RESERVOIR ENGINEERING

How wellbore dynamics affect pressure transient analysis

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ABSTRACT
There are numerous technical papers on pressure transient analysis which address both simple and complex reservoir-related phenomena. These papers all make the implicit assumption that reservoir pressure can be measured directly. It is a fact of life, however, that the pressure recorder is located in a wellbore, not in the reservoir. The wellbore is an intrinsic link between the reservoir and the recorders. Although the pressures recorded in the wellbore are normally representative of the pressures in the reservoir, they can also be affected by a number of wellbore-related phenomena.

The many wellbore related phenomena that can have a significant effect on the measured pressure have not been addressed in the literature, except for wellbore storage and the classical phase redistribution hump.

This paper presents several examples of tests that have been affected by wellbore dynamics, and shows that these could easily have been misinterpreted as complex reservoir phenomena (dual porosity, etc.) instead of wellbore effects. These effects are often accentuated by the (semilog) derivative which is traditionally used to diagnose reservoir characteristics. The fact that these are wellbore and not reservoir effects must be recognized to prevent misdiagnosis. Often this can only be done from examination of the test data other than the recorded pressure-time trace.

Introduction
There have been more than 1000 papers published on Pressure Transient Analysis. These publications address in great detail such fundamental topics as homogeneous infinite reservoirs, fractures, convolution, dual porosity, multi-layers, or such isoteric concepts as super-bilinear-equivalent-pseudo-time or integral type curves. With the progress made in both analytical and numerical solutions to reservoir problems, and with the ready availability of powerful computers, virtually every imaginable reservoir description can be modelled and the solution presented in graphical form (type curve).

In contrast, there are very few papers that deal with wellbore effects. The only two classical wellbore topics that have been studied in any detail, are the concepts of Wellbore Storage(1) and Phase Redistribution(2). Even then, the treatment has been more theoretical than practical. In this presentation the authors will address some of the many issues under the over-all umbrella of "Wellbore Dynamics". These reflect the experience with "practical" welltest interpretation, which stems from years of specialization in this field, (more than 10,000 tests have been analyzed in detail by the authors and their colleagues).

Wellbore Dynamics
The topics which will be addressed in this paper will obviously deal with wellbore phenomena. However, not all of these wellbore phenomena will be studied. For example, we will not be reviewing the effects of temperature on wellbore fluids or pressure recorders; nor will we address such topics as gas/oil solution/layeration or retrograde condensation. Moreover, some of the ideas discussed do not take place "in" the wellbore, but in the immediate vicinity of the wellbore, and often, their effects are inseparable from wellbore effects. The "Wellbore Dynamics" that we shall illustrate will be grouped into the following topics: Liquid Influx/Exflux, Phase Redistribution, Wellbore (and near-wellbore) Clean-up, Differences between Drawdown and Build-up, Plugging, Recorder Effects, Mysterious Effects.

Many, but not all, of these "wellbore" transients occur at very early time. Their detection and documentation has been facilitated by the advent of electronic pressure recorders. These recorders are so accurate that they will detect these wellbore effects very clearly, and can easily be misinterpreted as "Reservoir" effects. Indeed, the whole thrust of our field of engineering is to interpret the "Reservoir", by using pressures recorded in a "Wellbore". This often places the Reservoir and the Wellbore in a tug-of-war, and we find that, very often, "Wellbore" Transients will distort, or even, dominate our "Reservoir" Transients. This is not surprising in view of the fact that in this tug-of-war, the Wellbore has a distinct advantage over the Reservoir because this highly sensitive recorder is sitting in the Wellbore and not in the Reservoir.

Liquid Influx/Exflux
In this section, the authors will illustrate that the pressure trend observed with the recorders does not necessarily reflect the pressure in the reservoir. All the well test theory treats pressure as measured at the sandface. In many cases, it is impossible to land recorders at the sandface or even at the mid-point of perforations (MPP). In some cases the recorder run depth (RRD) is above MPP as shown in Figure 1, or at MPP in Figure 2. In the wellbore...
schematic of Figure 3, the RRD is at MPP, but because of the "U-tube" effect caused by the tubing being below the perforations, the same sandface pressure trend could appear very differently on the recorders of Figure 2 and Figure 3. This will happen every time that there is more than one phase in the wellbore, which, in the testing of oil and gas wells, is often the case.

