THE APPLICATION OF PRESSURE HISTORY MATCHING, RADIOACTIVE TRACERS AND TEMPERATURE LOGS TO ANALYZE HYDRAULIC FRACTURE TREATMENTS IN THE QUEEN SAND FORMATION, SOUTHEASTERN NEW MEXICO

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ABSTRACT

The Queen Sand of southeastern New Mexico is characterized as a sequence of laminated sandstones and shale, bounded by anhydrite seals. Good permeability is evident but still the Queen requires fracture stimulation to be successful. The case presented in this study is an injection well from Chaves County in southeastern New Mexico. For this stimulation study, surface treating pressure data from a fracture treatment was history-matched with a pseudo 3D fracture simulator. Fracture characteristics such as height and fluid distributions from the pressure match were compared with that from the radioactive and temperature tracers to analyze the fracture treatment in this formation. An additional complication is the existence of a compressible, friable sand bed, resulting in difficulties in hydraulic fracture effectiveness. Two fracture designs are compared: a vertical fracture with high proppant concentration in a restricted interval, and a horizontal fracture due to the shallow depth and high frac gradient.

INTRODUCTION

The Queen Sand formation located in southeastern New Mexico is a mature reservoir in which several successful water flood projects have been conducted in different fields in the past. This study is centered on the Round Tank Oueen field which was established in 1970. Six development wells have produced from the gas cap while three wells have produced from the narrow oil column. To date, the nine wells have produced approximately 26,000 barrels of oil, 4.2 BCF of gas and 788 barrels of water. The initial reservoir pressure was 600 psi, but after a long period of production, reservoir pressure has dropped to approximately 50 psi and the reservoir temperature to 75°F (Wilson, 2010). Also there is very low gas in solution, high nitrogen content in the gas and high oil viscosity. All these reservoir and fluid traits adds to the complexity of successfully water flooding the round tank queen because they lead to unfavorable mobility ratio (Engler, 2009).

The reservoir rock has a thickness of about 16ft and is divided into 3 pay zones, the upper, the middle and the lower Queen formations. The Upper Queen has a thickness of about 5ft and a corresponding porosity of about 16%, the middle queen is about 4 ft thick and has a porosity value of 18.5%. The lower Queen has the best reservoir quality and it is more porous, permeable and compressible than the top two layers, it has a porosity of 22.5% and it is 7 ft thick. The round tank field has a gas cap a thin oil column and water as shown in fig 2.

To successfully develop the round tank field, waterflooding was proposed. From figure 2, one can observe that the reservoir is quite tilited in cross-section from the up-dip GOC to the down-dip OWC, therefore the injection well is located at the down-dip edge of the oil column in the water leg of the reservoir so as to maximize reservoir sweep and move oil up-dip to the producing wells. The producing well was drilled along the up-dip edge of the oil column at the gas/oil contact. Normally hydraulic fracturing is employed to improve productivity of a well but in this case, the injection well was hydraulically fractured so as to improve the ease of water injectivity. The stimulation of this injection well is the focus of this study.

INJECTION WELL

A cased hole gamma-ray neutron log of the injection well is shown in figure 3.

The well has a casing depth of about 4000ft, OD of 5.5 in, ID of 4.95in. The thickness of the pay zone is 16ft (1582-1598ft). The well was drilled along the down-dip edge of the oil column in the water leg of the reservoir, thus the in-situ fluid in the near wellbore vicinity is water.

From figure 3, the gamma ray log on the left shows an alternating sequence of shale and sandstones, indicated by the high gamma ray count and low gamma ray counts respectively.

TREATMENT DATA

The treatment was performed using an optimized borate cross linked gel with high viscosity and low gel concentrations (Halliburton frac fluids, 2007). It consisted of approximately 30,000 gallons of fluid, 45,000 lbm of Brady sand (premium brown sand 12/20) and some additives. The slurry was pumped at an average rate of 29.8 bpm. During the initial stage of the pad, crosslink was lost and the job was shut down for about 2 minutes and then resumed after the problem was solved. This is illustrated with a circle in figure 4.

From figure 4, the circle area of the treating pressure shows the slurry rate dropping to zero at a time of about 09:56am and it rises back up two minutes later, when the pumping resumed.

The well was stimulated by hydraulic fracturing through the casing at perforation depths of 1582 – 1598 ft. The perforations had 20 holes (approximately 1 spf) with 0.42 inches in diameter. The casing depth was 4,000 ft with OD of 5.5 inches and ID of 4.95 inches.

For this study, limited data was available, therefore to effectively simulate the fracture, the porosity and gamma ray logs were analyzed and correlations were made for the permeability. Other data such as compressibility, fluid loss, poisson's ratio and stresses were imputed into the simulator and adjusted as necessary to obtain a pressure match.

METHODOLOGY:

One major challenge of this study was determining the fracture geometry. The reservoir is located at a considerably shallow depth of 1,582ft; at this depth the initiated fracture may be vertical or horizontal. API guidelines suggest horizontal fractures occur mostly at shallow depths below 2,000 ft (API, 2009).

Fracture geometry is mostly determined by the existing in-situ subsurface stresses in the formation. During hydraulic fracturing, the initiated fracture is oriented in a direction perpendicular to the least principal stress. In deep reservoirs (as high as 4,000ft deep), the overburden stress (principal vertical stress) is usually very high and is most certainly higher than the horizontal stress (in most cases 3 times higher), but in shallow reservoirs (lower than 2,000ft deep), the overburden is considerably low and may be lower than the horizontal stress. Thus for a shallow reservoir the least principal stress may be the overburden and if this is the case, the geometry of the initiated fracture will be horizontal.

Also in favor of the horizontal fracture theory is the high fracture gradient of 1.06 psi/ft (This means that it is easier to lift the rock than to split it). This fracture gradient is greater than the overburden of 1 psi/ft, which is considerably abnormal. For vertical fractures, fracture gradients are mostly less than 1 psi/ft. In direct relation to this is also the surface treating pressures, at a reservoir depth of 1582 ft, the treating pressures were in the region of 1600 to 1800 psi. This is extremely high for a vertical fracture, which suggests that the fracture could have been horizontal. The lamination of the reservoir rock also increases the chances of a horizontal fracture.

To successfully analyze and characterize the fracture geometry, two designs (vertical and horizontal) were pressure matched with a pseudo 3D fracture simulator (Mfrac) and the results were compared with the analysis from the tracer surveys.

