Improving estimates of recoverable oil with increased drilling density through applying 3D property volumes

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SUMMARY

This study presents a cloud-based, fully integrated workflow for evaluating the impact of drilling density on EUR, recovery factors, and NPV at both the per-well and drilling-unit levels. We demonstrate the value of applying 3D reservoir property volumes to quantify original oil in place (OOIP) per well, enabling a data-driven assessment of when recovery factors plateau with increased well density.

A case study of 4,386 horizontal wells in southern Midland and northern Upton County (Midland Basin) shows that EUR per well declines as drilling density increases, while recovery factors stabilize beyond an optimal spacing threshold. By integrating 3D property modeling with production and economic analysis, this workflow offers a scalable, automated solution for optimizing well spacing decisions across large datasets. The cloud-enabled framework allows operators to rapidly assess well density impacts, ensuring efficient resource development and maximizing economic returns.

INTRODUCTION

Unconventional resource plays are maturing from the initial drilling stages focused on play delineation towards full cube development with high development density both laterally and vertically in areas with stacked pay zones (Damani et al., 2020). This transition has highlighted the importance of understanding the impact of drilling density on well EUR and NPV (Wang et al., 2023).

The EUR for a drilling spacing unit (DSU) typically increases with each additional well drilled. However, there is a point of diminishing returns where the incremental EUR added approaches zero as any new well will cannibalize reserves from its neighboring wells.

This observation can also be stated in terms of recovery factors if the available OOIP for each well is known. Increased drilling density will result in a gradual increase and then plateauing of recovery factors at the DSU level (and hence lower recovery factors on a per-well basis).

As the EUR per additional infill well decreases, the expected NPV of that well, all things being equal, will continuously decrease until it is negative. At that point each additional offset well drilled will reduce the overall NPV attributable to the drilling unit.

To address these challenges, this study presents a cloud-based workflow for estimating recoverable oil and optimizing well spacing using 3D reservoir property models.

Unlike conventional methods that rely on static, local-scale models, this approach leverages cloud computing to analyze basin-scale datasets, enabling real-time assessment of EUR, recovery factors, and NPV. Advancements in cloud-based reservoir modeling (El Dabbour et al., 2022) and machine learning for well-spacing optimization (Fathi et al., 2024) highlight the shift toward automated, data-driven development strategies. Studies on ML-driven well placement (Mousavi et al., 2024) and NPV-optimized reservoir control (Kuk et al., 2021) further support integrating economic analysis with reservoir simulations. Our methodology builds on these innovations to determine optimal drilling density, balancing oil recovery and economic returns. This scalable workflow enables efficient field development, maximizing hydrocarbon recovery and capital allocation.

METHODOLOGY

The methodology employed in this study can be summarized by the following seven step process.

1. Data collection - The required data sets used in this study include wireline log data, whole and sidewall core data, production data, formation tops data, well deviation survey data, and well location data.

2. Geoscience evaluation - Constructing a robust structural and stratigraphic framework is necessary in order to effectively execute on the subsequent petrophysical interpretation and 3D property modeling. The framework is

constructed by generating structure grids for the tops and bases of each interval of interest.

3. Petrophysical interpretation - A regional petrophysical analysis is performed to calculate the key reservoir properties for each well. As the primary objective is to determine the OOIP calculations of porosity and saturation are required. Other reservoir properties such as clay volume, total organic carbon, and rock strength properties may be beneficial in understanding performance differences between otherwise similar areas.

4. 3D Property modeling - A 3D structural framework is constructed using the structure grids form the geoscience evaluation. 3D property models are then generated through combining the structural framework and the petrophysical interpretation.

To determine the OOIP it is necessary to generate models of porosity, water (or hydrocarbon) saturation, and formation volume factor. With these available the OOIP can then be determined across the area.

5. Property extraction and OOIP estimation - To calculate the recovery factor in later steps it is necessary to determine an OOIP for each of the horizontal production wells. However, these wells typically have minimal well log data as it has become common practice to collect minimal well log data in these wells.

Therefore, to determine OOIP values for each well, data is extracted from the 3D property models into the horizontal wells at the intersection of the deviated wellbore and the 3D property model. As the wells have undergone stimulation, it is necessary to assume the fracture height and fracture half-length so that the OOIP represents what is available to the wellbore to be drained.

