Abstract

The world’s first offshore Rigless Fully Retrievable Electric Submersible Pump (RFR-ESP) system has been successfully installed in the eni Congo Foukanda Field (Republic of the Congo). The project was developed between eni Milan and eni Congo as an Innovation Technology Application (ITA), and it is the world’s first offshore RFR-ESP system. The RFR-ESP technology provided by ZEiTECS allows the rigless deployment and retrieval of a conventional Electric Submersible Pump (ESP) system through tubing by means of standard oil field wireline, rod or coil tubing technology. The RFR-ESP system technology is based around a specially designed oilfield wet connector system. This “plug and play” connector design permits the use of any ESP manufacturer’s equipment, allowing ESP optimization to match changing well conditions and replacement of failed ESPs without rig interventions; thereby providing an opportunity for OPEX savings, a significant reduction in workover costs and deferred production due to limited rig availability.

The success of the first RFR-ESP completion and the positive results achieved to date are encouraging in the pursuit of extending this innovative and valuable ESP completion philosophy to eni Congo wells where ESP failures are primarily related to pump or motor and workover cost are high.

The paper describes the technical features of the new RFR-ESP completion, the experience acquired on the Foukanda well and shows, via theoretical study, the economic implications of applying this new ESP philosophy in all the eni Congo high OPEX wells.

Introduction

Electric Submersible Pumps (ESPs) have become a reliable and important tool in today’s global oilfield. ESP technology itself has evolved to meet new, more challenging, operating environments but, nevertheless, the vast majority of ESP deployments use techniques developed decades ago. ESP systems are still installed using jointed pipe, lowered with a pulling unit, drilling or workover rig while power cable is secured to the tubing by means of metal clamps or bands.

Even acknowledging the fact that the reliability of ESPs has increased tremendously since their first introduction, some form of remedial work will be required multiple times during the life of a producing field. If that work requires a pulling unit, a drilling or workover rig, the economics of field development may become unfavorable.

Eni is looking at reducing its ESP operating costs and, in doing so, decided to evaluate the relative merits of “alternative” ESP deployment options. The RFR-ESP provided by ZEiTECS was selected for an offshore test installation in one of the eni Congo fields.

The RFR-ESP technology represents a step change in ESP operating philosophy. ESP replacement without a hoist reduces operational disruption, reduces OPEX and deferment in production but, moreover, has profound safety and cost advantages with elimination of a number of the heavy offshore well interventions.

To gain confidence in the new technology and in its new deploying mode, eni selected the well FOKM 101, located on the eni Congo offshore Foukanda platform.

Based on the key drivers of rig cost, rig availability, mobilization time, installation time and initial installation cost in the considered area, an economic comparison between standard ESP and RFR–ESP has been carried out by means of theoretic study.

This paper describes the successful installation of the world’s first offshore RFR-ESP system and presents the economic
analysis of the results achievable by means of the application of this new ESP philosophy in those wells that represent high OPEX cost for eni Congo.

**Well candidate selection**

In this pilot project a standard 400/450 ESP had to be deployed in a 5 ½” 15.5 lbs/ft tubing, using the 550 series RFR-ESP technology described below.

In order to properly test the new ESP technology with minimum exposure to external factors, a rigorous well candidate selection process was implemented in order to define the best well to test the RFR-ESP.

The main screening criteria used to filter all the eni Congo wells were:

- 9 ⅝” casing
- Good track record with ESP;
- Well deviation @ ESP setting depth < 45°;
- No recorded sand production;
- No recorded problems with wax/asphaltens/scale/corrosion;
- GOR as low as possible;
- Easy access to the well head;
- Platform large enough to set a wireline or braided line unit;
- Target flow rate from 1000 to 10000 BFPD.

All the eni Congo ESP completed wells were considered during the selection process. The screening process resulted in the selection of FOKM 101. The FOKM 101 well matched all screening requirements and was selected as pilot well. It is a 9 ⅝” cased vertical well and was first completed in September 2001. The last ESP workover was completed in June 2011.

**Foukanda field overview**

The Foukanda platform, located offshore at 52 km west from Pointe Noire coast, in Republic of the Congo, started producing in July 2001. Most of the wells of the platform are completed with standard ESPs. While achieved ESP run lives are reasonable by industry standards, failures, when they occur, result in considerable production deferment and workover costs.

