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Assessment of the Risks and Challenges Encountered During Well Clean Up and Test on Niger Delta Gas Wells - Based on Practical Experience on Cases

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Abstract: In this work, the risks, non-technical and operational challenges encountered during well clean up and test on Niger Delta gas wells are assessed based on practical experience on four gas wells worked on by the authors. Previous works on general challenges and improvements in well clean up and tests were consulted, which formed the bedrock of this review paper. The reservoir and wells worked on are described. The reservoir is a non-associated gas reservoir in one of the Niger Delta fields. The challenges faced in the course of the cleanup and well test services on the four gas wells are presented in section 3 of the work. These challenges include issues of safety onsite; logistics management; commercial/contractual challenges and operational challenges like coiled tubing (CT) breakdown, CT inability to get to targeted depths, etc. The recommended and adopted solutions to the challenges are presented in section 4 of the work. The entire section 5 is a robust assessment of risks in gas well clean up and test operations. Risks probability, impact, consequences and mitigation methods are presented in Tables 1 to 5 of this section. Adhering to the recommended solutions and mitigation methods for the challenges and the risks illustrated in this work, would help eliminate downtime and unwanted happenings in the course of gas well clean up and test thereby making operations very successful.

Keywords: Gas Well, Clean-up, Well Test, Risks, Challenges

1. Introduction

Well cleanup is often overlooked, yet it is a very important step in the process of delivering a new well into production. Considerable expenses and efforts are frequently lavished on the drilling and completion designs, yet when it comes to bringing the well "on-line", very little thought is given as to how to put the well in its best condition for optimal production [1].

Well cleanup is the removal of solids, completion fluid, and sand workover fluids by production [2]. Well test results before well clean up may reflect temporary obstruction to flow that will not be present in later tests, since during that period the skin effect will still be changing due to the fact that drilling debris and fluids are still coming out of the formation and perforations [3].

Wellbore debris is a major challenge in wellbores worldwide. A clean wellbore is important when running expensive and sensitive completion strings. Any failure while running a completion will have a high impact in well costs. Therefore, the removal and collection of debris are of high importance [4].

Wellbore cleanup and displacement technology enhance operational efficiency by reducing risk and non-productive time. Wellbore cleanup mechanical tools and chemicals remove debris that interfere with normal operations without damaging the well structure. Effective wellbore clean up and debris management ensures successful completion operations and maximizing of reservoir returns. The complete suite of wellbore clean up mechanical tools include products for displacement, casing cleaning, blowout preventer (BOP), riser cleaning, and debris management [5].

A new technique to optimally clean-up wells has been developed [1]. The method employs coiled tubing and pumped nitrogen to provide a controlled lift of the wellbore fluids, it also makes use of a multiphase flow meter to monitor the results, and a simulation software to model the process in real-time so that timely operational decisions can be made. This new technique was successfully applied to several challenging near-horizontal extended reach well completions. The method can effectively clean out perforations and achieve an efficient displacement of the completion fluid out of the well. It also provides the control necessary to prevent damaging fragile formations and to minimize the risk of leaving bypassed completion fluid in a horizontal section. The method also avoids the undesirable use of electrical cable in the coiled tubing to monitor the downhole conditions. Real-time surface fluid recovery and downhole nitrogen injection rates and volumes are obtained with the method. Fluid lift simulations performed on-site during the lifting operation are history matched to actual well production data. Immediate adjustments to the lift can be made to optimize the well clean-up [1].

2. Challenges and Existing Improvements in Well Clean up and Test Operations

Wellbore cleanup is a critical component of any new well construction. Failure to adequately clean the wellbore can cause major difficulties in running the completion resulting in large amounts of non-productive time with all the associated costs. Conversely, performing over-complicated cleanups to ensure success adds additional risks and unnecessary extra cost [6].

