Discovery Capital L.L.C

Providing Integrated Solutions For the Energy Industry

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December 2002 Newsletter

Throughout the year I will be adding newsletters or articles to this website that I think will be of interest to readers. This is the first of what I hope will be many. Many of these topics will be controversial in that they may present ideas or research that is foreign to the way most producers in this area operate. If you have questions or comments please let me know.

Can depletion been seen with at DST?

Since I began evaluating DSTs, I have been presented with the idea that it was an excellent tool for many things including determining a limited reservoir. In talking with the old-timers they all have their rules of thumb for the amount of acceptable pressure drop between the Initial Shutin and the Final Shutin. I know that there are untold thousands of wells that have been abandoned due to these rules of thumb. I suspect that many of these wells may have been producers if they had been completed.

No, you cannot see depletion with a DST.*

Ok, this statement should get some blood pressure elevated. Please notice the asterisk, I will discuss this later. How can I make such a broad statement? There are several reasons, but let's start at the beginning.

Initial Flow Period (IFP) – Those of you who have heard my presentations on Well Test Analysis know that this is a pet peeve. Most of the DSTs I evaluate have an IFP that is much too long. Typically anything over 5 minutes eliminates any chance of ***measuring*** the Initial Reservoir Pressure (Pi).

A little background may help. A DST is typically broken up into two separate tests the Initial Flow/Shutin and the Final Flow/Shutin. The only purpose of the Initial Flow/Shutin is to remove any filtrate that has been forced into the formation and then to measure Pi. This is the only purpose of the Initial Flow/Shutin.

I have had innumerable discussions with operators as to why they run such long (30 minutes) Initial Flow periods. It all comes back to the same answer "That is the way we have always done it". I have yet to have anyone give me the correct reason for the Initial Flow/Shutin, which is to ***measure*** Pi.

I obviously have a hangup on ***measuring*** Pi. Isn't Pi just the last pressure measured during the Initial Shutin? No, not if you ran a 30-minute flow period it's not. In every case*, (that asterisk again) I have seen with a flow period longer than 5 minutes, the pressure was still building. This build may not be apparent on the chart supplied by the tester, but it is very apparent when the Derivative is displayed. If the pressure is still building then it must be extrapolated in order to know what Pi really is. It takes some very expensive software to extrapolate to Pi. ***If you don't know what the Initial Reservoir Pressure is, there is no way to determine depletion.***

I have probably beat this dog to death, but people will still corrupt their data by destroying any chance to measure Pi. **<u>A challenge. If you have any quantifiable reason to run the Initial Flow period longer than 5 minutes tell me why and I will publish the response here.</u>**

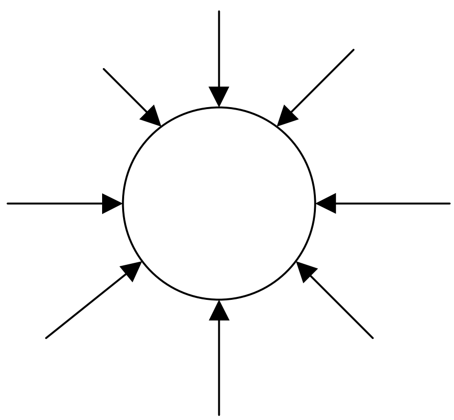
Ok, I give up on that topic. Let's move on to the other value needed to determine depletion, P*. A little more background is probably helpful here. What is P*? P* is the pressure remaining in the reservoir after the fluid recovered during the test has been removed. Because fluid was removed during the test P* will always be lower than Pi.

P* is not the last pressure recorded during the test. In every* (oops there it is again) test the pressure is still building and must be extrapolated in order to find P*. So how is the pressure extrapolated? Most people will simply say "Who Cares, this is close enough for government work". Another, somewhat more progressive, group will say "Make a Horner Plot". Both are wrong.

To the first group I say the government is in the business of playing Robin Hood. We are in the business of making money. Why spend money on a test that you only use 10% of the information available. If you simply accept the last point recorded as P*, then every test you run will show up as depleted. If you choose to complete the well you are going against your own logic. ***Why bother even recording pressures, you are only fooling yourself.***

To those brave pioneers that say "Make a Horner Plot", I say go ahead but it will always be wrong. Well "always" might be a little strong. In the hundreds of test I have evaluated the Horner Plot is valid in probably about 1% of them. Why isn't Mr. Horner's work valid, is a question that probably keeps you up at night. Much like "Why do Flammable and Inflammable mean the same thing?"

