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Completion Diagnostic Tools, Production Logging Technology Delivers Accurate Flow Contributions Vertical & Horizontal Wellbores

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Abstract

Over the past 18 years, the industry has focused on drilling and completing horizontal producing wells, in order to develop better deliverability and UER across the reservoir. These types of wells are drilled with various inclinations, trajectories which porpoise across the reservoir interval. Horizontal lateral sections consist of numerous selectively stimulated stages containing greater than 20 stages spread out across 2,000 ft to 25,000 ft of horizontal interval. (Heddleston, 2017).

Many indirect measurements such as chemical tracing or fiber optic sensing have been trialed, but the only direct measurement of real production contributing across a producing lateral is acquired using production logging measurements with production data analysis. This true measurement of production contribution is the best method which allow oil companies to understand and acknowledge which portions of the hydraulically stimulated reservoir is contributing the production and the value of their properties.

Introduction

The past two decades, the industry has trialed many technologies to measure the flow performance how a perforated reservoir delivers and contributes hydrocarbons and water. A few of the technologies trialed can be considered as "indirect" methods using chemicals, radioactive material and temperature with fiber optic (FO) sensing cables. All of these indirect measurements do not actually measure the fluid types nor the velocity of the flow traveling from the reservoir into the wellbore and out of the well. These indirect measurements mainly use algorithms, computer processing to generate a contribution profile, what a possible reservoir rate contribution may be.

Production log technology (PLT) is considered as the "direct" measurement of actual flow contribution. With various sensors along a logging string, it measures the fluid types also known as holdup and the flow velocity, this now can determine the flow rate contribution from each individual cluster, along the wellbore.

Contribution Determination

Indirect measurements such as chemical tracing or fiber optic sensing have been trialed, but the direct measurement of actual production contributing across a producing lateral is acquired using production log technology (PLT) measurements and actual production data analysis.

FO relies on a stationary cable placed across a horizontal lateral section and when the well is produced the FO sense temperature and acoustic change. A computer algorithm indirectly develops an output of what the oil, water & gas flow rates from each open perf cluster should be, solely based on these 2 measurements temperature and an acoustic change.

Temperature can be affected by pressure drop or change and gas expansion, but this Joules-Thompson (JT) doesn't always translate into a high contribution. For example, a sudden pressure drop, causes rapid cooling but at the same time will be a very small rate of change.

As per a study in (Yegor et al, 2020) the stabilized DTS temperature range from all wells was less than 0.25 deg C, despite a small drawdown. No zones with obvious Joules-Thompson cooling effect from gas entry could be clearly detected on flowing DTS temperature curve. Figure 1 shows the lack of response of DTS & DAS sensing the inflows across the lateral. Acoustic derived holdup also can be influenced by the wellbore trajectory and may show building holdup of fluids but may not be a zonal contribution.

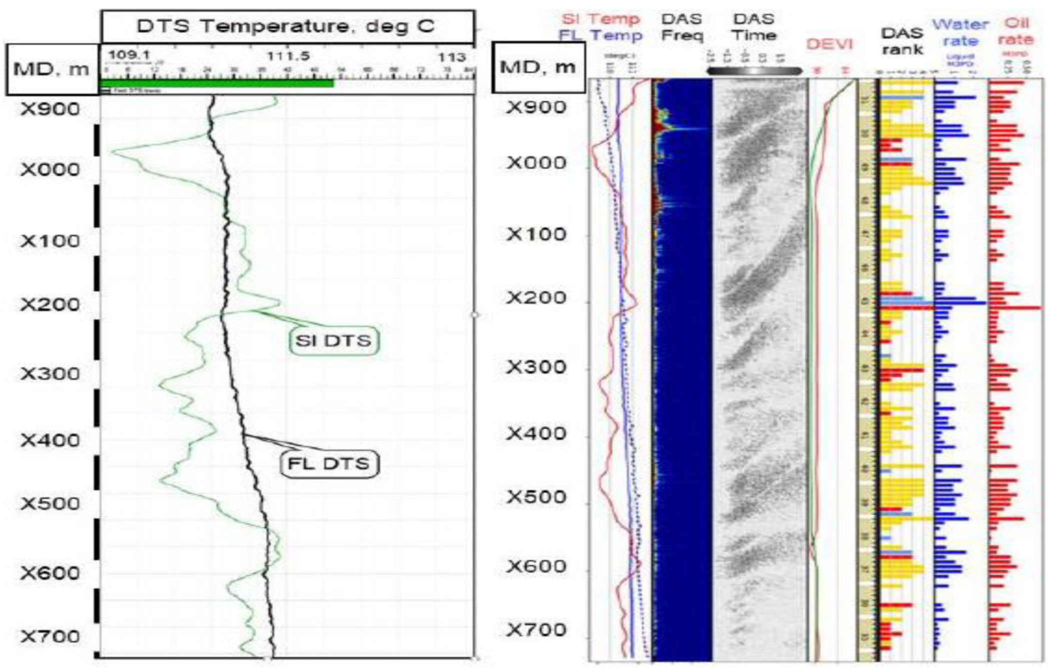

Figure 1—DTS/DAS Production Profile (Yegor et al, 2020)

The draw back with FO only using only 1 or possibly 2 sensors, the output relies heavily on mathematical algorithms which cannot define a real flow velocity. When compared to the actual production log data recorded on the same flowing well, the FO processed results and have significant errors and does not match the PLT results. Similar production rate results derived from chemical tracers have troubles matching an actual PLT survey result.

GEN 1 Production Log Process

In order understand the downhole flowing environment; how the lateral sections are contributing, an actual flow, velocity and phase contribution should be sensed & measured directly. A production log tool (PLT) platform has been offered throughout the industry over the past 50 years. The past 20 years the sensor technology and deployment experience has increased & the platform is able to measure with efficiency how a lateral section contributes.

After a well has been hydraulically stimulated and after initial flowback period has taken place, the geology and technical teams are interested to determine how the reservoir is contributing. The standard production logging survey measures downhole fluid phases and velocity across the flowing sections. Ancillary sensors such as pressure and temperature deliver qualitative indicators of how the reservoir is performing. All these sensors run together help deliver a high confidence, quality result of the production contributing. These types of surveys "directly" measure inflow contribution and how effective the completion is to allow the reservoir contribution performance. On horizontal wellbores, the deployment application of this technology usually is deployed with coiled tubing and wireline well tractors.