For the reservoir engineering equations to be applicable, the "recorded" pressures must obviously be converted to "sandface" (reservoir) pressures when the recorders are set either above or below the producing interval. This correction is performed by adding or subtracting the appropriate hydrostatic head of fluid (gas, oil or water). In the case of tubing below the perforations, Figure 3, it is very important to recognize that the fluids inside and outside the tubing may be different, and separate corrections must be done inside and outside the tubing. In performing the pressure correction from RRD to MPP, the effects of friction have been ignored to simplify the presentation, though in high rate wells, this may cause a significant error.

In the simplest case of a single phase fluid and a wellbore schematic, as in Figure 1, the correction from RRD to MPP is:

\[ \text{Pressure (MPP)} = \text{Pressure (RRD)} + \text{P (Hydrostatic)} \]
\[ \text{P (Hydrostatic)} = H \times \text{gradient} \]

where H is the vertical distance between RRD and MPP

gradient is

- 1 kPa/m for gas
- 5 kPa/m for oil (lube)
- 10 kPa/m for water

In this situation, as seen in Figure 4, the pressure response at RRD is parallel to that at MPP.

When there is more than one phase present in the wellbore, and the liquid interface is moving up or down, there can be significant differences in the pressure trends observed on the recorder (RRD) as compared to what is really happening at the sandface (MPP). We shall illustrate this using the simple case of a "Changing Liquid Level" in a gas well with water in the wellbore. The well is producing gas and water to surface, and is shut-in for a build-up test. Assume (for the sake of illustration) that the pressure at the sandface (MPP) is increasing in a straight line, as shown by the line labelled MPP in Figures 5, 6 and 7. The liquid (water) level is above RRD and is falling, which will occur at different
rates depending on permeability and damage ratio. At time $t_1$, it reaches RRD, at time $t_2$ it is halfway between RRD and MPP (Fig. 6) and at time $t_3$ the liquid level has reached, or is below MPP. In Figure 5, the pressure difference between MPP and RRD is a constant, equal to the hydrostatic head of water. It stays constant until the liquid level reaches the RRD. From then on, the difference between MPP and RRD varies and equals the sum of an increasing gas column plus a decreasing water column. Figure 6 illustrates when the liquid is halfway between MPP and RRD. When the liquid level is at, or below MPP, the correction from MPP to RRD is the hydrostatic head due to a column of gas.

It is obvious, as is illustrated in Figure 7, that whereas the response recorded on the pressure recorder at RRD shows a significant deviation from linearity, and could be (mis)interpreted as a reservoir phenomenon, the truth is, that the pressure trend at MPP was perfectly straight, and the recorded effect was a wellbore phenomenon, pure and simple. A rising liquid level would exhibit the opposite trend to that shown in Figure 7.

Is this ‘ivory tower’ thinking, or is the phenomenon real? From the thousands of well tests that we have analyzed, these effects have been observed on approximately 75% of well tests where more than one phase is flowing. Here are a few examples of very typical situations:

1. Oil wells flowing oil and gas to surface. At the end of a 2-week shut in for a build-up test, a static gradient is conducted and shows no liquid in the wellbore. Where did all the oil in the wellbore go?

2. Gas wells producing at high water-gas ratio: Once again, at the end of a build-up test, the static gradient shows not a drop of water above the perforations.

3. Acoustic well surveys (AWS): These very often indicate both rising and falling liquid levels. Admittedly, AWS are subject to a lot of interpretation problems, but the over-all trends of rising or falling liquid levels are clearly illustrated (quite independently of such problems as collapsing foam columns, misinterpreted reflections, etc.).

