Feasibility study formulation for the applicability of rigless temporary ESPs

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Received: 22 March 2022 / Accepted: 3 April 2022 / Published online: 20 April 2022
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Abstract
Electrical submersible pumps (ESPs) are a well-known artificial lift technology used in the oil and gas industry to enhance production. One of the major requirements to implement ESPs is the need for a rig to install or replace failed pumps frequently. Temporary rigless ESPs (TRL ESPs) are a new technology that is being developed and tested in many parts of the world. The main advantage of this technology is its much lower installation cost compared to the conventional ESPs because it is deployable through wireline. The main drawback of this technology is the low volumes of fluids it can lift from the wellbore compared to the conventional ESPs. Therefore, it is mainly used as a temporary replacement on top of a failed ESP awaiting a workover job. The feasibility and applicability of the utilization of such technology is studied in this paper using actual field data from more than 500 wells from two fields. The added value of using TRL ESPs is to supplement the lost production volumes from the wells with failed pumps during the waiting time for workover and hence reducing the number of needed backup wells. It was found that using TRL ESPs will reduce the number of needed backup wells over a three-year period by 17–25% based on the actual historical data. Overall, the main outcome of this study is the formulation and development of the predictive model and feasibility study of the TRL ESPs using the actual field data.

Keywords Electrical submersible pump · Rigless ESP · Artificial lift · Through tubing conveyed ESP

Introduction
Oil fields that are naturally flown experience either reservoir pressure depletion, water cut increase or both depending on the reservoir drive mechanism. This ultimately results in a drop in oil production rate, hence recovery solely depending on natural flow is affected. A common practice is to use artificial lift to improve production. In artificial lift, energy is added to the well by various means to increase the drawdown at the sand face thus increasing the production rate. Many operators use the electrical submersible pump (ESP) which is an efficient and reliable artificial lift method for lifting moderate to high volumes of fluids from wellbores.

Electrical submersible pumps (ESPs) are multi-staged centrifugal pumps that are powered by downhole motor. It can run on a certain speed or have a variable speed drive that can allow varying the well production rate by changing the pump speed. ESPs hold more than 40% of the global artificial lift system market. However, there is a significant downside when using ESPs. Typically, ESPs have a lifetime of around 3 years and once they stop working a workover is deemed necessary (Shimokata and Yamada 2010). This leads to production downtime which persists for a long period of time to plan a workover, order equipment, move a rig to the well location and finally execute the workover.

Denney highlighted that although most offshore fields utilize gas lift as the artificial lift method, if these fields start using Electrical Submersible Pumps (ESPs), oil production will increase, and reserves recovery will be more economic and efficient. ESPs can also lower the abandonment pressure of fields and reduce the well count required to produce a field due to the higher production rate per well being delivered with ESP. The drawdown achieved by using ESP is higher than the drawdown by gas lift. To maintain high production rate with ESP, reservoir pressure should be maintained by
reservoir management and voidage replacement practices. The higher drawdown achieved by ESP allows lower quality layers in stratified reservoirs to contribute to production which would not happen in the case of well producing with lower drawdown levels. Not all the wells need to be converted to ESP, sometimes converting some wells can provide relief to gas lift constraints due to compression or allow the company to sell a portion of its produced gas (Denney 2012).

ESPs also increase reserves by allowing production at higher water oil ratio and also accelerating production within operating life of asset. Production acceleration is very important in field economics due to the time value of money (Romer et al. 2012). ESPs are a reliable and robust means to produce wells with high flow rate and are very successful in lifting heavy oil in offshore fields (Jiang et al. 2007).

The main high cost associated with ESP is the requirement to replace ESP after their lifetime ends. This requires a workover which is costly due to the high cost of using a rig (Denney 2012). Although ESP has low surface footprint and can deliver high production rates with high water cuts compared to other artificial lift means its main disadvantages are the limited run life and susceptibility to frequent trips (Al-Sadah et al. 2019). The alternative to mitigate that disadvantage is to use coiled-tubing or wireline deployed ESPs (Denney 2012). ESPs also have low reliability with high bottom temperature and require smooth tangent section in the wellbore to be installed and operate effectively (Kolawole et al. 2020).

In many oil fields across the globe where it was a struggle to maintain production in the mature stage of the fields’ lifetime, ESP was implemented as means of Artificial lift. Successful results of ESP implementations were published. The success of these implementations led to prolonged producing life of the fields and improved field economics. It is worth to mention that ESP is used in both conventional fields and unconventional fields. Below is a walkthrough in different success cases across the industry.

In one of the offshore fields of Saudi Aramco, wells were not able to naturally flow against the surface pressure of the production network. As a result, the idea of using ESP was implemented to increase the drawdown downhole allowing the well to produce at the high surface pressure. This led to the field meeting its set production target. Another advantage that came out as well was that the increase in water cut of these wells did not constitute a problem to well performance, since ESP can lift high water rate producing wells (Al Zahran et al. 2009).

