TREATMENT CONTROL AND MONITORING CAPABILITIES IN PLACEMENT OF CHEMICALS AND/OR CEMENT SQUEEZES

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ABSTRACT

Utilization of computer simulations addressing the placement of chemicals and/or cements for remedial repair workovers has demonstrated valuable assistance in successfully repairing integrity problems. Various situations encountered such as casing leaks, annular isolation failures, needed repairs to the wellbores, and inter-reservoir communication problems may be addressed with a variety of solutions. Selection of the right solutions and selective placement of them into the problem areas have historically required a method for controlling and monitoring during the design and in real-time operations. Often, complicated situations are approached with highly complex solutions. The solutions are primarily selected based on the diagnostics performed to investigate and define the problems, their sources, and their features. In this approach, the needed attributes and capabilities of the solutions are determined based on the problem's requirements.

Computer simulation performed to address numerous conditions and situations has proven to greatly assistance in designing and performing workovers when developing planned steps. Pressure responses that compare actual treatments to design results enable operators to make decisions and make changes if needed. The techniques used and various cases employing this technology are discussed.

INTRODUCTION

The ability to predict placement and pressures during remedial squeeze treatments can enable operators to address problems without generating further complications and losses of integrity. Often, due to the speed of remedial squeeze operations, there is little time to perform detailed and complicated calculations to interpret the conditions and events affecting the treatment and its results. By developing computer simulation addressing placement of complex treatments, operators may visualize a plan and witness their ongoing remediation work in real-time. Crucial pressure analysis for determining whether the operator's job is progressing as desired and when to quit placement is a valuable knowledge tool. Having a predetermined design and plan to follow on location gives the operator detailed assistance in determining ongoing processes and safety points to follow.[1, 3, 4, 8, 11]

Pre-treatment determinations on placement into permeable rock matrix or into fissures, fractures, or vugs enable the operator to follow guidelines for the treatments. Placement conditions and guidelines that operators need to be following to stay within the desired controls necessary to maintain their planned treatments whether using liquids sealants or cementing materials can be determined.[3, 8, 17] The existence of a window of opportunity in placement is determined and is defined based on the maximum placement pressure allowed on the upper limits and down to the initial pressure of entry on the lower limits.

This paper will detail opportunities utilizing a computer design simulator and performing the treatments using this knowledge and planning. Case histories utilizing foamed cement to demonstrate the techniques and examples of job progressions were chosen. Capability to handle complex designs and even more complex solutions are demonstrated.

PERFORMING DIAGNOSTICS TO DETERMINE THE PROBLEM(S)

The ability to understand what problems exist and their remediation needs are often not taken into account when applying solution treatments. Many times, operators do not perform diagnostics because past experiences showed an inability to correctly interpret problems. Performing some diagnostic analyses can be expensive and often they show that what was assumed is correct. Often, the knowledge and understanding needed is not obtained due to complications from a multitude of effects. Often, providers of solutions imply that a product will work in any condition and that diagnostics are not needed. The operator will readily accept this implication because there is no need to spend money to develop a solution.

A solution for an identified problem should also be correctly tested for capability of placement. The ability to place a desired treatment into the identified problem interval and the controls required to help ensure proper selective insertions ideally should be determined next. Otherwise, many treatment solutions may be improperly placed and obvious failures can result.[13, 14, 15]

Often better understanding of the physical and architectural nature of the associated reservoir or near-wellbore problem(s) can be obtained through a "placement capability diversity testing" by injection analysis. Structurally, problems may exist in various mediums. One such structure is the contacted formation rock's permeable matrix and its communication capabilities. Reservoirs displaying fissure and fracture communication flows, voids, or vuggy portions represent a broad spectrum of highly conductive fluid transmission potentials. Poor near-wellbore isolation integrity allows direct communication between various intervals and possible unwanted fluid entries. Identifying the type of problem structures that exist and their probable influences or detrimental conditions that can influence the treatment placement or deterioration effects on the treatment should be utilized to construct the solution. This knowledge identifies the solution's needed, properties and attributes.[5, 6, 7, 9, 17]

MULTI-RATE INJECTIVITIES AND PLACEMENT

One aspect of problem or anomaly diagnostics that has improved the success of placement of sealants or cements in fractures or extremely high permeabilities is from the use of multi-rate injectivity analysis in conjunction with running tracer profiles. Understanding is needed to identify where unwanted fluids are being produced from and where injected fluids have gone during testing at different conditions. It is more important to know where fluids have gone than where they are going. Another aspect addressed in this investigation method is loss of integrity within wellbores and tubulars. The conditions that exist while a well is under injection can be used in determining treatment placement or restrictions that may exist. By varying the injection rates, pressure changes associated with fluid entry can be displayed. Most multi-rate analyses are conducted with a logging tool in the wellbore equipped with a release device capable of placing a specified amount of radioactive material into the flow stream above the logging tools. Generally, a base gamma analysis is used to determine variations. Normally, testing is performed with intensity releases of isotopes placed in segments up through the wellbore followed by a large shot of isotope placed above the entry zone as a velocity shot. The process is normally started at a reduced rate that is generally enough to establish entry only into the interval where a desired placement of chemicals or cement is desired. By releasing the intensity shots and a velocity shot, the injectivity of the tagged fluid can be traced to determine its path. The path is where it has gone. Using both intensity and velocity shots, comparison analysis can provide a better understanding of injectivity. Combining these with a temperature analysis also can enable a better understanding of injectivities and possible near-wellbore voids and lack of integrity. Initial injectivities may only exist in leak-off situations with a pressure decline. Depending on the problem, a majority of injectivity starts at a small leak-off in pressure or a minute injection rate into an un-fractured rock's matrix. The subsequent injection testing runs during multi-rates usually display incremented increases in pressures. Each injection rate step is increased following enough time for clearance of the prior shot isotopes and stabilization of fluid entry. The following steps may be taken up to a maximum rate of 1 1/2 to 2 BPM in most cases (wellbore configuration determinate), higher rates being difficult to follow within the wellbore tubulars. The focus is to determine whether there is a variation in entries at different rates and accompanying changes in bottom hole injection pressure (BHIP), if any.

