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Master Thesis 2018 supervised by:
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Improvement of a Full Field Reservoir Model for a MEOR Application

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To my family and my best friends

Specially my lost father

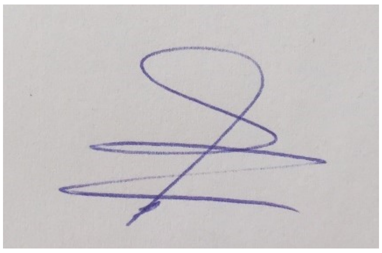
This thesis is dedicated to my best friends who have always been a constant source of support and encouragement during the challenges of my whole study life particularly my friends in Leoben. In addition, to my mother and my sister whom I am truly grateful for having in my life. This work is also dedicated to my lovely family who have always loved me unconditionally and whose good examples have taught me to work hard for the things that I aspire to achieve. At the end, I would like to say special thanks to my dear friends Fereshteh and Neda for the whole support and aid during this time.

Declaration

I hereby declare that except where specific reference is made to the work of others, the contents of this dissertation are original and have not been published elsewhere. This dissertation is the outcome of my own work using only cited literature.

Erklärung

Hiermit erkläre ich, dass der Inhalt dieser Dissertation, sofern nicht ausdrücklich auf die Arbeit Dritter Bezug genommen wird, ursprünglich ist und nicht an anderer Stelle veröffentlicht wurde. Diese Dissertation ist das Ergebnis meiner eigenen Arbeit mit nur zitierter Literatur.



Nazika Moeininia, 26 September 2018

Acknowledgements

The Master's Thesis has been carried out during the summer semester of 2018 in Witershall GMBH Company, EOR Department, The Technology and Innovation Section, MEOR Project.

First and foremost I would like to express my sincere gratitude towards my supervisors Dr. Hakan Alkan, Project Manager of MEOR Project at Wintershall GMBH Company and Zubair Ahmad Khan, Reservoir Engineer at Wintershall GMBH Company, and Professor Holger Ott, Head of The Chair of Reservoir Engineering, at Montanuniversitaet Leoben, for their guidance, discussion and valuable insights throughout the completion of Master's Thesis. In addition, I would like to thank all of my colleagues at Wintershall GMBH Company for their support and help during my work with this thesis.

Abstract

Microbial enhanced oil recovery (MEOR) is a biotechnology-based oil recovery method which involves the use of microorganisms and their metabolic products (metabolites) to enhance oil production from the screened mature oil reservoirs. One of the work packages of the technology project "MEOR studies" being conducted by Wintershall is the numerical predictions of the planned pilots and potential field applications. Field simulation model must be developed for launching the MEOR field pilot and plan next steps. Meanwhile, multi-well test (MWT) was planned to implement in the last part of this integrated project, and a tracer injection was designed and conducted to investigate the reservoir characterization and the connectivity between injection and production wells due to water breakthrough time. According to the old reservoir simulation model, the tracer predictions results could not match the actual tracer results in producers potentially due to the flow barriers and unpredicted heterogeneity. The issue revealed the necessity of seismic re-interpretation to improve the knowledge of the reservoir. The primary objective of this thesis is to re-establish the reservoir simulation model according to the revised seismic interpretation serving the acceptable reservoir description.

This thesis work focuses mainly on manual history matching carried out on the full field model improved with new geologic interpretations. The implementation of this reservoir simulation model has encountered the inevitable challenges which are described in the context including data collection and data accuracy regarding the high number of wells in this field and nearby field; high uncertainty in production and injection data and surveillance data; reservoir simulator issue; QC of the exported data file form the static model, and the structural model uncertainty. After a global match succeeded, the utilization of assisted history matching which aids in accelerating the history matching process can provide an algorithmic framework to minimize the mismatch and improve the simulated results. Sensitivity analysis was carried out to determine the most critical dynamic parameters that affect the adjustment between the simulated model and the known performance of the field. The new reservoir model obtained with the preliminary history matching is used then for the improved predictions in MWT location of the ongoing project. A sector model representing the MWT location was created. The tracer operation was modelled, and the results were compared with the results of the previous model. The last focus of this thesis is on the sensitivity analysis of the tracer simulation to provide the realistic interpretation of inter-well connectivity and optimize the flood parameters in the proposed well-sidetrack.

Zusammenfassung

Microbial Enhanced Oil Recovery (MEOR) ist eine auf Biotechnologie basierende Methode zur Erdölgewinnung, bei welcher Mikroorganismen und deren metabolischen Produkte (Metaboliten) verwendet werden, um die Menge an produziertem Öl aus erschöpften Lagerstätten zu erhöhen. Eines der Arbeitspakete des technischen Projektes „MEOR studies" welches von Wintershall durchgeführt werden, ist die numerische Prognose von geplanten Pilotprojekten und potentieller Anwendungen im Feld. Simulationsmodelle des Feldes müssen zum starten des MEOR Pilotprojektes und zur Planung der weiteren Vorgehensweise entwickelt werden. Währenddessen wurde die Durchführung von multi-well tests (MWT) im letzten Part des integrierten Projektes geplant und die Injektion eines Tracers entworfen und durchgeführt, um die Lagerstätten Eigenschaften, sowie die Verbindung zwischen einpressender und produzierender Bohrung aufgrund der Wasser Durchbruchzeit zu untersuchen. Gemäß der alten Lagerstättensimulationsmodelle übereinstimmen die Tracer Vorhersagen nicht mit den tatsächlichen Ergebnissen in der produzierenden Bohrung möglicherweise aufgrund von Durchflussbarrieren und unvorhergesehener Heterogenität. Dieses Problem zeigte die Notwendigkeit der Neuinterpretation der Seismik auf, um die Erkenntnisse über die Lagerstätte zu verbessern. Das Hauptziel dieser Arbeit ist der erneute Aufbau des Lagerstättensimulationsmodells gemäß der überarbeiteten seismischen Interpretation basierend auf einer angemessenen Lagerstättenbeschreibung.

Diese Arbeit beschäftigt sich hauptsächlich mit manuellem History Matching, welches mit dem verbesserten Ganzen Model mit neuer geologischer Interpretation ausgeführt wurde. Die Implementierung dieses Lagerstättensimulationsmodells stieß auf unvermeidbare Herausforderungen, wie die Datenerhebungen und Genauigkeit dieser von den vielen Bohrungen des Feldes und von einem benachbartem Feld; hohe Ungenauigkeiten der Produktions-, Injektions- und Überwachungsdaten; Simulationsprobleme; Qualitätskontrolle der exportierten Datein vom statischen Modell und die Ungenauigkeiten des strukturierten Modells, welche im Rahmen dieser Arbeit beschrieben sind. Nachdem eine allgemeine Übereinstimmung erfolgreich war, wurde unterstützendes History Matching verwendet, welches hilft die History Matching Prozesse zu beschleunigen und einen algorithmischen Rahmen zur Minimalisierung von Diskrepanzen und Verbesserung der Simulationsergebnisse zur Verfügung stellt. Sensitivitätsanalysen wurden durchgeführt um jene dynamischen Kenngrößen herauszufinden, welche die Anpassung des Simulationsmodells an die tatsächlichen Ergebnisse am meisten beeinflussen. Das neue Lagerstättenmodell, welches von den vorläufigen History Matching Ergebnissen kommt, wurde benutzt für die verbesserten

Vorhersagen der MWT Standorte des laufenden Projektes. Ein Abschnittsmodell repräsentativ für die MWT Standorte wurde erstellt. Die Tracer Operation wurde modelliert und die Resultate, wurden mit denen des vorherigen Models verglichen. Der letzte Schwerpunkt dieser Arbeit liegt in der Sensitivitätsanalyse der Tracer Simulationen, um realistische Interpretationen der Verbindungen zwischen Bohrungen und Optimierung der Flutungskenngrößen in den beabsichtigten Bohrablenkungen zu ermöglichen.

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Nomenclature

Kx	Permeability in X direction	[md]
Ky	Permeability in Y direction	[md]
Kz	Vertical Permeability	[md]
Pws	Static Pressure	[bar]
Pwf	Flowing well Pressure	[bar]
OOIP	Original oil in place	[MM sm3]
H	Depth	[mTVDss]
FVF	Oil formation volume factor	[Rm3/Sm3]
P_b	Bubble point pressure	[bar]
P_c	Capillary pressure	[bar]
P_{cow}	Oil-water capillary pressure	[bar]
μ	Viscosity	[cP]
φ	Porosity	[-]
OF	Objective Function	[-]

Abbreviations

AHM	Assisted History Matching
BHP	Bottom Hole Pressure
EOS	Equation Of State
FVF	Formation Volume Factor
GOR	Gas Oil Ratio
Hnf	Huff and Puff
QC	Quality Control
LSB	Lower Saxony basin
MWT	Multi Well Test
MDT	Modular Dynamic Test
RFT	Reapeat Formation Test
RMS	Root Mean Value
SGS	Sequential Gaussian Simulation
THP	Tubing Head pressure
TVDSS	True Vertical Depth Sub Sea
PLT	Production Logging Tools
PVT	Pressure, Volume, Temperature
ppt	parts per trillion
VCL	Volume of Clay Log
VFP	Vertical Flow Performance
WC	Water Cut
WEFAC	Well Efficiency Factor
WOC	Water Oil Contact
WOR	Water Oil Ratio
WPI	Well Productivity Index

Chapter 1

Introduction

Microbial Enhanced oil recovery (MEOR) is presented as one of EOR application based on feeding either injected or in-situ bacteria with nutrients. As a part of on-going Wintershall project “MEOR Studies”, this thesis aims to establish a new reservoir simulation model with respect to seismic re-interpretation and updated static model improving history matching in full field. The main goal of last work package presented by Alkan et al (2014) corresponds to the design of MEOR pilot operation in form of a multi well test (MWT) as a field application. Hence, prior to field application objective, it is essential to develop a numerical simulation being capable of simulating MEOR process in the field scale.

