Field Applications of Pressure Pulsing in Porous Media

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ABSTRACT: Enhancement of liquid flux and increase of reservoir pressure can be achieved by pressure pulsing the liquid phase. Several economically successful field cases involving viscous fluids have been carried out. In the case of the Lone Rock field in Saskatchewan, pressure pulsing was combined with water flooding in a high viscosity heavy oil reservoir. Measurements on offset wells show an increase in reservoir pressure with time as well as better injectivity. The micromechanical effects that are responsible for flow improvement are summarized. The major effects are thought to include reducing advective instabilities such as viscous fingering, overcoming non-Newtonian barriers to flow, and providing dynamic energy at the pore throat scale.

1 INTRODUCTION

Pressure pulsing the liquid phase in a porous medium using an impulse dominated by the appropriate frequency range can enhance the flow rate, overcome capillary and mineral blockages, and reduce the magnitude of advective instabilities (Spanos *et al*. 1999, Dusseault *et al.* 1999, Wang *et al*. 1998). The mechanism is linked to generation of slow porosity dilation waves that transit the medium (Spanos 2001), causing beneficial dynamic micromechanical effects (Dusseault *et al*. 2000) However, these phenomena cannot be predicted by conventional Darcy diffusion theory because this construct cannot account for inertial effects (∂^2-/∂t^2 terms) associated with the porosity dilation waves (Spanos *et al*. 2002). Biot-Gassmann formalism (Biot 1956) also cannot predict these effects because porosity is treated as a fixed quantity, therefore the presence of a dynamic wave of porosity dilation cannot be countenanced. Furthermore, in Biot formalism, it is assumed that a single energy potential for a fixed-boundary REV is sufficient. In fact, because a complete treatment requires additional degrees of freedom to account for multiple contiguous phases, a more complete theory is required (Spanos 2001).

Understanding the theoretical developments and the potential consequences of liquid phase excitation (e.g. Geilikman *et al*. 1993) preceded practical applications by several years (Dusseault *et al*. 2000). The practical aspects of pressure pulsing will be discussed and a brief historical review undertaken before some recent data are presented.

Several abbreviations are introduced for brevity:

- **PPT** – **P**ressure **P**ulsing **T**echnology
- **CFS** – **C**ontinuous **F**ield **S**timulation
- **DPWT** – **D**ynamic **P**ulse **W**orkover **T**echnology

2 APPLICATIONS

Three modes of implementing PPT have been developed to date:

- Reservoir-wide CFS, applied through single wells that may also be injection wells;
- Limited-time, single-well DPWT to re-initiate or improve near-wellbore flow behavior; and,
- Treatment chemical placement using DPWT.

These three modes exploit somewhat different physical aspects of the porosity dilation waves generated by dynamic excitation.

2.1 Continuous Field Stimulation (CFS)

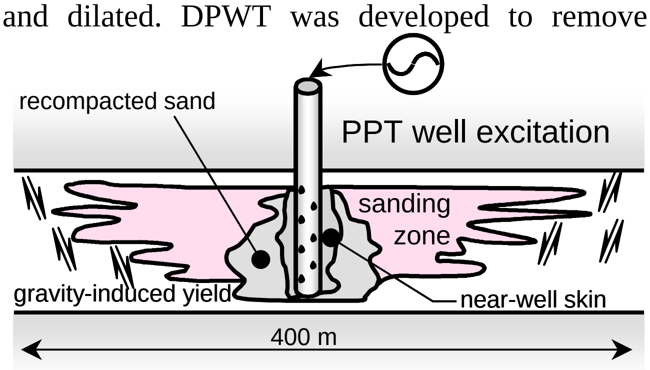
A pressure pulsing device is installed in one or more wells in a field. The well is continuously pulsed at a rate of 10-20 strokes/minute. Each stroke involves an aggressive impulse that pushes approximately 20-40 litres of fluid out through the perforations in about 0.5-1.0 s, followed by a slower recharge stroke. ~10^{-1}-10^{0} Hz as a characteristic impulse frequency seems best for unconsolidated sandstones saturated with heavy oil. The PPT device can be recharged by fluid flowing back through the perforations, fluid ingress from the surface, or any combination of the two, depending on the strategy or a desire to slowly place chemicals that may affect surface tension or viscosity. In the case of surface recharge, fluid can enter the PPT tool through the annulus, through the tubing that is linked to the tool, or a combination of the two. If the well is also an injection well, full recharge with water from the annulus is an easy way to maintain injection while also giving the fluid phase strong impulses.

