BOTTOMHOLE GAUGE DATA VERIFIES ISOLATION BETWEEN FRACTURES IN AN OPENHOLE SAN ANDRES HORIZONTAL FRACTURING TREATMENT

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ABSTRACT
The paper will discuss and analyze bottomhole pressure data recorded during actual horizontal fracturing work. The data will demonstrate isolation from one fracture point to the next. The paper will also discuss production results from 10 horizontal wells completed using an innovative openhole horizontal completion technique. In addition, the paper will compare production results from these horizontal wells to others in the same field that were completed using different techniques. This paper is a follow-up to the 2005 SWPSC paper entitled "Innovative Stimulation Technique helps Pin-Point Fractures in Open Hole Horizontal San Andres Wells."[1]

RESERVOIR DESCRIPTION AND WELL HISTORY

The area of study is the Cedar Lake unit and West Welch unit located in Dawson County, Texas and Gaines County, Texas. The target formation for the horizontal laterals is the San Andres formation. **Table 1** shows the typical reservoir parameters associated with the San Andres formation in each respective unit. The lithology can best be described as microcrystalline dolomite cemented fossil fragments with scattered amounts of anhydrite. Laboratory analyses of several core samples indicated the mineral composition ranged from 80-100% dolomite and 20-0% anhydrite. Acid solubility ranged from 85% to 93%. Permeability of each unit ranged from 1 md to 10 md; however, the Kv/Kh ratio is low at 0.01. It is also believed that a producing oil water contact (POWC) is prevalent in each field.

In 2000, four horizontal wells were drilled in the West Welch unit. The completion techniques used on these wells were coil tubing acid washes, high rate limited entry fracs using a pre-perforated liner, hydra-jetting, and a cement liner with a cup packer treatment. The individual treatments were previously published.[1] In 2004, an additional four horizontal wells were drilled and completed using the chemical packer and ball-actuated sliding sleeve (BASS) tools for stimulation. In 2005, six more wells were drilled and completed using the chemical packer and BASS tools for isolation. In the 2005 program, bottomhole memory gauges were run in the horizontal treatment string to record the bottomhole pressure and temperature during the frac jobs. An analysis of this data will be shown later in the paper. **Table 2** is a list of all the horizontal wells that will be discussed in this paper.

DESCRIPTION OF STIMULATION TECHNIQUE

To effectively drain the reservoir, the horizontal wellbores needed to be hydraulically fractured at specific points along the horizontal lateral. To generate hydraulic fractures at specific points in the horizontal you must be able to first pinpoint the position and second provide some type of isolation between these pinpointed intervals. Two items were developed to address this need: a ball-actuated sliding sleeve (BASS) tool and a chemical packer. The BASS tool enables the user to pump fracturing fluid in the horizontal at very specific points. The chemical packer is a mixture of reactive polymers spotted in the annular region between the BASS tools to provide the annular isolation needed to prevent fracture communication between tools.

Once the number of fractures needed in the horizontal wellbore has been determined and the placement of those fractures has been decided, the well is ready to be stimulated.

The operational process for stimulation is as follows:

1. Treatment tubing is run in the horizontal wellbore placing the BASS tools across from the intervals where a hydraulic fracture is desired.
2. A mechanical packer is also run on the treatment tubing in the vertical section of the pipe. This mechanical packer enables further isolation between the horizontal wellbore and vertical casing string.

3. Once the tubulars are placed in the wellbore, the chemical packer is pumped down and out the end of the tubing so it is placed in the annular region between the openhole horizontal and treatment tubing. The chemical packer is then allowed to set before the fracturing begins.
4. The first frac is now initiated out the end of the tubing string.
5. During the flush of this fracture, a ball (designed for the first BASS tool) is dropped. The balls will land in the tool and open ports to the annulus to divert all treatment fluid out the ports. The ball acts as a seal to help prevent fluid from flowing farther down the tubing string.
6. The ball-dropping process continues until all of the BASS tools have been opened and subsequently fractured.
7. Once all the fractures have been pumped, the well can then be shut in or flowed, depending on the preference of the operator.
8. Once the wellhead pressure has diminished and the chemical packer has dissolved, the tubing and tools can be pulled out of the well.