RADIOACTIVE TRACER

Gamma ray logs run before and after the injection of radioactive-tagged fluid or proppant can be compared to define intervals that actually received the radioactive material. When a radioactive fluid is used, it indicates the created fracture height, but when a radioactive proppant is used it indicates the propped fracture height and it is generally regarded as smaller than the created fracture height.

The use of radioactive-tagged fluid can be influenced by the relative permeability, pore pressure and fluid loss of the various zones that exist within the formation. This is due to the potential leak off of the fluid into the formation, which is a major disadvantage of using the radioactive-tagged fluid (Economides and Nolte, 1987). This problem does not occur when using the radioactive-tagged proppant. However, the use of the radioactive-tagged proppant also has a disadvantage in that the proppant may become embedded within the formation, if the formation is very soft or loosely consolidated. This is the case with the Queen formation as the sand bed is compressible and friable. However, this problem is less paramount when compared to that of the radioactive-tagged fluid (leak off). Thus in most cases, the operators prefer using the radioactive-tagged proppant, as is the case in this study.

When using the radioactive-tagged proppant, radioactive isotopes are usually mixed with the proppant and injected into the formation as part of the treatment slurry. After shut-in, a gamma ray is run to identify the intervals where the majority of the radioactive isotopes (proppant) are lodged, thereby tracking the proppant distribution within the fracture. This helps in determining the fracture height, geometry and proppant distribution within the fracture. Also, a pre-frac gamma ray log could also be run before treatment. This base gamma ray can then be compared to the post-frac tracer to determine the fracture geometry.

The gamma ray logging tool has a small investigative radius of about 4ft, thus it cannot probe deep into the formation, and therefore the radioactive tracer is only valid for near wellbore fracture analysis. It is usually difficult to distinguish between the radioactive material ((either proppant or fluid-tagged) within the wellbore from that within the fracture, therefore it is necessary to clean the wellbore after fracture treatment, but before running the post-frac gamma ray log so as not to distort the interpretation of radioactivity in the wellbore with that of the created fracture (Economides and Nolte, 1987). Also, multiple isotopes could be used in the different stages of treatment to make the interpretation easier.

From Fig 5, one can observe that on the far left, the base gamma ray (pre-frac) is shown, while the gamma ray (post-frac) is shown and the accompanying collar log is shown to indicate the pipe joints.

The gamma ray is observed to be fairly constant over the formation, except for a spike in the lower part of the perforations (i.e the lower Queen at about 1592 ft). This huge spike suggests that most of the radioactive proppant entered this interval; hence a propped fracture was created. This interval (1593-1594) is about 1ft and it represents the fracture height, this height is extremely small therefore the fracture is not vertical; it is horizontal within the near wellbore vicinity (4 ft from the well). This could change as the fracture propagates depending on the in-situ stress profile of the formation. If the fracture were to be vertical (near the wellbore), then it would have a highly disproportionate distribution of proppant as most of the proppant would be between 1592 ft and 1594 ft. The other intervals within the fracture would have negligible proppant or no propped width at all. Obviously, this is not the case as the fracture is most likely horizontal.

The high concentration of proppant (as indicated by the spike in the gamma ray of the radioactive tracer survey) within the lower queen is due to the loosely consolidated, highly porous and permeable friable sand bed within the lower queen. This friable sand bed would accept a significant fraction of the frac fluid (this is also indicated by the high leak-off in the velocity survey) due to the high permeability, thus leading to a high concentration of proppant within the lower queen.

TEMPERATURE SURVEY

Temperature logs that are run before and after a stimulation treatment can be compared to determine an interval that takes fluids and in which a fracture is initiated. The interpretation of these logs depend mostly on the detection of a cool anomaly in the post-treatment log. The fracture height determined from the temperature survey is reflective of the height that took the frac fluid, hence it determines the fracture height and not the propped height.

During the fracture treatment the Queen reservoir cools because the temperature of the fluid pumped is lower than the reservoir temperature, thereby altering the geothermal gradient. The cooling is caused by convection in the areas that actually come in contact with the fluid, and it is caused by conduction (within the reservoir) in areas that did not have any contact with the frac fluid. However once the well is shut-in (after the end of pumping) the reservoir temperature gradually heats back up (by means of conduction and convection) to its original geothermal state.

The fracture initiated in the reservoir converts the fluid flow (from the reservoir to the wellbore) from radial regime to linear regime. Heat transfer in a radial flow is faster than heat transfer in linear flow regime. Therefore after shut-in (end of pumping) the fractured interval will heat back up to the geothermal state in a manner that is slower than in the formation. Thus the post-frac shut-in temperature logs (after 1 and 2 hrs) would indicate a lag in temperature (significantly lower temperature) in the fractured interval, while the areas outside the fractured interval would show a normal temperature increasing towards the geothermal gradient. This lag in temperature is the “cool anomaly”.

The target zone is between 1582 -1598 ft, yet one can observe (from fig 5) that the temperature plot is indicating a drop in temperatures in depths as shallow as 1520 ft. The frac fluid did not reach this depth so the cooling is probably caused by heat convection while pumping. As we pump down the well, the frac fluid (coming at a lower temperature) cools the casing and the casing in-turn cools the cement (by heat conduction) which transfers the cooling effect to the adjoining formation, thus decreasing the temperature of the formation around the wellbore. Also heat conduction within the different strata in the formation could also lead to a temperature drop in regions that are not reached by the frac fluid.

From Fig 5, one can observe that there is a temperature anomaly shortly above the fractured interval (i.e perforations). This anomaly is not very distinct, but is within an interval of about 8ft. This interval is small for a vertical fracture; hence the fracture is considered horizontal.

Comparing the height predicted by the temperature survey to that predicted by the radioactive tracer, one would observe that the height predicted by the temperature survey (8ft) is more than that of the radioactive tracer (2ft) by about 6 ft difference. This is probably due to the fact that the radioactive survey only gives the "propped" height of the fracture and the temperature survey also tends to over-predict the fracture height. This temperature survey does not distinctly identify the fracture as is explained by its limitations.

LIMITATIONS OF TEMPERATURE SURVEY

This temperature survey was affected by the differences in the thermal conductivities of the rocks (Shale, clay, anhydrite) and differences in cement thickness at various depths within the formation. Dobkins (1981) suggested a method of reducing the thermal conductivity effects. He suggested circulating fluids through the wellbore at below-formation breakdown pressures or before perforating at rates similar to those of the fracture treatment and then running a pre-frac temperature survey. The pre-frac temperature survey would be affected by the thermal conductivities in a similar manner as the post-frac temperature survey, thus the differences would be the result of the treatment.

