TEAPOT ROCK

ECONOMIC-ENGINEERING ANALYSIS OF THE SHANNON SAND

TEAPOT DOME, NATRONA COUNTY, WYOMING

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by

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THESIS

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ABSTRACT

This study consisted of a geologic and lithologic description, prediction of future performance by primary means, and an economic analysis of the Shannon Sand at Teapot Dome Natrona County, Wyoming.

Reservoir analysis and prediction of future performance were made using volumetric and decline curve calculations. Surface acreage within the Shannon reservoir limits was established as 4900 acres, of which 3270 acres lie within Naval Petroleum Reserve #3.

Reserves per well were calculated as 54,000 STB, recoverable over a period of 22-23 years at current decline. Average investment cost for a Navy well fractured and completed in two pay zones was $19,666, and payout time was established as 6 months. Present worth of the well to the Navy at the time it is placed on production was calculated as $50,964.

Ultimate recovery from the Navy's current 75 well program was calculated as 4,050,000 STB. Total recovery as of 1 January 1962, was 396,000 barrels.

Recovery for the entire Navy acreage, assuming 10-acre spacing, was estimated at 14 million STB.

PREFACE

An economic-engineering analysis of a reservoir involves consideration of a number of subjects, ranging from reservoir engineering, law, accounting, geology, and taxation, to economics. All these areas required some consideration in the preparation of this thesis.

The purpose of this thesis is to present a report of the physical and geologic characteristics of Teapot Dome, located in Natrona County, Wyoming, and to analyze the producing characteristics of the Shannon Sand, with specific emphasis on that portion located within the confines of Naval Petroleum Reserve #3. The minerology and lithology are reported from previous works by accomplished geologists. A volumetric analysis of original oil-in-place is performed using contours of pay sections drawn from data provided by drillers' logs, coregraphs, and radiation and electric logs. The decline curve is used to study the production characteristics of the field and to make predictions as to future recovery by primary means. The present worth of total recovery is then calculated using accepted discounting procedures.

This work is the result of a suggestion made by Captain K. C. Lovell, CEC, USN, Director of Naval Petroleum and Oil Shale Reserves, and has served to familiarize the author with his "home" for the next tour of duty. It is hoped that it may prove of value to the Navy as it has proven of value to the author.

It should be noted here that the opinions stated herein are solely

those of the author and do not in any way represent official U. S. Navy opinion or policy.

Many thanks are due my supervising professor, Dr. H. H. Power, for his patient and knowledgeable guidance in engineering economics during this work. The author is also grateful to Drs. Carl Gatlin and Frank Jessen for their friendly guidance and technical excellence during his instruction at The University of Texas and as members of the supervising committee. To Cdr. "Bud" DuVal, USN at Teapot Dome and to his staff go my thanks for their patience and persistence in procuring data; to Mr. Jay Jorgensen of Intex Oil Company for his substantial preliminary work and assistance in working out the top contours of the Shannon; and to Mr. Oren "John" Baptist and his co-workers at the Bureau of Mines Research Laboratory in Laramie for their work on core sections.

The author believes that any writing of importance to the writer should be dedicated to someone important to the writer. This then is dedicated to my wife, Annette, and our children.

May, 1962 N.

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CHAPTER I

INTRODUCTION

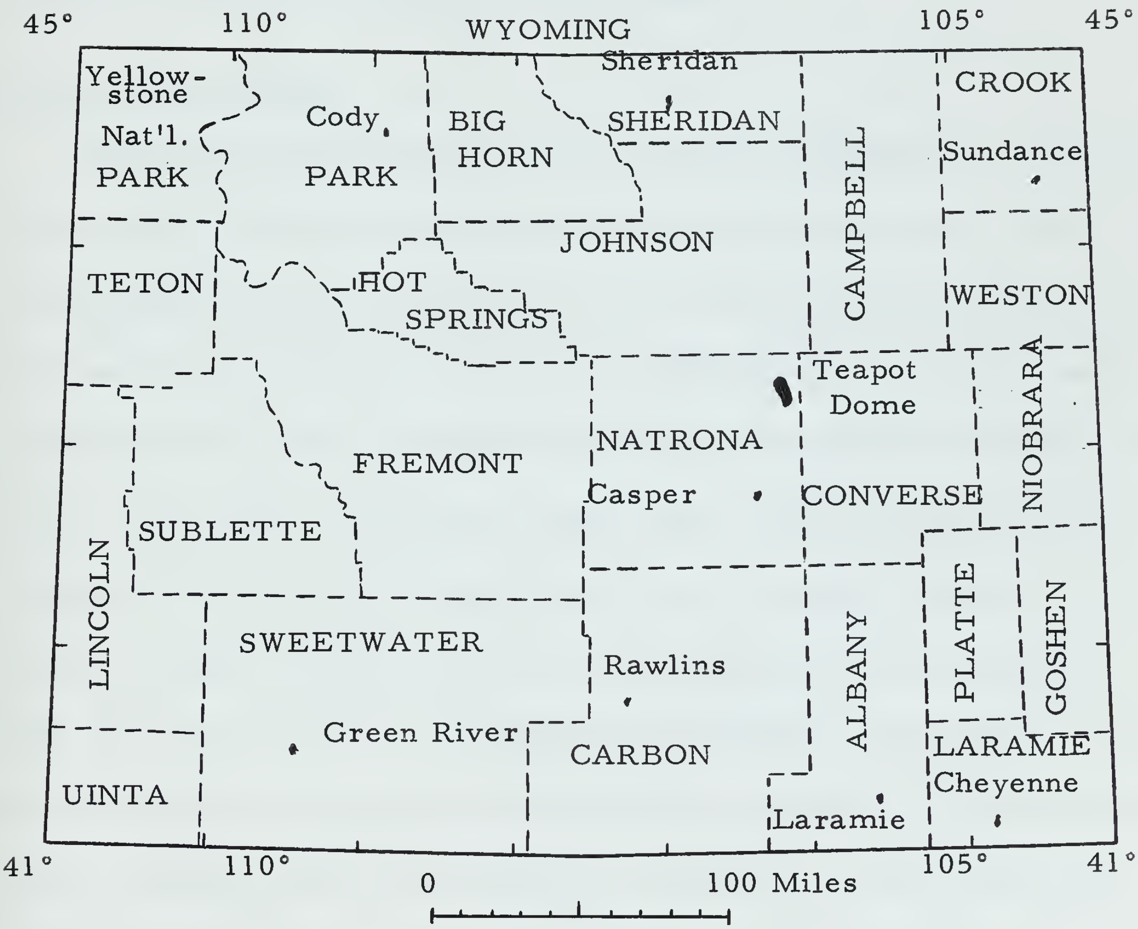
Geography and History

Teapot Dome is located within the boundary lines of Naval Petroleum Reserve #3, and the two names are often used synonymously. Naval Petroleum Reserve #3 (NPR3) is located in Natrona County, Wyoming, about 37 miles north of Casper and approximately the same distance southeast of the Big Horn Mountains (See Fig. 1). NPR3 was created by President Wilson on April 30, 1915, from lands in the public domain and has a present area of approximately 9320 acres.[1]

Teapot Dome is believed to have received its name through Mr. C. H. Wegemann, a U. S. Geological Survey geologist, who named it after Teapot and Little Teapot Creeks. These creeks provide surface drainage for the area and, in turn, were named after Teapot Rock, an isolated butte of sandstone located about six miles southwest of Teapot Dome, near which the creeks find their source. How Teapot Rock earned its name remains a mystery.

Teapot Dome first came to public notice in 1922, during the course of an investigation by the Committee on Public Lands of the U. S. Senate into leases of Naval Oil Reserves. As a result of this investigation, the U. S. Government brought suit to cancel the lease, then held by the Mammoth Oil Company under the control of Sinclair. This suit carried through a number of courts and was finally sustained by the U. S. Supreme Court.

Fig. 1: Sketch Showing Location of Teapot Dome
(After Thom & Spieker)[2]



As a result, the lease was cancelled and control of the Reserve was returned to the Navy in 1928.

It should be noted here that the oil produced from the Reserve during the 1920's was from the Wall Creek Sand, located about 2000 feet below the Shannon sand here under consideration. The state of the drilling and producing art was, at that time, not sufficiently developed to produce the Shannon economically. Hence, the drillers' logs simply noted the existence of the Shannon in drilling through to the Wall Creek.

Topographic Features

Naval Petroleum Reserve #3 lies near the western edge of the Great Plains region and has the topographic features, the plant life, and the climate normally found in high plains country. The surface elevation within the Reserve varies from somewhat over 5200 feet above sea level in its northern portion to less than 5000 feet above sea level in the southern portion.[3] The surface consists of a grassy plain, dotted with sagebrush, severely cut by deep ravines, and bordered by an encircling rim of sandstone. It might be of interest here to note that the natives sometimes refer to Teapot Dome as a "Sheepherder's oil field", undoubtedly because of the story book aspects of the anticline with a central, eroded, anticlinal valley, clearly evident to the observer in the encircling Parkman Sandstone as the Reserve is viewed from either the north or south end.

This part of Wyoming is semi-arid, averaging 14 inches of rainfall a year. As a result, the country is quite barren and desolate. The great

number of deep valleys cut by erosion are literally lost in the rolling expanse of the brown, treeless hills.

CHAPTER II

GEOLOGY

Structure

The Big Horn Mountains are flanked on the southeast by a number of anticlines, each one rising a little higher than the one before as one approaches the mountains. The most southeasterly, or outermost, anticline is the Salt Creek anticline which produces oil principally from the Wall Creek Sandstone. The fold of this anticline is not symmetrical, for its crest is much nearer its western than its eastern limit. The width of the eastern limb is about 20 miles; whereas that of the western limb is only 1 mile. The entire Salt Creek anticline is about 30 miles long.[4]

The Salt Creek anticline, the axis of which runs approximately N20W, is made up of three minor domes. The two most southern domes are separated from the northernmost dome by a major fault having a displacement estimated as high as 280 feet in some places. They are themselves separated by a shallow intervening saddle, the axis of which runs approximately N60E. They might be considered as one dome, and hence were originally referred to as "Saddlerock Dome" and later, "Teapot Dome." The most southern of these two domes is longer and larger than the other and is the dome under consideration in this work. This dome has a 250 foot closure and during the folding period was elevated about 1300 feet less than the northernmost Salt Creek Dome. This is evidenced by the fact that the Shannon which underlies Teapot Dome forms the escarpment around

Salt Creek Dome, and the escarpment of Parkman Sand around Teapot Dome is stratigraphically some 1300 feet above the Shannon. Teapot Dome then is on the southern tip of the southward plunging Salt Creek anticline.

Stratigraphy

The sedimentary formations within NPR#3 are found throughout eastern Wyoming and were deposited along the shore of a sea which, in Cretaceous time, extended over most of the Rocky Mountain area and later receded to cover much of the structural depression between the Big Horns on the west, the Black Hills on the east, and the Casper Mountains on the south.[5] The Teapot Field lies on the western shore of this later sea, or gulf, and the formations consist principally of marine shales interbedded with beach sand and sands deposited near a shoreline. These sands grow progressively thinner to the east where deeper water existed at the time of deposition.

The formation sequence is taken from Thom and Spieker,[6] and is shown in Table 1.

Thom and Spieker further described a partial section of the Shannon Sand as follows:

1.	Sandstone, hard, calcareous; caps bench	2 ft.
2.	Sand, thin bedded, grading down into dark sandy clay	26 ft.
3.	Clay, dark, containing green sandstone concretions	3 ft.
4.	Clay, bluish-gray, massive, somewhat sandy	35 ft.

TABLE I

ROCK FORMATION SEQUENCE IN TEAPOT DOME

System	Series	Formation & Member		Character	Thickness (Feet)
Cretaceous	Upper Cretaceous	Parkman Sand of Mesaverde Formation		Massive yellow sand or yellow - sandy shale	110 ±
				Carbonaceous shale, thin coal beds, lenticular sands, & two or three white sands near base.	190 ±
				Massive to flaggy marine sands, white sand at top. Inner Parkman rim.	170-190
		Steele Sh.		Soft, blue-gray Sh. containing concretionary beds. Group of bentonite beds & underlying thin sandstone 400-500' above base	1400-1460
			Shannon Sand	Green-gray marine sand (commonly in two benches), sandy shale and ferruginous beds.	135 ±
				Gray shale with thin ferruginous layers, few bentonite beds & a thin conglomerate bed 400-500' above base.	
		Niobrara Shale		Light-colored, with some harder calcareous beds, especially near top	1650-2140
		Carlile Shale		Dark marine shale	
		Frontier Formation	Wall Creek Sand	Cross-bedded sand & sandy shale, Commonly in two beds (First Wall Creek)	90-160
				Gray Shale, sandy shale and thin sandstones	390-400
				Gray to blue-white sand with partings of bentonite (Second Wall Creek)	40-90
				Gray Shale and irregular lenses of sand	220-250

TABLE I - Continued

System	Series	Formation & Member	Character	Thickness (Feet)
Cretaceous (Cont.)	Upper Cretaceous (Cont.)	Frontier (Cont.)	Fine-grained sand in discontinuous patches (Third Wall Creek)	0-30
			Dark shale, sandy shale, & hard sandstone lenses	300 $\pm$
		Mowry Shale	Hard shale, light gray, contains fish scales. Bentonite layers.	230
		Thermopolis Shale	Dark, soft shale	20 $\pm$
			Soft, fine sand with some coal & fossil wood fragments (Muddy Sand)	0-11
			Soft, black shale containing plant remains and shark teeth	200 $\pm$
	Lower Cretaceous	Cloverly Formation	Lenticular white or brown sand (Dakota Sand)	0-20
			Soft, light or massive dark shale	100 $\pm$
			Conglomerate & gritty sand, with coal lenses (Lakota Sand)	20-75
Cretaceous (?)		Morrison Formation	Soft, massive clay and thin hard sands	285-360 $\pm$
Jurassic	Upper Jurassic	Sundance Formation	Green & gray shale, gray-white-brown sand, & sandy lime	235-285
Triassic		Chugwater Formation	Soft, massive, red shale, red sand, thin lime, & massive beds of gypsum	700 $\pm$
Carboniferous	Permian	Embar Formation	Alternating red shale & varicolored limes & sands	220 $\pm$
	Pennsylvanian	Tensleep Sand	Massive white cross-bedded sand with calcareous layers.	270 $\pm$

5.	Ironstone layers, weathering to red flakes, sandy shale	3 ft.
6.	Sandstone, hard; caps lower bench	2 ft.
7.	Sandstone, thin bedded and thin shale beds	20 ft.
8.	Sandstone, ferruginous, thin irregular beds, shale partings	19 ft.
		110 ft.

Except for variations in thickness, this section has proved to be representative of the Shannon Sand at Teapot Dome. Thus, it is evident that the Shannon normally consists of two porous zones of sandstone, capped by hard layers, and separated by an interval of bluish clay. These two zones are the producing zones of the Shannon. In deference to local terminology, they will be referred to hereafter as the "upper bench" and "lower bench."

Origin and Accumulation of Oil

To the author's knowledge, no positive determination of source beds for the crudes in the various reservoirs underlying Teapot Dome has ever been made. As early as 1911, Wegemann determined that the oils of the Wall Creek and Shannon were quite similar in that they were both paraffinic and practically free of asphaltum and sulphur.[7] He also ventured the suggestion that they were not derived from the same source. However, minor differences in their characteristics could be accounted for by the different formations through which they were filtered.

We are reasonably convinced now that the oil originated in the shales

and was driven from it into the sandstone by heat and pressure involved in local earth movements and/or by a later upward movement due to the difference in specific gravity of oil and water. All known reservoirs underlying Teapot Dome contain water to a degree. The Shannon has a water-oil contact at +3600 feet on the east flank, indicating that there is sufficient water to encourage oil accumulation updip and to prevent a downward migration into the adjoining syncline. However, the Shannon water is not under high pressure and, though there may be localized restricted water drives on the reservoir's east flank, production to date from the Navy wells would indicate no active water drive of any extent. With the exception of a few wells in the northeast corner of NPR#3, the Navy wells characteristically produce with an initial water cut of 15-17%, the cut dropping off rapidly to about 1-2% after 6 months.

