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PR96-63

SANTOS LIMITED

E. MEREENIE WELL NO. 41
P4 TSO FRAC TREATMENT

18 OCTOBER 1996

E. MEREENIE WELL NO. 41
P4 TSO FRACTURE TREATMENT

Prepared for:
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18 October 1996

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SUMMARY

On 11 September 1996, a tip-screenout (TSO) fracture treatment was performed on Santos' East Mereenie Well No. 41 through "P4" sand perforations at 4917-4959 ft. Reservoir properties were estimated to be a net pay thickness of 31 ft, a reservoir pressure of 1830 psi (no depletion), and a BHT of 145°F. Because of problems with the primary cement job (discussed herein) only minimal pre-frac flow was obtained from the combined lower P3 and P4 zones. An attempt to remedy this by reperforating was unsuccessful and attempts to circulate between the zones behind the production casing were also unsuccessful. Thus, a remedial cement job could not be performed. With this problem and the inability to establish a steady flow from the well, a pre-frac pressure buildup test could not be conducted to determine formation permeability and skin.

Prior to the treatment, pre-frac tests were conducted to evaluate closure stress, fluid efficiency, and fracture geometry for final design formulation. The results indicated two possible closure pressures, one at 3450 psi and the other at 4600 psi. Corresponding fluid efficiencies were 0.75 and 0.46, respectively. The lower closure was thought to be the correct value based on its consistency with prior P4 and lower P3 measurements in other wells throughout the field. This resulted in a net BHTP of 1800 psi and gave an efficiency during injection, using the Mereenie correlation of decline to injection efficiency, of 0.39. A reasonably good model history match of the minifrac was obtained with (1) the higher indicated stress of 4600 psi in the top and bottom of the pay, 3450 psi in the main body of the pay, and boundary stresses of 5050-5100 psi; (2) a pay zone modulus of 8-8.25x10^6 psi and 8.5x10^6 psi in the boundaries; and (3) a leak-off coefficient of 0.0032 ft/srm. This "calibrated" model was used to design the final treatment.

With the desire to minimize fracture growth above the gas-oil contact, the final treatment design pad stage was limited to 2000 gals with an additional 4750 gals of gel carrying 16,250 lbs of 20/40 Carbo-Lite proppant at 0.5-7 ppg and at a rate of 15 bpm. The model-predicted TSO occurred at the end of the 3 ppg stage and net BHTP went from 1925 to 3419 psi with a corresponding average fracture width increase from 0.06 to 0.12 inches. Other fracture dimensions were a propped half-length of 203 ft, a maximum

height of 156 ft, an average conductivity of 808 md-ft, and an average in-situ concentration of 0.6 lbs/sq.ft.

The treatment screened-out early after placing only 52.4% of the designed proppant in the fracture. This could not be attributed to any pumping or gelling problems, and the primary casing cement held alright. To eventually model history match this behavior required (1) using the higher indicated closure pressure of 4600 psi in the pay, (2) increasing leak-off and stress in the P3-230/250 (based on simulation of this later treatment), and (3) a dramatic increase in the pay zone leak-off to 0.009 ft/srm. With the higher closure pressure, the efficiency from decline analysis and the injection efficiency generated from modeling with this higher leak-off were consistent with the Mereenie efficiency correlation. This relatively high leak-off, though, was inconsistent with the expected low permeability for this zone and thought to be due, at least in part, to fluid shear-thinning due to restricted width development in the higher modulus environment. Resultant fracture dimensions were a propped half-length of 88 ft, a maximum height of 179 ft, an average conductivity of 1176 md-ft, and an average in-situ concentration of 0.7 lbs/sq.ft. Based on these, and the apparent misinterpretation of the pre-frac test data, the treatment did not come very close to achieving design goals, particularly the desired penetration. If, in fact, though, formation permeability were considerably higher than expected, as suggested by the higher leak-off, this could still be a reasonably good treatment.

DISCUSSION

Introduction:

This report details the design, execution, and analysis of the tip-screenout (TSO) fracturing treatment performed in Santos' East Mereenie Well No. 41 on 11 September 1996. The treatment was pumped through Pacoota P4 perforations at 4917-4959 ft (MD), 4801-4842 ft (TVD), as shown in Fig. 1.

When perforated underbalanced with TCP guns, the well performed below expectations, i.e. only 8 bopd. The completion was pulled and indicated that all guns had fired and there was no plugging of the vent sub or perforated joint. A casing drift run was performed and indicated 30 ft of fill above the original PBTD. Bailer runs sampled the fill, which appeared to be unset cement of a putty-like consistency. Samples were sent out for analysis. This seemed to confirmed the original USIT log prior to perforating, which indicated a very poor cement bond. A second USIT log, run after perforating, showed that the bond had worsened and the only area remaining of similar quality was below the P4 perforations. In an attempt to prepare for a remedial cement job, a packer was set between P4 perforations at 4917-4959 ft (MD) and the P3-230/250 perforations and an attempt to circulate between the two was unsuccessful with each zone holding 1500 psi surface pressure for 15 minutes with minimal leak-off. Next an attempt was made to break circulation over a shorter interval between the P3-190 and added squeeze perforations 10 ft above. Again no circulation could be achieved. The result of this work indicated that the quality of the cement was such that it could hold a hydraulic seal under low injection pressures but might still be suspect during a fracture treatment. Assuming the low oil flow rate was due to significant blockage of the perforations with cement, the well was reperforated using TCP guns over both the P4 and lower P3 intervals. While there was an initial strong blow for approximately one hour, the well eventually died off and repeated swab runs were unsuccessful in establishing flow. At this point the only available method for testing the cement and obtaining an economic flow rate was to fracture stimulate the well.

This well intersected a total of 31 ft of net pay in the P4. Without a pre-frac flow, a pressure buildup test could not be conducted and, thus, permeability was unknown but

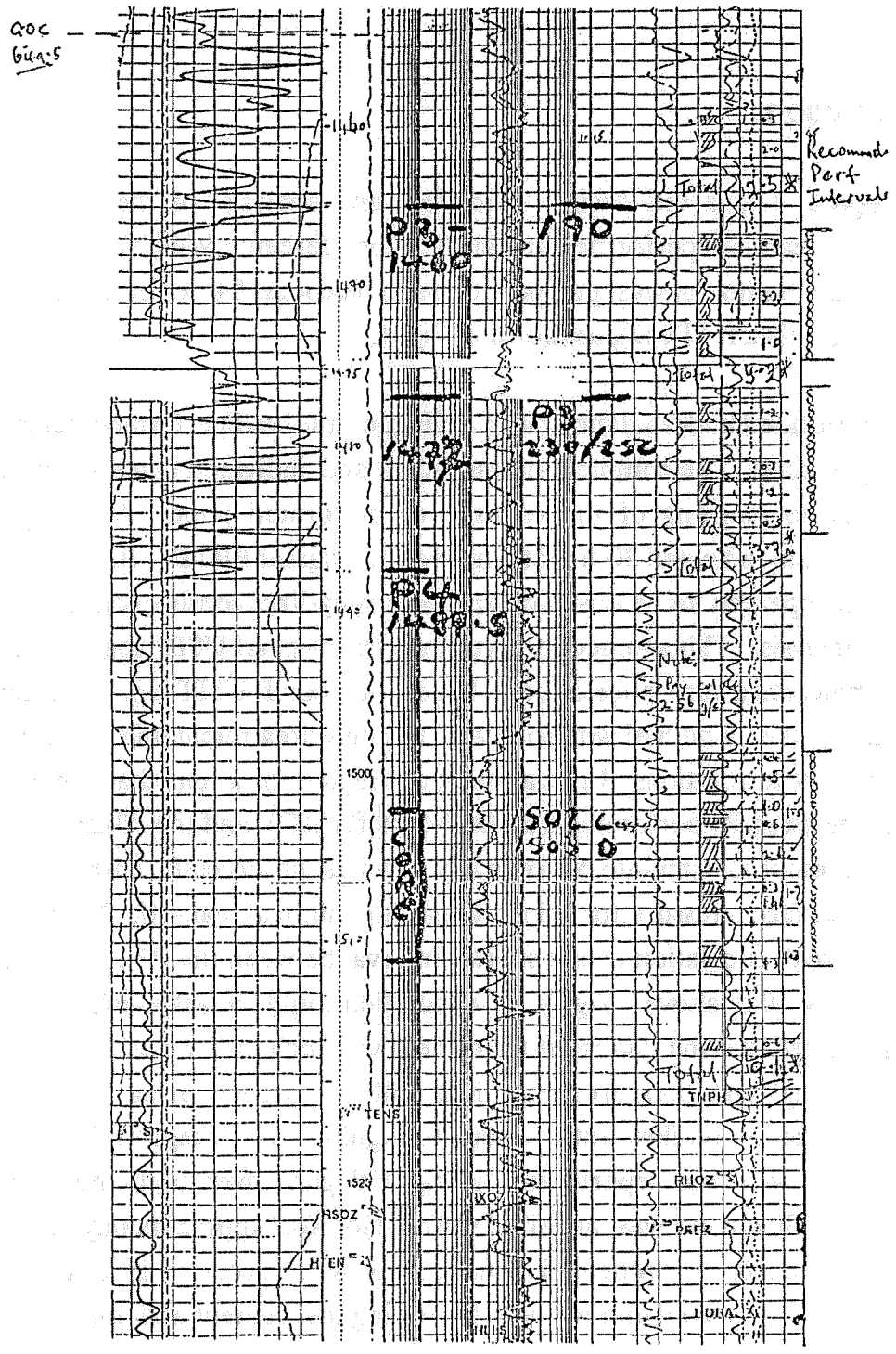

FIG. 1 - Log section thru pay interval and boundaries, E. Mereenie #41 (P4).

suspected to be relatively low. Reservoir pressure was thought to be at virgin conditions, i.e. 1830 psi, and the BHT was around 145°F. Wellbore deviation through the pay was 16.5°.

The P4 fracture treatment, performed by Halliburton, was preceded with pre-frac injection/decline tests to evaluate closure pressure, fluid efficiency, and fracture geometry for final design formulation. Bottomhole pressure was obtained with electronic memory gauges set in the tailpipe for both the testing and main treatment. The following discusses the details of this testing and treatment.

Pre-Frac Test Analysis:

Pre-frac testing consisted of (1) a 10 bbl slick water pump-in/shut-in (PI/SI) test at 5 bpm, (2) a slick water step-rate test (SRT)/SI at rates of 0.5-10 bpm, and (3) a 1500 gal, 30 ppt borate XL gel (Boragel H3595) minifrac at 15 bpm. The first two tests were designed to evaluate closure pressure and the minifrac was used to determine fluid efficiency and fracture geometry.

Fig. 2 shows a summary of the surface parameters for the sequence of tests and Fig. 3 shows the gauge BHP for the first PI/SI test. After an initial breakdown of about 5250 psi, pressure dropped to about 5000 psi and remained fairly constant up to shut-down. At shut-down, an ISIP of 4461 psi was measured, as shown in Fig. 4; this giving a downhole excess pressure of 563 psi. From the Horner plot of the pressure decline, Fig. 5, the pressure extrapolated to 1985 psi or higher than the expected reservoir pressure and probably due to insufficient decline data to reach the correct psuedo-steady-state straight line. The square-root of SI time plot, Fig. 6, indicated two possible closure pressures, one at 4189 and the other at 3208 psi. From the G-function plot, Fig. 7, there was no clear indication of closure.

Fig. 8 shows the gauge BHP record for the SRT/SI. At the end of injection, BHP was 5426 psi and the ISIP was 4937 psi (Fig. 9), giving a downhole excess pressure of 489 psi. From a plot of stabilized BHP versus injection rate, Fig. 10, fracture extension pressure appeared to be at about 4649 psi. The square-root of SI time plot of the pressure

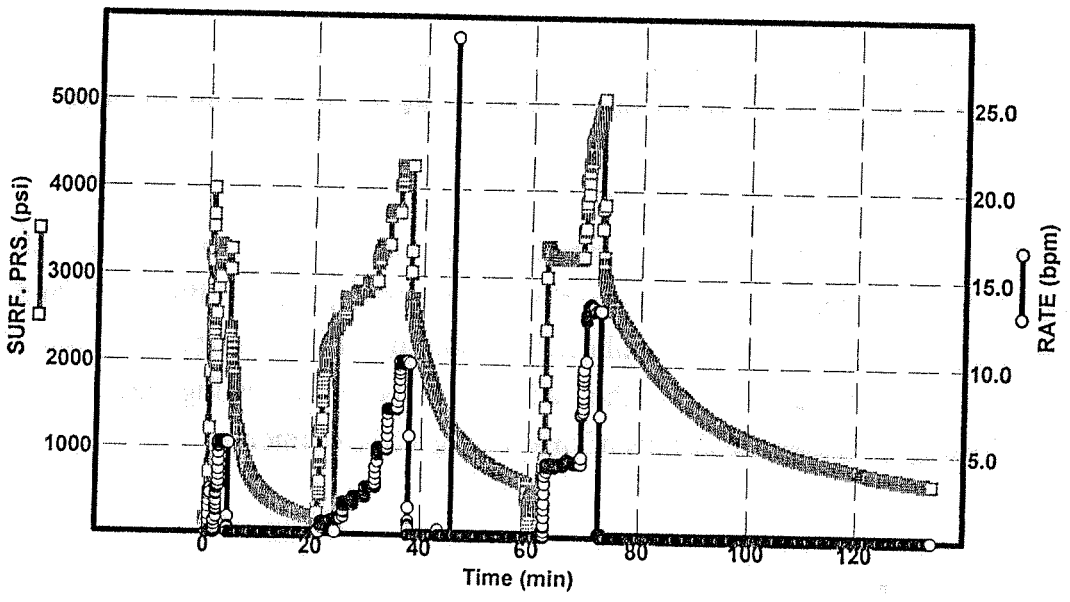

FIG. 2 - Pre-frac testing summary of surface parameters, E. Mereenie #41 (P4).

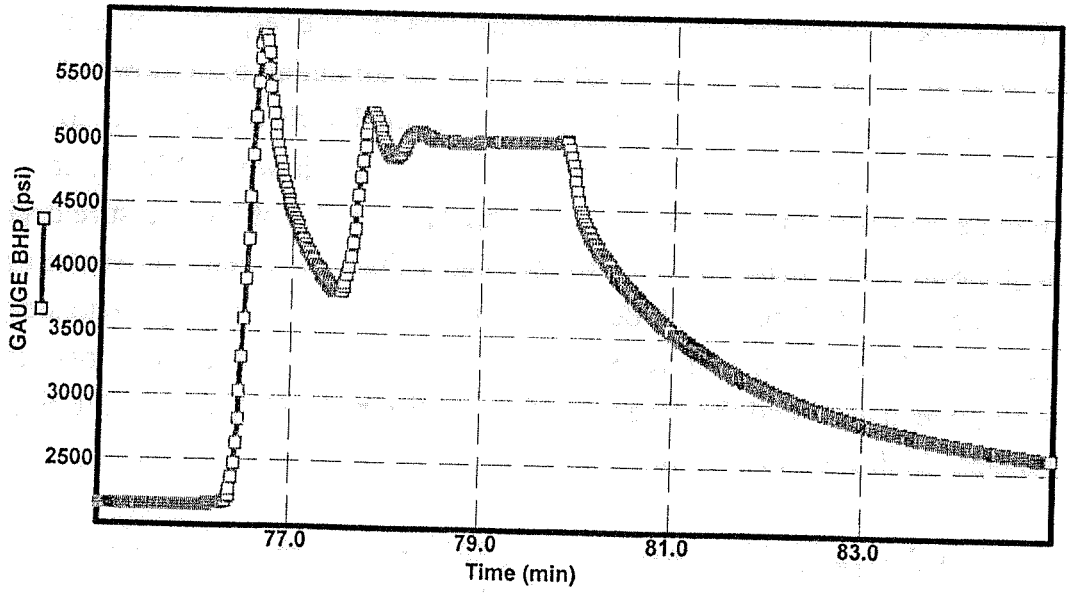

FIG. 3 - Slick water PI/SI test BHP record, E. Mereenie #41 (P4).

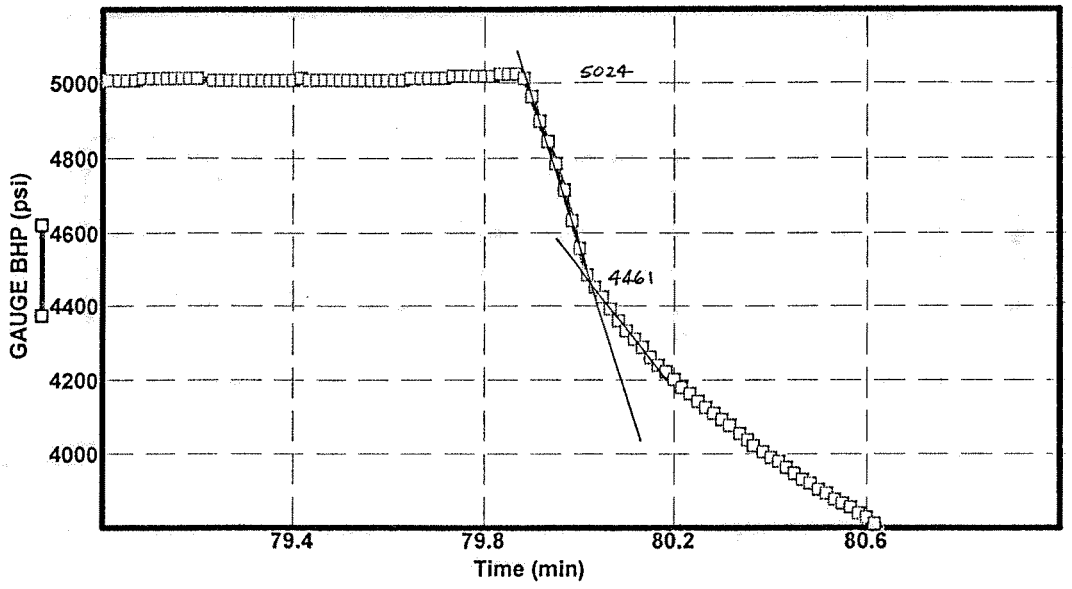

FIG. 4 - Slick water PI/SI test BH ISIP evaluation, E. Mereenie #41 (P4).

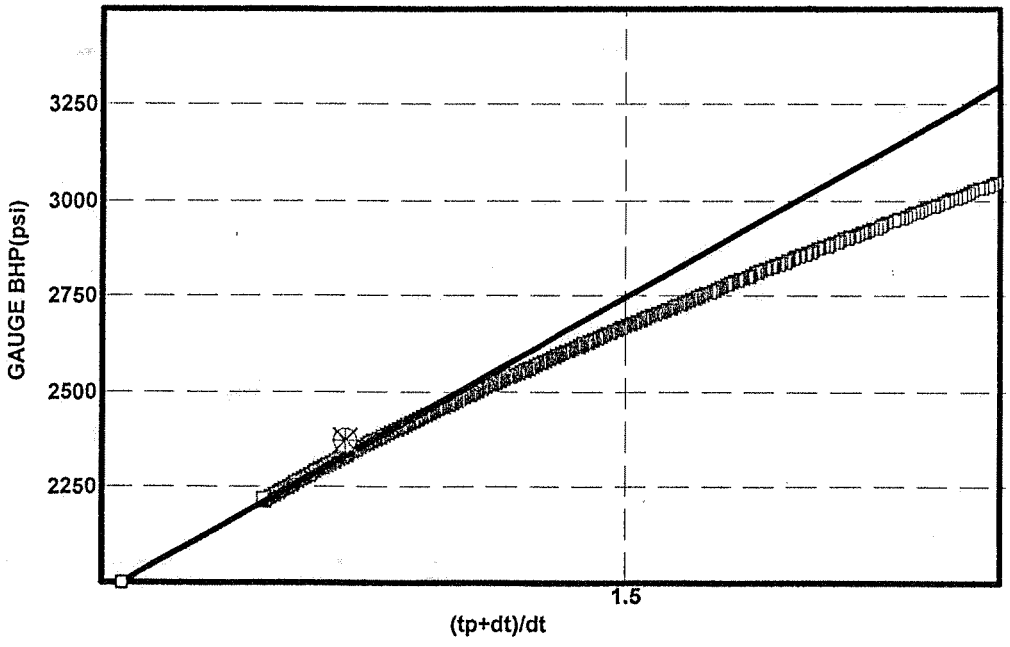

FIG. 5 - Slick water PI/SI test BH Horner plot, E. Mereenie #41 (P4).

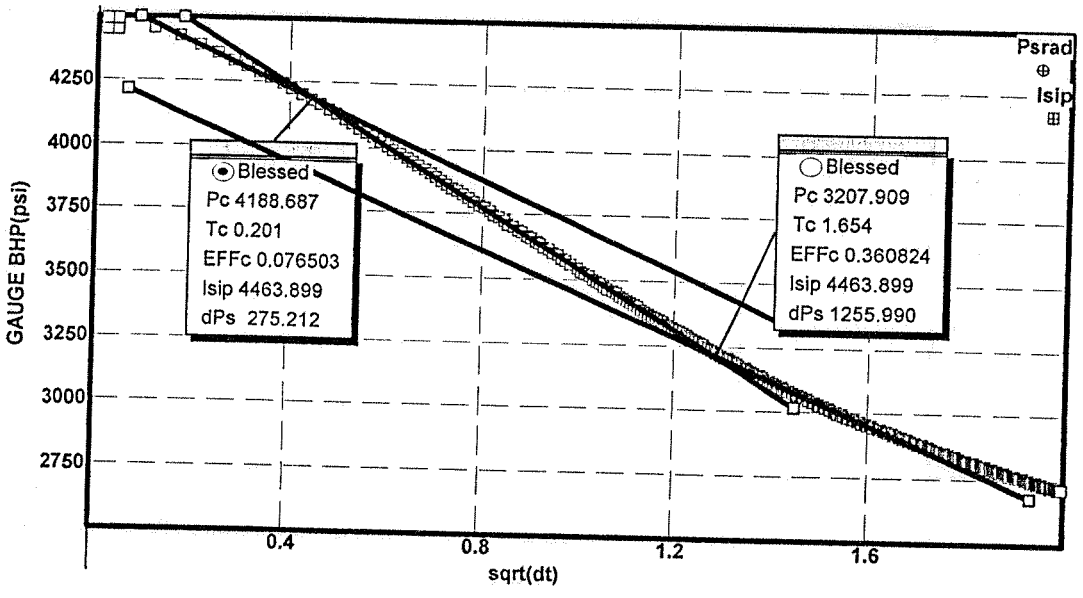

FIG. 6 - Slick water PI/SI test BH sq.rt. SI time plot, E. Mereenie #41 (P4).

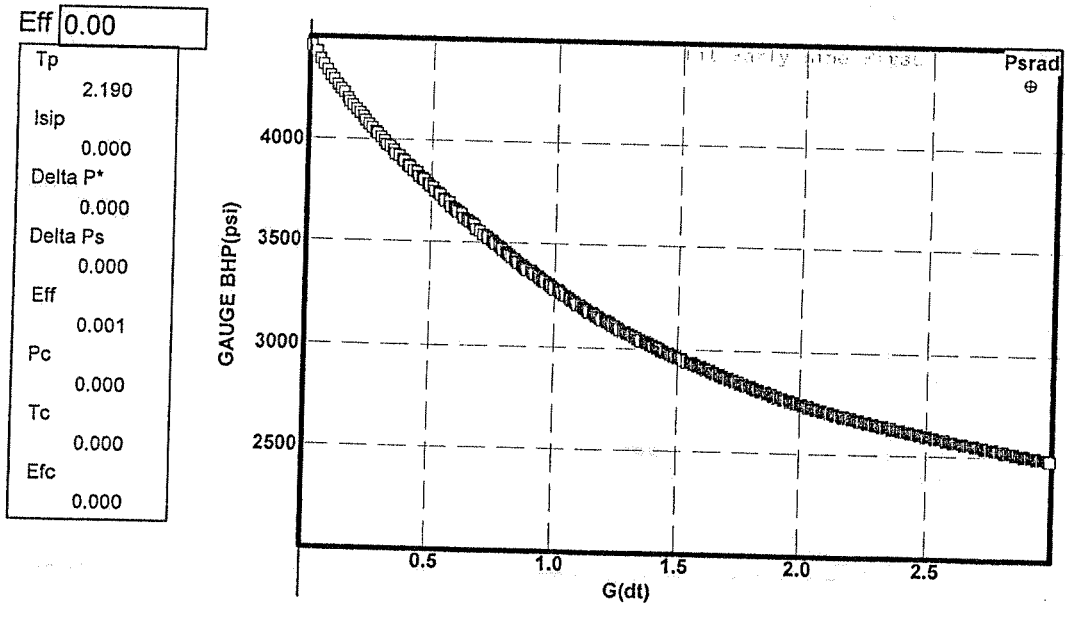

FIG. 7 - Slick water PI/SI test BH G-function plot, E. Mereenie #41 (P4).

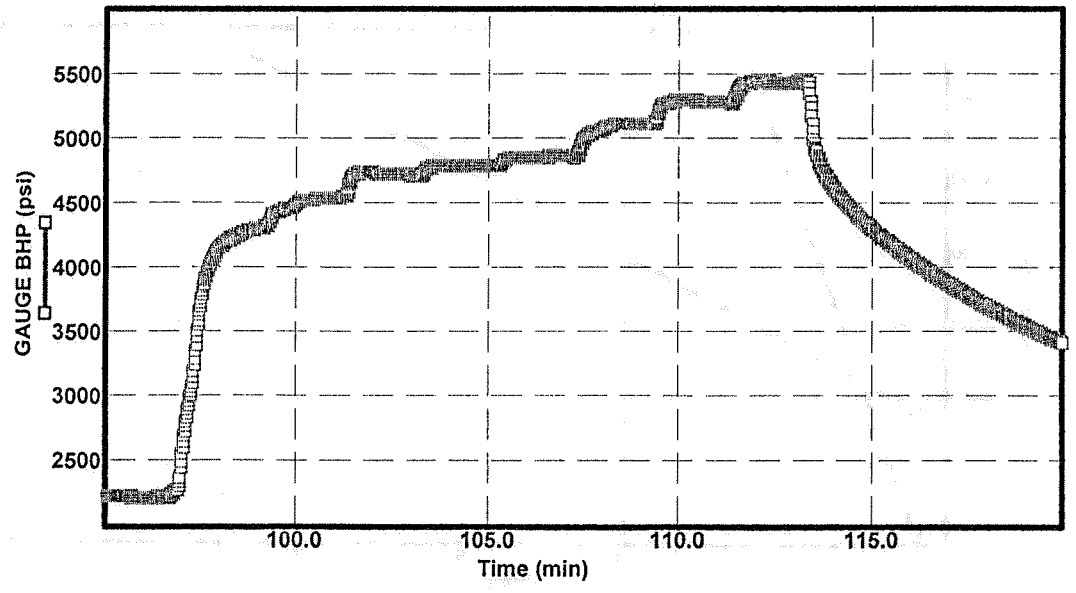

FIG. 8 - Slick water SRT/SI BHP record, E. Mereenie #41 (P4).

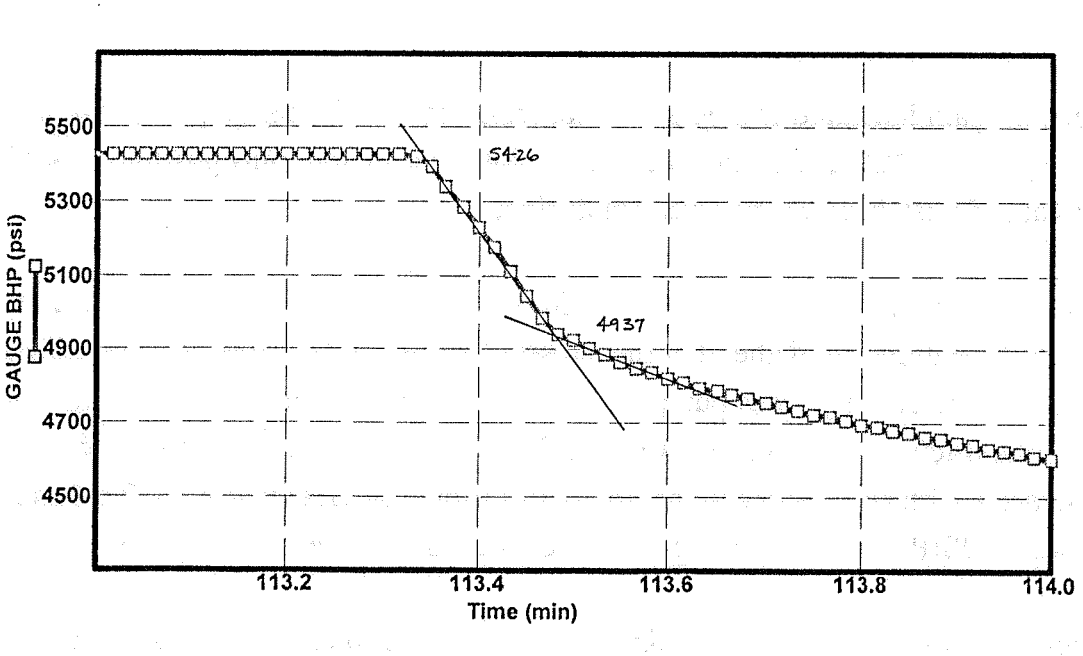

FIG. 9 - Slick water SRT/SI BH ISIP evaluation, E. Mereenie #41 (P4).

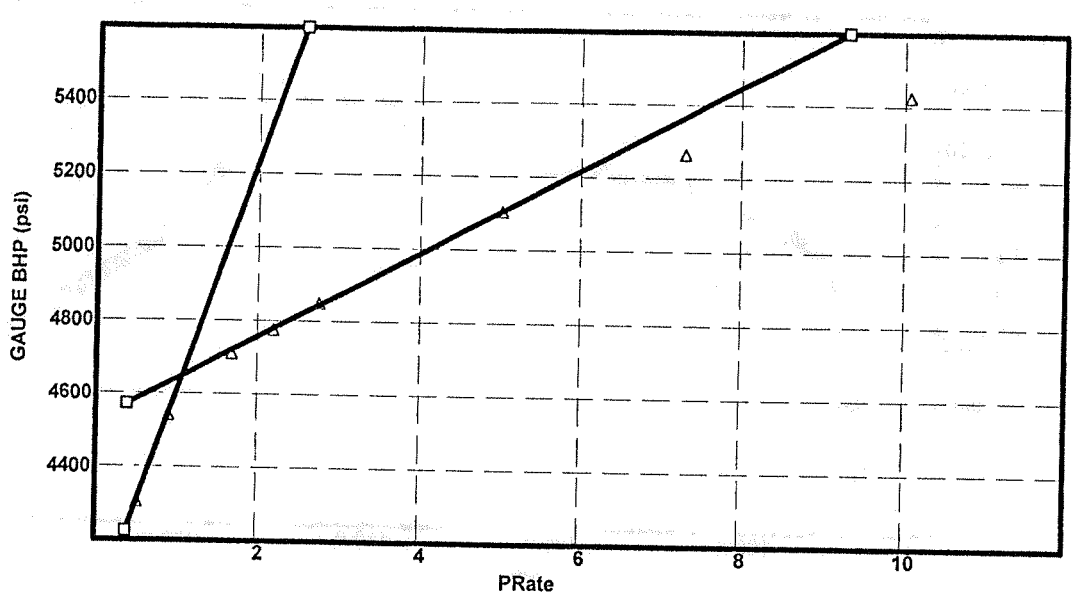

FIG. 10 - Slick water SRT/SI frac extension evaluation, E. Mereenie #41 (P4).

decline again indicated two possible closures, one at 4226 psi (Fig. 11) and the other at 3264 psi (Fig. 12). From the G-function plot, Fig. 13, the only possible pick of closure was at 3451 psi, however this was not distinct.

Fig. 14 shows the gauge BHP record for the minifrac. To minimize the effect of the residual wellbore fluid ahead of the crosslinked gel on determining fluid efficiency, the leading edge of the gel was pumped to near bottom at 5 bpm to bullhead the slick water into the fracture. The XL gel was then injected at 15 bpm. At the end of the minifrac, displaced with slick water to the top perforation, the BHTP was 5772 psi and at shut-down the ISIP was 5284 psi, Fig. 15, indicating a downhole "excess" pressure of 488 psi.