Sometimes the post-frac temperature log cannot be run immediately until all the sand is cleaned out of the wellbore. By this time it may be too late to observe the anomalies as the formation could have heated back to the geothermal state (Economides and Nolte, 1987).

Flowback of fluid from the formation before and after the job could also jeopardize the interpretation of the temperature log because this would induce cooling effects which would affect the temperature readings of the log. These limitations significantly affect the intergrity of the temperature log and hence it is inconclusive at best, because we cannot make a valid conclusion on the fracture height based from the temperature log. Therefore we rely mostly on the radioactive tracer and the pressure history matching to determine the fracture geometry.

VELOCITY SURVEY

The velocity tracer indicates massive fluid loss (66.9%) at the lower portion of the target zone (figure 5); this portion has the best reservoir quality. This result is consistent with the results from the radioactive tracer which also indicates a high proppant concentration at the lower portion of the zone. The lower portion of the target zone is the lower queen and the horizontal fracture as indicated by the high proppant concentration, was located at this zone due to the presence of the highly porous, permeable and loosely consolidated friable sand within the zone.

PRESSURE HISTORY MATCH

The surface treating pressures were matched for two fracture scenarios; the first case assumes that the fracture is vertical, while the second case assumes that the fracture is horizontal. The results of these models are then compared with that of the tracer surveys and the net fracture pressure plot. The simulator used for this study is M-frac, which is a pseudo 3D fracture simulator that is completely integrated in a suite of Windows software for fracture design, real-time data acquisition and mini-frac analysis (Raymond et al, 1996).

CASE 1, VERTICAL FRACTURE

From the analysis of the radioactive tracer, it was proposed that the fracture was horizontal due to the high proppant concentration at 1592 ft, but what if the fracture initiated was vertical? This thought lead to the investigation of the assumption that the fracture is probably vertical but has very high proppant concentration in a certain interval and has very low concentrations in the other intervals due to possible proppant embedment and fluid leakoff.

The vertical fracture design was pressure matched with the fracture simulator. The stresses, and the fluid leak-off, were the main parameters that were adjusted to obtain a pressure match. Twenty three layers of rock mechanical properties and fluid loss data were imputed into the simulator to accommodate the extent of the net interval requiring simulation and the reservoir seals. The fracture initiated had created and propped lengths of 374 ft and 302 ft respectively. It had an average height of 179 ft and a fracture efficiency of 44 %. It had a maximum width of 0.29 inches, propped width of 0.11 inches, dimensionless fracture conductivity of 2.05 and a fracture conductivity of 6096.3 mD-ft. The fracture permeability had an average value of 885.93 D.

From figure 6, the conductivity of the fracture is observed to vary from 0 mD-ft at the tip to 9000 mD-ft at the perforations. The pay zone (1582-1598) ft has the maximum conductivity within the fracture. The fracture also has an average height of 179 ft; therefore for a pay zone of 16ft, this height is excessive. Thus if the fracture was vertical, the treatment would suffer uncontrolled height growth into untargeted zones.

Proppant concentration within the fracture varied from 0 lbm/ft^2, at the tip of the fracture to about 0.9 lbm/ft^2, at the perforations. This proppant concentration is considerably small and is due to the small incremental amount of proppant used in the treatment stages (1 to 6ppg).

Actual and predicted treating pressures from the vertical fracture model are shown in figure 7. The model predicted pressures were within 100 psi of the observed data for most portions of the treatment. However, some dissimilarity between the model-predicted pressure and the observed treatment pressure occurred during the early time (about the first 5 minutes of treatment), this was due to a number of issues such as the difficulty in modeling the fraction of well that is filled with the frac fluid. Raymond et al, 1996 suggested that this problem could be due to the inability of the model to accurately handle more than one fluid at the beginning (well/ pad fluid ahead of treatment slurry). He also suggested that it could be due to near-wellbore stress effects.

Also the history match was affected by the untimely shut-in at about 09:56am (fig 7), for 2 minutes after crosslink was lost. This resulted in pressure dissimilarity as the model predicted pressures for treatment during this untimely shut-in period.

Apart from the early treatment stage and the untimely shut-in period the model predicted pressures were within 100 psi of the observed data for the fracture treatment

CASE 2, HORIZONTAL FRACTURE

The theory behind this model is that the fracture is horizontal. The fracture has a length of 376 ft, a breadth of 94 ft and a height (width) of 0.35 inch or 0.03 ft. It had a propped fracture length of 376 ft, thus almost the whole length of the fracture was propped. The fracture had a dimensionless fracture conductivity of 1.851, a fracture conductivity of 6847.4 mD-ft. The ellipsoidal aspect ratio (ratio of major to minor axes) of the fracture is 8. The fracture efficiency is 25%.

From figure 8, it is observed that the conductivity of the horizontal model varies from 4000 mD-ft at the tip of the fracture to 8000 mD-ft at the perforations, however there is an increase in conductivity at an area close to the tip of the fracture at about 10000mD-ft. Figure 9 further illustrates the quite irregular conductivity profile of the horizontal fracture. At 330 ft the conductivity increases sharply thereby distorting thr normal trend of gradual increase from the tip of the fracture to the perforations. This could be due to high permeability or leakoff to the formation at that point within the fracture.

Proppant concentration is very low. It ranges from 0 to 1.4 pounds per square foot, this low proppant concentration is due to the low proppant density used in the treatment stages.

A treating pressure match (figure 10) was obtained for the horizontal model. To obtain a pressure match for the horizontal model the insitu-subsurface stresses for the layers had to be increased above that of the vertical model to a value close to the overburden (0.9-1 psi/ft). Also the ellipsoidal aspect ratio (ratio between the length of the major and minor ellipse axes) was increased to 8 to achieve a good pressure match. The significance of this ratio is that if it is 1, then the fracture would be a standard radial or penny shaped geometry (Meyer user's guide).

As was the case with the vertical model, the pressure match had some dissimilarity between the model-predicted pressure and the observed treatment pressure occurred during the early time of treatment and the reasons are the same as those of the vertical model (see case 1, above).

Apart from the early treatment stage and the untimely shut-in period the model predicted pressures were within 100 psi of the observed data for the fracture treatment, thus achieving a good match.

