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Performance Evaluation and Economic Assessment of Electrical Submersible Pumps for Heavy Oil Production in Mature Niger Delta Oilfields

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Abstract

This study presents a comprehensive evaluation of Electrical Submersible Pump (ESP) performance as an artificial lift solution for heavy oil production in Well AB2LS, located in the Niger Delta. The research integrates detailed well modelling, natural flow analysis, and ESP simulation using PROSPER, a nodal analysis and well performance software. Initial natural flow assessment revealed that the reservoir's inherent energy was insufficient to sustain economic production for the slightly heavy crude (22° API), with oil rates declining sharply as water cut increased, highlighting the need for artificial lift intervention. An ESP system was subsequently designed and simulated, with key parameters including pump type, stage count, motor rating, and installation depth optimized to handle the oil viscosity, bottomhole pressure, and flow conditions. The ESP operating envelope was analysed using Best Efficiency Line (BEL) and Dunbar plots to ensure stable hydraulics, mitigate gas interference, and prevent cavitation. The results demonstrated that the ESP significantly enhanced well deliverability, achieving a design oil rate of 4,250 b/d within a stable operating regime, and maintained incremental oil production averaging 131% relative to natural flow over the productive period (2011–2019). Economic evaluation using Net Cash Recovery (NCR) and Net Present Value (NPV) indicated that the ESP system achieved an NCR of US$ 213,889,115 and an NPV of US$ 143,405,102 at a 10% discount rate, confirming financial viability despite higher operational expenditures associated with energy consumption and maintenance. The study underscores the technical robustness and economic feasibility of ESP deployment in heavy oil reservoirs, particularly in wells with medium-to-high production rates, and highlights its critical role in sustaining long-term production and maximizing ultimate recovery.

Keywords: *Electrical Submersible Pump, Artificial Lift, Heavy Oil, PROSPER, Nodal Analysis, Well Performance, Economic Evaluation.*

1.0 Introduction

The progressive loss of reservoir drive due to declining formation pressure, weakening natural displacement mechanisms, and a deteriorating productivity index (PI) constitutes one of the most critical limitations to sustained hydrocarbon recovery in brownfield operations. As wells mature and primary/secondary recovery efficiencies diminish, artificial lift becomes fundamental for maintaining commercial production rates. The selection of an appropriate artificial lift system is not based solely on crude oil API gravity but also on a combination of reservoir and operational parameters, including well depth, gas–oil ratio (GOR), fluid composition, water cut, production rate targets, and thermal conditions. Within this context, Electrical Submersible Pumps (ESPs) are selected due to their suitability for relatively deep wells, moderate-to-high GOR conditions within operational limits, and their ability to efficiently handle large fluid volumes with varying water cuts. Among the available artificial lift systems, ESPs have achieved global adoption owing to their high volumetric efficiency, capacity to sustain high production rates, and operational flexibility across a wide range of reservoir conditions [1]. An ESP system consists of a downhole electric motor, seal/protector assembly, and a multi-stage centrifugal pump. The pump imparts kinetic energy to the produced fluids, enabling them to overcome hydrostatic head, frictional losses, and tubing backpressure during vertical ascent [2].

This requirement becomes particularly pronounced in the Niger Delta, a geologically complex petroleum province characterized by a mixed depositional system in which fluvial, wave, and tidal processes have all played significant roles in shaping reservoir architecture. Rather than being purely fluvial-dominated, the Niger Delta exhibits wave-dominated shoreface systems, tide-influenced channel deposits, and delta-front environments, resulting in a heterogeneous assemblage of interbedded sands and shales with variable reservoir quality [3]. Furthermore, the eastern and western Niger Delta reflect differences in geological evolution and depositional history, with variations in sediment supply, structural styles, and stratigraphic architecture influencing reservoir continuity and performance. This complexity, combined with progressive field depletion, further accentuates the challenges associated with sustained hydrocarbon production. Mature wells across the basin increasingly exhibit reduced reservoir pressure, elevated water cut, and rising gas–liquid ratios (GLRs), conditions that challenge

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natural lift and demand robust artificial lift intervention [2]. Under such multiphase, thermodynamically evolving production regimes, ESPs must function reliably despite fluctuating bottomhole pressures, compositional changes, and flow regime transitions ranging from bubble to slug and annular flow.

However, despite extensive deployment in the region, ESP design and performance prediction methodologies often remain insufficient. Conventional ESP sizing workflows largely rely on steady-state nodal analysis where reservoir inflow and pump hydraulics are modelled independently [4]. Such simplification ignores transient behaviour associated with temperature gradients, FBHP variability, gas interference, and dynamic fluid rheology [5]. As a consequence, installed pumps frequently operate outside their best-efficiency range, resulting in short run life, frequent workovers, gas locking episodes, vibration-induced failures, and electrical overheating due to improper stage loading [3].

Operational challenges intensify in high-deviation and tortuous wellbores frequently encountered in Niger Delta field developments. Complex trajectories and uneven perforation coverage generate non-uniform fluid entry, flow regime instabilities, increased pressure drop, and gas-liquid separation anomalies at pump intake. In highly deviated or horizontal wells, gravitational segregation and transient regime shifts significantly impair pump efficiency-phenomena often neglected by traditional steady-state models [3]. Chemical and compositional fluid variability introduces further complications: wax- and asphaltene-rich crude oils promote deposition on pump components, leading to head degradation and rising power draw, while entrained formation sand causes erosional damage and accelerated wear [2].

Modern ESP modelling practice is further constrained by software limitations. Most design platforms such as PROSPER employ generic pump performance curves derived from laboratory test conditions rather than field-calibrated data [6]. The absence of intelligent frequency control, dynamic optimization, and real-time feedback severely restricts operational efficiency. Without digital twins, predictive monitoring, SCADA-linked surveillance, or machine-learning-enabled failure diagnostics, field interventions remain reactive instead of predictive often resulting in costly downtime and deferred production opportunities [7].

In this study, an integrated modelling workflow was developed to analyse and optimise ESP performance under realistic Niger Delta operating conditions. Reservoir inflow, wellbore multiphase flow, and pump hydraulics were coupled to create a representative simulation environment in PROSPER, enabling comparison between natural flow and ESP-lifted production scenarios. Sensitivity evaluation across GLR variation, water-cut increase, flowing pressure decline, intake behaviour, and frequency modulation established the dominant factors affecting pump efficiency and long-term stability. Model validation with field data confirmed reliability of the prediction framework, while output responses such as discharge rate, intake pressure, power demand, head degradation and overall fluid handling provided operational indicators for performance optimisation. The results define practical operating envelopes for ESP application in Niger Delta wells and form the basis for subsequent conclusions and recommendations on pump selection, sizing and real-time operational control.

2. Electrical Submersible Pumps

ESPs operate by converting electrical power (alternating current) to mechanical shaft rotation, generating multi-stage centrifugal pressure that reduces bottomhole flowing pressure (BHFP) and accelerates fluid movement to surface. Their downhole configuration, electric motor, seal section, intake/gas separator, and multistage pump enables continuous high-volume lifting even in deep, deviated and offshore environments where rod pumps or gas lift become uneconomical [1].

Central to ESP functionality is the multistage centrifugal pump, where rotating impellers introduce kinetic energy to incoming fluids and diffusers convert that energy to incremental pressure gains. The resulting total dynamic head (TDH) depends on stage number, impeller geometry, operating speed, and fluid density. Modern pump-stage designs increasingly rely on computational fluid dynamics (CFD) to improve hydraulic efficiency, control recirculation, and minimize erosive wear in abrasive or scale-prone wells. Corrosion-resistant materials such as nickel-alloys or stainless steels are employed to withstand chemically aggressive Niger Delta production environments [8].

Above the motor and below the pump sits the intake/gas separator, responsible for moderating free-gas entry into pump stages. This is critical because high gas volume fraction induces gas lock, loss of head, vibration, and potential pump stall. Advanced separators utilize vortex-based geometry to disperse gas, increasing volumetric efficiency when producing from high-GOR reservoirs [9]. Downhole, the seal section regulates thermal expansion of dielectric oil, transfers axial thrust, and prevents well fluid ingress into the motor [10].

The motor, typically a three-phase induction unit running at 3000–3600 rpm, provides rotational power while remaining submerged in dielectric oil for insulation and cooling. High-temperature designs enable deployment in HPHT and geothermal regimes. Real-time instrumentation including temperature, pressure, current and vibration sensors supports continuous performance surveillance and failure prediction [11]. Power is transmitted via armored cables clamped along the tubing, while surface hardware such as transformers, switchboards and Variable Speed Drives (VSDs) regulate voltage-frequency supply for speed control and system stability.

ESP operational response is interpreted using performance curves linking head, flow rate, brake horsepower, and efficiency. Although standard curves assume single-phase flow, real Niger Delta wells typically produce emulsified and gas-laden fluids requiring multiphase-corrected models. Performance degradation often arises from gas interference, abrasive solids, scale/wax deposition, or electrical failures. Mitigation strategies include gas handlers, abrasion-resistant metallurgy, chemical inhibition and SCADA-based monitoring [9].

