ABSTRACT

Various workover methods for re-establishing oil production in heavy oil wells that are co-producing large quantities of sand have evolved in the last 20 years in Canada. Operators interested in profitable extraction from unconsolidated sands must pay particular attention to workover strategies, as these comprise a substantial part of the operating costs. Workover methods that apply large physical perturbations to the wellbore region and the surrounding reservoir appear to be the most successful in re-establishing production, but are more costly. Thus, a staged approach using cost-benefit estimates based on the behavioral history of individual wells and fields is the best approach for well workover planning. The need for comprehensive well reviews and autopsies, careful data collection, and history-based probable-cause analysis is fundamental, as there are no strong theories that can predict a priori which workover method is most likely to be cost-effective.

INTRODUCTION

CHOP (Cold Heavy Oil Production) is the method of producing heavy oil from unconsolidated sandstones by encouraging sand influx. It has been slowly but successfully implemented in more and more Canadian heavy oil fields (500 - >10,000 cP; 400-900 m deep, 15-33°C, 4 - >25 m thick, φ ~ 0.30, Sr ~ 0.85, no free water leg or extensive gas cap) over the last 20 years, as operators have gradually evolved better methods of producing the well, to dispose of produced sand and fluids, and to re-establish well productivity (workovers).

New well development is now almost exclusively based on PCPs (Progressing Cavity Pumps). These were introduced in the early 1980’s and have undergone great improvements based on practical factors associated with the need to lift mixtures of oil, gas, water and sand reliably for many months. PCPs have solved the lifting problem: slurries with up to 60-70% sand by weight can be reliably produced for months, although such high concentrations generally only occur immediately after
initial completion, a workover, or prior to water break through. (Note that expressing the sand percent by volume of fluids entering the pump is difficult because the free gas volume in the fluid at the bottom-hole pump intake is generally unknown.) Typically, a good CHOP well will produce from 1 to 8% sand by weight of produced slurry for months and even years.

The problem of sand management has also been solved by gradual practical developments in the heavy oil fields around Lloydminster (Figure 1). Produced slurry is fed immediately into vertical gravity separators that are essentially insulated 100-150 m³ stock tanks heated to ~60-80°C. At this temperature, the sand settles out of the oil, dissolved methane evolves, water and oil stratify, and the stock tank is periodically drained of liquids and bottom sand. Sand is disposed of in various ways: by cleaning, by landfilling, by placement in dissolved salt caverns, by road spreading or by Slurry Fracture Injection™ (SFI™). An entire sub-industry to handle sand has developed in the Lloydminster area.

Heavy oil production using CHOP is now about 250,000 bbl/day; this could be easily doubled in a year if upgrading capacity was available. For example, Figure 2 shows the production rate increase achieved from a group of about 30-32 wells in the Luseland Field in Saskatchewan through the implementation of aggressive CHOP. This graph is current to the end of 1998, but recent data show that the excellent performance has been maintained. CHOP operating expenses have dropped from 10-12 SC$CDN/bbl in 1990 to 6-7 SC$CDN/bbl in 2000, a testimony to the incremental but cumulative efforts of dozens of innovative engineers, operators, and service providers who continue to find more economical and effective methods.

Nevertheless, continuing OPEX reductions remain a useful goal. Our task as engineers and provisioners of service is simple: to produce from each well the maximum oil volume with minimal OPEX over the optimal time to maximize netback. Simply stated, but technologically challenging. Probably the most fruitful area for more OPEX reductions is now in the area of well workovers. Given many different fields, many operators, many choices of workover method, evolving technology, and the vast amount of unanalyzed (or uncollected!) data, evolution of an ability to clearly predict workover efficacy and thereby to improve per-well oil production or rate is a challenging but rewarding goal.

This article will present an assessment of common workover options, exclusive of chemical methods and various water blocking agents that may be used. The assessments were made in an industrial context: a one-day workshop held in Lloydminster, March 15, 2000.

**SURFACE, WELLBORE, RESERVOIR**

CHOP well oil production generally increases for some time after the initial completion, then declines. The decline can be precipitous, rapid, or slow. The cause may be mechanical or reservoir related: surface facilities may fail, the wellbore system may fail, a near-wellbore (<3 m) blockage may develop, or production decline may be related to far-field reservoir behavior (>3 m).

Mechanical failures can usually be diagnosed easily. Flowline plugging, rod break or torque, stator failure, tubing back-off or wear, no-turn anchor release, and similar effects have dramatic and sudden consequences that are usually diagnostic, and the necessary response is clear. However, the root cause may relate to reservoir phenomena. Sudden or episodic sand slugs, episodic gas locking, concretionary nodules or metal fragments destroying the stator elastomer, episodic excessive water cuts (leading to sand settling), axial bucking of casing, and shear distortion of overburden bedding planes may lead to mechanical failures. Bad diagnosis may lead to failure recurrence and production loss.

