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Pressure Activated Sealant to Restore Tubing Integrity – case study of well TN-x in Mahakam

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Abstract.

Pressure activated sealant is used to repair tubing leak and restore tubing integrity without the need to install downhole devices which yield additional restriction inside tubing and reduce tubing ID.

Leak on tubing was detected in early production phase from the continuous increase of A annulus pressure. The leak point was indicated from Production Logging Tool (PLT) at 183 m suspected from tubing thread connection, with annulus pressure buildup rate 435 psi/24 hrs.

Pressure activated sealant was selected as the means to cure the leak. Retrievable plug was set below the leak point and sealant was pumped on top of plug, followed by inhibited water. Then pressure was applied at surface to squeeze and activate the sealant. The remaining fluid inside tubing remained liquid, allowing the plug to be retrieved.

A total of 59 L sealant mixture and 750 L of inhibited water was pumped to the well. Hesitation pressure was performed to activate the sealant, and got indication of chemical sealing at 1000 psi. The tubing was then pressure tested to 5000 psi and pressure was holding in 1 hour, indicating positive isolation has been established between tubing-annulus. From continuous annulus pressure monitoring, pressure in A annulus has been stable at ~40 psi for the last 8 months after sealant injection has been performed.

Pressure activated sealant is proven as a reliable method to cure small leak in tubing. Since the sealant will only be hardened inside the leaking point, there will be no additional restriction in the tubing, thus Internal Diameter (ID) reduction will not be a concern for future well intervention operations.

Pressure activated sealant could become one of the alternatives to cure tubing leaks, especially in the cases where tubing ID reduction is not favored.

Keyword: Pressure activated sealant; tubing leak; well integrity; sealant

1 Introduction

1.1 Pertamina Hulu Mahakam Overview

Pertamina Hulu Mahakam (PHM) operates in Mahakam Block which consists of 4 fields located in Offshore: Peciko, Sisi-Nubi, South Mahakam, Bekapai; and 3 fields located in Swamp: Tunu, Tambora, and Handil. Figure 1 shows illustration of fields under Pertamina Hulu Mahakam. Since its first operations in 1972, Pertamina Hulu Mahakam has drilled more than 2200 wells.

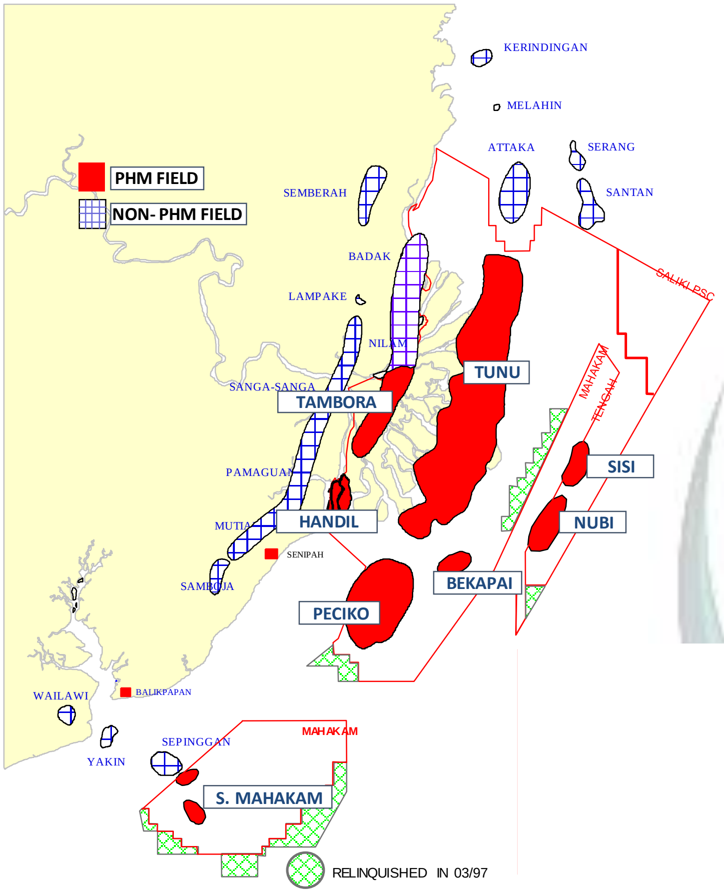

Figure 1. PHM Fields in Mahakam Block

With massive amount of wells exist, well integrity monitoring system becomes important to ensure all wells are monitored, tested, and operated within the safe working envelope. Pertamina Hulu Mahakam has developed a robust and well-established well integrity monitoring system, consisting of procedure and standard, as well as internally developed web-based application to store all required data of each well regarding its integrity. With this system, any anomaly happened in the well can be immediately identified and notified to the user to determine the next action plan. TN-x is one of the well with integrity issue that was first identified by the anomaly in annulus A pressure.

1.2 TN-x Well Specific Condition

TN-x is a gas well located in Tunu Field, and drilled on February 2019. It is a “Light Architecture” well consists of 20” Conductor Pipe (CP), 9-5/8” surface casing, and 3-1/2” tubing. The well has 2 annuli: Annulus A (annulus of 20” CP x 9-5/8” surface casing), and Annulus B (annulus of 9-5/8” surface casing x 3-1/2” production tubing). Well diagram can be seen on Figure 2.

