MECHANICAL PROBLEMS IN A MATURE WATERFLOOD

Fred Gipson

Conoco Inc.*

INTRODUCTION

Conoco trains engineers and waterflood operators in their on-going waterflood school. It is in this school that waterflood problems are presented and resolved. This presentation concentrates on waterflood operational problems, discussed in this school, such as: preventive maintenance, problem producing wells, flowline problems, corrosion, tubing, polished rods, casing,produced water clean-up, waterflood station vessels, and injection pumps and meters.

PREVENTIVE MAINTENANCE

In a mature waterflood, preventive maintenance cannot be justified on minor and auxiliary equipment but is a must on major equipment such as artificial lift equipment, fired vessels, injection pumps, produced water clean-up equipment, well test manifolds, meters, chemical injection pumps, cathodic protection systems and safety equipment, which includes gas blankets and electrical grounding systems.

Manufacturers will supply installation, operating and maintenance manuals on their equipment. Use will indicate required changes and additions.

PRODUCING WELLS

In most mature waterfloods, all of the producing wells should be on artificial lift. We can usually pump more than we can flow out of a well. Optimum artificial lift equipment will be able to pump a well off, reducing the producing bottomhole pressure to 10 percent, or less, of the shut-in reservoir pressure.

If the reservoir pressure at the start of the waterflood was low compared to reservoir pressure at fill up, some of the zones open in the producers will still be at low pressure when the more permeable zones have watered out. When the producers are not kept pumped off, water from these zones will back flow into the low pressure zones and push oil away from the producers. This will reduce the amount of oil that can be recovered.

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When pressure in the producers is not kept low, water injection rates into the injection wells will be reduced. This will increase flood life and reduce the present value of the waterflood oil.

Beam pumping units are used to artificially lift the typical waterflood producer. Beam pumping units are limited capacity devices. For example, A.P.I. Grade C sucker rods can lift about 1000 BFPD from 4000 ft. and 200 BFPD from 10,000 ft. If corrosion can be totally mitigated or the produced fluids do not contain H_2S, stronger API rods and larger pumps can be installed and larger volumes can be produced. Non A.P.I. rods are available that allow larger volumes to be pumped from H_2S wells, assuming corrosion is mitigated.

Larger and larger pumping units and larger and larger sucker rods are being manufactured. Theoretically, larger and larger pumps can be run deeper and deeper, but there comes a time when other forms of artificial lift should be considered. One user starts looking at other methods when the required polished rod stroke length exceeds 168 inches. Another stopping point could be when a gear reducer larger than 912,000 in-lbs is required. This is the reducer on the largest conventional beam pumping unit now manufactured.

If the field personnel are expert at installing, operating and maintaining one method of artificial lift equipment, think before you recommend a different method. Can the field personnel be trained during flood life to install, operate and maintain this artificial lift equipment? Will specific conditions or produced fluid qualities, etc. in this field keep another form of artificial lift from operating properly?

FLOWLINES

As producing rates increase, producing well flowlines can go from oversized to undersized. Generally the tubing-casing annulus is tied into the flow line downstream from the pumping tee. Flowline pressure is too high when atmospheric pressure, plus flowline pressure, plus gas column pressure, plus enough liquid column pressure to load the pump and/or cover the producing zone exceeds 10 percent of the shut-in reservoir pressure. Required liquid column pressure can be reduced to a minimum by placing the pump intake below the producing interval - this may not be wise if the well is an open hole completion or if the well produces sand. Also it may not be possible to do this if the oilstring does not extend, or is not drilled out, to below the perforated interval. Flowline pressure can be decreased by decreasing the pressure in the first vessel that the flowline enters at the battery, by keeping the flowline clean and maybe the flowline needs to be increased in size or shortened, but just maybe. A flowline and any other line is too large if what goes in at one end is not what comes out at the other end. In a water line, a velocity of about 3 ft. per second is required to keep the line clean. In a 2 in. nominal, 2.067 in. I.D., schedule 40 flowline a fresh water flow rate of 1075 BWPD is required to keep the line clean. At lower velocities, solids will fall out until the flow area is decreased enough to raise the velocity to about 3 ft. per second.

