Exhibit A

ENGINEERING STUDY OF THE ARBUCKLE RESERVOIR COMMUNICATED TO THE KERR-MCGEE CORPORATION NO. 1 SEQUOYAH WASTE STORAGE WELL SEQUOYAH COUNTY, OKLAHOMA

MAY 1, 1972

H. J. GRUY AND ASSOCIATES, INC.
PETROLEUM CONSULTANTS

H. J. GRUY AND ASSOCIATES, INC.
PETROLEUM CONSULTANTS
2501 CEDAR SPRINGS ROAD
DALLAS, TEXAS 75201

May 1, 1972

Mr. George Parks
Kerr-McGee Corporation
Kerr-McGee Building
Oklahoma City, Oklahoma 73102

Dear Mr. Parks:

In response to your request, we are transmitting the results of our engineering study of the Arbuckle reservoir communicated to the Kerr-McGee Corporation No. 1 Sequoyah Waste Storage Well, Sequoyah County, Oklahoma.

In summary, our study reveals the reservoir to have five major layers having a total pore volume of at least 860 million barrels. A reservoir description of the Arbuckle reservoir based on data taken during an injection profile and pressure fall-off test program is detailed in the attached report. A ten-year injection well performance is predicted based on an injection program furnished by your staff.

Yours very truly,

H. J. Gruy and Associates, Inc.

H. J. Gruy and Associates, Inc.

HJG:jt

H. J. GRUY AND ASSOCIATES, INC.

ENGINEERING STUDY OF THE
ARBUCKLE RESERVOIR
COMMUNICATED TO THE
KERR-MCGEE CORPORATION NO. 1 SEQUOYAH
WASTE STORAGE WELL
SEQUOYAH COUNTY, OKLAHOMA

—

MAY 1, 1972

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I. CONCLUSIONS

An accurate detailed description of the Arbuckle reservoir which is pressure communicated to the Kerr-McGee Corporation No. 1 Sequoyah Waste Storage well was achieved utilizing actual field injection test data and a three-dimensional, single-phase numeric reservoir simulation model in a high-speed computer. The data analyzed included the pressure response resulting from water injection tests of known flow rates, injection profile tests incorporating both radioactive tracer and temperature surveys, pressure fall-off response during injection shut-in periods, electric well logs, core analyses and regional geological studies.

The model studies indicate that the reservoir is divided into five significant layers totaling a pore volume of at least 860 million barrels (3.6×10^{10} gallons) and with three of the five layers definitely bounded on all sides. The other two layers are bounded top and bottom and on three sides, and the areal extent investigated in these relatively low permeability sections was such as to define the minimum distance to the boundary on the fourth side. (See discussion in Sections III (A) and III (F) and Figure 1.)

Our analysis indicates that there are no significant boundary leakages, no vertical interconnections between layers forming the reservoirs and no significant horizontal heterogeneities within each layer. (See discussion of these items in Sections III (A), III (G), III (H).)

Our study, utilizing the numerical reservoir simulation model, indicates that the pressure increase at the wellhead over an injection period of five years considering the planned injection rate will be 161 pounds per square inch gauge and that the calculated maximum distance of travel of injected fluid from the wellbore in this five-year period will be 900 feet. Thus, for this period of injection, the injected fluids will be confined within Kerr-McGee property limits. (See discussion of these items in Section III (A).)

II. INTRODUCTION

We have performed an engineering study of the Arbuckle reservoir communicated to the Kerr-McGee Corporation No. 1 Sequoyah Waste Storage Well, Sequoyah County, Oklahoma. Our study has included detailed injection pressure and pressure fall-off testing and injection profiling through the use of radioactive tracers.

The testing program data have been used to develop a three-dimensional, single-phase reservoir model compatible with the injection profile data and with the analysis performed on the pressure fall-off data. The numeric model was calibrated to the reservoir system by adjusting the geometry of the system until the calculated pressure performance from the model matched the pressure performance observed during the testing program. A predicted ten-year injection performance was then calculated using the numeric model and an injection schedule as furnished by Kerr-McGee Corporation.

III. DISCUSSION

(A) General Approach and Results

Our study reveals the reservoir to have five major layers having a total pore volume of at least 860 million barrels. The layers exhibit different permeabilities and no effective communication between the layers except in the wellbore. Layer 5 (the bottommost layer) with a permeability of 2,480 millidarcies and a thickness of 34 feet is calculated to have an area of only about 645 acres. Layers 1 and 2 having effective permeabilities of 2,469 and 2,279 millidarcies, respectively, and thicknesses of 24 and 8 feet are calculated to extend under 8,804 acres. Layers 3 and 4 exhibiting effective permeabilities of 964 and 1,709 millidarcies, respectively, and having thicknesses of 26 and 24 feet are calculated to extend at least under 19,580 acres and may be even larger. The geometry as presented in Figure 1 is based on the calculated distances to the layer boundaries. The direction and orientation of the boundaries cannot be determined from the calculations although certain boundary distances are compatible with faults inferred by surface and subsurface geology.

Based on an injection schedule furnished by your staff, we calculate that a wellhead injection pressure of 161 pounds per square inch gauge will exist after an injection period of five years. The wellhead pressure after an injection period of ten years is calculated to be 371 pounds per square inch gauge. The approximate maximum distance of injected fluid from the wellbore for the five layers studied at the end of the five years is as follows:

Layer	Injected Volume (barrels)	Maximum Distance (feet)
1	165, 200	700
2	62, 700	750
3	440, 600	900
4	500, 300	900
5	22, 600	140

The above distances assume no alteration of the reservoir resulting from chemical reaction between the injected fluids and the reservoir rock. If cavities are created by the injection, the distance that injected fluids will disperse will be less than calculated.

A reservoir description and a predicted ten-year injection well performance were calculated. The description of the Arbuckle reservoir was obtained from injection profiles and by analyses of pressure fall-off tests considering the available injection fluid properties, electric log, core and geological data. A testing program incorporating both injection profiling and pressure fall-off testing was designed and executed in the well from June 28, 1971 through July 26, 1971. The profiling in this program was conducted by the Well Analysis Company, Inc. (WACO). Radioactive velocity surveys were run at the outset of the program to check for any possible communication behind the wellbore casing. Results of these surveys indicate that no communication exists behind pipe. The static reservoir pressure measured prior to injection was 1, 238. 45 pounds per square inch gauge at a datum of 2, 650 feet. Sperry-Sun gauges were used to record bottom-hole and wellhead pressures during the program.

The data obtained from the program reveals that the Arbuckle reservoir communicated to the test well is a highly complex layered-permeability system with no effective vertical communication between layers in the reservoir. Accordingly, the pressure fall-off test data could not be analyzed with analytical reservoir models expressing fluid flow through a single-layer homogeneous reservoir and it was necessary to use a three-dimensional numeric model on a high-speed digital computer to obtain a reservoir description and a projection of injection well performance. The numeric model allowed us to study the effects of reservoir heterogeneity in the form of variable rock properties and boundary distances in each layer. Data input into the numeric model included the initial static reservoir pressure, injection rate schedules, pressure fall-off time periods, injection fluid properties, fault boundary distances as indicated by geological and pressure fall-off data, plus values of effective permeability, porosity and thickness of each layer. Boundary distances of each layer were systematically altered in the model executions until an acceptable match was obtained between calculated pressures and pressures measured during the long-term pressure fall-off test period from July 6, 1971 through July 12, 1971. Several model runs were required before a reasonable match was obtained. The best match obtained in this study is presented graphically in Figure 2, a plot of shut-in pressures measured and calculated during the long-term fall-off test period. The standard deviation of this match is $\pm$ 0.75 pounds per square inch. This standard deviation compares with the precision of pressure measurement of $\pm$ 0.55 pounds per square inch on the gauge element used during the fall-off tests.

A description of the reservoir system derived from the best test data match achieved is presented in Figures 1 and 3. A summary of the individual layer properties is contained in Figure 3. The depth interval and thickness of each layer are derived from the WACO injection profile data. Effective permeabilities are calculated from the early portion of the long-term pressure fall-off test data and the input rate distributions of the injection profiles. Values of porosity are calculated from electric log and core analyses. The areal extent shown for each layer in Figure 3 results in the best pressure data match of Figure 2. Figure 1 presents an areal view of each permeability layer and the boundary distances from the test well which result in the best pressure match. Some control on boundary distances is available from the measured pressure fall-off data and subsurface geology. An analysis of the early portion of the long-term pressure fall-off data indicates that the nearest boundary was reflected in Layer 5 at a distance of approximately 1,164 feet. Subsequent model runs indicated that two boundaries are located at equal distances of 1,164 feet from the well in Layer 5. The distances from the well to the geological fault boundaries shown in Figure 1 have been altered in seeking the best pressure match with the model; however, they are comparable in magnitude to the approximate distances indicated by a structure map contoured on top of the Arbuckle. The furthermost boundary in Figure 1 is a perpendicular truncation of Layers 3 and 4. This boundary is positioned as near the test well as possible to produce the minimum pore volume from the best pressure match. An additional study of this boundary position with the numeric model indicated that it could be removed without significantly affecting the pressure match. Therefore, the reservoir area investigated during the injection and pressure fall-off test periods is contained within a maximum distance of approximately 30,000 feet from the test well and any boundary located beyond this distance in Layers 3 and 4 remains undetected. The other layer boundaries are located within this distance. These boundaries are reasonably substantiated by the pressure match, the geology, and the nearest boundary reflection on the measured pressure profile of the long-term fall-off test. Therefore, the calculated value of reservoir pore volume investigated by the long-term fall-off test is approximately 860 million barrels. This volume is contained within an average reservoir area of 11,060 acres and it is considered to be a minimum value since total closure of reservoir boundaries was not reflected during the long-term pressure fall-off test for Layers 3 and 4.

The reservoir description and the minimum value of pore volume determined in this study were used in the numeric model to predict a ten-year performance of injection operations. A plot of the predicted bottom-hole and wellhead pressure performance is presented in Figure 4. The injection rate schedule used for the predictions was given by Mr. Foley's letter of July 29, 1971 and it consists of an injection rate of 652 barrels per day for the first five years followed by an injection rate of 848 barrels per day for the remaining period of injection. Calculated wellhead injection pressures are 161 and 371 pounds per square inch gauge at the end of the first five years and ten years of injection, respectively, while injecting at these rates. The calculated reservoir pressure distribution after the first five years of injection is presented as Attachments 5 through 9 for Layers 1 through 5, respectively. The reservoir area affected by the injected fluid at the end of the first five years of injection is cross-hatched on each of the pressure distribution plots. The grid area on each of these plots represents a portion of the respective layer area. The positions of the injected-fluid front as shown in Figures 5 through 9 range from a minimum of 140 feet from the well in Layer 5 to a maximum of 900 feet from the well in Layer 4.

The voluminous technical details involved in the study are not included in this report; however, they are available from our files on your request.

(B) The Numeric Model

The model used in this study incorporates a finite difference solution of the partial differential equation describing single-phase, three-dimensional flow of a compressible fluid in porous media. Such models have been in widespread use by the petroleum industry for several years.

The basic equation solved by the model is:

$$-\frac{\partial}{\partial x}(v_x) + \frac{\partial}{\partial y}(v_y) + \frac{\partial}{\partial_z}(v_z) + q = -\frac{\partial}{\partial t}\left(\frac{\phi}{B}\right)$$

where:

∂	=	Partial derivative
x, y, z	=	Coordinate directions
v	=	Darcy velocity, defined below
q	=	Fluid production rate per unit volume
t	=	Time
ϕ	=	Porosity
B	=	Fluid formation volume factor, the volume of reservoir fluid required for a unit surface volume of fluid.

The Darcy velocity is defined by:

$$v_x = -\frac{C\,k_x}{\mu\,B}\left(\frac{\partial P}{\partial x} + \rho_g \frac{\partial h}{\partial x}\right)$$

where:

C	=	Constant for units conversion
k	=	Permeability
μ	=	Viscosity
P	=	Pressure
ρ	=	Fluid density
g	=	Acceleration of gravity
h	=	Height above a horizontal plane

Analytic solutions of equation (1) are not presently possible for general cases. A finite difference technique is used in this model for its solution. In this technique, the reservoir is divided into blocks. Equation (1) is written in finite difference form for each block, resulting in a system of algebraic equations which must be solved simultaneously. There is one equation in this system for each block in the reservoir system. Practical solution of this large system of simultaneous equations requires a high-speed computer and an efficient solution algorithm. The solution algorithm used in this model is in widespread use. It is called the "Strongly Implicit Procedure" or SIP and it is published in: Stone, H. L.: "Iterative Solution of Implicit Approximations Of Multidimensional Partial Differential Equations", SIAM J. Numer. Anal., Vol. 5, No. 3, September, 1968, p. 530-558.

(C) Model Validity

One verification of validity of the actual model was made by using the model to calculate drawdown pressures for a two layer system for which analytic solutions from literature are available. The permeability ratio of the system was 5, that is, the permeability in one layer was five times that of the other layer. The results of the calculations compared to the analytical solution published in: Cobb, William M.: "A Study of Transient Flow in Stratified Reservoirs with Commingled Fluid Production", Ph. D. dissertation, Stanford University, Stanford, Ca. (1970) are tabulated below:

Cumulative Time Days	Pressure By Analytic Solution psi	Pressure By Model Solution psi	Percent Difference
0.00	1,000.00	1,000.00	-
0.82	959.50	959.55	0.005
3.29	935.71	935.89	0.019
8.23	892.02	892.52	0.560
32.90	707.08	707.45	0.523
82.30	353.63	353.81	0.509

The excellent agreement between the analytic and numeric model solutions clearly demonstrates the validity and capability of the model.

An additional check usually made on this type model is a material balance. The material balance is calculated each time step in the model. Excellent material balances were maintained in all runs.

(D) The Reservoir Model

Preliminary examination of test results indicated the proposed storage system was made up of several layers in communication through the wellbore only. Such a system was simulated by having vertical permeabilities of zero millidarcies except in the wellbore block. In the wellbore block a very high vertical permeability was assigned. In addition, an iterative technique was developed to proportion the injected fluid among layers so that the vertical flow potential in the wellbore approached zero.

Five layers were used to represent the reservoir. Each layer was divided into 13 blocks in the X-direction and 14 blocks in the Y-direction. Altogether, 910 blocks were used to represent the reservoir system. Variable X and Y dimensions were used. Large ΔX's and ΔY's were used away from the injection point, and very small ΔX's and ΔY's were used near the injection point. Potential changes and gradients are much greater near the injection point. The variable grid spacing allows better areal resolution of the potential and hence pressure distributions.

The specific data used in the model are presented in the discussion of the best match of model calculated pressures with observed pressures.

(E) Calibration of the Reservoir Model

Certain data are required for the numeric model. Some of these data can be fairly reliably established, others may vary. Usually reasonable limits can be established for those data that may vary.

Established data form the foundation for matching performance. Various combinations of data are systematically varied until a "best" match between calculated and observed performance is obtained. It should be pointed out that although a parameter may not be well established and may vary in a wide range, the reliability of other factors established through history matching may not be affected. The parameter that can vary within a wide range may not significantly affect the performance of the model.

There were several data that could be well established initially in this case. Injection profile surveys indicated five major layers could be used to represent the system. The net thicknesses of these layers at the wellbore were established from electric logs.

Porosities of each layer, again near the wellbore, were established from core analysis and electric log interpretation. Effective permeabilities were calculated analytically from the early portion of the long-term pressure fall-off test data and the input rate distributions of the injection profiles. The initial pressure was measured with a Sperry-Sun subsurface pressure recording gauge having a sensitivity of $\pm$ 0.55 pounds per square inch gauge. The pressure and measured formation temperature were used with very reliable correlations to obtain water viscosity and compressibility.

The geometry of the system was not well defined, but there was some control. Regional geology indicates the well is located between two major faults which are essentially parallel. One of these faults is about one mile southeast of the well and the other about five miles northwest of the well. In addition, analysis of the fall-off data indicated a nearest boundary some 1,164 feet from the well.

