THE ELK BASIN EMBAR-TENSLEEP RESERVOIR

PARK COUNTY, WYOMING

AND

CARBON COUNTY, MONTANA

By

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Figure

Table

Summary

Elk Basin is an old surface structure type of field that has been producing oil since 1915. The deeper Embar-Tensleep reservoir was discovered in late 1942 and intensive development followed. It is estimated that this reservoir contains 250 million barrels of recoverable oil. The reservoir was unitized in 1946 and inert gas injection, in conjunction with a gasoline plant and a sulfur plant, began in 1949. The present unit participating area is 6,322 acres, 63 per cent of which is Federal land. Approximately 44 million barrels of oil has been produced to date from the Embar-Tensleep reservoir.

The data obtained indicate that gravity drainage is now the dominant producing mechanism in the Embar-Tensleep reservoir, and that this producing mechanism is sensitive to rate. Gravity drive is considered to be highly efficient--the indicated recovery efficiency at the present time is 50 per cent. Much of this high rate of recovery can be attributed to modern production practices followed since unitization. It will be shown that unit operation and gas injection has benefited operators and royalty owners alike, and will increase the ultimate recovery. The study indicates that the present producing rate (20,000 barrels per day) is at, or near, the maximum efficient rate. With additional drilling, the present production rate probably can be maintained for 15 or more years before the loss of wells to the expanding gas cap forces a cut-back.

The production of critically needed sulfur from the high hydrogen sulfide gas, and the recovery of gasoline and liquid petroleum gases are true conservation measures.

It is to the credit of some of the operators that unitization was considered at an early date and that data were collected towards that end.

Introduction

This study was made with funds provided by the Petroleum Administration for Defense for the purpose of reviewing development and production rates in the Rocky Mountain region. Because a large reserve of oil has been developed in the Elk Basin field in the past decade, this field was selected for review of its development and capacity to produce. The modern engineering practices that have been adopted in the production of the Embar-Tensleep reservoir warrant further study. This report is primarily concerned with the Embar-Tensleep reservoir. A brief histroy of the Elk Basin field and a few comments about the other producing zones are included to provide the necessary background for those unfamiliar with the area. A large part of the data was furnished by the unit operator, the Stanolind Oil and Gas Company. For such a recent discovery a large amount of information is available. An attempt has been made to limit the size of the report by not going into great detail on a variety of subjects, and by eliminating calculations except where absolutely necessary.

Various features of the Elk Basin field have been discussed in previous publications, however, no general engineering report on the field has ever been published. A 1944 Geological Survey map by C. E. Dobbin showed the surface and subsurface geology of the field 1/. W. S. McCabe discussed the geology in an article in 1948 2/. U. S. Bureau of Mines R. I. 4768, by Espach and Fry, gave the results of a study of the characteristics of the Elk Basin Tensleep oil 3/. These are all splendid studies by recognized authorities and are recommended for reference.

__/ References given at end of paper.

No attempt has been made to weigh some of the data received, particularly that of a geologic nature. Included in this category are such items as the average porosity, the average permeability, cross sections, average connate water, structure contour maps, and compressibility coefficients. The specialists on the Elk Basin Engineering Committee have spent considerable time analyzing all available information to arrive at these conclusions, and the author could only duplicate their results.

Acknowledgments

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M. F. Green and J. W. Jones prepared some of the graphs and J. H. Hassheider, District Engineer, Thermopolis, Wyoming, who has direct supervision of operations at Elk Basin, supplied much valuable data.

General History of Field

Elk Basin was discovered in 1915 when a well in the NW$\frac{1}{4}$NW$\frac{1}{4}$, sec. 30, T. 58 N., R. 99 W., Park County, Wyoming was completed for an initial daily production of 50 barrels of 43° A.P.I. gravity oil from the Torchlight (First Wall Creek) sand in the Frontier formation at 1,335 to 1,402 feet. Later, oil was discovered in the Peay (Second Wall Creek) sand in the Frontier formation, approximately 135 feet below the Torchlight sand. As the Torchlight sand is shaly and relatively nonporous, oil is found only in scattered areas where porosity permits accumulation. The Peay sand, a porous uniform sand, has yielded 90 per cent of the Frontier oil. The average initial daily production of the Peay wells was 175 barrels per day. About 162 wells were drilled to the Frontier sands. Approximately 850 acres have been proved for Frontier production.

In 1922 gas was discovered in the Cloverly formation at 2,576 to 2,593 feet, approximately 1,000 feet below the Peay sand, in a well in the NE$\frac{1}{4}$SE$\frac{1}{4}$ sec. 24, T. 58 N., R. 100 W. Four gas wells drilled to the Cloverly formation, in the northern part of the field, had a total initial daily open flow of 160 million cubic feet; the shut-in well head pressure was 925 p.s.i. One of these wells had an estimated open flow of 90 million cubic feet a day. About 750 acres have been proved for Cloverly gas.

The major discovery at Elk Basin came in December, 1942 when the Minnelusa Oil Company struck oil in the Tensleep sandstone in their Henderson No. 1 in the NE$\frac{1}{4}$NE$\frac{1}{4}$, sec. 31, T. 58 N., R. 99 W. Initial production was 1,200 barrels of 30.2° gravity oil in 12 hours from the Tensleep at 4,494 to 4,538 feet. Owing to the strong demand for oil, intensive field development followed the discovery. The gas produced with the oil contained 13 per cent H_2S and 6 per cent CO_2. This was the highest concentration of H_2S ever encountered in any known production up to that date.

Another large oil reservoir was discovered in 1946 when Stanolind Unit 38-M, located on the crest of the structure, in the NE SE$\frac{1}{4}$NE$\frac{1}{4}$ sec. 24, T. 58 N., R. 100 W., was deepened to the Madison lime and produced 240 barrels of 30° gravity oil a day from a zone at 4,700 to 4,910 feet. The Madison gas and oil is quite similar to that produced from the Tensleep reservoir, and the gas is processed in the same manner as the Tensleep gas. The Madison structure resembles the overlying Tensleep structure. The Madison differs from the Embar-Tensleep in that it has an active water drive. The zone is unitized and there are now 4,412 acres in the participating area, 50 per cent of which is leased Federal land. The present well density is one well to each 163 acres. It is estimated that the Madison reservoir contains over 100 million barrels of recoverable oil.

In 1927, a gas drive was started in the Peay sand by returning to the formation the gas produced with the oil. The injection program has been quite successful and has resulted in the recovery of considerable additional oil. In December 1950, 20,000 cu. ft. was being injected daily at a pressure of 90 p.s.i., and 140 gallons of gasoline was being recovered. Cumulative gas injection to the Frontier sands to 1-1-51 amounted to 5,635,280,00 cu. ft.

In May 1946 with the approval of the Secretary of the Interior, the 29 working interests unitized the deeper horizons, and appointed one of their number, Stanolind Oil and Gas Company, as unit operator. Injection into the Embar-Tensleep reservoir started in September 1949.

By 1949 the Cloverly gas was nearly exhausted and in April 1949, the formation rights were sold to the Billings Gas Company. Gas is stored in the reservoir during the summer months and withdrawn during periods of peak demand. In 1949 when production ceased, 39,130,000,000 cubic feet of gas had been produced.

The status of the various producing zones in the Elk Basin field as of January 1, 1952 was as follows:

<u>Frontier Formation</u>

Active oil wells	118
Cumulative oil production	12,476,075 bbls.

<u>Cloverly Formation</u>

Active oil wells	None (used for storage)
Cumulative oil production	39,130,000,000 cu. ft.

<u>Embar-Tensleep Formations</u>

Active oil wells	128
Cumulative oil production	43,963,806 bbls.

<u>Madison Formation</u>

Active oil wells	27
Cumulative oil production	6,304,029 bbls.

During January 1952, daily production from the various zones was as follows:

Frontier	231 bbls.
Embar-Tensleep	21,077 bbls.
Madison	4,751 bbls.

To date, supply has exceeded demand at Elk Basin. However, Elk Basin has not suffered from production restrictions as much as some Wyoming fields, since the major companies active at Elk Basin have good marketing facilities. With the completion of the Platte Pipe Line to Missouri, with connections to the Chicago refinery area, an additional outlet for crude is expected.

Geography

The Elk Basin field is located on the Wyoming-Montana border along the northern rim of the Big Horn Basin, in Ts. 57 and 58 N., Rs. 99 and 100 W., 6th P.M., Park County, Wyoming and in T. 9 S., R. 23 E., P.M., Carbon County, Montana. The field is approximately 14 miles north of Powell, Wyoming on Wyoming State Highway 153. This is the only paved road leading to the field. The nearest railheads are at Powell and at Frannie, Wyoming, which is approximately 11 miles east of Elk Basin. Elk Basin is a major supplier of oil to the three refineries in the Billings, Montana, area via Interstate Pipeline. The other major outlet is to the Casper, Wyoming, refineries, and the Chicago area markets via Service Pipeline. Elk Basin's 1952 production was the largest in the State of Wyoming. The natural gas produced enters the Billings Gas Company's line, which serves Montana consumers. Sulfur is trucked to Powell and crushed and loaded into freight cars there. The natural gasoline and liquid petroleum gases are trucked from the plant.

Two smaller and separate oil and gas fields, Northwest Elk Basin and South Elk Basin, are located in the area. Northwest Elk

Basin produces from the Frontier, Lakota, and Madison formations. South Elk Basin produces from the Frontier, Cloverly, and Tensleep formations.

The basin itself, on the crest of the structure, is eroded out of the soft Niobrara shales. The Eagle and Mesaverde sandstones form an impressive rim rock 400 to 500 feet high around the basin. The southern part of the field is on a plateau. Surface altitude in the field ranges from 4,450 to 4,900 feet. The area is drained by the Clark Fork and Shoshone Rivers. Water for field operations is piped from the Clark Fork River.

The area is sparsely populated and stock raising is the chief industry.

Geology and Structure of the Field

The Elk Basin field is on a highly faulted anticlinal structure approximately 4 miles wide by 8 miles long. Oil and gas accumulation in the Frontier sands is related to this faulting (see Frontier contour map). Most of the surface faults die out with depth. The structure is a northwest-southeast trending asymmetrical anticline with dips of 20° to 50° on the northeast flank and 19° to 24° on the southwest flank. The estimated closure is 5,000 feet. The anticline was mentioned in coal reports of the U. S. Geological Survey as early as 1904 5/.

Many excellent articles have been written on the geology of the Elk Basin anticline, some of which are listed in the references. An attempt will be made to point out some of the highlights of the geology, mostly by means of maps. The surface and sub-surface formations are shown on the cross-section (fig. 1). The complex faulting in the Frontier producing zone is brought out by the Second Frontier structure contour map (fig. 2). The Geological Committee's contour map shows that very few of these faults reach the Embar. The log of a well in the NE SE$\frac{1}{4}$NE$\frac{1}{4}$, sec. 24, T. 58 N., R. 100 W., on the crest of the structure, showed the following formations tops: Frontier 930; First Wall Creek 1,070; Second Wall Creek 1,330; Thermopolis 1,389; Muddy 2,085; Cloverly 2,380; Morrison 2,535; Sundance 2,800; Gypsum Springs 3,290; Chugwater 3,330; Dinwoody 3,890; Phosphoria 3,906; Tensleep 3,936; Amsden 4,138; Madison 4,350; and total depth still in Madison, 5.013 feet. Dinwoody and Phosphoria are often called Embar by those in the oil industry and are so designated in this report. Untested formations and their estimated thickness are as follows: Three Forks, 100 feet (a few feet has been drilled in some wells); Jefferson, 300 feet; Bighorn, 300 feet; Gallatin, 500 feet; Gros Ventre, 500 feet; and Flathead, 150 feet.

Geology and Extent of the Producing Formation

The name, Embar-Tensleep, was adopted as a precautionary measure, when the unit was formed, as one or two wells in the southern part of the field had a little Embar production, and there was a possibility that Embar production might be found elsewhere on the structure. For all practical purposes the Tensleep can be considered the only producing formation. McCabe 2/ describes the Tensleep as consisting of fine-to medium-grained, white, quartzitic, friable sandstone with good porosity. Thin dolomite stringers are present throughout the formation, and the sandstone becomes increasingly dolomitic near the base. A transverse cross-section of the reservoir is shown in figure 4. Although this cross-section is somewhat typical of the reservoir as a whole, it should be realized that there is a wide variance of physical properties throughout the field.

Examination of the various cross-sections, geologic maps, and other data prepared by the unit operators, has led to the following generalizations:

The upper 10 feet of the Tensleep formation is uniformly hard and tight.

Directly below is producing zone No. 1, the most persistent and best producing zone in the reservoir. It averages about 50 feet in thickness. Usually one or two lenticular tight stringers break up zone No. 1.

Below producing zone No. 1 is a fairly persistent tight zone, usually about 10 to 20 feet thick.

This is followed by producing zone No. 2. The productive thickness varies from 20 to 30 feet. It is usually broken up by lenticular stringers.

Below producing zone No. 2 is a persistent tight zone 10 to 30 feet thick.

The last zone is classified as a "Undefined Lower Producing Zone". As the name implies, it is highly variable--it usually has one lenticular tight stringer. The productive thickness varies from 5 to 35 feet.

The base of the Tensleep is the hard, tight, dolomitic sand so typical of the formation.

The entire Tensleep formation averages 210 feet in thickness, of which the operators consider 105 feet to be "net pay". Based on this net pay, the average porosity is 15 per cent and the average horizontal permeability is 135 millidarcys. In general, the porosity of the net pay is remarkably uniform; the porosity decreases towards the north part of the structure and towards the flanks, but only on the order of one or two per cent. There is a wide variance of permeability over the structure. The permeability is greatest in the crestal areas and decreases rapidly towards the flanks. The highest values are found on the southern crest (500 md.) and the lowest near the oil-water contact (25 md.). The permeability of the northern one-quarter of the field is particularly low. Fracturing probably accounts for the high permeability in the crestal areas. The vertical permeability is also reported to be good.

The estimated connate water is low; on the order of 8 per cent.

In this study the Tensleep will be considered as one continuous reservoir. In spite of all the variations in reservoir properties noted above, there is no evidence indicating the reservoir is producing by zones.

The Unit Committee's contour map shows the conformation of the Embar-Tensleep reservoir. Total closure of the structure is estimated at 5,000 feet, of which 2,000 feet is filled with oil. The present Embar-Tensleep unit participating area is 6,322 acres, of which 3,982 acres, or 63 per cent is leased Federal land.

History of Embar-Tensleep Development

The discovery well in the Embar-Tensleep zone flowed 1,200 barrels of oil in 12 hours. The large increase in the demand for heavy oils during 1943 and 1944, owing to the war, resulted in the field being developed quite rapidly. The 25 wells completed during 1943 had an average initial production of 2,500 barrels per day. The reservoir was almost completely developed to its present well density by the end of 1945. A few edge wells have been drilled since that time in attempts to extend the participating area. Five dry holes have been drilled. Most wells are completed by setting 7" OD casing in a tight zone at the top of the Tensleep sand.

The production record of the Embar-Tensleep zone by years is given in table 1, and is also shown graphically on the performance graph (fig. 5). The amount of gas shown is not an exact figure. Those familiar with field practices appreciate the problems involved in securing good measurements of the gas produced with the oil, especially under competitive conditions. However, the data available on Elk Basin is much better than usually obtained, as unitization has permitted accurate measurements.

Pressure History

Since the significance of the pressure history of the reservoir is discussed in later chapters dealing with the producing mechanism and the rate of production, it will only be taken up in part here. The reservoir performance graph (fig. 5), Isobaric datum pressure maps (figs. 6 to 9), and Isobaric sand top pressure maps (figs. 10 and 11) are included in the report in order to give a comprehensive picture of the pressure distribution history of the reservoir. These maps show only the more significant pressure surveys. Sonolog was used to obtain some of the pressures.

Initial reservoir pressure at -400-foot datum was 2,234 p.s.i. The rapid decline in pressure in the early life of the field was due to the undersaturated nature of the reservoir oil, and the lack of any gas cap or substantial water influx to maintain the pressure. The change in the slope of the pressure curve around late 1944 or early 1945 probably indicates that gas has started to come out of solution in some of the crestal areas. Also noticeable is the decrease in the rate of pressure decline after unitization. Reservoir pressure has increased slightly since injection began because the injection volume is now exceeding the withdrawal volume.