**FOKM 101 RFR-ESP project**

Eni Congo and ZEiTECS in 2010 initiated the FOKM 101 RFR-ESP project. The scope of work was defined in order to install and test the first offshore RFR-ESP.

A new ESP well completion philosophy was outlined and use of each completion component was studied and analyzed in order to be in compliance with operator well control policy. A standard 400/450 ESP system had to be deployed in a 5 ½” 15.5 lbs/ft tubing for this pilot project using the 550 series downhole equipment provided by ZEiTECS.

A string make-up test was performed in an ESP provider test well in USA in April 2011. The test was designed to check complete system interfaces and ensure correct assembly practices of the ZEiTECS RFR-ESP system.

The project success criteria for this first application were further defined in order to analyze performance following the installation of the FOKM 101 RFR-ESP.

**Project Success Criteria**

The technical success criteria of the FOKM 101 RFR-ESP project were pre-defined as follows:

- demonstration and proof of engineering / mechanical functionality
- demonstration and proof of sucker rod or wireline installation / retrievability
- demonstration and proof of wet connector mechanical / electrical functionality
- demonstration and proof of system electrical integrity
- demonstration and proof of ESP start-up and re-start capability
- demonstration and proof of hydraulic functionality & expected fluids to surface

The operational success criteria of the FOKM 101 RFR-ESP project were pre-defined as follows:

- Stable ESP performance parameters for 1 week after each (re)-deployment
- ESP performance parameters within expected design range

The test would be deemed a success if all of the above conditions were met.
FOKM 101 completion design

FOKM 101 completion design was based on a combination of the eni Congo well barrier, operational and well intervention philosophies. Selection of the completion for the RFR-ESP installation would ensure a safe and efficient system that would allow future ESP replacements without use of the topside rig surface safety system, such as BOP.

The main completion components can be divided in two main groups, namely semi-permanent completion components and retrievable artificial lift components. Any well intervention that would require removal of the semi-permanent completion components requires use of a standard rig similar to any regular ESP installation.

The main semi-permanent completion components are:

- Wellhead
- Special cable clamps
- Tubing and deep-set packer
- Gas venting system
- Docking station assembly
- Landing nipple assembly
- ESP power cable
- Permanent monitoring system
- Chemical injection system
- Safety system

The retrievable artificial lift components are:

- ESP
- ESP monitoring system
- Motor connector assembly
- Sealing system
- Space-out and expansion system

The following describes the completion components used in FOKM 101 (please refer to the Figure 1 for details).

**Wellhead:** The existing FOKM 101 wellhead had to be replaced with a new one to allow for increased number of penetrations including split-phase wellhead ESP cable penetration system through the tubing hanger and the bonnet.

**Tubing and deep-set packer:** the 5 ½” 15.5 lbs/ft tubing with Tenaris Blue dopeless threads was chosen for this application. The deep-set packer (9 ¾” Quantum type) equipped with the Polished Bore Receptacle (PBR) was pre-installed in a separate run, with the semi-permanent completion components deployed on a tubing string and sealed off inside the PBR to isolate annulus from the production fluids during well interventions.

**Special Cable Clamps:** use of 5 ½” tubing and multiple lines required redesign of the cross-coupling cable protectors.

**Gas Venting System:** since the application required use of a gas management system described below, it was decided to equip the well with the means of evacuating excessive gas through the annulus. To achieve this, a joint of perforated 5 ½” tubing was located below the Landing Nipple Assembly thus allowing gas venting to avoid potential pump gas lock due to accumulation of the free gas in the annular space between the pump intake and the sealing system above.

**Penetrator Can and Docking Station Assembly:** The Penetrator Can Assembly is the point in the system where the ESP power cable is terminated and interfaces with the electrical wet-connectors inside the Docking Station where the retrievable assembly is landed and connected. The Docking Station Assembly accommodates the male (pin) part of the three-phase high voltage wet-mateable connectors. The assembly also provides a means by which the connectors deployed on the bottom of the ESP Motor are aligned to ensure successful electrical connection (mating) and is equipped with a means by which the ESP is seated at the correct depth and prevented from any rotational stresses during start-up torque being transferred to the electrical connectors.

