Pump III Program

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"Development Practices for Optimized MEOR in Shallow Heavy Oil Reservoirs"

Final Technical Report

Submitted by

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Abstract

The objective of this research project is to demonstrate an economically viable and sustainable method of producing shallow heavy oil reserves in western Missouri and southeastern Kansas, using an integrated approach including surface geochemical surveys, conventional MEOR treatments, horizontal fracturing in vertical wells, electrical resistivity tomography (ERT), and reservoir simulation to optimize the recovery process. The objective also includes transferring the knowledge gained from the project to other local landowners, to demonstrate how they may identify and develop their own heavy oil resources with little capital investment.

The first year period included soil sampling, geochemical analysis, construction of ERT arrays, collection of background ERT surveys, and analysis of core samples to develop a geomechanical model for designing the hydraulic fracturing treatment. Five wells were drilled to the second phase of the project.

During the second year of this project, three wells were equipped with ERT arrays. Electrical resistivity tomography (ERT) background measurements were taken in the three ERT equipped wells. Pumping equipment was installed on the two fracture stimulated wells and pumping tests were conducted following the hydraulic fracture treatments. All wells were treated monthly with microbes, by adding a commercially available microbial mixture to wellbore fluids. ERT surveys were taken on a monthly basis, following microbial treatments. Pumping tests were performed periodically on the two production wells.

Two extensions were granted in the project to allow for laboratory tests run on core samples. Results from this work included generating bacterial films from indigenous microbes.

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1.0 Executive Summary

The project was divided into three phases. Objectives of Phase I work were to initiate surface geochemical analysis and collect soil samples over the leasehold according to defined grid(s); to construct electrodes to allow ERT methods to be used in tracking microbial movement within the reservoir; to drill five vertical wells; to incorporate geochemical results in selecting well locations if data are available; to complete/equip the wells for subsequent MEOR treatments; and to prepare a detailed fracturing design. Phase II objectives were to commence MEOR treatments in all wells; to apply ERT monitoring to track microbial movement in the subsurface; to hydraulically fracture stimulate two wells according to the design developed; to analyze soil samples collected; and to prepare an annual report of progress. Phase III included a continuation of well treatment and analysis of results.

Due to funding and weather delays, drilling and hydraulic fracturing were delayed until August and September 2003. This, in turn, delayed the start of MEOR treatments beyond the first project year. All other objectives of the first year of work were met.

Preliminary meetings were conducted with project participants, and all participants were sub-contracted. Participants include Direct Geochemical (surface geochemistry), Nolte Smith, Inc. (hydraulic fracturing design), J-Environmental (MEOR treatments), Mr. Jim Long (consultant), Garland Oil and Gas (operator), and Dr. Lee Slater (ERT support). It should be noted that, at the time of the initial project award, Dr. Slater was located at the University of Missouri, but has subsequently moved to Rutgers University in New Jersey.

Soil samples were collected over several areas of the leasehold, to evaluate the use of geochemical analysis in identifying productive and non-productive areas of the Warner Sand, and also for differentiating the quality of the productive area throughout the leasehold. Soil samples and corresponding GPS data were collected over several areas and provided to Direct Geochemical for analysis. Results from this work demonstrate that the surface geochemistry across the leasehold, and over two known dry holes, is quite different and can be successfully differentiated.

Background electrical resistivity tomography (ERT) readings were taken over two areas of the leasehold. Two initial, 2-D resistivity lines were shot in lines running North-South and adjacent to the original corehole #1 (Figure 1). Data obtained indicated that the depth of the

ERT survey did not extend through the Warner Sand. This work indicated that the electrode spacing for future surveys would need to be altered. The electrode spacing was modified to achieve a greater depth of investigation. Three, 2-D lines were then shot E-W, between coreholes #4 and #5, since geochemical results indicated slightly stronger response in this area.

ERT probes for the ERT wells were also constructed. Three strings of plastic tubing were equipped with electrodes and wired for connections to surface. The initial plan provided for two ERT monitoring wells. After discussing the imaging methods, it was determined that three wells should be equipped with ERT probes. Three ERT probes were constructed, shipped to location and placed in storage.

Five wells were to be drilled in the project. Well logs, core data and results from the geochemical survey were reviewed to determine the optimum location, and general well configuration, for the five wells. ERT background work indicated wells equipped with ERT probes would need to be no more than 70' apart and could not be cased (initially). It was determined that the ERTs wells would be configured in an equilateral triangle, and the two wells to be fractured would be located 200-300 ft outside this triangle. The fractured wells would be cased and cemented.

Five wells were drilled through the Warner Sand to depths of approximately 220 ft. All wells were air drilled with 6-1/4" hole to total depth. The wells were logged openhole with resistivity, porosity and density tools. Well log data is included in this report. Well logs indicated that the Bluejacket and Warner sands in these wells were similar to the historical coreholes (Figure 1).

Three ERT wells (2,3,4) were arranged in an equilateral triangle, spaced 70 feet apart and these wells were completed open hole. ERT arrays constructed during phase I were installed and background surveys were taken.

Two wells (1,5) were drilled, one to the north of the ERT wells and the other to the south of the ERT wells (Figure 2). These wells were cased with 4-1/2" casing, cemented and perforated in the top of the Warner Sand.

Continuous cores from wells (coreholes) drilled prior to this project were selectively sampled to develop a geomechanical dataset for designing the hydraulic fracturing treatment. The process of developing a geomechanical dataset includes the development of a profile with depth versus Young's Modulus, in-situ stress and fracture fluid leak-off. Fifteen samples were taken from the Cushard #1 core, ranging from the shale immediately above the Bluejacket Sandstone, through the Bluejacket and Warner Sandstones, and into the Graydon Shale immediately below the Warner Sandstone. These samples were sent to NSI and analyzed in their laboratory. Results of this analysis indicated that the Warner sand was much more competent than the published geological reports indicated.

Based on the geomechanical study, a hydraulic fracture treatment was designed for wells #1 and #5 (Figure 2). The intent was to tip screen out (TSO) and perform high permeability fracturing. Each well was to be stimulated with a linear, 30 lb/gal guar based gel and 20/40 mesh Brady sand with and end of job concentration of 10 lb/gal. Total volumes per well were 23,000 gallons of fluid and 94,000 lbs of sand. Well #1 was stimulated according to plan but TSO was not possible. Blender problems were encountered while pumping on well #5. Sand concentrations of up to 17 lb/gal were pumped near the end of this treatment, but no TSO could be effected. It was concluded that the leakoff rate in the Warner was too low to accommodate a tip screen out.

Fifteen latest generation, self-leveling tiltmeters were placed in prepared surface holes, located around the #1 well in a circular array. Results of the tiltmeter readings are given in this report. The tiltmeters confirmed that a horizontal fracture was generated and verified the extent of the fracture. However, tiltmeter data could not confirm the exact depth of the fracture. At this point it is not clear if the induced fracture remained in the Warner Sand, or whether it propagated into another formation.

Although it was planned to begin MEOR treatments during the first year, delays due to an extremely cold winter and very wet spring meant that drilling and fracturing could not take place as planned. MEOR treatments commenced in October, 2003, after surface equipment was set.

All other technical work performed during Phase I-II was successful. The geochemical analysis of soil samples was completed and provided useful results. Adjustments to the ERT array were made and those adjustments subsequently proved the ability to image through the Warner Sand. Three ERT arrays were constructed and successfully installed in the three ERT wells. Available Cushard cores were sampled selectively for supporting the final hydraulic fracture design. Two wells were successfully stimulated and fracture morphology was verified.

Phase III included a period of repeated microbial treatment, ERT measurement and pumping. Due to technical difficulties in placing the ERT arrays in the openhole monitoring wells, it was also not possible to produce (pump) the ERT wells as planned. Two ERT arrays are permanently lodged in the wells and only one array remained removable. After removing this array one time, it was deemed impractical and risky to do so, on a monthly basis. Hence, all ERT arrays remained in the wells, which meant that MEOR treatments could not be pumped into those wells.

Monthly treatments of a commercially available microbial product were applied to the three ERT wells by a dump method at the surface. This treating method was extremely limiting. Without pumping, it was not possible to determine (with certainty) if the microbes penetrated the Warner sandstone as intended.

Electrical resistivity tomography readings were taken following each MEOR treatment. Subsequent to all treatments the fracture stimulated wells were pumped and samples were taken. ERT results did indicate a change in the oil bearing formation since the start of microbial treatment. Pump tests on the two fracture stimulated wells indicated a small increase in gas produced but oil production appeared unchanged following the treating period.

An extension of the project was granted to perform laboratory tests with the microbial product that was used in treating the wells. These tests were intended to verify the commercial product could reduce oil viscosity in a laboratory controlled setting. Unfortunately, the vendor refused to release samples for testing, nor any technical information regarding the microbes. Other microbial products were not tested as these would not be relevant to the treated wells.

Several experiments were conducted using oil and brine from the wells, in an effort to culture indigenous bacteria. These experiments were successful in growing microbial films immediately below the heavy oil layer in the beakers. Quantities of these microbes were not sufficient to allow core flooding experiments, however the success in cultivating the indigenous microbes demonstrates that microbes will appear and sustain from the heavy crude oil, which suggests that an indigenous microbe may be more beneficial in oil recovery.

2.0 Project Tasks

2.1 Develop Surface Geochemical Sampling Plan and Grid

In November 2002, Direct Geochemical met with the faculty at UMR to devise a soil-sampling scheme. The initial concept for the field-sampling plan involved two aspects, modeling and grid sampling.

2.1.1 Modeling

It was proposed to take sufficient sample to develop both local and regional models. Each model was expected to consist of one or more wells with known characteristics, i.e. a good well and a very bad well. The following sampling was proposed (referencing corehole locations shown in Figure 1):

* Well (corehole) 1 and Well (corehole) 4: 10 samples near each well
*Well (corehole) 12: 15 samples near the well
*Offsite Good well: 15 samples near the well
*Offsite Bad well: 15 samples near the well

"Near the well" samples were to be taken all the way around the location, in a rough circle. All of the samples were to be obtained close enough to be representative of the subsurface geologic characteristics but far enough away to be in natural or at least non-oil disturbed ground.

2.1.2 Grid

Three connected grids were initially proposed. Grid number 1 was to cover the main target area, in the E1/2 of the NE 1/4 of Section 32. The proposed grid for the target comprised 66 samples, approximately 265 feet on center. The grid proposed 11 rows of 6 samples.

Grid number 2 consisted of 160 acres in the SW1/4 of the SE/1/4 and the SE1/4 of the SW1/4 of Section 29 plus the NW1/4 of the NE1/4 and NE1/4 of the NW1/4 of Section 32. Sampling was proposed to be on 530' spacing, and consist of 33 samples arranged generally as 6 rows of 5 samples, plus 3 on the east line. This grid connected the main grid across to Well 4 (Corehole #4 in Figure 1).

Grid number 3 was proposed to connect Well 1 and the main grid across to Well 7, which was the medium quality well. It consisted of 3 rows of 5 samples in the S1/2 of the NW1/4 of Section 33.

The grids included 114 soils samples and the models proposed a further 65 soil samples.

The non-productive wells (offsite bad, offsite good) selected were the Ellis #1 dry hole located approximately one mile SE of the leasehold and the Harpel well, located several miles to the north-northeast of the leasehold area. These wells were selected because they were recent wells (2001), and the operator had leasehold rights for access to the wells.

2.2 Collect Soil Samples for Surface Geochemistry

Direct Geochemical provided soil sample instructions, sample field note sheets and sample jars for collecting the soil samples. GPS units were provided by the University, for noting the location of soil samples taken.

During January, 2003, model soil samples were collected, but weather conditions limited the number of samples taken and prevented grid samples from being collected. Extremely cold winter conditions hampered soil sampling efforts considerably.

During February, 2003, UMR students and faculty returned to the leasehold and collected approximately 100 soil samples over the three proposed grid areas. Figure 3 is a photograph from the soil collection effort.

The samples collected consisted of three sections, and approximated the proposed grids. The center section incorporated 53 samples, acquired on approximately 200-foot centers. The western section used 31 samples on 400-500 foot centers. The eastern section used 15 samples on 300-400 foot centers. These sample locations are shown as a base map in Figure 4.

Soil samples and GPS data were transmitted to Direct Geochemical for analysis. Figures 5-11 show sample hydrocarbon analysis and other results for the soil samples collected. A copy of the complete report from Direct Geochemical is provided in the Appendix.

Preliminary findings indicated that the area around corehole #4 might be slightly better than corehole #1. Based on these findings (and ERT results), it was decided to drill to the five wells for the project east of corehole #4, rather than near corehole #1 as originally planned.

The geochemical analysis revealed a difference between areas known to be productive and dry holes.   The Ellis dry hole and Cushard (corehole) 12 both appeared quite dry.

The Harpel well, which did have oil present, appeared different than the Cushard coreholes. It exhibited a lower overall concentration of hydrocarbons almost always. It predicted as a weaker version of the Cushard coreholes #1 and #4.

On a limited data set, it also appeared that the oil wells as a group show higher arsenic, calcium, and magnesium than the dry holes. The application of metals is not well understood.

A simple analysis of the geochemical data strongly supports the notion that the surface geochemistry can be used to differentiate where oil occurs in the Warner Sand.

2.3 Construct Plastic Tubing with Electrodes

Three ERT arrays were constructed for deployment in the wells. Array design was based on a modification of instrumentation used successfully in previous DOE projects and is summarized in Figure 12.

Lead electrodes were used as previous field experience has indicated that they are electrically quieter than electrodes constructed from Type 304 stainless steel mesh. We intend to obtain reliable cross-borehole induced polarization data in addition to electrical resistivity data during ERT data acquisition. For each array twenty-four electrodes were placed on 3-inch diameter PVC pipe at 1.5 m intervals. This provides a vertical dimension of 38 m for the image zone (Figure 12). The ERT image aspect ratio is 1.52 (35 m/22.9 m), which is appropriate for cross-borehole ERT imaging. Note that the zone of interest is designed to occupy about 33 % of the image plane (Figure 12).

Each electrode is connected to two 18 gauge copper wires that provide electrical contact with the electrical imaging system placed on the surface and at the center of the boreholes.

The arrays were constructed in 3.1 m sections for transportation and final construction during well installation. They were designed for removal and re-installation on an as-required basis by two-three persons. A heavy-grade rope is attached for lowering and retrieving the array to/from the approximately 50 m installation depth.

All three arrays were stored on-site until drilling was completed in August, 2003

2.4 Record Baseline ERT Survey

Geophysical students acquired 2 dimensional background resistivity data around corehole #1 in the late fall 2002 using a dipole-dipole array (DD). The results indicated that electrode spacing of 8 m (for a total spread length of 820 m) did not provide enough depth to image the entire reservoir (Warner). As a result new array geometry was recommended.

Weather conditions delayed the acquisition of the background resistivity data. Frozen ground during the winter and heavy rains in the spring hampered field data acquisition. Students returned to the field in early May, but could not complete the survey until June, because the fields were excessively muddy. Data acquired in May and June using new array geometry (pole-dipole array) allowed for greater depth penetration. We were able to image to depths exceeding the depth of the reservoir.

Resistivity profiles were acquired for three lines running E-W, between coreholes #4 and #5. Results of these 2-D profile surveys are shown in Figure 13.

The resistivity profile in Figure 13 shows that the shallow subsurface is very conductive with resistivities less than 12 Ohm.m. We interpret this to be due to shallow clays. Below this is a more resistive layer approximately 50 m thick, with resistivity values ranging from 32 to 50 Ohm.m. We correlate this with a shale unit. The reservoir layer is imaged beneath this more resistive layer at a depth of approximately 55-60 m with apparent resistivity values between 26-30 Ohm.m (dark tan color image). This layer appears to thicken towards the east (towards corehole #5).

2.5 Preliminary Fracturing Review and Design

During February, 2003 samples were selected from the Cushard #1 core, for geo-mechanical analysis. A summary of core samples selected for analysis is presented in Table 1. These samples were taken to NSI Laboratories in Tulsa, Oklahoma for analysis.

Table 1 presents results of the tri-axial compression tests on the core samples. Evaluation of these tests indicates that the Bluejacket and Warner Sandstones have an average Young's modulus of 3.1 and 1.3 x 10^6 psi, respectively. These values are relatively high, indicating that the formation is hard or consolidated. This was surprising since a geological study had previously reported the Warner sand a friable and somewhat unconsolidated.

Figure 14 depicts the geomechanical data set developed for the fracture design. In Figure 14, the first track of the geomechanical profile is the true vertical depth and perforation indicator track. Track two of the profile represents the closure pressure while tracks three and four represent the Young's Modulus and toughness, respectively. Tracks five and six show the fluid loss coefficient and spurt and track seven shows the gamma ray log.

Based on geomechanical results and known formation permeability of 350 mD (historical core analyses) it was believed that high permeability fracturing methods should be applied to the Warner sand.

The hydraulic fracturing treatment designed is summarized in Table 2. As shown, the preliminary design consists of pumping 94.5 Mlbs of 20/40 Brady sand in 23 Mgals of 30 lb/gal linear gel fracturing fluid. The treatment is designed for a proppant addition schedule from 0.5 ppg to 10 ppg. The purpose of the 0.5 lb/gal proppant stage is to mitigate the detrimental effects of near wellbore pressure loss due to the anticipated complex fracture geometry. Predicted net treating pressure and other details of the design can be found in the Appendix .

2.6 Project Communications/Publicity

A preliminary website was developed for this project (www.umr.edu/~doe) This webpage was not supported after the project finished.

Publicity for the project was generated through press releases and through KY3 in Springfield Missouri. KY3 ran a television spot in February, 2003 on the research project. The local Nevada, MO newspaper covered the hydraulic fracturing treatment. Copies of press releases will be provided in the final report.

2.7 Drill Five Wells

Five wells were drilled through the Warner Sand to depths of approximately 220 ft. All wells were air drilled with 6-1/4" hole to total depth. Each well was drilled to total depth in approximately 2-3 hours.

Drilling cuttings samples were collected every 5 feet, washed and placed into sample bags. Direct Geochemical provided a UV light box, and microscope for onsite analysis. Mr. John Fontana of Direct Geochemical was onsite during drilling and provided mud logging support for two wells drilled. This geological analysis is not included in this annual summary, but will be included in the project final report.

All wells were logged openhole with resistivity, porosity and density tools. Tool failure meant that the resistivity logs for wells #1 and #5 had to be computed from the density porosity log. Figures 15-18 are resistivity and porosity logs for wells #1 and #5. Complete well log data is included in the Appendix of this report.

Well logs indicated that the Bluejacket and Warner sands in all wells drilled in this project were similar to the historical coreholes. Figure 19 depicts the log for corehole #1, and highlights the Bluejacket and Warner Sands.

Three ERT wells (2,3,4) were arranged in an equilateral triangle, spaced 70 feet apart and these wells were completed open hole. ERT arrays constructed during phase I were installed and background surveys were taken.

Two wells (1,5) were drilled, one to the north of the ERT wells and the other to the south of the ERT wells (Figure 2). These wells were cased with 4-1/2" casing, cemented with Portland A cement, and perforated in the top of the Warner Sand. Cement returns were noted at surface or the annulus was filled from surface. Well #1 was perforated from 164-179 ft feet, 4 shots per foot (spf) using 60^o phasing. Well #5 was perforated from 162-177 ft. using the same density and phasing. Perforations were 0.25 inches in diameter.

Pictures taken from during the drilling and cementing operation are shown in Figure 20 and Figure 21.

2.8 Fracture Stimulate Two Wells

Halliburton Energy Services (HES) provided fracture stimulation services and fracture analysis in September, 2003. Each well was stimulated with a linear, 30 lb/gal guar based gel and 20/40 mesh Brady sand as planned. Two frac tanks were supplied by Garland Oil and Gas and frac water was trucked from Ft. Scott Kansas. Total fluid volumes per well were 23,000 gallons of fluid and 94,000 lbs of sand. The fluid injection rate was 15 bbl/min.

Although it was considered, microbes were not placed in the fracturing fluid. Microbes were not included due to the ERT work. ERT arrays were placed in the openhole wells after the hydraulic fracturing. It was believed that hydraulic fracturing with microbes might place the microbes near the ERT wells and disturb background reading when the arrays were installed.

Well #1 was stimulated according to plan. Figure 22 depicts the fracture data collection summary. An initial breakdown and step rate test was performed first. Following the step rate test, formation pressure was allowed to bleed off until closure pressure was observed. A mini-frac was then pumped to determine fluid efficiency. The main fracture stimulation follows the mini-frac.

A similar procedure (breakdown, steprate, minifrac and main treatment) was followed on well #5. However, blender problems were encountered while pumping on well #5. The treatment was shutdown after the slurry pumping schedule had begun. When the treatment was re-started, the slurry schedule was also re-started. Hence, there was insufficient fluid to pump the entire treatment as planned. Approximately 25% of the proppant was not placed in formation. In addition, control problems with the blender resulted in erratic concentrations, with values as high as 17 lb/gal pumped near the end of this treatment.

2.8.1 Hydraulic Fracturing Analysis

Figure 22 provides a summary of the initial break down, step-rate test and main treatment performed on well #1. Figure 23 is a detailed view of the step rate test. The step rate test was conducted with the 30 lb/gal linear gel and pump rates in increments from 2 bbl/min to 15 bbl/min (treatment design rate), with a step down to 4 bbl/min.

Formation breakdown pressure for well #1 was 770 psi. Analysis of the step-rate test revealed that the entire test was conducted above fracturing pressure, but the step down portion of the test was used to estimate a fracture extension pressure of approximately 140 psi. The 1.75 slope of the pressure-rate curve during step down also indicated there was considerable perforation friction.

Figure 24 provides a summary of the pressure fall-off following the mini frac treatment on well #1. Closure pressure was found to be 107 psi, which agrees well with the closure pressure found from fall-off data following the step-rate test. Pipe friction is evident in the early portion of the data and this friction may be explained by the complex fracture geometry due to the horizontal fracture orientation. Fluid efficiency was found to be 85%, which is very high in the context of conventional hydraulic fracturing. The high fluid efficiency is a result of low leakoff rate, which is expected in a heavy oil reservoir. This indicates that the pad volume (2000 bbls) is being ‘spent’ very slowly as the fracture propagates.

A mini frac net pressure history match was prepared, comparing the predicted net pressure to the actual net pressure of the treatment (Figure 25). As shown, early time data are not in agreement, but late time data do agree with the predicted net pressure. Early time data are affected by friction effects, which occur through the perforations due to tortuosity. Again, this is attributed to the creating of a horizontal fracture.

The actual treatment performed on well #1 is given in Figure 26. This treatment is exactly according to the treatment schedule prescribed in Table 1. A 2000 bbl pad was pumped. Following the pad, a sand slurry schedule of 0.5, 1.0, 2.0, 4.0, 6.0, 8.0, and 10.0 lb/gal was pumped. A constant injection rate of 15 bbl/min was used. Although it is not shown in Figure 26, treating pressure increased slightly every time sand concentration was increased. This indicated that the perforations or formation was reacting adversely to the increased concentration. During the treatment, bottomhole treating pressure declined continuously, indicating a radial fracture. The treatment never indicated a tip screen out.

Knowing the fluid efficiency was 85% in the first fracture treatment, and that tip screen out was not achieved, it was decided to reduce the pad volume by 50% (to 1000 gal) in well #5. It was hoped that with such a small pad volume, a tip screen out would occur.

However, due to problems with the blender, it was not possible to pump the treatment as planned on well #5. As shown in Figure 27, the pumps were stopped at 2 lb/gal slurry rate, and then re-started. Difficulty with the computer card in the blender meant that the proppant addition could not be controlled, and the addition of proppant was erratic. Concentrations of up to 17 lb/gal were reached, which is extraordinary for sand transport in a linear gel. Because the treatment was stopped and re-started, there was not sufficient fluid to continue pumping and inject all the sand volume. Approximately 25% of the 94,000 lbs of sand were not placed in the formation.

Despite the high sand concentrations applied to well #5, the continuous decline in pressure also indicated that a tip screen out did not occur. It was simply not possible to tip screen out. It is concluded that high permeability fracturing would not be possible in these subsurface conditions.

Figure 28 is a photograph of the hydraulic fracturing treatment applied in the project. Approximately 20 students and two faculty were on-site for the treatment (Figure 29). The local newspaper also ran a feature article.

2.8.2 Tiltmeters and Tilt Analysis

Pinnacle Technologies, Inc. provided the use of surface tiltmeters in support of the hydraulic fracturing treatment. The purpose of using tiltmeters was to confirm fracture morphology. Fifteen, self-leveling tiltmeters were placed in prepared surface holes (Figure 30), located around the #1 well in a circular array.

Results of the tiltmeter data were analyzed by Pinnacle Technologies and by a graduate student at UMR. Figure 31 depicts the tiltmeter data and final fracture morphology.

Tilt signals were extremely clear because of the shallow depth of the formation. A video movie of the fracturing treatment was prepared from the raw data. The movie clip is included on the disc containing this report, as a separate file.

Analysis of the tiltmeter information showed that the deformation was located approximately 80 ft. East and 20 ft. North of the well (#1). The primary feature induced is near horizontal, and elliptical, with dimensions of 200 ft by 300 ft. There appeared to be a vertical fracture that accompanied the horizontal fracture, with an azimuth of about N 73^{o} E. The vertical fracture is a questionable feature. If it exists, it is no larger than 25% of the injected fluid volume and it is not present above 150 ft. The tiltmeters used in the fracturing treatments confirmed fracture morphology and extent. However, tiltmeter data could not confirm the exact depth of the fracture. At this point it is not clear if the induced fracture remained in the Warner Sand, or whether it propagated into another formation.

2.9 Installation of ERT Arrays

Electrical resistivity tomography (ERT) electrode arrays were deployed in the ERT wells (#2, #3, #4- Figures 1,32) in September 22, 2003. In well # 2 the array extends from 33m below ground surface to 67.5m below ground surface; in well #3 the array extends from 34m to 68.5m below ground surface; in well #4 the array extends from 32m to 66.5m below surface.

The three ERT arrays were run into the open boreholes on ropes with the expectation of removing and reinstalling the assemblies monthly, so that MEOR treatments could be pumped into each borehole under an inflatable packer. However, when two of the arrays were run (#2, #3) they were rested on bottom and became stuck in the boreholes. It was determined that it would not be possible to remove them until after all ERT measurements were made. This limited the manner in which MEOR treatments could be made, i.e. treatments could only be added at the surface, not pumped at depth under pressure as originally planned.

The one ERT array (well #4) which could be removed was taken out of the well and the PVC connection fastened in a more robust fashion. However, since wells #2 and #3 could not have their arrays removed, it was decided that the #4 well array would also be left in place for the duration of treating.

2.10 MEOR Treatments

All MEOR treatments consisted of 40% Para-Bac S, 40% Ben-Bac and 20% Corroso-Bac. A 1 gallon flush was used at the end of each treatment. No food source was added to the treatments because the microbes employed survive off carbon chain and several of the cations that are in the produced water.

For cased and fracture stimulated wells, MEOR treatments were placed by pumping directly into the well for the first three treatments, and later down the well bore. In the openhole ERT wells, treatments were placed in the well by a dump method, adding fluid at the surface without pumping pressure. It was believed that this treatment method would still be acceptable since the microbes would move in the direction of the hydrocarbon (food source).

However, as the ERT wellbores were open holes, both the oil-bearing Bluejacket and Warner formations were exposed to treatment. Hence, there would be no way of controlling the treatment to either zone, or differentiating production from the zones.

Table 3 summarizes the MEOR treatments and dates performed.

2.11 ERT Measurements

Background ERT measurements were taken in September 2003, after initial MEOR treatment of the two hydraulically stimulated wells but prior to MEOR treatments on the three

ERT wells. In addition to background measurements, ERT measurements were subsequently taken as shown in Table 4. ERT measurements were typically taken within one week following the MEOR treatments.

2.11.1 ERT Acquisition

ERT data acquisition involves the collection of resistivity and chargeability (induced polarization(IP)) data between all three well pairs; wells #2 to #3; wells #2 to #4; wells #3 to #4. Each ERT dataset consists of 4733 data points. A subset of reciprocal measurements (voltage and current electrode pairs interchanged) is collected for error assessment. Datasets are filtered for the elimination of erroneous measurements based on (a) repeatability (b) reciprocity (c) a minimum voltage threshold (d) realistic bounds on the chargeability (IP measurements only). All datasets are initially inverted for a two dimensional (2D) image of the resistivity distribution for the three image planes (#2-#3; #3-#4; #2-#4). We are in the process of inverting combined datasets for a given time interval using a 3D inversion algorithm. Both algorithms are supplied by Andrew Binley of Lancaster University (UK).

Background ERT data were collected September 22-23, 2003. ERT data have been collected essentially every month since the initiation of microbial treatment. On October 25th (after the data collection) the array in well #4 was carefully removed to inspect for potential damage suspected to occur due to immersion in oil within the borehole. The array was in excellent condition and subsequently reinstalled at the same position as prior to removal.

2.11.2 ERT Results

This report presents the completed the 2D inversion of all the datasets excluding that collected 3/14-3/15/04. Note that this approach solves for a 2D resistivity distribution and thus does not account for variation in resistivity perpendicular to the image plane. Figure 33 shows the results for #2-#3, Figure 34 shows the results for #2-#4 and Figure 35 shows the results for #3-#4. Note that for each image plane the inversion is based on exactly the same number and sequence of measurements for each time interval. This prevents any apparent differences between images that can simply result from changes in the measurement sequence. In all three image planes we observe a resistive unit (Figure 3 - arrows) at a depth of ~50m that correlates very well with the depth and size of the heavy oil reservoir of interest in this study (approximately 5m thick). Downhole resistivity logs performed by Garland Oil and Gas and obtained in nearby wells are shown in Figures 33-35 for comparison. A second resistive unit is partially imaged at a depth of ~35 m. We do not fully resolve this unit (i.e. it is most probably continuous between the wells) as the ERT resolution of structure is reduced towards the top (and bottom) of the image plane as a result of a lower spatial sampling density. This thinner unit is also observed in the downhole resistivity logs, being consistent with another sand formation (bluejacket?) and a possible minor oil reservoir.

Our ERT datasets show strong evidence for electrical changes in the oil bearing formation since the start of microbial treatment. We have experimented with different presentation methods including (1) absolute differences in resistivity, and (2) relative differences in resistivity. However, small changes in the resistivity of the highly conductive shale unit can dominate such images. We thus choose to simply plot the resistivity images with time for comparison purposes (note that the color scale is identical for each image). We generally observe an increase in the resistivity of the primary sand formation with time since initiation of microbial treatment. There is evidence to suggest that this increase in the resistivity of the sand formation is associated with the microbial treatment. First, the greatest changes occur within the vicinity of borehole #3, the treatment borehole; second, the greatest changes propagate from #3 towards borehole #4, the borehole mostly affected by the fragmenting and hence possibly a preferential flow path for the injected bacteria. We suggest here that the observed increase in resistivity of the sand formation may result from the bacterial mobilization of oil from the mineral surface and into the pore space. Electrical conduction in sand formations primarily occurs as electrolytic conduction by the liquid-filled interconnected pore network. Hydrocarbons are poor conductors and an increasing percentage of oil in the pore space will presumably increase the resistivity.

2.14 Production Testing

Wells #1 and #5 were produced on rod pump until the fracture treatment load volume (23,0000 gallons) was recovered. These wells were also pumped subsequent to MEOR treatment in November, 2003. Although the wells produced larger amounts of salt water, only a trace of hydrocarbon was present.

Because the openhole ERT wells had arrays permanently lodged in the wellbore, and only one array could be removed, it was decided to continue monthly treatments for a period of time and measure only resistivity changes before pulling the array from well #4.

MEOR treatments were stopped in March 2004 with the intent of pulling the array from well #4 and testing the well's production. This required a workover to move a pumping unit onto the well. It was decided to move the pumping unit from well #1 to well #4.

All subsequent pumping tests produced only trace hydrocarbons with formation brine.

2.15 Well Abandonment

Subsequent to pump tests, and at the end of the project extension period, the field equipment purchased by Garland Oil and Gas was removed, and the five wells were abandoned with cement and cement plugs, as per regulations of the State of Missouri. Garland Oil & Gas company oversaw well abandonment and filed necessary regulatory reports.

2.16 Experimental Testing

Laboratory experiments were conducted to determine the MEOR products could stimulate an oil saturated core, in a more controlled environment. The manufacturer of the microbes was asked to provide samples for analysis and testing, but samples could not be obtained due to the proprietary nature of the product. Instead of these tests, beaker samples of formation brine and water were prepared, and indigenous microbes were allowed to grow. Results of this work establish that it is possible to culture and grow indigenous microbes, which may be far more effective in treating the formation.

3.0 Results and Observations

The objective of this research project was to demonstrate MEOR treatments could reduce oil viscosity and enhance production from the Warner sand in Western Missouri. The project also sought to investigate the use of geochemistry as a method to identify productive areas, and ERT as a means of monitoring reservoir response to MEOR treatment.

Results of the geochemical analysis are an interesting part of the work performed.. Examining the results for the Ellis #1 and Cushard #12 (insets to Figures 4,5,6,7 and 9) it is clear that the dry holes exhibit responses quite different than the productive wells found in the main leasehold. This strongly suggests that surface geochemistry might be used as an inexpensive way of identifying the existence of hydrocarbons in western Missouri. The finding is important, since no regional geochemical study has been undertaken to date.

The hydraulic fracturing treatment performed in this project provides another significant result, as there are no prior documented fracture treatments in the Warner Sand in Missouri. Much was learned by pumping this treatment, including formation breakdown, strength and fracture response characteristics. Knowledge of the formation breakdown pressure can aid other operators in avoiding formation breakdown while waterflooding, or performing steam injection. The fracture treatment also verified an elliptical and horizontal fracture morphology. Interestingly, the formation was successfully treated with very high proppant concentrations. Since leakoff was low (fluid efficiency 85%n) it is unlikely that high permeability fracturing techniques can work in this formation. These findings are all useful for future stimulation treatments in the Warner Sand.

Another finding of the work was that ERT requirements significantly limited the well design (openhole completions required) and ultimately well treatments. Since MEOR treatments could not be pumped into the open hole wells equipped with arrays, so it is questionable if microbes entered the Warner formation in those wells. This was a significant limitation of the project.

Commercial microbes were applied in this project because there was an indication these microbes had previously proven to successfully stimulate the formation. Results from this study indicate that the combination of Para-Bac, Ben-Bac and Coroso-Bac products were not successful in substantially increasing production from the Warner sand in Western Missouri. However, it should be emphasized that the treating method may have had some impact.

Through analysis of the ERT datasets we generally observed an increase in the resistivity of the primary sand formation with time, following initiation of microbial treatment. There is evidence to suggest that this increase in the resistivity of the sand formation is associated with the microbial treatment. However, with no oil production data to make laboratory measurement of compositional changes, it was not possible to perform compositional reservoir modeling and link that to changes in the ERT response. Laboratory data may have been used for this modeling, but the manufacturer of the commercial product used would not allow testing and analysis of the product.

Beyond the technical success of the work performed, it should be mentioned that the project publicity has also been highly effective, and that the University and project participants have had numerous calls regarding the work. At least four, major land and mineral owners in Western Missouri followed the project hoping to benefit from results of this work. Since results of the work were not promising, no technology transfer meetings were held.

4.0 Conclusions and Recommendations

The project "Development Practices for Optimized MEOR in Shallow Heavy Oil Reservoirs" has been successfully completed. Results of this project lead to the conclusion that the commercial products of Para-Bac, Ben-Bac and Coroso-Bac are ineffective in stimulating oil production from the Warner Sand in Western Missouri. However, indigenous microbes which are cultivated from formation brine, may prove more effective in reducing oil viscosity.

It is possible to successfully fracture the Warner formation, but high permeability fracturing methods (TSO) are unlikely to be successful in this formation.

Project results also suggest that surface geochemistry might be used as an inexpensive way of identifying the existence of hydrocarbons in western Missouri

It is recommended that researchers continue to study the problem of heavy oil extraction in Western Missouri. In addition to indigenous microbes, chemical treatments such as solvents or alkaline surfactant flooding can be investigated.

5.0 Outcomes and Impact on State of Missouri

Results from the "Development Practices for Optimized MEOR in Shallow Heavy Oil Reservoirs" project have been utilized in a new steamflooding project in Western Missouri, to aid the operator in understanding the behavior of fractures and how they may form with steam injection. The operator met with faculty and requested results of this project prior to initiating the steamflood. As of the last information, this steam flood was producing over 50 bopd. A project description can be found at http://www.megawestenergy.com/projects/missouri.html.

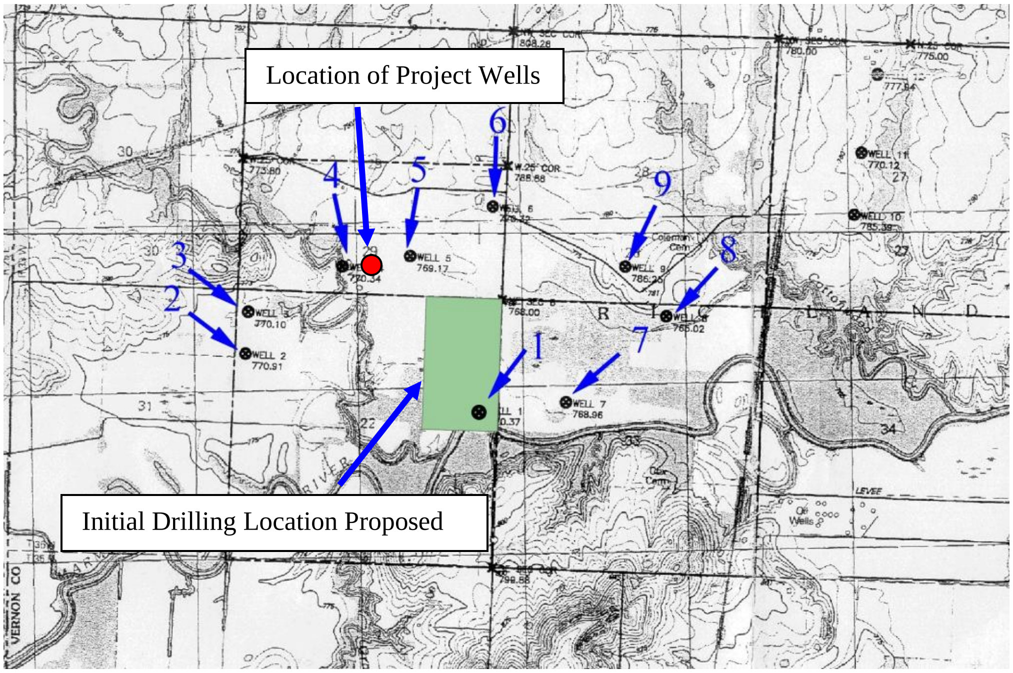


Figure 1. Leasehold in Vernon County.
Figure depicts the location of coreholes previously drilled and abandoned. Initially it was believed that area shaded in green would be proposed drilling area. Surface geochemistry and ERT surveys led to the project wells being drilled between coreholes #4 and #5.

