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# Treatments Increase Formation Pressure Integrity in HTHP Wells

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**Abstract**

This paper describes successful applications of new bore-hole pressure-integrity (BHPI) treatment materials and methods for increasing BHPI. BHPI treatments have allowed higher drilling and cementing circulation rates, helping to optimize drilling performance, improve hole cleaning, and obtain excellent zone isolation results through better mud displacement during primary cementing. It has been proposed that skin damage in the zones of interest can be minimized since BHPI treatments can be designed and targeted to enter areas with low BHPI. The productive interval in one well was successfully cemented without requiring a slim hole completion, which would have limited completion flexibility, after BHPI treatments helped regain wellbore integrity.

A theoretical rock mechanics model is discussed, explaining how the new BHPI treatment rapidly and substantially increases hole pressure integrity across sand and shale formations. Minor BHPI filtrate invasion in high- and low-permeability sandstone cores should explain why the new system may minimize skin damage.

## Introduction

Insufficient BHPI is a significant drilling challenge in deep, high-temperature, high-pressure (HTHP) wells in south Texas and in many other areas at any depth. Shales and/or sands weakened by depletion, leaking faults, or poor rock properties result in lost returns when mud weights are close to pore and bore-hole integrity pressures. In one field, short (~50 ft) transitions from normal (11 lb/gal) to over-pressured (17.5-18.0 lb/gal) Frio formations compound the severity of this challenge. Setting casing to isolate normal-pressure from high-pressure zones can be problematic if faults exist at the casing shoe and/or the cement job does not provide a good hydraulic seal. In one case, the intermediate casing shoe failed to test, and conventional cement squeezes were unable to correct the problem. Preventing skin and/or formation damage in the zones of interest during treatment of weak points in the productive hole section was another major concern heightened by a wide range of pore pressures (8.5 to 17.8 lb/gal) in the productive intervals.

Formations may have poor BHPI immediately below the casing shoe and in the hole drilled to the next casing seat depth. This lack of pressure sealing to contain bore-hole hydrostatic and circulating pressures may be due to natural in-situ stresses that cause weak points or flaws in rock such as natural fractures and faults. The balance of low BHPI causes are drilling induced stresses that create new fractures or leaking faults, along with a significant number of formations weakened by reactivity to certain drilling fluids. ECD (equivalent-circulating-pressure) and swab/surge pressures during drilling, tripping drill pipe, running casing or liners, and cementing often exceed low BHPI values. Well construction plans can be impaired by BHPI causal-effects such as severe lost circulation and formation fluid influx. These incidents may result in setting casing early, running a drilling liner, or setting a contingency casing string. Well construction costs can skyrocket from these events. In some wells with known low BHPI conditions such as deepwater and HTHP, extra well costs are budgeted to install several additional pipe strings necessary to allow drilling with very narrow margins between pore and fracture pressure profiles.

A survey of major operators indicated that unsatisfactory BHPI is a significant cost factor. If a reliable, quick method was available to increase BHPI, an average of 25% of well construction costs may be saved mainly by reduced rig flat-time and casing program costs. Potential cost savings for deepwater wells have been estimated to be between 30 and 50%. For example, pore and fracture pressure profiles before and after BHPI treatments illustrate how increased fracture pressures in a profile depth interval may eliminate two casing strings **(Fig. 1)**.

Discussion of industry practices for inadequate formation integrity tests (FITs---also referred to as pressure integrity tests, PITs) and leakoff tests (LOTs) is available in numerous publications. However, very little has been published on technology that significantly improves BHPI during LOT operations. This is likely due to poor results in obtaining large BHPI increases using conventional technology that can't seal leak-off paths and/or sustain widened fracture widths by resisting closure stress.

Conventional methods and materials such as cement squeezes have typically had poor success to restore or increase formation pressure integrity, even after several cement squeeze applications. This is likely due to cement slurries that mimic hydraulic fracturing fluid properties and dynamic conditions within fractures such as cement filter cake coating fracture faces just enough to prevent plugging by excess cake build-up and not enough to prevent fracture length extension. Multiple cement squeezes have also only increased BHPI in small amounts mainly by squeezing channels in primary cements. In some cases, operators have done many consecutive cement squeezes with little or no increase in LOT pressures. The frequency of poor casing shoe LOT results may typically range between 5 and 25 % of all shoe tests in a given area or field. Some fields are reported to have up to 50% poor shoe test results. This is based on data from thousands of primary cementing operations and the percentage that require shoe cement squeezes. Specific failure rates for shoe tests depend on well conditions such as formation integrity and drilling/cementing practices. Wells with harsh well conditions and un-favorable well construction practices have the highest percentage of poor shoe tests.

**Emerging BHPI Treatment Technology**

New technology has been developed for increasing BHPI. This technology includes a process that helps operators identify leak-off characteristics in formations, select chemical treatment systems, design down-hole chemical placement procedures, and evaluate treatment results before drilling ahead. A theory of the down-hole mechanism has been proposed to better understand how chemical systems increase BHPI. Although this theory is still evolving, it has been used to explain how the initial field-test applications successfully restored BHPI to expected values and, in many cases, exceeded expected values. This theory has also helped confirm that the initial field-test successes can be repeated under similar conditions. Results from future BHPI treatments should further optimize the process's down-hole performance, help improve formation LOT and FIT pressure analysis, and statistically support the theory for BHPI increases. Optimization requires continued review and analysis of operational and technical factors that contribute to successful performance.

**BHPI Treatment Materials, Procedure, and Theoretical Down-hole Mechanism**

The BHPI treatment procedure and chemical systems identified in this paper evolved from those reported in other papers[1,2] and patents[3] on new technology for controlling lost circulation. However, the procedure and chemical systems have been modified to focus on improving BHPI rather than simply halting lost circulation. Hole conditions to apply and optimize BHPI treatments differ mainly in that the hole should ideally circulate drilling fluid with full returns and without severe formation fluid influx.

