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TITLE: IMPROVEMENT OF TUBULARS USED FOR FRACTURING IN HOT DRY ROCK WELLS

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IMPROVEMENT OF TUBULARS USED FOR FRACTURING IN HOT DRY ROCK WELLS

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ABSTRACT

Completion of hot dry rock wells as it is currently envisioned, requires that hydraulic fracturing be used to develop a heat extraction reservoir and to provide low impedance flow paths between the designated water injection and production wells. Recent fracturing operations at measured depths from 11,400 ft to 15,300 ft at the Fenton Hill Hot Dry Rock Geothermal Test Site have resulted in numerous failures of tubulars caused by the high fracturing pressures, corrosive environment and large treatment volumes at high flow rates. Two new fracturing strings were designed and purchased. Physical and chemical properties exceeding API specifications were demanded and supplied by the manufacturers. These tubulars have performed to design specifications.

INTRODUCTION

In the completion of the first Hot Dry Rock (HDR) geothermal energy extraction system at Fenton Hill, west of Los Alamos, New Mexico, a reservoir was created by connecting two boreholes in hot, impermeable crystalline rock with hydraulic fractures produced with surface pumping pressures of less than 2500 psi. This initial system consists of two near-vertical 10,000 ft deep wells, openhole completed in Precambrian basement rock, at a bottom hole temperature of 400°F.

A second commercial-sized heat extraction system was begun in 1979. It presently consists of two boreholes drilled as shown in Figure 1.[1],[2]* A series of fracturing operations have been conducted in attempts to connect the EE-2 and EE-3 wellbores. A summary of these operations through November 1982 is presented in Reference 3. Fracturing operations conducted since then are briefly discussed here. The fracturing pressure of this deeper reservoir requires surface pumping pressures of 5200 to 5900 psi. High rate pumping operations have been conducted at up to 7100 psi. These higher than anticipated fracturing pressures have caused problems with the downhole hardware. The bottom hole temperature of the deeper well, EE-2 is 630 F.

SUMMARY OF FRACTURE STRING FAILURES

Three major problems arose during these early fracturing operations. First, fracturing pressures were much higher than in the earlier experiments. Second the tubing casing annulus was limited to a backside pressure of 2000 psi during all major fracturing experiments performed in EE-2 and to 1000 psi in EE-3. Third, the fluid flowback after the first major pump of 20,000 bbls contained significant amounts of dissolved CO_2 gas and a trace of H_2S gas. A summary of fracturing operations in EE-2 and EE-3 is given in Table 1.

Fracture gradients of 0.55 psi/ft were calculated for fracture extension pressures in the shallow (10,000 ft deep) reservoir at Fenton Hill. Extrapolation to 14,000 ft TVD predicted surface pumping pressure would be less than 2000 psi. However, fracturing operations carried out in the deeper EE-2 well required much higher pumping pressures, resulting in fracture gradients ranging from 0.8 to 0.96 psi/ft. A summary of fracturing pressures in Fenton Hill wells is presented in Figure 2. During the pumping operations of October 6, 1982, measured instantaneous surface pressures increased from 5200 to 5900 psi resulting in an increase in the fracture gradient from 0.89 to 0.96 psi/ft[3] (see Figure 2).

During the drilling of EE-2, considerable wear of the 9-5/8 in. casing occurred. This wear caused a limitation of 2000 psi on the 9-5/8 in. frac string annulus back-up pressure. In EE-3 a low pressure zone just below the 9-5/8 in. casing (see Figure 1) allowed only a 1000 psi annulus back-up pressure. These limitations significantly increased the triaxial loading on the frac strings.

During post fracturing operations, flowback of fluids contained corrosive gases. A 4-1/2 in. N-80 buttress casing coupling cracked early in the 2nd stage of the first major pump on June 4, 1982. It had been exposed to a 1/2 BPM flow of water out of the tubing-casing annulus for more than 2 days at the time of failure (see Figure 1). The water contained significant amounts of dissolved CO_2 gas and a trace of H_2S. All subsequent flowbacks also contained these gases. Both the frac string and the casing were exposed. These gases further

* References, Figures, and Tables at end of text.

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enhanced the possibility of downhole tubular, or other hardware failures.

