June 17, 2015

Mr. Stuart Ellsworth
Engineering Manager
Colorado Oil & Gas Conservation Commission
1120 Lincoln Street, Suite 801
Denver, Colorado 80202

Re: Injection Pressure Request – DJINJ Injection Well
NGL C12 (API# 05-123-41201)
NGL Water Solutions DJ LLC
SHL: 2312 FSL x 935 FEL / NESE-27-T5N-R63W
Weld County, Colorado

Dear Stuart,

NGL Water Solutions DJ LLC, operator of the subject well, **requests an injection pressure assignment of 2,724 psig and a maximum daily injection rate of 23,040 bwpd for the subject well based on the results of the step rate test**. A mechanical integrity test was conducted to 3,000 psig.

The Step Rate Test ("SRT") and Pressure Fall-Off Test ("PFOT") report is attached and the data indicates a fracture gradient of 0.63 psi/ft. The table below shows the estimated operating conditions for the well as completed with 4-1/2" coated injection tubing.

Rate (bpm)	Rate (bpd)	BH Pressure (psig)	BH Pressure Gradient (psi/ft)	Calculated Pipe Friction[1] (psi)	Est. Surface Injection Pressure (psig)
3.0	4,320	3,850	0.44	52	105
6.0	8,640	4,060	0.46	162	424
9.0	12,960	4,480	0.51	341	1,024
12.0	17,280	4,920	0.56	586	1,709
15.0	21,600	5,343	0.61	891	2,437
16.0	23,040	5,550	0.63	971	2,724
18.0	25,920	5,677	0.65	1,249	3,128
21.0	30,240	6,016	0.69	1,629	3,848
24.0	34,560	6,144	0.70	2,174	4,521

[1] Calculated pipe friction for normal operations based on 8,875 ft of 4-1/2" IPC and blank liner.

The top of the Amazon formation is at 8,720 ft MD (8,707 ft TVD) and the injection packer is set at 8,150 ft MD, 15’ above the liner top. Currently, the top depth of the casing open to injection is 8,800 ft MD (8,787 ft TVD).

Please contact me at (303) 947-9402 if you have any questions.

Kind Regards,

Neel L. Duncan, PE
Vice President, Operations

Attachment: *Step Rate Test and Pressure Falloff Test Analyses.*

1.0 Executive Summary

IPT analyzed and evaluated the step rate test (SRT) and pressure falloff test conducted on the completion on the Amazon and Council Grove formations in the NGL C12 well. This analysis was performed to determine the fracture propagation pressure and reservoir parameters of this interval. The results of the analysis are shown in Table 1 and Table 2.

The step rate test was conducted through slotted liner from 8,800 ft to 9,843 ft MD (8,787 ft to 9,830 ft TVD) and was performed by starting injection at 3.0 bpm and stepping up to a final rate of 24.0 bpm down the 2-3/8" x 7" annulus into the 4-1/2" liner. The bottom-hole gauge was set at 8,135' MD (8,122' TVD) so gauge pressures were adjusted to the 8,800 ft MD (8,787 ft TVD), which is the bottom of the blank liner. Tubing friction pressures were calculated at each injection rate to determine the maximum surface injection pressure based on the recorded bottom-hole pressure (Table 2).

The Lyons, Lower Satanka and Wolfcamp formations are currently isolated with ARES packers and blank casing. The Lyons formation will be completed for injection at a later date. There is a fish in the well from 8,717 ft to 8764 ft MD, which includes a 4-1/2" tubing packer and joint of 2-3/8" tubing. Fluid injected into the well will have to travel through the section tubing and packer, which will increase friction losses. It is unknown if the formations below the external casing packer and retrievable bridge plug at approximately 8,996 ft are isolated or not.

The following are the general conclusions and observations of these evaluations:

- The step rate test indicates the fracture propagation for the injection formations occurred at ~5,900 psi (0.63 psi/ft) at a rate of 16.0 bpm (23,040 bpd). Accounting for friction effects at 16.0 bpm in 4-1/2" IPC tubing, 4-1/2" blank casing and the 2-3/8" tubing and packer fish, this extrapolated bottom-hole pressure should be realized at a surface injection pressure of 2,724 psi (Table 2).