Even though we have developed “rules of thumb” respecting the phenomena to be expected, it is very hard to predict, a priori, whether, for a particular test the liquid level will rise and/or fall, or both, at what rate. Figures 8 and 9 show measurements of liquid levels obtained with static gradient surveys conducted every 3 or 4 days on two different oil wells. Figure 8 clearly illustrates liquid

“efflux” causing the liquid level in the tubing to fall. Note that (due to density segregation), during the first 5 days, only water effluxes from the wellbore (into the reservoir?), and after that, only oil is effluxing. Figure 9, on the other hand, shows that during the shut in of an oil well, only water “influxed” into the wellbore! (The first and last static gradients are questionable—the first one was taken a few hours into the build-up and the gas/oil/water levels are still unsettled).

Figure 10 illustrates a gas well which produced at a high water-gas ratio. The point at which the water level falls below the recorders is clearly seen at 100 hours, and at 108 hours the liquid level has reached the sandface. The pressure difference (approximately 300 kPa) corresponds to the distance between RRD and MPP multiplied by the difference between a water gradient and a gas gradient.

How do these effects appear when performing pressure transient analysis? The type curve and derivative plot of a typical falling liquid level test is shown in Figure 11. The derivative has the shape of the classical “Dual Porosity” reservoir, yet is caused only by
liquid level changes in the wellbore. Figure 12 illustrates the full set of pressure data on the same well as Figure 11, while Figure 13 illustrates the parallel semilog straight lines often seen with such tests.

Phase Redistribution

The phenomenon of phase redistribution also known as "humming" has been well documented in the reservoir engineering literature. It is distinct from the liquid influx/efflux situation described previously. It represents pressure changes (sometimes significant and dramatic) caused purely by the redistribution of the gas and liquid phases in the wellbore. An interesting explanation of the cause of the "humming" effect is given by Slidell, to which the interested reader is referred. In this section, we will provide three examples of phase redistribution effects, Figures 14, 15 and 16. These illustrate that the phase redistribution bump can be of the same magnitude (Fig. 14) or even significantly larger (Fig. 15) than the subsequent reservoir pressure response. Figure 16 shows the combined effect of phase redistribution and changing liquid level. It also illustrates that, sometimes, the subsequent reservoir pressure response does give analyzable semilog straight lines.

Figure 17 shows the first seven hours of a build-up in an oil well. The two tracks shown are for two electronic pressure recorders set for 30-second interval readings. Except for the slight offset in time, the recorders match exceptionally well, confirming that some event is actually taking place and what is being recorded is not a spurious aberration. It is the authors' contention that what we are observing is phase redistribution on a smaller scale than the humpling effect — gas bubbles, coalescing into slugs and bubbling through the oil column below the recorders. Whatever the true nature of this wellbore dynamic, we do not believe that what we are observing is a reservoir effect. Rather, we believe it is purely a wellbore effect which has totally masked the reservoir response.

Wellbore and Near Wellbore Cleanup

Consider the flow and build-up test shown in Figure 18. We have two tests on different reservoirs in different parts of Alberta, that
The pressure depletion of some 300 kPa was purely a wellbore effect. The reservoir pressure at MPP before and after the test did not change at all.

There are some effects that take place in the immediate neighborhood of the wellbore that are often observed during tests. Even though these are not truly wellbore effects, they distort the reservoir pressure data in the same way and can easily lead the analyst to a misdiagnosis of the reservoir response. The “bad news” case in Figure 18 clearly shows depletion, hence a limited reservoir. Yet, during the drawdown neither the rate nor the pressure is declining; in actual fact, the flow rate was increasing. The drawdown information is contradicting the build-up results. The explanation is that during the drawdown, the near-wellbore for-
mation is continuously cleaning-up and the corresponding decrease in skin is masking the anticipated pseudo-steady pressure decline. A more dramatic example is shown in Figure 19 in which the rate and flowing pressure are both increasing! This near-wellbore cleanup can last several weeks. In six tests on wells that were frac'd and tagged with identifying tracers, frac fluids were still being produced after three weeks of flow.

The reverse phenomenon has also been observed as shown in Figure 20. In this example the build-up data indicate a good permeability well with no depletion, while the drawdown data exhibit a steeply declining pressure in spite of a decreasing gas flow rate. This drawdown behaviour is usually caused by either a very tight reservoir or a depleting system, but the build-up in this case shows that neither is the case. In actual fact the drawdown is reflecting the increasing skin caused by water coning in the near-wellbore area. The logs showed 1 m of gas over water and the production showed a 25 fold increase in water-gas ratio.