The treatment procedure for placing a BHPI chemical system in a formation is illustrated in **Fig. 2**. The BHPI chemical system separated by spacers is pumped down the drill pipe. After the first spacer is circulated to the bit, pumping is stopped long enough for the annulus to be closed at the surface. Drilling fluid then is pumped down the annulus between the drill pipe and the casing and, at the same time, displacement fluid is pumped down the drill pipe. The displacement fluid easily pushes the BHPI chemical system through the bottom-hole-assembly (BHA) and out the bit nozzles. In areas[2] other than south Texas, some operators with high-cost daily drilling operations have saved drillpipe trips by pumping the BHPI chemical system through various types of BHAs which include motors and logging-while-drilling/measurement-while-drilling (LWD/MWD) tools. No malfunctions have been reported in the motors and tools exposed to the BHPI chemical systems.

Performing dual-injection pumping down the drillpipe and the annulus causes the BHPI chemical system and drilling fluid below the bit to mix in the distance between the bit and the formation. The mixing process initiates a chemical reaction that converts the mixture of both fluids into small aggregates that are dispersed in the drilling fluid as it travels into the formation. The chemical reaction in these aggregates forms a material that has rubber-like consistencies with the following characteristics and theoretical down-hole performance:

- extremely low filtrate loss into a formation's matrix permeability
- fast bridging in narrow flow pathways such as fractures and faults
- self-molding to fracture surfaces, providing a more effective seal in flow pathways
- rapid widening of fracture widths near the well-bore
- continued sealing by self-molding during the widening of fracture widths
- rapid increases in viscosity to values too high to measure in common laboratory instruments
- extremely high extrusion pressures that pack the aggregates together in flow pathways
- self-diversion to other flow paths after the initial paths of least resistance have been sealed
- resistance to limited swab pressures
- resistance to dilution by crossflows due to rapid-gellation with high consistencies
- limited penetration into formation matrix permeability (1/64 to 1/8 of an inch)
- sustained and substantially increased near-wellbore hoop stresses by limited fracture closure
- increased casing shoe BHPI through simultaneous sealing of annular channels and formations

Brief descriptions of the theory were included in earlier publications[1-3]. This theory may evolve and change as more BHPI applications are analyzed. For example, some applications have used BHPI chemical systems that were modified to achieve faster down-hole mud-reaction times and much stiffer consistency of the down-hole aggregate mixtures of chemical systems and drilling fluid. Theoretically, as the rubber-like viscosity of the down-hole chemical and mud mixture aggregate increases, the extrusion pressure increases when entering similar width flow paths in the formation. Each of the four separate treatments in the first well's production hole (Well B-1, **Tables 1-4**) was formulated with consecutively higher chemical concentrations of the active ingredients. Engineers discovered that each time the concentration of active ingredients was increased, higher BHPI values and greater resistance to swab pressures were achieved.

BHPI treatment aggregates may form flexible pressure seals that complement existing pressure seals formed on the formation surface (**Fig. 3**) by mud cake. BHPI treatment seals are impervious to temperature variations, corrosive formation conditions, and to drilling, completion, and acid stimulation fluids.

Some formations may have multiple-azimuth fracture planes sequentially created by increased pump pressures and plugged by diverted aggregates after sealing the initial azimuth fracture plane. Investigators[6] indicate that this may occur outside a short-radius altered stress-field emanating from the intersection of the initial fracture plane and the bore-hole. These investigators also predicted that, under the influence of unaltered, far-field stresses, the azimuth of secondary fractures might re-orient as it moves away from the wellbore and curve into a parallel azimuth with the initial fracture. Other investigators[9] report evidence from recent drill cuttings injection studies of secondary fracture orientation that show initiation of secondary fracture azimuths ~15 degrees from the first fracture azimuth and far-field re-orientation into multiple fractures with parallel planes.

BHPI sealing aggregates create wider fracture widths in short propagation of fractures with much smaller material volumes compared to propagation by mud mixed with LCMs (**Fig. 4**). Packed sealing aggregates act as solid, flexible proppants packed in an impermeable, immobile mass. When additional BHPI treatments are required, increased wellbore pressure ($P_w$) above initial treatment squeeze pressures may pack more sealing aggregates in the initial fracture wings and further widen the fracture width. Sustained fracture widths may maintain adjacent alterations in formation stress fields and allow a higher well-bore pressure ($P_w$) during drilling ahead.

These increased fracture width induced stress field alterations were partially explored in the DEA-13 project[4] on single-plane fracture plugging reported by Morita *et al*. This study found a "wedge" effect on near well-bore hoop stresses when fractures were plugged with dehydrated mud solids. Messenger[5] also reported hoop stress increases in his work on plugging single-plane induced fractures. Published claims[1-3] have been made that the BHPI systems described earlier have pressure isolating wedge effects that increase hoop stresses to account for increased formation pressure integrity mentioned in this paper's case histories.

In addition to fracture widening, the stress fields adjacent to the intersection of the fracture wings and the wellbore may be altered enough to inhibit secondary induced fractures within the area of the altered stress field. However, further increases in treatment squeeze pressures may allow secondary induced fractures during BHPI treatments at any point (depth) or azimuth outside the altered stress fields (**Figs. 5 and 6**). Investigators[1-3] claim that multiple-plane and different depth fractures are plugged with self-diverting BHPI systems that create sustained, increased width seals resulting in higher hoop stresses over longer open hole intervals.

Stress field alteration may cause the azimuth for the least principal stress to change orientation according to Soliman[6]. This re-orientation may allow secondary induced fractures with extended fracture lengths (**Fig. 5**) compared to those created in **Fig. 6**. Other researchers[7,8,9] have published similar secondary fracture initiation theories in SPE 17533, SPE 48987, and U.S. Patent No. 4,724,905. Most of the theoretical methods[6-8] are proposed to enhance production of hydrocarbons through multiple-plane hydraulic fractures in stimulation treatments. The purpose of another fracture orientation study[9] is to optimize drill cuttings injection for confined disposal of cuttings in selected formations.

