Pumping Well Analysis for Maximum Profit

By R. R. BARMAN
Sun Oil Company

INTRODUCTION

We have all been impressed during the past few years with the importance of reducing lifting cost simply because of the rapid changes in technology coupled with increased cost. This is the computer age with emphasis being placed on automation and time-saving devices. However, we and few other people can presently afford computerizing the operation and maintenance of pumping wells. We need a program, a program which depends upon the supervisor nearest to the job, a program managed by an engineer with both technical training and practical experience and a program entailing the cooperation and understanding of all field personnel. Gross income increases as does the barrels of oil and cubic feet of gas we sell. Sales are derived through a reduction of downtime and increase in operating efficiency. Proper control of these factors decreases operating expense and thus increases net income. A barrel of oil is normally worth $3.00. If we deduct for royalty, ad valorem and severance taxes, and finding and development costs, we must think in terms of 30 to 50 cents per barrel for operating costs. When we think in these terms, we can realize the dollar influence on pumping well costs.

Solving our pumping problems and obtaining optimum producing conditions will increase net income. A program of pumping well analysis will do this. The management and analysis of pumping wells will provide more efficient and economical practices. To institute a program of this nature we need all the facts pertinent to the well, its equipment, reservoir, fluid characteristics and changes throughout the life of the well. The performance and effect of one on another is of necessity. A successful program requires that well-devised forms and records be maintained. Through the understanding of all personnel, results will be obtained to more than pay for the cost of prevention.

INSTRUMENTS

A pumping well may appear simple but it is complex. Therefore, instruments must be supplied to simplify the complex mechanical and hydraulic changes taking place. An instrument or tool properly applied and understood is a device to save time and money. Briefly, these instruments are:

(1) The Dynamometer measures all loads acting on the polish rod during one complete pumping stroke. The "Dynamometer Analysis Record," Fig. 1, shows the most significant facts and calculations obtainable. It can determine whether or not the traveling or standing valves are functioning properly and measures the effective counter balance. Rod loads, fluid loads and levels, tubing leaks, rod and tubing stretches, and plunger travel can all be determined from the dynamometer card. The dynamometer records excessive loads caused by sticking pumps, paraffin, crooked hole, fluid pound conditions, gas locks, pump efficiency, parted rods, horsepower, harmonic order and other occurrences. These factors in conjunction with field conditions such as corrosion, scale and sand contribute to the failures and poor operation of pumping well equipment.

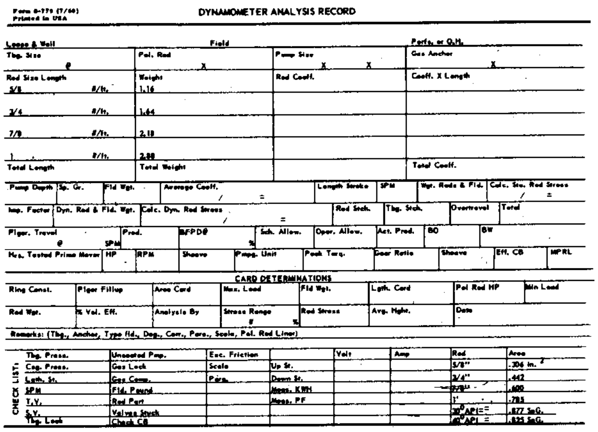
(2) The Acoustical Fluid Level Instrument. Often we can determine very little from loads alone; therefore, the dynamometer should be used in conjunction with other instruments such as the acoustical level recorder. This instrument is a sounding device that works on the echo principle recording depth to fluid. Our greatest single use of this instrument to date is in determining whether an oil well, which is responding to a waterflood, is being produced at its capacity. It has been and continues to be an invaluable tool in determining well bore pressure, optimum and most efficient operating fluid levels, well capacities and other special uses.

(3) The Volt-Ammeter for on-the-spot checks of existing power, counter balancing and

determining the most suitable direction of rotation on electrically powered wells.

(4) The Liquid Level Tank Recorder in studying pumping well produciton for time scheduling.

(5) The Tach-O-Meter to measure engine speed which varies with loads imposed on the unit.