Thom and Spieker, in reporting an earlier work by Mills,[8] stated that the Teapot Dome structure was, "literally cut to pieces by fault fissures, evidenced at the surface by rock displacement and by calcite veins and stringers."[9] This determination is strengthened by recent drilling experience and itself strengthens the belief that oil in the Shannon could have migrated from any number of source beds. It seems most likely, however, that it originated in the Upper Cretaceous shales and migrated upward as a result of a density difference. The remains of sea weed, fishes, and marine invertebrates found in the Shannon and in the

shales below it suggest this possibility.[10]

There is no evidence of gas accumulation updip in the Shannon reservoir. This is true of recent drilling and production experience. It was also noted in early investigations and specifically reported by Wegemann in 1918.[11] This lack of a gas cap appears entirely reasonable in view of the extensive fissuring that has taken place in the Teapot structure. Thom and Spieker reported that many of the fissures were only partly filled with calcite, and evidences of gas and oil seepages, though not numerous, were reported by Thom and Spieker and by Wegemann.

In developing a theory for the probable accumulation of the Shannon oil, we refer to the basic theory that the oil obtained from a porous sandstone by drilling was probably originally distributed throughout that sandstone in small amounts. It has for a long period of time been working its way upward in the rock, through gravitational separation and impelled by water pressure, and has collected in certain traps or areas capable of retaining it and preventing its escape. It would also, in the case of an anticlinal trap such as the Teapot structure, depend upon the presence of water downdip to prevent downward migration through the sand, across a syncline, and into an adjoining fold.

At Teapot Dome, this situation exists. However, as pointed out earlier, the crest of the anticline is much nearer its western than its eastern limit, the ratio of the width of the eastern limb to that of the

western limb being about 20 to 1. The eastern limb has a gentle slope and taps a broad supply area. The western limb is comparatively steep with a short slope. Most of the oil occurring on the eastern side of the Teapot axis would gradually migrate upward and be collected within the limits of NPR#3. Most of the oil occurring on the western side of the axis would be west of the axis of the adjoining syncline, and thus would migrate westward beyond the limits of NPR#3. Thus, we might expect that wells drilled on the eastern slope would tap a much greater supply area and have greater chance for success.

CHAPTER III

SCOPE AND THEORY

Scope

The scope of this thesis is limited to an economic and engineering analysis of the Shannon Sand at Teapot Dome. Its basic purpose is to arrive at a calculated ultimate primary recovery per well for Navy wells located on a 10 acre spacing within Naval Petroleum Reserve #3, and from calculated recovery rate, using investment and operating costs and accepted discounting procedures, to develop the present worth to the Navy of a newly completed well. Based on these figures, the primary recovery for the Navy's planned 75 well program is then calculated.

Theory

The calculation of primary reserves and prediction of ultimate recovery are basic problems to this analysis. In this thesis, primary reserves will mean that oil which can be recovered economically, using only the natural forces of the reservoir. It is evident that these reserves are dependent upon the type of drive mechanism, other factors considered equal. The producing mechanism of this sand is believed to be a combination of depletion drive and gravity drainage, with the gravity influence becoming increasingly important as the gas pressure declines. There is possibly some pressure maintenance along the eastern boundary of the reservoir due to a restricted water drive. This is localized, however,

and has not had any apparent effect on recoveries from Navy wells which lie updip from the private leases in the affected areas.

Because the reservoir is only partially developed and is, in fact, still under development, the material balance was considered applicable but susceptible to serious error. A basic problem then became the determination of future reservoir performance by some other means. The most reliable data available were those of individual well performances. Hence, the reservoir performance predictions were made using the decline curve.

The decline curve method of performance prediction is a primary tool where sufficient production data are available to describe a definite curve shape. Of course, the important assumption involved in its use is that all the factors which have operated in the past to produce the curve will similarly remain to affect it in the future.

The decline curve device was first used as a statistical method for extrapolating the variable trend of well production by R. H. Johnson and A. L. Bollens in 1927,[12] and later employed by Arps.[13] The method used by Johnson and Bollens is named the "Loss-Ratio Method", by which the production rates are tabulated for equal time intervals, then the successive drops in production rate are calculated in a second column and the ratio between successive production rates, or the loss-ratio, is listed in a third column. A curve investigated by this method normally

will show, after proper smoothing, a constant loss ratio or a constancy in successive loss ratios. Once the constancy is arrived at, the loss ratio column may be continued using the constant figures and then working backward to the production rate column to arrive at a calculated production rate for any period of time during the life of the well.

There are many methods in which decline curve production data may be shown graphically. This work employed what are probably the two most common methods which, incidentally, give this graphic approach the decline curve label. They are the production rate-time plot and the production rate-cumulative production plot.

Production rate-time and production rate-cumulative curves are generally classified as exponential or hyperbolic. Exponential decline occurs when the change in production per unit time is a constant percentage of production rate. Hyperbolic decline occurs when the drop in production rate per unit time is a fraction of the production rate raised to a power. Most decline curves actually fall within the hyperbolic category, and such was the case with the curves studied here.

Results of these plots were combined with results of volumetric calculations for original oil-in-place to arrive at a per cent recovery.

Calculations for original oil-in-place were carried out using the following expression:[14]

$$N = \frac{7758 \times Vo \times \phi \times (1 - \sigma wi)}{Boi}$$

where 7758 = number of 42 gallon API bbls per acre-foot
V_o = volume of producing formation in acre-feet
ϕ = porosity
σ_{wi} = irreducible water saturation
B_{oi} = estimated original formation volume factor

Calculations for declining production were carried out to the economic limit, working with the production rate of the average well. Economic limit is defined as the production rate at which the net revenue equals operating cost. It was calculated by the following:[15]

$$\text{Economic limit (bbls/day)} = \frac{\text{Monthly operating cost}}{\text{(30.4 days/mo.)(net price/bbl)(interest owned)}}$$

After determination of the economic life and ultimate production of the average well, it was possible to compute the annual cash return. Before this cash return could be discounted for future net receipts it was necessary to estimate the costs in connection with future production of the oil. These costs were divided into investment and operating costs, both of which were available from government records. The future estimated cash returns minus the above costs, multiplied by the appropriate discount factors, resulted in a present worth to the Navy of the average well as of its completion data.

The discounting procedure consisted of calculating the cash return from production rate and net income per barrel for each six month period over the economic life of the well. From the period cash return was subtracted the operating cost for the corresponding period (and the original investment cost of drilling and completing the well in the case of the first

six-month period). The net cash return for each period was then discounted to the completion date by means of the following:[16]

$$P = \frac{S}{(1 - i)^n}$$

where
- i = interest rate per interest period
- n = number of interest periods
- P = present worth
- S = sum of money at the end of n periods from the present date that is equivalent to P with interest i.

Note here that P is the present worth of a receipt of S, n periods in the future. It effectively considers that the total receipts for a six month period occur at the end of the period. That is, of course, not true, but it results in a conservative evaluation of present worth that at least partially offsets the effect of inflation, which was otherwise neglected. Since this is a government operation, the income tax consideration is also neglected, and all net receipts are effectively stated in terms of "before taxes."

The discount factor used was 4%. Its choice was a result of the following decisions:

(a.) The reservoir is reasonably well defined and there is little or no risk involved in any contemplated completions.

(b.) Net receipts after deductions for investment and operating costs, are deposited with the U. S. Treasury. The effect of this action in periods of deficit financing by the government is essentially to reduce the amount of borrowings by an equivalent amount. Since these

borrowings are normally consummated at some percentage less than 4%, this figure was considered an appropriate "rate of return" for the operation.

CHAPTER IV

ROCK AND FLUID PROPERTIES

Rock

The nature and lithology of the Shannon Sand and its surrounding formations have been described in Chapter II. One important characteristic of the Shannon Sand that has not been previously discussed is its sensitivity to fresh water. A study of most of the producing sands of the Powder River Basin in Wyoming has been made by personnel of the Bureau of Mines Research Laboratory at Laramie.[17] Its purpose was to determine which sands are water sensitive and what clay mineral is primarily responsible. The Shannon was judged to be highly sensitive and to contain significant amounts of illite, kaolinite, and montmorillonite, with montmorillonite being the principal cause of the water sensitivity.

The thickness-weighted averages of permeability found were 281 md. for the upper bench and 13 md. for the lower bench. The relatively high average for the upper bench may be somewhat misleading, however, since there were a large number of low (0-15 md) and high (800-900 md) permeabilities found in the core reports studied and relatively few found in the average region. These facts, while perhaps not of serious consequence at this time would become matters of concern in the event of a planned waterflood.

<u>Oil</u>

The Shannon crude has a paraffin base and an API gravity of 31.8° at 60°F. and O psig. The present formation volume factor is 1.02. Average reservoir pressure is estimated as 100 psia. Estimated original formation volume factor was 1.22. Formation temperature is 69°F. Bubble point pressure is 72 psia at formation temperature. Viscosity is 21.3 cp. Specific gravity of the crude is 0.88. Pour point is 5° F. The color is dark green. Gas solubility is approximately 10 cubic feet per stock tank barrel.

A plot of formation volume factor and viscosity versus pressure is shown in Fig. 2.

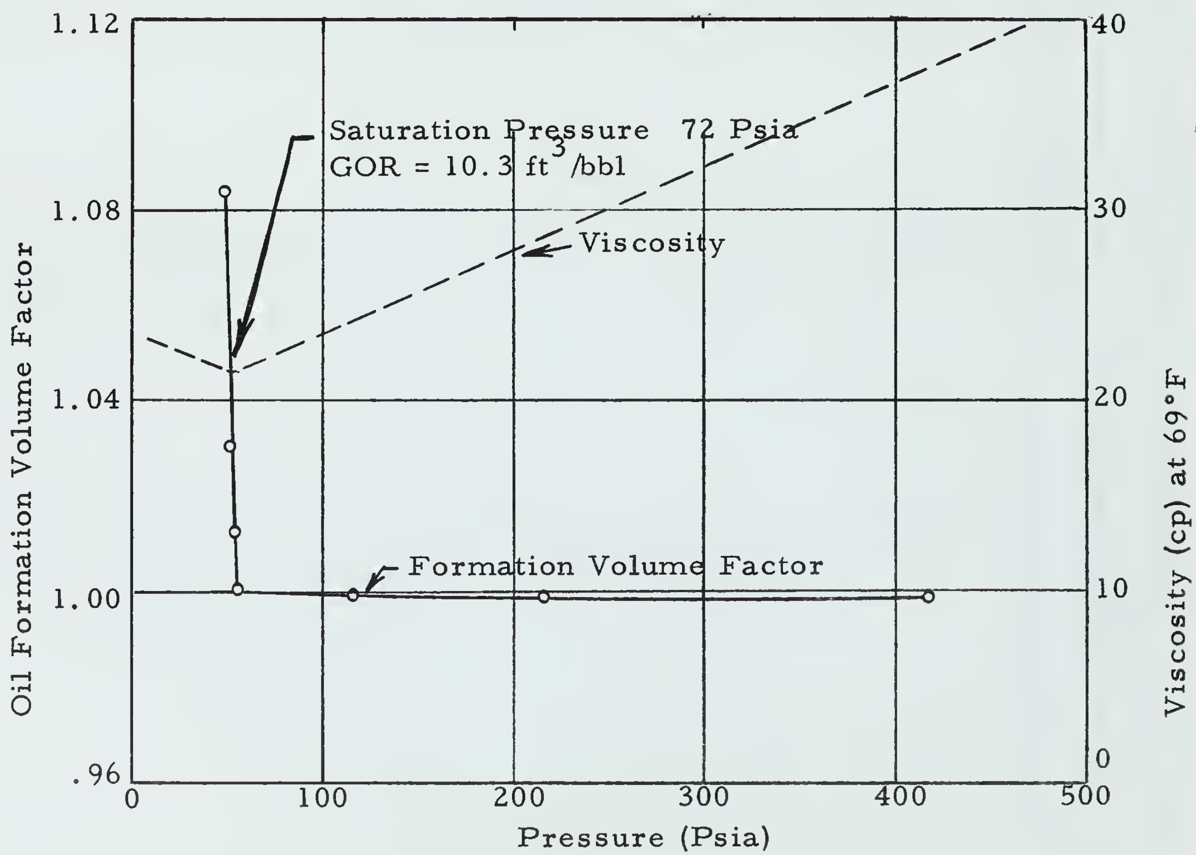
<u>Water</u>

In 1918, Wegemann reported analyses of three Shannon water samples.[18] Total dissolved solids varied from 3350 ppm to 6240 ppm with an average of 4430 ppm. Sulphate and sodium ions predominated.

In 1930, Trexel reported a chemical analysis of the water as 2380 ppm total dissolved solids.[19] Sulphate, sodium, and bicarbonate ions made up the principal solids.

Analyses of Shannon water made in 1960 indicated total dissolved solids as 11,400 ppm, with sodium, bicarbonate, and chloride ions predominating and no appreciable sulphate ion reported. These samples had a $_pH$ of 8.3.

Fig. 2: Formation Volume Factor and Viscosity Vs. Pressure



Inasmuch as the Shannon outcrops a short distance north of NPR#3, it undoubtedly acquires some surface water. Its "characteristic" water would then be a mixture of surface water and other formation waters, subject to variation in content from place to place, as borne out by the analyses. This variation in content of fresh water and its effect on the clays in the sand may partially account for the variations in permeability noted previously.

CHAPTER V

PRODUCTION HISTORY

Trexel reports the first drilling of the Shannon sand on or near Teapot Dome as being the No. 2 Shannon Well in 1889 or 1890.[20] His report shows a number of other instances since that time in which the Shannon on or near NPR#3 has been drilled for oil. However, no significant production was obtained from the Shannon on Teapot Dome until 1954-55, when a number of wells were drilled by private interests on the east flank of NPR#3. During 1955, 64 Shannon wells were drilled by private operators.[21] Further development by private interests raised the number of producing wells to 136. These wells are drilled on a 10 acre spacing and average 1300 feet in depth. They were placed on the pump upon completion, and their average initial production was 47 STB per day. An unknown number are completed in both benches. However, the majority are completed in the upper bench only, and relatively few have been fractured. As a result, production has dropped rather rapidly to a current average of 4 STB per well per day.

When it became evident that the Navy was losing its Shannon oil through drainage, an offset drilling program was initiated. The first three of the Navy's Shannon wells were placed on the pump in December 1958. The drainage prevention program is still in the development stage. There are currently 45 wells, drilled on a 10 acre spacing, completed

and producing, with an additional 30 wells planned.

The majority of the Navy wells have been and will continue to be completed and fractured in both benches before being placed on production. As a result, their average initial production rate is 81 STB per day, and their decline rate is less than that of the private wells. For this reason, the work in this thesis is done on the basis of an average well completed and fractured in both benches.

Below is a record of the total Shannon production from 1954 through 1961:[22]

Year	Production (STB)	Cum. Production (STB)
1954	7,141	7,141
1955	22,621	29,762
1956	411,388	441,150
1957	715,707	1,156,857
1958	550.213	1,707,070
1959	340,762	2,047,832
1960	251,026	2,298,858
1961	203,177	2,502,035

Total Shannon production as of 1 January 1962 is estimated as follows:

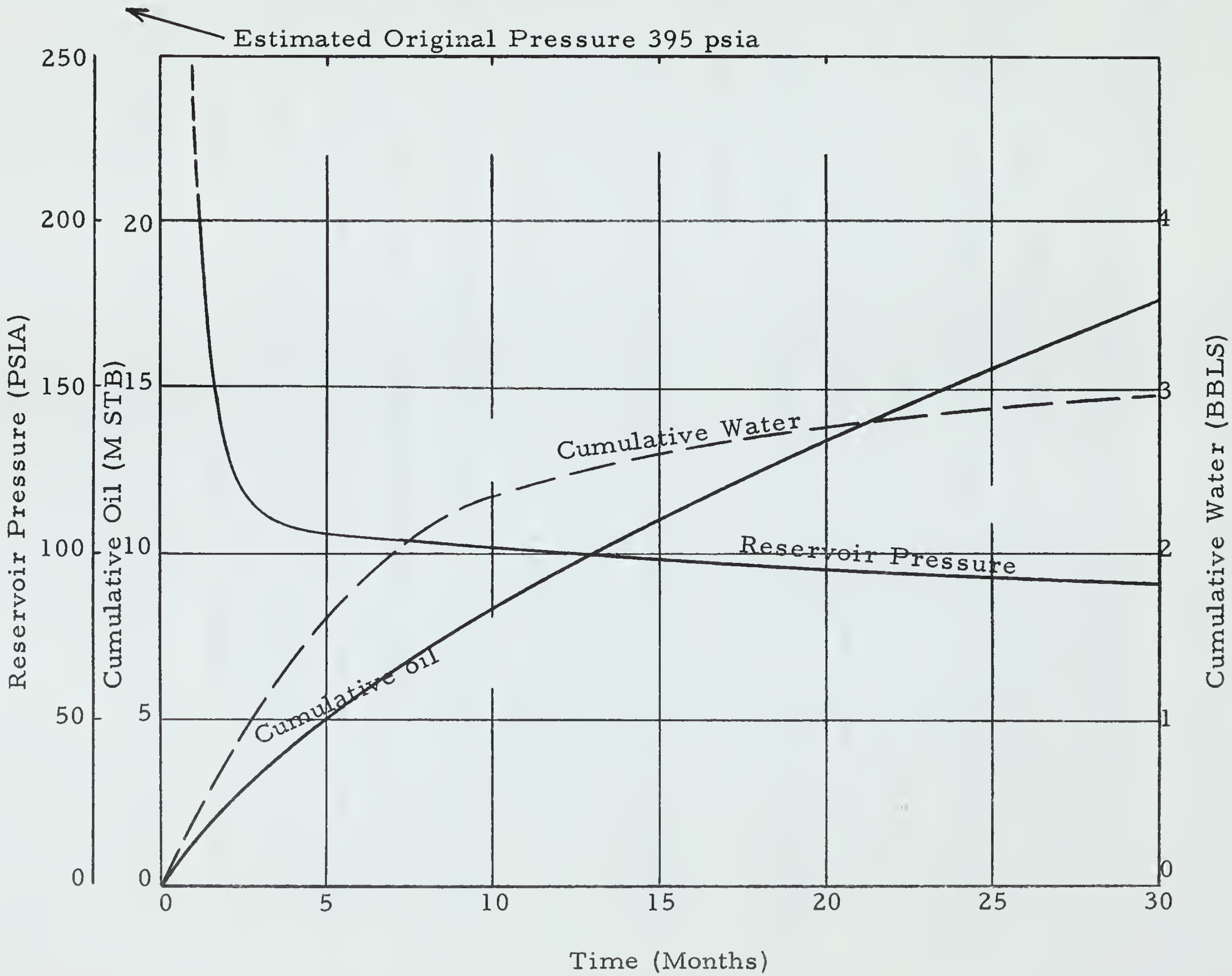
Private	2,502,000 STB
Navy	396,000 STB
Total	2,898,000 STB

This figure is believed accurate within 5,000 STB, or less than 0.2% error.

