WHITE PAPER
How to Sustain EOR Value in a Highly Variable Price Environment

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INTRODUCTION

Over decades, both academia and the oil industry have thrived in the area of enhanced oil recovery (EOR). Old paradigms have been derogated and new applications have been developed. However, in tough economic climates, the oil industry tends to fall back on remedial productivity tactics that, while possibly providing short-term profitability, may also lead to impaired, low-energy reservoirs along with losses in medium-term and long-term production and reserves. This paper postulates solutions to this paradox.

History has taught us the impact on EOR of past low oil price periods: significant reductions in research and development, early retirements, lost expertise, and suspended projects that are never revisited. How can we be assured that history won’t repeat itself this time?

Operators are currently implementing three types of strategies: i) continuing to design, pilot, and plan deployments; ii) further optimizing projects already in place; and iii) halting efforts “until the wind changes.” However, to go through the current low price period and make EOR sustainable, the industry is also in urgent need of three major improvements:

1. Reduce risk and cost per incremental barrel
2. Shorten the negative cash flow period during pilot and commercial deployments
3. Adapt and develop methods to expand applicability to harsher conditions

The following sub-sections address what has been done recently and what is currently being done to achieve such improvements.

REDUCE RISK AND COST PER INCREMENTAL BARREL

Reducing risk is about reducing uncertainties at the planning stage and better controlling flooding projects. Cost-per-barrel reductions can be achieved by either reducing the overall operational expenditure (OPEX) or by increasing production.

All actions related to these targets are connected, and sometimes these actions have opposite effects. In addition, the number of uncertainties (for example, permeability, net pay, remaining oil saturation distribution, and future oil prices) and decision variables (for example, the injection rate; slug size; and number, location, and drilling sequence of new injector and producer wells) is large.
For every decision, there are two or more options to be determined. Therefore, the combination of decisions and options generates hundreds to thousands of scenarios, raising the key question: How can we find the optimum scenario with the lowest possible risk?

The planning of a flooding project is of paramount importance. It is the time to make decisions that will affect the whole life cycle of the project. Some decisions are irreversible once implemented.

For a number of reservoirs, how to find the optimum scenario in the early planning stages was described in a 2013 blog by Mogollón and in these papers: Millán et al., 2012; Mogollón et al., 2016; Saputelli et al., 2009; and Tillero et al., 2014. Once the reservoir model is built and properly history-matched, the traditional deterministic/manual numerical simulation approach allows, within a reasonable time frame, for only a few scenarios to be examined on a trial-and-error basis. The transition from deterministic to a probabilistic/optimized plan is enabled by stochastic programs that automatically couple the reservoir and the economic models and use numerical algorithms to optimize the objective business function (for example, net present value [NPV], internal rate of return [IRR], and cumulative production [Np]). The workflow based on that experience is shown in Figure 1.

**Figure 1** Continuous flooding scenario optimization workflow

Reducing risk is about reducing uncertainties at the planning stage and better controlling flooding projects.
We have developed and tested optimizer software and demonstrate that it can identify a relatively large number of scenarios around the optimum for the objective function, thus providing unprecedented planning flexibility. Optima scenarios obtained in six case studies show NPV and Np increments of 30 percent or more with reduced risk compared to the traditional deterministic approach. Figure 2 shows an example of this optimization for a sandstone reservoir that is strongly pressure-depleted.

Once the most meaningful scenarios are identified, the stochastic analysis (considering all possible reservoir, production, and oil price uncertainties) provides metrics of economic risk which are invaluable for making a full field deployment decision.

Following the planning phase, many decisions must be made during execution, and the original plan may need to be modified depending on how the project evolves. So the next key question that arises is: How can we ensure flexibility and optimize project evolution?

Flooding digitalization using smart workflows is proving to be of great value and has been described in a blog by Mogollón and Carvajal (2014) and in papers such as those written by Al-Jasmin et al., (2013) and Ranjan et al. (2013). In a Middle Eastern carbonate reservoir, digitalization is helping engineers to evaluate waterflood scenarios and make better, faster decisions. The results have been satisfactory: 20 wells have shown better productivity indices than before, production has increased by 24 percent, and asset team performance has improved significantly. Additionally, optimization time has reduced by 75 percent, and the time that engineers devote to analysis and collaboration has doubled. Currently a design to make the digitalization of a field cyclic, and to continuously steam flood, is being developed.
SHORTEN THE NEGATIVE CASH FLOW PERIOD DURING PILOT AND COMMERCIAL DEPLOYMENTS

Depending on the type of EOR method employed, along with the oilfield size and complexity, the journey from screening to full field deployment may take 4 to 12 years (Figure 3). Investments of up to hundreds of millions in US dollars may be made, with returns achieved only at the very end of that period.

![Figure 3 Timeline of expenditures for a generic EOR project](image)

Particularly during low oil price periods, most operators are in the “reduce capital expenditure (CAPEX) and OPEX” mode. However, it is convenient to continue designing and piloting in order to be prepared to catch the next high oil price wave in full. Accordingly, this sub-section focuses on how to compress timelines and reduce costs as much as possible in EOR field pilot tests.