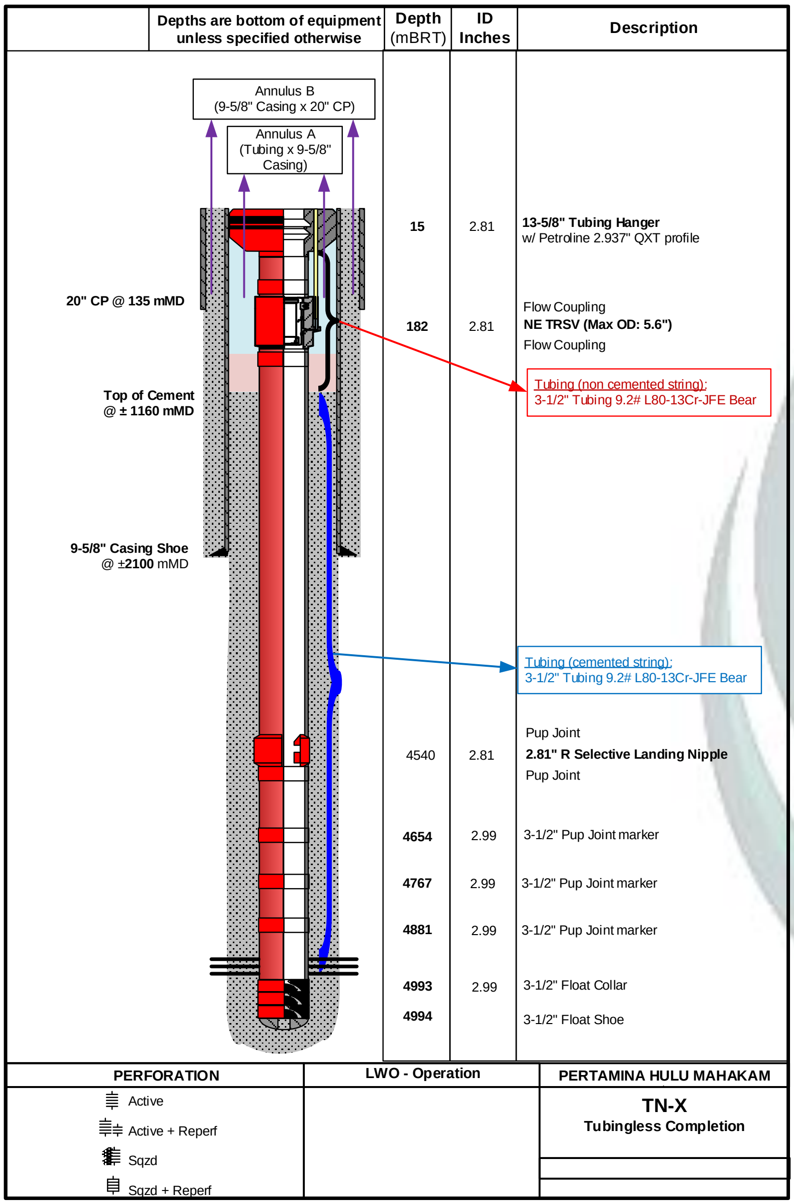

Figure 2. TN-x Well Diagram

Each annulus is assigned with MAWOP (Maximum Allowable Wellhead Operating Pressure), indicating the maximum pressure that can be tolerated by the annulus before one of the barrier components in the annulus fail. The MAWOP is 1500 psi and 200 psi for Annulus A and Annulus B, respectively.

The first abnormal pressure recorded in Annulus A was on 8th of April 2019. Annulus A pressure rises to 1378 psi (92% from MAWOP) after additional perforation (Shut-in Tubing Head Pressure/ SITHP = 2139 psi). Annulus A pressure then was bled off to 72 psi and observed for 24 hrs while flowing the well (Flowing Tubing Head Pressure/ FTHP = 189 psi). After 24 hrs, the pressure was found rise to 200 psi. Annulus leak rate measurement was performed using Dwyer flow meter, and found low gas leak rate (<3 scfm, standard cubic ft per minute), which is below the flow meter scale range. Then several bleed off and Pressure Build Up (PBU) monitoring was conducted while intervention was being performed in the tubing. The correlation between tubing pressure and Annulus A pressure is shown on Figure 3. The similar pressure trend observed indicates communication between tubing and Annulus A.

