A New Workover Approach for Oil Wells Based on High Amplitude Pressure Pulsing[1]

Maurice B. Dusseault, Porous Media Research Institute, University of Waterloo, Waterloo

JTJ (Tim) Spanos, Porous Media Research Institute, University of Alberta, Edmonton

Brett C. Davidson, PE-TECH Inc, Lloydminster Alberta

[1]Presented and published in the Proceedings of the 50th CIM Petroleum Society Annual Technical Meeting, Calgary, Alberta, June, 1999

ABSTRACT

*A new workover method based on large-amplitude pressure pulsing is being used in **C**old **H**eavy **O**il **P**roduction (CHOP) wells in Alberta and Saskatchewan. The **P**ulsing **W**orkover **T**ool (PWT) approach is based on prolonged high-amplitude, low-frequency pressure pulsing of the wellbore liquid, while adding additional fluid at a controlled rate through the annulus. Typically, pulsing is continued for 8-12 hours, after which the well is placed back on production.*

To date (March 15, 1999), over 25 workovers have been performed in the following fields: Lloydminster, Lindbergh, Morgan, Marsden, Luseland, Plover Lake, Bear Trap, Marwayne, and Wolf Lake. Several wells that had never produced much oil were improved to be economic producers. Blocked wells, where oil rate drops seemed to be associated with perforation plugging or stable sand arch formation, were substantially improved by the PWT approach. There have been many successful applications of PWT, and a few failures. Because candidate screening criteria are improving, the success ratio is increasing. The PWT approach will be useful for other applications as well in conventional oil well workovers.

CHOP WELL PRODUCTION PATTERNS

Successful **C**old **H**eavy **O**il **P**roduction (CHOP) in the unconsolidated heavy oil sands of Alberta and Saskatchewan requires that sand continue to enter the wellbore to maintain economic oil production rates[1]. All sand exclusion devices such as gravel packs, screens, filters, and slotted liners greatly reduce or eliminate oil production.

A "typical" CHOP well has an average oil production history similar to that in Figure 1. The main features are[2]:

- An extremely high sand rate (often in excess of 30% sand by volume of the dead produced fluids) that usually begins to drop off shortly after production begins.

- A “stable” sand production period where sand influx rate is approximately constant (“stable” sand rate = f(Q, μ, + reservoir-specific parameters). Steady-state rates can be as high as 8-10% sand for high viscosity oils.

- A liquid (oil + water) production rate that rises over a period of several months to a peak rate, then begins a gradual decline to an uneconomical oil rate, unless the well is plugged suddenly (e.g. by perforation blockages).

- After a successful workover has been implemented in a CHOP well, a period of renewed economic production occurs, but rarely do the oil and sand rates reach the peaks they did in the first cycle, because of foamy oil drive depletion and reduced pressure gradients.

- A number of cycles may ensue; several wells have sustained economial CHOP production for more than 10-12 years (5-8 years is most common for good wells).

After a number of these cycles, the well may become “exhausted”, as the zone that has been affected by the sand yield and channeling is large, gradients are low, and the solution gas may have become depleted. Nevertheless, a good CHOP well may produce 50,000-80,000 m^3 of oil and 1000-3000 m^3 of sand in a 10-year life span.

Because sand influx is vital to the CHOP process (screens, slotted liners, and gravel packs are avoided), it follows that any natural reservoir process that stops or reduces sand ingress may negatively impact oil production rates. Stopping or slowing of sand and oil rate may arise from one or more of the following physical reservoir processes:

- Perforations may become blocked by the formation of stable sand arches that cannot easily be destabilized by the low local pressure gradients, leading to a cessation of sand influx (Figure 2). Sand stabilization may also develop farther out from the well.

- Large fragments of intraformational shale or siltstone, pieces of chert or gravel, or lumps of cement may block the perforations (Figure 3).

- Water breakthrough (coning or high permeability piping channel connection to a water source) may lead to a local pressure gradient decline, stopping the sanding process (Figure 4), and causing wells to produce only water.

- Loading of the reservoir material by the overburden, a process that promotes shear destabilization of the sand, is reduced because stable inter-well regions develop that successfully support the overburden (Figure 5).

- Reservoir depletion leads to such low near-wellbore pressure gradients that sand can no longer be continuously destabilized (Figure 6).

- The near wellbore region may become “disconnected” from the far-field fluids and pressure, leading to a lack of local wellbore energy to drive foamy oil and sanding processes (Figure 6).

In CHOP wells, production may stop suddenly; a 7-8 m^3/day well may go to <1 m^3/day in less than an hour. More commonly, oil rate slowly declines over many months until operating expenses cannot be met; the well is then shut in. A sudden rate drop is probably caused by perforation plugging or sand recompaction in the near-wellbore region; a slow decline is probably related to pressure gradient reduction from depletion and CHOP zone growth (yielded or wormhole-permeated region). The larger the radius of influence (the disturbed zone), the lower the magnitude of local gradients that can be generated during “steady-state” flow (Figure 6).

Similar behavioral variability is observed for the water-to-oil ratios in wells near mobile water. The water cut may gradually rise over many months, yet in some cases, massive water breakthrough seems to occur in a few days or weeks. The latter is thought to be associated with breakthrough of a piping channel (“wormhole”) to a water-saturated zone; once this happens, liquid flux becomes water dominated.