This thesis considers improvement of reservoir simulation model in the full field. To achieve this goal, understanding of reservoir is regarded as a priority. To proceed the realistic history matching, all dynamic and static input data to the model should be substantially scrutinized in order to eliminate inaccurate data, which are not representative of the reservoir. Data validation can lead to faster converge towards a match, this step is accounted prior to initiate the history matching.

In this thesis, by using the new developed simulator Tnavigator incorporating complete work package, the reservoir model is designed based on geological model and further work executed on two different modules, reservoir simulator and assisted history matching module. The common workflow in the simulation study is described in this thesis to generate a dynamic reservoir model and validate all available information to be able to make more accurate production or tracer forecast. Data source in the simulation model is associated with inherent uncertainty. It is important to work out a set of study objectives in order to gain knowledge about the interest field how to make perturbation in history matching parameters.

After global history matching, optimization method or assisted history matching is executed on the improvement of the calibrated historical performance and simulated one.

The last objective of this thesis is tracer simulation in terms of MWT plan. The principal benefit of tracer applications is to quantify the inter-well reservoir connectivity that improves reservoir description and prediction in MEOR field application. To assess the inter-well connectivity, sensitivity analysis of tracer simulation is conducted to derive the results in drilled wells and proposed well sidetrack in MEOR pilot plan.

Chapter 2

Literature Review

2.1 History Matching

History matching is a procedure of making one or more set of numerical models representing a reservoir that account for measured and observed data. During model calibration process, it is worthy to note that history matching is undertaken for the purpose of decision-making and serves no purpose on its own. Additionally, reservoir models are assumed to be only model not reality. Therefore, there are inevitable approximations and errors, which are definitely found in any model of physical phenomena. The other important issue that is associated with reservoir model is relevant to model input. The model input has an inherent uncertainty and usually underestimated.

The history matching process constitutes a crucial phase in reservoir modeling and simulation process, where one intends to find a reservoir description; meanwhile, the difference between observed performance and simulator output must be minimized. It is one of the most computationally demanding issues in the reservoir simulation. The challenge called inverse problem with non-unique solution can be conventionally resolved by tuning selected uncertain reservoir parameters on the same time (Caers J., 2003) & (Schiozer D. J., 2005). This procedure nominated manual history matching can be iteratively carried out to reach an acceptable match between observation data and simulation results. Production forecasting and predictions of future reservoir performance will derive as a result of history matching.

The main objective is to create a reservoir model integrating all available information to be able to reduce the uncertainties on reliable production forecasts. Reservoir history matching is defined as an iterative process that involves using of the dynamic observed data (bottom hole pressure, oil, water and gas saturation, flow rates, etc) to estimate reservoir rock properties (porosity, permeability, etc) (Hoffman B. T., 2006) & (Maschio, et al., 2015). It is crucial for reservoir models to have an accurate description. However, a multitude of obstacle could be encountered during the history matching process to achieve an adequate match to the field data. The non-linear relationship between the reservoir properties and dynamic data can cause the non-unique history matched solutions (Woan J. T., 2012). The spatial heterogeneity and anisotropic nature of reservoir rocks can result in very large dimensionality of the reservoir model, which make this task more complex. As history matching can contribute to and understanding of current status of reservoir including fluid distribution and fluid movement, perhaps it can be functional for verification and identification of current depletion mechanism.

2.2 Manual History Matching Strategy

Periodic observation of shut-in bottomhole pressure (Pws) are predominantly available and more reliable than bottom hole pressure flowing (Pwf) for history matching purpose. Shut-in surface pressure can be more advantageous if accurate fluid levels and gradients are accessible to correct pressure to bottomhole conditions. It is imperative to be aware of the quality and the relative accuracy of rate and pressure data. These data should be plotted on a well-by-well basis to identify and to remove any obvious data inconsistencies.

Even though, field measured injection and production are commonly used without alteration, in some special cases, where it might be appropriate to assume that historical injection or production rates show partly error and require for adjustment. In general, the oil production rates can be precisely measured in the field; however, gas production measurements are not accurately reported particularly in old fields, especially if the gas has been flared. Injection data tend to be less precise than production data not only because of measurements error but also fluid loss as a result of casing leak or flow behind the pipe. These errors are not subject just for injection data; meanwhile, it can occur for production data; however, they are regularly found out and corrected.

Commonly, the appropriate match would be expected at the field level, average field pressure might differ from average model pressure a little; however, the quality of match will normally be poorest at the sub region or individual well level. Even though, no standard matching criteria exist, the quality of match can be judged by whether the reservoir model is good enough to permit the objectives of the study to be met (Mattax C. and Dalton, 1990).

In traditional manual history matching, the model calibration has generally been executed on a single deterministic model by using sequential trial and error to adjust reservoir model through sensitive parameters. Besides, regional flow units allow local parameters associated with flood front progression, reservoir energy, and afterwards individual well performance (Williams, 2004) & (Williams M.A., 1998). To put it simply, identification of known parameters with the most uncertainty based on knowledge and experience is widely used to achieve consistent match with the reality. Especially for large fields, manual history matching is tediously long process. It would be impossible to investigate about the relationships between the model responses and variations of different reservoir input parameters. History matching process is summarized in **Table 1**.

Table 1: Stepwise description of a history matching process (Ertekin T., 2001)

1	Define objectives for the history matching process
2	Determine what method to use for history matching. This should be dictated by the objectives of the history match, resources available for the history match, the deadlines for the history match and the data available.
3	Determine the historical production data to be matched and the criteria to be used to describe a successful match. These should be dictated by the availability and quality of the production data and by the objectives of the simulation study.
4	Determine what reservoir parameters that can be adjusted during the history match and the confidence range for these. The parameters to be chosen should be those least accurately known with the most significant impact on reservoir performance.
5	Run the simulation model with the best available input data.
6	Compare the results of the history match run with the historical production data chosen in step 3.
7	Make changes to parameters selected in step 4 within the range of confidence in order to improve history match.
8	Repeat steps 5 through 7 until the criteria established for a successful match in step 3 are achieved.

2.2.1 Establishing Realism in the Initial Reservoir Model

The preliminary step prior the initialization of history matching process is to assess how well the reservoir model is representative of actual reservoir. The initial reservoir model needs to incorporate the best available static and dynamic data in the reservoir. Reservoir simulation is usually started to reservoir characterization which bringing together diverse of information and expert opinions to develop a most realistic reservoir model (Gilman J. R., 2013). This information can form the foundation for the reservoir description and the prediction of future performance. It is stated that if the reservoir characterization is close to reality, thereby the history matching process can be sped up and converged towards the match more rapid than the poor reservoir description (Gilman J. R., 2013).

2.2.2 Adjusting of History Matching parameters

History matching is often an expensive, time consuming process since reservoir performance can be complex, meanwhile numerous interactions could be difficult to realize (Mattax C. and Dalton, 1990). Common practice has offered to choose and alter parameters, which are considered as the most uncertainty in the reservoir and consistent with reservoir description

(Ertekin T., 2001). A summary of issues involved in history matching process is listed as **Table 2**.

Table 2: Issues making history matching difficult (Gilman J. R., 2013)

1	History matching is an ill conditioned mathematical problem which is non-unique and infinite set of solutions, if considered as an inverse problem
2	Non-linearity of most models is strongly proved which means that not easy or even possible to clearly isolate changes in the output data to alter in input data
3	The key input parameters can contribute the output in such way to improve the history matching is not always apparent.
4	Extensive sensitivity studies are generally required to gain a good understanding of the reservoir model
5	Some input parameters are stochastic in the nature, particularly data describing the geological scenario
6	Production data are inherently biased particular old data and often associated with the large errors

2.2.3 Matching Criteria

No standard matching criteria exist to obtain an accurate matched reservoir model. The criteria should be determined on the basis of the required accuracy of simulated production forecast with the matched model. The necessity of using different matching criteria based on inherent uncertainty and the degree of contribution in the performance of reservoir can be helpful to reduce uncertainty as much as possible in the reservoir (Baker, 2006). It can be generally acceptable if the trend of reservoir performance is matched, and subsequently, it can imply that derive mechanisms and reservoir physics are correctly represented. Model performance can be evaluated in either field levels or individual levels. Nevertheless, field performance match should be expected to illustrate closer match to the recorded performance data than individual wells (Mattax C. and Dalton, 1990). When history matching is regarded as a successful model and meet the tolerance of matching criteria, the reservoir performance can be predictable with high accuracy and less uncertainty.