Reservoir “failures” are more challenging to diagnose because the location is usually inaccessible and diagnostic data incomplete, inaccurate, or irresolvable. The root causes may include inability to initiate sand influx, near-wellbore or distant blockage, coning, loss of pressure drive, and loss of gravitational drive. Gas or water coming may take place; blockage of perforations may occur because of cement or concretion chunks, flowing sand may recompact around the well and prevent oil ingress; and so on.

Few short-term workovers effect permanent change to the well bore or reservoir. Many can generate temporary improvements that appear to be technical successes, but that may not be economic. These experiences have led more recently to the implementation of continuous or
prolonged application of traditional workover techniques (e.g. continuous loading, continuous pump to surface, prolonged pressure pulsing, etc.).

Our goal is to rationalize diagnostic procedures, but responsibility to collect necessary information and implement diagnosis is a corporate task. Inadequate data collection or reluctance to establish a diagnostic framework will lead to lost opportunity and lost profits. Choosing the wrong workover procedure may cost $25,000, but if the reservoir is thereby impaired, the opportunity loss, always a difficult quantity to estimate, could involve millions. Diagnosis relies on a sound understanding of the physical processes taking place in the reservoir.

**CHOP RESERVOIR PROCESSES**

The literature should be accessed exhaustively by any company using CHOP, and personnel at all levels must be educated assiduously. Some references are listed, but there are more articles that can be accessed 1,2,3,4,5,6,7,8,9,10,11,12,13,14,15,16,17,18.

Sustained oil production requires sand flux; sanding requires continuous reservoir destabilization by a combination of gravitational forces and pressure-driven forces, including foamy oil behavior. These sustain the flux of a sand-oil-water-gas slurry that enters the well and is produced. The formation near the wellbore is completely yielded and liquefied; farther out, the formation is intact. In between is a disturbed and yielded zone that may be partially dilated sand, partially an array of piping channels. No large (> 0.1 m³) slurry-filled cavities can exist except adjacent to the wellbore and under an intact shale caprock or zone that has cohesion.

Gas behavior in CHOP wells is unusual. The solution kinetics of heavy oil and methane imply that equilibrium phase behavior is not attained during flow to the well; hence, compositional assumptions are insufficient. Furthermore, the gas appears incapable of substantially displacing oil from pore throats, so a significant continuous gas phase is rarely generated, and GOR values in many CHOP wells remain constant for years.

As long as sand can be produced, economic oil production appears to be sustained. If sand mobilization and borehole ingress is impeded, production declines and even ceases. If gradients are low, sand can settle around the wellbore and recompact. If there is insufficient gravitational and flow destabilization in the farfield, the well "disconnects" from the drive forces, and flow declines rapidly. There is increasing evidence from in-fill drilling and reservoir behavior that undisturbed viscous oil in the pores is a Bingham fluid, requiring a discrete gradient to begin flowing. If so, at a later time in a CHOP well when the drainage surface is large, disconnection from extant far-field pressures can occur.

CHOP is a high-gradient process, thus coning is favored, and CHOP is considered problematic in reservoirs that have access to active water legs, flank water, or mobile water zones with low oil saturations. Massive water breakthrough is the most difficult reservoir problem to rectify; a long history of failures in practice is mitigated by only a few successes in water exclusion.

**TIME SERIES INFORMATION**

Water cuts may remain slow for years, then gradually increase, or they may suddenly increase over a few days. Sand concentrations are generally high at early time, falling to values of 1-8%, depending substantially on oil viscosity, but minute-to-minute and day-to-day sand concentrations can vary chaotically. Pumping behavior is affected by mechanical state, but also by gradual or sudden modifications in the composition of the inflowing slurry, the occurrence of gas or unpredictable sand slugs. Diagnosis requires maintenance of a time-series history of a number of well parameters.

We recommend that time series data be maintained on each well for sand and fluids cuts ("SOR", GOR, WOR), pumping parameters, and annulus and pumping pressures. Gas collection is difficult, as many CHOP wells vent gas through the annulus as well as producing gas with the fluids. Nevertheless, changing GOR may be diagnostic. Any anomalous events should be registered, and the details of all workovers or other interventions must be documented for future analysis to lead to better workover screening and well production optimization. Data may include pumping irregularities, anomalous annulus pressures, volumes and rates of any annular fluids added to improve pump performance, the nature of chemical additives, and careful intervention histories that include documentation of all changes in the well conditions.
hardware. The amount of sand cleaned from the well during the workover is also recorded, and it is invariably useful to quickly sieve sand through a 5 mm screen to detect any large chunks of natural or foreign matter, which may be diagnostic.

As part of the time-series database, cost-benefit analyses of any workover should be executed systematically, using the production time series information. The payback time is calculated based on the additional oil produced that can be allocated to the workover activity. If the well is initially non-producing, all additional oil can be so classified; if the workover alters production, trend extrapolation is required to assess workover benefit. These all require good time-series data.