Implementing variable speed drive (VSD) for few wells in a mature oil field in the Middle East in place of switchboard panels allowed increasing production by more than 20% since running at a higher frequency allowed reducing the Pump Intake Pressure thus increase reservoir drawdown. Not only VSDs can increase production, they also give flexibility to monitor and control drawdown thus preventing or mitigating early water breakthrough. Another optimization job was carried out in this field; other wells had workovers to deepen the ESP landing depth. Thus, reducing free gas at pump intake and allowing further drawdown from the reservoir. This led to increase in production for these wells by more than 50%. (Aguilar et al. 2014).

ESPs were also used in Ras Fanar field, Gulf of Suez in Egypt. This field had wells that were producing by natural flow for 12 years. After that, some wells were converted to ESP in that field and this resulted in increased proved reserves by 20% (Naguib et al. 2002). Due to field pressure depletion coupled with low GOR production, ESP was successfully utilized in the horizontal wells of Al Khalij Field in Qatar raising field production rates. (Constant et al. 2007).

Not only ESP can be implemented in wells incapable of natural flow. In a mature reservoir located in North Kuwait, natural flowing wells were worked over to produce with ESP leading to production gains north of 500 barrel of oil per day per well. (Chetri et al. 2011).

Currently in the USA, 36% of unconventional wells use ESP. However, major challenge to operate ESPs continuously in unconventional wells is produced propping sand and produced gas (Pankaj et al. 2018). Fracturing sand and gas handling turned out to be the primary root cause of most ESP failures in the Permian Delaware Basin with run life of 3–6 months being rendered acceptable in the basin (Oyewole 2016). To achieve a successful application of ESPs in deep unconventional horizontal wells, one of the key parameters is the ESP setting depth since it controls lift capacity, production rate and gas separation (Kolawole et al. 2020). The most favorable landing depth for ESP is in the straight tangent section around the kickoff point. To mitigate free gas challenges, technologies such as gas separators and gas handler devices can be applied. In addition to that, for optimum well performance, a variable speed drive is required since reservoir productivity of unconventional wells changes throughout well life making it harder to predict. (Pankaj et al. 2018).

There are various reasons behind ESP failure. Fig. 1 shows the distribution of ESP failure indicators as observed on an operator’s horizontal well in the Permian basin. One of the most occurring reasons is excessive heat of motor. This happens due to a phenomenon called gas interference, which is frequent in high gas liquid ratio wells. Gas slugs in the horizontal section, travel upwards through the well, and as they pass through the ESP motor starve the motor of liquid. This leads to overheating of the motor, which results in shutdowns and eventually ESP motor failure. The gas slug flow along the horizontal section also intensifies the abrasive action from propped sand production exacerbating the ESP issues. Such issues lead to frequent ESP pump change-out. (Kimery et al. 2017).
A relatively new technology called Rigless ESP technology can greatly reduce the production deferrals caused by the waiting time between the failure of an ESP and the workover job. The rigless ESP technology is a compact electrical submersible pump (ESP) that is deployable through wireline (i.e. no rig intervention needed). The rigless ESP pump runs on a power cable through tubing. The minimum tubing size for this technology is 3½" tubing. The downhole pump is capable of lifting up to 1000 barrels per day and can operate in temperatures up to 125 °C. This technology can be retrofitted into existing wells since it does not require any initial well recompletion nor introduction of downhole connectors. Retrofitting involves replacing the ESP feedthrough spool with a dedicated through tubing deployed ESP spool below the Lower Master Valve. This methodology allows for the spool to be introduced without the need to change the Xmas tree height and hence requires no corresponding flowline modifications. Within this configuration a cable support system is incorporated into the electrical penetration system. Fluid flow is diverted past the cable termination and electrical penetration and onwards into the existing tree. A horizontal electrical penetration completes the electrical circuit. Prior to the retrofitting stage, slickline (SL) will be utilized to set a retrievable plug and/or a backpressure valve into the tubing to act as double barriers before removing the Xmas tree and removing the existing ESP spool and replacing it with a through tubing ESP hanger spool. Figure 2 illustrates the Xmas tree assembly after the installation of tubing rigless ESP hanger spool.

After installation, an anchor packer is installed utilizing E-line. This packer will isolate the pump discharge from the pump intake. This packer is also pressure tested via means of a snap in/snap out latch seal assembly that is also run on wireline. Running the pump uses standard wireline spooling and pressure control equipment. There is no need to kill the well since the operation can be conducted on a live well whilst implementing full well integrity barriers. As a result, there is no risk of formation damage that is common in well killing during workovers.

Tubing Deployed ESP technology has been implemented by various operators in different parts of the world. In 1998, an operator (ConocoPhilips) in the West Sak field located in North Slope of Alaska developed a technology called through tubing conveyed ESP (TTCESP)/through tubing conveyed progressive cavity pump (TTCPCP). This technology allowed failed pumps, whether an ESP or PCP to be replaced quickly and economically using slick line or coiled tubing (CT) without a rig (Bybee 2009).

ConocoPhillips Alaska has taken advantage of the through tubing conveyed capabilities to optimize pump performance to increase production. Pumps have been pulled early and replaced because of gradual pump degradation in cases where production losses could not justify rig-workover costs. Pumps have been replaced for upsizing/downsizing to account for higher- or lower-than-expected production rates (Bybee 2009).

