- DALY (01)
- LODGEPOLE A
(59A)
- DALY UNIT NO.1
- REPORTS
- WATERFLOOD STUDY - JUNE, 1989

WATERFLOOD STUDY ON
DALY UNIT #1

DALY FIELD, MANITOBA

Prepared For:

CANADA NORTHWEST ENERGY LTD.

Prepared By:

ADAMS PEARSON ASSOCIATES LTD.

June, 1989

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1989 07 17

WORKING INTEREST OWNERS
DALY UNIT #1
(Addressee List Attached)

Dear Sirs:

Re: <u>WATERFLOOD STUDY ON DALY UNIT #1</u>

Enclosed is a copy of the waterflood study on Daly Unit #1 completed by Adams Pearson Associates Ltd.

Yours very truly,

CANADA NORTHWEST ENERGY LIMITED

Karen Morrison
Engineering Secretary

cc: Manitoba Energy & Mines
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June 21, 1989

Mr. Ron Davison
Canada Northwest Energy Ltd.
Suite 2700, 300 - 5 Avenue S.W.
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File No.: 853

Dear Mr. Davison:

Re: Waterflood Study
Daly Unit #1

As instructed, we have carried out a waterflood study on Daly Unit #1. The scope of work for the study was detailed in our original proposal dated July 6, 1988 and was subsequently updated in our letter of November 15, 1988.

The enclosed report documents the data sources used, the methodology followed and the results of our waterflood performance analyses. In addition, we have included a prioritized listing of recommendations which we believe have reasonable probability of increasing current oil production rates and/or improving ultimate oil recovery from the Daly #1 Unit.

We appreciate the considerable assistance of CNWE staff in providing us with an accurate, updated set of well production histories. We also acknowledge the efforts of CNWE geological staff in reviewing the available core data and in constructing structural, gross isopach and net porosity thickness maps on each of the the three members of the Lodgepole formation on which we based our oil in place volumes. Finally, we also wish to thank Ralph Atkinson of Rundle Petroleums Ltd. for providing us with useful details on specific well completions and problem well histories.

We appreciate the opportunity to conduct this study for CNWE and will be pleased to answer any questions you may have on the report.

Yours truly,

ADAMS PEARSON ASSOCIATES LTD.

RMPearson

for D. M. Adams, P.Eng.
President

DMA/esl
Encl.

PERMIT TO PRACTICE
ADAMS PEARSON ASSOCIATES LTD.
Signature RMPearson
Date 14 / 7 / 89
PERMIT NUMBER: P 3705
The Association of Professional Engineers, Geologists and Geophysicists of Alberta

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INTRODUCTION

In December, 1988 Canada Northwest Energy Limited (CNWE) retained Adams Pearson Associates to conduct a waterflood study on Daly Unit #1 in Manitoba. Currently, the total oil production from the unit is about 9000 STB/mo with water cuts in the range of 94 to 95%. The field has been on production since 1951 and was unitized in 1970. A pilot waterflood was implemented in the same year and was expanded in 1971 with infill drilling of several injectors.

The objectives of this study, as detailed in our augmented proposal of November 15, 1988, are as follows:

(i) To determine the likely volume of original oil in place and its distribution throughout the Unit.

(ii) To estimate, based on production history, the likely primary recovery from the Unit.

(iii) To determine the efficiency of the existing waterflood and the likely incremental reserves recoverable.

(iv) To determine whether the efficiency of the existing flood can be improved and also whether it should be extended to other patterns in the Unit.

(v) To compare the Daly Unit #1 40-acre waterflood to the Daly Unit #3 80-acre waterflood to determine whether further infill wells are needed.

(vi) To conduct a preliminary screening study on applying a polymer flood in the Unit.

In this study, no effort has been made to differentiate production and injection on a zone by zone basis. Most wells in the pool have either been completed open-hole and/or sand frac'd resulting in obvious commingling of all producing intervals (refer to Table 1.1 for completion details).

Although production and injection plots were carefully examined on a well by well basis, projections of future performance were made on the basis of a series of composite plots for either the entire unit or specific flooded or unflooded portions of the pool. The unit was subdivided into 17 distinct patterns (including both 80-acre and 40-acre, flooded and unflooded patterns) to provide a more detailed analysis of pool performance and to allow meaningful comparisons of pattern recoveries with respect to size and waterflood status.

The data available and the methodology used in achieving these objectives are fully documented in this report. The effective date of this study is January 1, 1989 since the production histories received were available up to the end of December 1988.

CONCLUSIONS

1. Based upon the recent reservoir mapping undertaken by CNWE, Daly Unit #1 contains 31.62 MMSTB (5028 10^3m^3) of oil originally in place. This oil is found in three separate reservoir units within the Lodgepole formation: the First, Main and Cruickshank Crinoidal members. The Cruickshank Crinoidal unit found at the base of the producing section is by far the most significant zone and contains approximately 78% of the OOIP. The remaining oil is nearly equally distributed between the First and Main Crinoidal members.

2. From decline curve analysis of the production history prior to implementation of the waterflood in 1971, the primary recovery for the Daly #1 Unit was estimated to be approximately 13.0% OOIP.

3. The current cumulative production of 6.57 MMSTB (1045 10^3m^3) oil has resulted in an overall recovery factor to date of 20.8% OOIP from the Lodgepole formation.

4. Future oil production from the entire Daly #1 Unit, assuming no changes to the current operations, is predicted to be an additional 1.56 MMSTB (248 10^3m^3) for an ultimate oil recovery of 25.7% OOIP under waterflood. This is based on decline curve analysis which predicts another 21 years of production from the Unit.

5. On an overall basis, the Lodgepole formation of the Daly #1 Unit is considered to have performed very well under waterflood. Theoretical recoveries based on detailed analysis of the considerable core data available, suggests waterflood recoveries of the order of 24% OOIP. However, the performances of the individual zones are almost impossible to determine since many wells have been completed openhole and most have been fractured, virtually guaranteeing the commingling of production from the separate reservoir units.

6. Oil recoveries are considered to have been affected to some extent by reservoir rock quality. This has been quantified in terms of

permeability variance ratios across the Unit. Reservoir homogeneity increases toward the south west in the downdip direction and undoubtedly allows for some degree of communication with the underlying aquifer. Although this portion of the pool is not under waterflood, oil recoveries are still relatively high (18% to 24% OOIP) suggesting the influence of a natural water drive. Reservoir heterogeneity increases toward the north and east, which is reflected in generally lower waterflood recoveries.

7. The performance of the 80-acre flood patterns, with predicted oil recoveries of 29.4% OOIP (to date 26.6% OOIP), is generally better than the theoretical prediction of 23.8% OOIP while the 40-acre flood patterns, with predicted recoveries of only 16.8% OOIP (to date 16% OOIP) have performed more poorly than the theoretical estimates of 20.0% OOIP. Reservoir heterogeneity has been taken into account in both sets of theoretical predictions, suggesting mechanical well problems (plus a higher number of shut-in wells) are responsible for the poorer recoveries of the 40-acre flood patterns.

8. Individual areas of the waterflood have considerably different voidage replacement ratios (VRR). Although the overall VRR of the flooded patterns is about 0.91, on a cumulative basis, some areas of the pool, specifically those in the north east are substantially overinjected. This result suggests that, overall, injection in the 40-acre patterns is accomplishing very little in terms of driving oil to the offset producers. It is presumed that the injection water is either being lost to the aquifer (via fractures or permeability channels) or that there are insufficient wellbores available to produce oil from these patterns because of the shut in wells.

9. The performance of the 80-acre flood patterns of Daly Unit #3, with oil recoveries to date of only 15.4% OOIP is comparable to that of the 40-acre patterns Daly #1 with a 16.0% recovery of OOIP and considerably worse than the Daly #1 80-acre patterns (26.6% OOIP). Although WOR's of the Daly Unit #3 patterns are substantially lower than those for the 40-acre patterns of Unit #1 (suggesting

considerable remaining unflooded oil), the VRR's are similar and relatively high. This feature would suggest that much of the injected water in Daly #3 is not effectively flooding the reservoir beds but perhaps is being lost to the underlying strata. Assuming this inference is correct, there appears to be a considerable incentive to drill additional producers on 20-acre spacing in order to accelerate the recovery of the remaining oil reserves in the Daly #3 Unit.

10. The overall efficiency of the existing Daly #1 Unit waterflood can likely be improved without necessarily expanding the waterflood region. Rather, these production enhancements can be achieved by either:

    (a) Reallocating water injection volumes to optimize VRR's on all flood patterns.

    (b) Selectively acidizing those wells where productivity has been reduced by gypsum deposition.

    (c) Deepening, redrilling or recompleting specific wells in the pool.

    (d) Increasing fluid offtake from certain wells.

11. Implementation of a polymer waterflood could theoretically increase the ultimate oil recovery of the entire Daly #1 Unit by about 2.61 MMSTB (8.2% total OOIP) or 39.7% of the oil produced to date. However, it is unlikely that such a recovery enhancement could now be achieved in practice since water breakthrough has already occurred in most of the offset producers and current water oil ratios are high. Implementation of polymer addition would have been more likely to succeed earlier in the life of the flood before widespread water breakthrough.

RECOMMENDATIONS

The following specific recommendations have been prepared as discussed in detail in Section 8. They are presented here in order of priority where the priority has been determined on the basis of:

- Risk
- Reward
- Cost

1. Selectively acidize the following three wells:

	Potential Rate Increase (STB/D)
16-4-10-28 W1M	10
3-4-10-28 W1M	9
1-9-10-28 W1M	8
	27 STB/D (4.3 m^3/d)

Should these repairs prove successful, there are another seven wells where similar treatments might add another 37 STB/D (5.9 m^3/d) to the Unit production. At a relatively low cost of $12,000 per treatment, these are considered low risk, and therefore <u>very high priority recommendations</u>.

2. Deepen the following wells to the base of the Cruickshank Crinoidal member:

	Potential Rate Increase (STB/D)	Potential Incremental Oil Reserves (MSTB)
9-5-10-28 W1M	25	285
5-4-10-28 W1M	20	122
7-5-10-28 W1M	20	94
	65 (10.3 m^3/d)	501 (80,000 m^3)

Based on the results of additional drilling, there are another four wells where there may be possibly another 56 STB/D (8.9 m^3/d) of rate increase and incremental reserves of 493 MSTB (78,000 m^3).

At the reasonably low cost of $25,000 per deepening job, these are considered medium risk and therefore high priority recommendations.

3. The following locations are recommended for redrilling:

	Potential Rate Increase (STB/D)	Potential Incremental Oil Reserves (MSTB)
15-4-10-28 W1M	15	454
10-4-10-28 W1M	10	107
12-3-10-28 W1M	10	56
	35 (5.6 m^3/d)	617 (98,100 m^3)

Possibly one well drilled between locations 15-4 and 10-4 might suffice to recover unflooded oil in 40-acre patterns #11 and #14. This is relatively high cost ($200,000) and high risk and should therefore be considered a medium priority recommendation.

4. Only six wells in the Unit are currently not pumped off (15-32, 16-32-9-28, 11-4-, 12-4-, 2-5- and 9-5-10-28). However, with the exception of 16-32 and 9-5, increased offtake from the other four wells is probably not possible with conventional pumping units at these depths. For 16-32 and 9-5, larger pumping units could be considered at a cost of about $60,000 for potential rate increases of 11 STB/D and 5 STB/D, respectively. This is relatively high cost, medium risk and we therefore consider this to be a medium priority recommendation.

5. Should the 15-4/10-4 redrill be successfully completed as an economically producing oil well, then the drilling of an injector in 80-acre pattern #7 at location 11A-4-10-28 should be considered. A potential oil rate increase of 11 STB/D (1.7 m^3/d) has been estimated along with an additional incremental recovery of 161 MSTB (25,600 m^3) of oil from this waterflood pattern. This is a high cost ($140,000) operation and very high risk. We would classify this then as a low priority recommendation. Should a new injector indeed prove to be economically recovering additional oil, there is another potential injector location in 3A-5-10-28 in 80-acre pattern #2.

6. Finally, the voidage replacement ratios in the patterns could be adjusted to better approximate current values of 1, particularly in the 40-acre patterns where the VRR's are presently very high. This should be done in stepwise fashion in order to ensure no detrimental effects on production. Also, overall water production volumes required to be disposed of might need to be taken into account. Since, in general, VRR's are close to 1, this is considered a low priority recommendation.

DISCUSSION

1.0 LANDS AND WELLS OF INTEREST

Daly Unit #1 is located in Townships 9 and 10, Range 28 W1M, approximately 24 km southwest of the town of Virden, Manitoba.

Figure 1.1 is a land map of the study area; only those wells lying within the unit outline have been considered in this report. The present status of all wells in Daly Unit #1 is summarized in Table 1.2. Currently, there are 33 active producers and 9 injectors operating within this unit.

2.0 RESERVOIR DESCRIPTION

2.1 Reservoir Geology

A detailed description of the Daly area can be found in the 1960 publication by McCabe (Reference 1). Oil production in the Daly field is obtained from Mississippian strata comprising the lower sections of the Lodgepole formation. The approximate subsurface depth of the reservoir section in Daly Unit #1 is 2490 ft. The Lodgepole section can attain thicknesses of 100-150 ft. in most portions of the pool. The productive members of the Lodgepole include the following units, in descending order: the upper Lodgepole, the Daly member composed of the First and Main Crinoidal (or alternatively, the Middle and Lower Daly sections), the Cruickshank Shale facies, and the Cruickshank Crinoidal facies.

These reservoir units consist of slightly argillaceous, vuggy crinoidal limestone which is dolomitic in part. These porous limestones grade laterally into and are interbedded with a tight dolomite. This lateral litho-facies change results in a reduction of porosity and permeability which acts as the main mechanism for local oil entrapment. Structurally, the Daly #1 unit consists of a broad, somewhat irregular asymmetrical nose plunging to the southwest (see First Crinoidal Structural Contour map, Figure 2.1). There is effectively no structural closure within the producing area.

2.2 Reservoir Energy Sources

Primary oil recovery up to the late 1960's exhibited relatively rapid decline rates for both oil and gas production (see Figure 2.2) and showed little or no evidence of water encroachment. These observations, in addition to the available core analyses, suggested good effective oil permeability but low reservoir energy and an ineffective water drive. There are, however, some exceptions to this generalized reservoir performance. A natural water drive appears to be active at the downdip southwestern portion of the unit. Cumulative WOR's in this region are relatively high while oil recoveries in the three southernmost 80 acre unflooded patterns rival those of more northerly waterflooded patterns. There is also some evidence (McCabe, Reference 1) for an active water drive towards the eastern half of Section 3 (immediately outside the Daly #1 Unit). The suggestion was made that some sections of the Lodgepole formation near this area could communicate locally, possibly by fractures, with underlying waterbearing strata other than the First, Main or Cruickshank Crinoidal beds. (This might provide a possible explanation of the extremely high voidage replacement ratios apparent in the northeastern 40 acre flood patterns of Daly Unit #1 - refer to more detailed discussion in Section 8.)

2.3 Reservoir Rock Properties

Most of the wells in the field were drilled in the early 1950's and consequently, log quality is rather poor. Only radioactive logs were run on most wells; in addition, a limited number of sonic logs were available. Log interpretation is tenuous at best.

Fortunately, the main reservoir section comprising the First and Main Crinoidal, Cruickshank Shale and Cruickshank Crinoidal zones was cored in its entirety in many wells. Conventional core analyses were obtained on microfiche from 12 wells within the Daly #1 Unit plus an additional 8 wells immediately outside the Unit boundary. Assignments of pay thicknesses for each of the Lodgepole producing units were made strictly on the basis of core data (refer to Section 3, Estimated Oil In Place).

2.3.1 Porosity-Permeability Relationships

Core data indicates comparatively high permeability and porosity for most of the producing sections; oil permeabilities generally range from about 2 to 15 md with porosities in the order of 6 to 10%.

Vertical communication appears fairly limited between the reservoir beds since vertical permeabilities are nearly an order of magnitude lower than the corresponding horizontal values.

Appendix 1 contains core permeability/porosity cross-plots for all the available core within or immediately adjacent to Daly Unit #1. Overall, the relationship between core porosity and permeability is rather poorly defined and most of the cross-plots show a wide scatter of data points. The strongest correlation between core porosity and permeability was exhibited by the Daly 7-5-10-28 W1M core where the correlation coefficient was found to be 0.644. The remaining wells showed much weaker correlations which the average coefficient being in the order of 0.05 to 0.20.

For those four wells: 12-3, 12-4, 7-5, 15-5 exhibiting reasonably high correlation coefficients ($R > 0.25$) a combined core permeability vs. cross-plot was constructed. The average trend displayed in Figure 2.3 is described by:

$$\log k = .140\ \phi - .876$$

A previous reservoir study (Reference 2) derived a connate water vs. permeability relationship whereby an air permeability cut-off of 1.0 md was established. Given the permeability-porosity relationship shown in Figure 2.3, this corresponds to a porosity cut off of approximately 6.2%.

2.3.2 Water-Oil Relative Permeability Relationships

A series of waterflood tests were conducted form core plug samples (extracted, dried, resaturated) taken from Daly 15-1-10-28 W1M (Unit #3). The results of these studies are provided in Reference 3. Given the initial pore volume of each of the samples, the water/oil viscosity ratio, μ_w/μ_o, plus the measurements of the volume of water produced vs. the volume of oil produced, the ratio of relative permeabilities, k_{rw}/k_{ro} was calculated vs. S_w using Welge's method (Reference 4).

The average k_{rw}/k_{ro} curve vs. S_w curve was obtained by statistically averaging points from each of the eleven composite curves. The resultant curve is shown as Figure 2.4. The waterflood tests on 15-1 also provided estimates of average initial water saturation, residual oil saturation as well as end point water permeability. The results are summarized as follows:

$S_{wi} = 0.395$
$S_{or} = 0.28$
$k_{rw}/k_{ro} = 0.65$

2.3.3 Gas-Oil Relative Permeability Relationships

Although Reference 3 describes a series of gas-oil relative permeability tests which were apparently run on a selective set of core samples from the Daly 15-1 well, the final results of these gas drive tests could not be located in the Chevron files.

Consequently, theoretical solution gas drive recoveries for the Lodgepole formation in the Daly field could not be estimated.

2.4 Reservoir Heterogeneity

Appendix 2 contains Dykstra-Parson's Permeability Variance Plots constructed from all the available core data from Daly Unit #1. The co-efficient of variation is defined as:

$$V = \frac{k_{50\%\ probability} - k_{84.1\%\ probability}}{k_{50\%\ probability}}$$

A completely uniform sand has a co-efficient of variation of zero and a completely heterogeneous rock, a variance of 1. The results of these calculations are detailed in Table 2.1 and plotted on the area map of Figure 2.5. The permeability variance ranges from about 0.60 to 0.70 throughout most of the cored wells. The two wells 9-32 and 7-5 define a more homogeneous area (V ≃ .50) near the southwestern portion of the Unit while the 12-3 well, at the eastern edge of the unit, is rather heterogeneous (V = .78).

The relatively high coefficients of variation are consistent with the fairly heterogeneous character of the subject Mississippian formation consisting of several distinct units each of which is independently rather heterogeneous, e.g., cherty limestone zone, crinoidal zone and argillaceous limestone (shaly) sections.

2.5 Reservoir Fluid Properties

A search of the CNWE Daly Unit #1 and #3 files plus discussions with Chevron's Reservoir Engineer responsible for Daly Unit #3, yielded relatively little data on reservoir fluid properties. The primary source of fluid data was a California Research Corporation reservoir fluid study (Reference 5) performed on a bottomhole sample from Daly 6-10-10-28 W1M immediately outside the eastern boundary of Daly Unit #1 (refer to area map, Figure 1.1). The pertinent PVT data extrapolated/interpolated from the available fluid studies is summarized in Table 2.2.

The measured bubble point pressure, P_b = 436 psia (3000 kPa) indicates the Lodgepole zone was highly undersaturated at initial reservoir pressure, P_i ≈ 1000 psia (6895 kPa). The formation volume factors ($ß_o$) and solution GOR values given on Table 2.2 have all been corrected to the separator conditions of 45°F and 15 psia. Oil viscosities below the bubble point were determined by applying standard correlations. Reference 5 noted that considerable quantities of wax or asphaltic precipitate (melting point ≈ 115°F (46°C)) were found in the 6-10 fluid samples. The current reservoir temperature of the Lodgepole section is estimated to be 79°F (26°C).

3.0 ESTIMATED OIL IN PLACE

3.1 Methodology

The O.O.I.P. values for the First and Main Crinoidal zones of the Daly Unit #1 were determined from the net porosity-thickness maps of these two sections (Figures 3.1 and 3.2) provided by CNWE (M. Raymond, G. Lewis; May 1989). These maps were based primarily on the limited quantity of core data available from wells within and immediately adjacent to the Daly #1 Unit. The maps were constructed by applying uniform porosity and permeability cutoffs of 6% and 0.5 md to all cored intervals, regardless of the reservoir unit from which they originated. [The complete series of geological maps (including show maps, isopachous, Øh, kh maps) prepared for each of the three reservoir units is provided as Appendix 4].

An average Øh value for each zone was assigned to the 40 acre area surrounding each individual unit well. Since many of the unit wells did not penetrate the entire Cruickshank member, a representative Øh map for this reservoir zone could not be prepared. In order to obtain some estimate of the OOIP for this zone, an interpolated net/gross pay ratio was applied to the Cruickshank Shale/Crinoidal gross isopach (Figure 3.3) to obtain a reasonable estimate of the net pay per well spacing unit. A corresponding average porosity was also assigned to each 40 acre spacing unit, allowing a net Øh value to be calculated. These Øh figures are directly comparable to the Øh values determined for the two overlying Crinoidal units. The total Øh for all three reservoir sections was then summed for each unit well. The resultant total Øh map is given as Figure 3.4. This map indicates two main regions of the unit where the bulk reservoir volume is highest:

(a) The northern half of Section 4.
(b) The east central portion of Section 5.

Any future field production optimization schemes should take into account the distribution of oil reserves implied by this map.

Once the net ϕh had been determined for each well and each reservoir unit, the average water saturation and oil F.V.F. shown below were applied to obtain the original oil in place.

$$S_{wi} = .395$$
$$\beta_o = 1.095$$

Although these rock and fluid parameters could vary slightly from area to area or zone to zone in the pool, they are considered to be representative for the entire Daly Unit #1. Assuming an average porosity of 10%, these parameters give an average value of 429 STB/ac. ft. for correcting the bulk reservoir volume into an OOIP figure. This value compares to previous estimates ranging from 434 to 465 STB/ac. ft. for either the Daly #1 or #3 Units (see References 2, 13 and 14).

3.2 Distribution of Oil in Place

Based on the geological maps provided, the total original oil in place of the Daly Unit #1 was determined to be 31.62 MMSTB.

Table 3.1 provides details of the distribution of OOIP in each of the three reservoir units and for each individual well. The results are summarized by zone as follows:

Zone	$\bar{\phi}$ (%)	$\bar{h}$ (ft)	Total ϕh (ft.)	O.O.I.P. (MMSTB)
First Crinoidal	10	4.9	18.69	3.20
Main Crinoidal	9	6.1	21.05	3.61
Cruickshank Shale /Crinoidal	10	38.1	144.72	24.81
Total			184.46	31.62

From the foregoing tabulation it is very apparent that the Cruickshank Shale/Crinoidal member, containing fully 78% of the oil reserves, is the most important zone in the subject Daly unit. As discussed above, this reservoir horizon is not fully penetrated in several unit wells. This feature suggests a relatively inexpensive, low risk method to enhance current oil production rates would simply be to deepen a few wells in selected locations where the Cruickshank Crinoidal member has not been penetrated and/or where it attains its maximum thickness. This strategy is discussed more fully in Section 8.

4.0 OIL RECOVERY ESTIMATES

4.1 Primary Recovery

The primary reservoir drive energy for the Daly #1 Unit is provided by oil expansion above the bubble point, solution gas drive and possibly some limited bottom water drive in the southwestern and northeastern portions of the unit. The low initial solution GOR of 137 scf/bbl provides relatively little energy.

4.1.1 Material Balance

A material balance estimate of solution gas drive recovery alone at an abandonment reservoir pressure of 50 psi gives predictions of 7 to 13% OOIP. This calculation assumes a cumulative producing GOR of about 200 to 300 scf/bbl as well as a cumulative WOR of 2 to 3 which appear to be typical for the unflooded portions of the Daly pool.

4.1.2 Empirical (Arps)

The primary recovery for the Lodgepole formation based on the Arps (Reference 6) correlation for depletion drive reservoirs is predicted to be on the order of 14% OOIP.

4.1.3 Production Decline Curve Analysis

An exponential rate decline of 8.8%/year was evident in the Daly Unit #1 prior to the initiation of the waterflood in 1970 (see Figure 2.2). Based upon an extrapolation of this trend, the primary oil recovery, assuming a field-wide economic limit of 3720 STB/month (120 STB/D) is estimated to be 4.12 MMSTB or 13.0% OOIP. This recovery figure appears to be remarkably close to the material balance and empirical estimates described above.

Other estimates of unflooded primary oil recoveries are further discussed in Section 6 dealing with the individual pattern characteristics.

4.2 **Waterflood Recovery Predictions**

The various core and fluid properties discussed in Section 2.0 were used to estimate theoretical waterflood recovery factors for Daly Unit #1.

In summary the following theoretical recoveries were estimated as detailed in Table 4.1.

Buckley Leverett	-	6.5% OOIP
Stiles	-	26% OOIP
Dykstra Parsons	-	23% OOIP

As discussed below, we consider the Stiles and Dykstra Parsons prediction methods to give better results in heterogeneous carbonate reservoirs.

4.2.1 Buckley Leverett Fractional Flow

A fractional flow curve, based on the field-wide average water-oil relative permeability characteristics of the Lodgepole formation, is shown in Figure 4.1. The curve was developed using the Buckley Leverett theory (Reference 7). Using the Dietz modification to this theory (Reference 8), the fractional flow curve indicates that 32% of the original oil-in-place will be recovered assuming water breakthrough occurs at 90% water cut. This calculation assumes an initial water saturation of 39% and a residual oil saturation of 28% based on waterflood tests run on a series of Daly 15-1 cores. The maximum waterflood recovery at 100% water cut is estimated to be 57% of the original oil-in-place. These are pore volume recoveries and do not include vertical and areal sweep efficiencies.

Strictly speaking, the Buckley Leverett method of estimating waterflood recovery is applicable only to diffuse flow in homogeneous reservoirs. For the Lodgepole carbonates, however, the permeability variation and layering of the different units is likely to cause earlier water breakthrough and higher water cuts than would be predicted from the fractional flow theory.

An estimate of the vertical sweep efficiency that reflects the permeability variation of the stratified sands can be made using the expression (Reference 9):

$$\text{Vertical Sweep Efficiency} = \frac{1 - V^2}{M}$$

Where: V = Dykstra Parsons variance coefficient
M = End point mobility ratio

The series of V values for the various Daly Unit #1 wells is reported in Table 2.1. Based on oil water relative permeability measurements,

$$M = \frac{\mu_o}{\mu_w} \times \frac{k_{rw}}{k_{ro}}$$

$$= \frac{3.54}{0.86} \times 0.65$$

$$= 2.68$$

Since this value of M is greater than 1 the displacement of oil by water is less efficient after breakthrough and consequently, larger volumes of water must be injected to recover the remaining oil behind the flood front. Using the above formulae, the vertical sweep efficiencies for the Daly Unit #1 wells are estimated to range from 0.15 to 0.28. These vertical sweep efficiencies, coupled with an assumed areal sweep efficiency result in the recovery factors summarized in Table 4.1. Actual recoveries may be different, depending on capillary and gravity forces which are not directly addressed in the analysis. This method of estimating waterflood recoveries for heterogeneous carbonate reservoirs is not considered to give particularly good results.

4.2.2 Stiles Waterflood Calculations

Stiles (Reference 10) has presented a method of calculating oil recovery and water cut from stratified reservoirs. His approach assumes a linear waterflood, with no cross flow between reservoir layers. All available core analysis results from the Daly Unit #1 wells have been utilized to provide a description of reservoir layering. This has been coupled with the average Lodgepole oil-water relative permeability end points and fluid properties to perform the Stiles calculations.

Appendix 3 displays the results of these Stiles waterflood computations.

It should be noted that Stiles waterflood calculations only apply to a linear waterflood. Consequently, an areal sweep efficiency must be applied to arrive at the appropriate recovery factors as shown in Table 4.1. In practice, oil recoveries may be higher than predicted by Stiles calculation due to crossflow between the reservoir layers.

4.2.3 Dykstra Parsons Waterflood Calculations

Dykstra and Parsons have presented a method of calculating oil recovery from a stratified reservoir. This approach (Reference 11) correlates mobility, permeability variance and initial water saturation to predict recovery factors at various producing water cuts. The minimum recovery of oil in place at a producing water cut at 90% is predicted to be 19% for Daly 12-3-10-28 W1M while a maximum of 37% recovery of oil-in-place is predicted for the CanSup Thompson 9-32-9-28 W1M well.

Again, since the Dykstra Parsons waterflood calculations apply to linear waterflood, they must be coupled with an areal sweep efficiency to compute an appropriate recovery factor. The Dykstra-Parson's waterflood recovery estimates are also summarized in Table 4.1.

4.2.4 Areal Sweep Efficiency

The preferred method of determining areal sweep efficiencies is by using a numerical simulation model of the field. Despite the unfavourable mobility ratio, based on a series of standard waterflood correlations for the "quasi" inverted five spot flood pattern, the areal sweep efficiency is still expected to be on the order of 90% (Reference 12).

Assuming a 90% areal sweep efficiency and the range of vertical sweep efficiencies discussed above, the overall recovery factors for the series of Daly Unit #1 wells are given in Table 4.1.

5.0 FIELD PERFORMANCE

5.1 Historical Overview

Figures 5.1(a) and (b) show the historical performance of the Lodgepole formation of the Daly Unit #1 with respect to oil and water production plus oil cut versus time.

Production from the pool began in mid 1952 at about 500 STB/month and thereafter rose steadily during the first eighteen months of the field's life peaking at approximately 50,000 STB/month by early 1954. These high withdrawal rates were relatively shortlived, however; oil production levels had declined to about 20,000 STB/month by early 1956. These oil rates were sustained by drilling nine additional producers during 1955-1957. Beginning in 1960, the Daly field offtake rates began to experience exponential decline (refer to Figure 5.1(a)). The average decline rate during the period from 1960 through 1968 was estimated at 8.8%/year.

A pilot waterflood, centered about the 12D-4 well, was begun in 1970 by which time oil withdrawal rates had declined to about 9000 STB/month. The field was unitized in mid-1971. An expanded waterflood project was initiated in early 1972 with the drilling of three water injection wells (13C-3, 14D-4, 15D-4). By mid-1972 six injectors were in operation. The field's oil productivity showed a definitive and rapid response to water injection, with offtake rates rising to greater than 25,000 STB/month by mid-1973. Subsequently, the oil production rates began to decline rather rapidly at an estimated 12.7%/year until late 1978 when the rates had decreased to about 12,000 STB/month.

The drilling and completion of a seventh water injector, 13C-4-10-28 W1M, produced an almost immediate oil productivity response and withdrawal rates once again approached 20,000 STB/month by late 1979.

5.2 Oil Recovery to Date

The present oil production rate from the Lodgepole section is 295 STB/D or about 9,000 STB/month. The total cumulative oil produced as of the end of December, 1988 from the Daly Unit #1 was 6.57 MMSTB representing a recovery factor to date of 20.8% of the total OOIP. The cumulative oil and water production for the entire unit on an individual well basis as well as annually is provided in Table 1.2 and Table 5.1, respectively.

5.3 Projected Ultimate Recovery

The Daly Unit #1 production has been on exponential decline since the late 1970's and currently is declining at about 4.4%/year. Assuming no changes to the current operating conditions are implemented, Table 5.3 represents the expected future performance of the entire Daly Unit #1. An economic limit of 44,660 STB/year (120 STB/d) on a field-wide basis has been applied to this forecast based on 1989 operating costs (refer to Table 5.2 for details of this calculation). The ultimate oil recovery, assuming the continuation of the current decline trend, is thus expected to approach 8.13 MMSTB, equivalent to 25.7% of the OOIP in Daly Unit #1. Furthermore, the year of abandonment is predicted to be 2009 implying an additional 21 years of production from the unit.

The WOR curve was also plotted versus cumulative oil produced on a semi-log scale (Figure 5.2) to yield an extrapolation of the WOR when the pool's production has declined to the economic limit. For the subject unit, the limiting rate corresponds to a WOR of roughly 25 (96% water cut) which appears to be a reasonable cutoff for a mature waterflood.

Since only a portion of the unit is presently under waterflood, the recovery to date cannot be directly compared with the theoretical recovery calculations presented in Section 4.2. Relevant comparisons of theoretical vs. observed waterflood recoveries are presented in the following section.

6.0 FUTURE PERFORMANCE PREDICTIONS

6.1 Pattern Description

To determine the recovery efficiencies of the existing waterflooded portions of the unit as well as to predict the likely incremental reserves recoverable in the non-flooded sections of the pool, 6 x 80-acre plus 3 x 40-acre flooded patterns in addition to 4 x 80-acre plus 4 x 40-acre unflooded patterns were identified (see Figure 6.1).

Each of these patterns, both flooded and unflooded, were examined in some detail with respect to their OOIP, cumulative and current oil and water production plus water injection, cumulative and current WOR and voidage replacement ratio (VRR), as well as their cumulative oil recovery expressed as a percentage of OOIP. The results per pattern are provided in Tables 6.1 and 6.2 which list the pertinent cumulative and current reservoir performance parameters, respectively. The results are also plotted on the Daly Unit #1 base map as the series of Figures 6.1 through 6.12.

In order to assess the relative performance of both the flooded and non-flooded 80- and 40-acre patterns, plots of oil flow rate vs. time as well as WOR vs. cumulative oil production for the flooded patterns were prepared. The relevant tabular data as well as the corresponding graphs are provided as Table 6.3 through 6.6 and Figures 6.13 to 6.18, respectively.

6.2 Waterflood Areas

In order to effect a direct comparison of theoretical vs. observed waterflood recoveries, individual pattern recovery factors first had to be assigned. These were derived by assigning pattern-specific V values from the map of permeability variation, (Figure 2.5) and interpolating from the series of calculated recovery factors given in Table 4.1. The theoretical recoverable reserves per pattern were thus calculated (see Table 6.7). These, in turn, were compared to the current cumulative oil production for the flooded patterns. By applying decline curve analysis to the oil production plots (see Figures 6.13 and 6.14) and the WOR vs. cumulative oil production plots (see Figures 6.15 and 6.16), the theoretical ultimate oil recovery was estimated at the economic limit of 2.9 STB/D/well. The predicted future performance of both the 80-acre and 40-acre flooded patterns is documented in detail on Table 6.8 and is briefly summarized as follows:

Pattern Spacing	80-Acre		40-Acre	
		% OOIP		% OOIP
Total OOIP (MMSTB)	11.80	-	3.39	-
Theoretical Recoverable Oil Reserves (MMSTB)	2.81	(23.8)	0.681	(20.0)
Cumulative Oil Production to Date (MMSTB)	3.14	(26.6)	0.542	(16.0)
Extrapolated Ultimate Oil Recovery (MMSTB)	3.47*	(29.4)	0.571	(16.8)
Remaining Reserves (MMSTB)	0.33		0.29	
Ratio of Extrapolated Recovery to Theoretical	1.23		0.84	

*This ultimate oil recovery assumes production from the flooded 80-acre patterns is terminated once the WOR reaches 35 or at a water cut of about 97%.

Examination of the above recovery figures suggests that the performance of the 80-acre patterns is actually somewhat better than predicted while that of the 40-acre patterns is comparatively poorer than expected. Figure 6.2 shows that all six 80-acre patterns have oil recoveries as good as or better than predicted, suggesting that individual pattern optimization is not indicated, apart from small changes to the VRR's. Figure 6.2 also shows that 40-acre pattern 15 is performing as expected while patterns 13 and 14 are recovering less oil than predicted. The reasons for the lower recovery efficiency of the 40-acre patterns appears to be a combination of the poorer reservoir quality in the northeastern portion of the pool plus various mechanical problems in several wells within this region. These individual well problems, plus possible actions to alleviate them, are discussed in Section 8.0 - Recommendations to Improve Productivity.

6.3 Unflooded Areas

A similar decline curve analysis technique was applied to the unflooded 80-acre and 40-acre patterns to estimate the ultimate oil recovery in these portions of the Daly #1 Unit (refer to Table 6.9 for details). At the economic limit, the pattern recoveries are predicted to be as follows (refer to detailed rate forecasts in Table 6.10):

Pattern Spacing	80-Acre		40-Acre	
		% OOIP		% OOIP
Total OOIP (MMSTB)	5.09	-	3.56	-
Cumulative Oil Production to Date (MMSTB)	1.17	(23.0)	0.497	(14.0)
Extrapolated Ultimate Oil Recovery (MMSTB)	1.26	(24.6)	0.548	(15.4)
Remaining Reserves (MMSTB)	0.09		0.05	
Predicted Waterflood Recovery (MMSTB)	1.34	(26.2)	0.69	(19.5)

Included in this tabulation are the predicted theoretical waterflood recoveries, should these patterns be put under waterflood at some future date.

These results suggest that the three unflooded 80-acre patterns (1, 2, 3) at the downdip, southwestern extremity of the pool are already being rather effectively "flooded" by the natural waterdrive active in this portion of the unit. The only pattern with some potential for optimization appears to be pattern 7 with a current oil recovery of 16.5% OOIP (see Figure 6.2).

The performance of the individual 40-acre unflooded patterns (Figure 6.2) is considerably poorer than that of the 80-acre unflooded patterns and again is attributable to both the deterioration in reservoir quality plus the fact that four of the 40-acre pattern wells have been shut-in throughout much of the Unit's production history. Suggested re-drilling of several of these "problem" wells is discussed more fully in Section 8.0

7.0 COMPARISON TO DALY UNIT #3

As part of the scope of this study, a comparison was made between the pattern recoveries of Daly Unit #1 and Unit #3. The Daly #3 Unit, currently operated by Chevron, is located approximately 1.2 km to the east of Unit #1. It contains 44 active producers and 26 injectors producing oil from the same Mississippian Lodgepole section as Daly Unit #1 (see Figure 7.3).

7.1 Estimated Oil Reserves

Since detailed isopach maps were not available for the subject unit, original oil in place values were calculated assuming an average but representative set of rock and fluid parameters as follows (refer to Table 7.1 taken from Reference 13):

$S_{wi} = 0.40$
$B_o = 1.08$
$\emptyset = .109$
$\bar{h} = 47$ ft.

These inputs yield a value of 466 STB/ac. ft. for converting the bulk reservoir volume into an OOIP figure. When applied to the five sections (3200 acres) which the Daly Unit #1 covers, this conversion factor yields a rough estimate of the total oil originally in place as:

OOIP = 70.6 MMSTB

7.2 Field Performance

Figure 7.1 shows the historical performance of Daly Unit #3 in terms of its oil and water production rates plus WOR vs. time.

The present oil production rate from the Lodgepole Formation is about 540 STB/D. The total cumulative production as of December, 1988 from the subject unit was 9.26 MMSTB representing a recovery factor of 13.1% of the OOIP compared to a figure of 20.8% OOIP for Daly Unit #1.

Table 7.2 contains the cumulative volumes of produced oil, water and gas on an individual well basis, while Table 7.3 provides an account of the Unit's annual production figures.

7.3 Projected Ultimate Recovery

Figure 7.1 includes a plot of total annual Unit #3 oil production vs. time. Although the production rates for the last four years appear somewhat higher than the trend, a previous average exponential decline rate of about 2.0%/year can be identified. (These increased oil production rates may be the result of increased injection rates in Unit #3.) Assuming the same economic limit as derived for Daly Unit #1, 2.9 STB/D/well or 203 STB/D for the entire unit, yields a predicted total oil recovery of 15.40 MMSTB. This cumulative production figure corresponds to 21.8% OOIP for Daly Unit #3 as compared to 25.7% for Daly Unit #1.

To provide an estimate of the water cut at pool abandonment, the method proposed by Ershaghi and Abdassah (Reference 15) was used whereby the fractional water flow (f_w) was plotted versus cumulative oil produced on special scale graph paper. Table 7.3 provides the pertinent computations while Figure 7.2 shows a plot of the results for the last four years of water cut trends. Based on the previous identified oil decline rate of 2.0%/yr at a cumulative oil production volume of 15.40 MMSTB, the projected water cut is 94%. This compares to a water cut estimate at abandonment of 96% for Daly Unit #1. At 96% water cut, recovery from Daly Unit #3 would be 16.6 MMSTB or 23.7% OOIP as compared to 25.7% for Daly Unit #1. Finally, assuming no changes to the field's current operating conditions, Table 7.4 was constructed showing the expected future performance of the Daly #3 Unit. This table predicts the Unit should produce for another 50 years with pool abandonment occurring in 2038. Obviously, there is potential for accelerating this recovery either by increased injection rates and/or possible infill drilling. As will be discussed later, since current VRR's are already excessively high, infill drilling seems preferable.

7.4 Pattern Analysis

For the purposes of this study, some seventeen 80-acre inverted five-spot patterns were identified in Daly Unit #3. Each of these patterns was evaluated with respect to its cumulative oil and water production plus water injection volumes, WOR and VRR. As well, the cumulative oil recovery of each pattern, expressed as a percentage of OOIP, was computed. The results of these analyses are provided in Figures 7.3 through 7.8 as well as Table 7.5.

The individual pattern recoveries to date for Daly #3 expressed as a percentage of OOIP, are substantially less than the recoveries of the analogous 80-acre patterns in Daly Unit #1. While thirteen patterns have oil recoveries greater than 10%, only five patterns have recoveries to date in excess of 20% OOIP. The remaining four patterns have recoveries ranging from roughly 6 to 9%.

In summary, oil recoveries to date for the flooded portions of the two Daly units are:

	Daly Unit #1		Daly Unit #3
	80-Acre	40-Acre	80-Acre
Total OOIP (MMSTB)	11.80	3.39	30.02
Cumulative Oil Production to Date (MMSTB)	3.14	0.542	4.63
Oil Recovery (% OOIP)	26.6%	16.0%	15.4%

The Daly Unit #3 80-acre flood pattern recovery, on a percentage basis, is somewhat more than half of the recovery observed for similar sized patterns in Daly #1 and is comparable to that observed for the 40-acre patterns of Daly Unit #1.

7.5 Comparison of Flood Pattern Reservoir Performance - Daly #3 vs. Daly #1

Most of the oil production in Unit #3 has been obtained at relatively low WOR's compared to those observed for Daly Unit #1. On a cumulative basis, the Unit #3 WOR's range from less than 0.1 to about 0.8 with an average of 0.29 while those for the Daly #1 80-acre flood patterns are all in excess of 1.0 with an average WOR of 4.3 and a maximum figure of 6.9. The consistently low water cuts and relatively low current recoveries observed for the flooded patterns of Daly Unit #3 suggest that considerable unflooded oil remains in Daly Unit #3 and it will take an excessively long time to recover this oil under current producing conditions.

Moreover, on a cumulative basis, the VRR's for Daly Unit #3 are significantly greater than those of Daly #1. All the VRR's for Unit #3 are greater than 1.0; four figures are in excess of 5 with the maximum value reaching 13.8. For Daly Unit #1, in contrast, only one cumulative VRR exceeds 2.0, one is less than 1.0, while the remainder range from 1.0 to 1.5. This means the current flood in Daly Unit #3 is not efficiently displacing oil to the producers.

It is also instructive to compare the current water production, water injection and VRR's of the various flood patterns within the two Daly units:

	Production (STB/D)			Water Injection (STB/D)	Average Wellhead Injection Pressure (psig)	VRR
	Oil	Water	Total			
Daly Unit #1 (40-acre)	21	44	65	1046	1200	15.61
Daly Unit #1 (80-acre)	154	2756	2910	3349	1170	1.145
Daly Unit #3 (80-acre)	234	201	435	2313	1160	5.10

The high VRR's plus the relatively low oil recoveries of both the 80-acre patterns of Daly #3 and the 40-acre patterns of Daly #1 suggest that much of the water currently injected in both regions (80% and 94%, respectively) is being lost to the aquifer, possibly through localized fractures, and consequently, is not effectively flooding the reservoir section. Assuming this is indeed the situation in Daly Unit #3, it would appear that increased oil recoveries can likely only be achieved by drilling infill producers in the subject unit.

8.0 RECOMMENDATIONS TO IMPROVE PRODUCTIVITY

In light of the pattern analysis of Section 6.0, each pattern as well as each individual well production plot was examined to identify possible actions which might be taken to optimize the recovery of the remaining oil reserves of both the flooded and unflooded portions of the Daly #1 Unit. These recommended actions can be grouped into six basic types:

(a) Reallocate water injection volumes to optimize VRR's on several flooded patterns.

(b) Selective acidize a number of key producers to alleviate gypsum deposition problems.

(c) Deepen selected wells to more fully exploit the remaining oil reserves within the Cruickshank Crinoidal member.

(d) Pump off selected wells.

(e) Redrill specific wells to improve overall recoveries, particularly in the northeastern portions of the pool where mechanical problems have apparently caused premature suspension of several wells.

(f) Drill new injectors for unflooded patterns.

A dramatic example of rate improvement which can be achieved via a selective acidization treatment is the production plot from the 1-5-10-28 W1M well which shows a productivity increase in early 1988 from about 33 STB/mo (1.1 STB/D) at 10 to 20% oil cut to roughly 200 to 300 STB/mo (≈8 STB/D) at 30 to 45% oil cut within a few months of such an acid job (refer to Figure 8.1).

Wherever possible, an attempt has been made to quantify, both the incremental oil recovery as well as the incremental oil production rates expected as a result of each of these suggested measures. The approximate costs of each of these recommendations plus their expected payout times have also been included.

Finally, on the basis of their overall impact on the Unit's oil production and ultimate recovery, a priority ranking has also been assigned to each of these recommendations. The results, on both a pattern and individual well basis, are presented on Tables 8.4 to 8.6.

The individual well recommendations are listed in order of their priority; risk has also been considered in the following tabulation. That is, remedial actions, such as reallocating water injection volumes which are virtually risk-free are listed prior to other well operations such as selective acidization, deepening or redrilling all of which have a moderate to relatively high degree of risk associated with them.

8.1 Reallocation of Water Injection Volumes

An immediate measure which could be taken to optimize oil recovery within the Daly #1 Unit is to reallocate the current water injection volumes to achieve VRR's closer to unity. Flood patterns are listed below in order of the severity of their VRR problems.

Pattern	Current VRR	Current $q_{w(inj)}$ (STB/D)	Suggested $q_{w(inj)}$ (STB/D)
9	0.42	260	625
6	0.81	765	950
4	0.83	585	700
14	22.4	695	30
10	6.98	450	65
15	5.06	250	50
5	2.34	645	275
8	2.11	645	300
13	1.78	100	55
		4395	3050

These are numerical calculations only to achieve VRR values of 1. Practically, severe changes should be done in step fashion and offset production monitored to ensure no detrimental effects are taking place.

8.2 Selective Acidization Treatments

The productivities of numerous wells in the Daly field are currently reduced due to gypsum deposition problems. It is well documented that such wells respond readily to selective acid stimulation. The following wells are considered candidates for this remedial treatment:

		Possible Incremental Oil Production Rate (STB/D)
1.	16-4-10-28 W1M	10
2.	3-4-10-28 W1M	9
3.	1-9-10-28 W1M	8
4.	9-4-10-28 W1M	6
5.	8-9-10-28 W1M	6
6.	5-10-10-28 W1M	6
7.	2-4-10-10-28 W1M	5
8.	3-9-10-28 W1M	5
9.	6-4-10-28 W1M	5
10.	1-8-10-28 W1M	4
	Sub-Total	64 STB/D

These wells were selected based on detailed evaluation of their gross oil and oil cut production histories. We recommend this order of priority and a further review after say, the first three wells have been acidized.

8.3 Selected Well Deepening

Several wells in the Daly #1 Unit do not penetrate the Cruickshank Crinoidal member and hence the considerable volume of oil reserves within this section are possibly not being fully exploited. The following wells are proposed for deepening (and selective acidization) in order to remedy this situation. The incremental oil volume is based on an estimate of the unpenetrated net pay and assumes (perhaps optimistically) that no oil has been recovered to date below the TD of the well. The incremental oil rates were estimated in the same way (refer to Table 8.1 for details).

		Possible Incremental Oil Production Rate (STB/D)	Possible Incremental Oil Recovery (MMSTB)
1.	9-5-10-28 W1M	25+	.285
2.	5-4-10-28 W1M	20+	.122
3.	7-5-10-28 W1M	20	.094
4.	8-5-10-28 W1M	16	.151
5.	10-5-10-28 W1M	15	.131
6.	2-5-10-28 W1M	15	.115
7.	4-4-10-28 W1M	10	.96
	Sub-Total	121+ STB/D	.994 MSTB

These values may be somewhat optimistic - again, we recommend deepening say the first three wells and observing the actual production increases.

8.4 Optimization of Pumping Unit Performance

Only a few wells are not fully pumped off (15-32-, 16-32-9-28, 11-4-, 12-4-, 2-5-, 9-5-10-28). However, with the exception of 16-32 and 9-5, their total fluid production volumes are currently in excess of 600 STB/D which is likely near the lifting capacity of conventional pumping units for this reservoir depth. Hence, it is likely that little can be done to increase the productivity of these wells without resorting to more sophisticated pumping systems using, for example, fiberglass rods.

Examination of recent fluid level records suggests that some rate improvements could be achieved at wells 16-32 and 9-5 with the installation of larger size pumping units. Although this option has low risk, we have downgraded its priority due to the relatively high costs (≃$60,000/unit) involved and consequently, the longer payout times. Incremental oil pump rates were estimated assuming total fluid production of 600 STB/D and in conjunction with current oil cut values. We would anticipate:

		Possible Incremental Oil Production Rate (STB/D)
1.	16-32-10-28 W1M	11
2.	9-5-10-28 W1M	5
	Sub-Total	16 STB/D

8.5 Producer Redrilling

Three wells 10-4-, 15-4- and 12-3-10-28 W1M have all been shut-in for a number of years due to mechanical problems.

10-4 was producing oil at about 300 STB/mo at 10% water cut prior to a frac in 1960 which resulted in its going to 100% water; possibly the frac extended into the underlying aquifer. Remedial squeeze jobs have evidently failed.

Similarly, 15-4 was completed and frac'd in 1955 which resulted in oil production rates of about 200 STB/mo at water cuts of 85 to 90%. Following a cement squeeze, reperforating and a second sand frac treatment, oil flow rates dropped to less than 1 STB/D at a water cut of about 97%. An attempt in 1973 to drill out the cement and acidize open hole succeeded in reducing the water cut to about 70%; however, oil flow rates remained very low. The well was subsequently suspended.

Finally, 12-3 following its initial completion and frac treatment produced for nearly 10 years at rates of 200 to 400 STB/mo and water cuts of 60 to 70%. Following a second fracture treatment in 1966, 12-3 produced mostly water leading to its suspension later the same year.

All three wells are located in the northeast portion of the Unit where reservoir heterogeneity is greater, oil recoveries are lower, and the potential for communication with the underlying aquifer either through natural fractures or channelling appears to be highest. Consequently, redrilling any of these wells at off-target locations must be recognized as a high risk but potentially high reward venture. Primarily because of this considerable risk and uncertainty, we have assigned a correspondingly lower overall priority to well redrilling.

The incremental oil recovery is based on the difference between the cumulative oil produced by each well prior to shut-in and its predicted ultimate recovery, also taking into account the recoveries to date of offsetting producers. The incremental oil rates were based on the individual well productivities prior to suspension (refer to details in Table 8.2). We would prioritize the three wells as follows:

		Possible Incremental Oil Production Rate (STB/D)	Possible Incremental Oil Recovery (MMSTB)
1.	15-4-10-28 W1M	15	.454
2.	10-4-10-28 W1M	10	.107
3.	12-3-10-28 W1M	10	.056
	Sub-Total	35 STB/D	.617 MMSTB

Again, considering the higher risks involved, we would recommend drilling the first off-target well near the 15-4 location. Provided the completion is successful, the well's oil and water production should be monitored for several months prior to redrilling the 10-4 off-target location.

8.6 Injection Well Drilling

Finally, there appears to be some potential of expanding the waterflooded areas by drilling injectors in the two 80-acre unflooded patterns, specifically 2 and 7 with the highest volumes of remaining oil reserves. In view of the fact that Daly Unit #1 is a relatively mature waterflood, injection well drilling has been assigned a low priority accompanied by a high risk factor. This is particularly true for pattern 7; indeed, the risk for this injector is sufficiently high that it should not be considered until the

10-4-10-28 W1M (currently suspended) has been successfully re-drilled and has been on production for several months.

The risk associated with an injector in pattern 2 is also high since this pattern is located at the extreme southwest margin of the Unit where, it could be argued, the natural water drive is already rather effective in enhancing the primary oil recovery. Pattern 2 has been suggested as a candidate for waterflood since its cumulative recovery to date of 17.9% OOIP (see Figure 6.2) is less than those of the adjacent unflooded patterns (21.1% and 24.1% OOIP in patterns 1 and 3, respectively).

The two proposed water injection wells are:

		Possible Incremental Oil Production Rate (STB/D)	Possible Incremental Oil Recovery (MMSTB)
1.	11A-4-10-28 W1M (Pattern 7)	11	.161
2.	3A-5-10-28 W1M (Pattern 2)	10	.227
	Sub-Total	21 STB/D	.388 MMSTB

The incremental oil volume is based on a comparison between the pattern oil recovery to date and the estimated ultimate pattern oil recoveries (detailed on Table 6.7). The incremental oil production rates have been estimated from the current productivities of the offsetting flooded patterns (refer to Table 8.3 for details).

The overall impact of the above series of recommendations, if fully implemented, on the oil productivity of the Daly Unit #1 is rather difficult to assess since the response time of the various producers to the selective acidization treatments, deepening or injector drilling will obviously vary. The time period over which many of the recommended remedial measures might be carried out could also extend over several years.

However, in order to provide a concise overview of the initial and total potential productivity increases, the possible incremental oil recoveries as well as our assessment of the relative risks and the indicated priorities, we have compiled the following summary listing:

	Incremental Oil Production Rate (STB/D)		Incremental Oil Recovery (MMSTB)			
Action	Initial Workovers/ Drilling (STB/D)	Total Potential (STB/D)	Initial Workovers/ Drilling (MMSTB)	Total Potential (MMSTB)	Priority	Risk
Selective Acidization	27	64	-	-	Very High	Low
Well Deepening	≈65	121	.501	.994	High	Medium
Installation of Larger Pumping Units	11	16	-	-	Medium	Low
Redrilling Producers	15	35	.454	.617	Medium	High
Drilling Additional Injectors	11	21	.161	.388	Low	Very High
Totals	129	257	1.116	1.999		

9.0 FEASIBILITY OF CONDUCTING A POLYMER FLOOD

The final objective of this project was to conduct a preliminary screening study on applying a polymer flood in Daly Unit #1.

This objective can most readily be accomplished by comparing the theoretical increase in oil recoveries expected by reducing the mobility ratio from its current value of 2.68 to say, for example, a value of unity.

Rather than an estimated areal sweep efficiency of 90% at a producing water cut of 90% for the current mobility ratio, the areal sweep efficiency for an oil/water/polymer system is predicted to be of the order of 98%. Similarly, reducing the mobility ratio is expected to increase the Stiles estimates of waterflood recoveries from 23% to about 27% OOIP and the corresponding Dykstra-Parsons' predictions from 26% to 34% OOIP. As a rough estimate, an increase of 35% was applied to the previous waterflood recovery estimates and takes into account the improvements in both areal and vertical sweep efficiencies.

Applying this increased recovery efficiency to the calculation of theoretical oil recoveries of both the 80-acre and 40-acre floods results in predicted recoverable oil reserves of 3.79 MMSTB (32.1% OOIP) and 0.919 MMSTB (27.1% OOIP), respectively, for these two sets of patterns.

When applied to current extrapolations of ultimate oil recovery, these predicted values become 4.68 MMSTB (39.7% OOIP) and 0.77 MMSTB (22.7% OOIP) for the 80-acre and 40-acre flood patterns, respectively. Hence, in overall terms, a polymer-flood project might realistically be expected to improve the oil recovery from the waterflooded areas in the Daly #1 Unit by some 1.41 MMSTB (9.3% total OOIP of flooded patterns).

Likewise, the <u>theoretical</u> oil recoveries in the currently unflooded portions of Daly Unit #1 are estimated to be about 1.81 MMSTB (35.5% OOIP) and 0.93 MMSTB (26.2% OOIP) for the 80-acre and 40-acre unflooded patterns, respectively. Apply the same ratio of the extrapolated to the theoretical oil recovery as observed in the flooded portions of the pool yields ultimate oil recoveries of 2.23 MMSTB (43.7% OOIP) and 0.78 MMSTB (21.9% OOIP) for the 80-acre and 40-acre unflooded patterns, respectively. Thus, implementation of a polymer flood could increase oil recoveries in the unflooded segments of the Unit by about 1.20 MMSTB (13.9% total OOIP of unflooded patterns).

In practical terms, however these incremental oil volumes could likely never be recovered from the flooded patterns since water breakthrough has already occurred in many of the offsetting producers. Also, the combined effects of the reservoir heterogeneity plus the apparent water "sink" in both the flooded and unflooded 40-acre patterns to the northeast of the Unit could likely cause significant reductions from the theoretical predictions in this portion of the pool.

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TABLES

TABLE 1.1

DALY UNIT #1
WELL COMPLETION DETAILS

LOCATION	TD (ZONE)	PERF INTERVAL (FT)	TREATMENT	PRODUCING ZONE
10-32-9-28W1	1ST CRIN.	OPEN HOLE		1ST CRIN.
15-32-9-28W1	1ST CRIN.	OPEN HOLE		1ST CRIN.
16-32-9-28W1	1ST CRIN.	OPEN HOLE	SAND FRAC	1ST CRIN.
13-33-9-28W1	1ST CRIN.	OPEN HOLE	SAND FRAC	1ST CRIN.
12-3-10-28W1	DALY SHALE	2502-2506	ACID,VISCOFRAC	CRUICK CRIN
13-3-10-28W1	CRUICK CRIN	OPEN HOLE	SAND FRAC	
13-3C-10-28W1	CRUICK CRIN	2440-2450	ACID	1ST CRIN
		2494-2514		CRUICK CRIN.
2-4-10-28W1	DALY SHALE	2530-2535	STRATAFRAC	CRUICK CRIN.
3-4-10-28W1	MAIN CRIN	OPEN HOLE		
4-4-10-28W1	CRUICK SHALE	OPEN HOLE	SAND FRAC	
5-4-10-28W1	MAIN CRIN	OPEN HOLE	SAND FRAC	
5A-4-10-28 W1	CRUICK CRIN	2495-2501	ACID	
		2514-22,2532-38		MAIN CRIN,CRUICK SHALE
		2566-2572		CRUICK CRIN
6-4-10-28W1	CRUICK SHALE	OPEN HOLE	SAND FRAC	
9-4-10-28W1	CROMER SHALE	2513-2518	ACID,SAND FRAC	CRUICK CRIN
10-4-10-28W1	CROMER SHALE	2515-2519	SAND FRAC	MAIN CRIN
11-4-10-28W1	CRUICK CRIN	OPEN HOLE	HYDROFRAC	
12-4-10-28W1	CRUICK SHALE	OPEN HOLE	SAND FRAC	
				1ST CRIN.
12B-4-10-28W1	CROMER SHALE	2497-2504		
		2518-2542	ACID	MAIN CRIN, CRUICK SHALE
		2552-2580		CRUICK CRIN
12D-4-10-28W1	CRUICK CRIN	2556-62,2538-47	ACID	CRUICK CRIN
		2502-2512		MAIN CRIN
13-4-10-28W1	CROMER SHALE	OPEN HOLE	HYDROFRAC	
13C-4-10-28W1	CRUICK CRIN	2492-98,2512-18		MAIN CRIN
		2530-36,2562-66		CRUICK SHALE/CRIN
14-4-10-28W1	CRUICK CRIN	2490-2500	SAND FRAC	CRUICK SHALE
		2503-2508		CRUICK CRIN
14D-4-10-28W1	CROMER SHALE	2544-64,2520-40	ACID	CRUICK CRIN
		2509-14,2567-74		CRUICK SHALE/CRIN
15-4-10-28W1	CRUICK CRIN	OPEN HOLE	SAND FRAC	
15D-4-10-28W1	CRUICK CRIN	2460-65,2484-90	ACID	1ST,MAIN CRIN
		2500-05,2517-22		CRUICK SHALE/CRIN
16-4-10-28W1	CRUICK CRIN	2508-13	ACID SQ,SAND FRAC	CRUICK CRIN
		2456-2464	SAND FRAC	1ST CRIN
		2478-2486		MAIN CRIN
1-5-10-28W1	CRUICK SHALE	OPEN HOLE	SAND FRAC	
2-5-10-28W1	CRUICK SHALE	OPEN HOLE	SAND FRAC	
3-5-10-28W1	CRUICK CRIN	OPEN HOLE		
		2513-2517		
7-5-10-28W1	CRUICK CRIN	OPEN HOLE	SAND FRAC	
8-5-10-28W1	CRUICK SHALE	OPEN HOLE	SAND FRAC	
8B-5-10-28W1	CRUICK CRIN	2510-14,2524-36	ACID	1ST,MAIN CRIN
		2570-98		CRUICK CRIN

TABLE 1.1

DALY UNIT #1
WELL COMPLETION DETAILS

LOCATION	TD (ZONE)	PERF INTERVAL (FT)	TREATMENT	PRODUCING ZONE
9-5-10-28W1	MAIN CRIN	OPEN HOLE	SAND FRAC	
10-5-10-28W1	CRUICK CRIN	OPEN HOLE	SAND FRAC	
15-5-10-28W1	CRUICK CRIN	2547-68,2521-27	ACID	CRUICK SHALE/CRIN
		2492-98		1ST CRIN
15A-5-10-28W1	CRUICK CRIN	2504-10,2524-30	ACID	MAIN CRIN
		2542-48,2562-68		CRUICK SHALE/CRIN
16-5-10-28W1	CRUICK CRIN	OPEN HOLE	SAND FRAC	
		2506-2518		1ST CRIN
1-8-10-28W1	1ST CRIN	OPEN HOLE	SAND FRAC	
1A-9-10-28W1	BANFF SHALE	2512-15,2522-25	SAND FRAC	CRUICK CRIN
		2468-76,2480-88		1ST,MAIN CRIN
		2492-2498		CRUICK SHALE
2-9-10-28W1	BANFF SHALE	OPEN HOLE	HYDROFRAC	
3-9-10-28W1	BANFF SHALE	OPEN HOLE	SAND FRAC	
4-9-10-28W1	CRUICK CRIN	OPEN HOLE	SAND FRAC	
5-9-10-28W1	CROMER SHALE	OPEN HOLE	HYDROFRAC	
7-9-10-28W1	CROMER SHALE	2525-29,2533-37	SAND FRAC	CRUICK CRIN
8-9-10-28W1	CRUICK CRIN	OPEN HOLE	SAND FRAC	
4-10-10-28W1	CRUICK CRIN	OPEN HOLE	SAND FRAC	
5-10-10-28W1	SHALEY	2495-2501	SAND FRAC	CRUICK CRIN
		2446-52		1ST CRIN
		2482-90,2502-08		CRUICK CRIN

TABLE 1.2

DALY UNIT #1
CURRENT WELL STATUS AND CUMULATIVE PRODUCTION/INJECTION VOLUMES

LOCATION	CURRENT (DEC. 1988) OIL (STB/D)	WATER (STB/D)	WOR	WATER INJ (STB/D)	CUMULATIVES OIL (STB)	WATER (STB)	CUM WOR	WATER INJ (STB)
10-32-9-28W1		SHUT-IN			78,717.5	1,287,896.6 *	16.36	
15-32-9-28W1	14.5	592.1	40.83		135,741.2	2,417,623.6 *	17.81	
16-32-9-28W1	1.0	49.0	49.00		140,043.9	2,589,856.3 *	18.49	
13-33-9-28W1	6.6	3.4	0.52		86,363.2	19,391.1	0.22	
12-3-10-28W1		SHUT-IN			35,542.0	61,634.0	1.73	
13-3-10-28W1	11.8	44.8	3.80		303,818.9	211,075.4	0.69	
13C-3-10-28W1		WATER INJECTOR		252				3,300,818
2-4-10-28W1	1.7	2.4	1.41		66,571.4	52,123.4	0.78	
3-4-10-28W1	5.9	3.4	0.58		112,222.1	32,199.5	0.29	
4-4-10-28W1	11.5	14.1	1.23		216,033.0	70,030.1	0.32	
5-4-10-28W1	21.4	474.1	22.15		468,985.2	4,165,496.0	8.88	
5A-4-10-28 W1		WATER INJECTOR		644				2,144,897
6-4-10-28W1	8.0	8.5	1.06		258,640.0	60,134.6	0.23	
9-4-10-28W1	8.7	1.4	0.16		116,062.6	26,959.5	0.23	
10-4-10-28W1		SHUT-IN			21,369.0	34,340.5	1.61	
11-4-10-28W1	15.0	561.0	37.40		149,090.4	1,834,862.1	12.31	
12-4-10-28W1	19.6	533.5	27.22		467,711.5	2,232,098.2	4.77	
12B-4-10-28W1		WATER INJECTOR		766				5,419,674
12D-4-10-28W1		WATER INJECTOR		262				4,058,783
13-4-10-28W1	12.2	31.9	2.61		362,225.7	149,791.7	0.41	
13C-4-10-28W1		WATER INJECTOR		448				1,974,140
14-4-10-28W1	13.7	55.0	4.01		303,946.0	631,731.8	2.08	
14D-4-10-28W1		WATER INJECTOR		100				2,827,647
15-4-10-28W1		SHUT-IN			5,147.5	110,375.4	21.44	
15D-4-10-28W1		WATER INJECTOR		694				4,332,455
16-4-10-28W1	5.0	17.2	3.44		212,359.1	157,618.0	0.74	
1-5-10-28W1	5.8	18.4	3.17		283,535.9	344,454.8	1.21	
2-5-10-28W1	16.7	583.2	34.92		197,898.5	3,853,699.2	19.47	
3-5-10-28W1	2.7	1.7	0.63		65,804.1	10,657.3	0.16	
7-5-10-28W1	12.5	279.9	22.39		315,633.5	1,189,148.9	3.77	
8-5-10-28W1	17.7	470.8	26.60		194,715.3	1,442,311.9	7.41	
8B-5-10-28W1		WATER INJECTOR		583				4,304,999
9-5-10-28W1	12.9	343.6	26.64		320,305.5	1,301,610.6	4.06	
10-5-10-28W1	4.0	179.1	44.78		176,078.3	1,074,917.3	6.10	
15-5-10-28W1	5.7	8.5	1.49		39,969.8	17,394.2	0.44	
15A-5-10-28W1		WATER INJECTOR		646				2,568,089
16-5-10-28W1	20.1	34.6	1.72		230,363.4	191,683.0	0.83	
1-8-10-28W1	2.1	3.2	1.52		83,536.0	46,801.7	0.56	
1A-9-10-28W1	7.0	7.3	1.04		147,457.6	158,214.9	1.07	
2-9-10-28W1	9.5	8.2	0.86		254,898.9	77,165.2	0.30	
3-9-10-28W1	11.7	11.4	0.97		216,048.7	51,467.4	0.24	
4-9-10-28W1		ABANDONED			60,377.3	726,589.9	12.03	
5-9-10-28W1	3.9	7.9	2.03		114,565.0	51,415.8	0.45	
7-9-10-28W1		ABANDONED			96.2	30,806.3	320.12	
8-9-10-28W1	8.1	18.4	2.27		95,648.1	170,272.2	1.78	

TABLE 1.2

DALY UNIT #1
CURRENT WELL STATUS AND CUMULATIVE PRODUCTION/INJECTION VOLUMES

LOCATION	CURRENT (DEC. 1988) OIL (STB/D)	WATER (STB/D)	WOR	WATER INJ (STB/D)	CUMULATIVES OIL (STB)	WATER (STB)	CUM WOR	WATER INJ (STB)
4-10-10-28W1	3.1	0.7	0.23		102.184.4	8.588.6	0.08	
5-10-10-28W1	2.5	0.7	0.28		123.658.6	9.876.7	0.08	
	302.6	4369.4	14.44	4.395	6.567.426.4	26.918.666.9	4.10	30.931.504

Note: * In 1964 the cumulative production was entered incorrectly from previous year. The difference was 382 STB.

** 1-9 has been added to the cumulative totals.

TABLE 2.1

DYKSTRA-PARSONS' PERMEABILITY VARIATIONS

	Arithmetic Average Core Permeability (md)	Geometric Average Core Permeability (md)	50% Probability Core Permeability (md)	Permeability Variance
9-32	2.78	2.64	2.85	.51
16-33	3.72	4.17	3.80	.59
12-3	13.97	15.10	14.79	.78
2-4	2.63	2.78	2.63	.56
4-4	4.31	4.24	4.47	.62
6-4	5.03	5.29	5.01	.57
7-4	2.23	2.32	2.26	.62
10-4	8.43	8.98	8.61	.74
11-4	5.07	4.55	5.01	.64
12-4	5.68	4.80	5.62	.67
12B-4	5.88	6.74	5.93	.77
14D-4	6.83	7.26	6.92	.70
7-5	3.58	3.90	3.58	.55
15-5	7.03	7.19	7.12	.72
1-9	5.87	6.94	6.09	.70
6-10	3.52	3.97	3.55	.71

TABLE 2.2

RESERVOIR AND FLUID PROPERTIES

T_{res} = 79° F
P_i ≈ 1000 psia
P_{BP} = 436 psia
API gravity = 30.5°
$_{g}$ = 1.30
μ_w = 0.86 cp.

