SED-276

CoreLab Report November 12, 2015

I.19-06-016

ALJs: Hecht/Poirier

Date Served: May 3, 2021

Southern California Gas Company
Standard Sesnon 25

Completion Profiler

Company	*Southern California Gas Company*
Well Name	*Standard Sesnon 25*
Field	*Aliso Canyon*
Location	*Los Angeles County, California*
Customer Name	*Hilary Petrizzo*
Date of Survey	*November 8, 2015*
Date of Analysis	*November 12, 2015*
Logging Engineer	*Rick Kent*
Analyst	*Derrick George*

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Survey Objectives

- Identify casing and tubing breaches

Logging Procedures

Date	Time	Comment
11/08	N/A	Arrive on location
11/08	N/A	Gauge run start
11/08	N/A	Gauge run stop
11/08	10:44	Program Completion Profile String
11/08	11:31	Start GIH pass
11/08	11:31	Stop GIH pass
11/08	11:31	Start logging passes
11/08	15:37	Stop logging passes
11/08	14:22	Start out of well pass
11/08	15:37	Stop out of well pass
11/08	15:50	Start download
11/08	16:22	Stop download
11/08	17:00	Rig down

Interval Logged: [From Surface to 8,436 ft.]
50 ft/min
100 ft/min

Well Information

Surf Casing:	11.750"	42.0 lb/ft	surface to 990 ft	
Casing:	7.000"	23.0 lb/ft	surface to 2,398 ft	
Casing:	7.000"	23.0 lb/ft	2,398 ft to 6,308 ft	
Casing:	7.000"	26.0 lb/ft	6,308 ft to 8,282 ft	
Casing:	7.000"	29.0 lb/ft	8.282 ft to 8,585 ft	
Liner:	5.500"	20.0 lb/ft	8,559 ft to 8,749 ft	PBTD: 8,749 ft
Tubing:	2.875"	6.5 lb/ft	surface to 8,496 ft	

** Camco SSSV at 8451' (2.313" ID), Otis "XN" nipple at 8472' (2.205"), EOT at ~8496' (Packer depth). Tubing string installed 7/9/76. 6/673 – well was converted to gas storage well.

Perforations: 8,475 ft (S2 Sand)

8,510 ft - 8,538 ft; 8,538 ft - 8,542 ft; 8,542 ft - 8,559 ft (S6 Sand)

8,583 ft (S6 Sand)

Tool String

The 1 11/16" Completion Profiler string comprised the following sensors:

Battery housing; RS-232/CCL; Memory/CPU; Gamma Ray; Pressure/Temperature Combo; Induction Collar Locator; Fluid Density; Fluid Dielectric; Spinner Flowmeter.

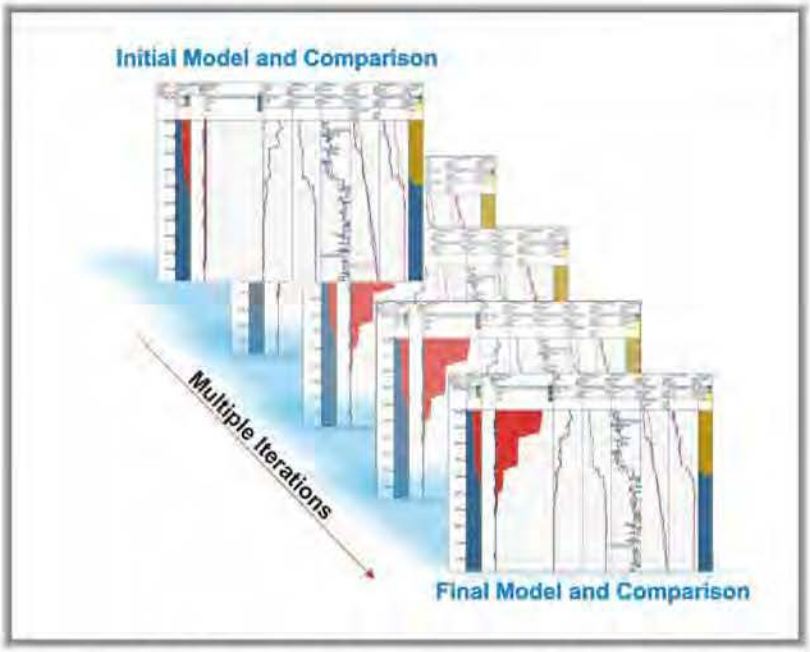
Observations:

