SPE-216837-MS

Adopting Cost Effective Cutting-Edge Technology to Mitigate Cemented Annulus Pressure and Reduce Carbon Footprint

R. M. Abdi, ADNOC Onshore, ADNOC Upstream, Inter Casing Pressure Control, Abu Dhabi, United Arab Emirates; A. H. Alhosani, Ali. S. Bin Sumaida, M. H. Ahmad, H. Alshehhi, A. Altamimi, F. H. Issa, F. M. A. Elrefai, D. Barker, and M. J. Murty, ADNOC Onshore, ADNOC Upstream, Inter Casing Pressure Control, Abu Dhabi, United Arab Emirates

This paper was prepared for presentation at the ADIPEC held in Abu Dhabi, UAE, 2 – 5 October, 2023.

Abstract

Sustained casing pressure (SCP) is one of the major well integrity challenges. A variety of annular pressures exist in the wells. Well integrity teams strive to ensure that once the well is flowing at steady state conditions, the pressure from all casing strings should be manageable as low as possible below the Maximum Allowable Annulus Surface Pressure (MAASP). If the annular pressure builds above this level, then the casing exhibits unacceptable SCP. The impact of SCP can develop to critical consequences if not timely managed and brought to an acceptable level.

This paper describes a new approach in controlling SCP using a technique with a high-density, solids-free, non-corrosive, environmentally approved, low-viscosity fluid to control and substantially reduce SCP to acceptable operating levels. The focus of this paper is to demonstrate how to mitigate SCP in the cemented annuli. Production (tubing and packer) and un-cemented annuli are not covered.

Introduction

Leakage in cemented annuli has become a serious issue in producing wells and is often associated with the failure of the cement column behind the casing strings. This occurs sometime after the well has been brought online and, in many cases, leads to undesired pressure (known as sustained casing, inter casing or annulus pressure (SCP/ICP/SAP) in the cemented annulus. This can lead to severe damage to the primary well-integrity barriers and possible loss of containment on the affected well. It has often been found that if the invading effluent is found to contain corrosive properties, or elements (H_2S, CO_2, etc.), causing degradation of the well integrity barriers, these render the previous MAASP values unreliable.

The existing methods of mitigating cemented annulus pressure can be technically complex, very costly (in terms of time, equipment, environmental damage & loss of production), and have proven to be ineffective in many cases. Many wells in ADNOC face the problem of sustained casing pressure.

Per the ISO standard 16530-1: 2017[1], SCP is defined as:

- Unintended pressure in a contained annulus resulting from pressurized formation fluids (liquid/ gas).
- The pressure is measurable at the wellhead termination of a casing annulus valves.
- The pressure rebuilds after having been bled down.
- The pressure is not caused by wellbore temperature fluctuations (thermal effect).

Many wells with SCP are shut-in leading to production deferrals and can ultimately lead to the eventual plugging and abandonment of the well. Frequently, SCP is the result of seepage of subsurface fluids through channels or fractures in the casing-cement bond.

ADNOC has been working with Inter-Casing Pressure Control Inc. (Technology Company) to develop a rig-less solution. The Technology Company has developed a unique treatment system to allow the operator to mitigate the SCP. The technology uses a high-density, solids-free, non-corrosive, environmentally approved, low-viscosity fluid to control and substantially reduce SCP. The pilot for the technology was conducted in four (4) annuli on offshore wells and two (2) annuli on an onshore well.

The objective of this Project was to lower the sustained annuli pressure risks in the cemented annuli by injecting a heavy fluid to substantially kill/reduce this SAP to safe operating levels and reduce the corrosion induced degradation to the tubulars in the well which serves as the primary well integrity barriers.

The solids-free and stable Heavy Fluid is used to build hydrostatic pressure with minimal volume and consequently control the SAP issue without affecting cement or tubulars. The heavy fluid was solids-free and had a specific gravity 2.2 gm/cm^3 as well as low viscosity. These properties aid maximum penetration into micro-annulus gas channels in cement; thereby creating sufficient hydrostatic pressure down the cement annulus to impede and. in most cases, eliminate any further influx of effluent from the zone causing the problem.

Technology Description

This innovative rig-less SCP mitigation solution uses a dynamic process to mitigate and control the cemented annulus SCP over time, substantially reducing the pressure to safe operating levels, as well as reduce the threat of corrosion damage to the tubulars in the well.

The heavy brine used in this innovative "Dynamic Bleed & Lube" process, a recently formulated fluid, has proven to be very effective and environmentally acceptable for offshore and onshore use, a game-changer in the control of sustained annular pressure in hydrocarbon wells.

The treatment entails injecting heavy brine (a cesium formate-based fluid) under controlled conditions into the affected annulus. The technology focuses on controlling the cemented annulus pressure at its source using the heavy brine with a specific gravity of 2.2 gm/cm^3(18.3 ppg). The fluid falls through the cement matrix creating hydrostatic pressure inside the cement column. With continued bleeding and injection cycles, a stage is reached where the source pressure is brought into a pressure equilibrium. The technology does not require the well to be shut-in or interrupt production during the treatment.

The SCP reduction occurs over time with continued cycles of injection and bleeding, the annular space reaches the acceptable limit below the MAASP. Once treated, the chemically and thermally stable heavy brine remains in the cement annulus in a fluid state, thus hydrostatically controlling the leaking fluids. According to ISO/TS 16530-2:2013(E), a hydrostatic column of heavy fluid can be regarded as a well barrier element.

The ADNOC internal Hazard Study conducted on the technology found it to be safe. It is economically compelling as it cures SCP without rig intervention and lost production. The technology has been assessed versus traditional repair methods.

ADNOC's trial in the UAE fields also captured the following additional benefits that are set to have impact to the Oil and Gas industry:

1. No shut-in time: the traditional rig workover activity to cure SCP could take 2-3 months of production loss, while the new technique does not require to shut-in the well
2. Consistent production rates: historically when a well is shut in and taken offline, production rates can drop from previous levels sustained prior to being shut in. This alternative solution removes this risk.
3. Improved well integrity: if untreated, SCP will eventually lead to the potential loss of well control and release of toxic effluents into the environment. This could lead to complete loss of well as a producing entity and require very costly abandonment program which could also directly impact other wells on a platform.
4. Rig availability: rig-less intervention means that rigs will remain available for other operations, such as drilling, which in turn will add to ADNOC productive capacity.
5. HSE benefits: reduced people exposure due to rig-less intervention, and reduced risk of uncontrolled release of subsurface fluids in the environment. Moreover, the compound has no environmental toxicity and is also perfect for application in Offshore environment.
6. It has a high chance of success.
7. The production casing is not compromised by perforations.
8. It is significantly cheaper as rig intervention is not required.