Fleming et al examined an operator's experience with wellbore cleanup over a wide range of assets in the UK and Norwegian sectors of the North Sea [6]. The operator wished to reduce the time taken by developing best practice guidelines. The work would provide a common approach to wellbore cleanup operations over all assets. In the work, reports from 19 offshore wells completed between 2002 and 2004, were used to split the time taken during cleanup operations between nine categories:

Running Tools
Chemical Clean up / Displacement
Pit Cleaning
Waiting on Equipment
Waiting on Weather
Pressure Testing
Non-cleanup Operations
Safety Events
Waiting on Permits

Fleming et al also identified the causes of extended time and the areas where most time could potentially be saved were pinpointed [6]. Some of those were:

Clean up tool failures
Over-complicated tool-strings
Becoming stuck due to over ambitious tool-strings
Rig equipment failures
Incomplete tools being sent offshore
Repeating of chemical clean up due to wellbore filters being full of mud/debris
Delays while waiting for pit cleaning to be completed
Lessons not being learned from other assets

These and other causes were discussed and further examined by operator staff in a workshop. Guidelines were then developed by combining existing good practices from different assets and other industry experience and were presented in [6].

In one of their well cleanup and testing operations, Abu et al encountered a challenge in improving water quality prior to discharge to the sea by the rig/barge [7]. They studied various technology in order to achieve the HSE requirements. They selected the following two systems for trials:

The 1st system (de-oiling) mainly consists of a degasser, hydro-cyclone, reject oil tank, pumping units, and control panel all on one skid.

The 2nd system is a two-stage treatment process using patented adsorption media.

In their paper, they discussed the process description, field trial data, impact on the environment and other related technical information in handling this challenge.

Onyeanuna et al presented the experiences of well clean-up operations carried out in the development wells of Akpo deepwater field which was producing about 175,000 barrels of condensates per day then. Akpo is located 135 km offshore Nigeria in 1400 m of water depth [8]. The reservoirs consist of faulted, unconsolidated, turbiditic channel and lobe sands with complex architecture. The fluids in each reservoir are near-critical. The sand control techniques then were Frac-Pack (FP), Stand Alone Screen (SAS) and Expandable Screen (ES). Early data acquisition during well clean-ups was essential in other to optimize the development strategy, ensure a production ramp-up in line with expectation and reduce remaining uncertainties which were mainly linked to sand communication within channel complexes, fluid behaviour, and faults behaviour (seal or conduit). Onyeanuna et al covered the clean-up design, execution, operations monitoring, data acquisition, and fluid sampling, along with the challenges and constraints encountered in the process for the different wells [8]. They described how the challenge of hydrates formation, exacerbated by the deepwater environment and peculiar nature of the reservoir fluid, was handled to ensure successful well clean-ups. They also gave an example of how the early data acquisition program impacted important field development decisions.

Conventionally, well completion would involve perforating the reservoir followed by a separate run to clean up the wellbore from perforating debris and burrs on the casing and liner to prevent damage to the completion packer when passing through the perforated interval. This is especially prevalent in dual completion and single selective completion wells where the lower packer will have to be run past the upper set of perforations. The wellbore clean up bottomhole assembly typically consists of a drill bit scraper and magnets run between the perforating and well completion phases. As a result of the increasing emphasis on reducing operating costs and increasing operating efficiency, a new system was designed for perforating wells in underbalanced condition and performing post perforation wellbore clean up in the same run by using standard equipment and techniques. The concept was developed after identifying the opportunity to optimize operations in wells where the perforating and wellbore clean up equipment operations are required. Five jobs had been performed employing this combined underbalanced perforating and wellbore clean up technique which has resulted in significant savings in rig time and increased operating efficiency. Lafontan et al summarized the practical experiences gained during the development and deployment of this integrated perforating and wellbore clean up technique [9].

Mollayev et al introduced an innovative completion clean-up design and execution [10]. Their paper described the design and operational performance of the 15kpsi Shah Deniz Stage 2 (SD II) completion clean-up surface process equipment which was designed to ensure solid/debris-free gas/condensate production at first gas in 2018. Their project demonstrated a genuine step change in the design and operation of well testing and clean-up systems. It took process safety to a new level whilst simultaneously reducing the overall equipment footprint, compared to traditional well test systems. The design brief for their project included a requirement to safely process and correctly dispose of all fluids produced from completed SD II production wells. That included formation hydrocarbons at elevated flow rates, completion fluids, and residual drilling fluids. The surface package also had to fit within the rig well test deck and individual skid weights kept within the rigs crane capacity. As a result, the decision was made to design, engineer and manufacture a customized set of equipment. Additionally, an upgraded data acquisition system was required to process the increased volume of data as well as provide the required level of system monitoring and control. An enhanced process shut down system was also needed in order to implement the shutdown philosophy demanded by the projects process safety policies.

