

A COMPREHENSIVE TECHNICAL ASSESSMENT OF WELL INTERVENTION OPERATIONS ACROSS ALL PVEP'S PROJECTS (2017 - 2021 PERIOD) AND RECOMMENDATIONS FOR ONGOING OPTIMIZATION

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Summary

This article provides a summary and assessment of well intervention activities, including perforation (add-perf/re-perf), acid treatment (acidizing), water/gas shut-off (WSO/GSO), hydraulic fracturing (HF), and electric submersible pump installation (ESP) at oil and gas production projects that the Petrovietnam Exploration and Production Corporation (PVEP) has participated in investment, operation, and optimization during the period of 2017 - 2021. Based on this, the effectiveness of well interventions in increasing production and reservoir recovery is evaluated. Additionally, the article analyzes lessons learned and proposes directions for optimizing well interventions for the next phase.

Key words: Well intervention, perforation, increased oil and gas production, electric submersible pump, water/gas shut-off, hydraulic fracturing, acid treatment.

1. Introduction

Oil and gas production wells are experiencing significant declines in production due to various factors such as contamination, sedimentation blocking pipes from the surface to the wellbore, and near-wellbore effects. Reduced pressure in the reservoir makes production conditions more difficult, and increased water/gas content negatively affects production efficiency. Using traditional technologies for wells with difficult-to-produce reservoirs faces additional challenges.

PVEP-invested oil and gas development projects also experience these challenges. To maintain or increase production, PVEP employs well intervention technologies such as treating sedimentation with acid (acid treatments), isolating multiple gas/water-producing layers (water/gas shut off), applying electric submersible pump technology

(ESP), optimizing systems by replacing gas lift valves, and perforating new zones (perforation).

As the increase of reserves insufficiently offsets the rapid decline, coupled with a decreasing number of new wells, well intervention becomes crucial to achieve annual oil and gas production plans in PVEP projects. This study aims to build a database and systematize well intervention activities, especially from 2017 to 2021, with the goal of minimizing costs and maximizing efficiency for the future. Through data analysis, the study recommends some directions to improve the effectiveness of well intervention by increasing production.

Well intervention methods are categorized into light intervention and heavy intervention. In light intervention, technicians insert equipment and sensors into the actively producing well while adjusting pressure from the wellhead equipment. In heavy intervention, production at the reservoir must be halted, and wellhead equipment needs to be dismantled to



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access the well directly. Tasks in this category include installing or replacing a new gas lift system, traditional electric submersible pump, replacing severely damaged production tubing, drilling new sidetrack wells among others... This article focuses on heavy well intervention methods.

2. Basis and research methodology

2.1. The necessity of evaluating well intervention activities

Most oil production wells at PVEP's joint ventures and projects have been operating for a long time and are currently experiencing a decline in output. Along with routine maintenance and repair to ensure the functionality of these wells, well intervention plays a crucial role in sustaining or even increasing production, slowing the natural production decline. Therefore, well intervention methods (such as perforation, acid treatment, water/gas shut-off, hydraulic fracturing, and electric submersible pump installation) applied during the 2017 - 2021 period have significantly contributed to boosting production and recovery for these fields. However, the success of these methods varies depending on the technology, implementation methods used, reservoir characteristics, wellbore features, geological conditions, and specific nature of oil and gas fields. Thus, a study has been conducted to build a well intervention database, extract lessons learned, and provide guidance for future well intervention activities.

In the period from 2022 to 2027, well intervention and repair will continue at production projects. To improve the effectiveness of these operations, gradually optimizing them, reducing costs, and continually supporting production increase while maintaining

production rates, a comprehensive assessment of well intervention activities during the 2017 - 2021 period must be conducted. Moreover, outlining the application of well intervention solutions from 2022 to 2027 is a timely, highly topical task, in line with PVEP's maintenance strategy and development needs.

2.2. Key well intervention methods

This study focuses on five well intervention methods having the highest potential to significantly contribute to increase production and improve economic efficiency: perforation (add-perf), downhole and near-wellbore sediment treatment (tubing cleaning and acidizing), water/gas shut-off (WSO/GSO), hydraulic fracturing (HF), and electric submersible pump (ESP) installation, as illustrated in Figure 1.

Solutions are selected based on annual workload and, more importantly, the potential to increase production and improve recovery factors. For instance, the perforation solution (Figure 1) is intended to establish a connection and a clear path between the near-wellbore region and the production tubing within the well. This operation is typically accomplished using slickline or e-line systems. In cases of high wellbore inclination, deployment of coiled tubing systems may be necessary. Perforation plan depends on surveying the well and the nearby ones to determine the depth of potential oil/gas-bearing formations. However, a plan to perforate any particular formation will be based on the overall field development plan (FDP/EDP). In the wells with multiple shared formations, an alternate perforating method is often implemented to minimize cross-well interference during production and optimize the recovery potential of each formation.

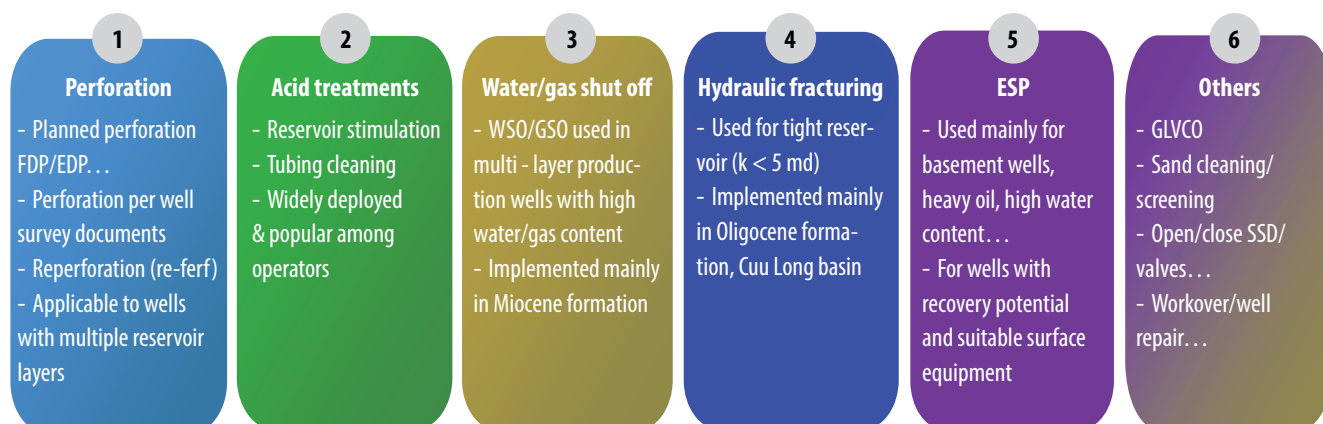


Figure 1. Well intervention solutions implemented at PVEP projects.

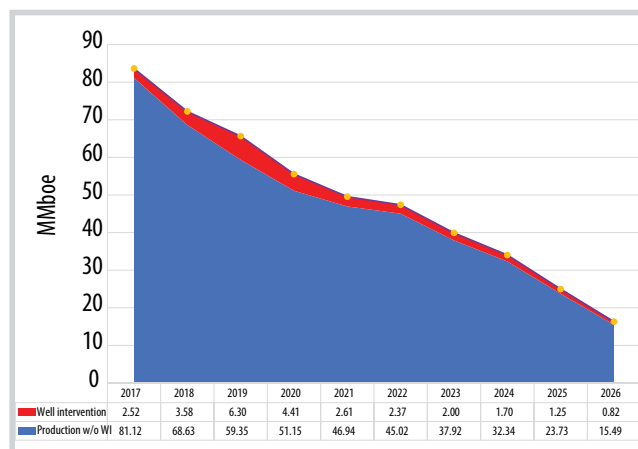


Figure 2. Contribution of well intervention to production during 2017 - 2026.