The impulses generate large dynamic energy surges that create both inelastic deformations in the near-wellbore region (in poorly consolidated strata) and elastic porosity dilation waves that propagate far into the medium. These waves are relatively conservative, but decay with distance as the result of geometric spreading, just as any other body wave does. If the reservoir is bounded by impermeable strata, the porosity dilation wave is apparently largely confined to the bounded stratum, so that the dynamic energy is efficiently dissipated in a useful manner.

The porosity dilation wave causes the fluid in the near-wellbore region to flow more easily, and this changes the static pressure gradient distribution within the reservoir, even if no fluid is being injected, facilitating down-gradient fluid flux. The energy also helps overcome capillary barriers, and breaks down fine-grained mineral or asphaltene agglomerations that block pore throats.

2.2 Dynamic Pulse Workovers (DPWT)

In heavy oil technology using sand influx as an aid to oil production (Dusseault and El-Sayed 1999. Geilikman and Dusseault 1999, 2000), sand influx must be maintained to sustain economical oil rates. In practice these wells often suffer production losses through sand blockage ("skin"), recompaction of loose sand around the wellbore, or through the more distant loss of gravitation energy (downward stress that helps destabilize the sand) so that intact sand can no longer be sheared and dilated. DPWT was developed to remove



"skin" from these oilwells (skin is a generic term for any near-wellbore mechanism that impedes flow), and also to help destabilize the distant regions so that gravitational energy drive could be restored (Fig 1).

Figure 1: Mechanisms that Stop Sand Flux

Over 100 heavy oil wells in Canada have been treated by DPWT. Typically, 150-400 litres of fluid are forced through the perforations in ~4 s with a sharp rise time. The restroke, with recharge from the perforations or from up-hole, takes from 20 to 75 s. Excitation is continued for 60-120 min, stopped for 15 min to measure pressure response, then continued for a total excitation time of 6-24 hours. The large liquid volume suddenly injected generates a strong impulse that propagates far into the reservoir, generating plastic deformations, and even retriggering distant gravitational destabilization of the reservoir sand to help re-establish sand flux. Repeated perturbations have a cumulative effect, and the physical analogy we use to explain this is the example of a grain hopper that is commonly unblocked by repeated vibrations, or a plugged pipe that can be unblocked by sudden backflow impulses.

2.3 DPWT with Chemical Placement

We have found that the placement of chemicals in a well, either during a workover (Dusseault *et al* 2001) or along with CFS, increases the efficiency of the chemical. The effects are because of several factors.

First, during the early part of the workover, pulsing is performed without chemicals; this has the effect of opening up all the perforations so that more uniform reservoir exposure is achieved.

Second, highly effective mixing is achieved when a chemical is trickled into the DPWT tool gradually (e.g. at a recharge rate of ~5%). This is because of the repeated intense liquid shear that takes place as the fluids are forced through the perforations.

Third, the chemicals are intimately mixed with actual reservoir fluids that are drawn back into the workover tool on each stroke. Because of ~95% recharge from the formation, the mixing is intense, and compatibility problems are fewer because pre-mixing with other fluids is reduced.

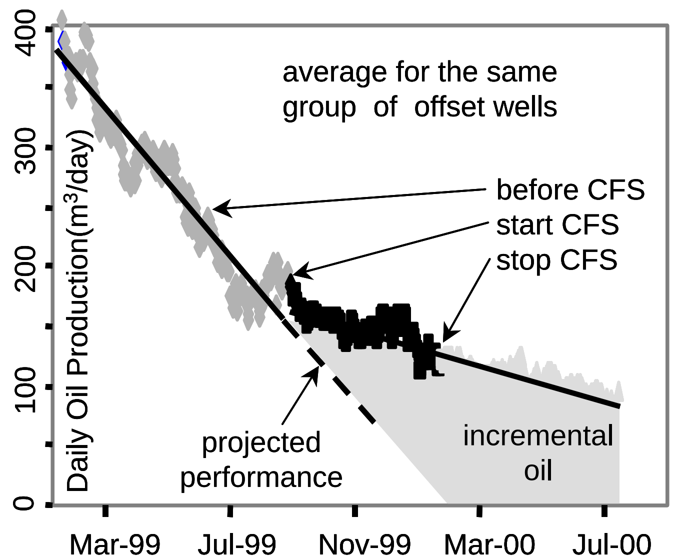
Fourth, because capillary barriers can be overcome and flow resistance reduced, a lower-viscosity chemical treatment experiences fewer advective instabilities such as channelling or viscous fingering. Dispersion is favored, and the contact area with the reservoir rock is improved.

