Economics of Water Flooding the Grayburg Dolomite in South Cowden Field

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INTRODUCTION

The Paul Moss et ux lease of Forest Oil Corporation is located in the South Cowden Field, Ector County, Texas. This lease is located near the western edge of the city limiits of Odessa, Texas (Fig. 1 and 2). By 1954, oil producing rates for the Paul Moss lease had declined to six BOPD per well. In order to increase producing rates Forest began deepening some wells and employing the technique of sand-fracing at other wells both with good success. In 1955, along with the well workover program, a pilot water injection project was initiated. Four injection wells and one producing well formed the first 40-acre 5-spot. In the past 10 years additional wells have been converted to injection wells (including 17 line injection wells with offset operators) in the 3,354.3 acre Paul Moss et ux lease waterflood.

The successful performance, both technically and economically, of this waterflood, which is operated under the proration rules of Texas, is attributed to the pattern chosen, the planned development rate and the experienced waterflood operation. The economics of this project to date indicate that profitable development and operation will continue for at least 18 more years.

GEOLOGY AND RESERVOIR DATA

The Grayburg Dolomite formation in this field is of Permian age and is located on the eastern shelf of the Central Basin Platform. Forest's Paul Moss et ux lease is on the eastern side of of the anticlinal structure where the dip is about 300 ft per mile to the southeast (see Figs. 3, 4 and 5). Near the center of the Forest project the top of the Grayburg is found at a depth of 4050 ft. The reservoir rock is of dolomite and sandy dolomite. No gas cap was present initially nor is one present now; also, neither is an oil-water contact indicated to be present. Under the Forest project the gross producing interval is near 200 ft with the average net waterflood pay near 40 ft.

From cores taken at the infill drilled injection wells, the porosity averages 7.5 per cent Permeability of the net pay averages 2.4 md. Routine core analysis of a core drilled in oil indicates the interstital water saturation to be 31 per cent of pore space. Reservoir Rock and Fluid Characteristic are presented in Table 1.

