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LABORATORY PREDICTIONS OF WATER SENSITIVITY COMPARED WITH FIELD OBSERVATIONS OF WELL DAMAGE - PATRICK DRAW, WYOMING

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ABSTRACT

Predictions of well damage that results from invasion of a reservoir sand by fresh water are compared with actual well damage observed in the field. The "sand" studied is the Almond sandstone of Cretaceous age in the Patrick Draw field of Southwestern Wyoming. Actual damage, or well response, is estimated from the interpretation of drill stem tests and observation of the rates of injection into two pilot waterflood wells where fresh water was injected into one well and brine into the other.

Laboratory tests generally indicate that the Almond sand should have a medium sensitivity to fresh water and somewhat less sensitivity to brine. Damage ratios interpreted from drill stem tests are high for gas sands but the damage is rapidly removed by production. Damage ratios are less in oil sands than in gas, and are even less in water sands. Injection rates for fresh water were about the same as those for brine, which does not agree with laboratory prediction but the results are not conclusive. The rates for brine injection are close to those calculated from laboratory relative-permeability curves.

References and illustrations at end of paper.

INTRODUCTION

The Problem

The possibility that the productive capacity of many oil and gas wells is seriously reduced if the producing formation is exposed to fresh water has been recognized for many years. Despite years of field observations and considerable laboratory research, methods of predicting quantitatively the susceptibility of formations to well damage have not been developed to a point of complete reliability and the extent of actual well damage is open to question in many cases. The need for developing better methods for predicting well damage and for assessing actual damage is self-evident.

A simple solution to this problem has not been found because of its complexity. The interplay of the many factors affecting well damage makes the determination of the relative effect of each variable almost impossible; the effect of each variable must be intuitively estimated from observation of gross behavior. All these problems are compounded by the simple economics of producing oil for profit.

The prediction of degree of susceptibility to well damage is based on the results of several interrelated laboratory tests. The problems inherent in duplicating reservoir conditions in the laboratory are well recognized but these limitations do not preclude successful predictions; many aspects of reservoir performance are now routinely reproduced in the laboratory and the conditions of well damage will be thus reproduced once the critical parameters are recognized and the results tested in the field.

The assessment of the degree of well damage usually relies on observation of well performance after some change is made in completion or workover techniques. Comparison of laboratory predictions with field results is unusually difficult in water-injection wells because of the long time required to observe the results of the operations.

The assessment of actual well damage in this study is based on the interpretations of all reliable drill stem tests that were available and analyses of results of injectivity tests made on two pilot water-injection wells.

PATRICK DRAW FIELD

Field Description

The Patrick Draw field is located in Townships 18 and 19 North, Ranges 98 and 99 West, Sweetwater County, in Southwestern Wyoming.[1] The oil-producing part of the field, discovered in 1959, is about 8-1/2 miles long and 3 miles wide. About 150 oil wells have been drilled on 80-acre spacing and range in depth from about 4,300 to 5,300 ft. Oil is produced mostly by solution-gas expansion. Some produced gas is returned to the gas cap through two injection wells. Present evidence indicates little edge-water encroachment. Oil produced in 1963 was about 5.1 million bbl, and cumulative production to the end of the year was about 22.1 million bbl.

The Patrick Draw field, Fig. 1, is divided into three units, Arch, Beacon Ridge, and Patrick Draw. Thus the name Patrick Draw is used for both a unit and the entire field.

Producing Sands

Oil and gas are found at a depth of about 4,600 ft in sandstones in the upper part of the Almond formation; this formation is the upper part of the Mesaverde group of Cretaceous age in this area. From the Rock Springs uplift the formations dip eastward at about 500 ft a mile. The Patrick Draw accumulation occurs down-dip from a permeability pinchout where shaley sandstones and shales grade downward into permeable sandstones.[2]

The main producing zone consists of about 30 ft of sandstones, sandy shales, thin shales, and coal seams. The approximately 20 net ft of permeable producing sandstones [hereinafter called "sands"] occur as 3 or more beds scattered through this zone. The producing sands are medium-grained, subangular, moderately well sorted graywackes. The grains are mostly quartz, black minerals and softer rock fragments. Some of the rock fragments appear to have been altered to clay minerals.

Extraneous gas sands are found below the main productive sand in portions of the field. The physical properties and response to laboratory tests of all productive sands in the field are similar and all are discussed as a single unit without distinction.

