ROCKY MOUNTAIN OILFIELD TESTING CENTER

PROJECT TEST RESULTS

FLUID LEVEL CONTROLLER

MARCH 31, 1998

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Fluid Level Controller

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Executive Summary

Automated pump-off controllers have been introduced to the market to improve the performance of pump timing. Some petroleum reservoirs produce with a pressure depiction mechanism. At this point, the pump efficiency drops dramatically, and it becomes advantageous to reduce the amount of time that the pump operates. When the pump operates intermittently, it difficult to optimize the pump and shut-in cycles. Automated pump-off controllers have been introduced to the market to improve the performance of pump timing. However, they are not capable of sensing the actual fluid level in the well's casing annulus.

Hi-Tech Off Company's Fluid Level Controller is capable of sensing the fluid level in the annulus. It uses acoustic signals with advanced sensing and filtering to determine the fluid level to within a foot. This information is then used to cycle the pumping unit on and off. The off fluid level can be set above the pump, so that it never goes into a pumped-off condition. This reduces wear on the pump's moving parts and reduces the risk of gas locking. The apparatus is very simple to install and operate.

Since this unit directly measures the fluid in a well, it should be able to increase production in a well that is operated on a timer, or even on a pump-off controller. Cost saving should be realized through better pumping efficiency. The pump does not have to start up in a gas locked condition. it should therefore be able to pump a full card on the first stroke. Pump wear, tubing wear, and rod wear is reduced, minimizing the time between required maintenance jobs. There will be reduced paraffin and scale deposition, reducing the required cleanup treatments. The fluid level controller should enable significant cost savings over conventional pumping installations.

Historically, it has been very difficult to control non-conventional rod pump installations such as the Rotoflex unit, the progressive cavity pump, and the submersible pump. The fluid level controller is able to handle these applications with ease. Many progressive cavity installations have experienced burnt up stators due to the pump being run dry. The fluid level controller can prevent this condition, and drastically extend the life of the stator and improve operating economics. The unit may also be very helpful to plunger lift applications if a packer is not being used.

The fluid level controller has the capability to interface with other SCADA systems or to allow remote access to the well's data through mobile phone, radio. or satellite. Remote control of the unit functions is also possible.

Well 83A4 at the Naval Petroleum Reserve No. 3 was selected as a test well. This well is rod pumped and had a stable production history. It produced enough gas through the casing annulus to produce into the flowline, bucking pump pressure. A digital signal generator (manifold assembly) and microphone assembly was installed on the wellhead. A microprocessor was used to interpret the return signal- This apparatus was able to significantly outperform a conventional fluid level sounder. It is capable of detecting the fluid level to an accuracy of one foot and demonstrated an ability to penetrate a foamy fluid column to read the underlying liquid level.

On February 20, 1998, a high manifold pressure was discovered at the test point. The well was producing very differently against this manifold pressure than against the test vessel. Since these problems caused a change in the stabilized well producing conditions. Dave and Karl packed up their equipment and planned to return the first week in March after we could get things stabilized again. Apparently, the well had not been producing to the manifold, since the higher pressure forced the pump into a gas-lock condition. When the well was put on test, it tested higher than its steady-state potential since it came out of the gas lock condition. The well obviously had a gas-locking problem when the pressure on the backside builds up above approximately 40 psi.

On March 10, David Hill made the decision to suspend the test and get the well producing under stabilized conditions. There was a new generation fluid level detector near completion. He planned to complete the test with the new fluid level controller and a more stable well in April.

Benefits

Production Increase

The fluid in the well will not be allowed to build up high enough to stop inflow, since this condition can be monitored. It could be set up to only build up to half that height before the pump starts up. This will decrease the time weighted average flowing bottom hole pressure and result in additional production.

Maintenance

Since the pump is not operated until it runs dry, there will be less wear on the internal pump parts. This will give the pump longer life and reduce pulling requirements. There should be less rod and tubing wear, since the pump will be pumping the same amount of fluid in fewer strokes. This should also reduce maintenance requirements.

