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Increasing Subsea Well Intervention Efficiency in West Africa

A report investigating recent riserless light well intervention (RLWI) case studies throughout West Africa, showcasing the efficiency benefits it serves to operators

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In West Africa's deepwater oil and gas patch, Riserless Light Well Intervention (RLWI) conducted from drilling or other support vessels is proving to be an important resource – providing a much faster and cheaper alternative to using rigs. A rising well intervention backlog and tight budgets means this effective solution needs to be quickly and widely deployed if legacy production declines are to be addressed.

PART 1: MARKET OVERVIEW

Information taken from Patience Maseli, Department of Petroleum Resources (DPR) OWI WA 2018

Competition for the E&P dollar is on the rise in West Africa, with ever more African countries developing an upstream sector, while crude prices (and associated capex budgets) remain relatively low.

Until the mid-2000s, upstream oil and gas activity in Africa was fairly steady in terms of the number of countries involved. In the 1990s, output was dominated by Nigeria, alongside well-established producers in north Africa, Algeria and Libya – which together make up the continent's OPEC members (along with Gabon for a short spell). Then, in the late 1990s, Angola joined their ranks, becoming the continent's second biggest producer with the rapid development of its deep and ultra-deepwater reserves. All four countries are also major gas producers, with Nigeria and Angola joining Algeria (which began exporting liquefied natural gas (LNG) in the late '60s) as LNG exporters, while both Algeria and Libya export gas by pipeline (to Italy and Spain).

Combined crude production from Angola and Nigeria (all offshore) peaked at 3.8 million b/d a few years ago – equivalent to more than 40% of OPEC production outside the Middle East at the time – but has since fallen slightly.

The resource potential in deeper waters up and down Africa's continental margin away from these big producers, along with a few choice onshore spots, began to be tested in the mid-2000s, backed by high oil prices and rising growth across the continent. In West Africa, exploration began in countries including Ghana, Equatorial Guinea and Senegal/ Mauritania, and upstream sectors there are continuing to grow; while in east Africa, Kenya and Uganda saw onshore activity and have also now managed to get liquids flowing. Mozambique has become a major centre of gas production, with interest from the biggest international oil and gas companies. To the North, Sudan is an established oil exporter with Chinese backers, and Egypt has become a major gas producer, albeit largely for its rapidly growing domestic market.

These fresh oil and gas provinces now compete for funding with Nigeria and other larger, more established African producers. At the same time, the oil price collapse has cut total funds available. Capital investment in Africa has fallen 60% from US$50 billion in 2014 to just US$20 billion per year over the last couple of years – worse than the global average decline of 40% - according to Nigeria's Department of Petroleum Resources (DPR). This leaves more African countries competing for a smaller pool of investment capital.

The capex decline comes even though estimated reserves in Sub-Saharan Africa suggest there is at least 23 billion barrels of oil and 54 Tcf of gas yet-to- find (YTF) - which is about 15% of the world's YTF total outside the US Lower 48 States. Around half of these predicted reserves are in Angola and Nigeria. On this basis, the region should be very attractive to upstream investors. But low prices and the high cost of operating in these countries have made commercial development challenging since the 2014 downturn.

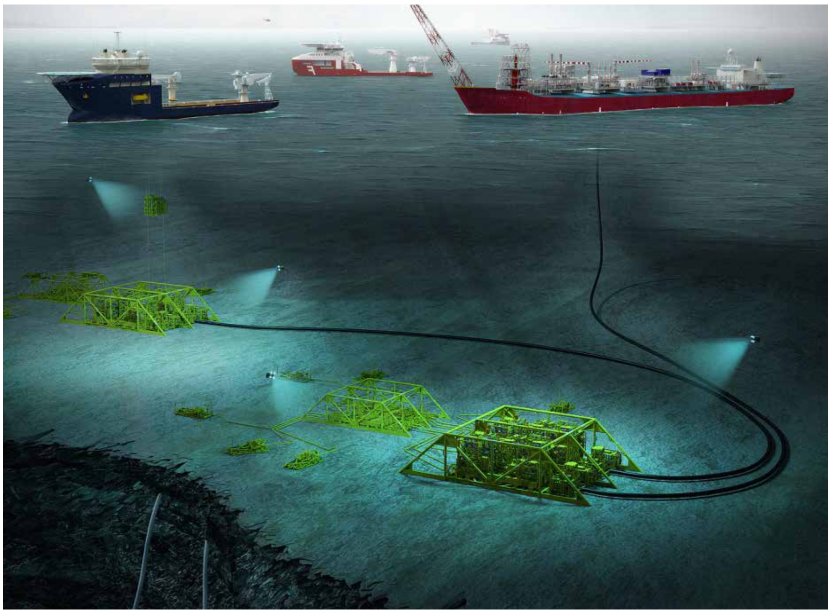
1.0 Maps showing growing regional competition and resource development