**Differences: Drawdown and Build-up**

The previously described cases will obviously show a distinct difference in analysis between the drawdown and the build-up. Figures
21 and 22 are examples of a drawdown and build-up from the same test. The data and derivative curves are very different in character. The drawdown shows a permeability of 19 mD and a skin of 31 while the build-up shows a permeability of 2 mD and a skin of -3. During this test, the well was producing frac sand and frac fluid left over from a stimulation treatment. Due to the frac sand production the choke was washing, thus causing a gradual increase in choke size throughout the drawdown. At the same time, the cleanup of frac fluids was causing a continuous change in the skin. In this instance, the drawdown analysis is not valid, and the build-up analysis provides the best estimates of the reservoir flow characteristics.

Build-ups are often analyzed using drawdown typecurves with equivalent time or using some form of superposition (convolution) of the drawdown equations. For oil wells, one should expect the early time response in drawdown and build-up to be significantly different because of the different wellbore conditions. In a drawdown, one can often start the flow from the condition of the wellbore full of a single phase fluid (hence a particular wellbore storage coefficient). However, in a build-up, in the majority of cases, the wellbore will contain a significant amount of free gas (and hence have a completely different wellbore storage coefficient). Moreover, the phenomena taking place in the wellbore are completely different — in drawdown we have expansion of wellbore liquid, in build-up we have gas being compressed and (possibly) going into solution throughout the build-up. (This is like squeezing toothpaste back into the tube!) In build-up tests for oil wells one would expect wellbore effects to last for a lot longer period. Drawdown tests, on the other hand, are affected by gas-liquid slugging and variable liquid holdup and often, the data is not analyzable. Because of these significant differences between drawdown and build-up wellbore behaviour, tests of short duration are particularly susceptible to misinterpretation.

**Plugging**

For one particular gas well test, there were four pressure recorders placed in a carrier at the same depth. Three of the pressure charts looked like Figure 23 and the fourth one looked like Figure 24. These charts were alike throughout the test, except for the last flow period in which three recorders show an increasing pressure while the fourth recorder showed a decreasing pressure. Our final analysis of the wellbore configuration showed that the three recorders were "inside" recorders while the fourth recorder was an "outside" one.

In fact, the three inside recorders had been affected by hydrates plugging during the last flow period, and the only true reservoir response was from the "outside" recorder. We have observed similar situations in waxy oil wells, in which a recorder port hole gets plugged with wax.

**Recorder Effects**

With the ever increasing use of electronic pressure recorders, the authors have observed phenomena that can only be ascribed to recorder (mis)behaviour. Figure 25 shows a sudden jump in pressure when the sampling rate is changed — its companion recorder did not show this effect. Figure 26 depicts two recorders (1 m apart) located in an observation well during an interference test. Note the unexplained significant pressure difference between the two recorders. There are numerous examples of tandem recorders (1 m apart) not tracking each other, some diverging, others crossing each other, while others tend to have a sinusoidal wave pattern. Electronic recorder drift is recognized but has not been quantified, and it is suspected that in some high permeability reservoirs the drift of electronic recorders is of the same order of magnitude as the reservoir response. This means that a recorder characteristic can be analyzed as a reservoir characteristic.
Mysterious Effects

The two recorders shown in Figure 27 are sitting in an observation well, and show a very erratic performance. When we looked at the first recorder, we thought that it was malfunctioning. However when we examined the second (and third and fourth) recorders, they showed an identical behaviour. These two recorders are not of the same type. One is a strain gauge, the other quartz crystal. What are all these spikes that we see? Note the pressure spike around 400 hours. There are several hundred data points down one side and up the other side of this spike, and the magnitude of this pressure aberration is 40 kPa (6 psi), 50 to 100 times the resolution of the gauges. This “detour” in pressure takes place over some 20 hours. We have no idea what causes these effects and can only guess that they might be micro-seismic effects (we could not find any documented earthquakes at the 400-hour time frame!). We have observed geo-tidal effects in other situations; they have a regularity to their pattern and do not look like Figure 26. In Figure 28 we present one of two recorders (identical behaviour on both) during a flow and build-up test in an oil well. Notice the “cilia” (hair-like attachments) during the drawdown and the build-up, except between points A and B. The regularity of this pattern is fascinating. The size of a typical spike is 30 kPa (5 psi) and the interval between spikes is approximately 30 minutes. The sampling frequency was such that there were some 20 data points for each of the spikes. We have no idea what causes this cilia behaviour, nor why it is absent between points A and B, nor why it appears so consistent during the drawdown which is expected to be in turbulent (hence erratic) flow. (As we write this, it occurs to us that this cilia behaviour could easily be caused by a casing gas regulator — a back pressure valve that opens and closes intermittently to release casing gas).

