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Rehabilitating Heavy Oil Wells Using Pulsing Workovers to Place Treatment Chemicals

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ABSTRACT

Workover chemicals were placed in a group of seven CHOPS wells in the Sparky and GP zones of the Canadian Heavy Oil Belt. Rather than direct injection, the chemicals were placed using aggressive pressure pulsing over a period of 7-10 hours. A three-month post-workover assessment shows that each well is producing far more total liquids than before the workover, and that the oil-to-water ratio has improved greatly. For the seven wells, oil production rates three months after the workover were approximately 5 times the rates before the workover.

Chemical placement in these wells that co-produce sand appears to be much more successful if pulsing is used, and this is attributed to a much more efficient dispersion mechanism associated the dynamic excitation. Instead of channeling out into the formation and being recovered largely undiluted after production is reinitiated, it appears that the pulsing mixed the chemicals much more thoroughly in the formation and that channeling and chemical isolation were suppressed. Importantly, the new method provided payback within 60 days of the workover termination.

INTRODUCTION

Aggressive pressure pulsing as a workover method for oilwells was introduced in the Canadian oil industry less than three years ago (Sept 1998)[1,2]. The method was proposed based on a two-year long series of laboratory experiments that demonstrated flow rate increases during active pulsing.[3] Assessment of the probable reservoir reasons for oil production decline in CHOPS (Cold Heavy Oil Production with Sand) wells led to the conclusion that pulsing workovers could help revitalize poor wells, and even turn non-producing wells into economic producers. The first 100 or so workovers in Canada were carried out without chemical placement, and an increasing success ratio was achieved, based on gradually better screening criteria and better understanding of the process effects in the reservoir.

Chemicals are added to wells to affect the conditions in the reservoir and achieve better production. In limestones, acidizing is widely used, and acids may also be used to dissolve clay minerals blocking sandstone pores in the near-wellbore region. In siliceous sandstones containing heavy oil, issues such as surface tension, permeability channeling, asphaltene and wax precipitation and wettability changes can often be addressed by chemical placement. However, in high viscosity oils in high porosity sandstones that have been exploited by CHOPS, chemical placement has in general not achieved a high success ratio. This can be attributed to a number of factors, discussed in more detail below.

Several years ago, it became apparent that placing chemicals with aggressive pulsing would likely achieve better results than simple injection. This judgment was based on the initial workovers carried out in 1999-2000. An opportunity to test this idea on a group of CHOPS wells in the Heavy Oil Belt presented itself in late 2000.

CHOPS WELL BEHAVIOR

Using CHOPS implies maintaining continuous sand influx in order to sustain economical oil production.[4] The approach is suited for unconsolidated sandstones saturated with viscous oil with dissolved gas; however, the concept of deliberate sand production developed in Canada has now percolated into the conventional oil industry, and has been applied successfully in high-rate offshore oil wells,[5] an extremely challenging environment. It should be noted that in high-rate conventional oil and gas wells, sand influx is a very small fraction of the rates observed in CHOPS wells, on the order of 0.005% by volume, rather than 0.25-8% by volume for the heavy oils in Canada.

It is now fully accepted that sand exclusion methods (screens, gravel packs…) are unsuccessful for implementation of CHOPS in vertical wells as a primary production method. For a number of reasons, oil production from CHOPS wells may decline, either gradually or precipitously.[6] Beyond the wellbore, a number of processes may occur.

Perforation Blockage: Sand arching behind perforations leads to filtration of fine-grained particles on the stable sand arch, totally blocking oil flow. Arching is more serious with small perforation ports, but it appears that it can in some circumstances develop even if large-diameter ports are used. If shale beds are destabilized by the withdrawal of large volumes of sand (200-300 m^3/yr/well is not unusual), large shale fragments can also block perforation openings.

Sand Recompaction: Under low flow rates, sand, particularly coarse-grained sand, can re-sediment in the near-wellbore environment and seriously impair free sand-oil-water-gas slurry to the wellbore.

Saturation and Wettability Changes: CHOPS involves massive formation alterations (3-D seismic maps demonstrate this clearly), remolding of intact sand by shearing, movement of sand, and generation of a bubble phase in the reservoir in the slurry zone. Indeed, common stable gas-oil ratios show that a connected gas phase rarely develops, as shown by the common occurrence of. These effects change fluid saturations and may affect grain wettability in the near-wellbore region, negatively affecting flow because of changes in capillary forces and cohesion between grains.

Far-Field Pressure Disconnection: Heavy oil *in situ* probably behaves as a Bingham liquid with a discrete yield point. As the disturbed zone (channels and yielded sand zones) grows, pressure gradients decline to the point where the oil can no overcome the yield point and flow ceases. Also, because gas diffusivity in heavy oils is extremely low, a continuous gas flux cannot be sustained, and production declines to uneconomic levels. In some fields more than 30 years old, despite evidence of inter-well pressures, wells have been noted to maintain extremely low bottom-hole pressures indefinitely, implying that there is a disconnection with the far-field.

Large-Scale Stress Arching: Part of the driving force behind CHOPS is the stress applied by the overburden. This serves to continuously yield and dilate the sand, allowing fluid flow to pluck loose sand from the outwardly propagating sand production sites around the well. If the inter-well region where sand is intact and dense (ϕ ~ 30%) can point sustain the overburden stresses without further yield and dilation, the well stops producing sand and oil.

Water Influx: Even in cases where there are no active water zones (CHOPS is contraindicated in such cases), water influx in most fields will increase with time, sometimes precipitously. This may be related to lateral coning, the channel network or disturbed zone intersecting mobile water pods, or breaching of the overlying shale so that hydraulic communication to overlying water sands is established.

Depletion: Ultimately, once a CHOPS field approaches a production of 12-20% OOIP, the channels and disturbed zone reach the interwell regions, and general pressure depletion takes place, reducing flow rates. If the reservoir exhibits a GOR that slowly increases with time, the gas phase is being depleted at a rate larger than the volumetric gas content in a unit volume of oil. This eliminates the beneficial driving forces associated with bubble phase generation and gas expansion down-gradient toward the wellbore, which acts as an efficient internal drive mechanism.

