COMPUTER PUMP-OFF CONTROL OF SUCKER-ROD PUMPED WELLS DENVER UNIT, WASSON FIELD GAINES AND YOAKUM COUNTIES, TEXAS

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ABSTRACT

The Shell-operated Denver Unit of the Wasson Field consists of approximately 850 producing wells. Over 700 of these are being produced by sucker-rod pump. Average production is about 400 BFPD with an average water cut of 60 percent.

Surveillance of the rod-pumped wells is being achieved with a computer-based pump-off control. Initial benefits of 4 percent increase in production and an 18 percent savings in electrical energy are being achieved. Other operational benefits which are realized are described.

INTRODUCTION

A problem in sucker-rod pumping design is trying to size the pumping equipment capacity to match the well capacity. Oversizing the pump capacity can result in serious equipment damage due to fluid pound while undersizing will result in less than optimum production. If a gas engine prime mover is used, some variation in pump capacity can be obtained with speed control of the engine. With an electric motor drive, pumping speed cannot be changed without changing sheave size.

A common method used with electric motors is to oversize the pump capacity and operate the pump less than 24 hours per day. Percentage timers are widely used which operate the pumping equipment some percent of a short interval, usually either 15 or 30 minutes. The lease operator can increase or decrease the total time pumped per day by changing one dial setting. A percentage timer can do a very effective job when properly set. The major drawback is that it will not adjust to changing well conditions.

A wide variety of pump-off controllers are available; they are designed to monitor some parameter and constantly adjust pumping time to match well changes. The control parameter is usually motor current, polished rod load, or vibration level. Several of these were described by Westerman.[1] The stand alone, local-logic controllers not tied to a computer have generally performed fairly well on test with close engineering surveillance. However, general experiences has shown that these devices have not performed as well beyond the test phase, probably due to the lack of engineering surveillance.

A computer production control (CPC) system has been installed in the Shell-Operated Denver Unit of the Wasson Field. A major element of the system is Pump-off Control (POC). This paper describes the operational benefits being obtained from POC and some of the engineering studies that can be performed using POC.

THE PUMP-OFF CONTROL SYSTEM

The Denver Unit Waterflood consists of some 850 producing and 325 injection wells. Production is from the San Andres at about 5000 feet. Average per well production is approximately 400 barrels of fluid per day, 60 percent water cut with a GOR of 650. Over 700 of the producing wells are equipped with sucker-rod pumps. The other producers are equipped with submersible pumps. Submersible pumping is used for wells located within the city limits of Denver City and for high-volume producers. The unit has been described by Ghauri, et al.[2]

The rod-pumped wells all have electric motor drive, either Nema D or ultra-high slip. Fifteen minute percentage timers have been in use on all the rod-pumped wells for several years. A pilot CPC system was installed on one central battery with 76 wells in 1975-6. Results of the pilot test were good and approval was obtained for expansion to the entire unit. Essentially all equipment is now installed and about 75 percent of the wells are on POC. All wells will be on control by fall 1979.

The CPC system performs POC, automatic well testing and data handling, and it monitors various alarms. Data is transmitted to central field computers by buried cable. The system configuration and pilot results have been described by Hunter, et al.[3] This paper will not discuss the data collection equipment but will be concerned with use of the POC data.

Each pumping well is equipped with two transducers. One measures load on the polished rod. The other determines polished rod motion by measuring walking beam angle. These data are sampled 12 times per second. The POC computer uses this data to construct and display a polished rod dynamometer card. On request, the computer will calculate downhole conditions using the method described by Gibbs, et al.[4] Examples of surface and pump cards are shown in Figures 1 and 2. In these figures, a card taken 2 minutes after start-up and a pumped-off condition are overlain.

The example in Figure 1 shows a well reaching about the proper degree of pump-off prior to shutting down. Figure 2 shows a well that has reached a severe fluid-pound condition. This well should have been shut down before reaching this condition. Note that there is only 12 minutes time lapse between the full pump and severe fluid-pound conditions of Figure 2. The area of the surface card represents energy input to the rod string. By monitoring this energy level, the computer senses when a given degree of pump-off is achieved.

