HYDRAULIC LIFT PERFORMANCE, TOM McKNIGHT LEASE, HEADLEE FIELD

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INTRODUCTION

Hydraulic lift performance of the Getty Oil Company McKnight Lease in the Headlee (Ellenburger) Field, Ector County, Texas is the topic of this discussion. Original artificial lift was by gas lift followed by fixed casing hydraulic pumps. Excessive operating costs due to the lack of gas availability resulted in a search for other means of artificial lift. The selection of hydraulic pumps resulted in reduced operating costs. Further evaluation of well capabilities led to the installation of additional surface HP and increased production. Also to be discussed is a unique method of power oil treating for salt and iron sulfide removal.

HISTORY

The Headlee Field is located in East Central Ector County, just east of the City of Odessa, Texas. (See Fig. 1).

Production is from the Ellenburger formation which is found at a depth of about 13,000 ft. The Ellenburger zone in this field is approxmately 180 ft in thickness with an average matrix porosity of about 2% and permeability ranging from 2-175 md. The BHP has declined from 5834 psig to an estimated 3000 psig where it has remained relatively constant due to a fairly active water-drive. Currently, some water is being injected at lower structural levels. Most of the existing wells yield some water along with the oil production. Water-cuts vary generally with structural position; however, sometime in the life of each well large volumes of water production can be anticipated.

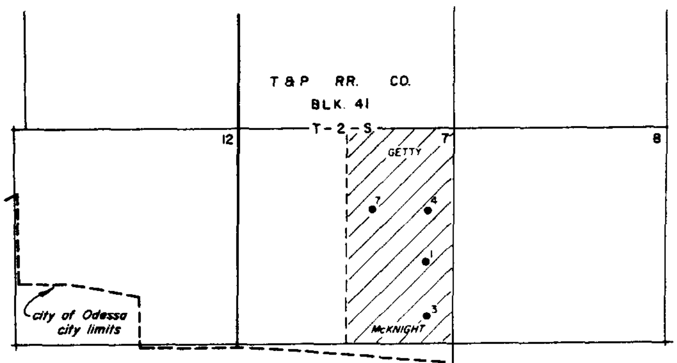

FIG. 1—GETTY OIL COMPANY TOM McKNIGHT LEASE, ECTOR COUNTY, TEXAS.

Artificial lift was first required on the Getty Oil Company Tom McKnight Lease in 1958. Gas lift valves were installed on each well as the water-cuts increased to the point where natural flow could not be maintained. A typical gas lift design consisted of several continuous flow valves generally spaced to a depth of about 8000-10,000 ft. This method of lift proved to be very successful in allowing increased volumes of liquids to be produced, and remained as the primary method of artificial lift in the field for most operators until produced lease gas became less than the volume required for gas lifting purposes. When "make-up" gas requirements became excessive, hydraulic lift installations were initiated in an effort to reduce lifting costs.

HYDRAULIC LIFT

The initial hydraulic lift installation on the Getty Oil Company Tom McKnight Lease was completed on February 6, 1970, (fixed casing pump), in Well No. 4. The typical installation consists of a 4-in. by 2¾ in. fixed casing pump set at about 13,100 ft with a production packer set at 13,130 ft in 5½ in. casing. The tubing size is 2⅜ in. This is illustrated by Fig. 2. Following the hydraulic pump installation on Well No. 4, Well Nos. 1 and 7 were similarly equipped. Surface facilities at this time consisted of a power oil tank, conventional header and a prime mover and pump capable of pumping 2800 BOPD at a pressure of 2200 psig. In November of 1970 additional surface pumping equipment was installed which increased the power oil pumping rate to 5060 BOPD at a pressure of 2800 psig. As illustrated from Fig. 3, the McKnight Lease producing rate was increased from about 400 BOPD in mid-1970 to an average of 550 BOPD in early 1971. The performance of this installation was observed for approximately six months and it was noted that production was remaining fairly constant and that further testing was warranted. Each well was tested to determine:

1. Pump intake pressure
2. Pump efficiency considering shrinkage
3. Engine performance
4. Down-hole friction losses
5. Surface conditions.