1. The log data indicates the following observations and gas flow path evaluation:
    - There is no gas flow inside the tubing down to ~8435'
    - Temperature profile appears to be a normal flowing response with the source below log depth and assumed to be from the gas storage zone.
    - At ~8435' the spinner appears to indicate flow up through the tubing and exiting to the annulus (tubing x prod casing).
    - A cooling anomaly appears to detect a leak through the surface casing at ~890' (depth confirmed with both down and up log pass temperatures). The reported bottom of the surface casing is at 990'. The temperature is ~26.9 degF (down pass) at this depth and continues to cool up to a warming anomaly that changes from ~365' during the down pass and ~65' during the up pass. This change in depth may indicate the gas flow path has changed between the passes. The warming interval would likely indicate that the gas flow has moved away from the near-wellbore zone and beyond the ability for the temperature sensor inside the tubing to detect cooling caused by the gas flow.
    - Summary: gas flow appears to be flowing up the tubing and exiting through a tubing failure at ~8435'. Gas flows up the tubing x production casing annulus until it exits through the surface casing at ~890'. Gas flow up the surface casing annulus and moves away for the near-wellbore region at changing depths based on the temperature warm-back response. Note: An ice plug was drilled out with coiled tubing just prior to this log run. The ice plug was reported around ~450', which is in the maximum cooling zone.

2. Other secondary observations:
    - The log run covered from surface to ~8440'.
    - The log was depth correlated to a supplied gamma ray which only cover a short interval of the bottom of the log. The depth correlation up around the surface leak area could be off depth but should be relatively close. If a complete pipe record was available additional depth correlation checks could be conducted.
    - The spinner kicks to a very high rps level as the tool sat down during the down logging pass. The target depth was a little deeper (just short of a previous coiled tubing cleanout run). Upon retrieving the spinner at surface the impeller was observed to have been exposed to an extreme flow rate or velocity that was above the design limits of the spinner. It is very likely that the logging string reached the gas flow inside the tubing at the tubing failure location at ~8435'. The up log pass indicated no spinner activity. The damage could not have been caused by just hitting something in the tubing because the tool was moving at only 60 ft/min line speed. A subsequent tubing plug run set a plug just above the top pup joint above the Camco SSSV. A setting depth was not reported but is estimated to be around 8380'. The plug run confirms no gas flow inside the tubing down to the plug setting depth and of course the plug did not shut off the gas flow to surface.
    - The differential pressure curve averaged ~0.01 bar/m. This calculates to ~0.044 psi/ft pressure gradient. This, in turn calculates to ~0.1g/cc fluid density.
    - The BHP recorded ranged from ~1600 psi to 2050 psi.

Brief Description of Process

The analysis is performed using a global stochastic optimization technique.
In this technique an initial flow model is estimated. Then from this model the theoretical log responses are derived. The theoretical responses are compared to all available data and the model is adjusted until the best possible match of the theoretical and actual data is obtained.



