ISSN 1993-9973, e-ISSN 2415-332X

Vol. 26, No. 1
2026

PROSPECTING AND DEVELOPMENT OF OIL AND GAS FIELDS

https://pdogf.com.ua/en

Received: 21.01.2026. Revised: 31.03.2026. Accepted: 29.05.2026. Published: 29.06.2026.

UDC 622.276, 622.279

DOI: 10.63341/pdogf/1.2026.56

Application of electric submersible pumps for post-fracturing gas well clean-up in depleted reservoirs

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Abstract. Given the long-term operation and depletion of most Ukrainian fields, the development of effective methods to restore their productivity is a priority for Ukraine's energy sector. This study focused on optimising the clean-up process of wells with abnormally low reservoir pressure after stimulation by hydraulic fracturing. The aim of the study was to introduce a technology for the successful extraction of fracturing fluid, which would significantly expand the criteria for well selection and enable the successful execution of hydraulic fracturing operations during the final stage of gas field development. The three alternative mechanised development technologies (electrical submersible pumps deployed on coiled tubing, cable, or jointed tubing) were compared through a theoretical techno-economic analysis to select the optimal method, considering the current state of Ukraine's gas production industry. The study was based on engineering calculations, nodal analysis, and hydrostatic imbalance evaluation for a typical deep well with depleted reservoir pressure (4,150 metres, 6.0 MPa). Hydrostatic imbalance calculations for the hypothetical well revealed a critical overbalance on the reservoir, which rendered development impossible without artificial lift. The hydrostatic pressure of the fluid column significantly exceeded the reservoir pressure, causing fluid fallback and subsequent fracture damage due to colmatation. Based on theoretical data, a comparative analysis of these technologies established that the rigless pump-on-cable option was technically unsuitable for depths exceeding 3,000 metres, whilst coiled-tubing deployment was economically unviable if a workover rig was already installed at the wellhead. The installation of an electrical submersible pump on jointed production tubing proved to be a pragmatic and economically sound solution. The parameters of the required assembly were calculated, and the complete cycle from the hydraulic fracturing stage to bringing the well on stream was modelled. A pragmatic approach was proposed that allowed the extraction of the fracturing fluid without overbalancing the reservoir, using available resources with minimal additional costs, which was critical for the cost-effectiveness of stimulation operations on depleted reservoirs

Keywords: reservoir; stimulation; flow rate; fracture; production; workover; coiled tubing

Introduction

The vast majority of gas and gas-condensate fields, particularly within the Dnieper-Donets Basin (DDB), are characterised by depleted reservoirs and significant colmatation of the near-wellbore zone in wells. This problem is one of the key issues, as it leads to a decrease in flow rates and well shut-ins. In conditions where drilling new wells becomes highly risky, and in some cases unprofitable, stimulation technologies are implemented to maintain production

Suggested Citation: Moroz, L., & Selinny, Ye. (2026). Application of electric submersible pumps for post-fracturing gas well clean-up in depleted reservoirs. *Prospecting and Development of Oil and Gas Fields*, 26(1), 56-64. doi: 10.63341/pdogf/1.2026.56.

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from the existing well stock. Improving existing and implementing new gas and condensate production technologies is a priority task for the industry, particularly through the improvement of hydraulic fracturing (HF) technology, which has been actively implemented in Ukrainian fields for over 20 years.

In their abstracts, researchers I.I. Lartseva *et al*. (2025) reported on the current state of development of the largest deposits in Ukraine and characterised them as "depleted". The experience of conducting HF was described, concluding that the implementation of HF technology could be a key step in extracting Ukraine's oil and gas resources and contributing to its energy stability. In their research, A.V. Shcherbyna (2024) demonstrates that the implementation of a complex of well interventions, particularly HF and additional perforation, had a significant impact on well productivity. The author also notes that the main driver for increasing production rates is conducting HF on new wells and the existing well stock, which confirms the expediency of applying HF to enhance production and stabilise development rates.

The article by Yu.V. Lazebna *et al*. (2022) examines the exploration prospects and development challenges of tight gas reservoirs in the DDB. The authors analysed the geological parameters of the Paleozoic complex (structure, degree of catagenesis, organic carbon content, reservoir properties, and burial depths) and concluded that there is a high probability of gas presence in basin-centred reservoirs. At the same time, it is emphasised that such deposits are hard-to-recover due to the low porosity and permeability of the rocks; therefore, their development is impossible without applying stimulation methods. Among modern technologies, HF is highlighted as the most optimal stimulation method for this task. According to the authors, the use of foam fracturing technology can serve as a starting point for the active development of hard-to-recover tight gas reserves, particularly from basin-centred reservoirs.

