DESERT RESEARCH INSTITUTE
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ESTIMATING HYDRAULIC PARAMETERS USING WILDCAT OIL AND GAS DATA: A FEASIBILITY STUDY IN EAST-CENTRAL NEVADA

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ABSTRACT

Analysis of over 100 wildcat oil and gas records yielded a variety of data useful in the State of Nevada's Carbonate Aquifer Project. Hydraulic conductivities (K) and transmissivities (T) derived from drill-stem tests (DST's) indicate a wide range of values in the carbonate rocks of east-central Nevada. K values ranged from 9.3 x 10^{-6} ft/day to 18.6 ft/day. T values ranged from 5.3 x 10^{-4} ft^2/day to 500 ft^2/day. Comparison of T's and K's derived from DST's with those obtained from aquifer tests suggest that DST method may underestimate these parameters by several orders of magnitude. Several sources of bias inherent in the DST technique are suggested to help explain these discrepancies.

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INTRODUCTION

The application of wildcat oil and gas data to analyze the hydrologic properties of a groundwater system is one component of the State of Nevada's Carbonate Aquifer Project. Established by the Nevada legislature in 1985 (SB277), the Carbonate Aquifer Project is a cooperative effort between the State and the U.S. Department of Interior to study and test the carbonate aquifers of eastern and southern Nevada.

The carbonate rock province of Nevada shows considerable promise for long–term water supply development. Aquifer tests at several wells completed in carbonate rocks have shown both excellent water quality and limited drawdown. Conversely, however, numerous "dry holes" have been drilled. Understanding these performance discrepancies is critical to the design of a coherent aquifer development program.

Generally speaking, the source of these discrepancies is obvious. In Nevada, the carbonate geology consists of thick sequences of Paleozoic rocks with variable hydraulic properties. These variations are the result of irregular depositional patterns complicated by structure–altering tectonic activity. The ability to quantify and predict these variations is paramount in the planning of any exploratory drilling program. While the practice of prediction and estimation of reservoir parameters is commonly employed in the petroleum industry, it has not yet been extended to the carbonate aquifer studies in Nevada.

The reliability of a predictive method is generally no better than the reliability of the data base from which it derives its input. In Nevada, three types of data exist which have potential application in hydraulic parameter estimation: long–term aquifer tests from such areas as the Nevada Test Site and Coyote Spring Valley; discharge and chemistry data from carbonate springs; and the broad category of wildcat oil and gas data which includes geophysical logs, lithologic logs, and drill–stem tests (DST's).

While other investigators in the CAP have examined the aquifer test and spring data with various goals in mind, the effort described herein has focused on evaluating the wildcat oil and gas data with respect to its utility in hydraulic parameter estimation.

WILDCAT OIL AND GAS DATA

Since the creation of the State Oil and Gas Conservation Commission in 1953, petroleum operators in Nevada have been required to file full and complete records of all wells drilled in Nevada. From that time (1953) until 1983, the Nevada Bureau of Mines and Geology (NBMG) was charged with maintaining those records. With the creation of the Nevada Department of Minerals in 1983, that agency assumed primary responsibility for oil and gas record keeping. The NBMG, however, has continued to maintain duplicate records on the campus of the University of Nevada in Reno.

To date, over 480 wildcat wells have been drilled in Nevada, and some type of record exists for each one. Due to the often subjective nature of geologic interpretation and the generally proprietary attitudes of petroleum operators, these records frequently contain incomplete and conflicting information.

A complete file for an individual well should ideally include the following items: permit to drill; completion and plugging reports; all logs and tests run; and production records where applicable. Additionally, drill cuttings are available for a number of wells.

Figure 1 is a map of Nevada showing the location of wildcat oil and gas wells with respect to the carbonate rock province.

GEOPHYSICAL LOGS

Traditionally, the most common application for geophysical logs was found in the correlation of specific zones to assist in structure and stratigraphic mapping. With time, however, open hole logs found additional application in defining physical rock characteristics such as porosity, pore geometry, and permeability. Several types of open hole logs are available at the NBMG and were evaluated with respect to possible application in the Carbonate Aquifer Project.

Guidelines for Application

The Paleozoic section in eastern Nevada is dominated by carbonate rocks which are divided into recognizable, if not discrete, stratigraphic intervals by shale

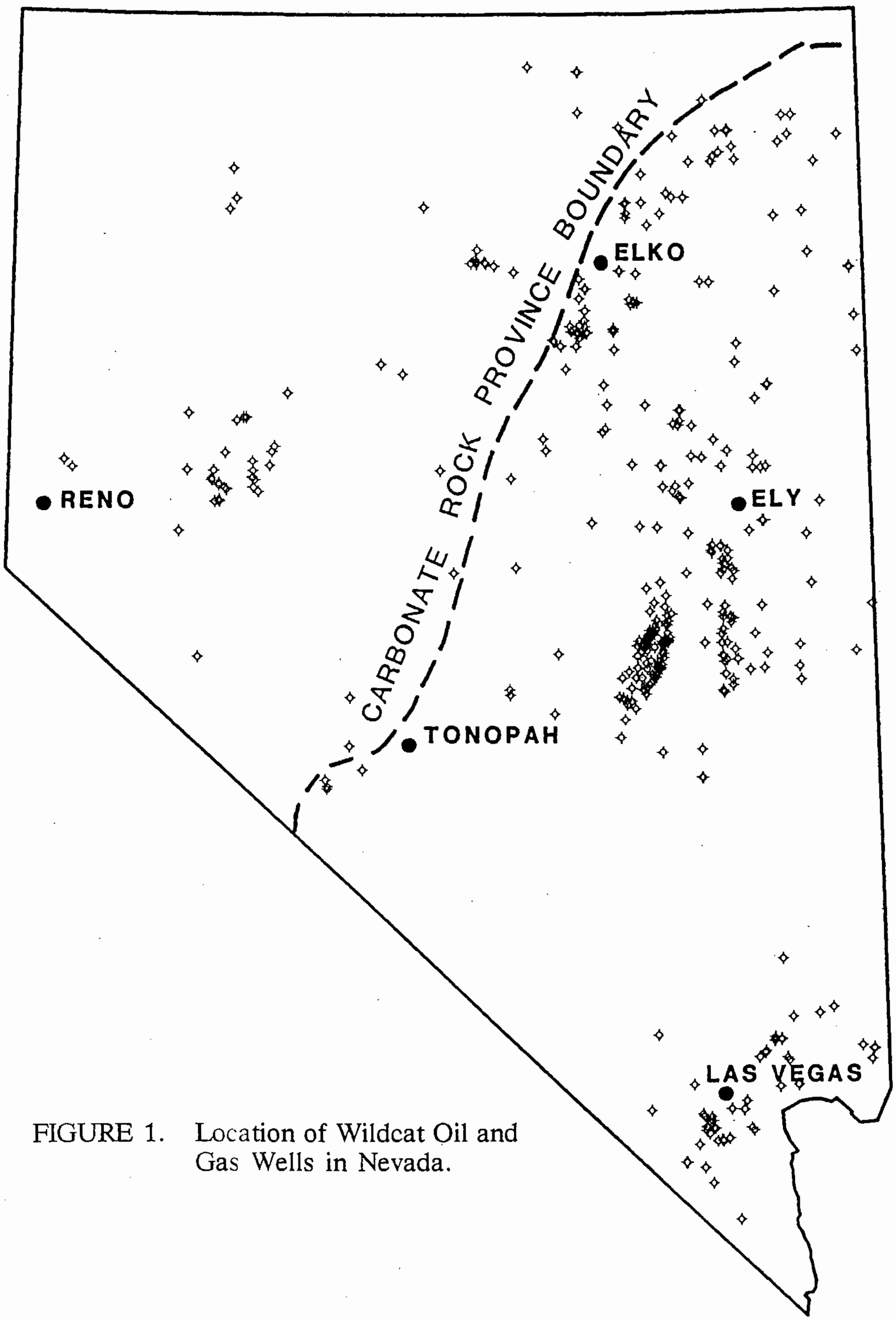

FIGURE 1. Location of Wildcat Oil and Gas Wells in Nevada.

and sandstone marker units. The former group includes the Ely Limestone (Pennsylvanian); Joana Limestone (Mississippian); and the Guilmette Dolomite (Devonian). The latter includes the Chainman Shale (Mississippian) and the Pilot Shale (Devonian).

Examination of the rock descriptions on the logs at the NBMG suggests that identifying individual formations is not an easy task. To develop some guidelines for working with geophysical logs and the Paleozoic rocks in eastern Nevada, three logs from American Stratigraphic Company (AMSTRAT) and the corresponding original material on file at NBMG were examined. These logs include: the American Hunter #1, Black Jack Springs, White Pine County; Northwest Exploration #1, White River, Nye County; and Grace Petroleum Corporation #1, Arrow Canyon, Clark County. Appendix D provides an annotated stratigraphy for these holes. In general, the gross shape of the various logs is cylindrical and, depending on the amount of shale or porosity variations present, may be smooth or serrated (Figure 2). The following discussion will include information from all three boreholes.

Cylindrical-Smooth

Cylindrical-Serrated

FIGURE 2. Idealized Sketches of Geophysical Log Shapes.

Gamma Logs

Probably the single most important log for identifying marker units is the gamma log. The natural gamma count reflects concentration variations in radioactive elements such as uranium, thorium or potassium bearing minerals. Carbonaceous shales and phosphatic shales or sandstones are enriched in uranium. The Chainman Shale in the White River Valley region is a good illustration of this. The upper Chainman has a number of sandstone units interbedded with the shale, and the gamma response, while indicating the presence of shale, is not as high as it is in the lower half of the formation where carbonaceous shale dominates. In some areas, this shale is also phosphatic. A similar increase in the natural gamma response was noted in a well in northern Lincoln County suggesting this might be a useful pattern for recognizing the Chainman in wells in the region. The Battleship Wash formation (Mississippian) at Arrow Canyon is also phosphatic and shows a similar pattern.

The White River Valley boreholes (Black Jack Springs shows a high natural gamma response in the Pilot Shale) commonly do not extend into the lower Paleozoic. Shales in the Pogonip, the upper Cambrian Dunderberg Shale, the middle Cambrian Patterson Pass Shale, and the lower to middle Cambrian Chisholm, Pioche and Cararra shale bearing formations should be detected. In the Arrow Canyon well, the Pogonip, Dunderberg, and Cararra are evident on the gamma log.

The upper Ordovician–Devonian interval is dominated by dolomite. Broadly, this interval gives a cylindrical shape to the geophysical logs, but shaly or permeable horizons will cause some serration. Shaly to sandy intervals show up in the Guilmette, Devil's Gate, Sultan, and Arrow Canyon formations (late Devonian) and at the Sevy–Simonson contact, lower Nevada formation and lower Piute formation (early Devonian). The Eureka Quartzite (middle Ordovician) generally does not have a distinctive natural gamma signature and closely resembles the overlying upper Ordovician dolomite. However, shaly and sandy carbonates of the upper Pogonip directly beneath the Eureka have a distinctive natural gamma response. Unfortunately, none of the wells in this study penetrated a complete lower Ordovician section so that the shale of the Ninemile formation, which should be detected, was not seen. Only the Arrow Canyon well penetrated through the Cambrian. As noted earlier, the upper Cambrian Dunderberg Shale has a strong natural gamma response and separates the upper Cambrian dolomite from the underlying massive carbonate of the Bonanza King formation (Highland Park formation farther north). There is a shaly interval within the Bonanza King that separates the Banded Mountain Member of the upper Bonanza King from the Papoose Lake Member of the lower Bonanza King. This interval can be detected on the natural gamma log.

Neutron, Density, and Sonic Logs

Borehole compensated (compensated for variations in hole size) neutron, density, and sonic logs are commonly part of the geophysical log package. These are useful lithologic indicators as well as measures of porosity. The density log set usually includes a bulk density and a density porosity curve, while the sonic includes a travel time (Δt) and a sonic porosity curve. The sonic porosity measure is sensitive to the matrix porosity, but not to secondary (vug or fracture) porosity. The neutron or density porosity tool is a more accurate measure of total porosity. A secondary porosity index could be calculated from the difference between the neutron (or density) and sonic porosity values. The Δt in shales is lower than in carbonates or sandstones, so shale markers will stand out. However, the natural gamma log seems to pick up thinner markers not evident in the sonic. The bulk density curve also picks up shales and sandstones (lower bulk density), but despite the density difference between limestone and dolomite, these carbonates were not separated.

To make some sense of the shifts in the neutron, density or sonic porosity logs, other logs, such as natural gamma, one of the resistivity logs or the caliper log, should be used in combination. For example, the neutron porosity values will be high in a shale or in a carbonate with secondary porosity. Fracture porosity in the Ely Limestone or the shales in the lower Chainman of the White River Valley illustrate this. Where shale is the cause, the natural gamma or resistivity logs will pick this up. The caliper log has to be looked at carefully because the hole may enlarge in a shale or highly fractured interval; however, if this same interval is highly permeable, a mud cake could form and narrow the hole. No evidence of mud caking in the three boreholes was found. Shales will show low resistivity and a low SP (Spontaneous Potential – shale line) value. Fracture zones, if highly permeable, could show a significant shift in the SP, but this was not observed with the SP curve across the fracture zone in the Ely Limestone (White River Valley).