One advantage of treating each BASS tool separately is the reduction in pumping rate and pressure. A reduction in pumping rate and pressure reduces the hydraulic horsepower (HHP) involved and reduces the overall cost of the treatment. It has been seen that this method has reduced the amount of HHP needed on location by up to 10 fold.

BOTTOMHOLE PRESSURE ANALYSIS

Obtaining real-time bottomhole pressures at various points in the horizontal wellbore during the frac job was not possible. To obtain the bottomhole pressure at various points in the horizontal wellbore, several memory gauges were installed in the tubulars. The memory gauges were able to record both internal and external pressure and temperature values. Approximately six wells were stimulated with these gauges in the treatment string. The data from all these wells helped verify the integrity of the chemical packer; however, only three of these wells will be discussed in this paper: Cedar Lake Unit 426 (CLU 426), West Welch Unit 2438 (WWU 2438), and West Welch Unit 1804 (WWU 1804).

Figure 1 is a schematic of the wellbore for CLU 426. In this well, approximately 11 fractures were placed using 10 BASS tools and a pre-perforated sub. The fractures are labeled numerically 1 through 11. A bottomhole pressure/temperature gauge was located at fracture point 1, fracture point 6, and fracture point 10. **Figure 2** is a plot of the bottomhole pressure data during the fracturing process. The bottomhole pressure gauge at fracture #1 rises sharply as soon as the fracturing rate increases to 10 bpm. The pressure gauge goes from 2,600 psi to approximately 4,400 psi, a fracture initiates, and then the pressure starts falling. At the same time that the bottomhole pressure gauge at fracture #1 is reading 4,400 psi, the bottomhole pressure gauge at the BASS tool #5 (only 1,390 ft away from frac #1) is reading 3,000 psi and has only increased 400 psi from the static state. The bottomhole gauge at BASS tool #9 (2,765 ft away from frac #1) does not change at all. Once the designed frac volume was pumped into frac #1, the ball was dropped and frac #2 was started out of BASS tool #1. During fracs #2–4, no increase in the bottomhole pressure gauges was seen in either the gauge at fracture point 6 or fracture point 10. When the ball landed in BASS tool #5 (fracture point 6) the bottomhole gauge pressure increased from approximately 2,800 psi to over 4,500 psi. Once again the bottomhole pressure gauge at fracture #10 did not change. The pressure at this point did not substantially change until the ball landed at BASS tool #9 and fracture #10 was initiated. Once this happened, the bottomhole gauge pressure at fracture #10 went from 2,900 psi to over 5,100 psi. When this stage was completed, the remaining ball was dropped and the eleventh and final stage was fractured.

Several of the pressure responses confirmed that the chemical packer was providing isolation between each fracture. First, the bottomhole pressure at fracture point #10 did not fluctuate until a fracture was initiated at fracture point #9, and then it only increased several hundred pounds. The bottomhole pressure did not dramatically increase until the fracture initiated at the same point. Second, the bottomhole pressure at fracture point #6 only slightly increased when the fracturing process started and then dramatically increased when fracturing at the same point (frac #10). Third, the pressure response following the fractures at fracs #1, 6, and 10 show a pressure falloff similar to fracture fluid leakoff in a vertical fracturing scenario.