Soft sand wells are typically more expensive completions due to the need for sand control. The cost of the wells makes the completions more high-risk and increases the need for laboratory testing to validate the screen or gravel pack sizing as well as drill-in fluid selection and filter cake clean up [11]. Dynamic drill-in fluid clean-up testing provides a state of the art methodology for determining the least damaging drill-in fluid and/or the most effective clean-up treatment for the filter cake. However, the test method to date, referenced in SPE 112497 and SPE 179024 has used a 100% uniform clean-up treatment approach. This approach has assumed that all of the clean-up treatment uniformly contacts and treats the filter cake. In the actual well, it is unlikely that 100% uniform clean-up exists [11]. It is possible in the wellbore to encounter selective clean-up treatment leak-off due to permeability differences or variable filter cake thickness. Fischer investigated the results when a less uniform clean-up environment is encountered [11].

Optimized well clean-up planning and procedures are crucial for the effective development of offshore subsea wells and subsequent fluid production to host facilities. The objective of the well clean up is aimed at ensuring a successful removal of the completion fluids and drill-in fluid out of the wellbore to restore connectivity with the reservoir, maximize well productivity while minimizing tensile sand failure, and properly conditioning the sand face completion (in a standalone screen scenario) [12]. To achieve this goal, the well clean-up time, bean-up procedure, rate, and fluid volumes to be produced should be appropriately estimated to properly size the surface testing equipment required for the operation [12]. Due to the highly dynamic and transient nature of the cleanup process, the use of a dynamic simulator was required to effectively capture the physics of the concurrent flow of the various phases present in the system [12]. Dimude et al performed an extensive modelling and simulation of the unload process through the use of a dynamic multiphase simulator to assess the transient displacement of the various wellbore fluids according to several unload strategies [12]. Potential clean-up times and volumes were assessed using flow rate ramp-up schedules designed for different completion fluid distributions in the wellbore. The constrained flow rate cases were considered to represent the constraint on the rig (restricted because of surface handling capacity issues). The well clean-up procedure was developed to minimize clean-up time, avoid formation damage, and minimize the volume of formation liquids on flow back during the rig well tests. During the execution, the movement of fluids along the wellbore, surface production rates, the drawdowns and duration of clean-up to predefined targets were monitored and recorded. The acquired field data from the clean-up operation was compared against simulation prediction and the reliability of the predictive model was validated. Dimude et al proved the transient multiphase simulation to be effective in capturing the physics of the multiphase flow process involved in the clean-up operation [12]. It also demonstrated that, when appropriately done, it could be an effective tool for the planning and strategy selection for the well cleanup operation.

Mesophase technology for wellbore clean-up and remediation in the drilling industry has been used in various oil fields to increase well productivity and injectivity. The majority of these applications include oil-based mud filter cake removal, near-wellbore remediation, and wellbore displacement [13]. The open hole wells completed with standalone screens in the deepwater tertiary formations offshore West Africa have benefited from previous knowledge and experiences accumulated by the operator and the service company in the application of Mesophase technology in other fields. Pietrangeli et al discussed the field application of the Mesophase technology in several deepwater offshore fields in West Africa [13]. Previous to the field application, the Mesophase formulation was customized for the field conditions, such as temperature, fluid density, type of completion brine, and specific oil-based mud. The customized formulation was evaluated to determine the regain of injection permeability, fluid compatibility and the breakthrough time. Intensive tests were required to fine-tune the formulation to obtain the desired high-injection permeability for the challenging conditions encountered in the field. Results from the laboratory and description of the field application were discussed and presented in their paper. The field applications data proved that, after placement of the mesophase treatment in the wells, diffusion of the treatment produced: (1) break-up of blocking solids from the completion screens; (2) removal of filter cake residues; and (3) water-wetting of all solid surfaces. This cleaning treatment gave very good results in the production and water-injection wells.