Much useful information also can be derived from a study of the datum pressure maps. There is a marked absence of any water drive pressure gradient on all of the maps. Enough wells were included in the August 1946 survey (fig. 7) to show the low pressure area in the northern part of the field. This condition was brought about by overproduction of a low permeability area. This pressure differential is still apparent in the August 1951 survey (fig. 9). The maps show, in general, that the pressure distribution across most of the reservoir is favorable--so favorable in fact, that 10-pound pressure contours are used on the maps. Figure 9 shows that very little pressure differential existed in the main part of the field at the time of the last pressure survey. This indicates that local pressure gradients, that would interfere with the proper operation of gravity drainage, have been suppressed.

The sand top pressure maps resemble the Embar-Tensleep structure contour map, and over most of the field they can be superimposed on each other. Figures 10 and 11 show that the gas cap has expanded evenly except along the axis of the plunging noses of the anticline. The tilting gas cap is much more pronounced along the northern nose than it is along the southern nose. The overproduction of this low permeability area probably brought about most of this undesirable condition. Some of the tilt on the northern nose and all of the tilt on the southern nose (which has good permeability) is probably due to a phenomenon associated with gravity drainage. The dips along the axes of the plunging noses are less than in any other part of the reservoir, consequently, the rate of gravity drainage is lowest. Under dynamic conditions of production, the producing wells, near the noses, draw some of their oil from downstructural areas and cause a tilting of the gas cap. Regardless of the explanation for the tilting gas caps, the condition is not desirable and will cause premature shutting in of producing wells and a loss of recoverable oil.

In view of the fact that the reservoir has only been operated as a unit for slightly over five years and injection began just two years ago, the results obtained are excellent. Latest field observations indicate that the tilting gas caps are being brought under control.

Formation Fluids and Gases -- Oil in Place

It is doubtful if many petroleum reservoirs follow the classic textbook examples -- certainly the Elk Basin Embar-Tensleep reservoir does not. The wide variance in characteristics of the oil and gas in the reservoir renders some methods of reservoir analysis unworkable. This variance is shown by Figures 12 and 13 and is discussed at length by Espach and Fry 3/. On the crest of the structure the oil has a saturation pressure of 1,250 p.s.i. and has 490 cu. ft. of gas in solution per barrel, while far down on the flank of the structure, the saturation pressure is 530 p.s.i. and the gas in solution is 135 cu. ft. Also, the per cent of H_2S in the gas decreases downstructure from 19 to 5 per cent at saturation pressure. A further complication is that the per cent of H_2S in the solution gas increases as the gas comes out of solution at lower pressures. This, and other factors, make it impossible to employ conventional methods of averaging pressures, temperatures, gas-oil ratios, etc.

The A.P.I. gravity of the produced oil varies from 27° on the flanks to 31° on top of the structure. The oil is dark brown in color and has a sulfur content of about 1.9 per cent (see analysis, table 2). The Tensleep gas contains an average of 6 per cent CO_2 and 13 per cent H_2S (see analysis, table 3).

The problem of reservoir analysis seemed to resolve itself into one of two choices. One choice was to divide the reservoir up into horizontal segments, small enough so that the characteristics of the fluids would be uniform, and study each section separately. The second choice was to develop a method of weighting the various properties of the fluids, so as to arrive at workable average figures for the reservoir as a whole. The first choice would, at the best, be tedious and time consuming. The principal reason, however, that this method was not used was the difficulty of taking into account the migration of fluids across zonal boundaries. Burthchaell 6/ has developed a method for structurally weighting physical and chemical properties of high relief reservoirs for use in reservoir calculations. His method, with slight modifications, has been used in this paper.

Fundamental to any reservoir study is a knowledge of the original stock-tank oil in place. Unit engineers and geologists used pore-volume methods to arrive at a figure of 606 million barrels of stock-tank oil in place in the Embar-Tensleep reservoir. An attempt has been made to determine the original oil in place by material balance methods, both as a check on the results obtained by pore-volume methods and as an additional tool in the analysis of the reservoir. The under-saturated nature of the crude make material balance difficult to apply in this reservoir--this will be discussed at the end of the chapter. A prerequisite to the structural weighting of the fluid properties by Burthchaell's method is the determination of oil in place in various zones of the reservoir. Approximate 400-foot horizontal "slices" of the reservoir were chosen as the basis for zoning, as it was felt that the fluid properties were fairly uniform over this interval. The initial oil in place for each of these zones was calculated by pore-volume methods. It should be emphasized that the figures on the tabulation on page 24, under the column, "Stock Tank Oil in Place", were not arrived at by material balance calculations but are the result of pore-volume studies. This determination called for a knowledge of the porosity, thickness, percentage of connate water, and areal extent of each zone. The areal extent was determined from sample, electric, and radio-active logs. Since the determination of the "net pay thickness", the average porosity, and the connate water content would have involved an unnecessary duplication of work, this data was obtained from the unit operator. The unit operator arbitrarily used a 3.5 millidarcy "cut-off", i.e., sand with a permeability of less than 3.5 millidarcys was considered non-productive in figuring net pay.

The bottom-hole sample data was read from Figure 13 prepared from U. S. Bureau of Mines data. The wells, for which samples are shown in the figure, are numbered from the crest of the structure downward and the figures in parenthesis are the elevations at the top of the Tensleep sand. Pressures for other than datum (-400 feet) were calculated using the fluid gradients shown in Figure 14. The compressibility factors, for the gas, were arrived at by estimating the composition at the time period involved, calculating the pseudo-critical temperatures and pressures, and reading the factor off a published chart. Actual laboratory results were available for some conditions and these were used whenever possible. It is hoped that the calculations are self-explanatory.

MATERIAL BALANCE

Formula after Pirson 7/.

N equals
$$\frac{n\left[B + \#\,(r_n - S)\right] - (W - w)}{\#\,(S_o - S) - (B_o - B)}$$

Definition of symbols used in calculations:

N is the number of barrels of stock-tank oil originally in place.

n is number of units of stock-tank oil produced up to a given time.

P_o is original absolute bottom-hole pressure, psia, before any production began.

p is absolute bottom-hole pressure, psia, at the time when n units of stock-tank oil have been produced.

B_o is initial reservoir volume of one unit of stock-tank oil with its complement of dissolved gas at P_o.

B is reservoir volume of one unit of stock-tank oil with its complement of dissolved gas at p.

$\#$ is reservoir volume of one unit of gas at standard conditions of temperature (60°F) and pressure (14.7 psia) when subjected to reservoir pressure (p) and formation temperature (T_f).

S_o is solubility of gas in oil on a unit per unit basis at pressure P_o.

S is solubility of gas in oil, on a unit per unit basis at pressure p.

r_n is net average gas-oil ratio in standard cubic feet of gas per unit of stock-tank oil; net gas-oil ratio is the difference between the gross or produced gas-oil ratio and injected or recycled gas-oil ratio.

W is total number of units of water which encroached into reservoir during production of n units of stock-tank oil.

w is total number of units of water produced with n units of stock-tank oil.

STRUCTURAL WEIGHTING
OF
PRESSURE AND FLUID DATA

Initial Conditions

-400 foot datum pressure equals 2,234 psia.

Interval	Stock Tank Oil in Place *	Mid-Interval Pressure	F.V.F.	Solution GOR
+600 to +200	122,854,000	1,957	1.22	469
+200 to -200	129,866,000	2,095	1.20	450
-200 to -600	129,178,000	2,234	1.18	350
-600 to -1000	116,202,000	2,375	1.12	200
-1000 to -1300	81,178,000	2,502	1.07	125
-1300 to P.L.	27,396,000	2,612	1.06	105
	606,674,000			

Interval	F.V.F. x Stock Tank Oil	Solution GOR x Stock Tank Oil
+600 to +200	149,881, --	576,185, ---
+200 to -200	155,839, --	584,397,
-200 to -600	152,430,	452,123,
-600 to -1000	130,146,	232,404,
-1000 to -1300	86,860,	101,472,
-1300 to P.L.	29,040,	28,765,
	704,196, ---	1,975,346, -----

Weighted Formation Volume Factor equals $\frac{704,196,000}{606,674,000}$ or 1.1607

Weighted Gas-Oil Ratio equals $\frac{197,534,600,000}{606,674,000}$ or 326 cubic feet per barrel at 14.4 psia.

* By pore-volume methods.

In these calculations, it is assumed that the oil produced from the lower intervals is replaced by oil draining down from the upper intervals. This, of course, assumes that the dominant producing mechanism is gravity (or segregation) drive. All the production from the reservoir is assumed to come from the crestal interval, as the gas cap expands, and the stock tank oil in place, in this crestal interval, is decreased accordingly. Since the volume of the lower intervals is considered to remain constant (no water influx), the stock tank oil in place, in these lower intervals, varies inversely as the relative formation volume factor.

STRUCTURAL WEIGHTING
OF
PRESSURE AND FLUID DATA

July 1, 1947 BHP Survey

-400-foot datum pressure equals 1,297 psia.

Interval	Stock Tank Oil in Place	Mid-Interval Pressure	F.V.F.	Solution GOR
+500 to +200	108,200,000	1,036	1.22	420
+200 to -200	128,423,000	1,158	1.225	439
-200 to -600	128,238,000	1,297	1.185	350
-600 to -1000	115,567,000	1,438	1.125	210
-1000 to -1300	80,955,000	1,565	1.09	125
-1300 to P.L.	27,368,000	1,675	1.087	105
	588,751,000			

Interval	F.V.F. x Stock Tank Oil	Solution GOR x Stock Tank Oil
+500 to +200	132,004, ---	454,440,----
+200 to -200	157,318	563,776
-200 to -600	151,962	448,833
-600 to -1000	130,012	242,690
-1000 to -1300	88,240	101,193
-1300 to P. L.	29,749	28,736
	689,285,---	1,839,668 ----

Weighted Formation Volume Factor -- 1.171

Weighted Solution Gas-Oil Ratio -- 312 cu. ft. per bbl. at 14.4 psia.

MATERIAL BALANCE
for
July 1947

-400-foot datum pressure -- 1,297 psia.

n -- 17,923,210 barrels or 100,500,000 cubic feet of oil.

P_o -- 2,234 psia.

B_o -- 1.1607

B -- 1.171

-- $\dfrac{\text{Base Press.}}{\text{Form. Press.}} \times \dfrac{\text{Form. Temp.}}{\text{Base Temp.}} \times$ Compressibility

or $\dfrac{14.4}{1,297} \times \dfrac{583}{520} \times 0.728$ equals $\underline{0.00906}$

S_o -- 326 cubic feet per barrel at 14.4 psia.

S -- 312 cubic feet per barrel at 14.4 psia.

r_n -- 376 cubic feet per barrel at 14.7 or 384 at 14.4 psia.

w -- 193,301 barrels or 1,083,000 cubic feet.

$$N \text{ equals } \frac{100,500,000 \left[1.171 + .00906 \left(\dfrac{384-312}{5.61}\right)\right] + 1,083,000}{.00906 \left(\dfrac{326-312}{5.61}\right) - (1.1607 - 1.171)}$$

or $\underline{712,060,000}$ bbls. of stock tank oil originally in place.

STRUCTURAL WEIGHTING
OF
PRESSURE AND FLUID DATA

April 1, 1949 BHP Survey

-400-foot datum pressure equals 1,189 psia.

Interval	Stock Tank Oil in Place	Mid-Interval Pressure	F.V.F.	Solution GOR
+460 to +200	97,446,000	934	1.208	400
+200 to -200	129,295,000	1,050	1.216	420
-200 to -600	128,130,000	1,189	1.186	350
-600 to -1000	115,484,000	1,330	1.127	210
-1000 to -1300	80,926,000	1,457	1.090	125
-1300 to P.L.	27,363,000	1,567	1.087	105
	578,644,000			

Interval	F.V.F. x Stock Tank Oil	Solution GOR x Stock Tank Oil
+460 to +200	117,714, ---	389,784, ----
+200 to -200	157,222	543,039
-200 to -600	151,962	448,455
-600 to -1000	130,150	242,516
-1000 to -1300	88,209	101,157
-1300 to P.L.	29,743	28,731
	675,000 ---	1,753,582 ----

Weighted Formation Volume Factor -- 1.167

Weighted Solution Gas-Oil Ratio -- 303 cu.ft. per bbl. at 14.4 psia.

MATERIAL BALANCE
for
April 1949

-400-foot datum pressure -- 1,189 psia.

n -- 28,031,405 barrels of oil

P_o -- 2,234 psia.

B_o -- 1.161

B -- 1.167

-- $\frac{14.4}{1,189}$ x $\frac{583}{520}$ x 0.75 equals 0.01019

S_o -- 326 cubic feet per barrel at 14.4 psia.

S -- 303 cubic feet per barrel at 14.4 psia.

r_n -- 373 cubic feet per barrel 14.7 or 381 at 14.4 psia.

w -- 348,568 barrels

Which when substituted in the formula gives us:

N equals 746,000,000 barrels of stock tank oil originally in place.

STRUCTURAL WEIGHTING
OF
PRESSURE AND FLUID DATA

July 1, 1950 BHP Survey

-400-foot datum pressure equals 1,181 psia.

Interval	Stock Tank Oil in Place	Mid-Interval Pressure	F.V.F.	Solution GOR
+365 to +200	92,255,000	944	1.210	400
+200 to -200	129,860,000	1,042	1.216	420
-200 to -600	128,196,000	1,181	1.186	350
-600 to -1000	115,272,000	1,322	1.127	210
-1000 to -1300	80,057,000	1,449	1.090	125
-1300 to P.L.	26,716,000	1,559	1.087	105
	572,356,000			

Interval	F.V.F. x Stock Tank Oil	Solution GOR x Stock Tank Oil
+365 to +200	111,628, ---	369,020, ----
+200 to -200	157,909	545,412
-200 to -600	152,040	448,686
-600 to -1000	129,911	242,071
-1000 to -1300	87,262	100,071
-1300 to P.L.	29,040	28,051
	667,790, ---	1,733,311, ----

Weighted Formation Volume Factor -- 1.1667

Weighted Solution Gas-Oil Ratio -- 303 cu.ft. per barrel at 14.4 psia.

MATERIAL BALANCE
for
July 1950

-400-foot datum pressure -- 1,181 psia.

n -- 34,317,956 barrels of oil.

P_o -- 2,234 psia.

B_o -- 1.161

B -- 1.167

-- $\frac{14.4}{1,181} \times \frac{583}{520} \times 0.75$ equals 0.01026

S_o -- 326 cubic feet per barrel at 14.4 psia.

S -- 303 cubic feet per barrel at 14.4 psia.

r_n -- 385 cubic feet per barrel at 14.7 or 393 at 14.4 psia.

In this case 393 is the produced GOR. As of July 1, 1950, 1,589,495,000 cubic feet of residue and inert gas had been injected into the reservoir. Since the injected gas has a different compressibility factor than the produced gas a substraction of the injected gas from the produced gas to give a net gas-oil ratio would not give a true answer. The following computations were used to account for the space occupied in the reservoir by the injected gas:

(for injected gas) equals $\frac{14.7}{898*} \times \frac{583}{520} \times 1.005$ equals .01847

* 898 psia was the average +400-foot datum pressure on 3-20-50 prior to injection and is the most reasonable figure for gas cap pressure in July, 1950, the author has available.

Space occupied by injected gas:

1,589,495,000 x 0.01847 equals 28,780,000 cu. ft.

or 5,130,000 barrels

w -- 400,025 barrels

N equals

$$\frac{34{,}317{,}956\left[1.167 + 0.01026\left(\frac{393-303}{5.61}\right)\right] + 400{,}025 - 5{,}130{,}000}{0.01026\left(\frac{326-303}{5.61}\right) - (1.161 - 1.167)}$$

or 852,000,000 bbls. of stock tank oil originally in place.

Actually the datum pressure used (1,181 psia), although the field pressure in July 1950, is not the correct pressure to use as far as the reservoir fluids are concerned. An extention of the pressure decline curve shown on Figure 5 shows that the datum pressure probably feel to at least 1,163 psia before injection began in September 1949. It is the accepted thought that you cannot restore the characteristics of reservoir fluids by raising the pressure back to the former level. A re-computation for July 1950, using reservoir fluid characteristics for a datum pressure of 1,163 psia gives an answer of:

838,000,000 barrels of stock tank oil originally in place.