PRESSURE PULSING FLOW ENHANCEMENT[i]

Based on a theoretical model of dynamic processes in granular media with multi-phase fluids[3&4], plus some anecdotal information that perturbations were favorable to CHOP production, a series of laboratory experiments was undertaken to test our predictions of fluid flow rate enhancement by large-strain, non-seismic excitation. The results of the tests were unequivocal: properly applied, pressure pulsing

[i] The PWT, methodology, and other aspects of pressure-pulse flow enhancement are the subjects of a series of Patent Applications and Patents Pending.

increases flow rates dramatically[5]. Two years of experiments have ensued; some of the test configurations are listed here:

- Static sand packs and sand packs where sand is allowed to exit with the fluid (sand production);
- Cylindrical packs from 30 to 70 cm long, 10 cm to 15 cm diameter, under various confining stresses, using vertical downward flow, with pressure monitoring;
- Rectangular flat sand packs (20-30 mm thick) of two different sizes (0.15 and 0.75 m^2), horizontal and tilted at angles up to 70° so that flow within the cell is upward, but under a pressure drop;
- Sand packs with mean grain sizes of 20-40 µm to as large as 2000µm (2 mm silica grains);
- Single phase flow of oil (30 cp and 10,600 cp heavy oil) and glycerin (~650 cp);
- Two phase systems in different configurations using different residual saturation phases (i.e. oil flow in water-wet systems, water or glycerin flow in oil-wet systems);
- Limited cases of three-phase fluid systems where one phase is dispersed gas bubbles;
- Displacement flow of a mobile phase (S = 0.85) by another immiscible phase of different viscosity (i.e. injection of water into an oil-saturated system).

These experiments formed a basis of physical proof that porous medium fluid flow could be greatly enhanced, and they also led to a number of findings related to dynamic flow enhancement, such as:

- Large flow rate enhancements occur when using large-strain, non-seismic excitation in porous media;
- Strain levels must be at least 10^{-5} or larger for the effect to be substantial; i.e., the strains are far above typical seismic strains (~10^{-7} – 10^{-10});
- The energy source can be a pressure pulse or a strain pulse: because of solid-fluid coupling at the pore scale, conversion occurs, and they are de facto equivalent;
- Excitation dominated by a range of low frequencies is needed for heterogeneous porous media (conversely, single frequency sinusoidal excitation is less effective);
- Viscous fingering instabilities can be substantially modified by pressure pulsing (this was proven by introducing less viscous fluids into a system by pulsing, and noting that instead of channeling, dispersion was favored);
- A detectable porosity diffusion wave is generated by each impulse, and this wave has a velocity in line with predictions of the theory: in the laboratory under low stress (0.5 MPa), velocities of 8-10 m/s were observed;
- A detectable porosity wave (a "tsunami") diffuses through the system and if the magnitude is large enough it leads to a synergetic internal pressure build-up in the flowing system, changing the pressure gradient from "steady-state" conditions to one where the exit gradients are larger, as well as internal pressures;
- The process is repeatable with no changes in phase saturations (confirmed by repeated periods of excitation on each test assembly);
- The fabric of the sand packs remained constant (elastic deformation) throughout repeated cycling of pressure pulsing, as proven by before-and-after static flow tests;
- The process seems relatively more effective in viscous heavy oils than in light, low-viscosity oils;
- Flow rate enhancement occurs in all cases, even at modest permeabilities (25 µm particle size); and,
- The permeability of the system and the magnitude of the external head dominate the absolute flow rate and post-excitation pressure decay behavior. (In other words, Darcy's law is perfectly valid for "quasi-static" flow that is not dynamically enhanced.)

Pressure pulsing technology was tested in field trials in 1998. A workover approach was designed and first tested in June, 1998 on a trial basis, then commercially since October, 1998 using the PWT. Reservoir-wide flow enhancement was tested starting December 07, 1998 in a 10-week field pilot trial. Results are reported in a companion article[6].

This article describes the workover technique, recounts some case histories, and attempts to explain the mechanics.

HOW THE PULSING WORKOVER TOOL IS USED

PWT workovers consist of large amplitude pressure pulsing applied through stroking a piston in a fixed cylinder. (Figure 7). The stroking forces liquid out the perforations in sudden surges; it works best in a liquid-saturated condition with the cylinder placed close to the perforations.

There are two different PWT configurations. At present (March 1999), the workover rig is used as a PWT stroker, and the downhole casing acts as the fixed cylinder. A fully hydraulically actuated PWT is being developed for summer, 1999, but all workovers to date have used the service rig stroking approach. The PWT is equipped with a continuous real-time pressure measurement with surface output; accelerometers will be installed on future tools to permit explicit energy calculations.

The stroking follows a pattern similar to that sketched in Figure 8. The down-stroke (surge) is controlled by the rate of fall of the 2200-2600 kg assembly of tool, collars, and tubing. The accelerative portions of the surge and the stroke velocity are affected in part by the handling of the drawworks (i.e. the brake), but in the new PWT, this will be programmable. The dwell time allows the surge to propagate as efficiently as possible into the reservoir, generating a large porosity diffusion wave. Immediate restroking would have the effect of reducing the transfer of energy. The slow upstroke allows fluids to back-flow through the perforations and to enter the bypass valve in a controlled manner. Dwell time, rise time, and upstroke can all be modified to meet specific needs.

A rapid upstroke and a low fluid level in the annulus means that almost all the recharge fluid is back-flow (Fig 7); a slow upstroke and an annulus filled with a low viscosity fluid means that the tool is largely recharged with the annulus fluid. The proportion of annulus fluids introduced is called the efficiency. The bypass valve opening affects this, and the valve opening will be programmable in new versions. Thus, at one extreme, the PWT can act as an efficient positive displacement pump; at the other extreme, 100% of the fluids being surged can be well back-flow, with no new fluids introduced. To date, we have operated more closely to the latter limit, trickling in small amounts of fluids to the annulus (5-25 m^3 over a 12-hour period). Which approach to use depends on the well history and the reason for production loss.

