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Horizontal Well Production Logging Deployment and Measurement Techniques for US Land Shale Hydrocarbon Plays

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Abstract

Traditional US land hydrocarbon bearing shale formations are presently being drilled & produced via horizontal wells. These horizontal wells consist of numerous selectively shot stages containing as many as 15 stages spread out across 2000 ft to 5000 ft interval.

These completions have been hydraulically fractured with water or slick water & require a flowback period of the injected water prior to the wells being kicked off with gas production. Since these types of formations are far from being homogeneous, the horizontal laterals can intersect existing natural fractures or faults in the formation or an aggressive hydraulic frac could induce fractures into existing natural fractures or faults.

When producing horizontal wells the lateral section draw down of the formation water has the ability to enter the wellbore from these faults or fractures causing the well's gas production performance to drop & eventually die off.

This paper will showcase US land horizontal well Production Logging deployment techniques using coiled tubing or well tractor examples & measurement techniques by imaging wellbore liquid / gas holdup, fluid velocity & thermal changes across the lateral. These techniques are successfully being used on US land horizontal wells in shale gas plays, whereby these case histories located inflowing gas and water entries across the lateral section.

The emerging trend of drilling and completing long horizontal laterals in unconventional shale gas formations leads to novel deployment techniques and measurements in order to efficiently measure data across these producing lateral sections.

Introduction

Traditional US land hydrocarbon bearing shale formations are presently being drilled & produced via horizontal wells. These horizontal wells consist of numerous selectively shot stages containing as many as 15 stages spread out across 2000 ft to 5000 ft interval.

These completions have been hydraulically fractured with water or slick water & require a flowback period of the injected water prior to the wells being kicked off with gas production.

Since formations are far from being homogeneous, the horizontal laterals can intersect existing natural fractures or faults in the formation or an aggressive hydraulic frac could induce fractures into existing natural fractures or faults which can penetrate a lower water sand interval.

US land shale gas producing wells are usually drilled to approximately 4,000 – 8,000 ft in depth & consist of a long radius dog leg and the producing lateral section extends out to 2,000 – 5,000 ft in length. These wells are normally completed with 4 ½" or 5 ½" casing and the lateral trajectory normally is drilled toe up (toe slightly above the heel, approximately 50 – 150 ft). These well are normally completed with 2 3/8" tubing with gas-lift mandrels installed to assist the water flow out of the heel section.

The shale gas formation hold a pressure transient left by the frac process, this allows the tight micro-Darcy formations to flow gas bound in the shale. Depending on how water wet the underlying formations high density (multi-stage) completed lateral sections can have the ability to communicate into geologic events such as faults & natural fractures.

Natural events such as fractures & faults can be located by seismic measurements but are considered to be low resolution & can be inaccurate. A production log run in across a horizontal wellbore has a higher degree of accuracy in measuring a fault that has started to communicate into the water interval. To accurately deploy and measure a horizontal producing lateral will be illustrated in this paper. Figure 1, illustrates a multiphase production regime across a horizontal well.

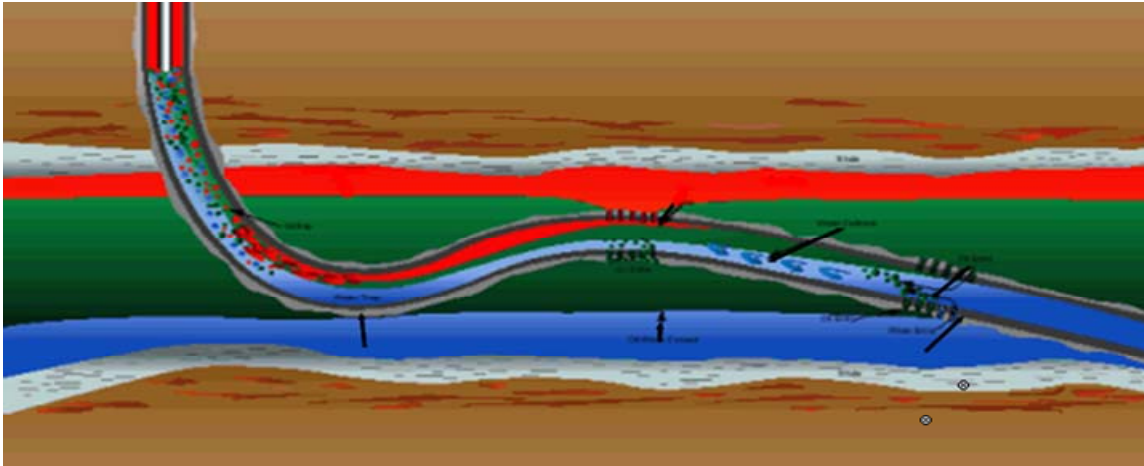


Fig 1. Horizontal Well Production illustration.