COMPARISON OF VERTICAL AND HORIZONTAL MODELS WITH TRACER SURVEY

As was indicated earlier on, for this study, the radioactive tracer is more reliable than the temperature survey because it has fewer limitations, therefore only the gamma ray results were compared with the vertical and horizontal models.

The fracture height from the radioactive tracer (Figure 5) is about 1 ft, while the height from the vertical model results was excessive at 179 ft and that of the horizontal model was about 0.03 ft. From these results, it can be concluded that the fracture is horizontal in an area within 4 to 5 ft away from the well bore. Therefore the horizontal model is adopted as the fracture geometry. But it is unknown if at greater lengths into the formation, the fracture changes to a vertical geometry or it simply continues as a horizontal fracture.

Also the horizontal model is adopted because the rock stresses were closer to the fracture gradient (1.06 psi/ft) than those of the vertical model. Stress gradients are always close to the fracture gradients, because the fracture is initiated at the point at which the fracturing pressure exceeds the rock stress.

Generally, horizontal fractures in a vertical well (pan cake fractures) are not as efficient as vertical fractures on a vertical well. In this study, the horizontal fracture efficiency was 25%, while the vertical fracture efficiency was about 44%. Since the injectivity of the reservoir was not improved (operator reported several problems such as sharp pressure increase during waterflooding) after the well was fractured, it is safe to say that the fracture treatment was not successful, therefore it is likely that the fracture remained horizontal throughout the reservoir, rather than change geometry to a vertical fracture with higher fracture efficiency and a higher chance of success. The success of any fracture treatment depends to a great extent on the fracture-well intersection.

From the radioactive tracer (Figure 5), the horizontal fracture is located at a depth of 1592 ft. This depth is the lower part of the pay zone, which has the highly porous, highly permeable friable sand bed. Thus the horizontal fracture is believed to be located within this friable sand zone.

FRACTURING PRESSURE ANALYSIS

Observe in figure 11, the net pressure plot can be interpreted as approximately constant (zero slope), neglecting the slight changes (in the slope) as stochastic variations within the formation. This means the treatment was dominated by large increases in fluid loss and unstable growth (Nolte and Smith, 1981). This is a reasonable interpretation, because the reservoir rock had high permeability, high porosity and was loosely consolidated. The high fluid loss can also be attributed to the highly porous friable sand zone within the formation. The constant plateau pressure behavior is indicative of creating a horizontal fracture.

CONCLUSION

Evidence supports the creation of a horizontal hydraulic fracture in the Queen formation

- Analysis of the tracer survey confirmed a fracture height of only one foot within this 16 foot sand.
- Analysis of Nolte-Smith net pressure plot exhibited a constant pressure plateau indicating that the fracture treatment was dominated by regions of high fluid loss (due to high permeability, loose consolidation) and unstable growth; both present in horizontal fractures.
- Using a pseudo-3D fracture simulator, a comparison was made between a vertical and a horizontal hydraulic fracture model. The horizontal model provided a better match to field data.

The treatment failed mostly because the created fracture was horizontal intersecting a vertical well (Pan Cake fractures), with a very small width and propped width.

The temperature survey was inconclusive due to the difficulty in identifying the “cool anomaly”, which was as a result of the differences in the thermal conductivities of the rocks and the time lag between the frac job and the running of the tracer survey (4 days).

RECOMMENDATIONS

- The radioactive tracer used only a single isotope; the use of multiple isotopes could result in a better interpretation of the tracer survey.
- The temperature survey should be taken immediately after the frac job as soon as the sand in the wellbore was removed. This way the temperature survey would have been more credible.
- The proppant density (pounds per gallon) utilized in the treatment should be increased so as to increase the proppant concentration within the fracture.

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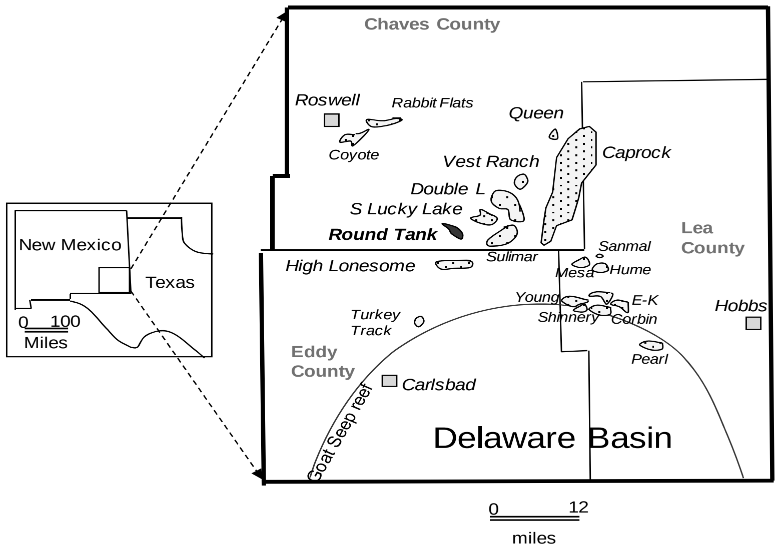

Figure 1 - Map of the queen sands fields with the round tank field indicated in red (Engler, 2009).

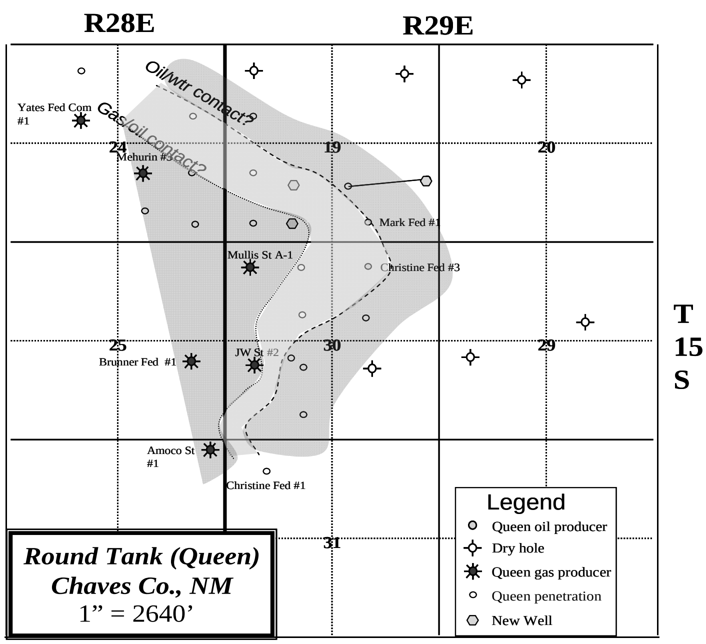

Figure 2 - Map of the round tank queen illustrating the an up-dip gas-oil contact (GOC) and a down-dip oil water contact (OWC). The thin oil column is shown in green. (Engler, 2009)

