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Integrated Field Development Modelling to Improve Recovery from a Complex Fractured Carbonate Reservoir with Potential for Low Salinity Waterflooding EOR

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Abstract

Integrated field development studies were performed to increase oil recovery from the Marrat reservoir in the Umm Gudair field, a large, low permeability, complex, naturally fractured and highly faulted carbonate reservoir. The studies involved rebuilding the static model, creating and history matching a new dynamic model and using it to examine redevelopment scenarios. These included well interventions and workovers under primary depletion, secondary waterflood and, following a screening exercise, low salinity flooding (LSF).

A new structural interpretation of 3D seismic data provided a revised static geological model and yielded insight into the number, geometry and origin of the many faults intersecting the reservoir. Rock types defined from core analysis were distributed in the static geological model using trends from Bayesian lithofacies classification based on pre-stack inversion of seismic data. Porosity and permeability were modelled by rock type. Saturation-height functions for each rock type were developed from mercury injection capillary pressure (MICP) data; and the reservoir free water level was varied so that these functions honoured the log-based water saturation interpretation.

The dynamic model input description was based on available and interpreted data for the assumed oil wet reservoir. The history matching was aided by sophisticated application of decline curve analysis (DCA) and used an Opportunity Index approach to optimise well placement. The history matching led to a simplified and effective solution for characterising the locally naturally fractured reservoir nature. The effect of high permeabilities associated with increased fracture density was accommodated by introducing facies-based and distance from fault-related permeability modifiers, while maintaining geological rigour.

The dynamic model was used to examine a range of field redevelopment scenarios. This showed that LSF could enhance field recovery and achieve a three-fold increase in estimated ultimate recovery, in conjunction with other improved reservoir management strategies. The results provided support for specialised laboratory and dynamic modelling investigations as a precursor to LSF pilot trials. A low cost source of LSF injectant was identified which could contribute to lowering the overall carbon footprint.

Introduction

The Umm Gudair Field straddles the border between Kuwait and the Neutral Zone immediately west of the Burgan field area. Oil with specific gravity of $\sim 34^\circ$ API is contained at Jurassic Marrat level in two faulted, elongate anticlines developed most likely as positive flower structures at restraining bends on deep strike-slip fault systems. One of the anticlines, West Umm Gudair (WUG), falls entirely within Kuwait, while the other anticline is divided into East (EUG) and South Umm Gudair (SUG) portions by the Kuwait / Neutral Zone border. The shallower reservoirs on the field began production in 1962, but oil rates remained low until development drilling commenced in 1967. Development of the Marrat reservoir in the Umm Gudair field started in 1985.

Integrated field development studies were undertaken, including new 3D static model for the Middle Marrat reservoir, which integrated all available data including 3D seismic, log data and core data from recent wells drilled in area. This static model was initialised for use in dynamic simulation, which in turn was used to estimate the remaining developed/undeveloped resources in Umm Gudair area. To maximise the utility of the model for prediction purposes, particular focus was placed on capturing reservoir heterogeneity and building a suitable petrophysical rock-typing scheme to capture saturation behaviour across the range of reservoir quality.

Reservoir Characterisation and Modelling

Geological Description of the Umm Gudair Marrat Reservoir

The Umm Gudair field is located on the southwest flank of the West Kuwait Arch. Structural interpretation suggests that, in common with the Abduliyah and Dharif fields, the present-day structure of the field is strongly associated with the West Kuwait Arch Lineament (Figure 1).



Figure 1—Structural Elements of Onshore Kuwait (Carmann, 1996)

The Umm Gudair Field is composed of two antiformal structures (west and east) separated by a saddle with relatively low relief. This overall structure is present throughout the stratigraphic succession. The structural trends of the east and west culminations of the field are slightly different and there is some evidence to suggest (Bou-Rabee, 1996; Carman, 1996) that the two structures evolved at slightly different times.

The Marrat "C" is the deepest of four producing reservoirs in the Umm Gudair field. Its uppermost part has good reservoir quality and is the deepest known oil reservoir in Kuwait. The "C" unit is the thickest in the Marrat formation and dominant carbonate section within the Jurassic sequence (Figure 2).

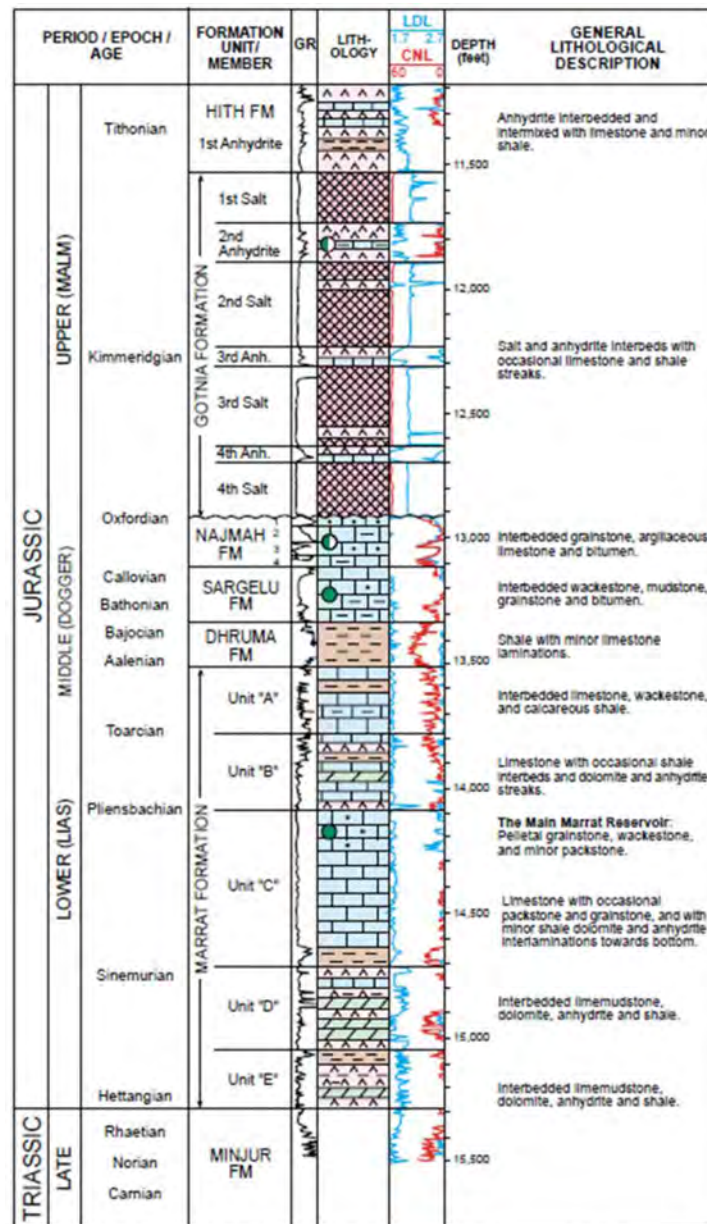


Figure 2—Jurassic Type Section from Minagish Field (Yousif & Nouman, 1997)

The Marrat reservoir consists of mainly oolitic grainstone and packstone and is primarily the uppermost portion of Marrat "C" unit in the south. The rest of the limestone is mainly micritic with scattered packstone, wackestone and some grainstone. The depositional environment of the Marrat "C" unit is restricted inner shelf and the reservoir is not developed in north Kuwait.

It was previously understood that reservoir quality in the Marrat is dominantly controlled by lithofacies overprinted by diagenesis, in particular cementation which has reduced the reservoir quality of grainstones and dolomitisation which affects the packstone and the wackestones in the deeper reservoir layers. Meteoric leaching and dissolution have improved the reservoir quality in the Dharif field. Lateral facies variations have resulted in better reservoir quality in the Dharif and Abduliyah fields than at Minagish and Umm Gudair fields.

Petrophysical Interpretation and Rock-Typing

A multimineral analysis and petrophysical evaluation carried out by the Operator in 2019 provides valid shale volume, porosity and water saturation. The volume of dolomite was observed to be overestimated compared to core mineralogy data.

The relationship of depositional environment interpreted from previous studies was analysed with the reservoir rock quality in terms of porosity and permeability. Figure 3 shows a cross-plot between porosity and permeability. The following observations were made:

1. Depositional facies architecture does not exhibit significant control on reservoir quality.
2. High permeability values can be observed even where porosity is low, indicating the presence of natural fractures.

