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A Summary of Artificial Lift Failure, Remedies and Run Life Improvements in Conventional and Unconventional Wells

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Abstract:- Artificial lift (AL) systems are crucial for enhancing oil and gas production from reservoirs. However, the failure of these systems can lead to significant losses in production and revenue. This paper explores the different types of AL failures and the causes behind them. The article discusses the traditional methods of identifying and mitigating these failures and highlights the need for new designs and technologies to improve the run life of AL systems. Advances in AL system design and materials, as well as new methods for monitoring and predicting failures using data analytics and machine learning techniques, have been discussed. The findings of this work provide valuable insights for researchers and practitioners in the development of more reliable and efficient AL systems.

Keywords:- *Artificial Lift, Failure, Run Life, Machine Learning, Pump.*

Abbreviations:-

AL	Artificial lift	KPIs	Key performance indicators
SRP	Sucker rod pump	ML	Machine learning
GL	Gas lift	RCFA	Root cause failure analysis
PCP	Progressive cavity pump	MTBF	Mean time between failure
ESP	Electrical submersible pump	OPEX	Operational expenditures
HJP	Hydraulic jet pump	EOR	Enhanced oil recovery
MTMPCP	Metal to metal progressive cavity pump	ESPCP	Electrical submersible progressive cavity pump

I. INTRODUCTION

Artificial lift (AL) is a crucial process for enhancing oil and gas production from reservoirs. However, AL systems are prone to failure, leading to production losses, additional costs, and increased downtime. Therefore, addressing the causes of AL failures and finding solutions to improve their run life is essential for the oil and gas industry (OGI). This review article examines the different types of AL failures, their causes, and the various remedies and new designs developed to increase the AL run life. The article presents a comprehensive review of the current state-of-the-art in AL design and operation, highlighting the key challenges and opportunities for improvement. The findings of this review article will provide valuable insights for researchers and practitioners in the OGI, as well as for those interested in developing new AL designs and improving their performance.

II. ARTIFICIAL LIFTFAILURE AND RUN LIFE IN CONVENTIONALS AND UNCONVENTIONALS

The consideration of AL failure and operational lifespan proves crucial in the selection process. Determined by field conditions, fluid characteristics, and reservoir properties, these factors are assessed through records of occurrences and running cycles. Several researchers (**Table 1**)have investigatedAL failures in both conventional and unconventional wells (conventionals and unconventionals) with the aim of identifying underlying causes and proposing solutions to extend operational life cycles.

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Table 1: AL Failure and remedies in conventionals and unconventionals

References	Problem	Mitigation	Remarks
Bucaram and Patterson 1994	Corrosion and erosion	Failure trailing system (type, location, cause)	Over 20 months MTBFover 18 years
Yang et al. 2011	Scale	Anti-scaling technique using ceramic coating, chemicals, and shortened rod length	Extended run life from months to 1 year
Ghareeb et al. 2012	Pump plugging, rod buckling	Scale inhibitors, sand screens, paraffin solvents, new pump designs	Extended run life from months to 2 years, saving 1 million USD workover cost
Lapi et al. 2014	AL failure and short run	RCFA	Up to 70% failure reduction
Rubiano et al. 2015	Sand, paraffin plugging, low productivity	RCFA and KPI	failure reduction from 161 to 92 in 2 years
Zhongxian et al. 2015	Short run life due to high axial and radial shear stress, rod buckling, rod-tubing friction, rod disconnection, stator damage	New pump designs (added grooves, elastomer alignment)	Efficiency jumped to 60%, extended run life up to 2 years
Al-Sidairi et al. 2018	Sand, scale, wear, and corrosion resulting from CO_2 and H_2S, rod buckling	long stroke pump, centralisers, sand screens, pump coating	Extended run up to 1 year
Mesbah et al. 2018	Sand	AL alternating strategy	The process was cost-effective but resulted in prolonged shutdowns
Chachula et al. 2019 (Unconventionals)	Gas slugging, erosion, and high temperature	New rotary gear pump	Low pump efficiency