Some of these mechanisms (e.g. field-wide depletion) cannot be rectified by a workover, as the energy sources have been eliminated. However, there are two classes of problems that can be addressed using one or more of a variety of workover methods. First, blockages, pressure disconnection, and far-field stress arching can be overcome by aggressive pressure pulsing (or other methods). Second, changes in wettability and saturation, near-wellbore asphaltene accumulations, and perhaps the common problem of gradually increasing water cut can be mitigated through the use of appropriate chemicals.

PULSING MICROMECHANICS

PPT (Pressure Pulse Technique) is implemented through use of a bottom-hole positive displacement system that generates a sudden large amplitude impulse to the liquid in the wellbore that is adjacent to the perforations. There are a number of ways that this can be achieved, but the most common is to use a service rig that mechanically strokes the device attached to the bottom of a tubing string. This allows a large amount of energy to be directly applied to the liquid because dropping the tool and tubing suddenly allows the entire weight, typically 3000 kg in 500 m deep wells, to serve as the motive force to generate the pulse.

PPT is carried out for a number of hours (5-24). Use of a down-hole pressure gauge allows monitoring of the shape of the pressure impulse and the back-pressure reaction of the formation to the excitation. Liquid can be simultaneously introduced aggressively through the annulus (“load fluid”). The rate of liquid influx during PPT is controlled by the annulus liquid level, the frequency and stroke length of the pulsing, and the design parameters of the pulsing tool. Specific operational parameters are chosen based on the workover goals and on the history of the well, which usually gives clues to the reason for production impairment.

The effectiveness of pulsing arises from a number of physical mechanisms.

Liquid Phase Impulse in the Near-Wellbore: Wellbore liquids are accelerated suddenly, generating a sharp impulse. If perforations are blocked, a large outward force is generated, destroying the stable arches and opening up the ports. The accelerative impulse will also remold re-compacted material in the near-wellbore region, allowing free flow of slurry when the well is placed back on production.

Porosity Dilation Wave Generation: The impulse energy is not fully dissipated in the near-wellbore region. Providing that reservoir gas saturation is not too high (a problem in highly depleted wells), a porosity dilation wave is generated in the porous medium. This wave is highly conservative and propagates outward from the well. The wave effect is focused in the reservoir, as it tends to be reflected by low permeability bounding strata, and the effects have repeatedly been recorded on distant (300-400 m) production wells as an increase in production rates or annular liquid levels. (PPT workovers have often had beneficial effects beyond the well that is being treated.)

The porosity dilation wave generates a flexure of pores, and the liquid in the pores responds incompressibly at the excitation frequencies used. This means that the liquid in the pore throats must move into and out of the pores in response to the passage of the wave. Because the wave velocity is on the order of 40-60 m/s, and because the pore-to-pore spacing is on the order of 0.0001 m (100 μm), this liquid movement occurs rapidly and suddenly, generating high local accelerations in the throats.

These effects are strongly frequency dependent: if high frequencies dominate the impulse, the liquid in the pores strains rather than displaces. At the other extreme, if the frequency content is too low, the impulse is insufficient to generate the pore flexure needed. A fundamental key to successful PPT is to maximize the energy within the optimum frequency range. The effects of excitation on the more distant reservoir are of great value to oil production, as a number of useful "micromechanisms" take place.

Unblocking of Pore Throats: If pore throat liquids accelerate suddenly in an oscillating manner, the force applied to any pore throat blocking materials (fine-grained minerals and asphaltenes) is large (Figure 1). These agglomerations are broken up, and the solid fragments can be mobilized through the pore throats into the general flow, reducing or eliminating the blockages. This effect can happen at great distances.

Overcoming Capillary Blockage: By the same accelerative mechanisms, additional forces can be brought to bear on pore throats blocked by interfacial (capillary) surfaces between oil and water (Figure 2). This is analogous to applying, at the microscopic pore throat level, an additional force to the interface, overcoming the stabilizing and blocking effect of surface tension, and allowing the oil to "punch through" the pore throat.

Destabilizing "Stable" Regions: Stable far-field stress arching depends on the stable transmission of the overburden stresses through the contact forces that exist in the matrix of grains. Just as a blocked grain hopper can be made to flow again by gentle tapping, the porosity dilation wave flexes the structures, momentarily altering the grain-to-grain contact forces, and promoting destabilization of the grains so that the gravitational forces can once again shear and yield the sand so that CHOPS can continue.

Enhancing Fundamental Liquid Flow Rate: Blood flows through capillaries successfully despite non-newtonian effects and the presence of red blood cells that are of the same diameter of the capillaries. This is because the heart generates a pressure impulse that sets up a dilational wave in the capillaries. For the same reasons, even in single-phase viscous liquid flow, the porosity dilation wave enhances the ability of liquids to flow in an existing general pressure gradient field.

Mitigating Permeability Channeling: Because of the radial spreading of the porosity dilation wave (it is of higher amplitude near the wellbore), oil can be displaced more effectively from near-by low permeability regions. This reduces the rate of separation of the displacement fronts between low and high permeability streaks. Laboratory evidence of this is clear: although conformance is enhanced, the effect of permeability channeling is not eliminated, but it is substantially reduced.

Pressure pulsing does not invalidate or overcome Darcy flow, it simply brings a new form of dynamic energy to flow systems that are essentially quasi-static in nature.

CHEMICAL PLACEMENT AND DISPERSION

Surface-active chemicals (e.g. sulfonates and phosphates with high polarity), diluents (e.g. high API gravity oils or naptha), dissolving agents (e.g. xylene), acids (HCl, HF, formic acids, or mixtures) and other materials are used for a wide variety of reasons to enhance well productivity. In CHOPS wells, chemicals are usually injected through the annulus without removing the pump. In other cases, when a pump is withdrawn or when large amounts are to be used, tubulars are withdrawn, and injection undertaken, either slowly or aggressively, depending usually on the personal views and experience of the operations engineer.

Particularly in heavy oil wells, but also in conventional oil production wells, chemical efficacy may be seriously impaired for several reasons.