This first generation rigless ESP technology requires a rig to deploy the electric cable, motor and seal sections, with a special latching device also called the crossover (Fig. 3) that allows the pump (only the pump, not the motor or seal) to be pulled and replaced by use of slickline or coiled tubing, without a rig (Carpenter 2019). The pump can be
replaced numerous times as long as the integrity of the tubing deployed components is intact (Julian et al. 2011). The crossover/intake assembly houses the intake shaft, which couples the slickline-deployed pump to the seal section. This part is designed to outlast the pump components to allow for multiple pump changes (Bybee 2009).

The pump eye (Fig. 4) is what mates to the crossover, it is a centralizing, antirotational and splined engagement device. It self-aligns and mates with the crossover shaft when the pump is run and set into the crossover by the slickline.

After the installation is complete, the slickline sets a pack-off assembly and slipstop above the pump to seal and lock the pump discharge to the tubing. Ideal candidates for this technology includes well with flowrates ranging from 600 to 6000 barrels per day (Julian et al. 2011). A schematic showing both the rig and slickline deployed components is presented in Fig. 5.

The success of first generation TTCESP was remarkable, it led to pump replacements taking place with 5–10% of rig costs to replace ESP conventionally. This technology
Fig. 4 Slickline deployed ESP pump-eye component (Bybee 2009)

Fig. 5 Rig (left figure) and slickline or coiled tubing (middle and right, respectively) deployed components of TTCESP (Julian et al. 2011)
allowed upsizing, downsizing or adding new pump components such as rotary gas separators cheaply, quickly and simply. This success led to the application taking place in another field, the Milne field. ConocoPhilips Alaska deployed the technology successfully in two wells at depths of 6160’ measured depth (MD) and 11,624’ MD, respectively. The deviation at which the pump was set was 82° in one well and 63° in the other well (Julian et al. 2011).

These two wells had the pumps run in 4.5 in tubing housed in 7 in casing. Due to the limited annular space, flat cable was used with low profile clamps. In order to apply such technology in those two wells, certain changes had to take place. The outer diameter (OD) of the 4.5 inch tubing did not allow a standard electrical penetrator to fit inside the 7 inch casing, this was overcame by a short wellhead spoolpiece. This spoolpiece, which is 18-inch long, adapted the well head from 7 to 9 inches to allow sufficient annular space for the electrical penetrator. Moreover, to ensure a clean tubing inside, the rig performed a bit and scraper run before installing the TTCESP for the first time (Julian et al. 2011).

Installing TTCESP in these two wells increased oil production rate in one well from 100 to 250 barrels of oil per day. The run time of the first well was at least 468 days and the second well had at least 245 days (both wells were producing normally till the paper was authored) (Julian et al. 2011).

In this first-generation design, if a sand blockage was created below the ESP, the sand could not be removed without pulling the tubing with a rig. This was resolved by the 2nd Generation rigless ESP technology that was introduced later in 2014. In this technology, the ability to pull motor and seal in addition to the pump was introduced. This leaves the full-bore access to the lower completion and producing zone. This fully retrievable ESP system brought additional value by allowing simple, low-cost SL, electric-line, and CT access to the lower completion once the ESP was retrieved without the need for a rig (Carpenter 2019).

For conventional ESPs, a failed pump or motor must be replaced with a rig. In the first generation, the pump can be replaced with slickline (SL) or coiled tubing (CT). In the second generation, the pump, seal, and motor can be replaced with SL or CT, leaving full-bore access to the wellbore (Carpenter 2019). Both first and second Generation systems have been able to pass through dogleg severity of 12⁰/100 ft and inclinations of 65° with SL, relying on weight and gravity to deploy the equipment to the pump setting depth. When the equipment cannot be deployed because of high deviation, it can be pumped down to the setting depth. CT has been used to run equipment in wellbores with angles greater than 65°. The choice of pulling the pump using SL, wireline tractor or CT mainly depends on well inclination (Carpenter 2019).

The second-generation design enabled the operator to carry out operations such as sand fill cleanout or replacement of failed motor/seal without the need for a rig intervention. This rigless ESP technology has reduced production downtime due to ESP failures; in addition to providing low-cost access to perform well interventions. This technology also enabled a proactive ESP-operating philosophy, i.e. to eliminate ESP-related downtime by pulling and maintaining ESP systems before failure (Carpenter 2019).

Based on the operator experience, the average lifetime of a first generation rigless ESP pump is around 2 years, compared to 4 years lifetime for conventionally run ESP. The main failure mode of TTCESP was erosion wear or plugging by sand. Out of 380 pump replacements, 280 pumps were carried out successfully through SL. The pump replacement operation using SL was highly successful with a rate of 93% (280 successful jobs out of 293 attempts). This success ratio is considerably high due to the abundant sand production issue in the West Sak field. The 13 unsuccessful operations were caused by inability to pull stuck pump, pump-to-motor coupling damage, hardpacked sand, parted pump and rotary gas separator, inability to seat the pump, and packoff sticking (Carpenter 2019).