ESP deployment must be matched to reservoir inflow characteristics through nodal analysis. Integrating Inflow Performance Relationship (IPR) with pump outflow curves ensures optimal drawdown, stable lifting, and avoidance of pump off conditions. Software such as PROSPER enables sensitivity-based design using reservoir pressure, PVT data, well geometry and VSD-controlled speed variation [10]. In the Niger Delta, where deep deviated wells produce multiphase fluids under dynamic drawdown, accurate modeling, transient calibration, and digital optimization are indispensable for reliability and run-life extension.

2.1 Design Principles of ESP Systems

The design of Electrical Submersible Pump (ESP) systems is a highly integrated engineering exercise grounded in fluid mechanics, reservoir inflow dynamics, electromechanical behavior, and multiphase wellbore flow characteristics. Achieving reliable ESP deployment requires predictive modeling of all components within the system, coupled with accurate estimation of downhole performance under evolving operating conditions [12]. This becomes more critical in the Niger Delta, where production is often complicated by high gas–oil ratios, sand and fines production, emulsified flow regimes, thermal fluctuations, and reservoir compartmentalization. In such settings, imprecise system sizing or inadequate component characterization can lead to rapid performance decline, premature failures, or sustained operation below best efficiency point (BEP), thereby compromising production economics [11].

Successful ESP design begins with aligning reservoir inflow capacity with pump outflow performance through coupled Inflow Performance Relationship (IPR) and pump curve modeling. Reservoir inflow prediction typically employs Vogel or Fetkovich formulations for solution-gas drive and boundary-dominated reservoirs, respectively, while transient productivity estimation incorporates dual-porosity models and pressure interference behavior. This inflow data is matched against pump performance curves to define an optimal operating point that satisfies total dynamic head requirements while maintaining flow above the minimum stable rate. In the Niger Delta, where multiphase inflow and water or gas coning are common, integration of multiphase correlations is required to reflect slip effects, phase fractioning, and transient saturation behavior, all of which influence intake pressure and stable operating envelope [13].

The hydraulic design of the ESP pump stage forms the backbone of component modeling, as each impeller–diffuser pair converts rotational energy into pressure head. The total number of stages is determined by static lift, frictional losses, and tubing or surface system backpressure [14]. Laboratory pump curves, normally developed under single-phase ideal conditions, must be corrected for downhole multiphase behavior using Beggs–Brill, Ansari or Mukherjee–Brill models to account for gas interference, gas holdup, and flow regime transitions typical of Niger Delta wells. Increasingly, CFD enhanced numerical solvers are incorporated to capture real-world turbulence, slip velocity variations, and recirculation losses that cannot be inferred from standard factory curves [15].

A critical element of ESP design involves modeling gas separation at the intake to prevent head degradation and gas locking. Selection of standard intake, rotary separator or vortex gas handler is governed by predicted gas volume fraction at pump depth. Separator efficiency is a function of geometry, slip velocity and drainage capacity, and models must simulate gravitational segregation in deviated or horizontal wells where gas stratification occurs. High GOR conditions may require staged separation or dual gas handlers to maintain liquid continuity at the impellers, especially under aggressive drawdown conditions [16].

The motor is the driving power component and must be modeled thermally and electrically to ensure operational stability. Downhole motors experience heating from resistive losses and mechanical friction, and inadequate flow-induced cooling leads rapidly to insulation degradation and burnout. Finite element thermal modeling is therefore used to predict temperature distribution across windings and stator housing, particularly in hot wells exceeding 150–250°C. Resistance decay, dielectric breakdown, and insulation aging are introduced into model life prediction, enabling condition-based control strategies via downhole temperature telemetry and SCADA-driven frequency regulation [16].

In parallel, the seal chamber and thrust bearing assembly are modeled to accommodate pressure differentials and axial load generated during pump rotation. Seal reliability is evaluated in terms of oil expansion compensation capacity and exclusion efficiency against well fluids. Thrust loading is computed from pressure imbalance across pump stages, and bearing materials are analyzed for fatigue, creep resistance and lubrication-film stability. Finite element simulations help predict brinelling, abrasion and pitting, enabling appropriate material and configuration selection for abrasive Niger Delta environments [5].

Electrical cable and surface power infrastructure modeling completes the ESP design framework. Cable selection is governed by voltage drop, harmonic loading from VSD power modulation, thermal derating, and insulation endurance in high-salinity wellbores. Surface power components including transformers, breakers and drives must be simulated for power factor stability, switching surge tolerance and harmonic distortion. This is essential in the Niger Delta, where generator-driven operations and grid instability introduce transient voltage events capable of damaging motor windings or cable sheathing [10].

2.2 ESP Performance

The performance and reliability of Electrical Submersible Pumps (ESPs) are directly influenced by wellbore and reservoir conditions, which define the operational envelope of the system. Variations in pressure, temperature, fluid composition, multiphase behavior, and well geometry exert complex, non-linear effects on pump efficiency, lifespan, and total lift capacity. In geologically heterogeneous and multiphase-producing fields such as those in the Niger Delta, these conditions evolve over time, presenting operational and modeling challenges that require adaptive ESP design and real-time monitoring [1].

$$P\_shaft=(\varrho\ gQH)/\eta \qquad 1$$

Where

P_shaft= pump shaft power requirement

ϱ= fluid density (function of pressure, temperature, and composition)

Q=volumetric flow rate (depends on inflow–outflow balance and well conditions)

H= total dynamic head developed by the pump

η =overall pump efficiency (variable, condition-dependent)

Reservoir pressure fundamentally governs fluid inflow, and its depletion necessitates higher pump head to maintain production. As the reservoir declines, ESPs may need to operate at higher frequencies or undergo workovers to match reduced deliverability [17]. Niger Delta fields, with compartmentalized formations and high-permeability streaks, experience accelerated pressure drop, requiring ESPs capable of handling wide-ranging drawdown conditions. Changes in productivity index due to formation damage, scale deposition, or fines migration can further reduce inflow, pushing operations below the Minimum Stable Flow Rate (MSFR) and potentially inducing recirculation or stage wear. Conversely, high-PI wells may present excessive flow that destabilizes multiphase pumping, overloading motor or separator systems. Effective ESP deployment therefore demands coupled inflow and pump performance modeling, supplemented by real-time operational monitoring [6].

Downhole temperature impacts both mechanical and hydraulic ESP performance. Elevated temperatures influence fluid viscosity, gas solubility, motor efficiency, and seal reliability, while thermal gradients along deviated or extended-reach wells interact with fluid PVT properties in complex ways. Temperature drops can induce paraffin precipitation in waxy crudes, obstructing pump intakes, while high temperatures accelerate gas liberation and increase the likelihood of gas lock. Thermal modeling incorporating temperature profiling, fluid properties, and real-time sensor data is therefore essential to predict system behavior and prevent motor burnout or insulation failure [5].

The composition and phase behavior of produced fluids present major challenges to ESP efficiency. Multiphase flow introduces variable head generation and mechanical stress, with high Gas-Oil Ratios (GOR) causing gas interference, surging, and efficiency loss. Emulsified or high-water-cut fluids increase viscosity, modify flow regimes, and accelerate corrosion, while scaling from calcium or barium salts and the presence of solids such as sand and fines lead to impeller erosion, bearing wear, and seal degradation. Modeling these effects requires coupling multiphase flow predictions with erosion and deposition algorithms, often enhanced by CFD simulations to accurately assess stage degradation and hydraulic performance under realistic field conditions [10].

Wellbore trajectory and completion geometry further influence ESP performance. Deviated or horizontal wells induce phase segregation, affecting intake pressure distribution and gas separation efficiency. Gravitational stratification can generate intermittent gas slugs, destabilizing pump operation, while extended flow paths increase frictional losses and elevate required total dynamic head. Completion components such as packers, inflow control devices, or sliding sleeves may create localized backpressure, pressure transients, or scale accumulation points, all of which must be considered in system modeling. Accurate integration of wellbore and completion effects into ESP design ensures that pumps remain within their hydraulic and mechanical limits throughout the production lifecycle [16, 18].

Gas interference and gas lock represent some of the most critical limitations in Electrical Submersible Pump (ESP) operation. When free gas enters the pump above the separator's handling capacity, volumetric efficiency declines sharply, and the impellers may operate in a predominantly compressible gas phase, resulting in head degradation and potential gas locking. These effects are particularly pronounced during low production rates and transient pressure fluctuations typical of Niger Delta reservoirs. In practical ESP operation, the Best Efficiency Line (BEL) provides a critical reference boundary for stable ESP performance, representing the operating condition at which hydraulic efficiency is maximized for a given pump speed. Deviation from the BEL toward lower flow regimes increases susceptibility to gas breakout and flow instability, while operation beyond it may induce excessive hydraulic loading and inefficiency. Therefore, maintaining ESP operation close to the BEL ensures optimal energy transfer and minimizes gas-related disruptions. Mitigation strategies such as vortex-type gas separators, staged tandem pumping, and variable frequency drive (VFD)-based speed modulation are commonly implemented to maintain the pump operating point within the stable BEL envelope. Complementary use of Dunbar plots further supports identification of gas-handling limits under multiphase flow conditions, enabling predictive control of instability onset, optimization of operating parameters, and sustained ESP performance within safe hydraulic regimes [3].