- The pressure falloff analysis suggests the injection interval has high reservoir permeability. Based upon the analysis of the late time pressure data trends, average reservoir permeability is estimated to be 36.5 md and reservoir pressure is calculated to be 3,250 psi (0.37 psi/ft pressure gradient). The character of the pressure falloff derivative suggests an undamaged completion with a skin factor of -4.0.

- Utilizing the injection rate calculation below and the parameters from Table 1 for the falloff test, the injection rate is calculated to be approximately 13.8 bpm at the fracture propagation pressure. This provides a cross-check but we accept the step rate test as the more reliable as it is empirical.

$$q = \frac{kh\Delta P}{141.2\beta\mu\left[ln\left(\frac{r_e}{r_w}\right) - \frac{3}{4} + s\right]} = \frac{4300 * (5550 - 3295)}{141.2 * 1 * 1\left[\ln\left(\frac{1320}{0.333}\right) - \frac{3}{4} - 4.0\right]} = 19814\ bpd = 13.8\ bpm$$

Table 1: Reservoir parameters.

Reservoir Parameter	Pressure Falloff Test
Effective reservoir permeability (md)	36.5
Flow capacity (md-ft)	4,300
Net pay thickness (ft)	118
Skin factor (-)	-4.0
Reservoir pressure (psi)	3,250
Reservoir pressure gradient (psi/ft)	0.37

Table 2: Injection rates and pressures during test.

Rate (bpm)	Rate (bpd)	Surface Pressure[1] (psig)	BH Pressure (psig)	BH Pressure Gradient (psi/ft)	Calculated Pipe Friction[2] (psi)	Hydrostatic Pressure[3] (psig)	Est. Surface Injection Pressure (psig)
3.0	4,320	0	3,850	0.44	52	3,797	105
6.0	8,640	300	4,060	0.46	162	3,797	424
9.0	12,960	750	4,480	0.51	341	3,797	1,024
12.0	17,280	1,240	4,920	0.56	586	3,797	1,709
15.0	21,600	1,740	5,343	0.61	891	3,797	2,437
16.0	23,040	N/A	5,550	0.63	971	3,797	2,724[4]
18.0	25,920	2,170	5,677	0.65	1,249	3,797	3,128
21.0	30,240	2,520	6,016	0.69	1,629	3,797	3,848
24.0	34,560	2,835	6,144	0.70	2,174	3,797	4,521

[1] Step rate test pumped down 2-3/8" x 7" annulus.
[2] Calculated pipe friction for normal operations based on 4-1/2" IPC set at 8,150' MD, 618' of 4-1/2" blank casing and the packer-fish.
[3] Fresh water used during the step rate test (8.33 ppg).
[4] Requested injection pressure based on estimated fracture gradient and calculated pipe friction. Rate not use during test.

2.0 Review of step rate test

The step rate test in the NGL C12 was performed on June 4, 2015. Rates of 3.0, 6.0, 9.0, 12.0, 15.0, 18.0, 21.0 and 24.0 bpm were utilized during the test. A total of 1,905 bbls of fresh water was pumped during the test.

The following figures are used in the analysis:

Figure 1: SRT time chart.
Figure 2: SRT rate chart.

Observations from the step rate test (SRT) evaluation are shown below:

- The change in the bottom-hole pressure trend with increasing rate (Figure 2) at ~16.0 bpm (extrapolated) indicates that the fracture propagation pressure is approximately 5,550 psi at the bottom of the 4-1/2" blank casing. This corresponds to a fraction propagation gradient of 0.63 psi/ft.