Figure 3 is a schematic of the wellbore for WWU 2438. In this well, approximately 11 fractures were placed using 10 BASS tools and a pre-perforated sub. The fractures are labeled numerically 1 through 11. A bottomhole pressure gauge was located at fracture points 1, 3, and 6. **Figure 4** is a plot of the bottomhole pressure data during the fracturing process. As in the CLU 426 analysis, several of the bottomhole pressure responses helped confirm that the chemical packer was providing isolation between each fracture. First, the bottomhole pressure at the initial fracturing point (frac #1) increased from 2,500 psi to approximately 3,400 psi. At the same time, the bottomhole pressure at fracture point #6 does not fluctuate. The bottomhole gauge pressure at frac #6 does not start until fractures #4 and 5. When fracture #6 is initiated, the gauge at #6 increases to 3,800 psi. This is approximately 300 psi higher than the pressure reading at the gauge at frac #1. Second, the chemical packer is again verified by analysis of the temperature profile. **Figure 5** is the plot of bottomhole temperatures. The temperature at fracture point #1 increases from reservoir temperature (94°F) to 103°F when the fracturing process starts. The temperature increases due to the temperature of the treatment fluid being approximately 115°F. The temperature at fracture point #3 oscillates during the first three fracture treatments due to the heat transfer of the hot treatment fluid (115°F) and the colder displacement fluid (80°F). The gauge at fracture point #1 starts declining to reservoir temperature once the ball lands and treatment at fracture #2 begins. The same decline to reservoir temperature is seen at fracture point #3 when fracture point #4 is stimulated. An interesting temperature increase is seen at fracture point #3 during the process of fracturing #8. It is believed that fluid from one of the fracture treatments performed at #5, #6, or #7 is coming back inside the tubing and cross-flowing down to the temperature gauge at fracture point #3.

Figure 6 is a schematic of the wellbore for WWU 1804. In this well, approximately 11 fractures were placed using 10 BASS tools and a pre-perforated sub. The fractures are labeled numerically 1 through 11. A bottomhole pressure gauge was located at fracture point 1, and fracture point 10. **Figure 7** is a plot of the bottomhole pressure data during the fracturing process. The bottomhole pressure at the initial fracturing point (frac #1) increased from 2,300 psi to approximately 4,000 psi. At the same time, the bottomhole pressure at fracture point #10 only fluctuated about 200 psi. The bottomhole gauge pressure at frac #10 starts to increase as the fracture points start getting closer to the gauge. One explanation for the rise in pressure is that the chemical packer is going through a “compression,” and as the treatment points get closer, the more it is being “compressed.” Since there were no shutdown periods between each fracture, the chemical packer did not have time to “relax,” which supports the “compression” theory.

FRACTURE AND FLUID DESIGN

As discussed in the initial paper,[1] each fracture along the horizontal was designed for a specific length, height, and conductivity. The fracture height needed was determined by the proximity of the sliding sleeve to the producing oil water contact (POWC). A 3-D fracture modeling simulator was used to determine the rate and volume needing to be pumped to achieve each desired height. The pump rates can also be adjusted at each fracture point in accordance with the position of the POWC and the relative fracture height to be generated. The acid was heated to increase the reaction rate and thus yield better conductivity in the fracture. The acid volumes were also selected to achieve a desired contact time of 25 to 30 minutes. Acid fracture conductivity tests were conducted on core samples from several wells in the field in the early 1980s. The testing showed a substantial increase in conductivity with an increase in acid contact time.

PRODUCTION SUMMARY

Production results for all of the horizontal wells are shown in **Table 3**. All four laterals in the Welch unit from 2005 resulted in increased production over its production as a vertical well. The average production from the vertical wells (before being drilled as horizontals) was approximately 11 bopd and 34 bwpd. After drilling the horizontal and completing the fracturing, the average producing rate was 69 bopd and 457 bwpd. Six months later the average production rates were 46 bopd and 191 bwpd.

Production results for both of the Cedar Lake horizontal wells are also presented in Table 3. Oil production increased in both wells, but fell below expectations. The average production prior to drilling the well horizontally was 7 bopd and 197 bwpd. After drilling the wells horizontally and stimulating, the production was 32 bopd and 1,229 bwpd. There was a dramatic improvement in total fluid produced per day (206 bpd vs. 1261 bpd); however, the majority of fluid was water.

Table 4 shows the average production from each year’s horizontal completions. While the vertical well performance for all the wells is very similar (6 to 11 bopd), the initial and 6-month production numbers are dramatically different. The 6-month production data point shows that wells completed in 2000 (using various completion techniques) yielded a production increase of 22 bopd and 50 bwpd. The increase from the 2005 wells was 35 bopd and 122 bwpd.