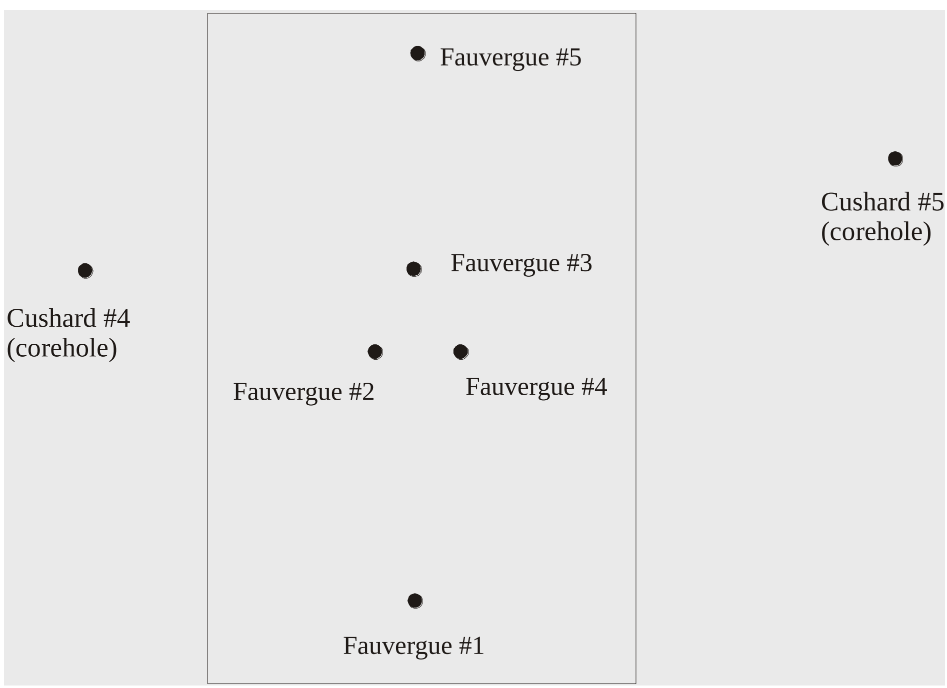


Figure 2. Arrangement of Wells Drilled (Fauvergue #1-5)

Figure 3. Student collecting soil samples over leasehold, February 2003.

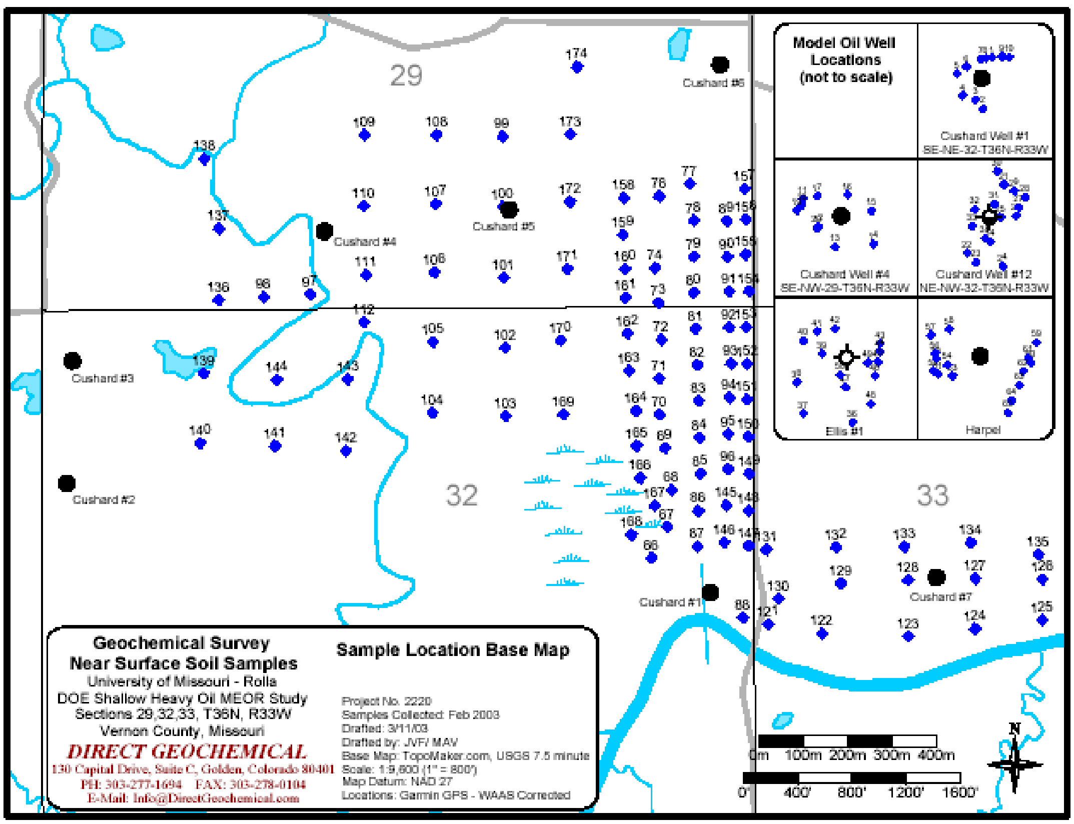


Figure 4. Leasehold Base Map showing location of soil samples.

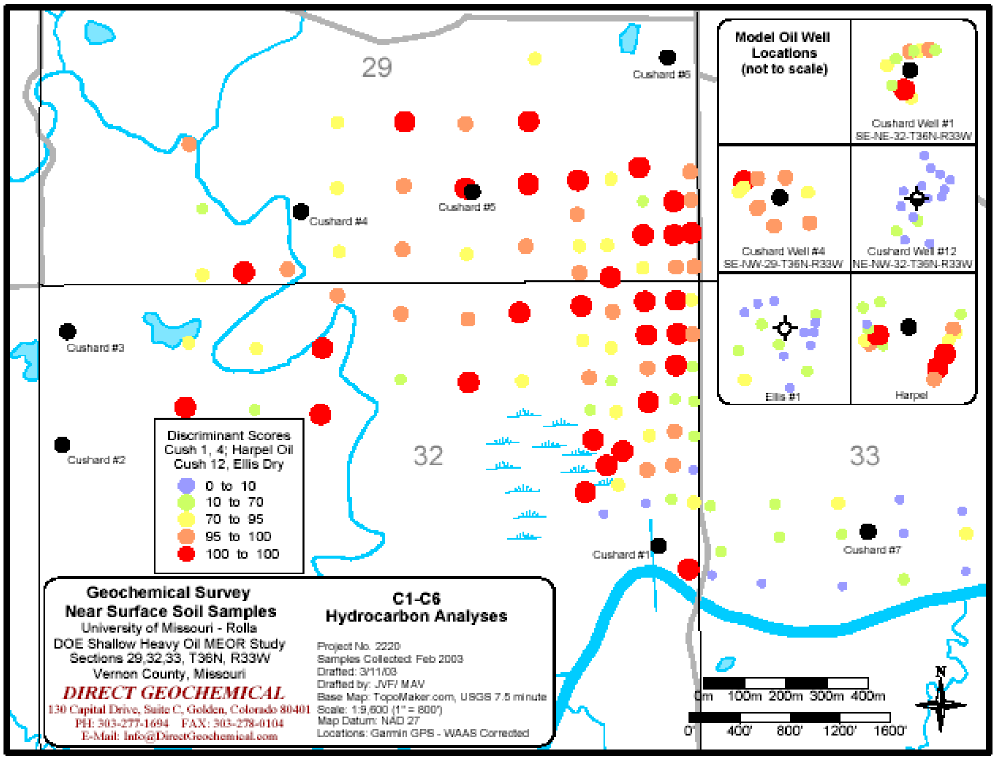


Figure 5. C_1-C_6 Composition

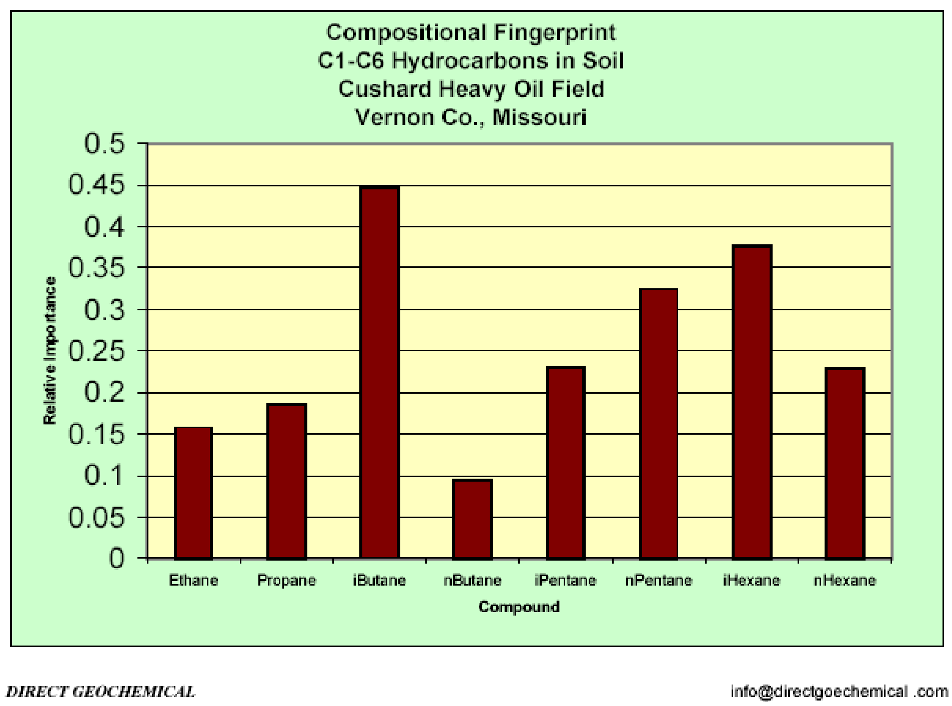


Figure 6. C_1-C_6 Discrimination

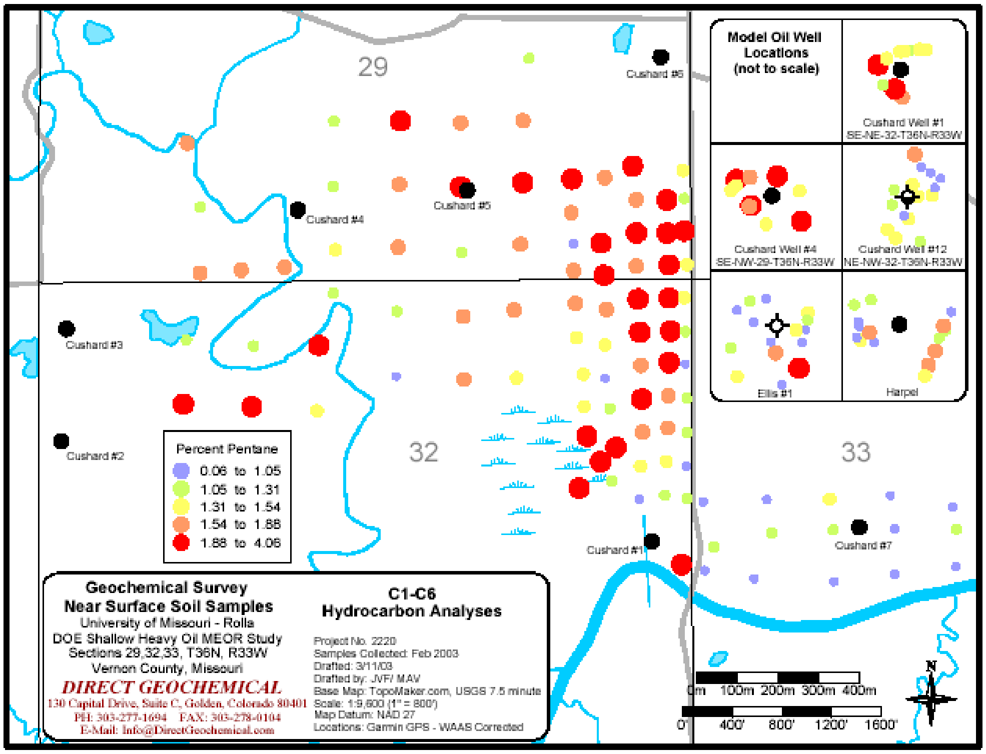


Figure 7. Percent Pentane

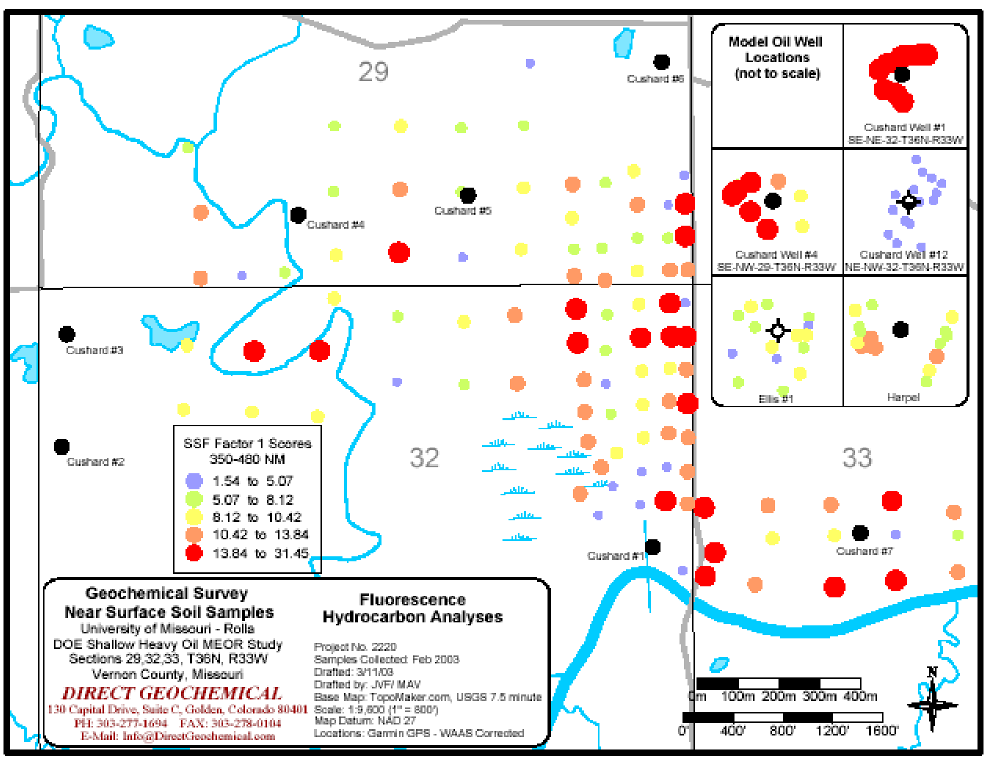


Figure 8. Fluorescence Hydrocarbon Analysis SSF 1

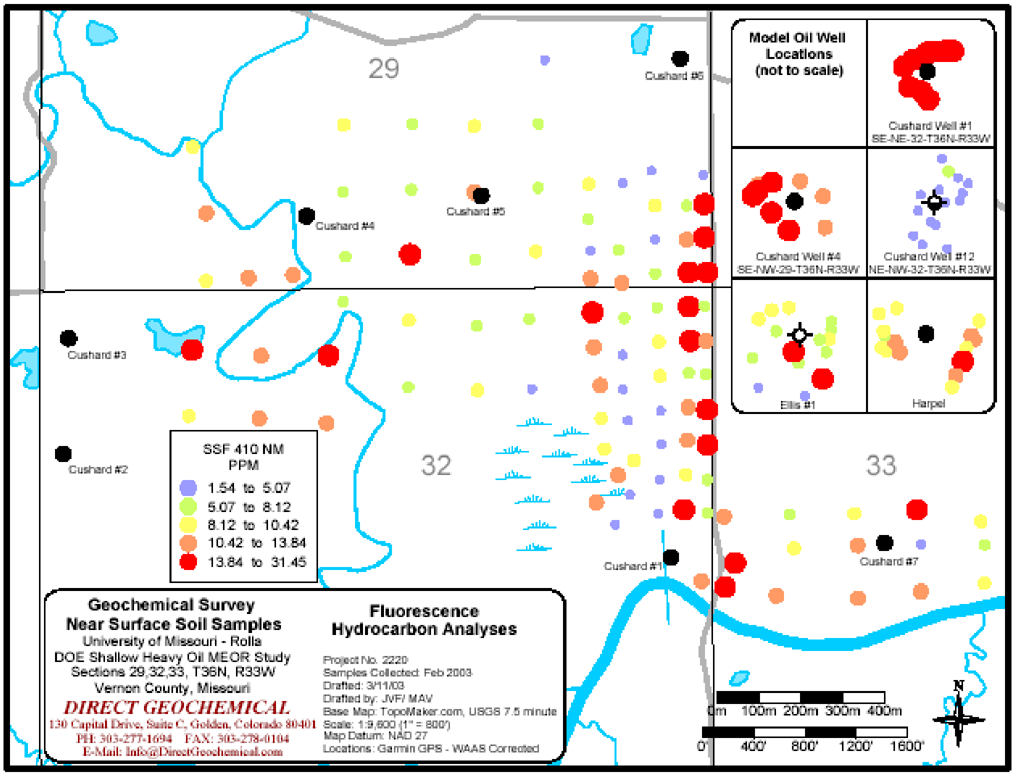


Figure 9. Fluorescence Hydrocarbon Analysis SSF 410

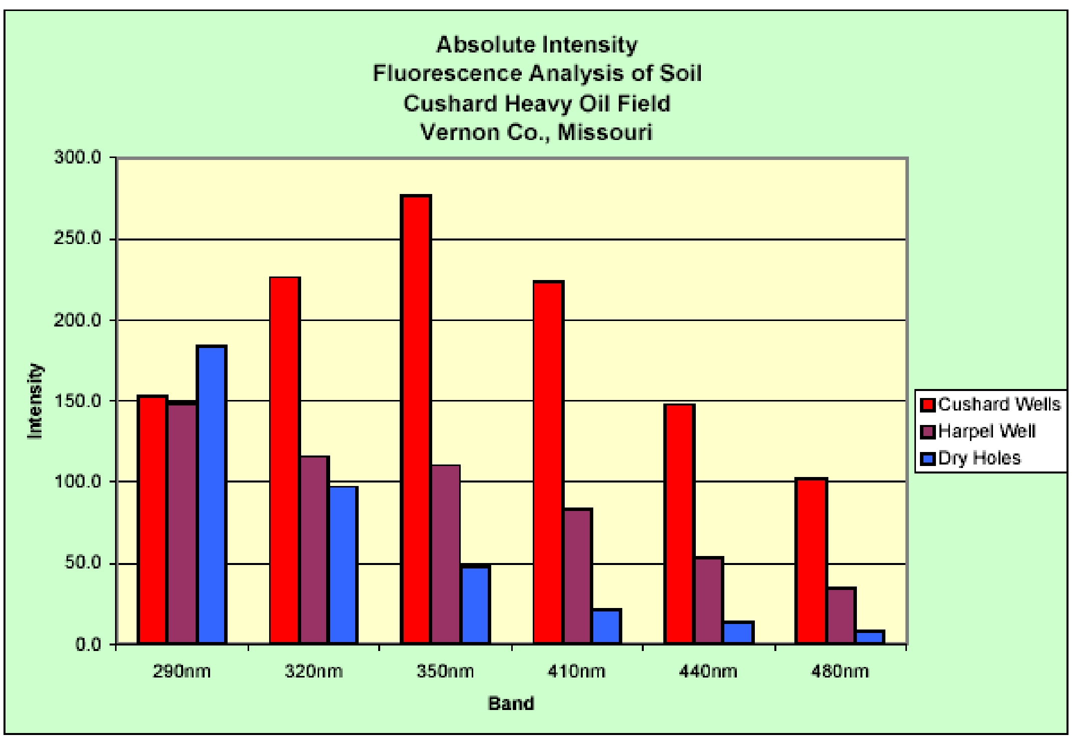


Figure 10. SSF Intensity by Well

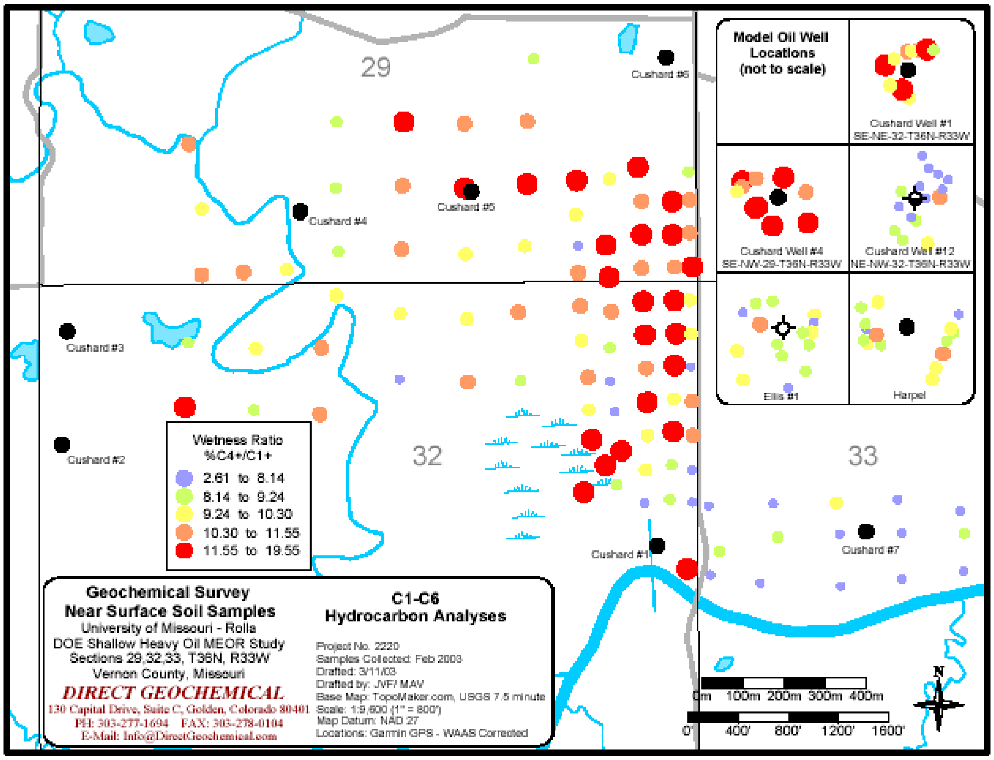


Figure 11. Wetness Ratio

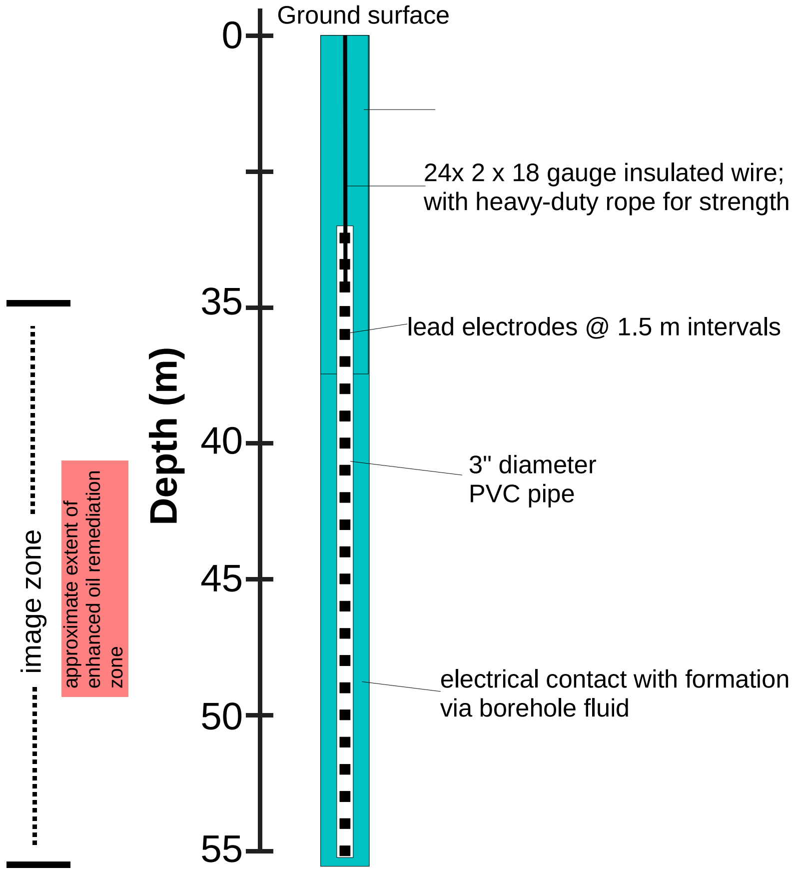


Figure 12. Schematic of electrode arrays constructed for ERT imaging and relationship to depth in formation and location of zone of interest for MEOR

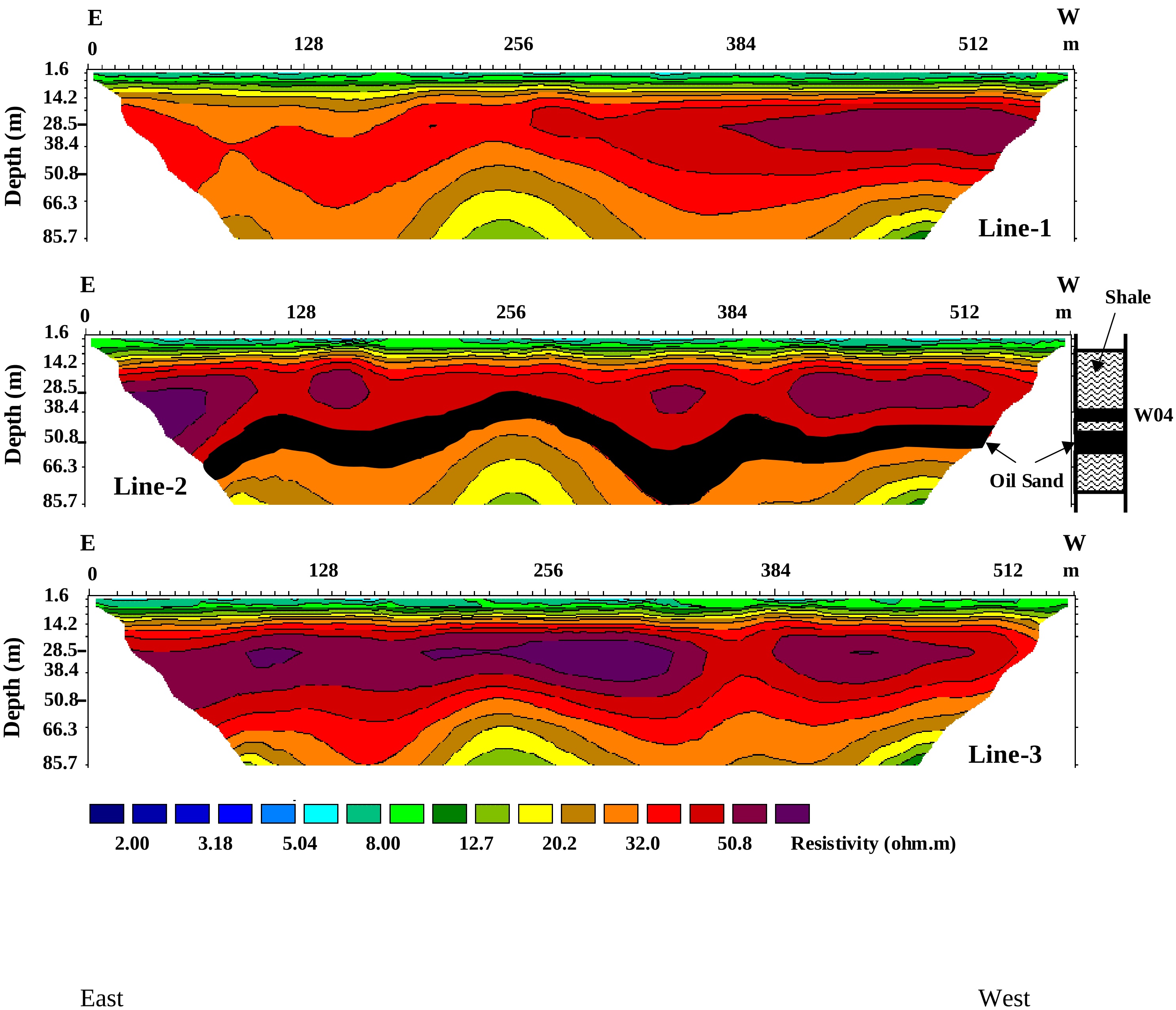


Figure 13. Electrical Resistivity Tomography Lines Between Corehole #5 to Corehole #4.
Vertical scale is depth in meters.

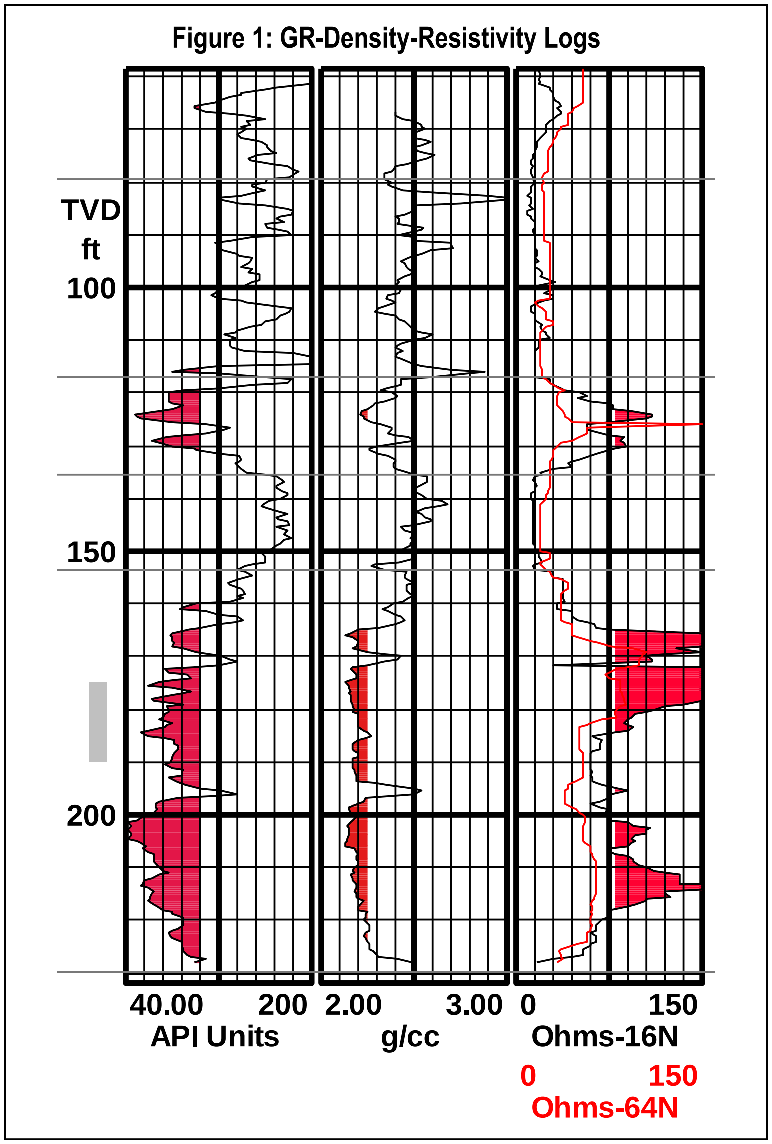


Figure 14. Composite Well Log, Corehole #1
This log was part of historical corehole data acquired prior to current project.