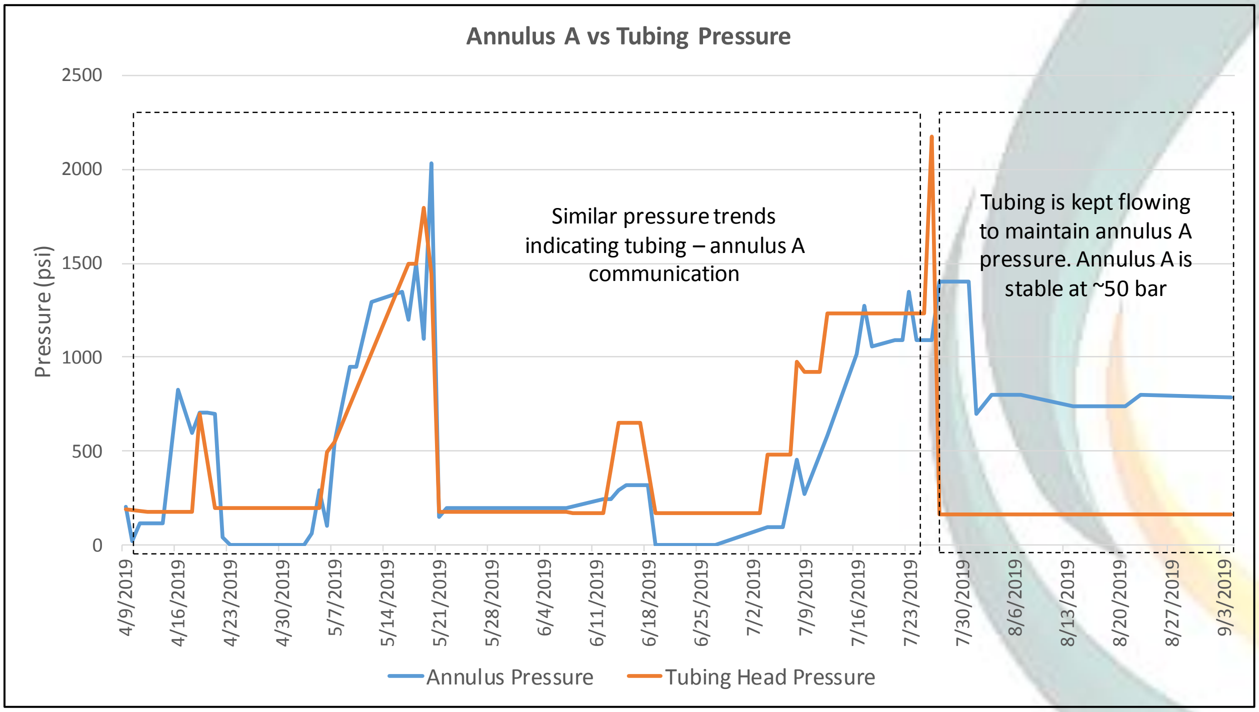

Figure 3. Similar trends between Annulus A and Tubing Pressure before the intervention, indicating communication between tubing and annulus

In order to confirm the communication, well intervention unit is deployed to perform survey with Production Logging Tool (PLT). The leak depth indicated by PLT then was confirmed by setting plug at several depths near the leak point, then pressure tested to observe the tubing – annulus pressure communication. When the plug was set at 189 mMD, tubing was pressure tested to 570 psi, then tubing pressure dropped to 305 psi in 1 hr (loss rate ~265 psi/hr), and annulus A builds up from 19 psi to 20 psi (1 psi/hr). From the investigation, it was concluded that the leak point was from thread connection between pup joint of DHSV (Downhole Safety Valve) and the full joint below, located at 183.4 mMD.

With high SITHP and confirmed leak and communication to Annulus A, tubing integrity needs to be restored to prevent any escalation to undesired incidents. Aside from safety reason, the leak also needs to be repaired first before putting the well back on production. By resuming production from this well, estimated total of 1.65 MMUSD can be unlocked from the remaining unproduced stakes.

2 Methodology

2.1 Conventional Methods

Tubing leak cases in PHM was usually treated with conventional mechanical methods. When a leaking point is confirmed, mechanical isolation will be used to seal the leaking point. Two most common mechanical isolations are Pack Off Spacer and Casing Patch. The utilization of these devices have its benefits and drawbacks, however in TN-x case, both of the tools are not preferable.

Pack-off spacer is a mechanical device which is installed to isolate some interval in the tubing temporarily, while keeping production path open so that the well can still be produced. It consists of lower tubing stop, lower pack-off for isolation from below, spacer joints to cover the interval, upper pack-off for isolation to above strings, then upper tubing stop. The device is retrievable, and shall be retrieved prior intervention to lower section, since downhole tools cannot pass thru the restriction.

Pack-off spacer is a relatively cheap and simple tool to isolate tubing leak. However, in TN-x case, the leak is located very close to DHSV profile and its accessories, which operationally will be tricky since there is very tight interval to set the upper tubing stop and upper pack-off, if not impossible.

Meanwhile, Casing Patch is the permanent-type of mechanical isolation. The patch has seals on the top and bottom end so the leak point will be isolated from the rest of the well. Well intervention tool can still be run across the casing patch, but limited to certain size depends on the casing patch ID. Since the leak point is located in a shallow depth, installing casing patch would not be preferable since it will limit the type of interventions that can be performed. Moreover, in this case, TN-x is a new completed well which still have several intervention plans in the future.

Other method to solve this issue would be to have a workover on the well, by retrieving the leaking tubing and replace it with the new one. However, not only workover is a complex and heavy operations, it will also induce significantly higher cost.

2.2 Pressure Activated Sealant

Pressure activated sealant is a special polymer-type chemical that will be activated (polymerized) by turbulence flow induced when the fluid enters a leak point. This chemical is water-soluble, non-toxic and non-flammable. Differential pressure was then applied to create turbulence flow to shear the liquid and allow it to polymerize in the leaking point. Since the chemical will only be activated when entering the leak point, the remaining fluid on top will remain in liquid phase, and could be left in the well or flushed as needed.