Surface measurements should be taken during the deployment of the PLT tools. Figure 2 illustrates the surface pressure recorders. These tools can verify the perturbance and effectiveness of the flow, which ultimately can affect the down hole production profile from the reservoir.

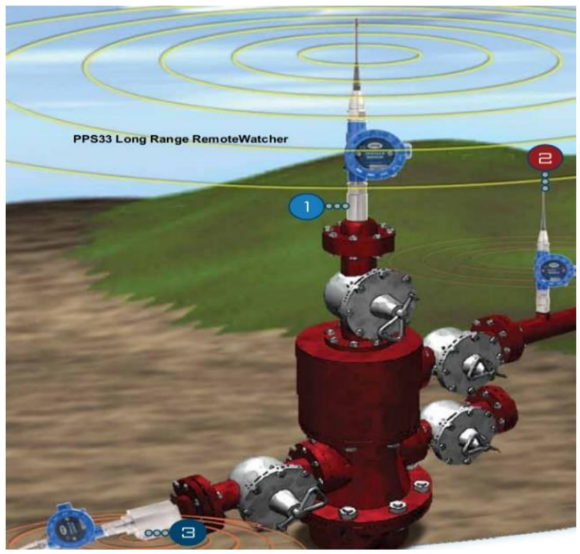

Figure 2—Surface Pressure Temperature Monitor

A Generation 1 (Gen 1) version PLT platform as shown on figure 3, measures the environment within the pipe diameter. The Gamma Ray (GR) tool shows the types of formation the lateral is located in, and also if the well has been traced with a frac sand trace material. The CCL locates all the casing collars, the Temperature shows the temperature profile across the producing interval and can be converted into a derivative temperature, shedding more detail on the inflow locations.

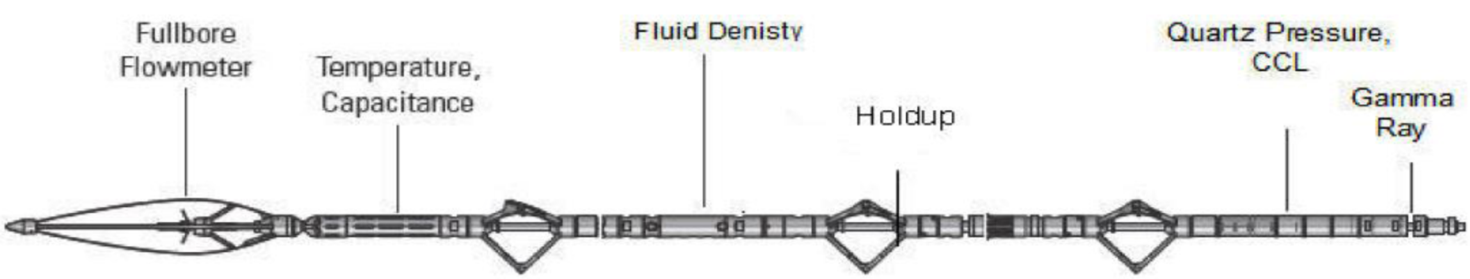

Figure 3—Gen 1 Production Logging Technology (Heddleston, 2009)

The Fluid Identification measurements (Density, Capacitance, Resistivity) determines the Holdup or Phase Fractions occupying the pipe cross section as more fluids and gas flow into the pipe cross section. The Pressure tool is used not only for the bottom hole pressure but also is needed to create formation volume factors of the fluids downhole. The Flowmeters measure the velocity change from interval to interval as products enter the wellbore.

GEN3 Production Log Technology

On a horizontal well in the cross section of the flow area under multiphase flowing conditions, an ideal PLT platform is a Generation 3 (Gen 3) Multi-Sensor Array technology. The Gen 3 Array technology as shown on figure 4, measures the holdup & velocity in discreet points across the cross section of the flowing lateral. A Gen 3 Array technology has all the sensors at 1 point in the tool with no depth difference (offsets) along the string. The Gen 3 Array technology in a horizontal flowing wellbore defines the phase segregation & velocity of each phase as the fluids move through the lateral & out of the wellbore.

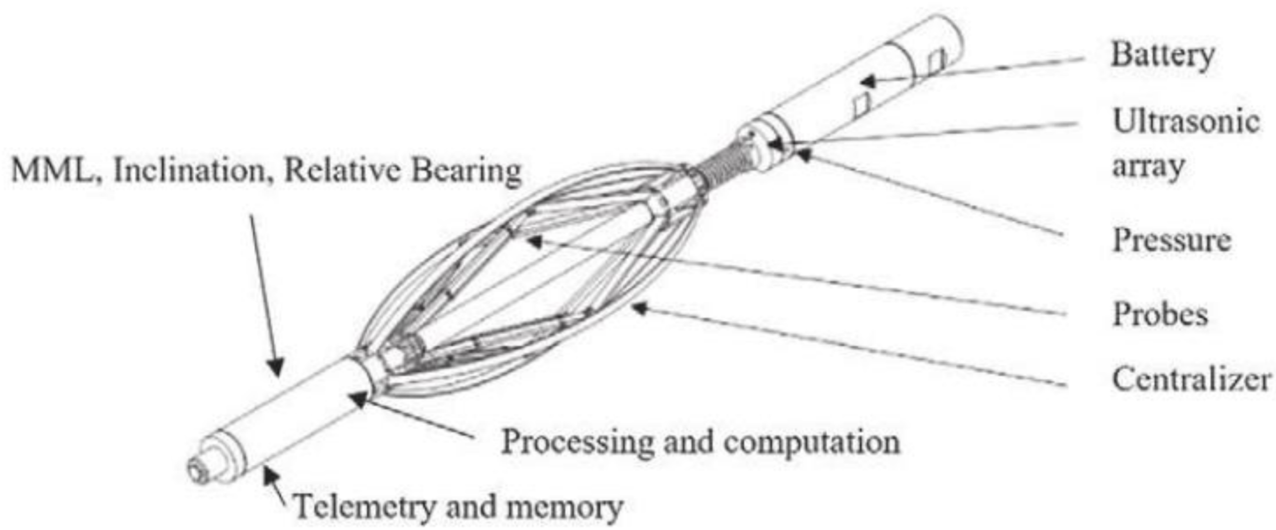

Figure 4—Gen 3 Openfield Horizontal Production Log Tool (Petrophysics, Vol. 59, No. 4)

Case Study 1

The following case study is a horizontal memory mode multi-flowing standard production logging platform deployed with a well tractor via electric wireline on a newly completed multi-phase producing lateral, with subsequent Fiber Optic (FO) measurements.