Bucaram and Patterson (1994) conducted a historical analysis of AL failures with the objective of averting future incidents. They established a comprehensive failure tracking system encompassing (1) failure category (tubing, rod, pump), (2) failure site (barrel, plunger), and (3) failure cause (corrosion, sand, rod cut). The data generated from this system was collected for the examination of the AL production system and its performance. Yang et al. (2011) implemented preventive measures against scaling issues in a Chinese oilfield to enhance the performance and extend the operational life of progressive cavity pumps (PCPs) and sucker rod pumps (SRPs). The introduction of an alkaline surfactant polymer for enhanced oil recovery (EOR) led to scaling problems, resulting in pump and rod failures such as pump-stuck and rod disconnection. To address this, modifications were made to the designs of PCPs and SRPs. For PCPs, ceramic coating was applied to the rod string, and elastomer hardness was increased to minimize scaling effects. In the case of SRPs, the piston's length was reduced, resulting in a pump length twice as long as the standard design. Additionally, chemicals were introduced to eliminate any scale accumulation. These adaptations significantly extended the lifespan of PCPs from 47 days and SRPs from less than 30 days to one year, resulting in substantial cost savings on workover procedures. In a separate investigation,Ghareeb et al. (2012) evaluated the failures of five artificial lift (AL) methods employed in oil production within an Egyptian field: electrical submersible pump (ESP), SRP, PCP, gas lift (GL), and hydraulic jet pump (HJP). To prevent pump plugging in ESP, scale inhibitors, sand screens, and paraffin solvents were utilized. SRP underwent design improvements by contacting the manufacturer to reduce rod bending (buckling) and lower the strokes per minute (SPM) to counter fluid pounding, preventing dry pump running. For PCP, new materials were employed, and downhole real-time measurements and frequency control were implemented, significantly reducing failures and extending running life from 90 days to 2 years, leading to a saving of 1 million USD in workover costs. GL, employed offshore, faced challenges with high water cuts for which no solution was provided in the paper. Due to difficulties in monitoring bottom hole pressure (BHP) and high fluid surface requirements, HJP is often substituted with SRP. In a case study byZhongxian et al. (2015) concerning polymer flooding in a Chinese field, the elevated viscosity of the oil and polymer induced significant axial and radial shear stress, curtailing the life cycle of both SRP and PCP to 2-3 months. The increased rates of rod buckling, rod-tubing friction, rod disconnection, and stator damage prompted engineers to seek solutions to prolong pump life. A novel SRP design, termed the "low-friction pump," was introduced, featuring multiple grooves inside the barrel to diminish friction between the barrel and the plunger. This proved successful, elevating the run life of 235 wells to approximately one year, with pump efficiency reaching 60%. For PCP, a redesigned rod and elastomer alignment were implemented to minimize breakage and friction, coupled with the use of a smaller pump, resulting in a 2-year life cycle and reduced power and torque requirements. As perDave and Mustafa (2017), mitigating rod buckling and fluid pounding involves the implementation of a smaller pump, an extended stroke, and a reduction in strokes per minute (SPM), thereby enhancing pump longevity and overall performance. In Oman, a field experienced a 40% failure rate in both SRP and PCP following a shift from water to polymer flooding aimed at augmenting oil recovery in a heavy oil sandstone reservoir. Al-Sidairi et al. (2018) conducted trials to address AL failures attributed to sand, scale, wear, and corrosion induced by CO2 and H2S. To tackle erosion issues, low-frequency and long-stroke pumps were deployed, and the use of a continuous rod string with centralisers reduced buckling, extending pump life by an additional five months. In addressing corrosion concerns, successful outcomes were achieved with pump coatings in certain wells, and the application of sand control mesh enabled pumps to operate for over 12 months. Alsiemat and Gambier (2016) implemented a novel design for ESP completion to prolong the production period and minimize workovers. The use of dual ESP completion, termed rigless-deployed ESP, enabled continuous production; if one pump malfunctioned, the second maintained production until a workover was executed. The author highlighted that this approach significantly decreased downtime from months to mere hours. Conversely, Scarsdale et al. (2019) contended that through-tubing ESP (TTESP) was more dependable than dual ESP. Since the backup ESP encounters the same conditions leading to primary ESP failure, it might not offer the requisite efficiency. Its primary role is thus to mitigate production loss until a workover is undertaken. Mesbah et al. (2018) introduced an alternating AL strategy in a heavy oil field subjected to cyclic steam stimulation (CSS) in Kuwait, aiming to address AL failures and conserve 500-750 barrels. Two AL methods, SRP and metal-to-metal PCP (MTMPCP) were employed. The presence of sand caused complications for both pumps, necessitating workover operations to clear the sand and replace failed pumps shortly after each CSS cycle. This situation led to a further decline in temperature and an increase in viscosity. Additionally, the installation of MTMPCP after the steam cycle proved unsuccessful due to dry pump running. Consequently, a new strategy was proposed to mitigate workover costs and downtime. Production would commence using SRP after the CSS cycle, and following viscosity increase, PCP would be installed until the next cycle. While cost-effective, the rig arrangements resulted in extended shutdowns. Facing premature Electric Submersible Pump (ESP) failures in unconventional reservoirs caused by gas slugging, erosion, and elevated temperatures,Chachula et al. (2019) devised a novel rotary gear pump. This positive displacement pump, speed-dependent rather than pressure-dependent, represented an ESP body devoid of a conventional pump to overcome the mentioned challenges. The pump, characterized by low speed and high production capacity, achieved a discharge pressure of up to 4000 psi for a single stage. Although installed as a field trial, the pump exhibited lower efficiency than standard ESP due to backpressure arising from gear lubrication; however, efficiency could potentially be enhanced by elevating the operating frequency.Lapi et al. (2014) employed root cause failure analysis (RCFA), as illustrated inFig.1, for ESP and PCP oil production in Chad. The process commenced with the collection of data for each lifting method, incorporating reservoir, well, and operational parameters into a failure analysis workbook. Subsequently, the failed AL was disassembled in a designated workshop for thorough inspection to discern the underlying cause of the failure. Finally, company staff meetings were arranged to discuss and evaluate the findings of the RCFA. The application of RCFA from 2007 to 2013 resulted in a 70% reduction in failures for 615 ESP and a 50% reduction for 210 PCP.