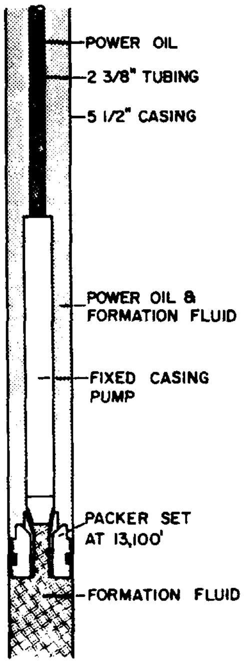

FIG. 2—FIXED CASING INSTALLATION

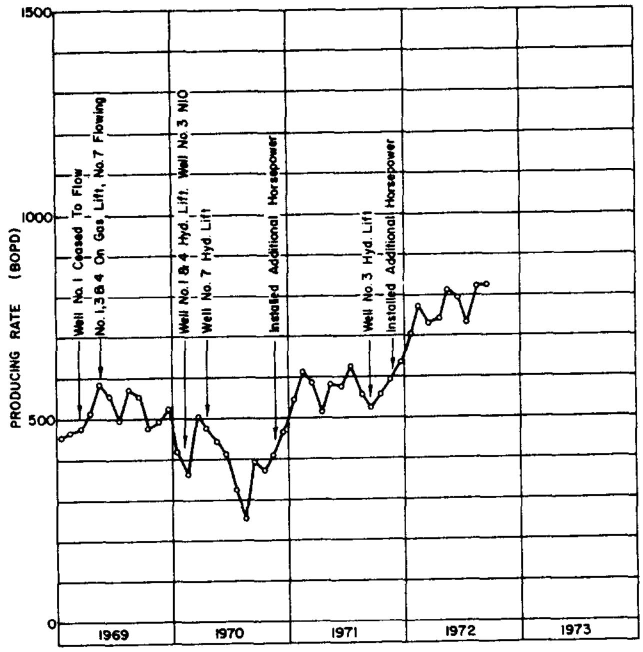

FIG. 3—PRODUCTION RATE

Surface conditions were monitored to determine actual operating conditions and to assist in determining pump speed and if such problems as gas interference or fluid pounding were occurring. Following these tests it was concluded from the calculated pump intake pressures that if additional power oil was available at a pressure of about 3500 psig, an increase in oil production was possible. The results of this testing are illustrated in Table 1. The increases shown in Table 1 are theoretical with maximum operating conditions of down-hole equipment at a required wellhead pressure and volume of power oil. With this information, along with a recording of the surface operating conditions, estimates regarding anticipated operating conditions at the increased rates were possible. Figure 4 is a strip chart illustrating the change of wellhead flow-line pressures and the wellhead power oil pressure in Well No. 3 during a complete cycle of the down-hole hydraulic pump. From this chart it was concluded that gas interference and fluid pound were not indicated. Based on the data obtained, it was decided to install additional surface horsepower to provide the necessary power oil to achieve the indicated production increases. The final configuration of the surface pumping facilities is shown in Fig. 5. Figure 3 illustrates the resulting increase in oil production from an average of 570 BOPD to 800+ BOPD. This increase was essentially accomplished with the same down-hole equipment which existed during the testing period. Present producing rates and size of down-hole pumps are shown on Table 2.