**Landing Nipple Assembly:** The Landing Nipple Assembly containing a landing shoulder and a seal bore is located above the retrievable ESP assembly and deployed as part of the semi-permanent completion. The space-out between the motor connector and landing nipple assembly is an important parameter and is determined by (i) calculating the change in pump length and
motor requirements as the reservoir conditions change through field life, (ii) establishing whether there is a need for gas management and (iii) including the necessary distance for efficient landing of the system.

**Permanent Monitoring System:** in addition to the retrievable ESP monitoring system described below, eni Congo opted to have a tubing deployed permanent quartz pressure/temperature gauge located above the deep-set packer. Use of this system required use of a single \( \frac{1}{4} \)" instrument line to surface.

**Chemical Injection System:** as per any ESP completion run in hole in eni Congo wells, a chemical injection nipple was put as deep as possible in order to allow for future chemical injection if required. A \( \frac{3}{8} \)" injection line serves the injection nipple.

**Safety System:** a downhole safety system for RFR-ESP completion was chosen to have two independent barrier type devices deployed as part of the semi-permanent completion and located below the RFR-ESP: a flapper type tubing retrievable surface controlled sub-surface safety valve (TR-SCSSV) and a deep set ball type lubricator valve. Use of these devices required further three \( \frac{1}{4} \)" hydraulic control lines, two for the lubricator valve and one for TR-SCSSV. These two mechanical safety barriers allow using the 5 \( \frac{1}{2} \)" tubing as a long ‘lubricator’ during deployment or retrieval of the retrievable artificial lift components.

**ESP System:** the ESP system comprised of a 180 Hp 450 series motor, a 400 series seal section, a Gas Management system, which included a 400 series vortex type gas separator and a 16 stages 400G22 multiphase pump, as well as a 252 stages 400P16 main pump section.

**ESP Cable:** a #2 AWG lead sheathed, 5 kV, Monel armor round ESP cable was selected for this project in order to maximize cable run life. The copper cross section area, the biggest used in eni Congo wells, leaves the possibility to increase the motor horsepower during future rigless ESP replacements, if needed.

**ESP Monitoring System:** the RFR-ESP system technology used on the FOKM 101 installation necessitates use of a specially designed downhole monitoring system since the motor Y- point, which is normally used for connecting a standard ESP gauge, is located on top of the motor and the power is supplied through the downhole gauge itself. To achieve that, in addition to the gauge sub-assembly, the downhole monitoring system design incorporates an artificial choke used for superimposing the DC signal on the AC power conductors. The monitoring system used on the FOKM 101 installation provided a standard set of ESP monitoring parameters including Pump Intake Pressure (PIP) and Temperature (PIT), Vibration x & y, Current Leakage and Motor Temperature.

**Motor Connector Assembly:** the Motor Connector Assembly is attached to the ESP assembly at the base of the monitoring system or a motor section. Its design provides both mechanical and electrical interfaces necessary to properly locate, align and mate into the permanently installed Docking Station. The assembly houses a female (socket) part of a three-phase high voltage wet-mateable connection system. It has the corresponding features to the Docking Station to ensure the ESP is seated at the correct depth and prevented from rotational stresses during start-up.

**Seal Assembly:** a Seal Assembly is designed to locate and seal off against the Landing Nipple to prevent re-circulation of fluids and is subject to a pressure difference between the Pump Intake and Pump Discharge Pressures. It also incorporates a GS-tool latching profile on the top. The Seal Assembly used for the FOKM 101 installation consisted of a multi-stack of lip-type seals equipped with wear rings.

**RFR-ESP installation in FOKM 101**

The RFR-ESP technology allows utilization of a variety of tools, including wireline, coiled tubing, or a rod string, in order to deploy, connect/disconnect and retrieve the ESP assembly. In the FOKM 101 case, use of standard \( \frac{7}{8} \)" rod string was chosen, based on availability of the material and cost considerations. The deployment string included (bottom to top) 5" GS tool, two 1.5 m long sinker bars and a 30" spang jar assembly. The latter would ensure mechanical release of the GS tool from the GS profile once the ESP assembly deployed to the setting depth and electrically connected is confirmed. The deployment string also included 166 joints of the \( \frac{7}{8} \)" rods.

In order to save rig time, first time installation involved making up the retrievable ESP assembly and pre-installing it inside the docking station before running the tubing string with the ESP power cable and associated control and instrument lines to the planned ESP setting depth. This was followed by pressure testing of the sealing assembly prior to releasing the GS tool to ensure integrity of the system being deployed downhole.

