

RESERVOIR STUDY
OF THE ARBUCKLE FORMATION
SEQUOYAH FUELS CORPORATION
SEQUOYAH WASTE STORAGE WELL
SEQUOYAH COUNTY, OKLAHOMA

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February 1984

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INTRODUCTION

H. K. van Poolen and Associates, Inc., has performed an engineering study of the Arbuckle formation, which is exposed to the Sequoyah Fuels Corporation waste storage well located in Sequoyah County, Oklahoma.

The purpose of the engineering study was to determine if the Arbuckle formation at the site is finite in size and suitable as a disposal reservoir for the waste water by-products produced by the Sequoyah Fuels Corporation at its Sequoyah County facility.

In order to determine whether or not the reservoir is finite, a volume of fluid was injected into the formation at essentially a constant rate. The pressure required to accomplish the injection was carefully monitored at the surface and also at a depth of 2,650 ft below ground level (G.L.), see Figure 1. Pressure readings were taken at depth to eliminate most frictional pressures of the fluid movement through the tubulars and to measure the actual pressure being exerted on the formation. At the conclusion of the injection of fluids, the pressure at depth was closely monitored to determine the amount of residual incremental pressure increase that has occurred from injecting a known volume of fluids into the reservoir. Since the final average formation pressure is indicated to be greater than the initial formation pressure, the formation must be finite. Had the final average formation pressure not increased from the starting pressure, then the formation would have been considered to be infinite or leaky. In addition, analyses were performed to determine reservoir size, near wellbore conditions, and future injectable volumes.

The Sequoyah waste storage well was subjected to an injection test for the first time in the time period from June 18 to July 26, 1971. During this test, 836,143 gals. of fresh water were injected into the well over four separate time intervals at rates that varied from 25 gals./min. to 91 gals./min. This first test, conducted by H. J. Gruy and Associates, Inc., did indicate that the Arbuckle was finite, but was deemed to be inconclusive by the Atomic Energy Commission.

The second test and subject of this report utilized the injection of five million gals. of neutralized, barium treated, filtered

raffinate injected at an average rate of 60.7 gals./min. from June 6 to August 2, 1983. The injection rate did vary to a small degree, but not significantly so. The conclusions of this report are reached from the analysis of the data gathered from this second test only. In order to assist in the interpretation of the data, a series of four fluid injection profiles was run (see Figures 2 - 5). The fluid injection profiles quantitatively identify the portions of the exposed Arbuckle formation that were taking the injected fluids at the time of the surveys. Inspection of the surveys indicates that the injection profiles did not vary significantly during the injection period.

CONCLUSIONS

Based on extensive pressure testing and analysis of the Sequoyah Fuels Corporation waste disposal well completed in the Arbuckle formation, Sequoyah County, Oklahoma, it has been determined that the reservoir is multilayered and finite. Interpretations of the radioactive tracers taken from the four 1983 surveys confirm that several layers are taking injection fluid, and that there are no leaks or channels behind the casing or around the packer. Approximately half of the injection fluids appears to be entering the upper layers (1,750 ft - 1,825 ft) with the remaining fluid entering the lower layers below 2,650 ft. This observation was shown to be consistent for all four surveys.

Currently, the waste disposal well has an average effective permeability of 988 md for the zones taking fluid. A total net effective thickness, "h net", (portion which takes injected fluids) of 390 ft was calculated by assuming a core permeability cutoff of 1.0 md and determining a corresponding core porosity cutoff of 5% (see Figure 6). All zones with FDC-SNP log crossplot porosity¹ (corrected for lithology) greater than or equal to 5% were totaled to obtain the net effective thickness.

An average effective porosity (ϕ_{eff}) of 8.25% of bulk rock volume was calculated using the thickness weighting formula:

$$\phi_e = \frac{\sum \phi_i h_i}{h_{net}} \quad (1)$$

A reservoir volume of 7.7 billion Bbls [$4.323(10^{10})$ cu ft] was calculated by material balance methods, as discussed in the section entitled, "Material Balance Calculations".

A reservoir area of approximately 48 square miles (30,898 acres) is then calculated volumetrically from the above data.

With this reservoir volume and a maximum wellhead pressure of 250 psig, this reservoir is suitable for 450 million gals. of additional disposal.

RECOMMENDATIONS

Based on the results of the injectivity and falloff test performed on the Sequoyah Fuels waste disposal well which show the reservoir to be of a finite nature, the well would be a satisfactory candidate for designation as a waste disposal well.

The disposal of all current inventory stocks of raffinate and future raffinate production, anticipated to be 85,000,000 gals., will cause a pressure increase in the reservoir of only 38.65 psi. The pressure increase is calculated as follows:

$$dp = \frac{1}{C_t} \frac{dV}{V_{res}} \quad (2)$$

Where:

dp = pressure increase from injection (38.65 psi)

C_t = total compressibility (6.8×10^{-6} Vol/Vol/psi)

dV = injected volume (85×10^6 gals.)

V_{res} = reservoir volume (7.7×10^9 Bbls)

$$dp = \frac{1}{6.8 \times 10^{-6}} \times \frac{85 \times 10^6 \text{ gal.} \times \frac{1 \text{ Bbl}}{42 \text{ gal.}}}{7.7 \times 10^9 \text{ Bbls}}$$

$$= 38.65 \text{ psi}$$

During all future raffinate disposal, the injection rate, cumulative injection, and pressure behavior of the injection well should be carefully monitored. To facilitate calculation, the fluid should be injected at a constant rate for extended periods of time, whereafter the well should be shut in at the wellhead for, preferably, twice the time of injection. During the injection and shut-in periods, pressures should be observed and recorded. The resulting falloff data will permit extrapolation of static reservoir pressures, which will allow for material balance calculations to be updated.

WELL TEST ANALYSIS

The well test analysis involves both the injectivity portion of the test as well as the pressure falloff portion. Figure 7 is a graph which summarizes the pressure changes, taken at the 2,650 (downhole) depth, for the entire test.

Injectivity Test Analysis

Permeability Determination

The permeability of a formation is a measure of the ease at which fluids can move through a formation. The unit of permeability in general use within the oil industry is the millidarcy (md). The larger the number, the easier it is for fluids to move through the formation.

The determination of permeability is made by analysis of the pressure response curves, and the method is outlined in the Society of Petroleum Engineers Monograph No. 5, entitled, "Advances in Well Test Analysis", p. 75, written by Robert C. Earlougher, Jr. This method is well established in the oil industry and has been proven through numerous applications to be a proper method of establishing the permeability of a formation.

Figure 8 shows a plot of the logarithm (base = 10) of the difference between the downhole injection pressure ($P_{w \text{ inj}}$) and the initial reservoir pressure (P_i) versus the log of injection time (t, hrs). An initial reservoir pressure of 1,257.73 psia was used as measured at 2,650 ft below ground level (G.L.) with the Lynes CWL-300 PTX-SK-5K pressure gauge. This plot is made to determine when wellbore storage effects cease to dominate the pressure response. Simply stated, wellbore storage effects could result here if the well was not full of fluid at the start of surface injection, thus resulting in a time lag before the downhole injection rate equals the surface rate. The lack of a unit slope on the above plot shows that early wellbore storage effects are negligible, and that the first established semilog straight line on the pressure versus log injection time plot (Figure 9) should yield data suitable for calculation of average effective permeability in the Arbuckle formation as follows:

$$\text{Permeability, } k = \frac{-162.6 \ q \ B \ \mu}{m \ h} \quad (3)^2$$

$$k = \frac{-162.6(-2,088)(1.0037)(0.98)}{(1.33)(390)}$$

$$= 643.8 \text{ md}$$

where:

k = permeability (millidarcies)

q = injection rate (BPD)

μ = viscosity of the raffinate (centipoise)

B = Formation volume factor for the raffinate and
formation fluid (dimensionless - $\frac{\text{Reservoir Barrel}}{\text{Stock Tank Barrel}}$)

m = slope of the plotted pressures on the Horner
Plot, Figure 9, early shut-in time.
(psi/log cycle)

h = effective thickness of the formation (ft)

The values of the parameters are determined as follows:

k = the unknown to be determined

q = towards the end of injection, the rate was measured as an average of 60.9 gals./min.
Converting this value to BPD:

$$60.9 \times 60 \times 24 \times 1/42 = 2,088 \text{ BPD}$$

Note that the injection rate is entered as a negative value. By convention, this merely denotes that it is fluid being injected into the formation rather than being produced from the formation.

μ = 0.98 centipoise, surface measurement of viscosity adjusted for bottom-hole conditions

$B = 1.0037 \frac{\text{Reservoir Barrels}}{\text{Stock Tank Barrels}}$; from Hewlett Packard Petropac program for Arbuckle water having 142,000 ppm total dissolved solids.

$m = 1.33$ psia/log cycle, determined from Figure 9, the semilog plot covering the pressure decline that occurred during the early shut-in time.

and:

$h = 390$ ft, determined by totaling the thicknesses of those intervals within FDC-SNP crossplot porosities greater than or equal to the 5% porosity cutoff established via Figure 6.

The permeability value calculated above agrees sufficiently with that calculated for the falloff portion of the test (see Pressure Falloff Analysis), thereby validating the interpretation. Exact agreement is not to be expected, since injection rates were not precisely constant during the injection phase.

Calculation of "Skin" Effect

The "skin", S , is a measure of the deviation of a well's performance from that predicted by Darcy's law and diffusivity solutions. As such, a positive skin indicates the well will perform

less than ideally; i.e., the well is damaged. Conversely, a negative skin indicates stimulation. For injectivity testing, the skin is given by:

$$S = 1.1513 \left[\frac{P_{1hr} - P_i}{m} - \log \left(\frac{k}{\phi \mu C_t r_w^2} \right) + 3.2275 \right] \quad (4)^3$$

where:

P_{1hr} = pressure extrapolated from slope m one hour after injection has ceased (psi)

P_i = pressure in the formation before starting injection (psi)

m = slope of a straight line constructed through the pressures plotted (psi/log cycle)

k = permeability (millidarcies)

ϕ = porosity expressed as a fraction of bulk volume from log

C_t = total compressibility of the reservoir system (Vol/Vol/psi)

r_w = radius of the wellbore (ft) from caliper logs

μ = viscosity of injected fluid (cp)

$$S = 1.1513 \left[\frac{1,262.7 - 1,257.73}{1.33} - \log \left(\frac{643.89}{(0.0825)(0.98)(6.8 \times 10^{-6})(0.5)^2} \right) + 3.2275 \right]$$

$$S = -3.12$$

Thus, indicating the well is stimulated. This results in the following pressure drop.

$$\begin{aligned} \Delta P_s &= \frac{141.2 q B \mu}{k h} S \\ &= 3.60 \text{ psi} \end{aligned} \quad (5)^4$$

The above would indicate that the downhole injection pressure is 3.60 psi lower than the theoretical value.

Inspection of Figure 9 shows a constantly changing slope after the initial semilog straight line. Boundary effects are responsible for the gradual increase in slope here. This indicates that the skin effect calculation for the falloff data will likely give different results.

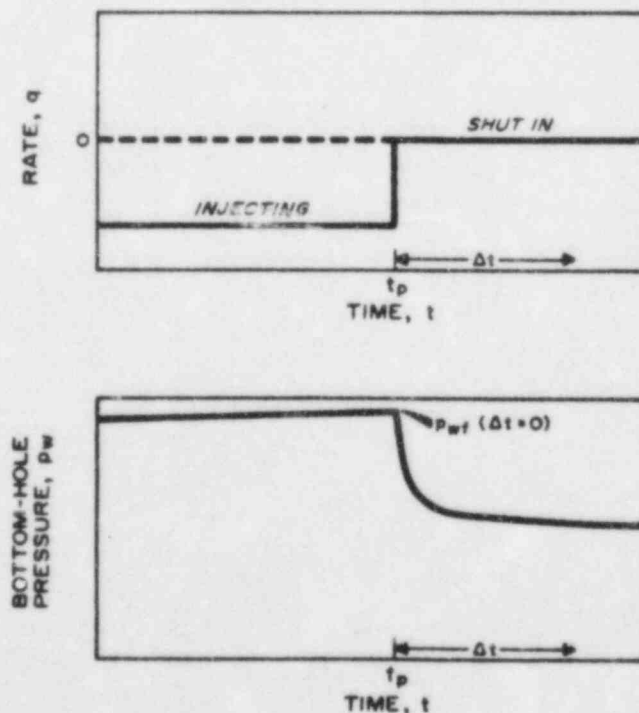
Pressure Falloff Analysis

Pressure falloff analysis means analysis of those pressures recorded after the fluid injection has stopped.

Permeability Determination

The determination of permeability in injection wells is made by analysis of the pressure response curves. The methods are outlined in the Society of Petroleum Engineers Monograph No. 5, entitled, "Advances in Well Test Analysis", p. 77, written by Robert C. Earlougher, Jr.

Figure 7, as well as the following illustration, will serve as an aid in understanding some of the terms and concepts pertinent to pressure falloff test analysis:



Idealized rate schedule and pressure response for falloff testing.

Figure 10 is a plot of the logarithm (base 10) of the difference between the last measured injection pressure: $P_{wf}(\Delta t=0)$ and the subsequent falloff pressures: $P_w(\Delta t>0)$ versus the logarithm of the shut-in time, Δt . Note that $\Delta t = 0$ at the instant of shut-in, and further, that the total elapsed time, t , is the sum of the injection time, t_{inj} plus the shut-in time, Δt ; i.e., $t = t_{inj} + \Delta t$.

In computing Horner time, t_{inj} is calculated from the following equation:

$$t_{inj} = \frac{24 V_{inj}}{q} \text{ (hours)} \quad (6)^5$$

where:

V_{inj} = total volume of injected fluid (Pbls)

q = the last constant injection rate just before shut-in, Bbl/D

This is done because the pressure falloff response after shut-in is most strongly influenced by this last rate. Using the last stabilized rate of 60.9 gal./min. (2,088 B/D) and an injected volume of 5×10^6 gal. (119,047.6 Bbls), an adjusted injection time, $t_{inj} = 1,368.36$ hrs, was calculated and used in all Horner time computations.

Figure 10, like Figure 8, is made to determine when wellbore storage effects cease to adversely influence the data. As before, the lack of a unit slope here indicates wellbore storage effects to be negligible, and thus permits the use of the first established straight line on the Horner Plot (Figure 11) to determine permeability and "skin".

Figure 11 shows the downhole falloff pressure plotted against the logarithm of Horner time. Horner time is defined as the ratio of total elapsed time divided by shut-in time; i.e.,

$$\frac{t}{\Delta t} = \frac{t_{inj} + \Delta t}{\Delta t} = \text{Horner time}$$

This type of plotting is referred to as a "Horner Plot" in the oil industry. This graph is read from right to left; in other words, the pressure corresponding with the earliest shut-in time is plotted on the right side of the graph and the pressures incurred later in the shut-in time are plotted moving to the left.

The simultaneous solution of the radial flow diffusivity equation yields the following:

$$P_{ws} = P^* - m \log \frac{t_{inj} + \Delta t}{\Delta t} \quad (7)^6$$

Here it is noted that P^* is read from the extrapolation of data to a Horner time of 1 (equivalent to an infinite shut-in time) and m is the first semilog straight line slope on the Horner plot, and is equal to the quantity:

$$m = \frac{162.6 q B \mu}{k h} \quad (8)^7$$

The simultaneous solution involves the principle of superposition, in which the injectivity equation for an infinite reservoir is summed with a similar equation which assumes that production from the well (at a rate equal to the injection) begins at the instant of shut-in. By summing the two expressions, we get the expression for falloff behavior, Equation 7 above.

It should be noted that even though in reality the rate, q , during falloff is zero, Equations 7 and 8 require the use of the injection rate prior to shut-in for solution. From Figure 11, we measure a slope, m , of -0.867 psi/cycle. The formula used to calculate the permeability is as follows:

$$k = \frac{162.6 q B \mu}{m h} \quad (9)^8$$

Knowing all other values as shown previously, we calculate the value for the permeability from the falloff data:

$$k = \frac{162.6 \times (-2,088) \times 1.0037 \times 0.98}{-0.867 \times 390} = 987.6 \text{ md}$$

The value calculated above agrees sufficiently with that previously calculated for the injectivity portion of the test thereby validating the interpretation. Exact agreement with values calculated for the injectivity test is not to be expected since injection rates were not precisely constant during the injection phase. As such, the value calculated for the falloff phase above is the most reliable since the injection rate is then known to be constant and equal to zero. The use of Darcy's law equations assume constant flow rates.

Calculation of the "Skin Effect"

As mentioned before, skin effect is a measure of formation damage (or improvement) that has occurred in the area of the formation close to the wellbore, probably within 3 ft. The cause of the damage could be from the original drilling operation, from fluids previously injected into the well, from fluids injected into the well during this testing procedure, or from a combination of all these factors. The probability of the skin damage being caused by an adverse chemical reaction of the raffinate on the Arbuckle Limestone is considered to be remote, but nonetheless, a possibility.

The skin factor and, subsequently, the pressure loss due to skin damage are common oil field phenomena and use formulae as referenced. The values of the parameters needed for solution of the formula are derived from the Horner Plot and from previous known or calculated data. The formula for skin factor (S) was given in Equation (4). For falloff data, P_i is changed to $P_{wf} (\Delta t=0)$ which is the pressure immediately prior to stopping injection.

The values of the parameters, with the exception of the extrapolated pressure one hour after termination of injection, have been given previously.

The value of P_{1hr} is obtained by reading the pressure off the extrapolated semilog straight line at a shut-in time of one hour, and is 1,289.1 psi (Figure 11). The wellbore radius averages 0.5 ft from caliper surveys. Entering values into the formula, we have:

$$S = 1.1513 \left[\frac{1,289.1 - 1,309.12}{-0.867} - \log \frac{987.6}{(0.0825)(0.98)(6.8 \times 10^{-6})(0.5)^2} + 3.2275 \right] \quad (10)$$

$$S = +18.95$$

The value, being a positive number, means that there is apparently wellbore damage present. The value of "S" can vary from about -5 for a hydraulically fractured well to $+\infty$ for a well that is too damaged to produce or accept injected fluids. The calculated skin for the injectivity test is usually more reliable than that for the falloff (if $q = \text{constant}$) since rigorous inspection of the falloff solution shows that "S" cannot be uniquely determined if boundary effects are present. Nevertheless, some additional calculations can be made for comparative purposes with data from subsequent tests.

The equation to calculate the pressure deviation from the theoretical was given previously in equation (5). The equation can be modified for simplicity by the realization that since $m = \frac{162.6 q B \mu}{k h}$, all the parameters in the formula, with the exception of S, can be equated to 0.87 m; therefore, the formula becomes $\Delta P_s = 0.87 m S$. Solving for the equation to determine the pressure loss through the skin, we have:

$$\Delta P_s = 0.87(-0.867)(18.95) = -14.29 \text{ psi}$$

The 14.29 psi calculated for the pressure loss through the skin compares reasonably well with the recorded downhole pressure loss of 17.35 psi noted at the instant of shut-in, as shown in Figure 7. To further evaluate the value for the skin pressure loss, we have noted that the surface pressure reduction at the moment of stopping injection was recorded to be approximately 30 psi. This pressure loss is composed of two parameters: the friction loss of the fluids in the tubing and surface lines, and the pressure loss through the skin, of $\Delta P_{\text{surface}} = \Delta P_{\text{friction}} + \Delta P_{\text{skin}}$. Substituting in this formula the two observed values of 30 psi for the reduction in surface pressure ($\Delta P_{\text{surface}}$) and 17.35 psi for the observed downhole pressure drop at

shut-in (ΔP_{skin}) would result in a value for the friction loss ($\Delta P_{\text{friction}}$) of 12.65 psi. Considering that the 60 gpm flow moved through the surfacing piping (Figure 13), 1,600 ft of 3-1/2 in. (O.D.) tubing and 1,050 ft of open borehole, this friction loss is in the range of an expected value.

The effect of the skin damage is to reduce the injection efficiency; that is, a lower injected fluid rate is being attained than could be under ideal conditions with the bottom-hole pressure that has been applied. The formula for flow efficiency is as follows:

$$FE = \frac{P_i - P(\Delta t=0) - \Delta P_{\text{skin}}}{P_i - P(\Delta t=0)} \quad (11)$$

(as modified from that in Reference No. 10)

and, substituting in the known values, we obtain:

$$FE = \frac{1,257.73 - 1,309.12 - (-14.30)}{1,257.73 - 1,309.12} = 0.722 = 72.2\%$$

During subsequent injection tests, the skin effect and flow efficiency should be calculated to note changes in well performance.

Boundary Analysis

Multiple faults near a well may cause several transient-test characteristics. For example, two faults intersecting at a right angle near a well may cause the slope to double, then redouble, or may cause a four-fold slope increase. It is not safe, however, to assume that additional boundaries continue to double transient-test response slopes. The problem is further compounded by the probability that the Arbuckle Formation at Sequoyah behaves as a multi-layer reservoir with crossflow occurring in the wellbore. Since permeabilities from core analysis were shown to vary widely in the formation, it can be shown that pseudo steady-state flow will generally begin much later in such a commingled system than in the equivalent single-layer system, because of the complex variation of injection reception of each layer and the different times required for boundary effects to be observed in each

layer. If the average formation damage (calculated above) varies from layer to layer, the behavior becomes increasingly difficult to interpret analytically and, as such, it is improbable that an accurate distance to the fault(s) can be determined by analysis of the Horner Plot. While the distances and direction to various faults would be academically interesting, it is not necessary information to develop the premise that the Arbuckle Formation is finite. It is safe, however, to state categorically that the very shape of the injectivity portion of Figure 7 is not characteristic of an infinite reservoir (which would show a quicker flattening of the pressure curve than was recorded).