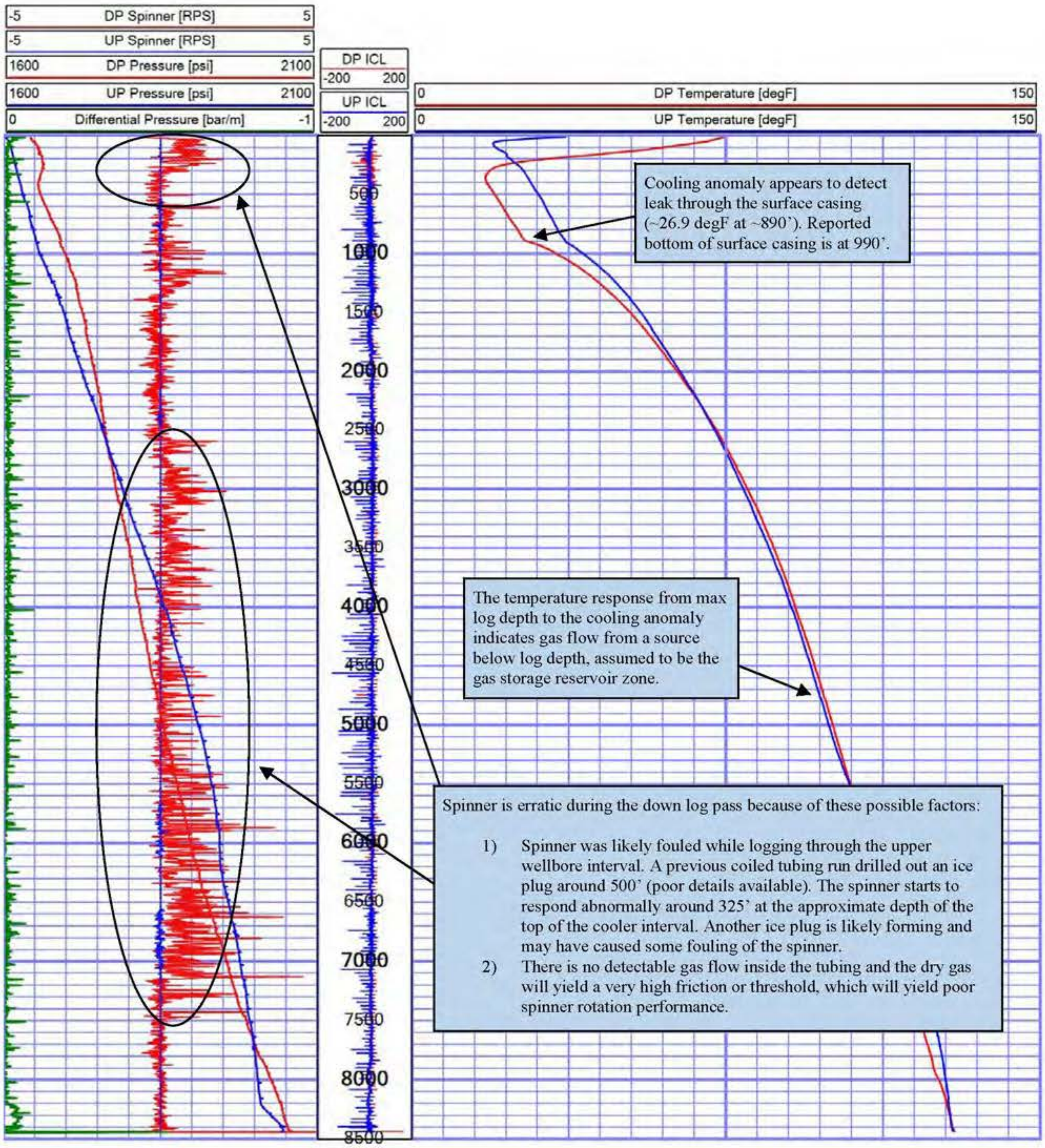
A comparison between the model responses and the recorded data is shown in this report. Good correlation between the theoretical and log data curves indicates that the flow model is in agreement with the log data and the actual well production profile. Discrepancies between the theoretical and raw data curves can be due to tool deficiencies, conflicts between the parameters or conditions that make the underlying empirical models (such as flow regimes) less applicable.

- The flow regimes were determined, directly from the flow rates and holdups, according to the Dukler-Taitel analytic model.
- The profile factors, to calculate the average effective fluid velocity from the apparent velocity, were based on the Reynolds number, calculated from the phase velocities and phase properties.
- Where gas was present the density, heat capacity and Joule-Thompson coefficients were derived from the Lee Kesler Pitzer equation of states.
- Solution gas in oil was derived from the Vasquez and Beggs or Ostein Glas0 correlation.