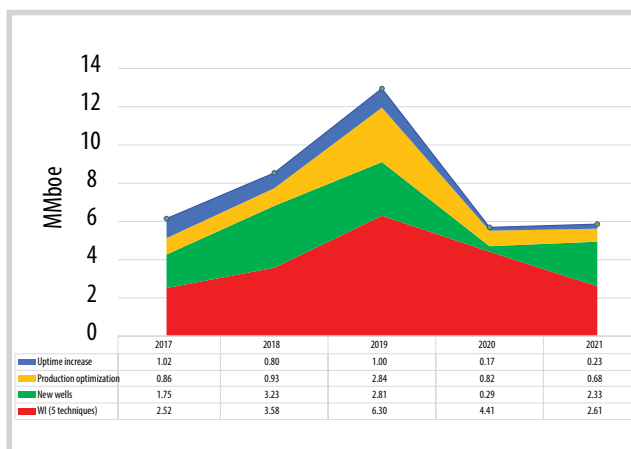


Figure 3. Effectiveness of reservoir recovery enhancement solutions during 2017 - 2021.

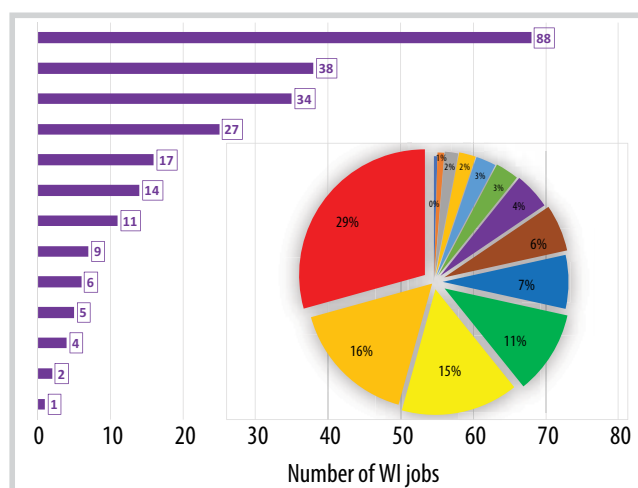


Figure 4. Well intervention by operators during 2017 - 2021.

3. Impact of well interventions on increasing recoverable hydrocarbon reserve in the period 2017 - 2021

In the period 2017 - 2021, five well intervention solutions helped increase production by approximately 19.42 million barrels of oil equivalent (MMboe), accounting for about 6% of the total production over those five years (Figure 2). The estimate of production contributed by well intervention in the period 2022 - 2026 is shown in Figure 2.

Figure 3 illustrates the effectiveness of the reservoir recovery enhancement solutions during the period 2017 - 2021. Compared to other solutions to increase production in the same period, it shows that well intervention plays a key role by constituting nearly 50% of the increased production. This proves the importance of these activities in the future.

3.1. Number of well intervention operations and the increased production

Well intervention was actively implemented in the context that newly drilled wells were less, and the total

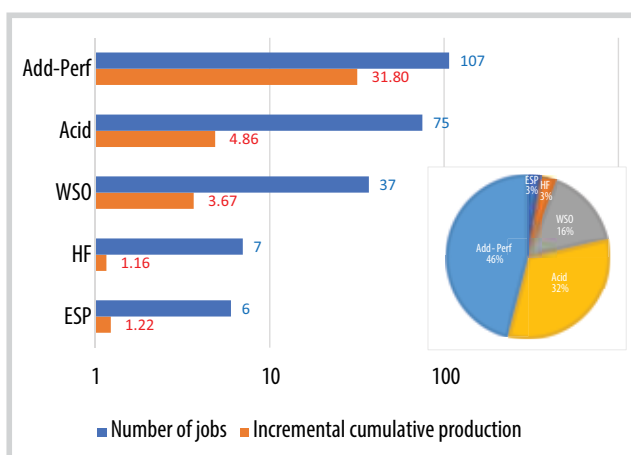


Figure 5. Well intervention and the corresponding production increase (MMboe) by methods.

number of wells was naturally declining. Figure 4 shows the number of wells for each project, with nearly 260 well intervention operations during the period 2017 - 2021. An operator in Cuu Long basin is the most active one with 88 operations.

Figure 5 presents the number and proportion of well interventions classified as perforation, acid treatment, water shut-off, hydraulic fracturing, and electric submersible pump installation, along with corresponding increased recovery (MMboe). Perforation is the most applied method (107 operations), providing the highest production increase (31.8 MMboe).

The increased production for each well intervention solution during 2017 - 2021 is shown by year in Figure 6. Well intervention operations in 2019 brought the highest production increase with 6.3 MMboe. Figure 7 illustrates the budget for well intervention and work-over (WO) by years with USD 78.39 million for well intervention, lower than USD 145.96 million for work-over.

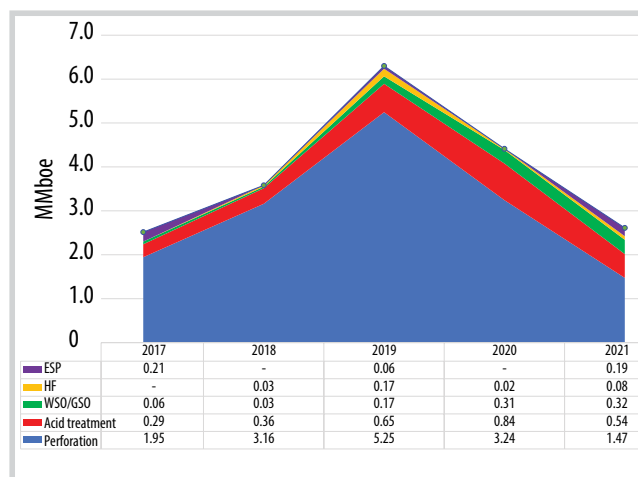


Figure 6. Production increased by well intervention solutions in 2017 - 2021.

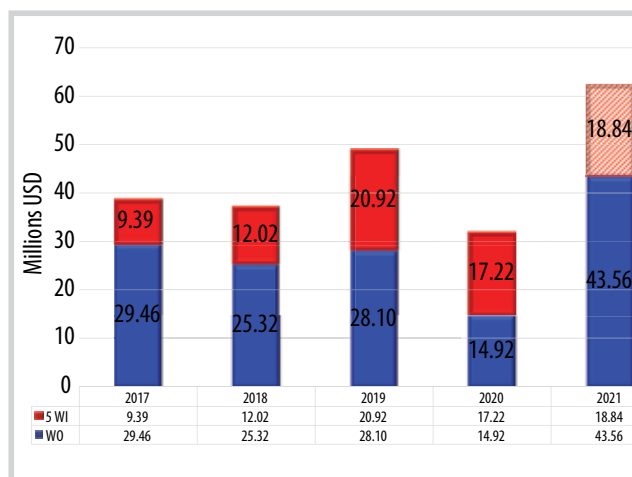


Figure 7. Budget for well intervention and well work-over by years in 2017 - 2021.