These material balances were calculated on the basis of the most significant pressure surveys; numerous others have been run. Ignoring the first calculation for July 1950, the three answers average out 765 million barrels of oil initially in place, which is considerably higher than the 606 million barrel pore-volume estimate. The higher values obtained by material balance methods are partly due to the fact that zones of less than 3.5 millidarcys permeability were ignored in the pore-volume work. These tight zones do contain oil, even though it probably never will be produced, and this oil does affect material balance calculations. How well the method of structural weighting used reflects the true picture is unknown. Material balance is severely handicapped at Elk Basin. The Tensleep oil was originally undersaturated and contained relatively little gas in solution, consequently a considerable pressure reduction has resulted in very little change in fluid properties such as gas in solution and the reservoir volume factor. Material balance is based on these changes in properties. With these considerations in mind, the agreement of values is considered satisfactory. The pore-volume estimate of the oil in place is undoubtedly the more reliable figure.

The Producing Mechanism and the Rate of Production

In this section of the report an attempt will be made to determine what types of reservoir drives have affected the Embar-Tensleep reservoir. The various types of reservoir drives as defined by Pirson 7/ are: 1. Expulsion by internal gas expansion (here called internal gas drive) in which the expulsion energy is derived from volumetric expansion of solution gas liberated from the reservoir oil. 2. Expulsion by external gas expansion (here called gas cap expansion drive). 3. Frontal drives (here called water drive) by either water or gas under which the expulsion energy is provided by the invasion of water or gas under pressure. 4. Segregation, or gravity drive (here called gravity drive or gravity drainage) in which the expulsion energy is primarily derived from the differential density of the reservoir fluids and gas-cap expansion as a result of oil and gas counterflow. 5. Capillary drive (here lumped with gravity drive) in which the expulsion energy is derived from the differential pressure existing between the oil, gas, and/or water phases. Evidence seems to indicate that at the present time gravity drive is the dominant force in the Elk Basin Embar-Tensleep reservoir.

Evidence of internal gas drive.

There have been localized indications of internal gas drive, especially in the very early life of the field when some wells were produced in excess of 1,000 barrels per day, but since unitization internal gas drive has been of minor importance. Apparently, the early flush production has not caused any permanent damage to the reservoir--controlled production since unitization became effective has resulted in the re-saturation of these damaged areas. It is perhaps worth noting here that conditions beyond the control of the various operators limited production and prevented permanent damage to the reservoir. Incomplete development, lack of pipeline capacity, and low market demand have turned out to be blessings in disguise. Production characteristics usually determine whether a certain type of reservoir drive is effective. In the case of the Embar-Tensleep reservoir, around 17 per cent of the recoverable oil has been produced; if internal gas drive were effective the gas-oil ration should now be rising sharply and the productive efficiency (barrels of oil produced per pound of pressure drop) should be falling. Figures 5 and 15 show that neither of these conditions prevail. Since internal gas drive is the least effective of the various reservoir producing mechanisms, the field should continue to be produced so as to avoid this type of control.

Evidence of gas cap drive.

There was no original gas cap in the reservoir so no energy has been derived from the expansion of an original gas cap.

Evidence of water drive.

Unfortunately, the absence or presence of a water drive in the Embar-Tensleep reservoir is not so easy to establish. Points tending to substantiate the absence of an active water drive are: That the water table has not been entirely established; the water table does not occur at a constant level throughout the field; very little water has been produced (1 per cent of production); there has been no measurable increase in the elevation of the water table; the absence of a water drive gradient on datum pressure maps (figs. 6 to 9); and the fair check of the material balance equation, which is calculated on the assumption of no water influx. Also the decreasing permeability towards the flanks would tend to hold back edge water. On the other side of the discussion is the drop in pressure, with reservoir withdrawals, of Garth Well No. 1, on the western flank, and U.S.A. Tract No. 3, Well No. 1, on the east flank, completed in the water zone and retained for pressure measurements. This pressure drop definitely establishes communication between the oil and water zones. Furthermore, the pressure drop implies water movement into the reservoir. Since the underlying Madison reservoir has a water drive, it is rather hard to accept the premise that there is none in the Embar-

Tensleep. The present program of pressure maintenance by injection into the gas cap should tend to hold back, or retard, any water influx into the reservoir. The conclusion is that at the present time water drive is not an effective force in the reservoir, but it cannot be ignored and may be important later in the life of the reservoir.

Evidence of gravity drive.

Production experience to date seems to indicate that gravity drive is now the dominant productive mechanism in the Embar-Tensleep reservoir. At this point, some general discussion of gravity drive seems in order. Gravity drive might more accurately be called segregation drive as Pirson suggests. Although gravity has long been recognized as a minor force in petroleum reservoirs, it has been only in recent years that its importance as a highly efficient recovery mechanism has been fully appreciated. Some authorities consider gravity drive the most efficient method known. In this type of drive, oil moves down-structure to the producing wells and gas moves up-structure to fill the space vacated. An over-simplified illustration of gravity drainage would be that of draining oil from a stock tank--as the oil is withdrawn, the fluid level in the tank drops. Gravity drainage principles require that a gas cap be formed to replace the oil produced. Also to be effective, oil must be produced from the flanks of the structure at or near the solution gas-oil ratio--excess gas production would lead to inefficient internal gas drive. In line with this, wells must be shut-in as the expanding gas cap reaches them.

However, the important factor in producing a field under a gravity control is rate! The oil cannot be produced faster than it will drain down structure, or internal gas drive conditions will result. The controlling factor is the rate of drainage in the capillary zone, at the gas-oil contact.

Just what is the optimum rate in a reservoir that is presumed to be controlled by gravity drive? From a recovery viewpoint it would be a rate so low that every drop of oil that could possibly be drained from the sand would be recovered. From an economic viewpoint it might be the fastest rate at which you could produce and sell the oil. The former would require hundreds of years, the latter would result in waste. In this study the optimum rate is considered to be the maximum rate at which the oil will drain down structure without internal gas drive conditions resulting. This rate depends on many factors all of which are peculiar to the reservoir being studied. Elk Basin has several physical characteristics which are considered favorable for gravity drainage. These are: large closure, high angle of dip, fairly uniform porosity, good permeability (including vertical permeability), apparent lack of an active water drive, low connate water, and a continuous reservoir (based on field behavior). Viscosity of the oil and gas, the relative permeability to oil and gas, and the capillary characteristics of the sand itself are other items to be considered. It is apparent that no two portions of the reservoir could possibly possess all of these physical characteristics to the same degree. A correct field rate, then, is a compromise between the proper rates for individual portions of the reservoir.

Some of these physical properties can be determined closely, some approximately, and some are in the realm of engineering "guesses". A brief resume of how some of the better known characteristics are thought to be affecting the Embar-Tensleep reservoir follows. Theory tells us that the gravity drainage rate is directly proportional to the sine of the angle of dip--which ranges from 0.2 to 0.7 at Elk Basin. Theoretically, then, the steeply dipping northeast flank can be produced more rapidly than the southwest one. In practice, the operators are "holding back" the steep flank to maintain an even gas-oil contact. The rate of drainage is also a function of oil viscosity--at present conditions of pressure, this varies from about 1.3 centipoises on the crest of the structure to about 4.0 on the flanks 3/. This means that the oil on the crest (where the gas-oil contact is now located) will drain more rapidly than it will on the flanks. This condition is further accentuated by the better permeabilities on the crest of the structure.

The correct rate is also a function of time. The pace is set by the rate of drainage at the gas-oil contact. At the present time, the gas-oil interface is located at the crest of the structure where conditions are more favorable for drainage than they will be when the interface is located far down the flanks. Fundamental to correct gravity control is the shutting in of wells as the gas cap encroaches on them--this means less and less wells are available for producing oil as time goes on. At the present time, the productive capacity of the reservoir wells exceeds the optimum rate of drainage. The reverse will be true later in the life of the reservoir (see prediction of future performance and fig. 16).

Gas cap injection has increased the permissible rate. Under natural conditions of reservoir control by gravity drive, the oil drains down structure and the gas, released by the oil, flows up structure to the gas cap. This counterflow of gas interferes with the downward flow of oil. This upward flow is eliminated, at Elk Basin, in two ways. The reservoir pressure is maintained so that no free gas is released and the solution gas, produced with the oil, is processed in the plant and injected directly into the gas cap. This elimination of harmful gas counterflow also explains the increased recoveries expected to result from injection operations. The higher rates permit more oil to be recovered before production drops below a point where the wells have to be abandoned.

Therefore, the determination of the correct rate of production is complicated by all of the aforementioned factors and properties and probably by others of which engineers are not cognizant. This writer feels that the correct rate of production, at Elk Basin, can be more accurately determined from actual production experience than from theoretical relations. The obvious disadvantage of working with actual production experience is that a withdrawal rate has to be imposed on the field before it can be determined if it is the proper rate, although some careful extension of lower production rate results is probably permissible. The Embar-Tensleep reservoir, as a whole, has never been produced at the maximum rate.

It is felt that if the following conditions are fulfilled the reservoir is not exceeding the optimum rate: 1. The gas cap is spreading evenly; 2. The producing GOR is at or near the solution GOR;

3. The recovery factor is high. The recovery factor is defined as the ratio of the oil produced to the oil originally in place in the volume now occupied by the gas cap (with allowances for liquid expansion). Since most of the Embar-Tensleep reservoir meets these three requirements, it follows that the maximum field rate is at, or above, the last steady rate (20,000 barrels a day). At various stages in the history of the reservoir, the production from portions of the reservoir has exceeded the amount that would normally be assigned to that portion on the basis of acreage or gravity drainage theory. If this excess production has resulted in localized internal gas drive condtions, it would be unwise to assign this production rate to the reservoir as a whole. No damage would indicate efficient performance and suggest the reservoir could safely sustain this higher rate. Some of the areas of the reservoir have produced without apparent damage at rates as high as 38,000 barrels (if applied to the field as a whole), while some other areas, particularly in the northern part of the field, have been unable to sustain their share of the present field rates. The tilting gas caps on the structural noses pose the most difficult problems in arriving at a maximum permissible production rate. These tilting gas caps have been previously discussed under pressure history. When the gas cap reaches a well it is lost to production, and the chances of the well returning to production are slim. Some of the oil left around wells shut in because of high GOR's may be recovered by the remaining wells, further down structure, but hardly all of it. A tilting gas cap is essentially gas channeling, a production danger signal everyone in the industry is familiar

with. It would seem unwise, at the present time, to raise the daily production substantially above the present level unless production could be distributed to prevent any further gas channeling on the structural noses, particularly the northern nose.

Gravity drive has been the primary producing mechanism in the Embar-Tensleep reservoir since quite early in the life of the field. This is in marked contrast to most other gravity drive fields mentioned in the literature 8/. The fields mentioned were in advanced stages of depletion before gravity drive became effective. The explanation for the difference in behavior lies in the early productive history of the fields. Most of the fields mentioned were produced "wide open" under inefficient gas drive condtions. It was only after the high well day rates could not be sustained that gravity drive became effective. The early influence of gravity drive at Elk Basin, made possible by restrictions on production, has resulted in exceptionally good recovery. Based on the space now filled by the gas cap, the recovery is now on the order of 50 per cent. There is talk, and hope, of achieving 60 and 70 per cent recovery (based on pore-volume estimates of oil in place). The author's 250 million barrel recovery estimate represents 41 per cent of the oil in place by pore-volume methods and 33 per cent of the oil in place by material balance methods, and could be conservative.

The selection of the best producing mechanism for any reservoir is all important. The only way to determine the most efficient mechanism is by the application of sound engineering studies. The author does not mean to imply that gravity drainage will work well in every field or that the high recoveries obtained at Elk Basin can be realized everywhere. However, in a large field the size of Elk Basin, a one per cent increase in the ultimate yield would more than repay the cost of a good engineering program.

Analysis of Present and Past Producing Methods

For all practical purposes the history of the Elk Basin Embar-Tensleep reservoir dates from January 1943. The discovery well flowed 1,200 barrels of 30° gravity oil in 12 hours from a sand that had been presumed to be very hard and quite tight. From the very beginning, the discovery was considered to be of major importance and rapid development, by the various operators, followed. In this study, the history of the field has been divided into four time periods: Discovery to the middle of 1944; the middle of 1944 to unitization (middle of 1946); unitization to pressure maintenance (September 1949); and pressure maintenance to the present time. A glance at the reservoir performance graph (fig. 5) will give a good idea of the rate of development and production. Note that in late 1943, daily production was 15,000 barrels from only 24 wells. The Embar-Tensleep reservoir was almost completely developed in the space of three years. Various economic conditions, mentioned previously, forced a drop in well-day production and kept field production at a reasonable figure. Since unitization, the average daily production for the Embar-Tensleep reservoir has stayed around 15,000 barrels--in recent months the rate has been increased to around 20,000 barrels.

Initially all of the oil in the reservoir was undersaturated and most of the early flush production was produced as a result of crude expansion. The additional source of energy to sustain this high well-day rate was undoubtedly internal gas expansion. The gas produced with the oil, being "sour", was flared and burned. It is felt that this large reservoir was able to produce at these high well-day rates without damage because the gas saturation has to reach a minimum value (maybe 10 per cent) before free gas flow develops. Gas-oil ratios stayed reasonably low during the early life of the field, indicating very little free gas production. There was some evidence of a small gas cap forming in the northern part of the field during 1944, which would indicate that excessive production from this low permeability area had liberated some free gas. It was late 1944 before the bottom-hole pressure dropped below the saturation pressure of the crestal oil. It is probably safe to assume that up to the middle of 1944, when about four million barrels of oil had been produced, that fluid expansion and internal gas drive had accounted for nearly all of the production.

As can be seen from the performance graph, production was cut back in early 1944. The period July 1944 to July 1946 marked an intermediate phase in the history of the reservoir. The productive efficiency (see fig. 15) began its upward rise, and it is probable that gravity drive supplanted internal gas drive as the dominant producing mechanism. Because of the limited market, some degree of selective withdrawals, by the various operators, was possible during this intermediate period.

From the effective date of unitization in July 1946, to the start of injection operations in September 1946, the field was produced as a unit disregarding lease boundaries. Increased efficiency was achieved by operating the field on an engineering basis. The usual advantages of unit operating were all realized at Elk Basin. Gas was conserved, production was allocated, tank batteries, gathering systems, and supplies were consolidated, needless drilling was eliminated, and the number of operating personnel reduced. One of the outstanding achievements was the restoring of some of the damaged areas to optimum saturation conditions by carefully controlling production.

The final phase in the operation of the Embar-Tensleep reservoir began with injection operations and has continued to the present time. Production is allocated to the wells on the basis of the calculated oil in place. All the gas produced from the Embar-Tensleep and the Madison reservoirs is processed in the Elk Basin plant. The reaction of the reservoir is carefully observed by competent engineering personnel.

It is to the credit of the various operators that unitization of the deeper reservoirs was considered from the very beginning. Some operators instituted a plan whereby information that would be valuable in reservoir planning would be collected. It is extremely fortunate that this vital early data, missing in so many fields, was obtained. In 1943, the U. S. Bureau of Mines, at the request of the Geological Survey, secured bottom-hole samples that have proven invaluable in analyzing the reservoir 3/. Frequent bottom-hole pressure and gas-oil ratio surveys have been made.

An intensive study, conducted prior to unitization, indicated that some form of pressure maintenance was desirable. At the time, it was thought that the Embar-Tensleep reservoir was under volumetric control (internal gas drive) with a partial water drive of 3,000 to 4,000 barrels a day. Pressure maintenance by water injection was determined to be the most attractive economically of any of the methods considered. Although a sufficient supply of water presented a problem, it probably could have been solved if water injection had been approved. It is thought that gas injection was chosen because of the close relationship between gasoline plant operations and gas injection. Although inert gas injection operations and gravity drainage control are the main themes of this paper, the author does not want to give the impression that the recovery methods now being used are the only methods. There is every reason to believe that a program of primary water injection could have been successful. There is a good possibility that water may be injected, as a supplementary drive, later in the life of the reservoir. As the water production from the Madison Limestone Reservoir increases, it will present a disposal problem. A logical use of the water would be for injection into the Embar-Tensleep reservoir.