Horner only works when the well is in Radial Flow. What is Radial Flow you may ask? Radial Flow is when the fluids are coming into the wellbore at equal rates from all sides. Below is a cartoon depicting it.



The arrows indicate the flow path to the wellbore. Back before powerful desktop computers and software this was the only flow regime that was easy to model for the typical engineer. It was easy to plot up the data and in the case of permeable sandstone it was often correct. Whenever the flow does not match the above diagram the correlations are wrong.

When would you apply this type of correlation you ask?   Whenever the reservoir is homogeneous in regard to permeability, porosity or any of the hundreds of other factors that make up a reservoir. Have any of you ever seen a homogeneous reservoir? Not me!

Well now we know that P* is not the last measured point and that it cannot be extrapolated by using the Horner Plot, what can we do. Call me.(This is a paid political advertisement etc.).   Through the use of high-speed computers, expensive software, local knowledge and wishful thinking, I can usually extrapolate to P*.

So on your next test, being capable bright petroleum professionals who want to make the best use of your hard earned money, you decide to run a 5 minute Initial Flow and a Final Shutin equal to at least 3 time the flow period. And being very progressive you ask me to evaluate the data for you. When the analysis come back you notice that Pi =1200 psi and that P* equals 1198 psi. You say to yourself "depletion". After all we did everything right and still there is a difference in pressures cause by removing fluid from the reservoir.

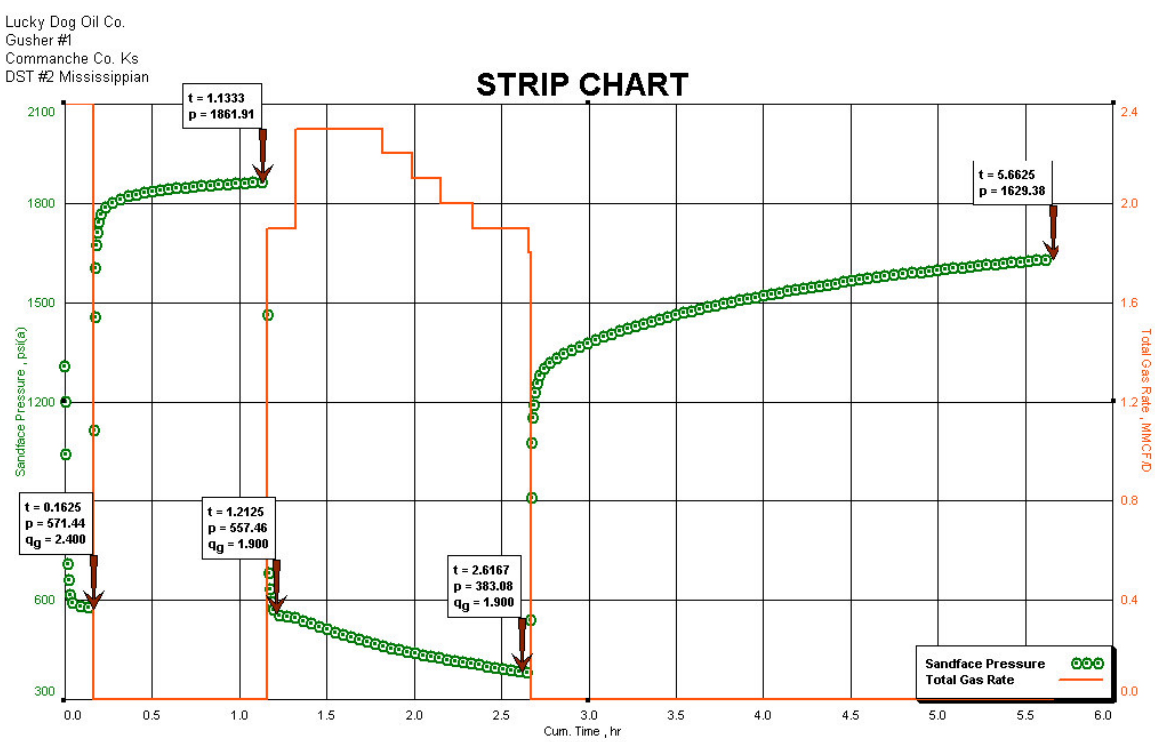
Wrong! There is another factor that plays a prominent role, tool error. The tools we use have an accuracy of about 0.5%. At 1200 psi this amounts to about 6 psi of error. What this means to us is that if the pressure drop is less than 6 psi then the tool does not have the accuracy to measure it. For the drop to be meaningful the drop must exceed 6 psi.