Form 8-779 (7/60)
Printed in USA

DYNAMOMETER ANALYSIS RECORD

Lease & Well | Field | Perfs. or O.H.
Tbg. Size @ | Pol. Rod X | Pump Size X X | Gas Anchor X
Rod Size Length | Weight | Rod Coeff. | Coeff. X Length
5/8 #/ft. | 1.16
3/4 #/ft. | 1.64
7/8 #/ft. | 2.18
1 #/ft. | 2.88
Total Length | Total Weight | | Total Coeff.
Pump Depth | Sp. Gr. | Fld Wgt. | Average Coeff. / = | Length Stroke | SPM | Wgt. Rods & Fld. | Calc. Sta. Rod Stress / =
Imp. Factor | Dyn. Rod & Fld. Wgt. | Calc. Dyn. Rod Stress / = | Rod Stch. | Tbg. Stch. | Overtravel | Total
Plgr. Travel @ SPM | Prod. | BFPD@ % | Sch. Allow. | Oper. Allow. | Act. Prod. | BO | BW
Hrs. Tested Prime Mover | HP | RPM | Sheave | Pmpg. Unit | Peak Torq. | Gear Ratio | Sheave | Eff. CB | MPRL

CARD DETERMINATIONS

Ring Const. | Plgr Fillup | Area Card | Max. Load | Fld Wgt. | Lgth. Card | Pol Rod HP | Min Load
Rod Wgt. | % Vol. Eff. | Analysis By | Stress Range # % | Rod Stress | Avg. Hght. | Date

Remarks: (Tbg., Anchor, Type fld., Dep., Corr., Para., Scale, Pol. Rod Liner)

CHECK LIST:

Tbg. Press.	Unseated Pmp.	Exc. Friction		Volt	Amp	Rod	Area
Csg. Press.	Gas Lock	Scale	Up St.			5/8"	.306 in.^{2}
Lgth. St.	Gas Comp.	Para.	Down St.			3/4"	.442
SPM	Fld. Pound		Meas. KWH			7/8"	.600
T.V.	Rod Part		Meas. PF			1"	.785
S.V.	Valves Stuck					30° API =	.877 SpG.
Tbg. Leak	Check CB					40° API =	.825 SpG.

Figure 1—Front side of Dynamometer Analysis Record Form.

Numerous papers have been written on these instruments, their use, application and interpretation. The scope of this paper is not sufficient to enumerate more on the instruments, pumping problems and corrective measures. It is assumed that anyone who initiates a pumping analysis program will understand actual instrument application. Correct interpretation will come only with use.

THE ANALYSIS PROGRAM

Any program in our business relies on instruments, records, technical knowledge, experience and all personnel from superintendent to pumper. Every one of these is a manager in the true sense but any program needs a person with the responsibility and ability to get things done through other people. He must have and retain control of the program. In a pumping analysis program, he must have field experience. Because of the special problems of technical nature, he must possess technical training and the ability to apply it. Our program places an engineer in charge.

Cooperation, opinions and motivation are essential for a well balanced system. One of the things that we haven't done well in the past but which has vastly improved, is finding out what has or hasn't been done and where prudent practices are not being followed. There has been a slack in the delegation of control and responsibility. This delegation which is now more clearly defined has substantially improved the program within the last few months. Without it, you are not able to coordinate or communicate ideas and improvements to the problem. Each person's contribution to a program of this nature cannot be defined nor placed within limitations. It requires the efforts and cooperation of each operating person to obtain the desired results. We depend upon: (1) reservoir engineers and geologists to provide reservoir data, (2) clerical personnel to record production, proration, performance and equipment data related to the analysis, (3) laboratory analysts to determine fluid content and study special field problems and (4) service agencies and suppliers to provide special equipment and design problems. A pumper can contribute to the analysis since he is in daily contact with the wells. Without his help and that of the foreman, who actualy manages and repairs the wells, you will not have a successful program. A foreman's experience is invaluable but he understands that his training for technical problems may be somewhat limited. However, foremen and other supervisors know that if we cannot get production we lose money. As a result, wells have been placed back on production which shouldn't have been without some thought being given to them. This has resulted in many more premature failures than is necessary. By thinking more and applying it with experience, many pumping well problems can be solved without technical training.

An "Artificial Lift Service Record," Fig. 2 is maintained any time alterations are made in downhole equipment. The supervisor, who repairs the well, records all pertinent data pertaining to rods, tubing, pump, anchor, well data and so forth plus type of failure and problems. Only changes made should be entered to eliminate repetition and excessive detail. The service record related to a particular well can then be kept in chronological order with easy reference to the most recent well data change and last failure. Material changes on the form are also shown for accounting charges. A copy should be retained by the foreman to eliminate unnecessary communication and outside supervision on problems that can be remedied by adequate thought and practical experience. The office copy is checked by the engineer in charge of the program for completeness and accuracy on the type of failure and changes made. Correct data recording is essential in order to eliminate re-occurring problems.