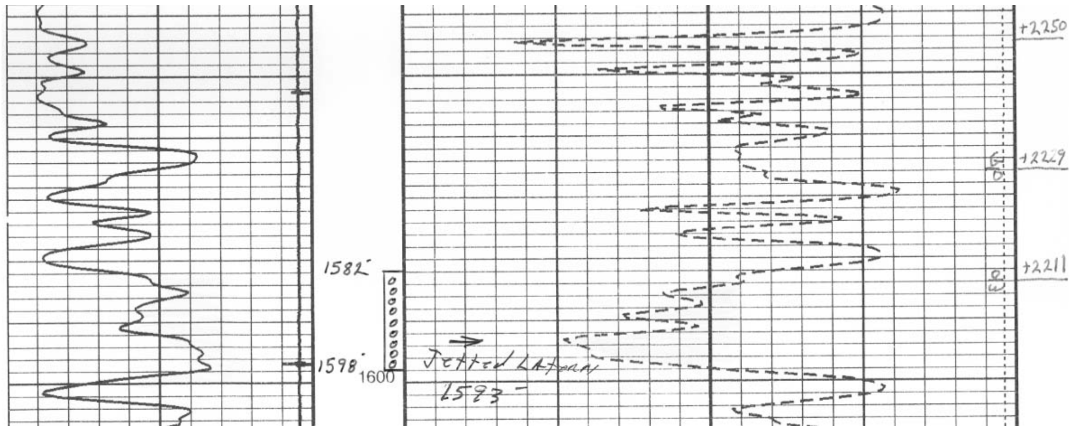

Figure 3 - Gamma-ray neutron log of the Injection well

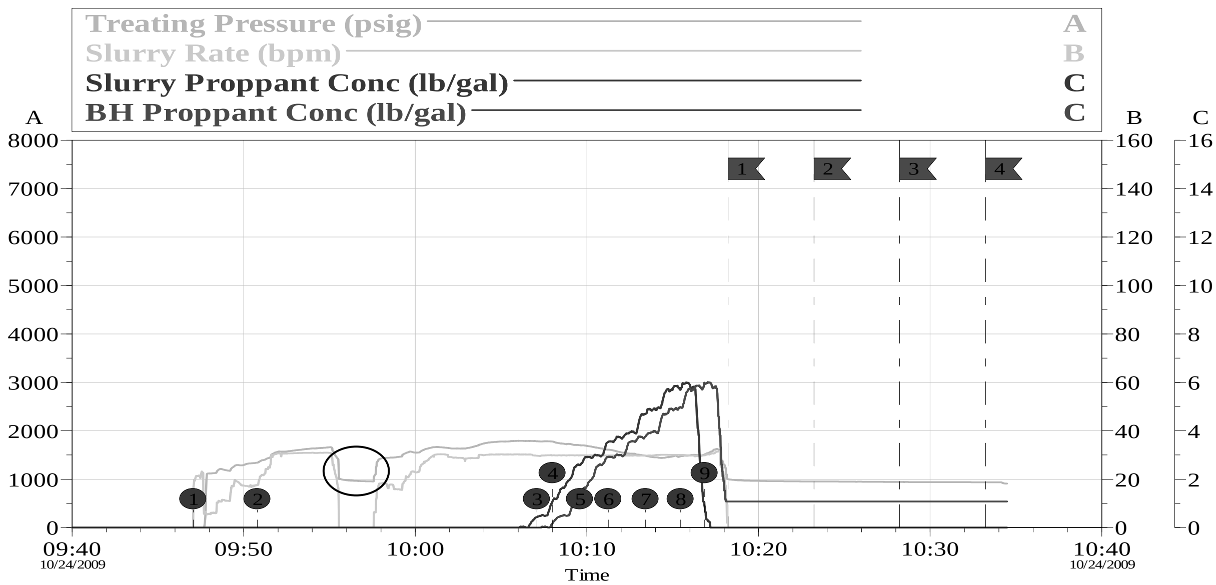

Figure 4 - Frac job treatment volume summary

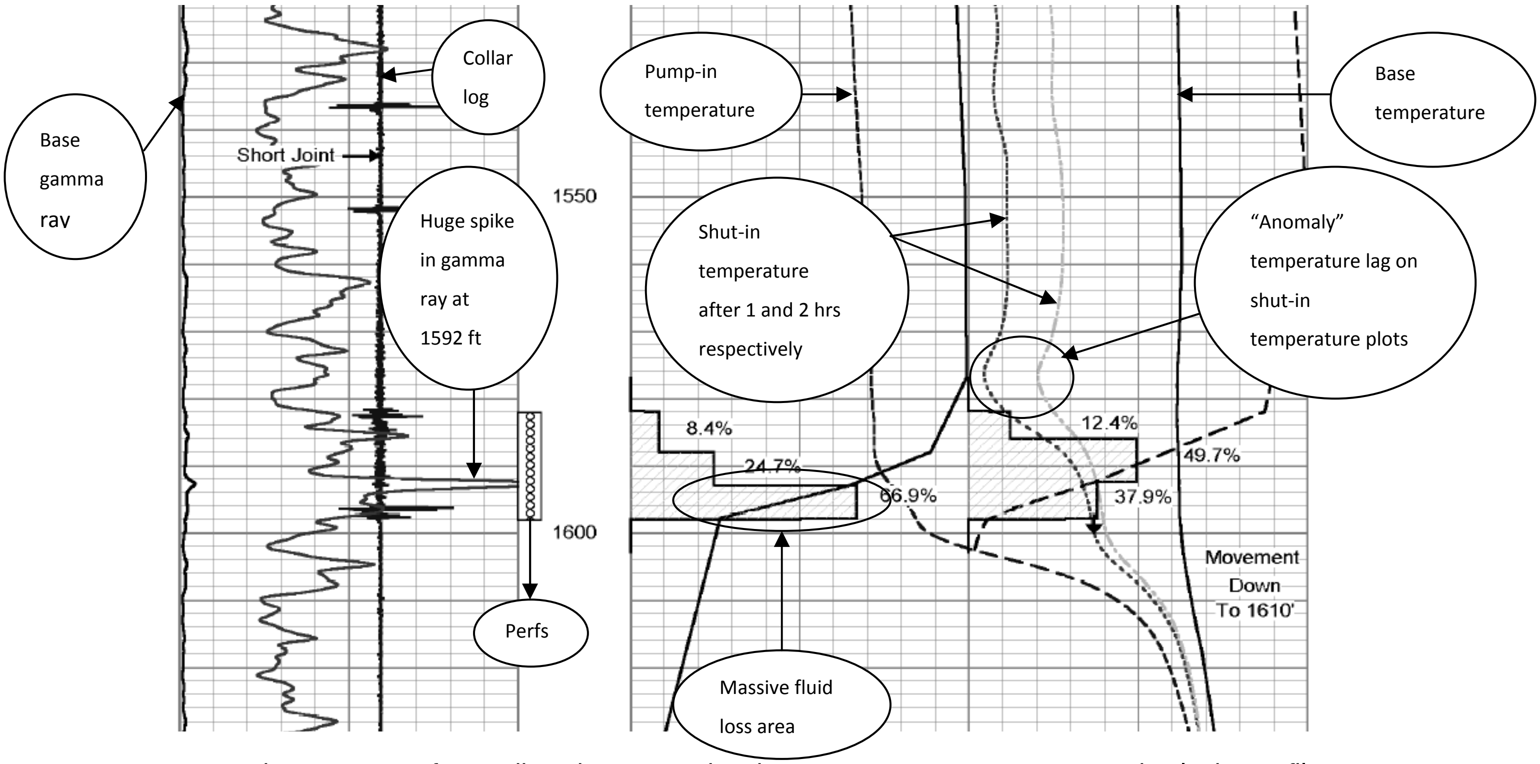

Figure 5 - Post-frac radioactive tracer showing gamma-ray, temperature and velocity profiles.

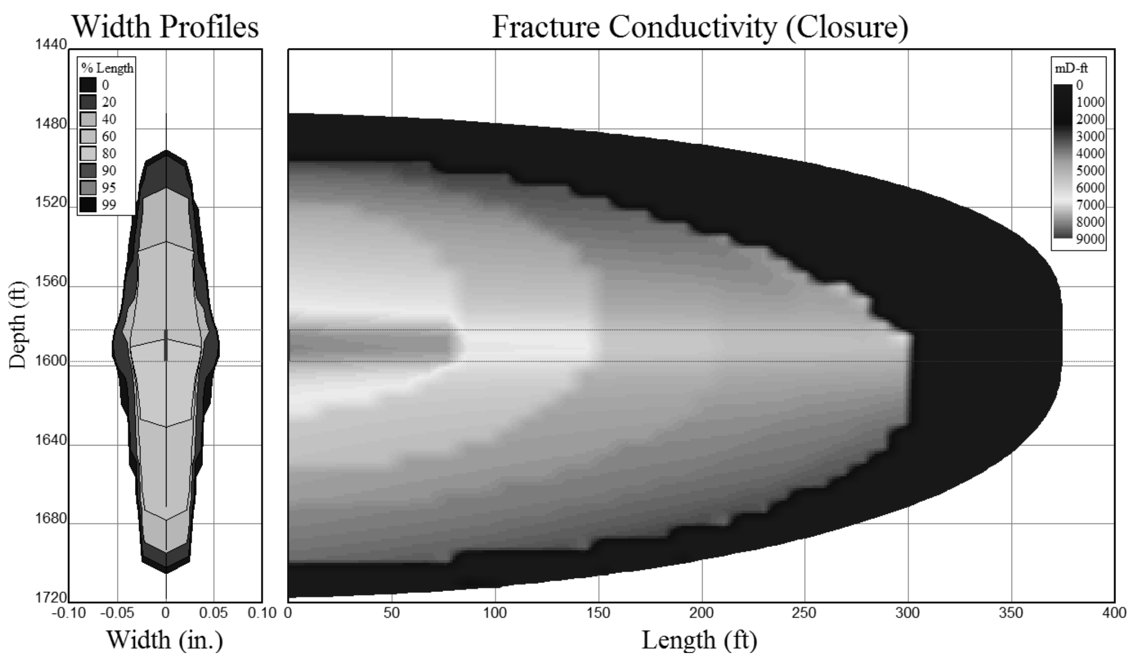

Figure 6 - Vertical fracture profile showing the conductivity across the length of fracture