The workover using the PWT tool is done in "stages" (Figure 9). This involves a period of active stroking, followed by a period of no stroking (station stop), when the higher pressures and effects built up in the near-wellbore environment can diffuse out into the reservoir. During the station stop, there is no dynamic excitation, thus no porosity diffusion wave is generated, but fluid flow still takes place under quasi-static Darcy diffusion. After the station stop, fluid levels are determined before excitation recommences. A PWT workover may involve 8-12 of these stages, each a minimum of 45-minutes to a maximum or 2-hours in duration.

Once a 8-12 hour workover is completed, the PWT is withdrawn, the well pump replaced, and the well returned to production. Because the technique is highly effective at remolding the sand in the vicinity of the wellbore, production re-initiation may encounter a large increase in sand cut, compared with the pre-workover behavior, and the facilities and production strategy must be adjusted to cope with this.

CONSEQUENCES ON WELL PRODUCTIVITY

As with any new technology, attempts with limited or no success arise simply because the bounds of applicability are ill-defined. For example, in early PWT trials, wells were included that had been massively depleted over the years or wells with no annulus fluids and large volumes of free gas behind the well casing. These showed little improvement. Currently, for properly selected candidates, the ratio of economic successes is reasonable and is rising as screening criteria are improved and applied systematically.

Despite the method's novelty and a short experience base, considerable success has been achieved in a number of different situations. Table 1 gives the general vicinity or reservoir pools where the PWT has been used to March 1, 1999. Several of these will be highlighted in the form of short case histories. Specific wells are not identified as some companies are sensitive about public identification of their workover strategies.

The initial trial wells (fully confidential) were for the most part inactive CHOP wells that had begun producing excessive water/oil ratios. The pulse excitation in these wells was for periods of 5-8 hours, and afterward, much higher annulus fluid levels were measured. Trial production showed that in two cases the wells had reverted to reasonable oil production rates.

A Luseland Field CHOP well that had produced 60,000 m^3 of heavy oil (and undoubtedly >1000 m^3 of sand) over its life was treated for 10 hours with the PWT. Unfortunately, the well did not show an increase in oil rate, compared to pre-PWT pulsing. This well is considered a typical poor candidate because of massive depletion.

A well in the Lindbergh Field that had been shut in for 15 months after a rapid production drop was re-established as a good CHOP producer, yielding over 8 m^3/day several months after the PWT treatment. Figure 10 shows the recent production history of this well.

A well completed in 1997 in the Morgan Field was subjected to several attempts to establish CHOP flow but never produced beyond 1 m^3/d. It was exposed to PWT excitation for a 6-hour period. It became a moderate producer, yielding up to 5.5-6 m^3/day, and has continued to produce well beyond the typical production pattern for this well.

One well was provided with no fluid in the annulus and massive amounts of gas behind the casing; PWT treatment failed to re-establish production, but in a similar situation in a different well, using fluid addition to the annulus, modest, short-term well productivity was re-established. This was also considered a poor candidate because the PWT method is far less effective in the presence of massive free gas.

Other wells have similar records. Some are superb successes, especially cases where a non-producer is turned into an economic well; other cases are less easily classified as successes because production rose, but insufficiently to pay back workover costs as rapidly as hoped. Overall, the operating companies estimate the economic success ratio to be >50%, and the technical success ratio is ~90% (i.e. cases with substantially increased flow rates).

PHYSICAL MECHANISMS

What are the mechanisms involved in a successful PWT workover treatment of a CHOP well? A number of beneficial effects occur, all related to the prolonged excitation at high amplitude.

It is instructive to examine several PWT pressure-time curves before discussing mechanisms. Figure 11 shows the pressure trace from a well that had never produced much oil in its history. The PWT treatment increased pressure substantially, until fracture took place (fracture pressure being the natural upper limit for any pressurization process). Figure 12 is a pressure trace with little build-up, but in this case production was re-established successfully, undoubtedly because of eliminating blockages and some re-connection with far-field pressure drive mechanisms.

Pulsing unblocks perforations by aggressively and repeatedly pushing on the blocking agents, whether they are large rock or cement fragments or stable sand arches. It is presumed that this is the major effect in the region directly adjacent to the casing. The applied force F on blocking material is $\sim \boldsymbol{F} = \boldsymbol{A} \cdot \Delta \boldsymbol{p}_{\max}$, where A is the perforation opening, typically 3.5-4 cm^2, and Δp_{max} is the maximum pressure difference between the pressure inside the well generated by the stroke, and the pressure just outside the well. Because Δp_{max} is linked to pressure impulse on the down-stroke, ~0.2-1.5 MPa, the outward directed force on a single plugged perforation can approach ~100-400 N for about 2-3 seconds, and this is repeated each minute. Compared to typical hydrodynamic effects in quasi-static fluid flow, this is a large force. Repeated dynamic loading also accentuates the effect, when compared to a single pulse.

At the next scale, the region of several meters radius around the well, there is a beneficial effect that arises from dislodgement of mineral matter and precipitated asphaltenes that are blocking the pore throats. This may not be an important factor in CHOP wells, but becomes extremely important in conventional oil wells, as the generation of strongly positive skins because of fines and asphaltenes is a major factor in reducing productivity indices.

The pulsing, combined with the addition of some fluids, liquefies the sand in the near-wellbore environment, at the scale of perhaps 5-15 m away from the wellbore, depending on how long and how aggressively the PWT is used. It is widely believed that sand stabilization leading to flow blockage occurs through local stress arching and sand recompaction. This occurs more easily in older CHOP wells because flow gradients decline with time. The PWT treatment liquefies these regions, and because the workover lasts for many hours, the effect is propagated far beyond the immediate wellbore vicinity. At the present time, no independent data exist to indicate how far out this region can extend during a workover, but fluid level changes have been observed in offset wells (150 m) at the end of one PWT treatment, suggesting that the radius of influence is substantial.