The following pilot objectives are generally recognized by the industry:

» Ascertain reservoir response in order to weigh and reduce technical/economic risk
» Gain operational experience and build operator confidence
» Book reserves

Determining whether or not a pilot is needed must be assessed on a case-by-case basis (Teletzke et al., 2008). For a well-known EOR method and a well-characterized reservoir, the risk of implementation is low. Therefore, conducting a pilot may not be justifiable. It may be even harder to justify a large-scale pilot because skipping it would save years of time and tens or hundreds of millions of dollars, substantially improving the project’s NPV.

When it is determined that a field pilot has to be conducted, the following best practices should be followed to minimize time and costs:

» Ascertain the correct geometry and dimension of the well pattern
» Conduct as many activities in parallel as possible
» Avoid multistage pilots
» Conduct single-well and inter-well tracer tests in advance
It is important not to confuse EOR piloting with filling in the gaps of unaccomplished reservoir characterization. In most cases, EOR is deployed in mature fields, and that information should be available.

Integrated oil services companies, such as Halliburton, play the very important role of implementing and combining lessons learned with best practices. Knowledge gathered in pilot projects around the world is used in the next application.

The Halliburton five-phased process shown in Figure 4 goes through initial planning, laboratory analysis, reservoir modeling, and optimized subsurface and surface design before construction and execution. These phases enable tailored solutions at any stage of the project. Key features of our approach are the use of world-class laboratories, smart algorithms, and the stochastic techniques described in the “Reduce risk and cost per incremental barrel” sub-section. This approach resolves economic risk assessment hurdles before further investing and aids real-time monitoring and project control.

Resolve economic risk before further investing.

ADAPT AND DEVELOP METHODS TO EXPAND APPLICABILITY TO HARSHER CONDITIONS

This strategy is a continuous quest with many new developments. One of the biggest challenges is proving that incremental oil can be produced with relatively low risk and cost per barrel. Some examples of recent and current developments are presented below.

First, the extension of EOR application criteria is remarkable, as in the case of polymers to heavy oils and offshore reservoirs. While the maximum oil viscosity was initially believed to be 150 cp, polymer floodings are currently successful with oil viscosity up to 3,000 cp and possibly even higher. Three examples of work done in this area are given in the papers by Manichand et al. (2010); Mogollón and Lokhandwala (2013); and Mogollón et al. (2016).

Summary of how polymer flooding challenges have been tackled in viscous oil reservoirs (after Mogollón and Lokhandwala, 2013)

<table>
<thead>
<tr>
<th>Field</th>
<th>Challenge</th>
<th>Solution</th>
</tr>
</thead>
<tbody>
<tr>
<td>Pelican Lake, Canada</td>
<td>Maintain polymer injectivity</td>
<td>Use of extended-reach horizontal wells</td>
</tr>
<tr>
<td>Tambaredjo Field, Suriname</td>
<td>Maintain polymer injectivity</td>
<td>Exploit near-wellbore fractures, inject above parting pressure</td>
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<tr>
<td></td>
<td>High formation water salinity</td>
<td>Use of hydrophobically associating polymers</td>
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<tr>
<td>Bohai Bay, China</td>
<td>Limited offshore space</td>
<td>Use of portable and automated surface equipment</td>
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There are new paradigms. Waterflooding is suitable for heavy oil reservoirs, as reported in papers by Beliveau (2008), Millan et al. (2012), and Tillero et al. (2014). Successful waterflooding cases have been reported in more than 20 sandstone reservoirs with oil viscosities ranging from 120 to 1,900 cp. Waterflooding a viscous oilfield does require a different operational mindset than waterflooding a conventional field; however, it may extend the reservoir life and increase the recovery factor at a relatively low cost.

New chemical compounds that react in situ are under field trial to improve the EOR fluid allocation in the reservoir and to solve limitations of thermal recovery due to heat losses in steam generators, surface pipelines, and tubing.

Impairment and even failure of EOR projects can be caused by reservoir heterogeneities. To address that challenge, the Halliburton reservoir and completion team developed the concept of coupling the water-alternating-gas (WAG) method with smart completions (that is, with downhole control valves [WAG-CVs]). The gas-to-water injection alternates by zones, and slug volumes are controlled by a workflow that incorporates smart algorithms. At a given time, water and gas are injected in different zones. Numerical simulations presented at EAGE conference by Carvajal et al. (2014) are encouraging (Figure 5). The case study considered a pair of injection wells and a producing horizontal well located 3,000 feet (914 meters) apart, each with 4,000-foot (1,219-meters) laterals and with six permeability zones within 10 md and 150 md. Results are shown in Figure 5. A field pilot test is to be conducted to confirm the concept value for highly heterogeneous reservoirs.

Figure 5 Comparison of WAG-CV methodology forecasted results with traditional flooding methods

Successful waterflooding cases have been reported in more than 20 sandstone reservoirs with oil viscosities ranging from 120 to 1,900 cp.
FINAL REMARKS
Clearly Halliburton has consolidated a team that is able to both deploy traditional EOR projects and innovate, thus adding more value and extending EOR to harsher conditions. Maximization of economic benefits and risk reduction have been accomplished by a variety of techniques and approaches that are now commercially available. With so many recent and forthcoming developments, this remains an exciting time for EOR.

REFERENCES