The commercial deployment of the second generation rigless ESP system began in Alaska in 2014 with no failure recorded till 2019 in both the SL-retrievable portion of the system (pump/motor/seal/wet-connect) or the tubing-deployed portion of the system (downhole side pocket mandrel wet-connect/cable). Post 2019, the proactive replacement approach was implemented with one entire ESP swap (pump/seal/motor/wet-connect) and three pump-only swaps (four ESP interventions in total). All these swaps were carried out using slick line to replace a degrading pump before it failed. The lost production time per swap was 2–6 days compared to production downtime of 6–18 months in the case of conventional ESP replacement using a rig (Carpenter 2019).

The rigless ESP technology was also trialed in Saudi Aramco in the Khurais field. Due to the high H₂S content of this field, with H₂S levels up to 15% in the vapor phase, a special power cable was used. A metal-jacketed power cable was able to protect against H₂S and provided a smooth outside diameter that could be gripped on and sealed. Moreover, to apply this technology safely, a vertical cable-hanger spool was developed to enable the ESP cable to be terminated below the master valve; this is for well control purposes. The trial involved one well, where the pump was placed at 4920' measured depth and 40° deviation. A comparison between the time and cost saving of this technology in this trial shows that rigless ESP required around 46% less time to be set up (Roth et al. 2018).

Applying the rigless ESP technology in oil fields will bring about great value since wells that need a workover...
to change their ESP pumps will continue producing whilst they are waiting. Deferred production whilst scheduling of workover rigs will be greatly reduced. From a strategic point of view, this reduced production deferral will cut the required number of newly drilled wells to maintain production targets.

Saving both time and money, cable deployment of rigless ESP enables operators to resume production quickly without having to kill the well. The short-term result is a decrease in deferred production without having to wait for the rig required in standard ESP operations at zero production. The long-term positive impacts include eliminating rigs from ESP workovers altogether. But, the temporary rigless ESP (TRL ESP) has less production capacity due to its size and power rating. Therefore, assessment of the business feasibility is important.

Currently, there isn’t a published study on the applicability or feasibility of the TRL ESP technology. The literature is lacking a comprehensive study on the applicability and feasibility of such new and innovative technology. With actual data from two different fields over several years, the study in this paper is highlighting the main key parameters influencing the success of implementing this technology in any field in the future. In this study, an assessment of the potential utilization of TRL ESPs is conducted on actual historical data from two fields. The data consist of actual run life, workover data and failure data of 553 ESPs. The objective of this study is to develop a predictive model that is capable of predicting the expected failure date of ESPs based on statistical analysis of historical data and assign the appropriate number of needed rigless ESPs for every field. Also, a comparison between utilizing TRL ESPs based on the developed predictive model and not utilizing TRL ESPs is conducted to showcase the cost efficiency potential of using TRL ESPs based on the developed predictive model. The main addition of this study is showcasing the formulation and development of the predictive model and feasibility study of the TRL ESPs using the actual field data. The developed models in this study can be implemented to study the feasibility of this technology in another field utilizing the constructed guidelines and workflow of the predictive model.

### Data accusation and preparation

Data from two fields is used in the study. Field A and field B both have wells that are producing with ESP. Field A has 349 wells while field B has 204 wells. The difference between the ESP run-in-hole date and the ESP failure date is calculated, the resulting value is called the ESP run life. This calculation is carried for both field A and field B. $P_{10}$ represents the number of years that 10% of the dataset has a corresponding value equal to or less than the $P_{10}$ value, $P_{50}$ parameter value indicates what 50% of the dataset has a corresponding value equal to or less than that $P_{50}$ value and $P_{90}$ parameter value indicates what 90% of the dataset has a corresponding value equal to or less than that $P_{90}$ value.

The statistical parameters for field A wells’ ESP run life are shown in Table 1 and 2, respectively. Also, the histogram for run life of fields A and B are shown in Figs. 6 and 7, respectively.

By comparing the run life analysis results of field A, and field B, it seems that the run life in field A is smaller than the run life in field B, this is due to high sand production in field A. This highlights that there is more opportunity for the TRL ESP technology to be applied in field A since there are more frequent ESP failures.

The next part of the analysis was to look at the workover date for each well that had an ESP failure, the difference between the workover date and the ESP failure date was called the locked potential period. Since the TRL ESP technology requires one month to be installed and run in the hole in the well and also requires one month to be pulled out of the hole before the rig workover date, the Locked Potential Period is adjusted by subtracting 2 months of the period. The longer the adjusted Locked Potential Period means the more deferred production is happening which can be partly produced by the TRL ESP technology -since this technology is only capable of producing 1000 barrels per day. Table 3 summarizes the statistical analysis for Field A wells’ adjusted Locked Potential Period. The $P_{10}$ values is negative due to subtracting two months. Also, Fig. 8 shows the histogram of field A wells’ adjusted Locked Potential Period.

