A STUDY AND ANALYSIS OF THE DEVELOPMENT AND UNIT OPERATION OF NAVAL PETROLEUM RESERVE NO.1

Will M. Adams, Jr.

Letter on front cover:

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By

Lt. Will M. Adams, Jr., USN

11 10 June 1954

FOREWORD

This report was prepared and submitted to the Petroleum Engineering Department of the University of California at Berkeley as one of the requirements for the degree of Master of Engineering, Petroleum. It was prepared under the direction and guidance of Professor John A. Putnam.

The report was sponsored by the U. S. Naval Postgraduate School to which this officer was attached as a petroleum engineering student from 1951 to 1954.

The student wishes to acknowledge the great amount of liaison work, authorized by the Director Naval Petroleum Reserves and the Inspector Naval Petroleum Reserves in California, and accorded the student by the staff members of the above officers. This report would not have been possible without their cooperation.

W. M. Adams, Jr.

University of California, Berkeley
10 June 1954

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OF

EACH RESERVE

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There are four naval petroleum reserves and three oil shale reserves. These public lands are in the possession and under the authority of the Navy. The Secretary of the Navy is responsible to Congress and the President for their administration and for the operation of petroleum reserves. The Secretary of the Navy administers the reserves through a senior naval officer appointed as the Director Naval Petroleum and Oil Shale Reserves. The administrative staff of the Director is described in Chapter VII of this report.

LOCATIONS

The general locations of the reserves within the continental United States are shown in Figure 1-1. The only reserve lying outside the boundaries of the United States is shown in Figure 1-2.

CHAPTER I

LOCATION, DESCRIPTION, AND BRIEF HISTORY

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EACH RESERVE

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LOCATION

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NAVAL PETROLEUM AND OIL SHALE RESERVES IN CONTINENTAL UNITED STATES

LOCATION MAP

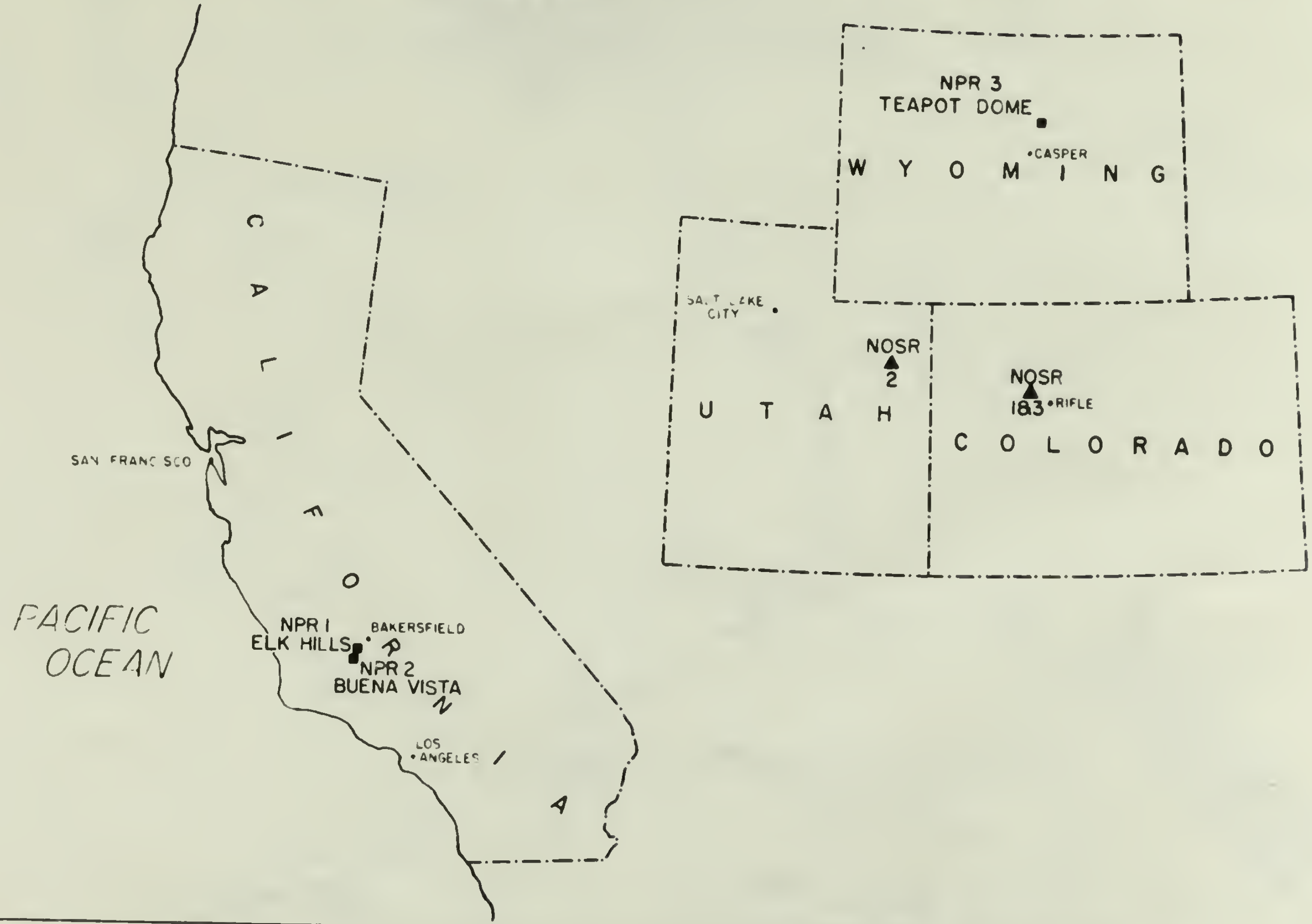

FIG. 1-1

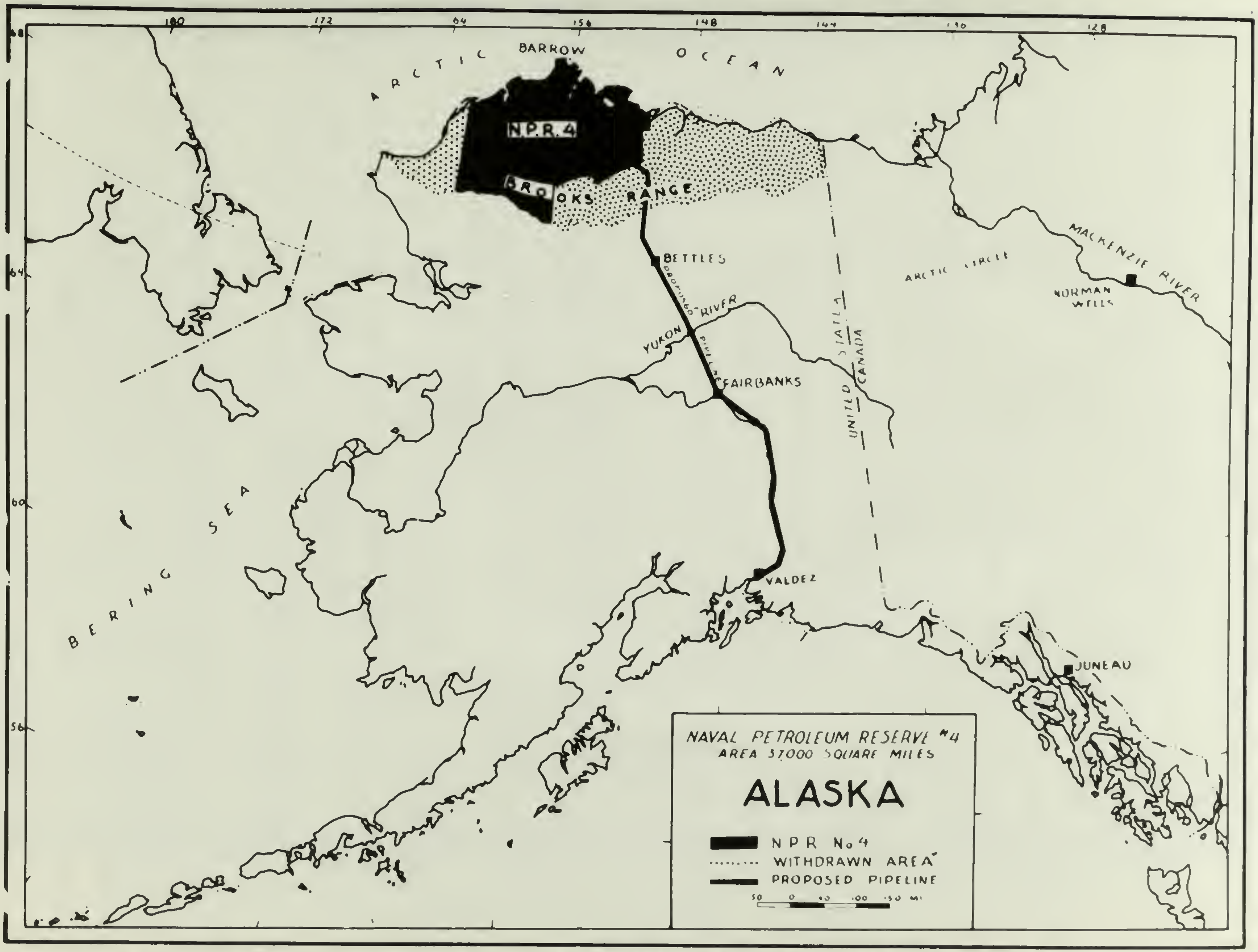

FIG. 1-2, Showing the Location of the Navy's Largest Petroleum Reserve Which Was Actively Explored from 1944 to 1952. An Enlarged Map of the Reserve is Shown on FIG. 2-11.

BRIEF DESCRIPTIONS AND RELATIVE IMPORTANCE[2]

Naval Petroleum Reserve No. 1 (Elk Hills).

This reserve is located near Tupman, Kern County, California. It lies approximately 20 miles west of the city of Bakersfield. The reserve covers 46,095 acres and is one of the greatest oil fields in the United States. A map of the reserve showing its boundaries at different times in the field's life is shown in Figure 1-3. As of January 1954, it was the largest oil field in California with estimated recoverable reserves exceeding 700 million barrels of oil and an estimated constant productive capacity of about 140,000 barrels per day for five years, or an initial emergency capacity of over 200,000 barrels per day.

The field is jointly owned by Navy and Standard Oil Company of California, with Navy having the majority interest. It is unitized with Standard as the Operator for Navy who has complete control of the reserve.

N.P.R. No. 1 is currently the most important of all the naval petroleum and oil shale reserves. It is the only one functioning as a true petroleum reserve.

A typical view of this reserve is shown on Figure 1-4.

Naval Petroleum Reserve No. 2 (Buena Vista Hills).

This reserve lies adjacent to the southern boundary of N.P.R. No. 1 as shown on Figures 1-1 and 1-3. Sections of the city of Taft, California, lie within the reserve. The reserve comprises 30,181 acres of which only 34.6 percent belong to Navy.

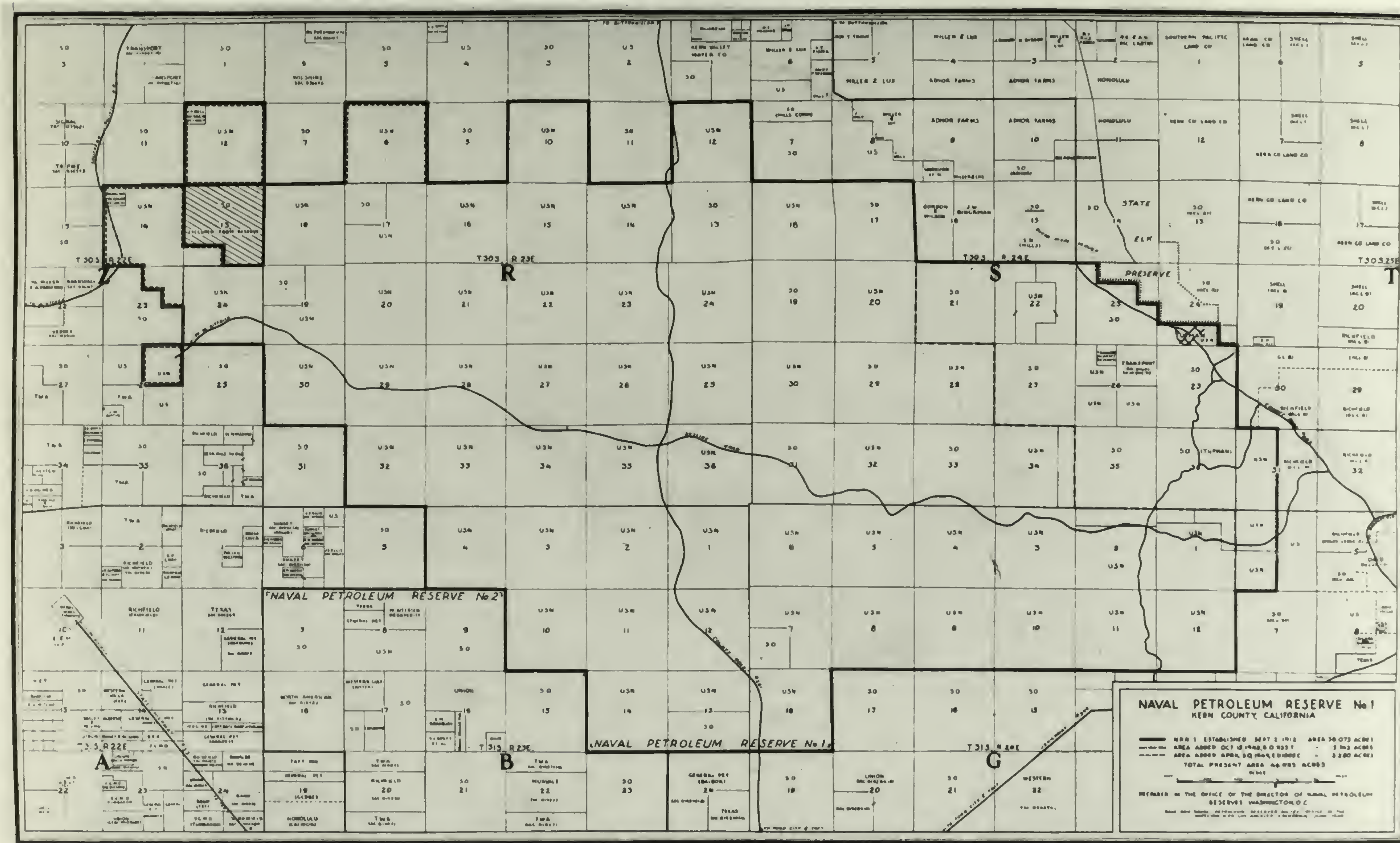

FIG. 1-3, Showing the Different Boundaries During the Life of the Navy's Currently Most Important Petroleum Reserve, N.P.R. No. 1 (Elk Hills), Tupman, Calif. Note that N.P.R. No. 2 is Adjacent to N.P.R. No. 1 on the South.

FIG. 1-4. Typical View of N.P.R. No. 1 (Elk Hills) Showing Stevens Zone Well Head in Left Foreground with Background of Shallow Zone Derricks. Note Arid Nature of Terrain and Surface Reflection of Anticlinal Structure. (Reproduced from Art. On N.P.R. No. 1 by Cdr. W. M. Gustafson, USN, Ref. 111, Biblio.)

Because of Navy's minority interest, it was never practical for the Government to attain control from numerous private interests intent on producing oil. Consequently, the reserve has been on continuous production since its discovery in 1909 with a cumulative production of approximately 138 million barrels by 1952.

About 88 percent of the Government's land within the reserve is leased to private interests who produce the oil and pay Navy the equivalent value of the royalty oil. As of 30 June 1952, the Government had received approximately 27 million dollars from reserve in lease payments and petroleum sales. Of the estimated remaining recoverable oil of nearly 23 million barrels, the Government is due to receive only the equivalent value of about 3.6 million barrels of royalty oil.

Thus this field has never functioned as a true petroleum reserve. It is of importance only in its past and future income to the Government.

Naval Petroleum Reserve No. 3 (Teapot Dome).

This reserve, located near Casper, Wyoming, comprises 9,321 acres. All of the land is owned by the Navy. The field was partially developed by lessees for Navy; but all of the producing wells were shut-in on 31 December 1927 and have remained shut-in ever since. Prior to being shut-in, the field had produced approximately 3.5 million barrels of oil with a royalty value of about 6 million dollars accruing

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Remaining reserves from the developed Second Wall Creek Zone ar estimated at 8.4 million barrels. Several deep exploratory wells in 1952 and 1953 discovered an oil accumulation in the Tensleep Sand Zone. The results of these tests and the exact estimates of the recoverable oil in the Tensleep Horizon is not well known by this student, except the fact that the new reservoir is considered only a minor oil reserve.

Although this reserve is perhaps the best known of all the reserves as a result of the Teapot Dome scandals of the twenties, it is in no true sense of the word a naval petroleum reserve. It has been tested and found wanting in oil reserves and capacity. The only value lies in the income the Government eventually may receive from the royalty oil.

Naval Petroleum Reserve No. 4.

This huge, 37,000 square mile reserve, is located in Northern Alaska, just south of Point Barrow in the area shown on Figure 1-1. In 1944, during the last war, with the Government anticipating a possible oil shortage, Navy commenced actively exploring the reserve for possible oil deposits. This exploration program continued for nine years until it was suspended in March 1953.

Oil or gas was found in almost every one of the 45 test holes drilled---a few of which went as deep as 12,000 feet. Only one extensive oil deposit was found at Umiat in the to the Government.

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What is the relative importance of this reserve? At the present time it is of little importance due to the small amount of oil discovered and the great difficulty involved in getting any oil out of the area. However, it is possible that in any area of 37,000 square miles great oil deposits may one day be found; and this oil will be produced and transported in spite of all difficulties and expense involved, provided the demand is great enough and the selling price is high enough. This reserve is believed to have great potential value.

The Oil Shale Reserves.

The great oil shale holdings of the Navy are divided into three reserves as shown on the location map of Figure 1-1: Shale Reserves No. 1 and No. 3 in western Colorado; and Shale Reserve No. 2 in eastern Utah. NOSR No. 1 comprises an area of 41,353 acres with an estimated shale oil reserve in rich shales of about 5 billion barrels. NOSR No. 3, bordering NOSR No. 1 on three sides, has less than 15 percent of its area as shale, but it was still necessary to establish this area as a reserve in order to provide working space and spent-shale disposal areas for future operations of NOSR No. 1.

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The oil reserves from both the rich and lean shales of NOSR No. 1 and No. 3 are estimated at 36 billion barrels. NOSR No. 2 is the largest of the three with an area of approximately 92,160 acres. No estimate has been made of its great shale oil reserves.

Although Navy is responsible for the administration of the oil shale reserves, it is specifically prohibited by the Act of 30 June 1938 from developing or operating these reserves.

The oil shale reserves are of tremendous potential value. Judging by the results and reports of BuMines experimental work at the Oil Shale Demonstration Plant near Rifle, Colorado, and personal discussions with engineers in the petroleum industry, the economic production of oil shale on a competitive commercial basis with crude oil may now, or soon will be, possible. It is the considered opinion of many men, in and out of the petroleum industry, but all concerned with the needs of this nation in any future emergency, that the Government should take immediate, positive steps to finance and establish a Shale Oil Recovery Unit or Units on a commercial scale. This step could be taken with proper safeguards and guarantees to the petroleum industry as regards any possible harmful effects of such a program on the industry's economy.

But we'll probably wait until it's (almost) too late.

POLICY

As summarized in a "History of the Naval Petroleum and Oil Shale Reserves" issued by the Director,[2] the Navy's policy concerning these reserves is as follows...

"Navy's policy as to the future administration of the naval petroleum reserves will be, as it has in the past, that there shall be the maximum conservation of oil consistent with the needs of the national military and naval security. The Navy has regarded itself as charged by Congress with the responsibility for maintaining its present holdings of oil lands as a reserve in the ground, insofar as that can possibly be achieved, and for restricting production to the minimum necessary to maintain the field in a state of readiness.

As to the oil shale reserves, the Navy's policy is to watch and encourage research, both Governmental and private, in synthetic liquid fuels from shale. The potential value of the shale reserves must not be underestimated."

HISTORY

Aside from stating that the Naval Petroleum Reserves originally were set aside over a span of years for the purpose of providing future naval fuel-oil supplies, the history of the reserves and of the development of the present national policy concerning them will not be attempted in this report. Prior to the establishment of the first Reserve, N.P.R. No. 1, in 1912, and continuing to the present time, this history has been stormy and controversial. It would be difficult to present a clear and unbiased review of this history without writing a long and detailed report. However, excellent historys, referred to in the selected bibliography below, have been written summarizing the numerous Acts of Congress, Presidential Executive Orders, Congressional Hearings, and litigation related to the reserves. Most of these items are listed in the bibliography of this report, together with a short brief of the contents of each, which may supply the reader with enough information.

SELECTED REFERENCES IN THE BIBLIOGRAPHY

2, 3, 5, 6, 111, 124, 170, 245, 247

CHAPTER II

GEOLOGY

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GEOLOGY

NAVAL PETROLEUM RESERVE NO. 1

Regional Geology.

The immediate regional geology associated with Elk Hills is best shown by the geologic section of Figure 2-1. It shows the Reserve to be a separate and distinct field except for some off-set drainage production on the southern and eastern edges of the Reserve. There are numerous nearby oil and gas fields in this lower end of the San Joaquin Valley. However, only three appear to directly affect N.P.R. No. 1, and they are:

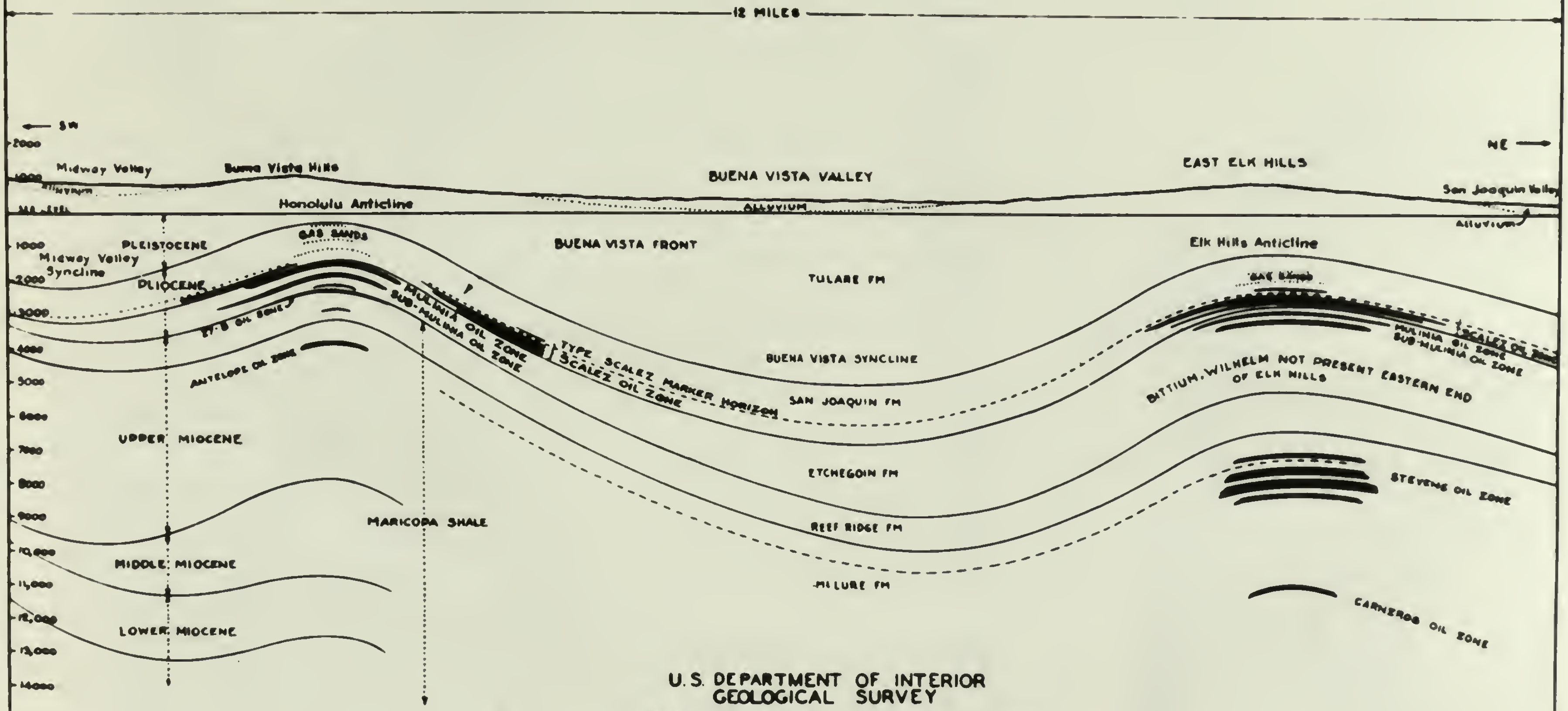
(1) the Buena Vista Front Field on the southern edge, from which the Reserve produces some oil to prevent drainage from Section 14-B but not drainage from the Elk Hills structure itself;

(2) the North Coles Levee field on the eastern edge, which has a finger of oil productive Stevens Sand lensing out in the Reserve and from which the Reserve produces some oil to prevent drainage;

(3) and the Buena Vista Field (N.P.R. No. 2), which appears to have the same aquifer as the Shallow Oil Zone on the Reserve and thereby to affect greatly the Shallow Zone reservoir.

Structural Features of Elk Hills.

The Shallow Oil Zone structure, as shown by Figures 2-2



U.S. DEPARTMENT OF INTERIOR
GEOLOGICAL SURVEY

CONSERVATION BRANCH - OIL AND GAS LEASING
LOS ANGELES, CALIFORNIA

GENERALIZED GEOLOGIC SECTION
SHOWING
BUENA VISTA, BUENA VISTA FRONT AND
ELK HILLS OIL FIELDS

PREPARED BY J.D. CERKEL MARCH 17, 1944
DRAWING NO 7097

(MODIFIED 1952, W.M.G.)

FIG. 2-1

Generalized Geologic Section Showing the Structure and Stratigraphic Relationship Among N.P.R. No. 1. N.P.R. No. 2 and the Associated Buena Vista Front Field.

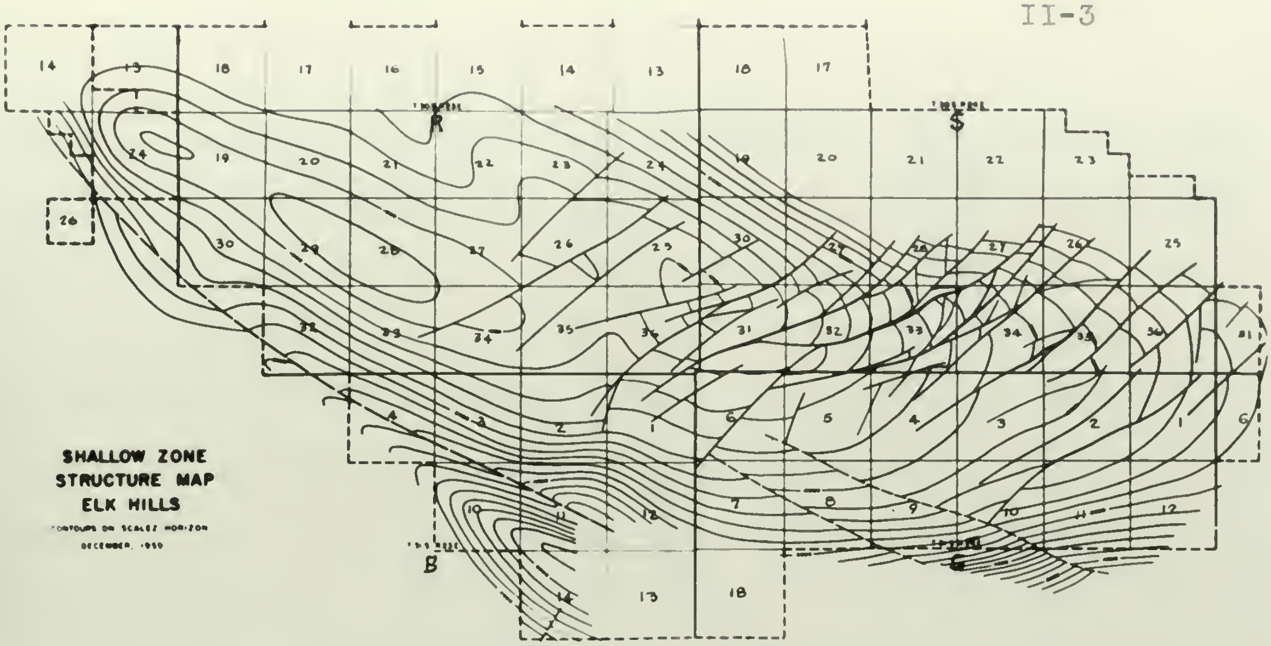


FIG. 2-2

Structure Map of the Shallow Oil Zone, N.P.R. No. 1, Showing the Intense Faulting Which Complicates the Anticlinal Structure. Contours on the Scalez Marker.

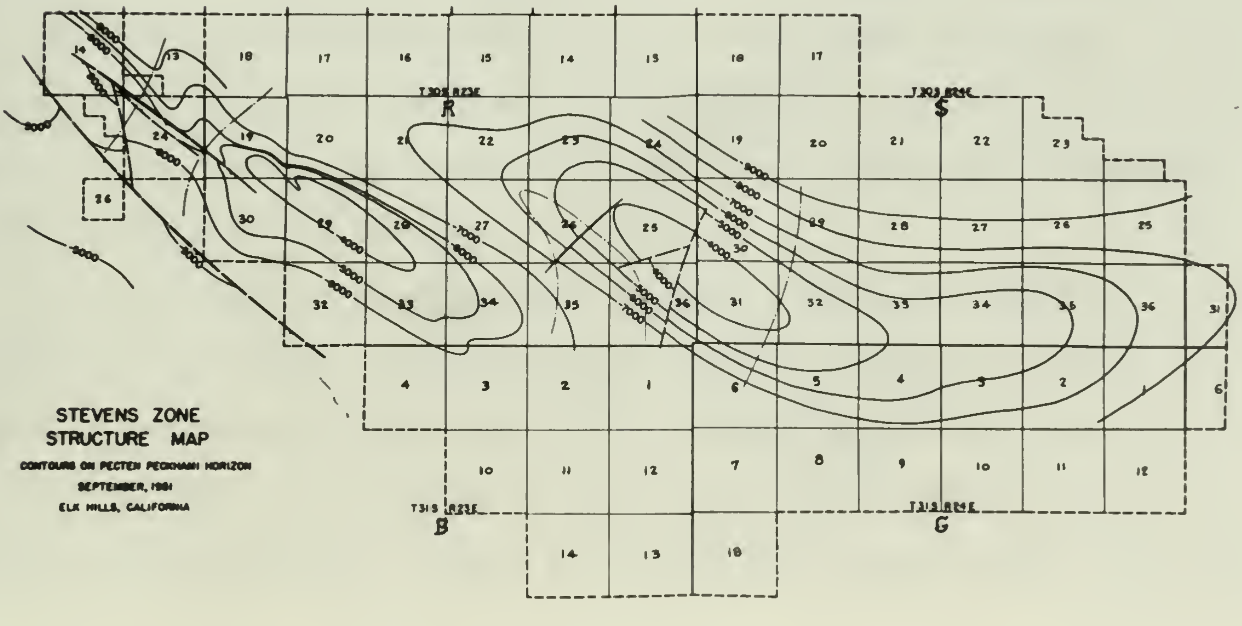


FIG. 2-3

Structure Map of the Stevens Zone, N.P.R. No. 1, Showing the Two Enechelon Folds of the Anticlinal Structure.

and 2-4, consists of a broad faulted anticline with several closed highs and is reflected by the surface structure. The anticlinal structure on the surface is 17 miles long by 6 miles wide with hills rising 1200 feet above the valley floor. As shown by the contour map of Figure 2-2, most of the faults are normal except for apparent high-angle reverse faults along the south flank. Only a few of the faults have proven to be competent fluid barriers.

The Stevens Zone structure, as indicated by the contour map of Figure 2-3 and the cross-section of Figure 2-4, consists of two enechelon folds with numerous thrust-faults.

The accumulation of oil in the Shallow Oil Zone is controlled primarily by the anticlinal structure and secondarily by faulting and stratigraphic pinch-outs.

The Dry Gas Zone lies above the Shallow Oil Zone.

The Carneros Zone underlies the Stevens Zone. The exact nature of the Carneros structure is not well known. However, it does have very steep beds dipping to the north and south as shown on Figure 2-4 and may be an anticline or a homocline open to the west with competent faults or stratigraphic barriers serving to trap the oil.

As the depth increases, the general structural trend of Elk Hills is up-dip toward the west. Any additional accumulation traps in the western end of the field, therefore, would depend on local dip reversals, faulting, pinch-outs or other permeability barriers. There are favorable possibilities for

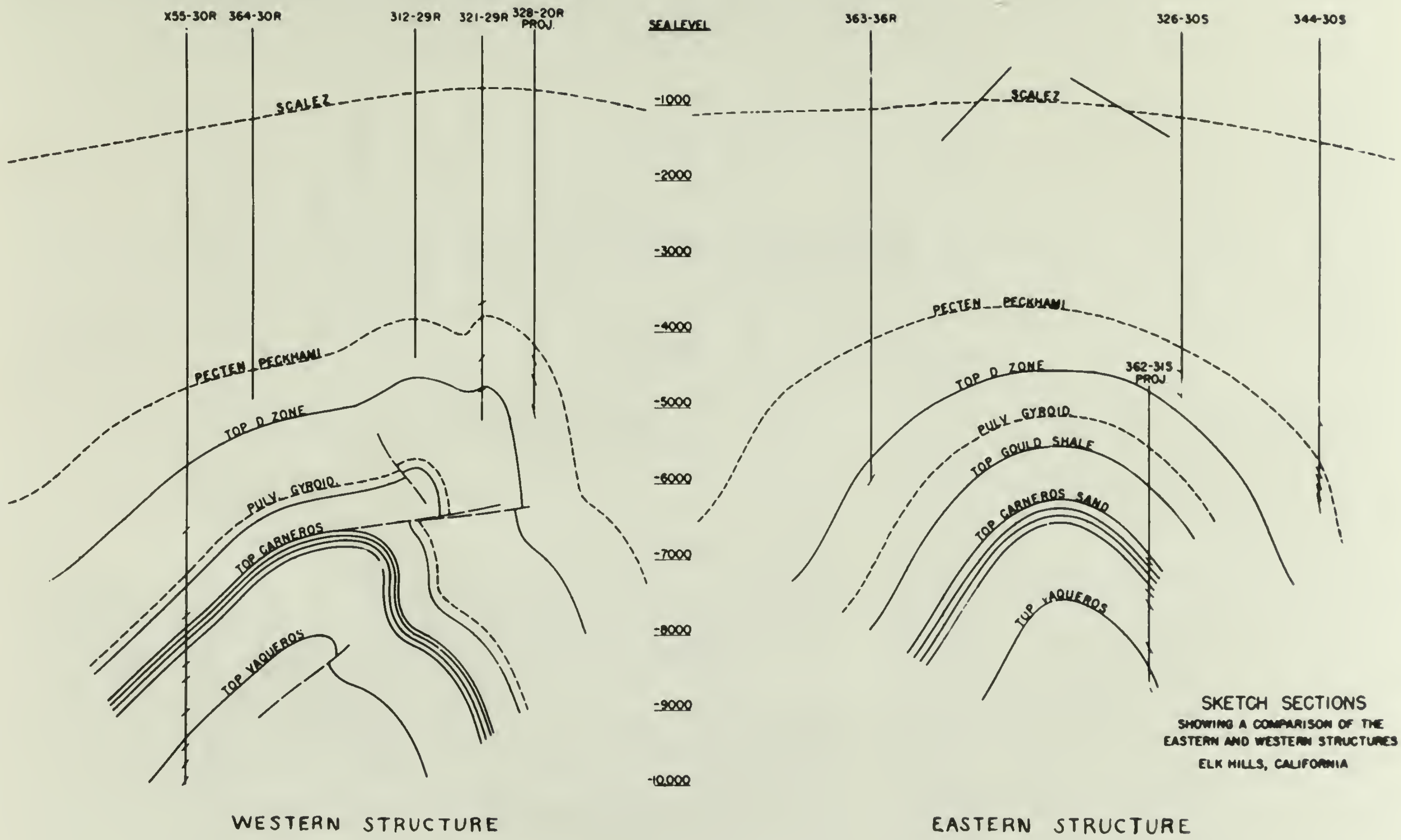


FIG. 2-4

(Reproduced from Article on N.P.R. No. 1 by Cdr. W. M GUSTAFSON)

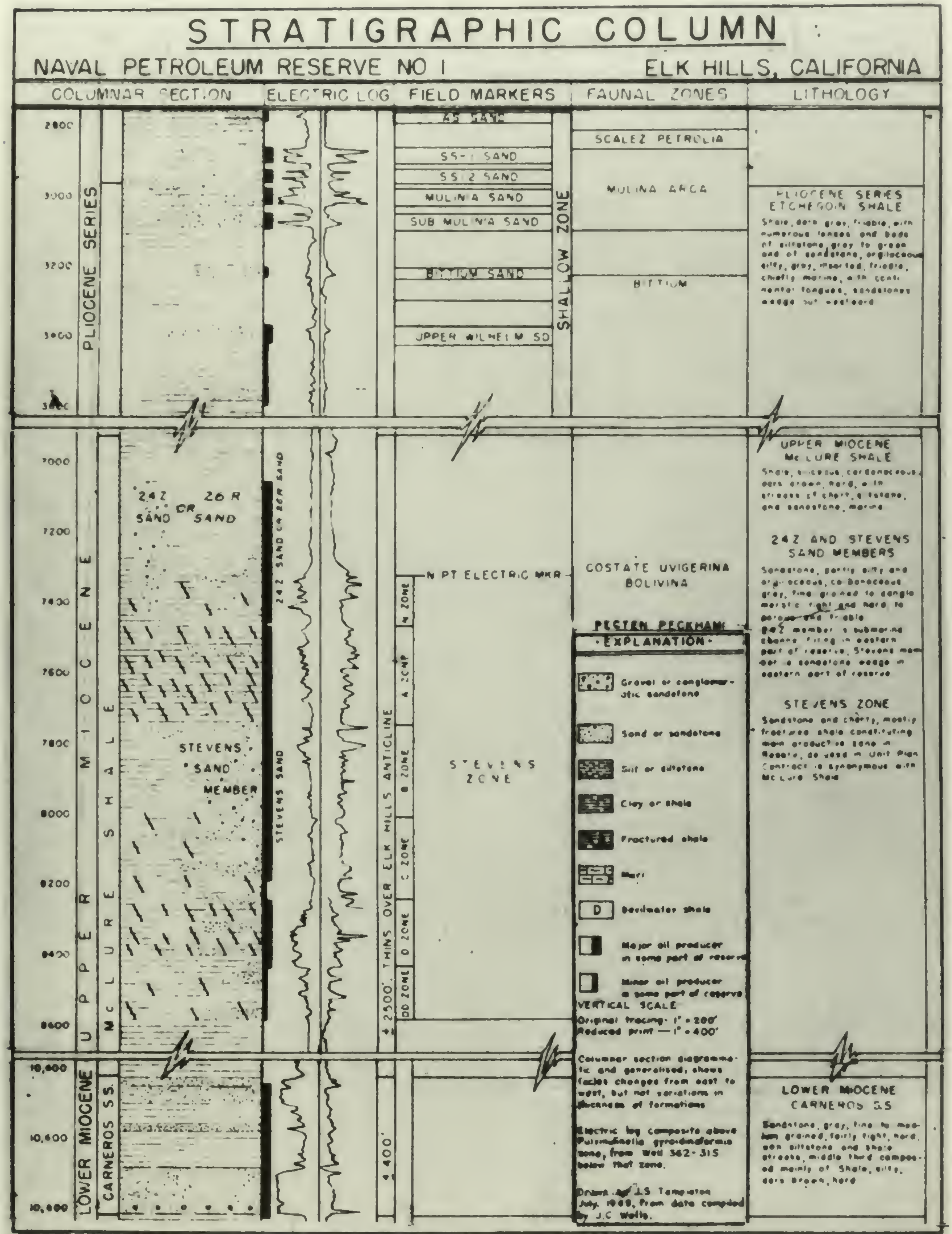
Generalized Sketch Sections of the Western and Eastern Structures of N.P.R. No. 1, Elk Hills, Showing Depths Below Sea Level to the Main Productive Horizons.

future production from additional deep zones such as the Phacoides Reed Sandstone at about 11,000 feet and the Point of Rocks Sandstone at about 13,000 feet.[121] As of May 1954 four deep exploratory wells had been drilled in the field to test for deep production. The deepest depth penetrated was about 12,900 feet. Two of these deep wells in the western portion of the field found commercial oil production in the Carneros Sand at about 10,000 feet and were completed there. As regards the other two deep tests, it is believed that they failed to find deep production and were plugged back and completed in the Stevens Zone.

A composite electric log alongside the stratigraphic column of Figure 2-5 indicates the various oil productive horizons in the stratigraphic column of Elk Hills.

The Dry Gas Zone comprises the several dry gas productive sand measures lying in the upper portion of the San Joaquin clay formation about 1200 to 2200 feet below the surface. Four of these sands, termed the Mya dry gas sands, have a net productive sand thickness of about 50 feet.

The Shallow Oil Zone sands are of Pliocene Age, varying in depth from 2000 to 3600 feet below the surface. For mapping structure, contours are normally based on the Lower Scalez fossil marker, Scalez Petrolia, which occurs throughout most of the field.



Reproduced from Article on N.P.R No. 1 by Cdr. W. M. Gustafson

FIG. 2-5

In the Shallow Oil Zone there are at least ten different oil sands, subdivisions being caused by the interbedding of shales and sands. These sands are tabulated below:[113,136,138]

Sand	Net Productive Sand Thickness Feet	Porosity % of Pore Volume	Water % of Pore Space	Average Permea-bility Md.
E Laminated (EL)	-	-	-	-
Above Scalez (AS)	10	38.2	-	2000
Sub-Scalez 1 (SS-1)	46	34.0	30	2100
Sub-Scalez 2 (SS-2)	18	34.6	32.0	1600
Mulinia (M)	23	35.4	40.1	2400
Sub-Mulinia (SM)	8	33.4	43.0	700
Sub-Scalez 2 and M (SS-2-M)	20	34.4	27.2	1700
Bittium (B) Above Bittium (AB) Bittium (B)	3	36.4	-	750
Wilhelm (W)				
High Produc. (HPW)	7	32.1	-	200
Low Produc. (LPW)	16	31.7	-	75

The abbreviations in parentheses after each sand above will be used throughout this report in discussing the Shallow Oil Zone. The first four sands above are found in the basal portion of the San Joaquin clay formation. The other sands occur in the upper part of the Etchegoin formation.

The most prolific oil sands are the SS-1, SS-2, and M sands,

from which approximately 95 percent of the oil produced to date has come and from which 90 percent of the future production could be expected.[112]

The Stevens Zone consists of seven different horizons in the Upper Miocene. These oil productive zones are listed below:[111]

Zone	Remarks
N	Productive at a few axial locations and in certain sand areas.
A	Fractured silicious shale and some low permeability sands; productive over most of eastern and western structure.
B*	Includes most of the permeable Stevens Sand at eastern end of Elk Hills and a fractured shale on the western structure; *most productive of all the zones.
C	Massive shale; serves as a fractured rock type reservoir in only a few locations.
D	Highly fractured silicious shales; some low permeability sand lenses; productive on both structures at crestal position.
DD	Low permeable sands and shales; marginally productive on crest of eastern structure.
PG	Sands and shales below DD zone; marginally productive on crest of eastern structure.

The above stratigraphic series of shales with sand streaks and fractured shales varies in thickness from 80 to 800 feet.[113] For correlation and mapping of the Stevens Zone the fauna, Pecten Pechami, and the "N" point electric log marker generally are used. The porosity, permeability and water content of the various sands and shales in the Stevens Zone varies considerably; therefore, it is extremely difficult to assign average values

for these quantities as was done for the Shallow Oil Zone.

The Carneros Zone of Lower Miocene Age has been penetrated by four wells, two on the eastern structure and two on the western. The two or three oil productive sand members composing this Zone have an equivalent total sand thickness of about 200 feet. As of May 1954, two commercially productive wells had been completed in the Carneros Zone.

GEOLOGY OF THE OTHER RESERVES

Since this report is primarily concerned with N.P.R. No. 1, no attempt will be made here to give a description of the geology of the other reserves. However, an excellent idea of the structure and the stratigraphy of the oil productive horizon of N.P.R. No. 2 (Buena Vista) may be obtained by a study of Figures 2-1, 2-6, 2-7, and 2-8 of this chapter.

Likewise, for N.P.R. No. 3 (Teapot Dome), Figures 2-9 and 2-10 will provide the reader with the essential geologic features of this field and of its productive horizons.

As regards N.P.R. No. 4 (Alaska) an enlarged geographic map of the reserved area proper indicated on Figure 1-2 is presented in Figure 2-11 of this chapter. This latter figure also shows somewhat the extent and relative success of the exploratory drilling as of August 1952.