Trials have shown that the treatment succeeds from a business perspective as well as from the operational standpoint, as it was demonstrated to be a very practical solution.

The well integrity is improved, which reduces the possibility of a loss of well control and the risk of the well having to be plugged and abandoned. Moreover, it is a very effective "mitigation solution" that can allow continued production until the well is scheduled for workover for other reasons. CO2 emissions related to rig-based interventions are eliminated. Conventional methods of curing SCP wells are very costly, disrupt production, add significant risk and offer no guarantee of success.

Treatment Overview

The overall objective of the treatment is to build a hydrostatic fluid column in the cement annulus using heavy brine, 2.2 S.G., and a lubricate and bleed strategy to control the SCP. The treatment unit is designed to inject the heavy brine treatment fluid at a specified injection rate and build the annulus pressure to a calculated value while never exceeding MAASP/MAWOP. Fluid volume being injected is carefully tracked along with injection pressure while the treatment fluid is being placed in the cement annuli.

Once the required volume of heavy brine has been injected into the cement annuli, multiple bleed & lube cycles may be required. The annulus will be allowed to rest for a period. This is to allow gravity to help the heavy brine treatment fluid fall in the cement matrix and begin to create the necessary hydrostatic pressure needed to control the influx of hydrocarbons into these annuli (Fig 1).

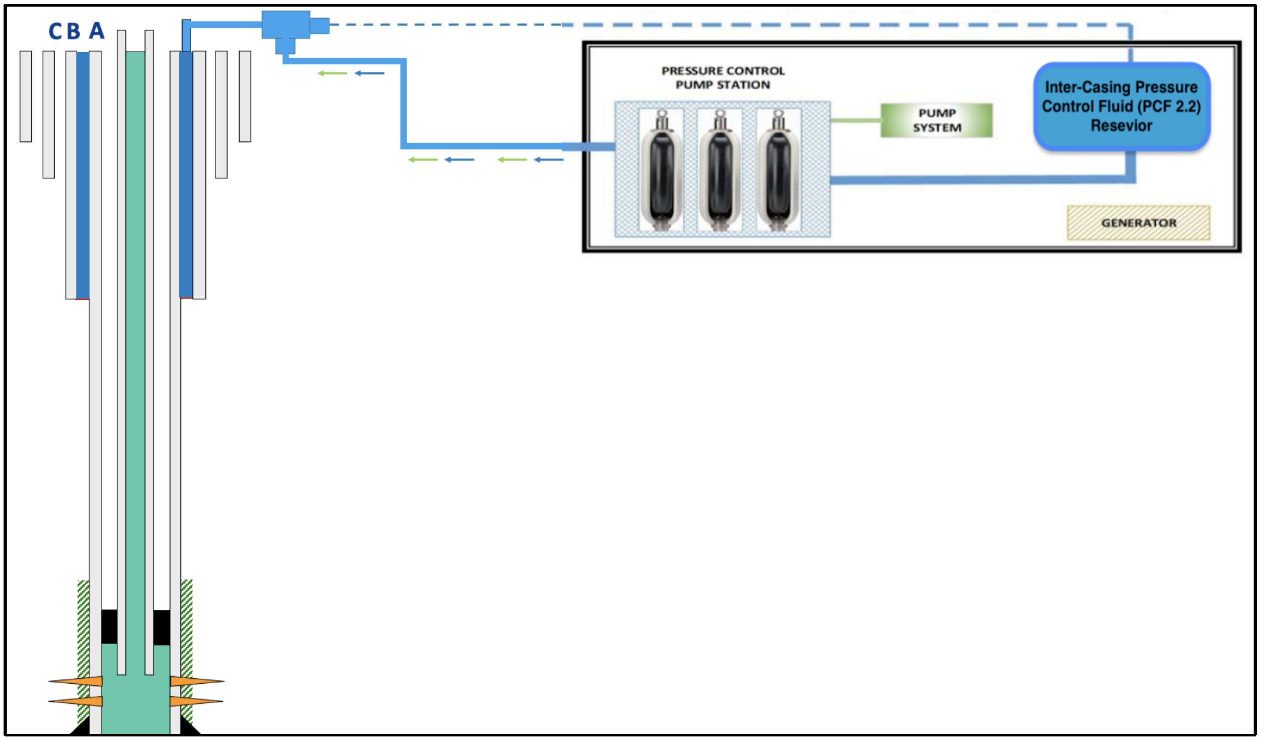


Figure 1—Treatment Complete with the Fluid Injected in the Cemented B Annulus

Fig. 2- is a graphical representation of the steps required to complete the treatment.