Gas injection presented a different problem. The gas produved with the oil (see analysis, table 3) contained high percentages of H_2S, CO_2, and N_2. The gas would be extremely difficult to handle, unless it was sweetened. Moreover, the sweetening and extraction processes would have left an insufficient quantity of residue gas for injection. Sufficient outside gas was not available to make up the difference. Air could not be injected because it would form a corrosive mixture with H_2S. To overcome these problems, it was decided to burn the gas (thereby increasing the volume) and inject the inert combustion gases. This decision was a bold one in view of the fact that a smaller project of this type, in another state, was an utter failure because of extreme corrosion. The engineers were confident that the corrosion was due to the water present in the manufactured gas and that dehydration would eliminate the corrosion--performance to date has justified this confidence.

This program of pressure maintenance had two broad aims as far as the reservoir was concerned. One was to preserve desirable reservoir fluid properties by preventing any gas from coming out of solution. The other was to provide an additional source of energy to aid in producing the oil. Table 4 shows how the trend towards more pumping wells has been reversed by injection. The production of sulfur, gasoline, and liquid petroleum gases was an integral part of the plan and made the inert gas production possible. Since this discussion is confined to the reservoir, the Elk Basin Plant is briefly described in another section of the report.

In 1947, estimates were made that 180 million barrels could be produced without unitization and that it would take 54 years to do it. With unitization, it was estimated that 196 million barrels could be produced in 43 years. With gas injection, a recovery of 230 million barrels was predicted in 25 years. It is the author's opinion that these recovery figures appear to be too low and 190 million, 210 million, and 250 million barrels, respectively, would be conservative estimates at this time. This upward revision is due to the unexpectedly good recoveries to date. However, while the recoveries utilizing gravity drive, will probably exceed former estimates, the time necessary to recover the oil will be extended. This 250 million-barrel figure is based primarily on production experience to date. It is doubtful if the indicated recovery efficiency of 50 per cent of the oil in place can be maintained for the life of the reservoir. Oil is now being taken from the crestal areas under the most favorable conditions for gravity drainage. The pressure is high, the oil viscosity is low, the permeability is good, the equipment new, and the hydrostatic head is high. The estimate is based on an assumed recovery efficiency of 50 per cent until the gas-oil contact drops to the -600-foot level, and 30 per cent thereafter.

Prediction of Future Performance

If gravity drive continues to act as efficiently as presently indicated, the Elk Basin Embar-Tensleep reservoir should be capable of producing at the rate of 20,000 barrels a day for many years. This field rate must inevitably fall as the gas cap expands and more and more wells are shut in because of high gas-oil ratios. This loss of wells is shown graphically in Figure 16. If the present program of increasing the bottom-hole pressure by injection is continued, the well productivity (theoretically speaking) will not drop. In actual practice, however, the Productivity Index of wells seems to decline slightly, even though the pressure is maintained. On the assumption that the average well in the field is capable of producing 275 barrels oil a day, only 73 wells will be needed to maintain a 20,000-barrel per day rate. Approximately 120 million barrels of oil will have been produced before the number of available wells drops to this figure--this would be in 1963 at a rate of 20,000 barrels per day. There are at least 10 logical locations for additional wells in the field. An intelligent program of drilling new wells in flank areas, where they would have the longest productive life, would enable the operators to maintain high rates of production past the time limits shown. Since wells will be lost to production from the crest towards the flanks in the Embar-Tensleep reservoir and from the flanks toward the crest in the Madison reservoir (due to the water drive), a timely program of plugging back, or deepening, would utilize wells twice. It is also quite possible that formation packers could be used to control the gas-oil ratios, in wells near the gas cap, thereby extending the producing life of the wells.

A critical phase in the later life of the field will be reached when the volume of the gas produced with the oil is not enough to justify the continued operation of the Elk Basin Plant. This minimum volume is probably around 4 to $4\frac{1}{2}$ million cubic feet per day. This condition is somewhat unusual, as most pressure maintenance and cycling plants are faced with the problem of handling more and more gas as time goes by.

Just how long the field will continue to produce and how much oil would have to be produced to justify continued operations is intimately tied in with future economic conditions. Oil could be a precious commodity 75 years from now.

The author cannot help wondering if a use will be found for the billions of cubic feet of inert gas (mostly nitrogen) that will be in the reservoir at depletion.

Brief Description of the Elk Basin Plant

The plant design, unique in the United States, represents one of the finest examples of unit conservation to be found. In addition to recovering liquid hydrocarbons, sweetening sales gas, and producing inert gas for injection, the plant also converts the toxic H_2S gas, which is usually burned, into pure sulfur 9/. A field network, consisting of 10 miles of thin wall pipe ranging in diameter from 6 to 22 inches, brings the low pressure gas from the Embar-Tensleep and Madison tank batteries to the plant. Low spots in the line have underground drip collection tanks. The gas is compressed and the H_2S and CO_2 removed by a two-stage amine process. After further compression, liquid hydrocarbons are removed in absorption towers. Part of the sweetened gas is used for fuel, part is burned in a special boiler to produce inert gas, and the remainder is sold to the Billings Gas Company. The H_2S is converted to sulfur by a modification of the Claus process. The inert gas is compressed to around 1,350 p.s.i. for return to the Embar-Tensleep reservoir. Three 1,000 hp. and five 1,200 hp. gas engine driven compressors are used in the plant. Two 1,000 kw. steam turbine driven generators supply 10,000 kw. hrs. per day for field and camp use. Approximately 8,000 barrels of water per day is pumped from the Clark Fork River, west of the field, through a 16.6-mile, 6-inch pipeline for plant and field use.

Design basis for this seven million dollar plant was:

Gas intake, cu. ft. per day	12,000,000
Propane, gals. per day	19,000
Butane, gals. per day	20,000
Natural gasoline, gals. per day	17,000
Sales gas, cu. ft. per day	4,000,000
Inert gas, cu.ft. per day at 1,500 p.s.i.	14,000,000
Sulfur, long tons per day	74

The plant has never been operated at capacity because of the method of producing the field. In January 1952, the Elk Basin Plant was operating as follows:

Gas intake, cu. ft. per day	9,094,000
Propane, gals. per day	11,800
Butane, gals. per day	13,050
Natural gasoline, gals. per day	9,950
Sales gas, cu. ft. per day	1,600,000
Inert gas, cu. ft. per day	10,400,000
Sulfur, long tons per day	45

Note: Slightly higher than an average month.

Inert gas is injected into 8 wells, on the crest of the structure, and surplus liquid petroleum gases are injected into a well on the northeastern flank. Cumulative injection to 1-1-52 amounted to 6,956,447,000 cu. ft. of residue gas and inert gas and 9,764,611 gallons of gasoline and liquid petroleum gases. The percentage composition of the produced inert gas is 89.0 N_2, 0.1 CO, 0.63 rare gases, and 10.39 CO_2.

Some Operating Problems at Elk Basin

Elk Basin was the first of the high H_2S fields in the Big Horn Basin. Although the deadly nature of high concentrations of H_2S was known at the time of discovery, it was not fully appreciated; especially by oil field personnel accustomed to working with sweet gases. Several men have lost their lives in Elk Basin and other high H_2S fields. Some of the safety precautions now being taken at Elk Basin are: pumpers travel in pairs, gas masks are worn when any contact with gas is probable, and remote gauging and sampling equipment have been installed.

Liquid level gauges which permit the oil level in the tanks to be read from ground level were installed. Corrosion rendered them inoperative in a few days. Patient experimentation finally developed a satisfactory gauge that the pumpers would trust. Ordinary remote sampling devices also failed until they were modified for the H_2S and the cold weather.

A blanket of inert gas is maintained above the oil in the zinc coated stock tanks to minimize corrosion and explosion hazards. Since the tanks cannot stand much pressure, low pressure separators have to be used. The separators are mounted on platforms slightly above the level of the tanks, and the oil flows by gravity to the tanks. A thermostatically controlled pump injects methanol into the gas, during cold weather, after it leaves the separators to prevent freezing and the formation of hydrates.

Although the injection gas is dehydrated to a dew point of -20°F, enough rust is formed in the injection lines to plug the sand face of the injection wells. Another source of plugging is the lubricating oil carried over from the compressors. The injection wells are cleaned by periodic blowing and the spotting of methanol opposite the formation. Periodic Nitrogen determinations are run on the produced gas to check on the spread of the injected gas in the gas cap. Some wells are equipped with a Kobe type head so that a pressure bomb can be run in the annulus.

Conclusions

1. Gravity drive is now the dominant producing mechanism in the Embar-Tensleep reservoir.

2. The indicated recovery efficiency to date is high--around 50 per cent.

3. Unit operation has benefited operators and royalty owners alike and will increase the ultimate recovery.

4. The gas injection program will further increase the amount of oil recovered and also permit higher rates of withdrawals.

5. The present producing rate (20,000 barrels per day) is at, or near, the maximum efficient rate.

6. The production of critically needed sulfur from the hydrogen sulfide gas and the recovery of gasoline and liquid petroleum gas are true conservation measures.

Recommendations

1. The reservoir should continue to be operated with gas cap injection so as to take full advantage of gravity drive.

2. Production should be adjusted to control the gas channeling along the axes of the structural noses.

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9/ Lyon, L.R., Feagan, R. A. Jr., and Manley, H. B.: Elk Basin Plant a Conservation Project. Oil and Gas Jour., vol. 48, June 30, 1949, pp. 70-89. Also in Pet. Engr., vol. 21, July 1949, pp. A-41 to A-48.

TABLE 1

Elk Basin Embar-Tensleep Production
by Years

Cumulative Production

Year	Oil (Barrels)	Water (Barrels)	Gas (Mcf)	Approx. Cum. Prod. GOR	Injection Gas (Mcf)
1942	8,458		4,788	474	
1943	2,226,880		869,597	386	
1944	5,597,771	21,195	2,096,894	371	
1945	9,419,261	54,937	3,323,689	350	
1946	15,025,094	135,012	5,087,573	337	
1947	20,806,211	225,963	6,867,028	329	
1948	26,681,938	324,744	8,526,367	319	
1949	31,839,346	382,411	10,534,715	330	536,020
1950	37,010,629	412,925	12,735,421	344	3,068,102
1951	43,963,806	456,156	15,156,905	345	6,956,447

CRUDE OIL ANALYSIS

ndition of sample Trace of water present — Laboratory No. [illegible]
alysis by J. G. Crawford at Casper, Wyoming — Date Dec. 8, 1942

GENERAL CHARACTERISTICS

ecific Gravity .877 — A.P.I. Gravity 29.9
r cent Sulphur 1.66 % — Pour Point Below 5°F
ybolt Universal Viscosity at 70°F. 78 sec. — Color Brownish black
ybolt Universal Viscosity at 100°F. 58 sec. — Base Intermediate

DISTILLATION, BUREAU OF MINES, HEMPEL METHOD

stillation at atmospheric pressure 628 mm. — First Drop 45°C (113°F)

action No.	Cut at °C.	°F.	Per Cent	Sum Per Cent	Sp.Gr. 60/60°F.	°A.P.I. 60°F.	C.I.	S.U. Visc. 100°F.	Cloud Test °F.
1	50	122	0.5	0.5	.700	70.6			
2	75	167	1.9	2.4					
3	100	212	3.6	6.0	.711	67.6			
4	125	257	5.0	11.0	.732	61.8			
5	150	302	5.3	16.3	.756	55.7			
6	175	347	4.7	20.9	.775	51.1			
7	200	392	4.0	24.9	.790	47.6			
8	225	437	4.9	29.8	.806	44.1			
9	250	482	5.3	35.1	.825	40.0			
10	275	527	6.5	41.6	.844	36.2			

stillation continued at 40 mm.

11	200	392	0.3	0.3					
12	225	437	5.8	6.1	.880	29.3		52	20
13	250	482	6.1	12.2	.901	25.6		68	35
14	275	527	5.8	18.0	.917	22.8		105	50
15	300	572	6.4	24.4	.928	21.0		202	65

iduum

rbon residue of residuum 12.5% — Carbon residue of crude 4.0%

APPROXIMATE SUMMARY

	Per cent	Sp.Gr. 60/60°F.	°A.P.I. 60°F.	Viscosity, secs.
ht gasoline	6.0	.707	68.6	
al gasoline and naphtha	24.9	.748	57.7	
osene distillate	10.2	.816	41.9	
oil	9.1	.853	34.4	Below 50
viscous lubricating distillate	12.0	.884-.915	28.6-23.1	50-100
ium lubricating distillate	6.2	.915-.928	23.1-21.0	100-200
cous lubricating distillate	3.3	.928-.934	21.0-20.0	Above 200
iduum	30.0	.988	11.7	
tillation loss	3.7			

9-546
(September 1943)

UNITED STATES
DEPARTMENT OF THE INTERIOR
GEOLOGICAL SURVEY

Casper, Wyoming, Laboratory

INFORMATION TO BE FURNISHED WITH EACH SAMPLE OF CRUDE OIL

Marks on container Tagged   Lab. No. 43-080 (Filled in by Chemist)

Field Elk Basin, Wyoming   Farm or Lease Cheyenne 044186
(Serial Number)

Operator Minnelusa Oil Corporation   Address

Well No. 1-NT, NE ¼ NE ¼ sec. 31, T 58, R 99W, 6th

Sample taken by R. R. Patterson   Date taken 11-28-42

Name of sand (or formation) from which this sample
was obtained (if unknown or doubtful, so state) Tensleep

Depth to top of sand 4494   Depth to bottom of sand

Depth well drilled 4538   Present depth 4538

Depths at which casing is perforated

If drill stem test, depth at which packer is set

Depth at which last shut-off string of casing
is landed, cemented or mudded (state which)

Depths (if known) where water encountered

If acidized, dates, depths and gallons of acid

Place where sample was obtained (drill stem,
lead line, flow tank, bailer, etc.) Flow Tank

Method of production (flowing, pumping, air, etc.) Flow

Initial Production:	Present Production:
Barrels Oil 2,500	Barrels Oil New well - completed
Barrels Water none	Barrels Water for production 11-[illegible]
Gas Volume	Gas Volume
Rock Pressure	Rock Pressure

REASON FOR ANALYSIS

Note: A sample for analysis is of no value unless accompanied by above information. Complete information on this form is to be attached to each sample container; otherwise sample will be disregarded. Be sure to seal or tightly cork all containers immediately after sampling and label all samples so that there will be no confusion.

TABLE 3

**Pod
Analysis
of
Elk Basin Tensleep Gas ***

Constituent	%(Volume)
Hydrogen Sulfide	18.99%
Oxygen	.0
Nitrogen	.57
Carbon Dioxide	7.10
Methane	46.72
Ethane	15.30
Propane	6.05
Iso-butane	1.32
Normal butane	2.08
Iso-pentane	.95
Normal	.35
Hexane plus	.57
	100.00%

G.P.M. for 22# Product	.881
G.P.M. of Iso-pentane plus	.7355
Gravity by Pod	.967
Gravity by Weight	.973
Average "N" by Pod	1.630
Average "N" by Combustion	1.561

* Not an average analysis -- the composition of the produced gas varies widely over the reservoir.

TABLE 4

Number of Pumping and Flowing Wells

Date	No. of Active Wells	Flowing	Pumping	Injection
1942	1	1	-	-
1943	26	26	-	-
1944	84	78	6	-
1945	128	74	53	-
May 1946	128	55	71	-
May 1947	128	40	61	-
May 1948	127	28	76	-
May 1949	124	21	83	8
May 1950	128	18	94	8
May 1951	128	20	90	9
Feb 1952	128	35	81	9

Tabulation does not include shut-in wells.