In a two phase flowline the "keep the line clean velocity", ft. per second, is about 23 divided by the square root of the composite density, lbs. per cubic foot. For example: Given:

I.D. area of flowline, A = 3.355 in.^{2}

GOR,R = 1000

Gas Specific Gravity, S_g = 1.0

Oil Specific Gravity, S_ℓ = 0.85

Flowline pressure at the point of interest, P = 100 PSIA

Flowline temperature at point of interest, T = 80°F;T, °R = 460+ °F= 540°R

Find: minimum oil flow rate, BOPD, that will keep the line clean and keep slug flow from occurring at the battery

Solution:

1. Assume a velocity, V_c, FT./SEC. = $23/(\rho_m)^{0.5}$ will keep line clean, etc.

2. Equation 2.9, API RP 14E: $\rho_m = (12409 S_\ell P + 2.7 R S_g P)/(198.7P + RTZ)$
   Assume Z = 1.0

   ρ_m = (12409 x 0.85 x 100 + 2.7 x 1000 x 1.0 x 100)/ [198.7 x 100 + 1000 x (460 + 80) x 1.0]

   = (1054765 + 270000)/(19870 + 540000) = <u>2.366</u> LBS./FT.^{3}

3. $V_c \geqq 23/(\rho_m)^{0.5} = 23/(2.366)^{0.5} = 23/1.538 \geqq$ <u>14.95</u> FT./SEC. = Velocity required to keep this two phase line clean

4. Equation 2.10, API RP 14E:

   $A_c = [9.35 + (ZRT/21.25P)] / V_c$

   = (9.35 X1.0x1000x540/21.25x100)/14.95

   = 17.0 IN.^{2} /1000 BBLS. of liquid per day.

5. If actual area, A = 3.355 in.^{2} , (3.355/17.0) x 1000 = 197.4 BOPD = Q_1, oil flow required to keep this line clean. Gas flow, Q_g = 0.1974 MMSCFPD

Pressure drop in this line, if it is clean, will be about 0.53 psi per 100 ft.* Allowable pressure drop, psi/100 ft, in a flowline is determined by flowline length, etc. I would look at a larger surface line if pressure drop exceeds 2 psi/100 ft. I would look at installing larger tubing in a producing, injection or disposal well if pressure drop exceeded 4 psi/100 ft.

Note that a well test far from a well that has an oversized, clean flowline is probably not accurate.

All steel flowlines should be o.d. wrapped, buried and cathodically protected if the lowest expected temperature could cause the flowline contents to freeze. Slack should be laid in all lines that will see temperature extremes. A.P.I. R.P. 14E, equation 2.14 from ANSI 31.3 indicates the amount of pipe that must be laid between two fixed points to insure that the pipe does not fail in collapse or tension because of temperature changes. Never install straight piping between two fixed points.

CORROSION

Corrosion usually is a problem in waterflood producing wells after the water cut exceeds about 20 percent and can be a problem at much lower water cuts if the well is produced intermittently. Corrosion cannot be economically controlled if oxygen is allowed to enter any system that also contains hydrogen sulfide and/or carbon dioxide. There are no economical, effective inhibitors for oxygen corrosion. The effectiveness of corrosion inhibitors and other oil field chemicals can change with time because the raw materials used to make the chemicals can be changed, as can the produced fluid qualities. An effective corrosion inhibitor will reduce the corrosion rate of carbon steel to, or below, 5 mils per year and there will be no pitting corrosion. Corrosion inhibitors can cause emulsion problems. This can cause the produced water clean-up system to be inefficient. Therefore, corrosion inhibitors that do not cause an emulsion problem should be selected. No more than about 25 parts of an effective corrosion inhibitor per million parts of produced liquid should be required.

It is practically impossible to keep oxygen out of a corrosive production system if gas pressure greater than atmospheric pressure is not held on the system at all times. Therefore, it is recommended that producing well casing tubing annulus gas be vented into the

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*Equation 2.11a, API RP 14E:

ΔP, PSI/100 Ft. $= 5 \times 10^{-6} W^2 / (d^5 \rho_m)$

W, LBS./HR. $= 3180\, Q_g S_g + 14.6 Q_\ell S_\ell$

$= 3180 \times 0.1974 \times 1.0 + 14.6 \times 197.4 \times 0.85 = 3077.5$ LBS./HR.

$\Delta P = 5 \times 10^{-6} \times 9470797 / (2.067^5 \times 2.366) = 0.53$ LBS./IN.^{2} /100 FT.

flowline through a properly sized check valve. If a check valve is too large, it will chatter, destroy the valve seat and leak. The manufacturer of the valve will tell the user the flow rate that is required to keep the valve from chattering. For example one manufacturer published that his angle check valve requires a velocity of $35/\rho^{0.5}$ and his conventional check valve requires a velocity of $60/\rho^{0.5}$ ft./sec.

