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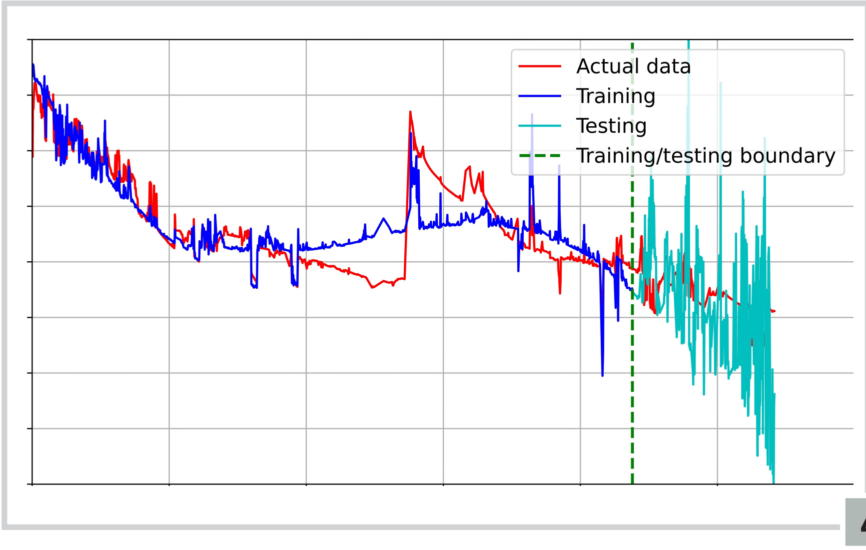

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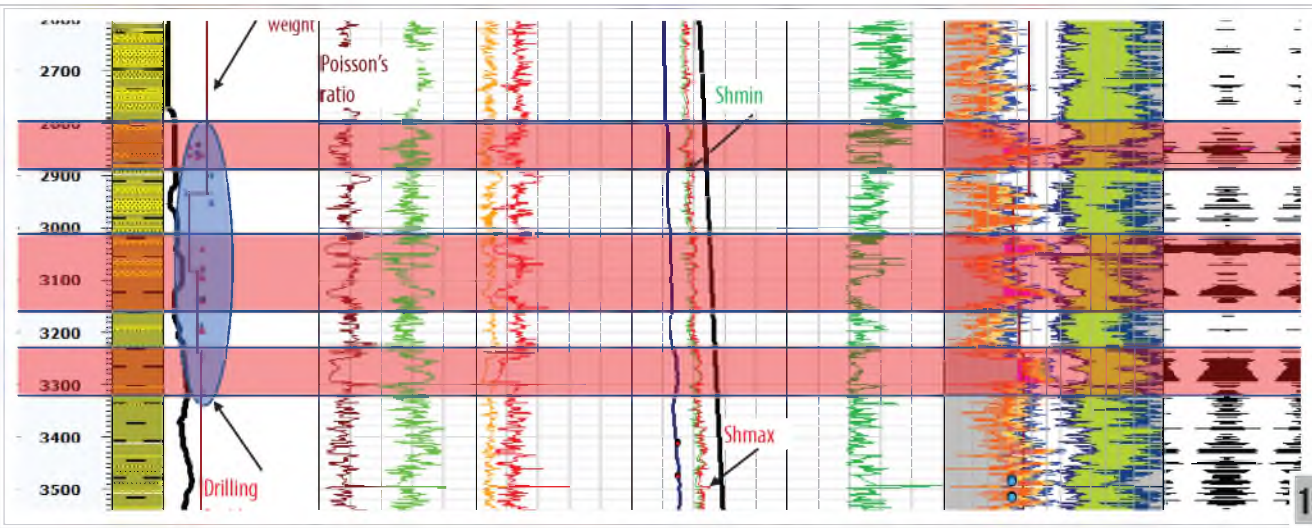

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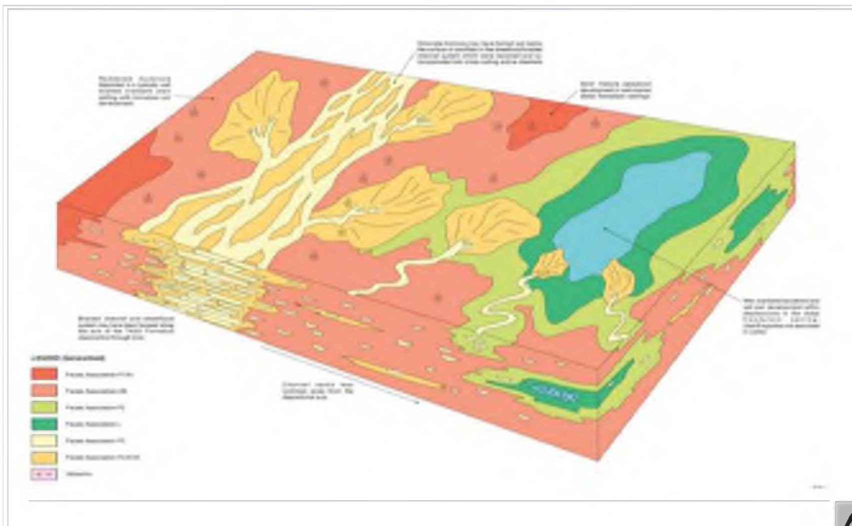
ENERGY TRANSITION

77. Petrovietnam leveraging its technology and services inherited from oil and gas operation into the construction and supply chain of offshore wind power



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APPLICATION OF MACHINE LEARNING TO DECLINE CURVE ANALYSIS (DCA) FOR GAS-CONDENSATE PRODUCTION WELLS WITH COMPLEX PRODUCTION HISTORY DUE TO ADD-ON PERFORATION OF NEW RESERVOIRS

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Summary

For every oil and gas operator, DCA plays an essential role since it provides crucial information for production planning and reserves estimation. DCA is the analysis of the decline in production rate or pressure over time, which can be done by fitting a curve through production or pressure historical data points and making a forecast for the well based on the assumption that the same declining trend will continue in the future. However, the conventional DCA method has been shown to have some limitations. On the other hand, machine learning has been vigorously and extensively researched in the last decade; its applications can be found in every aspect of life as well as in the oil and gas industry. Therefore, it is the ideal time to study the application of machine learning to DCA, to complement this important analysis. In this case study, machine learning was used to predict the decline of wellhead pressure, thereby determining well life as well as estimating reserves. The method was applied to 2 wells with very complex production histories due to add-on perforation of new reservoirs. The prediction was verified to have high reliability by comparison with dynamic modeling results.

Key words: Machine learning, decline curve analysis, wellhead pressure, production forecast, reserves.

1. Introduction

For an oil and gas operator, DCA plays an indispensable role by providing predictions about the productivity and reserves of the well, which are the key input for planning operation, business, and evaluating reserves. The standard procedure of DCA contains two elements. First, the historical data points are matched with a curve of 3 types namely hyperbolic, harmonic, and exponential. Then, once the production history is matched, the DCA model can give prediction of pressure and/or production of the selected well, based on the assumption that the same declining trend will continue in the future. The result from DCA can help determine when the well can no longer produce and estimate the reserves of the well at the time of abandonment. As illustrated in Figure 1, the black part of the decline curve passing through the blue data points represents the history matching process, the red part is the forecast results for the future. Physically, the production and pressure of wells decline with time, eventually leading to well abandonment. Despite many improvements that have been made since the first DCA model introduced by Arps in 1945 [1], the modern-day process of DCA is still

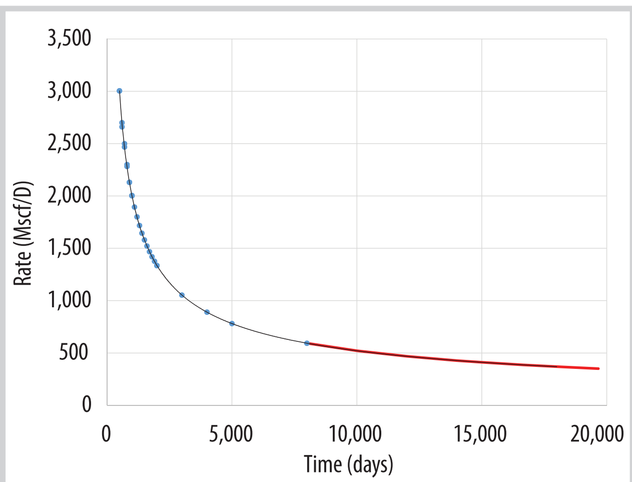

Figure 1. *A simple example of DCA.*

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complex work requiring much time and effort. BIENDONG POC is currently performing DCA in the conventional way, which has shown a few limitations. Moreover, the results are affected by subjective assessment of the analyst. Inspired by the strong development of machine learning in recent years, the authors realize that this is the right time to apply machine learning to DCA. In recent years, machine learning has permeated the global oil and gas industry, for example for lithofacies classification [2, 3], depositional facies prediction [4, 5], history matching [6, 7], and virtual flowmeter [8]. Regarding DCA, outstanding successful applications in production forecasting have been made. In 2019, Lee et al. published a case study in which a long short-term-memory (LSTM) model was constructed, trained, tested, and then utilized to perform DCA [9]. A dataset of 315 wells in the Duvernay formation, western Canada, was studied. The model was tested on a random sample of 15 wells, while the remaining 300 wells were designated for training purposes. The testing results of 15 wells showed that the model could predict production with higher accuracy than the hyperbolic DCA. However, the model had a limitation that it was designed for short-term forecasting (1 month into the future). In another study, Zhan et al. used data from more than 300 unconventional oil wells with 2 years of production history for each well to build two LSTM models, one to forecast the decline in production rate and the other to predict cumulative production [10]. For each well, the production history of the first 3 months was used to train the model and the remaining 21 months was used for testing. To overcome the problem of error accumulation in time series prediction and the challenge of capturing the steep production decline at the beginning, in addition to tubing pressure and oil rate, 12 wells with production rates similar to the analyzed well were selected from the database and translated into additional machine learning features. The results from the LSTM models showed over-prediction for the production rate and under-prediction for the cumulative production. Therefore, the authors combined the two models using weighted averaging to achieve better cumulative prediction results.

In another study about the application of machine learning in regression analysis, Han et al. used 3 different supervised learning models including random forest (RF), gradient boosting machine (GBM), and support vector machine (SVM) [11]. The authors used data collected from 129 dry gas horizontal wells in the Eagle Ford basin, Texas, USA, including completion and reservoir parameters to forecast the cumulative gas production after 36 months. Variables importance analysis and k-fold cross validation were used to prevent overfitting. For all three models, 80% of the data was used for training, the remaining 20% was used to test the accuracy of the model. Forecast results from all three models were compared with actual data and they showed that the RF model had the highest predicting accuracy among the three models in the study.

In general, the machine learning models introduced in the aforementioned studies had the same limitation that they could not capture sudden changes in the production or pressure history. Failure to history match yields a negative impact on the reliability of the forecast results. In this study, we aim to overcome the above limitation, thereby making more reliable predictions of wellhead pressure and reserves.

2. Methodology

The first step of the study is data preparation. Then the complete dataset of each well will be split into training/testing datasets. Several machine learning algorithms are then tested and evaluated to determine the optimal algorithm. Finally, the machine learning model will be used to predict the decline in wellhead pressure, thereby determining when the well depletes and its reserves at the time of abandonment. This paper is part of the results of the research project to improve the efficiency of management and production of the Hai Thach - Moc Tinh gas-condensate field [12].

The machine learning model in this study is developed to perform two tasks. The first task is to generate a decline curve that matches historical data points. The second task is to predict the future trend of wellhead pressure decline when subjected to a constant gas production rate, thereby estimating the time when the wellhead pressure reaches the minimum threshold. In this study, two gas-

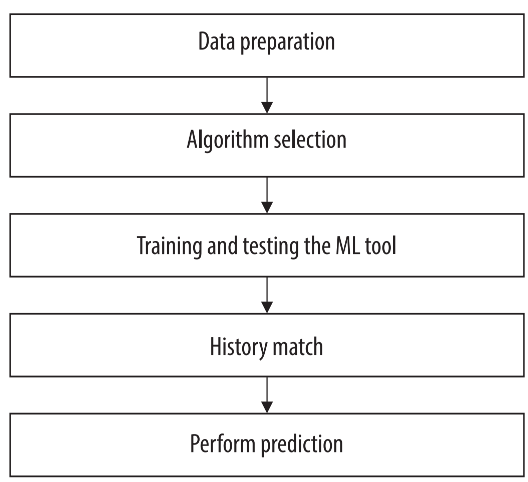

Figure 2. *Flow chart of the methodology.*

condensate wells with sudden changes in production history due to add-on perforation of new reservoirs are selected for the application.

2.1. Data preparation

The data used in this study was historical data of the two selected wells, including the following types: day/month/year data; number of opening hours in a day (uptime); gas rate; and wellhead pressure (WHP). In order to obtain a representative data set, the authors used only data points with 24 hours of well opening in a day.

2.2. Algorithm selection

Several algorithms are initially selected to build the machine learning model including LSTM, extreme gradient boosting (XGBoost), linear regression, polynomial regression, and piecewise regression. The XGBoost, linear regression, and polynomial regression algorithms quickly fail at the history matching steps because of too many errors, especially at abrupt changes in the pressure history due to add-on perforation of new reservoirs. The LSTM model provides decent history matching results but is proven incompetent in predicting wellhead pressure decline. With piecewise regression, this algorithm uses the decision tree regression algorithm to group the data (bucketization) and the linear regression algorithm to find trends for each group. With this principle, the algorithm is suitable for datasets with many different trends, such as complex production history. Research on the application of the piecewise regression algorithm can be found in many topics related to all aspects of life. One of the notable studies is the research by Al-Azzeh et al., on the method of applying the piecewise regression algorithm to increase the accuracy of mathematical models [13].

2.3. Training and testing the machine learning model

To train the machine learning model, the production history of each selected well is used as input, with a frequency of one data point per day. Day/month/year data was converted to datediff format (number of days from the first data point). The training/testing split of 50/50 from the point when the wellhead pressure changes suddenly due to add-on perforation is used. During training, the error between the wellhead pressure predicted by the model and the actual wellhead pressure is calculated to check the accuracy of the model. This error is the basis for choosing the most optimal model to predict the wellhead pressure in the future.

2.4. Application of the machine learning model

For predicting when the wellhead pressure will reach the cut-off threshold, the entire historical data is used instead of the previous 50/50 split. The machine learning model is trained again on this new dataset to increase the accuracy of the prediction results. The error in this process is also calculated and used as a foundation of model selection for future forecasting. For the prediction part of each well, the datediff data is set to increase one day at a time while the gas production is kept the same as the last data point available. Finally, the most optimal model is used to forecast the decreasing trend of wellhead pressure in the future. In the scope of this study, the machine learning model is applied to two wells, HT-A and HT-F, to forecast the trend of wellhead pressure decline, thereby predicting the time of abandonment of the well and reserves at the time of abandonment.

3. Results

The results of testing extreme gradient boosting (XGBoost), linear regression and polynomial regression are shown in Figure 3 to Figure 5. As discussed in the above section, the mentioned algorithms quickly failed at the history matching steps with too many errors.

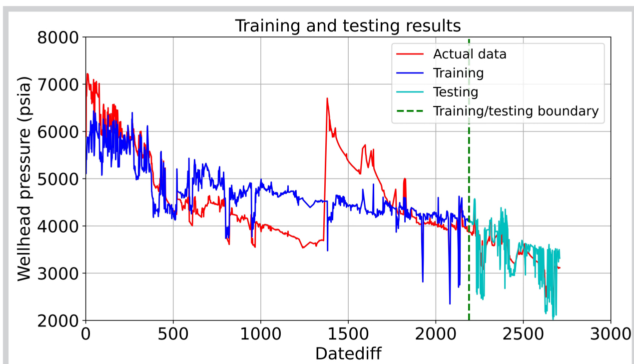

Figure 3. *Training/testing results for HT-F using XGBoost still have limitations.*

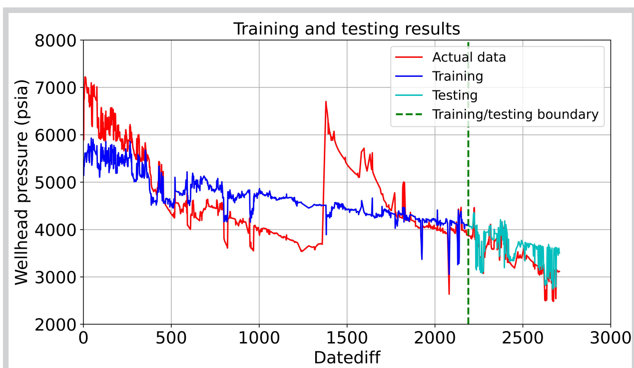

Figure 4. *Training/testing results for HT-F using Linear Regression still have limitations.*

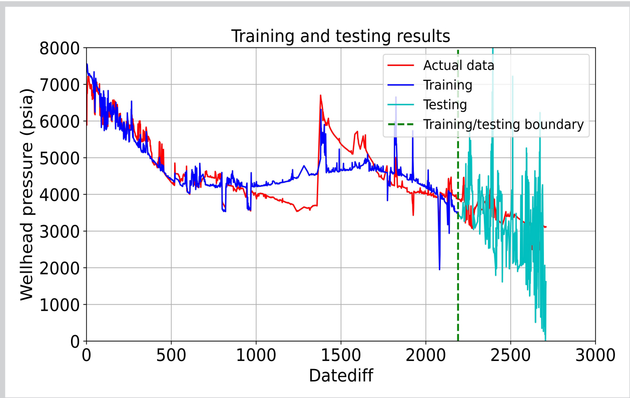

***Figure 5.** Training/testing results for HT-F using Polynomial Regression still have limitations.*

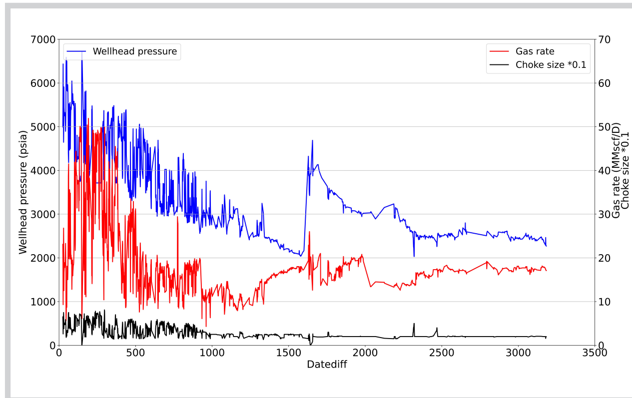

***Figure 6.** The production history of HT-A.*

3.1. Well HT-A pressure prediction results

Well HT-A started production in the second quarter of 2014. Initially, this well appeared to be a powerful producer with the gas rate as high as 50 MMscf/d and the wellhead pressure was approximately 7,000 psia. However, after 4 years of production, the wellhead pressure dropped to below 2,000 psia with the production of the well fluctuating around 10 MMscf/d. HT-A was add-on perforated in the third quarter of 2018, corresponding to a datediff of about 1,600. The results after the perforation campaign showed that at the same choke size of 20%, the wellhead pressure increased from approximately 2,000 psia to nearly 5,000 psia and followed a new decline trend (Figure 6). In addition, gas production increased from about 10 MMscf/d to about 18 MMscf/d.

The training and testing results show that the machine learning model matches the wellhead pressure historical data of the HT-A very well (Figure 7). The sudden change in the wellhead pressure curve caused by add-on perforation is also captured by the machine learning model.

As for the forecast results from the machine learning model (Figure 8) with a constant production rate of 18 MMscf/d, HT-A can sustain production until the fourth quarter of 2027. Meanwhile, the dynamic model predicts that HT-A would have the abandonment time one year earlier than what is foreseen by the machine learning model. The reason for this difference is the dynamic model could not match the last year of the historical data very well while the machine learning model matches this period with nearly perfect accuracy. In this case, the machine learning model is more reliable than the dynamic model. HT-A well reserves would reach 72 Bscf at the time of abandonment in the fourth quarter of 2027.

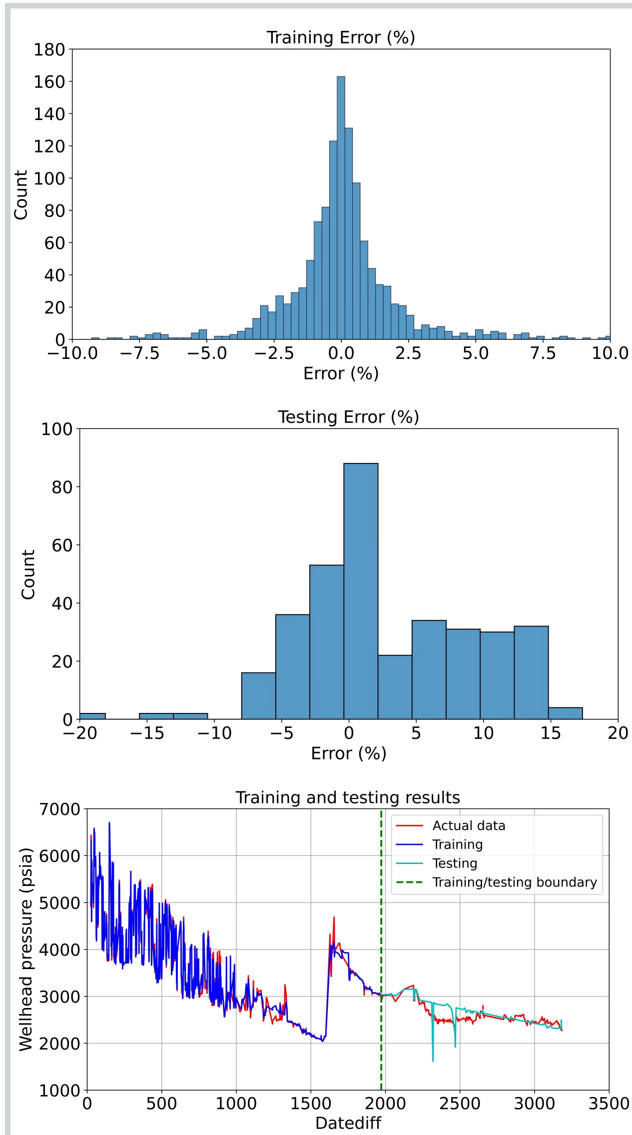

***Figure 7.** Training/testing results for HT-A.*

3.2. Well HT-F pressure prediction results

Well HT-F has been producing since the second quarter of 2015. The wellhead pressure of this well at

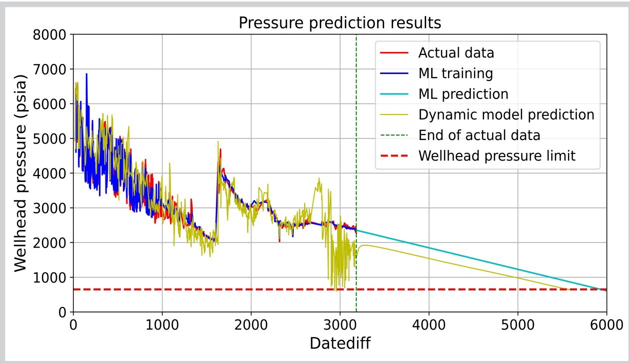

Figure 8. *HT-A wellhead pressure prediction results.*

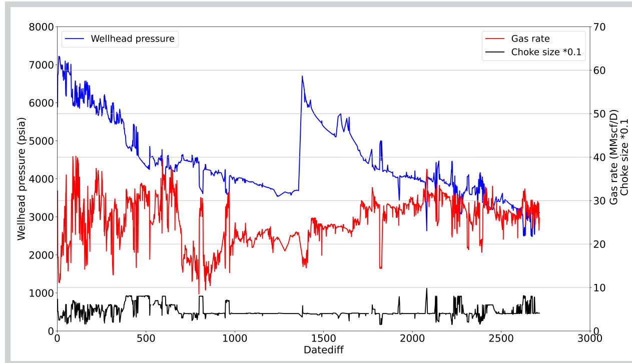

Figure 9. *The production history of HT-F.*

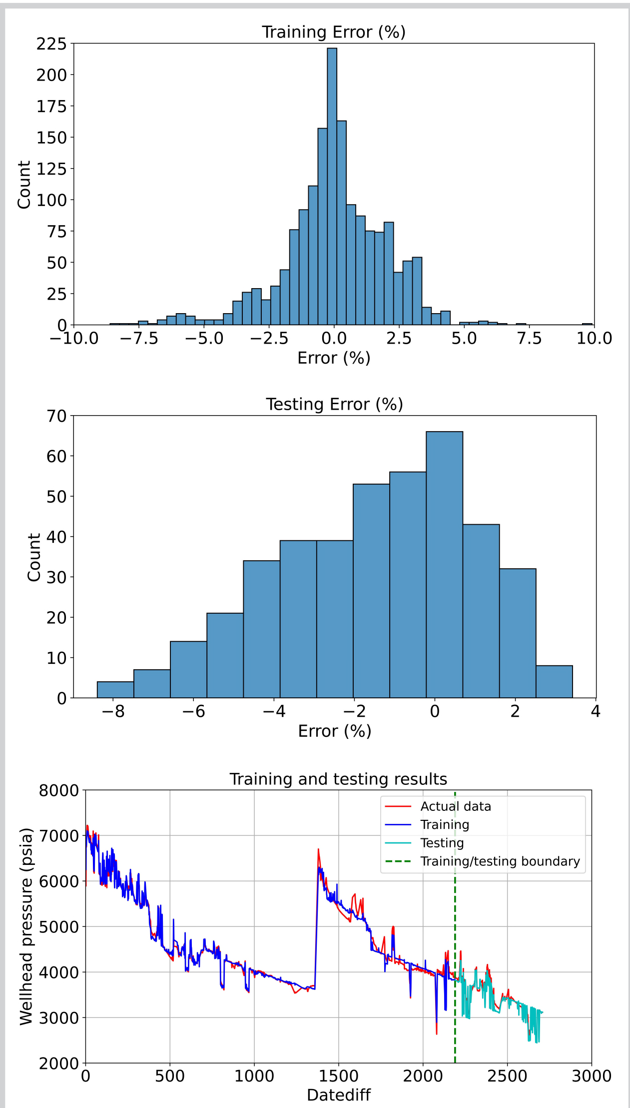

Figure 10. *Training/testing results for HT-F.*

the start of production was as high as 7,000 psia and dropped to below 4,000 psia after nearly 4 years. Add-on perforation was carried out for HT-F in the first quarter of 2019 to improve productivity, corresponding to a datediff of about 1,400. The results after add-on perforation

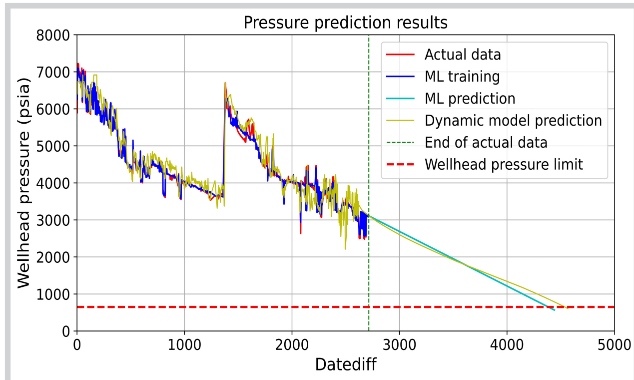

Figure 11. *HT-F wellhead pressure prediction results.*

showed that the wellhead pressure increased to nearly 7,000 psia, close to the initial value. Afterward, it declined in an entirely different trend compared to before add-on perforation. In addition, gas production also increased from approximately 20 MMscf/d to approximately 25 MMscf/d (Figure 9).

Similar to HT-A, the machine learning model is successful in matching the production history of HT-F well, including the sudden increase in pressure caused by add-on perforation, as shown in Figure 10.

The wellhead pressure of HT-F is forecasted using piecewise regression algorithm to reach the cut-off threshold in the second quarter of 2027 if it keeps producing with a constant rate of 25 MMscf/d, as shown in Figure 11. Unlike HT-A, throughout the production/pressure history, and forecasting period of HT-F, the machine learning model and the dynamic model are similar. Therefore, the results from both models have high reliability. The reserves of HT-F at the time of closing the well will reach 100 Bscf.

4. Conclusions

In this study, a machine learning model is developed and applied to perform DCA analysis. The machine learning model is succesfully applied to generate a pressure decline curve that matches the historical dataset including periods of sudden and significant pressure changes due to add-on perforation of new reservoirs. Finally, the machine learning model could provide a reasonable prediction of the time of abandonment for the selected wells, as shown by the comparison with the best dynamic models available.

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PETROVIETNAM SCIENCE, TECHNOLOGY & INNOVATION PETROVIETNAM

APPLICATION OF MACHINE LEARNING TO PREDICT THE TIME EVOLUTION OF CONDENSATE TO GAS RATIO FOR PLANNING AND MANAGEMENT OF GAS-CONDENSATE FIELDS

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Summary

One of the most important parameters for the evaluation, forecast, and management of gas-condensate fields is the evolution of the condensate to gas ratio (CGR) over time. This parameter tends to decrease as reservoir pressure declines. In the conventional approach, gas and condensate samples are collected at the beginning of production and periodically later to conduct laboratory experiments on composition, CGR, and fluid properties. However, sample collection, transportation, and analysis require a lot of time and effort and could be very expensive. Likewise, dynamic models are also frequently used to predict CGR over time. However, these models could include many uncertainties due to ambiguous input data, including reservoir structures, fluid phase interaction, and reservoir property distribution. Therefore, the application of machine learning to predict the time evolution of CGR in this research could be a new and effective approach to supplement conventional methods.

Key words: Machine learning, condensate to gas ratio, production forecast, Hai Thach field.

1. Introduction

Predicting condensate to gas ratio (CGR) is an important task in gas-condensate field management. Whitson et al. showed that the main difference in managing dry gas reservoirs against gas-condensate reservoirs is the requirement to forecast CGR so that condensate production can be reliably estimated [1]. Therefore, this parameter is extremely important, and the prediction on its evolution over time must be reliable.

The conventional method to predict CGR during pressure depletion is based on PVT (pressure - volume - temperature) model. To generate this model, representative samples of reservoir fluid must be collected, and PVT experiments must be conducted. This process is both costly and time consuming. After the main parameters of the fluid are determined, the equation of state (EOS) is then generated to describe the characteristics of the reservoir fluids. Without the representative samples and the main parameters acquired by experiments, the EOS cannot be derived. Similarly, if fluid properties from different reservoirs are used as analogue, the EOS may not reflect the actual characteristics of the reservoir fluids.

Another conventional method for prediction is dynamic simulation. However, for most of Hai Thach wells, CGR prediction using this method is difficult although history matching of wellhead pressure is acceptable as shown in Figures 1 and 2.

History matching of CGR is challenging in Hai Thach field due to many reasons. First, there are 9 separate reservoirs in Hai Thach field but only one representative sample could be collected. Therefore, there is insufficient data to generate PVT models for all reservoirs. For reservoirs without representative samples, it is assumed that they might have similar properties to the sampled reservoir; thus, PVT models for these reservoirs have many uncertainties. Furthermore, most Hai Thach wells are produced from commingled reservoirs with contribution among them varying over time. Therefore, history matching of CGR using dynamic simulation is

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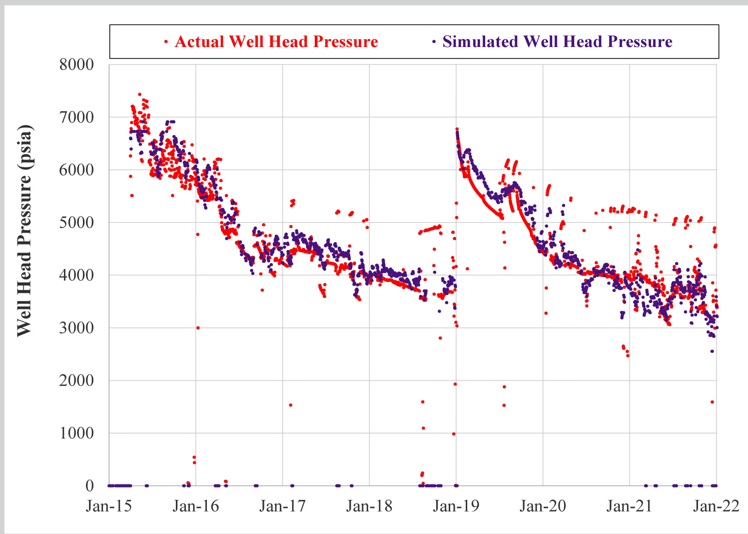

Figure 1. *History matching results of well head pressure using dynamic simulation are reasonable for HT-Y.*

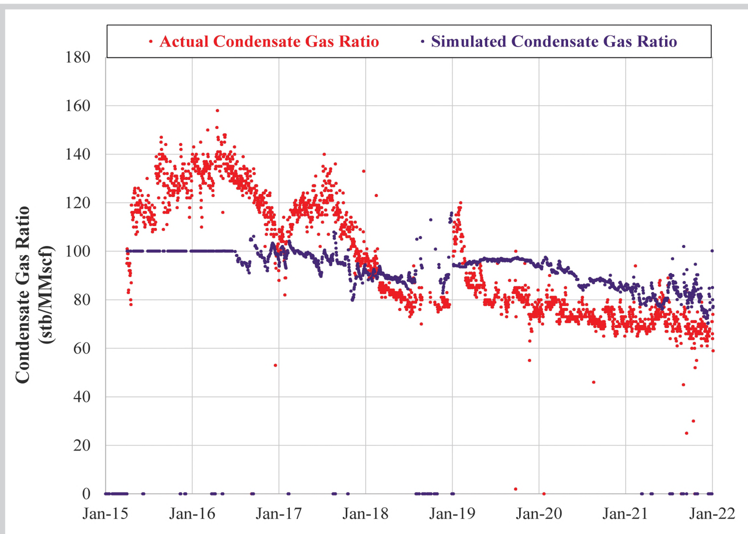

Figure 2. *History matching results of CGR using dynamic simulation for HT-Y still have some difficulties.*

complicated and there is certain deviation from actual values, causing great difficulty in forecast. Regarding short-term forecast, this deviation has impact on condensate lifting because condensate production forecast would be too low or too high compared to reality, leading to high risks of shortage or tank top issues. With respect to long-term production forecasts, deviation in forecasting CGR results in inaccuracy of condensate production rate and cumulative condensate production and affecting the economic evaluation of the whole project. As a result, the necessity to develop an auxiliary method to precisely forecast CGR is very urgent.

In comparison with complex EOS modeling or dynamic simulation, machine learning can perform forecast with fewer input parameters. Therefore, it has been widely used to solve many forecasting problems. The application of this method in predicting the fluid properties of oil and gas reservoir has also been studied by a number of research groups, for example applying machine learning algorithms to predict the dew point pressure of gas condensate reservoirs [2 - 5], estimate CGR [6, 7], and fluid composition [8]. However, these studies have not concentrated on predicting the change of CGR over time as reservoir pressure declines during production.

For production wells, it can be observed that CGR is highly dependent on wellhead pressure, wellhead temperature, as well as choke size. Additionally, add-on perforation also showed great impact on CGR. Since the values of wellhead pressure, wellhead temperature, and choke size are monitored and recorded regularly, establishing the relationship between these parameters with those more difficult and expensive to obtain such as CGR will bring lots of practical values. Consequently, the application of machine learning to forecast CGR can be an alternative to overcome the difficulties of traditional methods.

However, machine learning also has some difficulties in forecasting over time, especially relatively long-term forecast, as reported in the following studies. Lee et al. constructed a long short - term memories (LSTM) network trained on the data of 300 wells to predict the production of 15 wells with good results but they are short term forecasts of just one month [9]. In another study, Zhan et al. used data from more than 300 unconventional oil wells to build two LSTM models, one to forecast the decline in production rate and the other to predict cumulative production [10]. For each well, the production history of the first 3 months was used to train the model and the remaining 21 months was used for testing. To overcome the problem of error accumulation in time series prediction and the challenge of capturing the steep production decline at the beginning, in addition to tubing pressure and oil rate, 12 wells most similar to the well being analyzed were selected from the database and translated into additional machine learning features. However, the results from the LSTM models still showed over-prediction for the production rate and under-prediction for the cumulative production. It can be observed that many machine learning models have certain

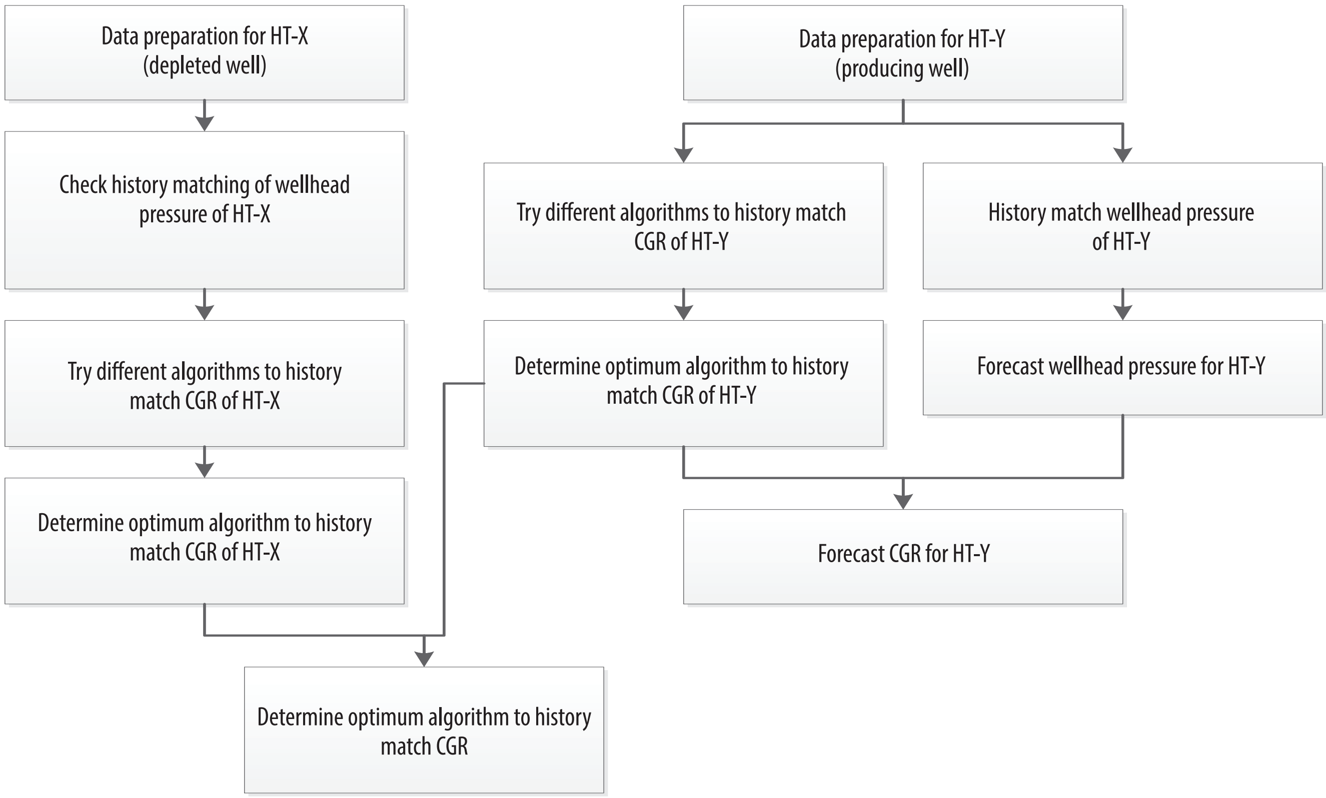

Figure 3. *Flow diagram of the study.*

Table 1. *HT-X WHP prediction using machine learning with different split ratios of training and testing dataset*

Split ratio of training and testing dataset	Mean_leaf	Training error (%)	Testing error (%)	Prediction results
50/50	20	-1.5 to 1.5	-15 to 0	Not very good
60/40	100	-15 to 15	-7.5 to 10	Relatively reasonable
70/30	50	-3 to 3	-10 to 7.5	Good forecast results
80/20	100	-8 to 8	-2 to 10	Good forecast results

difficulties in long-term forecasting. Furthermore, picking up abnormal changes in the production history is also a great challenge for wells with add-on perforation. Due to the above challenges, piecewise regression combined with linear regression and XGBoost is used to solve this forecasting problem.

2. Methodology

CGR is a parameter that depends on reservoir pressure, and therefore on wellhead pressure. Thus, this study was divided into two steps. The first step was to forecast the decline of wellhead pressure during production period. The next step was to forecast CGR according to the decline of wellhead pressure.

In the Hai Thach field, the HT-X well started production in 2015 with good deliverability. After 5 years of production, HT-X was depleted with wellhead pressure decreasing to process pressure and CGR decreased from initial value of 100 stb/MMscf to only 10 stb/MMscf. Since the historical data of wellhead pressure and CGR of HT-X was complete, this well is used to develop the machine learning model. The wellhead pressure data set consists of 1566 data points from daily production history of HT-X including uptime, choke size, and gas production rate. The CGR data set consists of 52 data points from flow tests including uptime, choke size, and wellhead pressure. Since the production history dataset used for forecasting CGR of HT-X is relatively small, the mean_leaf parameter will have a big impact on forecast results. The combination of piecewise regression and linear regression or piecewise regression and XGBoost will be used for the prediction of CGR of HT-X with different split ratios of training and testing datasets to find the optimal algorithm.

The same process is then applied to the prediction of well head pressure and CGR of HT-Y which is the main target of this study. HT-Y also started production in 2015 but this well has better performance and pressure was not declining as fast as HT-X. After 7 years of production, HT-Y is still the strongest gas producer in Hai Thach field. The forecast of CGR over time will help better manage HT-Y production. The wellhead pressure data set of HT-Y consisted of 1658 data points from daily production history including uptime, choke size, and gas production rate. The CGR data set consists of 132 historical data points of flow tests including uptime, choke size, and wellhead pressure. A big difference between HT-Y and HT-X is that HT-Y had add-on perforation that significantly changes the historical trend and that event would be used to check the capability of the algorithms.

The flow diagram of the study is shown in Figure 3.

3. Study result

The dataset used for forecasting wellhead pressure of HT-X is splitted into training and testing set with different ratios. The mean_leaf parameter is optimized based on the highest score of correlation factor by comparing forecast results and actual data on training dataset. The calculation results are shown in the following figures.

The combination of piecewise regression and linear regression is applied to history match wellhead pressure data of HT-X with different split ratios of training and testing dataset as shown in Table 1, and representative results shown in Figure 4.