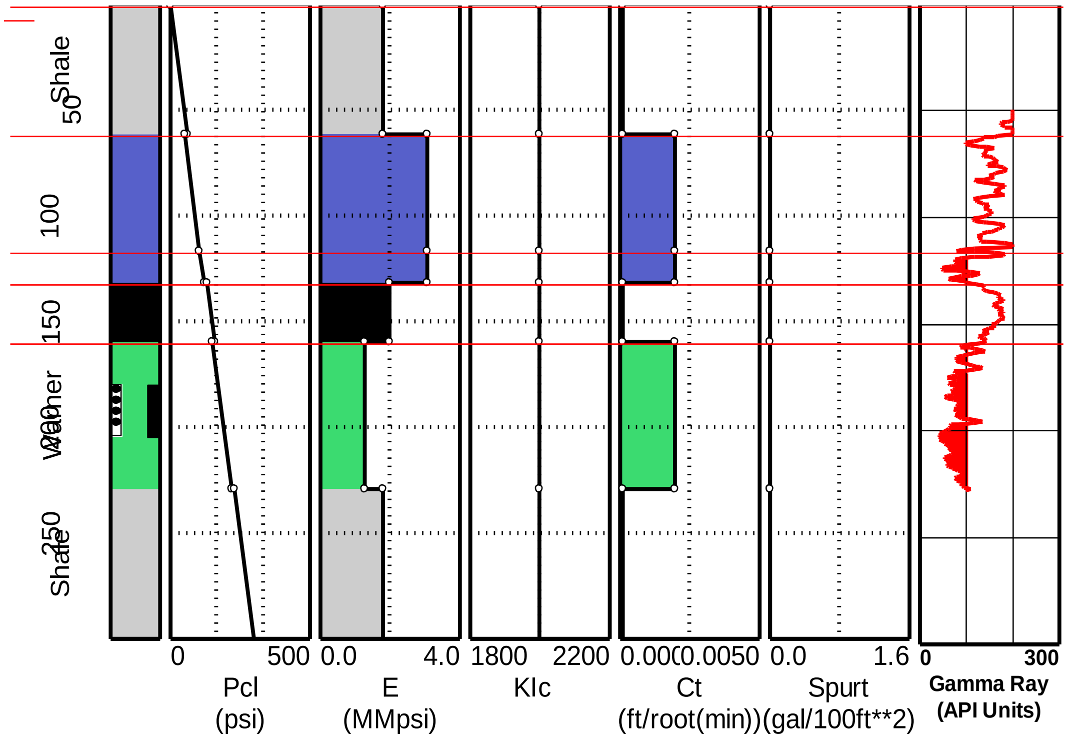


Figure 15. Geomechanical Dataset used for Hydraulic Fracturing Design

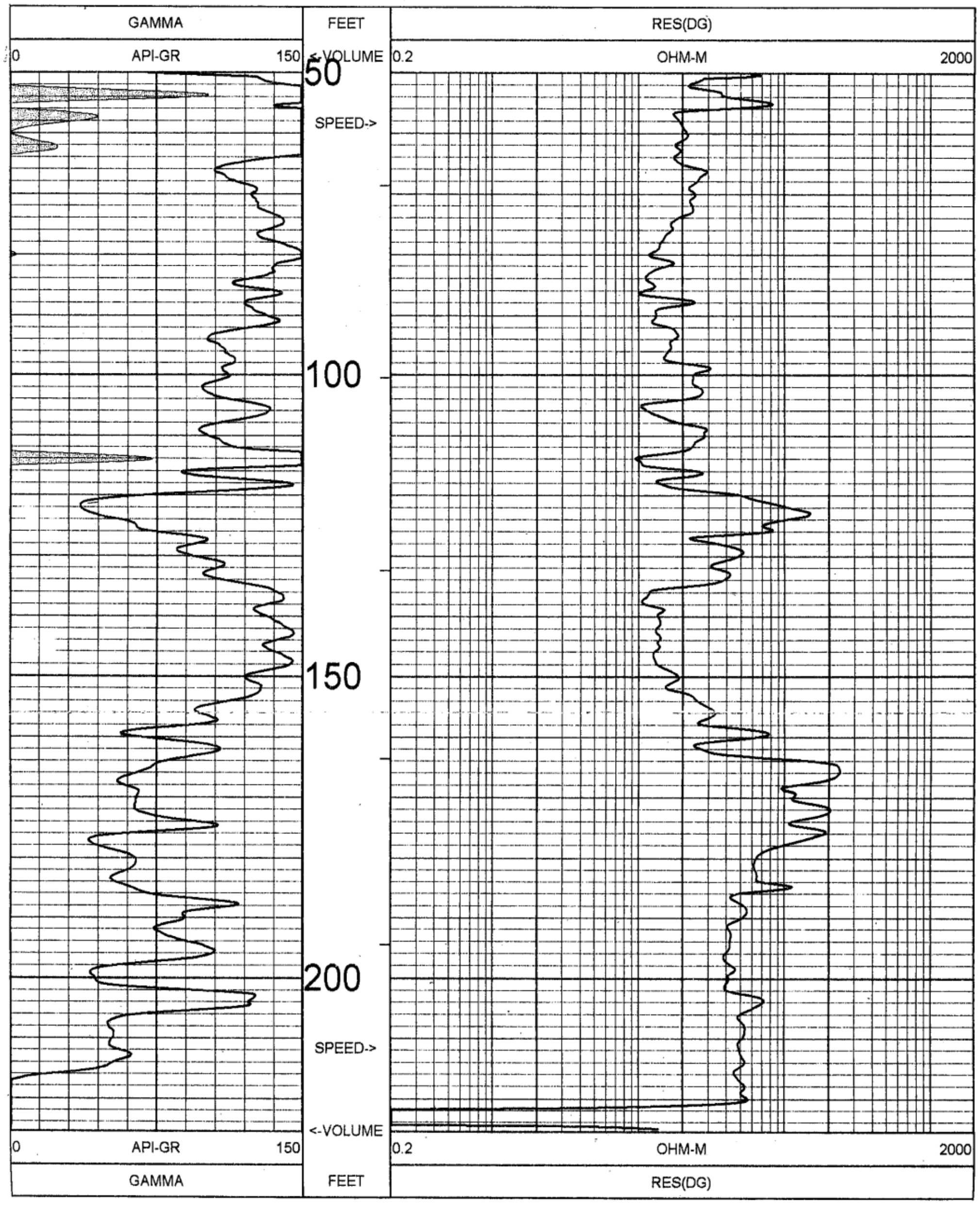


Figure 16. Well #1 Resistivity Log

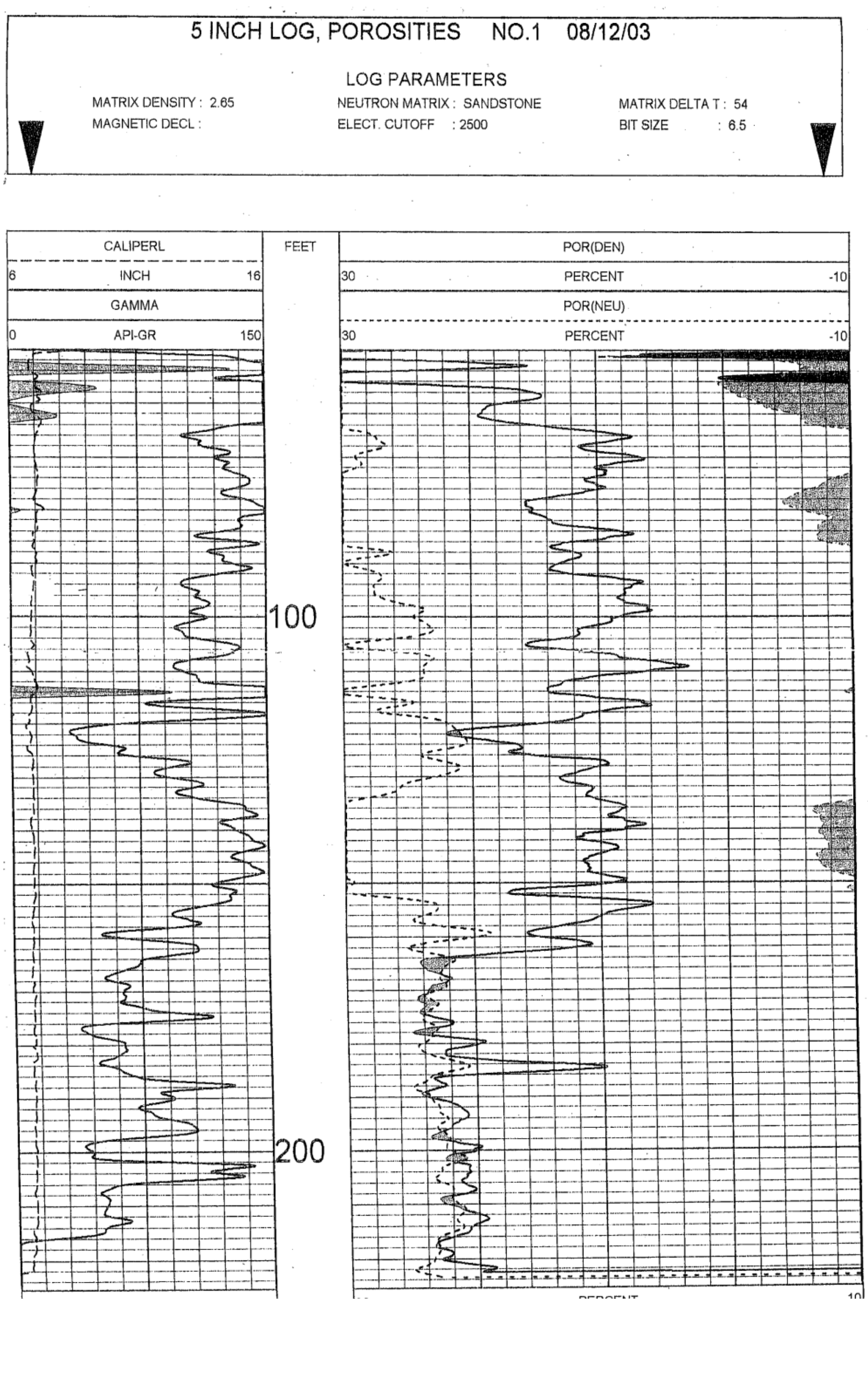


Figure 17. Well #1 Density Neutron Porosity Log

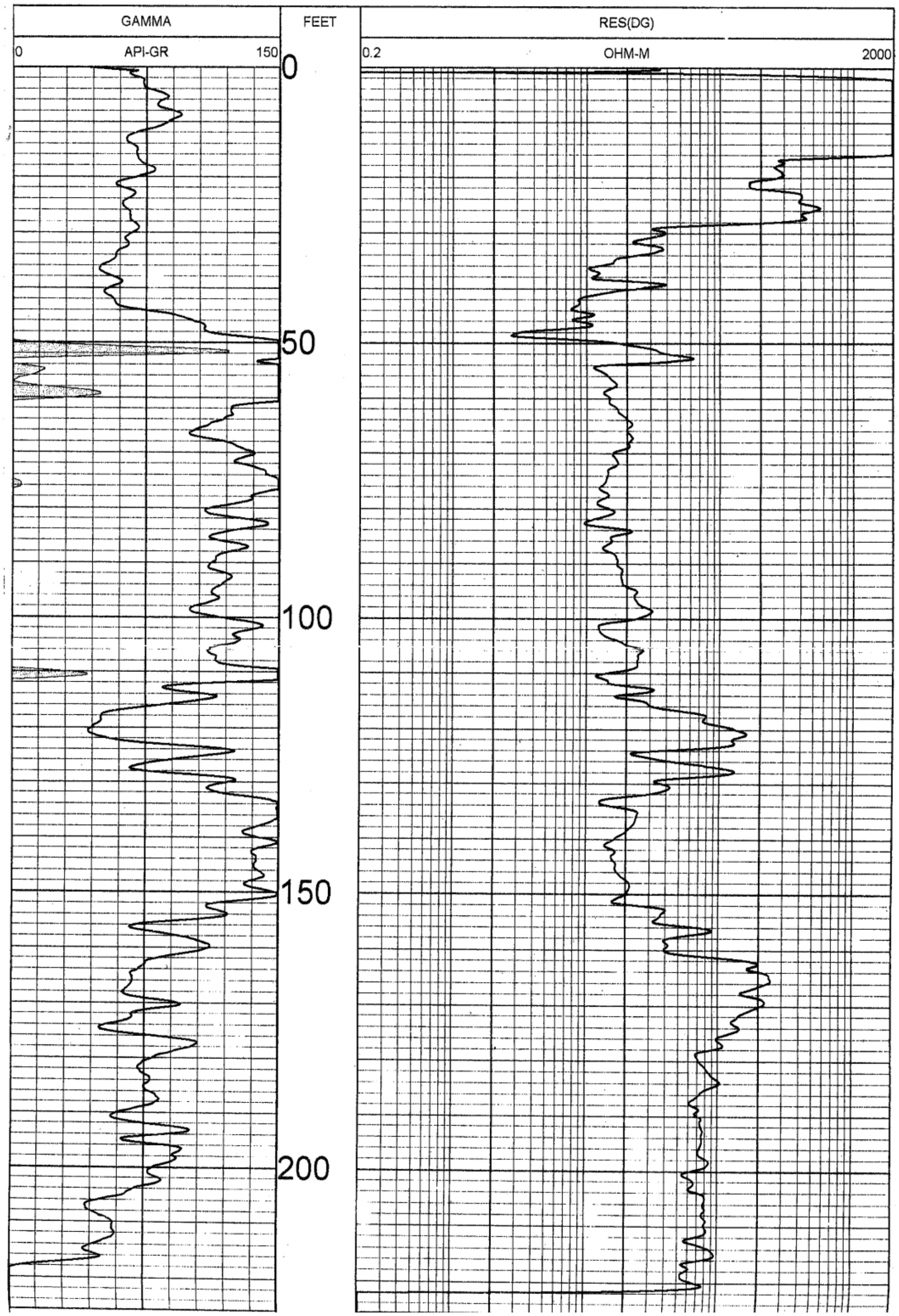


Figure 18. Well #5 Resistivity Log

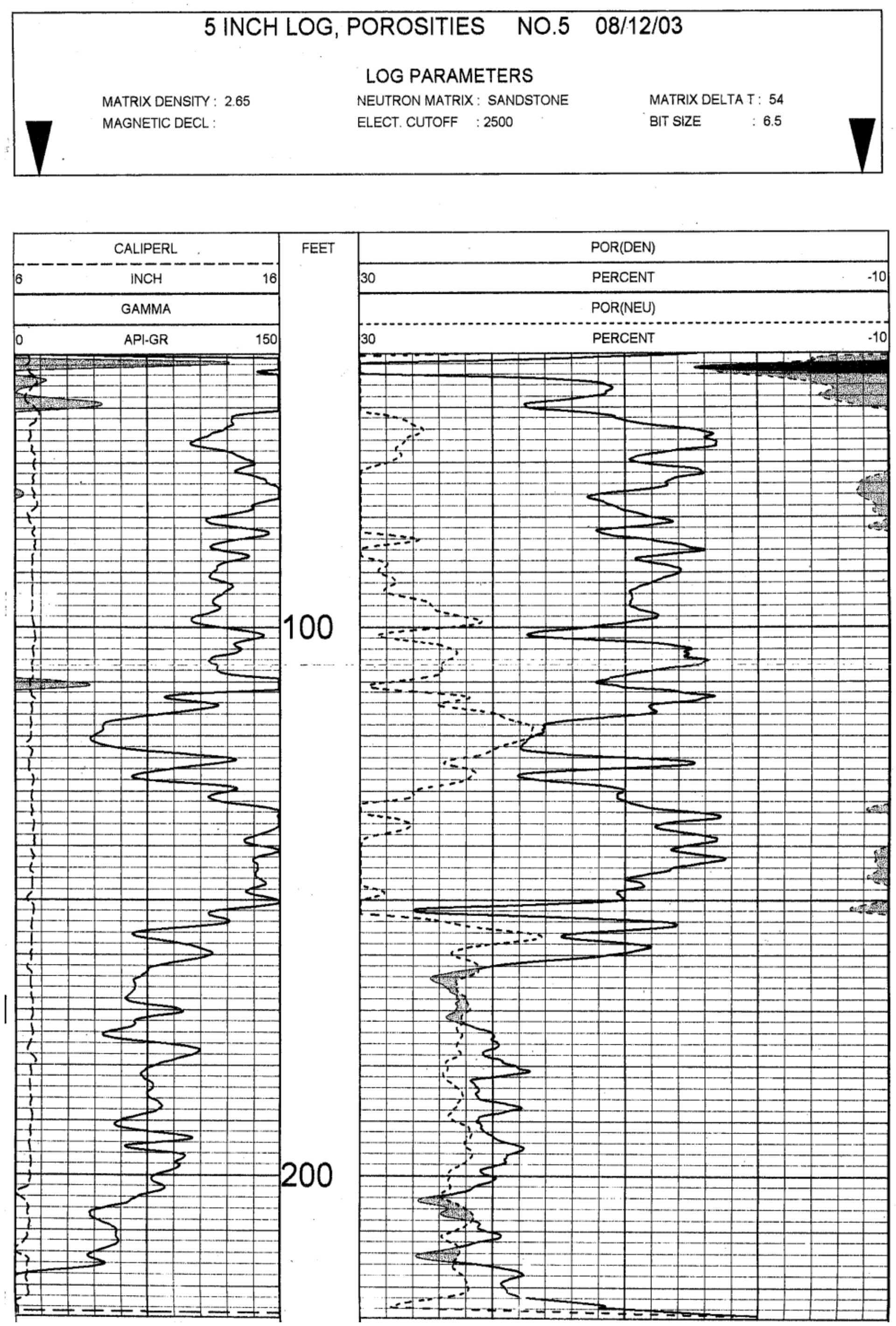


Figure 19. Well #5 Density Neutron Porosity Log

Figure 20. Photograph of Drilling Operation

Figure 21. Photograph of Cementing

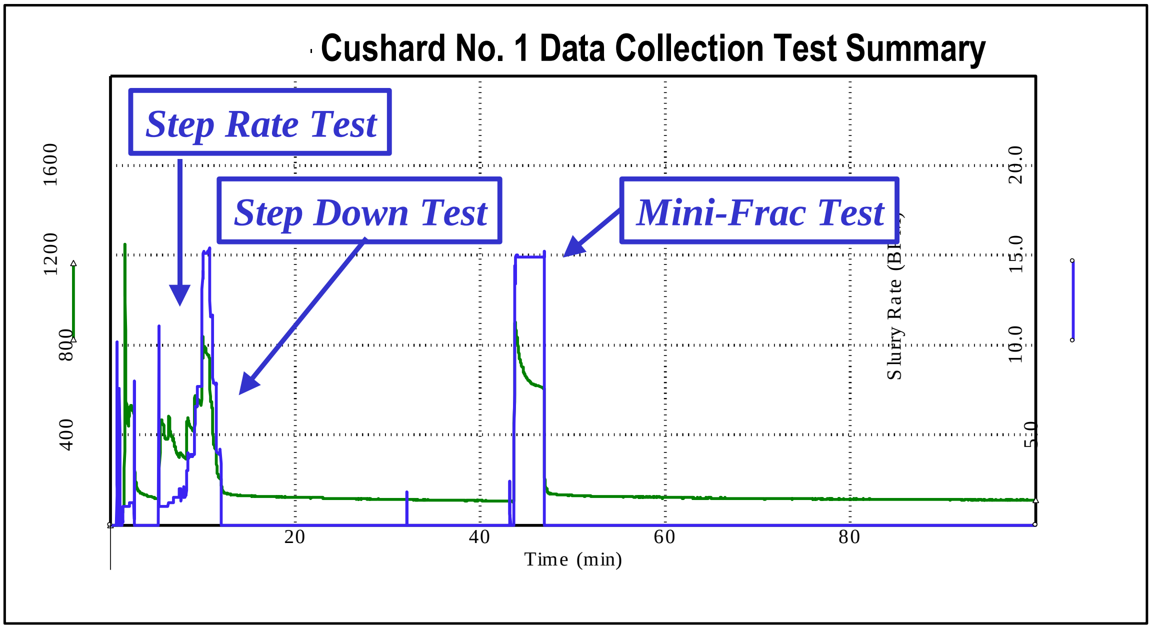


Figure 22. Well #1 Frac Treatment Data Collection Summary

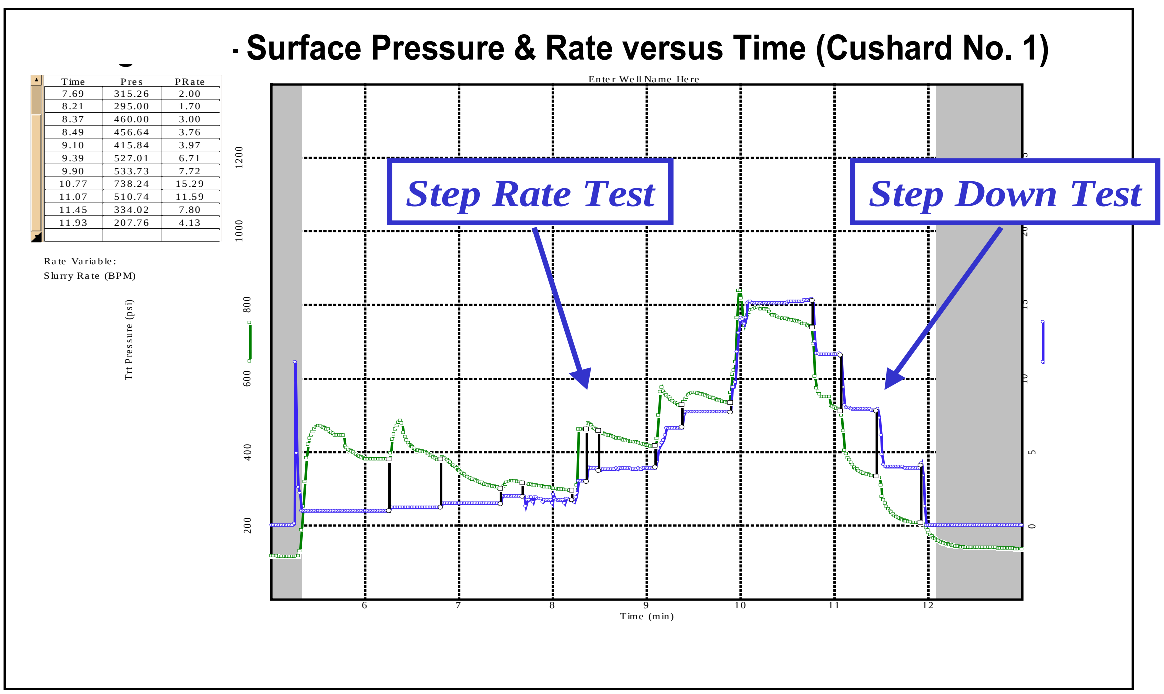


Figure 23. Well #1 Surface Pressure and Rate vs. Time

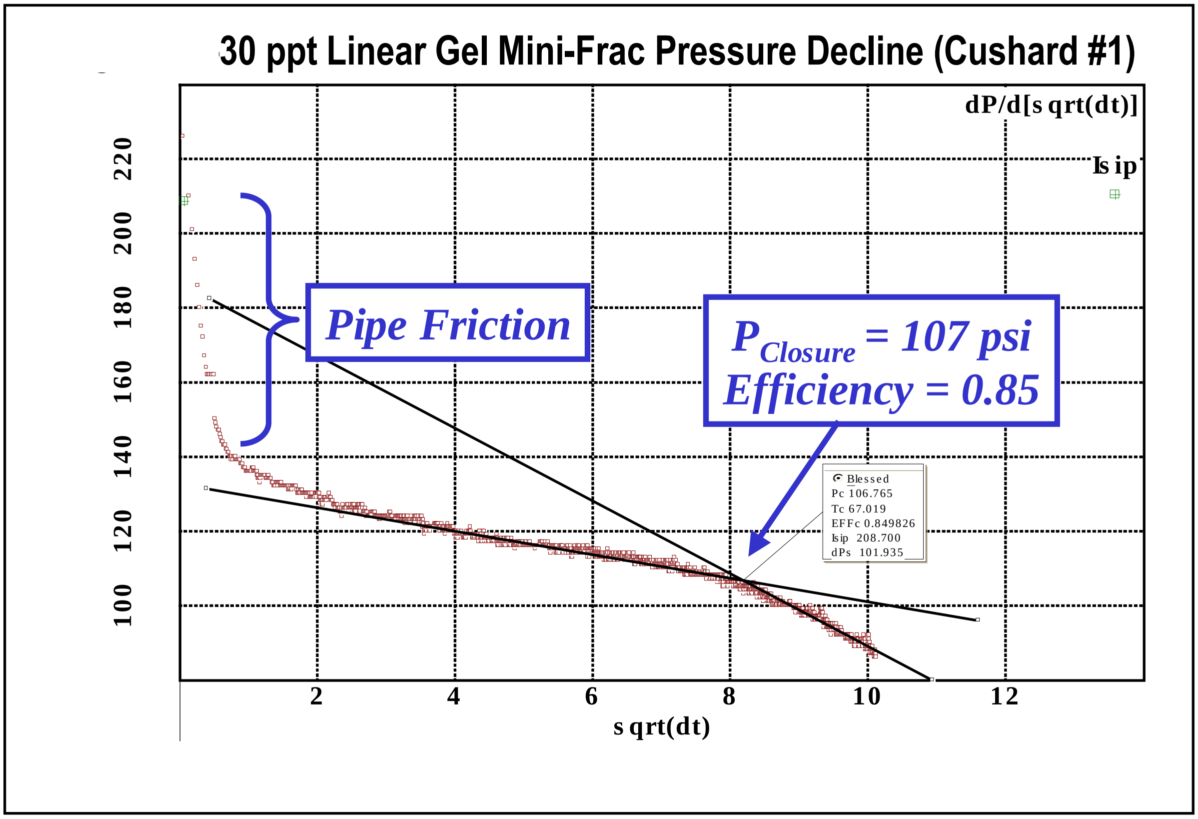


Figure 24. Well #1 Mini Frac Pressure Decline

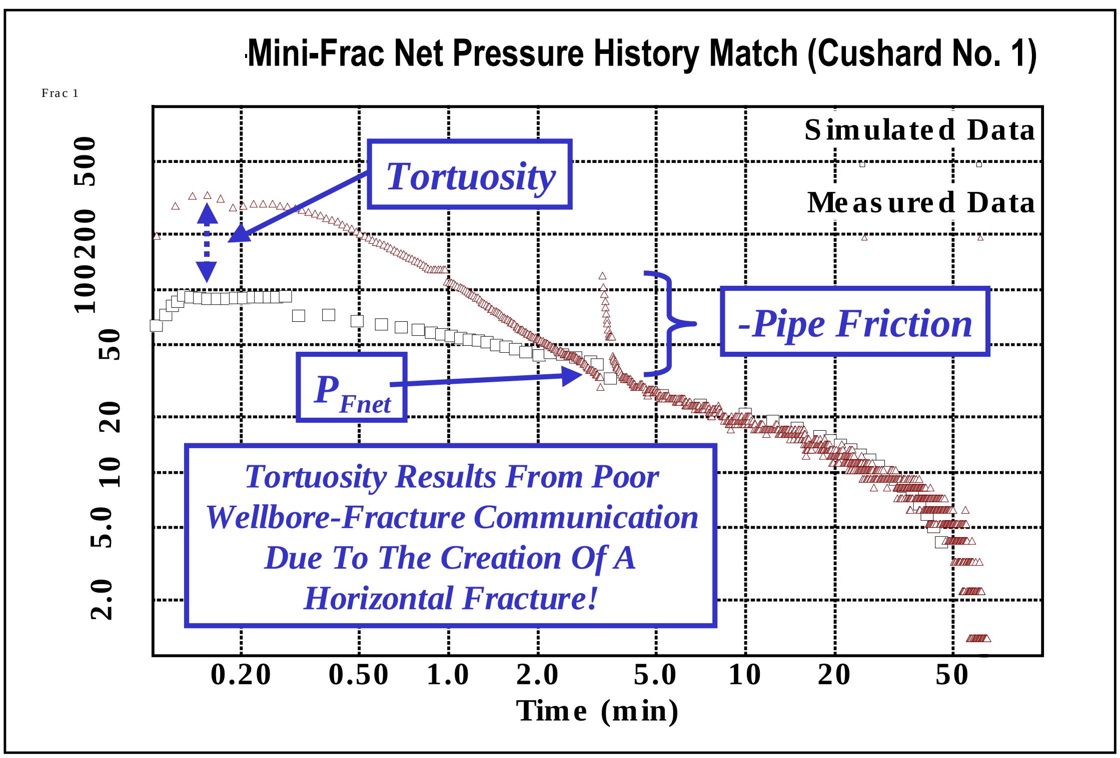


Figure 25. Well #1 Mini Frac Net Pressure History Match

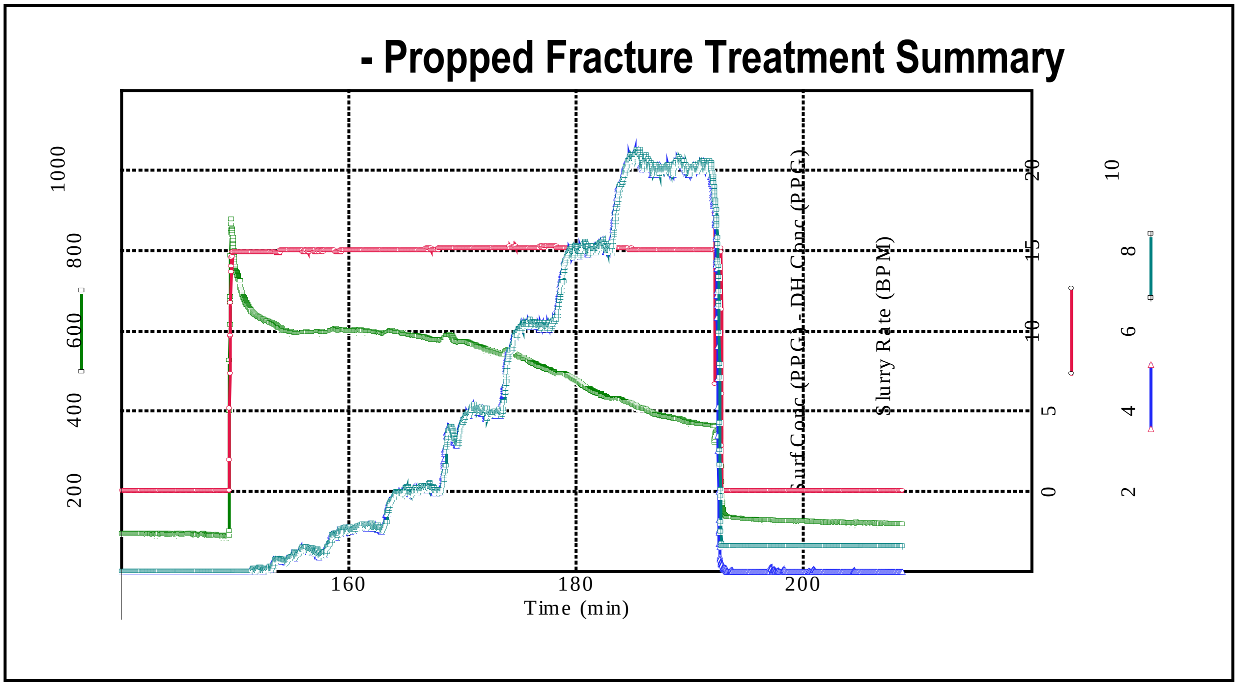


Figure 26. Well #1 Propped Fracture Treatment Summary

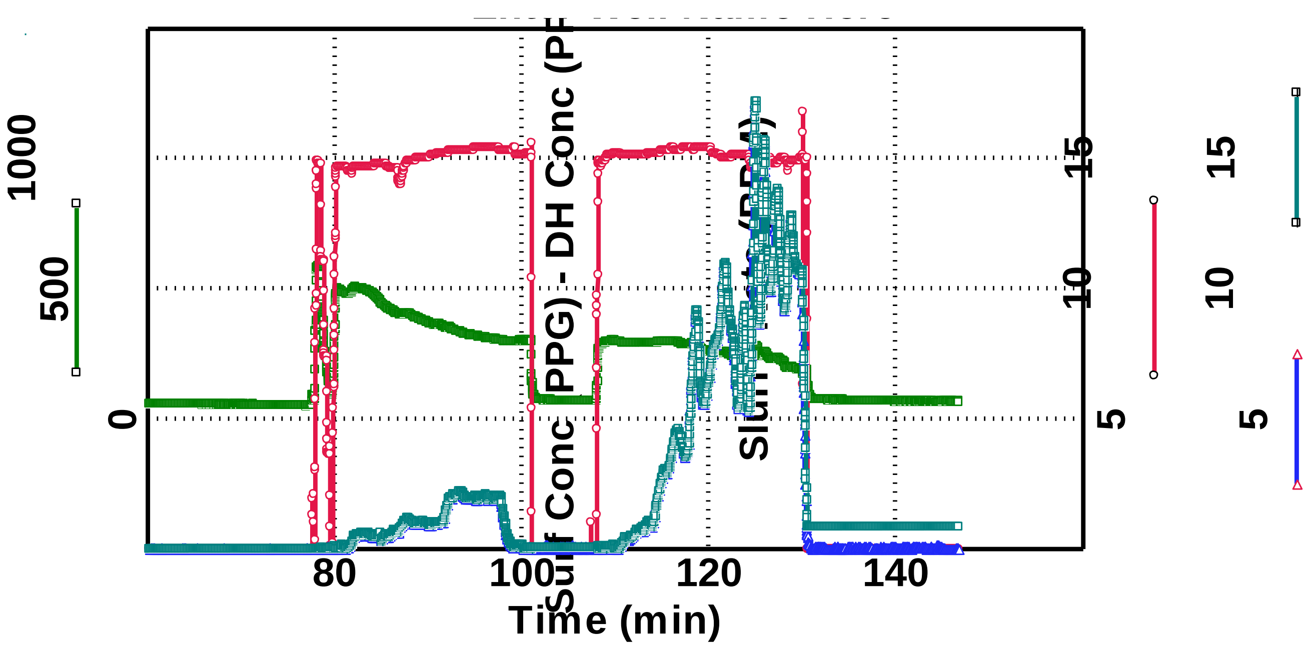


Figure 27. Well #5 Propped Fracture Treatment Summary

Figure 28. Photograph of Hydraulic Fracturing Treatment

Figure 29. Faculty and Students On-Site During Frac Treatment

Figure 30. Surface Hole Equipped with Tiltmeter

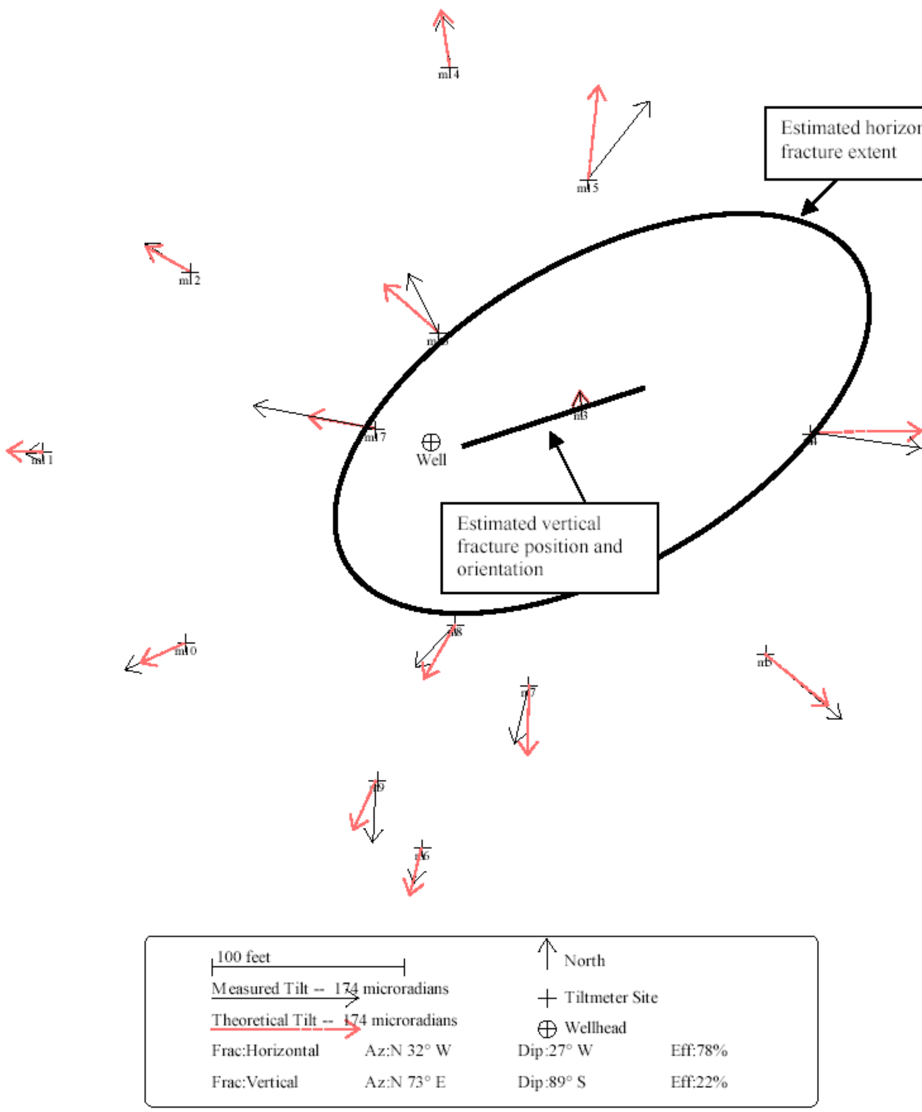


Figure 31. Tiltmeter Array and Results

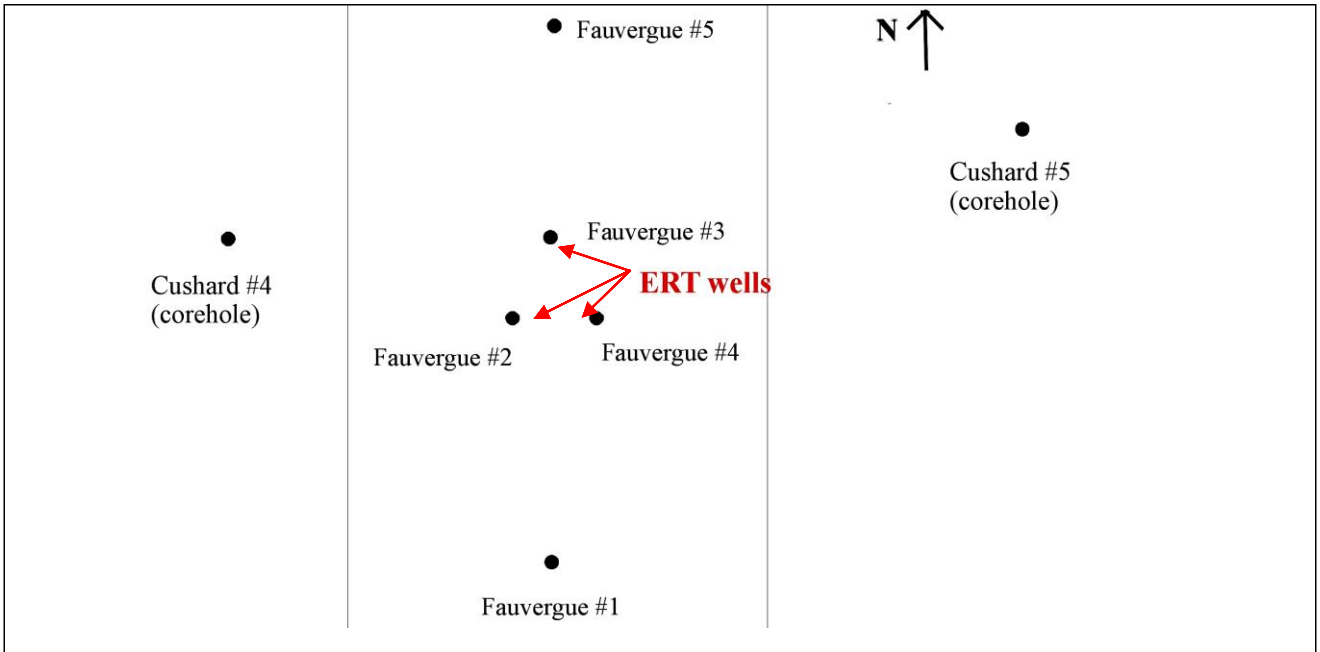


Figure 32 General Well Locations and Placement of ERT Wells

Figure 32 Schematic of electrode arrays used for ERT imaging showing depth of installation and location of zone of interest for MEOR