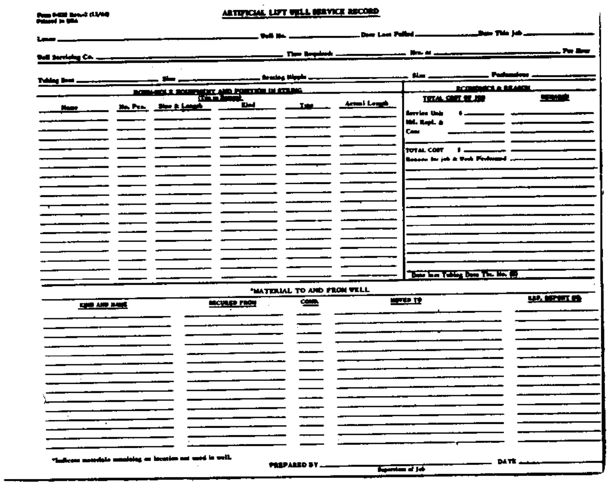


Figure 2

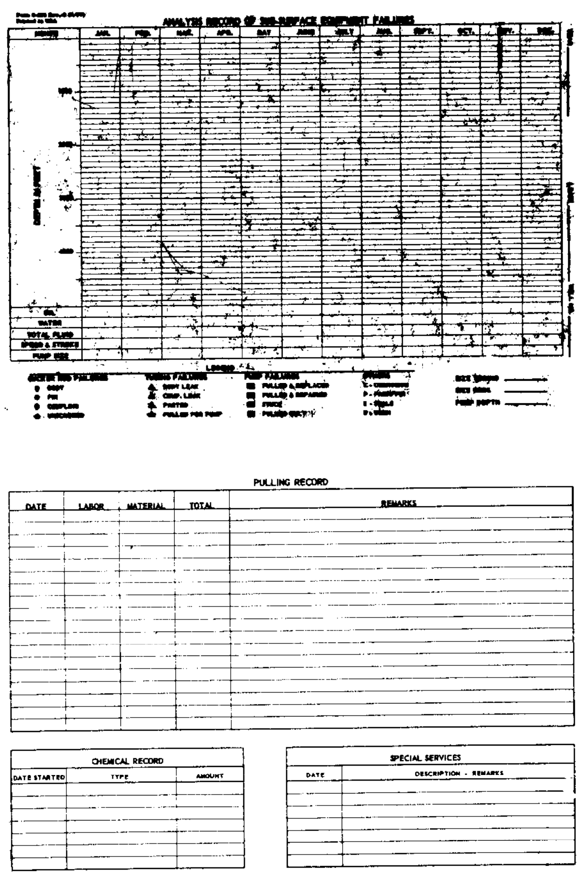


Figure 3—Front and back side of Analysis Record of Sub-Surface Equipment Failures Form.

The service record of failures, cost, production and other pertinent information is plotted on the "Analysis Record of Sub-Surface Equipment Failures," Fig. 3. We believe the graphical record is essential to illustrate before-and-after results on remedial measures or problem frequency.

The failures are plotted on a month versus depth basis and are for a 12-month period. Various symbols are used to classify subsurface failures. Classification of each job as the result of corrosion, paraffin, scale and so forth is also used to explain causes. Inhibition and miscellaneous services can be recorded on the reverse side. An excellent paper titled "A Graphic Study of Pumping Wells" by Bennie L. Franks, Sun Oil Company, was presented in the 1959 Short Course Proceedings and covers in detail failures, types, causes and examples. A form of this type is a quick and easy reference and a valuable aid in annual cost analyses. It can be re-designed to suit your company's needs.

Our actual field measurement is done by an engineer technician. Similar to the engineer in charge, the technician must be well versed in pumping-well problems and general engineering principles. Individual well data are required in the analysis. The "Dynamometer Analysis Form," previously discussed, is devised for all the well data. All or portions of this data, in conjunction with instrumentation and calculation, are normally required for correct interpretation of pronounced pumping problems. The recommendations made by the engineer are the result of either all or part of well weighing, well testing and the aforementioned recording forms. Other forms on labor and material repair of surface equipment are commonly used.