Fracturing: In CHOPS wells that have produced large sand volumes, the fracture gradient is often as low as 7-8 kPa/m and the BHP can be much lower. Attempts to introduce liquids, even at moderate rates, simply generate fractures and channeling, reducing reservoir exposure to the chemicals. Most of the chemicals may even be back-produced largely undiluted.

Permeablity Channelling: The presence of highly permeable channels means that the injected liquids only contact the permeable zones, even if the liquids are introduced aggressively (which may lead to fracturing of course). Undiluted chemical may be back-produced.

Incomplete Perforation Interval Treatment: Liquids will only flow through open perforations. Under normal conditions in CHOPS wells, only 10-30% of perforations are open and flowing before a treatment.

Non-Homogeneous Formation Saturations: Liquid saturations that are non-homogeneously distributed around the wellbore will lead to preferential flow of chemicals into limited regions. Also, if there are regions of the near-wellbore environment that are blocked by interfacial effects, these may be unavailable to permeants.

Viscous Fingering: Even in a perfectly intact porous medium, introduction of a low-viscosity injectant will lead to massive fingering, limiting contact volume severely.

Low Diffusivity: During the soak phase of a chemical workover, diffusion of the injectant into adjacent pores through Fickian diffusion processes increases the contact volume. This is a slow process, particularly in high viscosity oils, and cannot in general be counted on to occur in an economically attractive time frame.

Gravity Segregation: If the injected liquids have a substantially different density than the formation liquids, there may be effects of gravity segregation. At a distance from the wellbore, lighter liquids will override, denser liquids will move downward.

These difficulties can be largely overcome by aggressive pressure pulsing (see section on micromechanisms). In laboratory experiments, the effects are obvious: pulsing generates better dispersion in all cases (Figure 3). There is no reason to believe that this does not occur in the field. Pulsed chemical placement generates far less fingering, better conformance, and around a well, likely generates a more uniform propagation front, rather than generating a strongly channeled geometry (Figure 4).

An additional major benefit of pressure pulsing is that the chemicals are intimately mixed with the reservoir liquids by virtue of the rapid flux (high shear) through the perforations during each stroke. Also, reservoir liquids are allowed to flow back into the wellbore during each restroke cycle (the proportion of flowback can be varied), thus the chemicals are well dispersed in the virgin reservoir liquids, and this enhances their efficacy.

CASE HISTORY

A group of seven CHOPS wells producing from a single field in the Lloydminster region were treated with chemicals placed under conditions of aggressive pulsing.

Geology and Lithostratigraphy

The wells are completed in the Sparky and the GP sands of the Middle Mannville strata, the central part of the Mannville Group of east-central Alberta and west-central Saskatchewan. In these strata, the reservoirs are channel and blanket sands of Cretaceous age (~110 MYBP). Many Mannville Group horizons containing heavy oil are being exploited by CHOPS in the Lloydminster region of the Heavy Oil Belt, with formation (or zone) names such as the Rex, Wascana, Dina, GP, Sparky and McLaren.

The deposition environment for the reservoirs in question was an anastomosing river channel system in an accreting sedimentation regime of extremely low relief so that the lateral migration of river channels was not seriously impeded by topography. Sediments were reworked many times before burial by accretion in the northward draining system.

The shallow epicontinental sea lay to the north and northwest, and the synchronous deposits several hundred kilometers to the north-northwest are characteristically shallow marine in nature. The seacoast was migrating slowly northward at this time. Later, well after the end of the Middle Mannville period, after the reservoir sand bodies were in place, relatively rapid transgression (seacoast advance) took place, covering the region with laterally continuous shales. Sediment load provenance was dominantly from the tectonically affected and topographically superior region to the south-southwest, into present-day Montana. Also, given the proximity of the Canadian Shield, there was undoubtedly a lesser component of quartzose sand from the east.

These reservoirs are all fine- to occasionally medium-grained sands, and the sediments also have small amounts of clay that can be mobilized under liquid flow. The natural gamma ray values are 40 to 60 API units, indicating the presence of K^{40} in the feldspars and clay minerals (clean quartzose sands tend to have values of 30). The surrounding non-oil bearing strata have natural gamma ray values of 60-75, indicating that they are dominantly clayey silts and clayey very fine-grained sands, rather than shales.

In this region of the Heavy Oil Belt, the oil tends to be on the order of 13-17°API gravity with an estimated *in situ* viscosity of 1,000 - 11,000 cP, whereas the formation waters have viscosities on the order of 1 cP and are somewhat saline, on the order of 50,000 ppm TDS. The oils are generally asphaltenic in nature although wax problems are reported in some fields.

Well History

The wells that form part of the study are all about 600 m deep in one field with 16-17°API oil, at the low end of the viscosity range, ~1200 cP, with some variability among wells. The asphaltene content is probably on the order of 5-6%, and this asphaltene can be precipitated under pressure decline. Average oil saturation at the time of initial development was 82% in the lower thinner zone (GP zone), 85% in the upper thicker zone (Sparky sands). The wells are in unconsolidated sands of 30-32% porosity; the sands have no tensile resistance, and they produce sand and heavy oil readily under appropriate operational conditions (i.e. CHOPS).

The field was first developed over four decades ago, produced using beam pumps for about 15-20 years, and subsequently suspended. It is estimated that the primary recovery factor in the upper zone was ~9% and ~5% in the lower zone. Most wells remained inactive until a program of revitalization of the field was recently initiated.

The wells use 7″ casing, and most of the wells have perforations in both the lower zone (2.5 m) and the upper zone (5 m). Nevertheless, several were perforated only in the upper, thicker zone, in cases where the lower zone was so thin as not to warrant development. Perforations of 10 to 13 mm diameter were placed at a spacing of 13 shots per meter, and the full interval was generally perforated. None of the wells were recently reperforated, despite this being a common practice in the region for well revitalization.

During the initial production phase, the wells produced small amounts of sand, but aggressive sand production was not pursued at that time. On well re-entry, BHP values proved to be surprisingly low, averaging 800 kPa, indicating that there had been minimal pressure recovery over several decades since suspension of production. This indicates no active water recharge, and likely also indicated serious disconnection from any extant reservoir pressures.

Of the seven wells treated, six had several months production history before the pulsed chemical treatment, therefore average before-and-after data bases exist. One well had been shut in for many months because it began to produce 100% water. This is a particularly interesting well, and will be discussed later.

