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Pressure Activated Sealants-Non-Rig Solutions in Mature Fields in Alaska

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Abstract

Pressure-activated sealants are used to repair small surface and downhole leaks and have been successful remediating many instances of small pressure anomallies in mature Alaska fields since 1999. The sealants are unique in that the pressure drop through the leak site causes the sealant to polymerize into a flexible solid. Only at this point of differential pressure will the sealant polymerization process occur. As the reaction proceeds, polymerized sealant forms at the edges of the leak site and simultaneously links together to form a flexible bond across the leak site. The remainder of the sealant in the system remains liquid.

This paper discusses the history, implementation, and success rate of pressure activated sealants in Alaska including successful deployment methods used to repair small production casing leaks in naturally flowing wells and injectors. The advantage sealant repair has over a conventional RWO for casing repair is that there is no need to pull tubing, resulting in the well being returned to service faster. Typical sealant procedure costs are less than 5% of the costs for production casing repair with a rig workover (RWO). Pressure activated sealants are particularly attractive in areas where RWO cost is high, such as subsea, offshore, remote, or arctic locations.

Results will be presented from a study of jobs performed in Alaska from 2005 to 2012. Since 2005, Alaska has performed 56 of BP's 102 worldwide treatments with a 77% success rate to repair wellhead packoffs, casing, bradenheads, tubing, cement microannuli (Table 1).

Introduction

BP operates 13 producing oilfields on the North Slope which account for approximately two thirds of Alaska's oil production, and owns a significant interest in six other producing fields. As with other mature fields, aging tubulars can lead to pressure anomalies which must be addressed. Anomalies, such as annulus repressurization, are an indication that mechanical integrity may have become compromised. One method of remediating anomalies is the use of pressure-activated sealants.

Pressure-activated sealant technology was developed in 1995 to seal leaks in surface controlled subsurface safety valves and hydraulic control lines. The technology has expanded to encompass many applications including repairing surface leaks. These chemicals, which initially are in a liquid form, polymerize and harden when pumped across a leak to seal it (Figure 1). The sealant only polymerizes at the point of differential pressure created by the pressure drop across the leak site. As the reaction proceeds, the hardened sealant plates-out on the leak's edges, resulting in a flexible plug. The seal is good to the pressure used for activation in the original direction of application. The sealants have been tested to 22,000 psi and 500 degrees F. Both oil-based and water-based pressure activated sealants are employed, depending on the fluids in the system and temperature and pressure conditions.

The engineered sealants have been used worldwide to repair small leaks, including surface leaks (pipeline pinholes, weld defects, flange connections, and ball valves), wellhead leaks (ring gaskets, gate valves and actuators, pack-offs, bradenheads, tubing and casing hangers), downhole leaks (surface-controlled subsurface valves, control lines, chemical injection mandrels, fiber optic control lines on distributed temperature completions, pressure and temperature gauge mandrels, sliding sleeves, seal units and packers, tubing and casing leaks, casing liner hangers, and tieback assemblies) and cement leaks (including microannulus, abandonment cement plugs, and cavern casing shoes). The sealants have also been used in subsea remediation including pipeline ball valves, swivels and misalignment flanges, umbilicals and manifolds, riser choke and kill lines, subsea connectors, subsea trees and wellheads, gate valves and actuators, choke bodies, and tubing and other downhole leaks. According to the vendor, the success rate for 2000 jobs performed to date is 84%.

Because the pressure activated sealant remains liquid except in the presence of differential pressure, there are many ways it can be placed at the leak site. It typically doesn't matter how long it takes to deliver the sealant to the leak site because it will not harden until exposed to differential pressure. The pressure and temperature (below 500 degrees F) of the well is also not critical to the success of the procedure. The sealant is easily removed by mechanical means and does not add difficulty to future workover operations. Common sealant delivery methods include pumping down control lines, tubing, and casing. For subsea applications, the sealants have been pumped down subsea umbilicals, service umbilicals, through remotely operated vehicles through hot-stab, or from a subsea injection cylinder.

Wellhead Packoff Repairs

Wellhead packoff repairs are the most common type of pressure activated sealant procedures in Alaska, accounting for 32 of 56 sealant jobs completed since 2005. Wells that exhibit indications of annulus repressurization may be a result of a leak across wellhead seals (or pack-offs) and are tested to ensure the integrity of the primary & secondary seals. Both sets of seals must be compromised in order to rule out downhole communication.