6. EUR and NPV determination - The oil, gas, and water production (if available) are forecasted to determine EUR and economics are calculated to determine the NPV or each well.

When possible, the forecast should be performed on a well-by-well basis instead of applying a type-curve to drive future production as it may otherwise be difficult to capture the impacts of offset wells on production.

7. Spacing impact analysis - Determining the impact of spacing on production requires (1) calculating the number of offset wells; (2) summing the total production from each group of wells; and (3) bucketing those into groups based on the number of offset wells.

In evaluating the number of offset wells it is necessary to consider both horizontal and vertical offsets as both impact production (albeit to varying amounts).

Case Study

The workflow described above was applied to a study area in the southern Midland County and northern Upton County sector of the Midland Basin.

Wireline logs from 300 vertical wells with a triple-combo logging suite were gathered for use in building the structural and stratigraphic framework and for petrophysical interpretation. Production data and deviation surveys from 4386 horizontal producers from the zones of interest were underwent analysis for production forecasting and spacing.

Formation tops were correlated across all the vertical wells for several zones. The intervals of interest were subdivided into an Upper and Lower Spraberry zones and Wolfcamp A, B, C, and D zones (Fig. 1). Structure grids were then constructed for each of the zones (Fig. 2).

The petrophysical workflow used in the interpretation comprised log clean-up and preprocessing, interpretations of clay volume, TOC, a mineral inversion-based porosity, and water saturation. Cross-sections and property maps were made for each zone to QC the results.

A 3D structural framework was constructed from the structure grids derived from the tops correlation. Model layering was set to twenty feet and distributed proportionately. Total porosity, water saturation, and formation volume factor were then propagated through the model via interpolation (Fig. 3). The structural framework was also used to determine the landing zone of each well.

The data were then extracted from the model and combined to calculate an OOIP, as shown in Equation (1):

$$OOIP = 2 * X_f * X_H * \emptyset_T * (1 - S_W)/B_o \qquad (1),$$

where X_f is the fracture half-length and X_H is the fracture height growth. By combining these two properties with the modeled petrophysical properties we obtained the stimulated OOIP available to each of the horizontal wells. X_f and X_H were assumed to be 500' and 200', respectively. The spacing impact analysis was conducted, assuming a lateral search radius of 2640' laterally for wells identified as having the same landing zone and within twice the assumed X_H. For each well the number of neighbor wells, EUR, NPV, and recovery factor were determined. For each group of wells (a well and its neighbor wells) the total EUR and NPV were determined. Example results for the EUR per well and recovery factor with increased drilling density results are shown in Figure 4.

Once the above is established each metric can then be modeled to provide a more generalized trend to highlight the impact of increased drilling density across the play and each zone. Modeled results for NPV with increased drilling density are shown in Figure 5.

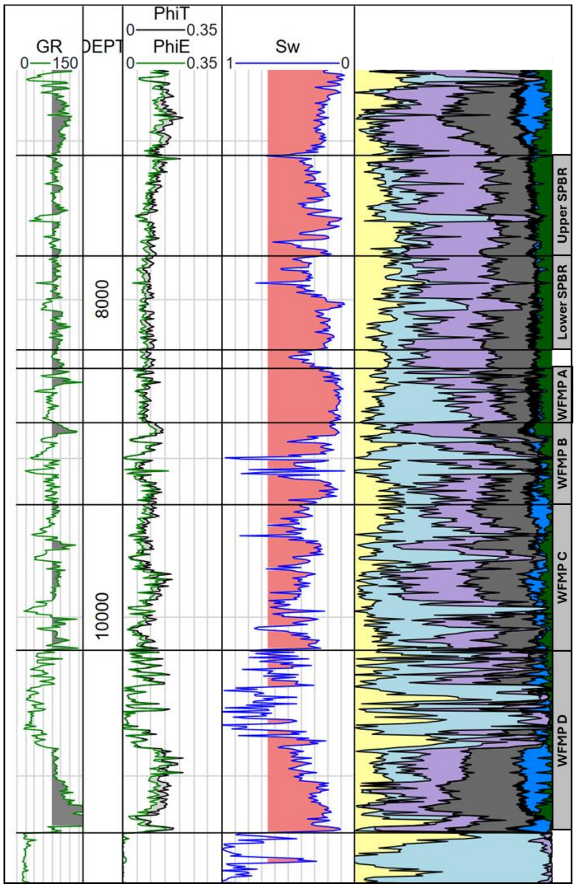

Figure 1: Example well log showing gamma ray, porosity, water saturation, mineralogy, and zone designations.