### Table 1 Statistical parameters for field A wells’ ESP run life

| Parameter | Value (years) |
|-----------|--------------|
| Mean      | 2.72         |
| Median    | 0.14         |
| Standard deviation | 2.61     |
| $P_{10}$  | 0.07         |
| $P_{50}$  | 1.97         |
| $P_{90}$  | 6.38         |

### Table 2 Statistical parameters for field B wells’ ESP run life

| Parameter | Value (years) |
|-----------|--------------|
| Mean      | 5.02         |
| Median    | 4.39         |
| Standard deviation | 3.36     |
| $P_{10}$  | 1.02         |
| $P_{50}$  | 4.39         |
| $P_{90}$  | 10.06        |
The analysis of the adjusted Locked Potential Period data for field A shows a similar signature to a log-normal distribution. It seems that more than 120 wells have a negative value for adjusted Locked Potential Period which means that the rigless ESP technology is not applicable in these quick response cases. There are more than 25 wells that had a rig response time of more than 1000 days, applying the technology to these wells would be of great value. Table 4 summarizes the statistical analysis for Field B wells’ adjusted Locked Potential Period. Also, Fig. 9 shows the histogram of field B wells’ adjusted Locked Potential Period.

The analysis of our “locked potential period- 2 months” data for Field B shows a similar signature to a log-normal distribution. It seems that here in field B we have just shown of 18 wells that have a negative value for Locked Potential-2 months which means that the rigless ESP technology is not applicable in these quick response cases, however, the number of wells sitting in this category is fewer compared to Field A. Most of the wells in Field B have a “locked potential period-2 months” value of 0–100 days; however, there are plenty of wells that have higher values which can be up to 500 days.
Methodology

The temporary rigless ESP predictive model

In order to build the predictive model, it was assumed that the historical conventional ESP performance in terms of run life and number of failures in the last 3 years will be repeated in the next 3 years. This is given that there are no recent changes in the conventional ESP technology to reduce failure or prolong ESP run life.

The first step in building the predictive model is to determine the probability distribution model that fits the historical data for field A and field B. The parameter that was studied is the “Locked Potential Period”. By observation of the histogram charts of the Locked Potential Period for field A and field B (Figs. 8 and 9, respectively), it is apparent that the locked potential period is not following a normal distribution probability model. The data actually looks more similar to log-normal probability distribution. A normal distribution model is where around 68% of the results fall within one standard deviation and around 95% fall within two standard deviations. The shape of the distribution is symmetric and unimodal. It is also called the bell-shaped or Gaussian distribution. On the other hand, the log normal distribution model is a model in which $X$ is lognormally distributed if $Y = \ln(X)$ is normally distributed.

In this study, $\ln($Locked Potential Period$)$ is calculated and histogram is plotted to observe if the data resembles how a normal distribution model would look like. This is to confirm whether the Fields’ Locked Potential Period data actually resemble a log normal distribution model or not. Figures 10 and 11 represent the histogram for $\ln($Locked Potential Period$)$ for field A and field B, respectively.

The histograms revealed that there is resemblance to the normal distribution model. Therefore, using the Mean and Standard Deviation of Locked Potential Period, a log normal distribution dataset built by randomly generated cumulative probability is created. The modelled dataset is then plotted as histograms as shown in Figs. 12 and 13 for field A and field B, respectively. Then they are compared to the actual Locked Potential Period data for both fields (Figs. 8 and 9, respectively).

The Modelled Locked Potential Period is resulted in a very similar outcome to the Actual Locked Potential Period.

![Fig. 8 Adjusted locked potential period for field A](image-url)

### Table 3 Statistical parameters for field A wells’ adjusted locked potential period

| Parameter    | Value (years) |
|--------------|---------------|
| Mean         | 1.08          |
| Median       | 0.093         |
| Standard deviation | 3.02     |
| \(P_{10}\)   | 0.13          |
| \(P_{50}\)   | 0.09          |
| \(P_{90}\)   | 2.08          |

### Table 4 Statistical parameters for field B wells’ adjusted locked potential period

| Parameter    | Value (years) |
|--------------|---------------|
| Mean         | 0.29          |
| Median       | 0.18          |
| Standard deviation | 0.44     |
| \(P_{10}\)   | 0.013         |
| \(P_{50}\)   | 0.18          |
| \(P_{90}\)   | 0.62          |
Tables 5 and 6 show the Mean and Standard Deviation for Actual and Modelled Locked Potential Period for field A and field B, respectively.

The next stage in the analysis is to determine the number of failures for field A and field B in the last 3 years. For field A, 31 instances of failure occurred while 149 instances occurred in field B.

The developed workflow for the predictive model is as follows:

1. The study is based on a 3 year term.
2. In this 3 year term, the number of ESP failure instances predicted in field A and field B will be the same as the number of failures in the last 3 years of history data.
3. Use the lognormal distribution model to generate numbers for locked potential period in days.
4. Deduct 60 days to calculate the adjusted Locked Potential Period, the result is also known as Operating Time.
5. Generate random ESP failure dates between for the 3 years for all the ESP failure instances.
6. Filter out the instances where the Locked Potential Period - 2 Months is less than 14 days and larger than 365 days.
   a. The rationale behind filtering out what is lower than 14 days is that it will be operationally challenging to
install the pump and retrieve it 14 days later along with all other associated necessary wireline jobs and wellhead spool change out work.

b. The rationale behind filtering out what is larger than 365 days is that these wells in reality could have had their faulted ESP remain in hole due to other well downhole challenges or subsurface performance that prevented an imminent workover.