A technical team with an oil company, decided to measure and monitor their recently hydraulically stimulated producing horizontal well. They had recently experimented with different perforating charges and wanted to see how the deliverability difference from stage to stage. The well was producing a high-rate gas with low water contribution, the technical team were interested to compare the technologies production log data set versus FO which was installed in an electric wireline.

Prior to running the production log (PLT) survey, a coiled tubing as shown on figure 5, was used to deploy into a well. The CT is used to perform various mechanical services such as a TD check/cleanout the lateral of any sand & plug parts. A 2 3/8″ CT was deployed to perform a clean out trip to ensure the production log survey can be run without any issues.

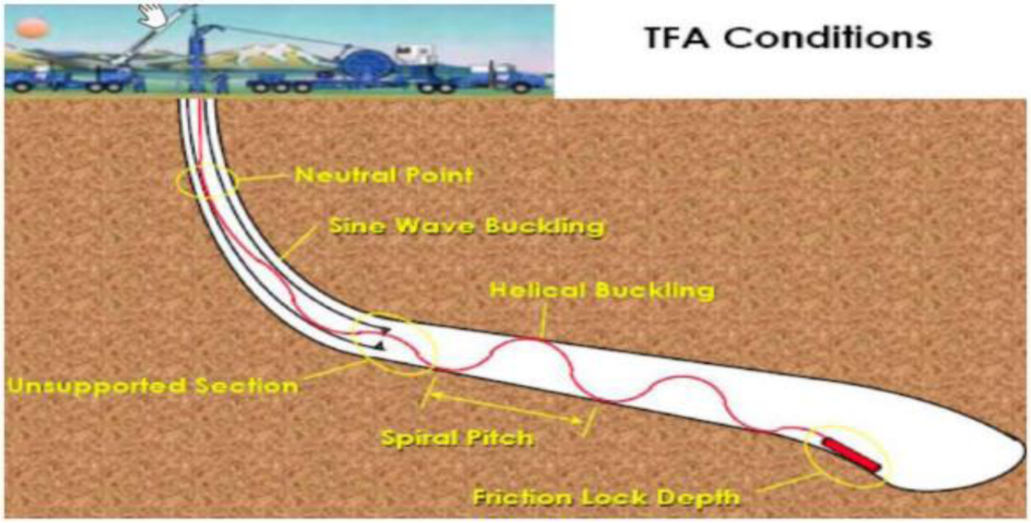

Figure 5—Coiled tubing deployment (Heddleston, 2017)

A wireline tractor, illustrated on figure 6, is used to convey the PLT logging tools across a horizontal lateral powered through an electric wireline. Wireline tractors deployed are 2 1/8″ OD or 3.5″ OD and are powered to tractor to roll along into a horizontal lateral ~ 20 – 40 foot / min.

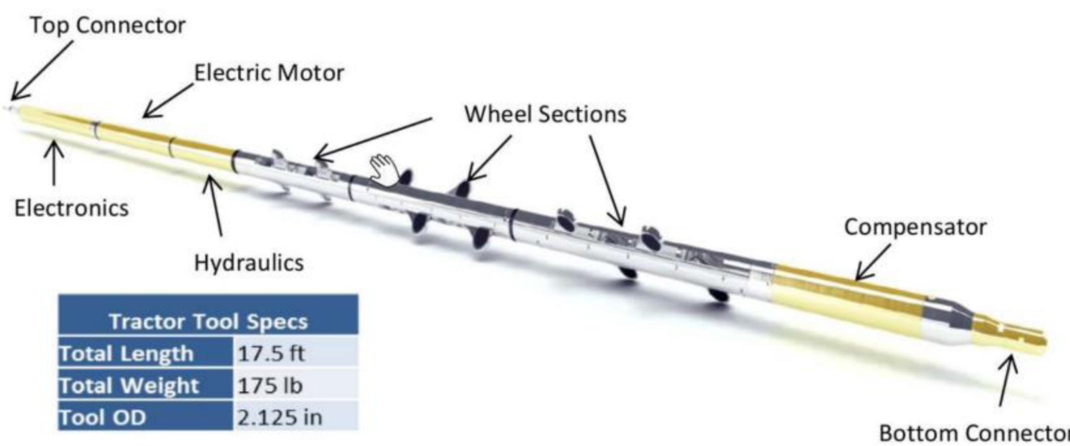

Figure 6—Well tractor (Heddleston, 2017)

Findings

These particular wells produced majority high-rate natural gas with very little water production; a standard GEN 1 - PLT platform was deployed. The string consisted of a centralized memory deployed using a GR / CCL / FLUID ID [DENSITY / CAPACITANCE] / PRES / TEMP /3 FLOWMETERS.

Deployed with electric (E-Line) via well tractor the logging speed across the lateral is ~ 40 foot / min. Since the well-produced roughly 20-25 MMscfd the flowmeters & temperatures are the strongest sensors for determining which perforated clusters delivered the gas production. This Gen 1 - PLT final result was delivered to the oil company within 2-3 days after completion of the service.

Observations

An observation found that the fiber optic company referenced production logging data sets was required to help correct the Fiber Optic (FO) data sets. The delivery time for FO final analysis results and reporting took ~ 6 months before the final product is sent to customer. The observations found that the oil company engineering staff had difficulty believing the FO data sets final results. More emphasis of how the reservoir was truly delivering was put on the Gen 1 – PLT results. With the rapid delivery of PLT results (within 1-2 days) after the survey was completed, the oil company had data in hand. They could then analyze and understand the results correlated back to their geology information.

Conclusions

This case study illustrates the quality of the Gen 1 - PLT log data sets and how the measurements relate to the actual flow back production of the well. In addition, this case study represents the effectiveness of the stimulation across the completed lateral from the horizontal production log data. This example of a flowing well produced majority gas at a rate ~ 20 MMCFD with some liquids. Deployed with an electric line with a FO was deployed with a well tractor, a production log was deployed on the end of the tractor.