Baker et al 2006 proposed to establish a collection of matching criteria that should be assumed to judge about the degree of success in history matching. Tabulated matching criteria are commonly used as a guideline to set up the tolerance of appropriate criteria (**Table 3**).

Table 3: Matching criteria used to describe a successful history match (Mattax C. and Dalton, 1990)

Parameter	Matching criteria
Production rate (oil, gas or water)	+/- 10%
Cumulative production (oil, gas or water)	+/- 10%
Bottom hole flowing pressure	+/- 20%
Field average pressure	+/- 10%

2.2.4 Simulation Approach for History Matching

Selection of history matching parameters is normally carried out according to uncertainty. Adjustments should be applied for those parameters with the highest uncertainty as listed in the hierarchy of uncertainty (Fanchi J.R., 2006). According to Crichlow 1977, the variation of several parameters is done singly or collectively to minimize the difference between observed data and simulated one can be modified as **Table 4**:

Table 4: Change of parameters

Rock data Modifications	Fluid data Modification	Relative Permeability Data	Individual well completion data
Permeability Porosity Thickness Saturations	Compressibility PVT data Viscosity	Shift in relative permeability curve Shift in critical saturation data Corey exponents	Skin effect Bottom hole flowing pressure

Mattax and Dalton (1990) outlined order of priorities and rarely alteration for some parameters. Therefore, the reservoir and aquifer properties can be varied to diminish the order of uncertainty at first of mutation. **Table 5** shows general sensitive parameters to reduce the uncertainty; however, these criteria are typically dependent on the field of study.

Table 5: General history matching parameters in order of decreasing uncertainty (Ertekin T., 2001)

1	Aquifer transmissibility, kh	
2	Aquifer storage, Φhct	
3	Reservoirpermeability thickness, kh	Vertical flow barriers and high conductivity streaks permeability anisotropy, kv/kh
4	Relative permeability and capillary pressure function	
5	Reservoir porosity and thickness	
6	Structural definition	
7	Rock compressibility	
8	Oil and gas properties (PVT)	
9	Fluid contact	
10	Water properties	

As a general rule, these parameters which are listed in **Table 6** can affect fluid flow or volumetric parameters. It can be seen that the uncertainty is volumetric parameters can effectively be addressed and reduced from material balance calculations and decline curve analysis (Gilman J. R., 2013). Whereas, fluid flow parameters should be adjusted during history matching process.

Table 6: History matching parameters affecting fluid flow or volumetric parameters (Gilman J. R., 2013)

Volumetric parameters	**Fluid Flow Parameters**
Compartmentalization	Flow barriers
Fluid contacts	High permeability streaks
Drainage capillary pressure curve and	Conductive faults
endpoint	Permeability distribution
Pore volume	Fracture properties
Aquifer properties	Porosity distribution
Leakage or fluid loss	Matrix fracture exchange
Fluid influx	Saturation function end points
Pore volume compressibility	Imbibition capillary pressure curves
Fluid composition distribution	Relative permeability curves.
PVT properties	

2.2.5 Consideration and Constraint in the Reservoir Model

Some historical performance data must be available to perform history match. By using well constraint in the simulation, the wells with a chosen type of performance data can be able to compare the calculated model response with any other available data (Ertekin T., 2001). A dynamic model reflects the discretized version of partial differential equation that can depict multiphase flow within reservoir. It is required to set up boundary of conditions in addition to the initial conditions during initialization to acquire a solution, similar to solving partial differential equation. Boundary conditions can be specified as either Dirichlet type or Neumann type. A Dirichlet type determines the pressure either tubing head pressure or bottom hole pressure, whilst a Neumann type identify the rate of a given phase produced from the reservoir (Gilman J. R., 2013). The most commonly used boundary condition or well constraint is to specify the production rate of individual wells. However, the choice of production data to determine is very dependent on the present hydrocarbon in the reservoir. If oil were produced in the reservoir, it would be common to use the oil rate as a well constraint or similarly for gas field. Nevertheless, this constraint allocation could be water rate or gas rate, if high gas rate (GOR) or water rate (WC) are produced (Ertekin T., 2001). Pressure sensors are rarely installed downhole to record continuously pressure performance data. Thus, pressure as a well constraint is infrequently used. The main reason to specify oil rate is to account for the most valuable production and being more readily available (Gilman J. R., 2013).

When constraining wells with a given phase rate, the simulator will honor the specified phase rate. Hence, the main goal of history matching becomes to represent accurately production of the unspecified phases. By using plot to view the cumulative production of all phases, GOR, WC, historical and calculated rate, any mismatch between reservoir model and the historical data will easily be spotted one the defined plot. Furthermore, phase ratio plot for instance water cut and gas oil ratio can illustrate the breakthrough time of a given phase, relative mobility of phases and verification of displacement efficiency. As a result, it can assist to recognize any vertical and lateral flow barriers (Gilman J. R., 2013). Besides, displacement efficiency can be evaluated through breakthrough time, which is obviously related to geology, zonation, inter-well transmissibility and mobility ratio (Ertekin T., 2001). Gas oil ratio is experienced to be strongly dependent on PVT characteristics (Gilman J. R., 2013). A sudden increment in GOR behavior can imply that reservoir pressure around the well has fallen below bubble point pressure, then two phases will be appeared due to come out gas from solution.

Generally, static pressure that obtained from observation wells or pressure transient analysis can be employed for history matching. Build up pressure analysis can provide valuable interpretations which will elaborate permeability-thickness, average reservoir pressure, flow regime, skin and reservoir geometry. Accordingly, the reservoir model should be modified in order to reflect pressure transient analysis results (Gilman J. R., 2013).

Pressure versus depth profile commonly obtaining from repeat formation test (RFT) and modular dynamic test (MDT) can provide an important information about fluid contacts. If the mentioned profile is set up before the beginning of production, the fluid contact will be most likely detected such as water oil contact and gas oil contact (Gilman J. R., 2013). In mature field, the discontinuity in the pressure gradient have a capability to characterize bypassed zones and vertical flow barriers. To improve the confidence of the calculated phase rates, it is essential to match measured bottom hole pressure (BHP) or tubing head pressure (THP). To specify vertical flow performance (VFP), the table should be incorporated to apply THP in the model. This table account for pressure loss between wellhead and reservoir through the tubing that elaborate robust function of flow rates, phase ratio, fluid properties and artificial lift projects applied to wells (Gilman J. R., 2013).

Production logging tools (PLT) is calibrated with reservoir simulation and give noteworthy information to identify or match zonal contributions, fine tunes parameters and align the model with the empirical performance data. Saturation profiles along wells can be achieved from petrophysical log interpretation and it can be compared against the simulated saturation profile of wells to verify the fluid distribution within the reservoir model, although it will be helpful only qualitatively due to difference in scale (Gilman J. R., 2013).

2.2.6 How to Apply Manual History Matching

The process of history matching is based on exclusively on manual changes to preselected history matching parameters. It is required to run firstly the entire historical period to establish a comparison of the simulated model to the known performance of the field. Then, the adjustment should be made in a trial and error fashion and relies heavily upon intuition and experience of reservoir engineer as well as the good understanding of the field to reduce the deviation of simulated and actual performance of the field (Gilman J. R., 2013) & (Mattax C. and Dalton, 1990). Therefore, if personnel performing the match could not fully realize the processes taking place in the reservoir and how to apply the changes of matching parameters, the time of this process may be severely prolonged. It is imperative to split this process into two phases as a general approach, a gross matching phase and detailed matching phase.

In early stage, the gross matching phase is approached which means to average reservoir pressure, regional pressure gradients and well pressures through time should be matched. The volumetric parameters including aquifer size, connectivity, pore volume and system compressibility can affect pressure match. If the history match of pressure encounters some problems, the initial volume of fluid in place should be checked out and simple material balance calculation can be implemented to decrease this uncertainty (Ertekin T., 2001). Another possibility might be related to reservoir characterization, the static model requires to be properly modified to enhance the reservoir description (Gilman J. R., 2013). The accuracy of volumetric calculation is specified as the substantial aim of matching pressure. To obtain pressure match of individual wells, the well constraint is determined by voidage not specific phase rate. The more investigation in difference of the pressure distribution between model and field can facilitate to find out the presence of sealing faults, unconformities, pinch outs and poor reservoir communication. It is suggested to change the permeability in case of pressure gradient problem. Hence, between well permeability can be multiplied by a factor equal to the ratio of the actual and calculated pressure gradient (Mattax C. and Dalton, 1990).

The matching of fluid movement is considered as the detailed matching phase or saturation matching phase, which is performed on the well by well basis. The main flow mechanism in the reservoir and the most likely contributed properties in the fluid movement should be identified to get efficiently improvement in the matching (Mattax C. and Dalton, 1990). If the reservoir model is experienced a poor initial match in water oil ratio or gas oil ratio and breakthrough time of water or gas, permeability increment or coning behavior can be contributory factor to optimize the WOR or GOR match (Mattax C. and Dalton, 1990). A saturation match can be affected by fluid flow parameters have been described in **Table 7**. Since each reservoir has a unique behavior, it is very unlikely to generalize which contributors to make more diverse to achieve a reasonable match of fluid movement. Regarding reservoir perturbations, it should be minimized or even avoided to make any localized near well changes not correspond with geological reality (Ertekin T., 2001). The systematic approach accounts for what alterations are made globally before shifting to more localized changes. However, the selection of how to apply changes may not be straightforward and needs to make extensive trials.