3. Materials and Methods

This section focuses on the practical application of PROSPER for the design, evaluation, and optimisation of Electrical Submersible Pump (ESP) systems in mature oilfields. PROSPER is a nodal analysis and well performance simulator that integrates reservoir inflow, tubing hydraulics, and artificial lift modules, enabling accurate prediction of multiphase flow behaviour and system performance under varying reservoir conditions.

For naturally flowing wells, key reservoir parameters such as initial pressure, permeability, skin factor, bubble point pressure, viscosity, gas-oil ratio, and formation volume factor are used to construct an Inflow Performance Relationship (IPR). Simultaneously, Vertical Lift Performance (VLP) is calculated, accounting for friction, hydrostatic gradients, and flow acceleration. The intersection of IPR and VLP curves defines the natural operating point, guiding choke optimisation and identification of flow restrictions.

As reservoir pressure declines, ESP modules are used to simulate artificial lift, requiring detailed inputs including pump type, stage count, efficiency curves, motor rating, and surface power supply. Models are validated against production data under natural flow, then integrated with ESP configurations to evaluate production rate, intake and discharge pressures, motor load, and power consumption. Sensitivity analyses allow optimisation of parameters such as pump stages, motor size, intake conditions, and drawdown, ensuring reliable operation in deviated or multiphase-producing wells. Comparing natural flow forecasts with ESP-augmented predictions enables quantification of incremental recovery and economic benefits. In this study, PROSPER was used to model natural flow, design a gas lift backup, and configure an ESP system to maximise oil recovery, extend well life, and mitigate operational risks, providing a technically robust and economically justified design.

3.2 Case Study

Well AX2LS is a naturally flowing well that maintained stable hydrocarbon production until a decline in reservoir pressure and an increase in water cut reduced its economic output. The produced fluid is moderately heavy, with an API gravity of 23° and a solution GOR of 314 scf/stb, indicating limited natural energy for sustained lift. As water encroachment intensifies, the well's ability to maintain production without intervention diminishes, necessitating artificial lift. An Electrical Submersible Pump (ESP) was selected to sustain and enhance production, owing to its ability to handle high liquid rates, operate efficiently in wells with moderate-to-low GOR, and tolerate significant water fractions. The ESP's deployment is technically justified provided free gas at the pump intake is adequately managed, ensuring stable hydraulic performance and maximizing ultimate hydrocarbon recovery.

3.3 Input Data

The input data consist of the parameters required to construct models for both the naturally flowing and ESP-lifted well in PROSPER. These include reservoir properties, PVT characteristics, well specifications, and well test measurements as detailed in Table 1. The PVT input data, the well data and the well test dada are presented in Table 2, Table 3 and Table 4.

Table 1: Reservoir Data [19]

Parameter	**Amount**
Static Reservoir Pressure (psi)	4000
Reservoir Temperature (^oF)	234
Reservoir Permeability (mD)	50
Reservoir Thickness (ft)	200
Drainage Area (Acres)	500
Wellbore Radius (ft)	0.354
Average Porosity	0.23
Reservoir Pressure at artificial lift (psi)	3000

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Table 2: PVT Input Data [19]

Parameter	Amount
Bubble Point Pressure (psi)	2528
Oil gravity (API)	25
Gas Gravity	0.766
Injection Gas Gravity	0.8
Oil formation volume factor	1.16
Oil Viscosity @ bubble point (cP)	2.37
Oil Viscosity @ atmospheric condition (cP)	10.31
Gas Oil ratio (scf/stb)	402
Water salinity (ppm)	140,000
Compressibility factor (psi^{-1})	11.01 x 10^{-6}

Table 3: Well Data **[19]**

Parameter	Amount
Water-cut	10%
Water-cut during Gas Lift	50%
Well head Pressure, psig	195
Well head flowing Temp, ^{0}F	84
Skin (Well Test)	3
Tubing Size	3.958
Geothermal gradient, btu/hr/ft^2/^{O}F	11.2188
Well Depth, ft	9890

Table 4: Well Test Data

Parameter	Tubing Head Pressure (psi)	Tubing Head Temp (F)	Water-cut (%)	Liquid rate (bbls)	Gauge Depth (ft)	Gauge Pressure (psi)	Reservoir Pressure (psi)	GOR (scf/stb)
Amount	195	84	10	2760	9400	2330	4000	314

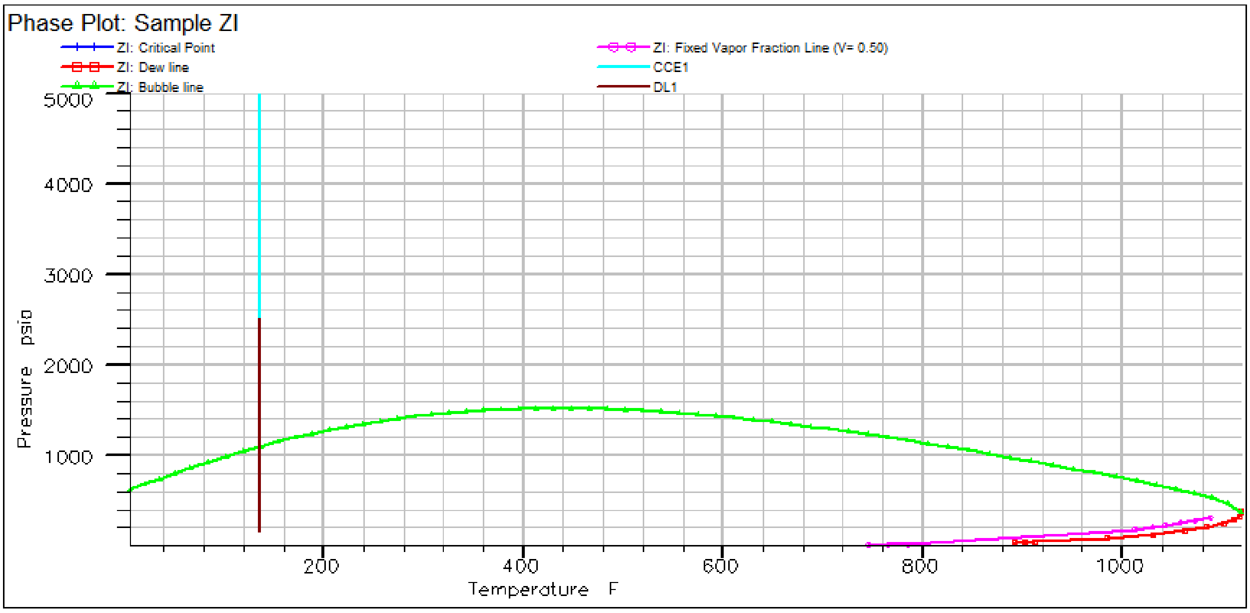


Figure 1: Formation fluid phase diagram (CE and DL)

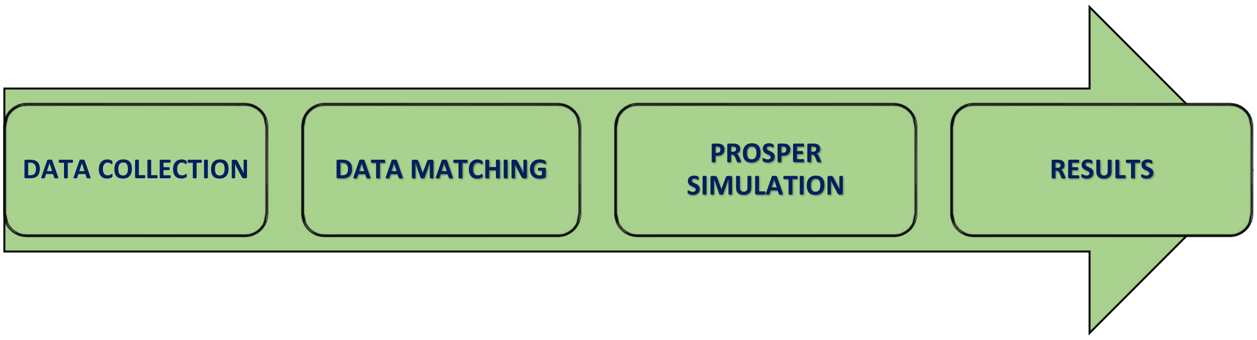
Figure 1 presents the phase envelope derived from the constant composition expansion (CCE) and differential liberation (DL) PVT tests on the reservoir oil. This diagram characterizes the pressure–temperature behavior of the fluid and informs the design and performance prediction of the ESP in PROSPER. The bubble point pressure is approximately 2528 psia, marking the onset of free gas emergence as pressure declines at reservoir temperature. The bubble line, which separates the single-phase liquid region from the two-phase region, dominates the left side of the envelope, while the dew point line appears only as a minor segment at higher temperatures, reflecting a slightly heavy to medium crude with low solution gas content. Consequently, the reservoir fluid remains predominantly liquid across most operating conditions.

The bubble point exceeding expected bottomhole pressures indicates gas evolution during primary depletion. However, the modest gas-oil ratio (API ~25°) limits free gas interference at the pump intake. Nonetheless, the ESP design must account for this gas fraction to prevent gas lock and efficiency loss. Additionally, the relatively high oil viscosity increases pump head requirements and stage count, necessitating careful selection of motor horsepower, stage number, and intake/discharge configuration in PROSPER to maintain optimal performance.