Tug-of-war: Wellbore vs Reservoir

Of the many wellbore related effects that we have observed, only a few have been presented in this paper. Many of the effects have logical explanations while others are still a mystery. Many of these effects occur at early time (Fig. 17), but they are certainly not confined to early time (Fig. 26). We have documented cases of changing liquid level effects a full 2 weeks after shut-in.

The primary function of welltest analysis is to determine the reservoir characteristics, and not to study the wellbore (even though some wellbore coefficients can be calculated). The best way to study the reservoir is to place the recorder inside the reservoir. Unfortunately, that is not possible, and the pressure recorder must be placed inside a wellbore that is in communication with the reservoir. This means that any wellbore pressure effects will be felt instantaneously by the recorder and will be accentuated in comparison with the more diffuse reservoir response. In the continuous tug-of-war between wellbore response and reservoir response, the wellbore has the unfair advantage of having (a) infinite transmissivity and (b) immediate proximity of the pressure recorder. This means that in most situations wellbore effects will dominate over the reservoir effect.

This state of affairs is unfortunate in that wellbore dynamics can mask or completely obliterate the reservoir response, and as a result, can easily lead to misdiagnosis of the response.

Conclusion

The presence of Wellbore Transients must be recognized and taken into consideration when performing a (Reservoir) Pressure Transient Analysis. All too often, analysts work with a set of pressure-time data, oblivious of the practicalities of test operations. It is our hope that, in this paper, we have illustrated some of the anomalies that can easily be (mis)interpreted as reservoir characteristics. To avoid these pitfalls, the analyst must be familiar with the operation of surface and bottom hole test equipment, field conduct and practices, and details of the test performance. We estimate that approximately 50% of the well test analyst’s time should be spent examining the raw data and conducting validity checks and reconciliation of all the data. The following procedures must be performed routinely, before or simultaneously with any pressure transient analysis:

1. examine wellbore configuration — packer, sliding sleeve, recorder depth, tubing depth, perforation depths, etc.
2. compare all the pressure recorders for inconsistencies; do not rely on one recorder when one or more backup recorders are used.
3. adjust pressures to mid-point of perforations based on static gradient surveys conducted before and after the test —
adjustments may vary with flow rate and time.

4. compare bottom hole pressure behaviour with surface tubing and annulus pressures.

5. examine flow periods for constancy and accuracy of: flow rates, gas-oil ratio, water-oil ratio, gas-water ratio.

6. if a large capital investment depends on the results of a test; calibrate the recorders before and after the test to confirm the integrity of the recorders.

7. maintain constant dialogue with the field supervisor to resolve any anomalies in the data (leaks, operations, not reported in the field notes).

8. conduct pressure transient analysis taking into consideration all of the above practical aspects in conjunction with all of the relevant reservoir engineering/geological factors.

Wellbore Dynamics have been ignored for far too long. They must now be fully incorporated into any analysis. With the arrival of extremely sensitive pressure recorders, we may be approaching the point of "information overload" — 30 000 to 50 000 data points per recorder per test is not uncommon. The recorders are so sensitive that the response is dominated by "noise" (extraneous effects as far as reservoir analysis is concerned) and we may be at the point of not being able to "see the forest for the trees".

NOMENCLATURE

H = Vertical distance between RRD and MPP
MPP = Mid-point of Perforations
RRD = Recorder Run Depth
P = Hydrostatic pressure difference between RRD and MPP

REFERENCES