Table 2 is a complete record of the Shannon production for NPR#3 through August, 1961.

Figure 3 represents a production history for the first 30 months of the average well on NPR#3. It will be noted that the water production starts relatively high (initial water cut of 17%) and drops rapidly after six months of production. The pressure experiences an immediate drop to an average of 110 psia and then levels off and drops very slowly thereafter. Flush production is apparently closely associated with this pressure drop. It will be noted in subsequent chapters that the production rate drops rapidly during the first 3-6 months of production.

Fig. 3: Production History Per Well



CHAPTER VI

VOLUMETRIC CALCULATIONS

Reservoir Limits

The first step in the calculation of original oil-in-place by volumetric means is the determination of the probable reservoir limits. In the case of the Shannon Sand at Teapot Dome, the reservoir is clearly defined on the east flank by a water-oil contact at + 3600 feet, evidenced by a series of dry holes (see Plate 1). It is defined on the north by a major fault with a throw of approximately 280 feet. Dry holes mark the north side of this fault.

On the west and south flanks, no drilling has ever been attempted to positively determine the reservoir limits. In order to arrive at a probable limit in these regions, it was necessary to resort to the drillers' logs of the Mammoth Oil Company, made in the 1920's, which marked the top and bottom of the Shannon and indicated any oil or water shows in drilling through to the Wall Creek Sand. Here the assumption was made that if the driller was careful to note the presence of oil on one log he would do so on every log, and that the absence of such an indication meant the absence of oil. From the statements contained in these logs, a probable reservoir limit was established as shown on Plate 1. The mammoth wells used in this determination are those wells shown on Plate 1 within the confines of NPR#3.

Why the reservoir should be limited as shown has not been determined, but there are plausible explanations. As explained in Chapter II, the width of the eastern limb of the anticline is about 20 times that of the western limb. Thus, it taps a much greater oil supply or source bed area and would reasonably be expected to contain much more oil under favorable trapping and containing conditions.

A second explanation arises from recent work performed by Atlantic Refining Company personnel in identifying and classifying reservoir nonuniformities affecting oil production.[23] This study confirms previous beliefs that permeability and/or effective porosity are affected by the geologic sedimentation process, and that permeability is related to grain size distribution, degree of grain packing, and cementing material content and compaction. It indicates that the presence of shale greatly reduces permeability and increases the variance in permeability from region to region. It further acknowledges that the presence of clay in a sand will reduce permeability somewhat by deforming and cementing to adjacent quartz grains, but that it will not affect permeability variance greatly because of a normally uniform distribution throughout the sand.

In the Shannon, we have a sandstone that is laced with shale and which contains significant amounts of clays. We know that it once lay at the western edge of a shallow sea and was probably subjected to a lagoonal

type deposition process because shales are normally deposited in relatively calm waters. Hence, it is entirely feasible that these shales and clays under differing degrees of compaction and sedimentation could cause permeability pinchouts in the sand from region to region.

It is also possible, as a third explanation, that the western limb has undergone less fissuring than the eastern limb, and that the oil has simply not had the same opportunity to work its way up from the source bed to the Shannon.

Gross Sand Thickness

After establishing the probable reservoir limits, the next step in the volumetric calculation was to determine the gross sand thickness of the Shannon within the reservoir boundary.

Reliable depth information was available for the top and bottom of the sand for 84 of the old Mammoth wells near the crest of the Teapot structure. Top and bottom data were also available from 48 recently drilled Navy wells further downdip. Reliable data for the top of the Shannon on the east flank were obtained from local records of the 136 private wells. The bottom of the Shannon in the region of the private leases was extrapolated from the nearest Navy wells for which data were available. From the above information, shown in Table 3, the top and bottom of the sand were established. A contour map of the top of the Shannon is shown in Plate 2.

<u>Net Pay Thickness</u>

After determination of total sand thickness, the next step was to establish effective pay thickness.

As noted in Chapter II, the Shannon consists of two porous zones varying in thickness from 15 to 30 feet and separated by a clay-shale layer varying from 40 to 80 feet thick. The pay zones in these porous zones vary from 6 to 26 feet thick.

In determining net pay, use was made of core data from 23 Navy wells and electric and radiation log data from 5 Navy wells. Sections with less than 2 md. permeability were arbitrarily considered as questionable oil producers on the basis of discussions with local producers and laboratory personnel. Some of the 2 md. sections would undoubtedly produce oil under hydraulic fracturing, but previous experience with these low permeabilities had been unfavorable.

From the weighted averages of core analyses and log data, the average porosity and irreducible water saturation were established as follows:

ϕ - - - upper bench-21%
lower bench-20%

σ_{wi} - - - upper bench-15%
lower bench-29%

Data were available for only the 45 producing Navy wells to establish net pay thickness in the two benches. Hence, in contouring the net pay sections, the following approximations were made:

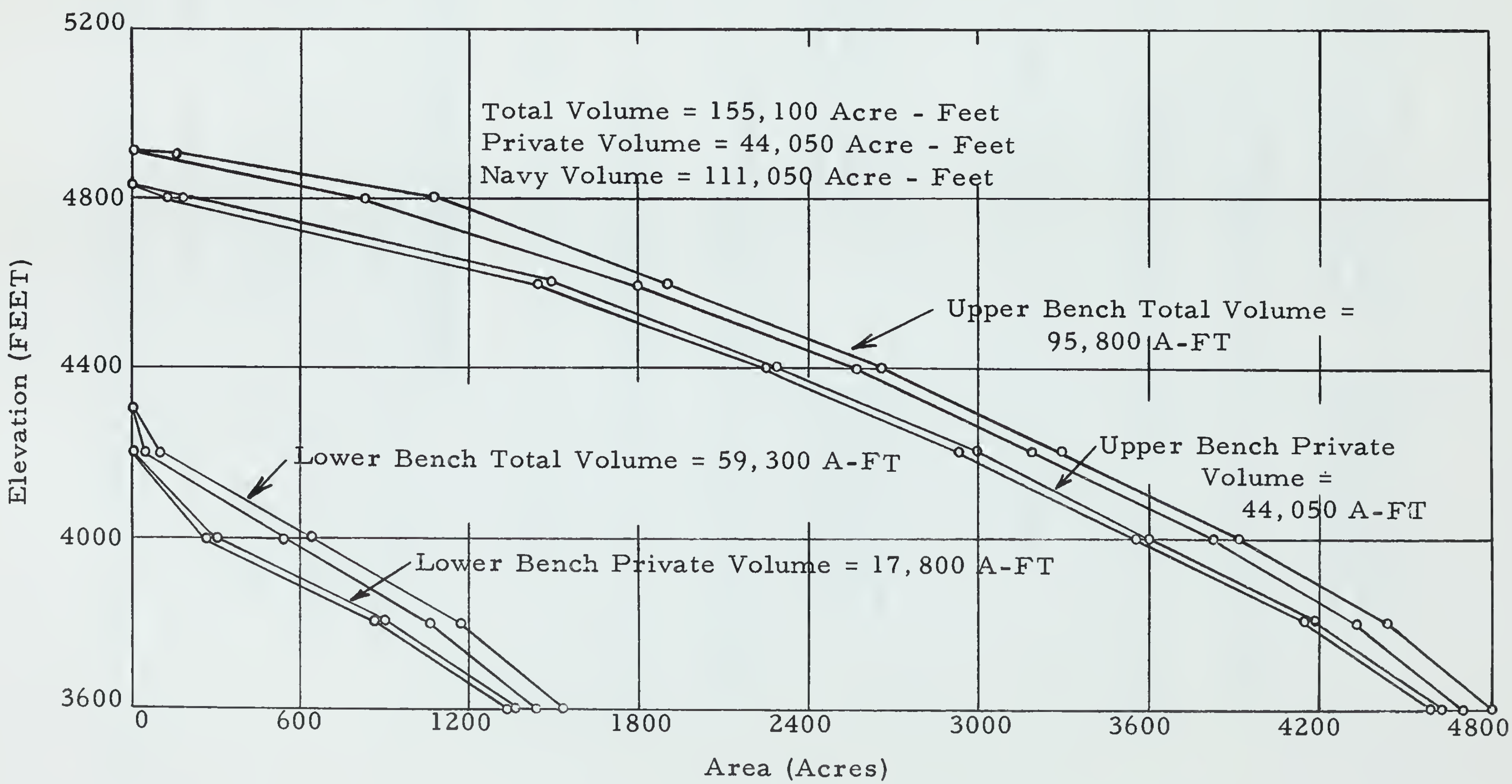
1. In an effort to retain meaningful evelations, the pay section of the upper bench was considered to exist at the top of the bench, i.e., the top of the pay became the top of the Shannon. Similarly, the pay section of the lower bench was considered to exist at the bottom of the bench, i.e., the bottom of the pay became the bottom of the Shannon. Net pay thicknesses were then plotted from the top and bottom of the Shannon as reference elevations at each well.

2. Inasmuch as no pay data were available for the old Mammoth wells near the top of the structure or the private wells on the east flank, the pay thickness of the nearest Navy wells for which data were available were extrapolated both up and downdip using ratios of total sand thicknesses as a basis for the thickness determinations.

These approximations made progress of the work possible and, it is believed, resulted in reasonable accuracy of results.

Upon completion of the net pay calculations, it was possible to then contour the tops and bottoms of the two pay zones. These contours, shown in Plates 3-6, were then planimetered, with the results presented in Table 4. The net pay areas from Table 4 were then plotted on a large scale presentation, similar to that shown in Figure 4, for determination of reservoir volume in the two benches. Volumes and original oil-in-place were calculated to be:

Fig. 4: Contour Elevations Vs. Reservoir Area



Upper Bench

Total reservoir volume	95,800 acre-feet
Private reservoir volume	26,250 acre-feet
Navy reservoir volume	69,550 acre-feet

$$N\ (\text{total}) = \frac{7758 \times 95,800 \times .21 \times .85}{1.22} = 108.8 \times 10^6\ \text{STB}$$

$$N\ (\text{private}) = \frac{7758 \times 26,250 \times .21 \times .85}{1.22} = 29.8 \times 10^6\ \text{STB}$$

$$N\ (\text{navy}) = (108.8 - 29.8) \times 10^6 = 79.0 \times 10^6\ \text{STB}$$

Lower Bench

Total reservoir volume	59,300 acre-feet
Private reservoir volume	17,800 acre-feet
Navy reservoir volume	41,500 acre-feet

$$N\ (\text{total}) = \frac{7758 \times 59,300 \times .20 \times .71}{1.22} = 53.5 \times 10^6\ \text{STB}$$

$$N\ (\text{private}) = \frac{7758 \times 17,800 \times .20 \times .71}{1.22} = 16.1 \times 10^6\ \text{STB}$$

$$N\ (\text{navy}) \quad (53.5 - 16.1) \times 10^6 = 37.4 \times 10^6\ \text{STB}$$

Total Original Oil-in-place (Both Benches)

$$N\ (\text{total}) = (108.8 + 53.5) \times 10^6 = 162.3 \times 10^6\ \text{STB}$$

$$N\ (\text{private}) = (29.8 + 16.1) \times 10^6 = 45.9 \times 10^6\ \text{STB}$$

$$N\ (\text{navy}) = (79.0 + 37.4) \times 10^6 = 116.4 \times 10^6\ \text{STB}$$

The formation volume factor of 1.22 used in the above calculations is the value used by core laboratories in the Casper area based on past

experience with similar Shannon reservoirs.

As a matter of general interest, the total surface area within the probable Shannon reservoir limits, as defined on Plate 1, was planimetered as 4900 acres. Of this total, 3270 acres were within NPR#3 and 1630 acres were outside the NPR#3 boundary.

CHAPTER VII

DECLINE CURVE RESERVE CALCULATIONS

Plotting Production Data

As mentioned earlier, the majority of the Navy's wells are completed and fractured in both benches before being placed on production. Hence, in developing decline curve data for calculating future production, only wells fractured and producing from both zones were considered. The production data for twelve such wells were used in these calculations.

During the current development period the number of wells has been constantly increasing, and the field production rate has been increasing accordingly. This fluctuation plus the normal factors affecting the production curves presented a problem in attempting to accurately reflect well productivity by a plot that could be extrapolated. This problem was circumvented by combining the equivalent monthly rates of the 12 wells used in the study and working with a production rate per average well (see Table 5 for this production data). To dampen out peaks and valleys, the production rates for three month periods were used in extrapolating the average well curve by the Loss-Ratio Method.

An individual using the decline curve graphic approach is confronted by two principal problems. The first is that of working the rough production data into a representative curve. The second is that of finding some means of smoothing this representative curve into a straight line

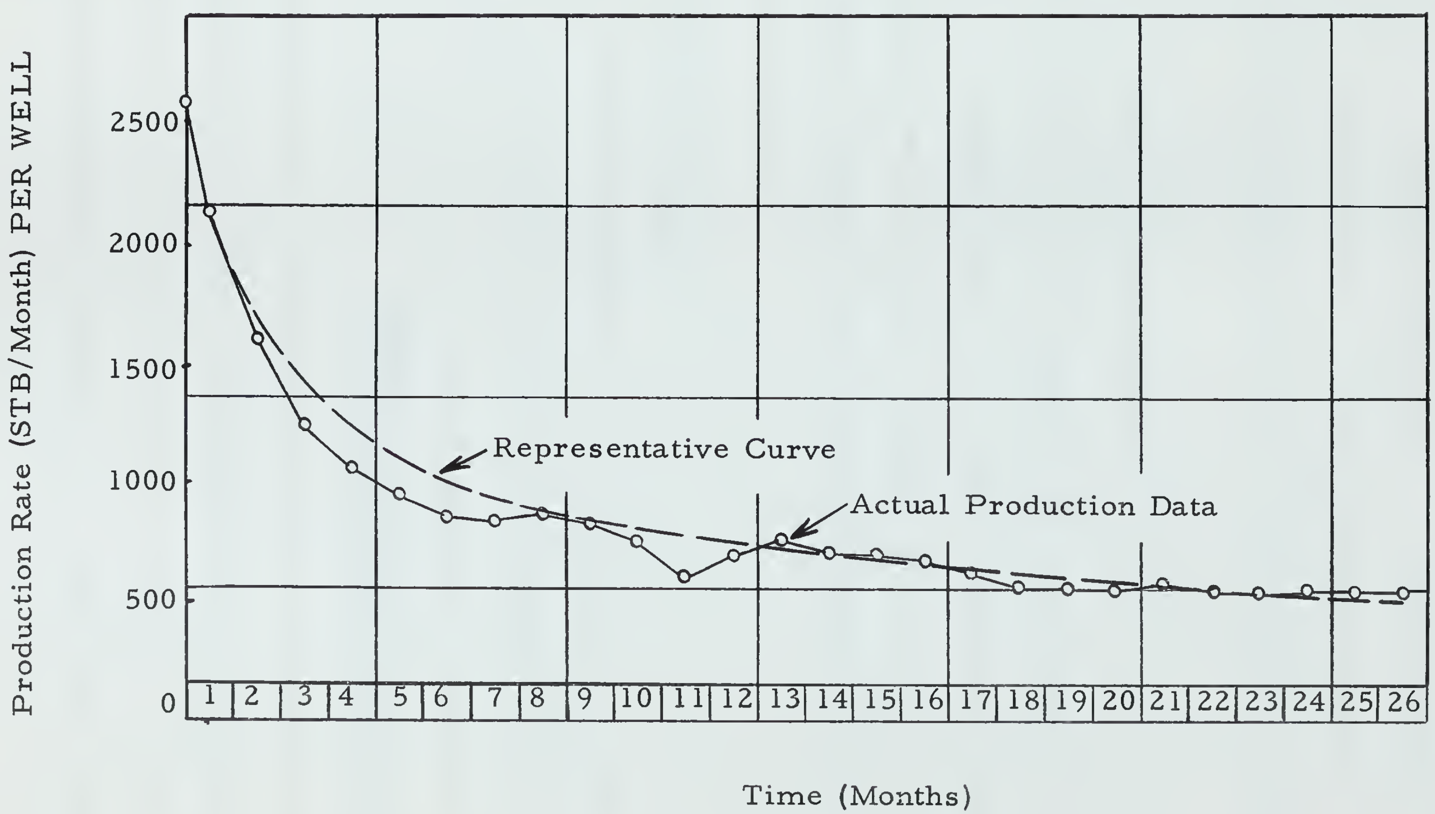
for extrapolation purposes.