CONCLUSIONS

Being able to achieve annular isolation when fracturing is critical to the process of pinpointing fractures in an openhole horizontal well. The bottomhole pressure and temperature data showed conclusively that the chemical packer was providing the annular isolation needed and the BASS tools were working to achieve fracture placement. The production numbers were another verification that this process was successful. As was seen with the 2004 horizontal program, the production results for the 2005 wells were once again better than the 2000 horizontal program.

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Table 1
Reservoir Parameters

	Cedar Lake Unit	**West Welch Unit**
Pay Horizon	San Andres	San Andres
Lithology	Dolomite	Dolomite
Structure	Anticline	Anticline
Trap Type	Structural and Stratigraphic	Structural and Stratigraphic
Measured Depth, ft	4900	4900
Gross Pay Interval, ft	250	125
New Pay Interval, ft	100	61 ft
Porosity, %	12–14	9.5
Initial Water Saturation, %	28	31
Permeability, md	3–10	1
Initial Reservoir Pressure, psi	1,950	2,100
Reservoir Temperature, °F	96	92

Table 2
List of Horizontal Wells

Year	Well	Hole Size	Lateral Length (ft)	Direction
2000	WWU 705	4 3/4-in. OH	2,100	North/South
2000	WWU 1404	4 3/4-in. OH	2,150	North/South
2000	WWU 4853	4 3/4-in. OH	3,500	North/South
2000	WWU 4951	4 1/2-in. cemented liner	3,250	North/South
2004	WWU 3706	4 3/4-in. OH	2,450	East/West
2004	WWU 3920	4 3/4-in. OH	2,250	East/West
2004	CLU 359	4 3/4-in. OH	1,850	East/West
2004	CLU 446	4 3/4-in. OH	1,800	East/West
2005	CLU 430	4 3/4-in. OH	2,249	East/West
2005	WWU 2438	4 3/4-in. OH	4,102	East/West
2005	CLU 426	4 3/4-in. OH	3,828	East/West
2005	WWU 1804	4 3/4-in. OH	3,674	East/West
2005	WWU 3812	4 3/4-in. OH	2,980	East/West
2005	WWU 3930 (e)	4 3/4-in. OH	2,212	East/West
2005	WWU 3930 (w)	4 3/4-in. OH	2,315	East/West

Table 3
Production Results for Horizontal Wells (bpd)

Year	Well	Vertical Oil	Vertical Water	IP Oil	IP Water	6-Month Oil	6-Month Water
2000	WWU 705	5	50	48	33	30	16
2000	WWU 1404	9	100	65	402	30	260
2000	WWU 4853	3	10	41	610	9	87
2000	WWU 4951	6	70	54	134	43	70
2000	**WWU Average**	**6**	**58**	**52**	**295**	**28**	**108**
2004	WWU 3706	5	6	20	127	20	69
2004	WWU 3920	14	17	245	235	66	36
2004	**WWU Average**	**10**	**12**	**133**	**181**	**43**	**53**
2004	CLU 359	10	135	107	547	67	616
2004	CLU 446	2	34	36	597	20	396
2004	**CLU Average**	**6**	**85**	**72**	**572**	**44**	**506**
2005	WWU 1804	6	29	30	240	18	104
2005	WWU 2438	8	57	75	250	48	120
2005	WWU 3812	11	41	76	573	38	233
2005	WWU 3930	20	10	94	766	81	305
2005	**WWU Average**	**11**	**34**	**69**	**457**	**46**	**191**
2005	CLU 430	9	103	12	449	12	506
2005	CLU 426	4	290	51	2008	20	1619
2005	**CLU Average**	**7**	**197**	**32**	**1229**	**16**	**1063**

Table 4
Average Production Results (bpd)

Year	Vertical Oil	Vertical Water	IP Oil	IP Water	6-Month Oil	6-Month Water
2000 WWU	6	58	52	295	28	108
2004 WWU	10	12	133	181	43	53
2004 CLU	6	85	72	572	44	506
2005 WWU	11	34	69	457	46	191
2005 CLU	7	197	32	1229	16	1063