There are many manufactures and generations of wellheads in Alaska which each require specific pack-off test procedures (Figure 2). Pack-off testing on all wellheads, especially those with internal check valves, must be conducted using caution and procedures must be strictly adhered to. In the past, some wellheads have been treated with various compounds and materials (such as WKM, Chemola, or Furmanite sealants) which are pumped into the test voids to try to obtain a seal. These products can result in the sealant material plugging the test ports leading to trapped pressure within the void presenting a safety hazard. Pressuring the void area may give a false positive pack-off test if the void has been packed with compounds in the past. Competent barriers are verified before opening wellhead fittings, and field crews must be trained and aware of trapped pressure potential in wellhead components. Fittings such as lock down screws have been known to eject from the wellhead, and check valve fittings can plug off and fail.

Testing consists of rigging up a high pressure bleed tool and pack-off test manifold to the wellhead void test ports. Typically in Alaska, tubing hanger pack-off test voids are pressured to 5000 psi, inner casing hanger voids to 3500 psi, and outer casing hanger voids to 2000 psi. The pack-off pressure test is monitored for 15 minutes, re-pressuring the pack-off test void if necessary. The pack-off test void is then tested for 30 minutes. The pack-off test is successful if the pressure declines less than 10% in 30 minutes and exhibits pressure stabilization. If the pressure bleeds off more than 10% in 30 minutes, the pressure is bled from the pack-off test void and the lock down screws (LDS) are tightened to a specified torque. The LDS may need to be tightened more than one time to achieve a passing test. On some wellheads it can be necessary to re-energize the secondary seals with plastic packing.

If a passing packoff test cannot be achieved, on the tubing, inner casing or outer casing void, an approximate liquid leak rate is determined and used to design the sealant application plan. The wellhead configuration is reviewed for internal packoff assembly, hanger, and wellhead type and a leak path evaluation is performed to determine if both sets of packoff seals are leaking. If one set is holding, then the communication is not through the wellhead, but downhole instead. Communication across wellhead seals can be temperature dependent. The treatment may be altered depending on how the well communicates when it is on-line or shut in. After reviewing pressure data plotted with production or injection data it may be apparent that the liquid leak rate is higher when the well is in service. In this case, leak rate diagnostics are performed with the well online and heated up.

Wellhead Repair Procedure

To begin the repair, the well is secured and if the secondary seals have been re-energized with plastic packing, this void is flushed to remove as much residual plastic as possible. Thorough cleaning of the void and removal of past repair attempts improves the chances of success. If the well has a history of having plastic packing injected into the pack-off test void, each of the LDS's will be pulled, the plastic removed, and LDS re-run per a specified procedure. Heaters and diesel or solvent soaks can help to remove solvent.

A and B annulus pressures are bled to 0 psi for an inner casing pack-off treatment and tubing and "A" annulus pressures are bled to 0 psi for a tubing pack-off treatment. The wellhead technician stings into the appropriate pack-off test void and pressure is bleed to 0 psi. The pack-off test void Alemite fittings are replaced with ¼ turn ball valves rated for 5000 psi. A pump is rigged up to the pack-off test void and after pressure testing surface equipment, a leak rate is obtained to determine the optimum sealant type.

After the packoff test void has been flushed with hydraulic oil or diesel, the sealant is injected, increasing pressure in increments until the maximum required test pressure is achieved. A well specific procedure, provided by the sealant engineer, outlines the time and maximum pressure of each cycle. The sealant is typically allowed to cure 15 minutes at each pressure increment. Typical maximum treatment pressure is 3500 psi for the inner casing packoff and 5000 psi for the tubing packoff. After a seal is achieved and has cured, the test pressure is cycled multiple times to pack the sealant. Once the specified days of curing have passed, the well is placed back in service and pack-off void pressures are monitored daily to verify effectiveness of the repair. The well is re-treated if necessary. Repair may require various selants injected over the course of several days.