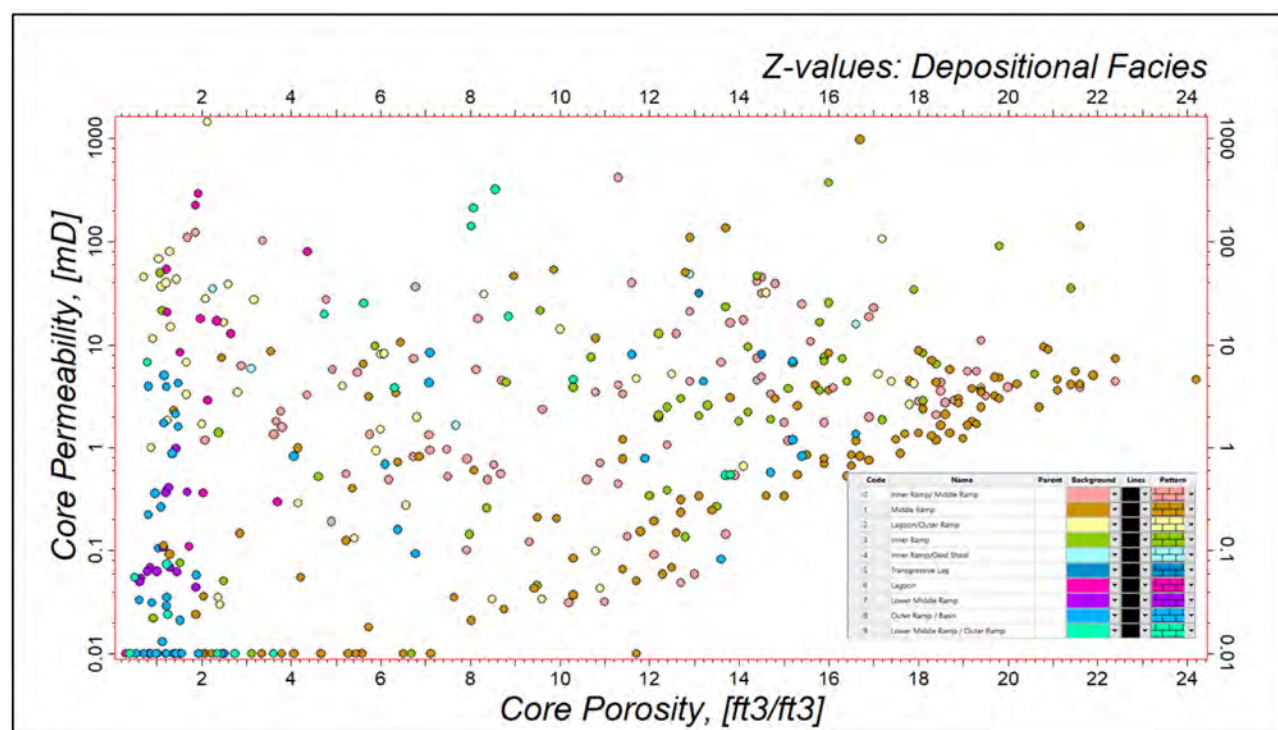


Figure 3—Core Porosity vs. Permeability by Depositional Facies

Since the depositional and lithofacies as observed from the core do not bin the data into distinct porosity and permeability classes, the study team faced a challenge as to how to distribute the properties without having a distinct reservoir architectural element. It was decided to investigate other options, e.g. having simplified rock types controlled by seismic attributes to map the horizontal variability of the reservoir.

Rock typing was carried out using the workflow illustrated in Figure 4 below.

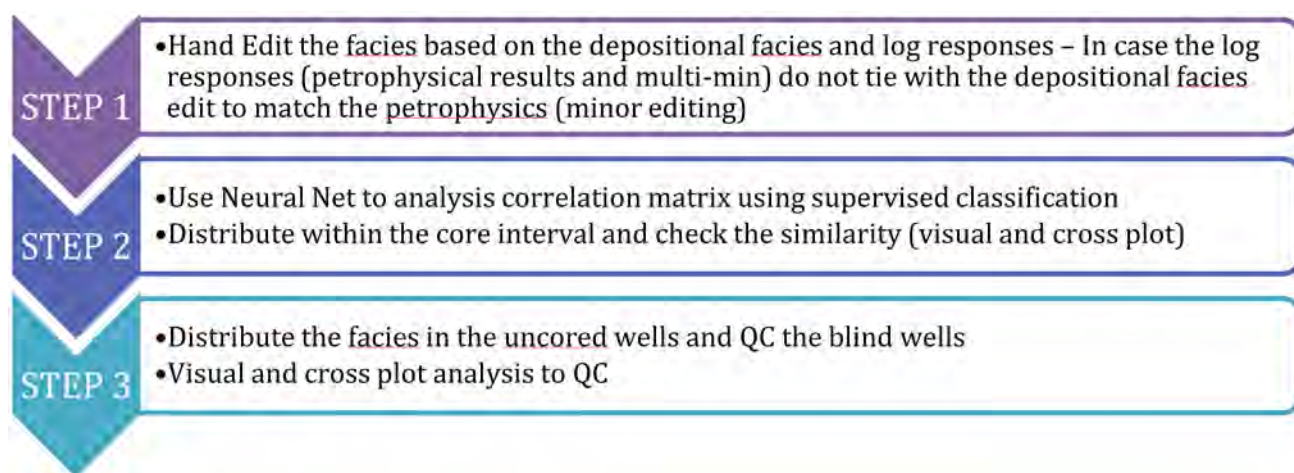


Figure 4—Rock Typing Workflow

The following rock types were defined:

Cross-plots of bulk density vs. porosity show that there is a distinct segregation between the rock types (Figure 5). This has important implications for the use of seismic inversion volumes to guide facies distribution in the reservoir model.

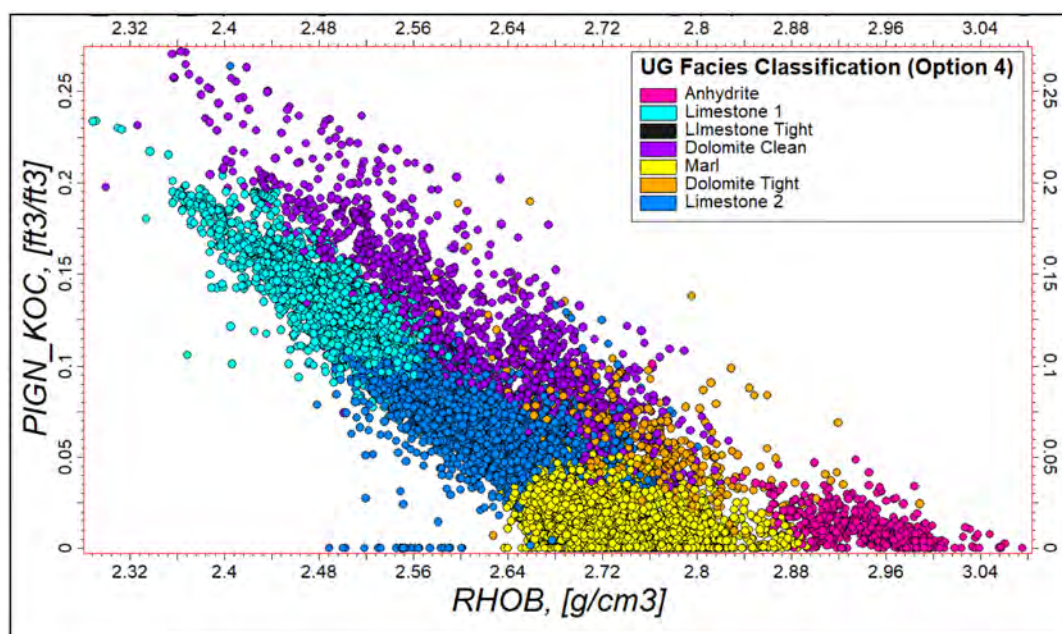


Figure 5—Bulk Density vs. Porosity Cross-Plot, Coloured by Rock Type

Possible Impact of Natural Fractures

Fracturing was also noted from a review of the available borehole image interpretations. Of particular interest was the interpretation from horizontal wells. Detailed digital interpretation (i.e. bedding and fracture picks and dips) were only provided for the Najmah / Sargelu section. However, a composite image from the structural model and image log interpretation (Figure 6) shows that some wells in the crestal areas of the field intersected a large number of open and mineralised fractures. This is important because it gives the impression that fracture intensity is highest in the crest of the field and possibly also associated with the faulting.

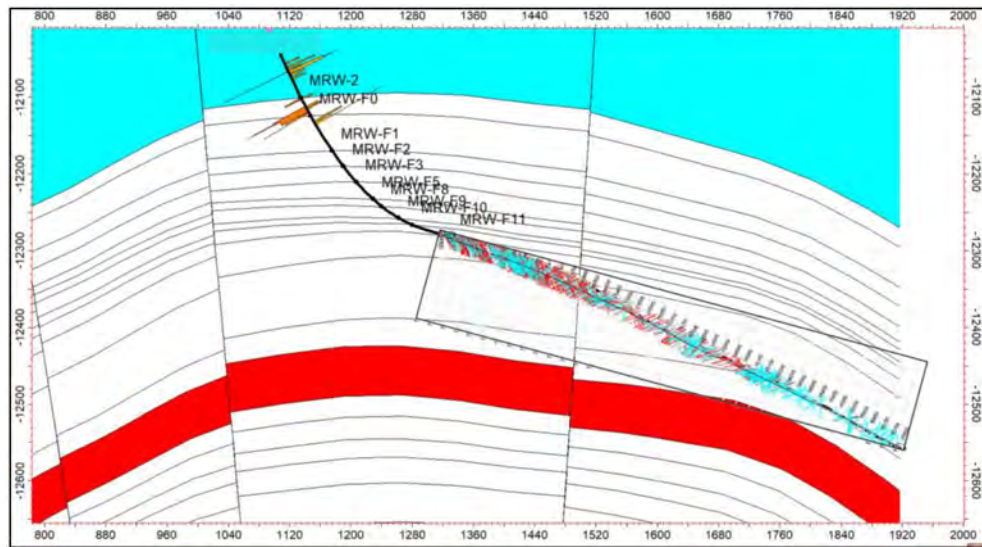


Figure 6—Composite of Structural Model and Fractures from Borehole Image Interpretation

Static Reservoir Modelling

A completely new static geological model of the Marrat reservoir in Umm Gudair field was constructed, incorporating data from recently-drilled wells, new seismic interpretation and seismic inversion.

A completely new seismic interpretation was carried out, which provided new horizon inputs for the static model and led to an improved understanding of the likely structural evolution of the field. The new fault framework was significantly different from previous interpretations and is considered to provide a more realistic structural model. Further analysis of the apparent fault throws in the model provided the basis for further assumptions regarding the fractured nature of the Umm Gudair Marrat, taken forward into the dynamic modelling.

The new fault model (Figure 7) provides the basis for a structural framework that can be used to explain well behaviour in different areas of the field and may also may partially explain the distribution of fractures – and therefore regions of enhanced permeability – within the field.