3. Theory

3.1. Description of Study Case

The field is located +85km North-West of Port Harcourt. The wells have encountered six hydrocarbon bearing horizons between 9000 and 12,600 feet. These are the R5M, R6, R7N, S15X, S2X, and S3M. The S Reservoirs are completely gas bearing while the R Reservoirs are oil bearing. All the horizons down to a depth of 12,600 ft are hydrostatically pressured.

The gas wells ZX8, ZX9, ZX10 and ZX11 found in the S3M reservoir, were drilled to achieve minimum intervention during the wells' lifetime. In line with operating company guidelines, Expandable sand screens (ESS) and external gravel packs (EGP) were used to prevent sand production to give better inflow performance. The wells were drilled from one location using cluster drilling, to achieve cost savings on location preparation and rig move. The wells would produce to a manifold situated in the field and then fluids would be evacuated through a dedicated multiphase pipeline to the nearby Central Processing Facility (CPF).

The majority of the gas in the NAG reservoirs is in S3M. This reservoir contains an estimated Expectation GIIP of 17.01 Bscf of gas and condensate CIIP of 66.4 MMstb.

It should be emphasized that the S3M is considered to be the primary NAG reservoir in Phase 1 of the present Node Integrated Oil and Gas Development Project (IOGP). This reservoir contributes around 50% of the start-up GIIP and up to 450 MMscf/d of the 900 MMscf/d required from the Node under normal operating conditions.

3.1.1. ZX8

The well encountered the top of the target S3M reservoir at 12188 ftss (12957 ftah) and the well TD is 13324 ftah (12514 ftss). It has an initial production offtake of 100 MMscf/d with an expected recovery of ca. 166 Bscf of gas and 8.0 MMstb of associated condensate respectively.

The well was completed as a single string (SSS) gas producer with 7" 13Cr tubing equipped with non-self equalizing TRSCSSSV and Permanent Downhole Gauge (PDHG) for well and reservoir surveillance. 270-micron Expandable Sand Screen (ESS) was installed as the sand control mechanism over an interval of ca. 238ft (12957 – 13195 ftah). A 5.85" monolock was installed @5,000ft to secure the well while an NRV was installed in the tubing hanger.

3.1.2. ZX9

The well encountered the top of the target S3M reservoir at 12193 ftss (13480 ftah) and the well TD is 13727 ftah (12410 ftss). It has an initial production offtake of 100 MMscf/d with an expected recovery of ca. 175 Bscf of gas and 8.9 MMstb of associated condensate respectively.

The well was completed as a single string (SSS) gas producer with 7" 13Cr tubing equipped with non-self equalizing TRSCSSSV and Permanent Downhole Gauge (PDHG) for well and reservoir surveillance. 270-micron Expandable Sand Screen (ESS) was installed as the sand control mechanism over an interval of ca. 240ft (13480 – 13720 ftah).

3.1.3. ZX10

This gas well encountered the top of the target S3M reservoir at 12,168 ftss (13,406 ftah) with TD @13770ftah. It has an initial production deliverability of 100 MMscf/d with an expected recovery of ca. 159.8/8.2 Bscf/MMstb of gas and condensate reserves respectively.

The well was completed as a single string (SSS) gas producer with 7" 13Cr tubing equipped with non-self equalizing TRSCSSSV. External Gravel Pack (EGP) consisting of 20/40 mesh gravel held in place with 250-micron Poromax Screen was installed as the sand control mechanism over an interval of ca. 184 ft (13406 – 13586 ftah).

3.1.4. ZX11

The well encountered the top of the target S3M reservoir at 12021 ftss (12747 ftah) and the well TD is 12960 ftah (12210 ftss). It has an initial production offtake of 100MMscf/d with an expected recovery of ca. 152.5 Bscf of gas and 8.5 MMstb of associated condensate respectively.

The well was completed as a single string (SSS) gas producer with 7" 13Cr tubing equipped with non-self equalizing TRSCSSSV and Permanent Downhole Gauge (PDHG) for well and reservoir surveillance. 270-micron Expandable Sand Screen (ESS) was installed as the sand control mechanism over an interval of ca. 213 ft (12747 – 12960 ftah).