According to researchers I. Kuper *et al*. (2025), the main problem for well productivity is the presence of the skin effect. The paper analyses how restrictions in the near-wellbore zone affect well performance and presents the modelling of the pumping technology itself, which minimises the negative impact on the near-wellbore zone. The proper selection of fracturing fluid, proppants, and control of fracture geometry through the modelling of pumping parameters allow for the complete elimination of near-wellbore flow capacity restrictions accumulated over years of production. B. Chen *et al*. (2022) emphasised that HF is critically important for oil and gas production from low-permeability reservoirs. The study analyses modern methods of modelling HF technology, describes the physical processes occurring during HF, and presents the capabilities of modern software. One of the problems arising during the pumping process is described as fluid leak-off into the formation, which leads to dynamic changes in fracture geometry and complicates the HF operation. However, for reservoirs with reduced formation pressure, there is an additional problem, namely fluid flowback to the surface after fracture propping.

In their work, researchers V.S. Biletskyi *et al*. (2025) described modern stimulation methods, including a characterisation of the HF process. The paper describes modern development trends in HF technology aimed at improving modelling and pumping process monitoring technologies, while also highlighting the focus on developing and applying environmentally safe fluids. In the article by A. Abdelaziz *et al*. (2023), a study was conducted and a digital model of fracture propagation during HF was created. Based on data obtained from laboratory experiments, it was established that under real conditions, fractures propagate chaotically, forming complex channel networks that are both induced by pumping and act as extensions of pre-existing faults within the reservoir. Researchers L.B. Moroz *et al*. (2023b) established the impact of polymer concentration in the working fluid on fracture dimensions and conductivity during HF. For all fluid types used in the modelling, an increase in polymer concentration led to an increase in the primary geometric parameters, such as fracture width and height, and a decrease in its length.

The analysed studies cover a wide range of aspects associated with HF stimulation technology. The articles describe the expediency of implementing HF in Ukrainian fields and confirm the high potential for increasing production from gas and gas-condensate reservoirs at the late-life stage of development. Existing research broadly covers the specific challenges of executing high-quality HF operations and shows ways to improve this technology. However, available studies do not sufficiently focus on the recovery of residual technological fluid from the reservoir after fracture propping. It is at this stage that a fundamental technological problem arises: the reservoir energy of a depleted reservoir is insufficient to autonomously lift the HF fluid to the surface. Standard practice in such cases is well clean-up using a coiled tubing unit (CTU) with the injection of an inert gas (nitrogen) below the fluid level to aerate the fluid column. However, as global practice shows, under conditions of severe reservoir depletion, when the hydrostatic pressure of the fluid column significantly exceeds the formation pressure, this technology becomes ineffective. The objective of this study was to conduct a techno-economic analysis of existing artificial lift technologies for well fluid extraction to determine the feasibility and possibility of their further use during the clean-up of wells stimulated by HF.

Materials and Methods

The study was conducted using engineering modelling and techno-economic analysis based on the methodology outlined by S.V. Matkivskyi & L.I. Khaydarova (2021), since it calculated the impact of electrical submersible pump (ESP) parameters on the production characteristics of water-loaded gas wells and proved that at high water-gas ratios, an ESP can operate stably and assist in lifting liquid to the surface. The selection of this methodology for investigating novel ways of recovering technological fluid after HF is justified, as the processes of recovering formation fluid and residual fracturing fluid are quite similar, despite their fundamentally different origins. A prolonged period usually elapses between the HF operation and the start of well clean-up, which includes a technological shut-in for gel breaking, as well as a period of operations for packer retrieval, tubing string replacement, and workover rig dismantling, which in total can take up to 1 month. During the final well preparation period, the pumped fluid is evenly distributed within the well drainage zone, which provides grounds for equating the reservoir conditions in this case to those of a naturally water-loaded gas well. A typical deep gas well from one of the depleted DDB fields (synthetic well No. 202), which is a candidate for HF, was selected as the base object (Table 1).

