THE ECONOMIC TRADEOFFS WHEN DEVIATING WELLS TO PRODUCE FROM DOWNHOLE LOCATIONS THAT EXACTLY COMPLETE INJECTION PATTERNS

Erileck Cameron, Steve Gault, Joe Johnson, Sebastian Millan,
Ryan Owen, and Calvin Stewart

Occidental Petroleum Corporation

ABSTRACT

Occidental's Permian Enhanced Oil Recovery Unit (PEOR) has over a 100 active CO_2 and water floods in various mature conventional reservoirs throughout West Texas and New Mexico. Due to the high well count, there is limited space between the wells, making it challenging to drill new ones from surface locations directly above the desired bottomhole targets. Moving the well's location to avoid surface obstacles increases the probability of having a deviated trajectory.

The Drilling Well Calculator is the result of collaboration among the Reservoir Management Team, the Drilling Department, the Artificial Lift Team, and the Planning/Financial Team to maximize the value of a well from the very start of a development program. Rob Vincent, a former company employee, presented the idea of "Drilling Wells to Accommodate Artificial Lift" at the company's Artificial Lift Roundtable on February 11, 2016. In the presentation, he proposed the following iterative process to carry this out:

1. Reservoir Management Team (RMT) proposes a well with surface location, TVD, landing depth (if applicable for horizontal wells) and bottomhole location.
2. Drilling Team proposes a drilling plan to meet those RMT requirements.
3. Artificial Lift Team evaluates lift designs for the proposed drilling plan.
4. If the lift plan cannot be achieved with that drilling plan, then revisit the drilling plan.
5. Repeat until collective requirements from RMT, Drilling, and Lift Teams can be met.

In early 2017, a group of individuals from the respective departments formed a team in charge of developing the Drilling Well Calculator. This tool will provide a better sense of how to maximize a well's value based on surface locations and associated deviations. The Drilling Well Calculator Team was tasked with the following:

1. Estimate the additional cost of drilling wells with various configurations.
2. Estimate the additional cost of operating wells with various configurations.
3. Estimate the lost value of deferring oil production resulting from non-ideal surface and bottomhole locations.
4. Develop a tool that optimizes a well's value by selecting the best surface location.

Calculating the well's value will provide important input in the process of deciding whether to drill a deviated well to reach the ideal bottomhole location, or to drill a vertical well with a different bottomhole location. Each decision will inherently have its own set of compromises.

This paper reflects the work done by the Drilling Well Calculator Team to date. Further analysis and modification are required in the development of the final Drilling Well Calculator.

DRILLING TEAM

The Drilling Team was tasked to analyze the wellbore configuration and associated drilling costs of 125 Permian EOR wells drilled in 2017. The study area was bounded by Lubbock/Levelland to the north, Odessa to the south, Jal to the west, and Snyder to the east.

Well data was then grouped by measured depth, inclination angle, and horizontal displacement. The majority of the wells drilled in 2017 were San Andres/Clearfork vertical wells that had measured depths ranging from 4,250 to 7,750 ft. The same wells had inclination angles of 12.5° or less, with a few outliers ranging from 17.5° to 37.5°. The horizontal displacement was generally less than 375 ft, with only a small group of wells exhibiting displacements between 525 and 1,125 ft. All correlations derived from this data, using cost as the dependent variable, had very low coefficients of determination (R^2). Even when limiting the area in which the wells were drilled, the rig mobilizations costs, rentals, different mud weights, running different formation evaluation tools, or the expenditures associated with non-productive time events, such as rig downtime, drilling cost for a vertical well were very similar to those of a slightly deviated one. The only good correlation, as to be expected, was between drilling cost and number of days on location. It was therefore concluded that as long as the bottomhole location is within 300 ft of the surface location, the incremental cost of deviating a well could be considered negligible.

OPERATING COST TEAM

An analysis of the relationship between the failure frequency of a deviated well and a vertical well was used to quantify the impact of deviation on operating cost. Beam failure data from 628 deviated wells and 5,824 vertical wells from 2014 through 2018 were analyzed. The total number of failures for deviated wells was 639, compared with 5,548 failures for the vertical wells. For this analysis, only mechanical failures such as rod failures and tubing failures were evaluated, whereas failures due to electrical, fluid/gas, or foreign material problems were omitted from the study.

The failure frequency (FF) for both deviated wells and vertical wells was calculated as follows:

FF = (total number of mechanical failures) / (total number of deviated or vertical wells) / 5 years

The failure frequency for deviated wells was 0.20, compared with 0.19 for vertical wells. It was surprising to learn that there was no stark difference in the failure frequencies of the two groups.