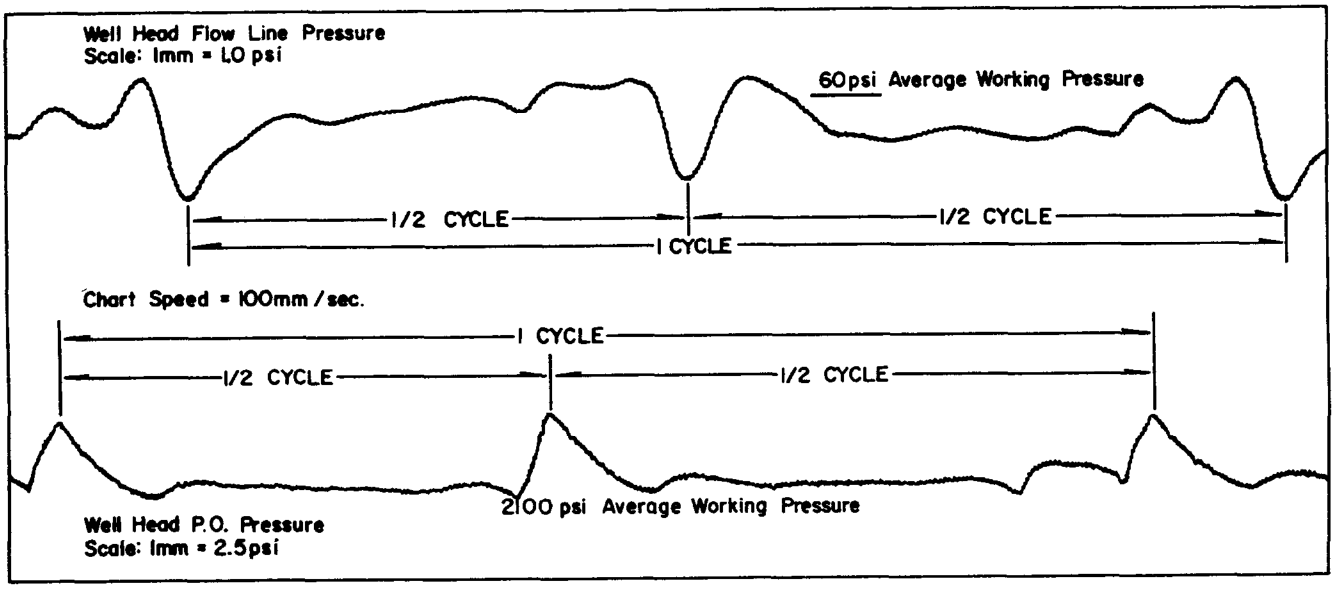

FIG. 4—STRIP CHART, HYDRAULIC PUMP SIZE 4x2⅜x2, GETTY OIL CO., TOM McKNIGHT NO. 3

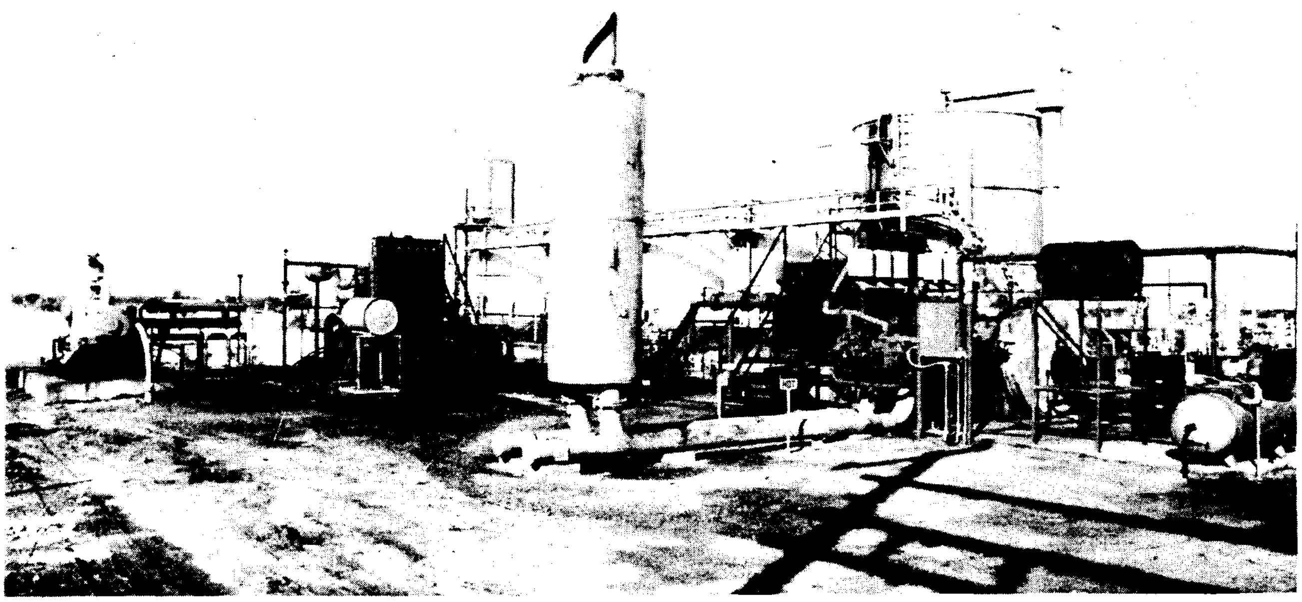

FIG. 5—SURFACE FACILITIES

TABLE 1

WELL NAME	ORIGINAL TEST DATA BOPD/BWPD	BPOPD	WHP	PIP	PREDICTED INCREASES AT MAXIMUM OPERATING CONDITIONS OF EXISTING DOWNHOLE EQUIPMENT BOPD/BWPD	BPOPD	WHP	PIP	OIL,BPD
Tom McKnight #1	287/584	1473	2750	2178	311/634	1808	3027	2104	24
Tom McKnight #3	46/431	957	2100	2825	99/931	2070	3074	2465	53
Tom McKnight #4	220/462	1450	2775	2505	311/653	1808	3322	2187	91
Tom McKnight #7	135/328	1080	2800	2154	228/555	1808	4277	1171	93
Total	688/1805	5060			949/2773	7710			261

TABLE 2—CURRENT TEST AND EXISTING DOWNHOLE EQUIPMENT

	TEST DATA BOPD/BWPD	BPOPD	WHP	PUMP TYPE AND SIZE
Tom McKnight #1	294/448	1885	3400	4 in. X 2¾
Tom McKnight #3	103/710	1540	3350	4 in. X 2¾
Tom McKnight #4	107/528	2149	3500	4 in. X 2¾
Tom McKnight #7	221/594	1500	3900	4 in. X 2¾
Total	935/2280	7074		

TESTING

One of the major problems involved in analyzing this system was production testing. The primary reason was due to the fact that the oil production was very small in relation to the total fluids that were required to be measured. The volume of oil measured daily while testing a single well would approximate 4100 bbl. This volume represents the power oil volume in, power oil out, plus the average well's oil production of about 200 BOPD. Assuming normal metering accuracy of 0.5-1.0%, the variance in test results becomes 20-41 bbl, yielding a possible error in the production test results of about 10-20%. The method now being utilized consists of measuring the power oil