Table 1. Initial parameters of the facility (reference well No. 202)

No.	Parameter	Value	Unit
1	Field name	Field 1	Name
2	Well No.	202	No.
3	HF intervals	4,120-4,140	m
4	Perforator type and shot density	ZPK-62m; 18 hol./m.	
5	Formation pressure	60	atm
6	Reservoir temperature	103	°C
7	Porosity	14	%
8	Permeability	0.15	mD
9	Formation fluid viscosity (in-situ)	0.015055	mPa·s
10	Gas formation volume factor	0.010287	m^3/m^3
11	Saturation pressure	280	atm
12	Gas compressibility factor (Z)	0.8917	
13	Production casing	168	mm
14	Production casing wall thickness	12	mm

Source: created by the authors

Based on the experience of conducting HF operations in analogous horizons, the design parameters of the HF operation necessary for further calculations on the research topic were adopted using the methodology of L. Moroz *et al*. (2023a). Before starting the HF operation, a packer assembly is run on a work string; therefore, kill fluid remains in the wellbore. The wellbore volume must be taken into account, as to initiate the fracture and create a "pad", it is necessary to displace the kill fluid with the fracturing fluid, which is accompanied by forcing the former into the productive horizon. The total fluid volume, including the volume of the kill fluid used during the workover in the well preparation process, is 240 m^3. Another important parameter for conducting justified calculations is the average density of the fluid pumped into the formation during the HF process; a value of 1,030 kg/m^3 was adopted. For the modelling and theoretical substantiation of the study, Schlumberger (n.d.b) software was used. The capabilities of this software suite, highlighted on the company's official resource, allowed for the full execution of the entire cycle of calculations necessary to substantiate the method proposed in the study, without the use of additional tools. The formulas used for the calculations in this work are presented below.

Hydrostatic pressure of the fluid column on the formation:

$$P_g = \rho \times g \times H, \tag{1}$$

where P_g is the hydrostatic pressure of the fluid column on the formation; ρ is the fluid density; g is the acceleration due to gravity; H is the depth to the middle of the perforation interval (under conditions where the gas-producing part of the formation is not determined, the middle of the perforation interval is assumed).

Excessive overbalance in a fluid-filled well:

$$P_e = P_g - P_r, \tag{2}$$

where P_e is the excessive overbalance on the formation; P_r is the measured formation pressure before the start of operations.

Dynamic fluid level:

$$h_d = H - \frac{P_{bh}}{\rho_l \times g}, \tag{3}$$

where P_{bh} is the bottom-hole pressure; ρ_l is the fluid density.

Pump system head:

$$H_p = h'_d + h_2 + h_f - h_g, \tag{4}$$

where H_p is the head; h'_d is the distance from the wellhead to the dynamic fluid level; h_2 is the required head at the wellhead (assuming Pm = 0.5 MPa backpressure on the gathering line $h_2 = 50$ m); h_f represents friction head losses during fluid flow in the tubing of length L; h_g is the fluid lift height in the tubing due to gas energy ($h_g = 0$ since fluid without gas is pumped at the first stage).

Motor shaft power:

$$N = (Q \times \rho \times g \times H_p)/\eta, \tag{5}$$

where N is the motor shaft power; Q is the fluid flow rate; η is the system efficiency.

Results and Discussion

The key factor that precludes well clean-up is the hydrostatic imbalance between the formation pressure and the pressure of the fluid column in the well before the start of clean-up operations. First, the pressure of the HF fluid column on the formation was calculated. In conditions where no surveys were conducted during the well's operation to determine the exact part of the formation directly producing gas, the midpoint of the perforation interval is assumed in the calculations to minimise the margin of error. For the well under consideration, $H = 4{,}130$ m:

$$P_g = 1{,}030 \times 9.81 \times 4{,}130 = 41.6 \text{ MPa}.$$

Thus, knowing the formation pressure measured before the start of operations, the excessive overbalance applied to the formation with the well filled to the wellhead with kill fluid was determined:

$$P_e = 41.6 - 6.0 = 35.6 \text{ MPa}.$$

As a result, a significantly high value of excessive overbalance on the formation was obtained. This indicates that standard fluid recovery methods, such as well clean-up using compressor equipment or a CTU to inject inert gas below the fluid level, are unsuitable for the conditions of this well. To ensure the pumping of 25 m³/day of HF fluid and create sufficient drawdown on the formation, a standard ESP assembly (size 3 or 4) run on a 73 mm (2 7/8") tubing string is used. The first stage in designing the ESP installation is determining the setting depth and the dynamic fluid level that must be maintained to cool the motor. To create a drawdown on the formation (with $P_r = 6.0$ MPa), the dynamic fluid level in the well must be lowered to a value corresponding to a pressure below the formation pressure. $P_{bh} = 5.8$ MPa is assumed (a drawdown of 0.2 MPa). The required dynamic fluid level from the wellhead is:

$$h_d = 4{,}130 - \frac{5.8\times10^6}{1{,}030\times9.81} = 3{,}555 \text{ m}.$$

According to the technological solutions for the installation of ESP described by M.A. AL-Hejjaj *et al.* (2023), the pump setting depth must ensure sufficient submergence below the fluid level to create sufficient intake pressure for the motor (≈5-10 atm). Thus, the adopted ESP setting depth is $L_p = 3{,}650$ m. This provides 95 m of submergence at the pump intake at the initial stage, and as the fluid in the wellbore gradually changes into a gas-liquid mixture, it will provide a power reserve at the final stage of well clean-up. To subsequently determine the rated motor power of the ESP assembly, the required head was calculated using formula (4) for determining the well's theoretical system curve. The friction head losses in a 73 × 62 mm tubing string ($d_{in} = 0.062$ m) with a length of 3,650 m at a flow rate of $Q = 25$ m³/day will be approximately 150 m. The total required head is:

$$H_p = 3{,}555 + 50 + 150 = 3{,}755 \text{ m}.$$

Motor shaft power:

$$\mathrm{N} = \frac{(0.00029 \times 1{,}030 \times 9.81 \times 3{,}755)}{0.4} = 27{,}507 \text{ W} = 27.5 \text{ KW}.$$

Based on the performed calculations, the clean-up of well No. 202 requires a standard size 3 (Ø 3.38") ESP assembly capable of generating a head of ~3,800 m at a flow rate of 25 m³/day. To select the ESP for fluid recovery, the built-in "ESP design" function was used, which allows for the automatic selection of the optimal system considering the specified wellbore conditions. Based on the well model parameters, the REDA MT2A-30 ESP system was selected, which, operating at 53% of its rated load, ensures the pumping of 25 m³/day of HF fluid from the formation (Fig. 1).

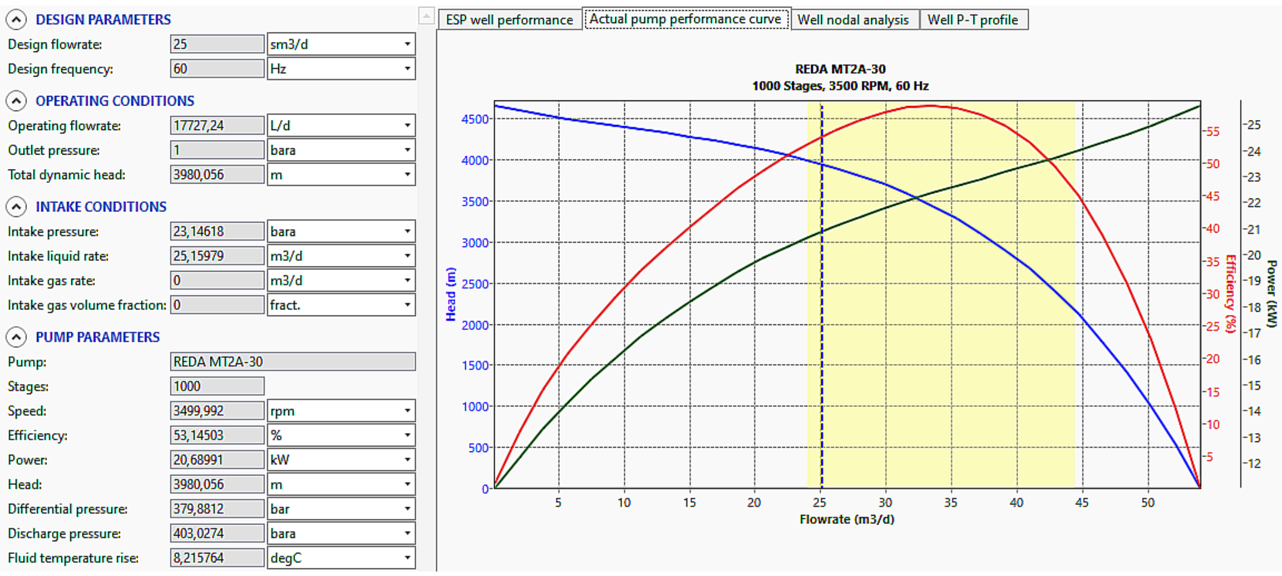

Figure 1. Pump performance curve of the REDA MT2A-30 ESP
Source: created by the authors