Table 7: order of how to apply alterations to the reservoir model in most geological consistency (Ertekin T., 2001)

Vertical Adjustments	Areal Adjustments
Global (all simulation layers)	Global (all grid cells)
Reservoirs (In fields made up of vertically stacked reservoirs)	Reservoir/Aquifer
	Fault blocks within reservoir
Flow units within a reservoir	Facies (Areal facies envelop)
Facies (in laminated reservoirs)	Regional
Simulation layers	Individual wells

2.3 Assisted History Matching

Over the years, a number of history matching algorithms have been proposed. Two categorizations can identify these algorithms. By using automated history matching, achieving history matching is much faster with less simulation. In the beginning, the initial sensitive variable should be defined by assuming the specified range to change, afterwards, the filed data should be integrated in an automatic loop.

The main output of flow simulation is to provide a range of the variation in dynamic properties over the reservoir formations and production time according to multiple realizations (Hoffman B.T., 2005). After obtaining the results, the difference between the observed dynamic data and the corresponding simulated responses are computed in a least squared sense by terms of an objective function (OF). To minimize the objective function, various parameters of workflow can be adjusted. The objective function must be formulated based on the objectives of each case study.

Assisted history matching is utilized to adjust the reservoir parameters rather than direct intervention of reservoir engineer by utilizing computers and software tools. This technique relies on non-linear optimizing techniques to obtain best-fit model (Mattax C. and Dalton, 1990). As it can seek to minimize an objective function (defined by user), corresponding to finding the model with the least discrepancy between calculated and observed data (Rwechungura, 2011). Assisted history matching can be categorized in two different methods: deterministic algorithm and stochastic algorithm

2.3.1 Deterministic Algorithm or gradient based algorithm

It consists of the Levenberg- Marquardt (Reynolds A., 1996). Traditional optimization approach is used to obtain one local optimum reservoir model within the number of simulation iteration constraints (Reynolds A., 1996). The gradient of objective function is firstly computed in implementation and in next step; the direction of optimization search is identified (Liang B., 2007). To minimize the objective function, the following loop is considered.

- ✓ First step is running simulation for historical period by integrating field data
- ✓ the cost function must be assessed
- ✓ Last step is modifying the static parameters and return to the first step

2.3.2 Stochastic Algorithm or non-gradient based algorithm

It is included the simulated annealing (SA) (Sultan, 1994) and the GA (Liang B., 2007). Despite the fact that the stochastic algorithm can take considerable amount of computational time compared to a deterministic one. This algorithm is advantageous in three main direct:

- ✓ This approach can be more suitable to non-unique history matching problem due to the fact that the stochastic algorithm generates a number of equal probable reservoir model.
- ✓ By using this equal probable model, this is straight forward method to quantify the uncertainty performance forecasting
- ✓ Theoretically, this algorithm can reach the global optimum

2.3.2.1 Parameter estimation

Parameter estimation is a useful application of history matching to specify the reservoir properties and regarded in three major steps.

a) Construct a mathematical method

A mathematical model can anticipate the system behavior under different conditions with reasonable accuracy. A forward problem is described as the response of mathematical model to an external perturbation. The opposite problem using for history matching is an inverse problem that constitutes finding a set of parameters for a given model, thus the predicted system behavior replicates the true behavior under the same set of external conditions. The mathematical model is built by combing the fundamental laws, which are relevant to the dynamic of the reservoirs, and results in a system of differential equations. This principle laws consist of mass conservation law, Darcy’s law, equation of state and last but not least relative permeability and capillary pressure relationships (Dadashpour M., 2011).

b) Define an objective function

The objective function can measure the discrepancy between the observed data and the simulator response for a given set of parameters. Three different formulas are used to calculate the objective function.

1) Least squares formulation
2) Weighted Least squares formulation
3) Generalized Least squares formulation

c) Choose an optimization method

In mathematical formulation, the optimization is the search of minimum and maximum in the value of a certain response function performed in an iteration way. The maximum number of iterations or no further improvement is expected such can stop the iteration process. In implementation of history matching process, the objective function cannot reach the zero value, especially when the prior term is included (Storn R., 1996).

The gradient of the objective function is required to obtain gradient search direction, by computation of the sensitivity coefficient or using an adjoint equation (Storn R., 2005). Commonly, the gradient-based algorithms can be more advantageous for cases with a small number of parameters. However, the computation of gradient would become costly with a large number of parameters. Furthermore, the main drawback of these methods might be stuck in local optimum and provide a single solution for nonlinear and multidimensional problem. The common solution is using global search method (Storn R., 1996). The gradient free methods can take advantage of the global search space to improve the computational efficiency, which indicates a desirable performance in non-linear cases and complex reservoirs.

2.3.3 Optimization algorithms

2.3.3.1 Response surface

RS is described as an approximation-based optimization algorithm in order of minimizing an objective function. Maximal number of iteration can be used to define for this algorithm. This method explore the relationship multiple descriptive variables and response variables to obtain finally optimal response. The second degree of polynomial is utilized to execute the model.

On each iteration, the algorithm must build a quadratic polynomial approximation of an objective function. First, the Pearson correlation is calculated for each monomial. Monomials with least correlation values remain unused. Therefore, coefficients of this polynomial are chosen by the method of least squares. Finally, the minimum of current polynomial is computed and this point set as a next point of an algorithm (TNavigator_toturials, 2017).

2.3.3.2 Differential Evolution

DE algorithm was developed by Storn and Price (1995) as a stochastic population-based algorithm for continuous and real-valued numerical optimization problem (Storn R., 2005). This evolutionary algorithm method composed of three steps: selection, mutation and recombination. The DE constitutes a very effective global optimization due to its simple mathematical structure. The low number of control parameter cause to become the DE simple, fast and easy to apply (Storn R., 1996).

The basis of this algorithm is stochastic aimed to minimize objective function in defined search space. Maximal number of iteration can be determined for this algorithm. This optimization method classified as a population-based optimization algorithm. The theory of this algorithm is developed to optimize real parameter and real value function. DE is a evolutionary algorithm consisting of Generic algorithms, evolutionary strategy and Evolutionary programming. Generic algorithm procedure is following steps:

- Initialization
- Mutation
- Recombination
- Selection

After defining variable, upper and bottom bounds must be identified, and then random selection will assign the initial parameter values uniformly on the interval. Each of parameter vectors will undergo mutation, recombination and selection. The search area is expanded for mutation. Next, the weighted difference of two of the vectors is added to the third for another alteration to create another vector called donor vector. Recombination is in cooperation with successful solutions from the previous generation step. The trial vector is combination of the elements of target vector and donor vectors with the probability CR. The CR parameter is representative of probability of every component of target vector to be replaced by component of mutant vector. At the end of trial, the target vector is compared with trial vector. The one with the lowest function value is entered to the next generation (TNavigator_toturials, 2017)

2.3.3.3 Particle swarm optimizer

PSO is determined as a stochastic optimization algorithm aimed to minimize objective function in defined search space. Maximal number of iteration is specified for this algorithm. The algorithm operates with some set of particles nominated swarm. Each particle can be described by position in search (X), velocity vector (V) and local best position (LBEST). global best position for swarm (GBEST) is always stored.

During first iterations algorithm simply fills swarm with random particles. Particle corresponding to base model is always included in swarm. During next iterations, objective function is evaluated in point which corresponds to particle positions. Additionally, global best position for swarm and local bests for particles are updated (TNavigator_toturials, 2017). After calculations, the updating of each particle's position and velocity follow the below law:

$$Vnew=F(Vold, Xold, LBEST, GBEST, \text{other parameters})$$

$$Xnew=Xold+Vnew$$

Where F is in the formula, which describes velocity updating.

2.3.3.4 Simplex Method or The Nelder-Mead method

NM is defined as a simple-based optimization algorithm of minimizing an objective function. Maximal number of iteration is specified for this algorithm. The algorithm operates with the simplex in the search space. If the search space is n-dimensional for n variable, a simplex S is identified as the convex hull of n+1 point (simplex vertices). The initial simplex is constructed using the initial point (base variable values).

During first iteration, the initial simplex vertices are calculated. Then at each step, a transform of the simplex is performed for decreasing the objective function values as its vertices. Simplex transformation begins with ordering by the objective function value. Then the algorithm attempts to replace the worst simplex vertex with a better point. Four-test reflections are generated by using reflection, expansion and contraction with respect to the centroid of all simplex vertices but the worst one. First, the reflection point is computed then, if needed, one of the other three points does. If this shows failaure the simplex is shrunk to the best towards the best vertex. Thus, each step typically requires one or two iterations (point calculations) (TNavigator_toturials, 2017).

2.4 Tracer Application

2.4.1 Introduction

For inter-well studies as this is the case in multi-well pilot applications, tracers are used to tag injected water, gas or oil phases to identify phase's movement through the reservoir. The practical and essential outcome of an inter-well tracer application is to confirm the hydraulical connectivity between the wells. Moreover, inter-well tracer data is commonly used to assess sweep efficiency and to verify reservoir simulation model.