The testing results show that history matching and

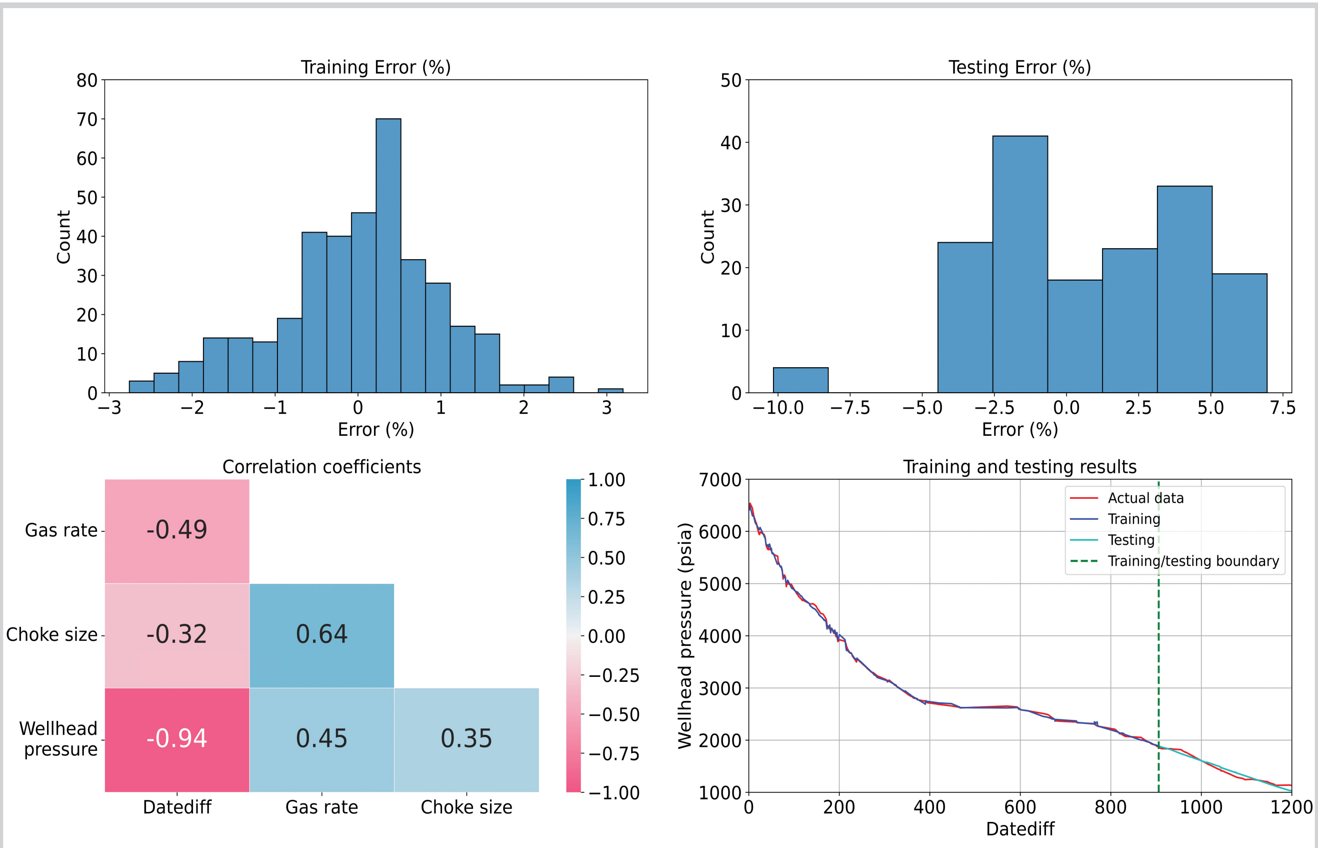

Figure 4. *HT-X WHP prediction using machine learning with split ratio of training and testing dataset of 70/30.*

Table 2. *HT-Y WHP prediction using machine learning with different split ratios of training and testing dataset*

Split ratio of training and testing dataset	Mean_leaf	Training error (%)	Testing error (%)	Prediction result
50/50	83	-5 to 5	-8 to 3	Reasonable
60/40	199	-8 to 8	-8 to 4	Reasonable
70/30	61	-8 to 8	-12 to 2	Reasonable
80/20	184	-8 to 8	-3 to 6	Reasonable

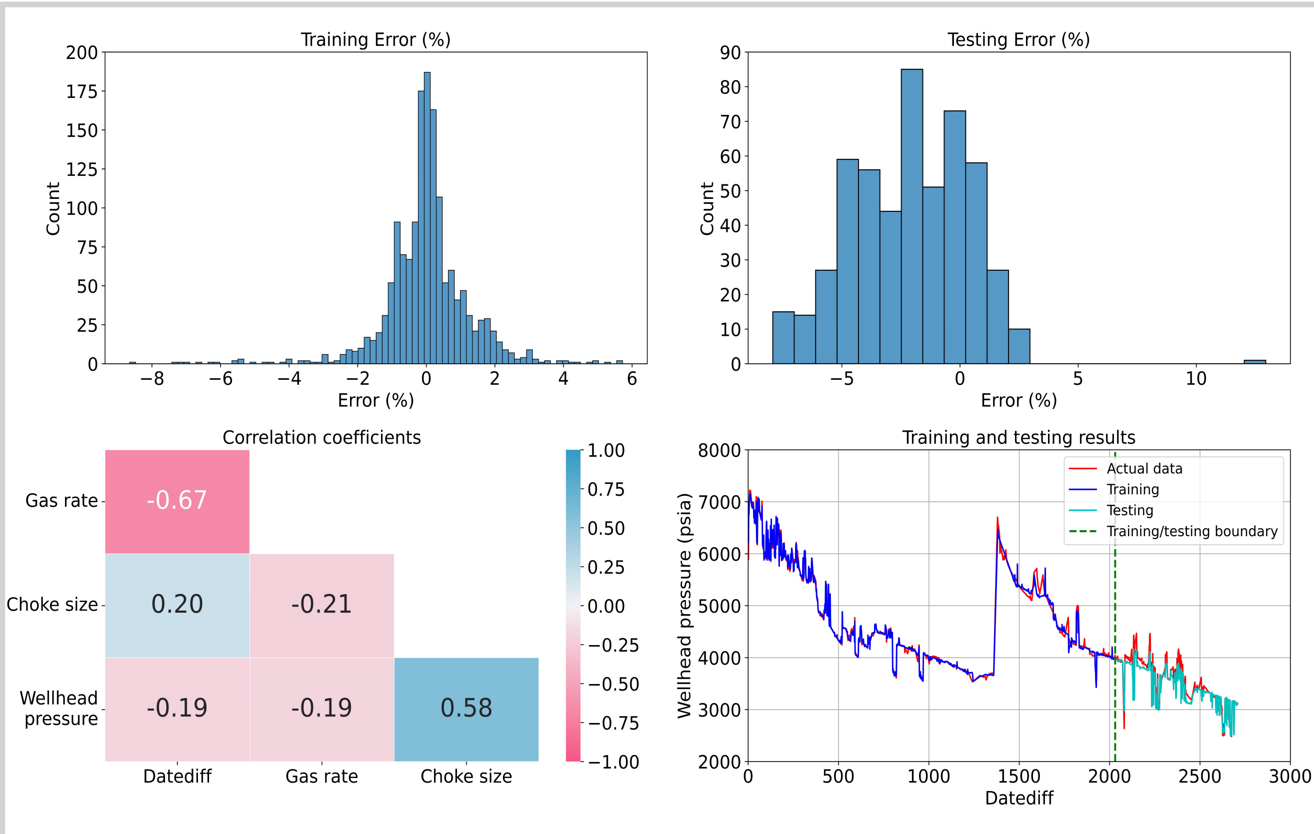

Figure 5. *HT-Y WHP prediction using machine learning with split ratio of training and testing dataset of 50/50.*

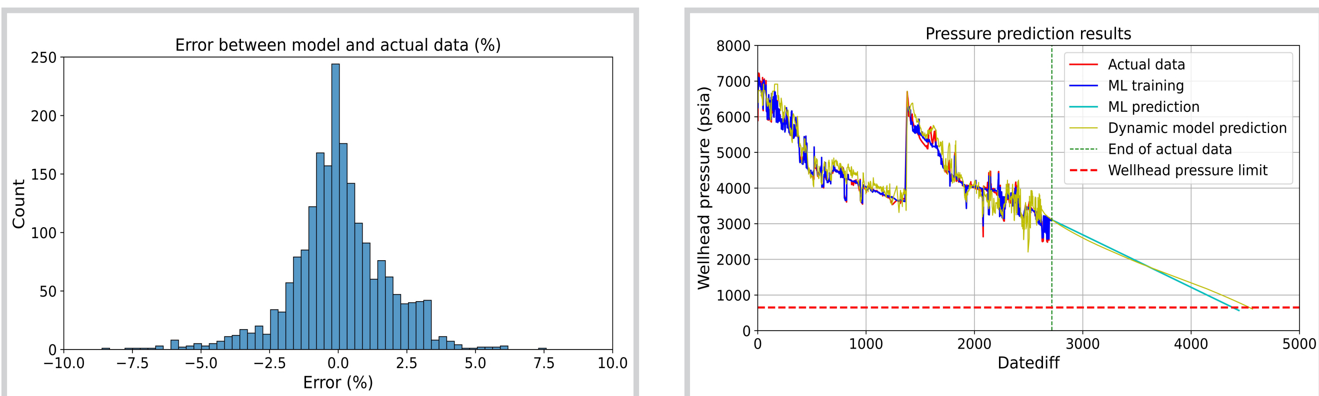

Figure 6. *HT-Y WHP prediction using machine learning in comparison with dynamic simulation results.*

Table 3. *HT-X CGR prediction using different split ratios of training and testing dataset*

Split ratio of training and testing dataset	Algorithm	Mean_leaf	Training error (%)	Testing error (%)	Prediction results
70/30	Piecewise regression combined with linear regression	6	-10 to 25	0 to 70	Reasonable
80/20		8	-15 to 25	-30 to 40	Reasonable
70/30	Piecewise regression combined with XGBoost	6	-10 to 25	0 to 70	Reasonable
80/20		8	-15 to 25	-40 to 40	Reasonable

forecast for wellhead pressure decline is feasible for HT-X when the ratio of historical data/forecast data is at least 60/40. The same process is then repeated for history matching and forecast of wellhead pressure of HT-Y. Since HT-Y wellhead pressure changes significantly after add-on perforation, the same split ratios of 50/50, 60/40, 70/30, and 80/20 are still applied, but only to the data after add-on perforation. The prediction results with different split ratios are summarized in Table 2 and representative results shown in Figure 5.

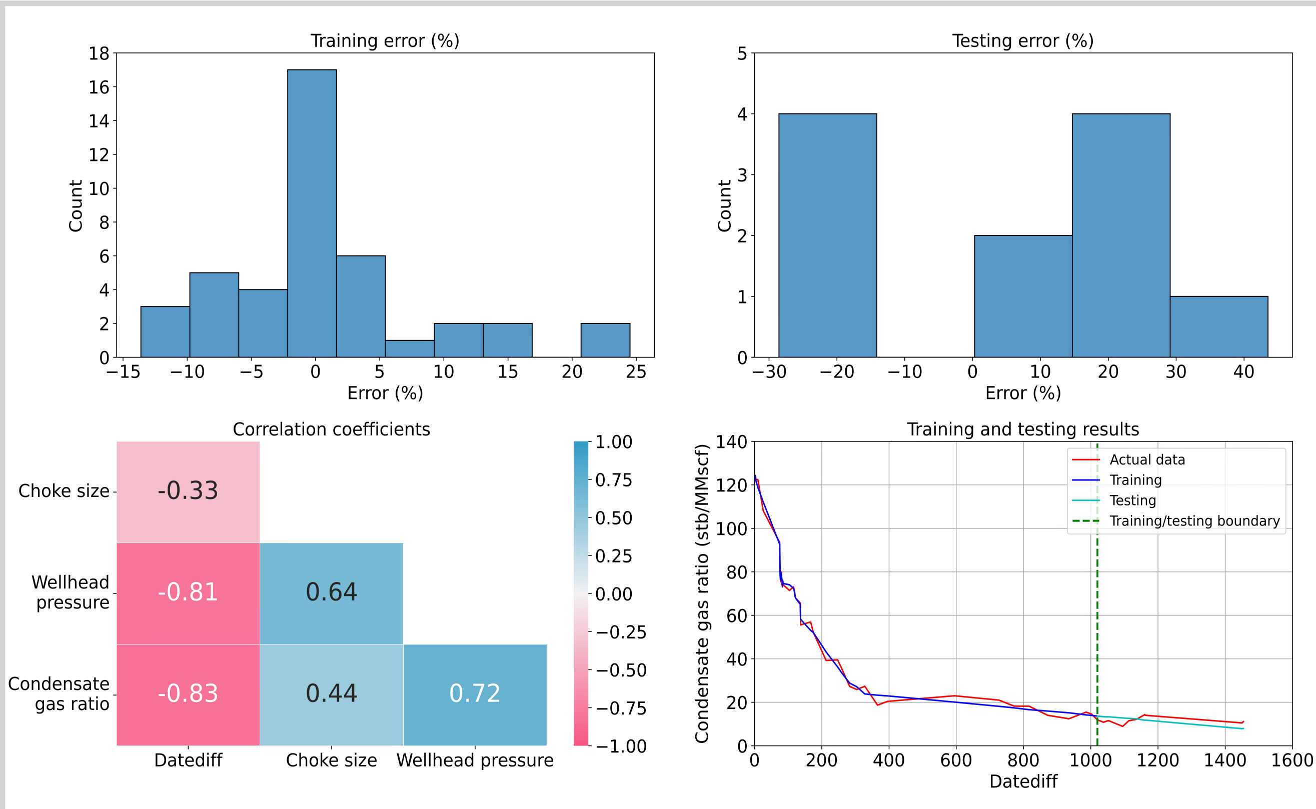

Figure 7. *HT-X CGR prediction using piecewise regression and linear regression with split ratio of training and testing dataset of 80/20.*

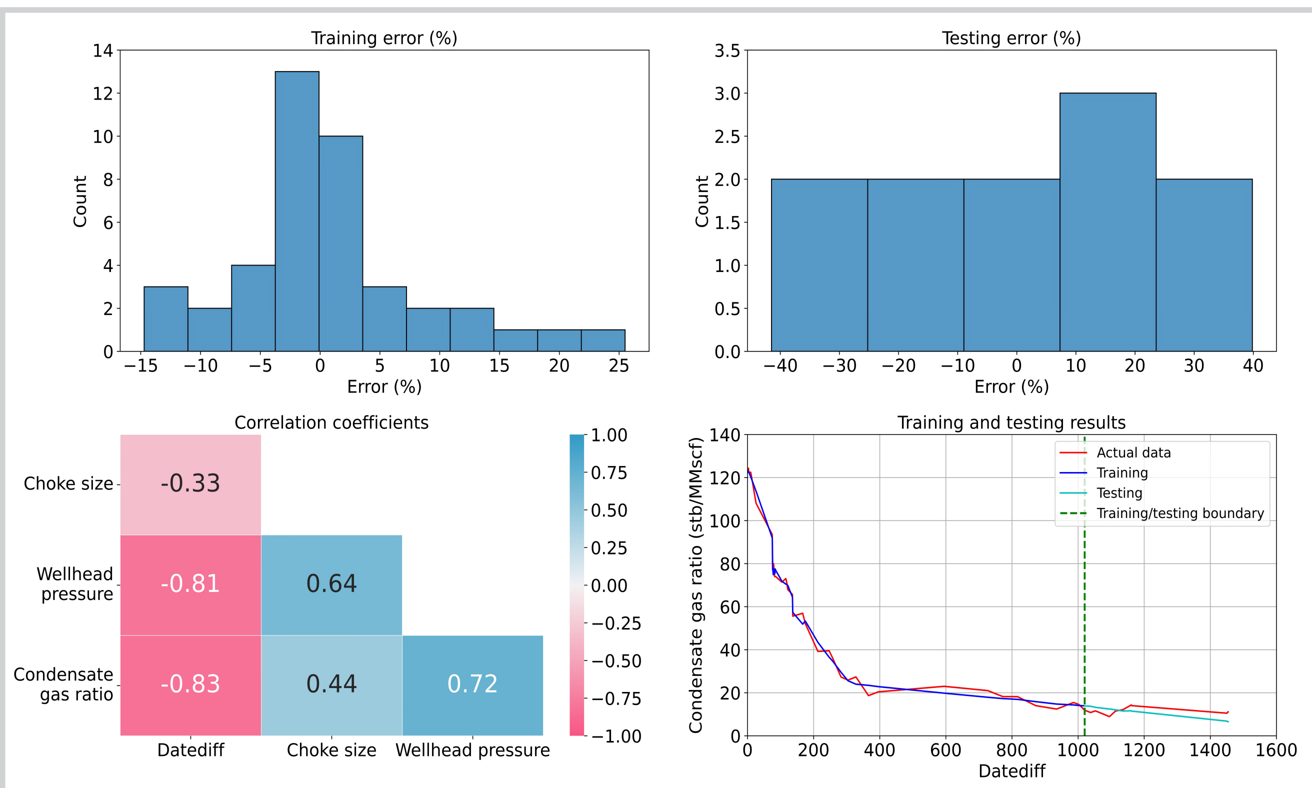

Figure 8. *HT-X CGR prediction using piecewise regression and XGBoost with split ratio of training and testing dataset of 80/20.*

The forecast results of wellhead pressure for HT-Y in the future by machine learning are compared to the results forecasted from dynamic simulation in Figure 6. The comparison of the results of the two forecasting methods shows that the use of machine learning for predicting HT-Y wellhead pressure is reasonable and slightly different compared to dynamic simulation results.

After the wellhead pressure is predicted with good accuracy, CGR is then derived by machine learning. Since the CGR dataset is relatively small compared to the wellhead pressure dataset, only 70/30 and 80/20 split ratios of training and testing datasets are applied. The forecast results for HT-X are summarized in Table 3 with representative results shown in Figure 7 and Figure 8.

For the CGR prediction of HT-X, piecewise regression combined with linear regression or XGBoost provide similar forecast results. Therefore, CGR of HT-Y was also predicted by both algorithms with split ratios of 70/30 and 80/20 as shown in Table 4.

Piecewise regression combined with XGBoost has better prediction results than piecewise regression combined with linear regression at 70/30 split ratio. Forecast results are similar for both algorithms at 80/20 split ratio, as shown in Figures 9 and 10.

In summary, piecewise regression combined with XGBoost has better and more stable forecast results, so this algorithm is used to predict future CGR of HT-Y and the results from machine learning are compared to the forecast results by dynamic simulation in Figure 11. The comparison of two methods shows that machine learning prediction of CGR for HT-Y is reasonable and can be used as a supplement of dynamic simulation forecast for production management.

Table 4. *HT-Y CGR prediction using different split ratios of training and testing dataset*

Split ratio of training and testing dataset	Algorithm	Mean_leaf	Training error (%)	Testing error (%)	Prediction results
70/30	Piecewise regression combined with linear regression	20	-15 to 10	-15 to 30	Overestimated
80/20		30	-15 to 10	-15 to 25	Reasonable
70/30	Piecewise regression combined with XGBoost	20	-15 to 10	-20 to 15	Reasonable
80/20		30	-15 to 10	-20 to 20	Reasonable

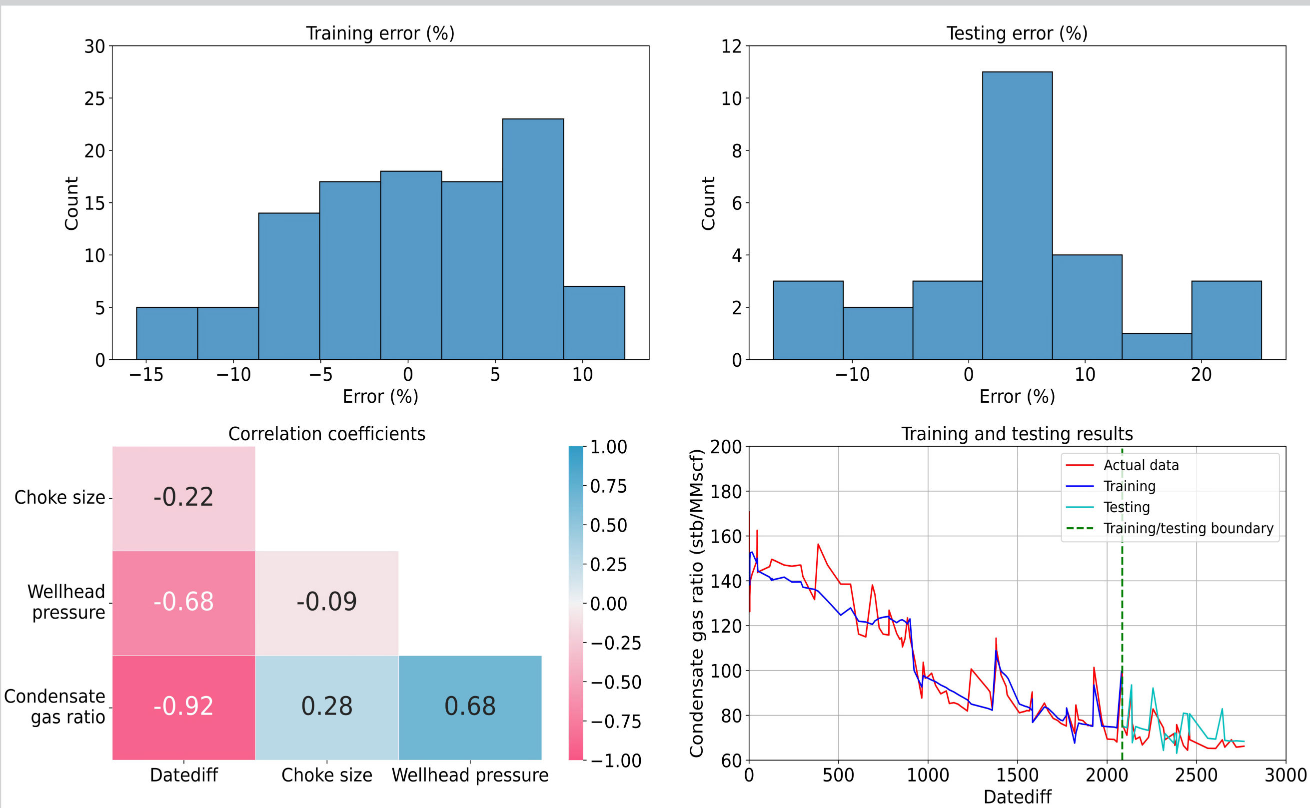

Figure 9. *HT-Y CGR prediction using piecewise regression and linear regression with split ratio of training and testing dataset of 80/20.*

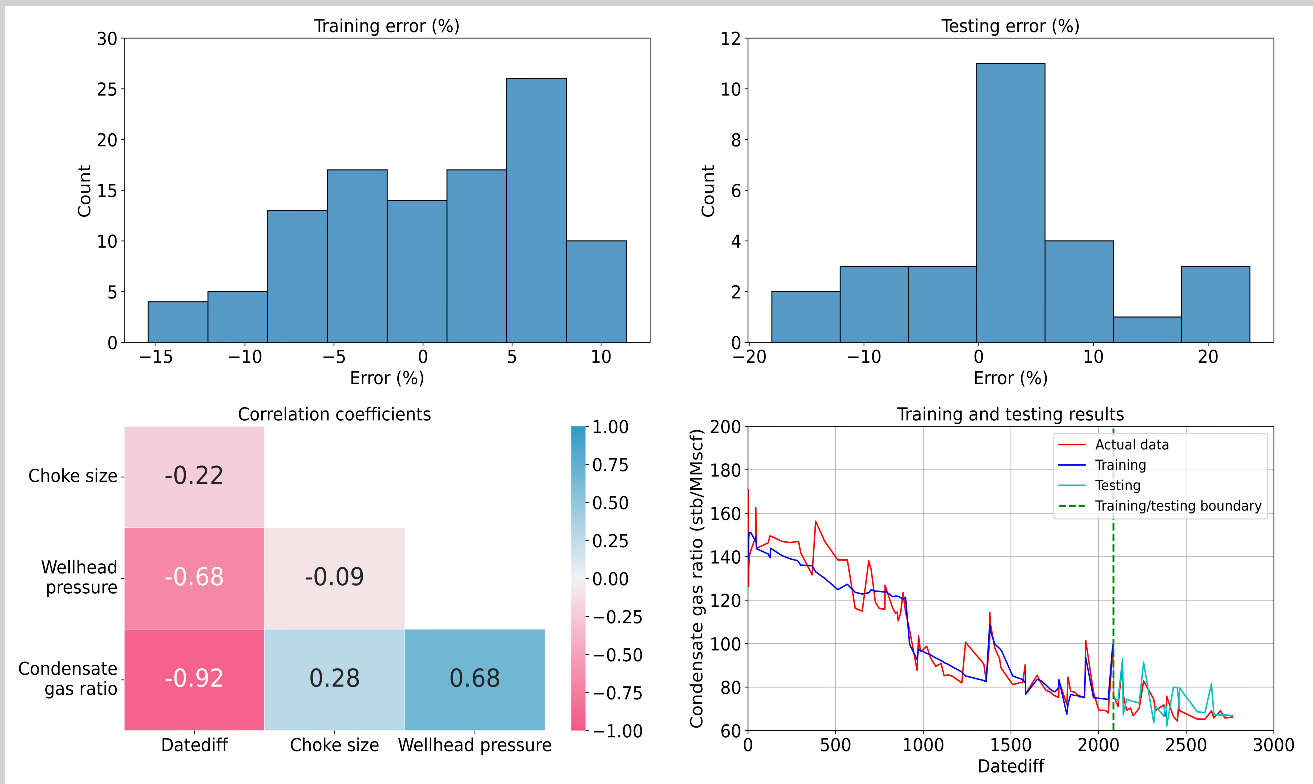

Figure 10. *HT-Y CGR prediction using piecewise regression and XGBoost with split ratio of training and testing dataset of 80/20.*

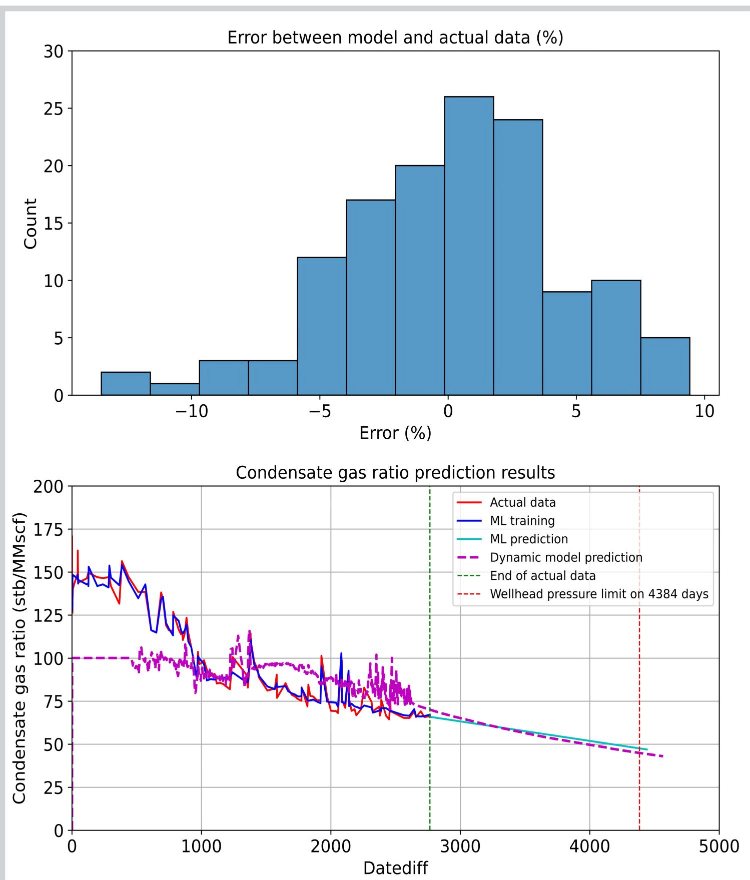

Figure 11. *HT-Y CGR prediction using piecewise regression combined with XGBoost in comparison with dynamic simulation results.*

4. Conclusions

The main conclusions of the study can be summarized as follows:

- Machine learning is applied successfully to predict the changes overtime of CGR which is one of the most important parameters for gas-condensate reservoirs but very challenging to forecast using traditional methods;

- About machine learning algorithm, piecewise regression combined with XGBoost provides reasonable and reliable forecast results for CGR;

- The successful application of machine learning in forecasting CGR during production provides significant support to the prediction of condensate production, thereby helping to better optimize production management of gas condensate fields.

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INTEGRATION OF GEOLOGICAL AND WELL LOG AND GEOMECHANICAL MODELING TOWARD A SAFE MUD WEIGHT FOR WELLBORE STABILITY: A CASE STUDY OF RUBY FIELD, BLOCKS 01&02, CUU LONG BASIN

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Summary

There is a high density of drilled wells in Blocks 01&02 which is a part of the Cuu Long basin. The geological settings of this area have undergone a complicated evolution, resulting in heterogeneous lithology and variable stresses. Consequently, drilling activities in the Ruby oil field have faced numerous challenges, such as stuck pipe, gas kick, mud loss, and even lost well, etc. leading to substantial time and financial setbacks. It is essential to thoroughly understand the geomechanical characteristics of Ruby field to ensure safe operation and optimize drilling. In this paper, several downhole geophysical data sets such as wireline logging data as gamma ray (GR), density log (RHOB), neutron (NPHI), compression/shear sonic travel time (DTC/DTS), image formation log (FMI), pressure test (MDT) and leak of test (LOT, XLOT) are used to construct the 1D geomechanical model. The objective of this modelling is to compute parameters of pore pressure, vertical stress, horizontal stress, elastics properties, rock strengths. Then, these parameters are used to analyze the wellbore stability and to recommend appropriate drilling mud weights for the wells under study. This analysis can subsequently be extended to cover the entire Ruby oil field for the future drilling operations to enhance overall safety and efficiency.

Key words: Geomechanical model, wellbore stability, mudweight, Cuu long basin

1. Introduction

The Ruby field, situated within the Cuu Long basin, has undergone a complex geological evolution, resulting in a zone characterized by lithological heterogeneity and varying stresses. Consequently, drillings in this area encountered various challenges such as stuck pipes, mud losses, and even lost wells, incurring significant financial and time expenses for the petroleum company. Therefore, it is crucial to comprehend the geomechanical properties of the rocks in this study area to prevent well damages and optimize the drilling costs. This study aims to construct a 1D geomechanical model to calculate vertical stress, pore pressure, horizontal stress, elastic properties and rock strengths. Wireline logging data in Ruby field including gamma-ray (GR), density log (RHOB), neutron log (NPHI), shear slowness travel time (DTS), compressive slowness travel time (DTC), image logs, pore pressure tests (MDT/RFT) and data of leak of test, extended leak of test or mini-frac for the identification of minimum horizontal stress, are utilized in this modeling process. Finally, the results from the 1D geomechanical model are employed to analyze wellbore stability and recommend drilling mud weights for the upcoming wells in the Ruby field.

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2. Background

Up to now, 85% of oil and gas production in Vietnam primarily comes from fields in the Cuu Long basin [1], marking the crucial role of this basin in the country's oil and gas industry. The Cuu Long basin is a typical rift basin that has been undergoing a complexity of tectonic evolution including pre-rifting, rifting and thermal subduction mechanisms [2]. These tectonic activities contributed to the formation of various types of rocks with different lithological components corresponding to different rock facies, depositional environments and buried conditions, leading to differences of geomechanical properties such as pore pressure, stresses, etc. Therefore, many challenges need to be addressed during drilling, such as bore hole wall collapse, total circulation losses, stuck pipe/logging tools, etc. Because of these problems, the petroleum company may suffer critical loss financially due to an increase in non-productive time, e.g. solving and fixing problems, leading to higher drilling costs. In order to fix these problems, it is a must to minimize non-productive time related to wellbore

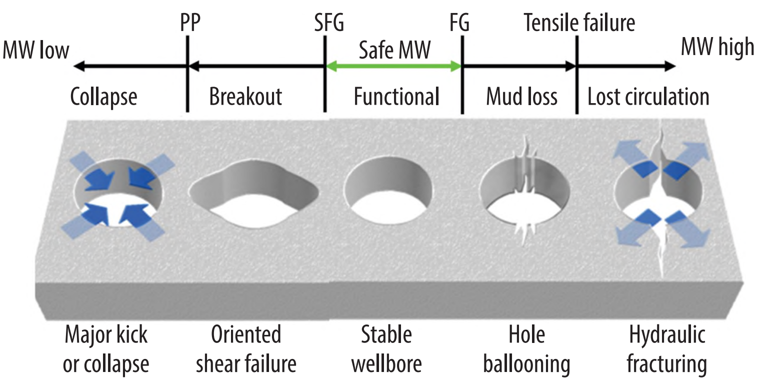

Figure 1. The influence of pressure and drilling mud weight on the wellbore conditions [4].

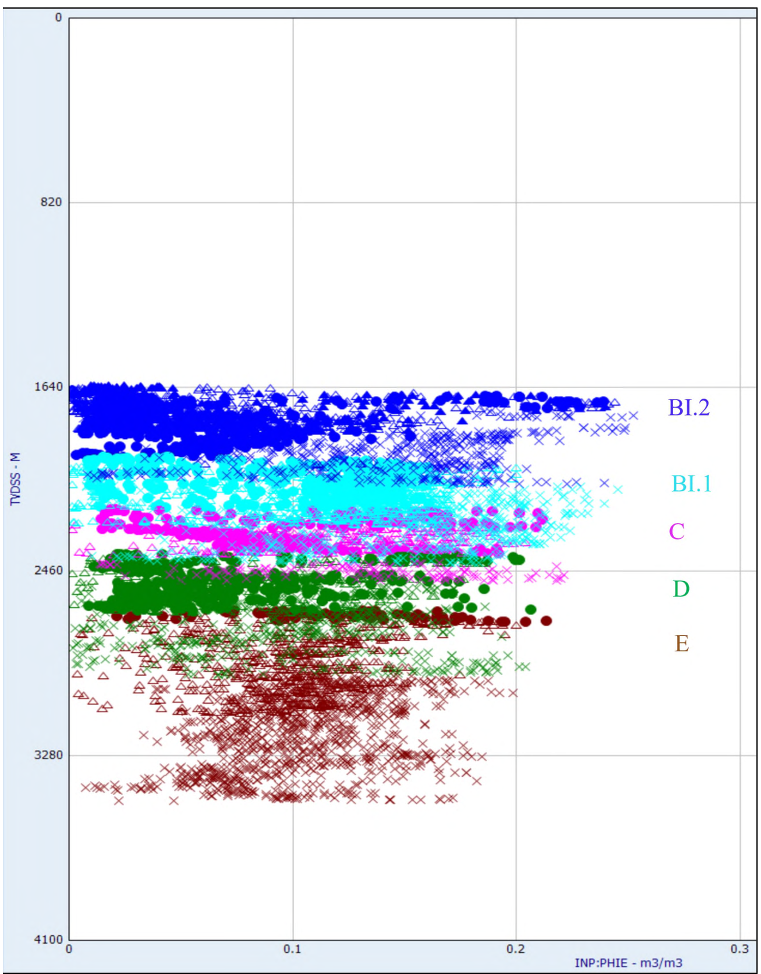

Figure 2. The porosity versus the depth in some well in Ruby field, Blocks 01&02, Cuu Long basin.

instability and undesired issues caused by the pore pressure mechanism of formations. This is a complex task that needs to be proposed before drilling and updated during and after drilling. This task includes the assessment of drilling risks, identifying geological variations at the wellbore to develop contingency plans for unforeseen issues [3]. Therefore, understanding the geomechanical properties of rocks plays an increasingly important role in solving the problem of wellbore instability, optimizing well costs, and ensuring safety in drilling progress.

Throughout drilling progress, the cuttings are removed by drilling bit; the drilling fluid will be brought to the surface, and immediately replace equally the volume of the excavated formation; the stresses around the wellbore will be redistributed, and induced stresses will also be generated. To ensure the wellbore stability, the drilling mud weight must be consistent with controlling the induced wellbore stresses. In more details, the shear stress and tensile are the main factors that cause the mechanical instability of the wellbore [4]. Obviously, if the drilling mud weight is high, it will create induced fractures causing mud loss, called tensile failure; but on the contrary, if it is too low, it will lead to wellbore collapse, called shear failure (Figure 1).

The selection of the mud weight should be greater than the pore pressure but less than fracture pressure. This is a principle in wellbore designation and identification of casing depths, saving several millions of dollars when applied to design casing shoes [5]. In this paper, the authors will use wireline logging data including gamma ray, density log, resistivity log, sonic log, in conjunction with drill stem tests (DSTs), LOT, MDT, drilling events, and production data from the Ruby field, Blocks 01&02, Cuu Long basin. This comprehensive dataset will be used to construct the 1D geomechanical model (1D MEM), providing parameters such as the pore pressure, formation stresses and mud weight windows [6]. Afterward, this model continues to be updated and refined with the future wells to ensure the minimization of drilling incidents and optimization of the drilling operations and associated production progress.

3. Geological settings of the Ruby field.

The research area is the oil field named Ruby in Blocks 01&02, located in the Northeast of Cuu Long basin. There are 37 drilled wells in the field, comprising 4 exploration wells and 33 production wells. The hydrocarbon-bearing formations consist of consolidated sand reservoirs with effective porosity ranging from 18 - 23% in the Miocene and 11 - 20% in the Oligocene (Figure 2).

Oil flows from DST results and production in the Oligocene to Miocene formations mostly show characteristics of oil in the study area, which is the relatively light oil with API from 39 to 44 degree.

Rifting, compression, and thermal subduction are primarily typical tectonic activities in the Cuu Long basin and particularly in the research area (Figure 3).

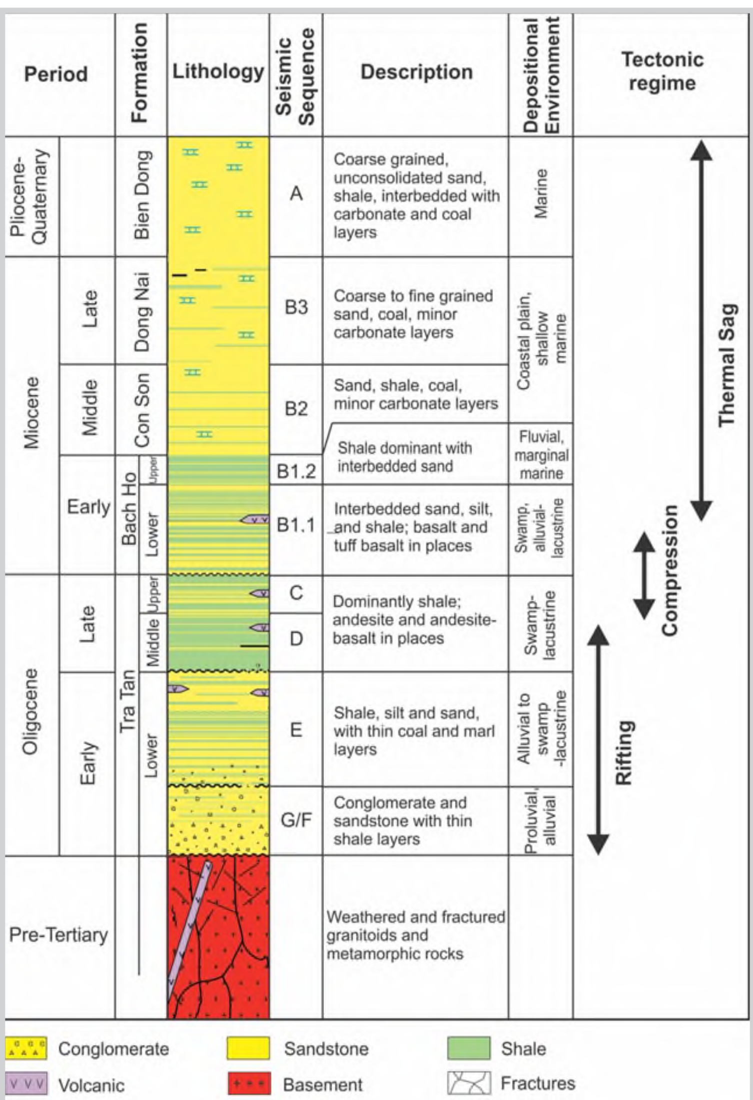

Figure 3. *Lithological and stratigraphic column of the Ruby field [7, 8].*

Onset of the rifting progress commenced from Eocene to early Oligocene [9], giving rise to a series of narrow, localized basins oriented in the NE - SW and E - W directions. Subsequently, the study region experienced alternating phases of compression and rifting during the transition from the late Oligocene to the early Miocene, with a predominant NE - SW orientation. Particularly, the basin was continuously compressed, leading to the creation of a series of reverse faults, notably encountered in Bach Ho, Diamond field [10]. The tectonic progresses mentioned above had created a sedimentary basin with closed boundaries, resembling a large lake [2, 7]. Finally, the Cuu Long basin has been undergoing thermal subduction from the early Miocene to the present, representing a relatively stable phase and a significant influence of the marine environment.

The strata of Blocks 01&02 are relatively similar to those in the Cuu Long basin, as mentioned by previous studies. According to Tran Le Dong and Tran Dac Hoai [8], a stratigraphic and lithological column refers to a graphical representation or chart that depicts the geological formations in a specific area. In this context, the column includes both the pre-Tertiary fractured basement and Tertiary sedimentary rocks. The construction of this column involves detailing the characteristics of petrography, fossils, and sedimentation for each stratigraphic unit. Figure 3 is likely a visual representation accompanying this construction, providing a detailed illustration of the geological layers and their respective features in the studied region. Six sedimentary sequences, labeled from F to A, are identified, along with one pre-Tertiary fractured basement unit. Below is a brief description of both the basement and the overlying clastics:

- The Tertiary basement rocks consist of intrusive crystallized granite rocks, contemporaneous with three complexes: Hon Khoai, Dinh Quan, and Ca Na [8].

- The F sequence (or G sequence with local distribution) spans from the Eocene to the lower Oligocene, constituting the earliest formation and likely present in the deepest sections of the Cuu Long basin. This formation comprises lithological elements such as sandstones, conglomerates, siltstones, and interspersed thin shales. These deposits originated in a high-energy environment, characterized as alluvial and proluvial.

- The E sequence, dating to the early upper Oligocene, is composed of well-sorted to fine-grained sandstones along with thin conglomerates, siltstones, and interbedded shale.

- The D sequence, dating to the middle upper Oligocene, predominantly comprises sandstones, silt, and shale. These sediments were deposited in swampy, alluvial, and lacustrine environments..

- The C sequence, dating to the late upper Oligocene, is primarily composed of sandstones with varying grain sizes, including medium, fine, and very fine grains. These sandstones are interbedded with silt and claystones, and they were deposited in deltaic plains and lacustrine environments. Additionally, they completely filled the remaining lakes within the rift basin.

- The sedimentary sequences, dating from the late Oligocene to the Miocene B, are primarily composed of shale with interbedded sandstones and minor carbonate layers. These sediments were deposited in swampy, lacustrine, and shallow marine environments.

- The sedimentary sequence A, spanning from the Pliocene to Quaternary A, is characterized by coarse-grained, unconsolidated sandstones interbedded with shale, carbonate, and coal layers [7].

4. Fundamental theory for constructing a 1D geomechanical model from geological and wireline logging

The 1D geomechanical model (1D MEM) comprises mechanical, elastic properties of rocks and states of in-situ stresses along the wellbore [11]. Fundamentally, the 1D geomechanical model uses geological and various wireline logging data to obtain vertical stress (σ_V), pore pressure P_p, elastic properties including shear (G_{dyn}) and bulk K_{dyn} modulus, Young's modulus E and Poisson's ratio (ϑ). It also calculates rock strengths such as uniaxial compressive stress UCS, tensile TS, friction angle FANG, minimum σ_{hmin} and maximum σ_{Hmax} horizontal stresses.

There is a workflow to construct 1D MEM model as following:

(i) Review and collection of data. In this research, the

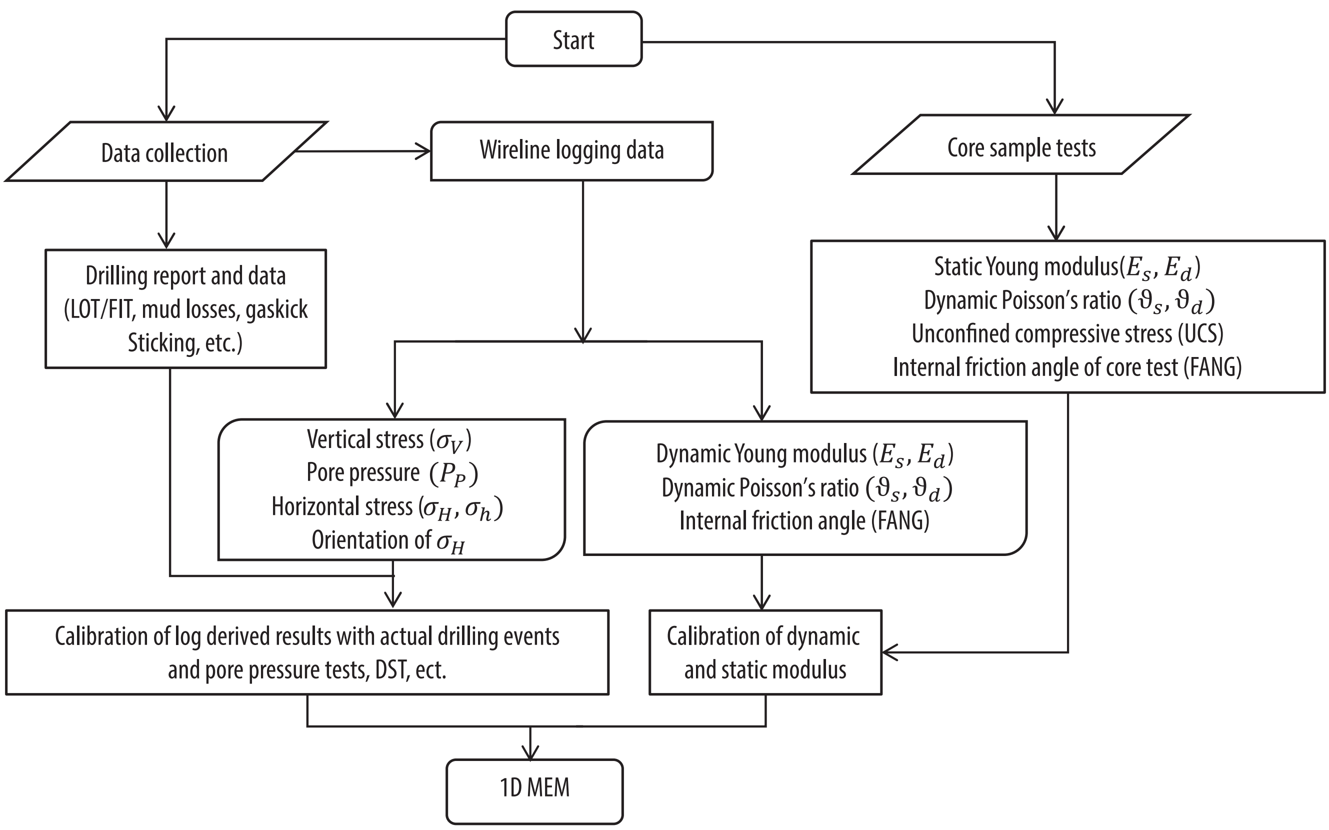

Figure 4. *Workflow for determination of the 1D MEM geomechanical model.*

authors review and collect wireline logging data in Blocks 01&02, the Northern East part of Cuu Long basin. The data encompass completion well data, drilling reports, laboratory core tests and wireline logging data such as gamma ray (GR), caliper log, density log (RHOB), neutron (NPHI), compression/shear sonic travel time (DTC/DTS), image formation log (FMI), pressure test (MDT) and leak of test (LOT, XLOT).

(ii) Determination of vertical stress, pore pressure, magnitude and orientation of maximum horizontal stress, magnitude of minimum horizontal stress.

(iii) Determination of elastic parameters, rock strengths, and final interpretation of the failure of the rocks (Figure 4).

4.1. Determination of vertical stress and pore pressure

- Vertical stress

The vertical stress (psi) or overburden stress (σ_V) is the pressure exerted on a formation at a given depth due to the total weight of the rocks and fluids above that depth and derived by Equation (1) [12]:

$$\sigma_V = \rho_w . z_w . g + \int_0^z \rho_b(z) . g . dz \quad (1)$$

where ρ_b, ρ_w are density of rocks (RHOB) and density of fluid in g/cm^3; g is the gravity acceleration in m/s^2; z and z_w are respectively vertical depth and sea water height in meters. Normally, density log is not measured fully along a wellbore. Therefore, the density data must be filled for gap intervals using several empirical correlations. One of those frequently used to process is the extrapolation density method. Mostly, the density of seawater and average density of rocks are 1.03 g/cm^3 and 2.3 g/cm^3, respectively [12].

- Pore pressure

Pore pressure is the pressure of fluids in the pore space of rocks. It is one of the most important parameters of exploration and production wells. According to Eaton's method, the pore pressure (psi) is determined from the vertical stress and sonic log as follows [13, 14]:

$$P_p = \sigma_V - (\sigma_V - P_{p\_norm}).(\frac{DT_{obser}}{DT_{norm}})^3 \quad (2)$$

Where P_p is the pore pressure; P_{p_norm} is hydrostatic pressure in psi; DT_{obser} is the measured log (DTC); DT_{norm} is the normal compaction trend, in ms/ft. Afterward, the results of pore pressure will correlate with pore pressure points which are measured directly from MDT/DFT/RCI logs or DST results.