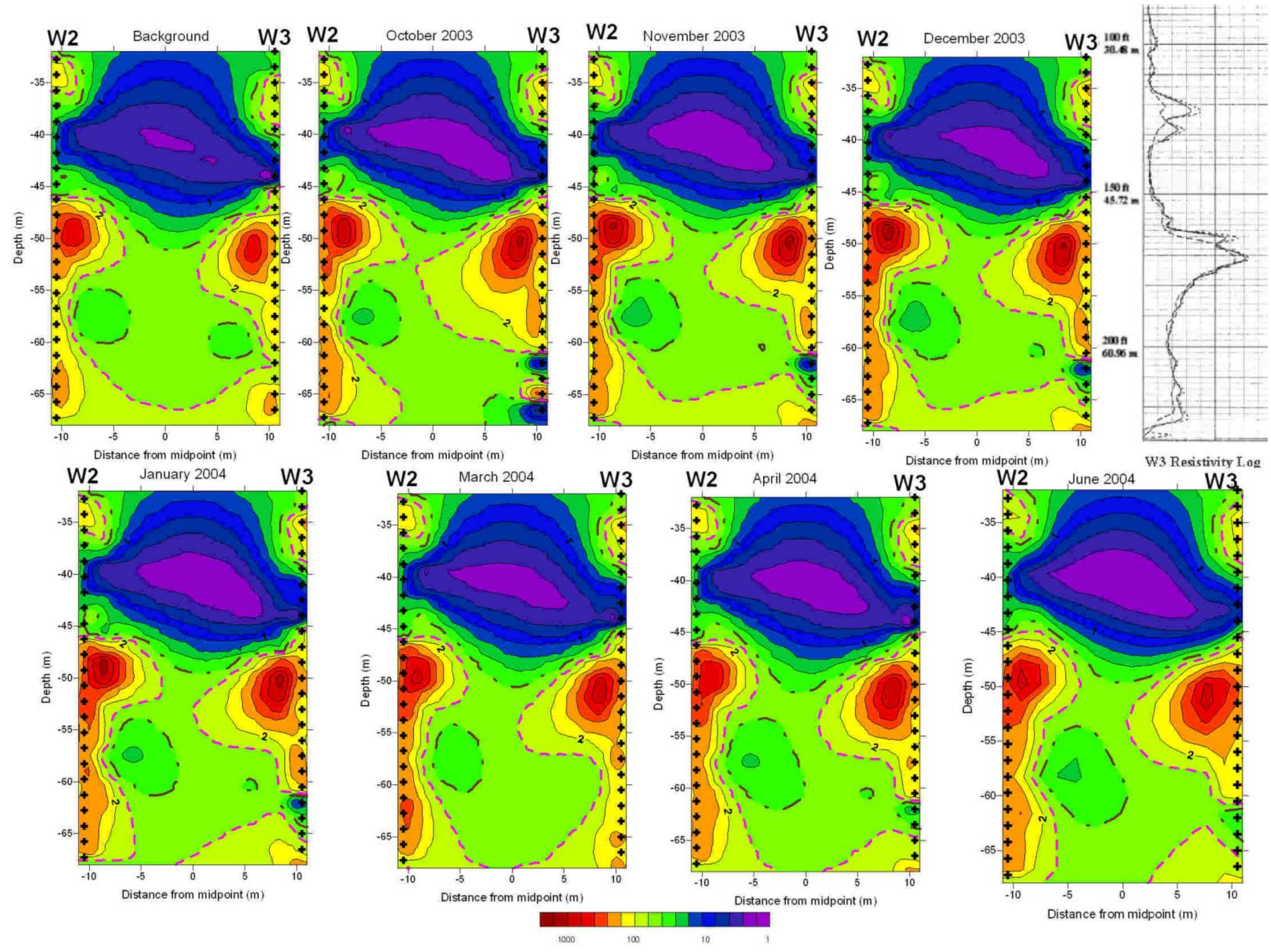


Figure 33. Well #2/Well #3 2-D Inversion Data

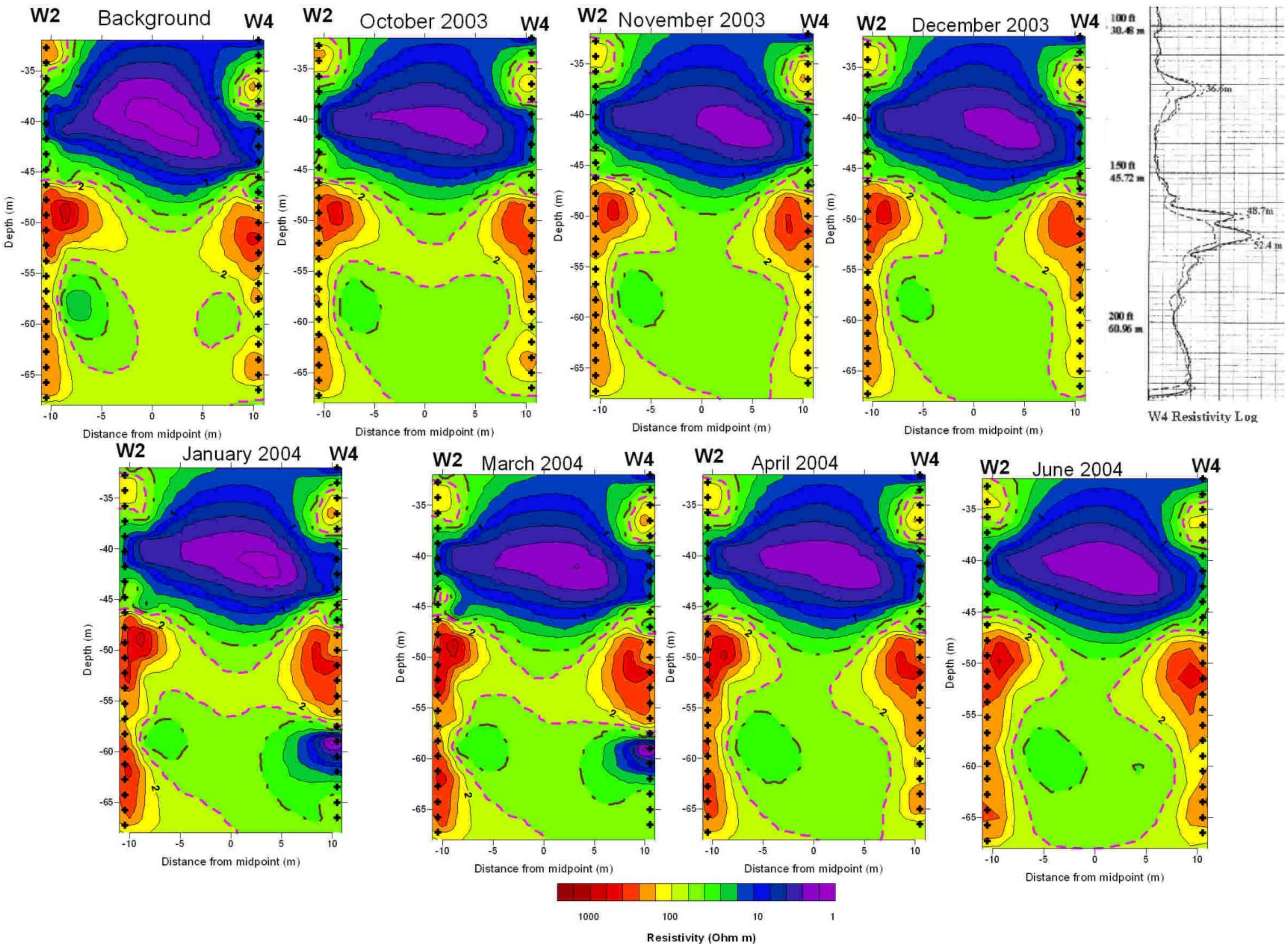


Figure 34. Well #2/Well #4 2-D Inversion Data

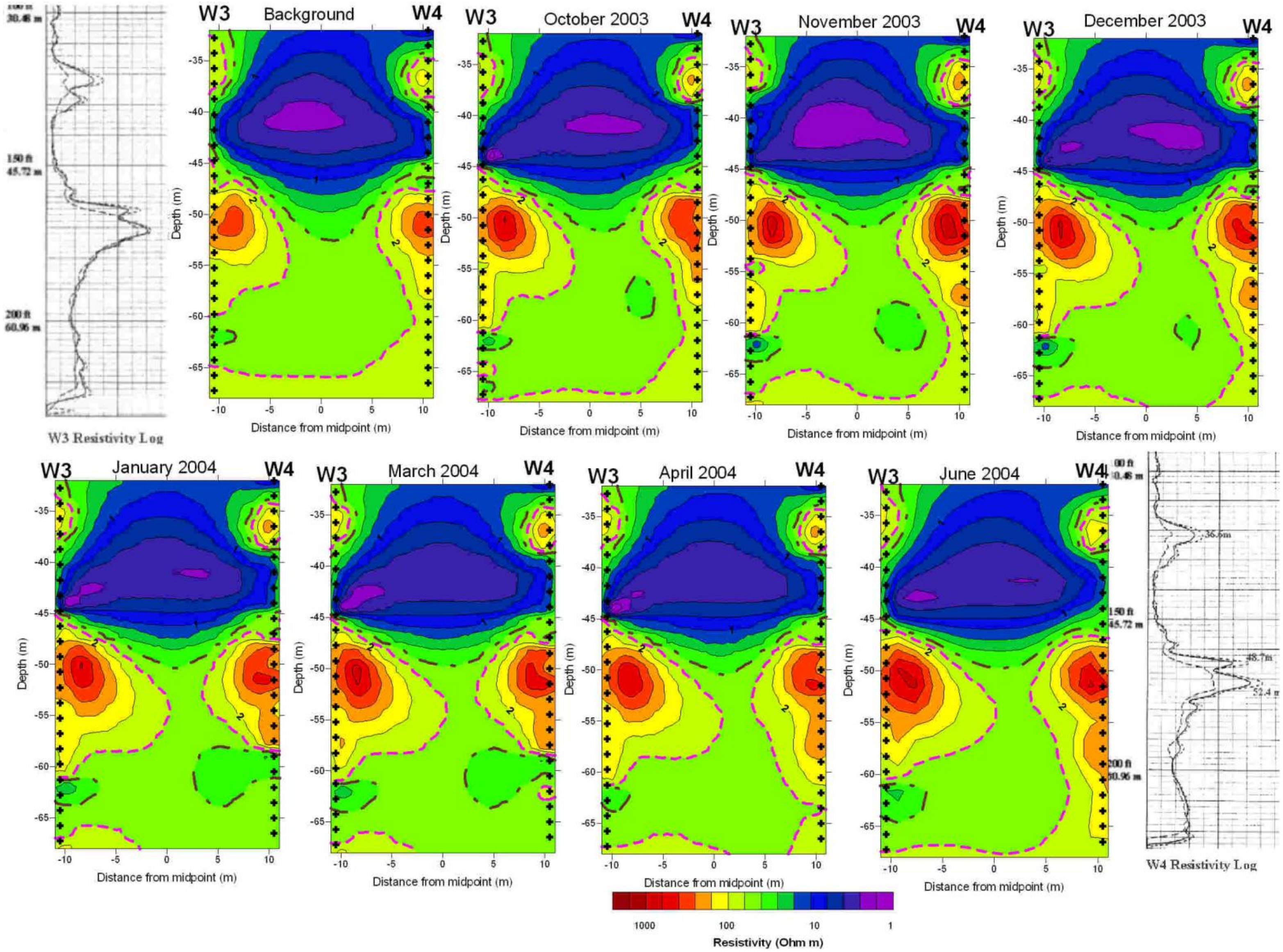


Figure 35. Well #3/Well #4 2-D Inversion Data

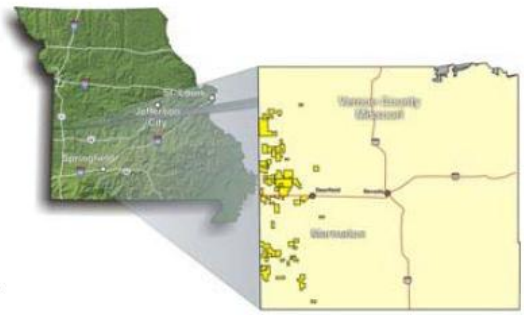
MEGAWEST ENERGY CORP

MANAGEMENT | PROJECTS | INVESTOR RELATIONS | TECHNOLOGY | CONTACTS

Missouri

The Missouri lease holdings include a 100 percent interest in 32,909 gross unproved acres of land. The Company has drilled 38 exploration/delineation wells (drill, log and abandon) with a 66% success rate and completed 120 development, service and observation wells with a 100% success rate to date.

MegaWest has two projects in the area, Marmaton River and Grassy Creek, as described below. Subject to exploration success, it is anticipated that up to 14 additional projects of similar design may be drille



Marmaton River

The Marmaton River project area spans 215 gross acres and comprises 13 steam injection wells, 40 producing wells, one water source well and one water disposal well on approximately 10 acres. A steam generation and oil treating plant with a throughput capacity of 500 barrels of oil per day has been constructed on site. Commissioning and start up of the facility was completed on March 16, 2008 when steam injection commenced. First oil sales from the project occurred on August 4, 2008 and daily production levels are increasing. The remaining project acreage will be drilled in approximately 10 acre increments in future years to extend the project life and maintain the target production plateau. Drilling of 10 injection wells and 24 production wells on approximately 10 additional adjacent acres is underway.

Marmaton River Project

Click her to view Slideshow
March 19, 2008
(39 Slides)

Grassy Creek

Grassy Creek Project

The Company is midway through construction of a second project, Grassy Creek, comprising 46 production wells, 15 injection wells, 2 observation wells and 2 service wells on approximately 15 acres. The total leased area of the project is 320 gross acres. To date, construction of the Grassy Creek facilities is estimated to be 50% complete and drilling of the project wells is completed. The Company intends to complete the construction and commence injection of steam by the fourth calendar quarter of 2008. This project will have a steam injection and production treating plant similar to ~~Marmaton River~~ with a design capacity of 500 barrels of oil per day. Ongoing drilling is planned to maintain this project at target production rates.

(Information updated to August 28, 2008)

Figure 36. Megawest Energy Projects in Missouri (http://www.megawestenergy.com/)

Sample ID	Depth, feet	Formation	Rock Type	Young's Modulus, Mpsi	R^2
03030401-A	110.50	Shale	Shale	1.03	0.9996
03030501-A	119.00	Shale	Shale	1.44	0.9996
03030502-A	121.50	Bluejacket	SS	3.94	0.9998
03031101	128.50	Bluejacket	SS	3.12	0.9995
03032401-B	130.00	Bluejacket	SS	2.33	0.9988
03032601	136.50	Rowe	Coal	1.48	0.9989
03032502-B	138.50	Rowe	SS	2.44	0.9996
03030701	144.00	Warner	SS	0.92	0.9994
03031102-A	167.00	Warner	SS	1.30	0.9985
03032402	170.00	Warner	SS	1.72	0.9984
03031001-A	176.00	Warner	SS	0.96	0.9988
03032501-B	178.00	Warner	SS	1.56	0.9991
03031002-B	191.00	Warner	SS	1.52	0.9957
03030601	200.30	Graydon	Shale	3.27	0.9987
00000211-B	211.00	Graydon	Shale	1.43	

Table 1. Triaxial Stress Analysis of Core Samples

Stage	Slurry Volume (M-Gal)	Fluid Volume (M-Gal)	Proppant Conc Strt (PPG)	Proppant Conc End (PPG)	Rate (BPM)	Fines Conc. (Vol Fraction)
1	2.00	2.00	0.00	0.00	15.0	0.00
2	3.07	3.00	0.50	0.50	15.00	0.00
3	3.14	3.00	1.00	1.00	15.0	0.00
4	3.27	3.00	2.00	2.00	15.0	0.00
5	3.54	3.00	4.00	4.00	15.0	0.00
6	3.82	3.00	6.00	6.00	15.0	0.00
7	4.09	3.00	8.00	8.00	15.0	0.00
8	4.36	3.00	10.00	10.00	15.0	0.00

Table 2. Hydraulic Fracture Treatment Design

Table 3 MEOR Treatments, Phase III

Date		Para-Bac	Ben-Bac	Well Corroso-Bac	Flush	Tbg. Press	Csg. Press
10/08/03	8 gals	4 gals	8 gals	Well #5	1 bbl	n/a	0
	8	4	8	Well#1	1 bbl	n/a	0
11/19/03	8 gals	8 gals	4 gals	Well#5	1 bbl	n/a	0
	.8	.4	.8	Well#1	1 bbl	n/a	0
	4	2	4	Well#2	1 bbl		
	4	2	4	Well#3	1 bbl		
	4	2	4	Well#4	1 bbl		
12/22/03	.8	.4	.8	Well#5	1 bbl	0	32
	.8	.4	.8	Well#1	1 bbl	0	35
	.8	.4	.8	Well#2	1 bbl		
	.8	.4	.8	Well#3	1 bbl		
	.8	.4	.8	Well#4	1bbl		
1/16/04	.8 gal	.4 gal	.8 gal	Well#5	5 gals	blow	68
	.8	.4	.8	Well#1	5 gals	blow	72
	.8	.4	.8	Well#2	5 gals		
	.8	.4	.8	Well#3	5 gals		
	.8	.4	.8	Well#4	5 gals		

*No treatment or measurement in February due to weather

Date		Para-Bac	Ben-Bac	Well Corroso-Bac	Flush	Tbg. Press	Csg. Press
3/18/04	.8 gal	.4 gal	.8 gal	Well#5	5 gals	blow	60
	.8	.4	.8	Well#1	5 gals	blow	70
	.8	.4	.8	Well#2	5 gals		
	.8	.4	.8	Well#3	5 gals		
	.8	.4	.8	Well#4	5 gals		
4/16/04	.8 gal	.4 gal	.8 gal	Well#5	5 gals	blow	62
	.8	.4	.8	Well#1	5 gals	blow	70
	.8	.4	.8	Well#2	5 gals		
	.8	.4	.8	Well#3	5 gals		
	.8	.4	.8	Well#4	5 gals		
5/20/04	.8 gal	.4 gal	.8 gal	Well#5	5 gals	sig blow	68
	.8	.4	.8	Well#1	5 gals	sig blow	72
	.8	.4	.8	Well#2	5 gals		
	.8	.4	.8	Well#3	5 gals		
	.8	.4	.8	Well#4	5 gals		
6/19/04	.8 gal	.4 gal	.8 gal	Well#5	5 gals	sig blow	70
	.8	.4	.8	Well#1	5 gals	sig blow	72
	.8	.4	.8	Well#2	5 gals		
	.8	.4	.8	Well#3	5 gals		
	.8	.4	.8	Well#4	5 gals		

Table 4. Timeline for ERT activities

Date	Dataset Collection	Notes
9/22 - 9/23/03	Background data	*Electrodes installed*
10/24 - 10/26/03	1st data set *	*W4 array removed*
11/15 - 11/16/03	2nd data set	*W4 array reinstalled*
12/20 - 12/21/03	3rd data set	
1/25 - 1/26/04	4th data set	
3/14 - 3/15/04	5th data set	
4/19 - 4/20	6th data set	
6/3 – 6/4	7th data set	

* the numerical classification begins after the background data collection

Appendix

This appendix contains a copy of the preliminary report from Direct Geochemical, scanned copies of all well logs, the hydraulic fracture design provided by NSI and the frac treatment data collected from the two fractured wells (1,5).

DIRECT GEOCHEMICAL

May 2, 2003

Dr. Shari Dunn-Norman
University of Missouri
Rolla 149 McNutt Hall
1870 Miner Circle
Rolla, MO 65409-0420

Re: Initial Findings: Cushard Heavy Oil Field

Dear Shari:

The attached is a preliminary report on the findings of the surface geochemical survey undertaken by Direct Geochemical at the Cushard Heavy Oil Field, being part of a Department of Energy project entitled: "Development Practices for Optimized MEOR in Shallow Heavy Oil Reservoirs."

Under the original scope of work proposed, Direct Geochemical was to have received a set of soil samples and analyzed them for a variety of components, including light and heavy hydrocarbons using several methods. During the ensuing period of time, Direct Geochemical has developed additional experience with other methods and is in the process of applying such methods to the samples received from the field. This report deals with the first three methods applied:

C1-C6 Light Hydrocarbons
Synchronous Scan Fluorescence Heavy Hydrocarbons
Trace metals by aqua regia extraction and ICP-ES finish

As additional data come available, they will be forwarded to you.

Thank you for the opportunity to participate in this project.

Sincerely,

Jim Viellenave President

130 Capital Drive, Suite C • Golden, Colorado 80401 • Phone 303.277.1694 • FAX 303.278.0104 Web Site: www.DirectGeochemical.com E-Mail to: info@DirectGeochemical.com

Preliminary Findings
Surface Geochemical Survey
Cushard Heavy Oil Field
Vernon County, Missouri

Introduction

Under terms of a US Department of Energy Project, entitled "Development Practices for Optimized MEOR in Shallow Heavy Oil Reservoirs," DE=PS26-02NT15378-1, Direct Geochemical performed a surface geochemical survey across portions of the Cushard Oil Field in Vernon County, Missouri. The primary objective of the survey was to determine what geochemical characteristics most closely could be used to identify and map "sweet spots" in the Warner Sandstone. This process would optimize the location of both production wells and enhanced recovery system wells, as contemplated elsewhere in the project. In addition, the geochemical data would be evaluated to determine if other patterns or correlations were observed.

Procedures and Methods

Surface geochemical surveys rely on the movement of hydrocarbons from subsurface accumulations to the surface where they can be captured, analyzed, and evaluated as to meaning. In addition, they can rely on byproducts of chemical and biological processes at and near the surface, which alter such conditions as pH, redox, conductivity, and other characteristics. Finally, there is increasing evidence of the migration of very small concentrations of trace metals in response to geologic processes, including those that are responsible for the accumulation of hydrocarbons.

The above are manifestations of a series of physical and chemical processes, which have been described by various authors, but rarely documented thoroughly. Among the processes are pressure and temperature gradients from subsurface to surface, hydrodynamic influences, gas migration (methane, helium, etc.) and others. In the present case, virtually none of these exist in any significant way: the Warner SS is located a few hundred feet below grade; there is no gas pressure and no water drive. Were these processes operating, the oil would be producible. Thus, conventional reasons to expect surface geochemistry to operate are not obviously in play at this site.

The literature contained no significant reports of previous surface geochemical studies designed to find such sweet spots in heavy oil fields. As a result, Direct Geochemical proposed to evaluate a series of methods, ranging from conventional C1-C6 hydrocarbon concentrations in soil samples, to heavy hydrocarbon residues, trace metals, physical characteristics, etc.

The survey was divided into two components:

The analog or model samples
The grid of unknown or prospect samples

The model samples were obtained from the vicinity of 5 wells of known character. Three were located within the Cushard Field: Cushard 1 and Cushard 4, which have been identified as good wells for treatment by MEOR methods to enhance production; and Cushard 12, which was identified as being unsuitable for such treatment. Evaluation of the wells logs and permeability/porosity tests confirmed the characterization. In addition, soil from near two wells from outside the Cushard Field was also sampled. The Ellis 1 is a dry hole, located a mile or so SE of the field, in a separate producing area. The Harpel well is located several miles to the north-northeast of the Cushard field in a very different environment.

No well logs were available to Direct Geochemical from the Ellis or Harpel wells, so it is not possible to comment on their similarity to the Cushard field.

The grid consisted of three sections. The center section incorporated 53 samples, acquired on approximately 200-foot centers. The western section used 31 samples on 400-500 foot centers. The eastern section used 15 samples on 300-400 foot centers. The sampling locations are shown in Figure 1, Base Map. Students using protocols developed by Direct Geochemical acquired all of the samples.

Analysis

Several analytical methods were planned for the project.

1) Thermal Desorption C1-C6 Light Hydrocarbons by GC-FID 2) Heavy Hydrocarbons (C6-C30) by Synchronous Scan Fluorescence 3) Gasoline Range Hydrocarbons (C6-C13) by GC-PID/FID 4) Trace metals by various extractions
  i. Aqua regia
  ii. Partial extraction 5) Physical characteristics: pH, conductivity, ferrous iron ratios

Data Presentation

Methods 1, 2 and 4i have been completed and are the results are included in this report. The data are presented in this report in two ways. Full, raw data are given from all three methods in a spreadsheet. In addition, we have used a variety of interpretive tools to characterize the geochemistry of productive and non-productive areas and then predict areas of high potential for productivity in the grid. These data are given in map form.

Interpretive Methods

The methods described here are applied to light hydrocarbon (C1-C6) data, Synchronous Scanning Fluorescence data, Gasoline Range Hydrocarbon (C6-C13) data, trace element data, including iodine, and oxidation/reduction conditions (O2/CO2, ferric/ferrous, etc.). The data can be used as somewhat independent data sets or can be fully integrated into a single data set.

Two independent methods are used to interpret geochemical data:

- o Compositional
- o Quantitative

Quantitative Interpretation

The absolute concentration of individual or groups of geochemical components is sometimes directly related to the subsurface accumulation of hydrocarbons, especially in simply stratified environments involving conventional trapping mechanisms. (It is less frequently observed in relation to coal bed methane deposits or accumulations such as the Heavy Oil Field.) Ratios of hydrocarbons provide additional information on source types. These include wetness and dryness ratios, plus hydrocarbon ratios that indicate whether the samples are in the oil, gas, or background window. Ratios, as well as raw data, can be mapped directly. Most regions exhibit “apical” anomalies, but “halos” are not unknown. Multiple productive horizons, presence of intense fracturing or faulting, and other factors can make interpretation difficult and are the cause of both false positive and negative anomalies.

Compositional Interpretation

The composition of geochemical data can reflect the character of subsurface accumulations. It is important to identify and correlate the numerous near-surface compounds with their sources—particularly petroleum accumulations. Many compounds, including methane and ethane (plus such obvious ones as ethene and propene), have vegetative or biogenic origins. It is vital to separate the petroleum related compounds from the others. In addition, different accumulations yield different near-surface compositional signatures, which can be used to determine if the accumulation is in the oil or gas range. In the case of indirect indicators, metals, pH, conductivity, redox character, both genetic relationships and geographic patterns are important to evaluate.

Statistical Methods

Two primary statistical methods are generally applied to compositionally evaluate geochemical data:

- Principal Component (Factor) Analysis.
- Discriminant Analysis.

Both Factor and Discriminant Analysis are multivariate statistical tools that allow the evaluation of large numbers of data variables simultaneously. The use of these multivariate tools permits the user to appreciate the existence of complex factors, comprised of multiple individual variables in the data set. In oil and gas exploration, this is important because the presence of oil or gas in the subsurface is rarely imaged by one or two variables.

The basic statistical method summarizes the data set in a series of mathematical “vectors” or “factors,” which are combinations of co-varying hydrocarbon species. The Factors (when combined together) account for all of the variation in the dataset, but in fewer variables than are in the data set. For example, there may be 15 variables measured in a dataset, but there may be only 5 Factors of significance.

Factor Analysis identifies and ranks these factors in descending order of the amount of variance in the dataset that is accounted for. Factor 1 accounts for the most variance, Factor 2 the second greatest, and so on. For each Factor, it is possible to identify the mixture of variables (components) and their relative importance. An examination of the chemistry of each Factor may allow for the identification of the source (or cause or origin) of the mixture in the Factor.

It is very common for Factor Analysis of hydrocarbons to result in at least one Factor reflecting a mixture of light hydrocarbons (that can be related to “gas,”) and at least one reflecting a mixture of heavy hydrocarbons (that can be related to “oil,”) depending on the basin and environment. The other factors can be related to environmental characteristics, soil changes, or contamination, or sampling and laboratory correlated components are important because they describe compounds that vary together, meaning they relate to one another genetically, and belong together. As a result, they are probably sourced together. Thus, a Factor can allow the user to describe the spatial and chemical relationship of surface chemistry with subsurface chemistry or subsurface geologic processes. The degree to which any given sample exhibits the presence of a given factor can be mathematically calculated, and the result (Score) can be mapped and contoured.

Discriminant Analysis is a form of pattern recognition and matching, in which statistically significant groups of samples are used as "models" of known geologic conditions, and then compared against grid or unknown samples. The method calculates the probability of an unknown sample being like the model composition for a given geologic condition. The Discriminant probability values or scores are mapped and contoured. This method is usable under two circumstances:

- o There is a sufficient number of model samples to generate a representative or statistically significant population
- o The model area is representative of the production conditions desired

The objective of modeling is to identify two key phenomena for each known geologic condition (e.g., an oil or gas field). The first is to identify the chemical signature, which is most diagnostic of the geochemistry over oil (or gas) production while differentiating it from background. The second is to identify the range of chemical signature that is representative of that oil or gas production. To do so requires a potentially large number of samples, with experience showing that at least 20-25 samples per class of geologic condition being the minimum. If, however, reservoir, soil, or other conditions are variable, then a larger number of samples may be needed.

Once the statistical analysis is performed, whether using Factor Analysis or Discriminant Analysis, it is essential to evaluate the results in terms of both geology and chemistry. Both the Factor and Discriminant analyses of petroleum related geochemistry surveys reveal a compositional relationship among a number of co-varying hydrocarbon components. It is this group of components and their relative abundances that must make chemical sense when used to map a geologic phenomenon to be considered valid.

Results

Table 1 gives the raw data from the light and heavy hydrocarbon and trace metal (aqua regia extraction) analyses. These data were used for all of the interpretive work to follow. Table 2 provides average values for different classes: oil and dry for all of the analytes generated. First, some general observations:

1) The Harpel well is different from the Cushard productive wells. It exhibits lower overall concentrations of hydrocarbons almost always. It predicts as a "weaker" version of the Cushard 1
and 4 wells. It is a heavier oil, according to Jim Long. Its fingerprint is not heavier, using these
measures, than the Cushard 1 and 4, but actually relatively similar to them. But, it generates

a weaker signal, probably owing to its overall heavier nature.

2) The data suggest that the Cushard 4 well may be slightly better than the Cushard 1, but in the absence of testing a large number of wells, this could be minor variation on a theme.

3) The Ellis dry hole and Cushard 12 both look quite dry. The Ellis exhibits much high very light hydrocarbon responses, but these are not indicative of producible oil, so are not important in the analysis.
4) On a limited data set, it appears that the oil wells as a group show higher arsenic, calcium, and magnesium, than the dry holes, but are almost uniformly lower than dry holes in the transition elements. Because of limited data, we do not know to what extent this is a function of soil type and local conditions or whether it responds to redox conditions.
5) A simple observation of these data strongly supports the notion that the surface geochemistry is quite different and can be successfully differentiated. The differences in concentration among the light hydrocarbons is subtle, and well within naturally occurring variation. This means that the light hydrocarbons should be used to identify drilling locations only with the use of more sophisticated statistical tools. The fluorescence data exhibit more obvious variations between the producing wells and dry holes. This makes a great deal of sense, as we are looking for differences among liquid hydrocarbons, and the heavy hydrocarbon measure does an excellent job of seeing it. The C1-C6 data are probably just beginning to see the differences. The application of C6-C13 should enhance the effects.
6) The application of metals is difficult to understand at this point. If future field work is possible during reasonable weather, there are some measures that will be interesting. Further, it might be possible to get some subsurface correlations by acquiring produced water or in well water samples from the producing horizons across the field.

Light Hydrocarbon Data

Figure 3 provides a graphic illustration of the results of the compositional evaluation of the light hydrocarbons. The height of the bar indicates the relative importance of the compound for identifying producible oil. In other words, it is primarily the heavier of the hydrocarbons that differentiate the producing from dry areas. Note that methane is not a discriminant at all. Too much of the methane is not associated with oil and therefore is part of background.

Using this compositional model, we used Discriminant Analysis to calculate the probability of each unknown or grid sample being like the producing oil areas. A map of these is shown in Figure 4. Each map shows the three grid areas, and as insets, the model samples. The values are reported as bubbles of different colors and sizes. There is a clear zone of high scores extending from the NE part of the main grid to the southwest part of the grid, and extending in somewhat spotty fashion, across the western grid toward Cushard 4. Cushard 1 appears a bit isolated, although the grid did not expand around the well. Of note, Cushard 7 and the area around it, appears not to be particularly prospective using this measure.

Two other measures were mapped as well, to illustrate what the Discriminant function was accomplishing. Figure 5 maps percent Pentane, which approximates the findings of the Discriminant. Figure 6 shows the Wetness Ratio, which is the percent C4+ hydrocarbons. The Harpel well is not particularly strong using this analysis. It is easy to see, among the 3 maps and the compositional fingerprint, that the higher carbon number hydrocarbons are clearly differentiating producible from dry.

Fluorescence Data

As seen in the tables, the fluorescence data quite strongly differentiate producible from dry well areas in the model. This is shown graphically in Figure 7. Using only the lightest hydrocarbons, the 290 NM band (single ring aromatics), all of the wells look alike. As hydrocarbons increase into the 2-5 ring range, the intensity at oil wells rises dramatically, while the intensity at the dry holes drops dramatically. This suggests that the evaluation may use both compositional and quantitative measures to assess producibility. Figures 8 and 9 illustrate the results. Figure 8 is the result of compositional analysis, with the key parameters being the 350, 410, and 480 NM bands (heaviest hydrocarbons). Figure 9 shows the intensity readings from the 410 NM band. The distributions are very nearly the same, and are generally similar to those from the light hydrocarbons.

In particular, the areas in the NE corner and along the eastern edge of the main grid appear to be most anomalous. Unlike the light hydrocarbons, the heavy hydrocarbons find the area around Cushard 7 to be anomalous and prospective.

Preliminary Conclusions

Both of the hydrocarbon tests exhibit the ability to discriminate between productive and background models, and predict similar regions of the main grid as most prospective. This area should be considered the most appropriate for future drilling. The area around Cushard 7 needs further investigation. The density of sampling is low, but the differences between the light and heavy hydrocarbons suggest a need for some validation. Perhaps the additional tools we bring to the project will help us.

Century GEOPHYSICAL CORP. century-geo.com	COMPENSATED DENSITY COMPENSATED NEUTRON NO.1

COMPANY	: GARLAND OIL & GAS, INC.	OTHER SERVICES:
WELL	: NO.1	
FIELD	: FAUVERGUE	CDL
COUNTY	: VERNON	CNL
STATE	: MISSOURI	

LOCATION	: 525' FSL & 2855 'FEL
SECTION	: 29
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RANGE	: 33W
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UNIQUE WELL ID.	:

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WITNESSED BY	: MR.LONG
RECORDED BY	: RUNNELS
REMARKS 1	:
REMARKS 2	:

ALL SERVICES PROVIDED SUBJECT TO STANDARD TERMS AND CONDITIONS

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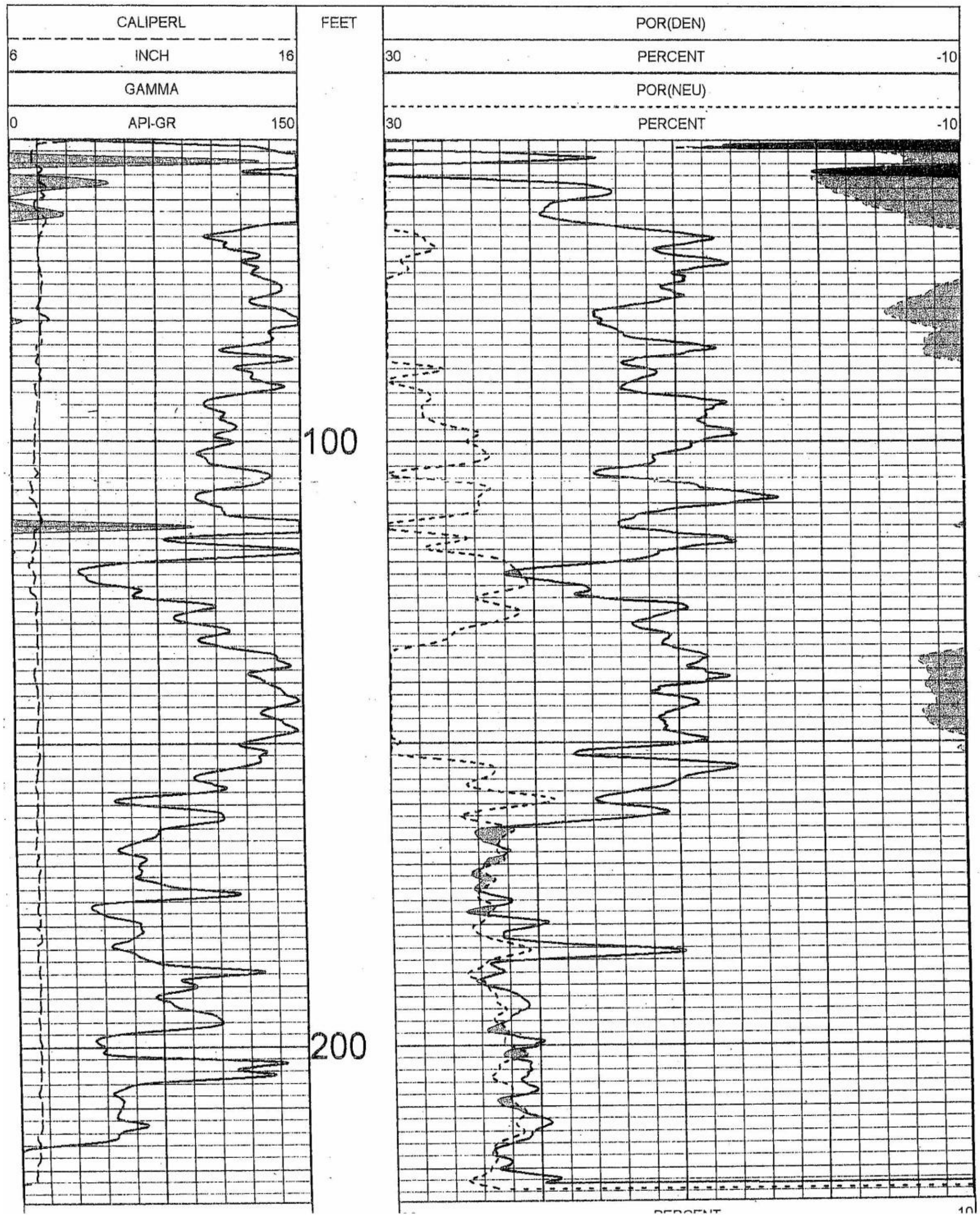

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GEOPHYSICAL CORP.