The analysis was performed in five steps:

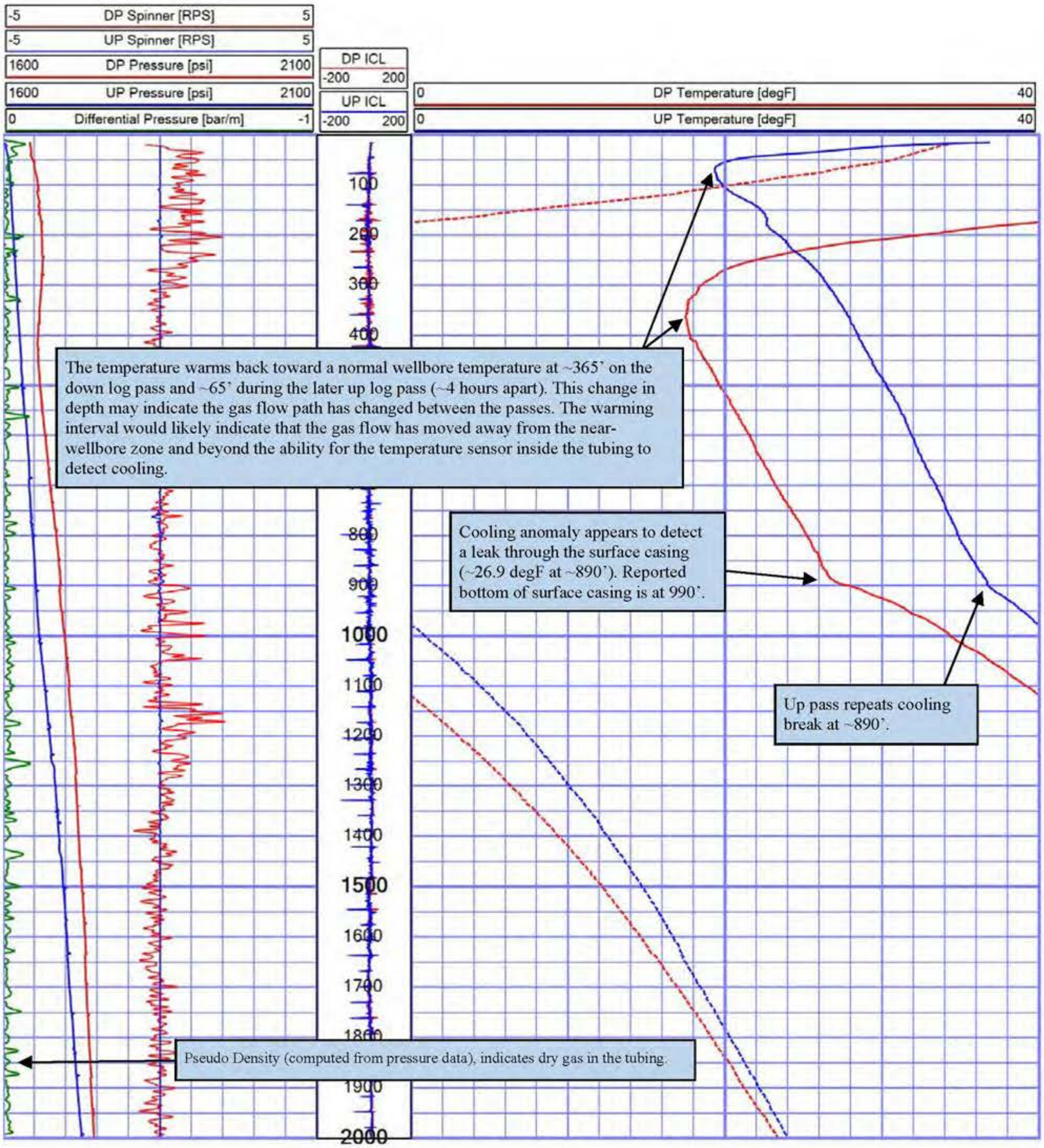
- The data preparation to filter the data, compute gradients and error estimates.
- The flow meter analysis to compute the apparent velocity.
- The profile determination to identify the potential producing and/or injecting zones.
- The computation of the flow rates (model) by global optimization.
- The computation of surface production rates and reporting

Temperature Profile
0' - 8436'