The Arrow Canyon well has a series of logs, including drill porosity, drilling strength, mud porosity pressure, and mud loss. These were used to define fracture zones. Where these zones occur in carbonate intervals, the neutron porosity curves showed significant increases in value and the caliper log indicated the hole had opened up. In these fracture zones, the drilling strength drops off (psi x 1000) and the mud porosity pressure goes up.

In the low porosity carbonates, both the neutron and the density logs will track together commonly with porosities around 5 percent or less. This is a typical pattern for significant portions of the upper Ordovician–Devonian succession and the middle to upper Cambrian interval. However, portions of these two sequences will show sharp single porosity peaks or serrated zones indicative of significantly higher porosity (note the Arrow Canyon well discussed above). Again, combinations of other logs will generally indicate the cause of the porosity. Only the White River #1 had a sonic porosity log along with a neutron log. Across the fractured portion of the Ely Limestone, the sonic porosity was lower by some 8 to 12 percent than the neutron porosity.

Spontaneous Potential and Resistivity Logs

Spontaneous potential and resistivity logs reinforce data from the other logs. Shales have lower resistivity and carbonates much higher values. Shaly carbonates will have a highly serrated pattern. The SP trace across a unit like the Chainman will show a shale-line effect through the shale intervals, but will be strongly deflected (positive deflection) across the sandstone units (matrix porosity). A similar pattern occurs on the resistivity tracks because the sands have a higher resistivity than the adjacent shales. Except for picking up shaliness (which the gamma, neutron, and sonic logs also do), it was not felt that SP or resistivity logs materially aided in recognizing stratigraphic units or zones of secondary porosity. In the White River #1 well, the zone of fracture porosity in the Ely Limestone was not seen by SP or resistivity, but a combination of neutron, sonic, and gamma logs indicates their presence.

THE DRILL-STEM TEST

Background

Since the 1920's, petroleum geologists have employed the drill-stem test to evaluate zones of unknown potential in a well being drilled. While providing a temporary completion of this zone, a transient pressure test is run and a fluid sample collected from the reservoir. Thus, the DST can supply both petroleum and groundwater geologists with information on three very important subsurface formation properties: fluid chemistry, pressure head, and permeability. Hydrologists, however, have traditionally found limited application of the method. This is due to a variety of reasons, including, but not limited to: a general lack of knowledge concerning the availability and applicability of the technique; the cost of the service (several hundred to several thousand dollars), which is generally prohibitive within the limited budgets in groundwater studies; and a reputation that DST's experience relatively high rates of mechanical failure.

Historically, DST's from petroleum exploration have found their most common hydrologic application in regional groundwater studies (Hackbarth, 1978). Bair et al. (1985) constructed potentiometric maps of the Palo Duro Basin in Texas utilizing initial shut-in pressures; and Orr and Kreitler (1985), using similar data for the same area, analyzed the components of vertical flow from pressure-depth plots.

A less common hydrologic application of the DST has been in the area of hydraulic parameter estimation. Bredehoeft (1965) noted the similarities between the Horner method employed by petroleum geologists, and the Theis recovery method which is commonly used by hydrogeologists for estimating aquifer transmissivities. As will be seen in a later section dealing with this particular application, the data requirements are greater for transmissivity calculations than for potentiometric mapping, and this may explain the discrepancies in frequency of application.

Drill–Stem Testing Tools and Technique

To conduct a drill–stem test, multiple 'tools' are attached to the drill–stem and run into the borehole. Figure 3 shows the tool assembly for a typical open hole, single packer test in an idealized cross-sectional setting. Generally, a minimum of six components, or tools, are necessary to conduct a DST (see Earlougher, 1977). The drill pipe carries the other tools into the hole and serves as a conduit into which the formation fluid may flow during the test. The packer isolates the zone of interest from the rest of the hole and, hopefully, prevents contamination from overlying drilling and formation fluids. The valve assembly serves as the main control for opening or closing fluid flow from the formation. The perforated pipe allows formation fluid to enter the drilling string. The temperature recorder obtains continuous bottom hole temperature readings during the test. The pressure gage–recorders (usually a minimum of two) obtain continuous pressure vs. time data during the test.

Figure 4 is an idealized pressure–time chart showing the events of a typical two–cycle DST. As can be seen from Figure 4, the test can be divided into five distinct phases or periods:

1. The first phase consists of lowering the tool into the hole. The pressure increase, represented by segment AB on the pressure graph, is due to the increase in hydrostatic head caused by drilling fluids. The "noisy" nature of this segment is due to the stepwise procedure of adding drill–pipe as the tool is lowered (Bredehoeft, 1965).

2. The packers are then seated and the tester valve opened (segment BC) for the initial flow period (IFP). The IFP, represented by CD, is generally short (5 to 15 minutes) and will help flush the bottom hole environment of entrapped drilling fluid.

3. The tester valve is then closed for the initial shut–in period (ISIP). The formation pressure is allowed to build–up (i.e., recharge or recover) to the undisturbed formation pressure (segment DE on the curve). This period generally ranges from 15 to 45 minutes.

4. After the ISIP, the valve is opened (EF on chart) and the final flow period (FFP) is begun. During this production period, formation fluid flows into the pipe and as the column of fluid grows, the pressure increases (segment FG on chart). The FFP generally lasts from 1 to 2 hours.

5. After the final flow period, the tester valve is again closed (point G) and the formation pressure is allowed to recover. The final shut–in period (seg-

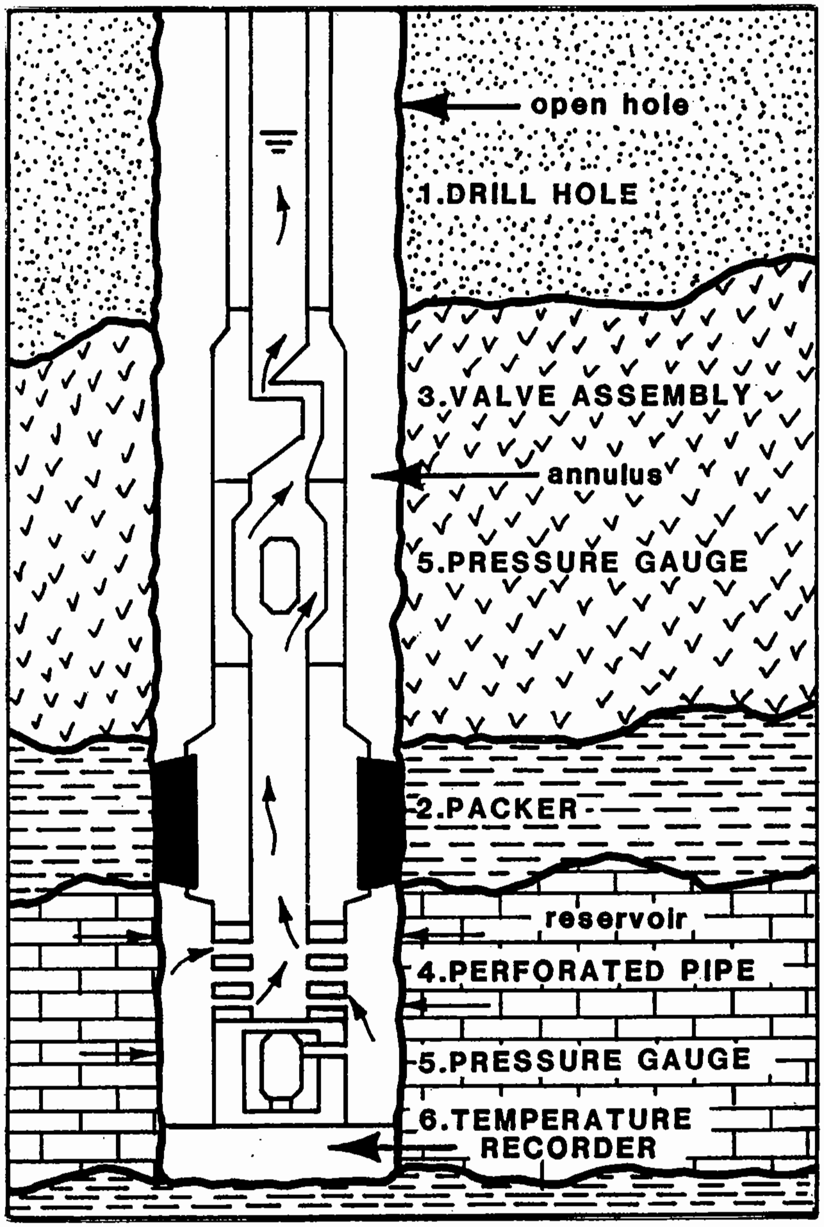

FIGURE 3. DST Tool Assembly in a Typical Cross-Sectional Setting.

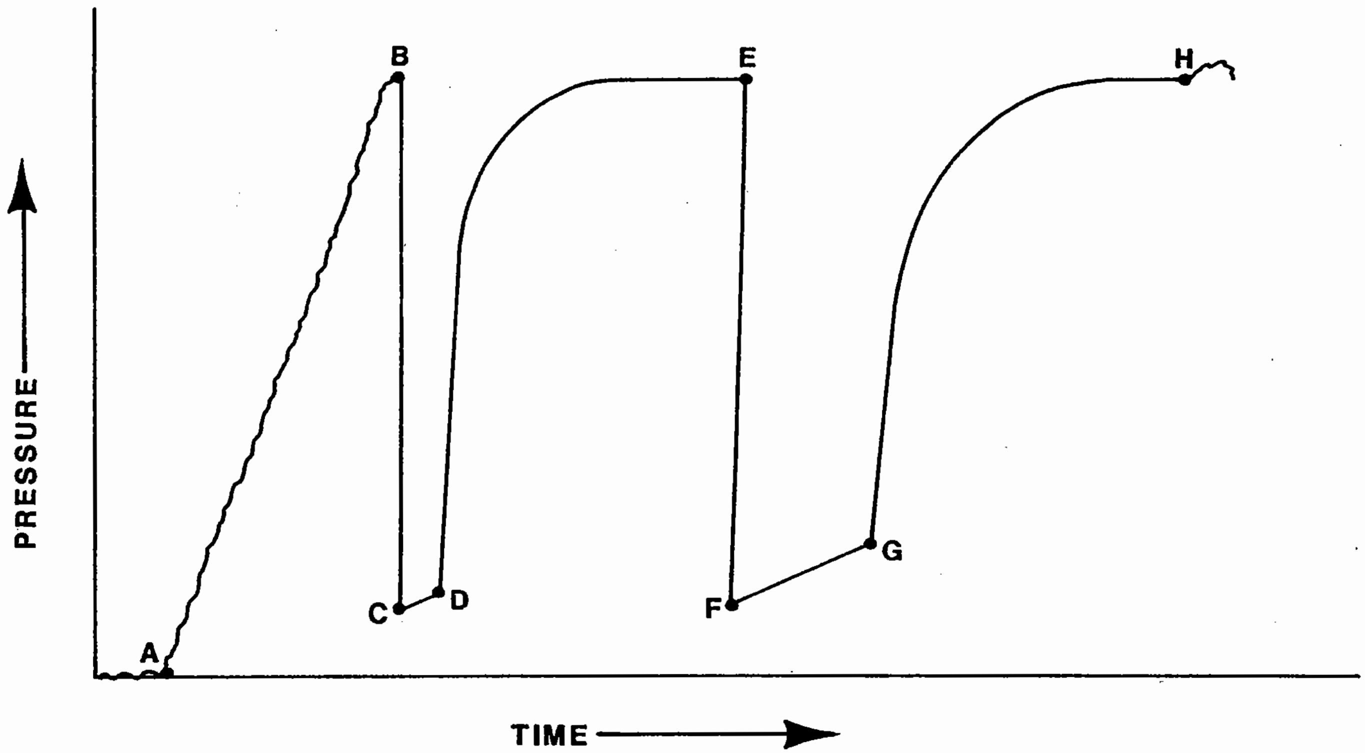

FIGURE 4. Idealized Pressure–Time Chart from a Drill–Stem Test.

ment GH) is analogous to the recovery period of a pump test. Final shut-in periods generally range from 30 minutes to 2 hours.

After the final shut-in period, the packers are unseated (point H) and the pressure becomes a function of the drilling fluid column in the hole. The produced formation fluid remains in the drill pipe and provides a sample from the zone of interest. Additionally, the number of pipe joints filled with fluid are used to compute the total production volume during the flow periods.

DST Data Base

Typically, a complete drill-stem test report will include continuous records of transient pressure changes during both flow and shut-in periods, amount of fluid recovered, bottom-hole temperatures (BHT's), and pertinent fluid properties, including densities and some chemistry. Regrettably, the chemistry data included in most DST records are limited to analysis results for only a few constituents, most notably chloride and bicarbonate. The complete DST report, if present, will be found in the pertinent NBMG well file under the separate cover of the testing company (i.e., Halliburton, Lynes, etc.).

Frequently, the DST records are incomplete and may include only the initial shut-in pressure (ISIP), initial shut-in time (ISIT), final shut-in pressure (FSIP), final shut-in time (FSIT), and the depth interval of measurement. In the NBMG files, this incomplete information can be found in a variety of places; usually the official well completion report, the geologist's report, or Petroleum Information (PI) cards, which are present in almost every file.

Because of the irregularity with which petroleum operators conduct tests, it was impossible to know in advance which file would contain any evidence (complete or incomplete) of DST's in carbonate rocks. Consequently, early in the study, large amounts of time were expended searching through files for which all that was known was the wells were located in an acceptable physiographic region (i.e., the carbonate rock province).