From the minifrac pressure decline analysis, again two closures could be picked on the square-root of SI time plot, Fig. 16, one at 4611 and the other at 3425 psi. Both were also apparent on the G-function plot, Figs. 17 and 18. Using only the pump time of the

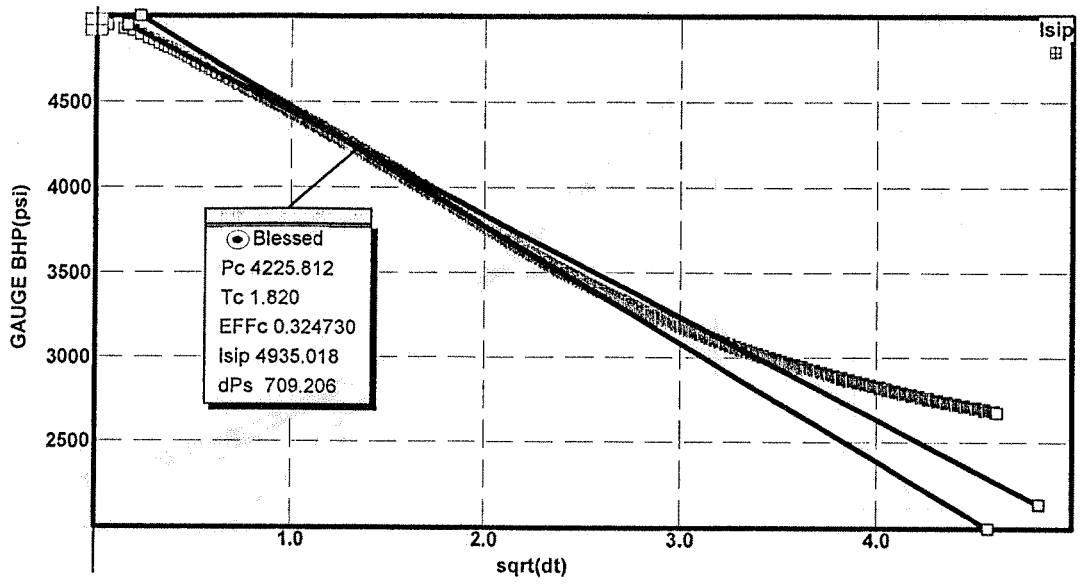

FIG. 11 - Slick water SRT/SI BH sq.rt. SI time plot #1, E. Mereenie #41 (P4).

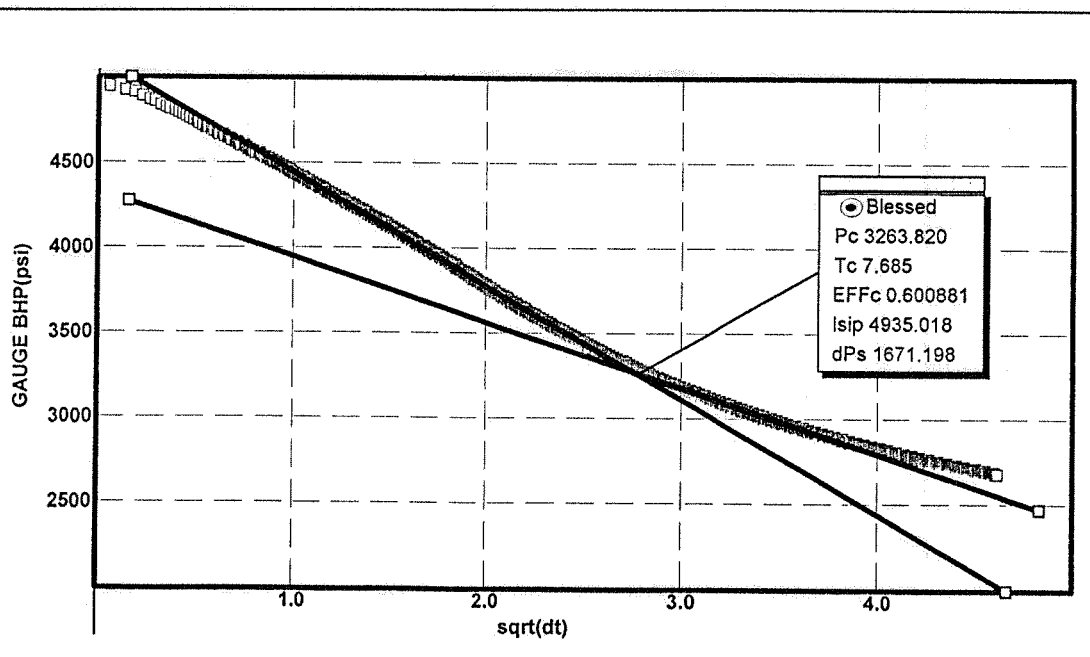

FIG. 12 - Slick water SRT/SI BH sq.rt. SI time plot #2, E. Mereenie #41 (P4).

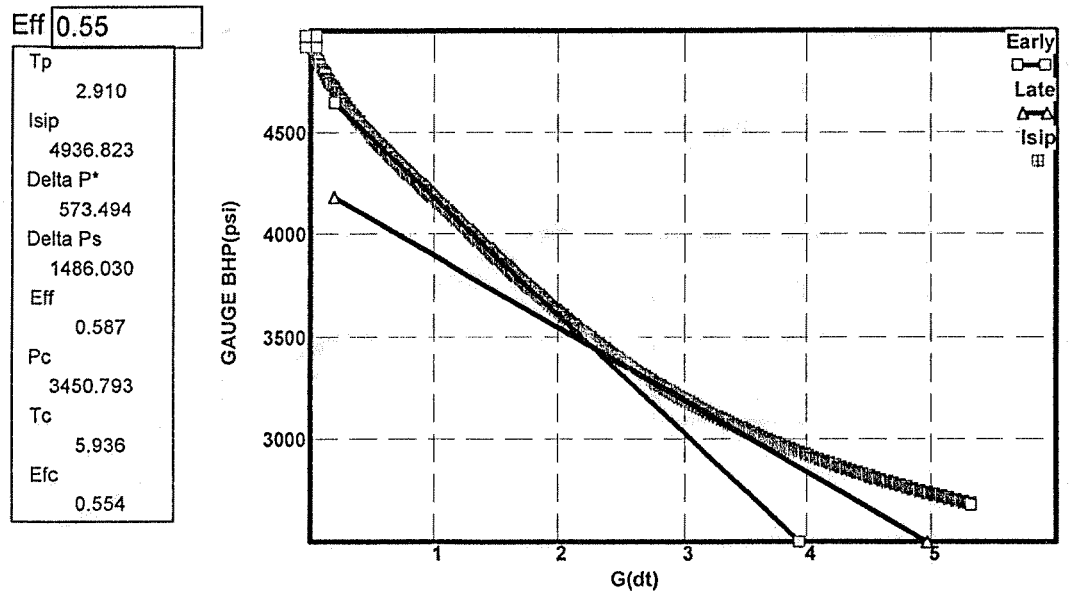

FIG. 13 - Slick water SRT/SI BH G-function plot, E. Mereenie #41 (P4).

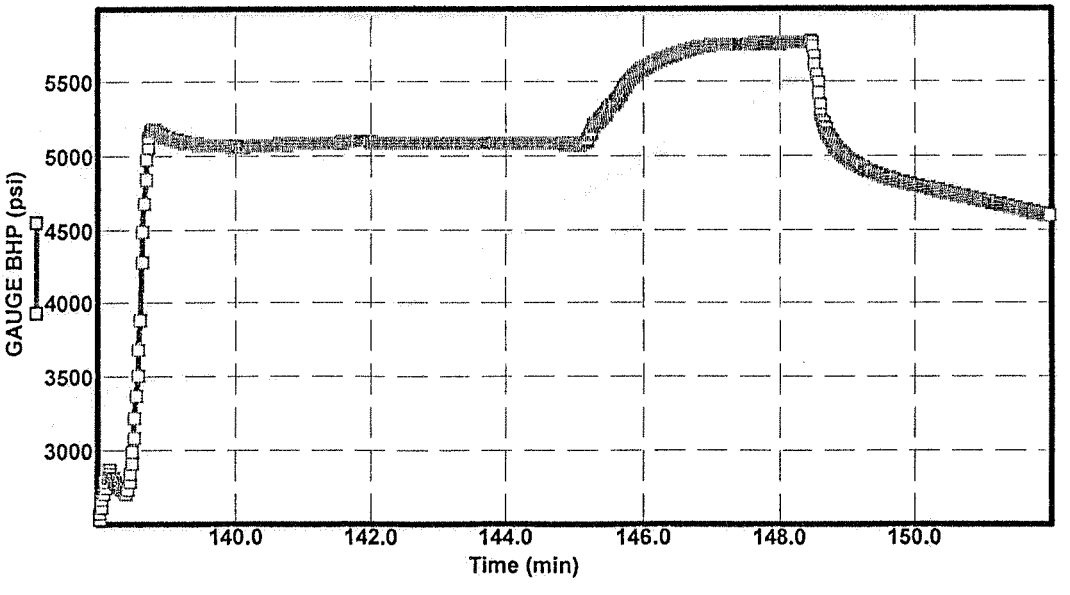

FIG. 14 - Boragel minifrac/SI BHP record, E. Mereenie #41 (P4).

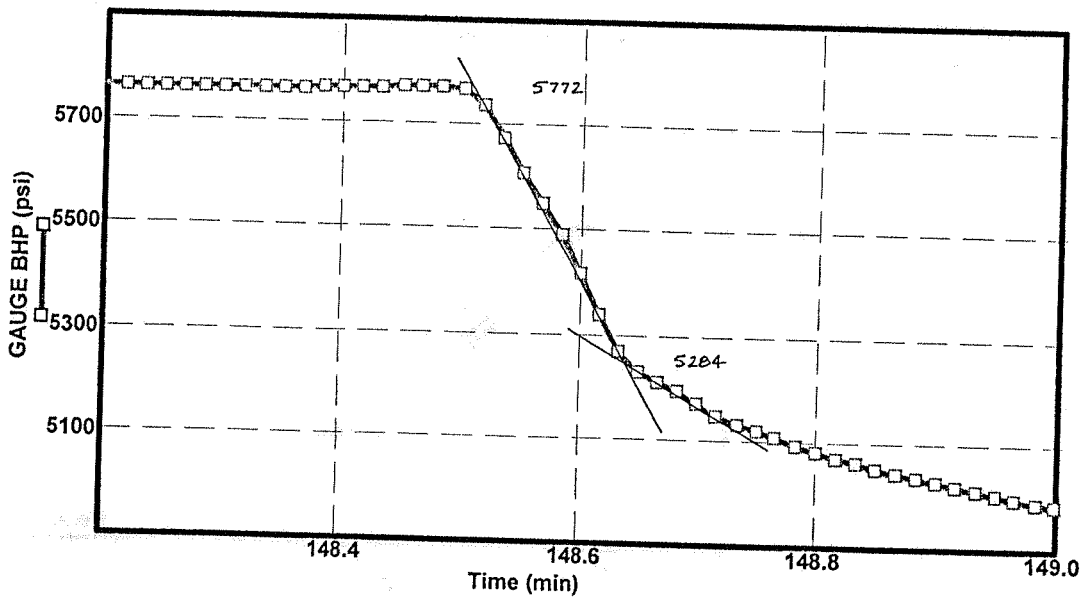

FIG. 15 - Boragel minifrac/SI BH ISIP evaluation, E. Mereenie #41 (P4).

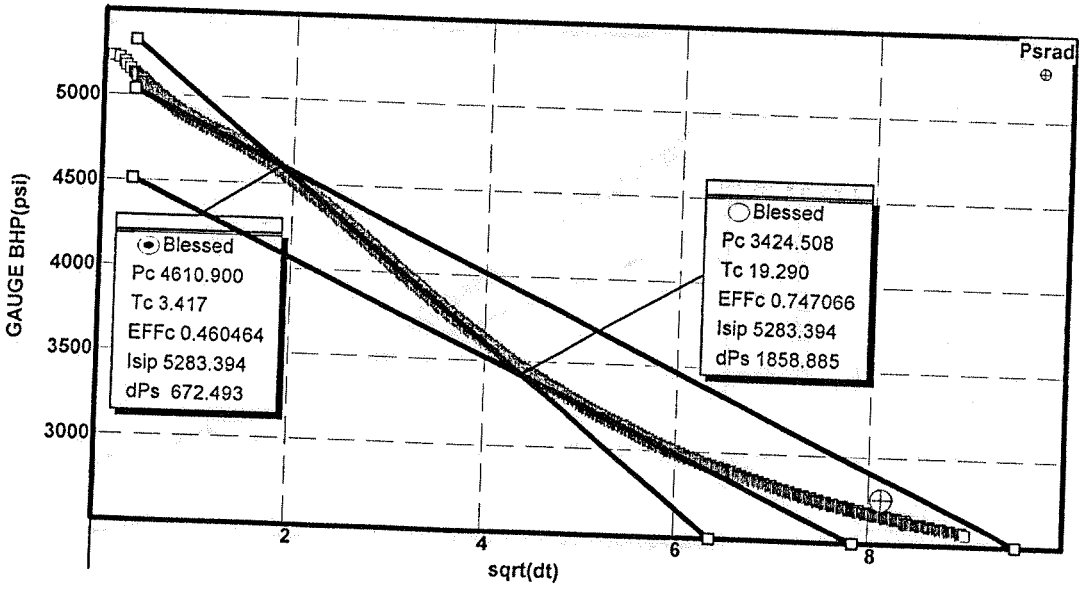

FIG. 16 - Boragel minifrac/SI BH sq.rt. SI time plot, E. Mereenie #41 (P4).

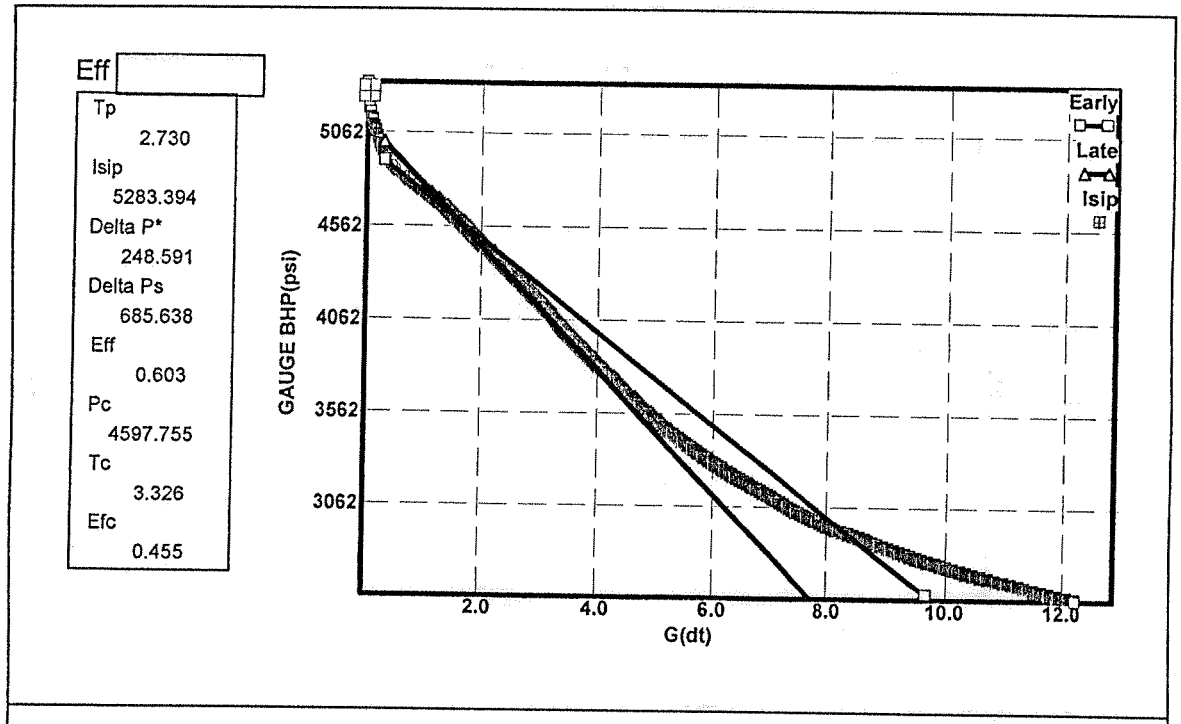

FIG. 17 - Boragel minifrac/SI BH G-function plot #1, E. Mereenie #41 (P4).

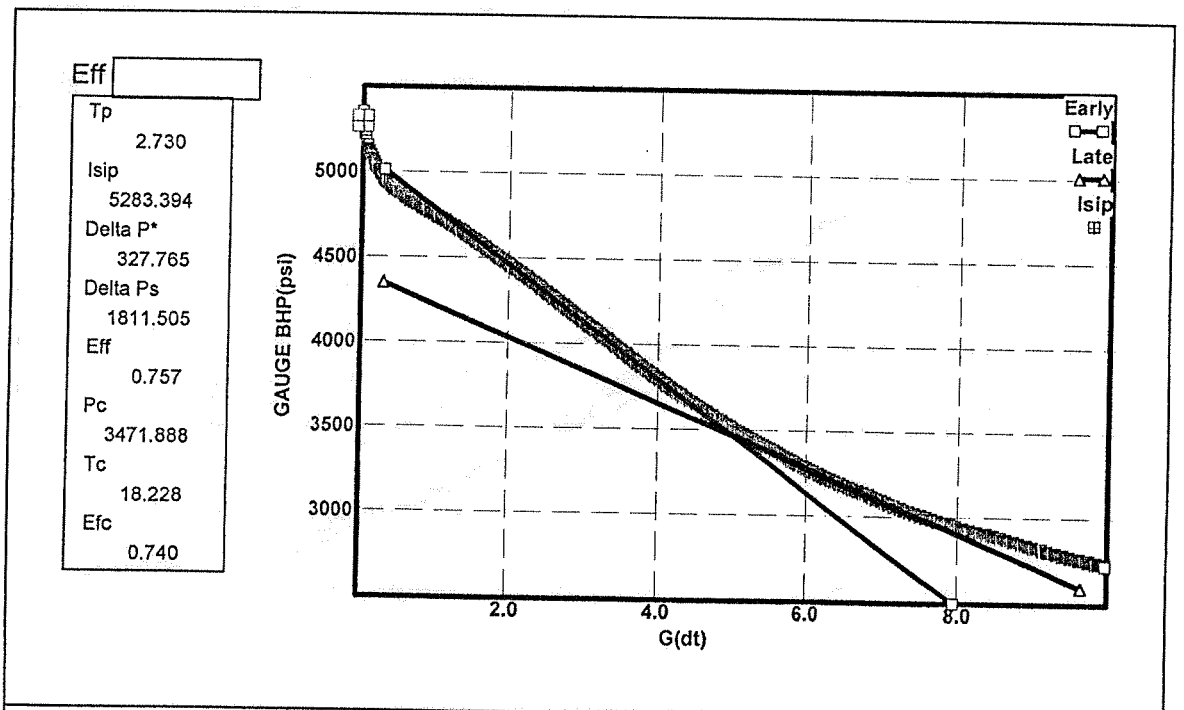

FIG. 18 - Boragel minifrac/SI BH G-function plot #2, E. Mereenie #41 (P4).

crosslinked gel, i.e. 2.73 minutes, the higher value corresponded to a fluid efficiency and net BHTP of 0.46 and 680 psi and the lower closure resulted in a fluid efficiency of 0.75 and a net BHTP of 1830 psi. With the total injection time of the slick water (5 bpm) and the crosslinked gel injection (15 bpm), i.e. 9.94 minutes, the resultant fluid efficiencies were 0.23 for the higher closure pressure and 0.54 for the lower closure pressure, Fig. 19. In comparison to other closure pressure measurements in the P4, i.e. 3740 psi on EM#38 and 3570 psi on EM#40, the lower value of 3425 psi seemed more reasonable. This value was also more consistent with the general correlation of closure to reservoir pressure across the field. Thus, this value was thought to be the pay zone closure stress and the higher value indicative of the boundary stress level. With a decline efficiency of 0.75, ignoring the slick water low rate portion of the injection, an injection efficiency of 0.39 was derived from the Mereenie efficiency correlation for use in subsequent model calibration.

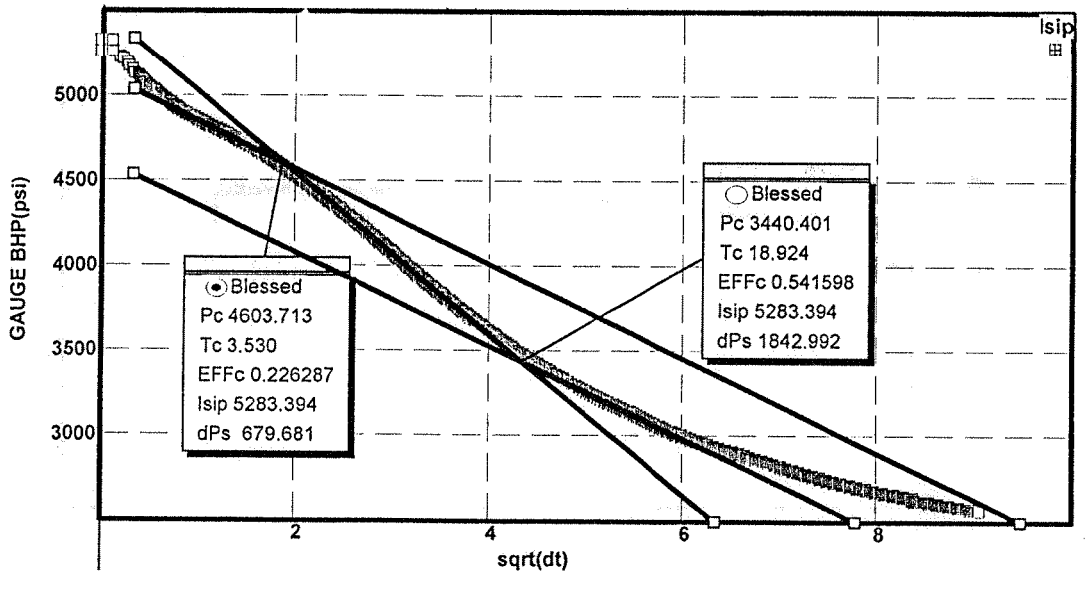

FIG. 19 - Boragel minifrac/SI sq.rt. SI time plot with slick bullhead accounted for, E. Mereenie #41 (P4).

To further the minifrac analysis and generate a "calibrated" model for final design evaluation, the minifrac injection profile was history matched. Net BHTP's were calculated with a closure pressure of 3450 psi and a downhole excess pressure of 488 psi. As shown in Fig. 20, a reasonable match was obtained of the crosslinked gel portion at the elevated rate. To match this and the resultant injection fluid efficiency required (1) using the higher indicated stress of 4600-4650 psi in the top and bottom of the pay zone and 5050-5100 psi for the boundary stresses, (2) a pay zone modulus of 8-8.25x10^6 and 8.5x10^6 psi in the boundaries, and (3) a leak-off coefficient of 0.0032 ft/sq.rt. minute in the pay. The model-predicted fracture dimensions were a created half-length of 120 ft and a maximum height at the wellbore of 106 ft as shown in Fig. 21. The top of the indicated fracture was at 4765' (TVD) or 5' below the bottom of the P3-230/250 sands. The I/O for this simulation is included in Appendix Table A-1.

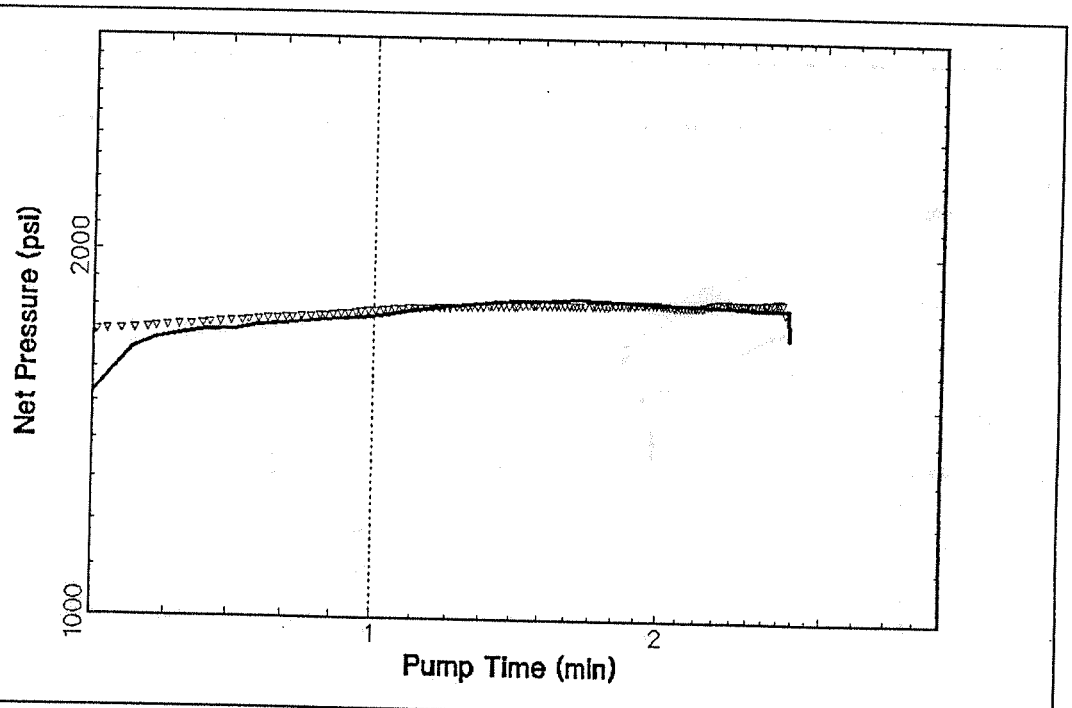

FIG. 20 - Boragel minifrac net BHTP model history match, E. Mereenie #41 (P4).

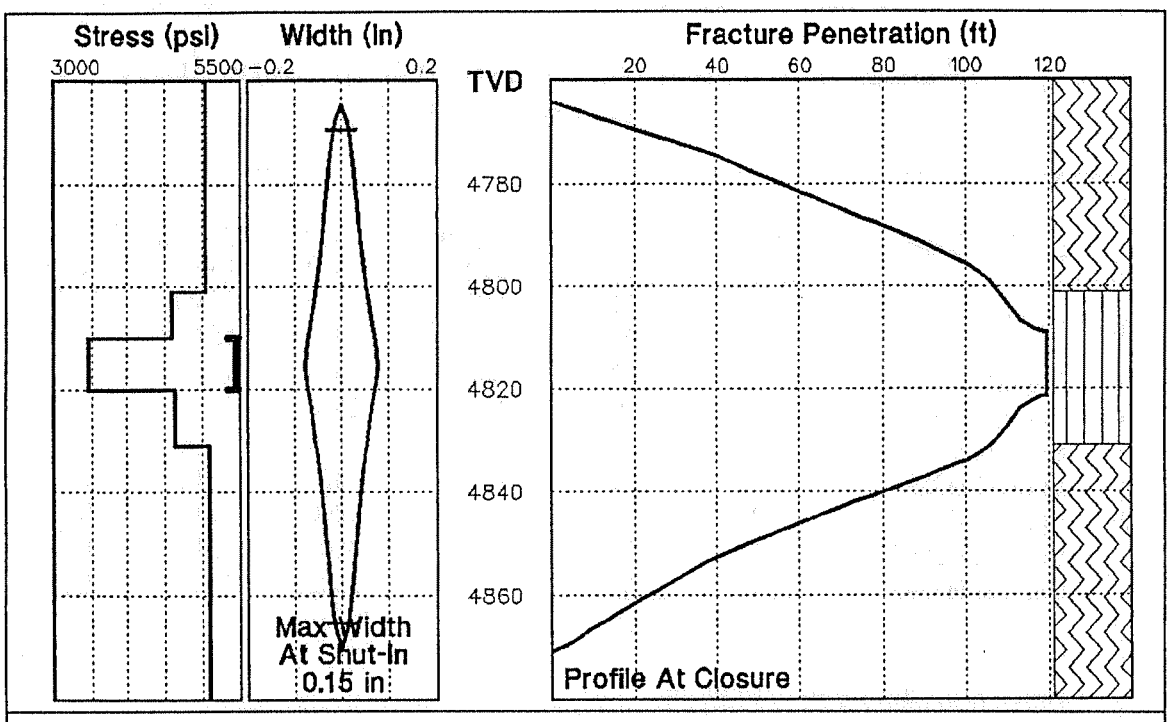

FIG. 21 - Boragel minifrac history match predicted frac geometry, E. Mereenie #41 (P4).

Final Treatment Design:

Using the "calibrated" design model, the final design pad stage was limited to 2000 gals to minimize upward growth into the P3-230/250 (Table 1). The slurry stages consisted of an additional 4750 gals of gel carrying 16,250 lbs of 20/40 Carbo-Lite at 0.5-7 ppg. With this pad and the design injection rate of 15 bpm, the model-predicted TSO started at the end of the 3 ppg stage (Fig. 22) and net BHTP increased from 1925 to 3419 psi with a corresponding average fracture width increase from 0.06 to 0.12 inches. At the wellbore, the final predicted average and maximum widths were 0.14 and 0.35 inches. Other modeled dimensions were a propped half-length of 203 ft, a maximum height at the wellbore of 156 ft, an average conductivity of 808 md-ft, and an average in-situ concentration of 0.6 lbs/sq.ft. These are shown in Figs. 23-25 with the model I/O included in Appendix Table A-2.

TABLE 1 - Final treatment design schedule, E. Mereenie #41 (P4).

Fluid Type	Slur. Vol. (gal)	Fluid Vol. (gal)	Prop Conc. (ppg)	Prop Amt. (lbs)	Avg. Q (bpm)	Pump t (min)
Boragel H3595	2000	2000	0.00	0	15.00	3.17
Boragel H3595	613	600	0.50	300	15.00	0.97
Boragel H3595	626	600	1.00	600	15.00	0.99
Boragel H3595	707	650	2.00	1300	15.00	1.12
Boragel H3595	736	650	3.00	1950	15.00	1.17
Boragel H3595	764	650	4.00	2600	15.00	1.21
Boragel H3595	732	600	5.00	3000	15.00	1.16
Boragel H3595	632	500	6.00	3000	15.00	1.00
Boragel H3595	654	500	7.00	3500	15.00	1.04
	7464	6750		16250		11.83

Note: Proppant 20/40 Carbo-Lite.

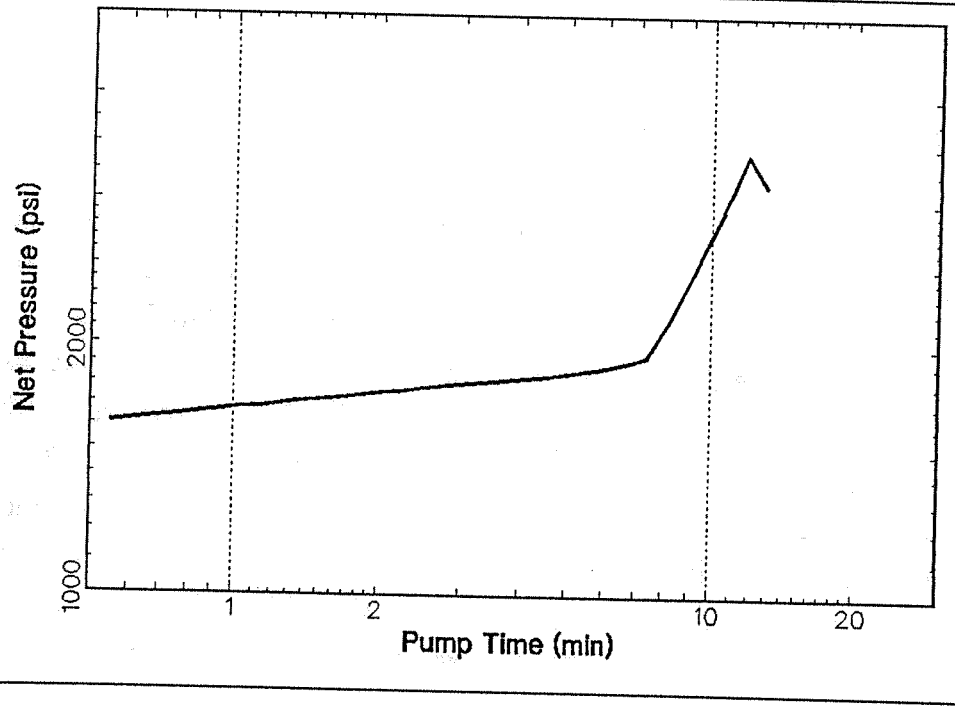

FIG. 22 - Final treatment design predicted net BHTP, E. Mereenie #41 (P4).