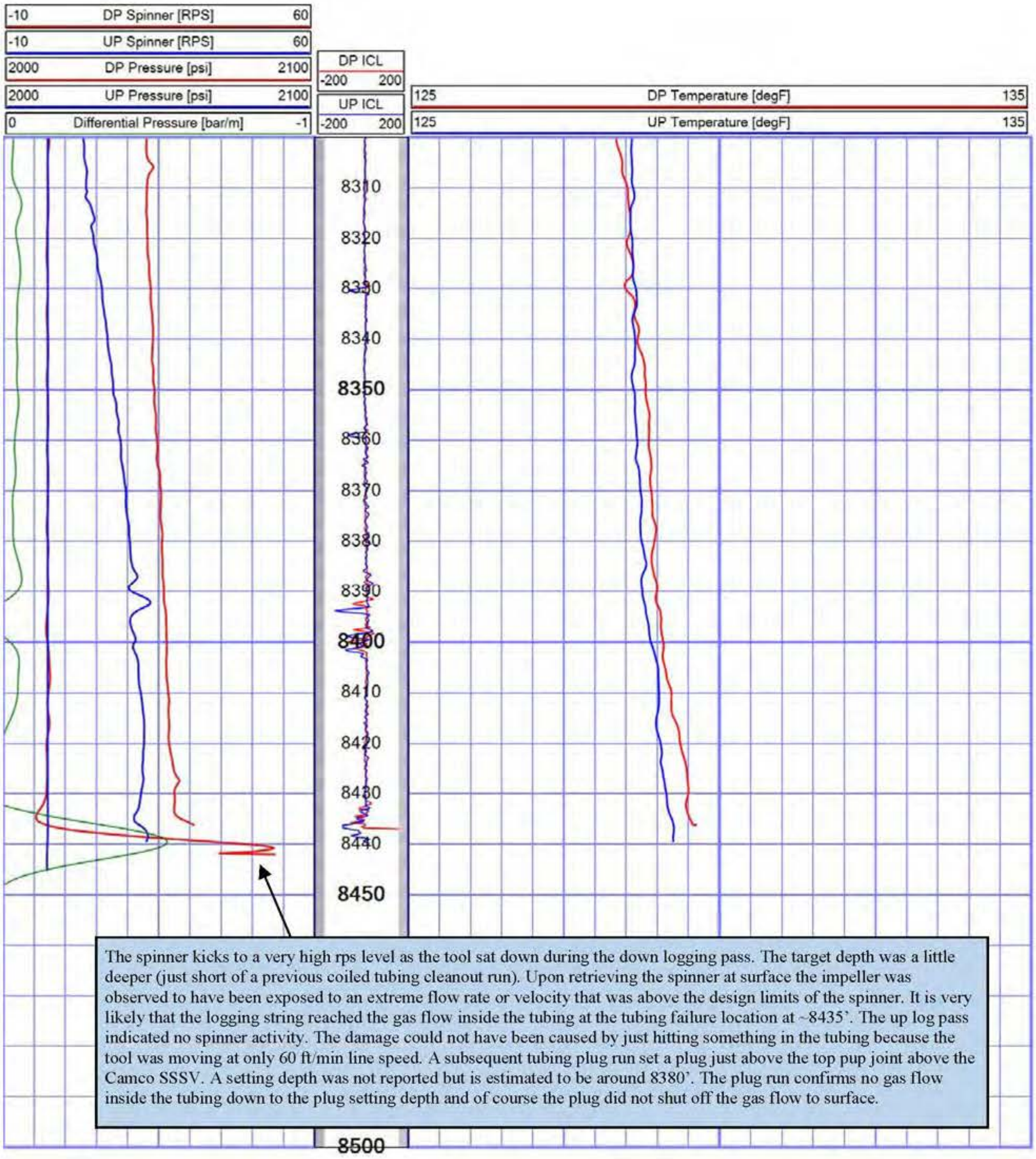
Completion Profile Analysis

Temperature Profile
0' - 2000'



Completion Profile Analysis

Temperature Profile
8,300' - 8,500'