Thus, the main parameters that could be varied in history matching were geometry and rock properties away from the well site.

Numerous computer runs were made before a suitable match between calculated and observed pressure fall-off data were obtained. It was found during these runs that the complex nature of backflow in the wellbore sometimes made it very difficult to predict the direction a parameter should be varied to help match history. The determination of the quantity of variation was possible only through trial with the model. The effects of some parameters on the history match are detailed in a later section.

The best match obtained with the fall-off test data measured from July 6, 1971 to July 12, 1971 is shown in Figure 2, a plot of measured and calculated fall-off pressures during the test.

The model cannot predict the orientation of a system or even the orientation of each layer relative to the other layers. The view presented in Figure 1 is consistent with regional surface and subsurface geology.

(F) Effects of Volume Distribution and Boundary Changes

Five computer runs were made in which the X-dimension in Zones 1 and 2 was changed. In these runs, the total pore volume of the system was held constant by changing the X-dimension in

Zones 3 and 4 on the X-boundary furthermost from the well location. These runs were numbered 16, 19, 28, 30 and 32. The calculated pressure-time relationship for these runs is shown in Figure 10. Run 32, the final run, is clearly the best match. However, the sensitivity of calculated pressures to the X-dimension is more clearly shown in Figure 11.

Figure 11 shows pressure versus the X-dimension of Zones 1 and 2 at shut-in times of approximately 5, 65 and 115 hours. The most significant point is the sensitivity of calculated pressures to the X-dimension for X between 12,600 and 14,000 feet. In order to match either the 65-hour or the 115-hour observed shut-in, the X-dimension must lie in a fairly narrow range of from 12,900 to 13,300 feet. The latter value was used in the run considered to be the best fit. The five-hour shut-in time does not vary significantly until the X-dimension is less than 13,300 feet. It is clear from these figures that holding other properties of the system constant the X-dimension in Zones 1 and 2 must lie in a narrow range around 13,000 feet.

The X-dimension in Zones 3 and 4 is not as well defined. One run was made in which the X-dimension in these zones was arbitrarily increased 850 feet. There was less than 0.1 pounds per square inch change in the calculated pressures. Thus, the X-dimension could be any value greater than the value used in these zones. We can likewise conclude from this that it is not possible to detect leakage at the furthermost X-boundary in Zones 3 and 4 by comparison of the model results with observed data.

The sensitivity of computed results to changes in near boundaries can be seen by comparing the results of Runs 15 and 16, plotted in Figure 12. In Run 15, Zones 1 through 5 had common Y-direction boundaries at a distance of 3,500 feet from the injection site. In Run 16, this distance was increased to 4,250 in Zones 1 through 4 and left unchanged in Zone 5. As can be seen from the figure, significant changes in pressure level are noted. Immediately after shut-in, the results of these runs vary by 2 pounds per square inch, by 5-hours shut-in the difference is 1.2 pounds per square inch, and by 15-hours shut-in the difference is only about 0.4 pounds per square inch.

This trend was noted in other runs. Changes in near boundaries had greatest effect in the very early shut-in period, with diminishing effect as shut-in time increased.

The sensitivity of results to volume and boundary change in Zone 5 was examined by comparing Runs 16 and 17. The volume of Zone 5 in Run 17 was decreased by moving the north boundary to a distance of 3,500 feet from the injection point. This decreased the Zone 5 volume to 58 percent of its value in Run 16. The total volume of the system was held constant by adjusting the most distant boundaries in Zones 1 through 4. These were small adjustments because less than 0.02 percent of the total pore volume of the system was in Zone 5 for Run 16.

This small change, when considering the system as a whole, produced significant changes in pressure results. Initial shut-in pressures in Run 17 were 7.4 pounds per square inch higher than those in 16. After 115-hours shut-in, this difference had increased to almost 10 pounds per square inch.

(G) Effects of Heterogenieties Within Layers

Some attempts were made to investigate the effects of permeability heterogenieties within layers at distances greater than 1,164 feet from the wellbore. This is the distance to the nearest barrier in the most permeable zone. The changes made were at the west side of Zones 3 and 4 at distances greater than 1,164 feet. These changes affected about 68 percent of the reservoir volume.

The permeabilities in these zones were varied in ratios of from 0.19 to 1.44 of their original values. The results are shown in Figure 13. Several conclusions can be reached. First, increasing the permeability over the range studied had no significant effect. Second, decreasing the permeability did have significant effect. The largest reduction in permeability produced a uniform increase in pressure of about 3.5 pounds per square inch, but the general configuration of the pressure fall-off curve was not changed. Third, all changes had the effect of shifting the pressure-time relationship upward or downward almost uniformly over the time interval studied. This last conclusion eliminated permeability heterogeneities, at least in the zones considered, as a parameter that might be varied to get a better match with observed data in the latter part of the fall-off period.

(H) Evaluation of Maximum Undetected Possible Leakage

Of prime importance in a storage project of this type is the detection and avoidance of leakage to other formations. Leakage could be possible vertically through semi-permeable overburden or underburden or horizontally across semi-permeable barriers.

Vertical leakage was evaluated through the profile testing and with the reservoir model. All model work and the wellbore fluid velocity surveys indicated no communication between layers taking fluid except through the wellbore. If good vertical communication existed between the layers, the counterflow as observed and measured in the wellbore during the testing would not have occurred in this exact same manner. No leakage vertically to other adjacent formations is indicated. Had such leakage been occurring in the vicinity of the wellbore, it would have affected the observed pressure fall-off data. These pressure data were matched using the model with no leakage considerations.

The investigation of horizontal leakage was studied with the model. Any change in east boundary location influenced the match between the calculated pressure and the field data. Runs made with different boundaries on the west side showed that impervious boundaries in Layers 3 and 4 would have to be such great distances from the well that they would not be significant. The proposed volume of injected effluent to be stored in five years was small enough that only possible leakage at the near boundary on the east side of all of the layers appears to be significant in affecting the distribution of the injected fluid.

Leaking boundaries were simulated in the model by considering a zone of lowered permeability 152 feet wide at the nearest boundary location beyond which the zone was considered to have the same properties as the reservoir.

Figure 14 presents the calculated pressures from three computer executions of the model along with the observed pressure data. The computer runs include, (a) the impermeable boundary best fit case, (b) a case for a boundary of blocks having a permeability of 0.1 millidarcies and (c) a case for a boundary of blocks having a permeability of 0.01 millidarcies. The execution considering the boundary to have a 0.1 millidarcy permeability showed a significant difference in the calculated pressures when compared to the observed pressure data. All calculated points in this case are from 0.4 to 0.6 pounds per square inch below those calculated without the leakage. To the 115-hour shut-in time the standard deviation of these points from observed data is $\pm$ 0.88 pounds per square inch. This may be compared to the standard deviation for the best fit impermeable boundary case of $\pm$ 0.68 pounds per square inch for the same interval of time. The numeric model calculated a maximum efflux for this case of approximately 40 barrels per day. It can be concluded that there are statistically significant differences between the calculated and observed pressure data for even this low permeability. Because the match between the calculated and the observed pressures for the impermeable boundary case reflect a statistically significant improvement over the 0.1 millidarcy case, it is felt that any boundary could not have a permeability as much as 0.1 millidarcies.

The 0.01 millidarcy permeability case resulted in a standard deviation of $\pm$ 0.72 pounds per square inch. Although this fit to the actual observed data is not as good as the standard deviation achieved with the impermeable boundary consideration, it is not felt to be statistically significant and it is conceivable that the small pressure differences ranging from 0.1 to 0.3 pounds per square inch would not be detected. The numeric model execution indicated the maximum efflux for this case to be 4.4 barrels of fluid per day. We are of the opinion that the impermeable boundary case still represents our best match of the observed data, but feel that the 0.01 millidarcy case is a practical limit for the sensitivity of the calculation.

There are other observations that should be made. The best fit calculated deviates most from the observed data during the latter part of the test. The calculated pressures are less than observed pressures during this period. Numerous model runs showed that any changes made to affect this portion of the calculated data had greater effects on points at earlier times, and such changes resulted in poorer overall fits with observed data. Any leakage would aggravate this match even more. From this standpoint, it seems unlikely that any leakage occurred during the test period.

It is also important to note that the model results are sensitive to a small degree of leakage. As a result, the numeric model should be an important tool in monitoring for possible leakage during storage operations.

Detailed pressure monitoring of the injection well will provide the data necessary to confirm to a higher degree of confidence the integrity of the reservoir.

H. J. GRUY AND ASSOCIATES, INC.

RESERVOIR MODEL
ARBUCKLE ZONE
KERR-McGEE NO. I SEQUOYAH WASTE STORAGE WELL
SEQUOYAH COUNTY, OKLAHOMA

MAY, 1972
DALLAS, TEXAS

H. J. GRUY AND ASSOCIATES, INC.

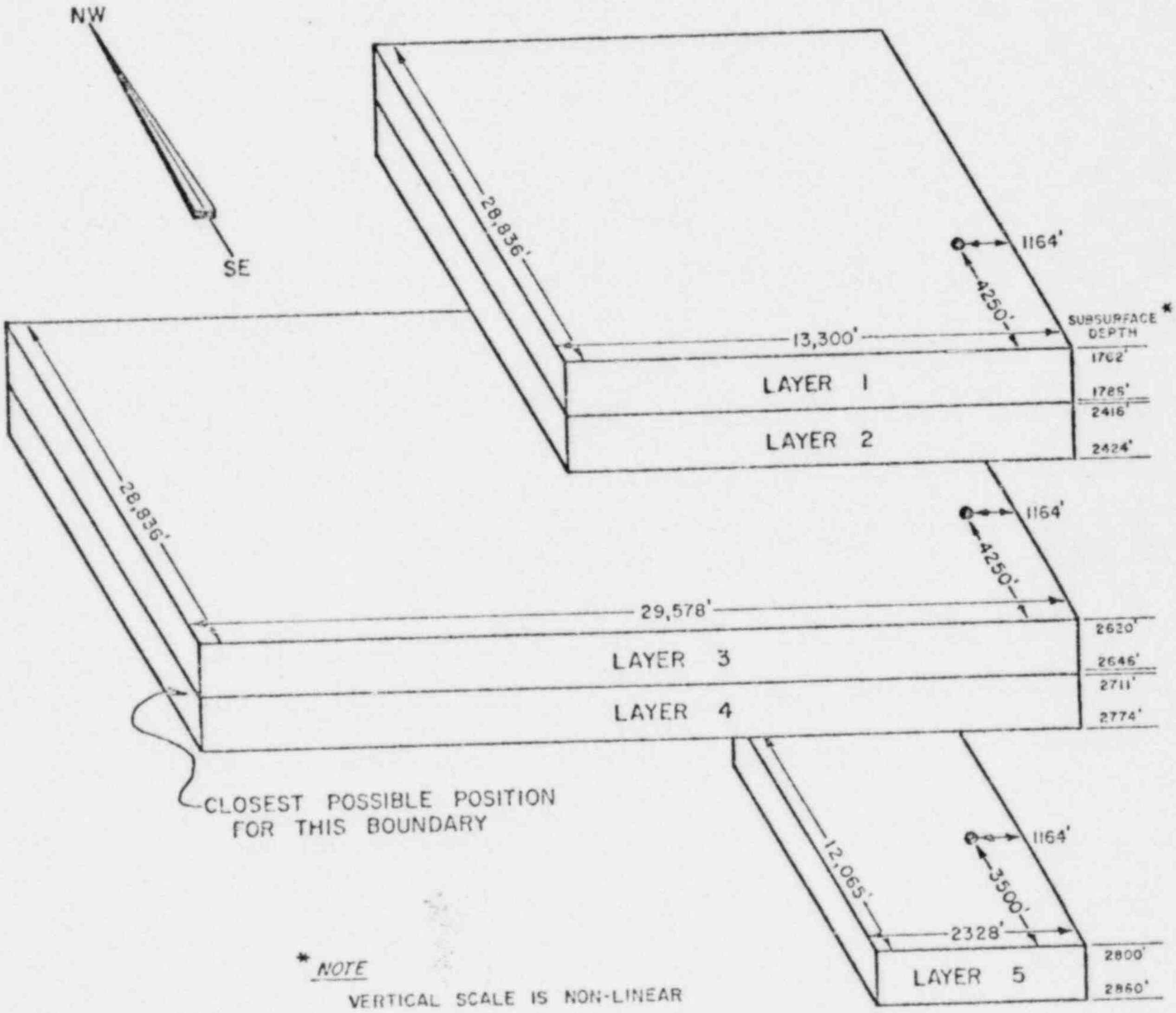

Figure 1

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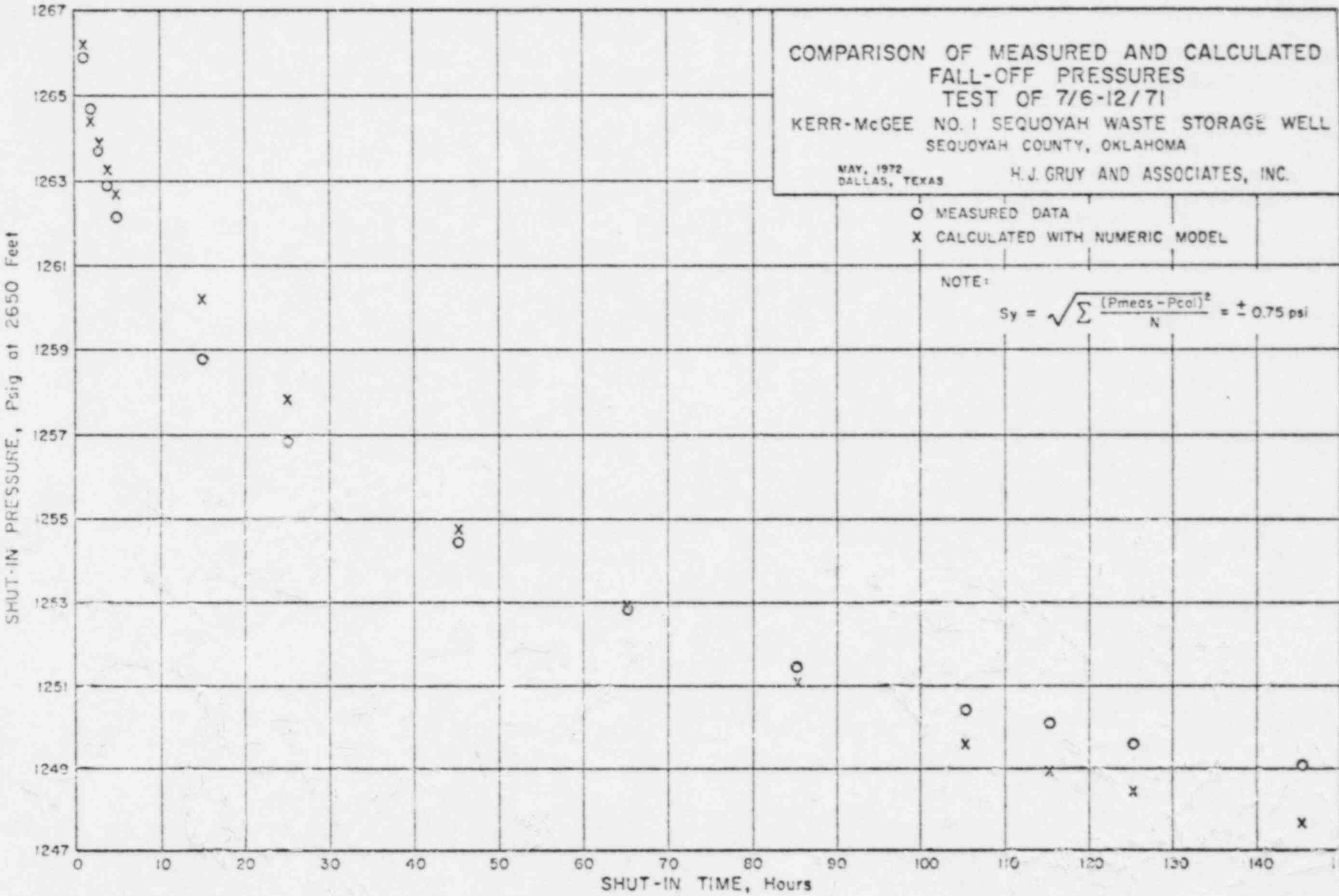