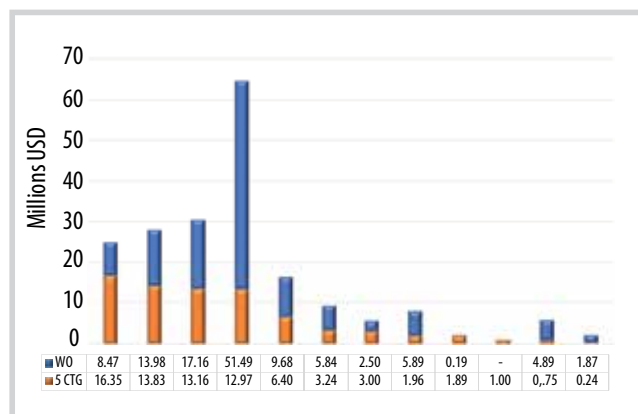


Figure 8. Budget for well intervention and well work-over by operators, 2017 - 2021.

Figure 8 represents the budget for well intervention and well work-over during the period for each project, with an operator in North Malay basin having the largest budget.

The data and analysis show that PVEP's well intervention in 2017 - 2021 significantly contributed to the increased production and successfully stabilized the overall operation at various fields with reasonable costs. The top four operators that actively implementing well intervention contribute 187 operations in the period. Perforation, water shut-off, and acid treatment accounted for 94% of all well intervention operations. Perforation was the most common method, constituting 46% of the total, with low costs and the highest efficiency, contributing to 78% of the total increased production. However, the remaining potential for this method is not abundant anymore in the next period. Economically, the total cost for well intervention during 2017 - 2021 was USD 78.39 million, resulting in a recovery of 42.7 MMboe (calculated from 2017 - 2026+) with an average price of USD 1.84 per barrel of oil equivalent.

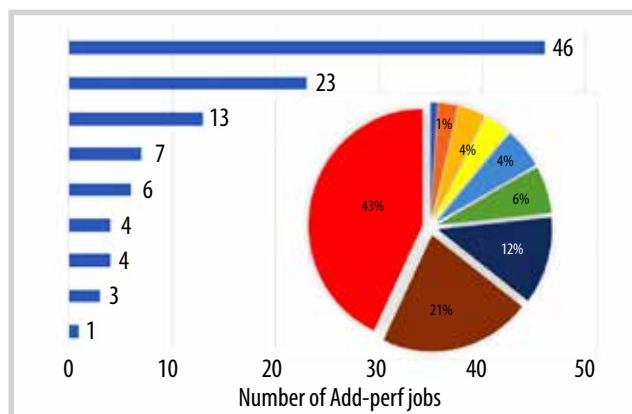


Figure 9. Number of perforations by operators.

3.2. Perforation method (Add-perf and Re-perf)

3.2.1. Introduction

Perforation is the most effective among well intervention methods applied at PVEP's projects during the period 2017 - 2021. It is carried out on wells that have been previously drilled, and the order of perforation is commonly applied across various fields.

3.2.2. Perforation cost and production increase

During 2017 - 2021, the operators of oil and gas fields in PVEP's projects conducted 107 perforations, of which 83% (89/107) was conducted by the top four most active operators (Figure 9). The yearly statistics for the number of perforations during this period are presented in Figure 10.

In 2019, the number of perforations increased significantly while the cost reduced considerably, only USD 0.56 per barrel of oil equivalent. It was due to perforating new gas layers in North Malay basin project and new oil layers in two operators in Cuu Long basin. The

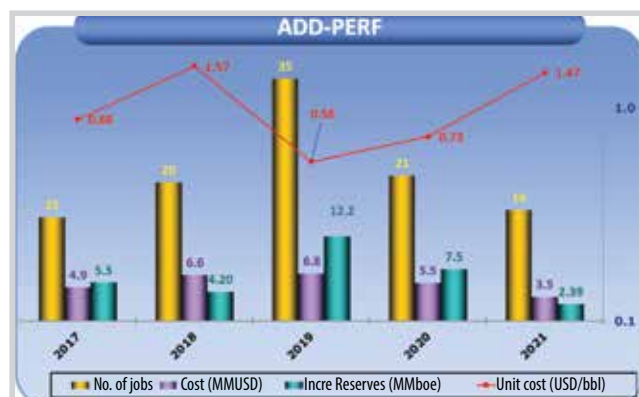


Figure 10. Number of additional perforations by years.

effectiveness of perforations by operators was shown in Figure 11.

Through the statistical chart, it can be seen that the operator in North Malay basin project has the highest contribution from producing reserves, mainly due to the potential of new gas fields, with high recovery due to oil conversion from gas. The well opening operation in an operator in Cuu Long basin achieved the highest efficiency.

3.2.3. Reasons for unsuccessful well perforation operations

Out of 107 well opening operations, 13 (12%) had actual results worse than expected (about 10% lower), primarily due to the following reasons:

- Perforating wells to assess the potential of reserves, evaluate the production capacity of new targets, or maximize resource recovery.
- Difficulties in field execution: Shooting through sand screens led to poor effectiveness; failure to shoot through stuck points (HUD); guns not activating (misfire), etc.
- Unpredicted reservoir characteristics: Poor reservoir characteristics; difficult to predict S_w behind casing.

3.2.4. Assessing perforation operations and proposing measures to implement

Though perforation is the most efficient among well intervention solutions, its contribution in the future will decrease as most wells with potential have been put into production. Therefore, it is necessary to strengthen technical research, evaluation, and screening of the potential for opening the remaining wells (prioritizing those that have ceased production).

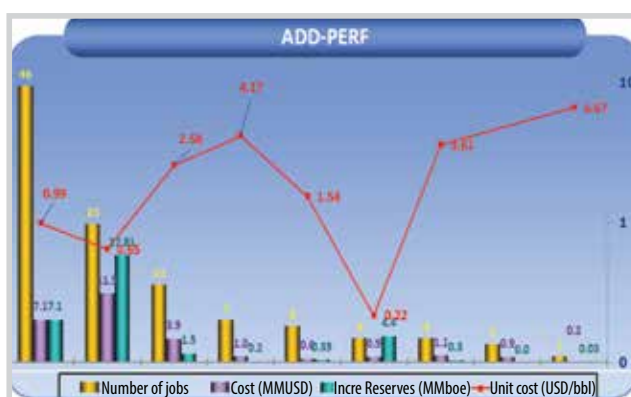


Figure 11. Perforation effectiveness by operators.

PVEP needs to coordinate closely with operators to implement a combined approach of well opening and other well intervention methods as part of the campaign, also try to take advantage of any shutdown time for well maintenance. Research and integrate opening technologies to optimize costs. For new wells, especially the infills, trajectories should be optimized to drill through multiple layers; utilize well opening to exploit thin and small layers.

The well perforation targets need to be reviewed by experienced specialists given that necessary data is sufficiently provided to minimize risks and increase the success rate. The action plan should be reviewed early for each wellbore to ensure the feasibility of well opening operations, and specific steps should be taken with the support of experts and specialized software.

Before a well opening, operations using wireline should be conducted to assess the condition of production tubing (deviation of the well, casing diameter, check for corrosion/deposits/sand in the well, etc.). For wells with large inclinations (higher than 55°) and buckling, it is proposed to use slickline roller stem (SRT) attached under the wireline equipment to carry out well opening campaigns. With SRT, the possibility of successfully opening wells in the future will be higher.