The results from the case study demonstrate the efficacy of the method and the value of extending the analysis with 3D property modeling. The combination of presenting both the decreasing EUR per additional well and the plateauing of recovery factor with increased drilling density presents a powerful argument that over drilling will lead to inefficient capital allocation. Without the extension of the methodology into 3D property modeling space it would be less clear if the decrease in EUR was only applicable to zones with lower total OOIPs.

The plateauing and subsequent decrease of NPV with further infill drilling shows the negative economic consequences of further drilling, which has been observed in previous empirical studies.

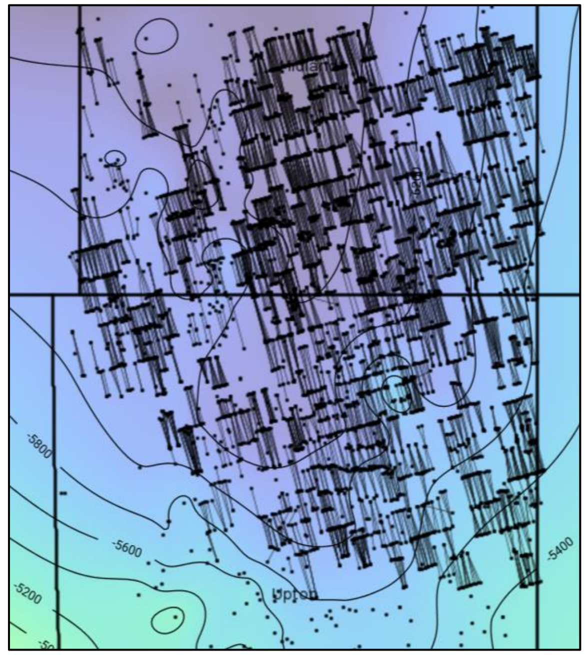

Figure 2. Top Wolfcamp structure grid with well locations.

CONCLUSIONS

The methodology outlined herein provides an important extension to previous work. Our work demonstrates two important concepts:

1. EUR decreases with each additional neighboring well drilled within a well's expected drainage area. Establishing this relationship can allow operators to quickly understand the impact of decreasing spacing.

2. The cumulative recovery factor from a group of wells displays a plateau, once a certain density of wells has been drilled, which is well before the optimal density of wells to maximize NPV.

Furthermore, without 3D reservoir property models, accurately estimating OOIP across thousands of horizontal wells would be unfeasible, making recovery factor calculations unreliable. This study shows how integrating spatial modeling with production and economic analysis enables a scalable and data-driven approach to well-spacing optimization, ensuring more efficient resource development.