The first problem was approached by plotting actual monthly unrestricted production rate per average well versus time for approximately a two year period (Figure 5). The period represented is the life of the field for which dependable data were available. A representative curve was then superimposed on the actual data (Figure 5), using the "equal area" method, i.e., blaancing the over-under areas between the two curves.

After a number of trials, it was found that any representative curve which balanced the areas during the first 8 months of production would not lend itself to straight line extrapolation in accurately representing actual production for all times after 8 months. For some reason, the first 8 months of actual production apparently did not represent the "average" production in the same declining manner that the remainder of the production curve represented "average" production.

A possible explanation for this was discovered in reviewing the individual well production curves. It was observed that every well was being subjected to progressive waxing which resulted in a progressively reduced production rate. Hot oil treatments were begun on a well after the first 6-8 months of production. Thus, during the first 6-8 months of production, all wells were being subjected to progressive waxing with none receiving any treatment to raise the average rate to a representative average. After this initial period, however, the normal schedule

Fig. 5 Production Rate (Per Well) Vs. Time



of hot oil treatments insured that some wells were producing at nearly full potential at all times, thus affording a representative average production rate after about the first 8 months of well life. To negate the effect of this phenomenon, the representative curve was arbitrarily applied to months 0-8 at the same hyperbolic decline rate which existed for months 8 to 26.

Because of the extended production time involved, it was most convenient to plot production rate-time data for the representative curve on a log-log plot, thus compressing the time scale to facilitate extrapolation. The resulting plot was essentially a straight line, as shown on Figure 6, in which both the actual and representative production data are shown for comparative purposes.

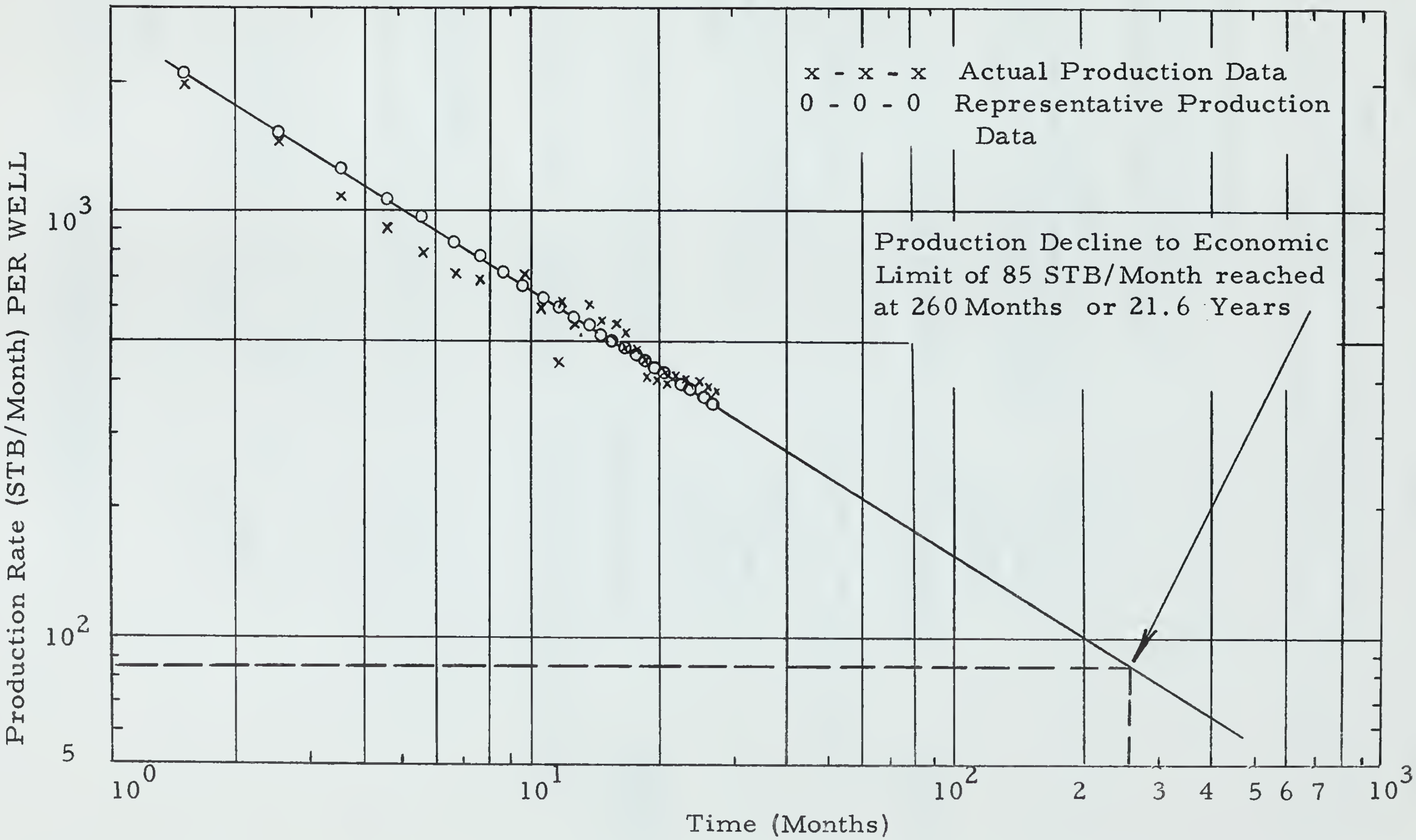
Determination of Economic Limit

For purposes of determining the time on decline and recoverable reserves per well, it was necessary at this point to determine the economic limit. This term has been previously defined and is restated as:

$$\text{Economic Limit (bbls/day)} = \frac{\text{Monthly operating cost}}{(30.4)(\text{net price/bbl})(\text{interest owned})}$$

Monthly operating costs for the field were obtained from the current operating budget prepared by the Navy. Included are all costs incurred in connection with field operations by the civilian contractor, including overhead. They do not include officers' salaries or Navy office overhead,

Fig. 6: Production Rate (Per Well) Vs. Time



inasmuch as these costs are incurred as a result of primary duties performed by the Officer in Charge of Naval Petroleum and Oil Shale Reserves in Colorado, Utah, and Wyoming, and would presumably continue if this field were shut in.

Monthly Operating Cost for 45 Wells

Direct operating expense (annual)	\$18,000	
Indirect operating expense (annual)	20,000	
Subsurface maint. expense (annual)	5,000	
Surface maint. expense (annual)	23,000	
Total operating and maint. expense (annual)		\$66,000

$$\frac{\$66,000}{12 \text{ mo. } \times 45 \text{ wells}} = \$123 \text{ per well per month}$$

Operator's fee (annual)	\$46,000	
Insurance expense (annual)	800	
Overhead	11,280	
Total fee and overhead		\$58,050
GRAND TOTAL		\$124,080

$$\text{Total monthly cost} = \frac{124,080}{12 \times 45} = \$230 \text{ per well per month}$$

Net Income per Barrel

Selling price per barrel (average)			\$2.80
Less:			
ICC tax	.05		
Transportation fee	.05	.10	.10
Net income per barrel			\$2.70

Economic Limit

$$\text{Economic limit} = \frac{\text{Total monthly cost}}{30.4 \times (\text{net price/bbl})(1.0)}$$

Economic Limit (Continued)

$$= \frac{\$230}{30.4 \times \$2.70} = 2.8 \text{ bbls/well/day}$$

$$= 85 \text{ bbls/well/month}$$

Determination of Total Production Time and Ultimate Production

The straight line plot of Figure 5 was extended to the economic limit of 85 STB/well/day in order to determine the economic life of the well. The result is as shown on Figure 6, 260 months, or 21.6 years.

In order to then determine graphically the cumulative production of the average well during its economic life, a plot was made of production rate versus cumulative production per well. This data did not plot as a straight line. Hence, it was necessary to shift it to make it straight.

The equation for a straight line on a log-log plot is:[21]

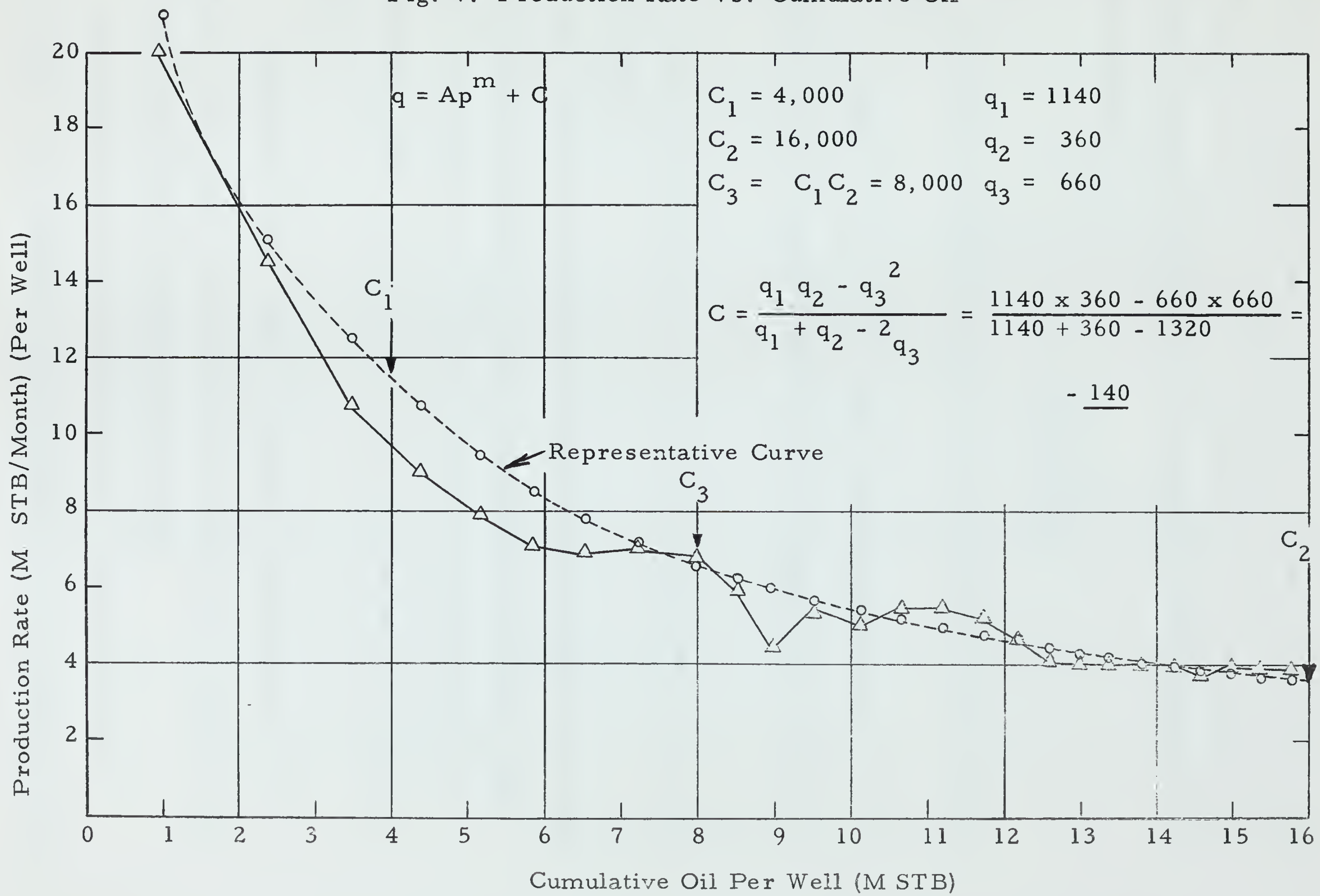
$$q = AP^{m} + C$$

where
- q = the value of production rate on the ordinate
- A = a constant
- P = value of cumulative production on the abscissa
- m = slope
- C = a number of such quantity that it will shift the curve to a straight line

The result is then a plot of q-C on the ordinate versus P on the abscissa.

The value of C was found by plotting actual production rate versus cumulative production on co-ordinate paper and establishing a representative curve (Figure 7) similar to that in Figure 5. Two values of cumulative

Fig. 7: Production Rate Vs. Cumulative Oil



production, C1 and C2, were selected near the ends of the curve, and a third value, $C3 = (C1 \times C2)^{1/2}$ calculated. The corresponding values of q were read from the graph, and the value of C calculated by the following equation:

$$C = \frac{q_1 q_2 - q_3^2}{q_1 + q_2 - 2q_3}$$

The graph, calculations, and value calculated for C are shown on Figure 7.

Using this value of C, the shifted curve for production rate-cumulative oil was plotted on Figure 8 and extended to the economic limit.

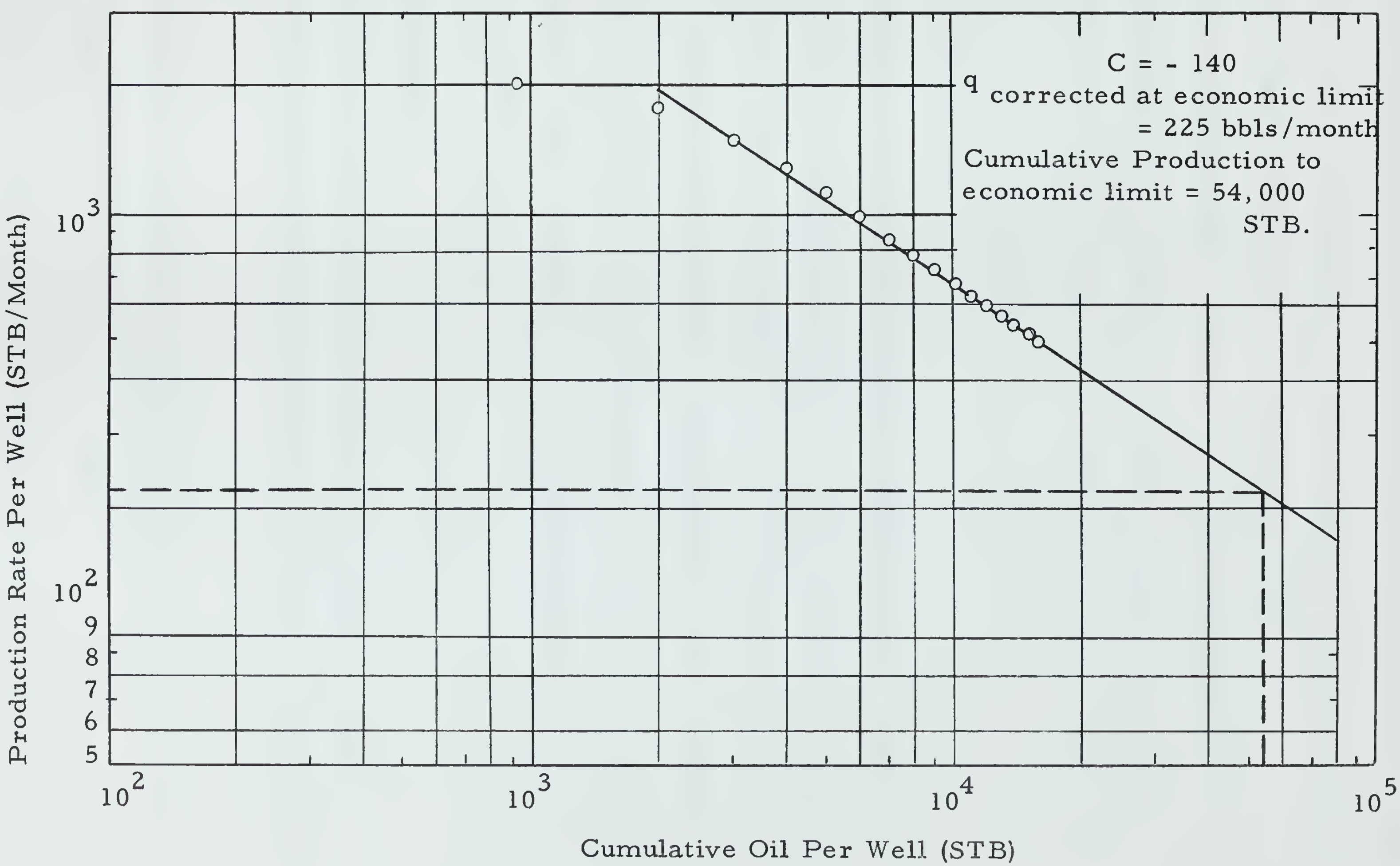
Cumulative production to economic limit was found to be 54,000 STB per well.

