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APPLYING FLOWRATE TYPE CURVES TO GEYSERS STEAM WELLS

Steve Enedy

Northern California Power Agency
Bear Ridge Road
The Geysers

ABSTRACT

Dimensionless flowrate type curves were applied to steam wells at The Geysers in an attempt to quantify reservoir properties and to predict flowrate decline. Although data scatter was a problem, the flowrate data was smoothed by a normalization routine based on the back-pressure equation and the wells were modeled by dimensionless functions for a radial system with a infinite or finite outer boundary and a constant pressure inner boundary (composite analytical-empirical type curve).

The "match" resulted in a unique D_i value for use in Arps' equation and a permeability-thickness product (kh) comparable to kh values obtained from pressure buildup analysis. Finally, it was shown that at least four years of data is required to obtain a unique b value.

INTRODUCTION AND BACKGROUND

Decline type curves have been applied to geothermal wells to model flowrate decline by several authors [1,2]. The purpose of this study was to determine if type curves could be applied to Northern California Power Agency's (NCPA's) wells at The Geysers. In particular, those used to start-up NCPA Geothermal Plant No. 1. These wells are exhibiting a hyperbolic or harmonic decline which complicates standard (semi-log) rate-time analysis.

NCPA's steam supply area is on the Sonoma/Lake County border near the southeastern edge of the field (Figure 1).

NCPA Activities at The Geysers

NCPA Geothermal Plant No. 1, rated at 124 megawatts (MW), and NCPA Geothermal Plant No. 2, rated at 114 MW, provide baseload power for the NCPA's 14 member utilities. Plant No. 1 was completed in 1983, Plant No. 2 was dedicated in 1986.

Steam for NCPA's two geothermal plants at The Geysers is provided by wells located on ten (10) drilling pads within federal leases CA-949 and CA-950 (Figure 1). In September of 1986, eight and one half miles of pipeline connected the thirty five producing wells to the plants. The combined electrical output of both plants is normally 238 MW gross.

In September of 1985, NCPA purchased the steam field from Grace Geothermal Company to become the operator of the largest <u>combined</u> power plant-steam field complex at The Geysers. Originally, NCPA had contracts with Shell Oil Company and later with Grace Geothermal Company to supply steam.

DECLINE ANALYSIS METHODOLOGY AND EQUATIONS

Arps' work forms the basis for many of the decline curve equations used for modeling apparent hyperbolic or harmonic decline[3].

$$q(t) = q\ (1+ bD_i t)^{-1/b} \qquad (1)$$

Fetkovich [4,5,6] recommends fitting Arps' equation only to the pseudo-steady state (non-transient) portion of the rate time data. A forced fit of transient data results in apparent b values greater that 1. Fetkovich also states that log rate-log time plots should be made to identify "transient data" and/or "depletion" data. This plot should be reinitialized in time to eliminate any constant rate production period.

Study Methodology

The above recommendations from the basis for this study. The methodology consists of the following steps:

1) Normalizing the flow data to a constant (nominal) back-pressure using the back-pressure equation.

2) Modeling the log rate-log time plots versus available decline type curves.

3) Calculating values of Di, b and kh from the type curve match.

The type curves which best fit the normalized data were the composite of the analytical constant wellbore pressure solutions and the Arps' exponential, hyperbolic and harmonic decline curve solutions (Figure 2).

Decline curve dimensionless rate and dimensionless time in terms of reservoir variables and standard geothermal steam units are defined as:

$$q_{Dd} = \frac{\dfrac{q_t}{kh(Pi - P_{wf})}}{1207\bar{v}u\bar{p}[\ln(^{re}/_{rw}) - 1/2]} \quad (2)$$

and

$$t_{Dd} = \frac{.00634\ kh\ t}{\phi h(uc_t)_i r_w^2} \times \frac{1}{1/2[(^{re}/_{rw})^2-1][\ln(^{re}/_{rw})-1/2]} \quad (3)$$

The boundary conditions are described in detail in References 4, 5 and 6 and are summarized in Figure 3. It is important to note that a constant wellbore pressure is assumed in the analytical solution. Since NCPA's pressure data exhibited a high degree of fluctuation, a normalization routine was required.

