Summary of Halliburton's SPIDR® Well Testing System

The benefits to running Halliburton's SPIDR® gauge system in lieu of running downhole gauges fall into four categories: 1) Safety/Risk; 2) Cost Reduction; 3) Instrumentation; 4) Data Processing. The following is a more precise explanation of these advantages and includes a discussion of how they relate to decisions based on well test results.

RISK REDUCTION AND SAFETY ENHANCEMENT

The SPIDR® gauge is installed at the surface on the crown of the wellhead. A typical wellhead configuration is a needle valve and a dial pressure gauge on the crown. The "tee" (1/2" NPT fitting) is placed between these two. A 1/16" capillary tubing is then attached from the "tee" to the SPIDR® gauge. After checking for leaks, the test may begin. The well does not need to be shut-in or isolated to install the SPIDR® gauge, which has a Class 1, Division 1 Explosion Proof and Intrinsically Safe Classification. The SPIDR® gauge has no moving parts and never enters the wellbore. Since we do not run tools into the well, there is no risk of getting equipment stuck or lost in the well. In addition, there is no chance of tool failure due to high temperature or pressure. Thus, the SPIDR® gauge system provides a safe, risk-free method to acquire wellhead pressures.

COST REDUCTION

The only piece of equipment required to rig-up/rig-down the SPIDR® gauge system is an adjustable wrench. We don't send out lift boats, lubricators or wireline crews. All we send is a 10 lb SPIDR® gauge and the installation instructions. We also don't send out an engineer or technician, it really is that simple.

INSTRUMENTATION

The SPIDR® gauge is unique in that it is the only electronic digital gauge that is specifically designed to acquire pressure transient data at the surface. The key features of the SPIDR® gauge are: 1) High Resolution; 2) High Accuracy; 3) High Repeatability; 4) Effective Thermal Compensation. In order to acquire data that is of sufficient quality to allow accurate bottomhole conversion and analysis (skin, perm, distance to limits), all four of these criteria must be met.

Gauge Accuracy

The SPIDR® gauge has an accuracy of 0.015% of full scale. This corresponds to a maximum error of 1.5 psi for our 10,000-PSI gauges. Gauge accuracy is not nearly as important in Pressure Transient Analysis (PTA) as Gauge Resolution. It does, however, affect the accuracy of the absolute bottomhole conversion.

Gauge Resolution

Resolution is the smallest change that a gauge can reliably and repeatedly detect. The SPIDR® gauge has a resolution of 0.01 PSI. If a high permeability reservoir had a mid-time slope of 0.5 psi per cycle; a SPIDR® gauge data file would show 50 distinct pressure values over that cycle; more than enough to determine the slope with confidence. Perhaps the largest problem with SCADA system data is the extremely low resolution of its pressure measurement. This renders SCADA data unusable in almost all cases of moderate to high permeability reservoirs.

Gauge Repeatability

This is the single most important characteristic of pressure gauges used for PTA. Repeatability is the measure of error observed when a gauge is repeatedly cycled between a known pressure and a second pressure (usually atmospheric pressure). Repeatability is expressed as the +/- PSI maximum deviations from the actual pressure observed after multiple pressure cycles. These deviations are the combined errors from hysteresis, accuracy and resolution. For high permeability wells (>150 mD), gauge repeatability should be at least 0.05 PSI or better. The SPIDR® gauge's repeatability is better than 0.01 PSI.
Thermal Compensation

Any high-resolution pressure transducer is also a good thermometer. In other words, at a true constant pressure, the transducer element will change properties with temperature. If the direction and magnitude of this thermally induced property shift is repeatable, it is then feasible to compensate the transducer for temperature change. Although simple in concept, thermal compensation of high-resolution pressure gauges is very difficult and is rarely done effectively. The amount of compensation required is both a function of pressure and the rate of change of temperature. Down-hole pressure gauges are very susceptible to thermally induced pressure shifts, especially when making gradient stops. Depending on the gauge, a stop may require 30 minutes or more to thermally equalize before the pressure reading stabilizes. In a gas well, down-hole gauges situated close to the perforations for a build-up may be subject to rapid heating when gas stops expanding across the perforations. Loss of this Joule-Thompson thermodynamic cooling has distorted the early time pressure readings on many build-up tests. Thermal compensation on surface pressure gauges is also very difficult. It is not uncommon to see 50-PSI pressure swings from night to day on surface gauges with inadequate thermal compensation. The design and construction of the SPIDR® gauge well testing gauge is unique in that it is the only known gauge, surface or downhole, that can withstand a 50 degree F step change in temperature without inducing a 1 PSI or greater pressure response. This has been accomplished by a combination of construction methods, installation techniques and a unique calibration procedure that maps the temperature/pressure response of the transducer over an infinite combination of temperatures and pressures. The failure to accurately compensate for a gauge’s own internal temperature can result in serious error in interpretation. If a particular well has a mid-time slope of 0.5 psi/cycle and the gauge thermal response error is 5 psi/cycle, the resulting error in the miscalculation of reservoir volume explored could be as high as an order of magnitude (10 Bcf vs. 100 Bcf).