3.4 Well Modelling in PROSPER

Well AX2LS was modelled in PROSPER to evaluate both its natural flow potential and its performance when operated under Electrical Submersible Pump (ESP) lift. The modelling workflow comprised two integrated components: (i) a coupled reservoir inflow model and wellbore vertical lift model to establish the natural operating point, and (ii) implementation of an ESP configuration to predict the incremental production achievable through artificial lift.

This integrated modelling workflow (Figure 2) provided a realistic performance profile for Well AX2LS, quantifying production potential under natural flow conditions and the incremental gains achievable with ESP deployment. The results guided both technical and economic decisions regarding artificial lift implementation, ensuring the final design is robust, efficient, and tailored to the well's specific production challenges, thereby supporting optimized field development and operational planning.



DATA COLLECTION

DATA MATCHING

PROSPER SIMULATION

RESULTS

Figure 2: Simulation Workflow

3.4.1 Modelling the Naturally flowing Well

The naturally flowing performance of Well AX2LS reflects production driven solely by the reservoir's primary energy, without artificial lift intervention. For simulation purposes, the well was modelled in PROSPER v11.5 using the black oil framework to accurately capture the phase behaviour of the slightly heavy crude. Reservoir-specific fluid and operational data were input, complemented by laboratory-derived PVT measurements. These data were calibrated against standard black oil correlations to ensure consistency between observed and simulated fluid properties. During PVT matching, the Vasquez-Beggs correlation was applied to estimate key parameters, including bubble point pressure (Pb), solution gas-oil ratio (Rs), and oil formation volume factor (Bo), owing to its suitability for moderately heavy crudes under the reservoir conditions. Oil viscosity was predicted using the Beal correlation, providing reliable estimates consistent with measured values. The Inflow Performance Relationship (IPR) was established using the productivity index (PI) entry method, with parameter 1 approximated to unity and parameter 2 set near zero. This configuration represents a linear inflow profile characteristic of the slightly undersaturated reservoir, enabling accurate representation of the well's natural deliverability prior to the introduction of any artificial lift system.

3.4.2 Modelling ESP Design

The Electrical Submersible Pump (ESP) was designed and modelled in PROSPER to assess its efficiency in lifting the slightly viscous reservoir crude and to provide a performance benchmark against the natural flow scenario and an alternative gas lift configuration. The simulation incorporated detailed operational and design parameters, enabling a rigorous evaluation of pump performance under the specific well conditions. The ESP was installed at a depth of 7,000 ft, with a maximum pump outer diameter of 6 inches. A target production rate of 2,000 STB/day was specified, and multiphase flow within the production tubing was modelled using the Hagedorn-Brown correlation to accurately capture pressure losses and flow behaviour.

For the pump, a CENTRALIFT K47SPHB unit with a nominal diameter of 5.38 inches was selected, offering a flow capacity between 1,430 and 5,900 RB/day. The driving motor was a Centralift 450 rated at 15 horsepower, 440 V, and 22 A. A copper power cable was selected to ensure reliable downhole power transmission, with a

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current-carrying capacity of 115 A to accommodate motor startup and operational loads. The cable design maintained an acceptable voltage drop within recommended limits for stable ESP operation under expected downhole conditions.

4. Results and Discussion

4.1 ESP Pump Design Plots

The Dunbar plot is a widely employed diagnostic tool for evaluating Electrical Submersible Pump (ESP) performance, providing a comprehensive visual representation of the pump's operating envelope. By simultaneously depicting the relationships between head, efficiency, power, and flow rate, the Dunbar plot allows for precise assessment of pump behaviour across the full range of operating conditions. In ESP modelling, it is particularly useful for identifying the Best Efficiency Point (BEP) and ensuring that the pump operates within its recommended envelope, thereby minimizing risks associated with hydraulic instability, cavitation, or excessive mechanical wear. By comparing actual well operating points against the ESP design curves, the Dunbar plot facilitates the identification of deviations such as high-flow operation, which can lead to gas locking and reduced lift efficiency, or low-flow operation, which increases the risk of motor overheating and recirculation. Integration of production parameters—including intake and discharge pressures, liquid rate, and gas–liquid ratio enables engineers to make informed decisions on pump sizing, stage selection, and operational adjustments. Consequently, the Dunbar plot serves as a critical tool in ESP modelling, providing validation of pump selection, optimization of performance, and assurance of reliable long-term operation under variable reservoir and wellbore conditions.

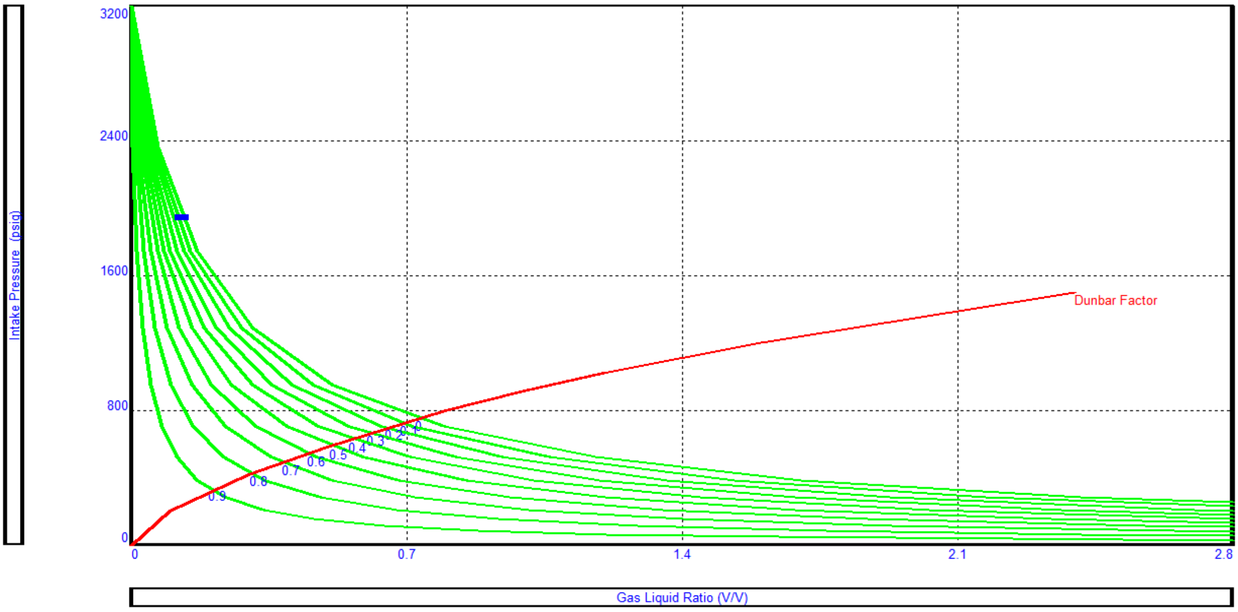

Figure 3: Dunbar plot for ESP design

The Dunbar plot presented in Figure 3 serves as a critical diagnostic tool for assessing the operating condition of the Electrical Submersible Pump (ESP) in relation to gas-handling requirements. In this representation, the red curve delineates the gas-handling limit of the pump, indicating the threshold below which the presence of free gas can significantly interfere with pump performance and typically necessitates the use of a gas separator to maintain stable operation. The simulation test points for Well AB2LS are all positioned above this red curve, demonstrating that the ESP is capable of managing the entrained gas within the produced fluid without the need for additional gas separation equipment. This positioning indicates that the gas volume fraction (GVF) at the pump intake remains within the acceptable operating range for the selected ESP, allowing the pump stages to function in a hydraulically stable regime. Operating above the gas-handling limit reduces the risk of performance-limiting phenomena such as gas locking, cavitation, recirculation, or loss of hydraulic head, thereby supporting consistent lift efficiency and reliable flow delivery. Consequently, the pump is expected to sustain the predicted production rates while minimizing fluctuations in discharge pressure and head degradation, which is especially important in heavy oil wells where pump reliability directly impacts overall field performance.