The object of the survey was to measure the flow profile of the producing wellbore across the entire lateral with tradition production log tool. In addition, measure the horizontal lateral flow profile with FO to verify an accurate profile using 2 separate data sets.

The well was produced while deploying into the wellbore the standard production log platform was setup in memory mode and tractored across the flowing interval to the end of the well.

The Fiber Optic (FO) measurement was then turned on & monitored during the flowing time frame. A 24-hour shut-in survey was performed then the tools were pulled out the wellbore.

Figure 7 illustrates the wellbore trajectory as a flat hook shape wellbore. A flat well trajectory allows for the well to unload from the toe. When a trajectory has numerous porposing along the lateral, water can load up and then restrict the flow from the toe sections.

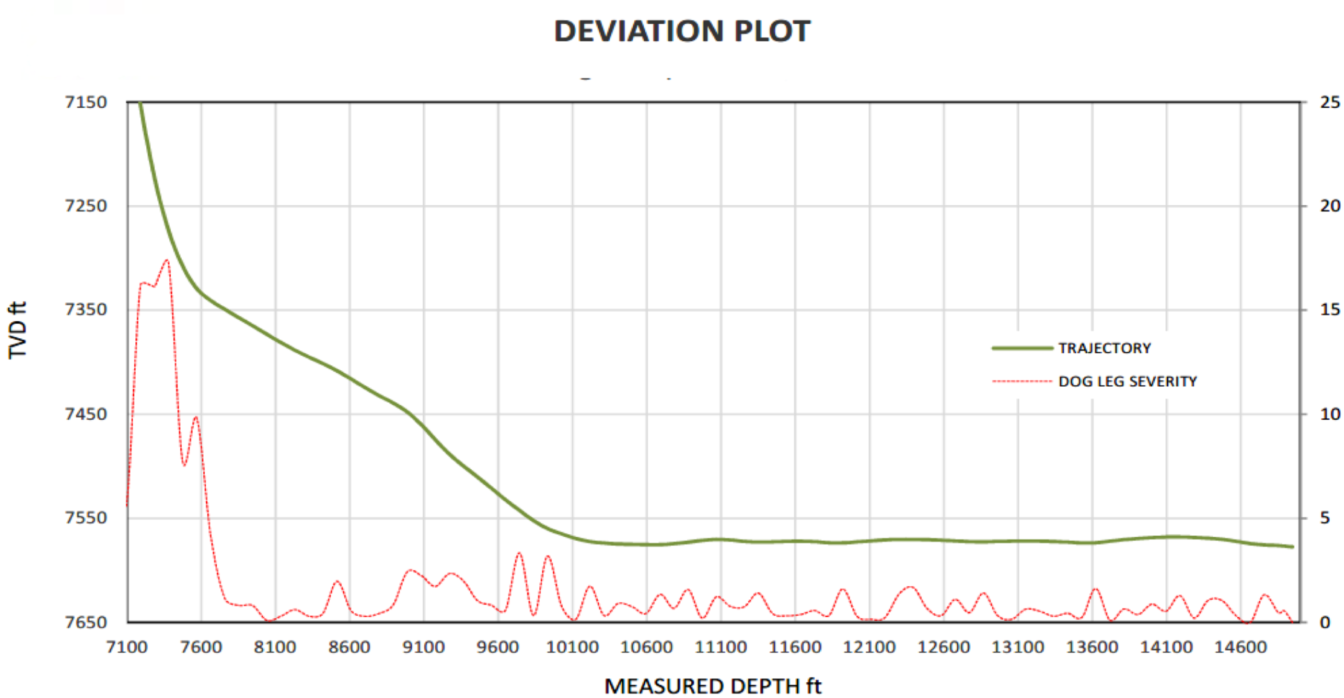

Figure 7—Case History 1- Gen 1 Horizontal Production Log Results – Well Trajectory

This particular survey the tubing pressure is always recorded, the well flowed back ~ 20 MM SCFD of mostly dry gas. Figure 8 illustrates the flowing pressures stayed rather stable ~ 1130 psi during the entire survey.