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GAMMA RAY-RES

NO.1

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WELL	: NO.1	
FIELD	: FAUVERGUE	CDL
COUNTY	: VERNON	CNL
STATE	: MISSOURI	

LOCATION	: 525' FSL & 2855 'FEL
SECTION	: 29
TOWNSHIP	: 36N
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API NO.	:
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RECORDED BY	: RUNNELS
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REMARKS 2	:

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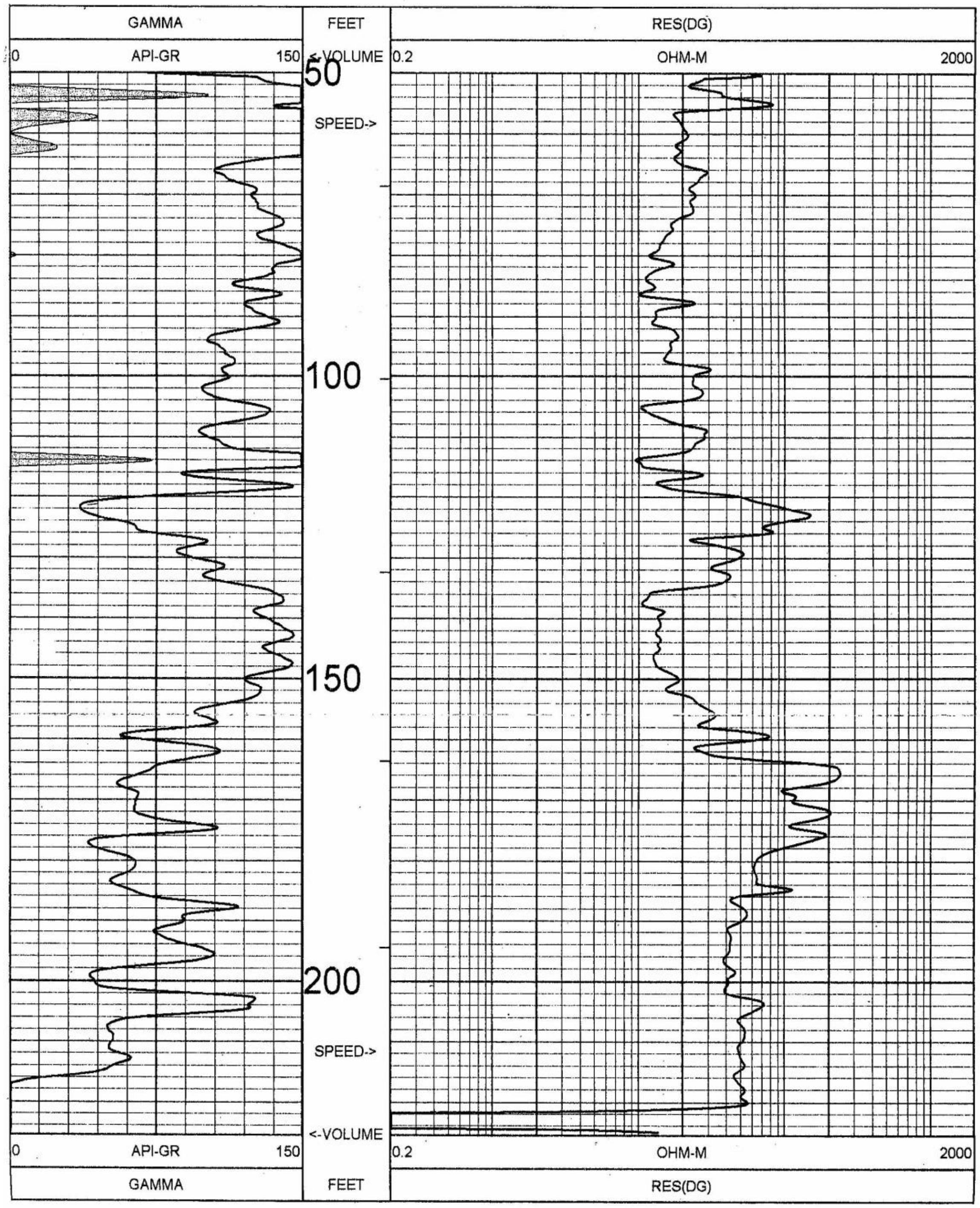
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GAMMA
FEET
RES(DG)

Century GEOPHYSICAL CORP. century-geo.com	COMPENSATED DENSITY COMPENSATED NEUTRON NO.2

COMPANY	: GARLAND OIL & GAS, INC.	OTHER SERVICES:
WELL	: NO.2	9057
FIELD	: FAUVERGUE	CNL
COUNTY	: VERNON	CDL
STATE	: MISSOURI	

LOCATION	: 790' FSL & 2905' FEL
SECTION	: 29
TOWNSHIP	: 36N
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RECORDED BY	: RUNNELS
REMARKS 1	:
REMARKS 2	:

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LOG PARAMETERS

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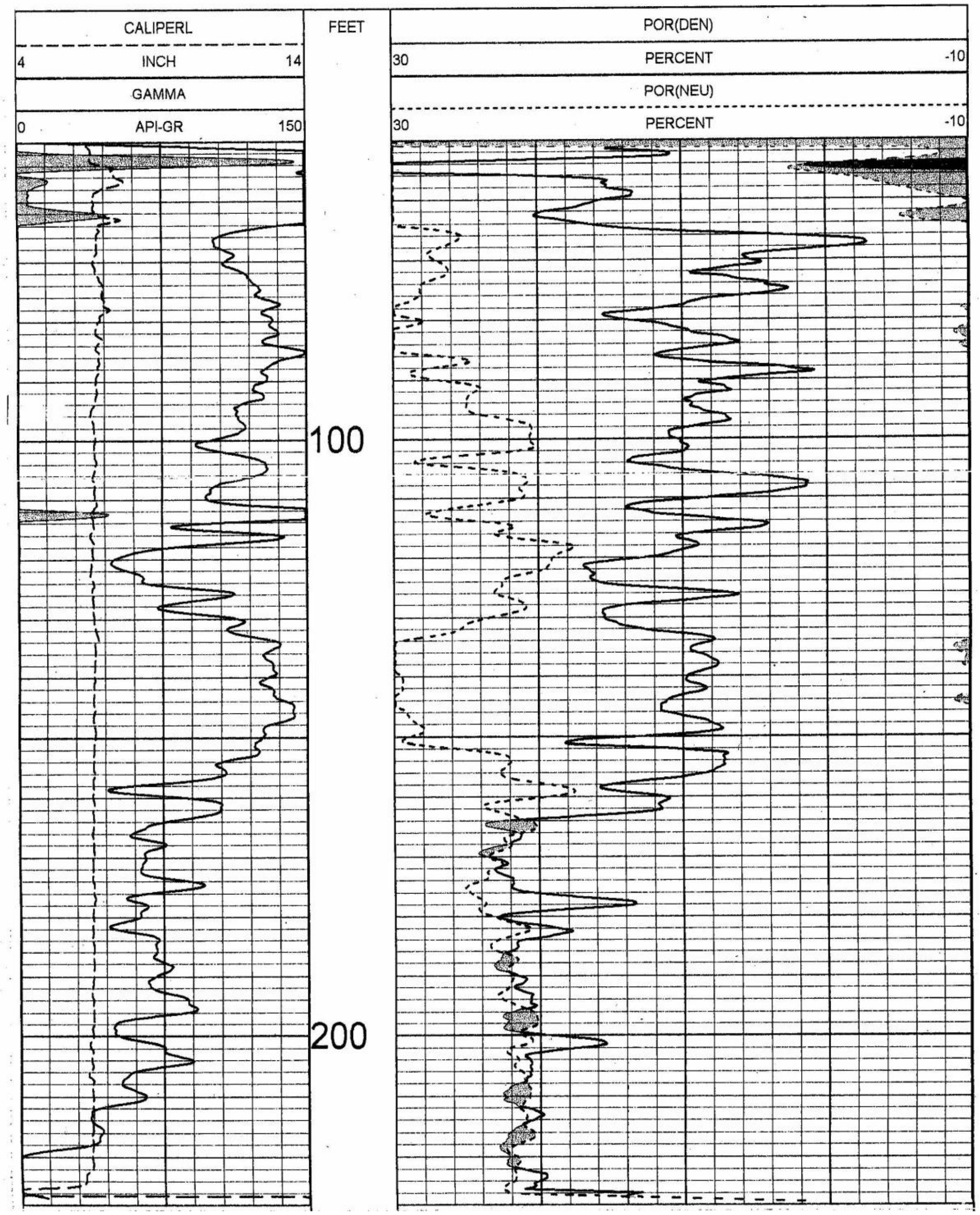

Century GEOPHYSICAL CORP. century-geo.com	GAMMA RAY-RESISTIVITY LOG NO.2

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FIELD	: FAUVERGUE	CNL
COUNTY	: VERNON	CDL
STATE	: MISSOURI	

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TOWNSHIP	: 36N
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RM TEMPERATURE	:
MUD RES	:
WITNESSED BY	: MR.LONG
RECORDED BY	: RUNNELS
REMARKS 1	:
REMARKS 2	:

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GAMMA RAY-RESISTIVITY LOG
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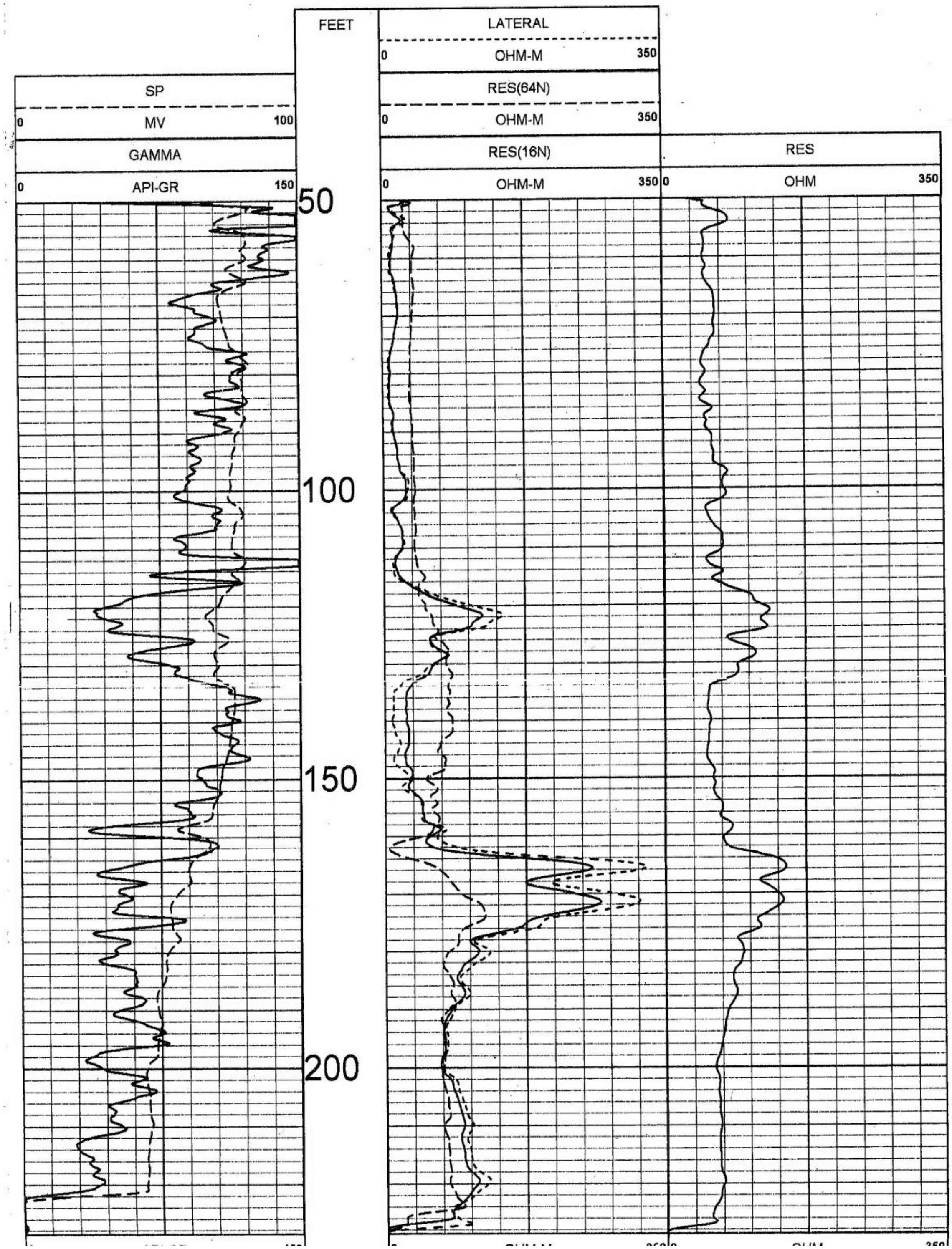

Century GEOPHYSICAL CORP. century-geo.com	COMPENSATED DENSITY COMPENSATED NEUTRON NO.3

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FIELD	: FAUVERGUE	9057
COUNTY	: VERNON	CNL
STATE	: MISSOURI	

LOCATION	: 840' FSL & 2855' FEL
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WITNESSED BY	: MR.LONG
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REMARKS 1	:
REMARKS 2	:

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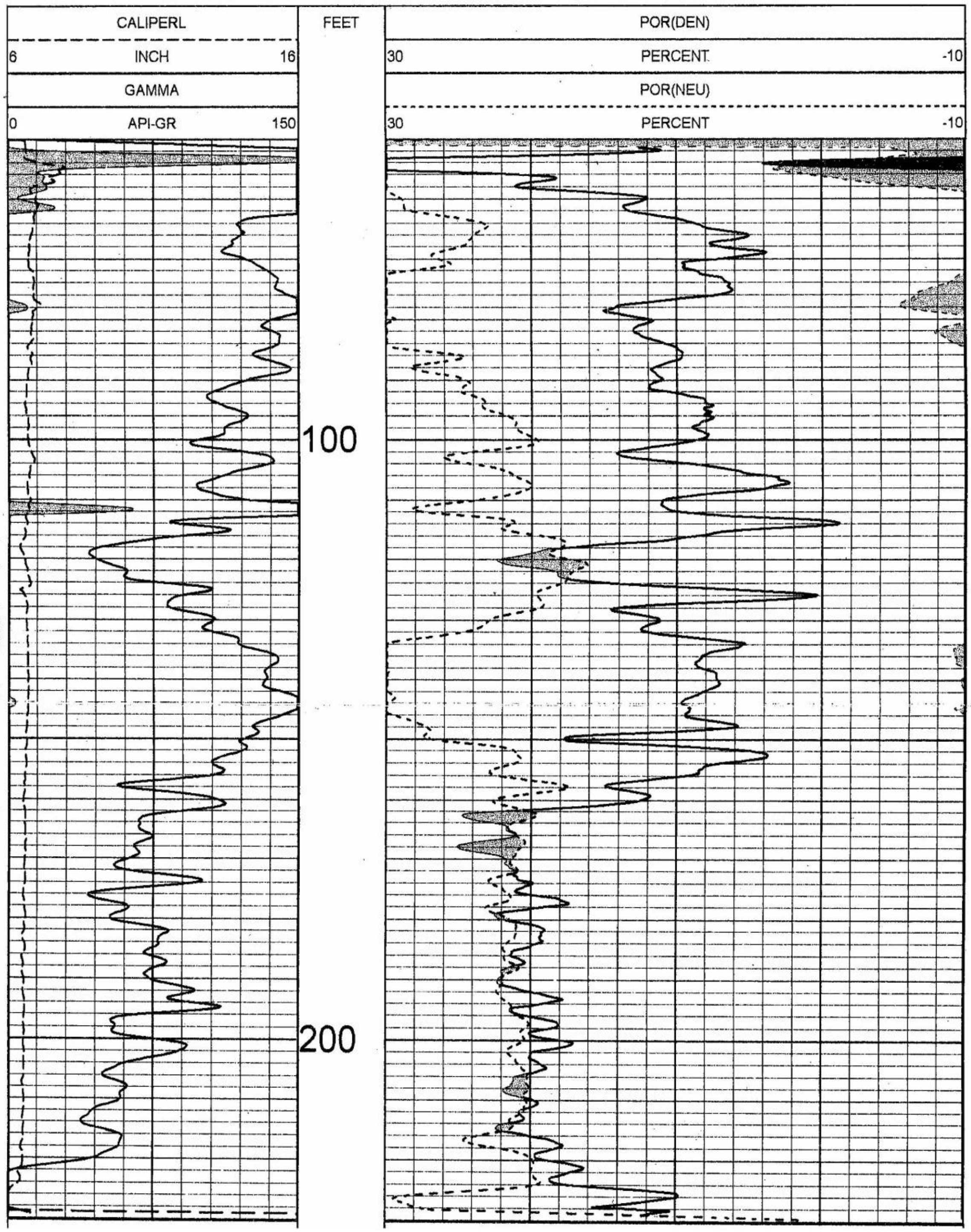
COMPENSATED DENSITY
COMPENSATED NEUTRON
NO 3



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GAMMA RAY-RESISTIVITY LOG

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COUNTY	: VERNON	CDL
STATE	: MISSOURI	

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MUD RES	:
WITNESSED BY	: MR.LONG
RECORDED BY	: RUNNELS
REMARKS 1	:
REMARKS 2	:

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GAMMA RAY-RESISTIVITY LOG
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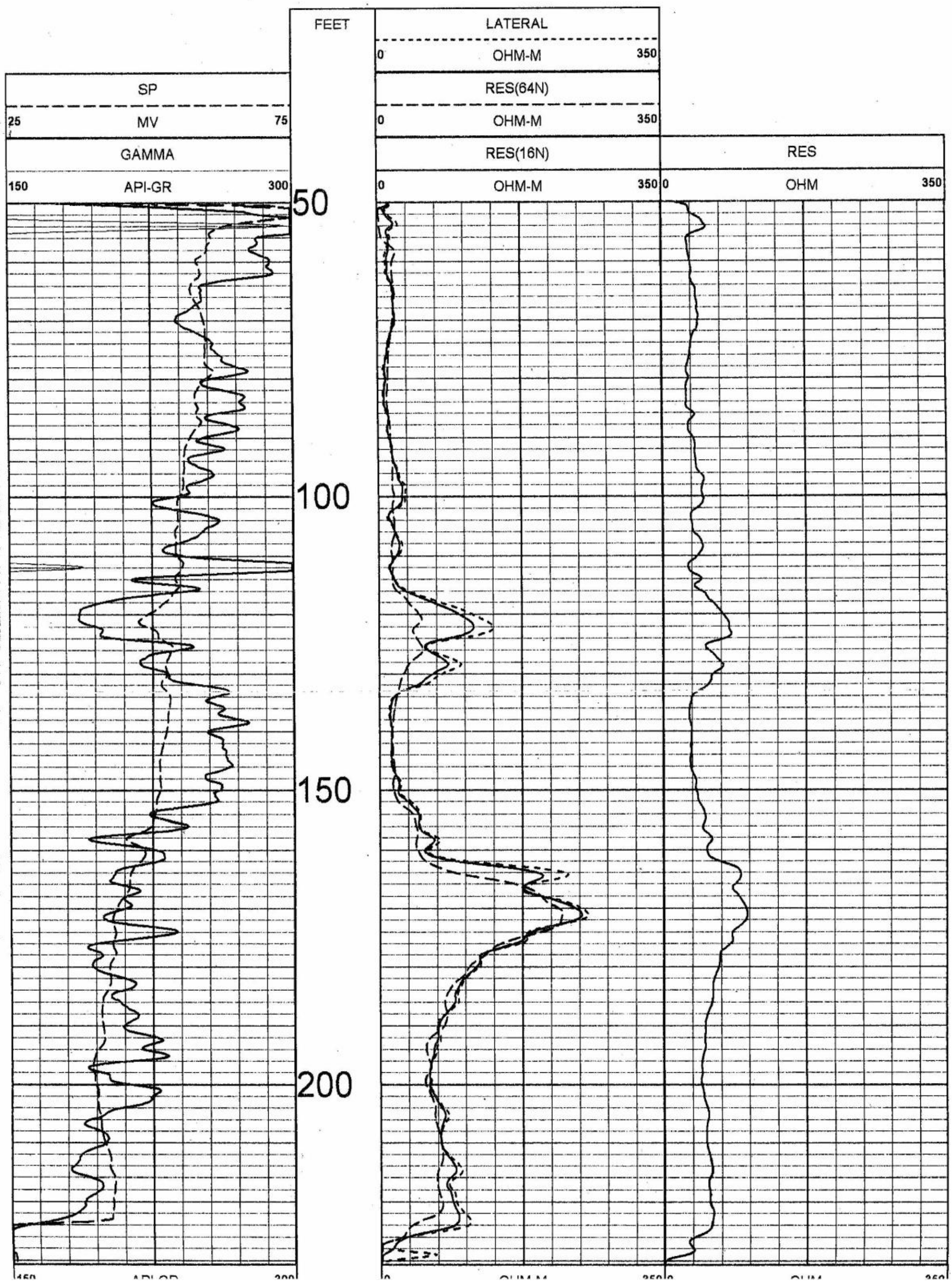

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COMPENSATED DENSITY
COMPENSATED NEUTRON
NO.4

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WELL	: NO.4	
FIELD	: FAUVERGUE	RES
COUNTY	: VERNON	CNL
STATE	: MISSOURI	

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REMARKS 1	:
REMARKS 2	:

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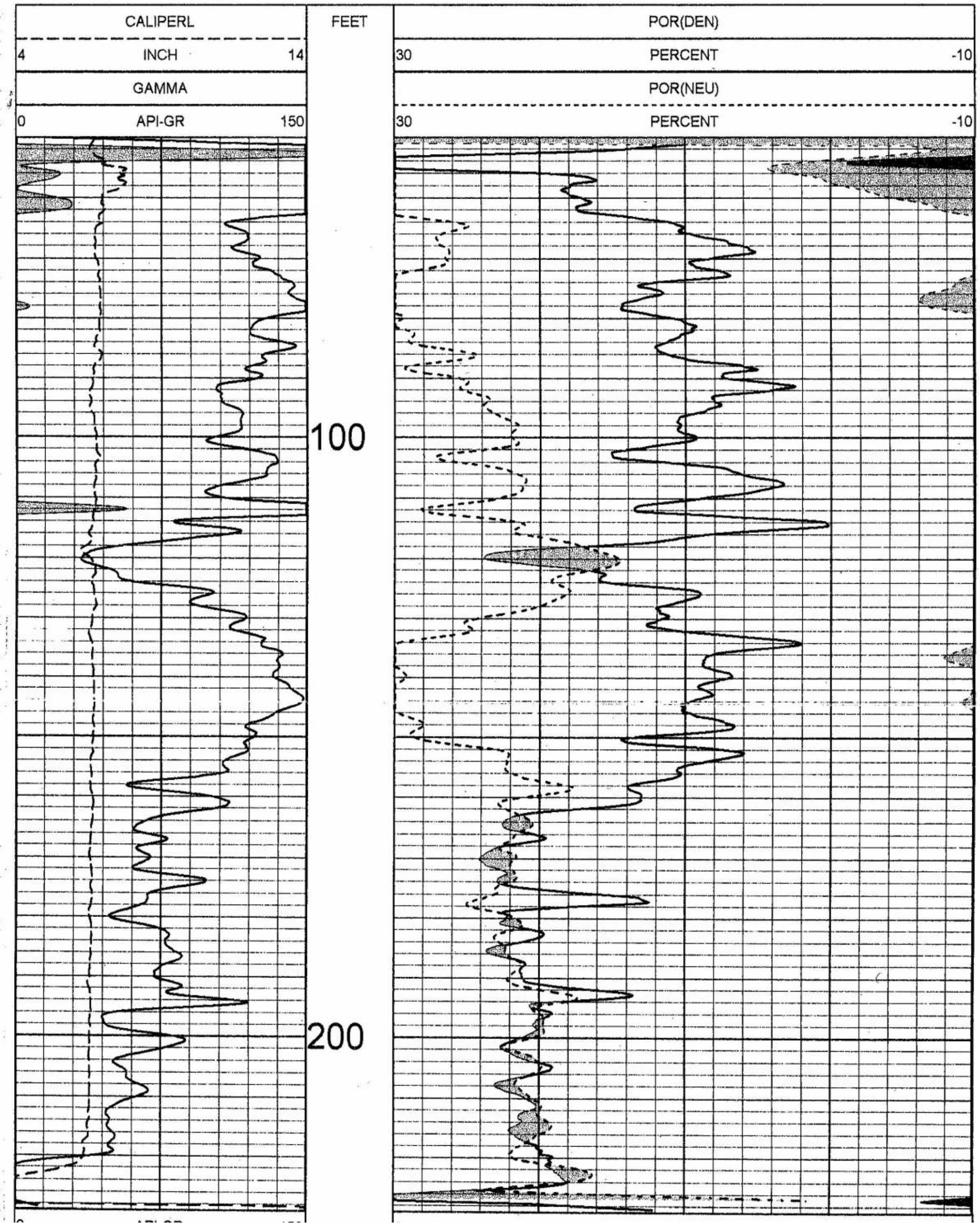
COMPENSATED DENSITY
COMPENSATED NEUTRON
NO 4



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GAMMA RAY-RESISTIVITY LOG

NO.4

COMPANY	: GARLAND OIL & GAS, INC.	OTHER SERVICES:
WELL	: NO.4	
FIELD	: FAUVERGUE	CDL
COUNTY	: VERNON	CNL
STATE	: MISSOURI	

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UNIQUE WELL ID.	:

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CASING BOTTOM	:
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RM TEMPERATURE	:
MUD RES	:
WITNESSED BY	: MR.LONG
RECORDED BY	: RUNNELS
REMARKS 1	:
REMARKS 2	:

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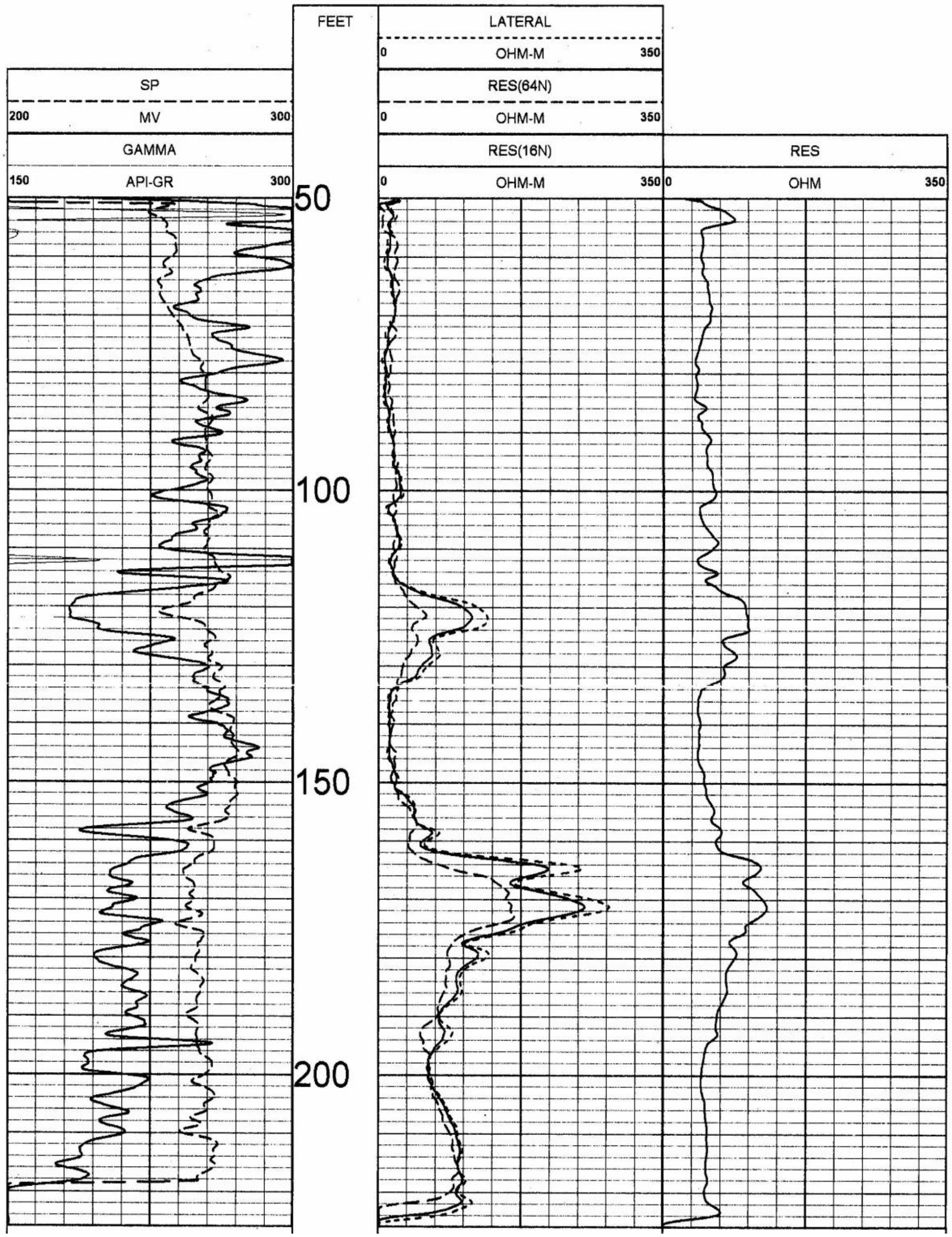
GAMMA RAY-RESISTIVITY LOG
NO 4



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COMPENSATED DENSITY
COMPENSATED NEUTRON
NO.5

COMPANY	: GARLAND OIL & GAS, INC.	OTHER SERVICES:
WELL	: NO.5	
FIELD	: FAUVERGUE	CDL
COUNTY	: VERNON	CNL
STATE	: MISSOURI	

LOCATION	: 1155' FSL & 2855' FEL
SECTION	: 29
TOWNSHIP	: 36N
RANGE	: 33W
API NO.	:
UNIQUE WELL ID.	:

PERMANENT DATUM	: 770.7	ELEVATION KB:	
LOG MEASURED FROM:	G.L.	ELEVATION DF:	
DRL MEASURED FROM:	G.L.	ELEVATION GL:	770.7

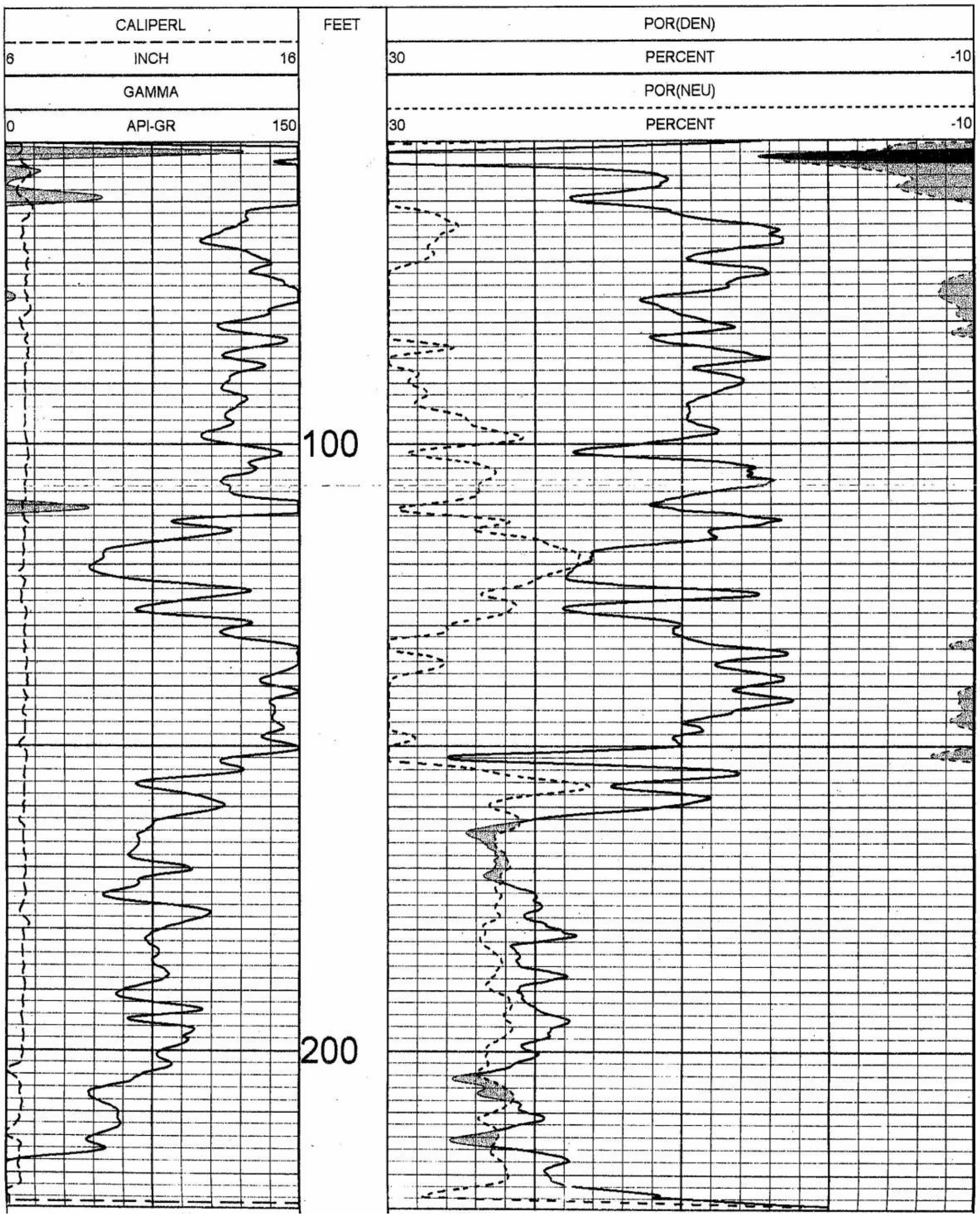
DATE	: 08/12/03
RUN NO.	: 1
DEPTH DRILLER	: 220'
BIT SIZE	: 6.5
LOG TOP	: -2.20
LOG BOTTOM	: 225.50
CASING OD	:
CASING BOTTOM	:
CASING TYPE	:
BOREHOLE FLUID	: WATER
RM TEMPERATURE	:
MUD RES	
WITNESSED BY	: MR.LONG
RECORDED BY	: RUNNELS
REMARKS 1	:
REMARKS 2	:

ALL SERVICES PROVIDED SUBJECT TO STANDARD TERMS AND CONDITIONS

5 INCH LOG, POROSITIES NO.5 08/12/03

LOG PARAMETERS

MATRIX DENSITY : 2.65	NEUTRON MATRIX : SANDSTONE	MATRIX DELTA T : 54
MAGNETIC DECL :	ELECT. CUTOFF : 2500	BIT SIZE : 6.5



Century GEOPHYSICAL CORP. century-geo.com	GAMMA RAY-RES NO.5

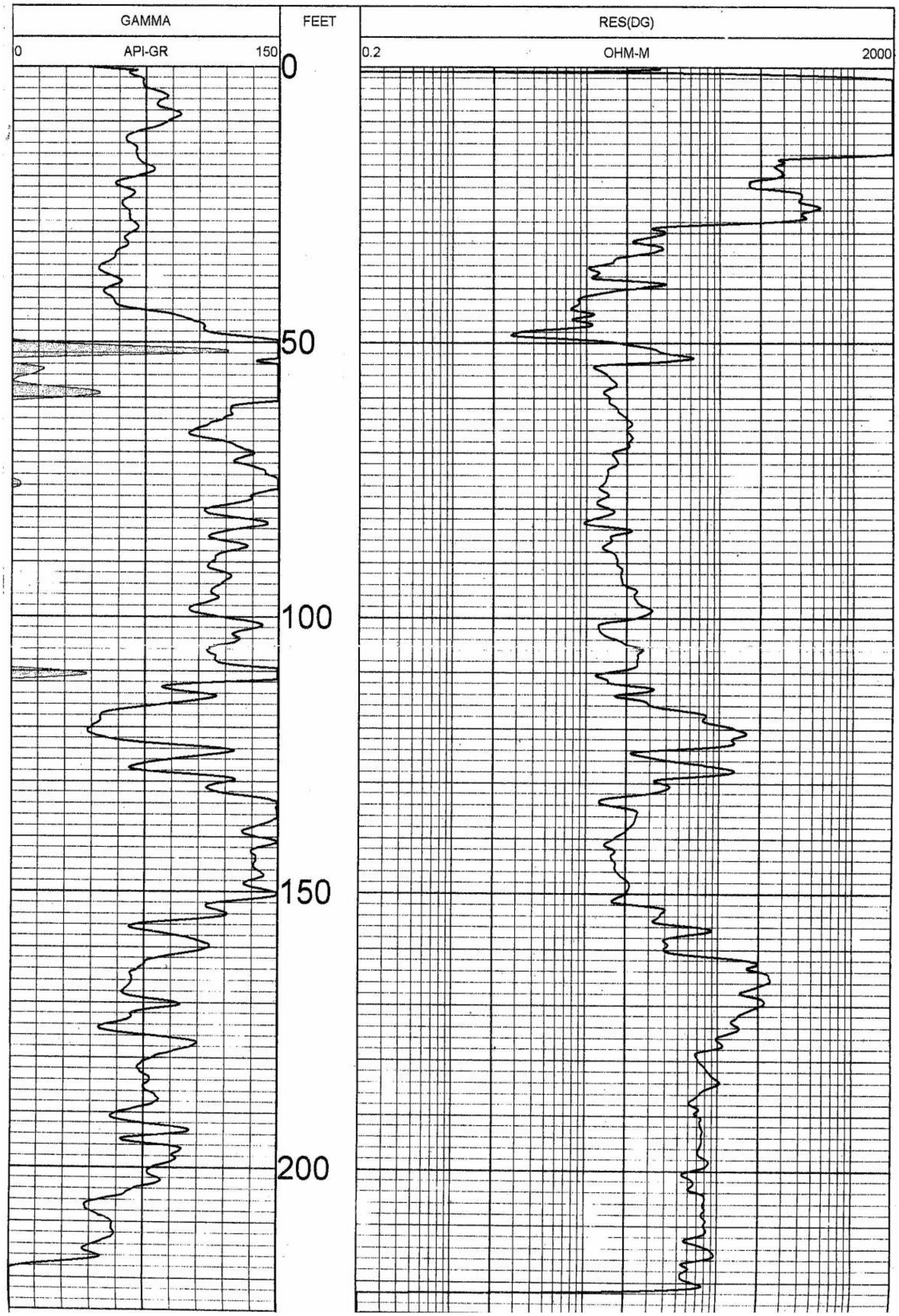
COMPANY	: GARLAND OIL & GAS, INC.	OTHER SERVICES:
WELL	: NO.5	
FIELD	: FAUVERGUE	CDL
COUNTY	: VERNON	CNL
STATE	: MISSOURI	

LOCATION	: 1155' FSL & 2855' FEL
SECTION	: 29
TOWNSHIP	: 36N
RANGE	: 33W
API NO.	:
UNIQUE WELL ID.	:

PERMANENT DATUM	: 770.7	ELEVATION KB:	
LOG MEASURED FROM:	G.L.	ELEVATION DF:	
DRL MEASURED FROM :	G.L.	ELEVATION GL:	770.7

DATE	: 08/12/03
RUN NO.	: 1
DEPTH DRILLER	: 220'
BIT SIZE	: 6.5
LOG TOP	: -2.20
LOG BOTTOM	: 225.50
CASING OD	:
CASING BOTTOM	:
CASING TYPE	:
BOREHOLE FLUID	: WATER
RM TEMPERATURE	:
MUD RES	:
WITNESSED BY	: MR.LONG
RECORDED BY	: RUNNELS
REMARKS 1	:
REMARKS 2	:

ALL SERVICES PROVIDED SUBJECT TO STANDARD TERMS AND CONDITIONS


GAMMA
API-GR
0
150
FEET
0
50
100
150
200
RES(DG)
OHM-M
0.2
2000

TECHNOLOGIES, INC.