Material Balance Calculations

The reservoir consists of a rock that has its porosity filled with saltwater under pressure and temperature conditions that were established prior to the beginning of the injection of the raffinate. The temperature of the formation will remain essentially constant and, therefore, need not be considered. Under these conditions, there are no gas filled void spaces within the formation into which injected fluids can readily be placed. There are three possibilities that can take place when fluids are injected into the formation:

1. A volume of fluid injected into the formation causes a like volume of fluid to be ejected from the formation. This event will happen if the formation is not sealed because it is continuous to a surface outcrop or has a termination at a non-sealing fault, or has been penetrated by another drilled hole that has been improperly plugged.
2. The formation is essentially infinite in size, being continuous over an enormous acreage so that the relatively small amount of fluid injected results in an unmeasurable increase in pressure.
3. The reservoir is finite in size and the injection of fluid does create a final, measurable pressure increase.

If the reservoir is finite, the additional "space" required to hold the injected fluid must be derived from the compression of the rock and the fluids in the rock. The amount of compression that takes place after injection results from the pressure increase that is determined to be permanent.

To determine a finite reservoir's ability to accept fluid requires a determination of the ability of the "rock" to compress with incremental pressure increase and the ability of the fluid(s) to compress (i.e. total compressibility " C_t "). A total compressibility factor of $6.8 \times 10^{-6} \text{ psi}^{-1}$ was used, which was the same compressibility factor used in the 1971 test.¹¹ The average reservoir pressure increase obtained by the injection of 5,000,000 gals. of raffinate has been determined to be 2.27 psia. The 2.27 psia pressure increase is the difference between the stabilized falloff pressure of 1,260 psia and the pre-injection downhole pressure of 1,257.73 psia. The former was obtained by extrapolation of the late-time measured falloff trend to an infinite shut-in time (equivalent to a Horner time of 1.0. See Figures 11 and 12).

Mathematically, the reservoir volume is calculated as follows:

$$V_{\text{res}} = \frac{1}{C_t} \frac{dv}{dp} \quad (12)$$

Where:

V_{res} = Reservoir volume (Bbls)

C_t = Total system compressibility ($6.8 \times 10^{-6} \text{ vol/vol/psi}$)

dv = Volume injected (5,000,000 gals. = 119,047.62 Bbls)

dp = Pressure increase resulting from dv (2.27 lbs/sq in.)

and:

$$V_{\text{res}} = \frac{119,047.62}{(6.8 \times 10^{-6})(2.27)} = 7.71 \times 10^9 \text{ Bbls}$$

The value computed above is considered to be the most probable since the pressure decline trend may deviate upwards from the extrapolated line, thus giving a larger pressure change and a smaller computed reservoir volume. For example, if the pressure ceased to decline below the last recorded pressure of 1,261.90 psia, we would calculate a ΔP resulting from the 5,000,000 gals. of injection of 4.17 psi, which would be 83.7% larger than the 2.27 value previously calculated from which we could compute a reservoir volume of

4.20×10^9 Bbls rather than 7.71×10^9 Bbls. The trend line in Figure 12 does not indicate that this is likely to be the case.

Two other considerations should be noted: first, the replacement of the broken down-hole pressure gauge No. 8009 with gauge No. 8007 may cause the pressure change to read as much as 0.206 psi higher than may have been recorded if the first gauge had not malfunctioned during the test, based upon the calibration data in Appendix I. Correcting this would show the reservoir to be 9.98% larger than the 7.7×10^9 Bbl figure. Also, it should be noted that other methods of estimating average reservoir pressure (i.e. Mathews-Brons-Hazebroek, Dietz, etc.) generally yield values of average reservoir pressure which are less than the P^* value obtained from the Horner Plot. Using the Mathews-Brons-Hazebroek method, we could calculate values of average reservoir pressure, which would be 4% to 14% below the 1,260 psia P^* from the Horner analysis, depending upon the exact position of the well within the bounded reservoir. As this information is indeterminable, it is concluded that the reservoir volume of 7.7×10^9 Bbls is still most probable with a range of certainty of + or -30%. This is on the order of 4,000 times the total volume of raffinate to be disposed of in the future.

Calculation of Future Injectable Volumes

The surface pressure that might create formation hydraulic fracturing has been set at 250 psig. This is the maximum amount of surface injection pressure that can be exerted at the surface without fracturing the formation at depth. The current surface pressure is 17.50 psig, and we estimate this pressure will decline by 1.90 psi at the time the entire finite reservoir has reached its final pressure. Thus, the "expected" surface pressure at the time of pressure stabilization will be $17.50 - 1.90 = 15.60$ psig. Therefore, we can determine the amount of pressure we have available for use to create further compression of the reservoir and fluids. This, in turn, equates to the volume of fluids that can be injected before any damage from hydraulic fracturing can occur. This calculation is as follows:

$$\Delta P_{res} = P_{wh_{max}} - P_{wh_{ex}} - (\Delta P_f + \Delta P_s) \quad (13)$$

Where:

ΔP_{res} = The reservoir pressure rise which can be accommodated under the stated constraints (psi)

$P_{wh_{max}}$ = Maximum permissible wellhead pressure (250 psig)

$P_{wh_{ex}}$ = Wellhead pressure expected at the time of resumption of injection (15.60 psig)

$(\Delta P_f + \Delta P_s)$ = As defined earlier, this quantity represents the observed surface pressure drop at the instant of shut-in and is composed of frictional and skin components for a 60 GPM rate (30 psig).

Solving for ΔP_{res} , we get:

$$\Delta P_{res} = 250 - 15.6 - 30 = 204.4 \text{ psi}$$

The future injectable volume dV_f may now be calculated as follows:

$$dV_f = V_{res} C_t \Delta P_{res} \quad (14)$$

$$= 7.71 \times 10^9 \times 6.8 \times 10^{-6} \times 204.4 = 10.7 \times 10^6 \text{ Bbls,}$$

or, 450 million gals.

We believe this calculated volume to be conservative because of the low value assigned to the pressure at which fracturing might occur. The above calculations apply only to injection rates of about 60 gpm.

The ranges of confidence outlined in the previous section (+30%) also apply directly here; i.e., the future injectable volume under the above constraints could range from 346 million gals. to 585 million gals. Of course, injection at higher rates will tend to reduce the allowable injection volume. The converse is true for injection rates less than 60 GPM.

COMPUTER MODELING

A three-dimensional radial model was set up with volumetric parameters as determined in the Material Balance section. The results of the model provided a good match with the actual data gathered during testing, thereby confirming the finite nature of the reservoir. Comparison of the model results with the actual recorded pressures (see Figures 15 and 16) shows good agreement, except that the trend of the pressures was not precisely matched because no near-well boundaries were input into the radial model. We feel that the critical parameters of reservoir size and finite character have been matched with the model.

The model was then used to make future predictions of reservoir pressure response to additional raffinate disposal. The model predicted a pressure increase from future anticipated injection of 85,000,000 gals, to be within 1 psi of the analytically predicted value of 38.65 psi (See "Recommendations" section).

The following table summarizes key modeling parameters:

Type: Radial, circular boundary at 16,477 ft radius from wellbore

Well Location: Centered

Pore Volume: 7.7×10^9 Bbls

Raffinate Viscosity: 0.98 cp

Initial Reservoir Pressure: 1,257.73 psia at 2,650 ft GL

Final Extrapolated Reservoir Pressure* = 1,259.8 psia @ 2,650 ft GL

Layer No.	Porosity %	Permeability md
2	6.4	1,469
3	6.0	1,179
4	8.9	600
5	9.9	600
6	5.8	2,480

*After injection of 5,000,000 gals.

REFERENCES

1. Schlumberger Log Interpretation Charts, Schlumberger Ltd. Chart CP-1a, "Porosity and Lithology Determination from Formation Density Log and Sidewall Neutron Porosity Log (SNP)", p. 30, 1972.
2. Earlougher Jr., R. C.: "Advances in Well Test Analysis", Monograph Series, Society of Petroleum Engineers of AIME, Dallas, Texas, p. 75, Equation 7.4, 1977.
3. Ibid, p. 75, Equation 7.5.
4. Ibid, p. 8, Equation 2.9.
5. Ibid, p. 77, Equation 7.11.
6. Ibid, p. 77, Equation 7.6.
7. Ibid, p. 77, Equation 7.7.
8. Ibid, p. 77, Equation 7.9.
9. Ibid, p. 77, Equation 7.10.
10. Earlougher, R. C., Monograph Series, Vol. 5, p. 9, Equation 2.12.
11. United States Atomic Energy Commission Hearing in the Matter of Kerr-McGee Corporation, Docket Sub. 1010, Washington DC, October 15, 1973, p. 162.

APPENDIX I
GAUGE CALIBRATION DATA

Instrument W1-100Serial # 8009

LYNES

Page 1 of 1Xdcr 7097

LYNES, INC. P.O. Box 12486 Houston, Texas 77217 Phone: (713) 943-0170 Telex: 774243 Cable: LYNESINC

Calibration Error Curve

RUSKA # 1970 Absolute Pressure	at 219 °F Probe Reading	P.S.I. Error	% Error F.S.
15.49	13.93	-1.56	-0.0312
114.51	112.90	-1.61	-0.0322
514.27	512.56	-1.71	-0.0342
1014.36	1012.62	-1.74	-0.0348
2014.38	2012.76	-1.62	-0.0324
2514.03	2512.34	-1.69	-0.0338
3014.16	3012.33	-1.83	-0.0366
4013.99	4012.26	-1.73	-0.0346
5014.33	5013.17	-1.16	-0.0232
2514.03	2513.25	-.78	-0.0156
514.27	513.14	-1.13	-0.0226
15.49	14.64	-.85	-0.0170

Maximum Permissible Error = .05% F.S.

Maximum Recorded Error = -.0366 F.S.Temperature Printout - 219.2

Domestic Instrumentation

W H

Serial # 8009Xdcr 7097**LYNES**

LYNES, INC. P.O. Box 12486 Houston, Texas 77217 Phone: (713) 943-0170 Telex: 774243 Cable: LYNESINC

Calibration Error Curve

RUSKA # 21970 Absolute Pressure	at 75 °F Probe Reading	P.S.I. Error	% Error F.S.
15.49	15.59	.10	0.0020
114.51	114.46	-.05	-0.0010
514.27	514.11	-.16	-0.0032
1014.36	1014.03	-.33	-0.0066
2014.38	2014.18	-.20	-0.0040
2514.03	2513.70	-.33	-0.0066
3014.16	3013.59	-.57	-0.0114
4013.99	4013.08	-.91	-0.0182
5014.33	5016.12	1.78	0.0356
2514.03	2514.06	.03	0.0006
514.27	514.10	-.17	-0.0034
15.49	15.38	-.11	-0.0022

Maximum Permissable Error = .05% F.S.

Maximum Recorded Error = 0.0356 F.S.Temperature Printout - 74.4°F

Domestic Instrumentation

N. H.

1961

100-11-1-1506



LYNES

Date: 5/11/83

LYNES, INC. P.O. Box 12486 Houston, Texas 77217 Phone: (713) 943-0170 Telex: 774243 Cable: LYNESINC

Model: CWL-300

Serial #: 8007

Calibration Coefficients

XX	49058.76
XY	142.2279
XZ	-3153.190
YX	25953.13
YY	4426.294
YZ	-20050.13
ZX	26.28309
ZY	-.074954
ZZ	.2926451
TX	-468.442678
TY	.371196

Note: Long term drift can be corrected by adjusting ZX for a reasonable reading at atmospheric pressure. A change of ± 0.001 in ZX will decrease the recorded pressure by about 2.4 psi.

Domestic Instrumentation

W. Hankins

Instrument CWL-300Date 5/11/83Serial # 8007Xdcr 6323**LYNES**

LYNES, INC. P.O. Box 12486 Houston, Texas 77217 Phone: (713) 943-0170 Telex: 774243 Cable: LYNESINC

Calibration Error Curve

<u>RUSKA</u> <u>#21970</u> <u>Absolute</u> <u>Pressure</u>	<u>at</u> <u>73 °F</u> <u>Probe</u> <u>Reading</u>	<u>P.S.I.</u> <u>Error</u>	<u>% Error F.S.</u>
15.52	15.21	- .31	-0.0062
114.54	114.16	- .38	-0.0076
514.30	514.06	- .24	-0.0048
1014.39	1014.21	- .18	-0.0036
2014.42	2014.60	.18	0.0036
2514.06	2513.87	- .23	-0.0046
3014.20	3013.66	- .54	-0.0108
4014.03	4012.74	-1.29	-0.0258
5014.37	5014.08	- .29	-0.0058
2514.06	2514.07	.01	0.0002
514.30	514.30	.00	0.0000
15.52	15.49	- .03	-0.0006

Maximum Permissible Error = .05% F.S.

Maximum Recorded Error = -.0258 F.S.Temperature Printout - 72.8

Domestic Instrumentation

n.x.

Instrument CWL-300Date 5/11/83Serial # 8007Xdcr 6323

LYNES, INC. P.O. Box 12486 Houston, Texas 77217 Phone: (313) 943-0170 Telex: 774243 Cable: LYNESINC

Calibration Error Curve

<u>RUSKA</u> <u>#21970</u> <u>Absolute</u> <u>Pressure</u>	<u>at</u> <u>217°F</u> <u>Probe</u> <u>Reading</u>	<u>P.S.I.</u> <u>Error</u>	<u>% Error F.S.</u>
15.51	13.70	-1.81	-0.0362
114.53	112.55	-1.98	-0.0396
514.28	512.34	-1.74	-0.0348
1014.37	1012.50	-1.87	-0.0374
2014.39	2012.42	-1.97	-0.0394
2514.03	2512.46	-1.57	-0.0314
3014.16	3012.51	-1.65	-0.0330
4013.98	4012.67	-1.32	-0.0264
5014.31	5013.46	-.85	-0.0170
2514.03	2514.24	.21	0.0042
514.28	514.51	.23	0.0046
15.51	15.82	.31	0.0062

Maximum Permissible Error = .05% F.S.

Maximum Recorded Error = -.0396 F.S.Temperature Printout - 216.4

Domestic Instrumentation

u.f.

APPENDIX II
CHRONOLOGICAL SUMMARY

APPENDIX II
CHRONOLOGICAL SUMMARY

Day 1, June 6, 1983

- 08:39 Started in well with Lynes Pressure Probe No. 8009. Temperature and pressure were recorded every 100 ft to 500 ft, and every 300 ft to total depth, which was 3,067 ft, at 10-second intervals.
- 08:40 The Lynes Pressure Probe was calibrated with the Lynes Surface Recorder. Atmospheric pressure was found to be 13.5192 psia, and temperature to be 72.2°F.

Results of pressure gradient with the gauge going in the hole:

Depth ft	Pressure psia	Temperature °F	Pressure Gradient psia/ft
100	67.618	66.61	0.247
200	92.285	66.38	0.488
300	141.120	66.16	0.378
400	178.877	66.16	0.483
500	227.135	66.24	0.473
800	369.058	67.08	0.473
1,100	510.945	69.16	0.485
1,400	656.588	71.46	0.443
1,700	789.372	73.72	0.497
2,000	938.520	76.21	0.495
2,300	1,087.030	78.25	0.496
2,600	1,235.68	80.33	0.441
2,900	1,368.00	81.76	0.557
3,067	1,460.99	89.05	0.557

Interpolating for the pressure at 2,650 ft results in 1,257.73 psia.

- 09:37 Injection started at 60.08 gals./min. Downhole pressure was 1,257.73 psia, and temperature was 90.33°F.
- 10:12 Started to pull gauge for tracer survey No. 1. The downhole pressure was 1,263.45 psia, with a temperature of 88.61°F. Pressures and temperatures were recorded at the same depths as when going in the hole. The results are:

Depth ft	Pressure psia	Temperature °F	Pressure Gradient psia/ft
100	112.619	78.60	0.466
200	159.169	78.75	0.387
300	197.843	78.75	0.449
400	242.781	79.01	0.615
500	304.319	79.06	0.402
800	424.906	80.28	0.436
1,100	555.573	81.40	0.440
1,400	687.443	83.05	0.447
1,700	821.650	83.34	0.446
2,000	955.418	87.50	0.464
2,300	1,094.58	88.40	0.485
2,600	1,240.03	88.50	

10:40 Pressure gauge out of hole. Start to run tracer survey.

16:00 Pressure gauge was started back into the well.

18:00 Pressure gauge was starting back out of the hole because it was not transmitting data. The problem was found to be a bad connection in the cable head.

19:15 Pressure gauge started back in the hole.

20:00 Pressure gauge was back in the well at 2,650 ft, and working properly.

24:00 Cumulative injection = 51,850 gals.
Last recorded pressure = 1,275.36 psia.

June 7, 1983

24:00 Smooth operations all day.

Cumulative injection = 138,950 gals.

Last recorded pressure = 1,280.45 psia.

June 8, 1983

20:35 Injection flow rate made a little jump, causing downhole pressure to make a spike.

24:00 Cumulative injection = 225,800 gals.
Last recorded pressure = 1,283.13 psia.

June 9, 1983

10:35 Rate dropped momentarily to 53 gals./min. while switching filters.

24:00 Cumulative injection = 312,300 gals.
Last recorded pressure = 1,285.47 psia.

June 10 1983

24:00 Cumulative injection = 399,400 gals.
Last recorded pressure = 1,287.51 psia.

June 11, 1983

12:20 Backflushing filter bank No. 1414 caused injection rate to spike from 60 to 43 to 73 gals./min.

24:00 Cumulative injection = 487,100 gals.
Last recorded pressure = 1,288.7 psia.

June 12, 1983

09:20 Spike in downhole pressure occurred, due to filter bank switching.

24:00 Cumulative injection = 573,700 gals.
Last recorded pressure = 1,290.16 psia.

June 13, 1983

00:50 Filter switch caused spike in downhole pressure.

06:00 Shutdowns and startups of fluorine plant probably caused small pressure spikes in the downhole pressure.

24:00 Cumulative injection = 660,350 gals.
Last recorded pressure = 1,291.02 psia.

June 14, 1983

- 00:35 Control valve is observed to swing through a 2 gals./min. range.
- 24:00 Cumulative injection = 747,000 gals.
Last recorded pressure = 1,291.52 psia.

June 15, 1983

- 08:32 Flow control valve was observed to be sticking.
- 08:38 The control valve was switched to manual over a 10-minute period. This caused a small change in the downhole pressure.
- 10:55 A new control valve was put into service.
- 10:57 and
11:07 New control valve would not control, causing abrupt pressure changes downhole; about 1 psia. Went back on manual bypass valve.
- 13:45 Old control valve was installed with a valve positioner on it.
- 14:05 The control valve was brought on line, causing a small spike in the downhole pressure.
- 14:20 The control valve was observed to be not working right.
- 15:35 The control valve was back in control.
- 23:10 The control valve was sticking, causing a small blip in the downhole pressure.
- 24:00 Cumulative injection = 834,750 gals.
Last recorded pressure = 1,290.18 psia.

June 16, 1983

- 11:15 New control valve was installed.
- 24:00 Cumulative injection = 921,800 gals.
Last recorded pressure 1,291.19 psia.

June 17, 1983

- 09:30 Injection flow rate dropped to 57 gals./min, jumped to 67 gals./min, and worked back to 62 - 63 gals./min.
- 12:50 Injection flow rate jumped, causing a pressure spike in the downhole pressure.
- 15:00 There were three flow rate jumps between 14:00 and 15:00. It was noted that the fluorine plant cell room was turned on and off three times. This caused three blips on the downhole pressure.
- 24:00 Cumulative injection = 1,009,150 gals.
Last recorded pressure = 1,291.48 psia.

June 18, 1983

- 24:00 Cumulative injection = 1,096,550 gals.
Last recorded pressure = 1,292.22 psia.

June 19, 1983

- 24:00 Cumulative injection 1,183,900 gals.
Last recorded pressure = 1,293.10 psia.

June 20, 1983

- 08:21 The control valve stuck, causing downhole pressure to drop about 2 psia.
- 19:35 Switching filters caused a spike in the downhole pressure.
- 24:00 Cumulative injection = 1,270,700 gals.
Last recorded pressure = 1,291.51 psia.

June 21, 1983

- 17:47 Switching of filters and control valve swing caused downhole pressure to spike 1 psia.

23:30 Fluorine plant went down, creating electrical surge, which caused downhole pressure to jump about 1.1 psia.

24:00 Cumulative injection = 1,357,800 gals.
Last recorded pressure = 1,293.36 psia.

June 22, 1983

15:35 The fluorine plant cell room was started up and the control valve stuck, causing the downhole pressure to drop about 2.5 psia.

24:00 Cumulative injection = 1,445,450 gals.
Last recorded pressure = 1,292.17 psia.