Brief descriptions of the tubing failures during fracturing operations are presented in Table 1. Failures occurred due to combinations of high stress, stress risers and corrosive environments. Four major jobs were conducted with the 4-1/2 in. N-80, P-110 buttress casing. Failures occurred primarily in the collars but tube failures also occurred in the P-110. Drill pipe was also used for fracturing. Failures were only found in the S-135 tubes of both 3-1/2 in. and 4-1/2 in. drill pipe. Drill pipe had been used as a workstring in EE-2 for more than three months prior to the fracturing experiments. It had been used to circulate out CO_2 gas bubbles containing H_2S during completion operations. After the 4-1/2 in. casing had been aerated for four months, it was redeployed. After replacing one bad collar, 20,000 bbls of water were pumped at pressures up to 7000 psi before the 4-1/2 in. casing failed.

The past fracturing string failures provided justification to procure a new fracturing tubing. Procurement of a new string was initiated. Because of the long lead time required an attempt was made to do a small volume fracturing experiment in EE-3. The injection zone selected, required that a cemented-in liner be used to bypass a low fracture gradient zone below the 9-5/8 in. casing shoe at 10,375 ft. A new 1300 ft long 4-1/2 in. 0.250 in. wall N-80 buttress casing was cemented-in from 11,400 ft to 10,850 ft using a puddling technique and hung in the 9-5/8 in. casing at 10,200 ft with a mechanical liner hanger under a polished bore receptacle (PBR) (see Figure 1). A seal assembly on a 4-1/2 in. 0.337 in. wall S-135 drill pipe string was sealed into the PBR. To prevent excessive injection into the low gradient zone backside pressure was limited to 1000 psi. The treatment ended with instantaneous pressure communication between the drill pipe and annulus. Upon removal a leak was found in the slip area of the drill pipe. The liner was collapsed just above the cement top. The liner failure was attributed to excessive stress and the drill pipe failure resulted from the corrosive environment.

PERFORMANCE OBJECTIVES FOR THE NEW TUBING

Improved tubing handling procedures, lower stress during fracturing and materials for service in a corrosive environment were needed to reduce the possibility of future failures. Fracturing experiments were being proposed for both wells and very large volume treatments were being considered for EE-2. The 9-5/8 in. casing in both wells was susceptible to the corrosive environment. 5-1/8 in. slick joints, 5-in. and 5-1/4-in. seal assemblies would be used to seal the bottom of the tubing into packers or PBRs. The capability to perform wireline work inside of pressurized tubing was very desirable.

As a result, tubing performance objectives required that the tubing be suitable for the following:

(1) Workstring service to depths of 14,400 ft with repeated use of connections after internal and external exposure to corrosive, 600°F fluids, 10,000 ft-lbs torque, and 400,000 lbs tension loads.

(2) Fracturing service to depths of 14,400 ft at rates up to 50 BPM, 7000 psi net internal pressure and very high compressive loads which result from the lower moving seal configurations needed to compensate for thermal contraction.

(3) Isolation service to protect the 9-5/8 in. production casing from corrosive water and steam during after frac flow or reservoir production at moderate pressures and temperatures up to 600°F.

TUBING SPECIFICATION

To meet the performance objectives, a 90,000 psi minimum yield stress moderate wall, large diameter tube with an internal flush, shouldered connection having both internal and external metal-to-metal seals was desired. The lead time to procure such a string was estimated at six months. This was unacceptable to the program. A strategy to procure two fracturing strings evolved. A specification which required a minimum lead time was prepared for tubing suitable for moderate workstring and fracturing service which would also be suitable for eventual production service in EE-3. An optimum specification was prepared for a second string which would satisfy all of the performance objectives and be used as high pressure injection string for a four to six million gallon fracturing treatment in EE-2. It would also be used as the injection string for reservoir testing operations once the wells were connected. The specifications for the compromise, readily available string and the desired string are listed in Table 2.

DESIGN CALCULATIONS AND CONSIDERATIONS

Grade selection for the minimum specification was based on the conclusion that L-80 was the strongest "sour service" material which could be specified with expedited procurement using standard specifications (API). Starting with 80,000 psi minimum yield strength and a 0.80 safety factor[4], a 0.250 in. wall tube provided adequate internal yield pressure. A 0.337 in. wall was selected because it provided 0.78 safety factor during fracturing for the triaxial stress just above a 5-1/4 in. seal assembly. With a 100% connection the tube provides 100,000 lbf over-pull to 13,400 ft with a 0.8 safety factor.

