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Gas/Condensate and Oil Well Testing - From the Surface

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Abstract

Since Cullender and Smith[(1)], surface pressures have been used to calculate bottomhole pressures on shallow, dry gas wells. If the original Cullender and Smith equations are modified to account for produced liquids, the correlation may be extended to gas/condensate wells that are single-phase in the well bore. Single-phase liquid wells (water injectors and oil wells above the bubble point) can also yield accurate well test results from the surface. Testing from the surface reduces the cost and eliminates the risk of running tools into well bores. Surface testing also allows the testing of high-pressure/high-temperature wells that cannot be tested with a downhole gauge because of harsh conditions. Thus, to reduce the cost and risk (or when no other option is available), many operators have chosen to run their pressure transient tests from the surface on single-phase wells.

Recently, it has become possible to test most naturally-unloading gas/condensate and oil wells from the surface. This is due to advances in multi-phase wellbore modeling along with improved pressure transducer quality. Of these, the most important advances are the improvements in transducer manufacture and calibration that make it possible for a surface pressure gauge to be effectively isolated from ambient and wellbore thermal transients. Although the technology exists to get representative reservoir data from the surface, testing procedures in multi-phase wells have to take into account the fluid's behavior in the well bore. With this in mind, the purpose of this paper is to propose guidelines for testing multi-phase wells from the surface. First, the general framework of the surface-to-bottomhole pressure calculation will be presented. Next, multi-phase wells will be categorized based on the type of fluid and the behavior of the fluid both in the reservoir and in the well bore. This categorization will be the basis for both surface testing candidate selection and recommended test procedures. Afterwards, wellbore phase and temperature modeling will be discussed. Next, instrumentation requirements will be presented. Finally, field data comparing calculated bottomhole pressures from surface gauges to measured bottomhole pressures from downhole gauges (and the subsequent analysis) will be presented for both a gas/condensate and an oil well.

These examples will be used to demonstrate that in order to test a multi-phase well from the surface, a thermally compensated quartz pressure gauge must be used in conjunction with a properly designed and executed test procedure. An explanation will also be provided as to why the best test that can be performed on a well to determine skin, permeability and the size of a reservoir is a constant-choke drawdown.

Wellhead to Bottomhole Pressure Calculations

In order to calculate the bottomhole pressure from the wellhead pressure, the following equation is used: (Note that kinetic energy is considered negligible and is not included.)

$$BHP = WHP + \Delta P_{friction} + \Delta P_{gravity}$$

For a well that is shut-in, or for a low rate single-phase liquid well, this reduces to:

$$BHP = WHP + \Delta P_{gravity}$$

While these equations are relatively simple for single-phase fluids, they become quite complex when other phases are introduced. In fact these complexities make it almost impossible to get analyzable build-up data from the surface on oil wells that are below the bubble point in the reservoir. Producing wells may slug, have liquid hold-up, have a standing liquid column, or behave in other fashions that are difficult, if not impossible, to model.

Nonetheless, there are conditions of multi-phase flow in the well bore that can be modeled to get useful information about the completion and the reservoir. These conditions center on the validity of three assumptions:

1) Constant total mass flow rate (dm/dt = 0)
2) Constant component flow rate ($dm_i/dt = 0$)
3) Effective fluid continuity from the well head to the reservoir

If these assumptions hold, then it is implied there is no accumulation of either a particular phase or a particular component. Therefore, any fluid component that enters the well bore at the completion will necessarily leave the well bore at the tree. Fluid continuity means that there is a continuous connection of monophasic molecules from the surface to the completion, providing effective pressure communication from the surface gauge to the reservoir. As long as fluid communication/continuity can be established between the surface and the completion, the relative pressure change over time should be accurate. The multi-phase flow regimes under which these assumptions hold are:

1) Mist Flow – liquid dispersed/gas continuous
2) Annular Mist Flow – liquid annulus/gas continuous
3) Bubble Flow – gas dispersed/liquid continuous

In addition to holding the three assumptions listed above, these flow regimes have another thing in common: each model has a single continuous phase. Therefore, while more than one phase is present, the fluid can communicate pressure from the reservoir in the same fashion as a single-phase fluid.

There are some special cases of dispersed multi-phase flow where, even though the above assumptions do not hold exactly, useful surface data/BHP conversions may be obtained. These flow regimes are called Churn or Froth Flow. In these regimes, the phases are constantly intermixing and can establish temporary fluid communication in the well bore. This roiling of fluids may make the data noisy, however valid data may still be gathered. Figure 1 shows converted bottomhole pressure on a gas well that was in the churn flow regime. The reservoir limits map derived from this data is presented in Figure 2. Note that although the data was noisy, the "Blind Image"[2] independently matched the two faults and two water contacts in the geophysical image. This result is possible because permeability and distance to limits calculations depend on the relative change in the pressure response. Least mean squares fits were taken through the data, generating several straight-line segments. These straight-line segments (colored segments in Figure 1) were then used to produce the "Blind Image".