Just to recap, we must know Pi and P* in order to determine depletion. Neither of these values is recorded during the DST. If you don't know these values it is obviously impossible to determine depletion.

What about that *?

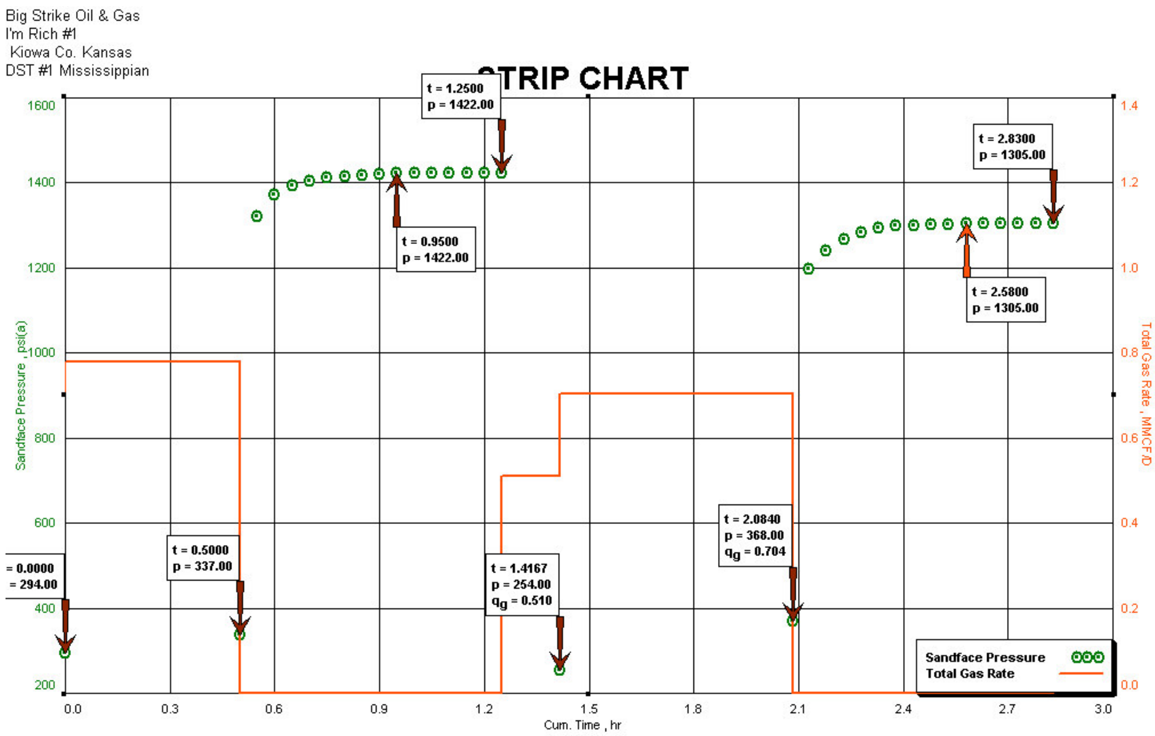
Until a couple of weeks ago that asterisk did not exist. A client sent me a DST to evaluate that has what I believe to be the only instance of depletion I have ever seen. Just to make things interesting I am going to show you DST Charts on two different wells, and I want you to tell me which one is a dry hole and which is a good well.

Candidate #1.