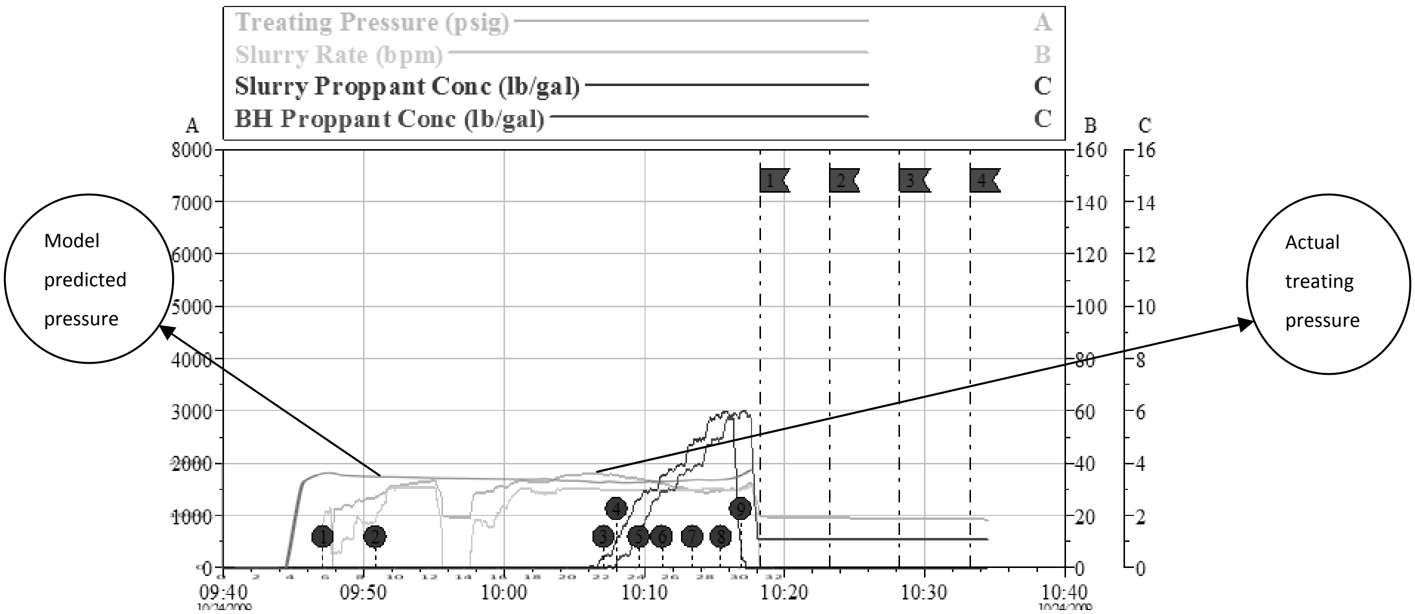

Figure 7 - Comparison of actual treating pressure and model predicted pressure for the vertical fracture model.