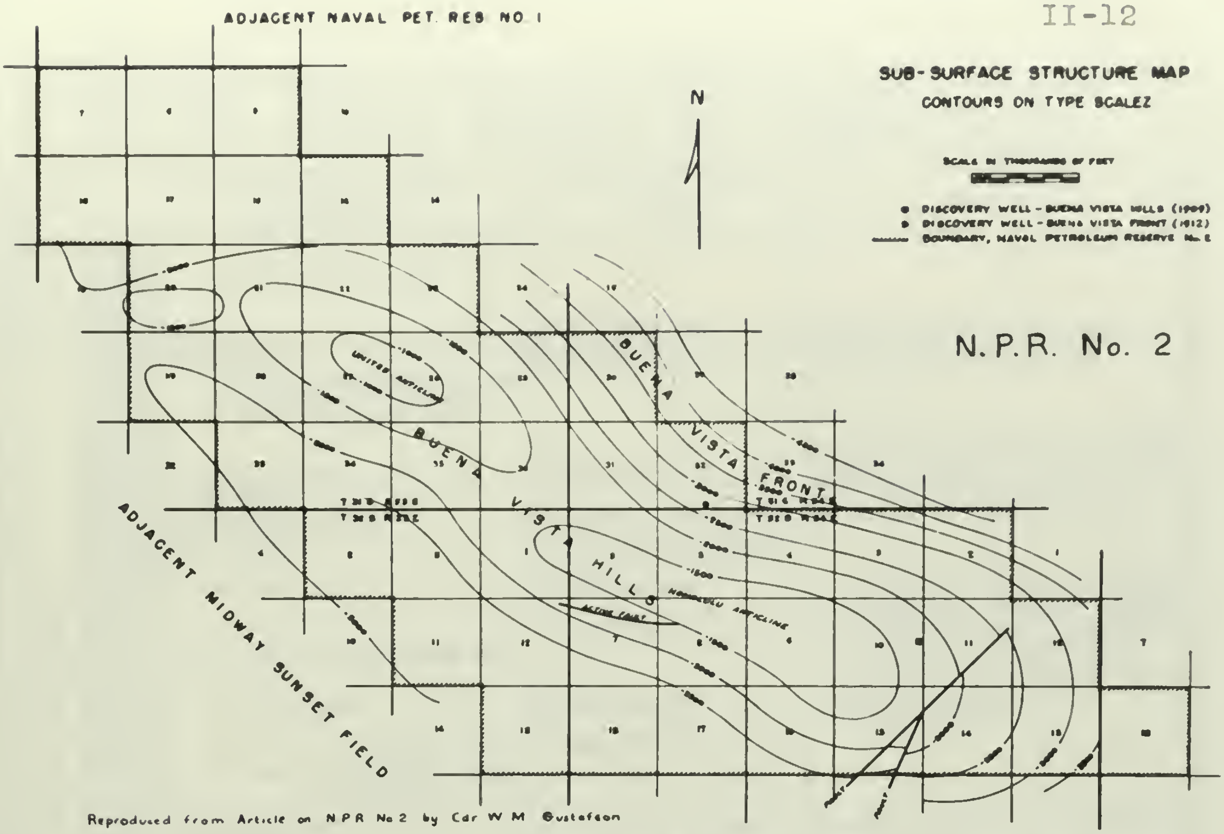

ADJACENT NAVAL PET. RES. NO. 1
SUB-SURFACE STRUCTURE MAP
CONTOURS ON TYPE SCALEZ
N
DISCOVERY WELL - BUENA VISTA HILLS (1909)
DISCOVERY WELL - BUENA VISTA FRONT (1912)
BOUNDARY, NAVAL PETROLEUM RESERVE No. 2
N.P.R. No. 2
BUENA VISTA FRONT
BUENA VISTA HILLS
ADJACENT MIDWAY SUNSET FIELD
Reproduced from Article on N P R No 2 by Cdr W M Gustafson

FIG. 2-6

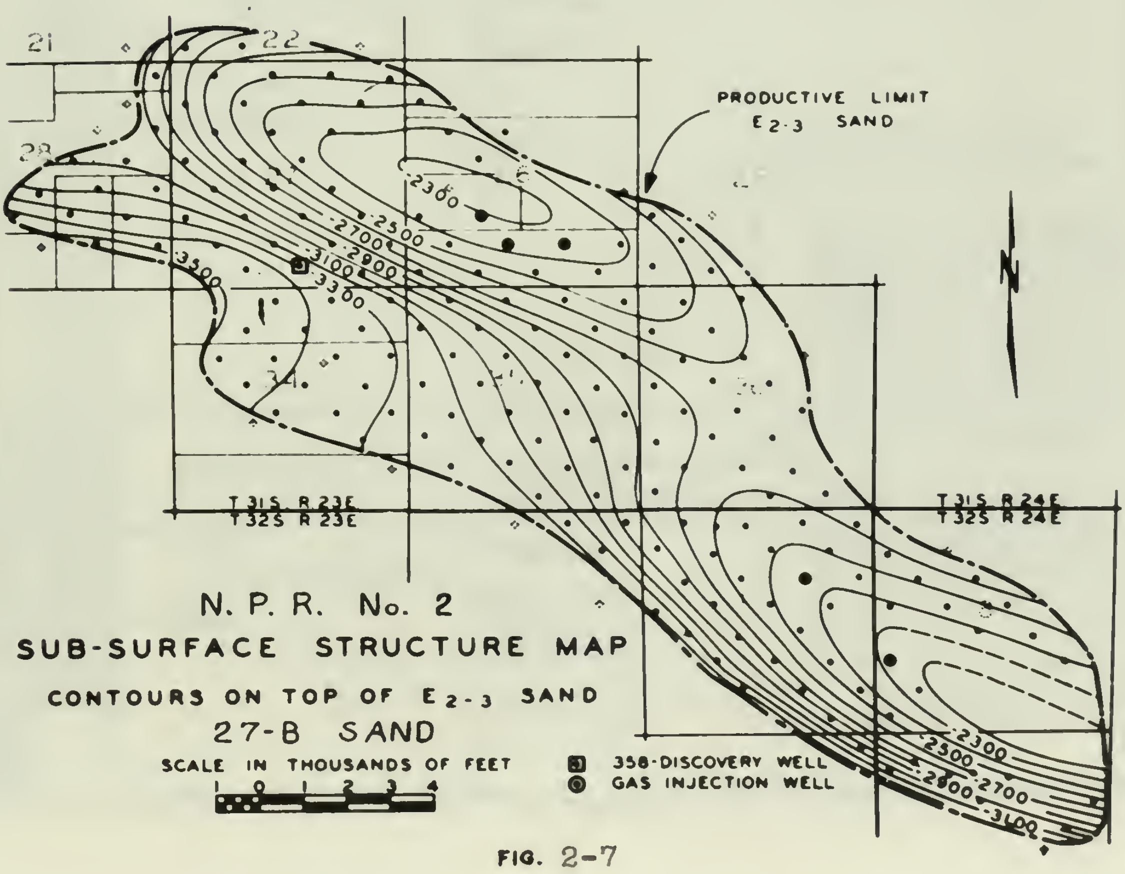

PRODUCTIVE LIMIT
E 2-3 SAND
-2300
-2500
-2700
-2900
-3100
-3300
-3500
T 31 S R 23 E
T 32 S R 23 E
T 31 S R 24 E
T 32 S R 24 E
N. P. R. No. 2
SUB-SURFACE STRUCTURE MAP
CONTOURS ON TOP OF E 2-3 SAND
27-B SAND
SCALE IN THOUSANDS OF FEET
1 0 1 2 3 4
358-DISCOVERY WELL
GAS INJECTION WELL

FIG. 2-7

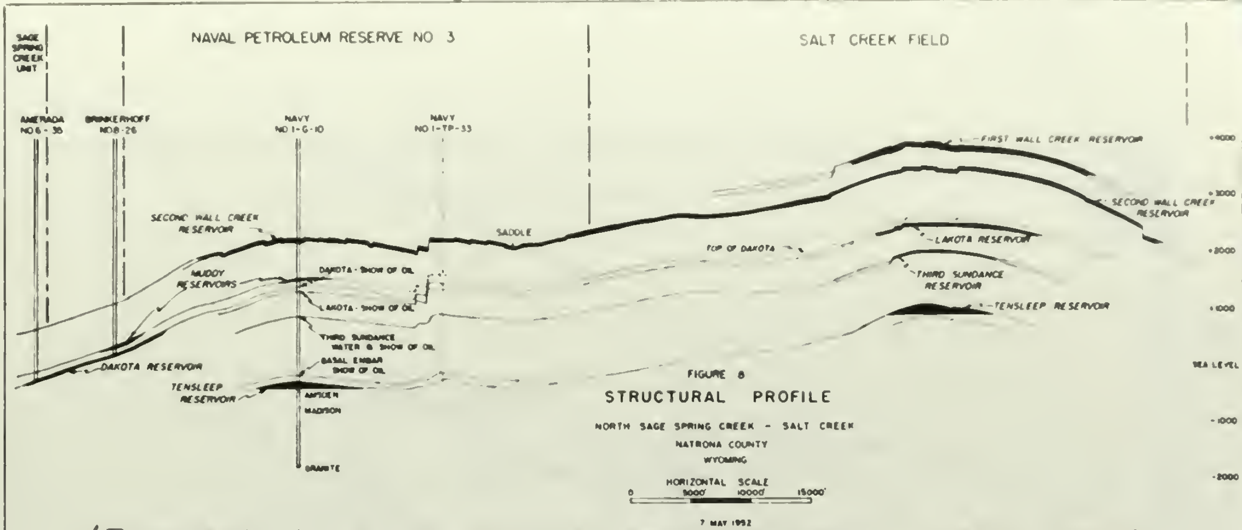
NAMES OF PRODUCING OIL & GAS ZONES & SANDS OF WEST SIDE FIELDS OF SOUTHERN SAN JOAQUIN VALLEY

INCLUDING McKITTRICK, MIDWAY-SUNSET, ELK HILLS & BUENA VISTA HILLS

AGE	FORMATION	DISTINGUISHING FEATURE or FAUNAL MARKER	PRODUCING SAND or ZONE	REMARKS
PLEISTOCENE	TULARE	*Alternating nonmarine sands, silts & clays. Fresh water fauna.*		
		AMNICOLA	Basal Tulare Sand	*Equivalent to Buttonwillow Gas Sand*
PLIOCENE	SAN JOAQUIN	OSTREA lurida	"B" Zone Gas Sand	*Equivalent to Semitropic Gas Sand*
		Predominately brackish & fresh water deposits with few marine fingers		
		"B" Zone - *Green Clay & Gray Silt*		*The sands of the San Joaquin Fm. are broadly lenticular in character and altho appearing at relatively the same stratigraphic positions are not continuous stratigraphic units.*
		2nd MYA Zone	2nd MYA Gas Sand	
		FLUMINICOLA		
		"C" Zone - *Brown Clay*	"C" Zone Gas Sand - 1st Finger	
		GONIABASIS-VALVATA		
		Upper SCALEZ	"C" Zone Gas Sand 2nd Finger	
		3rd MYA Zone	3rd MYA Gas Sand	*The "A" zone and 1st MYA zone of the south San Joaquin Clay section of Barbat & Galloway* are missing in this area except in the northernmost limits. The zones "A" to "E" refer to clay zones separating the 5 MYA zones and have no relationship to Pack's** producing zones, also alphabetically designated*
			"D" Zone Gas Sand	
		"D" Zone - *Green Clay & Gray Silt*		
		4th MYA Zone	4th MYA Gas Sand	** Barbat & Galloway, A.A.P.G. Bull. Vol. 18, 1934* *** R.W. Pack, U.S.G.S. P.P. 116*
		"E" Zone - *Thinly laminated Green Clay & Gray Silt*	"E" Zone Oil & Gas Sand	
		PECTEN eldridgei-MYTILLUS	PECTEN-MYTILLUS Sand	*Equivalent to Upper Finger Top Oil of Maricopa*
		AMNICOLITE		
		Type SCALEZ	1st Finger SCALEZ Oil Sand	*Equivalent to 2nd Finger Top Oil of Maricopa*
		5th MYA Zone	2nd Finger SCALEZ Oil Sand	*Equivalent to Upper Intermediate Water of Maricopa*
		AMNICOLITE		
	ETCHEGOIN	MULINIA-DISCORBIS	MULINIA Sand	*Equivalent to Kinsey Sand of Maricopa*
		MULINIA-ARCA	Sub-MULINIA Sand	*Has been called 1st sub-MULINIA*
		SILIQUA VOLSELLA BITTIUM		
		Marine Clays, Sands and Silts.	Wilhelm Sub-BITTIUM of B.V. Hills	*Has been called 2nd sub-MULINIA*
		PECTEN oweni	Gusher Sand	
		Midnorthern Shale		
		PECTEN terminus	Calitroleum Sand	*Fellows Silt of Fellows area and Transport, Calivada and Lower Gusher of Maricopa*
		BULIMINELLA		*Lower part of Etchegoin is not present on western border of basin. The Etchegoin thins out to the west and in some areas along the borders of the basin the various Etchegoin sands may rest directly on the Miocene. The BULIMINELLA Silts reach a maximum thickness in the East Elk Hills area.*
		Buliminella Silts	27-B SAND E_1, E_2, E_3, E_4	*The Etchegoin sands vary greatly in thickness and lateral distribution, in some areas the sands predominate and in others are missing.*
UPPER MIOCENE	MARICOPA SHALE (after Pack) — REEF RIDGE	*Punky Diatomaceous Shale or Massive Hard Brown Shale**	Lakeview Sand	*Sometimes includes Calitroleum where it rests directly on the Lakeview, also has been called the Hallmark.*
			Olig of McKittrick, Potter of Fellows 8 Foot Sd. of B.V. Mascot of 25 Hill Formax, O'Brien, Wier & Otis Hoyt of Maricopa	*Lenticular sands appearing at approximately the same stratigraphic positions*
	MARICOPA SHALE (after Pack) — THE HARD BROWN-MARICOPA	1st UVIGERINA	Webster Sand	*"The Hard Brown" shale is the stratigraphic equivalent of the McLure Shale. The sands of "The Hard Brown" of the West Side are lenticular, of limited geographic extent and appear locally at different stratigraphic positions.*
		Hard Brown Siliceous Shale	Republic Sand	
		2nd UVIGERINA	Signal Sand Williams Sand	
			ANTELOPE SHALE OF B.V. HILLS	*The Stevens Sand of Elk Hills and of Coles Levee and other central valley fields occupies the approximate stratigraphic position of "The Hard Brown" sands of the Midway-Sunset Area*

U.S.G.S. OIL & GAS LEASING, TAFT, CALIFORNIA — DWG. NO. 7944 — COMPILED BY: J.D. CORKEL, JR. - NOV. 12 '42

FIG. 2-8



(From Art. by R. E. Sparks, Navy CEC Bull., Sept. 1952)

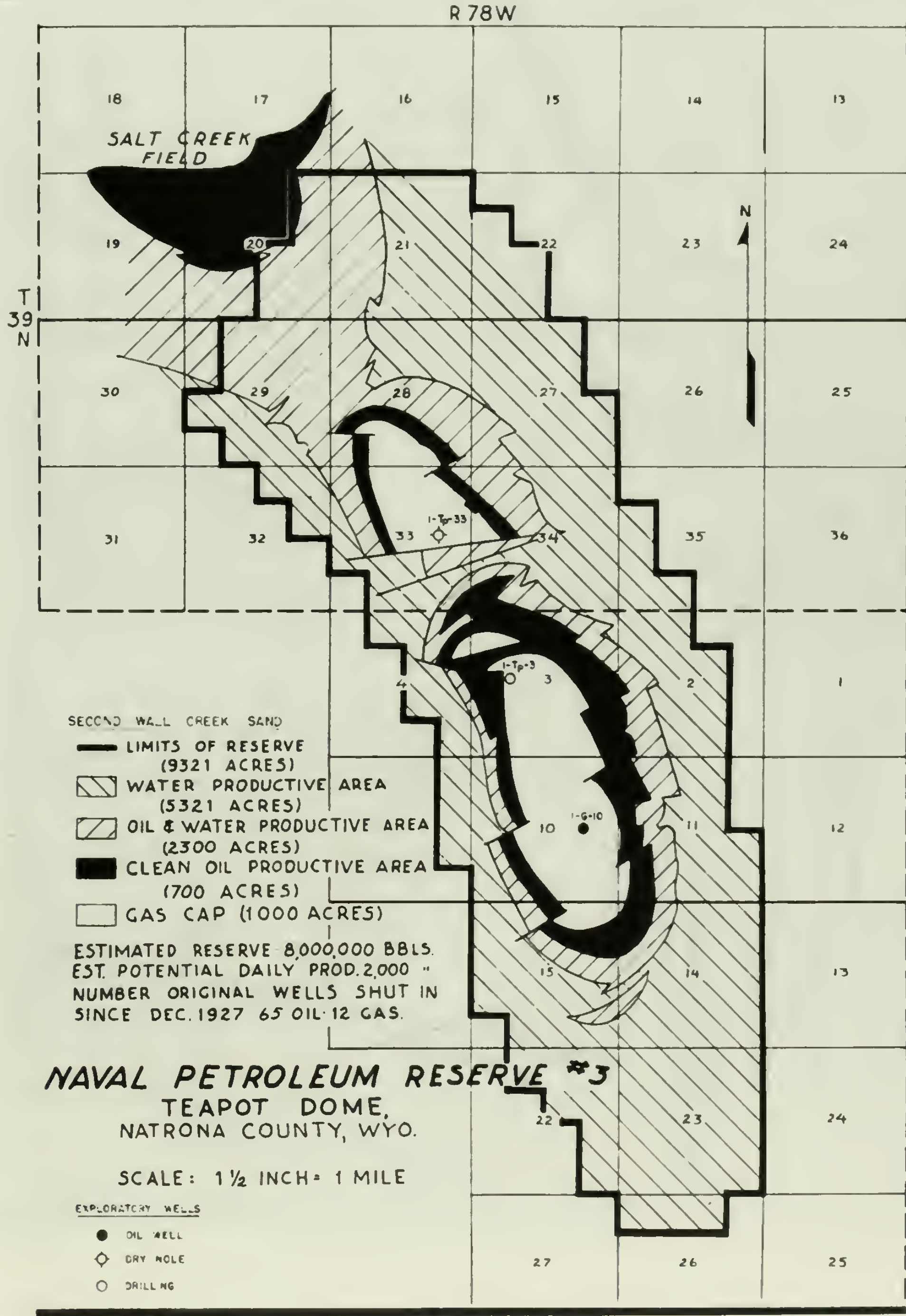


FIG. 2-10

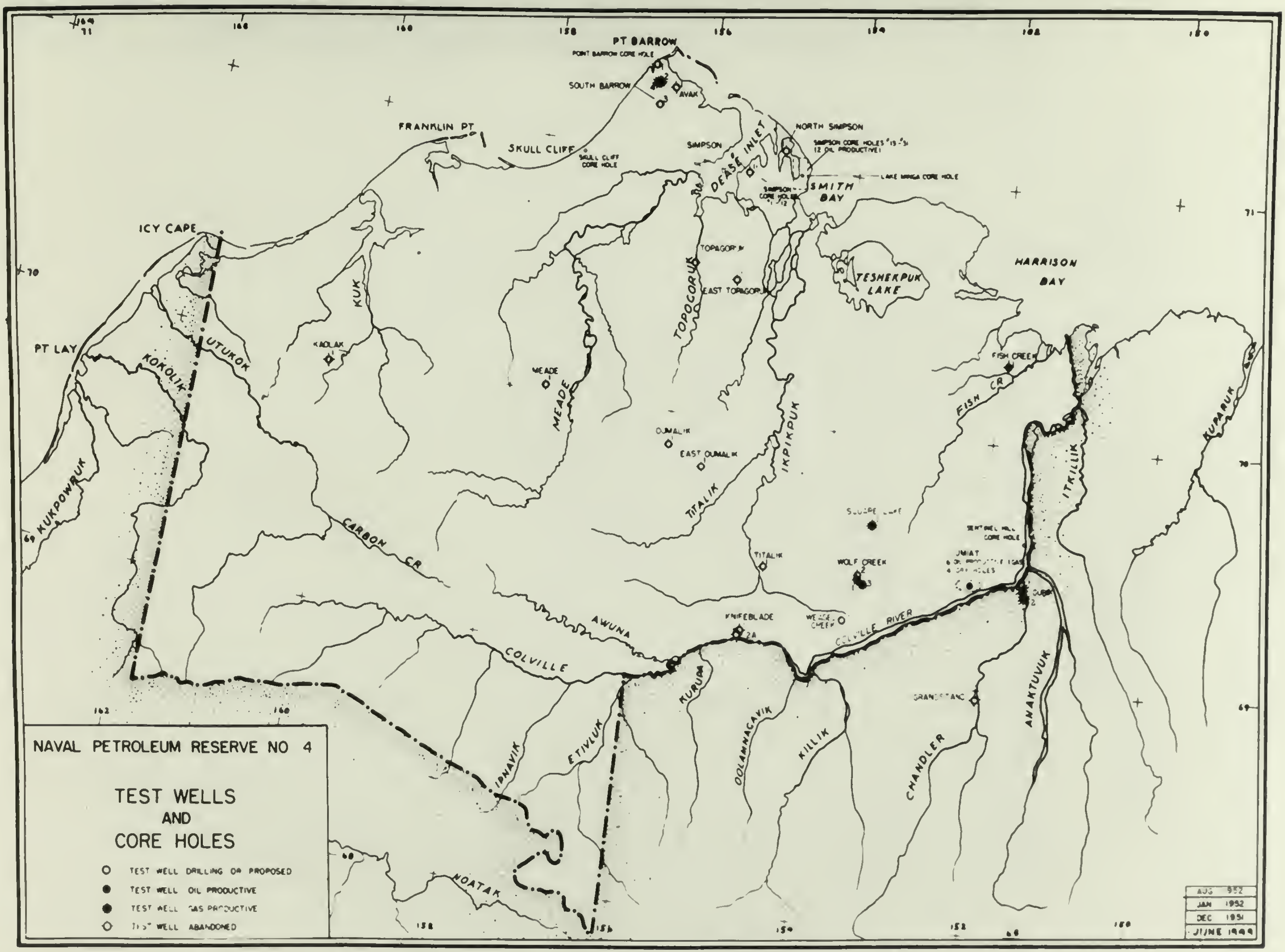


FIG. 2-11. Geographic Map of N.P.R. No. 4, Alaska, Showing the Boundaries of the Reserve and the Extent of the Exploration Drilling As of August 1952.

<u>SELECTED REFERENCES IN THE BIBLIOGRAPHY CONTAINING</u>

<u>GEOLOGIC INFORMATION ON THE RESERVES</u>

N.P.R. No. 1: 106, 111, <u>113</u>, <u>116</u>, 119, <u>124</u>, 128, 134, 136, 138

No. 2: 170, 171, 173, 179

No. 3: 188, 189, 190

No. 4: 215, 218, 219, 223, 235

Oil Shale Reserves: 245, 247

CHAPTER III

DEVELOPMENT

AND

PRODUCTION HISTORY

NAVAL PETROLEUM RESERVE NO. 1

DEVELOPMENT

AND

PRODUCTION HISTORY

NAVAL PETROLEUM RESERVE NO. 1

GENERAL REVIEW

The development and production history of Naval Petroleum Reserve No. 1, may be divided into three major periods which are listed and discussed below.

(a) 1910 to 20 November 1942 --- Discovery and competitive development and production of Elk Hills prior to unitization.

(b) 20 November 1942 to September 1945 --- Unitization and the World War II emergency development and production of Shallow Oil Zone.

(c) After September 1945 --- Post-War period of intensive exploration and development of all zones; and the State of Readiness Program for the Shallow Oil Zone.

1910 to 20 November 1942.

Between 1910 and 1919 some 35 unsuccessful prospect wells were drilled by private interests in search of oil in the Elk Hills area. Of these wells 33 were too shallow and 3 found oil in non-commercial quantities, probably as a result of poor completion methods.

In January 1919 Standard brought in the first commercially successful well, Hay No. 1 in Section 36-S. It was completed in what is now called the Shallow Oil Zone. During the next year, 47 other wells were completed in this area, none of which were particularly good oil producers.

In February 1920, when Standard brought in Tupman No. 1 (Section 36-S) at an initial production rate of 5200 barrels per day, the rapid development of Elk Hills commenced in earnest. Over 200 additional wells were drilled by Standard and other operators in the Old Area within the next few years. The area and the extent of this development may be seen on Figures 5-1 and 5-2.

It soon became obvious to the Government that the Reserve would suffer serious loss of oil by drainage to wells producing on private lands within and adjacent to the Reserve. Congress then gave Navy its first authority to issue strip-leases to private companies for the purpose of drilling offset wells to prevent drainage. Some of these strip leases are shown on Figure 5-2. Navy's protective drilling program was somewhat belated and not too successful, as illustrated by Figures 5-4 and 5-5.

By 1921 yearly production, mainly from what is now called the central or Tupman part of the Old Area, reached a peak of 18 million barrels or 16 percent of the entire production of California in that year. Overproduction in California then forced a big cut-back in Elk Hills production during subsequent years.[124]

After the Government oil reserve scandals of 1922 and repudiation of the wholesale leasing which had occurred, the Government stiffened in its policy of conserving the oil in the Reserve. As a result of this policy and the liberal attitude of the holders of patented land within the Reserve, development prior to unitization was confined largely to the Hay-Carman and Tupman areas shown on Figure 5-1. Nevertheless, by the end of 1928 more than 400 wells had been drilled in Elk Hills.

In 1932 nearly all of the high gas-oil ratio wells in the Hay-Carman area were forced to remain shut-in as a result of litigation.

In 1941 Standard drilled some deep exploratory wells and discovered the Stevens Zone. This zone, however, was not actively developed and produced until after 1946.

Production prior to unitization amounted to about 29 percent of the total estimated recoverable oil from the Shallow Oil Zone, based on the 1949 estimate.

The effects of the development and production practices during this competitive period in the field's life are discussed in Chapter V.

<u>20 November 1942 to September 1945</u>.

Although the Unit Contract and Operating Agreement were not executed until 19 June 1944, the field was effectively unitized by previous agreements on 20 November 1942. This unitization has been referred to as a "shotgun marriage"

which turned out very well.[164] At least it came at an opportune time considering the crucial state of the nation during World War II and the critical oil shortage rapidly developing on the West Coast at that time.

Orders from Congress and the President to take the lid off N.P.R. No. 1 came in June 1944. A detachment of Navy Seabees occupied the field almost overnight to build roads and level drillsites. The goal was to increase production as rapidly as possible from 15,000 barrels per day to 65,000 barrels per day. To accomplish this goal, all drilling effort was devoted to developing the Shallow Oil Zone in lieu of the deeper Stevens Zone. About 15 drilling rigs were in continuous operation with the goal of putting a new well into the tanks every 24 hours.[105] By July 1945, after a development period of 13 months, the goal of 65,000 barrels per day of sustained production had been reached.[125] A maximum production of 71,000 barrels per day was possible.

The principal areas of war-time development are indicated on Figure 5-1. The effects of the high war-time production rates on the Shallow Oil Zone are discussed in Chapter V.

With the cessation of hostilities, the Secretary of the Navy in August 1945 ordered a cut-back in production from 65,000 to 15,000 barrels per day. Later the production rate was decreased still further, and the emergency production period came to an end.

The total production from Elk Hills during the four years of World War II, about 31 million barrels of oil, was equivalent to only 15 percent of the total production from the Shallow Oil Zone to 1954. Thus only a relatively small percentage of oil produced from the Reserve has been used for the purpose Congress intended.

After September 1945, the Post-War Period.

This period to 1954 has consisted of the following principal development and production programs:[148]

(1) Intensive exploration and development of the Shallow Oil Zone and the Stevens Zone for Readiness purposes. The Stevens Zone development was completed in 1954.

(2) Additional off-set drilling and production along the boundaries of the Reserve---Section 14-B for shallow sands and Section 25S for Stevens Zone.

(3) Exploratory drilling by the Navy of Carneros Zone wells.

(4) State of Readiness Program for Shallow Oil Zone described in Chapter V. The principal purposes of this Program are to maintain the Shallow Oil Zone in a full state of readiness to produce the maximum amount of oil upon short notice, and to create reservoir conditions calculated to insure maximum ultimate recovery of oil.[125]

(5) Reduced production of oil to an extent necessary to carry out necessary testing and the projects under the State of Readiness Program.

(6) Construction of a 5.5 million dollar natural gas processing plant with 50 million cubic feet capacity; reconditioning of the existing 3G gas plant.

(7) Recent drilling in various areas to protect Reserve from drainage or loss of recoverable oil.

(8) Conservation of unused processed gas by injection into the Dry Gas Zone.

During the first eight years of the post-war period, production from the Shallow Oil Zone to 1 January 1954 had amounted to about 11.5 percent of the total cumulative production, or almost as much as the emergency production of World War II. Cumulative production from the Stevens Zone has amounted to only about one percent of its estimated recoverable reserves.

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(7) Recent drilling in various areas to protect Reserve from drainage or loss of recoverable oil.

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DEVELOPMENT NOTES

General Items of Interest.

During the Post-War Period the Unit has contracted all development work with several independent drilling companies. Rotary drilling equipment on light portable rigs is employed.

Under Unit Operations extensive coring, logging, and testing have been an integral part of the development and remedial programs. For the first wells drilled in any general area, all possible productive horizons are cored in a reduced hole. Drill-stem tests are made of each zone separately if evidence from cores, mud log, and electric log so warrant. This policy may mean coring 4000 feet of Pliocene Age formations lying above the Reef Ridge Shale at a depth of 1000 to 5000 feet from the surface. Also, drill-stem tests may be made of as many as nine different productive intervals.

The above procedure applies only to a few wells. Most are drilled without such extensive coring, logging, and testing.

Drilling costs and cost sharing are discussed in Chapter VIII.

Shallow Oil Zone.

There have been several principal periods in the development of the Shallow Zone. They are listed below:

(1) 1919 to 1928 --- Over 400 wells were drilled by private operators and by lessee's of the Navy.

(2) 1942 to 1945 --- Approximately 328 wells were drilled during the war-time emergency period.

(3) 1945 to 1947 --- An exploratory development program along mostly the south flank was continued after World War II.

(4) 1951 --- Readiness Development Program is still in progress.

(5) 1953 --- Protective well drilling as part of the revised State of Readiness Program was commenced to prevent drainage and loss of otherwise recoverable oil.

These wells average about 3000 feet in depth and require 7 to 14 days to drill.

In the heavily drilled Old Area the wells are generally on an 8-acre spacing. Development practice under Unit Operations has been a 20-or-40-acre well spacing for each major productive sand with the well-bore open to only one major sand body.

Stevens Zone.

Development periods in the life of the Stevens Zone are as follows:

(1) 1941 to 20 November 1942 --- On a deep exploratory test, Standard discovered the Stevens Zone in 1941. By 20 November 1942, the date of unitization, three producing wells had been completed by Standard in this zone. Except for one or two more wells, the Stevens Zone was not developed during the emergency

war-time development and production period of the Shallow Oil Zone.

(2) 1946 to 1947 --- A participating percentage (joint) exploration of the Stevens Zone was conducted.

(3) 1 July 1948 to 1 April 1954 --- An intensive Readiness Development Program for Navy was completed.

These wells average about 6500 to 7000 feet in depth and require approximately 47 days to drill.

The development program was carried out on a 40-and-80-acre well pattern.

Carneros Zone.

In 1951, Navy commenced a deep test exploratory program in the western portion of the field. Exploratory well X55-30R, completed 10 January 1952, resulted in the discovery of the Carneros Zone. The well was bottomed at 12,856 feet, plugged back to 9,385 feet and completed in an oil production finger of the Carneros Sand. Two successful wells had been completed in this zone as of May 1954. On test the wells flow at a rate of about 150 to 200 barrels per day of very high gravity crude, 54° API, and very high gas-oil ratio, 10 Mcf per barrel.

Dry Gas Zone.[2]

As of 1 January 1954, there were six productive wells in the Dry Gas Zone. There are 33 locations to be drilled on a 160-acre pattern. As far as is known, however, this development program has not been commenced nor is contemplated in the near future.

Section 14-B (Buena Vista Front Field).[125]

As of 1 January 1954, the Unit had drilled 16 off-set wells which are on continuous production at a total daily rate of about 545 barrels per day. This Section is discussed more fully in Chapter V.

PRODUCTION NOTES

Production Status of Wells, All Zones, As Of 1 January 1954.

Zone	Total No. Of Wells	No. Suspended Or Standing	No. Producible
Shallow	771	50	721
Stevens	220	1	219
Carneros*	1	0	1
Dry Gas	6	0	6
Sect. 14-B	16	0	16
Totals:	1014	51	963

*By May 1954 there were two producible Carneros Zone wells.

Rate of Production.

The Secretary of the Navy is required by Congress to keep production in normal times at a minimum consistent with good oil-field practice for routine testing and protection of the reservoir. Under existing law, the Secretary must find that increased production is essential for national defense and obtain permission from Congress in the form of a joint resolution before production from the Reserve can be expanded. The Navy must then dispose of its share of the petroleum produced by public sale. Also, contracts are held up while Navy confers with armed services committees of Congress.

To prevent these delays in putting N.P.R. No. 1 on full production in event of a national emergency, corrective legislation was introduced in Congress in January 1954

on the recommendation of the National Security Council. The proposed bill would give the Secretary of the Navy authority, subject to the approval of the President, to initiate production from the petroleum reserves during a national emergency or state of war declared by the Congress, and also, to negotiate sales of the products so produced. Reports would be required to the armed services committees of Congress concerning details and reasons for any expanded production and disposition of same.

The current status of this bill is not known.

Summary of Production, All Zones, From 20 November 1942 (Unitization) To 30 June 1953 [148]

	Crude Oil (Barrels)	Gas (MCF)	Natural Gasoline (Gallons)
Deliveries to:			
Navy	21,881,902	16,651,530	3,701,933
Standard	29,690,885	8,939,825	6,332,707
Total Deliveries	51,572,787	25,591,355	10,034,640
Inventory of 30 June 1953	156,052	-	19,265
Total Production	51,728,839	25,591,355	10,053,905

Comparison of Current and Ultimate Allocation of Production[148]

	Crude Oil (Barrels)	Gas (MCF)	Natural Gasoline (Gallons)
Navy's Participating Percentage Share of Total Production	35,056,688	19,026,053	6,907,202
Actual Deliveries to Navy	21,996,695	16,651,530	3,717,138
Due to Navy Under Ultimate Allocation of Production	13,059,993	2,374,523	3,190,064

The indicated unbalance in production receipts resulted from the extended "primary" period of the Unit Contract[150] As Amended[146] when Standard received most of the production from the Shallow Oil Zone. This extended "primary" period ended 2 August 1950. Production receipts from the Shallow Oil Zone are gradually being brought into balance with the participating percentages listed in Chapter IV, for Navy is receiving nearly eight-ninths of the Shallow Oil Zone production.[125]

Shallow Oil Zone

The gravity of oil produced from the Shallow Oil Zone has varied from 17° to 44° API with an average gravity of about 25° API.

From estimated production decline curves it has been estimated that the Shallow Oil Zone currently could be produced at maximum production rates well above 100,000 barrels per day. However, such high rates could not be sustained for many months or even days as excessive sanding of wells would occur. Consequently, estimated sustained production rates

are much lower. These rates are given in Chapter IV.

Most production in the past has come from the SS-1, SS-2, and M sands, and these sands would be the source of most production in the future.

The great majority of wells require pumping. Only rod-actuated plunger-displacement pumps are used. Some wells are flowing wells as a result of the increased reservoir pressure resulting from the gas injection program.

The production history of the Shallow Oil Zone is given on the graphs of Figures 3-1 to 3-3. Figure 3-1 is a graph of monthly production rates since discovery of the field. During the post-war period, the rate of production from each of the various projects under the State of Readiness Program is given by the curves of Figure 3-2. Cumulative production curves to 1 January 1954 appear on Figure 3-3.

Stevens Zone.

The average gravity of Stevens Zone Oil is about 36° API. Combined with its natural gas and natural gasoline content, Stevens crude has nearly twice the value of Shallow Zone crude combined with its gas and gasoline.

State of depletion, estimated constant production rates, and estimates of reserves all may be found in Chapter IV.

With the reservoir pressure averaging 2400 to 3300 psi, all wells are flowing wells with the exception of a few marginal producers which are pumped.

Current production consists of (1) test production from new development wells and (2) minor off-set drainage production are much lower. These rates are given in Chapter IV.

Most production in the near future will come from the [illegible] 26-2, and N sands, and these sands should be the source of most production in the future.

The great majority of wells require pumping. Only rod-actuated plunger-displacement pumps are used. Some wells are flowing wells as a result of the increased reservoir pressure resulting from the gas injection program.

The production history of the Shallow Oil Zone is given on the graphs of Figures 3-1 to 3-4. Figure 3-1 is a graph of monthly production rates since discovery of the field. During the postwar period, the rate of production from each of the various projects under the [illegible] is given by the curves of Figure 3-2. Cumulative production curves to 1 January 1954 appear on Figure 3-3.

Stevens Zone.

The average gravity of Stevens Zone Oil is about 35° API. Combined with its natural gas and natural gasoline content, Stevens crude has nearly twice the value of Shallow Zone crude combined with its gas and gasoline.

Status of depletion, estimated constant production rates, and estimates of reserves all may be found in Chapter IV.

With the reservoir pressure averaging 2400 to 3300 psi, all wells are flowing wells with the exception of a few marginal producers which are pumped.

Current production consists of (1) test production from new development wells and (2) direct off-set drainage production

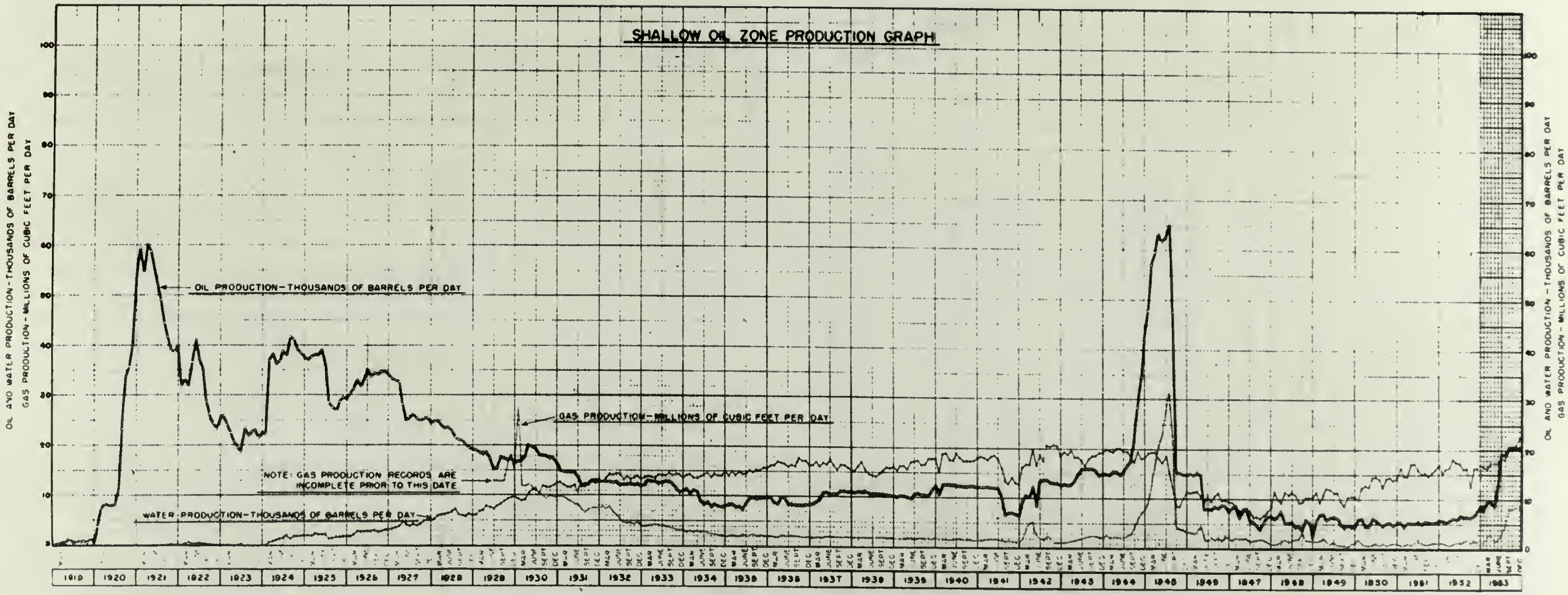

FIG. 3-1. Oil, Water, Gas Monthly Production Curves, Shallow Oil Zone, Elk Hills, Since Discovery of the Field (Reproduced from Annual Report, NPR #1, 1953)

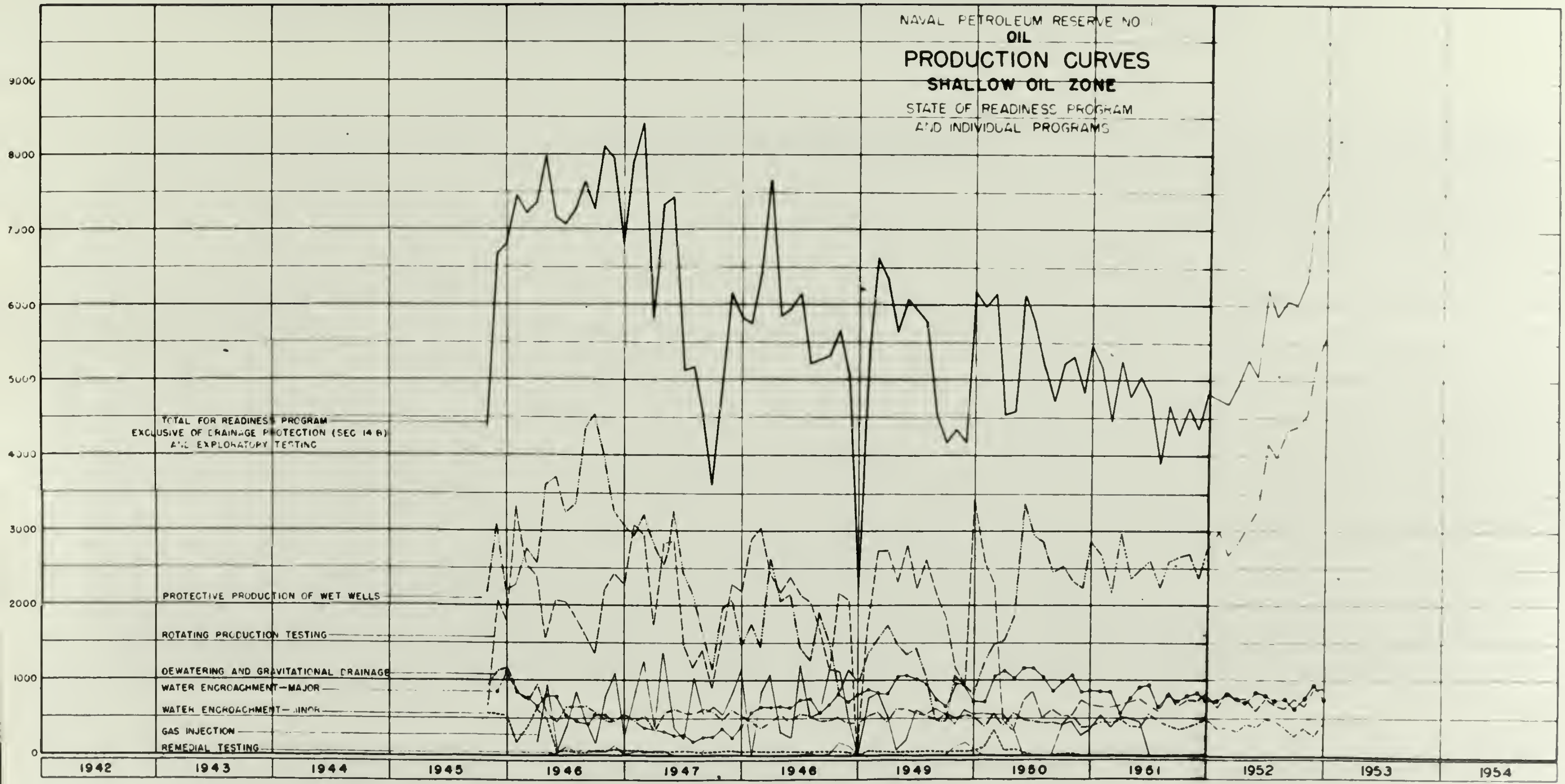

FIG. 3-2. Oil Production Curves, Shallow Oil Zone, State of Readiness and Individual Programs (Reproduced from Annual Report, NPR #1, 1952)

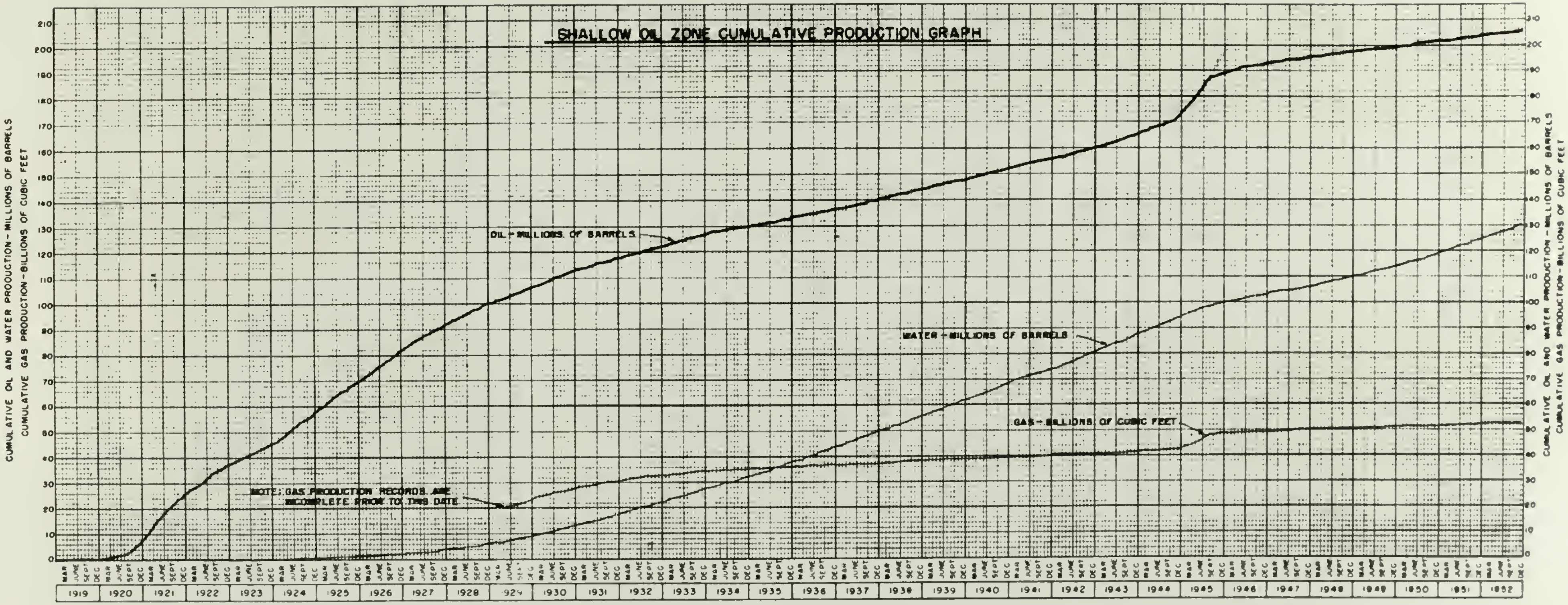

FIG. 3-3. Oil, Water, and Gas Cumulative Production Curves, Shallow Oil Zone, Elk Hills (Reproduced from Annual Report, NPR #1, 1952)

in Section 25-S to prevent drainage of oil from a finger of Stevens Sand reaching into the Elk Hills field from the adjacent Coles Levee field on the East.

