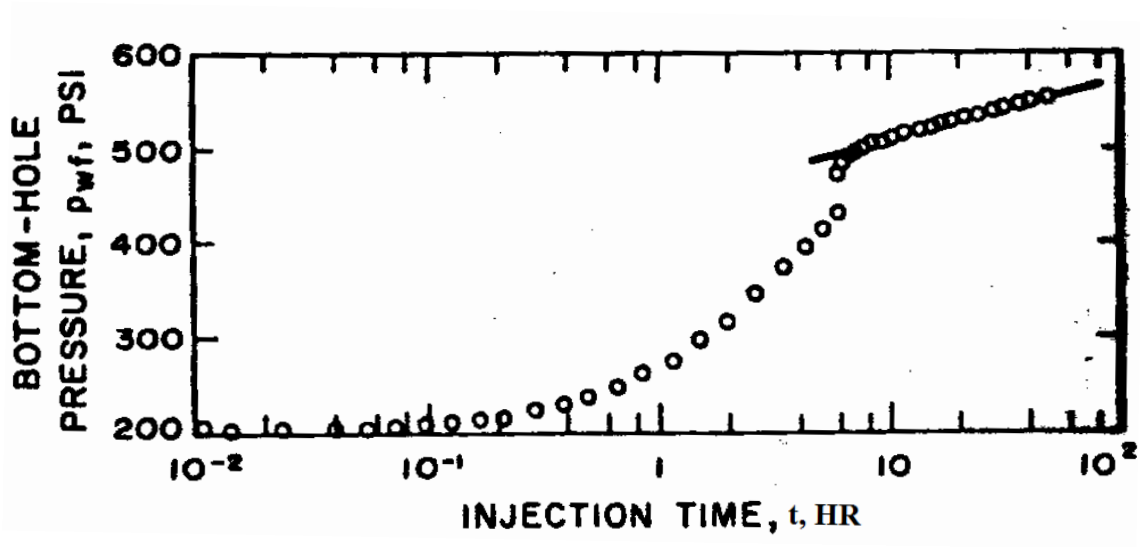
$$m^* = -0.16 \text{ psi/hr}$$

Example 13.2 *Injection-Well Test Design*

An injection-well transient testing program was proposed for several input wells in a waterflooded reservoir before starting fluid injection for a tertiary recovery project. The reservoir was liquid-filled with water flowing at residual oil saturation. Reservoir pressure was low with the static liquid level standing about 600 ft below the surface. Because of the importance of the tests, and since changing wellbore storage could be expected as a result of the low liquid level, we decided to compute the expected pressure response by using a reservoir simulator. .

We supplied estimated reservoir properties and computed the injectivity-test response shown in Fig. 13.). As expected, the liquid level rose in the well during injection until it reached the surface about 5.9 hours after starting injection. The rapid increase in pressure in Fig. 13. I is a result of the wellbore storage coefficient decreasing abruptly from a value corresponding to a rising liquid level to one for compression only. Note the similarity of the response in Fig. 13.1 to Figs. 11.5 and 11.6. We analyzed the apparent semilog straight line starting at about 10 hours to estimate a permeability about 15 percent lower than theinput value and a skin factor that is *low* by I. I. The discrepancy is due to choosing a semilog straight line with too steep a slope - apparently a result of the rapid wellbore storage decrease.

Fig. 13.1 Calculated injectivity pressure response for Example 13.2



The fact that the analysis of simulated data does not return the values supplied to the simulator indicates that the assumptions used in the analysis technique are not completely correct (assuming the simulator is working correctly). This says that if we wish to analyze data by standard techniques, we should seek a type of test for which conditions more closely approach the ideality of the analysis equations. Alternatively, we could use a more sophisticated analysis, perhaps one based on a reservoir simulator. Practically speaking, that is not often required.