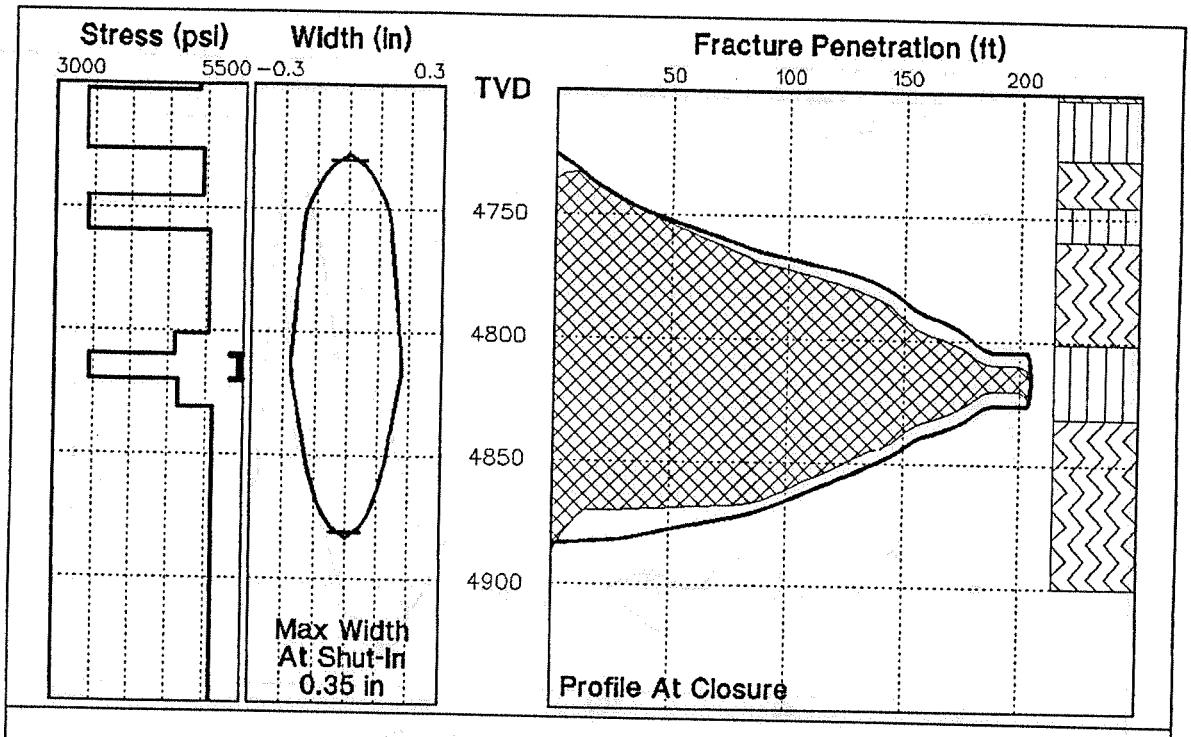

FIG. 23 - Final treatment design predicted frac geometry, E. Mereenie #41 (P4).

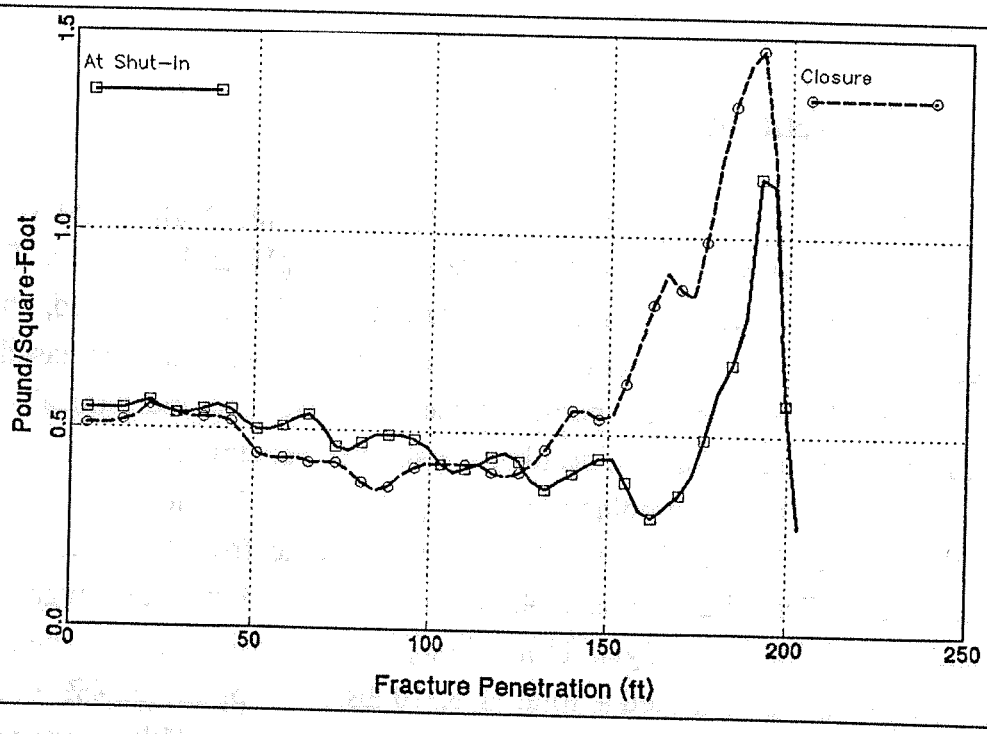

FIG. 24 - Final treatment design predicted conductivity, E. Mereenie #41 (P4).

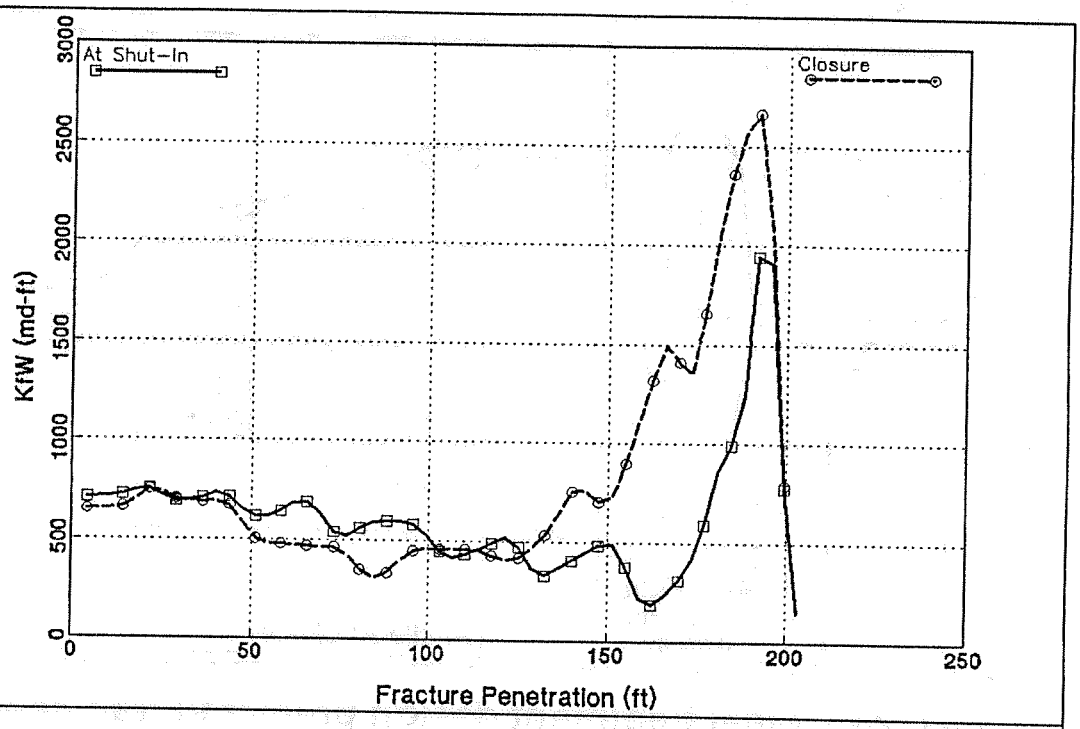

FIG. 25 - Final treatment design predicted in-situ conc., E. Mereenie #41 (P4).

Treatment Execution:

Samples of the gel were tested on-site prior to the treatment and found to possess the proper characteristics with respect to base gel viscosity, pH, and crosslink. To minimize the effect of the bullheaded residual wellbore fluid ahead of the pad, the pad was pumped to the bottom of the tubing at 5 bpm. The rate was then increased to 15 bpm for the remainder of the treatment. While there were no mechanical or blending mishaps and no indication of problems with the cement integrity, the treatment screened-out early during pumping of the 7 ppg stage. Fig. 26 shows the surface treating parameters, with Table 2 showing the surface schedule from Halliburton's computer printout. This indicated a total of 14,450 lbs of proppant pumped through the wellhead densiometer with 7029 gals of gel. Using these, the downhole treating schedule in Table 3 was calculated and indicated a total of 8,520 lbs of proppant (52.4% of design) was placed in the fracture with 6075 gals of gel (90.0% of design). This resulted in an actual

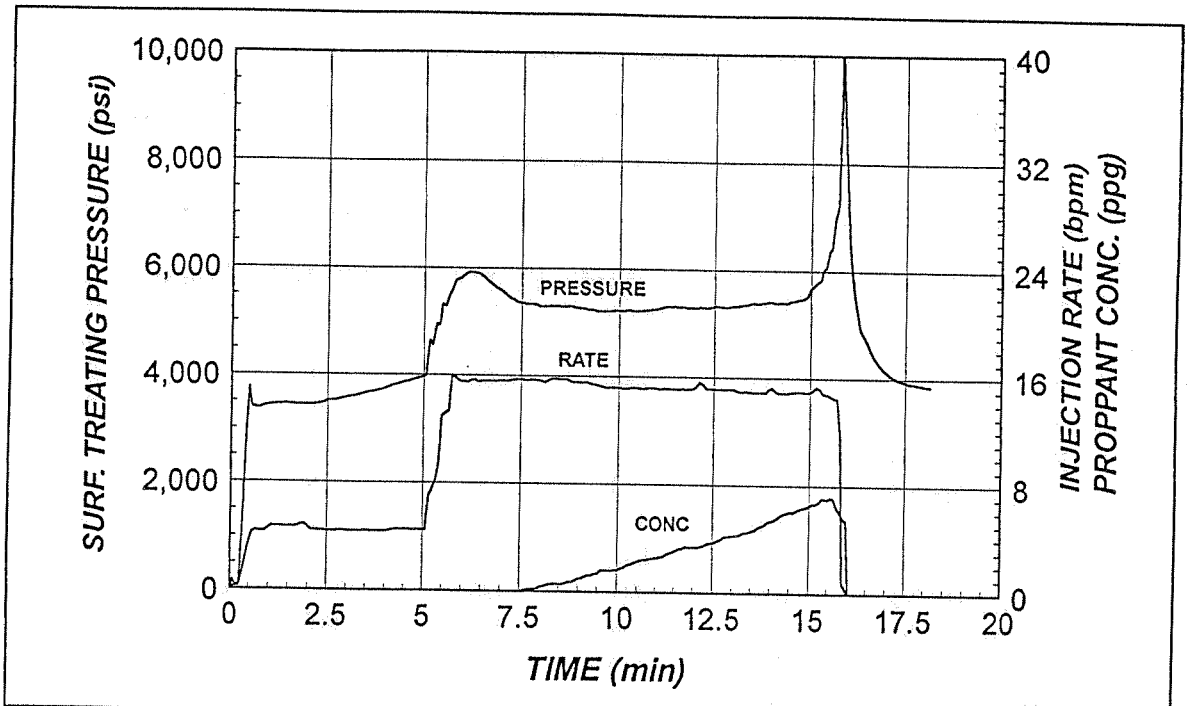

FIG. 26 - Treatment summary of surface parameters, E. Mereenie #41 (P4).

TABLE 2 - Halco (computer) surface pump schedule, E. Mereenie #41 (P4).

Fluid Type	Slur. Vol. (gal)	Fluid Vol. (gal)	Prop Conc. (ppg)	Prop Amt. (lbs)	Avg. Q (bpm)	Pump t (min)
Boragel H3595 (Fill hole)	17	17	0.00	0	-	0.33
Boragel H3595	881	881	0.00	0	4.35	4.82
Boragel H3595	236	236	0.00	0	9.63	0.58
Boragel H3595	1242	1242	0.00	0	15.56	1.90
Boragel H3595	427	422	0.25	106	15.64	0.65
Boragel H3595	863	832	0.86	717	15.61	1.32
Boragel H3595	892	821	1.96	1608	15.17	1.40
Boragel H3595	839	739	3.07	2267	15.17	1.32
Boragel H3595	677	576	4.01	2307	15.11	1.07
Boragel H3595	514	423	4.91	2077	14.98	0.82
Boragel H3595	512	405	6.00	2429	14.93	0.82
Boragel H3595	460	354	6.83	2415	14.60	0.75
Boragel H3595	93	72	6.48	469	13.28	0.17
Boragel H3595	11	9	6.09	53	1.57	0.17
	7664	7029		14448		16.12

Note: (1) Proppant 20/40 Carbo-Lite.
(2) Total screenout occurred in the 7 ppg stage.

TABLE 3 - Treatment downhole pump schedule, E. Mereenie #41 (P4).

Fluid Type	Slur. Vol. (gal)	Fluid Vol. (gal)	Prop Conc. (ppg)	Prop Amt. (lbs)	Avg. Q (bpm)	Pump t (min)
WB Fluid	881	881	0.00	0	4.35	4.82
WB Fluid	236	236	0.00	0	9.63	0.58
WB Fluid	81	81	0.00	0	15.56	0.12
Boragel H3595	2376	2376	0.00	0	15.59	3.63
Boragel H3595	75	74	0.25	19	15.61	0.11
Boragel H3595	352	348	0.25	87	15.17	0.55
Boragel H3595	863	832	0.86	717	15.17	1.35
Boragel H3595	892	821	1.96	1608	15.14	1.40
Boragel H3595	839	739	3.07	2267	15.03	1.33
Boragel H3595	488	415	4.01	1663	14.93	0.78
Boragel H3595	189	161	4.01	644	14.60	0.31
Boragel H3595	271	223	4.91	1095	14.60	0.44
Boragel H3595	104	86	4.91	420	12.04	0.21
	7647	7273		8520		15.63

Note: (1) Proppant 20/40 Carbo-Lite.
(2) Placed 52.4% of design prop amount in frac with 90% of design gel volume.

average slurry concentration of 2.30 ppg as compared to the design of 3.42 ppg. When compared to the design proppant schedule, Fig. 27, the actual schedule was considerably less aggressive than the design, which should have helped prevent the screenout. From this it appeared that leak-off was greater than anticipated from the minifrac analysis and that, possibly, the higher closure pressure of +/- 4600 psi was more indicative of the pay zone closure. This is investigated further in the following section.

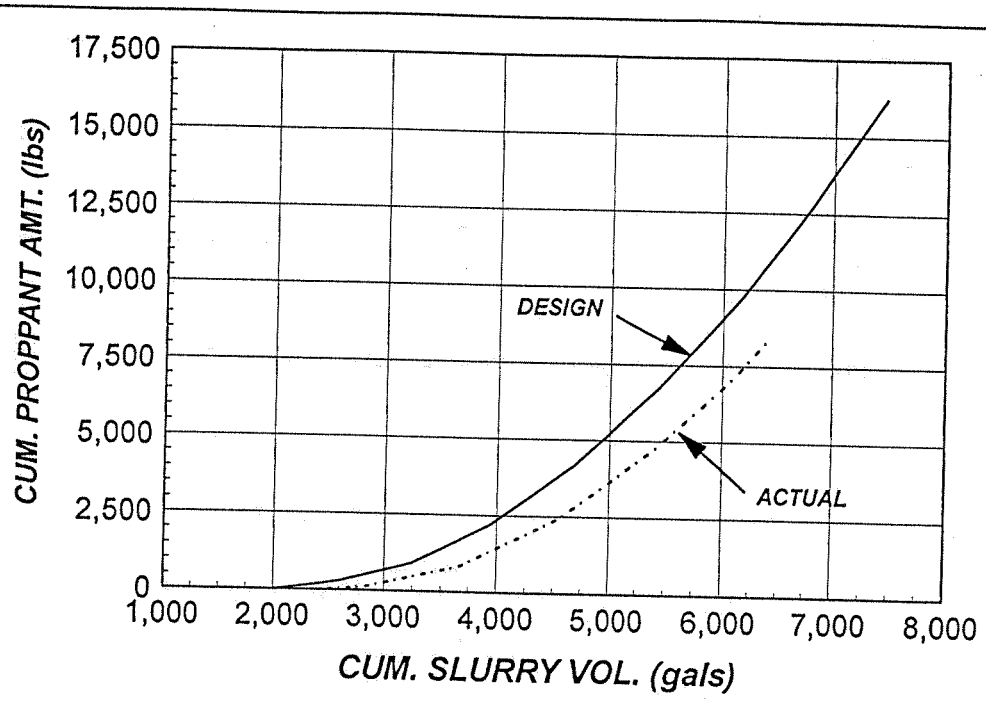

FIG. 27 - Comparison of actual to design prop schedule, E. Mereenie #41 (P4).

Post-Frac Evaluation:

Fig. 28 shows the gauge BHTP record plotted with the corresponding rate and downhole proppant concentration. Looking first at a comparison of the design model predictions with the actual schedule and the measured BHP behavior, Fig. 29, it was apparent that the two were not close in the later stages of the treatment. Instead of the start of the TSO pressure rise, the model predicted a pressure decline as the fracture grew through the upper barrier into the lower stressed P3-230/250 sands. From this it was apparent that the leak-off model used was not accounting adequately for that being encountered, keeping in mind that the leak-off in the P3-190/230/250 had not been directly measured at this point.

As an aid to this evaluation, the P3-230/250 fracture treatment was nest evaluated. The pre-frac test analysis was much clearer for this zone, the treatment was pumped to

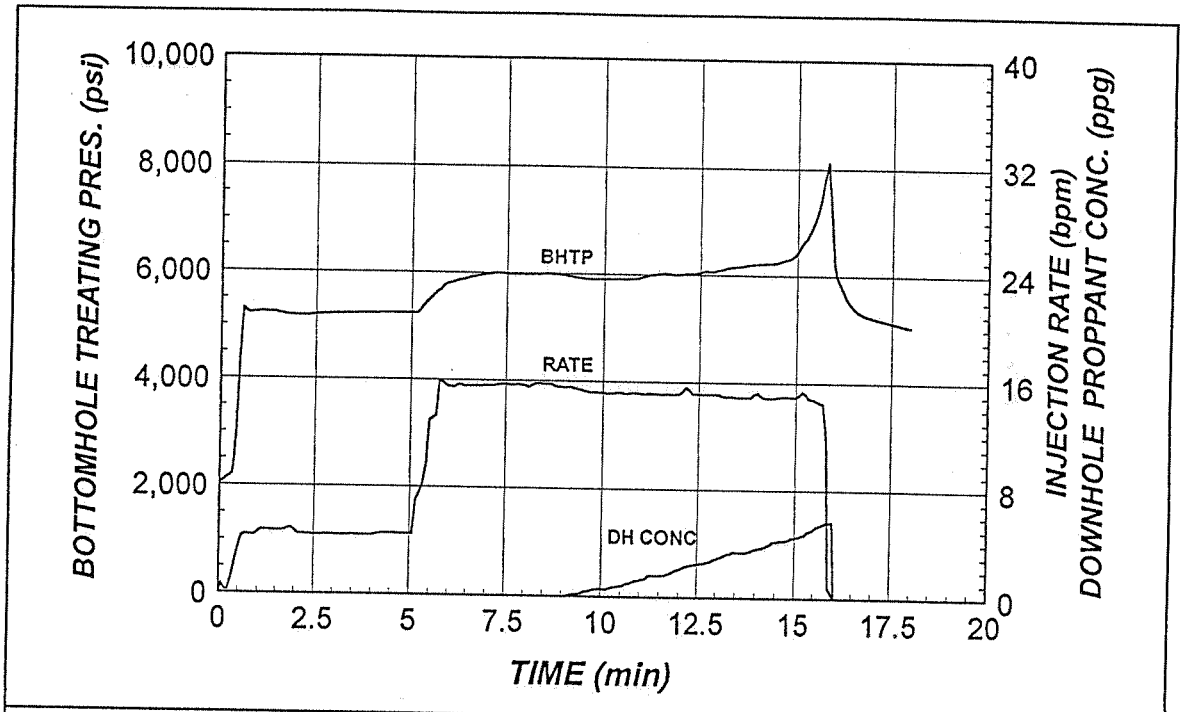

FIG. 28 - Treatment summary of bottomhole parameters, E. Mereenie #41 (P4).

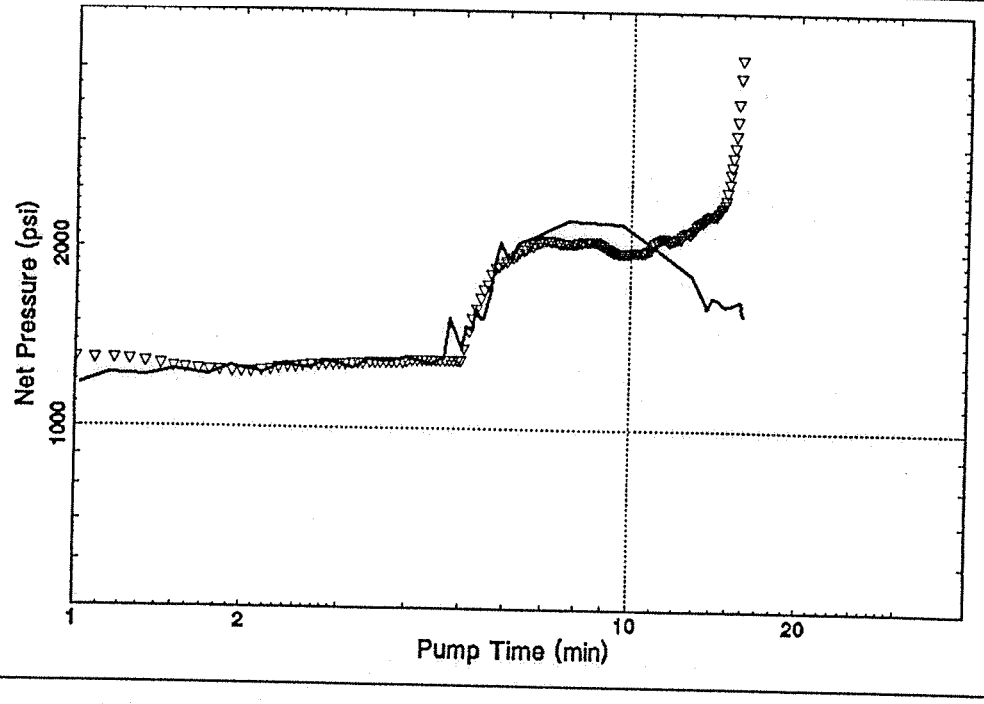

FIG. 29 - Treatment net BHTP history match with design model, E. Mereenie #41 (P4).

completion, and the pressure behavior was extremely close to that predicted from final design modeling. Figs. 30 and 31 show the model history match for this treatment, the required stress profile, and the resultant fracture geometry. This required a pay zone leak-off coefficient and spurt of 0.006 ft/srm and 0.5 gals/100 sf as opposed to 0.005 ft/srm and 0.2 gals/sf used in these same zones in the minifrac and final design evaluation for the P4. This, in itself, provided a higher source of leak-off for the P4 treatment. Additionally, the closure stress in the upper sands was found to be 3870 psi instead of 3435 psi used in the P4 evaluation and the modulus was somewhat less, i.e. reduced from $7x10^6$ to $6.5x10^6$ psi.

Incorporating the above changes from the lower P3 evaluation, another attempt was made to model match the P4 treatment. While the match, Fig. 32, showed some of the same pressure characteristics, it was still not very good. With a further increase in leak-off in the P4, from 0.0032 to 0.004 ft/srm, the accuracy of the match did not improve as seen in Fig. 33.

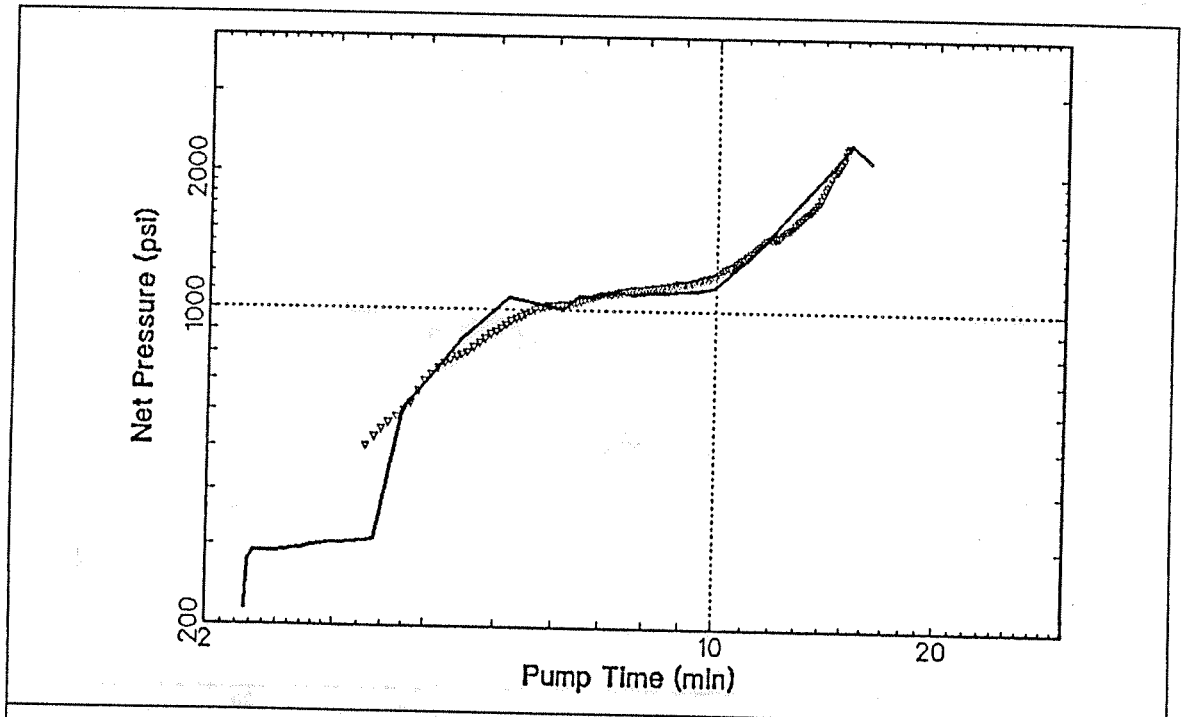

FIG. 30 - P3-230/250 treatment net BHTP history match, E. Mereenie #41.

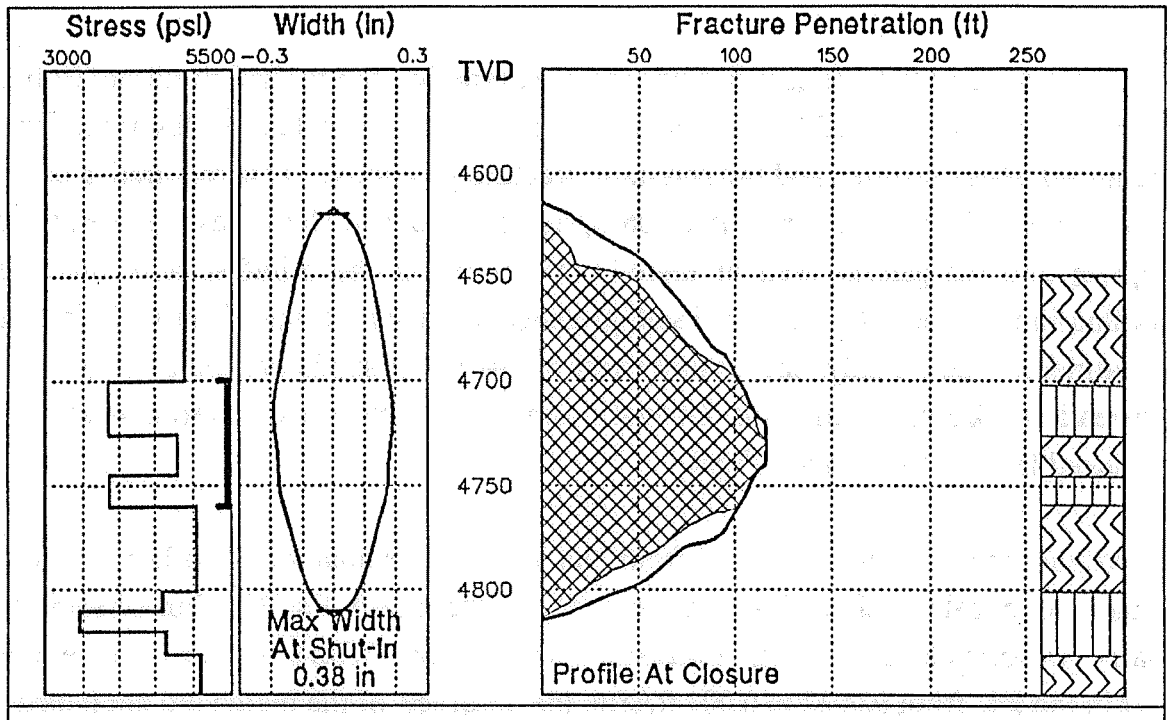

FIG. 31 - P3-230/250 treatment history match predicted frac geometry, E. Mereenie #41.

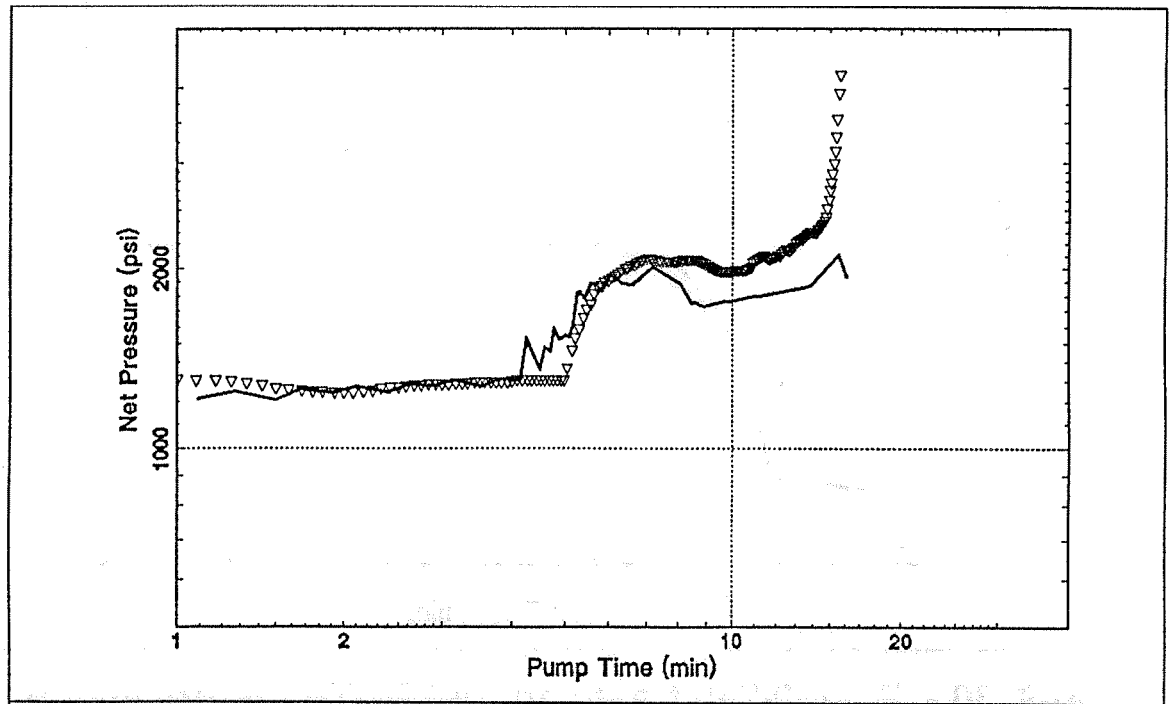

FIG. 32 - Treatment net BHTP history match w/ changes from lower P3 eval., E. Mereenie #41 (P4).

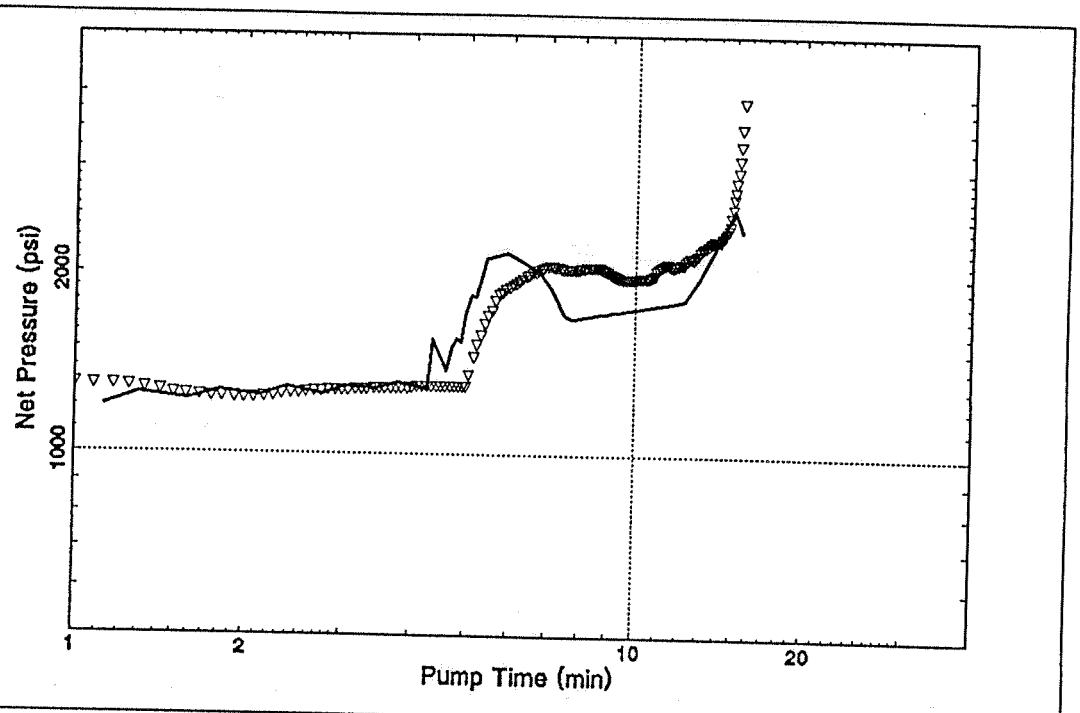

FIG. 33 - Treatment net BHTP history match w/ increased P4 leak-off, E. Mereenie #41 (P4).