Figure 2

H. J. GRUY AND ASSOCIATES, INC.

SUMMARY OF RESERVOIR LAYER PROPERTIES
KERR-MCGEE NO. 1 SEQUOYAH WASTE STORAGE WELL
SEQUOYAH COUNTY, OKLAHOMA

Layer Number	Depth Interval (feet)	Net Thickness (feet)	Porosity (dec. frac.)	Effective Permeability (md)	Area (acres)
1	1,762-1,786	24	0.064	2,469	8,804
2	2,416-2,424	8	0.060	2,279	8,804
3	2,620-2,646	26	0.089	964	≧ 19,580*
4	2,711-2,774	24	0.099	1,709	≧ 19,580*
5	2,800-2,860	34	0.058	2,480	645

* Minimum area proved by test program

Figure 3

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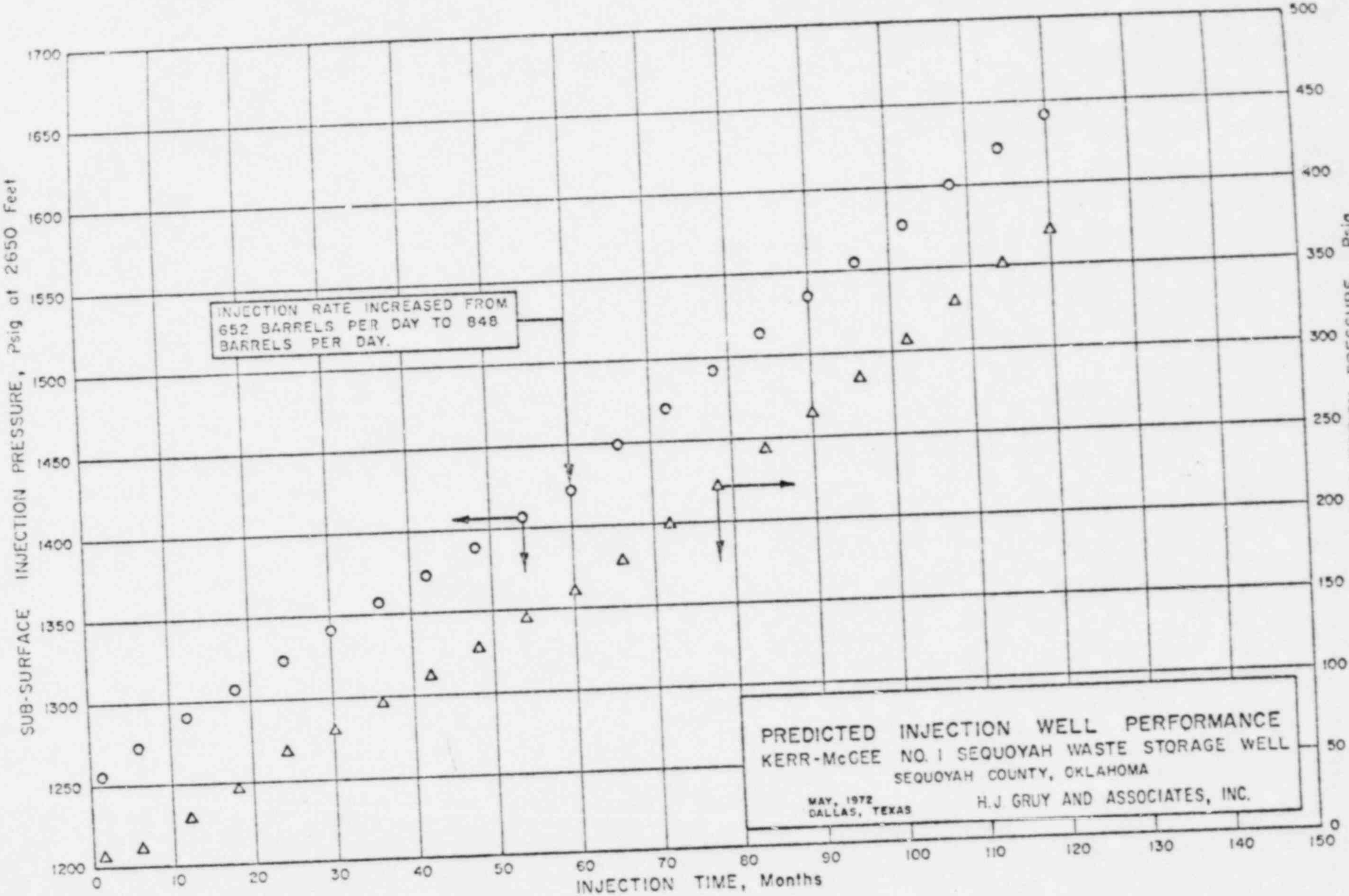

Figure 4

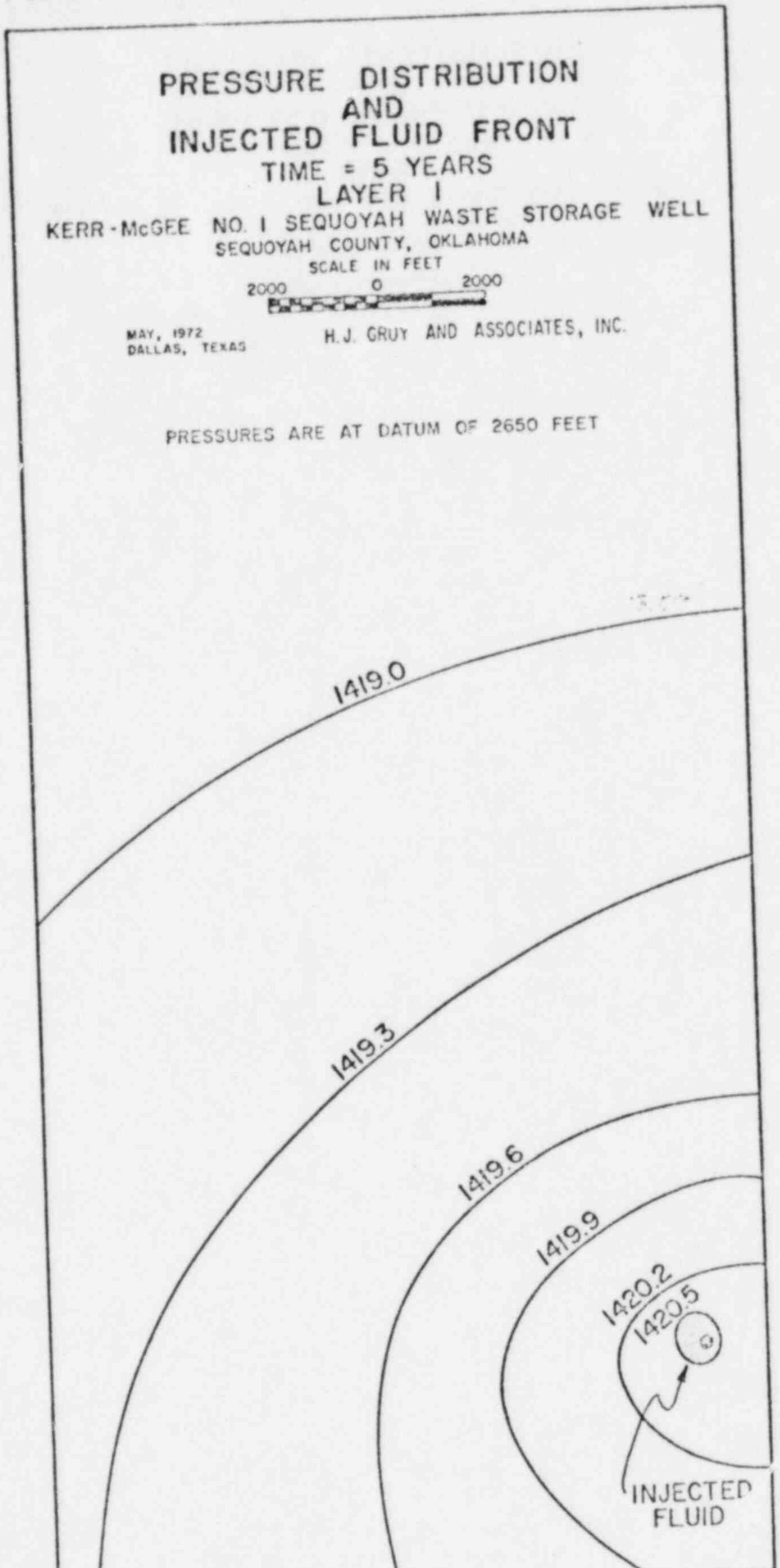
PRESSURE DISTRIBUTION
AND
INJECTED FLUID FRONT
TIME = 5 YEARS
LAYER 1
KERR-McGEE NO. 1 SEQUOYAH WASTE STORAGE WELL
SEQUOYAH COUNTY, OKLAHOMA
SCALE IN FEET
2000 0 2000
MAY, 1972
DALLAS, TEXAS
H.J. GRUY AND ASSOCIATES, INC.
PRESSURES ARE AT DATUM OF 2650 FEET
1419.0
1419.3
1419.6
1419.9
1420.2
1420.5
INJECTED
FLUID

Figure 5

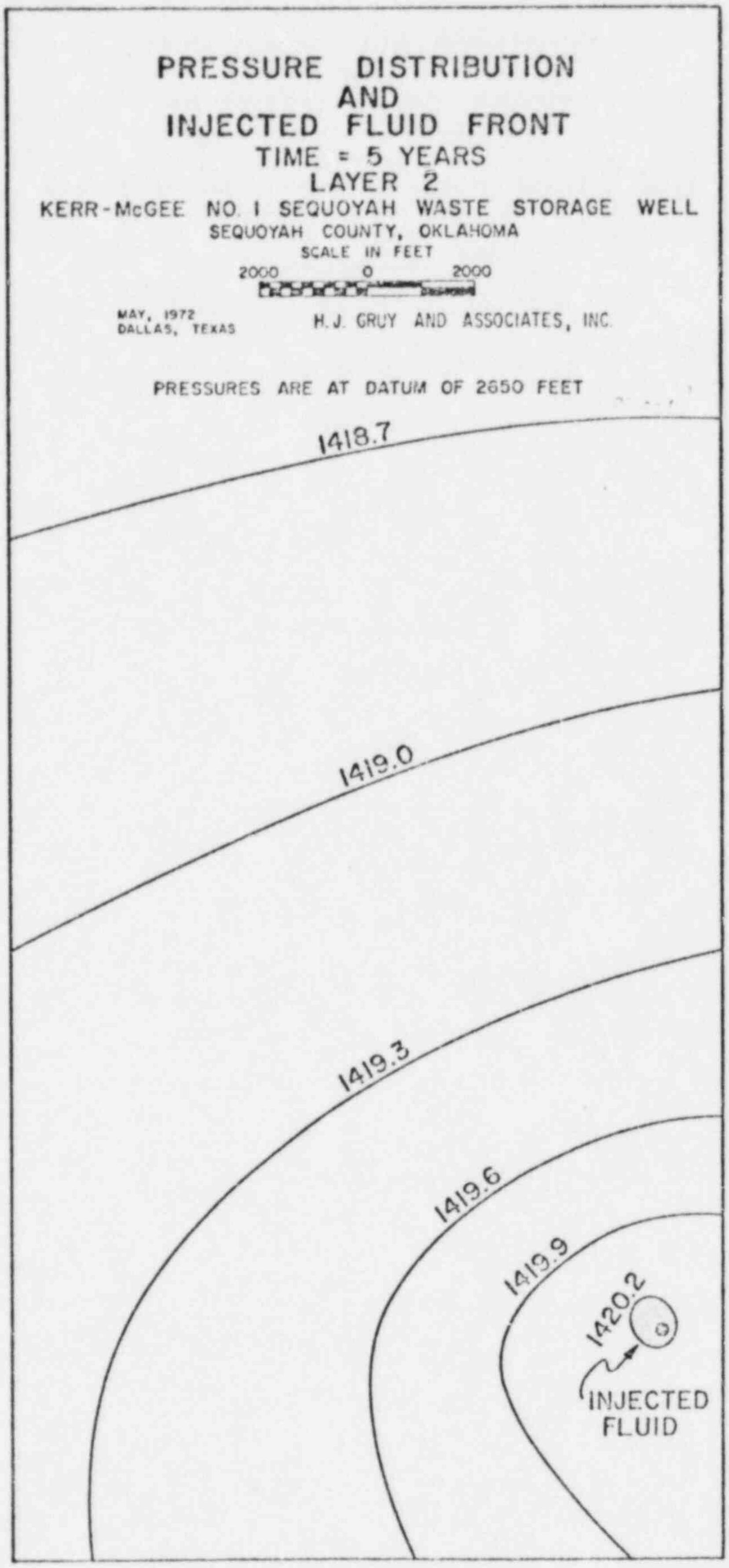
PRESSURE DISTRIBUTION
AND
INJECTED FLUID FRONT
TIME = 5 YEARS
LAYER 2
KERR-McGEE NO. 1 SEQUOYAH WASTE STORAGE WELL
SEQUOYAH COUNTY, OKLAHOMA
SCALE IN FEET
2000 0 2000
MAY, 1972
DALLAS, TEXAS
H. J. GRUY AND ASSOCIATES, INC.
PRESSURES ARE AT DATUM OF 2650 FEET
1418.7
1419.0
1419.3
1419.6
1419.9
1420.2
INJECTED
FLUID

Figure 6

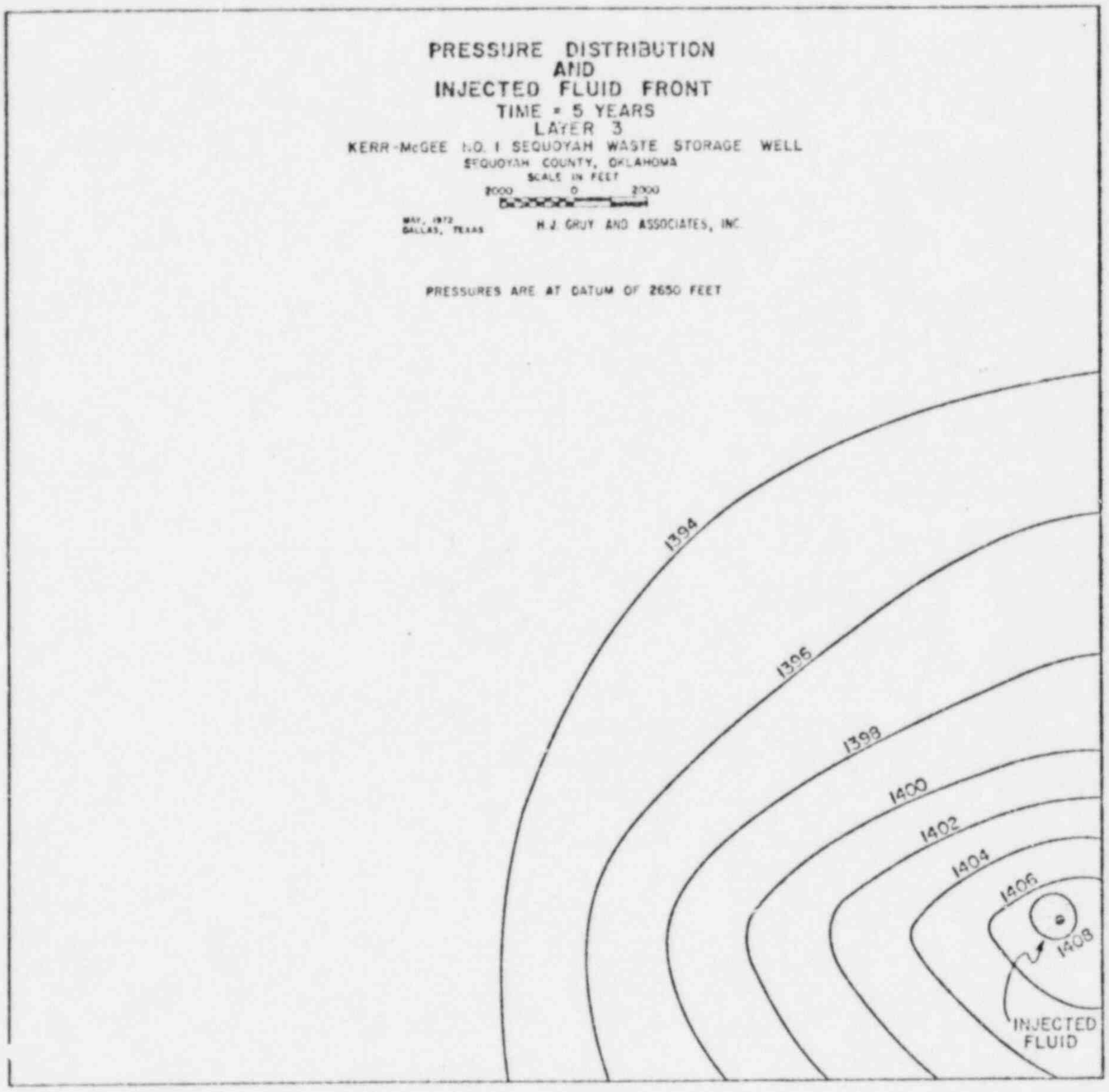
PRESSURE DISTRIBUTION
AND
INJECTED FLUID FRONT
TIME = 5 YEARS
LAYER 3
KERR-McGEE NO. 1 SEQUOYAH WASTE STORAGE WELL
SEQUOYAH COUNTY, OKLAHOMA
SCALE IN FEET
2000 0 2000
MAY, 1972
DALLAS, TEXAS
H. J. GRUY AND ASSOCIATES, INC.
PRESSURES ARE AT DATUM OF 2650 FEET
1394
1396
1398
1400
1402
1404
1406
1408
INJECTED
FLUID