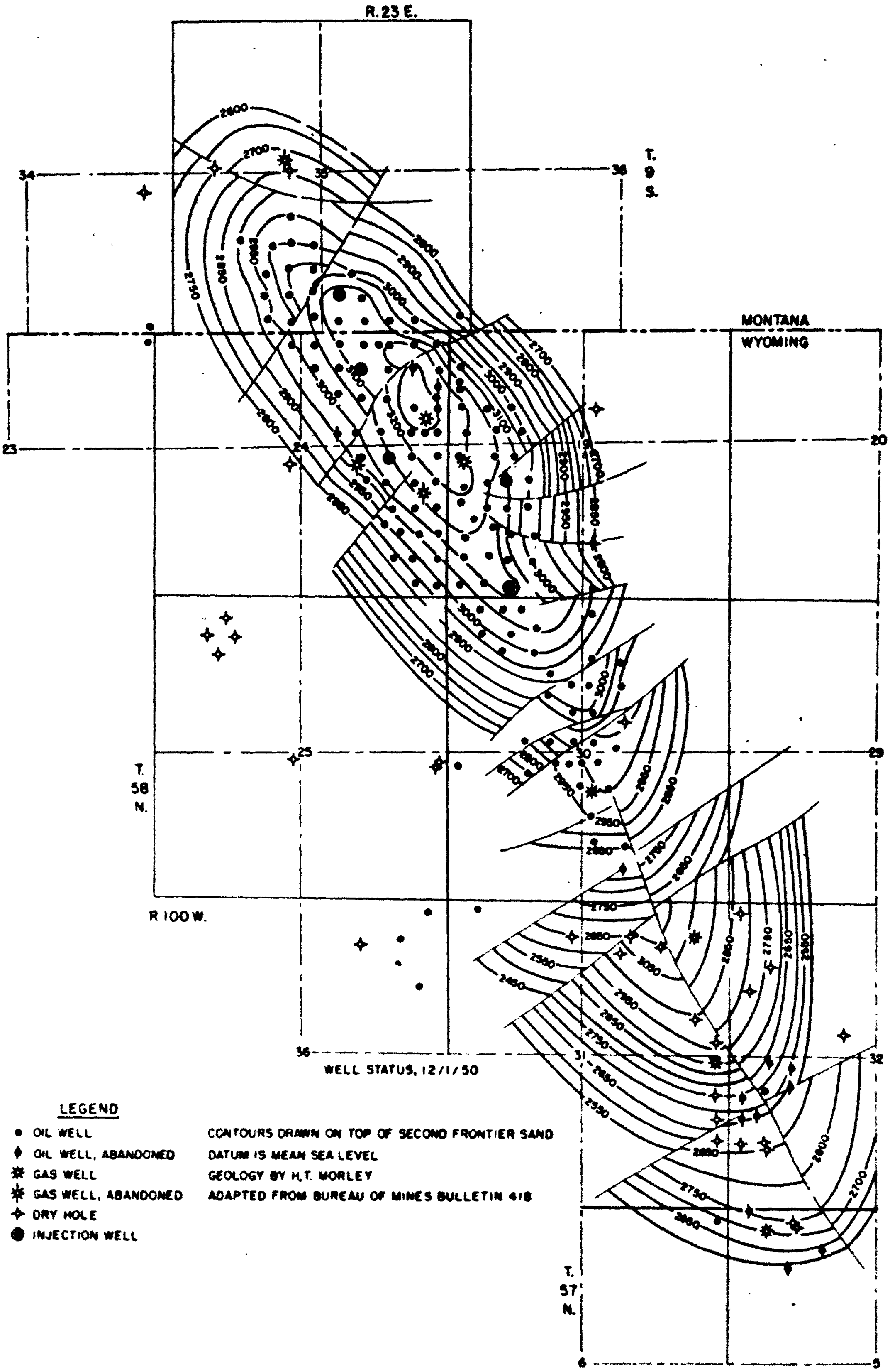


FIGURE 2 STRUCTURE CONTOUR MAP OF ELK BASIN FIELD.
CARBON COUNTY, MONTANA & PARK COUNTY, WYOMING

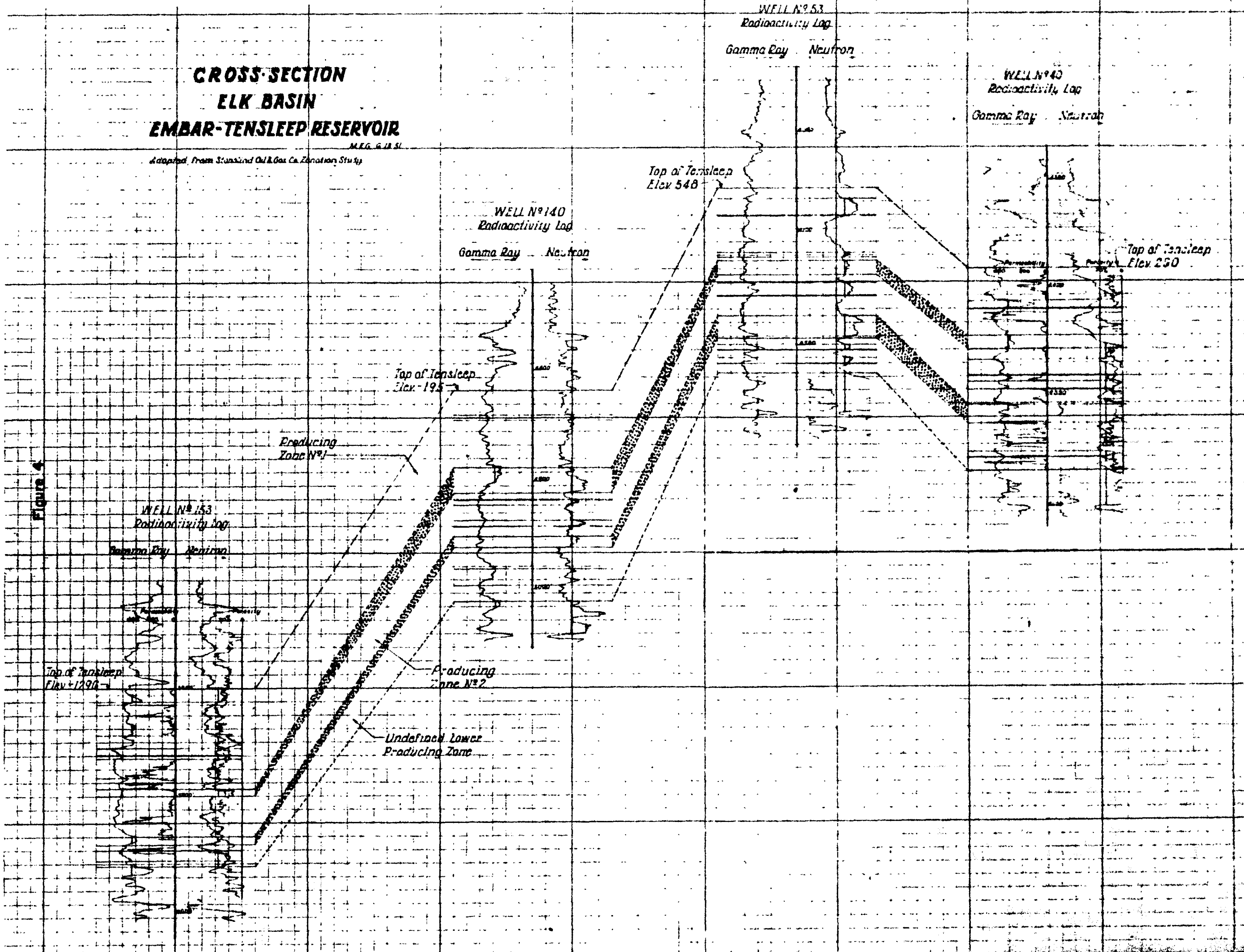

CROSS-SECTION
ELK BASIN
EMBAR-TENSLEEP RESERVOIR
Adapted From Stanolind Oil & Gas Co. Zonation Study
WELL Nº 153
Radioactivity Log
Gamma Ray
Neutron
Top of Tensleep
Elev +1290
WELL Nº 140
Radioactivity Log
Gamma Ray
Neutron
Top of Tensleep
Elev -195
Producing
Zone Nº1
Producing
Zone Nº2
Undefined Lower
Producing Zone
WELL Nº 53
Radioactivity Log
Gamma Ray
Neutron
Top of Tensleep
Elev 548
WELL Nº 40
Radioactivity Log
Gamma Ray
Neutron
Top of Tensleep
Elev 250

Figure 4

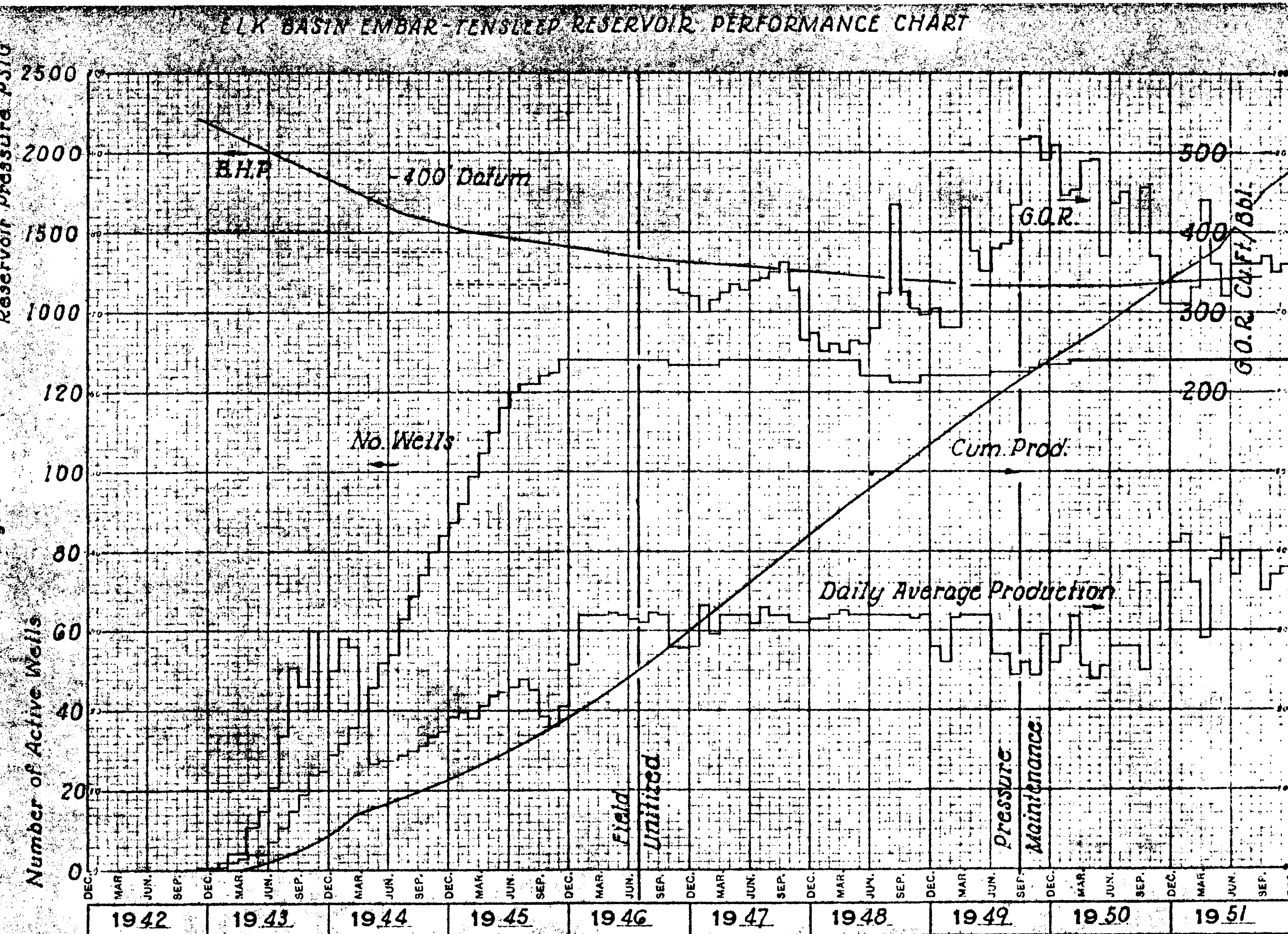

ELK BASIN EMBAR-TENSLEEP RESERVOIR PERFORMANCE CHART
Reservoir Pressure PSIG
2500
2000
1500
1000
120
100
80
60
40
20
0
Number of Active Wells
B.H.P.
-400' Datum
No. Wells
G.O.R.
G.O.R. Cu.Ft./Bbl.
500
400
300
200
Cum. Prod.
Daily Average Production
Field
Unitized
Pressure
Maintenance
35
30
25
20
15
10
5
0
Daily Average Oil Production 10³ Bbl.s./Day
Cumulative Oil Production 10⁶ Bbls.
DEC. MAR. JUN. SEP.
1942
1943
1944
1945
1946
1947
1948
1949
1950
1951

Figure 6

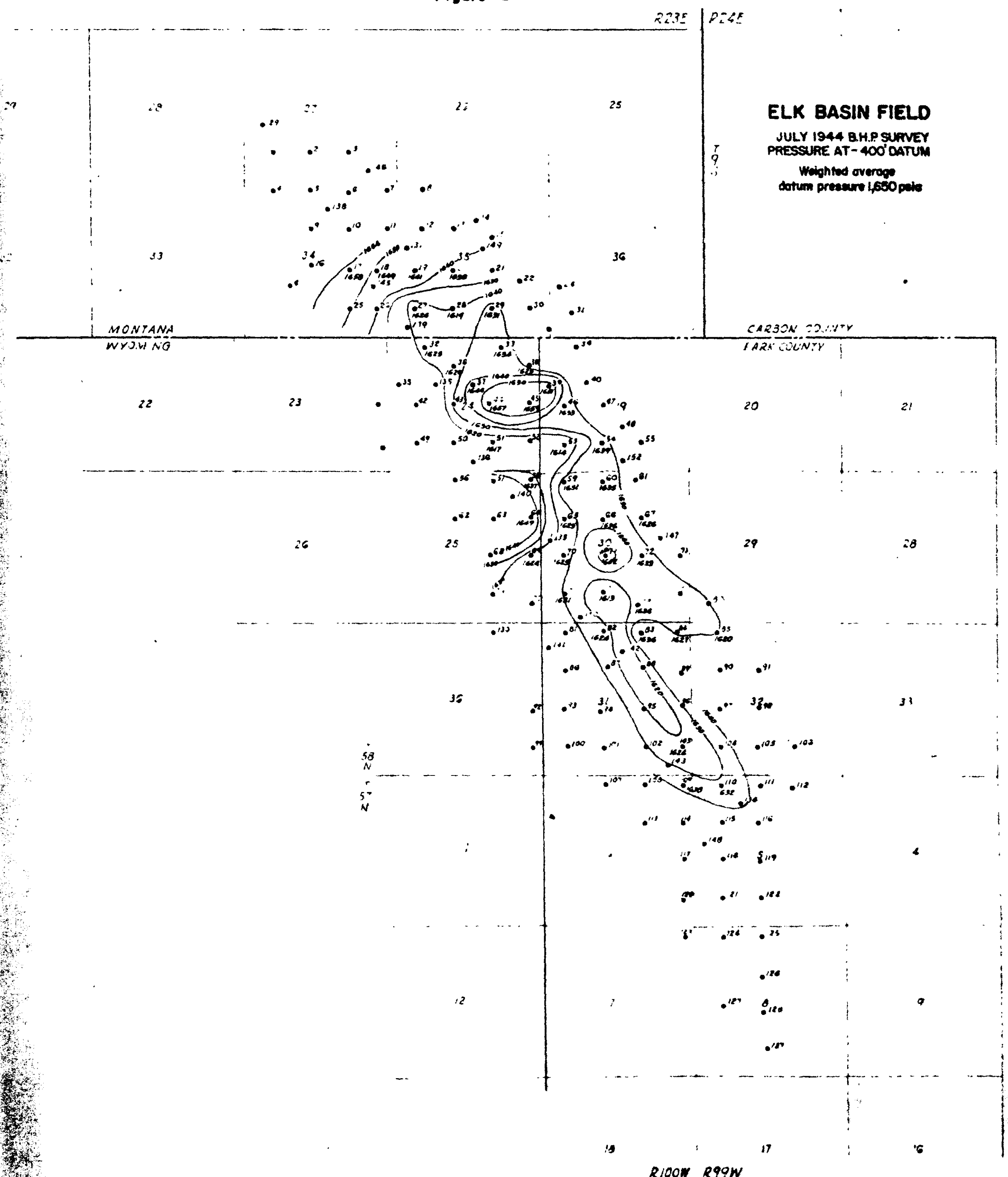
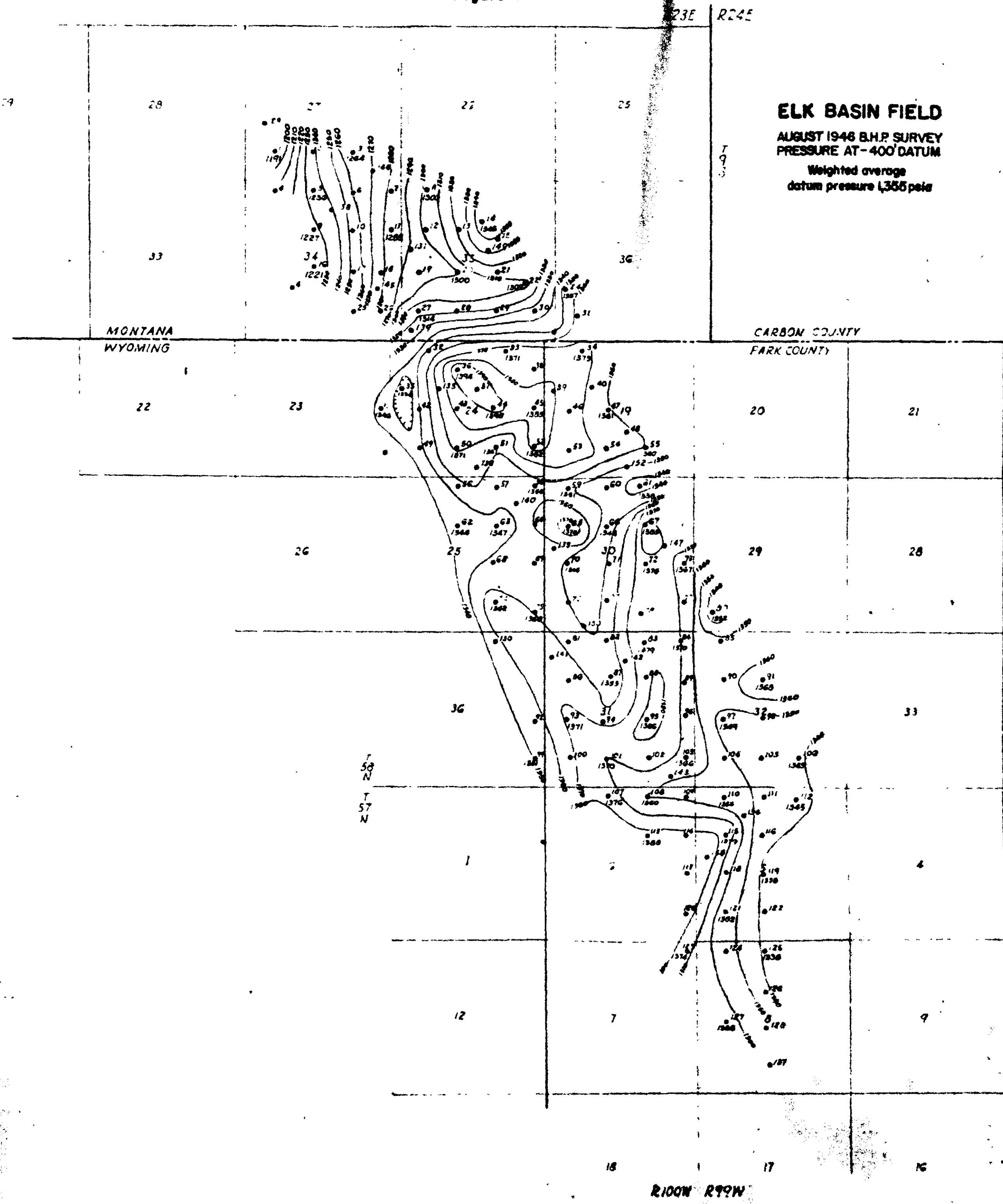