One of the deviated wells that had a high number of failures had a high dogleg severity (DLS), so we expected to find a higher number of failures with depth if DLS ≥ 6°/100 ft; however, it was determined that there was no correlation between high DLS and failure depth. In fact, most of the mechanical failures occurred at depths where the DLS was not alarmingly high.

One explanation for this is micro-doglegs. Standard practice is to take directional drilling surveys approximately every 100 ft, which may not accurately reflect the changes in azimuth and inclination at a higher sampling frequency. In Rob Vincent’s referenced presentation, he recommended taking deviation survey readings every 25 ft, instead of the usual 100 ft, to get an improved understanding of DLS to manage it better. Furthermore, when wells are repaired, there is no database that has the failure history of the replaced equipment. For example, yellowband tubing can be run that may have pre-existing damage in the string. A failure from the pre-existing condition does not correlate to high DLS.

An established standard is that wells with deviations greater than 1°/100 ft but less than 2°/100 ft, or with a vertical inclination less than of 12°, can be managed by applying either molded rod guides, smart rod rotators, co-rod, poly-lined tubing, or for extreme cases tubing rotators. Recent technological advances in managing side loads suggest that these standards should be expanded. The capital cost and replacement cost are going to be included in the calculator to reflect this scenario.

It is standard operating practice to replace a beam pump with an ESP if the production rate falls within the normal ESP operating range, and if the beam well has a high failure frequency due to a deviated wellbore.

This is only done if the well has a tangent section of at least 300 ft with DLS < 1°/100 ft at an inclination less than 80°. The additional capital and operating expenses for an ESP are going be included in the calculator.

If a well is within the normal operating range of a beam pump but below the normal operating range of an ESP and has an increased failure frequency due to a deviated wellbore, then the incremental Opex will be reflected in a feature in the calculator that enables the user to input a "% increase in Opex". This will provide the user flexibility to adjust things as they deem appropriate.

RESERVOIR MANAGEMENT TEAM

The Reservoir Management Team (RMT) was tasked with quantifying the loss in value in terms of Estimated Ultimate Recovery of a vertical well drilled some distance from the ideal bottomhole location. In the process, the RMT developed a methodology to estimate the change in production rate for Secondary and Tertiary Recovery based on the downhole location of a well versus the preferred location in the center of the pattern.

The methodology involved creating a simple calculation that could be input in a "Single Well Economic Model" (see Table 1). To keep things simple, a 5-spot pattern configuration was chosen for this exercise. The analysis was based on a pattern where the 25% contribution from each of the four surrounding injectors is affected by the location of the producer in the center of the pattern (see Figure 1). The range of values would vary from a maximum of 100% in the center to 50% at the edge of the pattern. Another assumption made was that the closer producers and injectors are to each other, the higher the likelihood of early breakthrough.

PLANNING DEPARTMENT

A model was developed to evaluate the iterative process of balancing the capital investment of drilling a new well with the well's full lifecycle operating costs. The main aspect to model is the potential loss in value, in terms of Estimated Ultimate Recovery (EUR), when selecting the ideal surface location versus drilling a deviated well at some specified distance from the center of a pattern.

There is a specific criterion required to adequately model and evaluate the optimal economic value derived from each independent investment decision related to drilling a new well, the selection and installation of artificial lift systems, and the subsequent operating costs. Once all of the following parameters are considered, we can calculate the discounted cash flow (DCF) and then compare the economic indicators (discounted cash flow analysis) for various scenarios:

1. EUR – The estimated ultimate recovery in black oil stock tank barrels
2. IP Rates – The initial production rates for oil, water, and total produced gas
3. Decline Rate – The oil decline defined as percentage (%) per annum
4. Capital Investment – The cost of drilling and completing the well, including the initial artificial lift
5. Operating Expense – The cost of ongoing maintenance, power (lifting), gas handling (processing/ CO_2 recycling), etc.
6. Realized Product Pricing (netback) – The posted benchmark prices (WTI/WTS/NYMEX) adjusted for price differentials, including gravity, quality, and transportation
7. Failure Frequency – The mean time between failures for each well type or lift type
8. Operating Company's WI, NRI, NPI, ORRI, etc.

The DCF indicators (NPV, DCF-ROI, DPI, After-Tax Payout) generated are derived from the differential results of the two user-defined investment decisions. This initial screening will provide a starting point to determine if a material difference in value exists between two alternative investment decisions and whether further evaluation is warranted.