As a check on the graphical methods of determining economic life and cumulative production of a well, calculations for the hyperbolic decline of the well were carried out using the Loss-Ratio Method of Johnson and Bollen. The results of these calculations are tabulated in Table 6.

Economic life of the well and cumulative production were 309 months, or 25.7 years, and 58,300 STB, respectively, compared with 21.6 years and 54,000 STB obtained graphically.

There are a number of possible reasons for the variance in these values. For example, it is well known that log-log extrapolations

Fig. 8: Production Rate Vs. Cumulative Oil Produced



for long periods of time are least accurate where the greatest accuracy is required, i.e., at the economic limit. A slight deviation from the true plot of points could cause a relatively large error.

Another possible cause is the fact that the Loss-Ratio Method uses a calculated average loss-ratio figure which is applied in calculating recoveries for the remainder of the well's life. Any error in this average figure would result in a significant deviation from true values over a long period of time.

Inasmuch as the graphical methods for determining economic life and cumulative production both resulted in values less than the respective results found in Table 6, the monthly production rate and producing life in Table 6 were adjusted downward to approximate a total production of 54,000 STB per well and an economic life of 22-23 years before proceeding with present worth calculations. The revised figures are found in Columns 1 and 2 of Table 7.

Per Cent Recovery

Before proceeding with present worth calculations, it was considered desirable to calculate the per cent recovery of initial oil-in-place.

It was noted in reviewing core lab reports that primary recovery for the Shannon is normally estimated at approximately 8%.

The per cent recovery for this study resulted as follows:

Navy surface acreage within reservoir limits - 3270 acres

Initial oil-in-place within NPR#3 = 116.4×10^6 STB

Initial oil-in-place per surface acre $= \dfrac{116.4 \times 10^6}{3270}$

$= 35,600$ STB/A.

Assuming 10 acre spacing,

original oil-in-place per well - $10 \times 35,600 = 356,000$ STB/well

Per cent recovery $= \dfrac{54,000}{356,000} = 15.2\%$

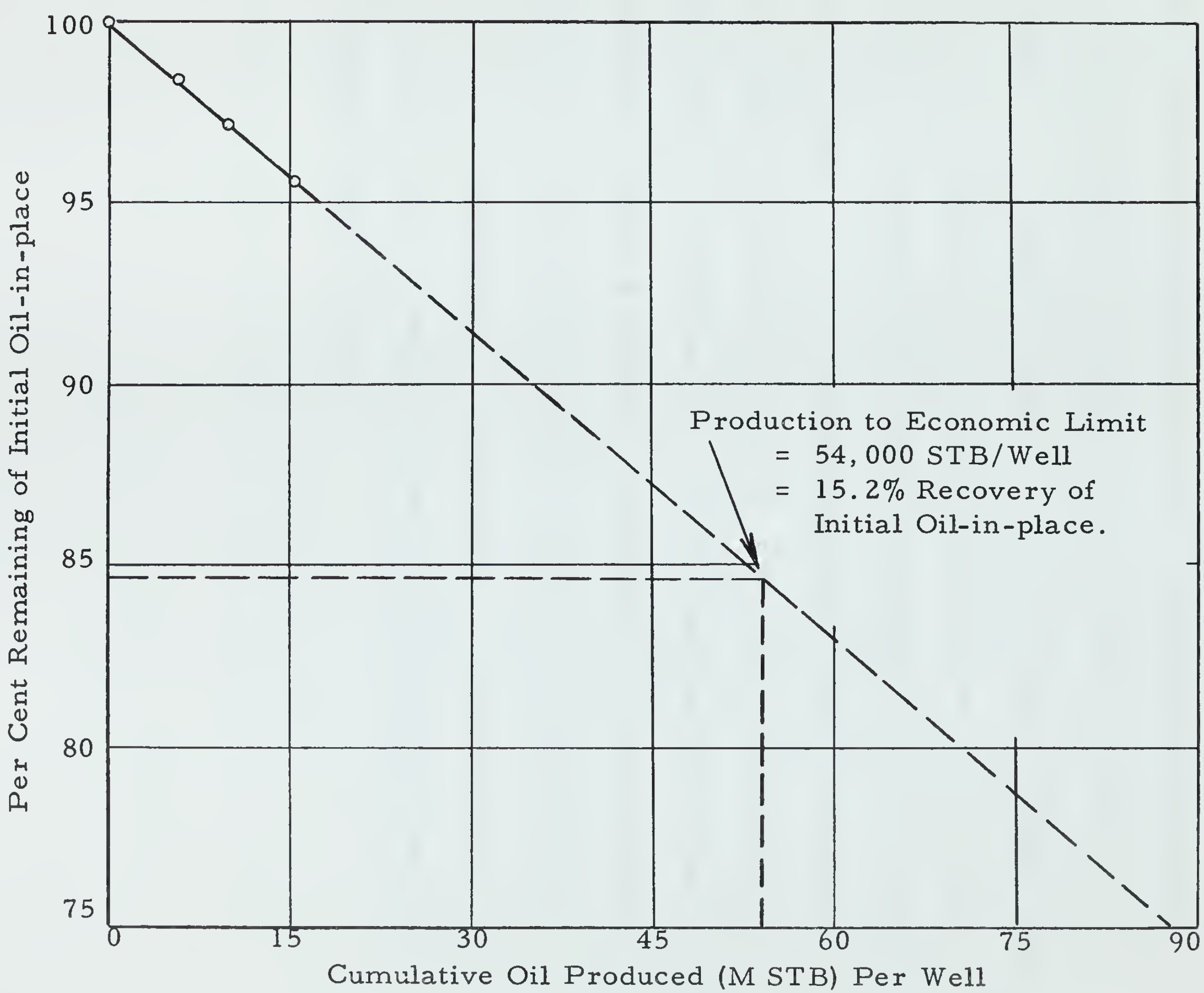
There is an apparent discrepency between the 15% calculated recovery figure and the 8% figure used by local testing laboratories. This is explainable, however, by the fact that the Navy wells lie down-structure on a 7-10° dip and are undoubtedly benefitting from gravity drainage. This could account for the additional recovery over that normally anticipated for a flat reservoir with the same crude characteristics.

The per cent recovery may also be shown graphically by plotting per cent remaining oil-in-place versus cumulative production, as in Figure 9. The author believes this plot to be informative because it shows graphically a volumetric calculation plotted against actual production to an economic limit calculated by the decline curve to arrive at a reasonable result for per cent recovery. In other words, it provides a check of methods, one against the other, for validity of results.

Production Potential

Consideration was given to the production potential of the average

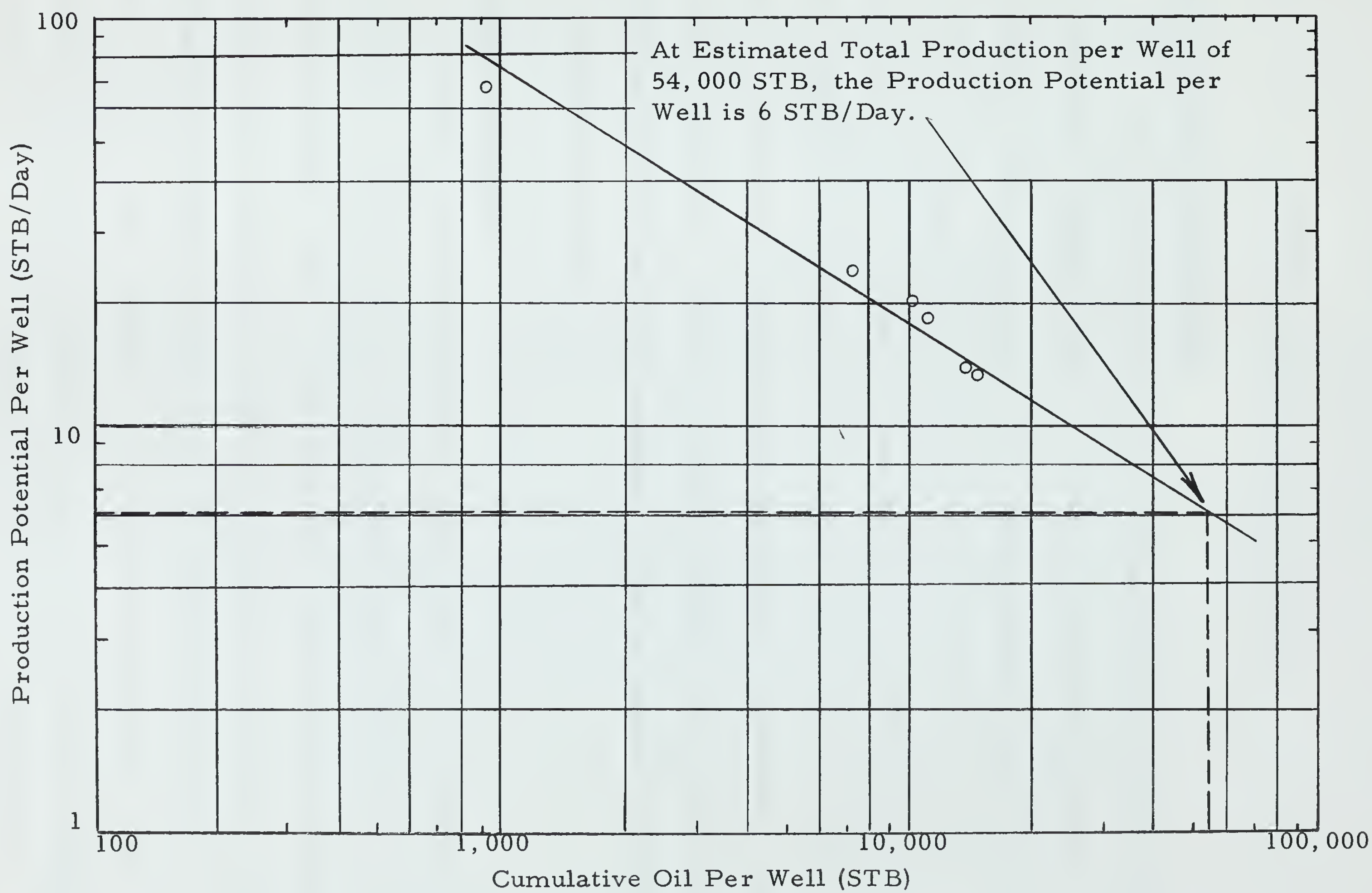
Fig. 9: Remaining Oil in Place Vs. Cumulative Production



well at various times during its life, with specific thought as to what the potential of the well might be at the end of its economic life.

Referring to Figure 5, it is noted that the actual production plot results in a number of peaks and valleys. The author interpreted the peaks as approximations of the potential of the well to produce, i.e., they represent the most favorable combinations of factors affecting production. By choosing the production rate at a number of these peaks and plotting them on a log-log plot of production potential versus cumulative production (Figure 10), a production potential of 6 STB per day was obtained at the economic limit of 54,000 STB when the average well is actually producing 2.8 STB per day. This is interpreted to mean that the average well is capable of producing additional oil at its economic limit, but that it is not economically feasible to do so on a field-wide basis under existing operating and overhead costs. It would undoubtedly be possible to "poor boy" the wells on a low overhead stripper basis for some additional number of years.

Fig. 10: Production Potential Vs. Cumulative Production



CHAPTER VIII

PRESENT WORTH CALCULATIONS

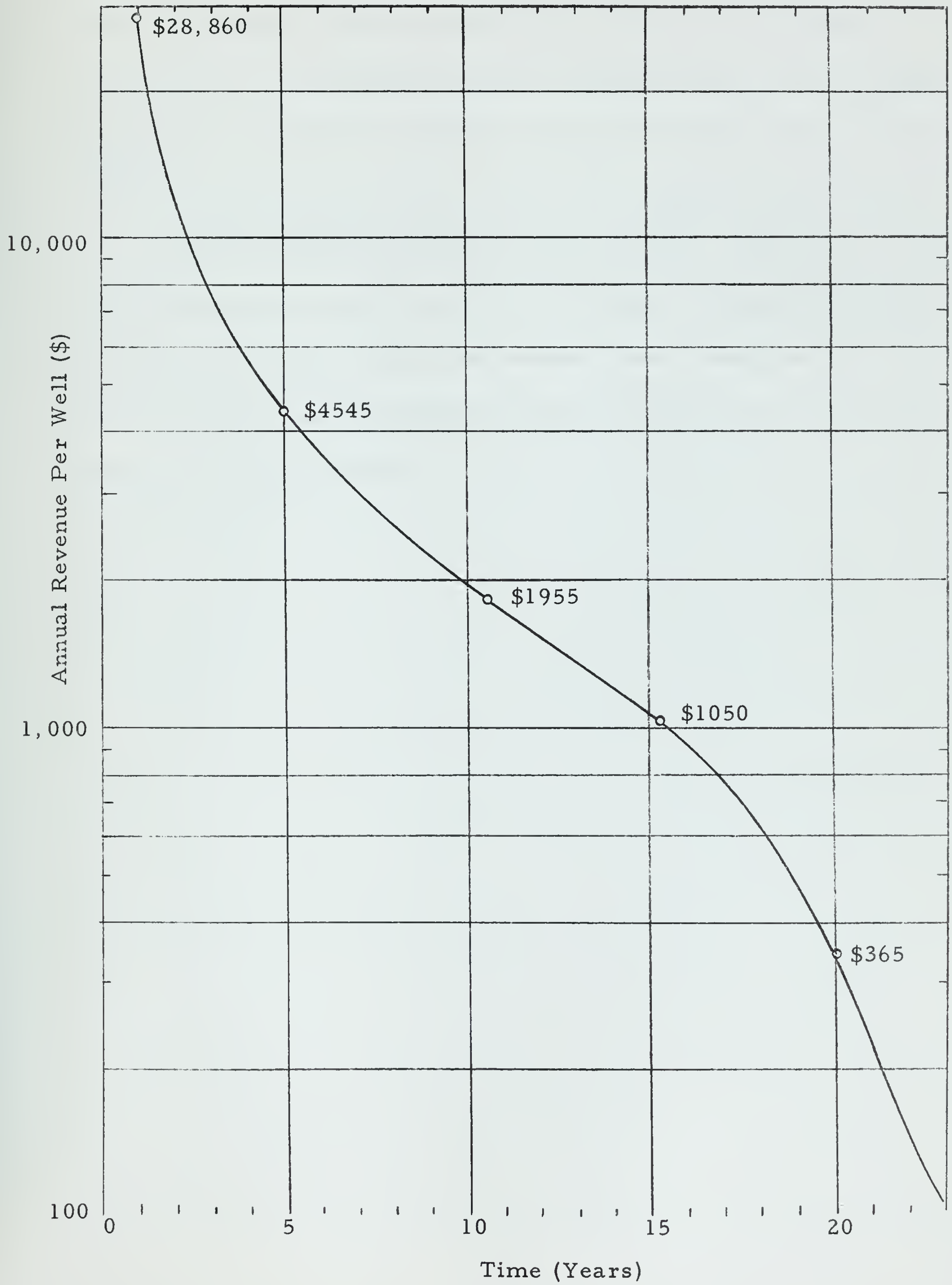
Projected Annual Cash Recovery

After calculating adjusted economic life and adjusted monthly rates of production from Figures 6 and 8 and Table 6, the adjusted quantities were utilized in Table 7 to develop semi-annual production rates for the life of the well. Using current market value of oil,[25] these production figures were converted to gross incomes for their respective periods. Current semi-annual operating costs were then subtracted from gross income for each period to arrive at net income before discounting to the date of well completion. Figure 11 is a plot of annual cash recovery per well after deduction of operating expenses. It does not include a consideration of original investment cost.

