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RESERVOIR MANAGEMENT

# Identifying reservoir opportunities using automated well selection and ranking

Effective reservoir management requires combining multiple engineering/geoscience disciplines to identify improvement opportunities. To optimize analysis, an AI-powered management platform was developed that delivers faster, more accurate results to maximize asset value.

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Successful reservoir management requires an up-to-date inventory of candidate opportunities that an engineering team can pursue to meet expected production targets. They include re-perforations, drilling a new well, or a sidetrack. Finding the best solutions requires combining geological knowledge, reservoir behavior, production history, completion information, and multi-disciplinary know-how. The conventional process of gathering, vetting and analyzing data is labor-intensive and generally takes several months. It requires the use of multiple software applications, making collaboration difficult and often leading to an unreliable set of candidates. Also, it is complicated to look at multiple scenarios under different hypotheses and leaves little time to rigorously vet options under review.

**SpeedWise Reservoir Opportunity** (SRO) is an AI-based technology, the result of a collaboration between Emerson and Quantum Reservoir Impact (QRI). The technology automates steps, typically performed during the selection of field development candidates, by applying advanced algorithms and AI/ML to multi-disciplinary datasets, enabling teams to rapidly review alternatives by leveraging cloud computing.[1-3] This cloud-native platform enables all members of an asset team to collaboratively assess field development possibilities.

It also integrates disparate sources of data, including well logs, 3D reservoir models, production history, and completion data, breaking down existing silos and opening new cross-functional workflows. Many steps are involved in generating a field development catalog, including identification of bypassed pay, drainage analysis, mapping of geo-engineering attributes to assess geological risks, and estimation of initial production potential. The process is an automated, systematic approach to assure a reliable ranking of recompletion, infill and sidetrack options.

Workflow automation allows asset teams to run many more scenarios, ultimately leading to better risk management and shorter decision cycles. The synergy that is formed between the domain experts and AI during the process ensures that the selected candidates are aligned with overall reservoir management strategy and that they satisfy pertinent engineering and economic constraints.

## METHODOLOGY

The framework consists of several components, including:

- **Engineering analytics -** Automatically performs decline curve analysis, using AI-based event detection and type curve generation; allocates production per zone for each well, using a series of data-driven techniques, integrating production, completion, rock and fluid properties, and PLT/ILT information.
- **Remaining pay identification -** Identifies uncontacted pay with many distinguishing features, such as pay connectivity analysis, automatic baffle identification, perforation strategy and standoff constraints.
- **Drainage analysis -** Estimates areas that have been drained by existing wells, by offering both volumetric and facies-based drainage areas.
- **Wellbore accessibility -** Automatically evaluates the mechanical feasibility via AI-based deciphering of wellbore diagrams (automated wellbore diagram digitization and feasibility classification).
- **Geological risk assessment -** Automatically assesses structural and mapping risks.
- **Production rate forecast -** Estimates production gains by selecting from many available options containing statistical,

**Fig. 1.** Summary of recompletion finder workflow.

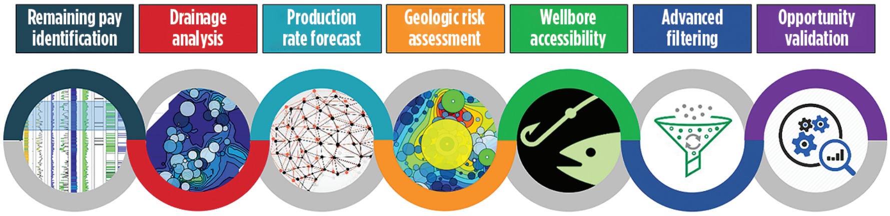
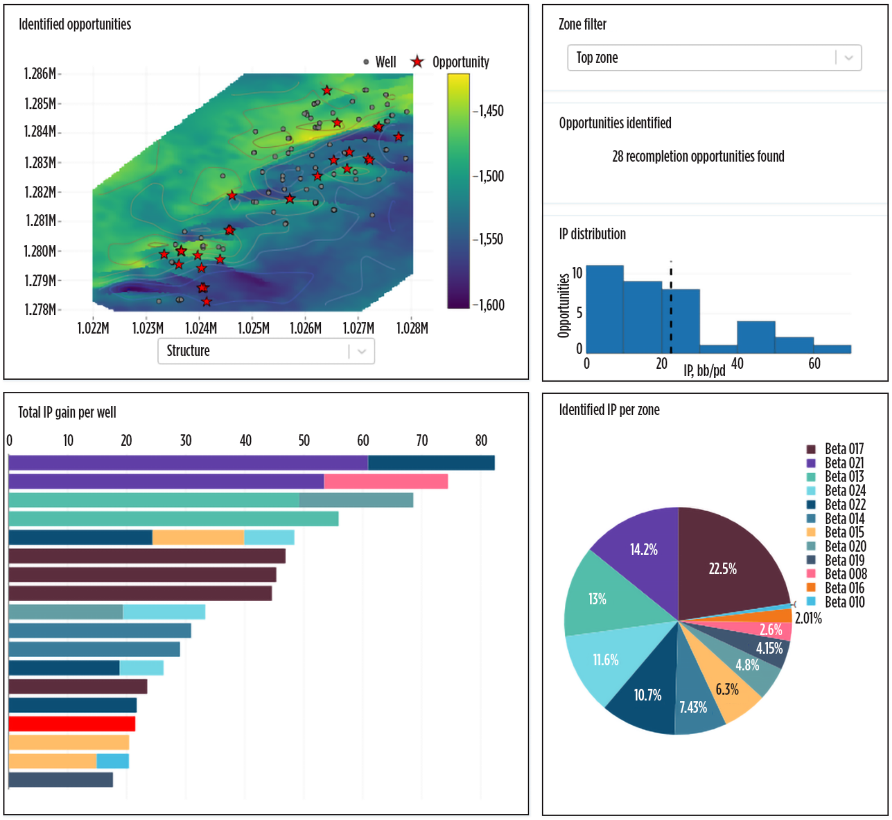