The fall in upstream capex has hit both new field development and led to a build-up in the number of wells requiring intervention – leading to an acceleration in legacy decline rates after what is now three years of low investment. Total West African regional production has fallen by 12% to 4.3 million b/d already this decade and will drop another 1.0 million b/d by 2026, according to Wood Mackenzie.

West Africa's Deepwater Solution in RLWI

Some in Nigeria and elsewhere in West Africa are aware that they need to introduce new legislation and a more streamlined and transparent regulatory environment in order to compete more effectively for the reduced pot of E&P funds from international investors. But faced with the immediate problem of tight budgets and a rising backlog of work, efforts are also being made to develop quicker and cheaper technical means of tackling the upstream challenges and boosting flagging output.

Among these, riserless well intervention is proving to be a cost-effective method of intervening in the region's offshore wells, using suitable support vessels instead of rigs. The higher operating efficiency and lower spread rate of an RLWI system results in a much lower cost per intervention compared to the use of rigs to do the job.



1.1 Image portraying deep-water RLWI Photo credit to Offshore Simulation Centre

Currently, the high costs of subsea well intervention using semisubmersible rigs, means subsea wells/fields tend to have lower recovery rates than fixed platform wells, where intervention can be performed at lower costs. So, there may be particularly attractive opportunities at West Africa's numerous subsea wells for more proactive and cheaper riserless well intervention - raising extraction rates while reducing cost per barrel extracted.

RLWI was established in the North Sea in the late 1980s, and since then it has become a well proven, mature, and recognized intervention method, with more than 1,100 wells intervened and an almost 30-year track record. More recently, the technique has been applied widely, including in the West African deepwater and the Indian Ocean (see case studies in Part 2).

As the technique has been improved, operators have been successful in using RLWI to achieve significant production gains from intervention of up to 100% for stimulation treatments and even going significantly higher for operations like scale or other obstructions removal – putting their capabilities on a par with rig-based intervention. Whatever the level of upstream funding, RLWI could be the best way to make the most of it, at least in terms of new barrels extracted per dollar spent.

Some observers even see this type of low-cost well intervention as the offshores answer to shale production – having as it does, a far lower outlay and a quicker payback than developing new large offshore fields, in a similar way to the outlay and payback profile of fracking operations. Such an approach could help address legacy declines in West Africa by substantially reducing intervention costs and increasing activity.

Nigeria still dominates the sector in the West African region, despite falling output over recent years. The country's Department of Petroleum Resources is among those hoping that new cheaper techniques - in particular RLWI - will help make the reduced capex that is available go further, enabling the country to stabilise its declining production profile and even help bring new fields onstream more quickly and efficiently.

As Nigeria's fields mature, wells suffer production declines or failures more frequently, and these have accumulated over the last few years as capex budgets have been cut. To combat this, Nigeria added 20,000 b/d from offshore well interventions in 2017 - highlighting the importance these programs already play in sustaining the country's oil production. The interventions were also carried out with reduced cost, time and production deferment than in earlier years.

Eventually, Nigeria's DPR hopes that riserless well intervention could boost output from 2.2 million b/d currently to as much as 4 million b/d. Dwindling exploration activity is adding to pressure to ensure maximum extraction at existing and marginal fields, which, along with reduced funds for big new developments, explains much of this increased anticipated reliance on well intervention in future. But the backlog of wells that have failed to get attention due to budget constraints need to be cleared first.

As operators increasingly switch from relying on rigs to cheaper vessels and drill-ships, and their associated riserless well intervention approach, many companies have begun developing new related procedures and technologies. While testing continues, they are steadily improving the efficiency of riserless intervention, which should make it an even more attractive option for those deciding where capex should be spent in future.