4.2. Elastic properties of the rocks

- Elastic parameters

The elastic parameters are necessary to construct the 1D geomechanical model and encompasses Young's modulus, Poisson ratio, shear modulus and bulk modulus [11]. In fact, the values of Young's modulus and Poisson's ratio calculated from the wireline logs are normally greater than those obtained from laboratory core tests. Therefore, it is needed to calculate Young's modulus and Poisson dynamic modulus [15], as follows:

$$E_{Dyn} = \frac{9G_{dyn} \times K_{dyn}}{G_{dyn}+3K_{dyn}} \quad (3)$$

Dynamic Young's modulus (E_{Dyn}) is a parameter indicating the deformation characteristics of rocks along any axis. It represents a capacity of rocks resisting elastic deformation.

$$\vartheta_{Dyn} = \frac{3K_{dyn}-2G_{dyn}}{2G_{dyn}+6K_{dyn}} \quad (4)$$

Where:

Dynamic shear modulus (G_{dyn}), shown below, is also known as the modulus of rigidity, a measure of the sample's resistance to shear deformation.

$$G_{dyn} = \frac{\rho_b}{DTC^2} \quad (5)$$

- Dynamic bulk modulus (K_{dyn}), shown below, is a measurement of the sample's resistance to hydrostatic compression.

$$K_{dyn} = \frac{\rho_b}{DTC^2} - \frac{4}{3}G_{dyn} \quad (6)$$

Derived parameters from wireline logs are terms of the dynamic elastic moduli. These values must be converted to the static elastic moduli through a correlation which is shown in Equations (7), (8) below [16].

$$E_{sta} = 0.032 \times E_{dyn}^{1.632} \quad (7)$$

$$\vartheta_{sta} = \vartheta_{Dyn} \quad (8)$$

- Rock strengths

Uniaxial compressive stress (UCS): The compressive strength is probably the most widely used and quoted rock engineering parameter. It is the maximum axial compressive stress that rocks can withstand before failure, denoted as UCS, in psi. The UCS values of rocks are determined through uniaxial compressive tests. In addition, there are many methods to calculate the unconfined compressive stress [17]. J.Fuller [16, 18] proposed a correlation between UCS and the slowness of travel time of rocks.

$$UCS = 0.77 \times \left(\frac{304.8}{DTC}\right)^{2.93} \quad (9)$$

+ Tensile failure (*TS*), in psi: It is the maximum strain stress that rocks can withstand before failure, denoted as *TS*. Tensile strength normally assumes to be 1/10 values of *UCS* [19, 20].

+ Internal friction angle (*FANG*), in degree: It is a characteristic parameter representing shear resistance of the rocks, describing the shear resistance due to a friction of rocks with effective stress at an angle. Friction angle is a function of porosity and clay volume which was proposed by Plumb [11].

$$FANG = 26.5 - 37.4(1 - \Phi - V_{cl}) + 62.1(1 - \Phi - V_{cl})^2 \quad (10)$$

+ Minimum horizontal stress and maximum horizontal stress, in psi: These are magnitudes of minimum and maximum compressive stresses in the horizontal direction, denoted as σ_{hmin} and σ_{Hmax}, respectively. In the field, values of σ_{hmin} can be referred to using LOT, XLOT and minifrac data from drilling wells [21]. Additionally, σ_{hmin}, σ_{Hmax} can be estimated from wireline logs (11), (12) [11, 16]

$$\sigma_{hmin} = \frac{\vartheta}{1-\vartheta}\sigma_V + \frac{1-2\vartheta}{1-\vartheta}\alpha P_p + \frac{E}{1-\vartheta^2}\varepsilon_h + \frac{\vartheta E}{1-\vartheta^2}\varepsilon_H \quad (11)$$

$$\sigma_{Hmax} = \frac{\vartheta}{1-\vartheta}\sigma_V + \frac{1-2\vartheta}{1-\vartheta}\alpha P_p + \frac{E}{1-\vartheta^2}\varepsilon_H + \frac{\vartheta E}{1-\vartheta^2}\varepsilon_{min} \quad (12)$$

+ Azimuth angle of the maximum horizontal stress: This parameter is determined by using wellbore image logs such as FMI, FMS, CBIL, ect. These are useful methods for determining the orientation of the maximum horizontal stress σ_{Hmax}. Analyzing wellbore image logs can show occurrence of faults, fractures yielding three types of structures: (1) Sinusoidal shape clearly visible around wellbore which marks plane fault or foliation planes. (2) Pairs of traces parallel to the wellbore axis offset by 180° and not interconnected around the wellbore wall are called drilling induced tensile wall fractures because they are formed during the drilling process as pure tensile fractures but do not appear to propagate significantly into the rock surrounding the borehole, and therefore are limited to the borehole wall. (3) Fracture traces 180° offset at their borehole wall but inclined with respect to the borehole axis [22]. The well used for this study lack of the wellbore image data. Therefore, the determination of the orientation of the maximum horizontal stress is based on references from surrounding area (Figure 5). Figure 5 indicates that the orientation of the maximum horizontal stress is N138+/-12.

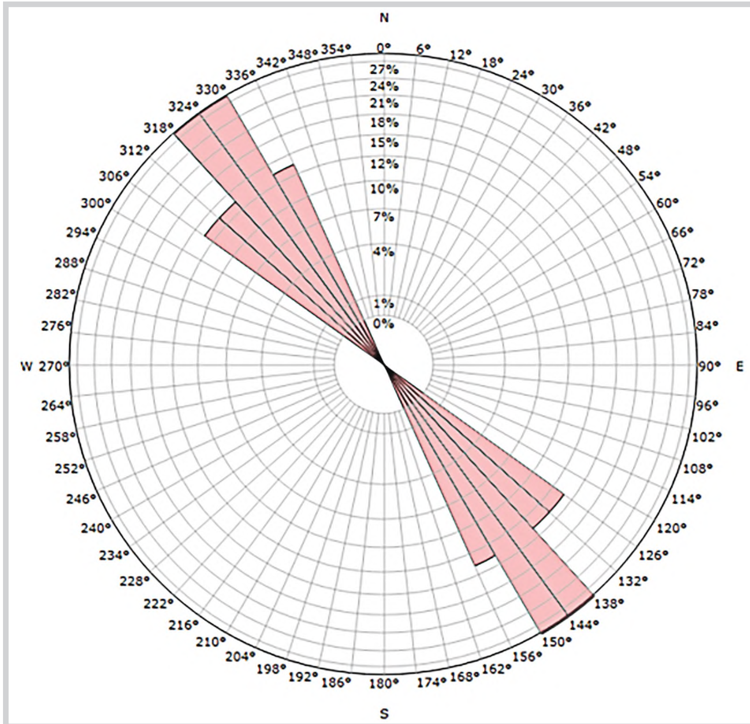

Figure 5. *The orientation of the maximum horizontal stress is referred surrounding area indicating an azimuth of N138 +/-12°.*

5. A case study of 1D geomechanical model for well Y-1 in Ruby field

The 1D geomechanical model is constructed for a well in the study area. Its results are quite similar to actual events that occurred during drilling processes such as breakout intervals, stuck or tight holes, etc. Figure 6 illustrates drilling progressive and drilling problems in well Y-1. It is noted that in the depth interval from 1,600 - 2,300 m with hole diameter of 12.25 inches, the drilling mud weight was applied as high as 10.0 ppg. However, a series of problems was taken place, such as tight spots and mud losses, prompting the petroleum operator to adjust the mud weight to 9.5 ppg. Nevertheless, well Y-1 continues to experience mud dynamic losses, and connection gases. In the section 8.5 inches, the mud weight increases from 9 ppg to 10.5 ppg. However, the well still encounters tight spots and stuck pipes, and then the wellbore gets more stability when mud weight increases further to 10.6 ppg despite some minor losses. Then, there are some tight spots when running the 7 inch liners.

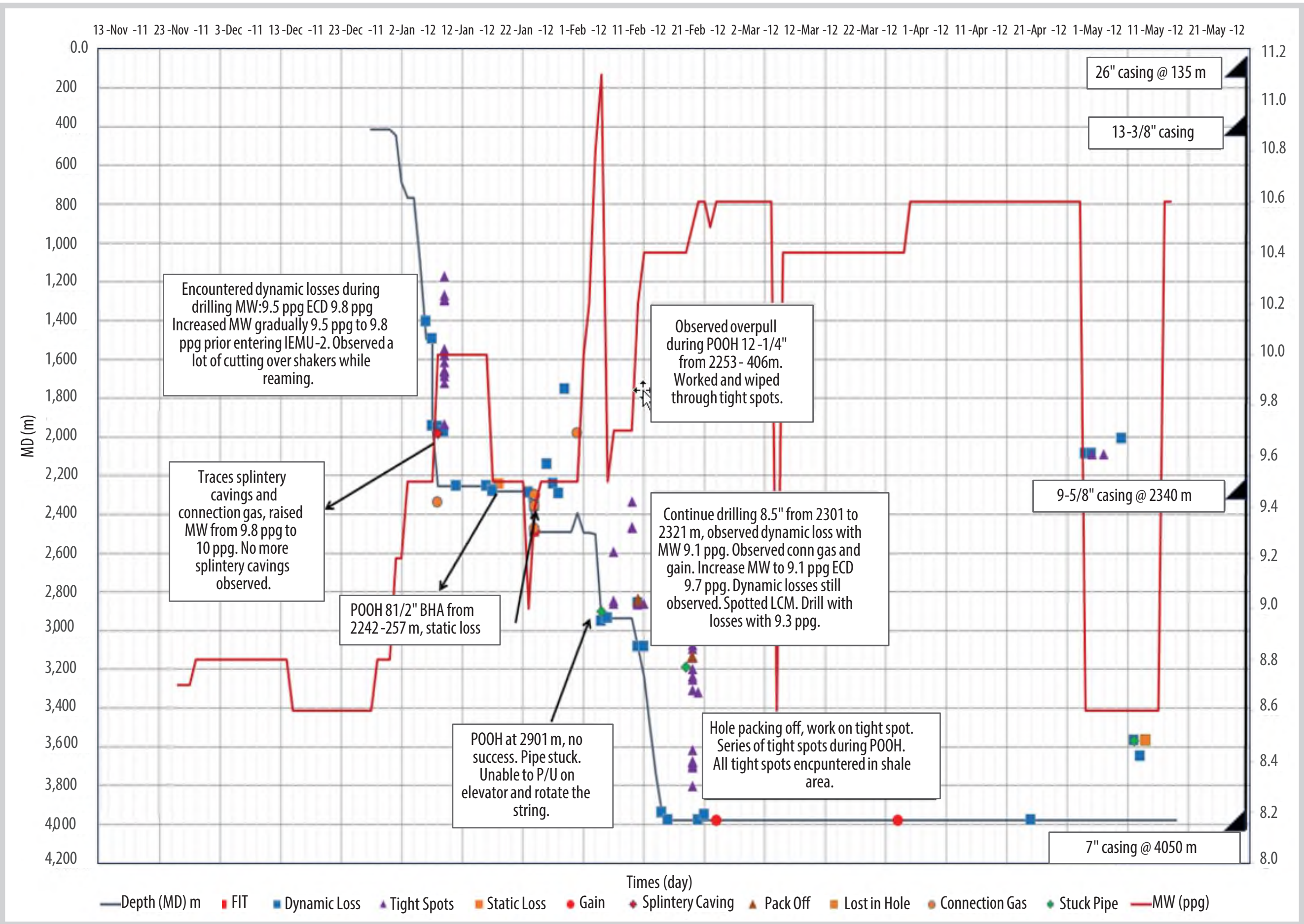

Figure 6. *Time verse depth chart of well Y-1, as shown incidents during drilling.*

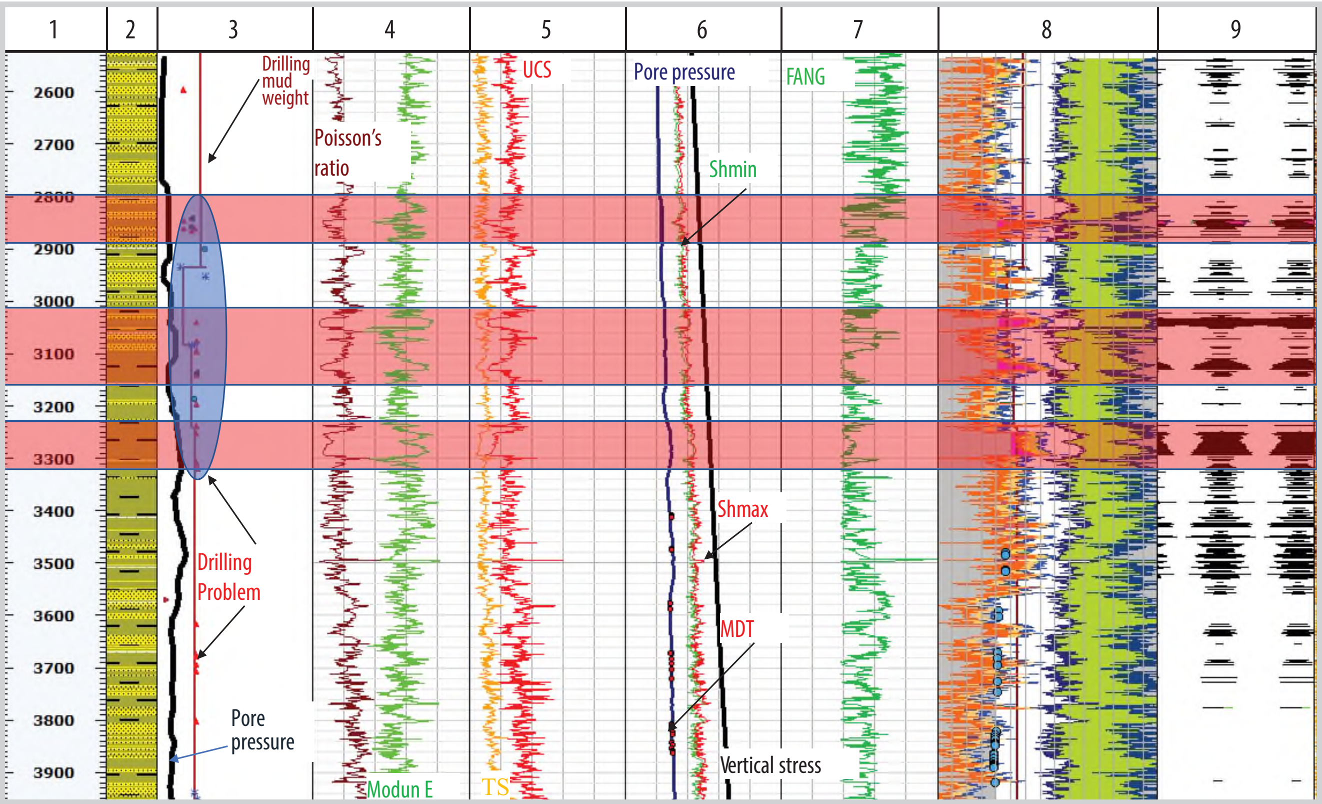

Figure 7. *Displaying outputs of the 1D geological model for well Y-1.*

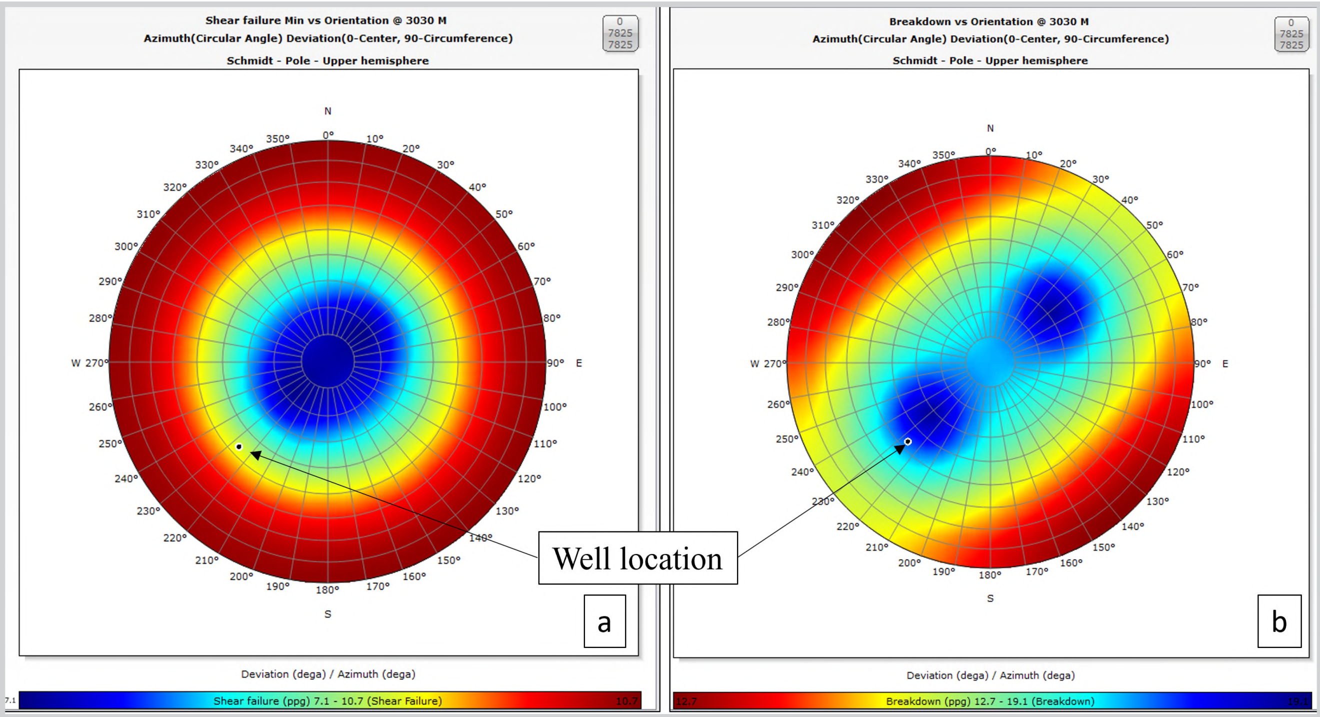

Figure 8. *The sensitivity of mud weight at a depth of 3,330 mMD: (a) No experience fracture failure; (b) Strongs washouts.*

Table 1. *Parameters of the 1D geomechanical model in depths of well Y-1*

Well status vs applied mudweight				Results of 1DMEM and Proposed Mudweight									
Depth (mMD)	Lithology	Used mudweight (ppg)	Well status	Pore pressure Gradient (psi/ft)	Vertical Gradient (psi/ft)	Shmin (psi)	Shmax (psi)	Poisson (frac)	Young E (pdi)	UCS (psi)	TR (psi)	FANG (deg)	Proposed mudweight (ppg)
2,750	Shale	10.80	Good	3240.58	3886.26	5019.00	5293.00	0.29	0.89	5391.2	539.20	30.60	10.80
2,800	Sand	10.80	Good	3297.60	7002.00	4927.60	5263.00	0.27	1.06	5744.8	574.40	34.90	10.80
2,850	Shale	10.80	Breakout	3558.50	7120.00	4632.90	4736.20	0.32	0.22	1779.2	177.90	19.00	11.40
3,120	Shale	10.20	Breakout	3851.60	7761.10	6205.20	6319.40	0.39	0.36	3558.2	335.80	19.20	12.00
3,280	Shale	10.40	Breakout	4415.30	8146.40	6581.40	6700.00	0.40	0.35	3352.7	335.20	23.30	12.00
3,500	Sand	10.40	Breakout	4583.40	8676.90	7395.20	7487.20	0.30	0.39	3849.2	384.90	19.00	11.70
3,630	Sand	10.40	Breakout	4381.10	9024.00	6866.00	7046.50	0.60	0.33	4327.7	432.70	20.80	11.00
3,900	Sand	10.40	Good	4668.70	9810.80	6816.50	7267.00	1.40	0.25	7064.2	706.40	27.90	10.40

Figure 7 shows the outputs from 1D geomechanical model. Track #6 shows parameters of vertical stress, pore pressure, maximum and minimum horizontal stresses; Poisson’s ratio and Young's modulus are expressed in track #4, while track #5 shows parameters of uniaxial compressive stress and tensile strength. Track #7 exclusively shows parameters of internal friction angle. Tracks #8 and 9 display the mud weight windows and breakout intervals. Track #3 records the mud weight used during drilling.

The interval of the study in the well ranges from 2,500 m to approximately 4,000 m with lithological components comprising sandstones interbedded and dominantly claystones.

There are some problems encountered while drilling, which are marked in red zones in depth intervals of 2,800 - 2,900 m, 3,020 - 3,187 m and 3,230 - 3,310 m. In these intervals, the drill mud weight is set down, from 10.4 ppg to 9.7 ppg, and then back to 10.4 ppg. Despite the similar mud weight applied, a series of drilling problems are still encountered, including tight spots, collapse, sticking and even gaskicks. Comparing the pore pressure calculation results to the applied drilling mud weight, there is a difference greater than 1 - 1.5 ppg, yet the wellbore wall remains unstable. Comparing the results of the 1D geomechanical model to the applied mud weight indicates that the wellbore wall is still experiencing breakout, collapsing that agrees with actual drilling events. Nevertheless, the 1D geomechanical model also suggests proper mud weights for each interval: 10 ppg for 2,500 - 2,810 m, 12 - 12.5 ppg for 2,810 - 3,550 m, respectively. The remaining intervals of the wellbore should have a reduced mud weight to around 11.7 - 11.5 ppg.

The sensitivity analysis of the mud weight regarding potential of breakout and fracture failure due to the inclination and the azimuth of the wellbore is carried out at a depth of 3,330 m. The result indicates that the wellbore is able to wash out strongly but not cause fracture failure, as illustrated in Figure 8.

The calculation results of the 1D geomechanical model are shown in depths of well Y-1 in Table 1.

6. Conclusions

The research area is located in the Northeast of Cuu Long basin, which is formed through complex tectonic evolutions from the pre-Tertiary to the present. It is a typical rift basin where rifting activities have been undergoing from the Eocene to the late Oligocene. There is also a short time period of compression from the late Oligocene to the early Miocene, though not very intense. Being considered to mainly undergo thermal subduction, the Cuu Long basin is therefore characterized by a normal fault regime with stress field $\sigma_V > \sigma_{Hmax} > \sigma_{hmin}$. The results of well Y-1 have a series of drilling problems relating to drilling mud weights such as sticking pipe, tight spots, gas kick, mud losses, breakout, etc. This study is based on geological and wireline logging data to calculate and construct the 1D geological model to determine parameters of vertical stress, pore pressure, elastic properties (Young's modulus, Poisson’s ratio), minimum and maximum horizontal stresses, unconfined compressive stress and mud window for each interval of well Y-1. The mud weight for each interval should be set around 10 - 12.5 ppg.

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GEOMECHANICS APPLIED TO THE PETROLEUM INDUSTRY: WELLBORE STABILITY, SAND PRODUCTION, AND HYDRAULIC FRACTURING

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Summary

This article introduces three applications of geomechanics in oil and gas industry, encompassing wellbore stability analysis, hydraulic fracturing, and sand production. In this paper, we reviewed three commonly used applications involving transforming stress values from the in situ coordinate system to the wellbore centric coordinate system, which have been published in the previous studies. Subsequently, various failure criteria are applied to these three geomechanical problems. First, wellbore stability analysis involves six distinct scenarios across different oil reservoirs. The results obtained enable the selection of appropriate drilling mud densities to prevent collapses and instability of wellbore. Second, regarding sand production modeling, three oil fields are presented as examples. The results consistently indicate instances of sand production under various well production conditions. Finally, the application of geomechanics in hydraulic fracturing is illustrated. The findings distinctly illustrate the evolutionary pattern of fracture dimensions, highlighting a consistent trend in fracture length development. Notably, the expansion phase of the fracture exhibits a rapid onset during the initial stages, followed by a transition into an exceedingly gradual propagation state.

Key words: Geomechanics, sanding, wellbore stability analysis, hydraulic fracturing.

1. Introduction

Geomechanics plays an important role in every operation involved in the exploitation of hydrocarbon, from drilling to production and right up to the time the wells are abandoned. Reservoir pressure changes during production modify the *in situ* stresses and cause strain in both reservoir and entire sedimentary column.

One of the primary applications of geomechanics in the oil and gas sector is wellbore stability analysis [1]. As drilling operations in different geological formations, the interaction between the wellbore and formation can lead to instability issues as borehole collapse, formation damage, or fluid influx. Through geomechanical modeling and analysis, engineers can anticipate potential challenges and implement preventive measures, including mud weight, wellbore reinforcement, or casing design modifications.

Geomechanics also plays a pivotal role in hydraulic fracturing, a technique extensively used in unconventional reservoirs. Assessing the stress distribution within the reservoir rock and understanding its response to hydraulic fracturing fluids is crucial in optimizing fracture design, enhancing production rates [2].

Another application of geomechanics is sand production prediction [3]. By analyzing the mechanical properties of the reservoir rock, geomechanical engineers can predict the conditions under which sand grains might detach and migrate into the wellbore. This involves studying factors such as formation strength, stress distribution, and the interaction between fluids and the rock matrix. Through geomechanical assessment, engineers can design effective sand control measures to minimize or prevent sand production. These measures may include gravel packing, sand screens, chemical consolidation, or altering production techniques to manage reservoir pressures and stresses. Moreover, ongoing geomechanical monitoring helps in identifying potential changes in reservoir conditions that might lead to increased sand production. By continuously evaluating stress changes and the mechanical behavior of the formation during production, engineers can implement proactive measures to mitigate sanding issues, thereby maintaining well integrity and productivity.

Ngày nhận bài: 6/11/2023. Ngày phản biện đánh giá và sửa chữa: 6-30/11/2023
Ngày bài báo được duyệt đăng: 7/12/2023.

The three above applications of wellbore stability analysis, hydraulic fracturing, and sand production prediction are typically presented in various studies and papers. However, these applications were presented in separate articles give rise to challenging and/or inconvenience for users to synthesize information of apply them to specific geomechanical problems. To address this issue, the author aims to integrate and introduce these three common applications of geomechanical problems in the oil and gas industry, providing engineers with a reference source for practical scenarious they might encounter. The paper presents three applied geomechanical problems as hypothetical cases applicable to diverse situations at a specified depth of the borehole. Depending on the particular situation and conditions of the boreholes, users can ascertain corresponding geomechanical parameters (e.g., via drilling log data) for application, analysis, and computation at varying depths by referencing the methodology outlined in this paper.

2. Stresses around deviated boreholes

Consider that the *in situ* principal stresses are vertical stress σ_v, major horizontal stress σ_H, and minor horizontal stress σ_h. These stresses align with the coordinate system (x', y', z'), depicted in Figure 1a. The z'-axis coincides with σ_v, x'-axis is parallel to σ_H, and y'-axis is parallel to σ_h. To analyze the stress distribution around a borehole, it is necessary to transform these original stresses into another coordinate system (x, y, z) as shown in Figure 1b. In this new coordinate system, z-axis is parallel to the borehole axis, the x-axis is parallel to the lowermost radial direction of the borehole, and the y-axis is horizontal. This transformation can be obtained by a rotation α around the z'-axis, and then a rotation i around the y'-axis (Figure 2) [4].

Using the stress transformation equation, the initial formation stresses expressed in the (x, y, z) coordinate system are transformed to:

$$\sigma_x = (\sigma_H cos^2\alpha + \sigma_h sin^2\alpha)cos^2 i + \sigma_v sin^2 i \quad (1a)$$

$$\sigma_y = \sigma_H sin^2\alpha + \sigma_h cos^2\alpha \quad (1b)$$

$$\sigma_z = (\sigma_H cos^2\alpha + \sigma_h sin^2\alpha)sin^2 i + \sigma_v cos^2 i \quad (1c)$$

$$\tau_{xy} = \frac{1}{2}(\sigma_H - \sigma_h)sin2\alpha cosi \quad (1d)$$

$$\tau_{xz} = \frac{1}{2}(\sigma_H cos^2\alpha + \sigma_h sin^2\alpha - \sigma_v)sin2i \quad (1e)$$

$$\tau_{yz} = \frac{1}{2}(\sigma_H - \sigma_h)sin2\alpha sini \quad (1f)$$

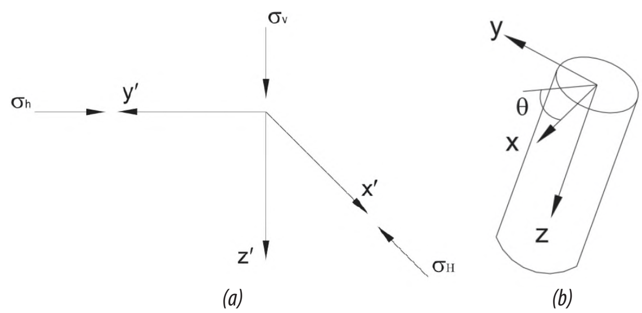

Figure 1. *In situ stress co-ordinate system.*

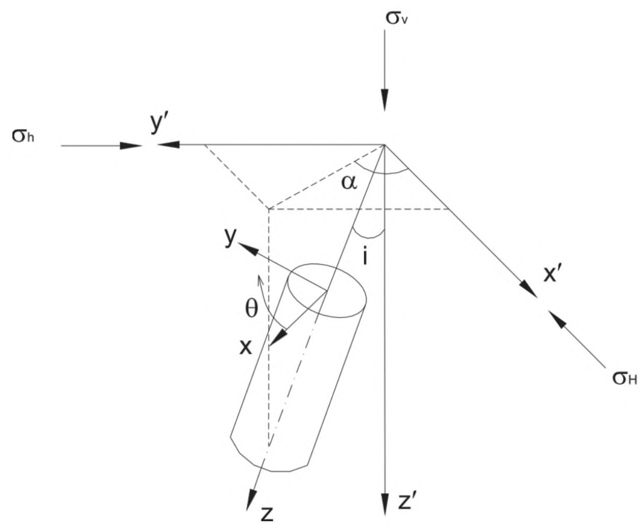

Figure 2. *Stress transformation system for deviated borehole.*

Nevertheless, the excavation of a wellbore will modify the *in situ* stresses that are given in the above equations. The complete stress solutions, in cylindrical co-ordinate system, around an arbitrarily oriented wellbore are:

$$\sigma_r = \frac{1}{2}(\sigma_x + \sigma_y)\left(1 - \frac{a^2}{r^2}\right) + \frac{1}{2}(\sigma_x - \sigma_y)\left(1 + 3\frac{a^4}{r^4} - 4\frac{a^2}{r^2}\right)cos2\theta + \tau_{xy}\left(1 + 3\frac{a^4}{r^4} - 4\frac{a^2}{r^2}\right)sin2\theta + \frac{a^2}{r^2}P_w \quad (2a)$$

$$\sigma_t = \frac{1}{2}(\sigma_x + \sigma_y)\left(1 + \frac{a^2}{r^2}\right) - \frac{1}{2}(\sigma_x - \sigma_y)\left(1 + 3\frac{a^2}{r^2}\right)cos2\theta - \tau_{xy}\left(1 + 3\frac{a^2}{r^2}\right)sin2\theta - \frac{a^2}{r^2}P_w \quad (2b)$$

$$\sigma_a = \sigma_z - 2\nu(\sigma_x - \sigma_y)\frac{a^2}{r^2}cos2\theta - 4\nu\tau_{xy}\frac{a^2}{r^2}sin2\theta \quad (2c)$$

$$\tau_{\theta z} = (\tau_{yz}cos\theta - \tau_{xz}sin\theta)(1 + \frac{a^2}{r^2}) \quad (2d)$$

$$\tau_{r\theta} = [\frac{1}{2}(\sigma_x - \sigma_y)sin2\theta + \tau_{xy}cos2\theta](1 - 3\frac{a^4}{r^4} + 2\frac{a^2}{r^2}) \quad (2e)$$

$$\tau_{rz} = (\tau_{xy}cos\theta + \tau_{yz}sin\theta)(1 - \frac{a^2}{r^2}) \quad (2f)$$

where "a" is the radius of the wellbore, P_w is the internal wellbore pressure, and ν is a material constant called Poisson's ratio. The angle θ is measured clockwise from x-axis as shown in Figure 2.

Deviated wellbore

For a deviated wellbore, the stress at borehole wall can be estimated by setting r = a in Equation (2), which givens:

$$\sigma_r = P_w \quad (3a)$$

$$\sigma_t = (\sigma_x + \sigma_y) - 2(\sigma_x - \sigma_y)cos2\theta - 4\tau_{xy}sin2\theta - P_w \quad (3b)$$

$$\sigma_a = \sigma_z - 2v(\sigma_x - \sigma_y)cos2\theta - 4v\tau_{xy}\frac{a^2}{r^2}sin2\theta \quad (3c)$$

$$\tau_{\theta z} = (\tau_{yz}cos\theta - \tau_{xz}sin\theta)(1 + \frac{a^2}{r^2}) \quad (3d)$$

$$\tau_{r\theta} = [\frac{1}{2}(\sigma_x - \sigma_y)sin2\theta + \tau_{xy}cos2\theta](1 - 3\frac{a^4}{r^4} + 2\frac{a^2}{r^2}) \quad (3e)$$

$$\tau_{rz} = (\tau_{xy}cos\theta + \tau_{yz}sin\theta)(1 - \frac{a^2}{r^2}) \quad (3f)$$

Vertical wellbore

In order to determine the stresses at wall of a vertical borehole, the inclination angle I can be set to 0 in Equation (1). For simplicity, the direction $\theta = 0$ is parallel to σ_H. Consequently, the stresses become:

$$\sigma_r = P_w \quad (4a)$$

$$\sigma_t = (\sigma_H + \sigma_h) - 2\ (\sigma_H - \sigma_h)cos2\theta - P_w \quad (4b)$$

$$\sigma_a = \sigma_v - 2v(\sigma_H - \sigma_h)cos2\theta - P_w \quad (4c)$$

$$\tau_{\theta z} = 0 \quad (4d)$$

$$\tau_{r\theta} = 0 \quad (4e)$$

$$\tau_{rz} = 0 \quad (4f)$$

Horizontal wellbore

To estimate the stresses at the wall of a horizontal borehole, substitute $i = \pi/2$ in Equation (1). Then by introducing this into Equation (3), the stresses at borehole wall can be determined as:

$$\sigma_r = P_w \quad (5a)$$

$$\sigma_t = (\sigma_v + \sigma_H sin^2\alpha + \sigma_h cos^2\alpha) - 2\,(\sigma_v - \sigma_H sin^2\alpha - \sigma_h cos^2\alpha)cos2\theta - P_w \quad (5b)$$

$$\sigma_a = \sigma_H cos^2\alpha + \sigma_h sin^2\alpha - 2v(\sigma_v - \sigma_H sin^2\alpha - \sigma_h cos^2\alpha)cos2\theta - P_w \quad (5c)$$

$$\tau_{\theta z} = (\sigma_h - \sigma_H)sin2\alpha cos\theta \quad (5d)$$

$$\tau_{r\theta} = 0 \quad (5e)$$

$$\tau_{rz} = 0 \quad (5f)$$

3. Borehole stability analysis and case application

Oil fields are commonly exploited through multiple platforms that significantly impact the development costs. The use of non-vertical production wells can mitigate the need for numerous platforms. Deviated and horizontal wells substantially expand the drainage area from a single source, enhancing productivity and potentially reducing the necessity for additional platforms. In some cases, deviated boreholes are drilled to reach a substantial distance horizontally away from the drilling location. This approach efficiently accesses diverse reservoir sections, aiding in reducing the required number of platforms. Moreover, deviated boreholes serve as crucial conduits to inaccessible locations unreachable by vertical boreholes. However, drilling nonvertical boreholes introduces new challenges, including cuttings transport, casing setting and cementing, and drill string friction. An increased borehole angle will also increase the risk of borehole instability during drilling process.

Borehole instability is a significant cause of wellbore failures, presenting a critical challenge in the drilling industry. Inaccurate wellbore stability analysis leads to various issues, including borehole washouts, breakouts, collapses, pack-offs, stuck drill pipes and drill bits, and even losses of boreholes. For instance, in the Gulf of Mexico, operators encountered substantial borehole instability and sanding due to the presence of unconsolidated sands and reactive shales. The chemical impact of drilling fluid on reactive shales is another important factor affecting wellbore stability, particularly in the shales containing more smectite clay minerals. The utilization of water-based drilling mud is used, triggers chemical reactions between the shale and the mud, resulting in shale swelling and subsequent wellbore collapse. Some instances of wellbore instabilities are linked to complex geological settings, where the *in situ* stress patterns are influenced by active faults.

During the drilling phase, critical considerations involve determining the mud composition and density to maintain wellbore stability while preventing drilling fluids loss. Before full production, downhole tests encompass open-hole logging, fluid sampling, and injection tests, which may induce wellbore failure and casing collapse. As hydrocarbons are extracted and reservoir pressure gets depleted, compacting of drained formations becomes a concern, potentially leading to solids production, casing impairment, surface subsidence, and wellbore instability. In all these stages, integrated borehole stability analyses are important to ensure reservoir production and minimize the costly problems induced by wellbore instabilities.

Wellbore stability is primarily influenced by the *in situ* stress system. During the drilling of a well, the rock surrounding the hole must take the load that was previously supported by the removed rock. Consequently, the *in situ* stresses are significantly modified near the borehole wall. This is demonstrated by the generation of increased stress around the wall of the hole, creating a stress concentration. Stress concentration can result in rock failure, particularly along the borehole wall, depending up on the existing rock strength. The fundamental challenge lies in understanding and predicting the rock behavior to the altered mechanical loading. This is a classical, though not very easy, rock mechanics problem. Typically, the possible adjustment of the borehole orientation is restricted. It is therefore obvious that wellbore instability could be prevented by mainly adjusting the mud pressure. Conventionally, the mud pressure is designed to inhibit flow of the pore fluid into the well, regardless of the rock strength and the field stresses. In practice, maintaining a minimum safe overbalance pressure, often within the range of 100 - 200 psi, or a mud density of 0.3 - 0.5 lb/gallon over the formation pore pressure, is maintained.

Stress-induced borehole failures can be categorized into three classes: hole enlargement or collapse due to brittle rock failure of the wall, hole size reduction due to ductile rock failure resulting from plastic flow of rock into the borehole, and tensile splitting of rock from excessive wellbore pressure. Selecting a failure criterion for wellbore stability analysis is challenging and confusing for drilling engineers. Determining which failure criterion should be used in the wellbore stability analysis. In fact, many failure hypotheses have been propounded as a result of theoretical reasoning only and could not be verified by experimental evidence. The Mohr-Coulomb and Drucker-Prager criterion are commonly used for wellbore stability analysis. While the Drucker-Prager criterion considers the influence of all three principal stresses on failure, the Mohr-Coulomb criterion implicitly ignores the impact of the intermediate principal stress on failure. Despite this difference, both of these failure criteria have been experimentally validated for modelling rock failure, based on conventional triaxial tests ($\sigma_1 > \sigma_2 = \sigma_3$). On the other hand, in practice, the Mohr-Coulomb criterion tends to be excessively conservative in predicting wellbore instability, whereas the Drucker-Prager criterion tends to be overly optimistic about wellbore stability. In the field, the wellbore is normally under a polyaxial stress state ($\sigma_1 > \sigma_2 > \sigma_3$), and the conventional triaxial stress state is special case that may only occasionally be encountered *in situ*. Neither the Mohr-Coulomb nor the Drucker-Prager criterion accounts for polyaxial failure mechanics. These failure criteria were established prior to the development of the first apparatus for true triaxial tests, contributing to their limited accuracy in modeling borehole failure.

Numerous authors have addressed different aspects of wellbore failure in deviated wells. Bradley [5] was the first to model compressive well failure of a deviated well, aiming to recommend appropriate mud weights to prevent borehole failure. However, his analyses were limited to the rare case where the two horizontal stresses are equal and less than the vertical stress. In a deviated well, the principal stresses acting in the vicinity of the wellbore wall are generally not aligned with the wellbore axis. To consider failure in a well of arbitrary orientation, three coordinate systems are defined. Authors always visualize wellbore failure by looking down deviated wells and assessing wellbore failure as a function of angle. Despite the complexities associated with such cases, the goal is to analyze whether the principal stresses acting in a plane tangential to the wellbore wall are such that they exceed the strength of the rock. In case of an arbitrarily deviated well, there is no simple relation between the orientation of far-field stresses and the position around the well at which either compressive or tensile failure might possibly occur. Thus, while breakouts in a vertical well always form at the azimuth of S_{hmin}, regardless of stress magnitude or rock strength (as long as the principal stresses are vertical and horizontal). This is not the case for a well that is arbitrarily oriented with respect to the *in situ* principal stresses. In this case, the position of the breakouts depends on the magnitude and orientation of principal stresses as well as the orientation of well concerning stress field.

Figure 3 illustrates the process of borehole stability analysis. The necessary input data include rock properties, earth stresses, pore pressure, and the planned trajectory of the well. For a simple analysis, only parameters listed in the first row of boxes are required. For a more advanced level of sophistication, chemical, thermal, plastic, anisotropic and time dependent features are added. In most cases, the effects are simply added by superimposing

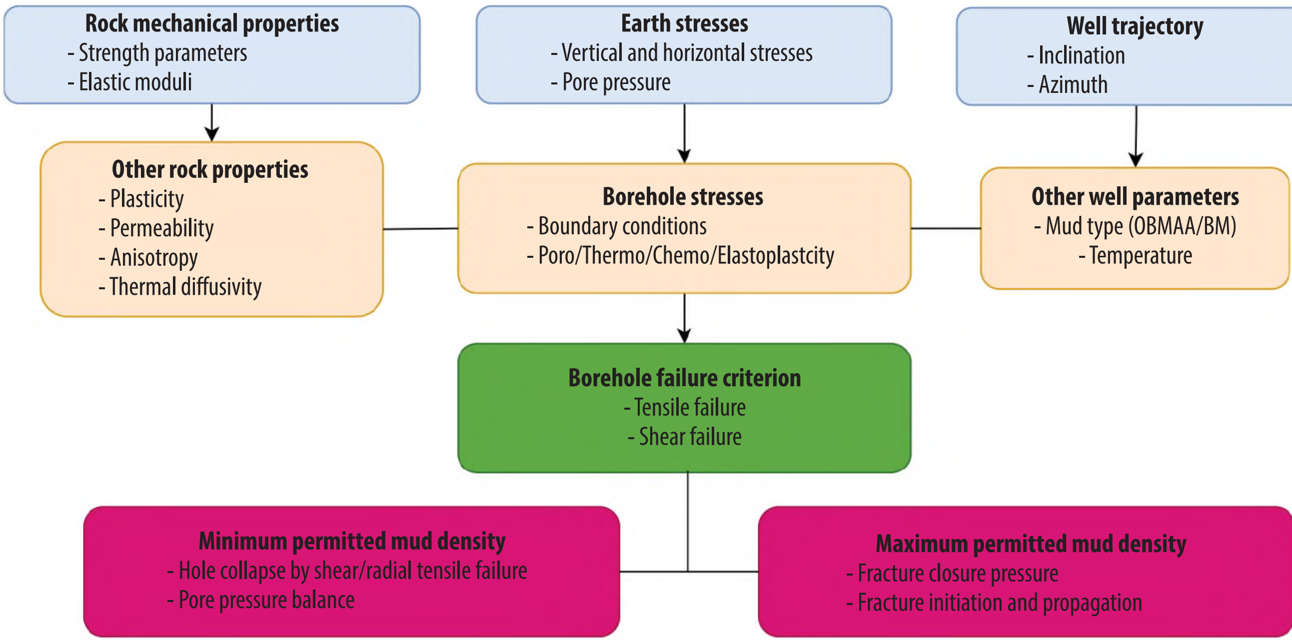

Figure 3. *Flowchart showing the process sequence for wellbore design and stability analysis.*

Table 1. *Conditions for shear failure in vertical borehole*

Case	$\sigma_1 > \sigma_2 > \sigma_3$	Borehole failure occurs at
1	$\sigma_t > \sigma_z > \sigma_r$	$P_{w,min} = P_f + \frac{2(\sigma_h - P_f) - C_0}{1 + tan^2\beta}$
2	$\sigma_z > \sigma_t > \sigma_r$	$P_{w,min} = P_f + \frac{(\sigma_v - P_f) - C_0}{tan^2\beta}$
3	$\sigma_z > \sigma_r > \sigma_t$	$P_{w,min} = P_f + 2(\sigma_h - P_f) - \frac{(\sigma_v - P_f) - C_0}{tan^2\beta}$
4	$\sigma_r > \sigma_z > \sigma_t$	$P_{w,min} = P_f + \frac{2(\sigma_h - P_f)tan^2\beta + C_0}{1 + tan^2\beta}$
5	$\sigma_r > \sigma_t > \sigma_z$	$P_{w,min} = P_f + (\sigma_v - P_f)tan^2\beta + C_0$
6	$\sigma_t > \sigma_r > \sigma_z$	$P_{w,min} = P_f + 2(\sigma_h - P_f) - (\sigma_v - P_f)tan^2\beta - C_0$

*Note: In practice, cases 4, 5, 6 are only of academic interest.

poroelastic, thermoelastic and osmotic contributions to the borehole stresses. This may be satisfactory for most purposes but implies that coupling between chemical and thermal processes are neglected. The output of the analysis is the mud weight window, i.e the minimum well pressure permitted to prevent hole collapse or fluid influx and the maximum allowable well pressure permitted to prevent loss of fluid to the formation by flow into existing or induced fractures. When these limits are known, the well may be designed.

Vertical wellbore

Consider first the situation where $\sigma_t > \sigma_z > \sigma_r$ at the borehole wall. According to the Mohr-Coulomb criterion, if the well pressure drops below the value $P_{w,min}$, shear failure is expected to occur at borehole wall:

$$P_{w,min} = P_f + \frac{2(\sigma_h - P_f) - C_0}{1 + tan^2\beta} \quad (6)$$

Next, $\sigma_z > \sigma_t > \sigma_r$, the failure criterion becomes:

$$P_{w,min} = P_f + \frac{(\sigma_v - P_f) - C_0}{tan^2\beta} \quad (7)$$

In order to map the region of mechanical stability for a vertical well, Erling Fjar et al. [6] examined six permutations of the three principal stresses σ_t, σ_z, σ_r. The equations from this analysis are summarized in Table 1.

Based on the results of authors, cases 4, 5, 6 are mainly of academic interest. However, since they imply a wellbore pressure higher than the overburden stress, a condition that is usually unacceptable in drilling.

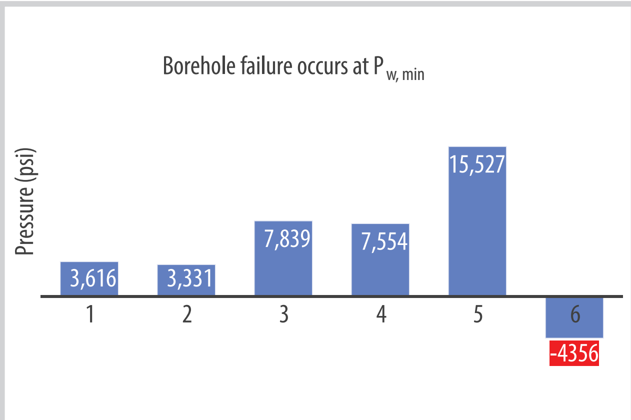

Figure 4. *Minimum mud pressure of vertical well for X-field.*

For a comprehensive analysis of X-field, the pay zone situated at depth of 2236.8 m, the rock reservoir had mechanical properties: $UCS = 3,744$ psi, $\phi = 25^o$, $\nu = 0.2$; Earth stresses condition: $\sigma_h = 6,852$ psi, $\sigma_H = 6,030$ psi, $\sigma_h = 5,585$ psi, $P_p = 3,484$ psi.