**Fig. 2.** An example dashboard displaying summary of identified opportunities, location map, distribution by production zone and ranking based on production gain.




analytical and ML-based models.

- **Target search** - Identifies optimal locations for placing target wells, using robust and fast optimization techniques, featuring relative probability of success mapping and comprehensive geo-engineering constraints.

These individual components are assembled to build larger distinct workflows, namely recompletion finder, vertical sweet spots, and horizontal target search. **Figure 1** illustrates the workflow for the recompletion finder, as many of the mentioned elements are connected.

After uploading the required multidisciplinary data for a field, it usually takes only a few minutes/hours to generate a catalog of field development candidates. First, the dataset is automatically QCed and validated by leveraging AI-based techniques. Once the integrity of the data is verified, the user is ready to experiment. Typically, several decisions need to be made for each experiment, controlled through more than 200 settings that provide ultimate flexibility and customization. For example, which method to use for mapping the geo-engineering properties; what should be minimum/maximum spacing between the wells; what are the cut-offs for net pay estimation; and how to define the probability of success parameters. By analyzing historical field performance and benchmarking against analog assets, the technology intelligently picks the best settings, tailored to address the unique challenges posed by the field.

The assumptions and settings can be altered to create many more scenarios effortlessly and account for uncertainties in the key parameters. After the job is executed in a scalable and secure cloud environment, typically in a matter of minutes, the results are accessible via a set of interactive browser-based dashboards, ready for the asset team's review and vetting. Multiple views integrating multi-disciplinary data and analysis are presented.

These include an executive summary, historical well card and individual opportunity cards summarizing the critical information related to each prospect. Additionally, petrophysical characterization, geo-model assessment, production forecast, and mechanical feasibility are available to accelerate the vetting process and promote collaboration between asset team members. An example dashboard highlighting selected options, location map, distribution by production zone and ranking based on production gains is shown in **Fig. 2.**

## CASE STUDIES

The technology has been applied successfully to a diverse portfolio of over 100 onshore and offshore oil and gas fields producing from carbonates and sandstones as primary production and waterflooding. Significant value has been generated in these fields by increasing production, reserves, and capital efficacy while enabling more robust decision-making and increasing organizational agility. Four case studies are highlighted below as a reference. **Table 1** exhibits orders of magnitude of efficiency attained for these case examples in terms of time, person-months spent, and the number of scenarios explored.

**Case study 1 -** Latin American sandstone. The asset is a mature field with over 70 years of production history from 200 wells (mainly vertical well development). After a long period of primary production, waterflooding has started over the last ten years. The reservoir is a tertiary fluvio-deltaic to alluvial siliciclastic in a faulted anticlinal trap, with low resistivity pay and 18 distinct layers. There was a need to identify recompletion and infill drilling candidates that are aligned with overall reservoir management strategy, satisfy both geological and engineering constraints, provide reliable forecasts and are mechanically viable. The asset team's existing workflow to update the inventory was deterministic and would take over six months. One of the key challenges was the poor understanding of reservoir compartmentalization and delineation of both original and current remaining oil. This jeopardized the reliability of the results generated by the existing deterministic workflow.