The pressure build-up shown in Figure 11 shows that in some cases fracture pressure is reached. This has occurred several times, and indicates the efficacy of the process in generating elevated pressures that are homogeneously distributed around the well, rather than concentrated along a single fracture plane. The gradual pressure build up, the good radial dispersion, and the minimal pressure decay after the fracturing pressure is reached all prove that pore pressures have been increased in a large region around the well, not just along a single plane (i.e. a fracture plane). In fact, this is a major advantage of the PWT treatment: it promotes strong dispersion rather than channeling or fracturing.

The large pressure pulses that are transmitted into the surrounding reservoir tend to collapse any open or high permeability channels by destabilizing the sand around these features. Thus, “wormholes” that are channeling water to the wellbore can be collapsed effectively. This phenomenon is well-known in hopper flow or piping channels: a strong physical perturbation, generally not available during quasi-static Darcy flow, can lead to collapse of the structure.

Laboratory work shows that high amplitude pulsing in the oil phase can cause retreat of water-containing viscous fingers, and this, combined with the collapse of channels mentioned above, is why many of the wells subjected to a PWT workover return to a substantially higher oil cut. In these cases, it is essential to pulse in the hydrocarbon phase, and this is why reservoir-compatible oil is trickled in through the annulus during the workover.

Finally, there is the beneficial effect arising from the pressure diffusion wave that is propagated outward on each stroke. This may be considered a porosity dilation perturbation, and is thought to be the mechanism behind earthquake-induced changes in hydraulic head[7] (this has been confirmed in the laboratory). With each stroke, a porosity diffusion wave travels outward and affects the pressure in the pores, helping the region around the wellbore recover a higher pressure. This perturbation has another beneficial effect in that it can destabilize the “unyielded” regions of sand between wells (Figure 5). Once these “pillars” are destabilized, gravitational forces can again contribute to the CHOP process by driving the sand to the production wellbores. Also, these regions between wellbores are known to often have virgin pressures (and hence virgin solution gas), and their destabilization can partially rejuvenate foamy oil flow mechanisms.

These mechanisms are important for CHOP wells, but equally so for conventional wells, although with a different ranking. For example, dislodging fine-grained minerals from the pore throats is vital in reducing mechanical skin. In chemical treatments in conventional wells (surfactants, acids, xylene for asphaltene dissolution…), a serious problem with channeling usually develops. Conventionally injected chemical treatments often just displace preferentially through a permeable channel or, in the case of massive depletion, the injection opens up a fracture that remains open as long as injection is occurring. When the well is placed back on production, typically 50-80% of the treatment fluid flows back immediately, having been ineffective in the reservoir.

If the PWT is used to introduce the fluid in a controlled way, the following advantages accrue:

- Before chemicals are introduced, the PWT can be operated for several hours to open all perforations and thus increase treatment coverage and efficacy.

- Watered-out channels or open “wormholes” will collapse or retreat from the wellbore, and this will reduce or eliminate channeling of the treatment chemicals.

- Pulsing promotes dispersion and homogeneity of treatment (the lab experiments are unequivocal in this regard), therefore viscous fingering and similar effects will be suppressed.

- Operating each stroke at, for example, 10% efficiency (see above), means that chemicals are being fed into the near-wellbore region well mixed with compatible reservoir fluids. Mixing continues throughout the treatment through the surge flow effect. (Since 90% of the fluids in this case are recharged by back-flow from the perforations, a continuous mixing and dilution of the treatment chemical with compatible fluids takes place.)

- Soak times should be massively reduced or totally eliminated by this method, as maximum dispersion will have been achieved, without a need to let the materials “diffuse” into the medium.

- If it is considered desirable to “chase” the treatment fluid in an attempt to displace it farther from the wellbore, there is no better way to do this than to pulse the chase fluid massively during injection.

We believe that the PWT approach will be a major boon to oilwell workovers. This enthusiasm must be tempered with moderation: not all workover candidates will benefit from the PWT approach and the evolution of good screening criteria to optimize the application of the method is important.

CLOSURE

A new workover method has been subjected to extensive field testing in Alberta and Saskatchewan. These tests took place in a challenging environment, CHOP wells that had experienced losses in oil rates, water breakthrough, or failure to successfully initiate economic oil production rates. The success ratio is already good and still improving as screening criteria are better understood and applied by the companies. The workover approach will be equally valuable in conventional oil applications, as the mechanisms exploited by the method will dislodge fines and asphaltenes, and place chemicals in the near-wellbore region more evenly.

ACKNOWLEDGEMENTS

We thank the universities that have allowed us the intellectual freedom to pursue new ideas. As well, the granting agencies such as the Natural Sciences and Engineering Research Council of Canada and the Alberta Department of Energy (formerly AOSTRA) have provided financial assistance over the years. We also thank the production engineers and technologists at Wascana Energy Inc., Canadian Natural Resources Limited, and Ranger Oil who were willing to implement new technology.

REFERENCES

[1] M.B Dusseault, 1998. Canadian heavy oil production experience using Cold Production. Proc. Trinidad and Tobago Biennial SPE Conf. Port-of-Spain. CD-ROM available from SPE Trinidad and Tobago Section.

[2] M.B. Dusseault, M.B. Geilikman, and T.J.T. Spanos, 1998. Mechanisms of massive sand production in heavy oils. Proc 7th Int. Conf. on Heavy Oils and Tar Sands, UNITAR, Beijing, PRC, 14 p.