To validate the research findings, a model of well No. 202 was developed with an ESP installed on a jointed tubing string with a nominal diameter of 73 mm; the formation properties were specified, along with the condition that 240 m³ of HF fluid was pumped into the near-wellbore zone (Fig. 2).

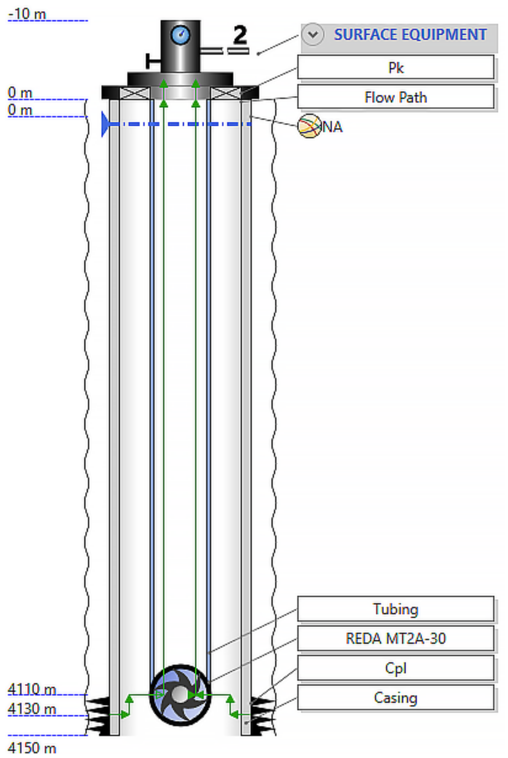

Figure 2. Conceptual well model

Source: created by the authors

Given that the HF was performed in a gas-bearing formation, the fluid will gradually become saturated with gas during the recovery process. It is necessary to verify whether the selected pump can continue to lift water as the gas-liquid ratio increases. Based on the sensitivity analysis conducted, it was determined that the pump can ensure stable fluid pumping even as the gas-liquid ratio in the production stream increases up to 400 cm³/cm³ (Fig. 3).

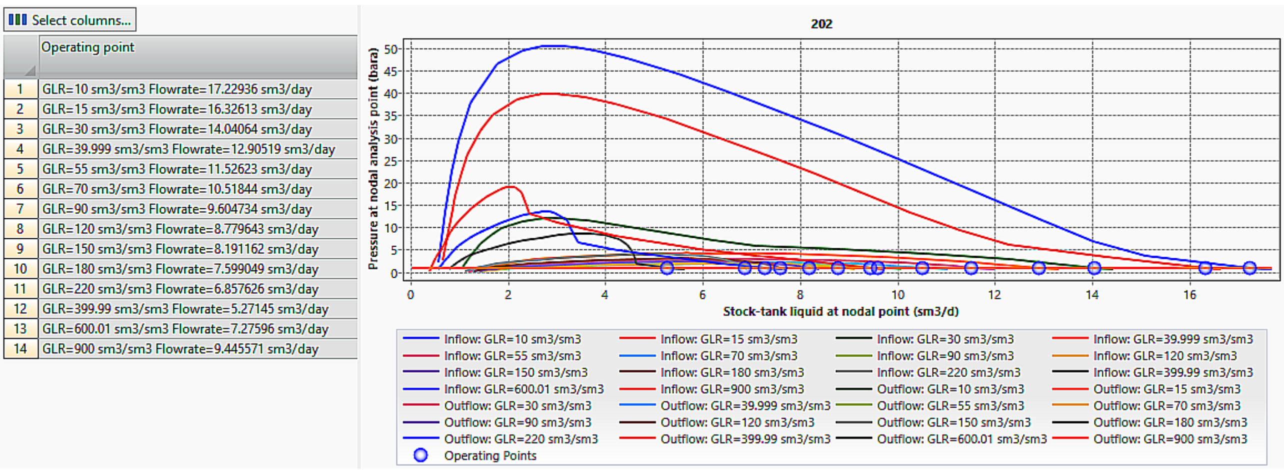

Figure 3. Sensitivity analysis of pump performance with increasing gas-liquid ratio