The Ericson sand [also Cretaceous age] lies about 400 ft below the Almond sand but has produced only water when tested in the field. Three tests of water in the Ericson are included in the discussion of drill stem tests [because these are the only water tests available] but otherwise the discussion of producing sands includes only sands in the Almond formation.

Pilot Water Injection

Water Injection Well 1 was drilled, May, 1962, in Section 3, R 99 W, T 18 N, in the southern end of the Patrick Draw Unit. The well is in the main part of the producing area in the southern end of the field. The injection well is in the center of a five-spot between four oil wells that are drilled on 80-acre spacing. The well was not fractured.

Fresh water for injection was obtained from springs or shallow wells at Antelope Springs and is piped 18 miles to Bitter Creek Station, a small settlement on the Union Pacific Railroad, where it is used for domestic purposes. Injection Well 1 is about one mile northwest of Bitter Creek Station. Following a series of injectivity tests, water injection was begun in June, 1962. Injection rates varied between 200 to 500 B/D at surface pressures of about 2,120 psi. Injection was continued for only about 10 days, then the well was shut in.

Injection Well 2 was drilled in May, 1963, in the center of the next five-spot southeast of No. 1. The well penetrated 32 ft of Almond sand [4,640-4,672 ft] including 20 ft of permeable sand with an average permeability [corrected to infinite mean pressure] of about 30 md. This value is the same as the average permeability of all cores from the field, Table 1.

Water injection Well 1 was recompleted as a source of salt water for injection into Well 2. This water is found in a sand in the Fox Hills formation at a depth of about 3,200 ft. The salinity is about 65,000 ppm which is mostly sodium chloride although a significant amount of calcium chloride is also present.

After testing, regular water injection into Well 2 began in Aug., 1963, and is continuing.

The injection rate has averaged about 400 B/D of water at surface pressures ranging from 2,000 to 2,200 psi. The cumulative volume of water injected to Feb., 1964, is about 60,000 bbl which is a small fraction of the amount needed for fill-up. No response has been noted in any of the oil wells.

EXPERIMENTAL METHODS AND PROCEDURES

Laboratory tests were made on 154 samples, representing the producing sand in 26 wells, to determine porosity, gas permeability, water permeability, and water saturation at a displacement pressure of 50 psi using the semipermeable-plate method. The water saturation at 50 psi is, for practical purposes, the irreducible saturation.

The relation of mercury saturation at each of a series of increasing pressures was determined on sufficient samples to determine the average response of the Almond sand to this test. A terminal injection pressure of about 1,200 psi was used in most of these tests because at this pressure the rate of mercury injection was almost zero. The capillary behavior of the samples to mercury [non-wetting] and water [wetting] was compared by applying a correction factor of 5.0 to the mercury-injection results to account for the differences in contact angle and interfacial tensions of the two fluids. Thus, the water saturation at a displacement pressure of 50 psi is compared with the pore volume uninvaded by mercury at an injection pressure of 250 psi.

The types and relative abundance of clay minerals in the sands were determined by X-ray diffraction analyses. These analyses, and the methods used in the other tests mentioned bebore, were described in detail in previous reports.[3,4]

The oil-water relative permeability curves were run with the displacement, or unsteady-state method.[5] Special sequences of liquid permeabilities were made on a group of 12 samples to determine the effect of initially flowing strong sodium and calcium brines on the subsequent fresh-water permeability of the sand. Distilled water, 1 normal NaCl brine, and 1 normal $CaCl_2$ brine were used in these determinations. After the initial liquid permeability was run, subsequent determinations were made by flowing a liquid through the sample, displacing the previous liquid, until a constant value of permeability was obtained.

About one-half the damage ratios were taken from interpretations of drill stem tests [DST] made by the Halliburton Co. The others were calculated using essentially the same techniques as Halliburton. These techniques are described in detail by Amman[6] and discussed more recently by Maier.[7]

DISCUSSION OF RESULTS

Interpretation of Laboratory Results

The average k_g [symbols are explained in nomenclature section] of the 154 samples is 30 md and the average k_w is 15 md, giving a k_w-k_g ratio of 0.5, Table 1. This ratio is an indication of the water sensitivity of the sand.[4] This ratio is compared in Table 1 with similar ratios obtained from other sands in other fields,[3] to show the range of values usually found in Wyoming producing sands. Based on this comparison with other sands, and previous experience, the Almond sand is classed as being moderately sensitive to fresh water.