[3] V. de la Cruz, T.J.T Spanos, 1989. Thermomechanical coupling during seismic…, Jour. Geophy. Res., 94, B1, 637-642.

[4] V de la Cruz, P.N. Sahay, T.J.T. Spanos, 1993. Thermodynamics of porous media. Proc. R. Soc. London, A 443, 247-255.

[5] J. Wang, M.B. Dusseault, B.C. Davidson, T.J.T. Spanos, 1998. Fluid enhancement under liquid pressure pulsing at low frequency. Proc. 7th Unitar International Conference on Heavy Crude and Tar Sands, Beijing, PRC, October 1998.

[6] T.J.T. Spanos, B.C. Davidson, M.B. Dusseault, 1999. Pressure Pulsing at the Reservoir Scale: A New IOR Approach. Petroleum Society of CIM Annual Technical Conference, Calgary, Alberta.

[7] M.B Geilikman, T.J.T.Spanos, and E.Nyland, 1993. Porosity diffusion in fluid-saturated media, *Tectonoph*..,217, 11-113.

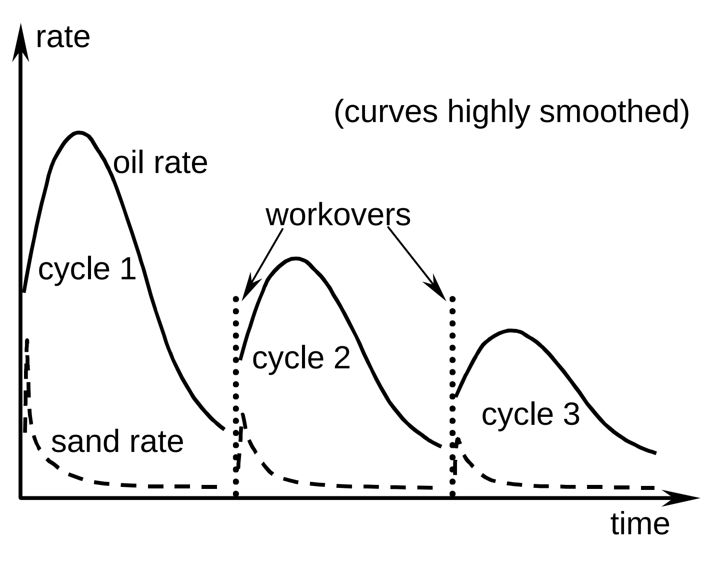

Fig 1: Typical CHOP well production history

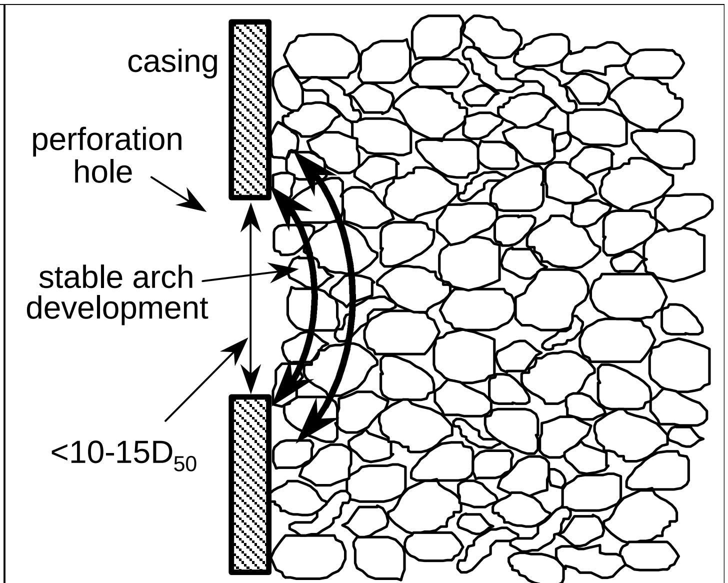

Fig 2: Stable sand arch behind perforations

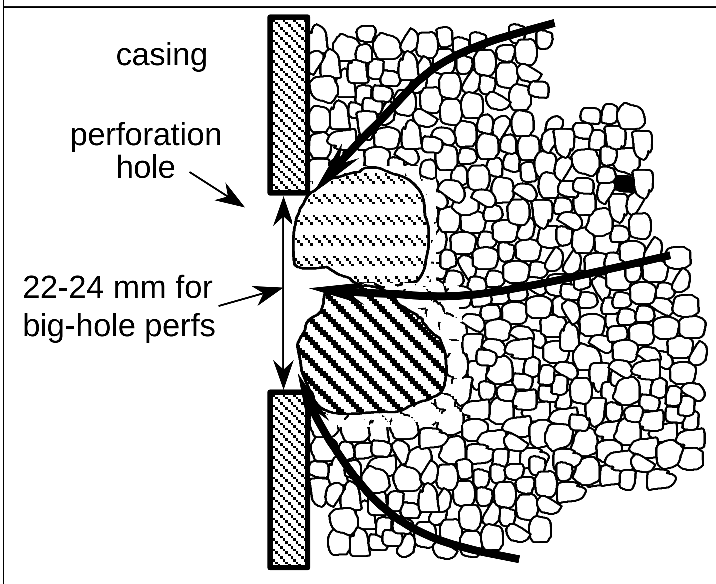

Fig 3: Cement or concretionary fragments

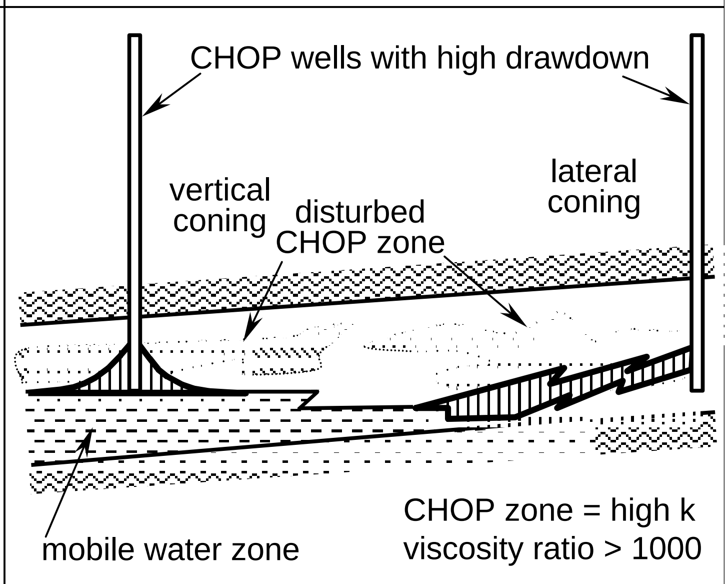

Fig 4: Water breakthrough in CHOP wells

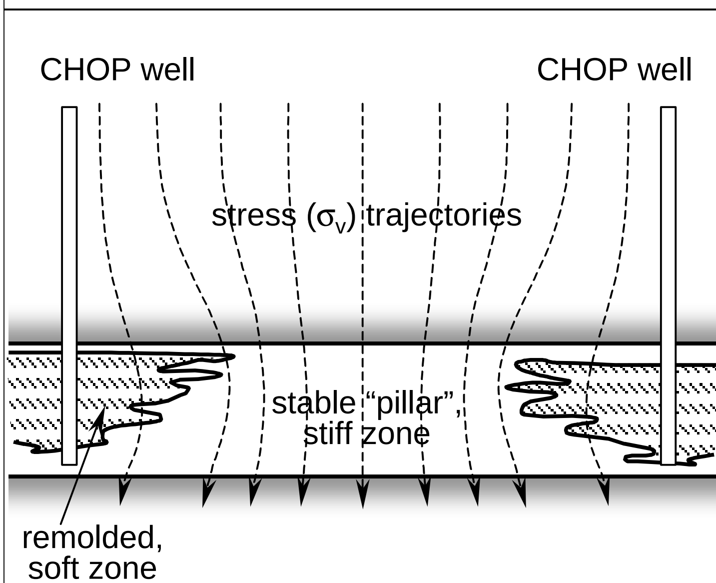

Fig 5: Stress arching, supporting overburden

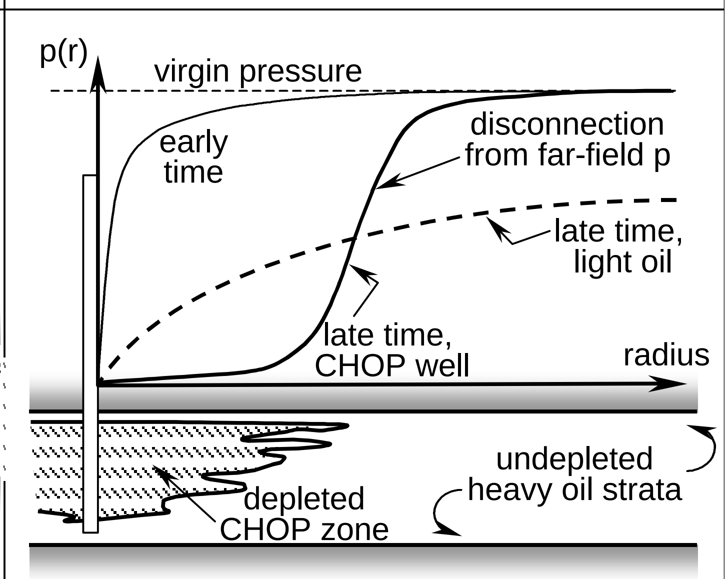

Fig 6: CHOP well disconnection from far-field

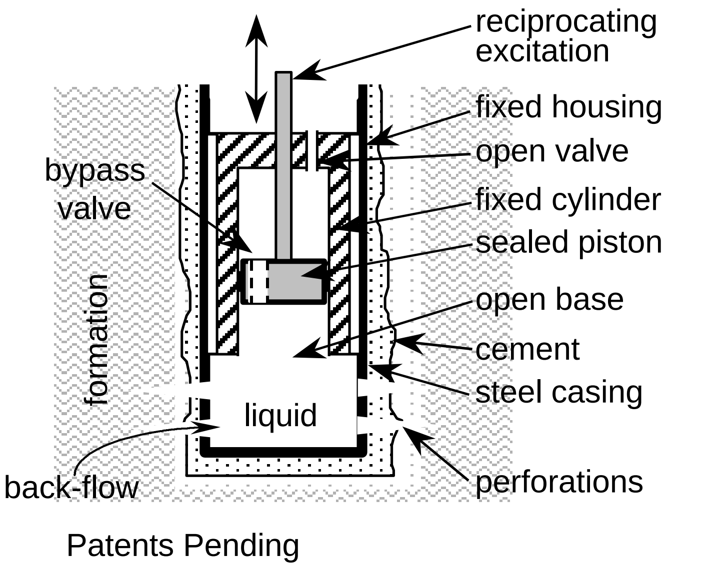

Fig 7: Basic principle for the PWT tool