Production Logging Theory

A production log is usually required by operators to measure a flowing wellbore to identify zonal contribution of the inflows of water or hydrocarbons for reservoir engineering calculations & simulations. The measurements also help identify problem areas such as channeling, leaks, cross flow, thieving intervals & bounding effects (A. Hill, 1990).

A compact horizontal well production logging sensor package consists of a (Fig 2);

- Gamma Ray – for depth correlation,
- CCL – for depth correlation,
- Pressure – determine downhole pressure & reservoir pressure for PTA analysis, Temperature – measure fluid or gas inflow or channeling behind pipe,
- Flowmeter – measures the rate of change of flow from interval to interval.
- Fluid identification sensors are used in dual or 3 phase flowing conditions,
- Fluid Capacitance – measures the difference between water & hydrocarbon,
- Fluid Density – measures the difference between water, hydrocarbon liquid & hydrocarbon gas.
- Holdup (YG) - is a direct measurement of holdup, fluids & hydrocarbons occupying the cross section of the wellbore.

The Fluid Density & Capacitance measurements are used to calculate a Holdup – gas to liquid occupancy in the pipe. All of these measurements are ideal for measuring flow in a vertical wellbore where mixing of the fluids is occurring across cross section of the wellbore. However the Holdup measurement is ideal for measuring 2 or 3 phase flowing in a horizontal wellbore (Kessler & Finch, 1995).

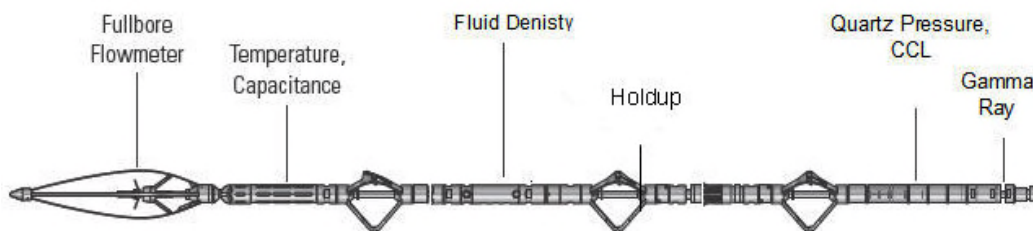


Fig 2. Horizontal well Production Logging sensor package

Horizontal Flow Regime

A well drilled with a Horizontal lateral leg not always remains perfectly horizontal across the formation. Depending on the production plan most horizontal laterals have various undulations across the lateral. The normal rule of thumb for Shale Gas planned wells is to drill the lateral section with a toe up format, the belief is to allow for gravity feed drainage of water to collect at the heel section, thus allowing gas velocity and gas lift assisted lifting mechanism to produce the water collecting in the lateral.

Horizontal flow regime in unconventional shale gas formations is dependent on the energy contributed from the perforated intervals. In most cases since the flow is 2 phase (water & gas) and low energy (under 1 MMSCFD & under 1000 bbl/d) the flow across the horizontal lateral is stratified flow.

Stratified flow consists of 2 phases, heavier (water) on the bottom, lighter (gas) on the top (Fig 3). Since the rates are considered to be relatively low, well under critical velocity of the pipe size since the lateral is very long, the production moves across the lateral in a uniform laid down (stratified regime).

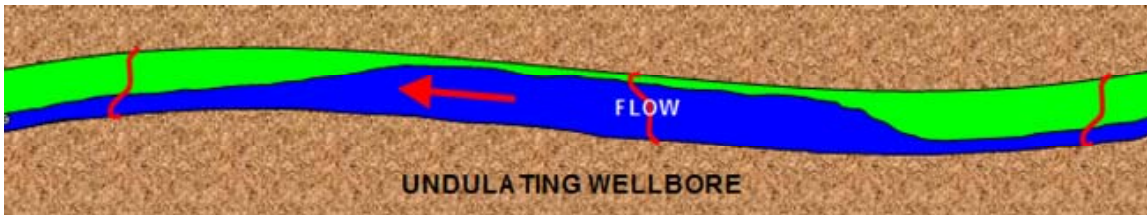


Fig 3. Horizontal wellbore 2 phase Holdup Image.

Horizontal Production Sensor Measurements

As talked about earlier, horizontal wellbore production does not mix well like in vertical wellbore, special sensors are required to properly measure the holdup across the entire lateral section. Vertical well production logging sensors consist of in line or point focused sensors whereby the sensors only measure the fluids that directly contact the sensor. This format is not ideal in a stratified flow regime which occurs in a low energy horizontal wellbore, as these sensors will not properly identify the holdup changes across the lateral.

In low flow energy, such as a horizontal wellbore the flow is stratified, the ideal sensors measurements come from full cross section wellbore Holdup & Temperature. A full-bore holdup measurement measures the entire cross section of the pipe, delivering a true image of the holdup changes as water or gas is starting to enter the wellbore & occupy more of the pipe volume (Fig 4.). The Temperature measurement is ideal for correlating to the changes in the holdup as water is usually a warmer event and gas (due to Joule Thompson expansion) is a cooler event.