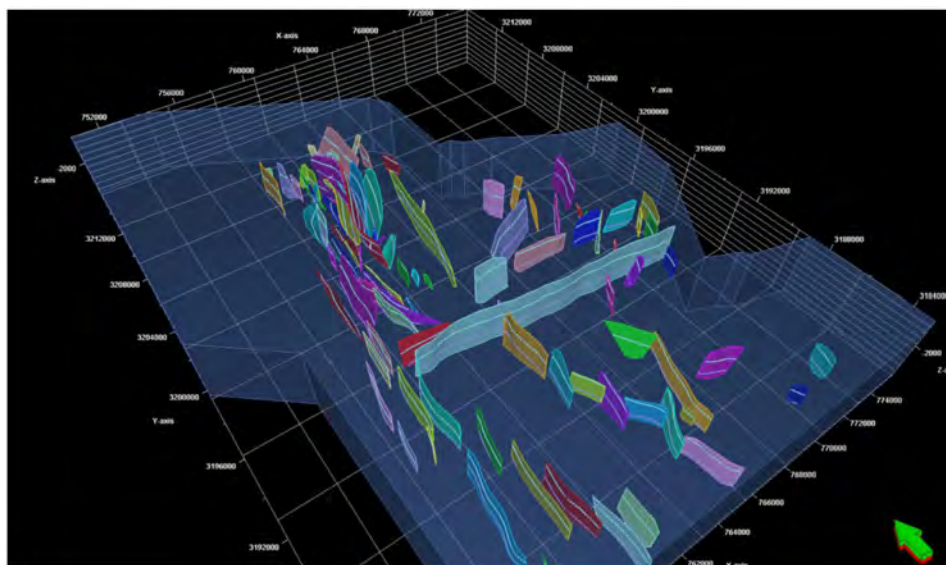


Figure 7—Field-Wide Fault Model

The model layering was based on a slightly revised horizon interpretation, together with the zonation scheme that divides the Marrat into zones numbered F0-F27. The main producing zones are F11-F13 and F15-16, with some minor production from deeper layers. The non-producing and shaley layer F13b is a relatively strong seismic reflector; and model zones were built up from this layer for the shallow reservoirs, and down for the deeper reservoirs.

A pre-stack seismic inversion was carried out based on supplied angle stacks rather than optimised CMP gathers. The inversion produced P- and S- impedance and density volumes, which were used to carry out a Bayesian facies classification whereby the inversion facies corresponded more-or-less to the defined rock types (Figure 8). Facies probability volumes for the reservoir end members were then used as 2D trends in the stochastic distribution of the rock types throughout the model.

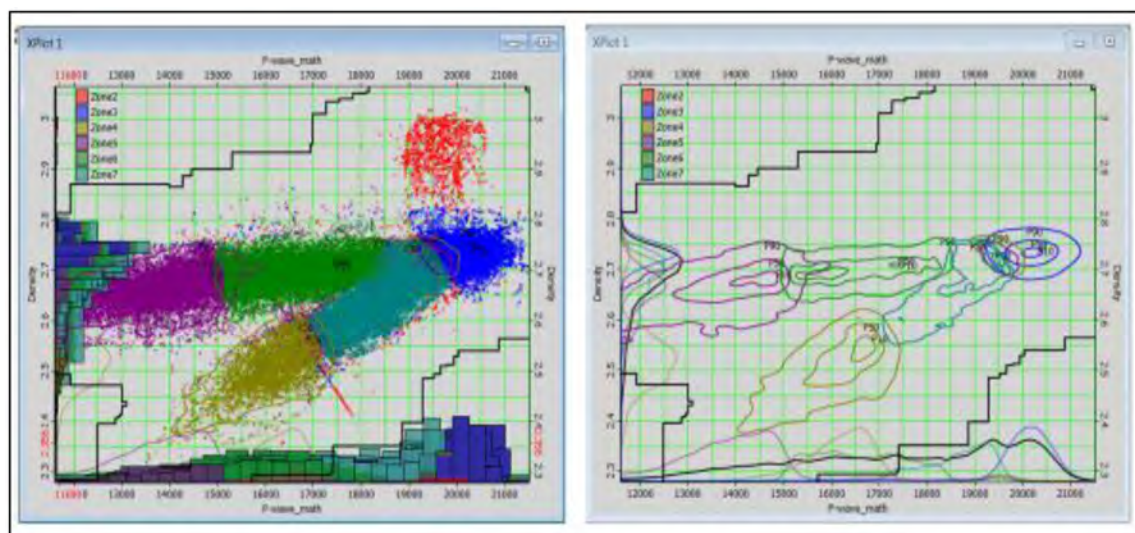


Figure 8—Bayesian Facies Classification from Seismic Inversion

Porosity was modelled stochastically for each rock type, with defined porosity-permeability transforms for background (non-fractured) permeability and saturation-height J-functions for each defined rock type.

Reservoir Engineering Pre-Analysis

The Umm Gudair field, Marrat reservoir (UGMR) production data were quality checked and data irregularities resolved. History plots were produced for each well indicating the various events, such as perforation, stimulation, acid frac, clean-up, etc. An example well event history is shown in Figure 9. This plot and others helped in understanding the causes of changes in oil and water rates during the production life of each well.

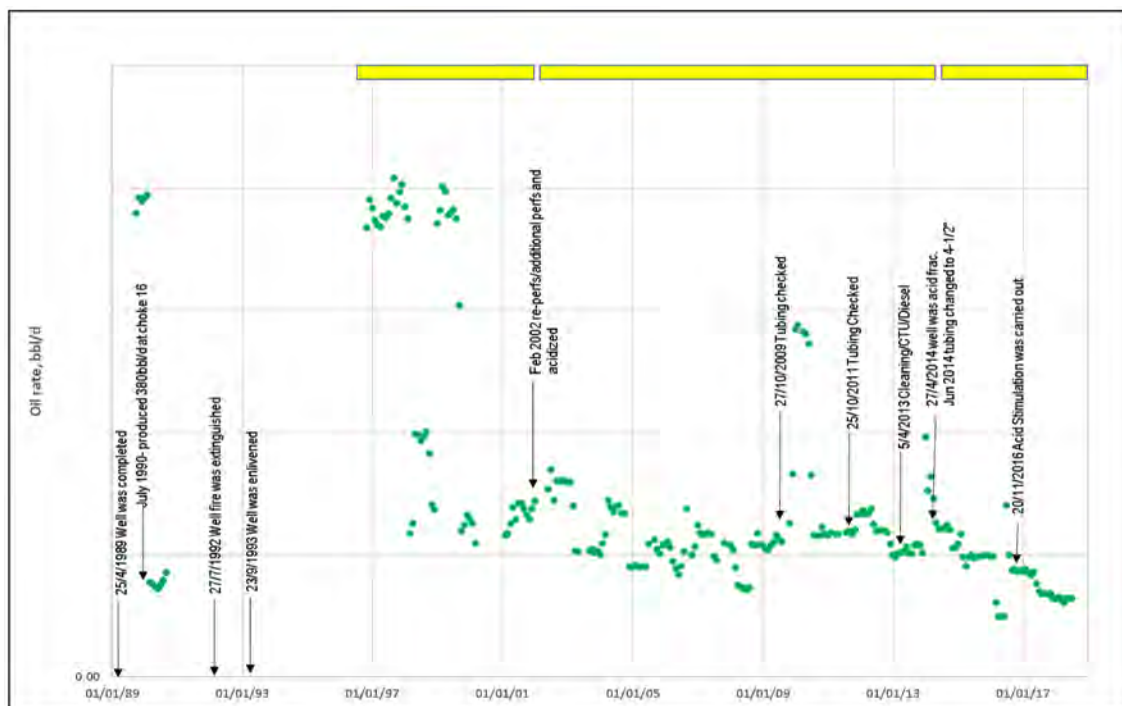


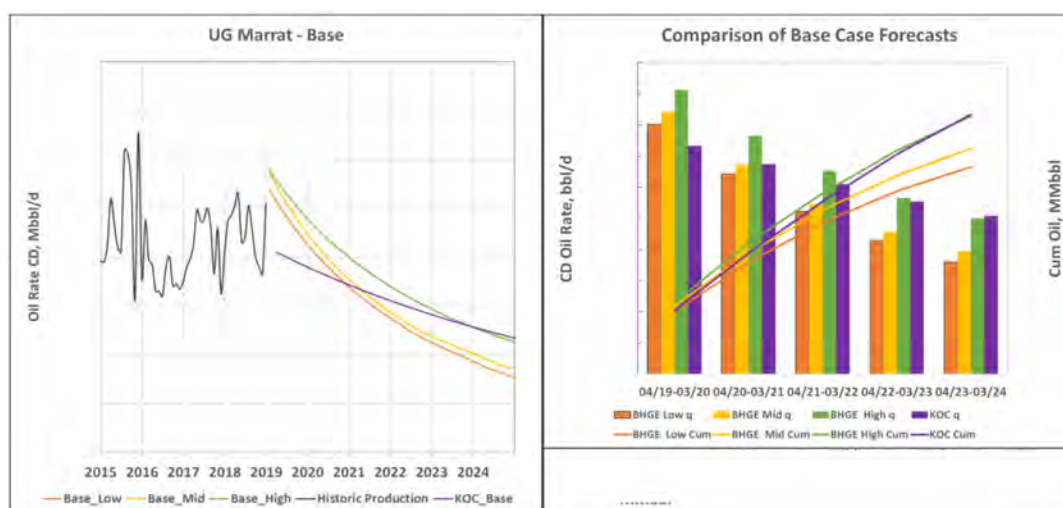
Figure 9—Example Well History Plot Identifying Events Through Time

UGMR production started in 1989. There was a brief blowout period in 1992 on two wells, for which blowout volumes were estimated and included in the production data during material balance analysis and dynamic model history matching.

Decline Curve Analysis

The future performance of the Marrat wells was predicted by Decline Curve Analysis (DCA) using a "best practice" approach (Hattingh, 2006). This involved performing DCA at the lowest feasible, well producing level, rather than at group level, thereby taking account of well events (shut-ins, acid fracs, clean-outs, etc.). Individual well reference plots were created showing all information relevant to DCA, enabling trend analysis periods to be selected as shown in Figure 9. Decline analysis was conducted using operating day rather than calendar day rates, avoiding historical well performance trends being masked by the effect of downtime. Exponential decline was used for all wells in a Low Base Case forecast. Depending on level of confidence, either an exponential, general hyperbolic or harmonic decline was used for wells in Mid and High Base Case forecasts.