Typically, the return on investment from an RLWI operation is five-to-10 times the cost of the intervention itself, and the payback time is in the order of a few months, bringing a positive cash flow for the operator soon after the operation is performed. Yet despite these returns and high riserless success rates, there is still a risk-averse culture that has resisted deploying RWLI in more complex and expensive environments, such as subsea and deepwater.

PART 2: RISERLESS LIGHT WELL INTERVENTION CASE STUDIES

In this section, we take a look at some recent riserless well intervention case studies that highlight the complex work that can be done using the technique, and the huge savings that can be made.

Total's Egina Oilfield, Offshore Nigeria

Information taken from Edward Kalu, Total Nigeria, OWI WA 2018

The first case study example of riserless intervention is from Total's Egina oilfield offshore Nigeria, which has only just begun production, with first oil in early January 2019. Once fully up and running, the field is expected to produce at a rate of 200,000 b/d of oil, representing about 10% of total Nigerian output.

- ✓ 4 interference/injectivity tests performed under budget
- ✓ 13.6M USD in savings

Well	Budget M$	Realized M$	Budget days	Realized days
Egina A	2.84	2.56	17	15.65
Egina B	1.43	1.94	9	9.2
Egina C	2.96	2.44	18.2	16.27
Egina D	2.6	2.3	14.15	13.78

- ✓ 5 rigless stimulation operations performed
- ✓ -~30M USD savings

Well	Realized M$	Realized days
Akpo stim #9	3.9	13.5
Akpo stim #10	2.6	11.2
Akpo stim #11	2.2	11.1
Akpo stim #12	2.1	8.9
Akpo stim #13	2.5	10.7

2.0 Table providing the summary of rigless intervention results at the Egina Oilfield

Overall, the project was brought onstream at a cost of about 10% less than its initial development budget, which represents more than $1 billion in capex savings, due mostly to improved drilling performance where drilling time per well was reduced by 30%. Total is operator at the field with a 24% interest, while CNOOC holds 45%; Petrobras 16% and Nigeria's national oil company (Nigeria National Oil Corp), 10%.

As part of the cost reduction initiative, the Water Injector Christmas Tree installation and testing was carried out from an Offshore Intervention and Maintenance Repair (OIMR) vessel. That intervention was also designed to gather information for placement of future wells in what is a highly faulted Egina reservoir structure. The job scope included opening reservoir isolation valves, followed by an injection test to estimate well productivity and interference testing to assess reservoir connectivity and fault behaviour.

Surface equipment required for the job included a filtration and pumping unit, along with storage tanks and chemical additives. A Reel Deployment System was used to feed a 2" downline and deployment chute, with control through a Mini IWOCS and umbilical from the OIMR vessel.

Intervention at the sea floor was conducted with the aid of a Flying Lead Interface System (FLIS), including the use of a modified low torque ROV. Access and control were established downline with the Umbilical Termination Head, modified Tree Running Tool and Subsea Router Module in order to carry out the required work.

The operation's performance was impressive, with the cost estimate $3.8 million per well less than if the injectivity and interference tests had been done by a rig. Time taken, including vessel demobilization, was just 5 days per well and the test flow pump rate reached 8 barrels per minute. Interference was observed at the Egina G well of more than 0.1 bar increase about five days after injection commenced, while that witnessed at Egina H was much less, at around a 0.05 bar increase after 10 days.