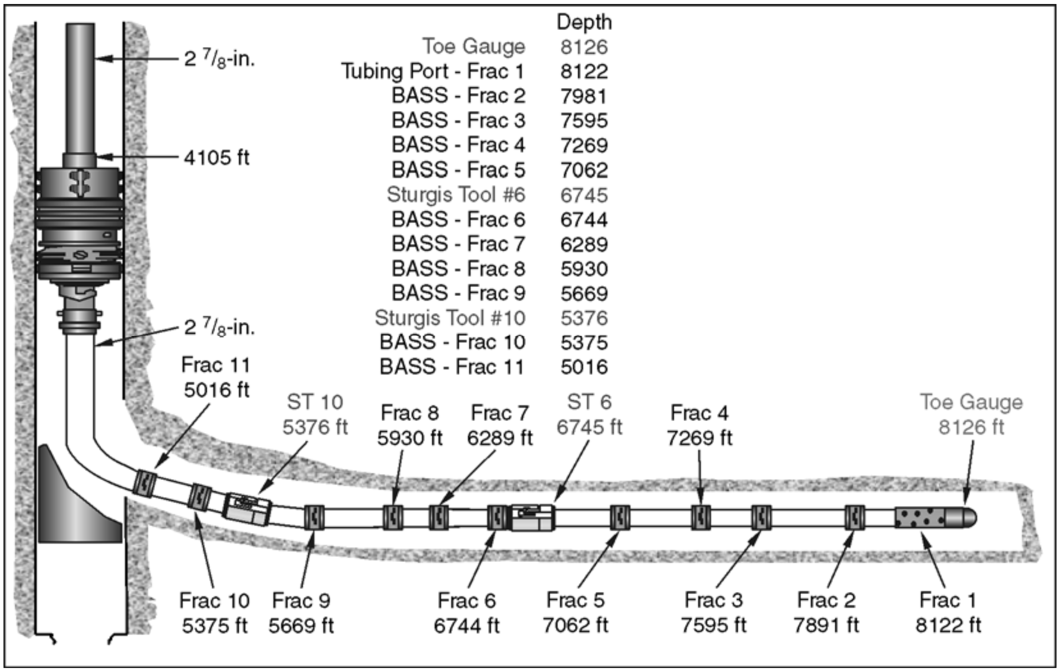

Figure 1—Wellbore Schematic for CLU 426

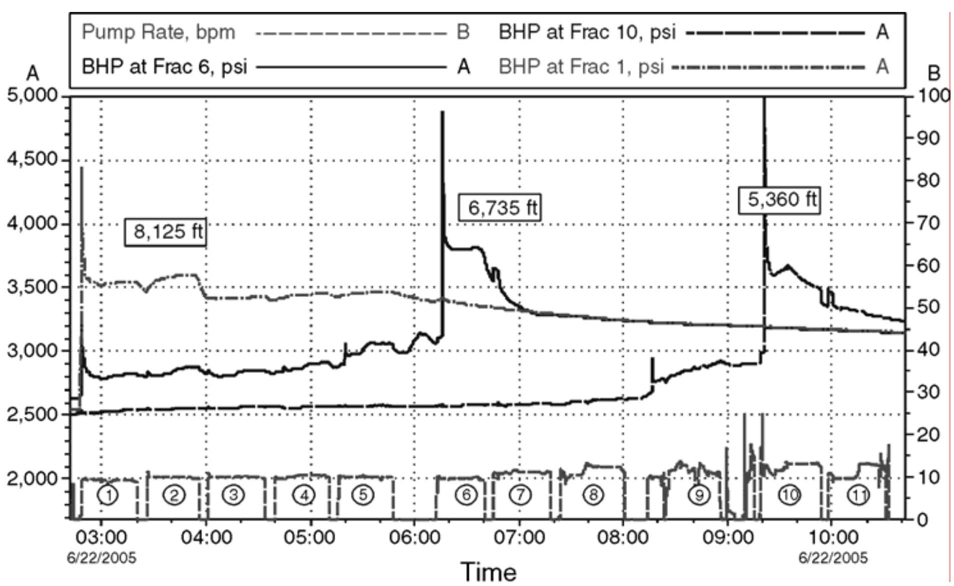

Figure 2—Bottomhole Pressure Data for CLU 426