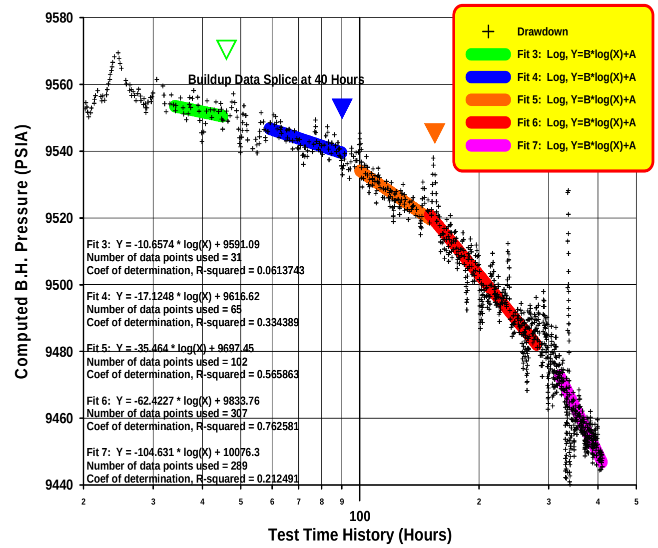

Figure 1: Churn Flow Data

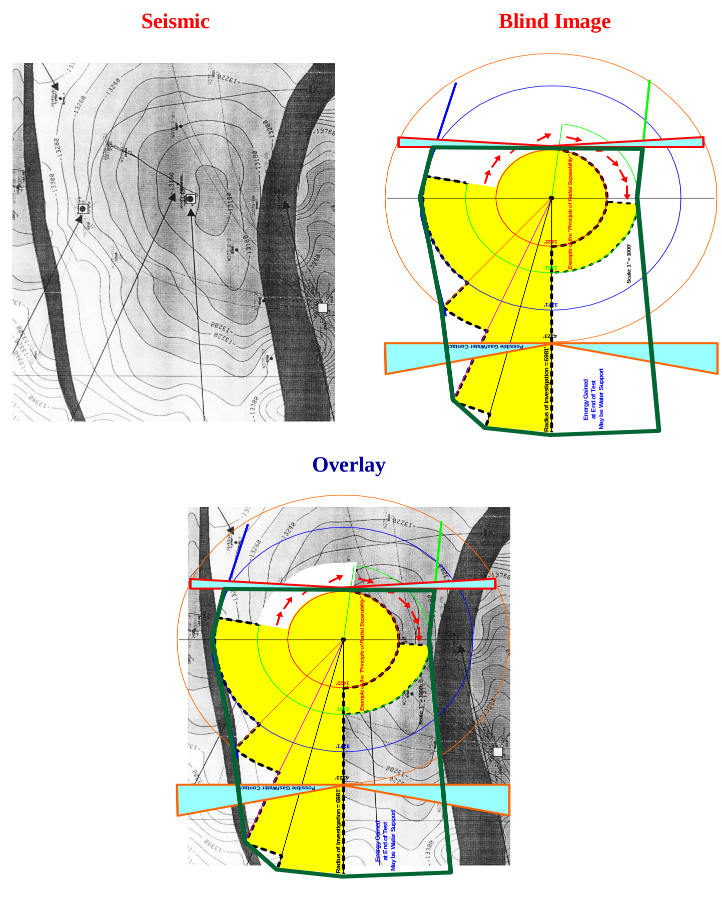

Figure 2: Churn Flow Well Geologic vs. Well Test Reservoir Map

Categorizing Gas/Condensate & Oil Wells

The phase composition of a fluid at separator or stock tank conditions is not the same as its phase composition in the reservoir or in the well bore. Just because a well makes 300 STB/MMscf of oil at the separator does not mean that there is 300 bbl/MMscf of liquid in the well bore. In fact, the fluid in the well bore may even be single-phase. Hence, the following well categories are based on the phase behavior of fluids in the reservoir and the well bore:

Category 1: Single-phase in the reservoir and in the well bore
Category 2: Single-phase in the reservoir, but multi-phase in the well bore
Category 3: Multi-phase in the reservoir and in the well bore

It is useful to associate a well category with the continuous phase in the reservoir, i.e. Category 2 oil. If the continuous phase is liquid, it's an oil well; if the continuous phase is gas, it's a gas well. It should be noted that the continuous phase can change over the course of the life of a reservoir. In addition, a gas well that produces significant water (>10 bbl/MMscf) should be classified as a Category 3 gas. A gas well with a yield less than 10 bbl/MMcf should be considered a Category 1.

Candidate Selection and Testing Options

For Category 1 oil and Category 1 and 2 gas wells, any well that unloads naturally may be tested from the surface. However, if the gas rate is not above the critical unloading velocity of the well bore, the surface data is likely to be invalid. A Dukler chart(3), shown in Figure 12 in Appendix A, or the critical unloading calculations in a nodal analysis package may be used to ensure that a gas well will be a good surface testing candidate. For these categories, the test procedure is not strict; any type of test may be run (build-up, drawdown, multi-rate, etc).

Category 2 oil wells must flow at conditions that avoid segregated multi-phase flow. Thus, it is necessary to calculate the superficial velocities of the phases and determine where the fluid lies on a Taitel-Dukler(4) flow pattern map (shown in Figure 3 for a gas/condensate mixture).

If the fluid falls in either the annular (V) or bubble flow (I and II) regions, it is a good candidate. If the fluid falls in the churn flow region (IV) it is a probable candidate (although the data will likely be quite noisy). If the fluid falls in the slug flow region (III), it will be difficult to test it from the surface. It should be noted that there are multiple flow pattern maps, depending on the temperature, pressure and compositions of fluids. Figure 3 presents the flow pattern map for moderately pressured natural gas and condensate. Different flow pattern maps must be used for different compositions, i.e. gas/water.

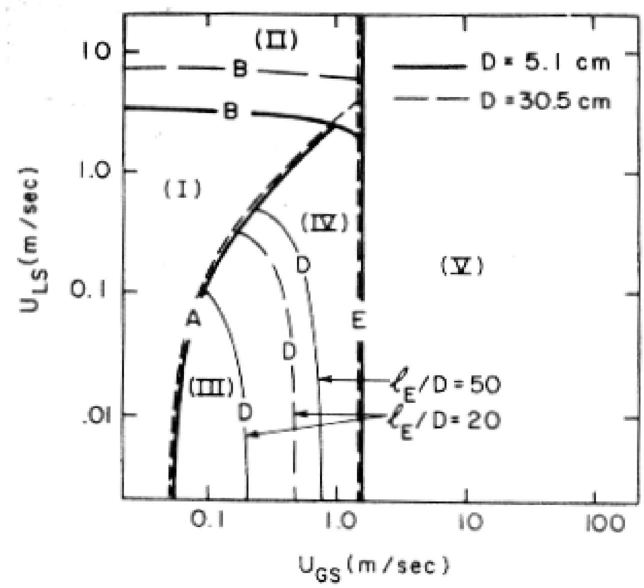

Figure 3 – Taitel-Dukler Flow Pattern Map for Gas/Condensate Systems

Testing procedures for Category 2 oil wells are slightly more limited than single-phase cases because they can experience significant phase redistribution during shut-ins. This, in turn, may obscure the true response of the reservoir. However, this does not absolutely preclude getting valid build-up data. Nonetheless, in Category 2 oil wells, a constant-choke drawdown following the build-up greatly increases the chances of getting reliable results.

