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Micro Tubing Leak Investigation with High Resolution Detection Technology and Leak Remediation with Pressure Activated Sealant – A Case Study

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Abstract

The paper discusses a cost-effective approach involving the implementation of a high-resolution detecting technology to identify a micro-tubing leak and further remediation by applying a method of injecting a pressure activated sealant to eliminate the leak.

Well A in field Kashagan was completed using 5 ½″ in single-string cased hole completion intersecting carbonate zones. It produced up to 20,000 BPD (3180 M3/D) on self-drive starting from March 2017. The reservoir pressure is up to 780 bar (11,300 psi) and well fluid composition is with 16% H_2S and 5% CO_2 mol.

In July 2018, an increase in A-annulus pressure up to 3.6 bar/day was observed. The diagnosis suggested an issue with a downhole tubing section above the production packer indicating a need to identify the leak point and remediate the leak to bring the well online.

A detailed analysis of various techniques for bringing the well in production was conducted keeping in mind the associated cost and time for each method. After performing a detailed technical and economic analysis, the decision was made to perform the operation in two stages. The first stage is to identify the micro-leak with high resolution spectral noise logging tool, while the second stage is to rectify the leak with straddle pack or pressure activated sealant.

This operation is also considered to be a proactive approach in reducing emissions, as it limits the emission sources, and those parameters controlling the individual emissions; and finally obtaining knowledge of the economic impact. The operation in well A was successfully executed and the well integrity was regained allowing bringing the well back online in shortest time (minimal as compared to the workover operations, far safer and more cost-effective).

Introduction

This paper describes the job design, technique implemented, and challenges overcome during the successful activation of a well producing up to 20,000 BPD (3180 M3/D) production, establishing the viability of through-tubing leak remediation. Learnings from the paper will help professionals plan for such well interventions involving downhole tubing integrity remediation.

After 1.5 years of production, Well A developed a micro-leak between the Production Tubing and A-annulus. This leak was located at the bottom of TR-SCSSSV area with a high-resolution spectral noise logging tool.

Firstly, the WR-SCSSV insert valve was installed to stop the communication between the tubing and A-annulus, and as expected the micro-leak persisted in the control line chamber envelope that operates the WR-SCSSV. Subsequently, the pumping of pressure activated sealant from TR-SCSSV control line was performed with several adjustments until a final execution program was successful. This program is a result of practical application and adjustment of the sealant volumes, curing times, and control line pressure testing values.

This paper provides the learnings from the leak identification process and modification of the sealant injection procedure that led to the reinstatement of the 20,000 BPD (3180 M3/D) well into production.

Geologic conditions and operating challenges

Kashagan is an isolated pre-salt carbonate platform in the southern margin of the Pre-Caspian tectonic depression. The structure is oriented north-east to south-west, and although it is a single platform it is geo-morphologically subdivided into an eastern platform (Kashagan East), and a western platform (Kashagan West) connected by a narrow "neck".

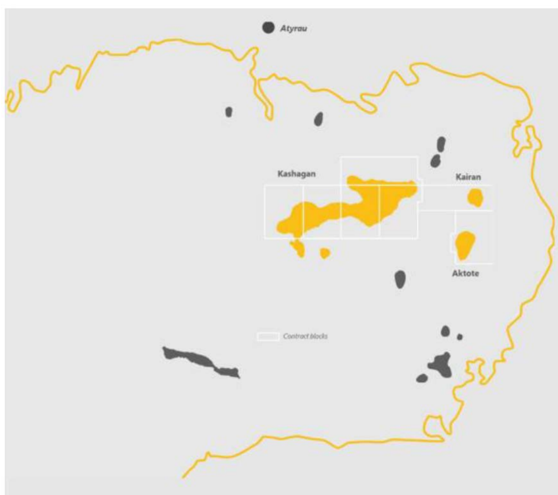

Figure 1—Location of Kashagan field

The platform is tilted to south-west with the top reservoir ranging from 3800 m to 4300 m. The interior platform forms a relatively flat area, and the platform margin (rim) forms a narrow elevated ridge that is up to 200 m higher compared to the interior and is better developed in Kashagan East. The flanks of the field (slope) are steeply inclined – up to 20°-25° – and are commonly affected by gravitational faults. The Lower Permian evaporates divide the sedimentary sequence into two units:

1. Pre-salt: Paleozoic carbonate sequence.
2. Post-salt: Mesozoic-Cenozoic clastic dominated sequence.

Geomorphologically the field is divided into two regions: platform and rim. The platform is characterized by grainstones with good matrix porosity and wells in this location tend to be good producers. In contrast, the rim consists mainly of boundstones with very poor matrix porosities and wells drilled in these regions target non-matrix features, such as karsts and fractures (Yerzhanov et. al. 2023).