Workover Protocol

The perception of several reasons for well decline and failure to recover pressure over many years led to the concept of a simultaneous pulsing and chemical placement workover. Also, a recent history of chemical treatments without pulsing was not entirely satisfactory, and means were being sought to improve workover results.

A proprietary liquid commercial product was chosen and placed in amounts averaging 1 m^3 per metre of perforations. The chemical is a hydrocarbon base liquid of much lower viscosity than the heavy oil in the reservoirs. It is commonly used to effect asphaltene and wax removal, and it contains appreciable amounts of low molecular weight cyclic aromatic chemicals to dissolve asphaltenes, as well as a surfactant to affect interfacial tensions and wettability.

It had been observed in previous non-pulsing chemical workovers in this field that better performance was related to longer chemical soak periods in the well. Therefore, an extended soak period was decided on before pulsing.

Because of the novelty of the pulsed chemical workover method that was decided on, a unique and fixed workover protocol was not followed. Rather, continuous optimization attempts were made in response to the behavior of the previous wells, and depending also on the specific well involved. Because all wells but one had been on production as a result of the revitalization project, production equipment was in the hole at the beginning of the procedure.

In general, the following protocol represents relatively well the general procedure adopted:

- The annulus was slowly displaced with the liquid chemical in quantities of 1 m^3/m perforations. Because of the low pressure and the annulus volume, most of the chemical undoubtedly flowed into the near-wellbore region. Also, the great majority of the chemical undoubtedly flowed into the upper thicker zone.
- The chemical was allowed to reside in place for five to seven days, to allow dispersion to take place, and in response to service rig scheduling.
- The tubing string was flushed with 4 m^3 of formation water mixed with 10 to 30% of the workover chemical.
- The production equipment was withdrawn from the hole, the level of sand was tagged, and the well cleaned of sand to below the lowermost perforation (if necessary).
- The pulsing tool and tool were installed in the hole just above the uppermost perforations to begin the pulsing workover.
- Pulsing was carried out using full 7″ displacement, a stroke length of 6 to 8 m, and the stroking rate was every 20 to 30 seconds (2-3 strokes per minute).
- Pulsing continued for seven to ten hours, the total number of strokes ranging from 840 to 1800 for individual wells.
- Annular liquid levels were taken about every hour during a brief cessation of pulsing.
- Depending on the liquid level, an amount of load liquid similar in composition to the tubing flush liquid was added slowly to the annulus.
- From 6 to 8 m^3 of load liquid were added during the pulsing period.
- The pulsing tool was withdrawn, the sand level tagged, the well cleaned if necessary, the production equipment reinstalled and pumping initiated.

To give an idea of the amount of liquid sloshed through the perforations, 1000 strokes of 8 m length displaces about 200 m^3 of liquid. Of course, because the tool was recharged by liquid flowback through the perforations (i.e. additional liquid was not being pumped into the hole), the actual amount of liquid introduced was on the order of 15-20 m^3/well (the sum of the annular placed liquid, the tubing flush liquid and the load liquid during the workover.

It is believed that the pulsing tended to open all the perforations and to generate new short-term displacement paths in the near-wellbore region during each stroke. This leads to a massive remolding and working of the chemical into the interstices of the sand, and undoubtedly greatly increased the volume of reservoir affected by the chemical.

Workover Results

Figure 5 shows the general results of the seven wells. Three months pre-workover production data for the six producing wells are presented with three months post-workover production for the seven wells treated, to give an overall view of the success of the project. The results are summarized as follows:

- Before the workovers, oil rates were approximately stable on a monthly average basis.
- All seven wells experienced dramatic increases in liquid production rate; overall, a factor of 2.3 increase was observed (Figure 6).
- The oil production rate increased by a factor of five on the wells.
- The oil-to-water ratios improved before and after the workovers from a total averaged value (based on total volumes produced for the group) of 0.16 to 0.43 (Figure 7).
- One well showed a slight decline in oil water ratio, but did produce at about a 20% greater oil rate overall. All other wells showed increases in the oil-to-water ratio.

Economic analysis showed that the pay-back period for the seven stimulations was ~60 days at the prices obtained during this period (differential prices, unfortunately, were quite unfavorable, and a more rapid pay-back is envisioned in future wells if the differential shrinks). Also, it is clear from comparison with previous non-pulsing chemical workovers that pulsing carries substantial advantages. These advantages are thought to be partly the massive perturbation effects combined a large improvement in the chemical dispersion around the wellbore.

One well deserves special mention. This well was producing 100% water and was shut in for several months before treatment. After treatment, it has produced on average 160 m^3/month of oil and 55 m3/month of water, giving an oil-to-water ratio of about 3. This is the highest ratio among the seven wells at the present time. For reasons that are singularly difficult to fathom, the worst well before pulsing became the best well after pulsing. Furthermore, the workover succeeded in greatly reducing water influx without use of a specific water-blocking agent. Perhaps the “channels” or high water saturation streaks generated during the CHOPS process were collapsed or otherwise resaturated more homogeneously with oil. It will be interesting to track the future production of this group of wells. At the time of publication April 15 2001, the data provided were up to date until the end of March, 2001.

FUTURE DEVELOPMENTS

At this stage in the development of pressure pulsing workovers, a much higher success ratio is being obtained that at its inception several years ago. This is because it is becoming ever more clear which candidates are favorable. Also, the addition of chemical treatment aspects with the pulsing essentially improves the odds of favorable results.

During this seven-well program, for various reasons, bottom hole pressures were not collected. The field engineers and the operating company believe that this should be collected in the future for a number of reasons.

- It would provide a better understanding of the current reason for the blockage or lack of inflow. Specifically, is it associated with the near-wellbore region (i.e. blocked perforations) or with the far-field (e.g. pressure disconnection).
- A discrete estimate of the time that it takes to overcome near-wellbore blockage can be obtained, and this can be correlated to well history for planning subsequent workover periods (e.g. should we pulse for 5 hours, 24 hours, more?).
- The reactive back-pressure generated by the formation against the impulse generates the amplitude of the pressure pulse, and this gives insight into the average state of the rock matrix in the intermediate region around the well (out to ~5 m or so).
- The data can be used in combination with liquid levels to optimize the pulsed chemical procedure by tracking the evolution of the formation response, allowing real-time optimization on an individual well

basis (e.g. by changing stroke length, load liquid rate, stroke recurrence, dwell time, and so on).