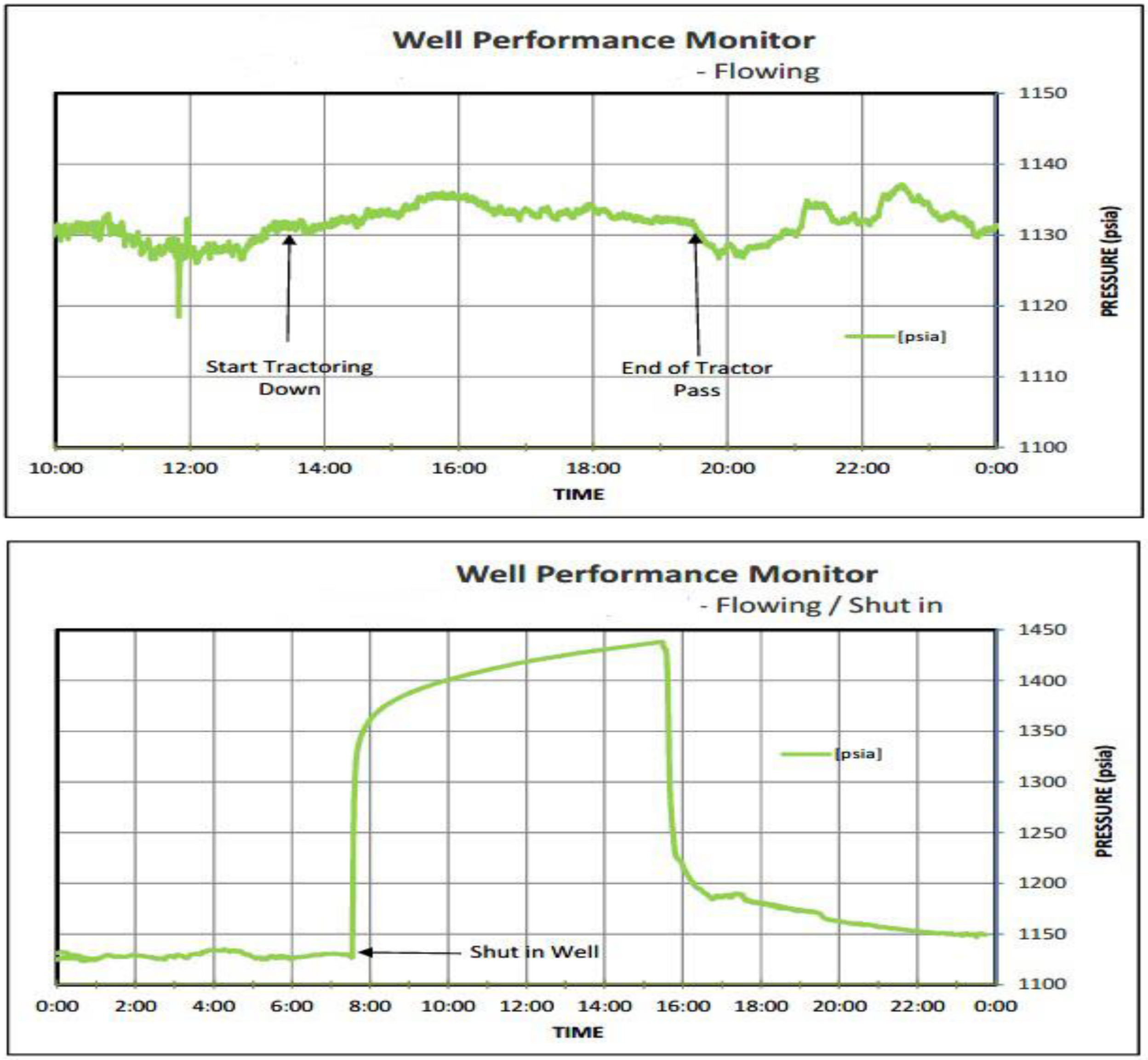

Figure 8—Flowback result during case 1 production log survey.

Figure 9 illustrates the flow profile of the reservoir and which stages are contributing the best production contribution. There are a few stages at 12,000 ft interval which used a different completion technique did not contribute as well as some of the other stages. The toe stage has heavy fluids trapped in some low spots in the lateral which have not flowed out of the well. This production log data was acquired while tractoring into/across the wellbore.

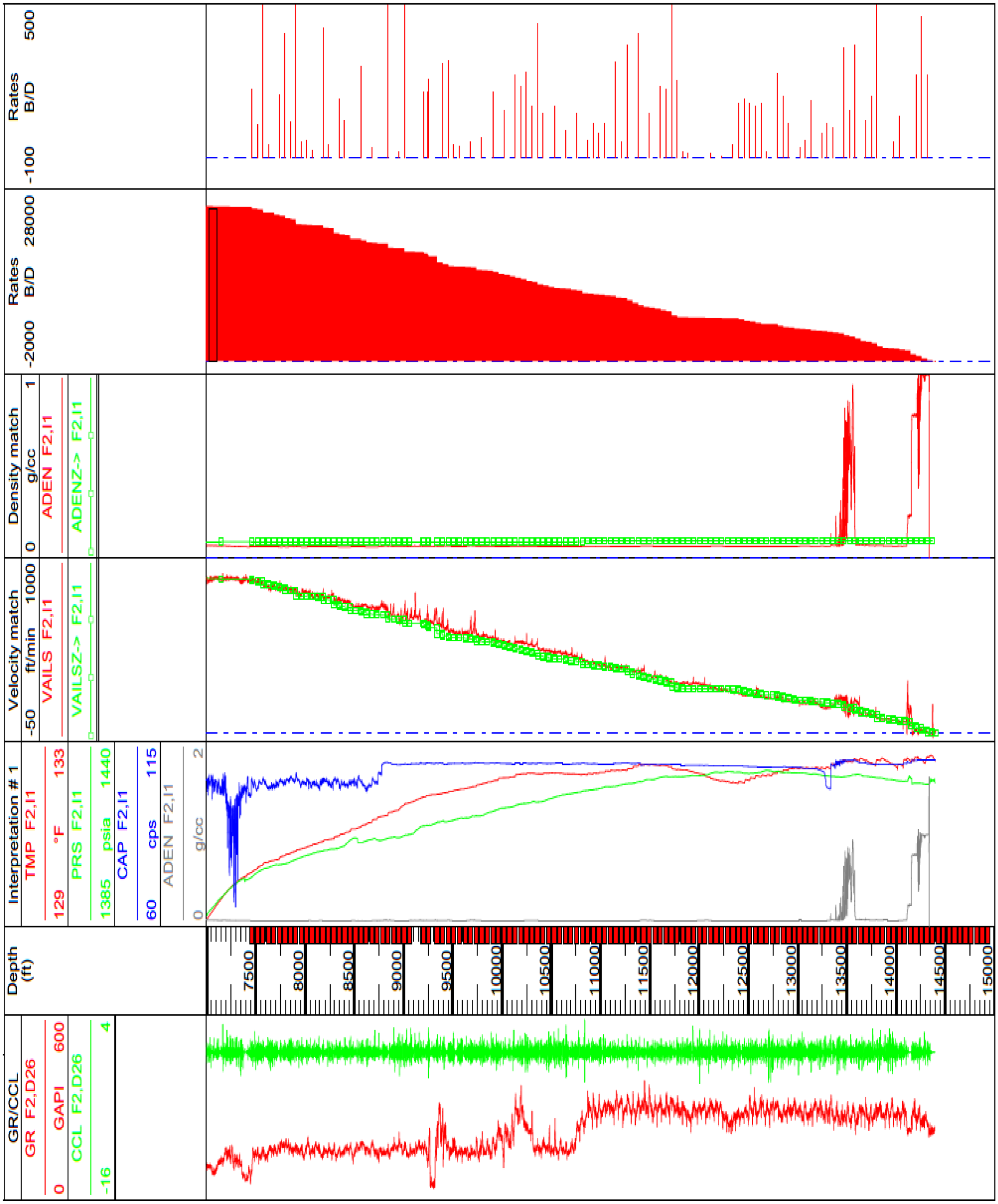

Figure 9—Case History 1- Gen 1 Horizontal Production Log Results

Case Study 2:

The following case study is of a horizontal memory mode Gen 3 Array (multi-sensor array) PLT platform deployed on coiled tubing on a newly completed multi-phase producing lateral.