### Summary Key Factors—"Why it Works"

- BHPI treatments can be pumped through a BHA – normally no need to trip pipe.
- Long-term circulation control is provided.
- BHPI system formulations are chemically predictable and verified by well-site sample tests.
- Drilling can be immediately continued with no waiting time, unlike cement and polymer gels.

### Producing Formation Permeability Protection

BHPI treatment penetration into formation matrix permeability is limited by mud-cake permeability, bridging of filtrate-carried, solid fines, filtrate viscosity increases from chemical reactions in the pore throats, and by limited filtrate volumes. Core tests were performed to determine if the BHPI treatments caused skin damage in the producing intervals. (See the following paragraphs.)

**Core Test Conditions**

*Conditions*

Cores tested: 1,275 md and 587 md man-made cores
Water-based mud: partially-hydrated-poly-acrylamide (PHPA) drilling fluid at 11.0 lb/gal
Oil-based mud used: synthetic drilling fluid at 11.0 lb/gal
Test temperature: 170°F
Differential pressure applied: 750 psi for 30 minutes

Two cores were prepared for each permeability value listed. This first core was subjected to tests for determining regained permeability. Researchers observed the second core under a microscope to determine the depth of filtrate invasion.

*Set 1*

The first set of tests used a BHPI chemical system, called BHPI-W. This system reacts with water-based drilling systems downhole. The cores for these tests were initially saturated with brine.

BHPI-W was prepared with 220 lbm/bbl of dry blended material and 30.3 gal/bbl of kerosene (with a specific gravity of 0.8). The BHPI-W slurry and PHPA drilling fluid were heated in an atmospheric consistometer to 170°F. Both materials were poured at a 50:50 ratio into a fluid-loss test cell containing the core and then stirred until reacted. Additional PHPA drilling fluid was added to fill the cell. The core was subjected to a pressure of 750 psi for 30 minutes. The cell was then disassembled, and filter cake was scraped from the core face.

The test results for cores with an initial permeability of 1,275 md follow:
Fluid Loss: Core 1 = 20 cc, and Core 2 = 4 cc
Regained permeability: 593 md (46.5% of initial) for the portion of the core invaded by filtrate
Permeability Invasion: ~1/64 in. filtrate penetration at 200x magnification

The test results for cores with an initial permeability of 587 md follow:
Fluid loss: Core 1 = 8 cc, and Core 2 = 12 cc
Regained permeability: 248 md (42.2% of initial) for the portion of the core invaded by filtrate
Permeability Invasion: ~1/64 in. filtrate penetration at 200x magnification

*Set 2*

The second set of tests used a BHPI chemical system, called BHPI-OBM, that reacts in-situ downhole with oil or synthetic based drilling fluids. The cores for these tests were initially saturated with kerosene.

BHPI-OBM was prepared with 80-lbm/bbl dry blended material, 16.5 gal/bbl of fresh water, and 20 gal/bbl of an organic additive. Synthetic based mud (SBM) was heated to 170°F. The BHPI-OBM slurry was not heated. BHPI-OBM slurry and SBM were added to the cell at a 50:50 ratio and stirred until reacted. The reaction time was approximately 1 minute and 15 seconds. Additional mud was added to fill the cell. The cores were subjected to a pressure of 750 psi for 30 minutes. The cell was disassembled and the filter cake scraped off.

The test results for core with an initial permeability of 1,275 md follow:
Fluid loss: Core 1 = trace, and Core 2 = trace
Regained permeability: 402 md (31.5% of initial) for the portion of the core invaded by filtrate
Permeability Invasion: ~1/8-in. at 200x (5 to 7 sand-grain diameters deep)

The test results for cores with an initial permeability of 587 md follow:
Fluid loss: Core 1 = trace, and Core 2 = trace
Regained permeability: 110 md (18.7% of initial) for the portion of the core invaded by filtrate
Permeability Invasion: ~1/16-in. filtrate penetration at 200x (3 to 5 sand-grain diameters deep)

**Test Conclusions**

The minor skin damage, evidenced by shallow filtrate penetrations, leads us to believe that perforation tunnels can easily communicate with permeability undamaged by BHPI treatments. Only the LOT leakoff pathways in fractures and faults are sealed by BHPI treatments. This has been proposed based on cases in South Texas where production from treated wells compared favorably to untreated wells. In one case, a BHPI treatment may have entered a low-pressure productive interval and nothing unusual was noticed in the post production rate. Future studies should evaluate BHPI chemical system removal by dissolution when exposed to certain chemical solutions and by swab pressures higher than those typical to drilling operations. One BHPI system has been developed to contain an acid-soluble component that, when contacted by acid soaks or washes, assists in removal of the system from plugged fractures.

## Future Developments

Future work for refining and proving the BHPI theory may include correlation of physical well model data, computer simulations with wellbore stability (WBS) software models, and field application data from LOT/FIT results before and after BHPI treatments. Enhanced BHPI chemical systems may also be developed along with optimized operational guidelines and job procedures from post-job analysis. Several synergistic combinations of these technologies may be utilized to improve WBS.

Except in References 1-3, other related literature does not discuss the idea of plugging multiple fractures as part of a process for facilitating drilling ahead and eliminating extra pipe strings. This omission implies that the process of multiple-plane and different-depth fracture plugging in the BHPI process for widening fractures with BHPI chemical systems is not well known and lacks industry and academic understanding and recognition. A substantial effort may be required to change this situation, including publishing more studies and developing industry training programs.