Category 3 gas wells face the same screening criteria as a Category 2 gas well. However, the testing options are more limited. When a Category 3 gas well is shut-in, liquid fallback and re-injection will occur. This will mask the reservoir response until the liquid re-injects below the top of the completion, re-establishing pressure communication with the reservoir and leaving single-phase gas in the well bore. Re-injection can be diagnosed by plotting the gauge pressure on a semi-log plot. As shown in Figure 4, the break-over in the pressure the number "3" marks the point where valid build-up data begins.(5)

Unfortunately, if boundaries are encountered before the end of the re-injection effect, they will be masked. This will cause the build-up analysis to be in error. To avoid this potential problem, a constant-choke drawdown test should be performed. It should be noted that prior to performing the drawdown, a Category 3 gas well must be shut-in for enough time to reach the end of re-injection. In this fashion, the reservoir pressure will be obtained from the build-up, while skin, permeability and the distance to limits/water contacts will be determined from the drawdown data.

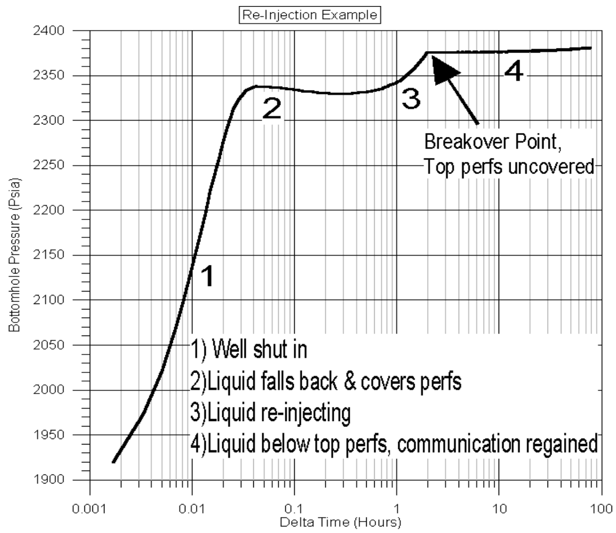

Figure 4 – Re-injection Process

Category 3 oil wells must meet the same screening criteria as Category 2 oil wells. Unfortunately, surface build-ups on Category 3 oil wells are not possible, as a gas/liquid interface will exist between the measurement point and the completion. However, if the bottomhole pressure is known, or can be measured by running a dip-in with a downhole gauge, the well can still be tested on a constant-choke drawdown, as long as the rate and GLR are relatively constant. In this fashion, the permeability and the distance to limits may be calculated from the data supplied from the surface gauge, while skin can be determined by inputting the estimated or measured bottomhole pressure.

An alternative to screening wells based on flow-pattern mapping is to use rules of thumb based on field experience. If a gas well flows with a Reynolds number above 500,000, it is a probable candidate for surface testing. If the Reynolds number is above 1,500,000, the well is an excellent candidate for surface testing. For oil wells, if the Reynolds number exceeds 50,000, it is a probable candidate; if it exceeds 100,000, it is an excellent candidate. (Keep in mind, that depending on the well category, build-ups may still not be possible). Examples of both the Taitel-Dukler Flow Pattern Map and Reynolds number screening methods are presented in the appendices. The addition of water complicates things. However, as long as the Reynolds numbers exceed those listed above, the water will be lifted out of the well.

Dealing with Deviated Wells

It should be noted that the screening criteria presented above are intended for use on vertical wells. While deviated wells can still be tested from the surface, they will require a higher flow rate than vertical wells to continuously unload without slugging. Most nodal packages have a method to calculate the critical gas rate for deviated wells, but do not have a means to determine the requisite oil rate to avoid slugging. With this in mind, a method to approximate the rate to sweep oil is to first calculate the Reynolds number corresponding to the critical unloading velocity of gas for a particular tubular. Divide the Reynolds number by 10 and calculate the rate of oil required for that reduced Re. If the well's production rate exceeds that value, the well can be tested from the surface.

Wellbore Modeling

An effective surface-to-bottomhole pressure calculation routine must be able to perform calculations for $\Delta P_{friction}$ and $\Delta P_{gravity}$ for each of the continuous or pseudo-continuous flow regimes: Single-Phase, Mist, Annular Mist, Bubble, Churn and Froth. In addition, the bottomhole pressure calculation routine must account for changes in fluid properties as the wellbore temperature and pressure change with time. In fact, it is more important to get these parametric changes right, since they affect the relative pressure change and therefore have a significant impact on the test results.

During the course of a pressure transient test on a multi-phase well, the phase compositions and volume percentages will vary with pressure and temperature. In addition, changes in rate will affect the temperatures in the well bore as a function of the heat loading on the well. This is most noticeable during well start-up and shut-in, where the wellhead temperatures can change as much as 250° F from flowing to shut-in conditions.[6] These temperature changes also affect the phase behavior of the fluids. Thus, an accurate wellbore model needs to account for the change in wellbore temperatures over time.

In Figure 5, the importance of accurate thermal modeling is demonstrated. For this example, the wellhead temperature dropped from 165°F to 70°F during the course of the build-up. As the temperature in the well bore dropped, the density of the wellbore fluids increased and the wellhead pressures actually dropped. If this is not accounted for in the bottomhole pressure calculation, well test results will be meaningless.