This technology has long been introduced to oil and gas industry. Previous published papers show wide range of applications around the world, including sealant treatment for microannulus leak (Rusch et al., 2004), production casing leaks (Chivvis et al., 2009), and tubing leak in subsea wells (Cary et al., 2013). In Indonesia specifically, there are not many references regarding application of pressure activated sealant that have been published so far.

There are several sealant providers available in the market, and the type that was used in PHM was a custom blend sealant made up from 3 individual liquid chemicals with unique characteristic: Liquid A, Liquid B, and Liquid Sealant. The ratio of each compound will depend on the type of treatment (e.g. thread connection leak, tubing/ casing leak, micro-annulus leak, etc) and how big the leak is. The formula of the mixture will be decided by sealant specialist onboard prior the job.

The limitation of this method is on the size of the leak. Pressure activated sealant will be effective to cure small leaks (e.g. thread leak). In theory, tubing leak due to corrosion or packer leak can also be treated, as long as the leak rate meets the service provider's criteria. In this case, the leak rate shall not be bigger than 12 L/min at 1000 psi (criteria will be different based on the sealant type by each service provider and the type of leak).

2.2.1 TN-x Well Program

The flow chart of the program can be seen on Figure 4. The first step is to set 3.5" retrievable plug below leaking point at 190 mMD as the base for the chemicals. Then by using the available data (depth of leak, leak rate and pressure build up), sealant formula was designed. The chemicals will be pumped through Xmas Tree kill valve, followed by filling up the tubing with inhibited sea water by lubricate and bleed method. Once filled up, pressure will be applied to squeeze the sealant into the leak point with several pressure cycle to ensure the sealant has been activated. Then the sealant will be left overnight to cure. Finally, the tubing will be tested with positive pressure to ensure no more tubing – annulus communication. At the end of the operations 3.5" retrievable plug will be retrieved to return the well to its original state.

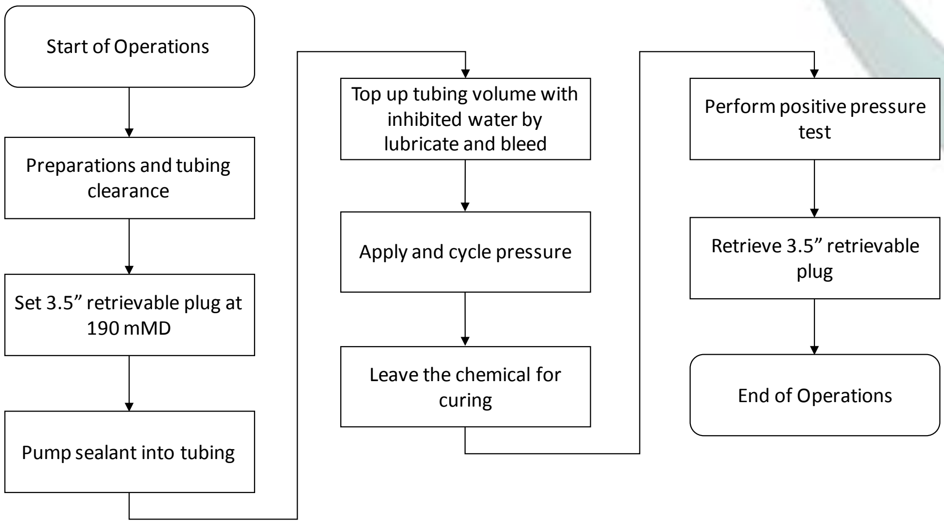

Figure 4. TN-x Pressure Activated Sealant Program Workflow

3 Results

3.1 Operation Chronology

The operation was carried out using well intervention barge Nesitor-3 on 21 – 26 September 2019. Pumping line is rigged up from pumping equipment to Xmas tree kill valve. Initial parameter: Tubing Head Pressure (THP)/Annulus A/Annulus B was 400 psi/700 psi/100 psi.

During tubing clearance with slickline, 2.78” gauge cutter stopped at 183 mMD (tubing ID 2.992”). When retrieved at surface sticky black substance was found on gauge body, which suspected as grease from the connection thread that was forced by the annulus pressure and feeds into the tubing through the leak, considering at the beginning of the operations, the Annulus A pressure is higher than tubing pressure. This finding supports previous conclusion that the tubing is leaking around that depth.

20 L of diesel was pumped into the tubing to clear out the grease, then restriction was cleared using wire scratcher and 2.78” GC can be run smoothly afterwards. Liquid level was identified at 922 mMD. 3.5” retrievable plug was set at 190 mMD as per program, then tubing pressure and annulus pressure was bled off to 0 psi. Pressure above plug was stable at 0 psi in 1 hr.

Total 59 L of sealant mixture was pumped, which consisted of 45.5 L Sealant + 4 L Liquid B + 9.5 L Sealant, sequentially. The mixture was equal to ~13 m tubing height, covering tubing volume from 177 – 190 mMD. Then 750 L of inhibited water was pumped to fill up tubing up to surface.