ELK BASIN FIELD
JULY 1944 B.H.P. SURVEY
PRESSURE AT -400' DATUM
Weighted average
datum pressure 1,650 psia
MONTANA
WYOMING
CARBON COUNTY
PARK COUNTY
R23E
R24E
R100W R99W
58 N
57 N

Figure 7



ELK BASIN FIELD
AUGUST 1946 B.H.P. SURVEY
PRESSURE AT -400' DATUM
Weighted average
datum pressure 1,355 psia
MONTANA
WYOMING
CARBON COUNTY
PARK COUNTY
R23E
R24E
T 58 N
T 57 N
R100W
R99W

Figure 8

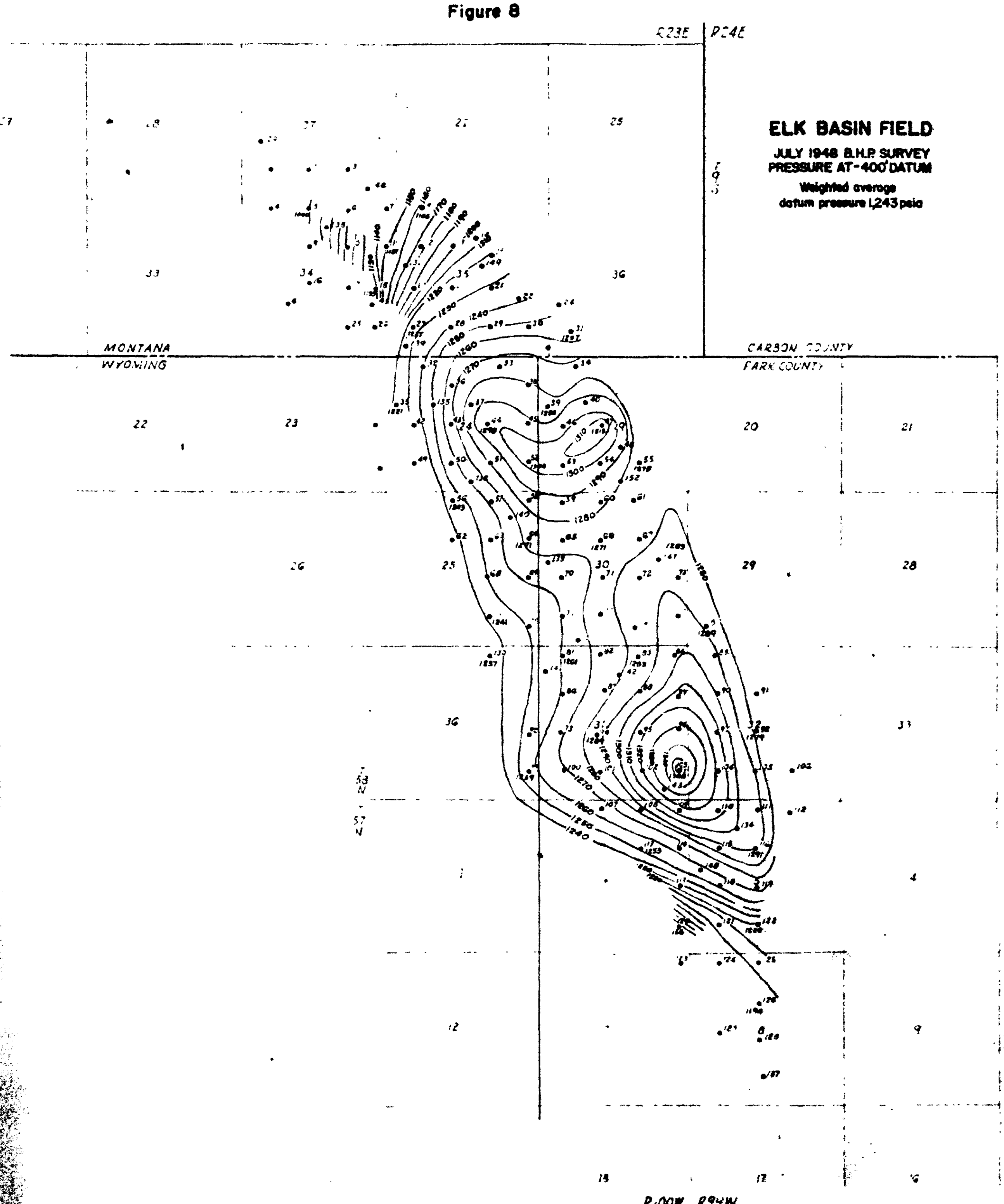

ELK BASIN FIELD
JULY 1948 B.H.P. SURVEY
PRESSURE AT -400' DATUM
Weighted average
datum pressure 1,243 psia
R23E
R24E
MONTANA
WYOMING
CARBON COUNTY
PARK COUNTY
R100W. R94W.

Figure 9

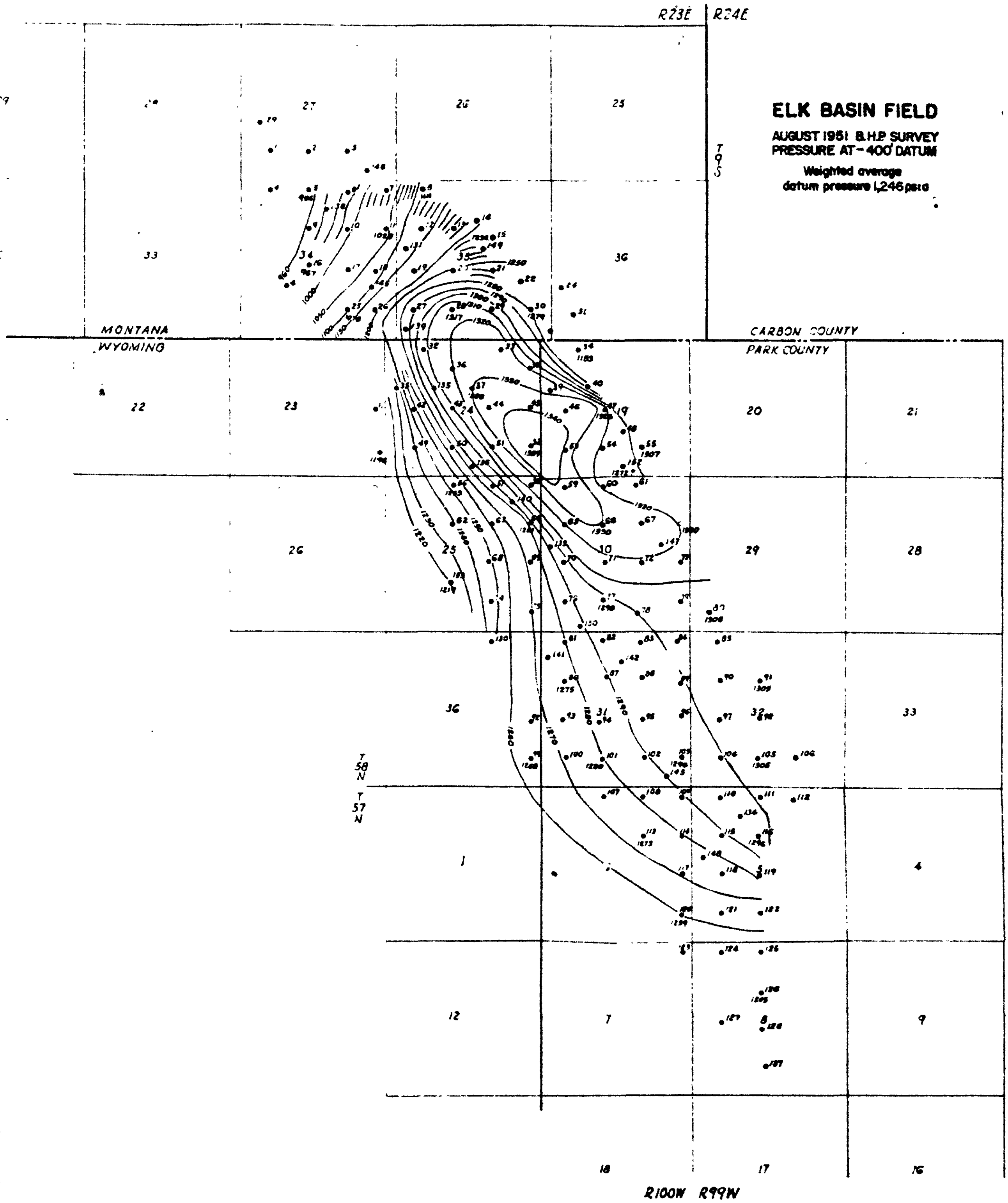

ELK BASIN FIELD
AUGUST 1951 B.H.P. SURVEY
PRESSURE AT -400' DATUM
Weighted average
datum pressure 1,246 psia
R23E
R24E
MONTANA
WYOMING
CARBON COUNTY
PARK COUNTY
R100W
R99W