3.3. Acid treatment method

The acid treatment method is employed for tubing cleaning and sediment treatment in the near-wellbore and reservoir areas. Acid is commonly used to dissolve sediments that affect the reservoir's productivity or the well. When cleaning the production tubing, chemicals are either pumped down or directly sprayed using coiled tubing into the sediment-affected section of the tubing. After a period, the sediments and chemicals are allowed

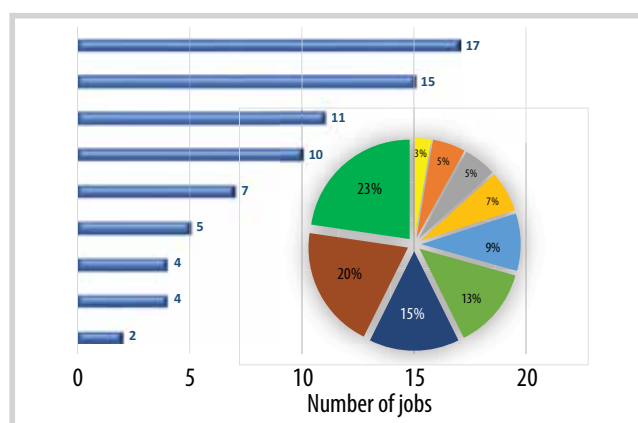


Figure 12. Number of acid treatment operations by operators/projects.

to flow back to the surface to prevent clogging the reservoir. Cleaning the production tubing is sometimes performed as a preparatory step before treating reservoir sediments. This step ensures that the chemical volume calculated for the main treatment is just adequate for interacting only with the sediments in the reservoir, not with the sediments in the tubing wall. In the treatment of sediments in the near-wellbore and reservoir, the main goal is to address the sediment clogging during production or other operations (drilling, completion, etc.) to restore the reservoir to its initial productive state. When treating carbonate formations, the acid treatment method can create new wormholes in the reservoir, enhancing the reservoir's productivity.

The first basis for implementing acid treatment is to meet the annual production plan. The selection of wells for treatment depends on the results of downhole equipment surveys or well surveys. Surveying downhole equipment, such as running a fractured rock sample measuring tool, can precisely determine the point where sediment adheres to the tubing wall when equipment jamming occurs. Closing these sediments can also be detected through wellbore pressure models when a significant pressure drop in the wellbore occurs compared to normal conditions. Sediment closure in the production tubing does not affect wellbore surveys for calculating skin. Wellbore surveys, often conducted by pressure buildup surveys, involve producing the well at a stable rate and then shutting it in for a period to obtain pressure information that changes over time. The survey results can be used to calculate reservoir permeability, skin, etc. The final basis before implementing acid treatment is to evaluate the economic efficiency of the operation. Increased production efficiency can be estimated in models when the pressure drop in the production tubing

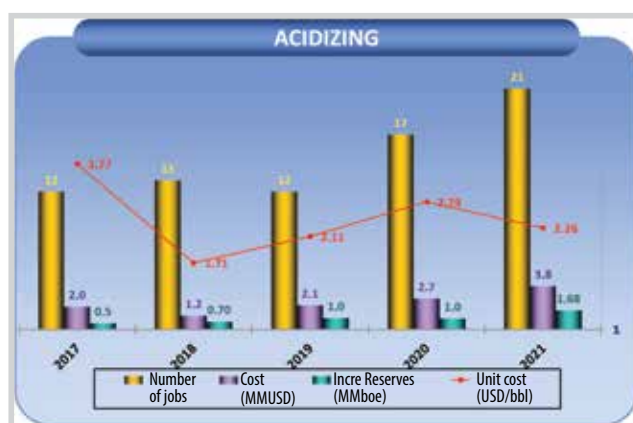


Figure 13. Number of acid treatment (acidizing) jobs by years.

or skin in the reservoir is reduced after treatment, resulting in higher flow rates.

Figure 12 presents the total number of acid treatment operations in nine projects recorded from 2017 to 2021.

Figure 13 shows the annual operations of acid treatment (including tubing cleaning and reservoir sediment treatment), construction costs, and increased production efficiency. Average costs per operation are calculated and presented in the figure. From 2017 to 2019, the number of operations remained relatively constant. However, treatment effectiveness varied. Specifically, in 2017, the treatment of reservoirs at an Operator in Nam Con Son basin was unsuccessful, resulting in the smallest production increase, while having the highest average costs in those years. In contrast, 2018 showed low costs for cleaning production tubing, particularly in a project in Cuu Long basin, which yielded similar efficiency. The following years underscore the necessity of acid treatment, with an increasing number of jobs to meet annual production targets.

Figure 14 illustrates the number of acid treatment operations at an operator in Cuu Long basin being the highest, with the lowest average costs. The production efficiency increase at this Operator is also very high compared to other projects. This positive result demonstrates the effective combination of low-cost operations (tubing cleaning) and sediment treatment in the wells. This operator is actively researching improvements in sediment layer treatment to achieve even higher efficiency.

Various factors can lead to poor or unclear results in acid treatment, including but not limited to construction methods, poor reservoir characteristics, and declining reservoir pressure. Construction methods, including

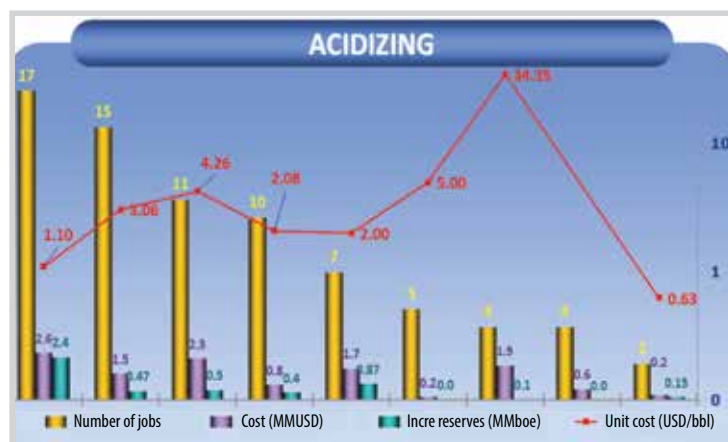


Figure 14. Acid treatments by projects.

Common application	Acid treatment currently contributes approximately 14% of the total incremental production of WI solutions, especially at some big operators. The majority of acidizing jobs are for production pipe cleaning, accounted for 60% of all jobs.
Recover well flow capacity	Especially effective in wells with reduced PI due to formation damage, low WCT. Low efficiency with wells of highly declined reservoir pressure, high WCT.
Short time effectiveness	The acid treatment effective time is short (3 - 6 months) depending on the mechanism of downhole contamination. It is necessary to consider acidizing multiple times during well production process.
Research enhancement	Continue researching/applying acid treatments for Cuu Long basin basement due to the high probability of success.
Operator coordination	Coordinate with operator in optimizing the acid treatment systems, optimizing the time/method of acidizing operation, sharing experiences among operators.

Figure 15. Conclusions on acid treatment.

chemical systems and methods of introducing chemicals into the formation, are critical for the success of acid treatment. An operator in Cuu Long basin deployed various chemical systems for sediment treatment, but the results were not consistently successful until the introduction of Volcanic acid II. Another operator canceled the reservoir sediment treatment because the pumping test results showed poor acceptance, below 1 barrel per minute. A basement oil producer in Cuu Long basin is a very typical example where acid treatment effectiveness strongly depends on reservoir pressure. In the period 2017 - 2019, this well achieved a very high production efficiency increase (around 1,500 barrels of oil per day), but the effectiveness did not meet expectations in subsequent years when reservoir pressure significantly decreased.

Figure 15 gives an insight into acid treatment work. This method, including tubing cleaning and reservoir sediment treatment, is widely applied across projects, ranking second in the total number of well intervention solutions. Tubing cleaning accounts for 60% of all acid treatment operations and contributes 14% to the total production efficiency increase of all well intervention solutions.