Current and ultimate allocation of Stevens Zone production is in agreement with the latest revised participating percentages as given in Chapter IV.

The production history is graphed in Figure 3-4.

Carneros Zone.

The gravity of Carneros Zone oil is about 54° API.

As of 1 April 1954, there were only two wells---both flowing wells.

Production to date has been only minor test production. All production has been allocated to Navy since the program is still 100 percent Navy's.

Dry Gas Zone.

Until June 1952, when the gas injection program was halted, the Dry Gas Zone provided some gas for injection into the Shallow Oil Zone.

Currently, for conservation reasons, all produced gas from other zones which is not burned or sold is injected into the Dry Gas Zone.

Since the field was unitized in 1942 until 30 June 1953, approximately 16 million Mcf of gas has been produced from this Zone. Current and ultimate allocations of production agree with the participating percentages for this Zone.

Section 14-B.

As of 1 January 1954, the Unit's 16 wells on Section 14-B in Section 22-B to prevent drainage of oil from a number of Stevens Sand reaching into the Elk Hills field from the adjacent Coles Levee field on the east.

Current and ultimate allocation of Stevens Zone production is in agreement with the latest revised participating percentages as given in Chapter IV.

The production history is graphed in Figure 5-4.

Carneros Zone.

The gravity of Carneros Zone oil is about 36° API.

As of 1 April 1954, there were only two wells---both flowing wells.

Production to date has been only minor test production. All production has been allocated to Navy since the program is still 100 percent Navy's.

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Section 14-B.

As of 1 January 1954, the Unit's 16 wells on Section 14-B

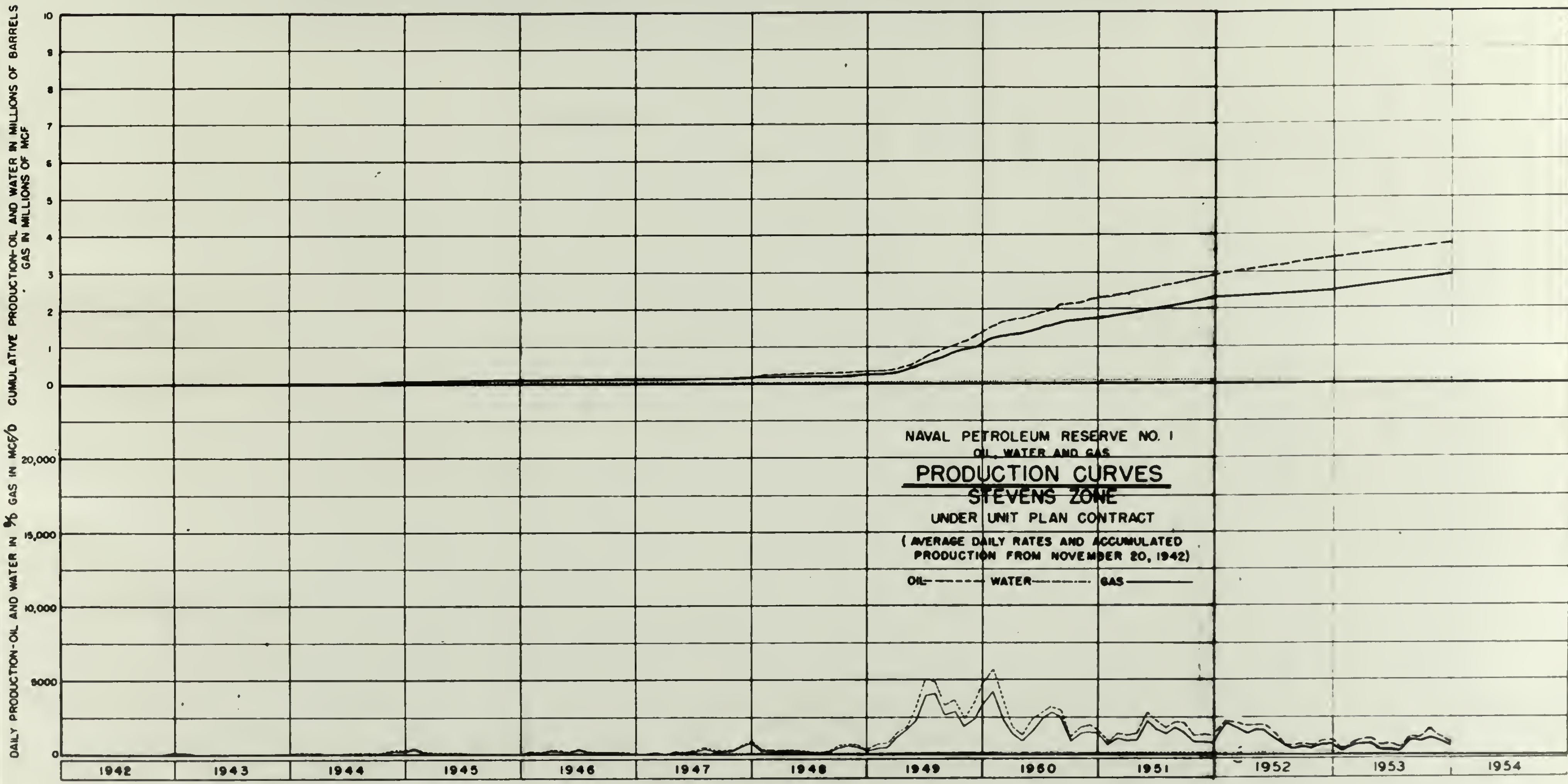

FIG. 3-4. Production History Curves, Stevens Zone, Elk Hills, from 20 November 1942. Date of Initial Production: 30 August 1941. (Reproduced from Annual Report, NPR #1, 1953)

were producing a total of 545 barrels per day from the Buena Vista Front field. The production history of this section is tabulated below:

Year	Yearly Production (Barrels)	Cumulative Production (Barrels)
1945	55,815	55,815
1946	180,097	235,912
1947	133,490	369,402
1948	101,292	470,694
1949	113,299	583,993
1950	126,560	710,553
1951	104,415	814,968
1952	149,036	964,004
1953	197,917	1161,921

PIPELINES AND REFINERIES

Eight crude oil pipe lines with high aggregate capacity are directly or indirectly connected to the Reserve.[105] Six of these lines can reach marine terminals. None of these lines are owned by Navy but by different oil companies, such as Standard, Union, Texas, and Norwalk. As of 1 April 1951, INPR in C estimated that the major companies could, independently of each other, ship and refine about 46,000 barrels per day of Elk Hills oil in the event the field was put on full production. Also, INPR in C pointed to indications that the whole industry, with mutual cooperation, could ship and refine 100,000 barrels per day of Elk Hills oil. A more than adequate available refining capacity, 137,000 barrels per day, exists in the nearby refineries of the Los Angeles area.[123] Additional refinery capacity is available in the San Francisco Bay region and Bakersfield.

With the subsequent development of both the Shallow and Stevens Zones and the discovery of the Carneros Zone, the estimated constant production rate for Elk Hills exceeds 100,000 barrels per day. Consequently, in 1954, the Navy indicated that it plans to propose the construction of a 14 inch pipe line 100 miles in length to Los Angeles to handle the increased productive capacity in case of an emergency. Costs of this project are discussed in Chapter VIII.

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125

CHAPTER IV

OIL RESERVES

AND

PRODUCTIVE CAPACITY

OF

NAVAL PETROLEUM RESERVE NO. 1

CHAPTER IV

OIL RESERVES

AND

PRODUCTIVE CAPACITY

OF

NAVAL PETROLEUM RESERVE NO. 1

TOTAL OIL RESERVES

Zone	Estimated Recoverable Oil As Of 1 January 1954 (Barrels)	Latest Revised Participating Percentages Standard	Navy
Shallow	337,568,562	33.0848	66.9152
Stevens	350,000,000	20.6911	79.3089
Carneros	No Estimate	-------	100
Total	687,568,562		
Dry Gas Zone	100,000,000 M.c.f.	77.0492	22.9508

Basis for the above values is discussed in later sections of this chapter.

STATE OF DEPLETION

Zone	Estimated Percent Depleted As Of 1 Jan. 1954
Shallow	39
Stevens	1
Carneros	0
Dry Gas	43

PRODUCTIVE CAPACITY[125]

1952 Annual Report

Estimated Maximum Production Capacity for Five Years, 1952-1956

Year	Shallow	Stevens	Total
1952	58,000	72,000	130,000
1953	55,000	72,000	127,000
1954	52,000	72,000	124,000
1955	51,000	70,000	121,000
1956	50,000	66,400	116,400

Revised Estimates
1953 Annual Report

Estimated Maximum Constant Producing Rates for Five Year Period, Barrels per Day

Year	Shallow	Stevens	Total
1953	74,000	65,950	139,950
1954	73,000	68,250	141,250
1955	72,000	------	-------
1956	68,000	------	-------
1957	64,000	------	-------

SHALLOW OIL ZONE

Reserves.[125,136]
(Official estimate by Engineering Committee; Revision of 1 December 1949)

Proven Acreage (oil and gas production).....19,200 acres

	Barrels
Estimated Ultimate Recovery...........	550,184,000
Production to 20 Nov. 1942...........	160,658,000
Est. Reserves as of 20 Nov. 1942.......	389,526,000
Production from 11-20-42 to 1-1-54...	51,957,438
Est. Reserves as of 1 Jan. 1954........	337,568,562

Discussion.

The values quoted above were from the latest Engineering Committee estimate[136] based on a combination of the decline curve and the volumetric method.

Old Area.

For the Old Area (Tupman), see Figure 5-1, the Unit engineers established average production decline curves for each of six different fault blocks within the area from the production history of each of the wells in the Area. Since many wells in this Old Area are completed in several major sands, as shown on Figure 5-3, it was necessary for the decline curves to include production from all sands penetrated. These curves were then used to obtain the estimated recoverable oil for each well in the Old Area by entering the appropriate

curve with the last representative daily production for the well and determining recoverable oil to an economic limit of 3 barrels per day. To this value was added the well's production back to the base date of 20 November 1942. Reserves from undeveloped areas scheduled for development were obtained similarly. A summation gave the estimated recoverable reserves from the Old Area.

New Area.

The remainder of the Shallow Oil Zone had been mostly developed during and after World War II. Since the production history of the wells in these areas was insufficient to establish representative decline curves, the recoverable oil was computed by the volumetric method using recovery factors based largely on analogy with the Old Area and comparison with similar nearby fields.

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STEVENS ZONE[125]

Reserves (Unofficial 1948 Navy Estimate):

Proven Acreage............................8,300 acres

	Barrels
Estimated Ultimate Recovery................	307,718,000
Production to 20 Nov. 1942................	107,000
Reserves as of 20 Nov. 1942................	307,611,000
Production from 11-20-42 to 1-1-54........	3,705,265
Reserves as of 1 January 1954..............	303,905,735*

Discussion.

As of May 1954 no official estimate by the Engineering Committee had been made of the recoverable oil in the Stevens Zone; however, one is now in progress. Unofficial estimates have been made, such as one above by Navy field engineers in 1948 and another by consulting petroleum engineers employed by Standard. *Discovery of the 26-R sand and other extensions of the Stevens Zone since 1948 have increased the recoverable reserves to about 350 million barrels.

It may seem strange to some observers that no official estimate of recoverable reserves exists after a lapse of thirteen years since discovery of the Zone. However, there are several good reasons. Although the field was discovered in 1941, it was not until 1946 that an intensive exploratory program was commenced. The development program which followed

[illegible]

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Proven Acreage..........................8,300 acres

	Barrels
Estimated Ultimate Recovery..................	307,718,000
Production to 20 Nov. 1948..................	107,000
Reserves as of 20 Nov. 1948..................	307,611,000
Production from 11-20-48 to 1-1-54..........	1,702,265
Reserves as of 1 January 1954..............	305,908,735"

Discussion.

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It may seem strange to some observers that no official estimate of recoverable reserves exists after a lapse of thirteen years since discovery of the Zone. However, there are several good reasons. Although the field was discovered in 1941, it was not until 1946 that an intensive exploratory program was commenced. The development program which followed was not completed until April 1954. Late development is thus one reason. Any detailed official estimate prior to completion of the scheduled development program would have been an unnecessary expense.

Another reason is simply the difficulty involved in making an estimate of this Zone on which all parties will agree. Since the Zone has not been produced except for minor test and maintenance production, no decline curves and material balance data are available. Consequently, about the only method for estimating reserves is a calculation based on the volumetric method and comparison of this field with similar producing fields to obtain a recovery factor. No reliable secondary method is available to use as a check on the volumetric method.

Moreover, any estimate cannot be considered entirely reliable or even relatively accurate, as the Stevens Zone contains a large volume of fractured shale with great variations in porosity and permeability. Thus, most of the difficulty in making an estimate lies in deciding how to interpret, or how reliable is, the data available.

As far as this student knows, the volumetric method has been used for all estimates to date. Possible increases in recovery by secondary recovery methods were not considered in any estimate.

CARNEROS ZONE[2,125]

By May 1954 only two wells had been completed in this deepest Zone. The wells have capacities of 150 to 200 barrels per day of very high gravity oil and high gas-oil ratio. No estimate of oil reserves has been attempted.

DRY GAS ZONE[2,125]

No detailed estimates have been made of the recoverable gas in the Dry Gas Zone which lies at a depth of 1500 to 2000 feet. However, approximate estimates are as follows:

Estimated Productive Area................6,056 acres

Rough Estimate of Gas Reserves:

Est. Ultimate Recovery............175,000,000 M.c.f.

Approx. Gas Production to 1954.... 75,000,000 M.c.f.

Est. of Gas Reserves as of 1-1-54.100,000,000 M.c.f.

SELECTED REFERENCES IN THE BIBLIOGRAPHY ON OIL RESERVES AND PRODUCTIVE CAPACITY

2, 103, 106, 114, 117, 125, 136

CHAPTER V

REVIEW OF
THE RESERVOIR ENGINEERING PROBLEMS
IN NAVAL PETROLEUM RESERVE NO. 1

(Elk Hills)

CHAPTER V

REVIEW OF THE RESERVOIR ENGINEERING PROBLEMS IN NAVAL PETROLEUM RESERVE NO. 1 (Elk Hills)

INTRODUCTION

The Elk Hills oil field (Naval Petroleum Reserve No. 1), potentially the largest oil field in California if it were to be opened to maximum production, is of particular interest from an oil reservoir engineering standpoint. Nearly every problem that can be associated with a petroleum reservoir has been encountered in the development of this Reserve. This field provides the petroleum engineer with an unusual opportunity to study the interaction and interrelation of many reservoir processes in one field. It provides an opportunity to study under actual field conditions some problems previously attacked only from a theoretical basis. Its relatively shut-in condition also makes it more unusual than a producing field and provides some information on reservoir behavior not furnished by the latter.

The problems have ranged chronologically from the age-old oil field problem of drilling off-set wells to restrict drainage of oil from one's own property to the problem of probable loss of oil by migration into edgewater sands along a receding edgewater front -- an unusual condition.

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Each particular problem or project was usually accompanied by exhaustive engineering analysis and detailed reports. The new employee -- Navy or Standard, officer or civilian -- who becomes associated with the Elk Hills field in some capacity and who is interested in the oil reservoir engineering history of the Reserve, normally finds these reports too numerous and voluminous.

The purpose of this section is an attempt to alleviate to some extent the above situation. Each engineering problem of major significance or special interest in the past and current history of the Reserve is presented in chronological order in as standard and concise form as possible, stressing the most important facts in each major problem or project.

Where they are necessary for clarity and better understanding of the problem, simplified maps and graphs accompany each discussion. For the reader requiring more detailed information, a bibliography at the end of each discussion refers him to the detailed reports concerning the particular subject.

This presentation is by no means the first summary of the engineering problems and projects at Elk Hills that has been made.* It is hoped, however, that this report will be

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*Early history and development through 1932 of Elk Hills field have been described in detail by Woodring, Roundly, and Farnsworth in reference 124; subsequent developments through 1947 by Eastman and Ruhlman in reference 109; and a report on the results of the postwar readiness and maintenance projects from 1945 through 1952 by the Engineering Committee in reference 138.

of some value in its wide scope, its standardized presentation of each problem, and the selected references included with each discussion.

Part A

SUMMARY OF THE OIL RESERVOIR PROBLEMS FROM THE DISCOVERY OF OIL IN ELK HILLS (JANUARY 1919) TO UNITIZATION OF THE RESERVE IN NOVEMBER 1942

The development and production history of Elk Hills during the more than twenty years before unitization has been reviewed in Chapter III. From an oil reservoir engineering standpoint, this period is important for the manner in which the field was developed and produced. The competitive drilling and producing practices of this period resulted mainly in an overall detrimental effect to the Shallow Oil Zone, reducing its productive capacity and decreasing its ultimate recoverable reserve to an unnecessary degree. On the credit side, however, the competitive nature of the operations did serve to promote the initial discovery of oil in the field, to provide the government with high royalties from its strip-leases, and to establish Elk Hills as a major oil field and an important Reserve by 1921.

It has often been said that the Elk Hills field has everything to interest and perplex the petroleum reservoir engineer.[108] It was equally true in this early period of the Reserve. The problems were typical of those always encountered in the development of any single closed-structure oil pool in which there are divided interests and many different operators. Each operator is dedicated to the task of maximum economic (not necessarily efficient) recovery of oil in the

Part I

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Some of the major problems encountered during the initial development of this field, or which resulted from the early development and production practices, included the following:

(1) Uncontrolled production methods with no attempt to maintain or restore reservoir pressure caused adverse effects on the reservoir, such as the following:

(a) Depletion of reservoir energy in the Old Area in the form of free gas and solution gas produced. No gas was returned to the SS-1 from 1919 to 1942.

(b) Creation of pressure sinks and an unbalanced reservoir.

(c) Creation of secondary gas caps.

(d) Rapid decrease in productive capacity.

(e) Abnormally high percentage recovery of oil from the Old Area at the probable expense of greatly reduced ultimate recovery from the Shallow Zone.

(2) Multi-zone well completion methods -- a procedure detrimental to maintaining good control of reservoir conditions. Completion methods during this competitive period called for opening up all horizons to the well-bore, regardless of gas, oil or water productivity. Only about 40 per cent of the nearly 700 producible wells in the Shallow Zone

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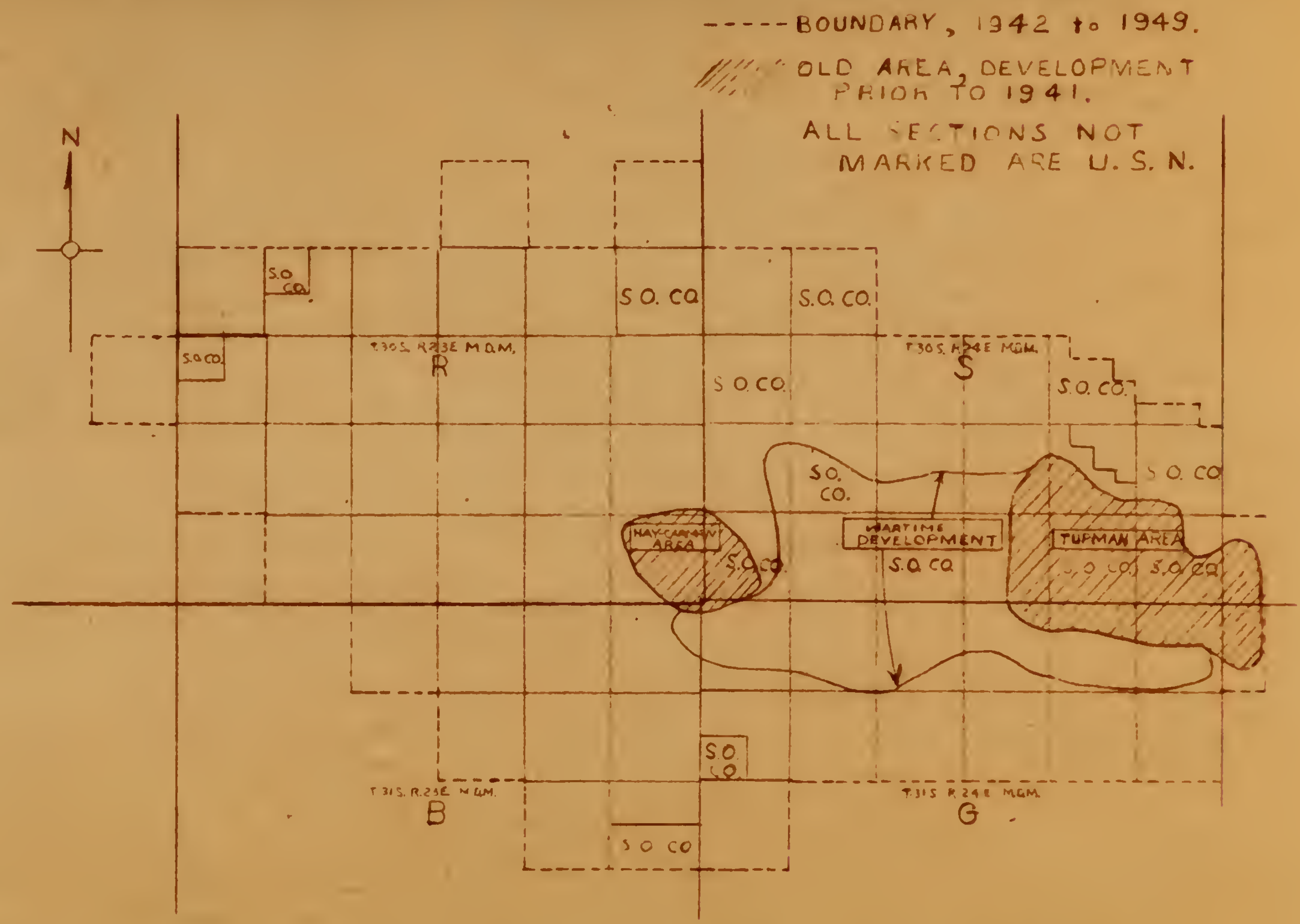


FIG. 1—DEVELOPED AREAS, ELK HILLS

FIG. 5-1, Showing the Areas of the Shallow Oil Zone Developed Prior To and During World War II

are completed in one zone only -- a fact which has prevented good control of reservoir fluids in the different zones and which has contributed to the unbalanced condition in the Shallow Zone. A sketch of three early wells is shown in Figure 5-3[104] to illustrate this early well-completion technique, now mainly abandoned in favor of single-zone completions.

(3) Off-set drilling and production practices. It was necessary for the Government to issue strip leases for the drilling of off-set wells to restrict drainage from the Reserve to neighboring developed lands outside of the Reserve. Some drainage occurred before the off-set wells were completed and some drainage probably continued after completion; also, the worst result was the production of great amounts of oil from a structure primarily set aside by Congress as a reserve of oil to be held in the ground for future emergency use.

(4) Production at excessively high gas/oil ratios occurred in the Hay-Carman, or central part, of the Old Area indicated on Figure 5-1.[109] The resulting rapid depletion of reservoir energy in the form of high-pressure gas from the original crestal gas cap of the SS-2 and other sands led to lawsuits which eventually shut in all of these wells in stages from 1925 to 1934. They remained shut in until 1944.

The Old Area of Elk Hills is indicated on the base map of Figure 5-1. It was composed of the crestal, less important central area (Hay-Carman) and the highly productive eastern

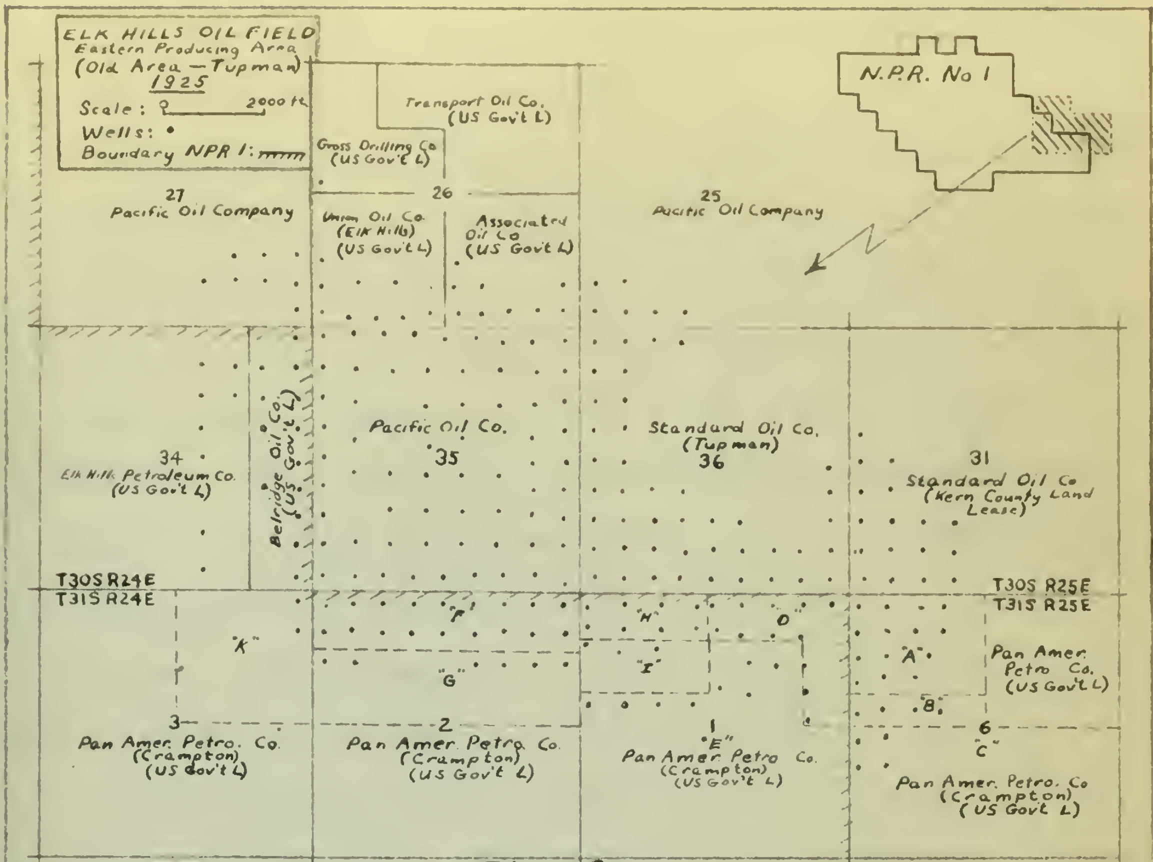
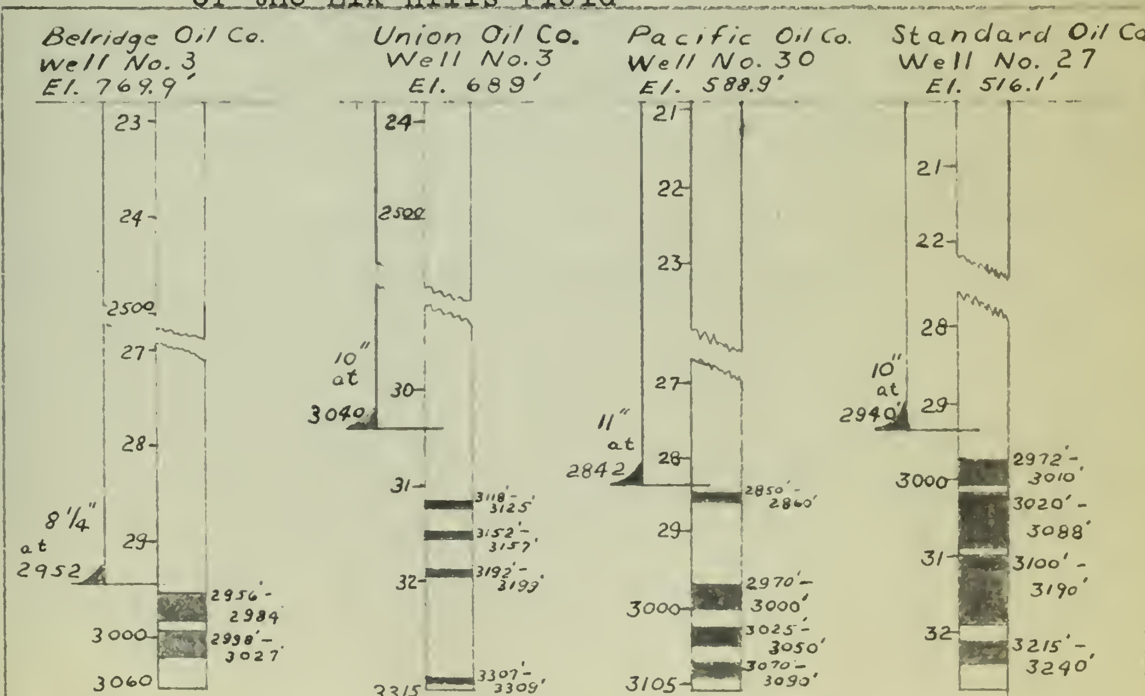


Fig. 2

FIG. 5-2, Showing the Complexity of Leases and the Off-set Drilling Practices During the Competitive Period of the Elk Hills Field



Examples of Multi-Zone Completion Methods for Wells in Old Area of Fig. 2. Result: Poor Reservoir Control in Shallow Oil Zone.

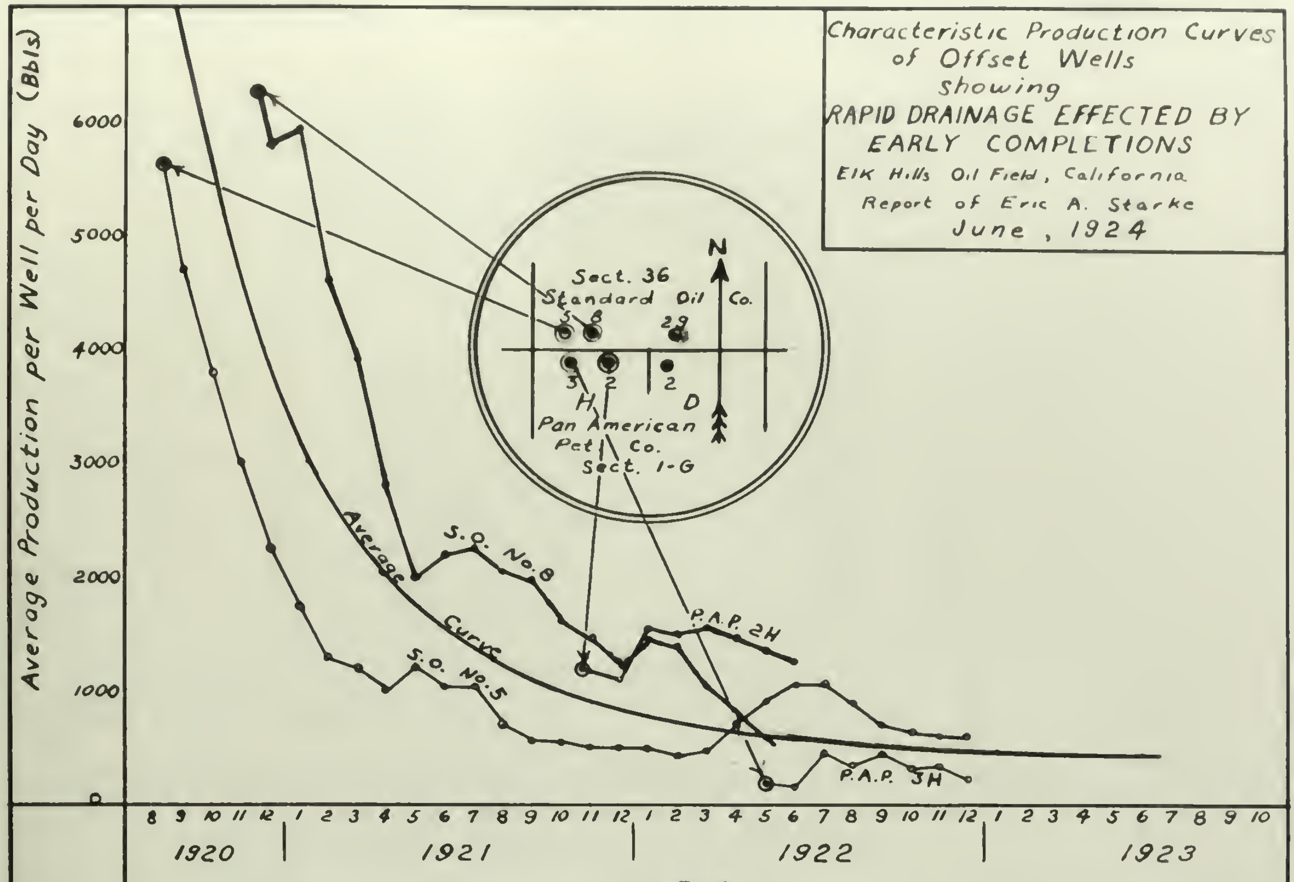
Fig. 3

FIG. 5-3

area (Tupman). These areas represent the development occurring prior to unitization in 1942.

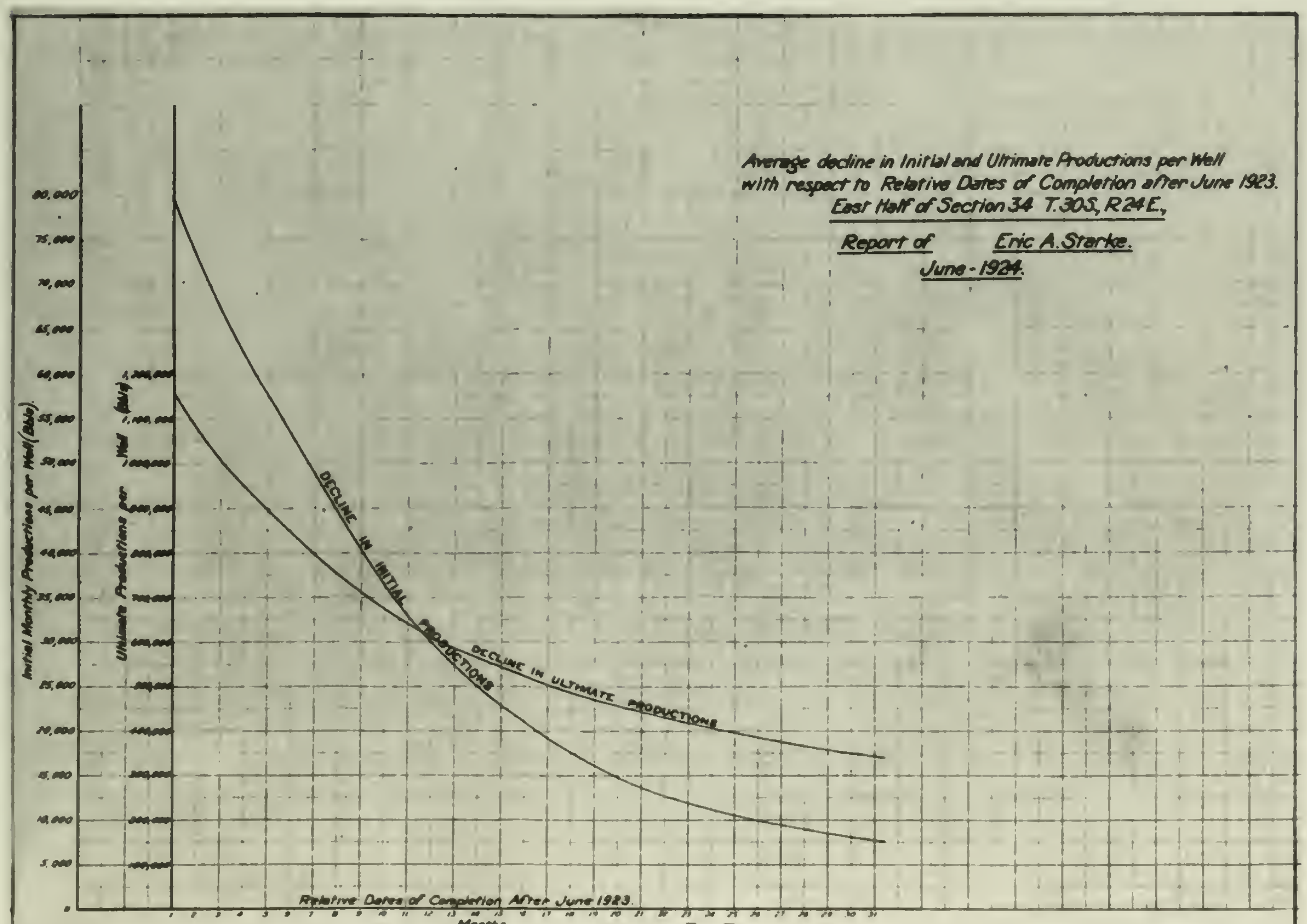
From Figure 5-2[104] may be obtained some idea of the complexity of leases and large number of operators involved in the initial development of the Shallow Zone of the Elk Hills field. The operators included those on Navy or other government leased land and those on fee owned or privately leased land. The necessity that existed for each operator to protect his lease by off-set drilling is readily apparent. The near disastrous results to the party who was late in drilling his off-set wells -- a role consistently played by Navy -- is shown by Figures 5-4 and 5-5.[120]

The following tabulated data given by Starke in his investigation of Navy's off-set drilling program well illustrates the great loss of oil which the Government suffered before it could put into effect its strip-lease, off-set drilling program. As Starke pointed out, "The initial productions of wells on either side of the south line of Section 36 (30-24) are shown to be closely related to the dates of completion as shown by the following data":[120]



Characteristic Production Curves of Offset Wells showing RAPID DRAINAGE EFFECTED BY EARLY COMPLETIONS
Elk Hills Oil Field, California
Report of Eric A. Starke
June, 1924
Average Production per Well per Day (Bbls)
6000
5000
4000
3000
2000
1000
0
Sect. 36
Standard Oil Co.
N
5
8
29
3
2
2
H
D
Pan American Pet. Co.
Sect. 1-G
S.O. No. 8
Average Curve
S.O. No. 5
P.A.P. 2H
P.A.P. 3H
8 9 10 11 12 1 2 3 4 5 6 7 8 9 10 11 12 1 2 3 4 5 6 7 8 9 10 11 12 1 2 3 4 5 6 7 8 9 10
1920
1921
1922
1923

FIG. 5-4



Average decline in Initial and Ultimate Productions per Well with respect to Relative Dates of Completion after June 1923.
East Half of Section 34 T.30S, R.24E.,
Report of Eric A. Starke.
June - 1924.
Initial Monthly Productions per Well (Bbls)
Ultimate Productions per Well (Bbls)
DECLINE IN INITIAL PRODUCTIONS
DECLINE IN ULTIMATE PRODUCTIONS
Relative Dates of Completion After June 1923.
Months

FIG. 5-5

SETTLED INITIAL PRODUCTIONS IN ORDER

OF DATES OF COMPLETION

S. O. Co.	5	5700	Bbls	P.A.P.*	1 D.	300	Bbls
"	4	5550	"	"	2 D.	240	"
"	8	6274	"	"	1 H.	100	"
"	14	3834	"	"	3 D.	300	"
"	17	2777	"	"	4 D.	240	"
"	15	2618	"	"	2 H.	1209	"
"	29	1801	"	"	4 H.	795	"
"	30	289	"	"	5 D.	228	"
"	31	189	"	"	3 H.	144	"

*A Navy lessee.

Note: Wells in the two columns above are opposite one another along a section line between Standard's property and the Reserve.

Naturally, ultimate production in each case of later completion should be less, and cumulative productions to date indicate that they will be. It should be stressed that most of the commercial development described above was on privately owned lands outside of the Reserve and on the off-set strip-leases issued by Navy. Most of the fee-owned land within the original boundaries of the Reserve, except for the Hay-Carman Area, was not developed by the private owners, thereby co-operating with the Navy's policy of conserving the Reserve as a source of oil in a future emergency. However, the detrimental effects of the competitive development and production practices occurring in the Tupman area eventually led the Government to the realization that the Reserve had to be extended so as to cover the entire oil-producing structure and

that the field should be operated and developed as a unit. By an Act of Congress of 30 June 1938, all leases were terminated and action was taken to insure that the field was maintained as a Reserve. Standard was the only remaining operator in the area. As a step toward securing more information for unitization, this Company drilled thirteen exploratory wells in the area in 1941. Then followed the Presidential Decree of 15 October 1942 which extended the boundaries of the Reserve to include all sections of the Old Area and all the known productive areas of the field. The reader is referred to Chapter VI for a review of the considerations that led Navy and Standard to develop and operate all the land in the Reserve as a unit, effective from November, 1942.

DISCUSSION OF SPECIFIC PROBLEMS MENTIONED ABOVE

Initial Reservoir Conditions in the Shallow Oil Zone and Results of Production Practices Prior to Unitization. The oil in the SS-1 reservoir was probably saturated with dissolved gas at approximately the original reservoir pressure (about 1150 psi). The primary motive force to remove the oil was solution gas drive. As production proceeded, more gas was produced and reservoir pressure dropped rapidly. Gas began to fill part of the void space in the reservoir and gas caps were created. When unitization of the field finally occurred, the overall average reservoir pressure in the SS-1 was very low except in areas of active edgewater encroachment; the reservoir was unbalanced; reservoir oil had shrunk and increased in viscosity upon loss of solution gas; and relative permeability to oil had been greatly reduced. None of the produced gas was returned to the SS-1 from 1919 to 1942. The principal driving force remaining was gravity drainage.

The SS-2,M zones were initially at a similar high reservoir pressure and with an overlying gas cap. Early production methods produced several billion cubic feet of gas from a probable crestal gas cap before any significant amount of oil was produced from these combined zones. To replenish the gas cap, dissolved gas came out of solution with the oil. No attempt was made during divided or unit operation prior to January 1946 toward pressure maintenance of the gas cap by gas injection. The reservoir pressure was greatly reduced, the reservoir was unbalanced, the reduced reservoir pressure had

allowed the gas cap to expand, and a secondary gas cap was created.

SELECTED REFERENCES IN THE BIBLIOGRAPHY:

2, 104, 109, 111, 112, 118, 120, 124, 131, 134, 138, 143.

Part B

SUMMARY OF MAJOR RESERVOIR ENGINEERING PROBLEMS FROM NOVEMBER 1942 THROUGH DECEMBER 1945 -- THE WAR-TIME DEVELOPMENT AND PRODUCTION PERIOD

The effective unitization of the field in November 1942 and its rapid development during 1944 and 1945, and the emergency production period during which production rose from 15,000 barrels per day to a field capacity of 71,000 barrels per day,[109] have been traced in Chapters III and IV.

From a practical standpoint, one engineering problem dominated all others during this period: the necessity to increase the field's production as rapidly as possible to the authorized 65,000 barrels per day in order to relieve the shortage of oil on the West Coast and thus help prosecute the war. The short time (eight months) in which the 71,000 barrel per day capacity was reached is a credit to the oil industry of California and to the engineering staff at Elk Hills composed of employees of Standard Oil Co. and members of the Navy. Also, the program more clearly defined the limits of productivity of the Shallow Oil Zone.

The heavy withdrawals of oil and gas from the Shallow Oil Zone and its intensive development during the emergency period confirmed the presence of certain undesirable reservoir features and furnished evidence of new ones. Reservoir pressure had been materially reduced (250 psi drop during the emergency period) without an effective pressure maintenance

Part 2

SUMMARY OF MAJOR RESERVOIR ENGINEERING PROBLEMS FROM NOVEMBER 1942 THROUGH DECEMBER 1945 -- THE WAR-TIME DEVELOPMENT AND PRODUCTION PERIOD

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The heavy withdrawals of oil and gas from the Shallow Oil Zone and its intensive development during the emergency period confirmed the presence of certain undesirable reservoir features and furnished evidence of new ones. Reservoir pressure had been materially reduced (230 psi drop during the emergency period) without an effective pressure maintenance or restoration program until September 1945. The pressures in all productive sands of the Shallow Zone were unbalanced in all areas. Previously unknown secondary gas caps that were probably developed during the early days of competitive production were disclosed. Shallow Oil Zone development confirmed that the eastern part of the Old Area (Tupman) was pressure depleted, that certain areas along the north and east sides were subject to active edgewater encroachment, and that Sections 31-T and 6-M were almost completely flooded with water. More and more Shallow Zone wells along the north and east flanks were being drowned out and having to be abandoned.

During the war some produced gas was reinjected into the reservoir mainly as a conservation measure since no market existed for the gas, rather than as a repressuring attempt, the net volume injected being too small to counteract the rate of pressure decline. In September, 1945, the gas injection program was intensified. The entire gas injection program and results to 1952 are covered in a following section of this chapter.

Three other items of engineering interest during the World War II period were (1) the gas processing problem created by the large emergency production, (2) the 14-B offset drilling and production program, and (3) the helium tracer studies. These items are discussed on the following pages.

(1) Gas Processing: The large gas production during the emergency period presented problems in the proper processing and disposal of the gas. For example, during the peak production of 31,200 MCF per day, the gas was disposed of as follows:[112]

Burned as fuel for field operations	20.5%
Sold	9.0%
Injected in the Reservoir	46.4%
Vented to the Atmosphere	24.1%

As was mentioned above, the initial underlying purpose of injecting the gas was the desire to reduce the percentage of gas vented to the atmosphere. Also high gas production overloaded the facilities of the small natural gasoline plant on the Reserve, requiring some gas to be reinjected without the processing necessary to recover its liquid hydrocarbons. Relatively low gasoline recoveries were obtained with an average of only 0.75 GPM whereas wet gas analysis from wells representing all individual zones indicated that the recovery could have been about 2.50 GPM (gallons recovered per thousand cubic feet of gas), if only the butanes and heavier hydrocarbons were extracted.[112] Principally, as a result of the discovery and later extensive development of the Stevens Zone with an expected high rate of gas production from this zone and also from the Shallow Zone in a future emergency, and partially, as a result of the relatively low natural gasoline recovery obtained by the old plant during the World War II emergency -- a modern, efficient, natural gasoline plant of 50,000 MCF

capacity was built in 1952 and the old plant was modernized. The new plant (35R) is mostly in "mothballs," but it can be completely activated in about three months time.[125]

SELECTED REFERENCES IN THE BIBLIOGRAPHY:

109, 111, 112, 125, 138

(2) Section 14-B Production Program

Description: This program is an offset-drilling and production project in Section 14-B on the Southwest corner of N.P.R. No. 1, as shown on Figure 5-6. The productive area is part of the Buena Vista Front Field, a separate and distinct field lying between Elk Hills to the North and Buena Vista to the south.