7. Calculate the ESP demobilization date which is ESP Failure Date + 30 days + Operating Time.

8. Plot the ESP failure date and the demobilization date for all instances on a Gantt Chart.

Temporary rigless ESP feasibility study

By applying the developed predictive model on the data from the two fields in this study, a feasibility study is conducted to evaluate the potential cost efficiency of using the TRL ESP. To conduct the economic analysis for this study, the information in Table 7 are retrieved regarding costs of operation of TRL ESPs from a production enhancement
operator company in the Middle East. Furthermore, Table 8 illustrates the economic factors used in this economical study.

The main advantage in employing the TRL ESP is creating less number of needed backup wells in the field to offset the production drop due to ESP failure. Without TRL ESP, several backup wells need to be drilled and used for production in case of a failure in ESP from the production wells.

Table 5 Field A mean and standard deviation for actual and modelled locked potential period

| Dataset   | Mean, years | Standard deviation, years |
|-----------|-------------|---------------------------|
| Actual    | 1.25        | 3.02                      |
| Modelled  | 1.19        | 2.27                      |

Table 6 Field B mean and standard deviation for actual and modelled locked potential period

| Dataset   | Mean, years | Standard deviation, years |
|-----------|-------------|---------------------------|
| Actual    | 0.45        | 0.44                      |
| Modelled  | 0.44        | 0.31                      |

Table 7 Operation costs of TRL ESP

| Asset/operation | Cost, $ |
|-----------------|---------|
| TRL ESP opex (per day) | 5500    |
| Pump installment | 60,000  |
| Pump retrieval   | 60,000  |

In field development and planning, by taking into account using TRL ESP as a method to offset the production lost due to ESP failures and utilizing the built predictive models, less back up wells will need to be drilled and therefore, the capital cost for developing the field would be less. The estimated average cost of drilling a backup well used in the study is $4,000,000. Also, based on the available data, it is estimated that each well is producing at a rate of 4000 barrels per day. Table 9 summarizes the production data for each field.

The feasibility study is conducted on the basis that the predictive model will predict how many TRL ESP are needed to offset the production drop due to the predicted ESP failures for the next three years. Also, the number of times each TRL ESP is used is estimated for the entire study period. Each TRL ESP is estimated to provide up to 1000 barrel of oil per day. The cost of using (renting) TRL ESP includes the estimated daily operational cost.

Table 8 Economic factors

| Economic factor | % per year |
|-----------------|------------|
| Discount rate   | 10         |
| Inflation rate  | 3          |

Table 9 Field A and field B production data

| Field | Number of production wells | Daily production rate (barrels per day) |
|-------|-----------------------------|----------------------------------------|
| A     | 349                         | 1,396,000                              |
| B     | 204                         | 816,000                                |
Table 10  Field A and field B summary of required ESP pumps, wireline intervention jobs and days of operation

| Field | Number of TRL ESPs needed | Number of wireline jobs | Total operating days |
|-------|---------------------------|-------------------------|----------------------|
| A     | 3                         | 12                      | 1732                 |
| B     | 20                        | 100                     | 14,392               |

(Opex) which is paid during the usage period of the pump which is one month after the failure of an ESP until one month before the arrival of the rig to replace the failed ESP (Adjusted Locked Potential Period). The study conducted is for a 3 year period with the estimated cash flow per each year.
Results and discussion

Predictive model

Gantt Chart representing ESP failure date and ESP demobilization date are represented in Figs. 14 and 15 for field A and field B, respectively, for a period of 3 years.

By analyzing the Gantt Charts and looking at overlap of different bars - representing ESP failures, the number of required TRL ESPs needed in field A and field B are determined. The number of wireline intervention jobs will be equal to number of ESP failures in both field A and field B. The results are summarized in Table 10.

For these predictive models to be utilized and result in a cost efficient and effective plan, a comparison using the actual field data between the scenario of utilizing the TRL ESP based on the developed predictive models against not using the TRL ESPs needs to be conducted.

In the scenario of not using the TRL ESPs (which is the practice done on the data collected), the failed ESPs will be replaced and the time between ESP failure and the ESP replacement (using workover rig) is determined. The amount of production during this period using TRL ESPs is compared to the cost of TRLESPs to analyze the potential and the added value of this technology while considering its added costs.

Feasibility study

Utilizing the developed predictive model, Table 11 summarizes the investment needed for the 3 year period to employ TRL ESP in the two fields studied in this paper. Based on the developed predictive model results in Table 10, filed A, three TRL ESP will be needed and for three-year period, they are expected to be used 12 times. For field B, 20 TRL ESP are needed and they are expected to be used 100 times. Every time a TRL ESP, the cost for installation and retrieval are accounted for. For field A, TRL ESP is used for a total period of 1732 days in the different 12 wells that faced ESP failures. For field B, the TRL ESP is expected to be used for 14,392 days in the 100 wells that are expecting an ESP failure. After rigless ESP is retrieved a well workover is carried out to replace the failed ESP and return the failed well to normal production rate.