The relative magnitude of the S_{wr} is another indicator of water sensitivity. Sands that contain a swelling clay, large amounts of non-swelling clay, and/or a large proportion of fine capillaries for a given permeability, not only have a high initial S_{wr} but retain a high water saturation during production if the saturation is increased during completion. The comparison of the S_{wr} of the Almond sands with the others, Table 1, shows a higher value than the Tensleep, lower than the Frontier, but about the same as the Newcastle. Thus, consideration of the S_{wr} of the Almond sand again indicates a moderate water sensitivity.

The difference between the value of [100-S_{hg}] and S_{wr} is also considered to be an indicator of relative water sensitivity. Although this indication is not infallible, it has been shown to be of value in estimating the water sensitivity of producing sands in the Rocky Mountain region.[3] Since mercury is non-wetting, the value of [100-S_{hg}] depends only on pore size distribution in the dry sample. Saturating the sample with water changes the pore size of sands containing swelling clays and this change is reflected in the value of S_{wr}. The value of [100-S_{hg}] is about the same as S_{wr} in the relatively clean Tensleep sand but the values are significantly different in the Frontier sand which contains a swelling clay mineral. The behavior of the Almond sand is intermediate between these extremes, again indicating a moderate water sensitivity.

The average results of the series of permeability tests performed on 12 samples are summarized in Fig. 2. The permeability to strong sodium chloride brine is about 15 per cent greater than that to fresh water. More significant, however, is the loss of permeability to fresh water following exposure to sodium chloride. This brine strongly affected the samples [perhaps by ion exchange] and permanently reduced the permeability to both calcium chloride brine and fresh water. The interpretation of these tests is difficult and additonal work is planned to determine more specifically the ions adsorbed on the clay minerals in the reservoir and the effect of changing these ions by injecting water having a chemical composition different from that of the formation water.

The relative permeability curve, Fig. 3, shows a k_{ro} at S_{wr} of about 85 per cent while the k_{rw} at S_{or} is only 10 per cent. This k_{rw} is considerably lower than those in most published literature for similar sands. This low k_{rw} when considered with the low effective permeability indicated on DST, Table 2, indicates that the rate of water injection will be low.

X-ray diffraction tests show that the important clay minerals in the Almond sands, in order of decreasing abundance, are kaolinite, illite and mixed-layered montmorillonite-illite. The mixed-layered clay expands in fresh water but only trace amounts were present in most samples. The laboratory behavior of the Almond sand, if predicted on the basis of these clay analyses, is about the same as that actually observed.

In summary, the laboratory results indicate that the Almond sand should have a moderate water sensitivity. Consequently, it would be expected that if wells were drilled with mud having a fresh-water filtrate, the rate of gas production would be considerably reduced, especially after reservoir pressure is lowered to the point where energy to displace the excess water from the formation is no longer available. This reduction of gas production due to the relative-permeability effect occurs in all gas sands but is especially severe in water-sensitive sands. The rate of oil production would not be reduced as much as that of gas because oil displaces excess water from the formation more efficiently than gas does. It would also be predicted that fresh water could be injected into the sand but that the rate would be low. Rate of salt-water injection should be higher than that of fresh water; however, if a strong brine is used for injection, it should not be followed by fresh water.

Interpretation of Drill Stem Tests

The damage ratio [DR] is defined as the ratio of theoretical productivity index to the actual productivity index obtained during the drill stem test [DST].[6,7] Thus, a DR of 1 indicates no well damage while a DR of 2 indicates that production would be increased by a factor of 2 if all well damage were removed. Because of several inaccurate values usually used in these calculations, however, the DR should be considered as indicating an order of magnitude of well damage and not as a definitive value.

All available DST made in the Almond sands in the Patrick Draw field were studied. Of those tests that were of a permeable Almond sand, only about one-half could be used for the calculation of DR. The rest were rejected because of unreliable rates of fluid production or because of an inadequate pressure buildup during the shut-in period for extrapolating to a reliable static reservoir pressure.

The effective fluid permeability, DR, and other information interpreted from the 20 DST are summarized in Table 2. Permeability is plotted against DR on Fig. 4. Values obtained from the initial and final periods of flow are given where reliable calculations could be made for both periods.