Well A is a deviated development well drilled in batch drilling mode from a remote island and was planned to investigate the southern part of the Kashagan East platform interior production area. The well is envisaged as a producer of lower unit and not dedicated to penetrate deeper reservoir units.

Drilling operations took place in 2010-2014 period, reaching TD at 4,501 mMD. The well was completed with 5 ½″ CRA Tubing.

Due to decline in productivity caused by scaling in production liner zone, the diagnostic acid soaking was performed in summer 2018 by pumping HCL acid and leaving it soak in the liner and reservoir parts for a few days. Prior to well re-opening, a constant increase in A-annulus pressure was observed.

Following an investigation one month later in 2018, the trend of A-annulus pressure build-up did not change after several investigations on surface, which ruled out existence of external source and pointed towards potential tubing integrity failure. The decision was to close the TR-SCSSV and bleed tubing head pressure (THP) off till 22 bar (319 psi) to monitor possible leak above or below TR-SCSSV. The buildup checks at A-annulus indicated the leak is below the TR-SCSSV.

In autumn 2018, the leak detection operations with the use of spectral noise-temperature logging service were deployed on slickline. The leak has been identified at the depth of TR-SCSSV, being confirmed afterwards that communication point is located at just below the TR-SCSSV flapper. After the leak investigation well was secured by fully sweetening with diesel down to top of perforation intervals and installing two downhole plugs as barriers.

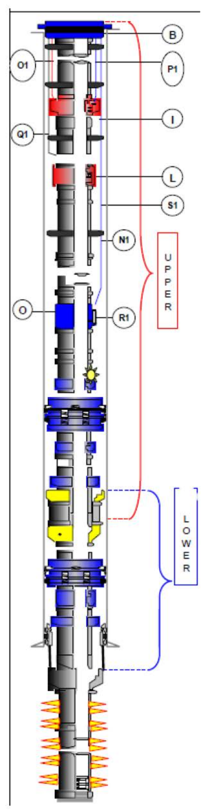

Figure 2—Generalized Well A Completion Schematic

Leak Investigation and Well Remediation Challenge

Further analysis of data obtained during spectral noise logging identified two potential leak points. However, precise identification of the leak point was not obtained due to small distance (30.3 in or 77 cm) between two of them and limited resolution of the SNL-HPT tool. The key challenges are the following:

1. The leak is so tiny (build up rate at 3.4 bar/d or 49 psi/d in A-annulus) that it is difficult to detect with spectral noising tool with standard resolution. Any change of the fluid medium in the well could also cause the leak to become undetectable. However, the leak does exist when it's on producing mode leading to A-annulus charging.
2. There are two potential leak paths just below the flapper:
    - Case 1 indicates the leak at the TR-SCSSV body thread, while Case 2 indicates the leak at the connection between TR-SCSSV and the lower pup joint.
    - In case 1, the body thread is only 8.6 in below the flapper. Mechanical remediation cannot be installed without jeopardizing the functioning of the TR-SCSSV.
    - In case 2, the TR-SCSSV lower seal bore is only 23.8 in long and just 8.6 in below the flapper itself, hence the straddle tool should be specially designed to allow top of the straddle to sit precisely below the flapper and seal against the TR-SCSSV lower seal bore.
3. Due to the high pressure and high H2S content, based on the quantitative risk assessment, any well intervention on remote Kashagan island will require shutdown of the entire island wells, so the production deferment (up to 70,000 bopd) caused by any well intervention poses a significant production shortfall. Therefore, the well access flexibility to perform the well intervention is extremely limited, which renders the final solution to be of the shortest duration possible and leads to the associated technical complexity for the operational execution.