Finally, from Arps' empirical decline curve solutions, the factor Di can be calculated from any matchpoint using Equation 4.

$$t_{Dd} = Di\ t \quad (4)$$

BASIC WELL AND RESERVOIR DATA

Source of Basic Flow Data

All wells producing to NCPA Geothermal Plants 1 and 2 are controlled by a supervisory system driven by two HP-1000 "E" Series mini-computers. An annubar (Dieterich Standard Corporation) is the primary flow sensor installed near the wellhead. Pressure, temperature and differential pressure are recorded every five seconds. Flowrate and pressure values are averaged every two minutes and stored for one month.

Following the purchase of the steam field by NCPA, instantaneous flowrates and pressures were recorded as often as requested (currently once per shift) then exported to an IBM-PC for further manipulation by a data-base (DB) manager program.

The DB manager verifies then sorts the data, performs all normalization calculations and outputs a file suitable for graphing.

Prior to the installation of the automated data collection system, instantaneous flowrates were recorded by the field operators. All available data was collected by GeothermEx for NCPA and input to a DB manager then combined with the data currently being stored by the supervisory system.

Both the quantity and quality of the basic flow data was acceptable for basic decline curve analysis following a normalization to a constant surface pressure. Ordinarily, flowrate, pressure and temperature values were available for each day the well produced. A general problem with the instrumentation was a lack of historical calibration checks on the pressure and temperature transmitters. NCPA currently checks calibration once per month.

The lack of stabilized (constant pressure) flow periods posed a problem with the rate data. The degree of fluctuations in the back-pressure required that all the rate-data be "normalized" to a constant "nominal" back-pressure. Flow tests are now conducted at a constant nominal back-pressure to determine a stabilized (constant pressure) flowrate. However, all historic data must be normalized.

Normalization Routine

Generally, only the surface normalization routine was warranted as the match was not improved using bottom-hole data. The normalization routine is a two-step process:

1) Adjust all rates to a nominal surface pressure using surface data.

2) Convert the adjusted flowrates to a constant bottom-hole pressure (if necessary).

The basis for the normalization calculations[7,8] is the back-pressure equation:

$$q = C(P_{ts}^2 - P_{tf}^2)^n \qquad (5)$$

The equation is sufficiently accurate for normalizing data provided the parameters Pts and n are adequately measured. These values are often calculated with special reservoir flow and buildup tests.

Source of Reservoir Data

Prior to the start-up of NCPA Plant No. 1, Shell Oil Company conducted isochronal type flow tests and pressure buildup tests[9]. From these tests, the initial reservoir pressure (Pi), kh and n factors were calculated then input into the DB manager. The Shell data was combined with subsequent flow and pressure buildup data for use in the normalization routine.

The reservoir pressure was modeled with a cubic regression equation:

$$P_{ts} = A + BX + CX^2 + DX^3 \qquad (6)$$

where X was either the days since start-up or the cumulative production since start-up at the time the pressure was recorded. This model allows the DB manager to quickly calculate a reservoir pressure for each flowrate to be normalized.

For the most part, P_{ts} and n factor data were limited in both quantity and quality. As a rule, operating companies cannot afford to shut-in a well for special well tests. The main reason Shell Oil Company conducted the special well tests prior to plant start-up was to quantify reservoir characteristics for a pending sale.

CONVERTING RATES FROM CONSTANT SURFACE TO CONSTANT BOTTOM-HOLE PRESSURE

A cubic regression equation was developed for each well to model the head and friction loss:

$$P_{wf}=A+B(Wnom)+C(Wnom)^2+D(Wnom)^3 \qquad (7)$$

Wnom is the surface normalized flowrate. The relationship between bottom-hole pressure and flowrate is based on the equations developed by Cullender and Smith[10]. Also, the surface shut-in pressure was adjusted to bottom-hole using the equation[11]:

$$P_{ws}=-6+(6 + P_{ts})e^{.000015H} \qquad (8)$$

where H is the vertical depth to the mid point of steam. The major advantage of Equations 7 and 8 is the direct calculation of bottom-hole conditions without using an iterative procedure.

Finally, the back-pressure equation (Equation 5) is solved for a normalized flowrate assuming a constant (nominal) bottom-hole pressure.

Although the constant bottom-hole pressure normalization routine was run on all wells, the data scatter always increased (probably due to the lack of quality bottom-hole measurements). Therefore, all decline type curve matches are based on constant surface pressure data.

LOG-LOG DECLINE CURVES (CONSTANT SURFACE PRESSURE)

Log rate - log time plots were generated from the normalized flowrates to the same scale as the decline type curve plots. A graphical match was attempted with several families of decline curves including 1) the infinite conductivity vertical fracture constant pressure solution, 2) naturally fractured reservoir and 3) the composite analytical-empirical solution.