Fortunately, with the recent computerization of the NBMG oil and gas data base (Hess et al., 1987), this task has been made much easier. Personnel at the NBMG have carefully reviewed all well files with respect to information contained therein; this includes, for example, DST's, geophysical logs, and formation top data. The investigator may then request a listing for just those records indicating the existence of DST information. Although the computer listing provides no indication as to the completeness of the DST data, the investigator is at least saved the time and effort of the previously mentioned random search technique.

It should be reiterated that while the petroleum operators are required to submit copies of all tests and logs to the Department of Minerals and NBMG, often only incomplete data finds its way into the records. Due to obvious time limitations, personnel from both agencies are unable to effectively monitor compliance by the operators, and are dependent on individual investigators (e.g., DRI personnel) concerning the omission of particular data. Experience has shown that the Department of Minerals is very responsive to investigator requests for missing DST data. Therefore, a logical next step in this investigation would be the compilation of a comprehensive "shopping list" for those well records which indicate DST's, but contain little or no usable information, and submission of this list to the Department of Minerals.

Transmissivity Estimations

A mathematical method developed by Horner (1951) allows the graphical extrapolation of measured shut-in pressures to the undisturbed, or initial, formation pressure, which is a natural analog to the pressure head term used by hydrologists. The following field conditions are assumed when applying the technique:

1. radial flow to the well;
2. consequent to the above assumption, the aquifer is considered to be areally infinite;
3. the formation fluid is assumed of constant density and dynamic viscosity (i.e., single phase at all times and places);
4. flow assumed horizontal and aquifer thickness constant; and
5. the well fully penetrates the aquifer.

The mathematical relationship between pressure and time can then be stated as:

$$P_w = P_o - \frac{q_{av}\mu}{4\pi kh} \ln\left(\frac{t + \Delta t}{\Delta t}\right) \qquad (1)$$

where: P_w = the measured shut-in pressure at some time, Δt (F/L^2)

P_o = the undisturbed, or initial, formation pressure (obtained graphically) (F/L^2)

q_{av} = the time averaged production rate (L^3/T)

μ = dynamic fluid viscosity (FT/L^2)

k = intrinsic permeability (L^2)
h = formation or aquifer thickness (L)
t = total production or flow time (T)
Δt = time since shut–in or recovery has begun (T)

To obtain the graphical solution to P_o, a semi–logrithmic plot of P_w vs. log (t + Δt)/Δt is constructed (Figure 5). If assumptions 1 through 5 are closely approximated in the field, the points should plot as a straight line. The straight–line portion of the plot is then extrapolated to log (t + Δt)/Δt = 0 and at this point $P_w = P_o$. Additionally, for a given test, both shut–in plots (initial and final) should extrapolate to the same formation pressure (P_o). Deviations from this ideal condition may arise from any one or more of the following (Hackbarth, 1978):

1. aquifer discontinuities (faults, pinch–out, facies change, etc.);
2. change of fluid properties in an aquifer;
3. mechanical failures (packer leaks); and/or
4. insufficient length of shut–in.

Using the technique described by Horner (1951) and Bredehoeft (1965), formation transmissivities can be calculated. Rearranging equation (1) to solve for permeability yields:

$$k = \frac{q_{av}\mu}{4\pi h(P_o - P_w)} \ln\left(\frac{t + \Delta t}{\Delta t}\right) \qquad (2)$$

and further rearranging give us:

$$\frac{kh}{\mu} = \frac{q_{av}}{4\pi(P_o - P_w)} \ln\left(\frac{t + \Delta t}{\Delta t}\right) \qquad (3)$$

where $\frac{kh}{\mu}$ is the coefficient of transmissibility as used by petroleum geologists which is analogous to the transmissivity term familiar to hydrologists.

Converting from natural to common logarithms yields:

$$\frac{kh}{\mu} = T = \frac{0.183\ q_{av}}{(P_o - P_w)} \log\left[\frac{t + \Delta t}{\Delta t}\right] . \qquad (4)$$

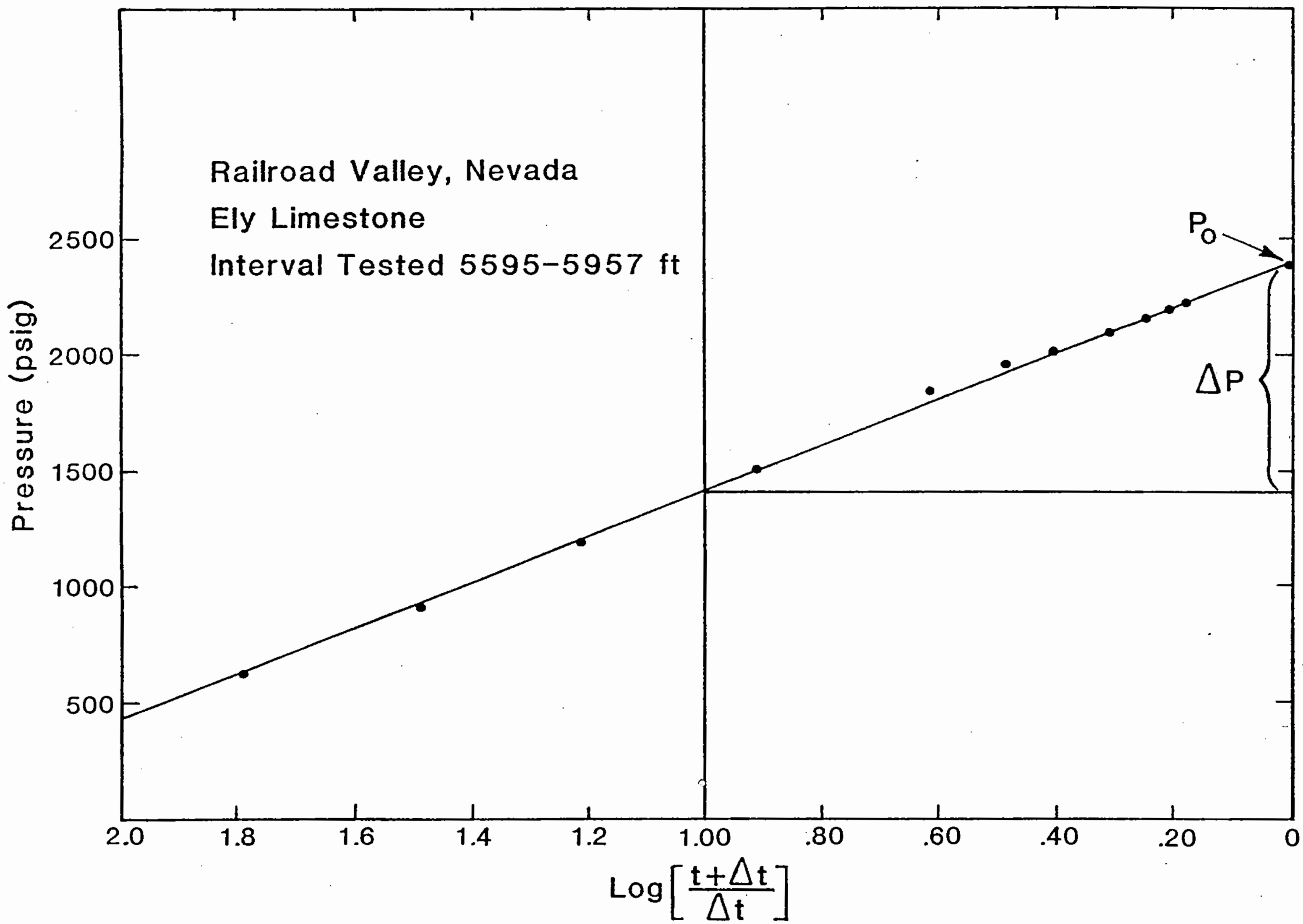

FIGURE 5. Pressure Build-up Graph from a Drill-Stem Test in Eastern Nevada.

Since $\left(\frac{0.183\ q}{P_o - P_w}\right)$ equals the slope of P_w vs. $\log\left[\frac{t + \Delta t}{\Delta t}\right]$, we can simplify equation (4) to:

$$T = \frac{0.183\ q_{av}}{\Delta P} \tag{5}$$

where ΔP is the change in pressure over one log cycle of the straight–line portion of the Horner plot. The time averaged production rate, q_{av}, may be obtained by converting the feet of drill pipe filled with fluid into an appropriate volume (i.e., barrels, gallons, ft^3, etc.), and dividing by the total flow period time.

In contrast to an aquifer test where a well is pumped at a constant discharge throughout the test, the flow rate for a DST may vary considerably during the production period. The reason for this is conceptually simple. During the flow period, rather than removing fluid from the drill pipe as in a pump test, a column of water is allowed to build inside the pipe, which, as it grows, inhibits the flow of fluid out of the formation. This would also explain why we see a slight pressure build–up, as opposed to a drawdown, during the flow periods, thus making it difficult to obtain a specific capacity analog for the DST.

It can now be noted the similarities between equations (4) and (5) and the recovery method developed by Theis (1935):

$$T = Kb = \frac{0.183\ Q}{S'} \log\left(\frac{t}{t'}\right) \tag{6}$$

where: T = transmissivity ($L^2\ T^{-1}$)
K = hydraulic conductivity ($L\ T^{-1}$)
b = aquifer thickness (L)
Q = average pumping rate ($L^3\ T^{-1}$)
S' = residual drawdown (L)
t = time since pumping started (T)
t' = time since pumping stopped (T)

The residual drawdown, S′, is simply the difference between the original, unpumped water level and the partially recovered water level at some time, t′, after pumping has stopped. $\Delta S'$ then, when taken over one cycle on the straight–line recovery plot, is analogous to ΔP in equation (5). A significant difference, however, lies in the fact that $\Delta S'$ represents the difference between two measured

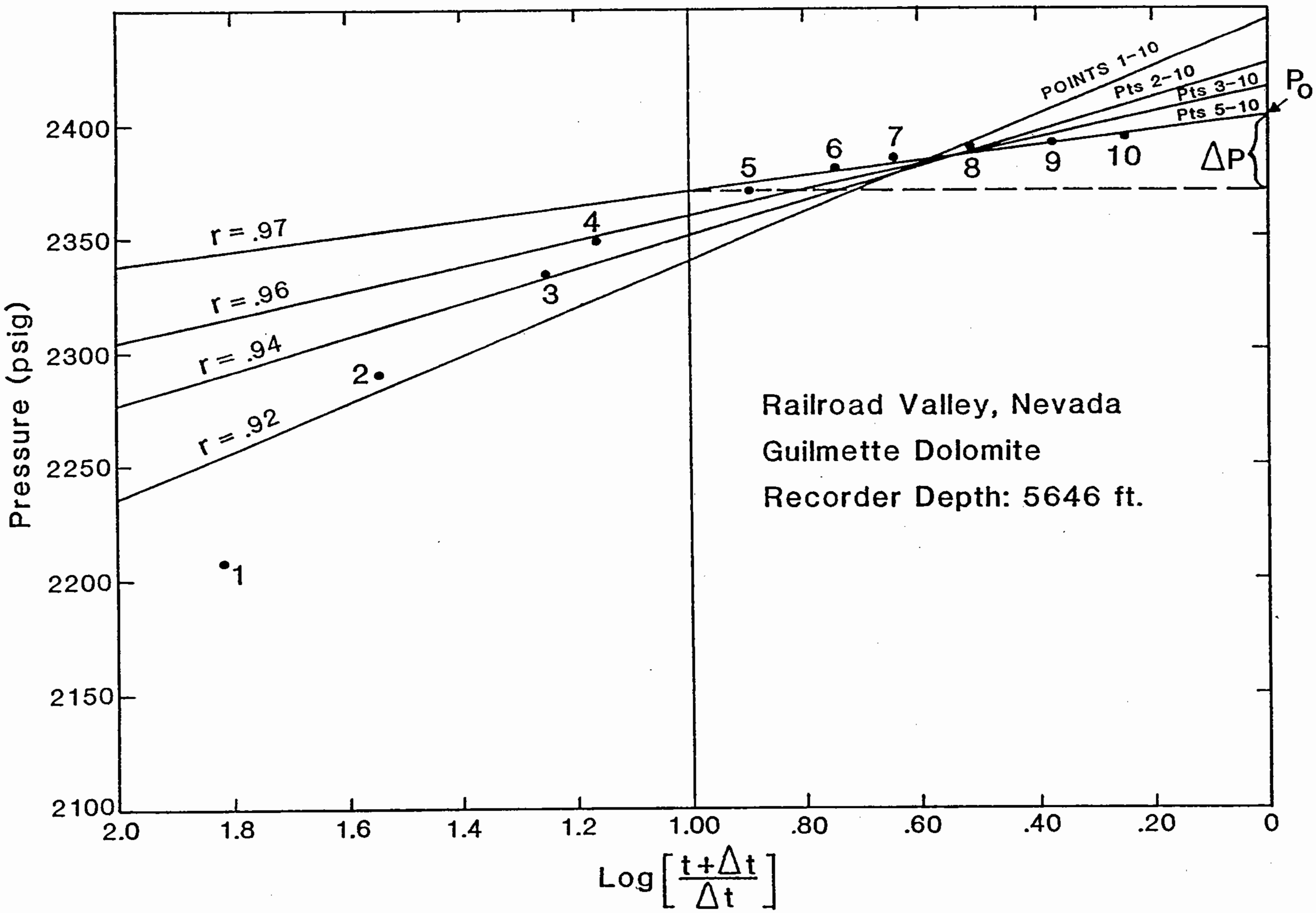

FIGURE 6. Regression Technique for Obtaining Straight-Line Solution to a Pressure Build-up Graph.

water levels, and ΔP is often the difference between one measured value (P_w) and some graphically obtained (extrapolated) pressure value, P_o.