Trials to date have been in heavy oils. There is reason to believe that acid placement into carbonate reservoirs for matrix dissolution or into sandstone reservoirs for clay dissolution using pulsing would also bring beneficial results for the same set of reasons.

Pulsing will in general help dislodge pore throat blockages whether it is executed in CHOPS wells or in wells with fully intact rock. Then, when wells are placed on production, the dislodged materials can be flushed out of the well.

There are many options to try that could further improve chemical treatment. It may be that a pulsed chemical workover will be more effective if the pulsing is executed first to open the perforations and unblock the near-wellbore environment. Then, the chemicals could be added slowly while pulsing, using the flowback through the perforations as the mixing and dispersing agent. The chemical could be "chased" with additiona volumes of reservoir compatible liquids (water or oil) to propagate the chemical treatment front farther into the reservoir. Then, the well would be allowed to soak before being placed on production again. Clearly, the scope for carefully implemented comparative field studies is great, and not just in heavy oil.

CLOSURE

Aggressive pulsing generates a group of macroscopic (impulsive) and microscopic (pore dilation waves) mechanisms that have beneficial effects on the condition of wellbores.

Chemical well workovers can be rendered considerably more effective if placement is effected with pulsing. Because pulsing favors dispersive behavior rather than inhomogeneous flow, the chemicals reach a much greater contact volume and are less subject to preferential channeling. This reduces the amount of undiluted chemical flowback, and generates a more uniform dispersive front around the well.

The economic data for pulsed chemical workovers in CHOPS wells showed an averaged payback period that is well within accepted norms, and with a substantially higher success ratio. Even without the future methodological improvements envisioned, this makes them a useful method to revitalize poor wells.

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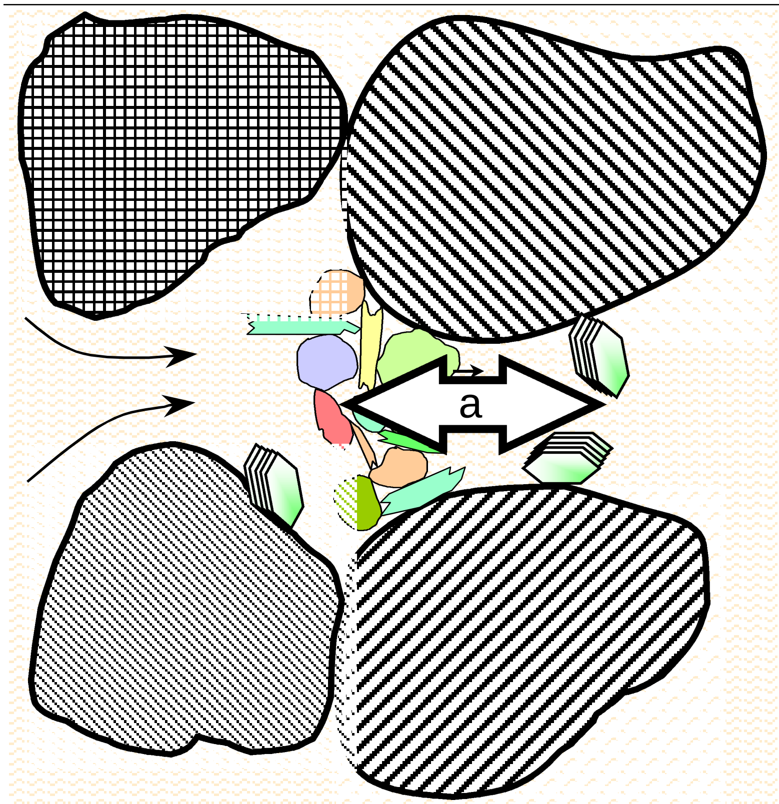
(Note of information:
The specific workover chemical used is a proprietary product.
The pressure pulsing workover approach is a patented method subject to international patent law in a number of jurisdictions.)



MECHANISMS:

- Pore throats become blocked
- Pulsing is applied properly
- Porosity dilation waves transit
- Pore volume changes rapidly
- Liquid behaves incompressibly
- High accelerations (**a**) at throats
- Repeated **a** dislodges particles
- Once moving, less blockage
- Liquids also flowing faster
- Higher drag, less blockage
- Thus, pulsing reduces blockage