A non-upset premium threaded and coupled 99% efficient connection was specified. This eliminated any concern that the upsetting process would reduce the stress corrosion resistance of the steel in the upsets.

The tube size for the optimum specification was increased from 4-1/2 in. to 5-1/2 in. This provided minimal friction loss at rates up to 50

BPM and greatly improved the possibility of successful wireline operations in a pressurized, buckled tube. A specified minimum yield stress of 90,000 psi was selected after determining that 95,000 psi in a sour service tubing had a high cost to benefit ratio when compared with 90,000 psi mys. A 0.361 in. wall provided adequate internal yield pressure at a 0.80 safety factor and also provided a 0.70 safety factor when the triaxial stress just above the seal assembly was calculated (7000 psi with no backup on the annulus). An upset integral joint with a premium thread was selected over a threaded and coupled connection. It provided both an internal and external metal-to-metal seal which eliminates the loss of thread lubricant in the high temperature environment (bakeout) and resulting corrosive exposure of the highly stressed threads. The connection was rated at 95% of the tube strength and allowed workstring service to 15,000 ft with a 150,000 lbf overpull at a 0.8 safety factor.

An initial specification was prepared. However, there was concern that the marriage of sour service 90,000 psi minimum yield strength tubes and the normal upsetting process would be incompatible. Material and fabrication expertise was enlisted to improve this initial specification. As a result of this input the revised specification in Table 2 evolved.

FABRICATION OF THE 5-1/2 IN. TUBING

Insofar as could be determined, there were, as yet, no efforts anywhere worldwide to produce upset-ended 90,000 psi mys pipe. Our task was to accomplish the following:

(1) Determine and define the necessary parameters for a complete specification.

(2) Evaluate all mills professing interest in the order and select those which could produce the pipe to specifications on the first attempt.

A dialogue was conducted with all possible producers. As a result key processing needs and product needs were specified. The product needs are shown on Table 2 under the revised specifications. The revised specifications included the following process parameters: (1) ladle refining, (2) minimum tempering time of 45 minutes. (3) id/od quench, (4) cold straightening prior to final tempering, and (5) three stage upsetting.

The technical problem was to achieve required properties in a pipe with 0.361 in. wall thickness in the body and 0.845 in. wall thickness in the upsets. Most producers felt that this would require a special chemistry as well as special heat treating parameters. It was decided that the best qualified processing facility be selected. The order was placed with Mannesmann. Several Japanese mills were considered equivalent but could not match delivery.

Mannesmann had ladle refining, continuous casting, rolling on a mandrel mill, and a versatile and outstanding heat treating facility (quenching by submerging and walking beam furnaces with eight heating zones).

Los Alamos National Laboratory metallurgist, William Turner participated fully with a three man team from the mill to select exact process parameters and controls. Mannesmann efforts were superb, but we feel user participation was vital.

The primary technical discussion was whether or not a special chemistry would be needed to obtain full martensite through the 0.845 in. wall. It was decided that very rapid quenching (submerged water with massive water flow) would do the job with standard chemistry. The time scale dictated pouring of the steel several months before development of the heat treating process. This correct decision was the primary basis of eventual complete success.

The steel making by Mannesmann was excellent. There was no ductile/brittle transition temperature from test temperatures as low as -112°F the lowest temperature possible for the apparatus. Martensite as quenched exceeded 99%. The minimum wall thickness was 2% below nominal. No defects occurred during upsetting, even as evaluated at 200 X. Sample sections passed the NACE stress cracking criteria at 100% loading. The calculated design strength of the pipe was increased by the high mys and minimum wall thickness (Table 3).

The upsetting was dimensionally excellent. The axis of the upset was within 0.010 in. radius of the axis of the pipe. Three stages of upset were required, as expected. Upsets allowed one or two recuts. All upsets cleaned up readily and all could be machined as a box or pin end. Threading was easily accomplished by chucking on the OD of the pipe body with a three jaw chuck with no correction factors for alignment.