CORRECTED PVT DATA

Pressure (psia)	B_o (STB/STB)	R_s (Scf/bbl)	μo (cp)
1000	1.096 (B_{oi})	137	3.54
800	1.098	137	3.47
600	1.099	137	3.40
*436	1.100	137	3.34
334	1.099	131	4.45
248	1.098	130	5.53
123	1.090	120	7.99
63	1.076	117	8.76
14.7	1.032	65	11.53

*Denotes bubble point pressure, P_{BP}

Above P_{BP}, $B_o = 1.100\ [1 - 6.3 \times 10^{-6}\ (p - 436)]$

$$R_s = 137 - (122 - R_{sd}) \times \frac{1.10}{1.0746}$$

$$C_o = 6.36 \times 10^{-6}\ \text{psi}^{-1}$$

TABLE 3.1

DALY UNIT #1
DISTRIBUTION OF OOIP

LOCATION	FIRST CRINOIDAL	MAIN CRINOIDAL	CRUICK. SHALE/CRINOIDAL			OOIP CALCULATIONS	
	POROSITY-FEET (NET)	POROSITY-FEET (NET)	INTERPOLATED POROSITY	NET PAY	POROSITY-FEET (NET)	SUM POR.FT	OOIP PER 40 ACRES
10-32-9-28W1	1.50	1.04	0.08	17	1.36	3.90	669,362
15-32-9-28W1	0.75	0.76	0.08	20	1.60	3.11	532,540
16-32-9-28W1	0.80	0.90	0.08	17	1.36	3.06	524,653
13-33-9-28W1	1.10	1.00	0.09	14	1.26	3.36	576,090
12-3-10-28W1	0.55	0.60	0.11	18	1.98	3.13	536,655
13-3-10-28W1	0.45	0.15	0.10	28	2.80	3.40	583,120
2-4-10-28W1	1.10	1.09	0.09	6	0.52	2.71	464,815
3-4-10-28W1	1.00	1.10	0.09	9	0.81	2.91	498,935
4-4-10-28W1	1.10	0.95	0.09	36	3.24	5.29	906,999
5-4-10-28W1	0.65	1.05	0.09	36	3.24	4.94	846,989
6-4-10-28W1	0.90	1.15	0.09	15	1.35	3.40	583,291
9-4-10-28W1	0.80	0.95	0.10	25	2.50	4.25	728,685
10-4-10-28W1	0.75	0.95	0.09	30	2.70	4.40	754,404
11-4-10-28W1	0.55	1.10	0.10	45	4.50	6.15	1,054,450
12-4-10-28W1	0.50	1.10	0.11	58	6.38	7.98	1,368,214
13-4-10-28W1	0.15	0.55	0.10	54	5.40	6.10	1,045,878
14-4-10-28W1	0.15	0.55	0.10	84	8.40	9.10	1,560,244
15-4-10-28W1	0.30	0.55	0.10	108	10.80	11.65	1,997,455
16-4-10-28W1	0.36	0.35	0.10	78	7.80	8.51	1,459,085
1-5-10-28W1	0.65	0.60	0.08	58	4.64	5.89	1,009,872
2-5-10-28W1	0.30	0.35	0.08	58	4.64	5.29	906,999
3-5-10-28W1	0.17	0.08	0.08	36	2.88	3.13	536,827
7-5-10-28W1	0.45	0.45	0.08	36	2.88	3.78	648,101
8-5-10-28W1	0.60	0.75	0.10	70	7.00	8.35	1,431,652
9-5-10-28W1	0.34	0.75	0.11	72	7.92	9.01	1,544,127
10-5-10-28W1	0.13	0.34	0.09	38	3.42	3.89	666,618
15-5-10-28W1	0.10	0.15	0.10	31	3.10	3.35	574,890
16-5-10-28W1	0.14	0.27	0.10	38	3.80	4.21	721,141
1-8-10-28W1	0.07	0.14	0.13	38	4.94	5.16	884,024
1A-9-10-28W1	0.30	0.17	0.10	42	4.20	4.67	800,696
2-9-10-28W1	0.14	0.17	0.10	42	4.20	4.51	772,578
3-9-10-28W1	0.08	0.17	0.10	32	3.20	3.45	591,521
4-9-10-28W1	0.06	0.17	0.10	21	2.10	2.33	399,491
5-9-10-28W1	0.05	0.10	0.10	35	3.50	3.65	625,641
7-9-10-28W1	0.06	0.10	0.10	29	2.90	3.06	524,482
8-9-10-28W1	0.20	0.14	0.10	42	4.20	4.54	779,093
4-10-10-28W1	0.70	0.09	0.10	37	3.70	4.49	769,834
5-10-10-28W1	0.70	0.15	0.10	35	3.50	4.35	746,345
TOTALS (NET POR.FT)	18.687	21.046			144.722	184.455	
(AVERAGE)	(0.49)	(0.55)			(3.81)	(4.85)	
OOIP PER ZONE (STB)	3,203,986	3,608,449			24,813,360		31,625,795 STB

TABLE 4.1

DALY UNIT #1
COMPARISON OF WATERFLOOD RECOVERY FACTORS

LOCATION	PERMEABILITY VARIANCE	FRACTIONAL FLOW CAL'N VERTICAL SWEEP EFF.	RECOVERY	DYKSTRA-PARSONS'	STILES	DYK-PAR/STILES AVERAGE
9-32-9-28W1	0.51	0.276	0.080	0.33	0.25	0.29
16-33-9-28W1	0.59	0.243	0.070	0.29	0.30	0.30
12-3-10-28W1	0.78	0.146	0.042	0.18	0.13	0.16
2-4-10-28W1	0.56	0.256	0.074	0.32	0.40	0.36
4-4-10-28W1	0.62	0.230	0.066	0.27	0.18	0.23
6-4-10-28W1	0.57	0.252	0.073	0.31	0.19	0.25
7-4-10-28W1	0.62	0.230	0.066	0.27	0.38	0.33
10-4-10-28W1	0.74	0.169	0.049	0.20	0.27	0.24
11-4-10-28W1	0.64	0.220	0.063	0.26	0.16	0.21
12-4-10-28W1	0.67	0.206	0.059	0.25	0.22	0.24
12B-4-10-28W1	0.77	0.152	0.044	0.19	0.21	0.20
14D-4-10-28W1	0.70	0.190	0.055	0.23	0.18	0.21
7-5-10-28W1	0.55	0.260	0.075	0.32	0.19	0.26
15-5-10-28W1	0.72	0.180	0.052	0.22	0.19	0.21
1-9-10-28W1	0.70	0.190	0.055	0.23	0.04	*
6-10-10-28W1	0.71	0.185	0.053	0.22	0.17	0.20
AVERAGE	0.70	0.226	0.065	0.26	0.23	

* Excluded from average due to single, relatively thick high permeability streak

ASSUMPTIONS

90 % areal sweep efficiency used for all calculations

S(wi) = 0.395 S(or) = 0.28
M = 2.68 VE = (1-V^2)/2.68 for fractional flow calculations

Pore Volume Recovery = 32 % OOIP for fractional flow calculations

Limiting Water Cut = 90 % throughout

TABLE 5.1

DALY UNIT #1
ANNUAL OIL AND WATER PRODUCTION FIGURES

YEAR	CUM OIL PROD'N	CUM WATER PROD'N	YEARLY OIL PROD'N	YEARLY WATER PROD'N	YEARLY WOR	YEARLY WATER CUT
PRIOR TO						
1951	4,497	0	4,497	0	0	0
1952	23,299	0	18,802	0	0	0
1953	243,413	0	220,114	0	0	0
1954	692,725	0	449,312	0	0	0
1955	968,709	0	275,984	0	0	0
1956	1,214,985	2,600	246,276	2,600	0.0106	0.0104
1957	1,446,320	493,826	231,335	491,226	2.1234	0.6798
1958	1,644,783	758,661	198,463	264,835	1.3344	0.5716
1959	1,830,774	1,064,278	185,991	305,617	1.6432	0.6217
1960	2,058,432	1,467,194	227,658	402,916	1.7698	0.6390
1961	2,263,572	1,829,694	205,140	362,500	1.7671	0.6386
1962	2,442,659	2,259,328	179,087	429,634	2.3990	0.7058
1963	2,603,009	2,755,991	160,350	496,663	3.0974	0.7559
1964	2,744,208	3,193,470	141,199	437,479	3.0983	0.7560
1965	2,880,041	3,660,645	135,833	467,175	3.4393	0.7747
1966	3,004,372	4,031,656	124,331	371,011	2.9841	0.7490
1967	3,123,714	4,318,969	119,342	287,313	2.4075	0.7065
1968	3,238,375	4,631,800	114,661	312,831	2.7283	0.7318
1969	3,350,924	4,948,287	112,549	316,487	2.8120	0.7377
1970	3,475,686	5,284,324	124,762	336,037	2.6934	0.7292
1971	3,638,780	5,600,786	163,094	316,462	1.9404	0.6599
1972	3,807,619	6,089,237	168,839	488,451	2.8930	0.7431
1973	4,100,739	6,995,309	293,120	906,072	3.0911	0.7556
1974	4,362,484	7,982,209	261,745	986,900	3.7705	0.7904
1975	4,570,653	9,008,428	208,169	1,026,219	4.9297	0.8314
1976	4,764,800	10,064,453	194,147	1,056,025	5.4393	0.8447
1977	4,940,907	11,061,816	176,107	997,363	5.6634	0.8499
1978	5,102,441	11,971,595	161,534	909,779	5.6321	0.8492
1979	5,315,758	12,838,589	213,317	866,994	4.0643	0.8025
1980	5,511,543	13,876,775	195,785	1,038,187	5.3027	0.8413
1981	5,679,039	14,856,952	167,497	980,177	5.8519	0.8541
1982	5,825,936	15,832,033	146,897	975,081	6.6379	0.8691
1983	5,956,592	16,899,625	130,657	1,067,592	8.1710	0.8910
1984	6,080,194	18,374,708	123,601	1,475,083	11.9342	0.9227
1985	6,204,161	20,560,820	123,967	2,186,112	17.6346	0.9463
1986	6,333,551	23,155,701	129,390	2,594,881	20.0548	0.9525
1987	6,454,077	25,300,634	120,526	2,144,932	17.7965	0.9468
1988	6,567,426	26,918,667	113,349	1,618,033	14.4929	0.9345

TABLE 5.2

ESTIMATION OF THE DALY UNIT #1 ECONOMIC LIMIT

$$\text{Economic Limit} = \frac{\text{Oper. Exp. (\$/well/mo.)} \times (\text{Infl})^{n+1}}{(\text{Price/bbl}) \times (\text{Infl})^{n} \times (1 - \text{Royalties} - \text{Taxes})}$$

Operating Expense = \$52,600/mo. (averaged from 1989 Operating and Capital Expense Forecast)

42 Wells (including producers and injectors)

Freehold & GORR	=	12.5%
Mineral Taxes	=	13.3%
Assume Inflation	=	5%
Oil Price	=	\$20/bbl

∴ Economic Limit = 120 STB/D for the entire unit
= 2.9 STB/D/unit well

TABLE 5.3

DALY UNIT #1
PREDICTED FUTURE PERFORMANCE - TOTAL UNIT

YEAR	OIL PROD'N (STB/YEAR)	OIL CUM PROD'N (STB)	CALC'D WOR	WATER PROD'N (STB/YEAR)
1988	113,349	6,567,426	11.875	1,346,043
1989	108,362	6,680,775	12.461	1,350,253
1990	103,594	6,789,137	13.047	1,351,611
1991	99,036	6,892,730	13.634	1,350,234
1992	94,678	6,991,766	14.219	1,346,252
1993	90,512	7,086,444	14.802	1,339,800
1994	86,530	7,176,956	15.382	1,331,023
1995	82,722	7,263,486	15.958	1,320,070
1996	79,083	7,346,208	16.528	1,307,093
1997	75,603	7,425,291	17.093	1,292,245
1998	72,276	7,500,894	17.650	1,275,679
1999	69,096	7,573,170	18.200	1,257,549
2000	66,056	7,642,266	18.742	1,238,005
2001	63,150	7,708,322	19.275	1,217,191
2002	60,371	7,771,472	19.798	1,195,253
2003	57,715	7,831,843	20.312	1,172,325
2004	55,175	7,889,558	20.816	1,148,542
2005	52,747	7,944,733	21.310	1,124,029
2006	50,427	7,997,480	21.792	1,098,906
2007	48,208	8,047,907	22.264	1,073,286
2008	46,087	8,096,115	22.724	1,047,277
2009	44,660	8,128,540	23.039	1,028,923

TABLE 6.1

DALY UNIT #1
CUMULATIVE RESERVOIR PERFORMANCE PER PATTERN

PATTERN #	PRODUCERS	INJECTORS	CONT'N TO PATTERN OOIP (MSTB)	CONT'N TO CUM. OIL PROD'N (MSTB)	CONT'N TO CUM. WATER PROD'N (MSTB)	OIL RECOVERY (% OOIP)	CUM PRODUCING WOR	CUM WATER INJ. (MSTB)	VOIDAGE REPLACEMENT RATIO
1		NONE							
	9-32		198.5453	33.5460	70.3025				
	10-32		334.6808	39.3587	643.9483				
	15-32		199.1454	67.8706	1208.8118				
	16-32		266.2701	70.0220	1294.9282				
			998.6416	210.7973	3217.9907	21.11	15.2658		N/A
2		NONE							
	14-32		199.1454	12.5505	2.7355				
	15-32		266.2701	67.8706	1208.8118				
	2-5		453.4994	98.9492	1926.8496				
	3-5		268.4133	32.9020	5.3286				
			1187.3282	212.2724	3143.7255	17.88	14.8099		N/A
3		NONE							
	16-32		262.3267	70.0220	1294.9282				
	13-33		288.0450	43.1816	9.6956				
	4-4		453.4994	108.0165	35.0151				
	1-5		504.9360	141.7680	172.2274				
			1508.8070	362.9880	1511.8662	24.06	4.1651		N/A
4		8B-5						4304.9992	
	1-5		504.9360	141.7680	172.2274				
	2-5		453.4994	98.9492	1926.8496				
	7-5		324.0506	157.8167	594.5745				
	8-5		715.8261	97.3576	721.1559				
			1998.3120	495.8916	3414.8074	24.82	6.8862	4304.9992	1.09
5		5A-4						2144.8971	
	3-4		249.4675	56.1110	16.0997				
	4-4		453.4994	108.0165	35.0151				
	5-4		423.4947	234.4926	2082.7480				
	6-4		291.6455	129.3200	30.0673				
			1418.1071	527.9401	2163.9301	37.23	4.0988	2144.8971	0.78

TABLE 6.1

DALY UNIT #1
CUMULATIVE RESERVOIR PERFORMANCE PER PATTERN

PATTERN #	PRODUCERS	INJECTORS	CONT'N TO PATTERN OOIP (MSTB)	CONT'N TO CUM. OIL PROD'N (MSTB)	CONT'N TO CUM. WATER PROD'N (MSTB)	OIL RECOVERY (% OOIP)	CUM PRODUCING WOR	CUM WATER INJ. (MSTB)	VOIDAGE REPLACEMENT RATIO
6		12B-4						5419.6744	
	5-4		423.4947	234.4926	2082.7480				
	12-4		684.1068	233.8558	1116.0491				
	8-5		715.8261	97.3576	721.1559				
	9-5		772.0634	160.1527	650.8053				
			2595.4910	725.8587	4570.7583	27.97	6.2970	5419.6744	1.01
7		NONE							
	6-4		291.6455	129.3200	30.0673				
	7-4		203.1746	16.4870	4.3330				
	10-4		377.2018	10.6845	17.1703				
	11-4		527.2252	74.5452	917.4311				
			1399.2470	231.0367	969.0016	16.51	4.1941		N/A
8		15A-5						2568.0894	
	9-5		772.0634	160.1527	650.8053				
	10-5		333.3092	88.0391	537.4586				
	15-5		287.4449	19.9849	8.6971				
	16-5		360.5706	115.1817	95.8415				
			1753.3881	383.3585	1292.8025	21.86	3.3723	2568.0894	1.50
9		12D-4						4058.7833	
	11-4		527.2252	74.5452	917.4311				
	12-4		684.1068	233.8558	1116.0491				
	13-4		522.9388	181.1129	74.8959				
	14-4		780.1218	151.9730	315.8659				
			2514.3926	641.4868	2424.2419	25.51	3.7791	4058.7833	1.30
10		13C-4						1974.1401	
	13-4		522.9388	181.1129	74.8959				
	16-5		360.5706	115.1817	95.8415				
	1-8		442.0119	41.7680	23.4008				
	4-9		199.7455	30.1887	363.2950				
			1525.2667	368.2512	557.4332	24.14	1.5137	1974.1401	2.05

TABLE 6.1

DALY UNIT #1
CUMULATIVE RESERVOIR PERFORMANCE PER PATTERN

PATTERN #	PRODUCERS	INJECTORS	CONT'N TO PATTERN OOIP (MSTB)	CONT'N TO CUM. OIL PROD'N (MSTB)	CONT'N TO CUM. WATER PROD'N (MSTB)	OIL RECOVERY (% OOIP)	CUM PRODUCING WOR	CUM WATER INJ. (MSTB)	VOIDAGE REPLACEMENT RATIO
11		NONE							
	9-4		182.1713	29.0156	6.7399				
	10-4		188.6009	5.3423	8.5851				
	15-4		499.3637	1.2869	27.5939				
	16-4		364.7712	53.0898	39.4045				
			1234.9071	88.7346	82.3234	7.19	0.9277		N/A
12		NONE							
	12-3		134.1638	8.8855	15.4085				
	13-3		145.7799	75.9547	52.7689				
	9-4		182.1713	29.0156	6.7399				
	16-4		364.7712	53.0898	39.4045				
			826.8863	166.9457	114.3217	20.19	0.6848		N/A
13		14D-4						2827.6472	
	14-4		390.0609	75.9865	157.9330				
	15-4		499.3637	1.2869	27.5939				
	2-9		193.1444	63.7247	19.2913				
	3-9		147.8802	54.0122	12.8668				
			1230.4493	195.0103	217.6849	15.85	1.1163	2827.6472	6.56
14		15D-4						4332.4555	
	15-4		499.3637	1.2869	27.5939				
	16-4		364.7712	53.0898	39.4045				
	1-9			1.0153	4.0883				
	1A-9		200.1741	36.8644	39.5537				
	2-9		193.1444	63.7247	19.2913				
			1257.4535	155.9810	129.9317	12.40	0.8330	4332.4555	14.41

TABLE 6.1

DALY UNIT #1
CUMULATIVE RESERVOIR PERFORMANCE PER PATTERN

PATTERN #	PRODUCERS	INJECTORS	CONT'N TO PATTERN OOIP (MSTB)	CONT'N TO CUM. OIL PROD'N (MSTB)	CONT'N TO CUM. WATER PROD'N (MSTB)	OIL RECOVERY (% OOIP)	CUM PRODUCING WOR	CUM WATER INJ. (MSTB)	VOIDAGE REPLACEMENT RATIO
15		13C-3						3300.8177	
	13-3		145.7799	75.9547	52.7689				
	16-4		364.7712	53.0898	39.4045				
	1-9			1.0153	4.0883				
	1A-9		200.1741	36.8644	39.5537				
	4-10		192.4586	25.5461	2.1471				
			903.1839	192.4703	137.9625	21.31	0.7168	3300.8177	9.47
16		NONE							
	1-9			1.0153	4.0883				
	1A-9		200.1741	36.8644	39.5537				
	2-9		193.1444	63.7247	19.2913				
	7-9		131.1205	0.0241	7.7016				
	8-9		194.7733	23.9120	42.5681				
			719.2123	125.5405	113.2030	17.46	0.9017		N/A
17		NONE							
	1-9			1.0153	4.0883				
	1A-9		200.1741	36.8644	39.5537				
	8-9		194.7733	23.9120	42.5681				
	4-10		192.4586	25.5461	2.1471				
	5-10		186.5863	30.9147	2.4692				
			773.9923	118.2524	90.8264	15.28	0.7681		N/A

TABLE 6.2

DALY UNIT #1
CURRENT RESERVOIR PERFORMANCE PER PATTERN

PATTERN #	PRODUCERS	INJECTORS	CURRENT OIL PROD'N (MSTB)	CURRENT WATER PROD'N (MSTB)	CURRENT PRODUCING WOR	CURRENT WATER INJ. (MSTB)	VOIDAGE REPLACEMENT RATIO
1		NONE					
	9-32		0.0000	0.0000			
	10-32		0.0000	0.0000			
	15-32		2.6407	108.0649			
	16-32		0.1789	8.9414			
			2.8197	117.0063	41.4964		N/A
2		NONE					
	14-32		0.0000	0.0000			
	15-32		2.6407	108.0649			
	2-5		3.0562	106.4252			
	3-5		0.4875	0.3025			
			6.1843	214.7926	34.7317		N/A
3		NONE					
	16-32		0.1789	8.9414			
	13-33		1.1976	0.6142			
	4-4		2.1048	2.5693			
	1-5		1.0601	3.3631			
			4.5415	15.4881	3.4104		N/A
4		8B-5				212.6990	
	1-5		1.0601	3.3631			
	2-5		3.0562	106.4252			
	7-5		2.2838	51.0821			
	8-5		3.2225	85.9186			
			9.6226	246.7890	25.6468	212.6990	0.83
5		5A-4				235.0020	
	3-4		1.0740	0.6233			
	4-4		2.1048	2.5693			
	5-4		3.9138	86.5161			
	6-4		1.4646	1.5422			
			8.5571	91.2510	10.6637	235.0020	2.34

TABLE 6.2

DALY UNIT #1
CURRENT RESERVOIR PERFORMANCE PER PATTERN

PATTERN #	PRODUCERS	INJECTORS	CURRENT OIL PROD'N (MSTB)	CURRENT WATER PROD'N (MSTB)	CURRENT PRODUCING WOR	CURRENT WATER INJ. (MSTB)	VOIDAGE REPLACEMENT RATIO
6		12B-4				279.7410	
	5-4		3.9138	86.5161			
	12-4		3.5729	97.3727			
	8-5		3.2225	85.9186			
	9-5		2.3621	62.7121			
			13.0713	332.5195	25.4390	279.7410	0.81
7		NONE					
	6-4		1.4646	1.5422			
	7-4		1.5897	0.2572			
	10-4		0.0000	0.0000			
	11-4		2.7442	102.3800			
			5.7985	104.1794	17.9667		N/A
8		15A-5				235.8010	
	9-5		2.3621	62.7121			
	10-5		0.7258	32.6807			
	15-5		1.0413	1.5561			
	16-5		3.6722	6.3208			
			7.8014	103.2696	13.2373	235.8010	2.11
9		12D-4				95.5280	
	11-4		2.7442	102.3800			
	12-4		3.5729	97.3727			
	13-4		2.2234	5.8161			
	14-4		2.5036	10.0418			
			11.0441	215.6106	19.5227	95.5280	0.42
10		13C-4				163.6070	
	13-4		2.2234	5.8161			
	16-5		3.6722	6.3208			
	1-8		0.3771	0.5758			
	4-9		0.0387	3.8197			
			6.3114	16.5325	2.6195	163.6070	6.98

TABLE 6.2

DALY UNIT #1
CURRENT RESERVOIR PERFORMANCE PER PATTERN

PATTERN #	PRODUCERS	INJECTORS	CURRENT OIL PROD'N (MSTB)	CURRENT WATER PROD'N (MSTB)	CURRENT PRODUCING WOR	CURRENT WATER INJ. (MSTB)	VOIDAGE REPLACEMENT RATIO
11		NONE					
	9-4		1.5897	0.2572			
	10-4		0.0000	0.0000			
	15-4		0.0000	0.0000			
	16-4		0.9186	3.1414			
			2.5083	3.3986	1.3549		N/A
12		NONE					
	12-3		0.0000	0.0000			
	13-3		2.1508	8.1706			
	9-4		1.5897	0.2572			
	16-4		0.9186	3.1414			
			4.6591	11.5693	2.4832		N/A
13		14D-4				36.6130	
	14-4		2.5036	10.0418			
	15-4		0.0000	0.0000			
	2-9		1.7407	1.4963			
	3-9		2.1404	2.0765			
			6.3847	13.6147	2.1324	36.6130	1.78
14		15D-4				253.3390	
	15-4		0.0000	0.0000			
	16-4		0.9186	3.1414			
	1-9		1.2740	1.3362			
	1A-9		0.0000	0.0000			
	2-9		2.1404	2.0765			
			4.3330	6.5542	1.5126	253.3390	22.42

TABLE 6.2

DALY UNIT #1
CURRENT RESERVOIR PERFORMANCE PER PATTERN

PATTERN #	PRODUCERS	INJECTORS	CURRENT OIL PROD'N (MSTB)	CURRENT WATER PROD'N (MSTB)	CURRENT PRODUCING WOR	CURRENT WATER INJ. (MSTB)	VOIDAGE REPLACEMENT RATIO
15		13C-3				91.8990	
	13-3		2.1508	8.1706			
	16-4		0.9186	3.1414			
	1-9		1.2740	1.3362			
	1A-9		0.0000	0.0000			
	4-10		0.5702	0.1286			
			4.9135	12.7769	2.6004	91.8990	5.06
16		NONE					
	1-9		1.2740	1.3362			
	1A-9		0.0000	0.0000			
	2-9		2.1404	2.0765			
	7-9		0.0000	0.0000			
	8-9		1.4718	3.3653			
			4.8862	6.7781	1.3872		N/A
17		NONE					
	1-9		1.2740	1.3362			
	1A-9		0.0000	0.0000			
	8-9		1.4718	3.3653			
	4-10		0.5702	0.1286			
	5-10		0.4519	0.1343			
			3.7678	4.9645	1.3176		N/A

TABLE 6.3

DALY UNIT #1

CUM. RESERVOIR PERFORMANCE - 80 ACRE FLOODED PATTERNS

YEAR	CUM OIL PROD'N	CUM WATER PROD'N	YEARLY OIL PROD'N	YEARLY WATER PROD'N	YEARLY WOR	YEARLY WATER CUT
PRIOR TO 1951	0	0	0	0		
1952	5,496	0	5,496	0	0	0
1953	119,787	7,632	114,291	7,632	0.0668	0.0626
1954	304,403	19,774	184,616	12,142	0.0658	0.0617
1955	433,651	30,000	129,249	10,226	0.0791	0.0733
1956	516,641	35,331	82,990	5,331	0.0642	0.0604
1957	630,845	140,066	114,204	104,735	0.9171	0.4784
1958	708,194	168,879	77,350	28,813	0.3725	0.2714
1959	788,828	200,828	80,634	31,949	0.3962	0.2838
1960	892,490	260,174	103,662	59,346	0.5725	0.3641
1961	982,443	322,460	89,953	62,286	0.6924	0.4091
1962	1,061,741	410,658	79,299	88,199	1.1122	0.5266
1963	1,132,171	493,984	70,430	83,326	1.1831	0.5419
1964	1,194,580	574,589	62,409	80,605	1.2916	0.5636
1965	1,250,878	658,555	56,298	83,966	1.4915	0.5986
1966	1,300,044	733,986	49,166	75,431	1.5342	0.6054
1967	1,347,544	810,670	47,500	76,684	1.6144	0.6175
1968	1,395,157	893,285	47,614	82,615	1.7351	0.6344
1969	1,441,955	984,453	46,798	91,169	1.9481	0.6608
1970	1,496,403	1,062,316	54,449	77,863	1.4300	0.5885
1971	1,704,614	1,222,203	208,211	159,887	0.7679	0.4344
1972	1,800,015	1,444,746	95,402	222,544	2.3327	0.6999
1973	1,944,024	1,980,636	144,009	535,890	3.7212	0.7882
1974	2,087,728	2,706,544	143,704	725,909	5.0514	0.8347
1975	2,199,637	3,401,484	111,909	694,940	6.2099	0.8613
1976	2,294,895	4,099,582	95,258	698,098	7.3285	0.8799
1977	2,379,093	4,843,788	84,199	744,207	8.8387	0.8984
1978	2,452,755	5,501,431	73,662	657,643	8.9279	0.8993
1979	2,563,241	6,064,369	110,487	562,939	5.0951	0.8359
1980	2,664,132	6,748,118	100,891	683,749	6.7771	0.8714
1981	2,743,492	7,431,482	79,360	683,364	8.6110	0.8960
1982	2,811,285	8,117,320	67,793	685,838	10.1167	0.9100
1983	2,869,581	8,882,392	58,296	765,072	13.1239	0.9292
1984	2,917,844	9,700,735	48,263	818,343	16.9558	0.9443
1985	2,968,631	10,841,898	50,787	1,141,163	22.4697	0.9574
1986	3,029,524	12,202,674	60,893	1,360,776	22.3471	0.9572
1987	3,086,984	13,418,354	57,460	1,215,680	21.1571	0.9549
1988	3,143,392	14,424,326	56,408	1,005,972	17.8339	0.9469

TABLE 6.4

DALY UNIT #1
CUM. RESERVOIR PERFORMANCE - 40 ACRE FLOODED PATTERNS

YEAR	CUM OIL PROD'N	CUM WATER PROD'N	YEARLY OIL PROD'N	YEARLY WATER PROD'N	YEARLY WOR	YEARLY WATER CUT
PRIOR TO 1951	1,124	0				
1952	6,203	0	5,079	0	0	0
1953	25,615	0	19,413	0	0	0
1954	40,420	0	14,805	0	0	0
1955	58,409	0	17,989	0	0	0
1956	77,216	1,300	18,807	1,300	0.0691	0.0647
1957	98,419	23,212	21,202	21,912	1.0335	0.5082
1958	115,901	24,657	17,482	16,535	0.9458	0.4861
1959	128,974	25,993	13,074	1,336	0.1022	0.0927
1960	144,654	27,663	15,679	1,670	0.1065	0.0962
1961	159,900	29,287	15,247	1,624	0.1065	0.0963
1962	173,901	31,798	14,001	2,512	0.1794	0.1521
1963	186,042	35,780	12,141	3,982	0.3280	0.2470
1964	197,310	39,607	11,268	3,827	0.3397	0.2535
1965	210,261	43,483	12,951	3,876	0.2992	0.2303
1966	223,237	47,124	12,977	3,642	0.2806	0.2191
1967	234,935	50,154	11,698	3,029	0.2590	0.2057
1968	245,008	53,304	10,073	3,151	0.3128	0.2383
1969	255,592	56,221	10,584	2,917	0.2756	0.2160
1970	267,025	58,904	11,433	2,683	0.2347	0.1901
1971	275,230	60,975	8,205	2,071	0.2524	0.2015
1972	289,373	74,738	14,143	13,763	0.9731	0.4932
1973	330,548	113,555	41,175	38,817	0.9427	0.4853
1974	362,319	139,076	31,772	25,521	0.8033	0.4454
1975	385,711	159,056	23,392	19,980	0.8542	0.4607
1976	407,817	177,714	22,106	18,658	0.8440	0.4577
1977	425,460	203,428	17,644	25,715	1.4574	0.5931
1978	440,930	232,910	15,470	29,482	1.9057	0.6559
1979	454,373	260,089	13,443	27,180	2.0219	0.6691
1980	466,160	289,968	11,788	29,878	2.5347	0.7171
1981	477,842	313,551	11,681	23,584	2.0190	0.6688
1982	489,163	340,173	11,321	26,621	2.3515	0.7016
1983	499,313	364,954	10,150	24,781	2.4414	0.7094
1984	509,288	390,599	9,975	25,645	2.5710	0.7200
1985	517,708	419,797	8,420	29,199	3.4676	0.7762
1986	525,144	441,220	7,436	21,422	2.8809	0.7423
1987	534,037	461,234	8,893	20,014	2.2505	0.6924
1988	541,653	477,417	7,616	16,183	2.1249	0.6800

TABLE 6.5

DALY UNIT #1
CUMULATIVE RESERVOIR PERFORMANCE - 80 ACRE UNFLOODED PATTERNS

YEAR	CUM OIL PROD'N	CUM WATER PROD'N	YEARLY OIL PROD'N	YEARLY WATER PROD'N	YEARLY WOR	YEARLY WATER CUT
1971	809,247	3,656,367				
1972	831,603	3,889,848	22,356	233,482	10.4440	0.9126
1973	860,814	4,161,503	29,211	271,655	9.2997	0.9029
1974	884,010	4,327,021	23,196	165,518	7.1356	0.8771
1975	903,326	4,589,336	19,316	262,315	13.5802	0.9314
1976	922,993	4,852,293	19,668	262,958	13.3702	0.9304
1977	941,139	5,006,272	18,146	153,979	8.4855	0.8946
1978	960,447	5,147,845	19,308	141,573	7.3325	0.8800
1979	987,940	5,295,894	27,494	148,050	5.3849	0.8434
1980	1,012,551	5,451,237	24,611	155,343	6.3119	0.8632
1981	1,034,239	5,570,240	21,688	119,002	5.4871	0.8458
1982	1,050,399	5,685,349	16,161	115,110	7.1228	0.8769
1983	1,063,632	5,781,978	13,233	96,629	7.3023	0.8796
1984	1,081,234	6,204,443	17,602	422,465	24.0009	0.9600
1985	1,106,233	6,966,054	24,999	761,610	30.4656	0.9682
1986	1,133,179	7,859,082	26,946	893,028	33.1410	0.9707
1987	1,155,276	8,546,774	22,096	687,692	31.1224	0.9689
1988	1,174,090	9,001,347	18,814	454,572	24.1609	0.9603

TABLE 6.6

DALY UNIT #1
CUMULATIVE RESERVOIR PERFORMANCE - 40 ACRE UNFLOODED PATTERNS

YEAR	CUM OIL PROD'N	CUM WATER PROD'N	YEARLY OIL PROD'N	YEARLY WATER PROD'N	YEARLY WOR	YEARLY WATER CUT
PRIOR TO						
1951	0	0	0	0	0	0
1952	1,691	0	1,691	0	0	0
1953	13,300	0	11,610	0	0	0
1954	27,342	0	14,042	0	0	0
1955	39,362	0	12,020	0	0	0
1956	58,439	1,300	19,077	1,300	0.0681	0.0638
1957	76,951	16,671	18,512	15,371	0.8303	0.4536
1958	89,630	18,717	12,679	2,046	0.1614	0.1390
1959	100,361	21,148	10,731	2,431	0.2266	0.1847
1960	113,002	24,857	12,641	3,709	0.2934	0.2268
1961	124,500	26,916	11,498	2,059	0.1791	0.1519
1962	136,020	29,957	11,520	3,041	0.2640	0.2088
1963	146,073	34,405	10,053	4,449	0.4425	0.3068
1964	156,074	39,191	10,002	4,786	0.4785	0.3236
1965	167,164	44,195	11,089	5,004	0.4513	0.3109
1966	177,854	47,425	10,690	3,230	0.3021	0.2320
1967	187,709	49,597	9,856	2,173	0.2204	0.1806
1968	195,772	51,465	8,063	1,868	0.2316	0.1881
1969	204,666	53,057	8,894	1,592	0.1789	0.1518
1970	214,716	54,586	10,050	1,529	0.1521	0.1320
1971	223,128	55,016	8,412	430	0.0511	0.0486
1972	233,098	61,721	9,970	6,705	0.6725	0.4021
1973	267,389	80,543	34,291	18,823	0.5489	0.3544
1974	295,975	102,353	28,586	21,810	0.7630	0.4328
1975	317,251	112,019	21,276	9,666	0.4543	0.3124
1976	341,309	134,576	24,058	22,557	0.9376	0.4839
1977	361,593	157,279	20,284	22,703	1.1193	0.5281
1978	379,529	184,224	17,937	26,945	1.5022	0.6004
1979	395,721	215,223	16,192	31,000	1.9145	0.6569
1980	410,598	243,442	14,876	28,219	1.8969	0.6548
1981	424,945	265,411	14,347	21,969	1.5312	0.6049
1982	438,439	287,505	13,495	22,095	1.6373	0.6208
1983	450,999	309,639	12,560	22,134	1.7622	0.6380
1984	463,657	333,340	12,657	23,701	1.8725	0.6519
1985	474,064	353,160	10,407	19,820	1.9044	0.6557
1986	481,777	365,207	7,714	12,047	1.5618	0.6097
1987	489,915	379,444	8,138	14,237	1.7495	0.6363
1988	497,626	392,509	7,711	13,065	1.6944	0.6289

TABLE 6.7

WATERFLOOD AREAS
THEORETICAL vs. EXTRAPOLATED OIL RECOVERIES

6 x 80-Acre Patterns

Pattern	OOIP (MMSTB)	Permeability Variation, V	Estimated Recovery Factor	Theoretical Reserves (MMSTB)
4	1.998	.57	.28	.559
5	1.418	.62	.26	.369
6	2.595	.69	.22	.571
8	1.754	.68	.23	.403
9	2.514	.67	.24	.603
10	1.525	.71	.20	.305
Total	11.804 MMSTB			2.81 MMSTB (23.8% OOIP)

Cumulative Production:

To Date:	3.143 MMSTB (26.6% OOIP)
Extrapolated:	3.469 MMSTB (29.4% OOIP)

3 x 40-Acre Patterns

Pattern	OOIP (MMSTB)	Permeability Variation, V	Estimated Recovery Factor	Theoretical Reserves (MMSTB)
13	1.230	.70	.21	.258
14	1.257	.71	.20	.251
15	.903	.73	.19	.171
Total	3.390 MMSTB			.681 MMSTB (20.0% OOIP)

Cumulative Production:

To Date:	.542 MMSTB (16.0% OOIP)
Extrapolated:	.571 MMSTB (16.8% OOIP)

TABLE 6.8

DALY UNIT #1

PREDICTED FUTURE PERFORMANCE - 80-ACRE FLOODED PATTERNS
(BASED ON WOR TREND)

YEAR	OIL PROD'N (STB/YEAR)	OIL CUM PROD'N (STB)	CALC'D WOR	WATER PROD'N (STB/YEAR)
1988	56,408	3,143,392	21.1684	1,005,972
1989	47,923	3,191,315	22.7935	1,092,335
1990	44,650	3,235,965	24.4196	1,090,338
1991	41,794	3,277,758	26.0467	1,088,588
1992	39,279	3,317,038	27.6746	1,087,043
1993	37,050	3,354,087	29.3032	1,085,670
1994	35,058	3,389,146	30.9325	1,084,440
1995	33,270	3,422,415	32.5623	1,083,334
1996	31,654	3,454,069	34.1926	1,082,332
1997	15,137	3,469,206	35.0000	529,795

PREDICTED FUTURE PERFORMANCE - 40-ACRE FLOODED PATTERNS
(BASED ON OIL RATE DECLINE)

YEAR	OIL PROD'N (STB/YEAR)	OIL CUM PROD'N (STB)	EST'D WOR	WATER PROD'N (STB/YEAR)
1988	7,616	541,653	2.1249	16,183
1989	7,167	549,269	3.5903	25,730
1990	6,744	556,436	3.8017	25,638
1991	6,346	563,179	4.0120	25,460
1992	5,972	569,525	4.2206	25,203
1993	2,033	571,558	4.2896	8,721

TABLE 6.9

UNFLOODED AREAS
EXTRAPOLATED OIL RECOVERIES

4 x 80-Acre Patterns

Pattern	OOIP (MMSTB)	Permeability Variation, V	Estimated Recovery Factor*	Theoretical Reserves (MMSTB)*
1	.999	.52	.28	.280
2	1.187	.49	.30	.356
3	903	.73	.25	.377
7	1.399	.68	.23	.322
Total	5.094 MMSTB			1.335 MMSTB (26.2% OOIP)*

Cumulative Production:

To Date: 1.174 MMSTB (23.0% OOIP)
Extrapolated: 1.255 MMSTB (24.6% OOIP)

*Predicted recoveries under waterflood.

4 x 40-Acre Patterns

Pattern	OOIP (MMSTB)	Permeability Variation, V	Estimated Recovery Factor*	Theoretical Reserves (MMSTB)*
11	1.235	.75	.18	.222
12	0.827	.73	.19	.157
16	.919	.70	.21	.151
17	.774	.70	.21	.162
Total	3.555 MMSTB			.692 MMSTB (19.5% OOIP)*

Cumulative Production:

To Date: .497 MMSTB (14.0% OOIP)
Extrapolated: .548 MMSTB (15.4% OOIP)

*Predicted recoveries under waterflood.

TABLE 6.10

DALY UNIT #1

PREDICTED FUTURE PERFORMANCE - 80-ACRE UNFLOODED PATTERNS
(BASED ON OIL RATE DECLINE)

YEAR	CUM OIL PROD'N (STB)	OIL PROD'N (STB/YEAR)	EST'D WATER PROD'N (STB/YEAR)
1988	1,174,090	18,814	454,572
1989	1,192,901	15,930	454,009
1990	1,208,828	13,488	384,409
1991	1,222,313	11,420	325,479
1992	1,233,731	9,670	275,583
1993	1,243,399	8,187	233,336
1994	1,251,585	6,932	197,566
1995	1,255,173	3,588	102,258

PREDICTED FUTURE PERFORMANCE - 40-ACRE UNFLOODED PATTERNS
(BASED ON OIL RATE DECLINE)

YEAR	CUM OIL PROD'N (STB)	OIL PROD'N (STB/YEAR)	EST'D WATER PROD'N (STB/YEAR)
1988	497,626	7,711	13,065
1989	505,337	7,015	12,277
1990	512,352	6,383	11,169
1991	518,735	5,807	10,162
1992	524,542	5,283	9,245
1993	529,825	4,807	8,411
1994	534,631	4,373	7,653
1995	539,004	3,979	6,962
1996	542,983	3,620	6,334
1997	546,603	3,293	5,763
1998	547,728	1,125	1,969

TABLE 7.1

DALY UNIT #3 - CALCULATION OF AVERAGE OOIP-STB/AC.FT.*

Zone	h(m)	Ø(%)	Øh(m)	k(md)
Upper Daly	2.8	11.1	.311	3.6**
Middle Daly	5.8	10.4	.603	5.3**
Lower Daly	2.6	10.3	.268	6.6**
Cruickshank Crinoidal	3.1	12.1	.375	2.7**
Totals:	14.3		1.56	

Average Ø = 10.9%

Average Net Pay = 47 ft.

Average S_W = 0.40 (assumed)

B_o = 1.08

Therefore: OOIP (STB/ac. ft.) = 469.8 STB ac.ft.
or OOIP = 469.8 x 80 x 47 = 17.66 MMSTB/80-acre pattern

* Adapted from Reference 13, Table DAL-1
** Fracture permeability not included.

TABLE 7.2

DALY UNIT #3
CUMULATIVE PRODUCTION VOLUMES

PRODUCERS		OIL PRODUCTION TOTAL CUM BBLS	OIL PRODUCTION TOTAL CUM M3	WATER PRODUCTION TOTAL CUM BBLS	WATER PRODUCTION TOTAL CUM M3	CUM WOR	GAS PRODUCTION TOTAL CUM MSCF	GAS PRODUCTION TOTAL CUM 10E3 M3
5-1-10-28 W1		30,990.5	4,927.1	10,719.7	1,704.3	0.346	2,527.2	71.2
11-1-10-28 W1		8,598.8	1,367.1	803.2	127.7	0.093	603.4	17.0
12-1-10-28 W1	(SUSP. IN 1968)	20,833.1	3,312.2	520.8	82.8	0.025	0.0	0.0
13-1-10-28 W1		361,622.0	57,493.3	21,725.0	3,454.0	0.060	28,895.4	814.1
14-1-10-28 W1	(SUSP. IN 1967)	11,213.5	1,782.8	473.0	75.2	0.042	0.0	0.0
15-1-10-28 W1		369,181.7	58,695.2	42,945.6	6,827.8	0.116	25,367.4	714.7
7-2-10-28 W1		19,796.5	3147.4	12,490.3	1985.8	0.631	468.5	13.2
8-2-10-28 W1		196,284.9	31,206.8	10,204.6	1,622.4	0.052	16,997.9	478.9
9-2-10-28 W1		133,447.8	21,216.5	8,217.6	1,306.5	0.062	5,206.9	146.7
10-2-10-28 W1		66,130.4	10513.9	7,327.0	1164.9	0.111	2,963.7	83.5
14-2-10-28 W1		166,156.0	26416.7	27,633.0	4393.3	0.166	7,943.5	223.8
15-2-10-28 W1		120,323.4	19,129.9	9,001.3	1,431.1	0.075	8,987.0	253.2
16-2-10-28 W1		31,984.3	5,085.1	6,991.8	1,111.6	0.219	0.0	0.0
9-10-10-28 W1		81,947.4	13,028.6	12,351.3	1,963.7	0.151	6,325.0	178.2
10-10-10-28 W1		110,103.8	17505.1	6,542.0	1040.1	0.059	8,908.9	251
1-11-10-28 W1		437,391.5	69,539.7	139,216.2	22,133.6	0.318	26,932.6	758.8
2-11-10-28 W1		17,016.5	2,705.4	3,110.9	494.6	0.183	0.0	
3-11-10-28 W1		100,214.9	15,932.9	2,009.6	319.5	0.020	6,963.9	196.2
4-11-10-28 W1		202,723.7	32230.5	8,980.0	1427.7	0.044	14,861.2	418.7
5-11-10-28 W1	(ABAN. IN 1967)	41,502.7	6,598.4	140,295.5	22,305.2	3.380	276.9	7.8
7-11-10-28 W1		167,138.5	26,572.9	3,419.8	543.7	0.020	12,383.8	348.9
8-11-10-28 W1	(SUSP. IN 1967)	17,728.5	2,818.6	1,271.2	202.1	0.072	0.0	0.0
9-11-10-28 W1		187,739.5	29,848.2	19,400.9	3,084.5	0.103	15,077.7	424.8
10-11-10-28 W1	(SUSP. IN 1967)	176.7	28.1	0.0	0.0	0.000	0.0	0.0
11-11-10-28 W1		84,145.1	13,378.0	168,726.7	26,825.4	2.005	6,797.0	191.5
12-11-10-28 W1	(SUSP. IN 1967)	71.7	11.4	0.0	0.0	0.000	0.0	0.0
13-11-10-28 W1		267,968.6	42,603.6	40,639.7	6,461.2	0.152	18,872.0	531.7
14-11-10-28 W1	(SUSP. IN 1967)	49.7	7.9	0.0	0.0	0.000	0.0	0.0
15-11-10-28 W1		212,589.3	33,799.0	19,789.0	3,146.2	0.093	15,230.4	429.1
16-11-10-28 W1	(SUSP. IN 1967)	32.1	5.1	0.0	0.0	0.000	0.0	0.0
1-12-10-28 W1		212,286.1	33,750.8	20,651.3	3,283.3	0.097	17,218.0	485.1
2-12-10-28 W1	(SUSP. IN 1967)	21,264.0	3,380.7	291.2	46.3	0.014	0.0	0.0
3-12-10-28 W1		582,784.3	92,655.3	270,111.5	42,944.3	0.463	25,126.0	707.9
4-12-10-28 W1	(SUSP. IN 1967)	109,332.0	17,382.4	3,726.1	592.4	0.034	0.0	0.0
5-12-10-28 W1		579,521.1	92,136.5	150,336.5	23,901.6	0.259	38,982.8	1,098.3
6-12-10-28 W1	(SUSP. IN 1967)	11,241.8	1,787.3	249.7	39.7	0.022	0.0	0.0
7-12-10-28 W1		215,617.2	34,280.4	14,164.0	2,251.9	0.066	16,156.7	455.2
9-12-10-28 W1		77,723.2	12,357.0	35,755.1	5,684.6	0.460	4,805.9	135.4
10-12-10-28 W1	(SUSP. IN 1968)	26,234.2	4,170.9	2,787.0	443.1	0.106	0.0	0.0
11-12-10-28 W1		333,985.2	53,099.4	12,281.5	1,952.6	0.037	26,233.4	739.1
12-12-10-28 W1	(SUSP. IN 1967)	8,435.9	1,341.2	562.9	89.5	0.067	0.0	0.0
13-12-10-28 W1		134,091.2	21,318.8	8,020.1	1,275.1	0.060	10,704.9	301.6
14-12-10-28 W1	(SUSP. IN 1968)	17,714.6	2,816.4	1,005.7	159.9	0.057	0.0	0.0

TABLE 7.2

DALY UNIT #3
CUMULATIVE PRODUCTION VOLUMES

PRODUCERS		OIL PRODUCTION TOTAL CUM BBLS	OIL PRODUCTION TOTAL CUM M3	WATER PRODUCTION TOTAL CUM BBLS	WATER PRODUCTION TOTAL CUM M3	CUM WOR	GAS PRODUCTION TOTAL CUM MSCF	GAS PRODUCTION TOTAL CUM 10E3 M3
15-12-10-28 W1		248,251.3	39,468.8	176,576.4	28,073.4	0.711	8,859.2	249.6
3-13-10-28 W1		26,863.8	4,271.0	176,185.8	28,011.3	6.558	0.0	0.0
4-13-10-28 W1	(SUSP. IN 1967)	14,823.8	2,356.8	2,812.8	447.2	0.190	0.0	0.0
5-13-10-28 W1	(ABAN. IN 1967)	115,082.8	18,296.7	18,167.5	2,888.4	0.158	8,841.5	249.1
6-13-10-28 W1		266,561.5	42379.9	46,510.6	7394.6	0.174	21,395.6	602.8
10-13-10-28 W1		319,382.1	50,777.7	27,313.5	4342.5	0.086	26,304.4	741.1
11-13-10-28 W1		53,565.9	8,516.3	117,988.7	18,758.7	2.203	3.5	0.1
12-13-10-28 W1		218,657.7	34763.8	201,113.5	31974.5	0.920	18,321.9	516.2
14-13-10-28 W1		178,518.0	28382.1	92,617.5	14725	0.519	10,726.2	302.2
15-13-10-28 W1		90,312.9	14358.6	120,302.1	19126.5	1.332	5,622.2	158.4
3-14-10-28 W1		254,840.5	40,516.4	34,465.0	5,479.5	0.135	20,973.2	590.9
4-14-10-28 W1		77,341.4	12,296.3	410,122.1	65,204.2	5.303	3,127.0	88.1
5-14-10-28 W1		45,348.3	7,209.8	24,237.2	3,853.4	0.534	49.7	1.4
1-23-10-28 W1		102,252.8	16256.9	1,250,855.3	198870.1	12.233	9,629.4	271.3
8-23-10-28 W1		194,352.6	30899.6	1,173,232.1	186529	6.037	12,674.8	357.1
9-23-10-28 W1		76,020.5	12086.3	2,231,195.8	354731.8	29.350	6,502.5	183.2
2-24-10-28 W1		54,919.5	8731.5	7,578.6	1204.9	0.138	4,064.0	114.5
7-24-10-28 W1		48,607.0	7727.9	9,439.7	1500.8	0.194	3,166.0	89.2
		8,181,036.5	1,300,680.9	7,365,462.5	1,171,015.0	0.900	532,079.4	14,990.8

TABLE 7.2

DALY UNIT #3
CUMULATIVE INJECTION VOLUMES

INJECTORS	WATER INJECTION TOTAL CUM BBLS	WATER INJECTION TOTAL CUM M3
12-1-10-28 W1	699,875.4	111,271.3
14-1-10-28 W1	984,105.0	156,460.2
16-2-10-28 W1	1,022,482.9	162,561.8
2-11-10-28 W1	855,863.3	136,071.4
6-11-10-28 W1	449,579.9	71,477.5
8-11-10-28 W1	737,249.5	117,213.3
10-11-10-28 W1	3,100,090.4	492,875.0
12-11-10-28 W1	1,691,866.0	268,985.2
14-11-10-28 W1	529,244.8	84,143.2
16-11-10-28 W1	93,834.5	14,918.5
2-12-10-28 W1	1,932,404.7	307,227.8
4-12-10-28 W1	891,785.7	141,782.6
6-12-10-28 W1	751,151.2	119,423.5
10-12-10-28 W1	1,701,259.8	270,478.7
12-12-10-28 W1	668,249.0	106,243.1
14-12-10-28 W1	2,590,532.1	411,861.7
4-13-10-28 W1	1,806,645.6	287,233.7
11-13-10-28 W1	475,616.6	75,617.0
4-14-10-28 W1	364,362.4	57,929.0
	21,346,198.7	3,393,774.5

TABLE 7.3

DALY UNIT #3
ANNUAL OIL AND WATER PRODUCTION FIGURES

YEAR	CUM OIL PROD'N (STB)	CUM WATER PROD'N (STB)	YEARLY OIL PROD'N (STB)	YEARLY WATER PROD'N (STB)	YEARLY WOR	YEARLY WATER CUT
1955	947,691	175,940				
1956	1,406,204	345,938	458,512	169,998	0.3708	0.2705
1957	1,803,615	570,933	397,411	224,995	0.5662	0.3615
1958	2,209,080	822,142	405,466	251,209	0.6196	0.3825
1959	2,577,589	1,112,352	368,509	290,211	0.7875	0.4406
1960	2,928,618	1,380,470	351,029	268,118	0.7638	0.4330
1961	3,273,192	1,606,745	344,574	226,275	0.6567	0.3964
1962	3,585,689	1,853,142	312,497	246,397	0.7885	0.4409
1963	3,875,420	2,091,840	289,731	238,698	0.8239	0.4517
1964	4,168,089	2,362,181	292,669	270,340	0.9237	0.4802
1965	4,443,714	2,642,350	275,625	280,170	1.0165	0.5041
1966	4,710,242	2,917,717	266,528	275,367	1.0332	0.5082
1967	5,043,150	3,175,400	332,908	257,683	0.7740	0.4363
1968	5,284,962	3,433,645	241,812	258,245	1.0680	0.5164
1969	5,518,419	3,668,535	233,458	234,890	1.0061	0.5015
1970	5,942,956	3,915,517	424,536	246,982	0.5818	0.3678
1971	6,156,891	4,120,621	213,935	205,104	0.9587	0.4895
1972	6,350,103	4,309,068	193,212	188,447	0.9753	0.4938
1973	6,535,833	4,523,086	185,729	214,018	1.1523	0.5354
1974	6,717,545	4,742,142	181,713	219,056	1.2055	0.5466
1975	6,894,588	4,993,542	177,042	251,399	1.4200	0.5868
1976	7,068,811	5,164,510	174,223	170,968	0.9813	0.4953
1977	7,253,114	5,391,688	184,303	227,178	1.2326	0.5521
1978	7,439,089	5,601,475	185,975	209,787	1.1280	0.5301
1979	7,622,275	5,808,344	183,186	206,869	1.1293	0.5304
1980	7,802,910	6,012,186	180,635	203,841	1.1285	0.5302
1981	7,979,409	6,216,932	176,499	204,746	1.1600	0.5370
1982	8,156,805	6,443,814	177,396	226,882	1.2790	0.5612
1983	8,331,509	6,650,122	174,705	206,308	1.1809	0.5415
1984	8,496,428	6,837,185	164,919	187,063	1.1343	0.5315
1985	8,682,170	7,143,162	185,741	305,977	1.6473	0.6223
1986	8,872,420	7,529,191	190,250	386,030	2.0291	0.6699
1987	9,068,013	7,916,830	195,593	387,639	1.9819	0.6646
1988	9,265,226	8,334,351	197,213	417,520	2.1171	0.6792

TABLE 7.4

DALY UNIT #3
PREDICTED FUTURE PERFORMANCE - ALL WELLS

YEAR	CUM OIL PRODUCTION (STB)	OIL PROD'N (STB/YEAR)	EST'D WATER CUT	WATER PROD'N (STB/YEAR)	CUM WATER PRODUCTION (STB)
1988	9,265,226	197,213	0.679	417,520	8,334,351
1989	9,458,495	193,269	0.715	484,867	8,819,218
1990	9,647,898	189,403	0.725	499,336	9,318,554
1991	9,833,513	185,615	0.742	533,824	9,852,378
1992	10,015,416	181,903	0.750	545,709	10,398,087
1993	10,193,681	178,265	0.763	573,908	10,971,995
1994	10,368,381	174,700	0.778	612,236	11,584,231
1995	10,539,587	171,206	0.790	644,059	12,228,290
1996	10,707,368	167,782	0.803	683,901	12,912,191
1997	10,871,794	164,426	0.810	700,974	13,613,165
1998	11,032,931	161,137	0.818	724,233	14,337,398
1999	11,190,846	157,915	0.822	729,246	15,066,644
2000	11,345,602	154,756	0.833	771,928	15,838,572
2001	11,497,264	151,661	0.840	796,221	16,634,794
2002	11,645,892	148,628	0.846	816,489	17,451,282
2003	11,791,547	145,655	0.852	838,503	18,289,785
2004	11,934,289	142,742	0.858	862,485	19,152,271
2005	12,074,177	139,887	0.864	888,697	20,040,967
2006	12,211,267	137,090	0.869	909,397	20,950,364
2007	12,345,614	134,348	0.873	923,510	21,873,874
2008	12,477,275	131,661	0.878	947,527	22,821,401
2009	12,606,303	129,028	0.883	973,774	23,795,175
2010	12,732,750	126,447	0.886	982,739	24,777,914
2011	12,856,669	123,918	0.890	1,002,611	25,780,525
2012	12,978,109	121,440	0.893	1,013,512	26,794,037
2013	13,097,120	119,011	0.896	1,025,326	27,819,363
2014	13,213,750	116,631	0.901	1,061,459	28,880,822
2015	13,328,049	114,298	0.903	1,064,034	29,944,856
2016	13,440,061	112,012	0.906	1,079,608	31,024,464
2017	13,549,833	109,772	0.908	1,083,402	32,107,867
2018	13,657,410	107,577	0.910	1,087,719	33,195,585
2019	13,762,835	105,425	0.913	1,106,357	34,301,943
2020	13,866,151	103,317	0.915	1,112,172	35,414,115
2021	13,967,402	101,250	0.918	1,133,509	36,547,624
2022	14,066,627	99,225	0.920	1,141,090	37,688,714
2023	14,163,867	97,241	0.921	1,133,655	38,822,369
2024	14,259,163	95,296	0.923	1,142,313	39,964,682
2025	14,352,553	93,390	0.925	1,151,810	41,116,492
2026	14,444,076	91,522	0.927	1,162,206	42,278,698
2027	14,533,767	89,692	0.928	1,156,027	43,434,725
2028	14,621,665	87,898	0.931	1,185,985	44,620,710
2029	14,707,805	86,140	0.932	1,180,624	45,801,334
2030	14,792,222	84,417	0.933	1,175,540	46,976,875
2031	14,874,951	82,729	0.934	1,170,738	48,147,613
2032	14,956,025	81,074	0.936	1,185,711	49,333,323
2033	15,035,478	79,453	0.938	1,202,043	50,535,367
2034	15,113,342	77,864	0.939	1,198,590	51,733,957

TABLE 7.4

DALY UNIT #3
PREDICTED FUTURE PERFORMANCE - ALL WELLS

YEAR	CUM OIL PRODUCTION (STB)	OIL PROD'N (STB/YEAR)	EST'D WATER CUT	WATER PROD'N (STB/YEAR)	CUM WATER PRODUCTION (STB)
2035	15,189,648	76,306	0.941	1,217,023	52,950,980
2036	15,264,429	74,780	0.942	1,214,535	54,165,515
2037	15,337,713	73,285	0.943	1,212,412	55,377,927
2038	15,402,137	64,424	0.944	1,086,005	56,463,931

TABLE 7.5

DALY UNIT #3
WATERFLOOD PERFORMANCE PER PATTERN (CUMULATIVE)

PATTERN #	PRODUCERS	INJECTORS	CONT'N TO PATTERN OOIP (MSTB)	CONT'N TO CUM. OIL PROD'N (MSTB)	CONT'N TO CUM. WATER PROD'N (MSTB)	CONT'N TO CUM. GAS PROD'N (MSCF)	OIL RECOVERY (% OOIP)	CUM PRODUCING WOR	CUM PRODUCING GOR	CUM WATER INJ. (MSTB)	VOIDAC REPLACE RAT
1		12-1								699.8754	
	5-1			7.7476	2.6799	631.788					
	11-1			2.1497	0.2008	150.848					
	12-1			20.8331	0.5208	0.000					
	13-1			90.4055	5.4313	7223.861					
	9-2			33.3619	2.0544	1301.733					
			1.766	154.4979	10.8872	9308.231	8.75	0.0705	60.248	699.8754	4.
2		16-2								1022.4829	
	13-1			90.4055	5.4313	7223.861					
	9-2			33.3619	2.0544	1301.733					
	15-2			30.0809	2.2503	2246.753					
	16-2			31.9843	6.9918	0.000					
	1-11			109.3479	34.8040	6733.161					
			1.766	295.1805	51.5318	17505.5077	16.71	0.1746	59.304	1022.4829	2.
3		14-1								984.1050	
	11-1			2.1497	0.2008	150.848					
	13-1			90.4055	5.4313	7223.861					
	14-1			11.2135	0.4730	0.000					
	15-1			92.2954	10.7364	6341.842					
	3-12			145.6961	67.5279	6281.503					
			1.766	341.7602	84.3693	19998.0549	19.35	0.2469	58.515	984.1050	2.
4		2-11								855.8633	
	15-2			30.0809	2.2503	2246.753					
	1-11			109.3479	34.8040	6733.161					
	3-11			25.0537	0.5024	1740.967					
	7-11			41.7846	0.8549	3095.941					
			1.766	206.2671	38.4117	13816.8218	11.68	0.1862	66.985	855.8633	3.
5		4-12								891.7857	
	13-1			90.4055	5.4313	7223.861					
	1-11			109.3479	34.8040	6733.161					
	3-12			145.6961	67.5279	6281.503					
	4-12			109.3320	3.7261	0.000					
	5-12			144.8803	37.5841	9745.691					
			1.766	599.6617	149.0734	29984.2159	33.96	0.2486	50.002	891.7857	1.

TABLE 7.5

DALY UNIT #3
WATERFLOOD PERFORMANCE PER PATTERN (CUMULATIVE)

PATTERN #	PRODUCERS	INJECTORS	CONT'N TO PATTERN OOIP (MSTB)	CONT'N TO CUM. OIL PROD'N (MSTB)	CONT'N TO CUM. WATER PROD'N (MSTB)	CONT'N TO CUM. GAS PROD'N (MSCF)	OIL RECOVERY (% OOIP)	CUM PRODUCING WOR	CUM PRODUCING GOR	CUM WATER INJ. (MSTB)	VOIDAE REPLACEN RATI
6		2-12								1932.4047	
	15-1			92.2954	10.7364	6341.842					
	1-12			53.0715	5.1628	4304.502					
	2-12			21.2640	0.2912	0.000					
	3-12			145.6961	67.5279	6281.503					
	7-12			53.9043	3.5410	4039.250					
			1.766	366.2312	87.2593	20967.0973	20.74	0.2383	57.251	1932.4047	4.
7		6-11								449.5799	
	3-11			25.0537	0.5024	1740.967					
	5-11			10.3757	35.0739	69.213					
	7-11			41.7846	0.8549	3095.941					
	11-11			21.0363	42.1817	1699.262					
			1.766	98.2503	78.6129	6605.3832	5.56	0.8001	67.230	449.5799	2.
8		8-11								737.2495	
	1-11			109.3479	34.8040	6733.161					
	7-11			41.7846	0.8549	3095.941					
	8-11			17.7285	1.2712	0.000					
	9-11			46.9349	4.8502	3769.434					
	5-12			144.8803	37.5841	9745.691					
			1.766	360.6761	79.3645	23344.2264	20.42	0.2200	64.724	737.2495	1.
9		6-12								751.1512	
	3-12			145.6961	67.5279	6281.503					
	5-12			144.8803	37.5841	9745.691					
	6-12			11.2418	0.2497	0.000					
	7-12			53.9043	3.5410	4039.175					
	11-12			83.4963	3.0704	6558.354					
			1.766	439.2187	111.9731	26624.7229	24.87	0.2549	60.618	751.1512	1.

TABLE 7.5

DALY UNIT #3
WATERFLOOD PERFORMANCE PER PATTERN (CUMULATIVE)

PATTERN #	PRODUCERS	INJECTORS	CONT'N TO PATTERN OOIP (MSTB)	CONT'N TO CUM. OIL PROD'N (MSTB)	CONT'N TO CUM. WATER PROD'N (MSTB)	CONT'N TO CUM. GAS PROD'N (MSCF)	OIL RECOVERY (% OOIP)	CUM PRODUCING WOR	CUM PRODUCING GOR	CUM WATER INJ. (MSTB)	VOIDAGE REPLACEMENT RATIO
10		12-11								1691.8660	
	9-10			20.4869	3.0878	1581.246					
	5-11			10.3757	35.0739	69.213					
	11-11			21.0363	42.1817	1699.262					
	12-11			0.0717	0.0000	0.000					
	13-11			66.9921	10.1599	4718.004					
			1.766	118.9626	90.5033	8067.7249	6.74	0.7608	67.817	1691.8660	7.84
11		10-11								3100.0904	
	7-11			41.7846	0.8549	3095.941					
	9-11			46.9349	4.8502	3769.434					
	11-11			21.0363	42.1817	1699.262					
	15-11			53.1473	4.9473	3807.590					
			1.766	162.9031	52.8341	12372.2270	9.22	0.3243	75.948	3100.0904	13.76
12		12-12								668.2490	
	9-11			46.9349	4.8502	3769.434					
	5-12			144.8803	37.5841	9745.691					
	11-12			83.4963	3.0704	6558.354					
	12-12			8.4359	0.5629	0.000					
	13-12			33.5228	2.0050	2676.227					
			1.766	317.2702	48.0727	22749.7064	17.97	0.1515	71.705	668.2490	1.74
13		10-12								1701.2598	
	7-12			53.9043	3.5410	4039.175					
	9-12			19.4308	8.9388	1201.463					
	10-12			26.2342	2.7870	0.000					
	11-12			83.4963	3.0704	6558.354					
	15-12			62.0628	44.1441	2214.809					
			1.766	245.1283	62.4812	14013.8005	13.88	0.2549	57.169	1701.2598	5.33

TABLE 7.5

DALY UNIT #3
WATERFLOOD PERFORMANCE PER PATTERN (CUMULATIVE)

PATTERN #	PRODUCERS	INJECTORS	CONT'N TO PATTERN OOIP (MSTB)	CONT'N TO CUM. OIL PROD'N (MSTB)	CONT'N TO CUM. WATER PROD'N (MSTB)	CONT'N TO CUM. GAS PROD'N (MSCF)	OIL RECOVERY (% OOIP)	CUM PRODUCING WOR	CUM PRODUCING GOR	CUM WATER INJ. (MSTB)	VOIDAGE REPLACEMEN RATIO
14		14-11								529.2448	
	11-11			21.0363	42.1817	1699.262					
	13-11			66.9921	10.1599	4718.004					
	14-11			0.0497	0.0000	0.000					
	15-11			53.1473	4.9473	3807.590					
	3-14			63.7101	8.6163	5243.311					
			1.766	204.9356	65.9051	15468.1676	11.60	0.3216	75.478	529.2448	1.87
15		14-12								2590.5321	
	11-12			83.4963	3.0704	6558.354					
	13-12			33.5228	2.0050	2676.227					
	15-12			62.0628	44.1441	2214.809					
	3-13			6.7159	44.0464	0.000					
			1.766	185.7979	93.2659	11449.3900	10.52	0.5020	61.623	2590.5321	8.99
16		4-14								364.3624	
	13-11			66.9921	10.1599	4718.004					
	3-14			63.7101	8.6163	5243.311					
	5-14			11.3371	6.0593	12.423					
	1-15			92.2953	10.7365	0.000					
			1.766	234.3346	35.5720	9973.7382	13.27	0.1518	42.562	364.3624	1.31
17		11-13								475.6166	
	6-13			66.6404	11.6277	5348.905					
	10-13			79.8455	6.8284	6576.101					
	11-13			53.5659	117.9887	3.549					
	12-13			54.6644	50.2784	4580.466					
	14-13			44.6295	23.1544	2681.551					
			1.766	299.3458	209.8775	19190.5726	16.95	0.7011	64.108	475.6166	0.91
TOTAL:			30022.00	4630.42	1350.00	281439.59					
AVERAGE:				272.38	79.41	16555.27	13.06	0.29	50.58	853.27	2.68

TABLE 8.1

DALY UNIT #1

SELECTED WELL DEEPENING

INCREMENTAL OIL PRODUCTION RATES

Well	Current Cruickshank Pay (ft)	Expected Cruickshank Pay (ft)	Current Øh (ft)	Expected Øh (ft)	Current q_o (STB/D)	Expected q_o (STB/D)	Possible Incremental q_o (STB/D)
1. 9-5-10-28 WIM	0	72	1.09	9.01	12.9	38+	25+
2. 5-4-10-28 WIM	0	36	1.70	4.94	21.4	42+	20+
3. 7-5-10-28 WIM	6	36	1.39	3.78	12.5	33	20
4. 8-5-10-28 WIM	30	70	4.35	8.35	17.7	34	16
5. 10-5-10-28 WIM	4	38	0.83	3.89	4.0	19	15
6. 2-5-10-28 WIM	27	58	2.82	5.29	16.7	32	15
7. 4-4-10-28 WIM	9	36	2.86	5.29	11.5	22	10

Total: 121+ STB/D

INCREMENTAL OIL RECOVERIES

Well	Estimated Unpenetrated Øh (ft)	Estimated Unpenetrated OOIP (MMSTB)	Estimated Permeability Variance (V)	Estimated* Recovery Factor	Possible Incremental Oil Recovery (MMSTB)
1. 9-5-10-28 WIM	7.92	1.358	.70	.21	.285
2. 5-4-10-28 WIM	3.24	.556	.68	.22	.122
3. 7-5-10-28 WIM	2.40	.411	.62	.23	.094
4. 8-5-10-28 WIM	4.0	.686	.63	.22	.151
5. 10-5-10-28 WIM	3.06	.525	.59	.25	.131
6. 2-5-10-28 WIM	2.48	.425	.53	.27	.115
7. 4-4-10-28 WIM	2.43	.417	.62	.23	.096

Total: .994 MMSTB

* Values interpolated from Table 4.1

TABLE 8.2

DALY UNIT #1
PRODUCER RE-DRILLING

Incremental Oil Production Rates

	Well	q_o Prior to Suspension (STB/D)
1.	15-4-10-28 W1M	15
2.	10-4-10-28 W1M	10
3.	12-3-10-28 W1M	10
	Total:	35 STB/D

Incremental Oil Recoveries

	Well	Cumulative Oil Recovery Before SI (MMSTB)	Estimated OOIP (MMSTB)	Estimated Recovery Factor	Ultimate Oil Recovery (MMSTB)	Possible Incremental Oil Recovery (MMSTB)
1.	15-4-10-28 W1M	.0051	1.997	.23*	.459	.454
2.	10-4-10-28 W1M	.0214	.754	.17**	.128	.107
3.	12-3-10-28 W1M	.0355	.537	.17**	.091	.056
					Total:	.617 MMSTB

*Based on current waterflood recovery of pattern 15.
**Based on current unflooded recovery in well 9-4-10-28 W1M.

TABLE 8.3

DALY UNIT #1
INJECTION WELL DRILLING

Incremental Oil Production Rates

Pattern	Current Pattern q_o (STB/D)	Current Offsetting Flooded Pattern q_o (STB/D)	Possible Incremental q_o (STB/D)
7	15.9	26.8	10.9
2	16.9	26.4	9.5
		Total:	≈20 STB/D

Incremental Oil Recoveries

Pattern	Cumulative Oil Recovery (MMSTB)	Estimated OOIP (MMSTB)	Adjusted Recovery Factor**	Expected Ultimate Oil Recovery (MMSTB)	Possible Incremental Oil Recovery (MMSTB)
7	.231	1.399	.28	.392	.161
2	.212	1.187	.37	.439	.227
				Total:	.388 MMSTB

**Based on ratio of extrapolated to theoretical oil recovery of waterflooded 80-acre patterns (Table 6.7).

TABLE 8.4

DALY UNIT #1

RECOMMENDATIONS TO IMPROVE PRODUCTIVITY

WATERFLOOD AREAS

80-Acre Patterns

Well	Comments	Recommended Action(s)	Predicted Incremental Oil Production Rate (STB/D)	Predicted Incremental Oil Recovery (MSTB)	Approximate Cost (M$)	Approximate Payout Time (mo.)	Priority
Pattern: 4							
1-5	Deepened/selectively acidized in 1988	-	4	110	-	-	Completed
2-5	Unexploited reserves in Cruickshank Crinoidal member	Deepen/selectively acidize	15	115	37	7	16
7-5	Unexploited reserves in Cruickshank Crinoidal member	Deepen/selectively acidize	20	94	37	6	13
8-5	Unexploited reserves in Cruickshank Crinoidal member	Deepen/selectively acidize	16	151	37	7	14
8B-5	Increase VRR (currently = 0.83)	Maintain $q_{w(inj)}$ = 700 STB/D	-	-	-	-	-
Pattern: 5							
3-4	Gypsum deposition problems	Selectively acidize	9	-	12	4	2
4-4	Unexploited reserves in Cruickshank Crinoidal member	Deepen/selectively acidize	10	96	37	11	17
5-4	Unexploited reserves in Cruickshank Crinoidal member	Deepen/selectively acidize	20+	122	37	5	12
6-4	Gypsum deposition problems	Selectively acidize	5	-	12	7	9
5A-4	Decrease VRR (currently = 2.34)	Maintain $q_{w(inj)} \approx$ 275 STB/D	- -	- -	- -	- -	- -

TABLE 8.4 (Continued)

Well	Comments	Recommended Action(s)	Predicted Incremental Oil Production Rate (STB/D)	Predicted Incremental Oil Recovery (MSTB)	Approximate Cost (M$)	Approximate Payout Time (mo.)	Priority
Pattern: 6							
9-5	Unexploited reserves in Cruickshank Crinoidal member	Deepen/selectively acidize	25+	285	37	4	11
	Well not currently pumped off	Install larger size pumping unit	5	-	60	36	19
12B-4	Increase VRR (currently = .81)	Maintain $q_{w(inj)}$ = 950 STB/D	-	-	-	-	-
Pattern: 8							
10-5	Unexploited reserves in Cruickshank Crinoidal member	Deepen/selectively acidize	15	131	37	7	15
15A-5	Decrease VRR (currently = 2.11)	Maintain $q_{w(inj)} \approx$ 300 STB/D	-	-	-	-	-
Pattern: 9							
12D-4	Increase VRR (currently = .42)	Maintain $q_{w(inj)} \approx$ 625 STB/D	-	-	-	-	-
Pattern: 10							
1-8	Gypsum deposition problems	Selectively acidize	4	-	12	9	10
15A-5	Decrease VRR (currently = 6.98)	Maintain $q_{w(inj)}$ = 65 STB/D	-	-	-	-	-

40-Acre Patterns

Pattern 13							
15-4	Well fractured into water zone SI since 1973	Redrill	15	454	200*	40	20
3-9	Gypsum deposition problems	Selectively acidize	5	-	12	7	8
13C-4	Decrease VRR (currently = 1.78)	Maintain $q_{w(inj)}$ = 55 STB/D	-	-	-	-	-

*Costs include drilling and completion plus installation of a pumping unit.

