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Pressure Activated Sealant Economically Repairs Casing Leaks on Prudhoe Bay Wells

R. W. Chivvis* and J. Y. Julian*, BP, Inc.; D.N. Cary, Seal-Tite International *SPE Members

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Abstract

A pressure-activated sealant was used to repair casing leaks in two Prudhoe Bay, Alaska oil wells without the use of rig workover. The results of the treatments, job screening criteria, significance of the treatments, and job procedures are reviewed.

Production casing leaks are a frequent problem in mature oil fields, particularly where there is corrosion. Wells with leaking casing usually do not meet well operating criteria so they must be shut-in, losing valuable production. Production casing leaks normally require a rig workover to repair since the tubing has to be removed. Rig workovers are very expensive in offshore locations, remote areas, or harsh climates. Special pressure-activated sealants, diagnostic tools, and treatment techniques have been developed to find and repair casing leaks without removing the tubing.

Case studies of three Prudhoe Bay production wells describe how pressure-activated sealant successfully repaired the casing leaks in two of the wells without removing the tubing. The third well was not treated because it did not meet the screening criteria. One case study was unusual because the sealant fixed four deep casing leaks in one treatment.

The case studies show how refinements in diagnostic techniques, candidate selection, treatment procedures, and the sealant formulation have extended the successful applicability of this treatment to repairing casing leaks in producing wells. Using pressure-activated sealant to repair casing leaks can result in significant cost savings and return wells to production sooner. The treatment can be particularly useful in mature fields with corrosion problems and in offshore, remote, and arctic fields where rig workovers are expensive and rig availability is limited.

Introduction

Repairing casing leaks is one of the more challenging issues facing operators of mature oil and gas fields. Casing leaks are a frequent problem in mature oil fields, particularly where there is corrosion. Wells with leaking casing usually do not meet well operating criteria so they must be shut-in, deferring and possibly losing valuable production. Casing leaks normally require a rig workover to repair since the tubing has to be removed. Rig workovers are very expensive and are often time consuming in offshore locations, remote areas, or harsh climates. Also, the repair usually requires cement or other solidifying material pumped into the “A” annulus. This can make future workovers and other well operations difficult and impractical.

Pressure activated sealant can repair casing leaks without removing the tubing or having an expensive rig workover. These sealants have been used to repair casing leaks in injection wells with the tubing in place (J.E. Johns 2007). This is the first time pressure activated sealant had been used to repair a casing leak on a producing well on the North Slope of Alaska. An advantage of the pressure activated sealant is that it will only solidify across a pressure drop so the excess sealant can be circulated out or left in the well. In addition, the sealant is easily removed by mechanical means and will not add difficulty to future workover operations.

The Prudhoe Bay Field is located on the North Slope of Alaska. It is a mature, enhanced oil recovery/waterflooded oil field with 1,400 wells. The majority of wells were completed with 9 5/8" L-80 carbon-steel casing which is subject to corrosion from well and formation fluids. When integrity problems with the casing arise, they have traditionally been repaired with a rig workover (RWO) since the tubing needs to be pulled to repair the casing. With RWO's costing over $3 million to repair casing, significant cost savings can be achieved by developing a pressure activated sealant repair method that does not require pulling the tubing. Three case studies are presented of producing wells in the Prudhoe Bay Field with casing leaks that were considered for pressure activated sealant repair. Two wells were successfully repaired using this sealant, while the third did not meet the criteria for the sealant treatment.

What is Pressure Activated Sealant?

Pressure activated sealant is unique in that a differential pressure causes the liquid sealant to polymerize into a flexible solid which can plug a leak. These sealants have been used successfully to repair a variety of oilfield, process, and construction equipment. The liquid sealant only polymerizes at the point of differential pressure which can be created by a pressure drop through a leak. As the polymerization reaction proceeds, the hardened sealant plates-out on edges of the leak to gradually seal it off (See Figure 1). The resulting seal is a flexible plug across the leak site. Both oil-based and water-based sealants are employed depending on the fluids in the system and the temperature and pressure conditions. By adjusting the specific gravity and viscosity of the sealant, a procedure is developed to place the sealant exactly at the leak site. Once positioned, the pressure differential across the leak can be manipulated to activate the sealant to solidify and plug the leak. Excess sealant that is not exposed to the pressure differential will remain in the fluid state. It can be left in the well or flushed from the well if desired.