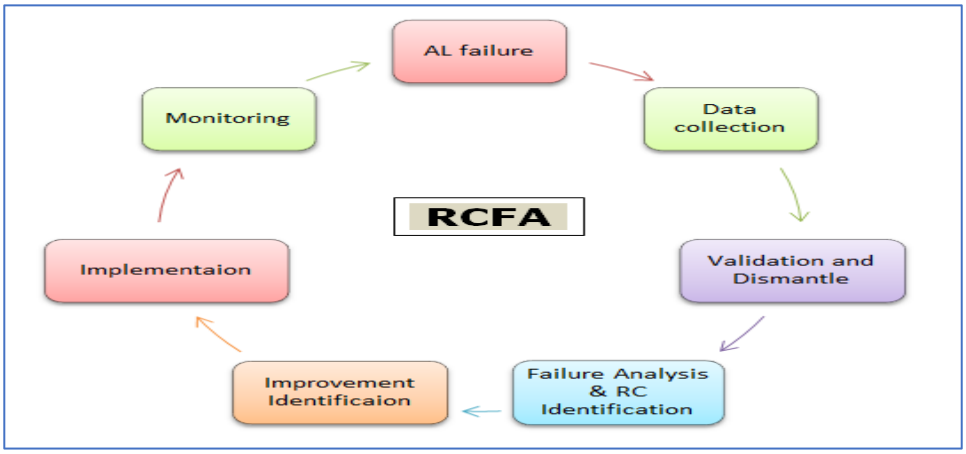

Fig. 1: RCFA criterion (Lapi et al. 2014)