From the findings depicted in Figure 4 across the six cases, it is evident that the maximum limiting pressure is observed in case 5. These results enable the selection of an appropriate fluid column pressure, thereby facilitating the choice of suitable drilling fluid density. Notably, in case 6, the result indicates an absence of collapse even under gas drilling conditions.

Table 2. *Conditions for shear failure in horizontal borehole*

	$\sigma_1 > \sigma_2 > \sigma_3$	
	$\sigma_t > \sigma_z > \sigma_r$	$P_{w,min} = \dfrac{M - UCS + P_p\,(tan^2\beta\, - 1)}{1 +\; tan^2\beta}$
	$\sigma_z > \sigma_t > \sigma_r$	$P_{w,min} = \dfrac{\sigma_z - UCS - Mtan^2\beta + P_p(tan^2\beta - 1)}{tan^2\beta}$
	$\sigma_z > \sigma_r > \sigma_t$	$P_{w,min} = \dfrac{UCS + Mtan^2\beta - \sigma_z + P_p(1 - tan^2\beta)}{tan^2\beta}$

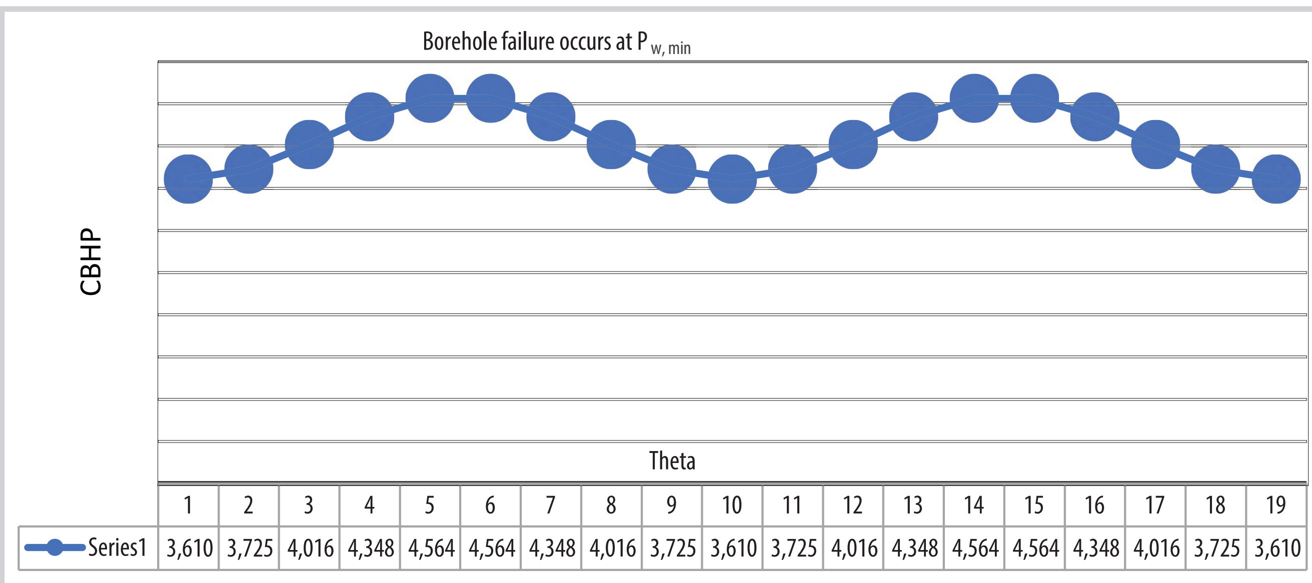

Figure 5. *Minimum mud pressure of horizontal well for X-field.*

Table 3. *Conditions for shear failure in deviated borehole*

	$\sigma_1 > \sigma_2 > \sigma_3$	
	$\sigma_t > \sigma_z > \sigma_r$	$P_{w,min} = \dfrac{\sigma_x + \sigma_y - 2(\sigma_x - \sigma_y)cos2\theta - 4\tau_{xy}sin2\theta - UCS + P_p\,(tan^2\beta - 1)}{1 +\; tan^2\beta}$
	$\sigma_z > \sigma_t > \sigma_r$	$P_{w,min} = \dfrac{\sigma_z - UCS - Mtan^2\beta + P_p(tan^2\beta - 1)}{tan^2\beta}$
	$\sigma_z > \sigma_r > \sigma_t$	$P_{w,min} = \frac{1}{tan^2\beta}(UCS + (\sigma_x + \sigma_y - 2(\sigma_x - \sigma_y)cos2\theta) - 4\tau_{xy}sin2\theta)tan^2\beta - \sigma_z + \nu(2(\sigma_x - \sigma_y)cos2\theta + 4\tau_{xy}sin2\theta) + P_p(1 -\; tan^2\beta))$

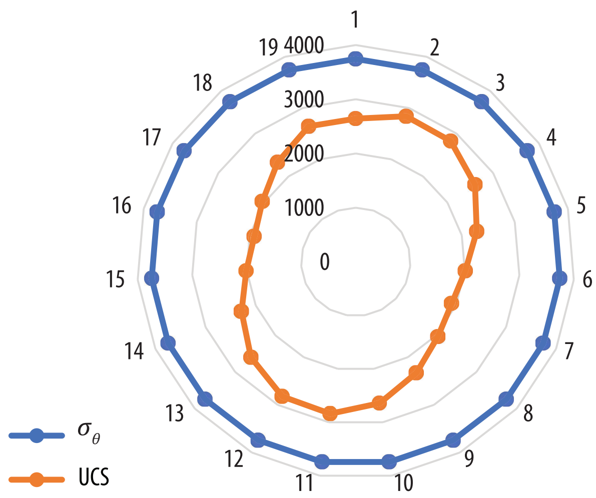

Figure 6. *Stress state around the well.*

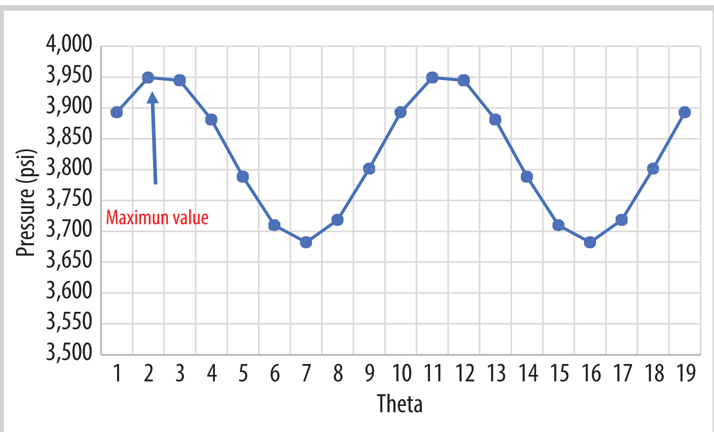

Figure 7. *Minimum mud pressure of deviated well for X-field.*

Horizontal wellbore

The equations for this analysis are summarized in Table 2 considering the situation where $M = (\sigma_v + \sigma_H \sin^2\alpha + \sigma_h \cos^2\alpha) - 2(\sigma_v - \sigma_H \sin^2\alpha\ \sigma_h \cos^2\alpha) \cos 2\theta$.

For a comprehensive analysis of X-field, the pay zone situated at depth of 2236.8 m, the rock reservoir had mechanical properties: $UCS = 3,744$ psi, $\phi = 25^o$, $v = 0.2$; Earth stresses condition: $\sigma_h = 6,852$ psi, $\sigma_H = 6,030$ psi, $\sigma_h = 5,585$ psi, $P_p = 3,484$ psi.

Deviated wellbore

For a comprehensive analysis of X-field, the pay zone situated at depth of 2236.8m, the rock reservoir had mechanical properties: $UCS = 3,744$ psi, $\phi = 25^o$, $v = 0.2$; Earth stresses condition: $\sigma_h = 6,852$ psi, $\sigma_H = 6,030$ psi, $\sigma_h = 5,585$ psi, $P_p = 3,484$ psi.

4. Sand prediction and case application

Sand production refers to the movement of grains from the reservoir rock into a wellbore by the production fluid. In gas and light oil reservoirs, or offshore production, above a certain proportion, sand production causes a number of undesirable problems such as damage to wellbore pumps and wellhead erosion, plugging of perforations or even total invasion of the production column. Numerous methods are available to tackle these issues, but their implementation tends to be costly and often results in decreased production rates. The term "solid" production is used to encompass a broader range of materials than the term "sand" which is more specific to a geological classification and grain size. In general, chalk and coal can also produce solids, ranging from sands to silts and clays. During production, stress changes around the well and the more or less constant flow of gas or oil creates instabilities which crumble the rock forming the reservoir and the fluid flow brings the material into the well. At microscopic scale, sand production is initiated when grains detach from perforations wall due to the impact of the production fluid. Particle dislodgment occurs only when the force applied to the sand particle by the fluid is greater than the sum of the shear strengths at the point of contact with the adjacent particles. It is estimated that around 70% of the world's hydrocarbon reserves are contained in reservoirs where solid production may eventually pose a problem. The issue is particularly prominent in sand reservoirs, hence sand production has attracted the most attention.

Several factors influence solid production, but not all can be incorporated into prediction methods due to some are difficulty to recording or complexities in understanding. A first series of parameters concerns the reservoir characteristics: reservoir thickness, porosity, type, and composition of the fluid (gas, oil, water), petrophysical characteristics (rock intrinsic permeability, relative permeabilities to oil and water, oil and water viscosities, water saturation), *in situ* stress field. A second series of parameters concerns the mechanical characteristics of the reservoir rock: unconfined compressive strength, cohesion, internal angle of friction. A third series of parameters concerns well completion: well orientation and diameter, completion type (open hole, perforations), perforation characteristics, perforation radius, perforation length.

Predicting sand production aids in identifying the most cost-effective sand control methods while maintaining the desired production rate. Once the production borehole has been drilled, cased, and cemented, the reservoir is perforated at regular intervals for production. Production begins by applying a bottomhole flowing pressure (P_{wf}) lower than the virgin reservoir pressure (P_r). The challenge arises when aiming to increase production: elevating the flowing pressure may trigger sand production, while maintaining a low flowing pressure could also induce sand production. Therefore, determining the minimum flowing pressure becomes crucial. The minimum flowing pressure in the bottomhole without sand production is the critical flowing pressure (P_{cwf}). The critical total drawdown pressure (P_{CDP}) is defined as the difference between the reservoir pressure and the critical flowing pressure. This value represents the critical drawdown from the reservoir pressure that induces failure, leading to sand production within the reservoir formation:

$$P_{CDP} = P_r - P_{cwf} \tag{8}$$

Charlez [7] examined a circular drainage area produced at a constant flow rate Q in a vertical open hole with isotropic horizontal stress ($\sigma_H = \sigma_h$). For an elastic plane stress condition and using the Mohr-Coulomb faire criterion, the critical total drawdown pressure was formulated in the following equation:

$$P_{CDP} = \frac{1}{1-\alpha}\left[\frac{UCS}{2} - (\sigma_r - P_r)\right] \tag{9}$$

where α is Biot's effective stress coefficient.

Willson et al. [8] proposed the critical bottomhole flowing pressure resulting in sand production with assumed linear-elastic behavior.

$$P_{cwf} = \frac{3\sigma_{max} - \sigma_{min} - U}{2 - A} - P_r\frac{A}{2 - A} \tag{10}$$

where σ_{max}, σ_{min} are the maximum and minimum *in situ* stresses, respectively; A is a poroelastic constant, and $A = \frac{\alpha(1-2\alpha)}{1-\alpha}$.

The critical total drawdown pressure (P_{CDP}) can be obtained:

$$P_{CD\{} = \frac{1}{2 - A}[2P_r - (3\sigma_{max} - \sigma_{min} - U)] \tag{11}$$

The effective strength of the formation (U) can be obtained from the thick-walled cylinder (TWC) test, which is used as the fundamental strength measurement for unsupported boreholes and perforations:

$$U = 3.1 * TWC \tag{12}$$

where TWC is the strength as determined in the TWC test. Factor 3.1 includes the scale transformation from laboratory (OD:ID = 3) to field (OD:ID = infinity).

Based on global data on laboratory tests of the TWC and unconfined compressive strength (UCS) conducted on sandstones [9], the following correlation is presented:

$$TWC = 11.46 * UCS^{0.53} \tag{13}$$

where UCS and TWC are in MPa.

Combining Equations (12) and (13), the effective strength can be written as the following form:

$$U = 35.526 * UCS^{0.53} \tag{14}$$

Input data for three fields as below table:

Parameters	Field-1	Field-2	Field-3
Poisson ratio, ν	0.1126	0.1067	0.1717
Biot coefficient, α	0.9267	0.8689	0.7648
TWC (MPa)	12.2	30.13	103.4
σ_1 (MPa)	45.1	57	50.3
σ_3 (MPa)	38.4	51.1	44.4
P_r (MPa)	21.2	27.2	24.7

The result for three fields presented as below:

Parameters	Field-1	Field-2	Field-3
A_p	0.8091	0.7651	0.60626
U (MPa)	37.8	93.4	320.5
P_{cwf} (MPa)	35.2	4.6	-164.3

According to the results, the P_{cwf} (or CBHFP) value at Field-3 is negative. Therefore, at Field-3 there is no occurrence of sand production during the production. For Field-1, to prevent sand production, the wellbore pressure needs to be maintained at a level higher than 35.2 MPa. However, the reservoir pressure at this field is only 21.2 MPa, which is lower than the CBHFP value, so sand production will always occur under any condition of production.

5. Hydraulic fracturing and case application

Reservoir stimulation by hydraulic fracturing has become increasingly important because of its introduction in the petroleum industry in 1947. This technique is employed to stimulate reservoirs with poor or low permeability or restore some highly clogged wells and is suitable for a wide range of reservoirs (sandstone, limestone) at depths up to several kilometers. Hydraulic fracturing is commonly associated with other recovery method-

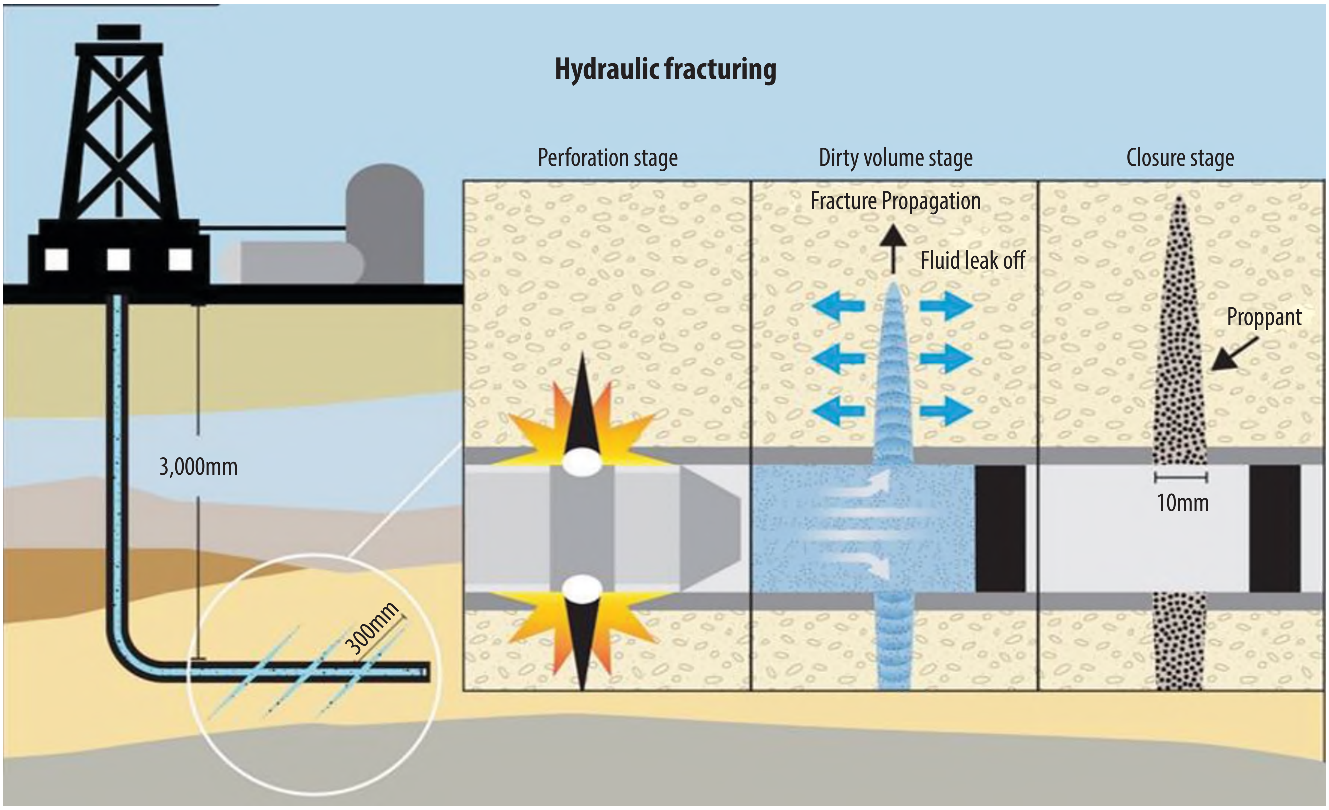

Figure 8. Schematic borehole stability analysis [11].

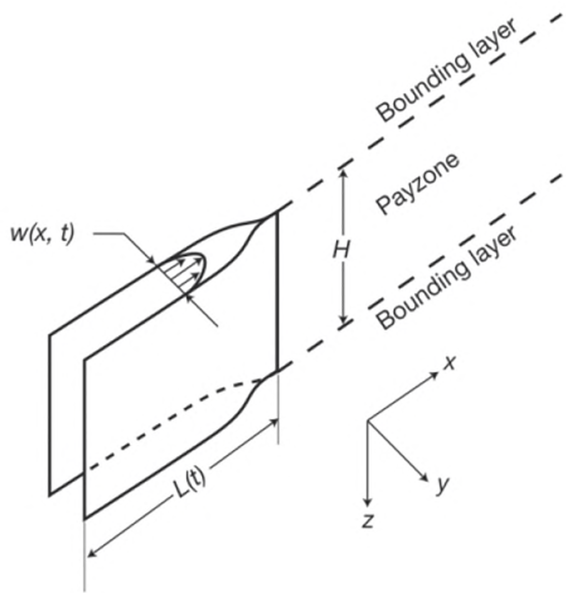

Figure 9. GDK model [13].

ologies, such as acid fracturing of carbonate formations, fracturing followed by *in situ* combustion in oil sands or oil shales.

From the viewpoint of geomechanics, the hydraulic fracturing process involves three stages (Figure 8):

- Initiation of the fracture by pressurising the medium (from the wall of the wellbore or the perforations).

- Extension of the fracture, during a granular material called a proppant in suspension in the fluid is injected, to keep the fracture open after injection.

- Removal of the fracturing fluid and recompletion of the well.

The length of the fractures ranging from 50 m to 300 m, depends on the petrophysical and mechanical properties of the treated rock. Injected volumes range from several cubic metres to several thousand cubic metres. The duration of hydraulic fracturing varies from 10 minutes to several hours. The primary challenge in designing a hydraulic fracturing operation is due to the fact that the fluid injected widens and extends the fracture but also leaks off into the formation. These two aspects must therefore be taken into consideration during the calculation. The geometry of fracture depends on the mechanical characteristics of the surrounding rock, its stress state and the fluid used.

Hydraulic fracturing modeling has been the subject of extensive research, as highlighted by Bin Chen et al., [10]. Various models have been developed to enhance the hydraulic fracturing treatment design or to understand some specific mechanisms. A series of classic hydraulic fracturing models have been developed in the period be-

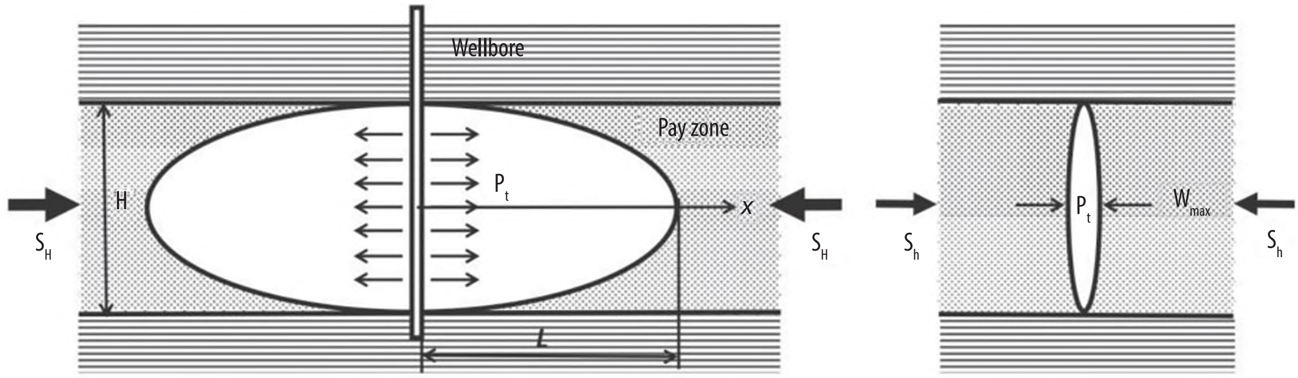

Figure 10. PKN model [13].

tween 1950s and the 1980s, such as GDK model, PKN model, the pseudo 3D (P3D) model, and the planar 3D (PL3D) model. In the following section, the author focuses on introducing the GDK and PKN models and provides real-world application examples.

GDK (Geertsma and de Klerk) type 2D models

Geertsma and de Klerk [12] presented 2D analytical solution (GDK model) for a linearly propagating fracture by assuming that the fracture height is much greater than the fracture length (height>>length). The assumptions of the GDK model are listed in the following:

- Elliptical cross section in the horizontal plane, as shown in Figure 9.
- Each horizontal plane deforms independently.
- Fracture height is a constant.
- Cross sections in the vertical plane are rectangular (fracture width is constant along its height).

The fracture width in GDK model was introduced in the following equation:

$$w^2(x) = w_0^2 \times (1 - \frac{x^2}{L^2}) \tag{15}$$

The thickness at the wellbore is given by

$$w_0 = 2.1(\frac{\mu Q L^2}{Gh})^{1/4} \tag{16}$$

PKN (Perkins, Kern, Nordgren) type 2D models

The model assumes that the plane strain condition is valid in each vertical plane normal to the propagation direction. It considers a constant pressure vertically, diminishing with distance x and reaching zero at the fracture tip. The fracture cross-section is elliptical (Figure 10). The following analytical solutions are obtained quite simply by associating with these assumptions: 2D expression of fracture thickness, head loss in each fracture length element dL.

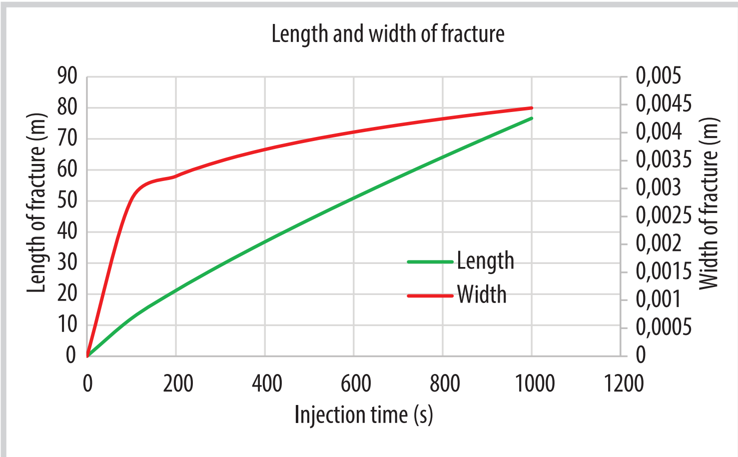

Figure 11. Fracture development using PKN model.

Without leak-off, the length and width of fracture are introduced as below:

$$L(t) = C[\frac{(1-\nu)\mu Q^2}{Gh}]^{1/5} t^{4/5} \tag{17}$$

with C = 0.68 for 1 wing, 0.45 for 2 wings.

$$w_0(t) = [\frac{(1-\nu)\mu Q^2}{Gh}]^{1/5} t^{1/5} \tag{18}$$

Input data as below:

Fluid viscosity, μ, MPa.s	0.00000056
Injection rate, q, m^3/s	0.004
Poisson's ratio, ν	0.2
Shear modulus, G, MPa	10,000
Fracture height, H, m	10
Injection time, t, s	1,000

The results obtained from simulating fracture development during fluid injection using the PKN model are presented as:

The length and width of the fracture exhibit rapid development within the initial 100 seconds. After this period, the rate of width expansion slows significantly, whereas the lengthwise growth of the fracture continues. This observation aligns with empirical findings across various types of rocks.

6. Conclusions

Evaluating applications of geomechanics within the oil and gas industry introduced in this article, allowed us to conclude that employing geomechanics in wellbore stability analysis, sand production, and hydraulic fracturing plays an important role in optimizing hydrocarbon production. Some main points can be concluded through this study:

- Enabling wellbore stability analysis in the selection of appropriate drilling mud densities to prevent collapses and instability of wellbore.

- Sand production modeling consistently shows instances of sand production under diverse well production conditions.

- Width of the fracture during hydraulic fracturing process exhibits rapid onset in the first stages followed by a transition into an exceedingly gradual propagation state.

Our evaluation and reviewing of the pre-exisiting geomechanics analysis in hydrocarbon drilling engineering aim to assist the users in referencing suitable prediction models easilly. It is noteworthy to note that modelling well stability, sand production and hydraulic fracturing is various from case to case, it depends on the input data and actual situation of each location.

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POROSITY CUT-OFF VALUES EVALUATED BY CLASSIFYING RESERVOIR ROCK TYPES FROM CORES DATA. A CASE STUDY FOR TRIASSIC RESERVOIR T1, BLOCKS 433A&416B, ALGERIA

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Summary

This paper introduces the method to determine the porosity cut-off values by classifying rock types from cores data based on permeability cut-off value by 1 mD (for sandstone reservoir with oil). The purpose of this method is to calculate net pay reservoir more precisely for estimating hydrocarbons initially in place and building static models. Normally, the cut-off values of porosity are defined on a cross-plot of porosity versus permeability obtained from core data. However, the results of petrophysical analysis are not consistent with DST results. There are some wells with reservoir net pay of several meters, but the DST does not deliver flows. The application of a new method determining the porosity cut-off values on T1 reservoir shows the reservoir net pay is consistent with actual data of the field.

Key words: Porosity, permeability, cut-off, rock type, net pay.

1. Introduction

The Blocks 433a&416b locates in the northern part of the Hassi Messaoud uplift in the Sahara basin. To the east of the uplift is the Berkin trough and to the west is the Oued Mya trough, approximately 550 km southeast of the Algiers capital and about 130 km northeast of the Hassi Messaoud oil field (Figure 1).

In 1996, Mobil Oil Company drilled the MAM-1 exploration well and discovered hydrocarbons in the sandstone reservoirs of the Ouargla and Triassic SI formations. Five wells were drilled to explore the Triassic-T1 reservoir. Two wells, MAM-3 and MAM-4, were conducted core sampling, while three wells (MAM-3, MAM-4 and MAM-5) got the DSTs conducted to evaluate the reservoir performance capacity. The DST showed the MAM-4 was dry well; MAM-3 and MAM-5 had good oil production rate with main flow rate of 1,300 barrels per day and 850 barrels per day, respectively.

The analysis of core samples from the drilling wells indicates significant variations in the porosity - permeability relationship within a wide range. This demonstrates changes in sedimentary characteristics and depositional environments, leading to changes in reservoir properties. Considering these distinct characteristics, the conventional approach applied in previous studies, using a porosity - permeability correlation coefficient of r^2 = 0.73 (Figure 19), does not accurately reflect the effective thickness of the reservoir. Therefore, a new approach is implemented, dividing the core sample data into relative rock types (RRTs). Each RRT exhibits similar flow unit characteristics which enables the determination of

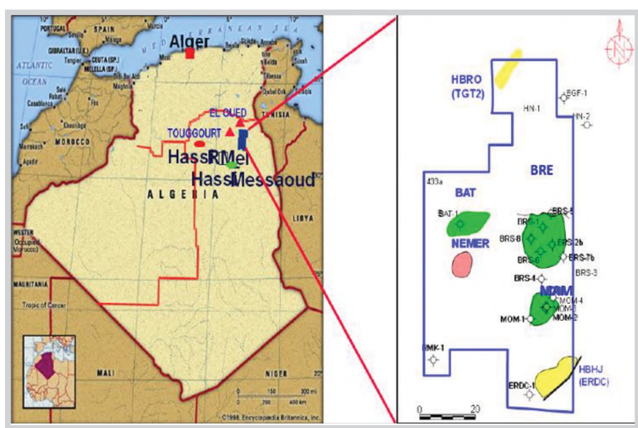

__Figure 1.__ Location of Blocks 433a&416b.

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separately critical values for each RRT, resulting in higher correlation coefficients r^2 ranging from 0.83 - 0.9. Based on the predicted RRT results and the application of cut-off values for each RRT, the net pay thickness of commercial value can be accurately determined. Additionally, this approach facilitates the construction of a detailed reservoir property simulation model.

2. Reservoir characterization of Triassic-T1 formation, Blocks 433a&416b, Algeria

The field is located on the Amguid Messaoud uplift, between the Oued Mya trough and the Berkine basin. The reservoir consists of Triassic-aged sandstone formations, with proven hydrocarbon systems. The source rock is Silurian-aged shale; seal rocks are shale and thick salt formations; reservoir rocks are TA and T1B sandstones belonging to the Triassic-T1 formation. The sedimentary rocks consist of interbedded sandstones, siltstones, and shales, with occasional dolomite layers. They were deposited in a fluvial to deltaic environment (Figure 2), fining upward as indicated on log data, sand body thicknesses ranging from 15 m to 20 m (Figure 3) [1]

In terms of petrography: the analysis of petrographic components in samples taken at depths of 3,692.3 mMD and 3,712.2 mMD from the well MAM-4 reveals that the rock is predominantly composed of quartz, accounting for approximately 75 - 77% of the composition. The main clay minerals present are chlorite and illite, constituting around 12% of the composition. Minor minerals include anhydrite, comprising 1 - 2% of the composition. The fine-grained sandstone is characterized by a grayish blue/dark gray color, medium grain size, good sorting, and subangular to rounded grains. The siltstones are green or light green, with medium hardness and fine grain size, while the shales are brown or reddish brown, with medium hardness and subangular grains (Figures 4 - 7) [2].

Rock properties: according to the results by applying the cut-off value to the porosity of 8% of reservoir T1A, the average net pay thickness is 4.3 m, the average porosity is 10%, and the average water saturation is 25%. Reservoir T1B has an average net pay thickness of about 5.3 m, average porosity is 12%, and average water saturation is 24%.

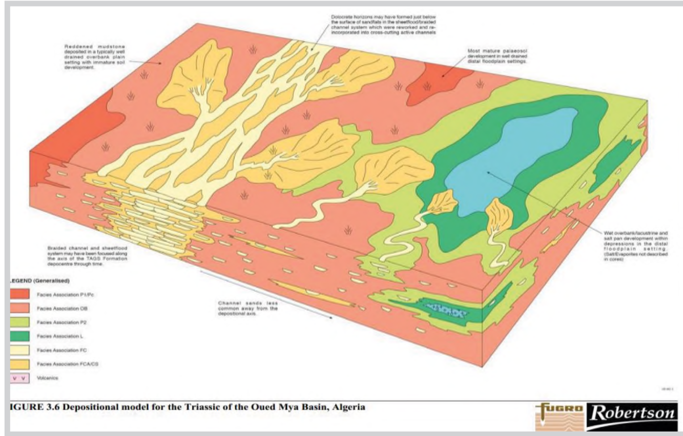


Figure 2. Triassic sedimentary model.

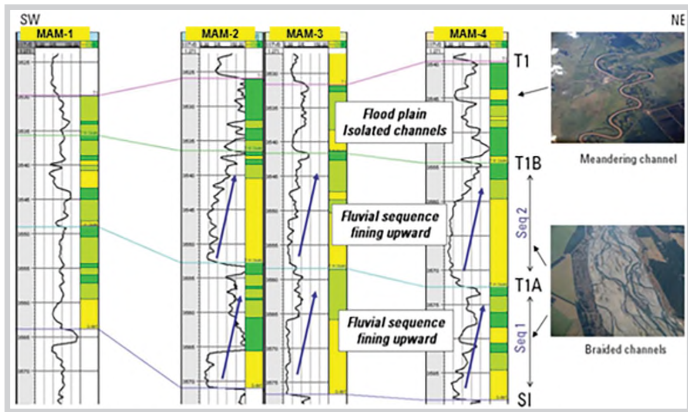


Figure 3. Characteristics of well log.

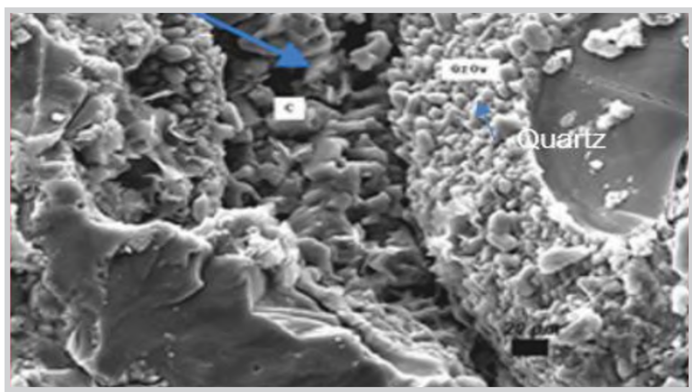


Figure 4. SEM sample at depth 3692.3 mMD MAM-4.

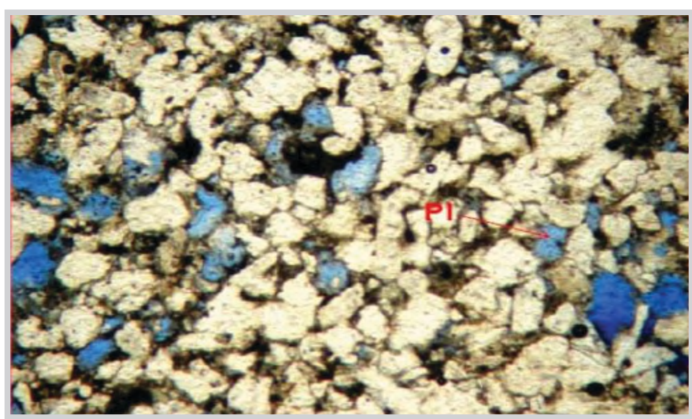


Figure 5. Thin section sample at depth 3692.3mMD, MAM-4.

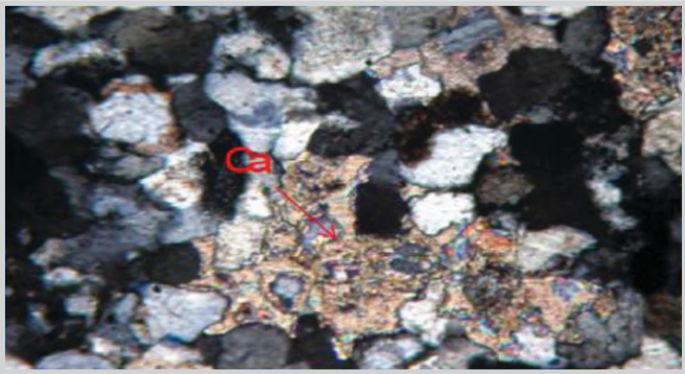


Figure 6. Thin section sample at depth 3712.2 mMD, MAM-4.

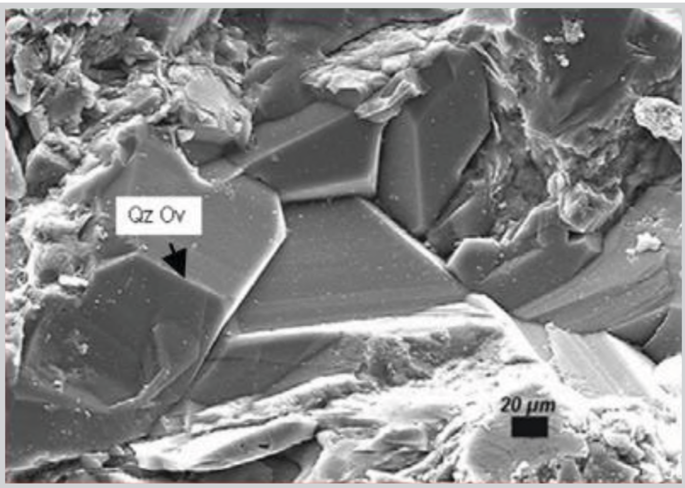
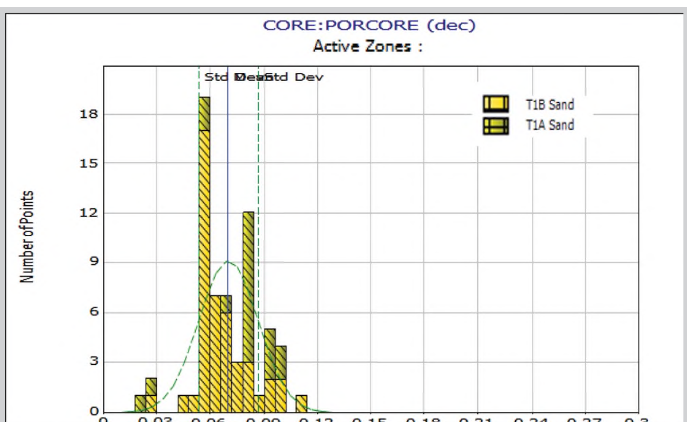


Figure 7. SEM sample at depth 3712.2 mMD, MAM-4.

Table 1. Summary of core data for MAM and nearby field wells.

Name of wells	sample	Sampling interval (mMD)		Formation	Length (m)	Recovery (%)
MAM-3	1	3,665	3,702	Triassic-T1	37	100
MAM-4	1	3,690	3,720.7	Triassic-T1	30.65	100
BRE-1	2	3,598.5	3,625	Triassic-T1	26.5	100
BRE-202	1	3,631	3,649	Triassic-T1	18	100



Min	Max	Mean	Std Dev	Mode	P10	P50	P90
0.03	0.11	0.0679	0.0145	0.057	0.06	0.064	0.088
0.02	0.1	0.0753	0.0206	0.081	0.054	0.08	0.094
0.02	0.11	0.0701	0.0167	0.057	0.06	0.0678	0.0923

Figure 8. Porosity distribution chart of well MAM-3.

3. Core data analysis result and rock typing classification (RRT) to determine the cut-off value of porosity

In the field area, core samples were taken from T1 formation at the wells MAM-3 and MAM-4. These core data were used for classifying RRT. In addition, core sample documents from the wells BRE-1 and BRE-202 in the nearby field BRE were also used (due to the same sedimentary formation and characteristics). The total length of the core samples is 112.15 m with a successful recovery rate of 100% (Table 1) [3].

All core data are used not only for petrophysical evaluation and interpretation but also for other studies, including identifying RRT to determine the cut-off value of porosity.

Detailed results of MAM wells core analysis are below:

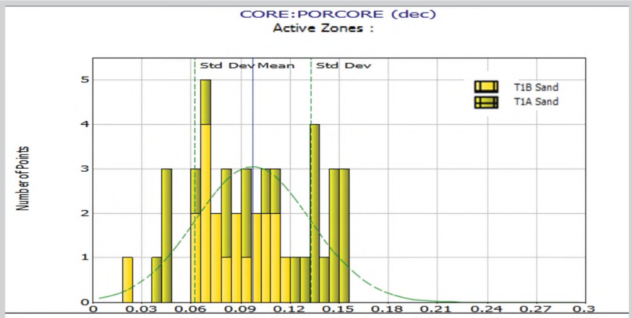
- The porosity at the well MAM-3 is from 2.3% to 15.4% with an average of 9.7%; the permeability is from 0.02 mD to 19.6 mD with an average of 1.2 mD. The T1A sand reservoir has better porosity and permeability than the T1B sand reservoir, as shown in Figures 8 and 12.

- The porosity of well MAM-4 is from 2% to 11% with an average of 7%; the permeability is from 0.01 mD to 72 mD with an average of 9.9 mD. The T1A sand reservoir has lower porosity and permeability than the T1B sand reservoir, as shown in Figures 9 and 13.

- The porosity of well BRE-1 is from 1.7% to 14% with an average of 7.3%; the permeability varies from 0.1 mD to 78 mD with an average of 15 mD. There is no T1B sand reservoir in the BRE mining area, Figure 10 and Figure 14.

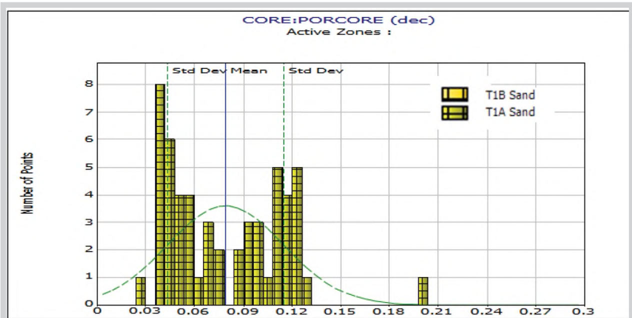
- The porosity of BRE-202 is from 2.9% to 13% with an average of 7.9%; the permeability is from 0.02 mD to 36.9 mD with an average of 5.3 mD. Like the well BRE-1, there is no T1B sand body in the BRE-202 drilling area, Figures 11 and 15.

The results of core data analysis from the wells show a large variation in porosity and permeability. This indicates variations in sediment characteristics and depositional environments due to changes in reservoir properties. The evaluation of the gamma ray curve characteristics (Figure 3) shows that sedimentary rocks formed in levee or floodplain



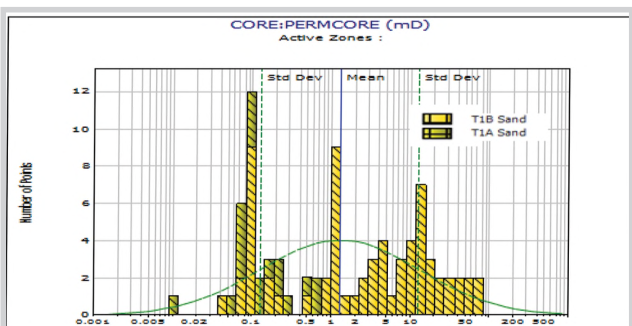
Min	Max	Mean	Std Dev	Mode	P10	P50	P90
0.0238	0.117	0.0834	0.0226	0.069	0.0635	0.0842	0.109
0.04	0.154	0.1086	0.0396	0.135	0.0457	0.1228	0.1506
0.0238	0.154	0.0974	0.0352	0.069	0.0528	0.0956	0.1471

Figure 9. *Porosity distribution chart of well MAM-4.*



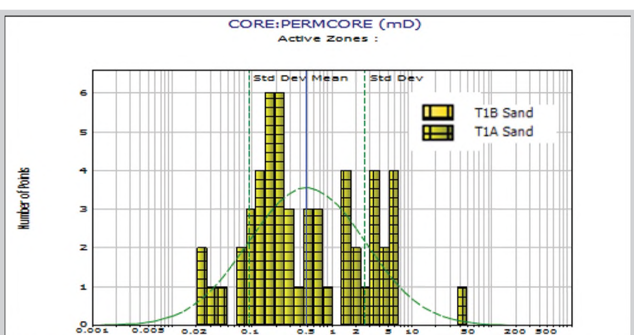
Min	Max	Mean	Std Dev	Mode	P10	P50	P90
0.0299	0.2018	0.0793	0.0359	0.039	0.0398	0.0712	0.1218
0.0299	0.2018	0.0793	0.0359	0.039	0.0398	0.0712	0.1218

Figure 11. *Porosity distribution chart of well BRE-202.*



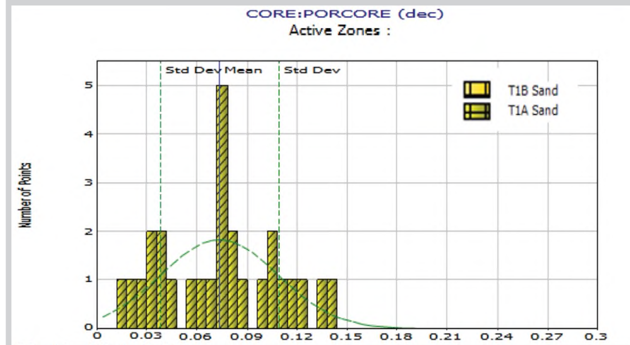
Min	Max	Mean	Std Dev	Mode	P10	P50	P90
0.04	71.9486	2.4611	8.5305		0.0916	3.3381	33.079
0.01	0.6807	0.1274	2.7038	0.0724	0.0668	0.1099	0.513
0.01	71.9486	1.3049	9.9851	0.0964	0.0831	1.1273	24.919

Figure13. *Permeability distribution chart of MAM-4.*



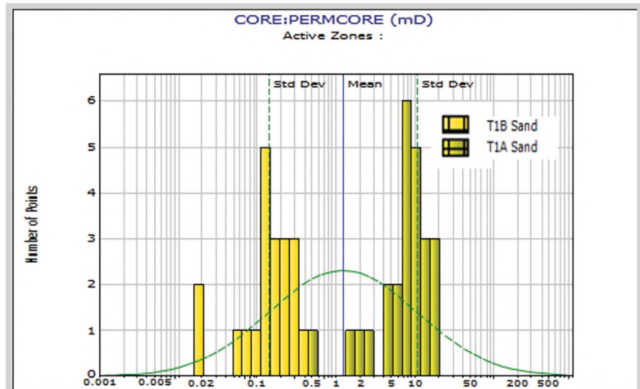
Min	Max	Mean	Std Dev	Mode	P10	P50	P90
0.0224	36.9566	0.4835	5.31		0.0826	0.2806	5.0242
0.0224	36.9566	0.4835	5.31		0.0826	0.2806	5.0242

Figure15. *Permeability distribution chart of BRE-202.*



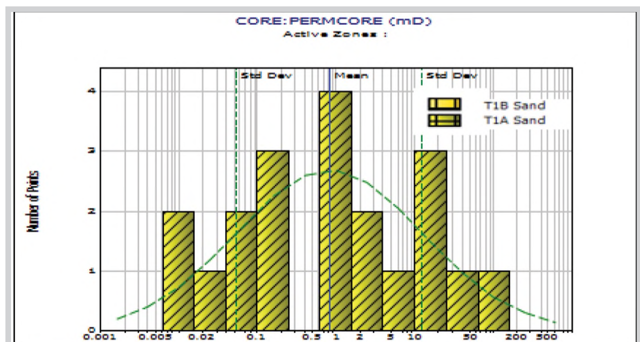
Min	Max	Mean	Std Dev	Mode	P10	P50	P90
0.017	0.142	0.0735	0.0352	0.075	0.0282	0.074	0.1172
0.017	0.142	0.0735	0.0352	0.075	0.0282	0.074	0.1172

Figure 10. *Porosity distribution chart of BRE-1 well.*



Min	Max	Mean	Std Dev	Mode	P10	P50	P90
0.02	0.34	0.135	2.2558	0.1259	0.0456	0.1497	0.2929
0.51	19.57	7.0357	2.3342	7.9433	2.1513	8.82	16.2505
0.02	19.57	1.2139	8.5894	8.0192	0.1039	2	14.6525

Figure 12. *Permeability distribution chart MAM-3.*



Min	Max	Mean	Std Dev	Mode	P10	P50	P90
0.01	78	0.8166	15.3108	1	0.0187	1.2274	21.0271
0.01	78	0.8166	15.3108	1.1079	0.0187	1.2274	21.0271

Figure 14. *Permeability distribution chart of BRE-1.*

environments correspond to lower porosity and permeability, while rocks formed in channel environments correspond to higher porosity and permeability. Based on these results, the core samples are divided into rock reservoir types (RRTs), each with similar characteristics to a specific flow unit, in order to determine individual cut-off values for each rock type. Applying these cut -

off values accurately determines the reservoir net pay thickness. This approach also builds a detailed simulation model.