The opportunity identification framework presented was leveraged by the asset team, aiming to increase the speed and accuracy of results. Fifteen scenarios (three different geomodels with five distinct setting groups varying most influential uncertain parameters) were generated to achieve a range of potential outcomes and account for the uncertainty in crucial parameters. After screening and evaluating more than 10,000 recompletion and 17,000 vertical well possibilities, dozens of recompletions/reactivations (with potential oil gains between 4,600 to 7,000 bopd) and vertical wells (with potential oil gains between 7,700 to 9,000 bopd) were selected that satisfied the geo-engineering constraints and passed the scrutiny of a team of domain experts. The full cycle of updating the inventory catalog took six weeks, which resulted in significant savings in time and workforce cost (eight person-weeks compared to 24 staff-months), while empowering the asset team with more robust probabilistic models for decision making.

**Case study 2 -** Middle East sandstone. The asset is a giant sandstone reservoir, with 55 years of production history and more than 1,000 producers. Oil production peaked near 2 MMbopd, but had declined to 0.8 MMbopd by the time of the study. The asset team was looking to identify recompletion prospects in existing wells for a short-term increase in production. The long history, commingled production, and geological complexity (120 producing zones with different properties) made it very challenging to update the inventory effectively. The existing workflow took more than a year and was unable to account for uncertainty in several vital parameters, due to its deterministic nature.

The asset team utilized the new AI-powered solution to overcome the existing obstacles and detect any remaining behind-pipe potential that could be tapped into by recompleting existing wells. More than 30 scenarios were generated to account for uncertainty in several key parameters. The post hoc analysis revealed that the current water-oil contact, net-pay identification criteria, and drainage estimation method were the most influential parameters for the inventory outcome. Thousands of contenders for each scenario were examined, and the final collection consisted of 155 feasible options, after applying a series of filters, which included minimum initial rate, minimum oil thickness, maximum acceptable uncertainty, and the inspection of geologists, reservoir engineers, and production engineers.

After performing a multi-faceted risk assessment, the candidates were grouped into 25 high-confidence selections with average initial production of 400 bopd, and 130 mid-confidence prospects with an average initial production of 600 bopd. The base scenario included 116 recompletions with an estimated total potential oil gain of 63,000 bopd. The study was completed in five weeks and involved ten person-weeks (compared to 24 staff-months), which significantly boosted the efficiency compared to the traditional approach.

**Case study 3 -** Middle East carbonate. The asset is a well-connected, highly faulted, mature carbonate oil field, with over 50 years of production history and 90 active producers (mainly vertical well development), under an active waterflood. Previous reservoir management and recent drilling strategy resulted in a rapid decline in oil production over the past three years, well below peak production (recorded near 200,000 bopd). In that period, the average oil rate per well dropped 40%, and the field water cut increased from 30% to 50%. It was impossible to achieve the expected ultimate recovery factor (54%) with the existing development plan, and the asset team was looking into horizontal drilling to increase recovery per well and improve well economics.

Although the team had recently drilled a few horizontal pilot wells to test the idea and gather information, there was no systematic approach to creating a robust development plan with horizontal wells. The asset team initially used the traditional reservoir simulation approach. However, they recognized that building and calibrating the simulation model would take at least a year to complete, and the robustness of the final model was not guaranteed, due to inherent uncertainty in the geomodel and complexity linked to carbonate reservoirs.

In pursuit of an alternative approach that could deliver faster and more accurate results, the asset team utilized the AI-based technology to systematically identify and inspect horizontal targets. The search covered: a) shorter laterals

**Table 1.** Summary of efficiency gains (orders of magnitude) achieved by the technology (compared to existing asset team's workflow) for the four case studies.

| | CASE STUDY 1: Latin American Sandstone *(Recompletions/Vertical Wells)* | | CASE STUDY 2: Middle East Sandstone *(Recompletions)* | | CASE STUDY 3: Middle East Carbonate *(Horizontal Wells)* | | CASE STUDY 4: Gulf-of-Mexico Carbonate *(Deviated Wells)* | |
|---|---|---|---|---|---|---|---|---|
| | 200+ Wells<br>18 Reservoir Zones<br>70 Years Production<br>10 years Waterflood | | 1,000+ Producers<br>55 Years Production<br>2 MMbopd Peak Production | | 90 Active Producers<br>50 Years Production<br>200,000 bopd Peak Production | | 8 Active Producers<br>20 Years Production<br>120 MMbbl Peak Production | |
| | SRO | Existing Workflow | SRO | Existing Workflow | SRO | Existing Workflow | SRO | Existing Workflow |
| Completion Time | **6** Weeks | **6** Months | **5** Weeks | **12** Months | **4** Weeks | **12** Months | **8** Weeks | **12** Months |
| Person-Months Spent | **8** Weeks | **24** Months | **10** Weeks | **24** Months | **10** Weeks | **30** Months | **6** Weeks | **30** Months |
| Number of Scenarios | **15** Cases | **1** Case | **30** Cases | **1** Case | **10** Cases | **1** Case | **6** Cases | None |

that could be accessible as sidetracks from existing wells to minimize water encroachment; and b) longer laterals that could be drilled as new wells. The overall search strategy was targeting the top of the reservoir, increasing reservoir contact, and maximizing standoff from water-oil contact. More than ten scenarios were produced to account for uncertainty in crucial parameters, namely the geomodel and water-oil contact surface. After filtering based upon geo-engineering attributes and rigorous vetting by domain experts, the final catalog consisted of 32 horizontal targets, ranging from 500 m to 1,000 m in lateral length, with a minimum spacing of 20 acres.