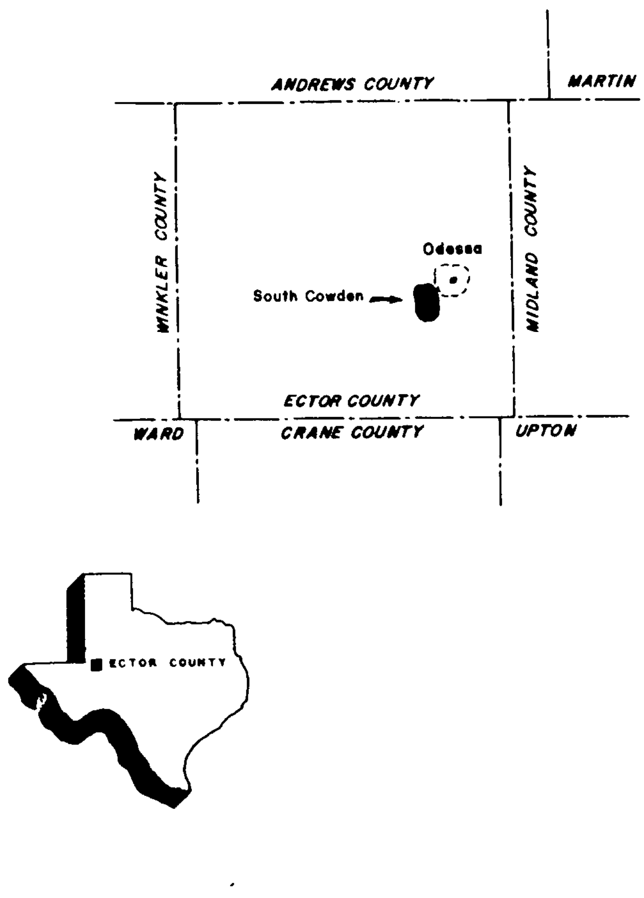

Figure 1 - Location of South Cowden Field, Ector County, Texas

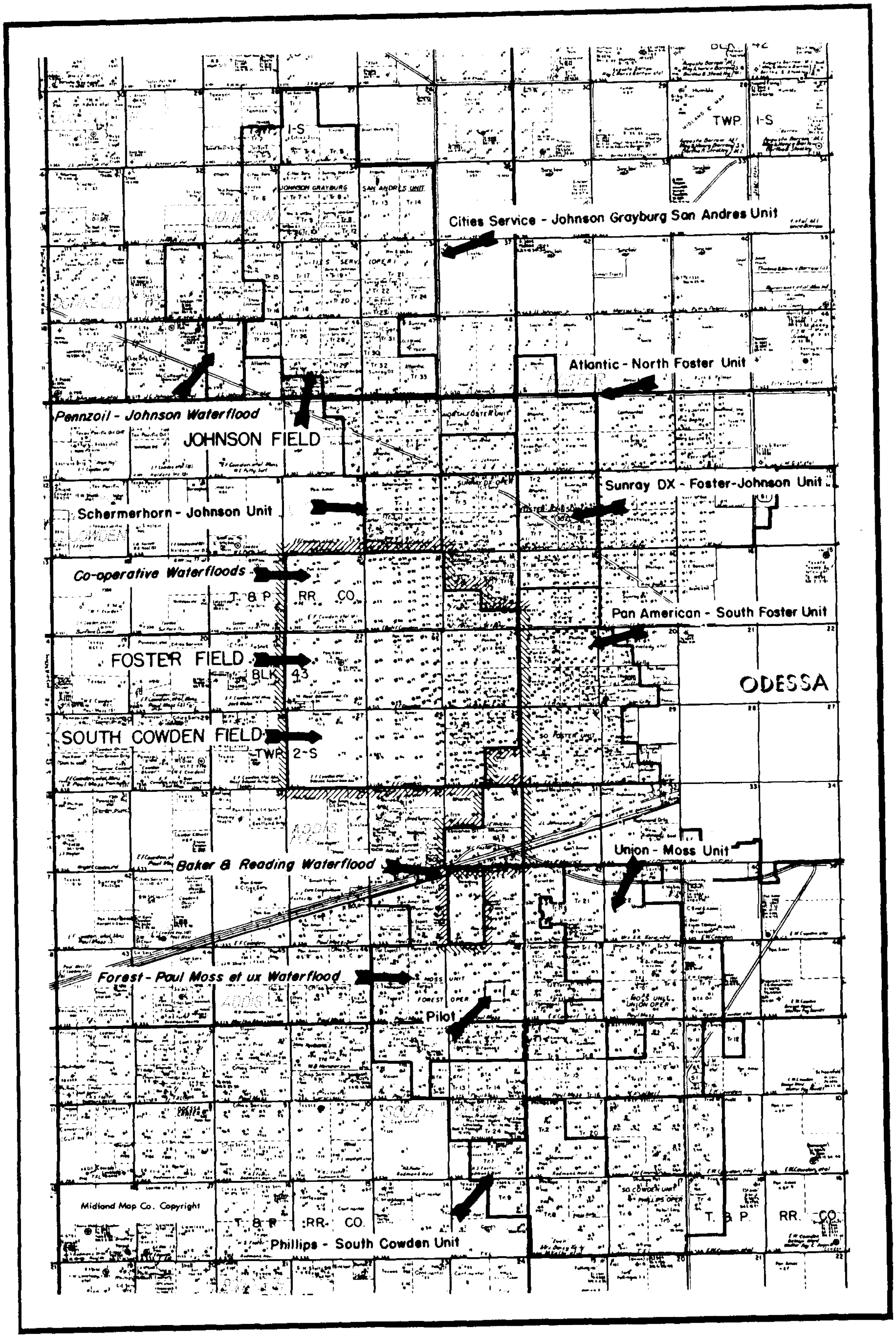

Figure 2 - Map of Forest's Paul Moss et ux Lease Along With Other Water Injection Projects In South Cowden, Foster and Johnson Fields