Once deployed to the ESP setting depth and engaged in the PBR on top of the lower completion packer, release of the GS tool with existing release mechanism set-up proved to be a challenge. This was believed to be associated with the length and the inertia of the rod string as well as the hoist’s ability to quickly release the load thus reducing required axial impact to shear the
pins of the GS tool. The retrievable ESP assembly was subsequently brought to surface while leaving the semi-permanent completion downhole. This operation allowed proving the retrievability of the ESP without engaging the rig facilities.

A new configuration of the release assembly was designed, including a centralizing device to ensure axial impact load transmission on the GS tool shearing pins, as well as use of a polished rod on the surface supported by a number of friction clamps for quick controlled release of the weight of the rod string thus ensuring maximum impact downhole. The ESP assembly was then run in hole, connected downhole and confirmed electrically engaged prior to successful release of the GS tool from the first attempt.

Prior to ESP start up, one more run in hole of a rod string was required, engaging GS tool with the top of the retrievable ESP assembly, lifting the ESP assembly approximately 6 ft from the sealing bore and re-engaging it downhole followed by once again a successful release of the deployment string.

A number of operations during initial installation resulted in achieving several success criteria related to system deployment and retrievability using chosen rod string deployment method.

Following standard ESP rotation tests, the ESP was then started up and delivered fluids to surface as per original design criteria. The RFR-ESP installation program was deemed to have completed successfully and the well was handed over to production on the 5th April 2012.

**FOKM 101 RFR-ESP completion time analysis**

An installation time breakdown analysis was carried out in order to find the time strictly necessary to deploy and start the RFR-ESP. Taking into account the fact that FOKM 101 project was considered to be a field trial installation of a new technology, it is accepted that the time required for the operation has to be significantly reduced in the future. The NPT breakdown of the complete program can be found in Table 1 below.

The rig skidded over the well and began preparatory work on FOKM 101 on 15 March 2012. The first component of the RFR-ESP completion was picked up at 13:30 on 22 March 2012 and marks the start of time analysis. Operations stopped at 01:30 on 23 March due to rain causing splicing of ESP cable to be suspended. Work restarted at 09:30 and continued at a steady and diligent pace. Operations stopped at joint 55 due to the reasons that required retrieval of the ESP at 22:00 on 24 March. From this point forward all operations are considered NPT until the re-running of joint 55 in the continuation of operations. When the permanent components were re-run, joint 55 was reached at 17:40 on 26 March and the system reached depth at 11:40 on 27 March. The tubing hanger was then landed at 22:00, BOP removed and the Xmas tree installed by 05:00 on 29 March. The DTL (Delivering The Limit) time for this first complete RFR-ESP installation was: 4 days 11 hours 50 minutes.

**Economic analysis for future RFR-ESP applications**

The success achieved during the first RFR-ESP installation and the good system performance after the ESP start-up have encouraged applying this technology in other wells in order to build up more confidence with new technology in more challenging environments. To evaluate a large-scale implementation of the new ESP deployment method for all the eni Congo high OPEX wells, an economic feasibility study was carried out in order to compare associated workover cost and the reduction in Non-Production Time (NPT).

Three eni Congo offshore fields operated from two platforms have been considered in the theoretical study outlined below. The study started from a workover root cause analysis based on the historical causes recorded for the fields in question. It was possible to group the workover root causes into 3 main categories:

1. ESP failures related to ESP components that could be rigless retrievable components (pump, motor) or related to ESP resizing or reservoir matrix stimulation to optimize oil production;
2. ESP failures related to ESP components that have to be permanent ESP components (ESP power cable, tubing) with both technologies, standard ESP and RFR-ESP;
3. Other reasons (Sidetrack, open a new producing zone, etc.).

Group 1 workover root causes could be addressed by means of rigless interventions utilizing the RFR-ESP and have been called “Avoidable Heavy Rig Workovers (AHRWO)”. Groups 2 and 3 workover reasons require Heavy Rig Workovers (HRWO) with both technologies, standard ESP and RFR-ESP.

Both considered platforms in the following study have high OPEX wells due to different reasons.