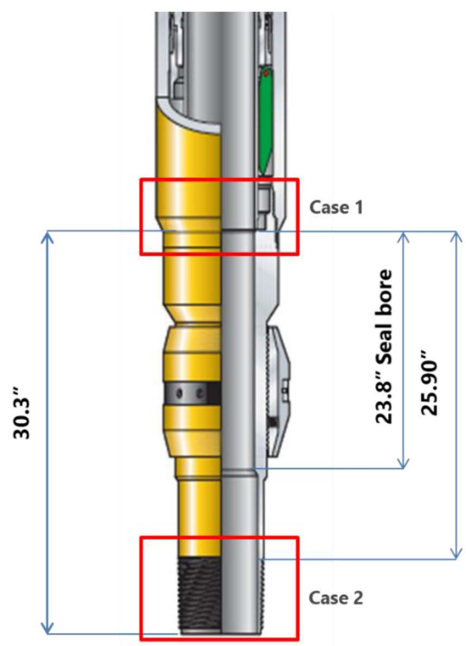

Figure 3—Potential leak paths below the flapper

Another leak investigation was performed three years later with a higher sensitivity spectral noise logging tool "CHORUS-X8" which clearly showed that the leak point is at RBT-6 thread within TR-SCSSV body. Tubing to A-annulus leak has been successfully isolated by straddling with Baker's "TEOFWS-15" WR-SCSSV. However, during the functioning of the WR-SCSSV at 758 bar (11,000 psi), Control Line fluid leaked into the A-annulus.

The well had been secured with two downhole plugs since 2018 after initial pressure build-up detected in A-annulus. Leak investigation successfully executed at the second attempt with CHORUS-X8 tool (acoustic detection log). The leak depth was identified at 265.6 m, which confirmed the leak at TR-SCSSV lower body thread (RBT-6), i.e. the leak was thought to be inside the safety valve body at a threaded connection allowing communication from the "A" production annulus to the TR-SCSSV and Control Line. The accuracy of the detection mechanism had been previously proven for a monobore completion (Tleulin et. al. 2019).

The concept select stage for further well remediation activities must have addressed the following hazards:

- Single barrier operation
- Working in Red/Yellow zone
- Confined Space Entry
- Line of fire
- Slips, trips, fall hazards
- Working at height
- H2S contained in the well and in process systems
- Pumping fluid under high pressure
- Diesel or base oil spills
- Pressure testing
- Breaking containment
- Lifting operations and potential dropped objects
- Hand and finger injuries while rigging up the PCE stack
- Escalation of Tubing/Annulus leak rate during the leak investigation and well remediation
- Process Safety incidents, such as loss of containment
- Unknown well conditions

Comparison of Methods & Technology Selection

The concept selection stage for further well remediation activities has considered the following aspects:

- Well barrier envelope
- Complexity of operation
- Probability of Success
- Long lead items
- Longevity of remediation
- Production deferment
- HSSE exposure during the operation
- Sustainable maintenance
- Emergency well control in final well status
- Escalation of the Tubing-Annulus leak rate during the leak investigation and well remediation
- Process Safety Incident risks (such as loss of containment)

Various concepts were scouted for leak remediation. The studied concepts are listed below with pros and cons.

