8 WORKOVERS FOR CHOPS WELLS

8.1 Surface, Wellbore, Reservoir

CHOPS 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 the 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 so on are dramatic events which require immediate and obvious responses. 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. 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 are incomplete, inaccurate, or cannot be analyzed quantitatively. The root causes include:

- Inability to initiate sand influx because the sand is insufficiently damaged by the perforation process
- Near-wellbore blockage (perforation sand arching) or more distant blockage (sand sedimentation and recompaction)
- Coning of water or gas into the well region
- Loss of pressure drive because of general depletion or loss of access to "virgin" oil with full solution gas content
- Loss of gravitational drive arising because of the weight of the overburden that continues to destabilize sand

Few short-term or low-energy workovers achieve permanent changes to the condition of the wellbore or the reservoir. Many can generate temporary improvements that appear to be technical successes, but these may not be economic. These experiences have led more recently to the implementation of continuous or prolonged use of traditional workover techniques (e.g. continuous loading, continuous pump to surface, prolonged pressure pulsing, etc.).

8.2 Time Series Information

Water cuts may remain low for years, then gradually increase, or they may suddenly increase over a few days. Typically, sand concentrations initially are high, falling to values of 1-8%, depending on oil viscosity. However minute-to-minute and day-to-day sand concentrations can vary chaotically. Pumping behavior is affected by the mechanical condition of the pump and wellbore, but also by changes in the composition of the inflowing slurry, such as the slugging of gas or the inflow of high sand concentrations for short periods. Diagnosis requires maintenance of a time-series history for a number of well parameters.

Time series data should be collected for each well for sand and fluids cuts (“SOR”, GOR, WOR), pumping parameters, and annulus and pumping pressures. Gas collection is difficult; nevertheless, changing GOR may be diagnostic, and semi-quantitative data or qualitative notes of behavior changes on report sheets are better than no data at all.

Any anomalous event should be registered, and the details of all workovers or other interventions must be documented for future analysis to optimize production. 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 any changes in the well hardware. The amount of sand cleaned from the well during the workover should also be recorded, and it is useful to quickly sieve sand through a 5 mm screen to detect any large chunks of natural or foreign matter, shale fragments, or even perforating debris, each of 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 should be based on the additional oil produced that can be allocated to the workover. If the well is initially non-producing, all oil produced can be classified as “additional”. Analysis of trends is required to assess workover benefit.

8.3 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 pump failures may take place. In some cases, intervention is carried out to deliberately upgrade pumping equipment, to reperforate the well, or to access a new zone. These activities also present a window of opportunity to improve production (proactive workovers, rather than reactive workovers).

Well Blockage Root Cause Workovers: The well may be fully or partially blocked internally by sand because of pump deterioration (typically elastomer failure) or because of changes in the fluid composition. This leads to a need to clean the sand from the well, which may be accomplished merely by introducing fluid into the annulus, or it may require a complete removal of tubular goods.

When downhole equipment is re-installed, sand must be removed from the well to a depth that is sufficient to allow PC pump reinstallation. Pump-to-surface, foam clean-outs, or mechanical sand bailing are the major approaches.

Near-Field Root Cause Workovers: The CHOPS well may block externally, near the wellbore. If a perforation entry port is partially impeded by a fragments sand movement toward the opening will aid the plugging process. Then, the pore throats between sand particles will become blocked by fine-grained minerals, drilling solids, smaller sand grains, and precipitated asphaltene, so that the perforation becomes completely ineffective as a flow channel. In typical stable CHOPS production periods, it is believed that only a small number of perforations (10-15%?) are actively producing oil and sand; the remaining ones are plugged. Initial blockages may arise from chunks of cement, concretionary nodules, shale fragments, coarse-grained pebbles, or even from the formation of stable sand arches behind the ports. If production is seriously impaired, the perforations must be opened. Aggressive introduction of fluids, ignition of rocket propellants, re-perforation of the casing, and pressure pulse workovers appear to be effective mitigation methods, and processes such as sand bailing and even the surges from running in the hole may help open ports.