June 23, 1983

24:00 Several spikes occurred during this day, due to the fluctuation of the control valve, which resulted in several spikes in the downhole pressure.

Cumulative injection = 1,531,250 gals.
Last recorded pressure = 1,292.74 psia.

June 24, 1983

08:26 Injection flow rate momentarily jumped from 63 gals./min to 100 gals./min with control valve in auto. This caused the downhole pressure to spike.

24:00 Cumulative injection = 1,618,750 gals.
Last recorded pressure = 1,293.60 psia.

June 25, 1983

11:23 to
15:33 Lynes Surface Recorder failed to make readings. At 15:33, started to record again.

20:30 Fluorine plant cell room shut down, causing downhole pressure to jump about 1.1 psia.

24:00 Cumulative injection = 1,705,900 gals.
Last recorded pressure = 1,296.14 psia.

June 26, 1983

24:00 The control valve fluctuated several times, causing pressure spikes downhole.

Cumulative injection = 1,792,900 gals.

Last recorded pressure = 1,297.45 psia.

June 27, 1983

08:23 Start to pull gauge for tracer No. 2.

10:00 Going in the hole with the tracer tool.

16:30 Tracers were done. Downhole pressure probe was not transmitting data. The probe was found to have a broken solder connection.

18:26 Lynes Pressure Probe No. 8007 was lowered into the well and was transmitting data.

24:00 Cumulative injection = 1,880,000 gals.

Last recorded pressure = 1,296.40 psia.

June 28, 1983

11:07 A fluctuation in injection flow rate caused a spike in the downhole pressure.

24:00 Small injection flow fluctuations caused several blips in the downhole pressure.

Cumulative injection = 1,966,900 gals.

Last recorded pressure = 1,296.87 psia.

June 29, 1983

24:00 Cumulative Injection = 2,053,500 gals.

Last recorded pressure = 1,298.17 psia.

June 30, 1983

24:00 Cumulative injection = 1,053,500 gals.
Last recorded pressure = 1,298.17 psia.

June 30, 1983

24:00 Cumulative injection = 2,141,000 gals.
Last recorded pressure = 1,298.95 psia.

July 1, 1983

24:00 Cumulative injection = 2,228,600 gals.
Last recorded pressure = 1,299.08 psia.

July 2, 1983

24:00 Cumulative injection = 2,316,050 gals.
Last recorded pressure = 1,299.66 psia.

July 3, 1983

24:00 Cumulative injection = 2,403,950 gals.
Last recorded pressure = 1,300.34 psia.

July 4, 1983

00:40 The injection control valve jumped, causing the downhole pressure to spike downwards.

24:00 Cumulative injection = 2,491,550 gals.
Last recorded pressure = 1,300.92 psia.

July 5, 1983

24:00 Cumulative injection = 2,579,050 gals.
Last recorded pressure = 1,301.58 psia.

July 6, 1983

24:00 Cumulative injection = 2,666,750 gals.
Last recorded pressure = 1,302.08 psia.

July 7, 1983

24:00 Cumulative injection = 2,754,700 gals.
Last recorded pressure = 1,302.49 psia.

July 8, 1983

24:00 Cumulative injection = 2,842,300 gals.
Last recorded pressure = 1,302.85 psia.

July 9, 1983

24:00 Cumulative injection = 2,930,150 gals.
Last recorded pressure = 1,303.81 psia.

July 10, 1983

24:00 Cumulative injection = 3,017,650 gals.
Last recorded pressure = 1,304.38 psia.

July 11, 1983

07:51 Downhole pressure dropped about 1 psia.
Cumulative injection = 3,105,550 gals.
Last recorded pressure = 1,302.42 psia.

July 12, 1983

06:11 A downhole spike in the pressure occurred of about 1.3 psia.
06:51 A downhole spike in the pressure occurred of about 3 psia. At this time, the cell room went down and back up.
24:00 The fluorine plant cell room went down and was brought up several times today, causing spikes in the downhole pressure.
Cumulative injection = 3,193,100 gals.
Last recorded pressure = 1,302.76 psia.

July 13, 1983

- 02:45 There was trouble with the fluorine plant control room, and the flow controller was put in manual. This caused a pressure spike downhole.
- 04:30 The after filter pressure started to go down. The filter banks were then switched, making the flow rate jump. This caused a spike in the downhole pressure.
- 08:11 Injection flow rate fluctuated, causing a spike in the downhole pressure.
- 24:00 Cumulative injection = 3,280,850 gals.
Last recorded pressure = 1,302.89 psia.

July 14, 1983

- 11:00 Fluorine plant went down, causing downhole pressure jump about 2 psia.
- 14:21 Trouble in the fluorine plant cell room caused the downhole pressure to drop about 2 psia.
- 15:30 Trouble in the fluorine plant cell room caused the downhole pressure to spike about 1 psia.
- 16:12 The fluorine plant cell room went down, causing the pressure to spike about 1.5 psia.
- 24:00 Cumulative injection = 3,368,550 gals.
Last recorded pressure = 1,303.82 psia.

July 15, 1983

- 06:30 Fluorine plant cell room went down, causing a downhole pressure spike of about 1.8 psia.
- 24:00 Cumulative injection = 3,456,100 gals
Last recorded pressure = 1,304.83 psia.

July 16, 1983

08:00 Shut the fluorine plant cell room down, which caused a downhole pressure increase of about 1.5 psia.

24:00 Cumulative injection = 3,543,800 gals.
Last recorded pressure = 1,306.43 psia.

July 17, 1983

24:00 Cumulative injection = 3,631,450 gals.
Last recorded pressure = 1,307.29 psia.

July 18, 1983

07:55 Fluorine plant came on, which caused downhole pressure to drop about 1.2 psia.

24:00 Cumulative injection = 3,719,100 gals.
Last recorded pressure = 1,306.17 psia.

July 19, 1983

24:00 Cumulative injection = 3,806,850 gals.
Last recorded pressure = 1,306.53 psia.

July 20, 1983

08:20 Start to pull Lynes downhole pressure probe.

08:52 Start tracer survey tool into the hole

14:00 Finished tracer surveys and started Lynes downhole pressure probe back into the well.

24:00 Cumulative injection = 3,894,700 gals.
Last recorded pressure = 1,305.17 psia.

July 21, 1983

09:00 Repeated switching of filters caused several blips on the downhole pressure.

14:45 The fluorine plant cell room went down and back up, which caused the downhole pressure to spike about 1.7 psia.

17:56 Switching of filter caused a downhole pressure spike.

24:00 Several filter switchings caused several spikes in the downhole pressure.

Cumulative injection = 3,982,400 gals.
Last recorded pressure = 1,306.95 psia.

July 22, 1983

12:40 Fluorine plant cell room went down in amperage, causing the downhole pressure to spike.

12:59 When the cell room went back up to 6,000 amp., the downhole pressure spiked.

23:45 Switching filters caused the downhole pressure to fluctuate slightly.

24:00 Cumulative injection = 4,069,950 gals.
Last recorded pressure = 1,307.11 psia.

July 23, 1983

07:44 Fluorine plant went down, causing the downhole pressure to increase by about 1.3 psia.

24:00 Cumulative injection = 4,157,800 gals.
Last recorded pressure = 1,309.67 psia.

July 24, 1983

15:06 Downhole pressure took a dip, resulting from a flow rate fluctuation.

24:00 Cumulative injection = 4,245,500 gals.
Last recorded pressure = 1,310.83 psia.

July 25, 1983

03:45 Switching filters caused downhole pressure to fluctuate slightly.

08:06 Downhole pressure decreased by 1.13 psia.

20:56 Downhole pressure increased by 0.98 psia.

24:00 Cumulative injection = 4,333,200 gals.
Last recorded pressure = 1,309.32.

July 26, 1983

13:26 Downhole pressure dropped by 1.22 psia.

22:50 Switching filters caused downhole pressure spike.

24:00 Cumulative injection = 4,420,900 gals.
Last recorded pressure = 1,308.42 psia.

July 27, 1983

24:00 Cumulative injection = 4,508,650 gals.
Last recorded pressure = 1,309.86 psia.

July 28, 1983

20:35 Switching filter caused downhole pressure to spike.

24:00 Cumulative injection = 4,596,500 gals.
Last recorded pressure = 1,310.57 psia.

July 29, 1983

13:56 Downhole pressure started to drop.

14:30 The filters were switched, causing the downhole pressure to go back up.

16:15 The control valve was put in manual, causing no significant change in the downhole pressure.

23:36 The downhole pressure increased 1.0 psia.
24:00 Cumulative injection = 4,684,100 gals.
Last recorded pressure = 1,311.02 psia.

July 30, 1983

08:00 The control valve was put in manual, causing the downhole pressure to spike.
09:00 Switching filters caused downhole pressure to jump.
11:35 Switching filters caused downhole pressure to fluctuate.
24:00 Several filter switches during the day caused downhole pressure fluctuation.
Cumulative injection = 4,771,950 gals.
Last recorded pressure = 1,312.33 psia.

July 31, 1983

07:15 The control valve began to swing, causing the downhole pressure to drop and then spike. The net result was that the downhole pressure dropped about 2 psia.
24:00 Fluorine plant cell room problems caused downhole pressure to spike during last few hours.
Cumulative injection = 4,859,700 gals.
Last recorded pressure = 1,308.47 psia.

August 1, 1983

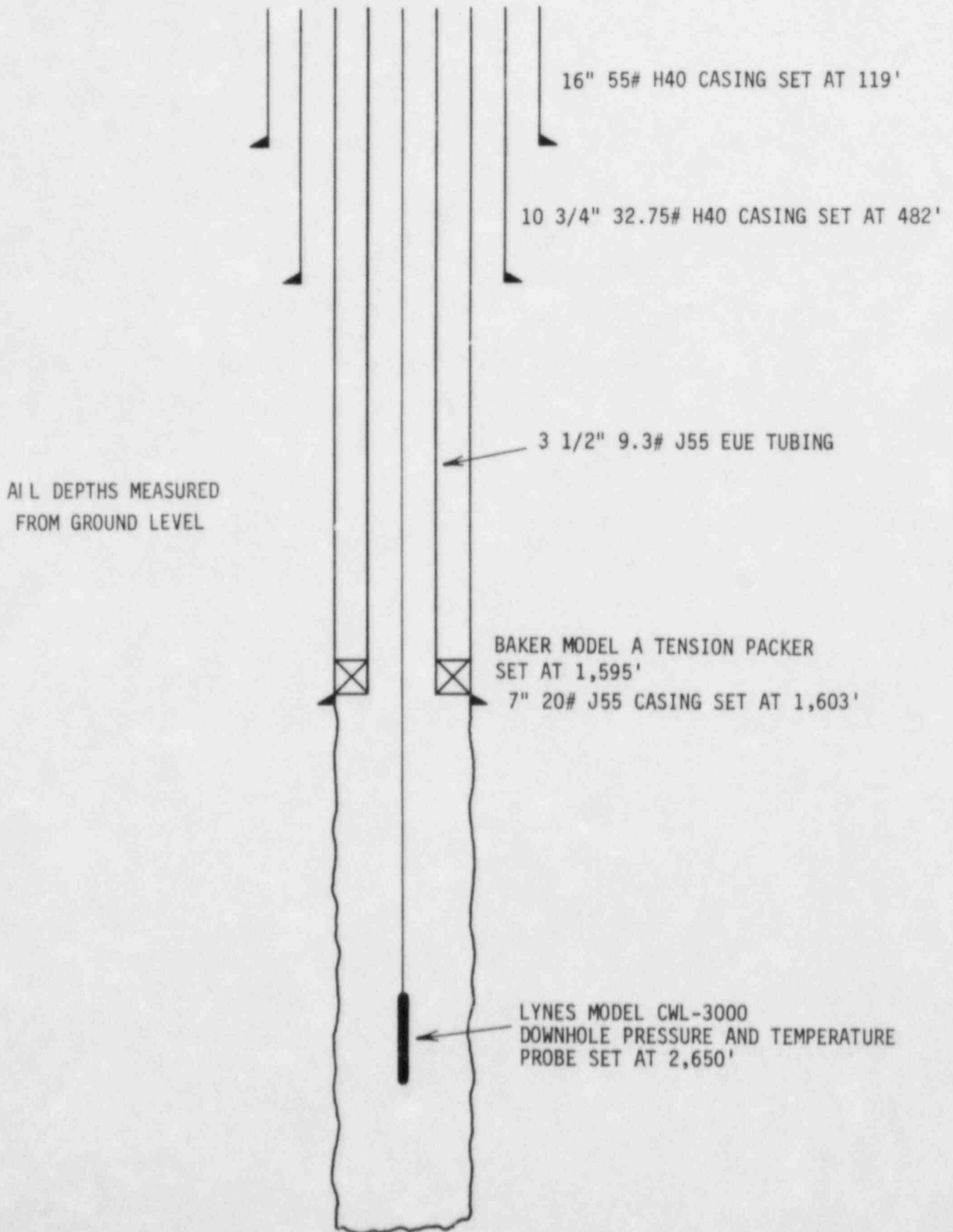
07:06 Pull pressure probe for tracer No. 4.
15:06 Pressure gauge back on bottom.
24:00 Cumulative injection = 4,547,500 gals.
Last recorded pressure = 1,309.32 psia.

August 2, 1983

14:24 Cumulative injection = 5,000,000 gals.
Last recorded pressure = 1,309.43 psia.

FIGURES

FIGURE 1
SEQUOYAH FUELS CORPORATION
WASTE DISPOSAL WELL No.1
GROUND LEVEL AT 563'



% Tracer loss

2 4 6 8 10 12 14 16 18 20 22 24 26

1650

1700

1800

1900

2000

2100

2200

2300

2400

2500

2600

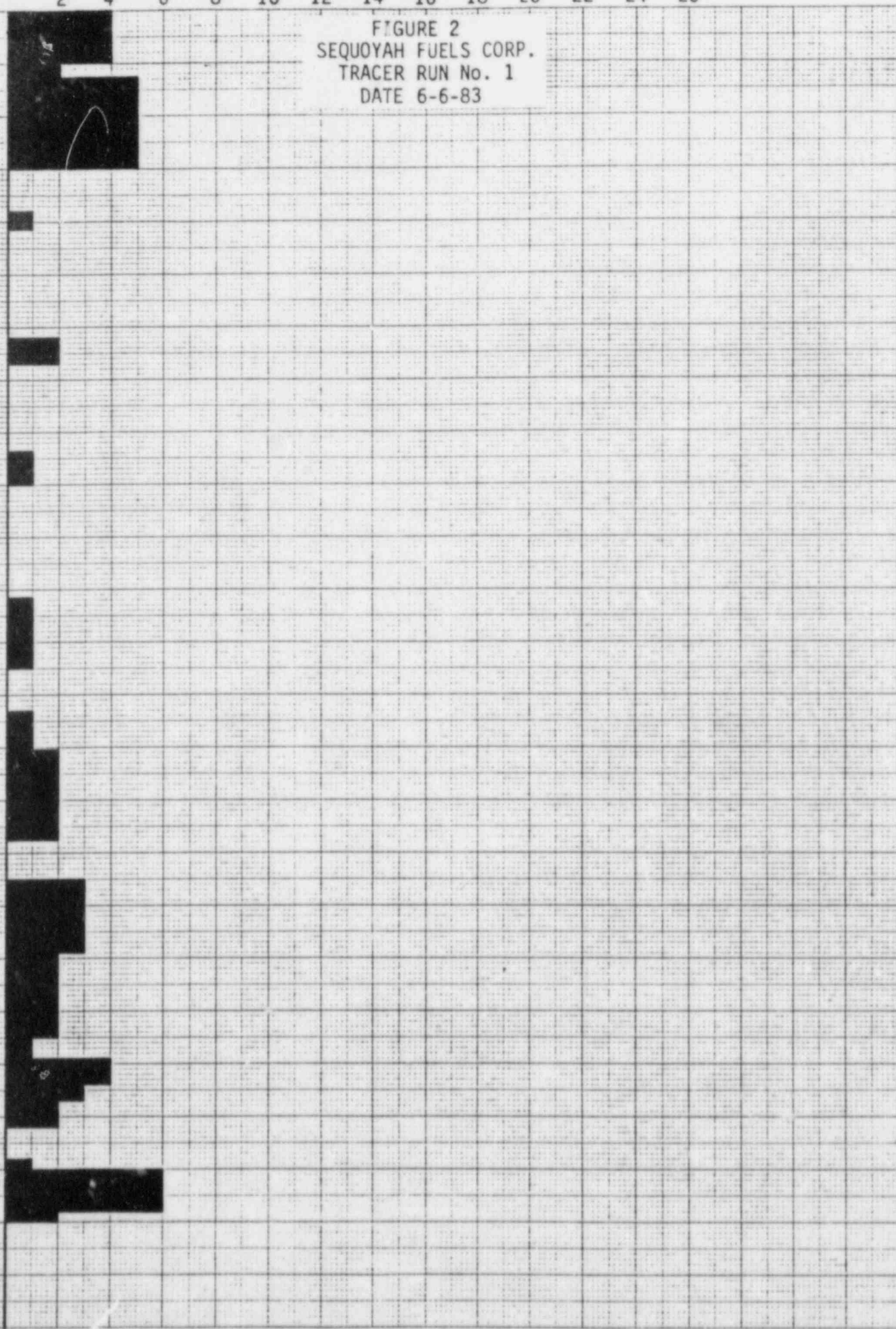
2700

2800

2900

Depth from G.L.

FIGURE 2
SEQUOYAH FUELS CORP.
TRACER RUN No. 1
DATE 6-6-83



% Tracer loss

2 4 6 8 10 12 14 16 18 20 22 24 26

1650

1700

1800

1900

2000

2100

2200

2300

2400

2500

2600

2700

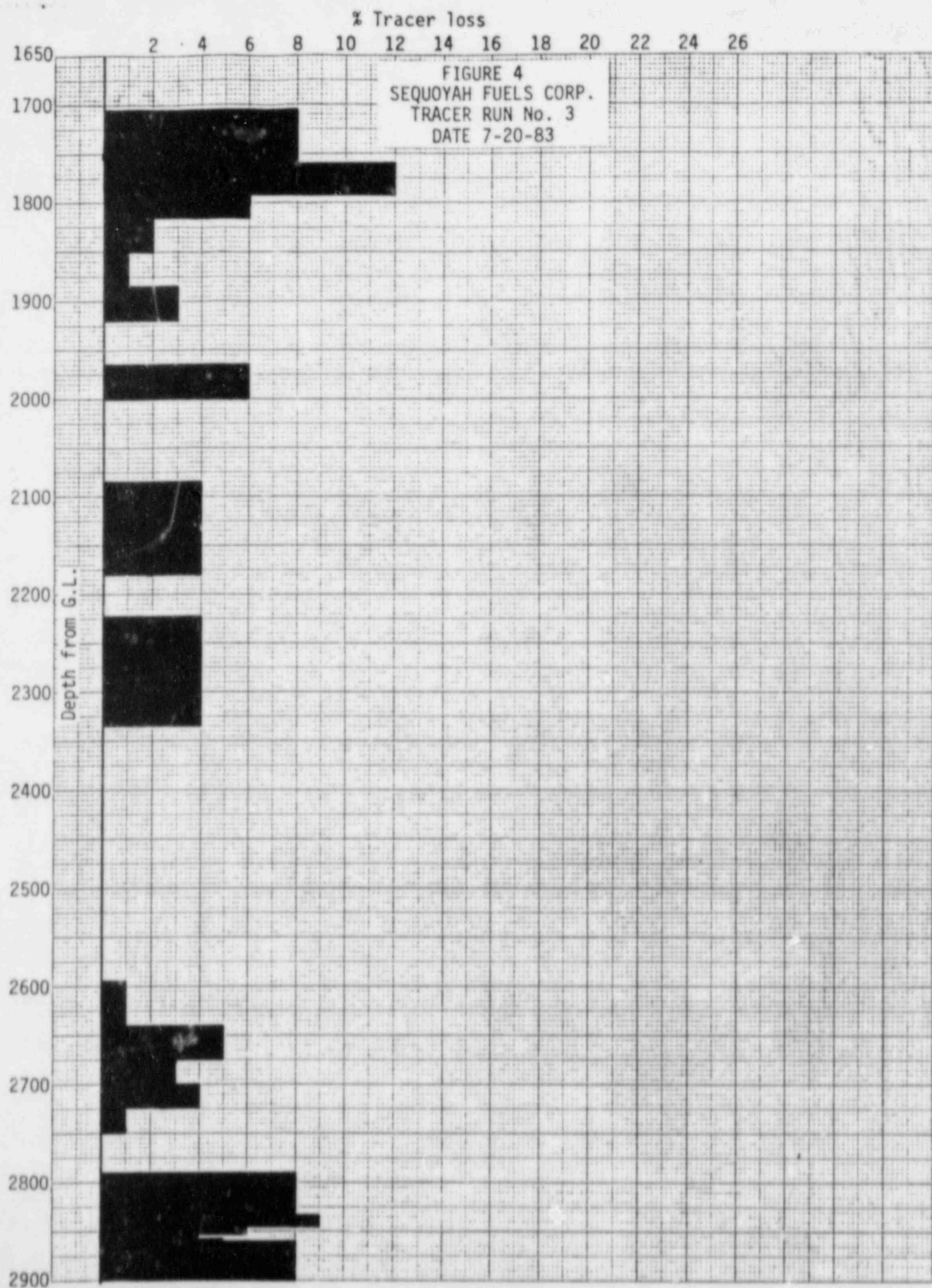
2800

2900

Depth from G.L.