Lucky Dog Oil Company drilled this well into the Mississippian in Comanche Co. Kansas this year. They called me to evaluate it because of the tremendous drop in pressure recorded during the test. In case you can't read the chart the pressure went from about 1860 psi to about 1620 psi or about a 230 psi drop. Also notice that the gas rate was dropping precipitously and the flowing pressure was following. You old timers will also notice that the Final Flow curve was "laid over" indicating a slow build up. All in all a very disheartening test.

Candidate #2



Big Strike Oil & Gas drilled this well a couple of years ago, also in the Mississippian. In an effort to cut costs they used an analog gauge for the test. The points shown above are manually read off of the chart, so we are not directly comparing apples and oranges to Candidate #1 which was digitally recorded.

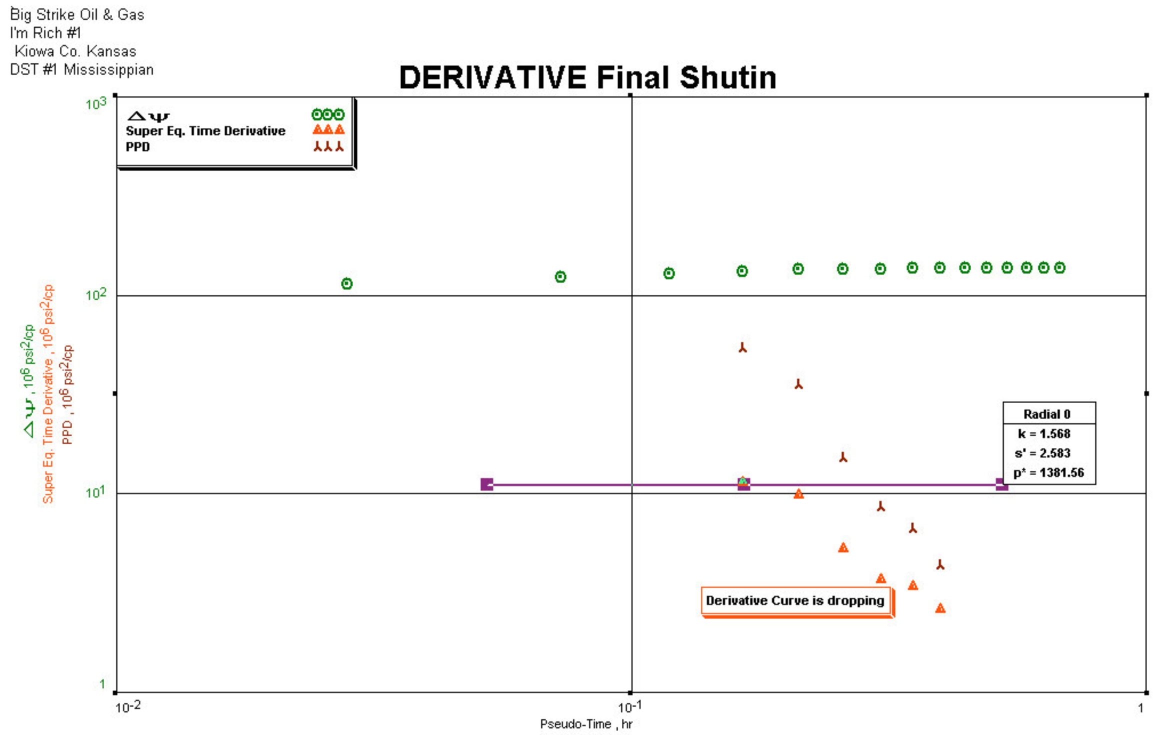
Notice on this well that the pressure drop between the two shutins is about 120 psi. The flow during the Final Flow period was climbing as were the pressures. This increase in flowing pressure is an indication that the well is cleaning up.

So, which one is the good well?

If you said Candidate #2 you just pissed away a whole lot of money on completion costs. But you say it was cleaning up, and the charts "looked" better and what about all that business about not being able to see depletion on a DST.

This is the only case I have ever seen where the well experienced depletion during the DST and we have the completion report to prove it. Pipe was set and the well produced about 3-4 MMcf and depleted.