by turbine meter which is periodically proved by tank gauge while the crude production plus power oil is metered and gauged for a minimum of four hours. From this, a 24-hour test is calculated as well as measured using the meter factor obtained during the four-hour interval. Test results obtained are then adjusted to the lease's combined crude production which is recorded daily.

POWER OIL HANDLING

The standard power oil handling facilities were originally designed to handle approximately 3500 BOPD. Because of the excessive salt content in the Ellenburger crude in this field, it is necessary to wash the oil with fresh water to reduce this content from 80 to about 8 lb per 1000 bbl. Power oil tanks are normally designed to give a vertical velocity of 1 ft per hour assuming uniform distribution. In view of the increase in production and power oil requirement (5+ ft per hr) it became necessary to either install additional tankage or make certain adjustments in the method of handling the power oil to assure salt removal. The high gravity of oil (51° API) and low suspended solids indicated that a satisfactory system could possibly be maintained utilizing existing tankage. The method chosen was to continuously monitor the wash water for salt content by circulating same over a conductance probe. When the salt content reaches a predetermined point, the wash water is automatically pumped to disposal and replaced with fresh water. The fresh water level in the power oil tank is controlled by a liquid level controller which stops and starts the water supply and maintains a constant water level. A schematic of this design is shown in Fig. 6.