The best match was obtained with the composite type curve. Although data scatter was still a problem, a general decline trend could be determined. A unique t_{Dd} match (therefore Di) was obtained on each well. However, the majority of the wells did not have a sufficient flow period to establish a unique match for b on the empirical hyperbolic and harmonic decline curve solution.

Individual Well Decline Curves

The type curve match for Well #3 was determined graphically and is shown as Figure 4. A match using the composite q_{Dd} - t_{Dd} type curve (Figure 2), at a real time of ten days, indicated t_{Dd} value of .0048. Table 1 lists the t_{Dd} value at a real time of ten days for all the study wells. Well #3 is a typical match and is illustrative of the usefulness of the type curve to quantify Di but not necessarily b. The limiting factor is the flow time. Apparently, at least four years of rate data is necessary to establish a unique b value.

The type curve matches for Wells #8 and #1 are shown as Figures 5 and 6. The late time data exhibits increased scatter. Because the parameters for the back-pressure equation were not well known, the normalization routine was affected. In addition, the unit demand fluctuates due to overhauls, hydro-curtailments, etc. which effects flowrates.

Although a unique b could not be determined for the above wells, a range of b values was found which aided in the steam supply forecast. Also, a unique b value was determined for several wells.

Figure 7 is the log-log plot of daily production for Well #12. The b=1.0 stem of the composite curve best models the data beyond t_{Dd} =.3.

The well with the lowest flowrate and the highest overall decline rate is Well #10 shown as Figure 8. The best fit of the empirical data is as exponential decline (b=0).

Once the average log rate - log time decline curve characteristics are established, exceptions to the average (Well #10) or problem wells (Well #11) are easily determined.

A wellbore problem was found in Well #11 (Figure 9) using type curves. The rate curve diverges from the type-curve match at the late time (>1000 days). A restriction was subsequently confirmed using a wireline survey.

MATCH RESULTS

The value of dimensionless time (t_{Dd}) at a real time of ten days was plotted at the mid-point of steam. An areal distribution is shown as Figure 10. The results are also listed in Table 1.

Based on the match of dimensionless time, the wells were divided into two groups:

Group A $.0015 < t_{Dd} < .0048$
Group B $.0060 < t_{Dd} < .0094$

The grouping is arbitrary as half of the wells were placed in each group. Figure 10 illustrates that the calculated value of Di (Equation 8) is a function of location within the reservoir and controlled by reservoir parameters.

It can be inferred that makeup wells drilled into each area will behave similarly to other wells in the group. Predicting the decline characteristic of a makeup well is useful in forecasting future steam supply.

Since the Group A wells behave in a similar manner, those wells could be combined to form a composite decline curve.

Figure 11 is a four well composite of the normalized rate data. The composite flowrate was calculated by adding the individual well flowrates on four wells within Group A. Although not demonstrated in this paper the advantage of the composite plot is that an overall average decline can be calculated on wells with a high degree of interference.

Calculated kh Values

Given a unique match of the analytical-empirical type curve, a permeability-thickness product can be calculated from Equation 2 if a value for ln re/rw can be either assumed or determined from the match.

Table 2 lists the calculated kh products obtained from the type curve match assuming the value for [ln re/rw - 1/2] is 9. The kh products obtained from pressure buildup tests conducted by Shell Oil Company prior to plant start-up are also listed. Although the absolute kh values obtained by the two methods are not exact, the general trend is similar (e.g. the high kh values are high by both methods).

For the most part, the kh products obtained from surface normalized decline curve matches are not as reliable as the kh products obtained from a pressure buildup test because a unique value of [ln re/rw - 1/2] could not be obtained by type curve matching or other tests.

An unsuccessful attempt to normalize the data to a constant bottom-hole pressure was made to determine if a unique match on the re/rw stem could be obtained.

LOG-LOG RATE-TIME PLOTS (CONSTANT BOTTOM-HOLE PRESSURE)

Log rate-log time graphs of rates normalized to a constant bottom-hole pressure were prepared and compared to surface normalized graphs. Figure 12 is such a graph for Well #1. It was found that the general characteristics of the early-time data (<100 days) of the high flowrate wells (>150,000 pph) was different enough to require a new match on the re/rw stem. However, the matchpoint results of Di and b did not change. Regardless of the re/rw stem modeled, once the well passes from the transient region to the depletion region the value for Di (obtained from Equation 8) does not change. Also, the overall data scatter increased. This decreased the confidence of the type curve fit.