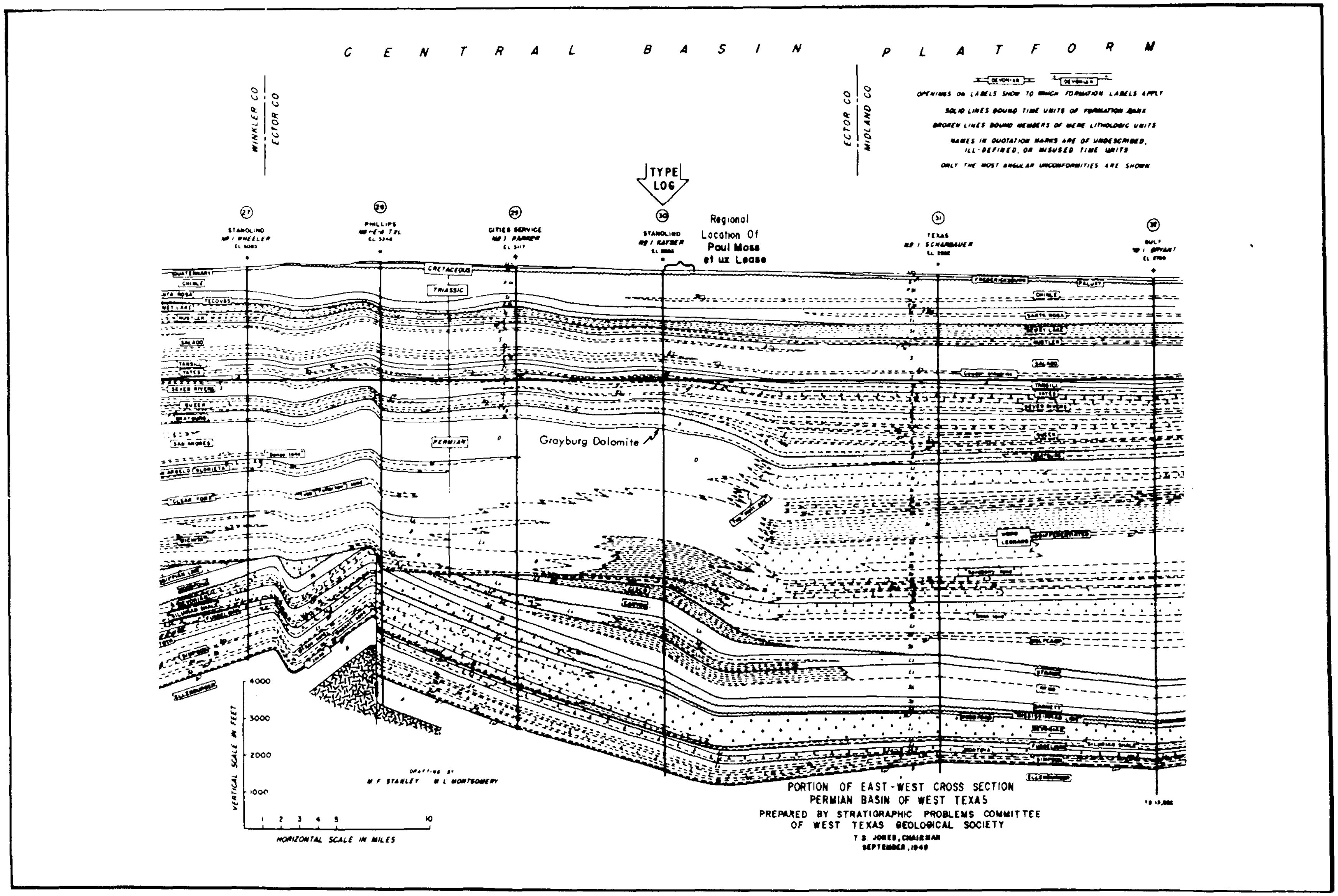

Figure 3 - East-West Cross Section

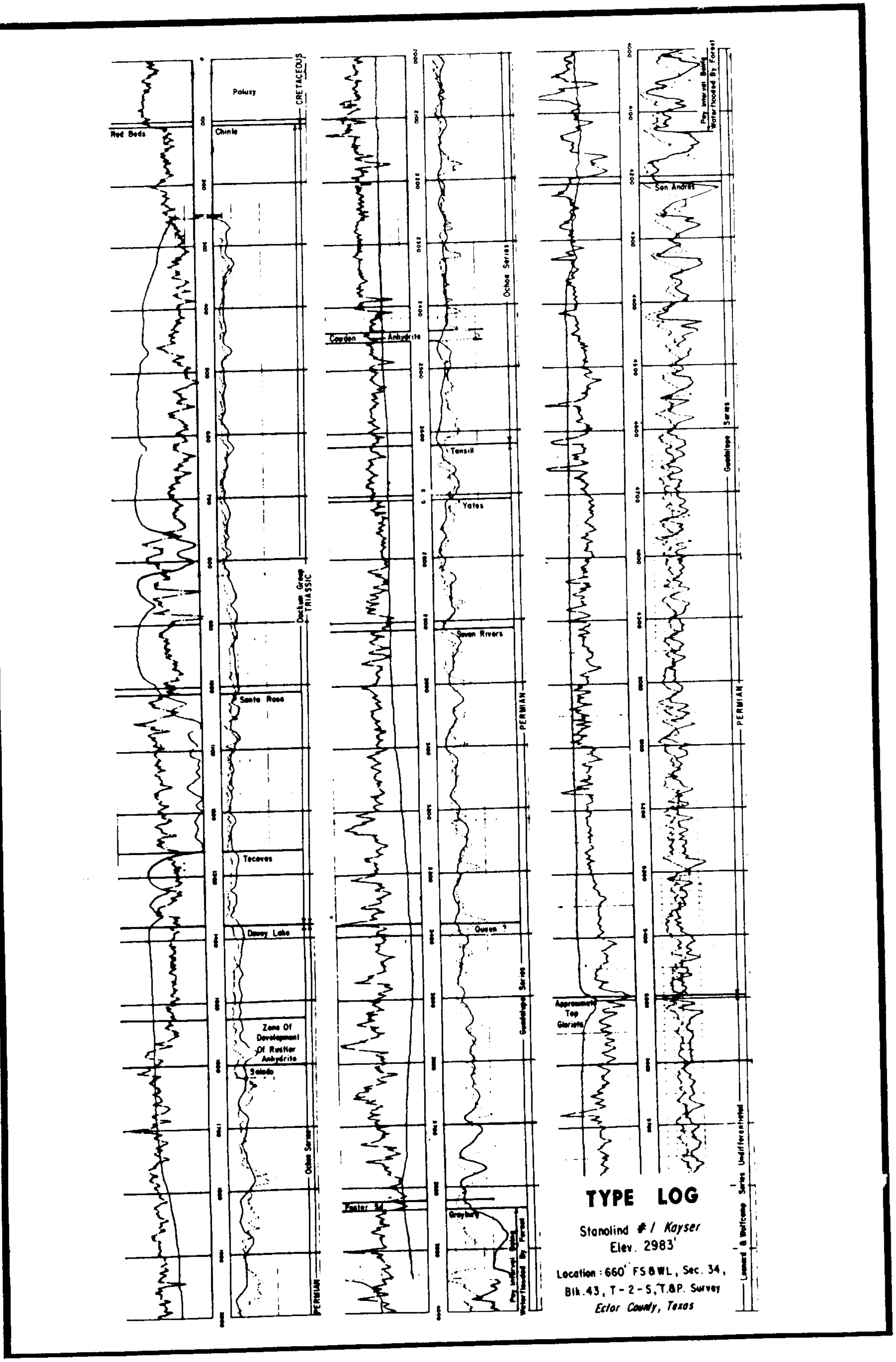

Figure 4 - Type Log

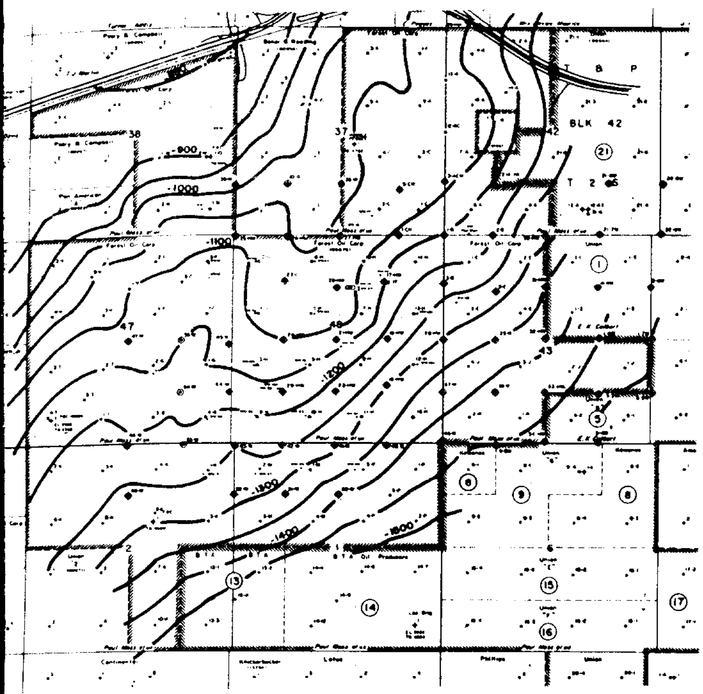

Figure 5 - Structure On Top of Grayburg

TABLE 1. RESERVOIR ROCK AND FLUID CHARACTERISTICS

Producing Zone	Grayburg Dolomite
Approximate Depth (feet)	4,050
Project Area (acres)	3,354
Effective Waterflood Pay Thickness (feet)	40
Physical Properties of Reservoir Rock	
Average Porosity (%)	7.5
Average Horizontal Permeability (md)	2.4
Average Interstital Water (% Pore Space)	31
Pressure and Temperature	
Estimated Original Pressure (psig)	1760
Estimated Saturation Pressure (psig)	325
Reservoir Temperature (°F)	96
Fluid Characteristics	
Oil Formation Volume Factor (bbl/STB at B.P.)	1.09
Oil Gravity (°API)	34.8
Solution Gas-Oil Ration (scf/STB)	160
Oil Viscosity (cp)	2.9

PRIMARY DEVELOPMENT AND PERFORMANCE

Oil production from the Grayburg Dolomite formation underlying the South Cowden Field was discovered November 23, 1932. By May 1, 1949 the field comprised some 234 wells. As Fig. 2 indicates, the South Cowden Field is a southern extension of Grayburg production in the Foster and Johnson Fields. As was the practice during primary development, most of the wells were completed in open hole; original stimulation for production was by shooting with nitroglycerine. With the advent of hydraulic fracturing, about half of the field wells were restimulated by sand-fracing. Infill producing wells were drilled on some leases allowing some wells to serve 20 acres while other wells served 40 acres.

Oil production during the primary phase was by a combination of fluid expansion and solution gas drive. Due to the low solution gas-oil ratio, artificial lift was required early in the producing history. Fig. 6 is a graphical representation of oil production history for the Paul Moss et ux lease as it exists at the present. The graph includes production for Forest's original 50 wells plus production for 26 wells purchased in 1959 and for 24 wells purchased in 1961. Ultimate primary recovery for the 3,354.3 acres was determined by production decline curve extrapolation and by volumetric analysis to be 10,400,700 bls. When the water injection project was initated in 1955, the composite cumulative production was 10,588,200 bbl of which 7,840,200 bbl are attributed to primary and 2,748,000 bbl are considered incremental waterflood bbl.