Figure 7

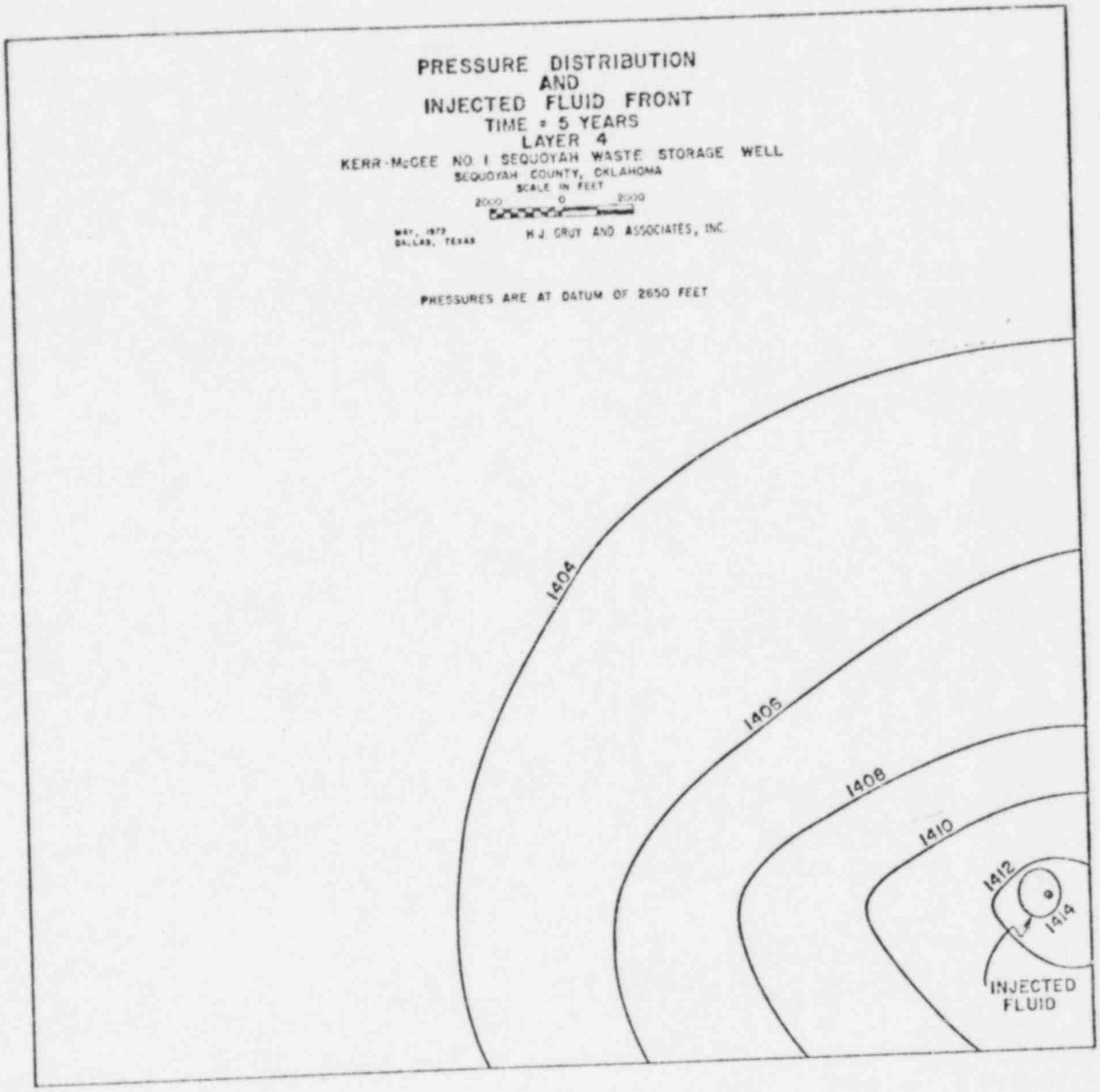
PRESSURE DISTRIBUTION
AND
INJECTED FLUID FRONT
TIME = 5 YEARS
LAYER 4
KERR-McGEE NO. 1 SEQUOYAH WASTE STORAGE WELL
SEQUOYAH COUNTY, OKLAHOMA
SCALE IN FEET
2000 0 2000
DALLAS, TEXAS
H. J. GRUY AND ASSOCIATES, INC.
PRESSURES ARE AT DATUM OF 2650 FEET
1404
1406
1408
1410
1412
1414
INJECTED FLUID

Figure 8

H. J. GRUY AND ASSOCIATES, INC.

PRESSURE DISTRIBUTION
AND
INJECTED FLUID FRONT

TIME = 5 YEARS

LAYER 5

KERR-McGEE NO. I SEQUOYAH WASTE STORAGE WELL

SEQUOYAH COUNTY, OKLAHOMA

SCALE IN FEET

2000 0 2000

MAY, 1972
DALLAS, TEXAS

H. J. GRUY AND ASSOCIATES, INC.

PRESSURES ARE AT DATUM OF 2650 FEET

NOTE:

ALL PRESSURES AT 1422.3 ±0.04 psi

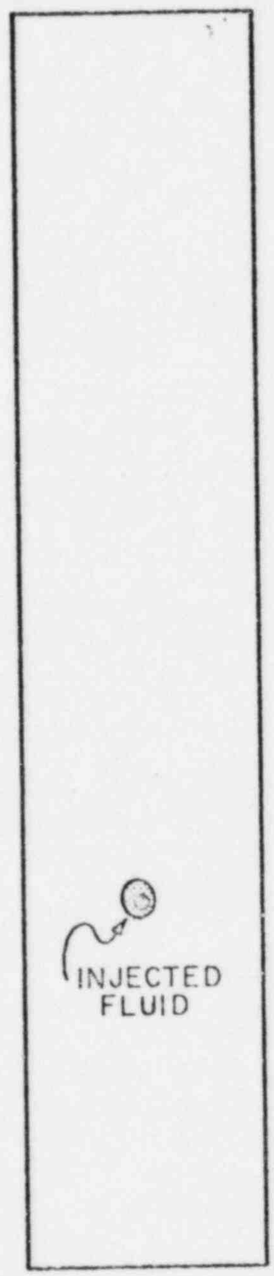

Figure 9

H. J. GRUY AND ASSOCIATES, INC.

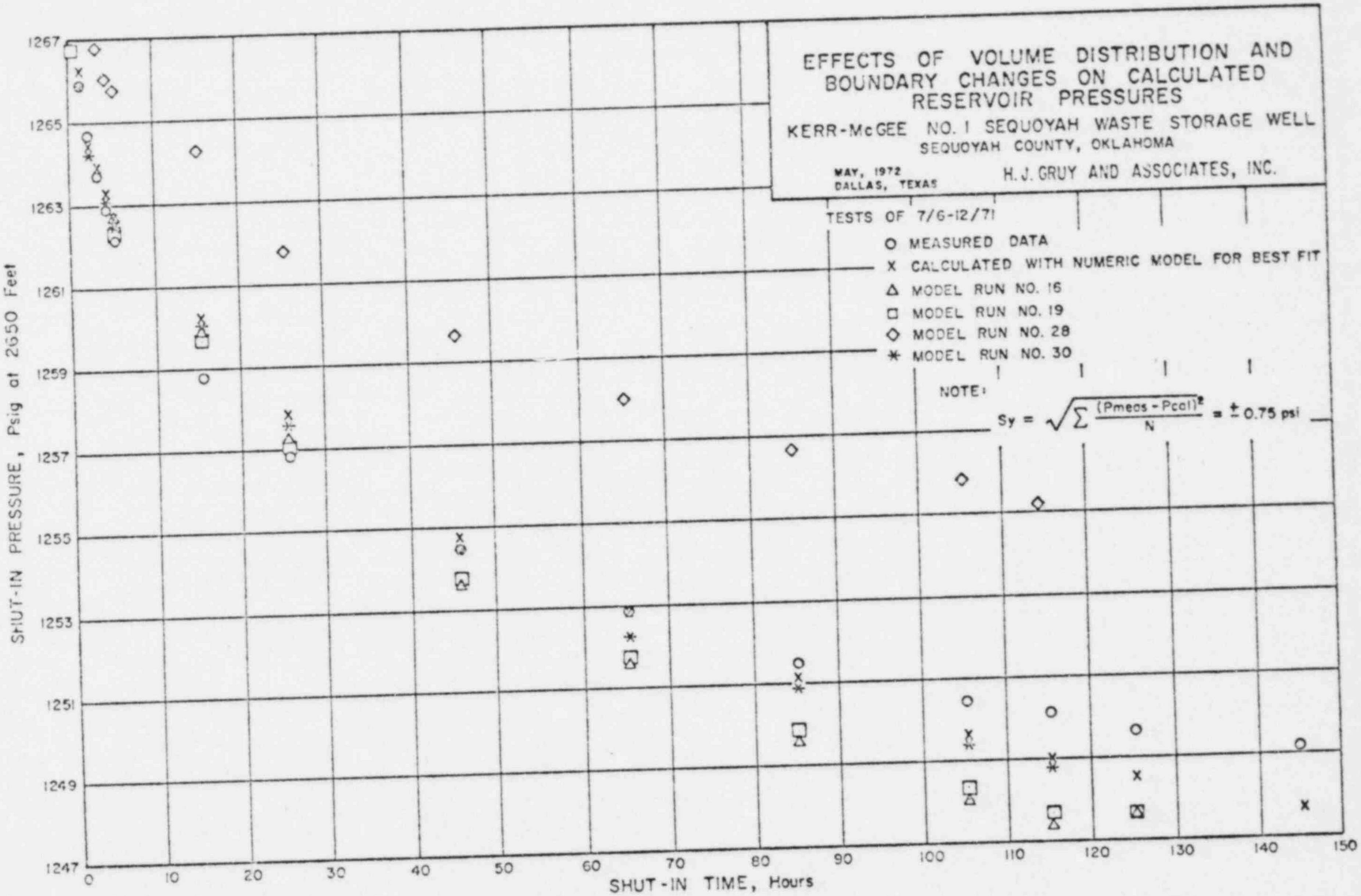

Figure 10

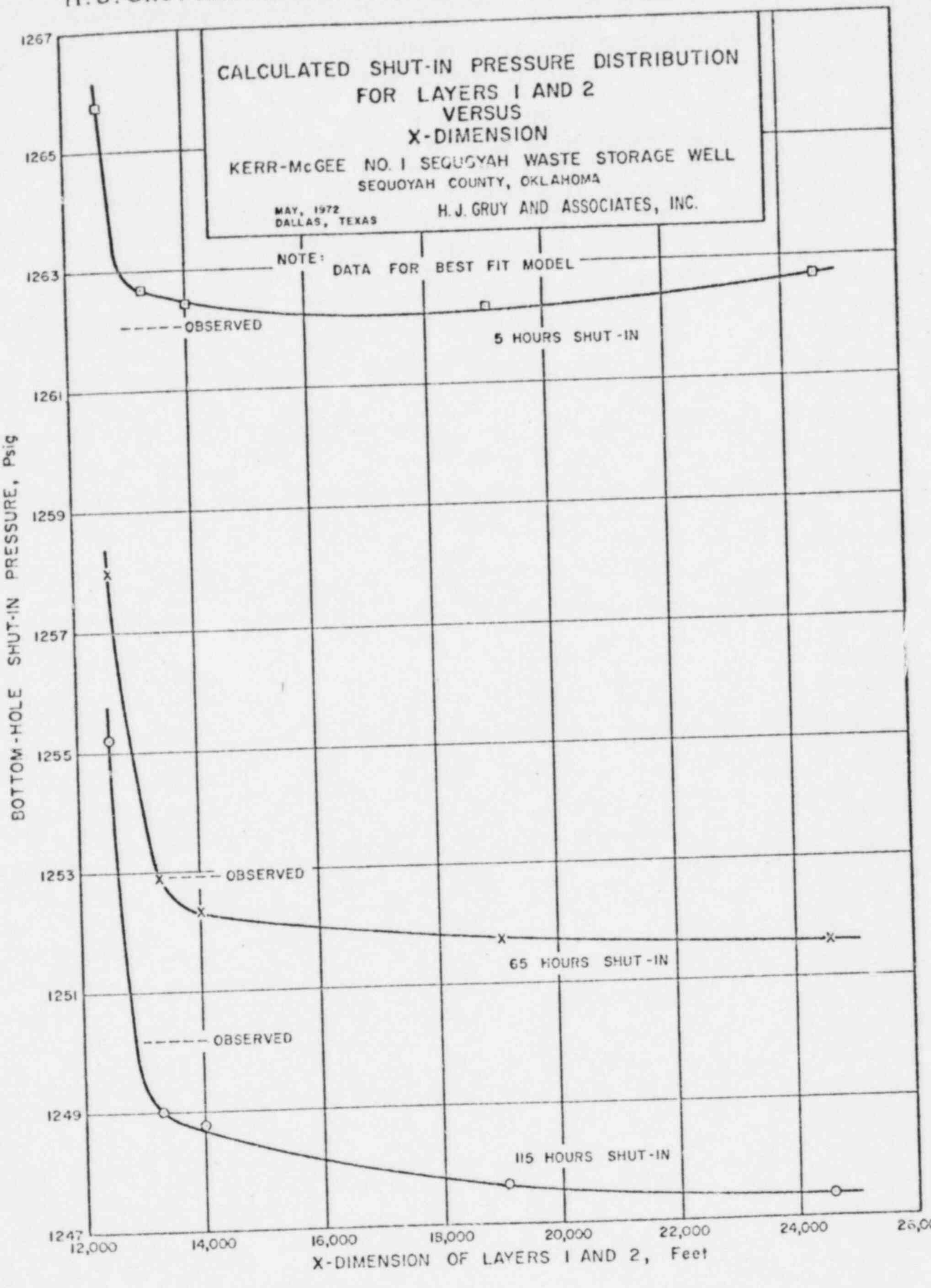
CALCULATED SHUT-IN PRESSURE DISTRIBUTION
FOR LAYERS 1 AND 2
VERSUS
X-DIMENSION
KERR-McGEE NO. 1 SEQUOYAH WASTE STORAGE WELL
SEQUOYAH COUNTY, OKLAHOMA
MAY, 1972
DALLAS, TEXAS
H. J. GRUY AND ASSOCIATES, INC.
NOTE: DATA FOR BEST FIT MODEL
OBSERVED
5 HOURS SHUT-IN
OBSERVED
65 HOURS SHUT-IN
OBSERVED
115 HOURS SHUT-IN
BOTTOM-HOLE SHUT-IN PRESSURE, Psig
1267
1265
1263
1261
1259
1257
1255
1253
1251
1249
1247
12,000
14,000
16,000
18,000
20,000
22,000
24,000
26,000
X-DIMENSION OF LAYERS 1 AND 2, Feet