What is the Procedure for Repairing Casing with Pressure Activated Sealant?

A complete understanding of the leak source, well conditions, and well equipment is critical when planning a pressure activated sealant repair. This is especially true when dealing with a casing leak behind tubing. Detection of casing leaks is difficult with tubing in the well. Often a temperature or noise log will not be able to find the leak. An ultrasonic log may be the only way to find the leak depth. The leak rate, leak location, and well conditions must be known to formulate the sealant and prepare the placement procedure. This understanding of the leak and well conditions increases the probability of success and reduces the overall repair cost.

The casing repair procedure using pressure activated sealant has three main steps. First, the size and depth of the casing leak must be determined. Then the well must be screened for using pressure activated sealant repair using several criteria. Finally, a procedure must be prepared and executed to precisely place the sealant across the leak site, force it into the leak, and activate the sealant to plug the leak. These steps are described in more detail below.

1. Determine the size and depth of the casing leak
    a. Measure liquid leak rate through the casing leak and the pressure required by pumping down the "A" annulus.
    b. Determine the depth of the leak using a leak detection log. Finding a casing leak is difficult with tubing in the well and can be nearly impossible if the liquid leak rate is low. If the liquid leak rate is less than 1 gal/min, a temperature or noise log would have a very low probability of success of finding the leak. For low rate leaks the ultrasonic leak detection log is recommended. 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).
2. Screen the well to determine if it is a good candidate for repair with pressure activated sealant. Six criteria had been established from prior experience. If the well meets these criteria then the repair has a high probability of success. The criteria are:
    a. The exact location of the leak must be known. The location is needed so the sealant can be formulated for the pressure and temperature at the leak, displaced to the leak with minimum dilution of the sealant, and to minimize the amount of sealant needed.
    b. The leak rate must be in the success range of pressure activated sealants, which have an upper limit due to the mechanics of pressure activated sealant and the sealant volumes and pump rate required. However, there must be some measured leak rate or the sealant will not go into the leak. Previous job histories provide an approximate lower and upper leak rate range for project guidance. Casing collar leaks have a much higher chance of long term success due to the high surface area and low cross sectional area (J.E. Johns 2007). Also, the sealant is custom blended for each repair so the liquid leak rate and pressure are important to ensure that the sealant viscosity, weight, and polymerization are formulated to optimize results.

   c. There must be a way to circulate the sealant and other fluids down the “A” annulus to below the leak depth. This would require a gas lift mandrel (GLM) or some other opening between the tubing and the “A” annulus below the leak depth. This is needed for several reasons.
      i. The existing lighter fluids must be cleared out of the “A” annulus by circulation and replaced with a heavy brine. If this is not done, the heavy sealant will swap out with the lighter fluids in the “A” annulus causing a loss of depth control of the sealant slug and dilution of the sealant. Also, the repair procedure must consider any fluids in the “A” annulus below the circulation point but above the packer to allow for accurate depth control of the sealant slug.
      ii. There must be a way to circulate the sealant slug to the leak depth. Bullheading the sealant into the “A” annulus is not feasible for two reasons. The liquid leak rate can be small so it would take a long time to get the sealant to the leak depth and the time lapse would allow the sealant to be diluted by other fluids in the “A” annulus.
      iii. The fluids in the “A” annulus and tubing must be known for depth control of the sealant slug. Different fluids have different compressibilities which can be a significant factor in positioning the sealant slug precisely at the leak.
   d. The well equipment must be rated for the pressures expected in the procedure. The pressure rating of the tubing plug and packer should especially be verified.
   e. The must not be any other “thief” leaks in the system during the sealant squeeze operation. Thief leaks may not allow the proper squeeze pressure to be attained or may upset the depth control of the sealant slug.
   f. A positive pressure differential from the “A” annulus must be maintained on the sealant plug after the well has returned to operation. If a positive pressure differential is not maintained on the sealant plug there is a greater chance the leak could reopen if the plug is forced back out of the leak. The pressure on each side of the sealant plug during normal well operation should be calculated to verify a positive pressure differential on the plug. If the “A” annulus is filled with liquid, the density of the liquid and the surface pressure can be adjusted to provide a positive pressure differential across the plug. If the well is gaslifted, the lighter gradient of the gas in the “A” annulus combined with the normal gaslift operating pressure should be calculated to verify there is a positive pressure differential on the sealant plug. If the leak is deep, a gaslifted well may not be able to maintain a positive pressure differential at the leak due to the lighter gas gradient.
3. Place the sealant across the leak, force it into the leak, activate the sealant, and plug the leak.
   a. Prepare the well to circulate fluids in the “A” annulus below the leak. Normally that would require pulling the lowest gas lift valve and setting a plug in the tubing.
   b. Circulate the “A” annulus and tubing with heavy weight brine to displace lighter fluids.
   c. Float a sealant pill on brine and displace it down the “A” annulus to the leak site using a lighter fluid such as diesel.
   d. “Squeeze” the sealant into the leak so the pressure drop in the leak will activate the sealant and cause it to plug the leak.
   e. Hold pressure on the sealant to allow it to cure for 3 days.
   f. Place the well online and maintain a positive pressure differential on the leak from the “A” annulus.