A program of this nature appears to be well organized and systematic but how can a smaller company have such a program? They may not be able to employ an engineer or technician. However, they can utilize the field knowledge and experience of their people plus the interest to gain additional knowledge. Through them and the use of good programming and control, most pumping problems can be alleviated. The oil industry also offers many service people and contractors as specialists in pumping problems from which assistance can be obtained. Through the cooperation and help of both parties, operator and outside source, mutual benefit can be derived and a reduction in the operating company's lifting cost can be realized. It may be a matter of poor economy for a small company to contract "well weighing" each time frequent problems are encountered. Many service people will do this without charge for the benefit of obtaining business by helping the operator. In addition, it doesn't take many wells or problems to justify purchasing a dynamometer or other instruments. Any person with reasonable intelligence, experience and interest in reducing lifting costs can be trained. A good pumper handling 25 to 50 wells where frequent pumping well problems are encountered can, through proper training, be utilized. It is surprising how fast such a program regardless of size, will pay out. Through the use and application of the dynamometer, everyone within the program gains additional insight and knowledge on pumping wells. This added knowledge in conjunction with good records, coordination and thinking on the part of the supervisor next to the job will enhance anyone's operation.

Programming and analysis are to control cost. No one wants to produce a barrel of oil for more than it is worth. Remember the 30 to 50 cents of every barrel that belong to operating cost. To save a few dollars is a responsibility, a responsibility of any supervisor to implement and manage a pumping well analysis program. A few dollars, five for example, in operating costs is equal to the profit from ten to fifteen barrels of oil. As a matter of interest, average per oil well production in the U. S. during 1964 was only 13 BPD. Of the artificially lifted wells, approximately 79 per cent produced less than 10 BPD. It has been said that we should believe in the work we're doing today and in the work we hope to do and in the sure reward that the future holds. That reward can be in the form of personal pride or money. We can be reasonably sure the reward will not be a pay raise if there is little profit because of high operating cost.

A pumping well analysis program is of no value unless a follow-up check is made to ascertain that the desired results have been obtained. It not only entails problem wells or wells with higher failure rates but also routine wells. With increased water flooding and normal changes in well conditions and equipment wear, routine wells must be constantly analyzed for preventive measures. To illustrate the dollar significance and the importance of a continuous program, Table 1 shows the change in the number of pumping wells we have operated and the downhole failure costs.

Prior years and others were not included because of the detailed work of such a survey and the number of wells varied very little. The average failure-free life of the years 1959 and 1961 was 18.7 and 17.5 months respectively. Of significance is the fact that average downhole equipment life has decreased in recent years. This is primarily due to equipment life, field problems becoming more acute, a much greater increase in flooding and water encroachment and the purchase or unitization of wells without operating history. An average failure-free life of one year is still a respectable figure. Any well or number of wells having premature failures or troubles will indicate that without "well weighing" or some form of program analysis, the failure-free life could be considerably less. Proper analysis on some pumping wells has increased downhole equipment life as much as two to nine years. With the complexity and rapid changes taking place in the oil business, it's almost impossible to make all improvements that are needed. We conducted some type of pumping program survey at least 600 times during 1965 on any of the 379 pumping wells. This indicates a continuous program requiring complex work.

Table 1

Well depths are from 1300-8000 feet

No. Wells	Year	No. Failures	Avg. Failure Free Life	Average Per Failure Material	Average Per Failure Labor	Average Per Failure Total	Grand Total
170	1957	219	9.3 Mos.	—	—	—	—
220	1960	181	14.6 Mos.	$133	$151	$284	$51,404
252	1963	200	15.1 Mos.	$132	$175	$307	$61,400
277	1964	275	12.1 Mos.	$ 96	$167	$263	$72,325
379	1965	383	11.9 Mos.	$102	$160	$262	$100,346

EXAMPLES

Failure frequency or life of the downhole equipment does not tell the whole story. There are improvements in inhibition, equipment types, equipment use and salvage that further reduce operating costs. To illustrate improvements that have saved pumping costs, examples are presented.