Thus, placement of chemicals with DWPT means that fewer cases of undiluted treatment chemical flowback will be encountered. Similarly, placement of materials such as acids will be more effective with pulsing (unless channeling is deliberately sought).

Although experience to date is exclusively in heavy oils, the mechanisms will also be effective in conventional oils, and laboratory data supports this view. However, if large amounts of gas are present as bubbles or a continuous phase, porosity dilation waves are rapidly damped and PPT is ineffective.

3 PPT HISTORY

The first workovers were in the late fall of 1998. Many were successful but some were not. Gradually, screening criteria have been refined, and for



the last 30-40 workovers, the success ratio is >90%. DWPT is particularly effective in making non-producers into producers by perturbing the sand sufficiently so that sand influx can take place. It is ineffective (as is any workover method) if all the solution gas energy in the reservoir is depleted. We have recorded changes in fluid level in offset wells over 300 m distant within 12-24 hours after the start of a workover. In viscous oil (1600 – 10,600 cP) with little net fluid being injected (5-30 m^3), one would expect no reaction whatsoever, based on Darcy flow. We believe this distant effect is because dilation waves excite fluid flow and helps sustain sand flux near the offset wells.

The first CFS trial took place in 1999 for 10.5 weeks in a 580 m deep 30% porosity sand 88% saturated with 10,600 cP viscous oil. A single well was used for excitation, and no waterflooding was included. At the end of the excitation period, the depletion curves of most of the surrounding wells (13 in all) had been reversed, production rate had increase by 37%, and fluid levels and sand production rates had also increased. Furthermore, the CFS well, which had ceased production long before it was used as a PPT well, was placed on production and became the best producer in the local group of wells for at least a year.

On this trial, microseismic monitoring was used in several offset wells. Although the data remain unanalyzed at this time, there appears to be evidence of interwell shear events arising because of the PPT. These are postulated to be evidence of distant destabilizing of sand and reestablishment of gravitational energy drive. Sudden and massive sand influx (from <1% to ~10% by volume) in at least two offset wells at the 6-8 week point of excitation would also tend to corroborate this.

The second and third CFS trials were water floods in heavy oil reservoirs (one 1600 cP, the other 10,300 cP). In both cases, the decline rate of wells surrounding the CFS well slowed, and the PPT projects were economical, generating profits. Fig 2 shows the change in decline rate of oil production for one of the cases. CFS extended the life of the field, and the beneficial effect lasted long after pulsing stopped. The shaded area is considered as additional production, and the PPT well also produced additional oil when placed on production.

CFS has been used in a shallow (2-15 m) case where a lighter-than-water but viscous resin was being slowly removed from an aquifer consisting of sand overlying jointed limestone. Implementing CFS for a limited time increased the withdrawal rate of the resin by a factor of 5 to 20 in the offset wells (typically from a few grams per day to 10s of grams per day). The mechanism appears to be additional mobilization through overcoming capillary barriers.

Figure 2: Incremental oil production with PPT-CFS

4 LONE ROCK, SASKATCHEWAN

The Lone Rock, Saskatchewan field (30 km SE of Lloydminster) is a highly depleted viscous (~10,000 cP in situ with depelted gas) heavy oil reservoir in the Sparky sand (ϕ ~ 30%), and has been shut-in since 1970. In March 2001, PPT with a CFS device in a single well was implemented along with water flooding in the same well. This pilot project was established with the intent of improving waterflood well injectivity and increasing the well reservoir pressure, as part of a much larger field redevelopment scheme (since cancelled).

4.1 CFS Pulse Well History

The CFS well was drilled at the end of 1949. The fluid production history for this well is shown in Fig. 3. It was shut-in in 1959 after cumulative production of 7,443 m^3 of fluid, of which 585 m^3 was water.

In the summer of 1959, the well was changed to a water injector, lasting until Nov 1970, with a total of ~180,000 m^3 of water injected in a series of four water injection episodes (Table 1). There is no record of any pressure build-up during these injection episodes. In Mar 2001, the injector was reactivated and a CFS pilot project initiated. Water was injected using a PPT bottom-hole device that ran for 6 months at a rate of approximately 15 strokes per minute. A total of 39,000 m^3 of water was injected; monthly data are shown in Table 2.