Threading of tubing was complicated by the requirement that the material properties in the upset be the same as those in the tube (allowable exceptions are shown in Table 2). Normal "oil field" threading requirements allow upsetting of quenched and tempered pipe without Q&T after upsetting or allow Q&T upsets to be softened by induction heating to improve machineability of the upset. Consequently, for our order, the speeds, feeds, depth of cutting and sequence of cutting normally used all had to be adjusted for threading harder than normal material. Because the steel mill and threading facility did not routinely work together, user participation provided early coordination which eliminated all but minor delays in the threading. Fabricating upsets with the proper dimension is critical, and providing pipe with stringent OD and straightness tolerances can make threading easier which results in a much improved product.

PERFORMANCE OF TUBING

The 4-1/2-in. (minimum lead time specification) L-80 VAM tubing has had very limited fracturing service to date. It performed satisfactorily during a pre-fracturing hardware test at pumping pressures up to 5800 psi with 1000 psi backside pressure. The string was installed, for isolation service in EE-3 for three months. Upon removal it was found to be in good condition with the exception of a few dried out joints which were hard to break out because the high temperature thread lubricant had been baked out.

The 5-1/2 in. (optimum specification) sour service C-90 Hydril TAC I has seen service in both wells. As a short 600-ft tie-back liner in EE-3 it was exposed to 450°F fluids for three months in isolation service. It was removed with no problems breaking out the joints and no evidence of bake-out of the thread lubricant.

An 11,350 ft long 5-1/2-in. tubing string was installed in EE-2 where it was used to pump 130,000 bbls of water at pressures up to 7100 psi with 2000 psi back-up at rates up to 50 BPM. A fatigue failure of a wellhead flange ended the pump. The surface equipment failure combined with operational problems exposed the tubing to differential pressures of 6000 psi, 100 BPM flow rates, eventual flowing temperatures above 425°F and bottom hole thrust loading sufficient to force tubing through blow-out preventer rams as it expanded during heat up. Tests conducted subsequent to the flow back of 60,000 bbls fracturing fluids showed that the tubing had pressure integrity but that it was partially stuck 2000 ft above the packer. The tubing has not been removed at this time, but permanent corkscrewing of the tubing is one of several modes of sticking that seem to be possible. If corkscrewing occurred as a result of a release of the packer slips on the 9-5/8-in. casing packer, combined (triaxial maximum energy of distortion theory) stresses in excess of 90,000 psi may be been imposed on lower part of tubing.

CONCLUSIONS

1. Proper definition of environmental conditions, detailed stress analyses and a very detailed product specification with fabrication process requirements have provided tubulars which are capable of withstanding the severe fracturing conditions in the Fenton Hill hot dry rock wells.

2. While the technology to produce, upset and thread a sour service 90,000 psi mys integral joint tubing existed, the totally successful production of the product on the first attempt would not have been achieved without early and very active participation with the steel mill and threading facility by Laboratory Staff.

3. Los Alamos National Laboratory participation in the setting of process parameters and fabrication techniques was vital for:

   a. Upsetting methods,

   b. Dimensional inspection of the upsets,

   c. Nondestructive testing and destructive tests of pipe body and upsets,
   d. Development of heat treating parameters,

   e. Decision to utilize standard chemistry.

ACKNOWLEDGMENTS AND DISCLAIMER

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Table 3

Result of Controls Of Minimum Yield Strength and Wall Thickness On Strength of 5-1/2 Inch Tubing

Parameter	Initial Specification	Final Specification	As Received
Minimum Yield Strength (psi)	90,000	90,000	95,000
Maximum Yield Strength	Not Specified	105,000	103,000
Minimum Allowable Wall Thickness (% of Nominal)	87-1/2%	92%	98%
Tubing Properties (API formulas) as a result of the above properties			
Pipe Body Yield Strength (lbf)	525,000	525,000	554,000
Internal Yield Pressure (psi)	10,340	10,870	12,220
Minimum Collapse Pressure (psi)	9640	9640	10,000
Connection Strength (lbf)	496,000	496,000	524,000
Maximum ID (in.)	4.868	4.836	4.792
Stress During Fracturing			
	Calculated Stress (psi)*		
Axial	-8,241	-8,241	-8,241
Bending**	±16,894	±16,112	±15,169
Tangential**	+52,631	+52,062	+51,294
Radial	-7,000	-7,000	-7,000
Triaxial	70,471	69,386	68,000
Safety Factor	0.783	0.771	0.716

* 7000 psi internal pressure with no back-up using a 5-1/8-in. OD seal assembly.
** Stress calculated for maximum internal diameter.