It is also noteworthy that the viscosity term, μ, employed by petroleum engineers is routinely neglected in groundwater studies. While this is a convenient and often necessary simplifying assumption, omission of μ could be a significant source of error when dealing in deep hydrologic systems, especially where temperature and chemical factors have an appreciable effect on viscosity. Due to the incomplete nature of fluid property data in DST reports, however, μ was assumed equal to unity (1 centipoise) for all transmissivity calculations reported herein. When one considers the variable nature of aquifer parameters and the large potential for error in the measurement technique, the effect the viscosity assumption on transmissivity calculations is probably minimal.

Sample Problem

Pressure and recovery data from a drill–stem test in Railroad Valley will be used to illustrate the mathematical method for estimating transmissivities. The test was conducted in the Devonian Guilmette formation within the Grant Canyon Field. The recording gage depth was 5,646 feet, however, the interval tested was not reported. The formation was allowed to flow initially for 15 minutes, shut–in for 30 minutes, opened for a 120–minute flow period, then shut–in for a final 180–minute period. The resulting flow period is therefore 135 minutes. Table 1 is a listing of the incremented pressure data for the final shut–in period. Figure 6

TABLE 1. PRESSURE TIME DATA FOR RAILROAD VALLEY DST SAMPLE PROBLEM.

Δt (minutes)	Shut–in Pressure (PSIG)	$\log\left(\frac{\Delta t + t}{\Delta t}\right)$
0	879	
1	2076	2.15
2	2208	1.83
4	2290	1.54
8	2338	1.25
10	2348	1.16
20	2372	0.89
30	2380	0.74
40	2385	0.64
60	2388	0.51
100	2391	0.37
180	2393	0.24

uses the final shut–in data to illustrate a graphical technique for obtaining the initial, undisturbed formation pressure, P_0. As can be seen, selecting a best fit straight line for the total points is not always an easy task. However, by constructing a series of regression lines using successively fewer points each time, solutions can be developed for the latter straight–line portion of the curve by using only the final 4 or 5 points (Bredehoeft, 1965).

Because the theoretical development dictates using the change in pressure (ΔP) over one log cycle on this graph, those points which fell in the final log cycle were generally used in constructing regression lines. Thus, using this technique for the sample problem, a regression line based on points 5 through 10 yielded a ΔP value of 33 psig per log cycle.

The production portion of the test resulted in a total 'recovery' of 1,954 feet of fresh water. The volume of fluid produced during a test is determined from the length of drill pipe filled with fluid. The drill string is generally composed of two different types of pipe: 1) drill collars used for weighting near the bottom on the string; and 2) normal drill pipe. For this test, there were 500 feet of drill collar with an inner–diameter (ID) of 2.76 inches and the remainder was normal drill pipe with an ID of 3.82 inches. The volume of recovered fluid was:

$$V = \pi \left(r_1^2 L_1 + r_2^2 L_2 \right)$$

where:
- V = total volume of fluid recovered (L^3)
- r_1 = inside radius of drill collar
- L_1 = length of drill collar containing fluid
- r_2 = inside radius of drill pipe
- L_2 = length of drill pipe containing fluid

$$\therefore V = \pi \left[(.013\ ft^2 \cdot 500\ ft) + (.025\ ft^2 \cdot 1454\ ft) \right]$$
$$= 135\ ft^3\ (24\ barrels;\ 1007\ gallons)$$

Recalling the earlier discussion concerning the time averaged production rate, we obtain q_{av} thusly:

$$q_{av} = \frac{135\ ft^3}{135\ minutes} = 1.0\ \frac{ft^3}{\text{min}}\ or\ 1440\ \frac{ft^3}{day}$$

where 135 minutes is the total flow or production time. Substituting ΔP and q_{av} into equation (5) yields the transmissivity:

$$T = \frac{0.183 \ (1440 \ ft^3/day)}{33 \ psi. \cdot \left(\frac{1}{.433 \ psi/ft} \right)} = 3.46 \ \frac{ft^2}{day} \ .$$

ANALYSIS OF RESULTS

Using the technique described above, carbonate rock transmissivities have been estimated at 20 wildcat wells in eastern Nevada. Although NBMG records indicate DST's have been conducted at over 60 wells in the region currently under study, incomplete data has permitted transmissivity estimations at only the aforementioned 20 points. Figure 7 shows the distribution of all 60 wells with respect to the Railroad Valley (Roth, 1988) and White River Valley (Kirk, 1987) flow systems. Table 2 provides a partial list of the data pertinent to the transmissivities which have thus far been calculated. Appendix A and B provide a complete list of DST data for those well records which were reviewed for this study.

At this stage of the study, a detailed statistical analysis of transmissivity data is precluded by the small number of 'samples' which are available. However, some routine methods have been applied so that the reader may more easily visualize any trends which might exist in the current set.

Figure 8, for example, is a frequency histogram of the estimated transmissivities distributed by geologic formation. Included in Figure 8 are the formation means ($\overline{T}$), standard deviations (σ), and ranges, respectively.

Although the primary focus of this study is on the Paleozoic rocks of eastern and southern Nevada, the Tertiary Sheep Pass formation is included here because it is often confused with the Joana and Ely Limestones. It is not clear whether the source of confusion is lithologic or stratigraphic ambiguities, however the reader will note the statistical similarities between the Ely Limestone and those samples grouped under the Sheep Pass.

Assessing the drill–stem test transmissivities with respect to their utility in a hydrologic study necessitated the comparison with transmissivities derived from aquifer tests conducted in carbonate rocks. Figures 9a and 9b shows the frequency distributions of two transmissivity data sets: those computed from DST's in eastern Nevada carbonate rocks and another group which were estimated from pump tests in eastern and southern Nevada carbonates. Listed also (Table 3) are the means, standard deviations, and coefficients of variation (CV).

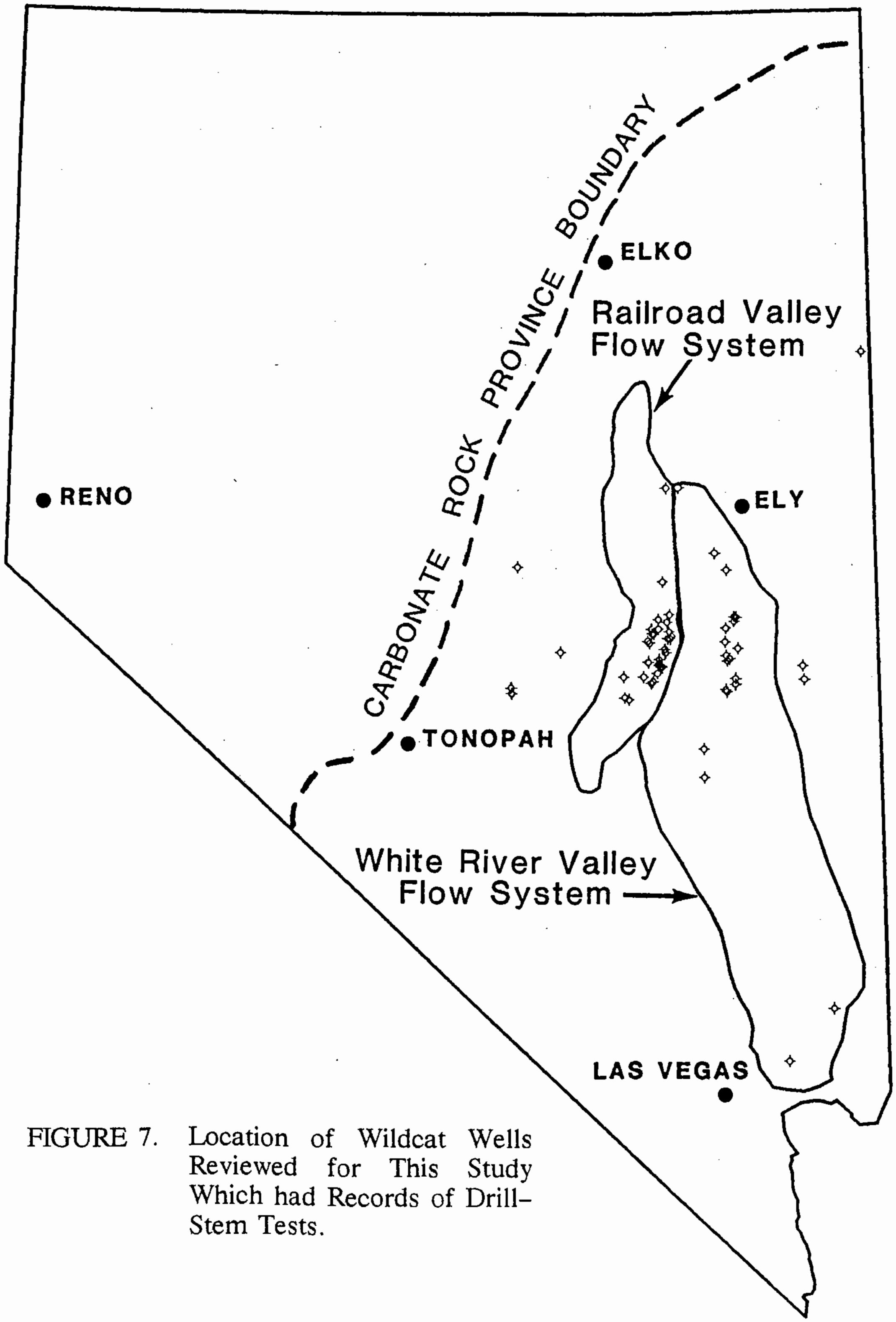

FIGURE 7. Location of Wildcat Wells Reviewed for This Study Which had Records of Drill-Stem Tests.

TABLE 2. HYDRAULIC CONDUCTIVITY AND TRANSMISSIVITY DATA FROM 20 DRILL-STEM TESTS.

NBMG Permit #	General Location	Formation	T(ft^2/day)	K(ft/day)
241	Railroad Valley	Ter. Sheep Pass	6.0×10^{-1}	2.4×10^{-2}
270	South White River Valley	Miss. Joana	8.2×10^{2}	4.0
272	Mormon Mesa	Perm. Kaibab	7.0×10^{-2}	1.4×10^{-3}
274	White River Valley	Ter. Sheep Pass	7.4×10^{-3}	7.4×10^{-5}
308	White River Valley	Penn. Ely	8.0×10^{-1}	8.7×10^{-3}
308	White River Valley	Penn. Ely	9.2×10^{-2}	1.6×10^{-3}
316	Railroad Valley	Dev. Guilmette	4.0	0.3
325	Railroad Valley	Penn. Ely	6.2×10^{-2}	3.1×10^{-4}
326	Railroad Valley	Dev. Guilmette	1.5×10^{1}	0.2
343	Railroad Valley	Dev. Guilmette	3.5×10^{2}	7.6
353	Railroad Valley	Dev. Simonson	8.5	8.5×10^{-2}
374	Railroad Valley	Dev. Guilmette	3.4	ND
375	Railroad Valley	Dev. Guilmette	2.3×10^{2}	.4
376	Railroad Valley	Dev. Guilmette	5.1×10^{2}	1.9×10^{1}
400	Railroad Valley	Dev. Guilmette	4.6×10^{2}	4.6
411	Monitor Valley	Undif. Pal. Carb.	6.9	5.6×10^{-2}
419	Railroad Valley	Ter. Sheep Pass	5.3×10^{-4}	9.3×10^{-6}
478	White River Valley	Ter. Sheep Pass	4.5	3.5×10^{-2}
480	Railroad Valley	Miss. Joana	8.4	1.6
482	Railroad Valley	Dev. Guilmette	6.2	0.2