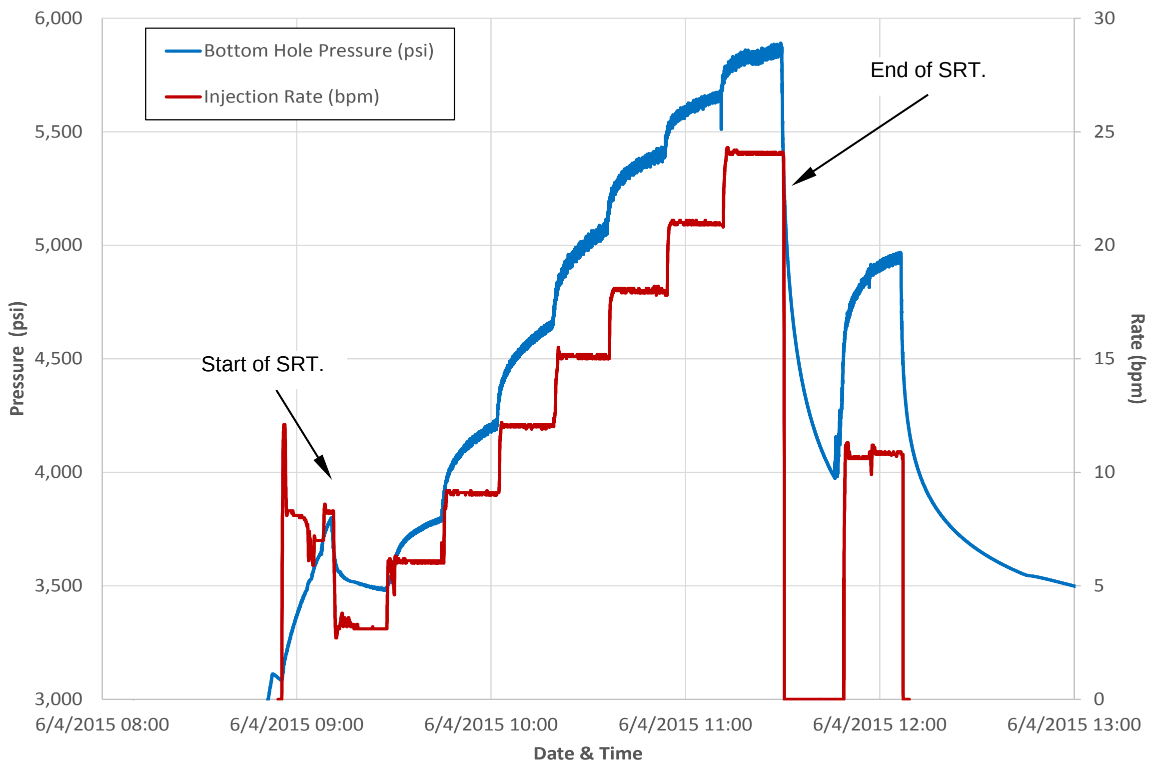

Figure 1: SRT time chart.