With 5000 psi being the MASP (Maximum Allowable Surface Pressure), the tubing then was pressurized incrementally to 4950 psi while annulus A is kept in open position to allow maximum differential pressure. Some pressure loss was observed but quickly stabilized, indicating the sealant has exited the leak point and was establishing the seal. The increment in tubing pressure is shown in Figure 5.

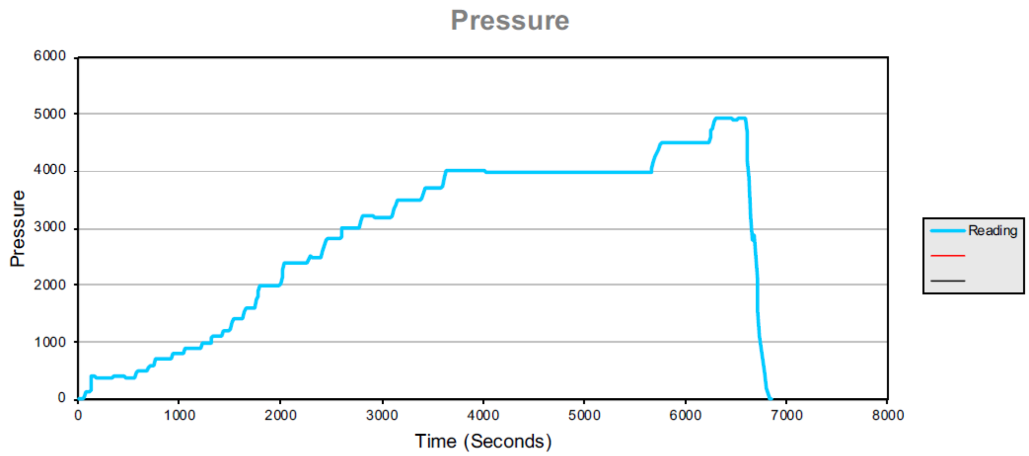

Figure 5. Incremental pressurization after pumping sealant mixture to activate the seal within the leak point

The initial leak off rate when tubing was pressurized to 100 psi was measured at 3 psi/min. The first indication of the established seal was achieved at 1000 psi, where the leak off rate decreased to 1 psi/min. The pressure then was continued brought up to 4950 psi, with total liquid pumped was 9.4 L. At 4950 psi, rapid pressure loss was observed which turned out to be a surface leak in the pumping lines. The pumping line was repaired and THP was brought back to 4925 psi, as seen in Figure 6. At this point, the final leak off rate was 1 psi/min. The well was then left overnight (~11 hrs) for curing period.

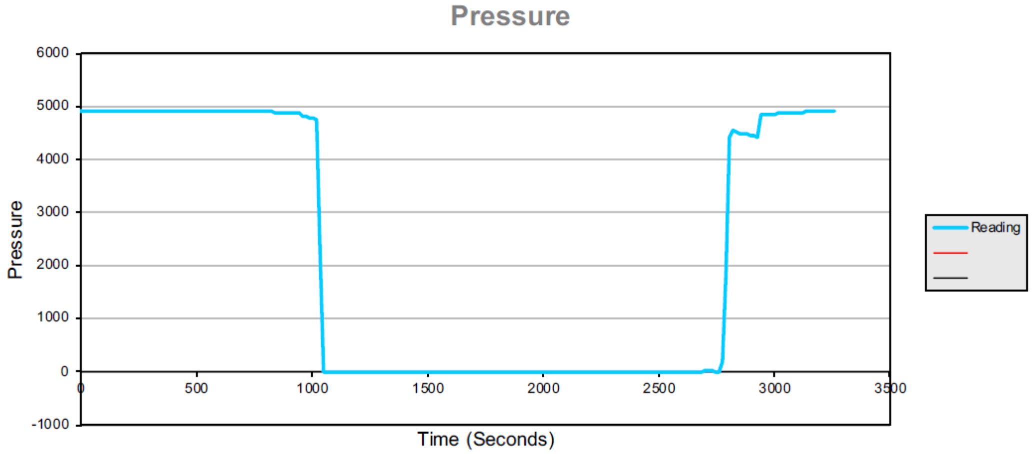

Figure 6. Final Tubing Head Pressure brought back to 4925 psi after repairing surface pumping line

The tubing head pressure found in the following day was 4848 psi, with 77 psi of pressure loss occurred during the night (Figure 7). Then two pressure cycling was performed to ensure the sealant is activated by bleeding off THP to 0 psi and pressuring up back to 4925 psi (Figure 8).