Furthermore, the relative position of the operating points provides strong validation for the robustness of the selected ESP configuration. Since the pump operates comfortably above the critical gas-handling threshold, there is no immediate requirement for additional gas mitigation strategies such as a rotary gas separator (RGS) or tandem pump installation. This not only simplifies the operational design but also reduces capital and maintenance costs, enhancing both the economic and technical feasibility of the ESP system. The Dunbar plot therefore confirms that the current ESP design is well-suited for the well's production profile, offering a stable and efficient artificial lift solution that balances operational reliability with cost-effectiveness. Figure 4 shows the ESP design pump curves

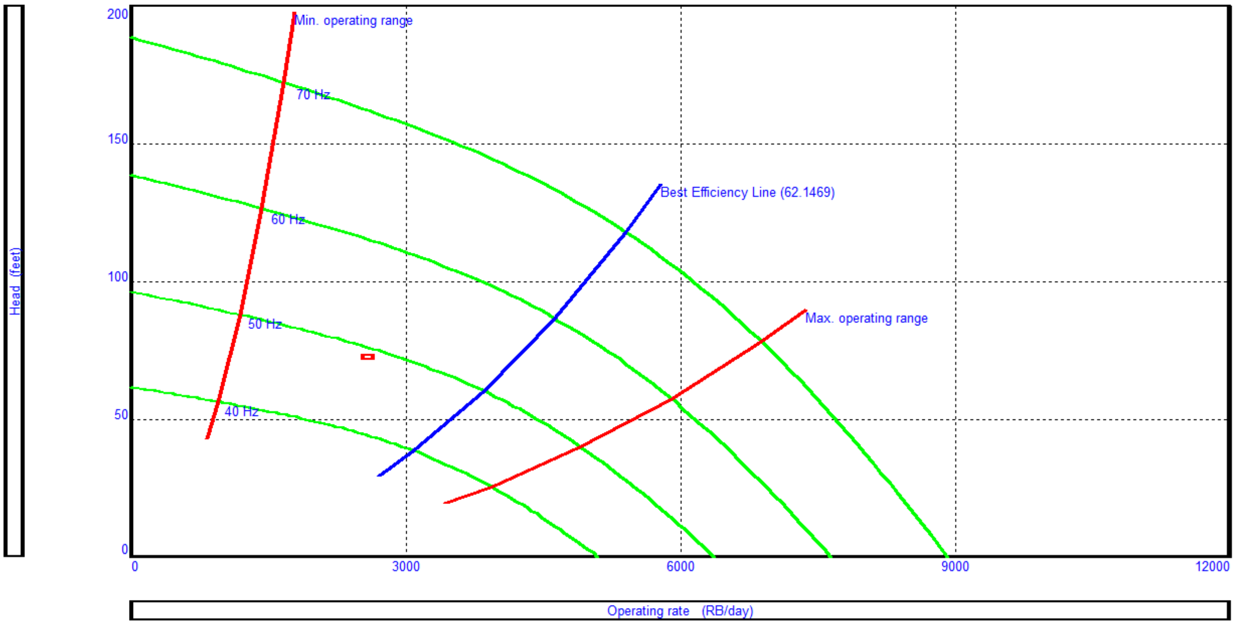

Figure 4: ESP design pump curves

Figure 4 illustrates the performance envelope of the Electrical Submersible Pump (ESP) operating at 60 Hz, defining a minimum flow rate of approximately 1,425 b/d and a maximum flow rate of about 5,925 b/d. These limits correspond to the hydraulic stability boundaries of the pump at the rated frequency, beyond which operational reliability is compromised. Operating below the minimum flow rate increases the risk of internal recirculation within the pump stages, overheating of the motor, and accelerated wear of mechanical components due to inadequate fluid flow for cooling and lubrication. Such conditions can lead to premature failure of the pump, increased maintenance frequency, and unplanned downtime. Conversely, operating above the maximum flow rate pushes the pump into a high-flow regime where stage head collapses, hydraulic efficiency deteriorates, and gas-handling capability diminishes. This results in reduced volumetric efficiency, potential gas lock, and elevated stress on pump components, all of which shorten the equipment lifespan and compromise operational reliability.

Within this envelope, the best efficiency line (BEL) at 62.15% marks the pump's Best Efficiency Point (BEP), representing the optimal operating condition where hydraulic losses are minimized, energy consumption is reduced, and mechanical wear is mitigated. The BEP effectively serves as the "perfect operating line" for ESP operation, balancing performance, reliability, and energy efficiency. Operating near the BEP ensures stable fluid handling, maintains pump head, and optimizes motor load, while minimizing adverse effects such as vibration, recirculation, and premature component degradation.

From an operational perspective, the proximity of the well's inflow performance curve to the BEP serves as a critical benchmark for pump sizing and system adjustment. When the intersection between the inflow performance relationship (IPR) and the ESP operating envelope occurs near the BEL, the pump is correctly matched to the reservoir and wellbore conditions, maximizing production while maintaining long-term stability. Deviations from the BEL—either toward the low-flow or high-flow limits—signal potential inefficiencies that may require operational interventions such as adjusting the choke, modifying the pump stage count, or integrating complementary artificial lift support.

Importantly, maintaining operation near the BEP not only improves pump efficiency and production rates but also reduces total life-cycle costs by limiting energy consumption and lowering maintenance requirements. In high-viscosity, heavy oil reservoirs such as those in the Niger Delta, where well conditions can fluctuate due to water cut, pressure decline, or gas interference, targeting the BEP ensures that the ESP continues to deliver consistent performance despite dynamic reservoir conditions. Therefore, Figure 4 not only defines the hydraulic operating limits but also underscores the critical role of the BEP as a guiding metric for ESP selection, well management, and operational optimization.

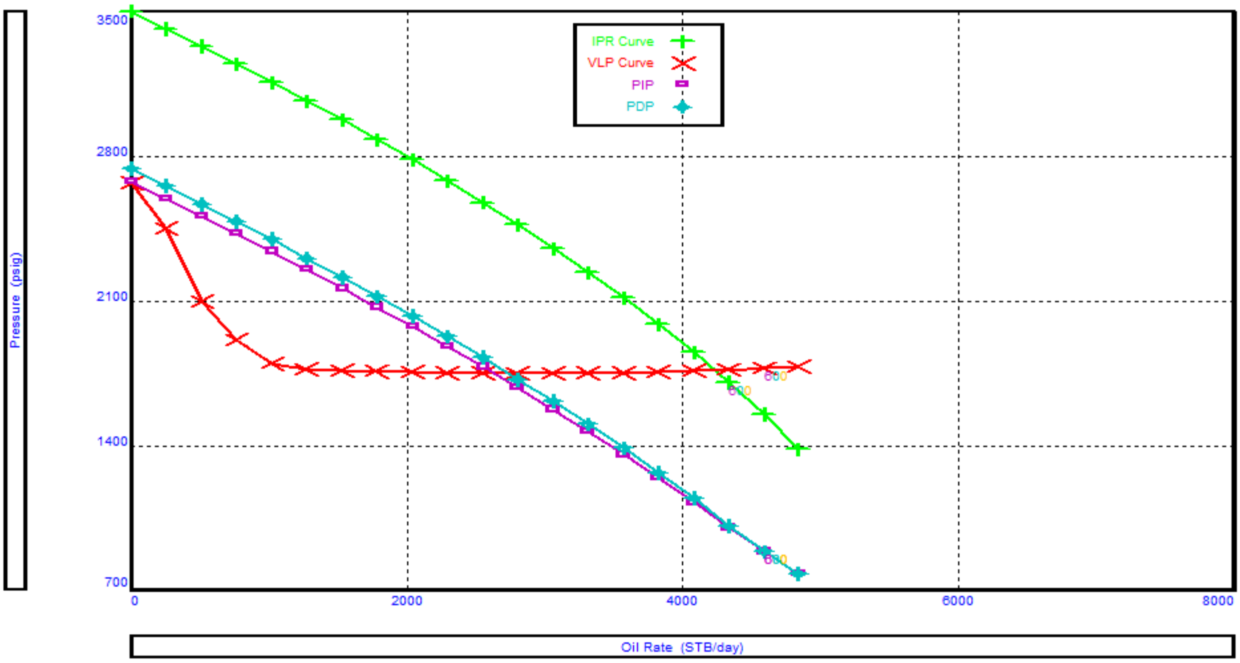

Figure 5: ESP design system

Figure 5 illustrates the nodal analysis of Well AB2LS with the Electrical Submersible Pump (ESP) installed, highlighting the targeted design operating point of 4,250 b/d. This operating point lies comfortably within the ESP's stable performance envelope, representing the equilibrium between the reservoir's deliverability and the artificial lift capacity of the pump. It marks the flow rate at which the system achieves optimal production without compromising pump reliability or efficiency. The red curve in the figure represents the Vertical Lift Performance (VLP), which characterizes the pressure losses that the produced fluids encounter as they ascend from the bottomhole to the surface. These losses arise from a combination of hydrostatic head, friction within the tubing, flow acceleration, and any additional surface backpressure imposed by separators, choke valves, or other flow restrictions. The slope and position of the VLP curve are therefore highly sensitive to wellbore geometry, completion design, fluid rheology, and multiphase flow dynamics. Steeper VLP curves indicate higher frictional or hydrostatic resistance, which reduces the drawdown achievable by the well and increases the demand on the ESP to maintain stable flow.

The green curve represents the Inflow Performance Relationship (IPR), capturing the reservoir's ability to deliver fluids to the wellbore. This curve is governed by key reservoir parameters, including pressure, permeability, skin factor, and fluid properties such as viscosity and gas-oil ratio. The intersection of the IPR with the VLP curve defines the natural operating point of the well in the absence of artificial lift, providing a baseline against which the ESP's incremental performance can be evaluated.

The ESP contribution is illustrated through the blue line, which represents the pump discharge pressure, and the purple line, indicating pump intake pressure. The discharge pressure curve shows the head the pump must generate to overcome system losses and transport fluids to the surface. At the design flow rate of 4,250 b/d, the discharge pressure is positioned above the VLP, confirming that the pump delivers sufficient head to maintain stable production without overloading the system. The intake pressure is equally critical; the purple line ensures that the pump suction remains above bubble-point conditions, preventing free gas evolution, cavitation, and gas lock. Maintaining adequate intake pressure ensures the pump operates fully submerged, stabilizing hydraulic performance and protecting the impellers and motor from mechanical stress.