The oil company technical team decided to measure and monitor their recently hydraulically stimulated producing horizontal well. The technical team had recently drilled into a new area & were interested to verify how the reservoir rock was delivering hydrocarbons (HC) across the lateral section. The well was producing a mixture of hydrocarbon (HC) & formation water.

Prior to running the Gen 3 – Array PLT survey, the coiled tubing was used to deploy into a well to perform various mechanical services such as a TD check/cleanout the lateral of any sand & plug parts. A 2 3/8″ CT was deployed to perform a clean out trip to ensure the production log survey can be run without any issues.

The Gen 3 Array - PLT tool ran was an Openfield FAST array PLT tool run in memory mode, in combination with a standard memory Spartek Gen 1 - PLT platform.

FAST Gen 3 – Array PLT tool platform consists of CCL, Pressure, 4 array multiphase fluid identification sensors, 4 array spinner & 8 doppler velocity sensors. The standard memory production logging platform is as listed above, Memory, Gamma ray, CCL, Pressure, Temperature, Fluid Density, Fluid Capacitance, 3 Flowmeters

The FAST Gen 3 – Array phase and spinners are able to determine the phases and fluid velocity in 4 discreet locations across the cross section of the wellbore. The standard Gen 1 PLT platform is able to measure the average velocity with redundancy using 3 spinners (flowmeters), also the fluid density & fluid capacitance (holdup measurements).

The FAST multi-phase fluid identification sensors design allows coverage of the full refractive-index range between 1.0 and 1.6 (Fig. 11) and therefore the ability to discriminate three phases: oil, water and gas on a single point. (Petrophysics, Vol. 59, 2018)

Figure 10 illustrates the 3 phase optical probe sensors are based in the measurement of the refractive index of the fluids present in the wellbore and measure the time the tip of the probe spends in each phase to determine the hold-up of the different phases. (SPE-205803-MS, 2021)

As the tool is logged through a main phase of water the tool signal drops when oil bubbles pass over the tool. Figure 11 illustrates the effect when gas bubbles pass through a heavier phase and are sensed by the optical probes during a production log survey. The refractive index versus counts per seconds for a 3-phase optical probe illustrated in figure 11 shows the regions for each of the phases of water, oil, gas. Each optical probe records every 30khz a bubble count in the majority phase (refractive index), the average refractive index, max & min refractive index & calculates a gas holdup, water holdup & oil holdup.

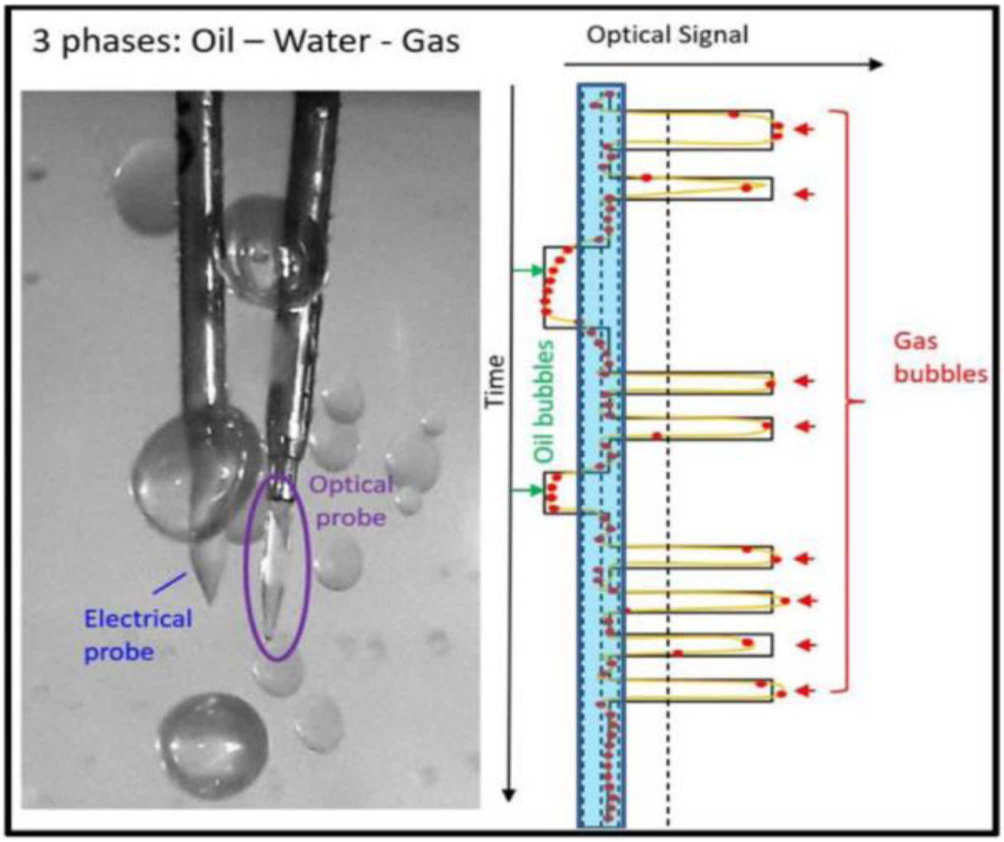

Figure 10—Optical probe response in water continuous phase detecting hydrocarbon bubbles. (SPE-205803-MS, 2021)