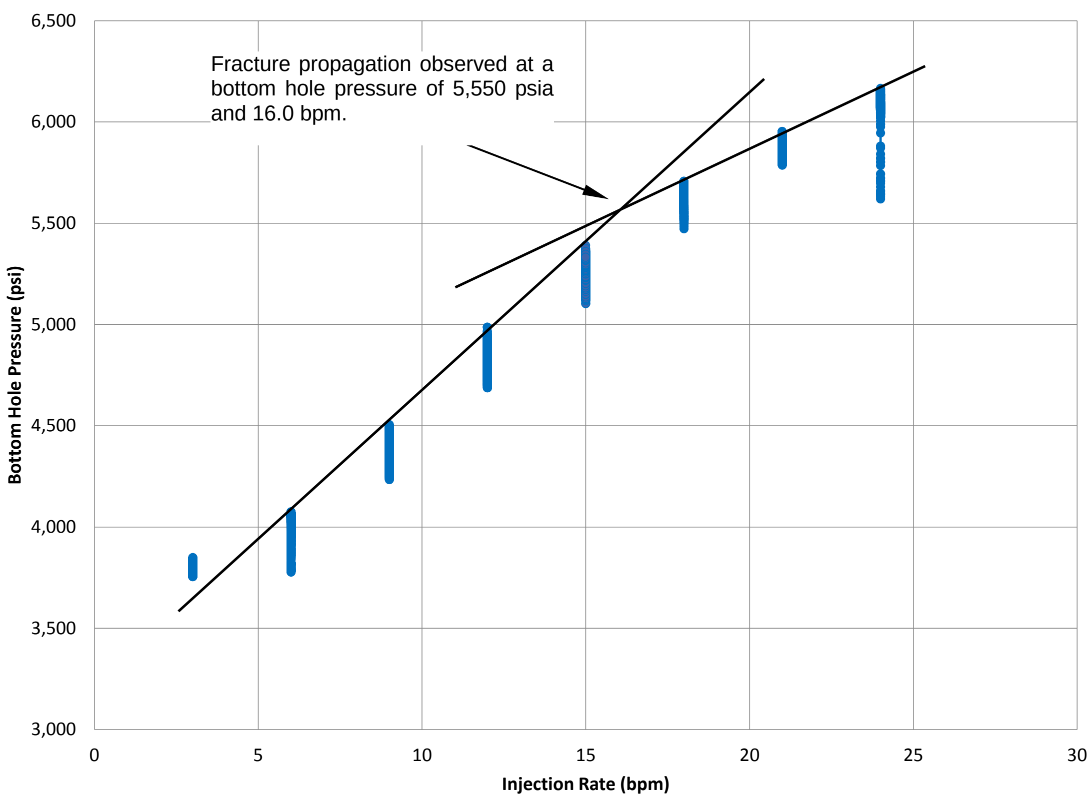

Figure 2: SRT rate chart.

3.0 Review of first pressure falloff test analysis

The NGL C12 was monitored for ~19 hours utilizing a bottom hole pressure gauge. A total of approximately 1,905 bbls of fluid was pumped prior to the shut-in on June 4, 2015. The pressure response was analyzed to determine the relevant reservoir characteristics. The reservoir pressure calculated from the pressure fall-off analysis (PTA) of the injection/falloff test are shown in Table 1.

The following figures are used in the analysis:

Figure 3: Cartesian plot of bottom hole pressure and temperature.
Figure 4: Diagnostic log-log plot.
Figure 5: Superposition plot.
Figure 6: Model match of pressure history.

Observations from the pressure fall-off (PTA) evaluation are shown below:

- The PTA log-log diagnostic plot (Figure 4) indicates several changes: 1.) Initial wellbore storage effects 2.) Possibly reaches infinite acting radial flow.

  The derivative response is unusual and the point of infinite acting radial flow is not definitive. This could be due to the complications in the wellbore including the fish and communication across packers in the liner section. While the pressure match is reasonable, there could be alternate interpretations.

- The type curve match of the late-time pressure trends (Figure 4) suggests a reservoir flow capacity of 4,300 md-ft. Based upon 118 feet of net pay, average reservoir permeability is calculated to be 36.5 md.

  This analysis assumes the Amazon and Council Grove formation are the dominant intervals affecting the pressure response. Based on the wellbore behavior, the additionally completed intervals could also be affecting the behavior. If so, a higher net pay would result in a lower permeability.

- The character of the pressure derivative (Figure 4) suggests an undamaged completion with a skin factor of -4.0.

- Based upon the late time pressure trends (Figure 4 and Figure 6), current reservoir pressure is approximately 3,250 psia (0.37 psi/ft).