As a well progresses toward a pumped-off condition, there is less energy input to the rod string in certain portions of the stroke. In other portions of the stroke, more energy input is required. We have found that reliable POC can be achieved by monitoring a portion of the stroke. The Data Analyst (the operator on duty at the computer console) selects 25, 35 or 50 percent of the stroke (from the top down). When the energy level drops below a selected level for that portion of the stroke, the well is shutdown for a predetermined amount of time. The data analyst uses the pump diagnostic

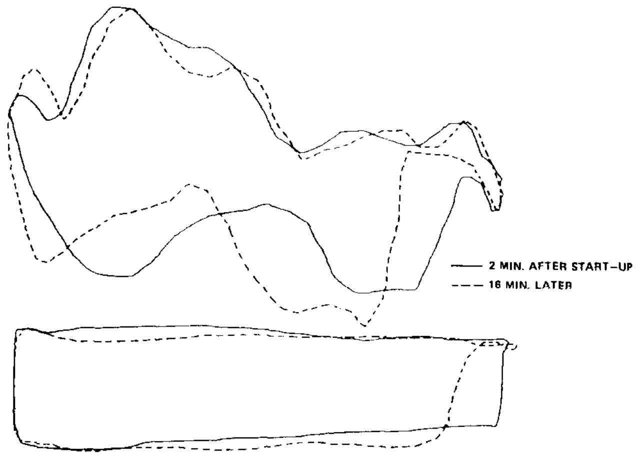

FIGURE 1—DU2824 SURFACE AND PUMP DYNAMOMETER CARDS

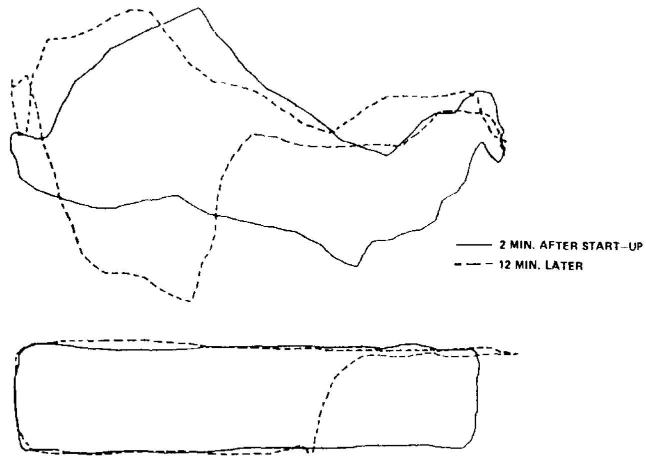

FIGURE 2—DU3911 SURFACE AND PUMP DYNAMOMETER CARDS

procedure to determine the proper energy level for shutdown and for troubleshooting. Control is then exercised on the surface data.

Currently, we select a shutdown time based on well production rate and casing size. Pumping equipment should be sized so that the well needs to pump about 20 hours per day. This minimizes loading due to oversizing while retaining some spare capacity to handle an increase in well productivity or a loss in pump efficiency due to wear. A normal pumping hours per day is determined and stored in the computer. A daily report of well pumping time is printed. Any well deviating more than a selected percentage from normal is spotlighted. The daily pumping time trends are an excellent surveillance tool for spotting pump wear, equipment problems, abnormal well decline, well response in secondary recovery, and others such things. We have studies underway to better define the optimum shutdown level in the pump-off cycle and the proper amount of shutdown time.

There are other features of the POC that are significant. As each well is monitored for pump-off, maximum and minimum loads are checked for limit violations. Two levels of alarm are provided. The first level indicates to the data analyst that a possible problem exists. The second level, which indicates a more severe problem, causes the well to be turned off and prevents it from reverting to the local percentage timer. The well will revert to local percentage timer if valid communication is not accomplished between computer and well during a selected time interval. The percentage timer is set to pump the well its normal pumping hours. This is very important in minimizing downtime if a cable is broken or some equipment malfunctions.