3.2. Challenges Faced During Clean up and Tests of the Gas Wells

3.2.1. The Issue of Safety Onsite

Activities with Safety Concerns carried out by the Engineering Contractor include:

Civil work: Excavation, sand filling, construction of concrete stands for flow-line stands.

Pipeline: Making up various flow lines and hooking up same to Wells ZX8, ZX9, ZX10, and ZX11.

Hot work: Welding the pipes and fittings.

Instrumentation: Installation of various instrument lines, transducers, and other accessories.

Others: Fitting of valves, chokes, and manifolds.

Heavy lifts: Transfer of heavy-duty equipment and sections of pipe around the location.

3.2.2. Operational Challenges

During the campaign the following operational challenges were met and handled with collaborative support of team and contractor(s) line management;

(i) Non-Return Valve (NRV) Retrieval on Well ZX8

In an attempt to retrieve the 6 -3/8" NRV prior to commencing work on ZX8, a pin on the NRV retrieval tool sheared unexpectedly causing the retrieval tool to get stuck in the NRV profile. The implication was that activity on ZX8 would not proceed as planned until the NRV was safely retrieved.

(ii) CT Breakdown

Though the breakdown of the Coiled tubing (CT) power pack had not occurred at S3M but nearby, this had a great impact on the work at S3M as a change in program plan/work scope necessitated the need for it. It was required to carry out repeat treatment on wells ZX9 and ZX11.

(iii) Coiled Tubing (CT) Inability to get to Targeted Depths (resulting in hold-up depths - HUD in wells)

The initial treatment across the ESS screens on wells ZX9 and ZX11 could not be achieved due to a hold up encountered at the top of the ESS packer while running coiled tubing in the hole.

3.2.3. Managing Logistics

With a large number of equipment onsite for both the testing and engineering teams, the huge task of managing logistics daily was indeed overwhelming.

At the onset, with concurrent work ongoing between the well test and engineering team, the initial planned pace of work had to be slowed down to give room for unforeseen situations during engineering work.

The plan for disposal of potentially hazardous waste effluent (brine returns from well during Coiled tubing operations) was to discharge it at the production facilities – the flow station. A vacuum truck was provided solely for this purpose. The volume of effluents generated at times required daily trips to the flow station to ensure there was enough temporary storage space in the tanks for further effluents from the wells. Frequent shutdowns at the station were not anticipated, as such, there were situations where all tanks on the site were filled up, with no place to dispose of the waste.

3.2.4. Commercial Challenges

The major challenge encountered during this campaign was managing the newly awarded integrated contracts**.** Unclear details on contract led to a setback on activities as service providers were unwilling to continue work.

Prolonged approval process which was encountered for newly raised purchase orders once the new contract was put in place, further agitated service provider(s).

Image of the operating company was put at stake as the level of trust/confidence by service providers was being affected due to unclear contract service lines.

4. Recommended and Adopted Solutions for Challenges Faced

4.1. Management of Safety Onsite

Equipment mobilization to the site and the cleanup and testing activities at S3M were all carried out concurrently with engineering activities ongoing and the rig moving out after drilling and completions operations.

Zero HSE incident was achieved from the start of operations to demobilization in spite of the complexities that arose from managing the well test operation concurrently with surface engineering activities. The concurrent operations guide was used as the guiding document to effectively manage the site and achieve the zero HSE incident objectives with the site supervisor driving this down the workforce ladder. Key aspects of the strategy used onsite include the following:

Daily concurrent operation meetings.

Permit to work system (no engineering work will proceed without authorization from the concurrent operations leader – Site Supervisor).

Compliance to an agreed Manual of Permitted Operations.

Compliance to site specific concurrent operations procedures.

Delineation of roles and responsibilities of key personnel.

Hazard identification, gas testing and other requirements.

4.2 Recommended and Adopted Solutions for the Operational Challenges

4.2.1. NRV Retrieval on Well ZX8

The solution was stripping the lubricator and lifting the Xmas tree to recover both tool and NRV.

This activity was carried out offline with the support of experienced senior engineers while the well test activity proceeded on the other wells concurrently to save time. Figure 1 is an image of the retrieved NRV from Well ZX8.