Preventing formation damage

If the formation face is not pumped completely off, there should be less pressure and temperature drop. This will result in a lower rate of scale, paraffin, and salt deposition in the perforations and nearperforation area. Less formation damage means less required cleanup treatments, higher production rates, and ultimate reserves.

Paraffin deposition

When gas breaks out of solution, there is an associated cooling effect, and a decreased solubility to paraffin. In many wells, there is a fluid level at which the conditions stabilize and gas breaks out of the oil column. This causes paraffin deposition on the inside and outside of the tubing. This paraffin deposition causes restrictions in the flow capacity of fluids in the casing annulus, and causes rod friction inside the tubing. The fluid level controller does not allow a static condition to develop. It keeps the fluid level moving up and down and reduces the tendency for specific paraffin deposition areas.

Cost Savings

Cost saving should be realized through better pumping efficiency. The pump will not have to start up in a gas locked condition. It should therefore be able to pump a full card on the first stroke. Pump wear. tubing wear, and rod wear will be reduced, reducing the time between required maintenance jobs. There will be reduced paraffin and scale deposition, reducing the required cleanup treatments. The fluid level controller should enable significant cost savings over conventional pumping installations.

Broader Range of Applications

Historically, it has been very difficult to control non-conventional rod pump installations such as the Rotoflex unit, the progressive cavity pump, and to a lesser degree, the submersible pump. The fluid level controller is able to handle these applications with ease. Many progressive cavity installations have experienced burnt up stators due to the pump being run dry. The fluid level controller can prevent this condition, and drastically extend the life of the stator and improve operating economics. The unit may also be very helpful to plunger lift applications if a packer is not being used.

Test Design

Well Selection

Well 83A4 was selected for the test since it made some gas production and was capable of sustaining some casing annulus pressure. The well was produced and tested to obtain background data. Several other candidate wells were also closely examined, including 17AXI I, 73AI5, 24AXIO and 88AXIO. These wells had various problems, including a hole in the tubing, high fluid levels, and no backside pressure. Well 83A4 had some measurable gas production from the casing annulus and was producing into the flowline.

Well Equipment Description

At the start of the test, Well 83A4 was pumping with the casing annulus closed. Gas produced through the annulus was routed through a check valve and into the flowline, where it was pumped to the production manifold with the oil and water. A schematic of the downhole configuration is shown in Figure 1.

A full port valve and nipple assortment was used to plumb in the test apparatus to the well head on 83A4. The instrumentation on the wellhead was wired to a motor home on location, where the information was monitored with a notebook computer. A 120V power supply was set up drawing power from the pumping unit through a transformer for the mobile home.

Data Acquisition

The fluid level controller uses microphones to acquire the return signals returning from downhole. An armored cable transmits this data to a microprocessor at the wellhead. The microprocessor on the wellhead then interprets the signal. From this interpretation. it determines the depth to fluid. This process is superior to a conventional well sounder in that it is able to read through foamy columns to determine the actual liquid interface.

Pumping Unit Controller

The operator can set the "Pump On" and "Pump Off' levels desired for the pump. These levels can be adjusted at any time to further optimize production from the well. The controller portion of the test has not yet been conducted.

Communications

The unit has the capability to interface with existing SCADA systems to transmit the data to any central point using mobile phone, radio, or satellite communications.

Test Chronology

Pretest Meeting

On February 18, 1998, David Hill and Karl Scheucher took the Fluor Daniel Safety Orientation and a pretest technical and safety meeting was held in the field safety training office. Leo Giangiacorno, project manager. Dick Webb, field engineering technician. and Bill Beahm, electrician, were also in attendance. Bert Eldredge, safety technician, was unable to attend due to a death in the family. The test and safety implications were discussed in detail.

Installation

The prototype data acquisition unit was installed on well 83A4 on February 18, 1998. A 2" full port valve was installed on the wellhead. The unit was plumbed between the pumping tee and the flowline.