The productive sands are the same Scalez Sands as for the Shallow Oil Zone; but as shown by the geologic cross section of Figure 2-1 the field lies on the Buena Vista structure, not the Elk Hills structure.

This program is under Unit Operation, but it has no relation to any other program pertaining to the Reserve.

Objectives: To offset producing wells to the south and west on privately-owned lands outside of the Reserve as shown on Figure 5-6.

Pertinent Dates:

October 1945: First Production. The program was commenced after oil along the Buena Vista Front was discovered by private interests on adjacent lands. Production is expected to continue until no longer profitable which is estimated to be in 1964 with a probable recovery of 1,700,000 barrels.

Action Taken: Initially five offset wells were drilled and put in continuous production in 1945. Subsequently eight more wells were added to this production by January 1953. Well sites for at least three more wells have been selected by the Unit. It is not desirable to extend the Reserve to

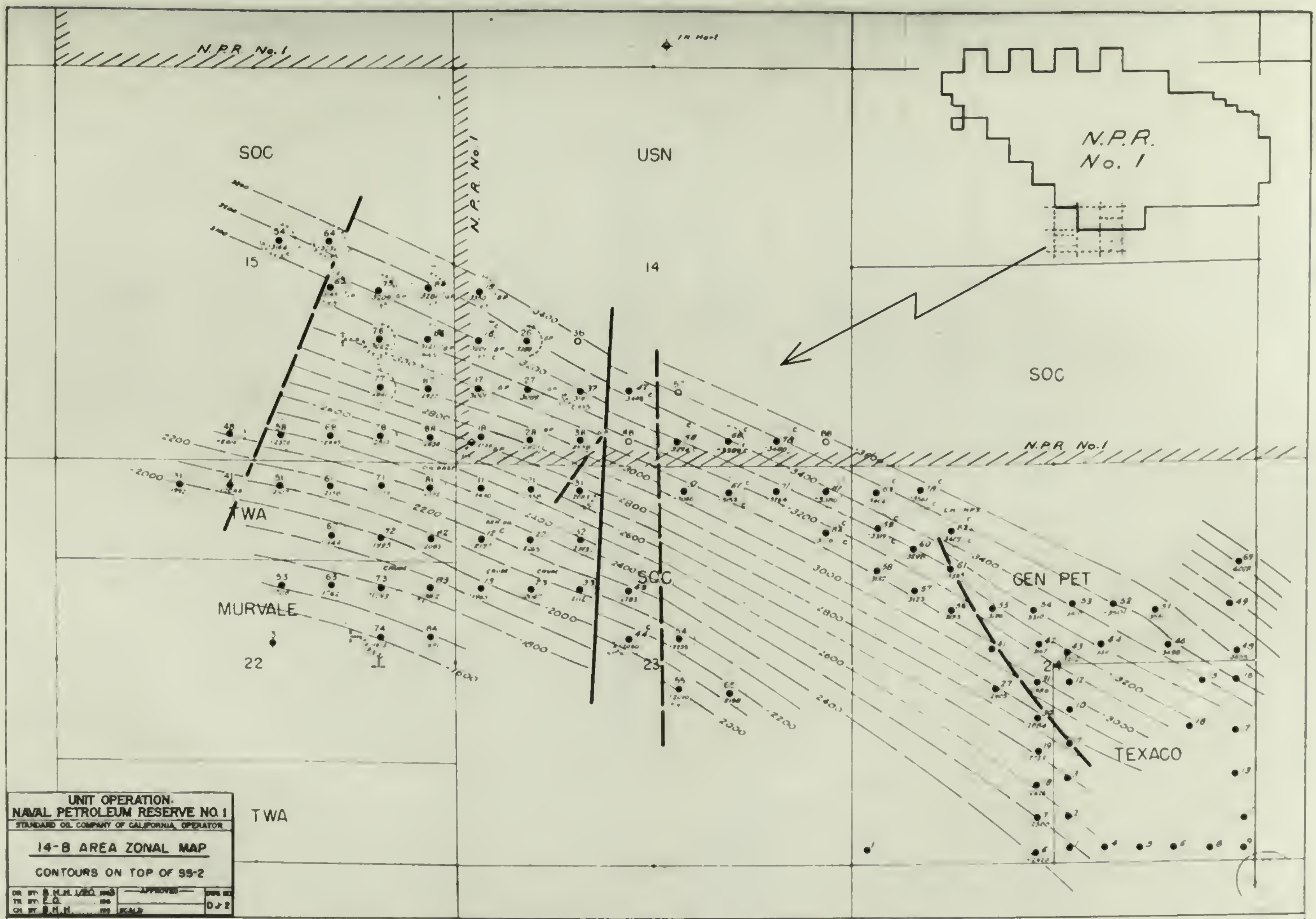


FIG. 5-6, Showing Section 14-B Production Area of N.P.R. No. 1. Production is From the Buena Vista Front Field

include all of the Buena Vista Front structure because the production and reserves from the whole area are relatively minor and Navy's share is relatively small. Being down-structure, Navy is in a relatively good position to produce its full share of oil.

Results:

1. Continuous production from Section 14-B since 1945 has given a cumulative recovery of 1,161,921 barrels by 1 January 1954.

2. Refer to Chapter III for yearly production values from 1945 through 1953.

SELECTED REFERENCES IN THE BIBLIOGRAPHY:

125

(3) Helium Tracer Studies in Elk Hills Field:[110]

Description: Upon request of the Navy Department for assistance in connection with a gas injection program during the emergency production from the field in 1945, the Bureau of Mines conducted helium tracer studies in a fault-block area of the Shallow Oil Zone as shown on Figure 5-7. Small percentages of helium were mixed with natural gas being pumped into Well 76-33-S, which was open to both the SS-1 and SS-2 sands. Movement of the injected gas was then traced by taking samples of produced gas from surrounding wells in an ever-increasing circle and subjecting the samples to an apparatus capable of determining minute quantities of helium at helium content percentages as low as 0.0001 per cent.

Objectives:

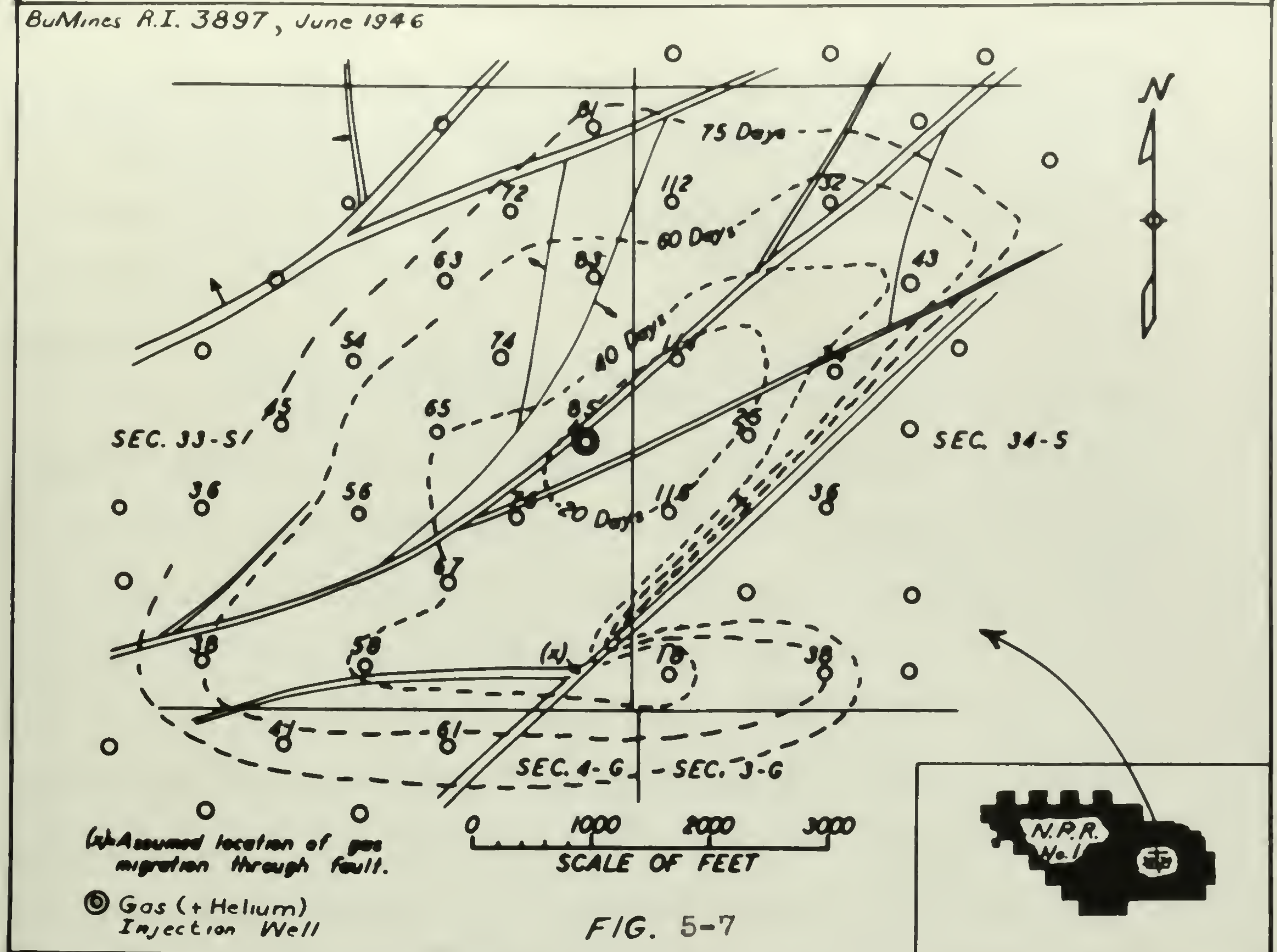
1. To determine the direction and extent of migration of injected gas in the fault-block area of the Shallow Oil Zone shown on Figure 5-7.

2. To determine the actual competency of faults previously judged by other methods of field analysis to be fluid barriers.

Inclusive Dates: May 25, 1945 until August 1945. The program was discontinued as a result of V-J Day, when sharp curtailment of production prevented continuing the studies effectively.

Procedure Employed: Helium was added to the injected gas in two distinct periods of 14 days and 30 days duration, separated by a period of no helium injection for 18 days.

HELUIM TRACER STUDIES



Dotted Lines Above Show the Direction and Extent of Migration of Helium-Laden Injected Gas at the End of Each Period.

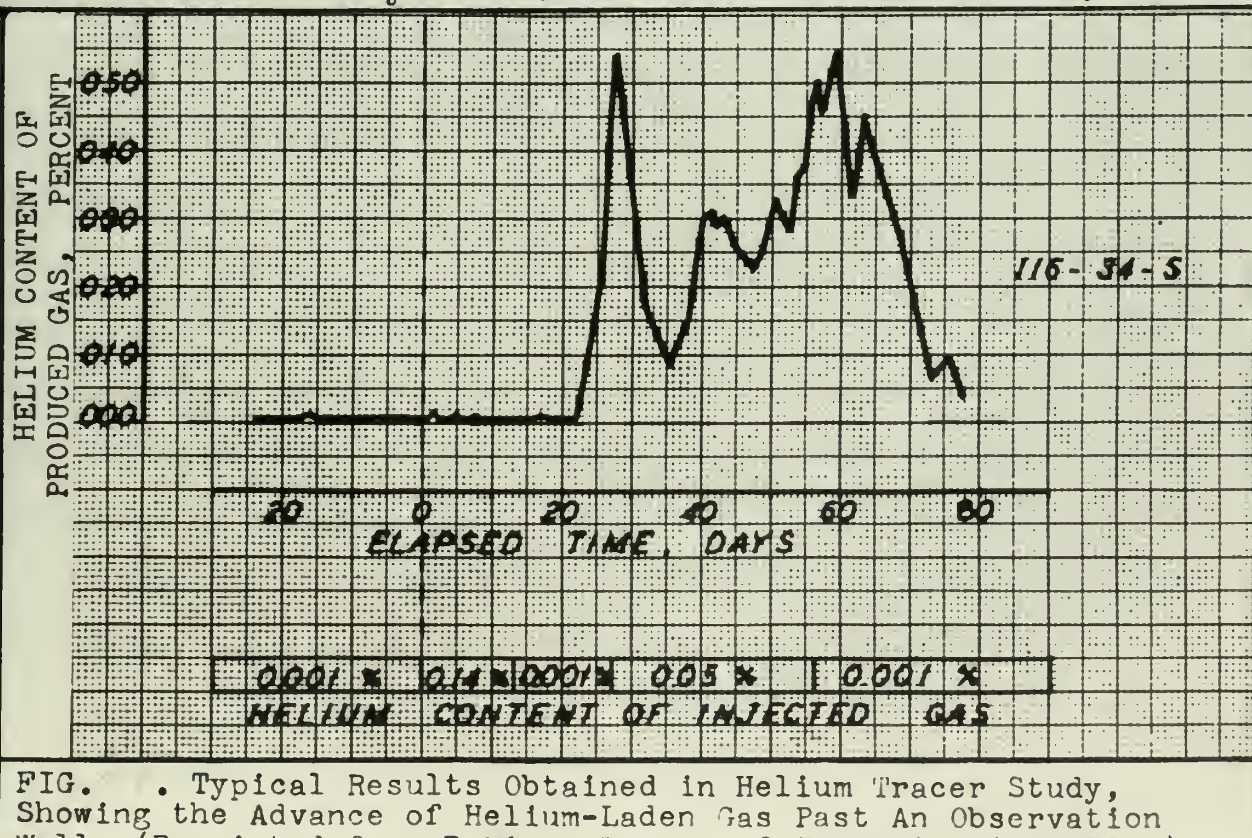


FIG. . Typical Results Obtained in Helium Tracer Study, Showing the Advance of Helium-Laden Gas Past An Observation Well. (Reprinted from BuMines Report of Investigations 3897).

Samples were collected and analyzed from nearby wells; and as the helium appeared in these wells, additional wells at a greater distance from the injection well were selected for sampling and analysis.

Results:

1. By plotting helium content in the gas of each well against elapsed time of helium injection into the reservoir, as shown on Figure 5-8, it was possible to obtain a plot showing movement of injected gas throughout a large area. This latter plot is superimposed on the map of Figure 5-7.

2. Some faults -- established by electric log correlations, drilling records, and bottom-hole pressure surveys and presumed to be competent fluid barriers -- were shown to be incompetent, especially at probable areas of extensive fracturing where faults cross. An example of a fault leak is marked (x) on Figure 5-7.

3. The information obtained enabled the field enginerrs to improve the gas injection pattern.

Discussion:

Not enough time elapsed between the two periods of helium injection to permit differentiation between the results obtained from the first run of gas and the results from the second run of gas. An appreciably longer time interval would be necessary in any future studies.

With the data obtained from this study, Bureau engineers are attempting to determine the characteristics of the flow

of gases through underground reservoirs and into well bores.

SELECTED REFERENCES IN THE BIBLIOGRAPHY:

110

Part C

SUMMARY OF RESERVOIR ENGINEERING PROBLEMS DURING THE POST-WAR PERIOD, 1945-1953

In August 1945, following the end of World War II, the emergency development and production program at Elk Hills was halted except for an Exploratory Drilling Program on the Reserve which was continued. Upon orders of the Secretary of the Navy, production was reduced from 65,000 barrels per day to 15,000 barrels per day and later reduced to even lower rates.

The war-time necessity for rapid development and high production was succeeded by the problem of restoring the Reserve to the best reservoir conditions possible, i.e., to a state that would permit a maximum rate of production in the event of another emergency with a minimum of production in the interim. If we may consider the Reserve as a ship, it was to be placed in the best condition possible, decommissioned and placed in moth-balls, subjected to constant inspection and testing by a caretaker crew, and maintained in a state of material readiness such that upon notice it could be placed in full operation within a minimum of time.

To accomplish the above general objective for the Reserve, the Unit commenced a State of Readiness Program for the Shallow Oil Zone late in the year 1945. Insufficient reservoir information was available upon which a rigid operating policy could be based, and it was necessary for

the Program to include experimental production projects to yield this information. This program for the Shallow Oil Zone only -- formulated by the Operating Committee and concurred in by the Engineering Committee -- consisted of eight interrelated projects:

1. Gas Injection
2. Major Water Encroachment Study
3. Minor Water Encroachment Study
4. Dewatering and Gravitational Drainage Study
5. Rotating Production Tests
6. Protective Production of Wet Wells
7. Remedial Program (started September 8, 1946)
8. Protection of Surface Equipment

The project areas for the first four projects listed above are shown on Figure 5-9.[138] These four projects, the most important and most interesting from a reservoir engineering viewpoint, are treated in some detail in succeeding sections of this chapter. The other four are described but are not discussed in any detail. An excellent graphical summary of the principal events and important dates relative to each project under this Program was presented in the Engineering Committee's Review of the Program and is reproduced here as Figure 5-10.[138]

The Operating Committee served as the supervisory body for the Program. The Engineering Committee served as the advisory group, reviewing all phases of the Program at least once each quarter, and recommending changes in the Program

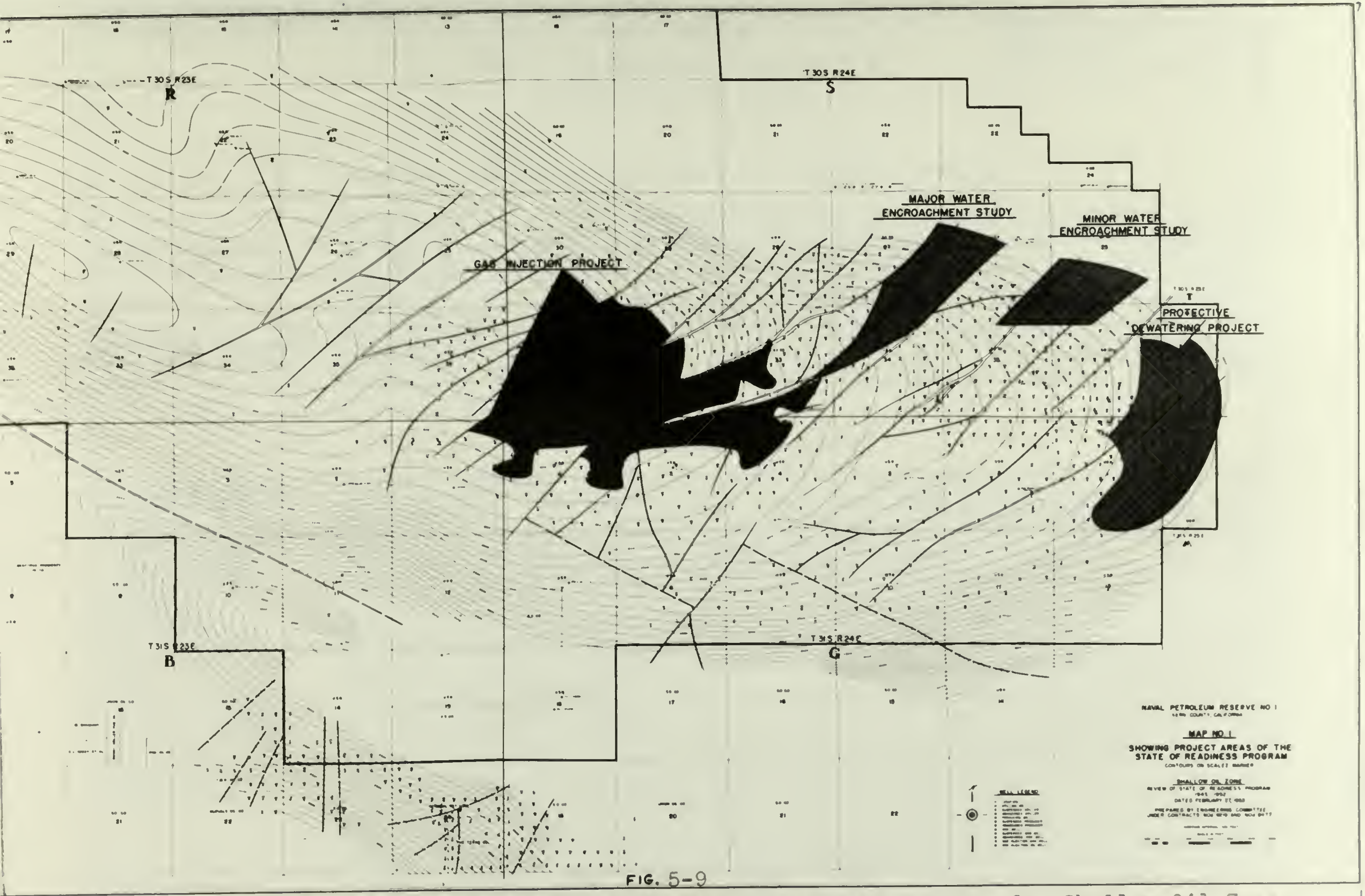


FIG. 5-9

FIG. 5-9, Showing Four Project Areas Under State of Readiness Program for Shallow Oil Zone Following World War II. Contours on Scalez Marker.

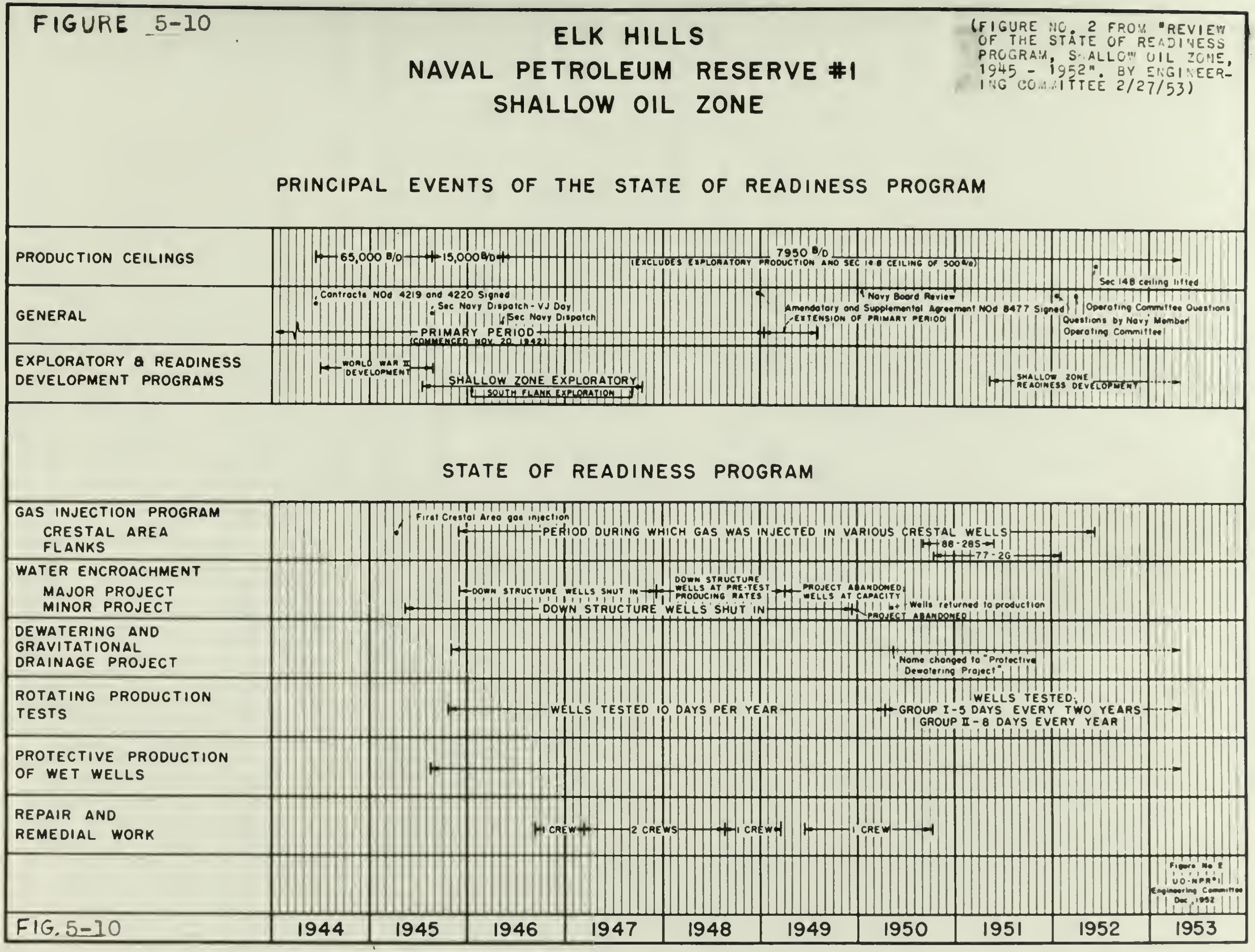


FIGURE 5-10
ELK HILLS
NAVAL PETROLEUM RESERVE #1
SHALLOW OIL ZONE
(FIGURE NO. 2 FROM "REVIEW OF THE STATE OF READINESS PROGRAM, SHALLOW OIL ZONE, 1945 - 1952". BY ENGINEERING COMMITTEE 2/27/53)
PRINCIPAL EVENTS OF THE STATE OF READINESS PROGRAM
PRODUCTION CEILINGS
65,000 B/D
15,000 B/D
7950 B/D
(EXCLUDES EXPLORATORY PRODUCTION AND SEC 14 B CEILING OF 500 B/D)
Sec 14B ceiling lifted
GENERAL
Contracts NOd 4219 and 4220 Signed
Sec Navy Dispatch - VJ Day
Sec Navy Dispatch
PRIMARY PERIOD
(COMMENCED NOV 20 1942)
Navy Board Review
Amendatory and Supplemental Agreement NOd 8477 Signed
EXTENSION OF PRIMARY PERIOD
Operating Committee Questions
Questions by Navy Member Operating Committee
EXPLORATORY & READINESS DEVELOPMENT PROGRAMS
WORLD WAR II DEVELOPMENT
SHALLOW ZONE EXPLORATORY
SOUTH FLANK EXPLORATION
SHALLOW ZONE READINESS DEVELOPMENT
STATE OF READINESS PROGRAM
GAS INJECTION PROGRAM
CRESTAL AREA
FLANKS
First Crestal Area gas injection
PERIOD DURING WHICH GAS WAS INJECTED IN VARIOUS CRESTAL WELLS
88-28S
77-2G
WATER ENCROACHMENT
MAJOR PROJECT
MINOR PROJECT
DOWN STRUCTURE WELLS SHUT IN
DOWN STRUCTURE WELLS AT PRE-TEST PRODUCING RATES
PROJECT ABANDONED; WELLS AT CAPACITY
DOWN STRUCTURE WELLS SHUT IN
Wells returned to production
PROJECT ABANDONED
DEWATERING AND GRAVITATIONAL DRAINAGE PROJECT
Name changed to "Protective Dewatering Project"
ROTATING PRODUCTION TESTS
WELLS TESTED 10 DAYS PER YEAR
WELLS TESTED; GROUP I - 5 DAYS EVERY TWO YEARS
GROUP II - 8 DAYS EVERY YEAR
PROTECTIVE PRODUCTION OF WET WELLS
REPAIR AND REMEDIAL WORK
1 CREW
2 CREWS
1 CREW
1 CREW
Figure No 2
UO-NPR#1
Engineering Committee
Dec, 1952
FIG. 5-10
1944
1945
1946
1947
1948
1949
1950
1951
1952
1953

as deemed necessary by the Unit and concurred in by the Committee.

The Stevens Zone was never included in the State of Readiness Program described above for the Shallow Zone. There was no need; for the Stevens was still essentially a virgin reservoir, virtually unaffected by the small production from its few wells drilled prior to unitization and not subjected to any of the ills besetting the Shallow Oil Zone. The post-war program for the Stevens Zone consisted mainly of an exploratory program followed by a development program, the initial production testing of each new well for 30 days after completion and the maintenance of its wells for full production in an emergency.

Running concurrently with the State of Readiness Program for the Shallow Zone were the Exploratory and Readiness Development Programs, affecting both the Shallow and Stevens Zones and, upon discovery, the deep Carneros Zone.

In summary, the main producing zones and the different programs applicable to each during this post-war period, 1945 through 1952, are tabulated below:

<u>Shallow Oil Zone</u> (A Unit Operation)

1. State of Readiness Program -- Sept. 1945 to 1953.
   a. Gas injection
   b. Water Encroachment
   c. Etc. See Figure 5-10.
2. Exploratory Development Program -- 5 July 1945 to October 1947. (Mostly South Flank)

as deemed necessary by the Unit and concurred in by the Committee.

The Stevens Zone was never included in the State of Readiness Program described above for the Shallow Zone. There was no need; for the Stevens was still essentially a virgin reservoir, virtually unaffected by the small production from its few wells drilled prior to unitization and not subjected to any of the ills besetting the Shallow Oil Zone. The post-war program for the Stevens Zone consisted mainly of an exploratory program followed by a development program, the initial production testing of each new well for 30 days after completion and the maintenance of its wells for full production in an emergency.

Running concurrently with the State of Readiness Program for the Shallow Zone were the Exploratory and Readiness Development Programs, affecting both the Shallow and Stevens Zones and, upon discovery, the deep Carneros Zone.

In summary, the main producing zones and the different programs applicable to each during this post-war period, 1945 through 1952, are tabulated below:

<u>Shallow Oil Zone</u> (A Unit Operation)

1. State of Readiness Program -- Sept. 1945 to 1953.
   a. Gas Injection
   b. Water Encroachment
   c. Etc. See Figure 5-10.
2. Exploratory Development Program -- 5 July 1945 to October 1947. (Mostly South Flank)

3. Readiness Development Program -- 1951 to 1954.

4. Equipment Maintenance Program.

<u>Stevens Zone</u> (A Unit Operation)

1. Rotating Production Tests

2. Exploratory Program (Unit) -- 1946 to 1947.

3. Readiness Development Program (Navy) -- 1948 to April 1954.

4. Equipment Maintenance Program

<u>Carneros Zone</u> (Navy Only)

1. Deep Test Exploratory Drilling. Two (2) wells completed in Carneros by 1954.

2. Equipment Maintenance Program

<u>Section 14-B -- Buena Vista Front</u> (A Unit Operation)

1. Offset-Drilling Development Program

2. Protective Production Program

3. Equipment Maintenance Program

The individual projects or studies under the State of Readiness Program for the Shallow Oil Zone from 1945 to 1953 are discussed separately on the following pages.

3. Readiness Development Program -- 1951 to 1954.

4. Equipment Maintenance Program.

<u>Stevens Zone</u> (A Unit Operation)

1. Retaining Production Tests

2. Exploratory Program (Unit) -- 1946 to 1947.

3. Readiness Development Program (Navy) -- 1949 to April 1954.

4. Equipment Maintenance Program

<u>Carneros Zone</u> (Navy Only)

1. Deep Test Exploratory Drilling. Two (2) wells completed in Carneros by 1954.

2. Equipment Maintenance Program

<u>Section 14-S -- Stevens Shale Crest</u> (A Unit Operation)

1. Offset-Drilling Development Program

2. Protective Production Program

3. Equipment Maintenance Program

The individual projects or studies under the State of Readiness Program for the Shallow Oil Zone from 1946 to 1953 are discussed separately on the following pages.

Gas Injection Project

Description:

This project consisted of the reinjection of produced gas from the Shallow Oil Zone and/or the Mya Dry Gas Zone into primary crestal and secondary gas caps of particular members of different productive sands comprising the Shallow Oil Zone.

During the emergency period of World War II, practically all of the gas injected was into the SS-1 sand; after the war, into the SS-2 and M sands.

Figure 5-11 shows the area of the primary gas cap and the various injection wells.[113]

Objectives:

Primary Objective

1. To restore and maintain the pressure within certain areas and sands (mainly the SS-2 and M sands) to at least the pressures existing prior to the heavy World War II emergency withdrawals in order to

   a. Increase the oil productive capacity of this Zone in event of another emergency.

   b. Increase the ultimate oil recovery.

   c. Stop water encroachment on the north flank and east nose of the SS-2 and M sands.

   d. Stop edgewater encroachment in the SS-2 and M sands of the south flank in Sections 1-B, 4-G, 5-G, 6-G.

The prewar crestal gas-cap pressures were about 800 to 850 psi.

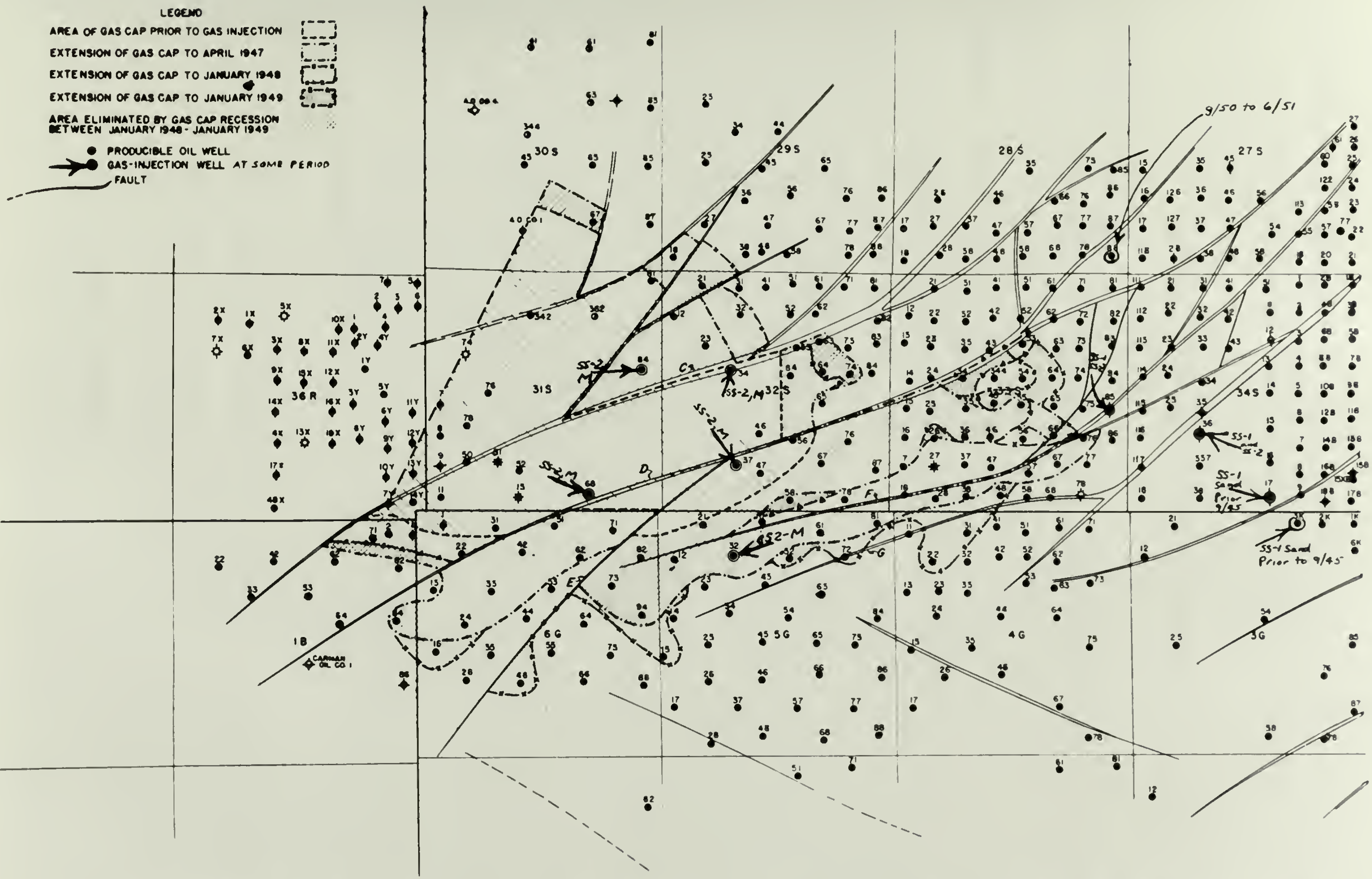


Figure 5-11. Map showing effect of gas injection on areal extent of gas cap, Shallow zone, Elk Hills field, Kern County, Calif. As of January 1949. (Reprinted from BuMines R.I. 4886 ; Modified May 1954 by W.M.A)

Secondary Objectives

1. To conserve the gas produced under the State of Readiness Program.

2. To reduce future production costs.

Pertinent Dates:

1. January to October, 1945: initial period of gas injection to decrease the reservoir pressure decline and to conserve excess casinghead gas.

2. October 1945 to June 1952: period of intensified gas injection into the crestal SS-2, M gas caps under the State of Readiness Program; however, this pressure-restoration program was not effectively commenced until 28 January 1946.

3. September 1950 to June 1951: period of gas injection in Well 88-28S into a secondary gas cap within a fault block on the North flank. The injection well is indicated on Figure 5-11; the secondary gas cap is not shown.

4. October 1950 to February 1952: period of gas injection in well 77-2G into a secondary gas cap of the SS-2 sand near the Southeast end of the south flank.

5. June 1952: All gas injection terminated by the Engineering Committee.[138]

Action Taken:

The three major divisions of the gas injection program in Elk Hills were the crestal gas cap injection and the two flank or secondary gas cap injections. These are discussed below.

Crestal Gas-Cap Injection

1. Over 1,700 M c.f. of produced gas, mostly excess

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Pertinent Dates:

1. January to October, 1945: initial period of gas injection to decrease the reservoir pressure decline and to conserve excess casinghead gas.

2. October 1945 to June 1952: period of intensified gas injection into the crestal SS-2, N gas caps under the State of Readiness Program; however, this pressure-restoration program was not effectively commenced until 23 January 1946.

3. September 1950 to June 1951: period of gas injection in Well 35-28S into a secondary gas cap within a fault block on the North flank. The injection well is indicated on Figure 5-11; the secondary gas cap is not shown.

4. October 1950 to February 1952: period of gas injection in well 77-2G into a secondary gas cap of the SG-2 sand near the Southeast end of the south flank.

5. June 1952: All gas injection terminated by the Engineering Committee.[139]

Action Taken:

The three major divisions of the gas injection program in Elk Hills were the crestal gas cap injection and the two flank or secondary gas cap injections. These are discussed below.

Crestal Gas-Cap Injection

1. Over 1,700 M c.f. of produced gas, mostly excess

casinghead gas produced with the oil from the Shallow Oil Zone, was injected from March to September 1945 into nine crestal gas-cap wells to conserve gas and reduce the rate of reservoir pressure decline. Injection wells during this initial period were:[112]

SS-1 Sand	76-2G 3K-3G 17-34S 15XB-34S
SS-1 and SS-2 Sands	85-33S 36-34S
SS-2-M Sand	68-31S 37-32S

2. In January 1946 under the State of Readiness Program an intensified crestal gas injection project was commenced. At rates varying from less than 1,000 M c.f. to over 10,000 M c.f. of gas a day, as shown on Figure 5-12,[113] gas was injected into the crestal gas-cap area of the SS-2,M Sand until June 1952, when all gas injection was abandoned. Injected gas was composed mostly of dry gas from the Mya sands supplemented by some gas produced with the oil from the Shallow Oil Zone. Injection wells used at various times were:

SS-1 Sand	15XB-34S (discontinued after a few months)
SS-2 M Sands	68-31S 34-32S 37-32S 32-5G 84-31S

Total gas injected into the Shallow Oil Zone from January 1945 to August 1951 was about 14,578.5 MMCF.[112] Most of the gas was injected directly into the SS-2 and M sands, casinghead gas produced with the oil from the Shallow Oil Zone, was injected from March to September 1945 into nine crestal gas-cap wells to conserve gas and reduce the rate of reservoir pressure decline. Injection wells during this initial period were:[112]

SS-1 Sand	76-20
	56-30
	17-34S
	15X3-34S
SS-1 and SS-2 Sands	88-33S
	36-34S
SS-2-M Sand	58-31S
	57-32S

2. In January 1946 under the State of Readiness Program an intensified crestal gas injection project was commenced. At rates varying from less than 1,000 M c.f. to over 10,000 M c.f. of gas a day, as shown on Figure 5-12,[113] gas was injected into the crestal gas-cap area of the SS-2,M Sand until June 1952, when all gas injection was abandoned. Injected gas was composed mostly of dry gas from the Wye sands supplemented by some gas produced with the oil from the Shallow Oil Zone. Injection wells used at various times were:

SS-1 Sand	15X3-34S (discontinued after a few months)
SS-2 M Sands	66-31S
	54-32S
	37-33S
	53-30
	64-31S

Total gas injected into the Shallow Oil Zone from January 1945 to August 1951 was about 14,879.5 MMCF.[112] Most of the gas was injected directly into the SS-2 and M zones, but migration of the gas definitely occurred between sands.

Gas Injection on the North Flank

For nine months, commencing in September 1950, gas was injected near the top of the fault block surrounding Well 88-28S, one of the wells used for injection, in an attempt to increase the pressure in the gas and oil bands to an amount equal to the pressure of the encroaching edgewater. The area and Well 88 are shown on Figure 5-11.

Gas Injection on the South Flank

For seventeen months, commencing in October 1950, gas was injected into a fault-isolated body of the SS-2 sand through Well 77-2G on the Southeast flank of the field. The purpose was to raise the pressure in the gas and oil belts and retard the rapid and damaging movement of water upstructure.[138]

The effects of these programs are discussed below under Results.

Alternate Actions Proposed:

1. Increased Gas Injection

During the period of gas injection the question often arose as to whether the rate and volume of gas injected should be greatly increased if the program were to be successful at all in retarding edgewater advancement and raising field's productive capacity. In August 1951, in answer to a request from the DNPR, Navy's member of the Operating Committee issued a report discussing the feasibility of increased gas injection to level off pressure gradients and permit reduction of large peacetime production from wet wells. Theoretically, increased

gas injection should raise the reservoir pressure to equal the edgewater pressure, and productive capacity of the field should be increased.

Basing his predictions on the results of the gas injection project up to August 1951, NMOC reached the following conclusions:[108]

a. Large scale gas injection was not desirable. The volume of gas required was excessive and would only tend to leak off more rapidly to lower pressure sands. Instead of reducing oil production during peacetime, increased gas injected would necessitate increased production of more observation wells in order to watch the progress of an intensified gas injection program.

   Also, severe fingering of gas already was damaging the productivity of many wells. Adverse pressure gradients would be increased.

b. Except for certain areas, it would be difficult to raise reservoir pressure sufficiently to match edgewater pressure, the reason being that few areas were competently separated from other lower pressure areas or sands by faults or other barriers. The exception was the gascap in the SS-2, M sands where productive capacity might be increased at a loss of ultimate recovery due to the aggravation of the pressure gradient promoting oil migration along the south flank downstructure into the grey sands.

c. Loss of production from wells added to or near to the gas cap due to excessive gas/oil ratios would occur.

d. It would not be possible to repressure to the extent desired due to connection of sands through well bores and faults, insufficient retaining force on the south flank, and possible disastrous effects of high pressure on old wells with weak, lap-welded casing.

NMOC then recommended continuation of the limited gas injection project increasing reservoir pressure without conflicting with good engineering practices. He also suggested the drilling of additional edgewater wells on the north flank to increase the withdrawal rate of encroaching water, possibly concurrently with limited gas injection in adaptable areas to help balance the pressure gradient.

2. Increased Gas Injection Combined with South Flank Water-Injection

Another alternate action was to combine an increased gas injection program into the SS-2,M sands with a drilling program along the edgewater of the north flank to provide a greater production of water and a drilling program along the edgewater of the south flank to provide injection wells for injecting the high-pressure water produced on the north flank. At the same time it was proposed to carry out an extensive well-corrective program to segregate the different sands of the Shallow Zone.

Theoretically, the above idea is sound; for reservoir

c. Loss of production from wells added to or close to the gas cap due to excessive gas/oil ratios would occur.

d. It would not be possible to repressure to the extent desired due to connection of sands through well bores and faults, insufficient retaining force on the south flank, and possible disastrous effects of high pressure on old wells with weak, lap-welded casing.

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2. Increased Gas Injection Combined with South Flank Water-Injection

Another alternate action was to combine an increased gas injection program into the 22-2,W sands with a drilling program along the edgewater of the north flank to provide a greater production of water and a drilling program along the edgewater of the south flank to provide injection wells for injecting the high-pressure water produced on the north flank. At the same time it was proposed to carry out an extensive well-corrective program to segregate the different sands of the Shallow Zone.

Theoretically, the above idea is sound; for reservoir potential energy in the form of high pressure gas and water could be retained, reservoir pressure would be increased, field's productive capacity and ultimate recovery should increase, and undesirable pressure gradients should be eliminated. Moreover, effective use of gas cap expansion and natural water-drive would be possible to raise the ultimate recovery of oil.

However, actual conditions in the reservoir and practical and economic reasons to date have prevented the application of this solution to the ills of the Shallow Oil Zone. It would be very expensive and the outcome doubtful. However, certain phases of this program are currently being accomplished, and a later engineering study may prove the entire program outlined above economically feasible.

<u>Results of the Actual Program</u>

1. <u>Beneficial</u>
   a. In the westernmost area of the SS-2,M Sand, pressure losses which occurred during heavy wartime withdrawals were restored mainly by gas injection into well 84-31S and pressure differential between north and south flanks practically equalized, thus necessitating a minimum amount of oil production from wet-wells.
   b. An over-all gain in current availability of the field had occurred, judging by the effect of the gas injection on productivity of all wells affected

potential energy in the form of high pressure gas and water could be retained, reservoir pressure would be increased, field's productive capacity and ultimate recovery should increase, and undesirable pressure gradients should be eliminated. Moreover, effective use of gas cap expansion and natural water-drive would be possible to raise the ultimate recovery of oil.

However, actual conditions in the reservoir and practical and economic reasons to date have prevented the application of this solution to the ills of the Shallow Oil Zone. It would be very expensive and the outcome doubtful. However, certain phases of this program are currently being accomplished, and a later engineering study may prove the entire program outlined above economically feasible.