TABLE 8.4 (Continued)

Well	Comments	Recommended Action(s)	Predicted Incremental Oil Production Rate (STB/D)	Predicted Incremental Oil Recovery (MSTB)	Approximate Cost (M$)	Approximate Payout Time (mo.)	Priority
Pattern: 14							
16-4	Gypsum deposition problems	Selectively acidize	10	-	12	4	1
1-9	Gypsum deposition problems	Selectively acidize	8	-	12	4	3
15D-4	Decrease VRR significantly (currently = 22.4)	Maintain $q_{w(inj)} \approx 30$ STB/D	-	-	-	-	-
Pattern: 15							
13C-3	Decrease VRR (currently = 5.06)	Maintain $q_{w(inj)} \approx 50$ STB/D	-	-	-	-	-

TABLE 8.5

DALY UNIT #1

RECOMMENDATIONS TO IMPROVE PRODUCTIVITY

UNFLOODED AREAS

80-Acre Patterns

Well	Comments	Recommended Action(s)	Predicted Incremental Oil Production Rate (STB/D)	Predicted Incremental Oil Recovery (MSTB)	Approximate Cost (M$)	Approximate Payout Time (mo.)	Priority
Pattern: 1							
16-32	Well not currently pumped off	Install large size pumping unit	11	-	60	16	18
Pattern: 2							
3-5	Deepened/selectively acidized in 1988	-	3	36	-	-	Completed
	Current recovery of OOIP relatively low - 17.9%	Could drill an injector	10	227	140	42	24
Pattern: 7							
10-4	Well fractured into water zone SI since 1960	Redrill	10	107	200*	60	21
	Current recovery of OOIP relatively low - 16.5%	Could drill an injector	11	161	140	38	23

40-Acre Patterns

Well	Comments	Recommended Action(s)	Predicted Incremental Oil Production Rate (STB/D)	Predicted Incremental Oil Recovery (MSTB)	Approximate Cost (M$)	Approximate Payout Time (mo.)	Priority
Pattern: 11							
9-4	Gypsum deposition problems	Selectively acidize	6	-	12	6	4
Pattern: 12							
12-3	SI in 1960 - appears capable of reasonable oil production (~ 10 STB/D) at 70% water cut	Redrill	10	56	200*	60	22
Pattern: 16							
8-9	Gypsum deposition problems	Selectively acidize	6	-	12	6	5

*Costs includes drilling and completion plus installation of a pumping unit.

TABLE 8.5 (Continued)

Well	Comments	Recommended Action(s)	Predicted Incremental Oil Production Rate (STB/D)	Predicted Incremental Oil Recovery (MSTB)	Approximate Cost (M$)	Approximate Payout Time (mo.)	Priority
Pattern: 17							
4-10	Gypsum deposition problems	Selectively acidize	6	-	12	6	10
5-10	Gypsum deposition problems	Selectively acidize	6	-	12	6	6

TABLE 8.6

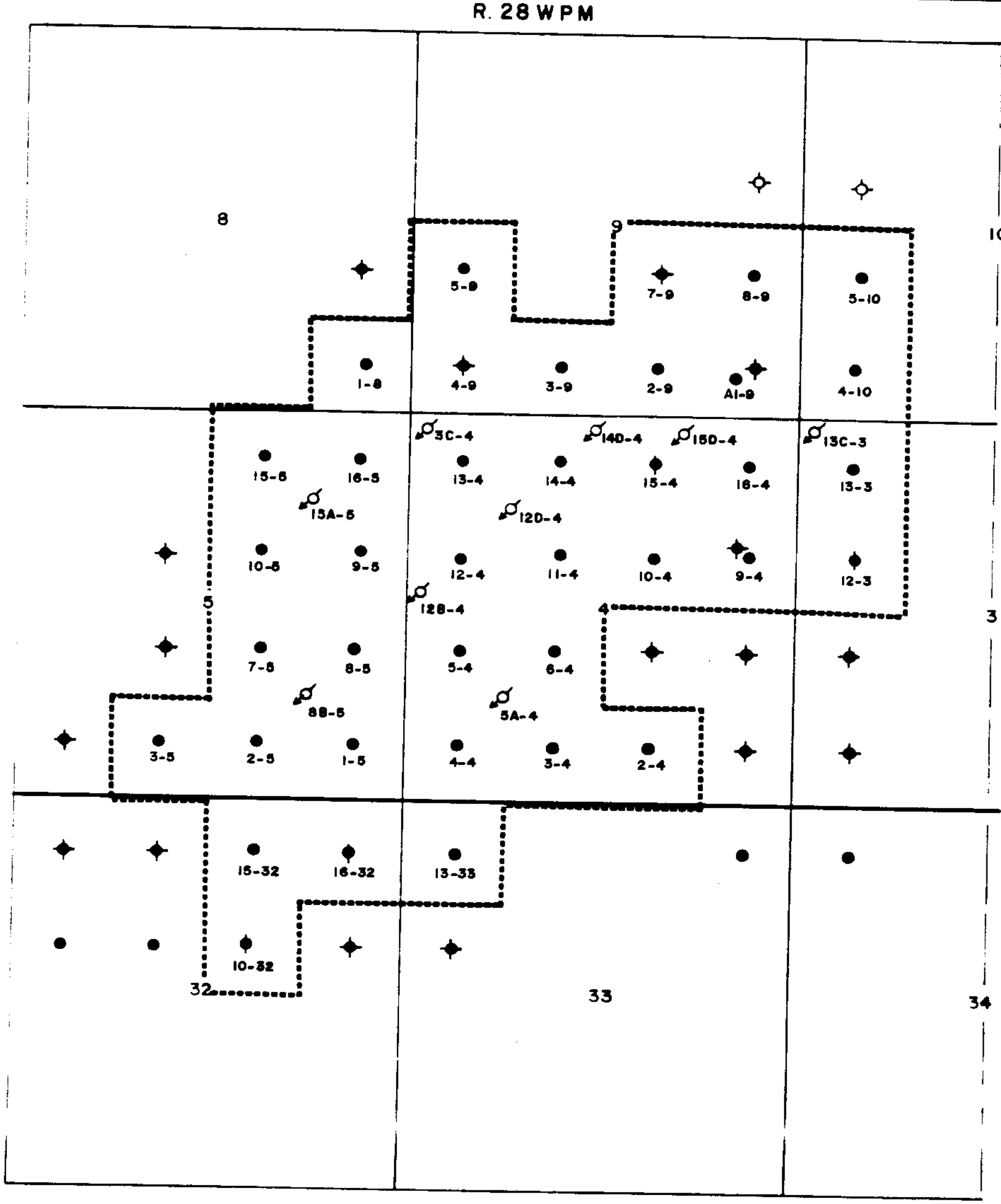
DALY UNIT #1

RECOMMENDATIONS TO IMPROVE PRODUCTIVITY

NON-PATTERN AREAS

Well	Comments	Recommended Action(s)	Predicted Incremental Oil Production Rate (STB/D)	Predicted Incremental Oil Recovery (MSTB)	Approximate Cost (M$)	Approximate Payout Time (mo.)	Priority
2-4	Gypsum deposition problems	Selectively acidize	5	-	12	7	7

FIGURES



- OILWELL
- WATER INJECTION
- SHUT-IN
- ABANDONED OILWELL

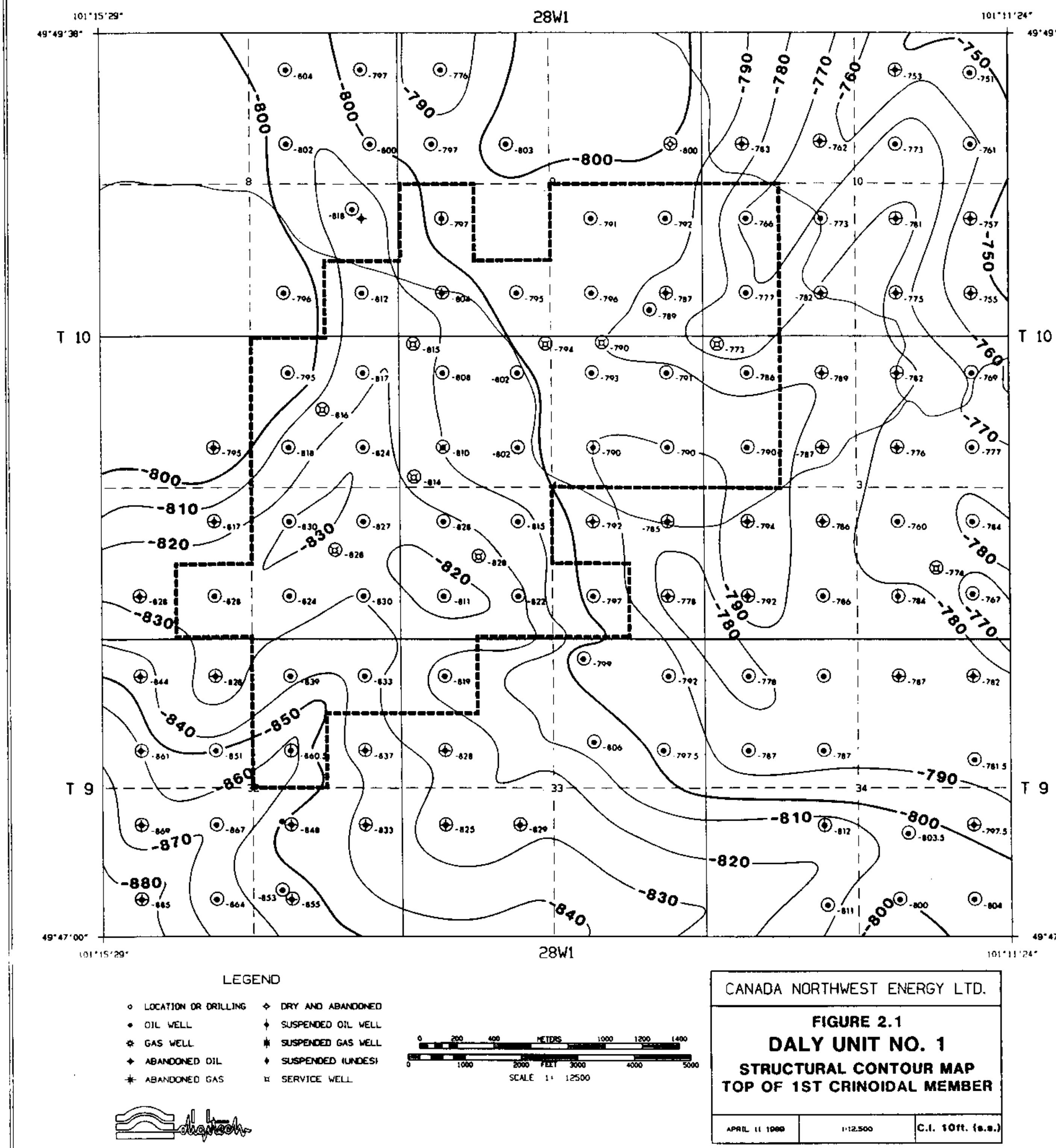
ADAMS PEARSON ASSOCIATES

DALY UNIT No. 1

LAND MAP

Date: June, 1989

Figure: 1.1



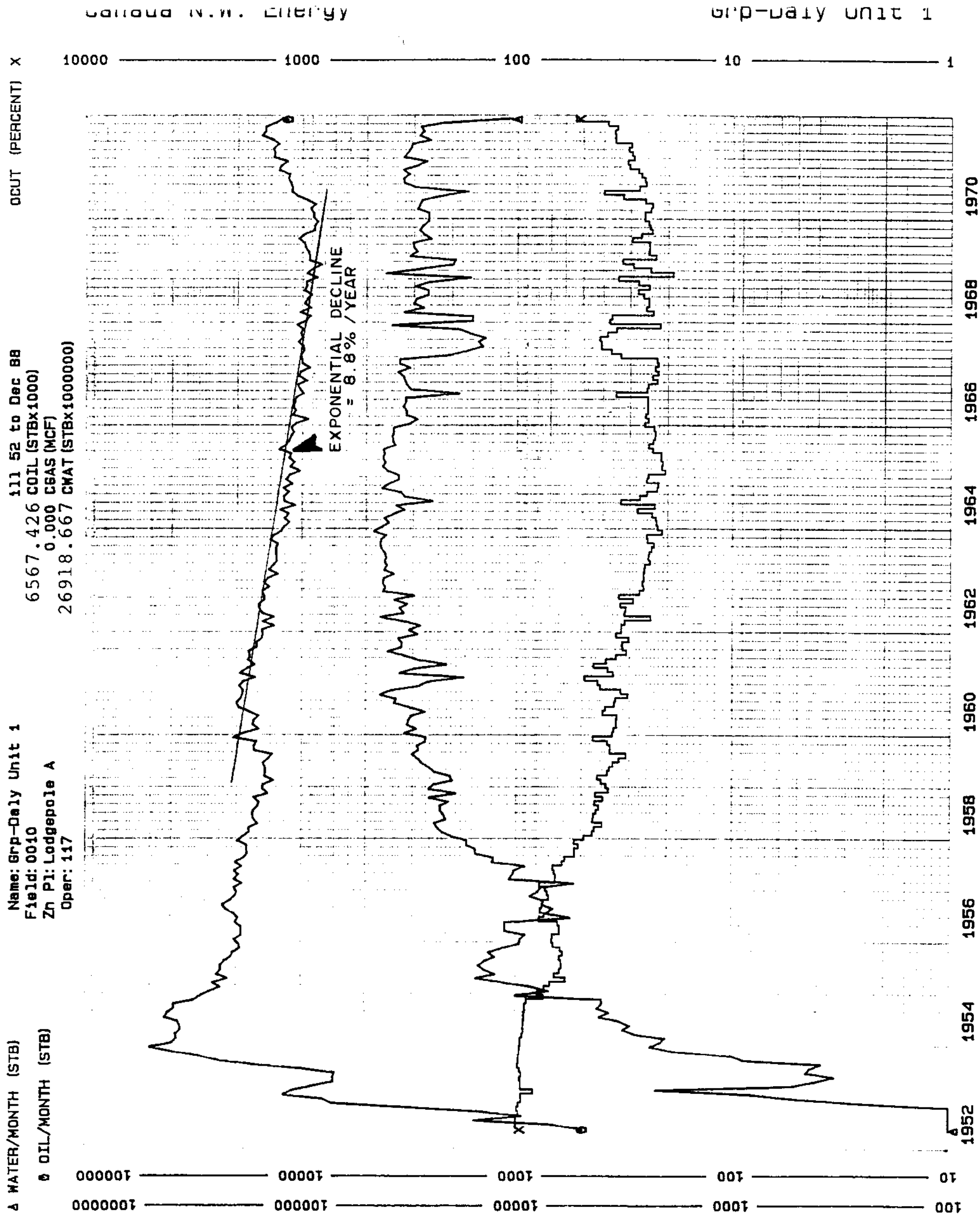
CANADA NORTHWEST ENERGY LTD.

FIGURE 2.1

DALY UNIT NO. 1

STRUCTURAL CONTOUR MAP
TOP OF 1ST CRINOIDAL MEMBER

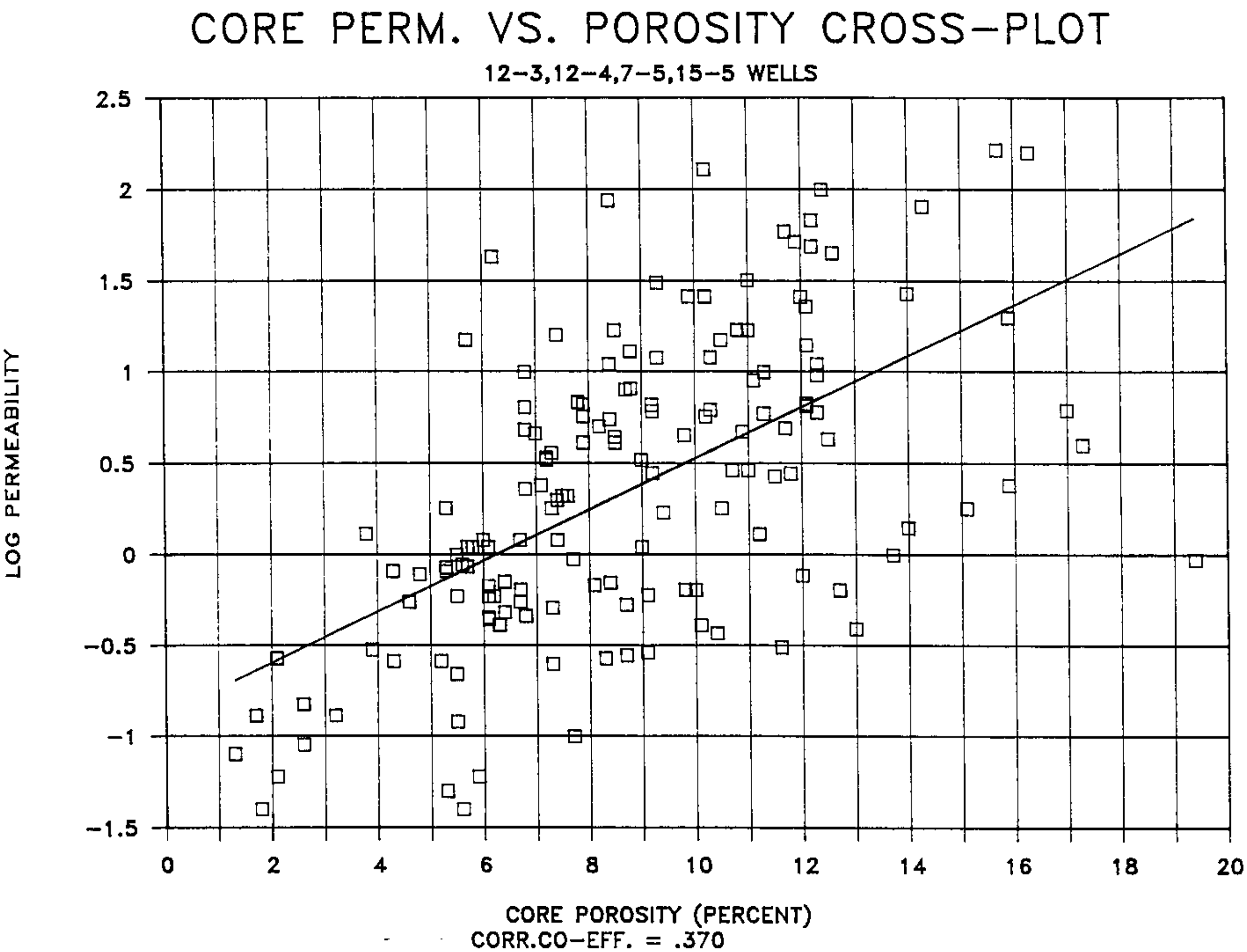
APRIL 11 1989	1:12,500	C.I. 10ft. (s.s.)



DALY UNIT No. 1

PRIMARY PRODUCTION HISTORY – 1952 TO 1969

Figure: 2.2

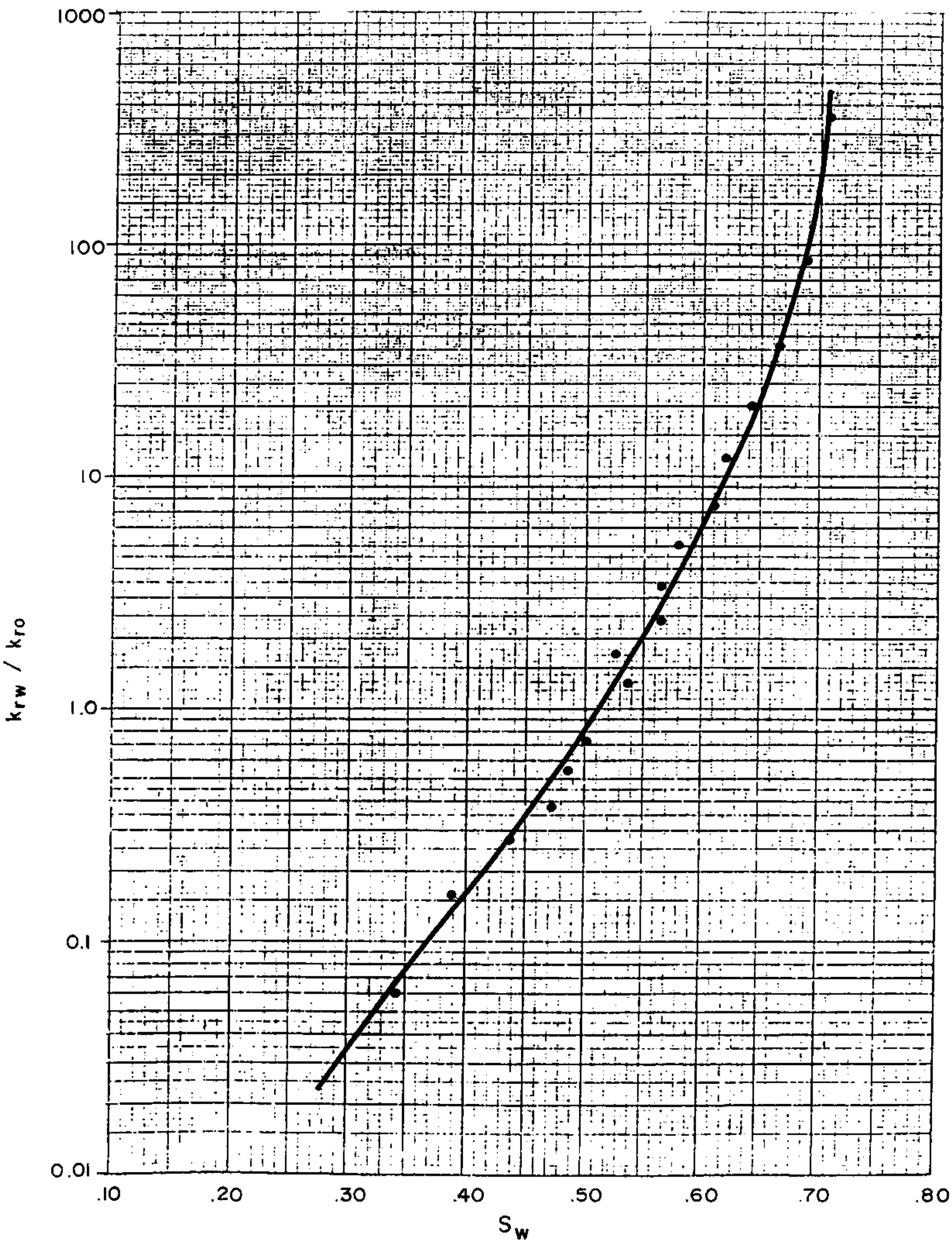


ADAMS PEARSON ASSOCIATES

DALY UNIT No. I

CORE PERMEABILITY VERSUS POROSITY CROSS-PLOT

Date: June, 1989	Figure: 2.3

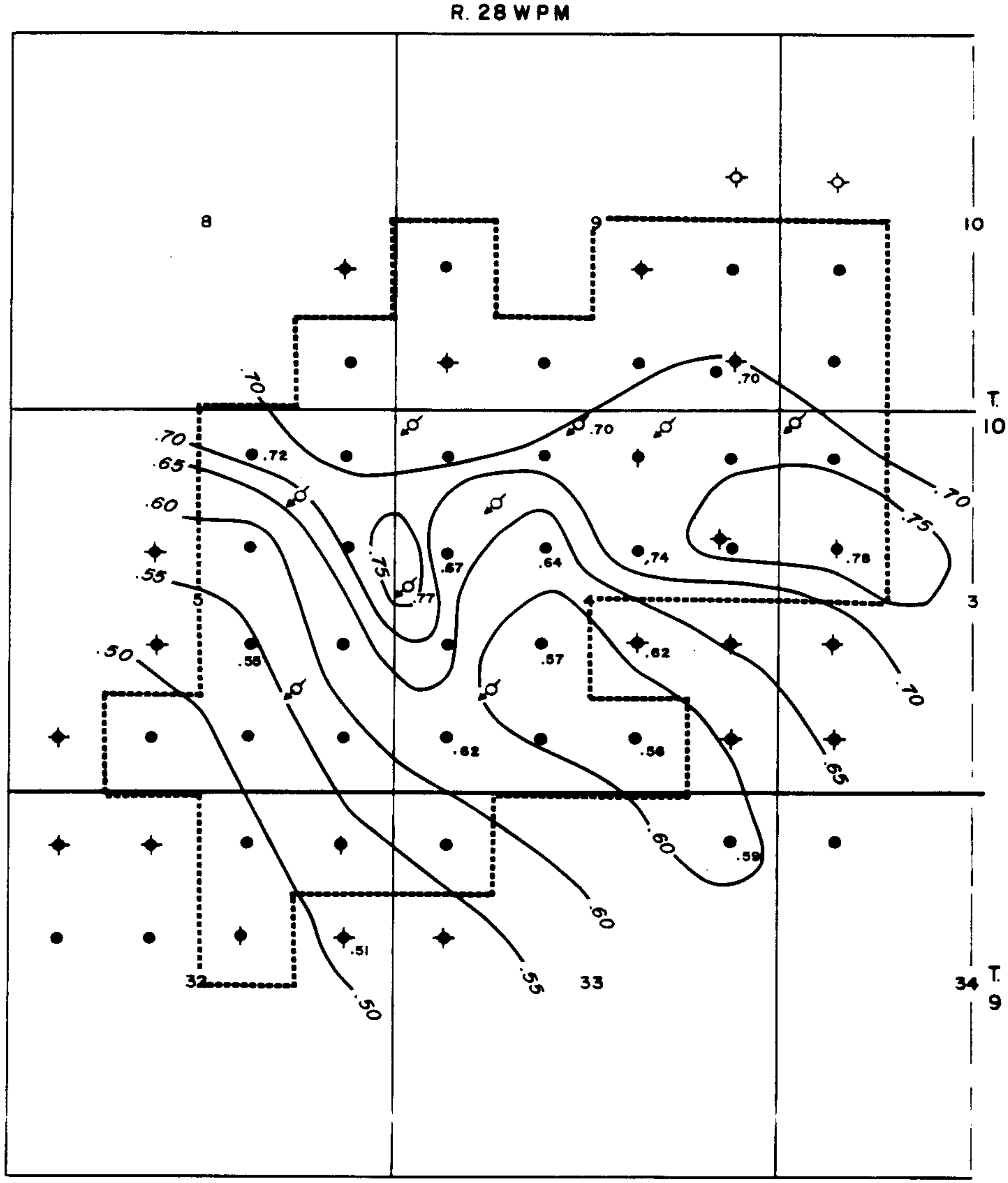


ADAMS PEARSON ASSOCIATES

DALY UNIT No. 1

AVERAGE OIL - WATER RELATIVE PERMEABILITY RATIO VERSUS WATER SATURATION (FROM REFERENCE 3)

Date: June, 1989	Figure: 2.4



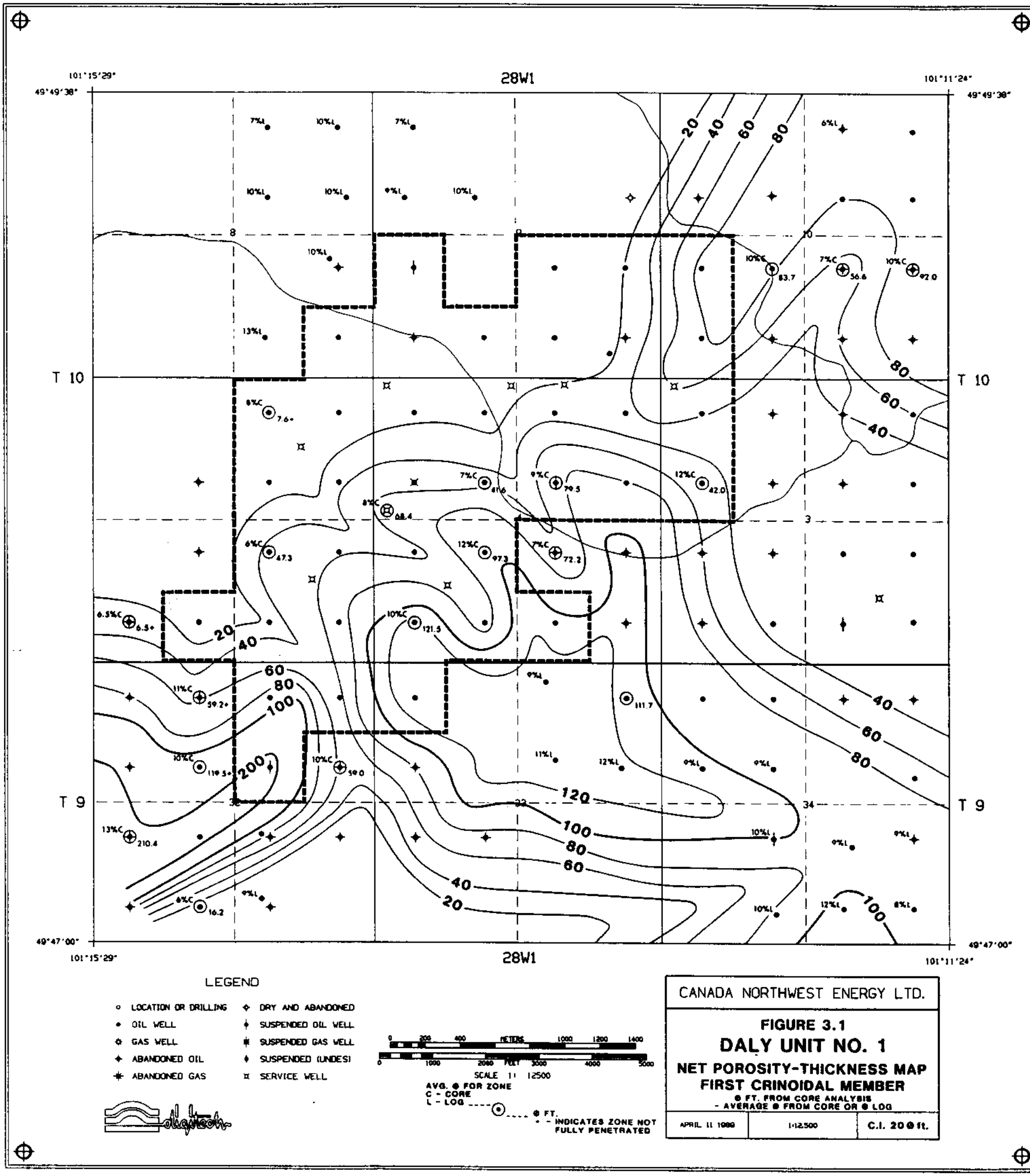
- ● OILWELL
- WATER INJECTION
- SHUT-IN
- ABANDONED OILWELL

ADAMS PEARSON ASSOCIATES

DALY UNIT No. 1

PERMEABILITY VARIATION (V) MAP

Date: June, 1989	Figure: 2.5



CANADA NORTHWEST ENERGY LTD.

FIGURE 3.1

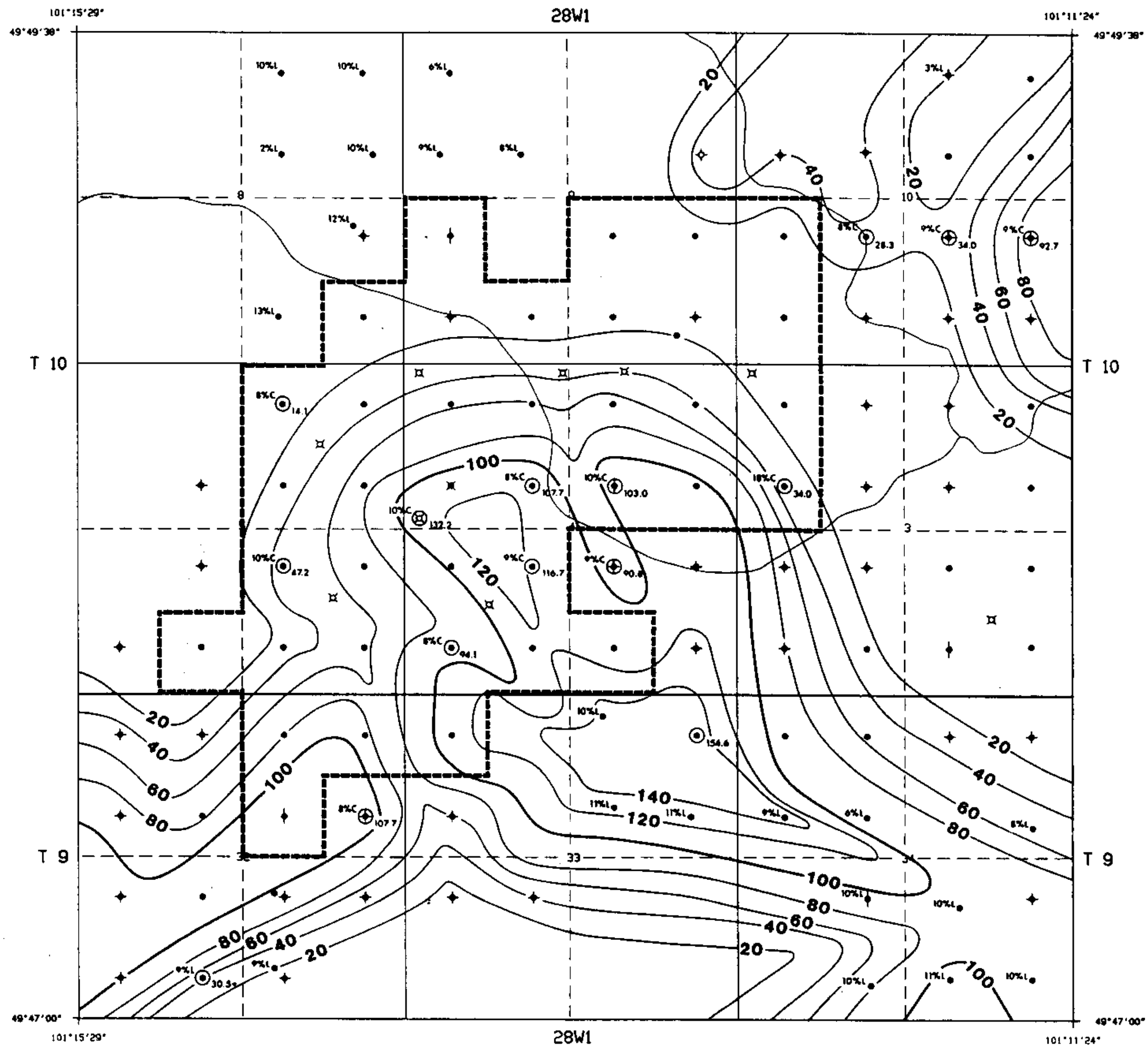
DALY UNIT NO. 1

NET POROSITY-THICKNESS MAP

FIRST CRINOIDAL MEMBER

⊙ FT. FROM CORE ANALYSIS
- AVERAGE ⊙ FROM CORE OR ⊙ LOG

APRIL 11 1989	1:12,500	C.I. 20 ⊙ ft.



LEGEND

LOCATION OR DRILLING	DRY AND ABANDONED
OIL WELL	SUSPENDED OIL WELL
GAS WELL	SUSPENDED GAS WELL
ABANDONED OIL	SUSPENDED (UNDES)
ABANDONED GAS	SERVICE WELL

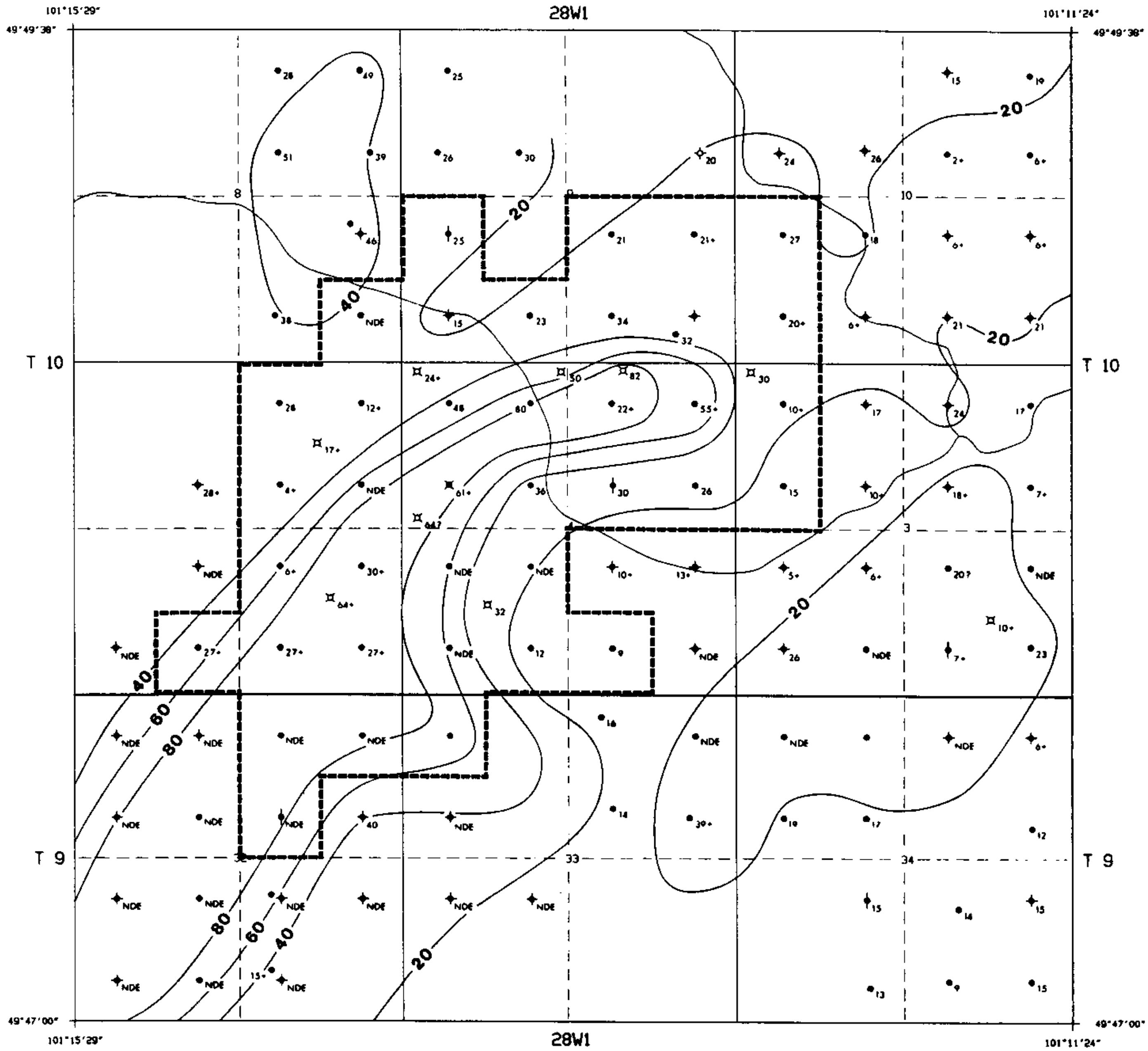
0 200 400 METERS 1000 1200 1400
0 1000 2000 FEET 3000 4000 5000
SCALE 1: 12500

AVG. Φ FOR ZONE
C - CORE
L - LOG
Φ FT.
* - INDICATES ZONE NOT FULLY PENETRATED

CANADA NORTHWEST ENERGY LTD.

FIGURE 3.2
DALY UNIT NO. 1
NET POROSITY-THICKNESS MAP
MAIN CRINOIDAL MEMBER
Φ FT. FROM CORE ANALYSIS
- AVERAGE Φ FROM CORE OR Φ LOG

APRIL 11 1989	1:12,500	C.I. 20 Φ ft.



LEGEND

- o LOCATION OR DRILLING
- • OIL WELL
- ☼ GAS WELL
- ✦ ABANDONED OIL
- ✦ ABANDONED GAS
- ◇ DRY AND ABANDONED
- ⦶ SUSPENDED OIL WELL
- ✱ SUSPENDED GAS WELL
- ✦ SUSPENDED (UNDES)
- ⌑ SERVICE WELL

SCALE 1: 12500

NDE - NOT DEEP ENOUGH

+ - INDICATES ZONE NOT FULLY PENETRATED

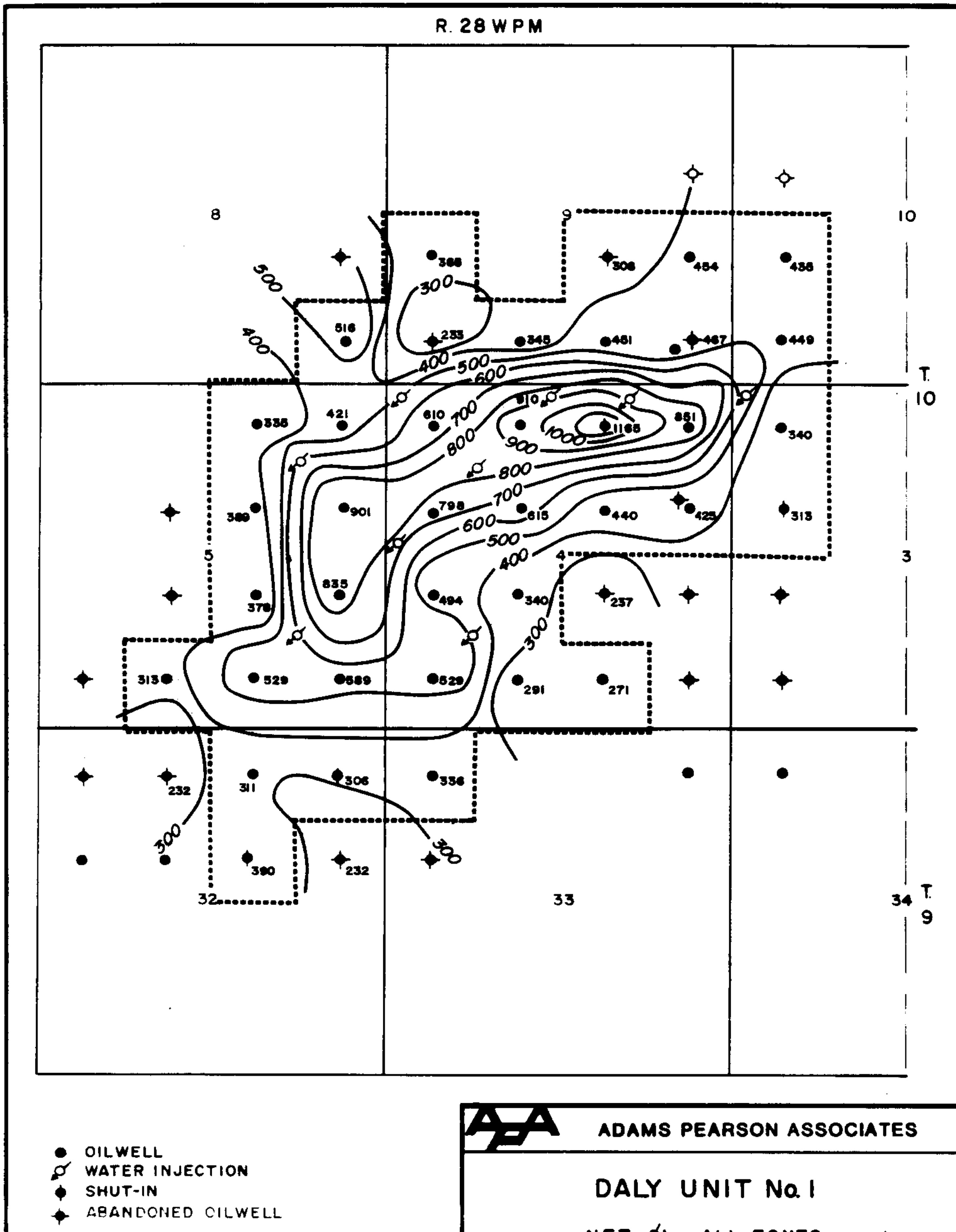
CANADA NORTHWEST ENERGY LTD.

FIGURE 3.3

DALY UNIT NO. 1

GROSS ISOPACH MAP - CRUICKSHANK SHALE & CRINOIDAL MEMBER

APRIL 11 1989	1:12,500	C.I. 20ft.

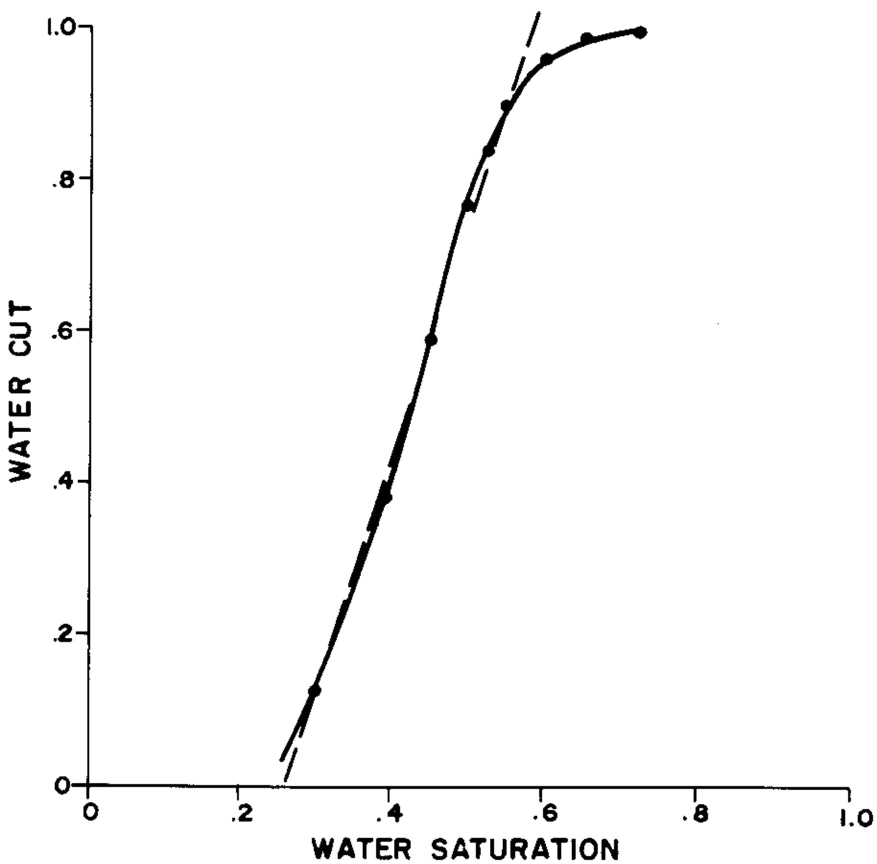


ADAMS PEARSON ASSOCIATES

DALY UNIT No. 1

NET Øh - ALL ZONES
(POROSITY IN % ; THICKNESS IN FT.)

Date: June, 1989 | Figure: 3.4



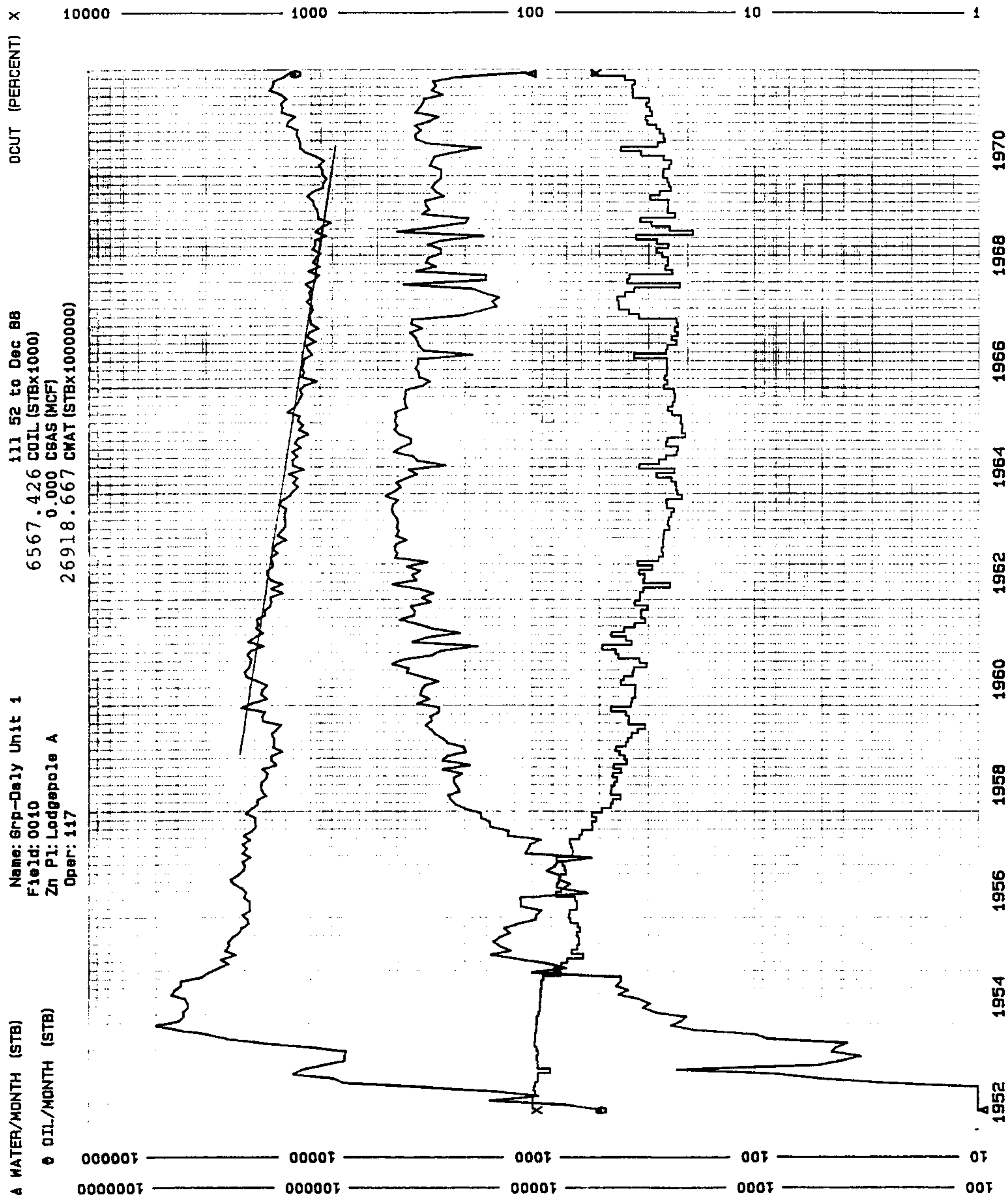
ADAMS PEARSON ASSOCIATES

DALY UNIT No. 1

BUCKLEY LEVERETT
FRACTIONAL FLOW

Date : June, 1989	Figure : 4.1

Canada N.W. Energy | Grp-Daly Unit 1



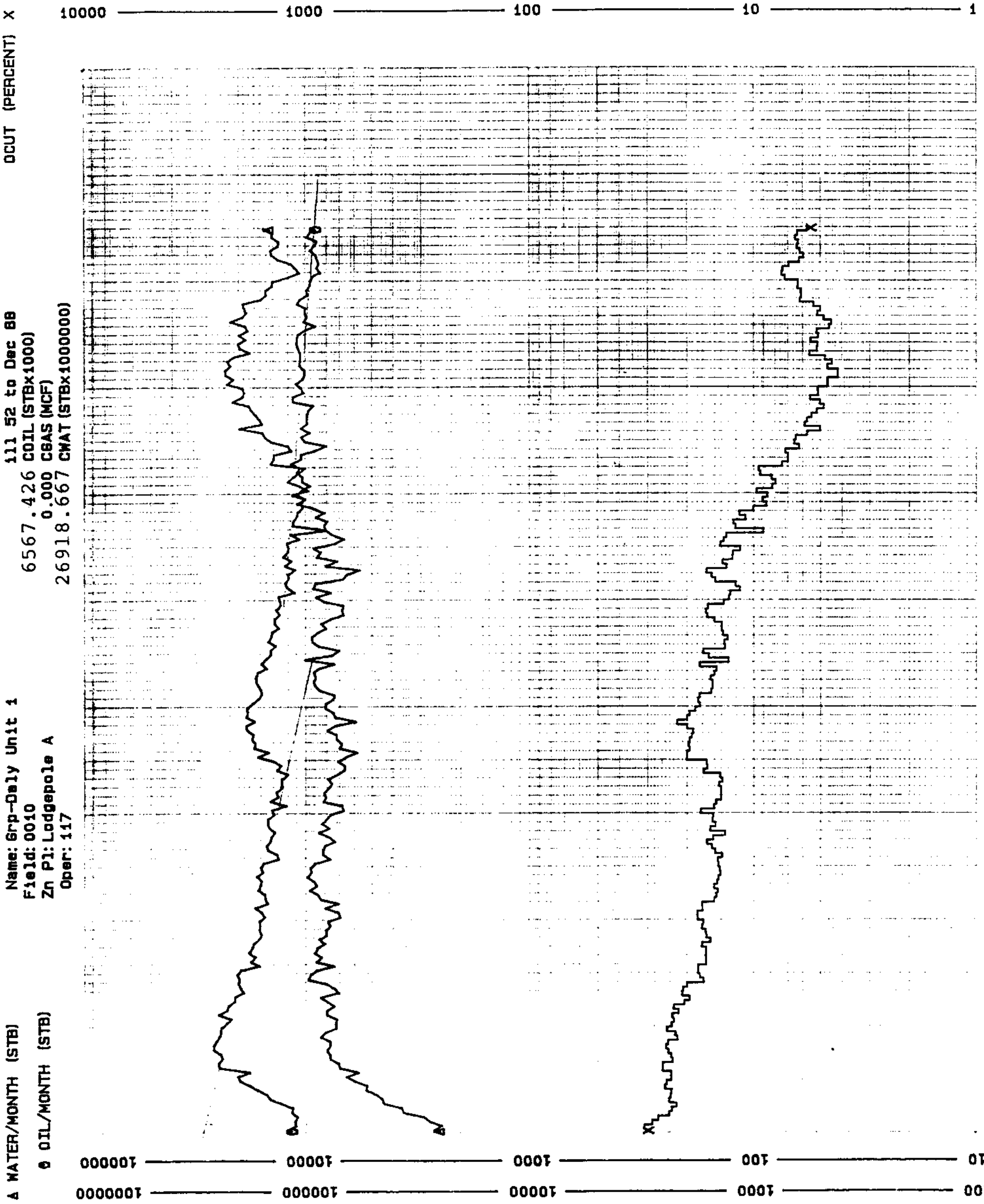
DALY UNIT No. I

PRODUCTION HISTORY PLOT

Figure : 5.I (a)

Canada N.W. Energy

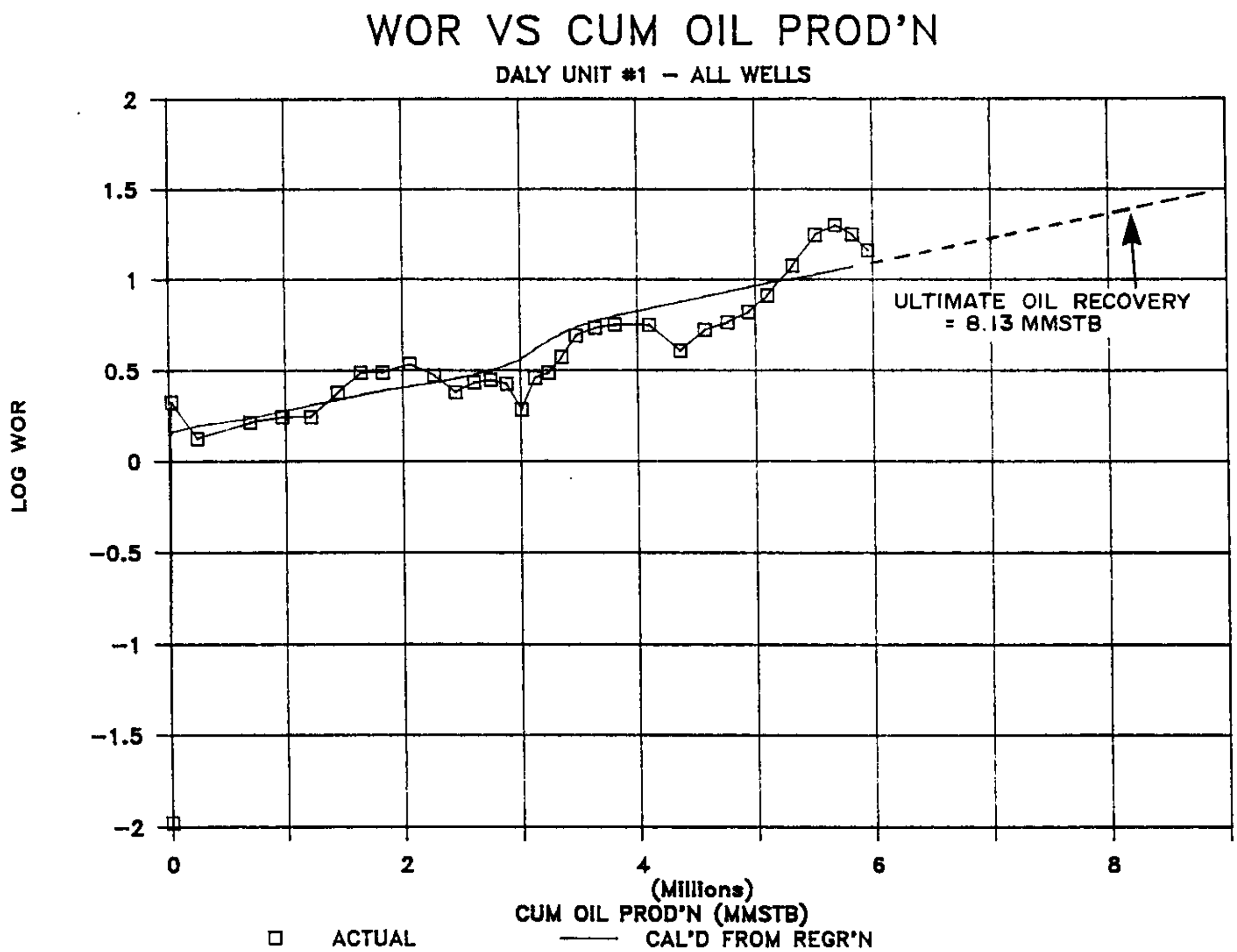
Grp-Daly Unit 1



DALY UNIT No. I

PRODUCTION HISTORY PLOT

Figure: 5.I (b)

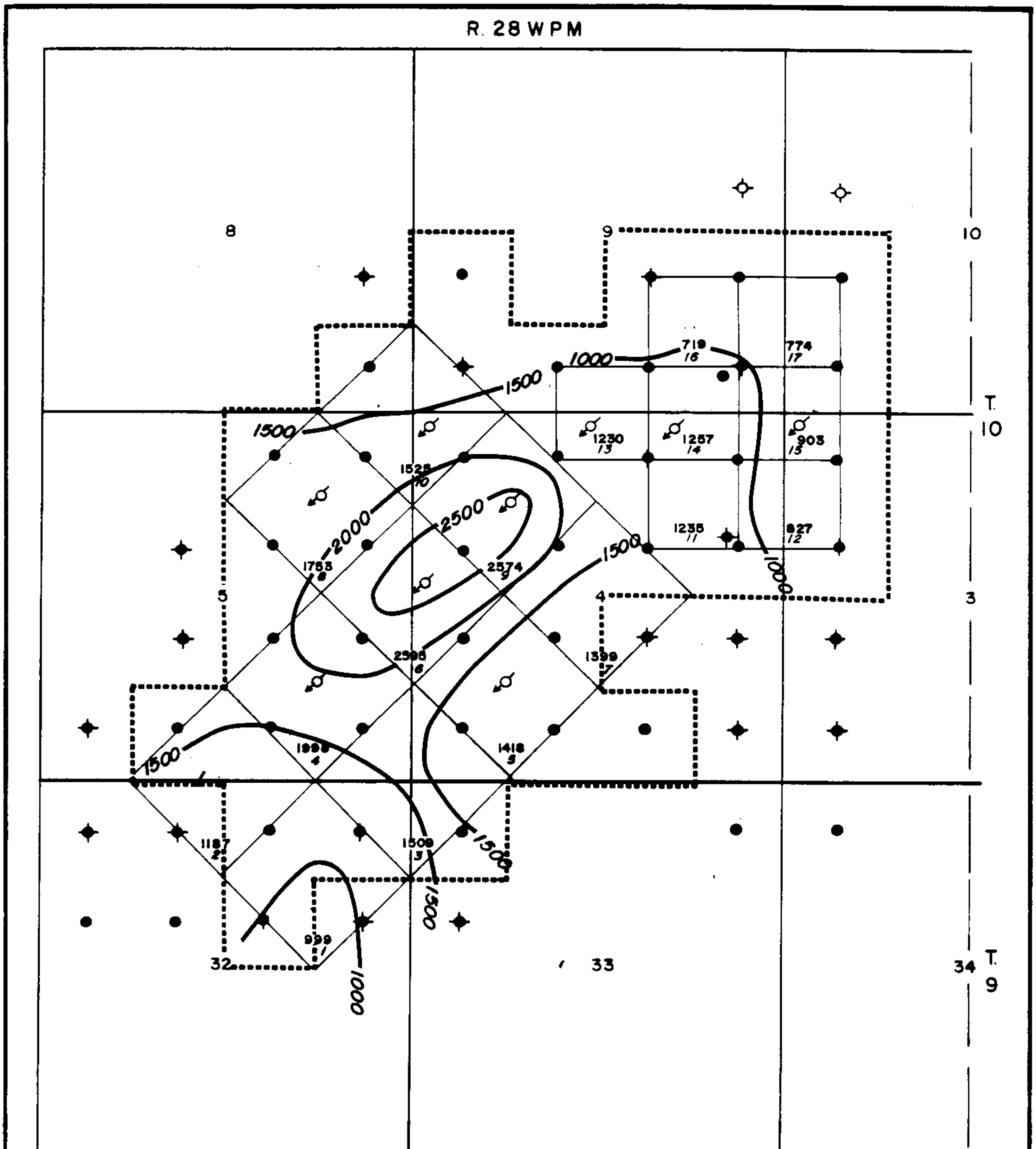


ADAMS PEARSON ASSOCIATES

DALY UNIT No. 1

WOR VERSUS CUMULATIVE OIL PRODUCTION – TOTAL UNIT

Date : June, 1989	Figure : 5.2



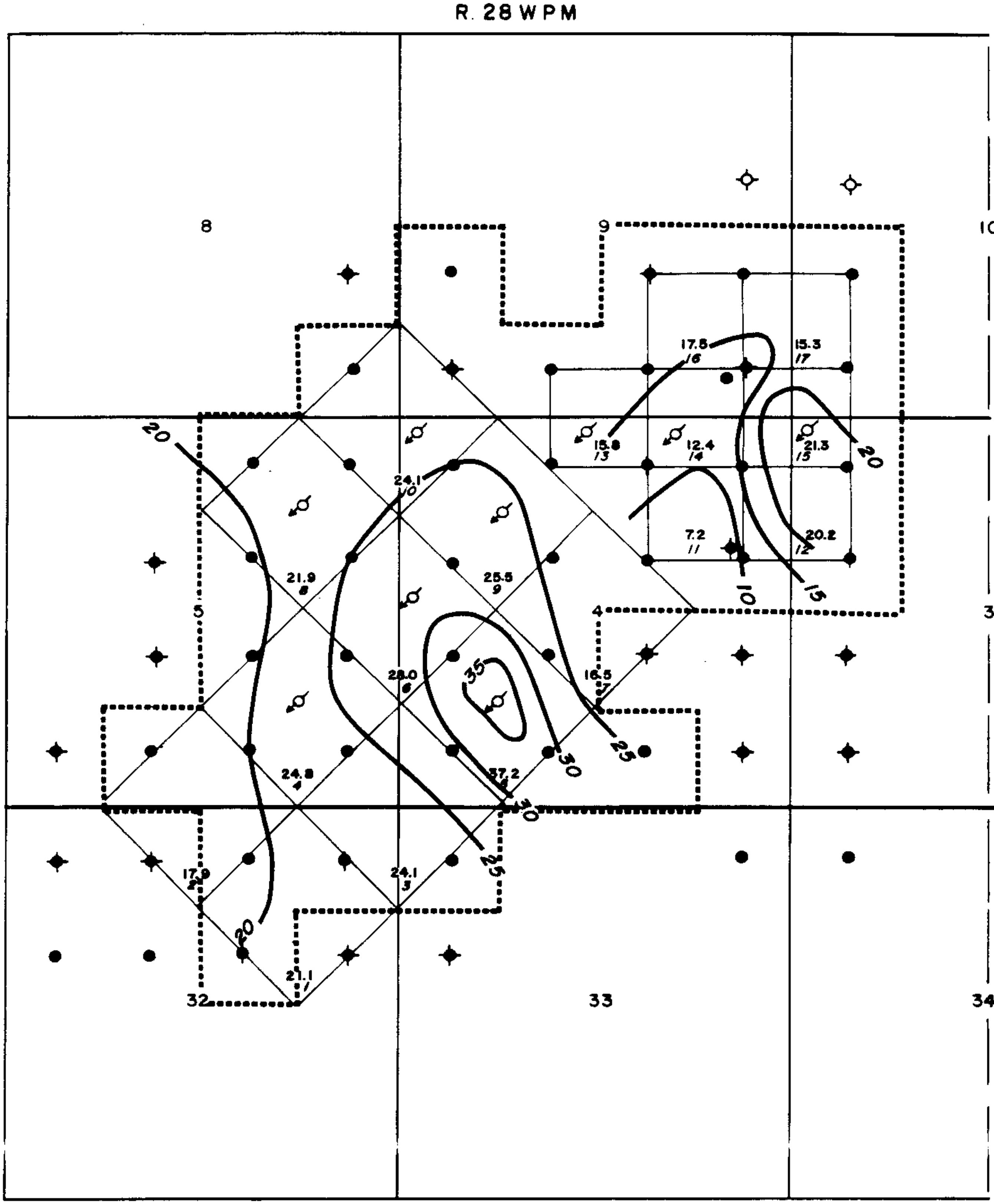
- ● OILWELL
- WATER INJECTION
- SHUT-IN
- ABANDONED OILWELL

ADAMS PEARSON ASSOCIATES

DALY UNIT No. 1

OOIP PER PATTERN – MSTB

Date: June, 1989	Figure: 6.1



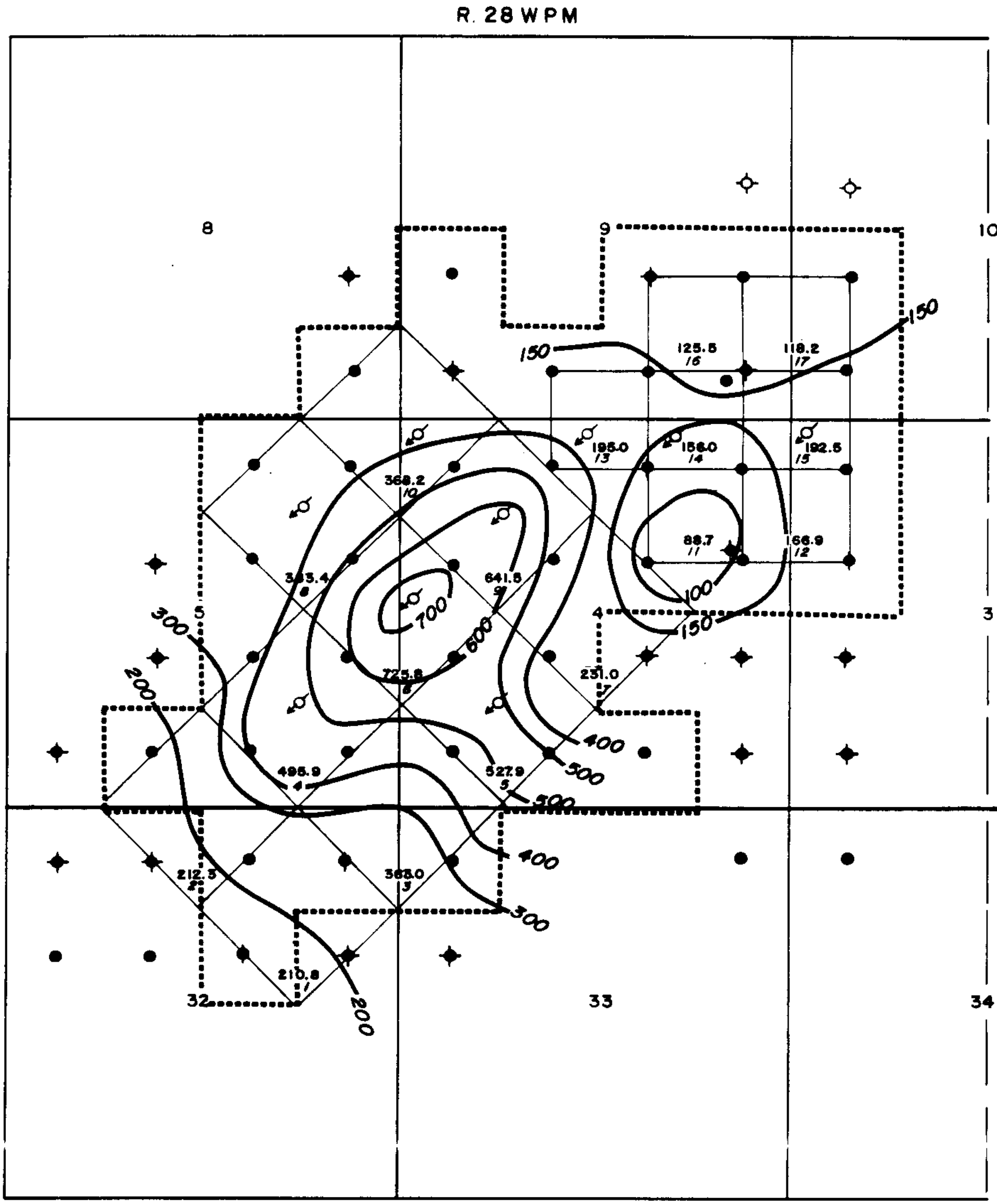
● OILWELL
WATER INJECTION
SHUT-IN
ABANDONED OILWELL

ADAMS PEARSON ASSOCIATES

DALY UNIT No. 1

OIL RECOVERY – % OOIP
(DECEMBER 1988)