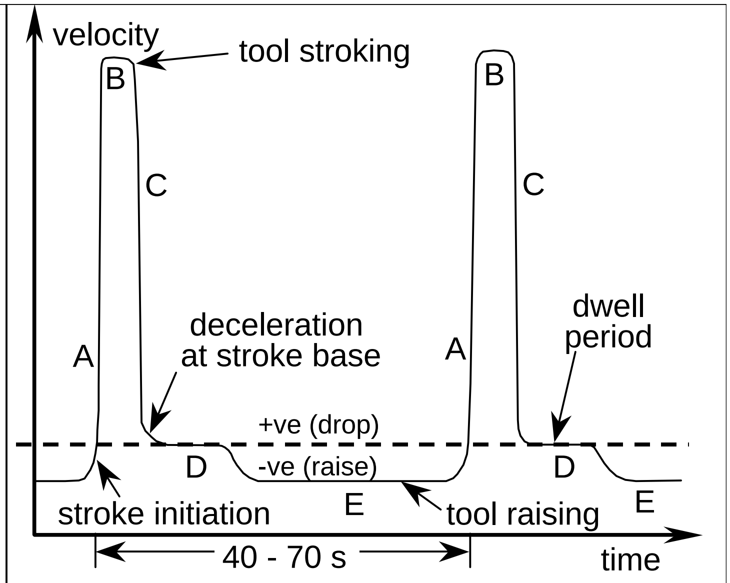

Fig 8: Velocity vs time for PWT cycles

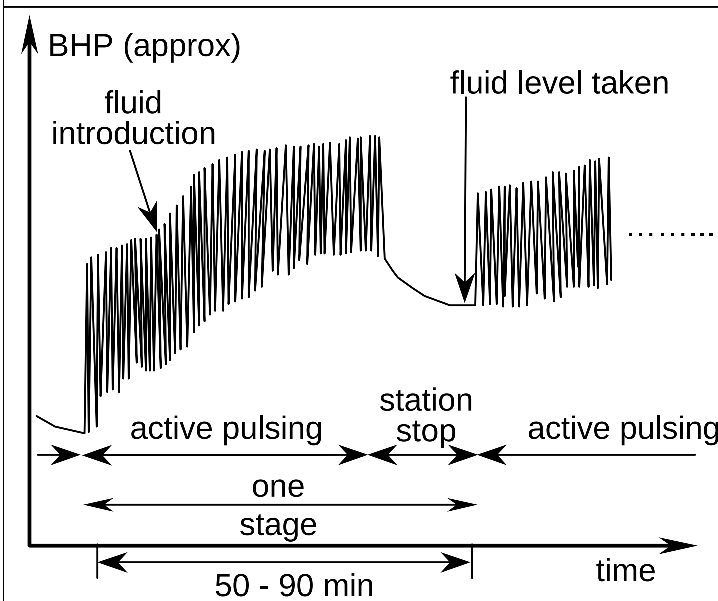

Fig 9: "Stages" in a PWT workover

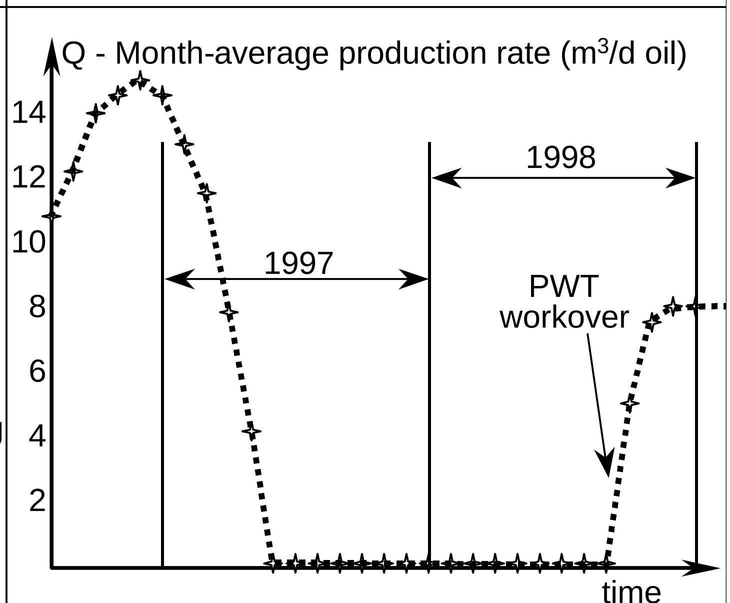

Fig 10: Q-t for XXX-55-5W4, Lindbergh

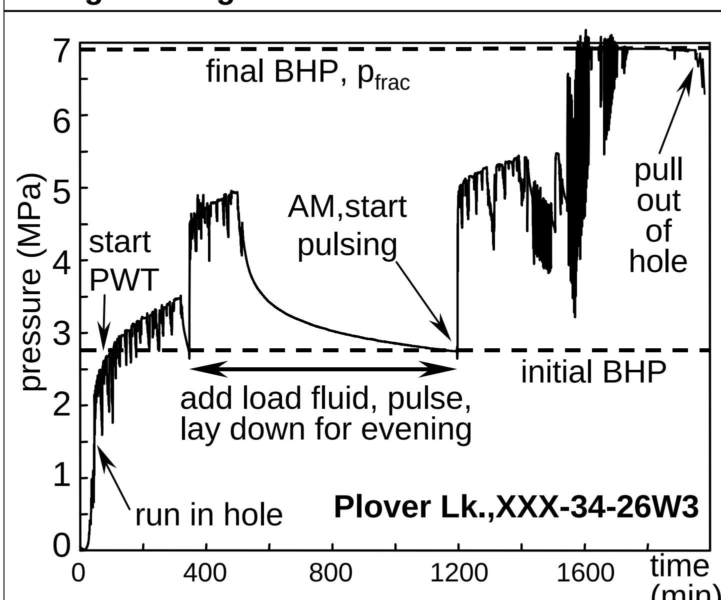

Fig 11: PWT response, initial non-producer

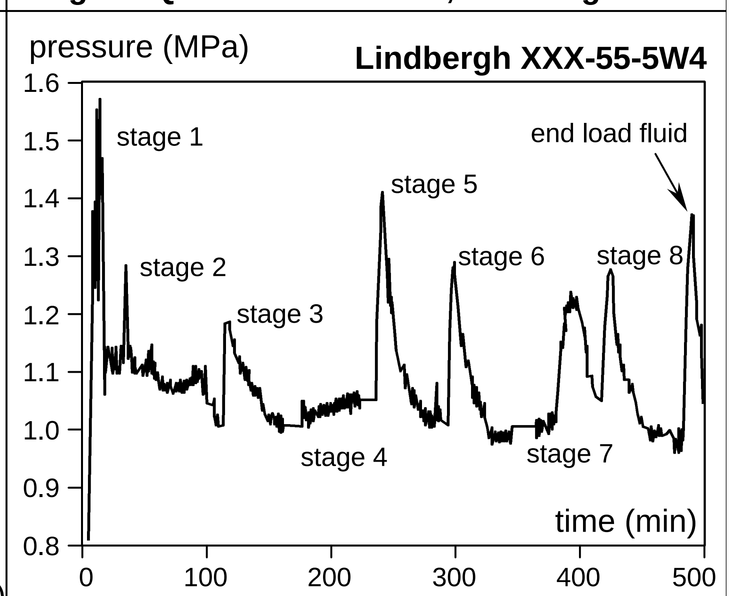

Fig 12: PWT response, good CHOP well

Table 1: PWT Workovers to March 02, 1999

PE-TECH Inc. Identification Number	Well Location	Stimulation Date	Comments *(1)
Tool Proving	Hwy.17 Lloydminster, Sask.	June 1, 1998	Four watered out wells. Some oil rate restored. *(2)
98-001	XXX 35-26W3 (Plover Lake)	September 23, 1998	Production decline, water breakthrough.
98-002	XXX 36-25W3 (Luseland)	October 5, 1998	60,000 m^3 produced. Poor candidate. *(3)
98-003	XXX 55-5W4 (Lindbergh)	October 5, 1998	Shut-in ~15 months. Low inflow.
98-004	XXX 45-27W3 (Marsden)	October 8, 1998	Suspected permeability impairment.
98-005	XXX 35-26W3 (Plover Lake)	October 14, 1998	Production decline. Below expected production.
98-006	XXX 52-4W3 (Morgan)	October 20, 1998	Repeated cycles of production/shut-in. Poor producer.
98-007	XXX 35-26W3 (Plover Lake)	October 21, 1998	Low inflow. Fracture pressure almost reached.
98-008	XXX 44-26W3 (Marsden)	November 3, 1998	Gassy well with low inflow. Poor candidate. *(3)
98-009	XXX 35-26W3 (Plover Lake)	November 9, 1998	Production decline. Below expected production.