Flowmeter single point or an array of spinners is not always reliable enough to correlate to the truer readings such as holdup & temperature. Horizontal producing laterals contain a high concentration of frac sand & plug debris that can cause anomalies in spinner velocities, coincided with changes in low (gas) to high (viscosity) fluids.

Flowmeters are reliable in much higher flow energy >1000 bbl/d per day of fluids for there are enough forces acting on the mechanical devices to respond to changes in flow.

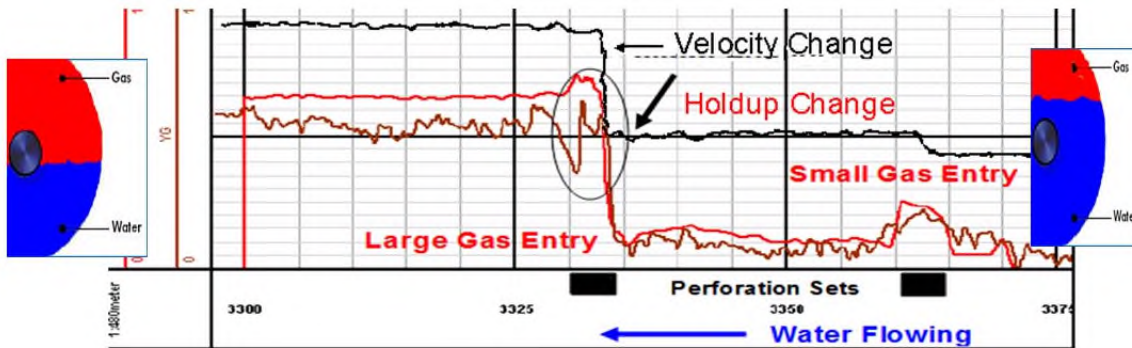


Fig 4. Horizontal wellbore phase fraction holdup measurement.

Horizontal Well Completions

Unconventional Shale Gas well completions traditionally are horizontally drilled holes ~6000 ft deep & ~ 2000 ft to 4000 ft lateral sections. Casing sizes are either 4 1/2" or 5 1/2". Production tubing is used to effectively assist production via artificial lift using gas lift mandrels to assist in flowing back frac water out the well & lift any formation water broken through across the perforated interval.

Most Barnett Shale wells lateral section are drilled as a toe up trajectory, the theory behind this trajectory setting is to assist any water flow across the lateral with a gravity feed back down to the deepest section, the heel.

The Completion of an Unconventional Shale Gas Horizontal Well consists of selectively perforating discreet intervals of the lateral 1 – 2 ft shot intervals spread out ~ 40ft – 100 ft across the toe section usually with tubing conveyed perforating. Approximately 4 to 5 intervals per stage are hydraulically fraced with slick water & sand. After the initial toe stage is completed subsequent stages are completed by using water to pump down perforating guns with a frac plug attached to the bottom of the perforating assembly. Short laterals contain 6 – 7 stages, longer laterals contain 10 –14 stages as shown on Figure 5. Figure 6 illustrates the typical wellbore trajectory completed in the Barnett Shale region.

Upon completion of the entire lateral section, initial flowback of the fresh frac water which is low salinity water 10,000 – 30,000 ppm begins. The hydraulic frac not only creates a conduit in micro-Darcy formations to allow fluids & gas to flow, but also creates a pressure transient across the formation.

Perforated intervals are normally chosen by the operators based on seismic information, whereby the data identifies natural geologic events such as faults & fractures. However this data can be somewhat low in resolution. Production Logs being run in these horizontal laterals are a better indicator of faults & natural fractures near wellbore, which can cause problems to the production of the well