Looking just at the crosslinked gel portion of the treatment, i.e. ignoring the 5 bpm bullheaded wellbore fluid, a much better match of the data could be obtained as shown in Fig. 34. Changes to the final design model were (1) an increase in the P4 leak-off to 0.0042 ft/srm, (2) an increase in the lower boundary modulus from 8.5 to $9x10^6$ psi, and (3) a fairly substantial increase in the crosslinked gel viscosity. This match predicted a propped half-length of 83 ft, a maximum height of 184 ft, an average conductivity of 487 md-ft, and an average in-situ concentration of 0.4 lbs/sf. These are shown in Figs. 35-37 with the model I/O included in Appendix Table A-3. With the seemingly unrealistic increase in viscosity primarily governing the pressure level, further analysis was warranted.

The next step was to evaluate the possibility that the wrong closure pressure was picked and that it was instead the higher value of 4600 psi. Recalculating the net BHTP's using this value gave net pressures in the 800 psi range instead of the 1800-2000 psi range.

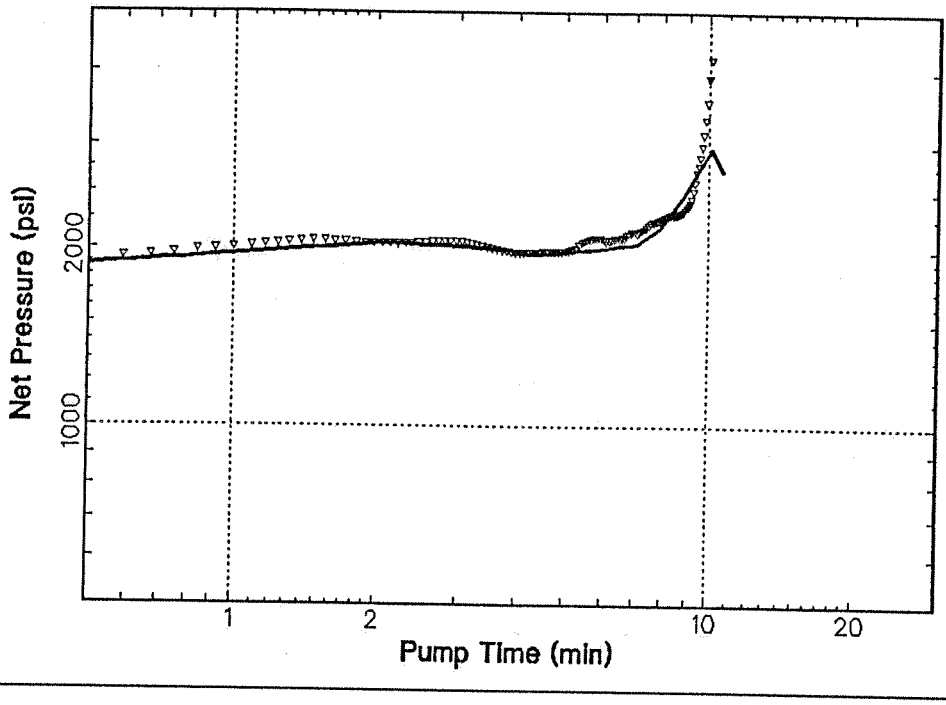

FIG. 34 - Treatment net BHTP history match of crosslinked gel portion only, E. Mereenie #41 (P4).

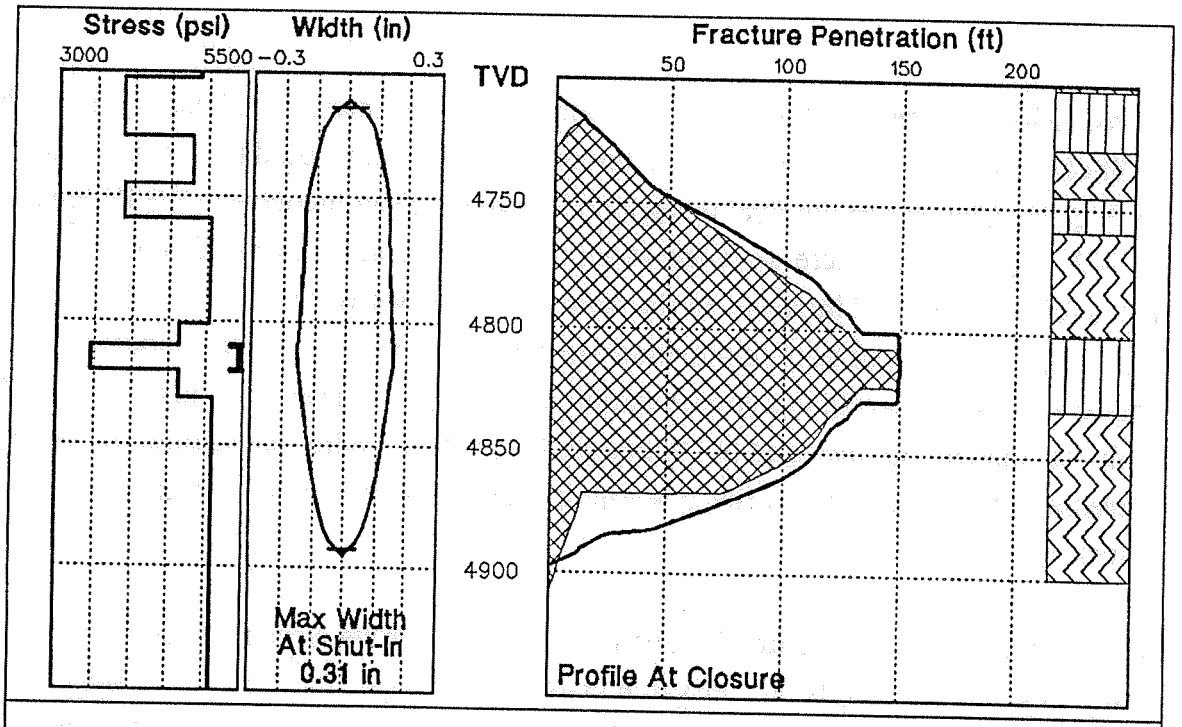

FIG. 35 - Treatment history match predicted frac geometry, E. Mereenie #41 (P4).

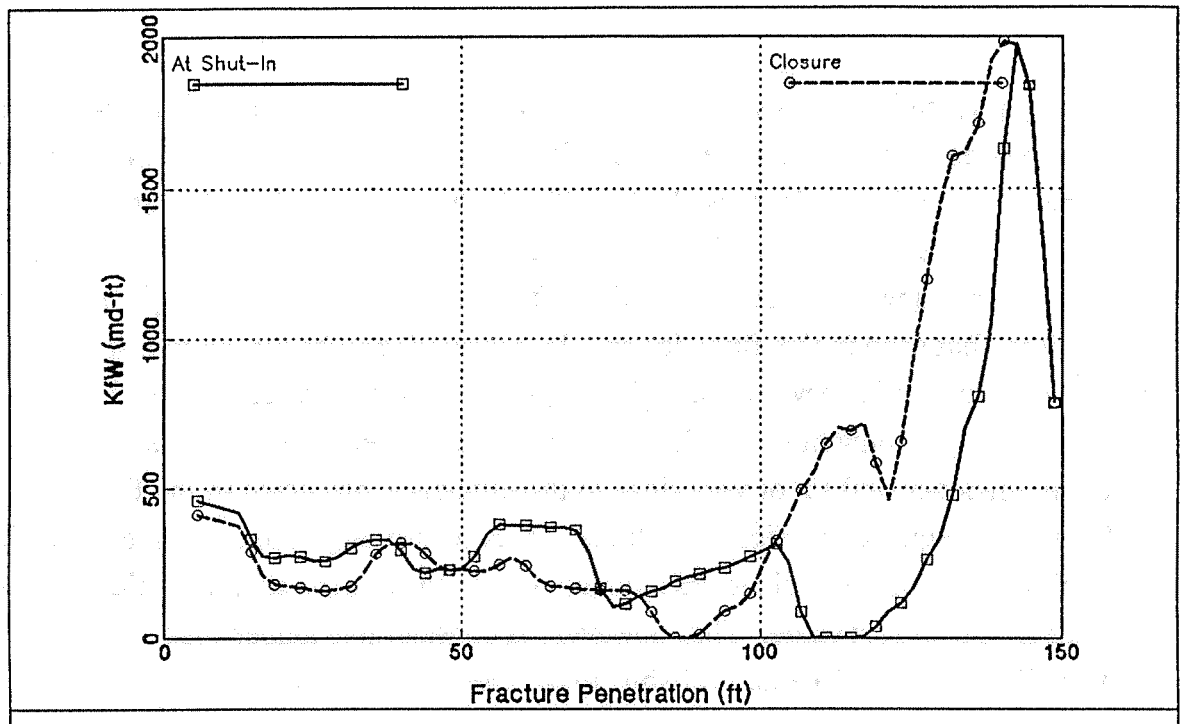

FIG. 36 - Treatment history match predicted conductivity, E. Mereenie #41 (P4).

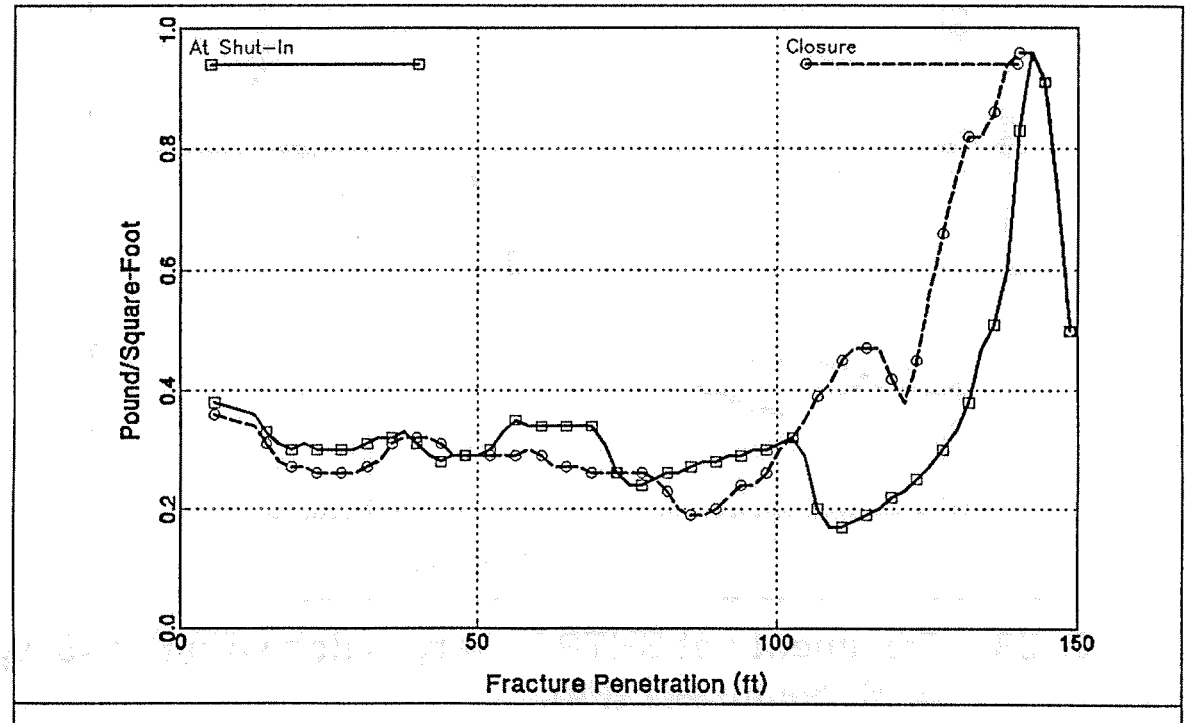

FIG. 37 - Treatment history match predicted in-situ conc., E. Mereenie #41 (P4).

this value gave net pressures in the 800 psi range instead of the 1800-2000 psi range. Using the stress/modulus profile devised from the original modeling of this treatment, with the pay zone stress increased to 4600 psi, and incorporating the stress/modulus changes from the lower P3 analysis, the reasonably good pressure match in Fig. 38 was obtained. This, however, required a P4 leak-off coefficient of 0.009 ft/srm or almost three times that used in the final design. As indicated earlier for the minifrac analysis, the decline fluid efficiency for the higher closure pressure was 0.23 (both slick water + crosslinked gel). Going into the Mereenie efficiency correlation, this gave an equivalent injection efficiency of 0.13 or very close to the efficiency predicted in the Fig. 38 match, i.e. 0.14 at the equivalent minifrac volume. This consistency and the more realistic gel viscosities required to achieve this match seem to suggest that the higher closure pressure is the correct value. This, however, is considerably higher than the P4 stresses used on EM#38 and #39 and, probably, these should be reviewed in light of this.

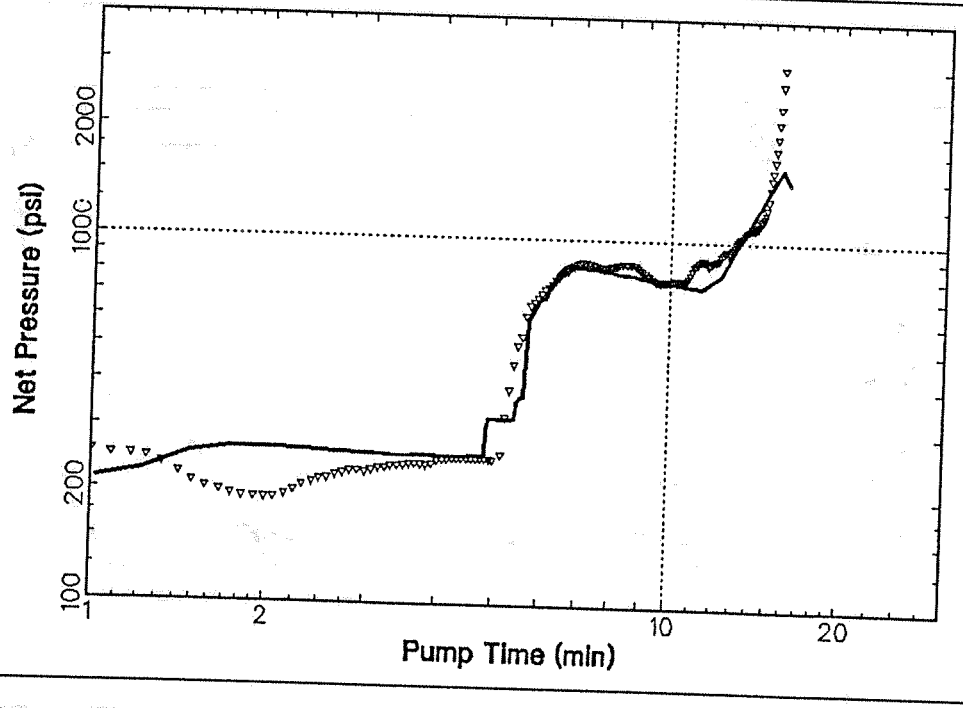

FIG. 38 - Treatment net BHTP history match with Pc=4600, E. Mereenie #41 (P4).

Also, the relatively high leak-off is inconsistent with the expected low permeability for this zone. Instead this is thought to be a result of fluid shear-thinning due to restricted width development in the high modulus environment. This would degrade the fluid and cause the higher leak-off during the minifrac and also on the main treatment until the TSO developed and width increased to reduce the shear-rate down the fracture.

From the match in Fig. 38, the model predicted dimensions were a propped half-length of 88 ft (design - 203 ft), a maximum height of 179 ft (design - 156 ft), an average conductivity of 1176 md-ft (design - 808 md-ft), and an average in-situ concentration of 0.7 lbs/sf (design - 0.6 lbs/sf). These are shown in Figs. 39-41 with the model I/O included in Appendix Table A-4. The shorter half-length and higher conductivity were a direct result of the higher than expect leak-off and the increased height growth was a result of the higher stress in the pay and less contrast between this and the boundary stresses. While modeling indicates that the treatment grew into the P3-230/250, the subsequent lower P3 treatment did not see any interference from this; fracture azimuth apparently not in line with the deviated wellbore azimuth and enough displacement existing between the fractures to prevent any such interference.

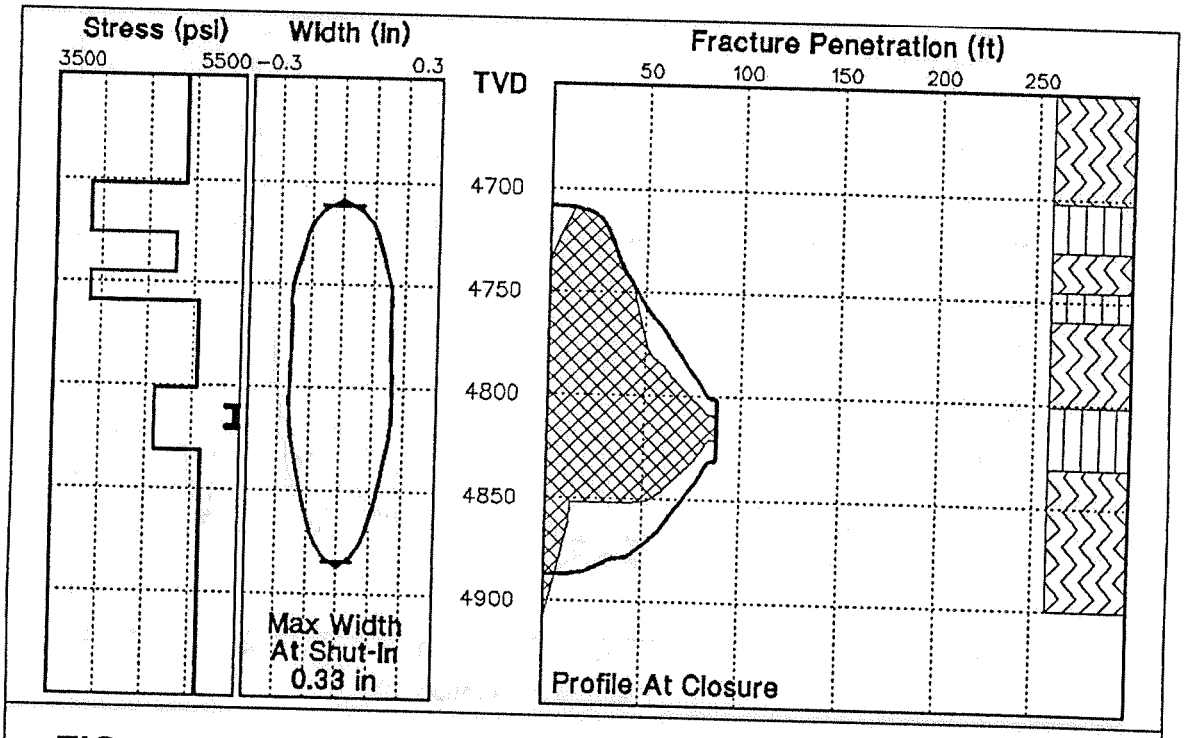

FIG. 39 - Treatment history match (Pc=4600) predicted frac geometry, E. Mereenie #41 (P4).

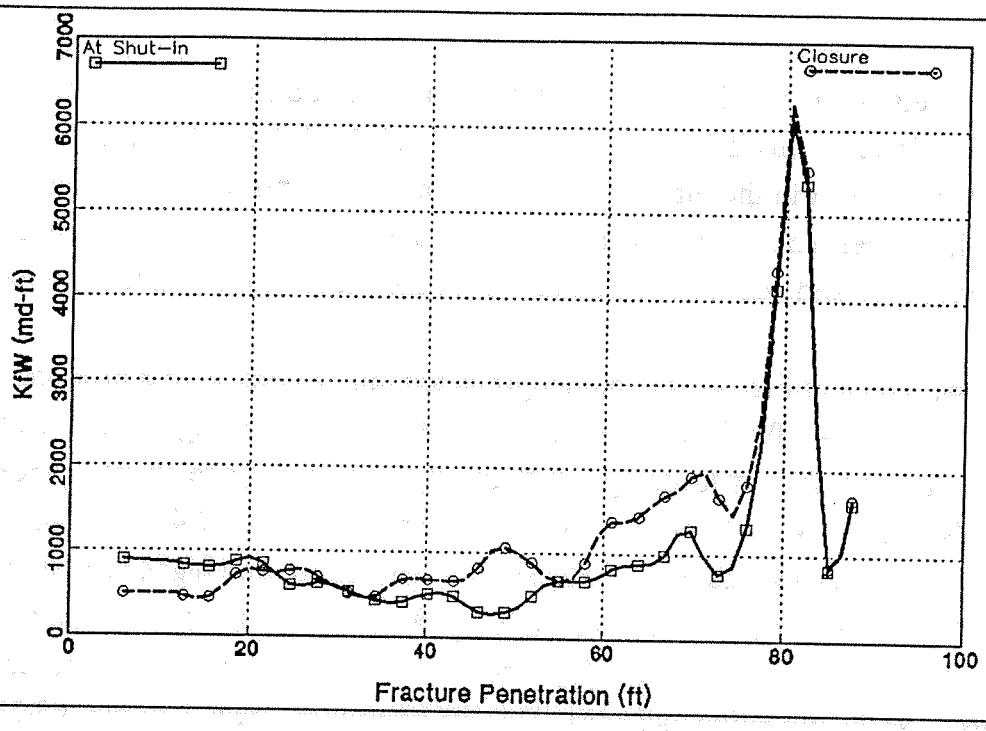

FIG. 40 - Treatment history match (Pc=4600) predicted conductivity, E. Mereenie #41 (P4).

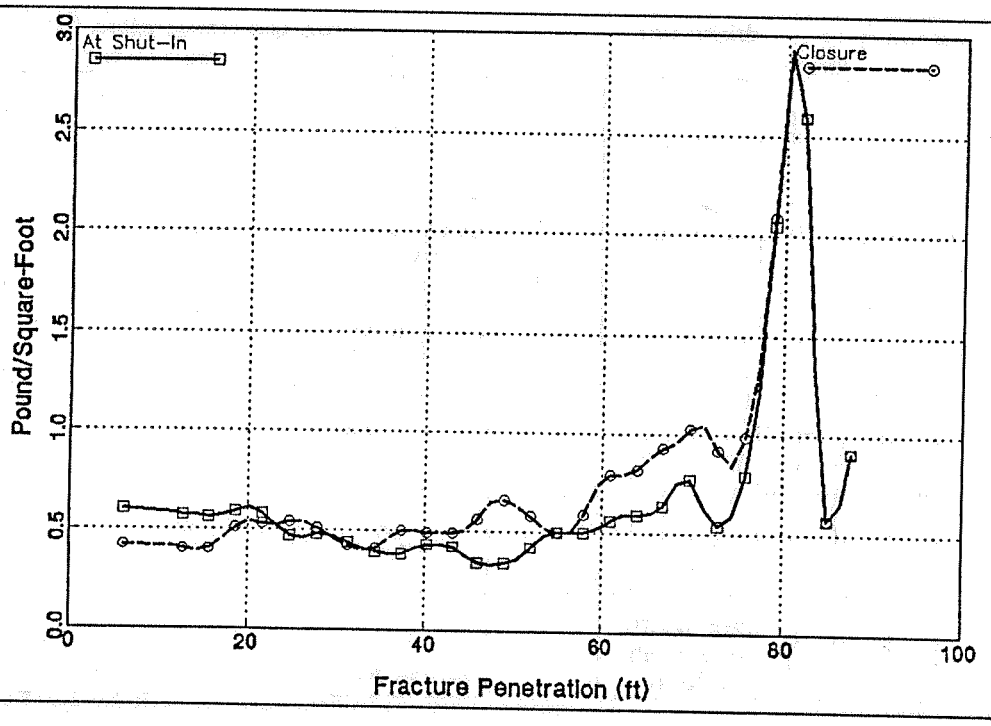

FIG. 41 - Treatment history match (Pc=4600) predicted in-situ conc., E. Mereenie #41 (P4).

CONCLUSIONS / RECOMMENDATIONS

From pre-frac test analysis, two closure pressures were possible, one at 3450 psi and the other at 4600 psi. Corresponding fluid efficiencies from pressure decline analysis were 0.75 and 0.46, respectively for the pump time of the crosslinked gel portion only. The lower closure was thought to be the correct value based on its consistency with prior measurements in this zone and the P3 on other wells. This, however, resulted in a net BHTP of +/-1800 psi for the XL gel at 15 bpm. Using the Mereenie correlation of fluid efficiency from pressure decline to injection efficiency, the efficiency was reduced to 0.39 for final design formulation. Downhole "excess" pressure during the minifrac was 488 psi, indicating moderate wellbore to fracture communication.

A reasonably good model history match of the minifrac net BHTP's was obtained with (1) the higher indicated stress of 4600 psi in the top and bottom of the pay zone, 3450 in the main body of the pay, and 5050-5100 psi in the boundaries; (2) a pay zone modulus of 8-8.25x10^6 psi and 8.5x10^6 psi in the boundaries; and (3) a pay zone leak-off coefficient of 0.0032 ft/sq.rt. minute.

When pumped, the final treatment schedule (based on the calibrated minifrac model) resulted in an early screenout after placing only 52% of the designed proppant amount. This could not be attributed to any pumping problems, with the actual proppant schedule be considerably less aggressive than the design called for. To match this behavior using the lower P4 closure pressure (3450 psi) required adjustments in the final design model including (1) higher leak-off and stresses in the P3-230/250 (not measured until later), (2) an increase in the P4 leak-off to 0.0042 ft/srm, (3) an increase in the lower boundary modulus from 8.5 to 9.5x10^6 psi, and (4) a substantial increase in the crosslinked gel viscosity. This resulted in a fairly good match of the crosslinked gel portion of the injection; however, the viscosities required were unrealistically high. The resultant dimensions for this match were a propped half-length of 83 ft, a maximum height of 184 ft, an average conductivity of 487 md-ft, and an average in-situ concentration of 0.4 lbs/sf.

With the gel viscosities required to match the pressure behavior with the lower closure being very high, further analysis looked at the possibility of the higher closure (4600 psi) being the correct value. This resulted in net BHTP's in the 800 psi range instead of 1800 psi. With the stress/modulus profile devised from the original modeling of the treatment and the pay zone stress changed to 4600 psi, and incorporating the changes from the lower P3 analysis, a reasonably good match was obtained. Gel viscosities used were also much more realistic. This, however, required a P4 leak-off coefficient of 0.009 ft/srm or almost three times that used in the final design. The injection and decline efficiencies, though, were consistent with the Mereenie correlation for this higher closure pressure and much lower fluid efficiency for the combined low viscosity wellbore fluid bullhead at 5 bpm and crosslinked gel, higher rate portions. The resultant fracture dimensions were a propped half-length of 88 ft, a maximum height of 179 ft, an average conductivity of 1176 md-ft, and an average in-situ concentration of 0.7 lbs/sf. This was thought to be the more plausible simulation of the treatment.

The higher closure pressure used in the final history match was considerably higher than the P4 stress measurements used on EM#38 and #39 and, probably, these should be reviewed in light of this. Also, the high leak-off is inconsistent with the expected low permeability for this zone. This, however, could have been a result of fluid shear-thinning due to restricted width development in the higher modulus environment and/or increased leak-off through a cement channel, although this later cannot be supported with any evidence.