Date : June, 1989 | Figure : 6.2



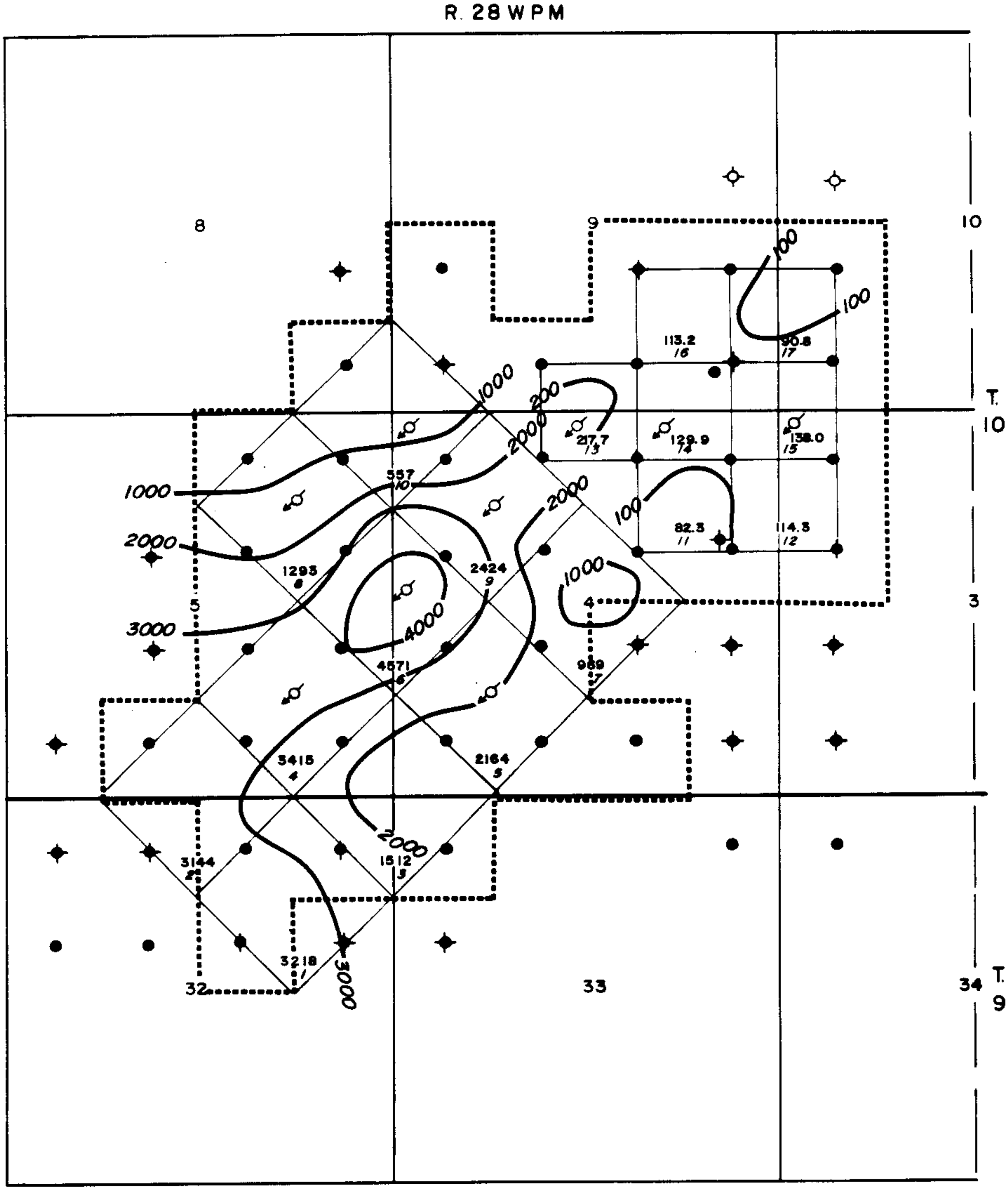
- OILWELL
- WATER INJECTION
- SHUT-IN
- ABANDONED OILWELL

ADAMS PEARSON ASSOCIATES

DALY UNIT No. I

CUMULATIVE OIL PRODUCTION - MSTB
(DECEMBER 1988)

Date : June, 1989	Figure : 6.3



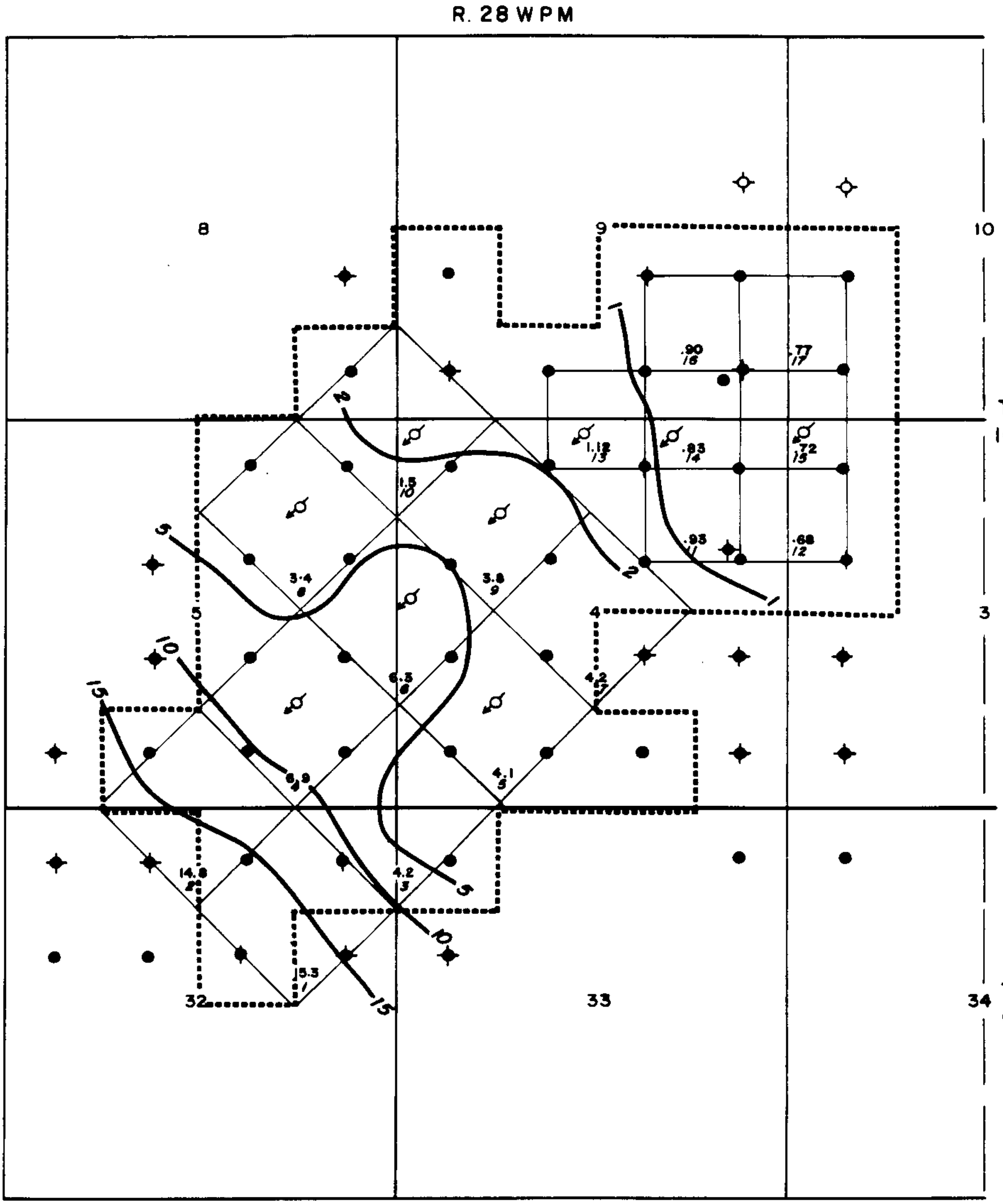
● OILWELL
WATER INJECTION
SHUT-IN
ABANDONED OILWELL

ADAMS PEARSON ASSOCIATES

DALY UNIT No. I

CUMULATIVE WATER PRODUCTION - MSTB
(DECEMBER 1988)

Date: June, 1989 | Figure: 6.4



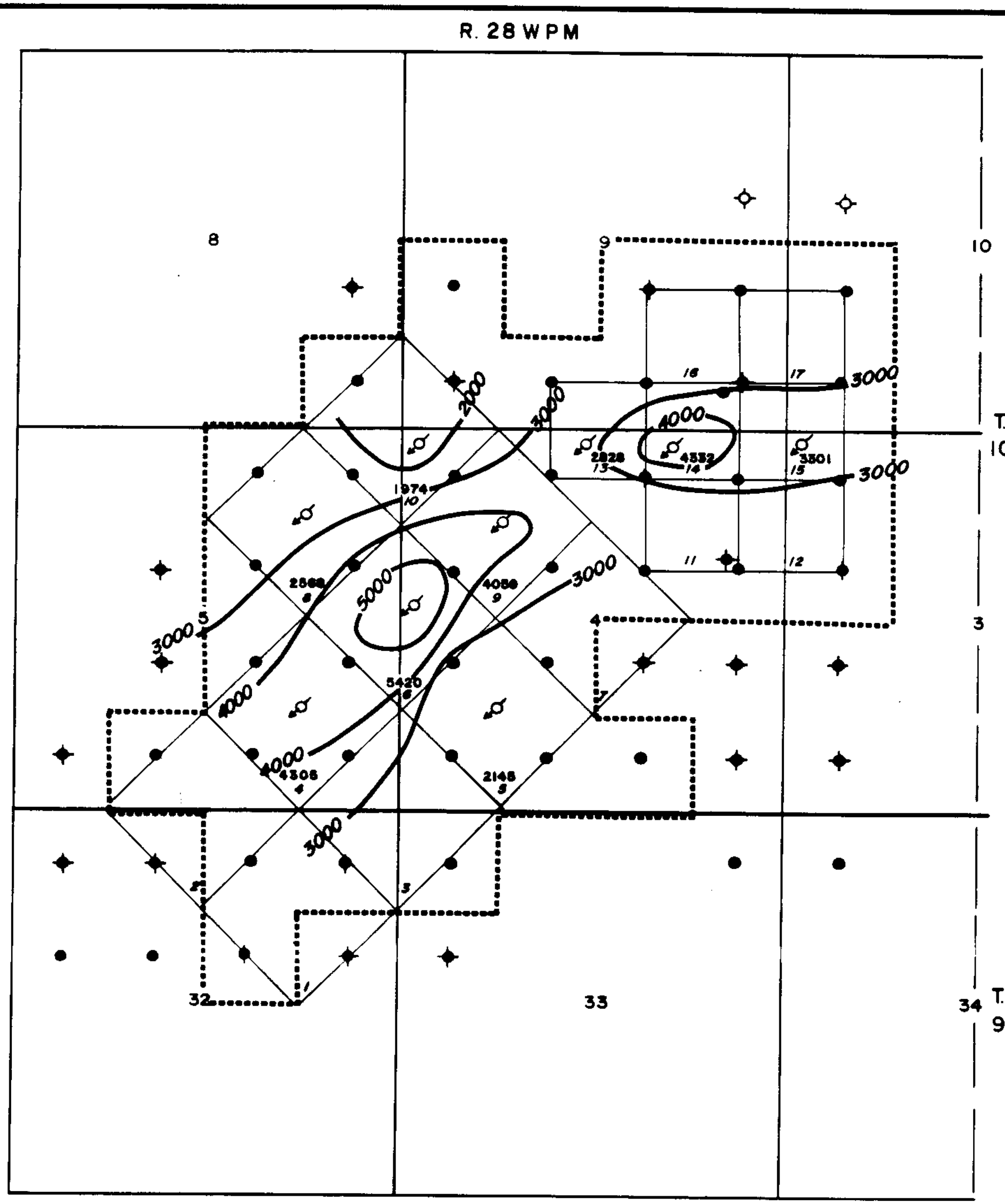
- OILWELL
- WATER INJECTION
- SHUT-IN
- ABANDONED OILWELL

ADAMS PEARSON ASSOCIATES

DALY UNIT No. 1

CUMULATIVE WATER OIL RATIO
(DECEMBER 1988)

Date: June, 1989 | Figure: 6.5



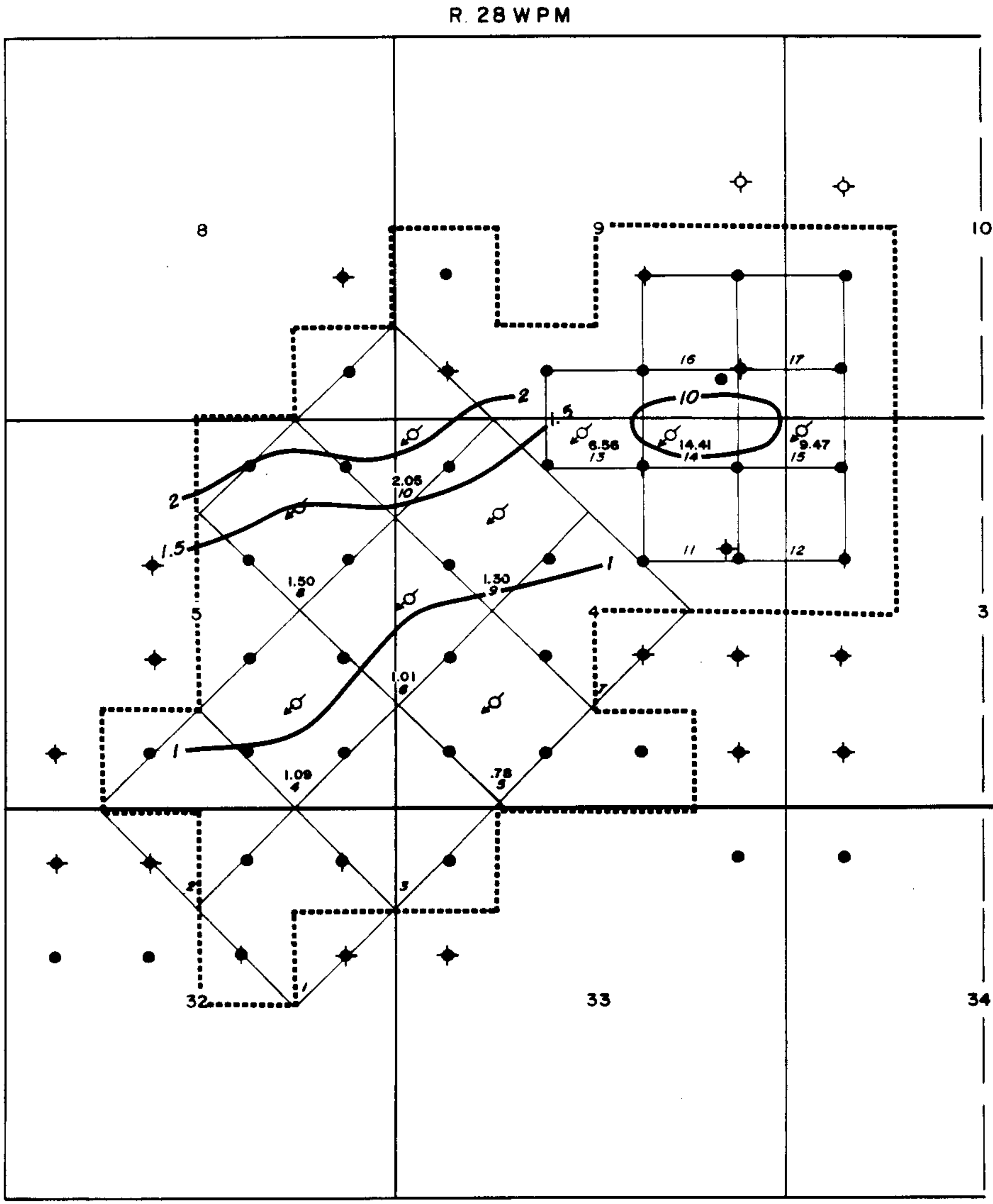
- OILWELL
- WATER INJECTION
- SHUT-IN
- ABANDONED OILWELL

ADAMS PEARSON ASSOCIATES

DALY UNIT No. 1

WATER INJECTION - MSTB
(DECEMBER 1988)

Date: June, 1989 | Figure: 6.6



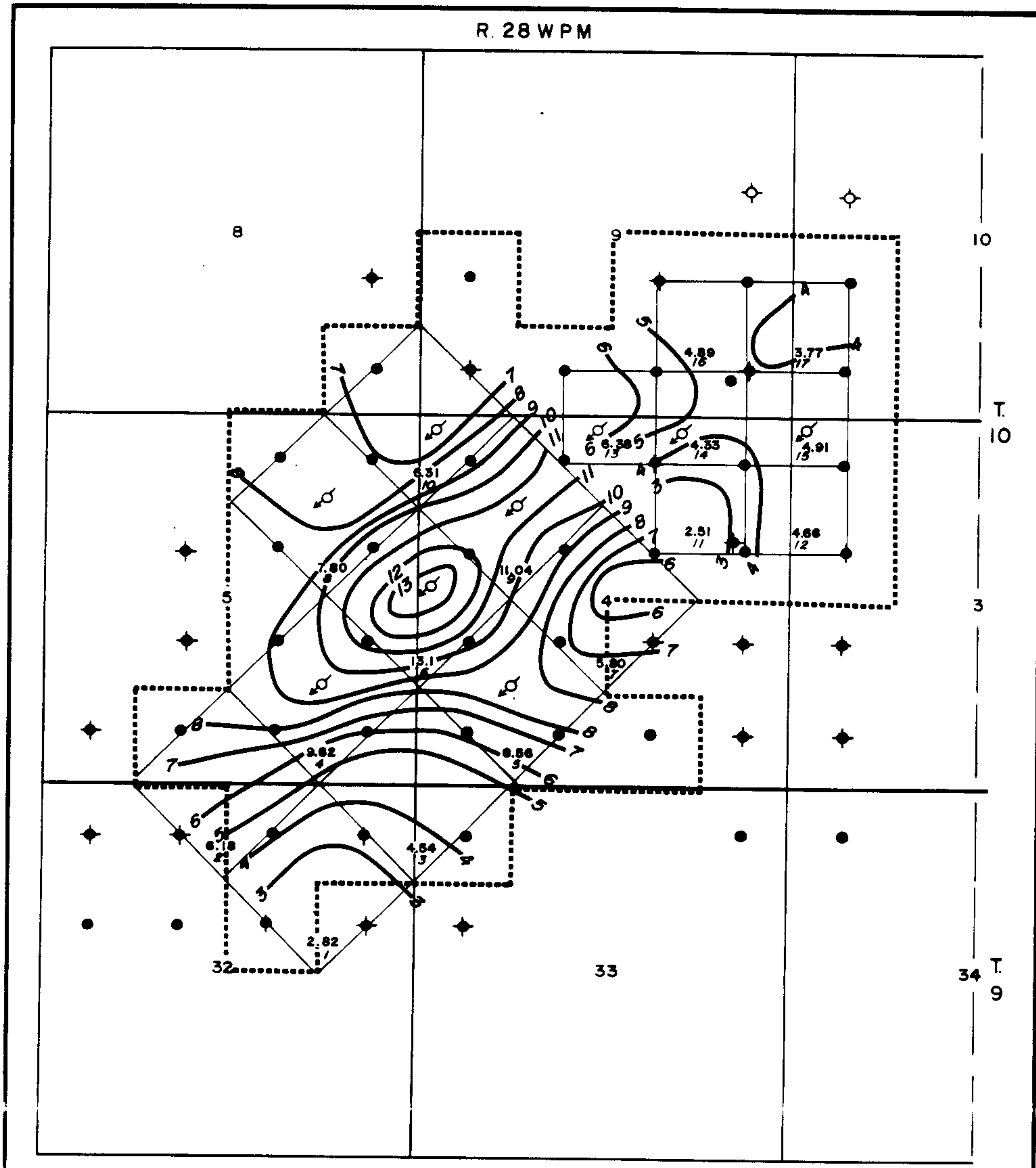
- OILWELL
- WATER INJECTION
- SHUT-IN
- ABANDONED OILWELL

ADAMS PEARSON ASSOCIATES

DALY UNIT No. 1

CUMULATIVE VOIDAGE REPLACEMENT RATIO
(DECEMBER 1988)

Date: June, 1989 | Figure: 6.7

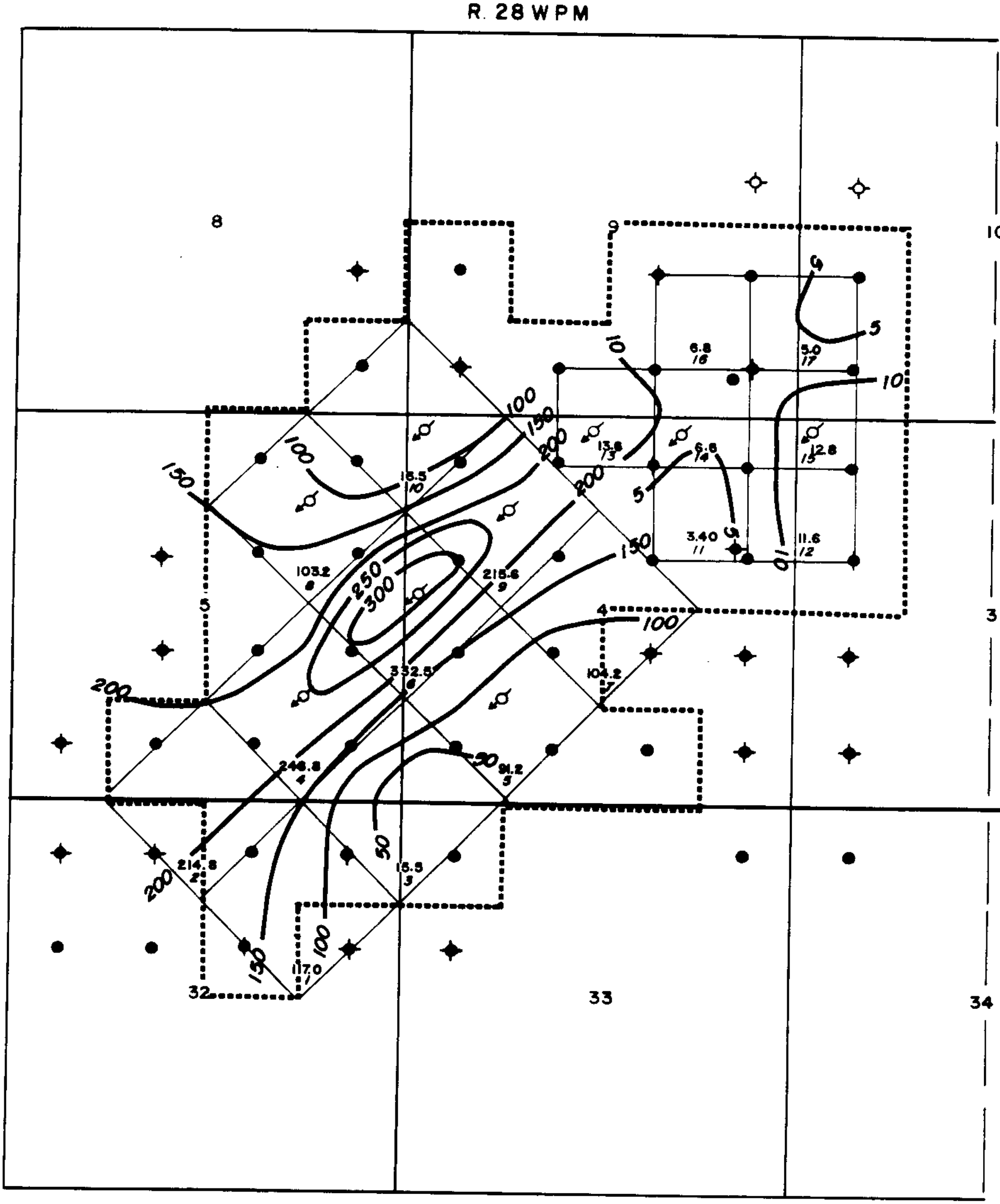


ADAMS PEARSON ASSOCIATES

DALY UNIT No. 1

CURRENT q_o – MSTB/YEAR

Date: June, 1989 | Figure: 6.8



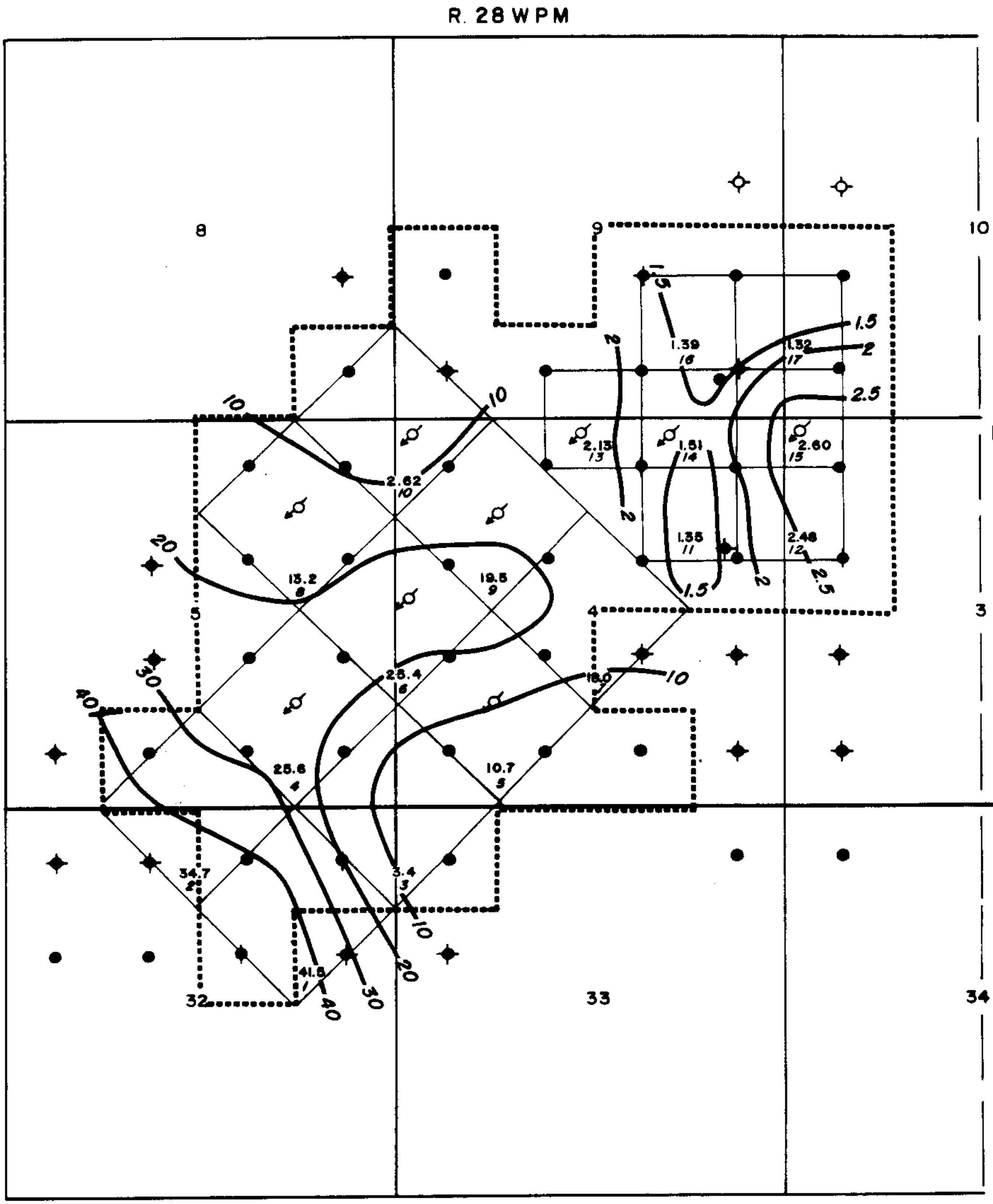
- OILWELL
- WATER INJECTION
- SHUT-IN
- ABANDONED OILWELL

ADAMS PEARSON ASSOCIATES

DALY UNIT No. 1

CURRENT q_w – MSTB/YEAR

Date: June, 1989 | Figure: 6.9



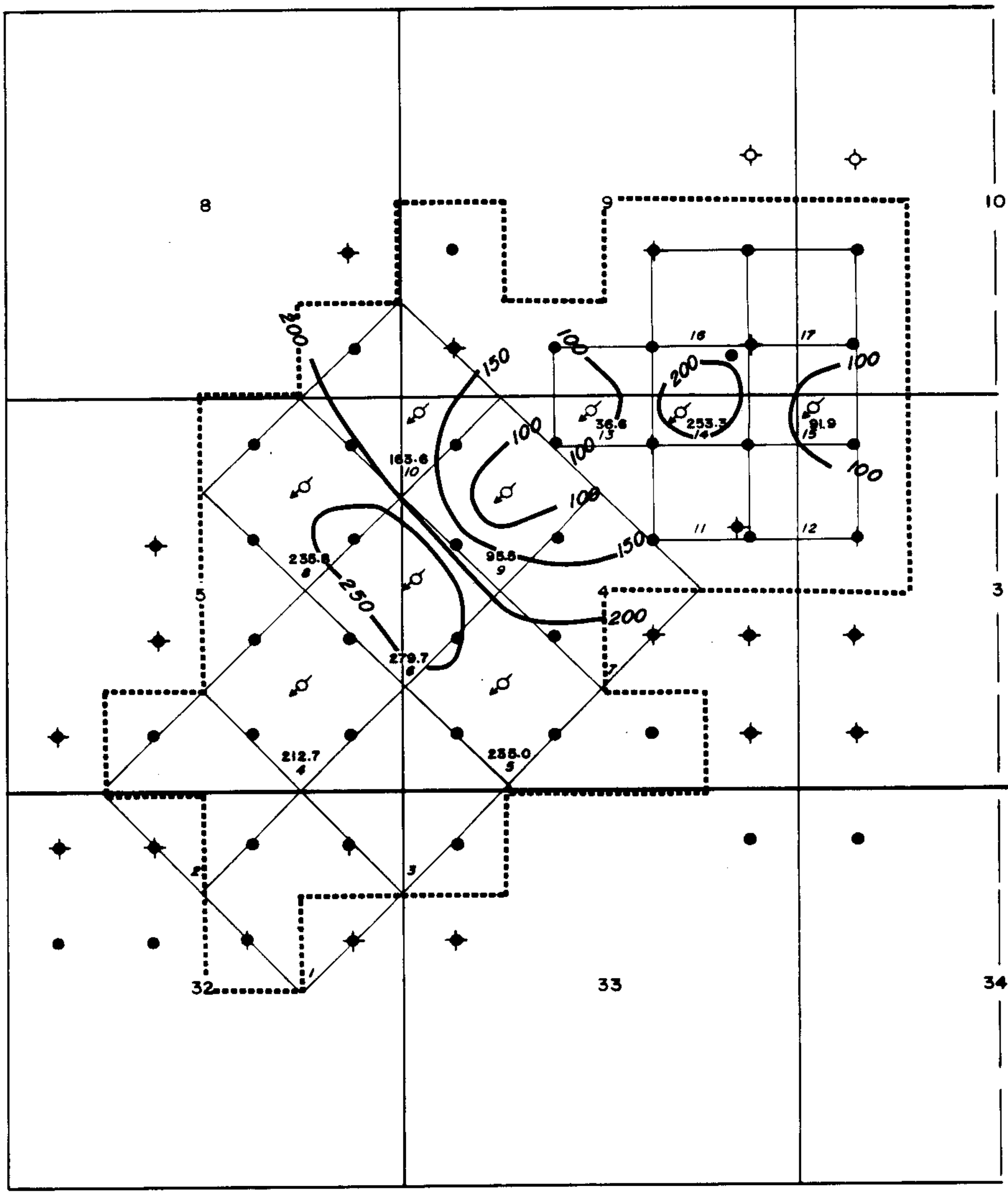
- OILWELL
- WATER INJECTION
- SHUT-IN
- ABANDONED OILWELL

ADAMS PEARSON ASSOCIATES

DALY UNIT No. 1

CURRENT WATER OIL RATIO

Date: June, 1989 | Figure: 6.10



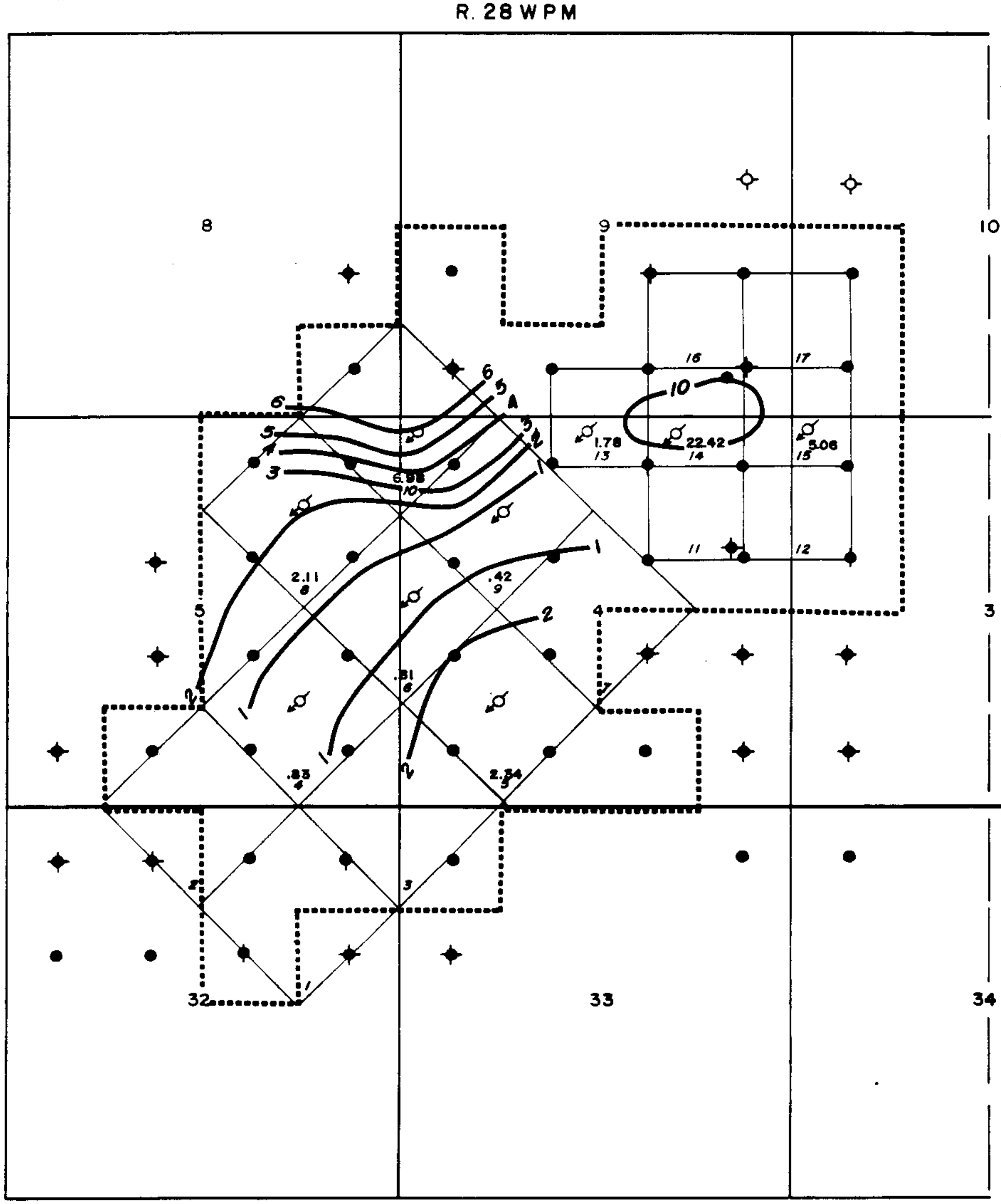
- OILWELL
- WATER INJECTION
- SHUT-IN
- ABANDONED OILWELL

ADAMS PEARSON ASSOCIATES

DALY UNIT No. 1

CURRENT q_w (INJECTION) - MSTB/YEAR

Date : June, 1989 | Figure : 6.11



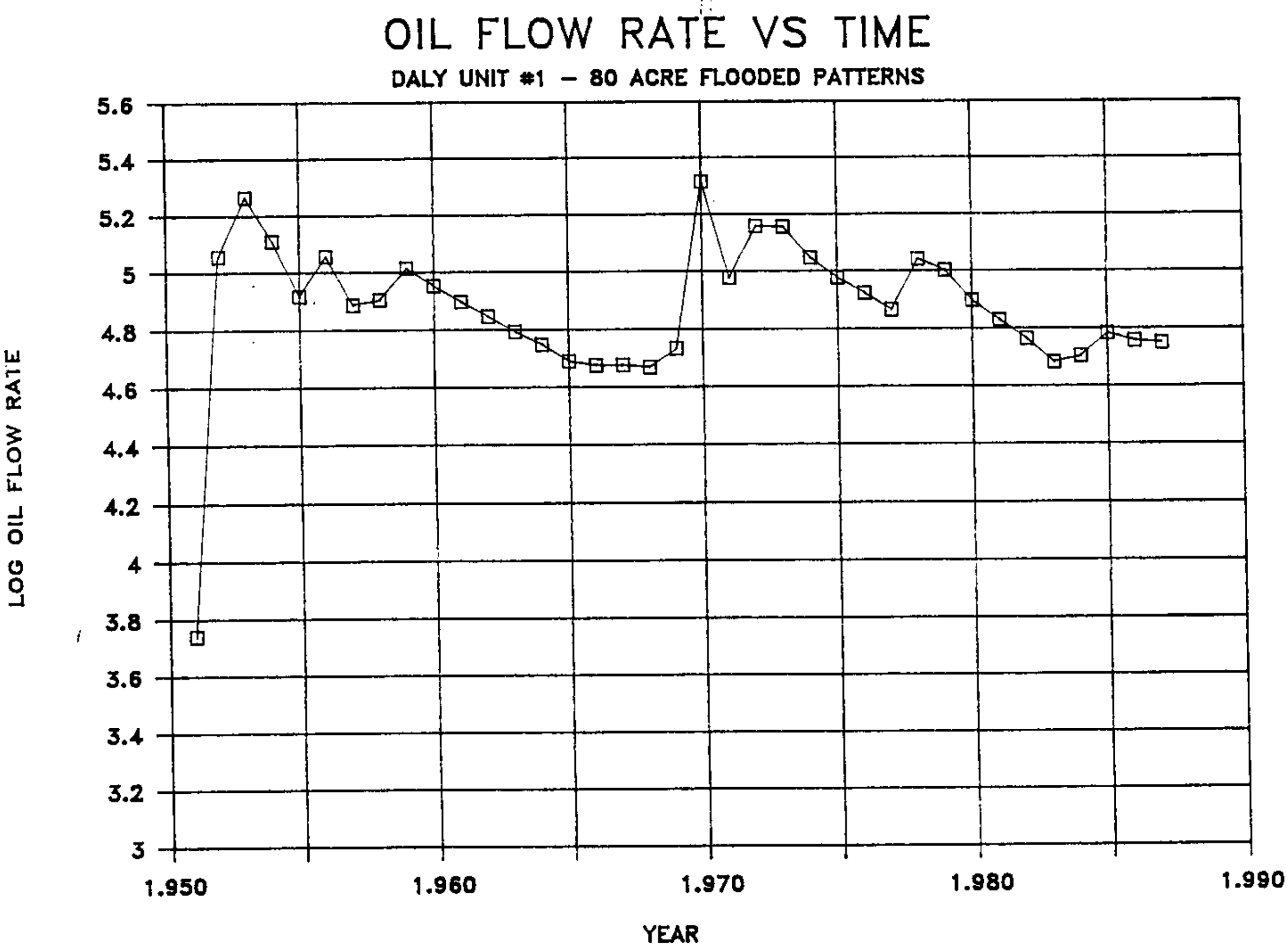
- OILWELL
- WATER INJECTION
- SHUT-IN
- ABANDONED OILWELL

ADAMS PEARSON ASSOCIATES

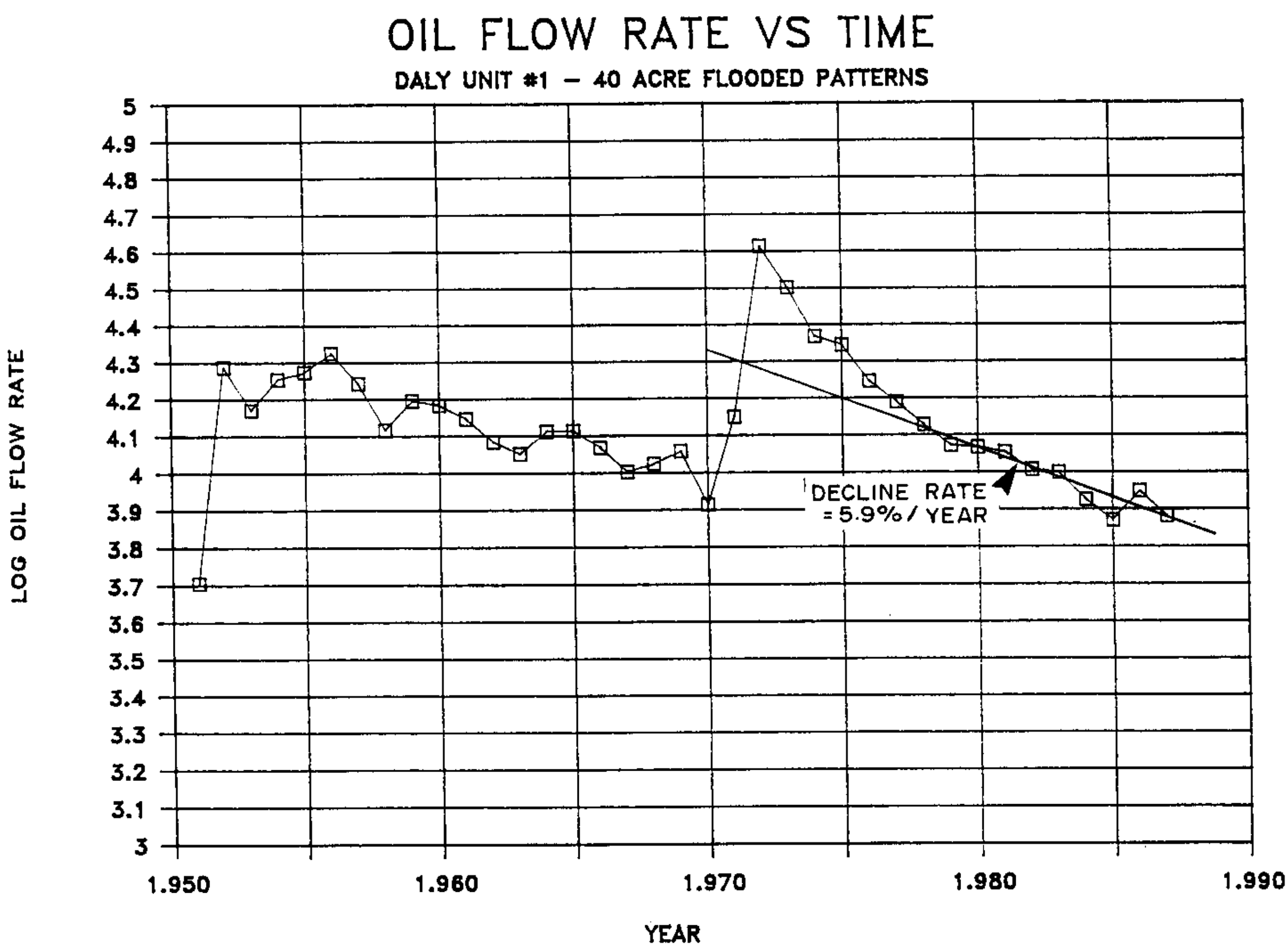
DALY UNIT No. 1

CURRENT VOIDAGE REPLACEMENT RATIO (DECEMBER 1988)

Date: June, 1989 | Figure: 6.12



ADAMS PEARSON ASSOCIATES	
DALY UNIT No. I OIL FLOW RATE VERSUS TIME 80 ACRE-FLOODED PATTERNS	
Date: June, 1989	Figure: 6.13

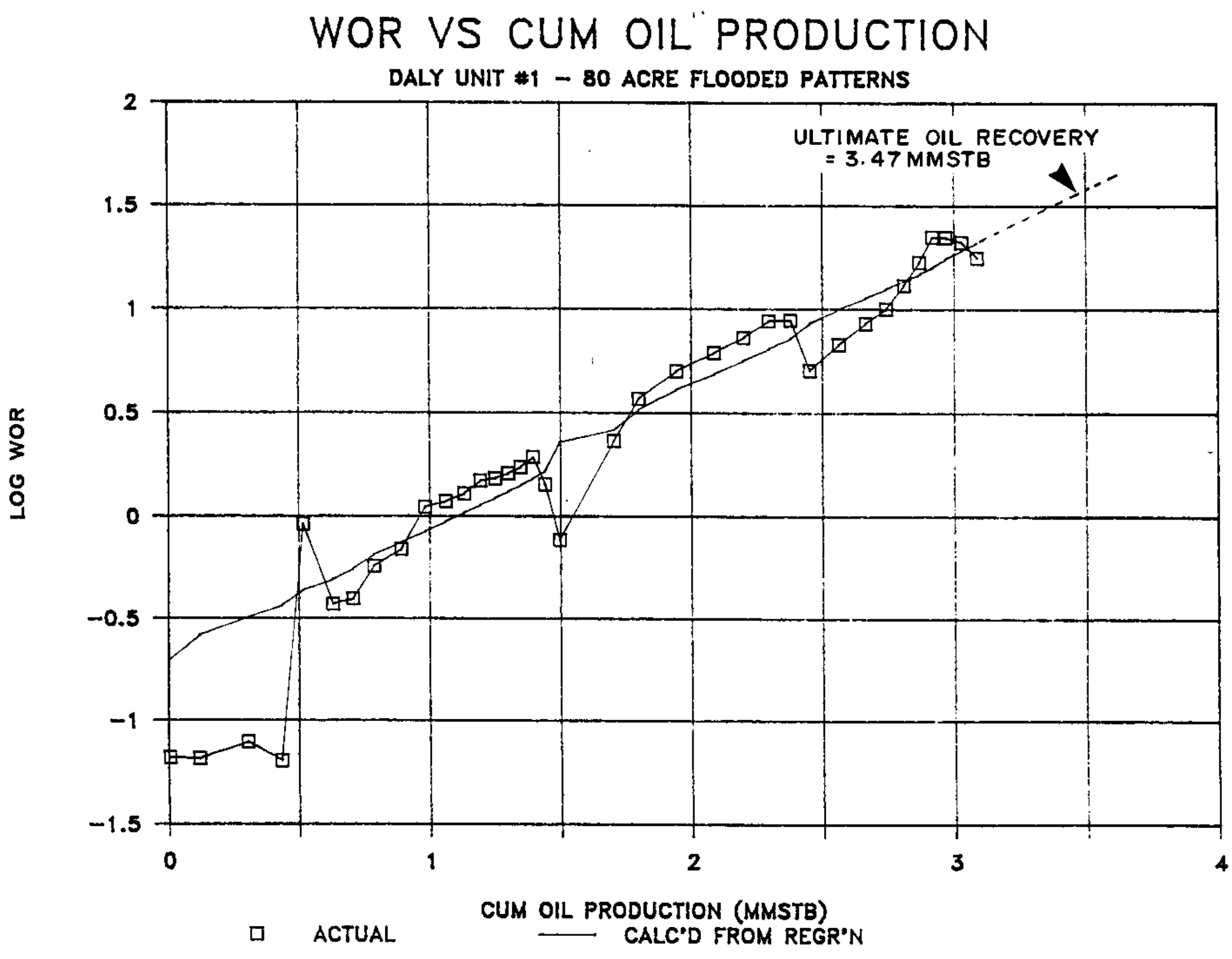


ADAMS PEARSON ASSOCIATES

DALY UNIT No. I

OIL FLOW RATE VERSUS TIME
40 ACRE-FLOODED PATTERNS

Date: June, 1989 | Figure: 6.14

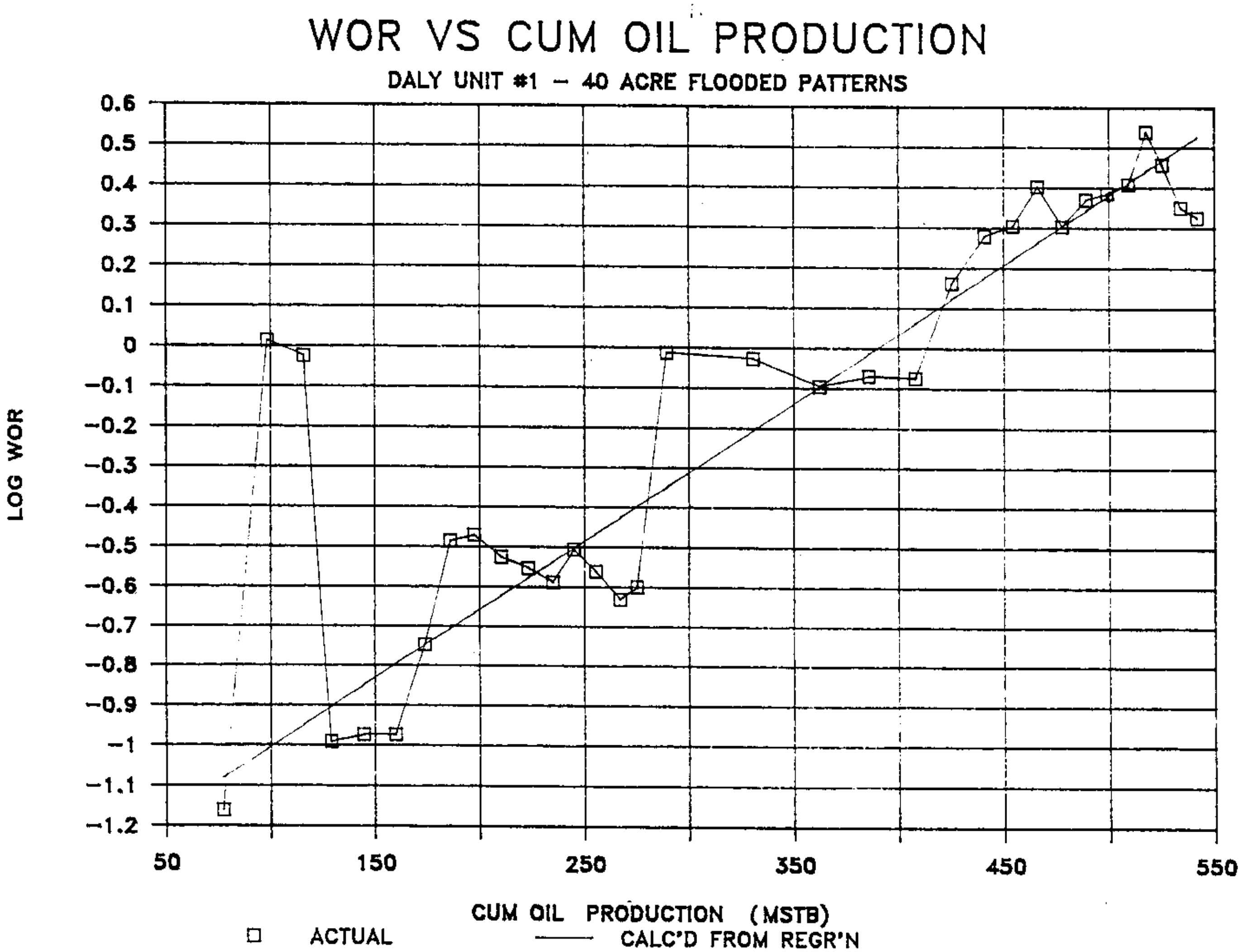


ADAMS PEARSON ASSOCIATES

DALY UNIT No.1

WOR VERSUS CUMULATIVE OIL PRODUCTION
80 ACRE-FLOODED PATTERNS

Date: June, 1989	Figure: 6.15

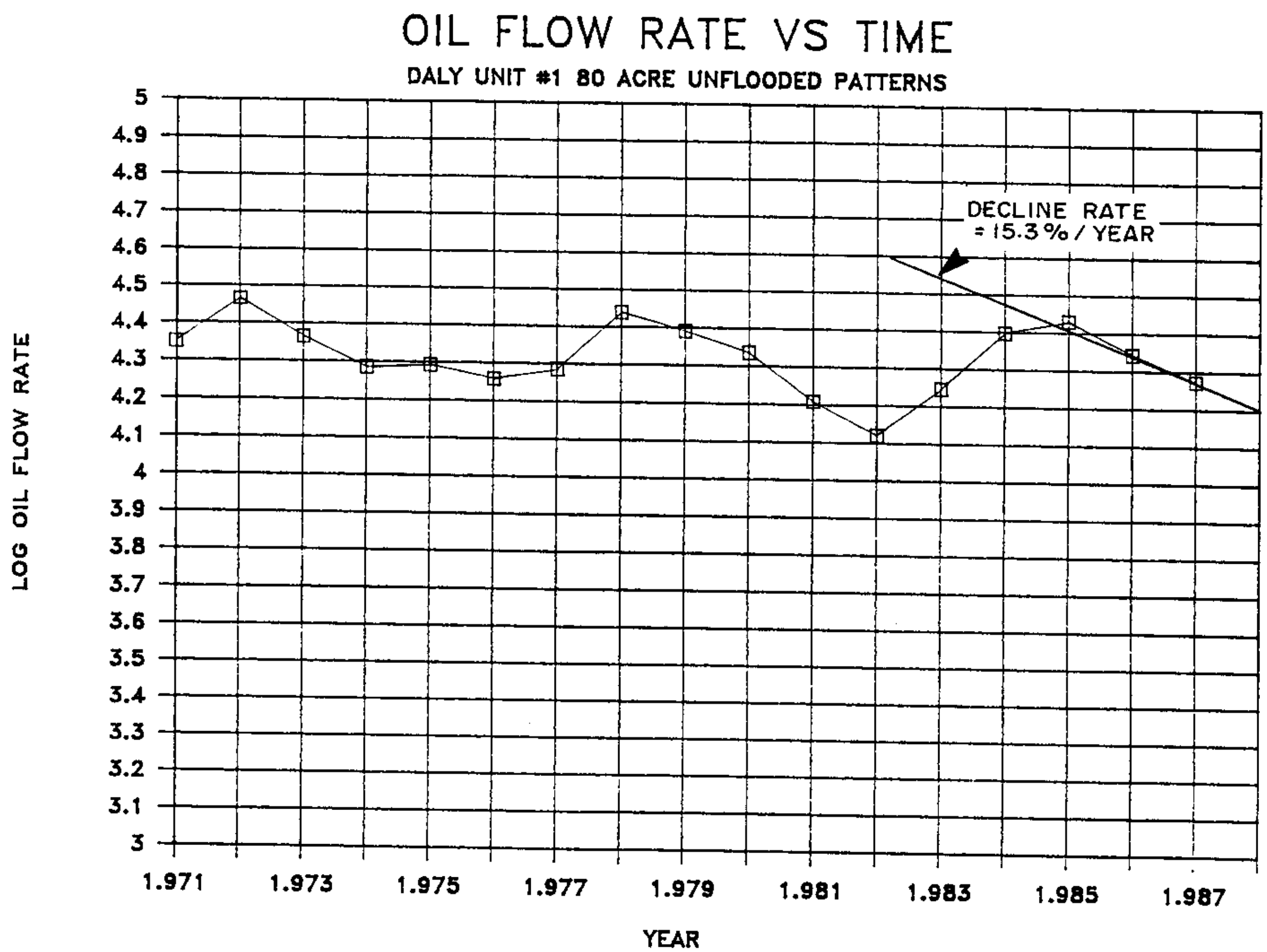


ADAMS PEARSON ASSOCIATES

DALY UNIT No. I

WOR VERSUS CUMULATIVE OIL PRODUCTION
40 ACRE-FLOODED PATTERNS

Date: June, 1989	Figure: 6.16

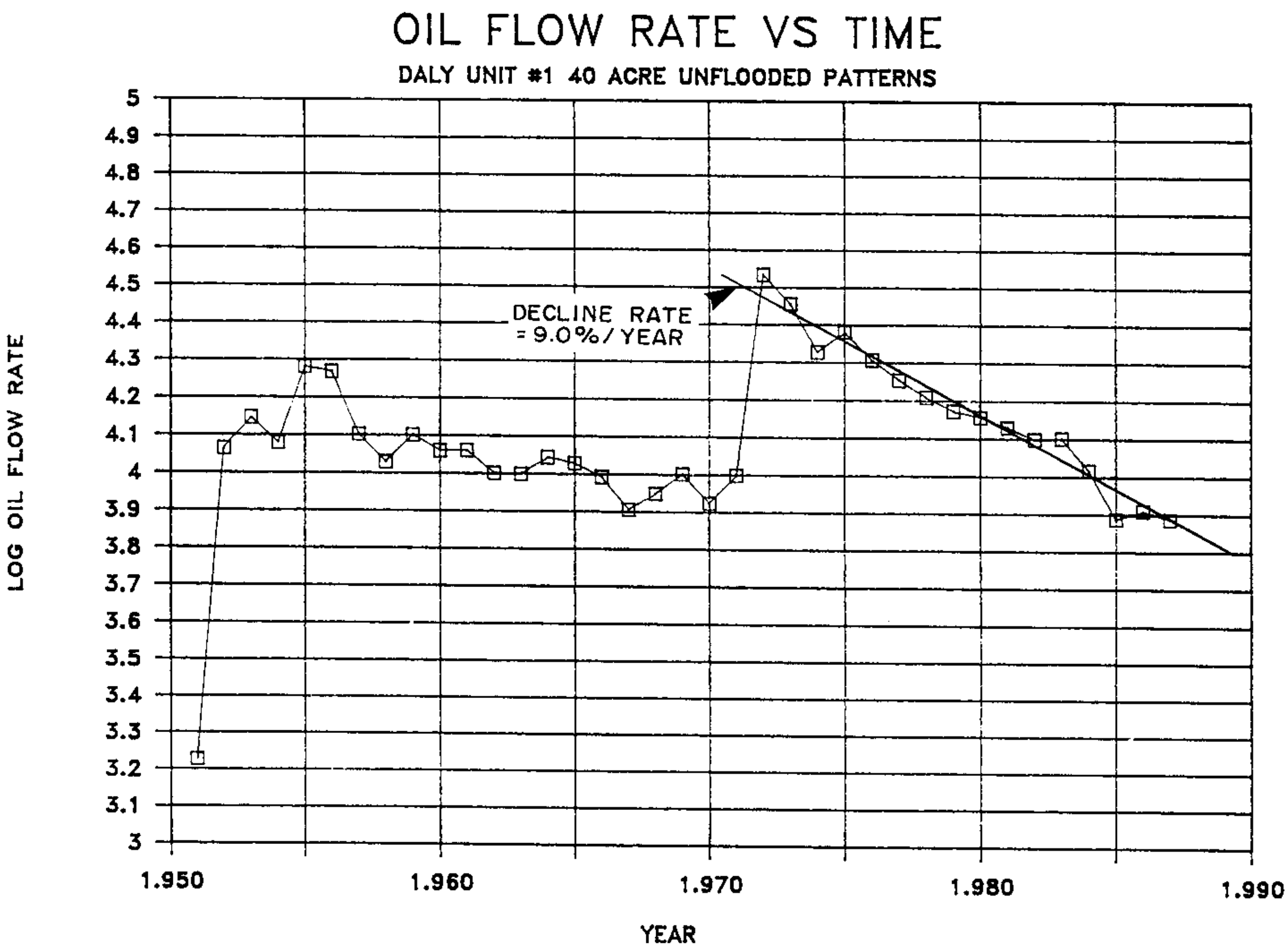


ADAMS PEARSON ASSOCIATES

DALY UNIT No. 1

OIL FLOW RATE VERSUS TIME
80 ACRE-UNFLOODED PATTERNS

Date: June, 1989	Figure: 6.17

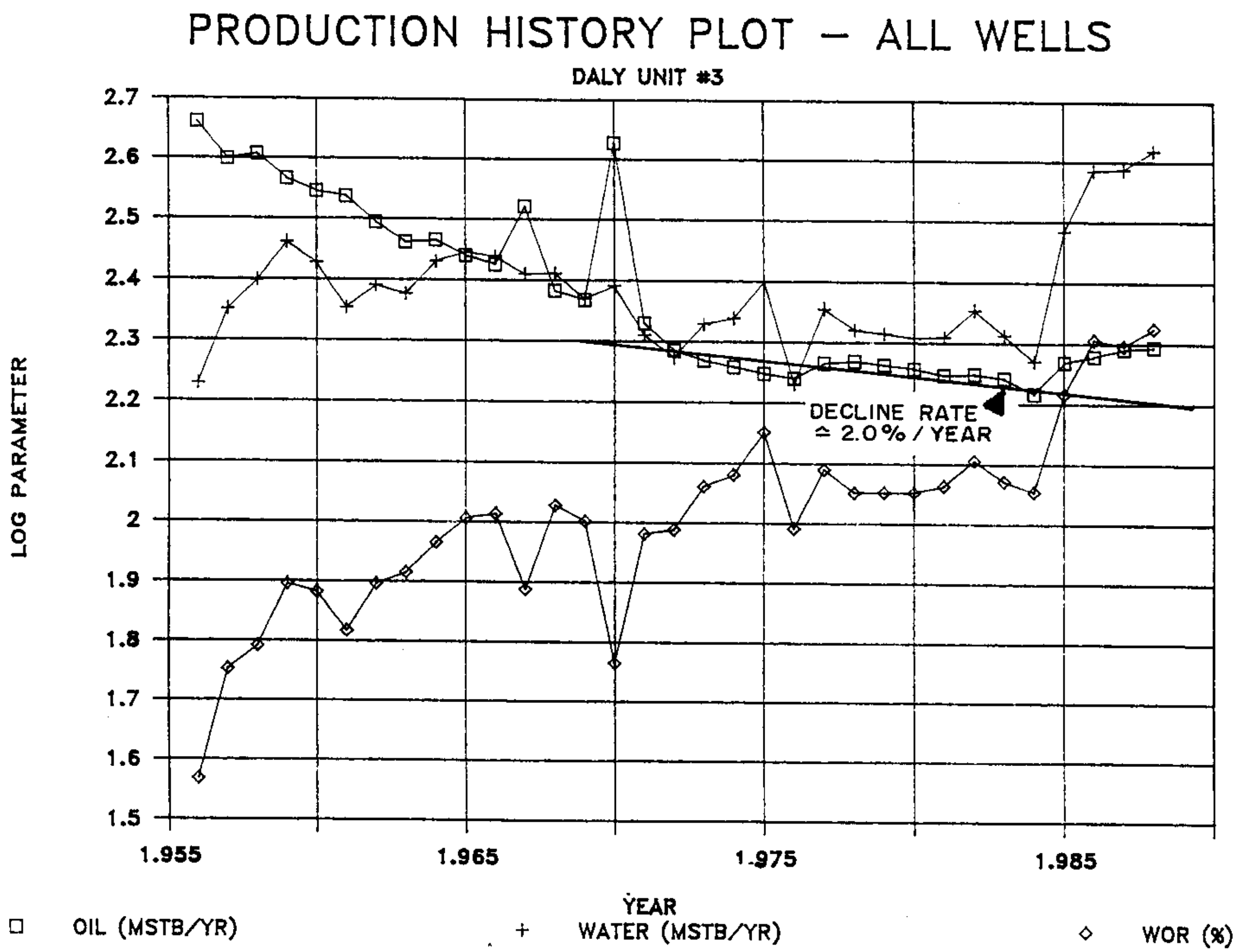


ADAMS PEARSON ASSOCIATES

DALY UNIT No. 1

OIL FLOW RATE VERSUS TIME
40 ACRE-UNFLOODED PATTERNS

Date: June, 1989	Figure: 6.18

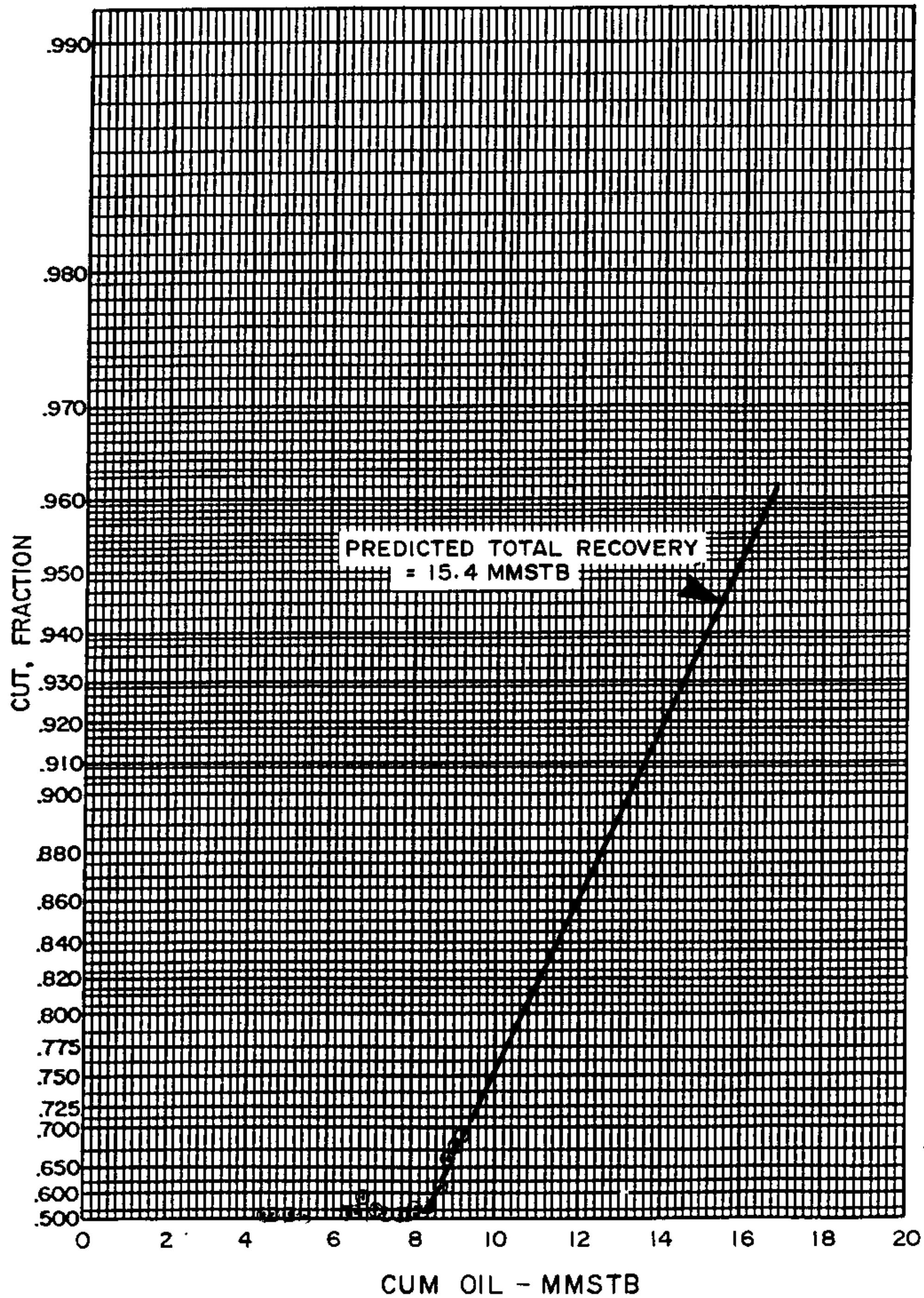


ADAMS PEARSON ASSOCIATES

DALY UNIT No. 3

PRODUCTION HISTORY PLOT–TOTAL

Date : June, 1989	Figure : 7.1

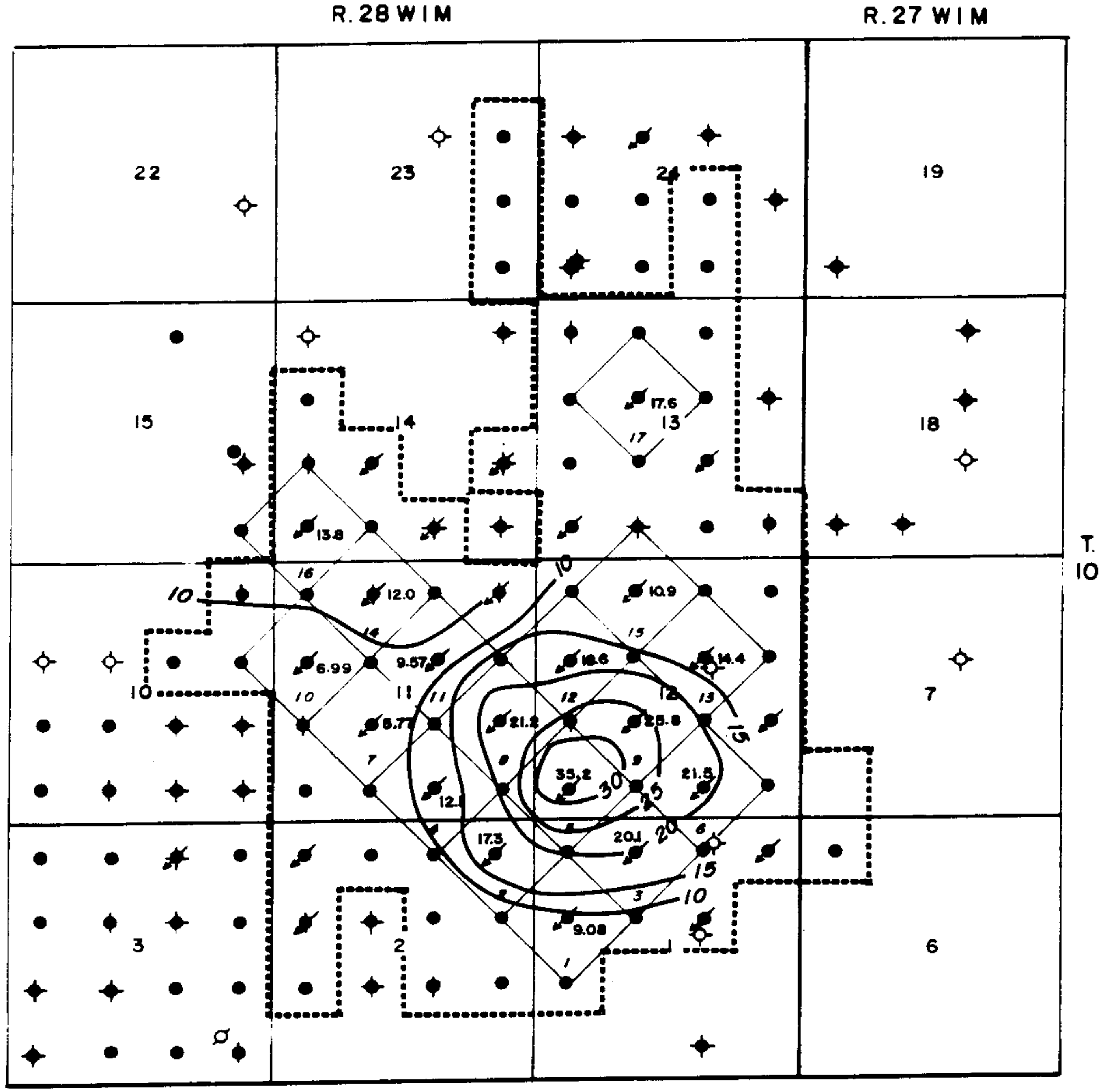


ADAMS PEARSON ASSOCIATES

DALY UNIT No. 3

WATER CUT VERSUS
CUMULATIVE OIL PRODUCTION

Date: June, 1989	Figure: 7.2



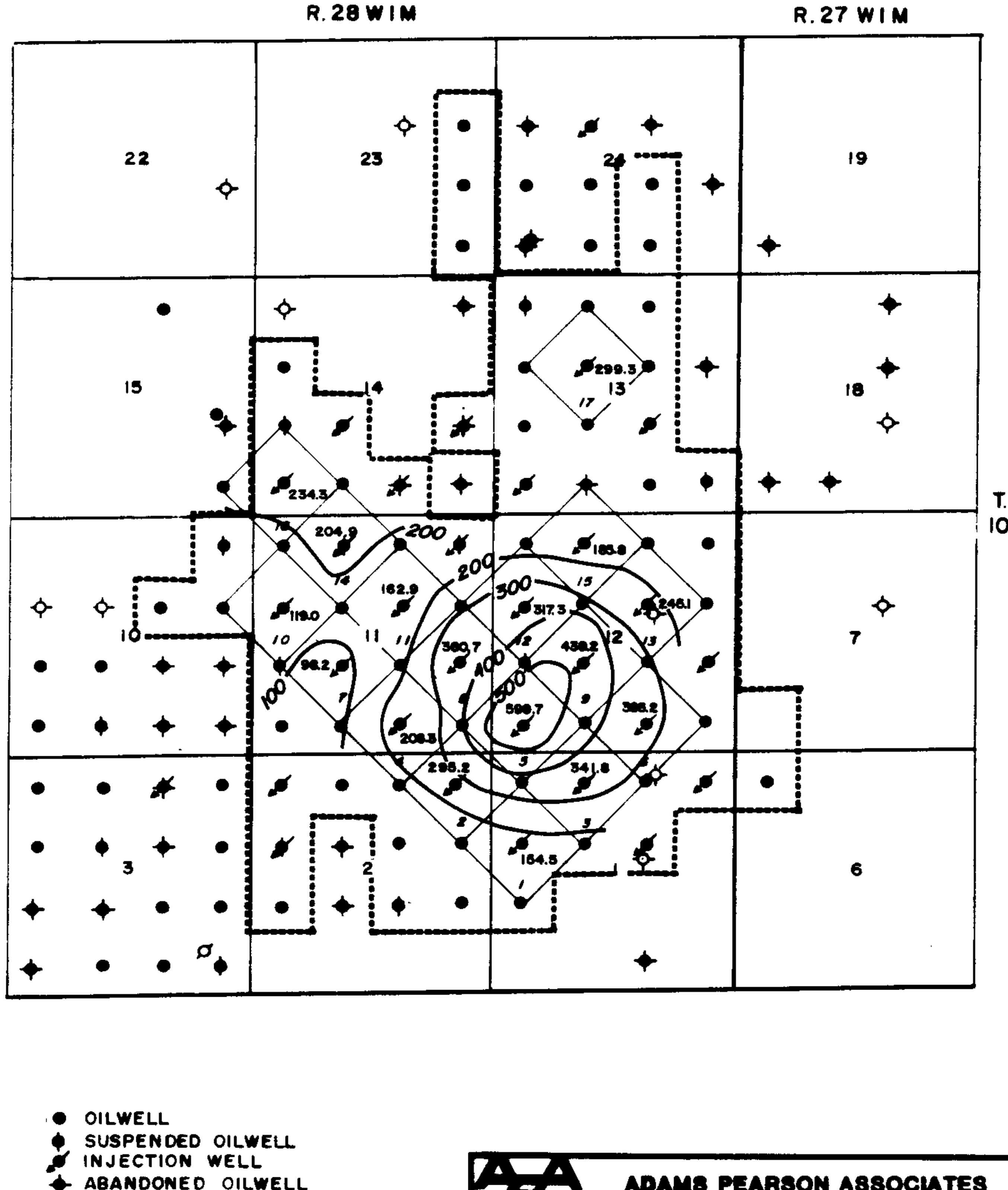
- OILWELL
- SUSPENDED OILWELL
- INJECTION WELL
- ABANDONED OILWELL

ADAMS PEARSON ASSOCIATES

DALY UNIT No. 3

OIL RECOVERY – % OOIP
(DECEMBER 1988)