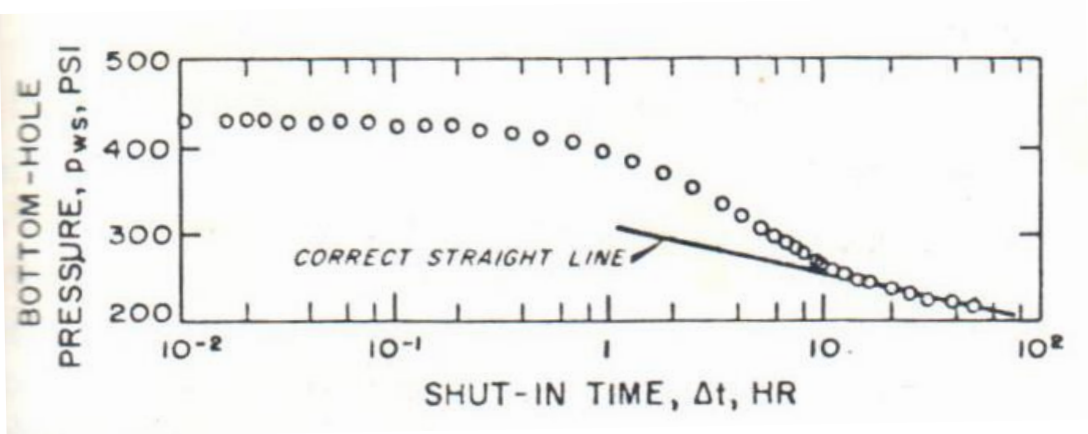


Fig.. 13.2 Calculated falloff pressure response for Example 13.2.

Fig. 13.2 shows a simulated pressure falloff test following 48 hours of injection. The well goes on vacuum about 40 seconds after shut-in, so wellbore storage *increases* from compression to falling liquid level. To analyze data from a 24-hour falloff, it would be

necessary to draw the straight line through the last five data points shown - a risky approach at best. We conclude the falloff test is essentially worthless. Although a

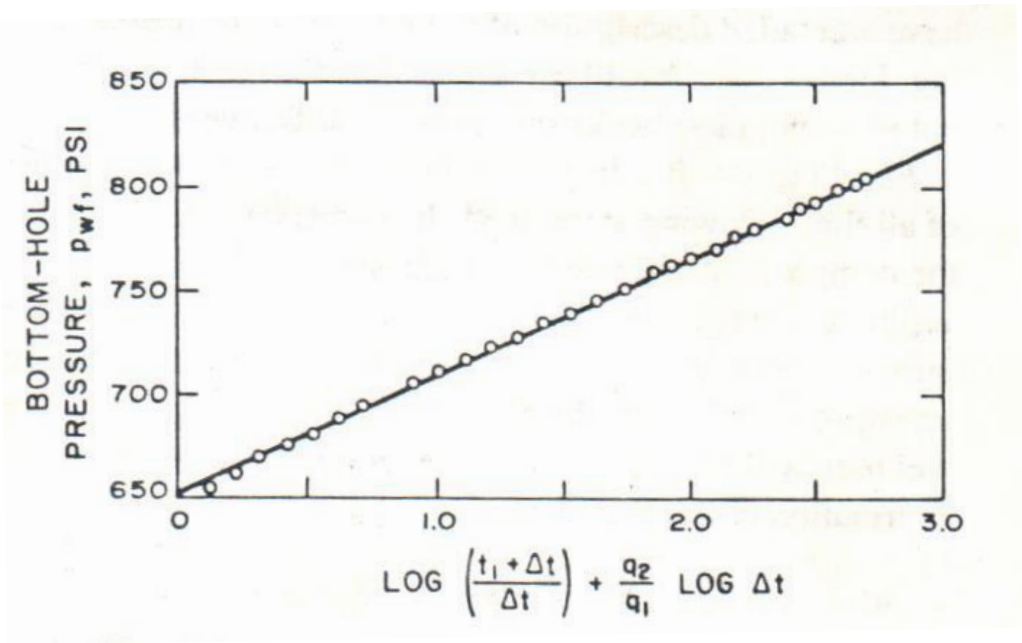
computer program similar to the one used to generate the data could be used with regression analysis to analyze such falloff data, such an approach is not often practical. Even when that is done, the margin for error is significant because the analyst must make some assumptions about the wellbore storage characteristics (constant, step increase, gradual increase because of a gas cushion in the well, etc.). Thus, we prefer to find a type of test that is relatively insensitive to wellbore storage effects.

We also simulated a two-rate injection test, with the injection rate increasing by 73 percent after 48 hours. The second rate continues for 24 hours. Since the wellbore storage was from liquid compression only (wellhead pressure is positive), wellbore storage had little effect on the pressure response to the rate increase. Fig. 13.3 shows the data plotted as suggested by Eq. 4.6. The straight line can be analyzed to give k within 3 percent of the input value and a skin factor within 0.2 of the input value.