Platform A is a small platform started in 2009 and is producing by means of 7 ESP wells. In case of standard workovers (pull and run ESP), only a pulling unit, usually used in the onshore fields operations, can be used on Platform A. Therefore, any time an ESP fails, it is necessary to move the pulling unit from onshore to offshore by boats. This generates a high workover cost and a considerable production downtime. Moreover, when an extra operation like production enhancement (matrix stimulation) is required, this can be done only after ESP retrieval, increasing the workover related cost.

Platform B was started in 2001 and is producing by means of 9 ESP wells and a natural flow well. Platform B is operable with any offshore rig subcontracted by eni Congo today. However, the Platform B workover cause analysis has highlighted that the most of the workovers done to date are related to ESP components that could be replaced riglessly by means of wireline or rods in case of an implementation of a RFR-ESP philosophy.
Using the historical ESP run data acquired to date for Platform A and Platform B during ESP operations and workovers, as well as the data acquired during the FOKM 101 RFR-ESP installation, it was possible to extrapolate economics for RFR-ESP system installation and rigless ESP replacement and compare the results achieved with standard ESP workover costs. The analysis was performed assuming to use a RFR-ESP system with an access to the reservoir once the retrievable ESP components are pulled out. No residual retrieved RFR-ESP equipment value has been taken in account after a workover for both semi-permanent and retrievable components thus representing the worst economic scenario.

Key data for the following analysis can be found in the Table 2.

### Platform A analysis and results

Platform A was started in 2009 and has 7 ESP wells that are producing 2 different fields. From 2009 up to now a total of 10 ESP workovers have been carried out with the main reasons being related to either the reservoir matrix acidizing treatments to restore the well productivity or the ESP mechanical failures. Platform A workover reasons are listed in Table 3 and have been grouped into 3 main categories:

1. Avoidable heavy rig workovers: acid jobs, broken shaft and motor shortage;
2. Cable related workovers;
3. Other reasons.

The data shows that 40% of the total workovers were related to the well productivity issues that required acid matrix stimulation. The RFR-ESP technology that allows for pump rigless replacement as well as for the reservoir access below ESP could be used for performing these interventions in rigless mode. Grouping acid jobs with workovers related to broken shaft and motor failures, up to 80% of the total interventions done to date in the Platform A could be performed in rigless mode allowing for a huge reduction in workover cost and production deferment. These workover reasons were grouped as Avoidable Heavy Rig Workovers (AHRWO). The Figure 2 shows Platform A workovers ranking.

Starting from current situation of the Platform A, an ESP failure triggers selection of one of the two following strategies:

1. To continue to use the standard ESP
2. To install a RFR-ESP system

Due to the small size of the Platform A deck, in case of standard workovers, its wells are only operable with a pulling unit usually used in the onshore fields for ESP interventions. The workover costs study was done considering use a heavy rig workover to perform the first installation for both ESP technologies. Pulling unit costs were considered for standard ESP future interventions while a rigless deployment mode by rods was used for the RFR-ESP. Once the RFR-ESP will require a heavy workover in case of a semi-permanent component failure, use of both technologies assumed utilization of a same heavy workover rig.

For standard ESP, standard workover costs have been evaluated. In case of the RFR-ESP implementation, the costs of the wellhead replacement and the special completion components in the completion string were also added to the model. As it is shown in the Figure 3, the initial cost to change the ESP deployment philosophy is 146% higher than the standard ESP workover cost. This is mainly due to the RFR-ESP semi-permanent and retrievable components as well as the additional completion components used for well safety reasons. After the ESP installation strategy selection at the time 0, the analysis covered 10 years field production life and assumed the average 589 days Platform A ESP run life.

Both cases required six interventions in total after the initial workover at the time 0, but the associated costs are quite different. In fact, using the standard ESP philosophy, six more heavy workovers per well are required in order to cover considered period of time irrespective of a workover reason requiring well intervention.

If a RFR-ESP system is installed in the well, the stochastic analysis has highlighted the possibility to drop to only one more heavy workover in ten years. In fact, based on the historical data collected, it was assumed a stochastic 20% of workovers related to ESP permanent components failure, meanwhile the 80% of workovers have been considered as avoidable heavy rig interventions. The drastic reduction in total number of heavy workovers allows to save up to 31% total workover costs in ten years and to have 65% less NPT in the same period (Figure 4 and Figure 5). In the Figure 4 total workover costs have been parameterized based on the standard ESP costs.