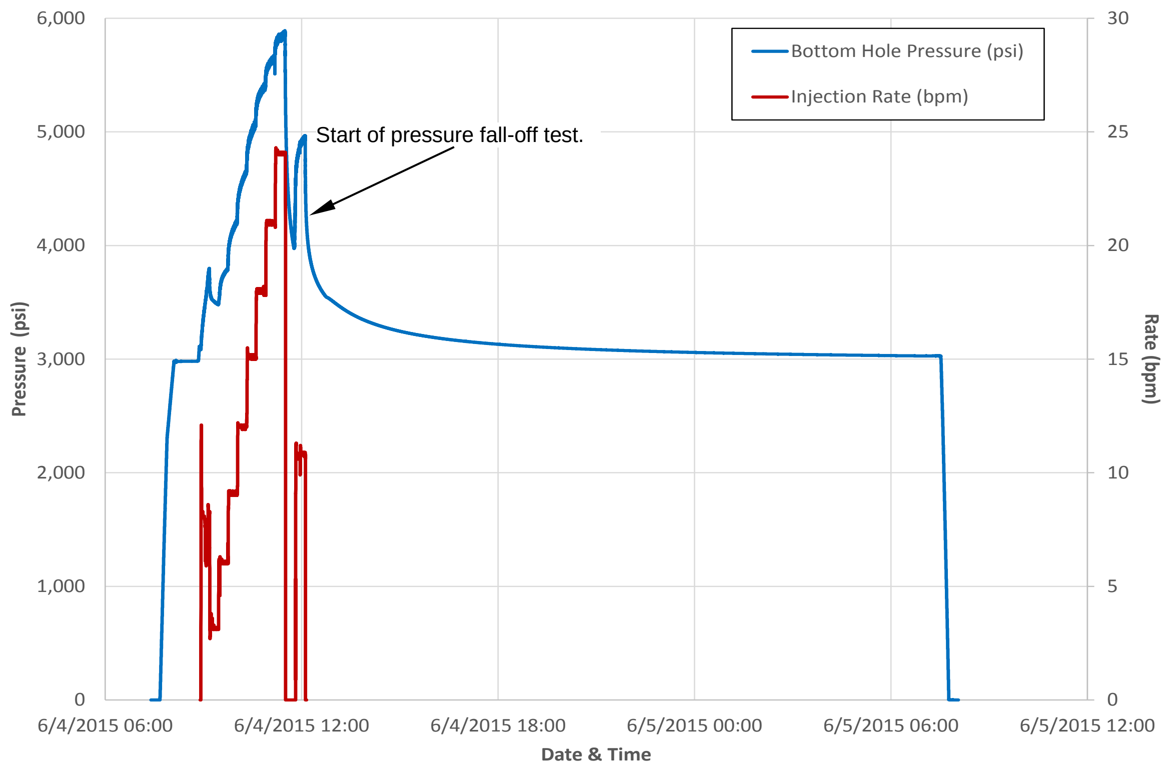

Figure 3: Cartesian plot of bottom hole pressure and temperature.