Packoff Repair Results

The first wellhead repair was performed in 1999 in Alaska and since then at least 32 procedures have been performed with 28 succcesses and 4 failures, or an 88% success rate. Eight procedures were performed in 2012. Some wells have required multiple applications, with one well requiring five procedures. This is probably due to the fact that the elastomeric material in pack-offs continues to break down as it ages, requiring further treatment. A recent review showed that economic payouts ranged from one to eighteen days.

Production Casing Repairs

Small production casing leaks pose industry challenges and may require expensive rig-workovers to repair. If shallow, these leaks manifest as sustained casing pressure or "A" to "B" annulus communication. Until the development of the ultrasonic leak detection logging tool, accurately identifying small casing leak detection was difficult, if not impossible, with tubing in the well. This log has proven very successful at detecting casing leaks less than 1 gal/min while logging down the tubing (J.E. Johns 2006 and J.Y. Julian 2007). This technique is far superior to other methods including noise logs and distributed temperature surveys. Since 2005, BP has run 231 ultrasonic logs in Alaska with an 81% success rate.

With behind-tubing leak locations precisely indentified, pressure-activated sealants can be used to repair casing without removing the tubing. Alaska’s first casing repair in 2008 was on an injector with a small 5 cup/minute production casing leak. After identifying the leak, the well’s tubing and annulus were circulated with brine. Then sealant was circulated into the annulus and displaced to the leak with diesel. This allowed the sealant to “float” on the brine across from the leak. Then the tubing and casing were pressured up, while the sealant cured. Eighteen hours later, the leak was sealed and the well was returned to service. SPE paper 108195 discusses these repairs. The technique was expanded to producers, and the successful repair of two producing wells with casing leaks is presented in SPE paper 120978. One well had four casing leaks repaired with one sealant treatment.

To date, seventeen wells have been treated with five failures for a 71% success rate. Some wells didn't have a path to circulate sealant into the “A” annulus, so the tubing was punched and straddles with sliding sleeves or gaslift mandrels were run so the sealant could be spotted across the leak. Of the five failures, one job failed due to the presence of a second leak, and another well is currently under reevaluation.

One of the failures was on a well that was gaslifted. As long as the sealant pill remains across the leak site as is the case in injectors and naturally flowing producers, the procedure is typically successful. To date, the success has not been able to be duplicated on gaslifted wells in Alaska, and work is ongoing. Misting treatments are currently planned. Misting technologies have been deployed to repair BP’s Saskatchewan Ethane Storage Cavern-108’s multiple casing leaks in 2010.

Bradenhead Repairs

Bradenhead repairs are conducted to repair very small thread leaks between the surface casing and the lower casing head (or bradenhead). The procedure involves first conducting leak rate tests and annular fluid verification and conditioning operations. A sealant pill is pumped and “squeezed” into the leak. After curing for a mimum of 8 to 12 hours and up to three days, the well is placed online and the “B” annulus pressure is bled. Adequate casing shoe integrity is necessary to allow sealant to be forced through the leak. It has been shown that annular fluid weight is critical to job success. A back-up procedure or plan should be prepared for possible shoe breakdown during the job. Some of the logistical challenges have been that the volume of sealant needed requires mixing and pumping from outside Alaska’s wellhouses, which can be challenging in artic weather conditions. Typical tri-plex pumps do not handle sealant well. The first procedure was performed in 11/18/2007 and to date six procedures have been performed with two failures for an overall 67% technical success rate.

Microannulus Repairs

Although pressure activated sealants have successfully been used to repair cement microannulus (one procedure performed in 2002 was still successful after 8 years), this same success has eluded repair of Alaskan wells. Two jobs have been attempted with no success. Work is ongoing to repeat the success the vendor has had in other areas.

Conclusions

The high success rate of the pressure activated program has increased confidence in production operations in Alaska. The following observations have been made:

1. Alaska's 77% success rates for 56 procedures completed between 2005-2012 are in line with the vendor's published success rate of 80% for 20000 procedures performed worldwide.
2. Wellhead packoff work compromises the majority of procedures, however, the development of the ultrasonic leak detection tool has increased the number of opportunities for sealant repair.
3. The ultrasonic leak detection log is essential for pressure activated sealant casing repairs since the ultrasonic log can pinpoint the depth of a small casing leak without removing the tubing.
4. Pressure activated sealants can remediate small downhole leaks at a tremendous cost savings in areas where rig workover cost is significant.
5. Typical payout is usually less one month and often just a few days.
6. Pressure activated sealant has significant potential for repairing subsea wells. In the future, high value wells may benefit by having initial completions designed to allow spotting of sealants in annuli, i.e. capillary tubes.