The plot of DR against permeability for gas production, Fig. 4, indicates uniformly high well damage. However, DR decreased and permeability increased significantly during the final flow period indicating that the well damage was removed rapidly when the well was opened to flow. The total flow time during these tests ranged from 40 to 71 minutes. The amount of decrease of DR or increase of permeability could not be specifically related to total flow time or permeability.

There is a suggestion of increasing DR with increasing permeability for the gas tests on Fig. 4. If more data should confirm such a relation, it would be contrary to that predicted from laboratory analyses, which usually indicate increasing sensitivity with decreasing permeability.[4] Sands having low permeability usually contain large amounts of clays which increases their susceptibility to well damage.

A trend of increasing DR with increasing permeability is more pronounced for the oil tests than for the gas tests, Fig. 4. The uniformly high DR in wells having the higher permeabilities indicates considerable well damage. Whether this damage is temporary or permanent could not be deduced from the DST available. Although various types of mud were used in drilling the wells, a limited study indicated no relation between type of mud and damage ratio.

Three of the four tests of water-bearing sand are in the Ericson sand which lies about 400 ft below the Almond but is similar to the Almond. All the water tests show DR less than 1 indicating that the mud filtrate did not damage the water-saturated sand. In the one test where calculations could be made for both the initial and final periods, permeability increased during the final flow period, thus again indicating that well damage in this field may be temporary and is removed during production.

Results and Calculations of Pilot Injection

The first two injectivity tests made on Wells 1 and 2 are shown on Fig. 5. The differential pressure on Fig. 5 is the difference between the static reservoir pressure [p_e] and the well pressure [p_w] at the sand face during injection. Stock tank oil was first injected into both wells; this was followed by fresh water in Well 1 and by Fox Hills brine in Well 2. At a differential injection pressure of 2,400 psi, fresh water was injected into Well 1 at a rate of 210 B/D less than that for oil while the injection rate for brine into Well 2 was 250 B/D less than the oil rate. This disagrees with the results of laboratory permeability tests, Fig. 2, which show that the injection rate for brine should be considerably higher than that for fresh water. This lack of conformity of laboratory with field data may be caused by the injectivity tests in the two wells not being directly comparable as assumed; or by fracturing of the formation during the injectivity tests. The injectivity curves, Fig. 5, will not extrapolate to the origin, indicating that fracturing of the formation occurred below the differential pressure of the first injectivity test on each curve.

The expected rate of brine injection into Wells 2 was calculated using the method outlined by Pirson[8] [p. 411] for the transient behavior of a water-injection well when an oil bank is being formed. This method is essentially an adaptation of the radial flow equation taking into account the relative permeabilities associated with the moving oil bank. The calculated injectivity index is plotted on Fig. 6 as a function of cumulative water injected. The reduction of calculated injectivity index with time, Fig. 6, is due to the decrease in net permeability of the reservoir in the flood pattern, which is caused by the low relative permeability to water and the increasingly larger volume of the reservoir invaded by water as the flood front advances.

The average injectivity index observed in Well 2 is also shown on Fig. 6. The actual injectivity index was much lower than the calculated when injection began but the two have been in reasonable agreement since the calculated radius of the water front was about 40 ft. The early increase of injectivity index in Well 2 may have resulted from fracturing of the formation, which exposed the undamaged formation having the characteristics assumed in the calculations.

CONCLUSIONS

The major conclusions drawn from this study are outlined below. Several other conclusions are given in Discussion of Results.

Laboratory tests are useful in predicting the order of magnitude of well damage that will be experienced in the field but the actual experience may differ from the predicted in significant details. For example, the rates of brine injection in a pilot well agrees with calculated rates based on laboratory tests, but higher predicted injectivity to brine than to fresh water was not observed. The results are not entirely conclusive, however, because of possible fracturing of the reservoir during injection.

Damage ratios derived from drill stem tests generally agree with laboratory predictions. Damage ratios are higher in gas sands than in oil or water sands, as expected. Damage ratios appear to increase with increasing permeability. This trend is opposite to that predicted from laboratory tests.

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NOMENCLATURE

- k_g - Permeability to gas [helium] corrected to infinite mean pressure [The Klinkenberg effect].
- k_w - Permeability to distilled water containing a bactericide.
- S_{wr} - Irreducible [residual] water saturation obtained from the capillary-pressure curve using the semipermeable-plate method at 50 psi. Also obtained from the oil-water relative permeability curve.
- S_{or} - Residual oil saturation from the oil-water relative permeability curve.
- S_{hg} - Mercury saturation from mercury-injection curve at an injection pressure of 250 psi.
- $[100-S_{hg}]$ - The pore space uninvaded by mercury at 250 psi.
- k_{rw} - Relative permeability to distilled water.
- k_{ro} - Relative permeability to oil.