Discounting Procedure

The discount factor determined as reasonable for this situation was 4% per annum, or 2% for each six month period used in the Table 7 calculations for present worth. "Present worth", in this instance, is based on the date of well completion. Deferred net income for each period was calculated using standard discount tables.[26] The deferred net profit is shown in the last column of Table 7. The figures in this column duplicate those of the previous column with the exception of the top two figures. The top figure shows a deficit of $516 for the first six months of the

Fig. 11: Projected Annual Cash Recovery Per Well



well's life because of the investment cost of $19,666 for drilling, completing and fracturing both zones of the well being subtracted from the deferred revenues for that first period. This figure also gives an indication that the payout time for the well is approximately six months.

The total deferred profit per well is $50,964. This is the "present worth" of the well at the time of its completion. It should be noted that this figure assumes no major replacement costs during the life of the well, all wells being electrically-powered and subject to no unusually severe corrosion problems.

CHAPTER IX

SUMMARY AND CONCLUSIONS

Summary

The Shannon Sand at Teapot Dome was studied for the purpose of establishing the probable limits of the Shannon reservoir and to determine the ultimate recovery of oil per average well and the profitability of the average well.

The probable limits of the Shannon were established accurately on the east and north flanks. The south and west limits were estimated on the basis of shows (or no shows) of oil reported in drillers' logs made some 40 years ago. Geologic data were presented to strengthen the author's argument for establishing these limits as shown.

Based on the established reservoir limits, core reports, and well logs, total reservoir volume was calculated. Initial oil-in-place was computed to be 162.3×10^6 STB. On the basis of 4900 surface acres within the reservoir limits, this amounts to 33,200 STB per surface acre. Note that this overall figure is somewhat lower than the 35,600 STB/acre computed for the Navy portion of the reservoir on page 46.

The decline curve approach was used on an individual well basis to arrive at an ultimate recovery of 54,000 STB per well over a period 22-23 years. These computations were based on an average well, hydraulically-fractured in both benches before being placed on production,

and produced to an economic limit of 2.8 STB per day. Production of 54,000 STB per well represents a 15% recovery of initial oil-in-place for those wells on NPR#3.

The average cost of drilling, completing, and fracturing a well in two zones is $19,666. Average monthly operating, maintenance, and overhead cost per well is $230. Based on these figures and a net income per barrel of $2.70, the "present worth" of a well's production at the time it is placed on production is $50,964.

Conclusions

The Shannon reservoir limits, as established in Plate 1, may be proved in error by subsequent drilling programs. Should this occur, it is believed that sufficient data have been provided to permit accurate re-estimation of oil-in-place and recoveries under the new boundary conditions. A drilling program designed to establish these limits and to obtain additional core and fluid data would be of value to the Navy.

In calculating recoverable reserves with the decline curve, the author was well aware of the dangers inherent in extrapolating two years of production data into 20 years of reserve estimates. Hence, the reader is warned that the recoveries found may not be the final answer. Rather, they are presented as the best that could be done with the information at hand. They should be used to check against actual production in preparing more accurate future estimates and will provide a handy foundation

for this purpose. In all cases, it is believed that sufficient background data have been provided to accomplish this.

The possible application of the 54,000 STB per well recovery figure to the entire reservoir has been explored. It is believed applicable to the present 75 well program, on the basis that a number of the wells used in this study are completely surrounded by other producing wells and are subject to normal well interference. Expansion of the field to the planned 75 wells will not materially change the updip drainage situation for most of these existing wells. Total recovery from the 75 wells is then estimated as 75 x 54,000 or 4,050,000 STB.

Whether this same figure could be applied to the total Navy acreage is doubtful. The present wells are probably gaining some advantage from gravity drainage, and the gravity mechanism grows increasingly important each day as the oil loses its gas. Extensive drilling updip on a 10 acre spacing would certainly reduce production downdip. If we were to apply the average recovery figure to the total NPR#3 acreage and assume a 10 acre spacing, total recovery would be $\frac{3270 \text{ acres}}{10 \text{ acres/well}} \times 54{,}000$ STB/well which would equal 17.7 million barrels. In view of the above considerations, however, the author would consider some smaller percentage of recovery more appropriate. The 8% figure used by local core laboratories for flat reservoirs is believed too low. Hence, we might assume a 12% recovery figure, midway between the values, as a first approximation.

This would result in a primary recovery of approximately 14 million barrels.

If we are to recover less than 15% of initial oil-in-place by primary means, some thought might then be given to possible secondary recovery. Such a venture would require a great deal of study because of the extensive fissuring of the Shannon on the east limb, the numerous permeability streaks in the sand, and the presence of hydratable clays. The study is beyond the scope of this thesis, and is simply reported as a matter of extreme importance if secondary recovery is ever contemplated.

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APPENDIX

TABLE 2

SHANNON PRODUCTION
NPR # 3

Well	Date On Prod.	IP	Mos. of Year Prod.	1958 Bbls Oil	1958 Bbls Water	Mos. of Year Prod.	1959 Bbls. Oil	1959 Bbls. Water	Mos. of Year Prod.	1960 Bbls. Oil	1960 Bbls. Water	Mos. of Year Prod.	1961 Bbls. Oil	1961 Bbls. Water	Total Oil Prod. thru 8-31-61	Total Water Prod. thru 8-31-61
28S-35	12-9-58	120 BOD, 0% Cut	1	770	16	12	7,947	636	12	4,965	157	8	3,654	180	17,336 bbls. Oil	989 bbls. Water
47S-35	12-9-58	72 BOD, 1% Cut	1	1,030	54	12	4,095	585	12	3,544	112	8	3,540	192	12,209 bbls. Oil	943 bbls. Water
83S-11	12-10-58	97 BOD, 0% Cut	1	1,081	147	12	9,034	1,566	12	5,066	391	8	2,653	170	17,834 bbls. Oil	2,274 bbls. Water
32S-2	8-18-59	107 BOD, 0% Cut		-	-	4	6,960	617	12	7,439	96	8	3,513	206	17,912 bbls. Oil	919 bbls. Water
27S-35	8-23-59	111 BOD, 2% Cut		-	-	4	6,936	535	12	8,919	557	8	3,807	189	19,712 bbls. Oil	1,282 bbls. Water
44S-2	9-3-59	91 BOD, 5% Cut		-	-	3	6,047	135	12	10,068	319	8	3,393	274	19,503 bbls. Oil	728 bbls. Water
71S-14	9-17-59	79 BOD, 14% Cut		-	-	3	4,178	750	12	6,408	374	8	3,197	253	13,783 bbls. Oil	1,377 bbls. Water
77S-11	9-19-59	73 BOD, 16% Cut		-	-	3	3,858	852	12	5,912	594	8	2,521	241	12,291 bbls. Oil	1,687 bbls. Water
86S-11	9-19-59	86 BOD, 5% Cut		-	-	3	5,043	638	12	6,477	831	8	2,450	163	13,970 bbls. Oil	1,632 bbls. Water
16S-35	5-26-60	129 BOD, 14% Cut		-	-		-	-	7	9,149	1,737	8	4,759	747	13,908 bbls. Oil	2,484 bbls. Water

TABLE 2 - Continued

Well	Date On Prod.	IP	Mos. of Year Prod.	1958 Bbls. Oil	1958 Bbls. Water	Mos. of Year Prod.	1959 Bbls. Oil	1959 Bbls. Water	Mos. of Year Prod.	1960 Bbls. Oil	1960 Bbls. Water	Mos. of year Prod.	1961 Bbls. Oil	1961 Bbls. Water	Total Oil Prod. thru 3-31-61	Total Water Prod. thru 8-31-61
33S-2	5-28-60	143 BOD, .1% Cut		-	-		-	-	7	6,106	228	8	3,136	265	9,242 bbls. Oil	493 bbls. Water
75S-11	6-6-60	75 BOD, 18% Cut		-	-		-	-	6	7,555	1,508	8	2,814	246	10,369 bbls. Oil	1,754 bbls. Water
31S-2	6-14-60	110 BOD, .2% Cut		-	-		-	-	6	7,901	328	8	3,828	338	11,729 bbls. Oil	666 bbls. Water
26S-35	6-15-60	106 BOD, 8% Cut		-	-		-	-	6	8,226	709	8	4,608	336	12,834 bbls. Oil	1,045 bbls. Water
65S-11	6-18-60	86 BOD, 4% Cut		-	-		-	-	6	8,557	462	8	3,539	204	11,596 bbls. Oil	666 bbls. Water
54S-2	6-26-60	105 BOD, .1% Cut		-	-		-	-	6	7,344	580	8	4 421	349	11,765 bbls. Oil	929 bbls. Water
55S-2	7-1-60	64 BOD, 10% Cut		-	-		-	-	5	5,624	551	8	4,028	482	9,652 bbls. Oil	1,033 bbls. Water
66S-11	7-5-60	94 BOD, 10% Cut		-	-		-	-	5	7,101	698	8	5,715	350	12,816 bbls. Oil	1,048 bbls. Water
54S-11	7-6-60	78 BOD, 6.5% Cut		-	-		-	-	5	5,448	603	8	5,903	796	11,351 bbls. Oil	1,399 bbls. Water
15S-35	5-21-61	109 BOD, 6% Cut		-	-		-	-		-	-	3	5,689	517	5,689 bbls. Oil	517 bbls. Water

TABLE 2 - Continued

Well	Date On Prod.	IP	Mos. of Year Prod.	1958 Bbls Oil	1958 Bbls. Water	Mos. of Year Prod.	1959 Bbls. Oil	1959 Bbls. Water	Mos. of Year Prod.	1960 Bbls. Oil	1960 Bbls. Water	Mos. of Year Prod.	1961 Bbls. Oil	1961 Bbls. Water	Total Oil Prod. thru 8-31-61	Total Water Prod. thru 8-31-61
14S-35	6-10-61	51 BOD, 40% Cut		-	-		-	-		-	-	2	1,945	1,880	1,946 bbls. Oil	1,880 bbls. Water
83S-34	6-21-61	42 BOD, 42% Cut		-	-		-	-		-	-	2	1,895	2,597	1,895 bbls. Oil	2,597 bbls. Water
78S-27	6-26-61	81 BOD, 25% Cut		-	-		-	-		-	-	2	1,863	1,143	1,863 bbls. Oil	1,143 bbls. Water
84S-34	6-28-61	81 BOD, 26% Cut		-	-		-	-		-	-	2	2,207	2,067	2,207 bbls. Oil	2,067 bbls. Water
71S-34	7-3-61	56 BOD, 30% Cut		-	-		-	-		-	-	1	1,958	950	1,958 bbls. Oil	950 bbls. Water
73S-34	7-9-61	41 BOD, 54% Cut		-	-		-	-		-	-	1	1,395	3,271	1,395 bbls. Oil	3,271 bbls. Water
		TOTALS		2,881	217		54,148	6,315		131,309	10,835		88,432	18,406	276,770	35,773
				(3 Producing Wells) in 1958			(9 Producing Wells) in 1959			(19 Producing Wells) in 1960			(26 Producing Wells) To Date in 1961 8-31-61			

TABLE 3

WELL DATA - SHANNON SAND
TEAPOT DOME

Well No.	Altitude of well Mouth (Ft)	Altitude Top of Shannon (Ft)	Altitude Bottom of Shannon (Ft)	Net Pay Upper Bench (Ft)	Net Pay Lower Bench (Ft)
101-20	5025	No Data	No Data	No Data	No Data
102-20	4991	4896	4781	"	"
103-20	5018	4928	4818	"	"
105-20	5006	4996	4876	"	"
401-20	5052	5047	4907	"	"
402-20	5014	4919	4809	"	"
403-20	5012	4907	4807	"	"
404-20	5004	4894	4832	"	"
405-20	4997	4880	4737	"	"
406-20	4999	4889	4789	"	"
407-20	5056	5041	4956	"	"
408-20	5029	5014	4904	"	"
409-20	5043	4961	4863	"	"
410-20	5022	4947	4817	"	"
201-21	4981	4881	4736	"	"
301-21	4991	4779	4676	"	"
302-21	4999	4859	4764	"	"
303-21	4991	4851	4751	"	"
304-21	4983	4908	4803	"	"
PPC1-26	No Data	3640	No Data	"	"
PPC2-26	"	3556	"	"	"
PPC3-26	"	3543	"	"	"
MJD3-26	"	3838	"	"	"
MJD4-26	"	3778	"	"	"
MJD5-26	"	3758	"	"	"
MJD6-26	"	3678	"	"	"
MJD9-26	"	3565	"	"	"
MJD10-26	"	3718	"	"	"
MKM1-26	"	4182	"	"	"
MKM2-26	"	4130	"	"	"
MKM3-26	"	4106	"	"	"
MKM4-26	"	4089	"	"	"
MKM5-26	"	3962	"	"	"

TABLE 3 - Continued

Well No.	Altitude of well Mouth (Ft)	Altitude Top of Shannon (Ft)	Altitude Bottom of Shannon (Ft)	Net Pay Upper Bench (Ft)	Net Pay Lower Bench (Ft)
MKM6-26	No data	3764	No Data	No Data	No Data
MKM7-26	"	3850	"	"	"
MKM8-26	"	3909	"	"	"
MKM9-26	"	3983	"	"	"
MKM10-26	"	4015	"	"	"
MKM11-26	"	3884	"	"	"
MKM12-26	"	4164	"	"	"
MKM13-26	"	3647	"	"	"
MKM14-26	"	3799	"	"	"
MKM15-26	"	4038	"	"	"
MKM16-26	"	3953	"	"	"
MKM21-26	"	3709	"	"	"
MKM27-26	"	3789	"	"	"
MKM32-26	"	3846	"	"	"
MKM35-26	"	4013	"	"	"
301-27	5058	4653	4618	"	"
302-27	5070	4820	4710	"	"
303-27	5069	4759	4629	"	"
785-27	5042	4322	4212	14	22
875-27	5082	4214	4104	10	0
201-28	5006	4831	4711	No Data	No Data
202-28	4964	4814	4714	"	"
203-28	4974	4799	4704	"	"
205-28	5018	4858	4708	"	"
301-28	5082	4807	4737	"	"
302-28	5094	4869	4779	"	"
303-28	5049	4824	4719	"	"
304-28	5072	4847	4717	"	"
305-28	5055	4834	4740	"	"
306-28	5040	4845	4730	"	"
401-28	5067	4819	4772	"	"
402-28	5082	4842	4742	"	"

TABLE 3 - Continued

Well No.	Altitude of well Mouth (Ft)	Altitude Top of Shannon (Ft)	Altitude Bottom of Shannon (Ft)	Net Pay Upper Bench (Ft)	Net Pay Lower Bench (Ft)
403-28	5060	4790	4680	No Data	No Data
404-28	5080	4890	4760	"	"
405-28	5049	4774	4664	"	"
101-29	5003	4883	4778	"	"
103-29	4988	4838	4698	"	"
104-29	4982	4812	4682	"	"
105-29	4985	4830	4685	"	"
106-29	4980	4840	4690	"	"
107-29	4974	4894	4744	"	"
108-29	4969	4879	4794	"	"
109-29	4965	4870	4715	"	"
110-29	4967	4852	4717	"	"
111-29	5025	4840	4705	"	"
201-29	5012	4912	4777	"	"
203-29	5020	4915	4840	"	"
204-29	5016	4855	4766	"	"
401-29	5036	4816	4721	"	"
402-29	5032	4797	4687	"	"
101-33	5154	4669	4554	"	"
102-33	5149	4849	4759	"	"
103-33	5132	4897	4842	"	"
104-33	5119	4909	4779	"	"
201-33	5150	4800	4675	"	"
401-33	5145	4730	4625	"	"
402-33	5162	4692	4562	"	"
403-33	5139	4694	4594	"	"
404-33	5160	4730	4615	"	"
201-34	5106	4601	4546	"	"
202-34	5093	4604	4528	"	"
203-34	5088	4613	4508	"	"
204-34	5093	4668	4578	"	"
615-34	5036	4439	4329	11	0
715-34	5063	4369	4254	20	22
725-34	5067	4411	4301	18	22