Each type of rock is characterized by specific geological permeability and properties, which are represented by a flow unit. There are various methods to determine the flow unit from porosity and permeability data, such as constructing a cross-plot graph between rock quality index (RQI) and porosity index (PhiZ) or using statistical analysis with the Ward algorithm. In this paper, the flow zone indicator (FZI) distribution chart method is used to determine and classify RRT [4].

FZI distribution chart method: reservoir quality indicators (RQI), flow zone indicator (FZI), permeability of rock, and porosity index (PhiZ) are determined from core data.

In which:

$$RQI = 0.0314 \times Sqrt(K/Phi)$$

$$PhiZ = Phi/(1\text{-}Phi)$$

$$FZI = RQI/PhiZ$$

To build an FZI distribution chart on a logarithmic scale, depending on the sample data set, there will be different distributions. When the sample groups are clearly separated, the number of RRT and the average FZI value for each RRT type can be determined.

Based on the core sample of the field and core samples from neighboring wells, the FZI distribution chart method has identified 3 main types of RRT (Figure 17) as follows:

- RRT-1: a non-productive background type with poor reservoir characteristics, varying porosity from 5.1% to 12.7%, permeability from 0.01 - 0.43 mD, with an average of 0.1 mD, and FZI ranging from 0.046 to 0.65, with an average of 0.37.

- RRT-2: is a type of RRT with average reservoir properties, porosity varies from 2.3% - 13.6%, permeability varies from 0.019 - 15 mD, average 0.96 mD, FZI changed from 0.64 to 2.19 with an average of 1.29.

- RRT-3: is a type of RRT with good reservoir properties, porosity varies from 3 - 14.2%, permeability varies from 0.17 - 78 mD, average 4.96 mD, FZI changed from 2.19 - 4.78 with an average of 3.

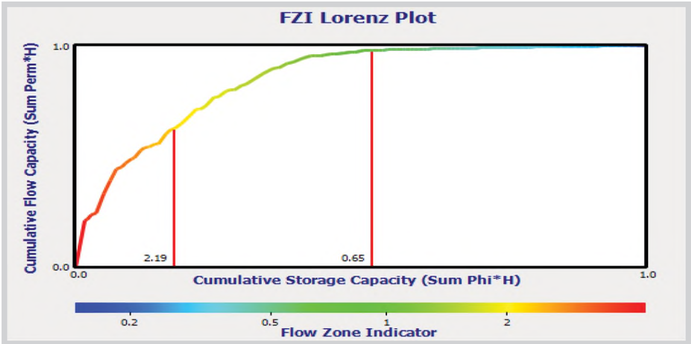


Figure 16. *Cumulative FZI distribution chart.*

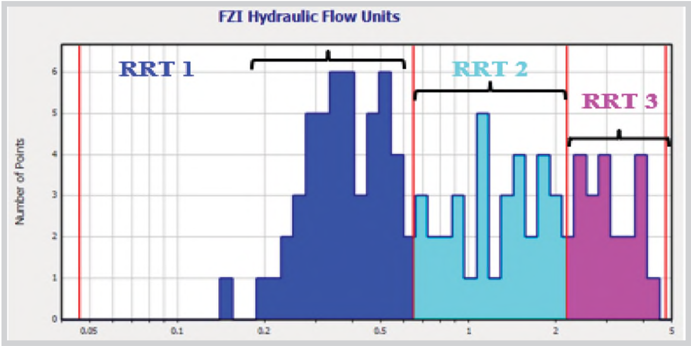


Figure 17. *FZI distribution chart.*

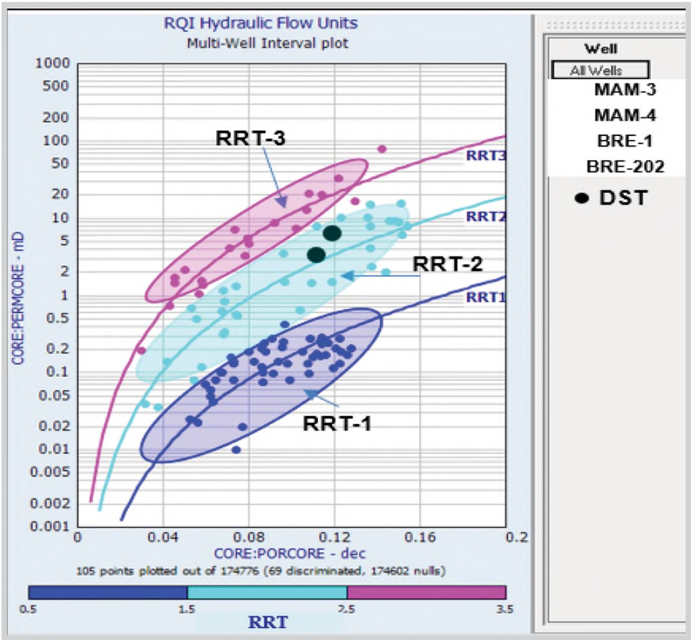


Figure 18. *Porosity/permeability cross plot.*

Determining the cut-off value of porosity:

Based on the porosity and permeability data from core samples of wells in the Blocks 433a&416b and nearby field, the relationship between porosity and permeability shows a large variation in permeability at the same porosity value. The conventional method of establishing the empirical relationship between porosity and permeability has a correlation coefficient r^2 = 0.73 (Figure 19). If a permeability cut-off value

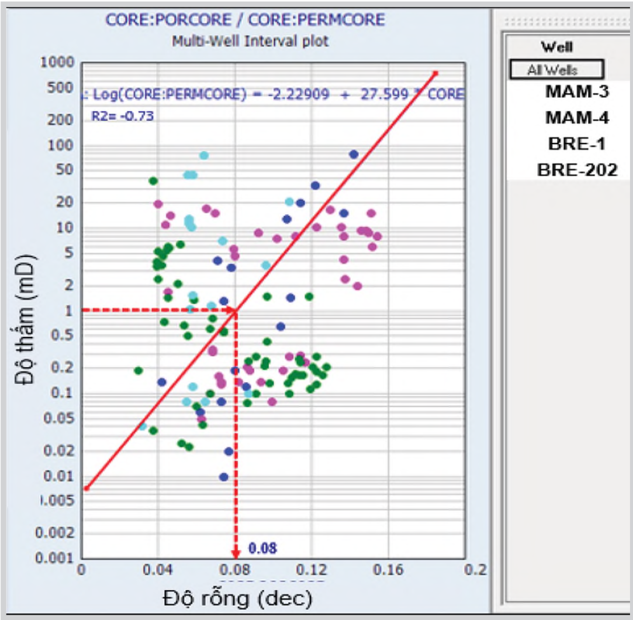


Figure 19. Determining the porosity cut-off value by conventional method.

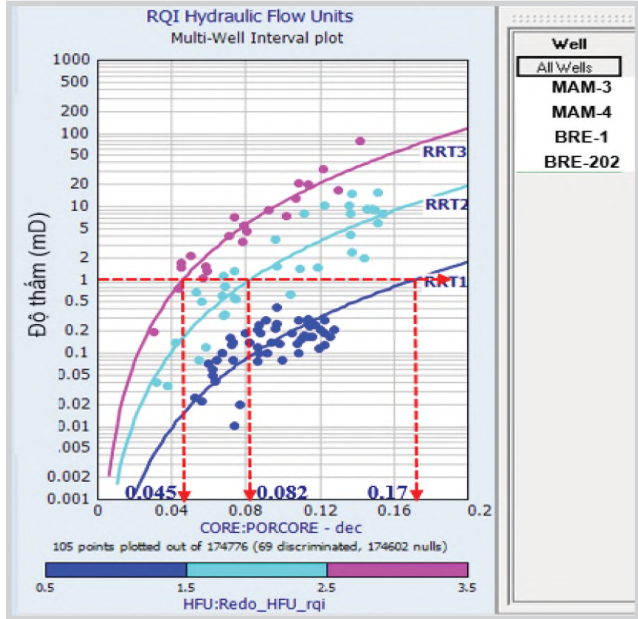


Figure 20. Determining the cut-off value for each RRT type.

of 1 mD is applied to determine the porosity cut-off value, it is 0.08 (Figure 19). Meanwhile, using the RRT division results from core sample documents and applying a 1 mD cut-off value for each RRT through the equation Perm = Phi3*(FZI/(0.0314*(1-phi)))^2 (Kozeny Carman empirical equation), the cut-off values are determined for each RRT type (Figure 20) as follows:

- RRT-1 porosity cut-off value is 17%, $r^2 = 0.29$
- RRT-2 porosity cut-off value is 8.2%, $r^2 = 0.83$
- RRT-3 porosity cut-off value is 4.5%, $r^2 = 0.91$

where r is the correlation coefficient.

4. The cut-off values after applying the RRT method.

Applying the permeability cut-off 1 mD for each type of RRT, where the cut-off value of porosity for RRT-1 is 17%, for RRT-2 is 8.2%, and for RRT-3 is 4.5%. The results show a significant decrease in the net pay of the T1B sand reservoir in most of the wells. In well MAM-4, if the cut-off value of porosity is applied using the conventional method (Phi ≥ 8%), the net pay thickness is 4.11 m, while the actual test results for this well show no flow. When the cut-off value of porosity is applied according to RRT, the net pay thickness is 0.76 m, which is more consistent with the actual data of the field (Figure 21).

For the T1A sand reservoir, if the porosity cut-off is applied according to RRT, the results show an increase in the net pay thickness at well MAM-3 by 0.44 m and a decrease in the net pay thickness at well MAM-5 by 0.45 m (Figure 22).

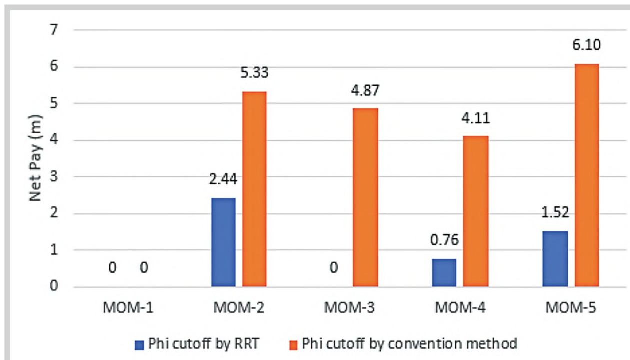


Figure 21. Distribution chart of the net pay thickness of the T1B reservoir.

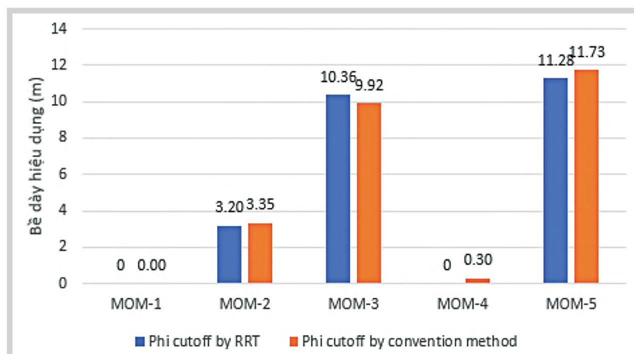


Figure 22. Distribution chart of the net pay thickness of the T1A reservoir.

Table 2. Summary of the effective thickness parameters applying the porosity threshold according to RRT

Reservoir Name	Net pay (m)	Different results
T1B	0.94	No flow in DST at MAM-4, tight RFT at MAM-5
T1A	4.97	Good flow in DST at MAM-3 and MAM-5

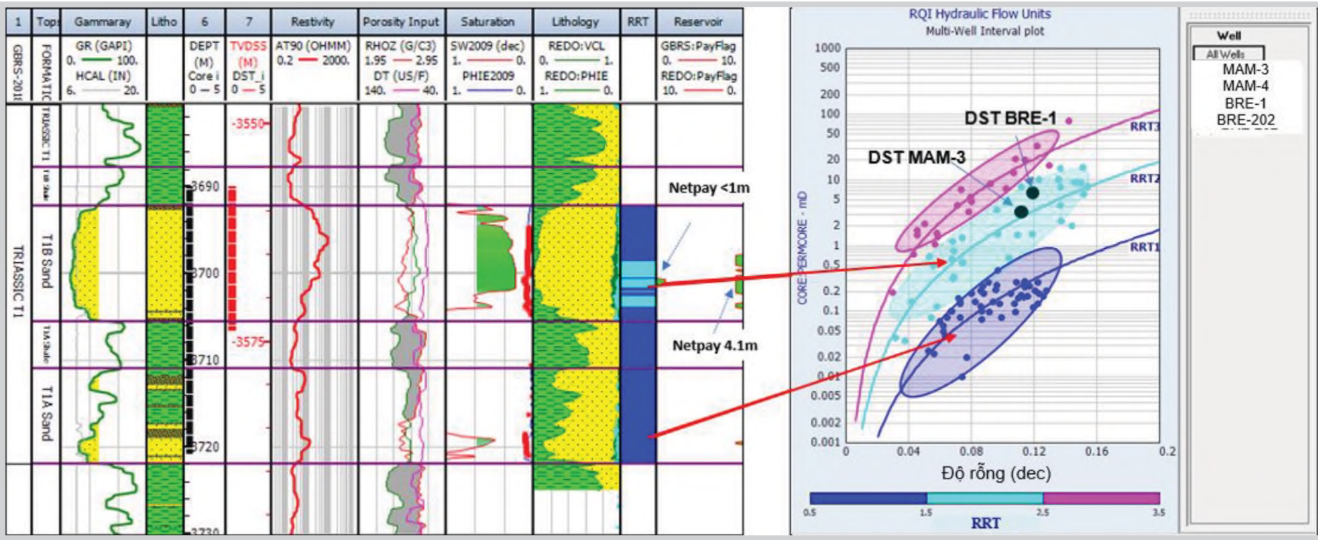


Figure 23. *Composite logs derived from the porosity cut-off by RRT and the conventional method.*

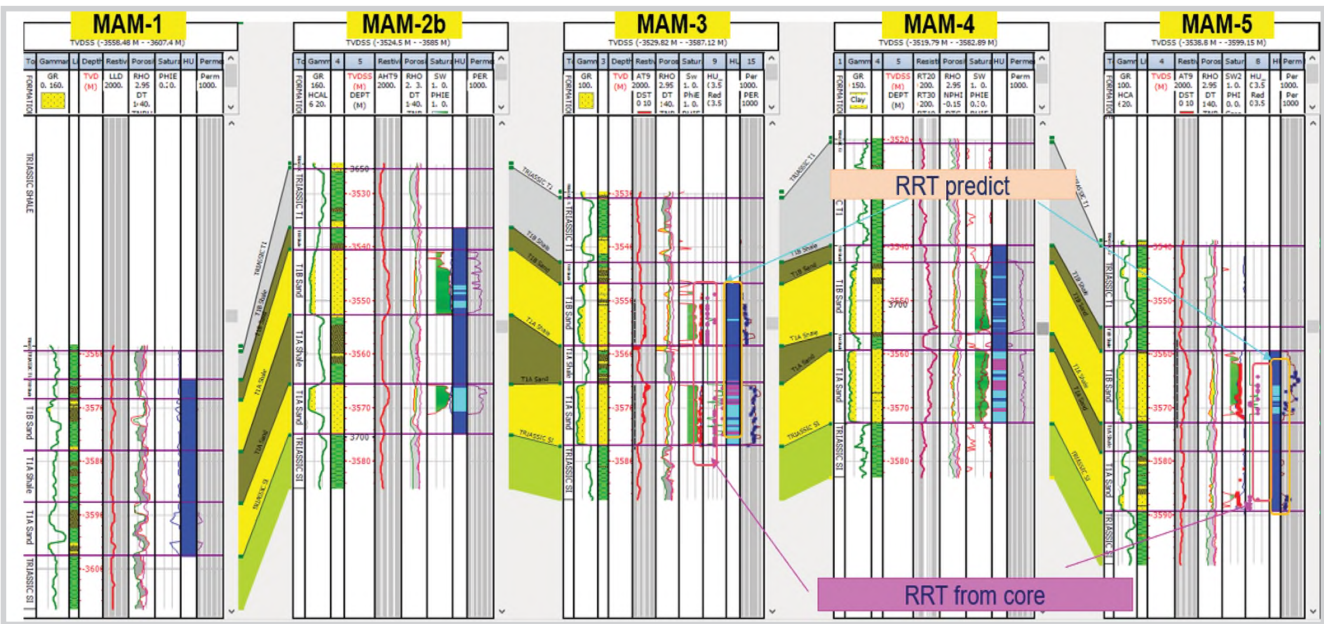


Figure 24. *Well correlation in Blocls 433a&416b area.*

Table 3. *Summary of the petrophysical parameters result by using the porosity cut-off by RRT and conventional method.*

Formation top				Petrophysical parameters using porosity cut-off by RRT method						Petrophysical parameters porosity cut-off by conventional method				
Reservoir/ well name		Top TVDSS	Bottom TVDSS	Thickness m	Net pay m	N/G	Av Phi dec	Av Sw dec	Vcl dec	Net pay m	N/G	Av Phi dec	Av Sw dec	Vcl dec
T1B	MAM-1	3,565	3,578	13.36	0	---	---	---	---	0	---	---	---	---
	MAM-2	3,537	3,553	15.82	2.44	0.15	0.09	0.18	0.13	5.33	0.34	0.09	0.23	0.15
	MAM-3	3,542	3,558	16.55	0	---	---	---	---	4.87	0.29	0.10	0.30	0.14
	MAM-4	3,555	3,573	18.15	0.76	0.04	0.09	0.26	0.04	4.11	0.23	0.10	0.29	0.04
	MAM-5	3,535	3,556	20.19	1.52	0.08	0.10	0.20	0.20	6.10	0.30	0.10	0.20	0.21
T1A	MAM-1	3,578	3,593	14.82	0	---	---	---	---	---	---	---	---	---
	MAM-2	3,553	3,571	18.5	3.20	0.17	0.11	0.31	0.07	3.35	0.18	0.11	0.32	0.07
	MAM-3	3,558	3,577	18.49	10.36	0.56	0.12	0.26	0.08	9.92	0.54	0.12	0.26	0.09
	MAM-4	3,573	3,589	16.32	0	---	---	---	---	0.30	0.02	0.08	0.51	0.11
	MAM-5	3,556	3,573	16.96	11.28	0.67	0.12	0.20	0.13	11.73	0.69	0.12	0.20	0.13

5. Conclusions

The Triassic-T1 sedimentary rocks deposited in a fluvial and deltaic environment, lithologically characterized by quartz and clay minerals such as chlorite and illite. In addition, there are accessory minerals such as anhydrite and calcite in a small quantity (up to 1 - 2%). The presence of clay minerals and accessory minerals is the main factor affecting the reservoir properties. Therefore, the cut-off value for porosity obtained by conventional methods and then the derived net pay thickness do not accurately reflect the effective thickness of the reservoir which can actually deliver flow.

A new approach for estimation of the cut-off value is introduced using the data from core analysis. Based on the lithological properties, the reservoir will be classified into reservoir rock types (RRT). Each RRT has certain lithological and physical characteristics and is represented by a "flow unit" and then the cut-off values will be defined. By using the newly derived cut-off value for each RRT type, net pay thickness is accurately determined for each reservoir of the wells. Based on this approach, the estimated net pay thickness at well MAM-3 and MAM-5 are 10.36 m and 11.28 m respectively, that conforms with the DST test results with a flow rate of 850 - 1,300 barrels per day. This new approach also serves to build a detailed simulation model.

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PETROVIETNAM SCIENCE, TECHNOLOGY & INNOVATION PETROVIETNAM

METHOD FOR ESTIMATING THE PROBABILITY OF GEOLOGICAL SUCCESS: A CASE STUDY OF THE HRA-E PROSPECT, BLOCK 106, NORTHERN SONG HONG BASIN

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Summary

Petroleum exploration and drilling represent fields fraught with inherent uncertainties, consequently, geological assessment is significantly important for precisely selecting prospects and well locations. The geological evaluation of prospective formations predominantly relies on 5 elements of the petroleum system including source, reservoir, seal, trap, and migration.

This article introduces globally applied geological assessment methods, and proposes an applicable methodology for exploration targets across regions with varying levels of available data. Applying this method of evaluating risk criteria for pre-Cenozoic carbonate objects of HRA-E prospect in Block 106 shows that the evaluation results align with the actual probability of success in drilling exploration activities in the region and could be extended to other projects within the Petrovietnam Exploration Production Corporation (PVEP).

Key words: Probability of geological success, pre-Cenozoic carbonate, HRA-E prospect, Song Hong basin.

1. Introduction

Oil and gas exploration is considered a risky investment field, so it is very important to evaluate the possibility of geological success of a structure before drilling. The probability of geological success of a structure is one of the input parameters to evaluate the economic efficiency of oil and gas projects and plays a crucial role in making final decisions.

Each company has its own choice of geological factors and evaluation criteria, using an independent evaluation guide form. Therefore, it is necessary to develop criteria to evaluate the probability of geological success for prospects of sedimentary basins on the Vietnamese continental shelf.

In this study, by integrating documents and research works on the probability of geological success (POS) evaluation methods used by companies around the world, the authors propose appropriate methods and relevant criteria that can be applied for exploration objects in areas with different levels of documents, limiting the subjective factors of evaluators.

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2. Method for assessing the probability of geological success

The most common and general method to calculate the success probability of a structure is determined by multiplying the probabilities of important geological factors, which are independent geological factors that ensure generation, migration, and accumulation. Geological factors must simultaneously exist and be present to ensure the discovery of oil and gas. It will be impossible to discover oil and gas when one of these elements is missing or non-existent.

In fact, the selection of the number of independent geological factors to evaluate the probability of structural success is different for each oil and gas company/author. White A. David proposed 12 independent factors for evaluation, according to group risk of play and individual risk of structure [1]. The difficulty with this method is that care must be taken during implementation to avoid each risk factor being assessed twice (double risk). Otis & Schneiderman determined the probability of oil and gas discovery according to four main factors including mature source rocks, reservoir rocks, traps (including seals), and migration. Each risk factor is evaluated according to criteria based on a 5-level rating scale from favorable to unfavorable, based on the level of direct or indirect documents and good or bad geological information [2]. CCOP provided guidance on evaluating structural success based on four key factors including reservoir rock, trap, charge, and preservation. Each main geological factor is evaluated according to two aspects: existence and effectiveness. The probability of each factor according to the risk table is assessed subject to the level of documents and geological characteristics [3].

Although the approach is different, the foundation of the structural assessment process is basically geological knowledge, understanding and the petroleum system concept developed over time. Independent geological factors are selected to evaluate the probability of success including 5 parameters of source, reservoir, seal, trap, and migration. Each geological parameter is evaluated through geological criteria on a quantitative scale from good to poor. In this article, the author uses evaluation factors for each criterion proposed by the Petrovietnam Exploration Production Corporation (PVEP) in 2023 (Figure 1) [4].

When evaluating the probability of success of a prospect, Rose found that oil and gas companies tend to be over optimistic for structures in new areas. Whilst for structures with high reliability and many chances of success, predictions tend to be lower than actual results [5]. The "risk matrix" model proposed by Rose (Figure 2) evaluates the probability of success of geological factors according to many dimensions of information based on confidence levels of high (A) - medium (B) - low (C) according to the number of documents, knowledge/nature of geology (more or less) and according to geological information/exploration results from good (1) - average (2) - bad (3) [5]. The model has an advantage of flexibly applying to areas from a few to many documents, limiting the subjective factors of evaluators, being consistent with actual exploration results, and currently used by many foreign oil and gas companies such as Shell, Repsol, KNOC, JOGMEC etc. [6, 7].

According to Rose (2001), the area has been explored in detail. Many documents, geological objects/models have been successfully confirmed through drilled wells. The evaluation objects tend to be separated into two differently successful fields: Field A1 possesses many good quality documents (high confidence - A) and geological information rated from good to very good (1), objects directly linked with truly geological nature having a high chance of success, from 80% to 100%. Field A3 has many good quality documents (high confidence - A), geological information re-evaluated from very poor - poor, evaluation objects having a low chance of success, 0 - 20%. In cases, where many documents have good quality but the geological object is very complex, the assessment results cannot distinguish the assessment factor into either field A1 or A3, then it will be included in the area with medium confidence - B, classified into success fields of B1 - B2 - B3.

Field B1 possesses average quantity and quality of documents (confidence - B), criteria for evaluating results from fair to good (1), chance of success of 60 - 80%; Field B2 (40 - 60%) owns confidence B and average assessment criteria (2) or cannot be clearly assessed (50/50 chance); Field B3 has confidence B of documents and assessment criteria below poor - very poor (3), chance of success from 20 - 40%.

Similarly, low confidence (C) is classified for basins/

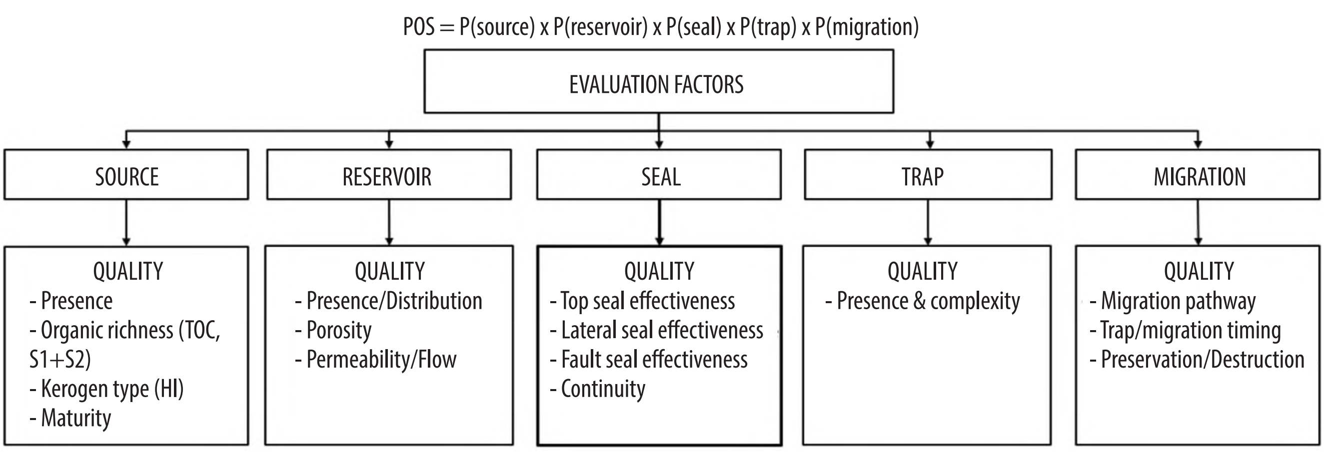
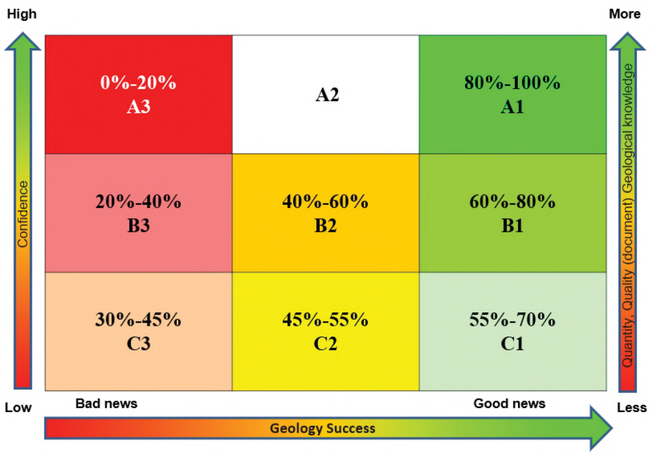


Figure 1. *Geological criteria to evaluate the probability of success [4].*



Geological information

(1) - Good geological information; (2) - Average geological information or 50/50

(3) - Bad geological information

Evaluate the level of confidence

(quantity/quality of documents, geological knowledge)

(A) - High confidence:

- Many documents (dense 2D seismic/3D, many wells)
- Good quality of documents; proven analog model
- Near analog/directly linked object
- Good geological understanding of object

(B) - Medium confidence:

- Average quantity and quality of documents (sparse 2D seismic), few drilled wells
- Evaluated analog model
- The linked/analog object is relatively far away.
- Geological nature is complex and not well understood.

(C) - Low confidence:

- No/limited documents (no/few seismic documents)
- No wells; linked/analog object very far away
- Understanding of geological objects is limited.

***Figure 2.** "Risk matrix" model according to Rose [5].*

areas that have not been explored, with no or very few documents, preliminary geological models/concepts, assessment factors falling into success field C1 (30 - 45%) - C2 (45 - 55%) - C3 (55 - 70%) with a chance of success corresponding to evaluation criteria of good (1) - average (2) and poor (3) (Figure 2).

Based on the analysis of models for assessing the probability of geological success proposed by different authors in the above section, the authors will apply the assessment of the probability of geological success according to the "risk matrix" model by Rose for the pre-Cenozoic carbonate prospect HRA-E in the Northern Song Hong basin. The chance of success (risk) of geological factors is assessed in the following steps: (i) Evaluate the reliability of documents, geological models/understanding; (ii) Evaluate the geological information results according to the quality scale from good – poor, and (iii) Evaluate the chance of success according to the matrix model, combining evaluator experience and exploration results/ regional success rate.

3. Evaluating the probability of success of prospect HRA-E

3.1. Location and geological information of HRA-E

Prospect HRA-E belongs to Block 106, which is located in the Northern Song Hong basin,

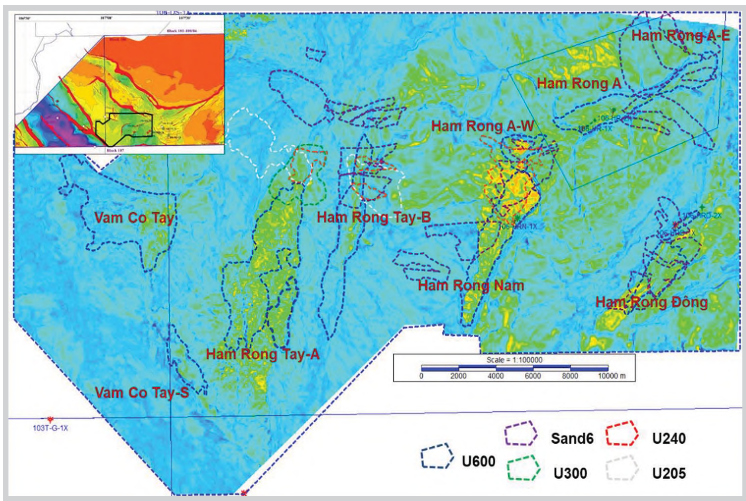


***Figure 3.** Location of HRA-E in Ham Rong trough [9].*

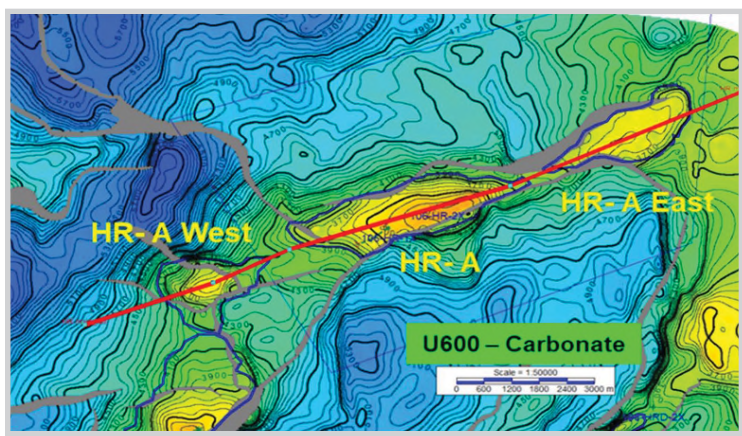


***Figure 4.** Map of carbonate basement structure (U600) of structural clusters HRA-W, Ham Rong & HRA-E.*

about 50 km from Hai Phong port at a water depth of 25 - 30 m. Block 106 borders Ha Noi trough to the northwest, Blocks 100 & 101/04 to the northeast, Blocks 103 & 107 to the south. From 1983 to present, by different operators, there are 14,476 km of 2D seismic and 2,224 km^2 of 3D seismic acquired and 13 wells drilled, of which 5 wells drilled into Miocene - Oligocene sandstone and 8 wells targeting pre-Cenozoic carbonate basement. In Block 106 area, there are important discoveries in carbonate basement objects such as Ham Rong field, discovery Ham Rong Nam, discovery Ham Rong Dong [8, 9].

HRA-E is adjacent to the northeast of Ham Rong field of Block 106 (Figure 3). The study area is covered by 650 km^2 of 3D seismic that were PSDM reprocessed by PVEP in 2014 with the object being deep pre-Cenozoic carbonate basement rocks. In addition to seismic data, well logs, reservoir testing documents, sample analysis results, well summary reports, and regional geological reports of the block and neighboring areas are also used to assess the probability of success for the prospect.

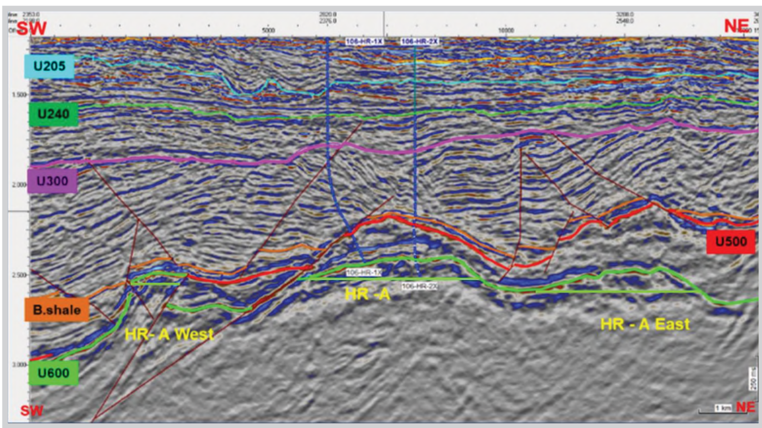


Figure 5. *Seismic section through structural clusters HRA-W, Ham Rong & HRA-E.*

The HRA-E basement structure is an extension of the Ham Rong structure trend to the northeast and separated from the Ham Rong field by a saddle (Figure 4). The carbonate basement is identified reliably on the U600 reflection surface map with a depth nearly equivalent to the Ham Rong discovery (about 3,290 m), a closed area of 3.75 km^2, structure height of 270 m (lower than Ham Rong). The basement object is completely covered by the sedimentary set below the U500 reflection boundary. The petroleum system has been proven by successfully drilled wells in the area.

3.2. Evaluating the probability of prospect success

3.2.1. Source rock evaluation

The probability of existence of mature source rock is assessed through the criteria of presence, quality (richness, kerogen type) and maturity according to the steps described in Section 2. Source rock assessment data from direct sample analysis results of drilled wells YT-1X, HR-1X, 2X, HRD-1X, HRN-1X (Figure 6) in the area shows that the source rock is of good quality with highly reliable assessment data - A.

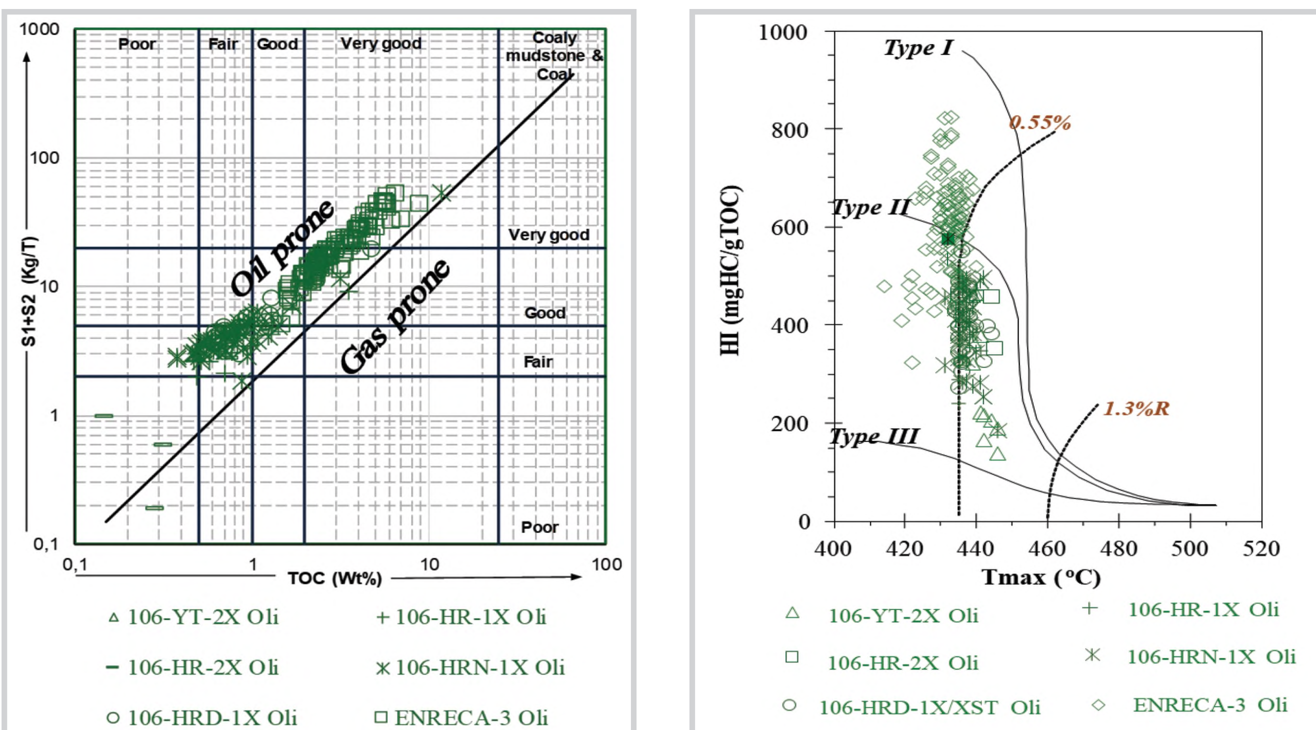


Figure 6. *Result of geochemical analysis of Oligocene source rock in Ham Rong area.*

Exploration results have shown many discoveries of good oil and gas flows, proving the presence of mature source rock set in the area. Geochemical analysis of Oligocene source rocks (Figure 6) shows that most samples have good to very good organic matter (TOC > 2%); good producing potential (S1 + S2 > 5mg/g). Kerogen belongs to types I and II; the maturity level is at the threshold of producing oil and wet gas (Ro = 0.75 - 1.2%). All criteria for evaluating the quality of source rock range from good - very good (1), assessed directly from well data, with good connectivity, close to structure, and high reliability (A). The criteria for evaluating source rock quality are classified into field A1 (Figure 2), the effective probability of existence of source rock is assessed as 100% (Psource = 1).

3.2.2. Reservoir Evaluation

Pre-Cenozoic fractured cavernous carbonate rock were discovered in 8 exploration and appraisal wells of DS-1X, YT-1X, YT-2X, HL-1X, HR- 1X, HR-2X, HRN-1X, HRD-1X at Block 106. According to seismic facies, the basement rocks in HRA-E are closely connected and quite similar to the Ham Rong basement zone. This parameter is rated with high reliability - A.

The quality of fractured basement rock is evaluated based on the following main criteria: Porosity, Phi*NTG coefficient, permeability criteria, flow capacity, thickness, and secondary changes. Carbonate basement rock has a total porosity of 5 - 7%. The thickness of the reservoir rock set is from 100 - 150 m. The ratio of effective thickness to gross thickness (NTG) is from 10 - 35%. Calculation results from DST data show that the permeability value varies greatly from ~11 - 500 mD, and the flow rate is very good. All evaluation criteria range from good to very good.

The structures near the discovered wells of HR-1X, 2X, HRN-1X and HRD-1X develop in the same structural zone, about 2 - 4 km apart, have a high level of reliability, similar to the result of wells in the area. The value of reservoir success probability is at 90% (Preservoir = 0.9).

3.2.3. Seal evaluation

Seal are evaluated based on the criteria of presence and effectiveness through lithological characteristics, thickness, continuity and fault seal capacity.

The basement structure is covered by thick sediment U500 on the flanks and top of the structure (Figure 5). Overlying HRA-E, there exists a top seal layer that is clearly and directly proven through HR-1X & HR-2X well documents. Top seal rocks are claystone, 20 - 30 m thick, found at drilled wells, good correlation with 3D seismic data.

The fault seal capacity is assessed at a good level (1), similar to the normal seal faults found in the structures Ham Rong and Ham Rong Nam. However, the object U500 has a complex geological nature; the reliability of the fault seal ability and the continuity of the clay set are assessed at average level (B). The criteria for effective seal risk assessment with successful zone is at level B1 (Figure 2). POS for the seal element is determined to be 80% (Pseal = 0.8).

3.2.4. Trap evaluation

Traps are evaluated based on criteria such as quality, level of certainty in seismic data and other documents, velocity conversion, trap type assessment map, complexity,

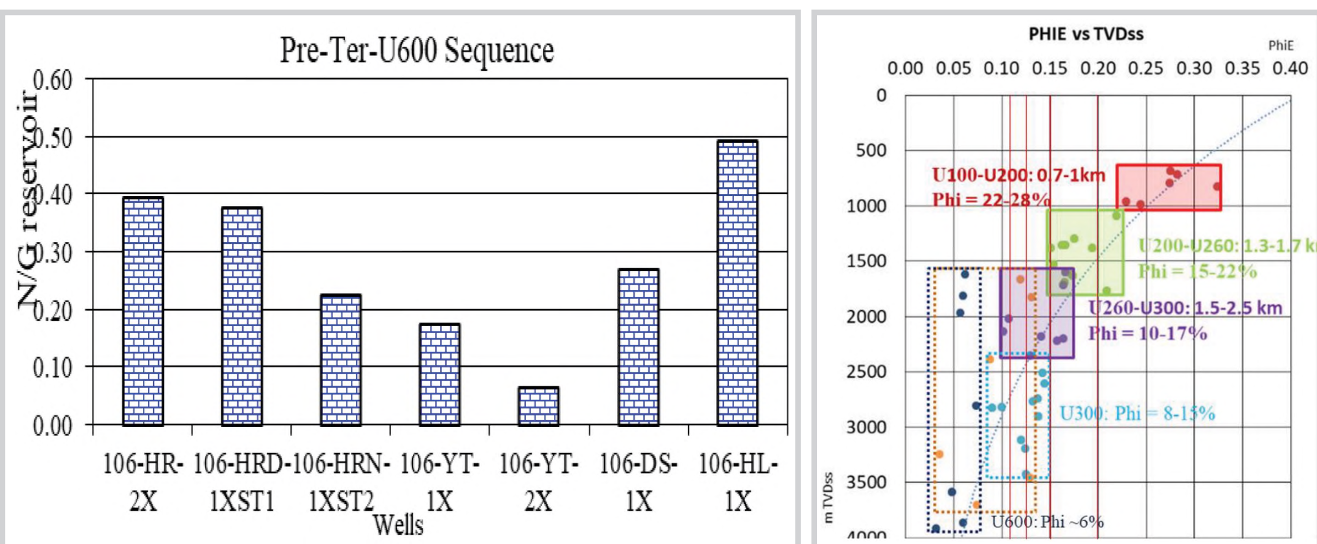


Figure 7. *Property of carbonate basement rock in Ham Rong area.*

and trap closure. Figure 5 shows the seismic correlation from prospect HRA-W to HR-A and HRA-E. Interpretation and correlation of seismic documents are clear. The conversion of time to depth to accurately determine the depth of the structural top is considered reliable.

The basement surface U600 is well observed on the seismic section and quite reliable on the U600 map with the depth nearly equivalent to the Ham Rong discovery. The trap was the 2-way closured structural trap and completed at the end of the Oligocene and. The trap develops in the same northeast - southwest structural trend, similar to the discovery of oil/gas as in the structures Ham Rong, Ham Rong Nam and Ham Rong Dong.

The trap evaluation criteria is good - very good (1), with high reliability (A). The probability for presence of trap is 90% (Ptrap = 0.9).

3.2.5. Migration evaluation

The prospect HRA-E has a favorable location, near the source of oil and gas generation (Figure 4). However, the basement block is covered on both sides by the U500 sediment layer, which limits the direct migration of oil and gas into the trap.

The traps formed early are cavernous, fractured carbonate basement blocks that were buried before the Cenozoic, so they are favorable in terms of receiving oil and gas. The trap is located in an area stable in tectonic activity and good in cumulative preservation.

Time, migration, and preservation factors are evaluated according to the evidence of oil and gas discovery in the same structural zone of Ham Rong and Ham Rong Nam; the trap was formed and completed before the main hydrocarbon migration time; tectonic activities stabilized after traps were formed.

Criteria for evaluating the migration line are quite favorable, average reliability (B), success field B1 (Figure 2). The probability of success is 70% (Pmigration = 0.7).