**Initial Field Tests and Case Histories**

The opportunity for the first case history came after an unexpected high-pressure water-kick caused an offshore well-control event in a hole being drilled for intermediate casing. The drill pipe rams in the blowout preventer (BOP) were activated to contain the sustained high pressure. This formation-induced pressure at the surface casing shoe (located at 4,400 ft below the mud line, BML) was higher than the LOT fracture pressure of 13.5 lb/gal equivalent density. The operator was concerned that this applied pressure may have "broken down the shoe," possibly creating a hydraulic fracture, and allowing a sustained water flow into the fracture and up behind the surface casing into a shallow sand at a rate of 1 to 2 bbl/min.

After several unsuccessful attempts to regain full circulation, stop the drilling fluid losses, and control the suspected water flow (all of which incurred expensive rig time), the operator agreed to try an experimental BHPI treatment and chemical system. The operator had already run six gunk squeeze systems, several cement squeezes, and numerous types of lost-circulation-materials (LCM) pills from different sources. None of these treatments controlled losses or regained full circulation.

Immediately before the experimental BHPI system was pumped, a temperature log was run inside the drill pipe past the point in the open hole at which water influx was expected. A nodal analysis of this temperature data indicated a sustained water flow of 20 bbl/min, close to 30,000 bbls per day. Water was traveling up the open hole and into a channel behind the surface casing at the casing shoe, explaining why all the previous gunk, cement squeezes, and LCM pills had no effect. These treatments had likely been severely diluted by the high-rate water flow, explaining why they failed to plug the fracture or channel at the surface-casing shoe.

The experimental BHPI treatment system was designed to resist dilution. The first treatment attempt successfully plugged the annulus around the casing shoe with a running squeeze pressure substantially above the shoe's LOT pressure. Based on the hydrostatic head of the static fluid column and the water-formation-induced surface pressure, the original 13.5 lb/gal pressure integrity at the shoe was increased by 5.1 lb/gal, making capable of holding a pressure of 18.6 lb/gal equivalent density.

***Well B-1***

The success of the first experimental BHPI application described above inspired the developers[1-3] to use the technology to stop lost circulation and increase BHPI in other wells without exceeding LOT values. Several months later, the opportunity to increase BHPI above the casing shoe LOT pressure was found in a deep, HTHP well in South Texas (Well B-1 in **Tables 1-4**) being drilled by Headington Oil Company.

During B-1 drilling operations in the production hole section at 13,800 ft, severe lost returns were experienced that also caused a higher-pressure gas sand to feed-into the well-bore, which was below the last casing shoe set at 13,490 ft. Despite several attempts to cut the mud weight, it was decided to attempt a BHPI chemical system squeeze to allow operations to continue. During the first three BHPI jobs, significant buildup of integrity was noted, but concern was also raised about whether the material was truly getting to the weak point in the well. This was due to the consistency of the BHPI material, and the distance from the bit to the suspected lost returns interval (about 1,000 ft). After each of the first three BHPI treatments temporarily halted losses, lost returns were once again encountered during continued operations. However, after the fourth treatment halted losses, it was noted that the influx of gas, which had occured on prior incidents of lost returns, did not occur. As such, it is assumed that the last BHPI squeeze was effective in preventing gas influx into the wellbore from the higher-pressure sand, and the operator was able to reduce the mud weight to drill and complete the well without further incidents.

Several other Headington Oil Company wells have been treated since Well B-1's successful completion including those mentioned below and in **Tables 1-4.**

***Well B-3***

After cementing the intermediate casing at 11,060 ft, the shoe was pressure tested (PIT vs. LOT) to an equivalent of 18.5 lb/gal. However, after the mud system was weighted up and drilling commenced, the well started to experience losses that ranged from 4 to 20 bbl/hr despite the fact that the mudweight was only 17.0 lb/gal. This EMW was well below the shoe test, but also well below the required TD mudweight of 18.1 lb/gal. Four attempts were made to fix the shoe with cement (three conventional squeezes with retrievable packers, and one through a cement retainer, all four with volumes of 400 sacks each). Subsequently, a BHPI chemical system was used to successfully squeeze the shoe, resulting in the well being able to drill ahead with no more severe losses. The post mortem on the well concluded that there was a fault or fracture near the shoe that was feeding up into formations with a lower pressure integrity.

On the same well, after TD was reached with 18.1 lb/gal drilling fluid, circulation was reduced to less than 1 bbl/min to keep from pumping the mud away. An open-hole log identified a suspect thief interval, which was also a shale interval, and not the casing shoe, which was squeezed earlier. The well was squeezed by placing the bit near the target interval of 13,650 ft, well below the casing shoe at 11,060 ft. The interval was successfully squeezed, circulation was regained, and the well was successfully cemented and completed.

***Well B-5***

While drilling at 13,760 ft, lost circulation occured, and despite three LCM pills, no improvement was noted. After squeezing with the BHPI chemical system, full circulation was regained and a drilling liner was successfully cemented. The suspected interval was identified as a faulted shale interval, which was most likely leaking drilling fluid through the fault in the shale up into another formation with lower integrity.

***Well J-19***

After cementing an intermediate casing string at about 11,800 ft, the casing failed to test to the desired integrity for the next hole section. A test with a retrievable packer confirmed that there were several collar leaks lower in the casing string, below the TOC (top-of-cement). Despite a cement squeeze and a LCM pill, the casing still would not test. The BHPI chemical system was then used and an integrity increase of 1 lbm/gal was achieved. The well reached the next liner setting point without any further problems.

***Well J-23***

After not finding any cement in the float joint of an intermediate casing string and the shoe not testing, the BHPI system was used to squeeze the shoe, increasing the integrity in the PIT by 3 lb/gal from 15.0 to 18.0 EMW. The well was drilled to the next desired casing point without any further problems.