On February 19, 1998, one of the microphones was not responding and had to be replaced. The new microphone was again blown when the backside valve was opened too quickly. The microphone was again replaced. As data was being gathered. noise contamination became a problem. it was traced to a flapper-type check valve between the casing annulus and the flowline coming from the pump tee. The data acquisition unit was moved to the vent side of the wellhead A much cleaner signal was obtained at this location.

On February 20, 1998, a high manifold pressure was discovered at the test point. The well was producing very differently against this manifold pressure than against the test vessel. It built to 100 psi and the well stopped making fluid. It was hypothesized that other batteries shipping to B-1-3 were causing high line pressures. When the pressure failed to subside after a few hours, a vac truck was used to pump hot water through the flowline and manifold to clean out possible paraffin plugs. Manifold pressure was 52 psi. When the well was pumping, pressure increased to 75 psi. The wellhead pressure was 90 psi. A Kimray backpressure regulator was installed on the test vessel to match the test conditions to the actual manifold conditions. Since these problems caused a change in the stabilized well producing conditions, Dave and

Karl packed up their equipment and planned to return the first week in March after we could get things stabilized again.

Apparently, the well had not been producing to the manifold, since the higher pressure forced the pump into a gas-lock condition. When the well was put on test, it tested higher than its steady-state potential since it came out of the gas lock condition.

A low-pressure gas gathering line was installed at the well on March 4 to allow it to produce against the high flowline pressure without imposing that pressure on the casing annulus. This allowed the well to produce at a higher rate. However, it invalidated all the background production data that had been collected.

Leo Giangiacoino was out of town the first week of March 1998 so the test was postponed until the following week. When he returned on March 9, 1998, the well would not pump. The tubing was pressured up to 450 psi and held, indicating there was no hole in the tubing. A rig was moved to location and the rods moved downhole 5" and still did not tag the seating nipple. The well would still not pump. The gas was bled off the backside to 30 psi, and the well began to pump. The rig was then moved off the well. Later that day, the well again built up backside pressure and quit pumping. When the pressure was bled off, the well started pumping again. The well obviously had a gas-locking problem when the pressure on the backside builds up above approximately 40 psi.

Future Plans

On March 10, David Hill made the decision to suspend the test and get the well producing under stabilized conditions. There was a new generation fluid level detector near completion. He planned to visit with DOE about extending the contract, and complete the test with the new fluid level controller and a more stable well in April. We also talked about the possibility of instailing the controller on 33-SHX-23. This well is the site of a Cameron test of a new elastomer in a PC pump. The pump recently ran dry and burnt up the elastomer. It would be a good synergistic test for both clients.

Conclusions

1. This fluid level controller has superior capability for detecting fluid levels. It is more accurate than a well sounder and has the capability for penetrating foam columns to detect the real liquid interface.
2. The fluid level controller microphone is sensitive to noise and vibration around the wellhead. A problem was detected with opening the backside valve to blow down the welt and with the chattering of the check valve.
3. The test identified a gas-locking problem with a pumping well that had gone undetected for years. It has the potential to increase oil production and reduce operating costs.

Recommendations

I. The fluid level controller should be further tested in the controller mode when stabilized conditions are reached on the 83A4 well or another suitable well.
2. The fluid level controller should be installed on 33ShX23 in conjunction with the Cameron PC pump test.
3. Recommendations for pumper interface with the controller should be thoroughly investigated.
4. Power consumption should be measured and the energy savings because of the operation of the fluid level controller should be accurately measured.
5. The remote monitoring capabilities of the system should be field-tested in conjunction with Orbcomm.
6. The capabilities of the unit to self optimize the pumping conditions should be further developed and field-tested.