3.2.6. POS evaluation result

The probability of discovering oil and gas in the basement block of the structure HRA-E by applying the risk matrix model and the evaluation criteria of 5 geological factors gives a success propability of 45%. The rate of exploration wells encountering carbonate basement objects is 6/6 wells (100%), of which 3/6 exploration wells discover oil and gas (50%). The results of the probability of geological success (POS) assessment of the structure HRA-E are consistent with the exploration result in the area.

4. Conclusion

Assessing the probability of geological success according to the level of confidence in geological information and understanding of the object is currently used by many oil and gas companies. By applying the method to evaluate the probability of geological success of the structure HRA-E in Block 106, north of the Song Hong basin, each independent geological element is analyzed in detail with specific geological criteria. The assessment results are consistent with the reality of the probability of success of exploration drilling in the area and can be applied to structural assessment for PVEP projects.

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PETROVIETNAM SCIENCE, TECHNOLOGY & INNOVATION PETROVIETNAM

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.

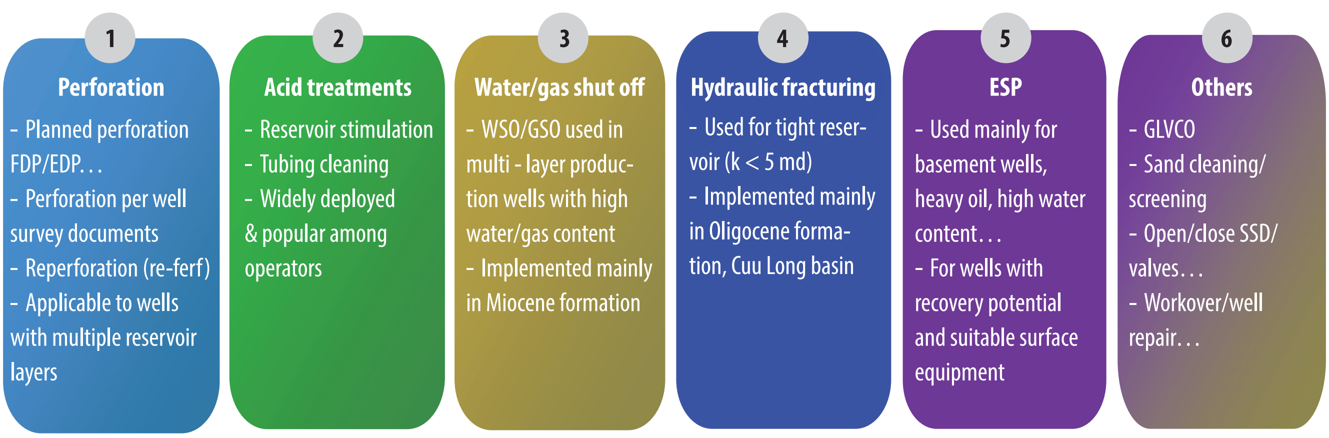

Figure 1. *Well intervention solutions implemented at PVEP projects.*

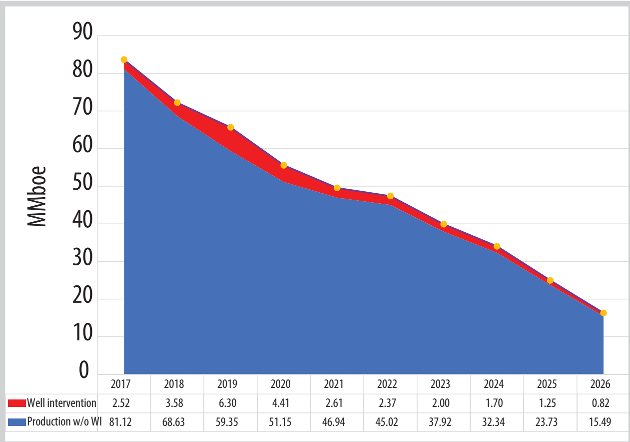

Figure 2. *Contribution of well intervention to production during 2017 - 2026.*

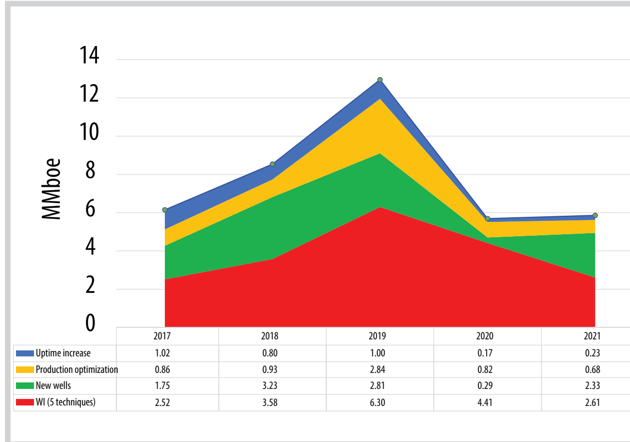

Figure 3. *Effectiveness of reservoir recovery enhancement solutions during 2017 - 2021.*

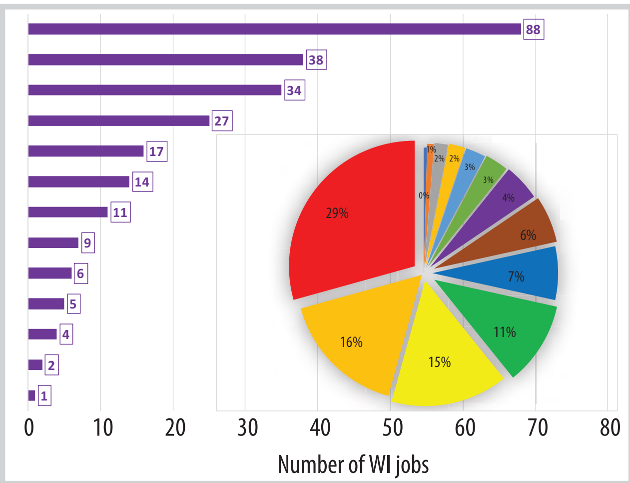

Figure 4. *Well intervention by operators during 2017 - 2021.*

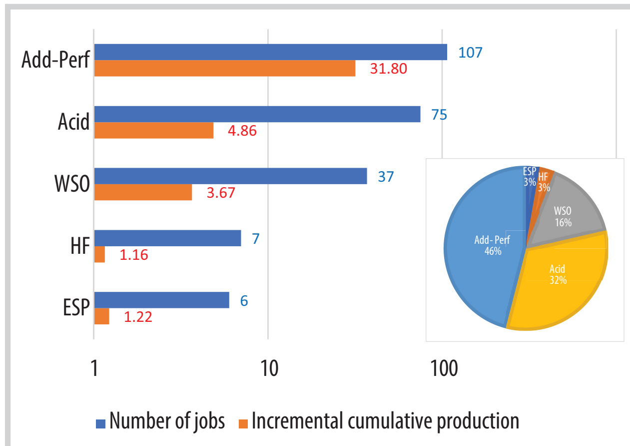

Figure 5. *Well intervention and the corresponding production increase (MMboe) by methods.*

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 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.

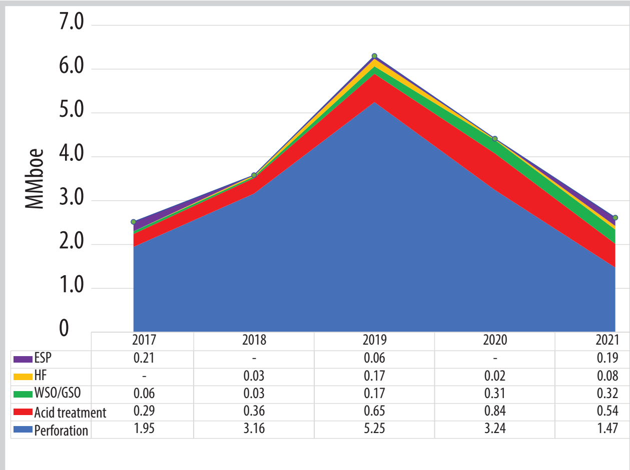

Figure 6. *Production increased by well intervention solutions in 2017 - 2021.*

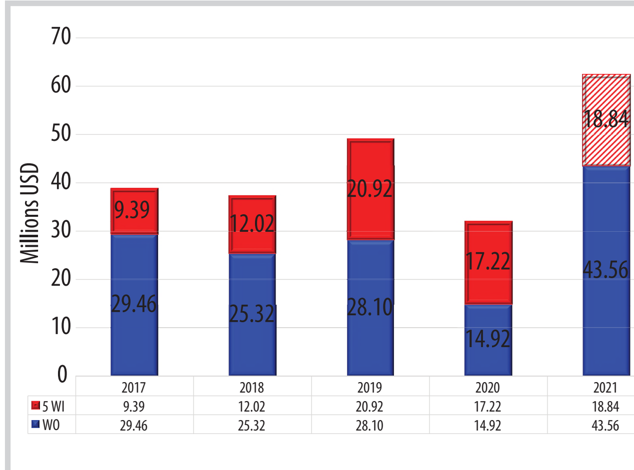

Figure 7. *Budget for well intervention and well work-over by years in 2017 - 2021.*

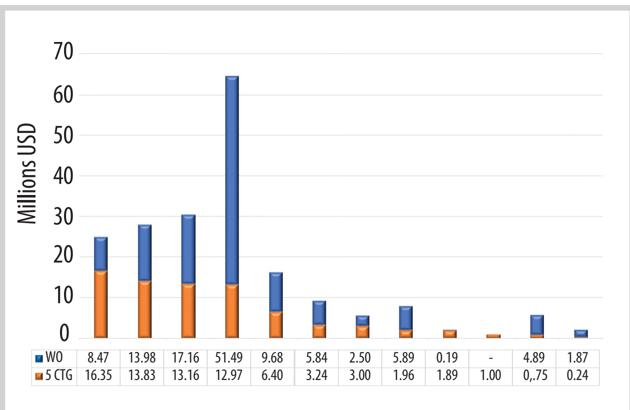

Figure 8. *Budget for well intervention and well work-over by operators, 2017 - 2021.*

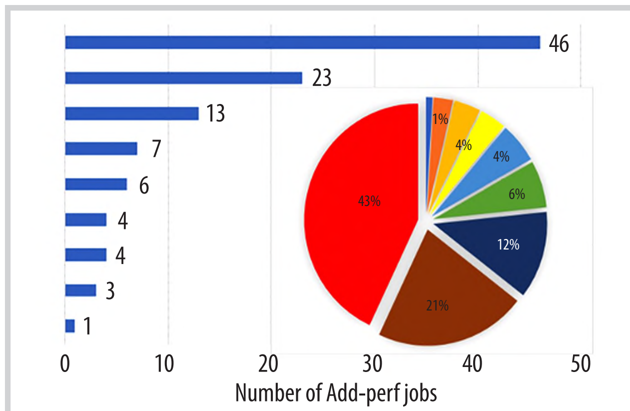

Figure 9. *Number of perforations by operators.*

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.

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

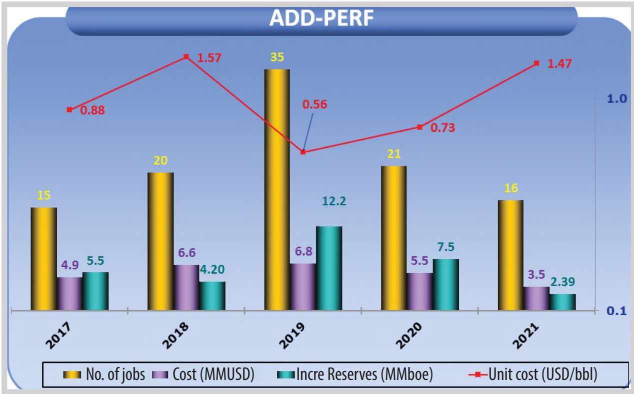

Figure 10. *Number of additional perforations by years.*

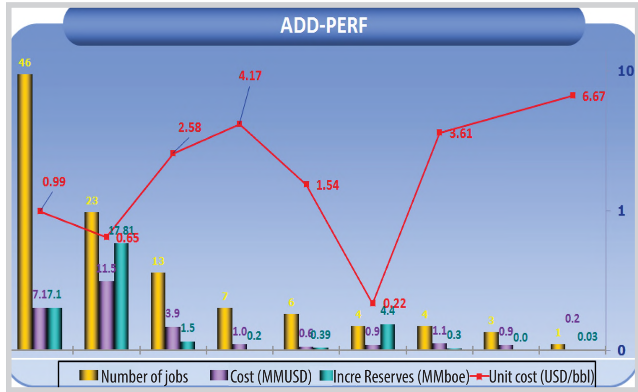

Figure 11. *Perforation effectiveness by operators.*

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). 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^o) 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

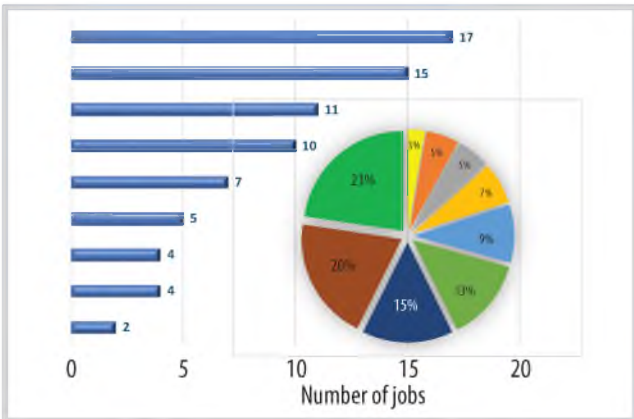

Figure 12. *Number of acid treatment operations by operators/projects.*

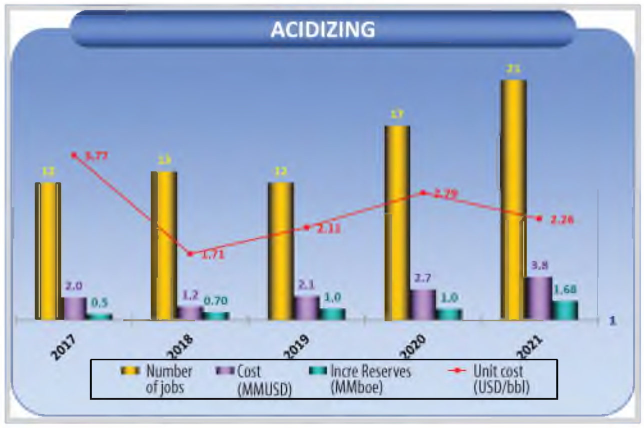

Figure 13. *Number of acid treatment (acidizing) jobs by years.*

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 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

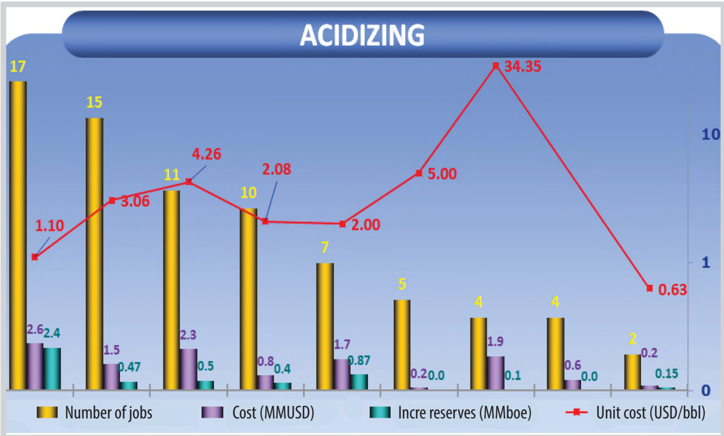

Figure 14. Acid treatments by projects.

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

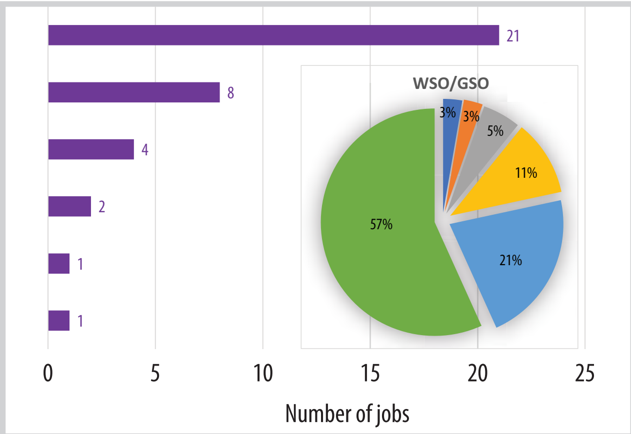

Figure 16. Water/gas shut-off jobs by operators.

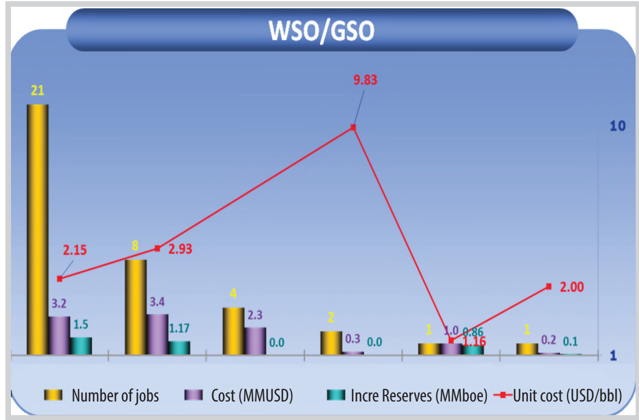

Figure 17. Water shut-off jobs, cost and increased production by operators during 2017 - 2021.

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.

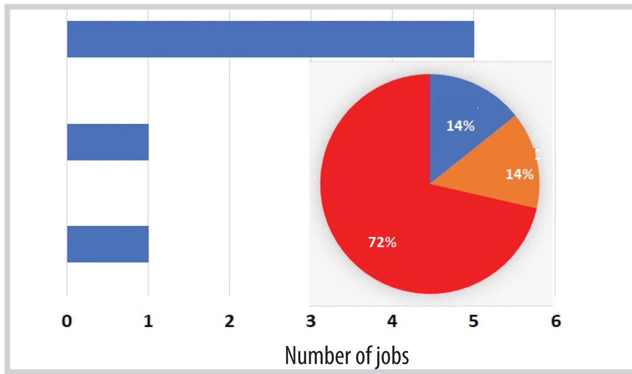

Figure 19. Number of hydraulic fracturing jobs by operators during 2017 - 2021.

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).

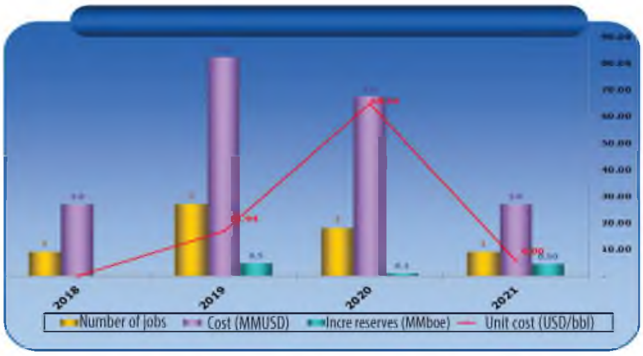

Figure 20. *Hydraulic fracturing jobs by operators during the period 2017 - 2021.*

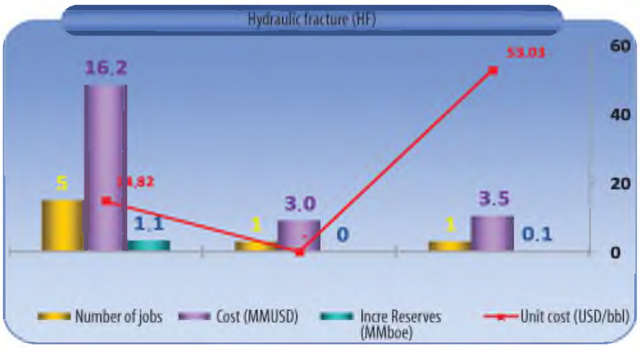

Figure 21. *Hydraulic fracturing jobs by operators - costs and production increase.*

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 fracturing work during the period 2017 - 2021.

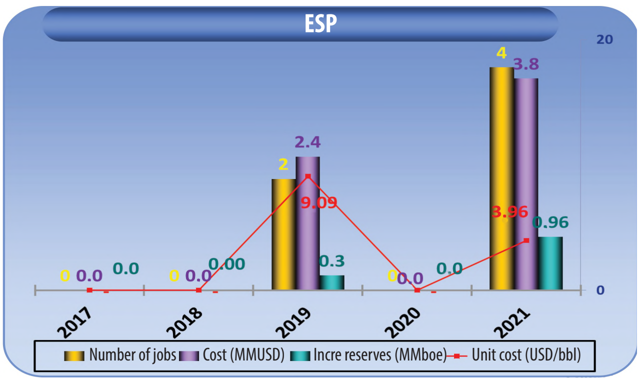

***Figure 23.** ESP installation work by years during 2017 - 2021.*

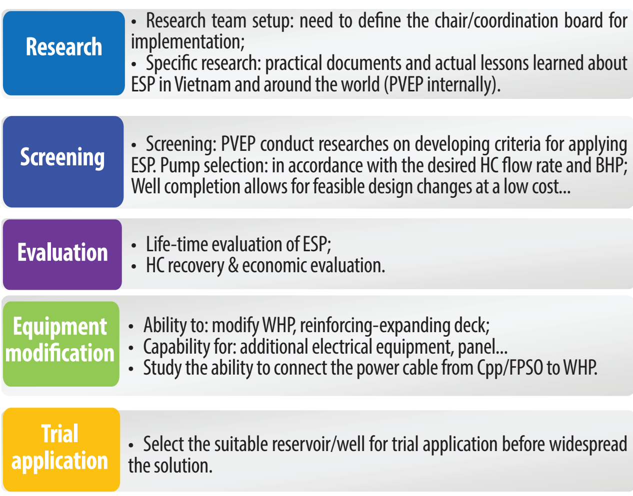

***Figure 24.** Directions for the future ESP installation work.*

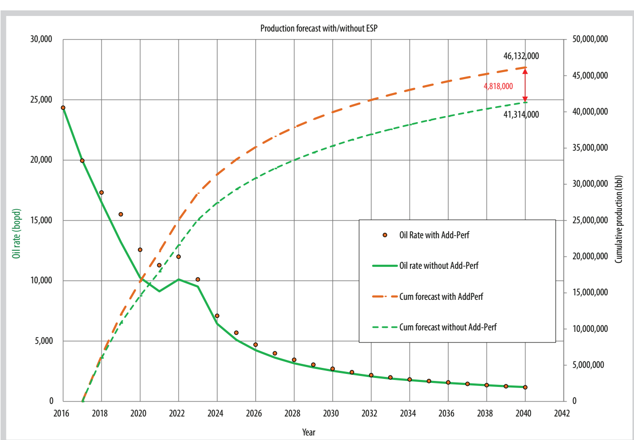

***Figure 25.** Forecast of production output with and without reservoir perforation in the in oil field, Cuu Long basin.*

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

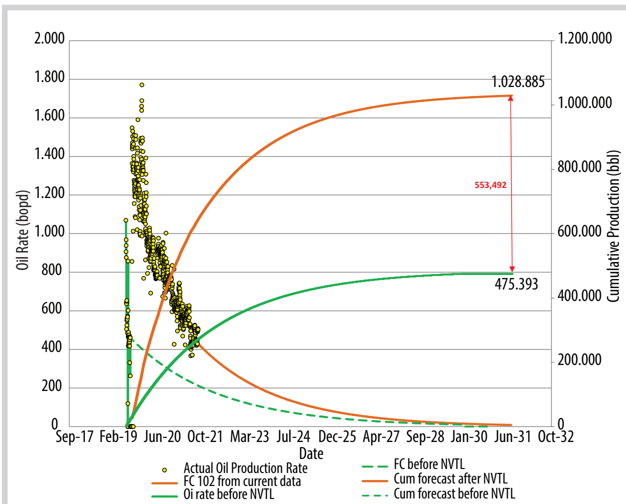

Figure 26. *Forecasted production rates with and without HF for a well in field A.*

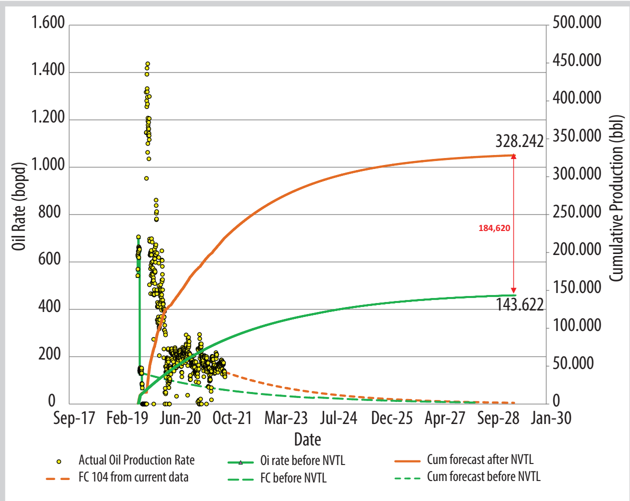

Figure 27. *Forecasted production rates with and without HF for a well in field A.*

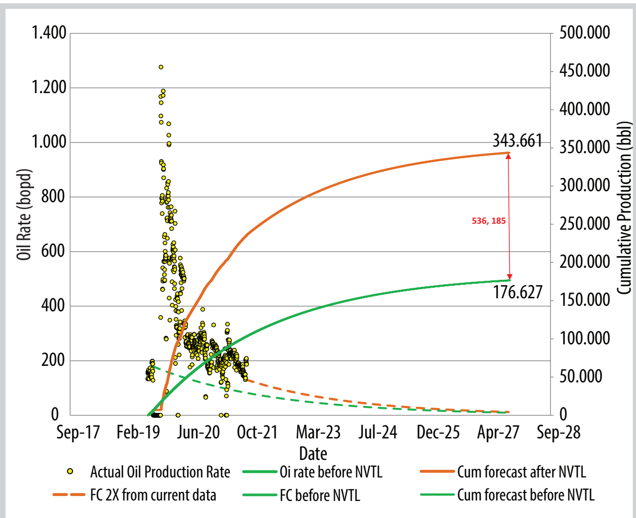

Figure 28. *Production forecast with and without HF at an oil well in field B.*

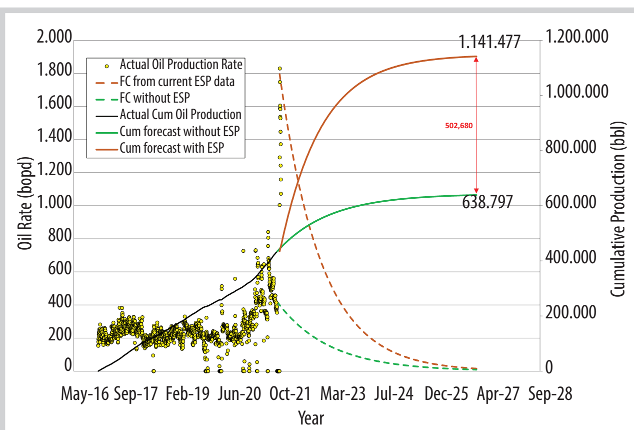

Figure 29. *Production forecast with and without ESP at an oil well in field B.*

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

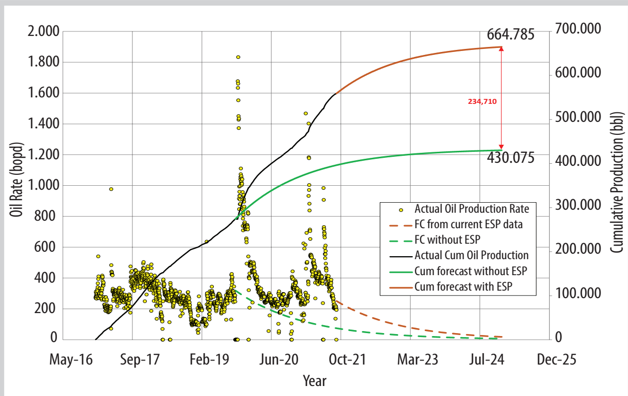

Figure 30. Production forecast with and without ESP at a well in field C.

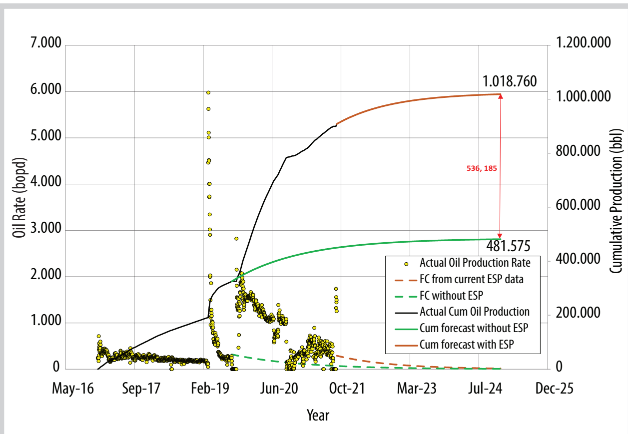

Figure 31. Production forecast with and without ESP at a well in field C.

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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PETROVIETNAM SCIENCE, TECHNOLOGY & INNOVATION PETROVIETNAM

EVALUATING THE DIGITALIZATION CAPABILITY AND DISPLAY OF KPIS FOR TWO FERTILIZER PLANTS OF PETROVIETNAM

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Summary

The study partially funded by the Vietnam Oil and Gas Group (Petrovietnam) assesses the infrastructure, OT/IT systems, and data handling at two fertilizer plants. Although well-equipped with automation control technology, the plants lack seamless integration, connectivity, and encounter limitations in communication between systems. To address these issues, the study advocates for the integration of digital technology, emphasizing its potential for enhancing efficiency, facilitating optimal management, and guiding strategic direction. Following an assessment of infrastructure, key performance indicator (KPI) system requirements, and data management, the study proposes an initial application of digital technology to link KPI displays. The outlined scope, initial costs, investment phases, and implementation schedule indicate a total initial investment of around VND 37 - 39 billion, accompanied by annual maintenance costs ranging from VND 3.7 to 4.1 billion. Expected economic and social benefits involve improved management at both Petrovietnam and plant levels through the KPI system, with an estimated energy cost savings of 1%, equivalent to roughly VND 44.6 billion. The project aims to position the fertilizer plants and Petrovietnam as leaders in technology, contributing to sustainability and enhancing their global industry reputation.

Key words: Digital transformation, key performance indicator, fertilizer plant, operational production.

1. Introduction

Industry 4.0 - also called the Fourth Industrial Revolution or 4IR - is the next phase in the digitization of the manufacturing sector, driven by disruptive trends including the rise of data and connectivity, analytics, human-machine interaction, and improvements in robotics. Industry 4.0 and digital transformation are marking a significant milestone in the industrial sector, particularly in the oil and gas. Advancements in artificial intelligence, the Internet of Things (IoT), machine learning, and smart automation have presented new opportunities and challenges for businesses in this sector [1 - 3]. By applying Industry 4.0, integrating these technologies into the production process, the plants can leverage digital solutions for safety management, production optimization, and asset management to enhance performance and reduce costs [4, 5].

The trends in the 4IR and digital technology have gradually influenced the operational and managerial practices of Petrovietnam and its affiliated companies. To bolster competitiveness, especially in ensuring the consistent operation of plants, Petrovietnam is strategically planning to integrate digital technologies progressively, aiming to establish smart factories in the foreseeable future.

The two ammonia plants funded by Petrovietnam, namely Phu My and Ca Mau fertilizers were constructed during the Third Industrial Revolution. Consequently, there is a need to explore the transition to implement technology for enhanced management, monitoring, and production optimization - not only technologically viable but also cost-effective. This transition improves managerial efficiency and fosters the exchange of experience and

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information among plants. Despite the advantages embedded in the current infrastructure and management framework, there exist certain limitations, including: (i) The system is geared solely towards internal management with a lack of external connections and information sharing, particularly with Petrovietnam and its managed plants; (ii) The synchronization of information technology application in control and automation systems within the plants is not uniformly high; (iii) There exists variability in investment levels, types, objectives, and timelines.

Furthermore, the current operational framework of both fertilizer plants does not incorporate key performance indicators (KPIs) for detailed monitoring and controling at each stage or production area. Instead, they rely on a set of analogous indicators termed "Operational consumption standards" for the entire plant, which are not fully digitized. On a monthly and annual basis, data collection occurs, and this information is inputted into an Excel spreadsheet known as "Overall specific consumption standards" for reporting or planning purposes.

Therefore, it is crucial to develop calculations for KPIs in production operations at various levels, as well as to standardize and synchronize the two plants. Integration and enhanced display capabilities are essential for monitoring, tracking, controlling production operations, and supporting decision-making processes for the leadership of Petrovietnam and its affiliated units.

For the oil and gas industry, especially in the operation of oil refineries and fertilizer plants, various information technology/operational technology (IT/OT) licensors such as Honeywell, Yokogawa, Dassault Systems, Siemens, ABB, etc., provide solutions to satisfy basic purposes such as improving productivity, reducing production costs, saving energy, optimizing plants, and enhancing reliability. They can be categorized into several main areas such as safety management, asset management, production optimization, management solution, etc., as illustrated in Figure 1 [6 - 9]. These

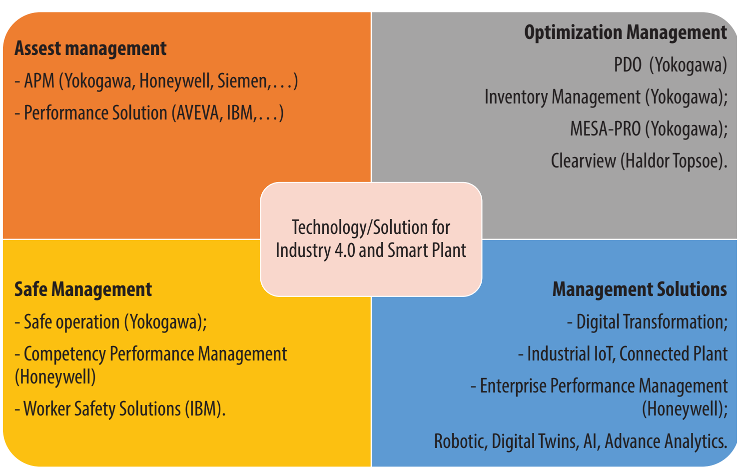

Figure 1. *Several technologies/solutions for fertilizer plants forward Industry 4.0 and smart operation.*

solutions encompass various small packages and specific technologies depending on each plant's requirements and applicability. The main solutions are software applications, and the licensors will evaluate the need for hardware supplements based on each plant's infrastructure to implement the solutions. The solutions are implemented separately, not requiring the plant infrastructure to reach the level of Industry 4.0 [10, 11].

As a result, Petrovietnam has assigned Vietnam Petroleum Institute (VPI) to implement the task "Research on the feasibility of applying digital technology in conjunction with software for the online management, monitoring, and control of KPIs related to the production operations of the two fertilizer plants of Petrovietnam". This initiative aims to align the two fertilizer plants with development trends, assess and enhance their management processes with plans to further extend this approach to other Petrovietnam facilities. In this paper, VPI focuses on evaluating the infrastructure (OT/IT) of the two plants, examining connectivity, digitization of KPIs, as well as data management to improve the management and monitoring capabilities of Petrovietnam and its two units. The methodology for deployment, the KPIs determination and results will be presented in a separate paper.

2. Objectives and methodology

As mentioned earlier, the primary aim is to define KPIs related to production operations, digitization, and smooth connectivity for effective management and monitoring of the plants. The overall methodology and solution for this project are illustrated in Figure 2. For Petrovietnam, the end-user, it is essential that the chosen KPIs set is consistent with current industrial development trends, emphasizing connectivity and online display capabilities. After implementation, Petrovietnam personnel can anticipate the ability to remotely monitor plant activities and receive automatic reports from plants while sitting at the headquarters.

To initiate the implementation, a thorough survey and assessment of IT/OT infrastructure,

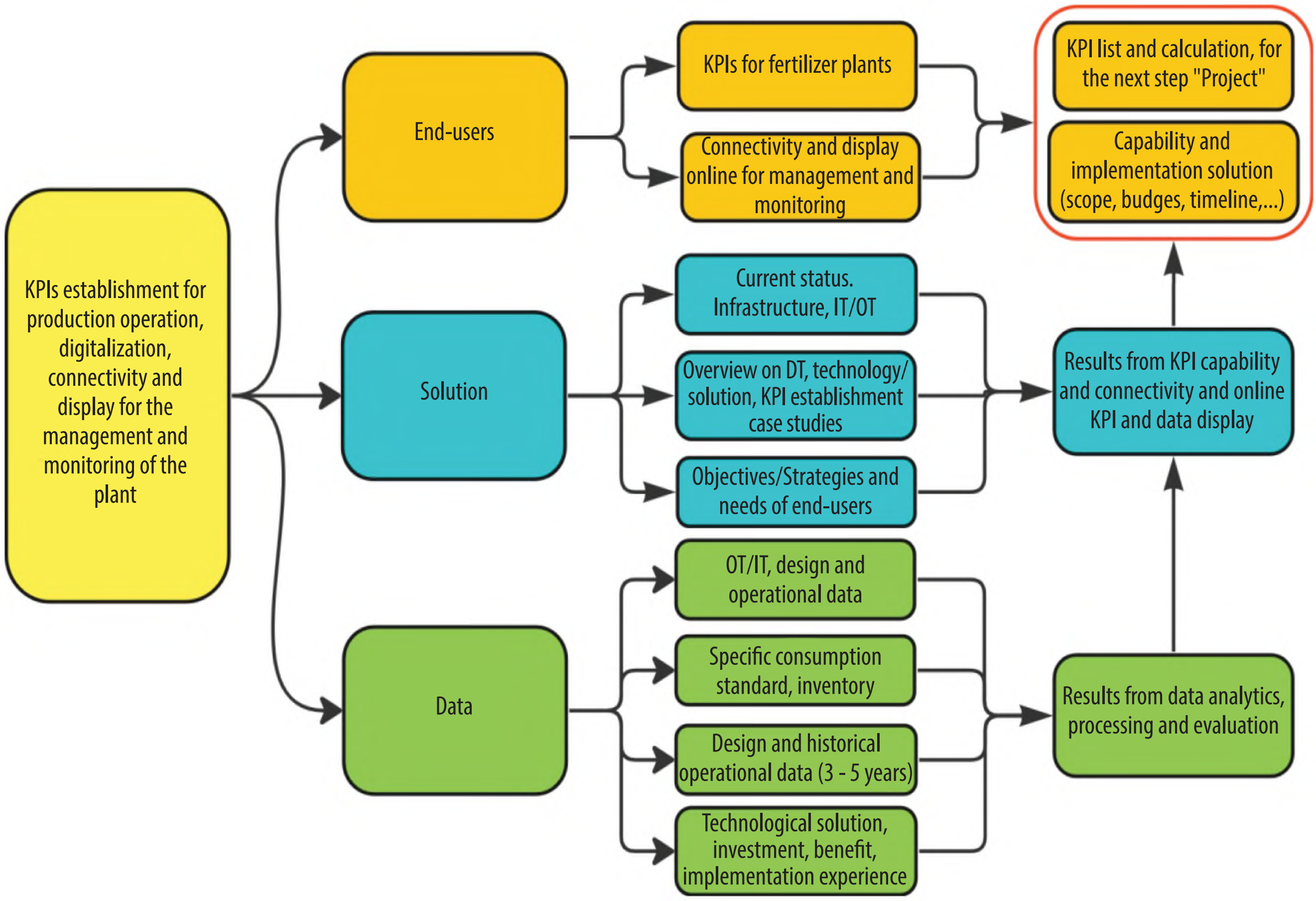

Figure 2. *The overall methodology and solution for this project.*

plant operations, and existing consumption standards at the plants are imperative. Collaboration with various OT/IT licensors and fertilizer production complexes such as PUPUK fertilizer plants (Indonesia) is vital to gain insights into technology/solutions for digital transformation, KPIs setup, best practices, and the status of technology/solution implementation in other plants. This collaboration aligns well with Petrovietnam's goals and directions. The data required to collect and evaluate encompass:

- IT/OT data, design data, operational data, specific consumption standards, maintenance, and inventory of supplies.

- Last 3 - 5 years' operational (process) data, digitalization solutions/technologies, etc.

Upon gathering this data, the subsequent steps involve analyzing and processing the information, assessing the feasibility of implementing KPIs, and exploring the potential for digitizing data connectivity. The result of this task will be a set of KPIs algorithms and data, facilitating the progression to the next phase, which includes "Project procurement". As mentioned above, the KPIs establishment and algorithms will be shown in another paper.

3. Current status of Petrovietnam's fertilizer plants

Petrovietnam operates two fertilizer production plants situated in Phu My and Ca Mau. Phu My Fertilizer is located in Phu My Town, Ba Ria - Vung Tau province. Ca Mau Fertilizer is situated in the southwestern province of Vietnam. Commencing operations in 2004 (Phu My) and 2012 (Ca Mau), both plants actively contribute to the market with a significant volume of urea, NPK, and other products like CO_2, UFC85, etc., further bolstering the agricultural development and economic progress of Vietnam. At present, these plants have control-automation systems that are predominantly installed, as outlined in Table 1.

The elements within a control-automation system, both software and hardware, communicate and exchange information across the network through a set of protocols. Broadly speaking, the communication protocols employed in both fertilizer plants are comparable and include ethernet, Modbus, OPC, Profibus, foundation Fieldbus, and hardwire. For a detailed overview of the primary signaling protocols utilized by each system in the two fertilizer plants, please refer to Table 2 and Figure 3.

***Table 1.** Main hardware and software installed in Phu My and Ca Mau fertilizers. Source: PVCFC, PVFCCo.*

No.	Hardware/Software	Function	Phu My Fertilizer's license	Ca Mau Fertilizer's license
1	Distributed control system (DCS)	Manage the entire technological process of the factory	Yokogawa VP	Yokogawa VP
2	Emergency shutdown (ESD)	Intervene in the operation of the plant to protect before a technological incident occurs	Yokogawa Prosafe Triguard SC300E	3 Triconex ESD systems
3	MPS/ Machinery managing system (MMS)	To manage several dynamic equipment in the factory	MPS: GE Bently Nevada MMS: System 1	MPS: GE Bently Nevada MMS: System 1
4	Advanced process control (APC)	For optimization of ammonia unit	Honeywell	Honeywell
5	Information Management System (IMS)	Keep track of several technology segments	IMS - Siemens system was put into operation in 2007. à Replaced IMS with self-built PMIS system 2020	Using PI (Aveva) in 2023
6	Computerized maintenance management system (CMMS)/Reliable centered maintenance (RCM)	Maintenance and maintenance management	Ivara - Siemens	RCM method
7	Enterprise resource planning (ERP)	Computer software for business administration	Oracle ERP	SAP ERP
8	Burner management system (BMS)	It is a form of safety PLC used for operation/ protection of boilers, waste heat boilers.	ELOP II- HIMA	SIMATIC S7
9	Motor control center (MCC)	A form of PLC used for the operation/protection of electric motors	ECS Siemens, 1 PLC S7-400H 2 HMI	PCS 7 V7.1
10	Complex compressor controller (CCC)	To operate compressors and steam turbines and are usually in the same control package as PLCs	CCC	4 Woodward Peak 150 system
11	Fire and gas system (FGS)	It is a type of safety PLC that utilizes detection of fire or leakage of hazardous gas/explosive substances	Triconex	Triconex, F&G Triconex system - 2 HMI machines, 3 MIMIC machines
12	Environment continuous management system (ECMS)	A form of PLC used to detect fire or leakage of hazardous/explosive gases Environmental impact monitoring	ECMS Emerson	Rosemount X-STREAM XEFD

***Table 2.** Main communication protocols at two fertilizer plants*

No.	System	Protocol description
1	IMS	Intranet computers using ethernet. Connect the DCS system via the OPC server (OPC protocol).
2	MMS	Connecting the Bently Nevada System for data collection (ethernet).
3	APC	Intranet computers using ethernet. Connect to the DCS system via the OPC server (OPC protocol).
4	ESD	In-network control cabinets using Modbus. Connecting a DCS system using Modbus or hardwire.
5	DCS	Control cabinets using Vnet protocol (coaxial cable or RJ45). Connect to subsystems using Modbus or hardwire.
6	PRM	Connect to the DCS system via the OPC server (OPC Protocol).
7	Truck scale	Intranet computers using ethernet. Connect to the Modbus balance bridge.

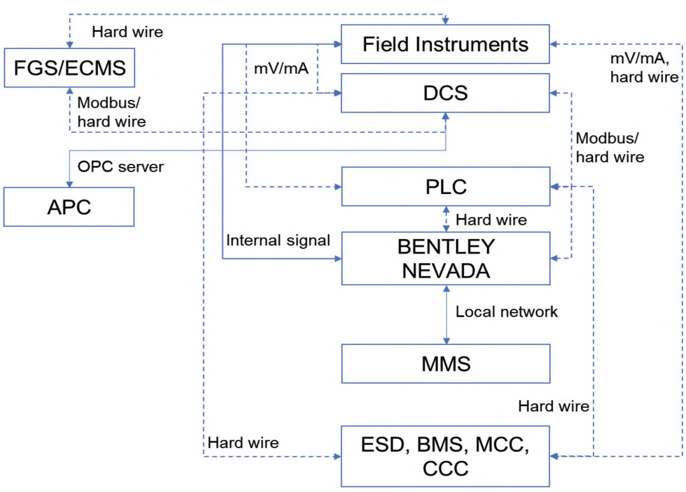

***Figure 3.** The control system connectivity at the two fertilizer plants.*

4. Digital transformation evaluation and proposal

4.1. Evaluation and proposal

At present, the plant runs with a comprehensive suite of automation control levels to manage its operations. However, this system lacks integration, optimization, and has limitations in communication, such as information connectivity between distributed control system (DCS) and utility units. Additionally, the facility has not embraced new technologies, notably wireless technology, Cloud integration, and other Industry 4.0 applications. The digitization and presentation of KPIs are contingent on the data connectivity system, extending from the process to

DCS, and the transformation of data volumes suitable for analytical applications via OPC. The operational data from the DCS of the two plants are stored in the system's historian server (HIS), as depicted in Figure 4. HIS redundantly stores data periodically and allows extraction, but the process is time-consuming and more challenging than extraction from the OPC server system. Notably, HIS does not cater to real-time data extraction.

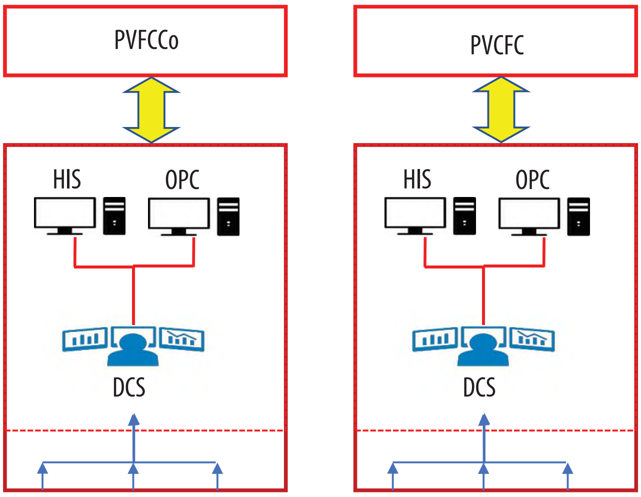

Figure 4. The overall structure of data connection of the fertilizer plants.