Table 1—Concept assessment for various technologies

Identification/ Remediation	Advantage	Drawback
High Resolution Leak Detecting Tool	Multisensory Acoustic tool with depth accuracy of 12″.	Need additional run to identify the leak as either Case 1 or Case 2. Resolution of Chorus 10 (standard type) is insufficient for the micro-leak. Chorus X is required (a repeat log).
Single-sensor passive spectral acoustics	Widely used in recent years in well integrity and reservoir performance diagnostics	Limitations in assessing the spatial distribution of the noise source.
Time Activated or Chemically Activated Sealant	Multiple products available from the market.	Leak geometry and unusual pumping path through Control Line pose high risks of undesired plugging in non-target areas.
Pressure Activated Sealant by squeezing from tubing	No downhole tools set across TR-SCSSV in final well status. Execution is less complicated than mechanical ways of leak isolation. Applicable for curing both leak cases (Case 1 and Case 2). Creates no restriction for further interventions.	Uncertainty on probability of success and longevity. No case history in Kashagan environment before. Execution requires deployment of Slickline and probably E-line to set plug below the leaking connection. Risk of plug stuck in the wellbore post treatment.
Pressure Activated Sealant by squeezing from TR-SCSSV control line	Sealant can be displaced precisely to the leak connection via control line. With WR Insert Valve in place, the leak will be isolated from tubing to annulus (pumped through CL)	Uncertainty on probability of success and longevity. No case history in Kashagan environment before. It requires installation of Wireline retrievable insert valve in well.
Straddle (designed for TR-SCSSV bottom connection, Case 2)	TR-SCSSV will be left operative & functional after straddle installation. The straddle is retrievable. There are successful cases globally and in Kashagan field. Contract in place for fabrication, procurement & installation service. Can be run using conventional techniques (E-line or Slickline).	Special Straddle will work only for bottom connection leak, Case 2. Straddle will create a restriction in the well. Need to be retrieved prior to well intervention. Detailed engineering and qualification testing to be performed. Long Lead time.
Velocity Valve (Storm Valve)	Velocity Valve designed to be installed within Baker Hughes SCSSV profile. Simple installation with slickline.	Not surface controlled. Creates restriction after installation. To be retrieved prior to any well interventions. Additional retrieval and settings could be required for selection of correct sized orifice before long-term installation as a barrier. In the Velocity Valve Manual, it is recommended that the O-rings and other resilient seals are changed after three months service. Regular maintenance is required on the valve. Equipment needs to be manufactured with long lead time. Only work for Case 1.
Pulse pressure surface-controlled Safety Valve	Surface controlled type - to be operated using pulse pressure principle	Decrease in completion ID - To be retrieved prior to any well interventions. Requirement to change replace the batteries – intervention required. Long Lead time. No case history in Kashagan field.
Surface-controlled Safety Valve with independent control line	Surface Controlled	Decrease in completion ID - To be retrieved prior to any well interventions. Requires partial modification or change to Wellhead/X-mas tree. Long lead time - minimum 1 year. No case history in Kashagan field.
Workover the well and replace existing TR-SCSSV	Robust solution as permanent fix	Require long duration of shut in the well and island causing huge production deferment. Higher cost and equipment complexity. Relatively big footprint and high emissions

After thorough investigation and multiple rounds of evaluation, it was decided to utilize the high-resolution leak detecting tool first to locate the leak since the remediation method would be with completely different challenges due to the small distance to TR-SCSSV flapper.

As of remediation in Case 2, considering the leak isolation needs to be robust and there was successful case history in Kashagan to install a straddle across tubing connection leak, a special straddle was designed to ensure the top of the straddle will not hinder the functionality of the TR-SCSSV. And for Case 1, considering the difficulty to place the pressure activating agent in tubing and complexity of relevant well interventions, it was decided to convey the sealant through existing control line to ensure accurate sealant placement.

High Resolution Leak Detecting Technology

Single-sensor passive spectral acoustics, known as spectral noise logging, has been widely used in recent years in well integrity and reservoir performance diagnostics (Kantyukov, 2017 and Vasilyev, 2019). The diagnostics answers are based on the interpretation of the acoustic power spectrum. However, this approach has certain limitations in assessing the spatial distribution of the noise source, which is critical in determining the source of sustained annulus pressure as accurate flow geometry is vital for proper remediation planning and the success of performed remediation is largely dependent on the level of diagnostic accuracy. To determine the spatial characteristics of the acoustics signals in the wellbore, multisensory passive acoustics for radial locating and associated methodology are developed. The instrument contains several sensors (from six to ten) with a 12″ distance between the sensors. These sensors measure acoustic power spectrum and signal time delays on different sensors, which makes it possible to physically estimate the distance from the tool axis to the source of acoustic disturbances.

Pressure Activated Sealant

The pressure activated sealant formula consists of a variety of proprietary components. Based upon the application and leak characteristics observed through diagnostic evaluation, the prospective sealant blend is developed specifically to address the leak at hand. Formulations of varying strengths are also provided on location to address sporadic leakage or fluctuations in leak severity. An engineered procedure is developed in tandem with the sealant blending process to inject the sealant via well tubulars or components to spot the pill directly at the leak site. Once displaced to depth, a prescribed pressure manipulation sequence is performed to obtain sealant penetration into and through the leak site before affecting sealant activation and isolation. The chemical mechanism by which the sealant is activated is referred to as polymerization.