Does it Work? Case Histories – North Slope, Alaska

Three case histories are presented of Prudhoe Bay Field wells considered for pressure activated sealant repair of a casing leak. There were two wells where the pressure activated sealant was successful in repairing casing leaks behind tubing. Both wells were producing wells and were repaired without removing the tubing. A pressure activated sealant repair was not done on the casing leak in the third well because it did not meet the screening criteria for a successful repair.

<u>Producing Well #1 with a Casing leak behind Tubing</u>

Well #1 is a natural flowing producer that had four leaks between 7303’ and 7610’ MD in the 9 5/8” 47# L-80 casing (Figure 2). This well has a tapered 5 ½”x 4 ½” tubing string inside the casing. The first indication of the casing leak was high “A” annulus pressure. The “A” annulus failed a mechanical integrity test (MIT) and the well was shut-in. The Mechanical Integrity Test (MIT) test results indicated a production casing or packer leak.

The size, depth, and location of the leak were needed to evaluate repair options and screen the well for a pressure activated sealant repair. A liquid leak rate of 0.5 gal/min was established by pumping down the “A” annulus at 3000 psi for 90 minutes while monitoring the tubing and “B” annulus pressure. The ultrasonic logging tool was run in the tubing while pumping 0.5 gal/min down the “A” annulus. The ultrasonic log found four small leaks in the 9 5/8” production casing between 7303’ and 7610’ (Figure 3). The ultrasonic log was used because well had a low liquid leak rate and the leak was behind tubing.

This well was screened according to six criteria to see if pressure activated sealant would have a high probability of success. The well met all the screening criteria:

1. The depth of the leak was known.
2. The liquid leak rate was low, below 1 gal/min.
3. The well had a GLM to circulate fluids down the “A” annulus below the leak depth.
4. The well equipment was rated for the pressures expected in the procedure.
5. There were not any “thief” leaks in the system.
6. A positive pressure differential could be maintained on the sealant plug when the well was returned to service.

A procedure was prepared using the well and leak information and the repair process was started. The valve was pulled from the lowest GLM. A wire-line retrievable plug was set in the tubing just below the lowest GLM. Brine that was 0.4 ppg heavier than the sealant was pumped down the tubing and back up the “A” annulus until both were completed filled with brine. Seven barrels of sealant were pumped down the “A” annulus and displaced with diesel. The sealant was carefully displaced down the “A” annulus to the top leak after allowing for the compression of fluids above and below the sealant. The tubing was closed and the “A” annulus pressured up to 3000 psi to force the sealant into the leak and activate the sealant with the pressure drop through the leak. The “A” annulus pressure was maintained at 3000 psi by bumping up the pressure as required when it slowly leaked off. After 12 hours at one leak depth, the sealant slug was displaced to the next lower depth by bleeding off tubing pressure and pumping diesel down the “A” annulus. This process continued until all four leaks were sealed. Then the “A” annulus pressure was reduced to 1500 psi and held for 3 days to allow the sealant to cure. The well passed a mechanical integrity test of the “A” annulus to 3000 psi and was returned to production.