The increased data scatter is probably due to the lack of reliable downhole data (P_{wf} and n). Even though the bottom-hole normalization routine should (theoretically) smooth the data, error was introduced.

Consequently, all flowrate projections were based on results of type curve matches (eg. b, Di) derived from surface pressure normalized data.

CONCLUSIONS

1. Steam wells (located at The Geysers) used to start-up NCPA Geothermal Plant No.1 exhibited hyperbolic or harmonic decline.

2. The log rate - log time curves for these wells were best modeled using composite analytical-empirical type curves after the data was normalized to a constant pressure.

3. The flow period of nearly four years was sufficient to determine a unique value of Di but not usually of b for use in Arps' equation. Overall, the type curve match was an aid to standard semi-log analysis.

4. Grouping wells with similar type curve matches and creating composite or average decline curves is a useful forecasting tool.

5. Normalizing the rate-time data to a constant bottom-hole pressure introduced increased data scatter and did not improve the match for Di or b.

6. Permeability-thickness products obtained from decline type curve matches cannot replace kh products obtained from pressure buildup tests unless an accurate re/rw value is known.

TABLE 1

DIMENSIONLESS TIME RESULTING FROM A MATCH AT REAL TIME = 10 DAYS

WELL	t_{Dd} @ Dt=TEN DAYS	Comparative Rank of t_{Dd}	GROUP
1	.0048	5	A
2	.0072	8	B
3	.0015	1	A
4	.0048	6	A
5	.0090	10	B
6	.0036	3	A
7	.0060	7	B
8	.0026	2	A
9	.0090	9	B
10	.0061	12	B
11	.0041	4	A
12	.0094	11	B

TABLE 2. COMPARISON OF KH PRODUCTS OBTAINED FROM PBU TESTS AND DECLINE CURVE MATCHES

WELL	PBU (D-FT)	DECLINE TYPE CURVE MATCH (D-FT)
1	175	162
2	250	148
3	18	69
4	17	42
5	13	34

NOMENCLATURE

A	coefficient of cubic regression equation
B	coefficient of cubic regression equation
b	reciprocal of decline curve exponent
C	coefficient of cubic regression equation or coefficient of back-pressure equation
c_t	compressibility, psi^{-1}
D	coefficient of cubic regression equation
D_i	initial decline rate, t^{-1} (eg. day^{-1})
H	vertical depth to mid-point of steam, ft
kh	effective permeability-thickness, md-ft
n	exponent of back-pressure equation
P_i	initial pressure at start of decline, psia
P_{ts}	surface shut-in pressure, psia
P_{tf}	surface flowing pressure, psia
P_{ws}	bottom-hole shut-in pressure, psia
P_{wf}	bottom-hole flowing pressure, psia
$\overline{p}$	average reservoir pressure, psia
q_{Dd}	decline curve dimensionless rate
q_t	mass rate of flow at time t, lbs/hour
q_i	mass rate of flow at time 0, lbs/hour
re	external boundary radius, ft
rw	effective wellbore radius, ft
t	real time, days
t_{Dd}	dimensionless time
u	viscosity, cp
$\overline{v}$	specific volume at $\overline{p}$ (lbm/ft3)
ϕh	porosity-thickness product, ft
Wnom	normalized flowrate, lbs/hour

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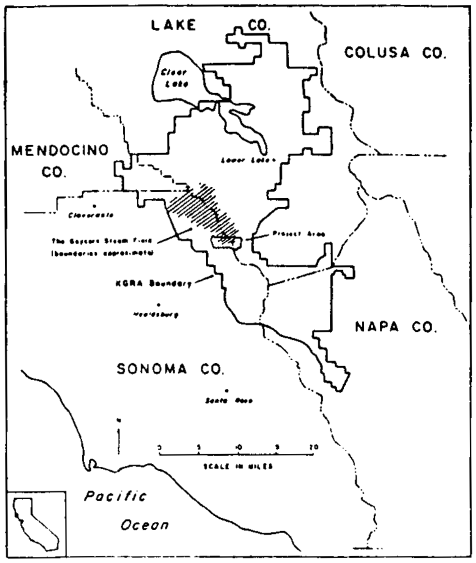

Figure 1. The Geysers - Calistoga KGRA and the Steam Supply Area.