In a similar vein, RCFA was executed in the La Caira field in Colombia across four lifting methods: SRP), ESP, PCP, and ESPCP (Rubiano et al. 2015). Following the withdrawal of the failed AL, data were compiled for failure analysis. The AL was then disassembled for meticulous inspection, leading to the preparation of a comprehensive report for discussion among clients and vendors to ascertain the root cause of AL failure, propose solutions, and outline a future management plan for performance assessment. Failures were categorized into three groups: (1) AL failure, indicating issues within AL components; (2) non-AL failure, signifying tubing failure due to sand or paraffin plugging; and (3) cases with no failure, where AL was removed due to high water cut, well abandonment, or low productivity. Additionally,Rubiano et al. (2015) implemented Key Performance Indicator formulas (KPIs) for performance evaluation, encompassing calculations for the failure index, pulling index, recurrence index, average run time, and average run life. Over the course of two years, the implementation of RCFA in the field resulted in a noteworthy reduction in total common (referred to as controllable) failures from 161 in 2012 to 92 in 2014, along with significant enhancements in critical wells experiencing more than one failure per year.

III. ARTIFICIAL LIFTRUN LIFE IMPROVEMENTS

Prolonging the operational lifespan of AL systems should commence by engaging in discussions with manufacturers regarding AL requirements and specifications to ensure appropriate designs before installation. Adherence to international standards such as API and ISO,is crucial. Subsequent to correct installation and operation, key factors contributing to success include vigilant monitoring, personnel training, and the application of RCFA (Stephenson 2019). In 2015, a team from Baker Hughes introduced a methodology aimed at mitigating ESP failure resulting from chemical injection in a CO2 EOR field in North America. The strategy involved balancing the impact of chemicals on the AL system with the desired production rate, taking into account environmental and safety considerations. Specifically, capillary tubes were designed to downhole inject asphaltene and scale inhibitors. The implementation of this approach in five wells yielded a noteworthy annual production increase of 100,000 barrels per day, a 133% extension of ESP running time, and an 80% reduction in workover costs over a five-year period (Phelps 2015). In addressing challenges posed by free gas in the Orinoco field in South America, a hydraulically regulated PCP (HRPCP), specifically designed to accommodate up to 40% free gas, replaced the standardPCP. The presence of gas elevated the temperature, causing elastomer damage and pump failure. The novel HRPCP featured redesigned rod and elastomer cavities to mitigate gas compression and temperature effects on the elastomer. Implemented in two wells with high GOR and viscosity, the run life of the first well increased from 28 to 622 days, boasting a mean time between failures (MTBF) of 166 days. The second well experienced an extension from 60 to over 800 days, with an MTBF of 96 days, resulting in more than 3 million USD in operational expenditure (OPEX) savings for both wells, coupled with an increase in pump efficiency from 30% to 40% (Caballero et al. 2014).Moving away from field applications, Ramdé et al. (2014) conducted a series of laboratory experiments and numerical simulations on pump materials and fluids to formulate a MTMPCP capable of enduring longer periods of thermal recovery and handling solid contents. The experiments included fatigue and corrosion tests, with the corrosion test specifically conducted on H2S and CO2 solutions at 200°C. Numerical simulation analysis was employed to assess stress and strain, utilizing Computational Fluid Dynamics (CFD) and Fluid-Structure Interaction (FSI). Subsequently, PCP tracking software was employed to calculate MTBF for both previous and modified designs. The adapted design demonstrated a run life of nearly 300 days, contrasting with the 160 days of the original design, representing a noteworthy outcome. Lastra (2017) contributed a significant discourse on the potential extension of ESP lifespan to 10 years, emphasizing the enhancement of three critical concepts: reliability, maintainability, and availability. Reliability pertains to the performance of the AL system, maintainability involves restoring system efficiency post-failure, and availability is the ratio of reliability to maintainability. The author proposed that pump longevity could be increased through the adoption of a dual ESP system, mitigating premature pump failures attributed to human factors, implementing preventive and predictive maintenance, including real-time failure assessment monitoring known as condition-based maintenance, and exploring novel designs and technologies. According to Skoczylas et al. (2018), key measurements for assessing AL reliability include mean time to failure (MTTF), representing the actual running period, and mean time to pull (MTTP), which signifies the duration between workovers. Kadio-Morokro et al. (2017) presented a case study focused on prolonging the lifespan of ESPs in the unconventional Permian Basin, attributed to challenges such as high GOR, low production and pump intake pressure (PIP). In newly drilled wells, three distinct gas handling techniques were implemented: (1) a tapered system featuring gas handling stages, (2) a tapered system incorporating a multi-vane pump, and (3) an encapsulated production system. These approaches collectively contributed to an extension of the ESP's operational duration. Castillo et al. (2018) and Khadav et al. (2018) conducted various interventions to mitigate PCP failures in deviated wells within the Bhagyam field in India and the Yaguara field in Colombia. RCFA and predictive analysis identified rod tubing wear as the predominant cause of AL failure. Khadav et al. (2018) implemented rod centralisers to alleviate this issue and utilized a hollowed rod string for hot water flushing, resulting in a 27% increase in the average pump life. Castillo et al. (2018) employed hollowed rods for axial load distribution, leading to an 80% reduction in stress, decreased OPEX, and an augmented run life. Khadav et al. (2018) reported that new completions, with or without packers, entail certain benefits and drawbacks concerning gas and cost considerations. The presence of produced gas through the annulus diminished pump efficiency, while the use of PCP completion inside the tubing curtailed workover costs and downtime by obviating the need to pull out the tubing. A simulation involving newly designed tubing (boronized tubing) capable of handling wear, friction, and accommodating large volume PCP for high flow rates and pressures exhibited promising outcomes for future field development plans. To enhance the run life of SRP in the Matzen field, Austria, OMV Company conducted RCFA aimed at mitigating the impacts of high water cut, corrosion, wear, gas, and sand on production and OPEX. The process involved extracting the equipment for thorough inspection, followed by a comprehensive failure analysis report. To further address these challenges, the company opted to enhance the quality of pump equipment and tubing through material design modifications. Monitoring the performance of the modified and conventional SRP involved the use of two KPI equations(1 and 2), namely MTBF and the failure recurrence index (OMV FRI). An economic analysis, factoring in the low oil price, indicated that the newly designed pumps would incur a 10% increase in cost but offer a substantial 50% extension in run life (Hoy et al. 2018).