BENEFITS OF PUMP-OFF CONTROL

A problem in POC is determining the optimum production rate for maximum profit. By definition, the maximum production rate would be obtained if we could reduce the bottom-hole pressure to zero absolute. This is physically impossible. However, we are frequently able to achieve production rates that are beyond the maximum profit rate. Many factors such as reservoir pressure, well productivity, equipment size, operating costs, and product price will affect the maximum profit rate. The better we understand our wells, the closer we can come to this optimum rate.

In the Denver Unit, we find two significantly different types of pump-off behavior. Some wells will exhibit a high pump efficiency for a period of time and then very rapidly go to a severe fluid pound. This can occur within one or two strokes. On these wells, it is very easy to set a pump-off limit. A majority of the wells do not exhibit this characteristic. They will gradually increase in severity of fluid pound. The degree to which the pumping equipment is oversized will affect the above. We are considering perhaps 20 percent oversizing here. The first type will occur where there is little or no gas present or excellent bottom-hole gas separation is occurring. When free gas is present and entering the pump with the liquid, the gas will expand as the pressure is lowered until a balance between well productivity and pump displacement is achieved. POC on this type well is more difficult.

With incomplete bottom-hole gas separation, some of the gas will enter the pump and the rest will rise up the casing annulus. This gas rising through liquid can cause a low gradient fluid column in the annulus.[5] Many Denver Unit wells on POC exhibit a high fluid level. In order to determine if pump-off control is actually obtaining optimum production, a series of tests were instituted. A pressure bomb was run underneath the pump with a seven-day clock in order to measure pump intake pressure. The well was put on production and pumped for 4 days using pump-off control. Figure 3 and 4 show the surface and pump cards of the well after the well has been pumping a few strokes and at the last stroke before the well is shut down by the computer. It is easily seen that the pump barrel is filling nearly 100 percent with liquid initially and progresses to a fillage of some 75 percent to 80 percent liquid, with the remaining space containing gas. During this time, the well was pumping about 19 hours per day. The well was then switched to continuous 24-hour pumping. The well was pumped at this condition for 48 hours, resulting in a pump card as shown in Figure 5.

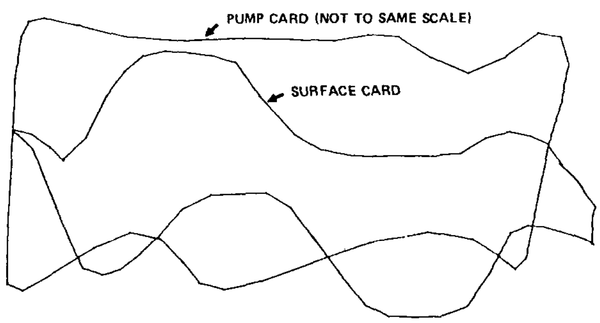

FIGURE 3—PUMP-OFF CONTROL EARLY IN CYCLE

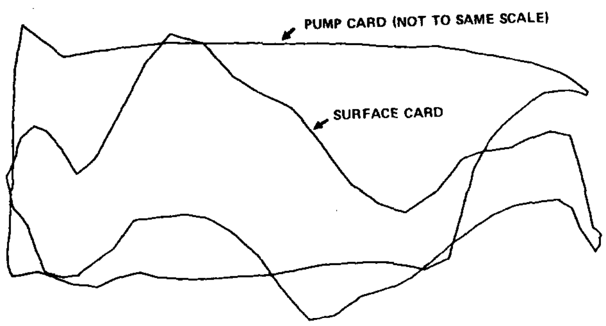

FIGURE 4—PUMP-OFF CONTROL LAST STROKE IN CYCLE

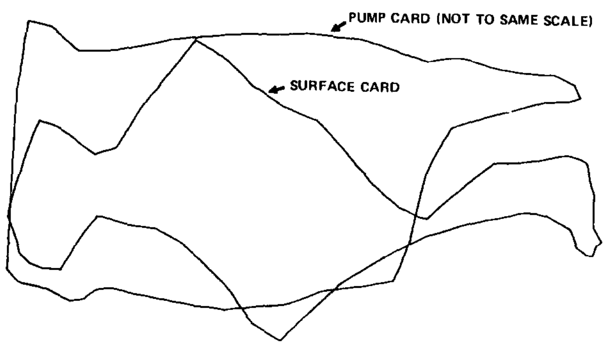

FIGURE 5—CONTINUOUS PUMPING

A comparison of these downhole pump cards, as shown in the overlay on Figure 6, shows that the well stayed in a slightly more pumped-off condition under the continuous pumping than the pump-off condition which was reached on the last stroke of the pump-off control operation.