The interaction between the IPR, VLP, and ESP performance curves demonstrates that the pump is correctly sized for the well. The ESP effectively shifts the system operating point from the natural flow intersection to the design target, enabling higher production rates while ensuring that neither the pump nor the reservoir is overstressed. This balance also allows the ESP to maintain efficiency close to the Best Efficiency Point (BEP), minimizing energy consumption, wear, and operational risks. Figure 5 validates the technical suitability of the selected ESP, illustrating how artificial lift enhances production by matching pump performance to reservoir inflow and wellbore constraints. This analysis highlights the critical importance of nodal modeling in artificial lift design, as it allows engineers to predict system behavior under dynamic operating conditions, optimize pump selection, and ensure reliable long-term performance.

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4.2 Sensitivity Analysis of the Lifting methods

Comparison is made on the production performance under Electrical Submersible Pump (ESP) lift and natural flow conditions. Table 5 summarizes the ESP performance relative to natural flow over the productive period from 2011 to 2019. To visualise these trends, Figures 6 and 7 present plots derived from Table 5, illustrating variations in oil rate and total liquid rate throughout the studied years.

Table 5: Sensitivity analyses table

Parameters	**Year**	2011	2012	2013	2014	2015	2016	2017	2018	2019
	Reservoir Pressure, psi	4000	3938	3875	3813	3750	3688	3625	3563	3500
Natural flow	**Oil rate b/d**	2026	1881	1737	1595	1454	1313	1125	908	0
	Liquid rate, b/d	2251	2090	1930	1772	1616	1459	1250	1009	0
ESP	**Oil rate b/d**	4201	4024	3846	3664	3482	3300	3114	2927	2738
	Liquid rate, b/d	4668	4471	4273	4071	3869	3667	3460	3252	3042

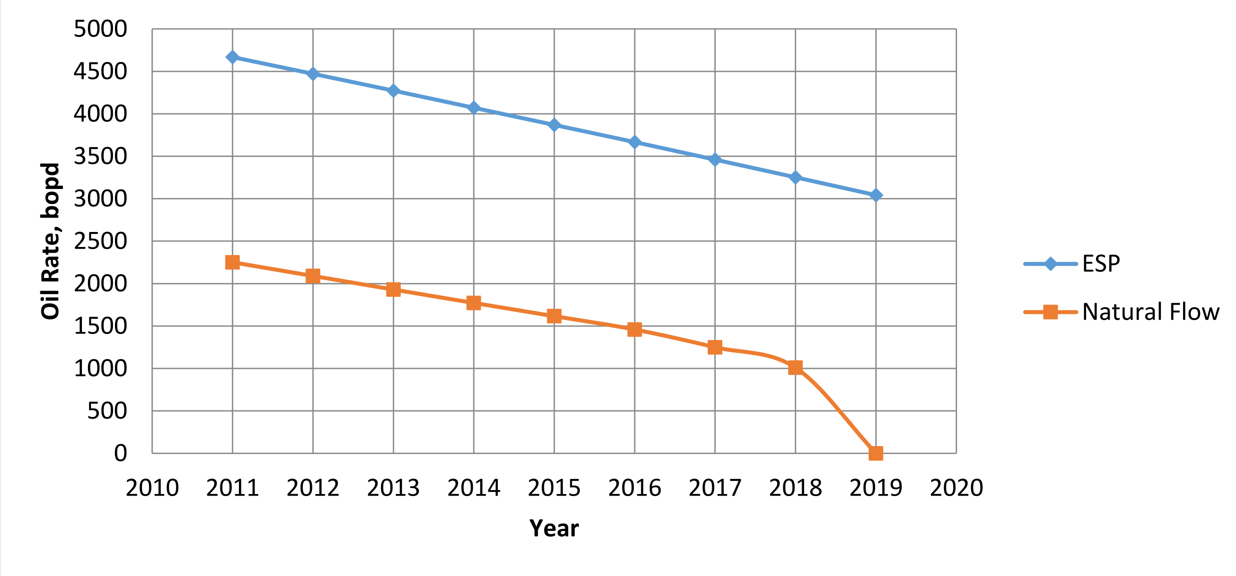

Figure 6: Oil rate Vs year ESP and natural flow

Figure 6 clearly demonstrates that natural flow produces the lowest oil rates among the scenarios evaluated. In this mode, production relies solely on the reservoir's inherent energy, which in this case is insufficient to sustain significant fluid volumes. The relatively high viscosity of the reservoir oil further increases flow resistance, limiting the well's natural deliverability. Consequently, primary recovery mechanisms are unable to overcome hydrostatic head and frictional losses in the wellbore, resulting in restricted production and emphasizing the need for artificial lift to enhance reservoir drawdown and fluid transport to the surface. The implementation of an Electrical Submersible Pump (ESP) significantly enhances well productivity compared to natural flow. By generating additional discharge pressure, the ESP lowers the bottomhole flowing pressure and increases the pressure differential between the reservoir and the wellbore. This enhanced drawdown promotes higher reservoir inflow, allowing the well to sustain substantially greater oil production rates. The pump effectively mitigates the limitations posed by high fluid viscosity and insufficient reservoir energy, enabling the lifting of larger fluid volumes to the surface.

The production gains achieved with ESP installation underscore the critical importance of artificial lift in prolonging the well's productive life. Whereas natural flow would result in rapid output decline due to diminishing reservoir pressure, the ESP maintains economically viable production levels over an extended period. In addition, the substantial increase in recovered volumes not only offsets the shortcomings of natural flow but also improves the overall recovery factor, ensuring more efficient exploitation of the reservoir throughout the well's productive life.

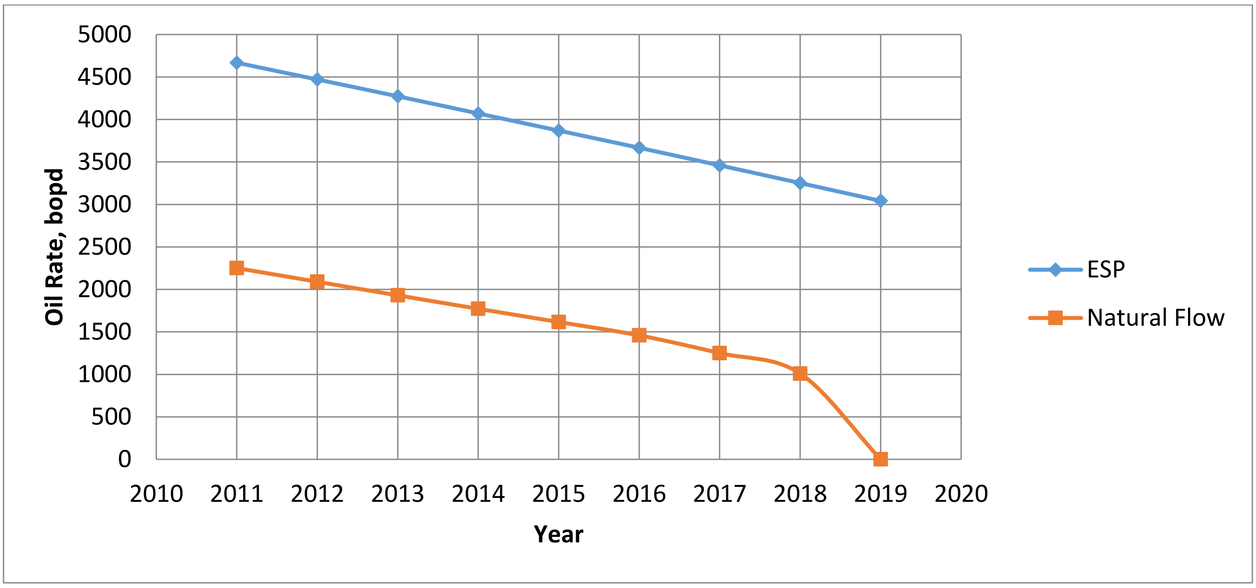

Figure 7: Liquid rate Vs year for lift methods considered

Figure 7 illustrates the total liquid production rates for both ESP-assisted and naturally flowing conditions, expanding the analysis beyond the oil-only focus of Figure 6. Total liquid rates encompass both oil and associated water, providing a more complete picture of well deliverability. This measure is crucial for artificial lift design, pump selection, and surface facility planning, as higher liquid volumes improve overall recovery but also introduce operational challenges such as water separation, handling, and disposal costs. Accurately capturing total liquid flow is therefore essential for evaluating both technical and operational performance.

Figure 8 further refines this evaluation by presenting the incremental oil rate, defined as the additional oil produced under artificial lift relative to natural flow. This metric directly quantifies the effectiveness of the lift system in enhancing production, isolating its contribution from the baseline reservoir performance. For heavy oil wells where natural reservoir energy is insufficient, the incremental oil rate serves as a critical indicator of lift efficiency and overall well performance. It also translates directly into potential revenue, making it a key parameter in technical-economic assessments.

From an economic perspective, incremental production forms the basis for evaluating the viability of different lift methods. While higher incremental oil rates reflect greater recovery, these gains must be balanced against the capital expenditure (CAPEX) for installation, operational expenditure (OPEX) for power consumption and maintenance, and additional costs associated with increased water production. ESPs, for instance, can achieve substantial incremental oil gains but generally incur higher energy and maintenance costs, whereas methods like gas lift may offer more moderate production increases with lower operational complexity and extended equipment life.