APPENDIX A

Fracture Model Simulations

Frac Summary * SANTOS - E. MEREENIE #41 (P4) MINIFRAC HISTORY MATCH
Filename: EM41P4MF.FRK ; Sep 10, 96

Design Data

FLUID LOSS LAYERS:	Top (ft)	Bottom (ft)	Thick (ft)	Loss Coef. (ft/sqrt(min))	Spurt (Gal/100 ft^2)
	4649.0	4702.0	53.0	0.00010	0.00
	4702.0	4726.0	24.0	0.00500	0.20
	4726.0	4745.0	19.0	0.00010	0.00
	4745.0	4759.0	14.0	0.00500	0.20
	4759.0	4801.0	42.0	0.00010	0.00
	4801.0	4831.0	30.0	0.00320	0.20
	4831.0	4900.0	69.0	0.00010	0.00

FORMATION:	Modulus (e6_psi)	8.00
	Perforated Height (ft)	10.0
	Permeability (md)	1.000
TEMPERATURE:	Bottom Hole (deg_F)	145
PRESSURE:	Reservoir Pressure (psi)	1830.0
	Closure Pressure (psi)	3450.0
DEPTH:	Well Depth (ft)	4810.0

FORMATION LAYER DATA - Multi-Layer Height Growth

-----Depth(ft)------ Top	Botm	Thick	-Stress (psi)-- Top	Botm	Gradient (psi/ft)	Modulus (e6_psi)	Toughness (psi/in)
4649.0	4702.0	53.0	4900.0	4900.0	0.000	8.50	3000.0
4702.0	4726.0	24.0	3400.0	3400.0	0.000	7.00	3000.0
4726.0	4745.0	19.0	4950.0	4950.0	0.000	8.50	3000.0
4745.0	4759.0	14.0	3425.0	3425.0	0.000	7.00	3000.0
4759.0	4801.0	42.0	5050.0	5050.0	0.000	8.50	3000.0
4801.0	4810.0	9.0	4600.0	4600.0	0.000	8.25	3000.0
4810.0	4820.0	10.0	3450.0	3450.0	0.000	8.00	3000.0
4820.0	4831.0	11.0	4650.0	4650.0	0.000	8.25	3000.0
4831.0			5100.0		0.000	8.50	3000.0

	Fluid Pressure Gradient (psi/ft)	0.450
	Perforations - Top (ft)	4810
	- Bot (ft)	4820
	Initial Fracture Top (ft)	4810
	Fracture Bottom (ft)	4820
3-D SIMULATOR	Step Size (ft)	2.5
PROGRAM CONTROL	Time Step (min)	1.0

Calculated Results
from 3-D Simulator
STIMPLAN (TM) , NSI , Tulsa,OK
Licensed To: ARCO Exploration & Production Technology

1/2 LENGTH:	'Hydraulic' length (ft)	119.5
	Propped length (ft)	0.0
PRESSURE:	Max Net Pressure (psi)	1836.4
TIME:	Max Exposure to Form. Temp. (min)	1.0
	Time to Close (min)	3.5
RATE:	Fluid Loss Rate during pad (_BPM) ..	0.00
EFFICIENCY:	at end of pumping schedule	0.38
PROPPANT:	Average In Situ Conc. (#/sq ft)	0.0
	Average Conductivity (md-ft)	0
HEIGHT:	Max Fracture Height (ft)	105.6
WIDTH:	Avg width at end of pumping (in) ...	0.05

TABLE A-1

StimPlan 2.61 (TM). NSI Technologies, Tulsa, OK
Licensed To: ARCO Exploration & Production Technology

WELL ID:
SANTOS - E. MEREENIE #41 (P4) MINIFRAC HISTORY MATCH

DEPTH:	Well Depth (ft)	4810
PRESSURE:	Reservoir Pressure (psi)	1830
	Closure Pressure (psi)	3450
TEMPERATURE:	Bottom Hole Temperature (deg_F)	145

** Pumping Schedule **

Sl Vol (MGal)	Fl Vol (MGal)	Conc (_PPG_) Start	End	Rate (_BPM)	Fluid Type	Prop Type	Cum Prop (MLbs)	Pump Time (min)
0.16	0.16	0.0	0.0	7.71	1	1	0.0	0.5
0.27	0.27	0.0	0.0	12.67	1	1	0.0	0.5
0.17	0.17	0.0	0.0	13.41	1	1	0.0	0.3
0.20	0.20	0.0	0.0	13.41	2	1	0.0	0.4
0.60	0.60	0.0	0.0	13.12	2	1	0.0	1.1

Total Slurry ...	1.4	Total Fluid ...	1.4
Total Proppant ...	0.0	Avg. Conc	0.0
Total Pump Time	2.7 min	Pad %	100.0

Proppant ID No. 1 20- 40 Un-Defined

Specific Gravity					2.65
'Damage Factor'					0.70
Proppant Stress (Mpsi)	0	2	4	8	16
KfW @ 2 #/sq ft (md-ft)	4800	3850	2750	990	50

Fluid ID No. 1 30#_BORAGEL

Specific Gravity 1.04

	@Welbor	@FormTmp	@1Hr	@2Hr	@4Hr	@8Hr
vis (cp @ 170 1/sec) .	650	650	550	300	10	2
non-Newtonian n'	0.38	0.40	0.41	0.42	0.90	0.95
K(lb·sec/ft^2)x1000	321.64	290.24	233.30	120.88	0.34	0.05

Fluid ID No. 2 30#_BORAGEL

Specific Gravity 1.04

	@Welbor	@FormTmp	@1Hr	@2Hr	@4Hr	@8Hr
vis (cp @ 170 1/sec) .	550	500	400	250	10	2
non-Newtonian n'	0.38	0.40	0.41	0.42	0.90	0.95
K(lb·sec/ft^2)x1000	272.16	223.26	169.67	100.74	0.34	0.05

Time History * NSI STIMPLAN 3-D Fracture Simulation
SANTOS - E. MEREENIE #41 (P4) MINIFRAC HISTORY MATCH

Time (min)	Pen (ft)	Pres (psi)	Rate (_BPM)	Prop (_PPG_)	Sl Vol (MGal)	Eff-ciency	Loss (_BPM)	Hght (ft)	W-Avg (in)
0.0	7.6	1376	7.71	0.0	0.0	0.54	3.7	17	0.01
0.0	10.1	1285	7.71	0.0	0.0	0.50	4.0	22	0.02
0.0	12.6	1321	7.71	0.0	0.0	0.45	4.8	27	0.02
0.1	15.1	1359	7.71	0.0	0.0	0.41	5.2	31	0.02
0.1	17.6	1408	7.71	0.0	0.0	0.38	5.4	34	0.02
0.1	20.1	1443	7.71	0.0	0.0	0.35	5.6	38	0.02
0.2	22.6	1472	7.71	0.0	0.1	0.33	5.7	41	0.02
0.2	25.1	1470	7.71	0.0	0.1	0.32	5.6	44	0.02
0.3	27.6	1488	7.71	0.0	0.1	0.32	5.4	46	0.02
0.3	30.1	1511	7.71	0.0	0.1	0.32	5.4	48	0.02
0.4	32.6	1527	7.71	0.0	0.1	0.32	5.3	50	0.02
0.4	35.1	1544	7.71	0.0	0.1	0.31	5.4	52	0.02
0.5	36.8	1524	7.71	0.0	0.2	0.31	4.3	53	0.03
0.6	39.3	1660	12.67	0.0	0.2	0.32	6.9	55	0.03
0.6	41.8	1690	12.67	0.0	0.2	0.34	6.7	57	0.03
0.6	44.3	1706	12.67	0.0	0.2	0.35	6.8	58	0.03
0.7	46.8	1720	12.67	0.0	0.3	0.36	7.1	60	0.03
0.7	49.3	1721	12.67	0.0	0.3	0.36	7.2	62	0.03
0.8	51.8	1738	12.67	0.0	0.3	0.37	7.4	64	0.03
0.8	54.3	1742	12.67	0.0	0.3	0.37	7.5	66	0.04
0.9	56.8	1753	12.67	0.0	0.3	0.37	7.5	68	0.04
0.9	59.3	1760	12.67	0.0	0.4	0.38	7.6	69	0.04
1.0	61.8	1767	12.67	0.0	0.4	0.38	7.6	71	0.04
1.0	64.3	1776	12.67	0.0	0.4	0.38	7.6	73	0.04
1.1	66.8	1792	13.41	0.0	0.5	0.38	7.7	75	0.04
1.2	69.3	1803	13.41	0.0	0.5	0.38	7.8	76	0.04
1.2	71.8	1811	13.41	0.0	0.6	0.38	7.8	78	0.04
1.3	74.3	1818	13.41	0.0	0.6	0.39	7.9	80	0.04
1.4	76.8	1824	13.41	0.0	0.6	0.39	7.9	82	0.04
1.4	79.3	1830	13.41	0.0	0.7	0.39	7.9	84	0.04
1.5	81.8	1829	13.41	0.0	0.7	0.39	7.9	86	0.04
1.6	84.3	1833	13.41	0.0	0.8	0.39	8.0	87	0.04
1.6	86.8	1836	13.41	0.0	0.8	0.39	8.0	89	0.05
1.7	89.3	1832	13.12	0.0	0.8	0.39	8.0	91	0.05
1.8	91.8	1829	13.12	0.0	0.9	0.39	8.0	93	0.05
1.9	94.3	1828	13.12	0.0	0.9	0.39	8.0	94	0.05
2.0	96.8	1822	13.12	0.0	1.0	0.39	8.0	96	0.05
2.1	99.3	1822	13.12	0.0	1.0	0.39	8.0	97	0.05
2.2	101.8	1820	13.12	0.0	1.1	0.39	8.0	99	0.05
2.3	104.3	1818	13.12	0.0	1.1	0.39	8.1	100	0.05
2.4	106.8	1815	13.12	0.0	1.2	0.39	8.1	101	0.05
2.5	109.3	1812	13.12	0.0	1.2	0.39	8.3	102	0.05
2.5	111.8	1808	13.12	0.0	1.3	0.39	8.4	103	0.05
2.6	114.3	1810	13.12	0.0	1.3	0.39	8.4	104	0.05
2.8	118.0	1810	13.12	0.0	1.4	0.38	8.2	106	0.05
2.8	118.2	1712	0.00	0.0	1.4	0.38	15.6	106	0.05
2.8	118.8	1619	0.00	0.0	1.4	0.36	7.9	106	0.05

Time History * NSI STIMPLAN 3-D Fracture Simulation
SANTOS - E. MEREENIE #41 (P4) MINIFRAC HISTORY MATCH

Time (min)	Pen (ft)	Pres (psi)	Rate (_BPM)	Prop (_PPG_)	Sl Vol (MGal)	Eff-ciency	Loss (_BPM)	Hght (ft)	W-Avg (in)
3.0	119.4	1496	0.00	0.0	1.4	0.34	7.3	106	0.04
3.0	119.5	1443	0.00	0.0	1.4	0.32	6.8	106	0.04
3.2	119.5	1327	0.00	0.0	1.4	0.30	6.5	106	0.04
3.3	119.5	1212	0.00	0.0	1.4	0.27	6.2	106	0.03
3.4	119.5	1096	0.00	0.0	1.4	0.25	5.9	106	0.03
3.6	119.5	981	0.00	0.0	1.4	0.22	5.6	106	0.03
3.7	119.5	923	0.00	0.0	1.4	0.21	5.4	106	0.03
3.8	119.5	866	0.00	0.0	1.4	0.19	5.3	106	0.02
3.8	119.5	808	0.00	0.0	1.4	0.18	5.2	106	0.02
3.9	119.5	750	0.00	0.0	1.4	0.17	5.1	106	0.02
4.0	119.5	692	0.00	0.0	1.4	0.16	5.0	106	0.02
4.1	119.5	635	0.00	0.0	1.4	0.14	4.9	106	0.02
4.2	119.5	577	0.00	0.0	1.4	0.13	4.9	106	0.02
4.3	119.5	519	0.00	0.0	1.4	0.12	4.8	106	0.01
4.4	119.5	462	0.00	0.0	1.4	0.10	4.7	106	0.01
4.4	119.5	404	0.00	0.0	1.4	0.09	4.6	106	0.01
4.6	119.5	346	0.00	0.0	1.4	0.08	4.6	106	0.01
4.7	119.5	289	0.00	0.0	1.4	0.06	4.5	106	0.01

GEOMETRY SUMMARY * At End of Pumping Schedule
SANTOS - E. MEREENIE #41 (P4) MINIFRAC HISTORY MATCH

Dstnce (ft)	Press (psi)	W-Avg (in)	Q (_BPM)	Sh-Rate (1/sec)	Hght (ft) Total	Up	Dn	Prop	Bank Fraction	Prop (PSF)
3	1805	0.07	6.5	391	106	45	50	98	0.00	0.00
6	1794	0.07	6.3	405	102	44	48	94	0.00	0.00
9	1786	0.07	6.2	417	100	44	47	92	0.00	0.00
11	1778	0.07	6.1	429	98	43	46	89	0.00	0.00
14	1770	0.07	6.0	438	97	42	44	88	0.00	0.00
16	1762	0.07	5.9	452	95	41	43	85	0.00	0.00
19	1753	0.07	5.8	463	93	41	42	83	0.00	0.00
21	1745	0.07	5.7	478	91	40	41	81	0.00	0.00
24	1736	0.07	5.6	492	89	39	40	79	0.00	0.00
26	1727	0.07	5.5	502	88	39	39	77	0.00	0.00
29	1718	0.06	5.4	520	86	38	37	75	0.00	0.00
31	1708	0.06	5.3	536	84	38	36	73	0.00	0.00
34	1699	0.06	5.2	549	82	37	35	71	0.00	0.00
36	1691	0.06	5.1	564	81	36	34	70	0.00	0.00
38	1683	0.06	5.1	580	79	36	33	68	0.00	0.00
41	1673	0.06	4.9	597	78	35	32	66	0.00	0.00
43	1663	0.06	4.8	620	76	34	32	64	0.00	0.00
46	1653	0.06	4.7	641	74	34	31	62	0.00	0.00
48	1641	0.06	4.6	662	73	33	30	61	0.00	0.00
51	1631	0.06	4.5	689	71	32	29	59	0.00	0.00
53	1618	0.06	4.4	714	69	31	28	57	0.00	0.00
56	1605	0.05	4.3	740	68	30	28	55	0.00	0.00
58	1594	0.05	4.2	773	66	29	27	53	0.00	0.00
61	1580	0.05	4.1	803	64	28	26	52	0.00	0.00
63	1565	0.05	4.0	834	63	27	25	50	0.00	0.00
66	1552	0.05	3.8	874	61	26	24	48	0.00	0.00
68	1537	0.05	3.7	913	59	26	24	46	0.00	0.00
71	1520	0.05	3.6	947	58	25	23	45	0.00	0.00
73	1503	0.05	3.5	997	56	24	22	43	0.00	0.00
76	1486	0.05	3.4	1043	54	23	21	41	0.00	0.00
78	1468	0.04	3.3	1081	53	22	21	40	0.00	0.00
81	1450	0.04	3.1	1141	51	22	20	38	0.00	0.00
83	1433	0.04	3.0	1210	50	21	19	36	0.00	0.00
86	1414	0.04	2.9	1274	49	20	19	35	0.00	0.00
88	1391	0.04	2.7	1349	47	19	18	34	0.00	0.00
91	1369	0.04	2.6	1472	45	18	17	32	0.00	0.00
93	1353	0.04	2.4	1575	43	17	16	30	0.00	0.00
96	1323	0.03	2.3	1690	42	16	16	29	0.00	0.00
98	1297	0.03	2.1	1915	40	15	15	27	0.00	0.00
101	1274	0.03	1.9	2263	38	14	14	25	0.00	0.00
103	1293	0.03	1.6	2277	38	14	14	25	0.00	0.00
106	1154	0.02	1.2	3740	31	11	11	19	0.00	0.00
108	1156	0.02	1.0	3887	30	10	10	17	0.00	0.00
111	974	0.01	0.6	5618	21	5	6	11	0.00	0.00
113	725	0.01	0.4	7315	17	3	4	10	0.00	0.00
116	470	0.01	0.3	5989	13	1	2	10	0.00	0.00

FLUID SUMMARY * At End of Pumping Schedule
SANTOS - E. MEREENIE #41 (P4) MINIFRAC HISTORY MATCH

Stage No	Gone	Fluid ID	Prop ID	Pos (ft)	Concentration In	Now	Desgn	Fl Vol (MGal)	Ex Tim (min)	Temp (deg_F)	Visc (cp)	Fall Frac
1	0	1	1	118	0.0	0.0	0.0	0.0	0.0	145	28	0.00
1	1	1	1	118	0.0	0.0	0.0	0.0	0.1	145	31	0.00
1	1	1	1	118	0.0	0.0	0.0	0.0	0.1	145	33	0.00
1	1	1	1	118	0.0	0.0	0.0	0.0	0.1	145	36	0.00
1	1	1	1	118	0.0	0.0	0.0	0.0	0.1	145	36	0.00
1	1	1	1	118	0.0	0.0	0.0	0.0	0.2	145	37	0.00
1	1	1	1	118	0.0	0.0	0.0	0.1	0.2	145	38	0.00
1	1	1	1	118	0.0	0.0	0.0	0.1	0.2	145	25	0.00
1	1	1	1	118	0.0	0.0	0.0	0.1	0.2	145	32	0.00
1	1	1	1	118	0.0	0.0	0.0	0.1	0.2	145	33	0.00
1	1	1	1	118	0.0	0.0	0.0	0.1	0.3	145	35	0.00
1	1	1	1	118	0.0	0.0	0.0	0.1	0.2	145	35	0.00
1	1	1	1	118	0.0	0.0	0.0	0.2	0.3	145	36	0.00
2	1	1	1	118	0.0	0.0	0.0	0.2	0.3	145	36	0.00
2	1	1	1	118	0.0	0.0	0.0	0.2	0.3	145	38	0.00
2	1	1	1	118	0.0	0.0	0.0	0.2	0.3	145	38	0.00
2	1	1	1	118	0.0	0.0	0.0	0.2	0.4	145	38	0.00
2	1	1	1	118	0.0	0.0	0.0	0.3	0.4	145	38	0.00
2	1	1	1	118	0.0	0.0	0.0	0.3	0.4	145	39	0.00
2	1	1	1	118	0.0	0.0	0.0	0.3	0.5	145	40	0.00
2	1	1	1	118	0.0	0.0	0.0	0.3	0.5	145	40	0.00
2	1	1	1	118	0.0	0.0	0.0	0.3	0.6	145	41	0.00
2	1	1	1	118	0.0	0.0	0.0	0.4	0.6	145	41	0.00
2	1	1	1	118	0.0	0.0	0.0	0.4	0.6	145	42	0.00
2	1	1	1	118	0.0	0.0	0.0	0.4	0.7	145	42	0.00
3	1	1	1	118	0.0	0.0	0.0	0.4	0.8	145	42	0.00
3	1	1	1	118	0.0	0.0	0.0	0.5	0.8	145	43	0.00
3	1	1	1	118	0.0	0.0	0.0	0.5	0.9	145	42	0.00
3	1	1	1	118	0.0	0.0	0.0	0.6	0.9	145	42	0.00
3	1	1	1	118	0.0	0.0	0.0	0.6	1.0	145	41	0.00
4	1	2	1	118	0.0	0.0	0.0	0.6	1.0	145	29	0.00
4	1	2	1	118	0.0	0.0	0.0	0.7	1.0	145	29	0.00
4	0	2	1	108	0.0	0.0	0.1	0.7	0.9	145	44	0.00
4	0	2	1	99	0.0	0.0	0.1	0.8	0.8	145	59	0.00
4	0	2	1	89	0.0	0.0	0.2	0.8	0.6	145	69	0.00
5	0	2	1	80	0.0	0.0	0.2	0.8	0.6	145	78	0.00
5	0	2	1	71	0.0	0.0	0.3	0.9	0.5	145	85	0.00
5	0	2	1	62	0.0	0.0	0.3	0.9	0.4	145	93	0.00
5	0	2	1	54	0.0	0.0	0.3	1.0	0.3	145	100	0.00
5	0	2	1	46	0.0	0.0	0.3	1.0	0.2	145	107	0.00
5	0	2	1	39	0.0	0.0	0.3	1.1	0.1	145	113	0.00
5	0	2	1	32	0.0	0.0	0.3	1.1	0.0	133	120	0.00
5	0	2	1	26	0.0	0.0	0.4	1.2	0.0	86	127	0.00
5	0	2	1	20	0.0	0.0	0.4	1.2	0.0	82	133	0.00
5	0	2	1	14	0.0	0.0	0.4	1.3	0.0	79	138	0.00
5	0	2	1	9	0.0	0.0	0.4	1.3	0.0	76	143	0.00
5	0	2	1	3	0.0	0.0	0.4	1.4	0.0	72	148	0.00

Frac Summary * SANTOS - E. MEREENIE #41 (P4) FINAL TSO FRAC DESIGN
Filename: EM41P4FD.FRK ; Sep 10, 96

Design Data

FLUID LOSS LAYERS:	Top (ft)	Bottom (ft)	Thick (ft)	Loss Coef. (ft/sqrt(min))	Spurt (Gal/100 ft^2)
	4649.0	4702.0	53.0	0.00010	0.00
	4702.0	4726.0	24.0	0.00500	0.20
	4726.0	4745.0	19.0	0.00010	0.00
	4745.0	4759.0	14.0	0.00500	0.20
	4759.0	4801.0	42.0	0.00010	0.00
	4801.0	4831.0	30.0	0.00320	0.20
	4831.0	4900.0	69.0	0.00010	0.00

FORMATION:	Modulus (e6_psi)	8.00
	Perforated Height (ft)	10.0
	Permeability (md)	1.000
TEMPERATURE:	Bottom Hole (deg_F)	145
PRESSURE:	Reservoir Pressure (psi)	1830.0
	Closure Pressure (psi)	3450.0
DEPTH:	Well Depth (ft)	4810.0

FORMATION LAYER DATA - Multi-Layer Height Growth

-----Depth(ft)------ Top	Botm	Thick	-Stress (psi)-- Top	Botm	Gradient (psi/ft)	Modulus (e6_psi)	Toughness (psi/in)
4649.0	4702.0	53.0	4900.0	4900.0	0.000	8.50	3000.0
4702.0	4726.0	24.0	3400.0	3400.0	0.000	7.00	3000.0
4726.0	4745.0	19.0	4950.0	4950.0	0.000	8.50	3000.0
4745.0	4759.0	14.0	3425.0	3425.0	0.000	7.00	3000.0
4759.0	4801.0	42.0	5050.0	5050.0	0.000	8.50	3000.0
4801.0	4810.0	9.0	4600.0	4600.0	0.000	8.25	3000.0
4810.0	4820.0	10.0	3450.0	3450.0	0.000	8.00	3000.0
4820.0	4831.0	11.0	4650.0	4650.0	0.000	8.25	3000.0
4831.0			5100.0		0.000	8.50	3000.0

	Fluid Pressure Gradient (psi/ft)	0.450
	Perforations - Top (ft)	4810
	- Bot (ft)	4820
	Initial Fracture Top (ft)	4810
	Fracture Bottom (ft)	4820
3-D SIMULATOR PROGRAM CONTROL	Step Size (ft)	3.7
	Time Step (min)	3.9

Calculated Results
from 3-D Simulator
STIMPLAN (TM) , NSI , Tulsa,OK
Licensed To: ARCO Exploration & Production Technology

1/2 LENGTH:	'Hydraulic' length (ft)	204.8
	Propped length (ft)	203.0
PRESSURE:	Max Net Pressure (psi)	3419.3
	Surface Pres-End of Pad (psi)	5173.7
	Surface Pres-Start of Flush (psi)	7067.6
	Surface Pres-End of Job (psi)	6791.2
	Maximum Hydraulic Horsepower	2650
TIME:	Max Exposure to Form. Temp. (min)	6.3
	Time to Close (min)	10.0
RATE:	Fluid Loss Rate during pad (_BPM)	9.24
EFFICIENCY:	at end of pumping schedule	0.42
PROPPANT:	Average In Situ Conc. (#/sq ft)	0.6
	Average Conductivity (md-ft)	808
HEIGHT:	Max Fracture Height (ft)	156.0
WIDTH:	Avg width at end of pumping (in)	0.12

TABLE A-2

StimPlan 2.61 (TM). NSI Technologies, Tulsa, OK
Licensed To: ARCO Exploration & Production Technology

WELL ID:
SANTOS - E. MEREENIE #41 (P4) FINAL TSO FRAC DESIGN

DEPTH:	Well Depth (ft)	4810
PRESSURE:	Reservoir Pressure (psi)	1830
	Closure Pressure (psi)	3450
TEMPERATURE:	Bottom Hole Temperature (deg_F)	145

** Pumping Schedule **

Sl Vol (MGal)	Fl Vol (MGal)	Conc (_PPG_) Start	End	Rate (_BPM)	Fluid Prop Type	Prop Type	Cum Prop (MLbs)	Pump Time (min)
2.00	2.00	0.0	0.0	15.00	2	1	0.0	3.2
0.61	0.60	0.5	0.5	15.00	2	1	0.3	1.0
0.63	0.60	1.0	1.0	15.00	2	1	0.9	1.0
0.71	0.65	2.0	2.0	15.00	2	1	2.2	1.1
0.74	0.65	3.0	3.0	15.00	2	1	4.2	1.2
0.76	0.65	4.0	4.0	15.00	2	1	6.8	1.2
0.73	0.60	5.0	5.0	15.00	2	1	9.8	1.2
0.63	0.50	6.0	6.0	15.00	2	1	12.8	1.0
0.65	0.50	7.0	7.0	15.00	2	1	16.2	1.0

Total Slurry ...	7.5		Total Fluid ...	6.7
Total Proppant ...	16.2		Avg. Conc	2.4
Total Pump Time	11.8	min	Pad %	26.8

Proppant ID No. 1 — 20- 40 CARBO-LITE

Specific Gravity					2.72
'Damage Factor'					0.60
Proppant Stress (Mpsi)	0	2	4	8	16
KfW @ 2 #/sq ft (md-ft)	10500	9200	7600	3200	500

Fluid ID No. 2 — 30#_BORAGEL

Specific Gravity 1.04

	@Welbor	@FormTmp	@1Hr	@2Hr	@4Hr	@8Hr
vis (cp @ 170 1/sec)	550	500	400	250	10	2
non-Newtonian n'	0.38	0.40	0.41	0.42	0.90	0.95
K(lb·sec/ft^2)x1000	272.16	223.26	169.67	100.74	0.34	0.05

Q (_BPM)	dP/dL (psi/100ft)
15.0	43.5

Measured Depth (ft) ... 4800.0

Time History * NSI STIMPLAN 3-D Fracture Simulation
SANTOS - E. MEREENIE #41 (P4) FINAL TSO FRAC DESIGN

Time (min)	Pen (ft)	Pres (psi)	Rate (_BPM)	Prop (_PPG_)	Sl Vol (MGal)	Eff-ciency	Loss (_BPM)	Hght (ft)	W-Avg (in)
0.0	12.4	1280	15.00	0.0	0.0	0.47	8.1	22	0.01
0.0	16.1	1280	15.00	0.0	0.0	0.47	7.8	31	0.02
0.1	19.8	1233	15.00	0.0	0.0	0.43	9.4	33	0.02
0.1	23.5	1392	15.00	0.0	0.1	0.43	8.6	36	0.02
0.1	27.2	1489	15.00	0.0	0.1	0.42	8.9	43	0.02
0.1	30.9	1475	15.00	0.0	0.1	0.41	9.3	50	0.02
0.2	34.6	1473	15.00	0.0	0.1	0.40	9.6	54	0.02
0.2	38.3	1511	15.00	0.0	0.1	0.40	8.5	57	0.02
0.3	42.0	1535	15.00	0.0	0.2	0.40	8.9	61	0.02
0.3	45.7	1547	15.00	0.0	0.2	0.41	8.8	64	0.03
0.4	49.4	1563	15.00	0.0	0.2	0.41	8.7	67	0.03
0.4	53.1	1582	15.00	0.0	0.3	0.41	8.8	70	0.03
0.5	56.8	1592	15.00	0.0	0.3	0.41	8.8	72	0.03
0.6	60.5	1607	15.00	0.0	0.3	0.41	8.8	75	0.03
0.6	64.2	1622	15.00	0.0	0.4	0.41	8.8	77	0.03
0.7	67.9	1633	15.00	0.0	0.4	0.41	8.9	79	0.03
0.8	71.6	1642	15.00	0.0	0.5	0.41	8.9	82	0.04
0.9	75.3	1656	15.00	0.0	0.5	0.41	8.8	84	0.04
0.9	79.0	1667	15.00	0.0	0.6	0.41	8.9	86	0.04
1.0	82.7	1679	15.00	0.0	0.7	0.41	8.8	89	0.04
1.1	86.4	1683	15.00	0.0	0.7	0.41	8.9	91	0.04
1.2	90.1	1695	15.00	0.0	0.8	0.41	8.9	93	0.04
1.4	93.8	1706	15.00	0.0	0.9	0.41	8.9	95	0.04
1.5	97.5	1714	15.00	0.0	0.9	0.41	8.9	98	0.04
1.6	101.2	1722	15.00	0.0	1.0	0.41	8.9	100	0.04
1.7	104.9	1730	15.00	0.0	1.1	0.41	8.9	102	0.04
1.8	108.6	1739	15.00	0.0	1.1	0.41	8.9	104	0.04
2.0	112.3	1747	15.00	0.0	1.2	0.41	8.9	106	0.05
2.1	116.0	1754	15.00	0.0	1.3	0.41	8.9	109	0.05
2.2	119.7	1759	15.00	0.0	1.4	0.41	8.9	111	0.05
2.4	123.4	1767	15.00	0.0	1.5	0.41	8.9	113	0.05
2.5	127.1	1775	15.00	0.0	1.6	0.41	8.9	115	0.05
2.7	130.8	1782	15.00	0.0	1.7	0.41	9.0	116	0.05
2.8	134.5	1789	15.00	0.0	1.8	0.41	9.2	118	0.05
3.0	138.2	1795	15.00	0.0	1.9	0.41	9.0	120	0.05
3.2	141.9	1802	15.00	0.0	2.0	0.40	9.2	122	0.05
3.3	145.6	1807	15.00	0.5	2.1	0.40	9.4	124	0.05
3.5	149.3	1810	15.00	0.5	2.2	0.40	9.5	126	0.05
3.7	153.0	1817	15.00	0.5	2.3	0.40	9.6	127	0.05
3.9	156.7	1824	15.00	0.5	2.5	0.39	9.8	129	0.05
4.1	160.4	1829	15.00	0.5	2.6	0.39	9.9	131	0.05
4.3	164.1	1832	15.00	1.0	2.7	0.39	10.1	133	0.05
4.6	167.8	1839	15.00	1.0	2.9	0.38	10.2	135	0.05
4.8	171.5	1848	15.00	1.0	3.0	0.38	10.4	138	0.05
5.0	175.2	1856	15.00	1.0	3.2	0.38	10.5	140	0.05
5.3	178.9	1864	15.00	1.0	3.3	0.38	10.5	142	0.05
5.5	182.6	1871	15.00	2.0	3.5	0.37	10.6	144	0.06

Time History * NSI STIMPLAN 3-D Fracture Simulation
SANTOS - E. MEREENIE #41 (P4) FINAL TSO FRAC DESIGN

Time (min)	Pen (ft)	Pres (psi)	Rate (_BPM)	Prop (_PPG_)	Sl Vol (MGal)	Eff-ciency	Loss (_BPM)	Hght (ft)	W-Avg (in)
5.8	186.3	1878	15.00	2.0	3.7	0.37	10.6	146	0.06
6.1	190.0	1889	15.00	2.0	3.8	0.36	10.7	148	0.06
6.4	193.7	1900	15.00	2.0	4.0	0.36	10.7	151	0.06
6.7	197.4	1912	15.00	3.0	4.2	0.36	10.7	153	0.06
Bridge Stage 0 at 7 min, at 171.9 (ft), Avg Dia/W 0.03/0.03 in									
7.4	204.8	1949	15.00	3.0	4.4	0.35	10.7	156	0.06
Bridge Stage 0 at 7 min, at 174.0 (ft), Avg Dia/W 0.03/0.03 in									
Screen Out in Stage 2 at Time = 7.4 min at 195.6 (ft)									
8.3	204.8	2169	15.00	4.0	5.2	0.36	8.5	156	0.07
Bridge Stage 0 at 8 min, at 189.8 (ft), Avg Dia/W 0.03/0.03 in									
9.1	204.8	2437	15.00	4.0	5.8	0.38	7.4	156	0.08
Bridge Stage 0 at 9 min, at 187.0 (ft), Avg Dia/W 0.03/0.04 in									
10.1	204.8	2741	15.00	5.0	6.3	0.39	6.8	156	0.09
Bridge Stage 0 at 10 min, at 184.4 (ft), Avg Dia/W 0.03/0.05 in									
10.9	204.8	3070	15.00	6.0	6.9	0.41	6.3	156	0.11
Screen Out in Stage 2 at Time = 10.9 min at 191.9 (ft)									
11.9	204.8	3419	15.00	7.0	7.5	0.42	5.8	156	0.12
12.9	204.8	3146	0.00	0.0	7.5	0.39	5.6	156	0.11
14.1	204.8	2872	0.00	0.0	7.5	0.35	5.3	156	0.10
15.2	204.8	2599	0.00	0.0	7.5	0.32	5.0	156	0.09
16.5	204.8	2325	0.00	0.0	7.5	0.29	4.7	156	0.09
17.1	204.8	2188	0.00	0.0	7.5	0.27	4.6	156	0.08
17.8	204.8	2052	0.00	0.0	7.5	0.25	4.4	156	0.08
18.5	204.8	1915	0.00	0.0	7.5	0.24	4.3	156	0.07
19.1	204.8	1778	0.00	0.0	7.5	0.22	4.3	156	0.07
19.8	204.8	1641	0.00	0.0	7.5	0.21	4.2	156	0.06
20.5	204.8	1504	0.00	0.0	7.5	0.19	4.1	156	0.06
21.2	204.8	1368	0.00	0.0	7.5	0.18	4.0	156	0.06
21.9	204.8	1231	0.00	0.0	7.5	0.16	3.9	156	0.05

GEOMETRY SUMMARY * At End of Pumping Schedule
SANTOS - E. MEREENIE #41 (P4) FINAL TSO FRAC DESIGN

Dstnce (ft)	Press (psi)	W-Avg (in)	Q (_BPM)	Sh-Rate (1/sec)	Hght (ft) Total	Hght (ft) Up	Hght (ft) Dn	Prop	Bank Fraction	Prop (PSF)
4	3415	0.14	7.5	82	156	82	64	142	0.00	0.55
11	3408	0.14	6.9	79	151	77	62	138	0.00	0.55
14	3403	0.14	6.7	77	148	75	63	135	0.00	0.55
18	3398	0.14	6.5	75	145	73	63	133	0.00	0.56
22	3394	0.14	6.3	73	143	70	62	130	0.00	0.59
25	3389	0.15	6.1	71	140	68	62	128	0.00	0.54
29	3384	0.15	5.9	69	138	66	62	126	0.00	0.54
33	3380	0.15	5.7	68	135	64	61	124	0.00	0.54
36	3375	0.15	5.5	67	133	63	60	122	0.00	0.54
40	3371	0.15	5.3	66	131	61	60	120	0.00	0.57
44	3366	0.15	5.1	65	129	60	59	118	0.00	0.56
48	3362	0.14	4.9	64	127	59	58	116	0.00	0.50
51	3358	0.14	4.7	62	125	57	57	115	0.00	0.50
55	3354	0.14	4.6	61	123	56	57	113	0.00	0.50
59	3350	0.14	4.4	60	121	55	56	111	0.00	0.51
62	3346	0.14	4.2	59	119	54	55	110	0.00	0.54
66	3342	0.14	4.0	57	117	53	55	108	0.00	0.54
70	3338	0.14	3.9	56	116	51	54	106	0.00	0.52
73	3335	0.14	3.7	55	114	50	53	105	0.00	0.44
77	3331	0.14	3.6	54	112	49	53	103	0.00	0.44
81	3327	0.14	3.4	52	110	48	52	102	0.00	0.48
85	3324	0.14	3.3	51	108	46	51	100	0.00	0.49
88	3320	0.14	3.1	51	106	45	50	98	0.00	0.49
92	3317	0.14	3.0	50	103	45	49	95	0.00	0.49
96	3313	0.14	2.8	50	101	44	47	92	0.00	0.49
99	3310	0.14	2.7	49	99	43	46	90	0.00	0.47
103	3306	0.14	2.6	48	97	42	45	88	0.00	0.40
107	3303	0.14	2.4	48	94	41	43	85	0.00	0.40
110	3299	0.13	2.3	47	92	41	42	83	0.00	0.41
114	3296	0.13	2.2	46	90	40	40	80	0.00	0.42
118	3292	0.13	2.0	46	88	39	39	77	0.00	0.44
122	3289	0.13	1.9	46	85	38	37	74	0.00	0.45
125	3285	0.13	1.8	44	83	37	36	72	0.00	0.46
129	3282	0.13	1.7	44	81	36	34	69	0.00	0.34
133	3278	0.13	1.5	44	78	35	32	66	0.00	0.37
136	3275	0.12	1.4	44	74	33	31	62	0.00	0.37
140	3271	0.12	1.3	43	72	32	30	60	0.00	0.41
144	3267	0.12	1.2	43	68	30	28	56	0.00	0.41
147	3263	0.12	1.1	45	64	28	26	51	0.00	0.44
151	3259	0.11	1.0	49	58	25	23	45	0.00	0.46
155	3254	0.10	0.9	56	51	22	20	38	0.00	0.40
159	3250	0.10	0.8	55	49	21	19	36	0.00	0.27
162	3245	0.10	0.7	54	47	19	18	34	0.00	0.29
166	3240	0.10	0.7	53	45	18	17	32	0.00	0.31
170	3234	0.10	0.6	52	42	16	16	29	0.00	0.35
173	3227	0.09	0.5	53	39	15	14	26	0.00	0.40
177	3208	0.09	0.4	56	34	12	12	22	0.00	0.46
181	3176	0.08	0.3	65	29	9	10	17	0.00	0.64
184	3129	0.07	0.3	91	22	6	6	11	0.00	0.73
188	3066	0.07	0.2	78	22	6	6	11	0.00	0.63
192	3033	0.07	0.2	63	22	6	6	11	0.69	1.22
196	2619	0.08	0.1	53	22	6	6	11	1.00	1.52
199	506	0.01	0.1	4573	22	6	6	11	1.00	0.25