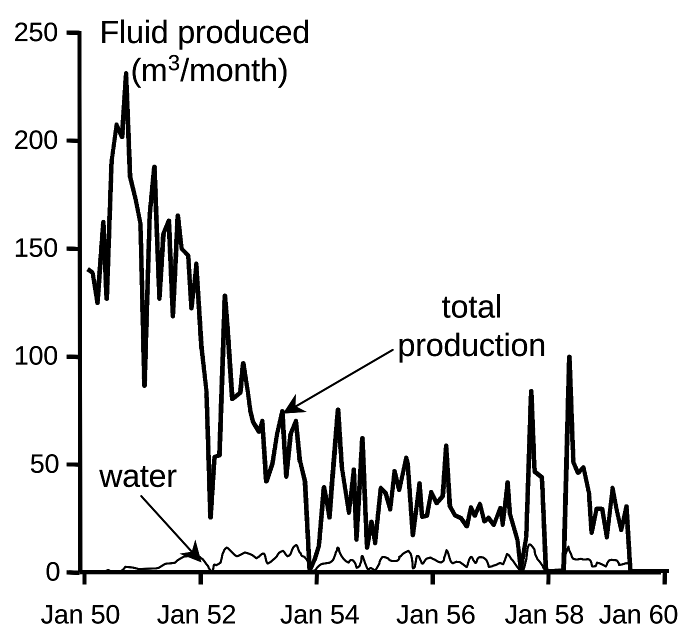


Figure 3: CFS Well Production History

Period	Average Injection m^3/mo	Total Injected Water – m^3
Feb 60 – Sep 61	1850	37,000
Aug 63 – Nov 64	3420	54,700
Jul 67 – Oct 68	3830	61,200
Dec 68 – Apr 70	1583	26,900
Apr 01 – Sep 01	6334	39,000

Table 1: Long-Term Injection Well History

Month	Max inject. Rates (m^3/day)	Min inject. Rates (m^3/day)	Monthly Injection Rate (m^3/month)
April-01	304	76	6,540
May-01	330	14	5,679
June-01	335	137	7,378
July-01	344	129	7,421
August-01	297	80	6,346
September-01	354	0	4,641

Table 2: Injection Well CFS Injection Period

4.2 CFS Injection Well Details

Water injection using CFS was pilot tested for 6 months, between April and September 2001. (The rate for September is low because of intermittent injection during this period.) The overall average of 6334 m^3/mo was sustained with only one three-day shutdown for mechanical reasons (hydraulic seals). Note that the CFS device was specifically designed for this project and the long run time bodes well for future implementation. During the study, there were several occasions when the water volume supplied was insufficient to allow for a full day of pulsing.

We conclude that PPT applied using CFS increased the injectivity of this well by a factor of two, showing that PPT has interesting applications in increasing the capacity of injection wells.

Figure 4 shows the field system. The hydraulic unit is on the right, the CFS mechano-hydraulically actuated system attached to the wellhead is on the left. The system is computer managed and monitored

Figure 4: The CFS PPT System in the Field

4.3 Injection Pressure

Surface injection pressures for the CFS injection well are presented in Figure 5. An increase in injection pressure at the wellhead was noticed on 20 June 2001, after ~19,500 m^3 of pulsed injection H_2O over three months. Larger fluid volumes might have been injected during the first three months had greater volumes of water been available.

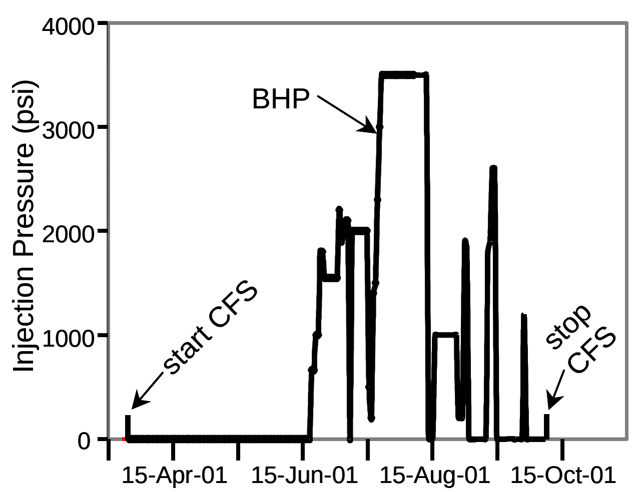


Figure 5 Pressure History at the CFS Well

Injection pressures reached a plateau at 3,500 psi one month after initial pressurization was noted. This is the maximum CFS injection pressure, and it is believed that hydraulic fracture was taking place in the formation on each pulse. The strong pulse energy used to generate a fracture probably means that less energy was available for the generation of porosity dilation waves, but this was probably compensated for by the overall increase in energy input.