With specific characteristics of wells in different projects, the purpose of acid treatment is primarily to restore the flow capacity of the well. However, the effectiveness may be low for wells with significantly reduced pressure and high water cut. Since the effectiveness of this method only lasts for 3 - 6 months, acid treatment may need to be periodic. To ensure a high production efficiency increase, continuous research is required to optimize the acid treatment method, especially for reservoirs in the Cuu Long basin. Additionally, to minimize cost and enhance economic efficiency, collaboration with operators is needed to optimize construction time/methods and share experiences among operators.

The synthesis of experiences in acid treatment outlined above indicates the inherent risks and the need for thorough research. With an increasing number of acid treatments over the years, in addition to proposing and evaluating a standardized process for each well, new technologies and approaches to safely treat downhole equipment and address multiple types of sediments simultaneously require in-depth research.

3.4. Water/gas shut-off (WSO/GSO) method

The water/gas shut-off (WSO/GSO) method is applied when the water/gas content in the produced oil stream becomes excessively high, affecting production efficiency. The proposed basis for applying this method includes the annual production plan, actual field operation, nearby well experience, well structure, reservoir layers, and economic efficiency. The annual production plan is related to the government/Petrovietnam's plan assigned to PVEP, gas purchase contracts (GSPA/GSA), and other production plans. This method is applied when the actual field operation has water/gas flow rates that excessively impact well production and surface equipment performance. Furthermore, based on experience, successful results from nearby wells where WSO/GSO has been effective are considered when the application of this method is evaluated. The application of the WSO/GSO method is also considered for wells with multi-layer exploitation, multiple reservoirs, and the determination of the

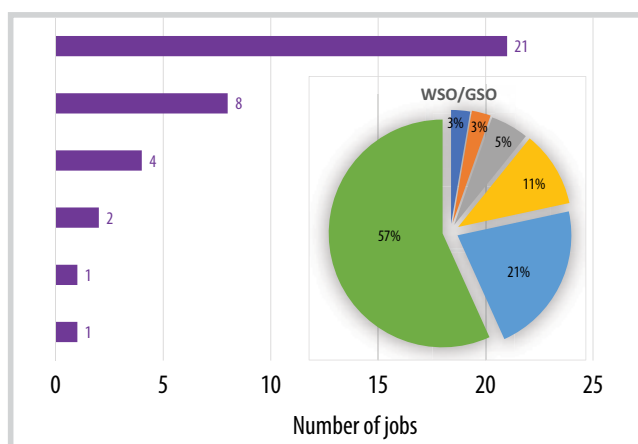


Figure 16. Water/gas shut-off jobs by operators.



Figure 17. Water shut-off jobs, cost and increased production by operators during 2017 - 2021.

Mechanical method

Mechanical WSO (Straddle packer, tubing pack-off, bridge plug...):
 + Contribute ~4.6% of total incremental production from WL
 + Carried out mainly in multi-layered production wells with high WCT.

Chemical method

+ Limited implementation, unclear results.
 + High cost: lab research required & complex operation.
 + Some operators in the feasibility study stage or about to implement in 2021.

Efficiency

+ WSO/GSO: the efficiency will gradually decrease in the future depending on the potential of the remaining reservoir candidates.

Figure 18. General findings on water shut-off work from 2017 to 2021.

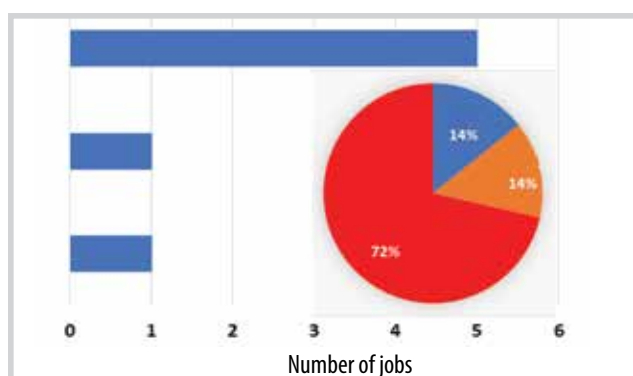


Figure 19. Number of hydraulic fracturing jobs by operators during 2017 - 2021.

flow distribution at different layers. Ultimately, applying the WSO/GSO method must ensure cost recovery and economic efficiency.

Figure 16 shows the number of WSO/GSO jobs implemented by various operators. The most active operator in this aspect applied the WSO/GSO method most frequently from 2017 to 2021, with 21 jobs, accounting for 57% of total WSO/GSO jobs by operators.

Figure 17 provides information on the number of WSO/GSO jobs carried out by operators, along with costs and the increased production efficiency. The most active operator achieved the highest production increase with 1.5 million barrels of oil.

Water shut-off tasks were mainly conducted by two operators in Cuu Long basin, accounting for 78% of the total jobs. In 2018, an operator in Song Hong basin successfully shut off gas in one well with high efficiency and low cost. In contrast, the water shut-off task in a gas well in Nam Con Son basin was unsuccessful, inefficient, and costly (in 2019). An operator in Cuu Long basin performed water shut-off in an oil well unsuccessfully.

Some WSO/GSO tasks are not effective, or their effectiveness is unclear due to various reasons: low reservoir potential, testing chemical methods for water shut-off, equipment installation issues, and more. For instance, an oil well showed no effectiveness, with no increase in flow rates before and after water shut-off, as the remaining reservoir potential was low. Water shut-off activities for a gas well in both 2017 and 2019 campaigns used chemical methods and were either ineffective or minimally effective. Another water shut-off for a gas well in 2018 campaign was also ineffective due to the poor potential of the remaining reservoir.

Some unsuccessful water shut-off tasks include an oil well, where equipment got stuck during execution, and a gas well (2017 campaign) was unsuccessful due to the failure to set the isolation packer (BP). In the 2019 campaign, there were unclear results, and the isolation packer was not successfully retrieved. Other unfavorable factors affecting WSO/GSO include the lack of PLT data or outdated PLT data.

Figure 18 provides a general overview of gas/water shut-off tasks (mechanical and chemical methods).

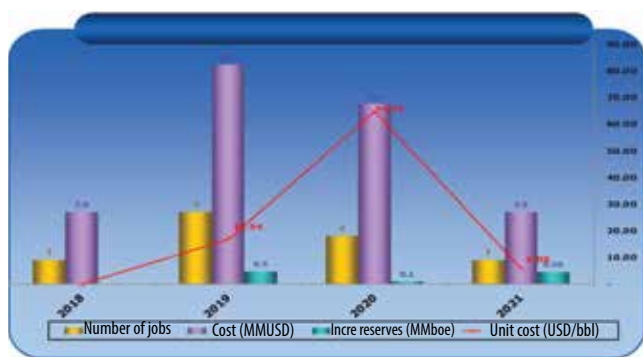


Figure 20. Hydraulic fracturing jobs by operators during the period 2017 - 2021.

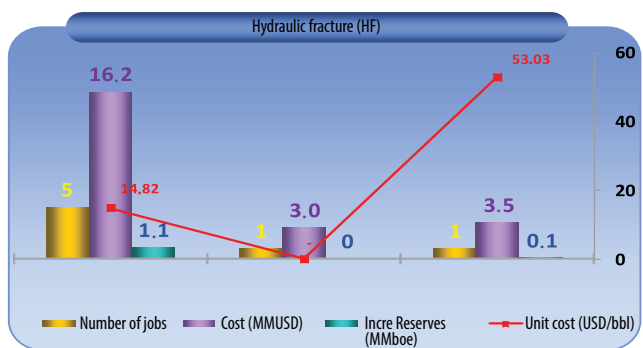


Figure 21. Hydraulic fracturing jobs by operators - costs and production increase.