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Figures and Tables.

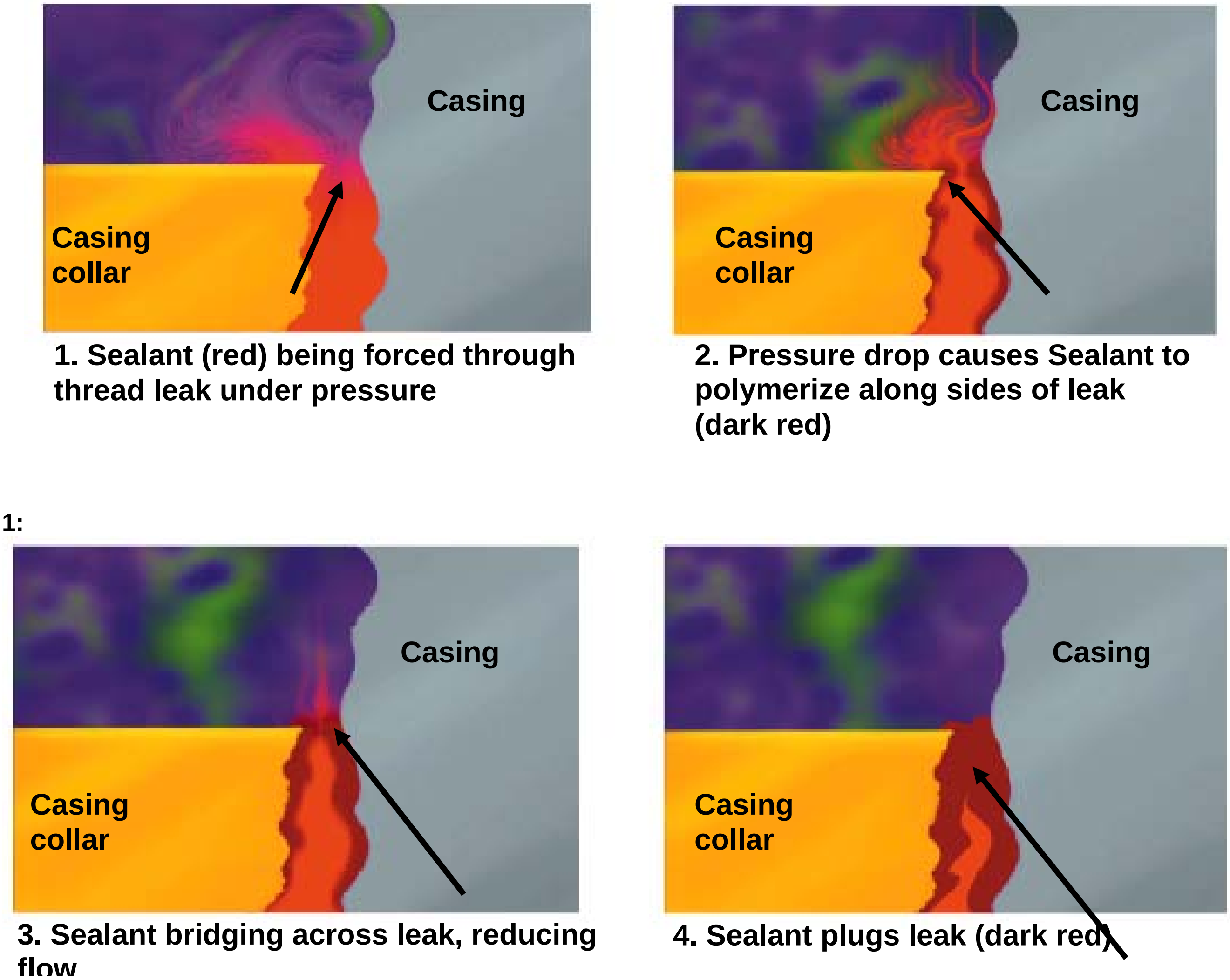

Figure 1. Mechanism of pressure activated sealant

Table 1: Sealant Repair type and success

Repair Type	Total	Failures	Successes	% Successful
Wellhead	32	4	28	88%
Production Casing	13	3	10	77%
Bradenhead	6	2	4	67%
Cement Microannulus	2	2	0	0%
Tubing	2	1	1	50%
Surface Casing	1	1	0	0%
Total	56	13	43	77%