FLUID SUMMARY * At End of Pumping Schedule
SANTOS - E. MEREENIE #41 (P4) FINAL TSO FRAC DESIGN

Stage No	Gone	Fluid ID	Prop ID	Pos (ft)	Concentration In	Now	Desgn	Fl Vol (MGal)	Ex Tim (min)	Temp (deg_F)	Visc (cp)	Fall Frac
1	1	2	1	205	0.0	0.0	0.0	0.0	0.1	145	14	0.00
1	1	2	1	205	0.0	0.0	0.0	0.0	0.1	145	19	0.00
1	1	2	1	205	0.0	0.0	0.0	0.0	0.1	145	19	0.00
1	1	2	1	205	0.0	0.0	0.0	0.1	0.1	145	20	0.00
1	1	2	1	205	0.0	0.0	0.0	0.1	0.1	145	20	0.00
1	1	2	1	205	0.0	0.0	0.0	0.1	0.2	145	21	0.00
1	1	2	1	205	0.0	0.0	0.0	0.1	0.2	145	22	0.00
1	1	2	1	205	0.0	0.0	0.0	0.1	0.2	145	23	0.00
1	1	2	1	205	0.0	0.0	0.0	0.2	0.3	145	23	0.00
1	1	2	1	205	0.0	0.0	0.0	0.2	0.3	145	24	0.00
1	1	2	1	205	0.0	0.0	0.0	0.2	0.4	145	24	0.00
1	1	2	1	205	0.0	0.0	0.0	0.3	0.5	145	25	0.00
1	1	2	1	205	0.0	0.0	0.0	0.3	0.5	145	25	0.00
1	1	2	1	205	0.0	0.0	0.0	0.3	0.6	145	26	0.00
1	1	2	1	205	0.0	0.0	0.0	0.4	0.7	145	26	0.00
1	1	2	1	205	0.0	0.0	0.0	0.4	0.7	145	26	0.00
1	1	2	1	205	0.0	0.0	0.0	0.5	0.8	145	27	0.00
1	1	2	1	205	0.0	0.0	0.0	0.5	0.8	145	27	0.00
1	1	2	1	205	0.0	0.0	0.0	0.6	1.0	145	27	0.00
1	1	2	1	205	0.0	0.0	0.0	0.7	1.0	145	28	0.00
1	1	2	1	205	0.0	0.0	0.0	0.7	1.2	145	28	0.00
1	1	2	1	205	0.0	0.0	0.0	0.8	1.2	145	28	0.00
1	1	2	1	205	0.0	0.0	0.0	0.9	1.3	145	29	0.00
1	1	2	1	205	0.0	0.0	0.0	0.9	1.4	145	30	0.00
1	1	2	1	205	0.0	0.0	0.0	1.0	1.4	145	30	0.00
1	1	2	1	205	0.0	0.0	0.0	1.1	1.7	145	30	0.00
1	1	2	1	205	0.0	0.0	0.0	1.1	1.7	145	30	0.00
1	1	2	1	205	0.0	0.0	0.0	1.2	1.8	145	31	0.00
1	1	2	1	205	0.0	0.0	0.0	1.3	2.1	145	31	0.00
1	1	2	1	205	0.0	0.0	0.0	1.4	2.2	145	31	0.00
1	1	2	1	205	0.0	0.0	0.0	1.5	2.3	145	32	0.00
1	1	2	1	205	0.0	0.0	0.0	1.6	2.6	145	32	0.00
1	1	2	1	205	0.0	0.0	0.0	1.7	2.7	145	33	0.00
1	1	2	1	205	0.0	0.0	0.0	1.8	2.6	145	33	0.00
1	1	2	1	205	0.0	0.0	0.0	1.9	2.7	145	34	0.00
1	1	2	1	205	0.0	0.0	0.0	2.0	2.8	145	36	0.00
2	1	2	1	205	0.5	45.3	0.0	2.1	2.9	145	33	0.00
2	1	2	1	197	0.5	45.3	0.0	2.2	4.3	145	213	0.00
2	1	2	1	197	0.5	45.3	0.0	2.3	4.9	145	275	0.00
2	1	2	1	196	0.5	45.3	0.0	2.5	5.6	145	353	0.00
2	0	2	1	190	0.5	13.4	0.3	2.6	6.3	145	386	0.00
3	0	2	1	183	1.0	12.5	0.6	2.7	6.0	145	372	0.00
3	0	2	1	176	1.0	6.9	1.0	2.9	5.7	145	449	0.00
3	0	2	1	170	1.0	4.9	1.4	3.0	5.5	145	467	0.00
3	0	2	1	163	1.0	3.9	1.6	3.1	5.2	145	463	0.00
3	0	2	1	157	1.0	3.3	1.9	3.2	4.9	145	456	0.00
4	0	2	1	153	2.0	7.2	2.0	3.3	4.9	145	468	0.00
4	0	2	1	148	2.0	6.3	2.2	3.4	4.6	145	509	0.00
4	0	2	1	141	2.0	5.6	2.4	3.6	4.2	145	530	0.00
4	0	2	1	135	2.0	4.9	2.7	3.7	3.6	145	526	0.00
4	0	2	1	129	2.0	4.4	3.0	3.8	3.6	145	526	0.00
5	0	2	1	126	3.0	6.8	3.1	3.9	3.6	145	522	0.00
5	0	2	1	121	3.0	6.2	3.3	4.1	3.6	145	514	0.00
5	0	2	1	113	3.0	5.6	3.7	4.2	2.7	145	508	0.00
5	0	2	1	105	3.0	5.2	3.9	4.4	2.7	145	498	0.00
6	0	2	1	90	4.0	6.6	4.2	4.9	0.9	145	487	0.00
6	0	2	1	75	4.0	5.8	4.8	5.1	0.9	145	466	0.00
7	0	2	1	65	5.0	7.4	4.8	5.4	0.0	145	451	0.00
7	0	2	1	52	5.0	6.6	5.3	5.7	0.0	127	439	0.00
8	0	2	1	42	6.0	8.0	5.3	5.8	0.0	86	442	0.00
8	0	2	1	[illegible]	[illegible]	[illegible]	[illegible]	6.2	0.0	82	428	0.00
9	0	2	1	21	7.0	8.3	5.9	6.3	0.0	78	415	0.00
9	0	2	1	10	7.0	7.6	6.5	6.7	0.0	74	395	0.00

PROPPANT SUMMARY * At End of Pumping Schedule
SANTOS - E. MEREENIE #41 (P4) FINAL TSO FRAC DESIGN

Lb/Sq-Ft Lost to Embedment 0.200

Distance (ft)	KfW (md-ft)	Prop Concentration(Total lb/sq foot) Prop ID--> 1
4.4	713	0.55
10.6	717	0.55
14.3	725	0.55
18.0	747	0.56
21.7	754	0.57
25.4	720	0.55
29.1	697	0.54
32.8	698	0.54
36.5	709	0.55
40.2	736	0.56
43.9	717	0.55
47.6	652	0.52
51.3	617	0.50
55.0	618	0.50
58.7	644	0.51
62.4	686	0.53
66.1	692	0.54
69.8	630	0.51
73.5	541	0.46
77.2	521	0.45
80.9	564	0.47
84.6	594	0.49
88.3	599	0.49
92.0	596	0.49
95.7	583	0.48
99.4	526	0.46
103.1	447	0.42
106.8	419	0.40
110.5	435	0.41
114.2	458	0.42
117.9	490	0.44
121.6	520	0.45
125.3	475	0.43
129.0	367	0.38
132.7	332	0.36
136.4	368	0.38
140.1	409	0.40
143.8	447	0.42
147.5	486	0.44
151.2	490	0.44
154.9	376	0.38
158.6	223	0.31
162.3	187	0.29
166.0	238	0.32
169.7	311	0.35
173.4	413	0.40
177.1	590	0.49
180.8	853	0.61
184.5	993	0.68
188.2	1241	0.80
191.9	1947	1.15
195.6	1910	1.13
199.3	778	0.58
203.0	150	0.27

Average Conductivity (md-ft) 620

PROPPANT SUMMARY * At Fracture Closure
SANTOS - E. MEREENIE #41 (P4) FINAL TSO FRAC DESIGN

Lb/Sq-Ft Lost to Embedment 0.200

Distance (ft)	KfW (md-ft)	Prop Concentration(Total lb/sq foot) Prop ID--> 1
4.4	651	0.51
10.6	655	0.51
14.3	663	0.52
18.0	701	0.53
21.7	750	0.56
25.4	740	0.55
29.1	705	0.54
32.8	693	0.53
36.5	690	0.53
40.2	696	0.53
43.9	673	0.52
47.6	585	0.48
51.3	506	0.44
55.0	482	0.43
58.7	477	0.43
62.4	473	0.43
66.1	469	0.42
69.8	465	0.42
73.5	463	0.42
77.2	426	0.40
80.9	352	0.37
84.6	312	0.35
88.3	335	0.36
92.0	399	0.39
95.7	449	0.41
99.4	461	0.42
103.1	460	0.42
106.8	459	0.42
110.5	458	0.42
114.2	450	0.42
117.9	428	0.40
121.6	408	0.39
125.3	418	0.40
129.0	466	0.42
132.7	534	0.46
136.4	642	0.51
140.1	753	0.56
143.8	760	0.56
147.5	706	0.54
151.2	730	0.55
154.9	899	0.63
158.6	1108	0.73
162.3	1320	0.83
166.0	1495	0.91
169.7	1412	0.87
173.4	1352	0.85
177.1	1657	0.99
180.8	2049	1.18
184.5	2362	1.33
188.2	2571	1.43
191.9	2666	1.47
195.6	2072	1.19
199.3	792	0.58
203.0	152	0.27

Average Conductivity (md-ft) 808

Frac Summary * SANTOS - E. MEREENIE #41 (P4) POST-FRAC EVAL. #4
Filename: EM41P4PF.FRK ; Oct 16, 96

Design Data

FLUID LOSS LAYERS:	Top (ft)	Bottom (ft)	Thick (ft)	Loss Coef. (ft/sqrt(min))	Spurt (Gal/100 ft^2)
	4649.0	4702.0	53.0	0.00010	0.00
	4702.0	4726.0	24.0	0.00600	0.50
	4726.0	4745.0	19.0	0.00010	0.00
	4745.0	4759.0	14.0	0.00600	0.50
	4759.0	4801.0	42.0	0.00025	0.00
	4801.0	4831.0	30.0	0.00420	0.50
	4831.0	4900.0	69.0	0.00010	0.00

FORMATION:	Modulus (e6_psi)	8.00
	Perforated Height (ft)	10.0
	Permeability (md)	1.000
TEMPERATURE:	Bottom Hole (deg_F)	145
PRESSURE:	Reservoir Pressure (psi)	1830.0
	Closure Pressure (psi)	3450.0
DEPTH:	Well Depth (ft)	4810.0

FORMATION LAYER DATA - Multi-Layer Height Growth

-----Depth(ft)------ Top	Botm	Thick	-Stress (psi)-- Top	Botm	Gradient (psi/ft)	Modulus (e6_psi)	Toughness (psi«in)
4649.0	4702.0	53.0	4900.0	4900.0	0.000	8.50	3000.0
4702.0	4726.0	24.0	3860.0	3860.0	0.000	6.50	3000.0
4726.0	4745.0	19.0	4800.0	4800.0	0.000	8.50	3000.0
4745.0	4759.0	14.0	3870.0	3870.0	0.000	6.50	3000.0
4759.0	4770.0	11.0	5050.0	5050.0	0.000	8.50	3000.0
4770.0	4801.0	31.0	5050.0	5050.0	0.000	8.50	3000.0
4801.0	4810.0	9.0	4650.0	4650.0	0.000	8.25	3000.0
4810.0	4820.0	10.0	3450.0	3450.0	0.000	8.00	3000.0
4820.0	4831.0	11.0	4650.0	4650.0	0.000	8.25	3000.0
4831.0			5100.0		0.000	9.00	3000.0

	Fluid Pressure Gradient (psi/ft)	0.450
	Perforations - Top (ft)	4810
	- Bot (ft)	4820
	Initial Fracture Top (ft)	4810
	Fracture Bottom (ft)	4820
3-D SIMULATOR	Step Size (ft)	2.1
PROGRAM CONTROL	Time Step (min)	1.0

Calculated Results
from 3-D Simulator
STIMPLAN (TM) , NSI , Tulsa,OK
Licensed To: Internal Use - NSI Technologies

1/2 LENGTH:	'Hydraulic' length (ft)	149.8
	Propped length (ft)	82.6
PRESSURE:	Max Net Pressure (psi)	2959.2
	Surface Pres-End of Pad (psi)	5520.5
	Surface Pres-Start of Flush (psi) .	6172.4
	Surface Pres-End of Job (psi)	6093.7
	Maximum Hydraulic Horsepower	2160
TIME:	Max Exposure to Form. Temp. (min)	4.5
	Time to Close (min)	7.7
RATE:	Fluid Loss Rate during pad (_BPM) ..	11.42
EFFICIENCY:	at end of pumping schedule	0.32
PROPPANT:	Average In Situ Conc. (#/sq ft)	0.4
	Average Conductivity (md-ft)	487
HEIGHT:	Max Fracture Height (ft)	184.3
WIDTH:	Avg width at end of pumping (in) ...	0.09

TABLE A-3

StimPlan 2.60 (TM). NSI Technologies, Tulsa, OK
Licensed To: Internal Use - NSI Technologies

WELL ID:
SANTOS - E. MEREENIE #41 (P4) POST-FRAC EVAL. #4

DEPTH:	Well Depth (ft)	4810
PRESSURE:	Reservoir Pressure (psi)	1830
	Closure Pressure (psi)	3450
TEMPERATURE:	Bottom Hole Temperature (deg_F)	145

** Pumping Schedule **

Sl Vol (MGal)	Fl Vol (MGal)	Conc (_PPG_) Start	End	Rate (_BPM)	Fluid Type	Prop Type	Cum Prop (MLbs)	Pump Time (min)
1.20	1.20	0.0	0.0	15.59	1	1	0.0	1.8
1.18	1.18	0.0	0.0	15.59	2	1	0.0	1.8
0.10	0.10	0.2	0.2	15.61	2	1	0.0	0.2
0.35	0.34	0.3	0.3	15.17	2	1	0.1	0.5
0.86	0.83	0.9	0.9	15.17	2	1	0.9	1.3
0.89	0.82	2.0	2.0	15.14	2	1	2.5	1.4
0.84	0.74	3.1	3.1	15.03	2	1	4.8	1.3
0.49	0.42	4.0	4.0	14.93	2	1	6.5	0.8
0.19	0.16	4.0	4.0	14.60	2	1	7.1	0.3
0.27	0.22	4.9	4.9	14.60	2	1	8.2	0.4
0.12	0.10	4.9	4.9	14.00	2	1	8.7	0.2

Total Slurry ...	6.5	Total Fluid ...	6.1
Total Proppant ...	8.7	Avg. Conc	1.4
Total Pump Time	10.2 min	Pad %	36.7

Proppant ID No. 1 — 20- 40 CARBO-LITE

Specific Gravity					2.72
'Damage Factor'					0.70
Proppant Stress (Mpsi)	0	2	4	8	16
KfW @ 2 #/sq ft (md-ft)	10500	9200	7600	3200	500

Fluid ID No. 1 — 30#_BORAGEL

Specific Gravity 1.04

	@Welbor	@FormTmp	@1Hr	@2Hr	@4Hr	@8Hr
vis (cp @ 170 1/sec) .	1300	1300	1200	300	10	2
non-Newtonian n'	0.38	0.40	0.41	0.42	0.90	0.95
K(lb*sec/ft^2)x1000	643.28	580.49	509.01	120.88	0.34	0.05

Q (_BPM)	dP/dL (psi/100ft)
15.0	43.5

Measured Depth (ft) ... 4800.0

Fluid ID No. 2 — 30#_BORAGEL

Specific Gravity 1.04

	@Welbor	@FormTmp	@1Hr	@2Hr	@4Hr	@8Hr
vis (cp @ 170 1/sec) .	950	900	850	350	10	2
non-Newtonian n'	0.38	0.40	0.41	0.42	0.90	0.95
K(lb*sec/ft^2)x1000	470.09	401.88	360.55	141.03	0.34	0.05

Time History * NSI STIMPLAN 3-D Fracture Simulation
SANTOS - E. MEREENIE #41 (P4) POST-FRAC EVAL. #4

Time (min)	Pen (ft)	Pres (psi)	Rate (_BPM)	Prop (_PPG_)	Sl Vol (MGal)	Eff-ciency	Loss (_BPM)	Hght (ft)	W-Avg (in)
0.0	13.3	1621	15.59	0.0	0.0	0.38	9.5	28	0.02
0.1	15.4	1561	15.59	0.0	0.0	0.39	9.3	34	0.02
0.1	17.5	1510	15.59	0.0	0.1	0.37	10.5	39	0.02
0.1	19.6	1585	15.59	0.0	0.1	0.37	9.7	43	0.02
0.1	21.7	1663	15.59	0.0	0.1	0.37	10.1	43	0.02
0.1	23.8	1810	15.59	0.0	0.1	0.36	11.0	47	0.02
0.2	25.9	1787	15.59	0.0	0.1	0.35	11.1	54	0.02
0.2	28.0	1731	15.59	0.0	0.1	0.35	10.3	60	0.02
0.2	30.1	1755	15.59	0.0	0.2	0.36	9.5	64	0.02
0.3	32.2	1815	15.59	0.0	0.2	0.36	9.6	68	0.02
0.3	34.3	1818	15.59	0.0	0.2	0.36	9.6	71	0.03
0.4	36.4	1827	15.59	0.0	0.2	0.37	9.5	74	0.03
0.4	38.5	1843	15.59	0.0	0.3	0.37	9.5	77	0.03
0.4	40.6	1858	15.59	0.0	0.3	0.37	9.5	80	0.03
0.5	42.7	1871	15.59	0.0	0.3	0.37	9.5	83	0.03
0.6	44.8	1888	15.59	0.0	0.4	0.38	9.4	86	0.03
0.6	46.9	1891	15.59	0.0	0.4	0.38	9.4	88	0.03
0.7	49.0	1904	15.59	0.0	0.4	0.38	9.4	91	0.03
0.7	51.1	1919	15.59	0.0	0.5	0.38	9.4	94	0.03
0.8	53.2	1922	15.59	0.0	0.5	0.38	9.4	96	0.04
0.8	55.3	1932	15.59	0.0	0.6	0.38	9.4	98	0.04
0.9	57.4	1942	15.59	0.0	0.6	0.38	9.4	101	0.04
1.0	59.5	1954	15.59	0.0	0.6	0.38	9.4	103	0.04
1.0	61.6	1961	15.59	0.0	0.7	0.38	9.4	106	0.04
1.1	63.7	1969	15.59	0.0	0.7	0.39	9.4	108	0.04
1.2	65.8	1979	15.59	0.0	0.8	0.39	9.4	110	0.04
1.3	67.9	1986	15.59	0.0	0.8	0.39	9.4	113	0.04
1.4	70.0	1992	15.59	0.0	0.9	0.39	9.4	115	0.04
1.4	72.1	2000	15.59	0.0	0.9	0.39	10.0	117	0.04
1.5	74.2	2007	15.59	0.0	1.0	0.38	10.0	119	0.04
1.6	76.3	2014	15.59	0.0	1.1	0.38	10.1	121	0.05
1.7	78.4	2020	15.59	0.0	1.1	0.38	10.1	123	0.05
1.8	80.5	2026	15.59	0.0	1.2	0.38	10.2	125	0.05
1.9	82.6	2036	15.59	0.0	1.3	0.38	10.2	128	0.05
2.0	84.7	2042	15.59	0.0	1.3	0.38	10.4	130	0.05
2.2	86.8	2041	15.59	0.0	1.4	0.37	10.7	133	0.05
2.3	88.9	2040	15.59	0.0	1.5	0.37	10.9	136	0.05
2.4	91.0	2035	15.59	0.0	1.6	0.37	11.1	138	0.05
2.5	93.1	2030	15.59	0.0	1.7	0.36	11.1	140	0.05
2.7	95.2	2030	15.59	0.0	1.8	0.36	10.9	143	0.05
2.8	97.3	2026	15.59	0.0	1.9	0.35	11.1	145	0.05
3.0	99.4	2022	15.59	0.0	1.9	0.35	11.2	147	0.05
3.1	101.5	2018	15.59	0.0	2.0	0.35	11.2	149	0.05
3.3	103.6	2014	15.59	0.0	2.1	0.34	11.3	151	0.05
3.4	105.7	2010	15.59	0.0	2.2	0.34	11.3	152	0.05
3.6	107.8	2005	15.59	0.0	2.3	0.34	11.3	154	0.05
3.7	109.9	2003	15.59	0.0	2.4	0.33	11.4	156	0.05

Time History * NSI STIMPLAN 3-D Fracture Simulation
SANTOS - E. MEREENIE #41 (P4) POST-FRAC EVAL. #4

Time (min)	Pen (ft)	Pres (psi)	Rate (_BPM)	Prop (_PPG_)	Sl Vol (MGal)	Eff-ciency	Loss (_BPM)	Hght (ft)	W-Avg (in)
3.8	112.0	1998	15.61	0.2	2.5	0.33	11.5	157	0.05
4.0	114.1	1982	15.17	0.3	2.6	0.33	11.9	159	0.05
4.1	116.2	1972	15.17	0.3	2.7	0.32	12.1	159	0.05
4.2	118.3	1963	15.17	0.3	2.7	0.32	12.3	161	0.05
4.3	120.4	1960	15.17	0.3	2.8	0.32	12.2	162	0.05
4.4	122.5	1960	15.17	0.3	2.9	0.31	12.1	163	0.05
4.6	124.6	1964	15.17	0.9	3.0	0.31	11.9	164	0.05
4.8	126.7	1970	15.17	0.9	3.1	0.31	11.8	166	0.05
5.0	128.8	1976	15.17	0.9	3.2	0.30	11.8	167	0.05
5.2	130.9	1983	15.17	0.9	3.3	0.30	11.8	169	0.05
5.4	133.0	1991	15.17	0.9	3.5	0.30	11.8	171	0.05
5.6	135.1	1993	15.17	0.9	3.6	0.29	11.8	173	0.05
5.8	137.2	1999	15.17	0.9	3.8	0.29	11.8	174	0.05
6.0	139.3	2007	15.14	2.0	3.9	0.29	11.8	176	0.05
6.3	141.4	2016	15.14	2.0	4.1	0.29	11.8	178	0.05
6.5	143.5	2026	15.14	2.0	4.2	0.28	11.8	180	0.05
6.8	145.6	2031	15.14	2.0	4.4	0.28	11.9	182	0.05
Bridge Stage 0 at 7 min, at 123.3 (ft), Avg Dia/W 0.03/0.03 in									
7.1	147.7	2042	15.14	2.0	4.6	0.28	11.9	184	0.05
Bridge Stage 0 at 7 min, at 140.4 (ft), Avg Dia/W 0.03/0.01 in									
7.9	149.8	2182	15.03	3.1	5.1	0.28	10.6	184	0.06
Bridge Stage 0 at 8 min, at 142.2 (ft), Avg Dia/W 0.03/0.02 in									
Screen Out in Stage 4 at Time = 7.9 min at 147 (ft)									
8.4	149.8	2318	15.03	3.1	5.4	0.29	9.0	184	0.07
Bridge Stage 0 at 8 min, at 140.6 (ft), Avg Dia/W 0.03/0.03 in									
8.8	149.8	2462	15.03	3.1	5.7	0.29	8.5	184	0.07
9.3	149.8	2626	14.93	4.0	5.9	0.30	8.1	184	0.08
Screen Out in Stage 4 at Time = 9.3 min at 145 (ft)									
9.7	149.8	2786	14.60	4.0	6.2	0.31	7.7	184	0.09
Screen Out in Stage 5 at Time = 9.7 min at 143 (ft)									
10.2	149.8	2959	14.60	4.9	6.5	0.32	7.3	184	0.09
Screen Out in Stage 5 at Time = 10.2 min at 140 (ft)									
10.7	149.8	2722	0.00	0.0	6.5	0.29	7.3	184	0.09
11.3	149.8	2486	0.00	0.0	6.5	0.27	6.8	184	0.08
12.0	149.8	2249	0.00	0.0	6.5	0.25	6.6	184	0.08
12.6	149.8	2012	0.00	0.0	6.5	0.22	6.3	184	0.07
13.1	149.8	1894	0.00	0.0	6.5	0.21	6.1	184	0.07
13.5	149.8	1776	0.00	0.0	6.5	0.20	6.0	184	0.06
13.9	149.8	1657	0.00	0.0	6.5	0.19	5.9	184	0.06
14.4	149.8	1539	0.00	0.0	6.5	0.17	5.7	184	0.06
14.9	149.8	1420	0.00	0.0	6.5	0.16	5.6	184	0.05
15.4	149.8	1302	0.00	0.0	6.5	0.15	5.5	184	0.05
16.0	149.8	1184	0.00	0.0	6.5	0.14	5.4	184	0.05
16.6	149.8	1065	0.00	0.0	6.5	0.13	5.3	184	0.05
17.1	149.8	947	0.00	0.0	6.5	0.12	5.1	184	0.05
17.8	149.8	829	0.00	0.0	6.5	0.11	5.0	184	0.04

GEOMETRY SUMMARY * At End of Pumping Schedule
SANTOS - E. MEREENIE #41 (P4) POST-FRAC EVAL. #4

Dstnce (ft)	Press (psi)	W-Avg (in)	Q (_BPM)	Sh-Rate (1/sec)	Hght (ft) Total	Up	Dn	Prop	Bank Fraction	Prop (PSF)
6	2952	0.12	7.3	96	184	99	75	156	0.00	0.38
12	2939	0.11	6.3	96	175	93	71	151	0.00	0.37
14	2934	0.11	6.2	99	171	92	70	149	0.00	0.32
16	2929	0.11	6.0	100	169	90	69	147	0.00	0.30
19	2924	0.11	5.8	102	166	89	68	146	0.00	0.30
21	2919	0.11	5.7	104	163	87	67	144	0.00	0.31
23	2913	0.11	5.6	107	161	85	65	143	0.00	0.30
25	2907	0.10	5.4	109	158	84	64	141	0.00	0.30
27	2901	0.10	5.3	108	156	81	64	139	0.00	0.30
29	2896	0.10	5.2	106	153	79	64	137	0.00	0.30
31	2890	0.10	5.0	105	151	77	64	134	0.00	0.32
33	2884	0.10	4.9	104	148	75	63	132	0.00	0.32
35	2878	0.10	4.8	103	146	73	63	130	0.00	0.32
37	2873	0.11	4.7	101	144	71	63	128	0.00	0.33
40	2867	0.11	4.5	99	142	69	63	126	0.00	0.33
42	2862	0.11	4.4	98	140	67	63	125	0.00	0.27
44	2856	0.11	4.3	96	138	66	62	123	0.00	0.29
46	2851	0.11	4.1	93	136	64	62	121	0.00	0.29
48	2845	0.11	4.0	91	134	63	61	120	0.00	0.29
50	2840	0.11	3.9	90	133	62	60	119	0.00	0.29
52	2835	0.11	3.8	88	131	61	59	117	0.00	0.29
54	2830	0.11	3.6	86	129	60	59	116	0.00	0.35
56	2824	0.11	3.5	84	127	59	58	115	0.00	0.35
58	2819	0.11	3.4	82	125	58	57	114	0.00	0.34
61	2814	0.11	3.3	80	124	57	56	112	0.00	0.34
63	2810	0.11	3.2	78	122	56	55	111	0.00	0.34
65	2805	0.11	3.1	76	120	55	55	110	0.00	0.34
67	2800	0.11	3.0	74	118	54	54	108	0.00	0.34
69	2796	0.11	2.8	73	117	53	53	107	0.00	0.34
71	2792	0.11	2.8	71	115	52	52	106	0.00	0.33
73	2787	0.11	2.7	69	113	51	52	104	0.00	0.24
75	2783	0.11	2.6	68	111	50	51	102	0.00	0.24
77	2779	0.11	2.5	68	109	49	50	100	0.00	0.24
79	2774	0.11	2.4	68	107	48	49	98	0.00	0.26
82	2770	0.11	2.3	68	105	47	48	96	0.00	0.26
84	2765	0.10	2.2	68	103	45	47	93	0.00	0.26
86	2761	0.10	2.1	68	101	44	46	91	0.00	0.28
88	2756	0.10	2.0	67	99	43	46	89	0.00	0.28
90	2751	0.10	1.9	67	97	42	45	87	0.00	0.28
92	2747	0.10	1.8	67	95	41	44	84	0.00	0.29
94	2742	0.10	1.8	68	93	40	43	81	0.00	0.29
96	2737	0.10	1.7	67	91	39	42	79	0.00	0.29
98	2732	0.10	1.6	67	89	38	41	77	0.00	0.31
100	2727	0.09	1.5	67	87	36	40	74	0.00	0.31
103	2723	0.09	1.4	67	84	35	39	71	0.00	0.32
105	2718	0.09	1.3	67	82	34	38	69	0.00	0.33
107	2713	0.09	1.3	67	79	33	36	66	0.00	0.16
109	2709	0.09	1.2	66	77	32	35	64	0.00	0.17
111	2704	0.09	1.1	67	74	31	33	61	0.00	0.17
113	2698	0.09	1.0	67	71	30	31	58	0.00	0.17
115	2693	0.08	1.0	70	66	28	29	53	0.00	0.20
117	2687	0.08	0.9	76	61	25	26	48	0.00	0.20
119	2680	0.08	0.8	88	54	22	21	40	0.00	0.21
121	2673	0.08	0.8	94	50	21	19	36	0.00	0.24
124	2665	0.07	0.7	94	47	19	18	34	0.00	0.24
126	2657	0.07	0.6	96	45	18	17	32	0.00	0.25
128	2647	0.07	0.6	100	42	16	15	29	0.00	0.31
130	2625	0.07	0.5	110	38	14	13	25	0.00	0.32
132	2567	0.06	0.5	175	28	9	9	16	0.00	0.35
134	2483	0.05	0.4	168	28	9	9	16	0.00	0.51
136	2382	0.05	0.4	161	28	9	9	16	0.00	0.51
138	2277	0.05	0.3	152	28	9	9	16	0.00	0.50
140	2168	0.05	0.3	141	28	9	9	16	1.00	0.89
142	2114	0.05	0.2	119	28	9	9	16	1.00	1.03
145	1818	0.05	0.2	102	28	9	9	16	1.00	0.89
147	1541	0.05	0.1	97	28	9	9	16	1.00	0.82
149	237	0.02	0.1	1219	28	9	9	16	1.00	0.36

FLUID SUMMARY * At End of Pumping Schedule
SANTOS - E. MEREENIE #41 (P4) POST-FRAC EVAL. #4