FIGURE 3
SEQUOYAH FUELS CORP.
TRACER RUN No. 2
DATE 6-27-83





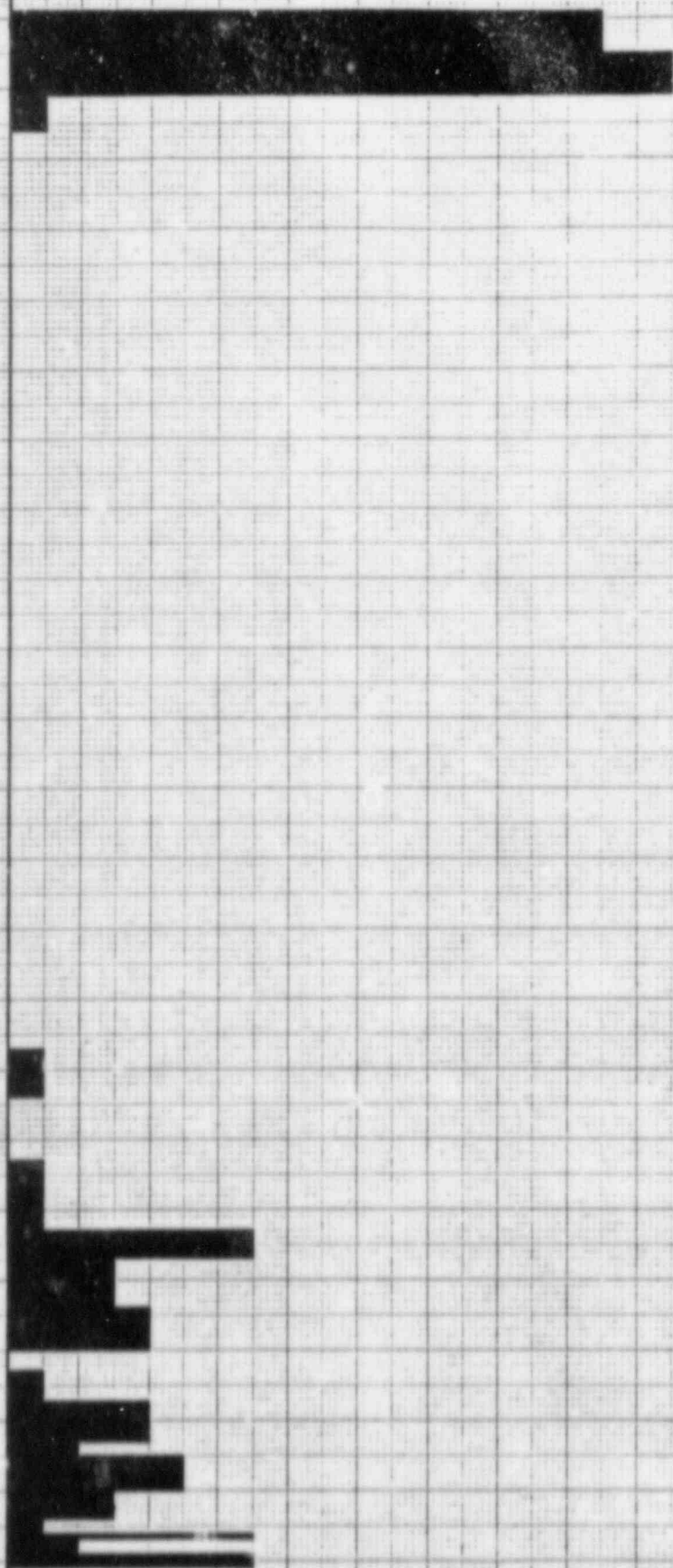
% Tracer loss

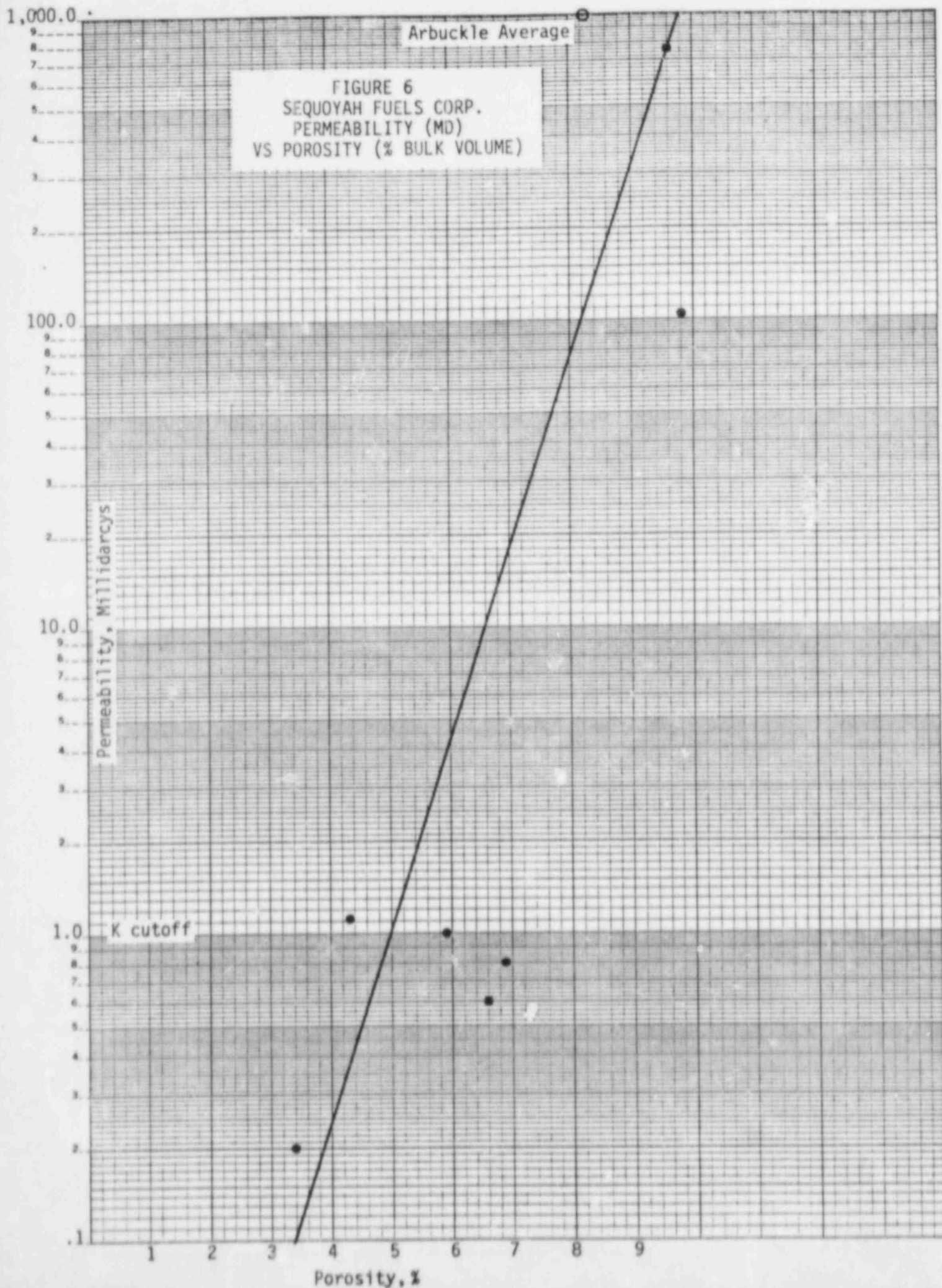
2 4 6 8 10 12 14 16 18 20 22 24 26

FIGURE 5
SEQUOYAH FUELS CORP.
TRACER RUN No. 4
DATE 8-1-83

1650
1700
1800
1900
2000
2100
2200
2300
2400
2500
2600
2700
2800
2900

Depth from G.L.