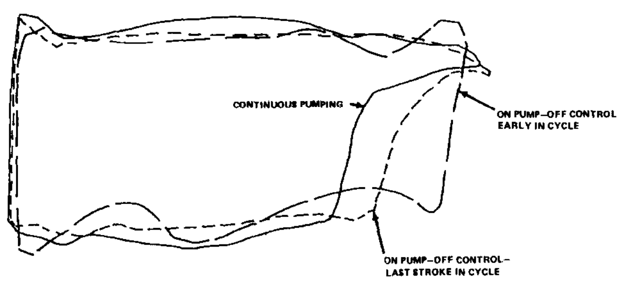

FIGURE 6—COMPARISON OF PUMP CARDS

Pressures were measured during this time and the well reached a stabilized pressure of 415 psi during the pump-off control operation. When the well was put on 24-hour continuous pumping, the pressure dropped over a 36-hour period to 315 psi, a 100 psi additional drawdown. Production increased from 342 B/D total liquid to 360 B/D or about 5 percent. However, our experience on other Denver Unit wells where we have increased the pumping time and tested for longer periods is that the initial increase is about 2 or 3 times the sustained increase after 4 or 5 days. On this basis, we would expect a sustained increase of about 2 percent. The Vogel IPR curve predicts a 2 percent increase for this amount of increased drawdown and a 200 psi static pressure.[6]

The continuous pumping, as shown in Figure 5, will result in increased costs due to greater power consumption and more frequent pulling jobs. Power consumption will increase linearly with pumping time and would be about 25 percent greater in this case. The constant fluid-pound with continuous pumping well increase pulling frequency due to rod, tubing, and pump problems by a substantial amount, probably double or more. The problems associated with fluid-pound will increase with pump size and stroke length. The Denver Unit wells are mostly equipped with large diameter, long-stroke pumps. In this case, if continuous pumping results in doubling the pulling frequency, the 2 percent production increase would be lost due to the additional downtime associated with the equipment problems. Continuous pumping in this case would result in equal or lower production and a lower profit level.

It must be stressed that the above conclusion is valid for the Denver Unit conditions but generalizations must be drawn with extreme care. Local conditions must be carefully considered. As one example, a reservoir might have one or more low-pressure, high-productivity zones which would not contribute unless the pressure is maintained very low.

A careful study of results for the 76 well pilot showed a 4 percent increase in production and an 18 percent reduction in electric power consumption as a result of POC.[3] These improvements were achieved in a field where the sucker-rod diagnostic technique was being used to set percentage timers.[4]

The production increase was accounted for by higher tests on specific wells. No credit was taken for increased production due to less downtime. Some of this will occur as, for example, a rod break is spotted by the computer immediately. The relationship between production increase and energy savings will vary with prior field philosophy—the "Let's get every barrel available" or "Let's not tear up equipment."

USE OF POC ON WELL PROBLEMS

The computer POC can be a powerful tool in solving problems. Quite often, defining the problem is more difficult than solving it. We can spend many hours solving the wrong problem. Onsite well diagnosis is a powerful tool but can be time consuming and expensive.[7] The computer POC offers this capability on a continuous basis.