For field A, it was found that using TRL ESP will reduce the number of needed backup wells from 4 to 3 which translates to a saving of $4,000,000. But, due to the high operation cost of TRL ESP and the low production rate they provide, this saving cannot be justified given the total operation cost for TRL ESP in field A for the 3 years is $10,966,000 resulting in a net loss of $6,966,000. For the TRL ESP technology to be profitable in field A, the breakeven operational renting cost should be less than $1478 per day. Table 12 summarizes the feasibility study conducted on the data from field

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Table 11  TRL ESP operational cost for field A and field B for the studied three-year period

| Field | Wireline jobs cost ($) | Operating cost ($) | Total operation cost ($) |
|-------|------------------------|--------------------|--------------------------|
| A     | 1,440,000              | 9,526,000          | 10,966,000               |
| B     | 12,000,000             | 79,156,000         | 91,156,000               |

Table 12  Feasibility study for field A without using TRL ESP

| Year | 2022 | 2023 | 2024 |
|------|------|------|------|
| Number of ESP failures | 7    | 2    | 3    |
| Number of ESP lifted wells operational for entire period | 342  | 347  | 346  |
| Number of ESP operational days | 124,830 | 126,655 | 126,290 |
| Number of days operation with failed ESP before failing | 1421  | 178  | 329  |
| Production from wells with ESP | 505,004,000 | 507,332,000 | 506,476,000 |
| Target production | 509,540,000 | 509,540,000 | 509,540,000 |
| Number of backup wells used | 4    | 2    | 3    |
| Number of production days from backup wells | 1134  | 552  | 766  |
| Production from backup wells | 4,536,000 | 2,208,000 | 3,064,000 |
| Total production days from ESP and backup wells | 127,385 | 127,385 | 127,385 |
| Total production from ESP and backup wells | 509,540,000 | 509,540,000 | 509,540,000 |
| Additional operational cost | $0 | $0 | $0 |
| Net cash flow | $0 | $0 | $0 |

Table 13  Key performance indicators for field A without using TRL ESP

| Indicator | Value |
|-----------|-------|
| Capital cost | $16,000,000 |
| Capital cost savings | $0 |
| Total additional operational cost | $0 |
| NPV (10%) | $−1,454,545.45 |
| Net profit | $0 |
assuming TRL ESP are not used. Table 13 summarizes the key performance indicators for this scenario. While, Table 14 summarizes the feasibility study conducted on the data from field A given the predicted days of employment of TRL ESP from the predictive model. Table 15 summarizes the key performance indicators for this scenario.

For field B, it was found that using TRL ESP will reduce the number of needed backup wells from 30 to 25 which translates to a saving of $20,000,000. But, due to the high operation cost of TRL ESP and the low production rate they provide, this saving cannot be justified.

### Table 14: Feasibility study for field A with using TRL ESP

| Year | 2022 | 2023 | 2024 |
|------|------|------|------|
| Number of ESP failures | 7 | 2 | 3 |
| Number of ESP lifted wells operational for entire period | 342 | 347 | 346 |
| Number of ESP operational days | 124,830 | 126,655 | 126,290 |
| Number of days operation with failed ESP before failing | 1421 | 178 | 329 |
| Production from wells with ESP | 505,004,000 | 507,332,000 | 506,476,000 |
| Number of wells operation with TRL ESP | 7 | 2 | 3 |
| Production from wells with TRL ESP | 714,000 | 432,000 | 586,000 |
| Number of wireline jobs | 7 | 2 | 3 |
| Number of days TRL ESP are used | 714 | 432 | 586 |
| Total production from ESP and TRL ESP | 505,718,000 | 507,764,000 | 507,062,000 |
| Target production | 509,540,000 | 509,540,000 | 509,540,000 |
| Number of backup wells used | 3 | 2 | 2 |
| Number of production days from backup wells | 420 | 120 | 180 |
| Production from backup wells | 3,822,000 | 1,776,000 | 2,478,000 |
| Total production days from ESP and backup wells and TRL ESP | 127,385 | 127,385 | 127,385 |
| Total field production | 509,540,000 | 509,540,000 | 509,540,000 |
| Additional operational cost from TRL ESP | $4,767,000 | $2,616,000 | $3,583,000 |
| Net cash flow | −$16,767,000 | −$2,616,000 | −$3,583,000 |

### Table 15: Key performance indicators for field A with using TRL ESP

| Indicator | Value |
|-----------|-------|
| Capital cost | $12,000,000 |
| Capital cost savings | $4,000,000 |
| Total additional operational cost | $10,966,000 |
| NPV (10%) | −$1,548,584.52 |
| Net profit | −$6,966,000 |