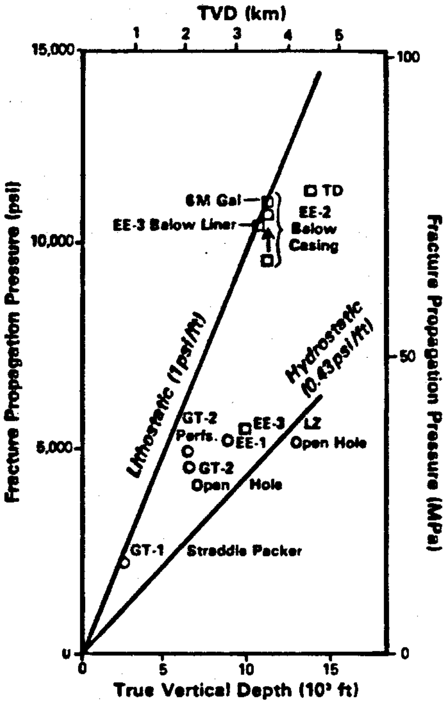

FIGURE 2
Fenton Hill fracture propagation pressure at various depths.

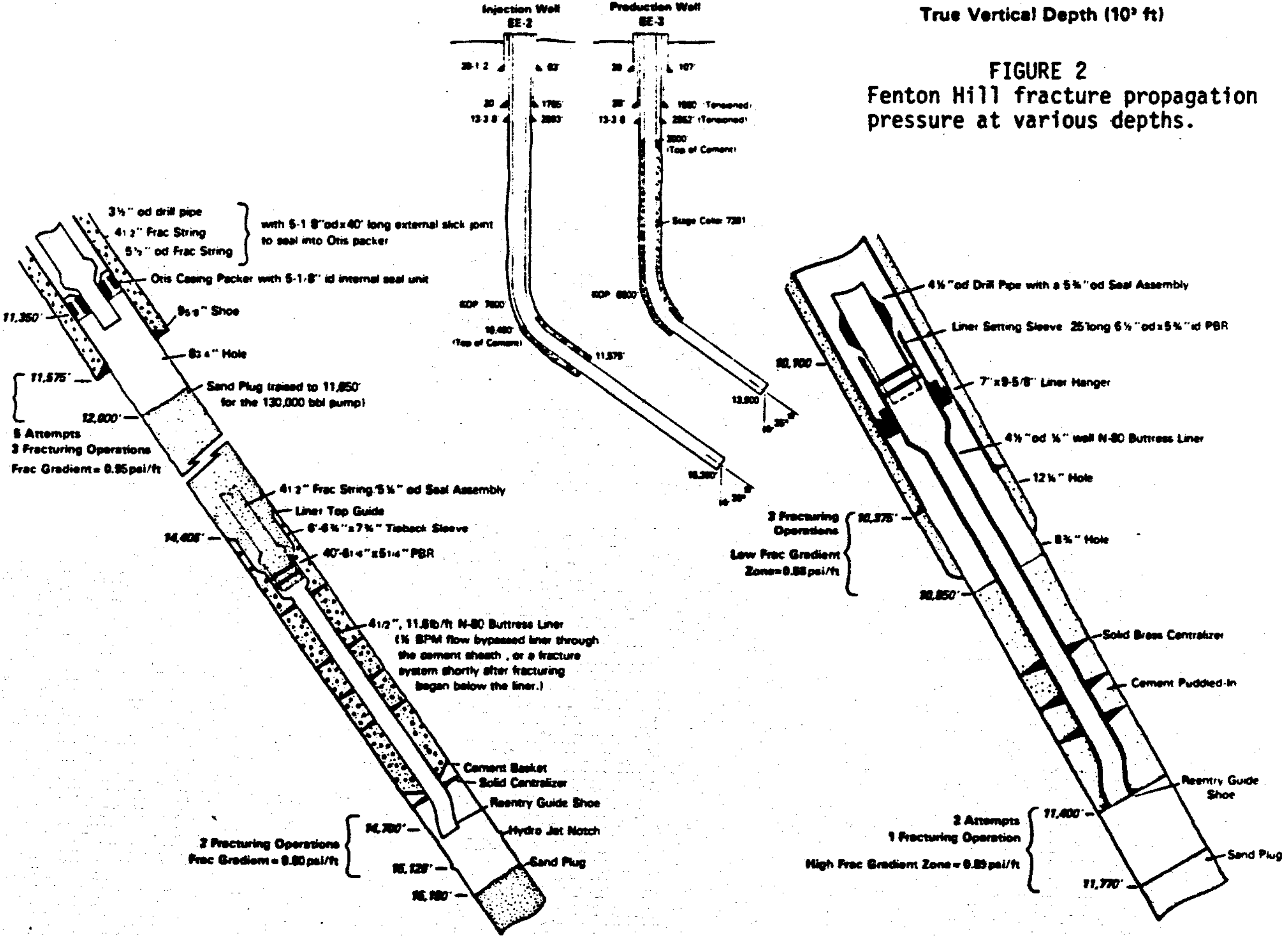

FIGURE 1
Schematic profile of wells EE-2 and EE-3 (center) with tubulars and fracturing hardware detailed (left and right)

Table 1

Summary of Downhole Tubulars Used for Fracturing in EE-2 and EE-3

	Seal Unit		Tubing Used				Measured Depth (ft)						
Date	O.D. (in.)	Style*	Size (in.)	Wall (in.)	Grade	Joint	Seal Unit	Inj. Zone Top	Volume Injected (bbl)	Surface Pressure (psi)	Injection Rate (bpm)	Maximum ISIP	Result
EE-2													
6-4-82	5-1/4	SA	4-1/2	0.250	P-110/N-80	Buttress	14,400	14,700	20,000	6600	30	5400	Split Collar on N-80 Joint
6-19-82	"	"	"	"	"	"	"	"	31,000	7040	36	5200	Master Valve Leak