Figure 1. *NRV Retrieved from Well ZX8.*

4.2.2. CT Breakdown

Viewing the cost impact of waiting for four (4) days to repair/carry out maintenance on the service company's CT unit, another service company's CT unit within the integrated contract service alliance was subsequently mobilized to replace the broken down CT unit.

4.2.3. Coiled Tubing (CT) Inability to get to Targeted Depths

It was established that the hold-up depths were caused by heavy mud (POBM) that had settled out preventing further access of the Coiled tubing BHA.

The wells were opened and cleaned up but pressures were below values from the prognosis. This necessitated the repeat wash on these wells. During this second treatment, the CT was able to get to target depths and an effective ESS clean up was achieved. A repeat clean and well test was then carried out.

4.3. Managing Logistics

The issue of logistics was not a minor one. Delays were encountered in the course of the operations due to the reasons outlined in section 3.2.3. Some of the recommendations to avoid such issues include:

There should be more emphasis on the involvement of external support teams (i.e. logistics) required to ensure efficient delivery on campaign wells.

A contingency plan should always be put in place for effluent evacuation from the site.

Better stakeholder engagements are required at every stage of the activity (from planning to execution) to ensure efficient management of operations, especially where different teams need to work together.

Other alternatives for waste evacuation from the site should be sought and contingency plans have to be prepared in case of failure.

4.4. Commercial Challenges

Considering the various commercial challenges encountered in the course of the work, these recommendations are made to resolve them:

Contractual issues are to be resolved prior to utilization of contract to avoid undue delays on operations.

The engineering team has to work in synergy with the supply team to align goals.

5. Gas Well Risks Assessment Matrix

The operational risks encountered in the course of drilling, completion clean up and well test of ZX8, ZX9, ZX10, and ZX11 wells and the risks management procedures are presented in Tables 1 to 5.

Table 1. *Risks and Uncertainties Matrix.*

Risk / Uncertainties	Description	Probability (L/M/H)	Impact (L/M/H)	Consequence	Management
Flatter Crest	Crest flatter than expected which could affect the volume of hydrocarbon expected	M	H	Volume Reduction	Check model and monitor correlation while drilling. Plug back and sidetrack.
Reservoir Structural Dip		L	H	Overestimation or underestimation of volumes	ZX3 and ZX5 are close to the well path and another well will be drilled before this well, the model will be updated
Overpressure	The onset of overpressure is much deeper than the R5M sand	L	H	Inability to reach TD and complete well	
Reservoir quality distribution	Reservoir heterogeneity	M	M	Fines migration, plugging of the screen, less production and reserves	Plan completion in cognizance of heterogeneity
Screen Rupture	Infant mortality of sand screen during deployment	M	H	Poor sand exclusion and control/ loss of well with respect to oil production.	Conduct Screen QAQC with certified inspectors.
Well Collision	The possibility of well colliding in the subsurface with wells in same cellar/slot	M	H	Well control issues, loss of integrity of well	Make spider plot and monitor, nudge the well below the conductor shoe.
Differential Sticking	Excessive mud weight due to solid build up in the mud	M	M	Increase overall well cost by additional cost for plugging back, lost in hole cost or redrill section.	Ensure good hole cleaning. Do not stay static in hole, good surface monitoring. Ensure good solid control is in place.
Community Issue		H	H	NPT/Cost overrun	Early community engagement.

Table 2. *Production Technology Well Operations Risks and Mitigations.*

Risk	Description	Probability (L/M/H)	Impact (L/M/H)	Consequence	Management
Completion fluid design	Selection of suitable fluids for completion	M	H	Integrity and loss of containment	The team will ensure that suitable fluid is selected as the design that covers the requirement for well control and safeguards productivity.
Sanding Tendency	Selection of fit-for-purpose sand exclusion technique.	H	H	Facility/flowline integrity and loss of containment.	Core samples had been acquired for the sands. Sieve analysis should be carried out to facilitate optimal sand exclusion selection.
Operation	Establishing well safe	L	H	Loss of well integrity, wellhead	Model well and establish CITHP and specify

Risk	Description	Probability (L/M/H)	Impact (L/M/H)	Consequence	Management
Envelope	limits with respect to materials, integrity, and throughput.			area, and surrounding environment	appropriately rated wellhead. Also specify the maximum allowable rate, drawdown limit, sand production tolerance.
Produced fluid composition	Produced fluid composition	L	H	Completion accessories integrity, high annular pressure, unsafe well, loss of containment.	Corrosive fluid contaminants are not a problem in this field, though well has been designed to take care of that in case of changes in water chemistry.