<u>Results of the Actual Program</u>

1. <u>Beneficial</u>

a. In the westernmost area of the 35-2,3 Sand, pressure losses which occurred during heavy wartime withdrawals were restored mainly by gas injection into well 84-31S and pressure differential between north and south flanks practically equalized, thus necessitating a minimum amount of oil production from wet-wells.

b. An over-all gain in current availability of the field had occurred, judging by the effect of the gas injection on productivity of all wells affected by the gas injection.

c. Raised the over-all reservoir pressure in the SS-2,M sands, as shown on Figure 5-12.

2. Detrimental or Unsuccessful Results

a. Uneven gas cap expansion with extensive gas fingering through the more permeable members had occurred, with gas capturing too many clean wells.

b. In all cases except one (Well 84-31S injection), gas injection had failed to stop the encroachment of high pressure edgewater on the north and east flanks, mainly because not enough gas was injected to raise the gas-oil pressure to match the hydrostatic pressure behind the edgewater.

c. Aggravated the pressure-gradients tending to promote migration and possible loss of oil into the low-pressure, receding edgewater sands on the south flank, thus reducing ultimate recovery of oil.

d. Great leakage of injected gas (approximately 3500 M.c.f. per day) occurs from the areas and sands (SS-2 and M) into which the gas is injected. This leakage occurs through incompetent faults and wellbores to lower pressure areas and sands (such as to the SS-1 Sand to the east) where additional gas and increased pressure are not necessarily desired, increasing the gas/oil ratio of many wells and lowering their productive capacity. This leakage is by the gas injection;

f. Raised the over-all reservoir pressure in the 25-C,B sands, as shown on Figure 5-12.

2. Detrimental or Unsuccessful Results

a. Uneven gas cap expansion with extensive gas fingering through the more permeable members had occurred, with gas capturing too many clean wells.

b. In all cases except one (Well 64-218 injection), gas injection had failed to stop the encroachment of high pressure edgewater on the north and east flanks, mainly because not enough gas was injected to raise the gas-oil pressure to match the hydrostatic pressure behind the edgewater.

c. Aggravated the pressure-gradients tending to promote migration and possible loss of oil into the low-pressure, receding edgewater sands on the south flank, thus reducing ultimate recovery of oil.

d. Great leakage of injected gas (approximately 2000 M.c.f. per day) occurs from the areas and sands (25-B and D) into which the gas is injected. This leakage occurs through incompetent faults and well-bores to lower pressure areas and sands (such as to the 25-L Sand to the east) where additional gas and increased pressure are not necessarily desired, increasing the gas/oil ratio of many wells and lowering their productive capacity. This leakage is ...

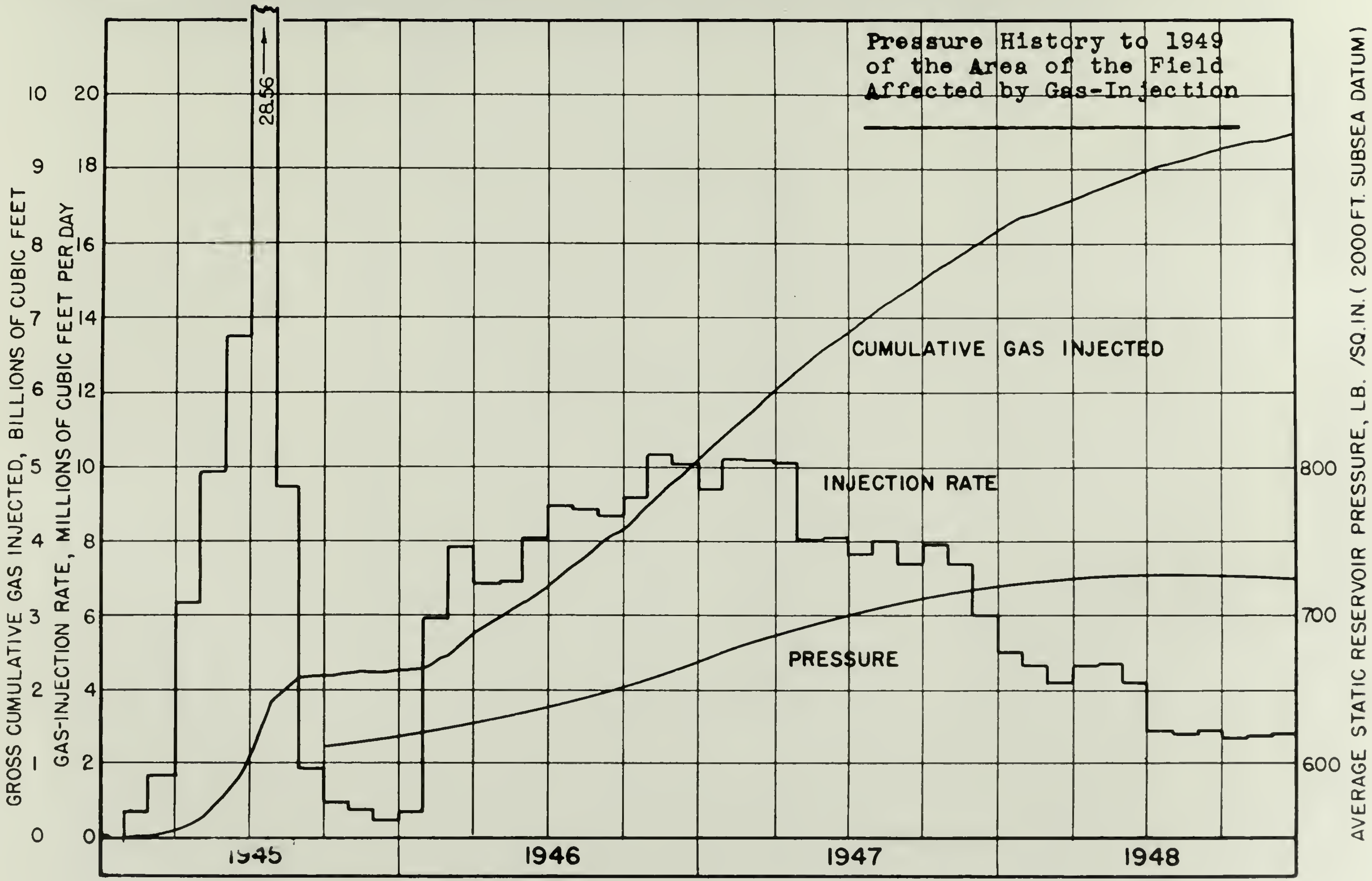

Figure 5-12. Curves showing effect of gas injection on reservoir static pressure, Shallow zone, Elk Hills field, Kern County, Calif. (Reprinted from BuMines Report of Investigations 4886).

indicated on Figure 5-12 by the drop in reservoir pressure about June 1948 when the injection rate dropped below 3500 M.c.f. per day.

3. Cumulative Effects and Resultant Action

With the cumulative effects of the gas injection program tending to promote losses in maximum economic ultimate recovery and future availability of oil from the Shallow Oil Zone, the gas injection project was terminated in June 1952.

SELECTED REFERENCES IN THE BIBLIOGRAPHY:

108, 109, 110, 112, 113, 122, 125, 135, 138.

MAJOR WATER ENCROACHMENT STUDY

Description:

This study formed a part of the State of Readiness Program for the Shallow Oil Zone following World War II. The study involved virtually shutting-in for a long period of 12 to 18 months most of the wells in an area relatively isolated and delineated by parallel and intersecting faults from the rest of the field. The area selected, shown on Figure 5-13,[113] was one subjected to a high pressure edgewater encroaching up-structure from the North. During the shut-in period the only production consisted of reduced production from several up-structure observation wells to obtain necessary reservoir information.

Sands primarily affected by the study were the SS-1 and SS-2. However, a few new wells in the fault-block are completed in the M and SM sands.

Pertinent information on the fault-block is listed between Figures 5-13 and 5-14.

Objectives:

1. To determine if an active water drive existed in the area selected.

2. To determine the effects of natural up-structure edgewater encroachment, accompanied with minimum production and resultant pressure build-up, on the productive capacity and ultimate recovery of oil from the Shallow Oil Zone, *i.e.*, to study the oil-producing efficiency of an active water drive.

MAJOR WATER-ENCROACHMENT STUDY

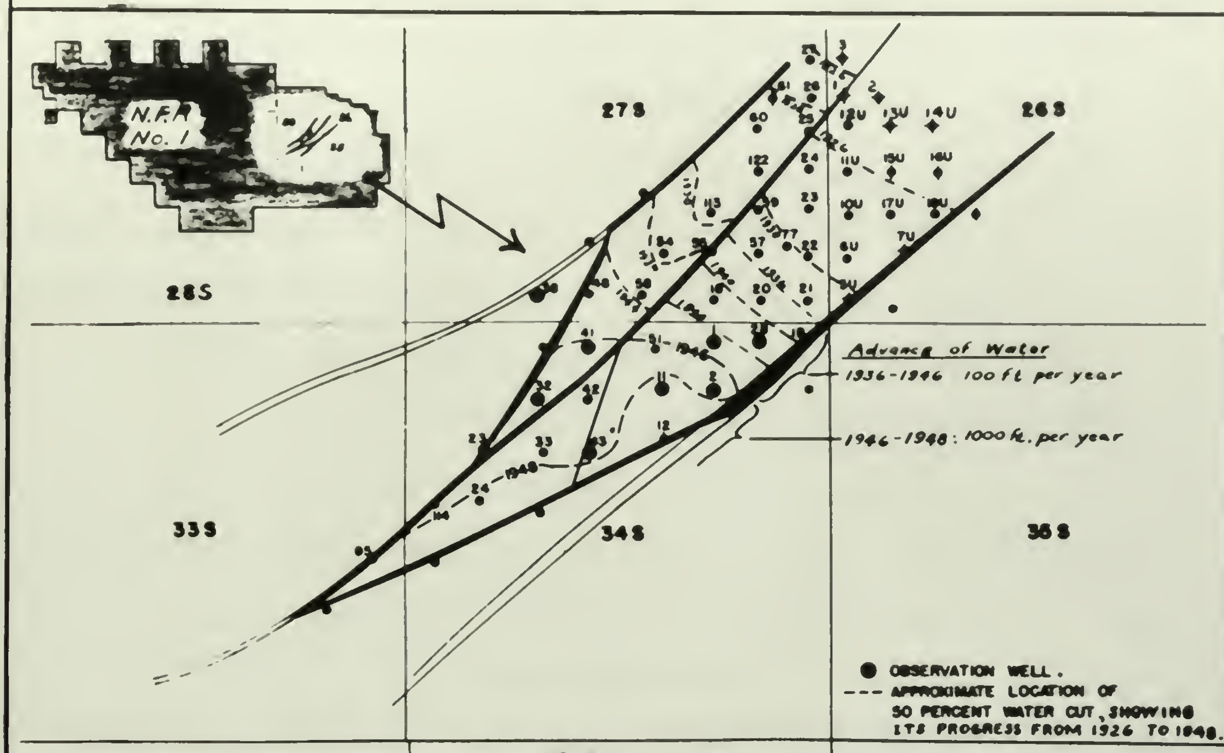

FIG. 5-13

PERTINENT INFORMATION CONCERNING FAULT-BLOCK AREA ABOVE CHOSEN FOR THIS STUDY

Sands Affected
- Primarily:
  - SS-1; SS-2
- Partially:
  - M; SM

Prod. Sand Vol.:
29,000 Acre-Ft.

Orig. Stock Tank Oil in Place:
48.6 Ml. Bbls.

Orig. Press.:
1125 psia at 2000 ft Sub Sea

Ave. Porosity:
34.6 %

Ave. Permeability:
1 to 4 Darcys

Original Water Saturation:
30 %

Structural Closure:
1100 ft

Est. Rate of Water Influx:
1.8 Ml Bbls per Yr

By 1945, prior to study, 2/3 of fault-block had been flooded to 50 % water cut.

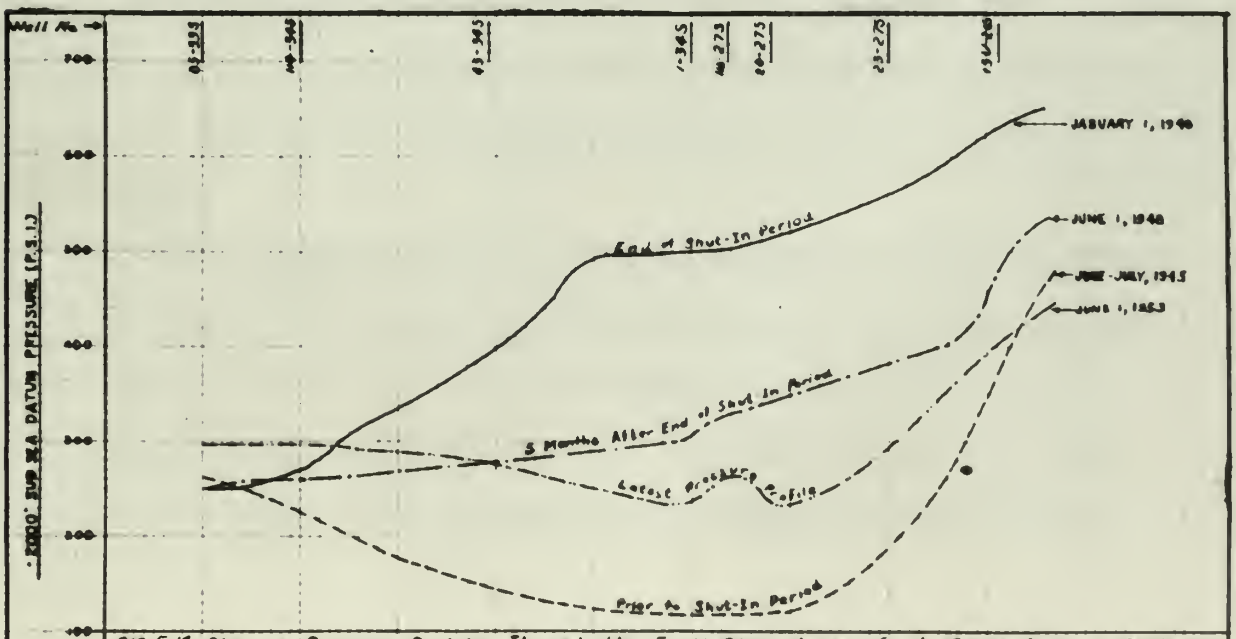

FIG. 5-14, Showing Pressure Profiles Through the Fault-Block Area of the Figure Above at Different Times Before and After and During the Shut In Period of the Study.

3. To compare the results of the above study with the probable results that might be obtained if the encroachment of water had been retarded by all means available, i.e., the relative advantages of different production methods.

Pertinent Dates:

14 December 1945.--Area of active water drive selected. Study commenced. Production greatly reduced.

October 1946.------Shut-in period ended. Twenty-seven wet wells in fault block put on full production.

January 1947-------Exploratory Well No. 77-27S completed in this fault-block area. This well provided additional information on the effects of water encroachment.

March 1949---------Production rate increased in an attempt to dewater this area more rapidly.

December 1949------Production rate again increased. High rate of wet well production continues from this area.

Action Taken:

In brief, the procedure consisted in completely shutting in most of the wells in the fault block for a long period, obtaining information on water encroachment and pressure build-up from observation wells during the shut-in period, and then opening the block to full production to determine the effects

of the shut-in period on the productive capacity of each well and ultimate recovery of oil from the fault block.

There were 32 active oil wells in the area. The 24 down-structure wells, with an average water/oil ratio of 5.2, were shut-in; about 8 up-structure wells were operated as observation wells, initially at their former production rates and later at about one-half their former rate. In December 1947, the shut-in period ended and the wells began to be returned to production.

Production from most of the wells in this area has been continued to date as part of the Protective Production of Wet-well Program and in an attempt to dewater the area. When up-structure wells return to clean oil production for three consecutive months, they are then shut-in.

Exploratory Well No. 77-27S was drilled in this area to evaluate the efficiency of the active edgewater in flushing oil ahead of it, *i.e.*, to determine the state of depletion of the different oil sands. Since its completion in January 1947, ten separate sand fingers in the SS-1, SS-2, and M zones have been selectively gun-perforated and tested. The well was finally completed in two clean oil productive sand intervals of the SS-2.

Shut-in periods, oil and water production rates, and other pertinent items are well illustrated on the graph of Figure 5-15.

Alternate Actions Proposed:

1. Remain Shut-in. Completely shut-in the fault block; allow

of the shut-in period on the production capacity of each well and ultimate recovery of oil from the fault block.

There were 30 active oil wells in the area. The 26 down-structure wells, with an average water/oil ratio of 5.5, were shut-in; about 4 up-structure wells were operated as observation wells, initially at their former production rates and later at about one-half their former rate. In December 1947, the shut-in period ended and the wells began to be returned to production.

Production from most of the wells in this area has been continued to date as part of the Protective Production of Wet-well Program and in an attempt to dewater the area. When up-structure wells return to clean oil production for three consecutive months, they are then shut-in.

Exploratory Well No. 7T-ST3 was drilled in this area to evaluate the efficiency of the active edgewater in flushing oil ahead of it, i.e., to determine the state of depletion of the different oil sands. Since its completion in January 1947, ten separate sand fingers in the S3-1, S3-2, and H zones have been selectively gun-perforated and tested. The well was finally completed in two clean oil productive sand intervals of the S3-2.

Shut-in periods, oil and water production rates, and other pertinent items are well illustrated on the graph of Figure 5-15.

Alternate Actions Proposed:

1. Remain Shut-in. Completely shut-in the fault block; allow

MAJOR WATER ENCROACHMENT STUDY

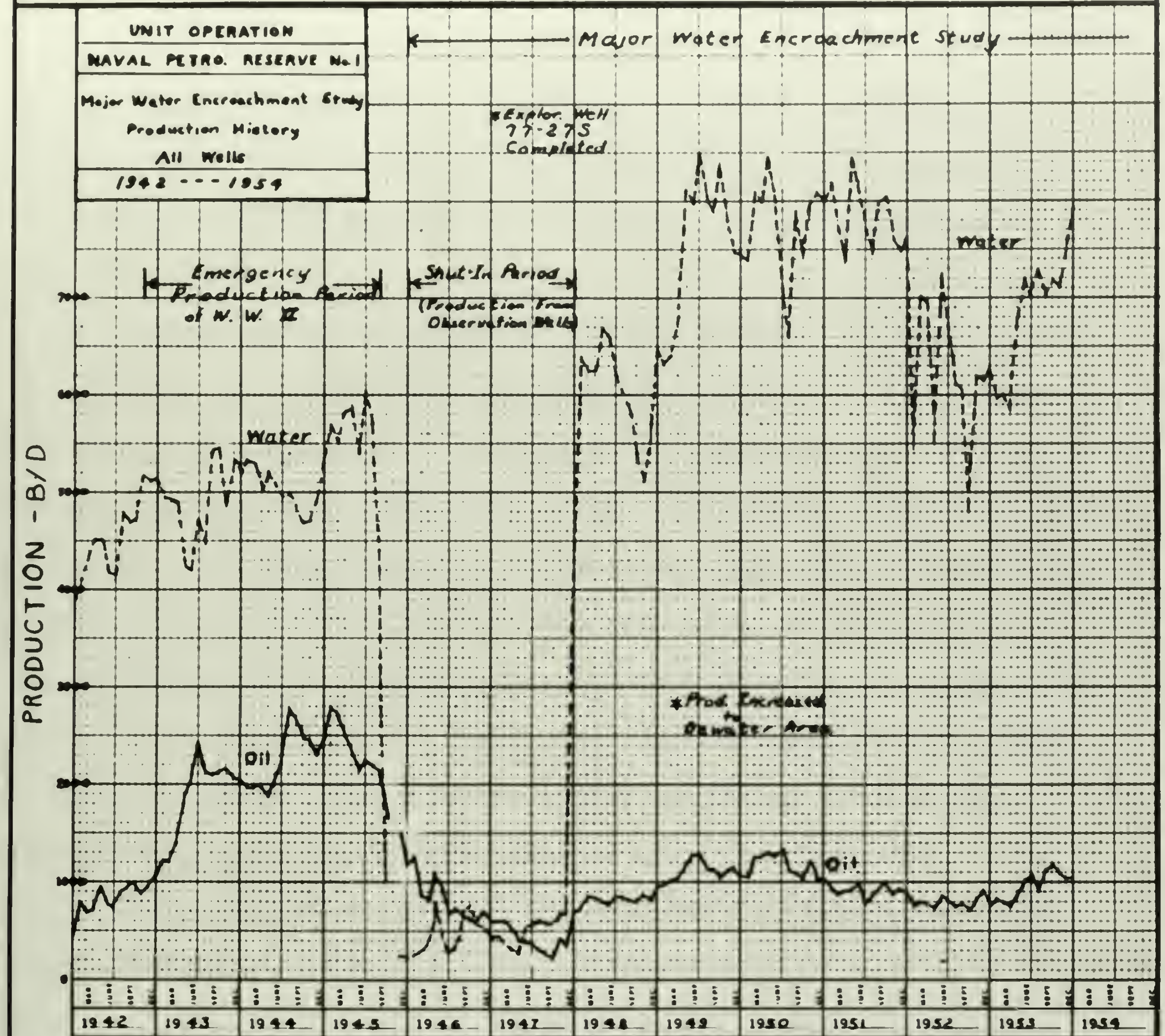

FIG. 5-15

A COMPARISON OF THE PRODUCTION CHARACTERISTICS OF THE GROUP OF WET WELLS SHUT-IN FOR THE STUDY AT DIFFERENT PERIODS

		During Emerg. Prod. Period (June 1945)	Four Months After Return to Prod. (April 1948)	After Four Yrs. on Wet-Well Prod. Program (1952)
No. of Wells	:	26	26	28
Oil, Bbls/Day	:	1000	375	763
Water, Bbls/Day	:	5500	5300	6236
Water/Oil Ratio	:	5.5	14.1	8.2
Oil Prod., % of 1945 Prod.	:	100	37.5	76.3
Oil Prod., % of 1948 Prod.	:	267	100	203

TABLE 5-1

the pressure to continue building up as water encroaches; accept some ultimate loss of oil bypassed by water in return for an initially high rate of production when an emergency demands it.[115]

The only fallacy in this method of recovery is that the expected high rate of production failed to materialize. Theoretically, it should have increased for the area as a whole; but when the shut-in area was put on production again, the productive capacity had materially decreased.

2. <u>Produce Wet-Wells</u> (Revive old system). Operate continuously wet down-structure wells to decrease the up-structure edge-water encroachment -- the production method employed by operators in the Tupman Area before unitization and by the Unit during the emergency wartime production.[113, 138]

   This production method was revived in 1948 and continues to date.

3. <u>Gravity Drainage Production by Drilling More Water-Wells and Dewatering</u>. Re-open fault block to production; if necessary, drill additional down-structure wells in order to produce water at a rate sufficient to prevent up-structure water encroachment; employ gravity drainage for oil production; expect a much greater ultimate recovery of oil at a reduced rate over a longer period of time than in (1) or (2) above.[115, 138]

   This production method will probably supplement or succeed the present production method described in (2) above.[138]

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This production method will probably supplement or succeed the present production method described in (2) above.[138]

Results of the Project

1. Observation Wells. Production characteristics of the observation wells being continuously produced initially tended to improve.
2. Rate of Water Advancement. Closing the down-structure wells accelerated the edgewater advancement from a previous 100 to 125 feet per year to about 1,000 feet per year -- too rapid for effective flushing of oil from the sands. See Figure 13.
3. Type of Water Advancement. Edgewater advancement was very irregular, fingering rapidly through the more permeable members. Water encroachment occurred primarily through the SS-1 sand with only minor fingering in the SS-2 and SM sands.
4. Water Cut. By the end of the shut-in period production from all observation wells was at least 60 per cent water -- some as high as 85 per cent water. Refer to the advance of the 50 per cent water-cut on Figure 5-13.
5. Pressures. In general, the bottom-hole static pressures in the down-structure and mid-structure wells increased considerably. However, in spite of the rapid up-dip encroachment of water, the pressures in the producing observation wells up-structure decreased until the normal production rate was halved. The average pressure increase was about 200 psi. The change in pressure with time and well position is well illustrated by the pressure profile curves of Figure 5-14.
6. Production Rate. In general, as the edgewater front

approached a well, there was a sudden rise in pressure and production; but as the front passed, more water was produced and oil production declined -- as to be expected.

7. State of Depletion of Reservoir Sands. Results of extensive production testing and core analysis of ten separate sand fingers in the new Well No. 77-27S indicated that large quantities of otherwise producible oil had been left behind by the encroached edgewater; that the more permeable sands (SS-1) were only water productive; tighter sands were oil productive.[145]

8. Productivity of Area at End of Study. After the wells were placed on sustained production again in 1948, the productive capacity of all wells in the area was only about 46 per cent of the 1945 rate prior to the shut-in period. The production characteristics of the wet wells shut-in for the study are compared as a group for the period before and after the study in Table 5-1 below Figure 5-15. A big drop occurred in oil productivity of the group.

9. Results after Return to Wet-Well Production Program. By January 1953 the productive capacity of the original 26 shut-in wells in this area had been restored to about 66 per cent of the 1945 rate and about 177 per cent of the 1948 rate.[125]

Conclusions and Corrective Action

1. Water Drive. Active edgewater drive definitely exists in this particular fault block. However, other studies have shown that in several areas of the Shallow Zone no active

approached a well, there was a sudden rise in pressure and production; but as the front passed, more water was produced and oil production declined -- as is to be expected.

7. State of Depletion of Reservoir Sands. Results of extensive production testing and core analysis of ten separate sand fingers in the new Well No. 77-275 indicated that large quantities of otherwise producible oil had been left behind by the encroached edgewater; that the more permeable sands (55-1) were only water productive; tighter sands were oil productive.[145]

8. Productivity of Area at End of Study. After the wells were placed on sustained production again in 1948, the productive capacity of all wells in the area was only about 46 per cent of the 1945 rate prior to the shut-in period. The production characteristics of the wet wells shut-in for the study are compared as a group for the period before and after the study in Table 5-1 below Figure 5-15. A big drop occurred in oil productivity of the group.

9. Results after Return to Wet-Well Production Program. By January 1953 the productive capacity of the original 20 shut-in wells in this area had been restored to about 65 per cent of the 1945 rate and about 177 per cent of the 1948 rate.[125]

Conclusions and Corrective Action

1. Water Drive. Active edgewater drive definitely exists in this particular fault block. However, other studies have shown that in several areas of the Shallow Zone no active

water drive exists, and in other areas a receding edgewater exists.

2. Inefficient. In this area of Shallow Oil Zone, oil production efficiency by natural water drive appears impaired due to severe fingering of encroaching edgewater through the highly permeable members. The water tends to bypass and surround an excessive amount of residual oil. This method of production does not appear applicable to the Shallow Oil Zone.
3. Losses. As a result of the Major Water Encroachment Study which permitted a too-rapid rate of edgewater advance, appreciable quantities of otherwise producible oil in the affected area were apparently bypassed, and the overall productive capacity of the area was abnormally reduced.
4. Corrective Action. The wet wells were returned to the Wet-Well Protective Production Program and the area partially dewatered in order to reduce edgewater level and perhaps restore availability of wet wells -- the production program still being used with some success in restoring productive capacity.

Discussion:

Natural water drive existed in the SS-1 sand as early as 1923 with water invasion occurring on the North and East flanks. A study in May, 1947, by California Research Corporation estimated that the net rate of water entry into the fault block is about 1.8 million barrels per year, or about 5,000

barrels per day.[115]

Down-structure two-thirds of the fault block area is in the Old Area (Tupman). This area was damaged early in the field's life by rapid depletion of reservoir energy through excessively high production rates, by high gas/oil ratios, and by unbalancing due to multi-zone completions. Some fault block energy has apparently been maintained by naturally encroaching high pressure water on the North flank. If permeabilities and permeability variations in the Shallow Oil Zone sands were not such as to promote formation of water stringers, this natural water drive could be employed as a very efficient oil-producing mechanism.

As part of this program, as already mentioned in the review of the gas injection program, some gas was injected up-structure into the apex of the fault block in an attempt to prevent the rapid encroachment and severe fingering of the high pressure water up-structure by correcting the great pressure differential existing between the aquifer and the oil and gas zones. The gas injection program was unsuccessful because the faults proved incompetent near the apex and the gas bled off to areas and zones of lower pressure.

Some objection has been raised to the procedure employed in this study of keeping the 8 up-structure wells on continuous production.[112] It was felt that the rapid water fingering through the more permeable sand members was aggravated by this production; and, if these wells had not been produced,

less severe fingering and a more even encroachment and better flushing might have resulted. Desirable reservoir data could have been taken at periodic intervals by intermittent production from different wells.

Also, theoretically, some objection may be raised to the present rapid production of high pressure water, representing a definite loss in vital reservoir energy. Rapid production of high pressure gas and resultant depletion of reservoir energy for production of oil is no longer approved or generally practiced; likewise, water at high pressure is recognized more and more as being just as vital a source of oil-producing energy as gas. Nevertheless, the practical aspects and results of this study, as have been explained, indicated this field to be no textbook example; rather, it was the exception to the rule. The presence of wide variation in the permeabilities of the sand members and the great pressure differentials existing over short distances were the main reasons the water drive failed.

It is still possible that in other areas of the Shallow Oil Zone, effective use of the active water drive may be made in recovering more oil during the later life of the field, profiting by the information and knowledge obtained from the Major Water Encroachment Study of 1945-1948.

Reservoir energy may be preserved and reservoir pressure gradients from North to South removed by producing high pressure edgewater along the North flank and injecting it into the

receding or static aquifer on the South flank, combined with a gas injection program into any low pressure gas or oil zones. To date this has not been done due to very high costs necessitated and questionable results of such a program.[138]

SELECTED REFERENCES IN THE BIBLIOGRAPHY:

109, 112-115, 122, 125, 135, 138, 145.

MINOR WATER ENCROACHMENT STUDY

Description:

This study, similar to the Major Water Encroachment Study previously described, involved shutting-in four down-structure wells which were heavy water producers and producing thirteen upstructure wells as observation wells. The fault-block area on the northeast flank chosen for the study is shown in Figure 5-16. Only the Shallow Oil Zone was involved in the study. Sand primarily affected was the SS-1.

Objectives:

The primary objective was to determine the extent and effects of encroaching water in Section 25-S on the productivity characteristics of upstructure wells.

Pertinent Dates:

April 1945-----The study was commenced. The four down-structure wells shown in Figure 5-16 were shut-in.

December 1949--The study was abandoned.

May 1950-------The shut-in wells were returned to production under the Protective Production of Wet Well Program.

Results:

1. No apparent effect of high pressure edgewater in Section 25-S on upstructure observation wells was observed. This fact is best illustrated by the pressure profile curves of Figure 5-17.

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Objectives:

The primary objective was to determine the extent and effects of encroaching water in Section 26-S on the productivity characteristics of upstructure wells.

Pertinent Dates:

April 1948----The study was commenced. The four downstructure wells shown in Figure 5-16 were shut-in.

December 1949--The study was abandoned.

May 1950-------The shut-in wells were returned to production under the Protective Production of Wet Well Program.

Results:

1. No apparent effect of high pressure edgewater in Section 26-S on upstructure observation wells was observed. This fact is best illustrated by the pressure profile curves of Figure 5-17.

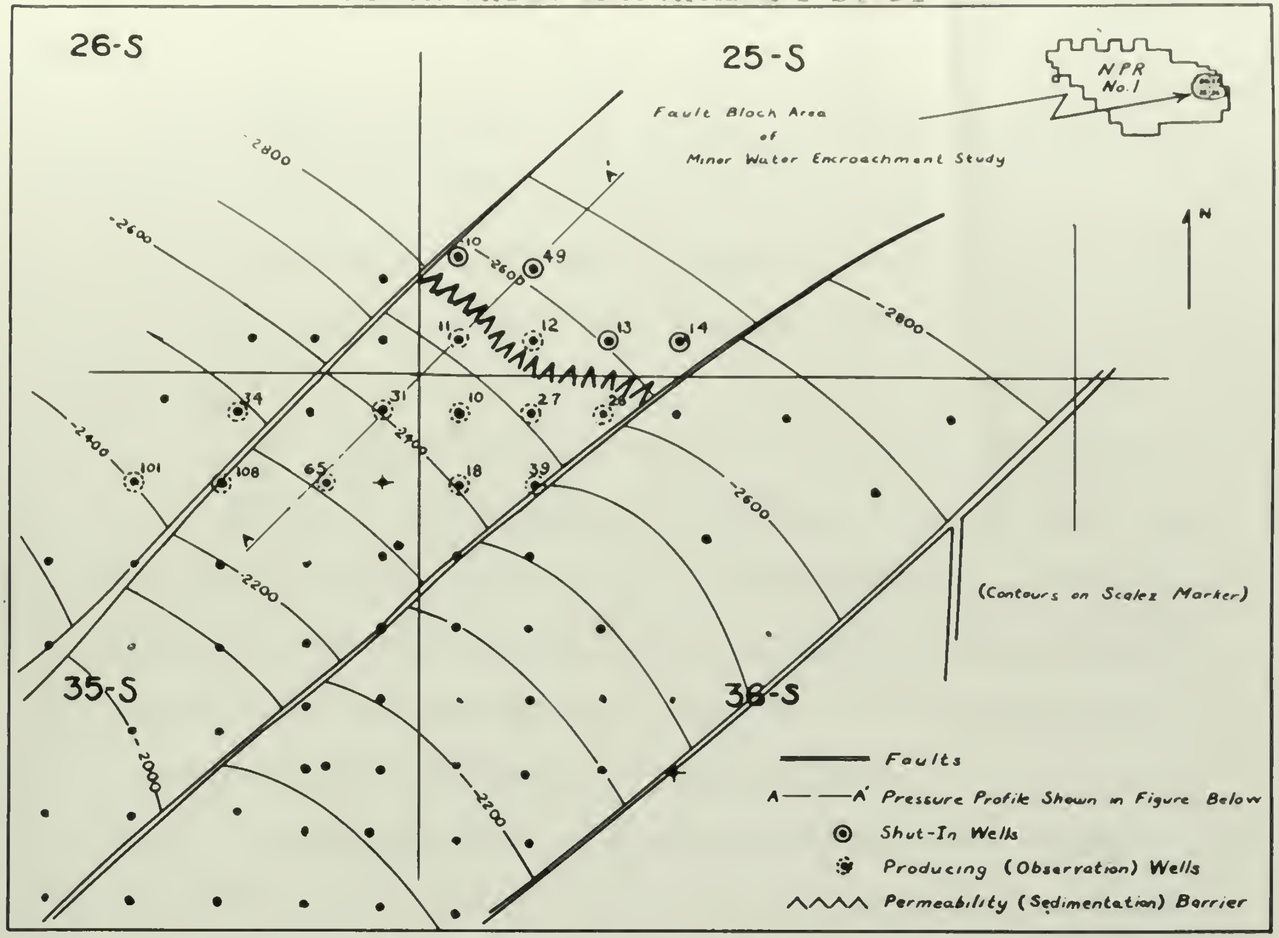


FIG. 5-16. Contour Map of Fault Block Area for Minor Water Encroachment Study Showing Apparent Location of Permeability (Sedimentation) Barrier.

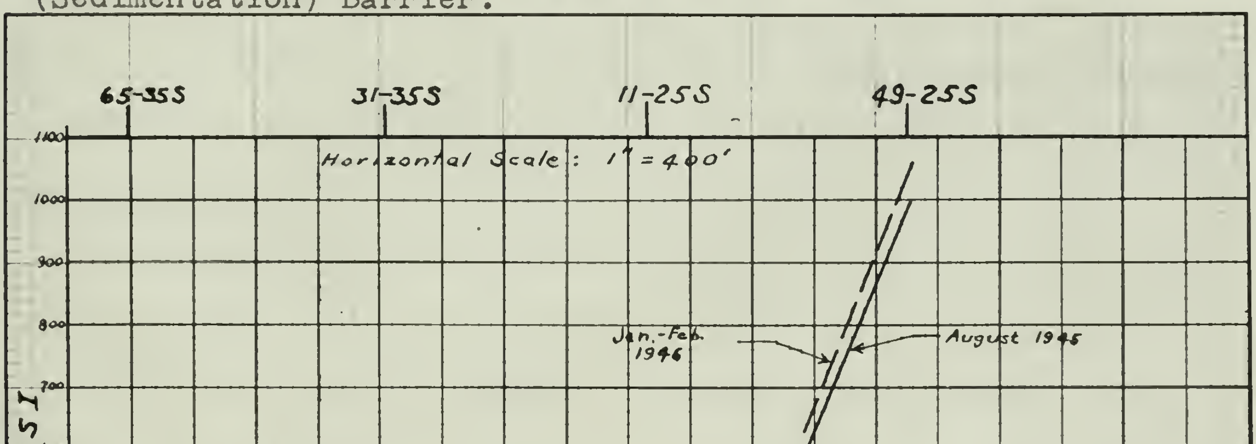


FIG. 5-17. Pressure Profiles Through Area Indicated In Fig. 5-16 and Supporting Existence of a Downstructure Barrier.

2. No apparent movement of edgewater upstructure was observed.

3. Pressures in the area increased only from 50 to 200 psi between January 1946 and January 1950.

Conclusions:

1. The failure of the edgewater to move upstructure, despite a pressure differential of 1000 psi between the shut-in wells and the observation wells, indicated the presence of a permeability barrier between the two groups. Pressure profiles like those of Figure 5-17 supported the theory of a permeability barrier indicated on Figure 5-16.

2. Again, as in the Major Water Encroachment Study, the conclusion was reached that a natural water drive along the North flank of the Shallow Oil Zone was not an effective production method but for diametrically opposite reasons to the Major Study. No active water drive could function through a localized area of very low permeabilities.

Discussion:

Since the pressure in this area is nearly depleted and natural water drive has not proved feasible, remaining methods of obtaining greater productive capacity and ultimate yield from this area are:

(1) Localized gas injection into the secondary gas cap of this fault-block.

(2) Water flood by injecting high pressure water from nearby downstructure wells into wells upstructure of the apparent permeability barrier.

2. No apparent movement of edgewater upstructure was observed.

3. Pressures in the area increased only from 80 to 200 psi between January 1946 and January 1950.

Conclusions:

1. The failure of the edgewater to move upstructure, despite a pressure differential of 1000 psi between the shut-in wells and the observation wells, indicated the presence of a permeability barrier between the two groups. Pressure profiles like those of Figure 5-17 supported the theory of a permeability barrier indicated on Figure 5-15.

2. Again, as in the Major Water Encroachment Study, the conclusion was reached that a natural water drive along the North flank of the Shallow Oil Zone was not an effective production method but for diametrically opposite reasons to the Major Study. No active water drive could function through a localized area of very low permeabilities.

Discussion:

Since the pressure in this area is nearly depleted and natural water drive has not proved feasible, remaining methods of obtaining greater productive capacity and ultimate yield from this area are:

(1) Localized gas injection into the secondary gas cap of this fault-block.

(2) Water flood by injecting high pressure water from nearby downstructure wells into wells upstructure of the apparent permeability barrier.

(3) Gravity drainage.

The success of localized gas injection would depend upon the fluid competency of the faults shown on Figure 5-16, which as shown on the map apparently form a closure for this area. Pressure gradients, however, indicate the eastern fault and the upstructure southern fault are not pressure barriers, and adverse pressure gradients might be developed toward the south flank, contributing to the migration of oil into wet sands.

Natural water drive having failed, an artificial water flood farther upstructure probably would not be attempted except as a secondary recovery method much later in the life of the field, provided economic considerations would warrant it.

Gravity drainage, therefore, remains as the most probable means of obtaining the most production economically from this area. Downstructure wells which are upstructure of the apparent permeability barrier would be produced. This production should reduce the pressures in the lower area and thus create a potential gradient inducing the drainage of oil downstructure into the producing wells.

SELECTED REFERENCES IN THE BIBLIOGRAPHY:

112, 122, 125, 138.

PROTECTIVE DEWATERING AND GRAVITATIONAL DRAINAGE STUDY

Description:

As part of the Gravitational Drainage Study, about 25 water wells and high water/oil ratio wells along the east flank of the Shallow Oil Zone in the area shown on Figure 15-18 were produced at maximum capacity; and the effect of this production on 7 upstructure observation wells was studied. The Program was later changed to the Protective Dewatering Project.

The SS-1 Sand was primarily affected. The program covered areas in Sections 1-G, 6M, 36S, and 31T.

Objectives:

Initially --

1. To create a drainage gradient along the east flank by dewatering and then to determine the possibility of obtaining maximum economic ultimate oil recovery by gravity drainage mechanism in the Shallow Oil Zone.

Finally --

1. To prevent damage to upstructure wells by encroaching edgewater.

Pertinent Dates:

1 November 1945--Study commenced.

May 1947---------Larger pumps installed.

April 1950-------Gravity drainage aspect of the study abandoned; shifted to a Protective Dewatering Project.

PROTECTIVE DEWATERING AND GRAVITATIONAL DRAINAGE STUDY

Description:

As part of the Gravitational Drainage Study, about 38 water wells and high water/oil ratio wells along the east flank of the Shallow Oil Zone in the area shown on Figure 15-18 were produced at maximum capacity; and the effect of this production on 7 upstructure observation wells was studied. The Program was later changed to the Protective Dewatering Project.

The [illegible] Sand was primarily affected. The program covered areas in Sections [illegible], 35S, and 31S.

Objectives:

Initially --

1. To create a drainage gradient along the east flank by dewatering and then to determine the possibility of obtaining maximum economic ultimate oil recovery by gravity drainage mechanism in the Shallow Oil Zone.

Finally --

1. To prevent damage to upstructure wells by encroaching edgewater.

Pertinent Dates:

1 November 1946--Study commenced.

May 1947---------Larger pumps installed.

April 1950-------Gravity drainage aspect of the study abandoned; shifted to a Protective Dewatering Project.

Action Taken:

From 25 to 29 water wells and high water/oil ratio wells shown in Figure 5-18 were produced at their maximum fluid capacity. Later larger pumps were installed and additional wells were added in efforts to increase the water withdrawal rate.

Three to four clean upstructure wells were produced to observe the results of the heavy downstructure production on their productivity characteristics.

Results:

1. The gravity drainage aspect of the program was unsuccessful. Even though larger pumps were installed and additional wells were produced, still the rate of fluid withdrawal from the wells in this area was never great enough to dewater the area and produce the necessary gradients for promoting gravity drainage downstructure. As shown by the pressure profiles of Figure 5-19, three years of dewatering production failed to produce the gradient necessary for gravity drainage.

2. However, the program did serve to reduce encroachment of high pressure edgewater into low pressure, clean oil sands on the southeast flank.

Discussion:

The low fluid withdrawal rate is attributed to the age and condition of the wells -- all old ones completed in the 1920's, and to the sand trouble attendant with high production rates. Some wells were in poor mechanical condition and the drainage channels around the well bores and liners were badly

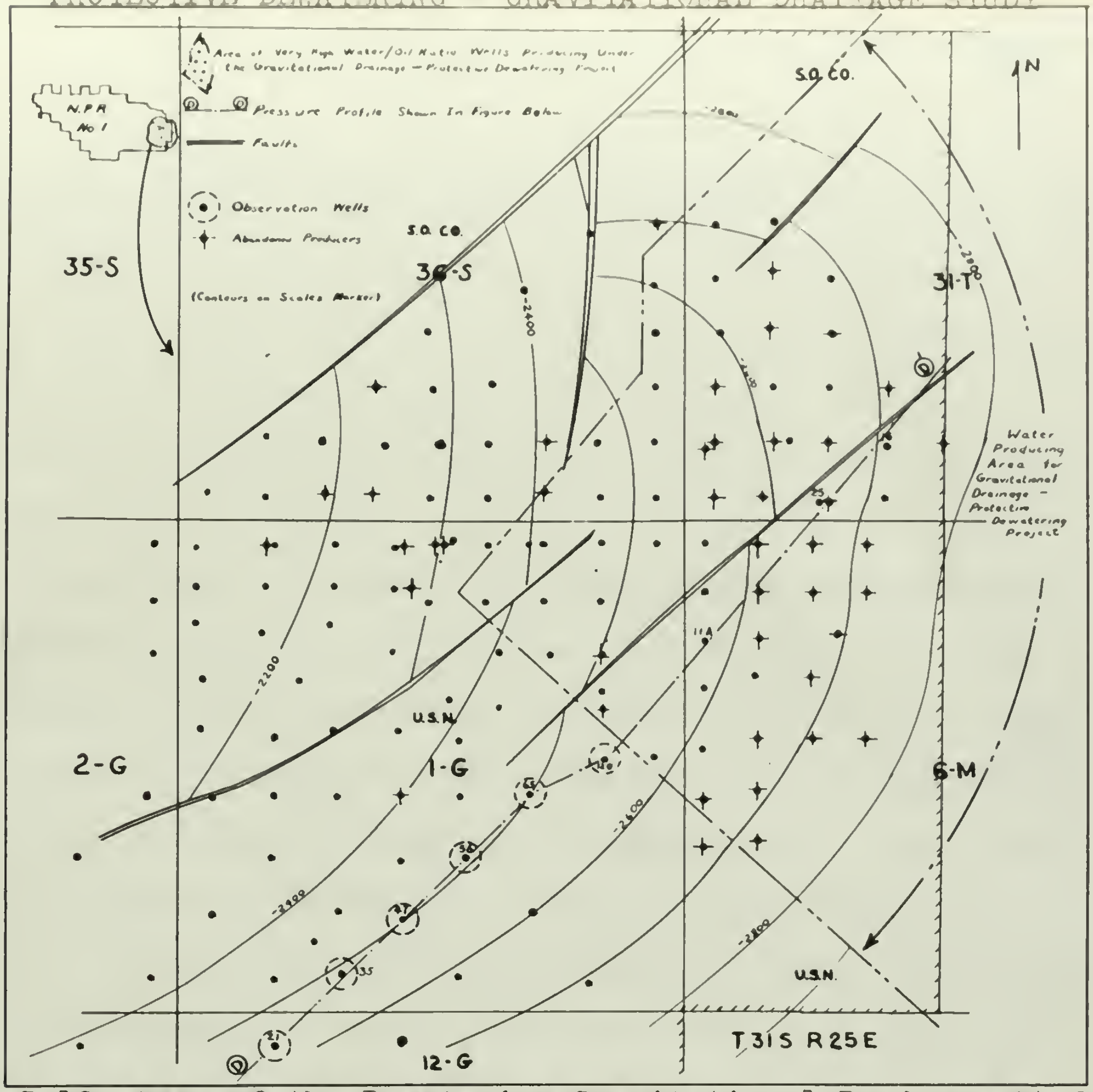
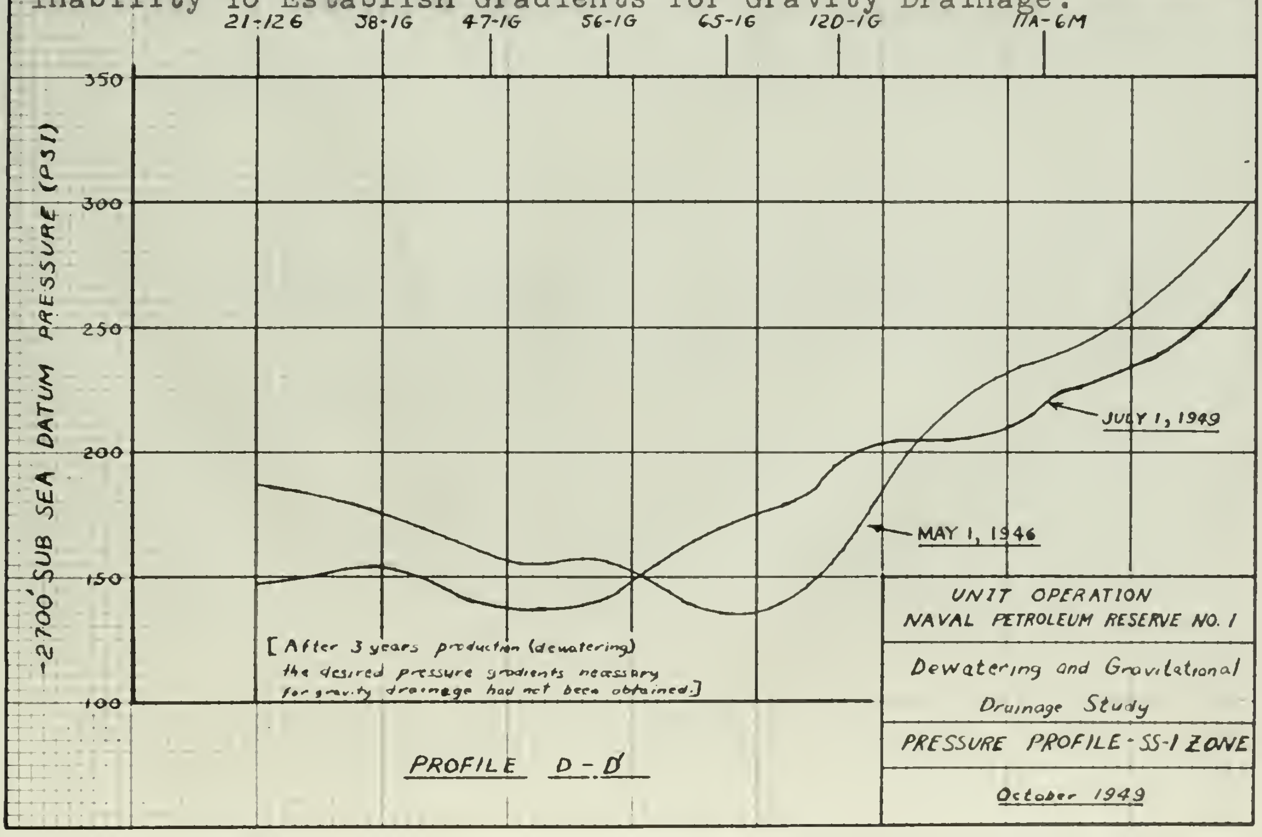


FIG. 5-18. Area of the Dewatering-Gravitational Drainage Study Showing Water Producing Area and Upstructure Observation Wells.