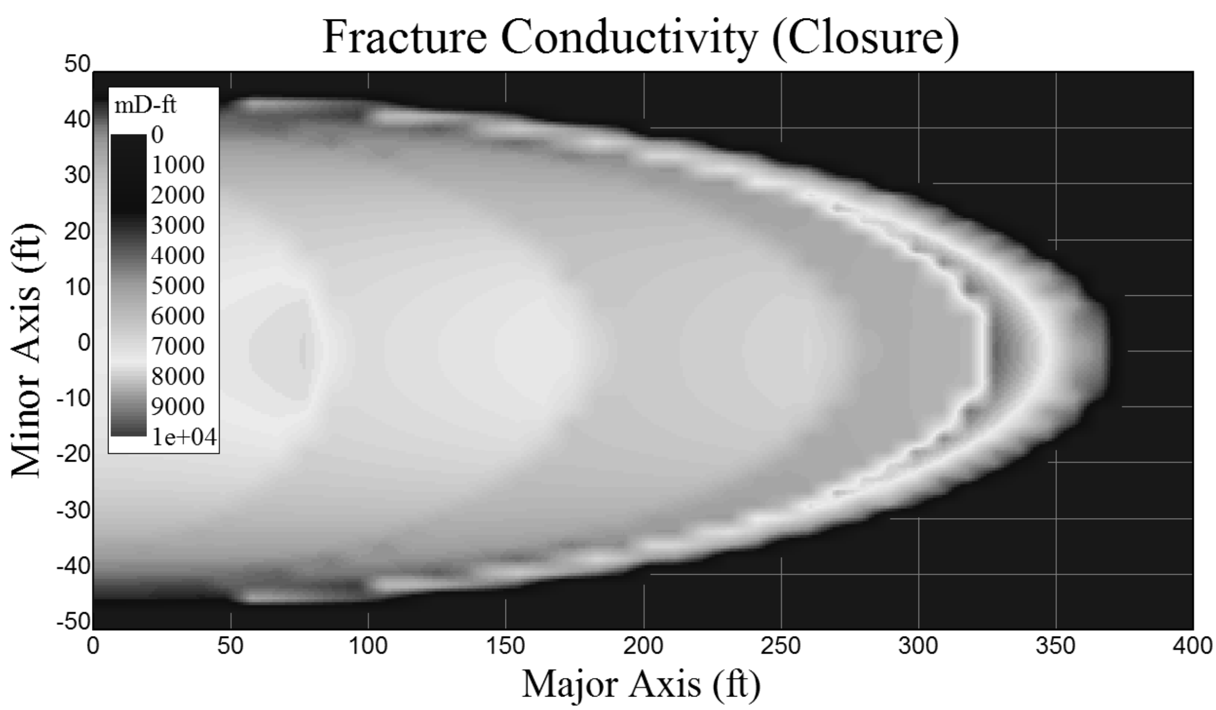

Figure 8 - Horizontal fracture conductivity profile

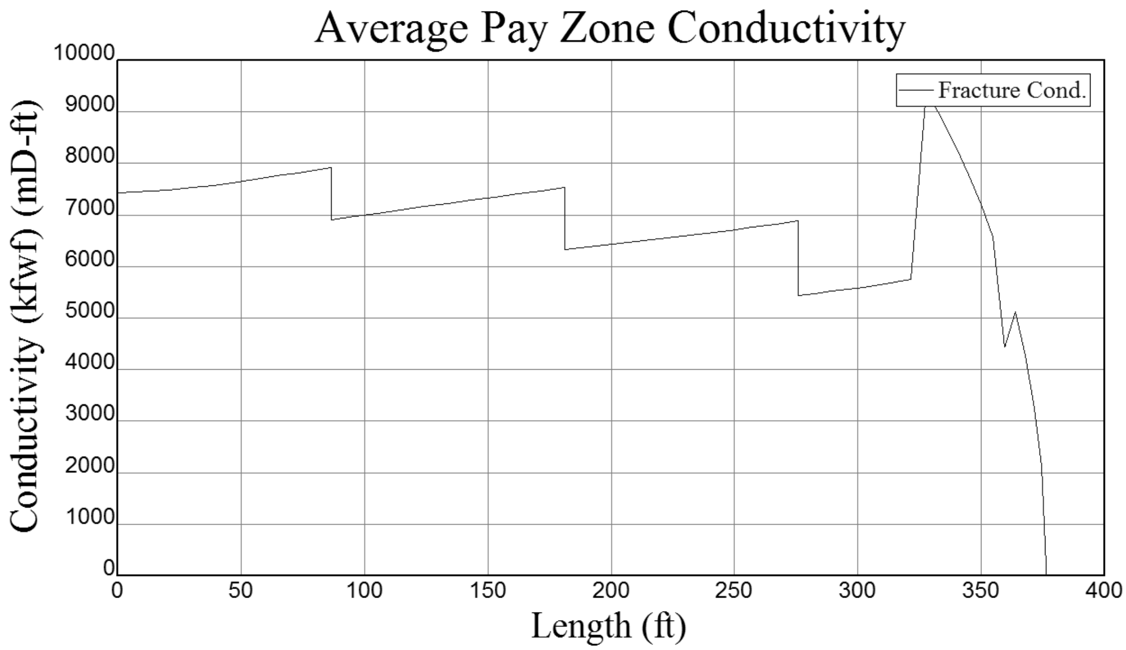

Figure 9 - Horizontal fracture average pay zone conductivity profile

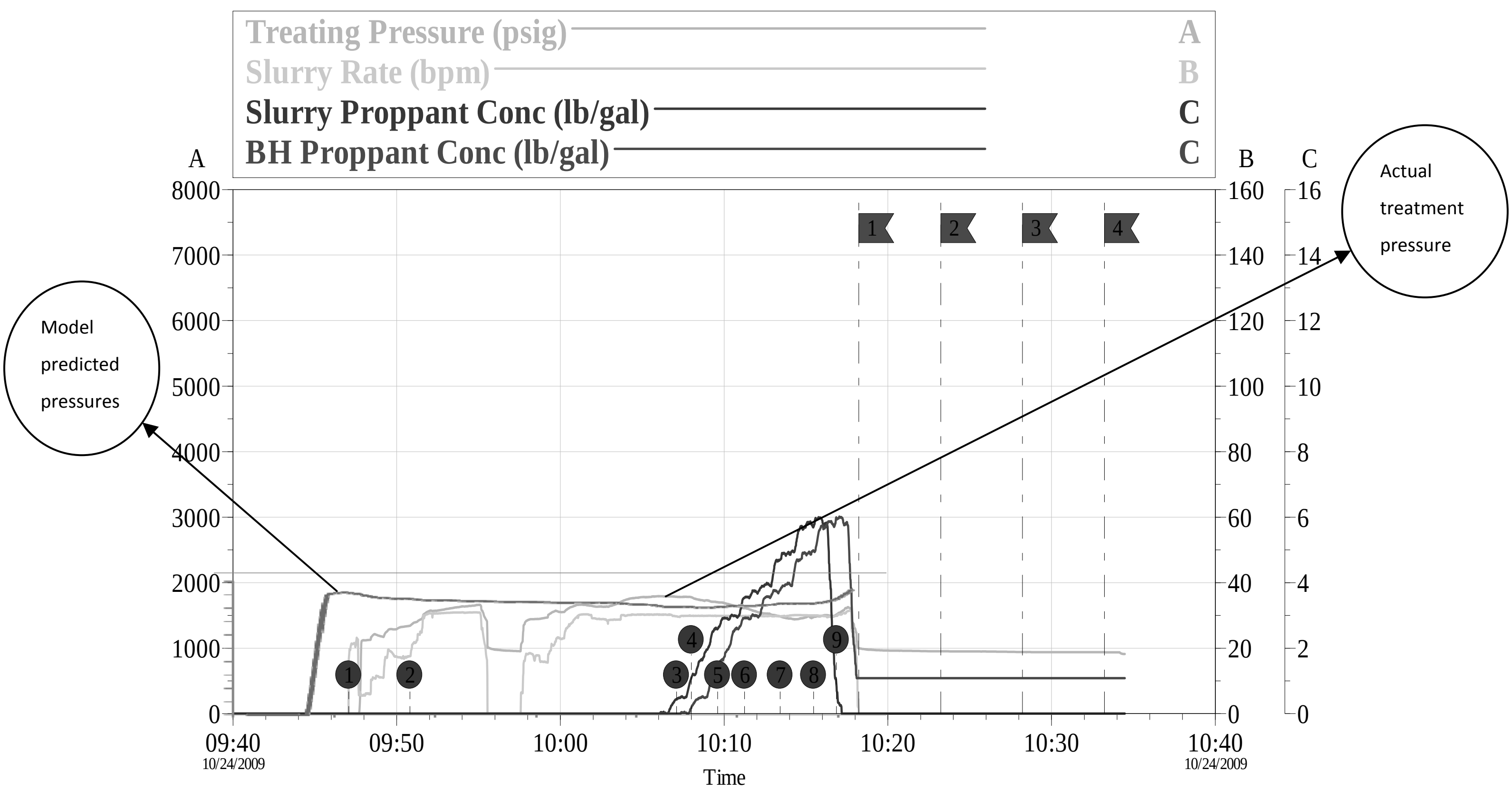