Date : June, 1989	Figure : 7.3

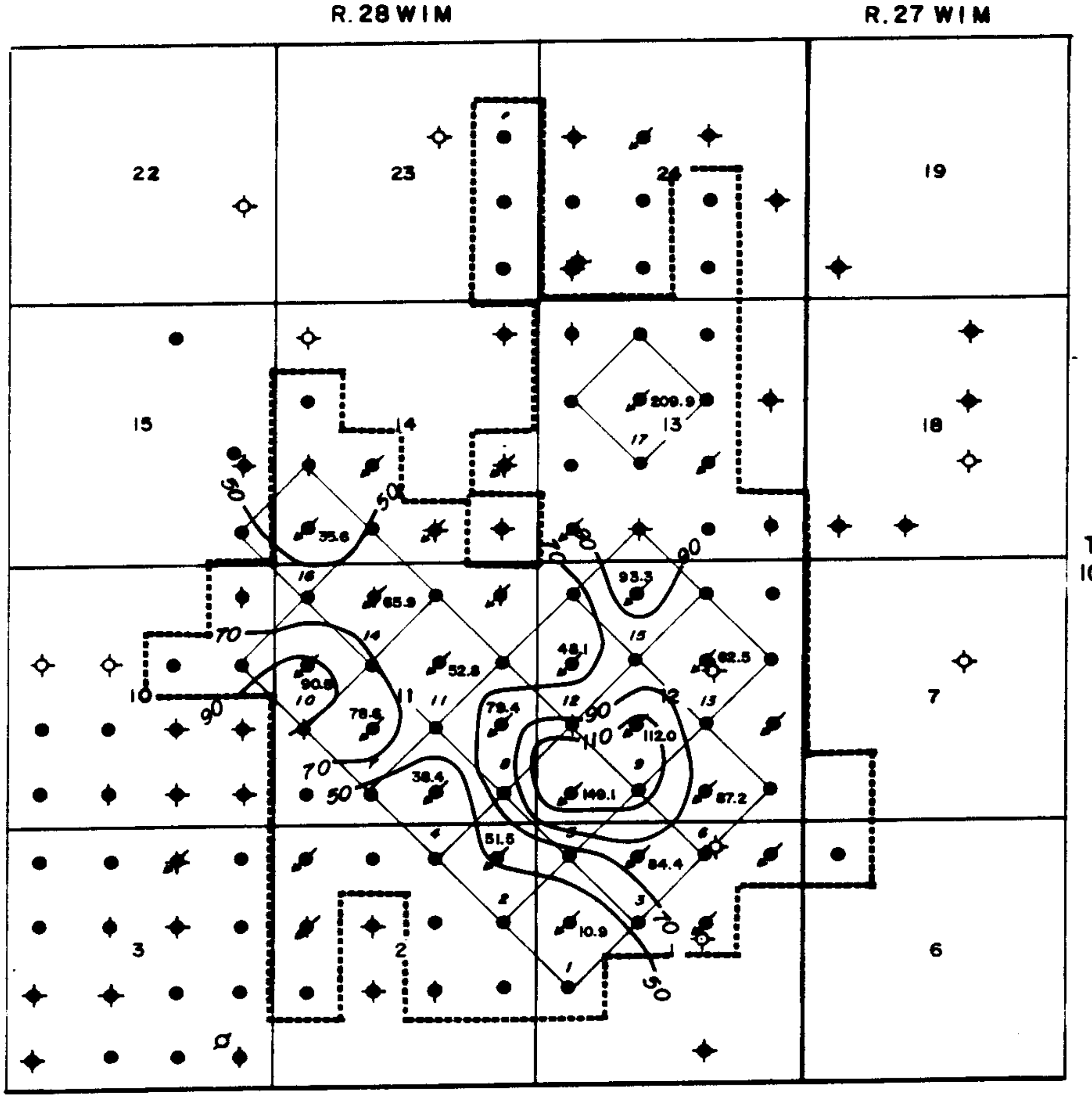


ADAMS PEARSON ASSOCIATES

DALY UNIT No. 3

CUMULATIVE OIL PRODUCTION - MSTB
(DECEMBER 1988)

Date : June, 1989	Figure : 7.4



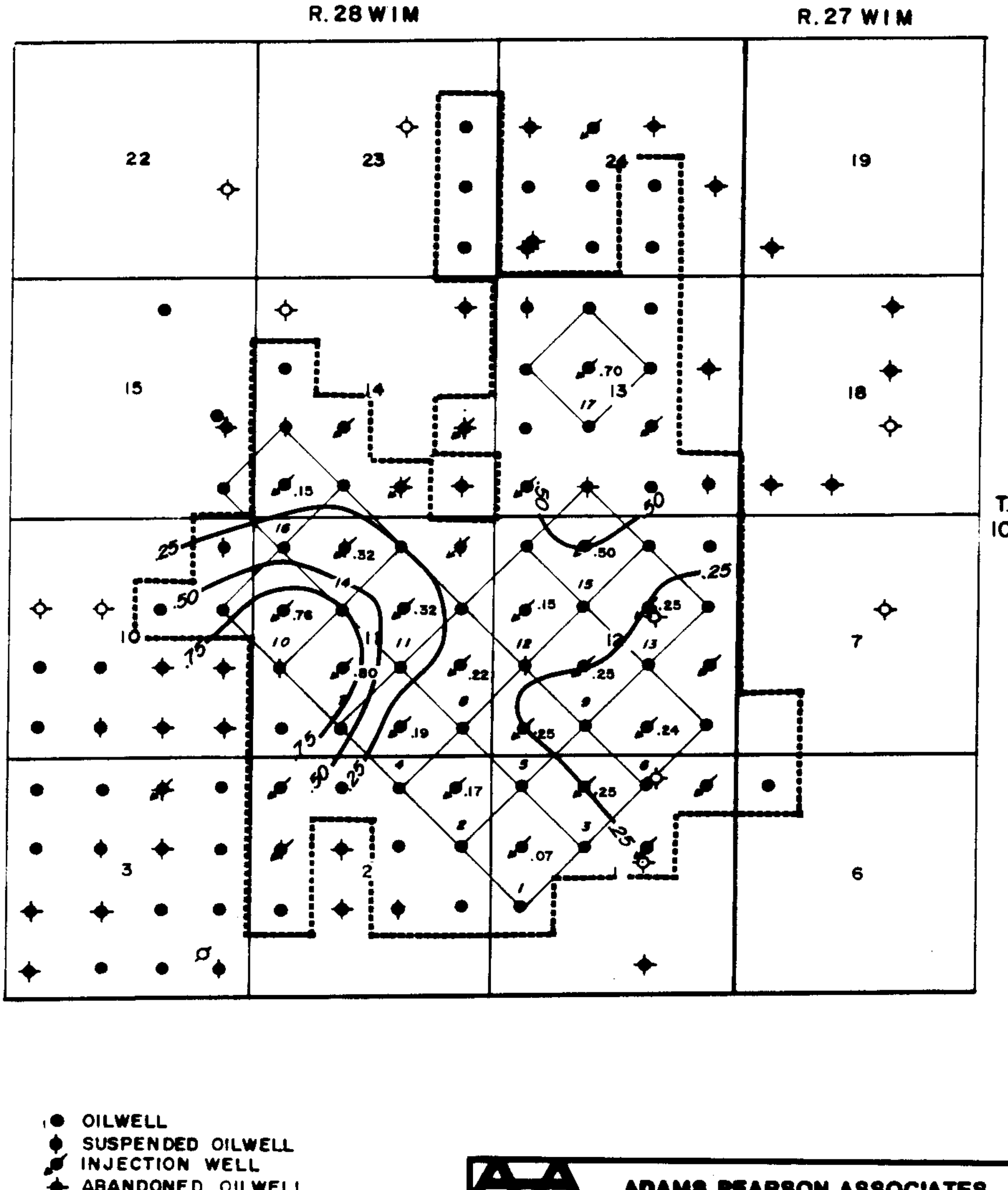
- OILWELL
- SUSPENDED OILWELL
- INJECTION WELL
- ABANDONED OILWELL

ADAMS PEARSON ASSOCIATES

DALY UNIT No. 3

CUMULATIVE WATER PRODUCTION – MSTB
(DECEMBER 1988)

Date : June, 1989	Figure : 7.5

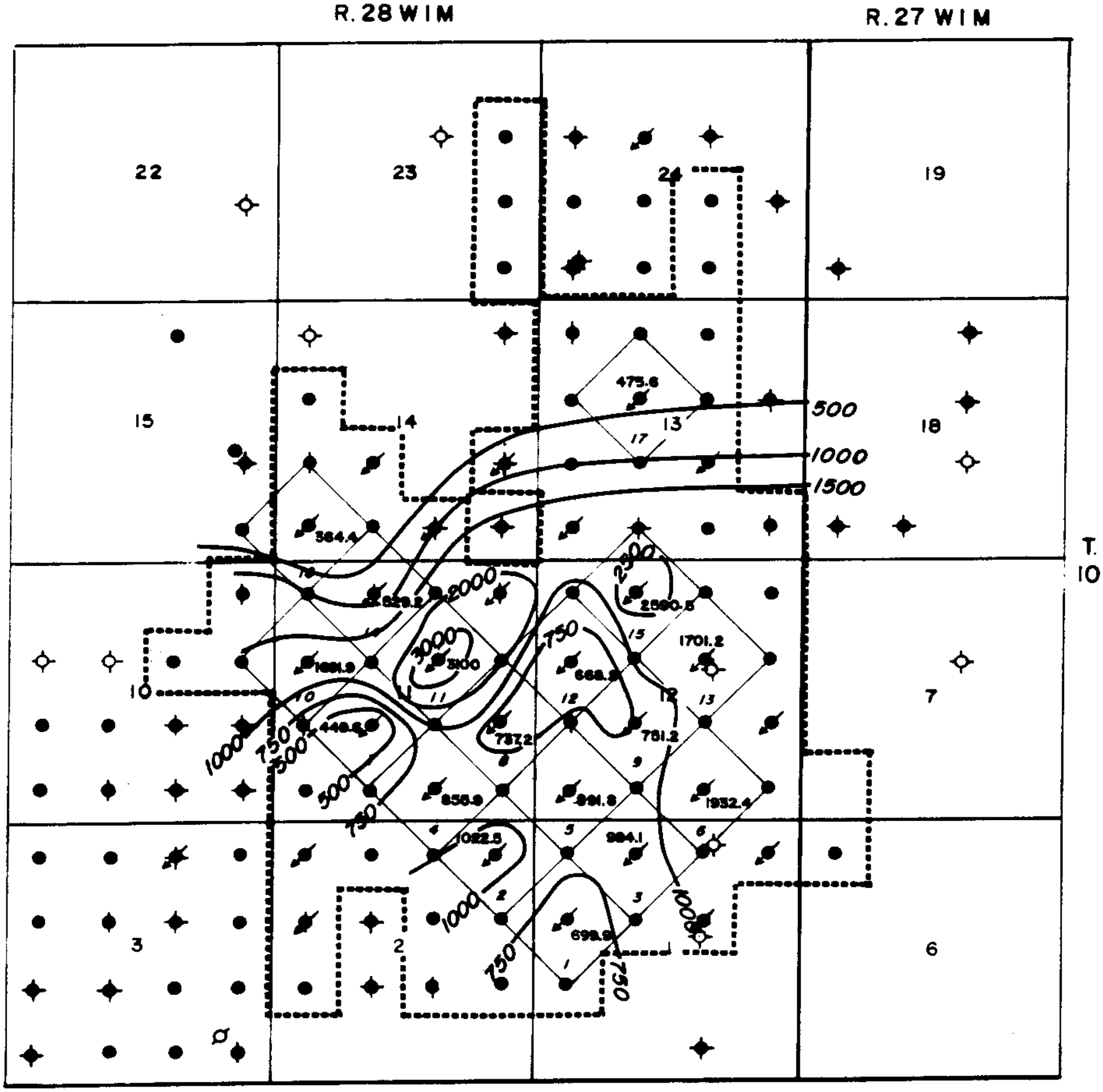


ADAMS PEARSON ASSOCIATES

DALY UNIT No. 3

CUMULATIVE WATER OIL RATIO
(DECEMBER 1988)

Date : June, 1989	Figure : 7.6



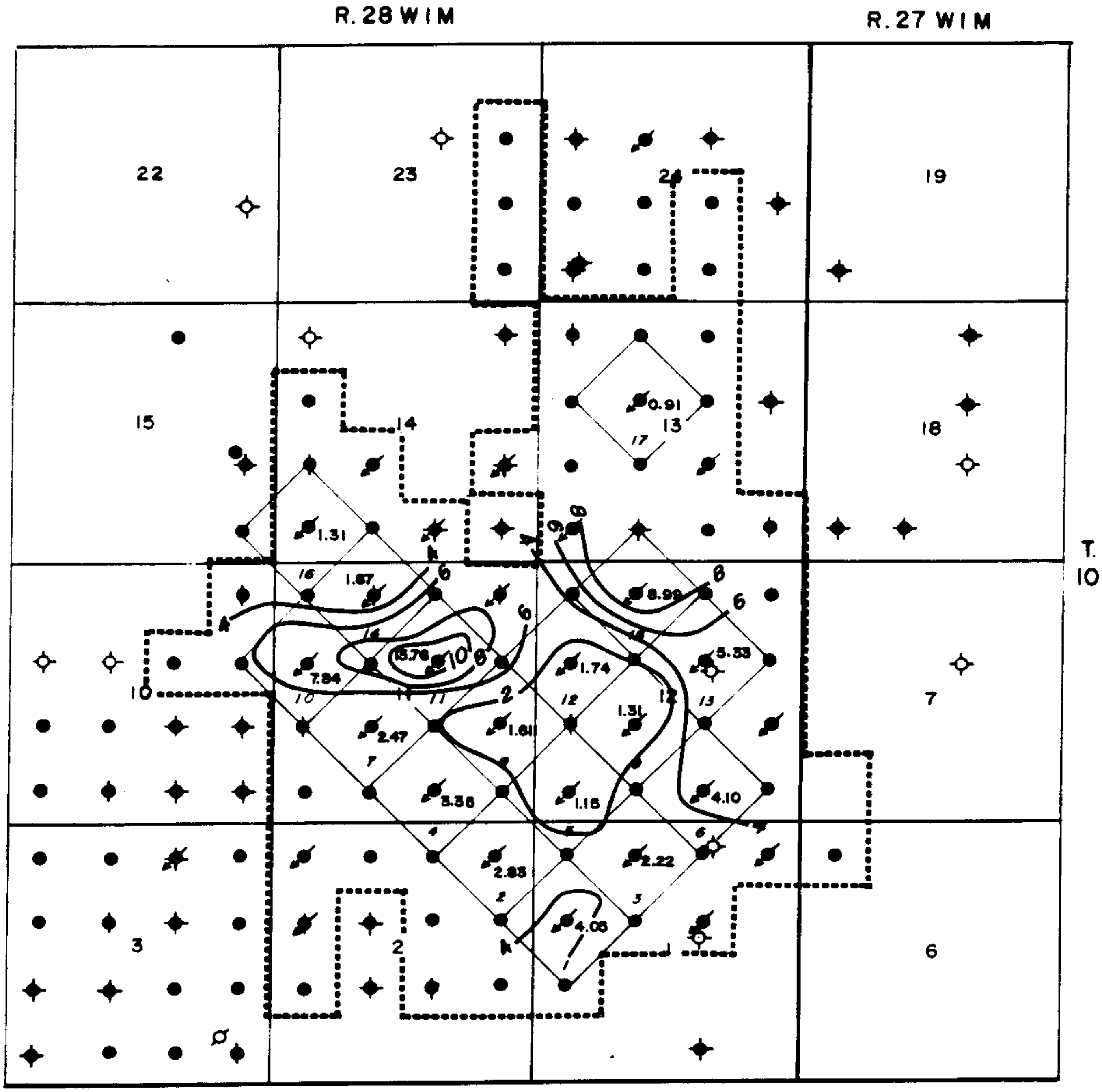
- OILWELL
- SUSPENDED OILWELL
- INJECTION WELL
- ABANDONED OILWELL

ADAMS PEARSON ASSOCIATES

DALY UNIT No. 3

CUMULATIVE WATER INJECTION - MSTB
(DECEMBER 1988)

Date : June, 1989	Figure : 7.7



● OILWELL
SUSPENDED OILWELL
INJECTION WELL
ABANDONED OILWELL

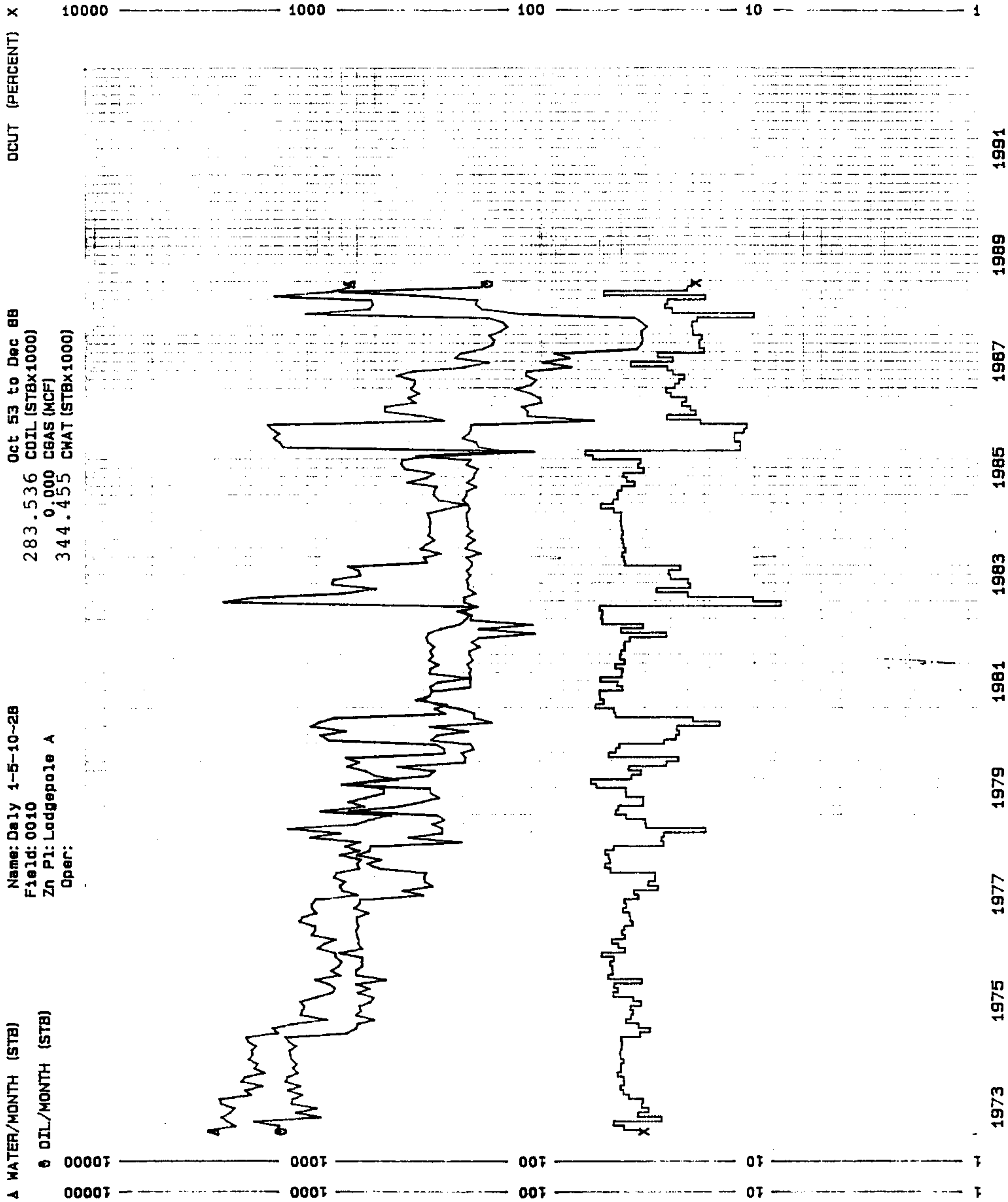
ADAMS PEARSON ASSOCIATES

DALY UNIT No. 3

CUMULATIVE VOIDAGE REPLACEMENT (DECEMBER 1988)

Date : June, 1989	Figure : 7.8

Canada N.W. Energy 01-05-010-28-W1



DALY UNIT No. I

OIL PRODUCTION RATE

IMPROVEMENT FOLLOWING SELECTIVE ACID TREATMENT

Figure: 8.1

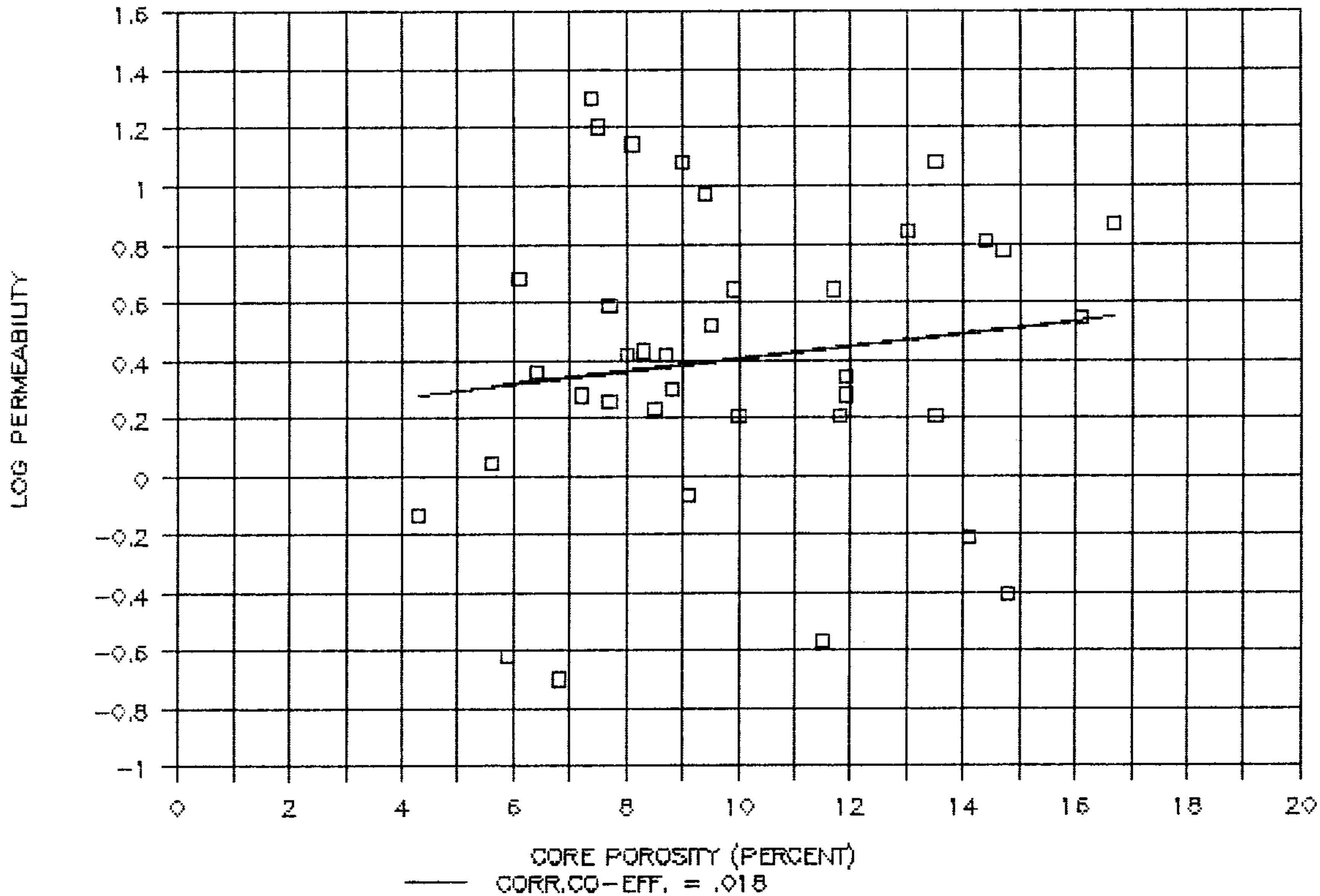
APPENDICES

APPENDIX 1

CORE PERMEABILITY/POROSITY CROSS PLOTS

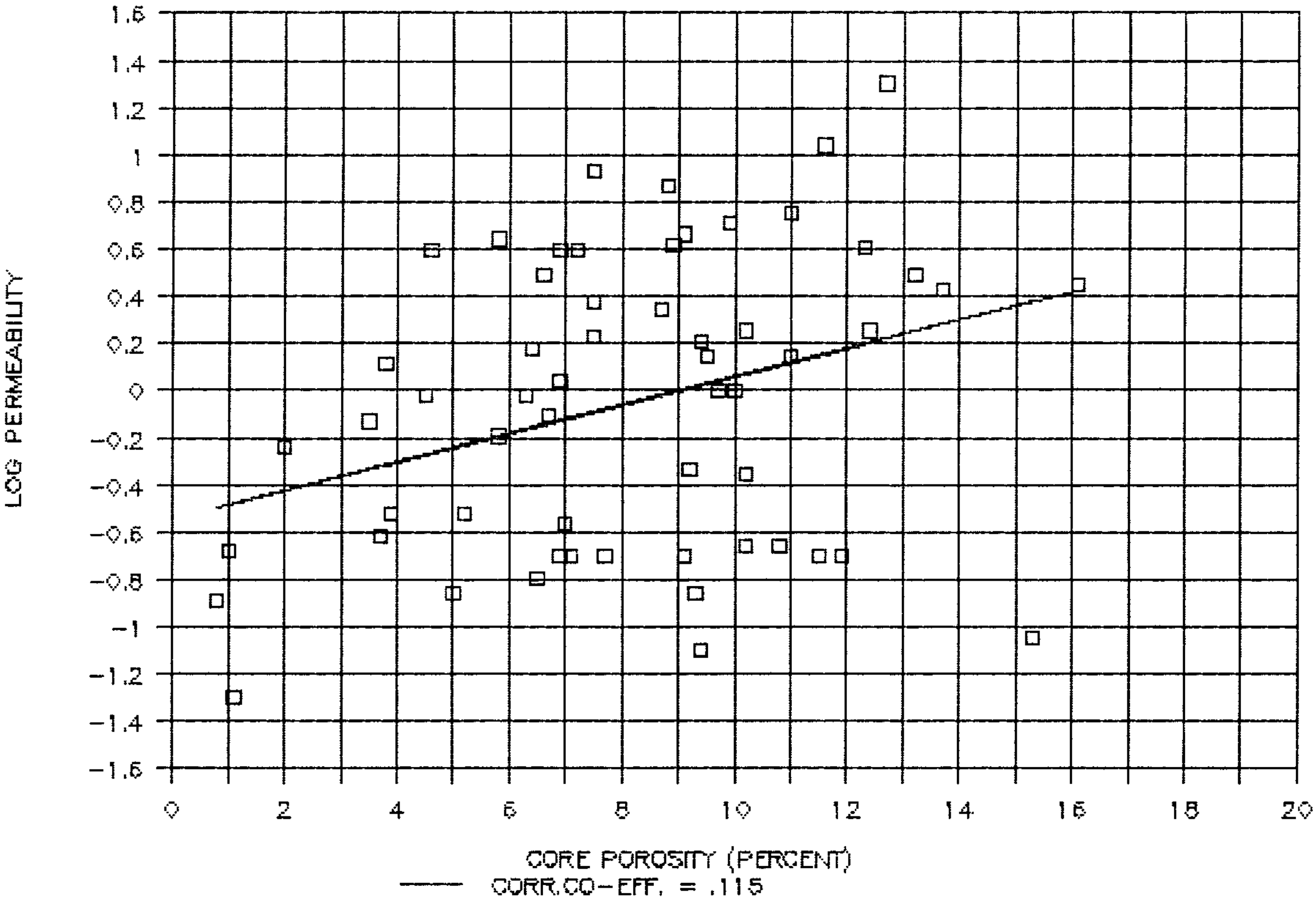
CORE PERM. VS. POROSITY CROSS—PLOT

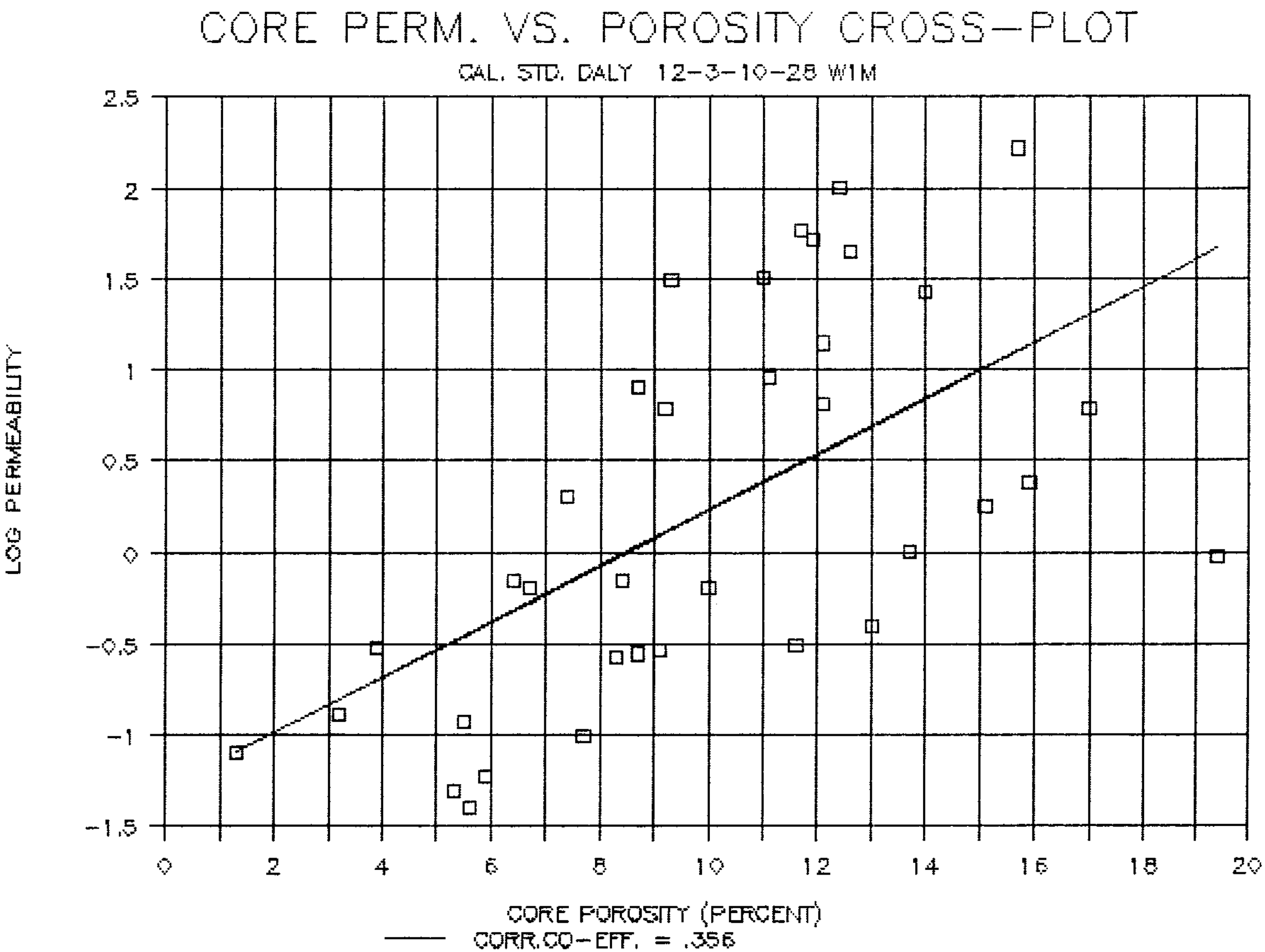
CAN. TEX. DALY 16-33-9 -28 W1M



CORE PERM. VS. POROSITY CROSS-PLOT

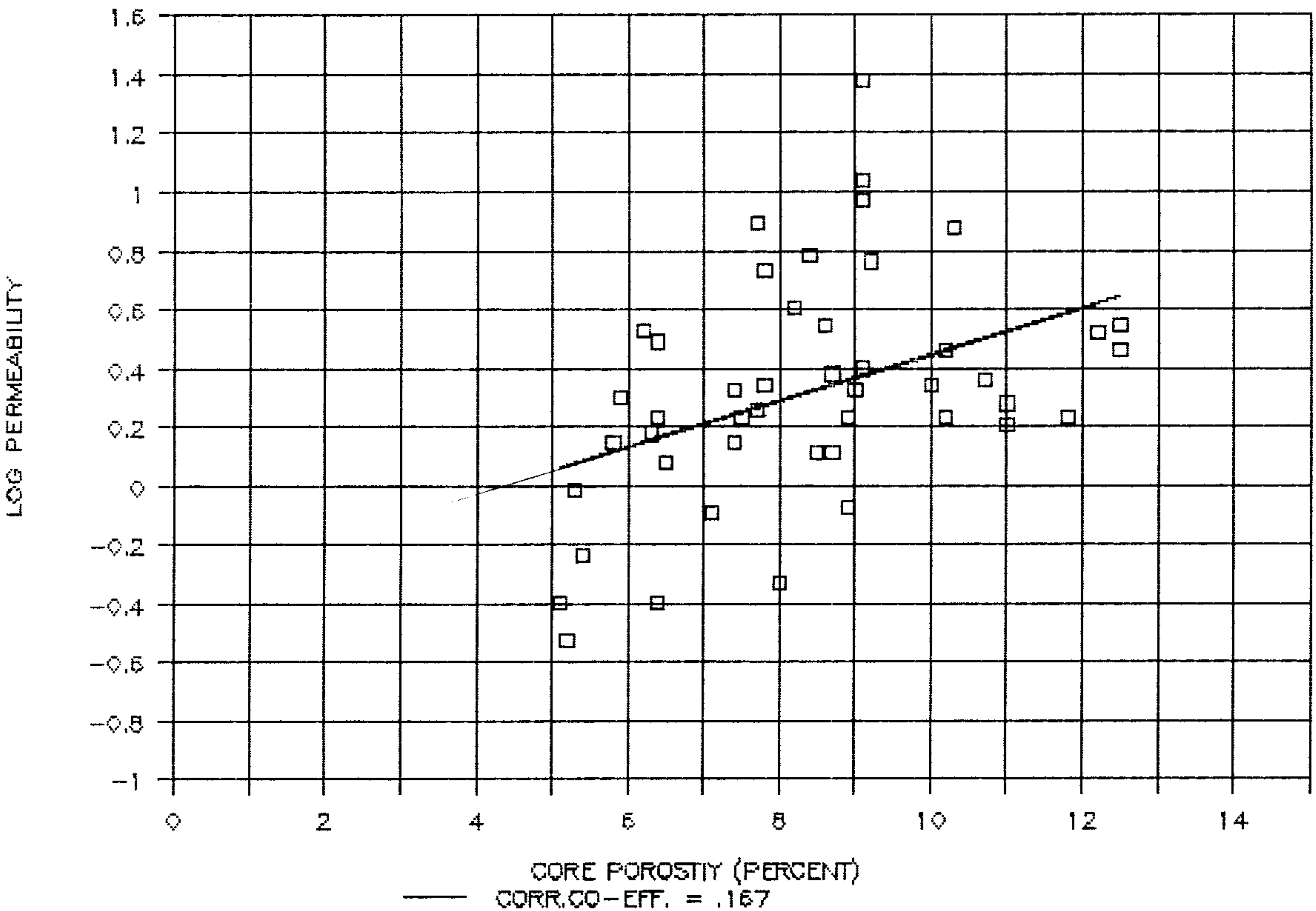
CDN. SUP. THOMSON DALY 9-32- 9 -28 W1M

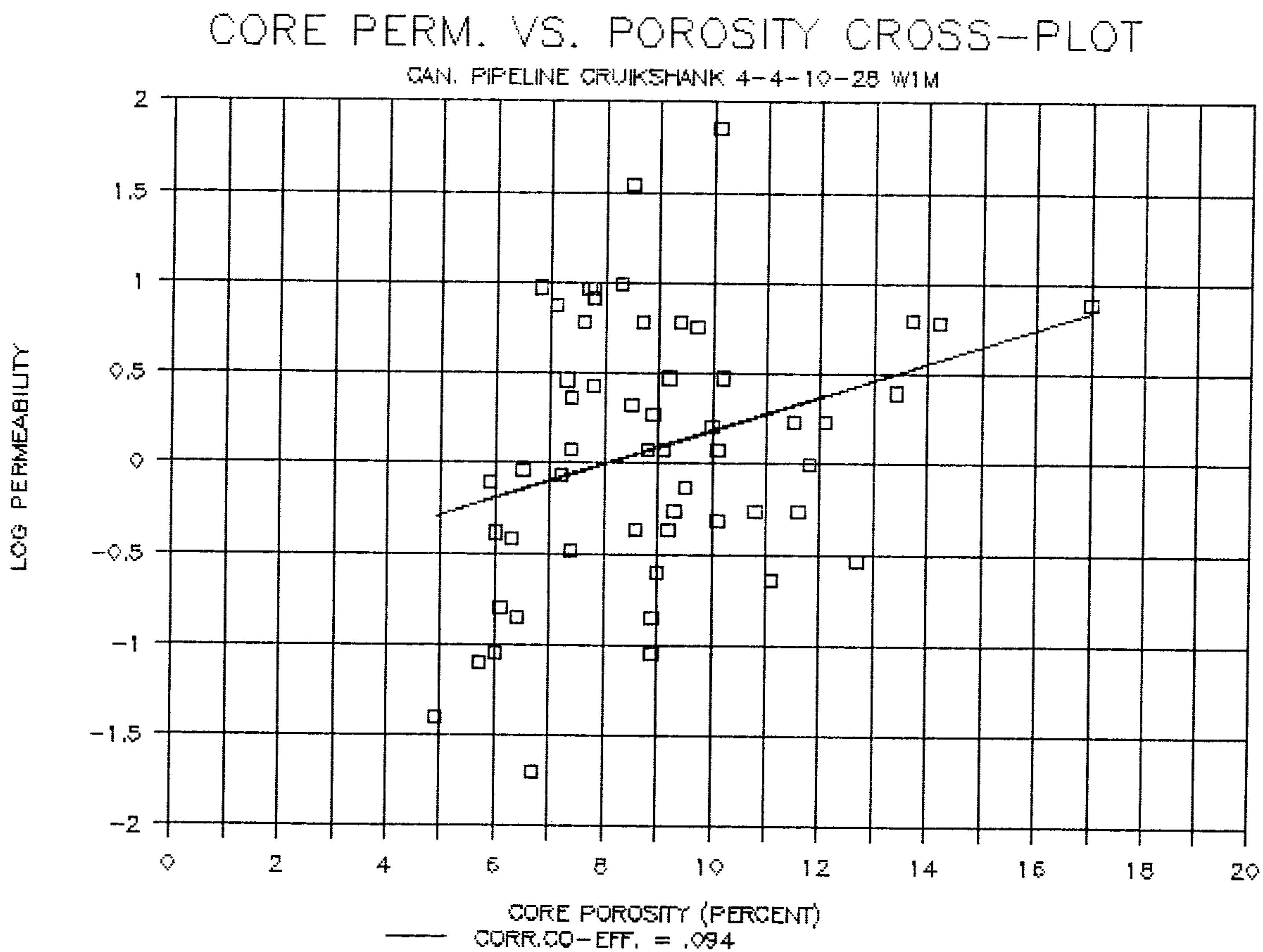


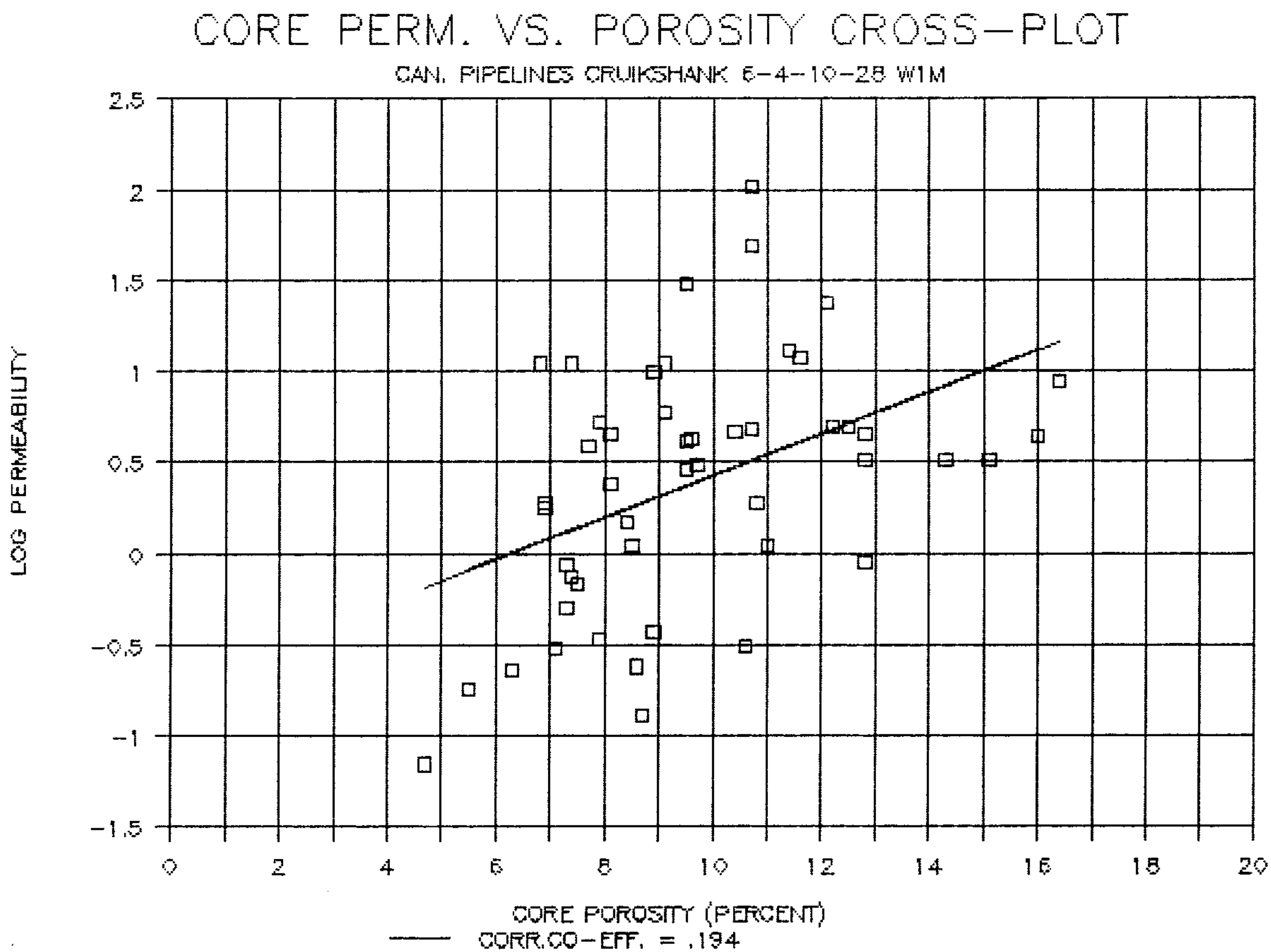

CORE PERM. VS. POROSITY CROSS-PLOT
CAL. STD. DALY 12-3-10-28 W1M
LOG PERMEABILITY
2.5
2
1.5
1
0.5
0
-0.5
-1
-1.5
0
2
4
6
8
10
12
14
16
18
20
CORE POROSITY (PERCENT)
CORR.CO-EFF. = .356

CORE PERM. VS. POROSITY CROSS-PLOT

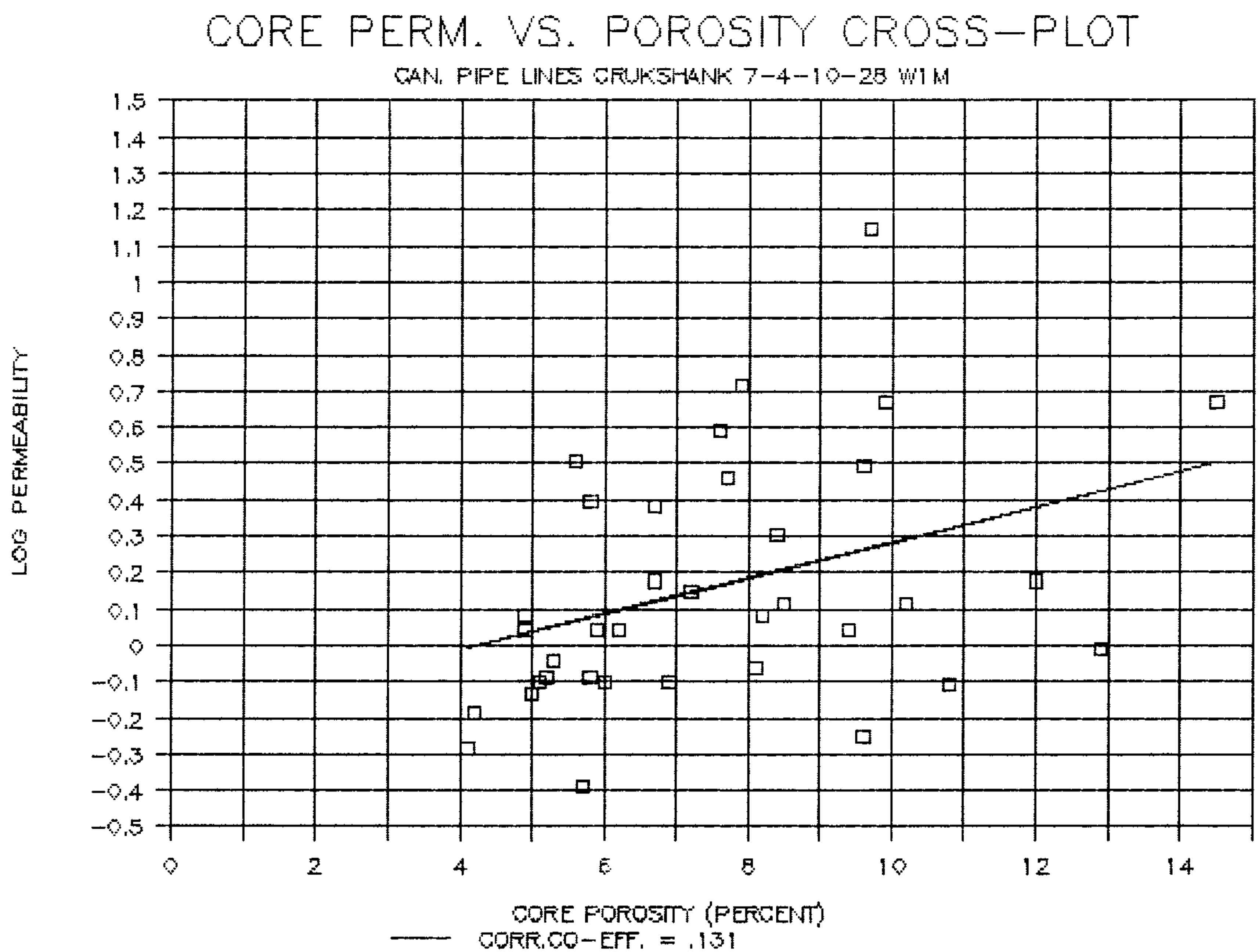
BASCO CRUIKSHANK 2-4-10-28 W1M



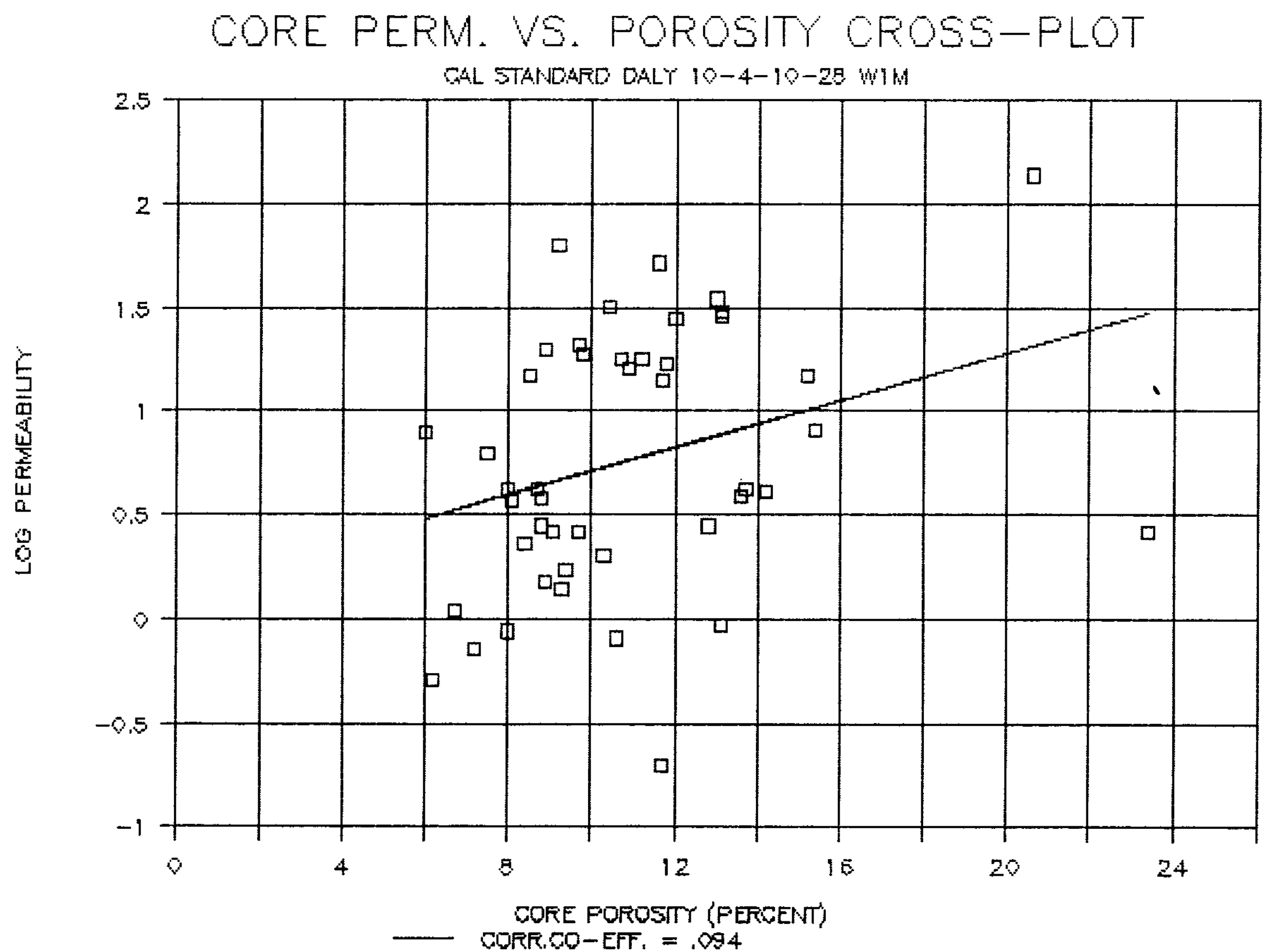

CORE PERM. VS. POROSITY CROSS-PLOT
CAN. PIPELINE CRUIKSHANK 4-4-10-28 W1M
LOG PERMEABILITY
2
1.5
1
0.5
0
-0.5
-1
-1.5
-2
0
2
4
6
8
10
12
14
16
18
20
CORE POROSITY (PERCENT)
CORR.CO-EFF. = .094



CORE PERM. VS. POROSITY CROSS-PLOT
CAN. PIPELINES CRUIKSHANK 6-4-10-28 W1M
LOG PERMEABILITY
2.5
2
1.5
1
0.5
0
-0.5
-1
-1.5
0
2
4
6
8
10
12
14
16
18
20
CORE POROSITY (PERCENT)
CORR.CO-EFF. = .194

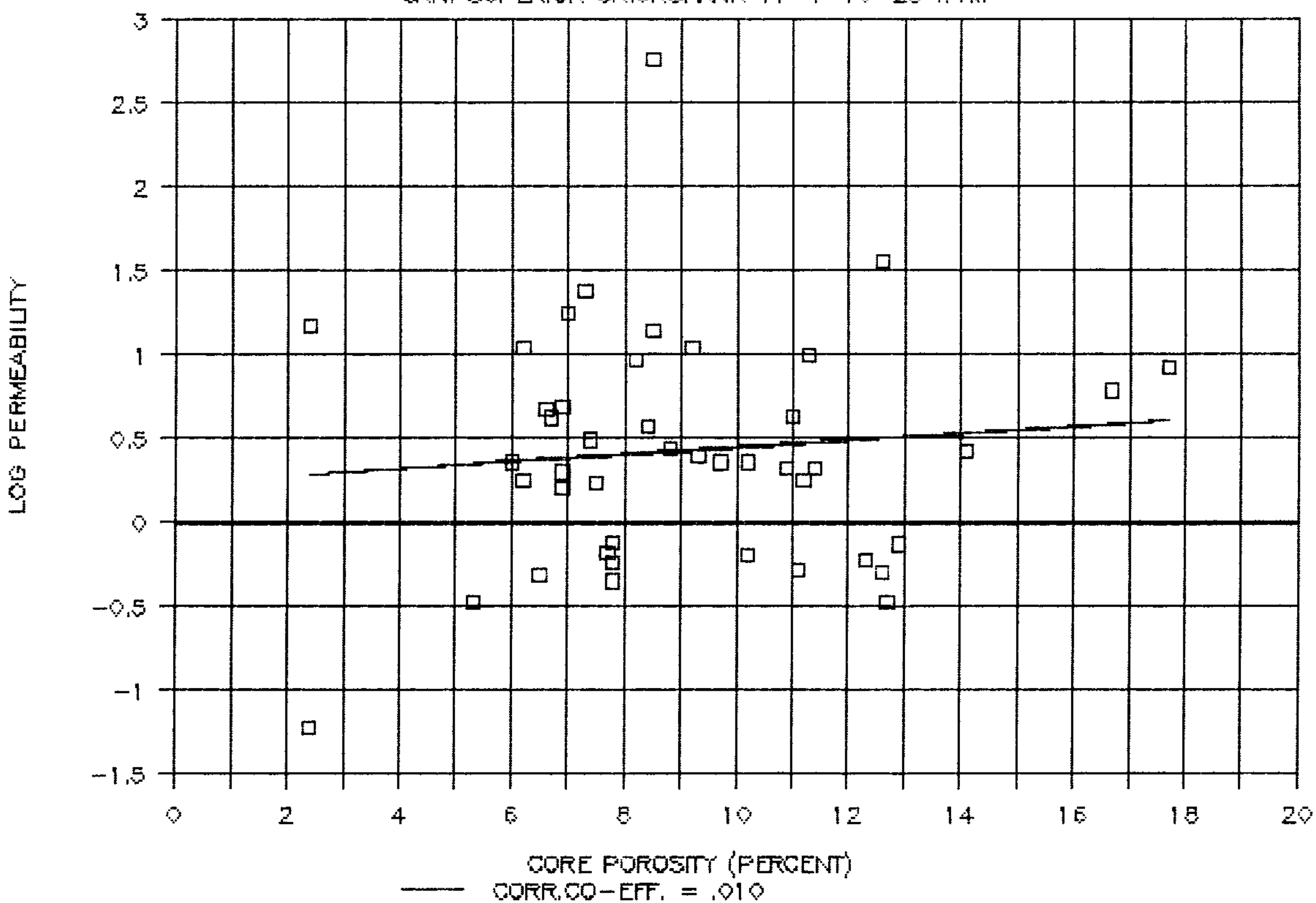


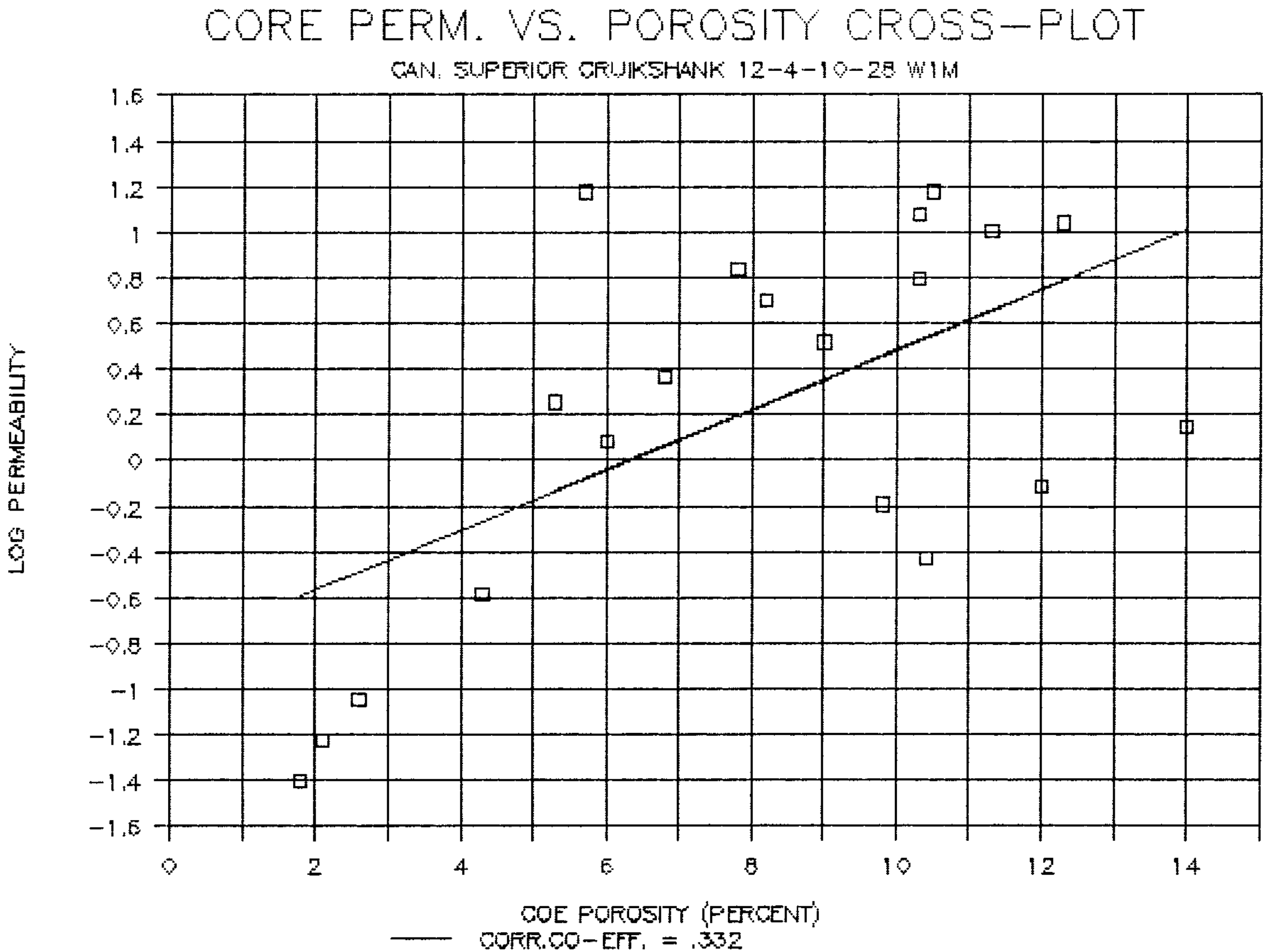
CORE PERM. VS. POROSITY CROSS-PLOT
CAN. PIPE LINES CRUKSHANK 7-4-10-28 W1M
LOG PERMEABILITY
1.5
1.4
1.3
1.2
1.1
1
0.9
0.8
0.7
0.6
0.5
0.4
0.3
0.2
0.1
0
-0.1
-0.2
-0.3
-0.4
-0.5
0
2
4
6
8
10
12
14
CORE POROSITY (PERCENT)
CORR.CO-EFF. = .131


CORE PERM. VS. POROSITY CROSS-PLOT
CAL STANDARD DALY 10-4-10-28 W1M
LOG PERMEABILITY
2.5
2
1.5
1
0.5
0
-0.5
-1
0
4
8
12
16
20
24
CORE POROSITY (PERCENT)
CORR.CO-EFF. = .094

CORE PERM. VS. POROSITY CROSS–PLOT

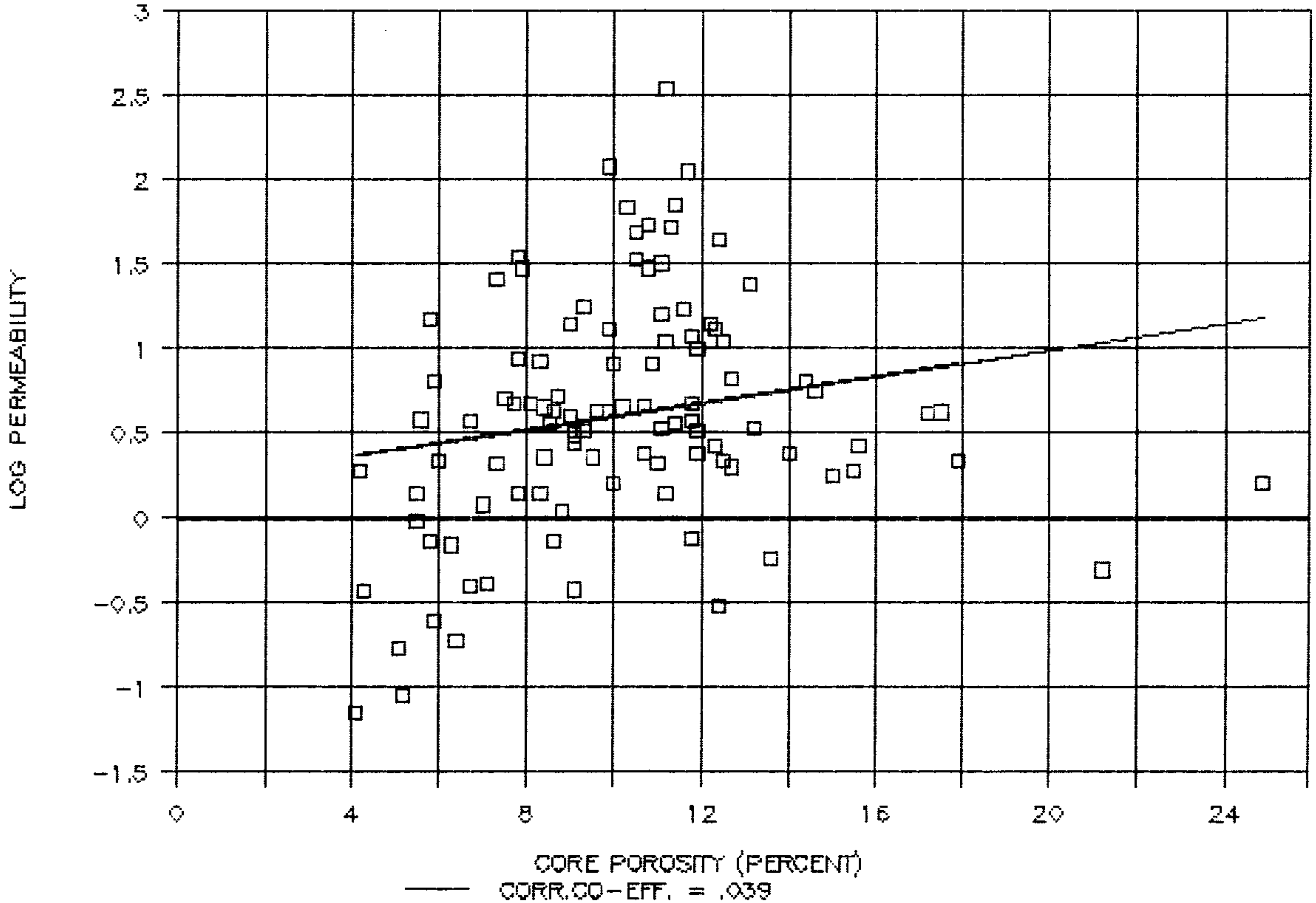
CAN. SUPERIOR CRIUKSHANK 11–4–10–28 W1M




CORE PERM. VS. POROSITY CROSS−PLOT
CAN. SUPERIOR CRUIKSHANK 12−4−10−28 W1M
LOG PERMEABILITY
1.6
1.4
1.2
1
0.8
0.6
0.4
0.2
0
−0.2
−0.4
−0.6
−0.8
−1
−1.2
−1.4
−1.6
0
2
4
6
8
10
12
14
COE POROSITY (PERCENT)
CORR.CO−EFF. = .332