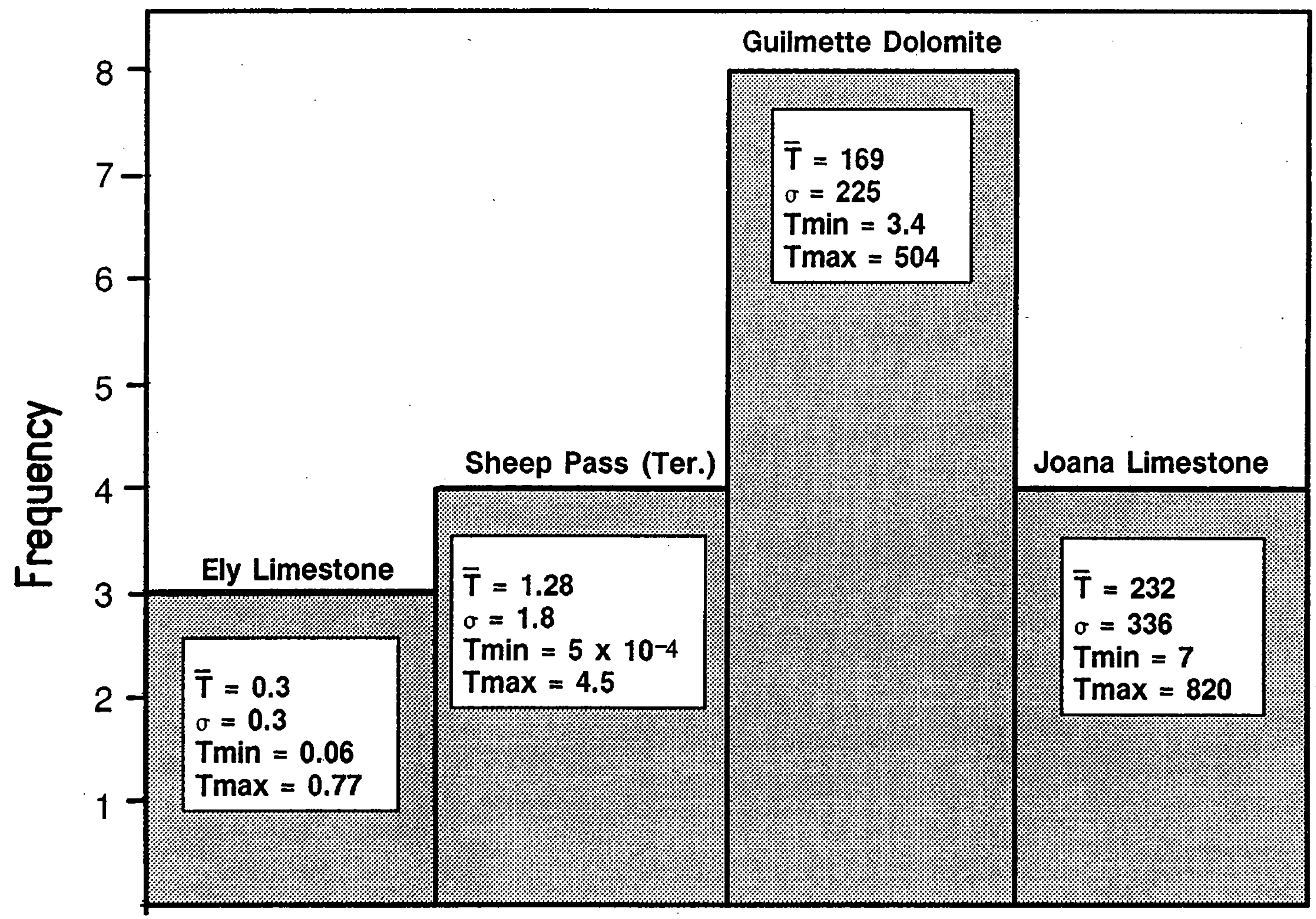

FIGURE 8. Distribution of Transmissivities (ft^2/day) by Formation.

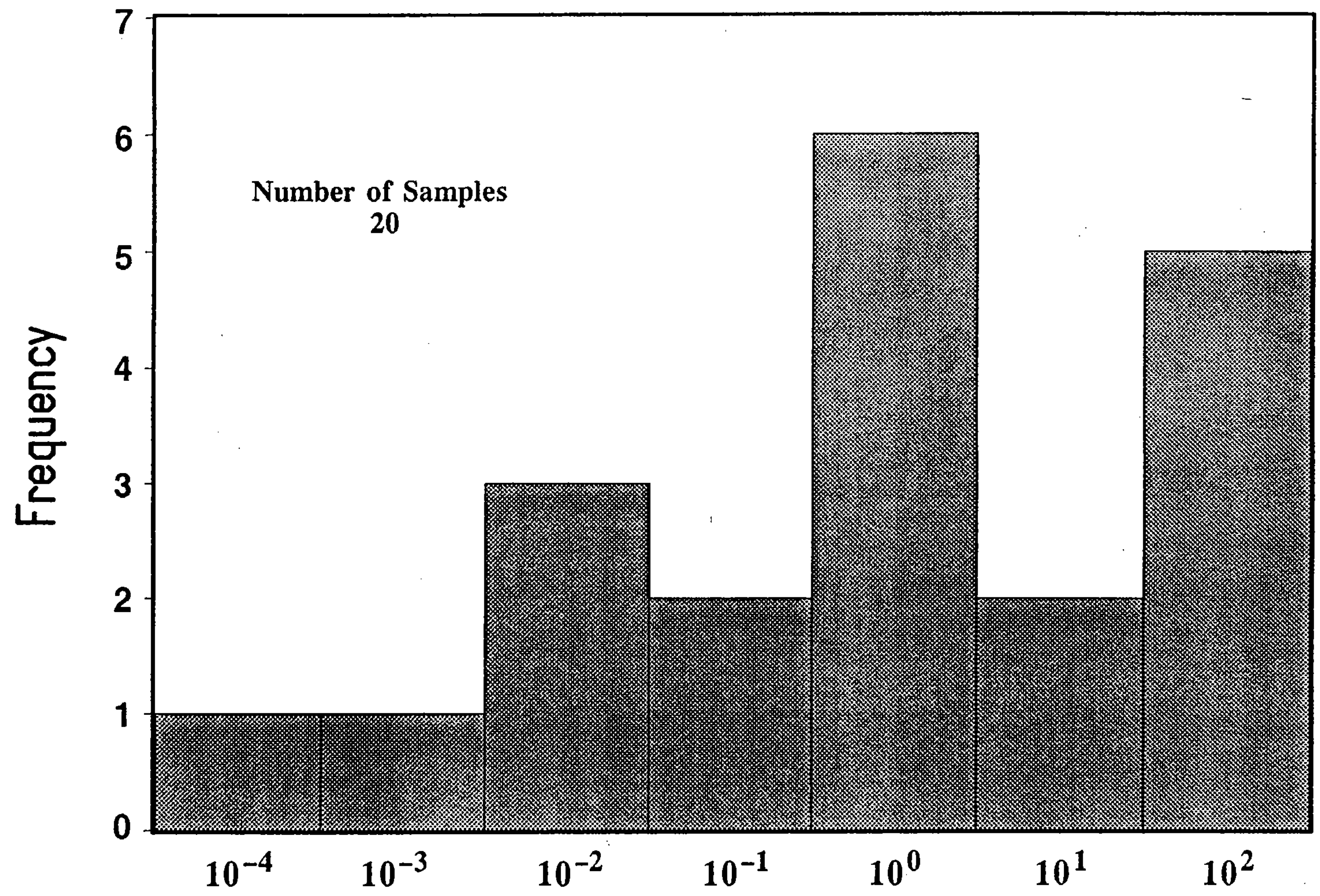

FIGURE 9a. Carbonate Rock Transmissivities (ft2/day) from 20 Wildcat Wells in Nevada.

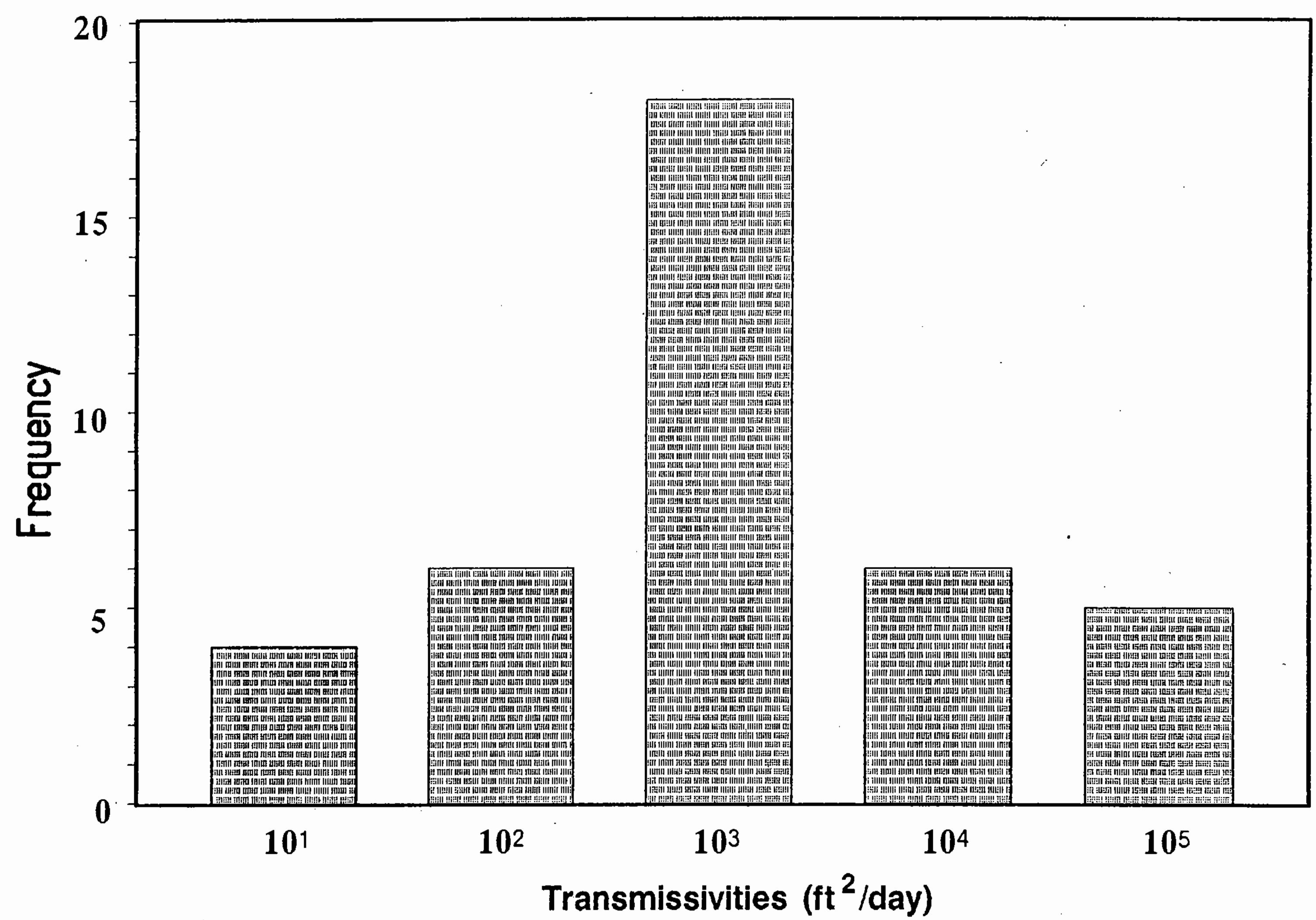

FIGURE 9b. Estimated Transmissivities from 38 Aquifer Tests in Carbonate Wells in Nevada (U.S.G.S. Unpub., 1987).

TABLE 3. SUMMARY STATISTICS FOR TRANSMISSIVITIES ESTIMATED FROM 20 DST'S AND 39 PUMP TESTS. ALL UNITS ARE IN FT^2/DAY.

	Mean ($\bar{x}$)	Stan. Dev. (σ)	Min.	Max.	CV[$(\sigma/\bar{x}) \cdot 100$]
DST's	125	231	.001	822	184
Pump Test	14,853	44,920	10.	254,010	302

Although the CV has no real statistical function, it can serve as a relative guide for determining the number of samples needed to obtain a "reliable" statistical analysis of a given parameter. Generally speaking, parameters like bulk density or particle size distribution have low CV's (10 to 40 percent) and require as few as 20 samples for statistical analysis. Hydraulic conductivities and transmissivities, on the other hand, have CV's ranging from 100 to 200 percent and can require up to 1,000 samples (Warwick and Nielsen, 1980) to obtain reliable results.

While the scope of many studies precludes the collection of 1,000 transmissivity measurements, the potential for error which is inherent in the measurement technique should dictate particular caution on the part of investigators attempting to analyze smaller groups of transmissivity data.

In comparing DST transmissivities with those estimated from pump tests in carbonate rocks (Figures 9a and 9b), several potential sources of error and/or bias in the DST method are suggested. As the reader can see from comparing the two frequency distributions, the transmissivities estimated from pump tests have significantly higher values than those from DST's.

Many of the potential sources of error are a result of violating assumptions on which the theoretical Theis/Horner developments are based. However, there are additional "procedural" factors inherent in the drill-stem test which may tend to bias T and K estimations in a generally negative (low) manner.