There may also be determination of a ratio for dual placement control, a maximum injection pressure if bullheading fluids, and an insight as to the type of solution that may be used. Differential pressure responses may help provide an understanding of the tortuosity aspects of fluid entry into specific portions of the reservoir, casing leak, annular filling interval, or other geometry. When rates exceed certain velocities, it may be determined that materials, such as cement slurries can be pumped into a portion of the well, leak, or out into the formation. With normal permeabilities ranging from 0.001 to 1000 md in shallow rocks down to Permian Age reservoirs, there is little chance of injecting a gelled fluid or slurry at the rates associated with multi-rate injectivities and only exhibiting matrix leak-off flow. Placing a treatment where it develops a blocking or squeezing effect without entering undesired portions of a formation may be determined with this analysis. If investigations show that at a specific pressure developed from varying injectivity would cause undesired entry, this information may be used to limit the treatment pressure and provide a stopping point in placement. The chosen solutions that can be placed under the criteria established in a multi-rate injection analysis are established with this analysis. [1, 3, 4, 7, 10, 18]

WHAT ARE THE ATTRIBUTES AND NEEDS?

Understanding physical attributes and capabilities of treatment solutions is helpful in selecting the correct materials and methods for implementing a solution for an identified problem. Ideally, solutions will need both physical attributes to withstand the conditions associated with the identified problem(s) and a capability to be properly and selectively placed in the best logical position to modify or change conditions for remediations. Solutions need to be placed without detrimental effects occurring during placement or following their final placement position. For example, a gel solution may not be placed into tight rock matrix without squeezing off on the rock face.[1, 7] In addition a cement mix may not be placed into tight fissures or matrix rock, due to the particle size of its materials. Many chemical solutions are not effective if placed into dynamic rapid flowing fracture systems. The ability to withstand extrusion from the desired placement should be understood and verified in solution selections. [2, 4, 5-7, 10-12] The capability to withstand deteriorations due to temperature, bacteria, gases, CO_2, H_2S, etc. should be used as a guideline in solution selections.[6, 11]

DEFINING THE ATTRIBUTES, CREATING A SOLUTION TO PLACEMENT TECHNIQUES

Developing the skill for interpreting the physical nature of a problem and how it affects a well's performance and integrity should follow a logical sequence. Most operators run to a solution prior to even effectively understanding the problem. Shopping for a solution seems easy when only using sales brochures or eager providers of solutions. Best practices in creating problem resolutions from loss of wellbore integrity to undesired performances within formations should follow logical steps. A thorough understanding of the problem and if needed; the reservoir, is the recommended first step. This step should be followed by clarification of the conditions and the techniques or placement means available. Build a solution based on what the well is telling the investigator. One should avoid running toward a solution or trying to make a solution fit the requirements. Historically this method has shown a preclusion to failure. Building the requirement list for a solution's attributes is normally associated with the determination of placement controls needed and analyzed. Success is often directly associated with the steps taken from (1) understanding, (2) identifying, (3) clarifying attributes, (4) selecting appropriate solutions with the required attributes and capabilities, (5) developing the solution from the placement-method-determination analysis, and (6) using precise control over actual treatments.[10, 11, 16]

HISTORICAL OCCURRENCES

Historically, remediations for associated problems have been qualified and shown significant success ratios when proper steps in logics and engineering were followed. Evaluations to qualify these values added to field units operating under the logical step process and use of computer simulation modeling for placement control have indicated a much higher rate of 90% as compared to randomly selecting solutions at 40%.[19]

DESIGNING THE SOLUTION

Simulation models are often utilized to design and plan placement into specific problem intervals. Computer simulation models using techniques that step through the processes by examining variable-length series of distinct points in time are helpful in determining design vs. actual treatments. After each point in time, an increment of fluid is injected into the given described tubulars within the well. Injection pressure into the squeeze interval (BHTP) is input for calculations and used to backtrack to the calculated wellhead treating pressure (WHTP) throughout the treatment. The calculations apply (1) hydrostatic loadings, (2) accumulating friction from the surface to the interval entered, and (3) all changes in fluid rheologies due to internal characteristics such as entrained gases. This iterative process is used to make the decisions and plans during job treatments.

Utilizing a discrete number of variable intervals describing the tubular length and wellbore geometries develops the calculation's position steps. Depending on the fluid's physical attributes and phases, modifications of coverage lengths within the wellbore geometry are accounted for due to expansion and contraction of the fluids corrected for ongoing friction changes. If energized fluids are being placed, the lengths of the incremental intervals (summing their hydrostatic and friction pressures), are variable and noted in the WHTP calculation.