The well-level forecasts with cut-off rates of 50 bbl/d were combined with predicted well uptime factors and aggregated to generate Low, Mid and High Base Case field-level, 5-year forecasts. Figure 10 shows these DCA forecasts compared to the Operator's previous base case forecast. The DCA forecast results were later compared against the dynamic model Base case forecast and an acceptable match was observed (see below). This provided a useful validity check on the dynamic modelling results.



Based on the 5-year forecast, three parameters, initial rate, decline factor and cumulative production, were further analysed. This showed that groups of wells could be differentiated by the character of their production performance trends, which could then be correlated to reservoir factors such location of wells with respect to geological features. This is illustrated in [Figure 11](#), which identifies crestal region wells as performing better, suggestive of better geological properties and perhaps a better-connected natural fracture network. These and other early insights gained from the DCA informed and benefitted the static and dynamic modelling workflows.

Fluid Types and PVT Properties

Pressure, volume, temperature (PVT) laboratory reports were available from six wells; four from wells in West region, one from a well in South region well and one from a well in East region. The laboratory PVT data were quality controlled prior to their use in numerical and material balance modelling using a best practice approach (Witson, 2000; Kshirsagar, 2012).

It was observed from the PVT analyses that the oil in the West is heavier (lower GOR and higher density) than that in the East, which in turn is slightly heavier than that in South. Three valid PVTs were used to define fluid models for each of the dynamic model regions.

Rock Wettability and Relative Permeability

Thirty-three core samples from development wells were available for analysis of rock properties. Seven types of test that had previously been conducted on the 33 core samples were reviewed and examined. Analysis of SCAL data from nine core samples provided Corey exponents which indicated that UGMR rock wettability is mixed wet to oil wet. The relative permeability data were normalised and de-normalised for input to simulation (Figure 12).

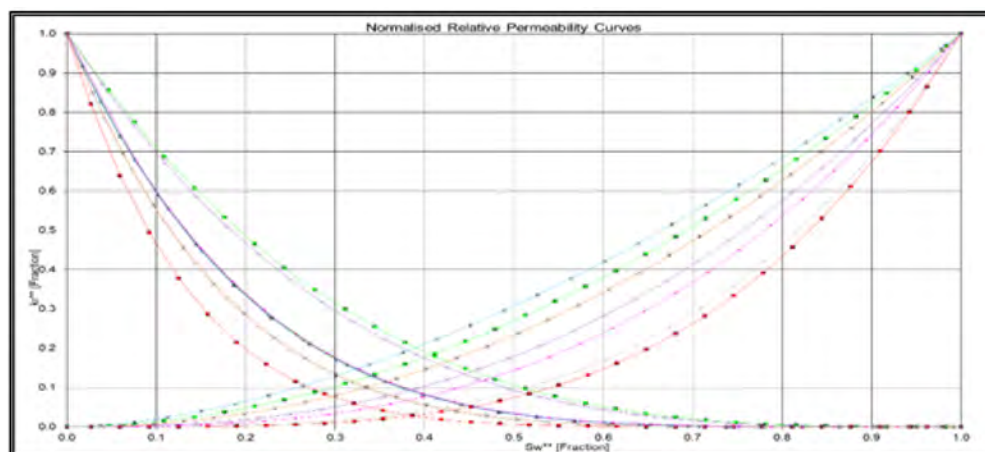


Figure 12—Relative Permeability Normalised Curves

The core samples were matched to the rock types generated from geological and petrophysical analysis (Figure 5). The previously-generated saturation-height J-function equations were used to calculate saturation values, entered with relative permeability as saturation tables in the dynamic model.

Shut-in bottom-hole pressure (SIBHP) data for 14 wells and RFT data from seven wells were used to interpret the pressure in UGMR and develop an understanding of the connected reservoir volumes. Three different oil-water contacts (OWCs) were interpreted (Figure 13) and pressure gradients for the separate West, East and South regions were calculated. As there were three reservoir regions, this resulted in nine equilibrium regions in the dynamic model.

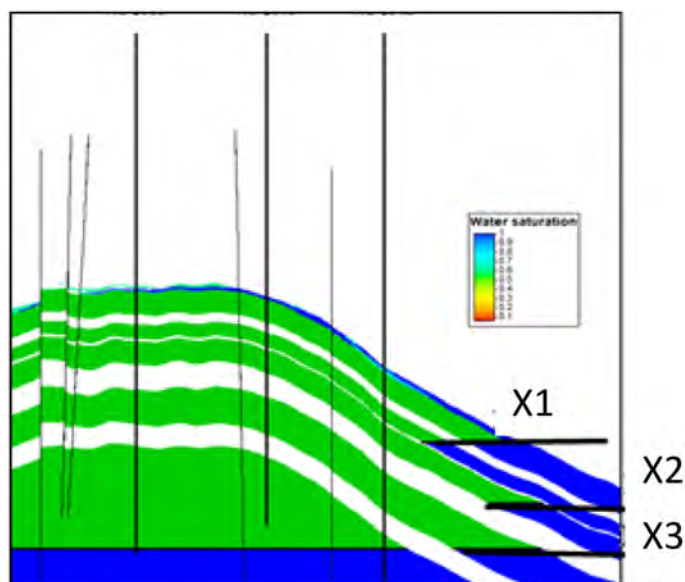


Figure 13—OWC Depths

Material Balance

Material balance analysis was used to investigate connected volumes and reservoir drive mechanisms for the interpreted UGMR compartments and sub-compartments. This indicated weak aquifer support with aquifer radii in the range of 1.6 to 2.1 times reservoir radius and highlighted the need for water injection to restore and maintain reservoir pressure.

The knowledge and insights gained, particularly regarding compartmentalisation and aquifer support, were used to aid the history matching process.

Dynamic Model Construction and Initialisation

The UGMR dynamic model grid was based on the newly constructed static model. A single porosity formulation was adopted as there was no evidence from the geological, petrophysical and reservoir engineering pre-analyses that a dual porosity-dual permeability formulation to explicitly represent fracture flow would be required. The model was populated with reservoir properties and rock and fluid input data and initialised. QC checks were performed, including verification of the model volumes against the static model volumes and an initial simulation run without any wells producing to confirm quiescent conditions.

It was determined, though, at an early stage in the dynamic model history matching process, that the matrix permeability array from the static model would be insufficient to match some observed well rates. Local modifications to increase permeability would be needed to match observed oil rates at those wells. However, as permeability was an input to the J-function derived saturations, any such permeability modifications would impact the model saturations and hence hydrocarbon volumes. It was therefore decided to initialise the dynamic model using the J-function approach but based on the original permeability array. The resulting dynamic model initial water saturation array (SWAT) was then output and saved as an initial water saturation array (SWATINIT). This SWATINIT array was then entered in all the subsequent history match cases. In this way, the initial water saturation array was fixed throughout the history matching exercise and independent of permeability modifications.

The justification for the above approach is that the presence of fractures, which it was found during history matching required local permeability modifications (see below), would not affect initial reservoir saturation. Capillarity would be unaffected by fracturing. In other words, the fractures would act as conduits to flow but would not retain water and hence the matrix alone would dictate the initial water saturation distribution.

The initialised dynamic model passed all QC checks including quality of match of the initialised model pressure and saturation profiles to relevant RFT and saturation log data.

Dynamic Model History Matching

Wells were controlled during history matching on oil production rate with a minimum flowing bottom hole pressure (FBHP) limit. Well models were also used to calculate FBHP data points, used for calibration in addition to observed FBHP and SIBHP during the history matching exercise.

The dynamic model was first used to examine the effect of varying key reservoir parameters and properties in a broad sense. The simulation modelling then focused on refining the history match at individual wells.

History Matching Parameters

Potential history matching parameters Kv/Kh ratio, pore volume multiplication, aquifer strength and OWC depths were not modified during the history matching exercise.

- Aquifer support had been interpreted as being weak from material balance analysis and so no additional aquifer support (in the form of aquifer models) was introduced in the dynamic model.

- There was some uncertainty in the interpreted OWC depths. However, it was considered that there would have to be a reasonable technical justification for changing any of the interpreted depths, rather than to improve the history match alone.

Hence, the main sensitivity parameters during the history matching exercise were those described in the following sections.

Permeability Modification Using "Distance to Fault" Property

Initial simulation runs showed that many wells were producing at significantly lower rates than observed. This was interpreted as due to the effect of natural fractures associated with faults or structural deformation, rather than higher matrix permeabilities. Hence, it was considered that enhancement of the model input (matrix) permeabilities in fault vicinities would be sufficient to incorporate this effect.

Faults are present in the UGMR and based on well borehole-image data (Figure 6) and non-digital interpretation data image it was observed qualitatively that:

- Fracture intensity is higher towards the crest and around faults.
- Fracture intensity decreases away from the crest, Figure 6.