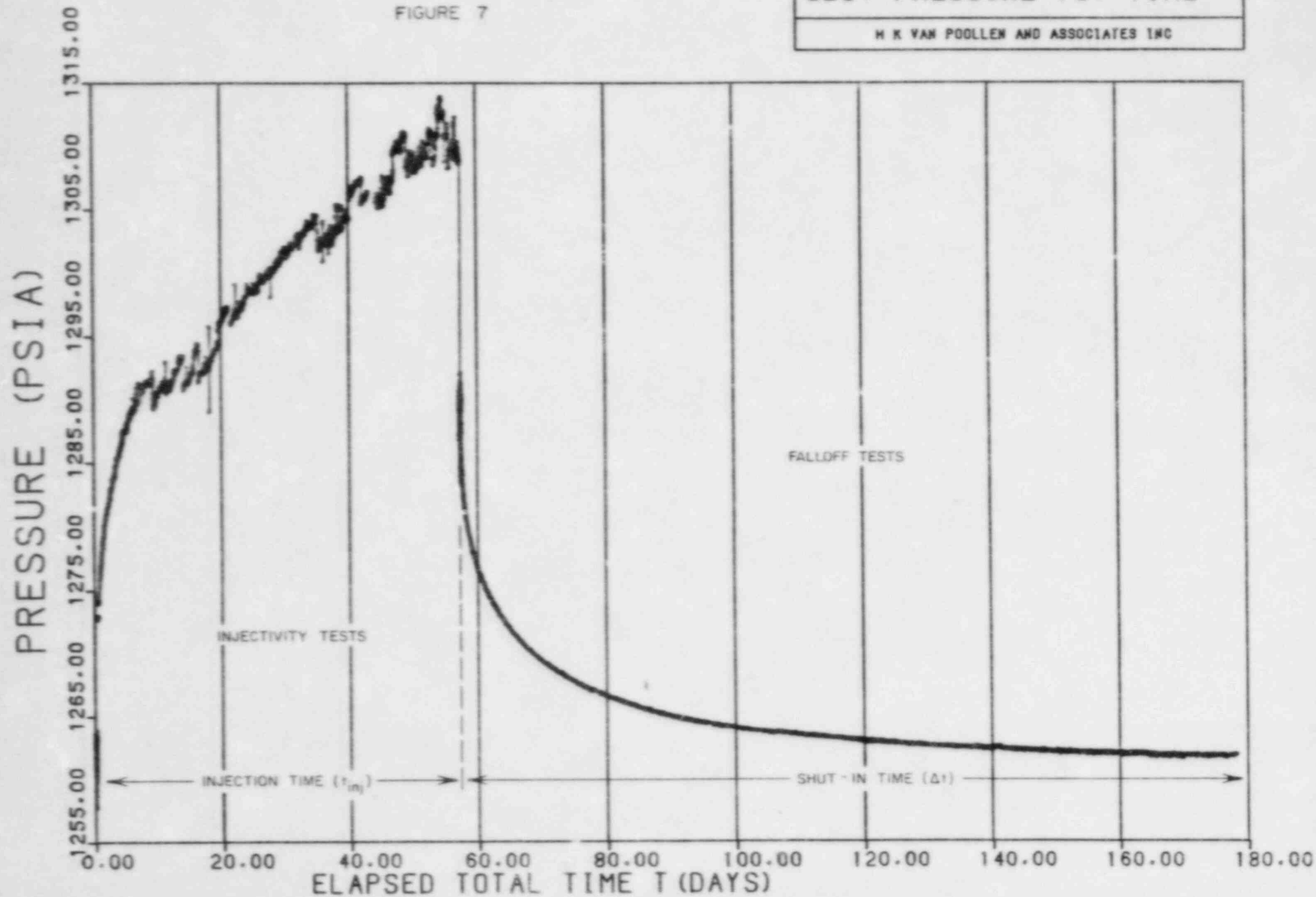




SEQUOYAH FUELS CORP.
JUNE 6 - DEC 1, 1983
OBS. PRESSURE VS. TIME

H K VAN POOLLEN AND ASSOCIATES INC

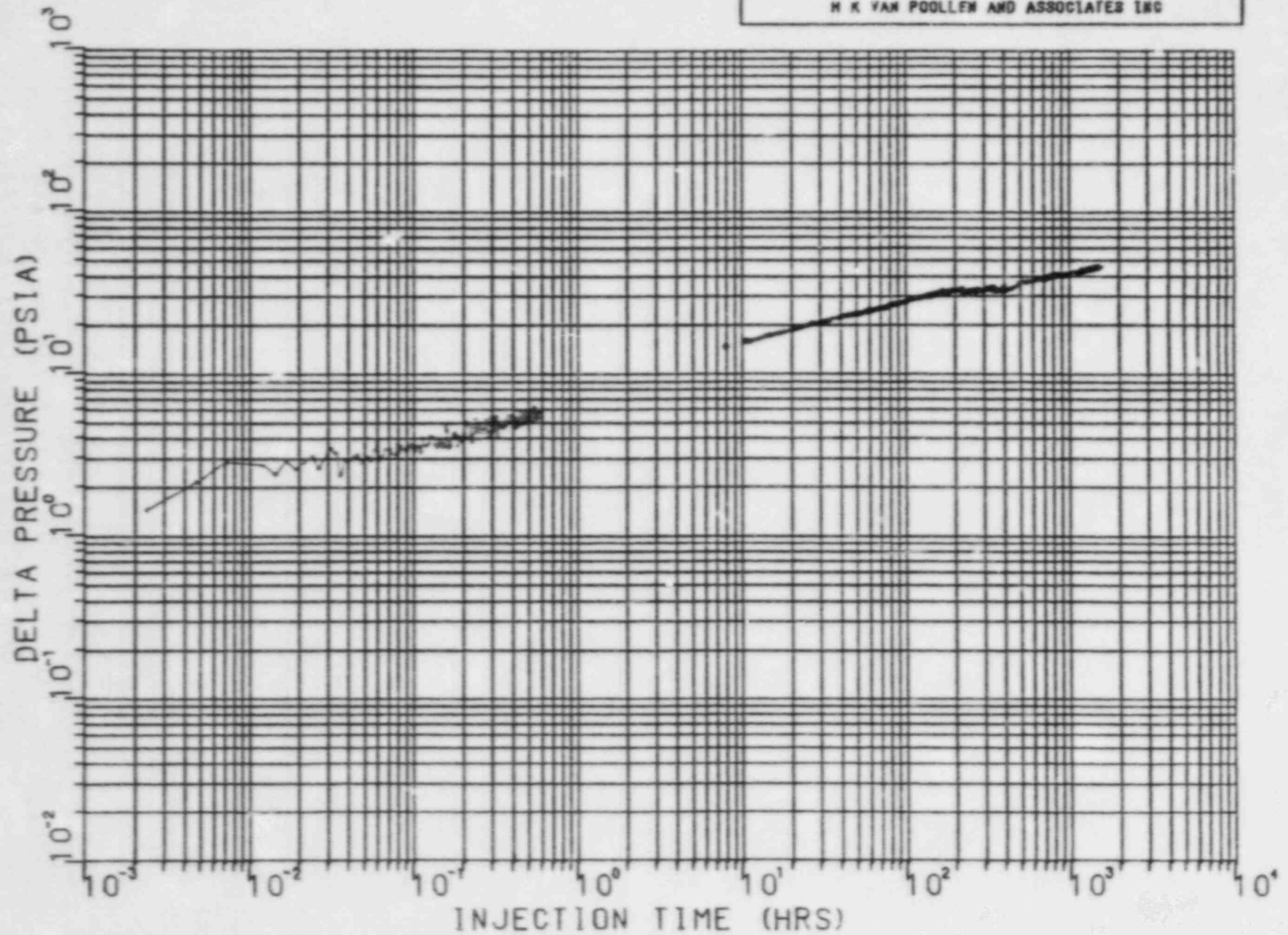
FIGURE 7



SEQUOYAH FUELS CORP.
JUNE 6 - AUG 2 INJECTION
DELTA PRESSURE VS. TIME

H K VAN POOLLEN AND ASSOCIATES INC

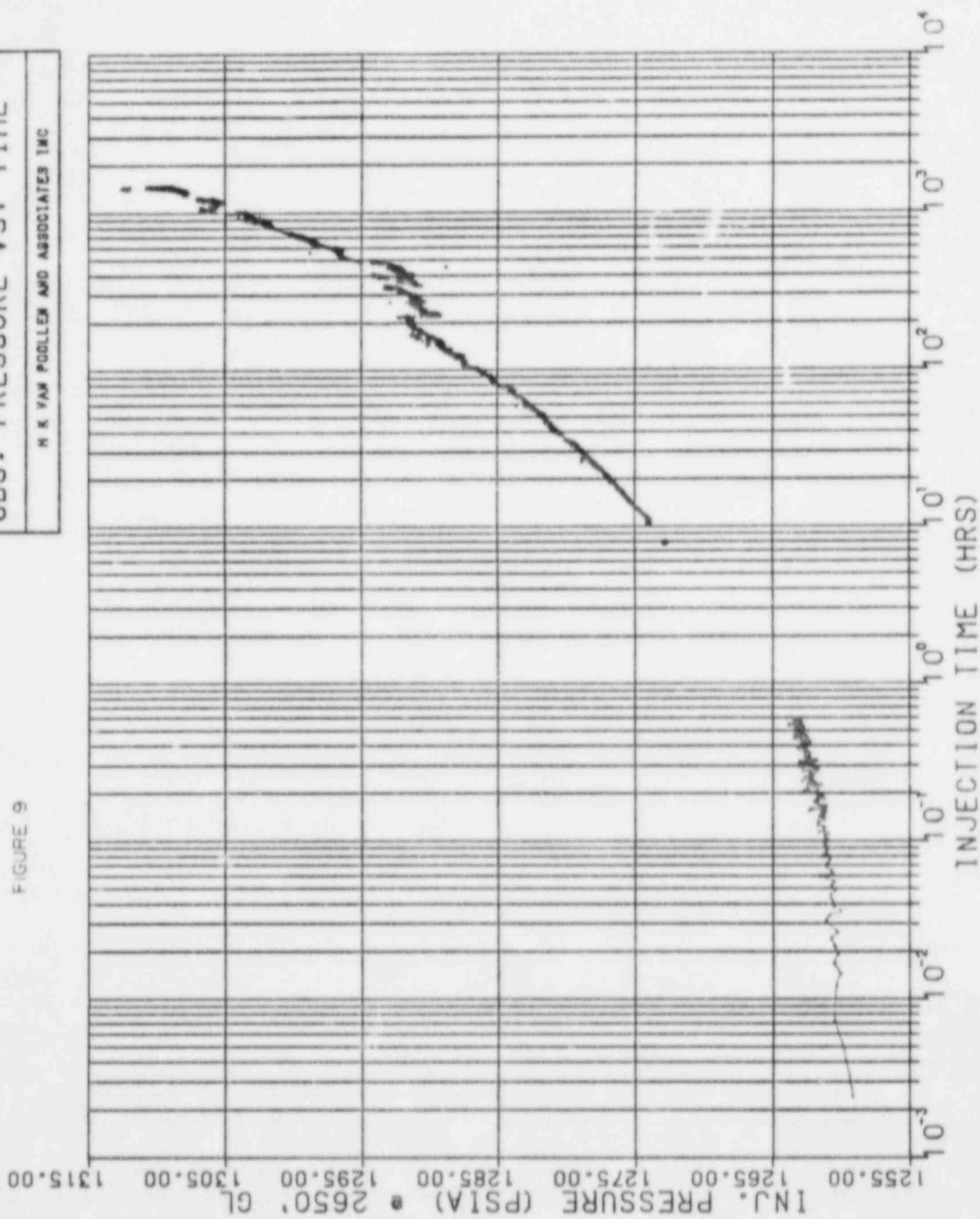
FIGURE 8



SEQUOYAH FUELS CORP.
JUNE 6 - AUG 2
OBS. PRESSURE VS. TIME

H K VAM POOLLEN AND ASSOCIATES INC

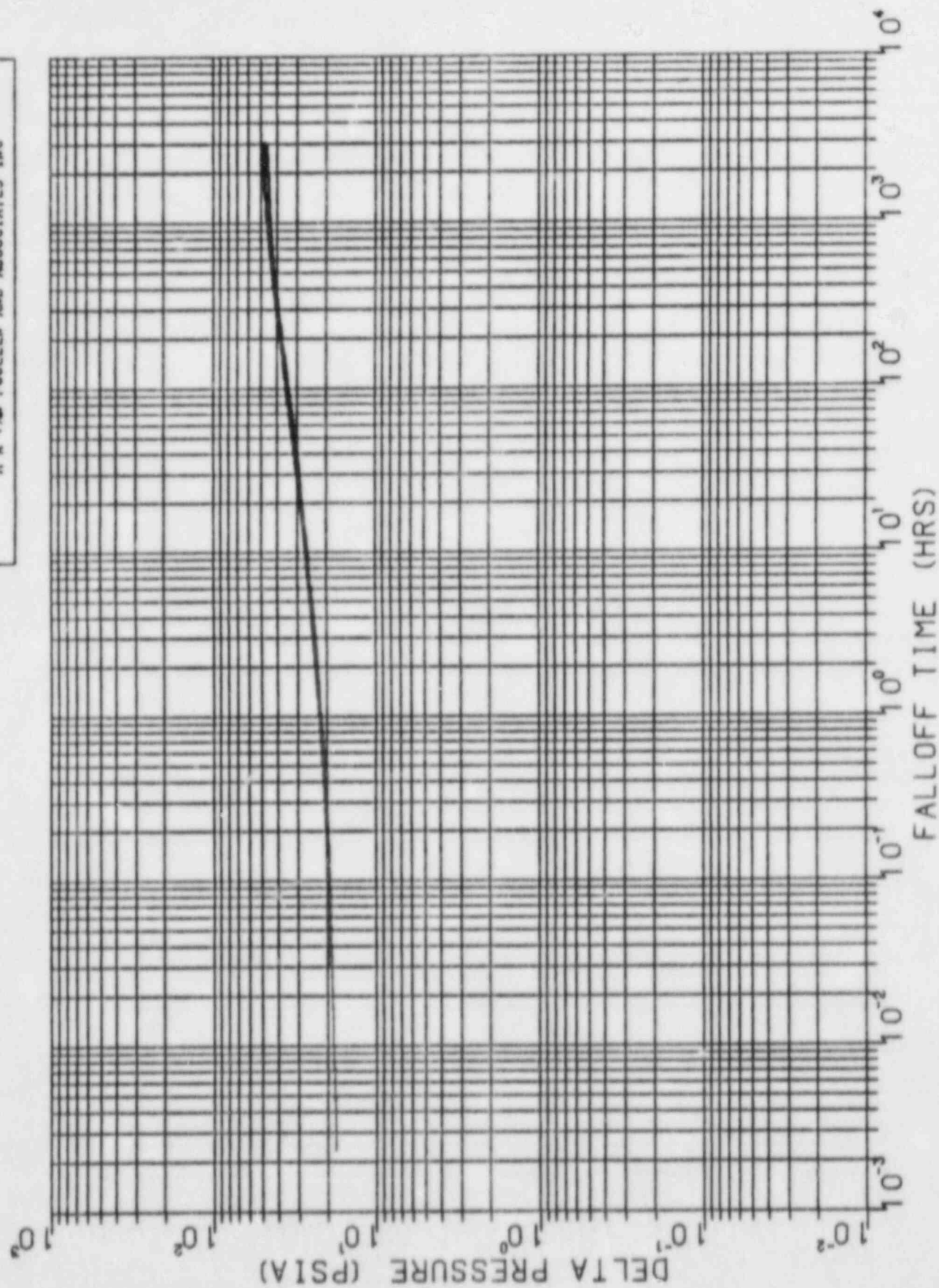
FIGURE 9



SEQUOIA FUELS CORP.
AUG 2 - DEC 1 FALLOFF
DELTA PRESSURE VS. TIME

H K VAN POOLLEN AND ASSOCIATES INC

FIGURE 10



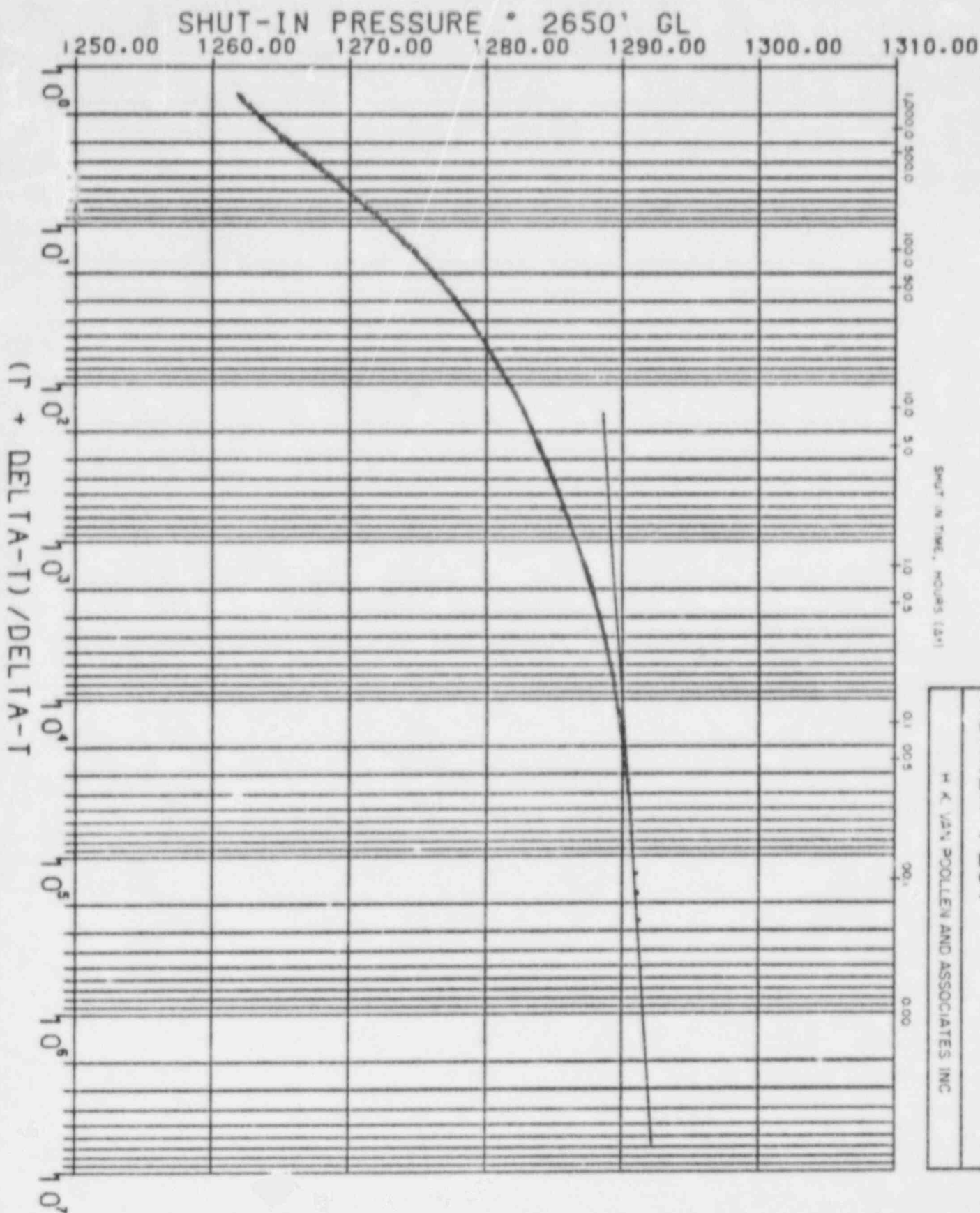


FIGURE 11

SEQUOYAH FUELS CORP.
AUG 2 - DEC 1
HORNERS PLOT

H. K. VAN POOLLEN AND ASSOCIATES INC

SEQUOYAH FUELS CORP. EXPANDED FALL OFF HORNER PLOT

H. K. VAN POOLLEN AND ASSOCIATES INC

FIGURE 12

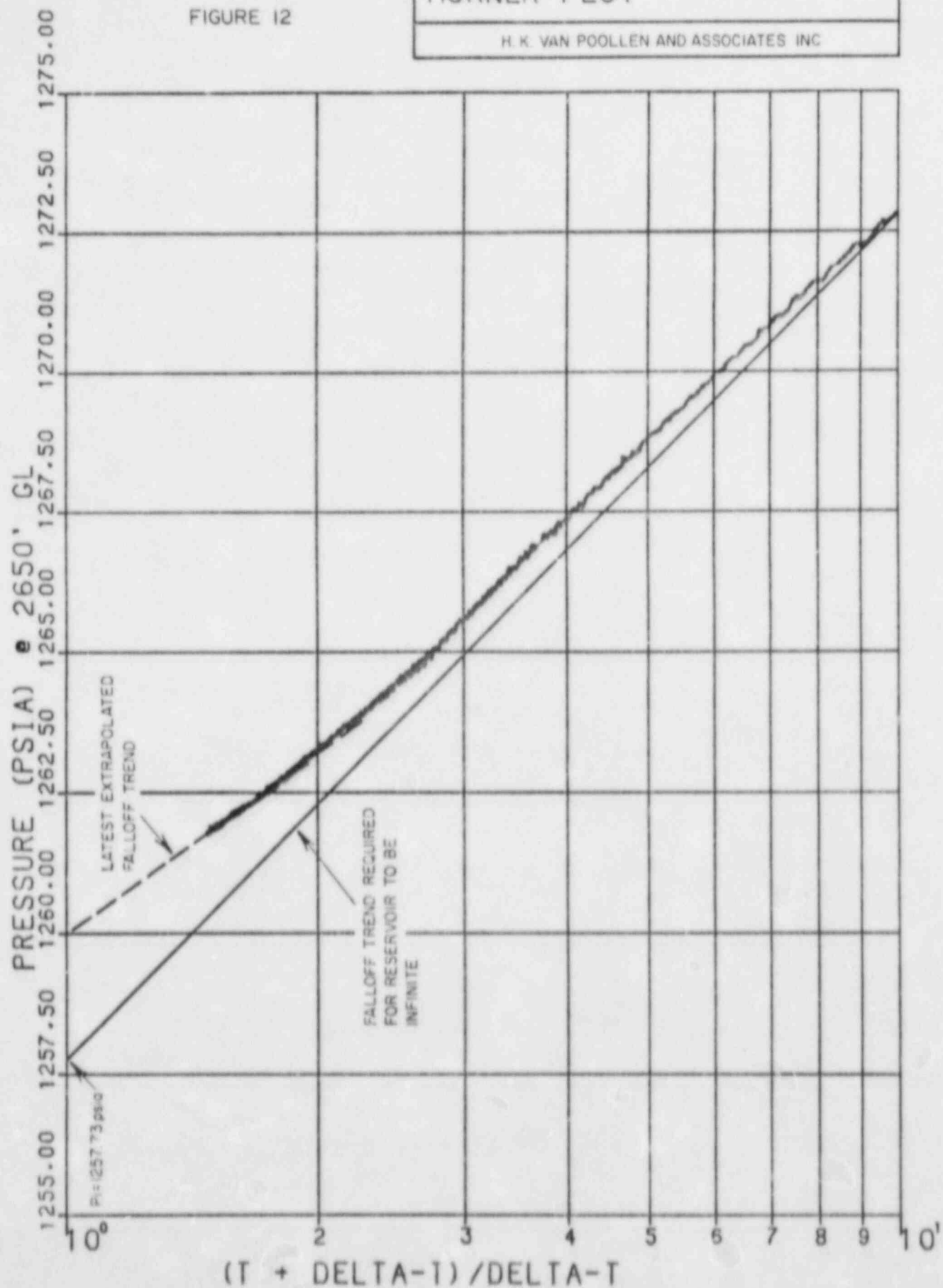


FIGURE 13

KERR McGEE

WELLBORE STORAGE SCHEMATIC

SEQUOYAH WASTE WELL

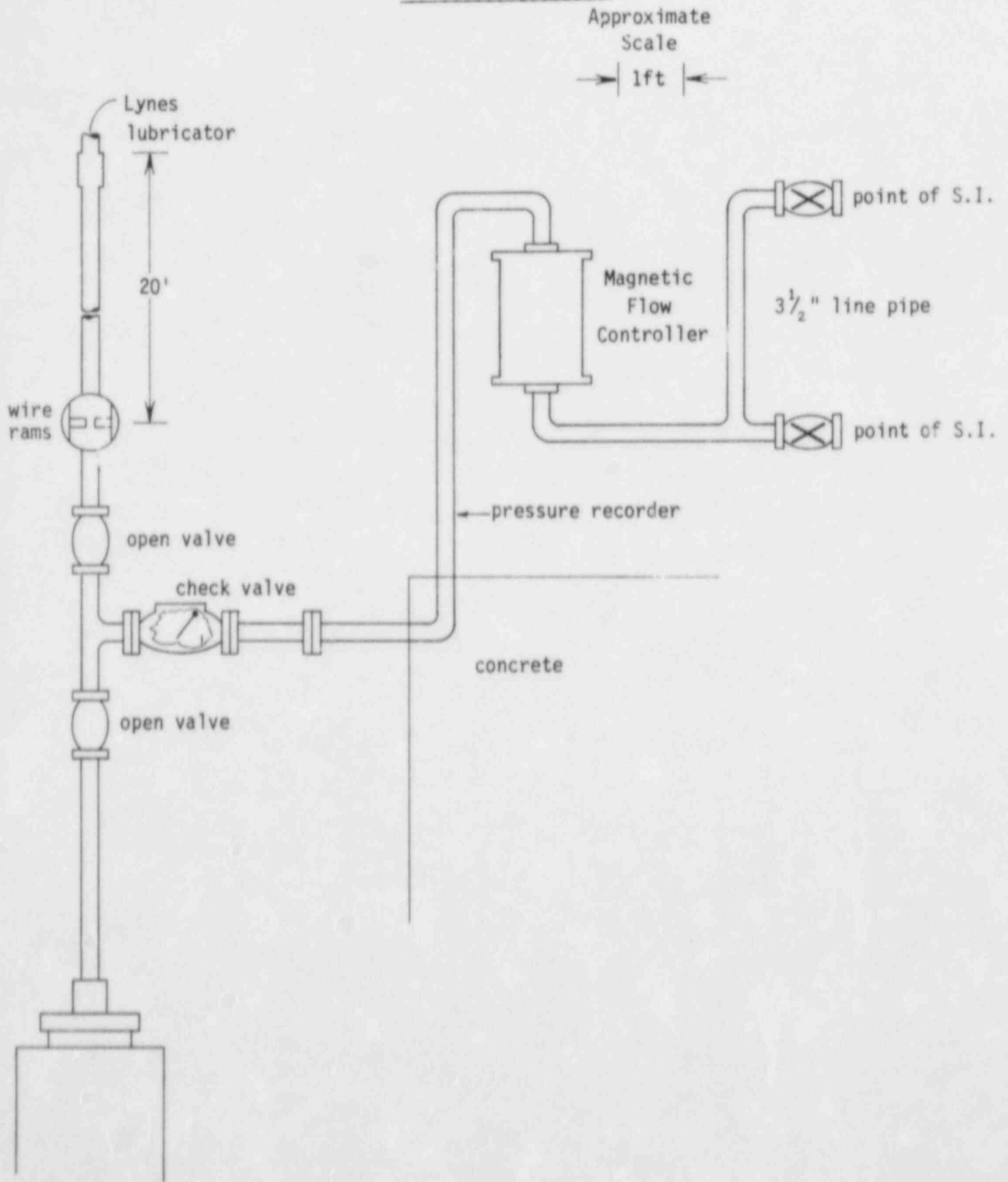
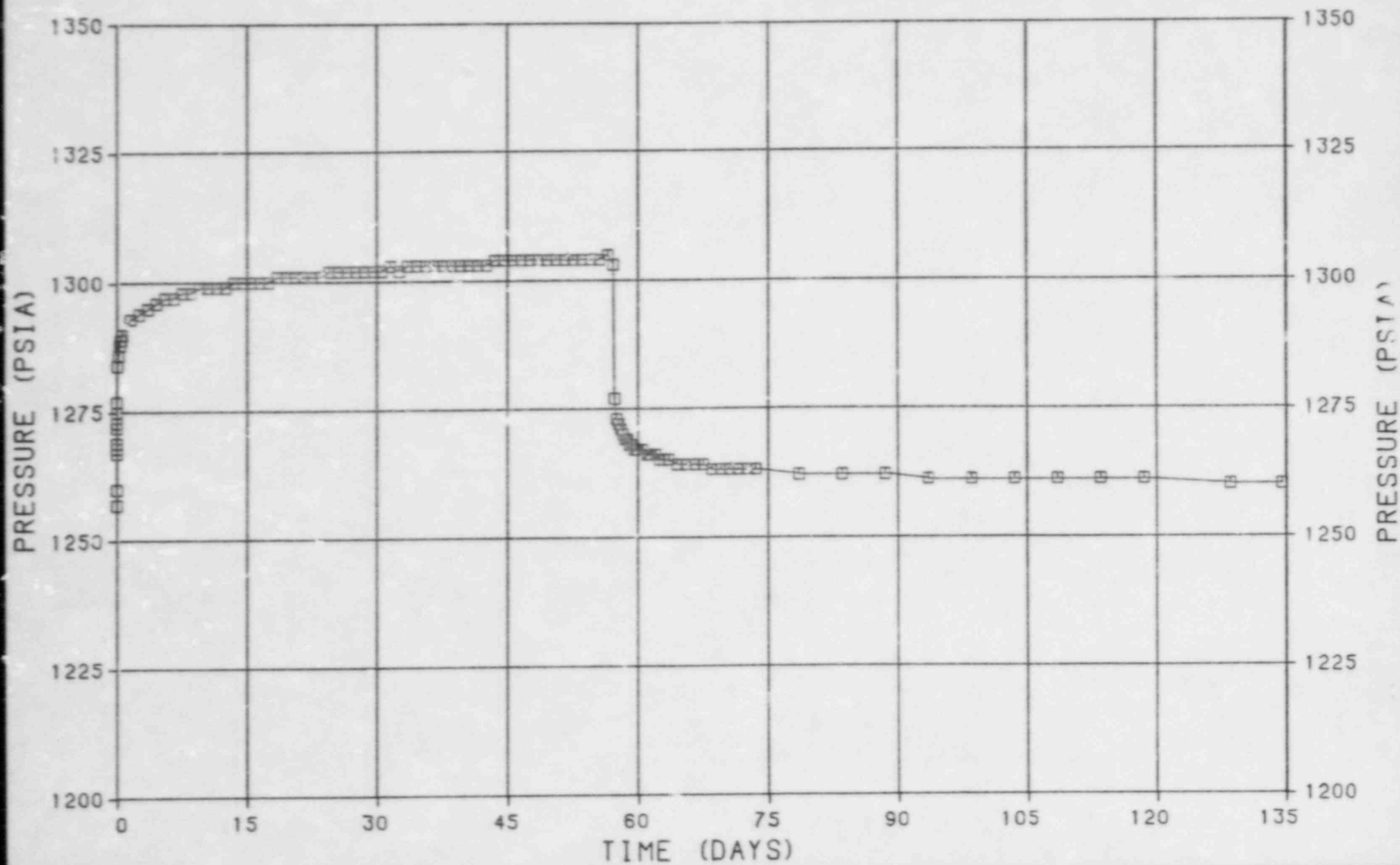


FIGURE 14

SEQUOYAH FUELS CORP.
HISTORY MATCH
MODEL OUTPUT

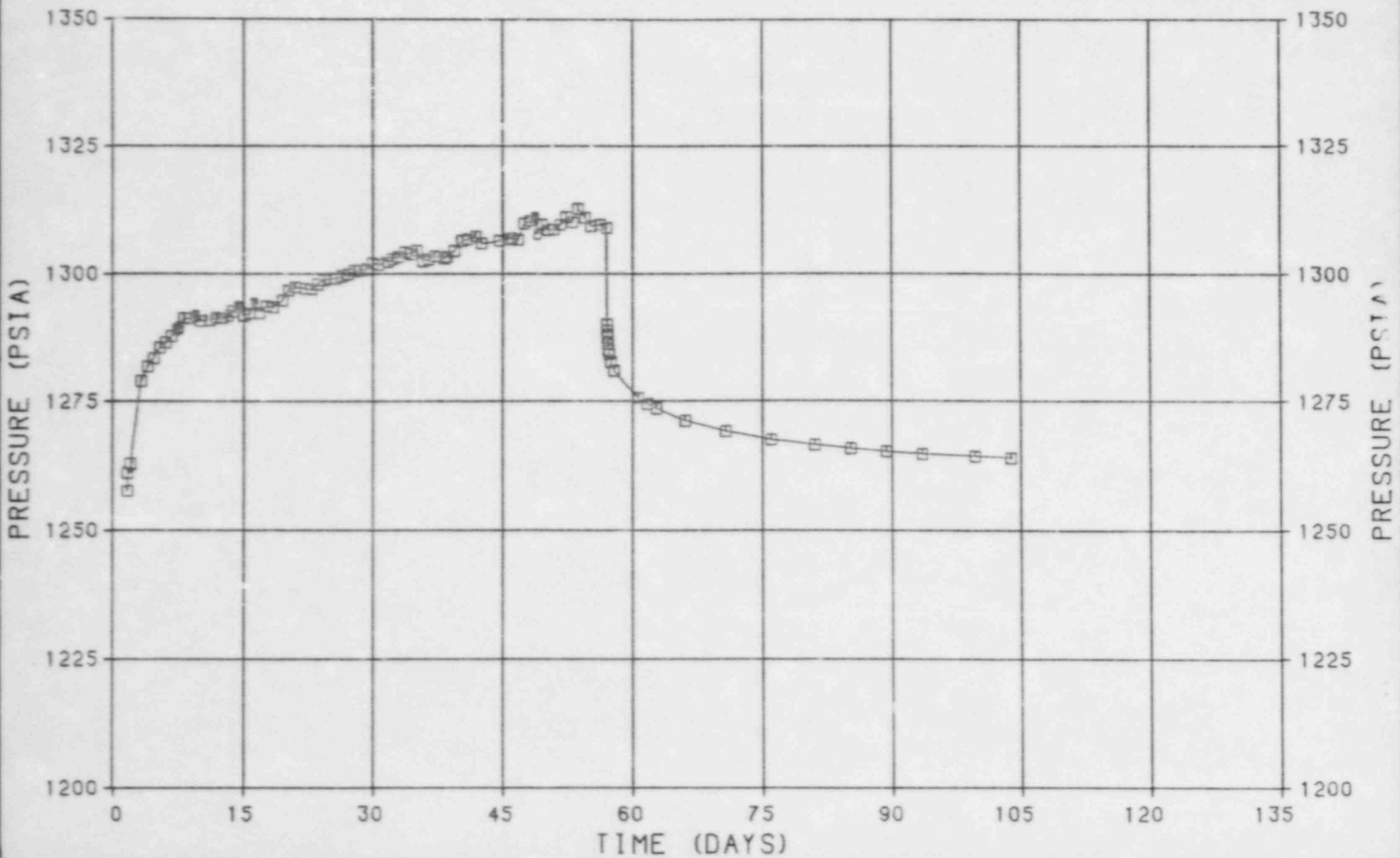
H K VAN POOLLEN AND ASSOCIATES INC



SEQUOYAH FUELS CORP.
HISTORY MATCH
ACTUAL DATA

H K VAN POOLLEN AND ASSOCIATES INC

FIGURE 15



**Analysis of Seismicity at the Kerr-McGee Waste Injection
Site in Sequoyah County, Oklahoma**

Final Report

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February 20, 1984

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Abstract

A seismic network was established at the Kerr-McGee nuclear fuel refinery in Sequoyah County, Oklahoma and was monitored from October 12, 1982 until September 2, 1983, for the purpose of determining if the injection of fluids in a waste-disposal well during the period June 6, 1983 to August 2, 1983 was responsible for inducing any seismicity in the area.