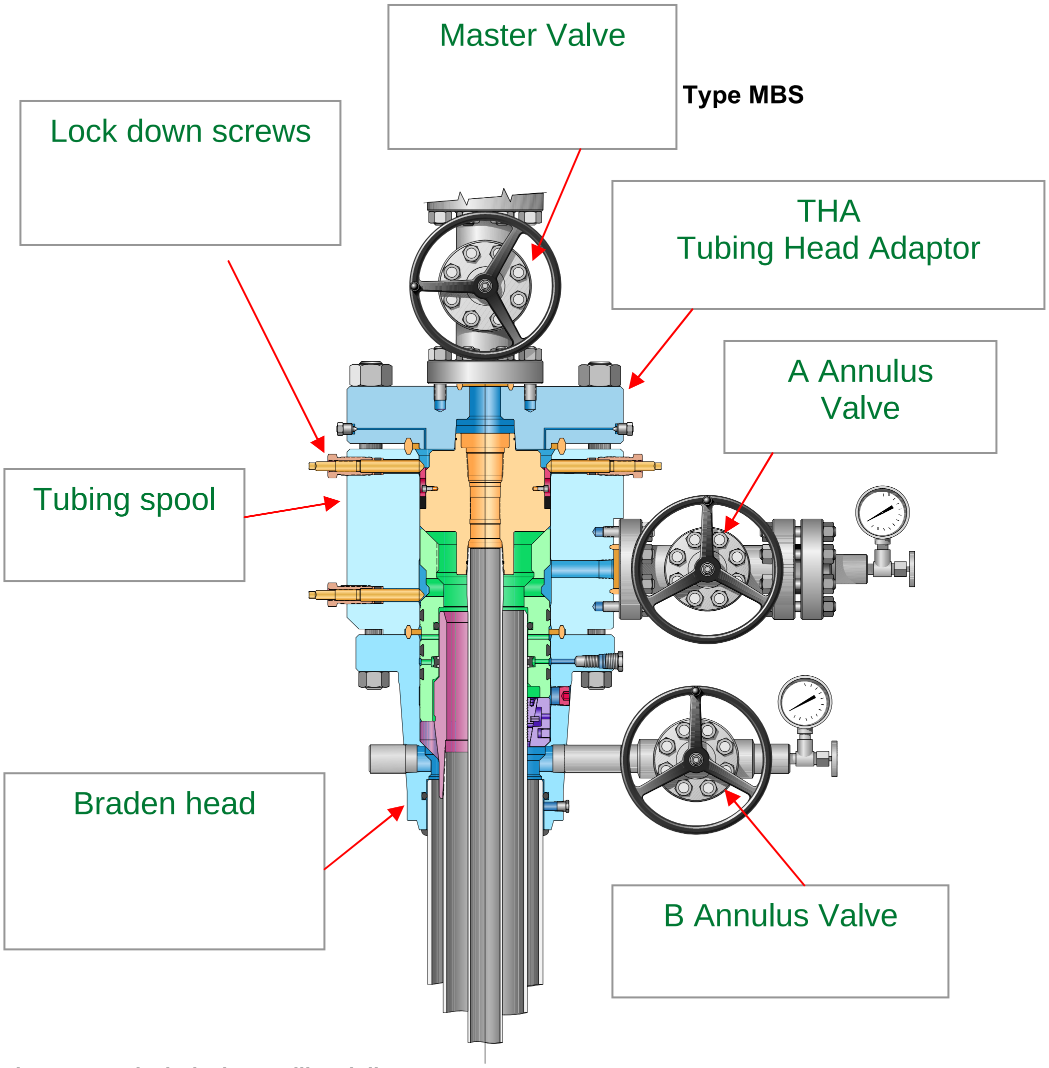

Figure 2 Typical Alaskan wellhead diagram.