After a shutdown Aug 14-16, after a period of 18 days at maximum pressure, the well pressure had dropped to a 1000 psi, and it gradually was built up again until the month of September when periods of pulsing and no pulsing were used to assess the reservoir recovery response. It was observed that the maximum daily volume injection rate occurred during the month when CFS was stopped and started several times, and not when the injection pressure was the highest. This is to be investigated in further pilot tests to see if CFS is more volumetrically effective if operated completely continuously, or episodically with relaxation periods in between active periods.

4.4 Offset Well Behaviour

Wells in this field were drilled on a 10-acre (4 ha) spacing (Figure 6). Except for one lone producer, the surrounding offset wells were (and remain) shut in.

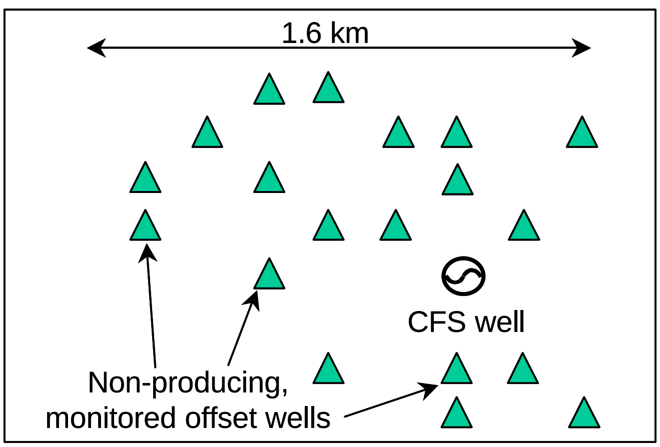


Figure 6 Location of Offset Wells

Annulus fluid levels were collected in offset wells with an acoustic fluid level device. The acoustic signal reflects off tubing collars, and thus gives an accuracy of about 10 m. An increase in the number of reflections to the top of the annulus fluid indicates a lowering of the fluid level, and a decrease indicates a rising fluid level.

The CFS increased the fluid level over the entire region by approximately 5-6 m, with an average of over 50 kPa pressure increase, and the pressure was rising at a rate of 10 kPa per month at termination. Although this value is far less than we had hoped, it represents a 17% increase in pressure in the massively depleted reservoir, and it indicates that the CFS effects are propagating a great distance from the excitation well. In such reservoirs, because of the huge viscosity contrast between the natural and the injected fluids, intense channeling and viscous fingering usually occurs, and some wells are affected by injection while others are not. With CFS, a general and homogeneous pressure increase can be achieved more or less isotropically around the injection well (better conformance, less by-passing).

4.5 Success or Not?

Much to our disappointment, to date the oil company has chosen not to place the surrounding wells on production because of poor prices for heavy oil due to a glut of production. Thus, it is not possible to say whether Lone Rock was an economic success, as the other CFS pilot trials in heavy oil have been.

Theory and previous experience indicates that PPT dynamic stimulation is effective when there is a substantial gradient of pressure. When there is no gradient, the beneficial effects (next Section) cannot be accrued. For example, even if the CFS is helping to destabilize interwell intact sand, as long as there is no active sand production, shear and dilation are suppressed, and the gravity component of the drive mechanism cannot be exploited.

Nevertheless, the oil company acknowledges that the CFS water injection has achieved:

- Injectivity levels that could not be achieved in previous episodes,
- A modest but widespread increase in fluid pressure, and,
- A homogeneous increase in pressure, rather than intense channeling of injected liquids.

Furthermore, the CFS system, consisting of an electrically driven hydraulic pump actuating a mechanical-hydraulic stroking device at the well bottom by lifting the entire tubing string, worked for six months with only one mechanical problem.