6510 W Sam Houston Parkway, Houston, TX 77041
+1-713-328-2320

Definitions

Curve Name	Description
Holdup	Holdups
PerfCount	Perforations
QGas	Total Gas Production at surface conditions
QpGas	Incremental Gas Production at surface conditions
QOil	Total Oil Production (if present downhole) at surface conditions
QpOil	Incremental Oil Production (if present downhole) at surface conditions
QWater	Total Water Production at surface conditions
QpWater	Incremental Water Production at surface conditions
GR	Gamma Ray/SpectraScan
Twf	Average Temperature
Vap	Apparent Velocity
Vap-Theo	Theoretical Apparent Velocity
Tgeotherm	Geothermal Gradient
RhoFluid	Average Fluid Density
Pwf	Average Pressure
HydroFrq	Average Fluid Dielectric
Flowrate	Total Flowrate at downhole conditions
Vap	Apparent Velocity
Vap-Theo	Theoretical Apparent Velocity
RhoFluid	Average Fluid Density
RhoFluid-Theo	Theoretical Average Fluid Density
DPwfDz	Differential Pressure
DPwfDz-Theo	Theoretical Differential Pressure
Twf	Average Temperature
Twf-Theo	Theoretical Average Temperature
Tgeotherm	Geothermal Gradient
DTwfDz	Differential Temperature
DTwfDz-Theo	Theoretical Differential Temperature
Regime	Flow Regimes
Temperature	Temperature Passes
Density	Fluid Density Passes
Spinner	Spinner Passes
Pressure	Pressure Passes
Linespeed	Linespeed Passes
Slope	Spinner Slope
Vthr	Spinner Threshold
SpinnerFlt	Spinner
DPipe	Inside diameter of the casing/tubing across logged interval
PipeAngle	Average pipe angle across logged interval
APIOil	Degree API of the oil
SPGG	Specific Gravity of the gas
TgeoRef	Reference Temperature for Geothermal Gradient calculations
DgeoRef	Reference Depth for Geothermal Gradient calculations
Goetherm	Geothermal Gradient across logged interval

Completion Profile Analysis

Tool Specifications

O.D.	1-11/16 in. (42.86 mm)
Length	11.9 ft.(3.63 m) in combination 23.28 ft. (7.1 m) stand alone
Pressure Rating	15,000 psi (103421.4 Kpa)
Temperature Rating	350°F (177°C)

Flow Measurement

Measurement of fluid velocity is made using the *Spinner Flowmeter*. This is calibrated by making logging passes at different line speeds to establish the relationship between instrument velocity in feet/minute and the spinner response in revolutions/second (RPS). With this relationship the measured RPS can be converted to fluid velocity in ft/minute. With a known pipe I. D. this can be used to calculate the flow rate in BPD.

Q_{BPD} = ft/min x 1.4 x I.D.^{2}

Mass flow rate can be computed using the *Temperature* data. This is based on an enthalpy model, taking into consideration; kinetic energy, frictional and Joule-Thompson heating as well as conduction and convection into the formation.

In gas wells the volumetric fraction of liquids (water) can be very small. Therefore water production may not be quantifiable by velocity measurement alone. Because of water's high mass relative to gas, mass flowrate computed from the *Temperature* data can be better at quantifying the water production.

Holdup Measurement

Holdup (γ) - The fraction of each phase in the wellbore (Water, Oil, Gas fraction) This should not be confused with Cut. i.e. 100% water holdup exists in the static rathole but does not flow.

The *Fluid Density* instrument uses a small gamma ray source and a gamma ray detector to measure the density of the wellbore fluid mixture. The mixture density is used to calculate the holdup fraction.

$$\gamma_{water} = (\rho_{mixture} - \rho_{gas}) / (\rho_{water} - \rho_{gas})$$

[For two-phase gas-water production]

ρ: density (gm/cc)

The *Fluid Dielectric* instrument works like an electric capacitor. The capacitor plates are exposed to the wellbore fluids and are a fixed size and distance apart. The value of the capacitance will change as the dielectric of the fluids between the plates change. The instrument response is then used to calculate the hydrocarbon and water fractions. This is possible because of the unique dielectric constant of water, oil and gas.
Water = 78, Oil = 4 and Gas = 1

The *Pressure* data can also be used to corroborate the fluid holdup measurements. This is done by measuring the pressure gradient or the derivative of the pressure curve with respect to depth. The resulting curve in psi/ft can be used to determine the water and gas fractions.

Note:
In three phase flow both fluid density and dielectric measurements are necessary. The dielectric is used to determine the water holdup then the density is used to calculate the remaining gas and oil holdups.