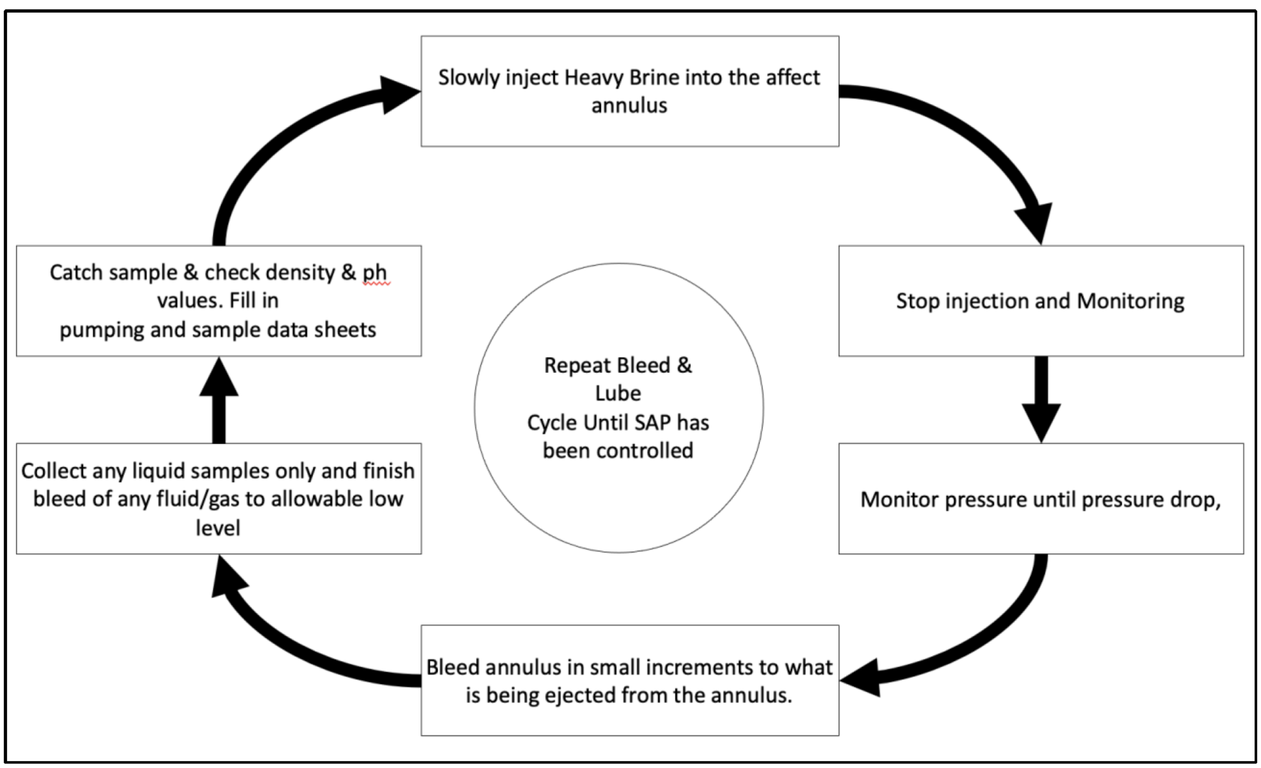


Figure 2—Treatment Process

Nitrogen Injection Technique

In most wells, nitrogen is used to evaluate the flow paths in the annuli and the injectivity to the point of influx. The injection is conducted using nitrogen pressurized bottles with a pressure control manifold, electronic recording gauges, one-way valves, and a set of high-pressure hoses.

This testing is important to help identify the estimated volume from the wellhead to top of residual liquid level or cement top for each annulus and to establish possible feed rates. The acquired data will help to design the treatment program and to better evaluate the post-job treatment.

After acquiring all the injection and pretreatment build-up results, an analysis is performed to identify the estimated treatment injection rate, volume, and annulus treatment feasibility.

SCP Diagnostic Testing Approach

It is important that a comprehensive approach to the diagnosis of SCP issues in a well is adopted. Focusing on the complete well behavior and not the specific SCP problem without considering all parameters may result in incorrect conclusions or a less than optimal remediation action. The Well Integrity Team must address all casing pressure diagnostics and issues on a whole well basis. This also means that when any annulus on a well needs a diagnostic test, field operators must check the pressure response on all casings at the same time.

The trial utilized a specific procedure for SCP diagnosis noting the bleed-down and build rates of pressure in each annulus over a period. The SCP buildup is recorded graphically (or in a table increments) for each casing annulus in the wellbore. If fluid is recovered during bleed-down, operators must record the type and amount. The technical complexity of the SCP mechanism requires the inclusion of the measurement of the gas and liquid flow rates as a part of the SCP risk evaluation. Operators should conduct pressure bleed-down in such a way to minimize the removal of liquid from the annulus.

The results are then analyzed, and tests repeated as necessary to understand the SCP source and the severity of the problem. Tubing and packer leaks can be fixed by a conventional workover but for cemented annuli, the use of a rig for SCP remediation is not recommended.

SCP Diagnostic Test Result

There are different types of results when diagnosing annuli. Generally, the following pressure patterns are observed:

- Immediate bleed down.
- Un-bleedable pressure.
- Normal build-up rates.

The immediate bleed down pattern occurs when the valve is opened and a small amount of gas or liquid bleeds to 0 psi within short time with no further flow while the valve is open.

The un-bleedable pressure is when the bleed process does not reach to 0 psi within a certain period and flow continues out of the annulus.

Normal build up behavior is when the pressure recovers quickly after the bleed down and then stabilizes at a certain period.

Candidate Selection and Treatment

A selection criterion was developed to assist for choosing the best well candidates for annulus treatment based on specific criteria set to prioritize the well treatment.

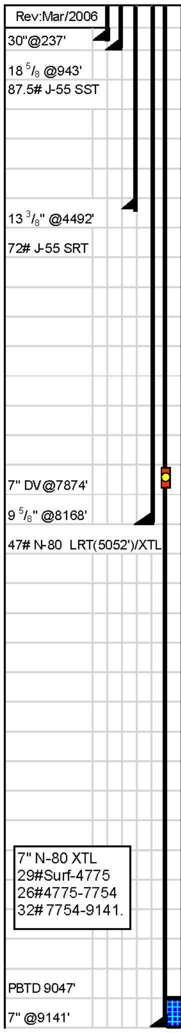
1. Identify candidate wells with SCP concerns.
2. Determine what annulus effluent is recovered. Determine both current and historical bleed and buildup rates and compare how fast doe the pressures recover after a bleed.
3. If there is no real-time data available, conduct annulus pressure monitoring for a minimum of two weeks by installing recording gauges to monitor the pressures.
4. Conduct a minimum of three (3) bleed and buildup cycles. The final bleed-off pressure should always be approximately the same value each time. Monitor returns, capture, and measure any fluid volumes recovered.
5. If there is water or oil to surface, evaluate the bleed and build-up and determine if nitrogen injection should be conducted.
6. If there is gas to surface, evaluate the bleed and buildup and determine if nitrogen injection should be conducted.
7. Evaluate drilling activity, cement bond log data, and all workover histories.
   - Assess the cement condition behind casing.
   - Identify probable leak source.
   - Review drilling report and evaluate cementing operations including, but not limited to, cement back flow, shoe strength test, cement return at surface, etc.

Below are some examples of well annuli data gathering and investigation to select a candidate for the treatment. Table. 1- shows direct surveys conducted to obtain the pressure bleed down and build up data.

Table 1—Manual Annulus Pressure Data Monitoring

Well	Survey Date	Annulus size	Pressure Psig	Bleed down	B/D	B/D Time	Effluent	B/U	B/U Time	Status
XYZ	15/07/2018	TBG X 7	0	N						
XYZ	15/07/2018	7 X 9 5/8	450	N						
XYZ	15/07/2018	9 5/8 X 13 3/8	350	N						
XYZ	15/07/2018	13 3/8 X 18 5/8	0	N						
XYZ	11/1/2018	TBG X 7	650	N						
XYZ	11/1/2018	7 X 9 5/8	100	Y	0	15	Oil	30	30	Active
XYZ	11/1/2018	9 5/8 X 13 3/8	0	N						
XYZ	8/11/2017	TBG X 7	100	N	0	20	Oil	40	30	Active
XYZ	8/11/2017	7 X 9 5/8	40	N						
XYZ	8/11/2017	9 5/8 X 13 3/8	0	N						
XYZ	8/11/2017	13 3/8 X 18 5/8	120	N						
XYZ	24/10/2017	TBG X 7	0	N						
XYZ	24/10/2017	7 X 9 5/8	0	N						
XYZ	24/10/2017	9 5/8 X 13 3/8	1200	Y	0	20	Oil	30	30	Active
XYZ	25/09/2017	TBG X 7	0	N						
XYZ	25/09/2017	7 X 9 5/8	10	Y	0	20	Oil	30	30	Active
XYZ	25/09/2017	9 5/8 X 13 3/8	1215	N						
XYZ	18/09/2017	TBG X 7	25	N						
XYZ	18/09/2017	7 X 9 5/8	20	Y	0		Oil			
XYZ	18/09/2017	9 5/8 X 13 3/8	0	N						

Fig. 3- is an example of a cement evaluation used to determine the best candidates for this treatment.