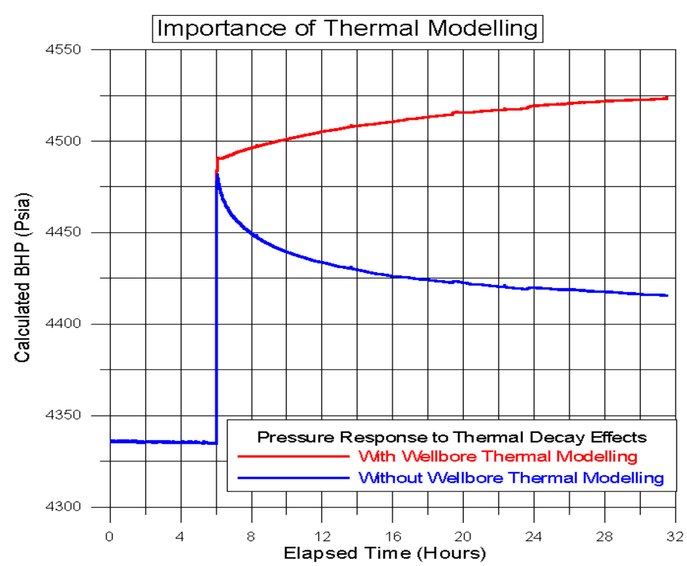

Figure 5 – Wellbore Thermal Modeling

To determine the phase behavior of a fluid, a representative well/reservoir fluid sample must be obtained. Subsequently, PVT analysis must be performed to evaluate the saturation pressure at the reservoir temperature (important for categorization), as well as the phase compositions and volume percentages of the liquid and vapor phases as a function of temperature and pressure. However, if the fluid composition has changed since the time of the sampling, some adjustments need to be made to the PVT parameters in order to model the current behavior of the well. The first adjustment is to increase or decrease the methane or the heavy component plus composition percentages (C7+, C20+, etc) to match up with the current GOR. The other is to alter the effective molecular weight of the heavy components to account for changes in density of the separator oil.

It is important to note that a wellbore model may have a significant error in the values calculated for $\Delta P_{gravity}$, yet still provide useful well test results, as long as that error is consistent. This can be seen in Figure 6, where a 500 psi scalar offset has no bearing on the skin or permeability. Scalar errors affect the absolute reservoir pressures calculations and can affect skin (if the $\Delta P_{friction}$ is incorrect), but do not affect permeability or distance to limits calculations. This is because perm and radius of investigation are relative quantities, based on the change of the pressure response. Thus, if the wellbore model has minimal relative error and can correct for changes in a fluid's PVT properties as a function of temperature and pressure, valid well test results may be obtained.

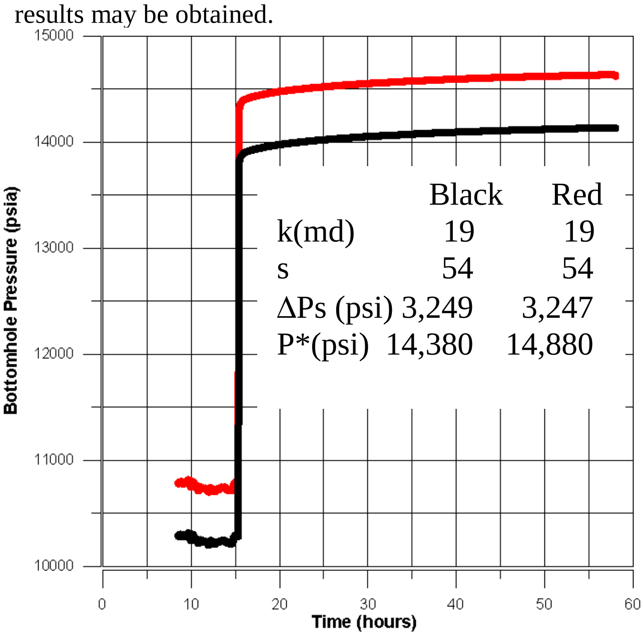

Figure 6 – Effect of Scalar Offset on Analysis

Instrumentation Requirements

When running a pressure transient test, it is critical that the pressure gauge be accurate, high-resolution, repeatable and thermally compensated. This is especially true for wells in moderate- and high-permeability reservoirs, where the magnitude of the pressure change during the mid- and late-time portions of the test is small. As shown in Figure 7, the use of a low-resolution gauge can make well test interpretation impossible. In this case, the low-resolution gauge can't even tell that the pressure is dropping.

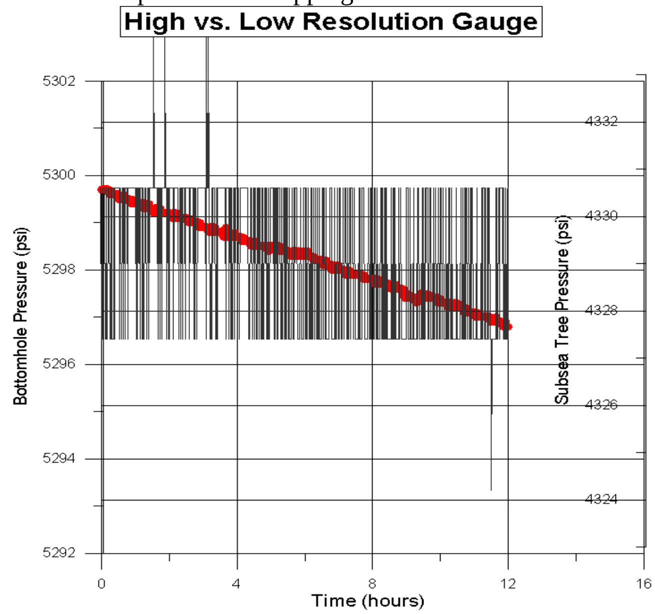

Figure 7 – Importance of Resolution in Test Data

The use of low-quality pressure transducers can also affect downhole gauge data, where poor thermal compensation in association with rate changes or Joule-Thompson cooling effects can cause an error in the pressure measurement. In Figure 8, a silicon/sapphire downhole gauge's pressure responds "bump for bump" to changes in temperature, leaving the operator to ask: Did this happen in the well, or just the gauge?