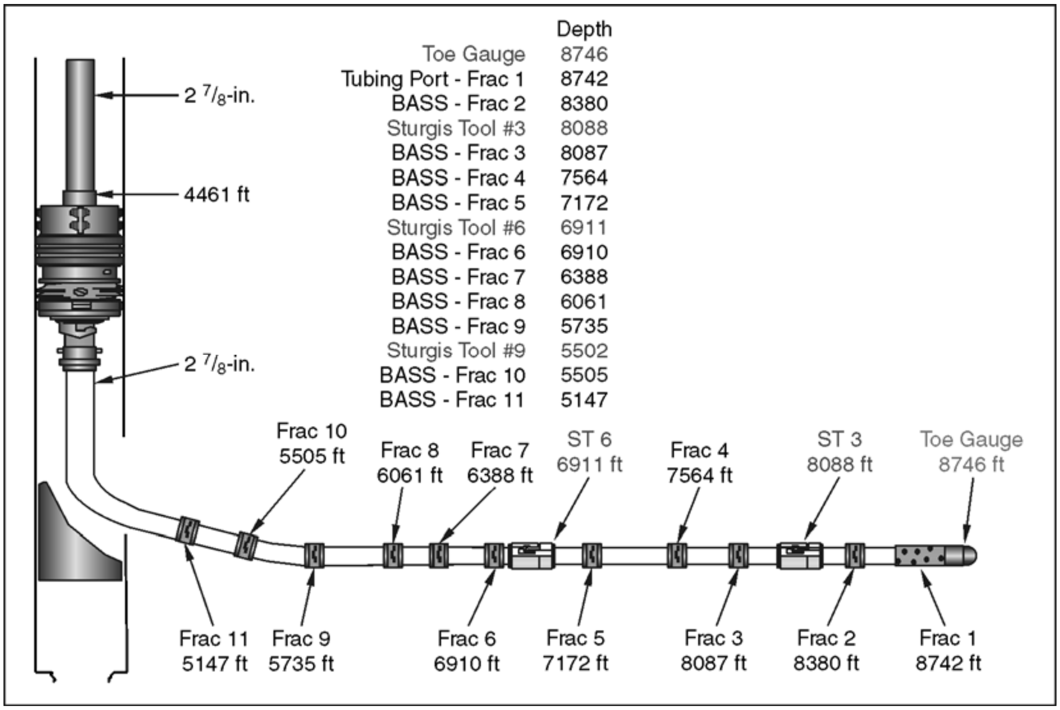

Figure 3—Wellbore Schematic for WWU 2438

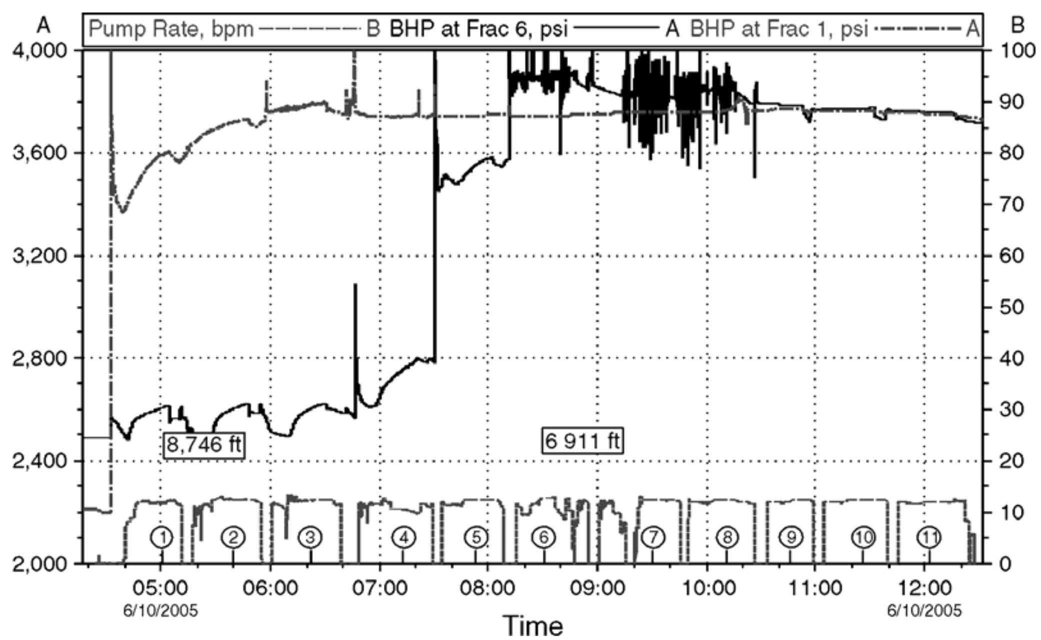