TUBING

It is normal for A.P.I. tubing in a beam pumping well to develop collar leaks if the well is allowed to pound fluid or if the thread dope dies. It is also normal for sucker rod couplings to wear holes in the tubing. This wear can be controlled by moving the couplings relative to the tubing every time the rods are pulled. This wear can be prohibited by installing elastomer centralizers on the rod string. If elastomer centralizer life is less than 1 year, the well may be too crooked to economically lift with sucker rods. If the tubing is dry, coupling wear rate will be about 4 times the wet wear rate. Always fill the tubing with liquid before start up.

If the tubing is not anchored, tubing collar-on-casing wear will occur and can result in casing leaks and parted tubing. Moving the tubing collars relative to the casing everytime the tubing is pulled will decrease the number of casing leaks.

If the tubing is not anchored, several hundred feet of tubing buckles every time the beam pump traveling valve closes and the standing valve opens. The portion of the tubing string that buckles should be moved to the top of the hole every time the tubing is pulled.

Injection well tubing must be protected from internal and external corrosion. It should be designed and installed so that pressure and temperature cycling will not cause the tubing to part or collapse or cause collar leaks to develop. The tubing inside diameter must be, and must remain, large enough to allow survey tools to be run from the surface to below the lowest perforation, or below the lowest zone that will be flooded, whichever is deeper.

If economics allow, the injection wellhead should be designed and equipped to allow survey instruments to be run in the well without disturbing injection.

We should consider designing injection well subsurface equipment to allow backflowing debris from plugged back depth, up into the tubing and out of the well. Recall that a velocity of 3 feet per second is required to move solids in a vertical water pipe.

POLISHED ROD FAILURES

Many of the problems that we see with equipment is not the problem, it is just a symptom of the problem. Many times we focus on the symptom, not the problem. For example, polished rod breaks and short stuffing box packing life is usually caused by the pumping unit not being set over the well. The pumping unit is over the well, the pumping unit is set properly, when the polished rod is in the middle of the pumping tee, with the stuffing box unscrewed and lifted up on the polished rod, throughout the pumping cycle. Polished rod failure just below the carrier bar can be caused by the carrier bar not being parallel to the earth and/or perpendicular to the tubing center line. It can be impractical to set the pumping unit over the well if the well head is not vertical and this does happen.

CASING LEAKS

If the surface casing is not cemented to the surface, rain water will run into the annulus and the surface casing will be completely corroded away in time. Open casing valves allow oxygen to enter the casing-tubing annulus and this causes massive casing I.D. and tubing O.D. corrosion, even when gas is venting out of the annulus.

PRODUCED WATER CLEAN-UP

All production vessels, waterflood station vessels, tanks and pumps should have well designed and properly installed sampling ports up and down-stream from the equipment so that representative samples of the fluid flowing in the line can be taken. This will enable the operators and technicians to analyze the system. The sample ports should be protected. Samples taken from the middle of the line with flow either up or down and at a velocity greater than 3 to 5 feet per second will be representative.

The produced water sent to the waterflood station for final clean-up and polishing must be relatively clean. If the water contains more than about 300 PPM oil, the free water knockouts and/or the emulsion treaters in the production battery are not doing an adequate job. Recall that corrosion inhibitors can cause emulsion problems. Iron sulfide in the produced fluid stream can also cause excessive oil carry over. Some like to think that iron sulfide comes out of the producing formation but we find that when and if we ever find an effective corrosion inhibitor and when we batch treat the producing wells adequately and effectively, and keep oxygen out of the system, that iron sulfide is no longer found in the produced fluids. Incidently, iron sulfide exposed to air burns spontaneously when dry with a visable flame and can serve as a source of ignition.

WATERFLOOD STATION VESSELS

All of the waterflood station water clean-up equipment must be designed so that it can be kept clean.

Water-oil gravity separators should be constant level vessels. Any oil that reaches the liquid - gas interface should flow over a weir and should then be pumped into oil sales.

A cone bottom and sump should be considered for all tanks that will receive liquid that could contain solids. Cone bottoms are also ideal for oil storage tanks where bottoms can build-up. All tank bottoms should be circulated back through the oil treaters automatically. If the bottoms are allowed to set for several days, you will never be able to circulate them out and you will end up having to open and clean out the tank bottom by hand.