TABLE 3 - Continued

Well No.	Altitude of well Mouth (Ft)	Altitude Top of Shannon (Ft)	Altitude Bottom of Shannon (Ft)	Net Pay Upper Bench (Ft)	Net Pay Lower Bench (Ft)
735-34	5040	4456	4344	20	22
745-34	5044	4496	4396	10	0
755-34	5083	4459	4359	12	0
765-34	5087	4513	4419	20	8
835-34	5090	4432	4322	18	20
845-34	5083	4454	4345	21	20
875-34	5097	4481	4385	22	9
145-35	5104	4402	4286	24	26
155-35	5069	4381	4267	18	22
165-35	5091	4351	4263	18	10
265-35	5096	4285	4181	20	14
275-35	5101	4347	4249	20	9
285-35	5103	4447	4418	16	6
475-35	5123	4243	4213	19	3
MKM1-35	No Data	4225	No Data	No Data	No Data
MKM2-35	"	4152	"	"	"
MKM3-35	"	4284	"	"	"
MKM4-35	"	4262	"	"	"
MKM1-35E	"	4077	"	"	"
MKM2-35E	"	4001	"	"	"
MKM3-35E	"	4192	"	"	"
MKM4-35E	"	4108	"	"	"
MKM5-35	"	4013	"	"	"
MKM6-35	"	4061	"	"	"
MKM7-35	"	4007	"	"	"
MKM8-35	"	3993	"	"	"
MKM9-35	"	3966	"	"	"
MKM10-35	"	4081	"	"	"
MKM11-35	"	4157	"	"	"
MKM12-35	"	4158	"	"	"
MKM17-35	"	3708	"	"	"
MKM18-35	"	3994	"	"	"
MKM19-35	"	3964	"	"	"
MKM20-35	"	3792	"	"	"

TABLE 3 - Continued

Well No.	Altitude of well Mouth (Ft)	Altitude Top of Shannon (Ft)	Altitude Bottom of Shannon (Ft)	Net Pay Upper Bench (Ft)	Net Pay Lower Bench (Ft)
MKM23-35	No Data	3893	No Data	No Data	No Data
MKM24-35	"	3822	"	"	"
MKM25-35	"	3788	"	"	"
MKM26-35	"	3949	"	"	"
MKM28-35	"	3728	"	"	"
MKM29-35	"	3855	"	"	"
MKM30-35	"	3894	"	"	"
MKM31-35	"	3698	"	"	"
MKM33-35	"	3796	"	"	"
MKM36-35	"	3640	"	"	"
MKM37-35	"	3754	"	"	"
MKM38-35	"	3949	"	"	"
CS1-35	"	4220	"	"	"
CS2-35	"	4199	"	"	"
CS3-35	"	4156	"	"	"
CS4-35	"	4083	"	"	"
CS5-35	"	4139	"	"	"
CS6-35	"	4224	"	"	"
CS1-35E	"	4113	"	"	"
CS2-35E	"	4026	"	"	"
CS3-35E	"	3937	"	"	"
CS4-35E	"	3840	"	"	"
CS5-35E	"	3920	"	"	"
CS6-35E	"	4150	"	"	"
MKM1-36	"	3748	"	"	"
MKM2-36	"	3737	"	"	"
T1-1	"	3768	"	"	"
T2-1	"	3842	"	"	"
T3-1	"	3840	"	"	"
T4-1	"	3876	"	"	"
T6-1	"	3913	"	"	"
T7-1	"	3980	"	"	"
T8-1	"	3987	"	"	"
T10-1	"	3873	"	"	"

TABLE 3 - Continued

Well No.	Altitude of well Mouth (Ft)	Altitude Top of Shannon (Ft)	Altitude Bottom of Shannon (Ft)	Net Pay Upper Bench (Ft)	Net Pay Lower Bench (Ft)
B1-2	No Data	4304	No Data	No Data	No Data
B2-2	"	4132	"	"	"
B3-2	"	4012	"	"	"
B4-2	"	4307	"	"	"
T1-2	"	4195	"	"	"
T2-2	"	4150	"	"	"
T3-2	"	4152	"	"	"
T4-2	"	4172	"	"	"
T5-2	"	4047	"	"	"
T6-2	"	3934	"	"	"
T7-2	"	4054	"	"	"
T8-2	"	3854	"	"	"
T9-2	"	3908	"	"	"
T10-2	"	4072	"	"	"
T11-2	"	4015	"	"	"
T12-2	"	4072	"	"	"
S1-2	"	4178	"	"	"
S2-2	"	4197	"	"	"
11S-2	5100	4536	4442	18	8
22S-2	5115	4568	4462	12	10
31S-2	5118	4437	4337	18	14
32S-2	5126	4469	4370	21	12
33S-2	5119	4500	4398	24	16
35S-2	5133	4517	4423	10	8
44S-2	5142	4390	4297	25	8
46S-2	5150	4468	4306	17	7
48S-2	5168	4493	4396	15	14
54S-2	5164	4293	4199	20	8
55S-2	5163	4326	4258	26	16
57S-2	5200	4386	4290	22	10
301-2	5154	4654	4539	No Data	No Data
101-3	5171	4771	4651	"	"
201-3	5215	4801	4696	"	"
202-3	5232	4816	4696	"	"

TABLE 3 - Continued

Well No.	Altitude of well Mouth (Ft)	Altitude Top of Shannon (Ft)	Altitude Bottom of Shannon (Ft)	Net Pay Upper Bench (Ft)	Net Pay Lower Bench (Ft)
203-3	5197	4787	4687	No Data	No Data
204-3	5170	4765	4655	"	"
301-3	5180	4884	4774	"	"
302-3	5199	4882	4789	"	"
101-10	5217	4917	4807	"	"
102-10	5218	4908	4808	"	"
201-10	5238	4833	4688	"	"
401-10	5192	4897	4802	"	"
201-11	5177	4767	4667	"	"
301-11	5165	4735	4625	"	"
31S-11	5157	4600	4517	18	6
42S-11	5172	4508	4414	20	10
51S-11	5176	4401	4306	11	10
53S-11	5192	4466	4374	18	8
54S-11	5198	4473	4379	12	12
55S-11	5201	4456	4367	11	10
57S-11	5213	4443	4353	10	10
65S-11	5227	4358	4266	12	12
66S-11	5238	4355	4263	10	12
75S-11	5252	4253	4155	10	16
77S-11	5258	4244	4146	9	19
86S-11	5295	4130	4031	19	18
88S-11	5289	4130	4035	10	15
B1-11	No Data	4282	No Data	No Data	No Data
B2-11	"	4047	"	"	"
B5-11		4173	"	"	"
T9-12	"	4002	"	"	"
T12-12	"	4016	"	"	"
T13-12	"	4005	"	"	"
T14-12	"	4013	"	"	"
T20-12	"	3881	"	"	"
T21-12	"	3899	"	"	"
T22-12	"	3876	"	"	"
T23-12	"	3856	"	"	"

TABLE 3 - Continued

	Altitude of well Mouth (Ft)	Altitude Top of Shannon (Ft)	Altitude Bottom of Shannon (Ft)	Net Pay Upper Bench (Ft)	Net Pay Lower Bench (Ft)
T28-12	No Data	3754	No Data	No Data	No Data
T29-12	"	3755	"	"	"
T15-13	"	4034	"	"	"
T16-13	"	4022	"	"	"
T17-13	"	4021	"	"	"
T19-13	"	3948	"	"	"
T30-13	"	3813	"	"	"
71S-14	5259	4249	4152	10	18
301-14	5239	4609	4504	No Data	No Data
101-15	5244	4839	4729	"	"

TABLE 4

AREA MEASUREMENT DATA
FOR CALCULATION OF RESERVOIR VOLUME

Planimeter # 3609 - Planimeter Factor: .478 = 640 Acres - Contour Interval = 100 Ft.

		Planimeter Reading			Area (Acres)		
	Contour	Total	Navy	Private	Total	Navy	Private
Top - Upper Bench +	3600	3.602	2.450	1.152	4820	3280	1540
	3700	3.490	2.450	1.040	4670	3280	1390
	3800	3.314	2.450	.864	4440	3280	1160
	3900	3.135	2.450	.685	4197	3280	917
	4000	2.934	2.450	.484	3929	3280	649
	4100	2.680	2.440	.240	3586	3265	321
	4200	2.455	2.373	.082	3290	3180	110
	4300	2.211	2.207	.004	2960	2955	5
	4400	1.991	1.991	0	2662	2662	0
	4500	1.623	1.623	0	2172	2172	0
	4600	1.419	1.419	0	1900	1900	0
	4700	1.164	1.164	0	1558	1558	0
	4800	.796	.796	0	1065	1065	0
	4900	.129	.129	0	172	172	0
Bottom - Upper Bench +	3600	3.532	2.450	1.082	4730	3280	1450
	3700	3.414	2.450	.964	4570	3280	1290
	3800	3.246	2.450	.796	4348	3280	1068
	3900	3.055	2.450	.605	4090	3280	810
	4000	2.854	2.450	.404	3820	3280	540
	4100	2.619	2.397	.222	3507	3210	297
	4200	2.373	2.320	.053	3176	3105	71
	4300	2.142	2.141	.001	2865	2864	1

TABLE 4 - Continued

		Planimeter Reading			Area (Acres)		
	Contour	Total	Navy	Private	Total	Navy	Private
Bottom - Upper Bench (Continued) +	4400	1.930	1.930	0	2582	2582	0
	4500	1.617	1.617	0	2164	2164	0
	4600	1.342	1.342	0	1796	1796	0
	4700	1.047	1.047	0	1402	1402	0
	4800	.620	.620	0	830	830	0
	4900	.001	.001	0	1	1	0
Top - Lower Bench +	3600	3.472	2.450	1.022	4648	3280	1368
	3700	3.300	2.450	.850	4417	3280	1137
	3800	3.117	2.450	.667	4174	3280	894
	3900	2.919	2.450	.469	3909	3280	629
	4000	2.688	2.449	.239	3600	3280	320
	4100	2.453	2.362	.091	3284	3162	122
	4200	2.240	2.229	.011	2997	2982	15
	4300	2.001	2.001	0	2678	2678	0
	4400	1.710	1.710	0	2288	2288	0
	4500	1.394	1.394	0	1867	1867	0
	4600	1.103	1.103	0	1477	1477	0
	4700	.683	.683	0	914	914	0
	4800	.133	.133	0	178	178	0

TABLE 4 - Continued

		Planimeter Reading				Area (Acres)		
		Contour	Total	Navy	Private	Total	Navy	Private
Bottom - Lower Bench	+	3600	3.462	2.450	1.012	4635	3280	1355
		3700	3.280	2.450	.830	4392	3280	1112
		3800	3.105	2.450	.655	4156	3280	876
		3900	2.901	2.450	.451	3883	3280	603
		4000	2.663	2.447	.216	3564	3275	289
		4100	2.435	2.353	.082	3256	3146	110
		4200	2.200	2.190	.010	2945	2932	13
		4300	1.974	1.974	0	2642	2642	0
		4400	1.691	1.691	0	2263	2263	0
		4500	1.378	1.378	0	1844	1844	0
		4600	1.081	1.081	0	1448	1448	0
		4700	.659	.659	0	883	883	0
		4800	.100	.100	0	134	134	0

TABLE 5

WELL PRODUCTION DATA

Monthly Production Rate

Well No.	Date on Production	Initial Production	Bbls. Oil (1)	Oil Water (1)	Bbls. Oil (2)	Bbls. Water (2)	Bbls. Oil (3)	Bbls. Water (3)	Bbls. Oil (4)	Bbls. Water (4)
14S35	6-10-61	51BPD-40% Cut	(775)* 516	225	780	685	652	970	670	1320
15S35	5-21-61	109BPD-6% Cut	(2850) 1140	730	2180	115	1550	192	930	140
27S35	8-23-59	111BPD-2% Cut	(3410) 910	38	2230	215	1610	115	1240	93
73S34	7-9-61	41BPD-54% Cut	(919) 735	1980	655	1280	720	1280	590	425
83S34	6-21-61	42BPD-42% Cut	(1500) 550	590	690	1160	660	835	655	690
84S34	6-28-61	81BPD-26% Cut	(2070) 207	78	1200	1110	820	890	690	830
32S 2	8-18-59	107BPD-0% Cut	(2215) 960	400	1930	187	1510	150	1340	135
44S 2	9-3-59	91BPD-5% Cut	(2187) 1970	405	1690	348	1250	250	1140	345
77S11	9-19-59	73BPD-16% Cut	(1882) 690	300	1320	330	1030	215	810	175
86S11	9-9-59	86BPD-5% Cut	(1880) 1315	215	1510	225	1160	175	1030	21
88S11	12-10-58	97BPD-0% Cut	(2025) 1080	145	1790	290	1030	175	950	160
71S14	9-17-59	79BPD-14% Cut	(1995) 930	175	1370	245	1020	177	860	152
TOTAL			(23908) 11003	5281	17345	6190	13012	5424	10905	4486
Average Prod. Rate		81BPD-17% Cut	(1992) 918	44	1445	516	1083	452	907	374

* Figures in parentheses indicate first month of production extended for full 30 days.

TABLE 5 - Continued

Well No.	(5) Bbls. Oil	(5) Bbls. Water	(6) Bbls. Oil	(6) Bbls. Water	(7) Bbls. Oil	(7) Bbls. Water	(8) Bbls. Oil	(8) Bbls. Water	(9) Bbls. Oil	(9) Bbls. Water
	Monthly Production Rate									
14S35	665	610	750	1230	740	1130				
15S35	710	117	765	85	635	48	720	55		
27S35	1030	65	920	81	770	125	780	0	775	24
73S34	415	630	460	980						
83S34	550	295	515	355	680	1340				
84S34	690	630	655	530	515	370				
32S 2	1250	107	925	10	695	10	725	10	730	0
44S 2	1030	11	860	10	890	16	935	24	825	21
77S11	625	54	555	10	590	41	555	26	580	80
86S11	890	46	730	148	790	69	785	30	690	170
88S11	850	145	730	135	590	108	595	109	570	103
71S14	770	115	620	39	640	41	605	19	600	9
TOTAL	9475	2825	8485	3613	7535	3298	5700	273	4770	407
Average Prod. Rate	790	236	707	301	685	300	713	34	682	58

TABLE 5 - Continued

	Monthly Production Rate									
Well No.	Bbls. Oil (10)	Bbls. Water (10)	Bbls. Oil (11)	Bbls. Water (11)	Bbls. Oil (12)	Bbls. Water (12)	Bbls. Oil (13)	Bbls. Water (13)	Bbls. Oil (14)	Bbls. Water (14)
14S35										
15S35										
27S35	670	21	525	16	460	38	1020	120	810	33
73S34										
83S34										
84S34										
32S 2	605	0	550	0	415	0	790	16	545	14
44S 2	810	20	625	19	1060	61	830	21	725	34
77S11	555	76	315	43	455	62	368	53	435	64
86S11	515	87	365	62	465	76	340	42	365	50
88S11	505	94	405	75	505	90	495	80	565	189
71S14	550	9	305	9	435	23	370	26	395	12
TOTAL	4210	307	3090	224	3795	350	4213	358	3840	396
Average Prod. Rate	601	44	441	32	542	50	601	51	549	57

TABLE 5 - Continued

Well No.	(15) Bbls. Oil	(15) Bbls. Water	(16) Bbls. Oil	(16) Bbls. Water	(17) Bbls. Oil	(17) Bbls. Water	(18) Bbls. Oil	(18) Bbls. Water	(19) Bbls. Oil	(19) Bbls. Water
	Monthly Production Rate									
14S35										
15S35										
27S35	805	38	725	26	650	34	545	26	495	13
73S34										
83S34										
84S34										
32S 2	525	16	445	11	520	25	475	33	452	31
44S 2	655	34	720	50	525	27	420	22	440	36
77S11	485	54	385	43	312	27	305	24	332	23
86S11	302	49	315	53	315	18	238	13	335	16
88S11	442	85	510	49	455	10	465	10	360	10
71S14	605	32	505	63	460	57	385	35	390	25
TOTAL	3819	308	3605	295	3237	198	2833	163	2804	154
Average Prod. Rate	545	44	515	42	462	28	405	23	401	22

TABLE 5 - Continued

Well No.	Monthly Production Rate (20) Bbls. Oil	Bbls. Water	(21) Bbls. Oil	Bbls. Water	(22) Bbls. Oil	Bbls. Water	(23) Bbls. Oil	Bbls. Water	(24) Bbls. Oil	Bbls. Water
14S35										
15S35										
27S35	520	11	510	16	465	15	400	10	412	41
73S34										
83S34										
84S34										
32S 2	488	26	440	23	397	19	435	13	445	29
44S 2	390	30	430	28	395	39	400	49	382	43
77S11	336	26	378	24	335	46	280	35	368	55
86S11	312	15	375	18	305	30	332	29	378	37
88S11	285	10	335	10	405	10	410	13	336	20
71S14	435	22	435	33	375	25	435	28	445	41
TOTAL	2766	140	2903	152	2777	185	2692	177	2766	266
Average Prod. Rate	395	20	415	22	397	26	384	25	395	38

TABLE 5 - Continued

Monthly Production Rate

Well No.	Bbls. Oil (25)	Bbls. Water (25)	Bbls. Oil (26)	Bbls. Water (26)
14S35				
15S35				
27S35	465	57	415	46
73S34				
83S34				
84S34				
32S 2	372	31	342	30
44S 2	415	41	565	53
77S11	378	37	378	38
86S11	368	24	310	20
88S11	375	10	355	22
71S14	368	50	338	46
TOTAL	2741	250	2703	255
Average Prod. Rate	392	36	386	36

TABLE 6

HYPERBOLIC DECLINE CALCULATIONS FOR AVERAGE WELL BY THE LOSS-RATIO METHOD

Month	Average Monthly Prod. Rate (Bbls/month)	Loss in Prod. Rate 3 mo. Interval	Loss Ratio on Monthly Basis $\frac{(3P)}{(\Delta P)}$	First Der. Loss Ratio $b = \frac{\Delta \frac{(3P)}{(\Delta P)}}{3}$
2	1625			
5	957	- 668	- 4.3	
8	723	- 234	- 9.3	- 1.66
11	600	- 123	- 14.6	- 1.78
14	522	- 78	- 20.0	- 1.80
17	462	- 60	- 23.1	- 1.03
20	419	- 43	- 29.2	- 2.20
23	386	- 33	- 35.1	- 1.80

Average b = - 1.71. Extrapolation uses this average.