Hence, a distance to fault property 'r' was created, as shown in Figure 14. A permeability multiplier based on a Power Law equation was calculated using this property (Johri, 2014):

$$F = F_0 \times r^{-n} \quad \text{Equation 1}$$

where

- F = Fracture intensity
- F_0 = Fracture intensity at fault
- r = Distance to fault
- n = Decay exponent

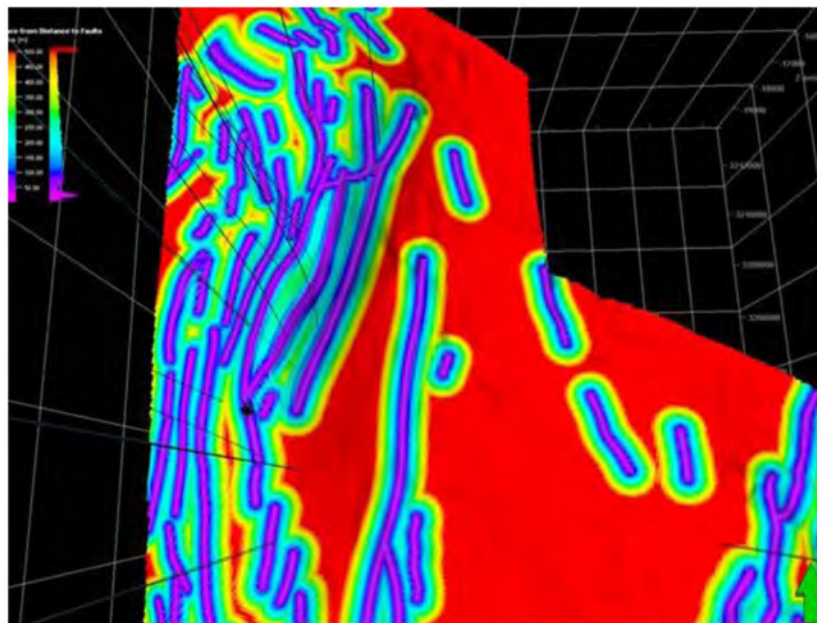


Figure 14—Distance to Fault Property 'r'

It can be seen from Equation 1 that F decreases away from a fault. F is then multiplied by a desired permeability multiplier to obtain a modified permeability, e.g. perm_multiplier_20 = $F \times 20$ (Figure 15). This

permeability multiplier property was applied to certain faults, 106 faults out of 126 faults in the dynamic model. Various sensitivities of this multiplier were performed to achieve a dynamic model history match to observed production and pressure data. This multiplier was only applied to production-contributing zones F11 to F15.

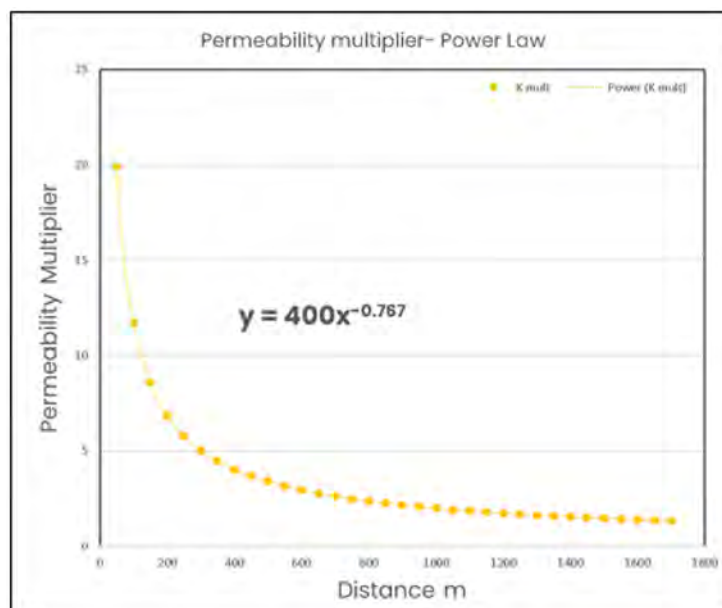


Figure 15—Permeability Multiplier of 20 Calculated Using Power Law

The distance to fault correlation was tested at different field-, region-, compartment- and well-levels and using a rock type-based approach. The rock type-based permeability modification approach gave most positive results and was selected for application during history matching.

Critical Water Saturation Modification

Critical water saturation (SWCR) played an important role in matching water production at a well level during dynamic modelling. SWCR modification was implemented at a rock type level, as for permeability multipliers.

Fault Seal Sensitivities

Faults from the static model were entered in the dynamic model. Two additional reservoir engineering, non-geologic barriers were introduced during history matching to refine the reservoir segmentation and improve the model history match. Sensitivities were performed on all sealing, partially sealing, and non-sealing faults/barriers.

Skin Modification

Historically, most UGMR wells were perforated and acid stimulated. The wells that had been acid stimulated were modelled by setting a skin value of -3 . Modifying the skin helped in matching FBHP and, after a number of sensitivities, the observed production data.

History Matching: West Region

There was a total of 17 wells in the West region in the history matching exercise. Most wells were drilled vertically initially and then later side-tracked. Recent wells had been drilled as highly deviated or horizontal.

Permeability modification and SWCR modification were determined to be key parameters in controlling the history match in the West region (see above). From the history matching it was found that less

permeability modification was required at the crest of West Central-Region 1, suggesting good quality, permeable matrix rock in that locality.

Specifying sealing faults between West Segment 2 and West Segment 3 and between West Segment 4 and West Segment 6 improved the pressure match in that region. Some of the faults within West Segment 2 were sealed to improve the match on pressure and rate. Figure 16 presents oil rate and pressure matches for selected wells.

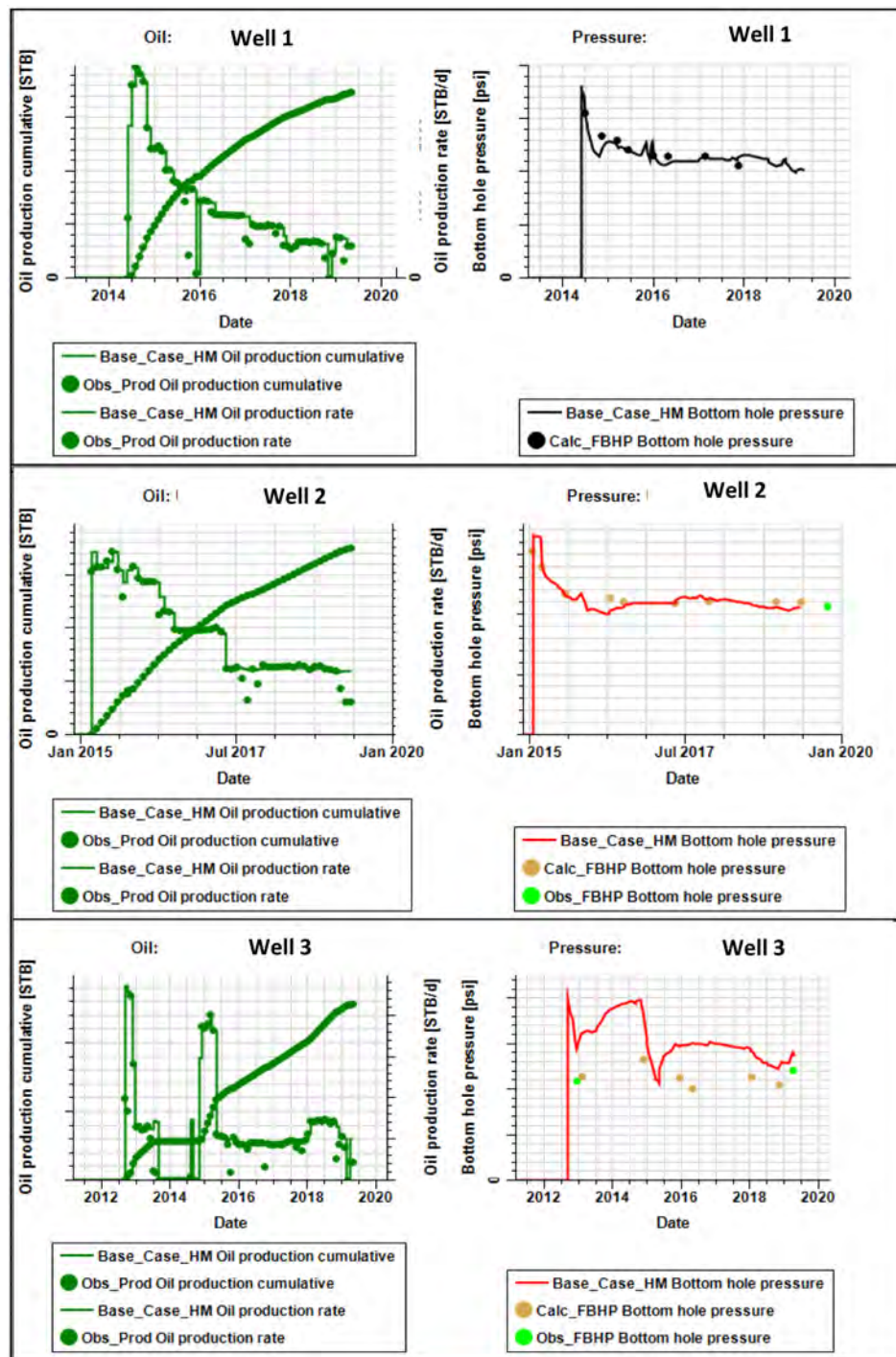


Figure 16—HM Oil and Pressure Plots for Selected West Wells

A good history match on oil rate and pressure was achieved for most wells. The history match on watercut was acceptable for most of West wells, as the West wells had either had no water production or watercuts of less than 1%.

History Matching: East and South Region

There was a total of 10 wells in the East region and three wells in the South region in the history matching exercise. Key parameters controlling the East region history match were found to be permeability modification and SWCR modification, as described above.

A good history match was achieved for most of the wells in the East and South region using field level modifications. Some wells required further well level permeability modification to achieve a good match.

Field Development Optimisation

The Marrat field had been developed via primary depletion with plans to implement a waterflood in the future. In order to formulate an optimum Field Redevelopment Plan, the next phase of the study involved using the history-matched dynamic model to assess the most highly-ranked well intervention and workover opportunities, the potential benefits of waterflood and options for Enhanced Oil Recovery (EOR). An EOR coarse screening exercise was therefore conducted to determine which options might merit detailed analysis via dynamic modelling studies.

EOR Coarse Screening

The coarse screening considered and ranked potentially viable EOR processes with respect to Marrat reservoir and fluid properties. The screening was based on criteria and experience in the literature (e.g. [Taber, 1997a, 1997b](#)). The positive and negative factors considered to be associated with each EOR process and conclusions drawn are summarised in [Table 2](#).