Within each of the variable intervals of the wellbore geometry, following fluid increments are likewise accounted for. In this iterative process, the steps of the planned treatment are accounted for from beginning to end. Constantly changing fluid rheologies, especially if energized, are recalculated based on correlations developed by Reidenbach.[4] With the new rheologies and densities modified throughout the placement steps, Reynolds numbers can be recalculated, allowing the friction factors to be calculated from each of these intervals in the design's described geometry.

Flow rates within the described geometry at any interval can be calculated, and using an algorithm that adjusts these pump rates into the tubulars based on the adjusting volume changes caused by enlargement or compaction are accounted for. If fluids are not energized, the design program can also determine the free-fall positions within the given wellbore geometry. [3, 4, 7, 8, 16]

Entered information may be modified to reflect changes and refined placement parameters. Required data input includes:[17]

- Base fluids – rheologies, volumes, and liquid densities
- Wellbore description - including deviations and excess factors
- Pump rates – job schedule
- Nitrogen injection schedule
- Bottomhole injection pressure (backpressure) job will encounter
- Depths and location of specific intervals of interest
- Surface temperature and bottomhole static temperature

Determined data output includes:[17]

- All input given data
- BHIP – WHTP tables with planned step increments
- Volume and rate calculations charting time, surface fluid in and out, unfoamed volume, and rates in and out
- Location of fluids
- Free-fall determination calculations
- Equivalent circulating density (ECD) at specified key intervals and zone of entry

CASE HISTORY #1: ANNULAR COMMUNICATION BEHIND CASINGS EXTENDING OUTWARD THROUGH FRACTURE NETWORK

A proposal was made and recommended for squeezing off an initial set of production perforations in the well producing 100% water from the formation's lower water drive. Once squeezed off, the well was reperforated and stimulated in an attempt to stay out of the lower portions of the formation with 100% water coming from the Lower San Andres pay.

Production Casing	0 - 4600 ft (MD)
Outer Diameter	5 1/2 in.
Inner Diameter	4.95 in.
Linear Weight	15.5 lb/ft
Casing Grade	K-55
TOC	Did not circulate on 1st stage
	Circulate cement off DV Tool at 1635 ft
Work String	0 - 4250 ft (MD)
Outer Diameter	2.375 in.
Inner Diameter	1.995 in.
Linear Weight	4.70 lb/ft
Tubing Grade	J-55
Squeeze Retainer:	at ±4250 ft
Perforations to Squeeze:	4283 – 4335 ft (1 JSPI)
	4392 – 4415 ft (1 JSPI)
	4426 – 4464 ft (1 JSPI)
	4,519 – 4536 ft (1 JSPI)
Static Temperature	100 - 110 deg F
Fracture Gradient	± 0.65 psi/ft or 2795 psi at 4300 ft
Initial BHIP:	± 1900 psi
Est. Res. Pressure:	± 1675 psi
Max BHP:	± 2900 psi.
Treatment History:	4250 gals 15% NEFE HCL w/ balls
	28,000 gals. 40 lb GBW w/ 815 sks 12/20 resin sand
Production Results:	16 BOPD – 1600 BWPD

Foam Cement Squeeze Job: It was recommended to run in the well with a sliding valve cement retainer on 2 3/8” workstring tubing to ± 4250 ft in the 5 ½ in. casing. Prior to setting the retainer, operations pumped the tubing capacity. After setting the retainer, operations attempted to load and pressure up to 500 psi on the tubing annulus.

The service provider established injectivity into the perforated sections from 4283 to 4536 ft – and into the voids and fractures existing therein.

Operations injected a pre-flush of 10 bbls

Lead Slurry: Mixed and pumped 100 sacks of class “C” cement foamed to a 10-lb/gal density at the static BHSP (1675 psi) of the interval.

Tail-in Slurry: Mixed and pumped 100 sacks of class “H” cement foamed to a 12-lb/gal density at the static BHSP (1675 psi) of the interval.

Once cement entered through the retainer, operations squeezed the zone to a maximum pressure to block off the fracture system in the perforated interval but did not exceed the pressure that would fracture into the upper portions of the formation behind casing (0.65 psi/ft – BHTP of 2795 psi at 4300 ft). It was desired to place as much volume into the fracture system to gain entry in a maximized distance away from the wellbore. If the maximum pressure was achieved during the cement injection, operations would stop injection, pull off the retainer, and reverse excess cement to the pit via staked lines. The squeeze treatment was placed at the desired pressure restrictions and shut in for strength development.

The cement squeeze was allowed to build strength prior to drilling out. The well was re-entered and perforated for stimulation into the upper San Andres interval at 4300 ft. A 1000-gal 15% HCL acid treatment was used to open the upper new perfs and well tests were performed.

Operations plots and results are included in Figure #1 and Table #1.

CASE HISTORY #2: EXTREME LOW PORE PRESSURE INTERVALS SELECTED FOR BLOCK SQUEEZING

A proposal was made and recommendations followed to squeeze off Simpson production perforations for a planned re-entry for horizontal drilling in the same pay. Determinations were made from logging that additional behind casing communication existed into the Ellenberger formation below the planned re-entry formation.