So, despite the initial installation cost of the RFR-ESP system being around 146% more than a standard ESP workover, the theoretical study has highlighted a possibility of 31% workover cost saving and the 65% NPT reduction if the RFR-ESP philosophy is adopted in Platform A. Considering the differential cost between standard ESP and RFR-ESP as cost savings and taking in account the associated production to the NPT reduction (Figure 6), a differential positive NPV up to 6,693 k$ in ten years per well was found for the RFR-ESP as compared to the standard ESP.

### Platform B analysis and results

Platform B was started in 2001 and is producing a multilayered reservoir using 9 ESP wells and a natural flow well.
Since 2001 a total of 30 heavy workovers have been performed. Workover root cause analysis was carried out and results are reported in the Table 4 below. The main workover reasons are related to ESP shaft mechanical failure or ESP motor shortage. Similar to the Platform A analysis, all workover root causes have been grouped into 3 categories:

1. Avoidable Heavy Rig Workovers: broken shaft, motor shortage, pump resizing
2. Cable related workovers
3. Others: sidetrack, ITA, tubing leakage, changing reservoir layer or open a new zone.

Figure 7 shows Platform B workover root cause breakdown.

Starting from current situation of the Platform B, an ESP failure triggers selection of one of the two following strategies:

1. To continue to use the standard ESP;
2. To install a RFR-ESP system.

After the ESP installation strategy selection at the time 0, the analysis covered 10 years field production life and assumed the average 517 days Platform B ESP run life. The workover cost study assumed the lowest rate for the workover rigs that can operate on this platform for standard ESP interventions and for the first completion and future required heavy workovers for RFR-ESP. For all the avoidable heavy rig workover interventions with the RFR-ESP, a rigless deployment mode by rods has been assumed.

Based on the historical field data, the model assumed that 63% of the future workovers are related to avoidable heavy workover reasons and 37% of them will still require a heavy workover intervention.

The use of standard ESP requires seven more heavy workovers after the first installation, while using the RFR-ESP technology assumed two heavy workover and five rigless well interventions have been assumed in the same period.

Similar to the Platform A case, initial installation cost of the RFR-ESP system is around 146% higher than a standard ESP for Platform B. This is mainly due to the special well control completion components and the RFR-ESP semi-permanent and retrievable components and is not rig cost dependent. The workover costs taken in account during the analysis have been parameterized based on the Platform B standard ESP costs.

Platform B analysis has showed that even if the total workover cost of the fully retrievable system is 11% more than the standard ESP in ten years (Figure 8), the RFR-ESP technology still allows for up to 45% NPT reduction (Figure 9).

Considering the differential cost between standard ESP and RFR-ESP as cost savings and taking in account the associated production to the NPT reduction (Figure 10), a differential positive NPV up to 1,190 k$ in ten years per well was found for the RFR-ESP as compared to the standard ESP.

**Lessons learned**

The success of the first RFR-ESP completion and the positive results achieved to date are encouraging in the pursuit of extending this innovative and valuable ESP completion philosophy to eni Congo wells where ESP failures are primarily related to pump or motor and workover cost are exceptionally high.

The lessons learned during the first RFR-ESP installation in FOKM 101 well have been taken in account for the future well completion designs with RFR-ESP.

Key learned lessons are listed below:

1. Use of multiple lines to serve TR-SCSSV, lubricator valve, downhole permanent gauge, chemical injection nipple, and the ESP power cable could create an issue with the number and placement of the sheaves in the derrick. An accurate rig floor / material movement study should be always performed before the job in order to understand how to manage the large number of lines and sheaves. Use of special slips would make the work easier, faster and safer.
2. Release of the GS tool with first release mechanism set-up proved to be a challenge. The length and the inertia of the rod string as well as hoist’s ability to quickly release the load thus reducing required axial impact to shear the pins of the GS-tool are supposed to be the main causes. A new successful configuration of the release assembly was designed, including a centralizing device to ensure axial impact load transmission on the GS tool shearing pins, as well as use of a polished rod on the surface supported by a number of friction clamps for quick controlled release of the weight of the rod string ensuring maximum impact downhole. Alternatively, use of hydraulic release GS tool can be considered.
3. The seal assembly design used in FOKM 101 has shown some weakness that will be addressed with a new more robust design. A locked down isolation device would minimize the eventual unsetting of the seal assembly when reverse circulating.
4. The larger size Xmas tree has presented a spacing challenge on Foukanda platform. Alternative solutions with removable Xmas trees while maintaining well control could be investigated.
5. Use of a downhole permanent gauge below the ESP has highlighted signal transmission interference between the ESP and instrument cable. An investigation has been carried out and demonstrated that the gauge was working properly when the ESP is switched off, and as soon as the ESP is turned on, the data on surface stop updating. The ESP noise level seems to be the root cause for the communication failure and a noise reduction could be achieved by filtering the signal at the input of the ASU.
Conclusions