***Well J-26***

While drilling at 13,000 ft., the well experienced severe lost circulation, which required the mud system to be cut by 2 lbm/gal, from 15.5 to 13.5 lbm/gal. The suspected interval with low integrity was a drawn-down gas reservoir, which, after logging, was confirmed to have a pore-pressure equivalent of nearly 6 lbm/gal. The sand was squeezed, and a buildup of 0.5 lbm/gal was achieved, which allowed drilling the well another 700 ft and setting a liner. **Figure 7** illustrates the job recorder chart of pressures, rates, and volumes during the J-26 BHPI treatment. Note that the second ISIP/leakoff had a slow bleed-off of pressure, less than 15 psi in one minute, indicating a sustainable BHPI increase. Some of the pressure changes between the first and second ISIP represent diversion and sealing by the BHPI plugging aggregates in multiple leak-off pathways in the interval.

***Well H-1***

After drilling 150 ft below the last casing shoe, this well experienced lost returns while attempting to circulate. Since the target interval had not yet been reached, and the estimated pressure was the same as the current mudweight, two BHPI treatments were finally used to regain integrity. In addition to the BHPI systems, three LCM pills along with two cement squeezes had been used. Although the final BHPI job showed an increase of 0.8 lb/gal in integrity, after only drilling 14 more feet, lost circulation was once again encountered. The problem area was suspected as being a fault or fractured zone, and possibly the side-track hole from this well.

**Lessons Learned**

Post-job evaluations included an analysis of each BHPI treatment performance for both success and areas for improvement, which provided the lessons learned, listed below and in **Table 4**:

- Spot the bit close to the target zone to limit mud entering the zone and prevent excess left in DP.
- Check DP integrity to contain high pressures.
- If high pressure occurs with chemical systems inside DP, continue pumping. It won't set like cement.
- Check the integrity of the surface lines with a pressure test to min. 8,000 psi to avoid unplanned shutdowns caused by leaking connections.
- Spacer volume ahead should a min. 2,000 ft. of DP capacity.
- Two cementing trucks are preferred for better dual injection rate accuracy and high-pressure capability.
- Use the pipe rams to close the annulus for the squeeze, not just the annular diverter.
- The typical BHPI chemical system volume is 10 to 20 bbl.
- Always perform a well-site quality control test using actual samples of mud and BHPI chemical system mixed together for <1-minute reaction time.
- Well-site test the compatibility of sample mixtures of spacer/mud and spacer/chemical system.
- Stage the BHPI system in 3- to 5-bbl increments (1- to 2-minute intervals) separated by spacer to enhance diversion & multiple point sealing.
- Squeeze at low rates, <1 bpm, when entering the

target zone & during packing/bleed-off.

- The squeeze is successful when the wellbore pressure is stabilized at the required pressure integrity.
- Wash and ream immediately after the squeeze at a rate of one stand in 30 minutes.
- Keep records of casing & DP pressures during the job for post-job review.

## Conclusions

- The pressure integrity of respective types and layers of rock can be restored and/or increased.
- Certain rock defects can be repaired, allowing the rock to withstand higher bore-hole pressures.
- Certain BHPI treated formations may have a very near bore-hole, altered stress-field region with a fracture gradient higher than the natural fracture gradient outside the region. Wellbore pressures ($P_w$) may then exceed expected fracture initiation pressures.
- The sum of the total improvement in bore-hole pressure integrity is the lowest increase (the weakest point in the hole after the treatment).
- Poor pressure integrity formations exposed during shoe tests (short holes typically less than 50 ft below the casing shoe) and poor primary cement sheaths in the cemented annulus may be repaired simultaneously with a single treatment just after an LOT.
- Multiple stage treatments may be necessary for treating long open hole intervals.
- Field test results show that sequential treatments may cumulatively increase the fracture gradient (BHPI).
- Field tests indicate that BHPI treatments can significantly decrease well construction costs as well as the time before commercial well production can begin.

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**Table 1—Field Test Results with BHPI Chemical Systems**

| | Condition of Wellbore | | Integrity of Borehole | |
|---|---|---|---|---|
| **l / J ob No.** | **Pre Job** | **Post Job** | **Pre Job** | **Post Job** |
| / 1 | lost circulation - gas influx | halted mud losses | 17.6 | 18.4 |
| / 2 | lost circulation - gas influx | halted mud losses | 17.6 | 19.3 |
| / 3 | lost circulation - gas influx | halted mud losses | 17.6 | 20.1 |
| / 4 | lost circulation - gas influx | halted mud losses and gas influx, then cut mud wt. | 18.5 | 22.8 |
| / 1 | losing 4 - 20 bph mud | drilled ahead | 16.1 | 18.4 |
| / 2 | circulated low rate | circulated full rate | 18 | 18.6 |
| / 1 | no circulation | circulated full rate | 17.3 | 17.6 |
| / 1 | casing wouldn't test | casing tested | 16.2 | 17.2 |
| / 1 | shoe wouldn't test | tested, drilled ahead | 15 | 18 |
| / 1 | lost returns, cut mud wt, circ | increased integrity | 14 | 14.7 |
| / 1 | low integrity - could not drill | circulation regained | 16 | 16.8 |

**Table 2—Field Test Results**

| *Well* | *Suspected Problem* | *Alternative Techniques Tried* |
|---|---|---|
| B-1 | leaking formations and high-pressure sand | lost-circulation-materials (LCM) |
| B-3 | fracture from shoe to low pressure | four - cement squeezes 400 sacks each |
| B-3 | leakage into a fault | n/a |
| B-5 | leakage into a fault | three - LCM pills |
| J-19 | leaking casing collars | 1 cement squeeze (100 sacks), 1 - LCM |
| J-23 | poor shoe cement | none |
| J-26 | low pressure sand | none |
| H-1 | fractures/faults/sidetrack hole | cement (1), LCM (3), BHPI system (2) |