Formations: Simpson at 11,935 – 12,020 ft
Ellenberger at 12,615 – 13,660 ft

Type Well: Production
Production Casing: 5 1/2in. 17-20# - N-80 at 12,615 ft
Tubing: 2 7/8" American Openhole at 11,800 ft (modified to ±10,900 ft)
Squeeze Retainer: SVB EZ Drill at 11,800 ft (modified to ±10,900 ft)
Perforations: 11,935 - 12,020 ft in Simpson pay (180 holes)
TD: 13,660 ft (Driller Report)
Injection Analysis Post Acid Treatment: Injection rate at 10 BPD and +/-250 psi
Temperature and Injection Test gave indications of behind casing travel down below casing shoe into Ellenberger formation.
Temp at Ellenberger: 240 °F
Temp at Simpson: 224 °F
Pore Pressure at Simpson: ±5,200 psi (tight Limestone)
Pore Pressure at Ellenberger: 350 psi with extensive fracture network
Past Acid Treatments: 29,000 gals 15% HCL – Ellenberger

Foam Cement Squeeze Job: It was recommended to run in the well with a sliding valve brass mandrel cement retainer on tubing, and prior to setting, pump tubing capacity (±69 bbls). Operations set the retainer t 11,800 ft in the 5 ½ in. casing. Operations loaded the annulus with water. Annulus loading was performed by leaving the annulus and BOP open and monitoring for any flow. The open BOP allowed the tubing to be pulled out of the retainer during the displacement at will.

Operations established injectivity into the perforated section from 11,935 – 12,020 ft into the casing annulus channel existing at 12,020 – 12,615 ft (the casing shoe depth).

Injected a pre-flush of 40 bbls fresh water containing 50 scf/bbl nitrogen to assist in reducing hydration of the following slurry due to the well being on an extreme vacuum.

Mixed and pumped 1000 sacks of class "H" cement foamed to an average 10.5-lb/gal foam density at the static BHSP (350 psi) at the Ellenberger interval. The BHSP was the current static pressure of the Ellenberger (350 psi BHP). Once cement was through the retainer, squeezed to a maximum pressure based on computer simulated analysis data to block off the channel down into the Ellenberger and fill the openhole section from 12,615 ft on down to 13,660 ft. Excess cement was calculated to fill the removed (etched) rock from the initial 29,000 gal 15% HCL treatment (estimated 315 cf rock). It was desired to not fracture the other portions of the Ellenberger (0.52 psi/ft). The maximum pressure was achieved during the cement injection and operations pulled off the retainer and reversed excess cement to the pit via staked lines.

The well data indicated that it would likely treat on a vacuum during the early and middle part of the foam cementing operation and certainly it could go on a vacuum during the displacement of water. Tubing capacity was around 69 bbl and it was suggested to consider pulling out of the retainer and shutting down squeezing with around 15 to 20 bbl remaining inside the tubing of water displacement so that the foam cement would not be over-displaced. Since the well squeezed off with foamed cement still being injected into the tubing, operations were halted and the cleaning of the tubing operation commenced.

Why did the tubing pump up into the retainer's test position? The ability to place enough weight down onto the retainer prior to the jobs was restricted by its capacity. During the latter part of the squeeze treatment, the expansion of the tubing shrank the tubing up into the retainer's test position. Following a shutdown and allowing the tubing to lengthen without the higher pressure, the retainer was stung back into the pump position. The surface pressure was noted and determinations were made that the squeeze was at its desired maximum. The tubing was pulled out of the retainer and the excess slurry reversed to the pit by staked lines.

The operation plot is included in the accompanying Figure #2.

CASE HISTORY #3: FRACTURE FILLING AND SQUEEZING FOR RE-STIMULATING UPPER INTERVAL

A proposal was made and recommendations followed to fill and repair annular communication and extended entry into a lower fractured fault.

Casing	0 – 11,500 ft (MD)
Outer Diameter	5 1/2 in. [LT&C]
Inner Diameter	4.950 & 4.892 in. w/ drift 4.825 & 4.767 in.
Linear Weight	15.5 – 17 lb/ft
Casing Grade	K55/N80 (collapse 3120 & 6280 psi)
	(burst 4810 & 7740 psi)
TOC:	Unknown
Intermediate Casing	8 5/8 in. 32# K-55 at 4,10 ft w/ TOC 1700 ft
Workover Tubing	2 7/8 in. 6.5# - L-80 EUE at 0 - 10,850 ft
Stimulation Tubing	3 1/2 in. w/ 2.992 in. ID
Old Perforations (Fusselman)	11,232 – 11,252 ft (21 JH's)
	11,255 – 11,273 ft (19 JH's)
Perforations (Devonian)	10,910 – 10,930 ft
Plug Back:	CIBP set at 10,980 ft w/ ? ft cement (PBTD 10,980 ft)
	50 ft rat-hole below lowest perf
TD	11,500 ft
PBTD	11,400 ft
Formation Devonian	
Static Temperature	±192° F
Est. Reservoir Pressure	±5730 psi (liquid)

Est. Fracture Gradient	±0.72 psi/ft (Initial) ±0.52 psi/ft (current)
Maximum Casing Pressure	1500 psi due to casing condition
Prior treatment Conditions	Injection Tests (03/27/03) Rate at 1 BPM – WHTP at 150 psi Major Fluid Storage effects at 10,932 – 10,946 ft Temperature Channel down to 10,964 ft Rate a 2 BPM – WHTP at 400 psi Major Fluid Storage effects at 10,932 – 10,946 ft Temperature Channel down below LTD at ±11,000 ft

The desire was to provide a consolidation and filling of a lower fractured entry (10,932–10,964 ft) possibly into faulting areas in this well below the Devonian perforations at 10,910–10,930 ft. If a channel was present behind casing and communicating either upward or downward, providing integrity was also desired. Tests indicated this entry and with multi-rate injectivity analysis, showed the desired entry and estimation of a maximized placement condition.