Figure 4—Photo of polymerized sealant sample

Based on laboratory testing and sealant composition, the polymer gel (sealant) is designed to polymerize only once it has reached the trigger differential pressure of 500 psi. This pressure drop is inherent to leaks at large, and as such, any sealant not exposed to the leak site will remain in the liquid phase indefinitely, unaffected by the temperature, system pressure, or the time that the sealant remains in the system. Once polymerized and cured, the sealant forms a flexible solid mold into the contours of the leak site to restore pressure integrity. The resultant seal will remain solid and cannot revert to a liquid state. The polymerization process is illustrated below.

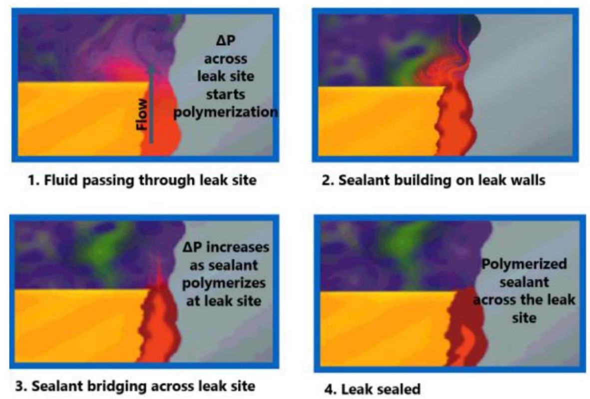

Figure 5—Polymerization process of pressure activated sealant

The key to a successful sealant treatment is the accurate description and analysis of well parameters, as well as the leak mechanism, geometry, and location. These factors are the cornerstone upon which the treatment philosophy and sealant formula are developed. Naturally, further insight into the leak and surrounding factors can allow for optimization of the remediation process.

This proprietary pressure-activated sealant technology is not new and alternative sealing products are offered by various vendors. However, due to leak specificity (see Remediation Concept table in sec.4) and particularity of the sealant application (whereby chemical and timer activation sealants were deemed unsuitable), this particular case presents an operational scenario, whereby a pressure-activated sealant treatment holds distinct advantages.

At the initial stage of a sealant remediation via control line, a volume of normal hydraulic fluid equivalent to roughly 2 times the system volume is pumped to pre-flush the control line prior to sealant injection. The purpose of this flush is two-fold; it ensures that the control line is both fully fluid packed, as well as unobstructed and clear of any particulates to the leak depth. Following this flush, further hydraulic fluid injection is performed at varying pressures to evaluate leak rates and their escalation as pressure is increased. Subsequently, the formulated sealant pill is injected and displaced to depth with further hydraulic fluid. Once at the target location, the sealant is squeezed to obtain an initial seal, and system pressure is then staged up in steps to above normal operating pressure. The system is then cycled from the maximum application pressure, down to a significantly lower pressure (generally 0 psi, or just above adjacent pressures as dictated by the well configuration) and then back up to maximum pressure. This process, which is performed several times, serves to promote further sealant penetration and improves the longevity of the newly created seal. Following the above steps, the sealant is then allowed to cure at the maximum pressure for an extended period prior to testing the repair.

Job Planning

The initial job preparation required to prepare for the unfavorable scenario assumptions when the seals of WR-SCSSV would leak. However, it was not the actual case. Therefore, the below decision tree only serves for the purpose of explaining the complexity of operational decisions, as Well Interventions team faced an uncertainty about whether CL would hold the pressure. Such scenarios require preparing for an unplanned intervention.

Decision tree below shows the planned steps for operational execution in Spring 2022.

Note that drift run with 4.4 in Gauge Cutter (GC) prior to installation of 4.312 in plug is required in case if we must secure the well. This GC size also addresses the installation of 4.25 in plug. The prudent approach is to optimize with a single run to be ready for both options.