**TYPES OF WORKOVER**

**Mechanical Root Cause Workovers.** Surface or down-hole hardware failure is the most obvious reason for a workover. Generally, if the problem is down-hole, all equipment must be pulled out of the wellbore to solve the problem. Tubing wear-through, rod breaks, and evident pump failures may take place. In some cases, intervention is to deliberately upgrade pumping equipment, to reperforate the well, or to access a new zone. These activities also present a window of opportunity to implement a production beneficiation attempt (proactive workovers, rather than reactive workovers).

**Well Blockage Root Cause Workovers.** The well may fully or partially block internally because of a degradation of pumping efficacy (typically elastomer failure) or because the fluid composition alters. This leads to a need to clean the sand from the well, which may involve only fluid introduction into the annulus, or a complete removal of tubular goods. Sand must be removed from the well to allow PCP reinstallation. Pump-to-surface, foam clean-outs, or mechanical sand bailing are the major approaches.

**Near-Field Root Cause Workovers:** The CHOP well may block externally, near the wellbore. If perforation entry ports are partially impeded, sand will complete the plugging process, aided by fines, drilling damage and asphaltene precipitation, so that the perforation is completely ineffective. In fact, during stable CHOP pro-
fluid addition) can be employed. Reperforations and other perturbations are considered too small to “shake-up” the far field to overcome Bingham effects or stable zone effects.

WORKOVER METHODS

We have chosen to present the workover method information as a number of Tables, and these constitute the core of the article. The workover methods are described and classified in various ways. One way to classify them (Table 1) is as “quick-fixes” that do not require a large effort and usually involve fluid addition into the annulus or tubing, methods to try and clean the well of sand, and methods to address cases of no-flow or low (partially blocked) flow. In this case, the costs can usually be considered to be low, moderate, and high for the three groups.

In Table 2, the descriptive scheme and the ranking are presented. For example, in the ranking part, the magnitude of the perturbation applied to the reservoir is included. Bailing using a mechanical bailer (“pounding sand”) is a means of cleaning the wellbore before introducing a PCP, but it also has some small perturbation effect because of impact, and perhaps a larger effect because of swab-surge effects during raising and dropping. The magnitude of the perturbation is linked to the energy put into the reservoir; of all methods, pressure pulsing is the highest energy method, although reperforating and rocket propellant give a very high and sharp (short time) impulse.

Relative expense is also listed on the classification charts. This is a difficult matter to estimate because of the various ways of doing business, but the best method in practice is probably to solicit the costs of the service purchased from an independent company. If a workover (e.g., pressure pulsing) is executed as a “workover of opportunity” in conjunction with a pump change-out for example, rather than waiting for the well productivity to crash, the costs are less.

Combined approaches can be employed. Combining a well cleanup with a fluid injection workover is common. During pressure pulsing, reservoir compatible fluids may be added, and toward the end of the workover, a treatment chemical may be introduced. Other examples are; perforation washing while foaming, perforating while foaming and chemical treatments while perforation washing, perforating, or propellant stimulation. One may choose to do these deliberately, or be prepared to do them jointly as data become available during the workover.

Tables 3, 4, and 5 are, respectively, examples of the three classes of workovers listed in Table 1. Our choice is random and in no way implies that they are better or worse that the other 10-15 approaches.

STAGED WORKOVER STRATEGY

Workover costs are strongly related to the time and type of service. If a full service rig is used, costs are invariably larger than if a pump-to-surface coiled tubing unit is used. Also, equipment rental and product costs are different. At one end of the scale, a tanker-pump truck to pump 10 m³ of fluid into the annulus is very cheap; at the other end, a full double-stand mobile service rig costs $300/hr, plus additional costs for the specific workover device. The range in costs are from perhaps $1000 for the former to $22,000 for a full pump change-out combined with a strong perturbation workover approach.

The range of costs and various root causes lead naturally to the concept of a staged approach to manage risk. The “steps” in this approach are:

- Identify the root cause carefully
- Rank order workover possibilities in terms of chances of well improvement
- Rank order the appropriate methods in terms of cost
- Execute a cost-benefit estimate to arrive at a final ranking
- Stage your workover attempts to reflect your final ranking
- Often, it is expedient to do the cheapest workover approach first, rather than pulling the equipment out of the hole, as this is often a major cost penalty
- Be prepared to be flexible and change your strategy “on-the-fly” as more data become available during the execution phases
- Do careful follow-up, success evaluation, economics-based
- Don’t just archive the data, add it to the corporate knowledge base
SUMMARY

There are no true “conclusions” from this study; it is a work in progress that must be undertaken by each company. There are different options, different opinions, different cases and different costs; therefore a rational risk-and-return-based approach should be used. What form and type of problem solving approach depends on each company’s operating philosophy. There is no “magic pill” or “cookie cutter approach” that will work in every situation. A thorough, methodical approach will result in choosing the best tool being properly applied. There is also room for an industry-wide joint data collection and analysis study to assess the efficacy of the various techniques in various circumstances. We recommend that this be considered.

Finally, we present a flow chart that outlines some of the decision-making paths and activities that must be incorporated into the corporate CHOP wellworkover assessment program.

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REFERENCES