The common approach in tracer applications is to add defined chemical components to water flooding to track the water phase. Detecting tracer molecules that in water phase is nevertheless challenging, as tracers need to be chemically and biologically stable at reservoir condition. This statement implies that tracers must not be adsorbed on the reservoir rock surface and must not react with the reservoir solid or liquid phases. In addition, tracer chemicals must be environmentally acceptable. Furthermore, tracers must be detectable at very small concentration of about 50 parts per trillion (ppt) or lower to restrict injected tracer amount within reasonable amounts.

The principal benefit of tracer applications is to quantify the inter-well reservoir properties, which improves reservoir models and forecasts from reservoir simulation. Conventional inter-well tracer tests is an established method to identify flow patterns.

The main objective to deploy the inter-well chemical tracer can be listed as following:

1) Determine the connectivity or fluid pathway between the injector and producer
2) Evaluate the sweep efficiency
3) Determine the breakthrough time of the tracer in production well
4) Using tracer information to refine the static and dynamic simulation models

A tracer application has been applied as a part of the multi-well test (MWT) field pilot of the technology project “MEOR Studies” aiming at partly or fully the objectives listed above.

2.4.2 A Technology Project ‘’MEOR Studies’’

Microbial enhanced oil recovery field applications are designed to increase microscopic and volumetric displacement efficiencies by injecting microbes and/or nutrients with the purpose of propagating microbial reaction products toward producing wells (Bryant R., 1996). The preliminary suggestion of using the microbes to enhance oil recovery was made by Beckmen (1926). The first successful field trial performed by Kuznetsov, et al (1962) in one oil field indicated an incremental oil recovery. In the recent past, some fields’ tests have been executed globally (Tingshan Z., 2005) & (Hou Z., 2011). The MEOR applications worldwide has been reported more than 400 cases so far.

Basically, each MEOR process seeks to obtain two major achievements, metabolization of residual oil after secondary recovery process and enhancement of the microscopic and volumetric sweep efficiencies (Bryant L., 2002) & (Ghazali Abd. Karim, 2011). This is usually attained through the stimulation of in-situ or external microbes in the reservoir followed by metabolic activities that eventuate the microbial growth and generation of metabolic products (Deng D., 1999) & (Brown L., 2000). A major advantage of applying MEOR as compared to another mainstream chemical or other EOR methods is the lower cost.

Furthermore, using natural substances instead of potentially harmful ones makes it environmentally friendly (Youssef M., 2009).

The concept of MEOR execution can be categorized based on the spot where the metabolites can be generated (Al-Sulaimani H., 2011). If the bacteria can be stimulated at the surface and subsequently, the produced metabolite can be injected into reservoir, this strategy should be accounted as ex-situ metabolites generation; this method seems to be similar to chemical injection (Sheng J., 2013). Meanwhile, the implementation of in-situ metabolite generation can be conducted in two different ways. The first strategy brings up one substantial challenge about the capability of living and breeding of exogenous bacteria under the certain reservoir condition. The second one is described as the injection of nutrients to stimulate indigenous bacteria that is highly recommended due to the tolerance of surviving indigenous bacteria in the reservoir condition (Gray M.R., 2008).

Wintershall Company has been conducting a technology project to develop field applications in Wintershall mature fields. Prior the selection of the current reservoir to execute MEOR field application, field screening was performed by Wintershall Company based on general screening criteria provided in **Table 8**. The analysis of injection and production liquid samples in the field-screening phase proved the presence of natural microbial community in a mature Wintershall reservoir.

Table 8: General screening criterion on the applicability of MEOR (Admita P., 2017)

The laboratory phase could achieve successful results, which led to a first single well test (SWT) as a Huff and Puff (HnP) pilot in a WO mature oil field (Admita P., 2017). After the objectives of this HnP applications have been met a second field pilot has been designed in the same field as a multi well test field pilot (**Figure 1).**

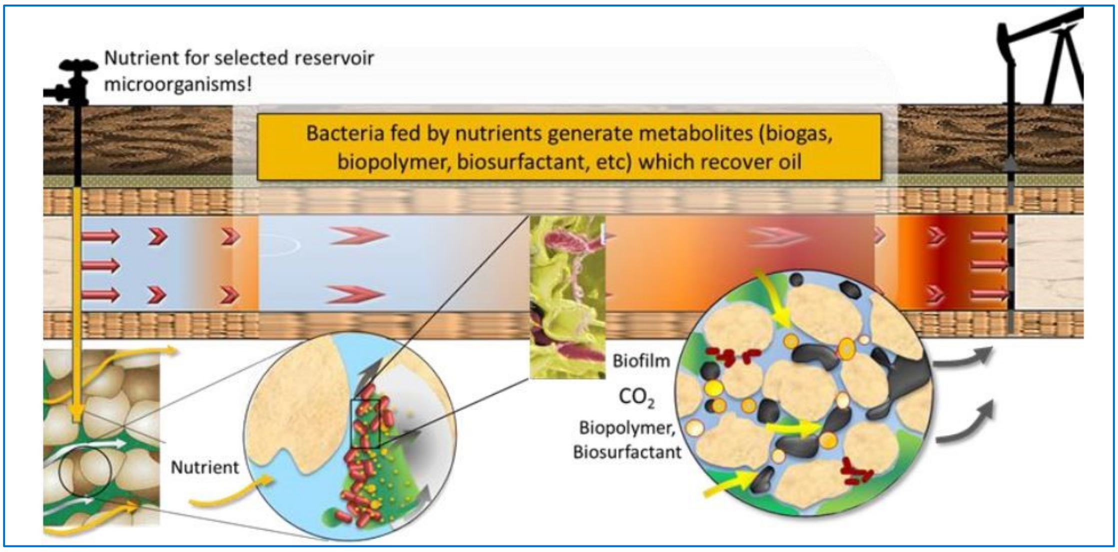

Figure 1: Schematic of an in-situ MEOR application (Alkan, 2016)

2.4.3 Tracer Application

Tracer technology has significantly evolved over the years and has been increasingly utilized as one of the effective tools in the reservoir monitoring and surveillance toolbox in oil and gas industry. Tracer surveys have been conducted either as inter-well test or single well test. This technology can be deployed to investigate more about reservoir well performance, reservoir connectivity, residual oil saturation and reservoir properties that can control displacement process particularly in either enhanced oil recovery or improved oil recovery (Taneem A. T., 2015).

This is an efficient approach to evaluate waterflood connectivity performance in complex compartmentalized reservoir regarding the MEOR pilot project. Tracers proves to be a robust method of determining connectivity between injector and producer. Generally, tracer breakthrough time is related to distance between injector and producer, high perm zone continuity, fault presence and perforated intervals. Interpreting the water tracer data can improve the reservoir description and the key parameters, which are important in the process of integrating the tracer data into reservoir model. This method can be very beneficial to get further comprehension of detail reservoir characterization, reservoir internal architecture, reservoir distribution, pressure monitoring and subsequently water flood sweep pattern efficiency (Taneem A. T., 2015).

2.4.3.1 General tracer consideration

It should be ensured that typical properties of the tracer meet the generalized criteria as blow (Dadashpour M., 2011):

- ✓ Non-reactive

- ✓ high stability
- ✓ Cost effective
- ✓ Minimal environmental consequences (low toxicity)
- ✓ By using very low concentration, it can be detectable (low detection limit)
- ✓ Not interact with hydrocarbon
- ✓ Not undergo adsorption or retardation with the formation

Chapter 3

Field of Study

3.1 WO Field

This chapter will give a comprehensive introduction to the WO field; some parts of this chapter are based upon the project work undertaken by Wintershall Company in 2015. The field of interest is a mature field in Germany was discovered in the middle of 1950. The WO field lies on the eastern flank of an elongated anticline-oriented NW-SE. The oil productive interval, which is sandstone reservoir nominated Dichotomiten Formation, corresponds to lower Cretaceous. The average thickness of Dichotomiten sandstone in the target reservoir is estimated approximately 10 meters to maximum 28 meters. The number of drilled wells is reported less than 90 wells that currently less than 20 wells have still been on production. Most of producing wells were drilled in the late of 1950 and early 1960 (**Figure 2**).

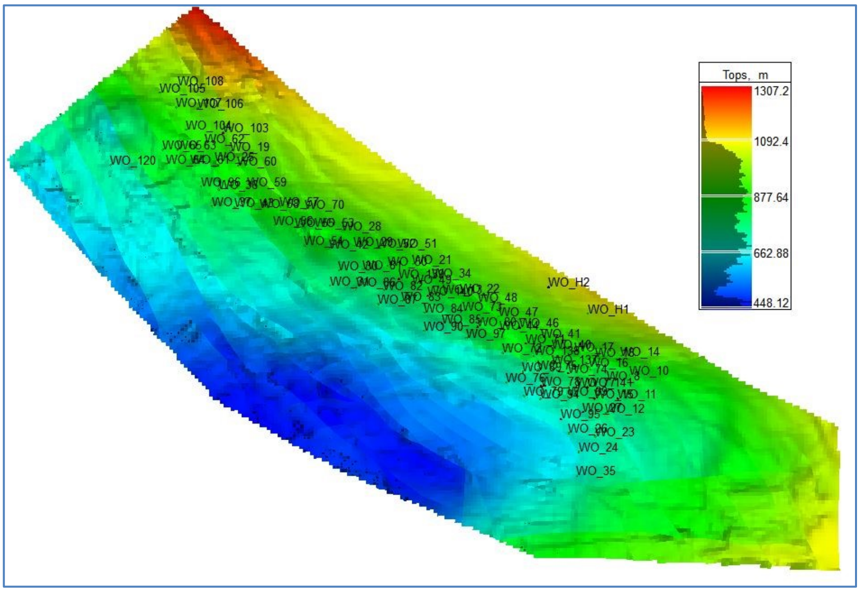

Figure 2: Well location in WO field on depth map of top Dichotomiten formation

The dynamic reservoir model will be performed based on static model, which updated in July 2018. In addition to using updated structural model and reservoir properties in geological model, current input data including well events and historical data should be validated in order to ensure that the provided model has realistically represented the reservoir. History matching applications can improve the reservoir prediction performance, sensitivity studies and the possibility to assess alternative plan in the WO field. The most important objective of history matching in this thesis is to reduce the uncertainty of the reservoir description in order to verify the reservoir simulation model particularly for the MEOR implementing purpose.