Table 3. *Technical Risks and Mitigations.*

Risk	Consequence	Mitigation
Inappropriately Sized Tools	Downhole components/tools may not get to desired depths.	Ensure the dimensions of tools to be RIH are appropriately sized for 3-1/2" tubing and accessories/profiles ID.
Ill-defined Operating Envelope	Loss of well integrity, wellhead area, and the surrounding environment.	Modelled well, established CITHP and specified appropriately rated wellhead.
Use of solvent chemicals and liquid Nitrogen during clean up and Unloading	Environmental contamination and harm to personnel.	Ensure safe handling of PARAVAN B-5, its constituents, and liquid Nitrogen as per standard handling procedures.
Crude Load Out	Spill, slippery floor, fire outbreak, injury, and fatality.	After the initial clean up and well lift to surface tanks, the well will be lined up to the CPF for production testing and subsequent production.
Emergency	Loss of order, injury, fatality, loss of equipment.	Presence of 3-barrier containment. Emergency Shut Down (ESD) system for wellhead, well site, and test skid. Adopt MOPO (Manual Of Permitted Operations) specifying when operations should be stopped if hazard mitigation is not being met.
Hydrocarbon under Pressure	Loss of containment, explosion, injury, fatality and environmental pollution.	Check integrity of the valves on the wellhead and TRSCSSSV are integral; install surface read-out gauges to monitor pressures and ensure BOP for the coil tubing unit is fully functional.

Table 4. *Critical Well Test Operations Risks and Mitigations.*

Risk	Description	Prob. (L/M/H)	Impact (L/M/H)	Consequence	Management
Incorrect PVT data	Specify reservoir fluid parameters to facilitate liquid evacuation strategy and containment.	H	H	Fire, fatality, and loss of containment	CGR was culled from S3.0 PVT (acquired in ZX7). The maximum expected rate of produced liquid specified. The reservoir has no oil rim.
Sanding Tendency	Selection of fit-for-purpose sand exclusion mechanism.	M	H	Facility/flowline integrity and loss of well and environmental contamination.	Core samples were acquired for the S3.0 sand. ESS Petroweave selection was based on results from sieve analysis.
Ill-defined operating envelope	Establishing well safe limits with respect to materials, integrity and gas offtake.	M	H	Loss of well integrity, wellhead area, and surrounding environment	Modelled well, established CITHP and specified appropriately rated wellhead. Selected 13Cr to safeguard against sweet corrosion. WellCat results confirm well integrity over lifecycle for all anticipated load cases.
Corrosive cleaning chemicals	Specify clean up fluid that is non-damaging and evacuation strategy.	M	H	Corrosion, environmental contamination.	The test trial of clean up chemical (N-flow) has been conducted in the laboratory and it has been confirmed to be non-corrosive. Nitrogen for lifting is tolerated by tubing/casing material.
Corrosive well stream	Produced well effluents and its impact on well integrity (leaks, wears, deposits, rusts etc.)	M	H	Corrosion, material integrity, reduced producibility and loss of well.	Corrosive fluid components are not a problem in this field. Well design ensured the insignificant impact of well stream on construction metallurgy over well lifecycle.
Undersized liquid handling capacity	Estimating volume of condensate/produced water expected during test operations to appropriately sized containments.	M	H	Spill, fire outbreak, injuries to personnel and equipment/asset damage	Correct equipment sizing for containment of expected liquid production using CGR from S3.0 PVT was done. Estimated expected maximum liquid (condensate/water) production during clean up and multirate test is ca. 2800 bbl.