After careful consideration, the top five options in the base scenario were selected for execution in the short term, with an estimated total oil gain of 40,000 bopd. To further support the development plan, minimize water production, maximize water injection efficiency, and improve pressure support, a proprietary waterflood management technology from QRI was utilized; this is an innovative solution, based on critical physics and data-driven models that have been deployed globally in many oil fields to manage active waterfloods and optimize well controls.[4,5] Delivering feasible and actionable inventory only took four weeks and involved ten person-weeks, awarding the asset team with much shorter decision cycles and smarter decisions than the labor-extensive, traditional simulation approach with unpromised returns.

**Case study 4 -** Gulf of Mexico fractured carbonate. The asset is a complex, highly fractured, mature oil field with over 20 years of production history. Over the past two years, oil production dropped almost 80% (from peak production of 120 MMbbl of oil to 25 MMbbl of oil), due mostly to rapid water encroachment that resulted in well shutoffs. A typical well was producing oil between 20,000 bopd and 30,000 bopd with no water, many years after commission. However, after the water breakthrough, oil production dropped by more than 90% in less than six months. It took the asset team more than a year to build and calibrate a traditional reservoir simulation model to understand water behavior in the field and optimize the development plan.

Despite all the effort, none of the models accurately predicted water behavior, resulting from a poor understanding of the fracture network and the limitations of conventional dual-porosity and dual-permeability finite difference models. As a result, the asset team had no choice but to write off 1P reserves by 90%, and there was no planned activity beyond operating the eight active producers.

The asset team turned to the AI-based technology to maximize the value of the asset before abandonment. The focus was on looking for a) workover candidates in existing wells to mitigate water encroachment, and b) sweet spots in the attic oil structure between the water cones to maximize the stand-off from water-oil contact, accessed by highly deviated wells to maximize reservoir contact. One of the key challenges was the poor understanding of the current water-oil contact. An ensemble of 25 dynamic reservoir models was built and calibrated to estimate the current water saturation map, using QRI's proprietary forecasting technology; an efficient and rapid well/reservoir forecasting technology that builds hybrid models (combining physics-based and data-driven approaches) with a systematic top-down approach. This solution aims for optimum complexity by addressing both bias and variance in the system.[6-8]

For the present study, the robustness of models was verified through error analysis on both a cross-validation set (used only to adjust the hyper-parameters, and not during the history matching) and a test set (data not accessible during model building). Subsequently, different saturation maps were used as input of the opportunity identification framework to generate several scenarios. After careful consideration, six scenarios were examined in more detail to uncover the remaining potential and manage risks. The base scenario consisted of 11 technically and economically feasible prospects, including eight workovers (plug-backs and choke optimization in existing wells) and three highly deviated targets. The incremental recovery for the base scenarios was estimated between 9.4 MMbbl and 25 MMbbl of oil. The complete process of identifying and ranking the candidates only took eight weeks—which is considered an industry record for addressing such a complex problem—and the unlocked potential gave new life to the field, where no alternative solution was available.

## VALUE ADDED

The oil and gas markets in the post-Covid-19 world represent a new ecosystem that is governed by the need for extreme efficiency in capex/opex. The new AI-powered automation technology brings speed, accuracy, value creation, and risk mitigation to field development plans, specifically to the selection of the best wells—clearly the most capital-influential part of upstream activities. Going forward, the conventional processes that usually take many months to produce sub-optimal field development candidates will be replaced by solutions that usher in the age of digital transformation in reservoir development planning.

The benefits of the technology presented are threefold: speed, accuracy/risk mitigation, and value creation. As highlighted in the examples, more than 90% of speed-up is typically achieved compared to conventional workflows. Also, due to enhanced data mining and AI-based vetting algorithms in well selection, the resulting field development catalog offers a much higher degree of confidence and accuracy than conventional manual work processes, leading to better risk management. Finally, the compelling list of ranked and vetted field development options—recompletions, side-tracks, and new wells—typically produces thousands of incremental barrels of oil/gas, both short-term and in EURs. SRO as SaaS can be described most succinctly as a capital-efficiency engine driven by AI, as demonstrated by the case examples and is essential in modern reservoir management.[9,10] Typical annual savings in capex/opex, at equivalent production levels, range from 20% to 50%. WO

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