Formation Name	Depth (Ft) Top	Depth (Ft) Bottom	13 3/8" NA	9 5/8" NA	7" CBL-VDL
Rus	1690	1966	Not Logged		
Radhuma	1966	3124	Not Logged		
Simsima	3124	3756	Not Logged		
Fiqa	3756	4158	Not Logged		
Halul	4158	4470	Not Logged		
Laffan	4470	4538	Not Logged	Not Logged	
Mishrif	4538	5153		Not Logged	
Salb Shil	5153	5587		Not Logged	
Nahr Umr	5587	6006		Not Logged	
TH I (5929)	6006	6197		Not Logged	
TH II (6120)	6197	6305		Not Logged	
TH III	6305	6930		Not Logged	
TH IV	6930	7146		Not Logged	
TH V	7146	7558		Not Logged	
TH VI	7558	8100		Not Logged	
HITH	8100	8168		Not Logged	Overlap section
	8168	8298			Possible Isolation
ARAB A0	8298	8326			Possible Isolation
ARAB A1	8326	8365			Possible Isolation
ARAB A2	8365	8400			Possible Isolation
ARAB B1	8400	8425			Possible Isolation
ARAB B2	8425	8463			Possible Isolation
ARAB C1	8463	8478			Possible Isolation
ARAB C2	8478	8499			Possible Isolation
ARAB C3	8499	8583			Possible Isolation
ARAB D2	8583	8677			Possible Isolation
ARAB D3U	8677	8752			Possible Isolation
ARAB D3M	8752	8805			Possible Isolation
ARAB D3L	8805	8867			Possible Isolation
ARAB D4U	8867	8956			Possible Isolation
ARAB D4M	8956	9022			Possible Isolation
ARAB D4L	9022	9056			Not Logged
ARAB D5	9056	9147			Not Logged

Cement Evaluation & Interpretaion Keys	
Possible Isolation	Possible isolation is expected across the evaluated interval.
Possible Communication	Possible communication is expected across the evaluated interval.
Possible Communication with gas	Poor cement or micro-annulus may cause communication and gas is expected.
Interpretation not Possible	Not enough reliable data to make an evaluation.
DV	
ECP	
TOL	
SN-AT packer	

Cementing Operations
30" Casing: Cmnt w/ 930 cft 1.75 sg slurry. Good cement returns to sea bed.
18 5/8" casing:2325 cuft 1.75 sg slurry.Plug not Bumped. No cmt returns. Top up jobs: 300 cft 1.8sg +327 cft 1.85sg + 30 cft 1.8sg. Tag TOC 895'. Unable to get satisfactory shoe bond test.
13 3/8" casing:3280cft 1.4 sg Diacel mix shallow well cmt + 1110 cft 1.75 sg shaloow well cmt.Temp log indicated TOC 2200'(1.4sg) & 3400'(1.75sg). Top up Jobs:2350 cft 1.3sg +70 cft 1.29 sg. **SBT**: Drill shoe.Test shoe to 500 psi, 1.09 sg mud.
9 5/8" casing:cmnt w/ 2730 cft 1.4 Diacel D cmt +89 cft 1.72 sg Dykherhoff cmt. Cmnt returns to surface. Tag TOC 8088'. Drill shoe. Test shoe to 600 psi, 1.28 sg mud.
7" Casing:1st stage: 225 cft 1.71sg. Open DV 1250 Psi. No cmt returns. After WOC 8 hrs, Test 7" x 9 5/8" annulus 1625 Psi, Ok. 2nd stage: 1250 cft 1.8 sg. Close DV 4000 Psi. Drill DV & test to 500 psi. Tag Toc 9012'. Clean to 9047.
Workover Mar 2006: To restore well integrity and change completion.

Figure 3—Example of Cement Evaluation sheet

Leak rate measurements should be conducted to evaluate the annuli leak before the treatment. The test includes acoustic measurements, pressure bleed-down test, communication test, direct leak metering, pressure build-up test, and a gas compositional analysis.

In Fig. 4- through Fig. 8- the pretreatment testing analyses show a persistent build-up and leak confirmed at surface.