DATA PROCESSING

The SPIDR® gauge is only used to acquire data. Once we have obtained the wellhead pressures, we convert them to bottomhole conditions. Most engineers who deal with natural gas are aware of the Cullendar/Smith or Gray correlations for calculating bottomhole pressure from surface pressures. At SPIDR® gauge, we have modified and expanded the validity of these models considerably and can now test almost any gas or gas/condensate well that naturally unloads its produced liquids. Once we have completed the bottomhole conversion, we then perform elementary analysis. The purpose of this section is to provide an overview of the different types of models/corrections that we use in order to provide both accurate BHP's and accurate analysis. The topics covered will be 1) The Model Framework; 2) Multi-phase flow correlations; 3) Wellbore Thermal and Phase Behavior Transients; 4) Elementary Analysis; 5) Error Analysis.

Model Framework

The backbone of all of our gas and gas/condensate BHP conversion is the Cullendar/Smith model. The Cullendar/Smith correlation is accurate for single phase, dry gas. It assumes an average temperature and average z-factor, along with laminar flow to perform their calculations. We have adjusted the Cullendar/Smith correlation by accounting for produced liquid, segmenting the tubing (with each element having its own fluid properties), and by allowing for multiple flow regimes (laminar, intermediate, turbulent, highly turbulent flow). The result is a much more rigorous (and accurate) treatment of the wellbore physics, which continues to be our single-phase gas/condensate model.

Multiphase flow models

When the pressures in the wellbore are below the dew point for a gas/condensate system, there will be some form of 2-phase (or 3-phase, if water is present) flow. If the well produces with enough gas rate (velocity) to continually unload itself naturally (avoid slugging), then the pressure drop in the wellbore/tubing can be calculated using either our Mist Flow or Annular Mist Flow models. We have also developed a Bubble Flow model for oil wells, though at this point we are still in the R&D phase with this model.

In Mist Flow, it is assumed that all of the liquid is entrained as droplets in the gas. Thus, the gas phase is still globally continuous to the perforations and from one side of a cross section (normal t the direction of flow) of the well bore to the other. In Annular Mist Flow, we assume that there is sufficient vorticity to force
and hold the liquids to the sides of the walls of the tubing. Thus, there is an inner core of gas and an annulus of liquid. The gas phase is still vertically continuous, but is not so in the horizontal direction, where a rough description of the wellbore and fluids is: Pipe wall-liquid-gas-liquid-pipe wall. Bubble flow is effectively a mirror image of the Mist Flow model, with the gas and liquid phases reversed (continuous liquid; entrained bubbles of gas).

Wellbore Thermal and Phase Behavior Transients

Thermal Decay

When any well undergoes a buildup or a drawdown, the wellbore is subjected to a thermal transient. If the well has been shut in for an extended period of time, the temperature profile in the wellbore closely resembles the surrounding geothermal gradient. When that well is brought on line, fluids enter the wellbore at reservoir temperature and lose heat through the tubing wall on the way to the surface. Eventually, the wellbore will assume a new thermal profile based on the flow rate of the well and the geothermal flux. The reverse is true on shut-in in which case the wellbore cools.

If PTA is to be performed using surface measurements, the ability to model these changes in wellbore temperature is essential. Halliburton has worked with several major Exploration companies in acquiring thermal data from hot wells with which to develop our Thermal Decay model. SPIDR® gauge has over 10 years experience testing wells in which Thermal Decay was a necessary consideration for correct analysis.

The WHP to BHP conversion routines which incorporate thermal decay cannot be used on surface data files that have been acquired by instruments that are subject to ambient thermal response. It is impossible to de-couple thermal decay effects from thermal compensation effects in a gauge which is responding to both at the same time. The failure to compensate for these effects on moderate to high permeability wells results in erroneous pressure transient interpretation. These errors can be several orders of magnitude.