Following the EOR coarse screening exercise, it became apparent that 280,000 b/d of 5,000 ppm salinity sewage effluent water could be available as a potential source of low salinity flood injectant. The sewage effluent water might be available at low or no cost, although it would require transportation and biological and oxygen treatment and filtration. This provided further support for investigating the LSF process in greater detail.

Modelling Low Salinity Flooding

Background to LSF. Low Salinity Flooding (LSF) gained increased attention after trials at Prudhoe Bay demonstrated that it could lead to increased oil recovery ([McGuire, 2005](#)). More recent and current LSF projects include Clair Ridge ([Robbana, 2012](#)) and others (e.g. [Yousef, 2012](#); [Sorop, 2013](#); [Rotondi, 2014](#)).

There are differing explanations for the factors that lead to increased oil recovery and differing observations regarding the optimum injected water salinity and composition to achieve maximum reduction in Sorw (e.g. [Yousef, 2011](#), [Romanuka, 2012](#) and [Mahani, 2015](#)). It is nevertheless generally accepted that injecting lower salinity water can cause an alteration in rock surface charge which:

- Alters rock wettability, reducing Sorw
- Improves microscopic sweep
- Potentially enhances connectivity between micro- and macro-pores
- Can potentially yield an incremental oil recovery of around 7-18% of OOIP

From the literature and evidence from laboratory tests ([Lundegard, 2015](#); [Katende, 2019](#)), the mechanism that leads to the release of additional oil might be described as follows and illustrated in [Figure 17](#).

- Polar organic species in oil become attached to negatively charged rock surfaces via cation bridges.
- Electric double layer forms, comprising inner adsorbed layer of cations and outer diffuse layer of mainly anions.
- Under high salinity water, containing more ions, double layer is more compact.
- Reduced salinity brines are able to break organic molecules' attraction to surface by exchanging divalent cation (Ca^{++} or Mg^{++}) for a monovalent cation such as sodium (Na^+) carried in injection water.
- Electrostatic repulsion between rock surface and oil is increased.
- Oil particles become desorbed from rock surface and swept away.

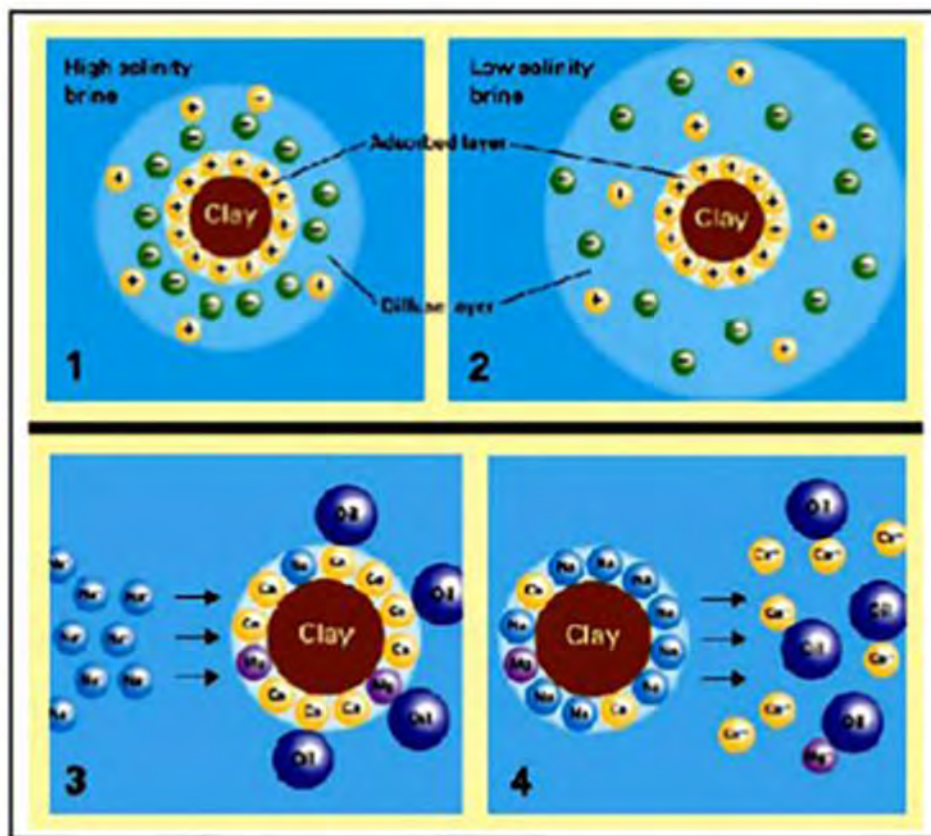


Figure 17—Mechanism for LSF Release of Additional Oil (Katende, 2019)

Different methodologies to dynamically model LSF are described in the literature (e.g. Al-Shalabi, 2013, Masalmeh, 2014 and Aljaberi, 2019).

Generating LSF Dynamic Model Input. The LSF data input in the dynamic model was based on data and results reported in two key technical references in the literature (Yousef, 2010 and Al-Shalabi, 2013).

(Yousef, 2010) describes core flooding tests that demonstrated increased oil recovery in composite carbonate cores by reducing the salinity of the flood water. Although the porosity and permeability of the composite cores were higher than typical UGMR porosity and permeability, the connate and flood water and oil compositions were similar to UGMR conditions. Hence, the (Yousef, 2010) paper provides a good analogue with which to generate data input for UGMR LSF dynamic modelling. Figure 18 illustrates the nature of the (Yousef, 2010) experimental results.

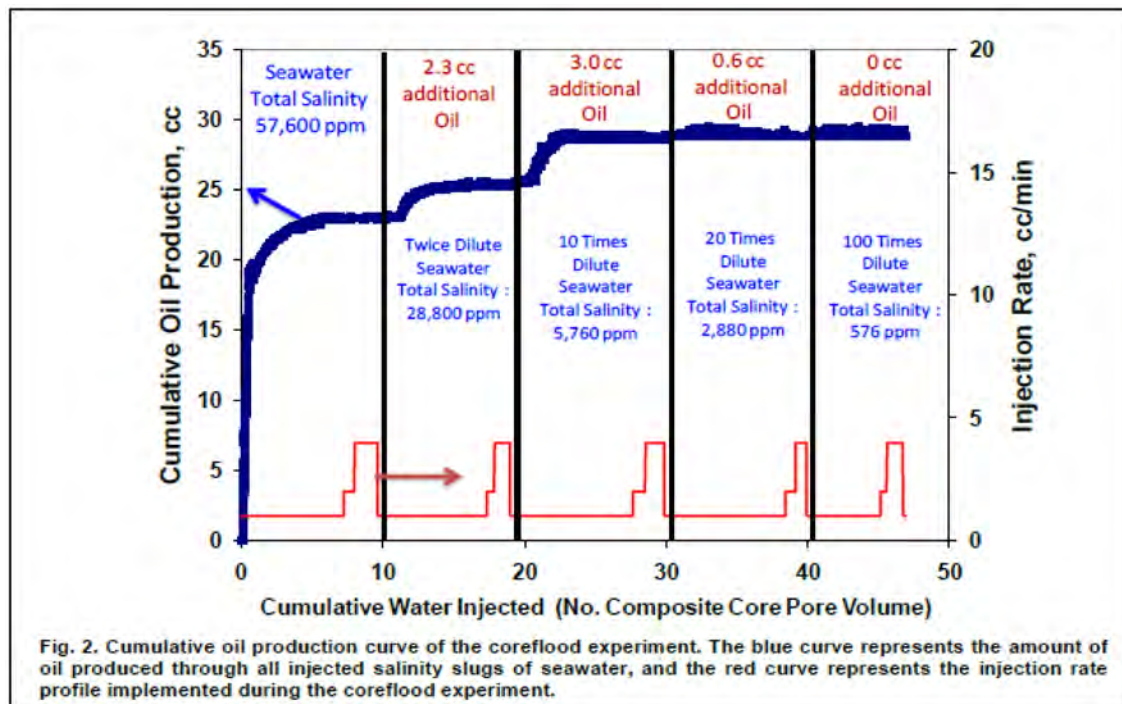


Figure 18—Illustration of experimental results demonstrating increased oil recovery from LSF, used as basis for dynamic modelling input (Yousef, 2010)

(Al-Shalabi, 2013) describes simulation history matching to better understand the mechanisms involved in the (Yousef, 2010) low salinity core flood tests. The history matching provided estimates of the changing values of water and oil relative permeabilities and Corey exponents during the core tests, as illustrated in Figure 19.

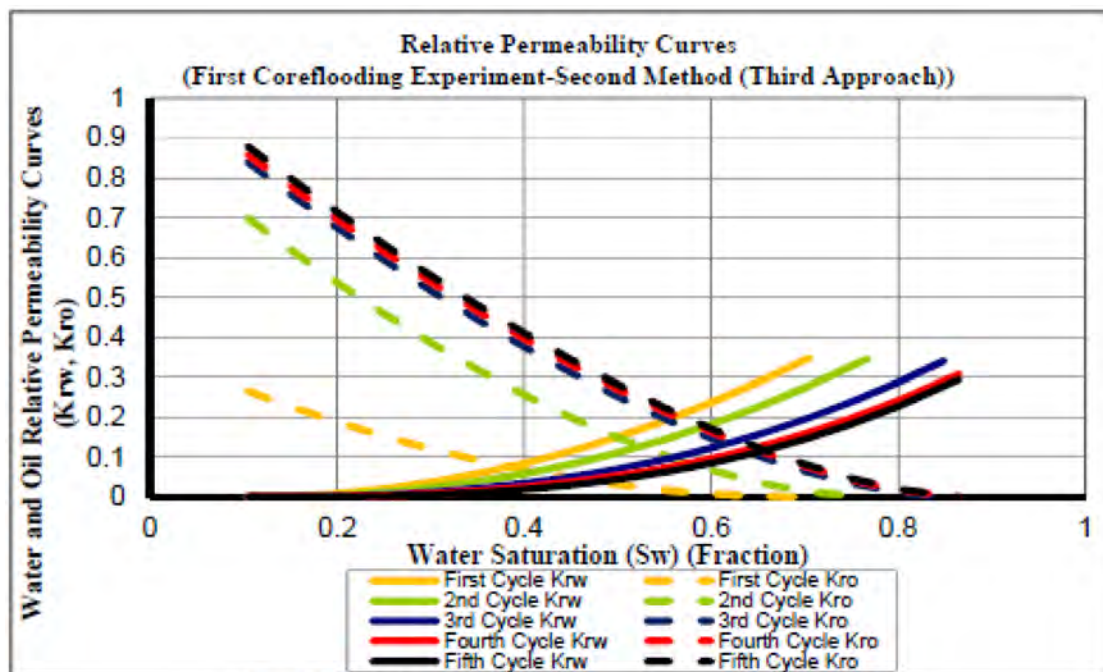


Figure 19—Illustration of low salinity core flood history matched results (Al-Shalabi, 2013).