Source: created by the authors

Through simulation, it was determined that the REDA MT2A-30 ESP system, run on a tubing string with a nominal diameter of 73 mm, ensures the recovery of the fluid pumped during the HF operation. As the gas-liquid ratio increases, the liquid rate slightly decreases; however, the pump operation remains stable even at a gas-liquid ratio of 400 cm³/cm³. This will be sufficient for well clean-up, as under these parameters, after the pump is retrieved, the well will be capable of naturally unloading water and continuing to clean up during the production phase. This study has proven that the use of an ESP allows for well clean-up after HF if there is insufficient reservoir energy to lift the fluid. Therefore, the method of temporarily installing an ESP system on jointed tubing is a technically and economically justified solution.

Based on the selected technology, the complete well clean-up cycle is as follows: after performing the HF operation and isolating the pay zone by leaving a sand plug, a workover rig is used to replace the packer-tubing assembly utilised for the HF with a production tubing string equipped with an entry guide and an ESP assembly. Fluid recovery is conducted for approximately 10 days until gas breakthrough occurs and the pump operation becomes ineffective. After this, the well is killed to ensure safe tripping operations, and the ESP is retrieved. To bring the well on stream, a production tubing string with an entry guide is run in hole, and a standard clean-up is performed using compressor equipment or a CTU.

In their study, O.A. Pashchenko *et al*. (2024) proposed a comprehensive approach to calculating the operational parameters of HF, based on a combination of geomechanical rock properties, fluid and proppant properties, and injection rates. The authors developed a methodology for determining the breakdown pressure, fracture geometry, near-wellbore permeability, and the expected production gain following the HF operation. Special attention is given to optimising proppant selection depending on in-situ stress gradients, as well as to developing an automated algorithm for the rapid selection of pumping parameters. The proposed approach allows for enhancing operational efficiency and serves as a foundation for developing software tools for automated HF design in field conditions.

M. Zhulaj & O. Serbin (2024) analysed the advanced methods and approaches actively implemented by Ukrainian companies to enhance oil and gas production efficiency and secure Ukraine's energy independence. It was established that modern technologies, such as HF, can effectively increase production even in depleted reservoirs. Although the cost of applying these technologies is substantial, their payback period becomes significantly shorter amid rising energy prices. For example, fracturing operations can increase production volumes by 20-50%, allowing the costs to be recovered within a few years.

Studies by F. Jahn *et al*. (2026) confirm that in low-pressure reservoirs, the well clean-up technique involving fluid column aeration relies heavily on the assistance of reservoir energy. However, when reservoir energy is insufficient, this leads to fluid fallback into the perforation interval and inefficient solids cleanout. In the present case, where gel degradation residues are present in the wellbore and directly within the created fracture, the re-exposure of the highly permeable fracture to such fluid leads to its plugging. Furthermore, research by I. Kuper *et al*. (2025) indicates that the incomplete removal of fracturing fluid induces a skin effect and can reduce the initial gas rate by 40-60%.

To address the given objective, the industry's available artificial lift technologies, which could potentially be used for the recovery of residual post-frac fluid, were considered. One such advanced rigless ESP deployment technology reviewed is the system proposed by leading companies Schlumberger (n.d.a) and Baker Hughes (2021), which involves deploying an ESP on power-cable coiled tubing (CT) using a CTU. At first glance, the use of this technology appears optimal as an existing "off-the-shelf solution", but it has several drawbacks. The rental cost of the specialised CT-deployed ESP package is extremely high, and the 3.38" (85.8 mm) ESP assembly is designed to operate inside the production casing. Therefore, after fluid recovery, the well must be killed to install the production tubing string. This offsets the benefits of using a CTU and significantly complicates the operations.

It is also critical to consider the technical risks associated with CT operations. Specifically, deploying and operating an ESP imposes significantly higher mechanical loads on the CT string than standard interventions. As described by Vechietti *et al*. (2022), a CT string parted during retrieval, causing a well control incident. Regaining control required pumping a high-viscosity fluid to form a resin plug. In post-fracturing scenarios, where any fracture plugging is impermissible, such risks completely ruin the stimulation results.