It is obvious that the process of integrating all available data to establish a realistic initial model is tough and time consuming. The majority of input data constitute a broad range of uncertainty; therefore, the preference is to verify all available data prior to be integrated in new reservoir simulation model. Not only have the reservoir properties formed a wide variety of uncertainty in simulation model but the fluid rates and pressure also illustrate some errors in measurements or recorded data.

3.2 Nearby Field

The EO field which operated by another company is in the vicinity of WO field. The indisputable evidence proves that the target reservoir for both fields are recognized as a part of same sandstone and often fully connected. From material balance point of view, it is vital to include the historical data of this field during history matching process (**Figure 3**).

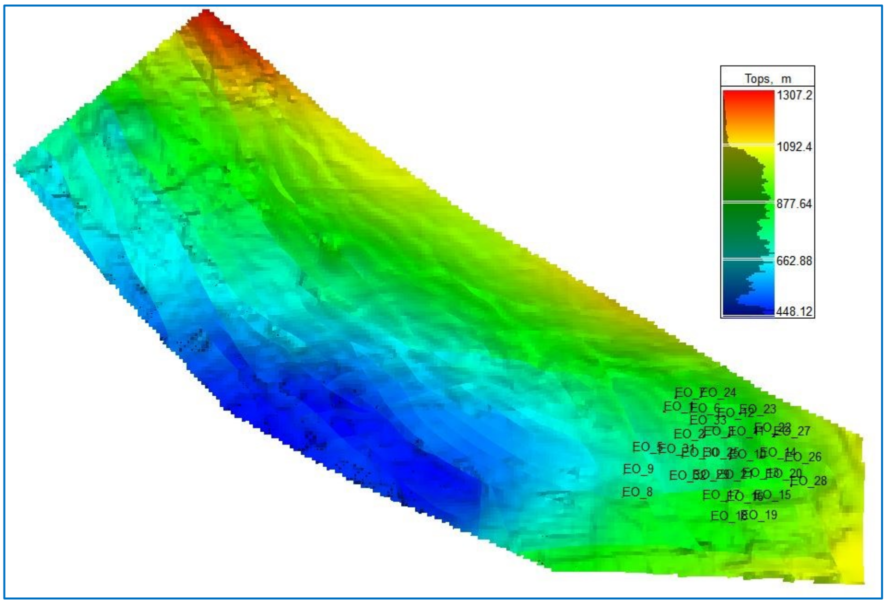

Figure 3: Well locations in the EO field on depth map of top Dichotomiten formation

3.3 Geological Review

The main intention building the static model was to assess the remaining potential of the field (bypassed oil). The secondary aim was to reduce the uncertainty between the geological model and seismic interpretation in order to evaluate the possibility of an infill drilling campaign.

The WO field is located in the lower Saxony basin (LSB). Middle Jurassic time was characterized by doming and uplifting processes. It was followed by an accelerated subsidence of the basin from Upper Jurassic to Lower Cretaceous, while Lower Saxony Basin becomes one principal depositional area. The basin was affected by inversion during Upper Cretaceous. Normal faults from Lower Cretaceous are reactivated as reverse faults accompanied by the uplift of the inversion of structures. The reservoir sandstone is pinched out on the crest of the anticline structure leading to stratigraphic trap component. The center of the basin is covered by marine clays, whilst the southern margin was accumulated with shallow-marine sandstones. The Dichotomites Sandstone was formed along the sandstone body. **Figure 4** is illustrative of depositional environment in the field of study.

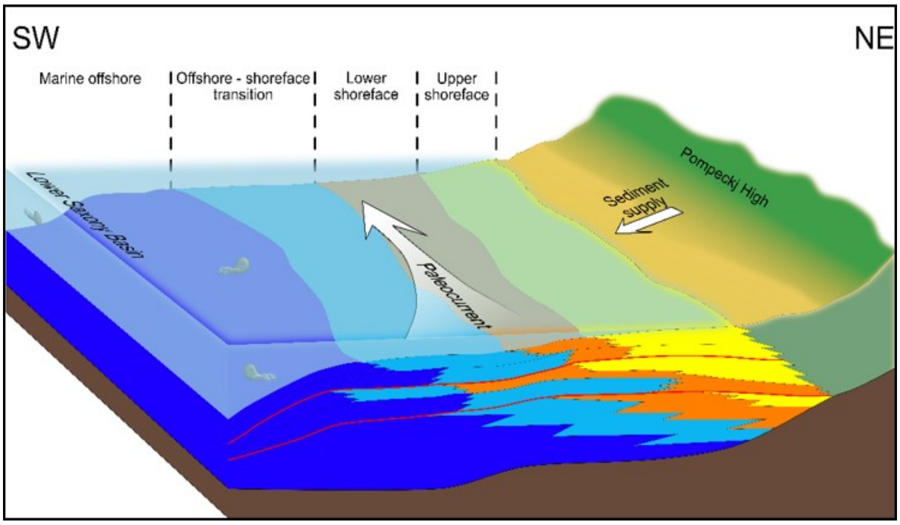

Figure 4: Depositional Environment in LSB

Even though, the reservoir trend has demonstrated reduction in the thickness toward the crest of the structure and sandstone is pinched out, the shale thickness is significantly increased (**Figure 5**). Hence, the location of identified ‘‘shale-out line’’ should be considered more towards west or crest of the structure. The structural map has illustrated all segments in the best part of the reservoir toward east have been already drilled. However, there are undrilled compartments including fine sand to silt thin sediments toward west beyond the shale line.

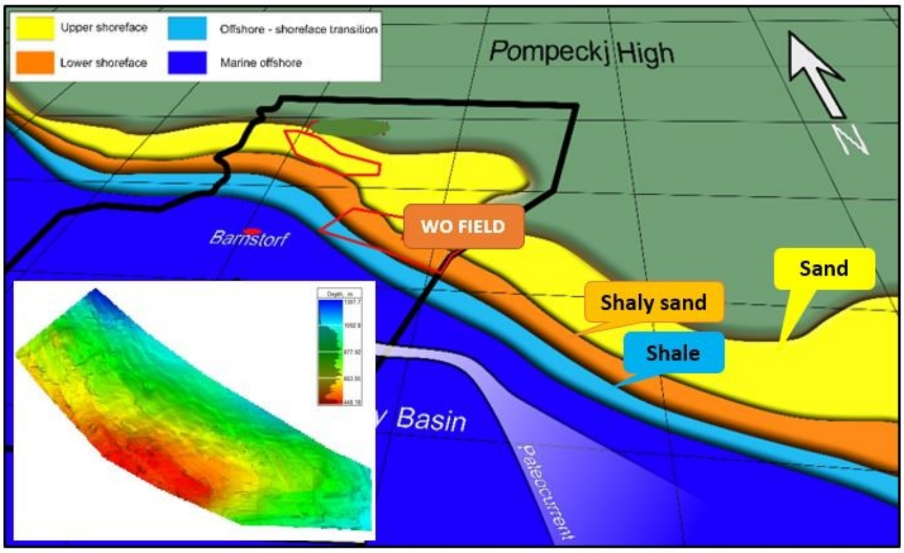

Figure 5: WO field location in sand body

The fault strike of this area has been described as NNW-SSE, which would be oriented perpendicular to the aquifer. If these faults would be confirmed as high transmissible faults, they would provide the appropriate path for the aquifer pressure support to the reservoir. However, the fault orientation in the central and north parts of the WO field are parallel to the aquifer. If these fault patterns would be described as an impermeable to flow, it could be an indication for the lack of pressure support for this part of reservoir.

3.3.1 Seismic Interpretation

The seismic reinterpretation had been initiated when the previous structural interpretation could not be consistent with the reality of the structure in the reservoir with respect to implement the tracer test in the MEOR pilot. Thus, the new geological model was generated according to the seismic reinterpretation. The average thickness of Dichotomieten sandstone is approximately 10 meters. From practical point of view, it is not possible to pick the top and base of the reservoir due to be less than seismic resolution and tuning. Therefore, the base of the reservoir was manually picked while the interpretation of top of the reservoir was associated with the biggest uncertainty (tied to wells).