All other symbols are the Standard Letter Symbols for Petroleum Reservoir Engineering suggested by SPE.

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TABLE 1 — COMPARISON OF CAPILLARY BEHAVIOR OF ALMOND SAND WITH OTHER SANDS

	k_g	k_w	k_w/k_g	S_{wr}	$100-S_{hg}$	Predominant clay
Tensleep	30	21	0.7	12	10	Illite, (S)
Almond	30	15	0.5	28	26	Kaolinite, (L)
Newcastle	30	18	0.6	25	11	Kaolinite, (M-L)
Frontier	30	0	0	30	15	Montmorillonite (M-L)

Relative amount of clay mineral in sample: (S) - Small
(M) - Moderate
(L) - Large

TABLE 2 -- SUMMARY OF INTERPRETATION OF DRILL STEM TESTS

Unit	Well No.	Production	Initial period: Permeability, md	Initial period: Damage ratio	Final period: Permeability, md	Final period: Damage ratio
Arch	1	Gas	9.3	9.2	10.2	4.3
Arch	3	Gas	0.7	4.1	1.1	2.4
Arch	38	Gas	3.8	8.7	4.0	4.2
Arch	55	Gas	2.9	6.1	3.6	4.0
Arch	74	Gas	1.8	7.8	5.3	6.7
Arch	75	Gas	3.5	8.6	8.6	2.6
Patrick Draw	1	Oil	14.6	3.5	---	---
Arch	3	Oil	1.3	0.9	1.4	1.0
Arch	28	Oil	10.9	1.6	---	---
Arch	34	Oil	1.1	0.9	---	---
Arch	46	Oil	---	---	0.2	1.7
Arch	64A	Oil	40.4	1.8	---	---
Arch	66	Oil	4.2	1.2	---	---
Arch	69	Oil	9.2	2.0	---	---
Arch	71	Oil	3.3	0.9	---	---
Arch	72	Oil	0.4	0.2		
Arch	1	Water 1/	---	---	1.0	0.5
Arch	3	Water 1/	5.2	0.4	14.0	0.4
Patrick Draw	4	Water	0.3	0.7	---	---
Arch	49	Water 1/	7.1	0.6	---	---

Notes:
1/ Ericson formation. All other tests are of Almond formation

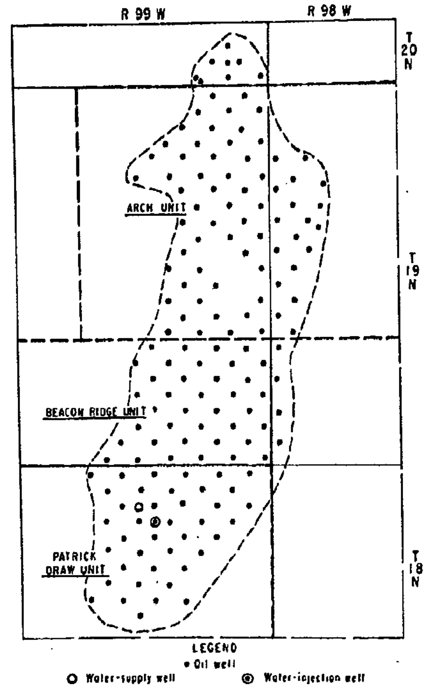

Figure 1. - Map of Patrick Draw field showing approximate outline of oil-producing area.

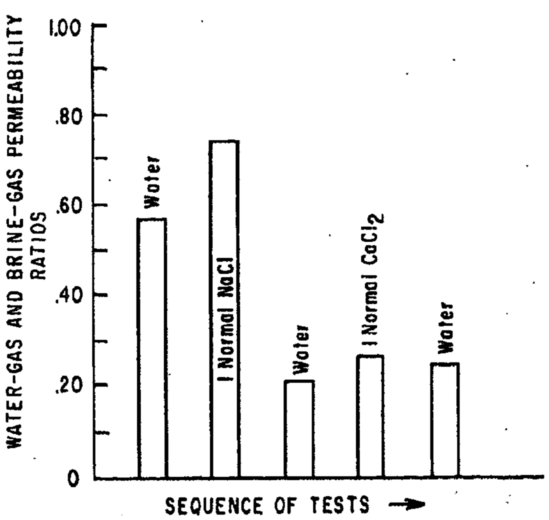

Figure 2. - Average relation of fresh water and brine permeabilities to gas permeability.