Testing of injectivity was utilized to determine a better estimate on volume and rate to squeeze foamed cement into the channel below the pay. The testing also gave the possible maximum squeeze pressure desired based on entry into the Devonian zone.

The technique of applying squeeze-designer foam cement into the communication pathways was to provide integrity and capability to stimulate the Devonian pay without losing fluid into the wrong intervals.

Squeeze attempt on Devonian perforations – entry behind casing channels process:

1. Ran in with a cement retainer on the 2 7/8 in. tubing and prior to setting, injected tubing volume
2. The treatment was conducted below a cement retainer set at ±10,850 ft
3. The tubing capacity was injected prior to setting the retainer
4. Once set, the annulus was loaded by injecting down the tubing pulled out of the set retainer in incremental steps of 25 bbl. Operations allowed the load to equalize in the well. This method was applied to help eliminate the water hammer associated with dumping fluid down the annulus. Once the hole was loaded, stung the tubing back into the retainer and placed 500 psi on the backside. (Maximum allowable pressure on the casing was 1500 psi)
    a. Establish injection and determined conditions of entry (vacuum)
    b. Establish injection down tubing at 2.0 bpm with a 10 bbl water spacer injected with nitrogen and foamer-stabilizer chemicals
    c. Mix and pump 250 sks of cement, foamed to a density of 13.5 ppg at the BHSP of ±5000 psi
    d. Design to displace the slurry to 1 bbl above the retainer if possible. If desired, under displace and pull off retainer to close in the injection. Pull off the retainer, reverse to pit through staked lines. (Note the maximum squeeze pressure throughout the job, using the pressure chart determined from computer simulation.) It was designed to also reduce the displacement if the placement was not building a rapid squeeze pressure.
    e. Shut in for 36 hr unless a noted squeeze is accomplished; otherwise shut-in for 24 hr. Rig up to drill-out retainer and cement squeeze, pressure tested squeeze interval
    f. Establish a substantial squeeze, drill out the intervals one at a time and test.

The well was re-entered and horizontally drilled to an extended reach. The subsequent stimulation into the new constructed horizontal re-entry has provided excellent gas recovery.

An operations plot is included in accompanying Figure #3.

CASE HISTORY #4: INTERWELL COMMUNICATION – HORIZONTAL PRODUCER IN CO_2 WAG FLOOD

Based on surveys and analysis, it was determined that there was a communication from an offset injection coming into the newly completed horizontal well at a MD of 5700 ft and possibly crossflowing into a MD of 5125 ft. Utilizing a foam cement squeeze, it was desired to squeeze off these fractures and leave a top of cement at 5000 ft MD. The desire was to squeeze off this communication fracture channel and not leave the well with a costly drill-out following the squeezing.

a. The treatment was conducted below a cement retainer (5 ½ in. 15.53#) set at ±4197 ft
b. Note that the tubing capacity was injected prior to performing the job (24.3 bbl)
c. Once the injection test was pumped, the annulus was loaded and pressured up to 500 psi
d. Inject down tubing at 3 BPM with a 10-bbl water spacer: (Note that the rate could have been modified based on the observed injection pressure)
e. Mixed and pumped 450 sks cement, foamed to a density of 11.5 ppg at the BHSP estimated at ±1400 psi
f. Displaced the foam slurry with a 17 bbl volume of a 50 lb gel system to place the top of the foam cement at ± 5000 ft. Followed the foamed gel system with tubing wiper plug from a container. Continued to displace the job with a 24-bbl volume of fresh water to land the tubing wiper plug on a nipple; placed a joint above the retainer. Pulled off retainer and came out of the hole with periodical swabs to remove the displacement water. Shut in the well for 24 hr. Rigged up to drill-out the top of the retainer and ran in to retrieve with special tools. Tagged top of foam cement in open-hole of horizontal section and determined it was suitable.
g. Would have rigged up to initiate horizontal drilling to polish off the squeeze had it been needed. The well was placed back on production and the fracture communicating CO_2 had subsided.

An operations plot is included in accompanying Figure #4.

DESIGN CRITERIA AND CONSIDERATIONS FOR CASE PROBLEMS

Laboratory Testing to Match Needs-

Laboratory analysis utilized were normal cement testing for rheology, pump time, free water, and fluid loss. Internal calculating with simulation software could be loaded with the cement parameters for placement control and restrictions.

Rheologies and Rates-

Based on simulations and high-pressure high-temperature (HPHT) consistometers, rheologies were determined for evaluations. Simulation software also calculated the foamed rheology based on pressure and temperature.[20]

Pump Times and Reactions-

Often the desire is to have a minimal placement time so that detrimental effects existing within wells do not have a long time to adversely change the properties of treatment chemicals or cements. Based on laboratory tests and wellbore simulations, foamed cements display a great resistance to influxes and dilutions normally associated with conventional cements.[20]

Pressure Responses and Limitation Facets-

The witness to downhole reactions is surface pressure, when derived through accurate predictions. Multiple simulations comparing test pressures have indicated a very close tolerance in calculations using the simulation programs discussed.[3, 4, 8]

Demonstration of physical appearance and details are included in accompanying Figures #5 & #6 along with Table #2.