UMR-DOE Fracture Stimulation Design for the **Warner Sandstone in the Cushard No. 4**

Background:

The Cushard No. 1 and 5 are planned Warner sandstone completions and fracture stimulations as part of the United States Department of Energy (DS-PS26-02NTI5378-1) project entitled: "Development Practices For Optimized MEOR in Shallow Heavy Oil Reservoirs." The objective of the fracture stimulations is to generate sufficient fracture dimensions (fracture length and conductivity) to facilitate the injection of an MEOR solution and production of the resulting hydrocarbons. To meet these objectives, the treatment will include the use of a 30 ppt linear gel and 20/40 Brady sand to create an effective fracture half length of 200 feet and fracture conductivity of approximately 5 pounds per square foot. The purpose of this memorandum is to document the fracture stimulation and data collection designs for the Cushard Nos. 1 and 5.

Conclusions:

The Warner Sandstone Formation should be perforated at 180 to 200 feet based on the Cushard No. 4 logs.

The static Young's Modulus for the Blue Jacket Sandstone Formation developed through tri-axial compression testing is 3.0 x 10^6 psi.

The static Young's Modulus for the Warner Sandstone Formation developed through tri-axial compression testing is 1.6 x 10^6 psi.

The static Young's Modulus for the bounding shale formations developed through tri-axial compression testing is 1.4 x 10^6 psi.

Executing a tip screen-out fracture stimulation may be difficult due to the limited leak-off resulting from the high oil viscosity in this reservoir.

The use of 20/40 Brady sand is warranted in the initial stimulation due to concerns over Near Wellbore Pressure Losses and mitigation strategies.

The use of a linear gel fracturing fluid is warranted in this shallow heavy oil reservoir.

Recommendations:

1) Perforate the Cushard No. 1 and 5 from 180 to 200 feet based on the Cushard No. 4 logs.
2) Utilize the Young's Modulus determined in the tri-axial compression testing to develop an initial geomechanical dataset and preliminary fracture design.
3) Conduct a small (approximately 500 gallon mini-frac) to determine leak-off coefficient and develop a tip screen-out fracture design while limiting extent of filter cake development.
4) Initially use 20/40 Brady sand but re-evaluate the use of larger more conductive materials following the first fracture stimulation.
5) Use a 30 ppt linear gel as the fracturing fluid.

Introduction:

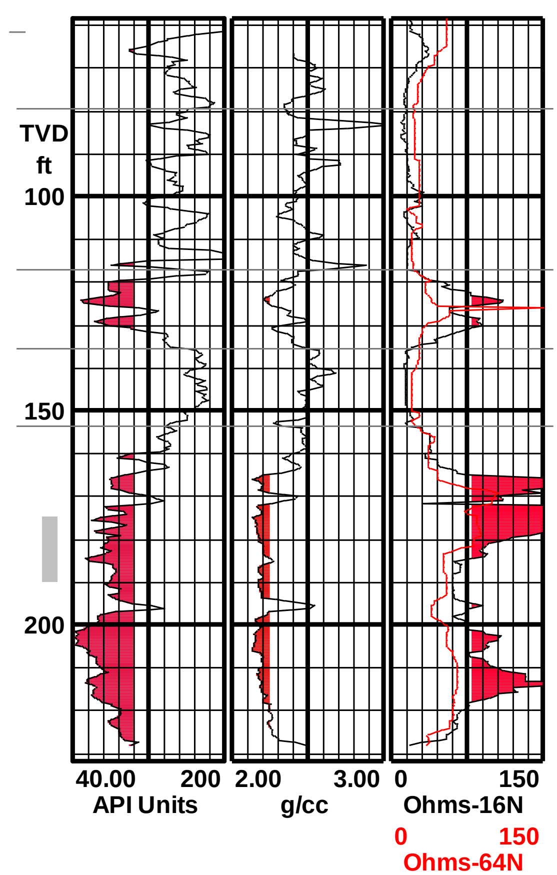
The Cushard No. 1 and 5 are planned Warner sandstone completions and fracture stimulatons as part of the United States Department of Energy (DS-PS26-02NTI5378-1) project entitled: "Development Practices For Optimized MEOR in Shallow Heavy Oil Reservoirs." The objective of the fracture stimulation is to generate sufficient fracture dimensions (fracture length and conductivity) to facilitate the injection of an MEOR solution and production of the resulting hydrocarbons. To meet these objectives, the treatment will include the use of a 30 ppt linear gel and 20/40 Brady sand to create an effective fracture half length of 200 feet and fracture conductivity of 5 pounds per square foot. The purpose of this memorandum is to document the fracture stimulation and data collection designs for the Cushard Nos. 1 and 5.

The purpose of this memorandum is to document the preliminary fracture stimulation design for the Cushard Nos. 1 and 5.

Geomechanical Dataset Development:

The purpose of this evaluation is to develop a geomechanical dataset that can be used to develop a preliminary design for the Warner Sandstone Formation in the Cushard Nos. 1 and 5. The process of developing a geomechanical dataset includes the development of a profile with depth of Young's Modulus, in-situ stress, and fracture fluid leak-off. Fortunately, core from the Blue Jacket and Warner Sandstone Formations and surrounding shales was available and tri-axial compression tests were conducted to determine Young's Modulus. In-situ stress and leak-off coefficient estimates were developed based on experience in similar shallow heavy oil reservoirs. The subsequent sections detail this evaluation and the development and calibration of a geomechanical dataset for use in optimizing the completion interval and fracture design. Note, since no logs are presently available from the Cushard Nos. 1 and 5, logs from the Cushard No. 4 were utilized in this analysis.

Figure 1: GR-Density-Resistivity Logs



In-Situ Stress Contrast

The in-situ stress contrast in the Cushard No. 4 was assumed to be minimal given the shallow nature of the reservoir and limited production and subsequent lack of depletion from the Warner Sandstone Formation in the area. As a result, a radial fracture geometry (either vertical or horizontal) was assumed. This assumption will be tested with the mini-frac test to be conducted prior to the fracture stimulation in each well.

Young's Modulus

Evaluation of the tri-axial compression tests, shown in Table I, indicates that the Blue Jacket and Warner Sandstones have an average Young's modulus of 3.1 and 1.3 x 10^6 psi, respectively. The Rowe Coal and the bounding shales have an average Modulus of 2.0 and

Sample ID	Depth, feet	Lithology	Static E, 10^6 psi
03030401-A	110.50	*Shale*	1.03
03030501-A	119.00	*Shale*	1.44
03030502-A	121.50	*L. Bluejacket SS*	3.94
03031101	128.50	*L. Bluejacket SS*	3.12
03032401-B	130.00	*L. Bluejacket SS*	2.33
03032601	136.50	*Rowe Coal*	1.48
03032502-B	138.50	*Rowe SS*	2.44
03030701	144.00	*Warner SS*	0.92
03031102-A	167.00	*Warner SS*	1.30
03032402	170.00	*Warner SS*	1.72
03031001-A	176.00	*Warner SS*	0.96
03032501-B	178.00	*Warner SS*	1.56
03031002-B	191.00	*Warner SS*	1.52
03030601	200.30	*Graydon Shale*	3.27
00000211-B	211.00	*Graydon Shale*	1.43

1.8 x 10^6 psi, respectively.

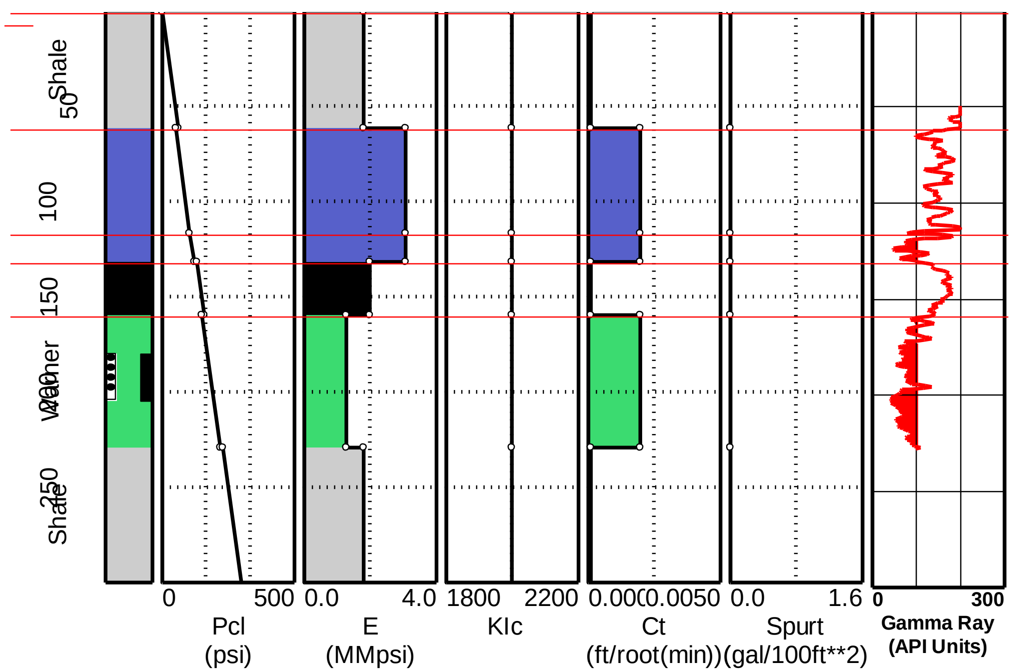
These static Young's Moduli were utilized in this analysis to develop the preliminary fracture design for the Cushard Nos. 1 and 5.

Determination of Leak-off Coefficient

With the in-situ stress profile and Young's Modulus determined in the preceding analysis, the next phase of developing a geomechanical dataset includes the determination of the leak-off coefficient. Due to the extremely high oil viscosity of the inplace hydrocarbons in this heavy oil project, a low value of fracture fluid leak-off given the 100 md reservoir permeability was assumed. For preliminary design purposes a leak-off coefficient of approximately 0.002 ft/min$^{1/2}$ was assumed based on experience with other heavy oil projects. The actual leak-off coefficient to the fracturing fluid will be determined as part of the preliminary testing and data collection prior to the fracture stimulation of the Cushard Nos. 1 and 5.

Figure 2 shows the geomechanical dataset developed in this analysis and used to evaluate the data collection program and fracture stimulation of the Warner Sandstone Formation in the Cushard 1 and 5. As shown, the first track of the geomechanical profile is the true vertical depth and perforation indicator track. Track two of the profile represents the closure pressure while tracks three and four represent the Young's Modulus and toughness, respectively. Tracks five and six show the fluid loss coefficient and spurt and Track seven shows the gamma ray log for this well. As shown in this profile, there are three Cadomin lobes separated by shaley/silty intervals. In order to best stimulate the entire Cadomin, while ensuring that the best porosity at the top of the Formation was adequately stimulated it is recommended that only the top two lobes of the Formation be perforated.

Figure 2: Geomechanical Dataset for the Cushard Nos. 1 and 5 (Cushard No. 4 GR)



Fracture Stimulation Design:

The geomechanical dataset developed in the preceding analysis was used to generate the fracture stimulation design for the Warner Sandstone Formation in the Cushard 1 and 5. Table II shows the preliminary fracture stimulation design developed in this analysis. As shown, the preliminary design consists of pumping 94.5 mlbs of 20/40 Brady sand in 23 mgals of 30 ppt linear gel fracturing fluid. The treatment is designed for a proppant addition schedule from 0.5 ppg to 10 ppg. Note, the purpose of the 0.5 ppg proppant stage is to mitigate the detrimental effects of Near Wellbore Pressure Loss due to the anticipated complex fracture geometry. In the event no NWPL is experienced, consideration should be given in the post mini-frac fracture redesign to eliminate this stage. Further, the use of 20/40 Brady sand is recommended for the first fracture stimulation in this reservoir, however, should no NWPL be experienced, larger more conductive 12/20 or 8/16 Brady sand should be considered for subsequent fracture stimulation treatments.

Table II: Preliminary Fracture Stimulation Design

Stage	Slurry Volume (M-Gal)	Fluid Volume (M-Gal)	Proppant Conc Strt (PPG)	Proppant Conc End (PPG)	Rate (BPM)	Fines Conc. (Vol Fraction)
1	2.00	2.00	0.00	0.00	15.0	0.00
2	3.07	3.00	0.50	0.50	15.00	0.00
3	3.14	3.00	1.00	1.00	15.0	0.00
4	3.27	3.00	2.00	2.00	15.0	0.00
5	3.54	3.00	4.00	4.00	15.0	0.00
6	3.82	3.00	6.00	6.00	15.0	0.00
7	4.09	3.00	8.00	8.00	15.0	0.00
8	4.36	3.00	10.00	10.00	15.0	0.00

Figure 3 shows a fracture plot of net treating pressure versus pump time resulting from this preliminary fracture stimulation design based on STIMPLAN simulations. As shown, a net treating pressure build from approximately 100 to 1,000 psi was designed. Such a net pressure build, if achieved, would significantly increase the propped fracture width and fracture conductivity.

Figure 3: Net Treating Pressure Plot

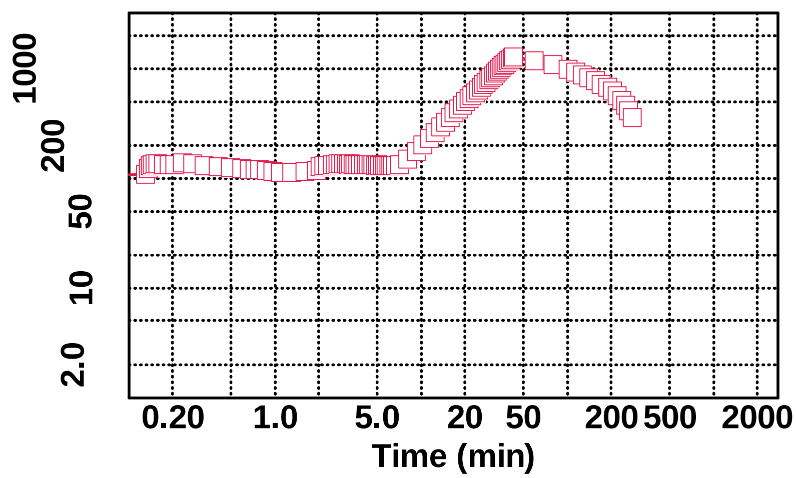
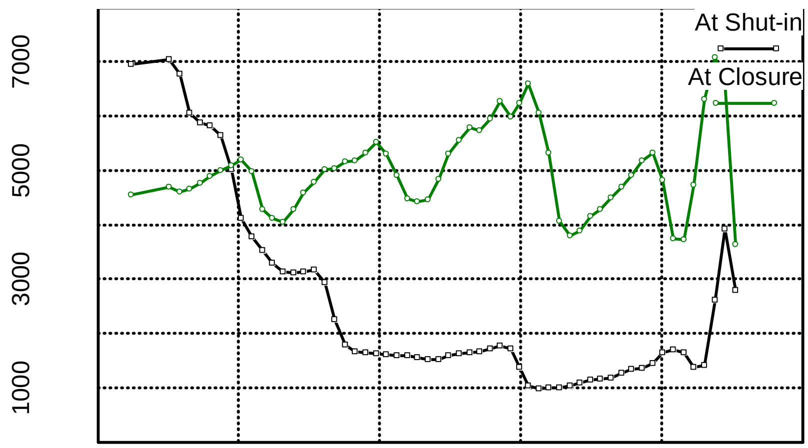


Figure 4 highlights this effect. As shown in this plot of fracture conductivity versus fracture half length a fracture length of 100 feet and an average fracture conductivity of nearly 5,000 mdft result from this preliminary fracture design. By using these fracture dimensions and assuming a reservoir permeability of 250 md, a dimensionless fracture capacity, F_{CD}, of 2.0 would be achieved. Therefore, the preliminary fracture design should result in optimum fracture dimensions for placement of the microbrial briat solution and hydrocarbon recovery.

Figure 4: Fracture Conductivity Profile



Sincerely,

Larry K. Britt

Larry K. Britt
NSI Technologies, Inc.
918-496-2071

JOB LOG

FBM: NA	NWA / COUNTRY: CENTRAL AREA	TICKET #: 2660771	TICKET DATE: 9/13/2003
MBU ID / EMPL #: FS0501	H.E.S EMPLOYEE NAME: FS0501 106288 EARL BARBER	BDA / STATE: Missouri	COUNTY: Vernon
LOCATION: Ft. Smith, Ar	COMPANY: University Of Missouri-Rolla	PSL DEPARTMENT: PE / STIMULATION	
TICKET AMOUNT: $0.00	WELL TYPE: GAS	CUSTOMER REP / PHONE: SHERI DUNN NORMAN	
WELL LOCATION: Nevada	DEPARTMENT: FRAC	API/UWI #:	
LEASE / WELL #: Cushard #1	SEC / TWP / RNG: 0	JOB PURPOSE CODE: 275	

H.E.S. EMP NAME / EMP # / (EXPOSURE HOURS)	HRS		HRS		HRS		HRS
EARL BARBER	6	GREG AYNES	6	DOLPH MATHIS	6	STELE JAMES	6
TOMMY CARR	6	DAVID HOLLAND	6	JEFF BATES	6	VINCE CALVARUZO	6
JOE SOUTHERN	6	DUSTIN DAWES	6	JOE ROAM	6	JAMES KING	6
MARKAS JACKSON	6	NESTOR HINOJOS	6	FRAN HOFFMAN	6	DAVID BLACK	6

Chart No.	Time	Rate (BPM)	Volume (BBL)(GAL)	Pmps T	Pmps C	Press.(PSI) Tbg	Press.(PSI) Csg	Job Description / Remarks
	0530							ON LOCATION - JSA
	0540		STAGE					SAFETY MEETING
	0555		VOL					SPOT TRUCKS
	0630		BH					RIGGED UP
	0730		GALLONS					HSE MEETING PRIME AND TEST
	0750							TEST LINES
	0848							START JOB
	0849	4.5	1593				432	FLUID EFFICENCY TEST
	0931	14.5	2016				665	MINI FRAC
	1117	14.6	2302				673	30 # WATERFRAC G PAD
	1121	14.7	3074				597	30# WATERFRAC G W/ 1/2 PPG SAND
	1126	14.3	3152				598	30# WATERFRAC G W/ 1 PPG SAND
	1131	13.8	3199				585	30# WATERFRAC G W/ 2 PPG SAND
	1136	12.9	3437				562	30# WATERFRAC G W 4 PPG SAND
	1142	11.9	2989				520	30# WATERFRAC G W 6 PPG SAND
	1146	11.1	3131				460	30# WATERFRAC G W/ 8 PPG SAND
	1151	10.4	5803				387	30# WATERFRAC G W 10 PPG SAND
	1200	13.1	154				324	30# WATERFRAC G FLUSH
	1200							END JOB
								AVG PSI 528
								MAX PSI 1249
								AVG RATE 13.8
								MAX RATE 17.3
								ISIP 132
								5 MIN 123
								10 MIN 120
								15 MIN 116
								LOAD 633 BBLS
								TOTAL SAND PUMPED 950SKS
	1215							POST JOB MEETING
	1400							RIG DOWN MOVE OFF

JOB LOG

		TICKET # 2660771	TICKET DATE 9/13/2003
FBM NA	NWA / COUNTRY CENTRAL AREA	BDA / STATE Missouri	COUNTY Vernon
MBU ID / EMPL # FS0501	H.E.S EMPLOYEE NAME FS0501 106288 EARL BARBER	PSL DEPARTMENT PE / STIMULATION	
LOCATION Ft. Smith, Ar	COMPANY University Of Missouri-Rolla	CUSTOMER REP / PHONE SHERI DUNN NORMAN	
TICKET AMOUNT $0.00	WELL TYPE GAS	API/UWI #	
WELL LOCATION Nevada	DEPARTMENT FRAC	JOB PURPOSE CODE 275	
LEASE / WELL # Cushard #1	SEC / TWP / RNG 0		

H.E.S. EMP NAME / EMP # / (EXPOSURE HOURS)	HRS		HRS		HRS		HRS
EARL BARBER	6	GREG AYNES	6	DOLPH MATHIS	6	STELE JAMES	6
TOMMY CARR	6	DAVID HOLLAND	6	JEFF BATES	6	VINCE CALVARUZO	6
JOE SOUTHERN	6	DUSTIN DAWES	6	JOE ROAM	6	JAMES KING	6
MARKAS JACKSON	6	NESTOR HINOJOS	6	FRAN HOFFMAN	6	DAVID BLACK	6

Chart No.	Time	Rate (BPM)	Volume (BBL)(GAL)	Pmps T	Pmps C	Press.(PSI) Tbg	Press.(PSI) Csg	Job Description / Remarks
	0530							ON LOCATION - JSA
	0540		STAGE					SAFETY MEETING
	0555		VOL					SPOT TRUCKS
	0630		BH					RIGGED UP
	0730		GALLONS					HSE MEETING PRIME AND TEST
	0750							TEST LINES
	0848							START JOB
	0849	4.5	1593				432	FLUID EFFICENCY TEST
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	1200							END JOB
								AVG PSI 528
								MAX PSI 1249
								AVG RATE 13.8
								MAX RATE 17.3
								ISIP 132
								5 MIN 123
								10 MIN 120
								15 MIN 116
								LOAD 633 BBLS
								TOTAL SAND PUMPED 950SKS
	1215							POST JOB MEETING
	1400							RIG DOWN MOVE OFF

HALLIBURTON

JOB SUMMARY

TICKET # 2660771	TICKET DATE 9/13/2003		
FBM NA	NWA / COUNTRY CENTRAL AREA	BDA / STATE Missouri	COUNTY Vernon
MBU ID / EMPL # FS0501	H.E.S EMPLOYEE NAME FS0501 106288 EARL BARBER	PSL DEPARTMENT PE / STIMULATION	
LOCATION Ft. Smith, Ar	COMPANY University Of Missouri-Rolla	CUSTOMER REP / PHONE SHERI DUNN NORMAN	
TICKET AMOUNT	WELL TYPE GAS	API/UWI #	
WELL LOCATION Nevada	DEPARTMENT FRAC	JOB PURPOSE CODE 275	
LEASE / WELL # Cushard #1	SEC / TWP / RNG		

H.E.S. EMP NAME / EMP # / (EXPOSURE HOURS)	HRS		HRS		HRS		HRS
EARL BARBER	6	GREG AYNES	6	DOLPH MATHIS	6	STELE JAMES	6
TOMMY CARR	6	DAVID HOLLAND	6	JEFF BATES	6	VINCE CALVARUZO	6
JOE SOUTHERN	6	DUSTIN DAWES	6	JOE ROAM	6	JAMES KING	6
MARKAS JACKSON	6	NESTOR HINOJOS	6	FRAN HOFFMAN	6	DAVID BLACK	6

H.E.S. UNIT #S / (R / T MILES)	R / T MILES		R / T MILES		R / T MILES		R / T MILES
SEE ATTTACHED LIST							

Form. Name CASEY Type: GAS
Form. Thickness ______ From ______ To ______
Packer Type ______ Set At ______
Bottom Hole Temp. #REF! Pressure #REF!
Misc. Data ______ Total Depth ______

	Called Out	On Location	Job Started	Job Completed
Date	9/13/2003	9/13/2003	9/13/2003	9/13/2003
Time	0400	0530	0848	1201

Tools and Accessories

Type and Size	Qty	Make
Float Collar		
Float Shoe		
Guide Shoe		
Centralizers		
Bottom Plug		
Top Plug		
Head		
Packer		
Other		

Well Data

	New/Used	Weight	Size	From	To	Max. Allow
Casing	used	10.5 lb/ft	4 1/2"		250	
Liner						
Liner						
Tbg. / D.P.						
Tbg. / D.P.						
Open Hole						Shots/Ft.
Perforations						
Perforations						
Perforations			#REF!	#REF!	#REF!	#REF!

Materials

Treat. Fluid 2% KCL Density 8.4 Lb/Gal
Disp. Fluid ______ Density 8.4 Lb/Gal
Prop. Type BRADY Size 20/40 Lb. 950 SKS
Prop. Type ______ Size ______ Lb. ______
Acid Type ______ Gal. ______ %
Acid Type ______ Gal. ______ %
Surfactant ______ Gal. ______ In
NE Agent ______ Gal. ______ In
Fluid Loss ______ Gal/Lb ______ In
Gelling Agent LGC-4 Gal/Lb ______ In
Fric. Red. ______ Gal/Lb ______ In
Breaker ENZYME-1 Gal/Lb ______ In
Blocking Agent ______ Gal/Lb
Perfpac Balls ______ Qty.
Other BC-140
Other
Other HC-2
Other KCL
Other BE3 & BE-6

Hours On Location

Date	Hours
13-Sep	6
Total	6

Operating Hours

Date	Hours
13-Sep	1
Total	1

Description of Job

N2 DELTA 140 FOAM FRAC

Hydraulic Horsepower

Ordered 3000 Avail. 3000 Used 3000

Average Rates in BPM

Treating ______ Disp. ______ Overall ______

Cement Left in Pipe

Feet ______ Reason ______

Cement Data

Stage	Sacks	Cement	Bulk/Sks	Additives	Yield	Lbs/Gal
				TOTAL LOAD 633 BBL		
				TOTAL SAND PUMPED 950 SKS		

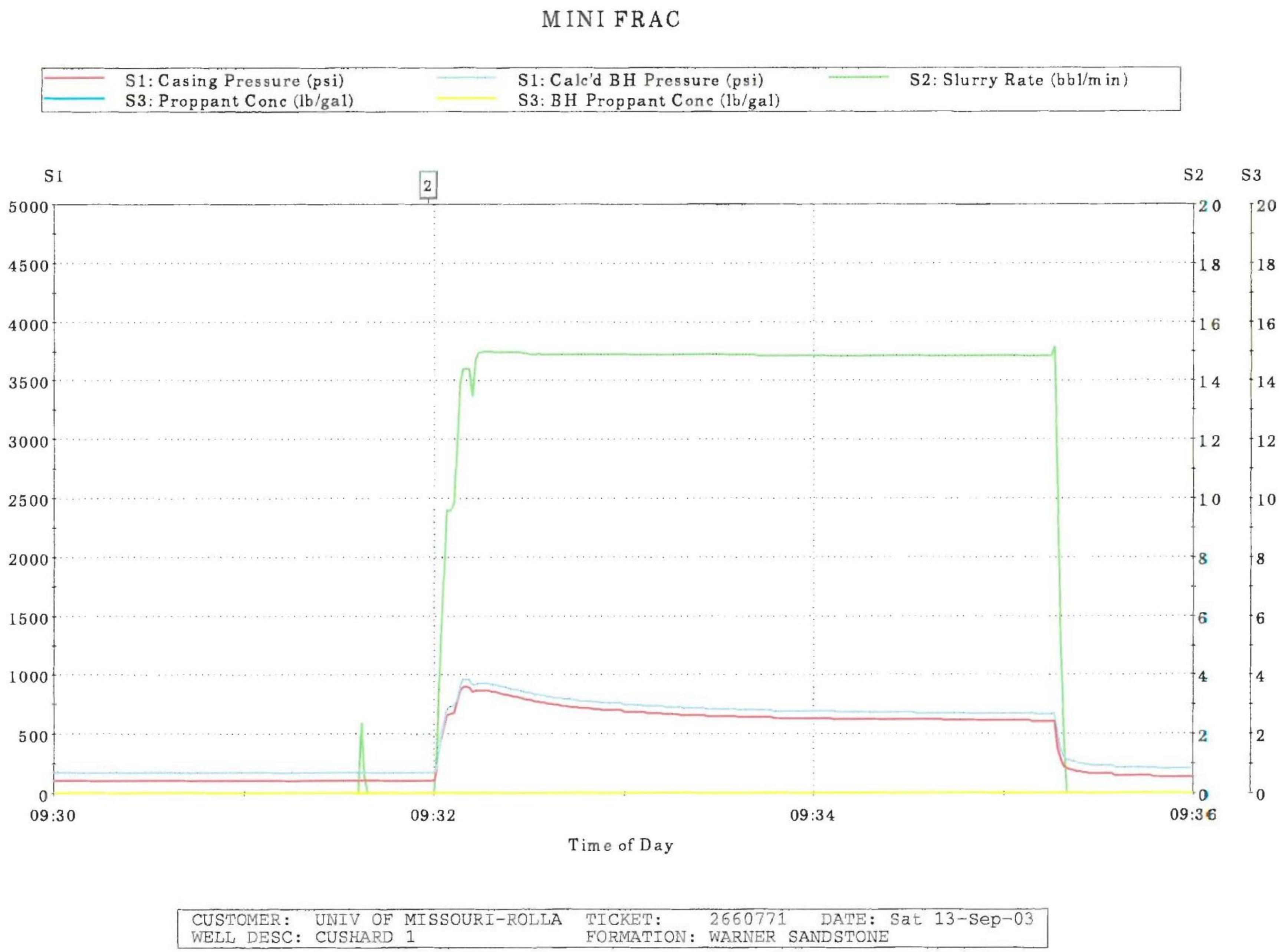
Summary

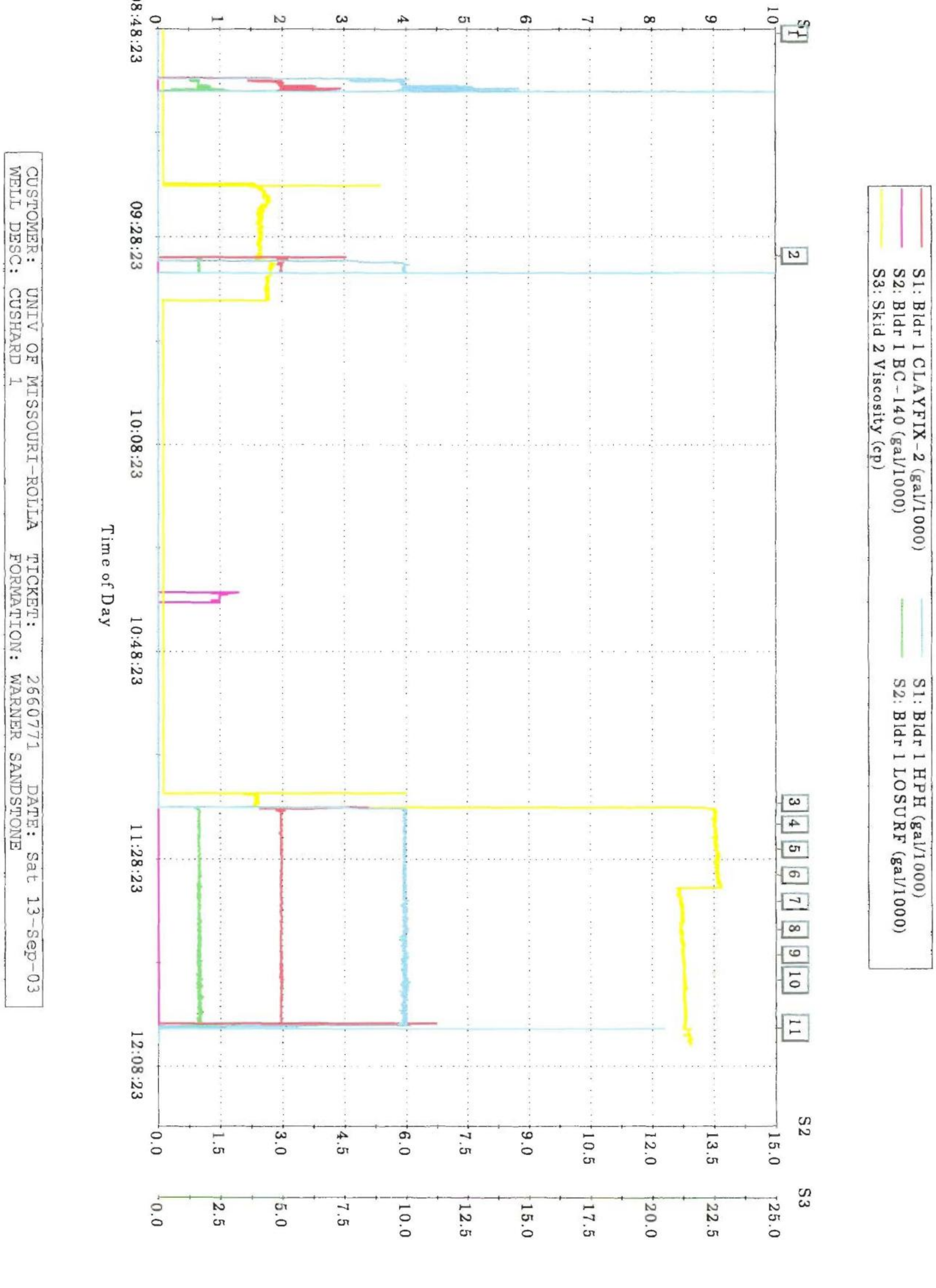
Circulating ______ Displacement ______ Preflush: Gal - BBl ______ Type: ______
Breakdown ______ Maximum ______ Load & Bkdn: Gal - BBl ______ Pad:Bbl -Gal ______
Average ______ Frac. Gradient ______ Treatment: Gal - BBl ______ Disp:Bbl-Gal ______
Shut In: Instant 132 5 Min. 123 15 Min 116 Cement Slurry Gal - BBl ______
Total Volume Gal - BBl ______

Form 4239-1

9/13/2003


FRAC DATA
S1: Casing Pressure (psi)
S3: Proppant Conc (lb/gal)
S1: Calc'd BH Pressure (psi)
S3: BH Proppant Conc (lb/gal)
S2: Slurry Rate (bbl/min)
S1
S2
S3
1
2
3
4
5
6
7
8
9
10
11
5000
4500
4000
3500
3000
2500
2000
1500
1000
500
0
20
18
16
14
12
10
8
6
4
2
0
08:48:23
09:28:23
10:08:23
10:48:23
11:28:23
12:08:23
Time of Day
CUSTOMER: UNIV OF MISSOURI-ROLLA TICKET: 2660771 DATE: Sat 13-Sep-03
WELL DESC: CUSHARD 1 FORMATION: WARNER SANDSTONE


MINI FRAC
S1: Casing Pressure (psi)
S1: Calc'd BH Pressure (psi)
S2: Slurry Rate (bbl/min)
S3: Proppant Conc (lb/gal)
S3: BH Proppant Conc (lb/gal)
S1
S2
S3
2
5000
4500
4000
3500
3000
2500
2000
1500
1000
500
0
20
18
16
14
12
10
8
6
4
2
0
09:30
09:32
09:34
09:36
Time of Day
CUSTOMER: UNIV OF MISSOURI-ROLLA TICKET: 2660771 DATE: Sat 13-Sep-03
WELL DESC: CUSHARD 1 FORMATION: WARNER SANDSTONE


S1: Bldr 1 CLAYFIX-2 (gal/1000)
S2: Bldr 1 BC-140 (gal/1000)
S3: Skid 2 Viscosity (cp)
S1: Bldr 1 HPH (gal/1000)
S2: Bldr 1 LOSURF (gal/1000)
S1
S2
S3
0
1
2
3
4
5
6
7
8
9
10
0.0
1.5
3.0
4.5
6.0
7.5
9.0
10.5
12.0
13.5
15.0
0.0
2.5
5.0
7.5
10.0
12.5
15.0
17.5
20.0
22.5
25.0
1
2
3
4
5
6
7
8
9
10
11
08:48:23
09:28:23
10:08:23
10:48:23
11:28:23
12:08:23
Time of Day
CUSTOMER: UNIV OF MISSOURI-ROLLA TICKET: 2660771 DATE: Sat 13-Sep-03
WELL DESC: CUSHARD 1 FORMATION: WARNER SANDSTONE

Customer:	**UNIV OF MISSOURI-ROLLA**	**Date:**	**13-Sep-2003**
Well Desc.:	**1**	**Ticket #:**	**2660771**
Formation:	**WARNER SANDSTONE**	**Job Type:**	**30# WATERFRAC G**

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HALLIBURTON ENERGY SERVICES
SOLUTIONS IN ACTION!