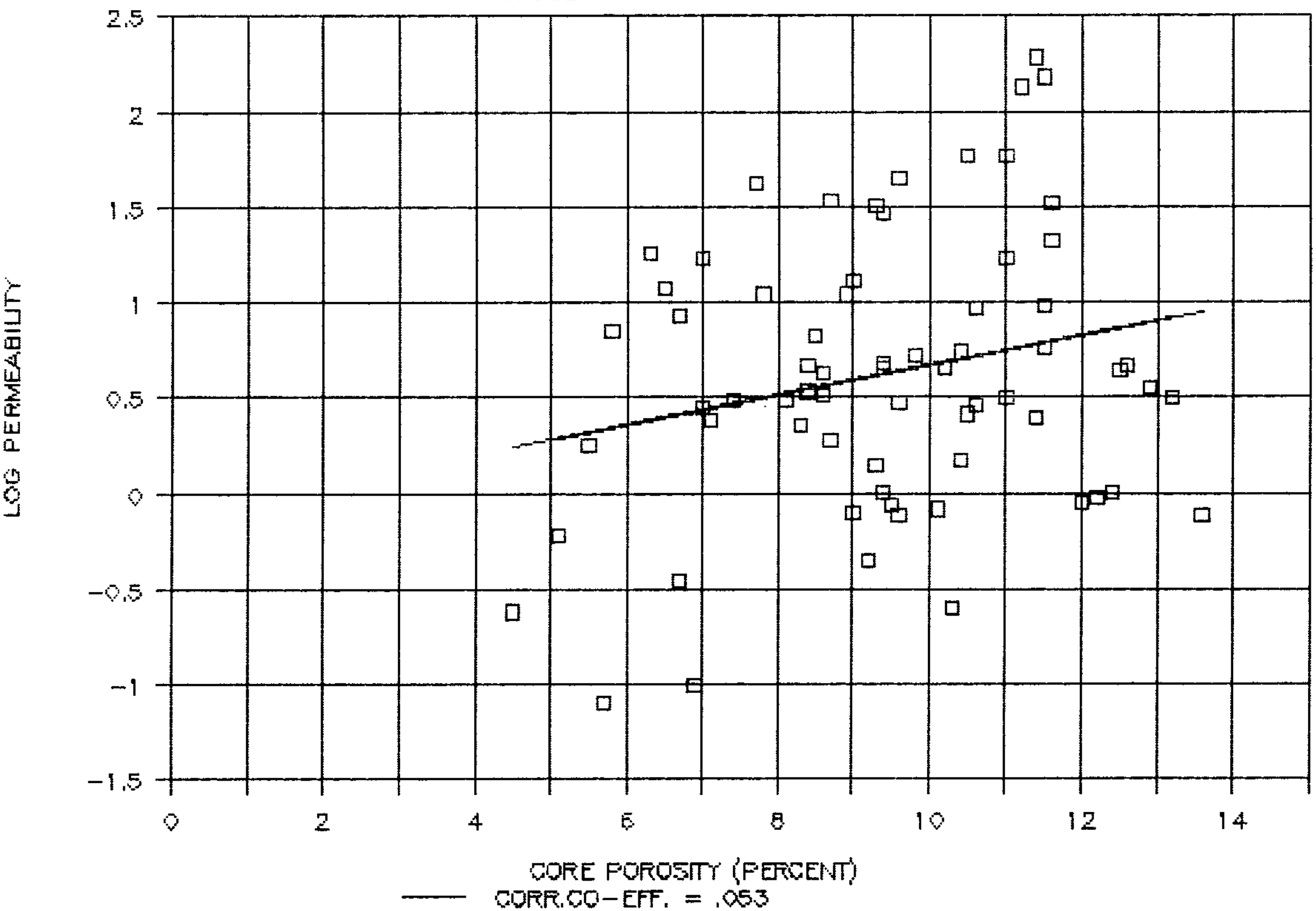
CORE PERM. VS POROSITY CROSS—PLOT

RUNDLE DALY 12B-4-10-28 W1M



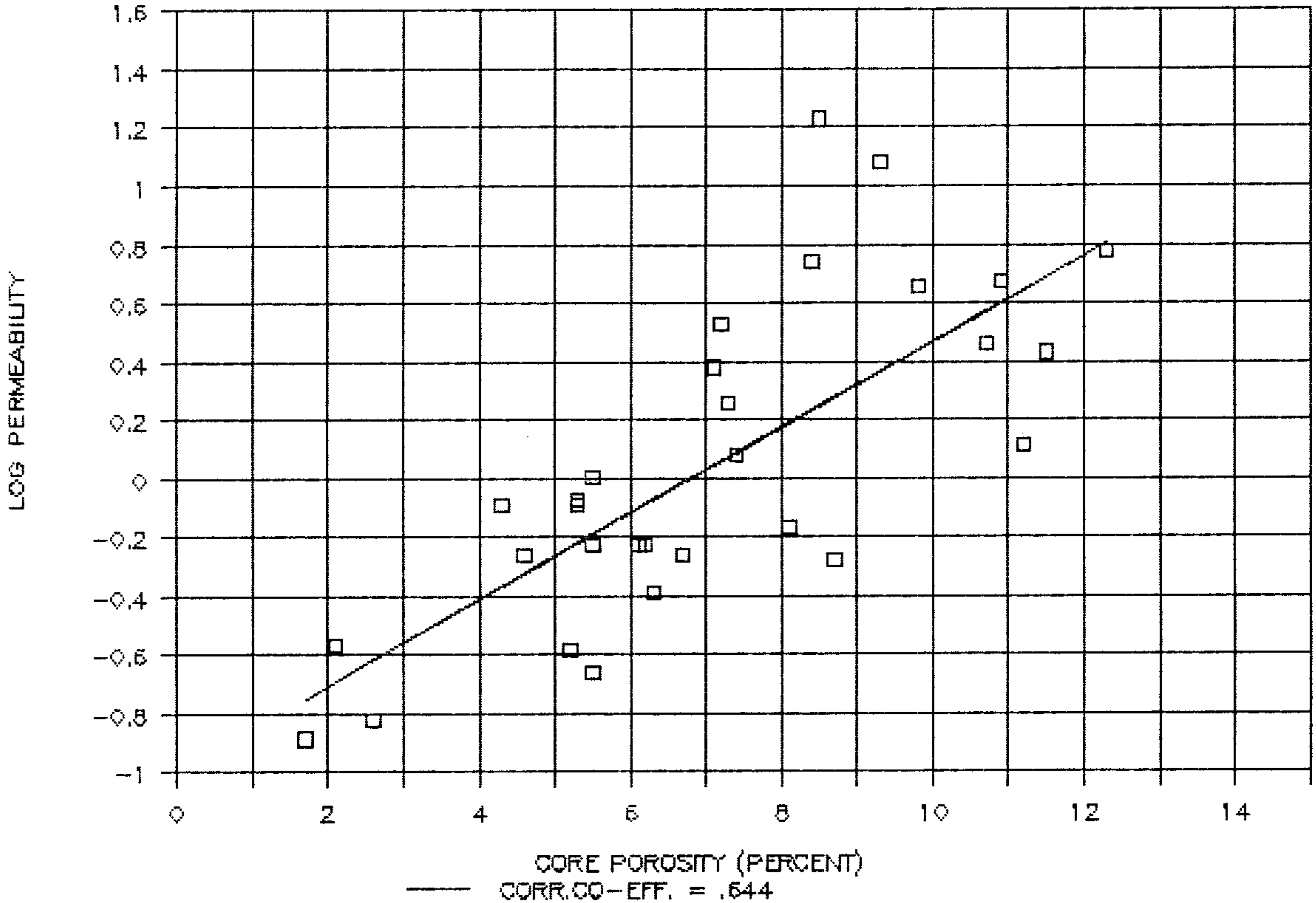
CORE PERM. VS. POROSITY CROSS-PLOT

RUNDLE DALY 14D-4-10-25 W1M



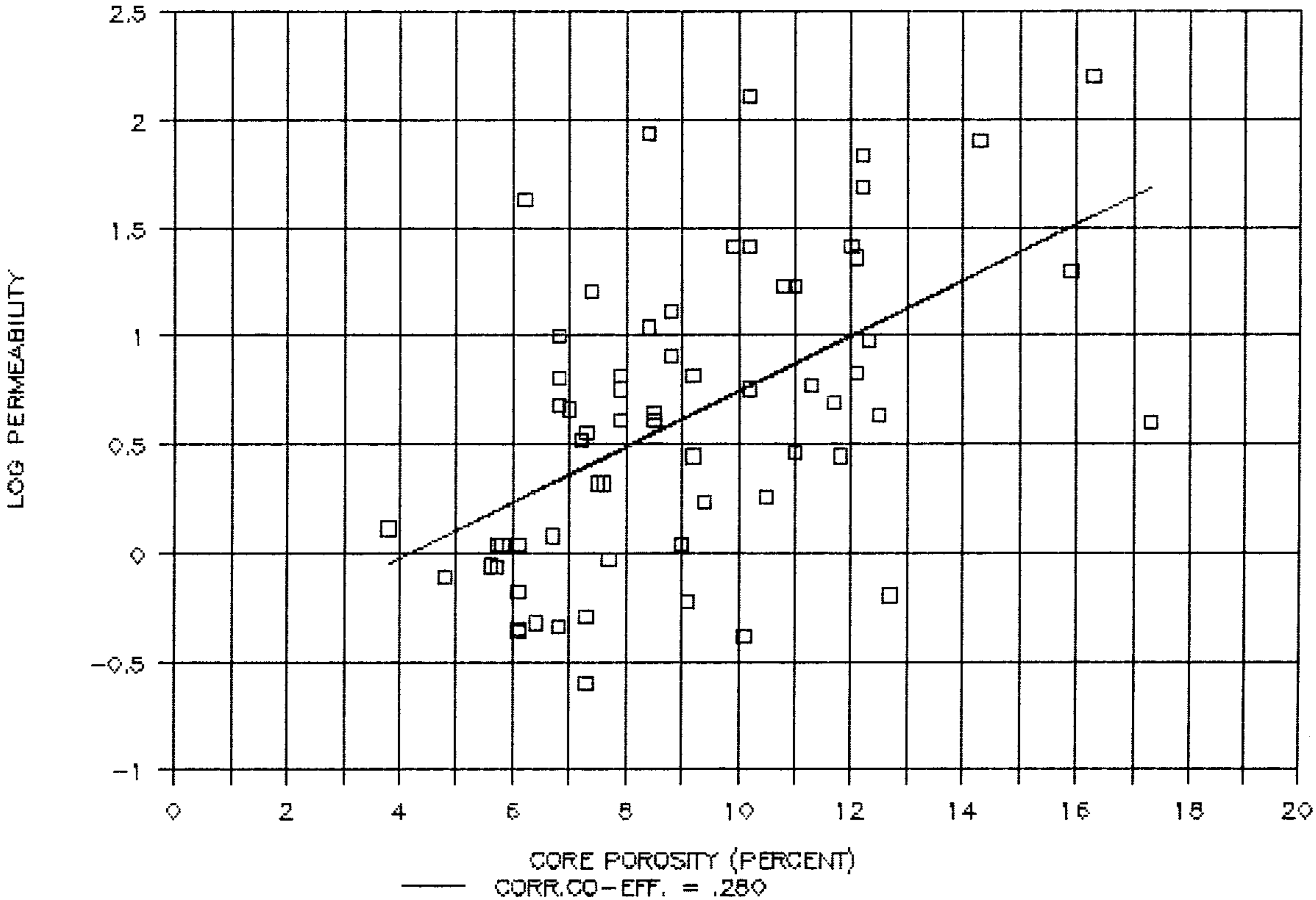
CORE PERM. VS. POROSITY CROSS—PLOT

CAN. SUPERIOR DALY 7-5-10-28 W1M



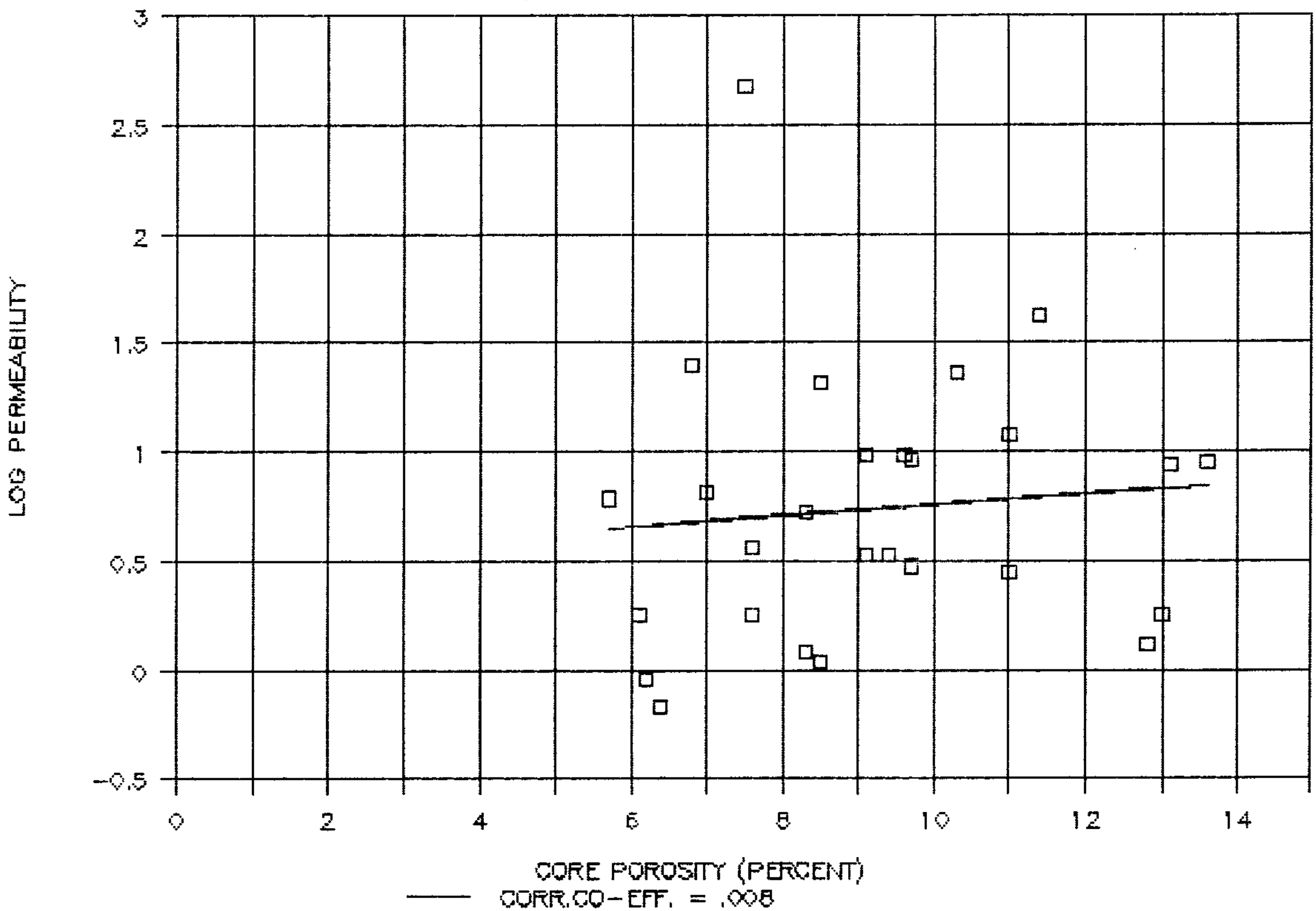
CORE PERM. VS. POROSITY CROSS-PLOT

RUNDLE DALY 15-5-10-28 W1M



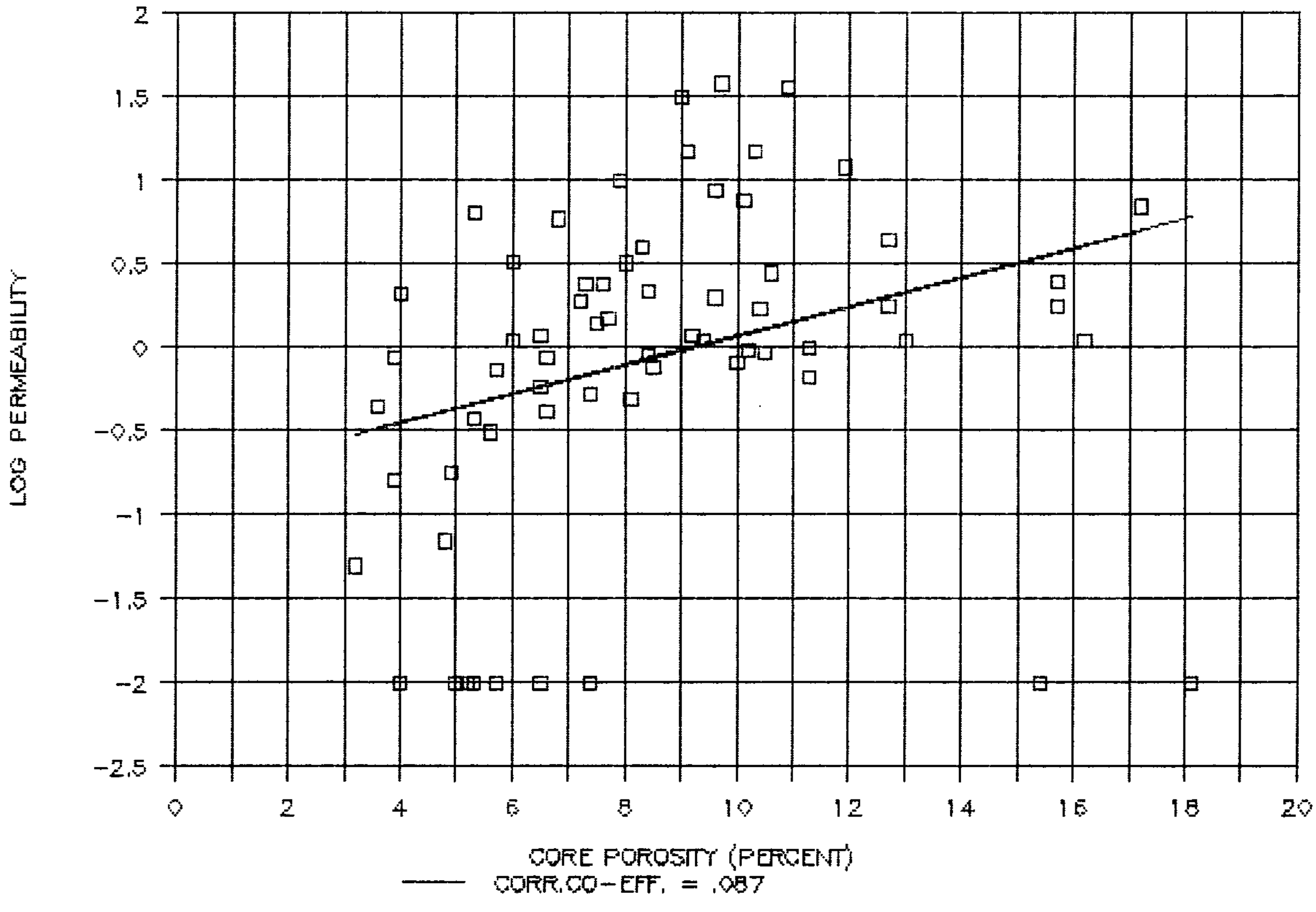
CORE PERM. VS. POROSITY CROSS-PLOT

CAL STANDARD DALY 1-9-10-28 W1M



CORE PERM. VS. POROSITY CROSS—PLOT

CAL. STANDARD DALY 6-10-10-28 W1M



APPENDIX 2

DYKSTRA-PARSONS PERMEABILITY VARIANCE PLOTS

DYKSTRA-PARSONS'

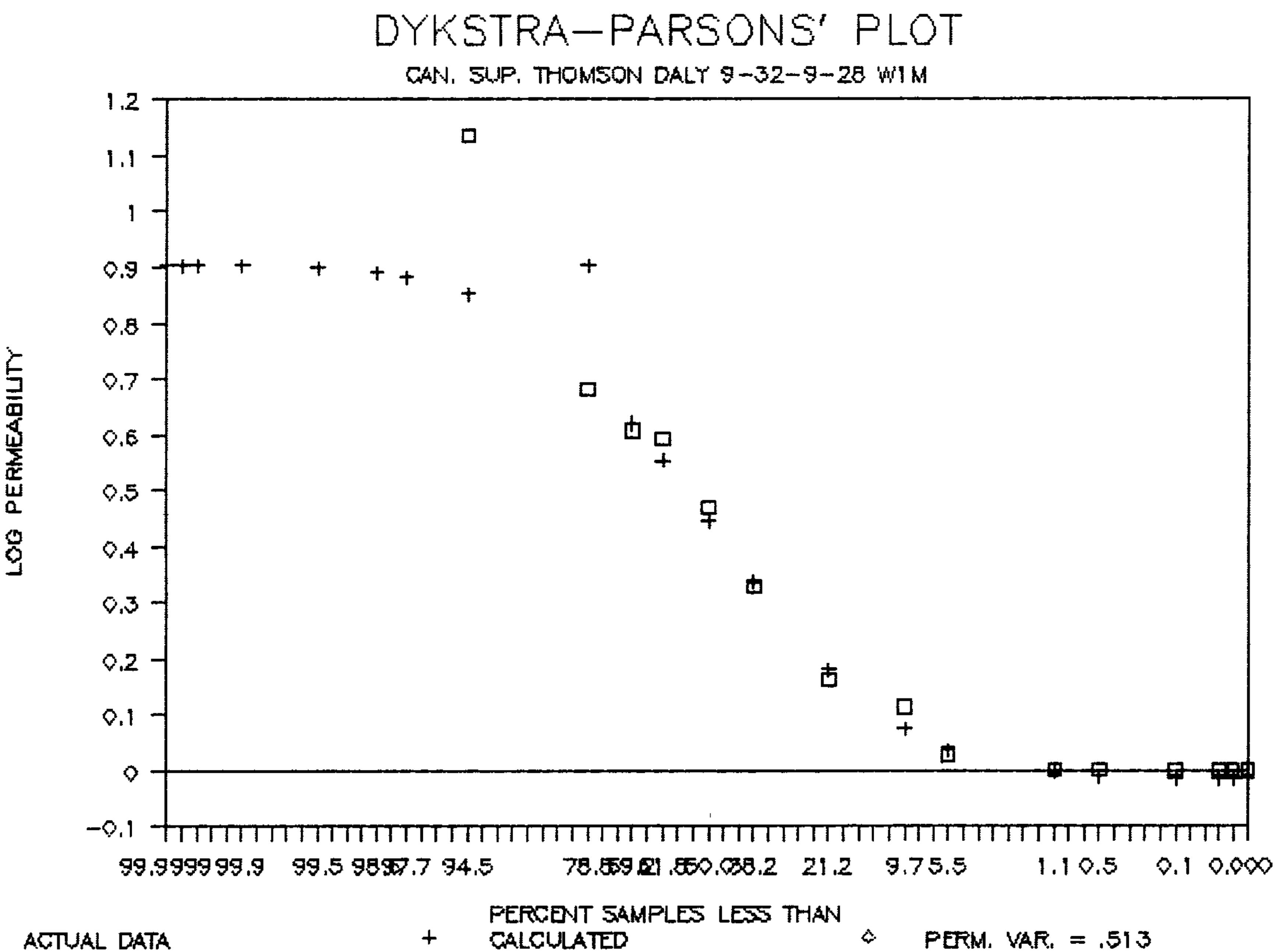
CAN. SUPERIOR THOMSON DALY 9-32-9-28 W1M

Regression Output:

Constant	-0.01394
Std Err of Y Est	0.028727
R Squared	0.982813
No. of Observations	6
Degrees of Freedom	4

X Coefficient(s)	0.917253
Std Err of Coef.	0.060648

Kmean	2.784084
Kstd	1.354874
Permeability Variation	0.513350



DYKSTRA—PARSONS' PLOT
CAN. SUP. THOMSON DALY 9-32-9-28 W1M
LOG PERMEABILITY
1.2
1.1
1
0.9
0.8
0.7
0.6
0.5
0.4
0.3
0.2
0.1
0
-0.1
99.5
94.5
21.2
9.7
5.5
1.1
0.5
0.1
PERCENT SAMPLES LESS THAN
ACTUAL DATA
+ CALCULATED
◇ PERM. VAR. = .513

DYKSTRA-PARSONS'

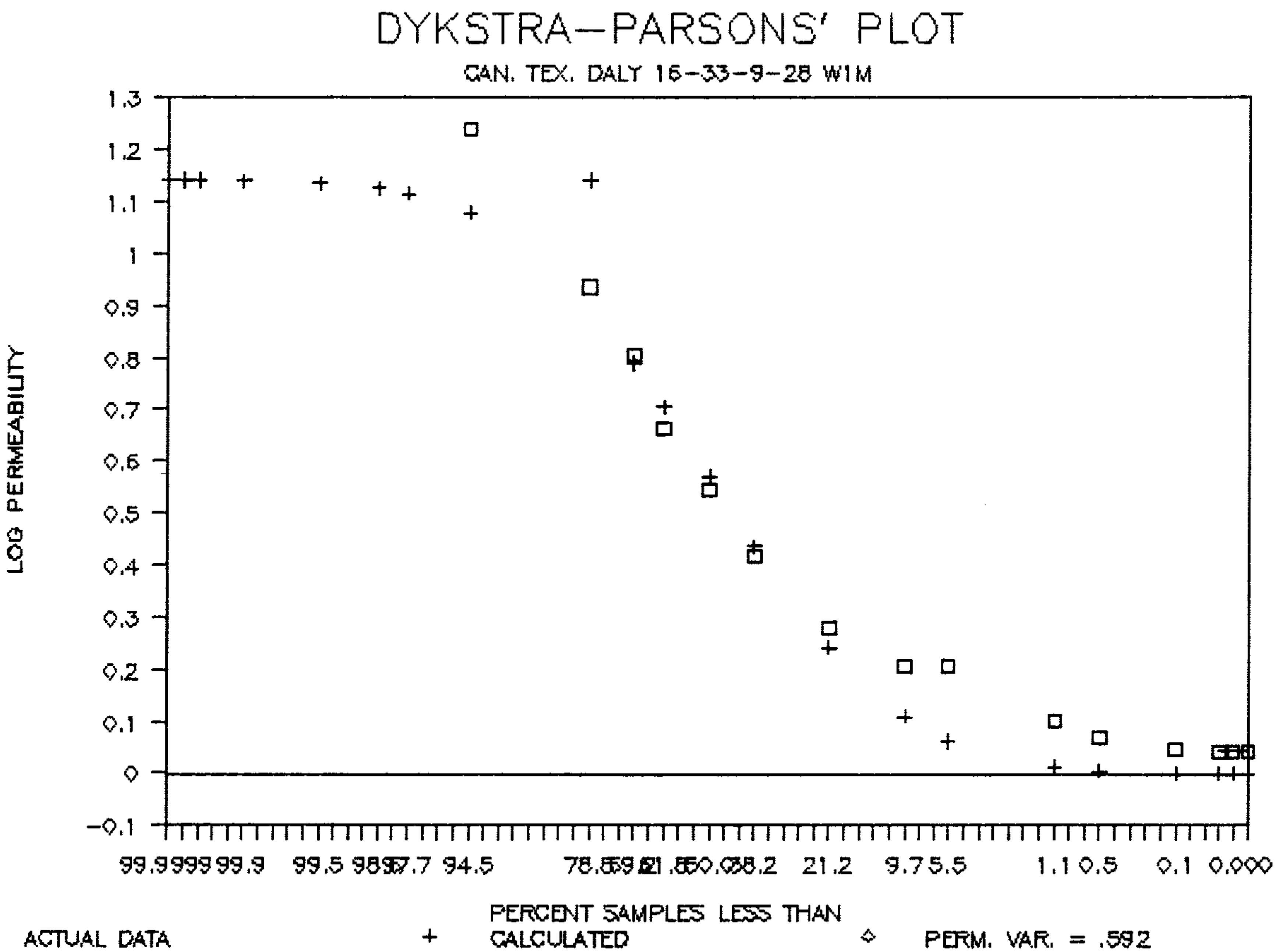
CAN. TEX. DALY 16-33-9-28 W1M

Regression Output:

Constant	-0.00089
Std Err of Y Est	0.037861
R Squared	0.980807
No. of Observations	6
Degrees of Freedom	4

X Coefficient(s) 1.142799
Std Err of Coef. 0.079931

Kmean	3.719638
Kstd	1.516373
Permeability Variation	0.592333


DYKSTRA—PARSONS' PLOT
CAN. TEX. DALY 16-33-9-28 W1M
LOG PERMEABILITY
1.3
1.2
1.1
1
0.9
0.8
0.7
0.6
0.5
0.4
0.3
0.2
0.1
0
-0.1
99.9 99.5 97.7 94.5 21.2 9.7 5.5 1.1 0.5 0.1 0.0001
PERCENT SAMPLES LESS THAN
ACTUAL DATA
+ CALCULATED
PERM. VAR. = .592

DYKSTRA-PARSONS'

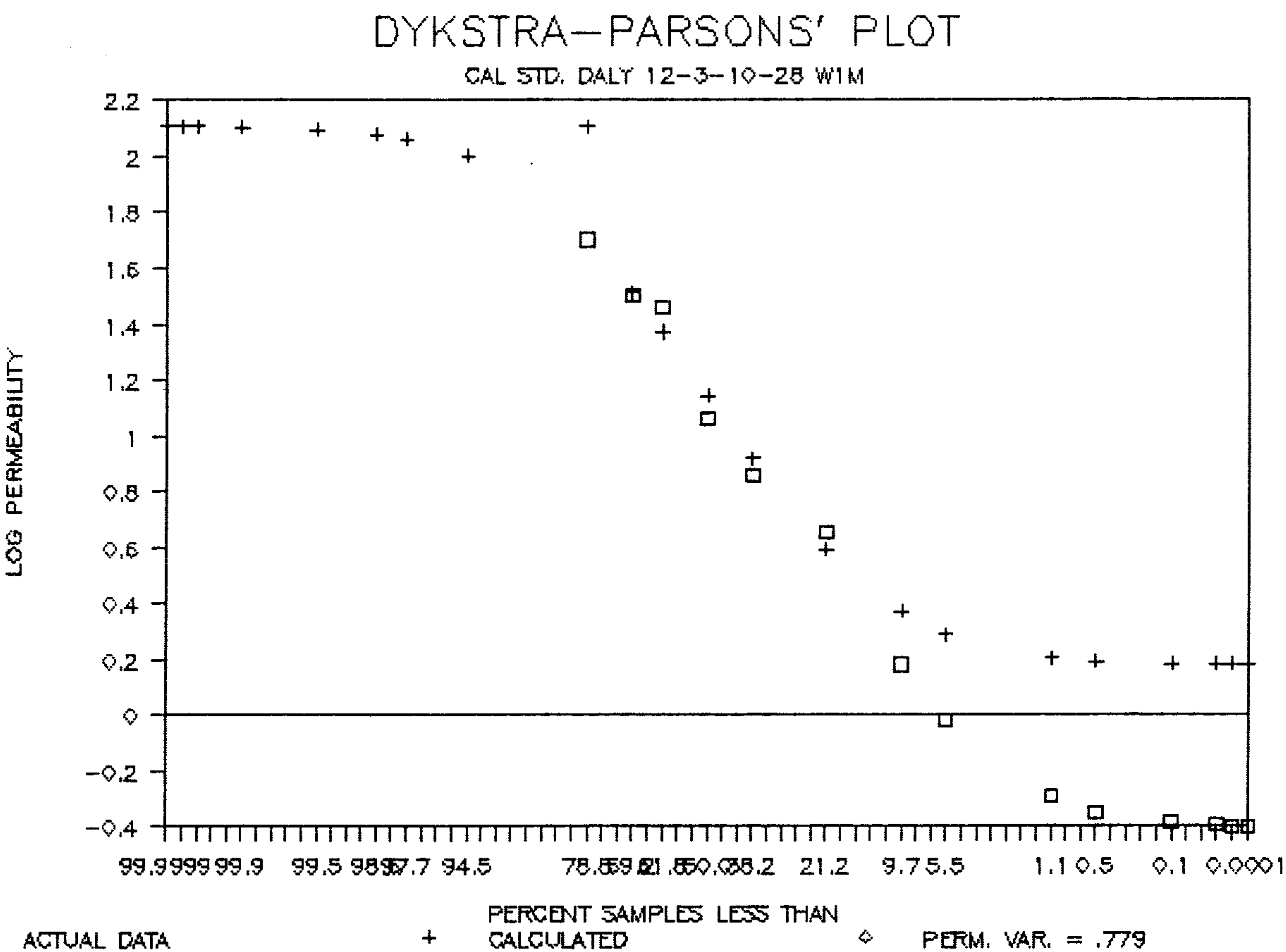
CAL. STD. DALY 12-3-10-28 W1M

Regression Output:

Constant	0.184376
Std Err of Y Est	0.074907
R Squared	0.973625
No. of Observations	6
Degrees of Freedom	4

X Coefficient(s)	1.921664
Std Err of Coef.	0.158141

Kmean	13.97038
Kstd	3.089732
Permeability Variation	0.778837



DYKSTRA—PARSONS' PLOT
CAL STD. DALY 12-3-10-28 W1M
LOG PERMEABILITY
2.2
2
1.8
1.6
1.4
1.2
1
0.8
0.6
0.4
0.2
0
-0.2
-0.4
99.9999 99.9
99.5
94.5
21.2
9.7 5.5
1.1 0.5
0.1
0.0001
PERCENT SAMPLES LESS THAN
ACTUAL DATA
+ CALCULATED
◇ PERM. VAR. = .779

DYKSTRAS-PARSONS'

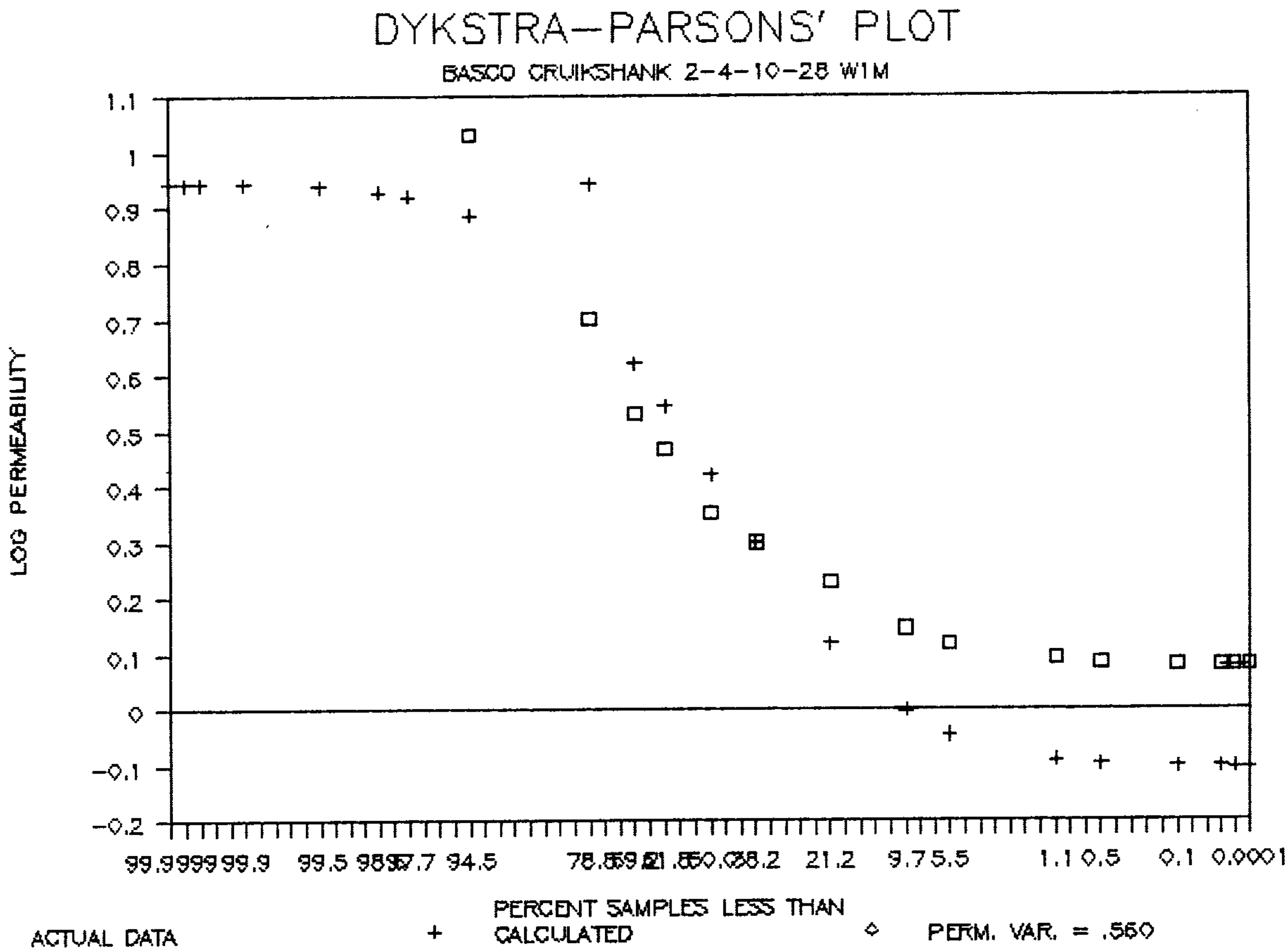
BASCO CRUIKSHANK 2-4-10-28 W1M

Regression Output:

Constant	-0.10254
Std Err of Y Est	0.102927
R Squared	0.884619
No. of Observations	7
Degrees of Freedom	5

X Coefficient(s)	1.046593
Std Err of Coef.	0.169036

Kmean	2.634803
Kstd	1.158403
Permeability Variation	0.560345



DYKSTRA—PARSONS' PLOT
BASCO CRUIKSHANK 2-4-10-28 W1M
LOG PERMEABILITY
1.1
1
0.9
0.8
0.7
0.6
0.5
0.4
0.3
0.2
0.1
0
-0.1
-0.2
99.9999 99.9
99.5
94.5
21.2
9.7 5.5
1.1 0.5
0.1
0.0001
PERCENT SAMPLES LESS THAN
ACTUAL DATA
+ CALCULATED
◇ PERM. VAR. = .560

DYKSTRA-PARSONS'

CAN. PIPELINE CRUIKSHANK 4-4-10-28 W1M

Regression Output:

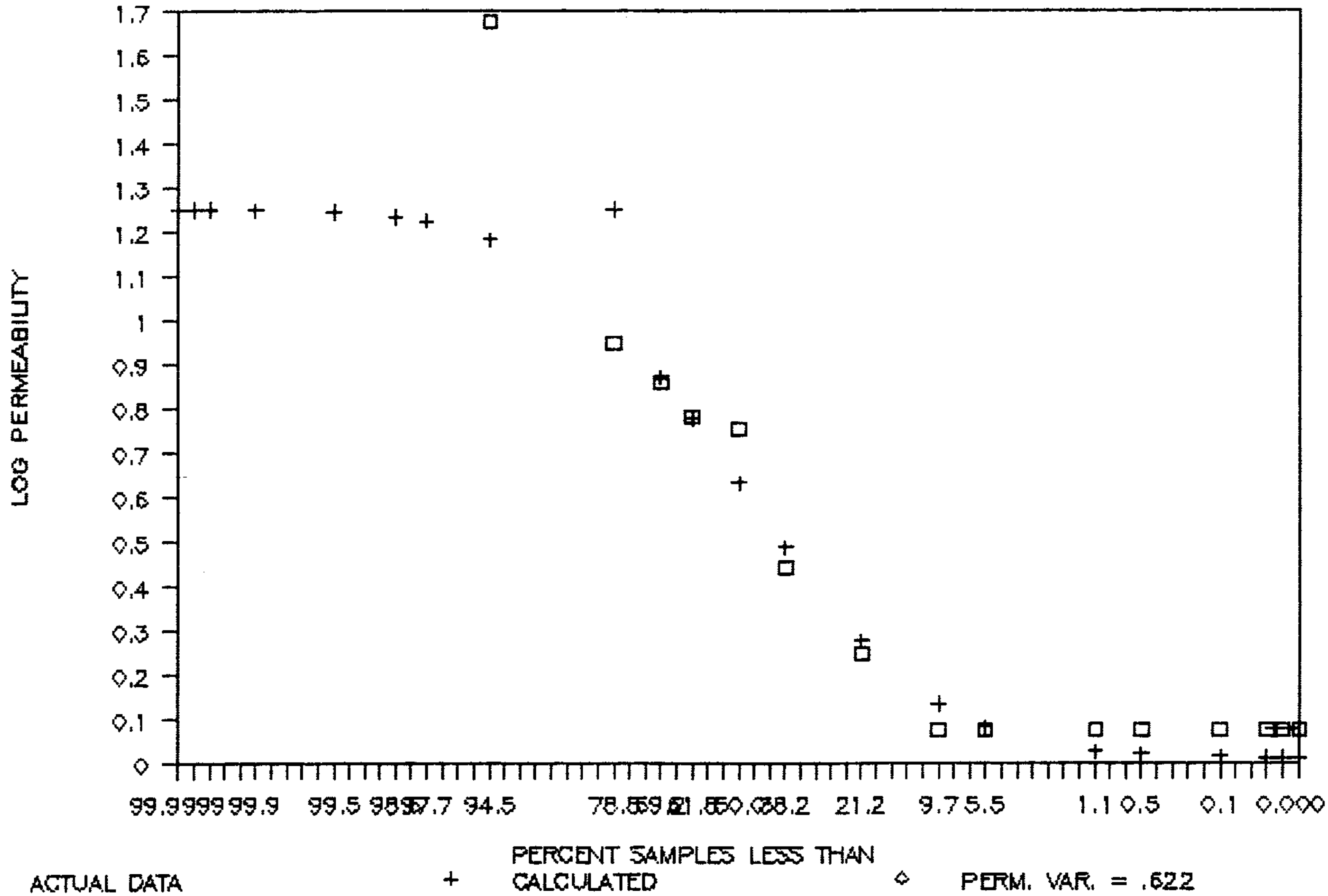
Constant	0.015946
Std Err of Y Est	0.069438
R Squared	0.946850
No. of Observations	6
Degrees of Freedom	4

X Coefficient(s) 1.237510
Std Err of Coef. 0.146597

Kmean	4.312229
Kstd	1.631965
Permeability Variation	0.621549

DYKSTRA—PARSONS' PLOT

CAN. PIPELINE CRUIKSHANK 4-4-10-28 W1M



DYKSTRA-PARSONS'

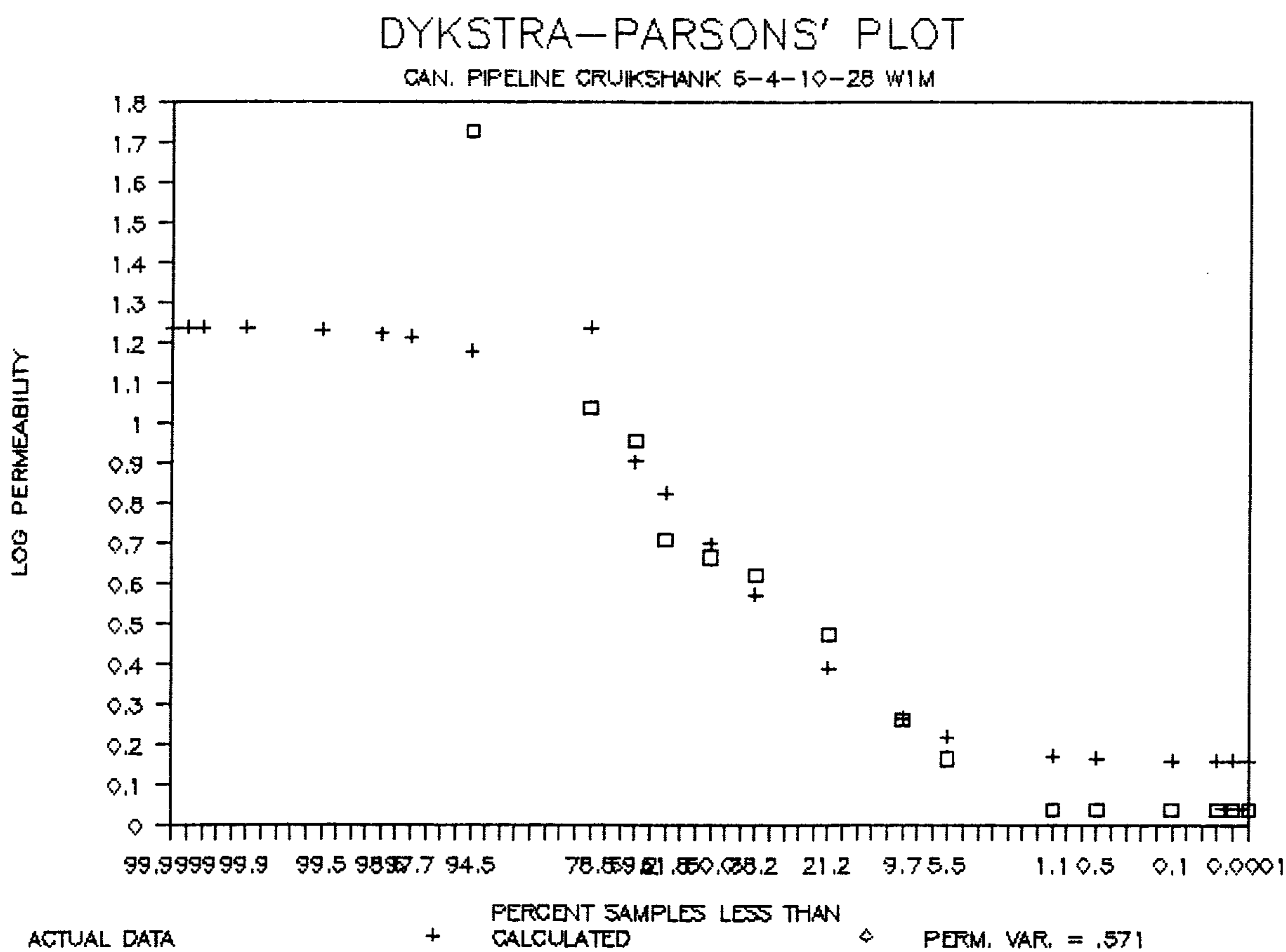
CAN. PIPELINES CRUIKSHANK 6-4-10-28 W1M

Regression Output:

Constant	0.198303
Std Err of Y Est	0.071198
R Squared	0.940549
No. of Observations	7
Degrees of Freedom	5

X Coefficient(s)	1.018382
Std Err of Coef.	0.114502

Kmean	5.028101
Kstd	2.157471
Permeability Variation	0.570917



DYKSTRA—PARSONS' PLOT
CAN. PIPELINE CRUIKSHANK 6-4-10-28 W1M
LOG PERMEABILITY
1.8
1.7
1.6
1.5
1.4
1.3
1.2
1.1
1
0.9
0.8
0.7
0.6
0.5
0.4
0.3
0.2
0.1
0
99.9999 99.9 99.5 98 97.7 94.5 78.8 59.8 21.8 50.0 38.2 21.2 9.7 5.5 1.1 0.5 0.1 0.0001
PERCENT SAMPLES LESS THAN
ACTUAL DATA
+ CALCULATED
◇ PERM. VAR. = .571

DYKSTRA-PARSONS'

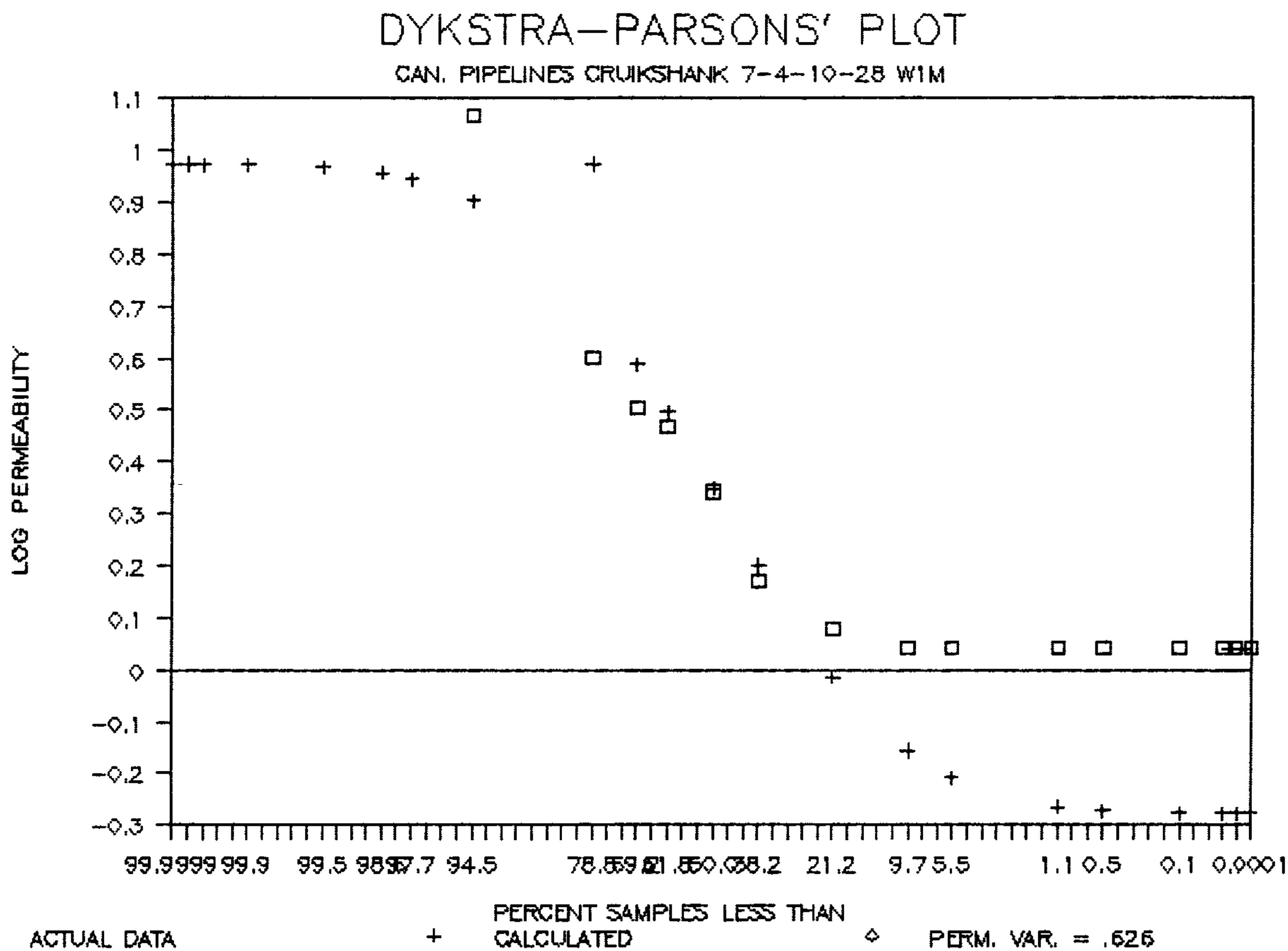
CAN. PIPELINES CRUIKSHANK 7-4-10-28 W1M

Regression Output:

Constant	-0.19928
Std Err of Y Est	0.028553
R Squared	0.977988
No. of Observations	5
Degrees of Freedom	3

X Coefficient(s)	1.034857
Std Err of Coef.	0.089635

Kmean	2.230029
Kstd	0.835008
Permeability Variation	0.625561



DYKSTRA—PARSONS' PLOT
CAN. PIPELINES CRUIKSHANK 7-4-10-28 W1M
LOG PERMEABILITY
1.1
1
0.9
0.8
0.7
0.6
0.5
0.4
0.3
0.2
0.1
0
-0.1
-0.2
-0.3
99.9999
99.9
99.5
94.5
21.2
9.7
5.5
1.1
0.5
0.1
0.0001
PERCENT SAMPLES LESS THAN
ACTUAL DATA
+
CALCULATED
PERM. VAR. = .626

DYKSTRA-PARSONS'

CAL STANDARD DALY 10-4-10-28 W1M

Regression Output:

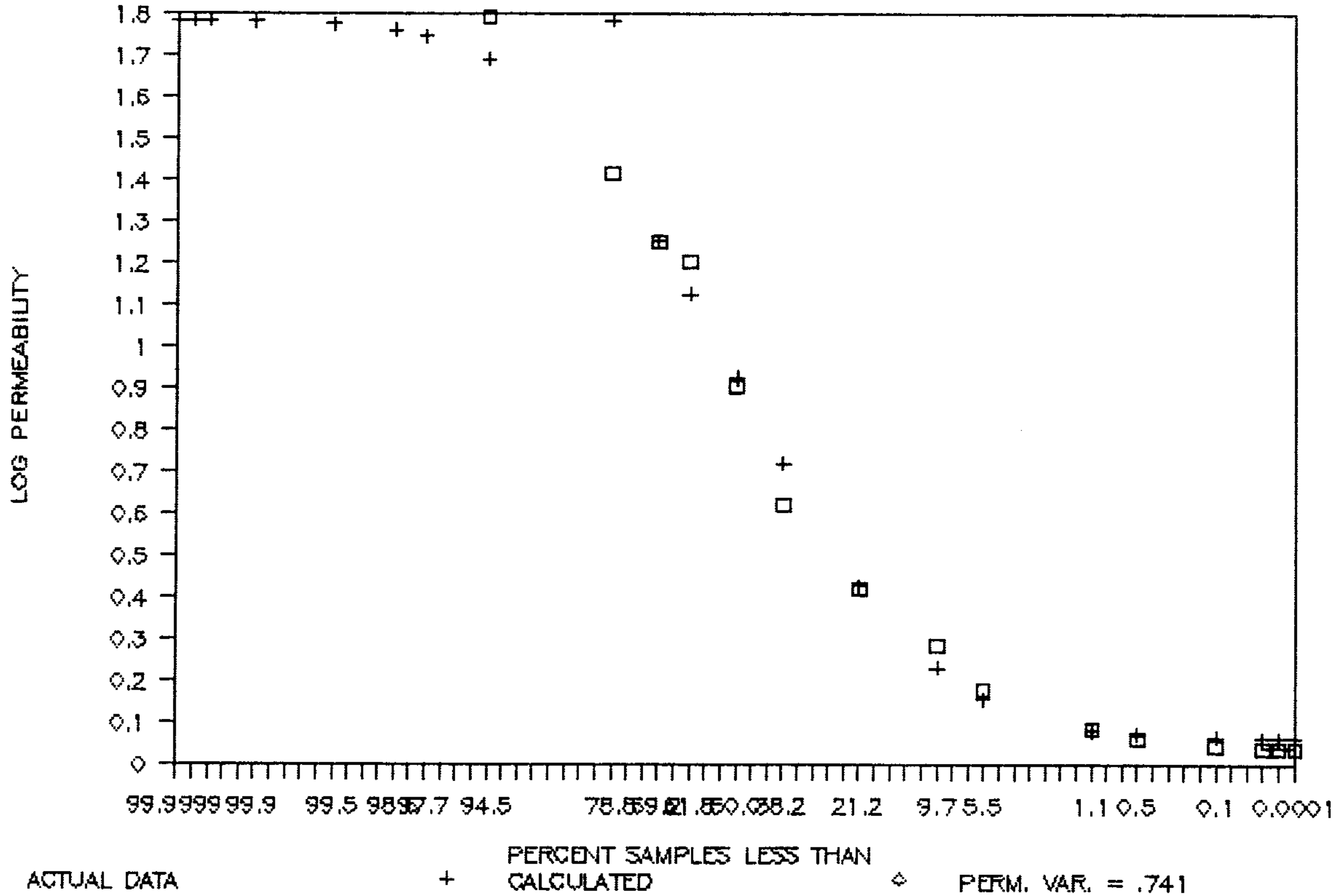
Constant	0.065662
Std Err of Y Est	0.062650
R Squared	0.983143
No. of Observations	7
Degrees of Freedom	5

X Coefficient(s)	1.720576
Std Err of Coef.	0.100755

Kmean	8.432395
Kstd	2.183908
Permeability Variation	0.741009

DYKSTRA-PARSONS' PLOT

CAL STANDARD DALY 10-4-10-28 W1M



DYKSTRA-PARSONS'

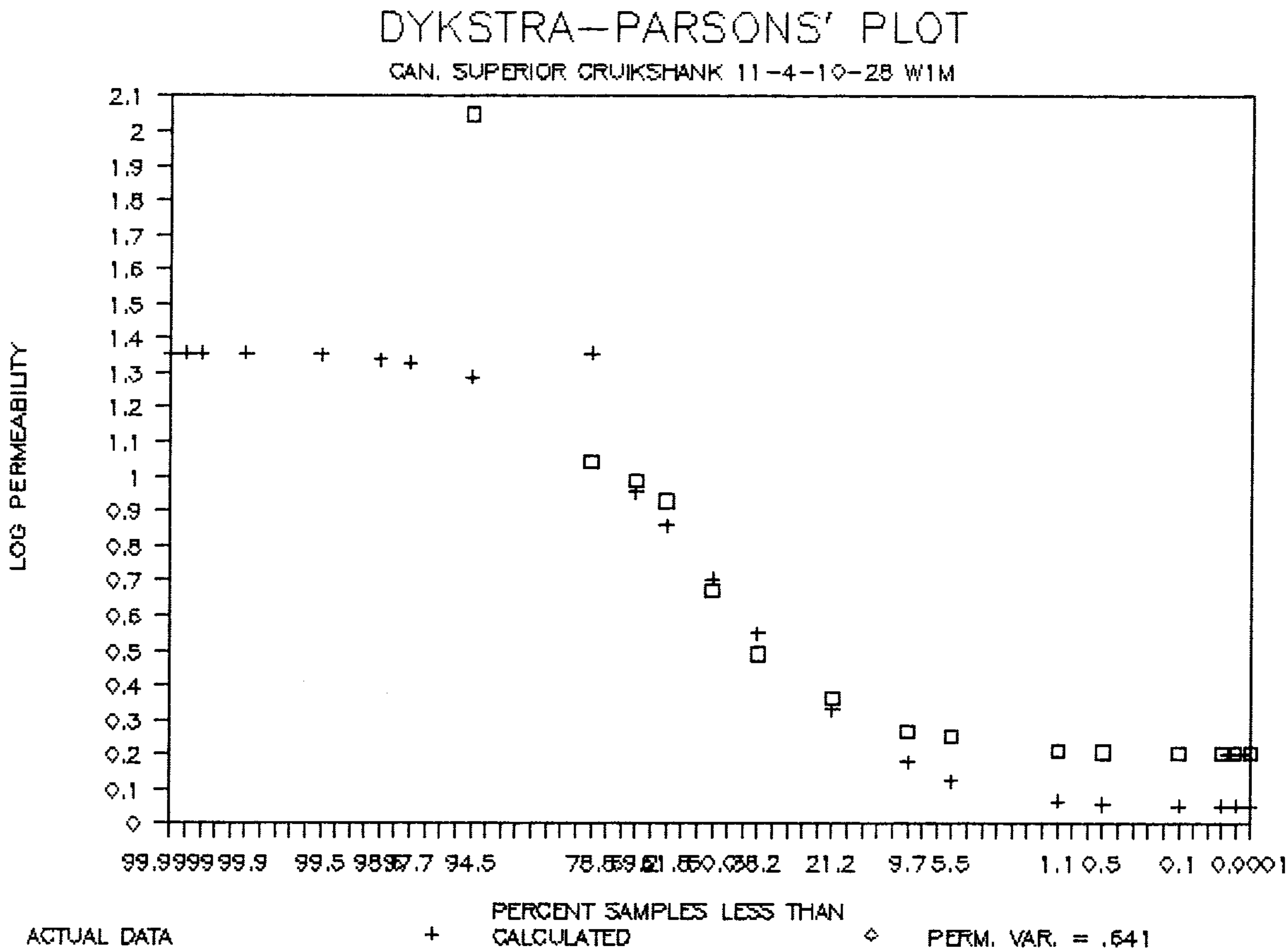
CAN. SUPERIOR CRUIKSHANK 11-4-10-28 W1M

Regression Output:

Constant	0.051862
Std Err of Y Est	0.057577
R Squared	0.966533
No. of Observations	6
Degrees of Freedom	4

X Coefficient(s)	1.306498
Std Err of Coef.	0.121555

Kmean	5.071206
Kstd	1.818006
Permeability Variation	0.641504


DYKSTRA—PARSONS' PLOT
CAN. SUPERIOR CRUIKSHANK 11-4-10-28 W1M
LOG PERMEABILITY
2.1
2
1.9
1.8
1.7
1.6
1.5
1.4
1.3
1.2
1.1
1
0.9
0.8
0.7
0.6
0.5
0.4
0.3
0.2
0.1
0
99.9999 99.9
99.5
94.5
21.2
1.1 0.5
0.1 0.0001
PERCENT SAMPLES LESS THAN
ACTUAL DATA
+ CALCULATED
◇ PERM. VAR. = .641

DYKSTRA-PARSONS'

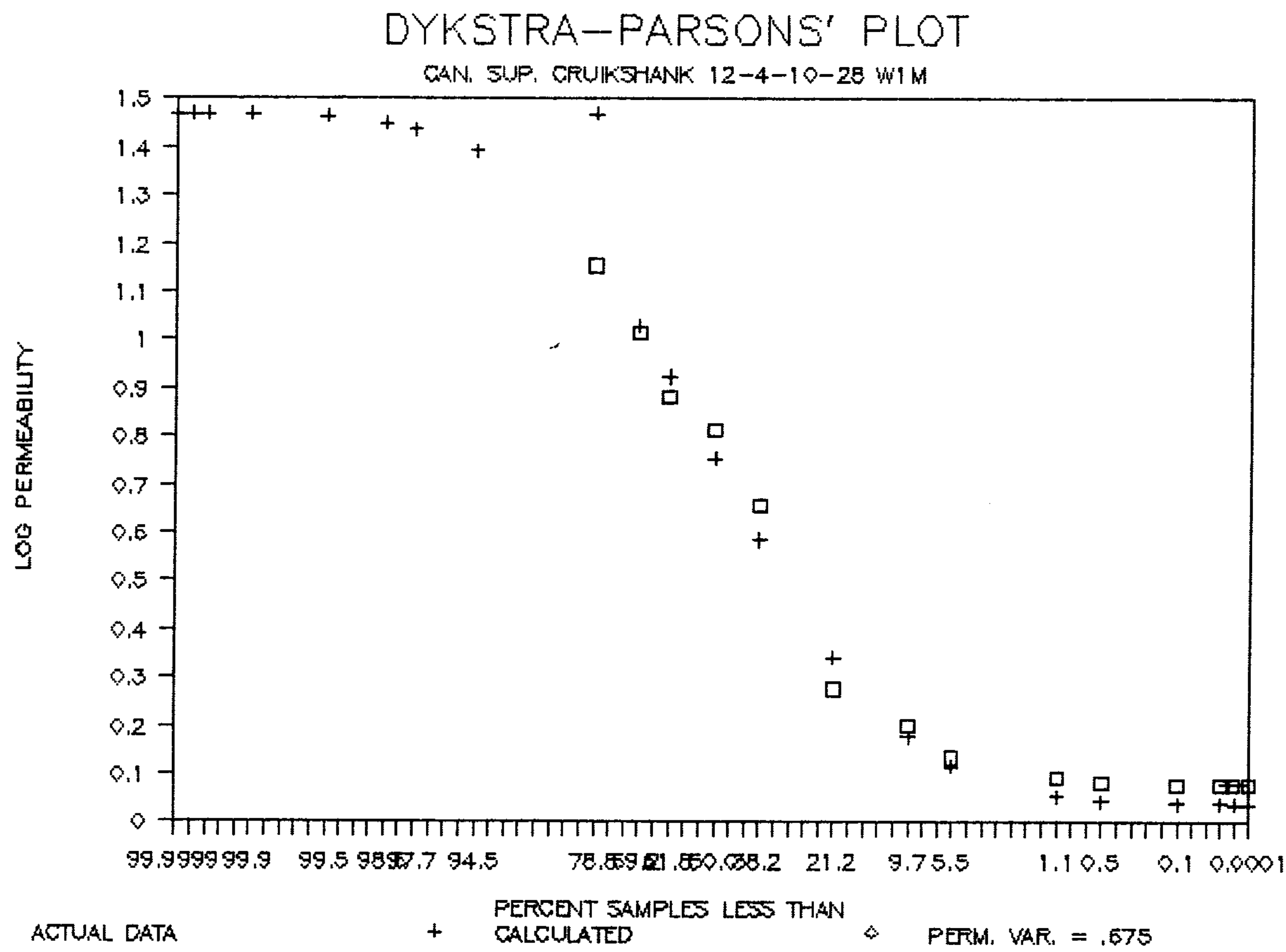
CAN. SUPERIOR CRUIKSHANK 12-4-10-28 W1M

Regression Output:

Constant	0.038864
Std Err of Y Est	0.060647
R Squared	0.968989
No. of Observations	6
Degrees of Freedom	4

X Coefficient(s)	1.431424
Std Err of Coef.	0.128036

Kmean	5.682982
Kstd	1.846973
Permeability Variation	0.674999


DYKSTRA—PARSONS' PLOT
CAN. SUP. CRUIKSHANK 12-4-10-28 W1M
LOG PERMEABILITY
1.5
1.4
1.3
1.2
1.1
1
0.9
0.8
0.7
0.6
0.5
0.4
0.3
0.2
0.1
0
99.9999 99.9
99.5
94.5
21.2
9.7 5.5
1.1 0.5
0.1
0.0001
PERCENT SAMPLES LESS THAN
ACTUAL DATA
CALCULATED
PERM. VAR. = .675

DYKSTRA-PARSONS'

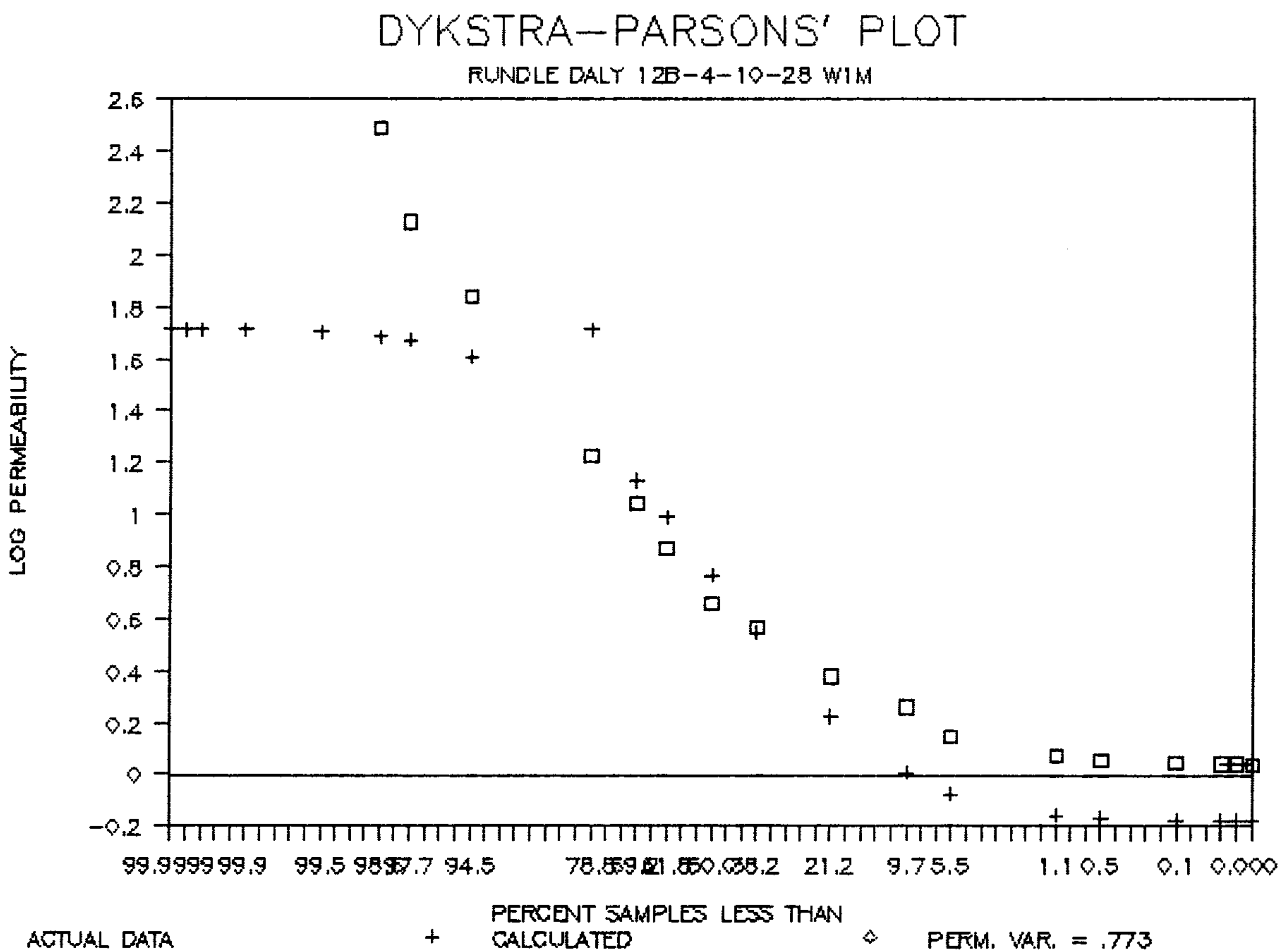
RUNDLE DALY 12B-4-10-28 W1M

Regression Output:

Constant	-0.17579
Std Err of Y Est	0.155856
R Squared	0.916027
No. of Observations	7
Degrees of Freedom	5

X Coefficient(s)	1.890361
Std Err of Coef.	0.255961

Kmean	5.880115
Kstd	1.332823
Permeability Variation	0.773333



DYKSTRA—PARSONS' PLOT
RUNDLE DALY 12B-4-10-28 W1M
LOG PERMEABILITY
2.6
2.4
2.2
2
1.8
1.6
1.4
1.2
1
0.8
0.6
0.4
0.2
0
-0.2
99.9999 99.9
99.5
94.5
21.2
9.7 5.5
1.1 0.5
0.1 0.0001
PERCENT SAMPLES LESS THAN
ACTUAL DATA
+ CALCULATED
◇ PERM. VAR. = .773

DYKSTRA-PARSONS'

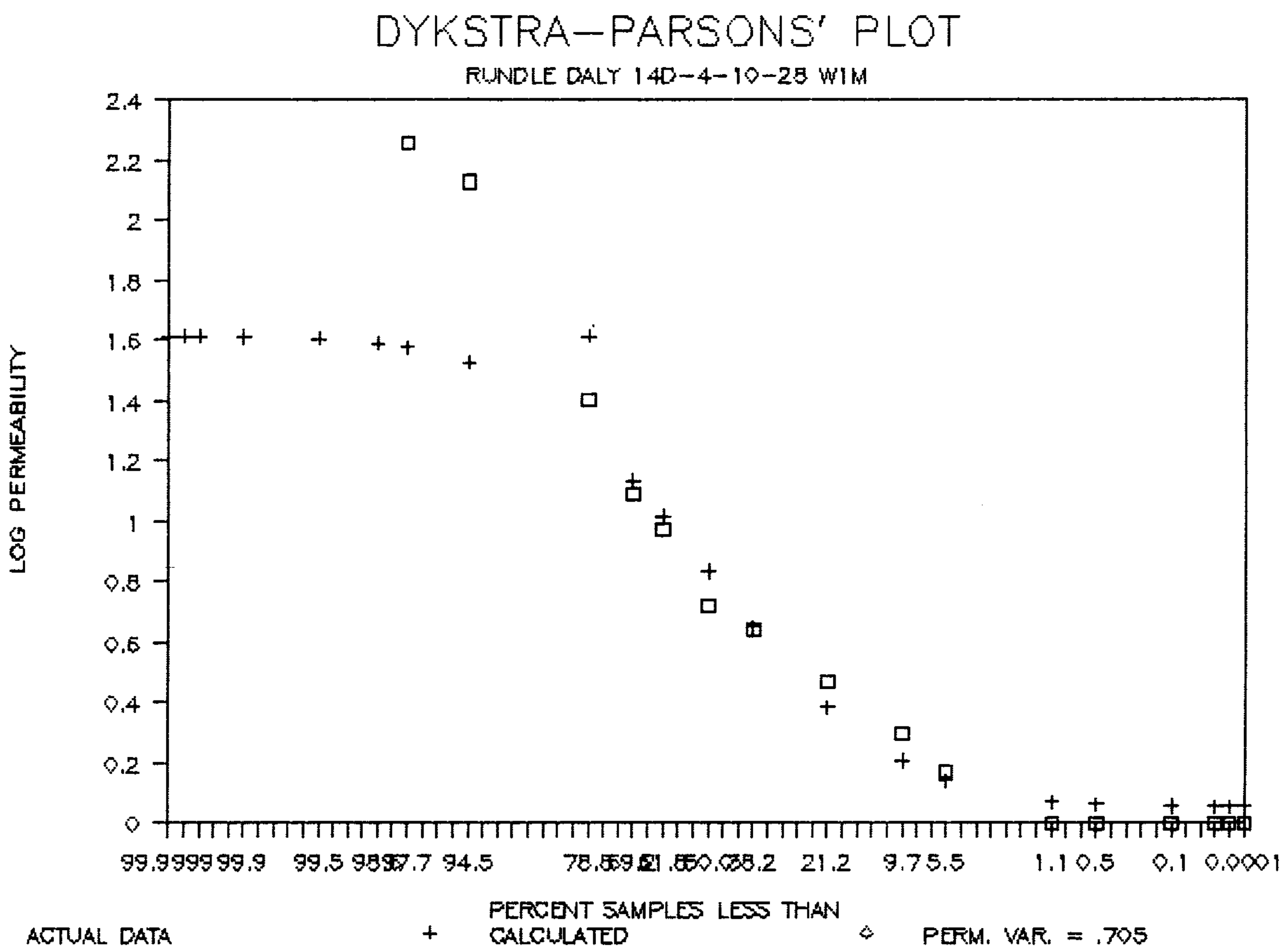
RUNDLE DALY 14D-4-10-28 W1M

Regression Output:

Constant	0.056571
Std Err of Y Est	0.097186
R Squared	0.934975
No. of Observations	6
Degrees of Freedom	4

X Coefficient(s)	1.556044
Std Err of Coef.	0.205177

Kmean	6.832718
Kstd	2.013642
Permeability Variation	0.705294


DYKSTRA—PARSONS' PLOT
RUNDLE DALY 14D-4-10-28 W1M
LOG PERMEABILITY
2.4
2.2
2
1.8
1.6
1.4
1.2
1
0.8
0.6
0.4
0.2
0
99.9999 99.9
99.5
94.5
21.2
9.7 5.5
1.1 0.5
0.1
0.0001
PERCENT SAMPLES LESS THAN
ACTUAL DATA
+ CALCULATED
◇ PERM. VAR. = .705

DYKSTRA-PARSONS'

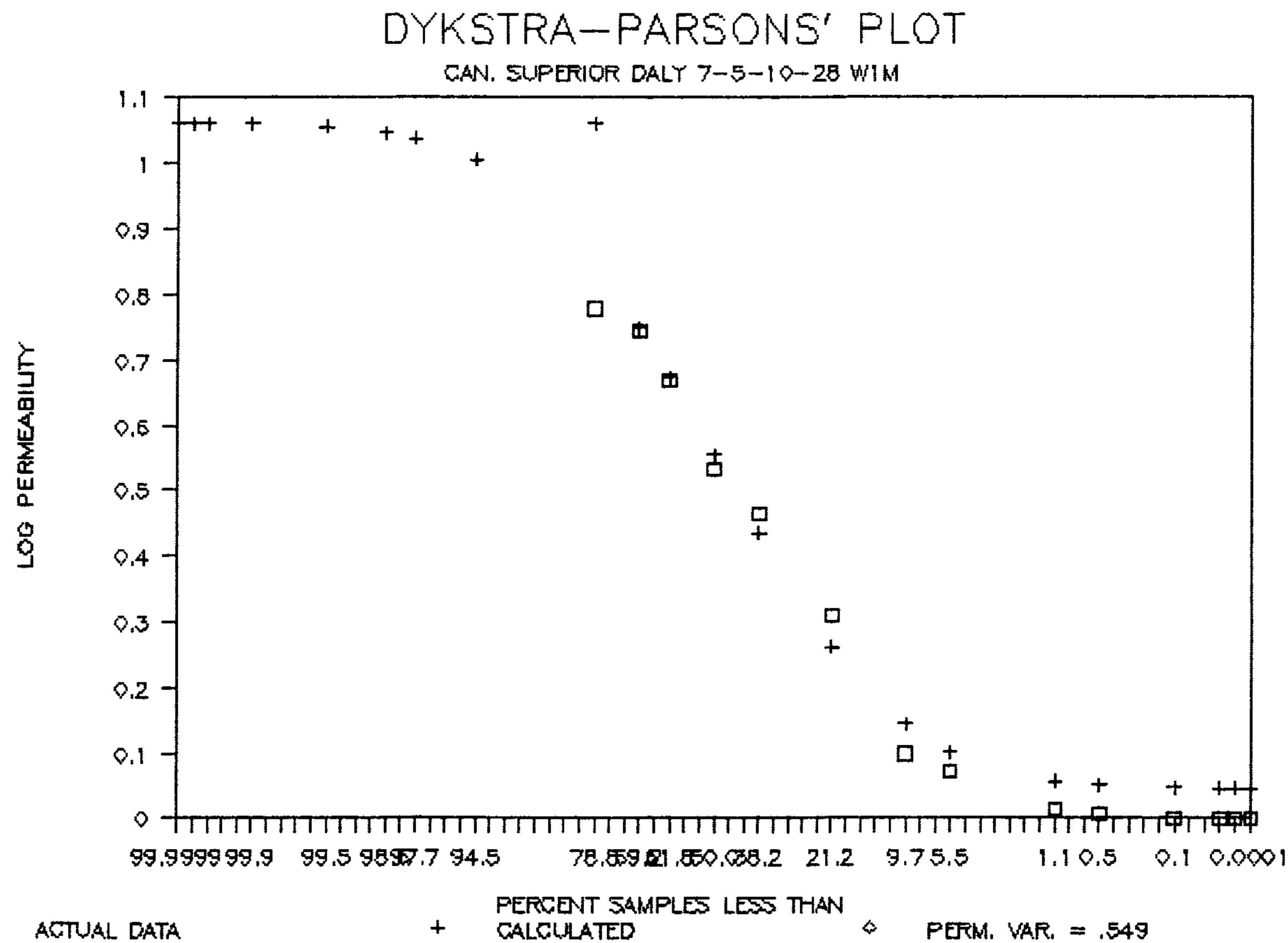
CAN. SUPERIOR DALY 7-5-10-28 W1M

Regression Output:

Constant	0.045887
Std Err of Y Est	0.037614
R Squared	0.979955
No. of Observations	6
Degrees of Freedom	4

X Coefficient(s)	1.015292
Std Err of Coef.	0.072602

Kmean	3.577118
Kstd	1.611827
Permeability Variation	0.549406


DYKSTRA—PARSONS' PLOT
CAN. SUPERIOR DALY 7-5-10-28 W1M
LOG PERMEABILITY
1.1
1
0.9
0.8
0.7
0.6
0.5
0.4
0.3
0.2
0.1
0
99.9999
99.9
99.5
94.5
21.2
9.7
5.5
1.1
0.5
0.1
0.0001
PERCENT SAMPLES LESS THAN
ACTUAL DATA
CALCULATED
PERM. VAR. = .549

DYKSTRA-PARSONS'

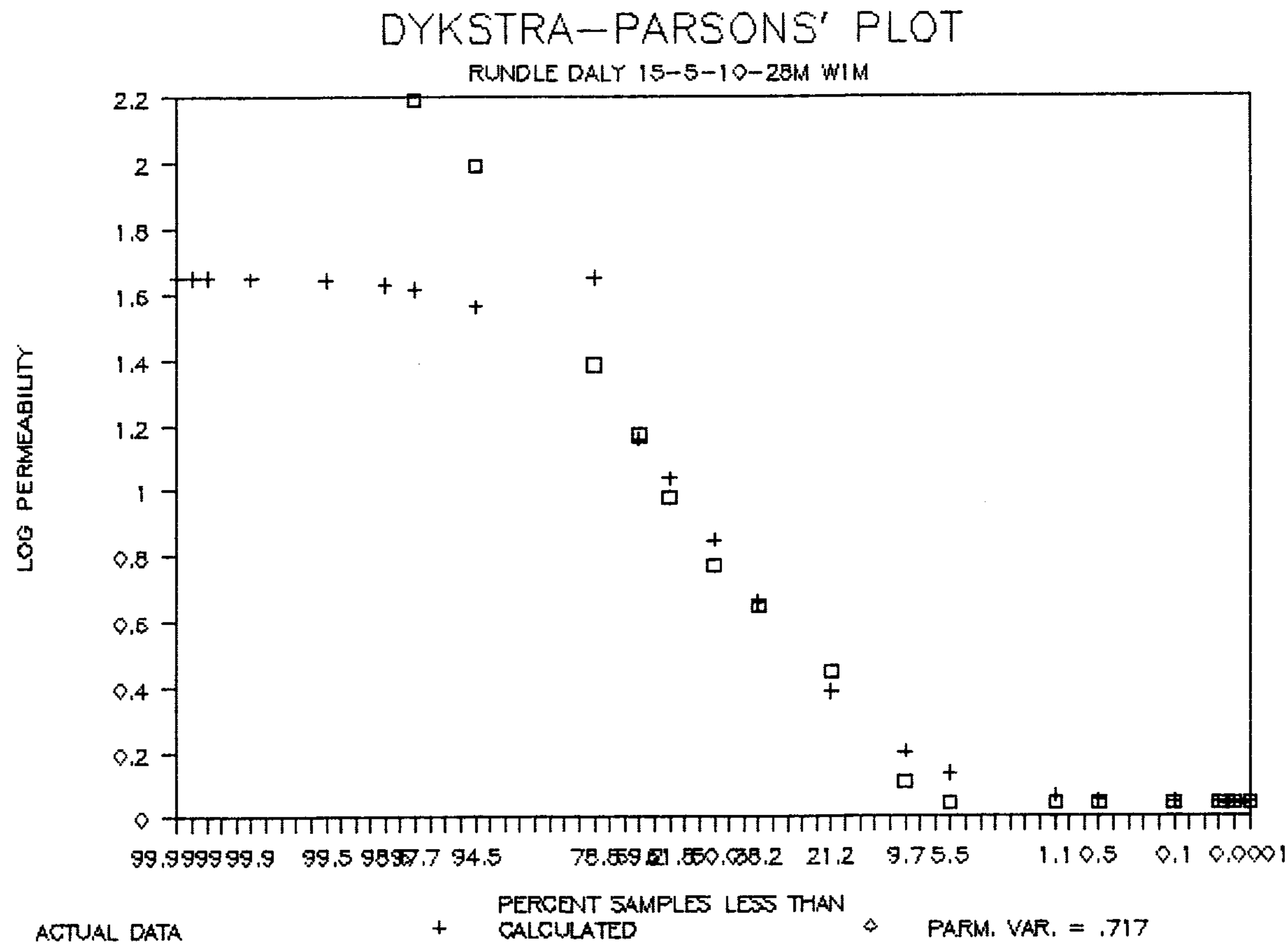
RUNDLE DALY 15-5-10-28 W1M

Regression Output:

Constant	0.044004
Std Err of Y Est	0.069579
R Squared	0.967634
No. of Observations	6
Degrees of Freedom	4

X Coefficient(s)	1.606369
Std Err of Coef.	0.146893

Kmean	7.033792
Kstd	1.992587
Permeability Variation	0.716712


DYKSTRA—PARSONS' PLOT
RUNDLE DALY 15-5-10-28M WIM
LOG PERMEABILITY
2.2
2
1.8
1.6
1.4
1.2
1
0.8
0.6
0.4
0.2
0
21.2
9.7
5.5
1.1
0.5
0.1
0.0001
PERCENT SAMPLES LESS THAN
ACTUAL DATA
+ CALCULATED
◇ PARM. VAR. = .717

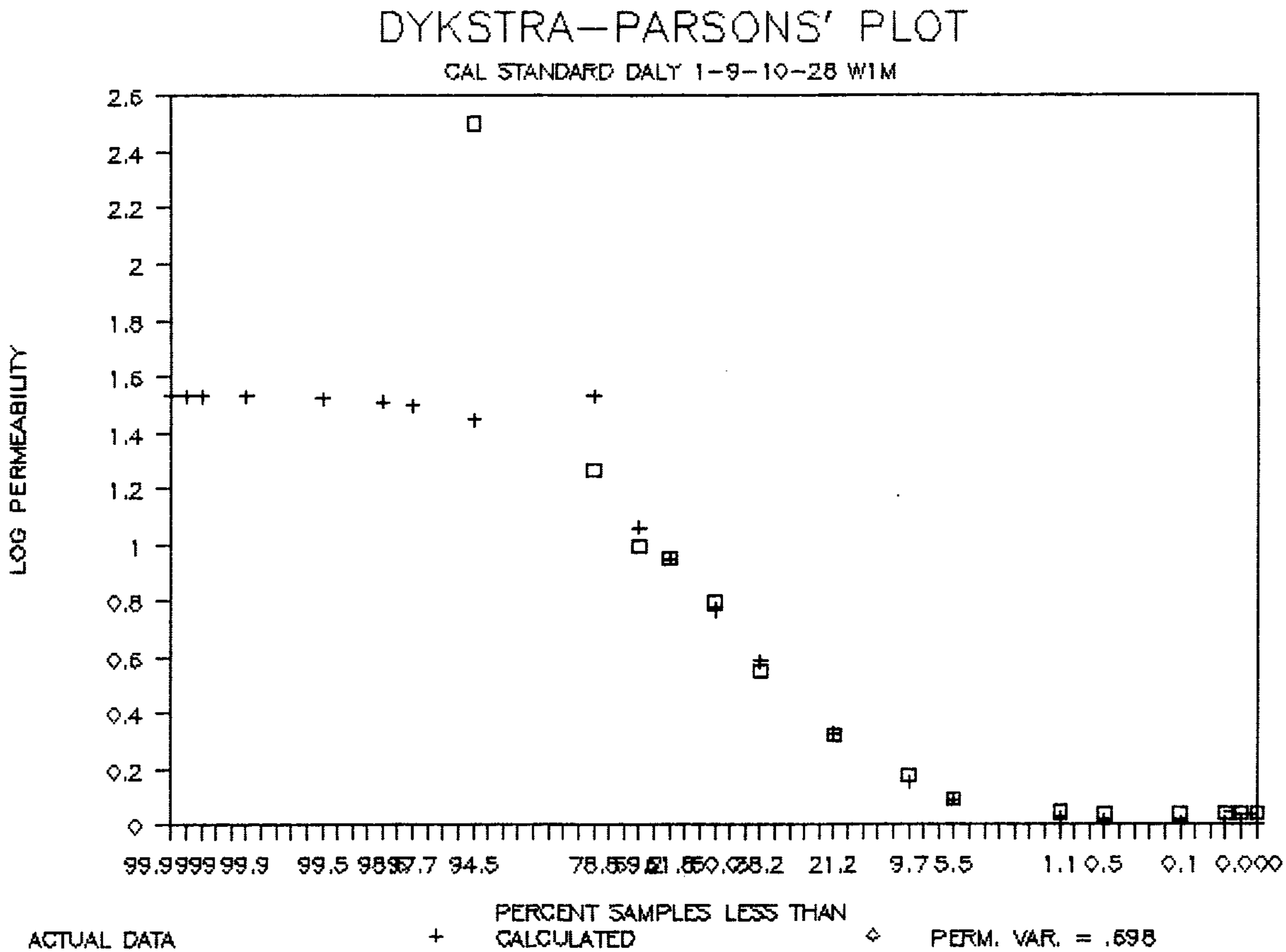
DYKSTRA-PARSONS'

CAL STANDARD DALY 1-9-10-28 W1M

Regression Output:	
Constant	0.006996
Std Err of Y Est	0.046597
R Squared	0.988053
No. of Observations	7
Degrees of Freedom	5

X Coefficient(s)	1.523931
Std Err of Coef.	0.074938

Kmean	5.874377
Kstd	1.775420
Permeability Variation	0.697768


DYKSTRA—PARSONS' PLOT
CAL STANDARD DALY 1-9-10-28 W1M
LOG PERMEABILITY
2.6
2.4
2.2
2
1.8
1.6
1.4
1.2
1
0.8
0.6
0.4
0.2
0
99.9999 99.9 99.5 98 97.7 94.5 21.2 9.7 5.5 1.1 0.5 0.1 0.0001
PERCENT SAMPLES LESS THAN
ACTUAL DATA
+ CALCULATED
◇ PERM. VAR. = .698

DYKSTRA-PARSONS'

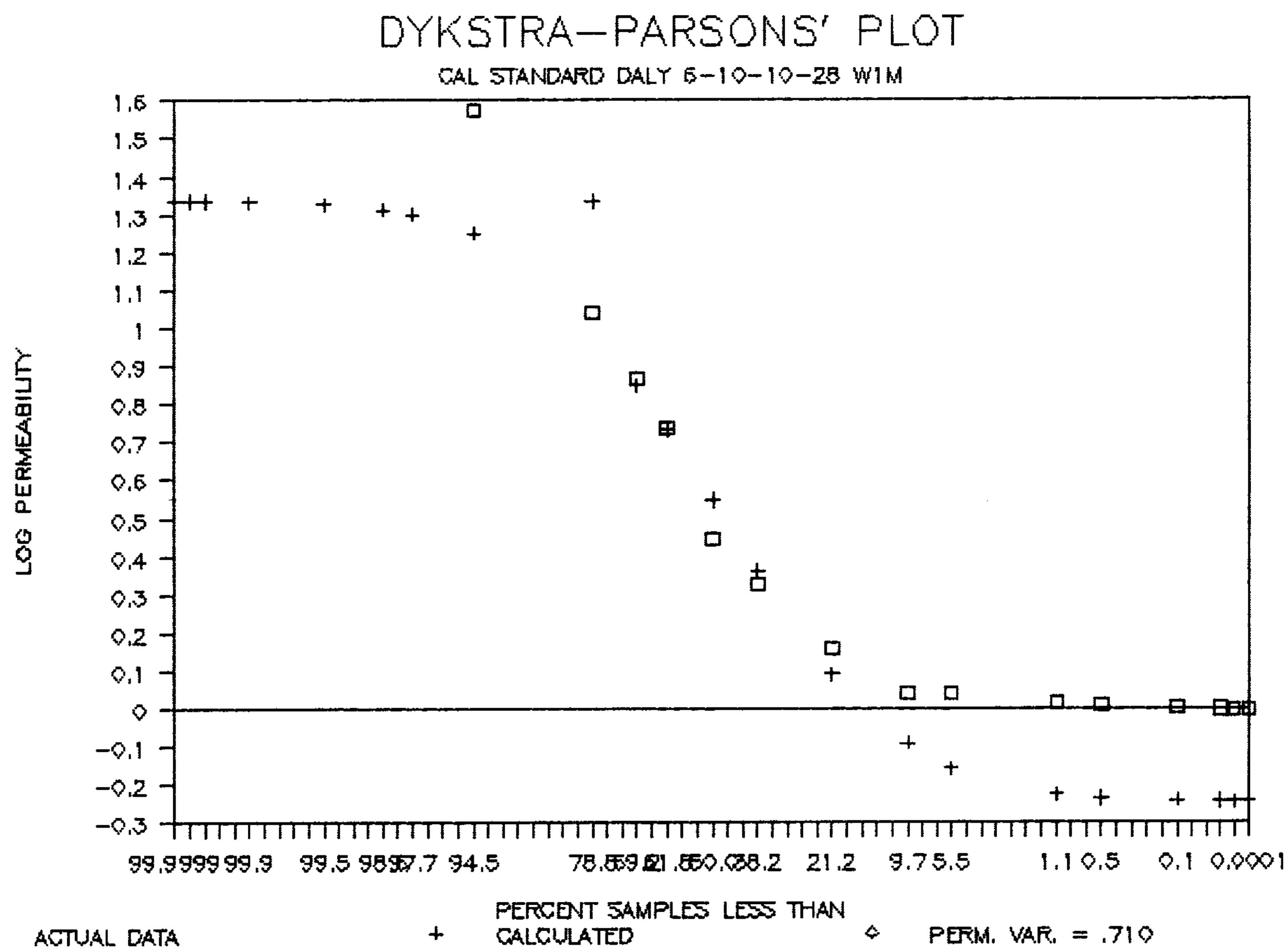
CAL STANDARD DALY 6-10-10-28 W1M

Regression Output:

Constant	-0.24211
Std Err of Y Est	0.066548
R Squared	0.969279
No. of Observations	6
Degrees of Freedom	4

X Coefficient(s)	1.578330
Std Err of Coef.	0.140494

Kmean	3.524141
Kstd	1.020569
Permeability Variation	0.710406

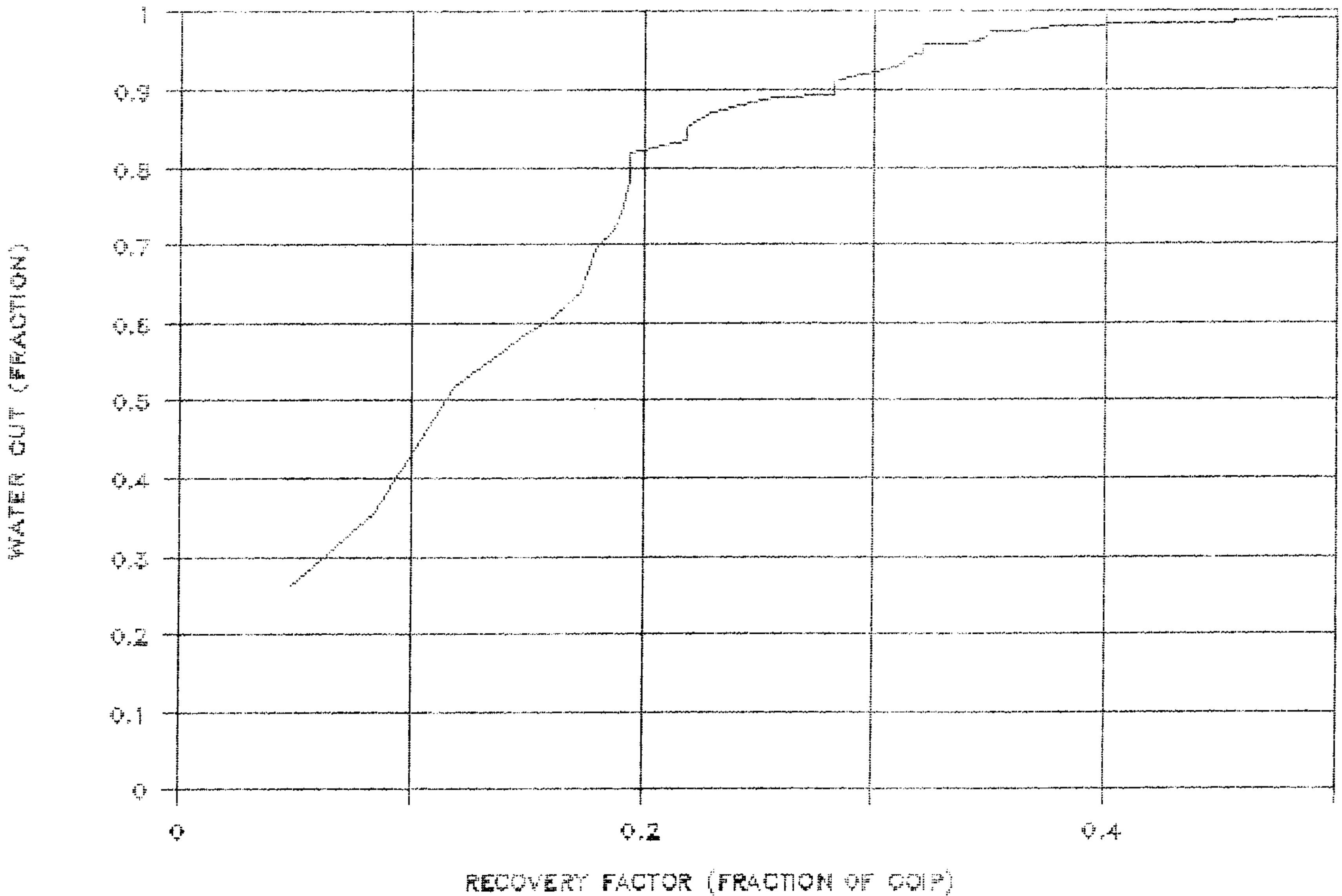

DYKSTRA—PARSONS' PLOT
CAL STANDARD DALY 6-10-10-28 W1M
LOG PERMEABILITY
1.6
1.5
1.4
1.3
1.2
1.1
1
0.9
0.8
0.7
0.6
0.5
0.4
0.3
0.2
0.1
0
-0.1
-0.2
-0.3
99.9999 99.9
99.5
94.5
21.2
1.1 0.5
0.1 0.0001
PERCENT SAMPLES LESS THAN
ACTUAL DATA
+ CALCULATED
◇ PERM. VAR. = .710

APPENDIX 3

STILES WATERFLOOD PLOTS

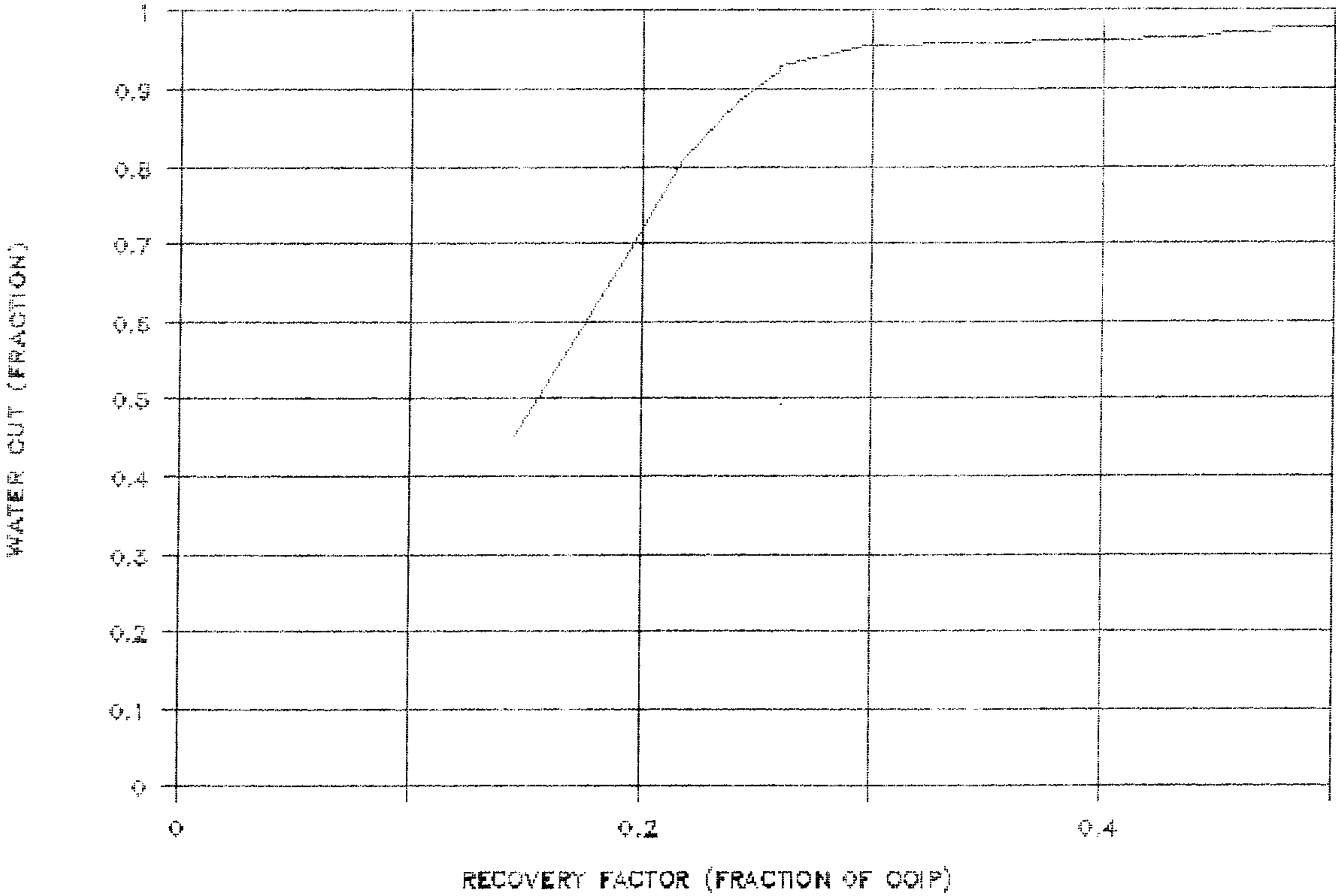
STILES WATERFLOOD CALCULATION

CAN SUP THOMSON DALY 9-32-9-29 W1M



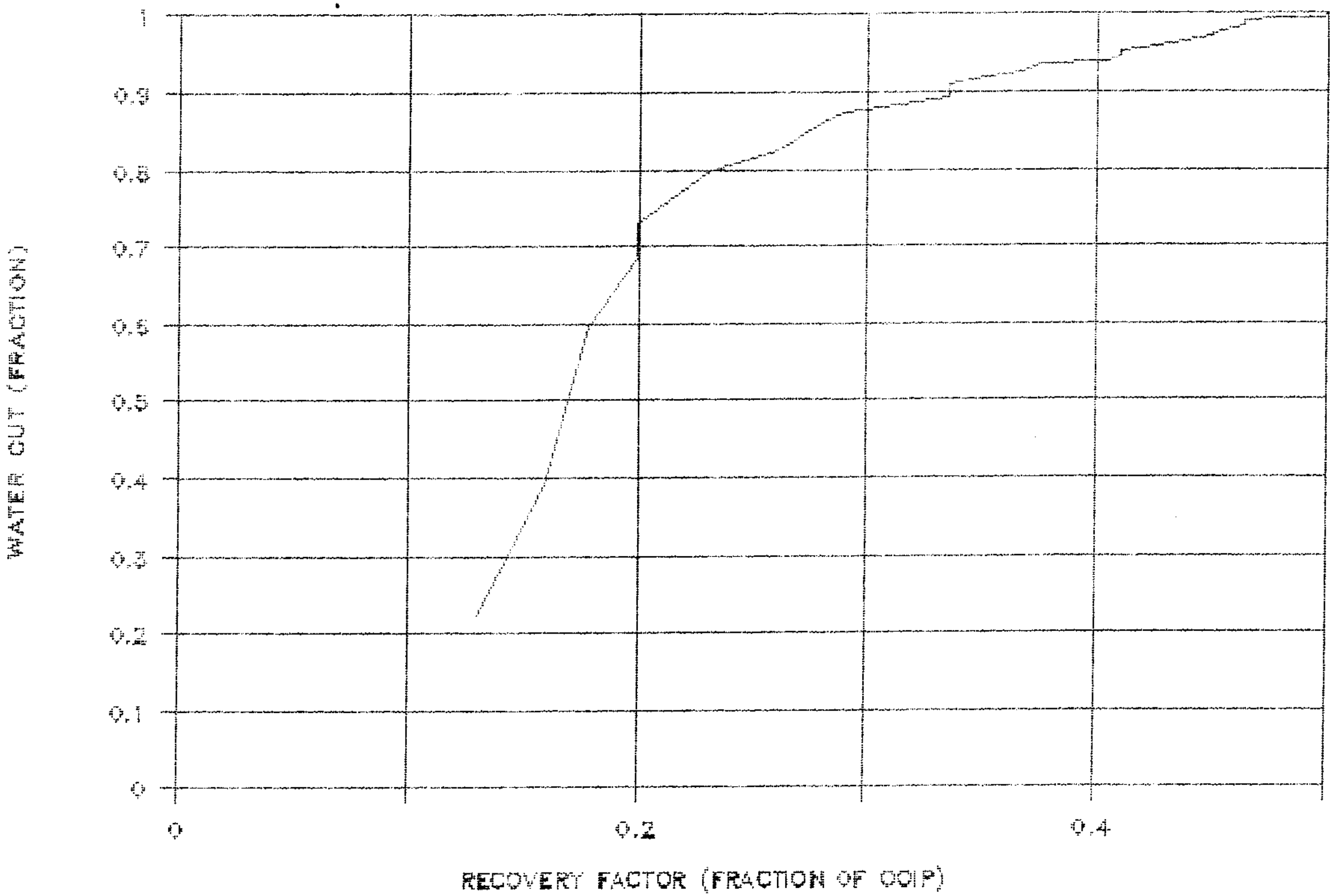
STILES WATERFLOOD CALCULATION

CAL. STAN DALY 11-32-9-28 W1M



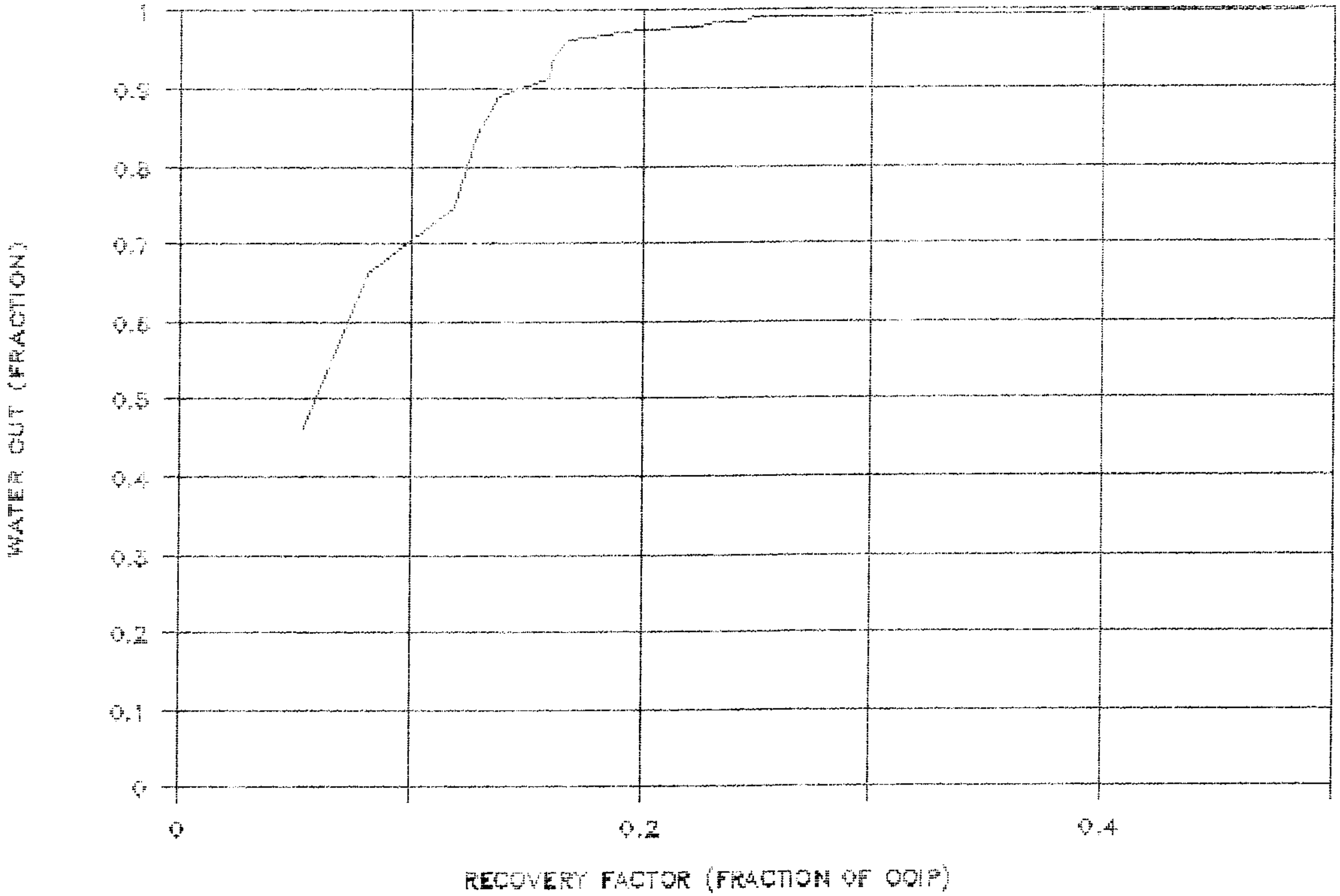
STILES WATERFLOOD CALCULATION

CAN. TEX. DALY 16-33-10-28 W1M



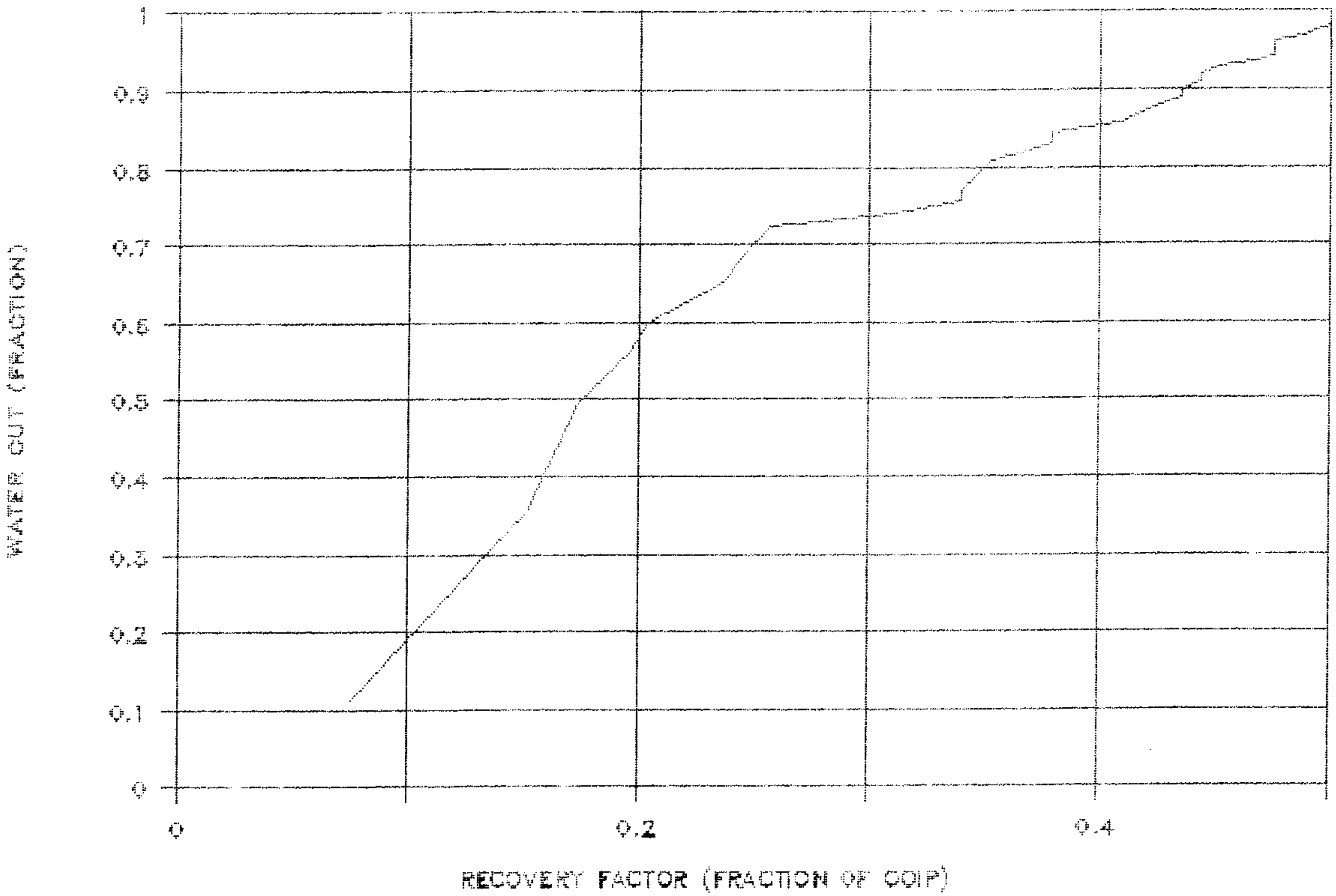
STILES WATERFLOOD CALCULATION

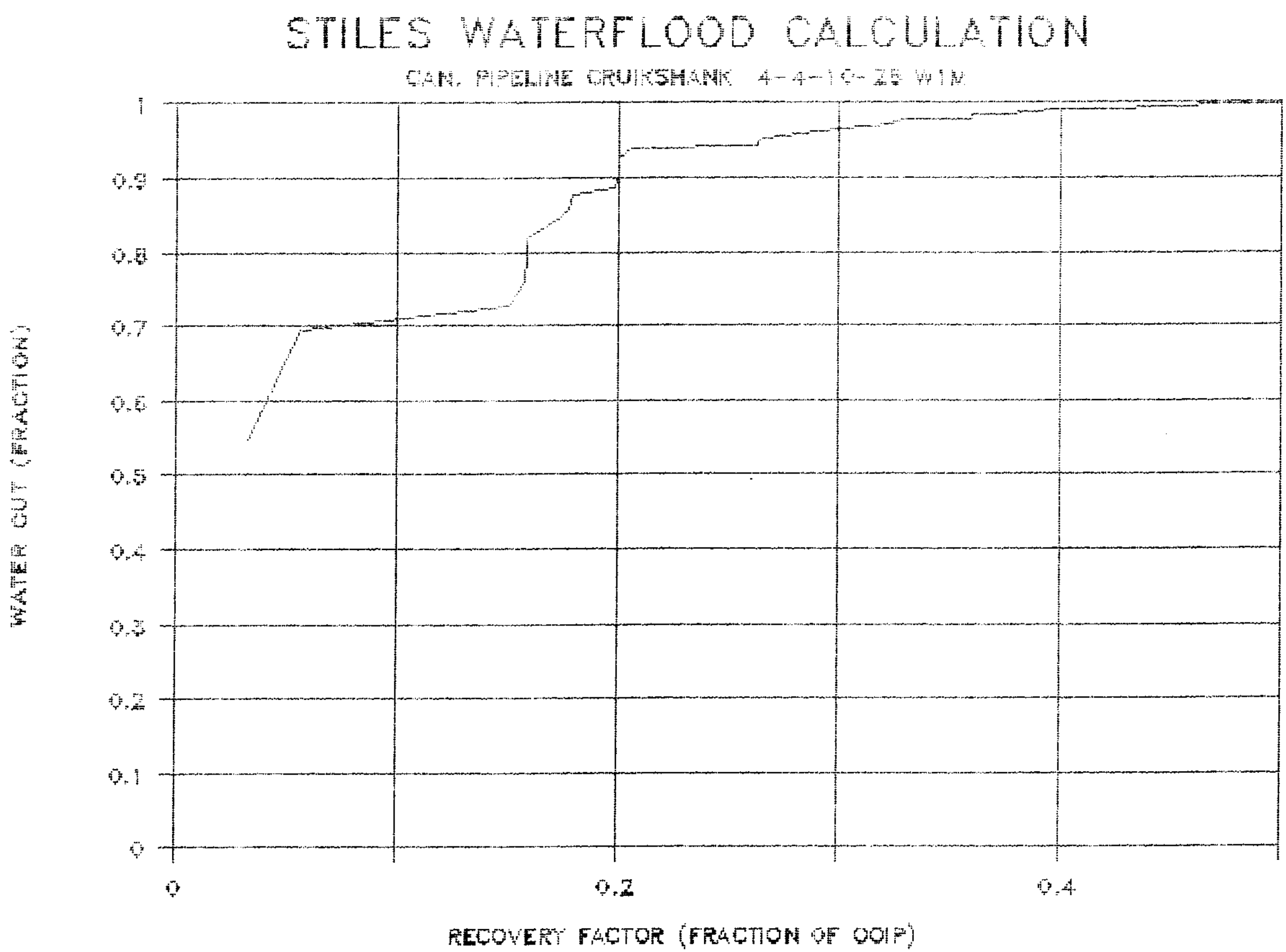
CAL. STD. DALY 12-3-19-28 W1M



STILES WATERFLOOD CALCULATION

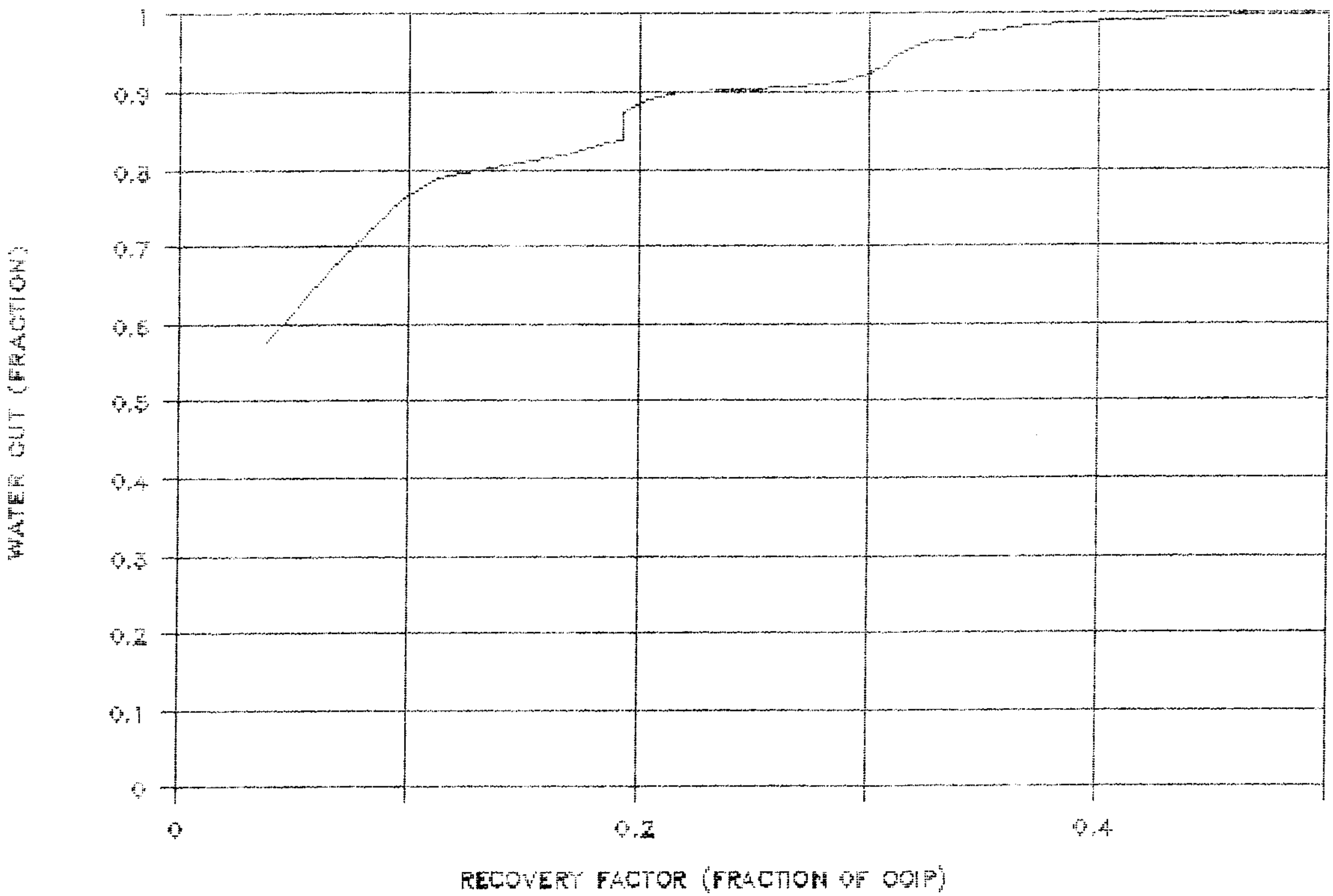
BASCO CRUIKSHANK 2-4-10-28 W1M

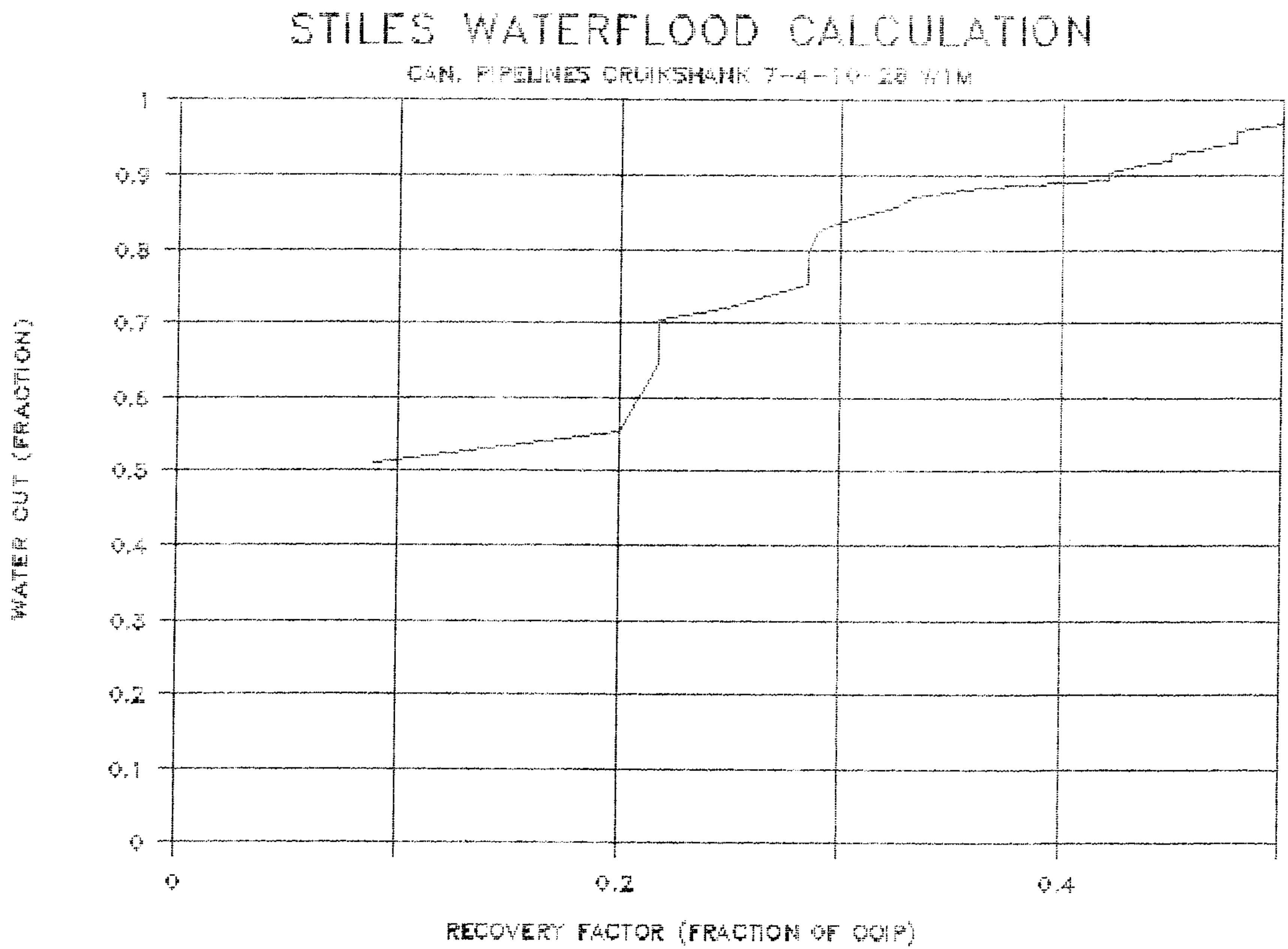



STILES WATERFLOOD CALCULATION
CAN. PIPELINE CRUIKSHANK 4-4-10-25 W1M
WATER CUT (FRACTION)
RECOVERY FACTOR (FRACTION OF OOIP)
0
0.1
0.2
0.3
0.4
0.5
0.6
0.7
0.8
0.9
1
0.2
0.4

STILES WATERFLOOD CALCULATION

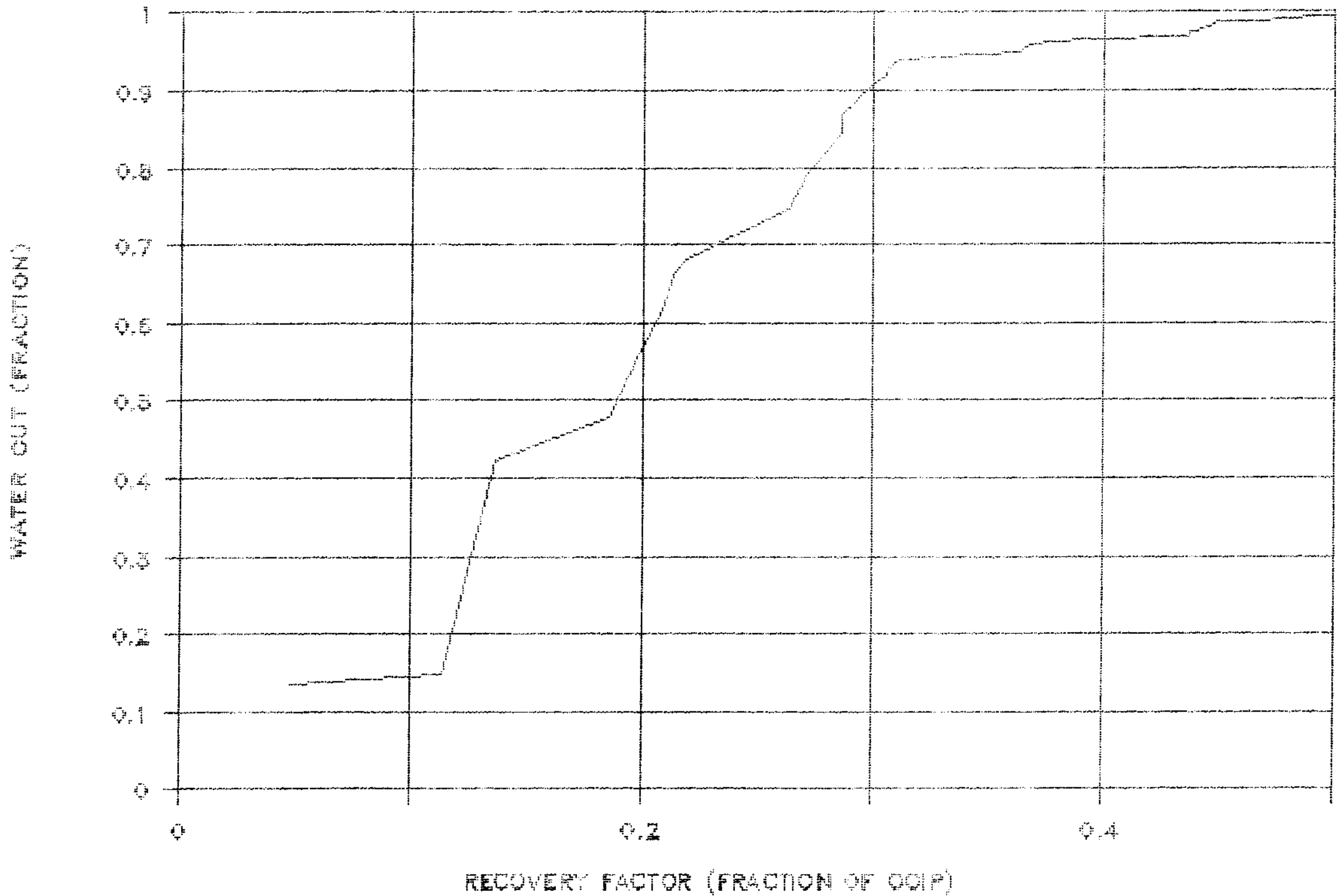
CAN. PIPELINES CRUIKSHANK 5-4-10-28 W1M




STILES WATERFLOOD CALCULATION
CAN. PIPELINES CRUIKSHANK 7-4-10-28 W1M
WATER CUT (FRACTION)
1
0.9
0.8
0.7
0.6
0.5
0.4
0.3
0.2
0.1
0
0
0.2
0.4
RECOVERY FACTOR (FRACTION OF OOIP)

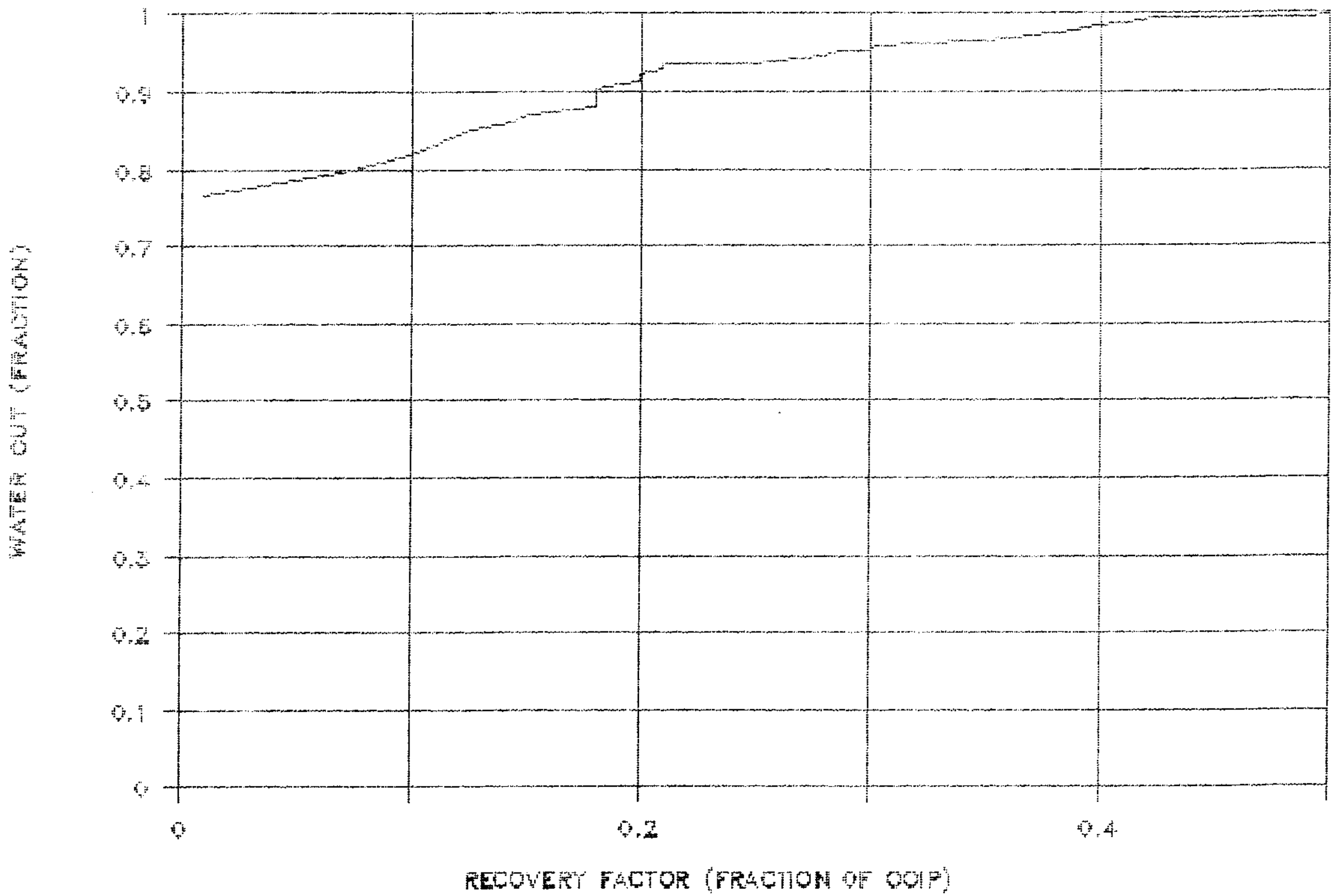
STILES WATERFLOOD CALCULATION

CAL STANDARD DALY 10-4-10-28 WIM



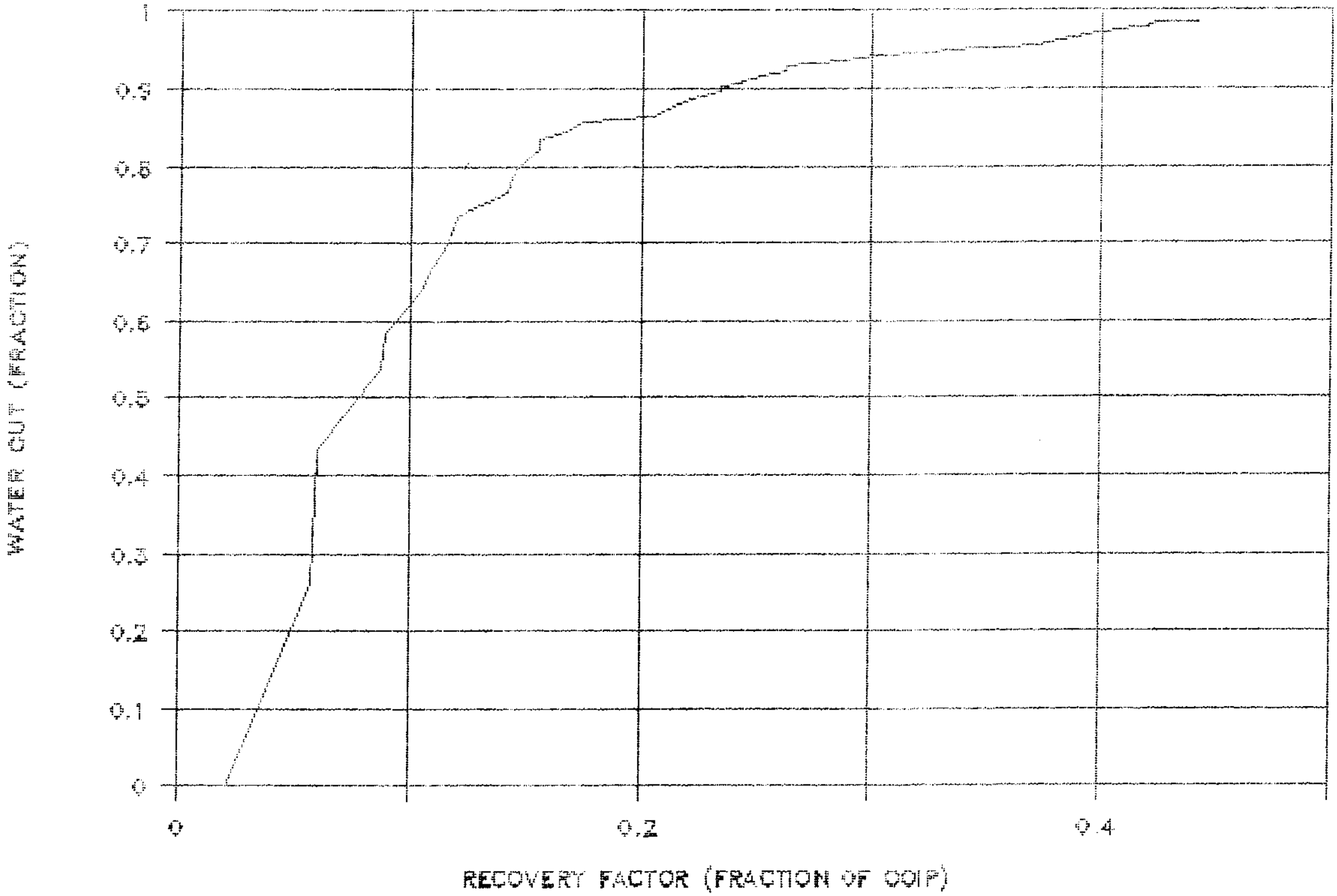
STILES WATERFLOOD CALCULATION

CAN. SUPERIOR CRIUKSHANK 11-4-19-23 W4M



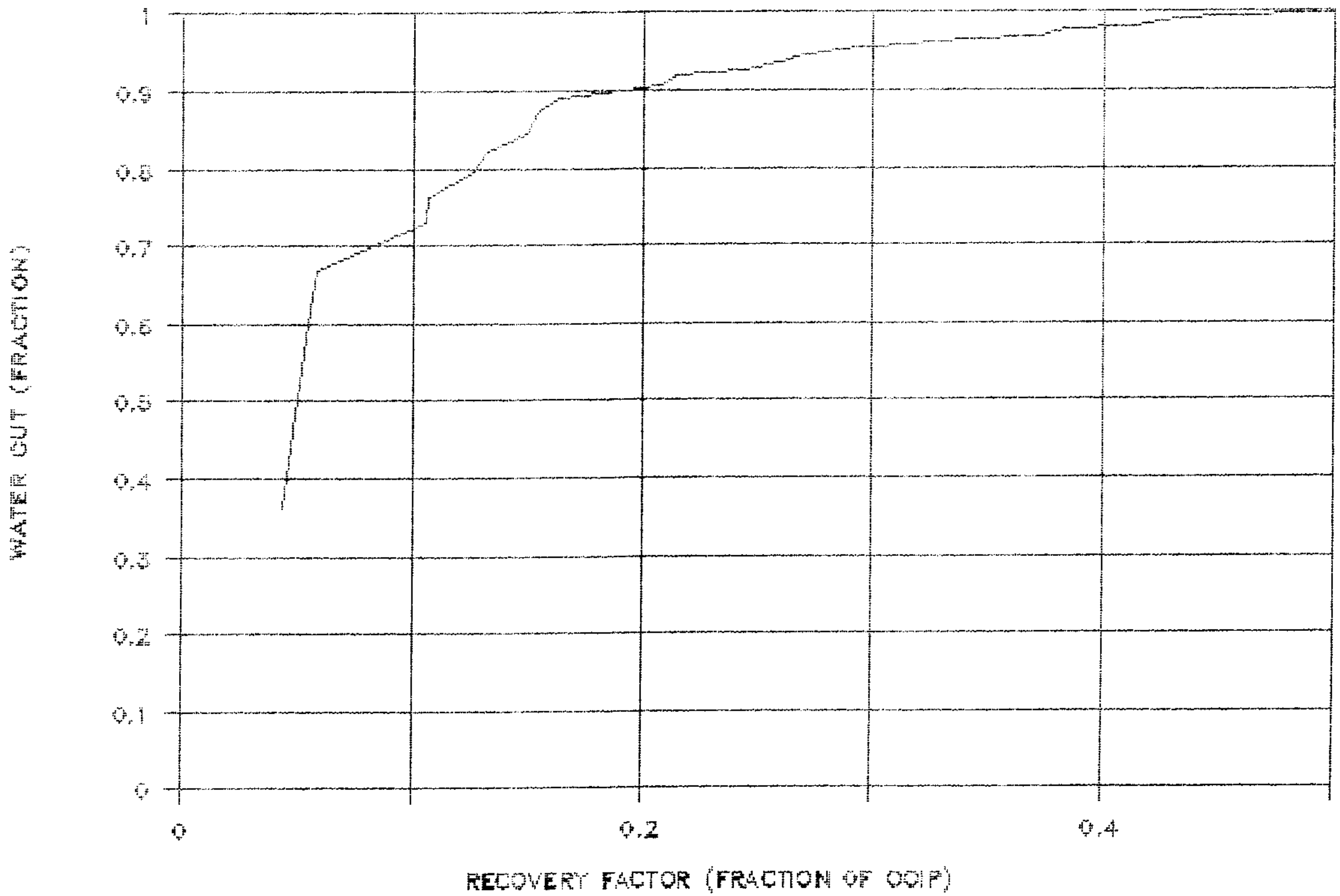
STILES WATERFLOOD CALCULATION

RUNDLE DALY 12B-4-10-28 W1M



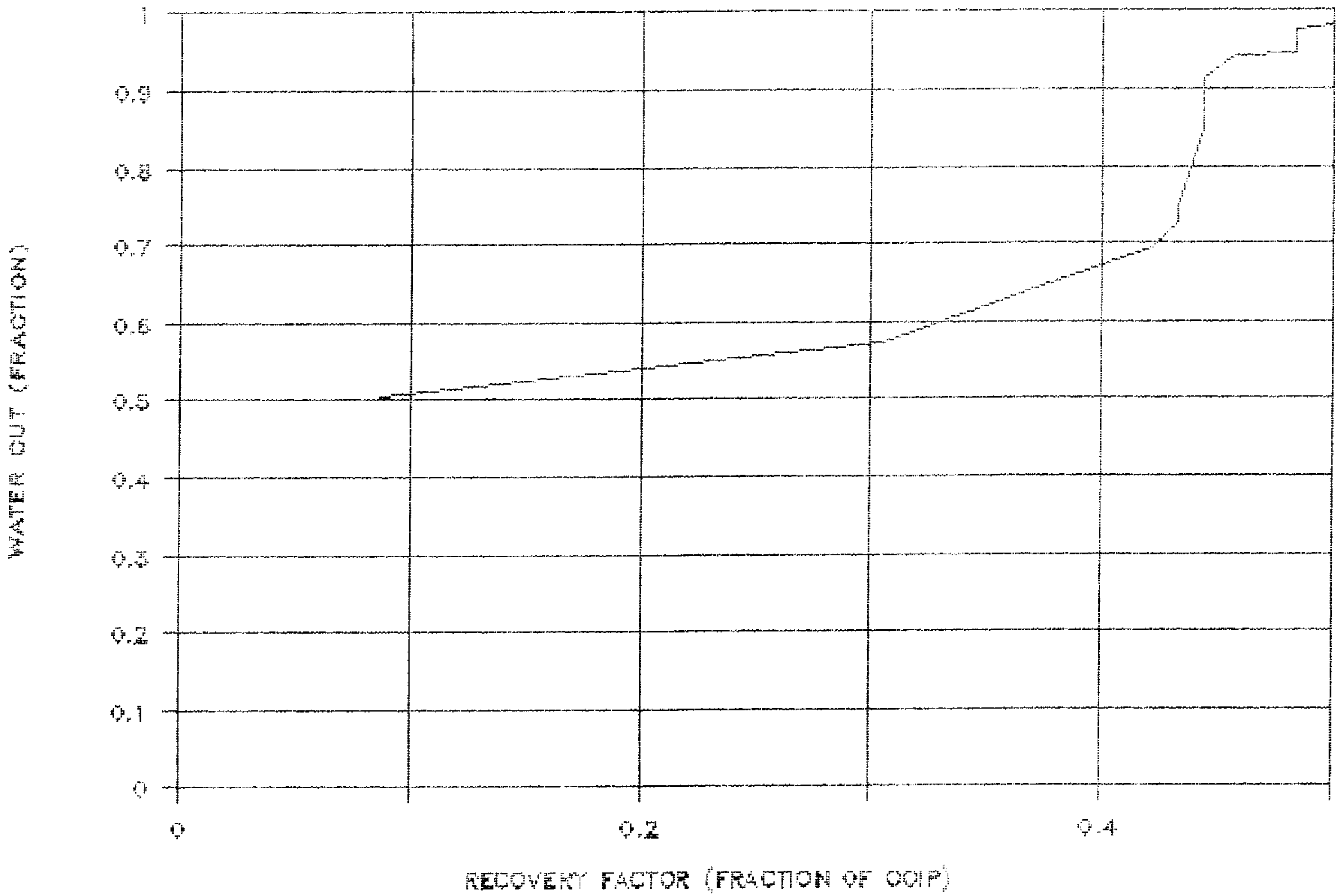
STILES WATERFLOOD CALCULATION

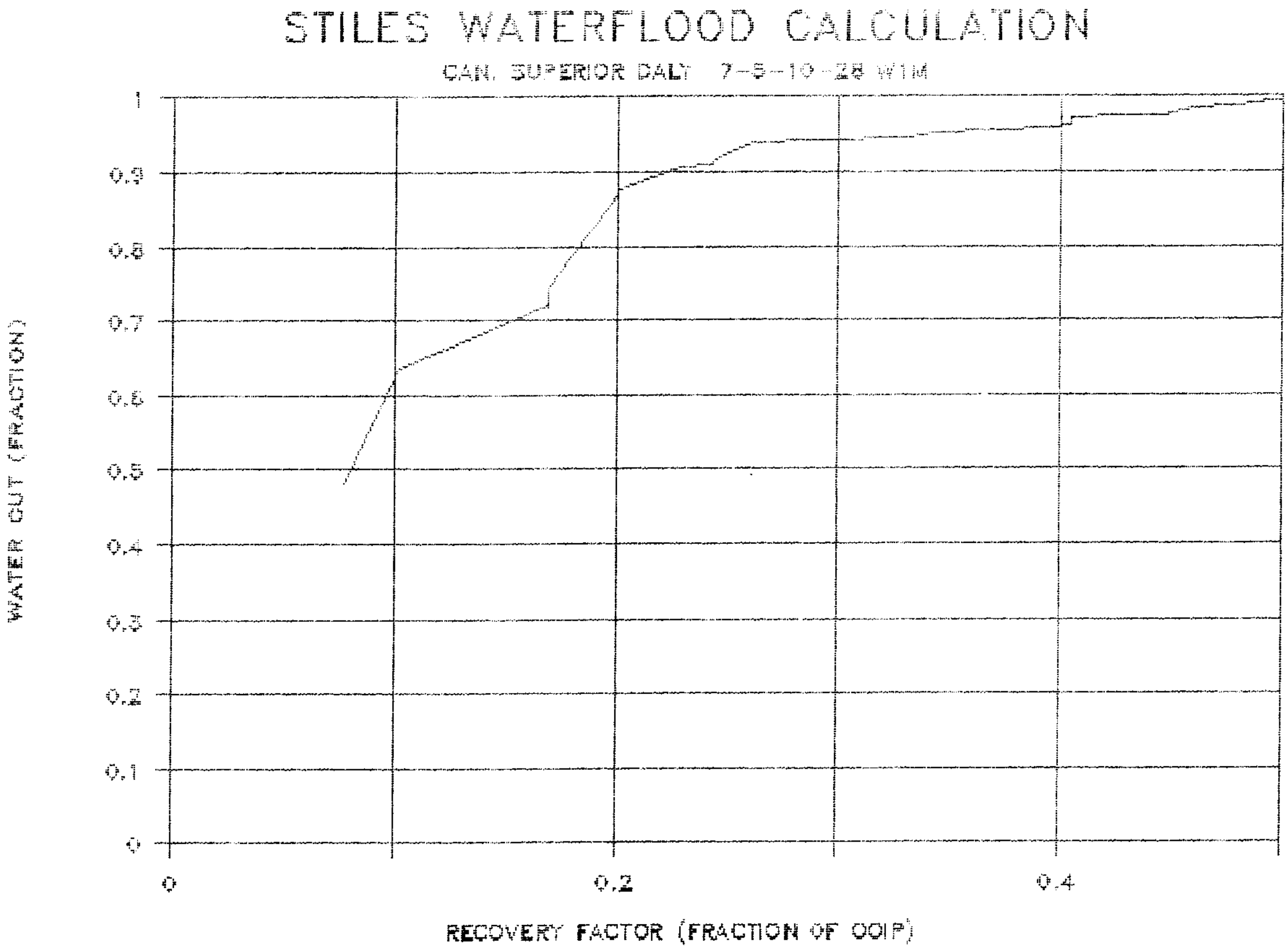
RUNDLE DALY 14D-4-10-28 W1M



STILES WATERFLOOD CALCULATION

CAN. SUPERIOR GRIEVE 4-5-10-25 W1M

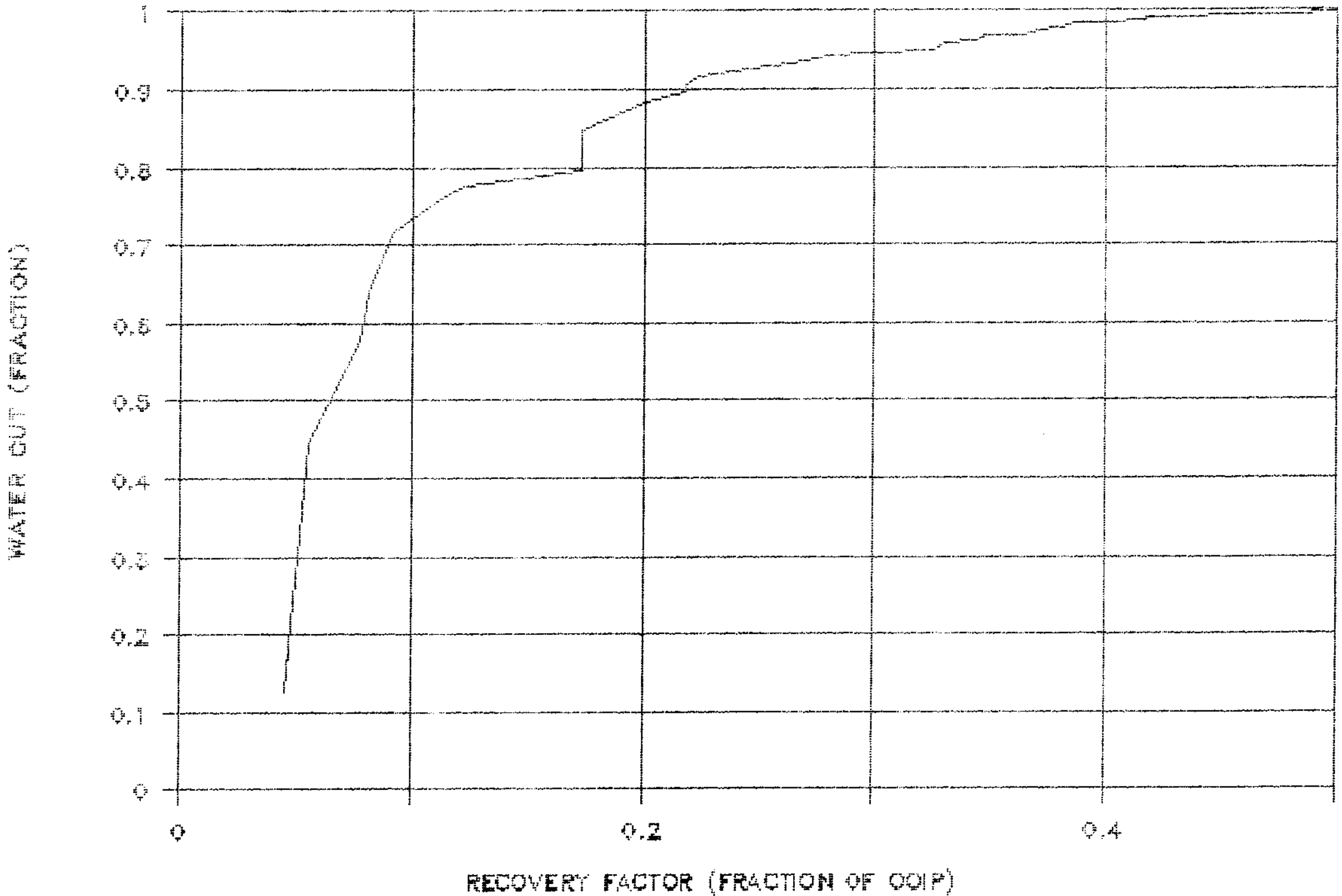




STILES WATERFLOOD CALCULATION
CAN. SUPERIOR DALY 7-5-10-28 W1M
WATER CUT (FRACTION)
1
0.9
0.8
0.7
0.6
0.5
0.4
0.3
0.2
0.1
0
0
0.2
0.4
RECOVERY FACTOR (FRACTION OF OOIP)