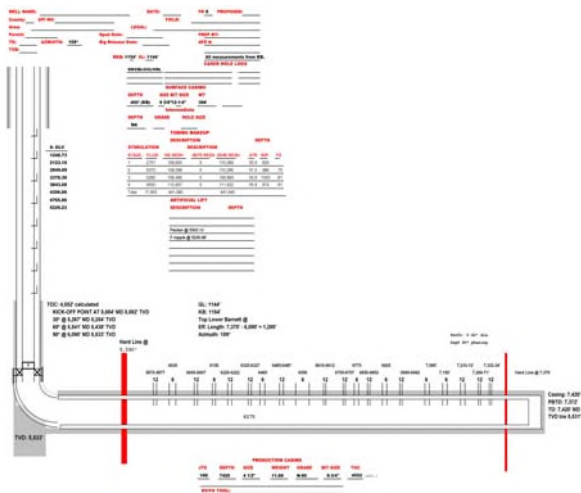


Fig 5. Typical Barnett Shale Completion

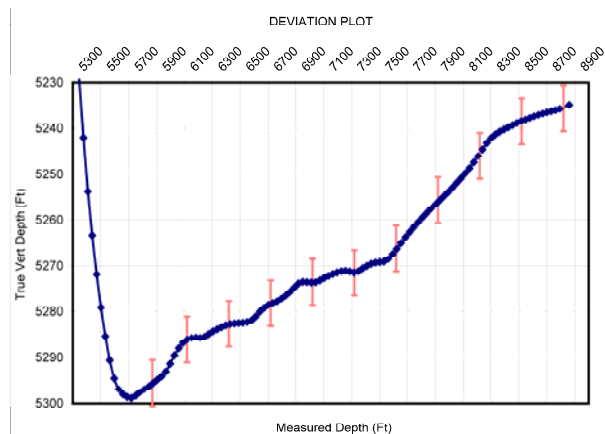


Fig 6. Typical Barnett Shale Well Trajectory

Horizontal Well Logging Tool Deployment

Unconventional Shale Gas producing wells require various techniques & expertise to be able to deploy horizontal production logging sensors while controlling the well to flow an effective rate to allow for quality measurements.

Since these types of wells produce gas & water at a low velocity, deployment technique of logging sensors is critical to enable the sensors to measure which zones contribute. Incorrect techniques can lead to killing the well while logging, which diminishes the dynamic of the data and impedes the ability to make accurate decisions. There are 3 types of scenarios for deploying production logging sensors in these types of wells;

- 1) 1 1/4" Coiled Tubing deployed through 2 3/8" tubing (producing up the tubing while gas-lifting down casing),
- 2) Well tractor deployed through 2 7/8" tubing (producing up the tubing while gas-lifting down casing),
- 3) 2" Coiled Tubing deployed down casing (producing up casing while Gas-lifting via Coiled Tubing).

Coil Tubing Deployment of Production Logging Tools

Coiled tubing is an effective and versatile method with which to deploy logging tools in a variety of wellbore situations. It allows for deployment into wellbores which may have accumulated unexpected sand or proppant blockages in the deviated

sections. Fluid or nitrified fluid can be pumped down through the coil to wash out the solids, allowing for movement to continue into the wellbore.

The primary requisite to completing a successful logging run is to reach a desired depth within the horizontal, usually past the lowermost set of perforations. The principal impediment to reaching the desired depth with the coil tubing / BHA & production logging tools is the force of friction between the coil and the completion which results when running in hole. These forces act against the movement of coiled tubing running in hole and the point at which the BHA will no longer move into the horizontal regardless of movement at the surface is referred to as Friction Lock (BJ Services 2008).

Figure 7 shows the conditions which occur between the coil and completion while running in hole (RIH) with a horizontal wellbore.

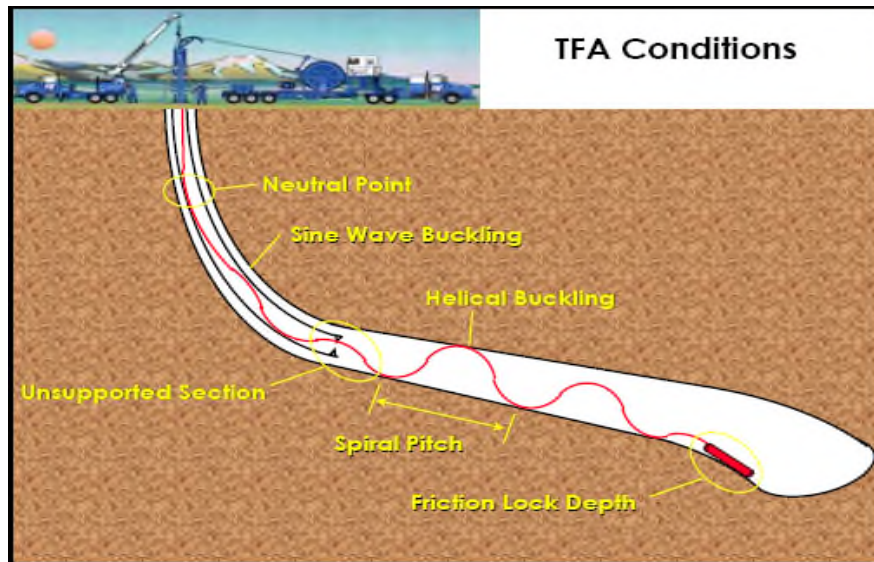


Fig 7. Coiled Tubing Illustration

The Coil Tubing simulation is implemented when designing logging runs in horizontal completions. Completion data provided by the customer such as wellbore schematic, deviation is entered to provide the virtual wellbore in which the software simulates all of the forces acting on the coil when running in hole (such as those in the above figure) to determine if desired depth will be reached. The simulation will also output the maximum amount of push to the BHA available to at any depth in the wellbore.