Figure 10

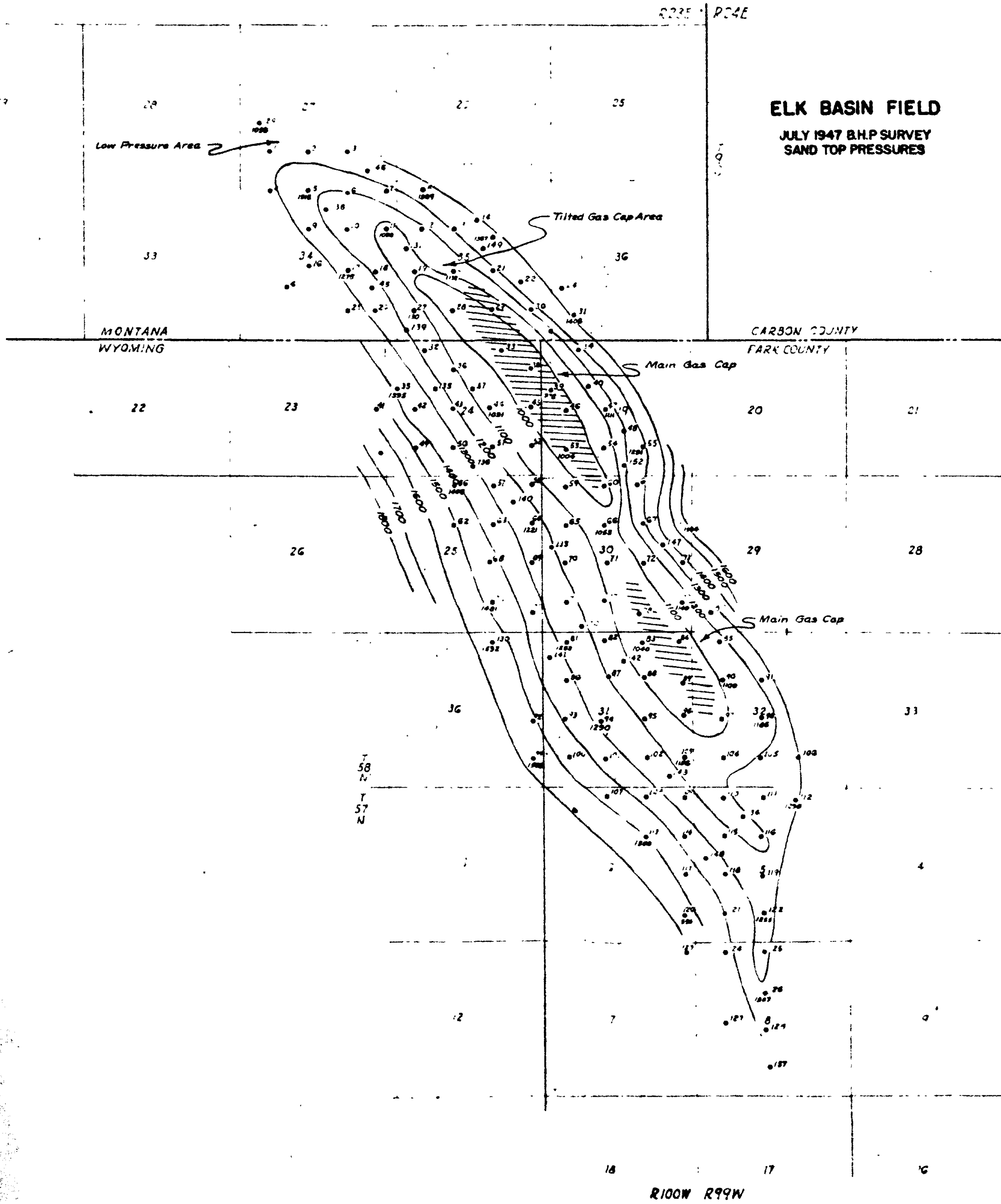
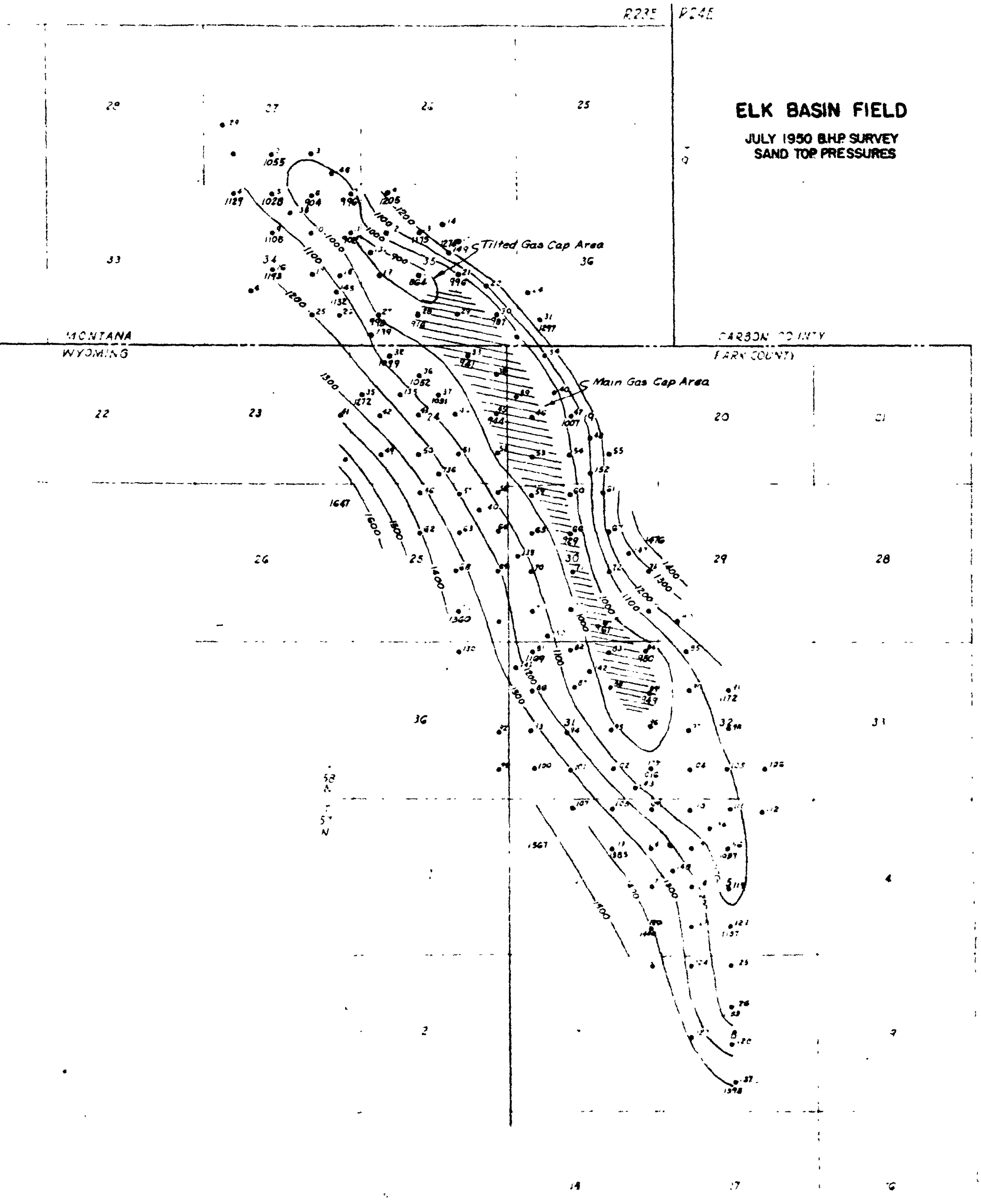

ELK BASIN FIELD
JULY 1947 B.H.P SURVEY
SAND TOP PRESSURES
Low Pressure Area
Tilted Gas Cap Area
Main Gas Cap
Main Gas Cap
MONTANA
WYOMING
CARBON COUNTY
PARK COUNTY
R100W R99W

Figure 11



ELK BASIN FIELD
JULY 1950 B.H.P. SURVEY
SAND TOP PRESSURES
Tilted Gas Cap Area
Main Gas Cap Area
MONTANA
WYOMING
CARBON COUNTY
PARK COUNTY
R.100W R.99W

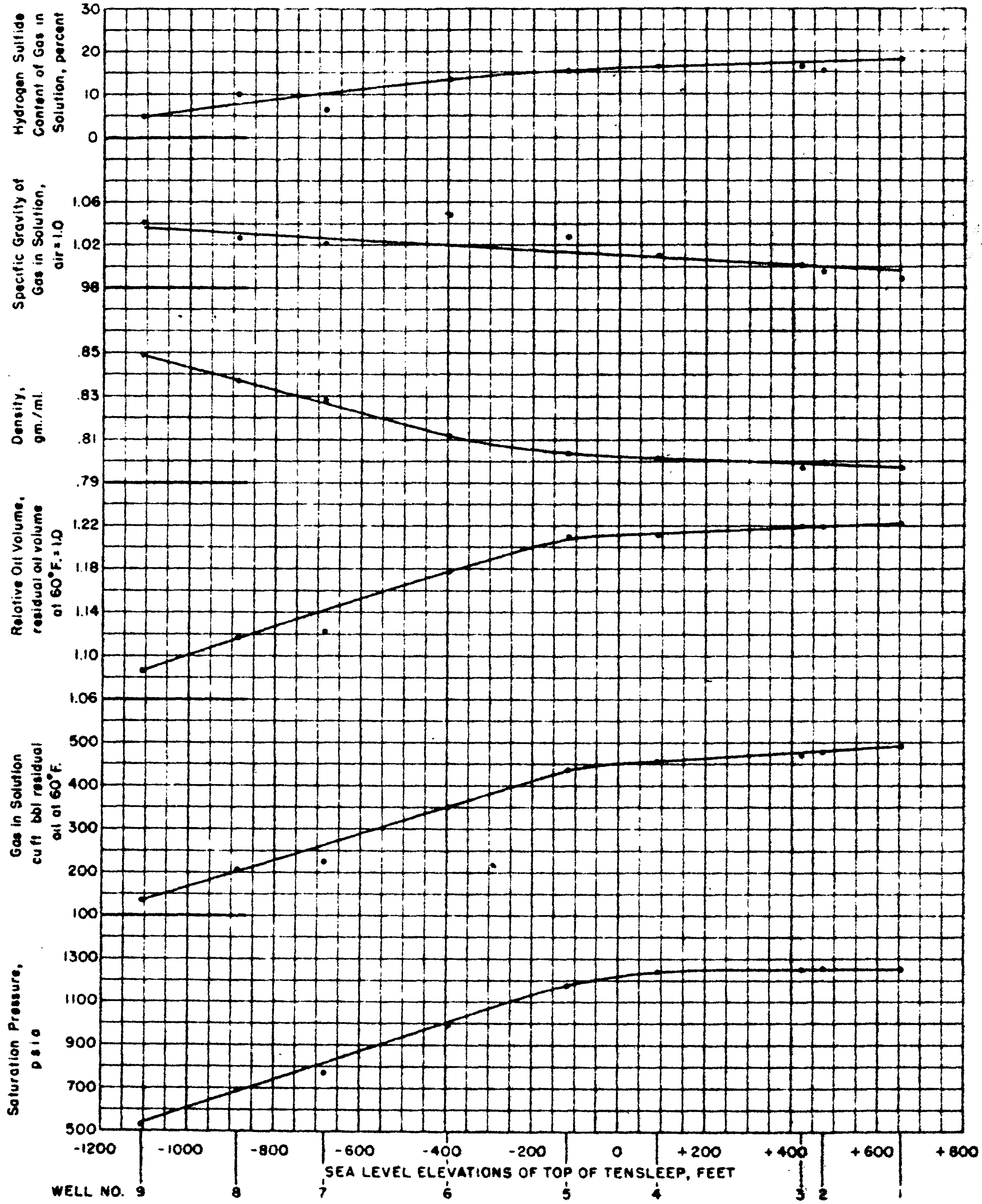
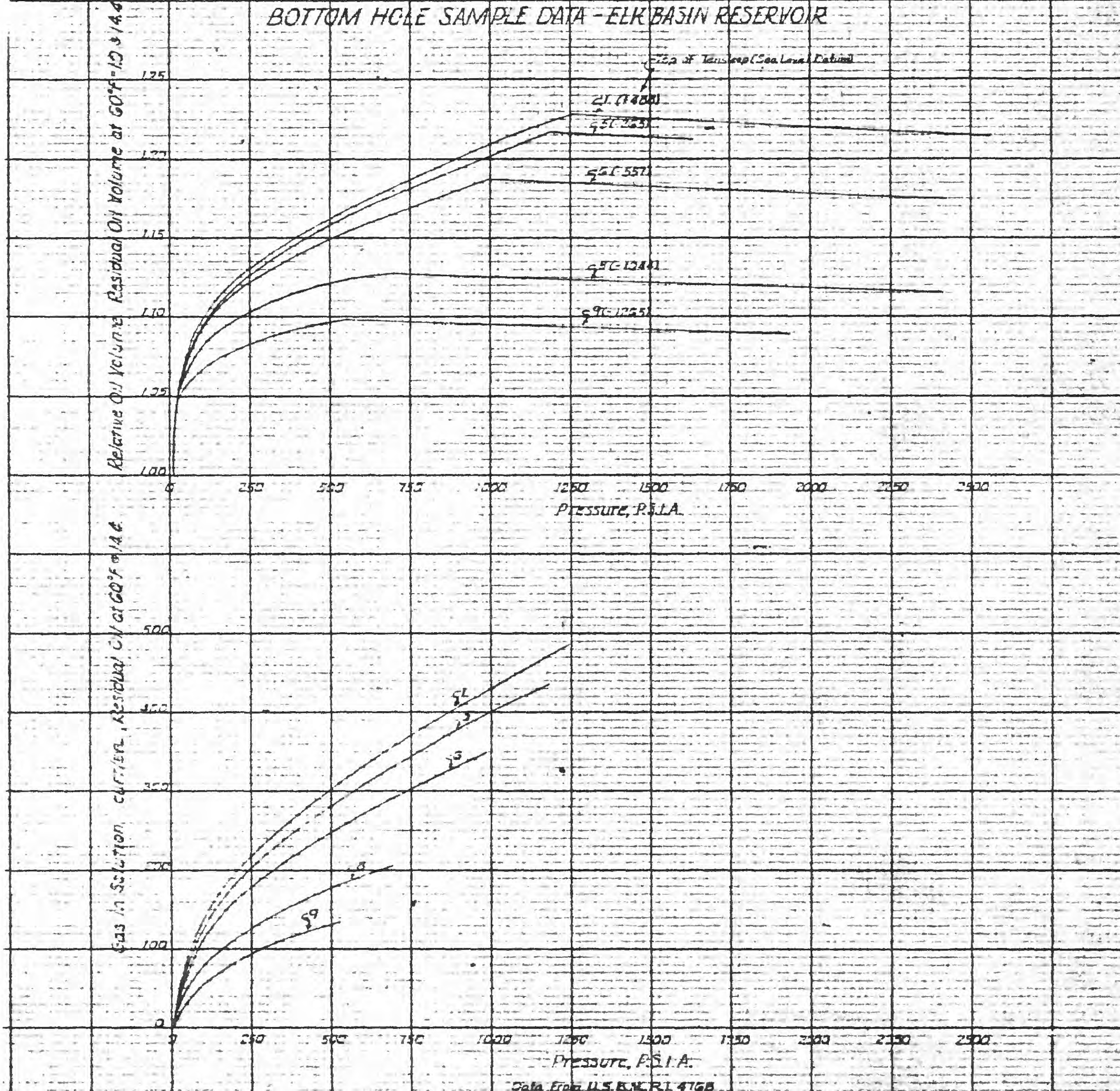


FIGURE 12 RELATIONSHIP OF THE CHARACTERISTICS OF THE OIL AT ORIGINAL CONDITIONS TO THE LOCATION OF THE OIL IN THE TENSLEEP RESERVOIR, ELK BASIN FIELD.

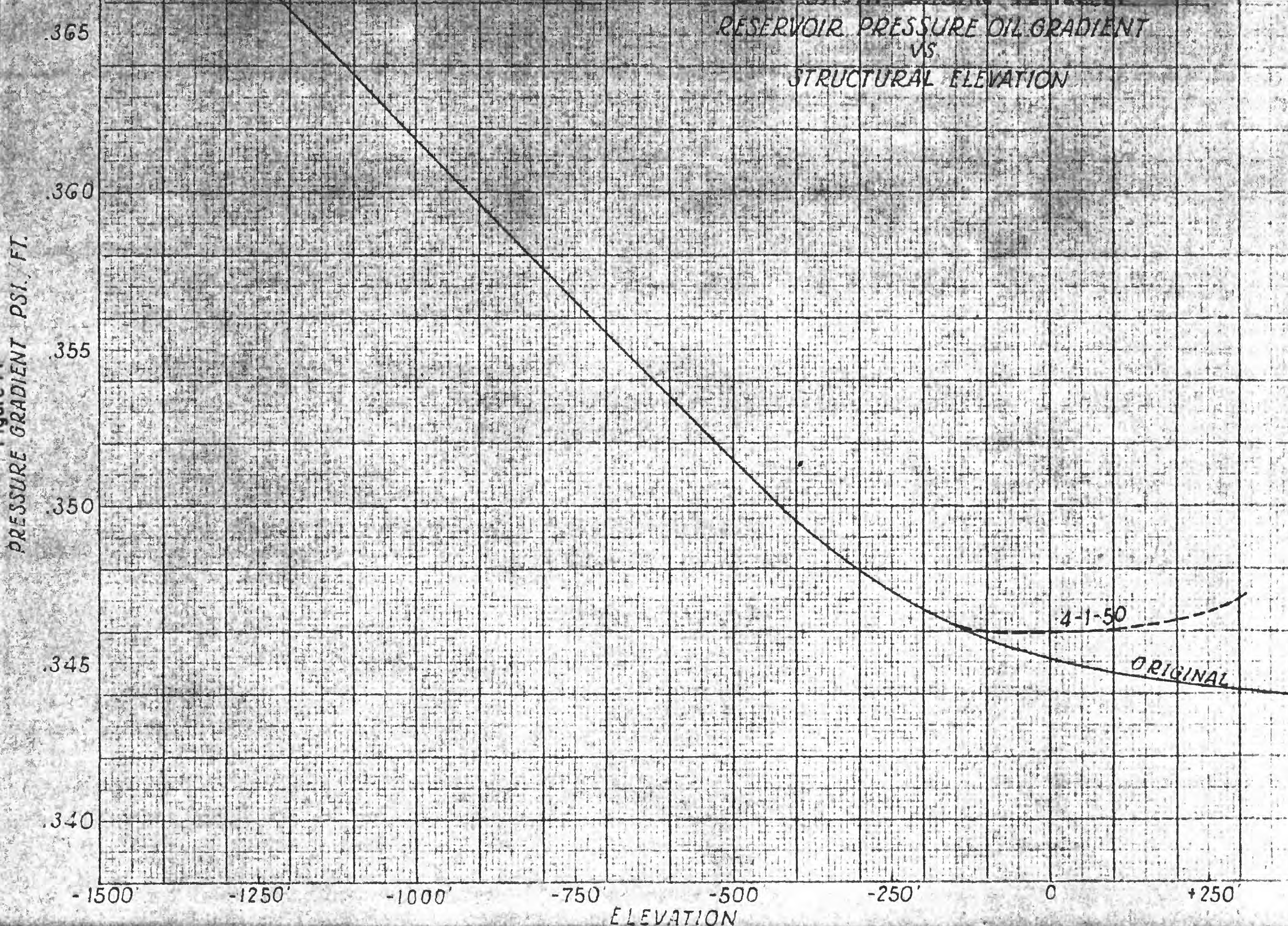
From B. of M., R.I. 4768

Figure 13



BOTTOM HOLE SAMPLE DATA - ELK BASIN RESERVOIR
Top of Tensleep (Sea Level Datum)
Relative Oil Volume Residual Oil Volume at 60°F = 1.0 @ 14.4
1.25
1.20
1.15
1.10
1.05
1.00
0
250
500
750
1000
1250
1500
1750
2000
2250
2500
Pressure, P.S.I.A.
Gas in Solution, cu.ft./bbl. Residual Oil at 60°F @ 14.4
500
400
300
200
100
0
Pressure, P.S.I.A.
Data From U.S.B.M. R.I. 4768