<u>Producing Well #2 with a Casing leak behind Tubing</u>

Well #2 is a natural flowing producer that had a leak at 70’ MD in the 9 5/8” 47# L-80 production casing (Figure 4). The well has a 4 ½” tubing inside the casing. The first indication of a casing leak was the “A” annulus pressure tracking the “B” annulus pressure. The “A” annulus subsequently failed a MIT which indicated a casing leak.

The size, depth, and location of the leak was needed to evaluate repair options and screen the well for a pressure activated sealant repair. A liquid leak rate of 2 gal/min at 1500 psi was calculated from the MIT. An ultrasonic leak detection log was run and found the casing leak at 70’ MD (Figure 5) and measured the leak rate of 1 gal/min over 3 hours. The ultrasonic log was used because the well had a low liquid leak rate and the leak was behind tubing.

This well was screened according to the criteria to see if pressure activated sealant would have a high probability of success. The well met all the criteria:

1. The depth of the leak was known.
2. The liquid leak rate was low, below 1 gal/min.
3. The well had a GLM to circulate fluids down the “A” annulus below the leak depth
4. The well equipment was rated for the pressures expected in the procedure.
5. There were not any “thief” leaks in the system.
6. A positive pressure differential could be maintained on the sealant plug when the well was returned to service.

The casing repair on this well used a similar procedure as the previous example. A plug was set in the tubing tail and a circulation valve was set in the bottom gaslift mandrel. Brine that was 0.4 ppg heavier than the sealant was pumped down the tubing and back up the “A” annulus until both were completed filled with brine. Two barrels of 9.2 ppg sealant were displaced down the “A” annulus to the leak depth with diesel. The “A” annulus was pressured to 1000 psi to force the sealant into the leak. The “B” annulus pressure was bled down and monitored. Once there was no increase in the “B” annulus pressure, the “A” annulus pressure was increased to 2500 psi and held for three days to cure the sealant plug. The “A” annulus passed a mechanical integrity test to 3000 psi and the well was put back on production.

<u>Producing Well #3 with a Casing leak behind Tubing</u>

Well #3 is a gas lifted producer that had a leak at 9974’ MD in the 9 5/8” 47# L-80 production casing (Figure 6). The well has a 4 ½” tubing inside the casing. The first indication of the casing leak was high “A” annulus pressure.

The “A” annulus failed a mechanical integrity test (MIT) and the well was shut-in. The MIT test results indicated a production casing or packer leak.

The size, depth, and location of the leak were needed to evaluate repair options and screen the well for a pressure activated sealant repair. A liquid leak rate of about 1 gal/min at 3000 psi was calculated from the MIT. An ultrasonic leak detection log was run and found the casing leak at 9974’ MD (Figure 7) and measured the leak rate of 0.36 gal/min at 3000 psi. The ultrasonic log was used because the well had a low liquid leak rate and the leak was behind tubing.

This well was screened according to the criteria to see if pressure activated sealant would have a high probability of success. The well met all the criteria except the last one:

1. The depth of the leak was known.
2. The liquid leak rate was low, below 1 gal/min.
3. The well had a GLM to circulate fluids down the “A” annulus below the leak depth
4. The well equipment was rated for the pressures expected in the procedure.
5. There were not any “thief” leaks in the system.
6. A positive pressure differential could not be maintained on the sealant plug when the well was returned to service. This well normally operates on gaslift. The pressure in the “A” annulus at the leak was calculated using the hydrostatic head of the gaslift gas and the normal surface operating pressure of the gaslift. This pressure was less than the pressure expected on the other side of the leak. Without being able to maintain a positive pressure differential on the sealant plug there was a low probability of success.

The pressure activated sealant treatment was not performed on this well since it did not satisfy all of the screening criteria.