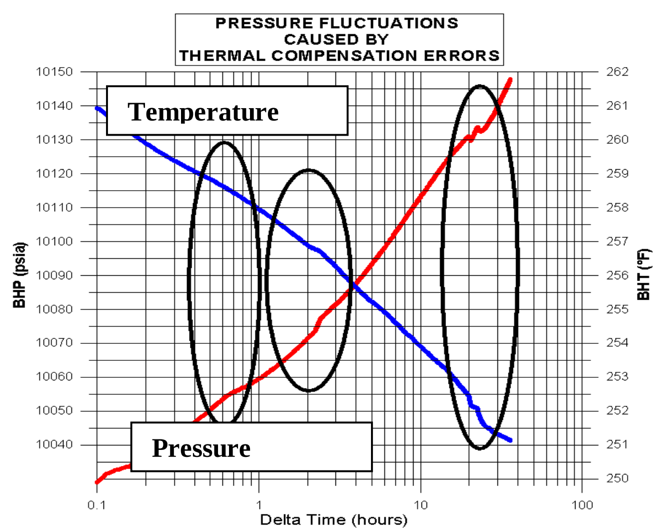

Figure 8

Nevertheless, low quality mechanical strain, bonded strain, and silicon/sapphire gauges can still play a role in well management. Even low-resolution, low accuracy gauges may be used to determine if a well is flowing, or to track the production trends of the flowing tubing pressure over a matter of months. However, in pressure transient testing, the objective is to accurately measure the pressure CHANGE over a relatively short period of time (hours or days). Therefore, an instrument whose pressure response is affected by both pressure and temperature fluctuations will not yield valid results unless the pressure change is significantly greater than the thermal response error and the gauge resolution.

Thermal compensation is even more critical when measuring the pressure at the surface, where the gauge is subjected to daytime/nighttime temperature changes. Further complicating things are wellbore temperature transients that accompany well start-up, well shut-in and rate changes. As illustrated in Figure 9, an uncompensated pressure gauge responds not only to its own temperature fluctuations, but also the REAL change in pressure caused by the change in the fluid density as a function of temperature.

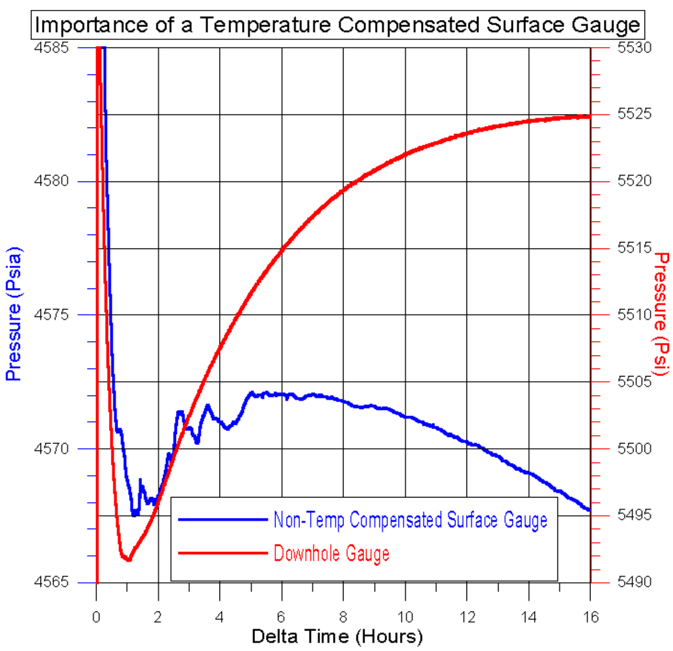

Figure 9

Consequently, any time a pressure gauge with poor thermal compensation is used, the question remains: Did a pressure change occur in the well or is the gauge simply responding to temperature fluctuations? Therefore, in order to perform surface pressure transient testing on moderate- to high-permeability reservoirs, a thermally compensated quartz gauge must be used.

In addition to pressure measurement, it is also useful to measure the flow rate during the course of a drawdown test. If possible, the well should be produced through the test separator for the duration of the test, where the flow rate should be continuously monitored and recorded with the appropriate instrumentation (d/p cell, venturi meter, etc.). This will provide verification that the rates and GORs are relatively constant and provide a means to check whether unexpected pressure changes are accompanied by rate changes.

A Caveat on Constant-Choke Drawdown Testing

If the objective of a well test is to determine completion or reservoir properties (skin & perm) and/or the distance to reservoir boundaries, a constant-choke drawdown should be performed. This is especially the case for a multi-phase reservoir, where choke changes are likely to significantly change not only the phase behavior in the well bore but also the relative permeability in the completion and in the reservoir.

In order to run a constant-choke well test, the well must start from a shut-in condition. Wells can be tested when they are first hooked up to sales or after downtime associated with facilities or pipeline maintenance.

Field Example 1 – Category 3 Gas

This well is a moderate depth, moderate temperature and pressure North Sea gas/condensate. The reservoir rock is an upper Jurassic (Ula) sandstone with a water saturation of 15% and a porosity of 25%. The dew point of the reservoir fluids at reservoir temperature is approximately 4,500 psi. At the time of the well test, the well was producing 48,000 Mscf/D and 2,060 bbl/D of condensate with a FTP of 2,780 psia and a reservoir pressure of 3,850 psia.

The subject well was equipped with a dual quartz, thermally compensated surface gauge and a permanent dual quartz downhole gauge, set at 8,600 feet TVD. The well was a Category 3 gas well at the time of the test, so liquid fallback and re-injection was expected during the build-up. Fortunately, re-injection ended about one hour into the shut-in, making it possible to use the build-up data to calculate completion and reservoir properties from both the downhole gauge and surface data.

For the surface-to-bottomhole pressure conversion, adjustments had to be made to the PVT data from July, 1999 to account for the change in fluid composition at the time of the build-up. When the PVT fluid sample was acquired, the well was making 60 bbl/MMscf of condensate, but only 43 bbl/MMscf at the time of the build-up test in November, 2000. The C7+ mole percentage was adjusted to account for this difference; the resulting fluid composition was used to perform a "blind" comparison with the downhole gauge.

After viewing the downhole gauge data, the C7+ mole percentage was adjusted again to match the shut-in condition of the well. This "tuned" data was then compared to the downhole gauge data. It should be noted that once a well or reservoir fluid has been tuned in this fashion, it should be possible to test other wells in the same reservoir using the fine-tuned PVT compositions. A plot of both the tuned and "blind" data can be seen in Figure 10. Both the "blind" and "tuned" BHP, as well as the downhole gauge data were analyzed for skin, permeability and reservoir pressure. These results are listed in Table 1.