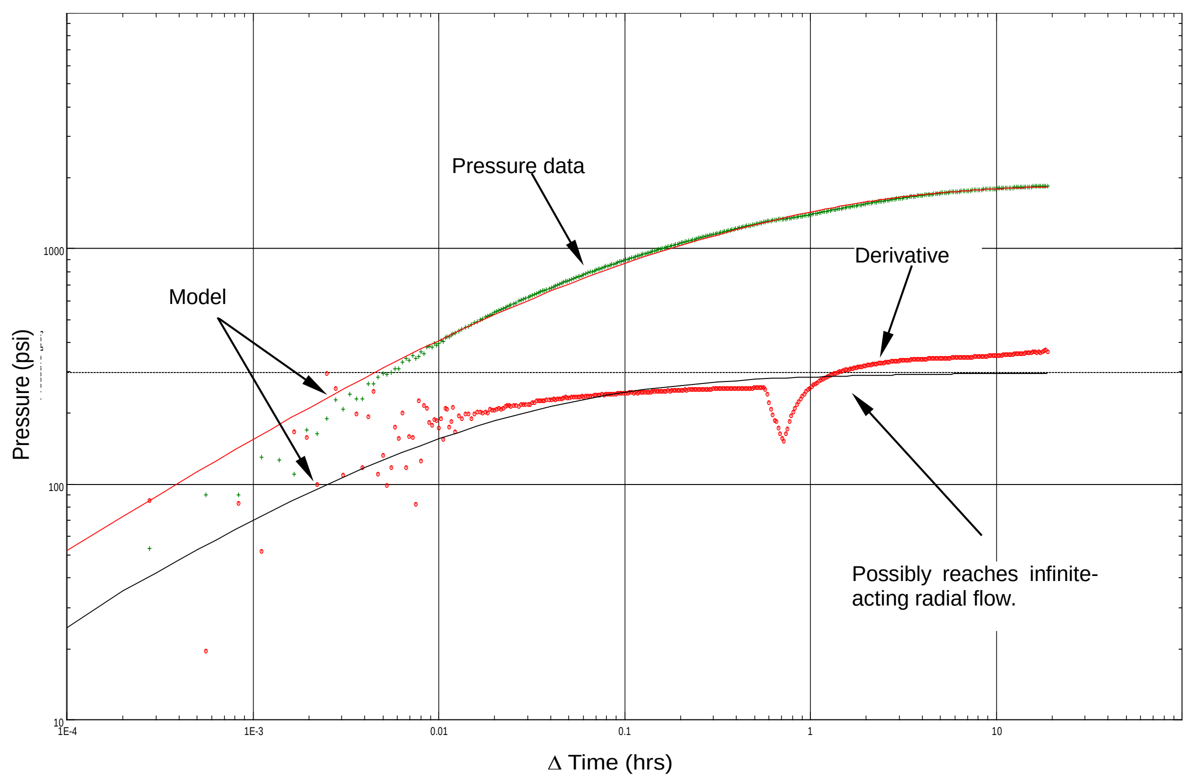

Figure 4: Diagnostic log-log plot.