All carbon steel vessels and tanks that contain a corrosive water phase should be plastic coated holiday free. Practically speaking, this is not possible. The vessels should be protected from corrosion at the holidays that are bound to exist with sacrificial anodes. If the tank is poorly plastic coated and/or if the coating fails, the anodes will produce excessive residue that will build up on the tank bottom. If the bottoms are not efficiently removed, this residue and the other solids that collect on the bottom will channel up to the clean liquid exits and dirty water will be coming out of the tank.

All tank and vessel exits, except in slurry service, should be equipped with vortex breakers. If a water drain off exit is not so equipped, a vortex will form and oil and possibly gas will start coming out of the water drain when the oil-water interface is several inches above the exit. Water can also cone up to an oil exit if the exit is not equipped with a vortex breaker. The vortex break can be a cross in the exit, a flat plate above the exit, etc. Size or design is not important. Vessel exits can be retrofitted with vortex breakers without steaming out the vessel if the vortex breakers are fabricated out of reinforced plastic and held in place with a set screw.

An outside source of gas should be available if a positive pressure must be held on all vapor spaces in the water flood station.

Bolted tank decks should be checked for leaks during construction. Spring loaded thief hatches with envelope gaskets will aid in maintaining positive pressure in tank vapor spaces. Piping must slope up to in-line vent valves and must slope down from the valve exit to the end of the vent line. Recall that vapor recovery systems operate between 0.5 in. and 2.0 in. of water column pressure. It doesn't take much liquid to block flow in a low pressure gas vent line. The emergency overflow from an oil-water gravity separation tank should be designed to discharge water and leave the oil in the tank when an upset occurs. It should also be designed to not allow vapor space gas to escape.

INJECTION PUMPS

Injection pumps can be expected to suffer from cavitation damage if the pumps are installed just to supply the net positive suction head that the Hydraulic Institute tests indicate. For centrifugal pumps, this net positive suction head required (NPSHR) results in a 3 percent loss in discharge head. For a positive displacement pump this NPSHR results in a 3 percent loss in discharge capacity. Cavitation started occurring in the centrifugal pump before discharge head started to decrease. Cavitation started occurring in the positive displacement pump before discharge capacity started decreasing. It is recommended that user engineers request 3 NPSHR curves from suppliers for important pumps: 1. The curve that shows NPSHR for 3 percent loss of discharge head for a centrifugal pump or 3 percent loss in capacity for a P.D. pump; 2. The curve that results in no loss, and 3. The NPSHR for no cavitation.

Pumps can suck air in at the packing if net positive suction head (NPSH) is less than that required for no cavitation. Samples up and down stream from a pump will tell if oxygen is entering the system through the pump seals. High pressure liquid can be piped from the discharge into the seals to decrease the entry of air.

Clamp type fittings on a reciprocating pump suction line may allow air to enter the system.

The piping between the suction tank and the pump must be flexible to handle temperature changes and because the pump and tank are usually not on the same foundation. No pipe weight should be supported by the pump. Formulae exist for determining pipe support spacing. Pipe supports should prohibit pipe vibration. If piping or waterflood equipment is allowed to vibrate at a velocity greater than about 0.5 ft./sec., fatigue failures will occur.

METERS

Turbine meter suppliers furnish curves that show pressure drop versus fresh water flow rate. This pressure drop is usually measured with pressure taps several pipe diameters up and down stream from the meter. These curves can be used for determining overall system pressure losses when liquid is pumped through the system but they cannot be used in designing metering systems where the liquid head in a pressure vessel or gas blanketed tank is used to cause flow through a meter. If the pressure on the liquid goes below the vessel vapor space pressure, it has gone below the vapor pressure of the liquid and two phase flow exists. We don't have a meter that will accurately meter two phase flow. The flow area through the turbine meter is a fraction of line inside area. The increased velocity through this area is greater than velocity in the line up and downstream from the meter. This causes the pressure in and immediately downstream from the meter to be lower than the pressure that was measured downstream from the meter when the pressure drop versus water flow rate curves were generated. This should be considered when determining how far below the low liquid level the meter must be installed to keep gas from coming out of solution before the liquid exits the meter.

No meter can accurately measure pulsating flow. The discharge of reciprocating pumps is pulsating flow. This may justify the installation of properly designed and operated pulsation dampners between the injection well meters and reciprocating pumps even when the piping does not require pulsation dampning. This should also increase turbine meter bearing life.

CERTIFIED PERFORMANCE CURVES

Actual performance of meters, pumps, gravity separators, dynamic separators, etc. can differ from sales literature performance curves because of manufacturing defects, field modifications, wear, scale and solids build-up, corrosion, etc. Certified performance curves should be purchased on critical equipment and used to determine present performance versus new performance.