$$\mathrm{MTBF} = \frac{\text{Operating wells} * \text{reporting periods (days)}}{\text{No. of failures}} \tag{1}$$

$$\mathrm{FRI} = \frac{\sum \text{Equipment failures}}{\sum \text{ALS subsystem failures}} \tag{2}$$

Almajid et al. (2019) presented an optimisation model aimed at improving the performance and life cycle of ESP, encompassing a comprehensive five-step approach:

- Data collection and analysis pertaining to surface and downhole parameters.
- Designing the ESP and ensuring robust manufacturing, with a primary focus on effectively managing gas and sand.
- Enhancing operational performance and production by expanding operating ranges through variable speeds and voltages.
- Real-time monitoring achieved by transmitting sensor data to SCADA and subsequently utilizing software to promptly alert of any faults.
- RCFA involving dismantling and thorough inspection.

The suggested model was employed on two wells, leading to an enhancement in pump performance, increased fluid production with minimal gas content, resolution of gas locking issues, and improvements in the operational lifespan of the ESP. Harris et al. (2019) noted that ESP cables contribute to over 20% of failures. Their evaluation of a newly designed cable, aimed at extending the ESP lifespan, revealed its potential to operate for up to 20 years, albeit at a higher cost.

Solutions to address challenges in unconventional fields are further explored by (Kolawole et al. 2019):

In a Canadian oil field, new designs for SRP and rods increased the run life of 25 pumps by 75% and the production rate of 14 wells by 90%. The Cunningham Modified Model and Total Well Management simulators were employed to investigate issues with plungers and HJPs. The results recommended resizing the pumps to address the effects of gas, ensuring plungers operate below a 74° deviation.

In the USA, the installation of dual ESP stages and packer-modified gas separators addressed gas slugging, resulting in a production increase of over 100% and reduced failure rates. Another developed gas separator elevated oil production to 224 B/D in 47 Texan wells. Artificial Sump Pumping (ASP) was introduced to replace ESP, reducing pump failures and increasing production. The new AL achieved a rate of 220 B/D with an operational period exceeding 332 days, compared to ESP production of 130 B/D over a 157-day lifecycle. In California, a new ESPCP was installed to minimize sand production and pump failures, resulting in fewer failures, lower OPEX, and a production rate of 50 B/D for an extended period.