FIG. 5-19. Press. Profiles Through Area of Fig. 5-18 Illustrating Inability To Establish Gradients for Gravity Drainage.



clogged and sanded. The high cost of reworking these wells to secure better drainage and less sanding and the doubtful results of a complete well reconditioning program sufficiently increasing the fluid withdrawal rate to dewater the area, necessitated shifting the program to a protective dewatering project.

Even if the area had been successfully dewatered and gradients promoting gravity drainage had been created, the rate of drainage and resultant production rate may well have been too low for economic production of oil due to the relatively low structural relief of this area and the high viscosity of the gas denuded oil. The high permeabilities, however, in this area would tend to offset these disadvantages.

Other areas of higher structural relief, equally good permeabilities, and lower rates of water encroachment might provide a more effective gravity drainage study, such as the fault-block area used for the Minor Water Encroachment Study previously described.

SELECTED REFERENCES IN THE BIBLIOGRAPHY:

112, 122, 125, 138.

ROTATING PRODUCTION TEST PROJECT

Description:

This project consists of the periodic production testing of all wells in the Shallow Oil Zone which have producing facilities and are not produced under one of the other projects of the Readiness Program. Most of the wells under this project are clean wells. As many as 423 wells have been included under this program at one time or another.

Objectives:

1. To determine the mechanical condition of each well and its productivity characteristics.
2. To provide information for a continuing estimate of the productive capacity of the field.

Pertinent Dates:

22 October 1945---Project initiated.

20 April 1950-----Testing methods changed and production under this project curtailed on advice of the Engineering Committee.

Procedure:

Initially, each well not being produced under another program was placed on maximum rate of production for a minimum period of 10 to 11 days each year while mechanical and production information was obtained.

Following a review of data the testing procedure was altered to reduce production under this program. The wells are now divided into two groups, each tested differently:

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Following a review of data the testing procedure was altered to reduce production under this program. The wells are now divided into two groups, each tested differently:

Group I includes clean wells with little or no water production. These wells are produced every 2 years for 5 days at good operating rates as determined by the Operating Committee, with the restriction that wells of capacities exceeding 300 barrels per day are not to be produced above 300 barrels per day.

Group II includes wells increasing in water production and clean wells near wet wells or in areas of active water encroachment. These wells are produced each year for 8 days at good operating rates as determined by the Operating Committee from the production history of each individual well.

About 270 wells were produced under this project in 1952.

Results:

1. The project has been successful in providing adequate information concerning the mechanical operating condition of the wells and in supplying desirable reservoir engineering information on the Shallow Oil Zone.

2. Production under this project was quite high under the original ten-day test procedure, reaching as high as 2900 barrels per day. Under the present system of two groups of wells and test procedures, the production has been reduced to an average of about 700 barrels per day, a rate considered a minimum to provide adequate operating and production information.

Discussion:

Controversial aspects of this project have centered around its primary objective. Is the objective to test the mechanical operating condition of the wells or to provide production and reservoir information?

Between 1945 and 1950 emphasis seemed to be on the latter with long production periods and high production rates.

In 1950, a Navy Board convened by the Director concluded that sufficient production history had been obtained, that production should be curtailed, and that clean oil wells could be tested by bore-hole measurements without production.

Based on a Navy directive production programs were curtailed. Emphasis was shifted to obtaining operating information rather than production information, resulting in a steep decline in production under this project. Determining the condition of clean oil wells by running suitable instruments in the hole, as recommended by the Navy Board Review, has not as yet been adopted.

However, in approving the new testing methods, Standard's representatives did so with the reservation that an eight-day test period in one case and a rate restriction of 300 barrels per day in another test method would not yield adequate reservoir information and thus reduce the effectiveness of the program in protecting the Reserve and insuring maximum ultimate recovery.

Since adoption of the revised testing methods, the

program has been followed with only slight variation.

SELECTED REFERENCES IN THE BIBLIOGRAPHY:

109, 112, 122, 125, 138.

program has been followed with only slight variations.

SELECTED REFERENCES IN THE BIBLIOGRAPHY:

109, 119, 122, 125, 139.

PROTECTIVE PRODUCTION OF WET WELLS

Description:

Wells of high water/oil ratios not being produced under other phases of the Readiness Program are produced under this project.

About 200 wells have been produced from time to time under this project.

Objectives:

1. To prevent losses in availability and ultimate recovery by protecting upstructure clean oil sands of the reservoir against damage by encroaching water surrounding and bypassing oil, rendering it unrecoverable.

2. To prevent water from high pressure, wet sands flooding lower pressure, clean sands through the well bore of multi-completed wells which are wet.

Pertinent Dates:

September 1945: Project initiated.

Procedure:

1. If a well on the Rotating Production Test Program appears wet, it is produced for a period of 30 to 60 days.

2. If the well remains wet at a substantially high water cut, it is placed on continuous production under the Wet Well Protective Production Program. Some wells clean up after the test production period or after continuous production. Others may be repaired and the encroaching water excluded. In these cases, the wells are then returned to the

Rotating Production Test Program.

Results:

General --

This Program may be considered relatively successful in its objective of retarding the invasion of clean oil sands by encroaching water through the well bore of wet wells and in retarding upstructure migration of water.

Specific -- (Results as of 1953)

Total number of wells produced on this project: 200.

Number of wells initially on this project: 58.

Number of wells which cleaned up (i.e., water/oil ratio reduced) sufficiently after continuous production to be removed from this project: 54.

Number of wells repaired (water excluded) and removed from this project: 61.

Number of wells currently producing on this project: 85.

Rate of production and cumulative production under this program may be found in Chapter III.

Discussion:

Judging by the number of initial wells on the program and the number produced under it currently or at one time, the project appears to have a snow-balling tendency. This effect is not necessarily the fault of the project itself; for it is essentially corrective in its nature, not preventative. If other programs fail to correct potential gradients and prevent water encroachment, some upstructure wells become wet and they are added to the Wet Well Protective Production Program. Thus

Rotating Production Test Program.

Results:

General --

This Program may be considered relatively successful in its objective of retarding the invasion of clean oil sands by encroaching water through the well bore of wet wells and in retarding upstructure migration of water.

Specific -- (Results as of 1953)

Total number of wells produced on this project: 200.

Number of wells initially on this project: 58.

Number of wells which cleaned up (i.e., water/oil ratio reduced) sufficiently after continuous production to be removed from this project: 84.

Number of wells repaired (water excluded) and removed from this project: 51.

Number of wells currently producing on this project: 65.

Rate of production and cumulative production under this program may be found in Chapter III.

Discussion:

Judging by the number of initial wells on the program and the number produced under it currently or at one time, the project appears to have a snow-balling tendency. This effect is not necessarily the fault of the project itself; for it is essentially corrective in its nature, not preventative. If other programs fail to correct potential gradients and prevent water encroachment, some upstructure wells become wet and they are added to the Wet Well Protective Production Program. Thus the damage has already been done by the time a well is put on this program. By the singular nature of its corrective action, there is little reason for the return of any well to sustained clean production without extensive water shut-off repairs, which have proved expensive and not too successful -- often resulting in all production being shut-off.

When is a well wet enough to be placed on this Program? Only an arbitrary answer can be used. The selection method has been that any well showing a 10 per cent water cut or producing 10 barrels of water on production tests is added to this program if not already on another continuous production program. However, this testing method is not conclusive evidence that water flooding is occurring. Also, it might serve unnecessarily to aggravate the unbalanced condition inducing the fingering of water into the well, causing more water encroachment rather than less.

At what rate should the wet well be produced? Very high production usually means rapid rate of oil withdrawal as well as water withdrawal; for conservation reasons this is not desirable. If the production rate is low, water may be bypassing the well, moving upstructure or into low pressure clean sands connected in the well bore. The general policy on production rate for wet wells has varied considerably during the life of this program. The initial practice of automatically producing a wet well at maximum fluid withdrawal was abandoned in favor of analyzing each case to determine the

best rate of production to protect the well and the reservoir. without excessive oil production. However, recent programs to be discussed have returned to the "maximum production" theory for wet wells.

SELECTED REFERENCES IN THE BIBLIOGRAPHY:

112, 123, 125, 138.

REPAIR AND REMEDIAL PROJECT

Description:

This Project consists of the repair or abandonment of Shallow Zone wells.

Objectives:

1. To maintain wells in the best possible condition for prompt availability of production.

2. To repair or abandon wells which constitute a hazard or which might damage the reservoir.

Pertinent Dates:

Sept. 1946 to March 1949: Period of intensive repair and remedial work.

March 1949 to------------ Occasional repair work only.

Action Taken:

1. One hundred and eight (108) wells were repaired primarily to exclude water from the well bore.

2. Ten (10) wells in the Hay-Carman area of high pressure gas were repaired and now serve as observation wells.

3. Thirty-eight (38) wells, about 25 years old, in Hay-Carman area were abandoned due to their hazardous mechanical condition.

Results:

1. Repair of the 108 wells resulted in successful water exclusion, but also, all too often, partial or complete oil exclusion occurred. The net result was an overall marked decrease in availability.

2. As a result of unsuccessful repair work some wells had to be abandoned.

3. Water encroachment in the area around the repaired wells continued.

4. The migration of fluids between sands was stopped only in the well bores of the few repaired wells.

Conclusions and Current Actions:

As far as guarding against hazardous conditions in wells of bad mechanical condition, the program may be termed successful.

As regards the repair of wells to prevent water encroachment without damaging oil productivity and to prevent the migration of fluids between sands -- these phases of the Program were unsuccessful and in effect have been abandoned.

Lack of current repair work, for which there is much justification or hope of success, has retarded other phases of this program.

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109, 122, 158.

Part D

RECENT ADDITIONAL RESERVOIR ENGINEERING PROBLEMS NOW IN PROGRESS OR PROPOSED AS OF 1952

In 1952 the Operating Committee and the Engineering Committee concluded that drastic changes and additions were necessary to the State of Readiness Program for the Shallow Oil Zone. The Program with modifications had been in effect for seven years, and sufficient production and reservoir data were available to permit a complete reevaluation. Also, considerable additional reservoir information had become available as a result of the extensive post-war exploratory and development drilling program in the Shallow Zone, especially along the South Flank and in the western portions of the Reserve. This information also indicated the urgent need for changes in the current Program.

Consequently, in 1952 and 1953, the Engineering Committee made a comprehensive review of the State of Readiness Program. This study culminated in the preparation by the Unit of a comprehensive report entitled, "Review of State of Readiness Program, Shallow Oil Zone, 1945-1952; Recommended Programs for Future Operation with Particular Reference to Present Losses of Availability and Ultimate Recovery."[138] This report, dated 27 February 1953, was submitted by the Engineering Committee to the Secretary of the Navy and to the Standard Oil Company of California.

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In brief the conclusions of the Engineering Committee were that "...losses in maximum economic ultimate recovery and availability of production have been and are taking place in the Shallow Oil Zone." The present Program had not and could not prevent the losses, which would continue under the existing reservoir conditions.

Recommendations of the Committee consisted of four programs designed to correct undesirable conditions. These programs as recommended and as approved will be covered briefly in the following pages. Since these programs constituted a two to three-fold increase in oil production, they were thoroughly reviewed and explained by Navy and Standard to the Congressional Committee on Naval Affairs. With a "green light" from Congress, the programs with some restrictive modifications were finally approved by the Secretary of the Navy in the spring of 1953. In addition to the new programs, the following projects under the original State of Readiness Program were continued: Rotating Production Test, Repair and Remedial Work, Protection of Surface Equipment and to a minor extent the Protective Production of Wet Wells. The latter project and other original projects under the Old Program were mostly absorbed or abandoned under the four new programs now in progress.

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SS-2 AND M SOUTH FLANK REMEDIAL PROGRAM

Objectives:

This program was designed to eliminate an adverse pressure gradient on the south flank of the SS-2,M sand, which indicated that oil was being lost by migration downdip into water sands. Calculations indicated that the migration was occurring at a rate of approximately 2 million barrels per year of which 50 per cent would probably be unrecoverable unless additional wells were drilled. However, additional drilling would not be economical.

Action:

Commencing in June 1953 a remedial production program was initiated consisting of continuously producing rows of high pressure upstructure wells, both in the gas cap and in the oil zone, in order to reduce upstructure pressure and thereby correct the North to South pressure gradient.

Results:

Commencing about December 1953 the pressure gradient already had been corrected in certain areas along the South Flank. As the gradient was corrected in each area the continuous producing wells except for some observation wells were removed from production. All of the area is approaching a balanced pressure condition. The program currently is being made more flexible to maintain the area in as near a static condition as possible.

59-2 AND N SOUTH FLANK REMEDIAL PROGRAM

Objectives:

This program was designed to eliminate an adverse pressure gradient on the south flank of the 59-2,N sand, which indicated that oil was being lost by migration downdip into water sands. Calculations indicated that the migration was occurring at a rate of approximately 2 million barrels per year of which 50 per cent would probably be unrecoverable unless additional wells were drilled. However, additional drilling would not be economical.

Action:

Commencing in June 1953 a remedial production program was initiated consisting of continuously producing rows of high pressure upstructure wells, both in the gas cap and in the oil zone, in order to reduce upstructure pressure and thereby correct the North to South pressure gradient.

Results:

Commencing about December 1953 the pressure gradient already had been corrected in certain areas along the South Flank. As the gradient was corrected in each area the continuous producing wells except for some observation wells were removed from production. All of the area is approaching a balanced pressure condition. The program currently is being made more flexible to maintain the area in as near a static condition as possible.

SS-1 SOUTH FLANK REMEDIAL PROGRAM

Description:

In essence this program is similar to the one described above for the SS-2, M South Flank. An adverse pressure gradient from North to South exists, coupled with an apparently receding and diminishing aquifer to the South. Extensive migration of oil (about 1.5 million barrels per year) downdip into the water sands is believed to be occurring as a result of the pressure gradient and as indicated by development well and production evidence.

Action:

To minimize this loss, an increased production program was initiated along the south flank as the only practical solution currently available. In addition, high gas-oil wells upstructure are being produced to correct the pressure gradient.

Commencing in 1953, an electric-analogy study of the regional aquifer affecting the SS-1 sand, particularly along the south flank, was in progress by California Research Corporation.

Status:

The current status of the above program and study as of May 1954 is not known by the author.

NORTH FLANK AND EAST NOSE REMEDIAL PROGRAM

Description:

Results of the various water encroachment studies under the original State of Readiness Program convinced the Engineering Committee that the encroachment of high pressure edgewater was damaging to the Shallow Oil Zone. Efforts to utilize this natural water drive as an effective producing force and sweeping mechanism had shown it to be inefficient for the Shallow Oil Zone sand with its great variation in permeability.

Recommendations:

With the above in mind and with heavy water encroachment still occurring along the North flank and East Nose, the Engineering Committee recommended an increased production program in these areas and the drilling of 36 new wells. The production was to be mainly from wet wells of high water-oil ratios and from all water wells. The new wells were to be drilled in high water-oil ratio areas, and placed on continuous production. The desired result was a water production rate to match the rate of water encroachment and thus prevent upstructure migration of high pressure edgewater.

Status:

The exact status of this program as of May 1954 is not well known by the author. However, it is known that many additional North flank and East nose wells have been placed on continuous production. Also, a reduced drilling program was approved by the Secretary of the Navy.

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Recommendations:

With the above in mind and with heavy water encroachment still occurring along the North Flank and East Nose, the Engineering Committee recommended an increased production program in these areas and the drilling of 38 new wells. The production was to be mainly from cut wells of high water-oil ratios and from all water wells. The new wells were to be drilled in high water-oil ratio areas, and placed on continuous production. The desired result was a water production rate to match the rate of water encroachment and thus prevent upstructure migration of high pressure edgewater.

Status:

The exact status of this program as of May 1954 is not well known by the author. However, it is known that many additional North Flank and East Nose wells have been placed on continuous production. Also, a reduced drilling program was approved by the Secretary of the Navy.

77-2G AREA (SS-2 SAND) REMEDIAL PROGRAM

Description:

This program is a small version of the previous program described for the North flank and East nose. To the southeast of the competent fault just north of well 77-2G the SS-2 acts as a separate and individual reservoir. Water encroachment upstructure is occurring, and efforts in 1950-1952 to stop it by gas injection in the secondary gas cap through well 77-2G were not successful.

Recommendations:

The program as recommended by the Engineering Committee consisted of drilling and producing three SS-2 downstructure wells to retard water encroachment, putting all SS-2 wells in the area on production, and producing wells in the gas cap to a limited extent.

Status:

The program is in progress but its present status is not known by the author.

77-20 AREA (S2-C SAND) REMEDIAL PROGRAM

Description:

This program is a small version of the previous program described for the North flank and East nose. To the southeast of the competent fault just north of well 77-20 the S2-C acts as a separate and individual reservoir. Water encroachment upstructure is occurring, and efforts in 1960-1962 to stop it by gas injection in the secondary gas cap through well 77-20 were not successful.

Recommendations:

The program as recommended by the Engineering Committee consisted of drilling and producing three S2-C downstructure wells to retard water encroachment, putting all S2-C wells in the area on production, and producing wells in the gas cap to a limited extent.

Status:

The program is in progress but its present status is not known by the author.

CHAPTER VI

UNITIZATION

AND

UNIT OPERATION

OF

NAVAL PETROLEUM RESERVE NO. 1

CHAPTER VI

UNITIZATION AND UNIT OPERATION OF NAVAL PETROLEUM RESERVE NO.1

BRIEF REVIEW OF EVENTS LEADING TO UNITIZATION[5,6]

For nearly twenty years after the discovery of oil in Elk Hills, Navy had not experienced much success in carrying out the settled policy of the Government of maintaining a great naval petroleum reserve in the ground. As evidenced by the production history of the Shallow Oil Zone, Figures 3-1 and 3-3, production from the Elk Hills field was continuous and heavy; for production from privately owned lands adjacent to and within N.P.R. No. 1 had compelled the issuance by Navy of off-set leases and continuous production from them to restrict drainage from the Reserve.

Finally, in 1938, Navy obtained legislation from Congress which enabled it to deal positively and constructively toward making Elk Hills a petroleum reserve in reality. This legislation was the Congressional Act of June 30, 1938.[162] It authorized the Secretary of the Navy in effect either (1) to make satisfactory agreements with private owners on the Elk Hills field for the conservation of petroleum from the field;

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or (2) in the event satisfactory agreements could not be reached, then he was authorized to proceed with the purchase or condemnation of all such privately owned lands or leases in N.P.R. No. 1.[5]

With this Act as a backdrop, negotiations with Standard---who was the only remaining owner and operator of any significance at the field---finally culminated in a contract of 20 November 1942 which effectively unitized N.P.R. No. 1 and gave the Secretary of the Navy complete and final authority over the Reserve.

In anticipation of the successful conclusion of the above contract, Navy obtained Executive Order No. 9257 from the President.[5] This order, dated 15 October 1942, extended the boundaries of N.P.R. No. 1 to include an additional 1720 acres of public land and approximately 4000 acres of privately owned land, mainly Standard's fee owned and leased land on the Elk Hills structure. This enlargement effectively included the balance of the known geologic structure of the Shallow Oil Zone. This boundary and others during the life of the field are shown on Figure 1-3.

Although this contract was never finally approved by Congress for legal reasons and was superceded by temporary agreements until the approval of the present Unit Contract on 19 June 1944,[150] the date of 20 November 1942 marks the effective unification of the Government and privately owned lands on N.P.R. No. 1.

UNIT OPERATION OF N.P.R. NO. 1

The Unit Operation of N.P.R. No. 1 is carried out under four interrelated contracts entered into by Navy and Standard.[147,148] These contracts are discussed below.

Unit Plan Contract, NOd 4219.[150]

On 19 June 1944 the Unit Plan Contract between the Navy Department and Standard Oil Company of California was approved. This Contract, retroactive to 20 November 1942, rescinded all previous temporary agreements and is the basic contract for the Unit development and operation of the entire N.P.R. No. 1 (Elk Hills field). Navy and Standard are the only participants in the Unit Operation.

In many ways it is similar to any contract completely unitizing an oil field. It eliminated all competitive features of past operations by substituting cooperative unit development and production methods. Procedures were established for determining relative participating percentages of each party in production receipts and costs. Methods of allocating and disposing of production were agreed to. And the other usual items---such as determination of disputes, accounting procedures, term of the contract, etc.---are all provided for in the Unit Contract. Advisory and operating committees established for the Unit Operation of the Reserve are discussed later in this chapter.

The Unit Contract, however, is unlike any contract unitizing a commercial oil field among private interests only. This fact

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The Unit Contract, however, is unlike any contract unitizing a commercial oil field among private interests only. This fact will be illustrated by some of the important and interesting features quoted from the Contract and/or discussed in succeeding paragraphs.

Reasons for unitization and basic provisions of the Contract are given in the following excerpts from the Recitals in the Unit Contract...[150]

"(6) The following considerations have led Navy and Standard to conclude that the most desirable and effective means of protecting the Reserve and of assuring the maximum ultimate recovery of oil, gas, natural gasoline and associated hydrocarbons from the Reserve is to develop and operate all lands in the Reserve as a unit:

(a) The Reserve is a part of a single geologic structure; and the practice of offset drilling has not proved to be an effective means of assuring to Navy its proper share of oil produced from the Reserve and does not conserve Navy's oil in the ground.

(b) The independent development and operation of privately-owned lands in the Reserve, from which oil may be freely produced without control or restraint by Navy, would constitute a grave threat to the security of the Reserve and would impair Navy's power to conserve oil in the ground.

(c) Navy deems it inadvisable to shut in the wells on Navy's lands forthwith in view of possible permanent damage to the wells or to the national interest in the ultimate economical production of oil therefrom, and in view of the probable drainage of oil from Navy's lands in the event lands not controlled by Navy are developed and operated without simultaneous protective development and operation of Navy's lands.

(d) The unit plan of development and operation as set out herein will:

(i) Afford Navy a means of acquiring complete control over the development of the entire Reserve and the production of oil therefrom in order that Navy may protect the Reserve and conserve in the ground all of Navy's share of the oil in the Reserve as well as a substantial portion of Standard's share of oil in the Reserve.

(ii) Make available to Standard a limited quantity of oil from one of its most important sources at a time when it is needed by Standard to meet its war requirements for refined petroleum products in the West Coast area.

(iii) Place the Reserve in a condition of readiness whereby it will be able promptly to produce oil in substantial quantities whenever the strategic situation of the United States in the future may so require.

(iv) Result in the eventual receipt by Navy and Standard, respectively, from the various commercially productive zones underlying the Reserve of the quantities of recoverable oil, gas, natural gasoline and associated hydrocarbons underlying their respective lands as of November 20, 1942.

(v) Provide for the economical and efficient development and operation of the Reserve.

(vi) Result in securing the maximum ultimate recovery of oil, gas, natural gasoline and associated hydrocarbons from the Reserve."

Thus, under terms of the Contract, Navy acquired complete control and was finally in a position to operate the field as a true naval petroleum reserve. As a special consideration to Standard, a "primary period" was established and later extended during which Standard effectively received all of the Shallow Oil Zone production from after the war until 2 August 1950. This production amounted to about 30 million barrels and was charged against Standard's ultimate share in the total production from the Shallow Oil Zone.

The unusual but necessary provisions for the current and ultimate sharing of all costs are extensively discussed in Chapter VIII.[147,152]

The Contract gives the Secretary of the Navy the final decision in all disputes arising in connection with the Unit

Operation of the Reserve. Moreover, he is the only party to the Contract with authority to terminate it.

Unit Operating Agreement NOd 4220 of 19 June 1944.[149]

Contingent with the signing of the Unit Plan Contract, Navy selected Standard as the Operator for the Unit Operation of N.P.R. No. 1, and the two parties entered into an operating agreement, Contract NOd 4220. This contract spells out the duties and responsibilities of the Operator and his relationships with Navy. It more clearly defines the duties of the Operating Committee; states the records and reports required; and outlines a specific accounting procedure to be followed.

Whereas only Navy can cancel the Unit Plan Contract, either Standard or Navy may terminate the Unit Operating Agreement. In such an event, Navy would have the right to select another Operator.

The Amendatory and Supplemental Agreement to the Unit Plan Contract, NOd 8477.[146]

On 22 December 1948, the Unit Plan Contract was amended and supplemented by additional agreements. The boundaries of the Reserve had been extended to include some land previously outside of the Reserve but later found to be on the same geologic structure of Elk Hills. The agreement extended the Unit Operation to these additional lands. Some of the other important terms of this Agreement are listed below:

(1) The primary period was extended.

(2) The Engineering Committee was given advisory functions to the Operating Committee.

(3) Maintenance readiness costs were to be paid currently by Navy and Standard in accordance with their percentage receipt of current production.

Supplemental and Exploratory Agreement, NOd 7166.[148,152]

This relatively less important of all the Contracts provided for the drilling of a well in Section 31-T on the east end of the Reserve. It was necessary to determine if oil sands in this region bordering on the North Coles Levee field were the same sands as in the Stevens Zone and thus if it would be necessary to extend the boundaries of the Reserve to include perhaps the North Coles Levee field.

After drilling this well, it was decided that, although the oil productive sand was a Stevens Sand, a stratigraphic or other barrier apparently separated the two fields; thus no action was taken to extend the boundaries of the Reserve farther east.

OPERATING COMMITTEE

The Unit Plan Contract created an Operating Committee to supervise and direct all exploration, prospecting, development, and producing operations on the Reserve.[150]

Membership.

The committee consists of two petroleum engineers, one from each of the two participants. Each member of the committee must have at least ten years' experience as a petroleum engineer, or be a graduate engineer with at least five years such experience.

Duties.[146,149,150]

In brief, it is the responsibility of the Operating Committee to formulate and execute..."plans and methods for developing and maintaining Naval Petroleum Reserve No. 1 in state of readiness that will make available, when the strategic demands of the country require, maximum production compatible with good engineering practice."[113]

Navy's member of the Operating Committee is referred to by the abbreviated title NMOC. Currently, Standard's member of the committee is also the Field Superintendent. This committee meets daily, and minutes are recorded of decisions and plans made at each meeting. Disagreements are settled by the Secretary of the Navy. The relationships of this committee in the Unit Operation are shown on the organization diagrams of Figures 7-3 and 7-4.

ENGINEERING COMMITTEE

The Unit Plan Contract established a committee entitled the Engineering Committee to carry out certain specific functions under the Contract and Operating Agreement.[150]

Membership.

The committee consists of six members, three each for Navy and Standard. Two of the members must be same members as for Operating Committee. The other four members must be petroleum engineers or geologists, with the same qualifications as for those for members of the Operating Committee.

Duties.[146,150]

Specific duties are enumerated in Contracts NOd 4219 and NOd 8477. In brief, the Engineering Committee is responsible for the review and approval of certain plans and methods and other engineering matters as may be referred to it by the Operating Committee or Standard and Navy. One of its most important functions is the fixing of the participating percentages of Navy and Standard in each zone.

The Committee now meets quarterly or more often as necessary. Formal but not detailed minutes are recorded of each meeting.

SELECTED REFERENCES IN THE BIBLIOGRAPHY REFERRING TO UNITIZATION AND UNIT OPERATION OF N.P.R. NO. 1

2, 5, 6, 60-69, 146-150, 156, 162, 258-261

CHAPTER VII

ADMINISTRATION

NAVAL PETROLEUM AND OIL SHALE RESERVES

CHAPTER VII

ADMINISTRATION

NAVAL PETROLEUM AND OIL SHALE RESERVES

ORGANIZATION

Congress -- by an Act of 1920[14] as amended[162] -- and the President -- by an Executive Order of 17 March 1927[9] -- placed the administration of the naval petroleum and oil shale reserves under the authority of the Navy, and gave the Secretary of the Navy authority for the exploration, development and operation of the naval petroleum reserves only, subject to many Congressional limitations.

In October, 1927, the Secretary of the Navy established the Office of Naval Petroleum and Oil Shale Reserves. The Director of this office is an officer of the Navy, appointed by the Secretary of the Navy. Different grades of officers have held this post; however, the billet is normally assigned to a Captain. The Director serves as a representative of the Secretary in executing the responsibilities of administration and control of the naval reserves as authorized by Congress and delegated by the President.[7] His functions are somewhat similar to those of a bureau chief.

General Field Organization. The general field organization of the Office of Naval Petroleum and Oil Shale Reserves

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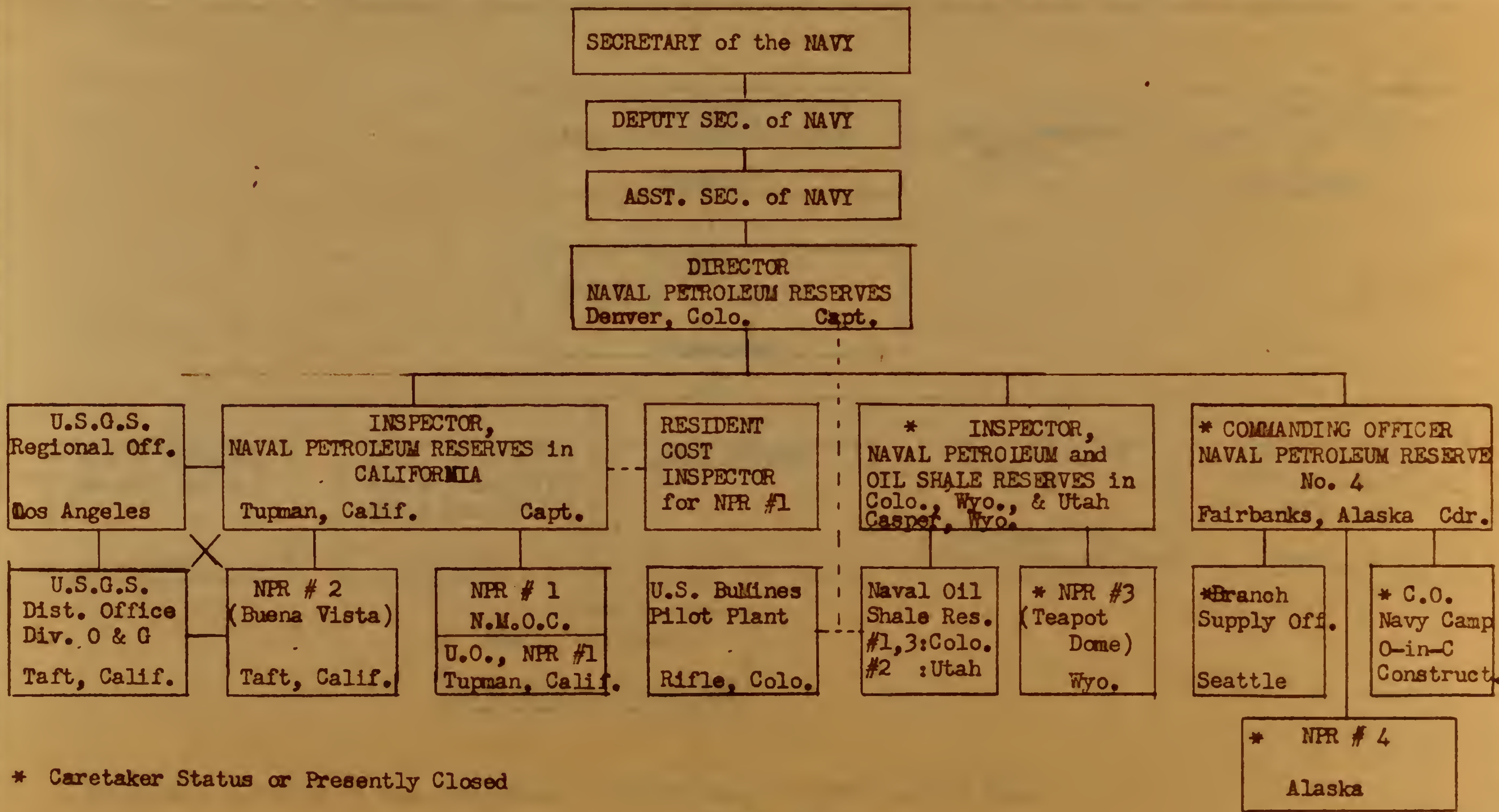
General Field Organization. The general field organization of the Office of Naval Petroleum and Oil Shale Reserves varies considerably, depending upon the location and extent of exploration and development work in progress in each Reserve from year to year.

In Figure 7-1 a recent Field Organizational Chart for the Naval Petroleum and Oil Shale Reserves is shown. The chart illustrates the extent which the field organization may assume during years of extensive exploration and development work in the various Reserves, such as 1944 through 1952, as provided for by Congressional appropriations. By 1954, however, most of the exploration and development work had been suspended except in Elk Hills (N.P.R. #1); and most of the field offices were on caretaker status or closed, as indicated by the asterisks on the Chart of Figure 7-1. The chart also indicates the rank of the officer in some of the billets at the date of the chart.

Office of the Director Naval Petroleum Reserves.[7] The organization and staff of the Director's Office is varied by the Director to meet current requirements. The type of organization and the number of civilian employees and officers on the staff may vary widely as the exploration and development program in each of the reserves changes.

The organization of this office as of January 1953 is shown in Figure 7-2. Even at the time exploration was in progress in Reserves No. 3 and No. 4 (Teapot Dome and Alaska), the staff was relatively small considering the work being done and the large funds involved. With the suspension of exploration in Teapot Dome and Alaska, the staff was reduced in 1953.

FIELD ORGANIZATION, NAVAL PETROLEUM RESERVES

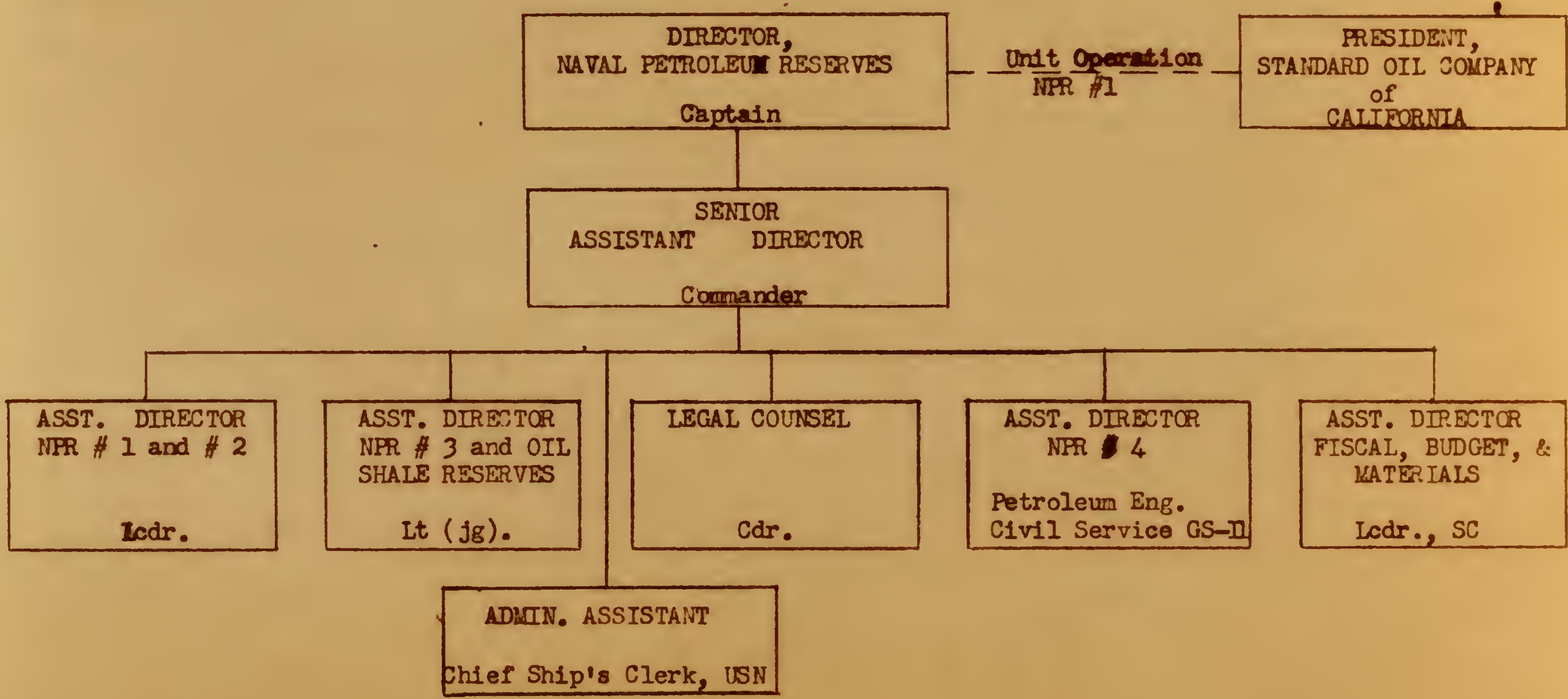


* Caretaker Status or Presently Closed

FIG. 7-1

15 January 1953

ORGANIZATION CHART
OFFICE OF THE DIRECTOR, N.P.Rs.



(Organization Varied at the Discretion of the Director to Meet Current Needs)

FIG. 7-2

15 January 1953

The Senior Assistant Director also serves as the Legal Counsel. At present there are two other Assistant Directors: a civil service petroleum engineer serving as technical advisor and an officer of the supply corps as fiscal, budget and material officer. The members of the Director's staff have advisory functions only in connection with the operation of the Reserves. Supervisory and executive control is administered by the Director for the Secretary of the Navy through the Inspector or Commanding Officer at each Reserve. The duties, relationships, and authority of each member of the Director's Office and of the Inspectors of the Reserves are covered in the ORGANIZATION MANUAL for this Office.[7]

During the years of considerable exploration and development activity in the petroleum reserves, the Office was in Denver, Colorado -- a relatively central location with respect to the field activities and to the Navy Department. In 1954, the Office was returned to Washington, D. C.

Organization of the Naval Petroleum Reserves in California. The field office of the Inspector, Naval Petroleum Reserves in California, is located on N.P.R. No. 1 at Tupman, California. The official representatives of the Secretary of the Navy in this office are the Inspector and Navy's Member of the Operating Committee. Through these representatives, the Director, Naval Petroleum Reserves, exercises control of N.P.R. No. 1 (Elk Hills) and maintains administrative control of Navy's leased lands in N.P.R. No. 2.

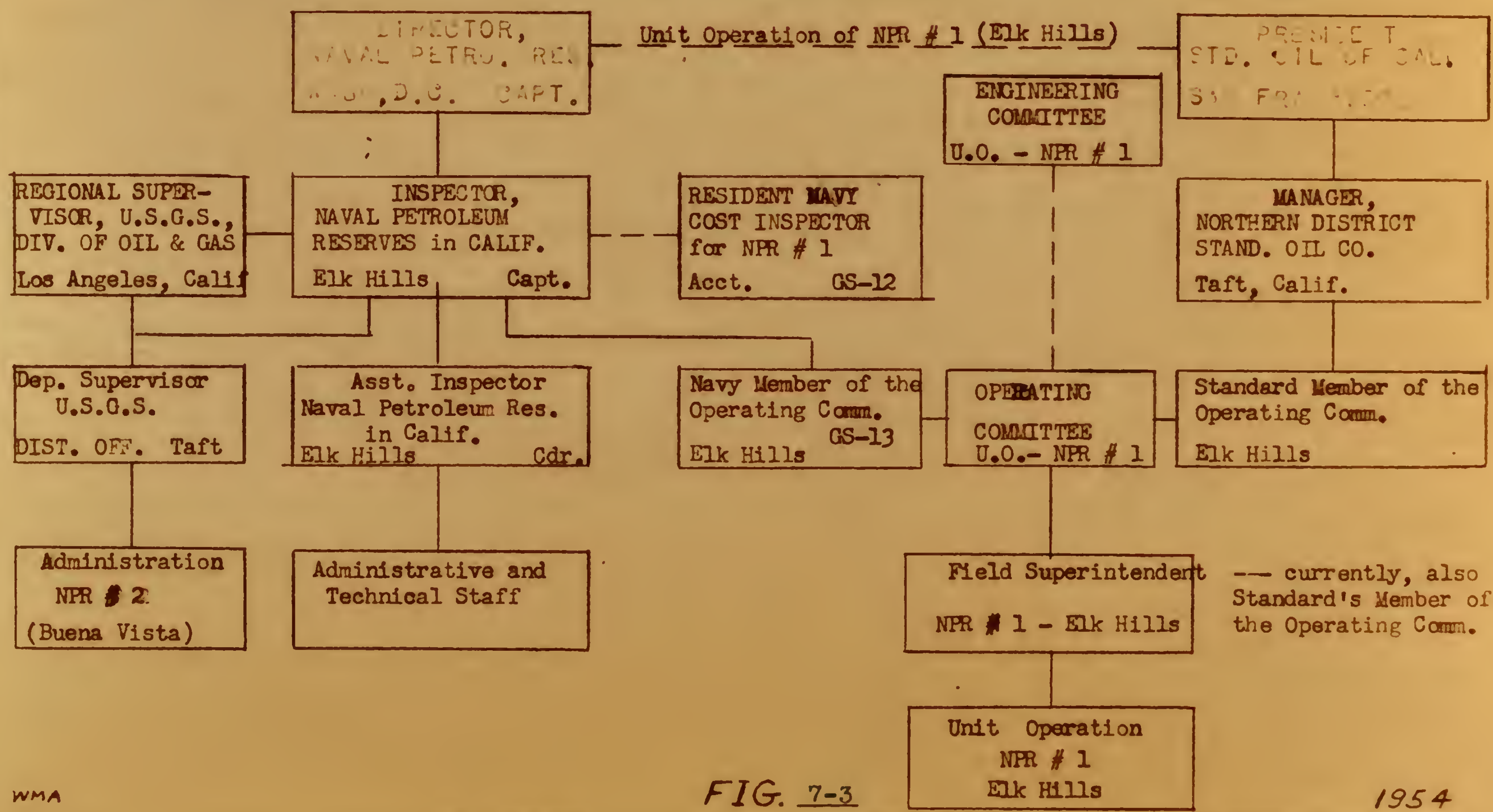
The general Organization Chart for the Naval Petroleum

Reserves in California is shown in Figure 7-3. The interrelationship indicated on this chart between the Inspector and Standard Oil Company of California as the unit operator for N.P.R. No. 1 has been discussed in Chapter VI. The independent status and duties of the Navy Cost Inspector and his relationship to N.P.R. No. 1 will be explained in Chapter VIII.

The unit operation of N.P.R. No. 1 -- with Navy and Standard as partners and Standard serving as the operator -- has been discussed in Chapter VI. Final resolution of all disagreements between Standard and the Navy rests with the Secretary of the Navy.

As has been shown in previous chapters, Navy has a minority interest in N.P.R. No. 2, controlling about 35 per cent of the total land and only about 25 per cent of the productive acreage; and its control over this Reserve is not as direct or complete as over N.P.R. No. 1.[125,170] The Inspector serves as the representative of the Secretary of the Navy in administering the leased lands under Operating Regulations promulgated jointly by the Interior and Navy Departments. Under these regulations, the U.S. Geological Survey performs certain supervisory and accounting services for the Navy for which payment is made by transfer of funds. The Supervisor of the U.S.G.S. District Office, Division of Oil and Gas, in Taft, California, is responsible for the gauging of produced oil and gas from Navy leases and for determining that good oil field practices are followed by the lessees.[176, 177] No restrictions other than the latter are placed on rate of production.