Conclusions

1. Pressure activated sealant is a cost effective method for repairing casing leaks without pulling the tubing. The treatment can be particularly useful in mature fields with corrosion problems and in offshore, remote, and arctic fields where rig workovers are expensive and rig availability is limited. Using pressure-activated sealant to repair casing leaks can result in significant cost savings and return wells to production sooner.
2. The successful use of pressure activated sealant for casing repair has been extended from injection wells to natural flowing producing wells on the North Slope of Alaska. It can also be used on gaslifted producing wells provided a positive pressure differential is maintained on the sealant plug during normal well operation.
3. The pressure activated sealant successfully fixed four deep casing leaks in one treatment as a result of precisely knowing leak depths and well conditions and executing a well planned procedure.
4. Candidate screening is critical to the success of the pressure activated sealant repair.
    a. The leak depth must be known so the sealant can be placed at the leak site. Leak depth is also needed for sealant pill and displacement volumes.
    b. The leak rate must be in the success range of pressure activated sealants, which have an upper limit governed by the ability to generate sufficient pressure drop and cell bonding across the width of the leak. . Also the leak rate and pressure are needed to determine sealant chemistry and squeeze procedure.
    c. An opening between the tubing and the “A” annulus below the depth of the leak is needed to displace brine and sealant down “A” annulus.
    d. Maintaining a positive pressure differential across the plugged leak increases the probability of success. This may preclude using the repair technique on gas-lifted wells with a deep leak.
5. The ultrasonic leak detection log is essential for pressure activated sealant casing repairs since it can pinpoint the depth of a small casing leak without removing the tubing.

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Nomenclature

GLM	=Gaslift Mandrel
gal/min	=Gallons Per Minute
MD	=Measured Depth
MIT	=Mechanical Integrity Test
ppg	=Pounds (w) per gallon
psi	=Pounds (f) per Square Inch
RWO	=Rig Workover

Reference List:

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2. J.E. Johns, D. N. Cary, J.C. Dethlefs, B.C. Ellis, M.L. McConnell, G.L. Schwartz; "Locating and Repairing Casing Leaks with Tubing in Place-Ultrasonic Logging and Pressure-Activated Sealant Methods" paper SPE 108195 presented at the 2007 Offshore Europe Conference held in Aberdeen, Scotland, 4-7 September 2007.
3. J.Y. Julian, G.E. King, J.E. Johns, J.K. Sack, D.B. Robertson; "Detecting Ultra-small Leaks With Ultrasonic Leak Detection-Case Histories from the North Slope, Alaska" paper SPE 108906 presented at the 2007 International Oil Conference and Exhibition held in Veracruz, Mexico, 27-30 June 2007.

Figures:

Figure 1 How Pressure Activated Sealant Works to Plug a Thread Leak

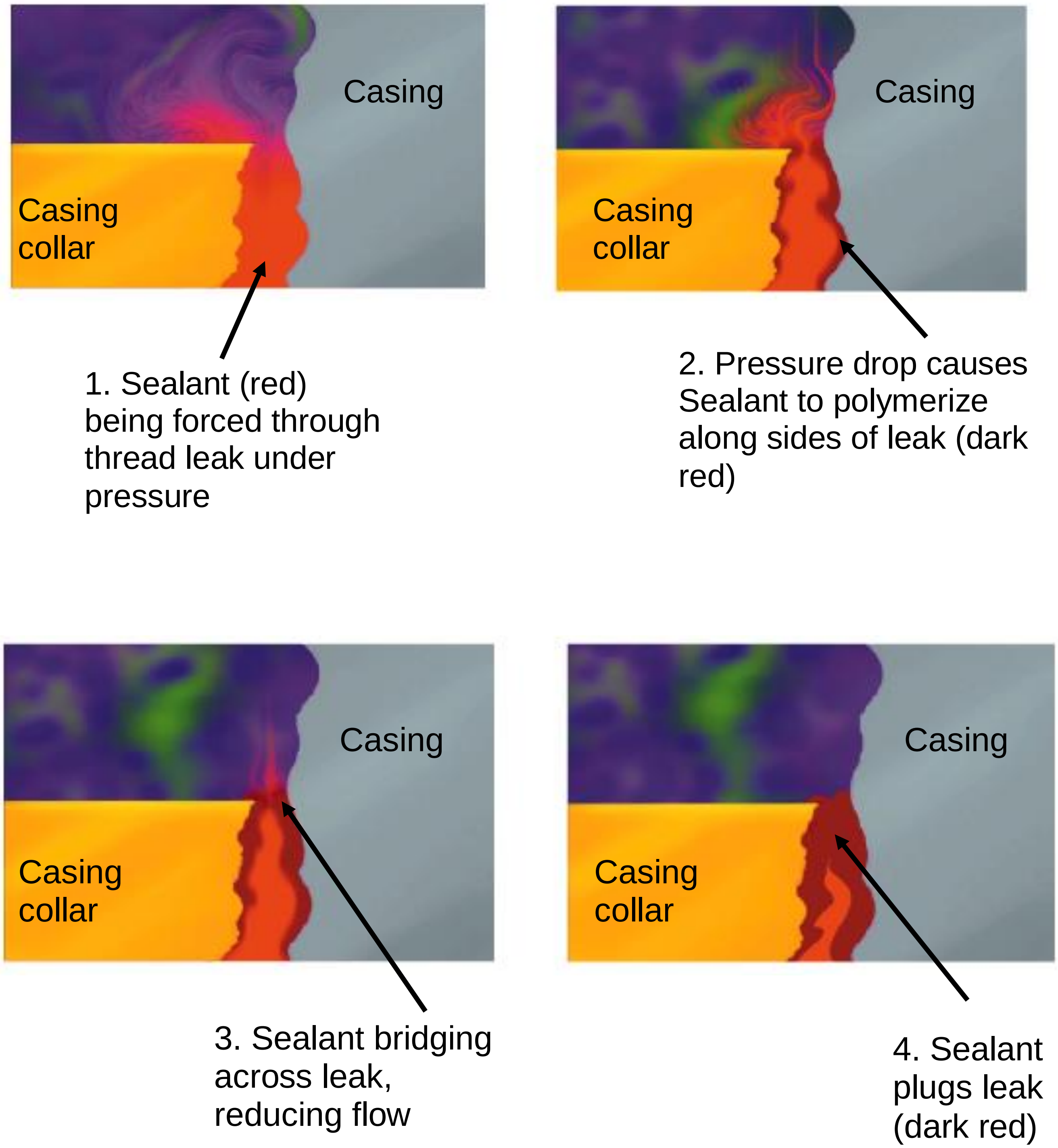