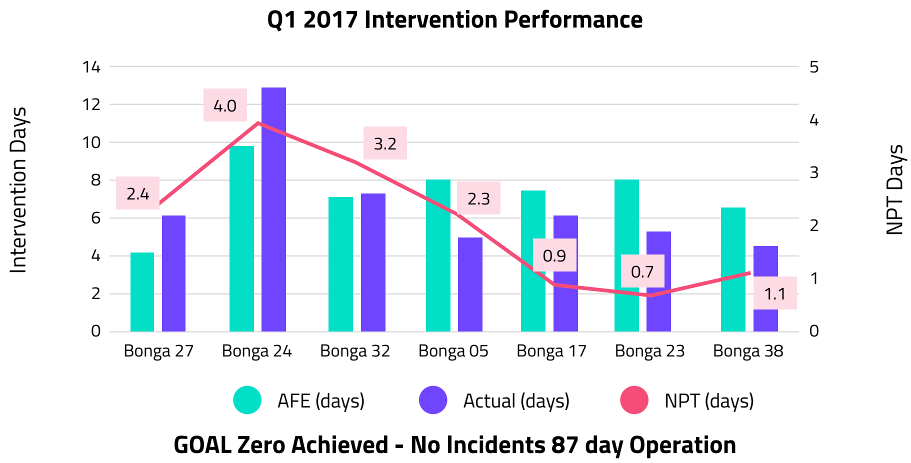
Altogether the group performed four interference/injectivity tests at the field, with all coming out under budget, realising a total of $13.6 million in savings; alongside five riserless stimulation operations that achieved a $30 million capex saving between them - compared to a rig-based operation. For example, Egina A interference/injectivity test was budgeted at $2.84 million over 17 days, but was achieved in 15.65 days for $2.56 million. In addition, both well intervention expenditure and duration fell over time, with efficiency improving as those involved fine-tuned techniques on the job.

Across the OIMR intervention project, total savings were estimated at about $45 million, with 3000 b/d gained from the well stimulations. The injectivity test results confirmed water injector wells' injectivity indexes and the interference data will help in future well placement. The intervention paves the way for extending the scope of similar light well intervention, with such non-self-supporting down lines increasingly proving to be a cheap and effective approach.

Shell's Bonga Field, Offshore Nigeria

Information taken from Ifeanyi Ugbor, Shell Nigeria, OWI WA 2018

The deepwater Bonga field off Nigeria was discovered in 1996 and produced first oil in 2005. Its liquids capacity is 280,000 b/d, with oil extracted using 62 subsea wells and exported by tankers via an SPM. Gas is produced at 210 mmcf/d and transported via pipeline to the Bonny LNG terminal, where it is exported around the world. There is a potential water cut of 60,000 b/d and hydrocarbon output is enhanced by water injection.



2.1 Graph showcasing rigless intervention performance within the Bonga Field

Early well interventions at the field were done by a rig, but this capital-intensive method was considered too expensive during the spell of low oil prices after 2014, and Shell decided to opt for the riserless technology to achieve a more cost-effective solution in this deep-water environment. Much was learned during the planning and execution phases of this project, which should make future intervention even smoother and more cost-effective.

The project was implemented during the first quarter of 2017 and involved three stages of work, beginning with temporary well suspensions at five wells. With the tubing disconnected, field support then removed subsea Christmas Trees for servicing at an onshore maintenance depot. The next stage was acid stimulation, which was applied to one well (B-27) to address production problems. It used a mixture of acids and other ingredients, with over 1000 barrels of the acidic mixture pumped to clear the well. This was followed by the final stage of Christmas Tree replacement, testing and plug recovery.

The project was able to fit all the contractors' equipment on-deck using a computerised system, with everything loaded at the quay-side.

Once at the field, operations began with the deployment of the Well Control Package (WCP) from a crane on deck to the sea bed. This was followed by deployment of the Subsea Intervention Lubricator, all the while being monitored and facilitated by an ROV operated from the vessel's bridge. The Umbilical Termination Assembly was then lowered nearby and the full Subsea Intervention Lubricator System (SILS) could then be deployed.

Major challenges included the need for a bespoke Christmas Tree connector and a late vessel change, while customs clearance delays lasted up to 13 days. All contracting and procurement was done through a single source, but there was split mobilization between the acid and wireline/tree parts of the operation. Other issues included single point failures and security concerns related to operating in the trouble waters off the Niger delta.

The 87-day operation incurred no accidents or safety incidents and was not only the first deepwater SILS deployment in the Gulf of Guinea but also achieved a new water depth record for Shell Global in subsea rigless intervention at 1115m (3657ft). The acid work was successful and resulted in a 26% increase in production at well B-27. At the B-24 well, 2 plugs were set and tested, the SSXT was recovered, and new one installed and two plugs recovered.

Similar results were achieved at the other wells, and the subsea trees from the five suspended wells were all harvested and refurbished ready for the 2018 oil drilling campaign.