No single event identifiable as a local microearthquake was recorded during the entire period. Furthermore, no events in the vicinity of the injection well were recorded by the Oklahoma Geophysical Observatory seismic network during this period. Statistical analysis of the number of small, unidentifiable, local events, most of which were noise, showed that there was no significant increase in the number of such events either during or after pumping, when compared to the number of events preceding pumping.

The finding of no induced seismicity is consistent with the tectonically inactive character of eastern Oklahoma, especially considering the very low pressure increase that was used during waste injection.

Additional pumping should pose little seismic risk, although reports of felt events should be investigated, and the records of the Oklahoma Geophysical Observatory should be examined for activity in the Gore area.

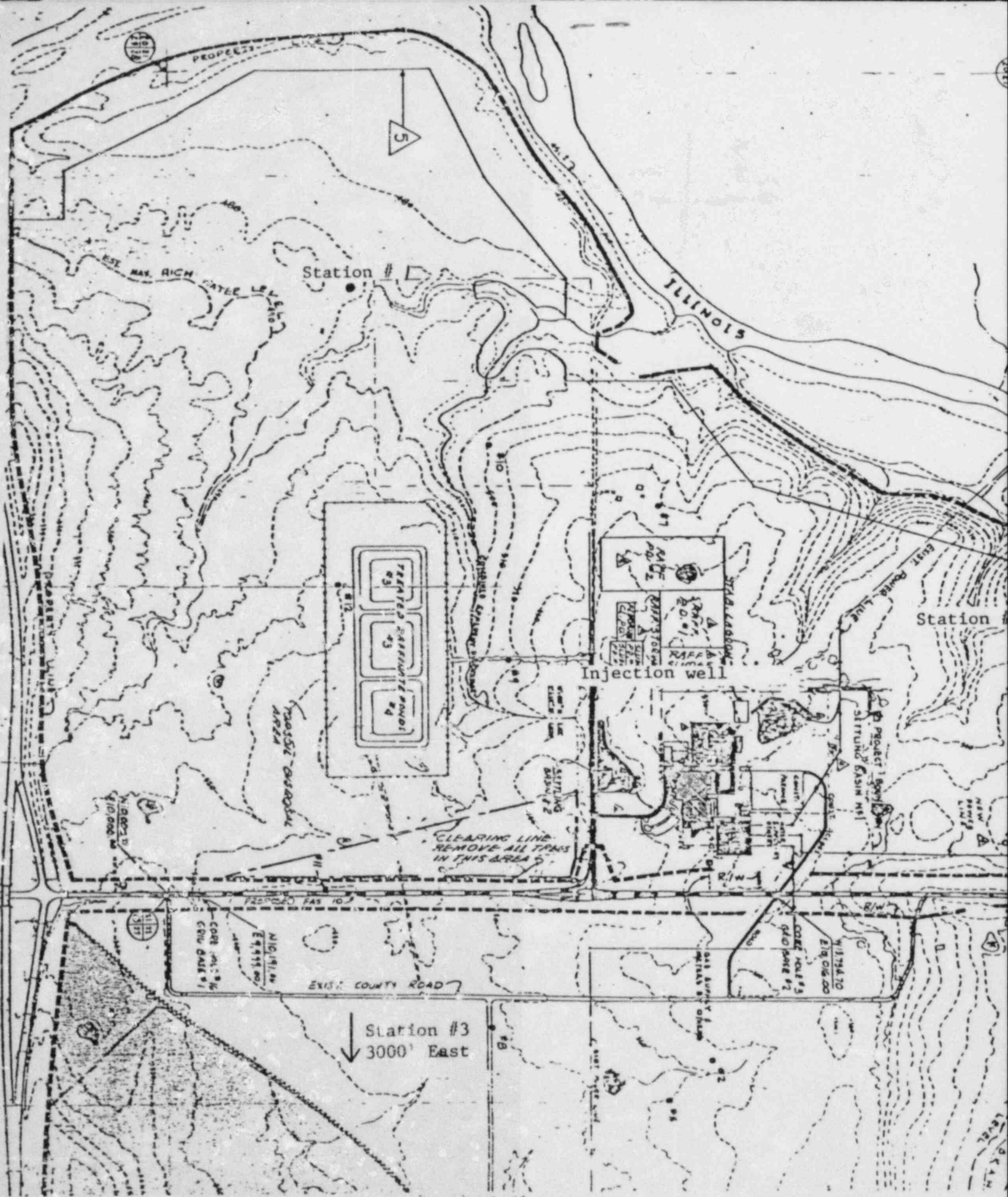
Introduction

From October, 1982, to September, 1983, Drs. Judson Ahern and Robert Dubois, of the University of Oklahoma's School of Geology and Geophysics, carried out a study of the seismicity in the area of Kerr-McGee's nuclear fuel refining facility in Sequoyah County, Oklahoma. The purpose of the investigation was to determine whether the injection of waste fluids, associated with the refining process, induced any seismicity in the area. (As discussed in our proposal to Kerr-McGee, induced seismicity associated with fluid injection has been documented in several instances; the best-known and perhaps best-documented of these involved seismicity associated with injection of waste fluids at the Rocky Mountain Arsenal near Denver.)

In this final report we describe the seismograph network established at the Sequoyah facility, discuss the quantity and quality of the data obtained, and analyze the data to determine whether any of the seismic events recorded might have been induced by the pumping activity.

Station Location

Three seismograph stations were established on the property of the Kerr-McGee Sequoyah facility. We will refer to these as station 1, station 2, and station 3; their locations are shown in Figure 1. Station 1 was moved shortly after it was established because its proximity to Interstate 40 resulted in excessive cultural noise; the new location is shown on the map. Station 3

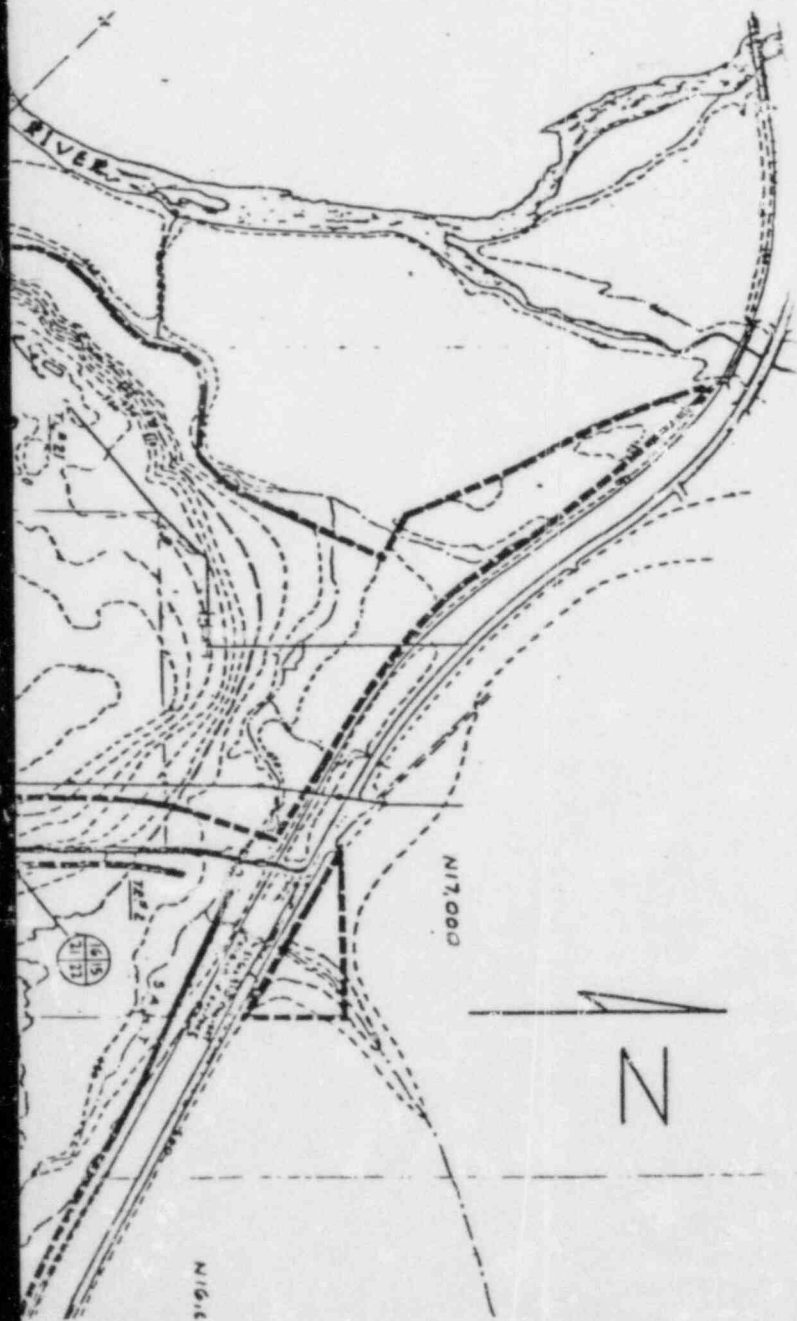


Also Available On
Aperture Card

Figure 1. Locations of seismographs and injection well.

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TI
APERTURE
CARD



was vandalized twice, and it was moved after each incident, but the station was not moved a significant distance. The location of the injection well is also shown in the figure.

Three factors were taken into consideration in choosing the station locations:

Triangulation. In order to accurately locate the epicenter (the vertical projection of the subsurface source onto the earth's surface) of any local earthquakes, the stations had to approximately lie on the vertices of an equilateral triangle which is centered on the injection well (the most likely site of any earthquake epicenters, at least in the absence of good subsurface geological information). Furthermore, to determine the depth of any local earthquakes with any degree of accuracy the stations should be located, as closely as possible, directly over the earthquake source. Placing all three stations over the injection well, however, is impractical for several reasons: 1) the noise from the pumps could mask any natural seismicity; 2) the ability to locate the earthquakes (triangulate) in the horizontal plane would be lost; 3) there is no guarantee that any induced seismicity would occur exactly beneath or in the well. The compromise we adopted was to place the stations a few thousand feet away from the well: far enough to allow for good triangulation and yet close enough to permit reasonable depth determinations.

Accessibility. It was clearly advantageous to locate the stations on Kerr-McGee's property. Furthermore, each of the stations was located near an access road, for the convenience of the record-changer.

Cultural Noise. Seismographs are sensitive to man-made ground noise (train traffic, highway traffic, and foot traffic) as well as to earthquake-generated ground waves. Power lines generate 60 Hz electromagnetic radiation which can produce noise on the seismograph records. The three stations were located as far as practical from such noise sources. As mentioned previously, station 1 was moved because noise from Interstate 40 was judged to be excessive. All three stations were subject to train noise (this is discussed later), but that was essentially unavoidable.

The Instruments

Three Sprengnether MEQ800B portable seismographs were used to record the data. Each seismograph was connected to a Teledyne S13 short-period seismometer.

The particular Sprengnether instruments were chosen because they have proven successful for the Oklahoma Geophysical Observatory's seismograph network. These seismographs are small, battery-operated, and are capable of two days of recording without a record change. We have added external lead-acid batteries to extend battery life to a nominal one month between chargings. The MEQ800B's internal clock is set each day by the record changer to within 100 milliseconds accuracy. The clock is stable to within about 50 milliseconds per day.

The Teledyne short-period seismometers were selected because they are rugged and well-shielded from the environment. (At two of the stations -- stations 1 and 3 -- the seismometers were

buried about two feet underground, for better coupling with the earth.) A short-period instrument (in this case, natural period = 1 Hz) was necessary to get the time resolution required to locate seismic events precisely in time and space.

It is estimated (Dr. Jim Lawson, Oklahoma Geophysical Observatory, personal communication) that the instruments were capable of detecting earthquakes as small as Richter magnitude of between 1.0 and 2.0. Given the short distance between the seismograph stations and any likely source of induced seismicity, we should have been able to detect earthquakes much smaller than can be felt by human senses.

Data Coverage

Quantity

Appendix 1 is a log of data collected at the three stations from initiation of the project on October 12, 1982 to September 2, 1983, when the seismographs were removed. An estimate of the quality of each seismogram is given therein. Coverage was particularly poor in December due to the holiday period, and due to vandalism (the batteries for station 3 were stolen twice).

Most days all three seismographs were recording. Only on a few days were one or zero seismographs working.

On March 26 the gearing on all three instruments was changed to slow the drum rotation so each record would cover 2 days instead of just one. This was done to reduce the time required by the record changer (Mike Chilton during weekdays, various personnel on weekends). The instruments were changed back to their

original gearing on May 13, 1983 in anticipation of the beginning of pumping.

The chances of detecting any induced seismicity clearly depend directly on the percentage of coverage available during the pumping period. Also, it is important to have relatively solid coverage immediately prior to pumping in order to detect any background seismicity; otherwise, events which occurred during pumping might be falsely attributed to the pumping activity. We think these objectives were achieved.

Quality

Several factors affect the quality of seismic data. The most significant of these is the proximity of the seismometer to sources of cultural interference. All three stations record nearby quarry blasts and wind noise, but these disturbances were not frequent enough nor of sufficient magnitude to cause problems in the interpretation of the records.

The periodic passing of trains on a nearby railroad track was also recorded and this did obliterate small portions (several minutes) of the record. Five to seven trains per day passed at various times but the overall disturbance was not significant.

Station 1 was located closest to I-40, within 1 mile of the bridge over the Arkansas river. This should have been reflected in an increase in cultural noise, but this was not the case. In fact, station 1 was consistently the most legible and easiest to interpret. It recorded almost continuously until December 22; it was out of operation until January 11. Coverage was relatively solid after that.

Station 2 also provided clear and legible records. It was out of operation less than either of the other stations.

Station 3 recorded almost continuously until its batteries were stolen on November 29 and again on December 5. It was not restored to operation (except for 2 or 3 days) until January 1.

The quality ratings given in Appendix 1 were based on clarity, legibility, and completeness. They were rated as good, fair, poor, or missing. The majority of the records are rated as good.

Detection of Induced Seismicity

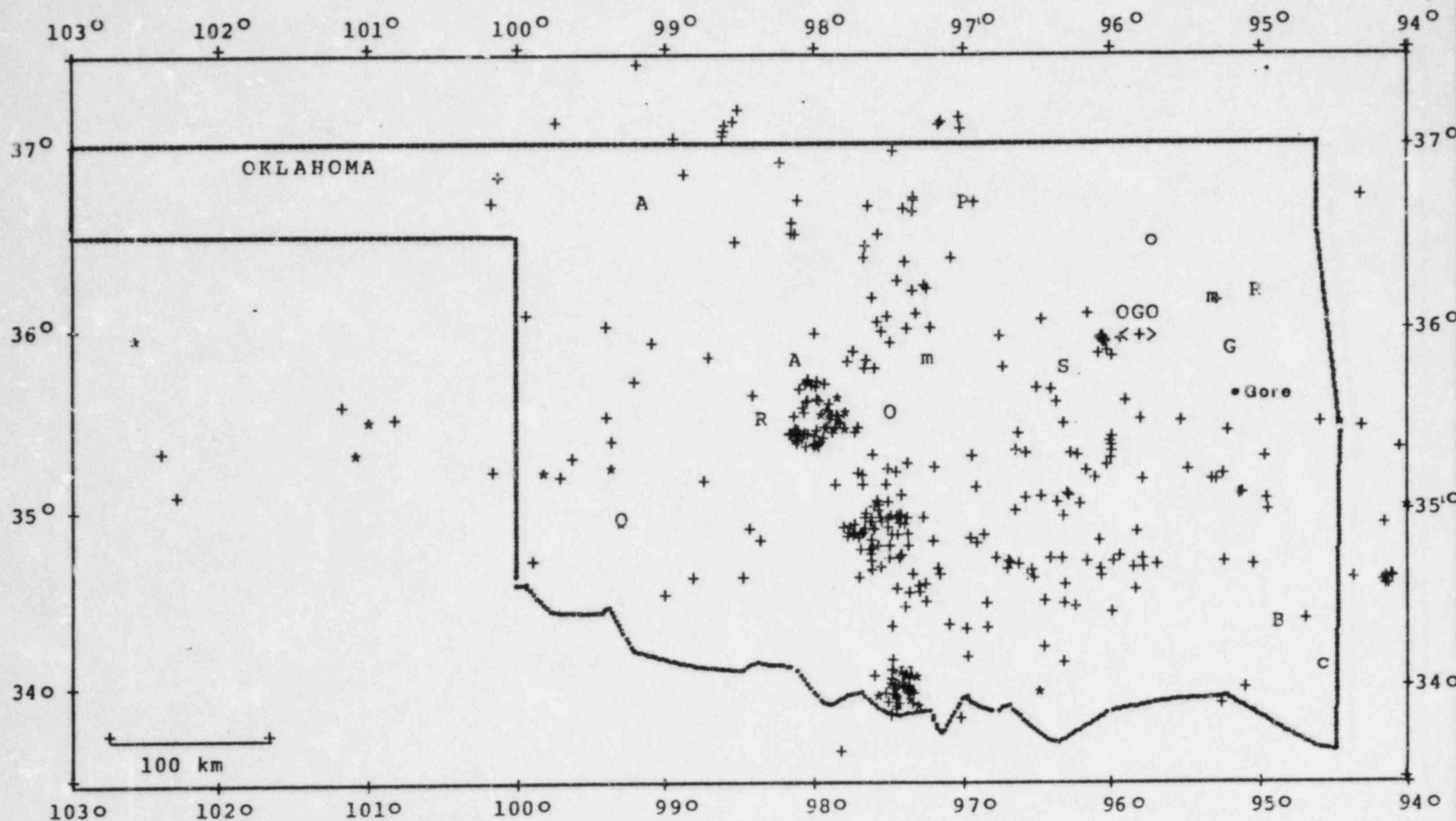
The instruments performed very well. Cultural noise interfered with only a small portion of each record. Quarry blasts and teleseisms were easily identified.

Local Earthquakes

No events were recorded that could clearly be identified as local earthquakes, either before, during, or after pumping. No felt events were reported to us during the time the seismometers were deployed.

Oklahoma Geophysical Observatory Network

Besides the three stations installed on the Kerr-McGee property, several stations around the state are operated by the Oklahoma Geophysical Observatory in Leonard, Oklahoma. The Observatory is run by the Oklahoma Geological Survey, and the director of the Observatory is Dr. Jim Lawson. Figure 2 is a map showing the location of the stations run by the Observatory. Three stations are close to the Kerr-McGee facility (the location of the



359 EARTHQUAKES IN OKLAHOMA AND 32 IN ADJACENT AREAS FROM 770101 TO 831231.

* earthquake known to be felt + earthquake not known to be felt

Letters represent seismograph stations

Figure 2.

city of Gore is shown on the map): Rose Lookout (indicated by R on the map); Fort Gibson (indicated by G); and Bethel (indicated by B). The Oklahoma Geophysical Observatory itself (indicated by OGO) is also reasonably close to the Kerr-McGee facility. These stations are capable of recording events down to magnitude 1, which is below the threshold of being felt by humans.

The map (Figure 2) also shows all earthquakes recorded by the Oklahoma Geophysical Observatory network from January 1, 1977 until December 31, 1983, which includes the period of pumping between June 6, 1983 and August 2, 1983. No earthquakes were recorded in the vicinity of Gore Oklahoma during this time.