7-19-82	5-1/8	SJ	3-1/2	0.368	S-135	IF DP	11,300	11,575	6700	7000	14	3900	Drill Pipe Joint Spit in Slip Area
7-24-82	"	"	"	"	"	"	"	"	270	5800**	5	—	"
10-2-82	5-1/8	SJ	4-1/2	0.250	P-110/N-80	Butt	"	"	170	3100**	4	—	Split Collar on P-110 Joint
10-6-82	"	"	"	"	"	"	"	"	20,000	7000	34	5950	4 Split P-110 Collars and 2 P-110 Joints Split in the Slip Area
EE-3													
12-4-82	5-3/4	SA	4-1/2	0.337	S-135	XH DP	10,200	11,400	3600	6900	25	—	Drill Pipe Joint Split in the Slip Area. 4-1/2 in. K-80 Cemented-in Liner Collapsed.
6-22-83	5	SA	4-1/2	0.337	L-80	VAM	"	"	470	5800	8	4980	Screw-in Collar on Cemented-in Liner Jumped Out
EE-2													
12-6-83	5-1/8	SJ	5-1/2	0.361	C-90	TAC-I	11,350	11,575	130,000	7100	50	6400	Companion Flange on Wellhead Failed in Fatigue.

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* SA = Seal Assembly; SJ = Slick Joint