Eni Congo currently operates many ESP wells in numerous offshore fields. Even though ESP run lives are reasonable in comparison to industry benchmarks, a sizable number of ESPs fail each year. Each failure requires heavy rig or hoist intervention to retrieve and replace the ESPs and results in considerable operational disruption, operating cost and production deferment. Furthermore, the ESP interventions distract the rigs from oil-generating Well and Reservoir Management (WRM) activities incurring further deferment.

The world’s first offshore RFR-ESP system has been successfully installed in eni Congo Foukanda field, FOKM 101 well. The RFR-ESP technology represents a step change in ESP operating philosophy for eni Congo. An ESP replacement without a heavy rig reduces operational disruption, lowers OPEX and deferment but, moreover, has profound safety and cost advantages with the elimination of a great many heavy interventions. Use of this technology allows thinking about preventative maintenance of ESP systems, which was never an option with the tubing deployed ESPs.

The economic analysis has highlighted the positive impact of the RFR-ESP technology in all those wells where well accessibility and rig cost are the main concerns (Platform A). Platform B analysis results have highlighted lower final cost savings for all those wells where rig cost are not so high to justify additional capital expenditure for the new RFR-ESP technology. One additional failure of the semi-permanent completion per well and the resultant necessity of a heavy workover over the time period considered could invalidate the benefits of the solution.

The RFR-ESP capital cost is expected to decrease in the future, as the solution becomes more widespread and the default choice for some environments. This, and the residual value of the RFR-ESP special components once retrieved, could positively affect the total OPEX reduction.

The paper has shown how the new RFR-ESP technology is particularly suited for wells where accessibility, rig cost and safety are major concerns, allowing for reduction in production deferment and intervention cost.

Following the resounding success of the FOKM 101 RFR-ESP pilot test in eni Congo Foukanda field, reported in this document, eni Congo and ZEiTECS are looking forward to further, offshore large-scale implementation of the technology.

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References

### Table 1: Timeline and NPT Analysis, RFR-ESP FOKM 101 Project

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14d 00h 30' 06d 04h 30'

### Table 2: Platforms A & B key data

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<th>Platform B</th>
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<td>RFR-ESP</td>
<td>Standard ESP</td>
<td>RFR-ESP</td>
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<td>1050</td>
<td>740</td>
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<td>Analysis Period</td>
<td>years</td>
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<td>10</td>
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### Table 3: Pltf-A Heavy WO Reasons

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<td>Acid Job</td>
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<tr>
<td>Broken Shaft</td>
<td>3</td>
<td>30%</td>
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<tr>
<td>Cable</td>
<td>2</td>
<td>20%</td>
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<tr>
<td>Grounded Motor</td>
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### Table 4: Pltf-B Heavy WO Reasons

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<th>Percentage</th>
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<tbody>
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<td>33%</td>
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<tr>
<td>Motor</td>
<td>8</td>
<td>27%</td>
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<tr>
<td>Cable</td>
<td>6</td>
<td>20%</td>
</tr>
<tr>
<td>ST</td>
<td>2</td>
<td>7%</td>
</tr>
<tr>
<td>ITA</td>
<td>1</td>
<td>3%</td>
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<tr>
<td>Tubing Leak</td>
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<tr>
<td>ESP Resizing</td>
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<tr>
<td>Add New Perfs</td>
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Figure 7 Pltf-B Heavy WO reasons

Figure 8 Pltf-B Cumulative WO costs

Figure 9 Pltf-B Comparative NPT

Figure 10 Pltf-B Comparative Differential Cash Flow

Figure 11 eni Congo Foukanda Platform Well Intervention

Figure 12 Support Vessel