REFERENCES

Gibbs, S.G. (1992, July 1). Design and Diagnosis of Deviated Rod-Pumped Wells. Society of Petroleum Engineers. doi:10.2118/22787-PA

Mo, Y., & Xu, J. (2000, January 1). Design and Optimization for Sucker Rod Pumping System in Deviated Wells. Society of Petroleum Engineers. doi:10.2118/62826-MS

Table 1 – Estimated Ultimate Recovery Calculation

5 spot pattern size in acres	area in sqft	length of side of square pattern in ft	Distance from well to edge of pattern in ft	distance to offset well in ft	Distance from Center of pattern for new well in ft	EUR of well in bbl	Potential loss of reserves due to poor "sweep efficiency" bbl	% loss of EUR
10	435,600	660	330	467	95	120,000	17,273	14%
20	871,200	933	467	660	95	120,000	12,214	10%
22	958,320	979	489	692	95	120,000	11,645	10%
30	1,306,800	1143	572	808	95	120,000	9,972	8%
40	1,742,400	1320	660	933	95	120,000	8,636	7%
80	3,484,800	1867	933	1320	95	120,000	6,107	5%
160	6,969,600	2640	1320	1867	95	120,000	4,318	4%
640	27,878,400	5280	2640	3734	95	120,000	2,159	2%