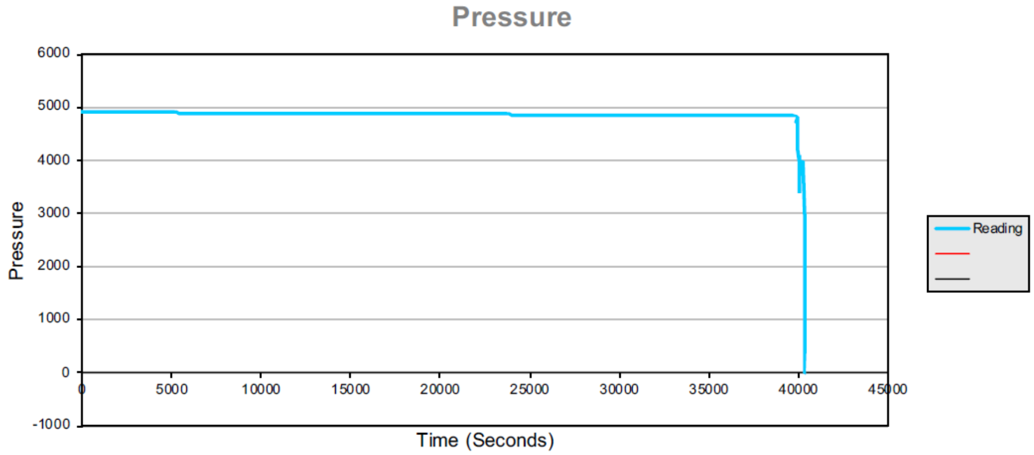

Figure 7. Tubing Head Pressure record during overnight curing period (total loss of 77 psi)

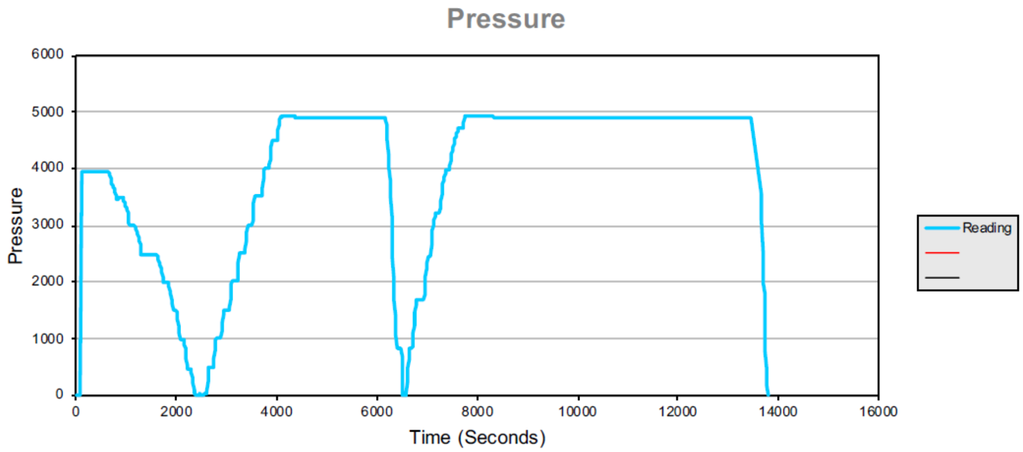

Figure 8. Two times of pressure cycling. The first one (left) was performed in increment pressure, while the second one (right) was performed rapidly

The first pressure cycle was performed in increment, while the second was performed rapidly. The final observation shows 0 psi/min leak off rate in 30 minutes. With the absence of pressure loss, the seal created in the leaking point was considered fully established. As the last step in the treatment process, final pressure test was performed at 4857 psi, which result in 0 psi/min leak rate in 30 minutes (Figure 9).

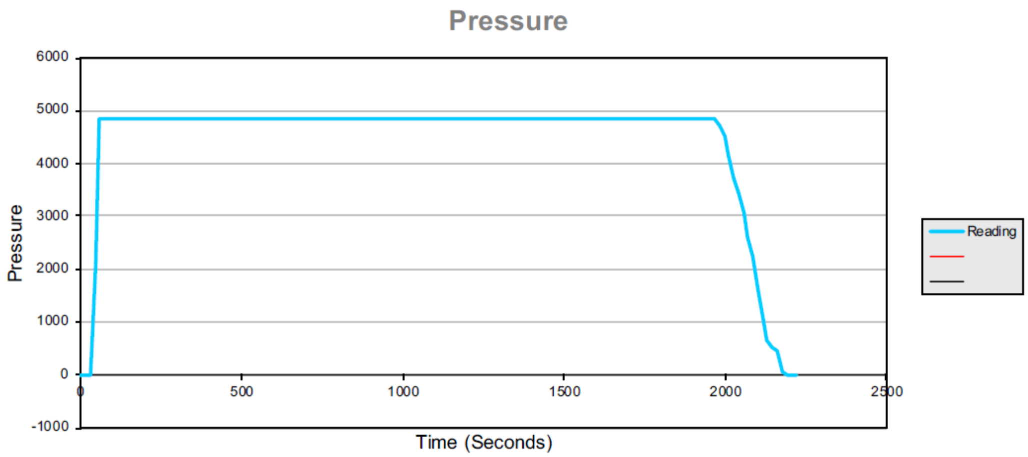

Figure 9. Final pressure test shows stable pressure at 4857 psi with 0 psi/min leak rate

The final step of the program is to retrieve 3.5” retrievable plug from 190 mMD to return the well to its original condition. While POOH (Pulling Out of Hole) the plug, at depth 38 mMD, the plug stopped and got loss jar action. After several attempts the plug is finally recovered to surface with high pulling weight (1800 lbs). At surface, the tool string and plug was found covered with sealant residue (Figure 10). The residue was also found inside slickline BOP and Xmas tree.

Figure 10. Recovered plug was found covered with Sealant residue

The above chronology is summarized in Table 1.