Non-Earthquake-Type Events

The three stations on the Kerr-McGee property recorded several tiny events each day which did not have the normal characteristics of microearthquakes. These events are assumed to be noise caused by traffic, equipment, wind, cattle, etc. For the sake of completeness, we have statistically analyzed the number of these events before, during, and after pumping to determine if the pumping might have had any effect on the number of events. It was reasoned that if pumping was inducing microearthquake swarms which did not appear as typical earthquakes, at least the number of events would increase during pumping and perhaps remain high for a short time after pumping.

Each day's records for stations 1, 2, and 3 were examined for short duration (and hence local) events. Quarry blasts and teleseisms were excluded. Events at the beginning and end of each record were excluded since they would probably represent noise

generated by the record changer approaching and leaving the station.

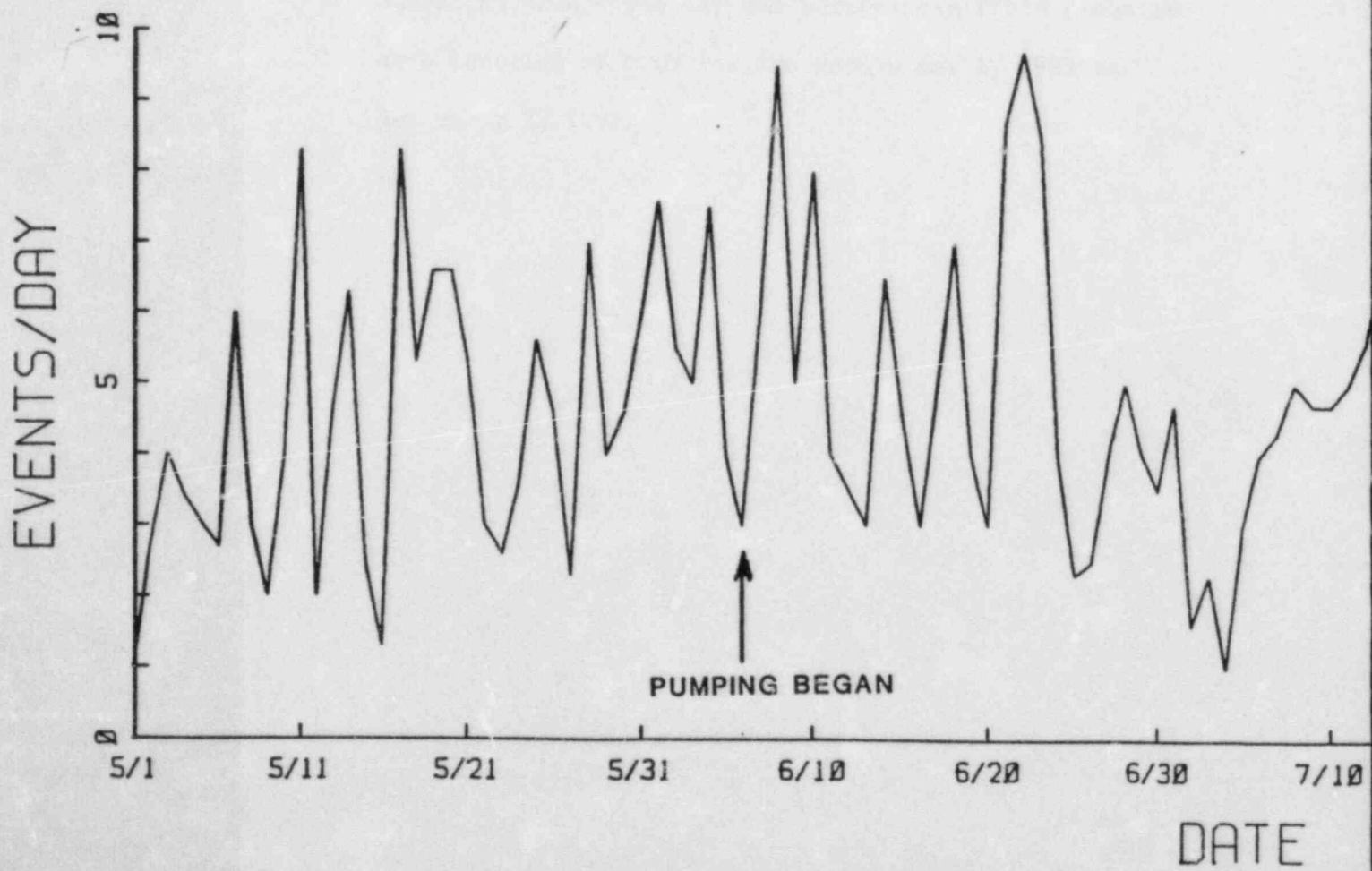
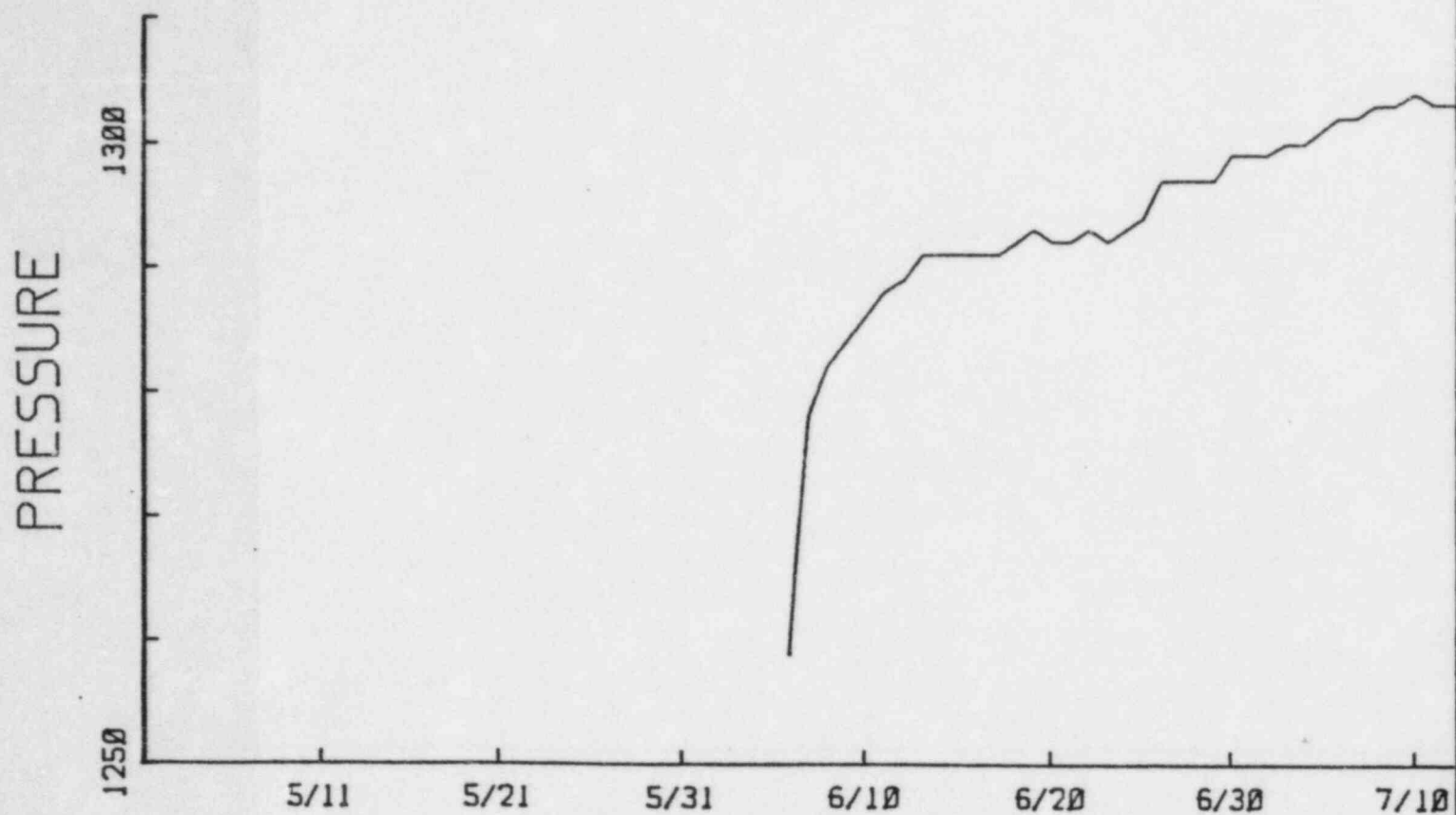
Since not all three stations necessarily recorded a particular event, the number of events was averaged among the three records for that day. Appendix 2 contains a listing of the average number of events recorded for each day from May 1, 1983 (approximately one month before pumping began) until September 2 (1 month after pumping ended).

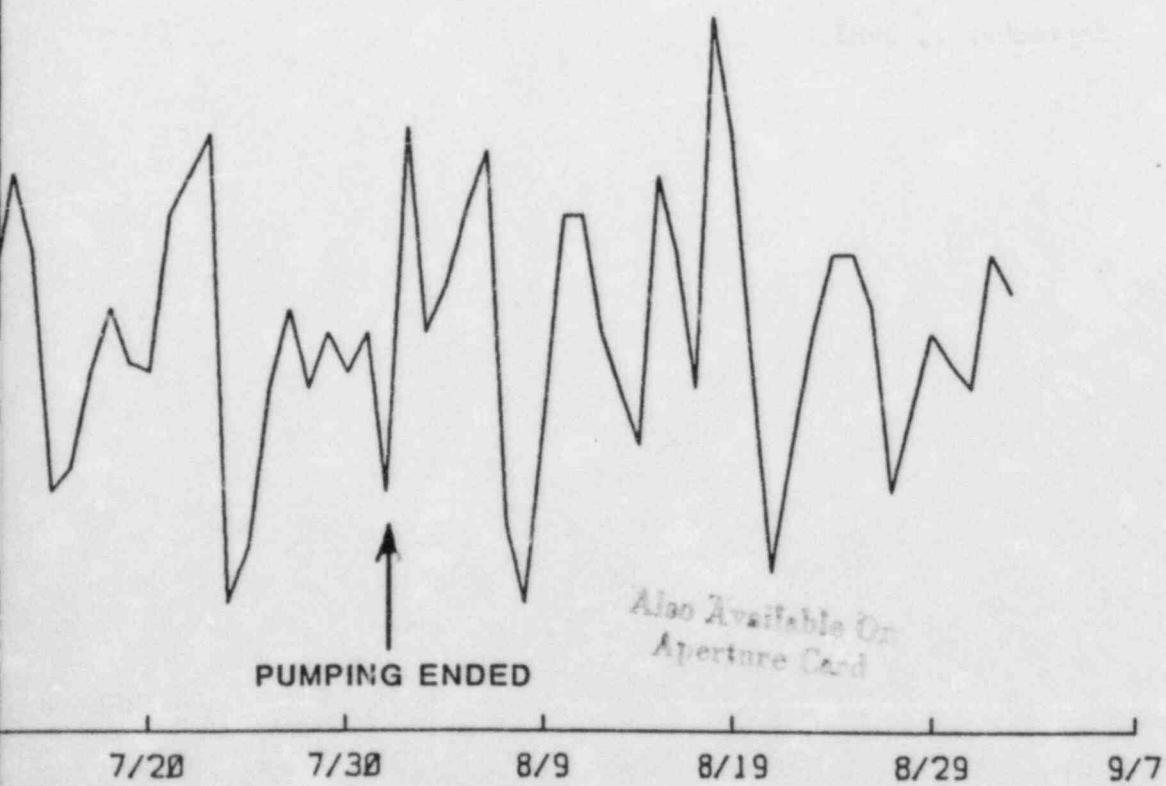
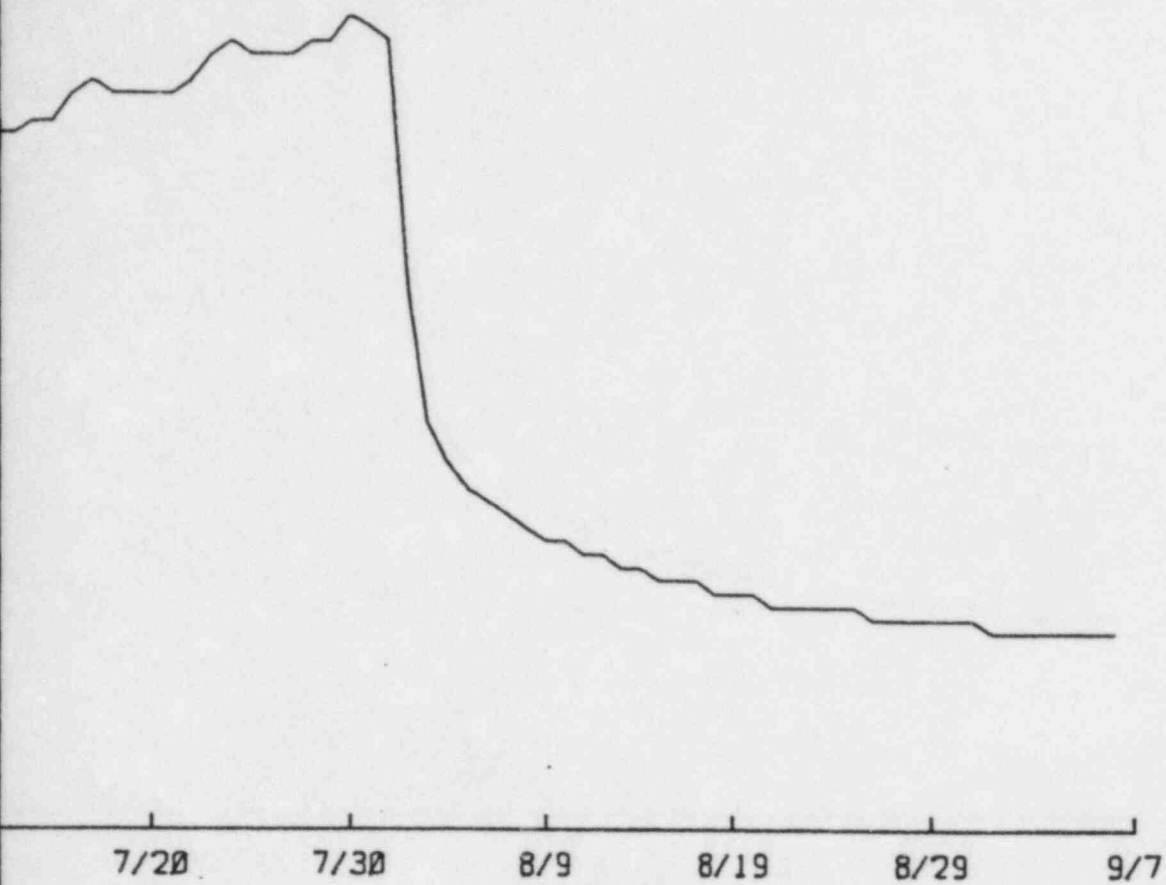
In Figure 3 the number of events per day is plotted against time. Also shown is the average daily pressure at the bottom of the well as recorded by H. K. Van Poulen and Associates. These data were made available to us on magnetic tape. The average daily pressure was calculated using the computer program listed in Appendix 3. The average daily pressure, the average rate of change of pressure, and the number of readings that went into calculating each average, are given in Appendix 4. It should be noted that pumping caused a pressure change of less than 60 pounds per square inch.

It is clear from Figure 3 that there is no obvious relation between the number of events and the pumping activity.

Statistical Analysis of Non-Earthquake-Type Events

The average number of events per day and the standard deviation were calculated for approximately one month preceding pumping, one month after pumping, and for the two month period during which pumping was taking place. The pre-pumping average was 4.49 before pumping, 4.74 during pumping, and 5.07 after pumping. While there appears to be a slight increase in these averages





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Figure 3.

Number of events per day and bottom-hole fluid pressure
as a function of time for the period May 1, 1983 to
September 2, 1983.

over time, the standard deviations for these means (1.96, 1.93, and 1.62, respectively) are large compared to the variations in the means.

A T-test was performed to determine whether there was a significant difference in the means for these three periods. The calculations are given in Appendix 5. The result of the tests was that neither the average during pumping nor after pumping differed significantly from the average before pumping.

Conclusions

The three seismic recording stations were carefully located, properly maintained, and operated well. Careful examination of the records indicated nothing that appeared to be induced seismicity. Statistical analysis of all small events show no correlation between pumping activity and the number of events. Records from the Oklahoma Geophysical Observatory confirm this lack of seismicity.

These results are not at all surprising based on 1) the tectonically inactive nature of the midcontinent region in which the injection well is located; 2) the lack of historical seismicity in the region (although in the well-documented Rocky Mountain Arsenal case there was also a lack of historical seismicity); and 3) the small increase in bottom-hole pressured used during injection.

Based on these results, we feel that additional fluid injection, at the rates and pressures previously used, is unlikely to induce seismicity in the region. However, if felt events are

reported in the region they should be investigated to determine their relationship, if any, to pumping activities. Furthermore, the records of the Oklahoma Geophysical Observatory should be examined periodically for any increase in seismic activity in the Gore area. These should be sufficient precautions to prevent the possibility of damage or injury due to induced seismicity.

APPENDIX 1

Quality of Data at
Seismograph Station GOK
(Gore, Oklahoma)

GOK Data Quality

G -> good F -> fair P -> poor X -> no data

OCTOBER

Sta. 1

Sta. 2

Sta. 3

(Stations first installed on October 12, 1982)

12	F	F	F
13	F	P	F
14	G	G	G
15	G	G	G
16	G	G	G
17	P	G	F
18	P	G	G
19	G	F	P
20	G	G	F
21	G	G	G
22	G	G	G
23	G	P	F
24	G	G	G
25	G	G	G
26	G	F	F
27	G	G	G
28	G	F	F
29	G	G	G
30	G	F	G
31	P	G	P

G -> good F -> fair P -> poor X -> no data

NOVEMBER

	Sta. 1	Sta. 2	Sta. 3
1	P	G	P
2	G	G	G
3	G	G	G
4	G	G	G
5	G	G	G
6	G	G	G
7	G	G	F
8	G	G	F
9	G	F	G
10	G	G	G
11	G	G	F
12	G	F	F
13	G	G	G
14	G	G	G
15	G	G	G
16	G	G	G
17	F	F	F
18	G	F	G
19	G	G	G
20	X	X	X (not picked up)
21	G	G	P
22	G	P	P
23	G	X	G
24	G	G	G
25	X	X	X (holidays)
26	X	X	X
27	X	X	X
28	G	G	G
29	G	G	X (batt.
30	G	G	X stolen)

G -> good F -> fair P -> poor X -> no data

DECEMBER

	Sta. 1	Sta. 2	Sta. 3
1	G	G	X
2	G	F	G
3	X	X	X (rain)
4	G	G	F
5	G	G	X (batt.
6	X	X (rain)	X stolen)
7	G	G	X
8	G	F	X
9	G	G	X
10	G	G	X
11	G	G	X
12	G	G	X
13	G	G	X (electr.
14	G	P	X problem)
15	G	F	X
16	G	F	X
17	G	G	X
18	G	P	X
19	G	X	X
20	G	P	X
21	P	G	F
22	X	F	G
23			
24			
25			
26		(holidays)	
27			
28			
29	X (motor	G	G
30	X broken)	G	X
31	X	X	X

G -> good F -> fair P -> poor X -> no data

JANUARY

	Sta. 1	Sta. 2	Sta. 3
1	X	G	G
2	X	G	G
3	X	G	G
4	X	G	G
5	X	F	G
6	X	G	G
7	X	F	G
8	X	P	G
9	X	F	G
10	X	F	G
11	G	P	P
12	G	F	P
13	G	F	G
14	G	F	G
15	G	F	G
16	P	F	F
17	G	G	G
18	G	G	G
19	G	F	G
20	G	G	G
21	G	G	G (interesting)
22	G	X	P
23	P	G	X
24	G	P	G
25	G	G	G (rain)
26	X	X	X
27	G	F	G
28	G	G	G
29	G	S	G
30	P	G	G
31	X	X	X

G -> good F -> fair P -> poor X -> no data

FEBRUARY

	Sta. 1	Sta. 2	Sta. 3
1	X	X	X
2	X	X	X
3	X	X	X
4	P	X	P
5	F	X	G
6	F	F	G
7	X	X	X
8	X	F	X
9	F	F	P
10	F	F	G
11	F	F	F
12	X	X	X
13	F	P	F
14	F	P	F
15	G	P	F
16	G	P	F
17	P	P	F
18	P batt. low	X	F
19	X	X	X
20	X	X	X
21	P	P	G
22	P	P	G
23	X	F	F
24	X	F	F
25	G	F	G
26	G	G	F
27	G	G	F
28	G	G	G

G -> good F -> fair P -> poor X -> no data

MARCH

	Sta. 1	Sta. 2	Sta. 3
1	X	X	X
2	G	G	G
3	X	F	G
4	F	F	X
5	F	X	X
6	F	X	X
7	X	F	X
8	X	F	X
9	F	F	F
10	G	F	G
11	G	F	G
12	G	F	F
13	G	F	F
14	X	X	X
15	G	F	G
16	G	F	G
17	P	F	F
18	P	F	F
19	G	F	G
20	G	F	G
21	F	F	F
22	F	F	F
23	X	X	X
24	P	P	P
25	P	P	P
26	F	F (switched to	F inner
27	F	gears, 1/2	length
28	G	min. marks,	2 days
29	G	per record)	G
30	G	X	X
31	G	X	G