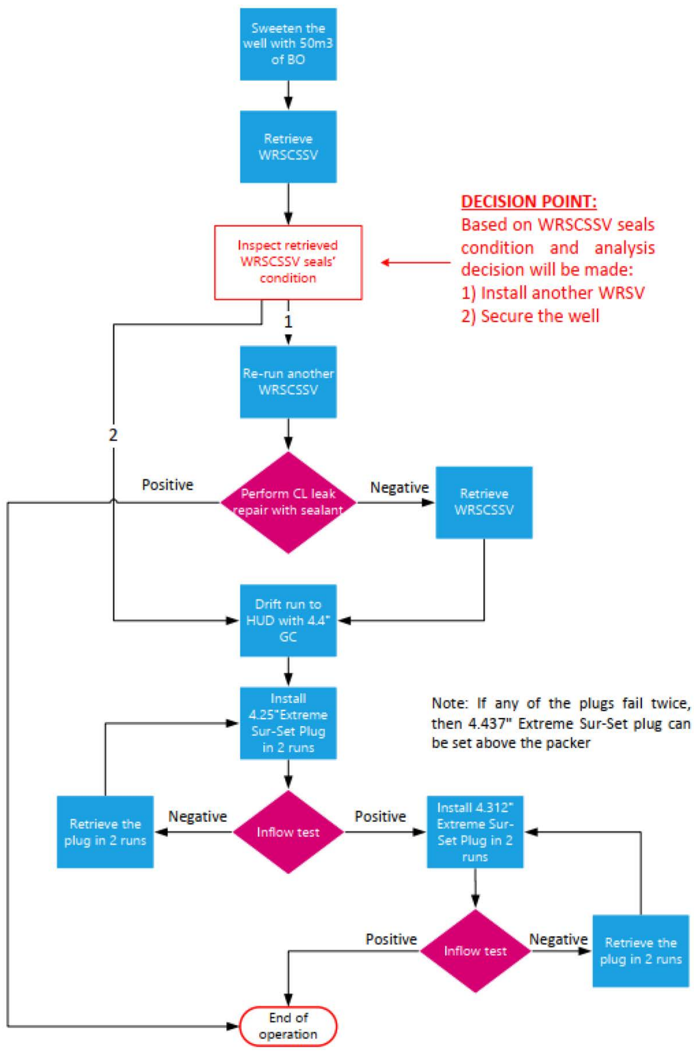

Figure. 5a—Well intervention scenario planning

Job Execution

Leak investigation successfully executed at the second attempt with high resolution leak detecting tool. The leak depth was precisely identified at 265.6 m, which confirmed the leak at TR-SCSSV lower body thread inside the safety valve body as Case 1 allowing communication from the production tubing to A annuli.

Well remediation campaign commenced in late 2021. The plan was to identify the leak location and restore integrity of the well at the nearest opportunity window. The remediation time window was narrow due to offshore logistical issues and high importance of maintaining the planned field production level.

The main repair option was chosen to be with pressure-activated sealant. Upon adoption of this methodology, prior to sealant injection, confirmatory diagnostics were performed to ensure correspondence with the findings achieved by logging. Communication between the CL and "A" Annulus was observed and a leak rate of 45ml/min at 10k psi was obtained.

The main job objectives were to perform pressure diagnostics to determine leak site and leak severity. The key mechanical consideration was that the well was a natural lift Production Well with locked open TR-SCSSV whose safety valve body has been punched.

Prior to the job, an acoustic leak detection identified a leak at the threaded connection at the bottom of the safety valve mandrel. In addition, a potential small leak was suspected at the control line connection to the SCSSV mandrel. The leak rate was measured at 45 ml/min in shut-in conditions.

The sealant was to be pumped down the control line into the chamber which is bound by the leaking threaded connection. The volume of this chamber is 4.3 liters, yielding a total system volume of 6.235 liters. The targeted section's parameters were as follows: Control Line ¼″, Inc. 825, WT=0.065″, ID=0.12″. Communication channel punched between insert safety valve and CL is round shaped, ID=0.188″.

The below figure demonstrates the overall depiction of well downhole equipment and not relevant to actual detection and remediation activities.