Lone Rock is somewhat of an exceptional case. It has had an exceptionally long history of exploitation, and the initial pore pressures have been drawn down to the point where only 200-300 kPa BHP is acting, even though >90% of the original oil is still in the reservoir. Low shut-in pressure is not recovered if the wells are left static; in some wells that were abandoned decades ago, the pressure on re-opening was the same as the pressure at shut-in. This indicates no natural recharge and almost complete depletion. Also, communication with any non-depleted regions of solution gas is so slow that in cannot be achieved in engineering time scales. Thus, the non-thermal production options seem limited to waterflood while trying to reactivate gravity drive effects and communication with extant pressure, using CFS.

We optimistically believe, based on our other experiences in heavy oil in high porosity sands, that technically successful revitalization of production from Lone Rock can be achieved with CFS, perhaps in a ratio of 1:8, and with the CFS wells being returned to production occasionally. Economical success is predicated by other factors such as the price for heavy oil; markets affect this, and the margins for heavy oil profitability are not wide.

5 MICROMECHANICAL CONTEXT

Laboratory tests of pressure pulsing show that effects such as viscous fingering and permeability channeling can be partially overcome, and that the liquid flow rate can be increased. It is appropriate to discuss several micromechanisms that explain these results. Figure 7 shows a capillary barrier to flow.

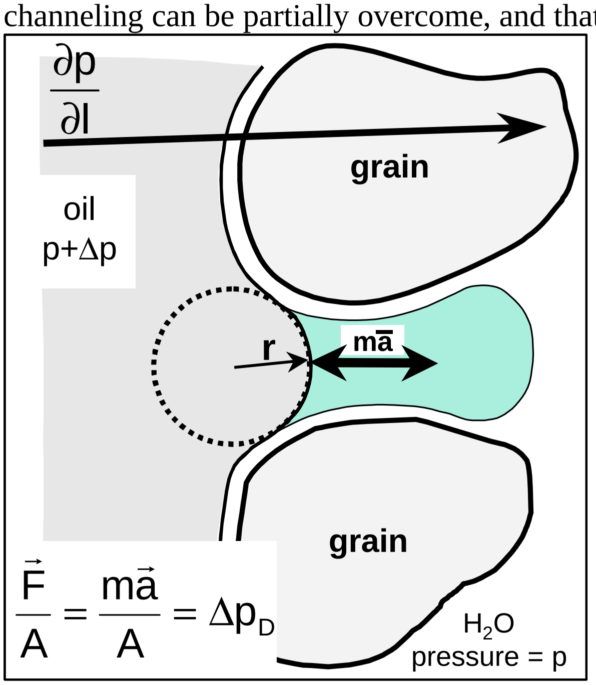


Figure 7: Porosity Dilation and Capillarity

At the right frequency, the porosity dilation wave arising from the pulsing leads to incompressible fluid behavior. This generates liquid acceleration into and out of the pore throats as waves transit, creating a dynamic pressure (see Fig) that can overcome static capillary resistance $\Delta p_s = 2\gamma/r$ (where γ is surface tension). Clearly, this dynamic energy source can reduce the intensity of typical advective instabilities.

Consider a CFS application like waterflooding. The dynamic energy becomes spatially attenuated by geometric spreading, thus near the well there is more dynamic energy to overcome capillary or mechanical blockages. The pulsing will tend to push away oil fingers near the well, but not advance water fingers far from the well. This means that the characteristic length of viscous fingers (a concept based on instability theory applied to static liquid diffusion only) can be substantially reduced, increasing the efficiency of sweep of flooding processes.

Finally, note that pore throat liquid acceleration can also help overcome Bingham fluid behavior, prevent blockage from fine-grained minerals or asphaltenes, and accelerate flow rates in a porous system with a pressure gradient. These are important phenomena that we are just beginning to fully understand and exploit.

6 CLOSURE

Pressure pulsing in over 100 workovers and four field-wide stimulation pilot trials in heavy oil has achieved economically interesting results in circumstances where other techniques had become ineffective. A reliable tool for the long-term application of frequency- and amplitude-tailored pulses to the liquid phase in a reservoir was developed and has proven reliable. The beneficial effects of pressure pulsing are largely related to the generation of long-wavelength displacement waves (porosity dilation waves) that bring dynamic energy to the liquids at the pore namic energy to the liquids at the pore scale, helping overcome barriers to flow and re-establish drive energy sources.

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