### Table 16: Feasibility study for field B without using TRL ESP

| Year | 2022 | 2023 | 2024 |
|------|------|------|------|
| Number of ESP failures | 14 | 35 | 51 |
| Number of ESP lifted wells operational for entire period | 190 | 169 | 153 |
| Number of ESP operational days | 69,350 | 61,685 | 55,845 |
| Number of days operation with failed ESP before failing | 2668 | 5651 | 7788 |
| Production from wells with ESP | 288,072,000 | 269,344,000 | 254,532,000 |
| Target production | 297,840,000 | 297,840,000 | 297,840,000 |
| Number of backup wells used | 7 | 20 | 30 |
| Number of production days from backup wells | 2442 | 7124 | 10,827 |
| Production from backup wells | 9,768,000 | 28,496,000 | 43,308,000 |
| Total production days from ESP and backup wells | 74,460 | 74,460 | 74,460 |
| Total production from ESP and backup wells | 297,840,000 | 297,840,000 | 297,840,000 |
| Additional operational cost | $0 | $0 | $0 |
| Net cash flow | −$120,000,000 | $0 | $0 |
given the total operation cost for TRL ESP in field B for the 3 years is $91,161,500 resulting on a net loss of $71,161,500. For the TRL ESP technology to be profitable in field B, the breakeven operational renting cost should be less than $556 per day. Table 16 summarizes the feasibility study conducted on the data from field assuming TRL ESP are not used. Table 17 summarizes the key performance indicators for this scenario. While, Table 18 summarizes the feasibility study conducted on the data from field B given the predicted days of employment of TRL ESP from the predictive model. Table 19 summarizes the key performance indicators for this scenario.

Conclusions

In this study, an overall view of temporary rigless ESP (TRL ESP) technology has been studied on actual field data from more than 500 wells. The main outcome of this study is the construction of a process to evaluate the feasibility of this technology. This process consists of a predictive model and a feasibility study that accounts for all the factors involved. The main impacting factor is the wait time between the time an ESP fails and a workover job is conducted. In this case, a backup well will compensate for the production loss due to the ESP failure until a workover job to fix or replace the ESP is done. The implementation of the temporary rigless ESP using the predictive and feasibility study conducted in this work will investigate the applicability of this technology in a new field where TRL ESP will compensate the production loss without the need to drill several backup wells. The formulation and development of this evaluation study is shown in this work in details to be implemented and tested with different assumption and inputs if needed.

Acknowledgements

The authors of this article acknowledge and highly appreciate King Fahd University of Petroleum & Minerals (KFUPM) for its support to publish this work.

| Table 17 | Key performance indicators for field B without using TRL ESP |
| Indicator | Value |
| --- | --- |
| Capital cost | $120,000,000 |
| Capital cost savings | 0 |
| Total additional operational cost | 0 |
| NPV (10%) | $10,909,090.91 |
| Net profit | 0 |

| Table 18 | Feasibility study for field B with using TRL ESP |
| Year | 2022 | 2023 | 2024 |
| --- | --- | --- | --- |
| Number of ESP failures | 14 | 35 | 51 |
| Number of ESP lifted wells operational for entire period | 190 | 169 | 153 |
| Number of ESP operational days | 69,350 | 61,685 | 55,845 |
| Number of days operation with failed ESP before failing | 2668 | 5651 | 7788 |
| Production from wells with ESP | 288,072,000 | 269,344,000 | 254,532,000 |
| Number of Wells operation with TRL ESP | 14 | 35 | 51 |
| Production from wells with TRL ESP | 1,602,000 | 5,024,000 | 7,767,000 |
| Number of wireline jobs | 14 | 35 | 51 |
| Number of days TRL ESP are used | 1602 | 5024 | 7767 |
| Total production from ESP and TRL ESP | 289,674,000 | 274,368,000 | 262,299,000 |
| Target production | 297,840,000 | 297,840,000 | 297,840,000 |
| Number of backup wells used | 6 | 17 | 25 |
| Number of production days from backup wells | 840 | 2100 | 3060 |
| Production from backup wells | 8,166,000 | 23,472,000 | 35,541,000 |
| Total production days from ESP and backup wells and TRL ESP | 74,460 | 74,460 | 74,460 |
| Total field production | 297,840,000 | 297,840,000 | 297,840,000 |
| Additional operational cost from TRL ESP | $4,767,000 | $2,616,000 | $3,583,000 |
| Net cash flow | $110,491,000.00 | $31,832,000.00 | $48,838,500.00 |

| Table 19 | Key performance indicators for field B with using TRL ESP |
| Indicator | Value |
| --- | --- |
| Capital cost | $100,000,000 |
| Capital cost savings | $20,000,000 |
| Total additional operational cost | $91,161,500 |
| NPV (10%) | $10,344,403.83 |
| Net profit | $71,161,500 |
**Funding** The authors would like to acknowledge the College of Petroleum Engineering & Geosciences, King Fahd University of Petroleum & Minerals for providing the funding for this research.

**Declarations**

**Conflict of interest** Authors have declared that no conflict of interest exist.

**Ethical approval** The research does not require any ethical clearance issue.

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