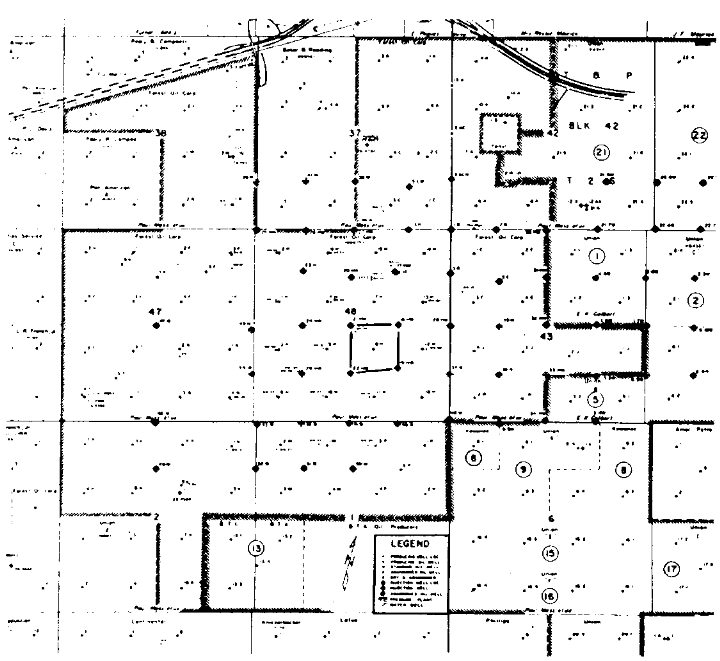

Figure 6 - Map of Paul Moss et ux Lease Showing Waterflood Development

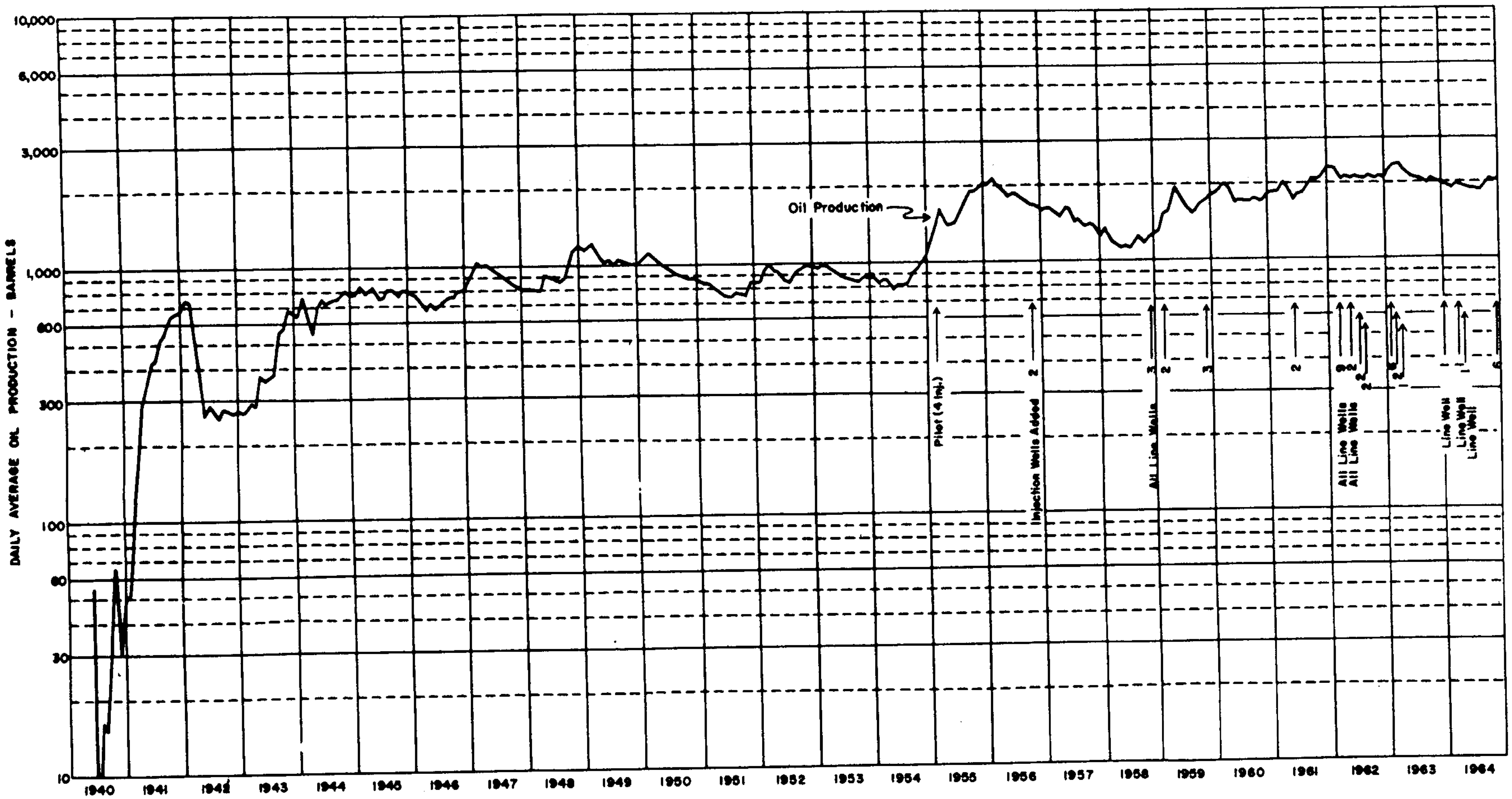

Figure 6 - Oil Production History, Paul Moss et ux Lease (Includes production from wells purchased)