98-010	XXX 35-26W3 (Plover Lake)	November 12, 1998	Production decline. Below expected production.
98-011	XXX 34-26W3 (Plover Lake)	November 17, 1998	Production decline. Below expected production.
98-012	XXX 36-25W3 (Luseland)	November 24, 1998	40,000 m^3 produced. Poor candidate. *(3)
98-013	XXX 44-26W3 (Marsden)	December 3, 1998	Suspected permeability impairment.
99-001	XXX 60-4W4 (Bear Trap)	February 2, 1999	On vacuum. No fluid in well. Below expected production.
99-002	XXX 60-3W4 (Bear Trap)	February 5, 1999	Production decline. Below expected production.
99-003	XXX 53-2W4 (Marwayne)	February 9, 1999	Production decline. Below expected production.
99-004	XXX 53-2W4 (Marwayne)	February 11, 1999	No production. Major blockage suspected.
99-005	XXX 63-5W4 (Wolf Lake)	February 18, 1999	Poor inflow. Below expected production.
99-006	XXX 63-8W4 (Wolf Lake)	February 25, 1999	Production decline. Below expected production.
99-007	XXX 63-8W4 (Wolf Lake)	February 27, 1999	Poor inflow. Below expected production.
99-008	XXX 63-8W4 (Wolf Lake)	March 1, 1999	Poor inflow. Below expected production.

Notes:

*(1) Specific details of economic or technical successes cannot be fully made at this time (Mar. 1999) because of an insufficient production history for the wells done since December, 1998. The production records for individual wells do not appear in the Energy Utilities Board computer database records until 2-3 months after the end of the month in question. Also, the EUB records do not contain details of workover history or well performance on a daily basis.

*(2) The initial four wells (June 1998) were not returned to production because of non-technical reasons. On two of the wells, the PWT caused all the water in the casing to be displaced, and when the workovers were completed, the casing liquid was entirely oil.

*(3) Of the three wells marked as poor candidates, two had massive amounts of gas behind the casing, and one of them went back on reasonable oil production after the workover. The third poor candidate was a well that had produced a large amount of oil historically, and thus was massively pressure-depleted in the CHOP-affected region.

The 90% technical success ratio reported in the text refers to the successes experienced in increasing well performance (oil production rate), compared to the pre-PWT well rate. The more modest economic success ratio reported refers to the fact that although a well may have been improved in oil rate, it still did not recover sufficiently to pay for the sunk workover costs in a projected 60- to 90-day period (approximately). Clearly, wells that have experienced a PWT workover since Dec 01, 1998 could not be economically assessed at the time of writing. Also, the economic definition of success varies among companies.