Eni's Deepwater Rigless Well Matrix Acid Stimulation, Offshore Nigeria

Information taken from Kelechi Victor, Nigerian Agip Exploration Limited, OWI WA 2018

Our third case study relates to a field intervention offshore Nigeria by operator Eni, involving the successful enhancement of production through depleted reservoir matrix stimulation by acid injection. This approach, known as "matrix acidizing" is intended to remove or dissolve damage or plugging in the perforations and in the formation pore network near the wellbore – increasing well productivity (PI).

RIG OPTION			
DESCRIPTION	Rig Cost Plus Equipment Rentals USD/DAY	Days	TOTAL COST (USD)
Rig Mobilization, positioning and Equipment mobilization	426,000.00	1	426,000.00
BOP run, LS deployment and WEll re-entry (pumping equipment rig up was done offline)	426,000.00	4	1,704,000.00
Nitrogen equipment + CT & Lifting Frame Rig up	426,000.00	1	426,000.00
CT run and Pumping operation	426,000.00	2	852,000.00
Secure well, Recover LS, Recover BOP and Risers	426,000.00	3	1,278,000.00
Rig Demobilization	426,000.00	1	426,000.00
TOTAL			5,112,000.00

FPS OPTION			
DESCRIPTION	Equipment Rental Cost Plus Vessel (NO Rig/FPSO Cost) USD/Day	Days	TOTAL COST (USD)
Equipment Mobilization with Vessel	26,000.00	1	26,000.00
Pumping Services (equipement rig up, pumping job and equipment rig down and load on vessel)	26,000.00	5	130,000.00
Equipment Demobilization	26,000.00	2	52,000.00
TOTAL			208,000.00

2.2 Table providing the costs differences between rig and rigless intervention

The acid treatment was executed from an FPSO 2km away from the wellhead, which meant a long flow line was required. The Well's PI had fallen from a peak of 13 b/d/psi to 2.9 b/d/psi as a result of wellbore formation damage from fine silt and clay migration. The matrix acid stimulation was performed over 3 pay zones, totalling 30.5m.

Methanol was injected to mitigate the risk of hydrates formation during the stimulation treatment. Simulation software was used to develop the job model, and the model was then calibrated using historic data from previous jobs. The calibrated model was then used to estimate anticipated placement rates and pressures during the job.

Equipment used included a 750HHP panther pump and V16 high pressure pump, both with maximum flow rates of 7 barrels/minute, along with a 50-barrel batch mixer. The operation succeeded in raising the PI to 10 b/d/psi without any health and safety issues, and within the stipulated time line of 2 days for the rig up and tests, 1 day for the fill-up, injectivity test and treatment, and 2 days for rig down and reloading the equipment on the vessel.

While the primary pump failed during the treatment, the contingency back-up pump was able to deliver the job as planned. The well was successfully flowed back using nitrified diesel displacement for the sandstone acid treatment, and well hydrocarbon production was successfully restored and sustained at the higher 10 b/d/psi rate once the intervention was complete.

The total cost of the operation if performed by a rig was estimated at $5.1 million, based on a total rig rate (plus equipment rentals) of $426,000/day for twelve days. The FPSO option that was used cost a total of just $208,000 (based on the FPSO rate (plus equipment hire) of $26,000/day for 8 days) – less than a single day's rig rate, and a total saving of over 95%. (These costs do not include chemicals and consumables, which would be the same in both approaches).

With savings on this scale, there is little doubt that similar operations will be a priority for upstream capex allocations over upcoming years.

TechnipFMC's Australian 12-Well RLWI Campaign

Information courtesy of TechnipFMC Island Offshore Subsea (TIOS)

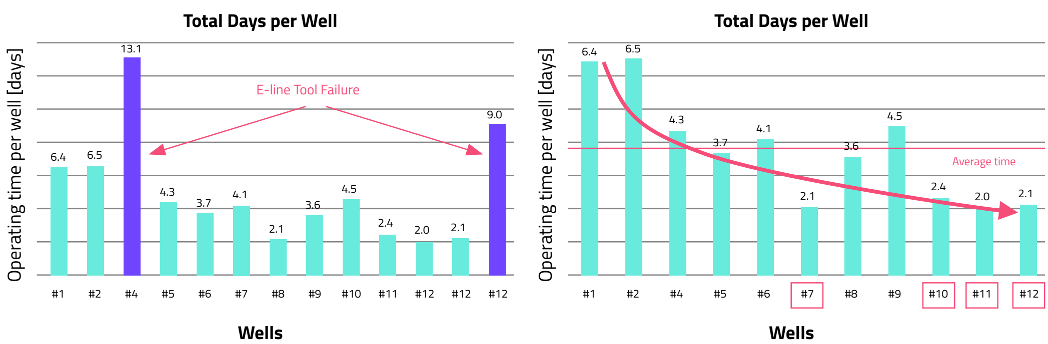
The fourth case study takes us away from the West African offshore to the northwest coast of Australia, where TechnipFMC recently carried out a 12-well RLWI campaign in the Inpex Ichthys field.