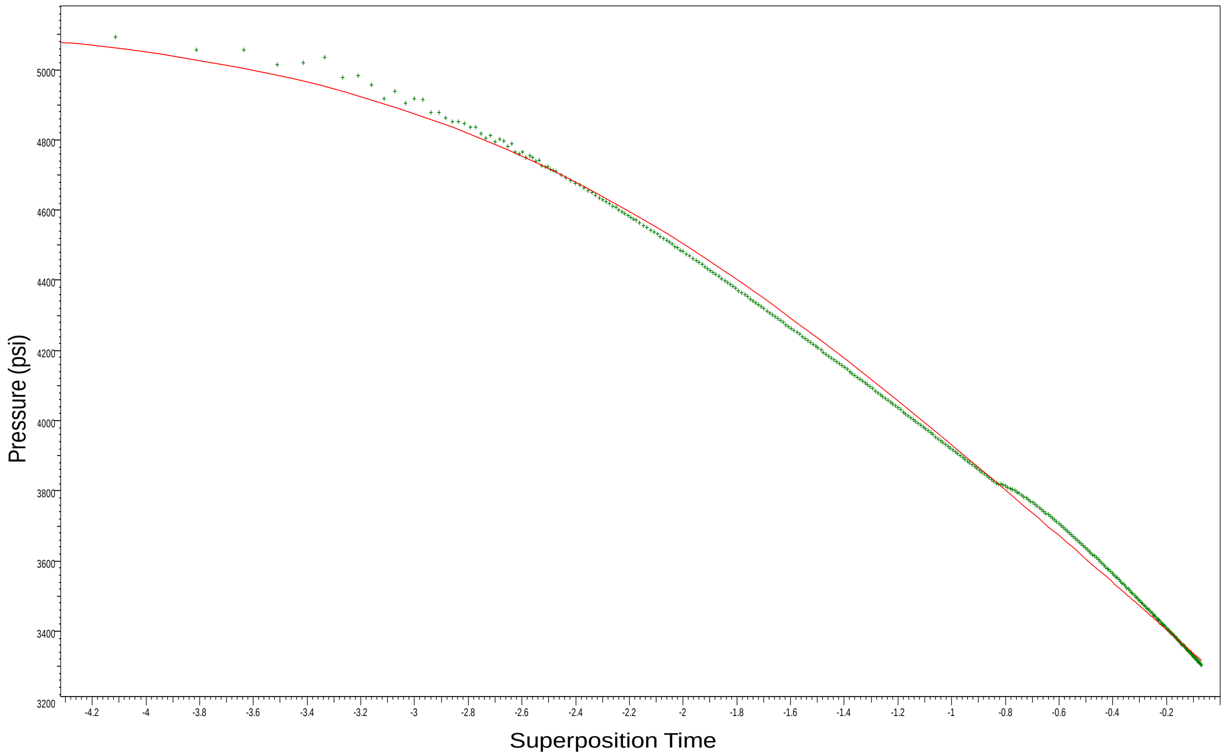

Figure 5: Superposition plot.

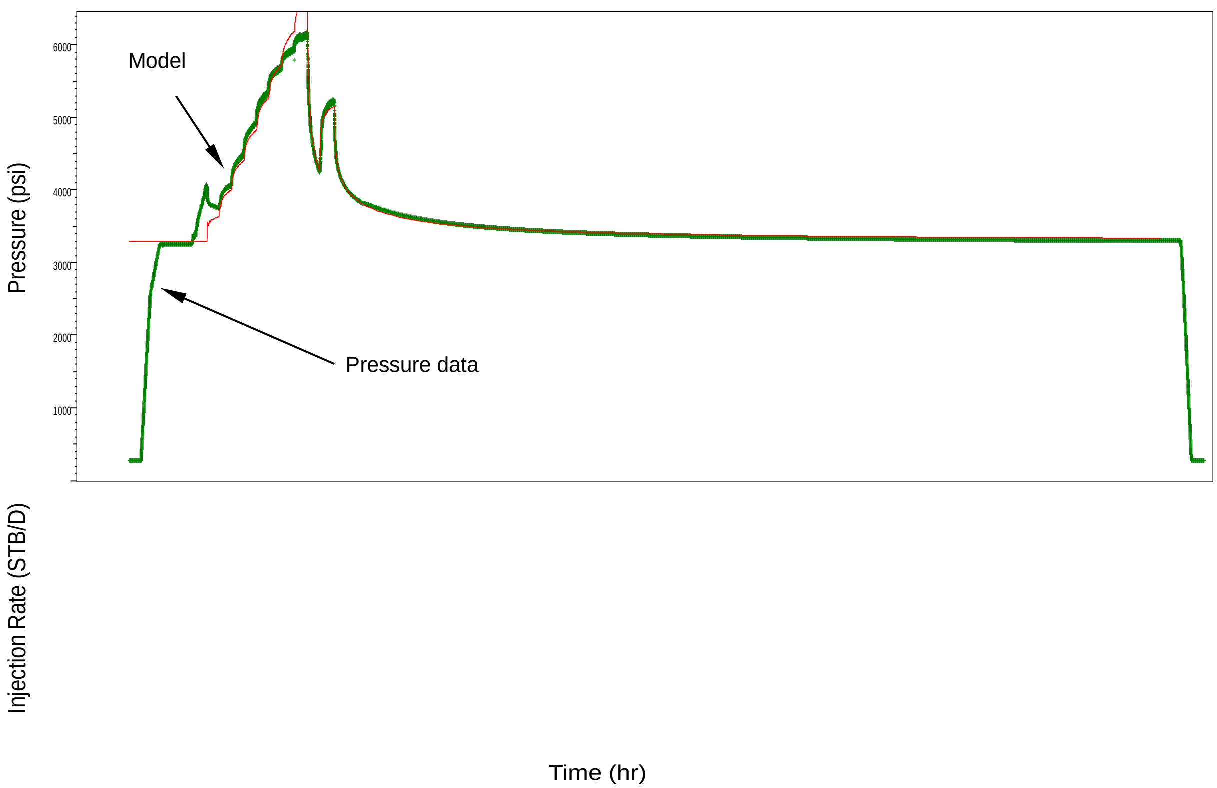

Figure 6: Model match of pressure history.