Stage No	Gone	Fluid ID	Prop ID	Pos (ft)	Concentration In	Now	Desgn	Fl Vol (MGal)	Ex Tim (min)	Temp (deg_F)	Visc (cp)	Fall Frac
1	1	1	1	150	0.0	0.0	0.0	0.0	0.1	145	47	0.00
1	1	1	1	150	0.0	0.0	0.0	0.0	0.1	145	60	0.00
1	1	1	1	150	0.0	0.0	0.0	0.1	0.1	145	57	0.00
1	1	1	1	150	0.0	0.0	0.0	0.1	0.1	145	57	0.00
1	1	1	1	150	0.0	0.0	0.0	0.1	0.2	145	58	0.00
1	1	1	1	150	0.0	0.0	0.0	0.1	0.1	145	59	0.00
1	1	1	1	150	0.0	0.0	0.0	0.1	0.1	145	60	0.00
1	1	1	1	150	0.0	0.0	0.0	0.1	0.2	145	62	0.00
1	1	1	1	150	0.0	0.0	0.0	0.2	0.2	145	63	0.00
1	1	1	1	150	0.0	0.0	0.0	0.2	0.2	145	64	0.00
1	1	1	1	150	0.0	0.0	0.0	0.2	0.2	145	66	0.00
1	1	1	1	150	0.0	0.0	0.0	0.2	0.3	145	66	0.00
1	1	1	1	150	0.0	0.0	0.0	0.3	0.3	145	67	0.00
1	1	1	1	150	0.0	0.0	0.0	0.3	0.4	145	68	0.00
1	1	1	1	150	0.0	0.0	0.0	0.3	0.4	145	69	0.00
1	1	1	1	150	0.0	0.0	0.0	0.4	0.5	145	69	0.00
1	1	1	1	150	0.0	0.0	0.0	0.4	0.5	145	71	0.00
1	1	1	1	150	0.0	0.0	0.0	0.4	0.5	145	71	0.00
1	1	1	1	150	0.0	0.0	0.0	0.5	0.6	145	73	0.00
1	1	1	1	150	0.0	0.0	0.0	0.5	0.6	145	74	0.00
1	1	1	1	150	0.0	0.0	0.0	0.6	0.8	145	75	0.00
1	1	1	1	150	0.0	0.0	0.0	0.6	0.8	145	77	0.00
1	1	1	1	150	0.0	0.0	0.0	0.6	0.8	145	77	0.00
1	1	1	1	150	0.0	0.0	0.0	0.7	0.9	145	79	0.00
1	1	1	1	150	0.0	0.0	0.0	0.7	0.9	145	80	0.00
1	1	1	1	150	0.0	0.0	0.0	0.8	1.0	145	80	0.00
1	1	1	1	150	0.0	0.0	0.0	0.8	1.2	145	81	0.00
1	1	1	1	150	0.0	0.0	0.0	0.9	1.2	145	82	0.00
1	1	1	1	150	0.0	0.0	0.0	0.9	1.3	145	82	0.00
1	1	1	1	150	0.0	0.0	0.0	1.0	1.3	145	82	0.00
1	1	1	1	150	0.0	0.0	0.0	1.1	1.5	145	82	0.00
1	1	1	1	150	0.0	0.0	0.0	1.1	1.5	145	81	0.00
1	1	1	1	150	0.0	0.0	0.0	1.2	1.6	145	76	0.00
2	1	2	1	150	0.0	0.0	0.0	1.3	1.7	145	49	0.00
2	1	2	1	150	0.0	0.0	0.0	1.3	1.8	145	52	0.00
2	1	2	1	150	0.0	0.0	0.0	1.4	1.8	145	53	0.00
2	1	2	1	150	0.0	0.0	0.0	1.5	1.8	145	55	0.00
2	1	2	1	150	0.0	0.0	0.0	1.6	2.0	145	57	0.00
2	1	2	1	150	0.0	0.0	0.0	1.7	2.0	145	57	0.00
2	1	2	1	150	0.0	0.0	0.0	1.8	2.1	145	57	0.00
2	1	2	1	150	0.0	0.0	0.0	1.9	2.1	145	58	0.00
2	1	2	1	150	0.0	0.0	0.0	1.9	2.2	145	58	0.00
2	1	2	1	150	0.0	0.0	0.0	2.0	2.1	145	60	0.00
2	1	2	1	150	0.0	0.0	0.0	2.1	2.3	145	63	0.00
2	1	2	1	150	0.0	0.0	0.0	2.2	2.4	145	64	0.00
2	1	2	1	150	0.0	0.0	0.0	2.3	2.4	145	65	0.00
2	1	2	1	150	0.0	0.0	0.0	2.4	2.6	145	91	0.00
3	1	2	1	150	0.2	45.3	0.0	2.4	3.1	145	91	0.00
3	1	2	1	150	0.2	45.3	0.0	2.5	3.0	145	91	0.00
4	1	2	1	150	0.3	45.3	0.0	2.5	3.0	145	79	0.00
4	1	2	1	147	0.3	45.3	0.0	2.6	2.8	145	113	0.00
4	1	2	1	148	0.3	45.3	0.0	2.7	3.3	145	299	0.00
4	1	2	1	148	0.3	45.3	0.0	2.7	3.7	145	395	0.00
4	1	2	1	147	0.3	45.3	0.0	2.8	4.0	145	453	0.00
4	1	2	1	145	0.3	45.3	0.0	2.8	4.4	145	485	0.00
5	1	2	1	144	0.9	45.3	0.0	2.9	4.2	145	450	0.00
5	1	2	1	141	0.9	45.3	0.0	3.0	4.5	145	488	0.00
5	0	2	1	136	0.9	14.7	0.4	3.1	4.2	145	439	0.00
5	0	2	1	130	0.9	6.8	0.7	3.2	4.0	145	523	0.00
5	0	2	1	123	0.9	4.6	0.9	3.3	3.8	145	604	0.00
5	0	2	1	117	0.9	3.6	1.2	3.5	3.5	145	685	0.00
5	0	2	1	111	0.9	3.0	1.4	3.6	3.3	145	743	0.00
5	0	2	1	107	0.9	2.6	1.6	3.7	3.3	145	744	0.00
6	0	2	1	104	2.0	6.3	1.6	3.7	3.0	145	740	0.00
6	0	2	1	100	2.0	5.6	1.8	3.9	2.4	145	741	0.00
6	0	2	1	94	2.0	5.1	1.9	4.0	2.4	145	738	0.00
6	0	2	1	88	2.0	4.8	2.0	4.2	2.4	145	737	0.00
6	0	2	1	82	2.0	4.3	2.3	4.3	1.8	145	735	0.00
6	0	2	1	75	2.0	3.8	2.5	4.5	1.8	145	732	0.00
7	0	2	1	64	3.1	5.9	2.6	4.9	0.9	145	683	0.00
7	0	2	1	55	3.1	5.9	2.6	4.9	0.4	145	643	0.00
7	0	2	1	48	3.1	4.7	3.2	5.2	0.0	145	613	0.00
7	0	2	1	41	3.1	4.2	3.6	5.2	0.0	145	591	0.00
8	0	2	1	36	4.0	5.5	3.6	5.4	0.0	111	580	0.00
8	0	2	1	26	4.0	5.0	3.9	5.6	0.0	83	568	0.00
9	0	2	1	20	4.0	5.0	3.9	5.7	0.0	81	578	0.00
9	0	2	1	16	4.0	4.6	4.2	5.8	0.0	79	591	0.00
10	0	2	1	12	4.9	5.7	4.2	5.9	0.0	75	608	0.00
10	0	2	1	7	4.9	5.3	4.6	6.0	0.0	73	610	0.00
11	0	2	1	2	4.9	5.3	4.6	6.1	0.0	73	610	0.00

PROPPANT SUMMARY * At End of Pumping Schedule
SANTOS - E. MEREENIE #41 (P4) POST-FRAC EVAL. #4

Lb/Sq-Ft Lost to Embedment 0.200

Distance (ft)	KfW (md-ft)	Prop Concentration(Total lb/sq foot) Prop ID--> 1
5.6	460	0.38
12.3	418	0.36
14.4	331	0.33
16.5	274	0.31
18.6	268	0.30
20.7	277	0.31
22.8	271	0.30
24.9	259	0.30
27.0	257	0.30
29.1	270	0.30
31.2	298	0.31
33.3	319	0.32
35.4	325	0.32
37.5	327	0.33
39.6	292	0.31
41.7	232	0.29
43.8	219	0.28
45.9	229	0.29
48.0	228	0.29
50.1	230	0.29
52.2	271	0.30
54.3	344	0.33
56.4	378	0.35
58.5	375	0.34
60.6	373	0.34
62.7	371	0.34
64.8	369	0.34
66.9	367	0.34
69.0	359	0.34
71.1	288	0.31
73.2	164	0.26
75.3	104	0.24
77.4	115	0.24
79.5	140	0.25
81.6	154	0.26
83.7	166	0.26
85.8	191	0.27
87.9	205	0.28
90.0	213	0.28
92.1	227	0.29
94.2	236	0.29
96.3	250	0.30
98.4	272	0.30
100.5	289	0.31
102.6	313	0.32
104.7	252	0.29
106.8	87	0.20
108.9	0	0.17
111.0	0	0.17
113.1	0	0.18
115.2	0	0.19
117.3	6	0.20
119.4	39	0.22
121.5	89	0.23
123.6	118	0.25
125.7	170	0.27
127.8	261	0.30
129.9	330	0.33
132.0	477	0.38
134.1	703	0.47
136.2	806	0.51
138.3	1047	0.60
140.4	1634	0.83
142.5	1978	0.96
144.6	1843	0.91
146.7	1365	0.72
148.8	785	0.50

Average Conductivity (md-ft) 368

PROPPANT SUMMARY * At Fracture Closure
SANTOS - E. MEREENIE #41 (P4) POST-FRAC EVAL. #4

Lb/Sq-Ft Lost to Embedment 0.200

Distance (ft)	KfW (md-ft)	Prop Concentration(Total lb/sq foot) Prop ID--> 1
5.6	412	0.36
12.3	374	0.34
14.4	290	0.31
16.5	212	0.28
18.6	180	0.27
20.7	174	0.27
22.8	169	0.26
24.9	161	0.26
27.0	159	0.26
29.1	162	0.26
31.2	171	0.27
33.3	214	0.28
35.4	280	0.31
37.5	312	0.32
39.6	317	0.32
41.7	313	0.32
43.8	281	0.31
45.9	241	0.29
48.0	227	0.29
50.1	227	0.29
52.2	224	0.29
54.3	225	0.29
56.4	246	0.29
58.5	268	0.30
60.6	242	0.29
62.7	194	0.27
64.8	174	0.27
66.9	170	0.27
69.0	167	0.26
71.1	163	0.26
73.2	160	0.26
75.3	158	0.26
77.4	157	0.26
79.5	142	0.25
81.6	88	0.23
83.7	25	0.20
85.8	0	0.19
87.9	0	0.19
90.0	14	0.20
92.1	53	0.22
94.2	92	0.24
96.3	105	0.24
98.4	149	0.26
100.5	249	0.30
102.6	322	0.32
104.7	396	0.35
106.8	493	0.39
108.9	551	0.41
111.0	648	0.45
113.1	701	0.47
115.2	690	0.47
117.3	715	0.47
119.4	581	0.42
121.5	464	0.38
123.6	653	0.45
125.7	948	0.56
127.8	1197	0.66
129.9	1432	0.75
132.0	1608	0.82
134.1	1622	0.82
136.2	1716	0.86
138.3	1926	0.94
140.4	1986	0.96
142.5	1977	0.96
144.6	1843	0.91
146.7	1365	0.72
148.8	785	0.50

Average Conductivity (md-ft) 487

Frac Summary * SANTOS - E. MEREENIE #41 (P4) POST-FRAC EVAL. #5
Filename: EM41P4PF.FRK ; Oct 16, 96

Design Data

FLUID LOSS LAYERS:	Top (ft)	Bottom (ft)	Thick (ft)	Loss Coef. (ft/sqrt(min))	Spurt (Gal/100 ft^2)
	4649.0	4702.0	53.0	0.00010	0.00
	4702.0	4726.0	24.0	0.00600	0.50
	4726.0	4745.0	19.0	0.00010	0.00
	4745.0	4759.0	14.0	0.00600	0.50
	4759.0	4801.0	42.0	0.00020	0.00
	4801.0	4831.0	30.0	0.00900	0.50
	4831.0	4900.0	69.0	0.00020	0.00

FORMATION:	Modulus (e6_psi)	8.00
	Perforated Height (ft)	10.0
	Permeability (md)	1.000
TEMPERATURE:	Bottom Hole (deg_F)	145
PRESSURE:	Reservoir Pressure (psi)	1830.0
	Closure Pressure (psi)	4600.0
DEPTH:	Well Depth (ft)	4810.0

FORMATION LAYER DATA - Multi-Layer Height Growth

-----Depth(ft)------ Top	Botm	Thick	-Stress (psi)-- Top	Botm	Gradient (psi/ft)	Modulus (e6_psi)	Toughness (psi«in)
4649.0	4702.0	53.0	4900.0	4900.0	0.000	8.50	3000.0
4702.0	4726.0	24.0	3860.0	3860.0	0.000	6.50	3000.0
4726.0	4745.0	19.0	4800.0	4800.0	0.000	8.50	3000.0
4745.0	4759.0	14.0	3870.0	3870.0	0.000	6.50	3000.0
4759.0	4770.0	11.0	5050.0	5050.0	0.000	8.50	3000.0
4770.0	4801.0	31.0	5050.0	5050.0	0.000	8.50	3000.0
4801.0	4810.0	9.0	4600.0	4600.0	0.000	8.25	3000.0
4810.0	4820.0	10.0	4600.0	4600.0	0.000	8.00	3000.0
4820.0	4831.0	11.0	4600.0	4600.0	0.000	8.25	3000.0
4831.0			5100.0		0.000	9.00	3000.0

	Fluid Pressure Gradient (psi/ft)	0.450
	Perforations - Top (ft)	4810
	- Bot (ft)	4820
	Initial Fracture Top (ft)	4810
	Fracture Bottom (ft)	4820
3-D SIMULATOR	Step Size (ft)	1.5
PROGRAM CONTROL	Time Step (min)	Automatic

Calculated Results
from 3-D Simulator
STIMPLAN (TM) , NSI , Tulsa,OK
Licensed To: Internal Use - NSI Technologies

1/2 LENGTH:	'Hydraulic' length (ft)	87.9
	Propped length (ft)	87.6
PRESSURE:	Max Net Pressure (psi)	1591.6
	Surface Pres-End of Pad (psi)	3455.5
	Surface Pres-Start of Flush (psi)	5954.7
	Surface Pres-End of Job (psi)	5876.0
	Maximum Hydraulic Horsepower	2084
TIME:	Max Exposure to Form. Temp. (min)	3.5
	Time to Close (min)	7.3
RATE:	Fluid Loss Rate during pad (_BPM)	13.04
EFFICIENCY:	at end of pumping schedule	0.23
PROPPANT:	Average In Situ Conc. (#/sq ft)	0.7
	Average Conductivity (md-ft)	1176
HEIGHT:	Max Fracture Height (ft)	178.6
WIDTH:	Avg width at end of pumping (in)	0.11

TABLE A-4

StimPlan 2.60 (TM). NSI Technologies, Tulsa, OK
Licensed To: Internal Use - NSI Technologies

WELL ID:
SANTOS - E. MEREENIE #41 (P4) POST-FRAC EVAL. #5

DEPTH:	Well Depth (ft)	4810
PRESSURE:	Reservoir Pressure (psi)	1830
	Closure Pressure (psi)	4600
TEMPERATURE:	Bottom Hole Temperature (deg_F)	145

** Pumping Schedule **

Sl Vol (MGal)	Fl Vol (MGal)	Conc (_PPG_) Start	End	Rate (_BPM)	Fluid Type	Prop Type	Cum Prop (MLbs)	Pump Time (min)
0.88	0.88	0.0	0.0	4.35	3	1	0.0	4.8
0.24	0.24	0.0	0.0	9.63	3	1	0.0	0.6
0.10	0.10	0.0	0.0	15.56	3	1	0.0	0.2
0.20	0.20	0.0	0.0	15.59	1	1	0.0	0.3
2.18	2.18	0.0	0.0	15.59	2	1	0.0	3.3
0.10	0.10	0.2	0.2	15.61	2	1	0.0	0.2
0.35	0.34	0.3	0.3	15.17	2	1	0.1	0.5
0.86	0.83	0.9	0.9	15.17	2	1	0.9	1.3
0.89	0.82	2.0	2.0	15.14	2	1	2.5	1.4
0.84	0.74	3.1	3.1	15.03	2	1	4.8	1.3
0.49	0.42	4.0	4.0	14.93	2	1	6.5	0.8
0.19	0.16	4.0	4.0	14.60	2	1	7.1	0.3
0.27	0.22	4.9	4.9	14.60	2	1	8.2	0.4
0.12	0.10	4.9	4.9	14.00	2	1	8.7	0.2

Total Slurry ...	7.7	Total Fluid ...	7.3
Total Proppant ...	8.7	Avg. Conc	1.2
Total Pump Time	15.7 min	Pad %	46.7

Proppant ID No. 1 — 20- 40 CARBO-LITE

Specific Gravity					2.72
'Damage Factor'					0.70
Proppant Stress (Mpsi)	0	2	4	8	16
KfW @ 2 #/sq ft (md-ft)	10500	9200	7600	3200	500

Fluid ID No. 3 — WELLBORE_FLUID

Specific Gravity 1.04

	@Welbor	@FormTmp	@1Hr	@2Hr	@4Hr	@8Hr
vis (cp @ 170 1/sec) .	1	1	1	1	1	1
non-Newtonian n'	1.00	1.00	1.00	1.00	1.00	1.00
K(lb*sec/ft^2)x1000	0.02	0.02	0.02	0.02	0.02	0.02

Q (_BPM)	dP/dL (psi/100ft)
15.0	43.5

Measured Depth (ft) ... 4800.0

Fluid ID No. 1 — 30#_BORAGEL

Specific Gravity 1.04

	@Welbor	@FormTmp	@1Hr	@2Hr	@4Hr	@8Hr
vis (cp @ 170 1/sec) .	250	200	150	100	10	2
non-Newtonian n'	0.38	0.40	0.41	0.42	0.90	0.95
K(lb*sec/ft^2)x1000	123.71	89.31	63.63	40.29	0.34	0.05

Fluid ID No. 2 — 30#_BORAGEL

Specific Gravity 1.04

	@Welbor	@FormTmp	@1Hr	@2Hr	@4Hr	@8Hr
vis (cp @ 170 1/sec) .	600	600	450	250	10	2
non-Newtonian n'	0.38	0.40	0.41	0.42	0.90	0.95
K(lb*sec/ft^2)x1000	296.90	267.92	190.88	100.74	0.34	0.05

Time History * NSI STIMPLAN 3-D Fracture Simulation
SANTOS - E. MEREENIE #41 (P4) POST-FRAC EVAL. #5

Time (min)	Pen (ft)	Pres (psi)	Rate (_BPM)	Prop (_PPG_)	Sl Vol (MGal)	Eff- ciency	Loss (_BPM)	Hght (ft)	W-Avg (in)
0.7	12.0	203	4.35	0.0	0.1	0.03	0.2	30	0.01
1.0	13.5	214	4.35	0.0	0.2	0.04	4.1	31	0.01
1.2	15.0	226	4.35	0.0	0.2	0.04	4.3	33	0.01
1.5	16.5	253	4.35	0.0	0.3	0.03	4.3	36	0.01
1.7	18.0	263	4.35	0.0	0.3	0.03	4.3	40	0.01
2.0	19.5	263	4.35	0.0	0.4	0.03	4.3	42	0.01
2.3	21.0	261	4.35	0.0	0.4	0.03	4.3	43	0.01
2.7	22.5	257	4.35	0.0	0.5	0.02	4.3	43	0.01
3.0	24.0	256	4.35	0.0	0.6	0.02	4.3	43	0.01
3.4	25.5	253	4.35	0.0	0.6	0.02	4.3	43	0.01
3.8	27.0	254	4.35	0.0	0.7	0.02	4.3	43	0.01
4.2	28.5	253	4.35	0.0	0.8	0.02	4.3	43	0.01
4.8	30.5	255	4.35	0.0	0.9	0.02	4.5	43	0.01
4.8	32.0	299	9.63	0.0	0.9	0.02	5.9	43	0.01
4.9	33.5	320	9.63	0.0	0.9	0.03	8.0	45	0.01
4.9	35.0	321	9.63	0.0	0.9	0.03	8.6	47	0.01
5.0	36.5	321	9.63	0.0	0.9	0.03	8.9	49	0.01
5.1	38.0	320	9.63	0.0	1.0	0.03	9.0	49	0.01
5.2	39.5	321	9.63	0.0	1.0	0.03	9.2	49	0.01
5.2	41.0	320	9.63	0.0	1.0	0.03	9.2	49	0.01
5.3	42.5	321	9.63	0.0	1.1	0.03	9.3	49	0.01
5.4	43.7	321	9.63	0.0	1.1	0.03	8.0	49	0.01
5.5	45.2	357	15.56	0.0	1.1	0.04	12.6	52	0.02
5.5	46.7	360	15.56	0.0	1.2	0.04	12.2	53	0.02
5.5	48.2	366	15.56	0.0	1.2	0.04	13.2	54	0.02
5.6	49.7	366	15.56	0.0	1.2	0.04	13.7	54	0.02
5.6	51.2	367	15.59	0.0	1.2	0.04	14.1	54	0.02
5.7	52.7	600	15.59	0.0	1.3	0.05	12.5	69	0.02
5.9	54.2	678	15.59	0.0	1.5	0.08	10.8	81	0.02
6.1	55.7	688	15.59	0.0	1.5	0.09	10.7	86	0.03
6.2	57.2	719	15.59	0.0	1.6	0.10	11.6	90	0.03
6.2	58.7	757	15.59	0.0	1.6	0.10	11.9	93	0.03
6.4	60.2	803	15.59	0.0	1.7	0.11	11.6	101	0.03
6.5	61.7	836	15.59	0.0	1.9	0.12	11.2	111	0.03
6.7	63.2	856	15.59	0.0	2.0	0.13	11.2	120	0.03
6.8	64.7	841	15.59	0.0	2.1	0.13	12.8	127	0.03
7.1	66.2	837	15.59	0.0	2.2	0.13	13.2	134	0.03
7.3	67.7	831	15.59	0.0	2.3	0.13	13.3	139	0.03
7.5	69.2	832	15.59	0.0	2.5	0.14	12.6	143	0.03
7.7	70.7	825	15.59	0.0	2.6	0.14	12.8	146	0.03
7.9	72.2	820	15.59	0.0	2.8	0.14	12.8	149	0.03
8.1	73.7	810	15.59	0.0	2.9	0.14	12.9	152	0.04
8.4	75.2	807	15.59	0.0	3.1	0.14	12.7	156	0.04
8.6	76.7	802	15.59	0.0	3.2	0.14	12.8	159	0.04
8.9	78.2	790	15.59	0.0	3.4	0.14	13.1	162	0.04
9.3	79.7	782	15.59	0.0	3.6	0.15	13.0	165	0.04
9.6	81.2	774	15.61	0.2	3.9	0.15	13.1	168	0.04

Time History * NSI STIMPLAN 3-D Fracture Simulation
SANTOS - E. MEREENIE #41 (P4) POST-FRAC EVAL. #5

Time (min)	Pen (ft)	Pres (psi)	Rate (_BPM)	Prop (_PPG_)	Sl Vol (MGal)	Eff- ciency	Loss (_BPM)	Hght (ft)	W-Avg (in)
10.0	82.7	766	15.17	0.3	4.1	0.15	12.9	170	0.04
10.4	84.2	759	15.17	0.9	4.4	0.15	12.9	173	0.04
10.9	85.7	752	15.17	0.9	4.7	0.15	12.9	176	0.04
11.4	87.2	748	15.17	0.9	5.0	0.15	12.9	179	0.04
Bridge Stage 0 at 11 min, at 79.1 (ft), Avg Dia/W 0.03/0.02 in									
12.3	87.9	811	15.14	2.0	5.6	0.16	11.7	179	0.05
Bridge Stage 0 at 12 min, at 71.8 (ft), Avg Dia/W 0.03/0.03 in									
Screen Out in Stage 7 at Time = 12.3 min at 83 (ft)									
13.0	87.9	941	15.14	2.0	6.0	0.17	9.8	179	0.06
Screen Out in Stage 7 at Time = 13.0 min at 82 (ft)									
13.7	87.9	1085	15.03	3.1	6.4	0.19	9.1	179	0.07
14.3	87.9	1242	15.03	3.1	6.9	0.20	8.5	179	0.08
Screen Out in Stage 8 at Time = 14.3 min at 80 (ft)									
15.0	87.9	1413	14.93	4.0	7.3	0.22	8.1	179	0.10
15.7	87.9	1592	14.60	4.0	7.7	0.23	7.6	179	0.11
Screen Out in Stage 8 at Time = 15.7 min at 79 (ft)									
16.2	87.9	1464	0.00	0.0	7.7	0.22	7.6	179	0.11
16.7	87.9	1337	0.00	0.0	7.7	0.20	7.3	179	0.10
17.2	87.9	1210	0.00	0.0	7.7	0.18	7.1	179	0.09
17.8	87.9	1082	0.00	0.0	7.7	0.16	6.9	179	0.09
18.1	87.9	1019	0.00	0.0	7.7	0.16	6.7	179	0.08
18.5	87.9	955	0.00	0.0	7.7	0.15	6.6	179	0.08
18.8	87.9	891	0.00	0.0	7.7	0.14	6.5	179	0.08
19.2	87.9	828	0.00	0.0	7.7	0.13	6.4	179	0.08
19.6	87.9	764	0.00	0.0	7.7	0.13	6.3	179	0.07
20.1	87.9	700	0.00	0.0	7.7	0.12	6.2	179	0.07
20.5	87.9	637	0.00	0.0	7.7	0.11	6.1	179	0.07
21.0	87.9	573	0.00	0.0	7.7	0.11	6.0	179	0.07
21.5	87.9	509	0.00	0.0	7.7	0.10	5.9	179	0.06
22.0	87.9	446	0.00	0.0	7.7	0.09	5.8	179	0.06
22.5	87.9	382	0.00	0.0	7.7	0.09	5.7	179	0.06
23.0	87.9	318	0.00	0.0	7.7	0.09	5.6	179	0.06

GEOMETRY SUMMARY * At End of Pumping Schedule
SANTOS - E. MEREENIE #41 (P4) POST-FRAC EVAL. #5

Dstnce (ft)	Press (psi)	W-Avg (in)	Q (_BPM)	Sh-Rate (1/sec)	Hght (ft) Total	Up	Dn	Prop	Bank Fraction	Prop (PSF)
6	1591	0.19	7.3	41	179	101	67	143	0.00	0.61
12	1590	0.18	5.8	33	178	101	67	143	0.00	0.57
13	1590	0.18	5.8	33	178	101	67	143	0.00	0.57
14	1589	0.18	5.6	33	177	101	67	142	0.00	0.57
16	1589	0.18	5.3	33	177	100	66	142	0.00	0.56
17	1589	0.18	5.2	32	176	100	66	142	0.00	0.56
19	1588	0.18	5.0	32	175	99	66	141	0.00	0.60
20	1588	0.17	4.8	31	175	99	66	141	0.00	0.61
22	1588	0.17	4.6	31	174	98	65	140	0.00	0.60
23	1587	0.17	4.4	32	172	98	65	140	0.00	0.51
25	1587	0.16	4.2	33	170	97	64	139	0.00	0.46
26	1586	0.16	4.0	34	168	95	63	137	0.00	0.45
28	1586	0.16	3.8	32	168	95	63	137	0.00	0.50
29	1586	0.14	3.7	40	162	90	62	132	0.00	0.47
31	1585	0.13	3.5	44	158	87	61	129	0.00	0.44
33	1584	0.12	3.3	49	154	85	60	126	0.00	0.41
34	1583	0.12	3.2	54	149	80	59	122	0.00	0.39
36	1583	0.11	3.0	59	145	76	59	118	0.00	0.38
37	1581	0.11	2.9	62	142	73	59	115	0.00	0.37
39	1580	0.10	2.8	65	139	70	59	112	0.00	0.42
40	1579	0.10	2.7	66	137	68	59	110	0.00	0.43
42	1578	0.10	2.5	66	135	67	59	109	0.00	0.43
43	1577	0.10	2.4	67	132	64	58	105	0.00	0.43
44	1575	0.10	2.3	67	129	62	57	100	0.00	0.38
46	1574	0.09	2.2	68	126	60	56	94	0.00	0.32
47	1572	0.09	2.1	68	122	58	55	88	0.00	0.33
49	1571	0.09	2.0	69	119	55	54	82	0.00	0.34
50	1569	0.09	1.9	69	116	53	53	77	0.00	0.34
52	1567	0.09	1.8	69	113	51	52	72	0.00	0.42
53	1566	0.09	1.7	70	109	49	50	69	0.00	0.50
55	1564	0.09	1.6	68	107	48	49	67	0.00	0.50
56	1562	0.09	1.6	67	104	46	48	65	0.00	0.50
58	1561	0.09	1.5	67	101	45	46	63	0.00	0.50
59	1559	0.09	1.4	67	97	43	45	60	0.00	0.51
61	1557	0.09	1.3	67	93	41	42	57	0.00	0.58
62	1555	0.08	1.2	68	89	38	40	54	0.00	0.59
64	1550	0.08	1.1	68	85	36	39	51	0.00	0.59
65	1543	0.08	1.1	70	80	34	36	48	0.00	0.60
67	1537	0.08	1.0	70	76	32	34	45	0.00	0.60
68	1535	0.08	0.9	70	73	30	33	43	0.00	0.76
70	1532	0.08	0.8	70	69	28	31	40	0.00	0.89
71	1528	0.08	0.8	70	65	26	29	37	0.00	0.55
73	1521	0.08	0.7	71	60	23	27	34	0.00	0.54
74	1508	0.07	0.6	69	58	22	26	32	0.00	0.55
76	1492	0.07	0.6	68	54	20	24	29	0.00	0.72
77	1475	0.07	0.5	66	50	18	22	26	0.43	1.17
79	1457	0.07	0.4	64	46	17	20	24	1.00	1.79
80	1448	0.13	0.3	32	40	14	16	19	1.00	3.44
82	984	0.14	0.3	58	35	11	14	15	1.00	3.04
83	699	0.04	0.3	393	31	10	12	13	1.00	0.86
85	227	0.02	0.3	2360	30	9	11	12	1.00	0.44
86	139	0.02	0.3	2460	30	9	11	12	1.00	0.55
88	88	0.04	0.1	517	30	9	11	12	1.00	1.07

FLUID SUMMARY * At End of Pumping Schedule
SANTOS - E. MEREENIE #41 (P4) POST-FRAC EVAL. #5

Stage No	Gone	Fluid ID	Prop ID	Pos (ft)	Concentration In	Now	Design	Fl Vol (MGal)	Ex Tim (min)	Temp (deg_F)	Visc (cp)	Fall Frac
1	1	3	1	88	0.0	0.0	0.0	0.1	0.2	145	1	0.00
1	1	3	1	88	0.0	0.0	0.0	0.2	0.3	145	1	0.00
1	1	3	1	88	0.0	0.0	0.0	0.2	0.2	145	1	0.00
1	1	3	1	88	0.0	0.0	0.0	0.3	0.3	145	1	0.00
1	1	3	1	88	0.0	0.0	0.0	0.3	0.3	145	1	0.00
1	1	3	1	88	0.0	0.0	0.0	0.4	0.3	145	1	0.00
1	1	3	1	88	0.0	0.0	0.0	0.4	0.3	145	1	0.00
1	1	3	1	88	0.0	0.0	0.0	0.5	0.3	145	1	0.00
1	1	3	1	88	0.0	0.0	0.0	0.6	0.0	145	1	0.00
1	1	3	1	88	0.0	0.0	0.0	0.6	0.0	145	1	0.00
1	1	3	1	88	0.0	0.0	0.0	0.7	0.0	145	1	0.00
1	1	3	1	88	0.0	0.0	0.0	0.8	0.0	145	1	0.00
1	1	3	1	88	0.0	0.0	0.0	0.9	0.0	145	1	0.00
2	1	3	1	88	0.0	0.0	0.0	0.9	0.1	145	1	0.00
2	1	3	1	88	0.0	0.0	0.0	0.9	0.1	145	1	0.00
2	1	3	1	88	0.0	0.0	0.0	0.9	0.1	145	1	0.00
2	1	3	1	88	0.0	0.0	0.0	0.9	0.1	145	1	0.00
2	1	3	1	88	0.0	0.0	0.0	1.0	0.1	145	1	0.00
2	1	3	1	88	0.0	0.0	0.0	1.0	0.1	145	1	0.00
2	1	3	1	88	0.0	0.0	0.0	1.0	0.1	145	1	0.00
2	1	3	1	88	0.0	0.0	0.0	1.1	0.1	145	1	0.00
2	1	3	1	88	0.0	0.0	0.0	1.1	0.1	145	1	0.00
3	1	3	1	88	0.0	0.0	0.0	1.1	0.1	145	1	0.00
3	1	3	1	88	0.0	0.0	0.0	1.1	0.1	145	1	0.00
3	1	3	1	88	0.0	0.0	0.0	1.2	0.2	145	1	0.00
3	1	3	1	88	0.0	0.0	0.0	1.2	0.3	145	1	0.00
3	1	3	1	88	0.0	0.0	0.0	1.2	0.2	145	1	0.00
4	1	1	1	88	0.0	0.0	0.0	1.2	0.2	145	12	0.00
4	1	1	1	88	0.0	0.0	0.0	1.3	0.2	145	9	0.00
4	1	1	1	88	0.0	0.0	0.0	1.4	0.2	145	10	0.00
5	1	2	1	88	0.0	0.0	0.0	1.5	0.3	145	32	0.00
5	1	2	1	88	0.0	0.0	0.0	1.5	0.4	145	31	0.00
5	1	2	1	88	0.0	0.0	0.0	1.6	0.5	145	32	0.00
5	1	2	1	88	0.0	0.0	0.0	1.6	0.5	145	32	0.00
5	1	2	1	88	0.0	0.0	0.0	1.7	0.7	145	32	0.00
5	1	2	1	88	0.0	0.0	0.0	1.9	0.6	145	32	0.00
5	1	2	1	88	0.0	0.0	0.0	2.0	0.6	145	31	0.00
5	1	2	1	88	0.0	0.0	0.0	2.1	0.7	145	31	0.00
5	1	2	1	88	0.0	0.0	0.0	2.2	0.7	145	31	0.00
5	1	2	1	88	0.0	0.0	0.0	2.3	0.7	145	32	0.00
5	1	2	1	88	0.0	0.0	0.0	2.5	1.0	145	35	0.00
5	1	2	1	88	0.0	0.0	0.0	2.6	1.1	145	35	0.00
5	1	2	1	88	0.0	0.0	0.0	2.8	1.2	145	36	0.00
5	1	2	1	88	0.0	0.0	0.0	2.9	1.3	145	37	0.00
5	1	2	1	88	0.0	0.0	0.0	3.1	1.4	145	37	0.00
5	1	2	1	88	0.0	0.0	0.0	3.2	1.1	145	38	0.00
5	1	2	1	88	0.0	0.0	0.0	3.4	1.2	145	38	0.00
5	1	2	1	88	0.0	0.0	0.0	3.6	1.3	145	66	0.00
6	1	2	1	88	0.2	45.3	0.0	3.6	2.0	145	66	0.00
6	1	2	1	88	0.2	45.3	0.0	3.7	2.0	145	60	0.00
7	1	2	1	88	0.3	45.3	0.0	3.9	1.6	145	44	0.00
7	1	2	1	83	0.3	45.3	0.0	4.1	2.0	145	155	0.00