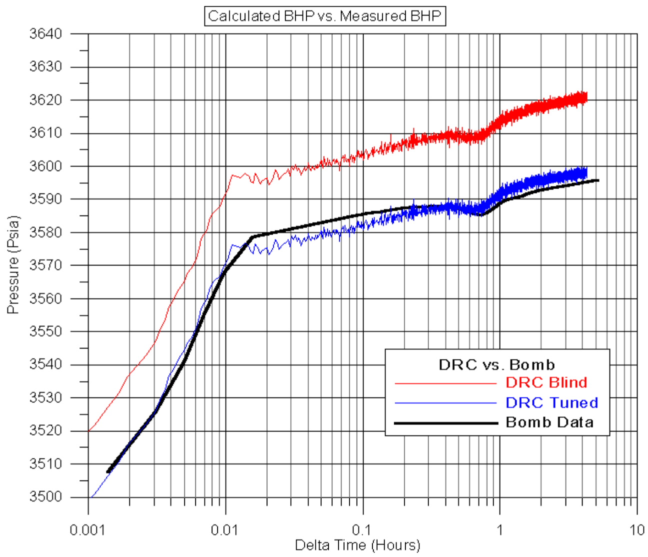

Figure 10 – Bomb/SPIDR Comparison

Analysis Comparison for Field Example 1

	Bomb	Blind	Tuned
BHP @ 48 MMcf/D	3,488 psia	3,509 psia	3,488 psia
Shut-in BHP	3,597 psia	3,621 psia	3,598 psia
Permeability	58 md	47 md	56 md
Skin	11.7	9.2	11.9
ΔP_{skin}	70 psi	65 psi	70 psi
PI Efficiency	45%	51 %	45%
P*	3610 psia	3640 psia	3615 psia

Table 1

This example demonstrates the effect of errors associated with inaccuracies in fluid composition. However, it also points out that these errors do not affect the conclusions drawn from the well test. In all of these cases, the well had a permeability between 45 and 60 millidarcies and a skin ranging from 9-12, corresponding to 65-70 psi pressure drop across the completion. Of course, it would be nice to have 0.001% error, but as engineers, it is often necessary to make the right decision without perfect data. In this case, regardless of whether the surface gauge or the downhole gauge was used, the calculated values of skin and perm are equivalent.

Field Example 2 – Category 2 Oil

This well is a deep, high pressure, high temperature, Gulf of Mexico oil well. The reservoir rock is a Miocene sandstone with a water saturation of 31% and a porosity of 13%. The saturation pressure at reservoir temperature is approximately 7450 psi. The flowing tubing pressure at the time of the test was 5,700 psi, while the reservoir pressure was 12,400 psi. The well was producing 5,900 Mcf/D of gas and 2,440 bbl/D of oil.

For this Category 2 oil well, data was gathered by a dual-quartz thermally compensated surface gauge and a quartz downhole memory gauge. The well was shut-in for three days, although surface data collection did not begin until two days into the build-up. After the build-up, the well was placed on a fixed choke and flowed for eight days. Five days into the drawdown, the downhole gauge failed. Thus, only surface data was acquired during the final three days of the drawdown.

There was no PVT data available for this well—only gas gravity, condensate API and an estimated saturation pressure at reservoir temperature. In order to model the behavior of the wellbore fluids, a recombination calculation was performed on the separator gas and oil. This was done by calculating the molecular weight of the gas, estimating the molecular weight of the oil, and performing a mass balance to calculate the percentages of oil and gas required to match the rates from the well. It was expected that this technique would introduce some scalar error. However, since well testing focuses on relative pressure change, this was not considered to be a problem. The surface pressures were then converted to downhole conditions "blind" and compared to the downhole gauge, as shown in Figure 11.

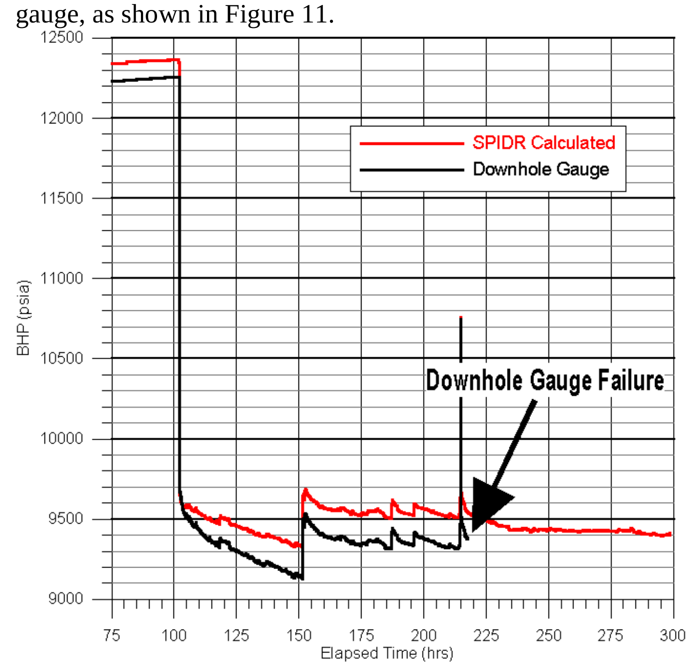

Figure 11 – Drawdown on Category 2 Oil Well

As expected, there was a scalar offset between the data sets. However, even though pressures were below the saturation point in the well bore, both the surface and downhole gauge pressures tracked each other with a consistent offset throughout most of the test (until the downhole gauge failed). The only time the surface data did not track the downhole gauge data was when both the flow rate and gas liquid ratio were fluctuating after the well was placed on production. Nonetheless, these errors did not significantly affect the overall results of the test: low perm, high skin.

Both sets of data were then analyzed for skin, perm and initial pressure. The results are summarized in Table 2.