Table 1. TN-x Sealant Injection Treatment Chronology

Date	Time	Activities
24-Sep-19	00.00 – 02.30	Preparations, review procedure and JRA, rig up equipment
	02.30 – 07.30	Tubing clear, clear restriction (grease) at depth 183 mMD, tag liquid level
	07.30 – 11.00	Set retrievable plug at depth 190 mMD
	11.00 – 13.35	Pump 45.5 L Sealant + 4 L Liquid B + 9.5 L
	13.35 – 15.00	Fill up tubing with inhibited water
	15.00 – 17.00	Begin incremental increase of THP. Raise THP to 100 psi, leak off 3 psi/min. Raise pressure to 1000 psi, total volume pumped 2.5 L, leak off rate 1 psi/min. Raise pressure to 2000 psi, total volume pumped 4.7 L, leak off rate 1 psi/min. Raise pressure to 3000 psi, total volume pumped 7.1 L, leak off rate 1 psi/min. Raise pressure to 4000 psi, total volume pumped 9.4 L, leak off rate 1 psi/min. Observed for 30 mins, pressure drop from 4010 – 3980 psi (1 psi/min).
	17.00 – 18.30	Raise pressure to 4950 psi, observed increase in leak off rate to 3 psi/min. Found leak on pumping lines. Repair leak, pressure test, and re-pressurized tubing to 4925 psi. Leak off rate 1 psi/min.
	18.30 – 00.00	Left the well overnight for curing.
25-Sep-19	00.00 – 06.15	Left the well overnight for curing. As found pressure was 4848 psi (77 psi loss from overnight curing, <1 psi/min).
	06.15 – 07.45	Cycle pressure 1: Bleed THP in increments to 0 psi, raise THP to 4925 psi in increments. Observed in 30 mins, loss of 3 psi/min in the first 5 mins, decreasing to 0.2 psi/min in the final 5 minutes.
	07.45 – 08.20	Cycle pressure 2: Bleed THP rapidly to 0 psi, raise THP rapidly to 4925 psi. Observed in 30 mins, loss of 1 psi/min in the first 5 mins, decreasing to 0.2 psi/min in the final 5 minutes. Extend the observation to 1 hr period, leak off rate decreased to 0 psi/min in the final 20 minutes.
	10.00 – 10.30	Run final pressure test at 4857 psi for 30 minutes. Final pressure is at 4857 psi, 0 psi/min leak off rate.
	10.30 – 13.30	Bleed off tubing pressure to 0 psi, rig down pumping equipment, observe tubing and annulus A pressure stable at 0 psi in 3 hrs.
	13.30 – 00.00	Attempted to POOH plug
26-Sep-19	00.00 – 06.00	Attempted to POOH plug. Plug recovered with some residue of Sealant
	06.00 – 14.30	Perform tubing clear, clear out tubing from any remaining residue of Sealant mixture, perform DHSV inflow test

14.30 – 16.00	Rig down slickline unit. End of operations.

3.2 Lesson Learned

The overall operation is concluded successful, with leak point is fully isolated. The obstacle was only found after the treatment while retrieving the plug. High pulling weight was observed with several loss jar action, and it turned out to be because of the "gelled-up" sealant residue inside the tubing string.

One possible explanation is because of the existence of small leak in the plug body that makes the sealant activated around the plug. However according to previous experiences of the provider, if the sealant was activated around the plug, it could be easily retrieved by jarring action and would not create the gelled up residue as in this case. But it is recommended to pull out the plug in a very low speed, to prevent the plug shearing the liquid around its surface.

Another possibility is because of the incompatibility between sealant mixture and well bore fluid. Sealant service provider has stated that the chemical is inert to almost all kind of well bore fluid, except chloride. Although there is low possibility of existence of chloride from brine/ produced water in the tubing on that depth, it is still recommended to take liquid sample inside the tubing and perform compatibility test. During several attempts in retrieving the plug, there was plan to pump friction reducer liquid. On-site compatibility test was performed by mixing sealant sample with friction reducer liquid. It is clearly seen that friction reducer reacted with sealant chemical and caused agglomeration, despite the claim that sealant mixture would be inert. Thus, it is highly recommended to perform compatibility test with well bore fluid and any intervention liquid prior the job.

Another fact that the pumping operation was performed through needle valve that connects to ½" NPT (National Pipe Tapered) thread on the kill wing valve (Figure 11).

Figure 11. Connection of pumping line to ½" NPT in kill wing valve of TN-x

In the beginning of the operations this was considered as the most effective method so that there is no need to rig down the slickline lubricator after setting retrievable plug. However, the small pumping line could also contribute to unintentional shearing effect, meaning that the sealant is already semi-activated when being pumped down the tubing. Hence, it is recommended to use the bigger hose and connection in the pumping line to prevent any shearing effect in the chemical.

The last possibility would be in the sealant blend itself. In TN-x case, the chemical mixture consisted of Liquid B and Liquid Sealant. Liquid B is a more aggressive agent that can accelerate Sealant activation. In small tubing leak case, Liquid B is usually not used (it will vary between different service providers). But it was pumped in this case as a mitigation if Sealant alone could not fully isolate the leak, since there was no diagnostic test (leak rate measurement using liquid) prior the intervention. For future operations, the diagnostic must be performed so that the composition of chemical blend would be effective and fit for the purpose.