Most prominent among the assumption violations may be the failure to achieve full formation penetration and thus, not satisfy the horizontal flow requirement. Failure to fully penetrate is generally a result of one of the procedural biases alluded to above. To illustrate, the reader is referred to Figure 10 which shows an idealized cross-section made up of hydrocarbon traps penetrated by wildcat wells. Due to the sequential relationship between oil, water, and the upper confining caprock, the so-called "target zone" as defined by the site geologist will often be in the very upper portion of the carbonate formation. As a result, the partially

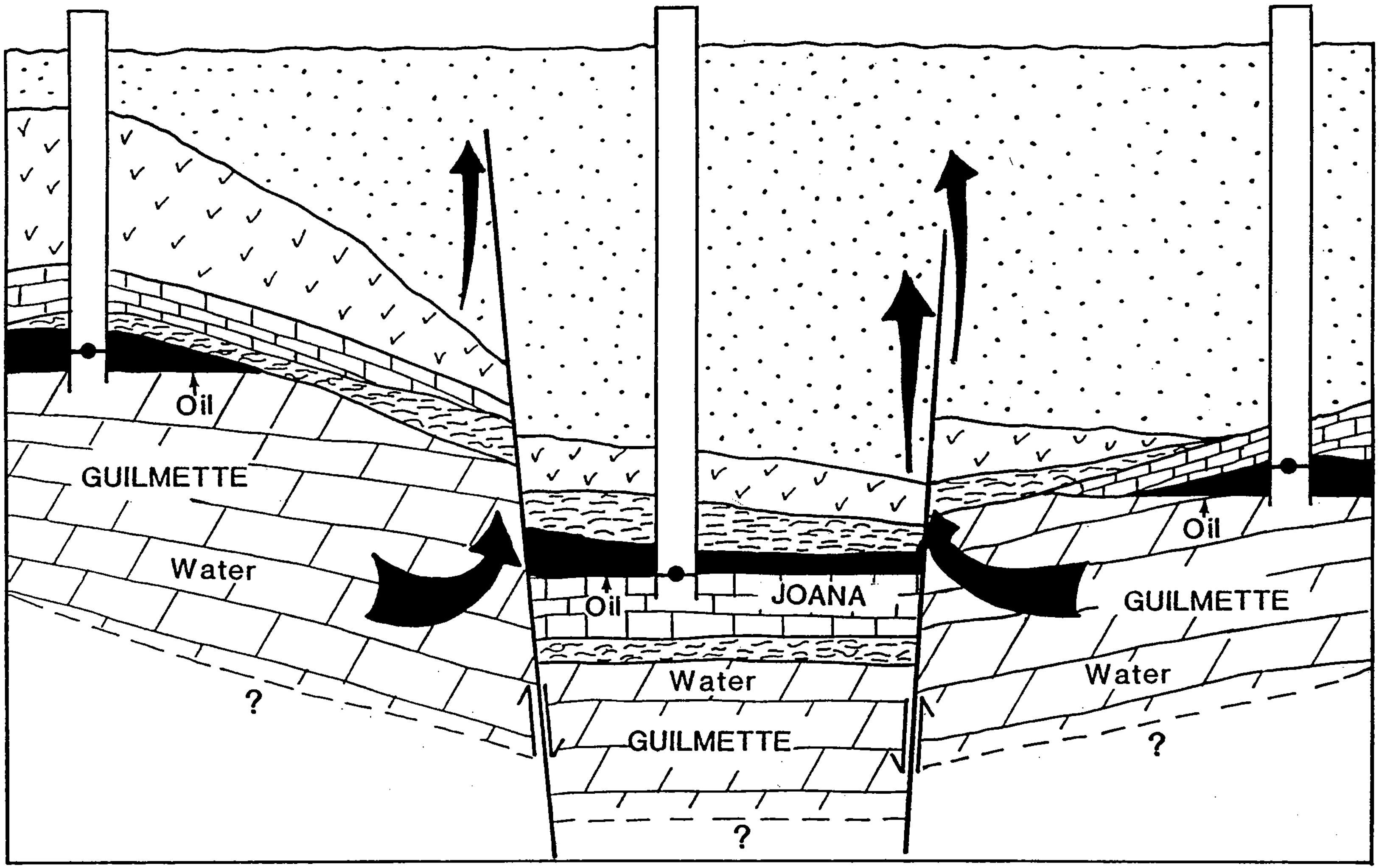

FIGURE 10. Idealized Sketch of Relationship Between Location of Drill-Stem Test and Total Formation Thickness.

penetrating scenario described in Figure 10 is frequently observed in the field situations.

In a pumped well, the effects of partial penetration are generally realized in the form of increased head losses and, subsequently, drawdowns in the vicinity of the well. Thus, in the pumping scenario, partial penetration will limit the estimated transmissivity by virtue of the larger drawdown term in the equation:

$$T = \frac{0.183\ Q}{\Delta S}$$

where these terms are defined in equation(6).

In the drill–stem test, however, partial penetration will often result in a smaller production, or q, value, particularly in the absence of significant upward gradients. The mathematical result in the above equation then is roughly equivalent to the pumping scenario since transmissivity values are directly proportional to q and will thus be smaller as a result of lower production rates.

Since transmissivity is also a function of the aquifer thickness, b, one might be inclined towards simply multiplying the computed K values by the total estimated aquifer thickness to obtain a total formation transmissivity. This, however, brings up another potential bias in the oil field practice of conducting DST's in the upper portion of a carbonate formation.

Field observations and discussions with other investigators suggest a relationship between carbonate rock fracture permeability and the location of the fractures relative to the overlying stratigraphy. Dettinger (personal communication, 1988), for example, has noted in field observations that fractures in carbonate rocks tend to become increasingly filled with muds and clays in direct proportion to their proximity to the stratigraphically younger shale beds; i.e., due to the filling in of carbonate fractures by either the parent or weathering by–product shale material, permeabilities may be greatly reduced in the stratigraphically upper portion of the carbonate formation.

Schneider (personal communication, 1988) has noted a similar relationship between fractured carbonate rocks overlain by Tertiary sedimentary and volcanic rocks in eastern Nevada. In this scenario, major downfaulting of carbonate blocks was followed by deposition of younger sediments which tend also to fill the stratigraphically higher fractures with fine-grained material, thereby decreasing the secondary permeability in the vicinity of the Paleozoic–Cenozoic contact.

While the depositional mechanisms necessary to complete the shale/carbonate scenario are more difficult to visualize than the second, Cenozoic/Paleozoic scenario, both have provided an impetus for looking at this problem more carefully. Analysis of computed transmissivities with respect to proximity of overlying contact, however, failed to reveal any consistent relationship between the two. Obviously, the small size of the current data base is an obstacle when attempting this sort of multi-variate analysis, and it is anticipated that an expanded data set would more readily reveal any trends which may exist.

An additional potential bias may result from the way that DST's are "called" in the field. A major factor in the geologist's decision to order a DST is the presence of trace hydrocarbons on drill cuttings as they are observed at the surface. Schneider (personal communication, 1988) speculates that it may be the less permeable formation cuttings that are capable of retaining trace hydrocarbons on the journey from hole bottom to land surface. Conversely, it was also speculated that more porous or permeable cuttings would be less likely to retain any hydrocarbons in the drilling mud environment from hole bottom to land surface. Consequently, it is possible that a preponderance of DST's are conducted in zones where the porosities and permeabilities, relative to other zones, are sufficiently low to allow for the retention of hydrocarbons.

Another factor which may influence transmissivity calculations is the duration of production or flow periods during a drill–stem test. The average length of a flow period for a DST is about 80 to 100 minutes. Aquifer tests, however, may be run for as long as 30 days or more. The average length of the pump tests described in Figure 9b is 62 hours, or about 2.5 days. The potential effect of this "procedural bias" on the computed DST transmissivities is not immediately obvious.

With aquifer (pump) tests, it is known that by pumping for extended periods of time (greater than one day), the likelihood of realizing the delayed effects of certain aquifer properties is increased. Examples would include recharge boundaries, no–flow boundaries, and primary porosity and/or permeability features. Since any of these phenomena, if encountered, may affect the time–drawdown curve, we would expect an ancillary result in the transmissivity calculations.

Conversely, one would expect that the relatively brief flow periods for DST's preclude the realization of certain "delayed effects". In the case of recharge or constant head boundaries, the resultant effect would be to depress transmissivities which would otherwise be enhanced by encountering a recharge boundary. However, in the case of a no–flow boundary (i.e., a fault), estimated DST transmissivities may be unrealistically high if the flow period was not long enough to realize the effects of this barrier to flow.

The previous discussion points out certain procedural aspects of DST's which may influence transmissivity estimations relative to transmissivities derived from pump tests. Most of the effects would seem to result in lower DST estimations, and the comparative frequency distributions in Figures 8a and 8b would support such an assumption. One should bear in mind, however, that while the two data sets from Figure 9 were obtained from carbonate rocks in Nevada, they really represent two different physiographic regions. The DST data were derived primarily from White River and Railroad Valleys and, on balance, represent a classic Basin and Range setting. Conversely, much of the pump test data were taken from extreme southern Nevada (Amargosa Desert, Coyote Spring Valley) and as such, represent the structurally complex transitional region comprised of the Sevier orogenic belt. Consequently, the contrast between data sets is not really an "apples to apples" comparison and thus, should not be treated as such.

SUMMARY AND CONCLUSIONS

Variations in the hydraulic conductivity of the carbonate rocks of eastern Nevada suggest that techniques must be developed to predict aquifer parameters in this province. The main sources of data which will provide the first steps in this process are the following: 1) long-term pump tests from southeastern Nevada; 2) discharge and chemistry data from carbonate springs; and 3) the broad category of wildcat oil and gas data in Nevada.

The wildcat oil and gas data on file at the Nevada Bureau of Mines and Geology (NBMG) includes records of over 480 wells drilled since 1953. While many of these records contain incomplete and conflicting information, many others provide valuable data from geophysical logs and drill-stem tests (DST's).

Geophysical logs on file at NBMG include natural gamma, neutron, density, sonic, spontaneous potential (SP), and resistivity logs. Natural gamma logs are an important tool in identifying key marker units in the stratigraphic column. While useful as lithologic indicators also, the neutron, density, and sonic logs all provide indirect measurements of primary or secondary porosity. SP and resistivity logs serve mainly to reinforce data from other logs.

The DST can provide a direct measurement of three important subsurface formation properties: 1) fluid chemistry; 2) pressure head; and 3) permeability. Regrettably, the fluid chemistry data are of such an incomplete nature that is of little use in groundwater studies. Analysis of pressure head data, however, can yield important information in the hydrodynamics of local and regional flow systems. Additionally, complete records of pressure-time data enables the calculation of hydraulic conductivity (K) and transmissivity (T) values.

Review of over 100 wildcat oil and gas files at NBMG revealed complete DST records for only 20 of those wells. Transmissivity calculations at these wells yielded highly variable and conflicting results. Comparison of DST transmissivities with those estimated from aquifer tests indicate that the DST technique may underestimate transmissivities by several orders of magnitude relative to pump test values. Several sources of bias inherent in the DST technique have been suggested to help explain this trend. Most notable was the tendency to conduct DST's at the upper portion of a carbonate formation, thereby violating the full penetration assumption and possibly testing in a zone of reduced permeability due to filling in of fractures.

Detailed statistical analysis of the current data set is precluded by the small number (20) of samples. As project efforts began to focus further to the northern portion of the state, the DST data base should continue to expand, thus facilitating the prediction of reservoir parameters in areas where little or no data are available. Additionally, future efforts should also attempt to obtain complete DST records where tests are indicated but data is omitted from the NBMG file.

Drill–stem tests conducted by petroleum operators offer a potentially inexpensive method for estimating hydraulic parameters (T and K) in the carbonate rock province. An enhanced data base should allow for comparing DST values with those derived from pump tests and thus reveal the utility of the technique in a hydrologic study.

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APPENDIX A

NAMES AND LOCATIONS OF WILDCAT WELLS

Explanation:

Lat. and Long.: Latitude and Longitude were obtained by converting the township–range designation commonly employed in petroleum industry.

Spud – Completion: These are the dates for drilling start–up (spud) and completion, when the total depth was reached.

LSE: Land Surface Elevation, in feet above mean sea level.

Depth: The total reported depth of the well, in feet below land surface.

NBMG Permit #	County	Operator	Hole Name	Lat.	Long.	General Location	Spud	Completion	LSE	Depth
2	White Pine	Gulf Refining	Dennison Federal No. 1	40.11	114.10	Goshute Mtns		3/1/54	5504	4502
11	Nye	Shell Oil Co.	Eagle Springs Unit No. 3	38.52	115.54	Railroad Valley	6/29/54	8/2/54	4783	6038
18	Nye	Shell Oil Co.	Lockes Unit No. 1	38.58	115.66	Railroad Valley		3/19/55	4729	7324
20	Nye	Shell Oil Co.	Eagle Springs Unit No. 58-26	38.61	115.53	Railroad Valley	4/13/55	5/28/55	4770	8300
35	White Pine	Standard Oil of CA	County Line Unit No. 1	38.72	115.05	White River Valley	6/23/57	8/28/57	5486	4850
48	Nye	Shell Oil Co.	Eagle Springs Unit No. 81-35	38.59	115.53	Railroad Valley	1/23/61	3/3/61	4781	7805
63	Nye	Shell Oil Co.	Eagle Springs Unit No. 45-5	38.49	115.59	Railroad Valley	11/8/61	2/5/62	4723	8587
74	White Pine	Suntide Petroleum	Nevada Federal A No. 1	39.41	115.52	Newark Valley	7/13/64	9/13/64	6588	7984
75	White Pine	Empire State Oil	Government No. 1	38.72	115.04	White River Valley	9/22/64	10/10/64	5625	3581
82	Nye	Western Oil Lands	Pennington Federal No. 3	38.60	115.51	Railroad Valley	6/3/65	9/6/65	4825	6570
95	Lincoln	Gulf Oil Corp.	Nevada Federal CM No. 1	37.85	115.27	Coal Valley	2/3/66	3/7/66	4940	2434
103	Nye	Trans Western	Eagle Springs Unit/ Pennington-Texota Unit No. 1	38.60	115.50	Railroad Valley	12/30/66	3/18/66	4877	4420
106	Nye	Gulf Oil Corp.	Duck Unit No. 1	38.41	115.70	Railroad Valley		7/21/67	4716	6553
109	White Pine	Tenneco Oil Co.	Illipah Federal No. 1	39.41	115.43	White Pine Range	7/5/67	8/29/67	7520	7620
113	Nye	Gulf Oil Corp.	Anderson 'D' Federal No. 1	38.48	115.66	Railroad Valley	11/26/67	12/23/67	4707	7800
118	Nye	Gulf Oil Corp.	Gose 'FQ' Federal No. 1	38.39	115.06	White River Valley		6/22/68	5283	3980
119	Nye	Gulf Oil Corp.	Gose 'DL' Federal No. 1	38.56	115.03	White River Valley	6/30/68	7/22/68	5437	7067
120	White Pine	Gulf Oil Corp.	Gose 'DQ' Federal A No. 1	38.74	115.11	White River Valley	8/1/68	8/22/68	5382	4957
122	Nye	Gulf Oil Corp.	Nevada 'DK' Federal No. 1	38.47	115.59	Railroad Valley	8/8/68	8/30/68	4717	7188
125	Nye	Gulf Oil Corp.	Gose 'EU' Federal No. 1	38.34	115.36	White River Valley	9/15/68	10/14/68	5202	5690
126	Nye	Gulf Oil Corp.	Gose 'CD' Federal No. 1	38.70	115.05	White River Valley	10/8/68	11/5/68	5469	4092
128	Nye	Gulf Oil Corp.	Russell - Federal No. 1	38.65	115.12	White River Valley	10/23/68	11/12/68	5324	6150
130	Nye	Gulf Oil Corp.	Standard of CA, Federal No. 1	38.51	115.13	White River Valley		1/12/68	5255	4350
151	Nye	Tenneco Oil Co.	USA - Shingle Pass No. 1	38.59	115.13	White River Valley	5/27/71	7/28/71	5301	6333
179	Nye	NW Exploration Co.	White River Valley No. 1	38.49	115.10	White River Valley	7/6/76	9/10/76	5240	10473
183	Nye	NW Exploration Co.	Blue Eagle No. 1	38.64	115.52	Railroad Valley	11/24/76	12/24/76	4868	9040
209	Nye	Texaco	Munson Ranch No. 24-1	38.63	115.63	Railroad Valley	8/18/77	3/20/78	4770	5600
241	Nye	NW Exploration Co.	Currant No. 1	38.70	115.53	Railroad Valley	9/28/78	10/19/78	4892	7800
244	Nye	Ferguson & Bosworth	Munson Ranch No. 11-23	38.65	115.64	Railroad Valley	12/5/78	12/19/78	4820	5020
261	Nye	Texaco	Duckwater Cr. No. 8-12	38.66	115.59	Railroad Valley	5/31/79	7/16/79	4790	6910
270	Lincoln	Amer. Quasar Petro.	Adobe Federal 19-1	38.01	115.28	White River Valley	10/79	10/79	5012	7706
272	Clark	Mobile Oil	Virgin River USA No. 1-A	36.64	114.40	Mormon Mesa	9/23/79	5/23/80	1905	19562
274	White Pine	NW Exploration Co.	White River Valley No. 2	38.73	115.06	White River Valley	1/31/80	3/17/80	5440	7588