Integrating production performance metrics—oil rate, total liquid rate, and incremental oil gain—with economic indicators such as NPV, payback period, and operating margins provides a comprehensive framework for selecting the most suitable artificial lift method. Figures 7 and 8 together offer both the physical and economic perspectives necessary for informed decision-making, ensuring that the chosen artificial lift system maximizes hydrocarbon recovery while maintaining long-term operational and financial efficiency.

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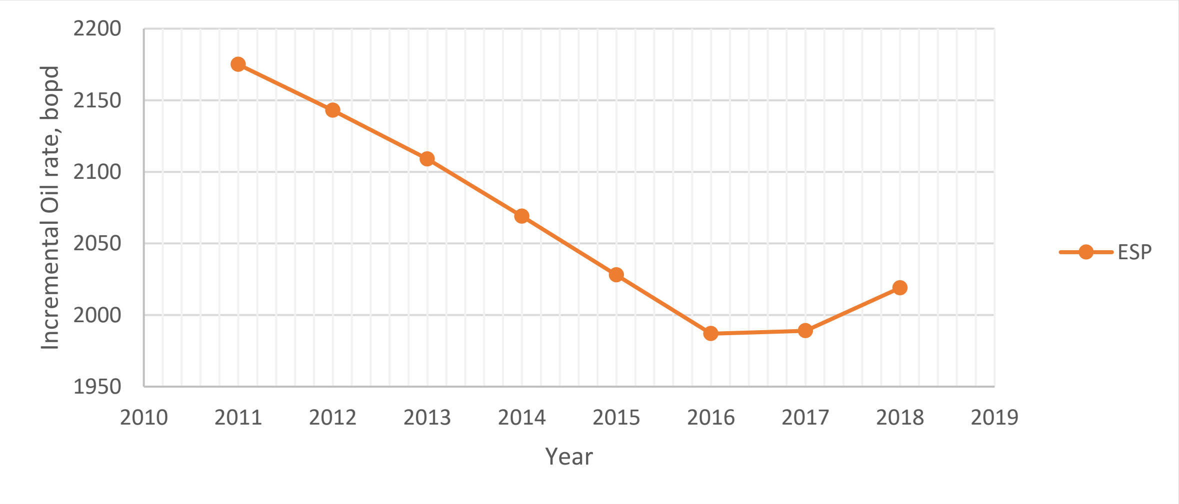

Figure 8: Incremental oil rate from ESP

Table 6: Percentage Incremental Oil rate for Artificial lift Methods

Year	**ESP**
2011	97%
2012	103%
2013	109%
2014	117%
2015	125%
2016	136%
2017	159%
2018	200%
Average	**131%**

Table 6 summarizes the percentage incremental oil rates for the artificial lift methods evaluated in this study. For ESP, the maximum incremental gain reached 200%, representing a two-fold increase in oil production compared to natural flow. Even at the lower bound, the minimum incremental rate was 97%, nearly matching natural flow output, demonstrating the consistent performance of ESPs under varying reservoir and operational conditions.

This performance range highlights the adaptability of ESPs to different well conditions while sustaining substantial production uplift. The upper bound of 200% illustrates the pump's capability to mobilize additional reserves by reducing bottomhole flowing pressure and enhancing drawdown, even in reservoirs with limited natural energy. The lower bound of 97% indicates that, under challenging scenarios such as high watercuts, increased gas interference, or declining reservoir pressure, ESPs still maintain production above economic thresholds. The consistent incremental performance of ESPs underscores their versatility and reliability as an artificial lift method, particularly in medium- to high-rate wells. Unlike natural flow, which depends entirely on reservoir energy, ESPs can be optimized through pump sizing, stage count, and variable speed control to meet specific production targets and maximize efficiency. This flexibility enables sustained hydrocarbon recovery and extends well life long after natural flow has diminished.

Economically, the incremental production gains achieved with ESP translate into higher revenue potential, although they must be weighed against higher energy consumption and maintenance costs. Overall, the results in Table 4.2 confirm that ESP deployment provides substantial incremental recovery, validating it as both a technically robust and economically feasible artificial lift solution for the reservoir conditions examined.

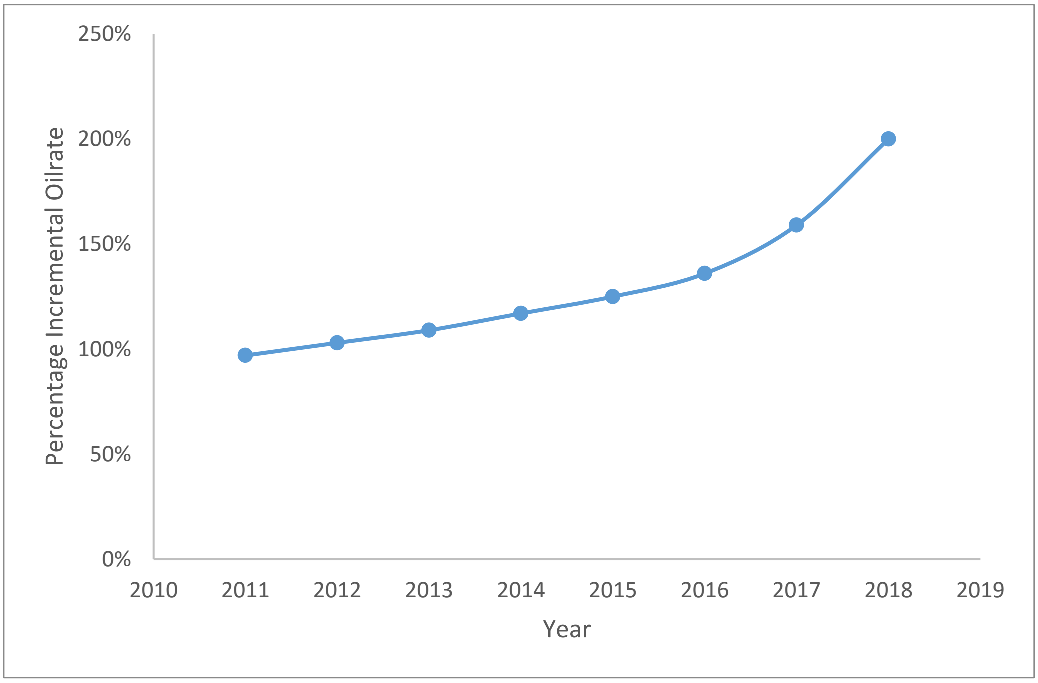

Figure 9: Figure showing percentage incremental oil rate

Figure 9 presents the trend of percentage incremental oil rates achieved by the ESP system over the productive period from 2011 to 2019. The data clearly indicate a progressive increase in the incremental oil contribution of ESP relative to natural flow, demonstrating that the artificial lift system not only sustained production but became increasingly effective as reservoir energy declined.

Analysis of the results shows that the average incremental oil rate due to ESP was 131% over the operational period, meaning that, on average, ESP-supported production nearly doubled the output compared to natural flow. This highlights the critical role of ESPs in enhancing well deliverability and extending field life. The sustained gains are attributed to the pump's ability to lower bottomhole flowing pressures, thereby maximizing drawdown and facilitating increased reservoir inflow, despite challenges from declining reservoir pressure and relatively high fluid viscosity. The upward trend in incremental oil recovery further emphasizes the growing relative importance of artificial lift as the reservoir's natural drive weakens. While natural flow production diminishes over time due to falling reservoir pressure and increasing water cut, the ESP maintains higher lifting capacity, ensuring stable oil recovery and a widening performance gap between ESP-assisted and natural production.

From both operational and economic perspectives, this trend is highly significant. The consistent average incremental gain of 131% validates the technical and financial justification for deploying ESP systems. Additionally, the progressive improvement over time underscores the potential of ESPs as a long-term production strategy, particularly when combined with variable speed drives (VSDs) that allow dynamic adjustment to changing reservoir conditions, ensuring sustained efficiency and recovery throughout the well's productive life.