Month	Average Monthly Prod. Rate (Bbls/month)	Loss in Prod. Rate 3 mo. Interval	Loss Ratio on Monthly Basis	First Der. Loss Ratio
26	360	- 26	- 40.23	- 1.71
29	338	- 22	- 45.36	- 1.71
32	319	- 19	- 50.49	- 1.71
35	303	- 16	- 55.62	- 1.71
38	289	- 14	- 60.75	- 1.71
41	276	- 13	- 65.88	- 1.71
44	265	- 11	- 71.01	- 1.71
47	255	- 10	- 76.14	- 1.71
50	246	- 9	- 81.27	- 1.71
53	238	- 8	- 86.40	- 1.71
56	230	- 8	- 91.53	- 1.71
59	223	- 7	- 96.66	- 1.71
62	217	- 6	- 101.79	- 1.71
65	211	- 6	- 106.92	- 1.71
68	206	- 5	- 112.05	- 1.71
71	201	- 5	- 117.18	- 1.71
74	196	- 5	- 122.31	- 1.71
77	192	- 4	- 127.44	- 1.71
80	188	- 4	- 132.67	- 1.71
83	184	- 4	- 137.70	- 1.71
86	180	- 4	- 142.83	- 1.71

TABLE 6 - Continued

Month	Average Monthly Prod. Rate (Bbls/month)	Loss in Prod. Rate 3 mo. Interval	Loss Ratio on Monthly Basis $\frac{(3P)}{(\Delta P)}$	First Der. Loss Ratio $b = \frac{\Delta \frac{(3P)}{(\Delta P)}}{3}$
89	176	- 4	- 147.96	- 1.71
92	172	- 4	- 153.09	- 1.71
95	169	- 3	- 158.22	- 1.71
98	166	- 3	- 163.35	- 1.71
101	163	- 3	- 168.98	- 1.71
104	160	- 3	- 173.61	- 1.71
107	157	- 3	- 178.74	- 1.71
110	154	- 3	- 183.87	- 1.71
113	152	- 2	- 189.00	- 1.71
116	150	- 2	- 194.13	- 1.71
119	148	- 2	- 199.26	- 1.71
122	146	- 2	- 204.39	- 1.71
125	144	- 2	- 209.52	- 1.71
128	142	- 2	- 214.65	- 1.71
131	140	- 2	- 219.78	- 1.71
134	138	- 2	- 224.91	- 1.71
137	136	- 2	- 230.04	- 1.71
140	134	- 2	- 235.17	- 1.71
143	132	- 2	- 240.30	- 1.71
146	130	- 2	- 245.43	- 1.71
149	129	- 1	- 250.56	- 1.71
152	128	- 1	- 255.69	- 1.71
155	127	- 1	- 260.82	- 1.71
158	126	- 1	- 265.95	- 1.71
161	125	- 1	- 271.08	- 1.71
164	124	- 1	- 276.21	- 1.71
167	123	- 1	- 281.34	- 1.71
170	122	- 1	- 286.47	- 1.71
173	121	- 1	- 291.60	- 1.71
176	120	- 1	- 296.73	- 1.71
179	119	- 1	- 301.86	- 1.71

TABLE 6 - Continued

Month	Average Monthly Prod. Rate (Bbls/month)	Loss in Prod. Rate 3 mo. Interval	Loss Ratio on Monthly Basis $\frac{(3P)}{(\Delta P)}$	First Der. Loss Ratio $b = \frac{\Delta \frac{(3P)}{(\Delta P)}}{3}$
182	118	- 1	- 307.09	- 1.71
185	117	- 1	- 312.22	- 1.71
188	116	- 1	- 317.35	- 1.71
191	115	- 1	- 322.48	- 1.71
194	114	- 1	- 327.61	- 1.71
197	113	- 1	- 332.74	- 1.71
200	112	- 1	- 337.87	- 1.71
203	111	- 1	- 343.00	- 1.71
206	110	- 1	- 348.13	- 1.71
209	109	- 1	- 353.26	- 1.71
212	108	- 1	- 358.39	- 1.71
215	107	- 1	- 363.52	- 1.71
218	106	- 1	- 368.65	- 1.71
221	105	- 1	- 373.78	- 1.71
224	104	- 1	- 378.91	- 1.71
227	103	- 1	- 384.04	- 1.71
230	102	- 1	- 389.17	- 1.71
233	101	- 1	- 394.30	- 1.71
236	100	- 1	- 399.43	- 1.71
239	99	- 1	- 404.56	- 1.71
242	98	- 1	- 409.69	- 1.71
245	97	- 1	- 414.82	- 1.71
248	96	- 1	- 419.95	- 1.71
251	95	- 1	- 425.08	- 1.71
254	94	- 1	- 430.21	- 1.71
257	93.5	- .5	- 435.34	- 1.71
260	93	- .5	- 440.47	- 1.71
263	92.5	- .5	- 445.60	- 1.71
266	92	- .5	- 450.73	- 1.71
269	91.5	- .5	- 455.86	- 1.71
272	91	- .5	- 460.99	- 1.71

TABLE 6 - Continued

Month	Average Monthly Prod. Rate (Bbls/month)	Loss in Prod. Rate 3 mo. Interval	Loss Ratio on Monthly Basis $\frac{(3P)}{(\Delta P)}$	First Der. Loss Ratio $b = \frac{\Delta \frac{(3P)}{(\Delta P)}}{3}$
275	90.5	- .5	- 466.12	- 1.71
278	90	- .5	- 471.26	- 1.71
281	89.5	- .5	- 476.38	- 1.71
284	89	- .5	- 481.51	- 1.71
287	88.5	- .5	- 486.64	- 1.71
290	88	- .5	- 491.77	- 1.71
293	87.5	- .5	- 496.90	- 1.71
296	87	- .5	- 502.03	- 1.71
399	86.5	- .5	- 507.16	- 1.71
302	86	- .5	- 512.29	- 1.71
305	85.5	- .5	- 517.42	- 1.71
309	85	- .5	- 522.55	- 1.71

19440.5 x 3 = 58,322 bbls

Time producing on decline to economic limit of 2.8 STB/day or 85 STB/mo. is 309 months, or 25.7 years.

N (Cum. production on decline to economic limit) = 58,322 bbls

Say 58,300 bbls.

TABLE 7

CALCULATIONS FOR PRESENT WORTH OF WELL PRODUCTION

Months	Adjusted Monthly Rate of Prod. (STB/mo)	Prod. for 3 months (STB)	Semi-Annual Prod. (STB)	Net Value Per Barrel	Gross Income	Semi-Annual Operat-ing cost	Undeferred Net Income	Discount Factor (4% per annum)	Deferred Net Income	Deferred Net Profit (6 mo. pd)
1-3	1625	4875								
4-6	957	2871	7746	$2.70	$20900.	$1380.	$19520.	.9804	$19150.	(-516)*
7-9	723	2169								
10-12	600	1800	3969	2.70	10720.	1380.	9340.	.9612	8980.	8464
13-15	522	1566								
16-18	462	1386	2952	2.70	7950.	1380.	6570.	.9423	6200.	6200
19-21	419	1257								
22-24	386	1158	2415	2.70	6515.	1380.	5135.	.9238	4740.	4740
25-27	344	1032								
28-30	323	969	2001	2.70	5405.	1380.	4025.	.9057	3650.	3650
31-33	305	915								
34-36	290	870	1785	2.70	4820.	1380.	3440.	.8880	3055.	3055
37-39	277	831								
40-42	265	795	1626	2.70	4390.	1380.	3010.	.8706	2620.	2620
43-45	255	765								
46-48	245	735	1500	2.70	4050.	1380.	2670.	.8535	2280.	2280
49-51	236	708								
52-54	229	687	1395	2.70	3765.	1380.	2385.	.8368	2000.	2000
55-57	222	666								
58-60	215	645	1311	2.70	3540.	1380.	2160.	.8203	1770.	1770
61-63	210	630								
64-66	204	612	1242	2.70	3350.	1380.	1970.	.8043	1585.	1585

TABLE 7 - Continued

Months	Adjusted Monthly Rate of Prod. (STB/mo)	Prod. for 3 months (STB)	Semi-Annual Prod. (STB)	Net Value Per Barrel	Gross Income	Semi-Annual Operat-ing cost	Undeferred Net Income	Discount Factor (4% per annum)	Deferred Net Income	Deferred Net Profit (6 mo. pd)
67-69	199	597								
70-72	195	585	1182	$2.70	3190.	1380.	1810.	.7885	1425.	1425
73-75	188	564								
76-78	184	552	1116	2.70	3010.	1380.	1630.	.7730	1260.	1260
79-81	180	540								
82-84	177	531	1071	270	2890.	1380.	1510.	.7579	1145.	1145
85-87	173	519								
88-90	169	507	1026	2.70	2770.	1380.	1390.	.7430	1030.	1030
91-93	165	495								
94-96	163	489	984	2.70	2660.	1380.	1280.	.7284	935.	935
97-99	160	480								
100-102	157	471	951	2.70	2570.	1380.	1190.	.7142	850.	850
103-105	154	462								
106-108	151	453	915	2.70	2470.	1380.	1090.	.7002	765.	765
109-111	148	444								
112-114	146	438	882	2.70	2380.	1380.	1000.	.6864	685.	685
115-117	145	435								
118-120	143	429	864	2.70	2335.	1380.	955.	.6730	645.	645
121-123	141	423								
124-126	139	417	840	2.70	2270.	1380.	890.	.6598	590.	590
127-129	138	414								
130-132	136	408	822	2.70	2220.	1380.	840.	.6468	545.	545

TABLE 7 - Continued

Months	Adjusted Monthly Rate of Prod. (STB/mo)	Prod. for 3 months (STB)	Semi-Annual Prod. (STB)	Net Value Per Barrel	Gross Income	Semi-Annual Operat-ing cost	Undeferred Net Income	Discount Factor (4% per annum)	Deferred Net Income	Deferred Net Profit (6 mo.prd)
133-135	134	402								
136-138	132	396	798	$2.70	2155.	1380.	775.	.6342	490.	490
139-141	130	390								
142-144	128	384	774	2.70	2090.	1380.	710.	.6217	440.	440
145-147	126	378								
148-150	125	375	755	2.70	2040.	1380.	660.	.6095	400.	400
151-153	125	375								
154-156	124	372	747	2.70	2020.	1380.	640.	.5976	380.	380
157-159	123	369								
160-162	122	366	735	270	1985.	1380.	605.	.5859	355.	355
163-165	121	363								
166-168	121	363	726	270	1960.	1380.	580.	.5744	335.	335
169-171	119	367								
172-174	118	354	711	270	1920.	1380.	540.	.5631	305.	305
175-177	117	351								
178-180	116	348	699	2.70	1890.	1380.	510.	.5521	280.	280
181-183	115	345								
184-186	114	342	687	2.70	1855.	1380.	475.	.5412	255.	255
187-189	113	339								
190-192	113	339	678	2.70	1830.	1380.	450.	.5306	240.	240
193-195	109	327								
196-198	108	324	651	2.70	1755.	1380.	375.	.5202	195.	195

TABLE 7 - Continued

Months	Adjusted Monthly Rate of Prod. (STB/mo)	Prod. for 3 months (STB)	Semi-Annual Prod. (STB)	Net Value Per Barrel	Gross Income	Semi-Annual Operating cost	Undeferred Net Income	Discount Factor (4% per annum)	Deferred Net Income	Deferred Net Profit (6 mo. prd)
199-201	107	321								
202-204	106	318	639	$2.70	1725.	1380.	345.	.5100	175.	175
205-207	105	315								
208-210	104	312	627	2.70	1690.	1380.	310.	.5000	155.	155
211-213	103	309								
214-216	102	306	615	2.70	1660.	1380.	280.	.4906	135.	135
217-219	101	303								
220-222	100	300	603	2.70	1625.	1380.	245.	.4812	120.	120
223-225	99	297								
226-228	98	294	591	2.70	1595.	1380.	215.	.4718	100.	100
229-231	98	294								
232-234	97	291	585	2.70	1580.	1380.	200.	.4624	95.	95
235-237	96	288								
238-240	95	285	573	2.70	1545.	1380.	165.	.4529	75.	75
241-243	94	282								
244-246	93	279	561	2.70	1515.	1380.	135.	.4444	60.	60
247-249	92	276								
250-252	91	273	549	2.70	1485.	1380.	105.	.4359	45.	45
253-255	90	270								
256-258	90	270	540	2.70	1460.	1380.	80.	.4274	35.	35

TABLE 7 - Continued

Months	Adjusted Monthly Rate of Prod. (STB/mo)	Prod. for 3 months (STB)	Semi-Annual Prod. (STB)	Net Value Per Barrel	Gross Income	Semi-Annual Operating cost	Undeferred Net Income	Discount Factor (4% per annum)	Deferred Net Income	Deferred Net Profit (6 mo. prd)
259-261	89	267								
262-264	88	267	534	$2.70	1440.	1380.	60.	.4189	25.	25
265-267	88	264								
268-270	88	264	528	2.70	1425.	1380.	45.	.4102	20.	20
271-273	87	261								
274-276	87	261	522	2.70	1410.	1380.	30.	.4025	10.	10
277-279	86	258								
280-282	85	253	512	2.70	1380.	1380.	0.	.3948	0.	
	TOTALS		54536 STB						$ 70630	$ 50964
		SAY	54500 STB							

* Cost to drill, complete and frac both zones of average well is $19,666.

VITA

Robert Henry Nelson was born in Burton, Ohio (Geauga County) on 21 July 1924, the son of Henry E. and Rena R. Nelson.

After completing his high school work at Parkman High School, Parkman, Ohio in June, 1942, he attended Fenn College in Cleveland, Ohio, until April, 1944, when he joined the U. S. Navy as an apprentice seaman. As a Radio Technician 3/c,he received a Secretary of the Navy appointment to the Naval Academy in 1945, graduating in June, 1949, and commissioned an ensign in the Line of the Navy. He has remained on active duty and is presently a Lieutenant Commander in the Civil Engineer Corps of the Navy.

His formal schooling since graduation from the Naval Academy with a B. S. includes 1-1/2 years at Rensselaer Polytechnic Institute, Troy, New York, for which he earned a Bachelor of Civil Engineering degree. Upon completion of this training, he was redesignated a Civil Engineer Corps officer in 1952.

He is married to the former Annette Berger of Washington, D. C., and they have three daughters.

He is a member of Tau Beta Pi, Sigma Xi, Chi Epsilon, Pi Epsilon Tau, and Sigma Gamma Epsilon honorary societies and is a Master Mason.

His principal hobbies are hunting and fishing.

This thesis was typed by Glad Purser