Fig 1: Pore Throat Blockages are Perturbed and Destabilized by Pressure Pulsing

$$d \cdot \frac{\partial p}{\partial l} = \Delta p_S$$

static force

$$\frac{\vec{F}}{A} = \frac{m\vec{a}}{A} = \Delta p_D$$

dynamic force

A = throat area
F = new force
m = fluid mass
a = acceleration

$Dp_D > Dp_S$ (g/2r)
= breakthrough

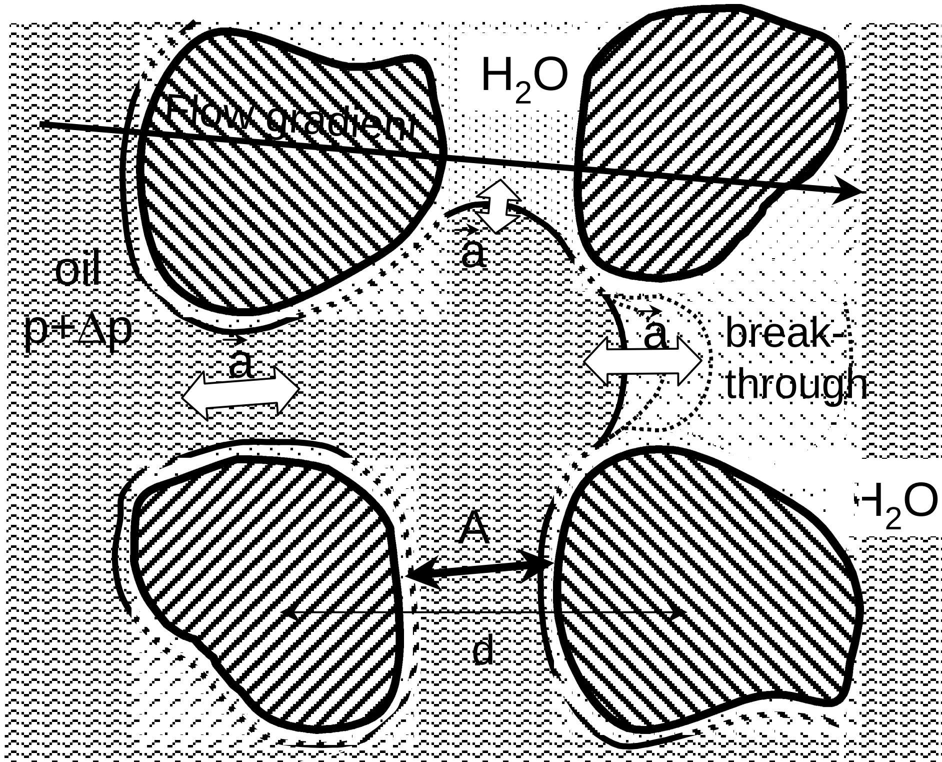


Fig 2: Capillary Pore Throat Blockages are Overcome by Pressure Pulsing

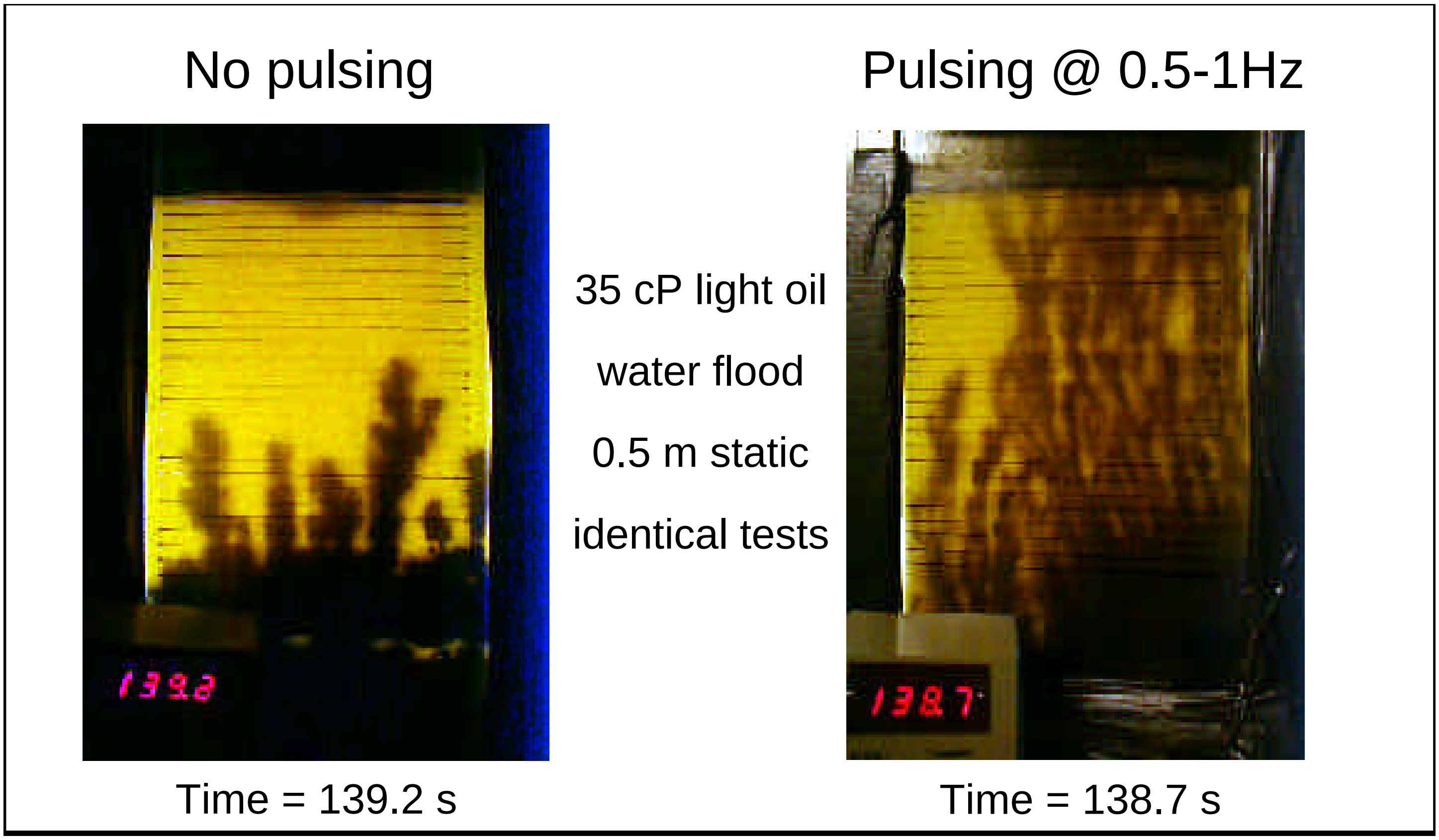


Fig 3: Increased Dispersion and Better Conformance During Pressure Pulsing

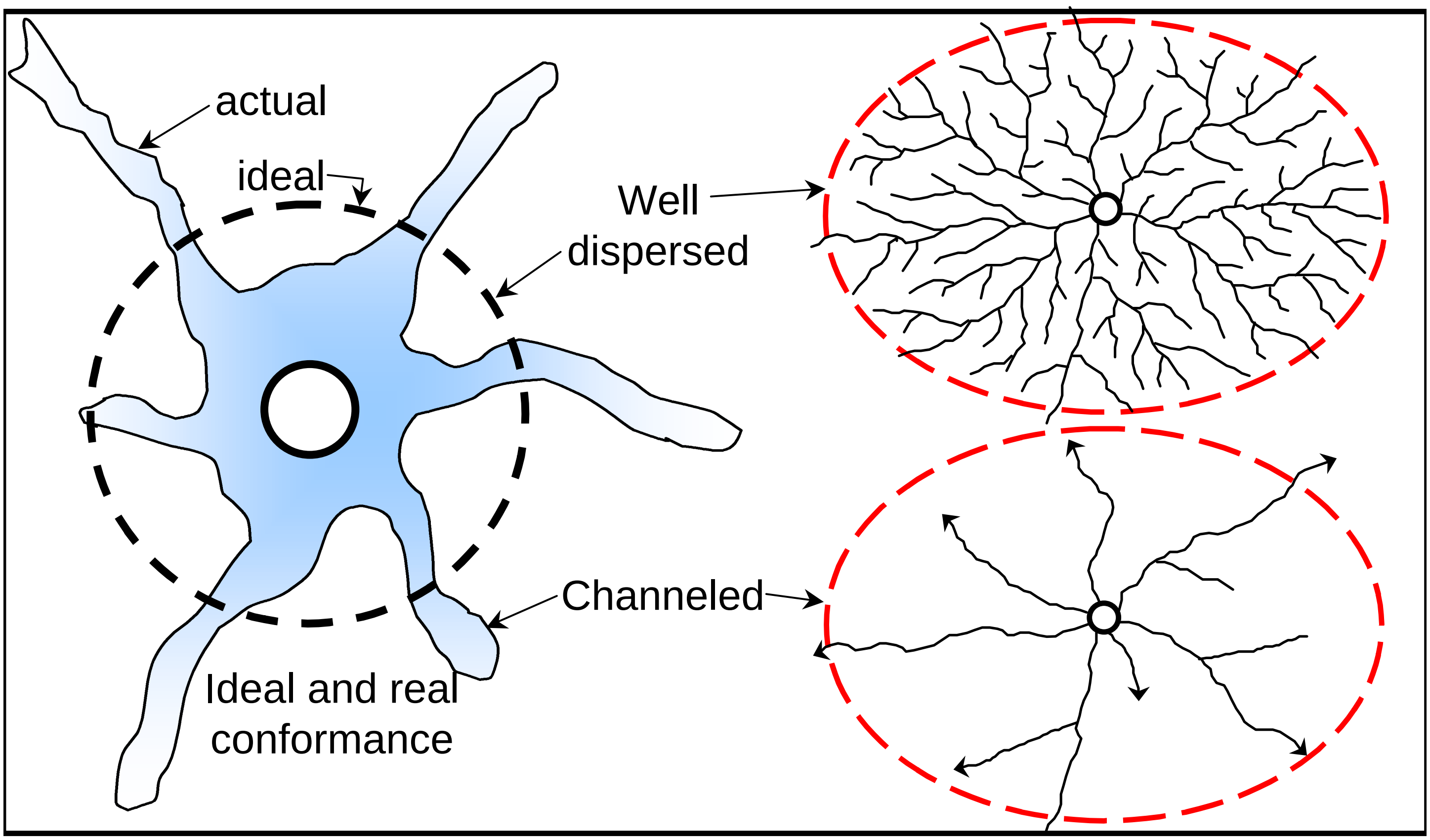


Fig 4: Conditions Around a Wellbore During Chemical Placement

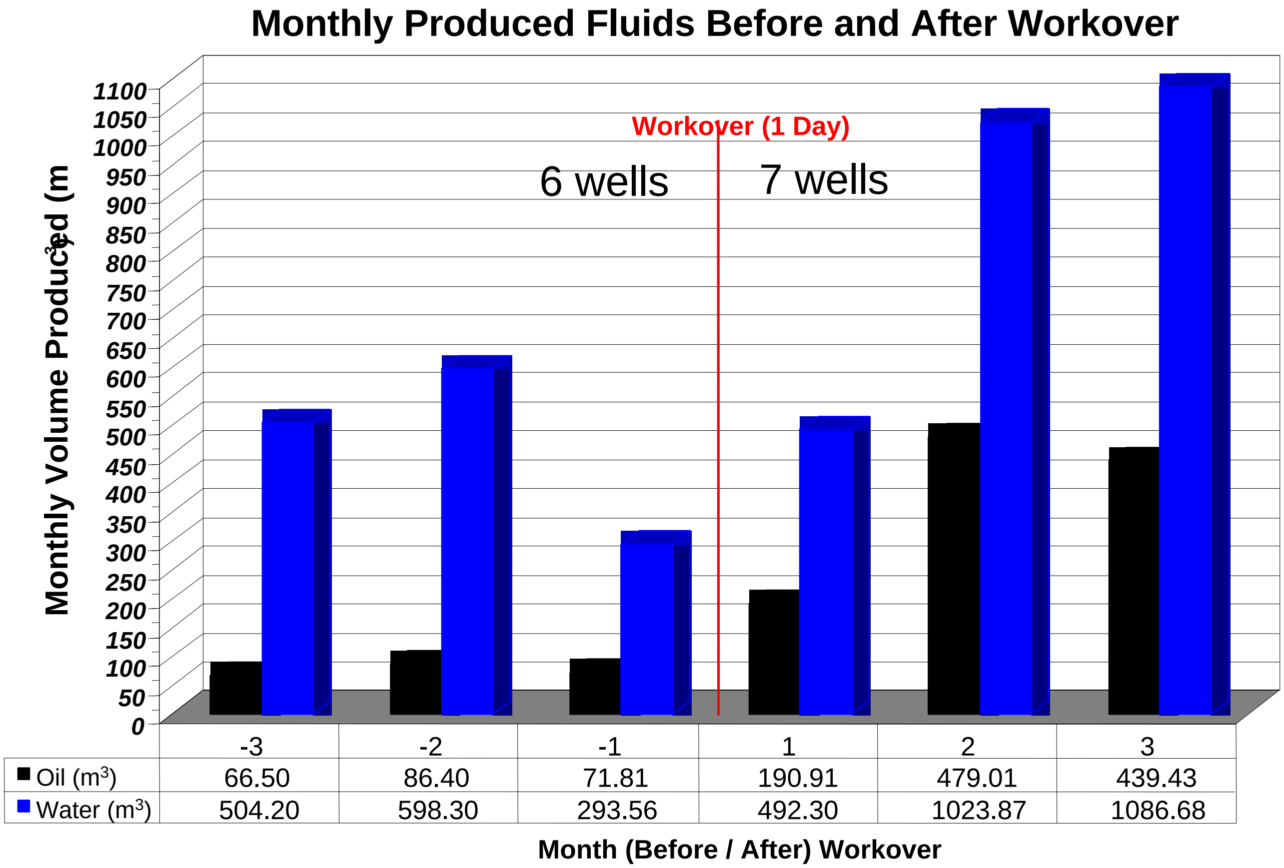