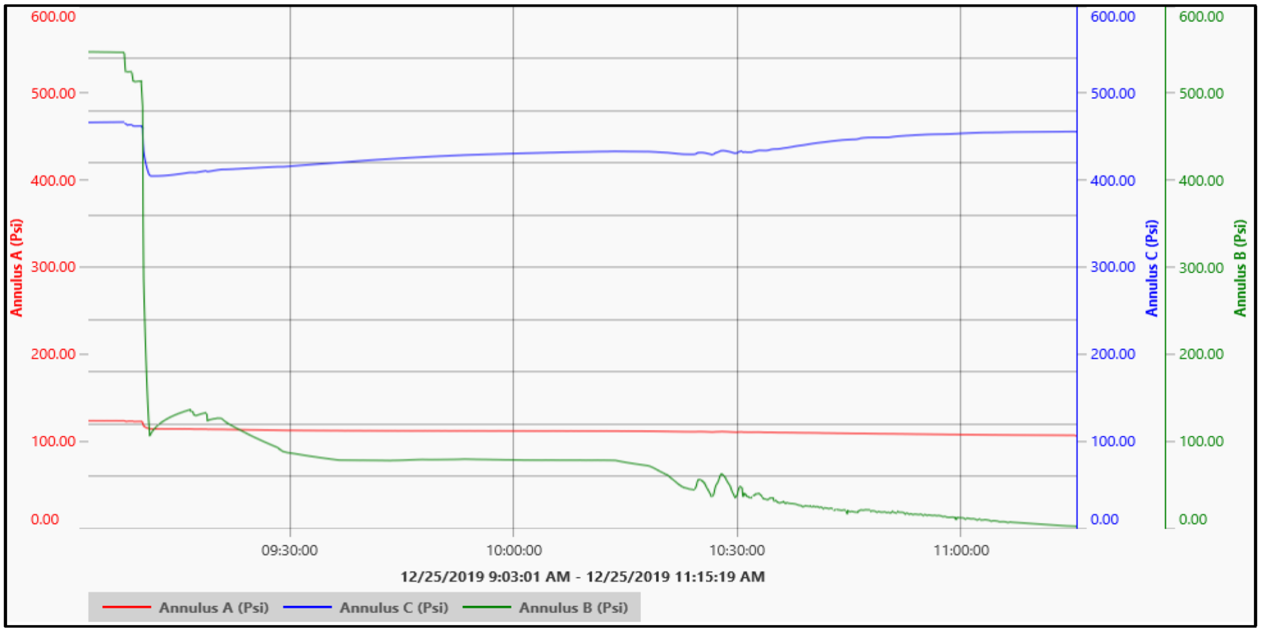


Figure 4—Bleed Down Period – Pressure Data

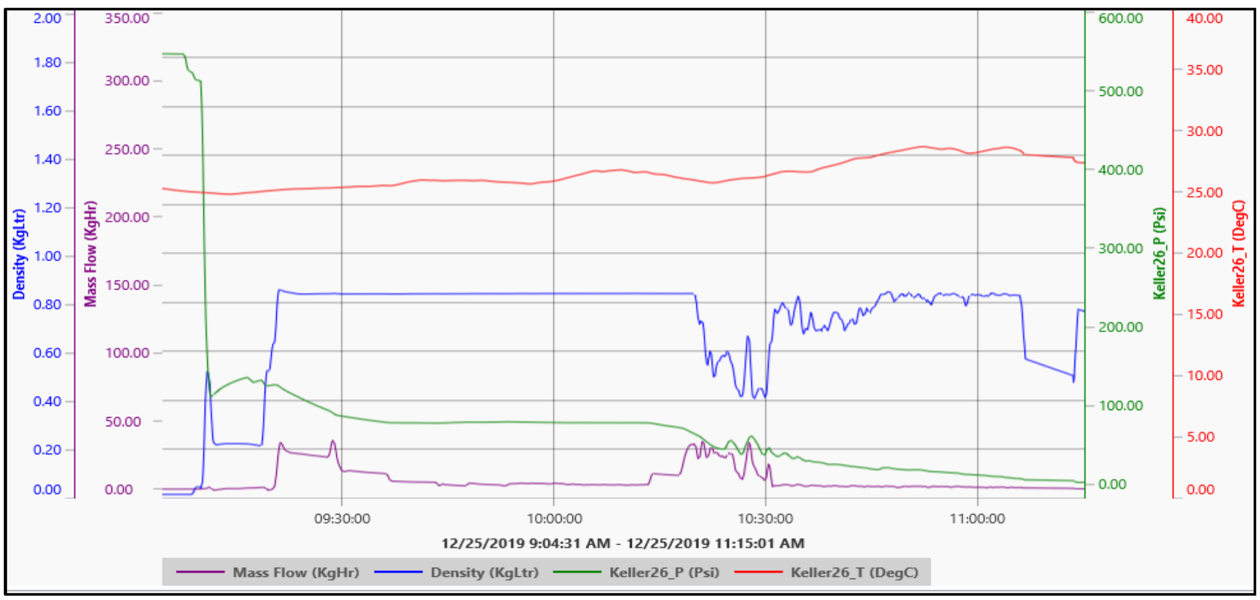


Figure 5—Bleed Down Period – Flow Data

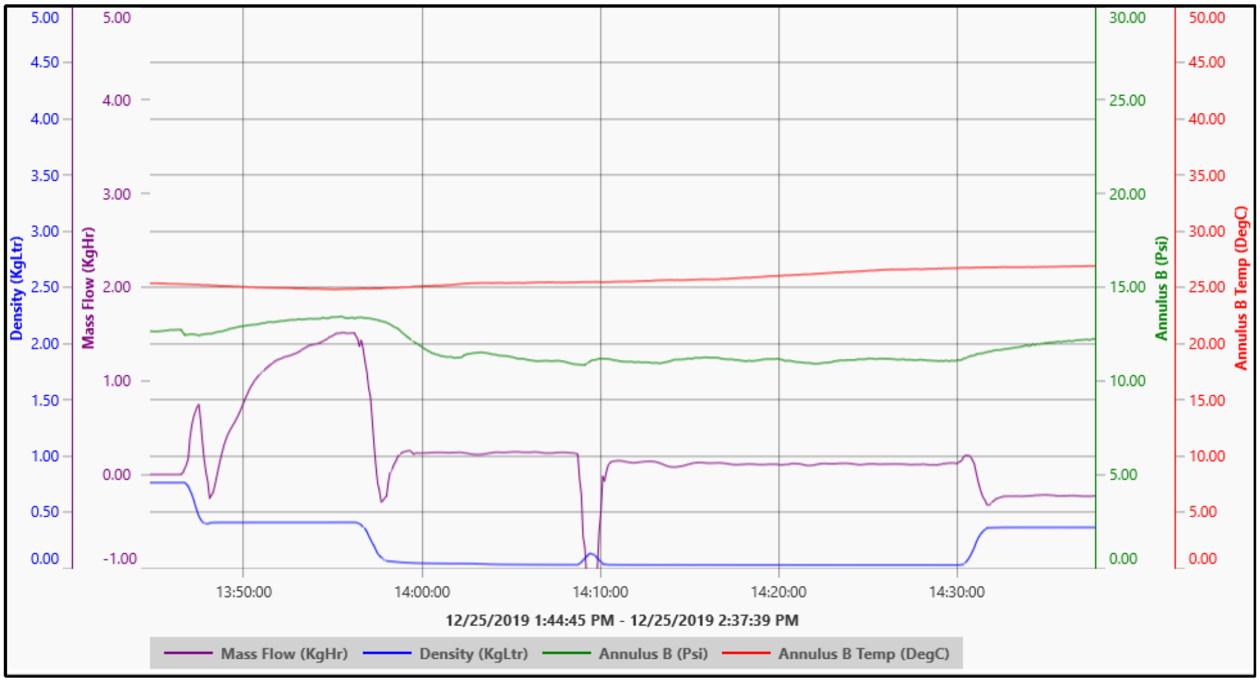


Figure 6—Direct Leak Metering

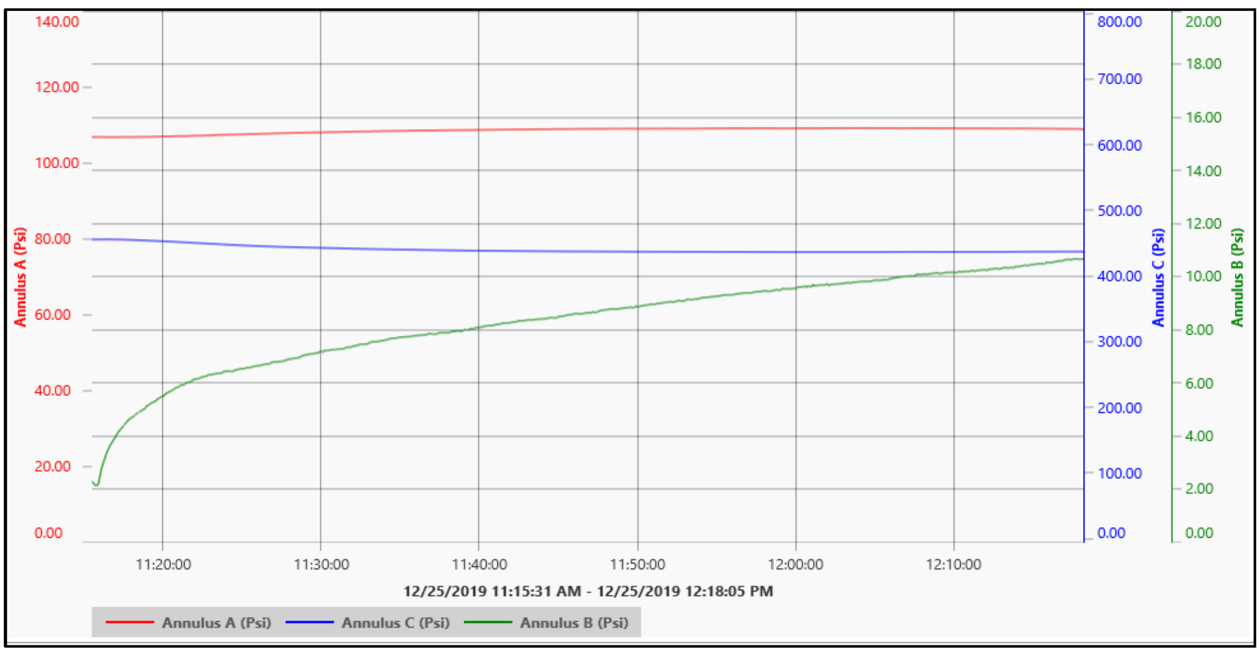