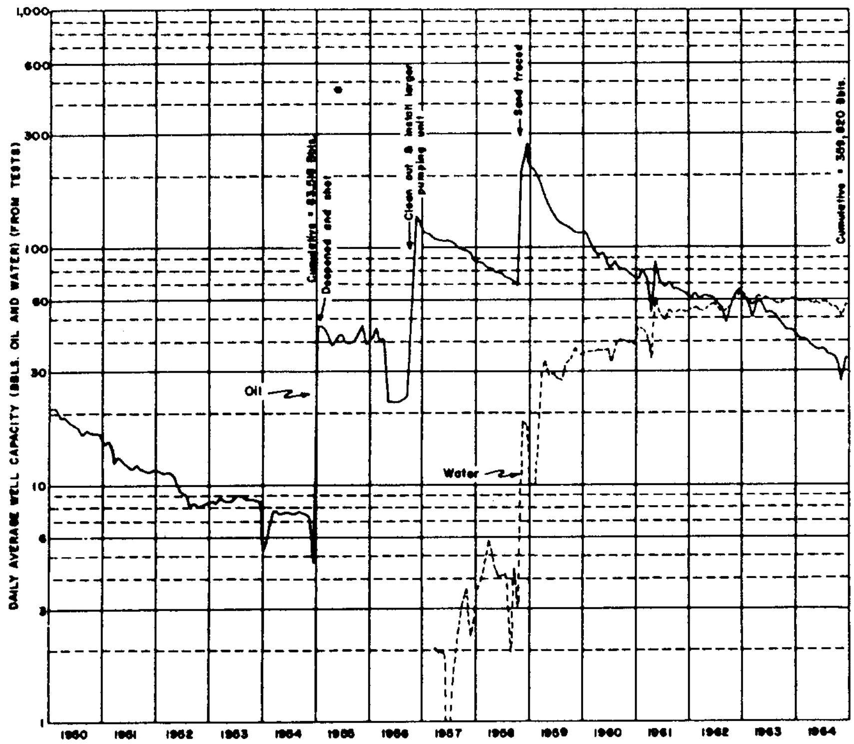

Figure 8 - Performance History, Well 8-H

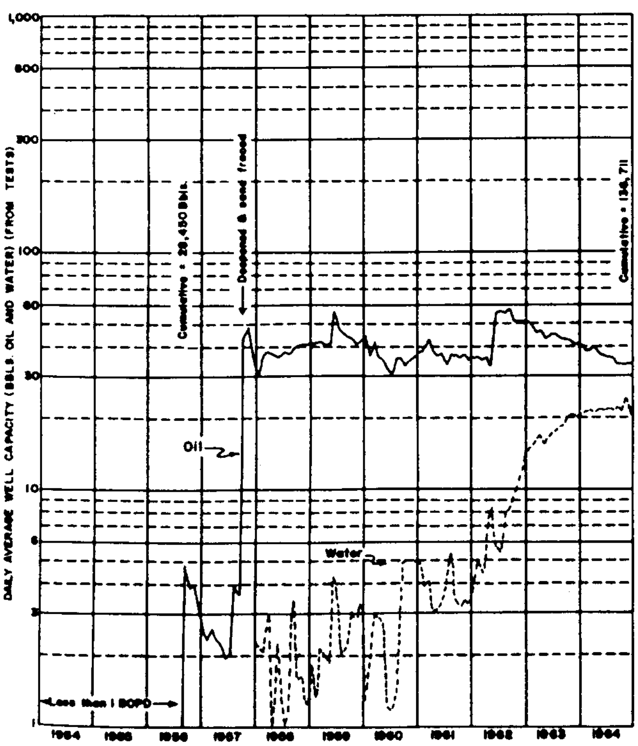

Figure 9 - Performance History, Well 7-H

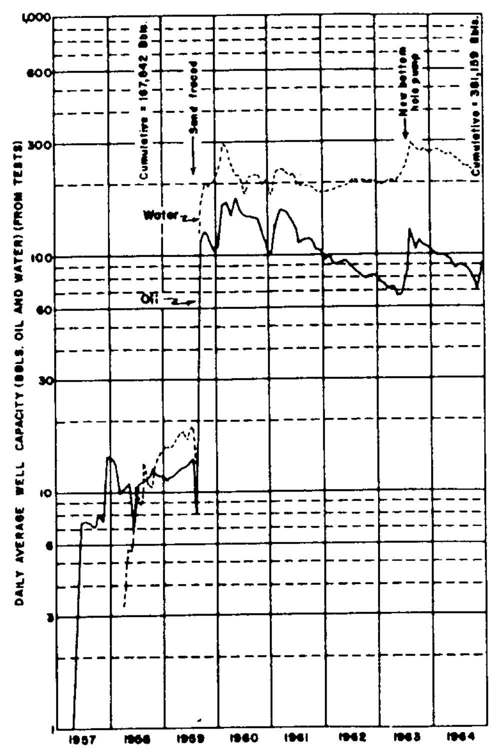

Figure 10 - Performance History, Well 14-H

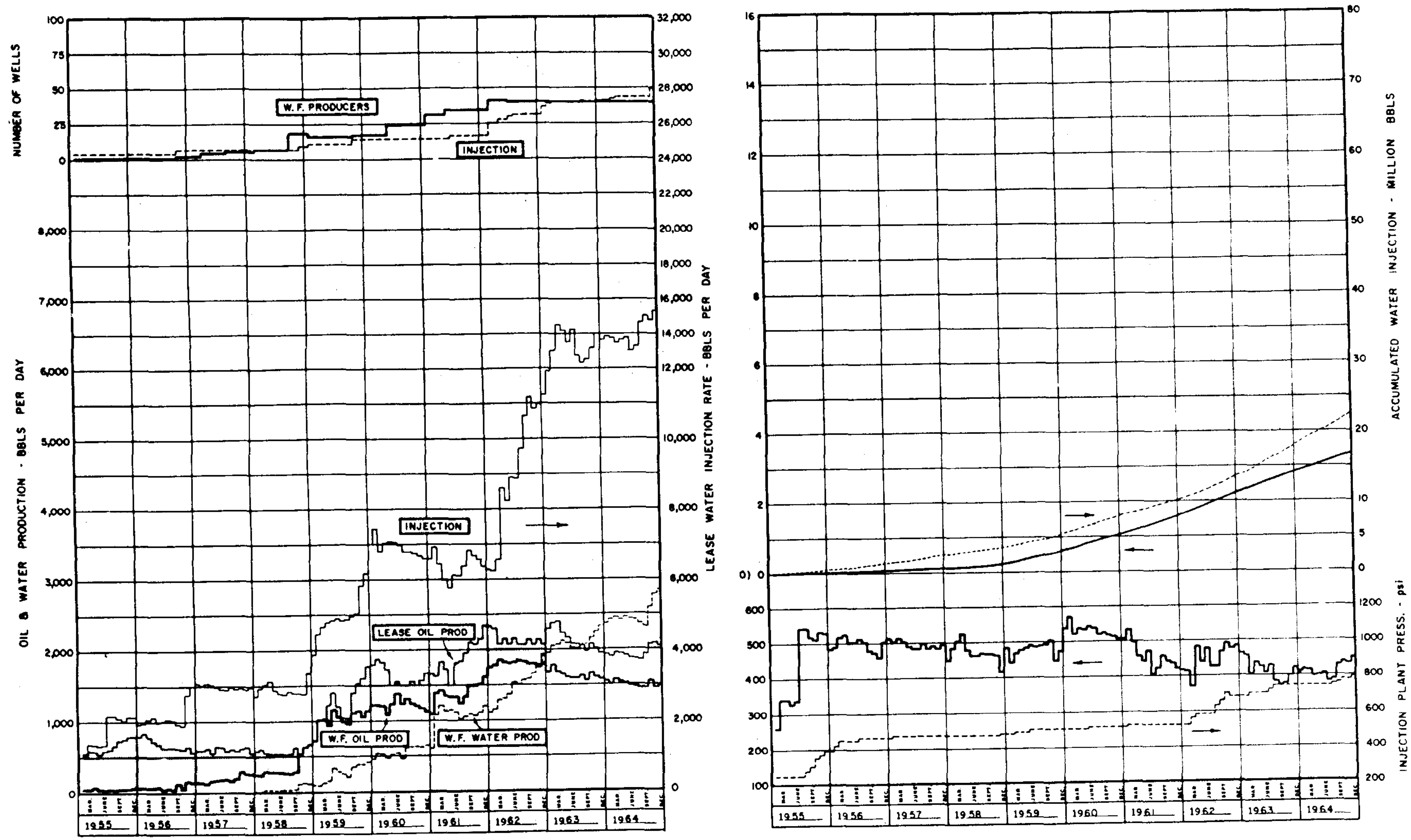

Figure 11 - Production and Injection Performance, Paul Moss et ux Lease

WATERFLOOD DEVELOPMENT AND PERFORMANCE

Production during the program of well deepening and sand fracing in the early 1950's Forest was already studying the area for possible waterflooding. A study of the available reservoir data and their past experience in waterflooding led Forest to believe that waterflood results would be better for 5-spot patterns of 40 acres as compared to that of 80 acres. The infill drilling which had taken place earlier fit in with the 40 acre pattern idea. Even though the well workover program had increased oil producing rates, four producing wells, (18-H, 19-H, 21-H and 22-H) as shown in Fig. 7, were converted to water injection and the pilot injection project was initiated in February, 1955. All four of these wells were completed open hole and none had been sand fraced; water injection took place down cement lined tubing which was set on a packer. The pilot producing well 8-H produced an average of five BOPD in December, 1954. In January, 1955 well 8-H was deepened and shot with 220 quarts of nitroglycerine resulting in a producing rate of 47 BOPD. Producing performance of well 8-H is shown graphically in Fig. 8. Prior to water injection, well 8-H had produced 83,518 barrels of oil compared to 276,302 bbl produced since injection began to January 1, 1965.