ORGANIZATION CHART
NAVAL PETROLEUM RESERVES IN CALIFORNIA



WMA

FIG. 7-3

1954

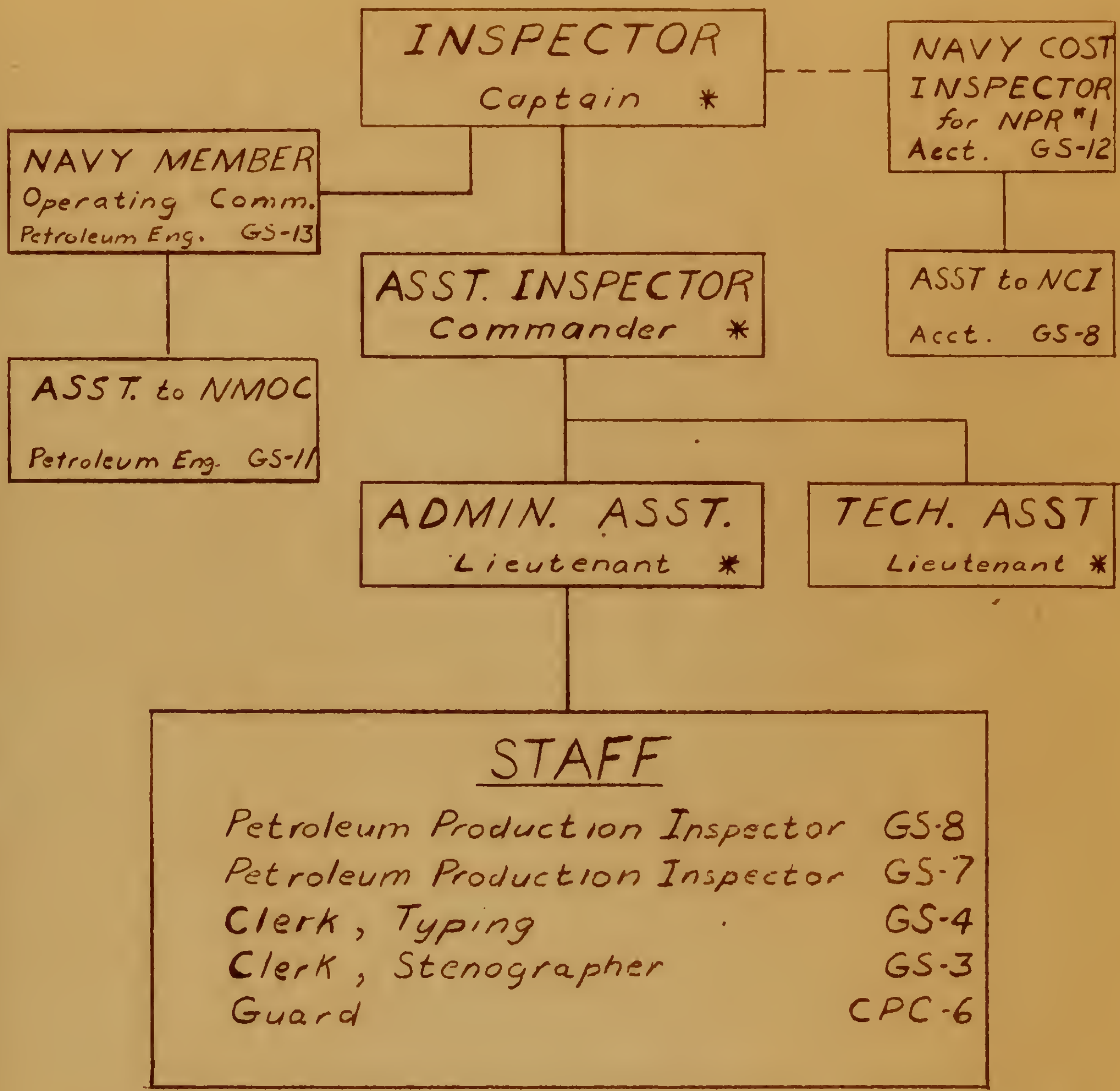
Accounting services for royalty payments to the Navy from the lessees are performed by the U.S.G.S. Regional Office in Los Angeles.

The INPR in C is under the military command of the Commandant, Eleventh Naval District.

Office of the Inspector, Naval Petroleum Reserves in California. The composition of the administrative and technical staff of the Office of the Inspector is shown in Figure 7-4. The rank of the officer in each officer billet and the service rating and title of each civil service employee is given as they existed about January 1954.

Standard's Field Organization at Elk Hills. Pursuant to the Unit Plan Contract of 1944,[150] Standard was selected as the operator for the unit operation of Naval Petroleum Reserve No. 1. Navy and Standard then entered into an Operating Agreement dated 19 June 1944,[149] retroactive to 20 November 1942 -- the date the Unit Operation was effectively commenced. In order to carry out its obligations under the above Contract and Agreement, Standard established a unit operation staff, the base of which was its own original operating force at the field prior to formation of the unit operation. During the emergency development and production period of World War II, the unit operation required the assistance of Naval Construction Battalions to accomplish essential survey work and road construction[111] and several Naval Officers qualified as petroleum engineers. In 1946 Standard again assumed all duties as operator.

ORGANIZATION CHART
Office of the Inspector, Naval Petroleum Reserves in Calif.



* Officers are C.E.C., E.D.O., or LINE contingent on petroleum engineering experience and training.

WMA

FIG. 7-4

January 1954

Standard's field organization at Elk Hills as of June 1953 is shown in Figure 7-5. The relationship of this organization with Standard's Northern District management is also shown. Navy and Standard share the expense of the unit operation staff on a participating percentage basis.[150] The chart shows two or three numbers after each group of employees -- Standard's accounting system for employees. The first column, P, indicates the number of employees on the payroll. The second column, B, indicates the equivalent number of full-time employees on the "basic" organization authorized by Standard's main office in San Francisco. The third column, circled B, lists the number of employees "authorized over the basic" number by Standard's Northern District Manager. If the actual organization is consistently running over or under "basic" on some employees, the basic organization is altered to reflect this condition. Standard's member of the Operating Committee, who is currently also the field superintendent, is charged with the responsibility of keeping the field force as small as possible and still adequate. If Navy feels that the field organization of the operator is inadequate or otherwise, desired changes may be requested by Navy's member of the Operating Committee through this Committee.

The number of employees varies with the field activity. Since all of the drilling and major construction work are accomplished by independent contractors, the actual work force at Elk Hills at any time may be considerably greater than the total of Navy's and Standard's employees.

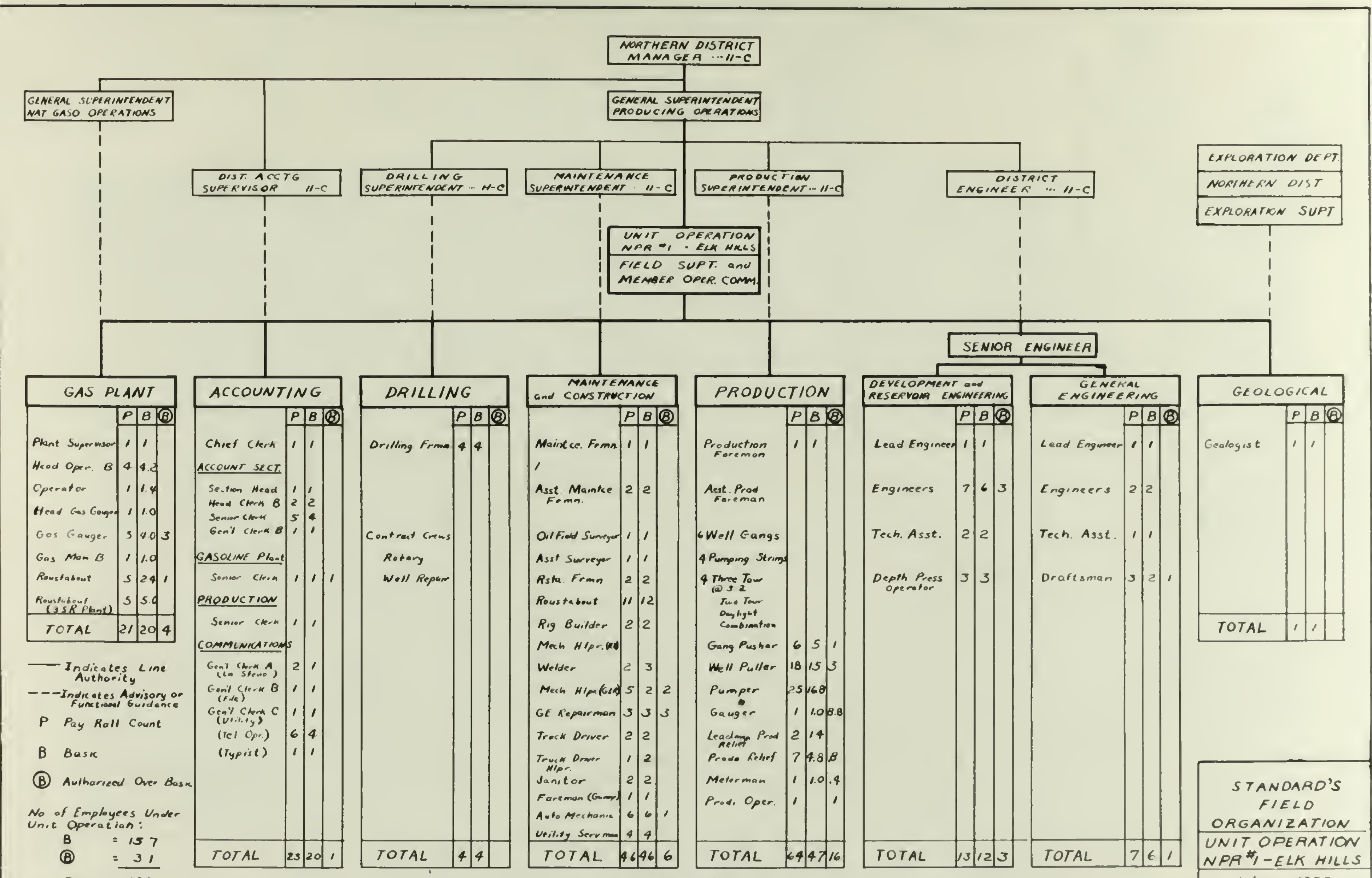

NORTHERN DISTRICT MANAGER ... 11-C
GENERAL SUPERINTENDENT NAT GASO OPERATIONS
GENERAL SUPERINTENDENT PRODUCING OPERATIONS
DIST. ACCTG SUPERVISOR 11-C
DRILLING SUPERINTENDENT ... 11-C
MAINTENANCE SUPERINTENDENT 11-C
PRODUCTION SUPERINTENDENT ... 11-C
DISTRICT ENGINEER ... 11-C
EXPLORATION DEPT.
NORTHERN DIST
EXPLORATION SUPT
UNIT OPERATION NPR #1 - ELK HILLS
FIELD SUPT. and MEMBER OPER. COMM.
SENIOR ENGINEER
GAS PLANT
P B Ⓑ
Plant Supervisor 1 1
Head Oper. B 4 4.2
Operator 1 1.4
Head Gas Gauger 1 1.0
Gas Gauger 3 4.0 3
Gas Man B 1 1.0
Roustabout 5 2.4 1
Roustabout (3SR Plant) 5 5.0
TOTAL 21 20 4
ACCOUNTING
P B Ⓑ
Chief Clerk 1 1
ACCOUNT SECT.
Section Head 1 1
Head Clerk B 2 2
Senior Clerk 5 4
Gen'l Clerk B 1 1
GASOLINE Plant
Senior Clerk 1 1 1
PRODUCTION
Senior Clerk 1 1
COMMUNICATIONS
Gen'l Clerk A (La Steno) 2 1
Gen'l Clerk B (File) 1 1
Gen'l Clerk C (Utility) 1 1
(Tel Opr.) 6 4
(Typist) 1 1
TOTAL 23 20 1
DRILLING
P B Ⓑ
Drilling Frmn 4 4
Contract Crews
Rotary
Well Repair
TOTAL 4 4
MAINTENANCE and CONSTRUCTION
P B Ⓑ
Maint.ce. Frmn. 1 1
Asst Maintce Frmn. 2 2
Oil Field Surveyor 1 1
Asst Surveyor 1 1
Rsta. Frmn 2 2
Roustabout 11 12
Rig Builder 2 2
Mech Hlpr.
Welder 2 3
Mech Hlpr. 5 2 2
GE Repairman 3 3 3
Truck Driver 2 2
Truck Driver Hlpr. 1 2
Janitor 2 2
Foreman 1 1
Auto Mechanic 6 6 1
Utility Serv man 4 4
TOTAL 46 46 6
PRODUCTION
P B Ⓑ
Production Foreman 1 1
Asst. Prod Foreman
6 Well Gangs
4 Pumping Strings
4 Three Tour @ 3 2
Two Tour Daylight Combination
Gang Pusher 6 5 1
Well Puller 18 15 3
Pumper 25 16.8
Gauger 1 1.0 8.8
Leadman Prod Relief 2 1.4
Prod. Relief 7 4.8 .8
Meterman 1 1.0 .4
Prod. Oper. 1 1
TOTAL 64 47 16
DEVELOPMENT and RESERVOIR ENGINEERING
P B Ⓑ
Lead Engineer 1 1
Engineers 7 6 3
Tech. Asst. 2 2
Depth Press Operator 3 3
TOTAL 13 12 3
GENERAL ENGINEERING
P B Ⓑ
Lead Engineer 1 1
Engineers 2 2
Tech. Asst. 1 1
Draftsman 3 2 1
TOTAL 7 6 1
GEOLOGICAL
P B Ⓑ
Geologist 1 1
TOTAL 1 1
—— Indicates Line Authority
- - - Indicates Advisory or Functional Guidance
P Pay Roll Count
B Basic
Ⓑ Authorized Over Basic
No of Employees Under Unit Operation:
B = 157
Ⓑ = 31
TOTAL = 188
STANDARD'S FIELD ORGANIZATION
UNIT OPERATION NPR #1 - ELK HILLS
1 June 1953

FIG. 7-5

JOB CLASSIFICATIONS OF PRINCIPAL NAVY EMPLOYEES AT NAVAL PETROLEUM RESERVE NO. 1

Inspector, Naval Petroleum Reserves in California (INPR in C):[7]

Qualifications:

1. Officer of the Navy, usually a Commander or Captain; or civil service employee of the Navy with GS-14 rating.
2. Petroleum background necessary; petroleum engineering degree is desirable.

Primary Duties:

1. Take custody and charge of the Petroleum Reserves in California on behalf of the Director.
2. Insure the proper execution of contracts between Navy and Standard.
3. Execute plans and programs to carry out the functions of the Petroleum Reserves as approved by the Director Naval Petroleum Reserves (DNPR).
4. Administer generally all operations on Reserves No. 1 and No. 2 under existing leases, cooperating under a working agreement with U.S. Geological Survey in the administration of N.P.R. No. 2.
5. Formulate general plans for the protection, conservation, development and use of the Reserves for the production of petroleum therefrom and make recommendations to the Director with reference thereto.

6. Consult and correspond with Navy activities up to and including District level and other government activities of comparable authority.
7. Communicate as desired with Engineering Committee and Operating Committee. The Navy Member of the Operating Committee corresponds through the Inspector unless otherwise directed.
8. Serve as Navy's representative between Navy and the California oil industry.

<u>Navy Member of the Operating Committee (NMOC)</u>:[149, 150]

Qualifications:

1. Officer or civil service employee of the Navy; currently civil service employee, GS-13.
2. Ten (10) years experience as a petroleum engineer, or a graduate engineer with at least five (5) years experience as a petroleum engineer.

Primary Duties:

1. Represent Navy on the Operating Committee and Engineering Committee.
2. Carry out duties of the Operating Committee as specified in the Unit Plan Contract, NOd 4219,[150] and in the Unit Operating Agreement, NOd 4220.[149] These duties have been discussed under "Functions of the Operating Committee" in Chapter VI on Unit Operation of N.P.R. No. 1.
3. Confer with and carry out orders and instructions

of DNPR and INPR in C as regards unit operation of Elk Hills, such as consulting INPR in C before putting any well on production, if not previously scheduled.

4. Serve as Petroleum Engineer on staff of INPR in C; make budget recommendations.
5. Make various reports to the California Conservation Committee, such as on the MER or optimum production rate of the different oil zones.

Assistant Inspector:

Qualifications:

1. Officer of the Navy
2. Petroleum Engineer

Duties:

1. Act as chief technical adviser to the Inspector.
2. Serve as correlation engineer for N.P.R. No. 1.
3. Assign and coordinate the work of the various officers on the staff serving as petroleum engineers or administrative assistants. This staff usually consists of one officer who is a qualified petroleum engineer and an officer who serves as administrative assistant.

Administrative Assistant to the Inspector:

Qualifications:

1. Officer of the Navy

Duties:

1. Expedites or initiates correspondence and reports

of DWPN and INTF in 8 as regards unit operation of Elk Hills, such as submitting INTF in 8 before putting any well on production, if not previously scheduled.

4. Serve as Petroleum Engineer on staff of DWPN in 8, make budget recommendations.
5. Make various reports to the California Conservation Committee, such as on the MER or optimum production rate of the different oil zones.

Assistant Inspector:

Qualifications:

1. Officer of the Navy
2. Petroleum Engineer

Duties:

1. Act as chief technical adviser to the Inspector.
2. Serve as correlation engineer for N.P.R. No. 1.
3. Assign and coordinate the work of the various officers on the staff serving as petroleum engineers or administrative assistants. This staff usually consists of one officer who is a qualified petroleum engineer and an officer who serves as administrative assistant.

Administrative Assistant to the Inspector:

Qualifications:

1. Officer of the Navy

Duties:

1. Expedites or initiates correspondence and reports

as necessary to carry out the functions of the Office.

2. Serves as custodian of funds allocated for administrative and technical expenses of the Office; maintains a balance ledger in this respect.
3. Responsible for all matters pertaining to office management and for supervision of all clerical personnel.
4. Advises Inspector on status and policies concerning civil service employees.
5. Assists in the administration of all leases pertaining to N.P.R. No. 1.
6. Assists in the initiation of requests for bids or the negotiations of contracts for sale of gas, gasoline, oil, and materials.
7. Other miscellaneous duties include public relations, transportation, security, custody of all classified and non-classified publications, preparation of the annual report, and matters pertaining to permits and right-of-ways on N.P.R. No. 1.

SELECTION OF NAVY EMPLOYEES

N.P.R. NO. 1

The Inspector is responsible for the hiring and firing of civilian employees on the Navy staff at N.P.R. No. 1, subject to civil service ceilings and examinations. As regards the NMOC, he is hired as a petroleum engineer by the Inspector. He then may be appointed by the Secretary of the Navy to the position of NMOC.

DNPR negotiates for the services of petroleum consulting firms, subject to the approval of the Secretary of the Navy. Often members of such firms are appointed by DNPR to serve as Navy's members or alternate members on the Engineering Advisory Committee for the Unit Operation of N.P.R. No. 1, subject to the approval of the Secretary of the Navy.

REPORTS AND RECORDS, OFFICE OF THE INSPECTOR
NAVAL PETROLEUM RESERVES IN CALIFORNIA

On the supposition that the reports issued and received by any activity often serve as an effective guide to its functions, responsibilities, and relationships -- a skeleton list of most incoming and outgoing reports from this office is given in Table I. Attention is invited to the large number of different addresses, a fact illustrating the complex relationships of the petroleum reserves within the Navy. Specific information on each report, as to its preparation or action required upon its receipt, is maintained on a card index system by the clerical staff at the Reserve. "Reports Issued" are grouped according to routine reports required by most Navy shore activities and to reports unique to its functions as a Petroleum Reserve.

TABLE I

REPORTS ISSUED BY INPR in C

A. Routine Navy Reports

Type	Title	To
Annual	1. Officer Data Card	Chief of Nav Pers
	2. Qualification Questionnaire - Active Duty Officers	Chief of Nav Pers
	3. Biography of Officers	Chief of Nav Pers
	4. Report on Salary and Wage Distribution of Civilian Employees	Chief of Industrial Relations, Navy Dept.
	5. Position Description Review	Personnel Officer, 11th N.D.
	6. Automotive Costs and Inventory	Transp. and Equip. Off., 11th N.D.

(Table I, continued)

Type	Title	To
Semi-Annual	1. Report on Fitness of Officers	BuPers
	2. Navy Awards and Incentives	Chief, O.I.R., Navy Dept.
	3. Plant Account Cards, Class Two	NSD, San Pedro, Calif.
Quarterly	1. Shore Duty Survey Report	Com. 11th N.D.
	2. Report of Agency Hiring	U.S. Civil Service
	3. Overtime Work Performed by Civilian Employees and Cost Thereof	DNPR
	4. Employee Development Program	Chief, O.I.R., Navy Dept.
	5. Agency Actions Under Executive Order 10450	Chief, O.I.R., Navy Dept.
Bi-Monthly	1. Mileage Report	11th N.D.
Monthly	1. Roster of Officers	BuPers
	2. Personnel Diary	PAMI, 11th N.D.
	3. Report of Personnel	O.I.R., Navy Dept.
	4. Expenditures Incurred on Travel Orders for Civilian and Military Personnel	D.N.P.R.
	5. Blanket Certificate of Assignment of Quarters	Navy Accts. Disb. Off., Long Beach
	6. Civilian Employment by Appropriations	Chief, O.I.R., Navy Dept.
	7. Personnel Housing Facilities under Cognizance of the Navy	Com. 11th N.D.
	8. Reservations for Quarterly Allotment	Naval Supply Depot, San Pedro
	9. Accident Data Report	Asst. Sec. Navy, Safety Div.
	10. Employees Savings Bonds Participation Data	Long Beach Naval Shipyard
	11. Government Transportation Requests	Regional Accounts Office, Wash. D. C.
Semi-Monthly	1. Officers' Regular Pay Day Payments	Naval Accts. Disb. Off., Long Beach
Weekly	1. Personnel Diary	PAMI, 11th N.D., San Diego

(Table I- continued)

Type	Title	To
Semi-Annual	1. Report on Fitness of Officers Ensigns	
	2. Navy Awards and Incentives	Chief, O.I.R., Navy Dept.
	3. Plant Account Cards, Class Two	ROS, San Pedro, Calif.
Quarterly	1. Shore Duty Survey Report	Com. 11th N.D.
	2. Report of Agency Giving	U.S. Civil Service
	3. Overtime Work Performed by Civilian Employees and Cost Thereof	[illegible]
	4. Employee Development Program	Chief, O.I.R., Navy Dept.
	5. Agency Actions Under Executive Order 10450	Chief, O.I.R., Navy Dept.
Bi-Monthly	1. Mileage Report	11th N.D.
Monthly	1. Roster of Officers	BuPers
	2. Personnel Diary	[illegible], 11th N.D.
	3. Report of Personnel	O.I.R., Navy Dept.
	4. Expenditures Incurred on Travel Orders for Civilian and Military Personnel	[illegible]
	5. Blanket Certificate of Assignment of Quarters	Navy Accts. Disb. Off., Long Beach
	6. Civilian Employment by Appropriations	Chief, O.I.R., Navy Dept.
	7. Personnel Housing Facilities under Cognizance of the Navy	Com. 11th N.D.
	8. Reservations for Quarterly Allotment	Naval Supply Depot, San Pedro
	9. Accident Data Report	Asst. Sec. Navy-Safety Div.
	10. Employees Savings Bonds Participation Data	Long Beach Naval Shipyard
	11. Government Transportation Requests	Regional Accounts Office, Wash. D. C.
Semi-monthly	1. Officers' Regular Pay Pay Payments	Naval Accts. Disb. Off., Long Beach
Weekly	1. Personnel Diary	PAMI, 11th N.D., Ash Bldg

(Table I, continued)

Type	Title	To
As Changes Occur	1. Personnel Diary	PAMI, San Diego
	2. Military and Civilian Personnel	DNPR
	3. Biography of Officers	Chief Nav. Pers.

B. Reports Pertaining to Petroleum, Issued by INPR in C

Type	Title	To
Quarterly	1. Inspector's Quarterly Reports on N.P.R. No. 1 and No. 2	DNPR
	2. Production Sales and Royalties N.P.R. No. 1 and No. 2	DNPR
Monthly	1. Liquid Fuel Report	Fuel Supply Office, Navy Dept.
	Billing for Crude Oil from the.....	Naval Supply Depot, San Pedro
	2. Shallow Zone	
	3. Stevens Zone	
	4. Carneros Zone	
	5. Billing for Natural Gas to Commercial Companies, N.P.R. No. 1	Naval Supply Depot, San Pedro
	6. Production Under the State of Readiness Program, N.P.R. No. 1	DNPR
	7. Status of Funds Report, N.P.R. No. 1	DNPR
	8. Verification of Unit's Monthly Statement of Production for N.P.R. No. 1	Resident N.C.I.
	9. Lessee's Monthly Report of Operation, N.P.R. No. 2	DNPR
	10. Report to Property Accounting Office for N.P.R. No. 2	DNPR
	11. Automotive Rental, and Pay and Allowances Invoices	U. O. - N.P.R. No. 1
When Occurring	1. Payment of Consulting Firms (Navy Members of Engineering Committees)	DNPR

TABLE II

REPORTS RECEIVED BY INPR in C

Type	Title	From
Annual	Annual Report, U.S. Geological Survey	U.S.G.S.
Quarterly	Rotating Production Test Program	U. O. - NPR #1
	Rotating Production Test Schedule	U. O. - NPR #1
	Shallow Oil & Dry Gas Zone Summary of Depth Pressure and Temp. Measurements - Elk Hills	U. O. - NPR #1
	Depth Pressure Summary for Stevens Zone Wells - Elk Hills	U. O. - NPR #1
	California Field and Pool, Max. Efficient Crude Prod. Rate - Scheduled Pools	Conservation Committee of Calif. Oil Producers
	California Anticipated Production Performance - Unscheduled Pools	Conservation Committee of Calif. Oil Producers
	Recommended Monthly Schedule of Production Elk Hills Field - Buena Vista Field	Conservation Committee of Calif. Oil Producers
Monthly	Monthly Engineering Report, U.S. Geological Survey, California Region	U.S.G.S.
	Summary of California Oilfield Operations	American Petroleum Institute
	Productive Capacity Estimates for Stevens Zone Wells	U. O. - NPR #1
	Monthly Well Production Report PRO-420 Elk Hills	U. O. - NPR #1
	Resume of Operations, 27-B Pool Unit	27-B Pool Operating Committee
	27-B Pool Statement of Production	Operator - 27-B Pool Unit
	Monthly Well Production Report - Pro 420 (27-B Pool)	Std. Oil Co., San Francisco
	Monthly Report, Buena Vista Hills 27-B Pool Operations	27-B Pool Administrative Group
	Mineral Industry Surveys, Monthly Petroleum Statement	U.S. Dept. of the Interior, Bureau of Mines
	District 5 Petroleum Statement No. 244-B, Statistical and Economic Surveys	U.S. Dept. of the Interior, BuMines Petroleum Statistics Branch
	Buena Vista Field, Summary of Production (Total Barrels)	California Conservation Committee

(Table II continued)

Type	Title	From
Monthly (cont.)	Monthly Summary of Production, Elk Hills (Total Barrels)	California Conservation Committee
	Preliminary Daily Average, California Crude Oil Production	California Conservation Committee
	Actual Production and Disposition of Oil Well Gas by Fields	California Conservation Committee
As Requested	Fractional Analysis, Field and Analysis Data - U. O. - NPR #1	California Research Corporation
As Group Meets	27-B Pool Unit Meeting of Administrative Group Representatives #15	27-B Pool Administrative Group

The lists of reports required also may serve to illustrate the large number of routine Navy reports required not only by this Naval activity but all Naval activities. Moreover, issuing these reports requires the constant services of an officer and a clerical staff. In spite of the efforts in recent years to reduce the great volume of routine reports, one cannot help but wonder -- after reading these lists and perhaps recalling personal experience elsewhere in the Navy -- whether "the axe to cut reports" more than scratched the surface. The only panacea would seem to be a greater delegation of authority to lower echelons of command and a less frequent collection of statistical information, which may be desirable but seldom urgent.

AWARDING OF CONTRACTS FOR THE SALE OF PETROLEUM ACCRUING TO NAVY FROM ITS PARTICIPATION IN THE UNIT OPERATION OF N.P.R. NO. 1[101, 102]

At the present time, Navy receives the major percentage of all petroleum produced from the Reserve. The petroleum is in the form of gas, natural gasoline, and crude oil which are being produced constantly, even in times of no emergency, as part of the development, readiness and maintenance, and conservation program in the Reserve. Consequently, Navy must have a means of disposing of its petroleum share. This is done under contracts with civilian concerns.

The Inspector at Elk Hills initiates negotiations for the sale of all products. He supplies information on products for sale such as quantity, storage, availability, specifications, transportation facilities, period of sale and deliveries -- to DNPR, who in turn makes arrangements with Navy's Bureau of Supplies and Accounts (BuSandA) for preparing a contract.[101] BuSandA provides a sample contract for revision by the Director or the Inspector. When the final form of the contract is approved by the Director, BuSandA issues a notice of sale to all interested parties -- i.e., to all oil companies in the vicinity on a mailing list maintained by the Inspector. Also, the notice of sale is advertised and posted at several post offices. The notice of sale, invitation to bid, contract form, bid form, corporate authority form, bond form, and other necessary forms are mailed as a packaged unit

HANDLING OF CONTRACTS FOR THE SALE OF PETROLEUM ACCRUING TO NAVY FROM ITS PARTICIPATION IN THE UNIT OPERATION OF N.P.R. No. 1[101, 102]

At the present time, Navy receives the major percentage of all petroleum produced from the Reserve. The petroleum is in the form of gas, natural gasoline, and crude oil which are being produced constantly, even in times of no emergency, as part of the development, maintenance and conservation program in the Reserve. Consequently, Navy must have a means of disposing of its petroleum share. This is done under contracts with civilian concerns.

The Inspector at Elk Hills initiates negotiations for the sale of all products. He supplies information on products for sale such as quantity, storage, availability, specifications, transportation facilities, period of sale and deliveries -- to DNPR, who in turn makes arrangements with Navy's Bureau of Supplies and Accounts (BuSandA) for preparing a contract.[102] BuSandA provides a sample contract for revision by the Director or the Inspector. When the final form of the contract is approved by the Director, BuSandA issues a notice of sale to all interested parties -- i.e., to all oil companies in the vicinity on a mailing list maintained by the Inspector. Also, the notice of sale is advertised and posted at several post offices. The notice of sale, invitation to bid, contract form, bid form, corporate authority form, bond form, and other necessary forms are mailed as a packaged unit by BuSandA and/or the Inspector's office to all oil companies on the Inspector's mailing list and to additional companies who indicate interest in the sale.

The notice of sale specifies the time and place for submitting bids. At a prearranged date and location, Navy representatives of BuSandA open all sealed bids in the presence of all bidders. All bids are announced. Representatives of the bidders may then bid higher or may even submit reasons tending to give their bid priority over all except higher bids. In other words, a public auction is held.

These bids -- original sealed bids and additional ones made at the auction -- are analyzed by a representative of BuSandA. He normally awards the contract to the highest bidder. In cases of equivalent bids, one bidder may receive the contract due to certain supporting reasons -- such as an emergency request for an additional crude oil source to keep a refinery in operation.

In some cases BuSandA may request assistance or an opinion from the Inspector in determining to whom the contract should be awarded. Also, a representative of DNPR and INPR-in-C is normally present at the bid opening (auction) to provide additional information as requested by prospective bidders and representatives of BuSandA.

The Secretary of the Navy has the right to reject any or all bids.

In 1952, Navy's petroleum share from N.P.R. No. 1 was disposed of as follows:[125]

by BuSandA and/or the Inspector's office to all oil companies on the Inspector's mailing list and to additional companies who indicate interest in the sale.

The notice of sale specifies the time and place for submitting bids. At a prearranged date and location, Navy representatives of BuSandA open all sealed bids in the presence of all bidders. All bids are announced. Representatives of the bidders may then bid higher or may even submit reasons tending to give their bid priority over all except higher bids. In other words, a public auction is held.

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In some cases BuSandA may request assistance or an opinion from the Inspector in determining to whom the contract should be awarded. Also, a representative of OPPR and INPR-1a-0 is normally present at the bid opening (auction) to provide additional information as requested by prospective bidders and representatives of BuSandA.

The Secretary of the Navy has the right to reject any or all bids.

In 1958, Navy's petroleum share from N.P.R. No. 1 was disposed of as follows:

a. Oil from the Shallow and Stevens Zones sold to Wilshire Oil Co.

b. Oil from the Carneros Zone sold to Caminol Co. of Hanford, California.

c. Gas sold to the Southern California Gas Co.

d. Natural gasoline sold to Sunland Refining Corp.

Money received from the sale of these petroleum products is handled by a naval supply activity and is credited to the Federal Government under Miscellaneous Receipts of the Treasury.

ISSUANCE OF OUT-LEASES, REVOCABLE PERMITS, AND RIGHT-OF-WAYS BY INPR-IN-C[101, 102]

OUT-LEASES. Another administrative function of the Inspector is the issuance of out-leases permitting the use of Navy land on the Reserves for various purposes not associated with mineral leases -- such as for grazing and farming.

The procedure followed in issuing one of these out-leases is given below:

a. The Inspector may originate a notice of the availability of certain land for various purposes; or an application for an out-lease may be received by the Inspector from an individual or party.

b. The application is analyzed by the Inspector's staff. It is submitted with recommendations and necessary illustrations, such as a sketch of the area, to DNPR who in turn forwards it with additional recommendations to the Navy Department, Bureau of Docks (BuDocks).

c. BuDocks prepares the legal contract form for the lease, the final form being approved by the Inspector and DNPR.

d. BuDocks conducts the bidding by public notice of availability and receives all bids.

e. BuDocks selects the bidder to whom the lease is issued. The Contract is signed by representatives of BuDocks and the applicant.

f. Duration: 5 years or less at which time the lease is re-negotiated. The lease may be renewed with the previous lessee only on a year to year basis, complying with certain specified conditions.

Two of these leases were issued in 1951 and 1952, amounting to a receipt of $6,157.60 by the Federal Government. In 1953 renewal of a grazing lease on N.P.R. No. 1 came to $6,157.60; a farming lease on N.P.R. No. 2, $815.

OIL AND GAS LEASES. There were no outstanding oil and gas leases on Navy property in N.P.R. No. 1 by the end of 1952.

REVOCABLE PERMITS AND RIGHT-OF-WAYS. These items are also administered by the Inspector. They include right-of-ways across the Reserve for country roads and pipe-lines of commercial companies. Permits may be issued for such items as the establishment of churches and schools on the Reserve, construction of an automatic radio repeater station within the Reserve, and location of oil field facilities of commercial companies on the Reserve. No charge is made for these privileges if they are of mutual interest and/or benefit.

The procedure for issuing these permits and right-of-ways is as follows.

a. Application is made by the interested party to the Inspector.

b. The Inspector analyzes the request, makes appropriate recommendations, and forwards it to Navy's Bureau of Yards and Docks (BuDocks) via DNPR.

c. If BuDocks approves the request, it will prepare

the legal form and return it to the applicant via the Director and the Inspector, either of whom may return the form to BuDocks with supporting reasons before it reaches the applicant.

d. The applicant signs the legal form, keeping the original. Copies are returned to the Inspector, the Director, and BuDocks.

e. These permits are revocable at will by the Navy within a specified time after notice is given the permit holder. Moreover, Navy cannot be held liable for any accidents or other legal action arising out of issuance of the permit. Consequently, the permit holder is required to be heavily bonded.

DISPOSAL OF USED EQUIPMENT

Under the Unit Operating Agreement, Section 6(d), Standard as Operator has the right and responsibility for disposing of all scrap, salvageable material, and other equipment belonging to the Unit Operation and determined by the Operating Committee not to be needed and desired to be disposed of. Standard sells or transfers this material, subject to the approval of the Operating Committee.

Payments received by Standard are retained by Standard. Proper adjustment is made on the accounts of the Unit Operation so as to give Navy its share of credit from the sale or transfer.

INSPECTIONS MADE OF THE RESERVES IN CALIFORNIA

GENERAL INSPECTIONS OF THE RESERVES. Routine Inspections of the Reserves in California are made by the Petroleum Committee of the Federal Munitions Board and the District Civil Engineer of the Eleventh Naval District.

INDUSTRIAL PROCEDURES AND RELATIONS AND ACCOUNTING METHODS. A periodic inspection is made of the Reserves by the Navy's Industrial Survey Board.

PERSONNEL REQUIREMENTS. Personnel requirement surveys of Navy's staff at Elk Hills is made annually by the District Supply Officer of the Eleventh Naval District.

AUTOMOTIVE. Representatives of the Commandant, Eleventh Naval District, make routine inspections of all

automotive equipment under cognizance of the Navy at Elk Hills. This equipment belongs to the Eleventh Naval District and is assigned to the Inspector.

TRAINING

An important activity at the Inspector's office is the training of various groups of naval personnel in petroleum production and oil field development practices. These groups include naval reserve officers on annual training duty, members of volunteer petroleum units, and naval postgraduate students in petroleum engineering.

SELECTED REFERENCES IN THE BIBLIOGRAPHY

2, 7, 9, 14, 101, 102, 111, 125, 146,
149, 150, 170, 173, 176, 177.

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TRAINING

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SELECTED REFERENCES IN THE BIBLIOGRAPHY

6, 7, 9, 14, 101, 109, 111, 125, 146, 149, 150, 170, 173, 175, 177.

CHAPTER VIII

ECONOMIC REVIEW

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ECONOMIC REVIEW

General Review of the Economic Factors of the Naval Petroleum and Oil Shale Reserves Program

In the administration and operation of Naval Petroleum Reserve No. 1, Navy is charged by Congress with the responsibility for normally conserving the oil in the ground, producing as little as possible during normal times, and maintaining the Reserve in a state of readiness for maximum production "whenever the strategic situation of the United States in the future may so require."[150] Navy's share of N.P.R. No. 2 (Buena Vista) is being produced under leases with royalties to Navy. N.P.R. No. 3 has a relatively small amount of recoverable oil and in no way qualifies as a petroleum reserve. It is more of a liability than an asset. If it were not such a political football, the Government probably would dispose of it. As regards N.P.R. No. 4 (Alaska), it is still commercially unproductive after 50 million dollars for exploration. Only experimental work has been done in relationship to the Oil Shale Reserves.

With the status of each reserve so different and under the policy demanded by Congress for N.P.R. No. 1 as described above, an economic appraisal and evaluation of this Program, as if it were a commercial venture, is not strictly plausible; for, from a strictly financial viewpoint, the Program cannot

be justified. Millions of dollars in revenue are deferred annually by not producing N.P.R. No. 1. Also, some actual loss of assets may be occurring by the migration of oil from N.P.R. No. 1, which a current program is attempting to correct. The Naval Reserve Program is in many respects comparable to maintaining a combatant ship in the line: it is expensive to build, maintain, and operate, of little or no commercial value normally, and yet it must be maintained constantly in a state of readiness to meet the emergencies of war. The principal facts to determine, then, are how efficiently is the Program administered, what have been the total costs and receipts, what has been accomplished, and what is the potential value in oil and money.

Expenditures and Receipts. Over a period of 36 years -- fiscal year 1916 through fiscal year 1952 -- a net profit of $2,300,000 had been made by the Naval Petroleum Reserve Program. This profit represented the difference between the total income, principally from the sale of Navy's share of oil from N.P.R. No. 1 and royalties from N.P.R. No. 2, and the total capital and non-capital expenditures resulting from the operation of the Reserve Program -- including the exploration and development of N.P.R. No. 1 to its present potential capacity of approximately 125,000 barrels per day and 700 million barrels of recoverable oil, the extensive exploration and exploratory drilling program in N.P.R. No. 4 in Alaska, the exploration and partial development of N.P.R. No. 3, and the administration of all of the reserves.

be justified. Millions of dollars in revenue are delayed annually by not producing N.P.R. No. 1. Also, some actual loss of assets may be occurring by the migration of oil from N.P.R. No. 1, which a current program is attempting to correct. The Naval Reserve Program is in many respects comparable to maintaining a combatant ship in the line: it is expensive to build, maintain, and operate, of little or no commercial value normally, and yet it must be maintained constantly in a state of readiness to meet the emergencies of war. The principal facts to determine, then, are how efficiently is the Program administered, what have been the total costs and receipts, what has been accomplished, and what is the potential value in oil and money.

Expenditures and Receipts. Over a period of 38 years -- fiscal year 1916 through fiscal year 1953 -- a net profit of $2,500,000 had been made by the Naval Petroleum Reserve Program. This profit represented the difference between the total income, principally from the sale of Navy's share of oil from N.P.R. No. 1 and royalties from N.P.R. No. 2, and the total capital and non-capital expenditures resulting from the operation of the Reserve Program -- including the exploration and development of N.P.R. No. 1 to its present potential capacity of approximately 125,000 barrels per day and 700 million barrels of recoverable oil, the extensive exploration and exploratory drilling program in N.P.R. No. 4 in Alaska, the exploration and partial development of N.P.R. No. 3, and the administration of all of the reserves.

Figures for the total appropriations, expenditures and income from 1916 through 1952 are tabulated below:

Total Appropriations Capital and Non-capital	$103,924,008
Total Expenditures	$ 95,544,939
Total Receipts	$ 97,855,228
Net Income to the Government	$ 2,310,289

<u>How Efficient?</u> This question is difficult to answer. The main criticism of the Program from an economic standpoint usually stems from a criticism of its objectives and purposes, such as the extensive exploration and drilling program conducted at great expense in Alaska. On the credit side for efficiency are such items as the relatively small staffs which the Navy has employed to administer the Program, the unit operation and development of N.P.R. No. 1 to its present huge capacity and reserve using the best oil field practices, and the cooperation with the U.S. Geological Survey in the administration of N.P.R. No. 2.

<u>Potential Value</u>. If N.P.R. No. 1 should be put on full production at 100,000 barrels per day, the Navy's share would be about 84,000 barrels daily with an income to the Navy from the oil alone of almost $202,000 daily at 1952 prices. The revenue from the oil, natural gasoline, and other hydrocarbons would give the Navy a gross income annually approximating $75,000,000. Over a five year period, the gross income annually should remain at approximately the above value or

Figures for the total appropriations, expenditures and income from 1916 through 1952 are tabulated below:

Total appropriations Capital and Non-capital	$103,924,008
Total Expenditures	$ 93,844,020
Total Receipts	$ 97,055,009
Net Income to the Government	$ 3,210,989

<u>How Efficient?</u> This question is difficult to answer. The main criticism of the Program from an economic standpoint usually stems from a criticism of its objectives and purposes, such as the extensive exploration and drilling program conducted at great expense in Alaska. On the credit side for efficiency are such items as the relatively small staffs which the Navy has employed to administer the Program, the unit operation and development of N.P.R. No. 1 to its present huge capacity and reserve using the best oil field practices, and the cooperation with the U.S. Geological Survey in the administration of N.P.R. No. 2.

<u>Potential Value.</u> If N.P.R. No. 1 should be put on full production at 100,000 barrels per day, the Navy's share would be about 64,000 barrels daily with an income to the Navy from the oil alone of almost $208,000 daily at 1952 prices. The revenue from the oil, natural gasoline, and other hydrocarbons would give the Navy a gross income annually approximating $75,000,000. Over a five year period, the gross income annually should remain at approximately the above value or

higher, depending on the price of oil and the possibility of increased development and production of oil from the deepest zone, the Carneros Zone -- oil of high gravity and high value.

The income from N.P.R. No. 2 in the form of royalties on all hydrocarbon products produced from government leases aggregated approximately \$862,000 in 1951 and \$805,000 in 1952 or nearly a million dollars each year. Income from N.P.R. No. 2 should continue for many years, perhaps a score or more, declining steadily each year as indicated by the values above. The possibility of production from as yet undiscovered deeper zones under Navy leases would keep the royalty income high from N.P.R. No. 2.

The potential value of the oil shale reserves controlled by the Navy is extremely great with the reserve of oil in several billions of barrels. The production of oil from shale is becoming more and more economically feasible with each passing year as oil prices and demand continue to rise.

The potential values of N.P.R. No. 2 and No. 3 are small, and that of N.P.R. No. 4 in Alaska may be great but still unproved. The present economic or actual value of N.P.R. No. 2 to the Navy is only the present-day value of about 3,652,000 barrels of oil, or only 3.5 per cent of the total recoverable reserves in N.P.R. No. 2. The value of N.P.R. No. 3 is that of approximately 8.4 million barrels from the Second Wall Creek zone plus the value of an undetermined, but not major, accumulation of oil in the deeper Tensleep sandstone.[2]

Appropriations, Expenditures, etc.

Breakdown of Appropriation, Expenditures, and Income
Figures where Available for Each Petroleum Reserve
from 1916 through 30 June 1952

	Naval Petroleum Reserve			
	#1[111,125]	#2[170,173]	#3	#4
A. Appropriations..	$53,491,327			$45,265,000
B. Expenditures:				
1. Administrative........		$1,877,719	$333,562	
2. Develop., Oper., etc..				
3. Total Expend......	$50,968,730			
C. Gross Income....	$64,375,098	$27,379,289	$6100,841	
D. Net Income......	$13,406,368	$25,501,570		None

(Note: All values were not available to the author.)

Items of Economic Interest under the Unit Operation of Naval Petroleum Reserve No. 1

COSTS

Plant Costs. Upon inception of the Unit Contract the respective value of Navy's share and Standard's share of the plant on the Reserve was credited to each on the accounting records of the Unit.

The inventory value of the plant as of 20 November 1942, subdivided into tangible costs (physical property such as derricks, buildings) and intangible costs (labor, fuel, power, etc.), is tabulated below:

	Tangible	Intangible	Totals
Navy	$ 826,805	$ 907,514	$1,734,319
Standard	$1,501,708	$1,582,049	$3,083,757
	$2,328,513	$2,489,563	$4,818,076

The total plant cost of nearly 5 million dollars in 1942 had increased to over 60 million dollars by 1954 -- approximately 42 per cent to tangible costs and 58 per cent to intangibles. This twelve-fold gain in plant costs over a twelve year period, representing only a third of the field's life to date, is ample evidence of the intense development which the field has experienced under the Unit Operation.