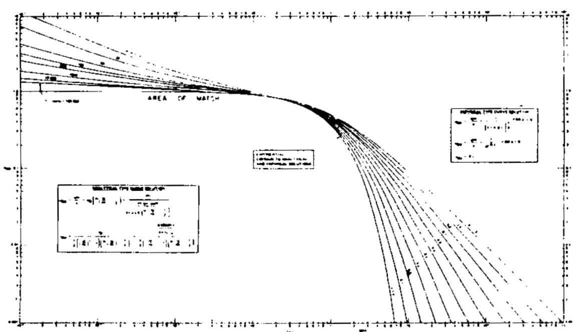

Figure 2. Composite of Analytical and Empirical Type Curves (Fetkovich)

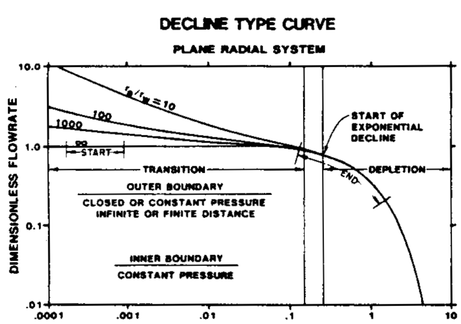

Figure 3. Collapsed Dimensionless Flowrate Functions with Boundary Conditions.

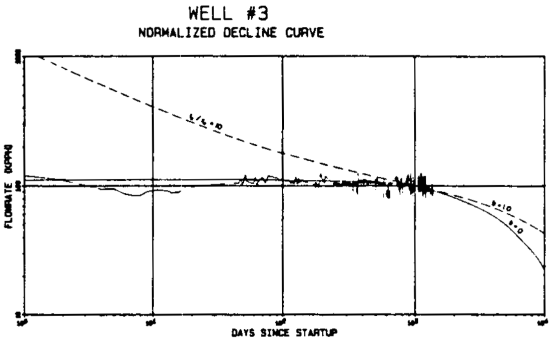

Figure 4. Type Curve Match For Well #3.

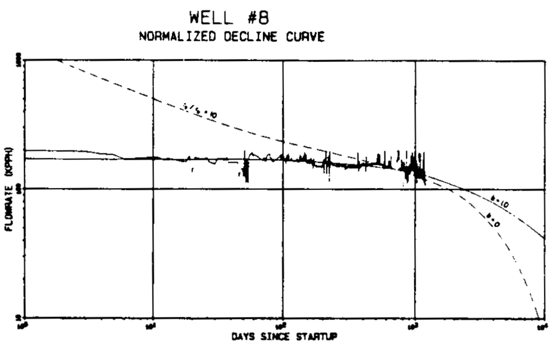

Figure 5. Type Curve Match For Well #8.

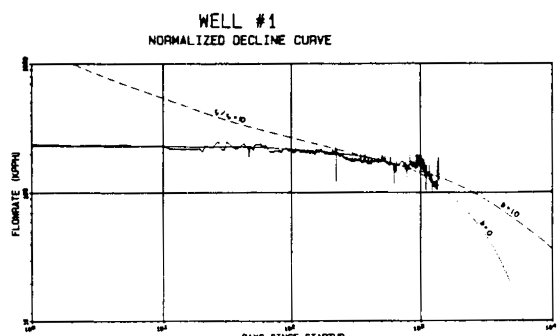

Figure 6. Type Curve Match For Well #1.

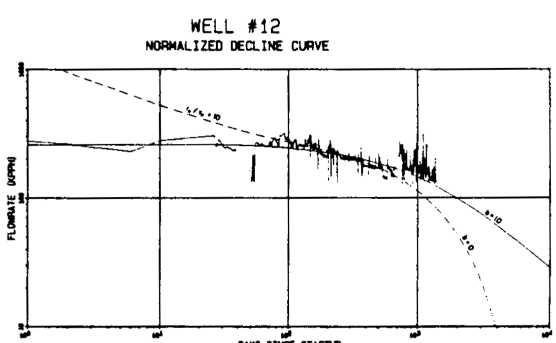

Figure 7. Type Curve Match For Well #12.