Limited application	Not yet widely implemented in PVEP's on-going projects (mainly implemented in Oligocene D wells in Cuu Long basin).
Highly effective near wellbore treatment	Highly effective in terms of near wellbore technical treatment
Unique method	It is the only viable technical method for production from tight formation reservoirs (Oligocene C/D formation, Cuu Long basin).
High success rate	High technical success rate (~70%) for Oligocene formation, Cuu Long basin
Cost optimization	Due to the high cost, it is necessary to thoroughly research before deploying. To optimize HF efficiency, it is necessary to collect enough data on geomechanical properties and rock contents to optimize the design/operation program.

Figure 22. General findings on hydraulic fracturing during 2017 - 2021.

The WSO/GSO method is typically applied to multi-layered well structures producing from multiple reservoirs and determining the allocation of flows at different levels. It is crucial to successfully determine the actual component flow rates from each producing layer, and hence PLT measurements are necessary and recommended for potentially applicable wells undergoing WSO/GSO tasks.

Isolating producing layers that are not the subject of WSO/GSO tasks should be carried out before implementing gas/water shut-off. Measurements of well completion quality and cement quality need to be completed before planning WSO/GSO tasks.

3.5. Hydraulic fracturing (HF) method

Hydraulic fracturing method is commonly applied to reservoirs with low permeability (less than 5 mD) and large reservoir thickness (higher than 10 m). To apply this method, it is proposed to consider the annual production plan, actual field operation, experience gained from neighboring wells, well structure, reservoir barriers and the number of reservoirs, quality of well facility, and economic efficiency. The annual production plan is related to the government/Petrovietnam plan assigned to PVEP, the field's production strategy, and other production plans. Additionally, based on the experience gained from neighboring wells, the historical effectiveness of hydraulic fracturing in wells with similar reservoir/well conditions that yielded positive results is considered when evaluating the application of this method. The application of hydraulic fracturing must ensure cost recovery and economic efficiency.

Figure 19 shows the number of hydraulic fracturing jobs conducted by various operators, among them an operator in Cuu Long basin is leading with 5 jobs out of total 7 from 2017 to 2021. This intervention method is limitedly applied, mainly by some operators in Cuu Long basin, and an onshore abroad project of PVEP due to its high cost and specific requirements for well structure/equipment. In Vietnam, hydraulic fracturing is primarily applied to the Oligocene layers in Cuu Long basin due to its tight reservoir characteristics. In 2020, only 2 hydraulic fracturing jobs were carried out at two operators in Cuu Long basin, and both were unsuccessful. Figure 20 illustrates the number of hydraulic fracturing jobs during the period 2017 - 2021 among various operators. In 2019, there was the highest cost and most increased production efficiency (Figure 20). Cost and production increase by operators are shown in Figure 21, with the most active operator having the highest number of wells applying hydraulic fracturing and the highest total costs.

Some hydraulic fracturing jobs lack efficiency due to various reasons such as the target of hydraulic fracturing being near the oil-water contact, very poor reservoir characteristics (super tight), limited recovery potential of the reservoir, and issues related to design, execution, and operation of hydraulic fracturing tasks. Examples of unsuccessful well interventions due to poor reservoir characteristics include an onshore well, which experienced water flooding and ceased production after hydraulic fracturing near the oil-water contact.

Unsuccessful well interventions due to tight reservoir characteristics and wells with no flow, and poor reservoir characteristics, which achieved a flow rate of only ~ 200 barrels of oil per day for a short period due to proppant washout and poor reservoir quality. An oil well did not show an increase in production after hydraulic fracturing due to limited recovery potential of the reservoir.

Figure 22 presents general observations on hydraulic

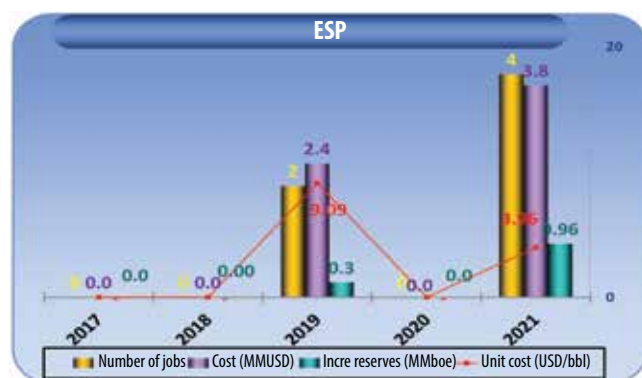


Figure 23. ESP installation work by years during 2017 - 2021.

Research

- Research team setup: need to define the chair/coordination board for implementation;
- Specific research: practical documents and actual lessons learned about ESP in Vietnam and around the world (PVEP internally).

Screening

- Screening: PVEP conduct researches on developing criteria for applying ESP. Pump selection: in accordance with the desired HC flow rate and BHP; Well completion allows for feasible design changes at a low cost...

Evaluation

- Life-time evaluation of ESP;
- HC recovery & economic evaluation.

Equipment modification

- Ability to: modify WHP, reinforcing-expanding deck;
- Capability for: additional electrical equipment, panel...
- Study the ability to connect the power cable from Cpp/FPSO to WHP.

Trial application

- Select the suitable reservoir/well for trial application before widespread the solution.

Figure 24. Directions for the future ESP installation work.

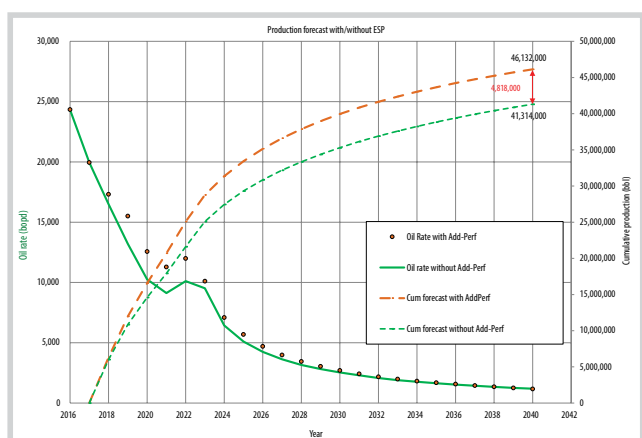


Figure 25. Forecast of production output with and without reservoir perforation in the in oil field, Cuu Long basin.

fracturing work during the period 2017 - 2021.

The hydraulic fracturing method is a technically efficient approach for dealing with near-wellbore regions and is also the only feasible technical method for producing tight reservoirs (Oligocene C/D layer in the Cuu Long basin). This method has not been widely implemented in PVEP's ongoing projects and should be researched for more widespread application. The technical success rate of hydraulic fracturing in the Oligocene layer of the Cuu Long basin is high (around 70%). Due to the high cost of hydraulic fracturing, thorough research is necessary before implementation. To optimize effectiveness and cost efficiency, it is crucial to collect sufficient data on the rock's physical properties and mineralogical composition for the optimal design/construction program.

The hydraulic fracturing process involves selecting treatment equipment, choosing fracturing fluid, selecting proppants, and determining optimal fracture apertures. In this process, treatment equipment needs to be compatible with the equipment already present in the well and the current well design. The selection of fracturing fluid and proppants must be studied to align with the hydraulic fracturing target, aiming for optimal results. Fracture apertures can be simulated using computer models to provide additional information about the hydraulic fracturing outcomes.