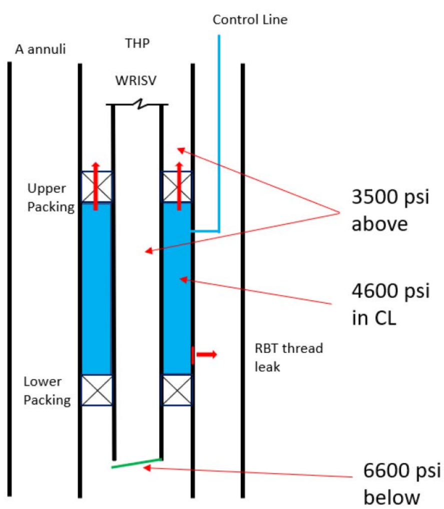

Figure 6—Simplified depiction of targeted downhole system

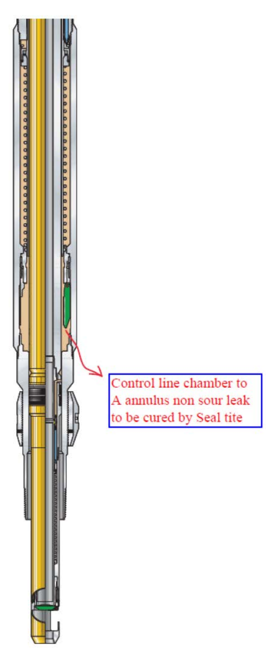

Figure 7—After installation of WR-SCSSV inside TR-SCSSV, RBT-6 thread leak turned into control line to A-annulus hydraulic leak

Note that after the insert valve installation, we checked the leak again. While injecting the sealant, we realized that the leak was bigger due to WRSSV upper seal failure.

The remediation sequence for the sealant injection included the pumping of 2.5-3 liters of hydraulic fluid (re-establish injection rates) followed by injection of 2 liters of sealant until the initial pressure hold is obtained at lower pressure ~6,000-8,000 psi, with subsequent increase to 13,000 psi in gradual steps.

After connecting the Well Production Panel pump and pressuring up to 13,000 psi to equalize the line, the needle valve to WR-SCSSV was opened. The well was put to flow for 48 hours at a minimum rate with WR-SCSSV held open by Well Production Panel pump (monitoring well pressures).

The situation was aggravated when prior to a third sealant treatment during leak rate diagnostics something changed within the valve body and a new leak was detected. The upper seal of WR-SCSSV stopped holding the pressure during one of the sealant injection attempts, whereas lower seal was confirmed to be holding.

The TR-SCSSV and control line were now communicating with the Tubing. A new leak rate of 500 ml/min at 10,000 psi was obtained. In addition, the lower set of packing seals on the WR-SCSSV began leaking during further diagnostics as well. This complication led to increased communication with the Tubing.

The Company Technical Review Committee took immediate action in accordance with requirements for Well Barrier management in order to isolate all energy sources. The way-forward plan was to mobilize a wireline crew to pull the existing WR-SCSSV and set a new WR-SCSSV within the locked open TR-SCSSV. This operation was successfully performed in Spring 2022, with the standard sequence for well securing. The main objective was to reinstate the WR-SCSSV integrity leading to Control Line chamber communication with the Tubing.

1. Sweeten the well with Base Oil (one volume above WR-SSV and extra half volume to displace and remove any debris).
2. Retrieve the WR-SCSSV.
3. Note: This is a decision point before proceeding further. WR-SCSSV seals to be checked for any scoring or damage (potential cause of failure).
4. It is required to check the condition. Once retrieved, the intermediary seal was not found, however the eventual root cause was never actually identified. It is plausible that the seal was within inside mechanism, but after the tool's breakdown it was impossible to tell with certainty.
5. Install the replacement WR-SCSSV
6. Repair Control Line leak using sealant. If CL leak repair failed, then retrieve WRSCSSV
7. Bullhead the well volume
8. Secure the well by installation of 2 plugs in the completion landing nipples (Optional)

    a. Drift the well with 4.4″ GC to the top of 4.312″ Landing Nipple
    b. Install 4.25″ Extreme Sur-Set plug at lower completion LN and inflow test
    c. Install 4.312″ Extreme Sur-Set plug at upper completion LN and inflow test

Tubing integrity was reinstated by the installation of WR-SCSSV into the existing TR-SCSSV and successfully inflow-tested several times. However, CL pressure test at 11,000 psi was not successful. CL fluid leaked through RBT-6 thread into A-annulus measured at 65 liters per day leak rate during well opening. The well was subsequently shut-in until further remediation plan for the CL system.