1300 Feet—31 Wells

Additional development in this field resulted in a total of twenty-two 2½-in. completions. Prior to 1965, operations were relatively trouble-free and initial economics justified the simplest pumping set-up. As a result, the 2½-in. completions were equipped with conventional top hold-down insert pumps seated in a seating nipple which was an integral part of the casing string. Standard ⅝-in. rods served as the connection between the power source and pump with fluid transmitted through the casing. Such an installation required that the pump handle all free and solution gas from the well bore. This proved efficient enough when productivity and pressure were adequate. However, during 1965, poor pump efficiency, scale and sand problems became pronounced. Well weighing pin-pointed the problem wells and where gas locking and compression occurred, pump efficiency had decreased considerably. One and one-half inch tubing, ⅝-in. rods and slim hole insert pumps were installed in nine wells. Conventional mud-gas anchor arrangements were employed and casinghead gas was vented to the flowline. The result was an increase of 65 bbl of oil per calendar day of sustained production paying out total expenditure including investment within three months. The prior equipment, which had been fully utilized, was placed in service elsewhere.

Conventional 2-in. tubing strings were lowered to the perforations in two wells after bottom-hole pressure substantially declined thus increasing production another 15 BOPD.

Composition ring plungers are employed at less cost in some wells where sand is not a problem in order to maintain pump efficiency by allowing gas slippage past the plunger on the down or compression stroke.

All our operations employ gas anchors and casinghead gas is vented to the flowlines or atmosphere. In low pressure wells, it is imperative that good gas separation exist and formation back pressure be minimized. Through good pumping practices we increased production and still maintained a 25 month failure-free life in this field.

1800 to 2900 Feet—45 Wells

Production in this field is characterized by very corrosive hydrogen sulfide, sand and some abnormal high water-cut. Corrosion control through inhibition has been employed in this field since 1952 but the type, amount and frequency had not been greatly improved until 1958. In 1954 there were 121 failures on 38 wells representing a ratio of 3.2 jobs per well. Of this amount, 52 service jobs were on a single seven-well lease. Within two years, well weighing, equipment changes and improvement in inhibition reduced failures by one-half. Constant surveillance extended the average failure-free life to 20 months per well in 1960. We have experienced a minimum of only 15 months per well during any one year since 1960. A survey comprising 13 wells with inhibition initiated during prior and subsequent years to 1960 indicates a reduction of $7500 to $1700 per year. Corrosion control costs were included. On three wells which produce volumes of 250 to 500 BPD at 90 to 98 per cent water-cut, operating costs have been reduced $800 per well per year. Treatment amounts and frequency have also been reduced to further cut chemical costs. Chemical contracts based upon total volume are employed to reduce the cost per gallon used.

Excellent results have been obtained using 3½-per cent nickel seamless steel tubes, stellite balls and seats and monel pull tubes in traveling barrel pumps.

A program of conversion from cup type pumps to the metal-to-metal inserts has shown additional savings. The savings, including the extra cost to repair and replace metal-to-metal pumps and consisting of nine wells, was $1700 per year. By converting, we extended pump life from a previous one to six months with cup pumps to four and eight years with metal pumps.

Downhole separation and compression are production problems in this field. Even with good gas anchor arrangements and the sour casinghead gas vented to the atmosphere, vent lines have to be kept clean of sediment or production is lost. A raise of two or three feet in tubing setting can lose production. This is a field where extreme conditions and problems can and do exist requiring both understanding and a good analysis program. We cannot necessarily condemn certain methods if one or two failures occur within a year. Consideration must be given to the life of the equipment in relation to fluid volume, depth and field conditions.

2700 Fee—139 Wells

Original fluid analyses indicated that paraffin deposition would present a problem and as a result, plastic flowlines were installed throughout the well development program. This has proven to be a wise decision based upon the history and cost of others employing steel flowlines on offset production. Within one to two years, paraffin became a downhole problem. Paraffin accumulation was scraped or hot-oiled on 42 wells at a cost of $2033. The average requirement was one job every 6.3 months at a cost of $48 per job. Chemical treatment and the use of rod scrapers were exploited during this period with neither proving economical nor fully effective. Two wells were also equipped with plastic lined tubing in the top 750 feet. Paraffin deposition was virtually eliminated in the wells containing plastic-lined tubing. There were no unbalanced loads or friction to contend with; therefore, energy costs were appreciably reduced on these two wells. Based upon this analysis, plastic-lined tubing has been employed where economics justify a chance. Thirty-two wells currently contain plastic-lined tubing.