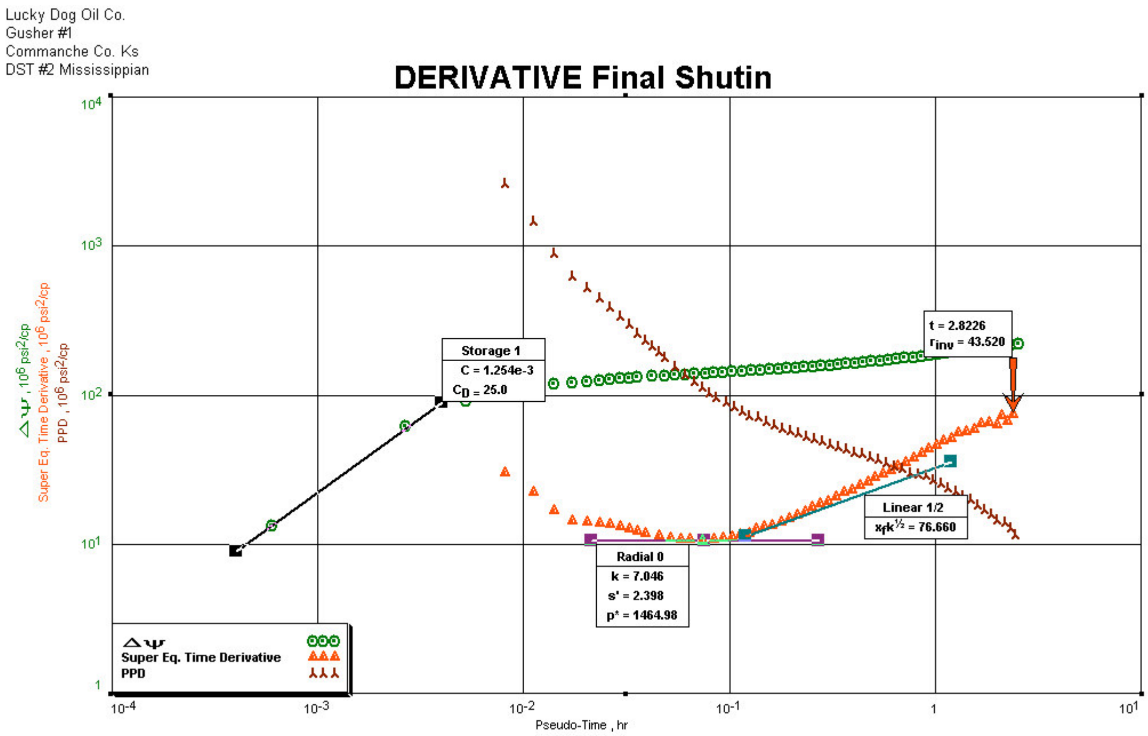
How did I know this was a dry hole?



This plot is the key to the evaluation. The red triangles, Derivative Curve, are dropping rapidly indicating that the well has finished building and has reached P*. The Initial Shutin Derivative exhibited the same behavior. So in the case of this well we actually **measured** Pi and P* and they differed by about 120 psi. The well had built up completely in both portions of the test. Because the pressure drop exceeded the accuracy of the tool, depletion was the only explanation.

The calculations show that this reservoir was about the size of my office. This was confirmed by the completion.

On the next page, for comparison purposes I will show the Derivative Curve for Candidate #1



In this example notice how the Derivative curve is still climbing rapidly. This indicates that the pressure is not completely built up and that I will need to extrapolate in order to determine P*. Also notice the red arrow at the end of the test. I have annotated the Radius of Investigation here. Despite the high flow rate this test only “looked” out into the reservoir about 50 feet.

Please notice that the Initial Flow Period was only 10 minutes. Although I do not show the Derivative curve for this portion of the test, trust me when I say that it looked just like the one above. The pressure was still building. Pi wound up 35 psi higher than the highest recorded pressure seen during the test.

As in 99.9999999999999999% of the DSTs no determination of drainage area can be made from this test.

I hope that I have clarified some of the uses of a DST. I believe that it is a wonderful tool to help with the evaluation of a zone, but it has severe limitations. These limitations are even more pronounced when the test is run improperly ie. Initial Flow period longer than 5 minutes.

Please call or email with your comments or questions on this topic, or others. Let me know if I can help with your test analysis.

Next month – “Do I have enough gas to lay a pipeline?”