Figure 11

H. J. GRUY AND ASSOCIATES, INC.

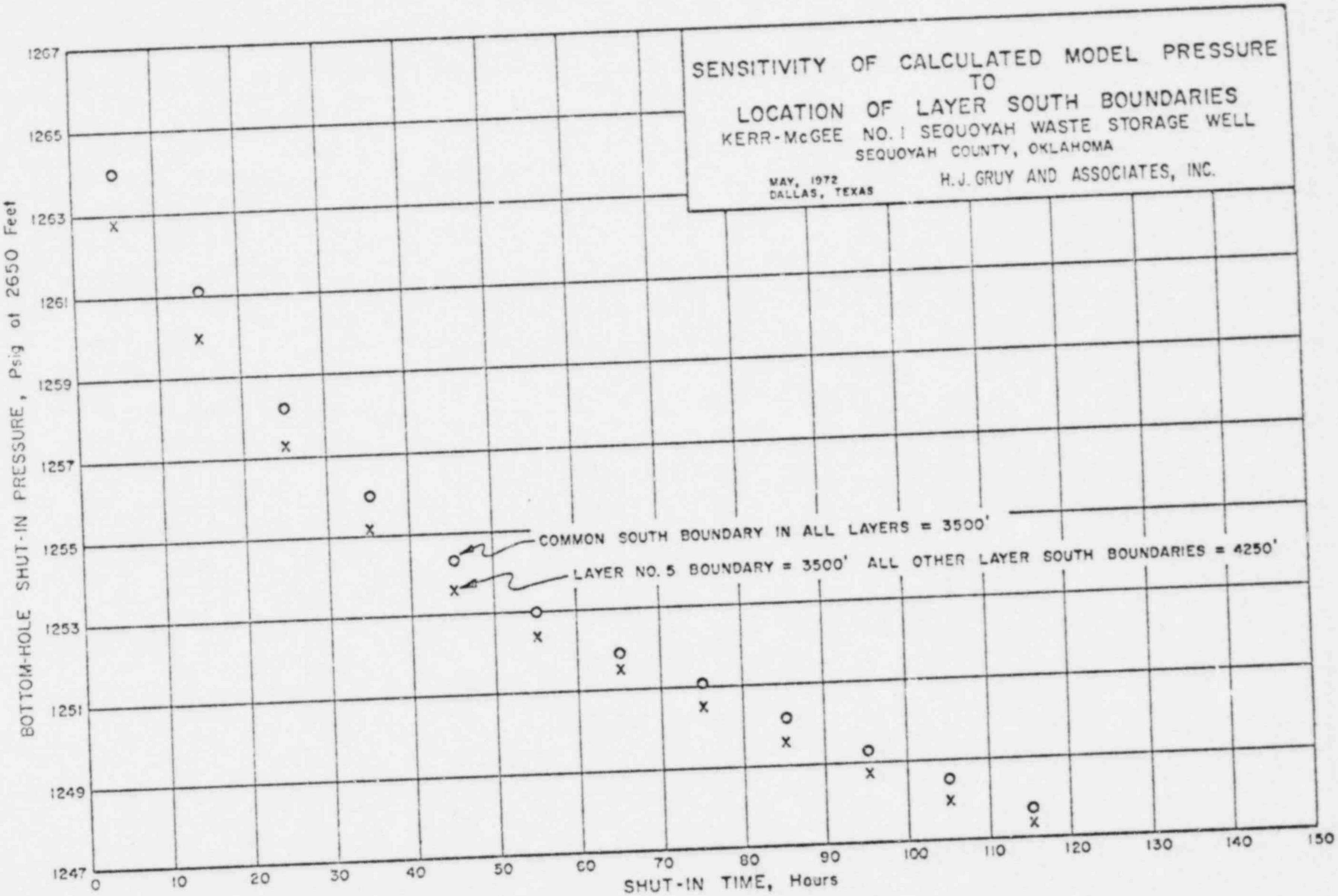

Figure 12

H. J. GRUY AND ASSOCIATES, INC.

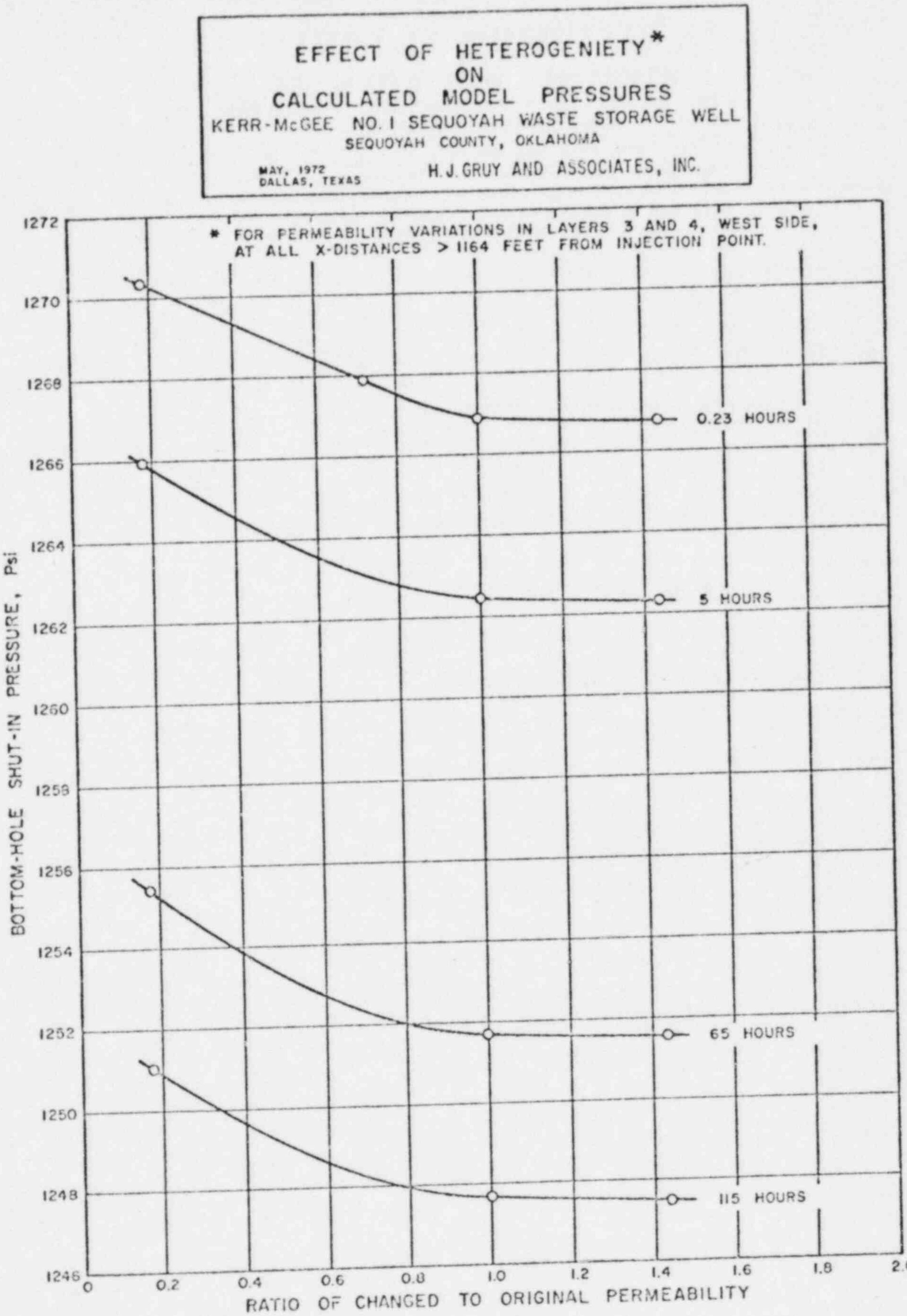

Figure 13

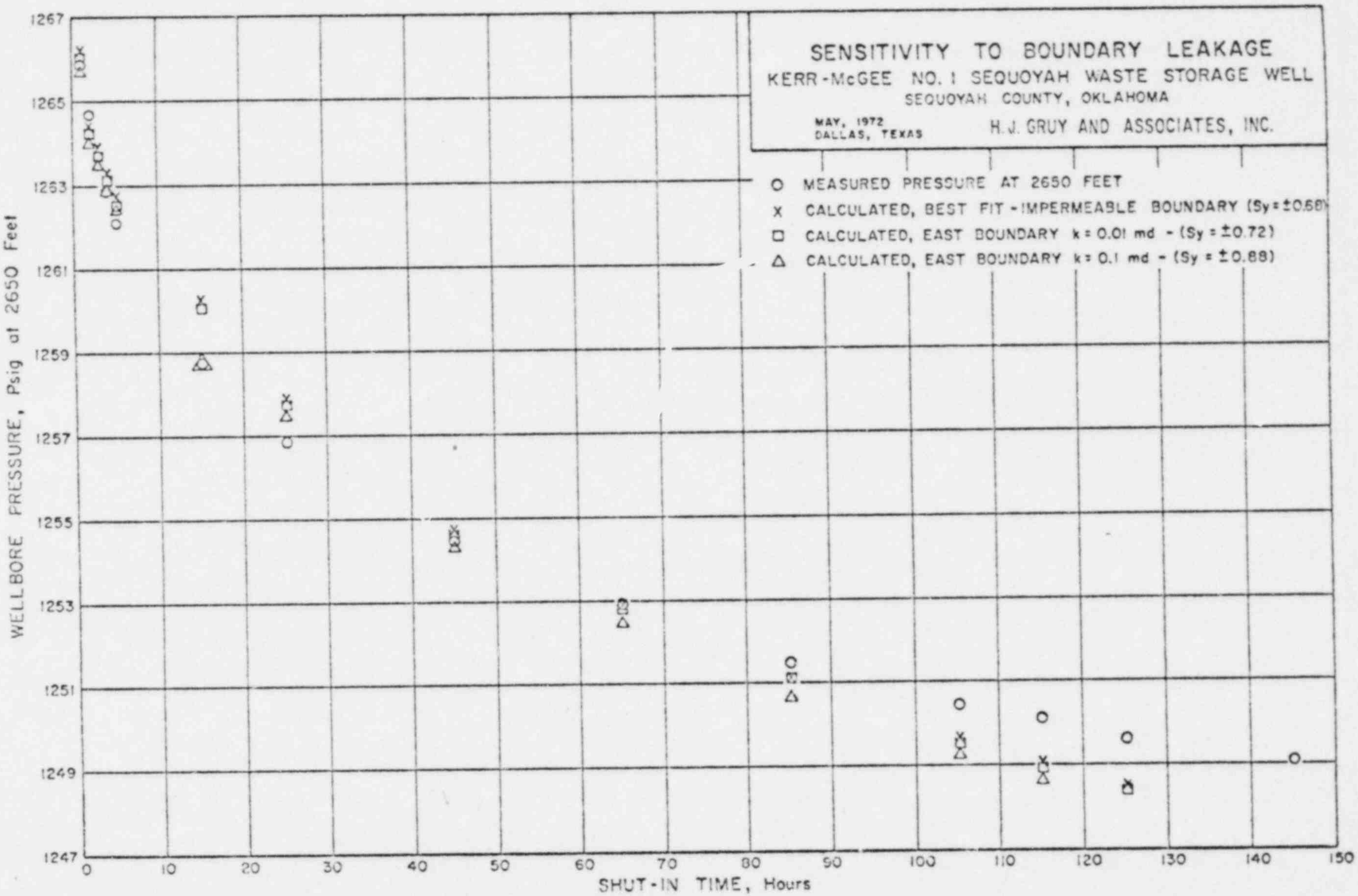
SENSITIVITY TO BOUNDARY LEAKAGE
KERR-McGEE NO. 1 SEQUOYAH WASTE STORAGE WELL
SEQUOYAH COUNTY, OKLAHOMA
MAY, 1972
DALLAS, TEXAS
H. J. GRUY AND ASSOCIATES, INC.
O MEASURED PRESSURE AT 2650 FEET
X CALCULATED, BEST FIT - IMPERMEABLE BOUNDARY (Sy = ±0.68)
□ CALCULATED, EAST BOUNDARY k = 0.01 md - (Sy = ±0.72)
Δ CALCULATED, EAST BOUNDARY k = 0.1 md - (Sy = ±0.88)
WELLBORE PRESSURE, Psig at 2650 Feet
SHUT-IN TIME, Hours
1267
1265
1263
1261
1259
1257
1255
1253
1251
1249
1247
0
10
20
30
40
50
60
70
80
90
100
110
120
130
140
150

Figure 14

WELL TEST PROGRAM AND DATA

KERR-McGEE CORPORATION

Although a comprehensive test program had been planned by H. J. Gruy and Associates in consultation with Kerr-McGee, the Well Analysis Company (who would perform all in-hole measurements except pressure), and the Sperry-Sun Well Surveying Company (who would provide the precision in-hole pressure recording instruments and pressure chart transcription), the plan was left flexible so that details of exact flow rates, duration of flow, duration of pressure fall off, etc. could be worked out based on the information received to date. Thus, it was that Phase B was conceived and run when it was determined that running temperature decay profiles in the hole during the pressure decay portion of Phase A would affect the pressure readings of the Sperry-Sun pressure recorder. And Phase D was conceived and run to quantify the backflow phenomenon noted in Phase A during the pressure fall off portion of the test.

A brief summary of the test phases and schedules as actually performed is outlined below and a detailed tabulation of the test data obtained on flow rates, well head pressures, and timing of test events is presented in the following 24 sheets:

Preinjection Tests

1. Checked out injection pumps, flow controls and flow meter.

2. Checked out water supply to injection pumps and checked entire injection system for leaks.

3. Checked well head for water pressure. Found static liquid level to be essentially at ground level. By time injection was started, pressure reading on well head was 30 psig. Check pressure of fluid in annulus between injection tubing and casing and found pressure to be positive. (Pressure was checked throughout test and it was found that it was affected by pressure and temperature of fluid in injection tubing, but not in a manner to indicate leak.)

4. Rigged up wire line and ran dummy instrument into hole to check that hole was clear all the way to the bottom and would not entangle or endanger tools. Checked out zero point of depth gauge on wire line.

5. Made new caliper survey of uncased hole.

6. Made temperature survey which had to be discarded when the calibration of the instrument was found to be faulty and there was not time to redo before start of injection.

7. Ran static pressure survey of fluid in-hole with Sperry-Sun pressure recorder.

8. Set up well head pressure measuring and recording instruments.

Phase A (Part of Phase 1 in W.A.CO. Report)

1. Started water injection at 05:31, 6/28/71. Increased flow from 50 to 70 to, finally, 90 gpm at 06:34, 6/28/71.

2. Started radioactive tracer surveys using velocity shot and R.E.V. method at 09:30, 6/28/71.

3. Completed surveys at 17:00, 6/28/71.

4. Injection flow stopped at 18:23, 6/28/71 after Sperry-Sun recorder had been inserted in the hole and left at 2900'.

5. Pressure fall off portion of test continued until 20:30, 6/29/71 when in-hole pressure recorders were removed.

Phase B (Part of Phase 1 in W.A.CO. Report)

1. Water injection started at 20:37, 6/29/71 at 25 gpm.

2. Temperature survey of hole during injection started at 08:15, 7/1/71.

3. Stopped injection at 08:45, 7/1/71 to make temperature decay surveys in hole.

4. Temperature surveys completed at 16:55, 7/1/71.

Phase C (Called Phase 2 in W.A.CO. Report)

1. Started water injection at 17:05, 7/1/71 at flow rate of 90 gpm.

2. Started radioactive tracer surveys using velocity shot and R.E.V. methods at 08:00, 7/5/71.

3. Completed tracer surveys at 14:15, 7/5/71.

4. Decreased flow from 90 gpm to 50 gpm at 05:20, 7/6/71, because of difficulties with water supply.

5. Inserted pressure recorders in hole at 09:00, 7/6/71.

6. Stopped water injection at 09:18, 7/6/71.

7. After removing pressure recorders to change full charts and replacing recorders in hole, finally removed pressure recorder at end of pressure fall off test at 15:45, 7/12/71.