A standard 1¼-in. stroke-through pump has been extremely beneficial in coping with scale deposition. Conversion from standard 1½-in. to 1¼-in. stroke-throughs has been in effect since 1958 and the stroke-through has outperformed the other three to one. Modification of the stroke-through liner type pump to heavy wall has been continuous when liner replacement costs dictate. A non-API but less expensive extension nipple for stroking out of the barrel is used to further reduce replacement costs another $8 to $10 per pump. Composition ring pumps in place of the more expensive precision stroke-throughs are being utilized where effective scale control chemical is employed. Within two years after field development and yet too early for many troubles, we increased downhole equipment life from nine to nineteen months.

As well life progressed, hydrogen sulfide corrosion became more acute. During late 1959, inhibition for corrosion control was started on five wells. The chemical program was reviewed with not only significant results in corrosion control but equally good results in scale prevention. Scale accumulation was prevented because of the chemical's film retention qualities.

Twenty-two wells are currently chemically inhibited for corrosion and scale control. A cost survey was conducted on 17 wells. The failure cost prior to control was $18,000 over a cumulative period of 392 months or $46 per month; whereas, the failure cost after control commenced was only $1000 over a cumulative period of 650 months or $1.54 per month. With inhibition costing only $7.50 per month, a saving of $37 per month was obtained. Projecting the cost differential over a 392 month period, a saving of $14,500 has been realized. This is the minimum saving as both corrosion and scale become more acute with time and equipment use. The comparison was obtained from 74 failures before and five failures after chemical inhibition was started. Chemicals used exclusively for scale prevention were also tried but were either partially or completely ineffective and at greater expense. The adopted chemical has and will also allow time scheduling pump-off wells without sticking the downhole pump. As mentioned, it has allowed the use of less expensive ring-type pumps without jeopardizing service life. No mention has been made of reduced loads and resulting energy cost reduction through inhibition. Any cost figure assigned to this reduction and increased operating efficiency would be guesswork.

Through the aforementioned examples and a continuous pumping-well program, a downhole equipment life of 13 to 25 months has been maintained over the last six years on 60 wells that Sun owned prior to unitization.

To again illustrate the importance of a continuous program, an analysis was conducted on eight 2½-inch-cased completions which Sun acquired through unitization during April, 1965. One well had been equipped with a conventional slim hole insert pumping intide 1½-in. tubing. We equipped the other as such within two months. However, the remaining six were equipped with pumps anchored inside the 2½-in. using a conventional pump anchor less the pack-off to allow gas venting. The well fluids were transmitted through one-in. Kobe tubing which also served as the rod string. Through August, these six wells had 21 failures attributed to scale, corrosion, paraffin and fatigue of the one-in. Kobe. Well production was low and the average failure cost per well was $79 per month. Since waterflooding had just started, a change to 1½-in. tubing, slim hole pumps and ⅝-in. rods was made. Based upon the cost study, which did not include recoverable investment values, total expenditure could be paid out in 24 months by eliminating failure costs. As a result of the change, both increased production and no failures have been reported to date.

With the acquisition of another 73 wells through unitization and waterflooding a constant program of proven practices, equipment changes and prudent pumping well techniques will be required even more to minimize expense.

Miscellaneous Wells

These wells included 36 wells at 2500-4000 ft., 33 wells at 4200-5900 ft, and 25 wells at 6000-8000 ft.

During 1965, we obtained a downhole equipment life of only 11.7 months on the 36 wells pumping from 2500 to 4000 ft. Twenty-eight of these wells, where downhole equipment had seen extensive life and corrosion control was needed but had not been conducted, were purchased during October, 1964. Normally we cannot justify chemical treatment or equipment changes unless similarity occurs nearly twice a year. The 28 wells had not reflected enough frequency in the type failure to improve performance to any degree. Even though the remaining six wells operated under more moderate conditions, their average failure-free life of 36 months indicates that certain improvements can be made only through adequate operating history.

The downhole equipment life of the 33 wells operating from depths of 4200 to 5900 ft has been sustained at 15 to 28 months. Of interest is a dual well wherein the lower zone required pumping under a permanent packer at 5400 ft. This zone was characterized by calcium carbonate scale and solution gas oil ratios of 1000 to 1500 cu ft/bbl. A stroke-through pump and later a ratio pump were employed but production could not be sustained above 2 to 3 BOPD. Finally, a special pump consisting of stroke-through features, sliding sleeves and guide seats were tried. It consisted of a short metal plunger on top with a regular traveling valve ball and seat to hold part of the fluid load. The application was successful in obtaining 24 BOPD while operating trouble-free for four years.