Both existing fertilizer plants have the potential to integrate new digital technology for real-time data management and retrieval. However, the most practical integration is primarily directed towards two key units, namely ammonia and urea, to oversee, optimize, and diagnose the operational processes. For other units, such as utilities, chemical management, catalysts, inventory, there are still numerous limitations stemming from the absence of meters or meters not connected to DCS, manual control, and lack of synchronous connection of the electrical system to DCS. Implementing digital technology across the entire factory will necessitate fresh investments in meter systems, management software, new servers, etc. Standardizing and centrally storing data will enable digitization and the application of data analysis technologies and machine learning throughout the plant's operations. The proposed overall connection configuration aims to display real-time information from the two fertilizer plants, synchronize data to cloud/on-premises, and provide the capability to monitor operations from Petrovietnam, as illustrated in Figure 5 [12, 13].

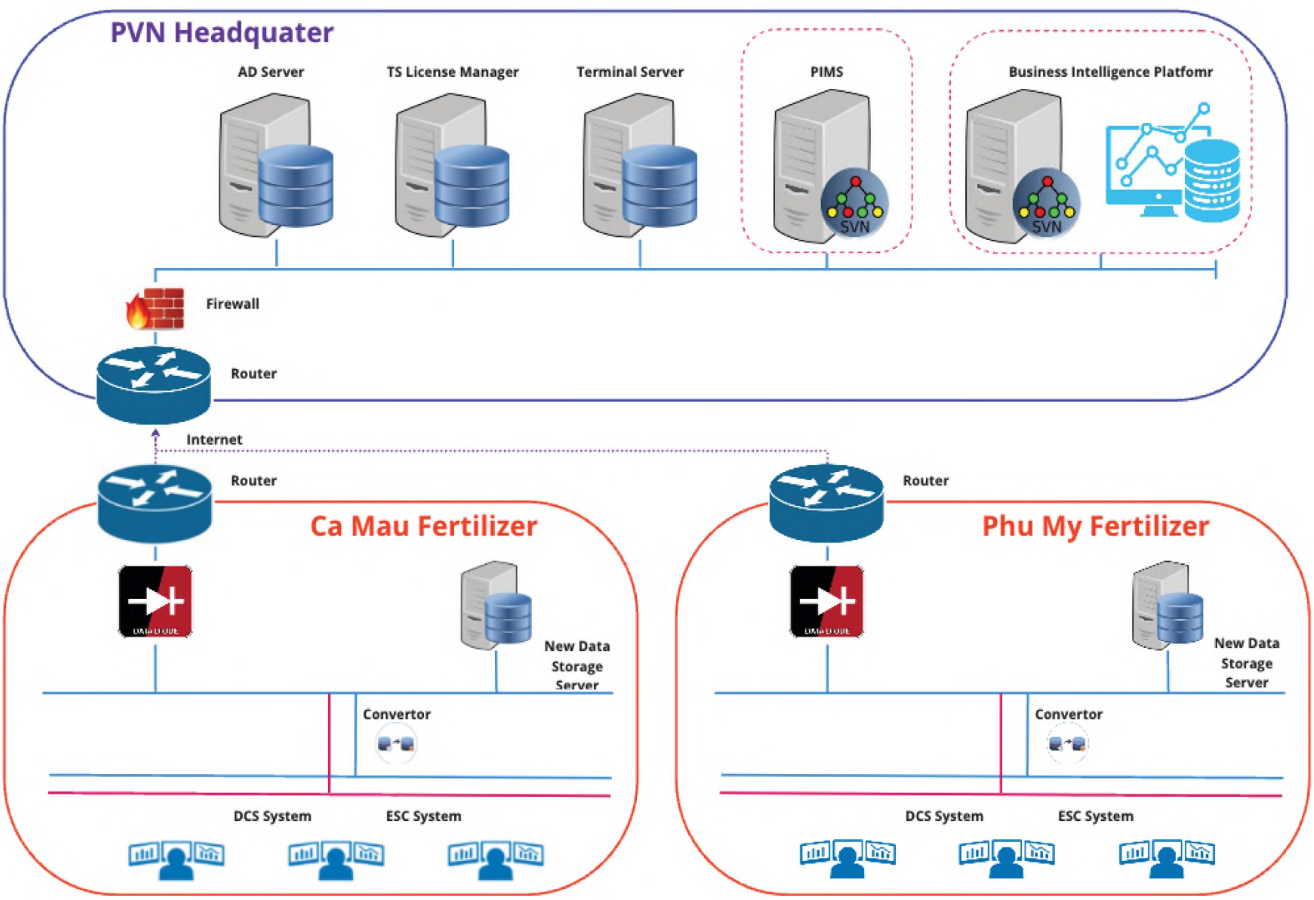

Figure 5. Overall architectural connection plan for Petrovietnam and two fertilizer plants.

Overall, each plant probably invests in an additional server dedicated to data storage, ensuring uninterrupted synchronization in case of transmission issues, and preparing for future factory optimization to minimize data latency. To guarantee network and data security, the system will incorporate a firewall and diode for one-way data extraction. The factory can reuse the OPC server system or PI system partially to act as a gateway and store data on a new server situated at both plants. Detailed evaluation of data transmission at the two plants is essential to meet response requirements from DCS, the number of tag names used, and the upgrade directions aligned with the OT/IT phases of the plant. Regarding the new OPC system, additional IoT devices can be seamlessly added or connected directly to the OPC. In cases where the current DCS system lacks compatibility, a direct connection to the new OPC system is feasible, thereby reducing the load on the existing DCS systems of both

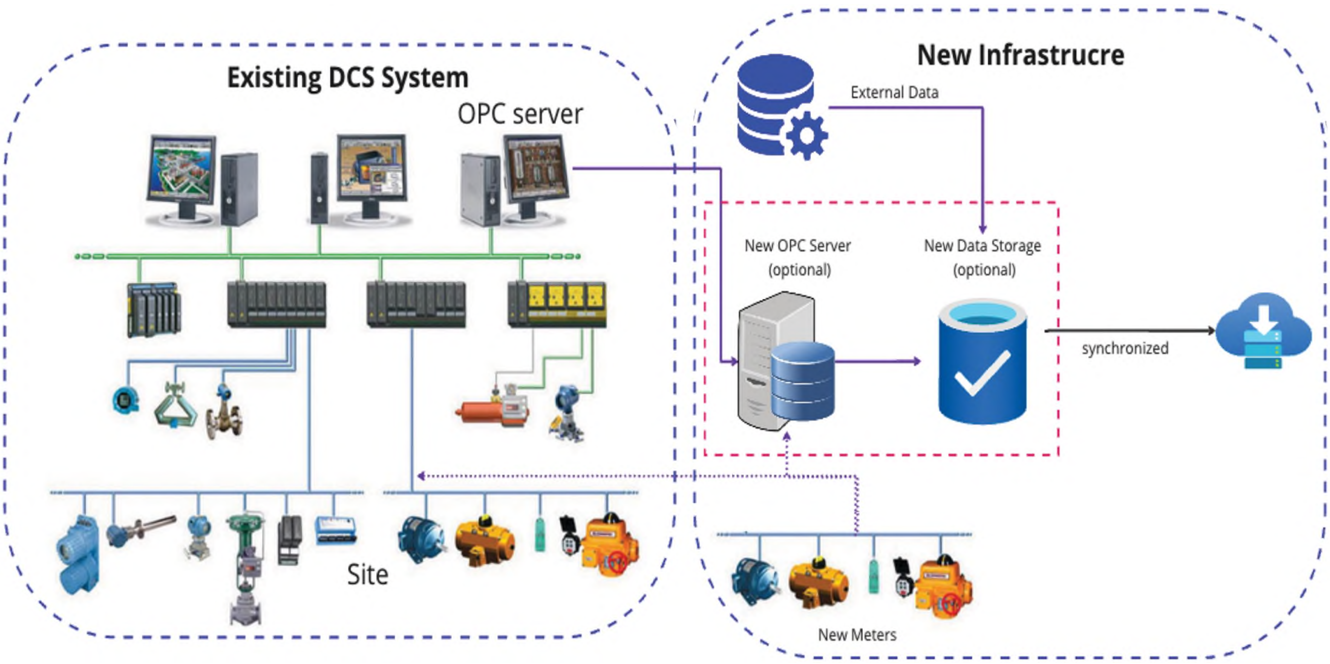

Figure 6. *Connection diagram at Ca Mau and Phu My Fertilizer Plants.*

Table 3. *List of software/hardware and engineering service requirements for two fertilizer plants and Petrovietnam*

No	Petrovietnam/Plants	Hardware	Software	Engineering & other services
1	Petrovietnam	On-premise - Active directory server - TS licenser manager - Terminal server - PIMS server on cloud (service)	1 x Exaquantum 3,000 tags 6 x User Inferface License 1 x Exaopc OPC Client 1 x OI license 1 x VPN package license 1 x software AMC (12 months) 1 x Cyber security (antivirus, firewall & data diode.	Project management in house engineering: hardware & software FAT SAT (7 days) Packing and shipping Online training (2 days).
2	Phu My Fertilizer Plant	1 x OPC server 1 x PIMS	1 x Exaquantum 3,000 tags 6 x User inferface license 1 x Exaopc OPC client 1 x OI license 1 x VPN package license 1 x Software AMC (12 months) 1 x Cyber security (antivirus, firewall & data diode).	Project management in house engineering: hardware & software FAT SAT (7 days) Packing and shipping Online training (2 days).
3	Ca Mau Fertilizer Plant (*)	In a similar manner to the Phu My Fertilizer Plant	In a similar manner to the Phu My Fertilizer Plant	In a similar manner to the Phu My Fertilizer Plant
(*): The next step involves verifying the potential for reusing the plant's infrastructure system components, including the OPC server, OSI PI, and other relevant elements.				

factories. Overview of the connection configuration at two fertilizer plants is referred to Figure 6.

With the suggested infrastructure framework above, the primary software/hardware requisites are detailed in Table 3.

With the connectivity choice mentioned earlier, future unit expansions (e.g., NPK, UFC85, etc.) can be smoothly executed by establishing data links to the existing (or supplementary) hardware system. This process involves employing similar calculation methods and algorithms, ensuring straightforward connectivity to exhibit KPIs at various levels.

4.2. Preliminary investment and economic and social benefits

The initial investment expenses and ongoing maintenance costs, outlined in Table 4, are delineated based on two alternatives: utilizing Cloud services or constructing an in-house storage server.

The benefits derived from digitization, KPI implementation, and the shift towards digital transformation in the two fertilizer production plants extend beyond improving operational efficiency and reducing production costs, such as energy and chemical consumption through KPI applications. These initiatives also result in advantages related to safety, personnel management, and supply chain optimization. More specifically, they enhance the level of management and administration at both plants and Petrovietnam, creating opportunities for sharing information and experiences across different plants and units within Petrovietnam. The overall benefits include:

(i) Direct management and supervision (economic efficiency): In addition to continuous efforts of the two

Table 4. *Total preliminary investment and annual maintenance costs*

No.	Categories	Preliminary initial costs (VND) (*)	Annual maintenance costs (VND/year)
1	Petrovietnam		
1.1	On premise	~ 21 billion	1.5 billion [0.8 (Maintenance/operation); 0.75 (software)]
1.2	On cloud	~ 19 billion	1.05 billion [0.3 billion (hire) + 0.75 billion (software)]
2	Ca Mau Fertilizer Plant	~ 9 billion	1.3 billion [0.55 billion (Operation/maintenance) + 0.75 billion (software)]
3	Phu My Fertilizer Plant	~ 9 billion	1.3 billion [0.55 billion (Operation/maintenance) + 0.75 billion (software)]
4	Total		
4.1	On-Premise	~ 39 billion	4.10 billion
IV.2	Cloud	~ 37 billion	3.65 billion
(*): The next step verifies the potential for reusing the plant's infrastructure system components (e.g. the OPC server, OSI PI, etc.) for investment optimization			

Table 5. *Benefits from similar projects*

Plant/Enterprise	Project overview	Benefits
PUPUK Indonesia	Digital transformation for ammonia/urea plants. PUPUK has implemented as planned the whole plant of PUPUK Indonesia	- 2 - 5% increase in ammonia production capacity; - 1 - 7% reduction in energy costs depending on the plant.
UOP Honeywell	Enterprise data and operations management: dashboards, reports, graphics, historian, alarms and operation monitoring	- USD 2 million/location; - Collect and report data according to standards; - Integrate data from multiple sources (data lake); - Collect aggregated data for analysis; - Increase productivity.
AVEVA	AVEVA maintenance management solution pays off for CF industrial fertilizer plant	- Improve operations and reduce costs by automating facilities operations; - Successful integration with multiple systems as well as merging intuitive dashboards and KPIs, creating an optimized business workflow; - Potential to improve revenue by up to 5%; - Reduce operating costs by up to 10%.
Yokogawa	Integrated performance management	- Profit brings USD 5 - 15 million after applying; - Reduce energy consumption: 1 - 5% depending on the factory and current energy consumption; - Increase production capacity; - Reduce labor costs related to the implementation of reports.

plants to reduce energy and chemical consumption, the application of KPIs based on actual operational data follows a scientifically validated approach used globally in fertilizer plants. This enhances the management and supervision of production operations by:

+ Measuring energy consumption and system efficiency;

+ Identifying areas for optimization and reasonable consumption reduction;

+ Optimizing operations and reducing standard consumption through continuous online monitoring using digital tools and constraint-based KPIs [5, 14, 15]. This optimization process results in reduced energy and input consumption for the plant, typically achieving energy savings ranging from 1% to 5% of the total energy consumption in the initial year of implementation based on experience from similar projects (Table 5) [16 - 19].

(ii) Indirect management and monitoring efficiency (Social efficiency)

- For Petrovietnam:

+ Adoption of a uniform online management tool using a consistent approach for both plants.

+ Implementation of digitalization through KPIs and benchmarks to elevate the level of management, enhance automation, and align with industry development trends. This contributes to strengthening Petrovietnam's brand in the realm of digital transformation and fostering sustainable development.

+ Real-time online data monitoring facilitates swift decision-making during emergencies, backed by a robust scientific foundation for approving targets in the annual plans of both plants and monitoring task execution.

- For PVFCCo/PVCFC:

+ Realization of benefits (like the Petrovietnam level), this creates a coherent chain of efforts and modern management practices.

+ Establishment of scientific benchmarks, from systems to the entire plant, provides crucial information for optimizing financial software.

+ Reduction in labor and other costs for collecting information from units, processing information from departments to execute and report to the Group's leadership.

+ Enhancement of safety, environmental protection, and process compliance, improvement in product quality.

+ Efficient operational team management and enhancement of the management/administration level.

+ Assessment of equipment and technology line performance.

+ Facilitation of experiences/information sharing and mutual learning between the two plants.

These management benefits, while challenging to quantify specifically, strategically contribute to the modern development of Petrovietnam's management for the two plants, particularly as the impact of digital transformation continues to grow in the oil and gas sector. This initiative sets the stage for Petrovietnam's comprehensive digital transformation across all its plants.

5. Conclusions

This study, partially funded by Petrovietnam, has conducted a comprehensive evaluation of the infrastructure, OT/IT systems, and data management for two fertilizer plants. Although equipped with advanced automation control technology, the plants face challenges in integration, connectivity, and inter-system communication. Recognizing the need for enhancement and integration of digital technology to improve efficiency, the study proposes a preliminary application to connect KPIs displays. The outlined project involves an initial investment of approximately VND 37 - 39 billion, with annual maintenance costs ranging from VND 3.7 - 4.1 billion.

Despite the initial high costs, the potential for significant energy and cost savings makes the digitization of the fertilizer plants economically feasible. Moreover, the project's positive impact extends beyond economic benefits, enhancing sustainability, management practices, and the overall reputation of both the fertilizer production plant and Petrovietnam within the community and the global business context. The project positions the fertilizer plants and Petrovietnam as technology leaders, contributing to sustainability and elevating their global industry standing.

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PETROVIETNAM LEVERAGING ITS TECHNOLOGY AND SERVICES INHERITED FROM OIL AND GAS OPERATION INTO THE CONSTRUCTION AND SUPPLY CHAIN OF OFFSHORE WIND POWER

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Summary

In the era of global integration, there is a clear shift from fossil fuels to renewable energies across nations. The investigation and utilization of renewable energy sources, especially offshore wind energy, emerge as a pivotal area for energy companies and corporations. The Vietnam Oil and Gas Group (Petrovietnam) is standing at the threshold of substantial opportunities and challenges in expanding its operational spectrum towards renewable energy with a particular focus on offshore wind power. This study analyzes Petrovietnam's inherent strengths and capabilities with the orientation and strategy to become a leader of the service supply chains for offshore wind power in Vietnam.

Key words: Offshore wind energy, offshore wind supply chain, oil field service, energy transition.

1. Introduction

The transition towards green and sustainable energy is an inevitable trend among nations worldwide. Alongside economic growth, Vietnam's demand for energy and electricity is projected to rapidly increase in the coming years. Concurrently, to ensure energy security, Vietnam is also developing an energy transition roadmap aimed at a "net zero" CO_2 emissions target by 2050. This strategic shift reflects the country's commitment to balancing economic development with environmental sustainability, positioning itself as an active participant in the global movement towards cleaner energy sources.

The Power Development Plan VIII clearly sets a direction for harnessing the full potential of offshore wind energy (around 600,000 MW) for power production. By 2030, it is projected that the capacity of offshore wind power to meet domestic electricity demand will be around 6,000 MW. This capacity will increase further and meet the target of 70,000 - 91,500 MW by 2050 if technologies foster rapidly and/or the cost of electricity and transmission reduce affordably. To achieve these goals, Vietnam needs to set up and develop a supply chain for the offshore wind energy industry.

Based on the experience developing supply chain in European countries, oil and gas companies hold a distinct and clear advantage when diversifying into the offshore wind sector.

First, with decades of experience in offshore oil and gas projects, these companies have unique advantages in managing logistics, engineering, manufacturing, installation and even providing professional manpower for offshore wind farms.

Second, many of the essential techniques for transporting and installing offshore wind structures such as platforms and foundations are very similar to those used in the oil and gas industry.

Third, oil and gas companies have existing infrastructure, facilities, and equipment that can be conveniently upgraded to meet the needs of building wind farms [1].

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Fourth, oil and gas companies normally have significant financial capacity, and, because of their internationally operational scale and expansive readiness, they have established local relationships in many global markets [2].

Facing significant opportunities and challenges in the energy transition, Petrovietnam is strategically positioning itself to become a leading energy and industrial group in Vietnam and Asia. Petrovietnam, with its array of competitive advantages, is well-equipped to engage in the offshore wind energy's (OWE) supply chains, leveraging its vast experience and existing facilities in offshore oil and gas. These strengths underpin Petrovietnam's goal to be a pivotal enterprise in Vietnam's OWE industry. To maximize its potential in OWE, Petrovietnam must swiftly adopt, integrate, and manage the advanced technologies in this sector. Considering the scarcity of OWE projects in Vietnam and Petrovietnam's limited experience in this area, it is essential to research OWE technologies to quickly seize technological expertise, integrate into the global value chain, and conquer the international market in this domain.

This research aims to analyze Petrovietnam's offshore wind technological and services supply chains capabilities, identify gaps that Petrovietnam must address to manage OWE construction technology, propose internal collaboration strategies for Petrovietnam to take the lead in the OWE market in Vietnam.

2. Overview of offshore wind supply chain

Wind energy is increasingly recognized as a pivotal solution in the near future for narrowing the gap towards achieving the global net-zero emissions target. The development of wind farm technology, particularly in the realm of offshore wind, has witnessed remarkable progress.

Recently, in line with the resolute commitments of various governments and the rapid global progress in offshore wind energy planning, many studies have been published on advanced technologies in OWE construction and operation.

Typical layout of a standard offshore wind farm project comprises wind turbines, offshore and onshore substations, array/export cable systems and transmission line as illustrated in Figure 1.

Within this framework, the overall components of an offshore wind power project generally include essential elements as follows.

2.1. Turbine system

A wind turbine system consists of a rotor, nacelle, tower, and foundation. Figure 2 shows a typical wind turbine with a monopile foundation.

- Turbine: The turbine assembly is often fabricated

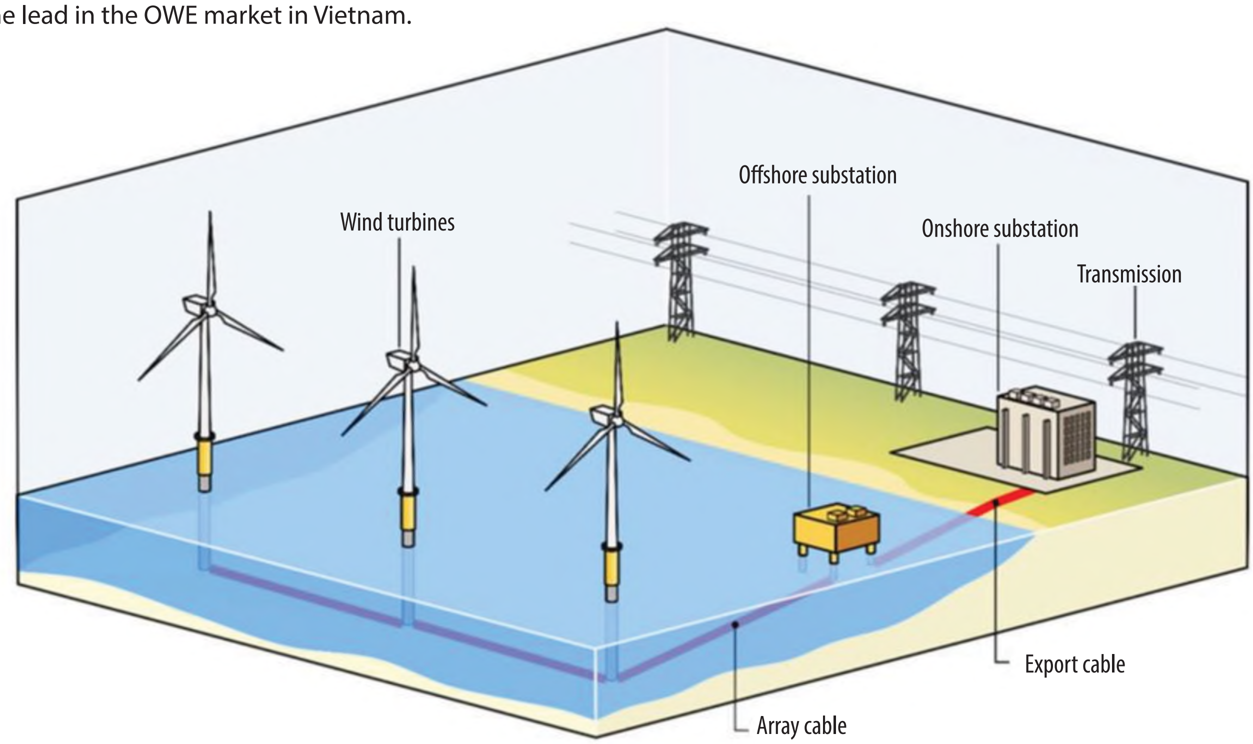

Figure 1. *Comprehensive layout of a prototypical offshore wind energy project [3].*

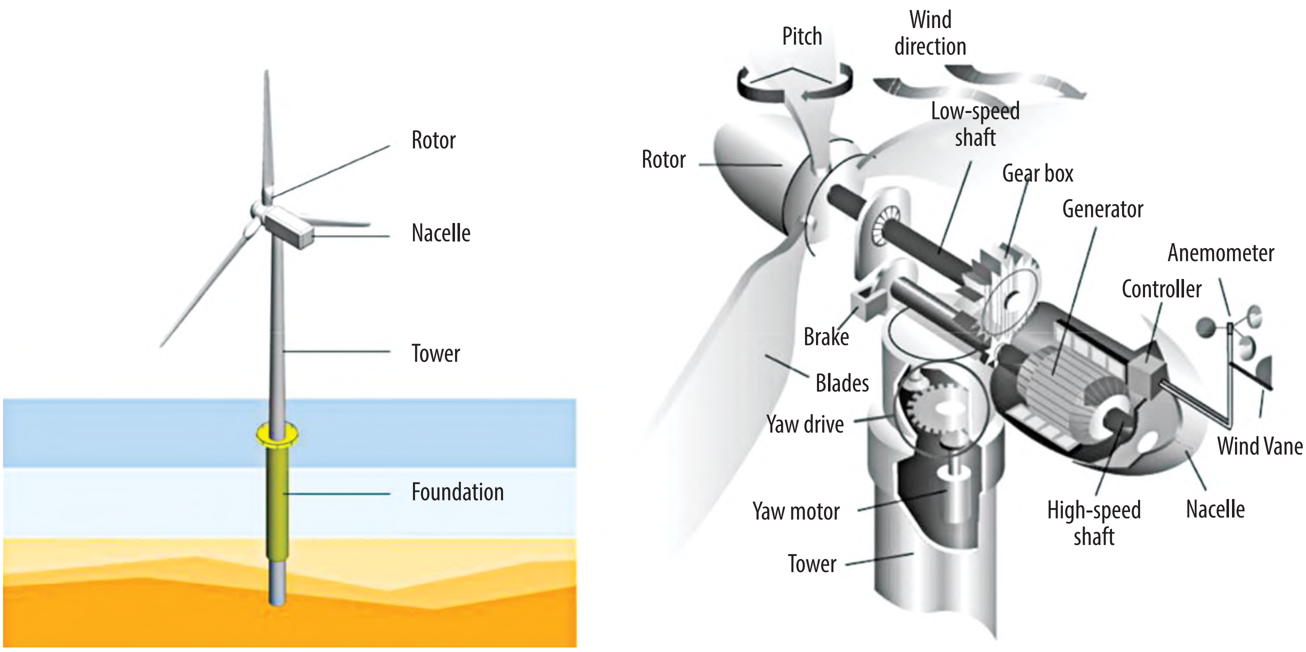

***Figure 2.** Configuration of the wind turbine technology assembly [4].*

by specialized wind turbine manufacturers. Globally, there are approximately 35 offshore wind turbine manufactures, of which 10 are located in China and the remaining in Europe, Japan, the US, South Korea, and Taiwan. Contemporary wind turbines are progressively being substituted with rotary magnet arrays, propelled by the kinetic energy of the blade system. This streamlined design principle enables the generator to function at significantly low rotational speeds while yielding a substantial electric power output. Other intrinsic benefits include shortened maintenance intervals, enhanced longevity, and reduced noise emissions.

- Blade: Approximately 60% of blades for the global wind industry are manufactured in-house by turbine producers, and this proportion is even higher for offshore wind. All blades used in renowned offshore wind turbines like Areva, Siemens, and Vestas are produced by the turbine manufacturers themselves. The materials commonly used for blade construction are plastics (polyester or epoxy) reinforced with glass fibres (FRP). However, in advanced technology, carbon fibres may become more prevalent due to its high strength and lightweight properties. To date, wind turbine blades have evolved to lengths over 110 meters, corresponding to a power generating capacity of up to 15 MW. The trend of manufacturing longer blades continues to rise, increasing the capacity of turbines.

- Towers: Offshore wind turbine towers are typically constructed from conical, rolled steel tubes, connected by flanged bolt joints in segments of about 30 - 40 meters. As turbines increase in size, the towers must also grow in dimensions and sectional divisions. The diameter of towers for 3 - 4 MW turbines is around 4 - 5 meters, while tower structures for 8 - 10 MW turbines can have a base diameter of up to 8 - 10 meters. These towers are assembled into complete wind towers either at ports or directly at the construction site, depending on the assembly strategy. To date, due to design, technology considerations, and technology, turbine towers are commonly produced by turbine manufacturers or through production partnerships with technology transfer from turbine to tower manufacturers.

- Foundation structure: Offshore base structures must endure high levels of dynamic loads and continuous fatigue stress. Featuring substantial steel thickness, these structures often employ cold-rolling methods. To counter fatigue loads and prevent cracking, the steel types used must meet stringent requirements and are sourced from specific companies (e.g., Tata, JFE, Nippon, etc.). Furthermore, the material thickness for the nodes of the foundation requires careful consideration. Offshore wind turbines are supported by either fixed foundations or floating foundations. Notably, floating foundations for offshore wind turbines enable stability in deeper waters (typically greater than 60 meters), at locations where fixed foundations are not feasible.

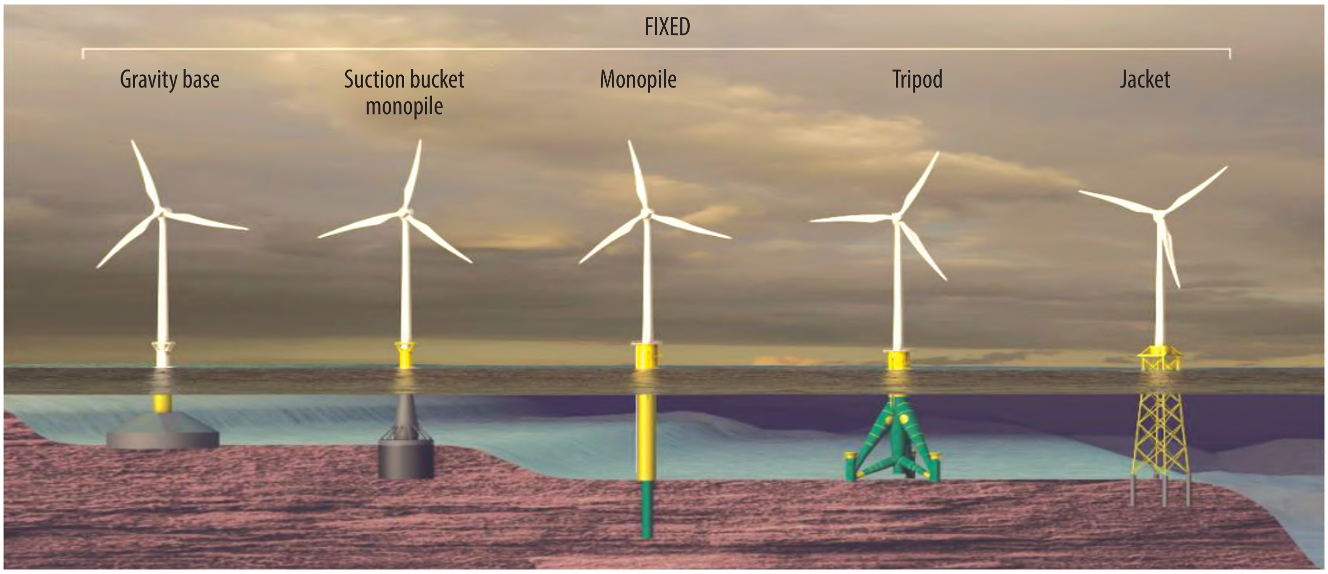

Figure 3. *Types of fixed foundations [4].*

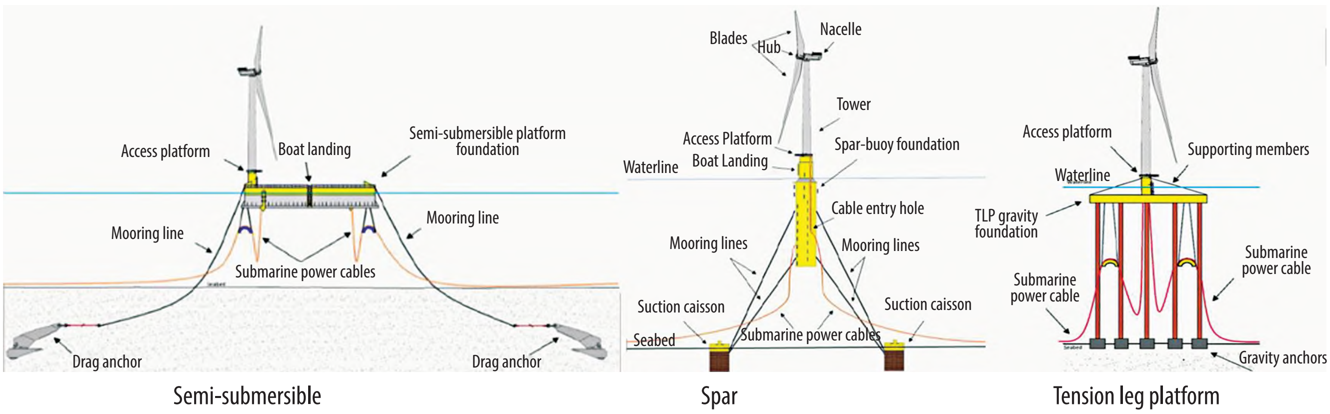

Figure 4. *Types of floating foundations [6].*

There are several types of foundations that are classified subject to water depth, geological and economic conditions. Different types of fixed foundation and floating foundation are shown in Figures 3 and 4.

2.2. Array cable

The turbine towers within the wind farm are interconnected via submarine array cables, most commonly to a centralized offshore transformer station, servicing varying numbers of turbine units and spanning distances of up to 50 kilometers. These offshore transformer stations are interconnected and their voltage is stepped up for transmission to the mainland via export cables. Depending on factors such as distance and turbine layout, the transformer station may utilize either high voltage alternating current (HVAC) or high voltage direct current (HVDC) transmission systems. HVDC systems, while more costly, offer superior transmission capacity and reduced power losses. The subterranean cables typically utilize cross-linked polyethylene (XLPE) composition, featuring tri-core arrangements with conductors made of copper or aluminum, and are insulated and positioned cohesively. These cores are collectively encased within a steel armoring, further enveloped by an external protective layer. Integral to these cores is an optical fibre cable, facilitating communication for remote monitoring and control functions.

2.3. Substation

- Offshore substation: This critical facility is used for voltage amplification, transitioning from the operational voltage of the interconnected array cables to the higher voltage of export cables. It is equipped with sophisticated switchgear for seamless connection or disconnection in contingency scenarios. Constituents of this station include high-capacity transformers, reactors, advanced switchgear, control apparatus, comprehensive fire suppression systems, and essential auxiliary mechanisms. These elements are purposefully placed within a robust topside structure anchored on a sturdy foundation. The

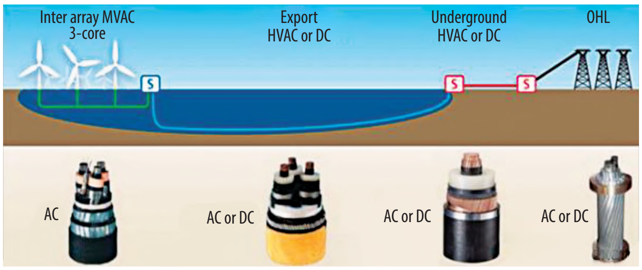

***Figure 5.** Types of offshore wind power cables [7].*

project's magnitude dictates the number of substations, with larger projects necessitating multiple offshore substations. Engineered to withstand the rigors of the marine environment, these substations are meticulously designed for enhanced endurance and corrosion resistance. To mitigate the risks posed by the maritime environment, the electrical components are securely enclosed within either multiple protective containers or a singular, hermetically sealed mega-container.

- Onshore substation: This integral component is tasked with assimilating electrical energy from the export cables, amplifying the voltage to match transmission standards, and forging a nexus between the offshore wind farm and the national electricity grid. Advanced switchgear facilitates seamless connectivity and disconnection, ensuring operational integrity during malfunctions. Technologically, these terrestrial substations for offshore wind farms mirror their onshore counterparts in sophistication and functionality.

The standard process in the wind energy industry typically consists of the following steps:

- Project development phase (including surveying, designing, permitting, financing) includes:

+ Wind resource survey;

+ Environmental survey;

+ Geophysical, geotechnical, geological, topographical, and oceanographic survey;

+ Environmental impact assessment report preparation;

+ Conceptual design (pre-feasibility study report);

+ Basic design (feasibility study report);

+ Technical design;

+ Detailed design and EPC (engineering, procurement, and construction) tendering;

- Manufacture, supply phase;

***Figure 6.** Offshore substation of ABB [8].*

***Table 1.** Main service supply chains and segments in OWE*

Supply chain	Items
Project development and management	Project development consulting (permitting)
	Project management
	Wind measurement
	Marine surveying
	Design consulting
Manufacturing and supplying turbines, generators, blades, and tower	Turbine (nacelles, yaw, hub, pitch, generator, gearbox, …)
	Blades
	Tower
	Auxiliary equipment
Manufacturing and supplying balance of plant (BOP) components	Electrical cables
	Transformer systems and electrical equipment
	Foundation and base structure
	Offshore substation
	Ancillary components
Transportation, installation, connection, and testing	Port and logistics services
	Vessel and barge services
	Foundation and base installation
	Turbine installation
	Offshore substation (OSS) installation
	Subsea cable laying
	Grid connection and commissioning
Operation, maintenance, and marine services	Operational services
	Inspection and maintenance services
	Vessel and operational support services
	Port and logistics services
Decommissioning	Port and logistics services
	Decommissioning services
	Waste management

- Transportation and installation phase;

- Operation and maintenance phase, including technical support;

- Decommissioning and dismantling phase.

In this context, the scopes of 6 service supply chains are described in Table 1.

3. Methodological approach and Petrovietnam's competency

By gathering data on existing facilities capabilities and the quality of human resources from the oil and gas service company of Petrovietnam, this study aims to analyze the degree of similarity and identify gaps that need to be addressed to master offshore wind power construction technology. The research involved collecting information from more than 20 service companies and major design and construction corporations within Petrovietnam, focusing on facility capabilities and human resources. This data then informed the identification of strategic steps towards achieving technological proficiency in the offshore wind power construction sector.

Within the aforementioned six service supply chains, Petrovietnam is identified to possess competitive advantages in services where it already has experience in the oil and gas sector. These services include project development/project management, surveying and design; fabrication of fixed/floating foundations and towers; transportation, service and installation; operational maintenance; port and marine support services for decommissioning.

In terms of facility and labor capabilities, Petrovietnam shows considerable similarity in supporting the supply chain services for offshore wind energy construction (OWEC).

- Regarding capabilities such as port and logistics services, vessels/barges, service ships and marine equipment, Petrovietnam can fully utilize these to supply transportation, construction support, and operations & maintenance (O&M) for offshore wind farms.

- For other facility equipment serving design and installation, Petrovietnam needs to upgrade to meet stricter requirements in the wind energy sector.

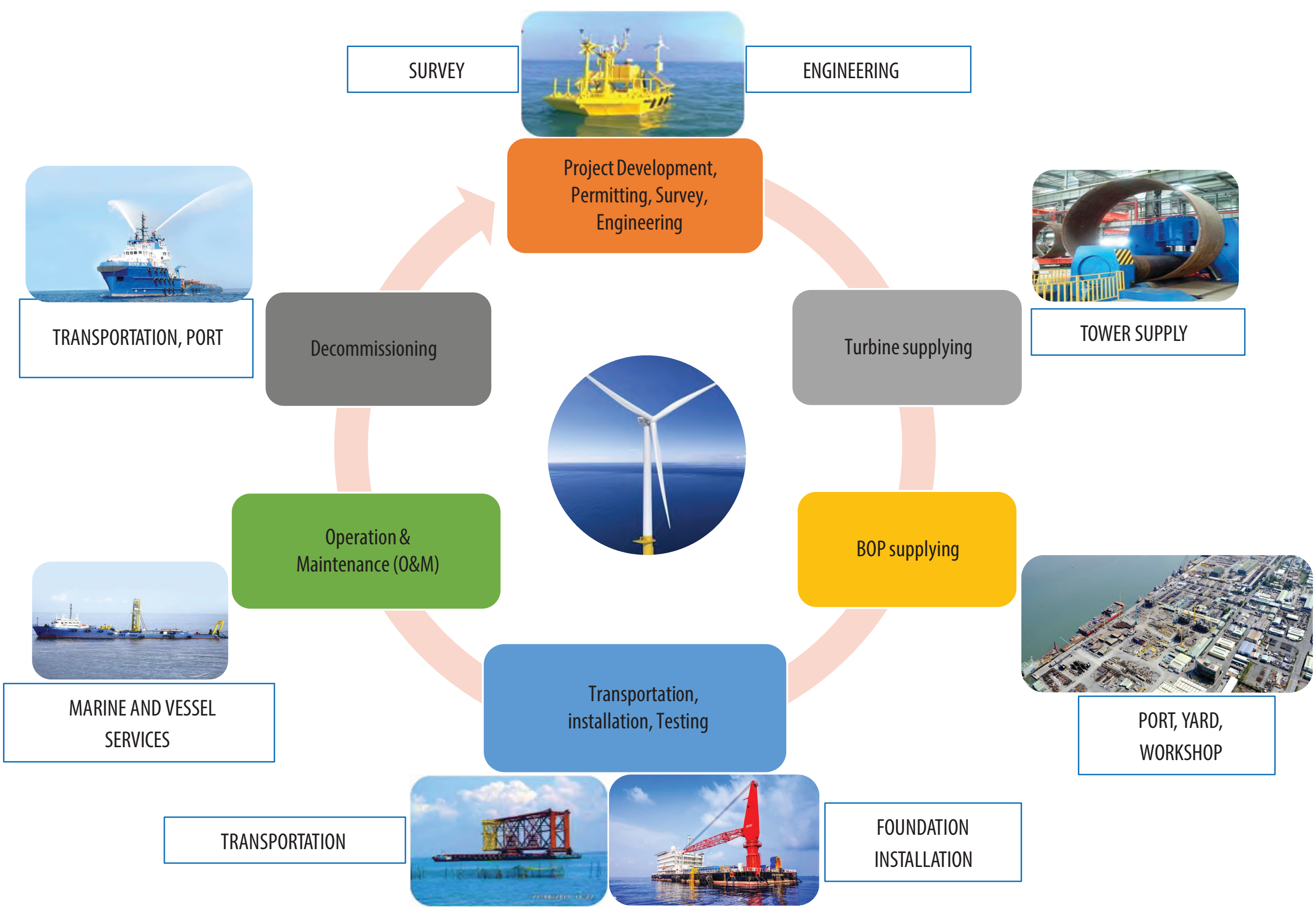

Figure 7. *The supply chains of OWE and the strengths services of Petrovietnam.*

Table 2. Analysis of Petrovietnam's capability to participate in the offshore wind energy service supply chain

Supply chain phase	Similar activities	Distinctive activities
Project development and management	Offshore project management capabilities; Collection and assessment of data on natural conditions and marine environment; Geophysical and geological data interpretation equipment; Marine service infrastructure, equipment capabilities.	Wind potential survey and evaluation capabilities; Wind farm planning capabilities, calculation and optimization of offshore wind farm power.
Survey	OWE natural and marine environmental survey; Marine environmental research and survey.	Need for specialized research and training in data interpretation; Wind capacity interpretation equipment and software.
Design	Design of jacket, foundation and pile structures; Mechanical fabrication design; Piping design; Electrical and control, instrumentation design for auxiliary components.	Wind turbine system design; Electrical system, subsea cable, and transformer design; Design of floating, semi-submersible, and tension-leg foundations.
Supply of turbine equipment and components	Experience in procurement for oil and gas, industry, and power plants; Expertise and high standards in fabrication, supply, and assembly of turbine components/parts.	Expertise and high standards in fabrication, supply, and assembly of turbine components/parts.
Manufacturing and supplying balance of plant (BOP) components	Mechanical fabrication capabilities (including structures like flanges, electrical technology systems, etc.); Infrastructure of workshops, systems for cutting and bending metal, welding machines, etc.	High precision and high-technology component manufacturing; Requirements workshop equipment with larger area (>20 ha), advanced manufacturing technology for the mechanical and control, high capacity and precision in the steel fabrication; Lifting and fabrication equipment: Cranes, welding machines, cutting machines, sheet rolling machines, transport vehicles, painting workshops...
Port and logistics services	Manufacturing warehouses and yards; Ports.	Expanded open-air and closed warehouses, workshop, yards for mass production lines; Seaports require additional investment in transport and lifting equipment, expansion and dredging of channels to accommodate heavy-lift construction vessels when needed.
Vessel and barge services	Vessel and barge service capabilities.	N/A
Transportation and installation of turbines	International standards, experience for transportation in construction.	Purchase or lease of heavy-lift vessels and barges for turbine installation (HLV, JLV); Crane vessels/barges with self-elevating capabilities higher than oil and gas service standards; Specialized support vessels and services tailored to offshore wind energy requirements; Expert in wind turbine assembly operations.
Transportation, installation/dismantling of offshore foundations, piles, substations	Capacity for offshore transportation of piles and substation transformers.	Construction technology for large foundations; High-capacity crane/ heavy-lift vessel for transportation and installation to minimize the marine movement.
Subsea cable laying	Subsea cable laying capability.	Cable storage vessel; trenching, cable laying equipment; cable towing and alignment devices; cable protection.
Interconnection and performance testing	Connection and testing capability for foundation.	Connection capability for electrical system, turbine generator.
Port O&M facilities; service vessels and equipment	Yard and service vessels capability.	N/A

- In terms of wind turbine design and supply of components and equipment, Petrovietnam currently lacks the capability to meet these demands.

Analysis reveals that activities involving core turbine technology require distinct competencies compared to offshore oil and gas projects; however, the remaining services supporting construction, operation, and maintenance are fundamentally similar and can be developed from the capabilities in oil and gas services.

Given the significant market potential for offshore wind service supply [9] and the analogous capabilities between oil and gas services and offshore wind power services, Petrovietnam can supply its services into the offshore wind power chain. Table 2 shows the offshore wind supply chain phases and comparable services of Petrovietnam.