As an example, paraffin build-up in the tubing is a problem in the Denver Unit. Circulating hot oil or hot water down the casing-tubing annulus periodically is commonly used. This has normally been done with the pumping unit continuing to operate during the job. We have frequently experienced a rod break or pump failure shortly after a paraffin removal job. The cause of these failures was unknown although we suspected it might be related to the heat induced. A well was monitored continuously by computer during a hot-oiling job. Figure 7-10 show the progression of the surface dynamometer cards. These show the well progressing from liquid pumping to a complete gas-lock to normal liquid pumping. This had to result from the hot oil or water moving down the annulus in a piston effect and moving the trapped annulus gas into the pump as a slug. Failure results from the detrimental effects of the severe fluid pound and severe sticking. This well has 5-1/2-inch casing and 2-7/8-inch tubing. Similar results have not been seen where the well has 7-inch casing, apparently due to the larger area allowing liquid-gas bypassing. When the pumping unit is shut down while most of the hot liquid is pumped in, the severe fluid-pound is avoided. This allows the liquid to adequately bypass the gas by gravity and prevent pushing a gas slug into the pump. This technique is now being used and seems to have solved the problem.

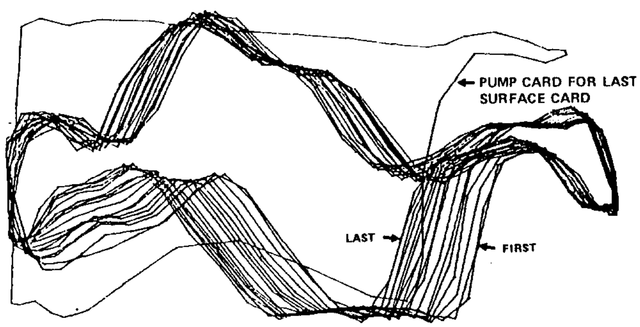

FIGURE 7—START OF HOT OILING

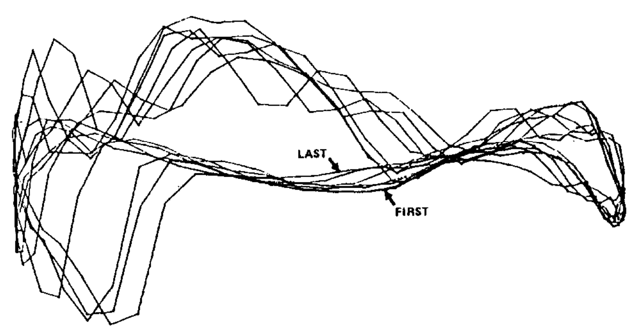

FIGURE 8—GOING TO COMPLETE GAS LOCK

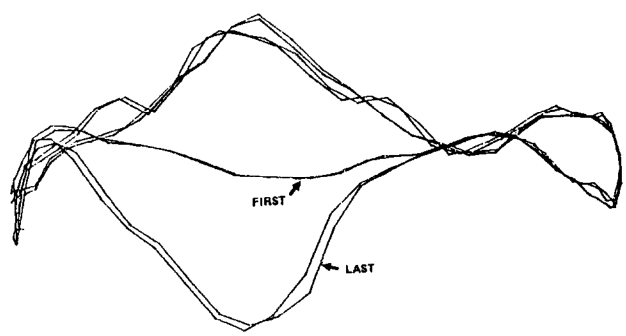

FIGURE 9—COMING OUT OF GAS LOCK

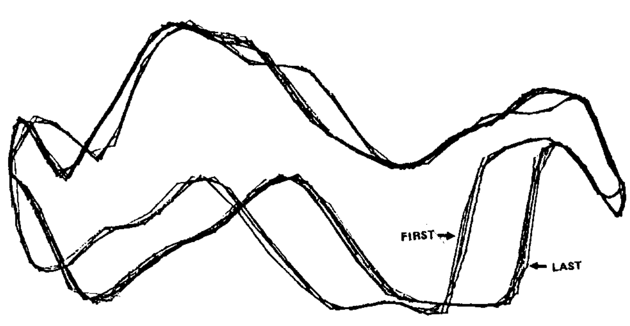

FIGURE 10—RETURN TO FULL LIQUID FILL OF PUMP BARREL

CONCLUSIONS

Computer POC is proving to be very effective in the Denver Unit. An excellent payout of the system is being achieved due to increased production and reduced electric power consumption. Additional benefits are occurring due to reduced maintenance and better understanding of our wells.

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