CONCLUSION

Allowing designs to be developed incorporating a well simulation for placement control has proven to be very beneficial in improving results. Knowledge is a key component in these developments, giving operators pertinent predictions as to the placement functions and addressing complex situations and solutions. A development in simulation programs using the geometry of wellbores and known fracture systems or faults can allow operations to predict placement and capabilities to perform treatments without the normally associated drill-outs or follow-up workovers. This ability encourages operators to perform remediations because of the ability to place a remedial solution without the cost of a workover unit or a drill-out operation.

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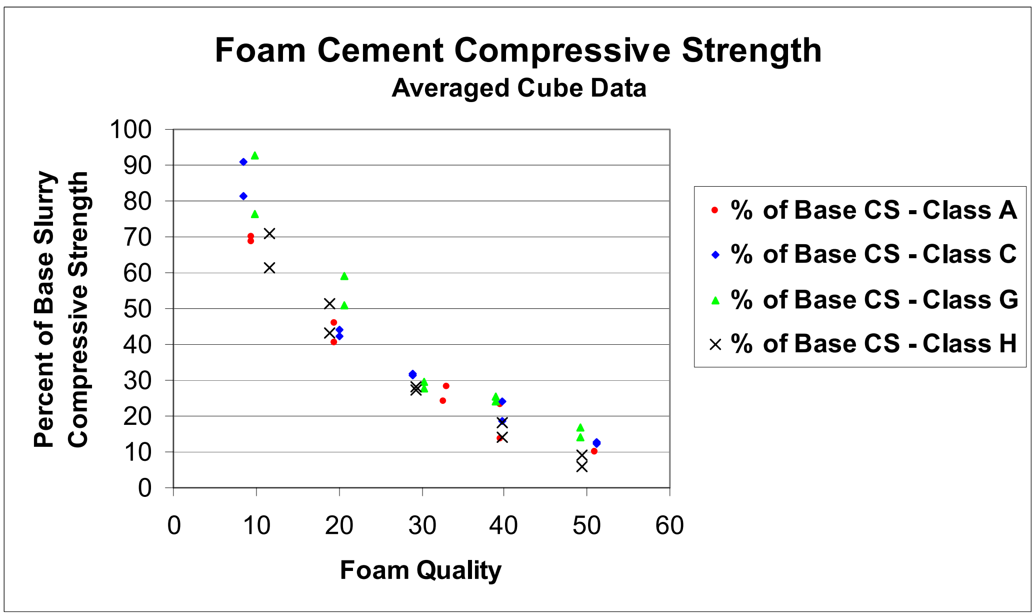
Table 1
Case 1 - Production Results Comparison

Results – Case 1	Oil (BPD)	Water (BPD)
Production from Stimulated Initial Perfs	16	1600
Production 1 week post workover Squeeze + Stimulation	26	280
Production 1 month post workover	66	148
Production 3 months post workover	75	120

Table 2
Foamed Cement Strength Comparisons



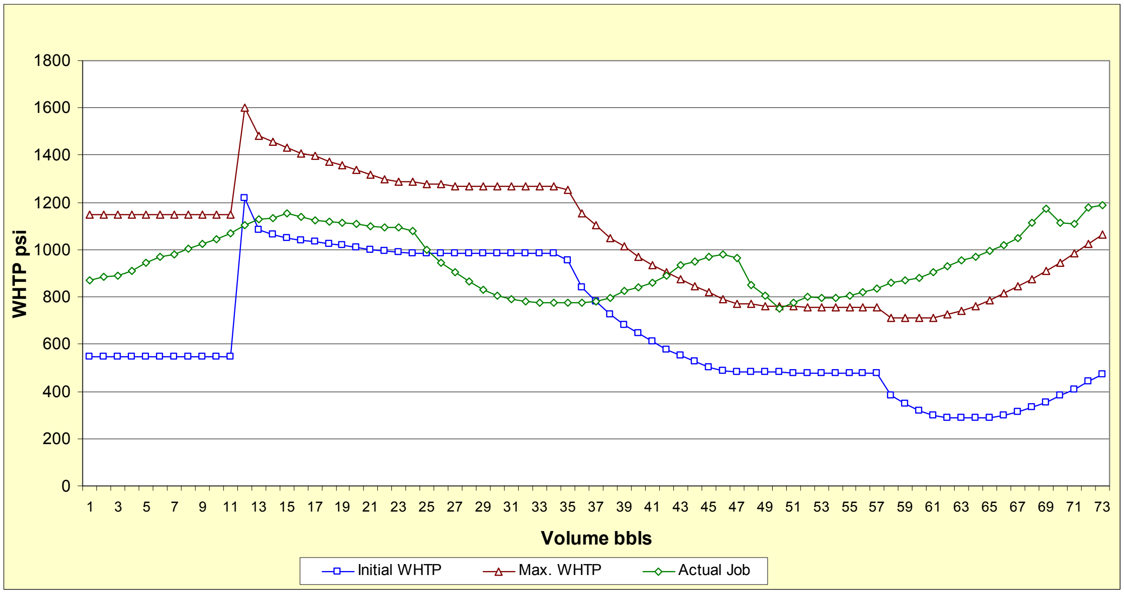


Figure 1 - Case 1 - Squeeze Simulation on Blocking-Off Undesired Water Production