Figure 7—Pretreatment Pressure Build-Up

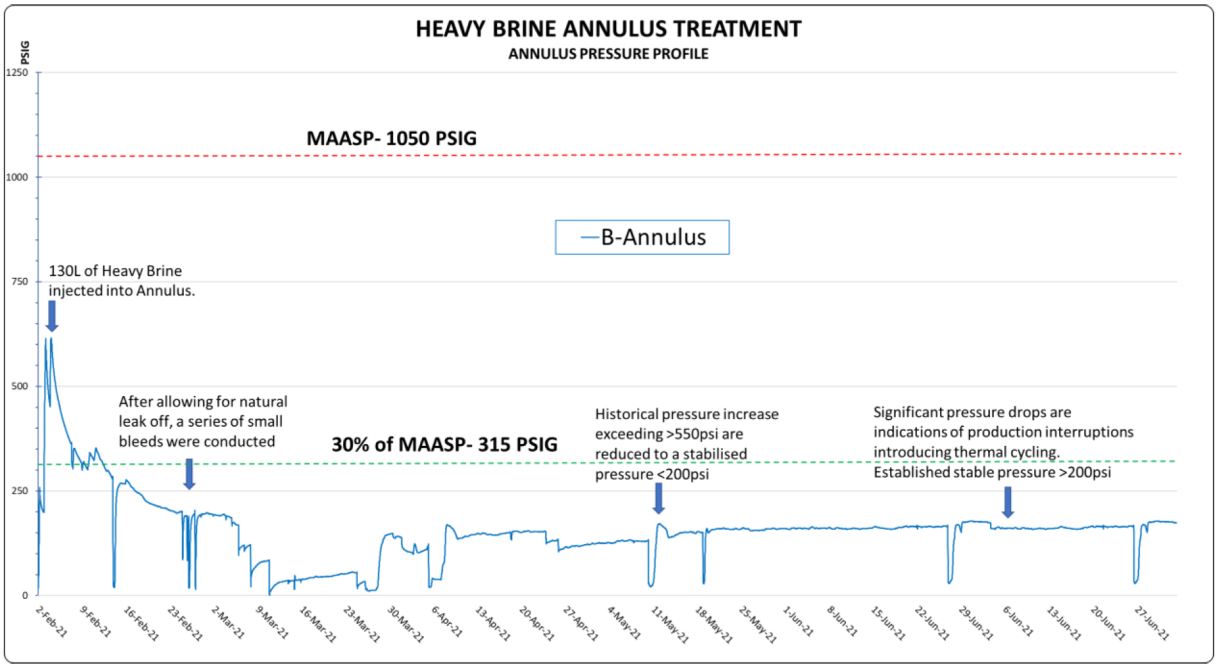


Figure 8—Pressure Data for Offshore Well B Annulus Treated with Heavy Brine

Treatment Pressure Data and Result

Fig. 8-through Fig. 11- show the treatment and post treatment pressure results on offshore wells' B and C annuli.