Figure 14


RESERVOIR PRESSURE OIL GRADIENT
VS
STRUCTURAL ELEVATION
PRESSURE GRADIENT PSI./FT.
.365
.360
.355
.350
.345
.340
-1500'
-1250'
-1000'
-750'
-500'
-250'
0
+250'
ELEVATION
4-1-50
ORIGINAL

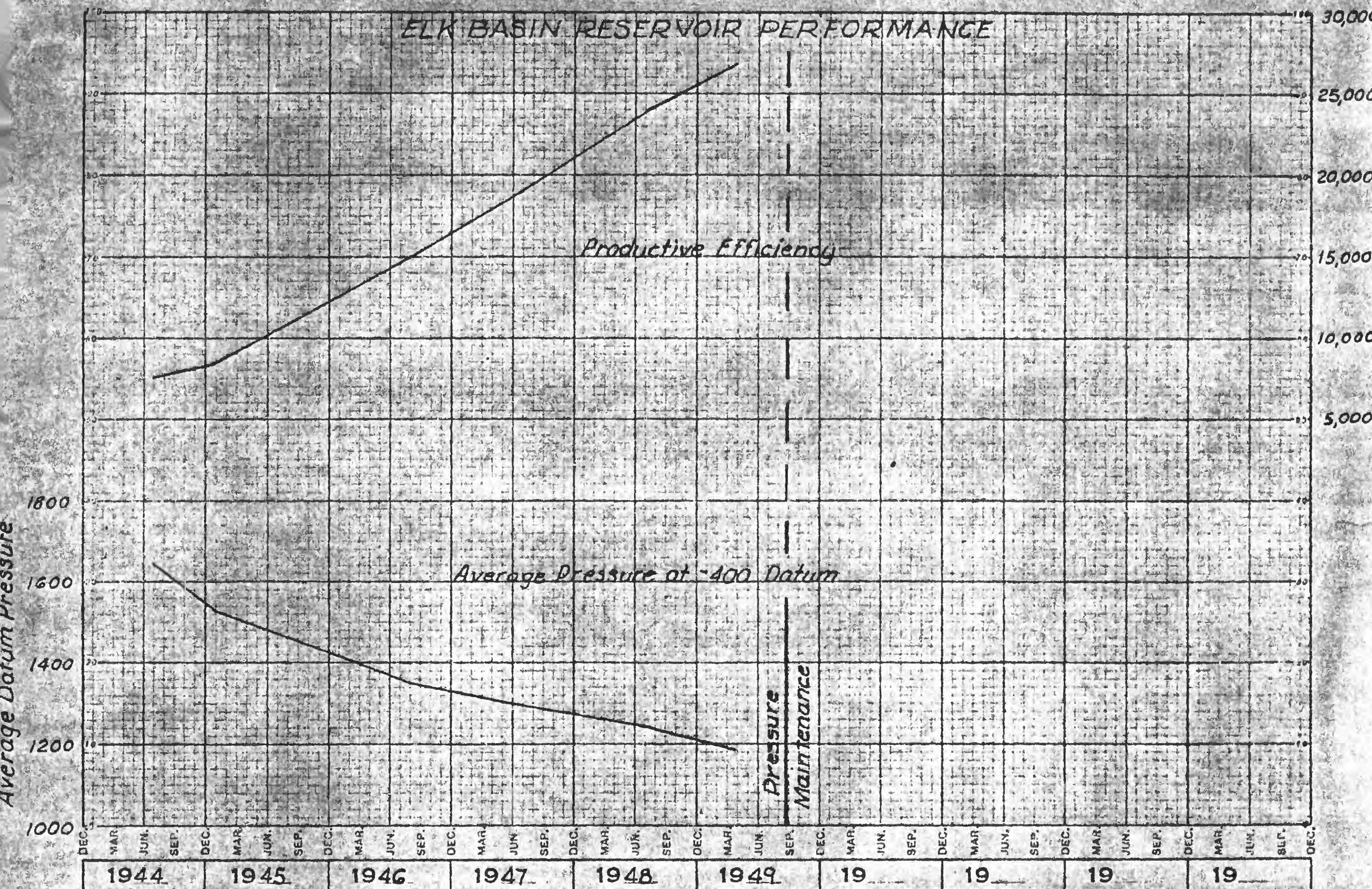
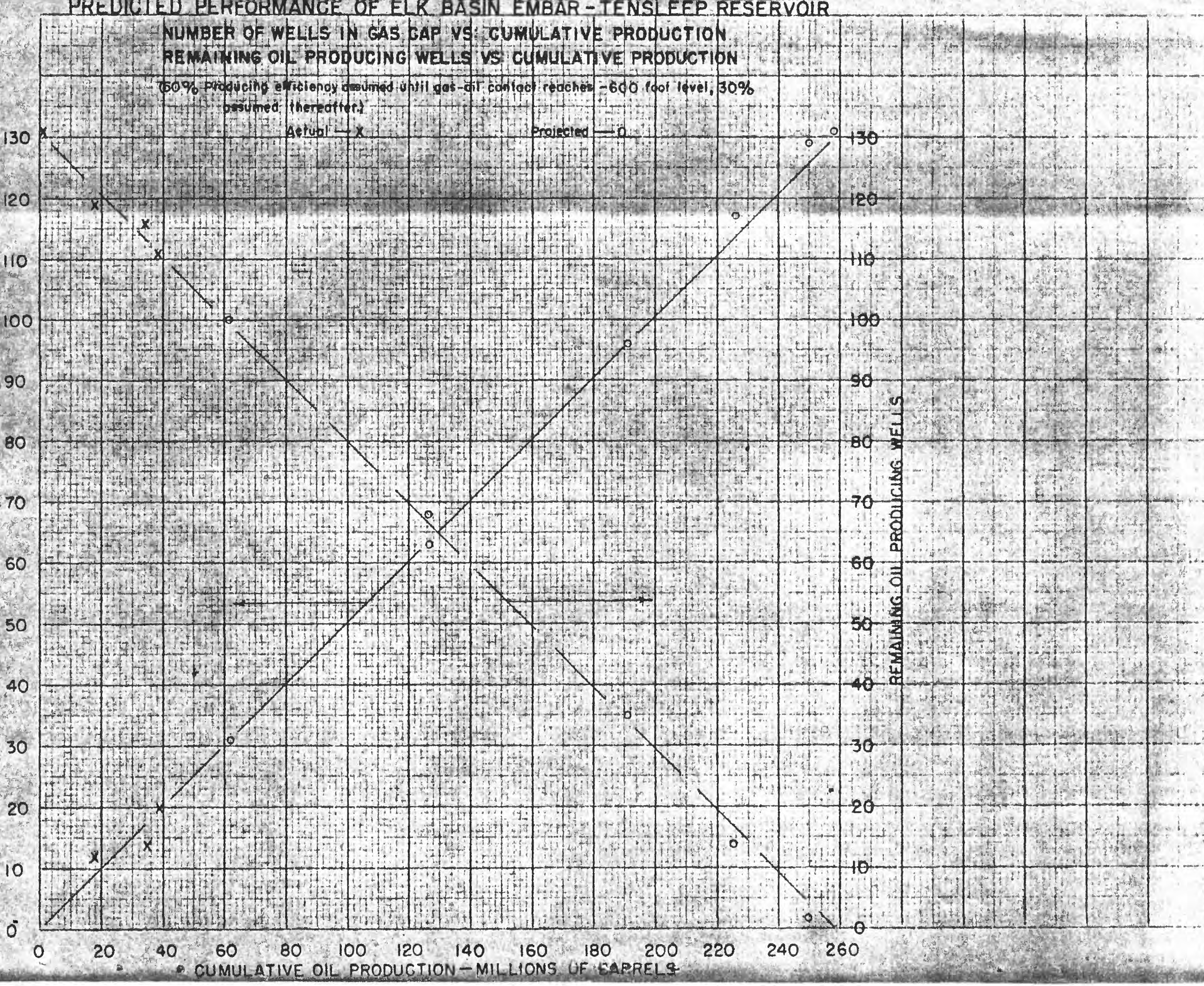

ELK BASIN RESERVOIR PERFORMANCE
Productive Efficiency
Average Pressure at -400 Datum
Pressure Maintenance
Average Datum Pressure
1800
1600
1400
1200
1000
30,000
25,000
20,000
15,000
10,000
5,000
DEC. MAR. JUN. SEP.
1944
1945
1946
1947
1948
1949
19
19
19
19

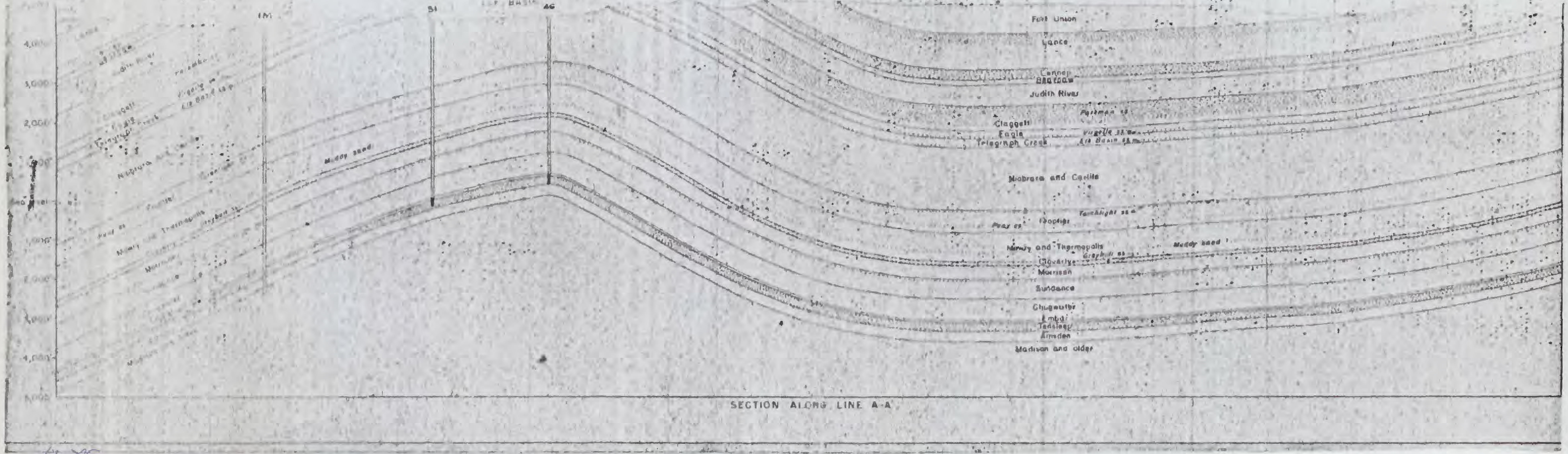
Figure 16



PREDICTED PERFORMANCE OF ELK BASIN EMBAR - TENSLEEP RESERVOIR
NUMBER OF WELLS IN GAS CAP VS CUMULATIVE PRODUCTION
REMAINING OIL PRODUCING WELLS VS CUMULATIVE PRODUCTION
(50% Producing efficiency assumed until gas-oil contact reaches -600 foot level, 30% assumed thereafter.)
Actual — X
Projected — O
NUMBER OF WELLS IN GAS CAP
REMAINING OIL PRODUCING WELLS
CUMULATIVE OIL PRODUCTION — MILLIONS OF BARRELS
0
10
20
30
40
50
60
70
80
90
100
110
120
130
0
20
40
60
80
100
120
140
160
180
200
220
240
260

Figure 1

S2-49



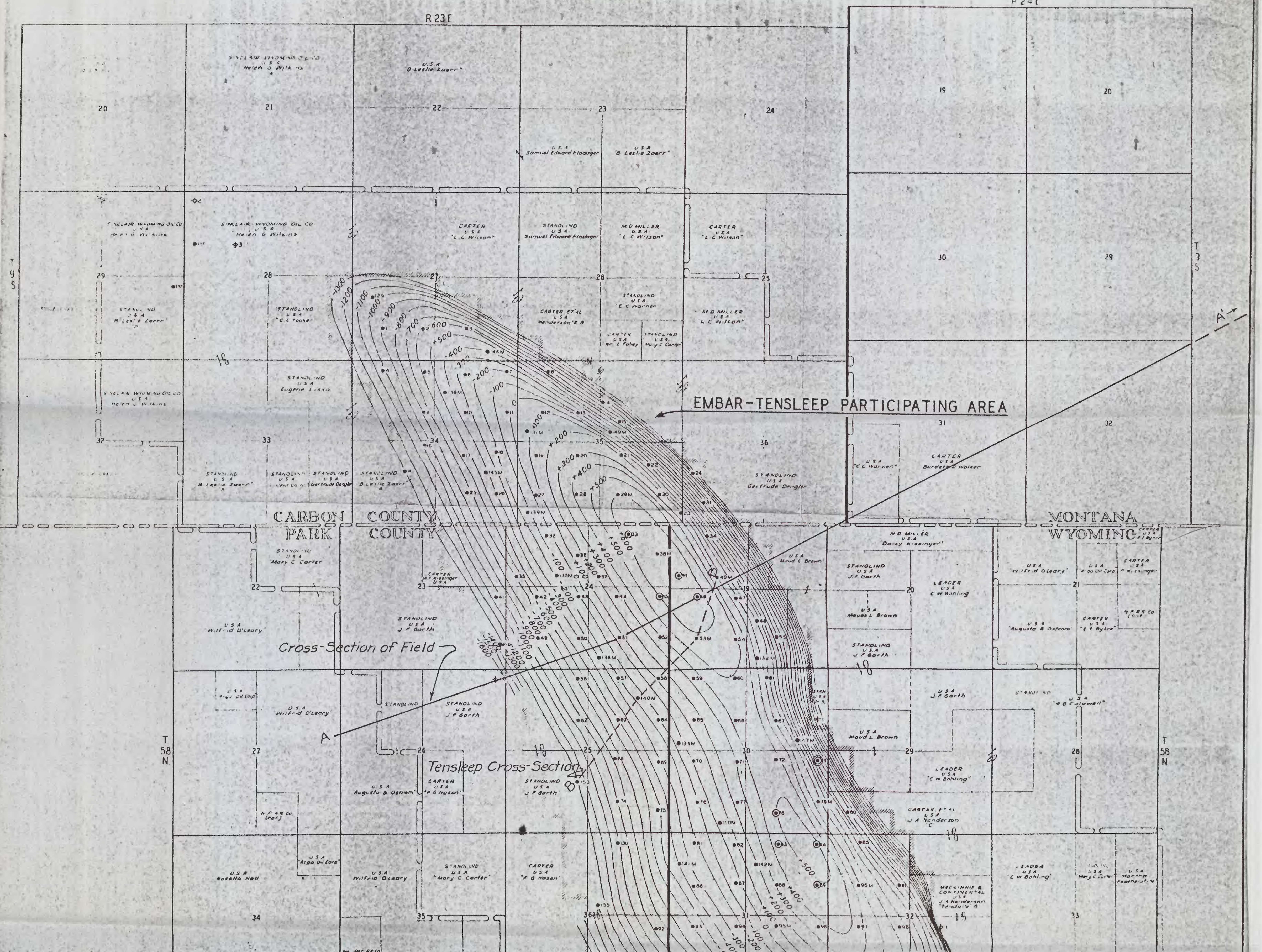


Fig. 3

CONTOURS ON TOP OF EMBAR
BY THE GEOLOGICAL SUB-COMMITTEE
JANUARY 3, 1946
REVISED BY THE GEOLOGICAL SUB-COMMITTEE
DECEMBER 15, 1947

STANOLIND OIL & GAS CO
ELK BASIN AREA
EMBAR-TENSLEEP & MADISON
PARK CO. WYOMING & CARBON CO. MONTANA
SCALE 1" = 2,000'

1-412 T