Time	Description
08:48:22	Start Job Saturday September 13, 2003
08:49:08	Stage Change Stage 1 - FET
09:31:58	Stage Change Stage 2 - PAD WATERFRAC G
09:52:26	SHUTDOWN MINIFRAC ANALYSIS 9.35 AM
11:17:34	Stage Change Stage 3 - PAD WATERFRAC G
11:21:42	Stage Change Stage 4 - PLF WATERFRAC G .5 PPG
11:26:35	Stage Change Stage 5 - PLF WATERFRAC G 1 PPG
11:31:37	Stage Change Stage 6 - PLF WATERFRAC G 2 PPG
11:36:40	Stage Change Stage 7 - PLF WATERFRAC G 4 PPG
11:42:05	Stage Change Stage 8 - PLF WATERFRAC G 6 PPG
11:46:48	Stage Change Stage 9 - PLF WATERFRAC G 8 PPG
11:51:44	Stage Change Stage 10 - PLF WATERFRAC G 10 PPG
12:00:56	Stage Change Stage 11 - WATERFRAC G FLUSH
12:17:03	End Job

Volumes

Stage	Job Slurry Vol gal	Stage Slurry Vol gal	Stage Clean Vol gal	Job Clean Vol gal
1	1593.2	1593.2	1593.2	1593.2
2	3609.6	2016.4	2016.4	3609.6
3	5901.2	2302.0	2299.2	5898.5
4	8964.8	3074.1	3017.9	8906.4
5	12127.4	3152.2	3010.2	11927.0
6	15326.3	3199.0	2936.2	14863.6
7	18763.2	3437.0	2932.7	17797.0
8	21752.2	2989.0	2345.4	20143.1
9	24883.7	3131.4	2298.1	22441.8
10	30686.7	5803.0	4004.8	26444.4
11	30851.9	154.8	151.7	26605.8
Totals:	(30851.9)	(30851.9)	(26605.7)	(26605.8)

Mass

Stage	Job Proppant Pumped sack	Stage Proppant Pumped sack	Proppant In Formation sack	Proppant In Wellbore sack
1	0.0	0.0	0.0	0.0
2	0.0	0.0	0.0	0.0
3	0.6	0.6	0.5	0.1
4	12.8	12.3	12.1	0.7
5	43.9	31.1	42.7	1.3
6	101.5	57.6	99.3	2.2
7	211.9	110.6	207.6	4.3
8	352.9	141.1	347.1	5.8
9	535.5	182.7	528.4	7.1
10	930.4	394.3	925.9	4.4
11	931.2	0.7	930.9	0.3
Totals:	(931.2)	(931.2)	(930.9)	(0.3)

Pressure

Stage	Casing Pressure psi (avg/max)	Calc'd BH Pressure psi (avg/max)
1	432 / 1249	497 / 1316
2	665 / 901	725 / 962
3	673 / 877	733 / 938
4	597 / 616	660 / 678
5	598 / 603	663 / 668
6	585 / 599	655 / 667
7	562 / 589	638 / 664
8	520 / 551	603 / 632
9	460 / 492	548 / 579
10	387 / 428	480 / 520
11	324 / 351	396 / 425
Totals:	(528/1249)	(600/1316)

Rate

Stage	Clean Rate bbl/min (avg/max)	Slurry Rate bbl/min (avg/max)
1	4.5 / 15.4	4.5 / 15.4
2	14.5 / 15.2	14.5 / 15.2
3	14.6 / 14.9	14.6 / 14.9
4	14.7 / 14.8	14.9 / 15.0
5	14.3 / 14.5	15.0 / 15.0
6	13.8 / 14.1	15.0 / 15.1
7	12.9 / 13.6	15.1 / 15.1
8	11.9 / 12.3	15.1 / 15.2
9	11.1 / 11.6	15.1 / 15.1
10	10.4 / 14.0	15.0 / 17.3
11	13.1 / 15.0	13.4 / 15.1
Totals:	(12.3/15.4)	(13.8/17.3)

STAGE 1	Planned	Actual	SUMMARY	@Surface	@Perfs
Clean Volume (gal)	500.0	1593.2	Treating Pressure Avg/Max (psi)	432 / 1249	432 / 1249
Slurry Volume (gal)	500.0	1593.2	BHTP Avg/Max (psi)	497 / 1316	497 / 1316
Start Fluid Rate (bbl/min)	15.0	1.6	Total Avg. Rate (bbl/min)	4.5	4.5
End Fluid Rate (bbl/min)	15.0	0.0	Avg. HHP (hp)	59.0	
Friction Model	WG-19				
Description : FET					

STAGE 2	Planned	Actual	SUMMARY	@Surface	@Perfs
Clean Volume (gal)	2000.0	2016.4	Treating Pressure Avg/Max (psi)	665 / 901	665 / 901
Slurry Volume (gal)	2000.0	2016.4	BHTP Avg/Max (psi)	725 / 962	725 / 962
Start Fluid Rate (bbl/min)	15.0	0.0	Total Avg. Rate (bbl/min)	14.5	14.5
End Fluid Rate (bbl/min)	15.0	0.0	Avg. HHP (hp)	238.1	
Friction Model	WG-19				
Description : PAD WATERFRAC G					

STAGE 3	Planned	Actual	SUMMARY	@Surface	@Perfs
Clean Volume (gal)	2000.0	2299.2	Treating Pressure Avg/Max (psi)	673 / 877	673 / 877
Slurry Volume (gal)	2000.0	2302.0	BHTP Avg/Max (psi)	733 / 938	733 / 938
Start Fluid Rate (bbl/min)	15.0	0.0	Total Avg. Rate (bbl/min)	14.6	14.6
End Fluid Rate (bbl/min)	15.0	14.9	Avg. HHP (hp)	242.1	
Friction Model	WG-19				
Description : PAD WATERFRAC G					

STAGE 4	Planned	Actual	SUMMARY	@Surface	@Perfs
Clean Volume (gal)	3000.0	3017.9	Treating Pressure Avg/Max (psi)	597 / 616	597 / 616
Slurry Volume (gal)	3068.4	3074.1	BHTP Avg/Max (psi)	660 / 678	660 / 678
Start Fluid Rate (bbl/min)	15.0	14.9	Total Avg. Rate (bbl/min)	14.9	14.9
End Fluid Rate (bbl/min)	15.0	15.0	Avg. HHP (hp)	218.6	
Sand	20/40	0.04560 (gal/lb)	Prop in Wellbore (lb)	68.7	
Start Conc (lb/gal)	0.50	0.13	Avg. Prop Concentration (lb/gal)	0.41	0.39
End Conc (lb/gal)	0.50	0.69	Prop in Formation (lb)	1212.0	
Friction Model	WG-19				
Description : PLF WATERFRAC G .5 PPG					

STAGE 5	Planned	Actual	SUMMARY	@Surface	@Perfs
Clean Volume (gal)	3000.0	3010.2	Treating Pressure Avg/Max (psi)	598 / 603	598 / 603
Slurry Volume (gal)	3136.8	3152.2	BHTP Avg/Max (psi)	663 / 668	663 / 668
Start Fluid Rate (bbl/min)	15.0	15.0	Total Avg. Rate (bbl/min)	15.0	15.0
End Fluid Rate (bbl/min)	15.0	15.0	Avg. HHP (hp)	219.2	
Sand	20/40	0.04560 (gal/lb)	Prop in Wellbore (lb)	125.2	
Start Conc (lb/gal)	1.00	0.69	Avg. Prop Concentration (lb/gal)	1.03	1.02
End Conc (lb/gal)	1.00	1.23	Prop in Formation (lb)	4269.8	
Friction Model	WG-19				
Description : PLF WATERFRAC G 1 PPG					

STAGE 6	Planned	Actual	SUMMARY	@Surface	@Perfs
Clean Volume (gal)	3000.0	2936.2	Treating Pressure Avg/Max (psi)	585 / 599	585 / 599
Slurry Volume (gal)	3273.6	3199.0	BHTP Avg/Max (psi)	655 / 667	655 / 667
Start Fluid Rate (bbl/min)	15.0	15.0	Total Avg. Rate (bbl/min)	15.0	15.0
End Fluid Rate (bbl/min)	15.0	15.1	Avg. HHP (hp)	215.7	
Sand	20/40	0.04560 (gal/lb)	Prop in Wellbore (lb)	221.0	
Start Conc (lb/gal)	2.00	1.40	Avg. Prop Concentration (lb/gal)	1.96	1.93
End Conc (lb/gal)	2.00	2.32	Prop in Formation (lb)	9927.3	
Friction Model	WG-19				
Description : PLF WATERFRAC G 2 PPG					

STAGE 7	Planned	Actual	SUMMARY	@Surface	@Perfs
Clean Volume (gal)	3000.0	2932.7	Treating Pressure Avg/Max (psi)	562 / 589	562 / 589
Slurry Volume (gal)	3547.2	3437.0	BHTP Avg/Max (psi)	638 / 664	638 / 664
Start Fluid Rate (bbl/min)	15.0	15.1	Total Avg. Rate (bbl/min)	15.1	15.1
End Fluid Rate (bbl/min)	15.0	15.1	Avg. HHP (hp)	208.2	
Sand	20/40	0.04560 (gal/lb)	Prop in Wellbore (lb)	426.5	
Start Conc (lb/gal)	4.00	2.35	Avg. Prop Concentration (lb/gal)	3.77	3.69
End Conc (lb/gal)	4.00	4.62	Prop in Formation (lb)	20763.0	
Friction Model	WG-19				
Description : PLF WATERFRAC G 4 PPG					

STAGE 8	Planned	Actual	SUMMARY	@Surface	@Perfs
Clean Volume (gal)	3000.0	2345.4	Treating Pressure Avg/Max (psi)	521 / 551	521 / 551
Slurry Volume (gal)	3820.8	2989.0	BHTP Avg/Max (psi)	604 / 632	604 / 632
Start Fluid Rate (bbl/min)	15.0	15.1	Total Avg. Rate (bbl/min)	15.1	15.1
End Fluid Rate (bbl/min)	15.0	15.1	Avg. HHP (hp)	193.3	
Sand	20/40	0.04560 (gal/lb)	Prop in Wellbore (lb)	580.7	
Start Conc (lb/gal)	6.00	4.62	Avg. Prop Concentration (lb/gal)	6.01	5.94
End Conc (lb/gal)	6.00	6.67	Prop in Formation (lb)	34709.3	
Friction Model	WG-19				
Description : PLF WATERFRAC G 6 PPG					

STAGE 9	Planned	Actual	SUMMARY	@Surface	@Perfs
Clean Volume (gal)	3000.0	2298.1	Treating Pressure Avg/Max (psi)	460 / 492	460 / 492
Slurry Volume (gal)	4094.4	3131.4	BHTP Avg/Max (psi)	548 / 579	548 / 579
Start Fluid Rate (bbl/min)	15.0	15.1	Total Avg. Rate (bbl/min)	15.1	15.1
End Fluid Rate (bbl/min)	15.0	15.1	Avg. HHP (hp)	170.3	
Sand	20/40	0.04560 (gal/lb)	Prop in Wellbore (lb)	711.2	
Start Conc (lb/gal)	8.00	6.70	Avg. Prop Concentration (lb/gal)	7.95	7.87
End Conc (lb/gal)	8.00	8.73	Prop in Formation (lb)	52840.2	
Friction Model	WG-19				
Description : PLF WATERFRAC G 8 PPG					

STAGE 10	Planned	Actual	SUMMARY	@Surface	@Perfs
Clean Volume (gal)	3000.0	4004.8	Treating Pressure Avg/Max (psi)	388 / 428	388 / 428
Slurry Volume (gal)	4368.0	5803.0	BHTP Avg/Max (psi)	480 / 520	480 / 520
Start Fluid Rate (bbl/min)	15.0	15.1	Total Avg. Rate (bbl/min)	15.0	15.0
End Fluid Rate (bbl/min)	15.0	14.9	Avg. HHP (hp)	142.7	
Sand	20/40	0.04560 (gal/lb)	Prop in Wellbore (lb)	444.5	
Start Conc (lb/gal)	10.00	8.77	Avg. Prop Concentration (lb/gal)	9.89	9.96
End Conc (lb/gal)	10.00	1.98	Prop in Formation (lb)	92590.9	
Friction Model	WG-19				
Description : PLF WATERFRAC G 10 PPG					

STAGE 11	Planned	Actual	SUMMARY	@Surface	@Perfs
Clean Volume (gal)	108.0	151.7	Treating Pressure Avg/Max (psi)	326 / 351	326 / 351
Slurry Volume (gal)	108.0	154.8	BHTP Avg/Max (psi)	398 / 427	398 / 427
Start Fluid Rate (bbl/min)	15.0	14.9	Total Avg. Rate (bbl/min)	13.4	13.4
End Fluid Rate (bbl/min)	15.0	0.0	Avg. HHP (hp)	112.2	
None	None	0.00000 (gal/lb)	Prop in Wellbore (lb)	31.8	
Start Conc (lb/gal)	0.00	1.28	Avg. Prop Concentration (lb/gal)	0.46	3.21
End Conc (lb/gal)	0.00	0.00	Prop in Formation (lb)	93086.6	
Friction Model	WG-19				
Description : WATERFRAC G FLUSH					

Initial Conditions

Treatment Parameters		
	Job Type	*30# WATERFRAC G*
	Well Treated Down	*Casing*
	Static Column Used	*NO*
	Earth Temperature	*70.0 f*
	Slurry Temperature	*69.0 f*
	BHTT	*60.0 f*
	Reservoir Pressure	*50 psi*
	Expected BHTP	*200 psi*
Initial Wellbore Data		
	Wellbore fluid	*Gel*
	Density	*8.33 lb/gal*
	n-prime	*0.4585*
	K-prime	*0.021500 lb*sec^n/ft^2*
Perf Data		
	Number of	*61*
	Diameter	*0.500 in*
	Disch. Coeff	*0.600*

Wellbore Data

Wellbore Segment Number	Actual Length (ft)	TVD (ft)	Casing ID (in)	Casing OD (in)	Tubing ID (in)	Tubing OD (in)
1	*164*	*164*	*4.052*	*4.500*	*0.000*	*0.000*

Time of Day	Casing Pressure	Slurry Rate	Proppant Conc	BH Proppant Conc	Job Slurry Vol	Stage Slurry Vol	Job Clean Vol
	psi	bbl/min	lb/gal	lb/gal	gal	gal	gal
08:48:23	0	0.0	0.00	0.00	0.0	0.0	0.0
08:49:23	32	7.6	0.00	0.00	40.2	40.2	40.2
08:50:23	439	1.0	0.00	0.00	79.4	79.4	79.4
08:51:23	156	0.0	0.00	0.00	125.3	125.3	125.3
08:52:23	130	0.0	0.00	0.00	125.3	125.3	125.3
08:53:23	117	0.0	0.00	0.00	125.3	125.3	125.3
08:54:23	381	1.0	0.00	0.00	168.4	168.4	168.4
08:55:23	350	1.5	0.00	0.00	219.8	219.8	219.8
08:56:23	302	1.5	0.00	0.00	290.8	290.8	290.8
08:57:23	418	3.9	0.00	0.00	427.8	427.8	427.8
08:58:23	837	13.9	0.00	0.00	728.6	728.6	728.6
08:59:23	521	11.6	0.00	0.00	1331.2	1331.2	1331.2
09:00:23	187	0.0	0.00	0.00	1589.7	1589.7	1589.7
09:01:23	136	0.0	0.00	0.00	1589.7	1589.7	1589.7
09:02:23	131	0.0	0.00	0.00	1589.7	1589.7	1589.7
09:03:23	129	0.0	0.00	0.00	1589.7	1589.7	1589.7
09:04:23	126	0.0	0.00	0.00	1589.7	1589.7	1589.7
09:05:23	125	0.0	0.00	0.00	1589.7	1589.7	1589.7
09:06:23	124	0.0	0.00	0.00	1589.7	1589.7	1589.7
09:07:23	123	0.0	0.00	0.00	1589.7	1589.7	1589.7
09:08:23	122	0.0	0.00	0.00	1589.7	1589.7	1589.7
09:09:23	120	0.0	0.00	0.00	1589.7	1589.7	1589.7
09:10:23	121	0.0	0.00	0.00	1589.7	1589.7	1589.7
09:11:23	119	0.0	0.00	0.00	1589.7	1589.7	1589.7
09:12:23	117	0.0	0.00	0.00	1589.7	1589.7	1589.7
09:13:23	116	0.0	0.00	0.00	1589.7	1589.7	1589.7
09:14:23	116	0.0	0.00	0.00	1589.7	1589.7	1589.7
09:15:23	116	0.0	0.00	0.00	1589.7	1589.7	1589.7
09:16:23	116	0.0	0.00	0.00	1589.7	1589.7	1589.7
09:17:23	115	0.0	0.00	0.00	1589.7	1589.7	1589.7
09:18:23	113	0.0	0.00	0.00	1589.7	1589.7	1589.7
09:19:23	113	0.0	0.00	0.00	1589.7	1589.7	1589.7
09:20:23	113	0.0	0.00	0.00	1589.7	1589.7	1589.7
09:21:23	112	0.0	0.00	0.00	1591.1	1591.1	1591.1
09:22:23	111	0.0	0.00	0.00	1591.1	1591.1	1591.1
09:23:23	110	0.0	0.00	0.00	1591.1	1591.1	1591.1
09:24:23	108	0.0	0.00	0.00	1591.1	1591.1	1591.1
09:25:23	109	0.0	0.00	0.00	1591.1	1591.1	1591.1
09:26:23	108	0.0	0.00	0.00	1591.1	1591.1	1591.1
09:27:23	108	0.0	0.00	0.00	1591.1	1591.1	1591.1
09:28:23	108	0.0	0.00	0.00	1591.1	1591.1	1591.1
09:29:23	106	0.0	0.00	0.00	1591.1	1591.1	1591.1
09:30:23	106	0.0	0.00	0.00	1591.1	1591.1	1591.1
09:31:23	106	0.0	0.00	0.00	1591.1	1591.1	1591.1
09:32:23	828	14.9	0.00	0.00	1790.7	197.6	1790.7
09:33:23	656	14.9	0.00	0.00	2416.3	823.1	2416.3
09:34:23	622	14.9	0.00	0.00	3040.7	1447.5	3040.7
09:35:23	186	0.0	0.00	0.00	3609.6	2016.4	3609.6
09:36:23	136	0.0	0.00	0.00	3609.6	2016.4	3609.6
09:37:23	133	0.0	0.00	0.00	3609.6	2016.4	3609.6
09:38:23	130	0.0	0.00	0.00	3609.6	2016.4	3609.6
09:39:23	130	0.0	0.00	0.00	3609.6	2016.4	3609.6
09:40:23	127	0.0	0.00	0.00	3609.6	2016.4	3609.6
09:41:23	126	0.0	0.00	0.00	3609.6	2016.4	3609.6
09:42:23	127	0.0	0.00	0.00	3609.6	2016.4	3609.6
09:43:23	125	0.0	0.00	0.00	3609.6	2016.4	3609.6
09:44:23	124	0.0	0.00	0.00	3609.6	2016.4	3609.6

Time of Day	Casing Pressure	Slurry Rate	Proppant Conc	BH Proppant Conc	Job Slurry Vol	Stage Slurry Vol	Job Clean Vol
	psi	bbl/min	lb/gal	lb/gal	gal	gal	gal
09:45:23	124	0.0	0.00	0.00	3609.6	2016.4	3609.6
09:46:23	123	0.0	0.00	0.00	3609.6	2016.4	3609.6
09:47:23	123	0.0	0.00	0.00	3609.6	2016.4	3609.6
09:48:23	122	0.0	0.00	0.00	3609.6	2016.4	3609.6
09:49:23	122	0.0	0.00	0.00	3609.6	2016.4	3609.6
09:50:23	121	0.0	0.00	0.00	3609.6	2016.4	3609.6
09:51:23	120	0.0	0.00	0.00	3609.6	2016.4	3609.6
09:52:23	118	0.0	0.00	0.00	3609.6	2016.4	3609.6
09:53:23	119	0.0	0.00	0.00	3609.6	2016.4	3609.6
09:54:23	120	0.0	0.00	0.00	3609.6	2016.4	3609.6
09:55:23	118	0.0	0.00	0.00	3609.6	2016.4	3609.6
09:56:23	117	0.0	0.00	0.00	3609.6	2016.4	3609.6
09:57:23	117	0.0	0.00	0.00	3609.6	2016.4	3609.6
09:58:23	117	0.0	0.00	0.00	3609.6	2016.4	3609.6
09:59:23	116	0.0	0.00	0.00	3609.6	2016.4	3609.6
10:00:23	116	0.0	0.00	0.00	3609.6	2016.4	3609.6
10:01:23	116	0.0	0.00	0.00	3609.6	2016.4	3609.6
10:02:23	116	0.0	0.00	0.00	3609.6	2016.4	3609.6
10:03:23	116	0.0	0.00	0.00	3609.6	2016.4	3609.6
10:04:23	115	0.0	0.00	0.00	3609.6	2016.4	3609.6
10:05:23	115	0.0	0.00	0.00	3609.6	2016.4	3609.6
10:06:23	116	0.0	0.00	0.00	3609.6	2016.4	3609.6
10:07:23	115	0.0	0.00	0.00	3609.6	2016.4	3609.6
10:08:23	116	0.0	0.00	0.00	3609.6	2016.4	3609.6
10:09:23	114	0.0	0.00	0.00	3609.6	2016.4	3609.6
10:10:23	115	0.0	0.00	0.00	3609.6	2016.4	3609.6
10:11:23	114	0.0	0.00	0.00	3609.6	2016.4	3609.6
10:12:23	114	0.0	0.00	0.00	3609.6	2016.4	3609.6
10:13:23	113	0.0	0.00	0.00	3609.6	2016.4	3609.6
10:14:23	113	0.0	0.00	0.00	3609.6	2016.4	3609.6
10:15:23	112	0.0	0.00	0.00	3609.6	2016.4	3609.6
10:16:23	113	0.0	0.00	0.00	3609.6	2016.4	3609.6
10:17:23	113	0.0	0.00	0.00	3609.6	2016.4	3609.6
10:18:23	112	0.0	0.00	0.00	3609.6	2016.4	3609.6
10:19:23	112	0.0	0.00	0.00	3609.6	2016.4	3609.6
10:20:23	111	0.0	0.00	0.00	3609.6	2016.4	3609.6
10:21:23	112	0.0	0.00	0.00	3609.6	2016.4	3609.6
10:22:23	112	0.0	0.00	0.00	3609.6	2016.4	3609.6
10:23:23	111	0.0	0.00	0.00	3609.6	2016.4	3609.6
10:24:23	111	0.0	0.00	0.00	3609.6	2016.4	3609.6
10:25:23	111	0.0	0.00	0.00	3609.6	2016.4	3609.6
10:26:23	111	0.0	0.00	0.00	3609.6	2016.4	3609.6
10:27:23	111	0.0	0.00	0.00	3609.6	2016.4	3609.6
10:28:23	109	0.0	0.00	0.00	3609.6	2016.4	3609.6
10:29:23	108	0.0	0.00	0.00	3609.6	2016.4	3609.6
10:30:23	109	0.0	0.00	0.00	3609.6	2016.4	3609.6
10:31:23	108	0.0	0.00	0.00	3609.6	2016.4	3609.6
10:32:23	108	0.0	0.00	0.00	3609.6	2016.4	3609.6
10:33:23	108	0.0	0.00	0.00	3609.6	2016.4	3609.6
10:34:23	109	0.0	0.00	0.00	3609.6	2016.4	3609.6
10:35:23	108	0.0	0.00	0.00	3609.6	2016.4	3609.6
10:36:23	108	0.0	0.00	0.00	3609.6	2016.4	3609.6
10:37:23	106	0.0	0.00	0.00	3609.6	2016.4	3609.6
10:38:23	108	0.0	0.00	0.00	3609.6	2016.4	3609.6
10:39:23	107	0.0	0.00	0.00	3609.6	2016.4	3609.6
10:40:23	106	0.0	0.00	0.00	3609.6	2016.4	3609.6
10:41:23	105	0.0	0.00	0.00	3609.6	2016.4	3609.6

Time of Day	Casing Pressure	Slurry Rate	Proppant Conc	BH Proppant Conc	Job Slurry Vol	Stage Slurry Vol	Job Clean Vol
	psi	bbl/min	lb/gal	lb/gal	gal	gal	gal
10:42:23	105	0.0	0.00	0.00	3609.6	2016.4	3609.6
10:43:23	105	0.0	0.00	0.00	3609.6	2016.4	3609.6
10:44:23	104	0.0	0.00	0.00	3609.6	2016.4	3609.6
10:45:23	104	0.0	0.00	0.00	3609.6	2016.4	3609.6
10:46:23	104	0.0	0.00	0.00	3609.6	2016.4	3609.6
10:47:23	102	0.0	0.00	0.00	3609.6	2016.4	3609.6
10:48:23	101	0.0	0.00	0.00	3609.6	2016.4	3609.6
10:49:23	102	0.0	0.00	0.00	3609.6	2016.4	3609.6
10:50:23	102	0.0	0.00	0.00	3609.6	2016.4	3609.6
10:51:23	100	0.0	0.00	0.00	3609.6	2016.4	3609.6
10:52:23	101	0.0	0.00	0.00	3609.6	2016.4	3609.6
10:53:23	100	0.0	0.00	0.00	3609.6	2016.4	3609.6
10:54:23	100	0.0	0.00	0.00	3609.6	2016.4	3609.6
10:55:23	100	0.0	0.00	0.00	3609.6	2016.4	3609.6
10:56:23	99	0.0	0.00	0.00	3609.6	2016.4	3609.6
10:57:23	98	0.0	0.00	0.00	3609.6	2016.4	3609.6
10:58:23	98	0.0	0.00	0.00	3609.6	2016.4	3609.6
10:59:23	98	0.0	0.00	0.00	3609.6	2016.4	3609.6
11:00:23	97	0.0	0.00	0.00	3609.6	2016.4	3609.6
11:01:23	97	0.0	0.00	0.00	3609.6	2016.4	3609.6
11:02:23	97	0.0	0.00	0.00	3609.6	2016.4	3609.6
11:03:23	96	0.0	0.00	0.00	3609.6	2016.4	3609.6
11:04:23	94	0.0	0.00	0.00	3609.6	2016.4	3609.6
11:05:23	95	0.0	0.00	0.00	3609.6	2016.4	3609.6
11:06:23	95	0.0	0.00	0.00	3609.6	2016.4	3609.6
11:07:23	92	0.0	0.00	0.00	3609.6	2016.4	3609.6
11:08:23	92	0.0	0.00	0.00	3609.6	2016.4	3609.6
11:09:23	92	0.0	0.00	0.00	3609.6	2016.4	3609.6
11:10:23	92	0.0	0.00	0.00	3609.6	2016.4	3609.6
11:11:23	90	0.0	0.00	0.00	3609.6	2016.4	3609.6
11:12:23	91	0.0	0.00	0.00	3609.6	2016.4	3609.6
11:13:23	90	0.0	0.00	0.00	3609.6	2016.4	3609.6
11:14:23	91	0.0	0.00	0.00	3609.6	2016.4	3609.6
11:15:23	88	0.0	0.00	0.00	3609.6	2016.4	3609.6
11:16:23	88	0.0	0.00	0.00	3609.6	2016.4	3609.6
11:17:23	87	0.0	0.00	0.00	3609.6	2016.4	3609.6
11:18:23	777	14.9	0.00	0.00	3849.0	239.4	3849.0
11:19:23	670	14.9	0.00	0.00	4474.6	865.0	4474.6
11:20:23	634	14.9	0.06	0.00	5099.1	1489.5	5098.4
11:21:23	621	14.9	0.11	0.06	5724.1	2114.5	5721.9
11:22:23	606	14.8	0.28	0.28	6347.8	436.2	6339.8
11:23:23	595	15.0	0.37	0.33	6975.9	1064.3	6959.8
11:24:23	592	15.0	0.55	0.55	7604.1	1692.4	7575.6
11:25:23	595	15.0	0.49	0.51	8232.1	2320.5	8189.0
11:26:23	593	15.0	0.58	0.46	8860.1	2948.5	8804.6
11:27:23	602	14.9	0.92	0.90	9487.9	502.1	9410.4
11:28:23	600	15.0	1.06	1.02	10115.9	1130.1	10010.3
11:29:23	601	15.0	1.09	1.06	10744.4	1758.7	10610.1
11:30:23	595	15.0	1.11	1.16	11373.0	2387.2	11207.8
11:31:23	591	15.0	1.06	1.02	12001.5	3015.8	11807.3
11:32:23	597	15.0	1.90	1.77	12632.0	494.1	12395.9
11:33:23	590	15.0	2.03	1.98	13262.7	1124.8	12974.7
11:34:23	584	15.0	2.01	2.06	13851.9	1714.0	13514.9
11:35:23	579	15.0	2.16	2.08	14525.6	2387.7	14130.8
11:36:23	574	15.1	2.06	1.98	15157.6	3019.7	14709.4
11:37:23	587	15.1	3.50	3.59	15791.1	454.3	15268.8
11:38:23	571	15.1	3.76	3.62	16425.4	1088.5	15818.2

Time of Day	Casing Pressure	Slurry Rate	Proppant Conc	BH Proppant Conc	Job Slurry Vol	Stage Slurry Vol	Job Clean Vol
	psi	bbl/min	lb/gal	lb/gal	gal	gal	gal
11:39:23	563	15.1	3.99	4.11	17060.4	1723.5	16356.6
11:40:23	553	15.1	4.02	3.96	17694.8	2357.9	16893.2
11:41:23	544	15.1	3.90	3.93	18329.5	2992.6	17431.5
11:42:23	549	15.1	5.44	5.09	18964.5	190.5	17960.2
11:43:23	534	15.1	6.04	5.97	19600.3	826.4	18463.6
11:44:23	521	15.1	6.18	6.25	20236.1	1462.2	18960.3
11:45:23	508	15.2	6.18	6.08	20872.0	2098.1	19456.9
11:46:23	495	15.2	6.21	6.21	21508.3	2734.5	19954.0
11:47:23	492	15.1	7.70	7.47	22144.1	381.3	20437.4
11:48:23	475	15.1	8.02	8.02	22778.9	1016.0	20903.4
11:49:23	456	15.1	7.94	8.06	23413.5	1650.7	21368.0
11:50:23	441	15.1	8.14	8.02	24048.2	2285.4	21832.6
11:51:23	429	15.1	8.02	7.98	24682.8	2919.9	22296.1
11:52:23	426	15.1	9.75	9.61	25305.9	411.7	22737.6
11:53:23	414	15.0	10.27	10.31	25948.9	1054.7	23177.5
11:54:23	402	15.0	10.36	10.07	26580.5	1686.4	23607.2
11:55:23	389	15.0	9.93	10.07	27211.8	2317.6	24039.5
11:56:23	383	15.0	10.07	10.03	27842.8	2948.6	24472.6
11:57:23	379	15.0	10.22	10.12	28473.5	3579.3	24904.6
11:58:23	370	15.0	9.93	9.93	29104.7	4210.5	25337.2
11:59:23	364	15.0	10.12	10.07	29735.6	4841.4	25769.8
12:00:23	361	15.0	9.43	9.84	30366.5	5472.3	26202.7
12:01:23	146	0.0	0.04	0.62	30851.9	154.8	26605.8
12:02:23	131	0.0	0.00	0.62	30851.9	154.8	26605.8
12:03:23	129	0.0	0.00	0.62	30851.9	154.8	26605.8
12:04:23	125	0.0	0.00	0.62	30851.9	154.8	26605.8
12:05:23	125	0.0	0.00	0.62	30851.9	154.8	26605.8
12:06:23	123	0.0	0.00	0.62	30851.9	154.8	26605.8
12:07:23	123	0.0	0.00	0.62	30851.9	154.8	26605.8
12:08:23	123	0.0	0.00	0.62	30851.9	154.8	26605.8
12:09:23	120	0.0	0.00	0.62	30851.9	154.8	26605.8
12:10:23	119	0.0	0.00	0.62	30851.9	154.8	26605.8
12:11:23	120	0.0	0.00	0.62	30851.9	154.8	26605.8
12:12:23	117	0.0	0.00	0.62	30851.9	154.8	26605.8
12:13:23	119	0.0	0.00	0.62	30851.9	154.8	26605.8
12:14:23	118	0.0	0.00	0.62	30851.9	154.8	26605.8

HALLIBURTON	JOB LOG	TICKET # 2,660,781	TICKET DATE 9/13/2003
FBM: NA	NWA / COUNTRY: CENTRAL AREA	BDA / STATE: Missouri	COUNTY: Vernon
MBU ID / EMPL #: FS0501	H.E.S EMPLOYEE NAME: FS0501 106288 EARL BARBER	PSL DEPARTMENT: PE / STIMULATION	
LOCATION: Ft. Smith, Ar	COMPANY: University Of Missouri-Rolla	CUSTOMER REP / PHONE: Sheri Dunn Norman	
TICKET AMOUNT:	WELL TYPE: GAS	API/UWI #:	
WELL LOCATION: Nevada	DEPARTMENT: FRAC	JOB PURPOSE CODE: 275	
LEASE / WELL #: Cushard #5	SEC / TWP / RNG:		

H.E.S. EMP NAME / EMP # / (EXPOSURE HOURS)	HRS		HRS		HRS		HRS
EARL BARBER	6	GREG AYNES	6	DOLPH MATHIS	6	STELE JAMES	6
TOMMY CARR	6	DAVID HOLLAND	6	JEFF BATES	6	VINCE CALVARUZO	6
JOE SOUTHERN	6	DUSTIN DAWES	6	JOE ROAM	6	JAMES KING	6
MARKAS JACKSON	6	NESTOR HINOJOS	6	FRAN HOFFMAN	6	DAVID BLACK	6

Chart No.	Time	Rate (BPM)	Volume (BBL)(GAL)	Pmps T	Pmps C	Press.(PSI) Tbg	Press.(PSI) Csg	Job Description / Remarks
	1300							ON LOCATION - JSA
	1310		STAGE					SAFETY MEETING
	1330		VOL					SPOT TRUCKS
	1630		BH					RIGGED UP
	1640		GALLONS					HSE MEETING PRIME AND TEST
								TEST LINES
	1656							START JOB
	1656	11.2	2,065				509	FLUID EFFICENCY TEST
	1814	11.6	1,635				400	30 # WATERFRAC G PAD
	1817	14.7	3,065				466	30# WATERFRAC G W/ 1/2 PPG SAND
	1822	14.9	3,204				381	30# WATERFRAC G W/ 1 PPG SAND
	1827	15.3	4,245				320	30# WATERFRAC G W/ 2 PPG SAND
	1834	14.9	5,190				288	30# WATERFRAC G W 4 PPG SAND
	1849	15.3	2,906				291	30# WATERFRAC G W 6 PPG SAND
	1854	15.2	4,140				253	30# WATERFRAC G W/ 8 PPG SAND
	1900	14.9	3,659				219	30# WATERFRAC G W 10 PPG SAND
	1906	14.1	149				183	30# WATERFRAC G FLUSH
	1907							END JOB
								AVG PSI
								MAX PSI
								AVG RATE
								MAX RATE
								ISIP 82
								5 MIN 67
								10 MIN 65
								15 MIN 64
								LOAD 643 BBLS
								TOTAL SAND PUMPED 710 SKS
	1920							POST JOB MEETING
	2100							RIG DOWN MOVE OFF

9/13/2003

Form 4239-4

JOB SUMMARY

HALLIBURTON

TICKET # 2660781	TICKET DATE 9/13/2003		
FBM NA	NWA / COUNTRY CENTRAL AREA	BDA / STATE Missouri	COUNTY Vernon
MBU ID / EMPL # FS0501	H.E.S EMPLOYEE NAME FS0501 106288 EARL BARBER	PSL DEPARTMENT PE / STIMULATION	
LOCATION Ft. Smith, Ar	COMPANY University Of Missouri-Rolla	CUSTOMER REP / PHONE Sheri Dunn Norman	
TICKET AMOUNT	WELL TYPE GAS	API/UWI #	
WELL LOCATION Nevada	DEPARTMENT FRAC	JOB PURPOSE CODE 275	
LEASE / WELL # Cushard #5	SEC / TWP / RNG		

H.E.S. EMP NAME / EMP # / (EXPOSURE HOURS)	HRS		HRS		HRS		HRS
EARL BARBER	6	GREG AYNES	6	DOLPH MATHIS	6	STELE JAMES	6
TOMMY CARR	6	DAVID HOLLAND	6	JEFF BATES	6	VINCE CALVARUZO	6
JOE SOUTHERN	6	DUSTIN DAWES	6	JOE ROAM	6	JAMES KING	6
MARKAS JACKSON	6	NESTOR HINOJOS	6	FRAN HOFFMAN	6	DAVID BLACK	6

H.E.S. UNIT #S / (R / T MILES)	R / T MILES		R / T MILES		R / T MILES		R / T MILES
SEE ATTTACHED LIST							

Form. Name CASEY Type: GAS
Form. Thickness ______ From ______ To ______
Packer Type ______ Set At ______
Bottom Hole Temp. #REF! Pressure #REF!
Misc. Data ______ Total Depth ______

	Called Out	On Location	Job Started	Job Completed
Date	9/13/2003	9/13/2003	9/13/2003	9/13/2003
Time	0400	1300	1300	1900

Tools and Accessories

Type and Size	Qty	Make
Float Collar		
Float Shoe		
Guide Shoe		
Centralizers		
Bottom Plug		
Top Plug		
Head		
Packer		
Other		

Well Data

	New/Used	Weight	Size	From	To	Max. Allow
Casing	used	10.5 lb/ft	4 1/2"		250	
Liner						
Liner						
Tbg. / D.P.						
Tbg. / D.P.						
Open Hole						Shots/Ft.
Perforations						
Perforations						
Perforations			#REF!	#REF!	#REF!	#REF!