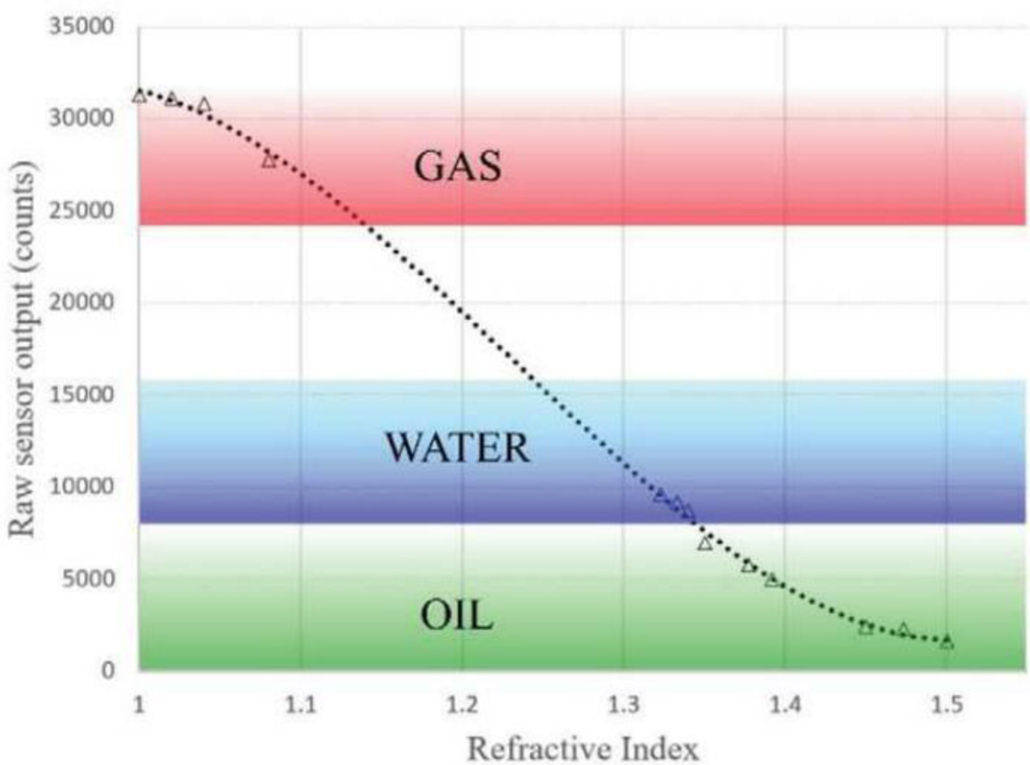

Figure 11—Optical probe response with fluids of various refractive index. (Petrophysics, Vol. 59, 2018)

Findings

This particular well produced majority water production ~ 1000 bwpd & 200-300 bopd, most of the gas comes out of the oil phase up hole in the vertical section. Since the well flowed mainly fluids, it was considered as a two-phase flow regime. The logging provider utilized a FAST -Gen 3 & Spartek Gen 1 PLT Tool platform all in combination.

The standard Gen 1 - PLT platform set up with the multiple spinners (3 flowmeters in series) in was able to consistently measure the average fluid velocity. The FAST Gen 3 - Array multiphase sensors were able to measure the oil phase entering the pipe cross section flowing on the high side of the well.

Observations

The survey was deployed via coiled tubing; therefore, multiple logging passes were made at various logging speeds to develop a spinner calibration routine. Something that a well tractor deployment is unable to achieve. This PLT final result was delivered to the oil company within 2-3 days after completion of the service.

Results

This case history paper illustrates the quality of the Gen 3 – Array in combination with the Gen 1 - PLT data sets and how the measurements relate to the actual flow back production of the well. The paper represents the effectiveness and reliability of PLT measurements and the sensors used along the flowing horizontal production wellbores.

Figure 12 illustrates the trajectory of this well has a toe down trajectory. A toe down trajectory will end up leaving heavier fluids build up at the deepest part of the wellbore. The production log measures this buildup of the liquid phases.

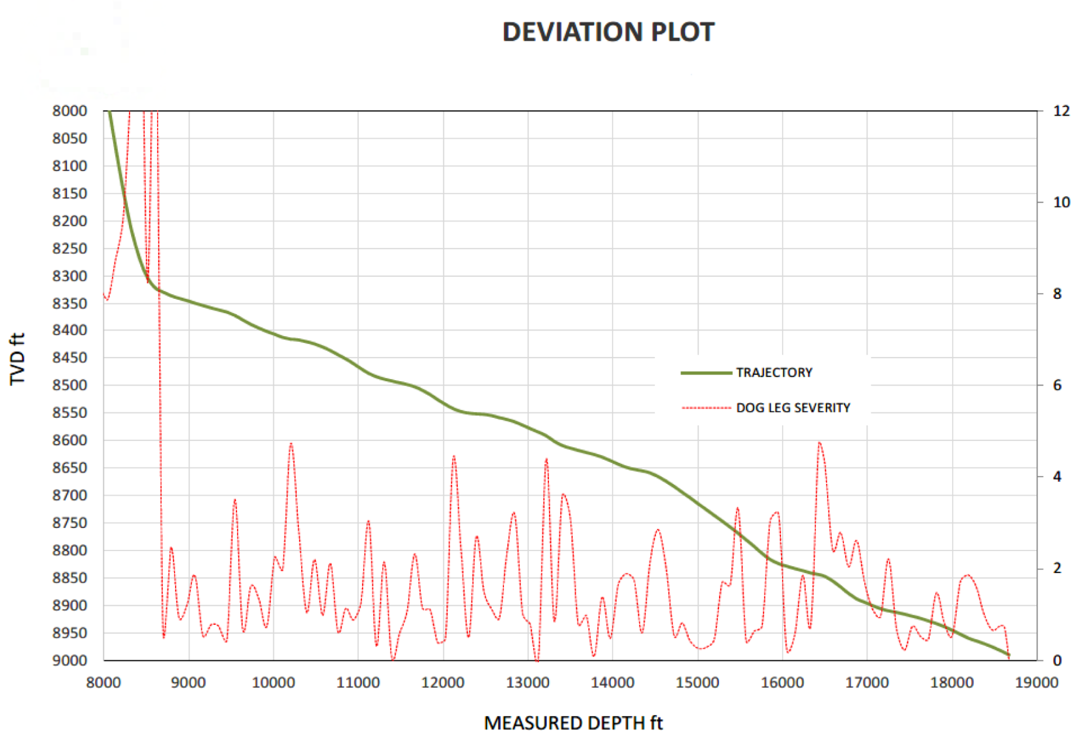

Figure 12—Case History 2 Gen 3 Horizontal Production Log Results – Well Trajectory

This PLT result, from the Gen 3 – Array data set displays how the holdup image across the cross section of the wellbore. The fluid ID sensors - optical probes were able to determine that the cross section of the lateral is 90% filled with water. The optical probes also showed that oil enter the wellbore in selective clusters and travelled on the top of the wellbore. The flowrate analysis is derived using 3 phase optical probe holdup data and by using the multiple array flowmeter sensors a velocity is calculated.