NBMG Permit #	County	Operator	Hole Name	Lat.	Long.	General Location	Spud	Completion	LSE	Depth
290	Nye	NW Exploration Co.	White River Valley No. 3	38.72	115.10	White River Valley	12/10/80	1/11/81	5367	5975
291	Nye	NW Exploration Co.	Railroad Valley No. 1	38.71	115.59	Railroad Valley	12/10/80	12/21/80	4847	3643
300	White Pine	Amer. Hunter Expl.	Black Jack Springs Fed. No. 1	39.06	115.20	Jakes Wash	11/29/80	2/1/81	6547	8133
302	Nye	Apache Corp.	Hot Creek Federal 24-13	38.54	116.29	Hot Creek Valley	1/81	3/81	5729	11028
308	Nye	NW Exploration Co.	White River Valley No. 6	38.48	115.11	White River Valley		1981	5236	6305
316	Nye	NW Exploration Co.	Bacon Flat No. 1	38.46	115.59	Railroad Valley	6/9/81	7/14/81	4726	5450
319	Clark	Chevron U.S.A.	Colorock Quarry No. 1	36.37	114.72	Muddy Mtns	9/26/82	2/28/83	2912	10030
325	Nye	NW Exploration Co.	Bacon Flat No. 5	38.46	115.58	Railroad Valley	9/15/81	10/11/81	4726	7300
326	Nye	NW Exploration Co.	Bacon Flat No. 2	38.45	115.59	Railroad Valley		1981	4707	6905
329	Clark	Grace Petroleum	Arrow Canyon No. 1	36.38	114.90	Arrow Canyon	1/14/82	12/6/82	2207	17110
343	Nye	Buckhorn Petroleum	Adobe Federal 19-1	38.41	115.84	Railroad Valley	9/17/82	10/15/82	4749	3945
353	Nye	NW Exploration Co.	Grant Canyon No. 1	38.45	115.57	Railroad Valley	8/12/83	9/11/83	4735	4487
366	Nye	Marathon Oil Co.	Soda Springs Unit No. 1	38.54	115.54	Railroad Valley	3/30/84	9/28/84	4736	8052
371	Nye	Amoco Production Co.	White River Unit No. 3	38.32	115.52	White River Valley		1984	5262	8700
374	Nye	Mapco Oil & Gas Co.	Grant Canyon No. 2	38.456	115.56	Railroad Valley	6/4/84	7/1/84	4740	6389
375	Nye	Mapco Oil & Gas Co.	Grant Canyon No. 3	38.464	115.571	Railroad Valley	7/6/84	8/4/84	4737	4302
376	Nye	Mapco Oil & Gas Co.	Grant Canyon No. 4	38.458	115.577	Railroad Valley	5/12/84	6/1/84	4737	4220
381	Nye	Harper Oil Co.	Nyala No. 1-R	38.28	115.81	Railroad Valley		1984	4799	4311
400	Nye	Mapco Oil & Gas Co.	Grant Canyon No. 5	38.457	115.583	Railroad Valley	8/8/84	8/21/84	4734	4798
411	Nye	Phillips Petroleum Co.	Dobbin Creek Fed. 'A' No. 1-6	38.99	116.62	Monitor Valley	12/31/84	1/26/85	7021	4679
419	Nye	Celsius Energy Co.	Duckwater Federal 9-1	38.91	115.565	Railroad Valley	11/7/84	12/23/84	5621	7115
421	Lincoln	Amoco Production Co.	Dutch John Unit No. 1	38.44	114.57	Lake Valley	11/21/84	2/8/84	5923	12750
422	Nye	Mapco Oil & Gas Co.	Trap Spring No. 17-12	38.63	115.639	Railroad Valley	1/13/85	2/2/85	4763	4379
424	Lincoln	Brent Energy Co.	Shogrin Federal No. 1	38.38	114.59	Lake Valley	12/27/84	3/29/85	5920	9178
456	Nye	BTA Oil Producers	Stone Cabin No. 1	38.32	116.64	Stone Cabin Valley		2/86	6044	9815
457	Nye	BTA Oil Producers	Stone Cabin No. 2	38.34	116.66	Stone Cabin Valley	2/26/86	3/2/86	6162	1184
460	White Pine	True Oil Co.	Shields Federal No. 13-22	38.97	115.09	White River Valley	11/16/85	1/86	5929	9125
473	Nye	Pioneer Oil & Gas Co.	Crows Nest No. 23-11	38.37	115.65	Railroad Valley	3/23/86	4/17/86	4744	5586
476	Nye	Marathon Oil Co.	Silver Spring No. 1	38.73	115.51	Railroad Valley	5/22/86	6/10/86	5012	5929
478	Nye	Amoco Production Co.	Sunnyside Unit No. 1	38.36	115.05	White River Valley	7/10/86	8/16/86	5321	6550
480	Nye	Diversified Oil Co.	D.O.C. Federal No. 5-18	38.291	115.83	Railroad Valley	10/25/86	11/11/86	4813	5813
481	Nye	Pioneer Oil & Gas	Willow Springs No. 1-31-33	38.42	115.60	Railroad Valley	12/7/86	1/4/87	4707	6071
482	Nye	Pioneer Oil & Gas	Lone Tree No. 1-14-43	38.38	115.63	Railroad Valley	1/29/87	2/19/87	4754	4550

APPENDIX B

DRILL–STEM TEST DATA

Explanation of Abbreviations and Units Used:

NBMG:	Nevada Bureau of Mines and Geology
ISIT:	Initial Shut–in Time (minutes)
ISIP:	Initial Shut–in Pressure (PSIG)
FSIT:	Final Shut–in Time (minutes)
FSIP:	Final Shut–in Pressure (PSIG)
Flow Time:	Total Production Period (minutes)
T:	Transmissivity (ft^2/day)
K:	Hydraulic Conductivity (ft/day)

NBMG Permit #	Test Interval(s)	Lithology	ISIT	ISIP	FSIT	FSIP	Flow Time	Fluid Recovery (ft³)	T(ft²/day)	K(ft/day)	Comments
2	3540 - 3675	Pal. Dolomite	30	1155			60	210	ND	ND	Recovered fluid pre-
	4133 - 4354	Pal. Dolomite	15	1425			45	260	ND	ND	dominantly freshwater
35	4060 - 4089	Ter. Lake Beds	30	1600							Lithology probable Sheep
	4310 - 4350	Ter. Lake Beds	30	1820							Pass Formation
11	5415 - 5427	Dev. Simonson	90	2360							
18	4489 - 4706	Tertiary Tuff	45	2100		2100					
20	6690 - 6780	Ter. Volcanics			60	1550					
	6789 - 6890	Ter. Volcanics	30	1100							
	6900 - 7135	Ter. Volcanics	30	2960	60	2925					
48	6454 - 6610	Ter. Volcanics	30	2440	61	2175					
	6620 - 6755	Ter. Volcanics	40	2525	60	1700					
63	8035 - 8131	Ter. Volcanics	130	3350							Very close to Tertiary–Paleozoic contact (2240′)
74	2875 - 2935	Miss. Joana	30	1080	30	1080	90	180			Open hole, straddle
	3505 - 3515	Dev. Guilmette	30	1263	30	1263	40	225			packer tests
	3420 - 3430	Dev. Guilmette	30	1253	30	1253	135	110			
	4013 - 4029	Dev. Simonson	30	1564	30	1564	26	280			
75	3130 - 3300	Ter. Sheep Pass	60	1259	90	1259					
82	6310 - 6390	Undiff. Carbonate	30		30	2666	120	215			AMSTRAT log indicates that carbonate rock may
	6392 - 6470	Undiff. Carbonate			30	2666	60	455			be Tertiary Sheep Pass Formation
103	4130 - 4410	Undiff. Paleozoic	30	1730	30	1730	45	300			Lithology and pressure
	4148 - 4178	Undiff. Paleozoic	30	1739			20	165			data from PI card

NBMG Permit #	Test Interval(s)	Lithology	ISIT	ISIP	FSIT	FSIP	Flow Time	Fluid Recovery (ft³)	T(ft²/day)	K(ft/day)	Comments
106	6352 - 6497	Miss. Joana	60	2333	60	2206	670	2			
109	4300 - 4370	Dev. Simonson	60	1190	120	1190	53	215			
113	4776 - 4930	Ter. Volcanics	60	2067	60	2067	60	275			
	6940 - 7120	Pal. Limestone	30	3091	30	3091	45	515			
118	3690 - 3804	T.V./Penn. Ely	60	1536	60	1536	?	80			Tertiary/Paleozoic contact
119	6633 - 6808	Penn. Ely	60	2407	60	1871					Suspect (bad?) test
120	3650 - 3737	Penn. Ely	60	214	60	267					Low pressures suggest possible tool plugging
122	6670 - 6800	Penn. Ely	60	3004	60	2896					
125	3908 - 4017	Penn. Ely	60	1689	60	1689					
126	1220 - 1263	Ter. Valley Fill	60	536	15	539					
	2750 - 2892	Pal. Limestone	60	1184	30	1184					
128	5630 - 5846	Penn. Ely	60	2099	60	2169					
130	3245 - 3484	Penn. Ely	60	1398	60	1356					Stratigraphic relationships somewhat suspect
	3645 - 3707	Eocene Illipah	60	1604	60	1604					
151	3788 - 3902	Miss. Joana	60	1631	120	1631		176			
	4938 - 5000	Dev. Guilmette	60	2203	90	2213		321			
179	7400 - 7490	Penn. Ely	60	2272	120	2272		280			
	8472 - 8550	Miss. Chainman	60	4068	90	3931					
183	6080 - 6147	Ter. Valley Fill	60	2240	160	2274					Test #2 suspect
	8070 - 8340	Ter. Sheep Pass	60	962	270	1778					
	8507 - 8565	Pal. Carbonate	60	3486	240	3378					