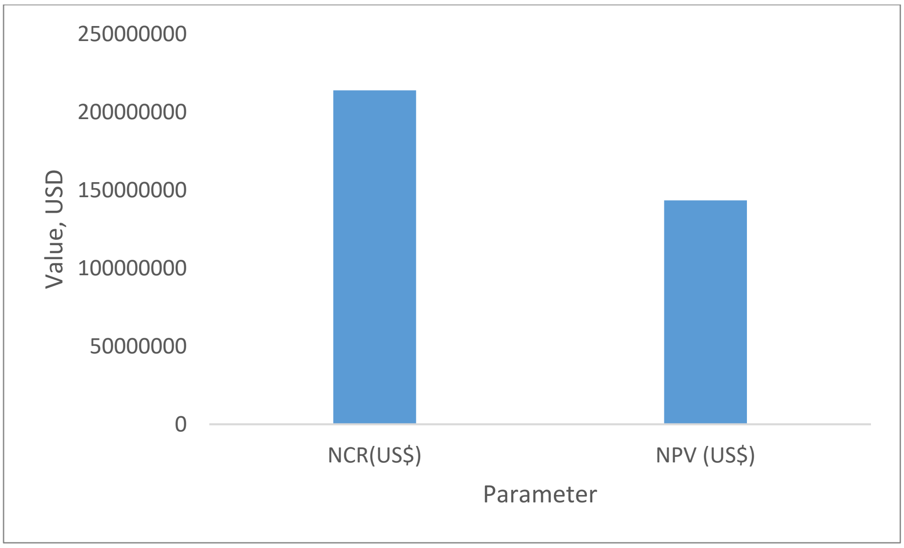

Figure 10: Economic indicators results

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4.3 Results for Economic analysis

The economic performance of the artificial lift systems in this study was assessed using Net Cash Recovery (NCR) and Net Present Value (NPV) as key financial metrics. For the Electrical Submersible Pump (ESP), the evaluation indicated an NCR of US$ 213,889,115 and an NPV of US$ 143,405,102 at a 10% discount rate. The NCR represents the total undiscounted cash inflow generated over the life of the project, while the NPV accounts for the time value of money, providing a measure of the net economic benefit of deploying the ESP within the studied production system.

Although the ESP yielded the lowest NCR and NPV relative to other artificial lift methods evaluated in the broader study, the absolute economic values remain substantial. An NPV exceeding US$ 143 million confirms that the ESP system generated a positive financial return over the well's productive life, validating the investment in this technology. The positive NPV further indicates that the incremental revenues from enhanced oil recovery more than offset the capital and operational expenditures associated with ESP installation, operation, and maintenance.

The comparatively lower economic performance of ESP is largely attributable to its operational characteristics. While ESPs deliver significant incremental oil recovery—as demonstrated in the production analysis—they incur higher operational expenditures, including elevated energy consumption, routine maintenance, and occasional pump replacement. These costs can reduce overall project profitability relative to lift methods with lower operating costs. Nevertheless, the NCR and NPV results demonstrate that ESP remains a financially viable and technically effective artificial lift solution, particularly suitable for wells with medium to high production rates where sustained recovery and operational reliability are critical.

4.4 Discussions

A comprehensive well performance analysis was conducted for Well AB2LS in the Niger Delta, producing moderately heavy oil with an API gravity of 22°. The study systematically progressed from natural flow modeling under primary reservoir drive conditions to the design and simulation of artificial lift systems, with particular focus on the deployment of an Electrical Submersible Pump (ESP). The analyses integrated reservoir, fluid, and wellbore properties, providing a robust evaluation of both technical and economic feasibility of ESP as a lift solution.

The baseline natural flow modeling highlighted the intrinsic limitations of primary reservoir energy in sustaining production of viscous hydrocarbons. At an initial reservoir pressure of 4,000 psi, the oil production rate at 10% water cut was 2,026 bopd at a solution node pressure of 3,263 psi, decreasing sharply to 549 bopd at 50% water cut and 3,740 psi node pressure. Corresponding liquid rates were 2,251 b/d and 1,098 b/d, respectively. These results underscore the inability of the natural drive mechanism to overcome the combined effects of high fluid viscosity, hydrostatic head, and declining reservoir pressure. The progressive reduction in deliverability illustrates that, without artificial lift, production would fall below economic thresholds, particularly in reservoirs characterized by high water encroachment and limited natural energy.

Introduction of the ESP markedly improved production capacity and stabilized well performance. The ESP design curve indicated a stable operating range from 1,425 to 5,925 b/d at 60 Hz frequency, with a best efficiency line (BEL) of 62.15%. The design production rate of 4,250 b/d lies comfortably along this BEL, representing the optimal operational point where hydraulic losses are minimized and pump efficiency is maximized. At this operating point, the ESP provides sufficient drawdown to mobilize viscous oil and water, maintaining steady inflow while mitigating risks of pump stalling, gas lock, or cavitation. These characteristics are particularly important in heavy oil reservoirs where free gas and viscous fluid properties can destabilize centrifugal pump operation if not adequately accounted for in design.

Integration of the Inflow Performance Relationship (IPR) and Vertical Lift Performance (VLP) curves further validated the ESP configuration. At the design rate of 4,250 b/d, the intersection of the IPR, VLP, and ESP pressure curves confirms that the pump can overcome wellbore hydraulic losses and sustain the projected fluid delivery. This nodal balance demonstrates that the ESP effectively compensates for declining reservoir pressure, high hydrostatic head, and viscous flow resistance, achieving stable and predictable production rates.

The incremental oil recovery analysis illustrates the transformative impact of the ESP. Compared to natural flow, the ESP provided significantly higher production by reducing bottomhole flowing pressure and increasing drawdown. Over the 2011–2019 production period, the incremental oil rate averaged 131%, indicating that ESP production more than doubled the natural flow baseline. The temporal trend shows a widening gap between ESP-lifted and natural flow rates, reflecting the ESP's ability to maintain lifting capacity even as reservoir energy declines and water cut increases. This performance advantage underscores the technical necessity of ESP deployment in mature heavy-oil wells, particularly in the Niger Delta where high water fractions and moderate-to-low gas content are common.

The Dunbar gas-handling assessment confirms the technical robustness of the ESP under multiphase conditions. Test points remained above the gas separation threshold, indicating that full gas separation was unnecessary. This minimizes the risk of gas lock and cavitation, ensuring stable pump operation. For heavy oil systems with moderate gas-oil ratios, such stability is critical, as fluctuations in gas fraction at the pump intake can otherwise compromise efficiency and equipment lifespan.

Economically, the ESP system demonstrated positive but relatively lower returns compared with other artificial lift methods considered in the broader study. The Net Cash Recovery (NCR) of US$213,889,115 and Net Present Value (NPV) of US$143,405,102 at a 10% discount rate confirm the financial viability of the ESP. The lower comparative economic performance primarily reflects higher operational costs associated with ESP deployment, including energy consumption, periodic maintenance, and pump replacements. Nevertheless, the substantial incremental recovery achieved by the ESP offsets these costs, providing a net positive return and validating its use in mature heavy oil reservoirs.

Overall, the results highlight the ESP as a technically and economically viable artificial lift solution for heavy oil production in Well AB2LS. Chronologically, the study demonstrates that natural flow alone is insufficient to sustain long-term production. The transition to ESP significantly enhanced oil recovery, stabilized production, and delivered consistent performance across declining reservoir pressures and increasing water cut. The average 131% incremental production gain illustrates the pump's transformative impact, confirming its critical role in maintaining commercial production. Although ESP operational costs are higher than some alternative lift methods, the positive NPV and NCR indicate a favorable balance between technical reliability and economic feasibility. These findings establish ESPs as a key artificial lift technology for heavy oil reservoirs in the Niger Delta, capable of sustaining production where conventional natural drive mechanisms fail, and providing a reliable framework for field development and operational planning in similar reservoir conditions.

5.0 Conclusion

This study presented a comprehensive evaluation of Electrical Submersible Pump (ESP) performance as an artificial lift solution for the production of heavy oil from Well AB2LS in the Niger Delta, employing detailed well modeling and simulation in PROSPER. The investigation began with a natural flow analysis, which established the limitations of primary reservoir drive mechanisms in sustaining production for moderately heavy crude (22° API). Under natural flow conditions, production declined rapidly as water cut increased, highlighting the necessity for artificial lift to maintain commercially viable rates.

ESP design and simulation demonstrated stable operation within a well-defined performance envelope, with flow rates ranging from 1,425 to 5,925 b/d at 60 Hz. The pump achieved a best efficiency line (BEL) of 62.15%, corresponding to the optimal operating point where hydraulic losses are minimized. The design production rate of 4,250 b/d, located along the BEL, was validated by the intersection of the Inflow Performance Relationship (IPR) and Vertical Lift Performance (VLP) curves with the ESP discharge and intake pressures. These results indicate that the ESP provides sufficient drawdown to overcome fluid viscosity, reservoir pressure decline, and hydrostatic head, ensuring sustained inflow and efficient lifting.

Incremental recovery analysis confirmed the effectiveness of the ESP, showing an average increase of 131% over natural flow during the 2011–2019 production period. This nearly doubled the baseline production, with incremental gains growing as reservoir energy declined. Gas-handling assessment using the Dunbar criterion indicated that full gas separation was unnecessary, as operating points remained above the critical gas threshold, thereby mitigating risks of gas lock and cavitation.

Economically, the ESP system proved both viable and profitable. The simulation yielded a Net Cash Recovery (NCR) of US$213,889,115 and a Net Present Value (NPV) of US$143,405,102 at a 10% discount rate, validating the financial justification for its deployment. While operational and maintenance costs, including energy consumption and pump replacements, moderated the comparative economic indices, the positive NPV and substantial incremental recovery confirm that the ESP offers a robust balance between technical performance and economic feasibility, making it a reliable artificial lift strategy for heavy-oil wells in the Niger Delta. In addition, the analysis indicates an estimated operational cost of approximately US$6–9 per barrel of oil produced over the production period, driven primarily by power consumption, periodic pump maintenance, and equipment replacement cycles. This unit lifting cost remains economically acceptable within offshore Niger Delta development thresholds, further reinforcing the viability of ESP deployment despite its relatively higher operating expenditure compared to other artificial lift systems.

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