Figure 4—Bottomhole Pressure Data for WWU 2438

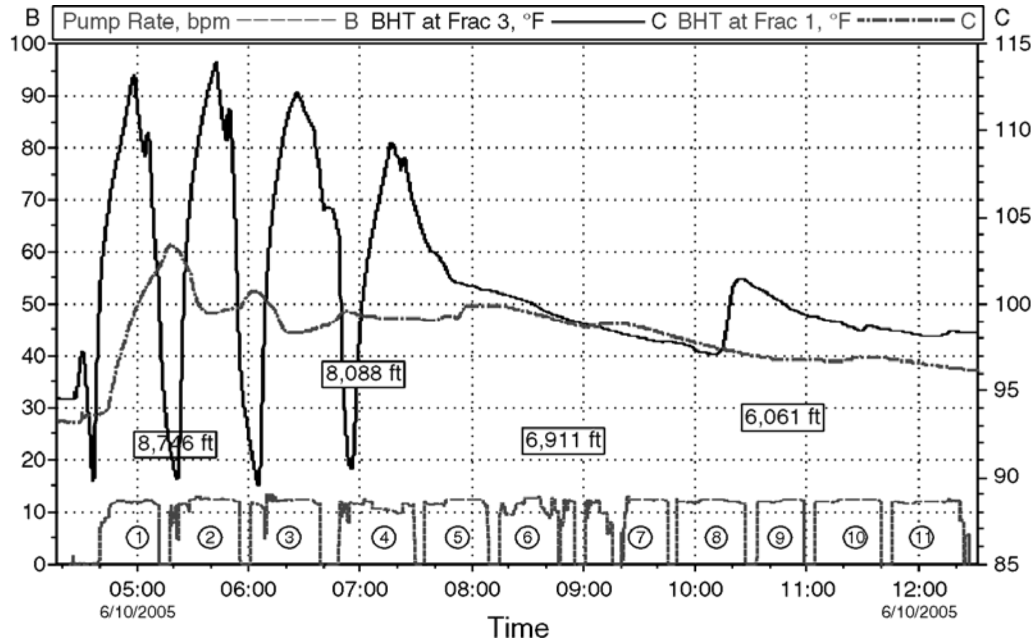

Figure 5—Bottomhole Temperature Data for WWU 2438