Figure 2 Wellbore Schematic of Well #1

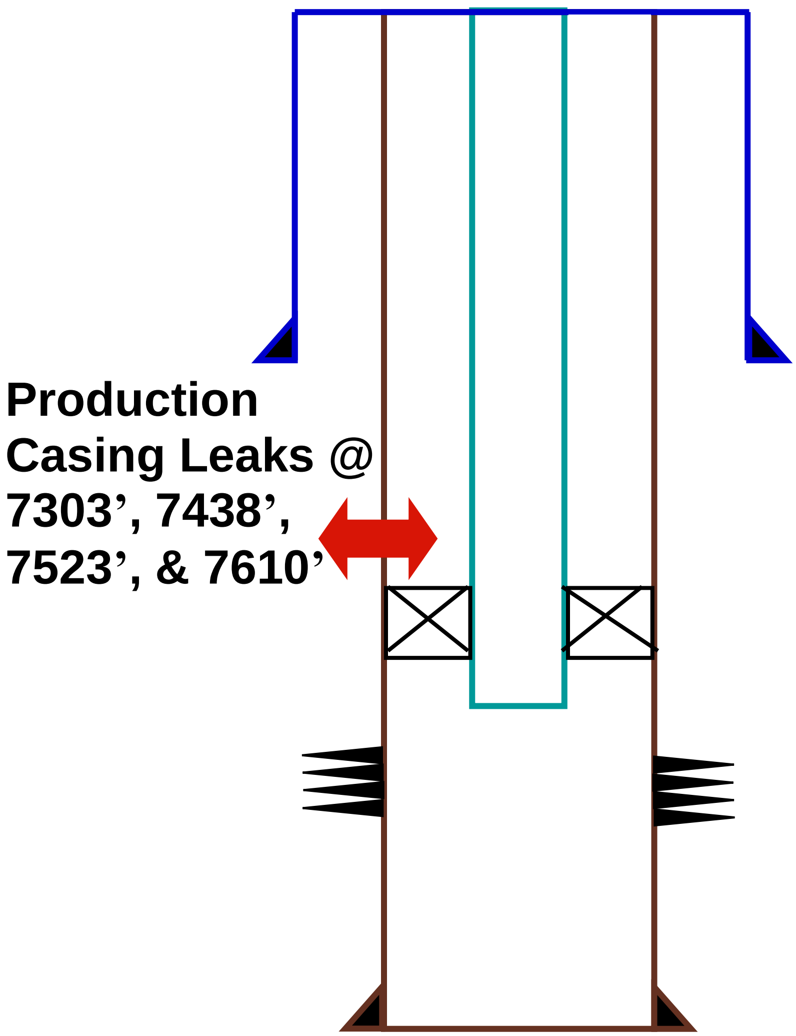
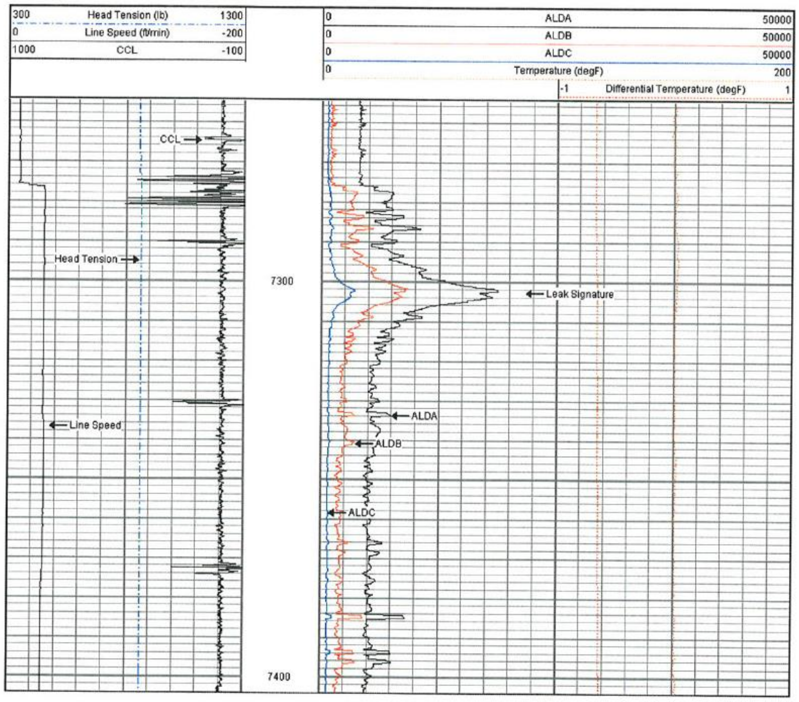