In Oman, a novel PCP design featuring an anchor capable of handling two strings—production and intervention—reduced water cut from 100% to 65%, increased oil production from 1 to 32 m³, and lowered workover expenditures.

In China, a different ESP design, known as Electric Submersible Reciprocating Pumping (ESRP), raised the rate from 35 to 66 B/D with an efficiency of 65.1%.

Meanwhile, in Kuwait, a permanent magnet motor hydraulically regulated PCP (PMM-HR-PCP) was recently developed to address conventional SRP and PCP issues in a sandy heavy oil field. The application results demonstrated a 20% increase in the oil rate with additional run life.

IV. MACHINE LEARNINGAPPLICATIONSIN ARTIFICIAL LIFTFAILURE AND RUN LIFE

Machine learning (ML) has become increasingly integrated into the assessment of AL failures and run-life predictions. Ounsakul et al. (2020) employed ML algorithms, specifically utilizing attribute forward selection (AFS) for diagnosing failures in ESPs and SRPs. The parameters for each AL were categorized into four groups: (1) failure information (depth, service days), (2) AL configuration (type, size), (3) wellbore geometry (DLS), and (4) subsurface/production information (oil rate, sand production, fluid level, and API). The AFS analysis summarized the results of 1450 failures in**Tables** 2 and 3,highlighting the impact of each parameter. Statistical analysis revealed that the average run life for SRP and ESP was 202 and 728 days, respectively, which was less than in other compared fields. To validate the results, a neural network was employed, raising concerns about the SRP application model. Failures in rod and pump equipment attributed to manufacturer faults were categorized as mechanical failures, while other failures related to corrosion were classified as chemical failures.

Table 2: SRP failure parameters (Ounsakul et al. 2020)

Ranking No.	Feature	% Weight
1	Tortuosity at Pump (deg)	17%
2	Pump Depth (mAH)	17%
3	Fluid Level (m)	16%
4	Sand Produce (pptb)	13%
5	Max Inc. above Pump (deg.)	8%
6	No. of Turn above Pump, DLS > 5 (#)	7%
7	API Gravity (deg)	6%
8	Max DLS above Pump (deg./30m)	5%
9	DLS at Pump (deg./30m)	4%
10	Pump Size (inches)	4%
11	Inc. at Pump (deg.)	3%
12	No. of each Rod Taper (#)	0%

Table 3: ESP failure parameters (Ounsakul et al. 2020)

Ranking No.	Feature	% Weight
1	Sand Production in Terms of Pump Distance from HUD (m)	25.20%
2	Pump Depth (mTVD)	23. 4 %
3	Pump Running Time per Cycle (days)	20.90%
4	Gas Production (MSCF)	11.50%
5	Flowing Temperature (C)	8.30%
6	Gross Production (BBL)	6.40%
7	Inclination at Pump (deg.)	4.30%