Phase D (Called Phase 3 in W.A.CO. Report)

1. Started water injection at 15:56, 7/12/71.

2. Ran tracer profile survey using R.E.V. method only starting at 10:22, 7/13/71.

3. Completed injection profile measurements and stopped water injection at 15:22, 7/13/71 after a total of 834,370 gallons of water had been injected in all phases of the test.

4. Continued with radioactive tracer surveys during period after water injection was stopped to investigate quantitatively the backflow in the well bore from one reservoir layer to another. Surveys completed at 20:10, 7/13/71.

5. Test completed with final well head pressure reading of 96.7 psig at 08:30, 7/14/71.

SEQUOYAH FACILITY

DEEP WELL INJECTION TEST DATA SHEET

Date of Reading	Time of Reading	Nominal Injection Flow Rate (gpm)	Flow Totalizer Reading (gallons)	Well Head Pressure (psig)	Remarks
6/25/71	—	—	—	0	Well Analysis Co. (W.A.CO.) Rigged up and prepared to make surveys.
	09:15	—	—	—	Started dummy run in hole with casing collar locator and sinker bar. Original well logs made by Schlumberger used ground level (elevation 563' above sea level) as a permanent datum point and measured their logs with zero at the drive bushing (Kelley Bushing or K.B.) 16' above the permanent datum. W.A.CO. adjusted zero point on their logging depth indicator to give same reading to top of casing as indicated on original records. Located T.D. (Total Depth)
(cont.)	(cont.)				

SEQUOYAH FACILITY

DEEP WELL INJECTION TEST DATA SHEET

Date of Reading	Time of Reading	Nominal Injection Flow Rate (gpm)	Flow Totalizer Reading (gallons)	Well Head Pressure (psig)	Remarks
6/25/71	(cont.) 09:15	—	—	—	at 3102'. Solid pick up of bottom
					with no indication of soft fill in
					hole
	12:20	—	—	—	Ran base temperature log. In hole
					at 12:20. Logged from 100' down to
					T.D. Bottom hole temperature 95°F
					which is depressed below normal or
					anticipated temperature (See entry for
					6/27/71 where recalculation of temperat
					instrument indicated this log faulty
	14:40				Out of hole at 14:40:
	15:00	—	—	—	Rigged up and ran Sperry-Sun
					pressure equipment into hole at
					15:00. Held instrument for 2 minutes
(Cont.)	(Cont.)				each at following depths: 150', 400

SEQUOYAH FACILITY

DEEP WELL INJECTION TEST DATA SHEET

Date of Reading	Time of Reading	Nominal Injection Flow Rate (gpm)	Flow Totalizer Reading (gallons)	Well Head Pressure (psig)	Remarks
6/25/71	(cont.) 15:00	—	—	—	800', 1200', 1600', 1900', 2100', 2400', 2500'
	↓				and 2600' and for 1 hour at 3100'.
	17:00				Out of hole at 17:00.
	17:00 +				Rigged up caliper tools. Ran caliper
					into hole, caliper failed. Withdrew
↓	↓				tools and shut in well for night
6/26/71	09:00	—	—	0	Rigged up caliper tools, ran caliper
					full length to bottom at 3102'.
					Average bore hole diameter approximately
					12". Sharp reduction to 7" at 2486'
					and reduction to approximately
	↓				6½" from casing seat to 1738'.
↓	14:00				Shut in well at 14:00

SEQUOYAH FACILITY

DEEP WELL INJECTION TEST DATA SHEET

Date of Reading	Time of Reading	Nominal Injection Flow Rate (gpm)	Flow Totalizer Reading (gallons)	Well Head Pressure (psig)	Remarks
6/27/71	—	—	—	—	Rechecked temperature survey calibration taken on 6/25/71. Decided calibration faulty and survey discarded. Rigged up dead weight pressure gauge and pressure recorder for well head pressure measurements. Ready for start of water injection tomorrow.

SEQUOYAH FACILITY

DEEP WELL INJECTION TEST DATA SHEET

Date of Reading	Time of Reading	Nominal Injection Flow Rate (gpm)	Flow Totalizer Reading (gallons)	Well Head Pressure (psig)	Remarks
6/29/71	05:31	0	1773	30	Starting Injection - Initial Flow Totalizer Reading
	05:45	50	—	60	
	06:01	50	3270	68	
	06:06	70	3560	74.5	Increased Injection Rate
	06:27	70	5011	88	
	06:32	70	5230	88	
	06:34	90	5385	100.5	Increased Injection Rate
	06:42.5	—	—	—	West Injection Pump Failed
	06:50.5	—	—	—	Resuming Injection Via East Pump.
	06:55	90	6655	108.5	
	07:03.5	90	7400	113.5	
	07:09	—	—	115.1	
	07:20	—	—	116.7	
	07:32	90	10,000	117.2	
	07:45	—	—	118.4	
	07:54	—	—	118.7	

SEQUOYAH FACILITY

DEEP WELL INJECTION TEST DATA SHEET

Date of Reading	Time of Reading	Nominal Injection Flow Rate (gpm)	Flow Totalizer Reading (gallons)	Well Head Pressure (psig)	Remarks
6/28/71	08:02	91	12,690	119.0	Calculated flow rate from totalizer = 89
	08:33	91	15,575	120.0	" " " " " = 93
	09:02	91	18,158	120.3	" " " " " = 89
	09:30	—	—	—	Initiated radioactive tracer surveys
					while continuing injection
	09:32	91	20,862	120.8	Calculated flow rate from totalizer = 90
	09:48	—	—	121.2	
	10:01.5	91	23,557	121.2	" " " " " = 91
	10:31	91	26,231	123.0	" " " " " = 91
	10:59.5	91	28,924	122.1	" " " " " = 94
	11:32	91	31,750	122.1	" " " " " = 86
	11:59.5	91	34,263	124.1	" " " " " = 93
	12:34	91	37,456	125.6	" " " " " = 92
	13:02	91	39,927	126.0	" " " " " = 88
	13:50	91	44,324	126.0	" " " " " = 92
(Cont.)	14:20	91	47,092	126.2	" " " " " = 92

SEQUOYAH FACILITY

DEEP WELL INJECTION TEST DATA SHEET

Page No. 7

Date of Reading	Time of Reading	Nominal Injection Flow Rate (gpm)	Flow Totalizer Reading (gallons)	Well Head Pressure (psig)	Remarks
(Cont.) 6/28/71	15:22	91	52,528	126.4	Calculated flow from totalizer = 86 gpm
	15:52	91	55,314	126.9	" " " " = 93 gpm
	16:23	91	58,088	126.9	" " " " = 90 gpm
	16:53	91	60,787	124.7	" " " " = 90 gpm
	17:00	—	—	—	Completed radioactive tracer surveys
	17.23	91	63,479	124.8	Calculated flow from totalizer = 89 gpm
	17:53	91	66,281	126.7	" " " " = 90 gpm
	—	—	—	—	Ran Sperry-Sun pressure recorder
					into hole. Landed recorder at 2900'
					for measuring pressure decay.
	18:23	—	$\boxed{68,959}$	127.2	Injection flow stopped for
					pressure fall off test.
	18:25	—		104.0	
	18:27			102.0	
	18:29			102.0	
(Cont.)	18:31			102.8	

SEQUOYAH FACILITY

DEEP WELL INJECTION TEST DATA SHEET

Date of Reading	Time of Reading	Nominal Injection Flow Rate (gpm)	Flow Totalizer Reading (gallons)	Well Head Pressure (psig)	Remarks
(cont.) 6/28/71	18:33			102.4	Pressure Fall Off test with
	18:43			101.3	Sperry-Sun pressure recorder in
	18:53			100.2	hole at 2900'
	19:03			100.0	
	19:33			98.1	
	20:03			96.1	
	20:33			95.5	
	21:03			94.0	
	21:33			93.0	
	22:03			91.0	
	22:33			90.1	
	23:03			89.9	
	23:33			87.5	
6/29/71	0:03			86.5	
	0:33			85.5	
(cont.)	1:03			84.5	

SEQUOYAH FACILITY

DEEP WELL INJECTION TEST DATA SHEET

Page No. 9

Date of Reading	Time of Reading	Nominal Injection Flow Rate (gpm)	Flow Totalizer Reading (gallons)	Well Head Pressure (psig)	Remarks
(cont.) 6/29/71	1:33			84.0	Pressure fall off test with
	2:33			83.0	Sperry-Sun pressure recorder in
	3:03			81.8	hole at 2900'
	4:03			80.4	
	4:33			79.9	
	5:33			78.8	
	6:03			77.9	
	6:33			77.7	
	7:33			75.2	
	8:33			75.2	
	9:33			74.4	
	10:33			73.7	
	11:33			73.0	
	12:33			72.2	
	13:33			72.0	
(cont.)	14:33			70.8	

SEQUOYAH FACILITY

DEEP WELL INJECTION TEST DATA SHEET

Date of Reading	Time of Reading	Nominal Injection Flow Rate (gpm)	Flow Totalizer Reading (gallons)	Well Head Pressure (psig)	Remarks
(Conc.) 6/29/71	15:33			69.0	Pressure fall off test with
	16:33			69.0	Sperry-Sun pressure recorder in
	17:33			67.0	hole at ±900'
	18:33			67.0	
	19:33			67.0	
	20:25			65.0	Started to remove pressure recorder
					from hole.
	20:30				Pressure recorder removed from
					hole.
	20:37	25		—	Started Injection flow at reduced
					rate
	20:45	25	69,214	70	
	21:15	25	69,923	78	
	21:45	25	70,675	84.5	
	22:15	25	71,475	90.0	
(Cont.)	22:45	25	72,235	94.0	

SEQUOYAH FACILITY

DEEP WELL INJECTION TEST DATA SHEET

Date of Reading	Time of Reading	Nominal Injection Flow Rate (gpm)	Flow Totalizer Reading (gallons)	Well Head Pressure (psig)	Remarks
(cont.) 6/29/71	23:15	25	72,985	95-97	Pressure Unsteady
↓	23:45	25	73,699	95-97	" "
6/30/71	0:15	25	74,512	95-97	" "
	0:45	25	75,138	95-97	" "
	1:15	25	75,687	95-97	" "
	1:45	25	76,466	95-97	" "
	2:15	25	77,238	95-97	" "
	2:45	25	78,179	97	" "
	3:15	25	78,669	97	" "
	3:45	25	79,444	96.5	
	4:15	25	80,149	97	
	4:45	25	80821	97	
	5:15	25	81,570	97	
	5:45	25	82264	97	
	6:15	25	83,000	97	
(cont.)	6:45	25	83,751	97	

SEQUOYAH FACILITY

DEEP WELL INJECTION TEST DATA SHEET

Date of Reading	Time of Reading	Nominal Injection Flow Rate (gpm)	Flow Totalizer Reading (gallons)	Well Head Pressure (psig)	Remarks
(cont.) 6/30/71	7:15	25	84,493	97	
	7:45	25	85,208	97	
	8:15	25	85,953	97	
	8:45	25	86,657	97	
	9:15	25	87,366	97	
	?			See Remarks.	Plant and pumps providing water to
					well lost power for 10 minutes.
					During loss of injection pressure
					dropped to a minimum of 42 psig
					at well head but returned to
					previous pressure immediately
					upon starting pump.
	11:15	25	90,061	97	
	13:15		92,880	97	
	15:15		95,782	97	
(cont.)	18:15	25	100,219	91.7	

SEQUOYAH FACILITY

DEEP WELL INJECTION TEST DATA SHEET

Page No. 13

Date of Reading	Time of Reading	Nominal Injection Flow Rate (gpm)	Flow Totalizer Reading (gallons)	Well Head Pressure (psig)	Remarks
(cont.) 6/30/71	21:15	25	104,560	97.5	
7/1/71	0:15	25	108,814	97.5	
	3:15	25	113,192	98.0	
	6:15	25	117,481	98.0	
	8:15	25	120,410	98.0	
	—	25	—	—	Rigged up and ran temperature
					survey tools in hole for base
					temperature run during injection
	8:[illegible]	—	121,253	98.0	Stopped injection to run temperature
					decay profiles.
	16:55	—	121,253	—	Temperature surveys completed
	17:05	90	121,253	—	Started injection at 90 gpm rate
	17:35	90	123,045	117	
	18:05	90	126,666	120	
	18:35	90	129,300	120	Injection pump failed for 5 minutes
(cont.)	19:05	90	131,620	121.8	

SEQUOYAH FACILITY

DEEP WELL INJECTION TEST DATA SHEET

Date of Reading	Time of Reading	Nominal Injection Flow Rate (gpm)	Flow Totalizer Reading (gallons)	Well Head Pressure (psig)	Remarks
(Cont.) 7/1/71	19:35	90	134,350	122.7	
	20:05	90	137,050	122.5	
	20:35	90	139,750	123.2	
	21:05	90	142,350	123.9	
	21:35	90	145,130	124.2	
	22:05	90	147,707	124.7	
	22:35	90	150,375	124.7	
	23:05	90	153,095	125.2	
	23:35	90	155,700	125.5	
7/2/71	0:05	90	158,422	125.4	
	1:05	90	163,215	126.0	
	2:06	90	169,315	126.5	
	3:05	90	174,458	126.5	
	4:05	90	179,747	126.9	
	5:05	90	185,133	127.0	
(Cont.)	6:05	90	190,532	127.0	

SEQUOYAH FACILITY

DEEP WELL INJECTION TEST DATA SHEET

Page No. 15

Date of Reading	Time of Reading	Nominal Injection Flow Rate (gpm)	Flow Totalizer Reading (gallons)	Well Head Pressure (psig)	Remarks
(cont) 7/2/71	7:05	90	195,928	127.3	
	8:05	90	201,125	127.1	
	9:05	90	206,368	128.7	
	11:05	90	217,070	129.5	
	13:05	90	227,686	129.0	
	15:05	90	238,390	129.5	
	17:05	90	249,040	129.0	
	19:05	90	260,150	129.5	
	21:05	90	270,846	129.7	
	23:05	90	281,545	129.8	
7/3/71	1:25	90	294,034	130.0	
	4:05	90	308,209	132.5	
	7:05	90	324,462	132.4	
	10:05	90	340,325	132.8	
	13:05	90	357,058	132.6	
(cont.)	16:05	90	372,490	133.5	

SEQUOYAH FACILITY

DEEP WELL INJECTION TEST DATA SHEET

Page No. 16

Date of Reading	Time of Reading	Nominal Injection Flow Rate (gpm)	Flow Totalizer Reading (gallons)	Well Head Pressure (psig)	Remarks
(cont.) 7/3/71	17:05	90	377,940	133.5	
	18:05	90	383,180	133.7	
	19:05	90	388,580	133.8	
↓	20:05	90	404,530	133.9	
7/4/71	1:05	90	420,778	134.5	
	4:05	90	436,222	134.9	
	7:05	90	452,998	134.9	
	10:05	90	468,950	135.1	
	11:05	90	474,263	135.1	
	12:05	90	479,669	135.5	
	13:05	90	485,000	135.5	
	16:05	90	501,060	135.8	
	19:05	90	517,020	136.0	
↓	22:05	90	533,000	136.5	
7/5/71	1:07	90	549,113	137.5	
(cont)	5:05	90	570,496	137.6	