7	1	2	1	83	0.3	45.3	0.0	4.1	2.7	145	184	0.00
8	1	2	1	83	0.9	45.3	0.0	4.1	2.7	145	184	0.00
8	1	2	1	82	0.9	45.3	0.0	4.3	2.8	145	316	0.00
8	1	2	1	81	0.9	45.3	0.0	4.4	3.5	145	467	0.00
8	1	2	1	79	0.9	45.3	0.0	4.6	3.5	145	570	0.00
8	0	2	1	77	0.9	21.8	0.3	4.7	3.5	145	487	0.00
8	0	2	1	73	0.9	9.2	0.6	4.9	3.5	145	476	0.00
9	0	2	1	70	2.0	19.8	0.7	5.0	2.7	145	477	0.00
9	0	2	1	64	2.0	10.2	1.1	5.3	2.7	145	482	0.00
9	0	2	1	57	2.0	7.8	1.4	5.5	2.1	145	486	0.00
9	0	2	1	52	2.0	7.1	1.5	5.5	2.1	145	480	0.00
9	0	2	1	48	2.0	4.9	2.0	5.7	1.4	145	485	0.00
10	0	2	1	41	3.1	7.4	2.2	5.9	1.4	145	496	0.00
10	0	2	1	33	3.1	5.5	2.8	6.3	0.0	145	617	0.00
10	0	2	1	25	3.1	4.4	3.4	6.5	0.0	145	763	0.00
11	0	2	1	21	4.0	5.7	3.5	6.7	0.0	113	777	0.00
11	0	2	1	16	4.0	4.9	4.0	6.9	0.0	84	755	0.00
12	0	2	1	11	4.0	4.9	4.0	7.1	0.0	77	671	0.00
12	0	2	1	9	4.0	4.4	4.5	7.1	0.0	76	649	0.00
13	0	2	1	6	4.9	5.4	4.5	7.3	0.0	76	649	0.00
14	0	2	1	1	4.9	5.4	4.5	7.4	0.0	76	649	0.00

PROPPANT SUMMARY * At End of Pumping Schedule
SANTOS - E. MEREENIE #41 (P4) POST-FRAC EVAL. #5

Lb/Sq-Ft Lost to Embedment 0.200

Distance (ft)	KfW (md-ft)	Prop Concentration(Total lb/sq foot) Prop ID--> 1
6.0	895	0.60
11.9	858	0.58
12.7	833	0.57
14.2	824	0.57
15.7	812	0.56
17.2	826	0.57
18.7	878	0.59
20.2	911	0.61
21.7	858	0.58
23.2	722	0.52
24.7	603	0.47
26.2	588	0.46
27.7	622	0.48
29.5	599	0.47
31.2	534	0.44
32.7	477	0.41
34.2	434	0.39
35.7	404	0.38
37.2	412	0.38
38.7	470	0.41
40.2	514	0.43
41.7	519	0.43
43.1	485	0.42
44.4	394	0.38
45.9	306	0.34
47.4	286	0.33
48.9	303	0.34
50.4	358	0.36
51.9	492	0.42
53.4	625	0.48
54.9	674	0.50
56.4	678	0.50
57.9	680	0.50
59.4	725	0.52
60.9	816	0.56
62.4	871	0.59
63.9	883	0.59
65.4	893	0.60
66.9	990	0.64
68.4	1239	0.75
69.9	1279	0.77
71.4	969	0.63
72.9	770	0.54
74.4	865	0.59
75.9	1311	0.79
77.4	2260	1.21
78.9	4135	2.05
80.4	6105	2.93
81.9	5359	2.59
83.4	2460	1.30
84.9	831	0.57
86.4	1014	0.65
87.6	1600	0.91

Average Conductivity (md-ft) 1024

PROPPANT SUMMARY * At Fracture Closure
SANTOS - E. MEREENIE #41 (P4) POST-FRAC EVAL. #5

Lb/Sq-Ft Lost to Embedment 0.200

Distance (ft)	KfW (md-ft)	Prop Concentration(Total lb/sq foot) Prop ID--> 1
6.0	503	0.42
11.9	494	0.41
12.7	464	0.40
14.2	433	0.39
15.7	451	0.40
17.2	567	0.45
18.7	723	0.51
20.2	783	0.54
21.7	765	0.53
23.2	749	0.52
24.7	773	0.54
26.2	789	0.54
27.7	705	0.51
29.5	591	0.46
31.2	514	0.42
32.7	459	0.40
34.2	476	0.41
35.7	590	0.46
37.2	682	0.50
38.7	691	0.50
40.2	675	0.49
41.7	666	0.49
43.1	667	0.49
44.4	683	0.50
45.9	826	0.56
47.4	1028	0.65
48.9	1059	0.66
50.4	998	0.63
51.9	887	0.58
53.4	739	0.52
54.9	681	0.50
56.4	701	0.50
57.9	895	0.59
59.4	1219	0.73
60.9	1368	0.79
62.4	1370	0.79
63.9	1432	0.82
65.4	1570	0.88
66.9	1680	0.93
68.4	1752	0.96
69.9	1916	1.03
71.4	1964	1.05
72.9	1664	0.92
74.4	1470	0.84
75.9	1815	0.99
77.4	2627	1.34
78.9	4350	2.09
80.4	6294	2.93
81.9	5525	2.59
83.4	2536	1.30
84.9	857	0.57
86.4	1045	0.65
87.6	1650	0.91

Average Conductivity (md-ft) 1176

APPENDIX B

Service Co. Treatment Job Log

TABLE B-1

Customer: Santos Ltd
Well Desc: EAST MEREENIE 41
Formation: PACOOTA P4

Date: 11-Sep-1996
Ticket #: EM41LF1
Job Type: FRACTURE TREATMENT

DATA LISTING

TIME	Tubing Pr (psi)	Annulus Pr (psi)	Slurry Rt (bpm)	Slry Vol (gal)	Clean Vol (gal)	Slurry Den (lb/gal)	Sand Conc (lb/gal)	Sand Vol (lb)
09:20:04	422	241	0.00	0	0	8.11	0.00	0.0
09:20:09	422	241	0.00	0	0	8.13	0.00	0.0
09:20:14	422	240	0.00	0	0	8.10	0.00	0.0
09:20:19	423	240	0.00	0	0	8.13	0.00	0.0
09:20:24	423	240	0.00	0	0	8.11	0.00	0.0
==== Stage Total 892.96 (gal) ====								
09:20:29 Stage #2 FILL HOLE								
09:20:28	423	239	0.00	0	0	8.12	0.00	0.0
09:20:33	38	239	4.20	6	0	8.10	0.00	0.0
09:20:38	44	240	0.71	15	0	8.09	0.00	0.0
09:20:43	63	241	0.24	16	0	8.10	0.00	0.0
09:20:48	100	241	0.24	17	0	8.09	0.00	0.0
09:20:53	1312	249	1.30	19	0	8.09	0.00	0.0
09:20:58	2796	279	2.44	26	0	8.13	0.00	0.0
09:21:03	3757	327	3.43	37	0	8.14	0.00	0.0
09:21:08	3390	347	4.24	51	1	8.14	0.00	0.0
09:21:13	3377	342	4.37	66	5	8.16	0.00	0.0
09:21:18	3375	340	4.35	81	13	8.17	0.00	0.0
09:21:23	3393	338	4.33	97	25	8.20	0.00	0.0
09:21:28	3414	337	4.36	112	39	8.21	0.00	0.0
09:21:33	3432	335	4.57	127	53	8.22	0.00	0.0
09:21:38	3439	332	4.72	144	69	8.21	0.00	0.0
09:21:43	3444	330	4.71	160	85	8.17	0.00	0.0
09:21:48	3448	327	4.71	177	102	8.16	0.00	0.0
09:21:53	3450	324	4.70	193	118	8.18	0.00	0.0
09:21:58	3458	321	4.67	210	134	8.16	0.00	0.0
09:22:03	3453	317	4.66	226	151	8.16	0.00	0.0
09:22:08	3445	313	4.68	242	167	8.19	0.00	0.0
09:22:13	3443	309	4.69	259	185	8.18	0.00	0.0
09:22:18	3435	305	4.73	275	202	8.21	0.00	0.0
09:22:23	3435	301	4.84	292	220	8.20	0.00	0.0
09:22:28	3438	297	4.88	309	237	8.20	0.00	0.0
09:22:33	3437	292	4.68	326	253	8.21	0.00	0.0
09:22:38	3437	288	4.47	342	269	8.18	0.00	0.0
09:22:43	3443	284	4.44	357	286	8.19	0.00	0.0
09:22:48	3455	280	4.43	373	303	8.17	0.00	0.0
09:22:53	3468	276	4.41	388	319	8.19	0.00	0.0
09:22:58	3482	272	4.41	404	335	8.17	0.00	0.0
09:23:03	3498	268	4.41	419	351	8.13	0.00	0.0
09:23:08	3513	264	4.39	435	367	8.14	0.00	0.0
09:23:13	3524	260	4.39	450	382	8.18	0.00	0.0
09:23:18	3535	255	4.42	465	398	8.23	0.00	0.0
09:23:23	3547	251	4.41	481	414	8.25	0.00	0.0

Customer: Santos Ltd
Well Desc: EAST MEREENIE 41
Formation: PACOOTA P4

Date: 11-Sep-1996
Ticket #: EM41LF1
Job Type: FRACTURE TREATMENT

TIME	Tubing Pr (psi)	Annulus Pr (psi)	Slurry Rt (bpm)	Slry Vol (gal)	Clean Vol (gal)	Slurry Den (lb/gal)	Sand Conc (lb/gal)	Sand Vol (lb)
09:23:28	3563	247	4.41	496	430	8.21	0.00	0.0
09:23:33	3576	243	4.40	512	447	8.22	0.00	0.0
09:23:38	3586	239	4.39	527	463	8.22	0.00	0.0
09:23:43	3597	235	4.39	543	479	8.21	0.00	0.0
09:23:48	3611	232	4.37	558	495	8.20	0.00	0.0
09:23:53	3627	228	4.39	573	510	8.20	0.00	0.0
09:23:58	3644	225	4.41	589	526	8.20	0.00	0.0
09:24:03	3661	221	4.42	604	542	8.20	0.00	0.0
09:24:08	3676	218	4.42	620	558	8.22	0.00	0.0
09:24:13	3686	215	4.39	635	573	8.22	0.00	0.0
09:24:18	3700	211	4.38	650	589	8.24	0.00	0.0
09:24:23	3714	208	4.37	666	605	8.24	0.00	0.0
09:24:28	3727	204	4.37	681	620	8.21	0.00	0.0
09:24:33	3747	202	4.39	696	635	8.19	0.00	0.0
09:24:38	3771	199	4.45	712	651	8.22	0.00	0.0
09:24:43	3797	196	4.50	727	667	8.23	0.00	0.0
09:24:48	3810	193	4.52	743	682	8.21	0.00	0.0
09:24:53	3824	190	4.52	759	698	8.20	0.00	0.0
09:24:58	3848	188	4.53	775	714	8.20	0.00	0.0
09:25:03	3864	185	4.53	791	729	8.22	0.00	0.0
09:25:08	3880	183	4.53	807	746	8.22	0.00	0.0
09:25:13	3895	180	4.52	822	762	8.21	0.00	0.0
09:25:18	3911	178	4.51	838	778	8.20	0.00	0.0
09:25:23	3934	176	4.53	854	795	8.20	0.00	0.0
09:25:28	3951	182	4.51	870	811	8.18	0.00	0.0
09:25:33	3967	209	4.50	886	827	8.20	0.00	0.0

==== Stage Total 898.31 (gal) ====

09:25:38 Stage #3 Start Pad

09:25:37	3984	226	4.49	898	839	8.20	0.00	0.0
09:25:42	4645	227	7.06	918	855	8.22	0.00	0.0
09:25:47	4563	228	7.51	943	872	8.23	0.00	0.0
09:25:52	4952	229	8.27	971	890	8.24	0.00	0.0
09:25:57	4932	230	9.59	1003	912	8.26	0.00	0.0
09:26:02	5321	230	12.97	1042	939	8.25	0.00	0.0
09:26:07	5283	229	13.18	1088	970	8.25	0.00	0.0
09:26:12	5506	227	13.33	1134	1006	8.23	0.00	0.0
09:26:17	5622	225	15.99	1184	1046	8.24	0.00	0.0
09:26:22	5770	225	15.88	1239	1089	8.25	0.00	0.0
09:26:27	5791	223	15.67	1295	1135	8.24	0.00	0.0
09:26:32	5833	220	15.52	1349	1183	8.23	0.00	0.0
09:26:37	5884	218	15.53	1403	1231	8.25	0.00	0.0
09:26:42	5921	215	15.50	1458	1281	8.29	0.00	0.0
09:26:47	5921	211	15.64	1512	1330	8.28	0.00	0.0
09:26:52	5915	208	15.70	1567	1380	8.27	0.00	0.0
09:26:57	5907	205	15.55	1622	1429	8.25	0.00	0.0

Customer: Santos Ltd
Well Desc: EAST MEREENIE 41
Formation: PACOOTA P4

Date: 11-Sep-1996
Ticket #: EM41LF1
Job Type: FRACTURE TREATMENT

TIME	Tubing Pr (psi)	Annulus Pr (psi)	Slurry Rt (bpm)	Slry Vol (gal)	Clean Vol (gal)	Slurry Den (lb/gal)	Sand Conc (lb/gal)	Sand Vol (lb)
09:27:02	5872	202	15.56	1676	1479	8.25	0.00	0.0
09:27:07	5810	198	15.57	1731	1528	8.23	0.00	0.0
09:27:12	5758	194	15.56	1785	1577	8.26	0.00	0.0
09:27:17	5720	197	15.60	1840	1627	8.28	0.00	0.0
09:27:22	5658	219	15.57	1894	1676	8.29	0.00	0.0
09:27:27	5617	235	15.59	1949	1725	8.28	0.00	0.0
09:27:32	5587	230	15.61	2003	1773	8.25	0.00	0.0

==== Stage Total 1148.83 (gal) ====

09:27:36 Stage #4 Start Sand

09:27:36	5545	226	15.59	2047	1812	8.27	0.00	0.0
09:27:41	5494	221	15.61	2102	1861	8.24	0.00	0.0
09:27:46	5446	217	15.62	2156	1911	8.26	0.00	0.0
09:27:51	5424	212	15.69	2211	1960	8.26	0.00	0.0
09:27:56	5379	207	15.72	2266	2009	8.30	0.00	0.0
09:28:01	5356	203	15.72	2321	2057	8.31	0.00	0.0
09:28:06	5355	199	15.73	2376	2105	8.32	0.00	0.0
09:28:11	5340	196	15.65	2431	2152	8.41	0.13	4.8
09:28:16	5334	193	15.65	2486	2199	8.43	0.16	13.2
09:28:21	5334	189	15.72	2541	2246	8.43	0.16	21.8
09:28:26	5329	186	15.70	2596	2293	8.46	0.21	32.2
09:28:31	5298	195	15.65	2651	2341	8.50	0.27	45.7

==== Stage Total 614.45 (gal) ====

09:28:33 Stage #5 Increase Sand

09:28:35	5295	218	15.59	2694	2378	8.57	0.38	61.0
09:28:40	5292	245	15.51	2749	2426	8.58	0.40	82.1
09:28:45	5298	246	15.66	2803	2473	8.63	0.49	105.6
09:28:50	5298	241	15.79	2858	2520	8.67	0.55	135.4
09:28:55	5301	237	15.80	2914	2567	8.69	0.59	165.9
09:29:00	5306	234	15.79	2969	2615	8.69	0.58	198.0
09:29:05	5290	230	15.75	3024	2661	8.67	0.56	228.1
09:29:10	5295	226	15.74	3079	2707	8.70	0.59	259.4
09:29:15	5300	223	15.74	3134	2751	8.75	0.68	294.5
09:29:20	5298	220	15.60	3189	2796	8.77	0.72	332.0
09:29:25	5283	217	15.55	3244	2841	8.80	0.76	370.9

==== Stage Total 625.68 (gal) ====

Customer: Santos Ltd
Well Desc: EAST MEREENIE 41
Formation: PACOOTA P4

Date: 11-Sep-1996
Ticket #: EM41LF1
Job Type: FRACTURE TREATMENT

TIME	Tubing Pr (psi)	Annulus Pr (psi)	Slurry Rt (bpm)	Slry Vol (gal)	Clean Vol (gal)	Slurry Den (lb/gal)	Sand Conc (lb/gal)	Sand Vol (lb)
09:29:30 Stage #6 Increase Sand								
09:29:29	5277	214	15.56	3287	2877	8.85	0.85	404.7
09:29:34	5272	211	15.52	3342	2923	8.92	0.98	452.9
09:29:39	5264	208	15.55	3396	2969	8.94	1.01	504.7
09:29:44	5252	205	15.56	3451	3015	9.02	1.14	560.3
09:29:49	5241	202	15.48	3505	3061	9.07	1.23	622.2
09:29:54	5244	200	15.43	3559	3107	9.07	1.23	685.9
09:29:59	5223	197	15.37	3613	3155	9.14	1.35	753.1
09:30:04	5212	194	15.31	3666	3202	9.15	1.38	822.3
09:30:09	5213	192	15.26	3720	3249	9.27	1.60	897.2
09:30:14	5215	190	15.17	3773	3295	9.27	1.59	976.4
09:30:19	5213	187	15.18	3826	3339	9.28	1.60	1055.3
09:30:24	5217	195	15.19	3879	3382	9.27	1.59	1134.1
09:30:29	5234	218	15.16	3933	3425	9.29	1.62	1215.6
09:30:34	5227	231	15.16	3986	3468	9.30	1.64	1296.9
==== Stage Total 708.91 (gal) ====								
09:30:35 Stage #7 Increase Sand								
09:30:38	5218	228	15.15	4028	3503	9.34	1.73	1363.9
09:30:43	5225	226	15.12	4081	3546	9.40	1.84	1451.8
09:30:48	5238	223	15.14	4134	3589	9.48	1.97	1543.8
09:30:53	5224	220	15.17	4187	3633	9.52	2.05	1642.3
09:30:58	5222	217	15.20	4240	3677	9.57	2.14	1744.1
09:31:03	5230	215	15.18	4293	3722	9.64	2.27	1850.2
09:31:08	5228	213	15.11	4346	3768	9.68	2.36	1962.9
09:31:13	5233	211	15.12	4399	3814	9.71	2.42	2077.3
09:31:18	5235	208	15.16	4452	3860	9.70	2.40	2193.0
09:31:23	5251	206	15.18	4505	3906	9.76	2.50	2310.9
09:31:28	5255	204	15.17	4558	3951	9.75	2.48	2430.4
09:31:33	5258	203	15.13	4611	3994	9.78	2.56	2551.1
09:31:38	5279	201	15.09	4664	4037	9.80	2.60	2673.7
09:31:43	5290	200	15.13	4717	4080	9.83	2.64	2799.5
==== Stage Total 731.54 (gal) ====								
09:31:45 Stage #8 Increase Sand								
09:31:47	5307	198	15.14	4760	4114	9.85	2.70	2900.8
09:31:52	5310	196	15.12	4812	4156	9.94	2.86	3032.7
09:31:57	5306	195	15.10	4865	4199	9.97	2.94	3168.9
09:32:02	5314	193	15.10	4918	4241	10.02	3.02	3309.2

Customer: Santos Ltd
Well Desc: EAST MEREENIE 41
Formation: PACOOTA P4

Date: 11-Sep-1996
Ticket #: EM41LF1
Job Type: FRACTURE TREATMENT

TIME	Tubing Pr (psi)	Annulus Pr (psi)	Slurry Rt (bpm)	Slry Vol (gal)	Clean Vol (gal)	Slurry Den (lb/gal)	Sand Conc (lb/gal)	Sand Vol (lb)
09:32:07	5302	191	15.09	4971	4284	10.07	3.14	3453.2
09:32:12	5306	189	15.11	5024	4327	10.12	3.24	3600.8
09:32:17	5304	186	15.11	5077	4369	10.14	3.28	3752.1
09:32:22	5284	185	15.08	5130	4412	10.20	3.41	3906.9
09:32:27	5291	183	15.12	5182	4456	10.18	3.36	4062.3
09:32:32	5291	182	15.13	5235	4499	10.20	3.40	4217.9
09:32:37	5288	180	15.32	5289	4543	10.18	3.36	4374.8
09:32:42	5303	197	15.62	5343	4585	10.20	3.40	4534.6
09:32:47	5295	225	15.47	5397	4628	10.23	3.46	4697.1
09:32:52	5290	232	15.18	5451	4670	10.28	3.57	4860.3

==== Stage Total 754.95 (gal) ====

09:32:56 Stage #9 Increase Sand

09:32:56	5301	229	15.15	5493	4703	10.33	3.67	4992.7
09:33:01	5310	227	15.14	5546	4745	10.34	3.70	5161.1
09:33:06	5326	225	15.11	5599	4787	10.36	3.75	5330.6
09:33:11	5321	224	15.10	5652	4829	10.43	3.89	5505.7
09:33:16	5312	221	15.11	5705	4871	10.47	3.97	5683.8
09:33:21	5305	219	15.11	5758	4912	10.55	4.16	5865.5
09:33:26	5310	218	15.11	5811	4954	10.57	4.19	6052.1
09:33:31	5327	216	15.13	5864	4996	10.59	4.25	6240.4
09:33:36	5330	215	15.10	5917	5037	10.60	4.26	6429.8
09:33:41	5334	214	14.99	5969	5079	10.62	4.30	6620.2
09:33:46	5349	212	14.94	6022	5121	10.63	4.33	6809.5
09:33:51	5356	211	14.96	6074	5163	10.69	4.47	7003.7
09:33:56	5365	210	14.95	6126	5206	10.71	4.51	7199.2
09:34:01	5385	208	14.93	6178	5248	10.72	4.55	7396.1

==== Stage Total 727.06 (gal) ====

09:34:04 Stage #10 Increase Sand

09:34:05	5396	206	14.92	6220	5282	10.77	4.65	7555.5
09:34:10	5379	206	14.91	6272	5324	10.80	4.71	7757.3
09:34:15	5387	204	14.92	6325	5365	10.89	4.92	7966.7
09:34:20	5402	203	14.90	6377	5407	10.92	5.00	8180.0
09:34:25	5407	202	14.90	6429	5449	10.96	5.10	8395.9
09:34:30	5421	200	15.16	6481	5491	11.05	5.30	8618.2
09:34:35	5420	198	15.26	6535	5532	11.08	5.38	8848.8
09:34:40	5396	197	15.02	6588	5574	11.11	5.46	9081.0
09:34:45	5402	196	14.90	6640	5615	11.17	5.61	9312.4
09:34:50	5406	194	14.87	6692	5657	11.25	5.80	9550.7
09:34:55	5396	193	14.87	6744	5698	11.30	5.93	9793.0
09:35:00	5406	192	14.87	6796	5737	11.32	5.98	10038.5

Customer: Santos Ltd
Well Desc: EAST MEREENIE 41
Formation: PACOOTA P4

Date: 11-Sep-1996
Ticket #: EM41LF1
Job Type: FRACTURE TREATMENT

TIME	Tubing Pr (psi)	Annulus Pr (psi)	Slurry Rt (bpm)	Slry Vol (gal)	Clean Vol (gal)	Slurry Den (lb/gal)	Sand Conc (lb/gal)	Sand Vol (lb)
==== Stage Total 617.70 (gal) ====								
09:35:04 Stage #11 Increase Sand								
09:35:04	5437	191	14.93	6838	5768	11.35	6.05	10236.3
09:35:09	5440	191	14.96	6890	5807	11.33	6.00	10484.2
09:35:14	5458	190	14.96	6943	5846	11.39	6.15	10735.3
09:35:19	5476	188	14.97	6995	5885	11.44	6.28	10990.8
09:35:24	5492	188	14.97	7047	5924	11.47	6.35	11249.3
09:35:29	5531	188	14.93	7100	5962	11.49	6.41	11510.0
09:35:34	5675	189	14.96	7152	6001	11.54	6.54	11773.2
09:35:39	5728	190	15.10	7204	6040	11.57	6.63	12042.2
09:35:44	5787	191	15.33	7258	6079	11.58	6.65	12317.4
09:35:49	5840	192	15.19	7311	6117	11.64	6.81	12595.5
09:35:54	6031	194	14.89	7364	6158	11.74	7.07	12872.6
09:35:59	6086	196	14.82	7416	6208	11.73	7.05	13151.9
==== Stage Total 629.69 (gal) ====								
09:36:03 Stage #12 Increase Sand								
09:36:03	6364	199	14.76	7457	6250	11.71	6.99	13372.9
09:36:08	6440	203	14.65	7509	6304	11.79	7.12	13648.9
09:36:13	6953	210	14.54	7560	6360	11.77	7.07	13924.6
09:36:18	7181	218	14.47	7610	6416	11.52	6.42	14188.0
09:36:23	10123	234	11.78	7653	6471	11.40	6.09	14393.7
09:36:28	8781	291	0.81	7662	6524	11.23	5.67	14438.3
09:36:33	7262	299	0.36	7664	6560	11.12	5.40	14445.9
09:36:38	6286	245	0.00	7664	6565	11.11	5.37	14447.1
09:36:43	5652	218	0.00	7664	6565	11.23	5.67	14447.1
09:36:48	5250	197	0.00	7664	6565	11.39	6.06	14447.1
09:36:53	4922	186	0.00	7664	6565	11.54	6.47	14447.1
09:36:58	4821	180	0.00	7664	6565	11.81	7.17	14447.1
09:37:03	4700	175	0.00	7664	6565	11.84	7.27	14447.1
09:37:08	4553	173	0.00	7664	6565	11.85	7.30	14447.1
09:37:13	4434	170	0.00	7664	6565	11.87	7.36	14447.1
09:37:18	4338	169	0.00	7664	6565	11.85	7.31	14447.1
09:37:23	4258	168	0.00	7664	6565	11.90	7.44	14447.1
09:37:28	4190	168	0.00	7664	6565	11.85	7.29	14447.1
09:37:33	4130	167	0.00	7664	6565	11.85	7.30	14447.1
09:37:38	4079	167	0.00	7664	6565	11.88	7.38	14447.1
09:37:43	4038	167	0.00	7664	6565	11.87	7.35	14447.1
09:37:48	4006	167	0.00	7664	6565	11.84	7.26	14447.1
09:37:53	3980	167	0.00	7664	6565	11.84	7.26	14447.1
09:37:58	3959	167	0.00	7664	6565	11.84	7.27	14447.1

Customer: Santos Ltd
Well Desc: EAST MEREENIE 41
Formation: PACOOTA P4

Date: 11-Sep-1996
Ticket #: EM41LF1
Job Type: FRACTURE TREATMENT

TIME	Tubing Pr (psi)	Annulus Pr (psi)	Slurry Rt (bpm)	Slry Vol (gal)	Clean Vol (gal)	Slurry Den (lb/gal)	Sand Conc (lb/gal)	Sand Vol (lb)
09:38:03	3942	167	0.00	7664	6565	11.85	7.30	14447.1
09:38:08	3927	167	0.00	7664	6565	11.83	7.25	14447.1
09:38:13	3915	168	0.00	7664	6565	11.85	7.31	14447.1
09:38:18	3904	168	0.00	7664	6565	11.87	7.36	14447.1
09:38:23	3893	168	0.00	7664	6565	11.85	7.30	14447.1
09:38:28	3883	168	0.00	7664	6565	11.86	7.31	14447.1
09:38:33	3874	168	0.00	7664	6565	11.88	7.39	14447.1
09:38:38	3867	168	0.00	7664	6565	11.85	7.28	14447.1
09:38:43	3859	168	0.00	7664	6565	11.85	7.29	14447.1
09:38:48	3852	168	0.00	7664	6565	11.84	7.28	14447.1
09:38:53	3844	168	0.00	7664	6565	11.83	7.25	14447.1
09:38:58	3836	168	0.00	7664	6565	11.84	7.27	14447.1
09:39:03	3828	168	0.00	7664	6565	11.82	7.20	14447.1
09:39:08	3820	169	0.00	7664	6565	11.82	7.21	14447.1
09:39:13	3812	169	0.00	7664	6565	11.84	7.27	14447.1
09:39:18	3805	169	0.00	7664	6565	11.85	7.30	14447.1
09:39:23	3797	169	0.00	7664	6565	11.86	7.33	14447.1
09:39:28	3790	169	0.00	7664	6565	11.87	7.36	14447.1
09:39:33	3783	169	0.00	7664	6565	11.88	7.37	14447.1
09:39:38	3777	169	0.00	7664	6565	11.82	7.20	14447.1
09:39:43	3770	169	0.00	7664	6565	11.80	7.17	14447.1
09:39:48	3764	169	0.00	7664	6565	11.83	7.25	14447.1
09:39:53	3758	170	0.00	7664	6565	11.84	7.28	14447.1
09:39:58	3752	170	0.00	7664	6565	11.86	7.32	14447.1
09:40:03	3746	170	0.00	7664	6565	11.85	7.29	14447.1
09:40:08	3740	170	0.00	7664	6565	11.84	7.28	14447.1
09:40:13	3735	170	0.00	7664	6565	11.84	7.26	14447.1
09:40:18	3729	170	0.00	7664	6565	11.83	7.24	14447.1
09:40:23	3724	170	0.00	7664	6565	11.83	7.25	14447.1
09:40:28	3718	170	0.00	7664	6565	11.87	7.36	14447.1
09:40:33	3713	170	0.00	7664	6565	11.85	7.31	14447.1
09:40:38	3708	170	0.00	7664	6565	11.85	7.31	14447.1
09:40:43	701	170	0.00	7664	6565	11.83	7.25	14447.1
09:40:48	691	170	0.00	7664	6565	11.85	7.29	14447.1
09:40:53	679	170	0.00	7664	6565	11.83	7.23	14447.1
09:40:58	669	170	0.00	7664	6565	11.85	7.28	14447.1
09:41:03	3659	170	0.00	7664	6565	11.85	7.29	14447.1
09:41:08	3650	170	0.00	7664	6565	11.86	7.32	14447.1
09:41:13	3642	170	0.00	7664	6565	11.84	7.28	14447.1
09:41:18	3634	170	0.00	7664	6565	11.86	7.31	14447.1
09:41:23	3627	170	0.00	7664	6565	11.85	7.29	14447.1
09:41:28	3619	170	0.00	7664	6565	11.82	7.22	14447.1
09:41:33	3613	171	0.00	7664	6565	11.80	7.16	14447.1
09:41:38	3606	171	0.00	7664	6565	11.82	7.21	14447.1
09:41:43	3600	171	0.00	7664	6565	11.84	7.26	14447.1
09:41:48	3594	171	0.00	7664	6565	11.82	7.23	14447.1
09:41:53	3589	171	0.00	7664	6565	11.85	7.29	14447.1
09:41:58	3584	171	0.00	7664	6565	11.84	7.26	14447.1
09:42:03	3579	171	0.00	7664	6565	11.82	7.22	14447.1
09:42:08	3574	172	0.00	7664	6565	11.87	7.35	14447.1