Materials

Treat. Fluid 2% KCL Density 8.4 Lb/Gal
Disp. Fluid ______ Density 8.4 Lb/Gal
Prop. Type BRADY Size 20/40 Lb. 710SKS
Prop. Type ______ Size ______ Lb. ______
Acid Type ______ Gal. ______ %
Acid Type ______ Gal. ______ %
Surfactant ______ Gal. ______ In
NE Agent ______ Gal. ______ In
Fluid Loss ______ Gal/Lb ______ In
Gelling Agent LGC-4 Gal/Lb ______ In
Fric. Red. ______ Gal/Lb ______ In
Breaker ENZYME-1 Gal/Lb ______ In
Blocking Agent ______ Gal/Lb ______
Perfpac Balls ______ Qty. ______
Other BC-140
Other
Other HC-2
Other KCL
Other BE3 & BE-6

Hours On Location Date	Hours	Operating Hours Date	Hours
13-Sep	6	13-Sep	3
Total	6	Total	3

Description of Job

N2 DELTA 140 FOAM FRAC

Hydraulic Horsepower

Ordered 3000 Avail. 3000 Used 3000

Average Rates in BPM

Treating ______ Disp. ______ Overall ______

Cement Left in Pipe

Feet ______ Reason ______

Cement Data

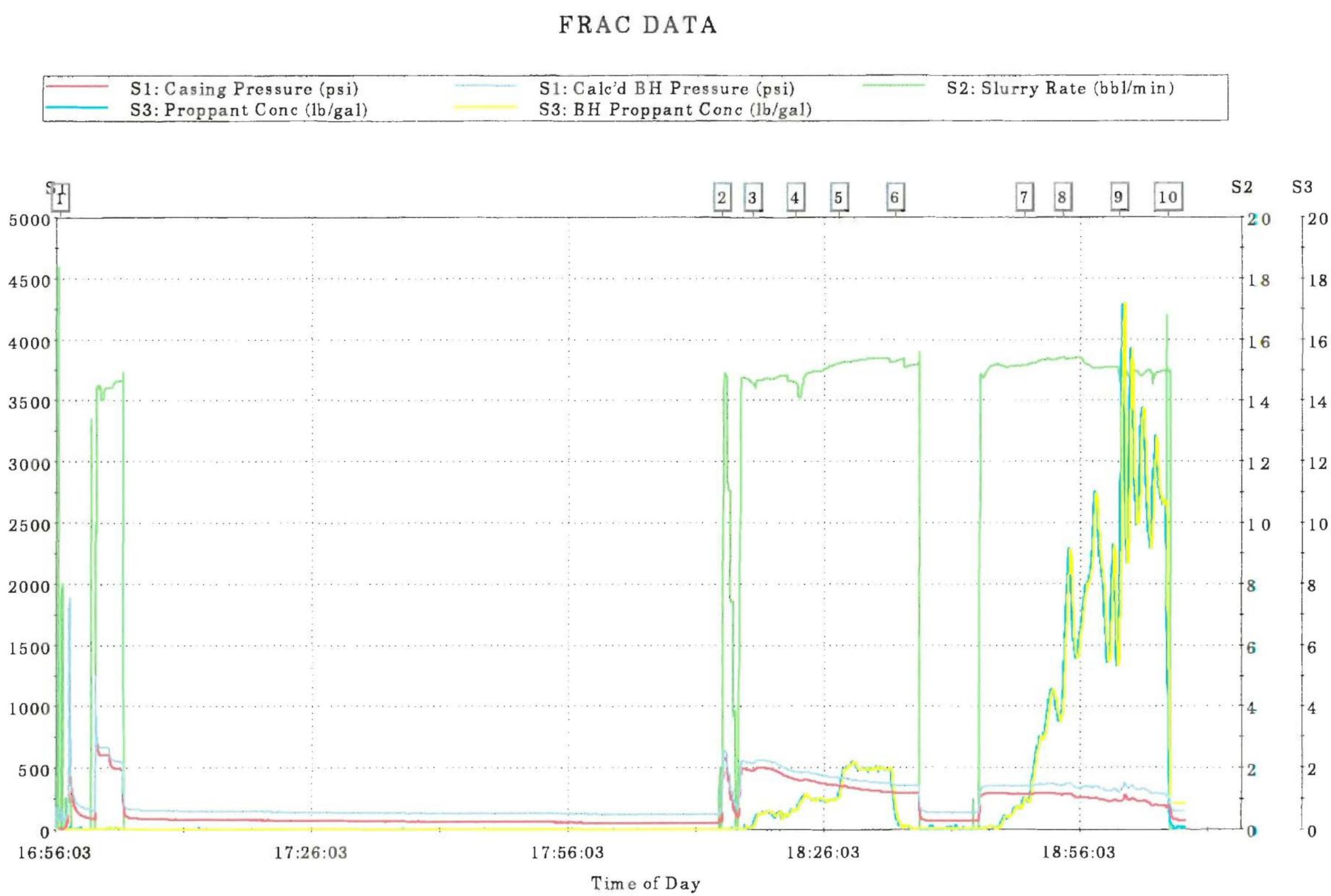
Stage	Sacks	Cement	Bulk/Sks	Additives	Yield	Lbs/Gal
				TOTAL LOAD 643 BBL		
				TOTAL SAND PUMPED 710 SKS		

Summary

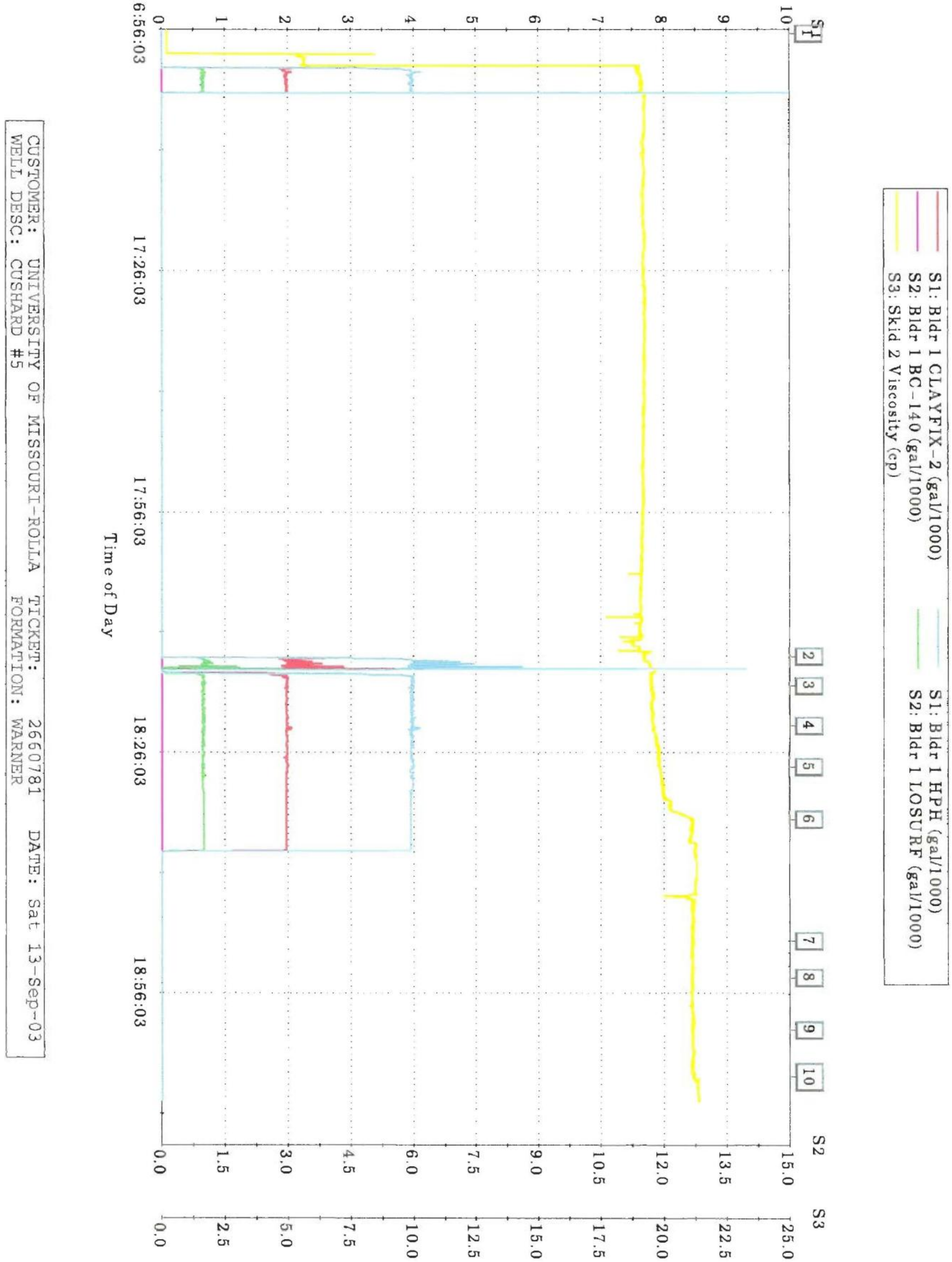
Circulating ______ Displacement ______ Preflush: Gal - BBl ______ Type:
Breakdown ______ Maximum ______ Load & Bkdn: Gal - BBl ______ Pad:Bbl -Gal ______
Average ______ Frac. Gradient ______ Treatment: Gal - BBl ______ Disp:Bbl-Gal ______
Shut In: Instant 82 5 Min. 67 15 Min 64 Cement Slurry Gal - BBl ______
Total Volume Gal - BBl ______

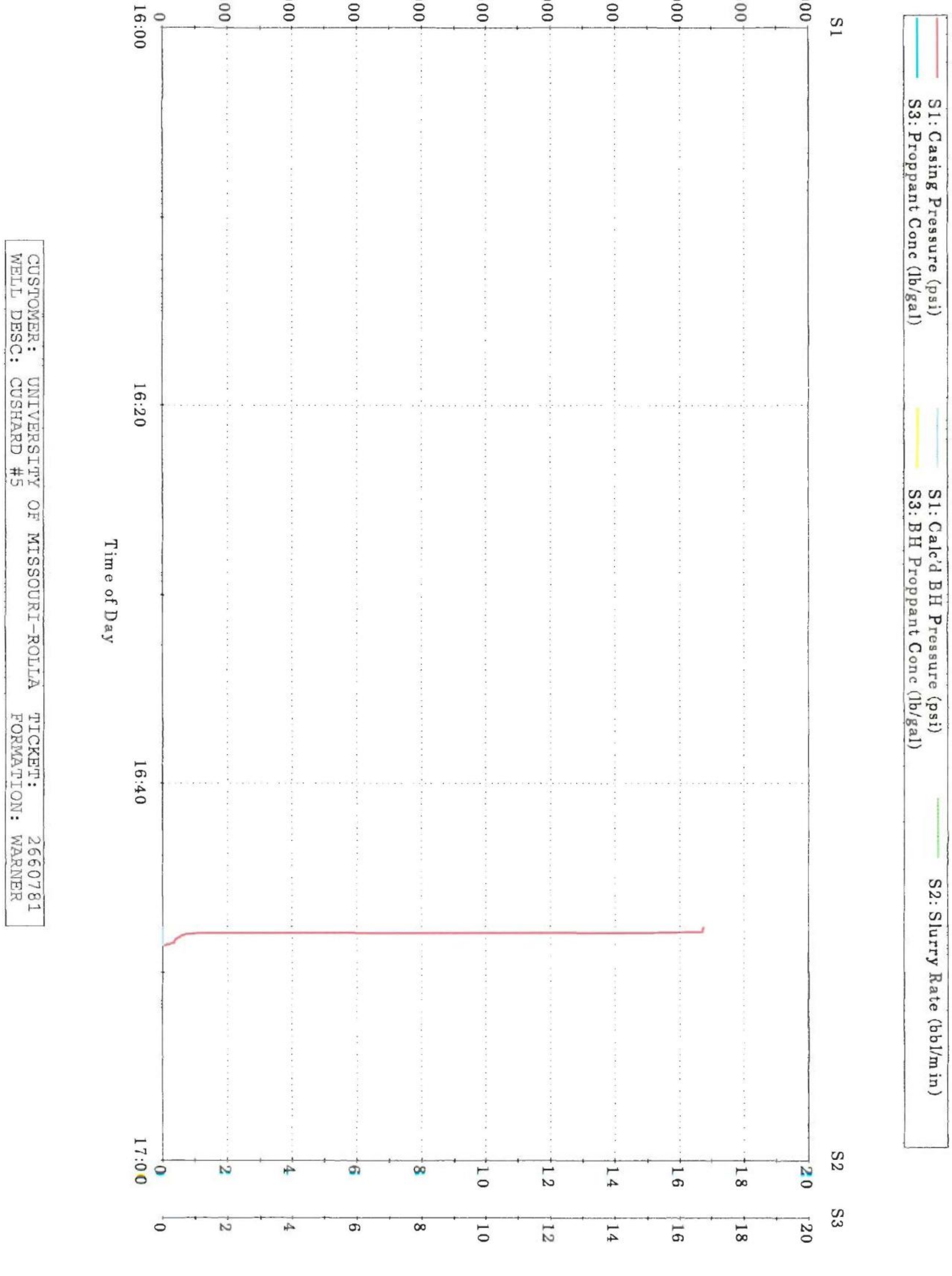
Form 4239-1

9/13/2003



CUSTOMER: UNIVERSITY OF MISSOURI-ROLLA TICKET: 2660781 DATE: Sat 13-Sep-03
WELL DESC: CUSHARD #5 FORMATION: WARNER


S1: Bldr 1 CLAYFIX-2 (gal/1000)
S2: Bldr 1 BC-140 (gal/1000)
S3: Skid 2 Viscosity (cp)
S1: Bldr 1 HPH (gal/1000)
S2: Bldr 1 LOSURF (gal/1000)
Time of Day
16:56:03
17:26:03
17:56:03
18:26:03
18:56:03
S1
S2
S3
CUSTOMER: UNIVERSITY OF MISSOURI-ROLLA TICKET: 2660781 DATE: Sat 13-Sep-03
WELL DESC: CUSHARD #5 FORMATION: WARNER



S1: Casing Pressure (psi)
S3: Proppant Conc (lb/gal)
S1: Calc'd BH Pressure (psi)
S3: BH Proppant Conc (lb/gal)
S2: Slurry Rate (bbl/min)
S1
0
500
1000
1500
2000
2500
3000
3500
4000
4500
5000
16:00
16:20
16:40
17:00
Time of Day
S2
S3
0
2
4
6
8
10
12
14
16
18
20
CUSTOMER: UNIVERSITY OF MISSOURI-ROLLA
WELL DESC: CUSHARD #5
TICKET: 2660781
FORMATION: WARNER

Customer:	**UNIVERSITY OF MISSOURI-ROLLA**	**Date:**	**13-Sep-2003**
Well Desc.:	**#5**	**Ticket #:**	**2660781**
Formation:	**WARNER**	**Job Type:**	**WATERFRAC G**

This report is based on sound engineering practices, but because of variable well conditions and other information which must be relied on, Halliburton makes no warranty,expressed or implied, as to the accuracy of the data or of any calculations or opinions expressed herein. You agree that Halliburton shall not be liable for any loss or damage, whether due to negligence or otherwise arising out of or in connection with such data, calculations or opinions.

HALLIBURTON ENERGY SERVICES
SOLUTIONS IN ACTION!

Time	Description
16:56:03	Start Job Saturday September 13, 2003
16:56:36	Stage Change Stage 1 - FET WATERFRAC G
18:14:04	Stage Change Stage 2 - WATERFRAC G PAD
18:17:43	Stage Change Stage 3 - WATERFRAC G PLF .5 PPG
18:22:41	Stage Change Stage 4 - WATERFRAC G PLF 1 PPG
18:27:49	Stage Change Stage 5 - WATERFRAC G PLF 2 PPG
18:34:25	Stage Change Stage 6 - WATERFRAC G PLF 4 PPG
18:49:34	Stage Change Stage 7 - WATERFRAC G PLF 6 PPG
18:54:05	Stage Change Stage 8 - WATERFRAC G PLF 8 PPG
19:00:35	Stage Change Stage 9 - WATERFRAC G PLF 10 PPG
19:06:26	Stage Change Stage 10 - WATERFRAC G FLUSH
19:22:47	End Job

Volumes

Stage	Job Slurry Vol gal	Stage Slurry Vol gal	Stage Clean Vol gal	Job Clean Vol gal
1	2065.7	2065.7	2064.3	2064.3
2	3701.5	1635.8	1633.9	3698.2
3	6767.4	3065.8	2998.0	6696.1
4	9966.9	3204.8	3069.1	9760.3
5	14211.8	4245.0	3908.3	13668.3
6	19402.6	5190.8	5131.4	18799.8
7	22314.6	2906.6	2559.1	21364.0
8	26450.1	4140.7	3086.5	24446.6
9	30109.9	3654.6	2424.7	26875.2
10	30259.0	149.1	144.5	27019.8
Totals:	(30259.0)	(30259.0)	(27019.8)	(27019.8)

Mass

Stage	Job Proppant Pumped sack	Stage Proppant Pumped sack	Proppant In Formation sack	Proppant In Wellbore sack
1	0.3	0.3	0.3	0.0
2	0.7	0.4	0.6	0.1
3	15.6	14.9	14.9	0.7
4	45.3	29.8	44.1	1.2
5	119.2	73.8	118.3	0.9
6	132.2	13.0	131.1	1.1
7	208.5	76.2	203.9	4.6
8	439.3	231.2	433.9	5.5
9	709.3	269.7	705.4	3.9
10	710.4	1.0	709.8	0.6
Totals:	(710.4)	(710.4)	(709.8)	(0.6)

Pressure

Stage	Casing Pressure psi (avg/max)	Calc'd BH Pressure psi (avg/max)
1	509 / 1790	564 / 1891
2	400 / 587	463 / 647
3	466 / 503	529 / 566
4	381 / 405	446 / 470
5	320 / 352	388 / 419
6	288 / 299	349 / 359
7	291 / 296	362 / 373
8	253 / 288	338 / 377
9	219 / 280	313 / 377
10	183 / 188	251 / 262
Totals:	(331/1790)	(400/1891)

Rate

Stage	Clean Rate bbl/min (avg/max)	Slurry Rate bbl/min (avg/max)
1	11.2 / 15.0	11.2 / 15.0
2	11.6 / 14.9	11.6 / 14.9
3	14.4 / 14.6	14.7 / 14.8
4	14.3 / 14.5	14.9 / 15.2
5	14.1 / 14.9	15.3 / 15.4
6	14.7 / 15.6	14.9 / 15.6
7	13.5 / 14.6	15.3 / 15.4
8	11.3 / 12.3	15.2 / 15.4
9	9.8 / 13.4	14.9 / 16.8
10	13.6 / 14.7	14.1 / 15.0
Totals:	(12.8/15.6)	(14.2/16.8)

STAGE 1	Planned	Actual	SUMMARY	@Surface	@Perfs
Clean Volume (gal)	1500.0	2064.3	Treating Pressure Avg/Max (psi)	509 / 1790	509 / 1790
Slurry Volume (gal)	1500.0	2065.7	BHTP Avg/Max (psi)	564 / 1891	564 / 1891
Start Fluid Rate (bbl/min)	15.0	0.0	Total Avg. Rate (bbl/min)	11.2	11.2
End Fluid Rate (bbl/min)	15.0	3.1	Avg. HHP (hp)	150.3	
Friction Model	WG-19				
Description : FET WATERFRAC G					

STAGE 2	Planned	Actual	SUMMARY	@Surface	@Perfs
Clean Volume (gal)	1000.0	1633.9	Treating Pressure Avg/Max (psi)	400 / 587	400 / 587
Slurry Volume (gal)	1000.0	1635.8	BHTP Avg/Max (psi)	463 / 647	463 / 647
Start Fluid Rate (bbl/min)	15.0	5.7	Total Avg. Rate (bbl/min)	11.6	11.6
End Fluid Rate (bbl/min)	15.0	14.5	Avg. HHP (hp)	127.4	
Friction Model	WG-19				
Description : WATERFRAC G PAD					

STAGE 3	Planned	Actual	SUMMARY	@Surface	@Perfs
Clean Volume (gal)	3000.0	2998.0	Treating Pressure Avg/Max (psi)	466 / 503	466 / 503
Slurry Volume (gal)	3068.4	3065.8	BHTP Avg/Max (psi)	528 / 566	528 / 566
Start Fluid Rate (bbl/min)	15.0	14.5	Total Avg. Rate (bbl/min)	14.7	14.7
End Fluid Rate (bbl/min)	15.0	14.6	Avg. HHP (hp)	167.8	
Sand	20/40	0.04560 (gal/lb)	Prop in Wellbore (lb)	69.9	
Start Conc (lb/gal)	0.50	0.15	Avg. Prop Concentration (lb/gal)	0.50	0.48
End Conc (lb/gal)	0.50	0.58	Prop in Formation (lb)	1492.6	
Friction Model	WG-19				
Description : WATERFRAC G PLF .5 PPG					

STAGE 4	Planned	Actual	SUMMARY	@Surface	@Perfs
Clean Volume (gal)	3000.0	3069.1	Treating Pressure Avg/Max (psi)	381 / 405	381 / 405
Slurry Volume (gal)	3136.8	3204.8	BHTP Avg/Max (psi)	446 / 470	446 / 470
Start Fluid Rate (bbl/min)	15.0	14.6	Total Avg. Rate (bbl/min)	14.9	14.9
End Fluid Rate (bbl/min)	15.0	15.2	Avg. HHP (hp)	139.0	
Sand	20/40	0.04560 (gal/lb)	Prop in Wellbore (lb)	124.6	
Start Conc (lb/gal)	1.00	0.60	Avg. Prop Concentration (lb/gal)	0.97	0.95
End Conc (lb/gal)	1.00	1.30	Prop in Formation (lb)	4407.6	
Friction Model	WG-19				
Description : WATERFRAC G PLF 1 PPG					

STAGE 5	Planned	Actual	SUMMARY	@Surface	@Perfs
Clean Volume (gal)	3000.0	3908.3	Treating Pressure Avg/Max (psi)	320 / 352	320 / 352
Slurry Volume (gal)	3273.6	4245.0	BHTP Avg/Max (psi)	388 / 419	388 / 419
Start Fluid Rate (bbl/min)	15.0	15.2	Total Avg. Rate (bbl/min)	15.3	15.3
End Fluid Rate (bbl/min)	15.0	15.3	Avg. HHP (hp)	120.2	
Sand	20/40	0.04560 (gal/lb)	Prop in Wellbore (lb)	88.1	
Start Conc (lb/gal)	2.00	1.30	Avg. Prop Concentration (lb/gal)	1.89	1.90
End Conc (lb/gal)	2.00	0.55	Prop in Formation (lb)	11831.7	
Friction Model	WG-19				
Description : WATERFRAC G PLF 2 PPG					

STAGE 6	Planned	Actual	SUMMARY	@Surface	@Perfs
Clean Volume (gal)	3000.0	5131.4	Treating Pressure Avg/Max (psi)	288 / 299	288 / 299
Slurry Volume (gal)	3547.2	5190.8	BHTP Avg/Max (psi)	349 / 359	349 / 359
Start Fluid Rate (bbl/min)	15.0	15.3	Total Avg. Rate (bbl/min)	14.9	14.9
End Fluid Rate (bbl/min)	15.0	15.2	Avg. HHP (hp)	106.2	
Sand	20/40	0.04560 (gal/lb)	Prop in Wellbore (lb)	112.7	
Start Conc (lb/gal)	4.00	0.53	Avg. Prop Concentration (lb/gal)	0.30	0.29
End Conc (lb/gal)	4.00	1.04	Prop in Formation (lb)	13107.2	
Friction Model	WG-19				
Description : WATERFRAC G PLF 4 PPG					

STAGE 7	Planned	Actual	SUMMARY	@Surface	@Perfs
Clean Volume (gal)	3000.0	2559.1	Treating Pressure Avg/Max (psi)	291 / 296	291 / 296
Slurry Volume (gal)	3820.8	2906.6	BHTP Avg/Max (psi)	362 / 373	362 / 373
Start Fluid Rate (bbl/min)	15.0	15.2	Total Avg. Rate (bbl/min)	15.3	15.3
End Fluid Rate (bbl/min)	15.0	15.4	Avg. HHP (hp)	108.9	
Sand	20/40	0.04560 (gal/lb)	Prop in Wellbore (lb)	456.9	
Start Conc (lb/gal)	6.00	1.02	Avg. Prop Concentration (lb/gal)	3.03	2.89
End Conc (lb/gal)	6.00	5.38	Prop in Formation (lb)	20388.4	
Friction Model	WG-19				
Description : WATERFRAC G PLF 6 PPG					

STAGE 8	Planned	Actual	SUMMARY	@Surface	@Perfs
Clean Volume (gal)	3000.0	3086.5	Treating Pressure Avg/Max (psi)	253 / 288	253 / 288
Slurry Volume (gal)	4094.4	4140.7	BHTP Avg/Max (psi)	338 / 377	338 / 377
Start Fluid Rate (bbl/min)	15.0	15.4	Total Avg. Rate (bbl/min)	15.2	15.2
End Fluid Rate (bbl/min)	15.0	14.9	Avg. HHP (hp)	94.2	
Sand	20/40	0.04560 (gal/lb)	Prop in Wellbore (lb)	548.4	
Start Conc (lb/gal)	8.00	5.44	Avg. Prop Concentration (lb/gal)	7.58	7.54
End Conc (lb/gal)	8.00	6.99	Prop in Formation (lb)	43386.6	
Friction Model	WG-19				
Description : WATERFRAC G PLF 8 PPG					

STAGE 9	Planned	Actual	SUMMARY	@Surface	@Perfs
Clean Volume (gal)	3000.0	2424.7	Treating Pressure Avg/Max (psi)	219 / 280	219 / 280
Slurry Volume (gal)	4368.0	3654.6	BHTP Avg/Max (psi)	313 / 377	313 / 377
Start Fluid Rate (bbl/min)	15.0	14.8	Total Avg. Rate (bbl/min)	14.9	14.9
End Fluid Rate (bbl/min)	15.0	14.9	Avg. HHP (hp)	79.7	
Sand	20/40	0.04560 (gal/lb)	Prop in Wellbore (lb)	394.5	
Start Conc (lb/gal)	10.00	7.06	Avg. Prop Concentration (lb/gal)	11.32	11.38
End Conc (lb/gal)	10.00	2.01	Prop in Formation (lb)	70540.0	
Friction Model	WG-19				
Description : WATERFRAC G PLF 10 PPG					

STAGE 10	Planned	Actual	SUMMARY	@Surface	@Perfs
Clean Volume (gal)	108.0	144.5	Treating Pressure Avg/Max (psi)	183 / 188	183 / 188
Slurry Volume (gal)	108.0	149.1	BHTP Avg/Max (psi)	251 / 261	251 / 261
Start Fluid Rate (bbl/min)	15.0	14.9	Total Avg. Rate (bbl/min)	14.0	14.0
End Fluid Rate (bbl/min)	15.0	0.0	Avg. HHP (hp)	63.1	
None	None	0.00000 (gal/lb)	Prop in Wellbore (lb)	56.2	
Start Conc (lb/gal)	0.00	1.83	Avg. Prop Concentration (lb/gal)	0.67	3.08
End Conc (lb/gal)	0.00	0.00	Prop in Formation (lb)	70979.5	
Friction Model	WG-19				
Description : WATERFRAC G FLUSH					

Initial Conditions

Treatment Parameters		
	Job Type	*WATERFRAC G*
	Well Treated Down	*Casing*
	Static Column Used	*NO*
	Earth Temperature	*70.0 f*
	Slurry Temperature	*69.0 f*
	BHTT	*70.0 f*
	Reservoir Pressure	*100 psi*
	Expected BHTP	*150 psi*
Initial Wellbore Data		
	Wellbore fluid	*WG-19*
	Density	*8.33 lb/gal*
	n-prime	*0.7951*
	K-prime	*0.000265 lb*sec^n/ft^2*
Perf Data		
	Number of	*61*
	Diameter	*0.500 in*
	Disch. Coeff	*0.600*

Wellbore Data

Wellbore Segment Number	Actual Length (ft)	TVD (ft)	Casing ID (in)	Casing OD (in)	Tubing ID (in)	Tubing OD (in)
1	*162*	*162*	*4.052*	*4.500*	*0.000*	*0.000*

Time of Day	Casing Pressure	Slurry Rate	Proppant Conc	BH Proppant Conc	Job Slurry Vol	Stage Slurry Vol	Job Clean Vol
	psi	bbl/min	lb/gal	lb/gal	gal	gal	gal
16:56:03	-28	0.0	0.00	0.00	0.0	0.0	0.0
16:57:03	12	0.0	0.00	0.00	32.5	32.5	32.5
16:58:03	237	0.0	0.00	0.00	60.5	60.5	60.5
16:59:03	114	0.0	0.06	0.00	60.5	60.5	60.5
17:00:03	91	0.0	0.00	0.00	60.5	60.5	60.5
17:01:03	614	14.4	0.00	0.00	293.3	293.3	293.3
17:02:03	605	14.4	0.02	0.00	891.9	891.9	891.4
17:03:03	495	14.6	0.00	0.00	1500.2	1500.2	1499.2
17:04:03	148	0.0	0.02	0.00	2058.0	2058.0	2056.6
17:05:03	94	0.0	0.00	0.00	2058.0	2058.0	2056.6
17:06:03	89	0.0	0.00	0.00	2058.0	2058.0	2056.6
17:07:03	86	0.0	0.00	0.00	2058.0	2058.0	2056.6
17:08:03	85	0.0	0.00	0.00	2058.0	2058.0	2056.6
17:09:03	83	0.0	0.00	0.00	2058.0	2058.0	2056.6
17:10:03	83	0.0	0.00	0.00	2058.0	2058.0	2056.6
17:11:03	80	0.0	0.00	0.00	2058.0	2058.0	2056.6
17:12:03	80	0.0	0.00	0.00	2058.0	2058.0	2056.6
17:13:03	77	0.0	0.00	0.00	2058.0	2058.0	2056.6
17:14:03	76	0.0	0.00	0.00	2058.0	2058.0	2056.6
17:15:03	76	0.0	0.00	0.00	2058.0	2058.0	2056.6
17:16:03	76	0.0	0.00	0.00	2058.0	2058.0	2056.6
17:17:03	75	0.0	0.00	0.00	2058.0	2058.0	2056.6
17:18:03	75	0.0	0.00	0.00	2058.0	2058.0	2056.6
17:19:03	74	0.0	0.04	0.00	2058.0	2058.0	2056.6
17:20:03	73	0.0	0.00	0.00	2058.0	2058.0	2056.6
17:21:03	73	0.0	0.00	0.00	2058.0	2058.0	2056.6
17:22:03	72	0.0	0.00	0.00	2058.0	2058.0	2056.6
17:23:03	73	0.0	0.00	0.00	2058.0	2058.0	2056.6
17:24:03	71	0.0	0.00	0.00	2058.0	2058.0	2056.6
17:25:03	70	0.0	0.00	0.00	2058.0	2058.0	2056.6
17:26:03	69	0.0	0.00	0.00	2058.0	2058.0	2056.6
17:27:03	70	0.0	0.00	0.00	2058.0	2058.0	2056.6
17:28:03	68	0.0	0.00	0.00	2058.0	2058.0	2056.6
17:29:03	68	0.0	0.00	0.00	2058.0	2058.0	2056.6
17:30:03	68	0.0	0.00	0.00	2058.0	2058.0	2056.6
17:31:03	68	0.0	0.00	0.00	2058.0	2058.0	2056.6
17:32:03	67	0.0	0.00	0.00	2058.0	2058.0	2056.6
17:33:03	66	0.0	0.00	0.00	2058.0	2058.0	2056.6
17:34:03	66	0.0	0.00	0.00	2058.0	2058.0	2056.6
17:35:03	64	0.0	0.00	0.00	2058.0	2058.0	2056.6
17:36:03	66	0.0	0.00	0.00	2058.0	2058.0	2056.6
17:37:03	65	0.0	0.00	0.00	2058.0	2058.0	2056.6
17:38:03	64	0.0	0.00	0.00	2058.0	2058.0	2056.6
17:39:03	64	0.0	0.00	0.00	2058.0	2058.0	2056.6
17:40:03	63	0.0	0.00	0.00	2058.0	2058.0	2056.6
17:41:03	63	0.0	0.00	0.00	2058.0	2058.0	2056.6
17:42:03	62	0.0	0.00	0.00	2058.0	2058.0	2056.6
17:43:03	62	0.0	0.00	0.00	2058.0	2058.0	2056.6
17:44:03	61	0.0	0.00	0.00	2058.0	2058.0	2056.6
17:45:03	62	0.0	0.00	0.00	2058.0	2058.0	2056.6
17:46:03	60	0.0	0.00	0.00	2058.0	2058.0	2056.6
17:47:03	61	0.0	0.00	0.00	2058.0	2058.0	2056.6
17:48:03	60	0.0	0.00	0.00	2058.0	2058.0	2056.6
17:49:03	60	0.0	0.00	0.00	2058.0	2058.0	2056.6
17:50:03	60	0.0	0.00	0.00	2058.0	2058.0	2056.6
17:51:03	58	0.0	0.00	0.00	2058.0	2058.0	2056.6
17:52:03	58	0.0	0.00	0.00	2058.0	2058.0	2056.6

Time of Day	Casing Pressure	Slurry Rate	Proppant Conc	BH Proppant Conc	Job Slurry Vol	Stage Slurry Vol	Job Clean Vol
	psi	bbl/min	lb/gal	lb/gal	gal	gal	gal
17:53:03	58	0.0	0.00	0.00	2058.0	2058.0	2056.6
17:54:03	59	0.0	0.00	0.00	2058.0	2058.0	2056.6
17:55:03	56	0.0	0.00	0.00	2058.0	2058.0	2056.6
17:56:03	56	0.0	0.00	0.00	2058.0	2058.0	2056.6
17:57:03	56	0.0	0.00	0.00	2058.0	2058.0	2056.6
17:58:03	55	0.0	0.00	0.00	2058.0	2058.0	2056.6
17:59:03	56	0.0	0.00	0.00	2058.0	2058.0	2056.6
18:00:03	55	0.0	0.00	0.00	2058.0	2058.0	2056.6
18:01:03	54	0.0	0.00	0.00	2058.0	2058.0	2056.6
18:02:03	53	0.0	0.00	0.00	2058.0	2058.0	2056.6
18:03:03	53	0.0	0.00	0.00	2058.0	2058.0	2056.6
18:04:03	52	0.0	0.00	0.00	2058.0	2058.0	2056.6
18:05:03	51	0.0	0.00	0.00	2058.0	2058.0	2056.6
18:06:03	53	0.0	0.00	0.00	2058.0	2058.0	2056.6
18:07:03	52	0.0	0.00	0.00	2058.0	2058.0	2056.6
18:08:03	52	0.0	0.00	0.00	2058.0	2058.0	2056.6
18:09:03	51	0.0	0.00	0.00	2058.0	2058.0	2056.6
18:10:03	51	0.0	0.00	0.00	2058.0	2058.0	2056.6
18:11:03	51	0.0	0.00	0.00	2058.0	2058.0	2056.6
18:12:03	48	0.0	0.00	0.00	2058.0	2058.0	2056.6
18:13:03	47	0.0	0.00	0.00	2058.0	2058.0	2056.6
18:14:03	113	3.1	0.00	0.00	2065.7	2065.7	2064.3
18:15:03	265	7.5	0.00	0.00	2575.8	510.1	2574.3
18:16:03	138	6.2	0.00	0.00	2723.7	657.9	2722.1
18:17:03	484	14.7	0.04	0.09	3302.5	1236.8	3300.2
18:18:03	495	14.6	0.46	0.26	3914.6	213.1	3908.6
18:19:03	499	14.7	0.58	0.60	4531.1	829.6	4511.1
18:20:03	483	14.7	0.44	0.53	5149.1	1447.6	5114.3
18:21:03	447	14.8	0.37	0.60	5769.2	2067.7	5721.4
18:22:03	419	14.6	0.55	0.51	6389.0	2687.5	6328.2
18:23:03	399	14.2	0.81	0.64	6999.2	231.8	6920.9
18:24:03	403	14.9	1.09	1.11	7610.0	842.7	7504.4
18:25:03	385	15.0	0.97	0.97	8237.1	1469.8	8104.4
18:26:03	370	15.0	0.92	0.99	8865.8	2098.4	8706.1
18:27:03	358	15.1	0.95	0.95	9499.4	2732.0	9313.6
18:28:03	348	15.2	1.67	1.43	10137.4	165.2	9920.0
18:29:03	335	15.3	2.08	2.03	10778.2	806.0	10507.9
18:30:03	325	15.3	1.90	2.01	11420.2	1448.0	11094.0
18:31:03	317	15.4	1.95	1.90	12064.0	2091.8	11685.4
18:32:03	312	15.4	1.98	1.98	12708.9	2736.6	12277.7
18:33:03	307	15.4	1.95	1.98	13354.2	3382.0	12869.7
18:34:03	300	15.3	1.28	1.83	13998.1	4025.9	13463.2
18:35:03	294	15.3	0.11	0.13	14640.2	423.0	14091.5
18:36:03	298	15.1	0.06	0.11	15278.4	1061.2	14726.6
18:37:03	296	15.2	0.02	0.04	15914.7	1697.5	15362.4
18:38:03	72	0.0	0.00	0.02	16017.3	1800.1	15464.9
18:39:03	70	0.0	0.02	0.02	16017.3	1800.1	15464.9
18:40:03	68	0.0	0.02	0.02	16017.3	1800.1	15464.9
18:41:03	67	0.0	0.02	0.02	16017.3	1800.1	15464.9
18:42:03	68	0.0	0.00	0.02	16017.3	1800.1	15464.9
18:43:03	66	0.0	0.00	0.02	16017.3	1800.1	15464.9
18:44:03	65	0.0	0.02	0.02	16018.0	1800.8	15465.6
18:45:03	292	15.0	0.06	0.00	16554.8	2337.6	16001.6
18:46:03	298	15.2	0.00	0.00	17188.6	2971.4	16633.4
18:47:03	292	15.1	0.40	0.24	17825.1	3607.9	17265.9
18:48:03	288	15.1	0.53	0.46	18459.6	4242.4	17888.4
18:49:03	287	15.1	0.64	0.78	19095.2	4878.0	18504.3

Time of Day	Casing Pressure	Slurry Rate	Proppant Conc	BH Proppant Conc	Job Slurry Vol	Stage Slurry Vol	Job Clean Vol
	psi	bbl/min	lb/gal	lb/gal	gal	gal	gal
18:50:03	288	15.2	0.92	0.92	19731.5	323.6	19115.2
18:51:03	295	15.3	2.72	2.53	20371.0	963.0	19703.4
18:52:03	294	15.4	3.62	3.20	21014.2	1606.2	20267.9
18:53:03	291	15.3	4.17	4.35	21658.4	2250.5	20807.1
18:54:03	281	15.4	5.35	3.93	22303.8	2895.8	21355.4
18:55:03	279	15.4	7.10	8.56	22948.9	634.3	21832.9
18:56:03	257	15.4	6.53	6.21	23594.8	1280.2	22340.3
18:57:03	256	15.1	8.18	8.02	24235.0	1920.4	22816.4
18:58:03	252	15.0	9.71	10.74	24868.0	2553.3	23253.8
18:59:03	234	15.1	5.61	6.70	25500.5	3185.9	23718.2
19:00:03	239	15.1	7.59	9.25	26133.7	3819.1	24197.4
19:01:03	243	14.7	17.10	16.15	26757.6	302.3	24638.7
19:02:03	252	14.8	15.24	15.12	27381.1	925.8	25042.5
19:03:03	225	14.8	13.10	10.74	28006.8	1551.6	25455.1
19:04:03	218	15.0	9.48	10.27	28631.6	2176.4	25859.2
19:05:03	196	14.9	11.75	12.71	29256.1	2800.8	26274.4
19:06:03	188	15.0	9.57	10.60	29883.4	3428.1	26694.9
19:07:03	79	0.0	0.02	0.83	30259.0	149.1	27019.8
19:08:03	71	0.0	0.02	0.83	30259.0	149.1	27019.8
19:09:03	71	0.0	0.00	0.83	30259.0	149.1	27019.8
19:10:03	68	0.0	0.00	0.83	30259.0	149.1	27019.8
19:11:03	68	0.0	0.06	0.83	30259.0	149.1	27019.8
19:12:03	68	0.0	0.00	0.83	30259.0	149.1	27019.8
19:13:03	67	0.0	0.00	0.83	30259.0	149.1	27019.8
19:14:03	67	0.0	0.04	0.83	30259.0	149.1	27019.8
19:15:03	67	0.0	0.02	0.83	30259.0	149.1	27019.8