Figure 3 Ultrasonic leak detection log on Well #1

4.2 Log –Leak @ 7,303' MD



4.1 Log – Leaks @ 7,438' - 7,523' and 7,610' MD.

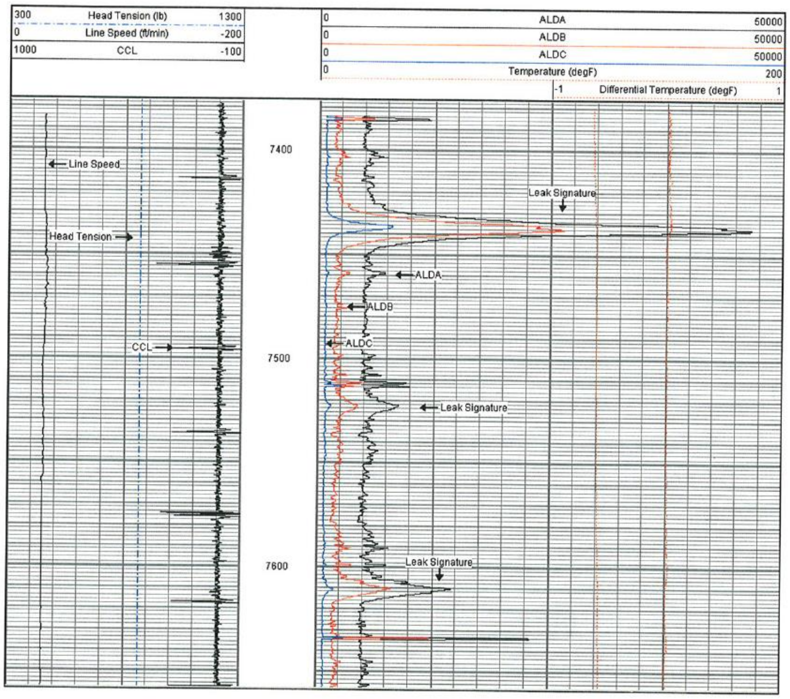


Figure 4 Wellbore Schematic of Well #2

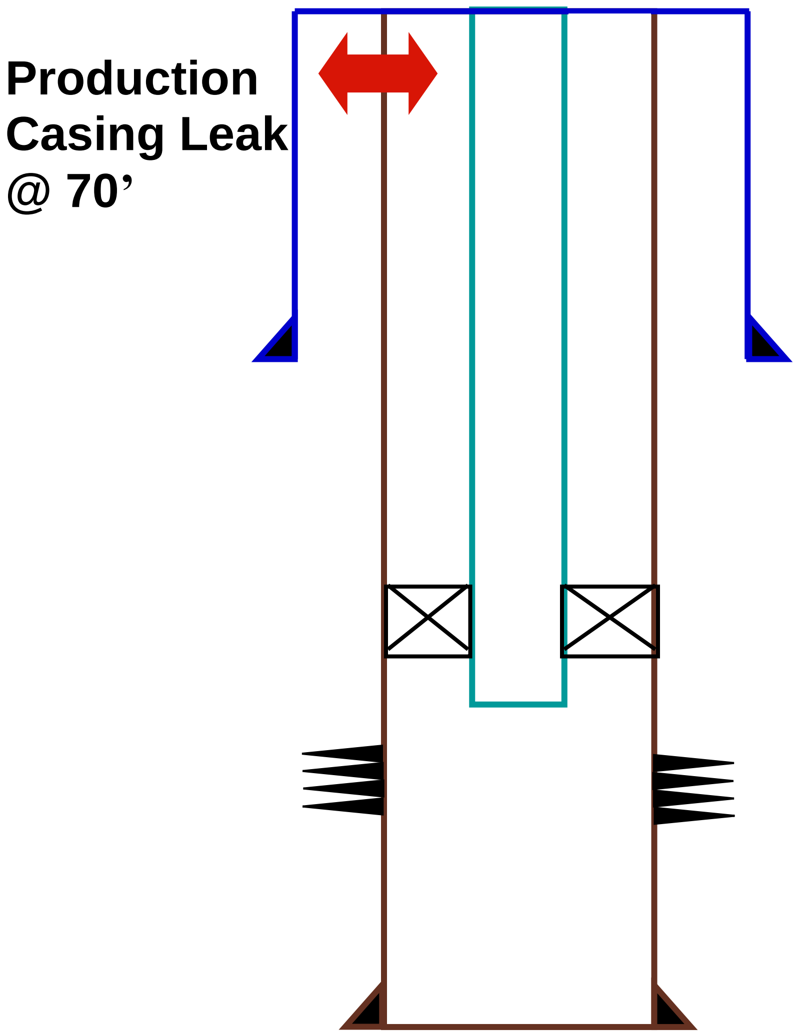


Figure 5 Ultrasonic Leak Detection Log on Well #2

4.1 Log – 9 5/8" Casing Leak @ 70' MD.

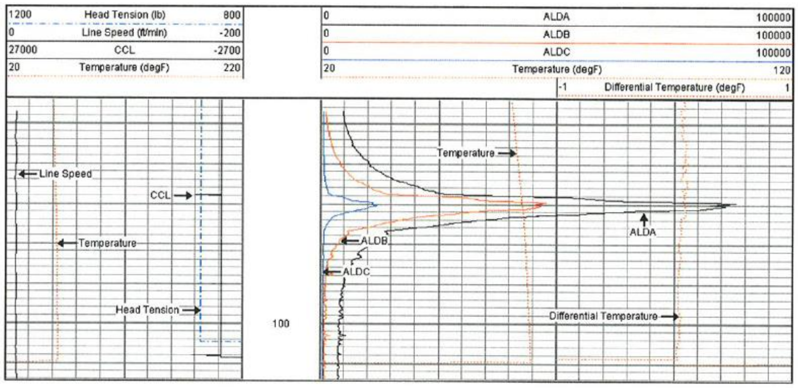


Figure 6 Wellbore Schematic of Well #3

Figure 7 Ultrasonic Leak Detection Log on Well #3