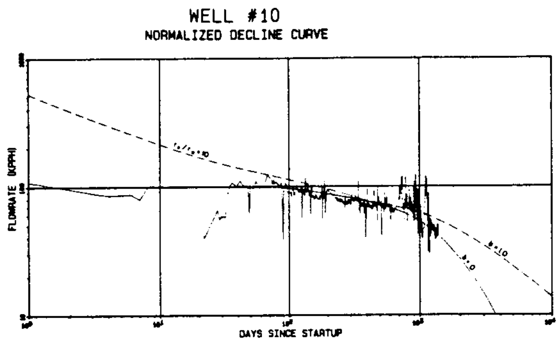

Figure 8. Type Curve Match For Well #10.

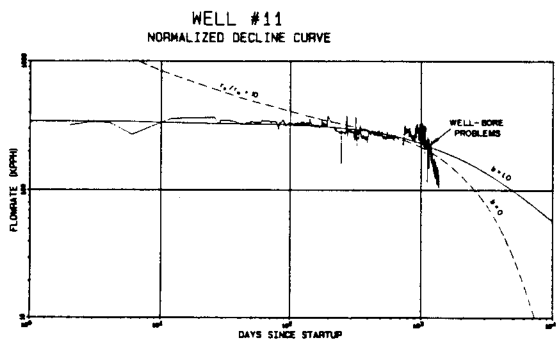

Figure 9. Type Curve Match For Well #11.

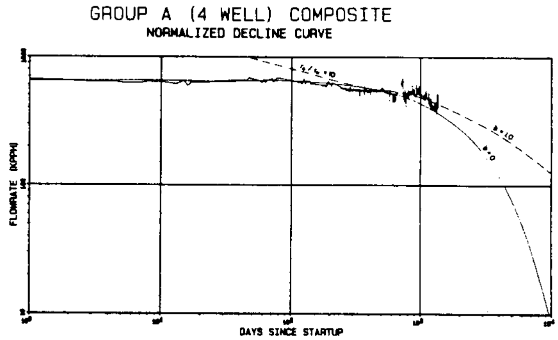

Figure 11. Type Curve Match For Group A (4 Well) Composite.

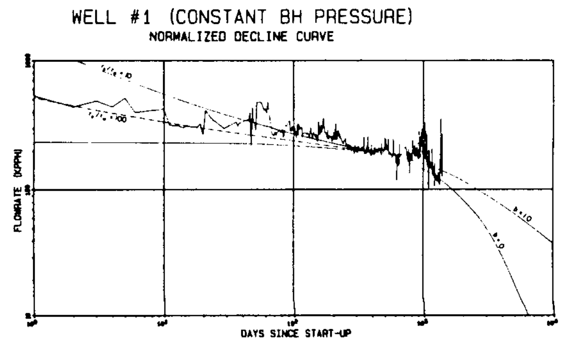

Figure 12. Type Curve Match for Well #1.

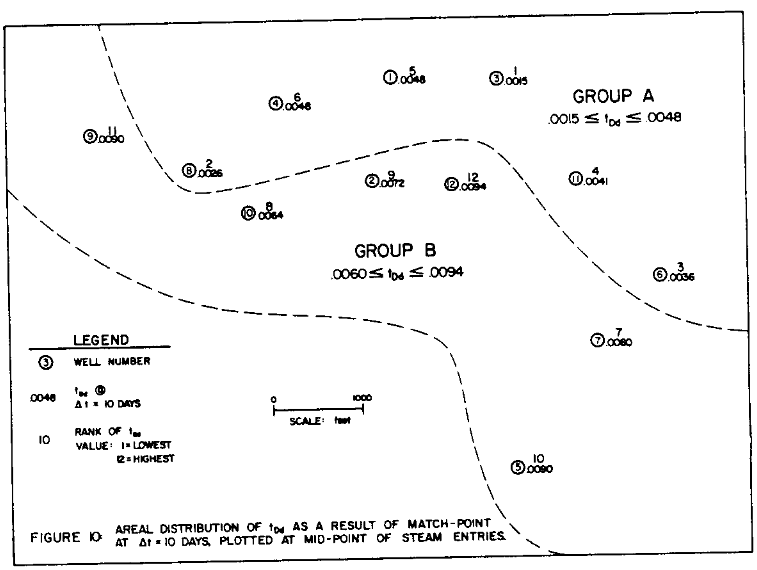

FIGURE 10: AREAL DISTRIBUTION OF t_{Dd} AS A RESULT OF MATCH-POINT AT Δt = 10 DAYS, PLOTTED AT MID-POINT OF STEAM ENTRIES.