G -> good F -> fair P -> poor X -> no data

APRIL

	Sta. 1	Sta. 2	Sta. 3
1	X	G	G
2	X	X	X
3	X	X	X
4	G	G	G
5	G	G	G
6	G	F	G
7	G	F	G
8	G	G	G
9	G	G	G
10	X	X	X
11	G	G	G
12	G	G	G
13	G	F	G
14	G	F	G
15	G	P batt. low	G
16	G	P	G
17	X	X	X
18	G	G	G
19	G	G	G
20	G	F	G
21	G	F	G
22	X	X	X
23	X	X	X
24	X	X	G
25	X	F	G
26	X	F	X
27	G	G	G
28	G	G	G
29	G	X	G
30	G	G	G

G -> good F -> fair P -> poor X -> no data

MAY

	Sta. 1	Sta. 2	Sta. 3	
1	X	G	X	
2	G	G	G	(Coalinga
3	G	G	G	quake?)
4	G	P	G	
5	G	P	G	
6	G	G	G	
7	G	G	G	
8	G	G	G	
9	G	G	G	
10	G	G	G	
11	G	G	G	
12	G	G	G	
13	G	G	G	
14	G	G	G	
15	P	F	G	
16	G	G	G	
17	G	G	G	
18	G	G	G	
19	G	G	G	
20	G	G	G	
21	G	G	G	
22	F	F	G	
23	G	G	G	
24	G	G	G	
25	G	G	G	
26	G	G	G	
27	G	F	G	
28	G	G	G	
29	G	G	G	
30	G	G	G	
31	G	G	G	

G --> good F --> fair P --> poor X --> no data

JUNE

	Sta. 1	Sta. 2	Sta. 3
1	G	G	G
2	G	G	X
3	G	G	X
4	G	G	X
5	G	G	X
6	G	G	X
7	G	G	X
8	G	G	X
9	G	G	X
10	G	G	X
11	G	G	P
12	G	G	X
13	G	motor burned	G
14	G	out	G
15	G	X	G
16	G	X	G
17	G	X	G
18	G	X	G
19	G	X	G
20	G	X	G
21	G	G	G
22	G	G	G
23	P	G	G
24	G	P bad elect.	G
25	G	G conn.	G
26	F	X	F
27	F	F	F
28	X	X	X
29	P wiring short	X	X
30	G	G	F

G -> good F -> fair P -> poor X -> no data

JULY

	Sta. 1	Sta. 2	Sta. 3
1	F	G	G
2	X	X	X
3	X	G	X
4	G	G	X
5	X	X	X
6	G	G	G 3 sec slow
7	G	G	G
8	G	G	G
9	G	G	G
10	G	G	G
11	G	G	P
12	G	G	G
13	G	F	G
14	G	G	G
15	G	G	G
16	G	G	G
17	G	G	P drive wrong
18	G	G	G large teleseism
19	G	F	G
20	G	G	P
21	P paper off	F	G
22	G	G	G
23	P paper off	G	G
24	G	G	G
25	G	G	G Dubois, Ahern
26	G	G	G visit
27	G	F	G
28	G	G	G
29	G	F	G
30	G	F	G
31	G	F	G

G -> good F -> fair P -> poor X -> no data

AUGUST

	Sta. 1	Sta. 2	Sta. 3
1	G	F	G
2	G	G	G
3	G	G	G
4	G	G	G
5	G	F	G
6	G	G	G
7	G	F	G
8	G	F	G
9	G	G	G
10	P	G	G
11	P	G	G
12	G	X	G
13	G	F	G
14	F	G	G
15	P	P	G
16	P	G	G
17	G	G	G
18	G	G	G
19	P	G	G
20	G	G	G
21	G	F	G
22	P	G	G
23	G	G	G
24	P	G	G
25	G	G	G
26	G	G	G
27	G	G	P
28	F	P cover wrong	G
29	G	P	G
30	G	G	G
31	G	G	G

SEPTEMBER

	Sta. 1	Sta. 2	Sta. 3
1	G	P	G
2	G	P	G

Appendix 2

Average Number of Local "Events" per Day

Month	Day	Events/Day
05	01	1.0
05	02	2.7
05	03	4.0
05	04	3.4
05	05	3.0
05	06	2.7
05	07	6.0
05	08	3.0
05	09	2.0
05	10	4.0
05	11	8.3
05	12	2.0
05	13	4.6
05	14	6.3
05	15	2.5
05	16	1.3
05	17	8.3
05	18	5.3
05	19	6.6
05	20	6.6
05	21	5.3
05	22	3.0
05	23	2.6
05	24	3.6
05	25	5.6
05	26	4.6
05	27	2.3
05	28	7.0
05	29	4.0
05	30	4.6
05	31	6.0
06	01	7.6
06	02	5.5
06	03	5.0
06	04	7.5
06	05	4.0
06	06	3.0
06	07	6.0
06	08	9.5
06	09	5.0
06	10	8.0
06	11	4.0
06	12	3.5
06	13	3.0
06	14	6.5
06	15	4.5
06	16	3.0

06	17	5.0
06	18	7.0
06	19	4.0
06	20	3.0
06	21	8.7
06	22	9.7
06	23	8.5
06	24	4.0
06	25	2.3
06	26	2.5
06	27	4.0
06	28	5.0
06	29	4.0
06	30	3.5
07	01	4.7
07	02	1.6
07	03	2.3
07	04	1.0
07	05	3.0
07	06	4.0
07	07	4.3
07	08	5.0
07	09	4.7
07	10	4.7
07	11	5.0
07	12	5.6
07	13	7.0
07	14	6.0
07	15	3.0
07	16	3.3
07	17	4.5
07	18	5.3
07	19	4.6
07	20	4.5
07	21	6.5
07	22	7.0
07	23	7.5
07	24	1.6
07	25	2.3
07	26	4.3
07	27	5.3
07	28	4.3
07	29	5.0
07	30	4.5
07	31	5.0
08	01	3.0
08	02	7.6
08	03	5.0
08	04	5.6
08	05	6.6
08	06	7.3
08	07	2.6
08	08	1.6
08	09	4.0
08	10	6.5

08	11	6.5
08	12	5.0
08	13	4.3
08	14	3.6
08	15	7.0
08	16	6.0
08	17	4.3
08	18	9.0
08	19	7.5
08	20	4.6
08	21	2.0
08	22	3.6
08	23	5.0
08	24	6.0
08	25	6.0
08	26	5.3
08	27	3.0
08	28	4.0
08	29	5.0
08	30	4.6
08	31	4.3
09	01	6.0
09	02	5.5

Appendix 3

DAYAVG.FORT -- Calculate Average Pressure Each Day

```

DIMENSION TIME(11971), PRESS(11971), PAVG(178)
DIMENSION DPDT(178), NP(178)
NDATA = 11971

C
C READ IN DATA
C
      READ (12,1000) (TIME(I), PRESS(I), I = 1, NDATA)
1000  FORMAT (1X,F8.4,1X,F7.2,2X,F8.4,1X,F7.2,2X,F8.4,1X,F7.2,
      * 2X,F8.4,1X,F7.2)
C
C INITITALIZE VARIABLES
C
      DO 15 I = 1, 178
        NP(I) = 0
        PAVG(I) = 0.0
        DPDT(I) = 0.0
15    CONTINUE
C
C CALULATE AVERAGES
C
C ADJUST IS ADJUSTMENT TO CONVERT TIME SINCE BEGINNING OF
C PUMPING (9.63 HOURS INTO JUNE 6, 1983) TO DAY NUMBER,
C WHERE JUNE 6 IS DAY 1
C
      ADJUST = 9.63/24.0
      NDM10 = NDATA - 10
      DO 20 I = 1, NDM10
        IDAY = INT(TIME(I) + ADJUST) + 1
        PAVG(IDAY) = PAVG(IDAY) + PRESS(I)
        DP = PRESS(I+10) - PRESS(I)
        IF (DP .NE. 0.0) GO TO 290
        GO TO 310
290    DPDT(IDAY) = DPDT(IDAY) + DP/(TIME(I+10)-TIME(I))
310    NP(IDAY) = NP(IDAY) + 1
20    CONTINUE
C
C OUTPUT RESULTS
C
      WRITE (6,1500)
1500  FORMAT(5X,'DAY',4X,'AVG. P',6X,'AVG. DP/DT',4X,'N')
      DO 30 I = 1, 178
        PAVG(I) = PAVG(I)/NP(I)
        DPDT(I) = DPDT(I)/NP(I)
        WRITE (6,2000) I, PAVG(I), DPDT(I), NP(I)
2000  FORMAT (5X,I3,2X,2E12.4,2X,I5)
30    CONTINUE
      STOP
      END

```

Appendix 4

Average Daily Pressure and Rate of Change in Pressure

(Day 1 corresponds to June 6, 1983)

Day	Pressure, PSIA	dP/dt, PSIA/day	number of readings
1	0.1259E+04	-0.4425E+04	369
2	0.1278E+04	0.5023E+01	130
3	0.1282E+04	0.2535E+01	144
4	0.1284E+04	0.2391E+01	144
5	0.1286E+04	0.2042E+01	144
6	0.1288E+04	0.1303E+01	144
7	0.1289E+04	0.1679E+01	144
8	0.1291E+04	0.5193E+00	143
9	0.1291E+04	0.3738E+00	118
10	0.1291E+04	-0.8672E+00	132
11	0.1291E+04	0.8626E+00	144
12	0.1291E+04	0.3457E+00	132
13	0.1292E+04	0.1033E+01	120
14	0.1293E+04	0.9390E+00	129
15	0.1292E+04	-0.4041E+00	132
16	0.1292E+04	0.1973E+01	144
17	0.1293E+04	-0.1595E+01	129
18	0.1292E+04	0.5130E+00	120
19	0.1293E+04	0.8119E+00	129
20	0.1294E+04	0.2955E+01	99
21	0.1297E+04	0.8939E+00	132
22	0.1297E+04	0.6628E+00	81
23	0.1297E+04	0.4247E+00	144
24	0.1297E+04	0.1274E+01	133
25	0.1299E+04	0.4582E+00	144
26	0.1299E+04	0.5150E+00	144
27	0.1299E+04	0.2780E+00	144
28	0.1300E+04	0.4644E+00	144
29	0.1300E+04	0.8460E+00	144
30	0.1301E+04	0.9243E+00	135
31	0.1302E+04	0.4174E+00	144
32	0.1302E+04	0.4935E+00	132
33	0.1303E+04	0.3573E+00	132
34	0.1303E+04	0.7465E+00	132
35	0.1304E+04	0.6100E+00	144
36	0.1303E+04	-0.2112E+01	144
37	0.1303E+04	0.3193E+00	145
38	0.1303E+04	0.2017E+00	144
39	0.1304E+04	0.6472E+00	115
40	0.1304E+04	0.6339E+00	132
41	0.1306E+04	0.1197E+01	132
42	0.1307E+04	0.8460E+00	124
43	0.1306E+04	-0.1026E+01	140
44	0.1306E+04	0.6128E+00	44
45	0.1306E+04	-0.1348E+01	34

46	0.1306E+04	0.8564E+00	144
47	0.1307E+04	0.9809E+00	144
48	0.1309E+04	0.2477E+01	144
49	0.1310E+04	0.1193E+01	144
50	0.1309E+04	-0.1706E+01	144
51	0.1309E+04	-0.8741E+00	144
52	0.1309E+04	0.1729E+01	144
53	0.1310E+04	0.9590E+00	144
54	0.1310E+04	-0.1195E+00	143
55	0.1312E+04	0.2036E+01	132
56	0.1311E+04	-0.3489E+01	144
57	0.1310E+04	0.6436E+00	94
58	0.1291E+04	-0.2300E+03	906
59	0.1281E+04	-0.4020E+01	176
60	0.1278E+04	-0.1914E+01	97
61	0.1276E+04	-0.1397E+01	96
62	0.1275E+04	-0.1127E+01	96
63	0.1274E+04	-0.9710E+00	96
64	0.1273E+04	-0.8743E+00	67
65	0.1272E+04	-0.6975E+00	24
66	0.1272E+04	-0.6094E+00	20
67	0.1271E+04	-0.5780E+00	24
68	0.1271E+04	-0.4930E+00	24
69	0.1270E+04	-0.4550E+00	24
70	0.1270E+04	-0.4220E+00	24
71	0.1269E+04	-0.3720E+00	24
72	0.1269E+04	-0.3500E+00	24
73	0.1269E+04	-0.3072E+00	24
74	0.1268E+04	-0.3065E+00	23
75	0.1268E+04	-0.2800E+00	24
76	0.1268E+04	-0.2620E+00	24
77	0.1267E+04	-0.2561E+00	24
78	0.1267E+04	-0.1873E+00	24
79	0.1267E+04	-0.2109E+00	12
80	0.1267E+04	-0.2091E+00	24
81	0.1267E+04	-0.2020E+00	24
82	0.1266E+04	-0.1969E+00	24
83	0.1266E+04	-0.1889E+00	24
84	0.1266E+04	-0.1780E+00	24
85	0.1266E+04	-0.1781E+00	24
86	0.1266E+04	-0.1569E+00	24
87	0.1266E+04	-0.1281E+00	24
88	0.1265E+04	-0.1379E+00	24
89	0.1265E+04	-0.1271E+00	24
90	0.1265E+04	-0.1379E+00	24
91	0.1265E+04	-0.1151E+00	24
92	0.1265E+04	-0.9985E-01	24
93	0.1265E+04	-0.9709E-01	24
94	0.1265E+04	-0.1089E+00	24
95	0.1265E+04	-0.8701E-01	24
96	0.1264E+04	-0.9769E-01	23
97	0.1264E+04	-0.7753E-01	13
98	0.1264E+04	-0.1110E+00	24
99	0.1264E+04	-0.5710E-01	24
100	0.1264E+04	-0.6286E-01	24

101	0.1264E+04	-0.8804E-01	24
102	0.1264E+04	-0.6106E-01	24
103	0.1264E+04	-0.7698E-01	24
104	0.1264E+04	-0.5591E-01	24
105	0.1264E+04	-0.4905E-01	24
106	0.1264E+04	-0.8909E-01	24
107	0.1264E+04	0.4004E-01	24
108	0.1264E+04	-0.7142E-01	24
109	0.1264E+04	-0.2445E-01	18
110	0.1264E+04	-0.7483E-01	23
111	0.1264E+04	-0.8909E-01	24
112	0.1263E+04	-0.1699E-01	24
113	0.1263E+04	-0.6995E-01	24
114	0.1263E+04	-0.4595E-01	24
115	0.1263E+04	-0.3804E-01	24
116	0.1263E+04	-0.3804E-01	24
117	0.1263E+04	-0.5203E-01	24
118	0.1263E+04	-0.4199E-01	24
119	0.1263E+04	-0.6599E-01	24
120	0.1263E+04	-0.4292E-01	23
121	0.1263E+04	-0.1202E-01	24
122	0.1263E+04	-0.2803E-01	24
123	0.1263E+04	-0.5604E-01	24
124	0.1263E+04	-0.4698E-01	24
125	0.1263E+04	-0.4498E-01	24
126	0.1263E+04	-0.4198E-01	24
127	0.1263E+04	-0.5707E-01	24
128	0.1263E+04	-0.1802E-01	24
129	0.1263E+04	-0.1001E-01	24
130	0.1263E+04	-0.6303E-01	24
131	0.1263E+04	-0.3297E-01	24
132	0.1263E+04	-0.1592E-01	24
133	0.1263E+04	-0.2503E-01	24
134	0.1263E+04	-0.1800E-01	24
135	0.1263E+04	-0.2603E-01	24
136	0.1263E+04	-0.2002E-01	24
137	0.1262E+04	-0.3905E-01	24
138	0.1262E+04	-0.6008E-02	24
139	0.1262E+04	-0.4603E-01	24
140	0.1262E+04	-0.2994E-01	23
141	0.1262E+04	0.1131E+00	23
142	0.1262E+04	-0.1603E+00	24
143	0.1262E+04	-0.3299E-01	24
144	0.1262E+04	-0.4501E-01	24
145	0.1262E+04	0.9010E-02	24
146	0.1262E+04	-0.1902E-01	24
147	0.1262E+04	-0.2403E-01	24
148	0.1262E+04	-0.1001E-01	24
149	0.1262E+04	-0.3704E-01	24
150	0.1262E+04	-0.9734E-03	24
151	0.1262E+04	-0.5700E-01	24
152	0.1262E+04	0.2000E-02	24
153	0.1262E+04	-0.2282E-01	24
154	0.1262E+04	-0.2844E-01	23
155	0.1262E+04	-0.2899E-01	24

156	0.1262E+04	-0.4303E-01	24
157	0.1262E+04	0.2603E-01	24
158	0.1262E+04	0.4007E-02	24
159	0.1262E+04	-0.2003E-01	24
160	0.1262E+04	-0.2102E-01	24
161	0.1262E+04	-0.3904E-01	24
162	0.1262E+04	0.3704E-01	24
163	0.1262E+04	0.1902E-01	24
164	0.1262E+04	-0.3104E-01	24
165	0.1262E+04	-0.1180E+00	24
166	0.1262E+04	-0.3497E-01	24
167	0.1262E+04	0.3297E-01	24
168	0.1262E+04	-0.2599E-01	24
169	0.1262E+04	-0.3502E-01	24
170	0.1262E+04	-0.1497E-01	24
171	0.1262E+04	0.5602E-01	24
172	0.1262E+04	-0.1096E-01	24
173	0.1262E+04	-0.3301E-01	24
174	0.1262E+04	-0.1401E-01	24
175	0.1262E+04	0.2714E-01	24
176	0.1262E+04	0.1546E-02	18
177	0.1262E+04	-0.1539E-01	23
178	0.1262E+04	0.6775E-01	24

Appendix 5

T-Test for Significance of Difference of Average Number of Events Before, During and After Pumping

The Data

Pre-pumping (5/1 - 6/5)	During pumping (6/6 - 8/2)	Post-pumping (8/3 - 9/2)
$m_1 = 4.49$	$m_2 = 4.74$	$m_3 = 5.07$
$s_1 = 1.96$	$s_2 = 1.93$	$s_3 = 1.62$
$n_1 = 36$	$n_2 = 58$	$n_3 = 31$

where m 's are the average number of events per day for each group, s 's are the standard deviation for each group, and n 's are the number of samples making up each group.

T-Test of Pre-pumping average against average During pumping

Null Hypothesis: The mean number of events during pumping is not significantly different than the number of events before pumping.

$$H_0: m_1 = m_2$$

Alternative Hypothesis: The mean number of events during pumping is significantly different than the number of events before pumping.

$$H_1: m_1 \neq m_2$$

The joint estimate of variance of population is s^2 :

$$s^2 = \frac{(n_1-1)s_1^2 + (n_2-1)s_2^2}{n_1 + n_2 - 2} = 3.77$$

$$\text{or } s = 1.94$$

The t-variable is:

$$t = [m_2 - m_1] / [s(1/n_1 + 1/n_2)^{1/2}] = 0.61$$

with 92 degrees of freedom

At a 90% confidence level ($\alpha = 10\%$, 5% in each tail of the two-tailed distribution), the critical t-value for 92 degrees of freedom is 1.662.

Therefore, at the 90% confidence level we are unable to reject the hypothesis that the means are equal. We must conclude that there is no evidence to suggest that the number of events per day during pumping was significantly different from the number of events per day before pumping began (p.99, J. C. Davis, 1973, *Statistics and Data Analysis in Geology*).

T-Test of Pre-pumping average against Post-pumping average

Null Hypothesis: The mean number of events after pumping is not significantly different than the number of events before pumping.

$$H_0: m_1 = m_3$$

Alternative Hypothesis: The mean number of events after pumping is significantly different than the number of events before pumping.

$$H_1: m_1 \neq m_3$$

The joint estimate of variance of population is s^2 :

$$s^2 = \frac{(n_1-1)s_1^2 + (n_3-1)s_3^2}{n_1 + n_3 - 2} = 3.28$$

$$\text{or } s = 1.81$$

The t-variable is:

$$t = [m_2 - m_1] / [s(1/n_1 + 1/n_2)^{1/2}] = 1.31$$

with 65 degrees of freedom

At a 90% confidence level ($\alpha = 10\%$, 5% in each tail of the two-tailed distribution), the critical t-value for 65 degrees of freedom is 1.669.

Therefore, at the 90% confidence level we are unable to reject the hypothesis that the means are equal. We must conclude that there is no evidence to suggest that the number of events per day after pumping was significantly different from the number of events per day before pumping began (p.99, J. C. Davis, 1973, Statistics and Data Analysis in Geology).

DOCKET NO. 40-8027
CONTROL NO. 23388
DATE OF DOC. 02/24/84
DATE RCVD. 02/29/84
FCUF ☒ PDR ☒
FCAF ☐ LPDR ☒
WM ☐ I&E REF. ☒
WMUR ☐ SAFEGUARDS ☐
FCTC ☐ OTHER ☐

DESCRIPTION:

enclosed are re-
ports regarding the
initial injection of
5 million gallons of
treated raffinate.
02/29/84 INITIAL CEC