Analysis Comparison for Field Example 2

	Calculated BHPs	Measured BHPs
FBHP (psia)	9,520	9,378
SIBHP (psia)	12,365	12,258
Perm (md)	6.0	5.3
Skin	17.3	14.6
ΔP_{skin} (psi)	2,000	1,900
PI Efficiency (%)	32	34

Table 2

Data from surface gauges resulted in similar calculated reservoir parameters such as skin and perm, as compared to the downhole gauge data. The three days of additional surface-measured drawdown pressures were used to supplement and extend the reservoir limits test derived from the downhole data. Surface gauges were chosen for a subsequent well test over downhole gauges because of extreme BHT limitations and the satisfactory results from the surface gauge data compared to downhole data in the initial test.

Conclusions

In order to test a multi-phase well from the surface, the wells must be categorized, screened and tested properly. Multi-phase wells should be screened based on a Taitel-Dukler flow pattern map, although gas wells can also be screened using a Dukler fluid-unloading chart. Once a well has been categorized and screened, a test procedure that minimizes operational and phase behavior complications should be employed. A single-choke drawdown fits this description and, for wells that are below the saturation point in the reservoir, may be the only way to acquire valid well test data. Finally, since surface instrumentation is subject to fluctuations in both wellhead and ambient temperature, the only way to test a well (either at the surface or downhole) and be certain that a pressure response really happened in the well is to use a dual-quartz, thermally compensated pressure gauge.

Appendix A – Example of Candidate Selection for a gas well

Well Parameters:
Gas Rate – 7,000 Mscf/D
Oil Rate – 840 STB/D
Water Rate – 14 bbl/D
Reservoir Pressure (est.) = 8,900 psia
Flowing Tubing Pressure = 5,800 psia
Est. Flowing BHP = 7,000 psia
Dew Point = 7,800 psia
Tubing ID: 2.992”
BHT = 330 F
Flowing WHT = 180 F

Fluid Parameters
$\gamma_g = 0.64$
Oil API = 46°
Water s.g. = 1.02
B_g @ 7,000 psia & 330 F = 0.67 RB/Mscf = 3.77 Rcf/Mscf
μ_g @ 7,000 psia & 330 F = 0.026 cp

It should be noted the formation volume factor and viscosity are calculated for a dry gas gravity of 0.64. These calculations do not include the produced condensate.

Step 1: Categorization – The reservoir pressure exceeds the dew point, but the FTP is below it. This is a Category 2 gas.

Step 2: Screening – The well makes 120 bbl/MMcf of condensate, so a Dukler Chart may be used to determine if the well is unloading. However, for the sake of the exercise, the flow pattern map and the Reynolds number methods will also be shown.

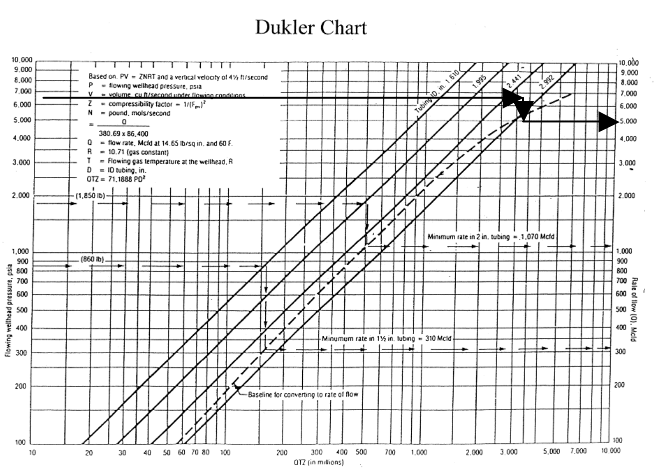

Figure 12

2a: Dukler Chart – Starting with the WHP (5,800 psia), going horizontally to the ID (2.992”), vertically to the equilibrium line, then horizontally to the gas rate, the well needs to flow above 5,500 Mscf/D in order to be a good surface candidate. Since it flows at 7,000 Mscf/D the well can be tested from the surface.

2b: Flow Pattern Mapping – The oil and gas superficial velocities must first be calculated. These velocities will then be plotted on the flow regime map. Assume a worst-case scenario that all of the separator liquid is a liquid in the well bore.

u_{ls} = oil rate/area = q_l/A

$$= \frac{840\,bbl/d * 5.615\,ft^3/bbl * (1d/86{,}400\,\sec)}{\pi/4 * (2.992\,in)^2 * (1/144\,ft^2/in^2)}$$
$$= 1.12\,ft/s = 0.34\,m/s$$

u_{gs}= gas rate @ flowing bottomhole conditions/area = $q_g * B_g/A$

$$= \frac{7{,}000\,Mscf/D * 3.77\,res.ft^3/Mscf * 1d/86{,}400\sec}{\pi/4 * (2.992in)^2 * (1/144\,ft^2/in^2)}$$
$$= 6.26\,ft/s = 1.91\,m/s$$

As shown in Figure 13, plotting these points on the Taitel-Dukler Flow Regime Map indicates that the well is in the annular region, making the well an excellent candidate for surface testing.

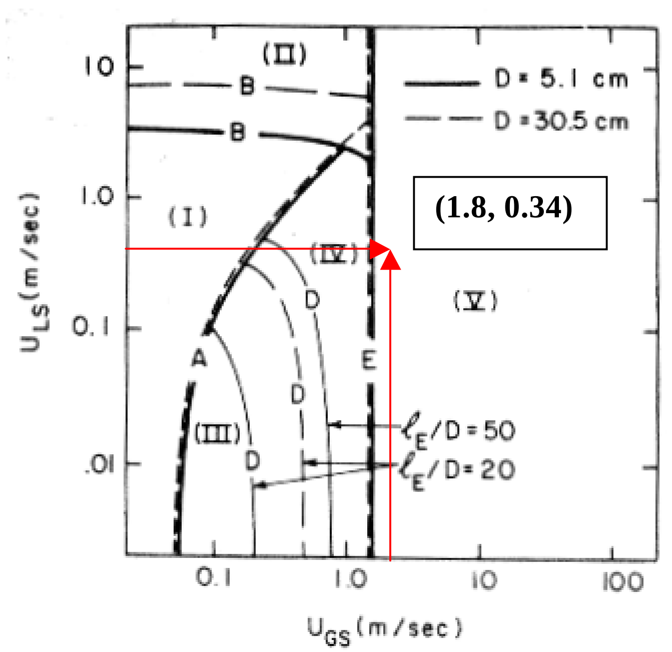

Figure 13 –Flow Pattern Map for Appendix A Well

Step 2c: Reynolds number method – The Reynolds number of the gas is calculated then compared to see if it exceeds 500,000 and/or 1,500,000.

$$\mathrm{Re} = \frac{20.09 * q_g(Mscf\ /d) * \gamma_g}{D(in) * \mu_g(cp)} = 1.16\,x10^6$$

In this case, the Reynolds number falls between 500,000 and 1,500,000, meaning this well is probably a good candidate for surface testing.