In some cases, sand production does not begin when the well is first placed on production. These cases are believed to be linked to insufficient remolding and damage to the sand around the wellbore, and possibly to subtle lithostratigraphic differences among wells. Processes that massively perturb the near-field are required so that sanding can begin and continue through cavity or channel growth. Pressure pulsing has been quite successful in this application.

Far-Field Root Cause Workovers: These problems are more difficult to diagnose and require larger energy inputs because the blockage is distant from the wellbore. Sand may simply be sedimenting and recompacting under low fluid velocities from low flow gradients, with insufficient energy to maintain influx at a rate where the sand stays in suspension. This tends to occur later in the well life when the drive energy has been partially depleted.

There is a general belief that viscous cold heavy oil *in situ* is in a state of gelation, so that a finite gradient at the pore scale is necessary to initiate flow (Bingham fluid behavior); when the disturbed zone is large, gradients are low, and it becomes difficult to mobilize the gelled oil.

Seimic 3-D data show the existence of large disturbed zones around good CHOPS wells, but with "seismically intact" interwell zones; infill drilling has occasionally found virgin pressures in these zones. This suggests that the gravitational drive that helps destabilize sand becomes ineffective when the interwell zone can successfully support the overburden weight without further destabilization. Destabilizing these stable regions and reactivating the gravitational component of the drive requires an energy input that travels out many tens of metres. Far-field root causes generally require large energy inputs; large amounts of fluid can be introduced aggressively, a large or repeated rocket propellant treatment may be used, or pressure pulsing (likely with simultaneous reservoir fluid addition) can be employed. Reperforations and other perturbations such as "super-flushes", occasional surging of the well, or sand bailing are considered too small to "shake-up" the far field sufficiently to overcome distant Bingham behavior or stable interwell zone effects.

8.4 Workover Methods

The workover method information is presented as a number of Tables in a separate Appendix, and these constitute the core of the knowledge base on CHOPS well workovers. Workover methods are described and classified in various ways:(Table 8.1)

- "Quick-fixes" requiring little effort or cost, usually involving fluid addition into the annulus or tubing;
- Methods to clean the well of sand (moderate cost); and
- Perturbation methods to address cases of far-field blockage leading to no sand flow or impeded sand flow to the well bore (high cost).

Table 8.1:
Workover Approaches

Workover methods seem to fall in one of three categories. An example of a ranking table is given for each of these three categories. Table two contains the "legends" for the ranking tables for the three examples.

1: Remedies - "Quick Fix"

Fluids are introduced into tubing or annulus to flush sand away from intake or perforations –
*Be **Very Selective** in workover fluid choice!!!*

- Vary casing pressure, RPM or fluid level
- Flushby
    - "SUPER" Flush
    - CTU and Flushby
- Loading
    - Continuous annulus loading with fluid
- Swabbing
- …others??

2: Remedies – Cleanouts

Often determined by: geometry, reservoir pressure and characteristics, sweet/sour

- Circulating
- Perforation wash
- Bailing
    - Sand Line
    - Sand Pump/Tubing
- Pump to Surface (PTS)
    - Rig
    - Portable
    - Continuous
- Stable Foam Cleanouts
    - CTU (Coiled tubing unit)
- …others?

3: Low/No Inflow Remedies

Often determined by "proximity" of damage to well

- Reperforating
- Abrasi-Jet
- Proppant/Hydraulic Fracturing
- Chemical Stimulations
- Chemical Treatments
- Pressure Pulse Flow Enhancement
- …others?

In Table 8.2, 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 PC pump, but a small perturbation effect occurs because of repeated impact, and perhaps a larger effect because of swab-surge effects during raising and dropping the long cylindrical tool. The magnitude of the perturbation is a measure of 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, but only once.