Liu and Patel (2013); Liu et al. (2013, 2010) employed data mining techniques to identify failures in Sucker Rod Pumps (SRP) by analysing well histories. Liu et al. (2010) utilized support vector machine (SVM), Bayesian Network, and semi-supervised learning, while (Liu and Patel 2013) applied pattern recognition. Liu and Patel (2013) approach involved three steps: (1) collecting data from sensors, (2) extracting information from the data, and (3) classification. They contended that many researchers, including (Liu et al. 2010), overlooked the importance of feature extraction, focusing primarily on classification, thereby impacting the leveraging of domain knowledge. Supervised learning was used to train the model, using dynamometer card readings as input data. The model provided either detection or false alarms. Testing the pattern on 100 SRP wells over one year and six months yielded results with over 85% correct detection, surpassing(Liu et al. 2010). Additionally,Liu et al. (2013) applied SVM to develop a prediction model for universal fields, highlighting that their initial model (Liu et al. 2010) was valid for a specific field but lacked scalability, requiring significant time for labelling. They leveraged data from approximately 2000 wells collected from pump-off controllers (POCs) and the Life of Well Information Software (LOWIS) database, incorporating labelling and clustering enhancements for improved outcomes. Furthermore, two evaluation methods, precision (the ratio of true predictions to all predictions) and recall (the percentage of instances truly predicted), were employed. The results demonstrated that the global model had a 1.5% higher recall and 11.5% higher precision compared to their previous method, indicating applicability in diverse fields. Sneed (2017) endeavoured to predict the run life of ESP using the SEMMA data mining approach (sample the data, explore the data, modify the data, model the data, and assess the model) and ML algorithms with the aim of reducing workover costs. Their study involved analysing the history of 51 pump failures in 37 wells over a year to identify the causes of pump failures and implement measures to prevent future incidents.In a separate application,Prosper and West (2018) employed ML in the design of PCP completions for coal bed methane (CBM). They conducted an extensive study of reservoir fluid characteristics, PCP production history, and failures based on 1499 samples, utilizing Gaussian process regression to predict and prolong the life cycles of pumps. Their model demonstrated the effectiveness of ML applications in enhancing PCP run life, offering promising implications for future designs. Another assessment of pump failure probability was conducted by (Bangert 2019) for SRP based on 35292 dynamometer card charts derived from 299 SRPs. The charts underwent thorough examination for failure diagnosis and detection through feature engineering. The dataset was partitioned into two segments, allocating 85% for training and 15% for testing. Four ML algorithms, namely a single-layer perceptron neural network, a multiple-layer perceptron neural network, extreme learning, and the decision tree, were employed. The outcomes demonstrated a detection accuracy exceeding 99%, enabling the identification of 11 failures in advance. Boguslawski et al. (2019); Pennel et al. (2018); and Saghir et al. (2020) employed ensemble ML algorithms in conjunction with the Internet of Things (IoT) to analyse real-time measurements for optimising the operation of rod pumps. The model segmented a set of dynamometer card readings (images) into clusters and conducted diagnostics to offer an interpretation. A recommended solution was then presented to assist field operators in identifying issues in their early stages. The model of Pennel et al. (2018) model demonstrated additional capability in detecting tubing failure through dynamometer card measurements.

V. DISCUSSION ON ARTIFICIAL LIFTFAILURE AND MACHINE LEARNINGAPPLICATIONS

Shauna Noonan, an AL expert, pointed out excellent questions regarding AL Do we possess sufficient comprehension of the current technology to identify the necessary enhancements? Are we making technological progress or simply offering temporary fixes without comprehending the underlying cause of failures? Where should the industry concentrate its resources: on technology advancement or on decreasing failures resulting from inadequate design, installation, and operational procedures? (Noonan 2010). These challenges persist as notable issues in the OGI. The complexity arises from handling multi-component fluids with uncertain parameters, making it difficult to comprehend downhole conditions. Consequently, there is a pressing need for advanced data analysis technologies and artificial intelligence (AI) tools in AL applications. Additionally, it is crucial to recognize that maximizing profit does not necessarily equate to achieving the highest oil rate. Unfortunately, some oil and gas companies misconstrue this concept, often operating pumps at elevated rates, leading to detrimental effects on pumps and reservoirs (Berry 2016; Bucaram and Patterson 1994; Ghareeb et al. 2012; Kefford and Gaurav 2016; Noonan 2010).ML has shown remarkable promise in detecting and predicting AL failures before they occur. It can identify the root causes that are difficult for humans to detect by analysing large amounts of data from production and well operations. This capability, in addition to proper design, can enable operators to take proactive measures to prevent costly downtime and improve AL run life, ultimately leading to higher production and profitability.

VI. CONCLUSION

In conclusion, this review article provided an overview of the challenges related to AL failure in the OGI. It highlighted the importance of understanding the underlying causes of AL failures, including production and operational issues, in order to develop effective remedies and new designs that improve run life. The article discussed the use of various technologies, such as real-time monitoring, and ML, to detect and predict failures and optimise AL performance.The deployment of new designs, implementation, and maintenance of AL systems continues to enhance productivity, reduce downtime, and improve profitability.

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