** Failure occurred Before Normal Injection Pressure Achieved.

Table 2

Tubing Specifications and as Delivered Parameters

Parameter	Specified Value Of String			Material Description as Received		
Tube	Minimum Lead Time Effort	Optimum Effort	Revised Optimum	Minimum String	Optimum String	
Outside Diameter (in.)	4-1/2	5-1/2	5-1/2	4-1/2	5-1/2	
Wall Thickness (in.)	0.337	0.361	0.361	0.337	0.361	
Minimum Wall	-12.5%	-12.5%	-8%	NC	-2%	
Joint Length (Range/ft)	API range II	API range II		API Range II	28.7'-32.8'	
Grade	API L-80	Proprietary C-90	C-90	L-80	C-90	
					Tube	Upset
Min. Yield Strength (psi)	80,000	90,000	90,000	86,240	95,430	92,824
Min. Tensile Strength (psi)	95,000	100,000	100,000	101,970	111,240	110,370
Min. Impact Strength (ft-lb)	not specified (NS)	NS	70*	NS	78.6	77.2 (32°F)
Min. Elongation	19.5%	18%	19%(22% in upset)	28%	23.6	23.2
Maximum Rockwell C Hardness	23	25	24.2	23	23.8	23.9
Minimum Rockwell C Hardness	NS	NS	18		19.0	18.5
Allowable Through Tube Hardness Variation	NS	3 (4 in. upset)	No Change (NC)	2.9	2.0	2.5
(%Martensite as quenched)	NS	90%	95%	NS	99+%	99+%
Grain Size	NS	ASTM 5 or finer	ASTM 7 or finer	NS	ASTM 11	11
Sulfide Stress Cracking Resistance	NS	NS	no failure at 80% of mys*	NS	no failures 100% mys	no failures 100% mys
Straightness	NS	NS	0.036"/meter	NS	as specified	
Parameter Connection	Required Features Minimum String	Optimum String				
Type	Premium non upset	Premium upset	NC	4-1/2 in. VAM	5-1/2 in. TAC I	
	Threaded and coupled	Integral joint	NC		Hydril	
Seal	Internal metal-to-metal	Internal and external metal-to-metal	NC	NC	NC	
Joint Efficiency	99%	95%**	NC	99%	120%	
Critical Members	coupling	pin		coupling	pin	
Recommended Maximum Makeup Torque	7200 ft lb	8750 ft lbs	NC			
Material	API L-80 coupling	Upset same as tube	NC	API L-80 coupling	Threads cut on full hardness (as received) upset	

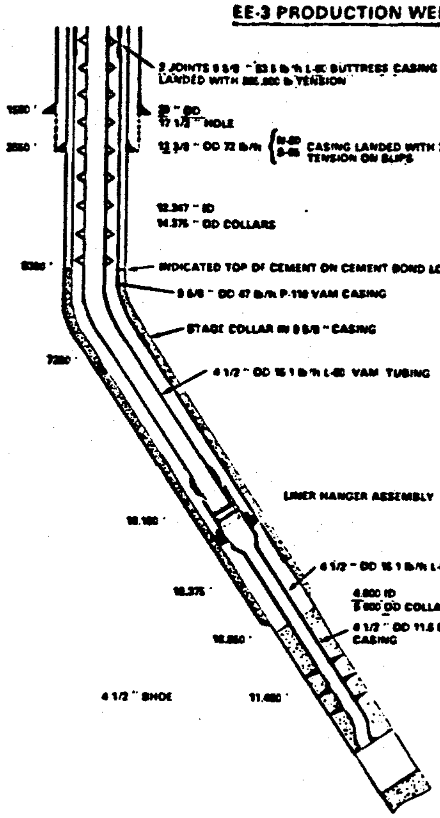

FIGURE 1
Completion of HDR geothermal well EE-3. This well was originally intended, and pre-tensioned, to serve as a production well for hot water.

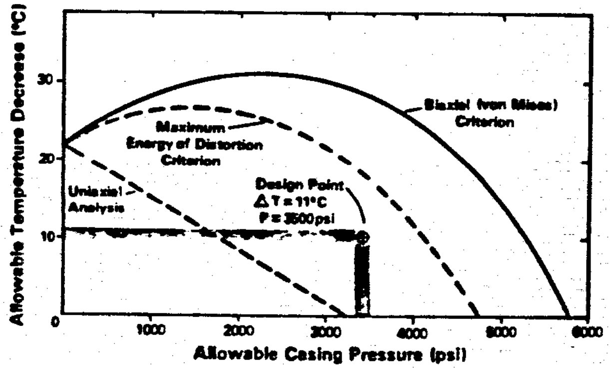

FIGURE 2
Allowable casing temperature decrease and allowable pressure based upon allowable yield strength of 64,000 psi (80% of actual yield) for upper joints of L-80 casing.

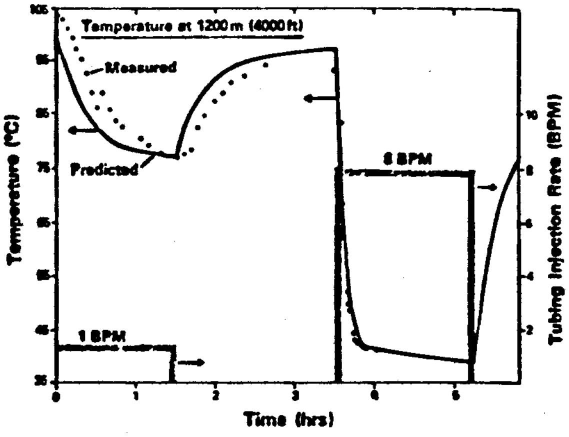

FIGURE 3
Comparision of measured and predicted temperatures in the tubing at 4000 feet depth during nitrogen gas insulation experiment. Predictions are based upon gas natural convection heat transfer correlation, equation (1).