Considering the drawbacks of using a CTU, the possibility of deploying an ESP assembly on a wireline is being considered. The existing technology, presented by J. Algerøy (2018), is primarily designed for rapid pump replacement in oil wells. It involves the prior deployment of a specialised tubing string equipped with a docking station. The ESP assembly itself (motor, protector, and pump) is run inside the tubing on a special load-bearing wireline. The main drawback of this technology, even if adapted for the current research objective, is the technical depth limitation. The maximum load the cable can withstand allows for ESP installation at depths of up to 3,000 meters, which is insufficient for wells developing gas reservoirs in the DDB.

In this case, the most promising approach for implementation is deploying the ESP on a tubing string. A method widely used in the oil industry that requires no additional technology implementation costs. This method involves using a standard ESP assembly as a temporary tool deployed by a workover rig. This approach is supported by case studies from A. Salah *et al*. (2025), where ESP installation was successfully used to lift gas-liquid streams. When compared to a gas lift system under standard operating conditions, the ESP efficiency was comparable; however, with an increasing water cut, the use of an ESP proved to be more effective. The primary advantage of applying this method to the study conditions is the low operational cost. ESP deployment does not require additional equipment or the involvement of expensive specialised packages demanded by the other described technologies. In most cases, during HF operations in Ukrainian fields M.A. Mysliuk & V.P. Kravets (2024), a workover rig is on standby on location. Furthermore, standard off-the-shelf ESPs are used, which are significantly cheaper than specialised slim-hole systems.

The obtained research result is validated by real-world challenges in global practice. In their study, A. Albahri *et* *al*. (2025) demonstrate that when applying the correct engineering approach to ESP optimisation, the system will operate continuously under high gas-water ratio conditions. The authors propose ESP design modifications and adjustments to mitigate the impact of phase separation as fluid passes through the pump stages. Additionally, one of the proposed solutions involves deploying the assembly below the perforation interval to reduce gas interference; however, for the given research conditions, specifically the significant well depth, implementing this approach will be problematic.

In global practice, deploying ESPs in high-GOR oil wells following HF is a widely adopted method. In their study, F. Leon *et al*. (2022) describe that when selecting the optimal pump stages, similar to the case of the current research, the ESP operates stably while lifting gas-liquid streams. One of their field trials involved installing an ESP in a fractured well, which demonstrated that the technology maintains high operational reliability even when subjected to abrasive proppant flowback.

However, the primary challenge of deploying ESPs to lift fluids with a high gas volume fraction remains the overheating of motor components. This issue is detailed by T. Chu *et al*. (2022) and aligns perfectly with the findings of the current study. Under conditions of a high gas fraction, ESP performance degrades, and motor cooling becomes insufficient. The researchers calculated that an increase in the free gas fraction to 40% results in a 50% drop in performance. They concluded that the ESP maintains stable operation at a gas ratio of up to 350 cm^3/cm^3, whereas at higher values, the motor rotational speed must be reduced to prevent overheating. These documented outcomes corroborate the modelling results obtained in this research.

An analysis of recent global studies confirms that deploying ESPs for gas well clean-up following HF presents no significant limitations in terms of equipment capabilities. While various case studies document ESP deployment for lifting gas-liquid streams to the surface, the specific scenario addressed by the proposed solution, characterised by a progressive increase in the gas-water ratio, has not been covered in existing literature. This validates the relevance of the research topic and highlights substantial potential for future studies. The availability of reliable post-fracturing clean-up technology, even under depleted reservoir pressure conditions, unlocks immense potential for applying stimulation methods in depleted Ukrainian fields. This, in turn, will ensure sustained gas production over the long term.