Within the 25 wells operating from 6000 to 8000 ft, 12 wells are located in a cyclic flood program. The flood program necessitates that a few of the wells be equipped with large bore pumps, rods and 2½-in. tubing to 6300 ft. The feasibility of the flood has been under trial for two years. Adverse loads caused by water break-through volumes of 400 BFPD declining to pump-off volumes of 100 BFPD per well within one and two month cycles have been detrimental to equipment. Corrosion became extremely acute within the first six months of 1965. Four offset wells within this flood had 19 failures, which were largely attributed to excessive stresses and corrosion, within a six to eight month period. The disapproval on recommended equipment changes plus the delay in initiating corrosion control were accountable for many failures. These changes in conjunction with corrosion control were later initiated and within the last few months, failures have not reoccurred. This illustrates that problem analysis and corrective measures should be primarily controlled from the field level. An 8000-ft zone contained three wells characterized by water volumes of 350 to 400 BPD per well, scale and severe hydrogen sulfide corrosion. A poor performance record was reflected last year on these wells because the original rods had reached their stress and fatigue life. The problems on these three wells and those within the cyclic flood became so pronounced within such a short time that equipment life averaged only five months for all 25 wells. Similar to the cyclic flood wells, failure on the three wells at 8000 ft have been completely eliminated within the last few months.

6700 Feet—62 Wells

The 62 wells from this depth are characterized by corrosive brine, scale, large water encroachment and flood water volumes. These wells are equipped with 2-in. and 1½-in. bore inserts with ¾-to-1-in. tapered rod strings and 2½-in. to 2-in. tubing from 4400 to 6700 ft operating depths. They require a constant vigilance because of depth, volume and field conditions.

Several years ago we purchased 375,000 ft of surplus rods at a savings of over $100,000. These were employed primarily in this field. We have experienced approximately 90 rod jobs accountable to surplus rod use at an average cost of $255 per job. This reflects a saving of $77,000 to date. Fatigue life became very pronounced last year and this, in conjunction with the inability to obtain power rod tongs in specific instances, accounted for 26 rod failures. The rod failures during 1965 were an increase of 90 to 150 per cent over the previous two years. These failures in conjunction with a more pronounced corrosion problem and water increases accounted for an average failure-free life of only 9.1 months during 1965. In 1963, the failure free-life was one year. Rapid improvements in rod equipment, operating depths and corrosion control have taken place within the last few months.

Pump improvements consisting of carbide balls and seats, special alloy tubes and plungers plus special fittings have been employed to further increase pump life.

A profound increase in water production, well capacity and changes in operating depths from water flooding and natural water encroachment during the last few months have resulted in the purchase of an acoustical fluid level instrument. The purchase price of this instrument was $3000. To date and through its use, we have recovered over $24,000 in tubing and rods which were valued at 75 per cent of original cost.

CONCLUSIONS

With downhole equipment service approximating $200 to $550 per pumping well failure, it is imperative that a pumping well analysis program be employed. An area with 350 pumping wells can spend $90,000 to $100,000 per year while conducting an intensive program of well analysis. The downhole failure cost will approach eight to ten cents per barrel of oil produced. This eight to ten cents per barrel is only one of the many variable costs that are combined into operating expense but yet it is the most significant. Without an analysis program, the cost can be two or many times this amount. The well's performance, its associated equipment and operation must be considered as one in a systematic program. The program should be managed by someone well versed in pumping wells and engineering principles. He must control and coordinate its operation from pumper to superintendent. To conduct a well planned program; accurate records and history must be maintained on:

(1) The well and equipment installations.

(2) The well production and equipment operation.

(3) Reservoir, fluid characteristics and changing conditions.

(4) Field conditions such as scale, paraffin, corrosion and other special problems.

(5) Operating cost and analysis result.

Certain well and equipment performance records must be maintained by the supervisor who normally repairs the well. The application of performance records and field experience can solve many pumping problems at the job site. A continuous program of analysis must be maintained because problems become more acute through equipment use, well life and changing conditions.

ACKNOWLEDGEMENT

The author wishes to thank Sun Oil Company for permission to present this paper and to thank the Sun Oil Company personnel whose assistance made this presentation possible. The opinions expressed in this presentation are those of the author and not necessarily those of Sun Oil Company.