To assess the capacity of Petrovietnam's units to partake in the offshore wind energy supply chain, we collected data on the requisite capabilities and the current capacity of the evaluated units for a comparative analysis across several dimensions. These include (1) Existing capabilities and capacities; (2) Ability to adapt

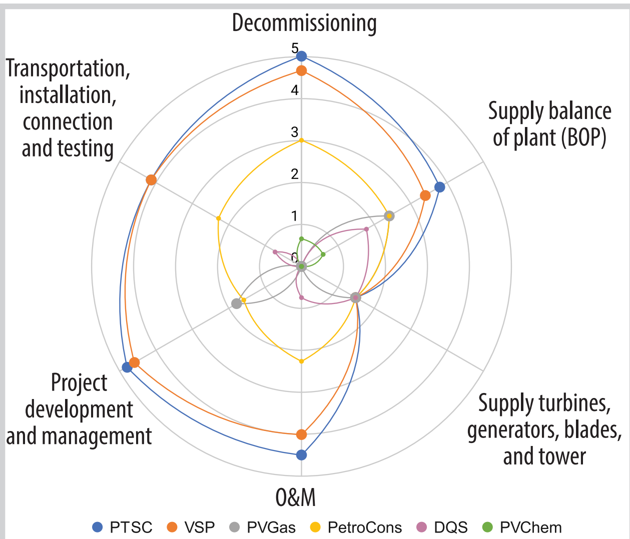

Figure 8. *Assessment of the capabilities of Petrovietnam in the offshore wind power supply chain.*

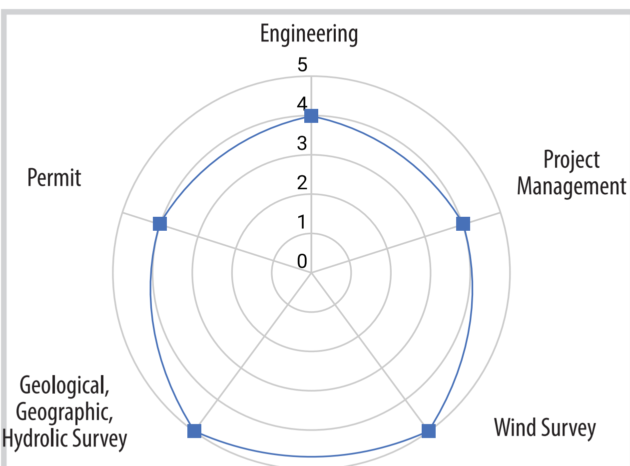

Figure 9. *Petrovietnam's capability in project development and management in offshore wind.*

or transition from the oil and gas sector; (3) Investment potential, encompassing scale and market entry timing; (4) Competitive ability. Figure 8 in the article presents the results of this comprehensive evaluation, offering insights

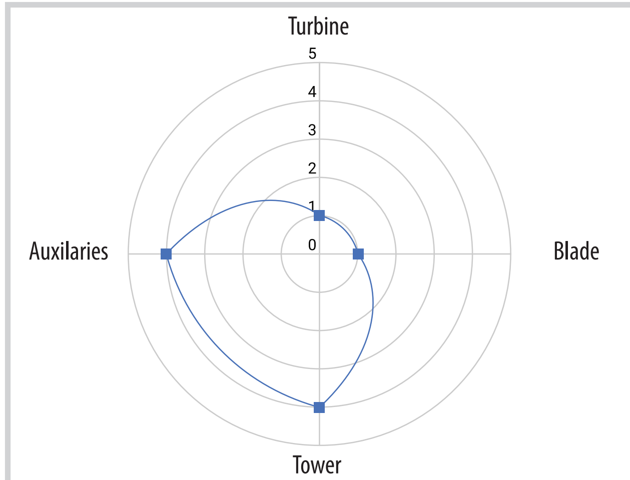

Figure 10. *Petrovietnam's capability in manufacturing and supplying turbines, generators, blades, and tower.*

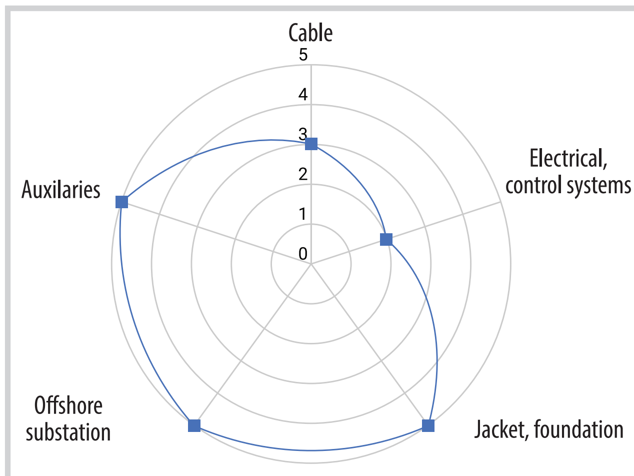

Figure 11. *Petrovietnam's capability in manufacturing and supplying balance of plant.*

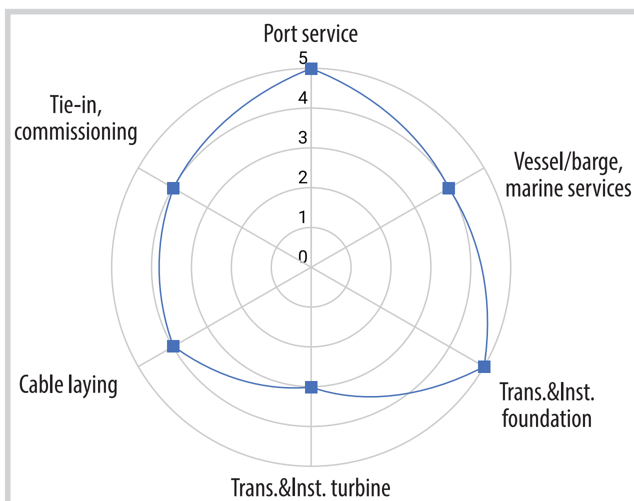

Figure 12. *Petrovietnam's capability in transportation, installation, connection, and testing.*

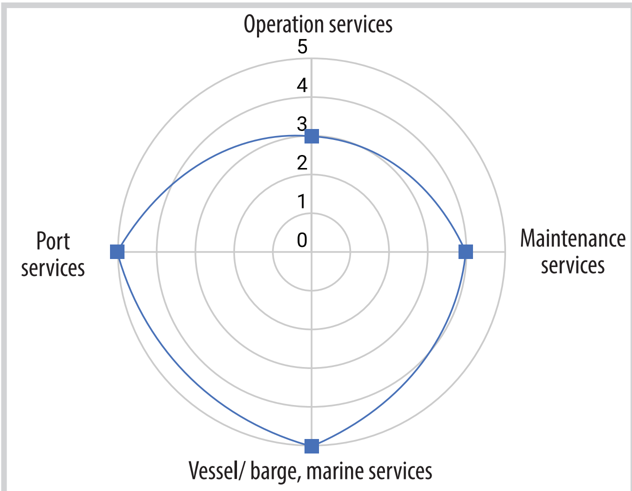

Figure 13. *Petrovietnam's capability in operation, maintenance, and marine services.*

Note: Rating on a scale from 1 to 5 reflecting the level of market entry opportunity, ranging from low to high.

Figure 14. *OWE project in a fabrication yard of a subsidiary of Petrovietnam.*

into Petrovietnam's readiness to effectively engage in the offshore wind energy sector.

Capitalizing on the strengths of each unit and utilizing existing facilities, Petrovietnam aims to master offshore wind power construction technology and dominate key service supply chain: development; manufacturing balance of plant (BOP) components, supplying towers, conducting; surveys and design; handling transportation, installation and commissioning, as well as operations and maintenance (Figures 9 - 13).

5. Conclusions

The oil and gas service industry exhibits notable parallels with offshore wind energy services, especially in domains such as project management, offshore construction engineering, and adherence to safety and environmental protocols. This parallelism unveils substantial opportunities for Petrovietnam in transition to the renewable energy sector. With a robust base and extensive experience in the oil and gas industry, Petrovietnam is strategically positioned not only to capitalize on its inherent competitive advantages but also to spearhead the integration and advancement of innovative technologies, especially in fabrication and construction, thereby enhancing its competitiveness in the offshore wind energy market.

PROJECT DEVELOPMENT (permitting, surveying, designing)	PTSC, VIETSOVPETRO, PETROVIETNAM PV GAS, PETROVIETNAM POWER, PETROCONs, PETROVIETNAM VPI, PETROVIETNAM ENGINEERING
SUPPLYING TURBINES	PTSC, VIETSOVPETRO, PETROVIETNAM PV GAS, PETROCONs, PETROVIETNAM DQS
SUPPLYING BOP (BOP, Foundation, Cable, Substration)	PTSC, VIETSOVPETRO, PETROVIETNAM PV GAS, PETROCONs, PETROVIETNAM PVCHEM - TECH, PETROVIETNAM VPI, PETROVIETNAM DQS
TRANSPORTATION, INSTALLATION, TESTING	PTSC, VIETSOVPETRO, PETROVIETNAM DQS, PETROCONs, PETROVIETNAM POWER, PETROVIETNAM PV Drilling
O&M	PTSC, VIETSOVPETRO, PETROVIETNAM POWER, PETROCONs, PETROVIETNAM DQS, PETROVIETNAM PV Drilling
DECOMMISSIONING	PTSC, VIETSOVPETRO, PETROVIETNAM POWER, PETROCONs, PETROVIETNAM PV Drilling

Figure 15. *Proposal for Petrovietnam's subsidiaries in the OWE's supply chain.*

Petrovietnam is progressively investing in and developing technology, facilities, and a team of highly skilled professionals for the offshore wind power sector, aiming not only to ensure a strong market presence but also to become a pioneer in this field in Vietnam. The goal is to emerge as a leading enterprise with mastery in technology, initially in project planning, design, construction, operation, maintenance, and dismantling within the offshore wind energy supply chain. This strategic shift is not only intended to meet the increasing energy demand but also to contribute to global sustainable development objectives.

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FERTILIZER PACKAGING COMPANIES OF PETROVIETNAM TOWARD CIRCULAR ECONOMY

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Summary

A circular economy is an economic system designed with the intention that maximum use is extracted from resources and minimum waste is generated for disposal... In the context of fertilizer packaging, manufacturers have been striving to produce green fertilizer bags which are recyclable, reusable and cost-efficient. When packages (both reusable and single-use) can no longer serve its function, the material should be circulated through recycling or composting. It is a matter of materials sciences (mono-material construction or material selection) and innovations in packaging formats (flexible packages, jumbo bags, sling bags, etc.) to make progress. Along with these, the sorting and collection infrastructure needs to be set up to keep products after use in a closed loop. As well, the economic attractiveness, incentives for stakeholders are essential to make the system work effectively.

Key words: Circular economy, recycle, re-use, compostable, plastic packages, fertilizer packaging.

1. Introduction

Seen as an auxiliary sector, the strong development of plastic packaging is driven by the development of other industries. Petrovietnam has two big fertilizer companies with a fast-growing rate recently, holding 50% share of the urea fertilizer market in the country. Therefore, Petrovietnam has expertise in making packages for agricultural products such as animal feed, chemicals, and fertilizers. However, the impacts of the plastic packaging industry on the environment are as significant as its growth rate.

The circular economy with the concept of minimizing negative externalities of products at the design stage is considered as one of the options for sustainable development of the packaging business. This paper focuses on fertilizer packaging in order to explore (i) What innovations of Petrovietnam fertilizer packaging over decades are; (ii) Whether circularity contributes to boosting the business performance; (iii) Which options for Petrovietnam fertilizer packaging be able to reach the circular economy.

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2. Theoretical framework

2.1. History of plastic packages

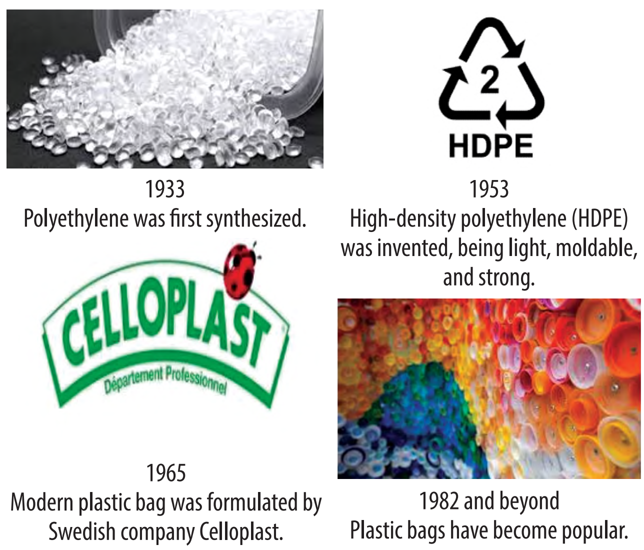

***Figure 1.** The development of plastic packages [1].*

Since 1933 when polyethylene was discovered, it has become the most common type of plastics which has been increasingly used across the economy, serving as a key enabler for sectors as diverse as packaging, construction, transportation, health care and electronics. Plastics have brought massive profits to these industries thanks to their

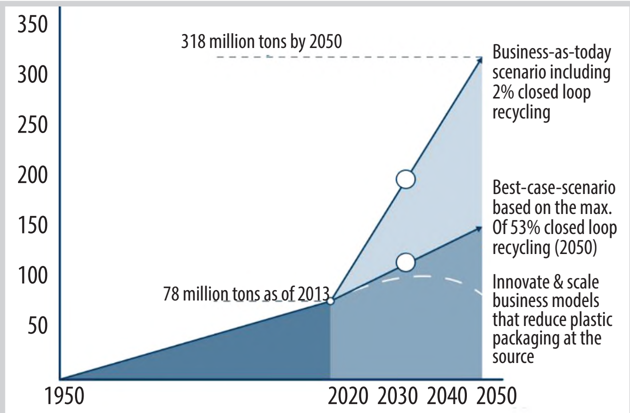

***Figure 2.** Global plastic packaging production in the period 1950 - 2050 [2].*

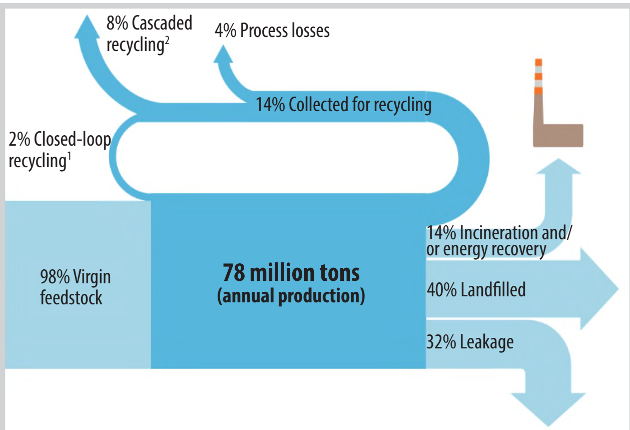

***Figure 3.** Plastic packaging after use, in 2013 [2].*

combination of low cost, versatility, durability, and high strength-to-weight ratio [1].

Plastic packaging, the focus of this article, is and will remain the largest application that currently represents 26% of the total volume of plastics used. The success of plastic packaging is reflected in the exponential growth in their production over the last half century. Since 1964, plastics production had increased twenty-fold, reaching 78 million tons in 2013. Plastics production is expected to double again in 2030 in the best-case scenario based on the maximum of 53% closed loop recycling or quadruple by 2050 in the business-as-today scenario including 2% closed loop recycling [2].

As packaging materials, plastics are especially inexpensive, light weight and high performing. However, these generate adverse effects: degradation of natural systems as result of leakage, especially in the ocean[1], greenhouse gas emissions from production and after-use incineration, health impacts from substances of concern [2].

2.2. Fertilizer packaging

PP is one of the cheapest raw materials for the packaging industry. Although fertilizer products have different storage requirements, cost-effectiveness has led

***Table 1.** Diferrent types of fertilizer packages*

	**Polyethylene (PE) bag** is flexible, durable and tear-resistant, high rate of waterproof/ moisture-proof; an anti-skid strip enables PE bags to stack steadier. However, it has weaker penetration resistance ability compared to PP woven bag [3]. Solutions: using the three-layered co-extrusion technology. This is a popular method recently applied in the production of PE bags by squeezing three layers of PE films into a stronger film so that it can stand to endure a higher level of penetration.		**PP woven bag** is not only extra strength, durability but alsoallows air circulation through which gases produced by the fertilizer can be exhausted without worrying about the swell of the bag. In addition, the price of the bag is cheaper than other bags such as PE bags and flexible pouches. The woven allows air circulation but makes it vulnerable to the external environment too. The nature of the woven has also allowed moisture and contaminants to enter the bag. Solutions: there are alternative PP woven bags with coating and bags with liners. The coating has various kinds of choices including PE film coating, nylon coating, aluminum foil coating [3].
	**Kraft paper bag** is high elasticity and high tear resistance, vulnerable to any form of water. Water, moisture, or vapor can easily damage the packaging which leads to unnecessary leakage. There is a solution by adding an outer or inner layer of plastic film (BOPP) to the paper bag [3].		**Flexible packaging[2]/flexible pouches** is the dominating packaging product that covers 80% of the total packaging production capacity. The cost of flexible pouches is relatively higher due to its production process. Additionally, the defects of flexible packages lie in their capacity. Flexible packaging is also called flexible pouches that have a capacity of only from 1 kg to 5 kg, which, to a certain degree, limited the usage in the industries that require larger capacity bags [3].

[1]At least 8 million tons of plastics leak into the ocean each year which is equivalent to dumping the contents of one garbage truck into the ocean per minute [2].

[2]According to the Flexible Packaging Association, flexible packaging is any package or any part of a package whose shape can be readily changed, all kinds of bags, boxes, sets, and packages made of paper, aluminum foil, fiber, plastic film, and their composites are flexible packages. Flexible packaging can reduce overall material weight by 93% compared to rigid formats like glass bottles, saving valuable greenhouse gas production.

Weight is Waste
-93%

to the widespread use of PP fertilizer bags. Recently, fertilizer packages have been considerably innovated with their own merits under different circumstances.

Fertilizer packages have changed over time, from PE bags, PP woven bags to kraft paper bag and flexible packaging, aiming to exclude the drawbacks to the environment and human health as shown in Table 1. Enhancing the circularity of plastic packaging while continuing to expand its functionality and reducing its cost could create a system that works - the circular economy.

2.3. Circular economy

In the current economy, we take materials from the earth, make products from them, and eventually throw them away as waste. The process is linear [4].

In a circular economy, we stop waste from being produced in the first place. A circular economy decouples economic activity from the consumption of finite resources. The circular economy is based on three principles [4]:

(i) Eliminate waste and pollution: we can treat waste as a design flaw. Specification for any design is that the materials re-enter the economy at the end of their use.

(ii) Circulate products and materials (at their highest value) by keeping materials in use, either as a product or as components or raw materials. This way, nothing becomes waste, and the intrinsic value of products and materials is retained. There are two fundamental cycles: the technical cycle and the biological cycle.

Figure 4. *The linear economy [4].*

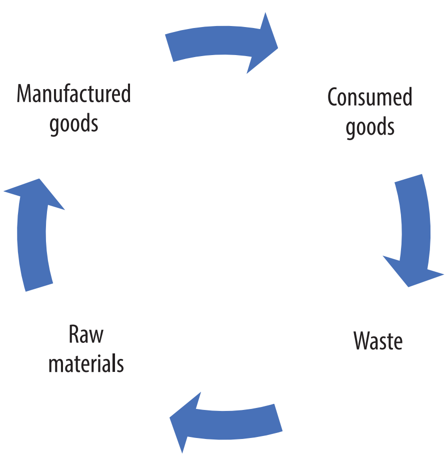

Figure 5. *The circular economy [4].*

In the technical cycle, products are reused, repaired, re-manufactured and recycled. In the biological cycle, materials are returned to the earth through processes like composting and anaerobic digestion.

(iii) Design is key: If designers thought about how their product could fit into the technical or biological cycles after use, that product could be made with that onward path in mind.

A circular economy - driven by design - is to consider waste and pollution as design flaws. Recycling might be called "end-of-pipe", dealing with a pipe of waste by energy intensive and supplemental virgin materials, while a circular economy's "upstream" solutions address potential problems right at the source - prevent waste from being create in the first place [4].

Two types of innovation are needed to achieve a circular economy: (i) upstream innovation (rethinking products and services at the design stage, for example: developing new materials, product designs or business models); (ii) downstream innovation (affecting a product or material after its first use, such as: developing new collection, sorting, and recycling technologies) [5].

3. Analysis of the cases

In December 2015, the European Commission adopted an EU Action Plan for a Circular Economy. It identified plastics as a key priority and committed itself to "prepare a strategy addressing the challenges posed by plastics throughout the value chain and taking into account their entire life cycle".

EU Regulations for Plastic Packaging includes key metrics: All plastics packaging must be reusable or recyclable in a cost-effective manner by 2030; recycling of 55% of plastics waste generated in Europe by 2030; greater use of innovative materials and alternative (i.e. non-fossil fuel) feed-stocks for plastic production where they are demonstrably more sustainable; a drastic decrease in the leakage of plastics into the environment; the consumption of single-use plastics will be declined, and the intentional use of micro-plastics will be restricted (banning of some products already in place); tax on plastics use; plastic packaging must be "single-piece" with no loose caps, fitments, etc, [6].

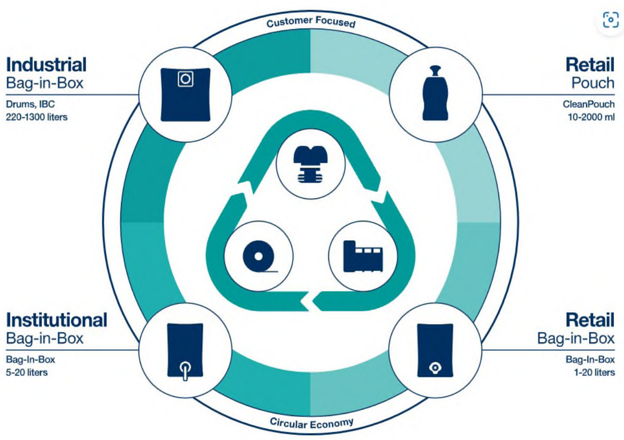

Figure 6. *Scholle IPN packaging solutions [6].*

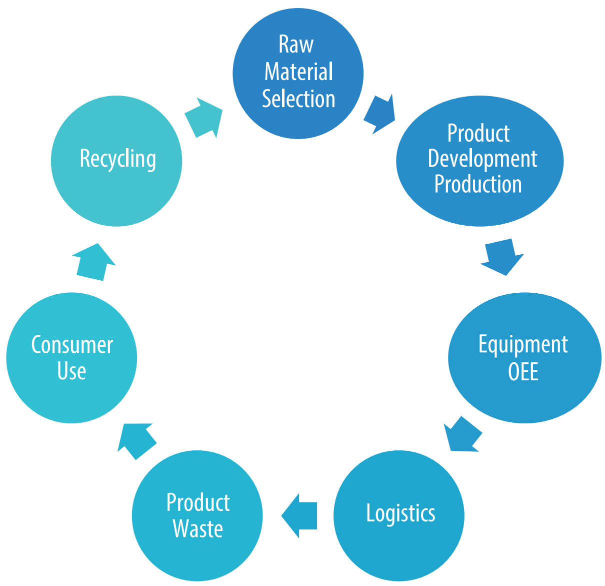

Figure 7. *Scholle IPN process [6].*

3.1. Scholle IPN

Scholle IPN is a leading packaging solution provider in the Americas and Europe. Products are packages for food, beverage to non-food such as: automotive fluids, coating, and agriculture chemicals (fertilizer, fungicide, herbicide, insecticide, plant growth regulator, rodenticide, seed treatment).

Scholle IPN approaches the circular economy with a wide range of principles.

Raw material selection: specifying base materials which are post-consumer recycled. Product development-production: Design for light footprint, recyclability, circularity with maximum performance. Equipment OEE: High-speed, efficient filling and sealing equipment runs on minimal inputs. Logistics: less weight, more product per pallet and truck, aseptic enables an ambient supply chain. Product waste: Extended shelf life with aseptic, 99.9% product evacuation, closed-loop dispensing options. Consumer use: Extended shelf life of opened products, simple ergonomics for all ages and abilities, re-closable fitments. Recycling: mono-material components engineered for mechanical/chemical recycling.

Scholle IPN practices recyclable film technology: extrude, laminate, and print flexible, barrier films; one-to nine-layer barrier films, as well as recyclable, mono-material structures; using solvent-free printing ink; eliminating solvents from the lamination process eliminates emissions; save raw materials by using fewer base materials (lightweight structures); eliminate lamination (films requiring no lamination use less energy and chemicals during production. The structures are also simpler, which aid in recyclability); and eliminate aluminum. Fitment innovation: injection mold and assemble fitments designed to provide an ergonomic interaction with products for all ages and abilities. Making sure closure components are disposable and recycled. Packaging equipment systems towards OEE: Engineered for maximum "up-time" to cut down time and materials wasted to troubleshoot production issues. Quick changeover: less waste in material, product, and labour with simple, fast changeover. Low maintenance requirements: simple maintenance regimens and easy to replace modules reduce downtime and travel required to service equipment in the field. Lifespan: Engineered sturdy materials that last for years when well-maintenance. Product flexibility: a single machine design could create several sizes and shape packages. Energy consumption: Designed to pull as little electricity, air and waste as possible during runs [6].

Scholle IPN with innovation and technical capabilities has enabled a significant reduction in the use of fossil materials and related CO_2 footprint along the whole process (from raw material selection to product development-production, logistics, consumer-use and recycling).

3.2. Petrovietnam packaging companies

In Vietnam Law on Environmental Protection 2020 taking effect on January 01, 2022, Article 54 Responsibility of Producers and Importers for Recycling requires: 1. Producers and importers of recyclable products and packages must recycle them according to the mandatory recycling rate and specifications, except for products and packages exported/temporarily imported or produced/imported for research, learning or testing purposes. 2. The producers and importers specified are entitled to recycle products and packages adopting one of the following methods: a) Organize recycling of products and packages; b) Make a financial contribution to the Vietnam Environment Protection Fund to support recycling of products and packages [7].

Petrovietnam Packaging Joint Stock Company (PPC) was established in June 2010, well-equipped with European modern technology. Products are mostly for the domestic market: 85% for PetroVietnam Camau Fertilizer Joint Stock company (PVCFC), 15% for the Southwest region of Vietnam. The overseas markets are neighboring countries such as Cambodia, Laos, India, and Bangladesh [8].

Products:

- Laminated bag (PP woven fabric + lamination + Flexo printing[3]): Woven fabric ensures the strength while lamination is responsible for water resistance and improves physical-mechanical properties of the products.

- PP woven bag: Based on PP woven texture with none-laminated or laminated with 1/2 sides to produce species of high-quality bags, sealed, load bearing, model advertisement and especially woven PP friendly with the environment. Flexible-printing. Products have further internal PEHD, PELD bags.

- BOPP bag: PP woven bags + laminated glue + OPP film (gravure printing). Woven fabric ensures the strength while laminated glue is responsible for sticking the woven fabric and OPP film together; the OPP film used for gravure printing creates water resistance and improves physical-mechanical properties of the products.

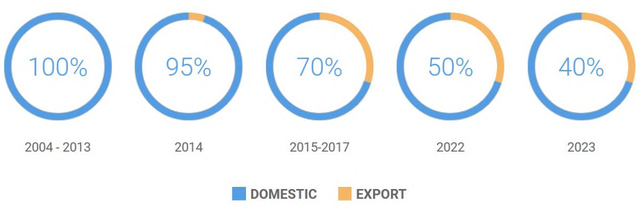

Figure 8. *Domestic and export share in 2004 - 2023 [9].*

Figure 9. *Samples of PP woven bag (a), sling bag (b), and jumbo bags (c).*

Dam Phu My Packaging Joint Stock Company (DPMP) was founded in 2004. During 10 years up to 2013, it only produced for the local market (Petrovietnam Fertilizers and Chemicals Corporation – PVFCCo) Since 2014 PVFCCo Packaging has stared exporting to EU (Italia, England), USA, Korea, Thailand, Japan, Singapore, and Malaysia. During 2015 - 2017, it had 70% of products for domestic and 30% for export. In 2022 - 2023, the domestic use was around 40 - 50% and the rest was for exportation (Figure 8).

Products: PP woven bags (with PP lamination, flexo printing, BOPP woven); two loops big bag; garden bags; PP woven fabric; FIBC, big bag, jumbo bag (FIBC circular bottom, anti-bulge FIBC bag, baffle FIBC, circular jumbo bag, 4 panels jumbo bag, anti-bulging bags, FIBC U panel, etc.).

In 2017, DPMP began promoting jumbo bags[4] and small pouches for home gardens. Recently, sling bags[5] have also been introduced [9] (Figure 9).

Petrovietnam packages over decades have been refined to meet the demands of customers and national legal requirements. As being recognized as well-certified factories, they are successful in exporting bags to the U.S, Canada, Australia, New Zealand, Southeast Asia, and the EU.

As can be seen in Table 2, raw material and sourcing, recycling and enviromental pollution treatment have a high ratio (more than 80%) of by-products recycled in both factories together with various activities of recycling

[3]Flexo Printing/Flexography is a modern high-speed printing process suitable for most packaging and label applications. It allows for fast, cost-efficient, high-quality label printing for a variety of mass-produced goods.
[4]Jumbo bag (FIBC - Flexible Intermediate Bulk Container) (big bag, bulk bag) is a large size packaging made from woven polypropylene (PP).
[5]Sling bags: Thin, light, super durable, can withstand loads from 500 kg to more than two tons of goods. Low cost, can be easily folded and reused many times, saving costs. Loading, unloading, transporting goods safely and quickly. Goods can be stacked on top of each other, saving warehouse space and container. Thus, this kind of bags can store or transport more goods. It has a long shelf life, is recyclable, environmentally friendly. Sling bags of PVFCCo Packaging: Material: 100% virgin PP. Capacity: 500 - 2,000 kg. Denier: 1,400 - 1,600D/ Fabric weight: 170 - 200g/m^2. Density: 12x12-14x14. Base cloth: PP + laminated/no laminated, anti UV/no UV protection. Safety factor: SF3.1, 5.1, 6.1.

water, material surplus and solid waste originated from PP, PE.

4. Discussion

Figure 3 shows that in 2013 just 14% of after-use plastic packages were captured in the world. Even in the United States and Europe with advanced collection systems, 170.000 tons of plastics leak into the ocean each year [2]. According to the World Bank, Vietnam is among the top four generators of plastic waste, approximately 280.000 tons per year [10].

In both cases of Scholle IPN and Petrovietnam packaging companies, the amount of after-use packages has not been accounted. There is a great potential to redesign materials, packaging formats from the outset for fertilizer packages to be reused, recycled or compostable and hence reducing leakage proportionally.

- Re-use built on redesigning packaging formats

Reusable packages would save single-use ones from waste streams. Jumbo bags, pouches, and sling bags have a sufficiently high material value to make reuse business models profitable. They are often used 20 to 100 times depending on the application [2] and the vast majority are recycled afterwards, with the redesigned and innovative bags - mono structure. When packaging (both reusable and single use) can no longer serve its function, the material should be circulated through recycling or composting.

- Recycling, which means creating value after the initial use, mainly depends on redesigning materials or choices of materials.

Fertilizer packages require chemical resistance, water resistance, durability and lightweight. These are often combined with properties of materials. Multi-material packaging can often offer enhanced performance and resulting functional benefits, such as providing oxygen and moisture barriers at reduced weight and costs. As being made from multiple materials, fertilizer packages might be technically unrecyclable. For some applications, technologies exist that, in theory, could capture part of the material value through downcycling, i.e., the process of converting materials into new materials of lesser quality, economic value and/or reduced functionality. For example, compatibilizers are chemical substances that can allow some multi-material packaging to be downcycled into blended materials. Still, such technologies lead to significant loss of material value in the recycling process and likely add just one extra use-cycle rather than creating a truly positive, virtuous material cycle[6].

In the case of Scholle IPN, flexible packaging focuses on source reduction and simple, mono-material construction (high-barrier mono-material films). Bag-in-box and pouch packaging with mono-material films are easier to recycle and require fewer materials to produce.

- Making plastic bags compostable, means that an item with specific materials can break down into carbon dioxide, water and biomass within a specific time frame

Table 2. *Related indicators of PPC and DPMP*

	PPC	DPMP
Raw materials and sourcing	The materials mainly come from Binh Son Refining & Petrochemical Joint Stock Company (BSR). The rest is imported from Taiwan, Korea, Thailand.	90% of materials (Polypropylene) are imported.
Energy use	Using electricity, diesel oil. The quota for electricity used is 01 kWh per 1 kg of products;	Total electricity consumed is 620.000 kWh per year.
Recycling	More than 80% of by-products are reused, recycled.	The company produces 7.000 tons of PP annually. The quantity of by-products accounts for 7%, of which more than 80% is reused, recycled. Surplus of ink, paper is collected, reused/recycled. Solid waste originated from PP, PE is recycled.
Water withdrawal	Water is taken from two sources: water supply factory and groundwater.	Water is circulated for manufacturing.
Environmental pollution treatment	The systems of environmental pollution treatment meet the legal requirements of the government.	Solvent, containers of ink are transferred to the manufacturers. Industrial wastewater is treated before discharging. Hazardous wastewater (small amounts) and hazardous waste (about 200 kg/month) is collected and treated by third parties.

[6] *There are two levels of recycling: (i) Closed-loop recycling: recycling of plastics into the same or similar-quality applications. (ii) Cascaded recycling: recycling of plastics into other, lower-value applications [11].*

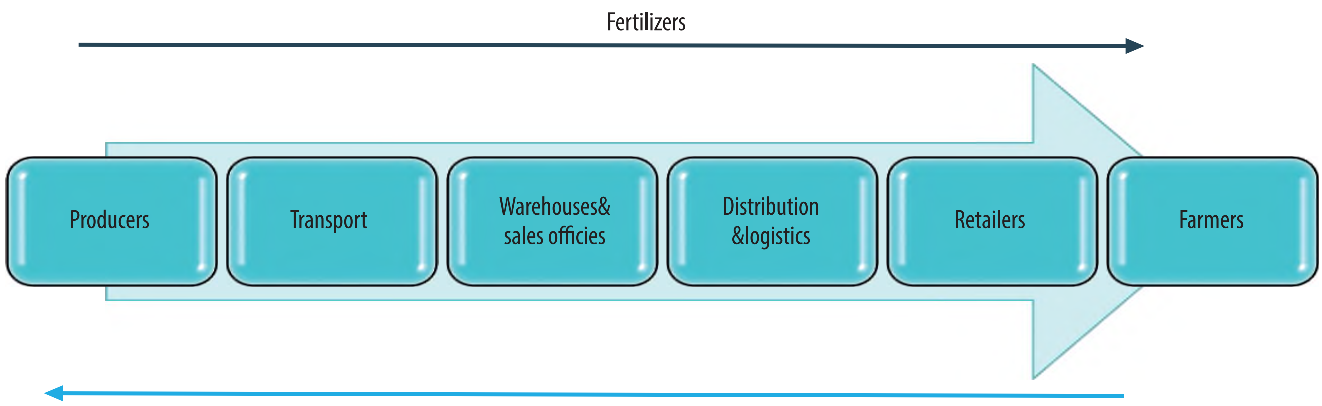

Figure 10. *The distribution of fertilizers and the collection of used bags [11].*

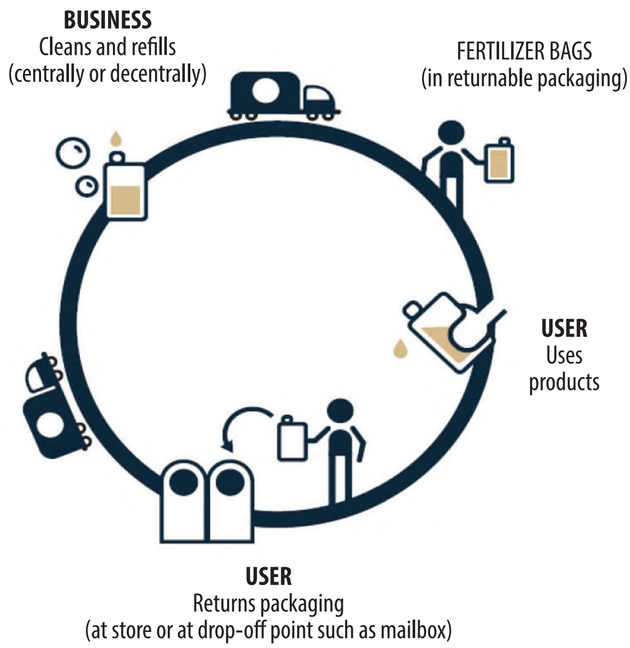

Figure 11. *The collection infrastructure [5].*

and under specific, controlled conditions. Industrially compostable and home compostable are subsets of the term as packages still need to be collected and composted in well-managed facilities [11].

- It needs the design in not only materials, packaging formats but also sorting and collection infrastructure. In the case of fertilizer packages, those consist of two segments: (i) from business to business (B2B) (packaging companies to fertilizer companies to wholesalers/agencies), (ii) from business to consumers (B2C) (retailers, shops to farmers) [2].

The collection infrastructure might be based on the existing product distribution systems: from producers to distributors, wholesalers, agencies to retailers, stores since the relationship formed to maintain a steady inventory flow. Now interconnected operators have responsibilities to manage a shared set of standardized, reusable packages [5]. The most important thing is to incentivize the return of packaging by developing the right deposit and reward mechanism for end-users (farmers) and other stakeholders in the chain.

Petrovietnam fertilizers have been distributed through more than 100 wholesalers/agencies, about 3.000 retailers/stores of PVFCCo and more than 53 wholesalers, and thousands of stores of PVCFC all over the country. These agencies and stores could be the drop-off points of fertilizer bags after use, and warehouses/wholesalers could be the collecting/sorting points to send used bags to the packaging companies.

- Besides environmental advantages, circular activities generate both economic benefits and costs. The costs are estimated to comprise investment in redesigning, related technologies (separation technology, reprocessing technology, etc.) and new materials (renewably sourced and decompostable plastics) plus expenses to remain the collecting scheme, etc. On the other hand, benefits of recycling, reuse might be quantified in regard to keeping materials in the system, creating economic values by increasing its reuse/recycling rates, decreasing budget for materials (for example, in PPC company, expenses of polypropylene are more than 70% of operating costs). Moreover, in the context of Vietnam Law on Environmental Protection as mentioned above, producers are entitled to either a) Organize recycling of products and packages; or b) Make a financial contribution to the Vietnam Environment Protection Fund. Once the companies approach circular activities, they would satisfy the legal requirements in the former way instead of the latter.

5. Conclusion

Two Petrovietnam fertilizer packaging companies have already developed products to be recyclable, re-usable, eco-friendly as well as meet international standards in recent years. In fact, achieving circulatory business would require joint efforts, not only designing better packaging (rethinking materials, packaging formats), but also increasing recycling/reuse rates (enhancing technologies), and introducing appropriate models for after-use collection/reprocessing infrastructure. Only when all of three axes come together, we can leverage the dematerialization process, reducing the need for raw feedstock and minimizing plastic waste. Particularly, the collection system could be integrated into the product distribution network: from producers to distributors, wholesalers, agencies to retailers together with the right deposit and reward for related stakeholders as economic attractiveness of returning used bags. In terms of cost-benefit analysis, environmental benefits and legal compliance would be determined in values in comparison with investment in redesigning, innovation, technologies and conducting the collection system for the packaging business to be sustainable.

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10 PREDICTIONS FOR ENERGY IN 2024

According Wood Mackenzie, consumption of oil, gas and coal has been growing, and all three fuels hit new record highs in 2023. But, at the same time, renewable energy has been booming. Production from wind and solar power worldwide in 2023 was about 55% higher than in 2020. Wood Mackenzie's experts have provided 10 important forecasts for the key developments in energy and natural resources in 2024.

1. THE GLOBAL SOLAR GROWTH SLOWDOWN WILL BEGIN

Michelle Davis - Head of Global Solar

Even though total global solar capacity will continue to grow rapidly over the coming decade, the pace of growth in annual installations will start to slow in 2024 compared to the rates seen in recent years. If Wood Mackenzie's forecast for 2023 holds, average annual growth in capacity installations over 2019 - 2023 was 28%, including 56% growth in 2023. By contrast, annual average growth from 2024 - 2028 will be about zero, including a few years with contractions. Growth in the global solar market is following a typical S-curve. Over the last few years, growth has climbed rapidly up the steepest part of the curve. Starting in 2024, the industry will be past the inflection point, characterised by a slower growth pattern. The global solar market is still many times larger than it was even a few years ago, but it's natural for an industry to follow this growth path as it matures. Not every region is currently in the same place along the S-curve. Africa and the Middle East, for example, have a long way to go before they hit their growth inflection points. But two major markets are driving this global growth pattern: Asia Pacific, dominated by China, and Europe.

2. NUCLEAR POWER WILL CONTINUE TO RISE UP THE POLICY AGENDA AS A CLIMATE SOLUTION

Julian Kettle - Vice Chair, Metals and Mining

A quote often misattributed to Albert Einstein is that nuclear power is "one hell of a way to boil water". It was actually coined in 1980, after the Three Mile Island reactor accident that helped to turn the tide of public opinion against atomic energy. In 2024, however, nuclear power is set to win widespread support as a key solution to the world's energy crisis, for the first time in over half a century. Nuclear power has faced, and still faces, challenges of public acceptability and economic competitiveness against renewables and fossil fuel generation. But it is the only reliable, dispatchable, small physical-and-material footprint, plug-and-play zero-carbon solution for power generation.

3. THE EVOLVING BALANCE BETWEEN DECARBONISATION AND SECURITY OF SUPPLY WILL ACT AS A BRAKE ON INVESTMENT DECISIONS IN GAS AND LNG FOR MANY COMPANIES

Kristy Kramer - Head of Gas and LNG Consulting

After Russia's invasion of Ukraine, the global gas and LNG industry reprioritised securing supply. More than 65 million tons per year of LNG sale and purchase agreements were signed by end-users in 2022 and 2023. Investments in new LNG supply were always going to slow in 2024, given the scale of investments already made and the expected market rebalancing. But COP28 has added new uncertainty to the outlook for gas. As a fossil fuel, it is one that the governments of the world aim to transition away from. But as the most widely accepted "transitional fuel", it will still have a role to play in providing energy security for some time.

Companies and governments will need to reconsider investments against this evolving backdrop, possibly slowing some of them further. Industry participants will need to realign their portfolios and strategies to navigate the contradictions and the range of possible outcomes for gas demand.

4. A SLOWDOWN IN NON-OPEC OIL PRODUCTION GROWTH WILL EASE THE PRESSURE ON THE OPEC+ COUNTRIES

Ann-Louise Hittle - Head of Macro Oils

This year, there has been a large increase in non-OPEC oil production of about 2 million barrels per day, piling the pressure on the OPEC+ group to cut its output to prevent a slump in prices. Next year, we expect that non-OPEC growth to slow to just 0.8 million b/d.

The largest factor in the projected slowdown is our expectation of a sharp deceleration in US oil production growth next year, but other countries including Brazil will also contribute. The non-OPEC slowdown will relieve the pressure OPEC+ has faced in 2023. Among the caveats to this view: a surge in US productivity (see below).

5. US OIL AND GAS PRODUCERS WILL DO MORE WITH LESS


Robert Clarke - Vice-President, Upstream Research

The biggest macro story from the US oil and gas industry next year could be that efficiency gains refuse to plateau. Total upstream capital spending in the Lower 48 states is expected to fall in 2024, for the second successive year. But, at the same time, total Lower 48 production of both oil and gas will continue inching higher, setting new records for each. Muted movement in the rig count will be more than offset by continued improvement in drilling speeds and pad cycle times, completion efficiencies and improved project execution. All this serves as a reminder of just how lean and mean US shale has become.

6. A LARGE US E&P COULD MERGE WITH A LARGE INTERNATIONAL E&P


Greig Aitken - Director, Corporate Research

The pure-play model of geographically focused exploration and production companies has lost its lustre since investors began rejecting production growth in favour of cash distributions. Large-scale M&A is increasingly targeting diversification, as companies look to build resilient financial platforms. Internationalisation is the next logical step in this strategy. US buyers' strong equity currency will be a lure for overseas targets, helping to make deals happen.

7. HYDROGEN PROJECT FIDS WILL CONTINUE TO SKEW BLUE


Melany Vargas - Head of Hydrogen Consulting

The ambitions for low-carbon hydrogen around the world, reflected in government policies and corporate project development, are quite remarkable. As is a 108-mtpa global project pipeline that skews 80% to green hydrogen, made from electrolysing water. However, the rate of project maturation for electrolyser hydrogen will remain slow as developers struggle to overcome key obstacles.

Two of the most important challenges that green hydrogen projects will face are achieving competitive costs and securing firm commitments from offtakers. Projects with credible counterparties and those targeting hydrogen as a feedstock in existing applications are most likely to move ahead. Those targeting new applications will struggle to achieve costs that compete with traditional fossil fuels. Blue hydrogen projects will also move slowly through the project development cycle, but more will achieve FID as they benefit from competitive economics and scaling more quickly.

8. CARBON OFFSETS WILL REGAIN MOMENTUM, AGAINST ALL THE ODDS


Elena Belletti - Global Head of Carbon Research

The voluntary carbon market was at a crossroads in 2023, with market activities bogged down by a loss of confidence, and buyers craving clarity. COP28 couldn't reach an agreement on Article 6 and market sentiment suffered frustration again. The situation seems dire, but there are reasons to believe this could be the dark before the dawn. Buyers are wising up and weeding out low-quality offsets from the market. In the absence of centralised oversight from the UN, independent governance bodies are setting guidelines and offering clarity. And offsetting programs are working hard to evolve. We expect to see the results of these efforts in 2024.

9. NOVEL CARBON CAPTURE TECHNOLOGIES WILL FINALLY ENTER COMMERCIAL SCALE


Mhairidh Evans - Head of CCUS Research

In 2024, new CCUS projects are no longer noteworthy in and of themselves. We track up to 100 commercial-scale projects, with 50 having a decent chance of progressing. What is new, however, is the much-awaited graduation of novel technologies from pilot to commercial scale. New techniques to capture carbon dioxide such as modularisation, solid adsorption and bio-recycling will be fully deployed for the first time in 2024. These promise lower energy intensity and cost reductions of up to 50% compared to incumbent methods. If successful, barriers will be lowered for emitters in vital heavy industries such as cement and chemicals. And the technology companies can expect a rush of orders.

10. GEOENGINEERING WILL BECOME A HOT TOPIC


Prakash Sharma - Vice President, Scenarios and Technologies

In the conclusions of the first Global Stocktake at COP28, countries acknowledged that the remaining global carbon budget is shrinking rapidly, with a risk of overshooting the 1.5°C goal. That means hundreds of billion tonnes of carbon dioxide will need to be removed or captured and stored to get the world back on course for no more than 1.5 °C of warming by 2100.

Geoengineering techniques can be used to enhance the carbon absorption capacity of the planet, and to reflect sunlight back into space, helping to keep the earth cool. For example, aerosols or other chemicals can be released a few kilometres up into the atmosphere, thus reflecting more sunlight away from the planet's surface. I believe that in 2024, governments and scientific institutions will come together to study this fascinating subject more deeply and discuss the pros and cons of pursuing it.