In November, 1956 the pilot area was expanded to include well 7-H by the conversion of wells 17-H and 20-H. Production performance of well 7-H is shown in Fig. 9 while Fig. 10 shows production performance of well 14-H. As indicated by Figs. 8 through 10, optimum waterflood producing rates do not occur unless the wells are sand fraced.

As it turned out, the choice of pattern was a fortunate one. In 1958 it was noticed that infill producing wells east and west of the injection wells responded to injection before the 5-spot producers did. This indication of a directional fracture trend has since been confirmed by vertical marks and cuts on open hole packers used during acidizing and by vertical fractures noted in cores. Encouraged by production response to water injection in the pilot area and feeling secure in their selection of pattern, Forest expanded the waterflood area in 1958 by converting two wells and by drilling three line injection wells with Baker and Reading, the offset operator to the north.

With the exception of 1960, Forest has systematically enlarged the waterflood area each year since 1958. Oil production always has been subject to proration control by the Texas Railroad Commission and therefore it has been necessary to follow on incremental plan of development as a result of the various allowables assigned to the lease. he development program has been and is designed to provide the stimulation necessary to produce the maximum allowable, but at the same time to not overstimulate to the extent that oil will be moved off the lease or that waterflood stimulated wells cannot be kept pumped off. Lease production and injection performance are shown graphically in Fig. 11. At the present time the developed and/or stimulated area of the Paul Moss et ux lease includes 1770 acres (1650 developed plus 120 stimulated).