As a result of the design work shown in Figs. 13.1 through 13.3, the wells were tested with a two-rate injection followed by a falloff. The injection-pressure data were analyzed successfully; standard analysis was not possible for the falloff data; no attempt was made to use computer analysis.

13.4 Test Data and Operation Requirements

An important part of test planning and execution is complete data acquisition and safe and correct test operation. The important parts of test operation include good and complete rate stabilization (or rate control during tests requiring the well to be active), placement of the pressure instrument before the test begins, and careful documentation of what happens during the test, both at the test well and at nearby operating wells.



Fi~. 13.3 Calculated two-rate test pressure behavior for Example 13.2.

The following general data check list is an aid to complete data acquisition. Depending on the testing situation and the information desired. it may require modification. When testing in wells or reservoirs that have been thoroughly tested before. much of the data may not be necessary based on past experience.

1. Well-Completion Data

Pipe in the Hole and Packers - Size and location of cas ing and tubing. location of any packers. and an indication of what pipe strings they separate should be recorded. A sketch of the well completion should accompany test data. Such information is important for running the gauge and detennining the effects of wellbore storage. It also should assure that the gauge can be run to the depth where pressure is to be measured.

Type of Completion in the Producing Interval - Data should include information about whether the well is open hole, cased. perforated. uses a liner or a gravel pack, type of completion fluid. etc. If there is a dual completion, give details. Data should include location and number of perforations and indication of partial penetration. if applicable.

Stimulation - Has the well been stimulated by shooting, acidizing, fracturing. etc?

2. Pattern Data

Well Pattern - Data should include pattern size and shape. and information about location of other wells. Usually a map suffices.

Rate Information at Other Wells - When testing developed patterns, it may be important to know how the rates behave at other wells before and during the test. We must know of any major rate changes during the test since these may influence the test response considerably

3. Rate Data

Stabilized Rate Before Testing - It is best to have spot checks on the rate for several days before testing so any problems can be isolated. Severe fluctuations may dictate postponing the test or changing the analysis technique. It is especially important to know when an active well might have been shut in before testing, if only for a few minutes.

Detailed Test-Rate Data - For producing, injecting, multiple-rate, and multiple-well tests, it is advantageous to have a detailed description of the rate behavior during testing. Ideally, one should use a recording flowmeter; if that is not possible, rate checks should be made frequently.

Fluid Type - It is important to know rates and properties of all fluids flowing at the well. It is advantageous to know the composite density and compressibility of the fluids for wellbore storage considerations and for correcting pressure measurements to some other datum. A separate pressure survey consisting of short stops at several depths in the wellbore will provide information relative to the density and distribution of fluids in the well.

4. Pressure Data

Bottom-Hole Measurements - Continuously recorded bottom-hole measurements are usually essential to good well test analysis. However, care in obtaining pressure data and additional data is also important. as stated below.

Trends Before Testing - We should know the pressure trend before testing since it may affect the analysis technique. Generally, such information is not important in un-developed reservoirs or in fluid-injection projects with injection and production approximately balanced.

Short- Time Data - It is advisable to take pressure data at short intervals while wellbore storage is important. That allows isolation of the storage-affected part of the response data and aids in correct analysis. Design calculations give some indication of how rapidly such data are required. In the absence of other information. we recommend taking data as frequently as every 15 seconds for the first few minutes of the test. Data should be taken at least every 15 minutes until wellbore storage effects have essentially ended.

Pressure Just Before Testing - Record the pressure observed just before the test is started. Skin-factor calculations and log-log plots depend on this information.

Wellhead Pressures -Ill wells that have not been tested before and whose characteristic response is not well known. it is good practice to periodically record surface tubing *and* casing pressures. Such data are usually recorded manually at intervals of 1 to 4 hours from pressure gauges on the wellhead. It is sometimes particularly useful to have such data at short test times. so that unusual wellbore effects may be more thoroughly understood. Usually by comparing surface pressures with bottom-hole pressures, it is possible to estimate how much fluid is accumulating in or leaving the wellbore.

5. Other Data

- *Surface Piping* - A diagram of wellhead and surface piping should-accompany test data. That information often helps explain anomalous test behavior. .

, *Chronology* - A complete list of how things happen during the test is frequently the only key to unraveling unusual test response. Thus. the engineer should keep a log of times at which various events occur.

References

1. Earlougher, R.C.Jr et al.: “Advances in Well Test Analysis”, Monograph Serie, SPE, Richardson, TX (1977), 165-170