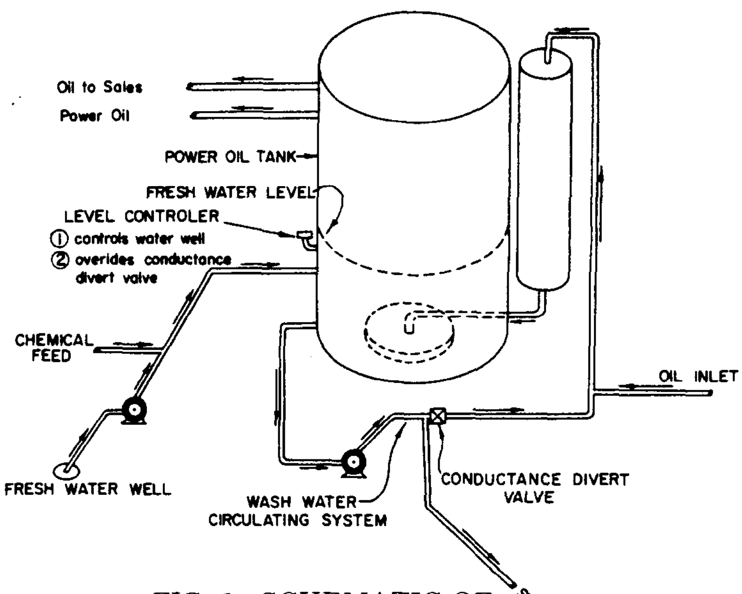

FIG. 6—SCHEMATIC OF WASH WATER HANDLING SYSTEM

The power oil is also treated for iron sulfide removal and inhibited for corrosion control. This overall treating cost is approximately 1.2 mils per barrel of power oil pumped. An attempt has been made to correlate capacitance readings with the iron sulfide content; however, to date, results have been very erratic.

OPERATING COST ANALYSIS

As previously discussed, the conversion from gas lift to hydraulic pump was dictated because of excessive gas requirements or costs. Overall operating cost was reduced from $0.53 per barrel of oil produced to $0.40 per barrel, primarily due to improved producing rates. Lifting cost from the standpoint of dollars per barrel of total fluid was reduced from $0.33 in 1968 to $0.12 in 1972. This is illustrated by Fig. 7. During 1968 Well Nos. 1, 3 and 4 were being produced by gas lift and Well No. 7 was flowing compared to 1972 when all four wells were being artificially lifted utilizing hydraulic pumps. Water production increased from 800 BPD to 1900 BPD during this same period. Figure 8 indicates the increase in contract service or pulling costs following the hydraulic pump installation in 1970 and also an additional increase in 1972. The latter increase in 1972 includes one additional installation and also reflects the performance of down-hole equipment operating at or very near maximum rated conditions. Pulling frequency under these conditions has averaged approximately 2.5 jobs per year per well compared to about 1.7 jobs per year prior to 1972. Figure 9 shows that the average monthly revenue from 1968 through 1970 was relatively constant at about $30,000, with an increase in 1971 to $50,000 and an additional increase in 1972 (first 8 mo.) to $67,000. The overall increase in revenue just from the interchange of lift systems is not as great as it appears because of low allowables from 1968 through 1970; however, existing revenue increase is estimated to be a minimum of 25% under the hydraulic lift system as compared to gas lift. It should not be concluded from the data presented that hydraulic pumping is universally more economical than gas lift in the Ellenburger formation at similar depths; however, under these conditions of gas availability and overall operating conditions, hydraulic lift has proved to be more desirable.

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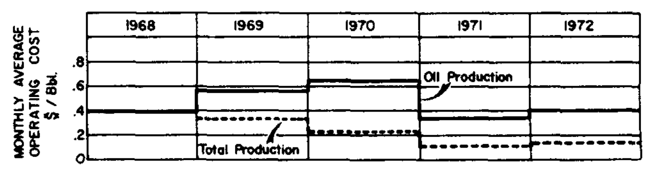

FIG. 7—OPERATING COSTS

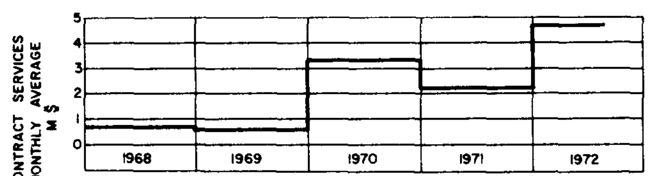

FIG. 8—CONTRACT SERVICES

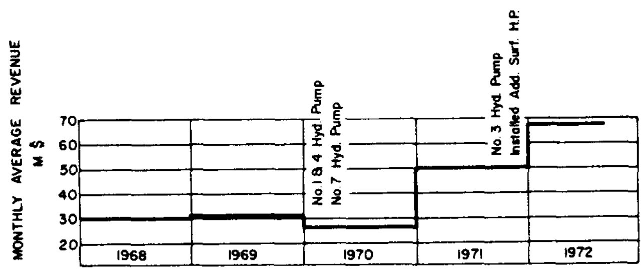

FIG. 9—REVENUE