Table 5. *Gas Well Test Risks and Mitigations.*

Risk	Consequence	Mitigation
Hydrate Formation	Blocked tubulars, increased pressure, blowout, injury, and fatality.	Inject glycol at low gas rates to combat hydrate formation. At high gas rates, tubing temperatures are high enough to combat hydrate.
Noise (Flare)	Damage to personnel eardrum, partial or permanent deafness.	Certified earplugs to be worn by personnel on site.
Radiation/Heat	Unconducive work environment, environmental degradation (loss of economic trees, scotching of flora, fauna, wildlife migration and death), Fire outbreak,	Conduct pre-well test modelling of wind flow and speed for optimal location of flare boom. Wear appropriate personal protective equipment at all times in the location. Mobilize water-spraying machines to reduce the impact of heat

Risk	Consequence	Mitigation
	damage to equipment, injury, and fatality.	radiation.
Condensate Load Out	Spill, slippery floor, fire outbreak, injury, fatality	Provide flare pit to burn off produced condensate.
Corrosion	Compromised well integrity, uncontrolled emission, harm to flora and fauna population, loss of well, injury, fatality, loss of reputation	Ensure appropriate material selection. Internal tubular is 13Cr, eliminates corrosion inhibitor injection. Wellhead has stainless steel clads
Fire Source	Fire outbreak, injury, and loss of equipment, fatality.	Barricade work area, prohibit the use of cell phone and smoking around the well's perimeter fence, restrict movement of unauthorized persons around the work area
Trapped Pressure	Blow-out, loss of well, injury, fatality, environmental contamination	Check Annular pressure periodically, bleed off excess pressure, activate annular pressure management control
Blow-out of high-pressure vessels	Loss of equipment, injury, fatality	Chain-down high-pressured pipes, restrict movement of personnel around HP vessels
Night Operations	Poor emergency response, damage to asset, injury, fatality	Obtain night operation approvals, Deploy Emergency Shut Down (ESD) system. Appoint competent Night operations Supervisor
Emergency	Loss of order, injury, fatality, loss of equipment	Presence of 3-barrier containment Emergency Shut Down (ESD) system for wellhead, well site & test skid Adopt MOPO (Manual of Permitted Operations) specifying when operations should be stopped if hazard mitigation is not being met

6. Conclusions

From the evaluation of the risks and challenges encountered during well clean up and test, the following conclusions can be derived:

Nigeria has one of the fastest growing gas businesses in the world with the potential to overtake the thriving oil business in 5-10 years.

The typical well testing activity is technically and operationally challenging, requiring huge investments and clear upfront planning and supply/commercial agreements.

Zero HSE can be achieved on any activity once focus is made on the management of safety at the worksite.

Apart from safety, the issue of equipment failure is also a very vital one. It is therefore advised that contingency plans be reviewed for possible equipment failure and then incorporated in the program.

To eliminate commercial issues or bring them to the barest minimum, it is very important that there is upfront planning to include a thorough review of any contractual issues which may hamper delivery on job objectives.

Adhering to the recommended and adopted solutions for challenges faced during clean up and test of gas wells, and the operational risks mitigation methods illustrated in this work would help eliminate downtime and unwanted happenings in the course of operations thereby making operations very successful.

Nomenclature

BHA = Bottomhole Assembly
Bbl = barrel
BOP = blowout preventer
Bscf = billion standard cubic feet
CGR = condensate-gas ratio
CITHP = Closed-in tubing pressure
CPF = Central Processing Facility
CT = Coiled Tubing
EGP = external gravel pack
ESD = Emergency Shut Down
ESS = expandable sand screen
ft = foot
GIIP = gas initially in place
HUD = Hold-up Depth
ID = internal diameter
IOGP = Integrated Oil and Gas Development Project
Km = kilometre
L/M/H = Low/Medium/High
MOPO = Manual of Permitted Operations
MMscf/d = million standard cubic feet per day
MMstb = million stock tank barrel
NAG = non-associated gas reservoir
NPT = non-productive time
NRV = Non Return Valve
PDHG = Permanent Downhole Gauge
POBM = pseudo-oil-based mud
PVT = pressure-volume-temperature
QAQC = Quality Assurance and Quality Control
RIH = run-in-hole
SCM = Supply Chain Management
SSS = Single String Single interval
TD = true depth
TRSCSSSV = Tubing Retrievable Surface Controlled Subsurface Safety Valve

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