An actual present-day or market value of the plant has not been determined.

Summary of Major Cost Divisions and Subdivisions.

Shallow Oil Zone Costs. Costs in this Zone are segregated under the following major subdivisions:

(1) Operating and Development

(2) Exploratory

(3) Readiness Maintenance

(4) Development Readiness

Stevens Zone Costs. Major cost subdivisions are:

(1) Operating

(2) Exploratory

(3) Exploratory, Extended Area (Contract NOd 8477)

(4) Development

Carneros Zone Costs. To date all costs have been charged to Navy. Standard has not entered into the Unit Operation of this Zone as yet.

Dry Gas Zone. Relatively little or no expenditures have been made on this zone in recent years.

Wet Gas Handling Facilities. No definite allocation of costs of Wet Gas Handling Facilities between zones has been made to date by the Operating Committee.

Drilling (Development) Costs. All drilling at the Reserve is accomplished by private drilling contractors who are hired by the Unit on a competitive bid basis. They use their own rotary drilling equipment -- usually light portable rigs -- and hire their own employees.

With three different oil zones at Elk Hills under active development, a fair comparison of the relative drilling and

equipment costs at different depths and for different years may be obtained. Total drilling and equipment cost data as available for each zone is tabulated and discussed below.[109, 111, 125, 148]

Period	No. of Wells Drilled	Av. Cost per Well	Average Footage	Av. Cost per Foot	Av. Cost per Day
		(Shallow Oil Zone)			
1946-1947	-------	$48,000	-------	$12.00	$1400
1952	39	$34,086	3048	$11.18	-----
		(Stevens Zone)			
1946-1947	-------	$280,000	-------	$35.00	$1300
1948-1951	99	$123,463	6504	$18.98	-----
1952	33	$132,655	6743	$19.67	-----
		(Carneros Zone)			
1952	1	$798,874	12,856 (Plugged at 9,385)	$62.00	

The unusually high cost of $280,000 for a Stevens Zone well in the 1946-1947 period was the result of extensive logging, coring, testing, and prolonged fishing jobs in certain wells. Actually, many wells were drilled for less than $250,000 per well; and thus the $35.00 per foot is not a particularly good representative figure.

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Period	No. of Wells Drilled	Av. Cost per Well	Average Footage	Av. Cost per Foot	Av. Cost per Day
		(Shallow Oil Zone)			
1946-1947	------	$47,000	------	$12.00	$1400
1952	49	$34,050	3048	$11.19	-----
		(Stevens Zone)			
1946-1947	------	$250,000	------	$35.00	$1800
1948-1952	95	$173,462	6504	$10.98	-----
1952	38	$132,655	8743	$15.67	-----
		(Carneros Zone)			
1952	1	$750,374	12,056 (Plugged at 9,335)	$62.00	

The unusually high cost of $250,000 for a Stevens Zone well in the 1946-1947 period was the result of extensive logging, coring, testing, and prolonged fishing jobs in certain wells. Actually, many wells were drilled for less than $250,000 per well; and thus the $35.00 per foot is not a particularly good representative figure.

In analyzing the costs above it is of interest that during the 1946-1947 period the average cost per foot for a Stevens Zone well was nearly three times that for a Shallow Zone well while the average cost per day for the deeper well was actually less.[109]

Comparing cost per foot figures for each zone in 1952 a rapid increase in costs with depth may be noted and should be expected. However, the $62.00 per foot for a Carneros Zone well is excessively high due to the extensive logging, coring, and testing attendant with the drilling of this deep exploratory well.

Ordinary Production and Readiness Maintenance Costs. With all the different programs simultaneously in progress in the Shallow Oil Zone, ordinary production cost values are difficult to obtain for this zone. An estimate of the production cost for each month is obtained by applying a weighted cost index factor to a cost per barrel value for the base year. The full year prior to unitization was considered a normal year, and as such, the base year.

The Readiness Maintenance costs are then obtained by subtracting the production costs calculated by the formula described above from the total Shallow Zone Operating costs.[147]

Since no Readiness Maintenance program exists for the Stevens Zone, production costs may be obtained directly. Some available production cost figures are tabulated below:

Zone	Year	Av. Cost per Barrel
Shallow	1948	0.1400
	1951	0.1588
	1952	0.1610
	1953	0.1598
Stevens	1952	0.328

Readiness Maintenance costs have varied but in recent years have been about equal to ordinary production costs.

Materials.[147] Most materials necessary for the Unit Operation of N.P.R. No. 1 are purchased by the Operator through Standard's Purchase and Stores Department. The materials charged to the Unit Operation at the same price paid by Standard plus a fee for storage and issuing service if the material is stored at Standard's 11-C Camp.

Standard's Purchasing Office in Los Angeles does all the purchasing for the Unit Operation.

Storage Costs. Navy does not own any large crude oil storage tanks at the Reserve. Consequently, to provide the necessary temporary storage space required for the collection and gauging of Navy's share of the crude production prior to its being delivered to the buyer, Navy rents four tanks from Standard. These tanks are of approximately 45,000 barrel capacity and are located on Standard's Section 16-G tank farm, south of the Reserve.

In 1953 the storage cost to the Navy was $0.005 per barrel of tank capacity per month.

Zone	Year	Av. Cost per Barrel
Shallow	1948	0.1400
	1951	0.1588
	1952	0.1610
	1953	0.1599
Stevens	1952	0.328

Readiness Maintenance costs have varied but in recent years have been about equal to ordinary production costs.

Materials.[147] Most materials necessary for the Unit Operation of N.P.R. No. 1 are purchased by the Operator through Standard's Purchase and Stores Department. The materials charged to the Unit Operation at the same price paid by Standard plus a fee for storage and issuing service if the material is stored at Standard's 11-C Camp.

Standard's Purchasing Office in Los Angeles does all the purchasing for the Unit Operation.

Storage Costs. Navy does not own any large crude oil storage tanks at the Reserve. Consequently, to provide the necessary temporary storage space required for the collection and gauging of Navy's share of the crude production prior to its being delivered to the buyer, Navy rents four tanks from Standard. These tanks are of approximately 46,000 barrel capacity and are located on Standard's Section 16-G tank farm, south of the Reserve.

In 1953 the storage cost to the Navy was $0.005 per barrel of tank capacity per month.

Passenger Car and Truck Rental.[147] The Unit Operation owns no cars or trucks, but rents all motor vehicles from the Motor Transport Department of Standard located at Standard's 11-C Camp in Taft.

All refined petroleum products necessary for these vehicles and for other miscellaneous operations are normally purchased by the Unit from Standard.

Miscellaneous Costs. In November, 1952, a new gas processing and pressure maintenance plant of 50 million cubic feet capacity was completed at a cost of about 5.5 million dollars. This 35-R Gas Plant is "mothballed" but can be activated in three months time. This plant has never been fully tested.

The older 3-G Gas Plant was repaired, overhauled, and modified during 1952 to more efficiently process current gas production and to serve as a booster station for compressing gas to 450 psi for delivery to the new 35-R Plant. The cost for this overhaul came to $555,500.

Over 100 miles of new gathering and injection lines serving the Gas Plants above were laid during 1952 at a cost of approximately 1.5 million dollars.

Estimated Major Costs in the Near Future. In 1954 a pipeline proposal was submitted to Congress for the construction of a 14-inch pipeline 100 miles long from Elk Hills to Los Angeles to deliver the field's capacity of over 100,000 barrels per day to the refineries in case of an emergency. As of April 1954 no action had been taken by Congress on this item.

If the exploratory drilling of the deep Carneros Zone is continued and this zone is developed like the Stevens and the Shallow Zones, development costs will soar to new heights.

As the age of the wells and associated equipment increases, repair and replacement costs, especially for the old wells of 1919 to 1930 vintage, will become increasingly heavy. Tubing and casing will need replacing, pumping equipment will tend to deteriorate, and many other items will require renewal.

STATUS OF COSTS AND REIMBURSEMENTS

FROM INCEPTION TO 30 JUNE 1953*

	Charged to		
Charges under all contracts	Navy	Standard	Total
Shallow Zone (Exhibit C)	$22,144,657	$7,424,543	$29,569,200
Stevens Zone (Exhibit D)	33,376,495	2,111,061	35,487,556
Dry Gas Zone (Exhibit E)	9,119	2,716	11,835
Carneros Zone (Exhibit F)	838,106	-0-	838,106
Wet Gas Handling Facilities (Exhibit G)	6,084,806	8,250	6,093,056
Deep Zone (Exhibit H)	357,854	-0-	357,854
Totals	$62,811,037	$9,546,570	$72,357,607
	(Exhibit B)	(Exhibit B)	(Exhibit B)

Reimbursement of Contractor by Navy

Payments for appropriations:		
17X1300 (Contract NOd 4220, P.V. #1 - #51, #63- #76)	$12,402,500	
1760307 (Contract NOd 4220, P.V. #15 - #56)	7,250,000	
1760307 (Contract NOd 7166, P.V. #1 - #14)	256,127	
1790307 (Contract NOd 4220, P.V. #52 - #81)	8,995,000	
1701307 (Contract NOd 4220, P.V. #64 - #87)	9,329,000	
1711307 (Contract NOd 4220, P.V. #79 - #93)	3,898,000	
1721307 (Contract NOd 4220, P.V. #93 - #116)	11,360,700	
1731307 (Contract NOd 4220, P.V. #116 - #127)	6,675,852	
Total reimbursements		$60,167,179
Materials and services furnished by Navy		2,643,858
Total charged to Navy		$62,811,037

*Exhibit A from Interim Audit Report #13[148] of 13 September 1953 under Contracts NOd 4219, 4220, 8477, and 7166.

SUMMARY OF COSTS, ALL ZONES, FROM INCEPTION TO 30 JUNE 1953*

	Navy	Charged to Standard	Total
Production expenses	$ 4,642,151	$5,284,500	$ 9,926,651
Productive wells			
Tangible well equipment	11,068,474	740,668	11,809,142
Intangible development costs	32,085,515	2,744,631	34,830,146
Unproductive wells	2,591,155	570,513	3,161,668
Geophysical exploration costs	63,135	16,472	79,607
Division and lease equipment			
Oil collection system	3,068,178	84,624	3,152,802
Gas collection system	1,897,124	16,182	1,913,306
Gas distribution system	145,355	18,384	163,739
Electric system	3,092	(701)	2,391
Water system	302,329	33,043	335,372
Telephone system	14,407	1,239	15,646
Waste water system	3,822	-	3,822
Racks and platforms	14,804	789	15,593
3G Gas plant	1,051,067	20,364	1,071,431
35R Gas plant	4,030,905	-	4,030,905
Buildings	204,734	8,601	213,335
Cottages	115,150	3,749	118,899
Garages	21,136	2,393	23,529
Recreational facilities	21,002	684	21,686
Construction equipment	11,183	243	11,426
Depth pressure equipment	23,099	2,403	25,502
Drilling and well pulling equipment	333,360	12,727	346,087
Engineering equipment	2,963	-	2,963
Fire equipment	2,611	(33)	2,578
Miscellaneous equipment	28,953	5,917	34,870
Motor equipment	(987)	2,233	1,246
Office equipment	17,823	1,112	18,935
Production tools	23,737	156	23,893
Plant tools	158	-	158
Inventories	994,637	5,642	1,000,279
Material transfers	29,965	(29,965)	-
Total of Exhibits C-H incl.	$62,811,037	$9,546,570	$72,357,607
	(Exhibit A)	(Exhibit A)	(Exhibit A)

*Exhibit B from Interim Audit Report #13[148] of the N.C.I. under Contracts NOd 4219, 4220, 8477, and 7166.

SUMMARY OF COSTS, ALL ZONES, FROM INCEPTION

TO 30 JUNE 1953*

	Navy	Charged to Standard	Total
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Productive wells			
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Geophysical exploration costs	63,135	16,472	79,607
Division and lease equipment			
Oil collection system	3,068,170	84,632	3,152,802
Gas collection system	1,897,124	16,182	1,913,306
Gas distribution system	145,355	18,384	163,739
Electric system	3,092	(701)	2,391
Water system	302,332	53,643	355,975
Telephone system	14,407	1,239	15,646
Waste water system	3,822	-	3,822
Racks and platforms	14,804	789	15,593
3G Gas plant	1,051,067	20,364	1,071,431
25E Gas plant	4,030,905	-	4,030,905
Buildings	804,734	8,601	813,335
Cottages	115,150	3,749	118,899
Garages	21,136	2,393	23,529
Recreational facilities	21,002	654	21,656
Construction equipment	11,183	243	11,426
Depth pressure equipment	23,099	2,403	25,502
Drilling and well pulling equipment	333,360	12,727	346,087
Engineering equipment	2,963	-	2,963
Fire equipment	2,611	(33)	2,578
Miscellaneous equipment	28,953	5,917	34,870
Motor equipment	(987)	2,233	1,246
Office equipment	17,823	1,112	18,935
Production tools	23,727	166	23,893
Plant tools	158	-	158
Inventories	994,637	5,642	1,000,279
Material transfers	29,985	(29,985)	-
Total of Exhibits C-H incl.	$62,311,037	$9,946,570	$72,257,607
	(Exhibit A)	(Exhibit A)	(Exhibit A)

*Exhibit B from Interim Audit Report #15[148] of the N.C.I. under Contracts NOd 4119, 4220, 8477, and 7194.

COST SHARING

Standard pays all costs each month and is then reimbursed by Navy for Navy's accrued share of the expenditures after audit of the monthly statement by the Navy Cost Inspector.

The Unit Plan Contract and Supplemental Agreement provide for the ultimate sharing of all costs, except certain exploratory costs, on the basis of participating percentages. The present participating percentage interests are as follows:[125]

ZONE	NAVY	STANDARD
1. Dry Gas Zone	77.0492%	22.9508%
2. Shallow Oil Zone	66.9152%	33.0848%
3. Stevens Zone	79.3089%	20.6911%
4. Carneros Zone	100%	(Participating percentage for Standard has not been established.)

Under the development, production and cost provisions of the Contract, few costs are shared currently according to the participating percentages listed above.

For example, all normal operating and production costs for the Shallow Oil Zone are shared currently on the basis of production received each month by the participants. Currently Navy and Standard are out of balance, according to the participating percentages, on the production received from the Shallow Oil Zone. This situation resulted after the end of the World War II emergency production period. From 23 August 1945, the cutoff date, to the end of the extended primary period under

the amended contract on 2 August 1950, Standard received practically all of the production from the Shallow Oil Zone. Navy is now receiving approximately 89 per cent of the production; all operating costs including Readiness Maintenance costs for this Zone are currently shared on the same basis.

Exploratory, prospecting and development costs with certain specific exceptions are to be shared ultimately according to the final revised participating percentages.[150] However, under terms of the Contract, the cost of wells drilled by Navy for development, readiness and exploratory purposes are paid currently 100 per cent by Navy. Standard shares current costs only for wells drilled for immediate production as the Section 14-B wells, or for protective or exploratory wells on which Standard has agreed to share the current costs.

The cost of new facilities for increasing the gas processing capacity, such as the new 5.5 million dollar gas plant, are paid currently 100 per cent by Navy, with costs to be shared ultimately.

Stevens Zone operating costs are currently shared according to the present participating percentages listed, as is the production from this Zone. All costs will be ultimately shared according to the final revised participating percentages.

The Carneros Zone production and expenses are still 100 per cent Navy. As this Zone is developed and proved commercially productive, participating percentage interests will be established under terms of the Unit Contract.

The best summary of cost sharing between Navy and

Standard is shown on Figure 8-1, which graphs cost allocations between Navy and Standard from inception of the Unit Contract to 1 January 1954.[125]

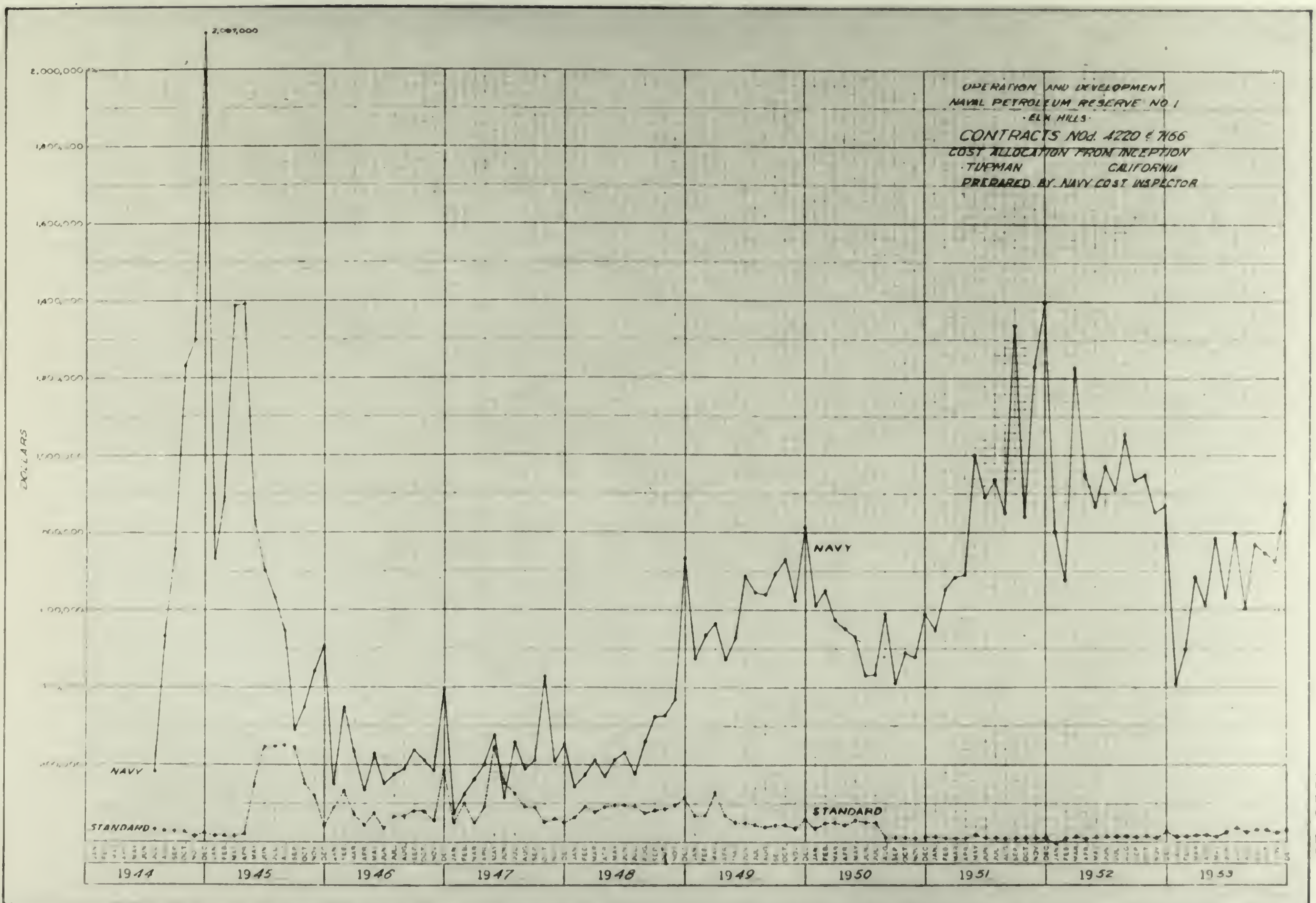

FIG. 8-1, Showing Cost Distribution Between Navy and Standard Since Unitization in 1944.
(Current Not Ultimate Distribution)

COST PROBLEMS

Ultimate Payment of Costs. As of 30 June 1953, Navy had paid an excess of over 9 million dollars above its ultimate share of the total cost to date in exploring, developing, and operating the Reserve.

Under the terms of the Contracts controlling the Unit Operation of the Reserve, this large differential was correctly obtained; and the Unit Contract even provides for the "ultimate" payment of any such differential, which under the terms of the Contract is certain to necessitate a large payment by Standard to Navy. Nevertheless, the nebulous manner in which the Contract provides for the "ultimate" payment and the relatively rapid rate at which the excess paid by Navy is growing have caused some concern on the part of both Standard and Navy. If the Stevens Zone is further developed and if it should prove feasible to develop the Carneros Zone extensively, the excess paid by Navy will soar to an excessively high figure if this development is carried out during non-emergency production periods. However, if Carneros production is obtained only from under Navy's lands, then the Carneros development may not affect the "excess" as the participating percentage for Standard will remain zero.

To the interest of both parties, a more definite time, arrangement, and formula should be developed for bringing costs, as well as production, into agreement on the participating percentage basis. "Uneconomic production," as presently used in the Contract, should be defined more clearly. A specific

formula for ultimate payment would be desirable. Also, it would be desirable to decide now whether the changing value of the dollar is to be considered when ultimate payment is made; for it is unlikely that Standard will wish to make ultimate payment with a dollar at a higher value than the dollar value at the time of the expenditures. In other words, should a cost index be applied?

A recent ruling by the Navy's Judge Advocate General, not seen by the writer but explained to him, apparently interprets the Contract to provide for equalization of costs as well as production should the field be put on full production and before the end of the economic life of the field. This ruling, if agreed to by Standard, may solve the ultimate cost problem to some extent, by bringing total costs as well as production receipts into balance during any extended period of full production.

Other Pending Cost Problems. Currently pending cost problems of a minor and probably temporary nature which serve to illustrate the types of cost distributing problem constantly being encountered in the Unit Operation of the Reserve, are briefly described below:

(1) Under mobilization preparations Navy has paid all costs for plans for new buildings. The problem is whether or not the costs of these plans ultimately will be shared.

(2) Standard as Operator has paid all costs for the new 35-R Gas Plant for which Navy is currently

formula for ultimate payment would be desirable. Also, it would be desirable to decide now whether the changing value of the dollar is to be considered when ultimate payment is made; for it is unlikely that Standard will wish to make ultimate payment with a dollar at a higher value than the dollar value at the time of the expenditures. In other words, should a cost index be applied?

A recent ruling by the Navy's Judge Advocate General, not seen by the writer but explained to him, apparently interprets the Contract to provide for equalization of costs as well as production should the field be put on full production and before the end of the economic life of the field. This ruling, if agreed to by Standard, may solve the ultimate cost problem to some extent, by bringing total costs as well as production receipts into balance during any extended period of full production.

Other Pending Cost Problems. Currently pending cost problems of a minor and probably temporary nature which serve to illustrate the types of cost distributing problem constantly being encountered in the Unit Operation of the Reserve, are briefly described below:

(1) Under mobilization preparations Navy has paid all costs for plans for new buildings. The problem is whether or not the costs of these plans ultimately will be shared.

(2) Standard as Operator has paid all costs for the new 35-A Gas Plant for which Navy is currently

obligated to reimburse Standard in full. The Navy Cost Inspector maintains that a final payment of about $6000 should not be made to Standard until formal acceptance of the new plant by Standard is given to the contractor. [Note: Plant has been accepted and final payment will be made in June 1954.]

(3) Standard has requested surcharges be made to Unit Operations for a supervisory geologist not stationed at the Reserve and for office expenses of the supervisor's office. Navy Cost Inspector disapproves this claim for charges.

(4) When production varies annually by three or more thousand barrels, a new formula must be devised for determining production cost per barrel. This item is important, for it determines how certain costs are distributed between Standard and Navy.

An example of a cost problem which has recently been settled is the following:

Navy drilled a deep exploratory well to hit the Carneros Zone, which was not found. Well was plugged back to the Stevens Zone and brought in as a commercially productive well. It was agreed that the cost of drilling and plugging from the plugged depth to the total depth would be charged entirely to Navy on its non-participating account. The cost of drilling to the productive Stevens Zone would be shared ultimately by Standard and Navy.

INCOME TO NAVY

Production Share. Under terms of the Contract, Navy and Standard ultimately will share in the production of petroleum from each Zone according to their respective participating percentage interests in each Zone -- the latest revisions being listed under the Cost Sharing section of this chapter.

Only the production from the Stevens Zone and Dry Gas Zone is currently shared on this basis. As regards the Shallow Oil Zone production, Navy is now receiving approximately 89 per cent and will continue to do so until the lack of balance in production receipts is brought into agreement with the participating percentages. The Carneros Zone exploration and production is still strictly a Navy undertaking, with Navy receiving all of the minor test production to date.

Sales. As provided under the Unit Contract and explained in Chapter VII of this report, Navy receives from the Operator its share of petroleum products and sells these products to buyers under sales contracts obtained through competitive bidding. Sales of these products from all zones in calendar year 1952 amounted to over 5.5 million dollars and are tabulated below:[125]

Product	Amount Sold	Sales Value
Oil	2,585,642.03 Bbls.	$5,531,761.11
Gas	37,468.00 MCF	5,507.36
Gasoline	553,742.00 Gals.	39,683.98
TOTAL		$5,576,952.45

INCOME TO NAVY

Production Share. Under terms of the Contract, Navy and Standard ultimately will share in the production of petroleum from each Zone according to their respective participating percentage interests in such Zone -- the latest revisions being listed under the Cost Sharing section of this chapter.

Only the production from the Stevens Zone and Dry Gas Zone is currently shared on this basis. As regards the Shallow Oil Zone production, Navy is now receiving approximately 80 per cent and will continue to do so until the lack of balance in production receipts is brought into agreement with the participating percentages. The Carneros Zone exploration and production is still strictly a Navy undertaking, with Navy receiving all of the minor test production to date.

Sales. As provided under the Unit Contract and explained in Chapter VII of this report, Navy receives from the Operator its share of petroleum products and sells these products to buyers under sales contracts obtained through competitive bidding. Sales of these products from all zones in calendar year 1952 amounted to over 5.5 million dollars and are tabulated below:[125]

Product	Amount Sold	Sales Value
Oil	2,585,642.05 Bbls.	$5,531,751.11
Gas	37,428.00 MCF	5,507.43
Gasoline	553,742.00 Gals.	39,663.88
TOTAL		$5,576,922.42

In 1953, total receipts from the sale of all petroleum products belonging to Navy rose to 13 million dollars. All receipts from sales are deposited in the Treasury of the United States under Miscellaneous Receipts.[125]

Unit Sale Values of Products. Of reference interest to some individuals may be the following compilation of approximate unit sale prices obtained by the Navy for its petroleum products over recent years:

Year	Av. Price per Bbl. Stock Tank Oil, Dollars		
	Shallow Zone Oil (°API)	Stevens Zone Oil (°API)	Carneros Zone Oil (°API)
1942*	0.9431		
1943*	0.9745		
1944-1946*	0.9786		
1947**	2.215		
1948	2.53		
1949	2.62		
1951	2.40		
1952	2.17	2.70	
1953#	2.27	3.15	3.17

Year	Natural Gasoline and Butane - Av. Price per Gallon, Dollars##	
	Natural Gasoline	Butane
1942-1943*	0.05375	0.025
1944-1945*	0.0537	0.0373
1946*	0.05583	0.0242
1947**	0.0670	0.0327
1948	0.0868	0.0237
1949	0.0944	------
1950	0.0558	0.0550
1951	0.0726	0.0390
1952	0.0717	------

Year	Natural Gas - Av. Price per M.C.F., Dollars##
1942 - June 1947*	0.06
July 1947**	0.10
1948	0.1079
1949	------
1950	0.12-0.14
1951-1953	0.14

*O.P.A. Ceiling Prices of World War II.
**O.P.A. Ceiling Prices were lifted.
#O.P.A. Ceiling Prices were terminated 2/12/53.
##Some values taken from the record of product prices obtained by Navy for royalty products from N.P.R. #2.

In 1953 it was estimated that the value of Shallow Zone oil with contained gas and natural gasoline was $2.33 per barrel; the value of Stevens Zone oil with contained gas and natural gasoline, $4.07 per barrel -- nearly twice the value of Shallow Zone oil.

STATUS OF APPROPRIATIONS AS OF 30 JUNE 1953*

Summary of All Appropriations	Amount of Appropriation	Expended	Balance
1731307 O & C NPR #1 - 1953	$12,663,000.00	$ 6,675,851.69	$5,987,148.31
1721307 O & C NPR #1 - 1952	11,360,700.00	11,360,700.00	-0-
1711307 O & C NPR #1 - 1951	3,898,000.00	3,898,000.00	-0-
1701307 O & C NPR #1 - 1950	9,329,000.00	9,329,000.00	-0-
1790307 O & C NPR #1 - 1949	8,995,000.00	8,995,000.00	-0-
1760307 O & C NPR #1 - 1946	7,506,127.13	7,506,127.13	-0-
17X1300 Naval Emergency Fund	12,402,500.00	12,402,500.00	-0-
Totals	$66,154,327.13	$60,167,178.82	$5,987,148.31

*Exhibit J from Interim Audit Report #13[148] of 13 September 1953 by NCI under Contracts NOd 4219, 4220, 8477, and 7166.

BUDGET

The preparation and submission of the budget for Naval Petroleum Reserve No. 1 is controlled by the DNPR, who submits cost estimates for the operation of all the Reserves for each fiscal year to the Secretary of the Navy. These cost estimates are submitted 8 to 12 months before the budget for the Federal government is submitted to Congress. The budget for the Reserves forms a part of the overall Navy Department budget submitted by the Secretary of the Navy to the Director of the Budget.

STATUS OF APPROPRIATIONS AS OF 30 JUNE 1953*

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1731307 O & C NPR #1 - 1953	$12,663,000.00	$ 6,675,851.69	$5,987,148.31
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1701307 O & C NPR #1 - 1950	9,329,000.00	9,329,000.00	-0-
1790307 O & C NPR #1 - 1949	6,993,000.00	6,993,000.00	-0-
1760307 O & C NPR #1 - 1946	7,508,127.13	7,508,127.13	-0-
17X1300 Naval Emergency Fund	12,402,500.00	12,402,500.00	-0-
Totals	$64,154,327.13	$58,167,178.82	$5,987,148.31

*Exhibit J from Interim Audit Report #13[148] of 11 September 1953 by NCI under Contracts NOd 4219, 4220, 5477, and 7166.

BUDGET

The preparation and submission of the budget for Naval Petroleum Reserve No. 1 is controlled by the DNPR, who submits cost estimates for the operation of all the Reserves for each fiscal year to the Secretary of the Navy. These cost estimates are submitted 8 to 12 months before the budget for the Federal government is submitted to Congress. The budget for the Reserves forms a part of the overall Navy Department budget submitted by the Secretary of the Navy to the Director of the Budget.

OPERATOR'S ACCOUNTING PROCEDURES[147]

1. Under Contract NOd 4220, Standard Oil Company, Producing Department, established a separate accounting unit at the Reserve to accomplish:
   (a) The determination of all costs of operation, current and cumulative.
   (b) The determination of quantities of production, oil, gas natural gasoline, and associated hydrocarbons, by zone and programs.
2. This unit of about 12 employees is under the supervision of a chief clerk, with functional supervision through the Northern District Accounting Supervisor to the Manager, Accounting Division, Producing Department in San Francisco. It accomplishes its duties under the guidance of accounting and other pertinent manuals which are in company-wide use.
3. At the inception of the contract, conferences were held to reconcile Standard's accounting procedures to Navy's accounting and auditing requirements, there being only minor differences at that time. Similar conferences are held periodically, when necessary, to revise, enlarge, or amend the procedures or form of data presentation, in accordance with the then current operational programs being accomplished under Contract NOd 4219.
4. Standard's procedures are based on:
   (a) Cross-entry journal vouchers summarizing direct or indirect costs.
   (b) Voucher Register. A voucher register is maintained by

OPERATOR'S ACCOUNTING PROCEDURES[147]

1. Under Contract NOd 4020, Standard Oil Company, Producing Department, established a separate accounting unit at the Reserve to accomplish:
   (a) The determination of all costs of operation, current and cumulative.
   (b) The determination of quantities of production, oil, gas natural gasoline, and associated hydrocarbons, by zone and programs.
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4. Standard's procedures are based on:
   (a) Cross-entry journal vouchers summarizing direct or indirect costs.
   (b) Voucher Register. A voucher register is maintained by

months in which each voucher is spread by accounts and prorated to the expenditure control accounts. After balancing, totals are posted to the general ledger.

(c) General Ledger. The general ledger consists of all the main cost accounts affecting the project together with such intra-company accounts affecting this activity as are necessary for the operator to maintain. A trial balance is prepared monthly.

(d) Work in Progress Accounts. Certain general ledger accounts are Work In Progress accounts; Incomplete Construction, Incomplete Wells Plant, Incomplete Development Costs, and Incomplete Shop Orders. On completion of wells or construction jobs they are closed by journal entry to Plant and/or Intangible Development Costs.

5. Cost Statement

A statement of costs is prepared monthly showing costs for the month by zone and program with the allocation of the costs to Navy and Standard; the cumulative costs are similarly shown from inception to date.

6. Production Costs

A statement of production is prepared monthly showing the production for the month of oil, gas, and natural gasoline by zone, and the allocation of the production to Navy and Standard; the cumulative production is similarly shown from inception to date.

7. Payrolls

(a) Field. Daily time cards are prepared and signed by each

field employee and approved by the supervisor in charge. They are reviewed in the accounting office for proper cost distribution, summarized on a bi-weekly time sheet, then sent to 11-C for processing on IBM.

(b) Office. Classified confidential and unclassified confidential payrolls are prepared in 11-C and San Francisco respectively, based on a semi-monthly time report prepared at this activity.

8. Drilling Contracts

All drilling costs, substantiated by verified contractor's invoices, are distributed to cost accounts, and to subaccounts for wells, the credits to Accrued Contract Drilling account. Payments by San Francisco office, offset these credits.

9. Material Sales

In accordance with Contract NOd 4220, Section 6 (d), Standard is required to sell scrap, materials, or equipment, no longer needed for current or future operations, with prior concurrence of the Operating Committee. The credit for these sales is given to the party or parties in the same percentage participation in which the charge was made.

#The majority of the above section on Accounting Procedures consists of direct excerpts, not necessarily complete, from a mimeographed but unpublished report prepared by the Navy Cost Inspector, Mr. Spencer Herrick, revised about 1 July 1952. This report summarizes cost accounting instructions, operator's accounting procedures, and audit procedures.

field employed and approved by the supervisor in charge. They are reviewed in the accounting office for proper cost distribution, summarized on a bi-weekly time sheet, then sent to 11-C for processing on IBM.

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8. Drilling Contracts

All drilling costs, substantiated by verified contractor's invoices, are distributed to cost accounts, and to subaccounts for wells, the credits to Accrued Contract Drilling account. Payments by San Francisco office, offset these credits.

9. Material Sales

In accordance with Contract NOd 4220, Section 8 (d), Standard is required to sell scrap, materials, or equipment, no longer needed for current or future operations, with prior concurrence of the Operating Committee. The credit for these sales is given to the party or parties in the same percentage participation in which the charge was made.

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*The majority of the above section on Accounting Procedures consists of direct excerpts, not necessarily complete, from a mimeographed but unpublished report prepared by the Navy Cost Inspector, Mr. Spencer Harris, revised about 1 July 1952. This report summarizes cost accounting instructions, supervisor's accounting procedures, and audit procedures.

COST INSPECTION

Office Established. On 15 July 1944 the Secretary of the Navy established a Cost Inspection Office at Naval Petroleum Reserve No. 1. Prior to this date there had been no Navy cost inspection service at the Reserve. Practically all costs from the actual inception of the unit operation in November 1942 to June 1944 had been paid by Standard. These expenditures were credited to Standard on the Unit Operations accounts, and a post audit was made by the Cost Inspection Office to determine the correctness of cost allocations back to 20 November 1942.

Organizational Relationships of the Navy Cost Inspector (NCI).[147, 152] The Resident Navy Cost Inspector and his staff at the Reserve are under the control of the Comptroller for the Navy; with chain of command through the Supervisory Cost Inspector for the Western Area located in San Francisco and the Supervisor in the Branch Office at Los Angeles. He is directly responsible to the above officials and no others.

The Navy Cost Inspector at the Reserve (NCI), however, does supply information, advice, and various reports to officials directly connected with the operation of Elk Hills. He provides the DNPR* and INPR in C** with copies of all fiscal reports, either directly or through chain of command. He consults with INPR in C and NMOC on the status of expenditures

*DNPR: Director of Naval Petroleum Reserves.

**INPR in C: Inspector Naval Petroleum Reserves in California.

and appropriations and on the allowability of certain costs. On this latter item, the Operating Committee may override the NCI. The NCI has no relationship with such bodies as the Engineering Committee or the Eleventh Naval District.

Staff of the Navy Cost Inspector

World War II. During the emergency development and production period of the War, a joint Navy-Civil Service staff of about ten members, headed by a Naval Supply Corps Officer, made complete audits of the Operator's expenditures.

Post-War. From 1945 to 1950 the number of employees was reduced to six; from 1950 to 1952, to three. Complete audits were still made but the production and drilling activities had greatly diminished.

Current. About 1 November 1952, the Cost Inspection force was reduced to two members -- the Inspector (Civil Service Accountant, GS-12) and an assistant (GS-8). Comprehensive audits were instituted in lieu of complete audits. These changes followed an inspection by the Navy's Industrial Survey Board. It was determined (1) that operations requiring audit had been reduced, (2) that the Operator's system of internal control was quite adequate, and (3) that the Operator was considered to be of the highest integrity -- a well-earned star in Standard's operation of the Reserve. The Board permits the NCI to continue to make comprehensive audits in lieu of complete audits as long as conditions (1), (2), and (3) above are met, in the opinion and judgment of the NCI.

Duties and Responsibilities of the Navy Cost Inspector[147]

1. Review the Contractor's (Standard's) accounting procedures and system of internal control from time to time in order to determine their adequacy for the Navy audit.
2. On all vouchers presented by Standard for Unit Operation charges or credits, determine the nature of and reason for the charge or credit, and perform the necessary audit. Establish specific auditing procedures for all recurring vouchers insuring that all expenditures are within the scope of the Contract. The Operating Committee may override the NCI on the allowability of disputed costs.
3. Audit Standard's monthly cost statement, reimbursement voucher, and other monthly reports and records. Audited reimbursement voucher is forwarded to the Disbursing Officer, Eleventh Naval District, for payment.
4. Monthly, submit the following principal cost accounting reports to the INPR in C, such reports being forwarded to DNPR:
   - (a) Status of Funds and Expenditures for the Fiscal Year as of the Last of the Month. The effect of this report is to give the Unit Operation staff an idea as to the funds still available for operation and drilling costs.
   - (b) Reconciliation of Costs and Reimbursements from Inception to the Last of the Month.
   - (c) Status of Appropriations as of the Last of the Month.

Reports (b) and (c) cover not only current monthly costs, reimbursements, and annual and special appropriations, but also cumulative totals for these items since inception of the Unit Operation.

5. Render monthly and special statements as required which relate and coordinate operating costs with production costs.
6. Semi-annually prepare a proof of payment schedule, i.e., verification of payment of invoices with cross references to vouchers.
7. Prepare and submit to the Navy an annual fiscal report, termed an Interim Audit Report, on the four interrelated contracts entered into by Navy and Standard. This report summarizes all costs, production, appropriations, cost allocations, and current status of funds and expenditures -- for all zones and for each zone -- from inception of the Unit Contract in June 1944 (retroactive to November 1942) to the end of each fiscal year.

Inspections or Reviews of the NCI Office.

1. Annually, by the Field Supervisor of the Los Angeles Branch Office, who checks accounting and auditing procedures.
2. Periodic review every 6 to 12 months, by a representative of the Government's independent General Accounting Office, who makes a detailed review of vouchers and supporting statements. This audit may result in "informal inquiries," which, if not properly explained, lead to "formal exceptions" and a possible reversal of the Resident Cost

Accountant's decision on a certain item. Although 25 informal inquiries have occurred, all were properly explained and reasons accepted except in one case. The formal exception on this one item, however, was properly cleared. The last informal inquiry occurred in January 1951, over three years ago.

The complete absence of any uncleared formal inquiries and the occurrence of relatively few informal inquiries reflect the excellence of the cost inspection service at the Reserve and the high integrity and excellent accounting procedures of the Operator.

SELECTED REFERENCES IN THE BIBLIOGRAPHY

2, 109, 111, 125, 147, 148, 150, 170, 173.

INDEX TO BIBLIOGRAPHY

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1. FERGUSON, W. H.: "The Public Domain and Naval Reserves," Our Oil Resources, edited by L. M. Fanning, Part 1, Chpt. VIII, pp. 230-237, 1945.
2. History of the Naval Petroleum and Oil Shale Reserves. Issued by the Office of the Naval Petroleum Reserves. (Amended to March 1953.)
3. ISE, JOHN: "The United States Oil Policy," 1926, Chpt. XXV: The Naval Reserves and the Teapot Dome Investigation, p. 356.
4. PETTENGILL, S. B.: "HOT OIL, The Problem of Petroleum," 1936, Chpt. 18: Uncle Sam - Landlord, p. 182.
5. RAGLAND, R. W.: "A History of the Naval Petroleum Reserves and of the Development of the Present National Policy Respecting Them," May 2, 1944.
6. TRACIE, R. G.: History of the Origin and Development of the Navy Department's Policy Relating to Naval Petroleum Reserves. 1 Feb. 1953 (unpublished report filed in Office, DNPR, Wash., D. C.).

B. ORGANIZATION:

7. "Organizational Manual of the Office of the Director Naval Petroleum Reserves, October, 1953.

C. EXECUTIVE ORDERS:

8. No. 3474 of May 31, 1921 - Committing administration of Naval Petroleum Reserves to Department of Interior.
9. No. 4614 of March 17, 1927 - Revoking Executive Order No. 3474 of May 31, 1921.

(Note: Additional Executive Orders Pertaining to Each Reserve Are Listed under the Selected Bibliography for the Respective Reserve.)

D. LEGISLATION RELATING TO NAVAL PETROLEUM RESERVES:

10. Act of June 25, 1910 (36 Stat. 847) "Pickett Act." An act to authorize the President of the United States to make withdrawals of public lands in certain cases.
11. Act of March 2, 1911 (36 Stat. 1015). An act to protect the locators in good faith of oil and gas lands who shall have effected an actual discovery of oil or gas on the public lands of the United States, or their successors in interest.
12. Act of August 25, 1914 (38 Stat. 708. - Amending Act of March 2, 1911 to grant relief to certain claimants.
13. Act of February 25, 1920 (41 Stat. 437) - "Minerals Leasing Act." An act to promote the mining of coal, phosphate, oil, oil shale, gas and sodium on the public domain.
14. Act of June 4, 1920 (41 Stat. 813). - Naval Appropriation Act for fiscal year ending June 30, 1921. Vested in the Secretary of the Navy the conservation, care, protection and operation of naval petroleum reserves.
15. Act of February 8, 1924 (43 Stat. 5). Joint resolution directing the President to institute and prosecute suits to cancel certain leases of oil lands in Naval Petroleum Reserves and incidental contracts.
16. Act of February 27, 1924 (43 Stat. 16) - Joint resolution providing an appropriation for the prosecution of suits to cancel certain oil and gas leases and incidental contracts in Naval petroleum reserves.
17. Act of February 25, 1928 (45 Stat. 148) - An act vesting administration of certain leases made pursuant to provisions of the Act of Feb. 25, 1920 in the Secretary of the Navy.
18. Act of May 13, 1930 (46 Stat. 277) - Joint resolution authorizing settlement in case U.S. v Sinclair Crude Oil Purchasing Company relating to purchase of production by Mammoth Oil Company from Naval Petroleum Reserve No. 3 (Teapot Dome) in Wyoming.
19. Act of June 27, 1930 (46 Stat. 822) - An act authorizing repayment of excess payments made under oil and gas leases.
20. Act of March 4, 1931 (46 Stat. 1523) - An act amending

Secs. 17 and 27 of the Act of Feb. 25, 1920 to authorize cooperative or unit plans of development.

21. Act of August 9, 1933 (47 Stat. 798) - An act amending Act of Feb. 25, 1920, adding Sec. 39 thereto, providing for extension of lessee's tenure during approved suspensions of operations.
22. Act of May 3, 1933 (48 Stat. 30) - An act authorizing the Attorney General with the concurrence of the Secretary of the Navy to release claims of the United States against Pan American Petroleum and Richfield Oil Companies in connection with judgment rendered against Pan American in E-G-I Case B-115M.

*Additional Acts of Congress are listed on page B-23.

E. CONGRESSIONAL REPORTS RELATING TO NAVAL PETROLEUM RESERVES:

23. No. 398 House Committee on Public Lands, re leasing bill S2775 66th Cong.
24. No. 600 Conference Committee report on S2775.
25. Report of House Committee on Appropriations re Naval Appropriation Act of 1921.
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*Additional Acts of Congress are listed on page B-23.

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O. LITIGATION INVOLVING NAVAL PETROLEUM RESERVES

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93. G. W. McCutchen et al., 217 Fed 650; 238 Fed 575
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D. CONGRESSIONAL MATTERS:

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182. No. 4225, May 16, 1925 eliminating additional lands from the reserve (excepting as to the oil and gas deposits therein). This order enlarged area set aside for Ford City Townsite and covered other lands in Sec 12 comprising first addition to Ford City Townsite.

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184. No. 10075, August 18, 1949 - Eliminating Certain Public Lands from Naval Petroleum Reserve No. 2 and reserving them for Townsite purposes. This order made certain of the drill sites in Ford City townsite and the first addition thereto available for townsite purposes.

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V.

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VI.

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251. June 12, 1919 - Order of restoration affecting certain lands in Naval Oil Shale Reserve No. 1, Colorado No. 1. Embraces approximately 3880 acres in T. 6S., R. 95W., 6th PM, Colorado.

NAVAL OIL SHALE RESERVE NO. 2, UTAH NO. 1:

252. December 6, 1916 - Setting aside Naval Oil Shale Reserve No. 2, Utah No. 1 (Embraced approximately 86,531 acres).
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NAVAL OIL SHALE RESERVE NO. 3, COLORADO NO. 2:

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SUBMERGED LANDS:

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260. Act of June 17, 1944 (58 Stat. 280) - An act further amending Act of June 4, 1920, to permit unit operation of private and government lands in Naval Petroleum Reserve No. 1.
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266. Act of August 7, 1953 (67 Stat. 462) - An act to provide for the jurisdiction of the United States over the submerged lands of the outer continental shelf and to authorize the Secretary of the Interior to lease such lands for certain purposes. Outer Continental Shelf Lands Act.

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