3.3 Final Result

Figure 12 shows the record of annulus pressure since the treatment in September 2019 to May 2020. In more than 7 months after the job, annulus A pressure is stable at ~40 psi and no longer observed having communication with the tubing. Several well intervention jobs have also been performed in this well after the treatment, with no restriction encountered in the tubing.

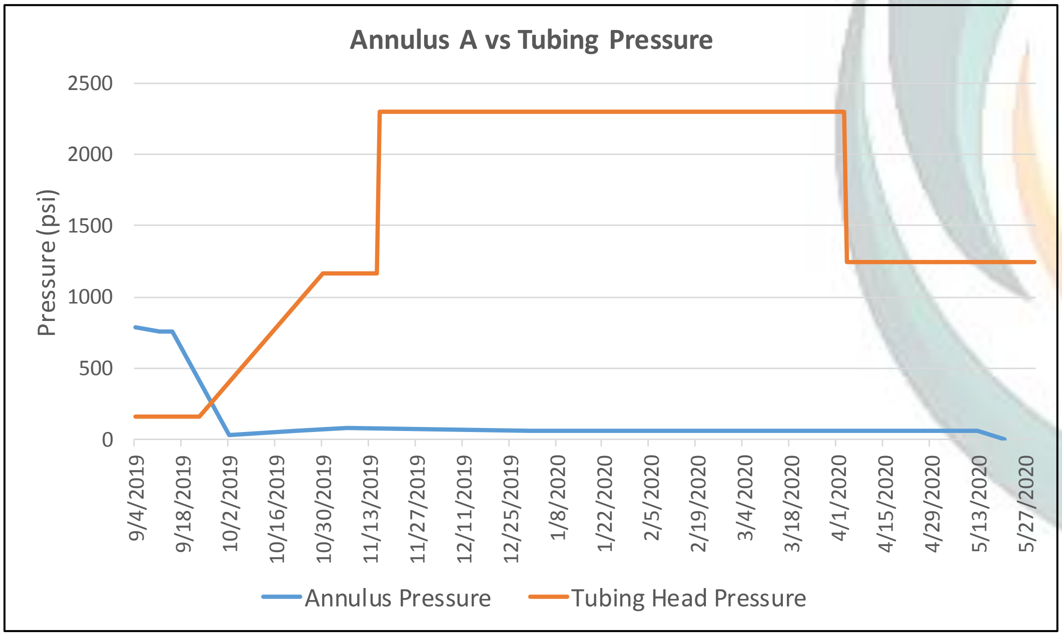

Figure 12. Annulus A pressure is stable at ~40 psi after the sealant injection in September 2019. No more communication observed between Tubing-Annulus

4 Conclusion

Pressure activated sealant is proven able to isolate small thread leak in the tubing. It was successfully applied in TN-x well with specific conditions as below:

1. *Simple well completion type with minimum tubing accessories*, refer to Figure 2. Wells with more complex type of completion (e.g. gravel pack completion, selective completion with SSD/ Sliding Sleeve Door, etc.) shall need further assessment to avoid the sealant activates near those accessories.
2. *Shallow depth of leak (183.4 mMD) with tubing full of gas across the leak.* For wells with deeper leak location, especially with liquid present in the well bore might need coiled tubing unit to spot the sealant in front of the leak rather than relying on gravity feed, to ensure sealant placement in front of the leak point.
3. *Low leak rate (<3 scfm).* Sealant treatment is effective to small leakage, since larger leak will be less effective to create the shearing effect and initiate the activation. The leak rate (in liquid) shall not exceed 12 L/min at 1000 psi.

The operation is relatively simple, and only took 2 to 3 days to complete. It is a good alternative solution for restoring tubing leak, especially in a well where restriction in tubing diameter is not desired.

5 Recommendations

Special precautions and thorough engineering study must be taken especially in the more complex case (e.g. deep leak point, high leak rate, etc). Operationally, it is recommended to: 1) ensure the base plug was in perfect condition with no leak to avoid the chemical activated around the plug; 2) perform compatibility test prior the intervention with well bore fluid, inhibited water, and any other fluid that is possible to be pumped inside the well bore during the operations; 3) avoid using small control line or any small diameter restriction in the pumping lines to avoid unintentional shearing effect in the chemical; 4) perform leak rate measurement using liquid (especially in gas wells) so that sealant mixture can be designed accurately.

List of Abbreviations

CP	= Conductor Pipe
DHSV	= Downhole Safety Valve
FTHP	= Flowing Tubing Head Pressure
ID	= Internal Diameter
MASP	= Maximum Allowable Surface Pressure
MAWOP	= Maximum Allowable Wellhead Operating Pressure
mMD	= meter Measured Depth
NPT	= National Pipe Tapered (technical standard for tapered threads on threaded fittings)
PBU	= Pressure Build Up
PHM	= Pertamina Hulu Mahakam
PLT	= Production Logging Tool
POOH	= Pull Out of Hole
SCFM	= Standard Cubic Feet per Minute
SITHP	= Shut-in Tubing Head Pressure
SSD	= Sliding Sleeve Door
THP	= Tubing Head Pressure

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