The numerous extensional faults which highly compartmentalize the structure have been revealed in Figure 8 presented in the next section. The orientation of fault pattern generally conforms to the elongated anticline. Two different fault patterns can be distinguished in this structure. The majority of these faults are orientated in NW-SE with the dipping towards NE. Whilst, another fault system in W-E direction have crossed the main faults. The throw of some faults oriented NW-SE is between 10 to 30 meters that it is higher than the average thickness of reservoir. Thus, this fault throwing can cause non-juxtaposition and non-communication in the reservoir. However, some other faults have minor throw so that the transmissibility of these faults must be investigated to act as either full sealing or partial sealing or fully transmissible.

3.3.2 Static Model

In the view of the necessity of dynamic simulation model, building an accurate static model was primary objective that has represented as closely as possible the subsurface reality of this anticline. The target reservoir has been encountered by most of the wells. The goal was to develop a model with the sufficient details to represent vertical and lateral heterogeneity at the well, multi wells and field scale. It is imperative that the nearby field data, EO field, is incorporated in the geological model, since the two fields are dynamically connected.

The geological model was created by integrating the relevant subsurface data, seismic interpretation presented in the preceding section. The 3D seismic structural interpretation with faults, lithological descriptions and facies classification, porosity, permeability and initial water saturation by using capillary pressure curves were used to generate new static model by PETREL version 2015. The general workflow to develop the geomodel has shown in the **Appendix Figure 1**.

3.3.2.1 Structural Modeling

The 3D structural grid was constructed with a lateral resolution of 45*45 in order to achieve a sufficiently undistorted grid and to attain a grid with a reasonable amount cells at the same time (**Appendix Figure 2**). The grid contains 85 faults and 54 segments. All faults have been modeled as smooth faults and completely vertical (**Appendix Figure 3**). As mentioned previously, the outline of this model is to integrate WO and EO fields regarding the stratigraphic connectivity.

The proportional layering was aimed at capturing equal layer thickness from top to the base of reservoir (**Appendix Figure 4**). Ten proportional layers were defined with average thickness around one meter, however, the range of cell height has a vast variation from 0 to 2.6 meters due to the utilized proportional method.

3.3.2.2 Property Modeling

a) Facies Modeling

A pseudo facies log was created to characterize the facies type in the WO field. The log was created based on cut offs on volume of clay log, which lead to define three pseudofacies (**Table 9**). Therefore, two lines are an indicative to subdivide into three regions called sand region, shaly-sand region and shale region. The ‘Truncated Gaussian Simulation with trend’ algorithm was utilized to populate the facies in the entire of the reservoir (**Figure 6**).

Table 9: VCL cut-offs to determine facies type

Reservoir Type Facies	Volume of clay
Good reservoir	VCL <= 0.18
Tight reservoir	0.18 < VCL <= 0.4
Non-reservoir (Shale)	VCL > 0.4

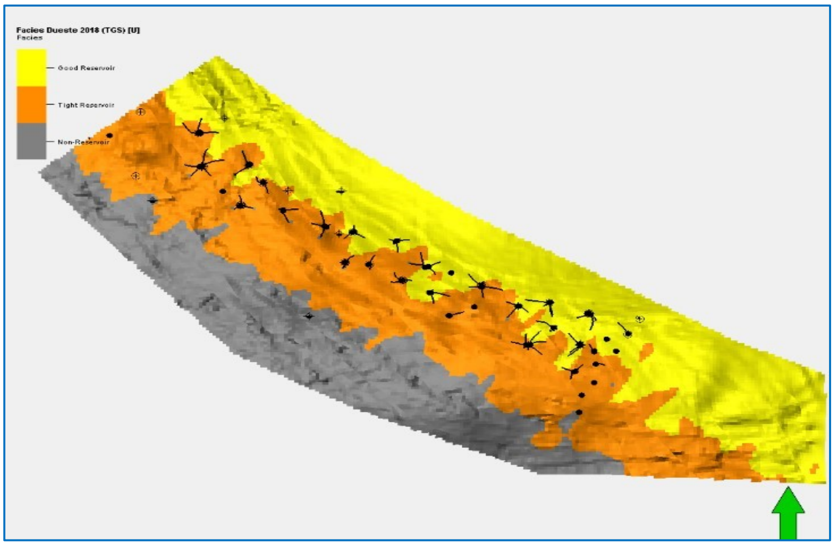

Figure 6: Facies model on VCL cut-offs distributed with the ‘TGS’’ algorithm.

b) Porosity Modeling

Two different iterations approached to propagate porosity and permeability in the entire field, data analysis process is applied for the upscaled well logs and biased with the defined facies. The used algorithm to distribute porosity was Sequential Gaussian Simulation biased with facies function and trend modeling as honor the vertical distribution. The modeled porosity with bias represents better the porosity distribution than the stochastic model without bias (**Figure 7**). The correlation of porosity with permeability was identified regarding the available core data.

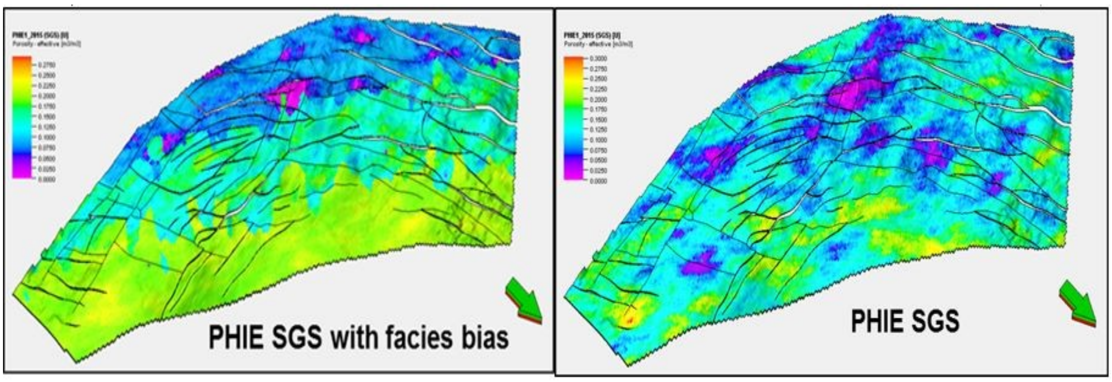

Figure 7: Porosity distribution modeled with SGS algorithm. Low porosities concentrated in the south (at the crest) and higher porosities in the north (on the flank).Left side showing porosity distribution baised to facies & right side showing non_bias

c) Peremability Modeling

Permeability model was implemented same as porosity modeling. The modeled permeability with bias to facies, is better representative of the porosity distribution than the stochastic model (**Figure 8**).

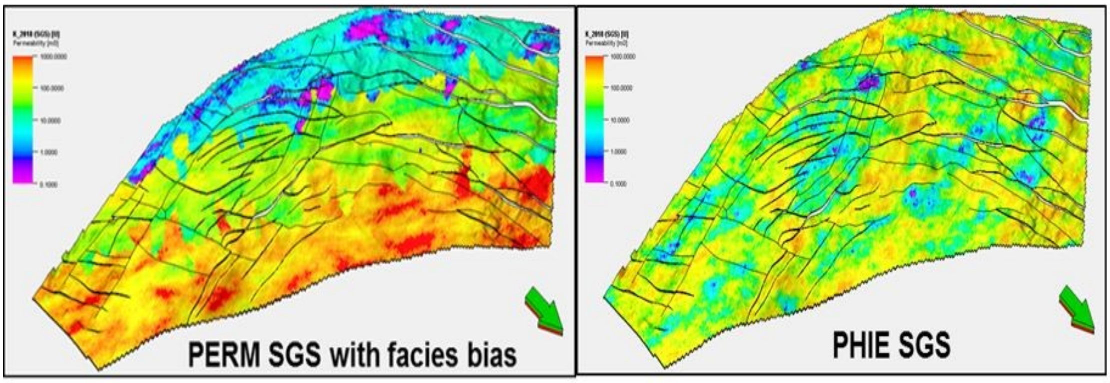

Figure 8: Permeability distribution modeled with SGS algorithm, Left side showing porosity distribution baised to facies & right side showing non_bias

d) Water Saturation Modeling

Dynamic analysis depicts two different free water levels or (oil water contact) in the field which are separated by one major fault. As **Figure 9** is shown, the OWC of the northern part is 920m TVDss, while deeper OWC is placed in southern part with 980m TVDss.

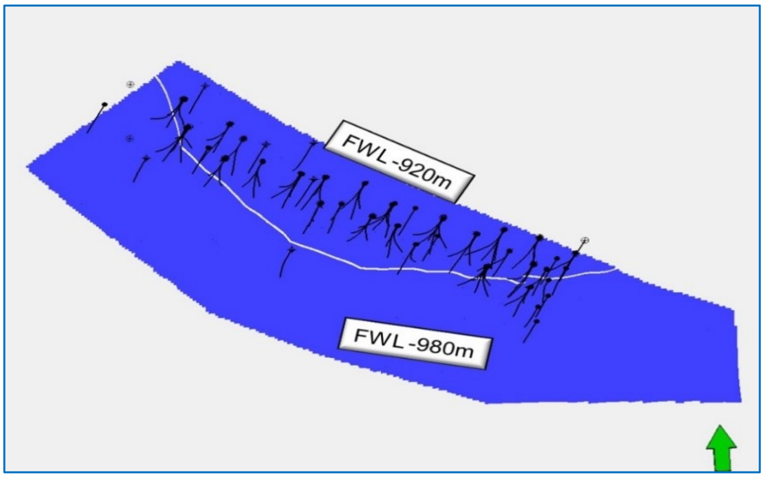

Figure 9: FWL distribution

5 capillary pressure curves provided by reservoir engineer are used to propagate water saturation. Each capillary pressure curve corresponds to one permeability category; thus, water saturation were directly calculated based on capillary pressure curves (**Figure 10**), j-function is not critical to use. Capillary pressure curves will discuss as an input data to dynamic model.