Typically, 1 1/4" coiled tubing is used for deploying Production Logs, it allows for deployment into wells with production tubing and is fatigued less per cycle than larger diameter coil. Larger diameter coil is recommended to be used in situations when a Coil simulation predicts if the BHA will friction lock well before the desired maximum logging depth. This will occur in wellbores with longer horizontals or shorter vertical sections. With shorter vertical sections, there is less coiled tubing hanging weight to push against the friction forces acting on the tubing. Larger diameter pipe (we have 1 3/4" and 2" here) has more weight per foot of tubing and consequently more push.

1 1/4" Coiled Tubing Deployed Through 2 3/8" Tubing

Standard unconventional shale gas completions consist of using 2 3/8" tubing for production. Using 1 1/4" CT deployed through 2 3/8" tubing while gas-lifting is the most economic setup to log the well if a workover with a service rig is not used to cleanout the lateral section. Prior to running the survey CT runs their deployment simulation in order to determine lockup & collapse weights during the logging job. Due to the nature of the wellbore trajectory (toe up) it is ideal to understand how far the CT can deploy across the lateral.

To ensure quality production measurements the well should be flowing a minimum of 3 days prior to logging and a top logging valve installed on the top of the wellhead in order to elevate any shut-in attempts of the well prior to running the log.

At the well site a proper test of gas rates & water rates should be rigged up & measuring the flow before & during the production log survey.

A normal setup for these types of survey, is to allow for the 1st day of deployment designated for the cleanout trip, the well should be allowed to come back to flow to a stable rate through the evening & day 2 the production log survey is run.

First Day the 1 ¼” CT is rigged in & deployed while the well is flowing, this deployment serves as a dummy run, cleanout trip & flow verification while deploying the CT.

Since almost every well contains debris such as sand, plug parts, etc, it is necessary to initially run the CT before installing the Production Sensors. If the CT tags up on debris at the bottom of the CT is installed a BHA designed to cleanout out sand debris. Care should be taken in choosing the material to cleanout the wellbore, as displacement of wellbore fluids with surface fluid deters from the quality of the downhole measurements N2 is the best fluid to use for cleaning any sand debris.

Monitoring flowrates while the CT is deployed is essential to maintaining a successful logging survey. The 1 ¼” CT occupies over 50% of the tubing volume which becomes a choking mechanism on the well. The combination of high separator & line pressure with dropping well pressure will in fact cause the well to choke & die. If the well makes water the water will also cause the well to produce less gas, since the flow area has changed the water slugs occupying the tubing act like a water plug for a certain period of time until the slug is produced, this will cause a cycle effect of water & gas flowing at different cycles.

The Field Technician needs to be able to recognize the falling surface pressure & adapt the flowback to the lowest back pressure possible to enable the well to consistently flow.

Second day the same techniques are used as on Day 1, attention needs to be given to both the flowback rates & gas-lift injection while deploying into the well. The logging field technician will determine the appropriate amount of passes required to measure the flowing lateral with the best quality of data.

Figure 8 illustrates the results from 1 ¼” CT deployed through 2 3/8” tubing while the well flowed up the annulus. The well was able to flow approximately 40 bbl/hr of water & 300 mcf/d of gas. Since seismic data was limited in the area, the operator didn’t have any idea where water would have broken out on this lateral. The production log shows that the water & gas both came from the toe region as the velocity (flowmeter) clearly displays the change in velocity as water enters the wellbore. The Holdup image shows the wellbore phase fraction of water occupies 80% of the lateral & the temperature warming indicates water inflow & the cooling spike verifies gas inflow.