Conclusions

In order to resolve the issue of well clean-up under conditions of excessive overbalance, where conventional clean-up methods, such as direct air injection from the wellhead or using a CT unit to deliver inert gas to the bottomhole, result in the fluid column being forced back into the productive formation through the existing high-permeability fracture, thereby severely undermining the ultimate effectiveness of the stimulation, available global practices of artificial lift methods using ESP systems for fluid removal were reviewed. A comparative analysis of advanced technologies for temporary ESP deployment revealed substantial technological limitations and their impracticality for resolving the given objective. When deploying via CT, the well completion must be free of a production tubing string, as the outer dimensions of commercially available ESPs exceed the drift diameter of the production tubing. An additional risk in this scenario is CT parting during pump operation due to the extra loads exerted on it. Fishing the parted tubing would require killing the well, leading to deep colmatation (plugging) of the bottom-hole formation zone, which completely negates the stimulation effect. An alternative method, which eliminates ESP size constraints and reduces the risk of operational failures, involves deploying the pump on a wireline. In this setup, the pump requires a seating nipple on the tubing string, while both its installation and power supply are facilitated via the wireline cable. However, a major drawback that precludes the implementation of this method is the strict limitation on the ESP setting depth; the pump would be positioned significantly above the dynamic fluid level in the well, rendering its efficiency negligible under such conditions.

The proposed approach of deploying standard ESP systems which are widely used in oil production, on jointed production tubing eliminates the aforementioned drawbacks and can be implemented without additional capital expenditures. Particularly when operating in depleted reservoirs, the application of robust and relatively cost-effective solutions significantly enhances the economic viability of such projects. The results of calculations, software modelling, and the review of recent literature on the research topic demonstrate that the ESP deployment technique for recovering residual fracturing fluid despite presenting certain operational challenges, such as motor overheating and limitations when operating with high gas volume fractions, ultimately enables conducting stimulation operations in depleted reservoirs. If this technology is successfully implemented in the field, and fracturing candidate criteria are adjusted (specifically regarding current reservoir pressure), the number of stimulation jobs will increase. This will help maintain high gas production from existing wells. For further technology development, future research should focus on reducing the number of tripping operations during ESP deployment and retrieving the pump without killing the well.

Acknowledgements

None.

Funding

None.

Conflict of Interest

None.

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Застосування електровідцентрових насосів для освоєння газових свердловин з пониженим пластовим тиском після гідравлічного розриву пласта

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Анотація. З огляду на тривалу експлуатацію та виснаженість більшості українських родовищ, пошук ефективних методів відновлення їхньої продуктивності є пріоритетним завданням для енергетичної галузі України. Робота присвячена оптимізації процесу освоєння свердловин із аномально низьким пластовим тиском після інтенсифікації припливу методом гідравлічного розриву пласта. Метою дослідження було впровадження технології успішного вилучення рідини розриву, що дозволить значно розширити критерії підбору свердловин та успішно виконувати операції гідравлічного розриву на завершальній стадії розробки покладів газу. Проведено порівняльний техніко-економічний теоретичний аналіз трьох альтернативних технологій механізованого освоєння (електровідцентровий насос на гнучкій трубі, на кабелі та на збірних трубах) для вибору оптимального методу, враховуючи поточний стан газовидобувної галузі України. Дослідження базувалося на інженерних розрахунках, вузловому аналізі та аналізі гідростатичного дисбалансу на прикладі типової глибокої свердловини з пониженим пластовим тиском (4 150 метрів, 6,0 МПа). Розрахунок гідростатичного дисбалансу для умовної свердловини показав критичну надлишкову репресію на пласт, що унеможливлює освоєння без примусового механічного відкачування. Гідростатичний тиск стовпа рідини значно перевищує пластовий, що призводить до зворотного заштовхування рідини (fluid fallback) та в подальшому до пошкодження тріщини через кольматацію. При порівняльному аналізі вищезгаданих технологій, на основі теоретичних даних, встановлено, що технологія спуску насоса на кабелі («Rigless») є технічно непридатною для глибин понад 3 000 метрів, а технологія спуску насоса на гнучкій трубі є економічно недоцільною в умовах, коли верстат капітального ремонту вже змонтований на гирлі. Встановлення електровідцентрового насоса на збірних насосно-компресорних трубах є прагматичним та економічно обґрунтованим рішенням. Розраховано параметри необхідної компоновки та змодельовано повний цикл від етапу проведення гідравлічного розриву до запуску свердловини в роботу. Запропоновано прагматичний підхід, що дозволяє вилучити технологічну рідину розриву без репресії на пласт, використовуючи наявні ресурси з мінімальними додатковими витратами, що є критичним для рентабельності робіт по стимуляції виснажених покладів

Ключові слова: поклад; інтенсифікація; дебіт; тріщина; експлуатація; ремонт; колтюбінг