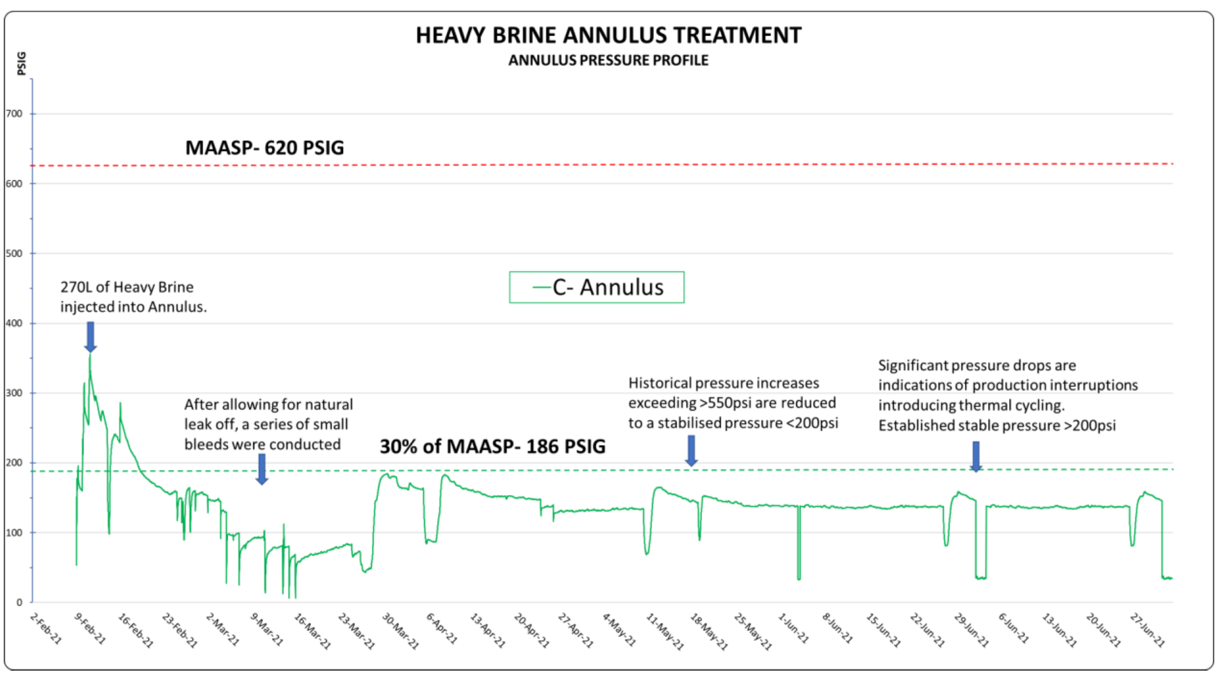


Figure 9—Pressure Data for Offshore Well C Annulus Treated with Heavy Brine

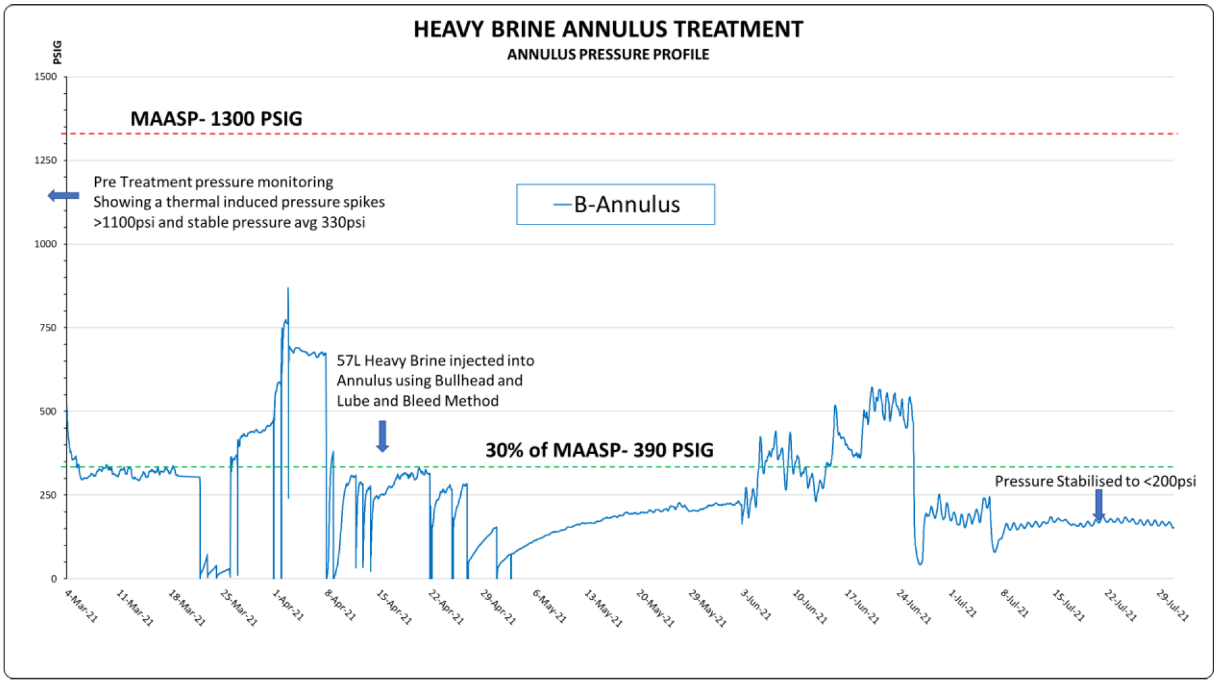


Figure 10—Pressure Data for Offshore Well B Annulus Treated with Heavy Brine

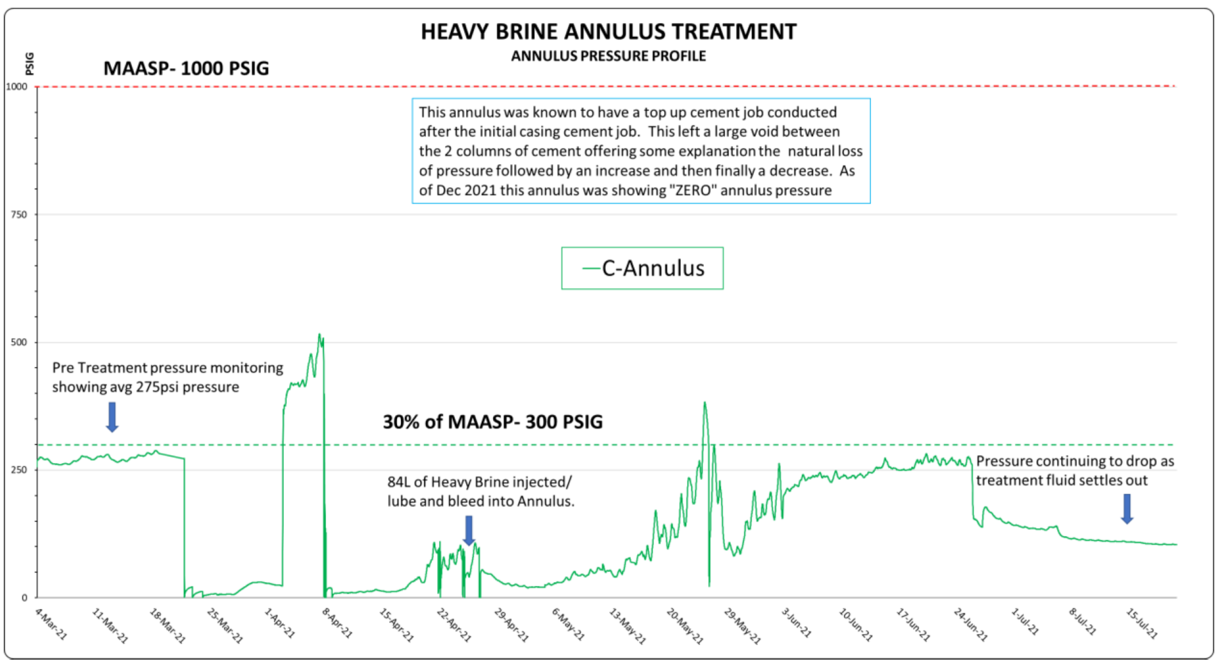


Figure 11—Pressure Data for Offshore Well C Annulus Treated with Heavy Brine

Fig. 12- shows the treatment and post treatment pressure results on an onshore well in the A annulus (tubing was cemented in place).