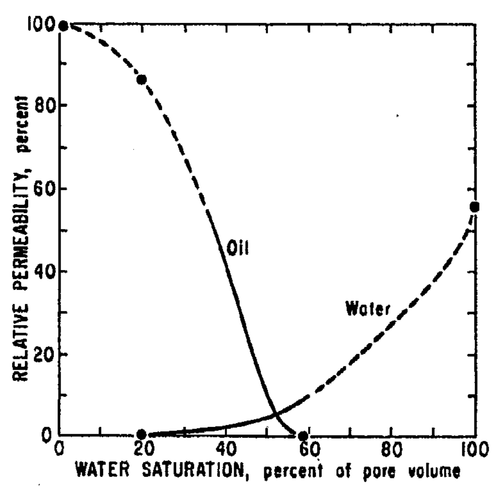

Figure 3. - Oil-water relative permeability curves, Injection Well 2.

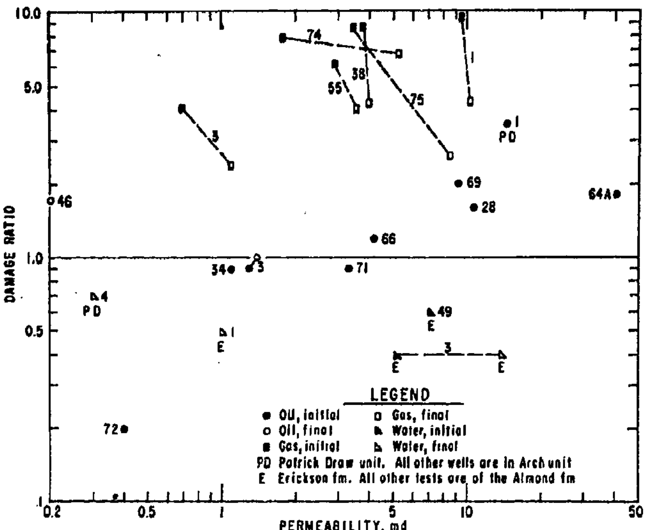

Figure 4. - Relation of damage ratio to permeability. Well numbers are shown.

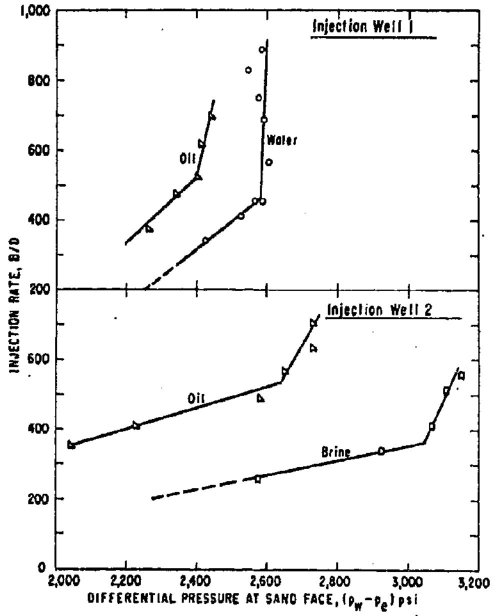

Figure 5. - Injectivity tests, Injection Wells 1 and 2.

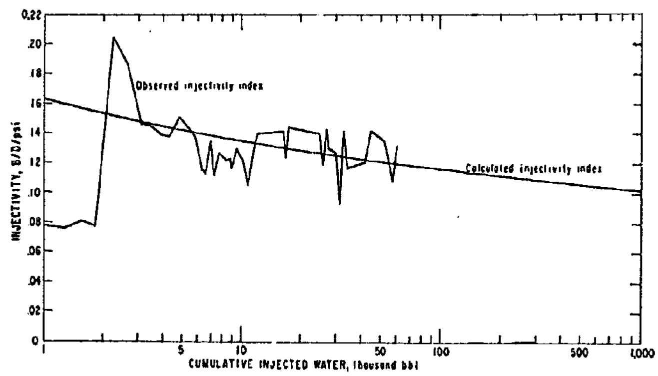

Figure 6. - Calculated and observed injectivity index, Injection Well 2.