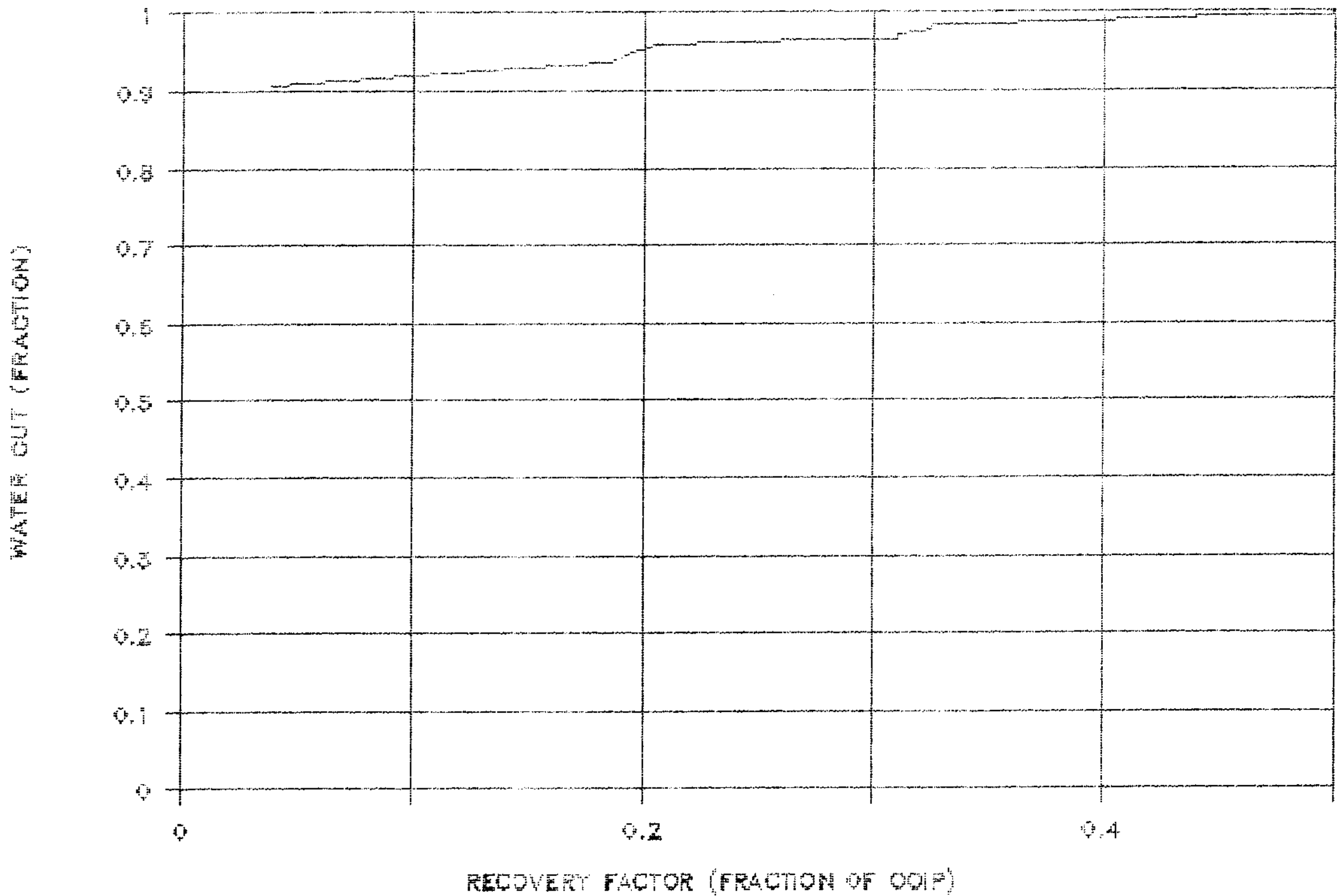
STILES WATERFLOOD CALCULATION

RUNDLE DALY 15-5-10-28 W1M



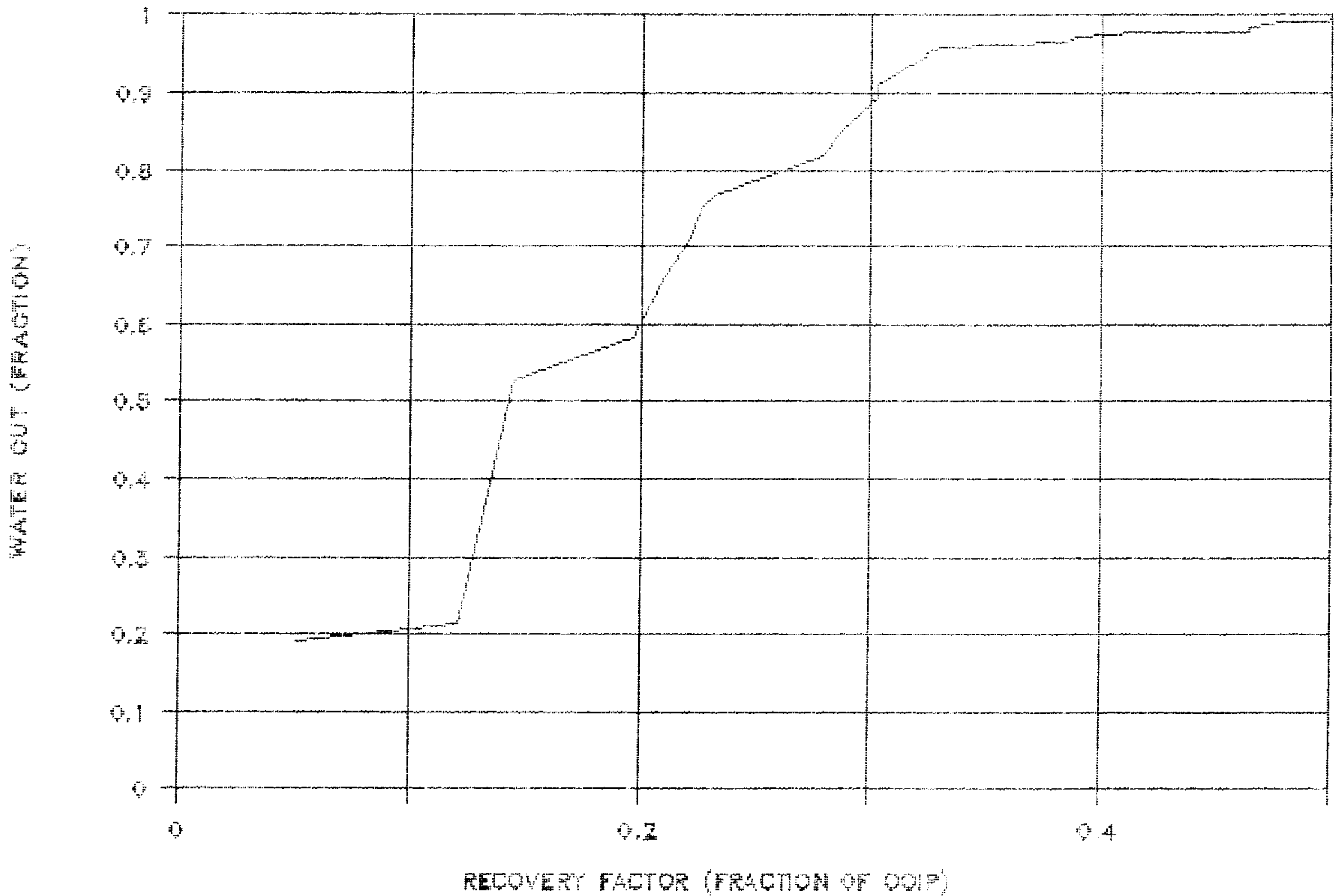
STILES WATERFLOOD CALCULATION

CAL STANDARD DALY 1-9-10-28 W1M



STILES WATERFLOOD CALCULATION

CAL STANDARD DALY 6-10-10-28 WIM



APPENDIX 4

DETAILED GEOLOGICAL MAPS

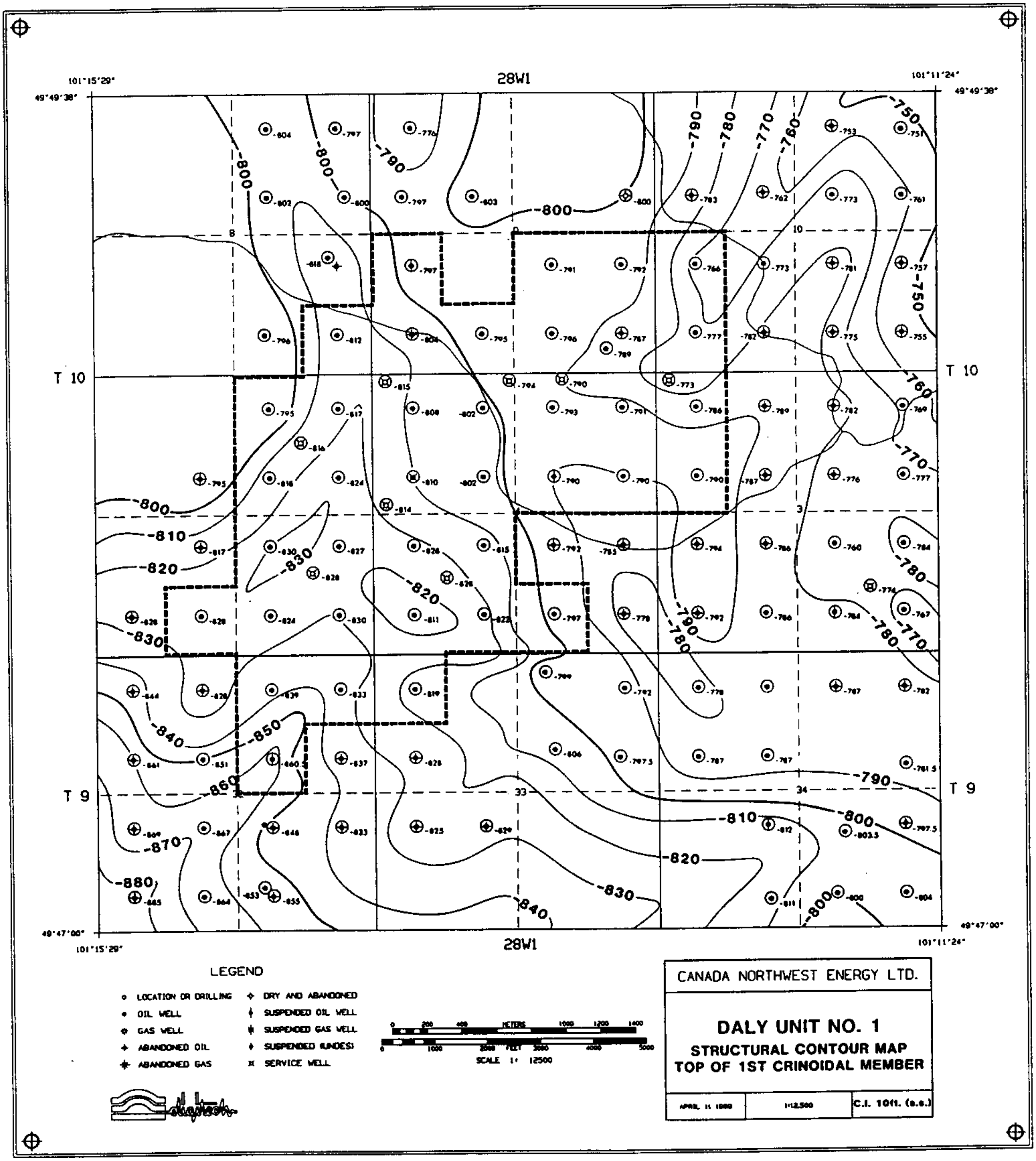

28W1
T 10
T 9
LEGEND
LOCATION OR DRILLING
OIL WELL
GAS WELL
ABANDONED OIL
ABANDONED GAS
DRY AND ABANDONED
SUSPENDED OIL WELL
SUSPENDED GAS WELL
SUSPENDED (UNDES)
SERVICE WELL
SCALE 1: 12500
CANADA NORTHWEST ENERGY LTD.
DALY UNIT NO. 1
STRUCTURAL CONTOUR MAP
TOP OF 1ST CRINOIDAL MEMBER
C.I. 10ft. (s.s.)

Figure A4-1

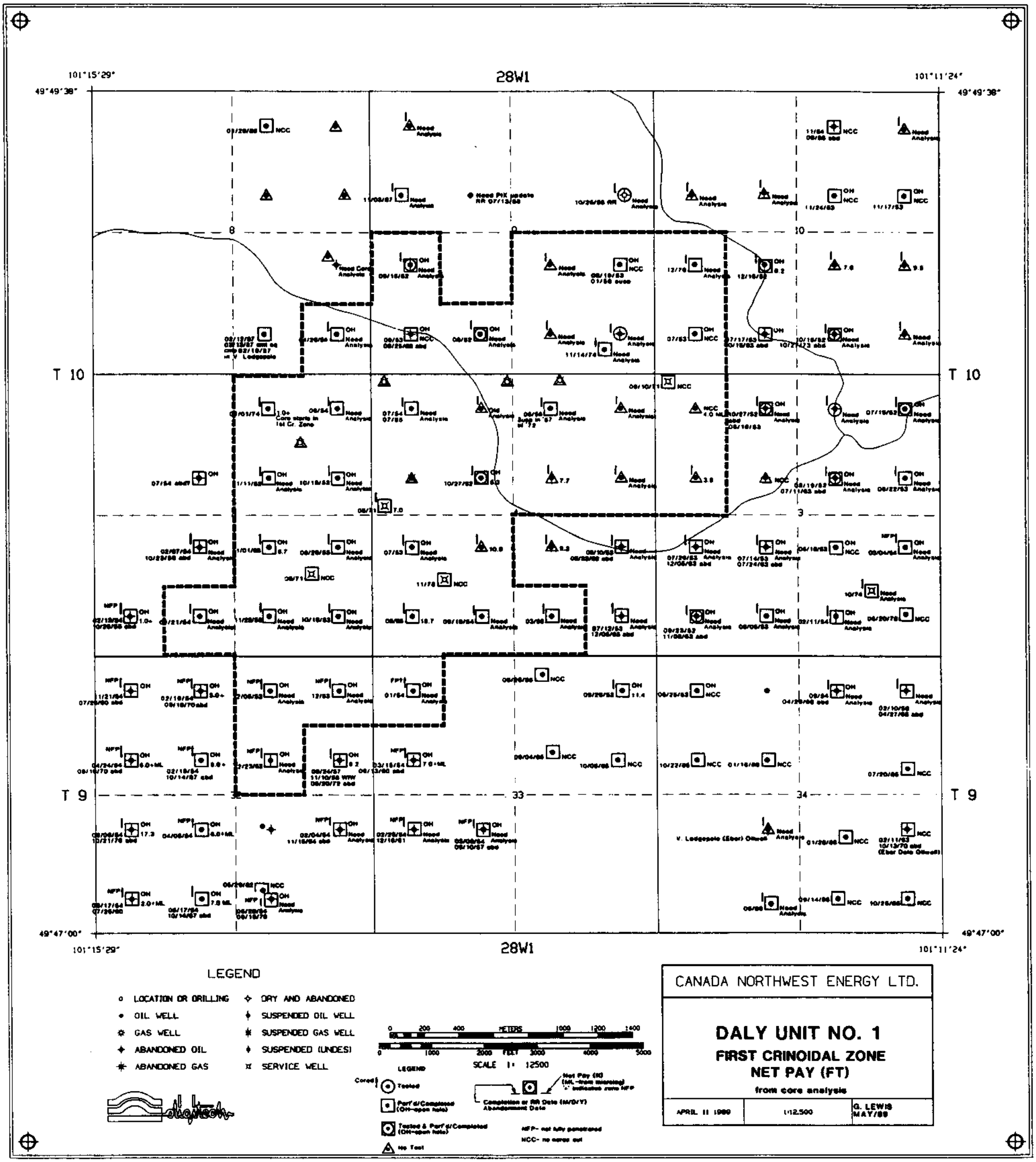

28W1
T 10
T 9
LEGEND
LOCATION OR DRILLING
OIL WELL
GAS WELL
ABANDONED OIL
ABANDONED GAS
DRY AND ABANDONED
SUSPENDED OIL WELL
SUSPENDED GAS WELL
SUSPENDED (UNDES)
SERVICE WELL
SCALE 1: 12500
CANADA NORTHWEST ENERGY LTD.
DALY UNIT NO. 1
FIRST CRINOIDAL ZONE
NET PAY (FT)
from core analysis
APRIL 11 1989
1:12,500
G. LEWIS
MAY/89

Figure A4-2

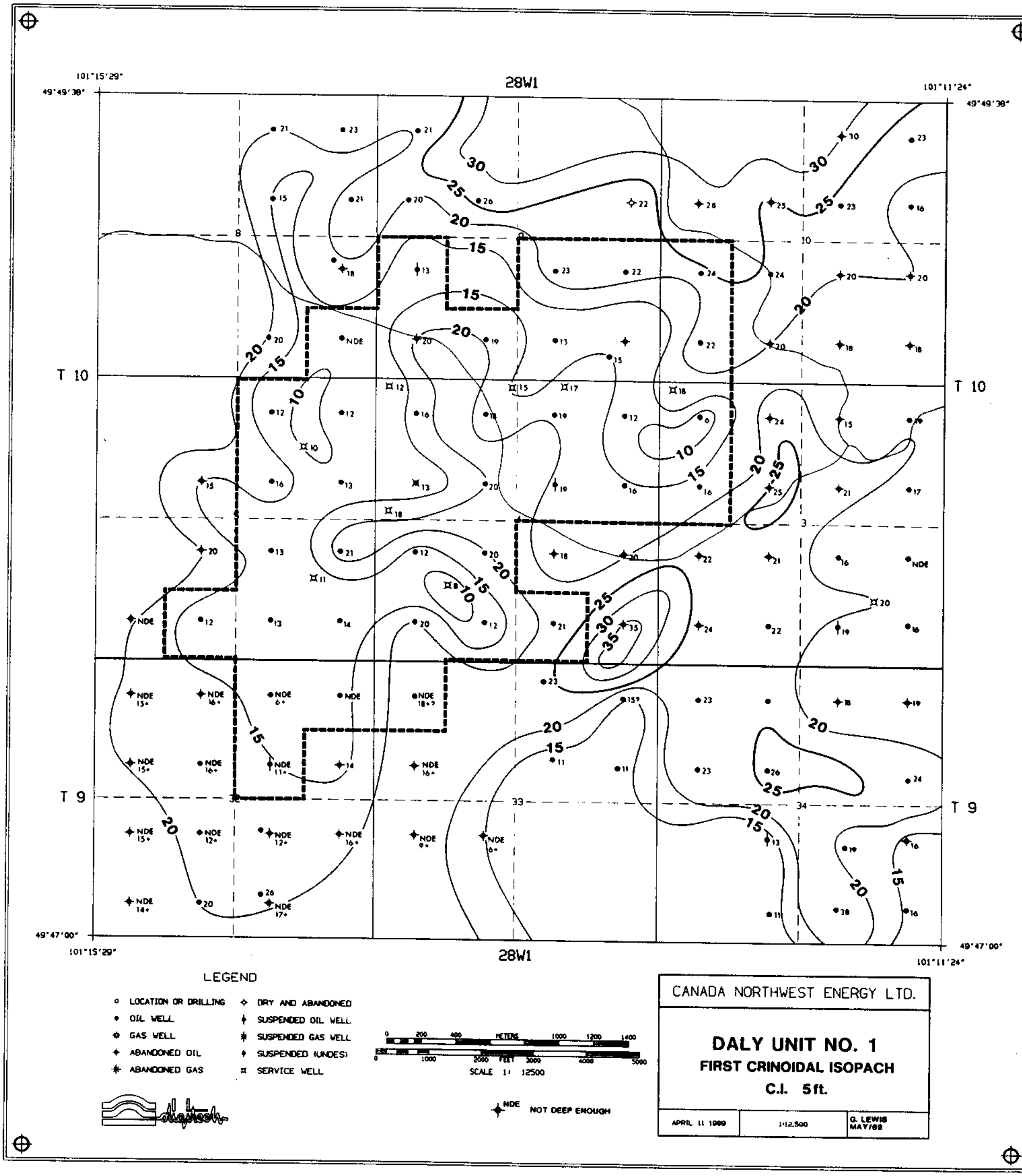
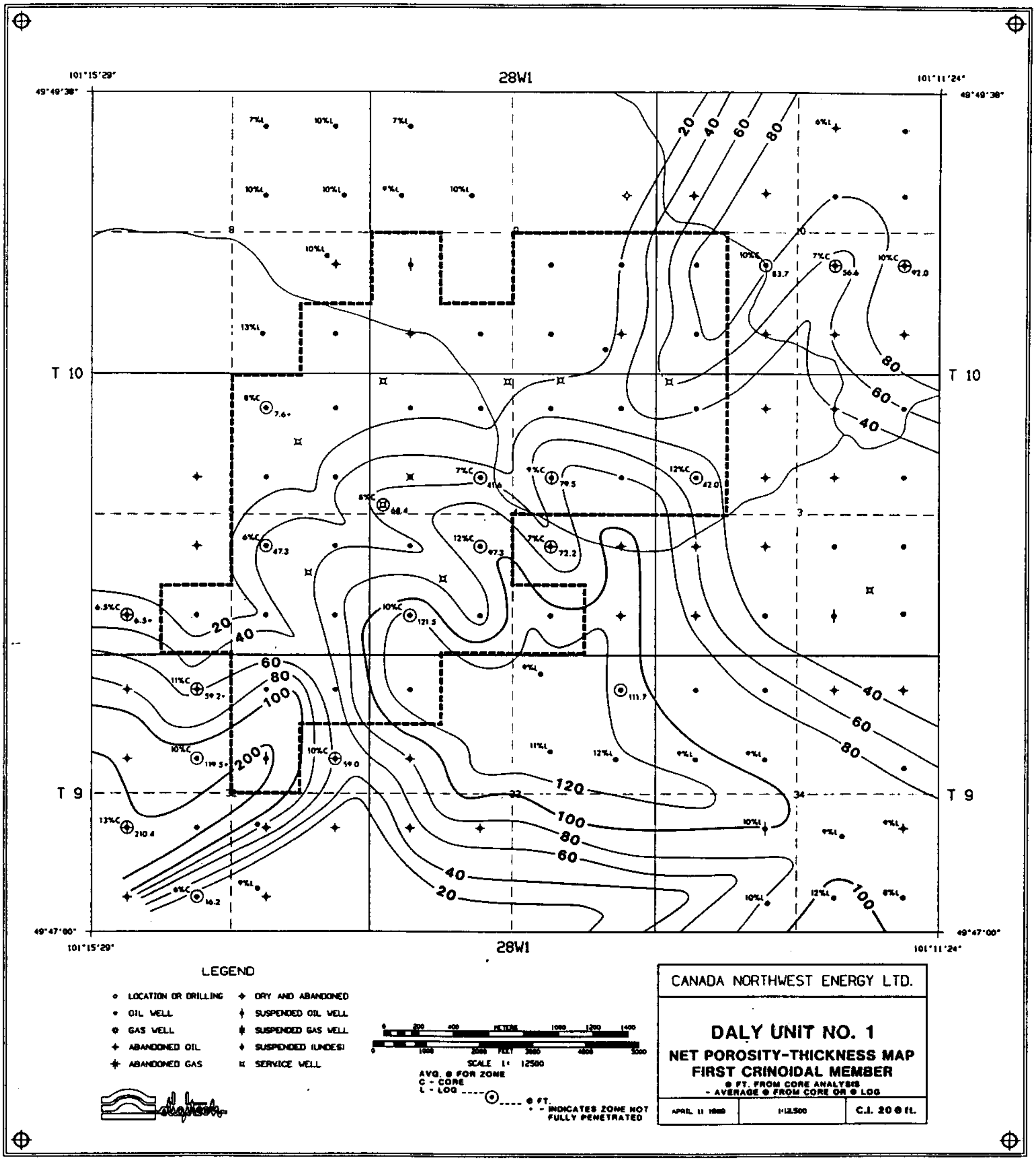

28W1
T 10
T 9
101°15'29"
49°49'38"
101°11'24"
49°47'00"
LEGEND
LOCATION OR DRILLING
OIL WELL
GAS WELL
ABANDONED OIL
ABANDONED GAS
DRY AND ABANDONED
SUSPENDED OIL WELL
SUSPENDED GAS WELL
SUSPENDED (UNDES)
SERVICE WELL
METERS
FEET
SCALE 1: 12500
NDE NOT DEEP ENOUGH
CANADA NORTHWEST ENERGY LTD.
DALY UNIT NO. 1
FIRST CRINOIDAL ISOPACH
C.I. 5ft.
APRIL 11 1989
1:12,500
G. LEWIS MAY/89

Figure A4-3



28W1
T 10
T 9
LEGEND
LOCATION OR DRILLING
OIL WELL
GAS WELL
ABANDONED OIL
ABANDONED GAS
DRY AND ABANDONED
SUSPENDED OIL WELL
SUSPENDED GAS WELL
SUSPENDED (UNDES)
SERVICE WELL
SCALE 1: 12500
AVG. Ø FOR ZONE
C - CORE
L - LOG
Ø FT.
+ - INDICATES ZONE NOT FULLY PENETRATED
CANADA NORTHWEST ENERGY LTD.
DALY UNIT NO. 1
NET POROSITY-THICKNESS MAP
FIRST CRINOIDAL MEMBER
Ø FT. FROM CORE ANALYSIS
- AVERAGE Ø FROM CORE OR Ø LOG
C.I. 20 Ø ft.

Figure A4-4

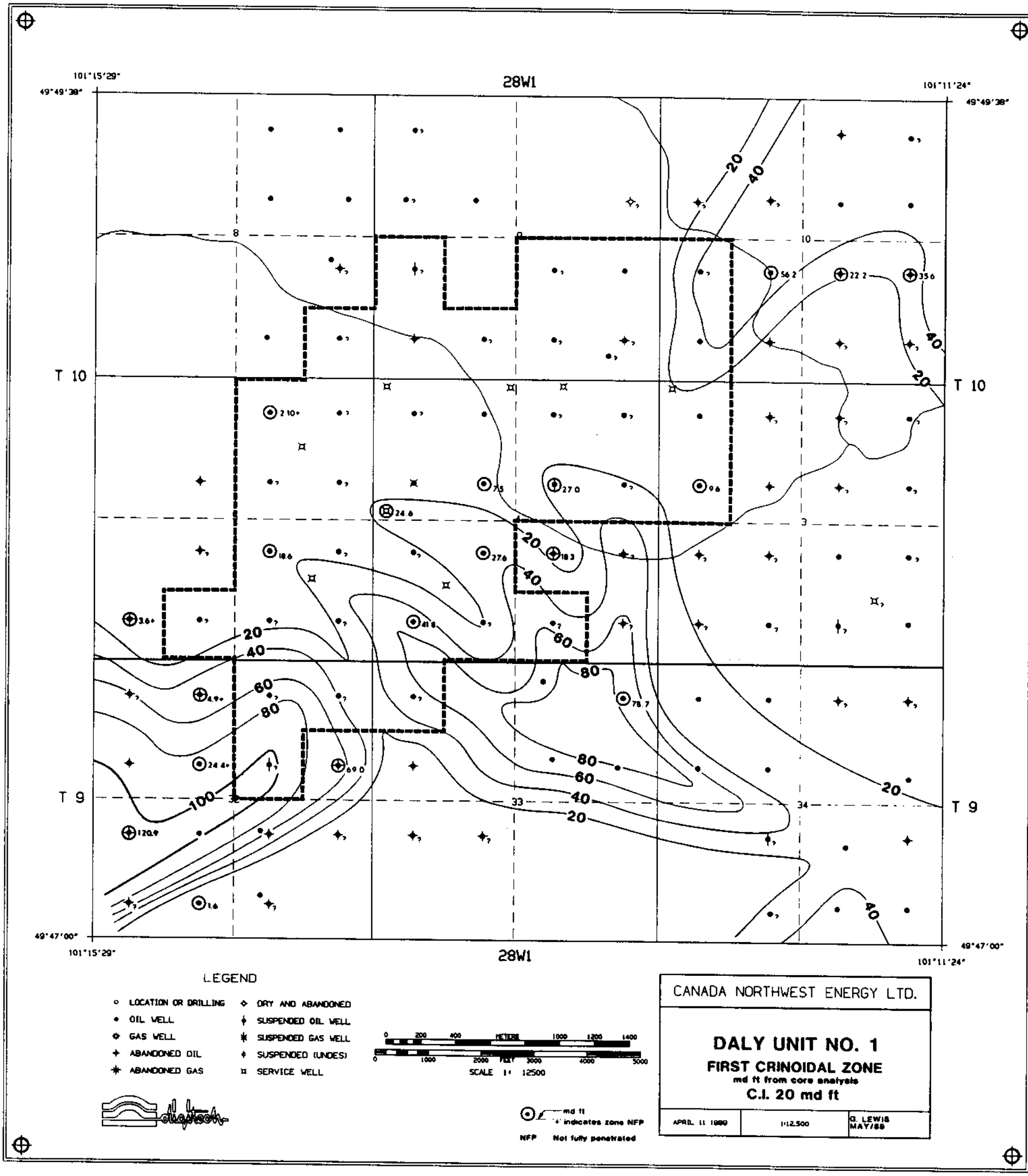

28W1
T 10
T 9
20
40
60
80
100
LEGEND
LOCATION OR DRILLING
OIL WELL
GAS WELL
ABANDONED OIL
ABANDONED GAS
DRY AND ABANDONED
SUSPENDED OIL WELL
SUSPENDED GAS WELL
SUSPENDED (UNDES)
SERVICE WELL
SCALE 1 : 12500
md ft
'+' indicates zone NFP
NFP Not fully penetrated
CANADA NORTHWEST ENERGY LTD.
DALY UNIT NO. 1
FIRST CRINOIDAL ZONE
md ft from core analysis
C.I. 20 md ft
APRIL 11 1989
1:12,500
G. LEWIS MAY/89

Figure A4-5

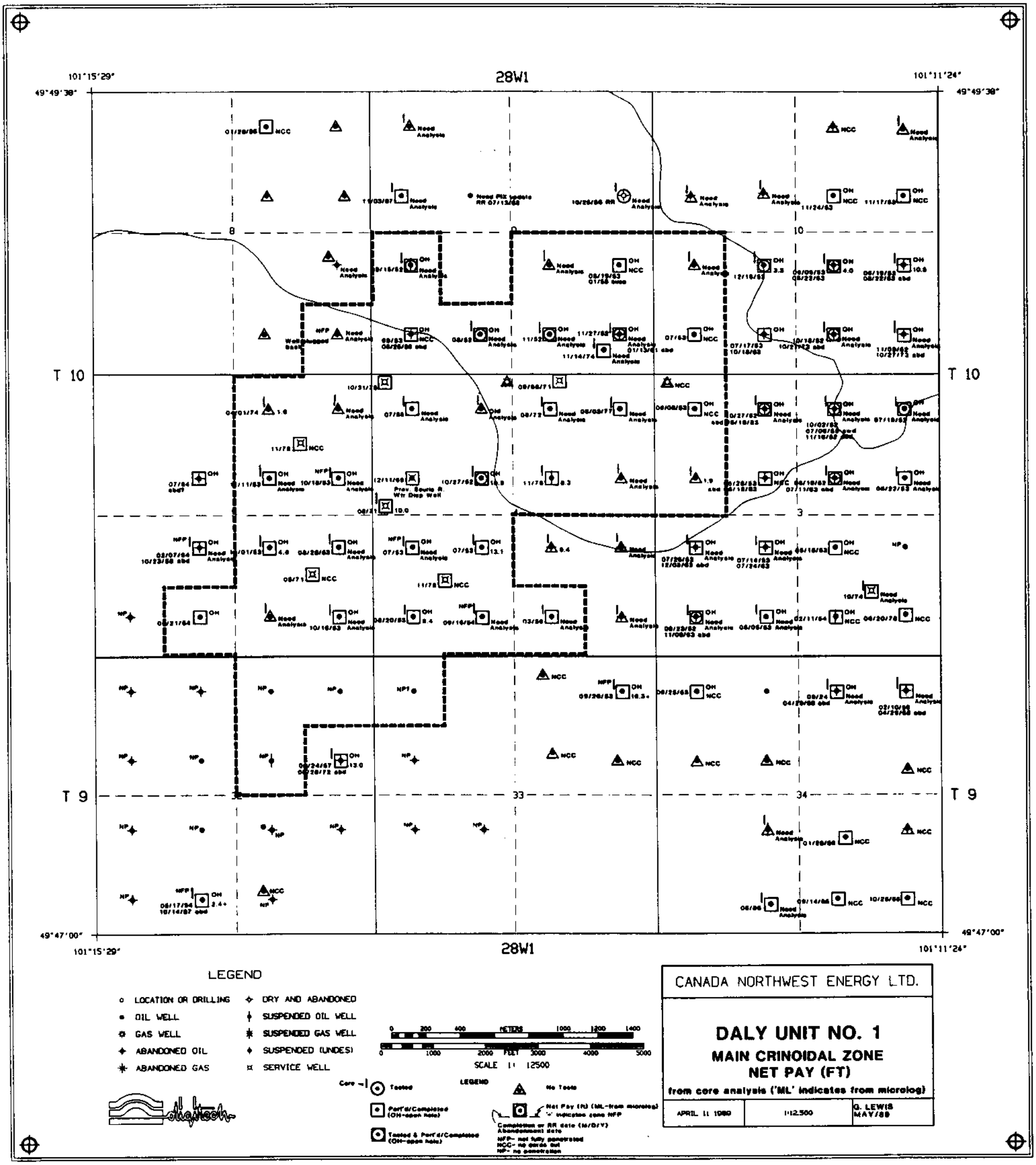

101°15'29"
28W1
101°11'24"
49°49'38"
49°49'38"
T 10
T 10
T 9
T 9
49°47'00"
49°47'00"
101°15'29"
28W1
101°11'24"
LEGEND
LOCATION OR DRILLING
OIL WELL
GAS WELL
ABANDONED OIL
ABANDONED GAS
DRY AND ABANDONED
SUSPENDED OIL WELL
SUSPENDED GAS WELL
SUSPENDED (UNDES)
SERVICE WELL
METERS
FEET
SCALE 1 : 12500
CANADA NORTHWEST ENERGY LTD.
DALY UNIT NO. 1
MAIN CRINOIDAL ZONE
NET PAY (FT)
from core analysis ('ML' indicates from microlog)
APRIL 11 1989
1:12,500
G. LEWIS
MAY/89

Figure A4-6

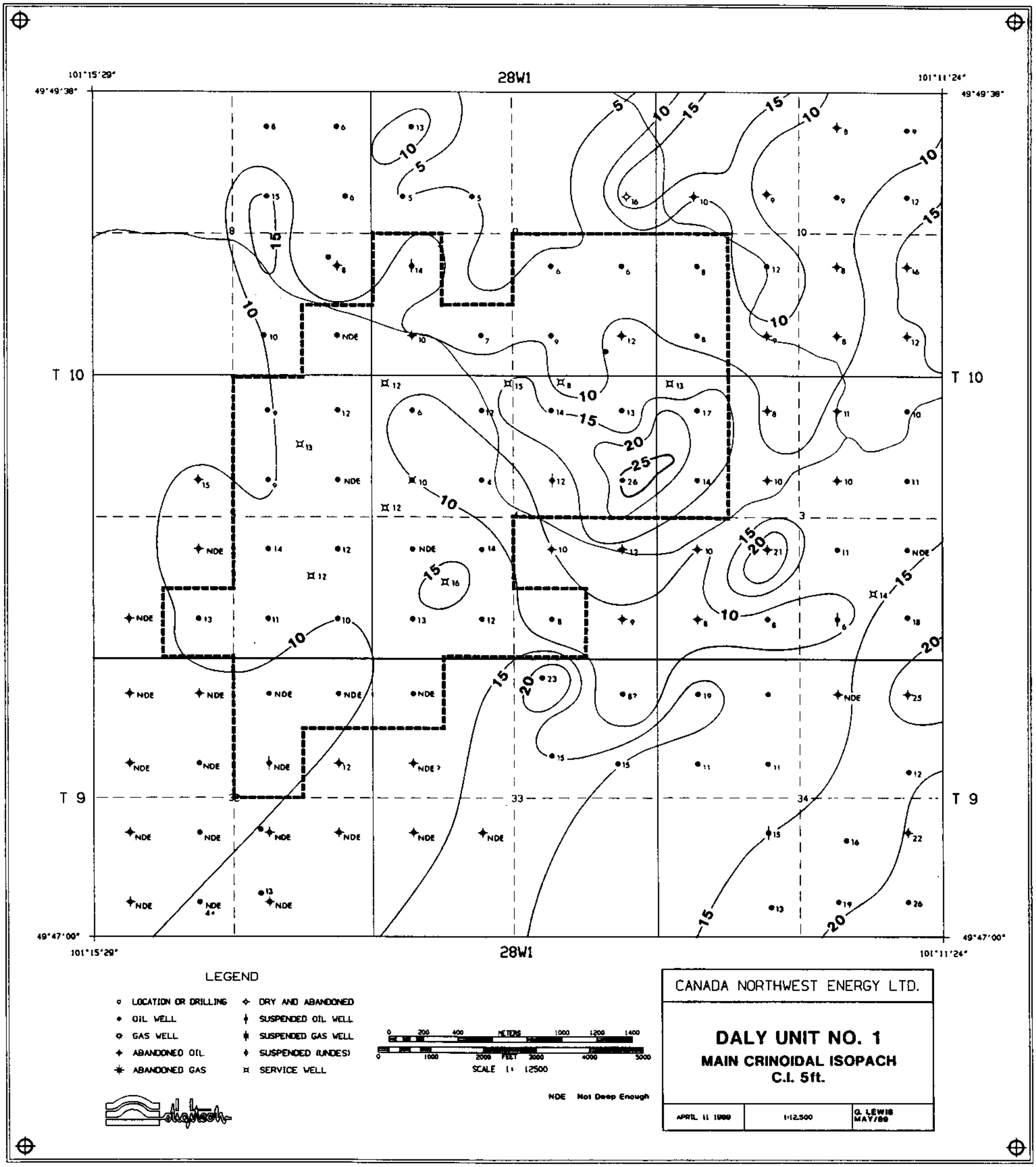

CANADA NORTHWEST ENERGY LTD.
DALY UNIT NO. 1
MAIN CRINOIDAL ISOPACH
C.I. 5ft.
APRIL 11 1989
1:12,500
G. LEWIS MAY/89
28W1
T 10
T 9
101°15'29"
101°11'24"
49°49'38"
49°47'00"
LEGEND
LOCATION OR DRILLING
OIL WELL
GAS WELL
ABANDONED OIL
ABANDONED GAS
DRY AND ABANDONED
SUSPENDED OIL WELL
SUSPENDED GAS WELL
SUSPENDED (UNDES)
SERVICE WELL
METERS
FEET
SCALE 1: 12500
NDE Not Deep Enough

Figure A4-7

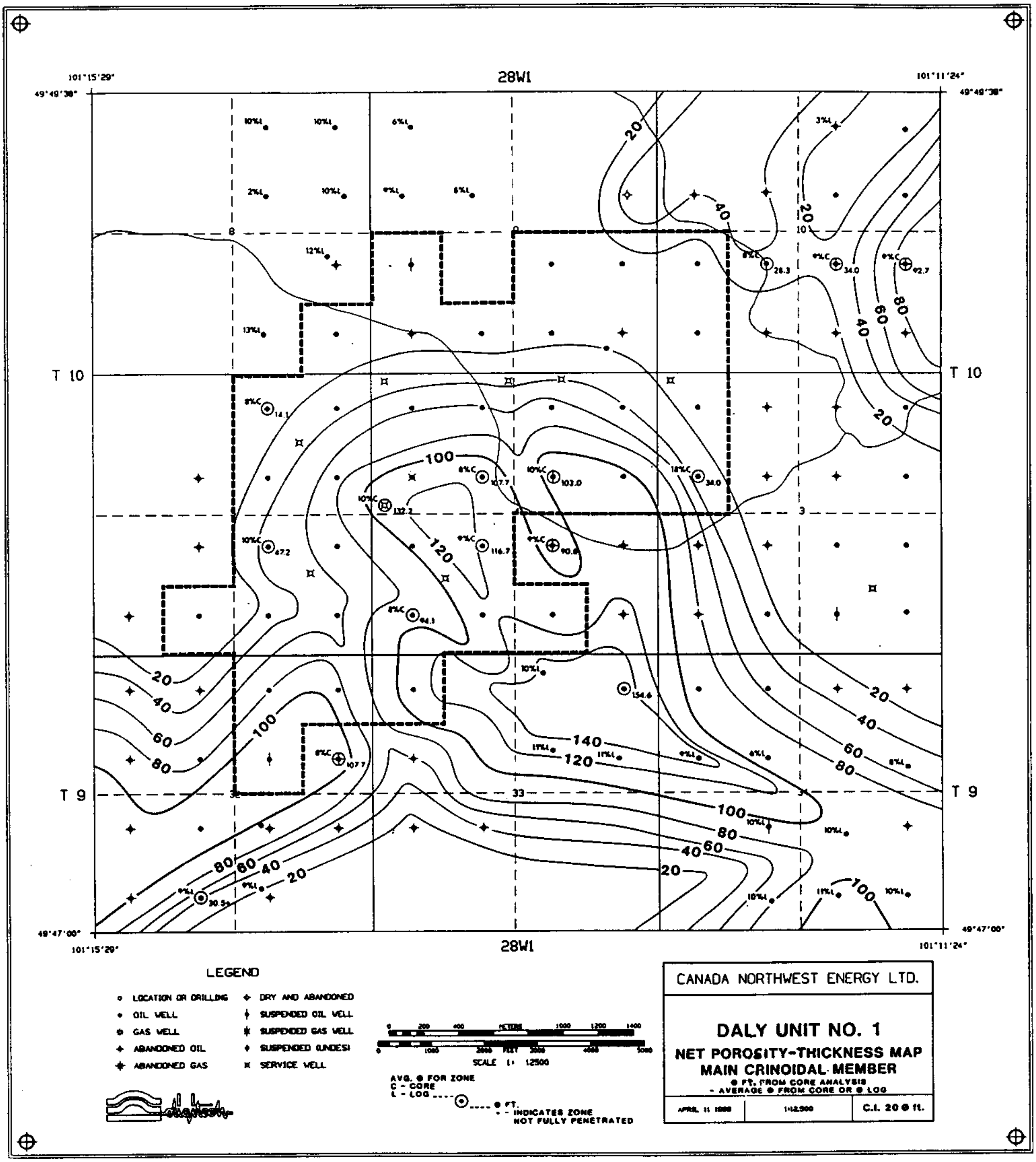
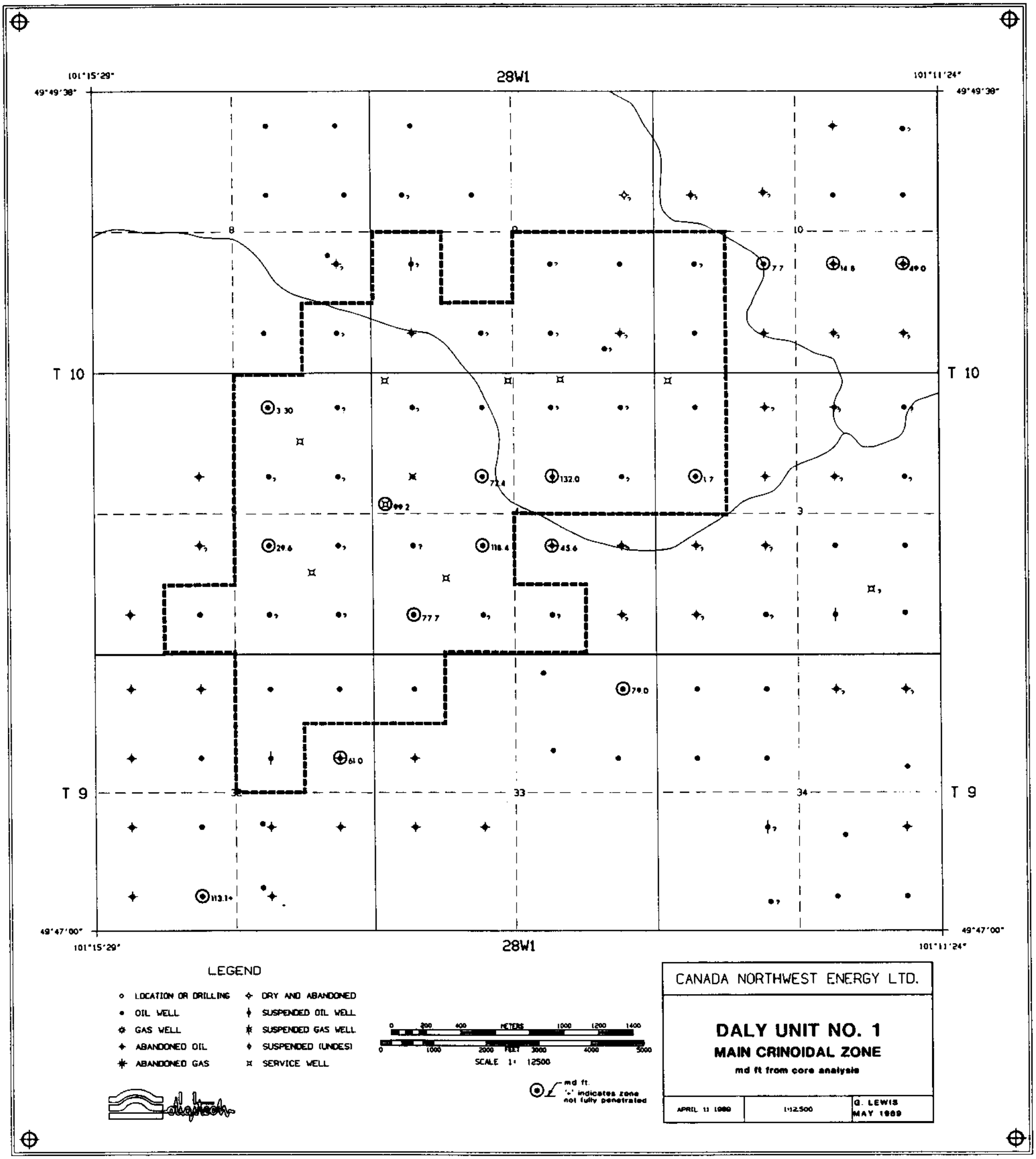
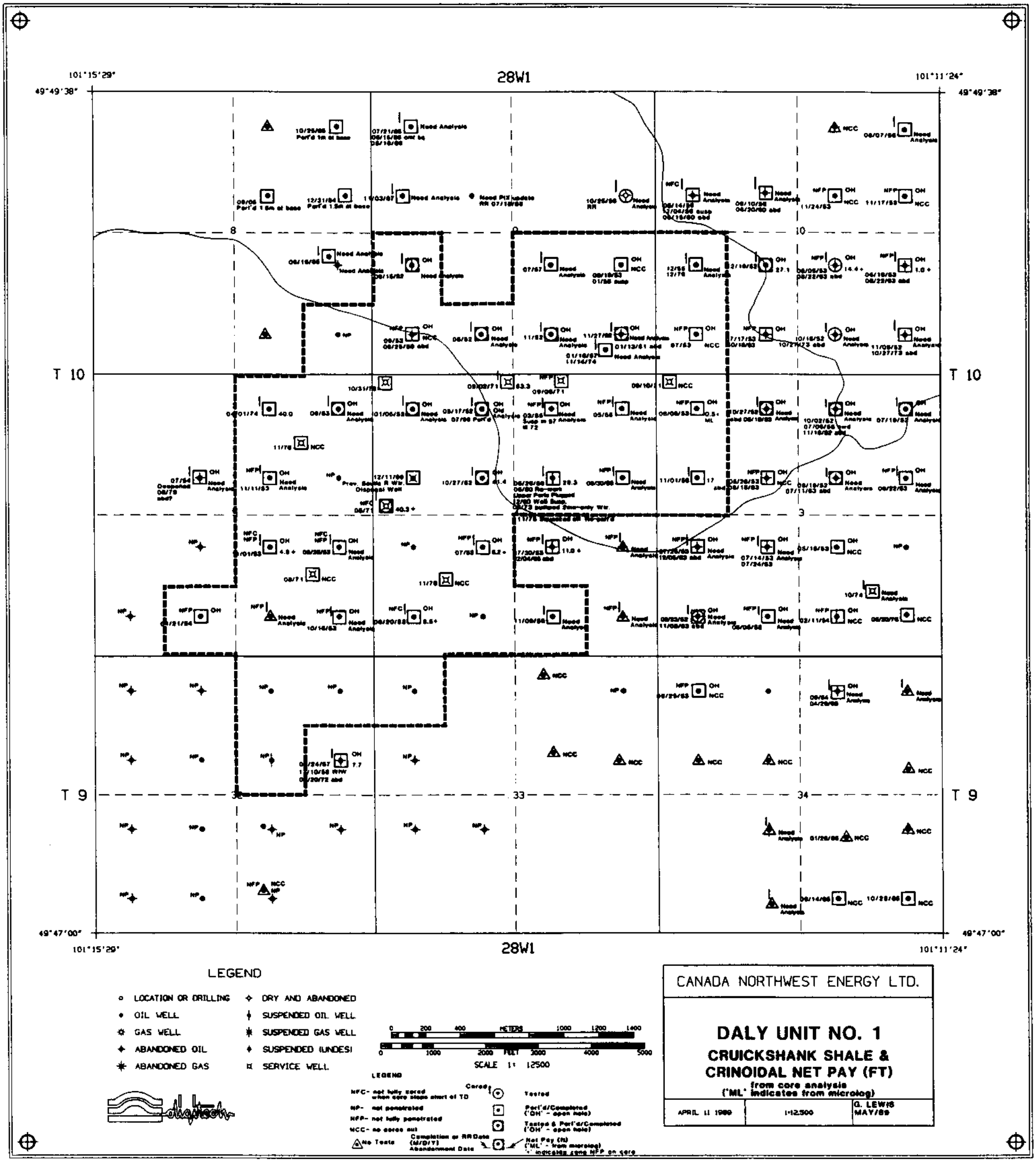

28W1
T 10
T 9
LEGEND
LOCATION OR DRILLING
OIL WELL
GAS WELL
ABANDONED OIL
ABANDONED GAS
DRY AND ABANDONED
SUSPENDED OIL WELL
SUSPENDED GAS WELL
SUSPENDED (UNDES)
SERVICE WELL
SCALE 1: 12500
AVG. Ø FOR ZONE
C - CORE
L - LOG
INDICATES ZONE NOT FULLY PENETRATED
CANADA NORTHWEST ENERGY LTD.
DALY UNIT NO. 1
NET POROSITY-THICKNESS MAP
MAIN CRINOIDAL MEMBER
C.I. 20 Ø ft.

Figure A4-8



28W1
101°15'29"
101°11'24"
49°49'38"
49°47'00"
T 10
T 9
8
9
10
3
32
33
34
3.30
77.4
132.0
1.7
99.2
29.6
118.4
45.6
77.7
79.0
61.0
113.1+
7.7
14.8
49.0
LEGEND
LOCATION OR DRILLING
OIL WELL
GAS WELL
ABANDONED OIL
ABANDONED GAS
DRY AND ABANDONED
SUSPENDED OIL WELL
SUSPENDED GAS WELL
SUSPENDED (UNDES)
SERVICE WELL
METERS
FEET
SCALE 1: 12500
md ft.
'+' indicates zone not fully penetrated
CANADA NORTHWEST ENERGY LTD.
DALY UNIT NO. 1
MAIN CRINOIDAL ZONE
md ft from core analysis
APRIL 11 1989
1:12500
G. LEWIS
MAY 1989

Figure A4-9



28W1
T 10
T 9
LEGEND
LOCATION OR DRILLING
OIL WELL
GAS WELL
ABANDONED OIL
ABANDONED GAS
DRY AND ABANDONED
SUSPENDED OIL WELL
SUSPENDED GAS WELL
SUSPENDED (UNDES)
SERVICE WELL
SCALE 1: 12500
CANADA NORTHWEST ENERGY LTD.
DALY UNIT NO. 1
CRUICKSHANK SHALE &
CRINOIDAL NET PAY (FT)
from core analysis
('ML' indicates from microlog)
APRIL 11 1989
1:12,500
G. LEWIS
MAY/89

Figure A4-10

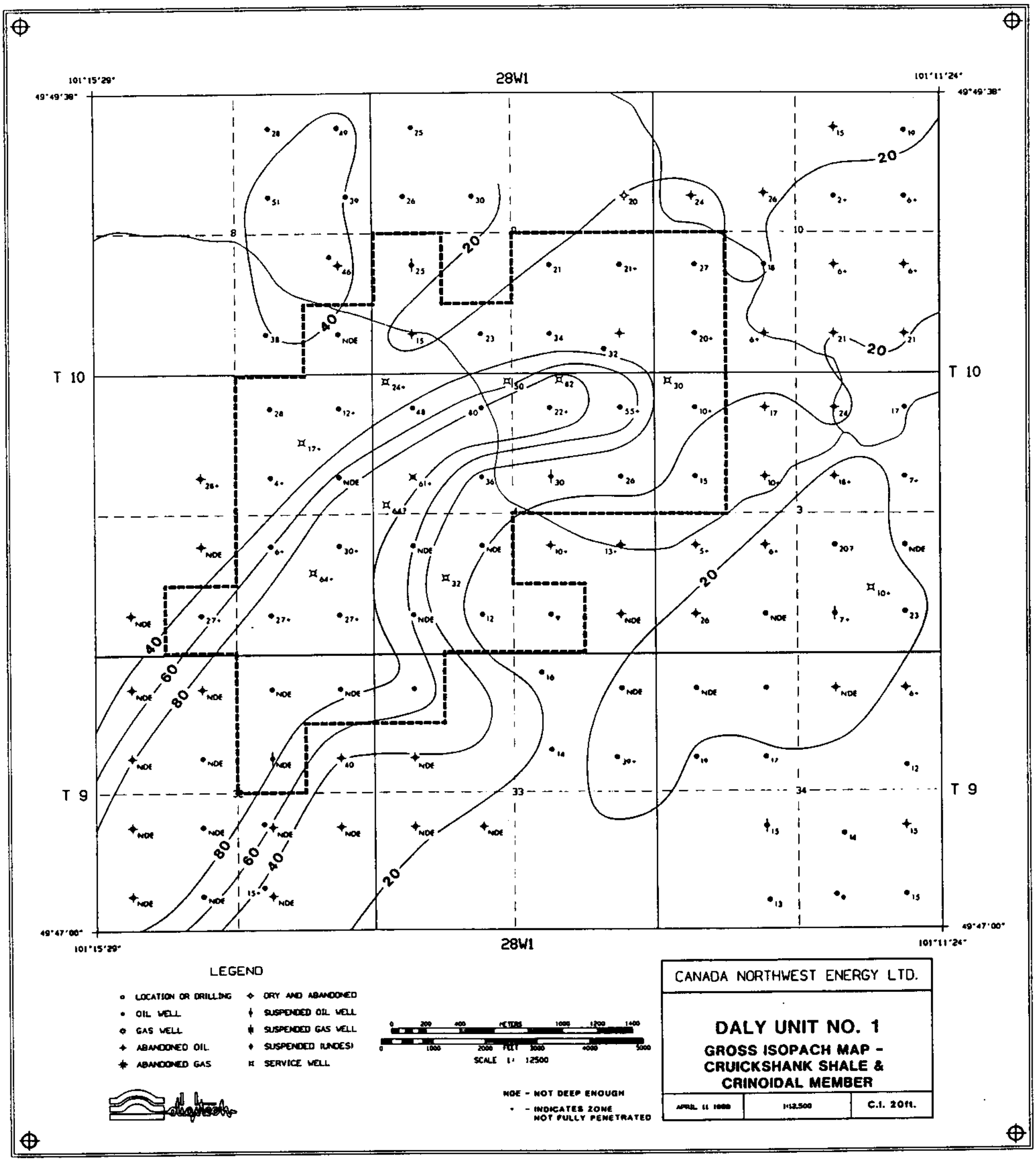

28W1
T 10
T 9
101°15'29"
101°11'24"
49°49'38"
49°47'00"
LEGEND
LOCATION OR DRILLING
OIL WELL
GAS WELL
ABANDONED OIL
ABANDONED GAS
DRY AND ABANDONED
SUSPENDED OIL WELL
SUSPENDED GAS WELL
SUSPENDED (UNDES)
SERVICE WELL
METERS
FEET
SCALE 1: 12500
NDE - NOT DEEP ENOUGH
• - INDICATES ZONE NOT FULLY PENETRATED
CANADA NORTHWEST ENERGY LTD.
DALY UNIT NO. 1
GROSS ISOPACH MAP -
CRUICKSHANK SHALE &
CRINOIDAL MEMBER
APRIL 11 1988
1:12,500
C.I. 20ft.

Figure A4-11

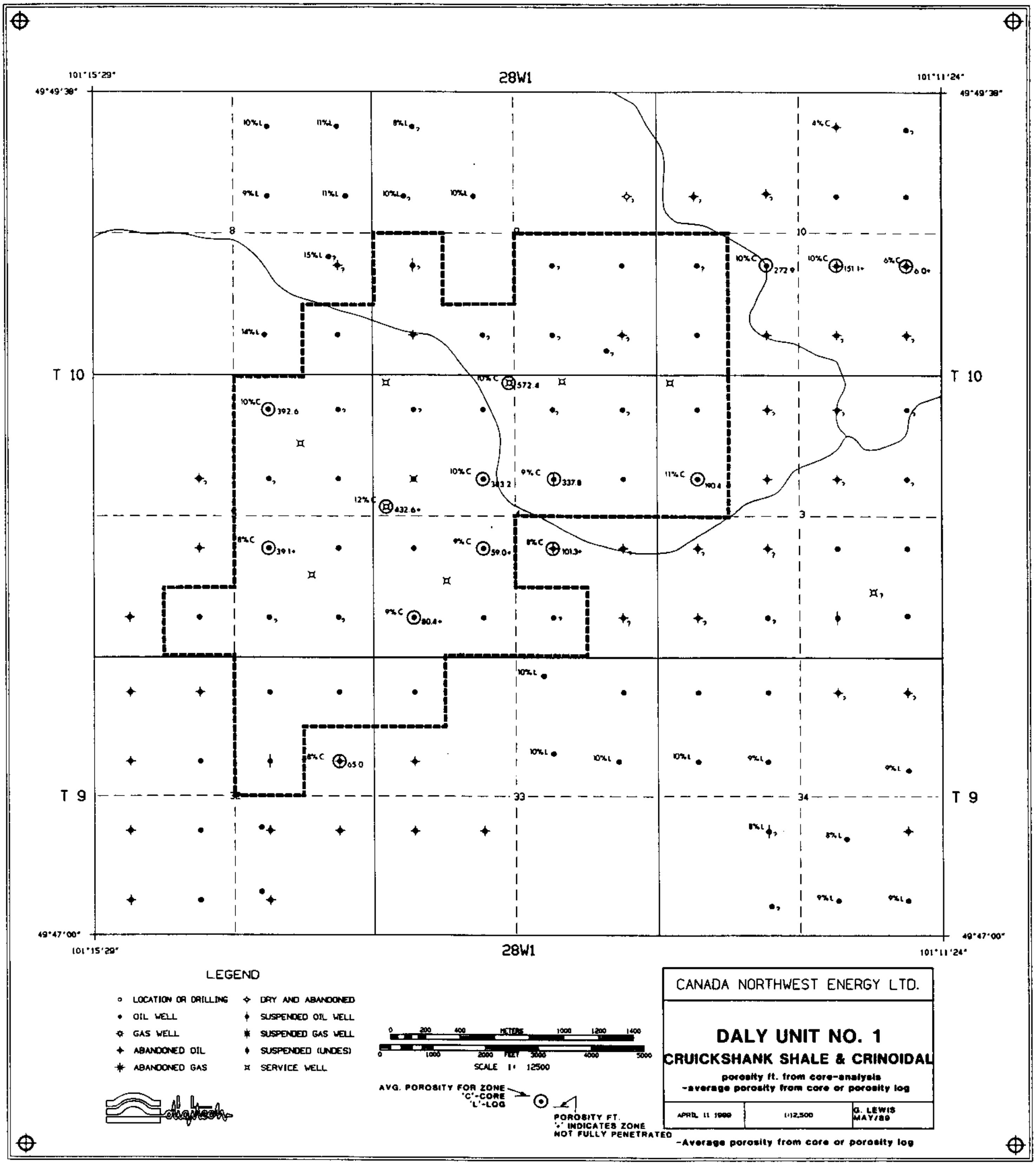

28W1
T 10
T 9
LEGEND
LOCATION OR DRILLING
OIL WELL
GAS WELL
ABANDONED OIL
ABANDONED GAS
DRY AND ABANDONED
SUSPENDED OIL WELL
SUSPENDED GAS WELL
SUSPENDED (UNDES)
SERVICE WELL
SCALE 1: 12500
AVG. POROSITY FOR ZONE
'C'-CORE
'L'-LOG
POROSITY FT.
'+' INDICATES ZONE NOT FULLY PENETRATED
CANADA NORTHWEST ENERGY LTD.
DALY UNIT NO. 1
CRUICKSHANK SHALE & CRINOIDAL
porosity ft. from core-analysis
-average porosity from core or porosity log
G. LEWIS
MAY/89
-Average porosity from core or porosity log

Figure A4-12

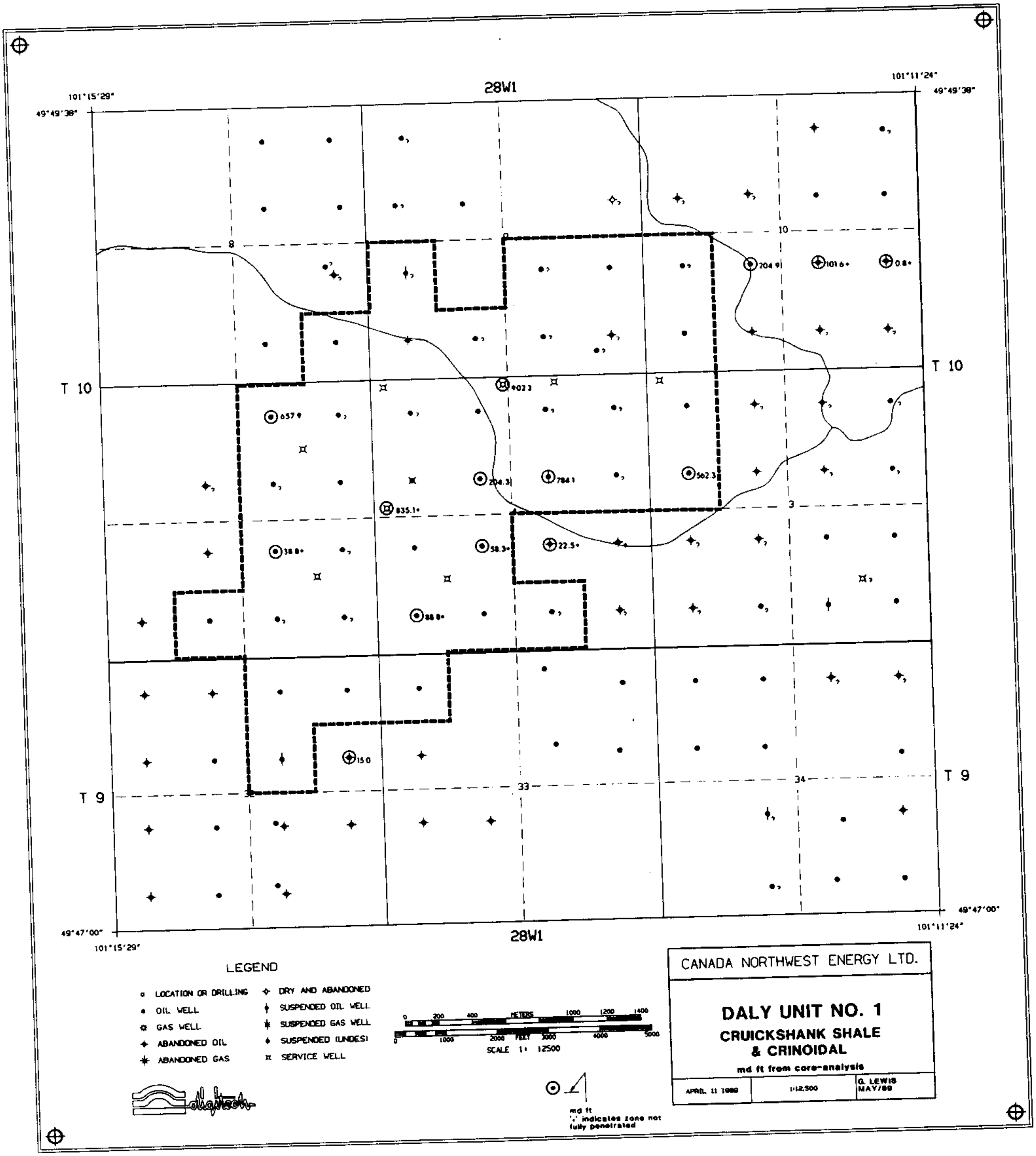

28W1
T 10
T 9
LEGEND
LOCATION OR DRILLING
OIL WELL
GAS WELL
ABANDONED OIL
ABANDONED GAS
DRY AND ABANDONED
SUSPENDED OIL WELL
SUSPENDED GAS WELL
SUSPENDED (UNDES)
SERVICE WELL
METERS
FEET
SCALE 1: 12500
CANADA NORTHWEST ENERGY LTD.
DALY UNIT NO. 1
CRUICKSHANK SHALE
& CRINOIDAL
md ft from core-analysis
G. LEWIS
md ft
'+' indicates zone not fully penetrated

Figure A4-13