Key - Describing Workover Methods

Description: Functionality	Candidate Selection: Criteria for greatest chance of success •Geometry (slant/vertical/deviated) •Depth, pressure •Sand cuts/ volumes, frequency •Degrees of severity (decreased,lower,no oil) •Frequency/past history/service success (episodic/frequent/continuous) •Past workover history, successes, failures
Pros: Relative to similar methods/functions	Cons: Relative to similar methods/functions
Diagnostic Value: What the method tells about the well/reservoir during and after workover •Infer damage mechanism/well characteristics •Inflow performance •Fluid/particle/debris sampling/diagnosis •Potential pressures	Reservoir Effects: What/How the methods effects the reservoir •Best for: near-well, proximal zone, far-field •Does the method "surge" or "swab" •Over- or underbalanced •Effect on skin, wetness, perm., porosity, ...
Equipment: What equipment is needed/required •Rig flushby/coiled tubing unit - CTU •Pressure or vacuum truck •Tankage on site, brought it •Specific workover fluid / chemicals •Special tools and services	Economics: Equipment/service cost, rig hours or total $$ •Rig: XX hours @ XX $/hour •PPT: XX hours @ XX $/hr or XX fixed price •Downtime or lost production not considered (each companies must address in-house)

Key - Ranking

Description:	Candidate Selection: (Frequency of Use) 1 – Seldom 2 – Often 3 – Always
Pros:	Cons:
Diagnostic Value: (amount of info gathered or inferred) What the method tells about the well/reservoir during and after workover 1 – Low 2 – Medium 3 – High	Reservoir Effects: What / How the methods effects the reservoir 1 – Wellbore only 2 – Near wellbore region only 3 – Far reaching, into the reservoir
Equipment:	Economics: (relative to similar methods) Equipment or service cost: rig hours, $$, etc. 1 – Cheap $ 2 – Moderate $$ 3 – Expensive $$$

Comments: The pros and cons are exhaustively listed for each method. Then, each method is ranked on whatever semi-quantitative scales can be developed.
Diagnostic Value is part of being flexible in workover choice: as the workover is executed, different methods will provide it may provide valuable data as to what the dominant mechanism was for loss in production.

Table8. 2: Descriptions of Methods and the Ranking Scheme Developed

Relative expense is also listed on the classification charts in the appendix. This is a difficult matter to estimate because of various ways of doing business, but the best method is probably to purchase the service or get estimates from an independent service company. If a workover (e.g. pressure pulsing) is executed as a "workover of opportunity" in conjunction with a pump change for example, the costs are less.

Combined approaches can be employed. Combining a well cleanout 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 might include perforation washing with simultaneous foaming to get returns to surface, or combining chemical treatments with a propellant stimulation.

8.5 Staged Workover Strategy

8.5.1 Stages to Manage Risk

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. A tanker-pump truck to pump 10 m^3 of fluid into the annulus is very cheap; while a full double-stand mobile service rig costs CAN$300/hr, plus additional costs for the specific workover device. Costs range from ~CAN$1000 for the cheapest workover to ~CAN$22,000 for a full pump change-out combined with a strong perturbation workover.

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
- Rank workover possibilities in terms of chances of well improvement
- Rank the appropriate methods in terms of cost
- Execute a cost-benefit estimate to arrive at a final ranking
- Stage the workover attempts to reflect the final ranking
- Consider doing the cheapest workover first, rather than an expensive workover requiring removal of equipment from the hole

- Be flexible and change strategy “on-the-fly” as more data become available during the workover
- Do careful economic evaluations
- Add the data to the corporate knowledge base

8.5.2 Workover Payback

For historical reasons related to low production rates in CHOPS wells, the payback period that appears to be standard is three months. Payback implies that the oil production in this period is sufficient to pay for the workover as well as for the OPEX engendered in the payback period.

8.6 Summary

There are no true “conclusions” in the area of workover efficacy because of a lack of industry-wide data collected similarly and because workover methods are evolving rapidly. A rational risk-and-return-based approach should be used to choose the best workover method in particular situations, but the company’s operating philosophy and experience may be a dominant factor. There is, however, no “magic pill” or “cookie cutter approach” that will work in every situation, a thorough analysis is required to choose the best method in most cases. Industry-wide data collection and analysis should be considered.[54]

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[54] D. Pavka, UPRI now Anadarko, J. Bootsman, Petrovera Resources, and C. Gall, consultant to Petrovera Resources assisted with the development of the tables and the format of the workshop from which this chapter was derived. The authors of the workshop also included Kirby Hayes, Chris Wallin and Mike Kremer