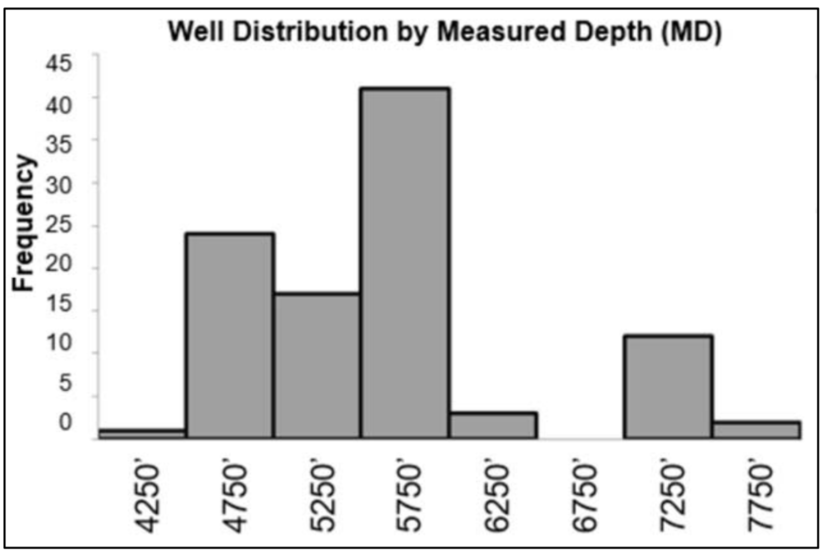

Figure 1 – Distribution by Measured Depth

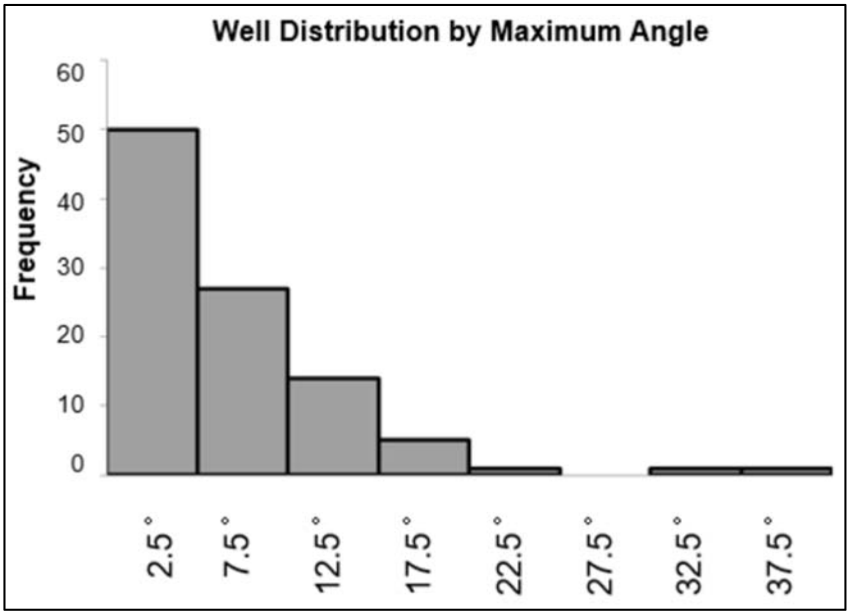

Figure 2 – Distribution by Maximum Angle

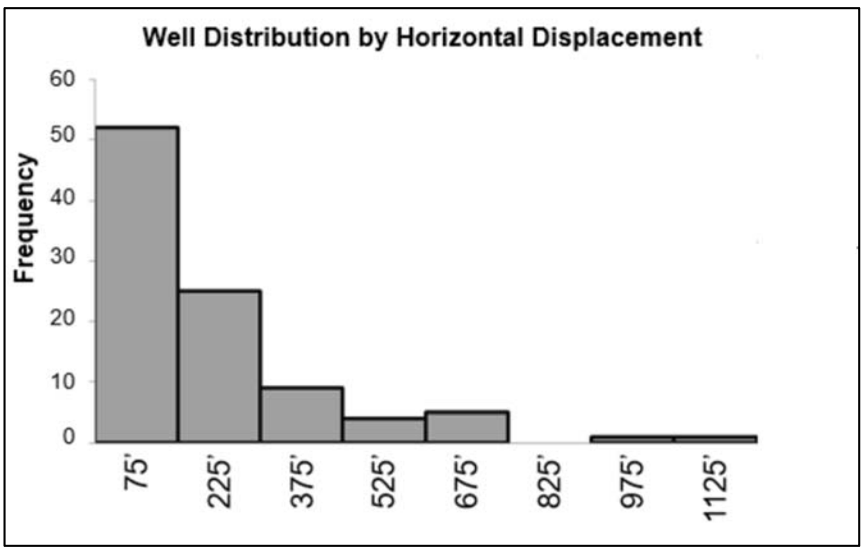

Figure 3 – Distribution by Horizontal Displacement

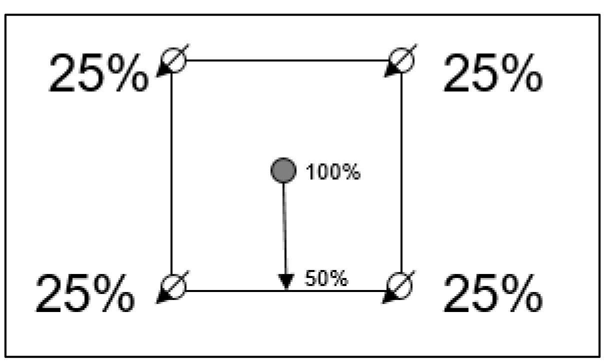

Figure 4 – Distribution of Injection Support

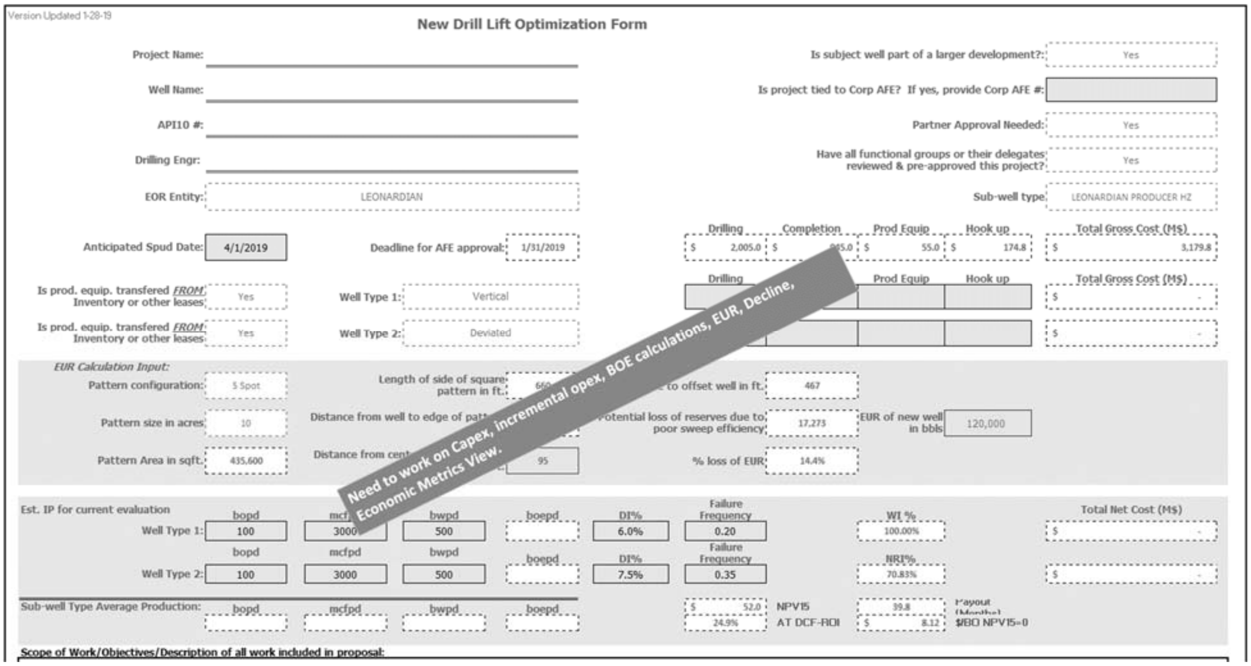

Figure 5 – New Drill Evaluation Form (Input)