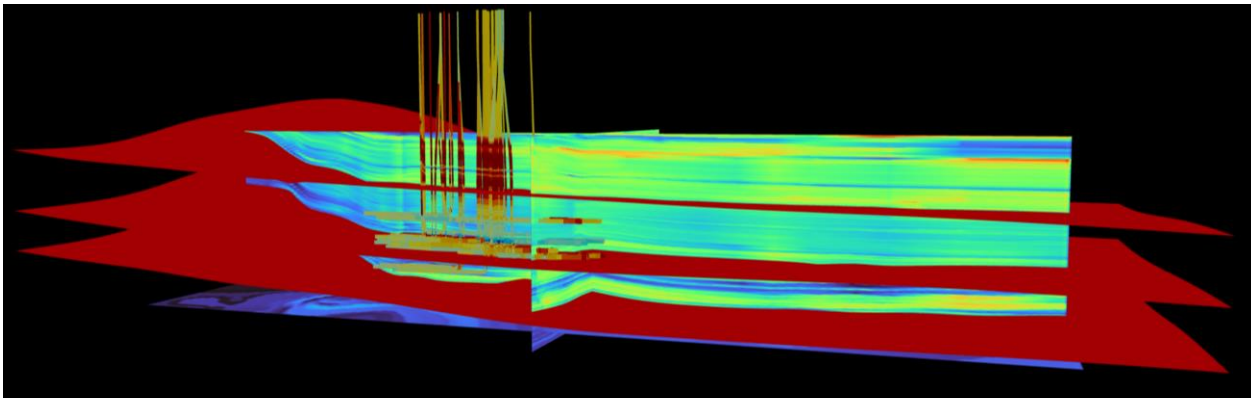

Figure 3. 3D property model showing porosity distribution with structural grids for Upper Spraberry, Wolfcamp C, and the base of the Wolfcamp D formation. Example extracted logs for a subset of horizontal wells shown.

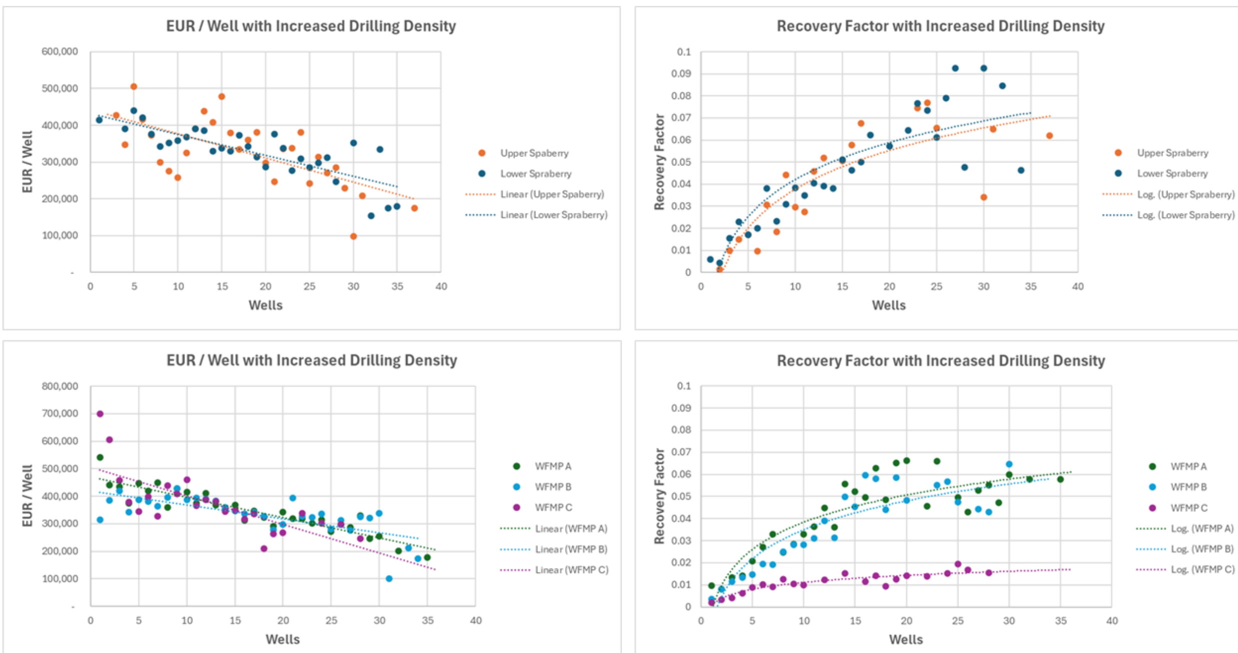

Figure 4. Results for EUR per well and cumulative recovery factor with increasing counts of neighboring wells. In all cases a strong negative correlation for EUR per well was observed in combination with a plateauing of recovery factors.

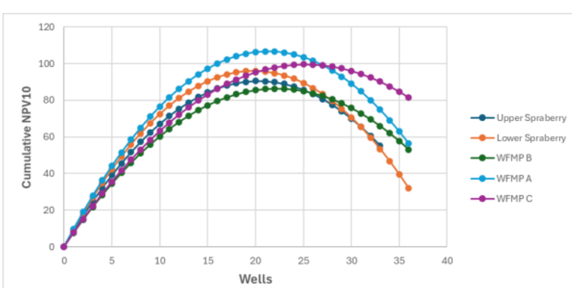

Figure 5. Modeled cumulative NPV per well group with increasing well density.