API 40-025-10366

Well 84AX3
Wellbore Schematic

Naval Petroleum Reserve #3
Teapot Dome Field
T 38N R 78 W SE NE Section 10
1650 FNL, 330 FEL

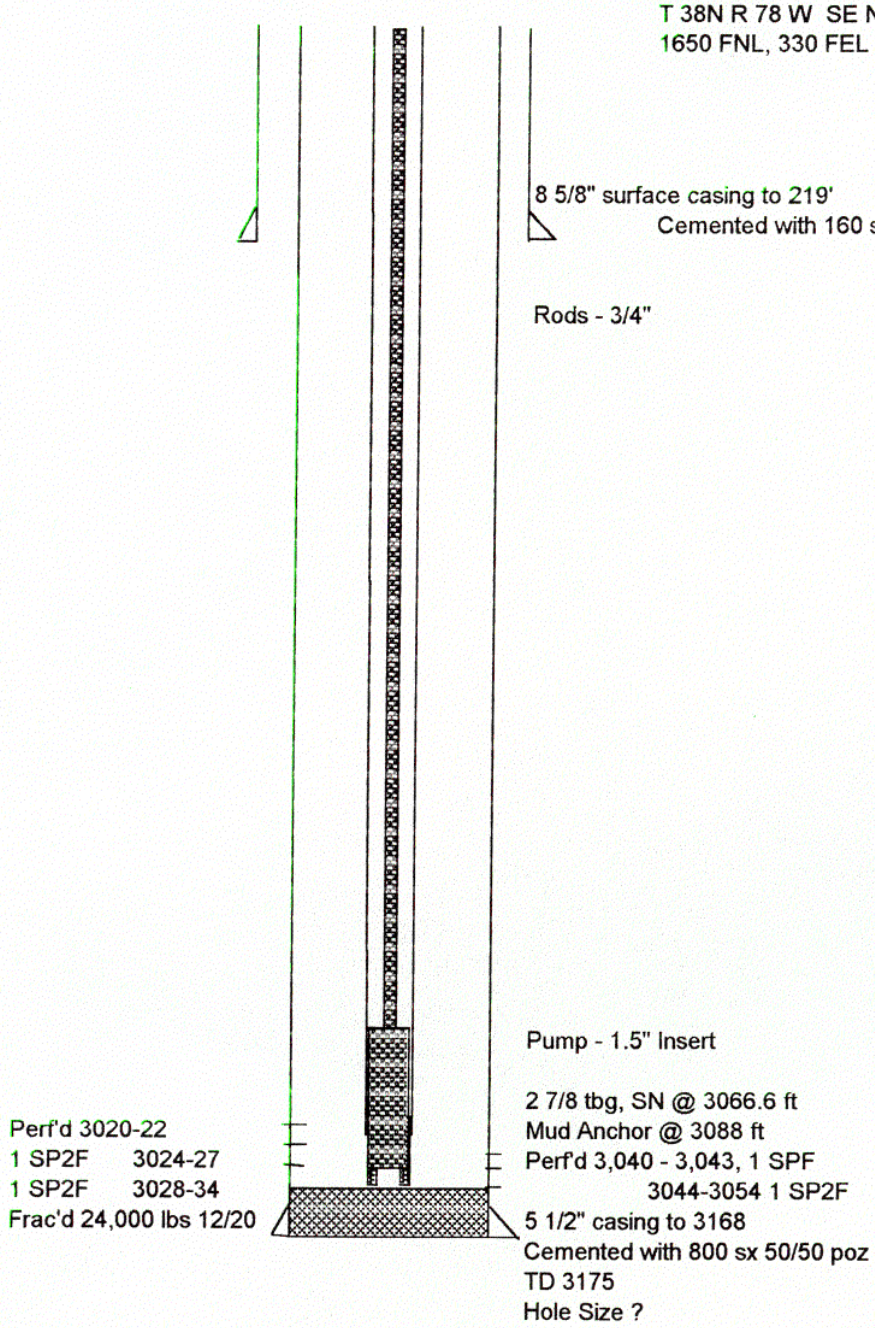
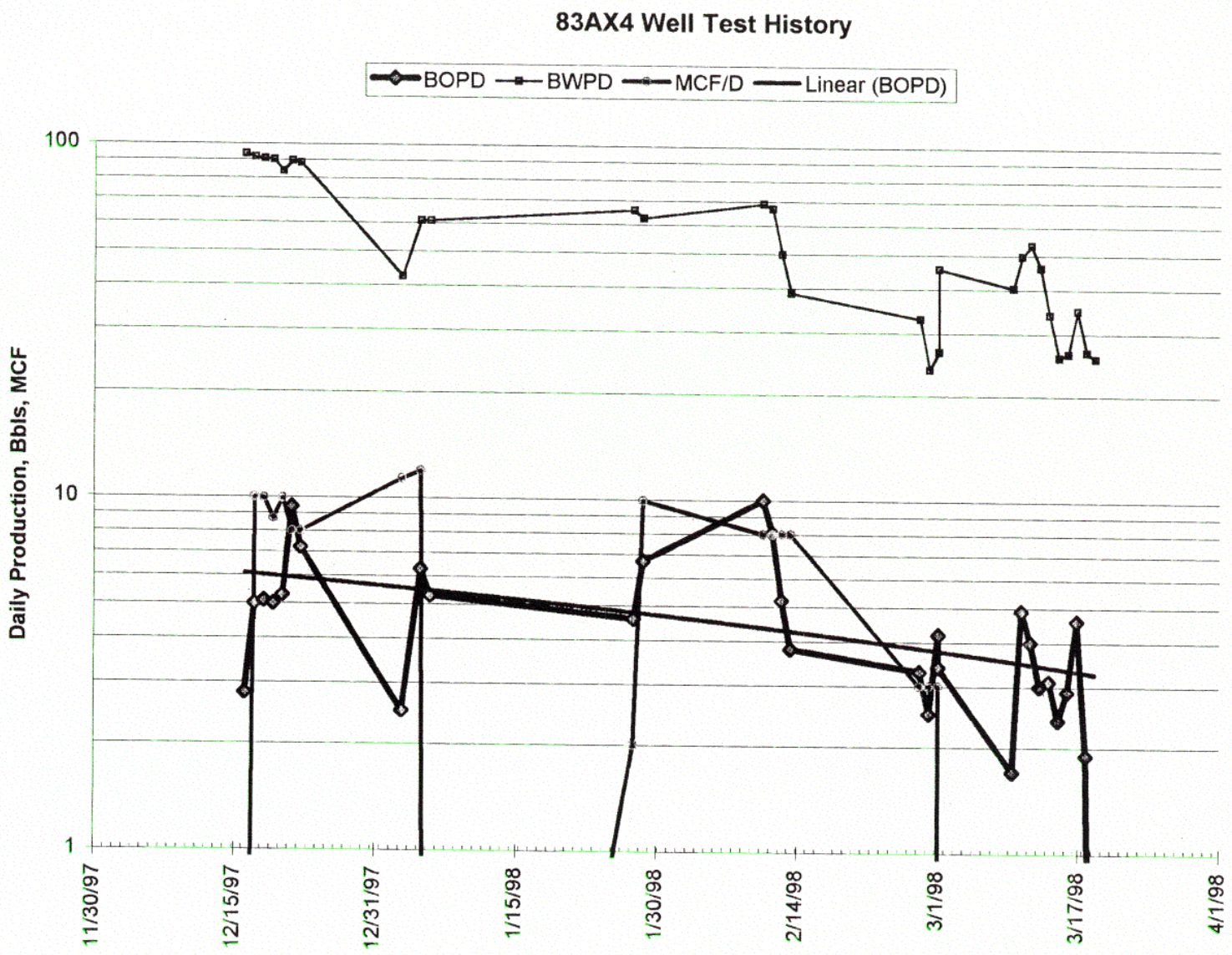


Figure 1. 83A4 Wellbore Mechanical Configuration


83AX4 Well Test History
BOPD
BWPD
MCF/D
Linear (BOPD)
Daily Production, Bbls, MCF
100
10
1
11/30/97
12/15/97
12/31/97
1/15/98
1/30/98
2/14/98
3/1/98
3/17/98
4/1/98