3.6. Electric submersible pump (ESP) installation method

Electric submersible pump is a method capable of significantly increasing production rates. For PVEP projects, ESPs can provide flow rates of up to 12,000 barrels per day. With this outstanding advantage, the basis for ESP installation depends on production plans, including but not limited to government/Petrovietnam plans and other production plans. However, before implementation, the experience obtained from deploying and operating ESPs in similar wells should also be considered. Unlike other well intervention methods detailed in this scientific study, ESPs must have compatibility with both surface and downhole equipment throughout the operation. For surface equipment, a separate power system is required to supply the ESP. Equipment on the platform, such as variable frequency drives, junction boxes, cable venting boxes, and wellheads, is essential to ensure ESP operation. For well design, the ESP is typically suspended at the end of the production tubing, with the size depending on the casing size. Well inclination, depth, and temperature also play crucial roles in the successful deployment of

ESPs. With the potential to meet high flow rates, the reservoir's production potential must be sufficient to justify ESP installation. Additionally, the fluid properties must be examined to ensure successful deployment. ESP installation must ensure economic efficiency as the deployment cost is high compared to other methods.

Figure 23 illustrates the ESP installation work carried out in the years 2017 - 2021. All ESP deployment work was done an operator in Cuu Long basin, with 2 pumps installed in 2019 and 4 wells using ESPs. The average cost for ESP installation in 2021 was much lower than in 2019, partly due to the combination of tasks during the 2021 installation, minimizing mobilization/demobilization costs. Figure 24 outlines the necessary directions for future ESP installations.

The technology for ESP deployment is currently divided into two main methods: traditional technology and non-rig technology. Regarding the former, ESP is directly attached to the end of the well completion assembly, with the power cable running along the outside of the production tubing and connecting to the motor. However, in this method, replacement or repair requires lifting the entire well completion assembly to the surface, leading to high costs. Additionally, the power cable and electric connections directly contact the production environment inside the well, posing a risk of damage. Non-rig technology uses a cable or coiled tubing to suspend the ESP within the well. Using a cable or coiled tubing, the power cable goes directly into the motor without the need for connections. This minimizes the risk of cable damage. Moreover, repairs or replacements can be done without the need for a rig, significantly reducing associated costs.

Several methods have been used to assess the effectiveness of ESP applications. The first evaluation criterion is the operating time of the pump system. With the ability to produce at high flow rates due to generating a significant pressure drop, when the ESP stops operating, no other lifting method can meet the production target. Therefore, maintaining operational conditions using ESPs directly affects economic efficiency. Subsequent methods aim to evaluate the economic efficiency of deploying ESPs in a project to serve as a basis for future installation campaigns. Calculations can be based on the economic efficiency of each well, each campaign, or historical deployment. Finally, the increased recovery factor's effectiveness also needs to be assessed, although implementation will be more challenging than other evaluation methods. A

typical example is the wells in the basement layers in Cuu Long basin, where after ESP installation, the oil flow rate increased significantly, with water cut decreasing in the initial stage. The hypothesis is that, in the initial period with high drawdown, ESPs can help produce oil from small fractures that gas lift cannot reach.

3.7. Evaluation of recoverable reserve volume increased by well intervention activities

Well intervention such as acid treatment, gas shut-off/ water shut-off, scale treatment, re-fracturing for low-flow zones, and wellbore workovers are strategic solutions focusing on maintaining production rate and well recovery to achieve production goals. Solutions like hydraulic fracturing and electric submersible pump installations not only increase production but also enhance recoverable reserve volume. To analyze and quantify the difference between increased production and increased recoverable reserve, it is necessary to separate production in a given year from increased recoverable reserve volume, then evaluate based on recoverable volume. Calculations, assessments, and quantifications of increased recoverable reserve volumes for well interventions at some typical fields have been conducted.

3.7.1. Evaluation of increased recoverable volume at the oil field A

Fracture stimulation solutions were applied to wells in the field A, Cuu Long basin. The updated production model from the operator was used to run production simulation for calculating the production volume difference for cases with/without fracture stimulation. The calculated results show an increased recoverable volume of 4,818 million

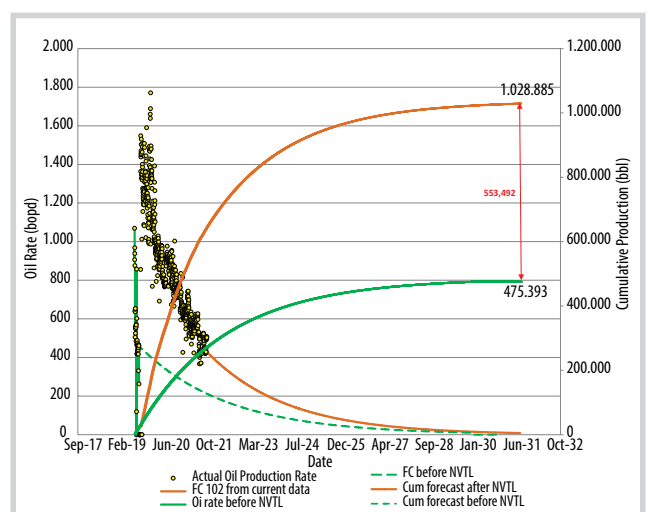


Figure 26. Forecasted production rates with and without HF for a well in field A.

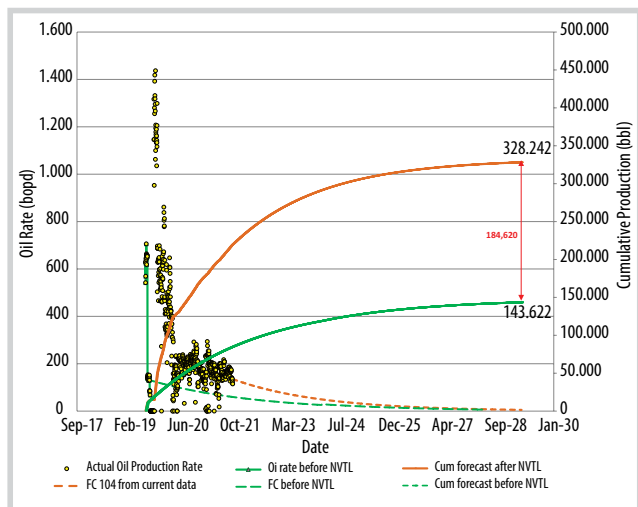


Figure 27. Forecasted production rates with and without HF for a well in field A.

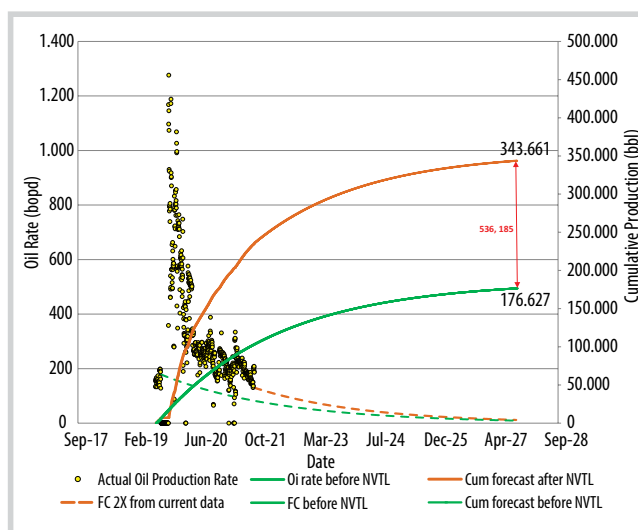


Figure 28. Production forecast with and without HF at an oil well in field B.