The 8 sector doppler sensors also can be used to determine a flowing velocity along the lateral section.

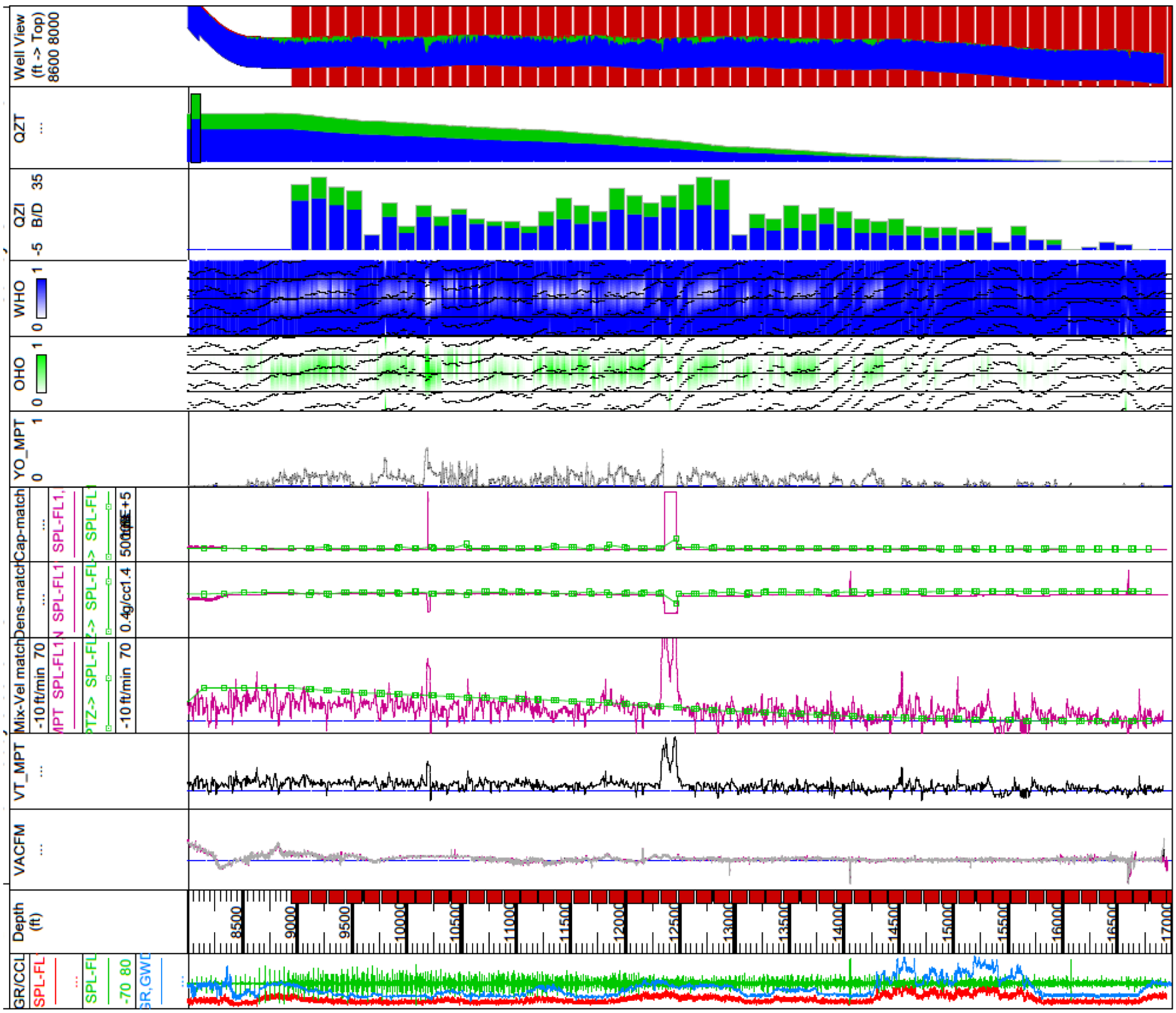

Figure 13—Case History 2 Gen 3 Horizontal Production Log Results

Conclusion

An advantage when deploying horizontal Gen 1 & Gen 3 PLT surveys with the deployment system, is the ability to use a fiber optic sensing. This added information can complement and assist horizontal PLT data set results to give an additional view of a reservoir is performing. However, new technology is not proven, it was found that distributed temperature (FO) was less useful on this job due to some accidental inflow of borehole fluid causing hydrogen darkening, something to consider on future deployments. (Hvedling, 2020).

In our case studies we encountered that the FO results relies heavily on the PLT data sets to help guide the FO results. Meanwhile, the Gen 1 and Gen 3 PLT platforms can easily deliver accurate, representative results without needing the guidance from other technology.

Therefore, in summary the Gen 1 and Gen 3 PLT platform, in the right hands, delivers accurate flow contribution results.

Nomenclature

FO	– Fiber Optic
PLT	– Production Logging Technology
DTS	– Distributed Temperature Sensing
DAS	– Distributed Acoustic Sensing
JT	– Joule Thompson Effect
Holdup	– Phase Holdup occupying a cross sectional area
Gen 1	– Generation 1 Production log platform
Gen 3	– Generation 3 Production log platform
GR	– Gamma Ray Tool
CCL	– Casing Collar Locator
CT	– Coiled Tubing
TD	– Total Depth
TVD	– True Vertical Depth
OD	– Outside Diameter
PRES	– Pressure
Temp	– Temperature
MMCFD	– Million cubic foot per day gas rate
Bwpd	– Barrel of water per day rate
Bopd	– Barrel of oil per day rate

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Biography

Duncan Heddleston holds a Petroleum Engineering Degree from the University of Alberta & earned an MBA Degree from Phoenix University as well as MBA Marketing from Caltech. In 2006 Mr. Heddleston created & founded Indepth Production Solutions, previous positions as the Global Manager for Baker Hughes Wireline head of the Specialty Cased Hole Logging product lines focused on production logging, over saw worldwide projects and was involved in building new technologies and data analysis packages for the industry. Mr. Heddleston has presented over 10 technical publications throughout the industry and is regarded as an industry subject matter expert in specialty cased hole & production logging services.