**Table 3—Field Test General Information**

| *ll* | *Csg. Shoe (ft)* | *Depth (ft)* | *Bit Size (in.)* | *Mudweight (lb/gal)* | *Temp (°F)* | *Mud System* |
|---|---|---|---|---|---|---|
| | 13490 | 13964-14400 | 6.5 | 17.1-18.0 | 325 | Oil Base - diesel |
| 3 | 11060 | 11100 | 8.5 | 17.7 | 220 | Oil Base - diesel |
| 3 | 11060 | 13650 | 8.5 | 18.1 | 260 | Oil Base - diesel |
| 5 | 11240 | 13760 | 12.25 | 17.3 | 260 | Oil Base - diesel |
| 9 | 11786 | 11786 | 10.625 | 14.8 | 230 | Oil Base - diesel |
| 3 | 12000 | 12000 | 10.625 | 15 | 230 | Oil Base - diesel |
| 6 | 11950 | 13100 | 9.875 | 13.5 | 250 | Oil Base - diesel |
| | 10650 | 10700 | 6.5 | 15.9 | 275 | Oil Base - diesel |

**Table 4—Lessons Learned**

| Job # | S/U* | Problems and Notes | Suspected Cause | Future Actions |
|---|---|---|---|---|
| **Well B-1** | | | | |
| 1 | U | very high drill pipe pressures (8000-9000 psi) once product was in DP<br>squeezed shoe, not weak interval | spacer contaminated with cement, product reacted in drillpipe<br>viscosity of reacted material | clean all product tanks<br>test compatibility of spacer and material<br>increase size of spacer<br>test lines to minimum of 8000 psi<br>use two pump trucks<br>squeeze closer to suspected problem |
| 2 | U | again high drill pipe pressures prior to squeeze | reacted product on the inside of drillpipe walls | increase spacer size for jobs pumped within short time span |
| 3 | S | no problems noted, able to cut mudweight–high pressure sand squeezed | material can work in both ways? | n/a |
| **Well B-3** | | | | |
| 1 | S | none noted–fixed shoe | | |
| 2 | S | annulus pressure exceeded shoe test–squeeze in open hole below the shoe<br>needed better way to monitor DP and BS pressure at same time | used too much material<br>two different recorders | install inside BOP and TIW far enough below the rotary so pipe can be pulled to the shoe if necessary<br>use a HUB to collect both pressure profiles on one chart |
| **Well B-5** | | | | |
| 1 | S | no problems noted | | |
| **Well LR-12** | | | | |
| 1 | U | did not get circulation back | overdisplaced material after trying to circulate | increase distance from bit to squeeze<br>exercise caution while trying to circulate due to contamination of material and spacer (will react with mud)<br>pull some pipe after squeeze |
| 2 | S | no problems noted | | |
| **Well J-19** | | | | |
| 1 | S | no problems noted during job, but running liner had problem breaking circulation | suspect residual material inside of casing | for tight tolerance liners, make a scraper run before running liner if a BHPI system job |
| **Well J-20** | | | | |
| 1 | S | no problems noted | | |
| **Well J-23** | | | | |
| 1 | S | no problems noted | | |
| **Well J-26** | | | | |
| 1 | S | no problems noted | | |
| **Well H-1** | | | | |
| 1 | S | no problems noted | | |
| 2 | S | no problems noted | | |
| 3 | S | lost returns after drilling | entire interval was not open | continue to try and drill entire interval prior to squeeze (if practical–could not in this case) |
| 4 | U | overdisplaced after job trying to circulate | small volumes–limited room, bit very close to the problem | increase distance from bit to problem–if practical<br>exercise increased caution when trying to break circulation<br>pull casing after job (did not in this case) |
| 5 | S | showed buildup, but losses started again after drilling | unsure | |
| 6 | S | able to circulate–no problems noted | | |