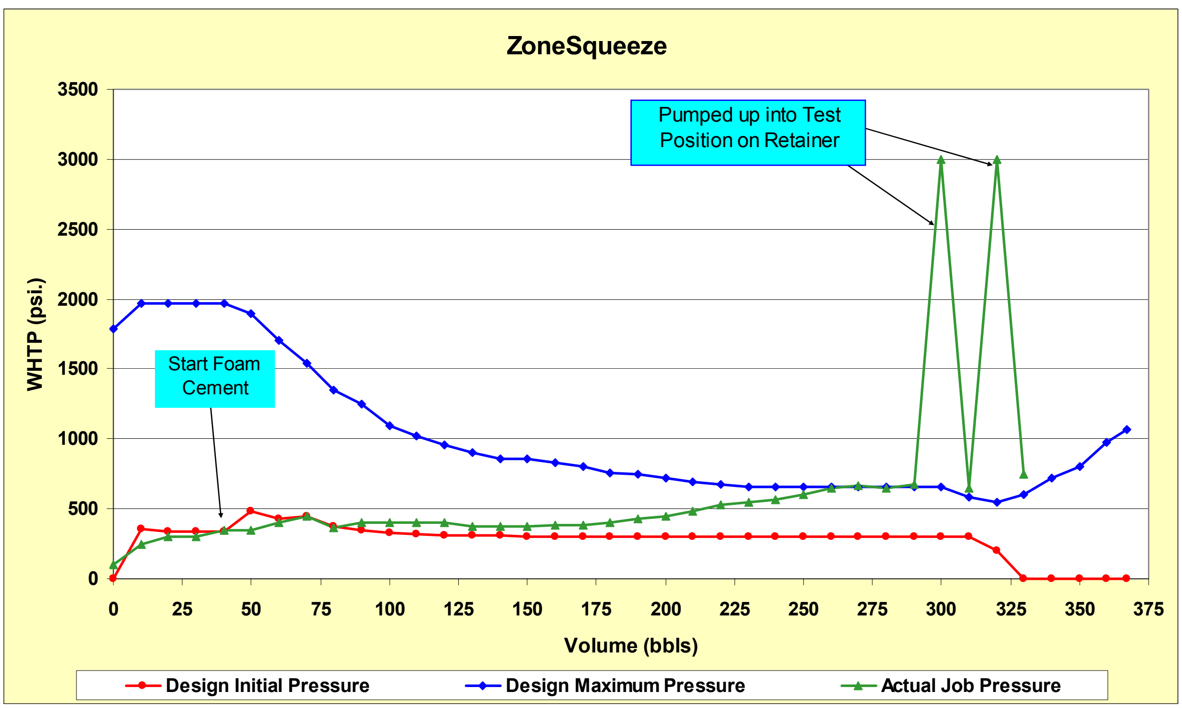


Figure 2 - Case 2 - Squeeze-off Extremely Low BHP Well

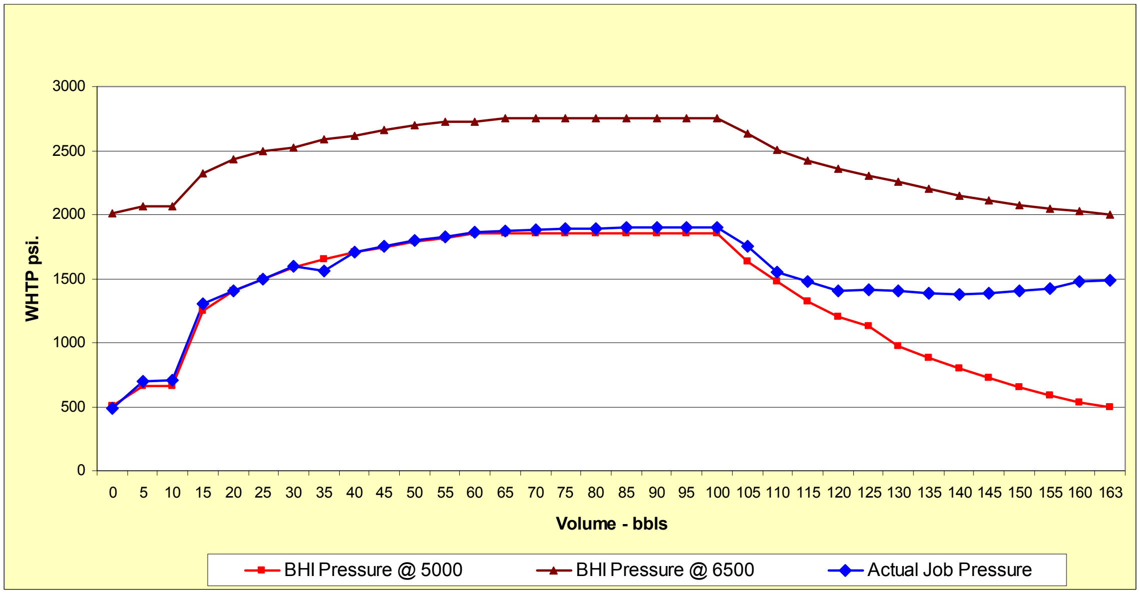


Figure 3 - Case 3 - Squeeze Off Fractured Network for Re-Completion of High Water Producing Well