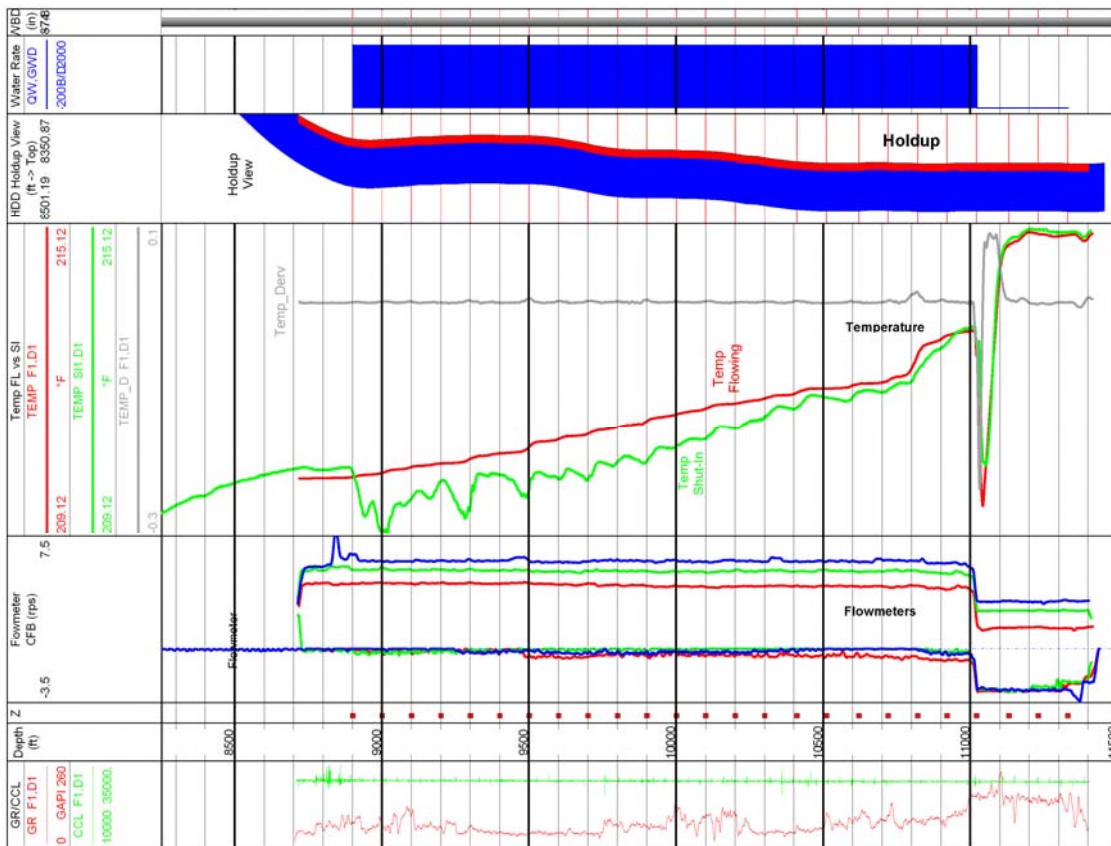


Fig 8. 1 ¼” CT deployed through 2 3/8” tubing Horizontal production log

Well Tractor Deployed Through 2 7/8" Tubing

The wireline well tractor allows logging tools to reach the end of a horizontal lateral section without the need to push as with coiled tubing or drill pipe as a conveyance method. The well tractor is deployed & activated via an electric wireline, which is powered on & 'tractors' the logging tools to the end of the lateral (Welltec, 2008).

Production Well Tractors minimum OD are 2 1/8", therefore traditional Unconventional Shale Gas well completions would require 2 7/8" production tubing installed. If gas-lift mandrels are required, 2 7/8" tubing with mandrels is limited to 5" casing or greater.

The benefits of Well Tractor deployed production logging surveys over CT methods are the system has little to no choking or perturbation affects on the well flow. Meaning, the well actually flows in its normal everyday state while production logging the lateral section. This allows for the best quality of measurements since the well performs at an optimum level during the survey.

Well Tractors are deployed via electric wireline 5/16" OD, the production logging sensors are installed below the Well Tractor. Once the Tractor exits the bottom of the tubing into the casing, the tractor roller arms & wheels are powered open via commands from surface down the wireline. The Tractor can be deployed across the lateral at ~ 40 to 60 ft/min simply by controlling the voltage applied to the Tractor. The reduction logging sensors can either be monitored & recorded in real time mode as data is sent up the wireline or the sensors can be programmed in memory mode & installed on the bottom of the tractor. Figure 9 illustrates a well tractor operating in a wellbore.

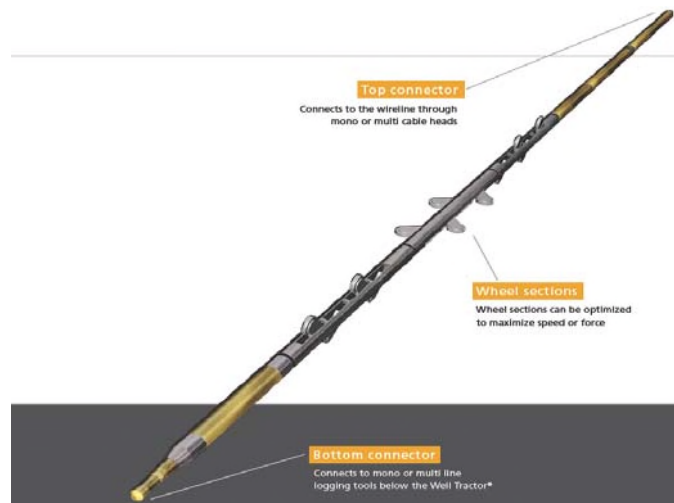


Fig 9. Welltec well tractor

In a standard shale gas well, this method of deployment requires the operator of the well to use workover rig to pull the existing 2 3/8" production tubing, make a cleanout trip with the rig down to the toe section, then replace the 2 3/8" tubing with 2 7/8" production tubing. The well tractor can have limitations in reaching the end of the lateral due to the amount of debris remaining in the well & the degree of trajectory as a toe up wellbore.