This RLWI campaign is the largest so far performed outside the North Sea and was safely and successfully carried out in a challenging region. The Island Performer vessel with its integrated RLWI system were mobilized from the Gulf of Mexico, and the NOPSEMA Safety Case was accepted at first submission with no major non-conformities. The full system was confirmed to be fully compliant upon inspection.

The scope of work included removal of suspension plugs in 12 subsea wells using a slickline, along with removal of one deep-set plug in Well #3 with wireline. In addition, auxiliary scope included replacement of six subsea flow control modules. The work was carried out at a water depth of 250m (800ft) and in very strong currents. The deep-set plug was at significant depth and temperature.

The quickest well was completed in 2 days, while the average for all wells was 3.8 days, excluding well #3 which experienced a downhole wireline tool failure. Average duration including also this well was 5.3 days.

Apart from the e-line tool issues, the campaign was completed successfully and safely. The NOPSEMA Safety Case was accepted at first submission with no major non-conformities, and the vessel was fully compliant upon inspection. The fully integrated RLWI rate was drastically lower than the equivalent rig rate, saving the Ichthys partners considerable expenditure. The RLWI also involved extensive inter-disciplinary training of regional personnel, and the culture of continuous improvement led to a dramatic reduction in operating times as the campaign progressed.



2.3 Graphs showcasing the operational summary

PART 3: CONCLUSION

These and other recent projects have ensured that riserless well intervention lessons are learned, and they have also illustrated the relative efficiency of RLWI and its importance in encouraging more well intervention activity in West Africa and elsewhere. Both the Egina and Ichthys riserless projects saw efficiency rates improve as the job progressed, suggesting there is even more room for cost and duration improvements as more experience is gained and operators or service companies fine-tune the new techniques.

While subsea intervention can still be challenging for riserless systems, performance is continuously improving. Riserless alternatives are already capable of most subsea jobs, including full well plugging and abandonment - with fast and efficient flexible platform-based P&A costing just $10-$15 million per well, compared to $20-$60 million per well from a fixed rig (which is also slower and difficult to intervene in if there's a leak).

The frequency of well intervention during the life of a field depends on numerous variables including reservoir characteristics, infrastructure and economic considerations. Deepwater fields in the West African region, such as Bonga, Agbami, Erha and most recently, Egina, are cutting-edge developments that should be able to leverage the riserless intervention approach to enhance production effectively.

Current low oil prices and capex budgets make it all the more important to maximize the recovery rates from existing fields and to reduce the time required to exploit a field, so that the return on capital and operational expenditure can be maximized. The approach could make an especially big difference to production enhancement at the growing number of West African subsea wells, as historically such wells have seen fewer interventions due to the high associated costs.

The overall recovery rate also plays a key role in the assessment of commercial viability of a field, with a few additional low-cost barrels often making the difference between whether or not a project proceeds.

So riserless capabilities have a particularly large potential for expansion offshore West Africa and could bring major benefits to intervention campaigns in terms of safety, cost savings and efficiency. Of course, riserless success is not guaranteed. Equipment and vessel integrity and compliance is key to achieving value creation in such intervention programs. The choice of technique and equipment to be deployed for intervention needs to be carefully vetted depending on scope and subsurface conditions. Safety must always remain paramount.

Current low oil prices and the expectation that these low prices will last for some time to come – underlined by the recent fall in Brent crude from over $85/barrel in early October, to under $55/barrel at the start of 2019 - are likely to maintain significant pressure on operators' budgets, making RLWI and other lower-cost means of maintaining or expanding production ever more attractive.