Listed in Table 3 are (Al-Shalabi, 2013) modelling results that were selected as a basis for generating the necessary water relative permeability input to the LSF dynamic modelling studies (it was impractical to use the (Al-Shalabi, 2013) estimated changes to oil relative permeabilities). It was thus inferred that LSF at UGMR might reduce Sorw to around 50% and end-point water relative permeability to around 93% (average of 98% and 88%) of their expected values under conventional, high salinity flood (HSF).

The effect of applying the modifications to the "tight" (Limestone – 2 and Dolomite – Tight, ref. Table 1) and "good" (Limestone – 1 and Dolomite – Clean, ref. Table 1) rock type relative permeabilities is shown in Figure 20.

Table 1—Defined Rock Types

Rock Type	Depositional Facies	Comment
Limestone - 1	Grainstone, Wackestone, Packstone, Oolitic Grainstones	Diagenetic overprinting of the depositional fabric
Limestone - 2	Same as above (with lower porosity)	Diagenetic overprinting of the depositional fabric
Marl/Mudstone	Mudstone/Marls	Considered non/marginal reservoir
Dolomite - Clean	Dolomite, Dolomicrite	Higher porosity dolomite
Dolomite – Tight	Dolomite, Dolomicrite	Low-porosity dolomites
Anhydrite	Anhydrite	Non-reservoir

Table 2—Summary of EOR Coarse Screening Results and Conclusions

Gas Displacement	
The hydrocarbon gas minimum miscibility pressure (MMP) was estimated from correlations to lie in an approximate range 1,740-4,750 psia (Firoozabadi, 1986; Cronquist, 1978; Kuo, 1985; Sebastian, 1992), which indicated that reservoir repressuring could probably enable miscible conditions to be achieved.	
Positive	- Relatively few natural fractures - Few high permeability streaks - Gravity-stable gas displacement might be possible in attic or flank regions of reservoir.
Negative	- Risk of asphaltene precipitation (e.g. ref. Khaleel, 2015; Okabe, 2010; Sarma, 2003; Memon, 2012; Adyani, 2011) - Lack of obvious gas injectant supply
Conclusion	Need to gain understanding of waterflood performance and perform relevant laboratory tests before embarking on a gas displacement process.
Polymer	
Positive	None
Negative	- Needs to be implemented with waterflood - Low oil/water viscosity ratio, ~1.2 - Possible poor sweep efficiency - Reduced injectivity - High in situ brine salinity and low permeability contraindicated for success - High formation water Cl⁻ and Ca⁺⁺ & Mg⁺⁺ - Potential asphaltene precipitation - Would be economically challenging
Conclusion	Polymer fails EOR coarse screening.
Chemical (micellar/polymer, surfactant-polymer (SP), alkaline-surfactant-polymer (ASP), alkaline)	
Positive	Low reservoir clay content
Negative	Needs to be implemented with waterflood

Gas Displacement	
	- Needs to be efficient to be economical - Relatively inhomogeneous formation, probable poor sweep efficiency - High Cl^- and Ca^{++} & Mg^{++}
Conclusion	If low salinity flooding was implemented (see below), negatives associated with high salinity might be overcome such that it could be worth considering chemical-based EOR.
Low Salinity Flooding (LSF)	
Positive	- Evidence of increased oil recovery from LSF projects (see below) - Generally accepted that LSF can reduce residual oil saturation to waterflood (Sorw) if reservoir conditions suitable - Might enable subsequent SP/ASP EOR (see above)
Negative	- Differing views on LSF mechanism and optimum injected water salinity - No Marrat LSF core tests - No conventional waterflood baseline - Possible poor sweep efficiency
Conclusion	LSF passes EOR coarse screening and warrants scoping dynamic modelling analysis.

Table 3—Core Flood Modelling Results Used to Generate Dynamic Model LSF Data Input

Injection cycle	Flood water salinity ppm	First core flood		Second core flood
		Interpreted Sorw	Interpreted krw'	Interpreted krw'
1 st	57,600	0.295	0.349	0.466
2 nd	28,800	0.233	0.346	0.440
3 rd	5,760	0.151	0.341	0.410
Reduction, 1 st to 3 rd cycles	90%	49%	2%	12%

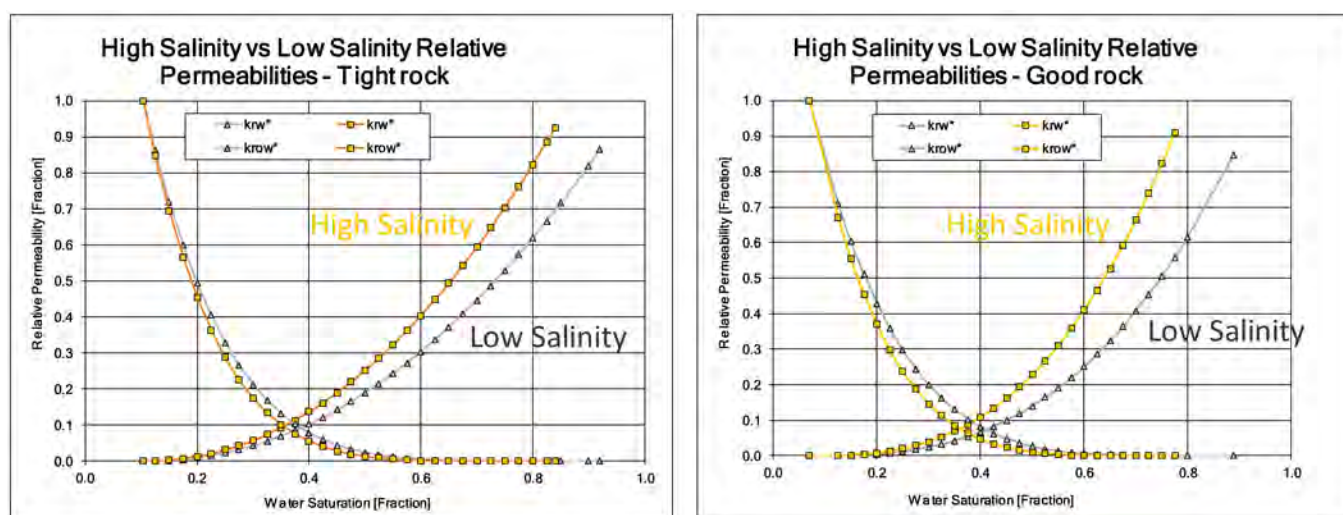


Figure 20—Comparison between dynamic model relative permeabilities under LSF and HSF

Modelling LSF in Dynamic Model. Various keywords were used to model LSF in the dynamic model. LOWSALT switched on the BRINE option, enabling mixing of waters with different salinities to be modelled. Relative permeabilities were interpolated between HSF and LSF end-members, according to prevailing water phase salt concentration. Salt concentration in the water phase also determined modified

values of water density and viscosity. The LWSLTNUM keyword defined low salinity saturation regions, associated to additional SWOF and SGOF table entries.

Dynamic Model Field Development Predictions

The history-matched dynamic model was used to examine nine field development cases, summarised in [Table 4](#) also

Table 4—Dynamic Model Prediction Results Summary

Cases	Summary details	Incremental EUR at 2070 compared to Base Case (%)
Base	No further activity	0
Base Maintained	Incl. well interventions & workovers	3
Planned	Incl. additional producers	11
Potential HSF	Incl. injectors	92
Potential LSF	Incl. injectors	102
Potential Optimised HSF	Relocated & switched wells	114
Potential Optimised LSF	Relocated & switched wells	130
Aggressive HSF	Additional producers & injectors	193
Aggressive LSF	Additional producers & injectors	211

The top five well interventions and workovers were ranked using simulation. It was predicted that a particular well frac design would yield the highest incremental gain.

A total of 13 (pre-drilled) vertical injectors were added to the Planned case as of 1st January 2027 to create the Potential prediction case. All the injectors were vertical with previously-specified locations. The injectors were controlled on maximum BHP using local guidelines and considering reservoir pressure uncertainties.

The Potential prediction case was optimised by replacing one producer in the East with one producer in the West in 2020 and replacing two injectors with two producers in the West. One injector was moved from the East to the South and six injector locations were changed.

The Aggressive prediction case was the Potential Optimised case plus 16 additional producers and 17 additional injectors. It assumed an aggressive drilling programme between 2029 and 2036 during which wells would be drilled bi-annually.

An Opportunity Index methodology ([Molina, 2009](#)) was used in conjunction with net oil and oil saturation maps to determine new target locations in the Potential Optimised and Aggressive prediction cases.

There was a good match between the dynamic model Base case and DCA 5-year predictions (see above), tending to corroborate the dynamic model predictions.

The dynamic modelling results in terms of estimated ultimate recovery (EUR) expressed as a percentage compared to the Base Case are also summarised in [Table 4](#). Forecast cumulative oil production is presented in [Figure 21](#).