Successful / Unsuccessful

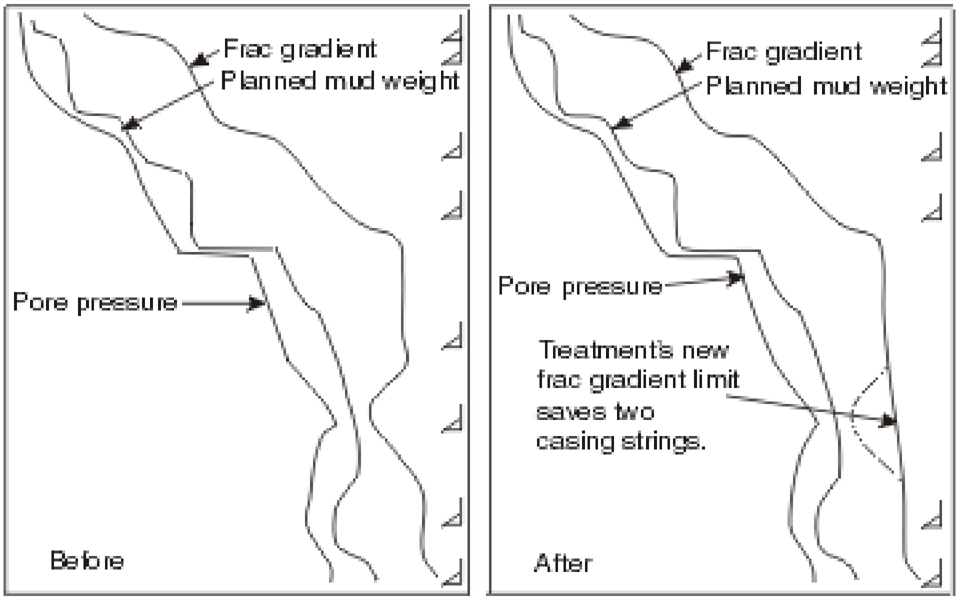



**Fig. 1—Balancing poor pressure and frac gradient.**

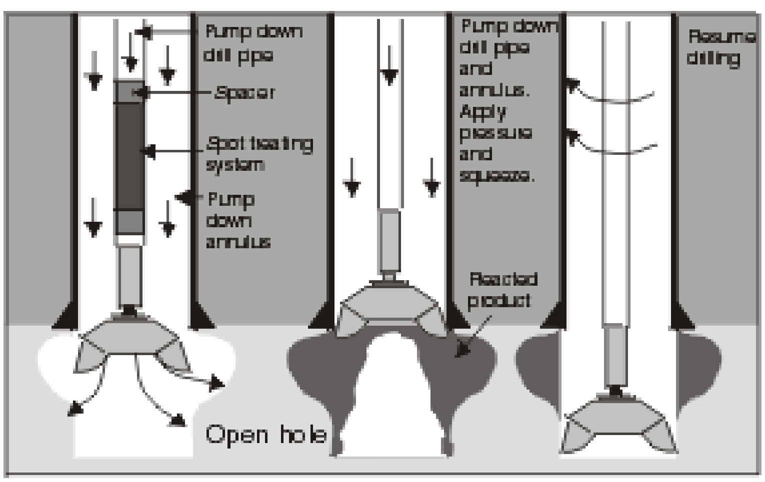



**Fig. 2—Application technique.**

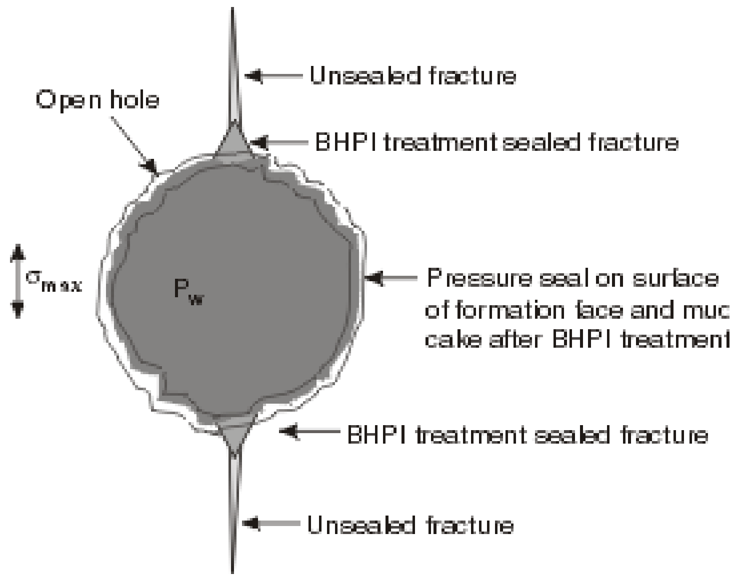



**Fig. 3—Pressure seal on formation face and mud cake after BHPI treatment.**

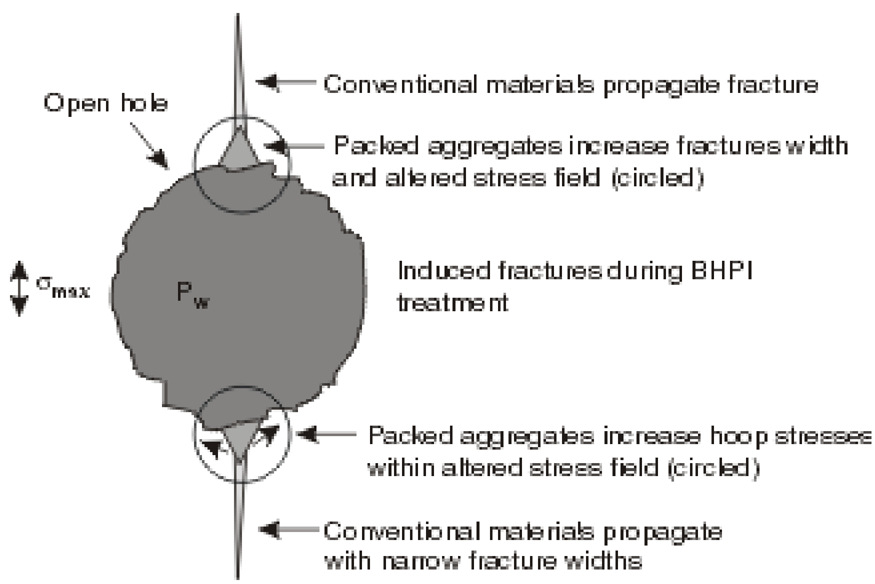



**Fig. 4—Induced fractures during BHPI treatment.**

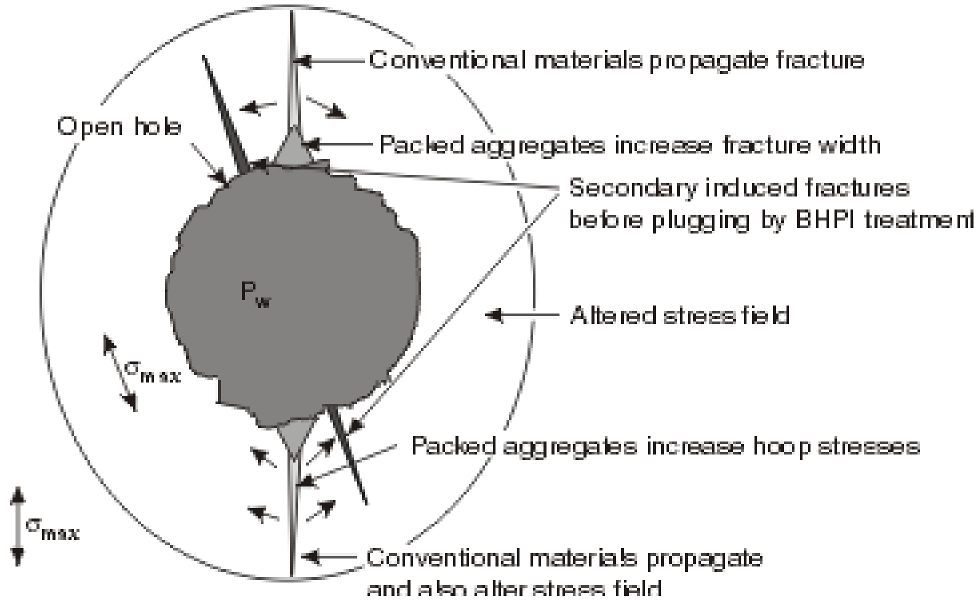



**Fig. 5—Secondary induced fractures *before* plugging by BHPI treatment.**

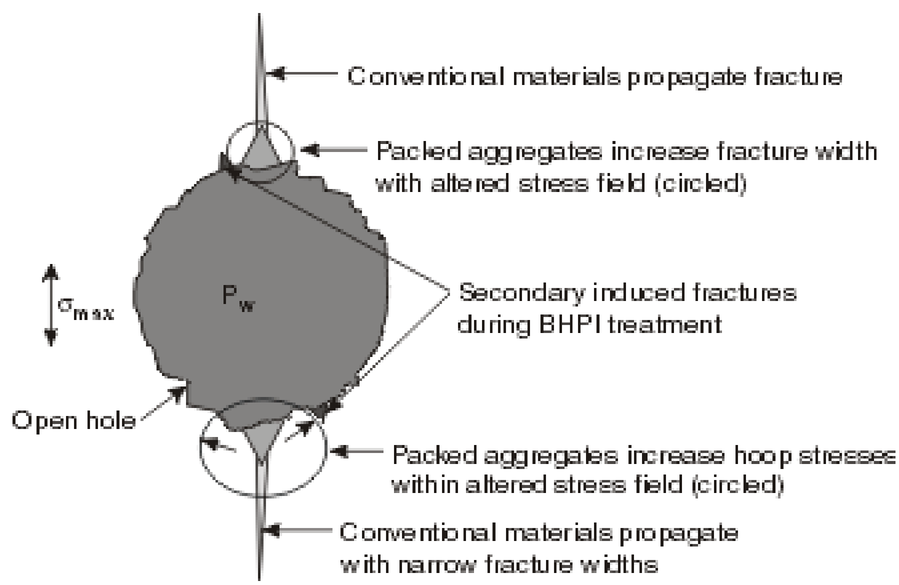
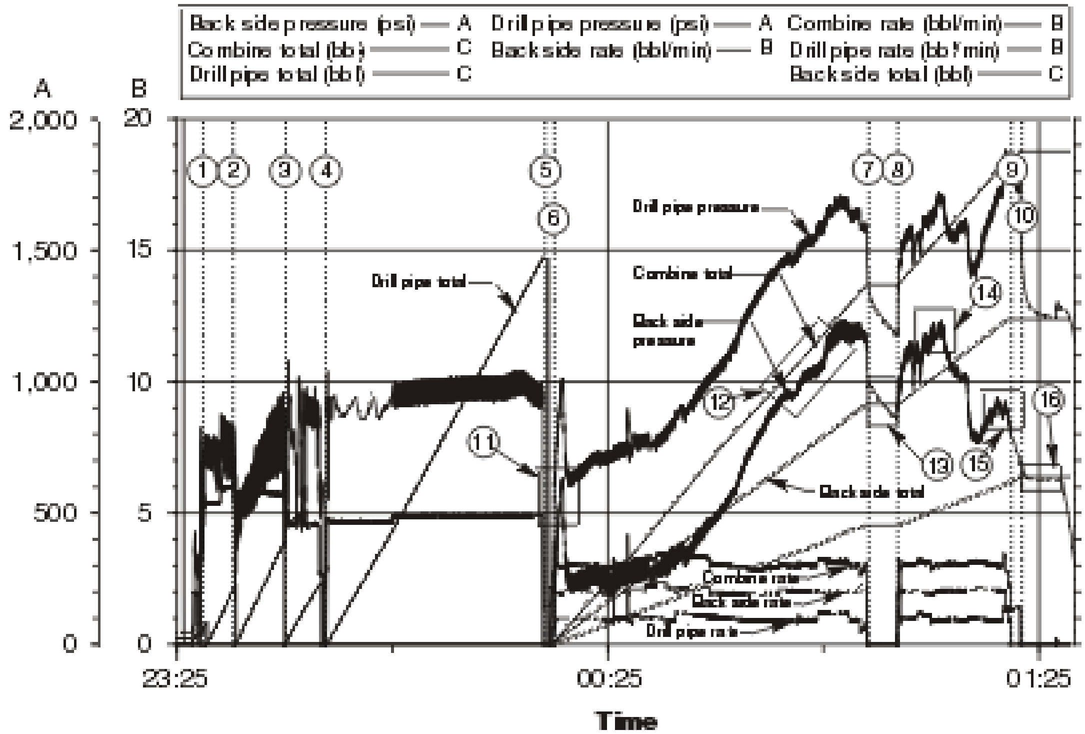



**Fig. 6—Secondary induced fractures during BHPI treatment.**




**Event Log**

| Intersection | | PP | DP | Intersection | | PP | DP |
|---|---|---|---|---|---|---|---|
| 1 Spacer | 23:28:37 | -9.422 | 693.7 | 6 Oil base mud - 2:1 commingle | 00:17:32 | 223.8 | 581.1 |
| 2 BHPI system | 23:32:50 | -8.440 | 682.2 | 7 Shutdown - ISIP - leakoff | 01:01:19 | 989.7 | 1347 |
| 3 Spacer | 23:40:09 | -7.777 | 893.9 | 8 Oil base mud - 2:1 commingle | 01:05:21 | 898.6 | 1207 |
| 4 Oil base mud | 23:45:42 | -8.099 | 218.7 | 9 Shutdown backside pump | 01:21:11 | 790.2 | 1789 |
| 5 Shutdown - close rams | 00:16:17 | -9.104 | 150.8 | 10 Shutdown | 01:22:38 | 695.2 | 1466 |

**Annotations**

11 Breakdown formation
12 Frac-Fill, Frac-Fill
13 LOT #1 - 100 psi/min
14 Opened larger fracture
15 Never returned to original squeeze pressure. Need more material
16 LOT #2 - 15 psi/min

**Fig. 7—Job recorder chart for Well J-26 BHPI treatment.**