To ensure quality production measurements the well should be flowing a minimum of 3 days prior to logging and a top logging valve installed on the top of the wellhead in order to elevate any shut-in attempts of the well prior to running the log.

At the well site a proper measuring system of gas rates & water rates should be rigged up & measuring the flow before & during the production log survey.

When deploying with a well tractor the complete service of making a dummy run & logging survey can be run in 1 day. Normally if the workover rig has recently cleaned out the well days prior to deploying the production survey the dummy run can be abandoned.

When deploying the tractor with the production logging sensors the field technician needs to be observant of the choking effects of the Tractor while running through the tubing.

The Tractor acts like a plug being run in hole, in order not to have the well die while running in-hole; care must be taken during the deployment stage.

Once the tractor & production logging system is out of the tubing, the field technician should wait a period of time in order to have the well come back to its stable rates prior to starting the logging passes. The logging passes are made across the lateral with the objective to measure a relative velocity profile, holdup image, density, capacitance & temperature changes across the lateral.

Figure 10 & 11 are illustrations of a Horizontal Production Log deployed with Well Tractor. The operators well was performing at 5 MMscd & very little water production. The well was completed with 3 1/3 tubing & 5 1/2 casing. Water broke through changing production to 3 MMscfd & 1000 bbl/d of water. The operator tried numerous times to deploy production logging with coiled tubing to evaluate where the water problem was coming from. However due to the choking effects of the coiled tubing the well kept on dying which resulted in 5 – 7 days of swabbing to get the well back performing.

A horizontal well Production Logging system was deployed with well tractor which allowed the well to flow at its natural rate while performing the production log survey. The results show the 2 intervals where water broke through. The Holdup measurement is an exact image of the phase occupancy of the wellbore, figure 11 identifies the phase changes across the water inflow zones. The flowmeter, temperature, capacitance & density all correlate to this water inflow zone.

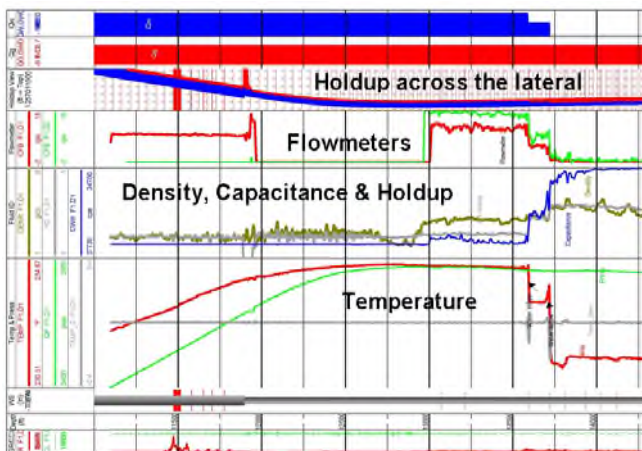


Fig 10. Well Tractor deployed production log

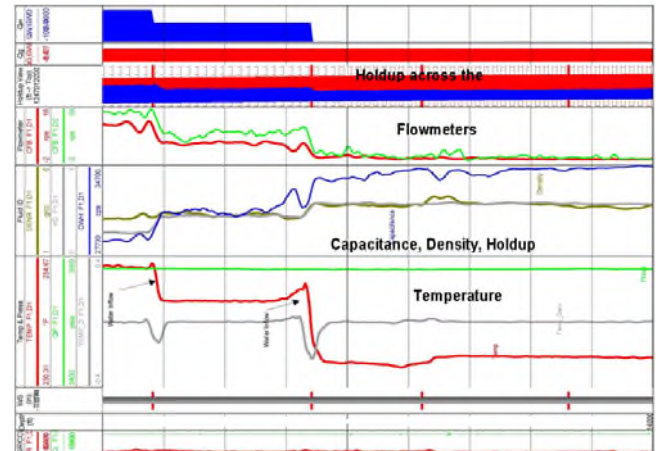


Fig 11. Expanded View

2" Coiled Tubing Deployed Down Casing

When longer lateral sections are completed and 2 3/8" tubing is set in the casing to assist flow, 1 1/4" CT deployment through the 2 3/8" tubing cannot be run to the end of the lateral section. Therefore to ensure the deployment of production logging tools can reach the end of the lateral section while the well flows requires gas-lift assistance. The ideal well candidates are laterals that make water & require a production log to determine the water break through. The most effective technique to generate water flow with the capability to reach the end of the lateral section is to use 1 3/4" or 2" CT with no production tubing in the well.

The well requires the existing tubing to be pulled, a workover cleanout is ideal to prevent any sand bridges & debris to affect the running of the production tools. With the well static, the production logging tools are attached to a BHA – a specially designed nozzle orientated to jet the well to flow water without the use of production tubing & gas lift mandrels. This BHA is attached to the bottom of 1 3/4" or 2" CT.