All of these methods indicate that the well can be tested from the surface. In addition, since the well is a Category 2 gas, there are no restrictions on the types of tests that can be performed on the well.

Appendix B - Example of Candidate Selection for an Oil Well

Well Parameters:
Gas Rate – 5,000 Mscf/D
Oil Rate – 12,000 bbl/D
Water Rate–1,000 bbl/D
Reservoir Pressure (est.) = 6,800 psia
Flowing Tubing Pressure = 2,800 psia
Est. Flowing BHP = 6,000 psia
Bubble Point = 5,900 psia
Tubing ID: 2.992”
BHT = 230 F
Flowing WHT = 170 F

Fluid Parameters
γ_g = 0.68
Oil API = 38°
Water s.g. = 1.08
B_g @ 6,000 psia & 230 F = 0.63 RB/Mscf = 3.53 Rcf/Mscf
μ_g @ 6,000 psia & 230 F = 0.025 cp
μ_l @ 6,000 psia & 230 F = 1.2 cp
ρ_o @ 6,000 psia & 230 F = 54 lb_m/ft^3

Step 1: Categorization – The reservoir pressure exceeds the bubble point, but the flowing tubing pressures are below it. This is a Category 2 oil well.
Step 2a: Flow Pattern Mapping – The oil and gas superficial velocities must first be calculated. These velocities are then plotted on the flow regime map.

u_{ls} = oil rate/area = q_l/A

$$= \frac{12{,}000 bbl/d * 5.615 ft^3/bbl * (1d/86{,}400 \sec)}{\pi/4 * (2.992 in)^2 * (1/144 ft^2/in^2)}$$

$$= 16.9 ft/s = 5.14 m/s$$

u_{gs}= gas rate @ flowing bottomhole conditions/area = q_g*B_g/A

$$= \frac{10{,}000 Mcf/D * 3.77 res.ft^3/Mscf * 1d/86{,}400 \sec}{\pi/4 * (2.992 in)^2 * (1/144 ft^2/in^2)}$$

$$= 4.47 ft/s = 1.36 m/s$$

This point falls in the transition between the finely dispersed bubble flow regime (Region II) and the annular regime (Region V) on the Taitel-Dukler plot, making the well an excellent candidate for surface testing.

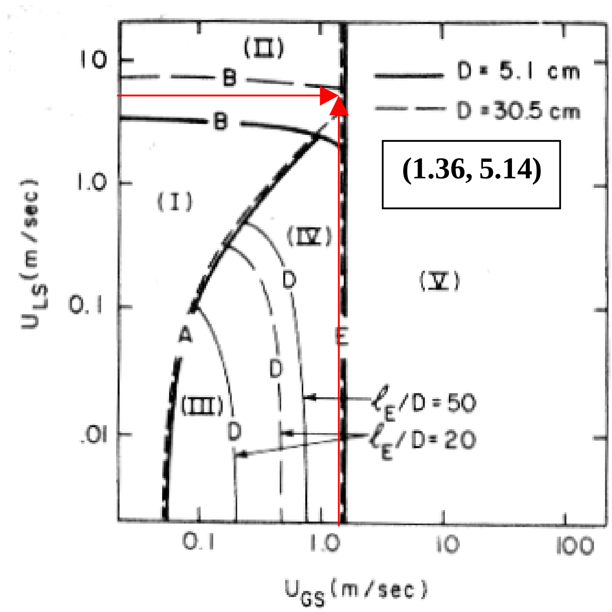

Figure 14 – Flow Pattern Map for Appendix B Well

Step 2b: Reynolds Number method – The Reynolds number of the oil is first calculated, then compared to see if it exceeds 50,000 and/or 100,000.

$$\mathrm{Re} = \frac{1.48 q(bbl/d) * \rho_o(lb_m/ft^3)}{D(in) * \mu_o(cp)}$$, where 1.48 has units that make the result dimensionless.

For this example, Re = 2.67 x 10^5, making the well an excellent candidate for surface testing, since it exceeds 1x10^5.

Both of these methods indicate that the well can be tested from the surface. However, since it is a category two oil well, there may be problems with phase redistribution during a build-up. Therefore, the recommended procedure for this well is a constant-choke drawdown.

Nomenclature

A	area (ft^2)
B_g	gas formation volume factor (reservoir cf/Mscf)
BHP	bottomhole pressure (psia)
BHT	bottomhole temperature (°F)
D	internal pipe diameter (in)
GOR	gas-liquid ratio (scf/bbl)
k	permeability (md)
m	mass (lb_m)
m_i	mass of a particular component (lb_m)
PI eff.	completion efficiency (%)
P*	theoretical pressure at the edge of the reservoir (psia)
q_g	gas rate (Mscf/D)
q_o	oil rate (bbl/d)
Re	Reynolds number (dimensionless ratio of inertial to viscous forces)
u_{gs}	superficial gas velocity (m/s)
u_{ls}	superficial liquid velocity (m/s)
WHP	wellhead pressure (psia)
ΔP_{skin}	pressure drop due to skin (psi)
μ_g	gas viscosity (cp)
μ_o	oil viscosity (cp)
ρ_g	gas density (lbm/ft^3)
ρ_o	oil density (lbm/ft^3)

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