NBMG Permit #	Test Interval(s)	Lithology	ISIT	ISIP	FSIT	FSIP	Flow Time	Fluid Recovery (ft^3)	T(ft^2/day)	K(ft/day)	Comments
209	5075 - 5200	Ter. Volcanics	?	2129	?	2039					
241	3700 - 3850	Ter. Volcanics	60	1588	120	1588	75	100			Test #3 recovered 100% oil
	6670 - 6795	Ter. Sheep Pass	60	441	120	355					
	7000 - 7069	Ter. Sheep Pass	60	2992	120	2935	75	< 1	9.7×10^{-3}	1.3×10^{-4}	
	7226 - 7251	Ter. Sheep Pass	60	3134	120	3144	75	30	6.1×10^{-1}	2.4×10^{-2}	
244	2675	Ter. Volcanics		1169		1171		150			No test interval reported; values are recorder depths
	3760	Ter. Volcanics		1513							
261	4717 - 4940	Ter. Valley Fill	60	1772	140	1686	88	61			
	6450 - 6591	Ter. Volcanics	60	2681	90	2681		450			
270	2670 - 2716	Ter. Valley Fill	60	850	120	820			1.4×10^{-1}		T and K values from geo-logist's report
	4605 - 4766	Ter. Volcanics	60	1734							
	7500 - 7706	Miss. Joana	60	2900	120	2900			8.2×10^{2}	4.0	
272	10,476 - 10,574	Tri. Moenkopi	15	4401	180	4037					Straight-line interpretation of final shut-in of test #2 difficult
	11,764 - 11,814	Perm. Kaibab	30	4059	120	2516	77	65	7×10^{-2}	1.4×10^{-3}	
	17,470 - 17,480	Penn. Callville	39	7420	957	7387					
274	6187	Ter. Sheep Pass	60	1473	120	1687	75	22	7.4×10^{-3}		No interval given; recorder depth only
290	5655 - 5770	Perm. Limestone	60	954	120	1144	75	< 1			Poor agreement between ISIP and FSIP
300	1728 - 1758	Miss. Diamond Pk		504		495					Regrettable lack of contin-uous P-T data. "Lots" of freshwater noted in driller's report
	4993 - 5054	Dev. Simonson		1651		1651					
	6330 - 6380	Dev. Sevy		2244		2244					
302	7408	Olig. Volcanics	60	1755	>120	1792					Recorder depth only

NBMG Permit #	Test Interval(s)	Lithology	ISIT	ISIP	FSIT	FSIP	Flow Time	Fluid Recovery (ft^3)	T(ft^2/day)	K(ft/day)	Comments
308	2190 - 2225	Valley Fill	60	904	120	904			5.7×10^{-2}	1.6×10^{-3}	Valley Fill T and K from geologist's report
	4490 - 4578	Penn. Ely	60	1920	120	1937	65	39	7.7×10^{-1}	8.7×10^{-3}	
	5378 - 5435	Penn. Ely	60	2303	120	2269	60	24	9.2×10^{-2}	1.6×10^{-3}	
316	5315 - 5346	Pal. Dolomite	60	2328		2289	65	35	4.2	3.1×10^{-1}	Recovered fluid predominantly oil
325	5595 - 5957	Penn. Ely	60	2379	120	2295	61	36	6.2×10^{-2}	3.1×10^{-4}	Chainman T and K from geologist's report. Fluid recovered from Ely >75% mud
	6228 - 6276	Miss. Chainman	60	2556	180	1641			4.1×10^{-2}	8.3×10^{-4}	
	6228 - 6350	Miss. Chainman	60	1865	180	979					
326	6457	Sheep Pass or Ely		2804		2844			15.4	1.5×10^{-1}	
343	1248 - 1342	Ter. Volcanics	60	515	90	515		81	2.6	2.7×10^{-2}	Volcanic T and K from geologist's report
	3785 - 3930	Dev. Guilmette	60	1706	60	1712	90	304	3.5×10^{2}	2.4	
353	4340 - 4441	Dev. Simonson		1852	60	1852	25	340	8.5	8.5×10^{-2}	Very little pressure build-up after shut-in. Possible tool plugging
366	7699 - 7796	Cam. Quartzite	30	3295	120	3244	75	65	7.2×10^{-1}	7.2×10^{-3}	
371	3504 - 3578	Miss. Chainman	60	1198	120	1149					
374	4690	Dev. Guilmette	30	1997	120	1997	75	360			No intervals reported. Insufficient build-up on test #1 for T and K calculations. Carbonate rock possible Miss. Joana
	5646	Dev. Guilmette	30	2362	180	2352	135	150	3.4		
375	3934 -3961	Dev. Guilmette	30	1715	60	1742	90	270	2.3×10^{2}	4.1×10^{-1}	Recovered mostly mud and oil

NBMG Permit #	Test Interval(s)	Lithology	ISIT	ISIP	FSIT	FSIP	Flow Time	Fluid Recovery (ft^3)	T(ft^2/day)	K(ft/day)	Comments
376	4034 - 4087	Dev. Guilmette	30	1748	62	1749	28	310	5.0×10^2	18.6	Recovered 100% oil
381	4235 - 4345	T.V./Pal. Carbs.		1701		1701	65	325			Volcanic-Paleozoic interface
400	4460 - 4555	Dev. Guilmette	30	1887	120	1887	75	340			High permeabilities re-
	4548 - 4648	Dev. Guilmette	30	2013	60	2013	75	340	4.6×10^2	4.6	flected in instantaneous pressure build-up (i.e., very small ΔP)
411	3650 - 4034	Undiff. Paleozoics	54	1449	3768	1449	40	85	12.1	3.9×10^{-2}	Open hole, straddle pack-
	3600 - 3660	Undiff. Paleozoics	15	1412	93	1442	109	10	5.3×10^{-1}	2.0×10^{-2}	er tests. T and K values
	3200 - 3480	Undiff. Paleozoics	15	1313	1245	1365	30	100	8.2	1.1×10^{-1}	reported in Table 2 are
	4542 - 4600	Ord. Eureka Qtzt.	46	1805	1276	1805					averages of the three listed here
419	4277 - 4343	Ter. Volcanics	30	1771	120	1771	44	325			
	6046 - 6135	Ter. Sheep Pass	30	2642	180	1837	134	110			
	6347 - 6404	Ter. Sheep Pass	30	2223	120	2130	90	7	5.3×10^{-4}	9.3×10^{-6}	
	6565 - 6738	Miss. Chainman	60	2761	120	2721					
421	5799 - 5859	Penn. Ely	60	1417	122	1440					
	6196 - 6251	Miss. Chainman	60	91	127	81					
	11,990 - 12,230	Dev. Simonson	60	5124	240	5129					
422	3788 - 3879	Tertiary Tuff	60	188	180	206	120	10			Lithology: Tertiary
	3881 - 3972	Tertiary Tuff	60	253	180	253					Pritchard Station and/or
	3973 - 4097	Tertiary Tuff	60	868	180	840					Stone Cabin Ignimbrites
	4190 - 4284	Tertiary Tuff	60	1103	120	848					
	4285 - 4379	Tertiary Tuff	60	249	120	959					
424	8056 - 8503	Miss. Joana	60	3308	180	3348					
	8730 - 9178	Dev. Guilmette	60	3823	60	3837					
456	5201	Ter. Volcanics	60	1317	120	1416					No interval reported;
	5297	Ter. Volcanics	60	1335	120	1447					recorder depth only

NBMG Permit #	Test Interval(s)	Lithology	ISIT	ISIP	FSIT	FSIP	Flow Time	Fluid Recovery (ft^3)	T(ft^2/day)	K(ft/day)	Comments
457	1157 - 1184	Ter. Volcanics	60	354	90	354	50	65			Fluid recovery >75% freshwater
460	1120 - 1155	Penn. Dmd Pk S.S.	30	388	60	393	75	65			
473	4737 - 4800	Dev. Simonson	60	2038	120	2038	74	280			
476	5698 - 5929	Dev. Carbonate		2396		2396					
478	1442 - 1571	Ter. Sheep Pass	60	531	110	531	75	45	4.5	3.5×10^{-2}	
	3680 - 3785	Penn. Diamond Pk	60	1425	120	1392	76	210			
480	5671 - 5725	Miss. Joana	30	2417	120	2417	45	370	84	1.6	Fluid recovery >75% freshwater
481	5020 - 5141	Dev. Guilmette	60	2184	120	2184	43	195			
482	4372 - 4430	Dev. Guilmette	60	1912	120	1924	10	250	6.2	1.1×10^{-1}	Non-linear pressure build-up

APPENDIX C

CONVERSION OF UNITS COMMONLY USED IN THE PETROLEUM INDUSTRY

VOLUME

1 barrel	42 gallons 5.61 ft^3 .158 m^3 159 liters
1 ft drill pipe (3.8 inch ID)	7.8×10^{-2} ft^3 .589 gallons 2.23 liters
1 ft drill collar (2.25 inch ID)	2.6×10^{-2} ft^3 .197 gallons .747 liters

FLOW

1 barrel/day	42 gal/day 6.5×10^{-5} 1.84×10^{-3}

PERMEABILITY

1 darcy	18.24 gpd/ft^2 2.44 ft/day .743 m/day
1 millidarcy (1×10^{-3} darcy)	1.82×10^{-2} gpd/ft^2 2.44×10^{-3} ft/day 7.43×10^{-4} m/day

TRANSMISSIVITY

1 millidarcy - foot/centipoise	55.95 gpd/ft 2.3×10^{-3} ft^2/day 2.13×10^{-4} m^2/day

APPENDIX D

ANNOTATED STRATIGRAPHY FROM THREE WILDCAT WELLS IN NEVADA

AMERICAN HUNTER #1 BLACK JACK SPRING, WHITE PINE COUNTY

/Pmd Diamond Peak Formation

Note: Log description suggests some modification of American Stratigraphic's, formation identification.

1304 - 1440 argillaceous limestone, chert, shale, sandstone stringers - this could be basal Ely Limestone.

1440 - 2040 sandstone, shale - siltstone about 10%.

2040 - 2827 shale, limestone less than 5%.

Probably Chainman Shale 1440 - 2827.

Mjo Joana Limestone 2827 - 3320 limestone, chert, some shale.

Dpi Pilot Shale 3320 - 3463 shale.

Dg Guilmette Limestone 3463 - 4509 dolomitic, argillaceous limestone.

Note: On Schlumberger log, limestone recorded to 4050 feet than dolomite to base of Guilmette. Am Strat shows interlayered limestone and dolomite.

Dsi Simonson Dolomite 4509 - 4876 dolomite, sandstone stringers at base. Schlumberger reports some limestone in Simonson.

Dse Sevy Dolomite 5876 - 6818 dolomite Schlumberger reports thin bedded silty limestone and dolomite at top of Sevy (consistent with gamma log) and vuggy dolomite lower 300 feet.

Sl Laketown Dolomite 6818 - 7542 dolomite, sandstone stringers at 7140, 7230, Schlumberger reports limestone in 7000–7450 interval. No chert reported. Lighter colored dolomite than adjacent units.

Ofh Fish Haven Dolomite 7542 - 7688 dolomite. Darker color than Laketown. Fracture porosity 7660–7670.

Oe Eureka Quartzite 7688 - 8012 sandstone, dolomite beds near top.

Op Pogonip Group 8012 - 8130

8012 - 8055 sandstone and dolomite

8055 - 8130 limestone, sandy

Note that except for the Guilmette, no chert was reported in the Ordovician through Devonian units.

NORTHWEST EXPLORATION #1 WHITE RIVER, NYE COUNTY

/Pe Ely Limestone 5416 - 7900 alternation of limestone, siltstone, and shale; limestone dominates, fossiliferous, cherty.

/PMc Chainman shale 7900 - 9426 Upper portion contains a number of sandstones interbedded with shale. Siltstone has intergranular porosity. Lower portion largely described as shale.

Note: The upper sandstone portion is sometimes called Scotty Wash Sandstone or the Illipah Formation.

Mjo Joana Limestone 9426 - 10473 silty limestone, cherty fossiliferous. Shale interbeds.

GRACE PETROLEUM #1 ARROW CANYON, CLARK COUNTY

Man Anchor Limestone 1030 - 1415 limestone, dolomitic, chert.

Mda Dawn Limestone 1415 - 1606 crinoidal limestone.

Note: These formations are members of the Monte Cristo Limestone elsewhere in Clark County.

Dcp Crystal Pass Limestone 1606 - 1720 limestone.

Note: In the Spring Mountains, this is the upper member of the Sultan Limestone.

Dac Arrow Canyon Formation 1720 - 2720 limestone, dolomite.

Note: The measure section shows sandstone beds in this unit some sandy limestone shows on log.

Dm Moapa Formation 2720 - 3047 dolomite.

Dp Piute Formation 3047 - 3300 dolomite, some shale unconformity at base.

Note: Piute, Moapa, Arrow Canyon have only been used in the Arrow Canyon Range. Elsewhere these correspond to Sultan or to the Sevy–Simonson interval.

Sl Laketown Dolomite 3300 - 3476 dolomite, generally lighter color than units above and below.

Oes Ely Springs Dolomite 3426 - 3827 dolomite.

Oe Eureka Quartzite 3827 - 3910 sandstone, shale.

Op Pogonip Group 3910 - 4000 dolomite, siltstone, shale.

Fault at 4000 feet cuts out rest of Pogonip

Gno Nopah Formation 4000 - 4450 sandy, silty dolomite.

Gds Dunderberg Shale 4450 - 4616 shale, shaly dolomite.

Gbk Bonanza King Formation 4616 - 6773 dolomite.

Gcr Cararra Formation 6773 - 7507 shale, limestone units.

Fault

Gbk repeated 7507 - 8260.

Fault

Gcr repeated 8260 - 8500.

Fault

Gbk 8500 - 9330.

Fault - Dry Lake Thrust at 9330

/Pbd Bird Spring Formation 9330 - 16050 upper portion largely siltstone, shale, sandstone calcareous and dolomitic; lower part includes beds of limestone, dolomite, and anhydrite; lowest 1/3 is dominantly limestone.

Unconformity

Mbw Battleship Wash Formation 16050 - 16237 shale, limestone.

Myp Yellow Pine Limestone 16237 - 16434 limestone, chert.

Mbu Bullion Limestone 16434 - 16857 limestone, dolomite, chert, lower 1/2 all dolomite.

Man Anchor Limestone 16857 - 17000 bottom of hole.

Note: Yellow Pine and Bullion are members of the Monte Cristo Limestone elsewhere in Clark County.