SEQUOYAH FACILITY

DEEP WELL INJECTION TEST DATA SHEET

Date of Reading	Time of Reading	Nominal Injection Flow Rate (gpm)	Flow Totalizer Reading (gallons)	Well Head Pressure (psig)	Remarks
(Cont.) 7/5/71	7:05	90	581,120		
	8:00	90	—	—	Rigged up and started in hole
					with radioactive tracer tools for
					injection profile measurements.
	9:05	90	591,759	139.3	Profile measurements continuing
	11:05	90	602,565	139.6	" " "
	13:05	90	613130	139.7	" " "
	14:15	90	—	—	Completed profile measurements
					and removed tools.
	15:05	90	623,780	138.2	
	19:05	90	645,510	140.2	
	23:05	90	666,925	139.7	
7/6/71	3:04	90	688,148	140.3	
	5:20	50	—	—	Changed flow rate from 90gpm to 50gpm
(Cont.)	7:05	50	707,065	138	

SEQUOYAH FACILITY

DEEP WELL INJECTION TEST DATA SHEET

Date of Reading	Time of Reading	Nominal Injection Flow Rate (gpm)	Flow Totalizer Reading (gallons)	Well Head Pressure (psig)	Remarks
(cont.) 7/6/71	9:00	50	—	—	Rigged up and ran Sperry-Sun pressure
				138	recorder into hole.
	9:15	50	—	—	Landed Pressure recorder at 2650' in hole
	9:18	0	715,589	138	Stopped water injection and started
					pressure fall off measurements
	10:20			124	Fall Off Test Continuing
	11:20			117	" " " "
	12:20			106.2	" " " "
	13:20			105.5	" " " "
	14:20			103.3	Pulled pressure recorder, changed chart and returned to hole
	15:20			103.4	Fall Off Test Continuing
	16:20			103.0	" " " "
	18:20			102.2	" " " "
	20:20			98.5	" " " "
7/7/71	0:20			94.7	" " " "

SEQUOYAH FACILITY

DEEP WELL INJECTION TEST DATA SHEET

Page No. 19

Date of Reading	Time of Reading	Nominal Injection Flow Rate (gpm)	Flow Totalizer Reading (gallons)	Well Head Pressure (psig)	Remarks
(cont.) 7/7/71	4:20			91.0	Fall off test continuing
	8:20			89.0	" " " "
	12:20			86.5	" " " "
	16:20			84.2	" " " "
	20:20			82.1	" " " "
7/8/71	0:20			79.3	" " " "
	4:20			77.6	" " " "
	8:20			76.8	" " " "
	12:20			74.8	" " " "
	16:20			73.7	" " " "
	20:20			72.5	" " " "
7/9/71	0:20			70.9	" " " "
	4:20			69.9	" " " "
	8:20			69.4	" " " "
	9:20			69.2	" " " "
(cont.)	10:20			68.7	" " " "

SEQUOYAH FACILITY

DEEP WELL INJECTION TEST DATA SHEET

Date of Reading	Time of Reading	Nominal Injection Flow Rate (gpm)	Flow Totalizer Reading (gallons)	Well Head Pressure (psig)	Remarks
(cont.) 7/9/71	11:20			68.7	Fall off test continuing
	12:20			68.2	" " " "
	13:20			67.8	" " " "
	14:20			67.7	" " " "
	—			—	Removed Sperry-Sun pressure recorder and
					changed chart. On way back into hole ran
					pressure survey at various levels. Landed
					pressure recorder at 2650' at 15:45 pm.
					Too much pressure fluctuation to read
					dead weight well head pressure gauge.
	16:20			67.7	Fall off test continuing
	20:20			66.5	" " " "
7/10/71	0:20			65.8	" " " "
	4:20			65.0	" " " "
	8:20			64.8	" " " "
(cont.)	12:20			64.2	" " " "

SEQUOYAH FACILITY

DEEP WELL INJECTION TEST DATA SHEET

Date of Reading	Time of Reading	Nominal Injection Flow Rate (gpm)	Flow Totalizer Reading (gallons)	Well Head Pressure (psig)	Remarks
(cont.) 7/10/71	16:20			63.8	Fall off test continuing
↓	20:20			63.1	" " " "
7/11/71	0:20			62.3	" " " "
	4:20			61.8	" " " "
	8:20			61.5	" " " "
	12:20			61.4	" " " "
	16:20			60.9	" " " "
↓	20:20			60.5	" " " "
7/12/71	0:20			59.8	" " " "
	4:20			59.4	" " " "
	8:20			59.4	" " " "
	12:20			59.0	" " " "
	15:45			—	Removed Sperry-Sun pressure recorder
	15:56	90	715,589		Started water injection at 90 gpm
	16 45	0	716,170	100	Stopped injection flow because water
(cont.)					supply hose to injection pump burst

SEQUOYAH FACILITY

DEEP WELL INJECTION TEST DATA SHEET

Date of Reading	Time of Reading	Nominal Injection Flow Rate (gpm)	Flow Totalizer Reading (gallons)	Well Head Pressure (psig)	Remarks
(cont.) 7/12/71	17:05				Attempted to start injection again
					but hose burst again.
	17:22	90	716,639	90	started injection at 90 gpm
	18:22	90	721,368	124	
	21:22	90	737,682	129	
	23:22	90	748,590	130.5	
7/13/71	1:22	90	759,539	131.0	
	3:22	90	770,474	131.5	
	5:22	90	780,951	132.0	
	7:22	90	792,318	132.5	
	8:22	90	797,939	133.0	
	9:22	90	803,306	135.5	
	10:22	90	808,710	136.3	Rigged up and started in hole
					with radioactive tracer instruments
					for velocity and injection profile
(cont.)					measurements. Instrument shorted out

SEQUOYAH FACILITY

DEEP WELL INJECTION TEST DATA SHEET

Date of Reading	Time of Reading	Nominal Injection Flow Rate (gpm)	Flow Totalizer Reading (gallons)	Well Head Pressure (psig)	Remarks
(cont.) 7/13/71	(cont.) 10:22				And was removed from hole
	10:53				Instrument repaired and started back in
					hole.
	11:22	90	819,010	136.8	Injection profile measurements continuing
	12:22	90	819,535	137.2	" " " "
	13:22	.90	825,035	137.0	" " " "
	14:22	90	830,460	137.0	" " " "
	15:22	0	836,143	137.0	Injection measurements completed
					Radioactive tracer measurements of
					back flow velocities and quantities
					in hole after injection shutdown
					initiated
	16:22			105.5	Back flow measurements continuing
	17:22			101.5	" " "
	18:22			100.0	" " "
(cont.)	19:22			100.8	" " "

SEQUOYAH FACILITY

DEEP WELL INJECTION TEST DATA SHEET

Date of Reading	Time of Reading	Nominal Injection Flow Rate (gpm)	Flow Totalizer Reading (gallons)	Well Head Pressure (psig)	Remarks
(cont.) 7/13/71	20:10				Completed backflow measurements,
					removed tools and shut in well.
	21:22			98.1	
	21:32			97.5	
7/14/71	8:30			96.7	

Exhibit C

WELL ANALYSIS COMPANY, INC.

Subsidiary SONICS INTERNATIONAL, INC.

WACO LOGGING SERVICES

563-0331
P. O. Box 1609
Odessa, Texas 79760

Mr. D.J. Foley, Manager
Project Engineering
Nuclear Operation Division
Kerr-McGee Corporation
Kerr-McGee Building
Oklahoma City, Okla. 73102

Dear Mr. Foley;

RE: Reservoir Analysis, Sequoyah Facility

Purpose

To establish feasibility of con:'stent storage of liquid waste materials into target reservoir without contamination of potable waters and other useable geologic horizons or endangering surrounding surface environment.

General Conditions for Consideration

Target well is completed in the Arbuckle Limestone with 7" completion string set through a Hunt, Sylan and Simpson and cemented at 1619', approximately 260 feet below the top of the arbuckle Limestone. Injection interval completed with uniform 11" open hole extending to the top of the granite at 3102'. Location is bounded by two major faults, one five miles to the northwest and one intersected by a third fault, approximately one mile to the East southeast. Total radial exposure to the nearest fault plane approximately 120°. Formation displacement and slippage control derived from seimic data and correlation of two dry hole attempts (the Smith #1, two miles east and the Highfield #1, approximately three miles south-southwest).

Target well is located upon Company controlled land both surface and sub-surface.

Reservoir evaluation was to be based primarily upon computer calculations and reservoir modeling utilizing high accuracy pressure, flow, time, and injection profile and inhole flow data developed during a well testing program made up of alternating periods of water injected and zero inflow. Additional evaluations of the reservoir and of the well casing and packer and near well bore formation from a leakage stand point were to be made by standard thermalprofile and radioactive profile techniques.

H.J. Gruy & Associates, Inc. of Dallas, developed the testing program, evaluated the pressure, flow, time, and injection profile data, performed the computer analysis and reservoir modeling, and evaluated the proposed injection well from an overall stand point. Well Analysis Company, Inc. of Odessa, Texas, provided downhole wireline services and performed caliper measurements, all thermal measurements and all radioactive tracer measurements and calculated the injection pattern and flow characteristics from established radioactive profile techniques and provided a progressive temperature decay analysis. High accuracy downhole and surface pressure recording instruments and chart conversion were provided by Sperry-Sun Well Surveying Company of Oklahoma City, Okla. Water injection, total injection flow, time measurements and additional surface pressure measurements were made by Kerr-McGee.

Multiple dependent and unpredictable parameters dictated that the water injection and data collection be done in phases, each phase determining the details of the subsequent test phase and series of data to be collected.

This discussion is primarily concerned with the interpretation and sequence of the injection profiles and temperature data analysis.

Greater in-depth discussion of the development and application of the survey methods utilized in this study is provided in the accompanying techical articles.

A.P.I. #906-9-E Review of Tracer Surveys.

S.P.E. #1329 Maximum Use of Profile Information.

A.P.I. "Factors Considered in Interpretation".

S.P.W.L.A. "Computers to Increase Value of Temperature Logs".

S.P.E. #1752 "Fluid Flow Analysis Techniques".

S.P.E. #2255 "Computerized Temperature Decay".

S.P.E. #2685 "Interpretation of Injection Profiles".

A.P.I. #906-15-J "Practical Field Interpretation of Temperature Surveys".

Other accompanying information:

5 Panel Composite of the Survey Results for Reference during discussion. Panel 1 and 2 are represenative of Phases One and Two, respectively. Panel 3 and 4 are Injection and Counterflow tests described during Phase Three. Panel 5 display the injection profiles of each of the three phases, plotted together for comparison. Panel 5 composit results are the qualified conclusion of the WACO log analyst. Quantitative results of the surveys have been modified by qualitative interpretation of both Temperature and Radioactive Surveys.

TECHNIQUES OF PROFILE INVESTIGATION

1. RADIOACTIVITY PROFILES - INJECTION OR PRODUCTION

1. Tools

Instruments used are two gamma sensitive detectors and a dispenser of a water solution containing Iodine-131 incorporated into a single downhole tool. The device is run in the well on a conductor line to a measured depth and a base radiation activity of the well bore recorded. A small quantity of the radioactive iostope solution is then released at a selected interval in the well and the path and rate of movement of the shot of liquid containing the radioactivity within the well bore is charted by observing the reaction of the detectors at various depths. These reactions are recorded and the data evaluated, both qualitatively and quantitatively, to define the pattern and relative volumes of injection accepted by each of the subsurface intervals.

2. Calculations and Methods

Two methods of data collection are used in the investigations.

a. VELOCITY DETERMINATIONS

Radioactive solution is released upstream of the gamma detectors and is carried past the detectors by the moving stream of injection. The transit time over a given interval (5' normal spacing) is measured and corrected for parabolic flow variations and well bore diameters. The volume of fluid contained in the measured interval of well bore (5') is calculated; and utilizing this information along with the transit time, the rate of fluid movement, expressed in bbl/day, past the interval is derived. This action is repeated at selected intervals in the well and a subtraction curve developed. The results are then plotted as fluid acceptance intervals, or the injection profile.

b. RADIATION EQUIVALENT VOLUMES R.E.V. OR SELF METHOD

These measurements are accomplished by releasing a given amount of solution containing a radioactive isotope at a point upstream of the zone of interest and measuring its relative activity by recording the reactions of logging tools (radiation detectors) during a traverse run through the zone containing the radioactive material. The resulting curve (or graph) is triangulated and an index number assigned which represents the total amount of radioactivity in the designated interval of the well bore. As this volume of fluid moves downstream, repeated timed traverses are made through the radioactive zone, charting the position and activity level in each instance. These curves are also triangulated and their indices assigned.

Should a portion or all of the increment of fluid carrying the isotope leave the well bore and enter the formation, a proportional amount of radiation will also be diverted, since the isotope is completely soluble and mixed within the fluid stream. (The radioactive material traveling into the formation quickly becomes non-dectible to the radioactivity instruments). The variation of the assigned indices will reflect the radioactivity and hence, fluid loss at each interval and may be plotted in relative percentage to the original index. When vertical dispersal of the isotope increases to the point that accurate measurement becomes difficult, a new increment of isotope is released, and assigned the percentage represented by the last traverse through the original shot or increment. The new shot of material is then followed downstream by the same logging methods and the continued reduction of index and hence, loss of fluid into the formation is defined.

These techniques are both subject to a possible 15% error (related to 100% fluid travel), but the parameters affecting each are different than those of the other and accuracy control is effected by comparison of the two results. Additional information may be inferred by these comparisons (i.e., vertical erosion or fracturing adjacent to and connecting with the well bore). These would affect the velocity determination, but leave the radiation equivalent relatively unaffected. Thin zones of fluid acceptance may be closely defined by velocity techniques but only averaged over an extended interval by R.E.V. methods. Caliper logs are essential to velocity calculations but not needed for R.E.V. velocity calculations usually represent maximum flow rate at any given interval- R.E.V. measurements are necessarily minimal determinations.

Profiles derived from these combined methods can be expected to exceed 95% accuracy with respect to total flow.

11. TEMPERATURE DECAY SERIES.

1. Tools:

The downhole instruments consist of pulsing oscillator controlled by a calibrated temperature sensor. The downhole tool is run into the well by conductor line containing signal wire running back to surface recording equipment and the indingent temperature is monitored at each depth. The signals are sent back to the surface and recorded as temperature in degrees F°.

2. Methods and Techniques:

Temperature data are collected in ambient temperature only. Variations expressed as differential, or delta logs, are derived from the basic collected data. Data may be recorded by station setting, (tool held stationary at selected depths for a specific recording time) or by a continuous traverse over the entire interval of interest. Repeated runs or traverses made with the smae tools and calibrations reflect the changing temperatures at all depths with respect to time, and are termed a "Temperature Decay Series".

Decay series are recorded with respect to time. A basic temperature under constant conditions is recorded by either traverse logs, or station settings. The base, or constant conditions are then altered and the resultant temperature transients during well bore recovery are recorded at timed intervals.

3. Interpretation:

The data recorded must be considered the temperature of the well bore only, since the information is collected at the terminal point of an equilibrium process.

The Temperatures at any point are the net results of all the surrounding thermal transfers. The temperature of the surrounding matrix is the influence for well bore temperature progression, however, and bore hole fluid attempts to assume the temperature of the adjacent dominant thermal field.

A depth of investigation may then be inferred by observation of the rates of change caused by these adjoining fields or cells.

Temperature fields generated by convection thermal transfer differ in initial recovery rates from fields caused by radiation or conduction only.

Comparison of these varying rates of recovery identifys the zone of fluid movement thru the formation by reflecting the influence of the more nearly isothermic conditions extending to a greater radius from the well bore.

Temperature influence from any matrix surrounding the well bore depends upon a completely static fluid column, else the reflected temperature will be distorted by vertical in-hole convection thermal transfer.

4. Information:

Properly executed, thermal decay surveys confirm fluid exit or entry intervals in the well, and define zone thickness or height beyond the limits of any in-hole rate determination method. Quantitative values cannot be applied however except under ideal conditions. They may also be useful in determining leakage from the casing or upward around the casing an thence into a higher formation.