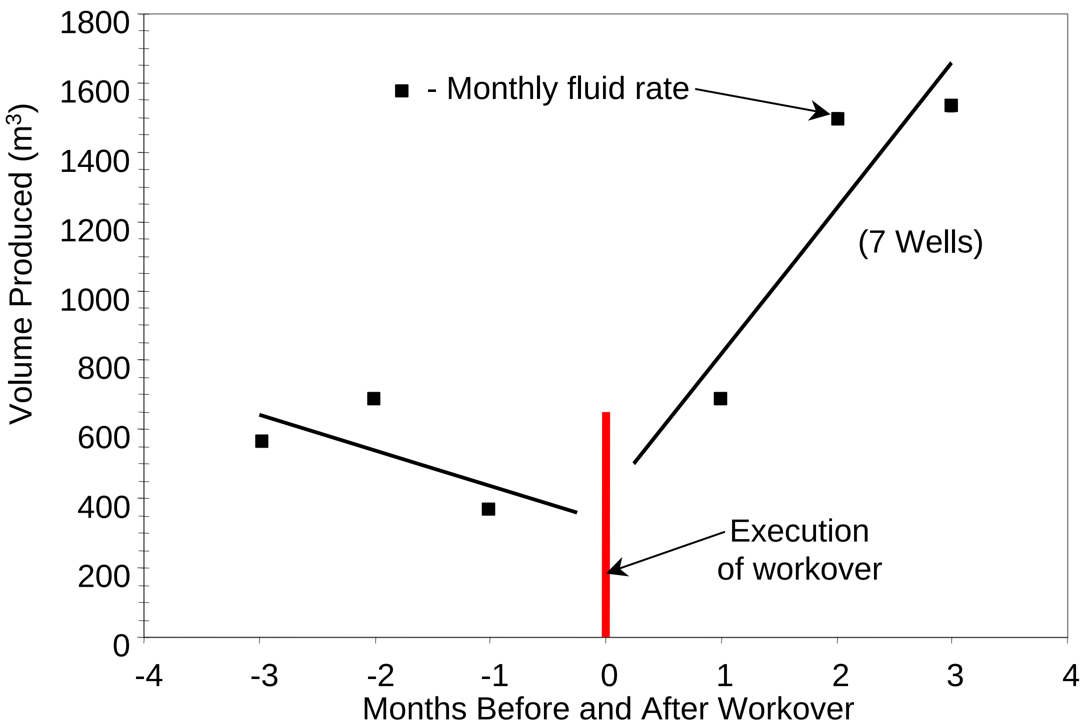


Fig 5: Fluid Production History Before and After Pulsed Chemical Workover

Fig 6: Monthly Fluid Production Rates for 3 Months Before and 3 Months After Pulsed Chemical Workover



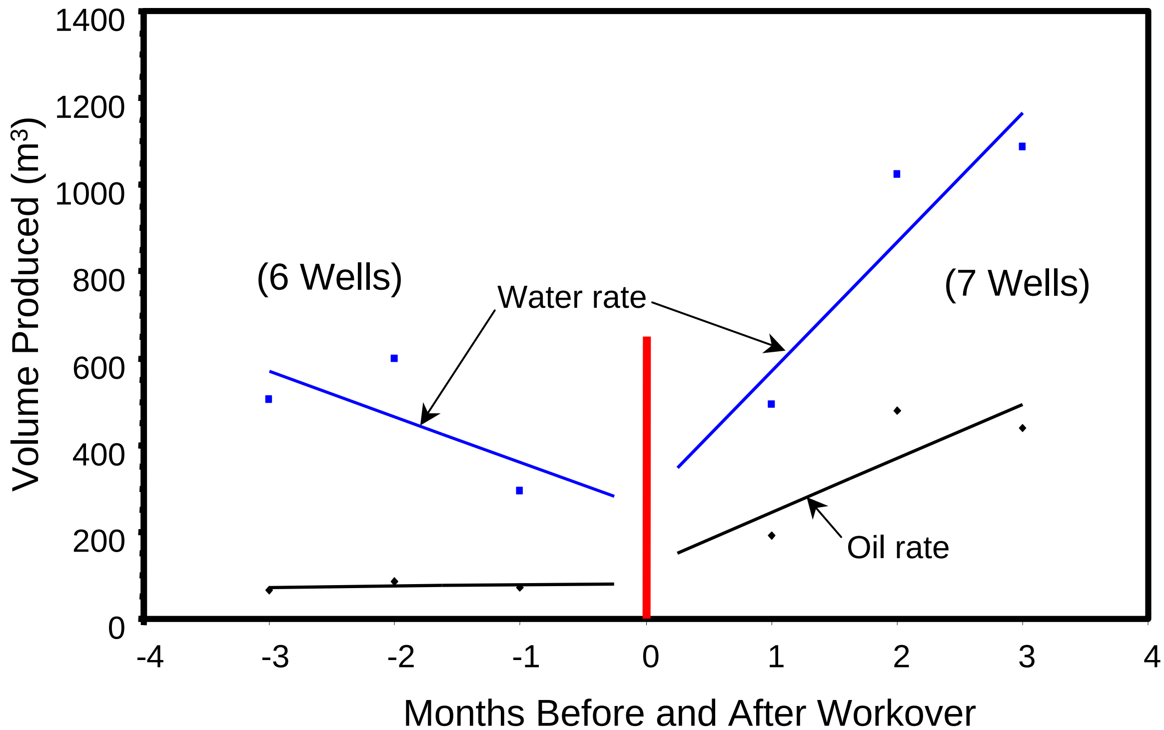


Fig 7: Oil and Water Monthly Rates Before and After Workover