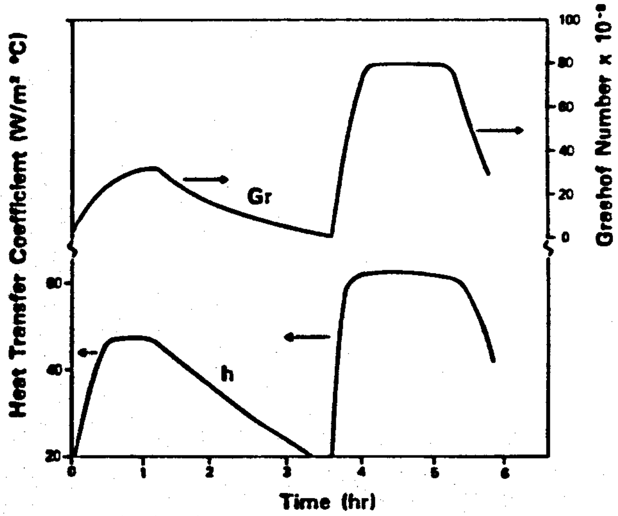

FIGURE 4
Variation of Grashof number and convective heat transfer coefficient at 4000 feet during nitrogen gas insulation experiment. Variations shown result from the changing temperature difference across nitrogen filled annulus induced by injection down tubing. Injection history shown in Fig. 3.

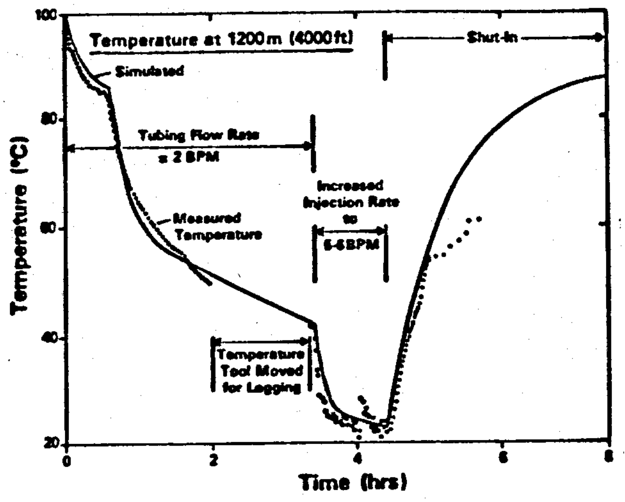

FIGURE 5
Comparison of measured and simulated temperatures in the tubing at 4000 feet during the foam insulation test. Simulations are based upon the heat transfer coefficients in Table I. Theoretical basis of these coefficients is discussed in the text.

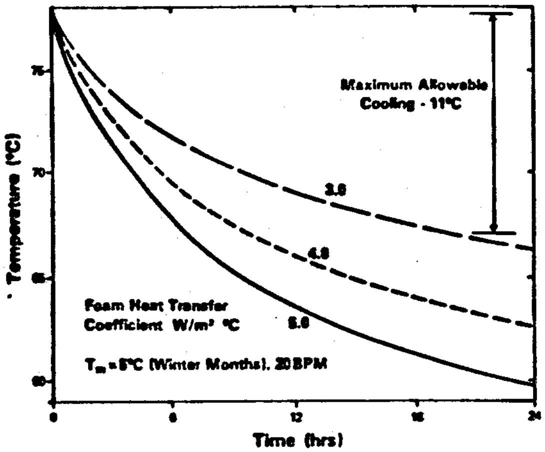

FIGURE 6
Variation of casing cooling for the annulus heat transfer coefficients indicated. Winter-time operation (water injection temperature = 5°C) at 20 bpm is shown. An injection of 1,000,000 gallons, requiring 20 hours, would result in casing cooling greater than 11°C unless the heat transfer coefficient is less than 3 W/(m^2°C).