111. ANALYSIS OF SURVEY RESULTS

The operating requirement of injectivity profiling and single point pressure fall off are not compatable to simultaneous surveying. A sequence of operation was scheduled to allow the most valid and efficient collection of all data.

Preinjection Testing:

1. After setting up well head for entrance of logging tools, dummy run was made to check hole for obstruction using simulated instrument package.

2. Caliper survey of the open hole was made.

3. Pressure survey and static bottonhole measurements.

Phase One Sequence:

1. Well was placed on injection at a selected rate and allowed to to reach initial relatively stabilized conditions.

2. A Radioactive profile was run using both velocity, and Radiation Equivilent Volumes for quantitative calculations. A base injection temperature run was made at this time.

3. Sperry-Sun pressure equipment and WACO Temperature Tool placed downhole @ 2900' and Well shut-in (injection stopped) for monitor of pressure.

4. Sperry-Sun instrument retrieved and well placed back on injection.

5. Injection stabilized and well shut-in for Temperature Decay Series.

6. Well placed back on injection.

Profile and Temperature Analysis of Phase One determined:
Four gross injection intervals.

A. 1720' to 1820' 30% of injection volume with 24% between 1755' and 1790'.

B. 2610' to 2655' 38% of injection volume.

C. 2760' to 2780' 12% of injection volume.

D. 2820' to 2855' 20% of injection volume.

No injection continued below 2860' during the first injection period and no other zones were accepting fluid at the time of the Radioactive Survey. (See plots of Velocity and R.E.V. calculations on right side of 1st. panel).

Temperature Decay monitors indicated that a Fifth zone may have opened up and accepted some small portion of injection during the second injection period. This is inferred from the definite indication of after shut-in counterflow from 2700' upward into three intervals. The injection zone "B" 2610'-2655' and two new intervals, 2300'-2305' and 2360'-2365' strong counterflow exists from 2700' into zone "B" (note isothermic pattern of temperature decay curves over this interval) with only a small amount continuing upward to the two new intervals.

The influence of the additional zone of injection, and the after shut-in counterflow was observed on both the pressure monitor and the station setting temperature decay. This evidence of the net injection interval change with fill up caused phase two to be designed around both short and long term pressure decline with an injection profile to determine the current net injection pattern.

Phase Two Sequence:

1. Injection resumed after the decay series temperature program was completed and continued for 112 hours for stabilization.

2. Radioactive Tracer (Velocity and R.E.V.) was run to establish injection pattern.

3. Sperry-Sun pressure equipment and WACO Temperature Tool run into hole to fixed position and well shut-in (injection stopped) for testing.

4. Five hour pressure and Temperature monitor run @ 2650', Then tools removed and replaced with Sperry-Sun pressure instrument only with recorder set for 72 hour record period.

5. Pull and re-run pressure instrument with recorder set for 72 hour pressure measurement.

6. Analyze first 72 hour pressure chart then remove pressure equipment and resume injection.

Phase Two Profile and Temperature Analysis:

Original gross intervals of injection still exist, but with a significant change in the fluid distribution into zone "B" 2610'-2655'. The net interval decreased to 25' (2620'-2645') and the volume into zone decreased from 38% (Phase 1) to 11% of total injection. The water originally entering this zone was diverted into three thin intervals between 2710' and 2810' (see panel 5). Both zone "A" and "D" decreased in net thickness with very little change in accepted volume.

A small interval just below the small areas which the temperature profiles indicated were accepting counterflow during Phase One, now accepted approximatley 8% of the diverted injection (2420'-2425').

Reference to the decay series of Phase One indicates that this zone may have been accepting injection intermittently during the first tests. (note retarded recovery of first shut-in temperature decay with respect to subsequent runs 1st. panel).

Erratic velocities between 2240' and 2370' indicate possible zone interference during injection but R.E.V. calculations show no significant fluid losses through the interval.

Phase Two pressure and temperature data again reacted to the after shut-in counterflow conditions and Phase Three was projected to chart the magnitude and full extent of fluid movement during shut-in.

Phase Three Sequence:

1. Injection continued for 24 hours.

2. Injection Profile run using R.E.V. methods only.

3. Well shut-in and production profile techniques used to determine counterflow extent.

Phase Three Results:

Injection patterns again changed but the 4 original gross intervals continued to accept fluid. The lower zones show a marked tendency toward reduced volumes with continued injection, and the diverted fluids are being accepted by the top interval (increased injection into zone "A" from 30% to 46% during testing phases).

The counterflow conditions during shut-in were more extensive than first analysis indicated (see panel 4).

Shots of Radioactive Isotope, placed at indicated depths and traced, show fluid moving up from zone "D" past "C" and"B" and a portion moving to the top of the section into zone "A".

Rate of initial counterflow is approximately 240-280 bbl/day but about 60% of this volume re-enters the formation between 2280' and 2380',one of the original zones accepting counterflow. The remainder of the fluid moves up the hole and is lost to zone "A" (1750'-1800').

Zone "B" (2620'-2645') which originally accepted the major portion of the counterflow is presently receiving none, but appears to be contributing a small increment instead.

No fluid is moving at 1700' and none is entering the well bore below 2870'. (see shots #3 @ 2865' and #8 @ 1675' 4th. panel).

Lines connecting the average slope centers of each shot of material as they progress uphole show a visual reference to the relative rates of fluid movement.

Zones of fluid acceptance may also be qualified by distortion of the material distribution patterns. (See consistant distortion and intensity loss @ 2300', and runs 10 thru 22).

Conclusion:

Examination of primary open hole logs show a net probable injection zone thickness of approximately 700' over the open hole section. Of this, only 175' (approximate) is accepting injection.

Permeabilities are layered throughout the entire interval with no apparent vertical permeabilities or fractures connecting the zone. (Hence, the counterflow under shut-in conditions).

Fluid is being accepted well above total depth, (bottom of the hole) and below the casing point, and there seems to be no problem in containing injection well within the vertical limits of the formation at this point in the reservoir.

From analyzing the thermal profiles and radioactive tracer records, there are no indication of channels, leaks, holes, or other mechanical failure at the casing seat or above and no channel or leak around the packer.

Injection zone locations and extent seem rather sensitive to pressure build up and the amount of fluid injected into new zones could probably be increased by selective acidizing. The tendency for intermittent injection seems to bear this inferrence out.

The tendency of the lower zones to accept progressively smaller volumes points to the possibilities of relativity smaller pore volumes of permeability pinch outs or local restrictions near the well. Should the pressure data indicate the latter, selective treatment will alleviate this problem.

The opinion of WACO analysts is that net injection interval could be increased approximately 200% by proper treatment.

A program of consistant scheduled monitoring should be initiated to identify and control net volume per foot into each interval and to guard against shortening the life of injection through ineffecient injection patterns.

Billy P. Morris

Billy P. Morris
Vice President
Well Analysis Company, Inc.
Midland, Odessa, Texas

Exhibit D

CORE LABORATORIES, INC.
Petroleum Reservoir Engineering
DALLAS, TEXAS

October 28, 1969

REPLY TO
8 N. W. 42ND ST.
OKLAHOMA CITY, OKLA.
73118

Kerr-McGee Corporation
705 Kerr-McGee Building
Oklahoma City, Oklahoma 73102

Attn: Mr. Tom C. Danie

Subject: Core Analysis
Sequoyah Factory Waste
Disposal No. 1 Well
Sequoyah County, Oklahoma
CLI File No. CP-1-7049

Gentlemen:

The Arbuckle Formation was diamond cored in the subject well at various intervals from 1451 to 3032 feet. The core was preserved at the well-site and transported to the Oklahoma City Laboratory for analysis by whole core methods. The analysis results are presented in tabular form on the accompanying page of this report.

Grain Density measurements were requested at scattered intervals and appear along with the tabular data.

Thank you for this opportunity to be of service.

Yours very truly,

CORE LABORATORIES, INC.

J. G. Evertson, Jr.

J. G. Evertson, Jr.
District Manager

JGE:sh
5cc: Addressee

CORE LABORATORIES, INC.
Petroleum Reservoir Engineering
DALLAS, TEXAS

CORE ANALYSIS RESULTS

Company KERR-MCGEE CORPORATION Formation ARBUCKLE File CP-1-7049
Well SEQUOYAH FACTORY WASTE DISPOSAL #1 Core Type DIAMOND Date Report 10-28-69
Field Drilling Fluid WATER BASE MUD Analysts BOYLE
County SEQUOYAH State OKLAHOMA Elev. 579' KB Location 997' FEL & 3231' FSL, SECTION 21-12N-21E

Lithological Abbreviations

SAND-SD	DOLOMITE-DOL	ANHYDRITE-ANHY	SANDY-SDY	FINE-FN	CRYSTALLINE-XLN	BROWN-BRN	FRACTURED-FRAC	SLIGHTLY-SL/
SHALE-SH	CHERT-CH	CONGLOMERATE-CONG	SHALY-SHY	MEDIUM-MED	GRAIN-GRN	GRAY-GY	LAMINATION-LAM	VERY-V/
LIME-LM	GYPSUM-GYP	FOSSILIFEROUS-FOSS	LIMY-LMY	COARSE-CSE	GRANULAR-GRNL	VUGGY-VGY	STYLOLITIC-STY	WITH-W/

SAMPLE NUMBER	DEPTH FEET	PERMEABILITY MILLIDARCYS		POROSITY PER CENT	RESIDUAL SATURATION PER CENT PORE		SAMPLE DESCRIPTION AND REMARKS
		PERM. MAX.	PERM. 90°		OIL	TOTAL WATER	
	WHOLE CORE ANALYSIS						
1	1451.2-52.1	4.0	3.4	9.5	0.0	89.1	Dol, vuggy, vert frac
2	52.1-53.0	0.1	<0.1	7.7	0.0	92.9	Dol, vert frac
3	53.0-54.5	0.1	0.1	9.9	0.0	91.6	Dol, few pp vugs
4	54.5-55.5	0.2	0.1	11.2	0.0	89.6	Dol, sl/vuggy
5	55.5-57.0	0.3	0.1	12.4	0.0	91.5	Dol, pp vugs
6	57.0-58.0	<0.1	<0.1	5.9	0.0	93.3	Dol, sl/shy, few pp vugs
7	58.0-59.0	<0.1	<0.1	11.0	0.0	92.2	Dol, pp vugs
8	59.0-60.0	0.7	0.6	8.5	0.0	87.8	Dol, few pp vugs
9	60.0-61.2	2.3	1.9	10.7	0.0	90.0	Dol, few pp vugs
10	61.2-62.0	1.2	1.1	12.1	0.0	87.7	Dol, few pp vugs, sl/cherty
11	62.0-63.5	1.5	1.3	13.4	0.0	88.5	Dol, few pp vugs
12	63.5-65.3	0.1	0.1	9.4	0.0	88.9	Dol, few pp vugs
13	65.3-66.8	<0.1	<0.1	5.1	0.0	91.4	Dol, sl/shy
14	66.8-68.2	<0.1	<0.1	3.7	0.0	89.3	Dol, sl/shy
15	68.2-69.5	<0.1	<0.1	3.4	0.0	90.6	Dol, sl/shy
16	69.5-70.6	<0.1	<0.1	4.4	0.0	93.4	Dol, sl/shy
17	70.6-71.7	0.1	<0.1	4.9	0.0	91.8	Dol, vuggy
18	71.7-73.3	0.1	<0.1	3.7	0.0	89.2	Dol, vuggy
19	73.3-74.4	0.1	0.1	8.2	0.0	91.5	Dol, few pp vugs
20	74.4-76.0	0.1	<0.1	6.8	0.0	97.2	Dol, shy
21	76.0-77.0	<0.1	<0.1	4.9	0.0	85.9	Dol, few pp vugs
	1477.0-1737.0						Drilled
22	1737.0-38.7	<0.1*		3.3	0.0	76.7	Dol, sl/shy, few pp vugs
	38.7-43.0						Lost core
	1743.0-1912.0						Drilled
23	1912.0-13.0	<0.1	<0.1	2.1	0.0	67.4	Dol, sl/vuggy
23	13.0-14.2	<0.1	<0.1	1.9	0.0	33.3	Dol
25	14.2-15.7	<0.1	<0.1	1.4	0.0	50.0	Dol, sl/cherty
26	15.7-16.7	<0.1	<0.1	1.9	0.0	47.6	Dol
27	16.7-18.3	<0.1	<0.1	2.4	0.0	39.8	Dol, sl/cherty
28	18.3-19.7	<0.1	<0.1	2.4	0.0	34.8	Dol
29	19.7-21.0	<0.1	<0.1	2.3	0.0	33.3	Dol
30	21.0-21.7	<0.1	<0.1	0.9	0.0	64.3	Dol, shy
31	21.7-23.3	<0.1	<0.1	3.1	0.0	46.9	Dol
32	23.3-24.2	<0.1	<0.1	1.4	0.0	41.9	Dol, sl/shy
	1924.2-2294.0						Drilled
33	2294.0-95.6	101	24	9.8	0.0	64.6	Dol, vuggy, sl/cherty
34	95.6-96.6	0.1*		9.0	0.0	69.1	Dol, vuggy, vert frac
35	96.6-98.0	768	1.8	9.6	0.0	67.3	Dol, vuggy
36	98.0-99.4	30	0.2	9.2	0.0	69.8	Dol, vuggy, vert frac

CORE LABORATORIES, INC.
Petroleum Reservoir Engineering
DALLAS, TEXAS

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Well Sequoyah Factory Waste Dispos[illegible] No. 1

CORE ANALYSIS RESULTS

SAMPLE NUMBER	DEPTH FEET	PERMEABILITY MILLIDARCYS MAX.	90°	POROSITY PER CENT	RESIDUAL SATURATION PER CENT PORE OIL	TOTAL WATER	SAMPLE DESCRIPTION AND REMARKS
37	2299.4-01.2	2.0	1.9	9.5	0.0	69.0	Dol, vuggy, vert frac
38	2301.2-02.8	0.8	0.4	6.9	0.0	68.5	Dol, vuggy
39	02.8-03.8	0.1*		5.2	0.0	73.6	Dol, vuggy, vert frac
40	03.8-05.2	22	0.2	6.7	0.0	75.1	Dol, vuggy, vert frac
41	05.2-06.5	1.1	0.9	4.3	0.0	76.4	Dol, vuggy
42	06.5-07.9	0.6	0.3	6.6	0.0	76.4	Dol, vuggy
43	07.9-09.4	0.2	0.1	3.4	0.0	86.4	Dol, pp vugs, cherty
44	09.4-11.0	1.0	0.9	5.9	0.0	77.2	Dol, pp vugs, sl/cherty
	2311.0-12.0						Lost core
	2312.0-3021.0						Drilled
45	3021.0-22.4	0.2	0.1	5.3	0.0	76.4	Sd, dol
46	22.4-23.2	0.5	0.2	5.2	0.0	78.6	Sd, dol
47	23.2-24.8	0.2	0.1	2.8	0.0	86.4	Sd, dol, sty
48	24.8-26.6	0.1	0.1	6.1	0.0	67.5	Sd, dol, sty
49	26.6-28.4	0.3	0.1	3.1	0.0	85.4	Sd, dol, sty
50	28.4-29.7	0.2	0.1	3.7	0.0	80.9	Dol, sl/sdy, vuggy
51	29.7-31.5	0.8	0.7	4.4	0.0	72.6	Dol, vuggy, vert frac
	3031.5-32.0						Lost core

	GRAIN DENSITY
1452-53	2.808
1455-56	2.769
1457-58	2.762
1459-60	2.815
1462-63	2.845
1464-65	2.799
1466-67	2.798
1469-70	2.793
1471-72	2.833
1474-75	2.840
1476-77	2.837
2294-95	2.817
2298-99	2.818
2303-04	2.808
2307-08	2.800
2310-11	2.794
3021-22	2.706
3024-25	2.693
3028-29	2.822
3031-31.5	2.827

*DENOTES PLUG PERMEABILITY

THIS IS THE FINAL REPORT.

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