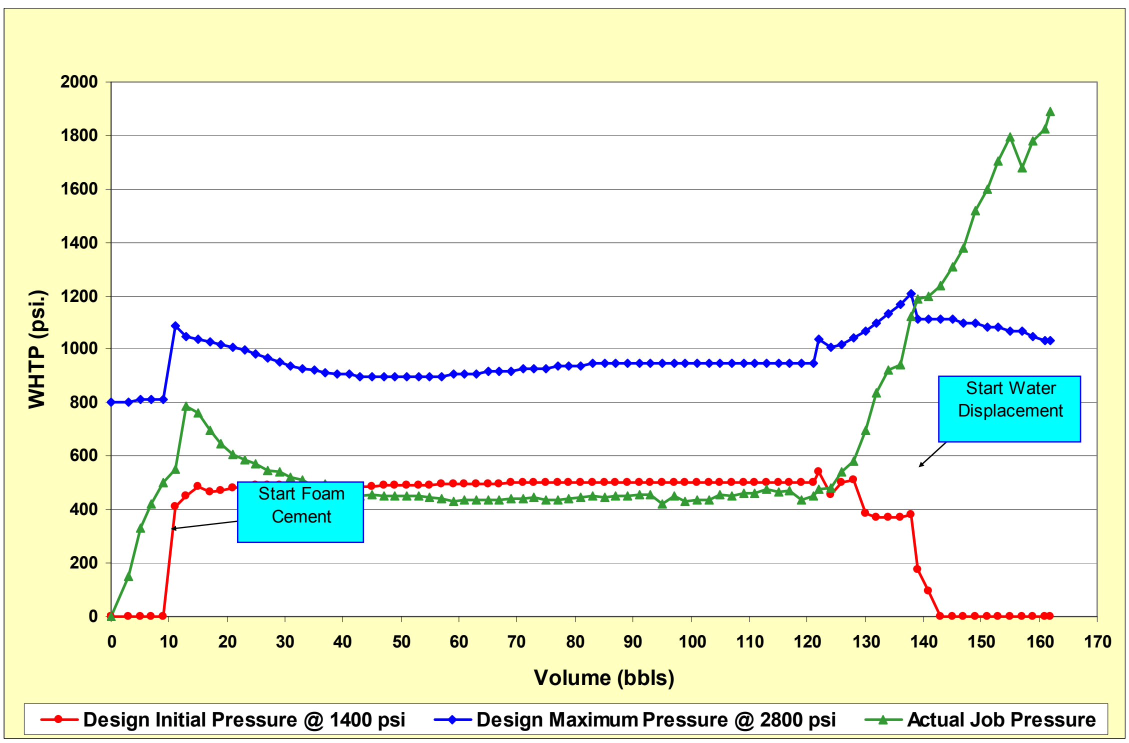


Figure 4 - Case 4 - Squeeze Horizontal Lateral Well with Fracture Communication

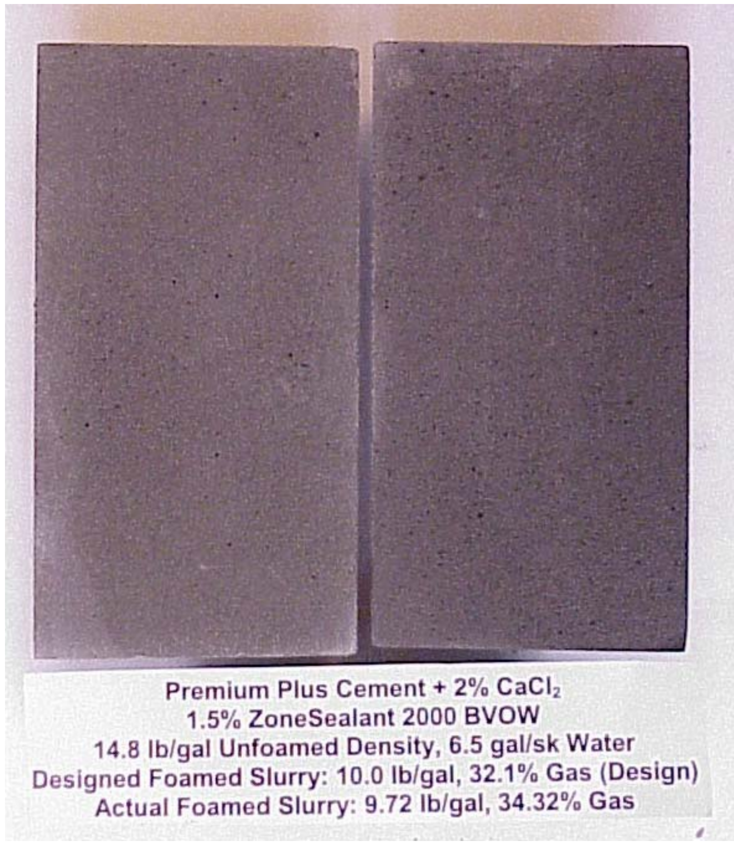


Figure 5 – Photo of Foamed Cement

Figure 6 - Photo of Foam Slurry Mixed for 30% Gas on API Testing For Foamed Slurries