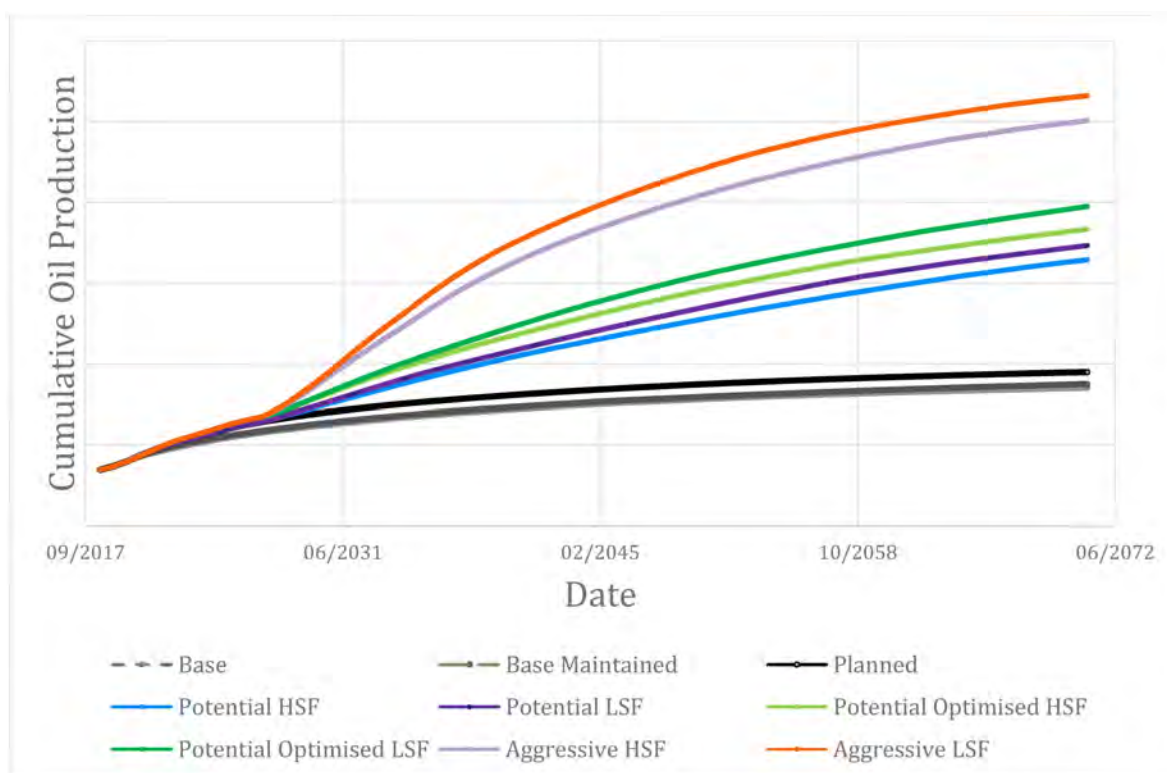


Figure 21—Dynamic Model Cumulative Oil Production Predictions

The forecasts show a modest increase in estimated ultimate recovery (EUR) as at 2070 for the Base Maintained case, compared to the Base case. There was a more significant increment for the Planned case and further, more significant increments for the Potential, Potential Optimised and Aggressive waterflood cases. In all cases where LSF was compared to HSF, LSF gave a higher oil recovery than HSF.

LSF Practical Considerations

The dynamic modelling demonstrated potential for LSF to increase oil recovery compared to conventional (HSF) waterflood. However, there are other practical and economic aspects to consider.

Figure 22 shows, for illustration, the Aggressive case predicted increased field-level water production and consequent water injection volumes resulting from LSF, in comparison to HSF. These arise from the lower LSF viscosity causing a less stable displacement within the reservoir, leading to earlier water breakthrough and more rapid water production increase.

Hence, surface facility issues to take into consideration in the assessment of an LSF scheme might include:

- Expensive desalination facilities may be required if low cost LSF injectant is unavailable.
- Lower salinity produced water may cause slower oil-water separation.
- Fresher produced water may lead to more stable emulsions forming in the surface facilities.

By contrast, lower salinity produced water is likely to reduce water scaling problems.

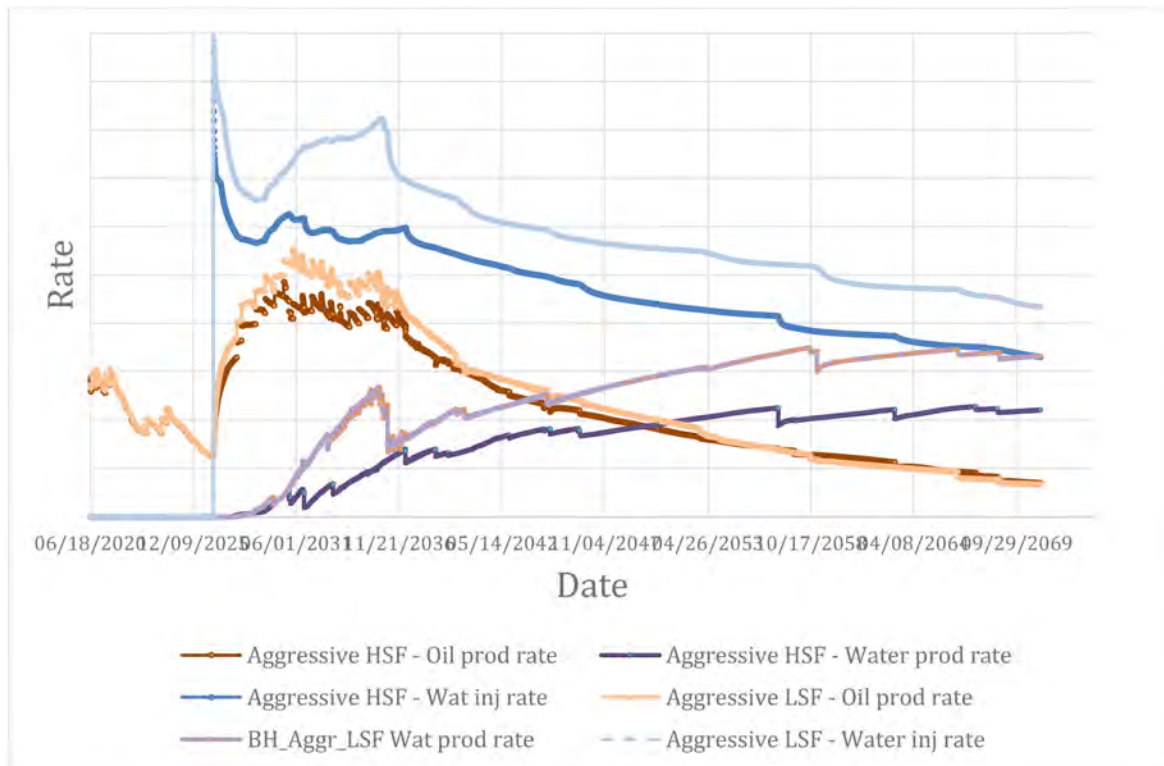


Figure 22—Aggressive Prediction Case – Field Oil and Water Production and Injection Rates

Reduced Carbon Footprint

Increasing efforts are being made worldwide to address concerns related to CO₂ emissions, to meet climate change targets and comply with regulations. It is generally agreed that oil and gas production will continue to play an important role during the transition to a future, low carbon energy system. Oil and gas companies are placing greater emphasis on decarbonising their operations, e.g. by employing new upstream processes and technologies to reduce CO₂ emissions associated with ongoing and new oil and gas field developments (Beck, 2021).

The symbiotic use of low salinity sewage effluent from pre-existing water processing facilities in a Marrat LSF EOR project would reduce the project's overall carbon footprint, energy requirements and environmental impact, i.e. in comparison to an alternative of constructing new desalination and water treatment facilities to generate low salinity injection water from either sea water or saline water produced from the subsurface via recompleted or newly drilled and completed wells.

This approach offers a potential solution to increase oil recoveries while reducing the associated carbon footprint of oil field developments where LSF may be an option. This in conjunction with other downstream and end-use processes and technologies may facilitate the progression to a future, low carbon energy system.

Conclusions

The integrated field studies led to the following key outcomes and conclusions:

- That rock types based on depositional facies or textural descriptions cannot be used to describe reservoir quality due to the impacts of diagenetic overprints and fracturing in proximity to faults.
- Instead, a revised facies classification was generated from hand-drawn facies logs, consolidating previous interpretations and core observations, and expanded to non-cored wells using a neural net. The resulting facies were distributed in the static geological model with the aid of a Bayesian facies classification based on pre-stack seismic inversion.

- A revised fault model based around a structural interpretation that considers the tectonic history of the area was generated, allowing segmentation of the field based on fault/fluid contact relationships, and the use of a "distance to fault" property as a proxy for natural fracturing based on observed data from the wells.
- The UGMR dynamic model history match was achieved within acceptable limits, without recourse to pore volume modification or addition of aquifer models.
- The history match modifications were validated by geological observations:
- Nine dynamic model prediction cases were run through to 2070.
- The dynamic model predictions demonstrated potential benefit from interventions and workovers and that waterflood might significantly benefit UGMR oil recovery, while LSF offered promise and should be investigated in more detail.
- A good match between the Base case and DCA 5-year predictions tended to corroborate the dynamic model predictions.
- An "Opportunity Index" approach was successful in optimising well types and locations.
- LSF model input based on analogue data in two key technical papers was sufficiently robust for initial UGMR scoping studies.
- LSF could enhance the UGMR oil recovery but surface facility considerations also need to be considered in an overall project analysis.
- Specialised LSF core and fluid compatibility laboratory tests should be conducted in conjunction with an LSF pilot trial, prior to progressing to a larger-scale field redevelopment project.
- The symbiotic use of available, low cost sewage effluent as an LSF injectant offers a novel and attractive solution to reduce the overall project carbon footprint and help progress towards a future, global low carbon energy system.

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