With reference to Fig. 11, the daily allowable for the waterflood from February 7. 1955 to June 15, 1958 was based on the ability of each well in the waterflood area to produce up to 93 BPOD with this amount supplemented by shutting-in wells outside of the waterflood area and transferring their assigned allowables to waterflood wells. All allowables, other than marginal, were subject to shut down days and all wells on the lease, except shut-in wells, were produced. From June 16, 1958 to April 12, 1959 the Paul Moss et ux lease was assigned top lease allowable of 93 BPOD for each of the 39 forty-acre proration units, or 3627 BPOD, subject to shut down days. This allowable was to be produced from the waterflood area only. although, as shown on the graph,some primary wells were produced during the period from June through September. 1958 while the transfer of allowables into the waterflood wells was being completed. From October, 1958 through April 12, 1959, all wells. except those in the waterflood area, were shut-in. On April 13, 1959 the Commission ruled that wells not stimulated by the waterflood could be produced as long as the top lease allowable of 3627 bbls of oil per producing day was not exceeded. This permitted considerable flexibility in adjusting production to shut-down day variations. On September 1, 1959 the original lease was expanded by adding 26 wells. However, due to opposition to a request to the Railroad Commission for the same type allowable assigned the original lease, these 26 wells were authorized an allowable based on 24 hour potential test of each well. The sum of these individual well allowables was added to the orginal lease allowable of 3627 bbls and produced from the unit as a lease allowable. On June 1, 1961 the Moss lease was again expanded by adding 24 wells, bringing the total number of wells to 108. Effective August 1, 1961 the Railroad Commission authorized the Moss lease, "A lease allowable limited to the number of producing wells multiplied by the top allowable, subject to shut-down days, to be assigned as needed". On January 1, 1963 the Railroad Commission authorized the Moss lease the following: "The maximum permissible lease allowable shall be equal to the sum of the top allowables under the field allocation formula for all producing and injection wells on the subject lease, subject to market demand proration limit ation." Further, the Commission approved the request that the subject lease be allowed to produce on a lease gas-oil ratio basis with the wells on subject lease to be exempt from the periodic GO-2 tests.

Production is gathered at six satellite batteries conveniently located on the lease. The oil and water is in turn transferred to a central battery where the clean oil is sold through a LACT Unit and the water is treated and re-injected. The satellite batteries are equipped with separating and testing equipment.

Cumulative oil production for the 3,354.3 acre lease on January 1, 1965 was 10,588,200 bbls. Since January, 1955, just before water injection was initiated, the area has produced 6,567,100 bbls of which the waterflood stimulated area has contributed 3,367,900 bbls. Cumulative water injected at January 1, 1965 was 23,368,333 bbls for a ration of 6.9 to 1 of water injected to waterflood oil produced.

INJECTION

Up until August, 1964 when Forest began purchasing water from Shell's El Capitan Water System, supply water was taken from the Santa Rosa sand found at 1000 ft and from shallow water wells. The Santa Rosa formation in the project area is very erratic in nature and of very poor quality which caused Forest to look elsewhere for a source of water. Before being injected into the closed system, the Santa Rosa and shallow water mixture was filtered and treated for bacteria. Water produced along with the oil is filtered, treated with polyphosphates and injected in a separate closed system. The pressure plant used to inject the Santa Rosa-shallow water mixture involved the use of triplex pumps. Vertical turbine pumps have now been installed to inject the El Capitan reef water which is not filtered or treated. Even though corrosion has not been indicated to be a problem, the entire injection system is protected. The surface injection lines are cement lined and most of the injection wells completed prior to 1962 are equipped with cement lined tubing which, due to the size of the survey tools, prohibits or limits the type of injection surveys available for use. In order to accomodate better injection profile surveys and to allow acidizing down tubing, injection wells completed since 1962 are equipped with plastic lined tubing. Injection well completions have also changed since 1962. It was found that in the open hole completions, vertical fractures native to the pay zone caused communication and poor acid jobs when acid breakdowns were tried using open hole packers. The present practice is to complete injection wells with casing set through the productive intervals. Perforations are then spaced to allow the setting of packers and the acidizing and breakdown of each zone as required.

WATERFLOOD ECONOMICS

Waterflood development cost to date has been $2,222,312 as summarized in Table 2. This amounts to $1350 per acre for the 1650 acres presently developed and includes the cost of production facility consolidation for the entire 3,354.3 acres. When waterflood development is complete Forest will have spent $1490 per acre which compares with the estimated primary development cost of $1400 per acre. The relatively high development cost for waterflood oil has been justified by production performance to date. Under primary operations it is estimated that operating costs (including production and ad valorem taxes) for the 10,400,700 primary bbls would have averaged $0.45 per gross bbl. For the remaining bbls of oil to be recovered under full waterflood operation during the next 18 years it is estimated that operating costs will average $0.65 per gross bbl.

TABLE 2. CUMULATIVE WATERFLOOD DEVELOPMENT COSTS

	Cost
Producing Wells	$466,978
Injection Wells	979,191
Tank Batteries	129,271
Oil Flow Lines	64,456
Electrical System	63,621
Water Distribution System	106,114
Water Supply Wells	164,899
Water Supply Gathering Lines	50,995
Main Water Plant	140,846
Prod. Water Injection System	55,935
	$2,222,312

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