The first deployment is made while the well is in the static condition; this allows the production logging sensors to measure the entire lateral as a baseline measurement. The production logging sensors are pulled back to the near vertical section & N2 is pumped down the CT getting the well to flow. Since the hydrostatic head of the fluid is now being lifted this technique can establish stable water rates for 2 – 3 hours. After the rates have become stable the N2 is shut off & the logging passes down across the lateral can be made. This technique allows the well to produce a high volume of water, whereby the production logging sensors; holdup, temperature, density, capacitance & velocity can identify the water break through in the lateral.

Figure 12 illustrates a horizontal production log run on 2" coiled tubing artificial lifting the well through the coiled tubing. The well maintained a steady rate of 600 bbl/d of water & 600 mcf/d of gas. This technique allowed the well to perform at its normal rate & the coiled tubing was able to reach the end of the horizontal lateral. The Holdup measurement verifies that gas is flowing from the toe section. The holdup, temperature, density & flowmeter measurements identifies that water enters the lateral section from 2 faults which match the seismic data.

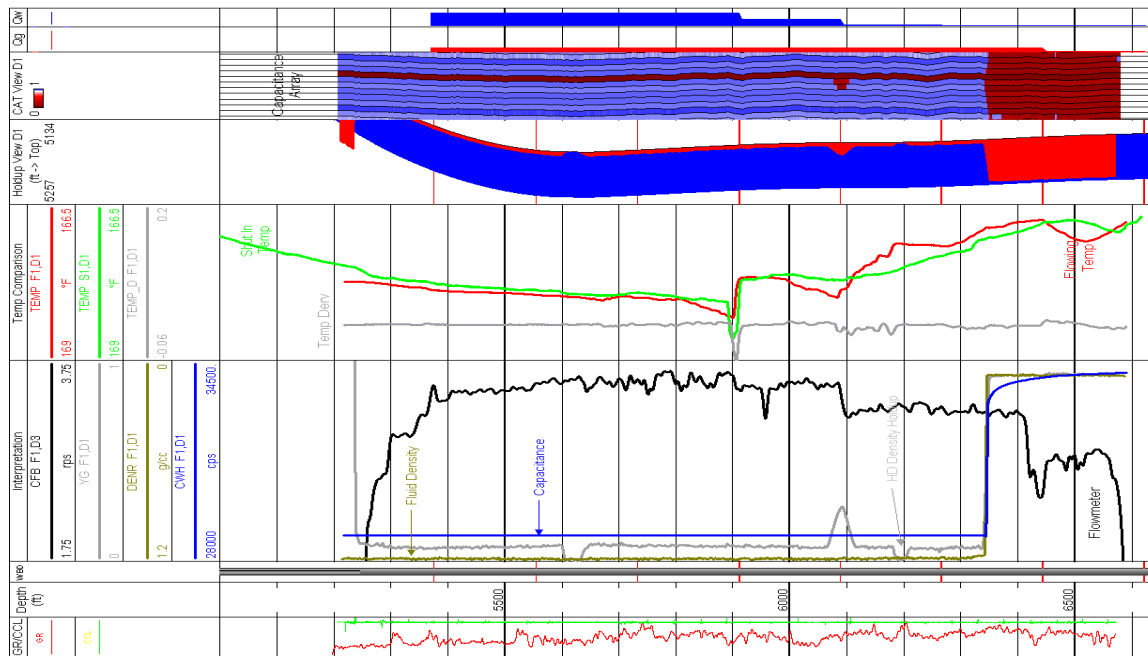


Fig 12. 2" CT deployed down casing Horizontal Production Log

Conclusion

These 3 unique deployment techniques need to be considered for deploying live well production logging sensors. However, there are a few variables that need to be considered as which deployment technique will deliver the best performance;

Is the existing completion satisfactory to;

- Allow the 1 1/4" coiled tubing to easily reach the end of the lateral section?
- Does the well flow at a high enough rate with the small coiled tubing deployed through the completion to allow for quality results from the production logging system?

The 3 case histories illustrated in this paper allowed for the best assurance of data quality to ensure the wells flowed at the closest to everyday normal flow.

About the Arthur

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Mr. Heddlestone is an industry leader in production logging & production log analysis, and has been involved in the Wireline Logging industry since 1992 with Baker Atlas, Expro Group & Indepth Production. Mr. Heddlestone has close to 10 years experience directly devoted to production & reservoir analysis helping develop and launch new technology throughout the world with Baker, Expro & RECON. Mr. Heddlestone is also an expert log analyst performing production analyses for many major wireline companies worldwide as well as many oil companies. Mr. Heddlestone has extensive experience deploying, measuring and analyzing vertical & horizontal well production logging data worldwide & pioneered the deployment, measurements & log analysis in the US land shale gas plays. Mr. Heddlestone is a P Eng and has a B.Sc in Petroleum Engineering from the University of Alberta & holds a MBA in Marketing.

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