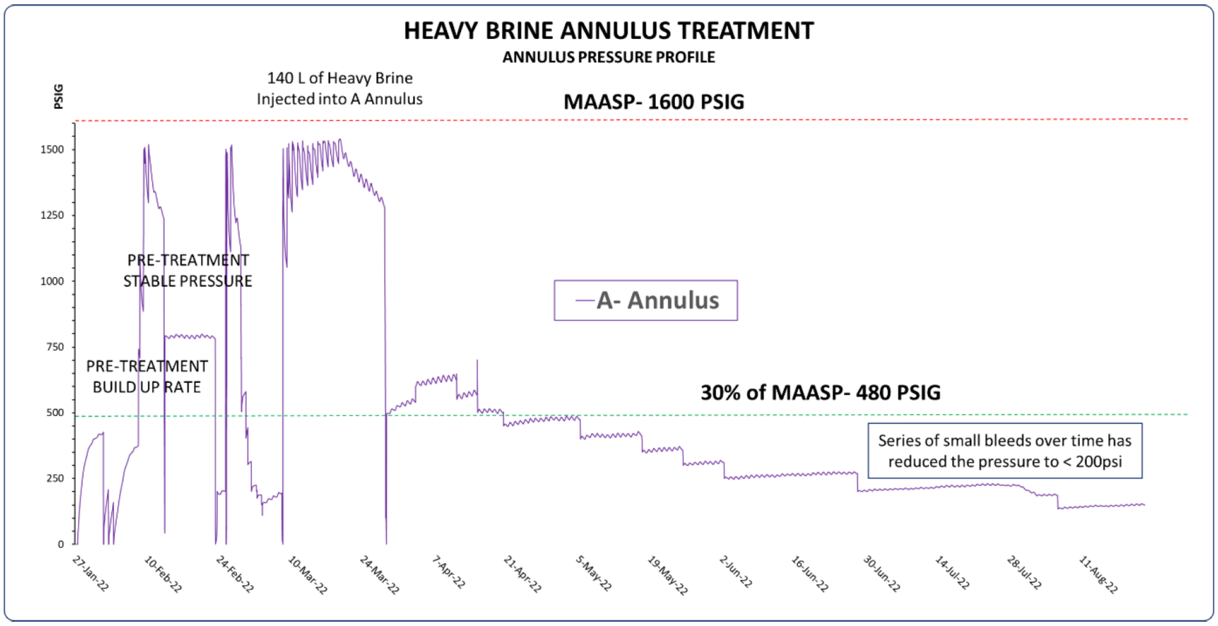


Figure 12—Pressure Data for Onshore Well A Annulus Treated with Heavy Brine.

Conclusion

The trial treatment project was successful. The trial has achieved the objective of reducing the pressure below 30% of MAASP for 3 out of 4 annuli on the offshore wells. The remaining annulus responded to the treatment but requires additional top-up heavy brine.

The onshore treatments achieved the objective of reducing the pressure below 30% of MAASP on one annulus with the second annulus needing additional heavy brine.

The treatments resulted in a fast and effective way to reduce SCP well integrity issues thereby reducing down-time and increasing the wells availability for production. Reportedly, the technique was used in more than 90 wells with a reported 90% success rate in another field outside of the UAE.

The required volume depends on the candidate well's annulus characteristics. Each annulus is different depending on the casing sizes, top of cement, and the characteristics of the SCP source. In general, larger volumes pumped in both annuli will reduce the pressures to lower values and increase the likelihood of success to manage the SCP.

- Actual annulus treatment duration depends on pressure response and effluent type.
- The injection time and operation vary and depends on different factors for location and well construction.
- Heavy brine may require different times to fall in the cement sheath depending on conditions within the annulus.
- Specific bleed down procedures needs to be implemented to avoid potential bleed of the injected heavy brine out of the annulus.
- Using nitrogen injectivity tests prior to the treatment assists the design and increases the probability of success.
- Annuli with low injectivity rates require additional time for treatment.
- The duration and rate of the bleed down(s) after completing the operation must be tailored to each annulus to release the energy induced by the heavy brine injection.
- The technique is a very effective mitigation solution to allow continued production until the well is scheduled for a workover for other reasons.

Project Added Value

ADNOC's trial in the UAE fields also captured the following additional benefits that are set to have an impact to the Oil and Gas industry

1. No shut-in time: The traditional rig workover activity to cure SCP could result in 2 or 3 months of production loss, while the new technique does not require to shut-in the well.
2. Consistent production rates: Historically, when a well is shut in and taken offline, production rates may drop from previous levels. This alternative solution removes this risk.
3. Improved well integrity: If untreated, SCP will eventually lead to the potential loss of well control and release of toxic effluents into the environment. This could lead to complete loss of the well as a producing entity and require a very costly abandonment program.
4. Rig availability: Rig-less intervention means that rigs will remain available for other operations for better resource optimization
5. HSE benefits are also observed, such as reduced personnel exposure and reduced risk of uncontrolled release of subsurface fluids in the environment. Moreover, the compound has no environmental toxicity and is perfect for application in offshore and onshore environments reducing CO2 emission.
6. Practicality: It can be implemented without any disruption to operations.

Further Observations

- Actual annulus treatment duration depends on pressure response and effluent type.
- Offshore weather conditions impact logistics and therefore the treatment timing and overall duration of the program.
- The initial equipment design weight and size can be problematic for offshore logistics. The new injection unit is easily helicopter portable and fully self-contained.
- The heavy brine may require longer time to fall in the cement sheath depending on conditions within the annulus.
- Well production disturbances have a temporary negative effect on the treatment, especially for gas wells. This appears to be a temporary situation which, with time, rectifies itself.
- Specific bleed down procedures needs to be implemented to avoid potential bleed of the injected heavy brine out of the annulus.
- Annuli with low injectivity rates require additional time for treatment.
- Well integrity industry standards (ISO 16530-1:2017[1]) recommend annular bleeds when SCP approaches MAWOP. This can not only make the issue worse but leads to needless environmental emissions when this novel method can now be applied.

Acknowledgments

The authors would like to extend appreciation and thanks to (Mr. Raymond Burke), Dr Elyes Draoui (VPFD US/NS/LZ), Dr Abdulla Naqbi (SVP LZ/US/NS/ABK), Mr. Mohamed Saleh Ali (Well integrity manager), Mr. Sultan D. AlHassani (Petroleum manager US) for their support to implement the pilot jobs. The authors also would like to thank Mr. Colin Cottrell and Mr. Stan LaMascus from ICPC for equipment supply, project oversight, and vision. Chemix Ltd. for provision of the heavy brine and stimulating the interest in the project at the outset.[DMTIAS1]

References

ISO 16530-1:2017, Petroleum and natural gas industries — Well integrity — Part 1: Life cycle governance Definitions Subsection 3.641.

ADNOC OFFSHORE. (2007). Cement evaluation report. Internal ADNOC OFFSHORE report: Unpublished 2.

ADNOC OFFSHORE. (2015). Well integrity data management system. Internal ADNOC OFFSHORE report: Unpublished 3.