The abovementioned sealant treatment sequence was then reiterated three times due to the creation of a temporary seal. Following the initial treatments, a third was performed up to 13,000 psi creating a seal that held for over 20 hours, however the seal was lost after performing the standard pressure cycles to open and close the WR-SCSSV valve due to unknown downhole conditions.

Subsequently, a fourth sealant pill was injected, ultimately creating a resilient seal which allowed for the well to be opened for production in Spring 2022. The seal had subsequently held firm during regular 1-yearly well integrity checks and remains in place at the date of this paper publication.

Well Monitoring Program

The recommendation is to keep the well at minimum choke opening until the planned anti-scaling job in Summer 2022 due to risk of scaling formation, therefore well bean-up is not supported to avoid any near-wellbore scaling precipitation. Also, the acid treatment cannot be performed since the well is equipped with WR-SCSSV (potential rubber seals damage).

All SSSV valves (TR-SCSSSV and WR-SCSSSV) on all remote wells on this island will be closed and VHP pressure will be bled off to zero during the Pre-Turnaround readiness period.

The well will be opened at a minimum choke opening followed by a well performance test as per below table after the anti-scaling job in Summer 2022.

Bean-up Step	Recommended Flow Rate/ (BPD)	Recommended Flow Durations (hours)	Approximate Choke Opening
1	5000-7000	Initial step	Mininal
2	10000	48	Medium
3	15000	48	Medium
4	20000	48	Half

Note: Well bean-up will be done gradually in steps of 2% choke increases every 5 minutes

Well Monitoring Program was agreed to continuously monitor well parameters for any abnormalities such as sudden drop/increase of pressure, temperature, and rate.

Results and Conclusion

Following the well's return to production in Spring 2022, the well was allowed to flow for approximately 3 months until the leak was observed to re-emerge. Investigation of the observed temporary sealing achieved over the prior treatments noted that "A" annulus pressure would increase as the well was brought online due to thermal effects, which would in turn serve to reverse the differential pressure direction at the repair upon bleeds. A follow-up, modified sealant treatment was performed in Autumn 2022, whereby emphasis was placed on extending the high-pressure cure of the seal to a span of months, with the goal of obtaining a two-way seal that could withstand a pressure differential from either direction (i.e., repaired direction – CL to "A" Annulus or reversed direction – "A" Annulus to CL). After discussions with the sealant vendor to this end, in regard to preserving seal resiliency post repair, "A" annulus pressure was agreed to be maintained at the lowest level operationally feasible. Additionally, planned shutdowns for the well were carefully managed such that the created seal would be subjected to full operating pressure for as long as possible, with minimized cycling of control line pressure. This extended cure at high pressure would aid in the creation of a two-way seal, robust enough to withstand a sudden pressure loss in the CL and reverse of differential in the case of an ESD.

After the repair in Autumn 2022, these actions were taken, and the well was kept online for the next 6 months allowing for the abovementioned extended cure. At the conclusion of this period, the required flapper test was performed by bleeding the SCSSV control line to just above "A" annulus pressure, preserving a slight differential in the repair direction. The flapper test was ultimately successful, and the well was brought online without any loss of SCSSV/ control line integrity. At the time of this writing, the repair has undergone many cycles during normal operation of the well and remains integral nearly two years later.

Abbreviations

BPD	– Barrels per Day
CFM	– Caged Flow Meter
CL	– Control Line
CO2	– Carbon Dioxide
CRA	– Corrosion Resistant Alloy
ESD	– Emergency Shutdown
GC	– Gauge Cutter
H2S	– Hydrogen Sulfide
HP/HT	– High Pressure/High Temperature
M3/D	– Cubic Meters per Day
RBT	– Rubber Bore Thread
SME	– Subject Matter Expert
SNL-HPT	– Spectral Noise Logging - High Precision Tool
TR-SCSSV	– Tubing Retrievable Surface Controlled Subsurface Safety Valve
THP	– Tubing Head Pressure
VHP	– Very High Pressure (related to process lines pressure)
WR-SCSSV	– Wireline Retrievable Surface Controlled Subsurface Safety Valve

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