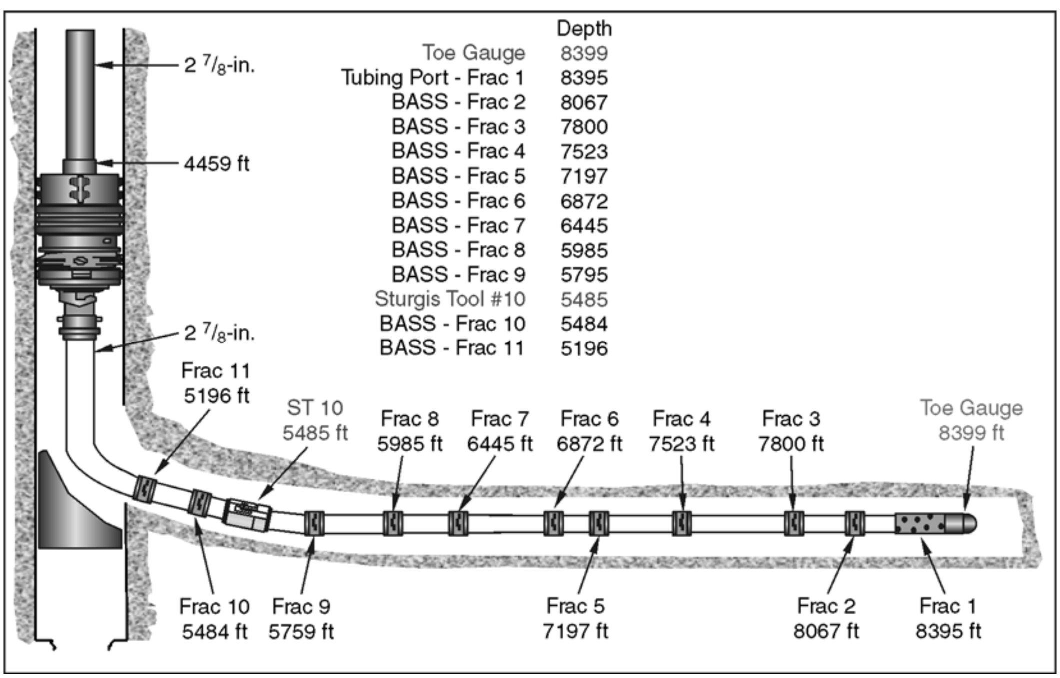

Figure 6—Wellbore Schematic for WWU 1804

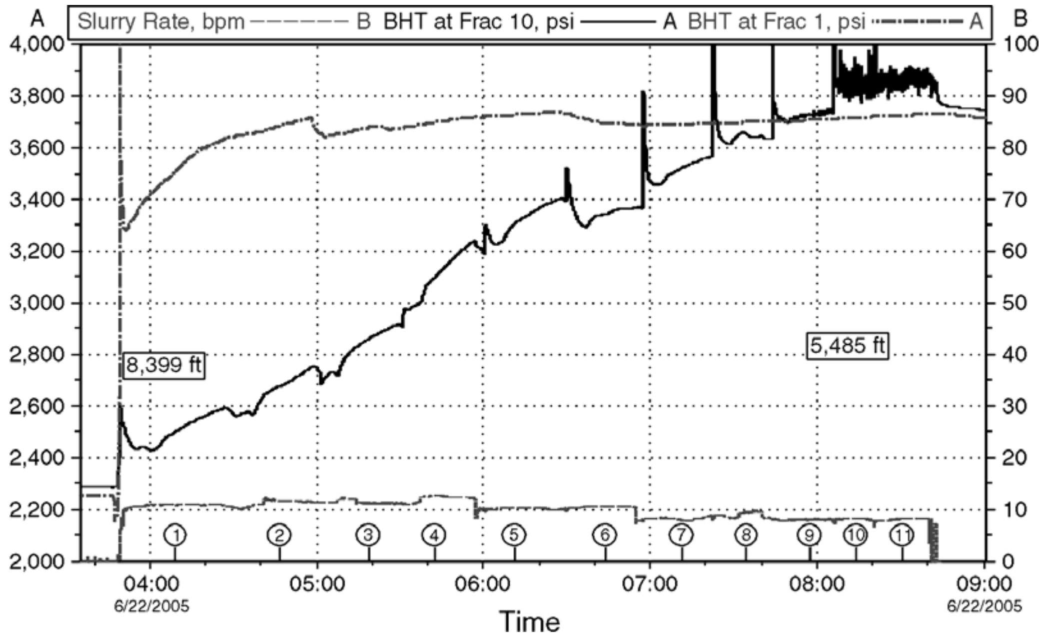

Figure 7—Bottomhole Pressure Data for WWU 1804