Condensate Drop-out/Liquid Re-injection

In a wellbore where the shut-in tubing pressure is below the dew point of the fluids, condensate (or water) dropout followed by liquid re-injection is frequently observed. Basically, if there are liquids present in the wellbore in a gas/condensate/water system, the gas lifts the liquids when the well is under production. When the well is shut-in, the mechanism by which the liquids are lifted is eliminated (gas velocity ~ 0). Thus, the liquid must either vaporize (fluids become single phase gas) or, since the liquids are much denser than the gas, fall to the bottom of the well. If the liquids drop-out, they will then re-inject into the formation, being displaced by much lower density gas. The way that Halliburton approaches this problem is to perform a flash calculation on the wellbore fluids at the final shut-in condition. This allows us to determine the amount of condensate that can remain in solution with the gas. We then assume that the condensate that is not in solution will fall back and form a liquid column before re-injecting. Unfortunately, while there is a liquid level of unknown height in the well, our bottomhole conversion is not accurate. Fortunately, most moderate to high permeability wells will finish re-injecting in a matter of minutes or hours. In case the re-injection period obscures the results of the shut-in, we recommend performing a single choke drawdown following the build-up. Since we can model the behavior of the well while it’s flowing, we’ll be able to evaluate skin and permeability from the drawdown and P* from the build-up. Basically, the drawdown can be used to see the portion of the test that was missed during re-injection.

ELEMENTARY ANALYSIS

Halliburton provides well test analysis as a service to customers who request that SPIDR® gauge surface data files be converted to reservoir conditions. In our interpretations, we calculate skin, permeability, reservoir pressure and, if a modified isochronal test is performed, mechanical vs. non-Darcy skin. We have found that the most important first step in analysis is to generate the MDH semi-log plot of event elapsed time vs. BHP. A visual inspection of the MDH plot usually provides very strong clues as to the magnitudes of the skin and permeability and also reservoir geometry. It also allows us to diagnose phase re-segregation, such as drop-out/re-injection. If the middle time region is readily apparent, then we can identify the inputs to our in-house spreadsheet, which computes the values for skin and permeability. If the middle time region is not apparent we will generate a pressure derivative to help us define the region. We feel this approach is much faster than type curve matching and is less subject to judgmental error.
Error Analysis

Since the crux of Pressure Transient Analysis is the observation of CHANGE, any absolute error will have very little effect on the interpretation of permeability or on reservoir volumes. In single-phase wells, there also is no effect on the skin calculation; in multiphase wells, the error is minor. The only parameter that is affected by any error in our BHP conversion is \( P^* \); for single-phase wells, the likelihood of having any error in \( P^* \) is very slight. In any case, we can quantify the amount of error that is possible for each well test objective for a given set of conditions. Our clients may then determine if this error could possibly change the conclusions of the test (high skin? Low permeability? Small reservoir?). If there are no differences in the conclusions, why bear the expense and take the risk of putting wire in the hole?

CONCLUSION: We are results oriented!

OUR GOAL IS TO PROVIDE OUR CLIENTS WITH INFORMATION THAT THEY CAN USE TO MAKE THE CORRECT DECISION ABOUT THEIR WELL AND THEIR RESERVOIR. In the previous discussion, we have described the methods that we use to acquire WHPs, convert to BHP, and analyze well tests using our SPIDR® gauge system and our proprietary conversion/data processing techniques. We have expended a considerable amount of effort to ensure the accuracy of our conversion and of our interpretation. While it is nice to be able to convert accurately from surface to bottomhole pressure, it is not the most crucial requirement to achieve accurate results from a well test. THE MOST CRITICAL THING TO GET DONE RIGHT IS TO MEASURE/CALCULATE THE RELATIVE PRESSURE CHANGE ACCURATELY. EVEN IF WE WERE TO HAVE A SIGNIFICANT AMOUNT OF ABSOLUTE ERROR IN OUR BHP CONVERSION, IT WILL HAVE MINIMAL EFFECT ON SKIN, PERM OR THE IDENTIFICATION OF BOUNDARIES. Accordingly, we have designed the SPIDR® gauge such that the only thing that it responds to is wellhead pressure. This means that anything that shows up in the SPIDR® gauge data really happened in the wellbore. Thus, using the SPIDR® gauge system, Halliburton can provide our clients results that are equivalent to running downhole gauges at a fraction of the cost and without the risks associated with wellbore intervention.

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