Figure 10 - Comparison of actual treating pressure and model predicted pressure
for the horizontal fracture model.

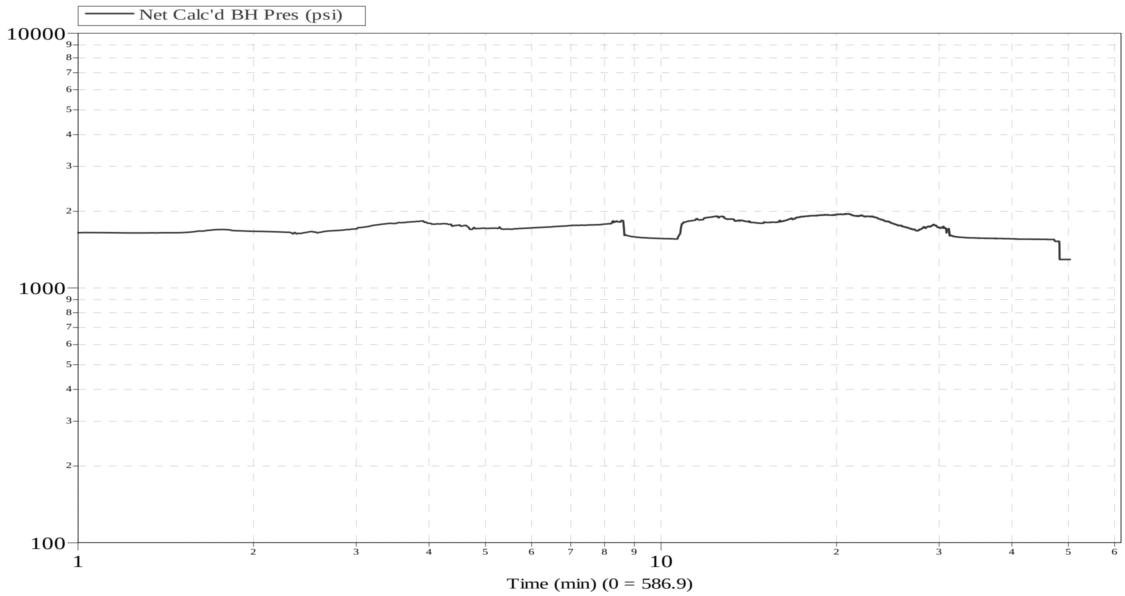

Figure 11 - Net pressure plot (Log Pressure vs Log Time)