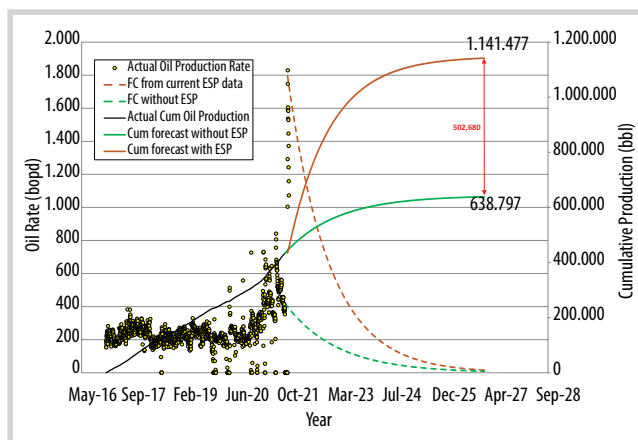


Figure 29. Production forecast with and without ESP at an oil well in field B.

barrels from 2017 until the end of the field's life (2040) (Figure 25).

3.7.2. Evaluation of increased recoverable volume at oil field B

The hydraulic fracturing solution to increase recoverable reserves has been applied exclusively to 3 wells in Oligocene formation of field B, Cuu Long basin.

To assess the recoverable reserve for this case, the reservoir model method was not chosen due to significant risks associated with limited historical data, the operator's operating characteristics, and the scarcity of surveyed production data (monthly flow rates and yearly pressure survey data for each well), leading to challenges in the history-matching process for wells without HF conducted on a daily basis. The HF model needs to be optimized, with the related risks taken into account: the HF model requires optimization of the geo-mechanical properties of rocks and other parameters. However, the parameters set in the exploitation model have not been investigated for the sensitivity of the HF parameters. Currently, these parameters are adjusted to match the history of pressure and exploitation

Therefore, they are not optimized for HF research. In the HF process, only a keyword is used to simulate the history matching of a pressure point. The unclear connectivity risk in the exploitation model, due to the lack of HF tests at this oil field, prevents the determination of the actual connectivity capacity in the formation. Therefore, the decline curve analysis (DCA) method has been chosen to calculate the recoverable reserve differences for cases with/without HF. Figures 26 - 28 show the forecasted production output charts for cases with/without HF corresponding to three wells. Calculations from the DCA method indicate an increased recoverable reserve for all three wells due to the HF solution from 2019 to the end of the field life (2031), totaling 905 million barrels.

3.7.3. Evaluation of increased recoverable reserves for oil field C

The ESP solution has been applied exclusively to three wells in field C, Cuu Long basin.

The DCA method has been chosen to calculate the recoverable reserve differences for cases with/without ESP installation using actual production data. Figures 29 - 31 show the forecasted production output charts for cases with/without ESP installation corresponding to three wells. The calculation results from the DCA method indicate an increased recoverable reserve for all three wells due to the installation of ESPs from 2017 to the end of the field life (2027), totaling 1.275 million barrels. The calculation of recoverable reserves increased by well

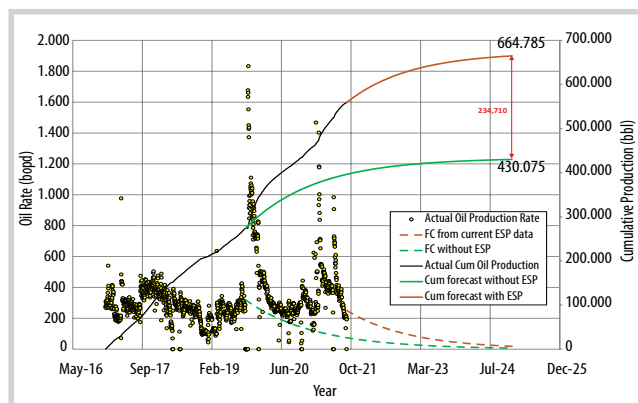


Figure 30. Production forecast with and without ESP at a well in field C.

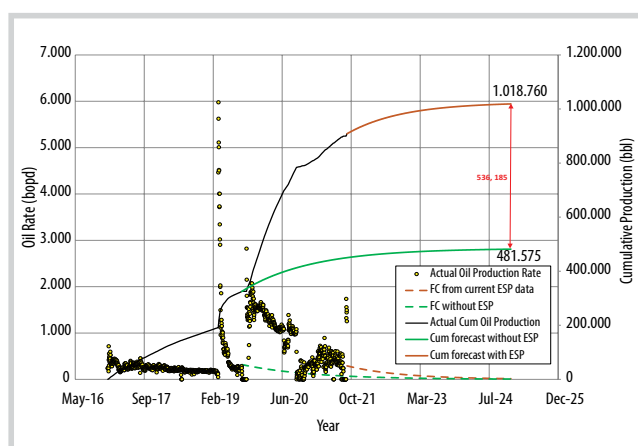


Figure 31. Production forecast with and without ESP at a well in field C.

interventions, including reservoir perforation, hydraulic fracturing, and ESP installation, shows that these solutions contribute significantly to increasing recoverable reserves.

The calculations show the total increased recoverable reserve for the above 3 fields is ca. 6.998 million barrels from around 2017 to the end of the field life.

The calculation results for the increased recoverable reserves for an operator in North Malay basin using the reservoir perforation method have also been provided by the operator, with 23 wells perforated and an increased recoverable reserve of ~17.811 million barrels. Table 1 summarizes the results of the increased recoverable reserve analysis.

In addition to the immediate effects of well interventions in increasing production, some measures also significantly contribute to the incremental recoverable reserve volume of each well as well as the entire field (Table 2).

4. Conclusion

Based on lessons from 2017 - 2021 well intervention activities in PVEP’s projects, in order to maintain and improve the effectiveness of this work in the next period, it is highly recommended to:

Table 1. Summary of increased recoverable reserve analysis results

WI method	Time (years)	Cum. Oil w/o WI (bbl)	Cum. Oil w/WI (bbl)	Incremental oil (bbl)	Incremental oil (%)
Add-perf	13	41,314,000	46,132,000	4,818,000	10.44
HF	12	475,393	1,028,885	553,492	53.80
HF	10	143,622	328,242	184,620	56.25
HF	9	176,627	343,661	167,034	48.60
		795,642	1,700,788	905,146	53.22
ESP	10	638,797	1,141,477	502,680	44.04
ESP	10	430,075	664,785	234,710	35.31
ESP	10	481,575	1,018,760	537,185	52.73
		1,550,447	2,825,022	1,274,575	45.12
	Total	43,660,089	50,657,810	6,997,721	13.81
Add-perf				17,810,885	

Table 2. Results of increased recoverable reserve analysis by oil and gas production volume

Hydrocarbon production	Well intervention results for the period of 2017-2021				
	Total annual incremental recoverable volume from 2017 - 2021	Accumulated incremental recoverable volume recovered by July 2021	Remaining incremental recoverable volume from August 2021	Total incremental recoverable volume from implemented well intervention solutions	
				By well	By field
Oil (MMbbl)	6.94	18.39	8.26	26.65	8.85
Gas (MMboe)	12.48	12.48	3.57	16.05	15.63
Total oil & gas (MMboe)	19.42	30.87	11.83	42.70	24.48

- Focus on and prioritize solutions delivering quick return on investment, low costs, and low risks (such as acid treatment, water shut-off, reservoir perforation, etc.).
- Research and evaluate high-cost solutions feasible for potential fields/projects (such as submersible pump installation, hydraulic fracturing...).
- Maximize the combination of well intervention solutions in the same campaign for the best possible efficiency (optimize the number of campaigns within the same operator, combine multiple operators).
- Recommend operators to carry out tasks: Research; prioritize, organize workshops; propose implementation...
- Recommend operators to submit to PVEP annual report on summarizing the results of well intervention applications, including tasks implemented, remaining potential, and future directions.
- Recommend relevant authorities to provide detailed guidance: Encourage operators to research, evaluate, and test potential small remaining reservoirs in production wells, minimize procedures to bring these reservoirs into production.

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