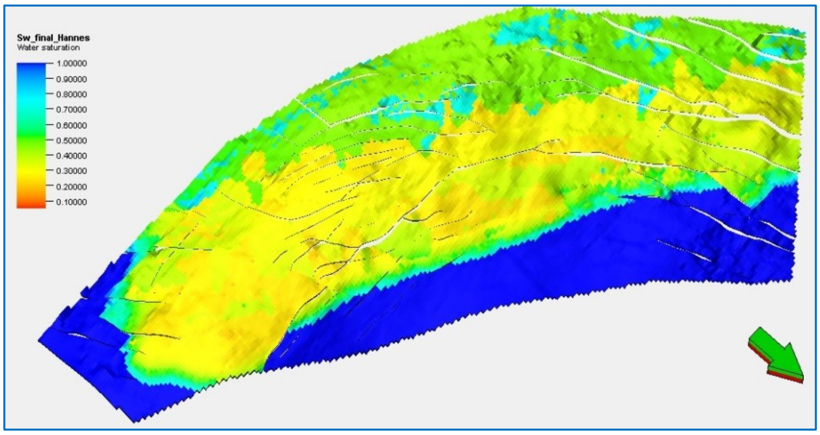

Figure 10: Water saturation distribution

3.3.2.3 Hydrocarbon Volumetric

The last step of this process was to estimate original oil in place. Volumetric calculations were performed based on two different considered strategies to create property modeling (**Table 10**).

Table 10: STOOIP with respect to property distribution biased facies

OOIP (MM sm3)	Biased Case
Full 3D structure	19
WO & EO Fields	16

3.3.3 Conclusion of Static Model Review

One of the main challenge is to choose the appropriate property modeling to employ in simulation model. According to porosity and permeability modeling, the iteration without bias to facies could not demonstrate a clear facies transition from sand to shale. However, both cases in dynamic model should be investigated to make a decision, which one could be more calibrated during history matching process.

The major fault is used to divide the reservoir into two regions concerning different water oil contact definition. However, the position of this main fault which constitutes multiple minor faults along each other is under question. Moreover, due to insufficient data provided from EO field, water oil contact (WOC) should be validated again by available data to ensure about WOC determination.

Another concern in static model is relevant to the structural model and fault definitions including fault displacement, fault position, fault transmissibility and compartmentalization of the reservoir. Sealing and baffling of cross fault flow can be controlled by juxtaposition between reservoir and non-reservoir rocks across the fault. Flow in reservoir compartmentalization is prevented across sealed boundaries in the reservoir. These boundaries can be caused by a variety of geological and fluid dynamic factors. Two basic types can be identified type of sealing; static seals that are fully sealed and capable of trapping petroleum column over geological time. Whilst, dynamic seals that are low to extremely low permeability flow baffles, which lead to reduce oil cross flow to infinitesimally slow rates. As a matter of fact, the latter can allow fluids and pressures to equilibrate across the boundary over geological time scale. However, acting as seals over production time scale can prevent cross flow at normal production rates. Accordingly, any misunderstood reservoir compartmentalization can influence on the volume of movable of the fluid that might be connected to any drilled wells in the reservoir or even lead to abandonment. Therefore, this key uncertainty should be accurately assessed in order to avoid any misleading during history matching step. After further evaluation in dynamic model, it might be required to change again in terms of the compartment boundaries.

In new seismic interpretation, some compartments are entirely isolated that it could be examined during history matching process. The diagnosis of fault behavior should be validated by either production and pressure data or different well tests.

Chapter 4

Dynamic Reservoir Model

This chapter will describe the dynamic reservoir model and the process should take into account to obtain good history match. Coarse grid cells can be more helpful to improve the convergence issue and reduce run simulation times, not only due to decrease the total number of grid cells but also take advantage of large grid geometry enabling easy dynamic fluid flow in the reservoir. However, the necessity of upscaling is not big issue due to the low number of defined grid cells and the geometry of grid cells are not specified very fine to leading any convergence problem or increase simulation run times. Prior to start the history matching, the dynamic report in 2015 is reviewed to form a solid understanding of the reservoir model. The reservoir is initially undersaturated but evolves gas as the reservoir pressure drops below the bubble point pressure over production time scale.

4.1 Introduction

Since the dynamic reservoir model is established by utilization of geological model and incorporating well and time dependent information from production and reservoir engineering disciplines, the simulation reservoir model must undergo the quality control and validation, which is executed in two distinct stages. The first quality control and validation is relevant to static mode called ‘’Model Initialization’’ and the second one in dynamic mode is called ‘’History Matching Process’’. As a conclusion, each data source in the simulation model can be unconditionally associated with inherent uncertainty.

The dynamic reservoir model is constructed based upon the original grid of the geological model (**Table 11**), the southern part prolonged into nearby field which was not interested part to simulate in the beginning; however, the robust stratigeraphic community between two fields lead to be involved to the reservoir simulation model. To be able to capture the vertical resolution and heterogeneity in the reservoir, the upscaling of layering is fully neglected.

Total number of included wells to simulation model are approximately 130 wells in both fields (WO &EO fields). Both fields is categorized as a mature oil field, producing since 1954, with a recovery factor ranging from 28% to 43% according to a rather wide estimated range of initial oil in place. Currently, the average water cut is approximately 97%.

Table 11: Grid properties in reservoir simulation

Grid dimension	10*159*237
Total Number of grid cells	376830
Active grid cells	176370
Average lateral dimension	45*45
average thickness of layers	1 meter

As it is mentioned in the geological review section, static reservoir properties such as porosity and permeability are propagated based on two different iterations including biased to facies and log interpretation. The range of distributed permeability and porosity model indicate large variation the entire reservoir due to the presence of sand body; whilst, the facies trend shows changing from shale to sand. The permeability in X and Y directions assumed to be equal throughout the model. Vertical permeability is presumed as a fraction of PERMX due to lack of sufficient interpreted data in this direction.

4.2 Validation of Input Data

To obtain the realistic history matching, it is substantial that both dynamic and static input to the model should be scrutinized in order to eliminate the inaccurate data, which are not representative of the reservoir. The validation of input data and quality check of data in the simulator is performed prior to embark on the actual history matching. Validation of the data will conclude faster converge towards an appropriate match and predict reservoir performance with greater confidence. This section will describe the validation process, which are executed in order to ensure that the reservoir model can be characterized as accurate as possible prior to initiate the history matching.

One of the time consuming part of the reservoir study process is data preparation and finding reliable data from different data sources since more precise and abundant data let having a more accurate model in this work. As a part of quality assurance and control process, all measurements involving some degree of errors or inaccuracy must be identified and corrected logically. The presence of missing information is also unavoidable; under such situation, judgment is applied and reasonable assumptions form analogues are made to fill the gap.

4.2.1 Porosity and Permeability

Porosity measurements were derived from well logs and core plugs. Permeability were measured only based on cores. As mentioned in the previous chapter, the porosity baised facies distribution is regarded to apply in the simulation model (**Appendix Figure 5**). Moreover, the same approach is employed to propagate spatially the permeability in different dimensions.The vertical permeability distribution is most likely to be in proportion to the areal distribution. As it is observed in permeability histogram (**Appendix Figure 6**), the permeability is propagated over a wide range. Potentially the flow behavior will be dominated through the low permeability cells. **Table 12** summerizes the reservoir properties characteristic in the property distributions.

Table 12: Reservoir properties specifications in the reservoir model

Properties	Min	Max	Mean	RMS
Porosity	0	0.31862	0.15597	0.065866
Permeability (md)	0	3599.9	182.25	248.24

4.2.2 Capillary pressure

According to capillary pressure experiments on different cores, the range of irreducible water saturation was specified from 4.4 to 86.6. Therefore, it led to determine 5 capillary pressure curves to be representative of each saturation ranges. Due to the shortcoming of information on the experimental set up, oil/ brine displacement was presumed to utilize and some corrections to the reservoir condition based on the literature value. The core properties were utilized to characterize capillary pressure curves, which steer to permeability definition classes (**Table 13**). This is totally unlikely to group the defined curves in the way to support the usage of J-function based on available dynamic model report is written in 2015. All capillary pressure are plotted in **Figure 11** and distribution map is shown in **Appendix Figure 7**.

Table 13: Permeability classification with respect to irreducible water saturation, Dynamic model internal report 2015

Swc	Well	Core No	K class [mD]
0.736	103	1	K<1
0.483	11	2	1< K <10
0.298	18	3	10< K<100
0.246	18	4	100< K<1000
0.183	97	5	K >1000

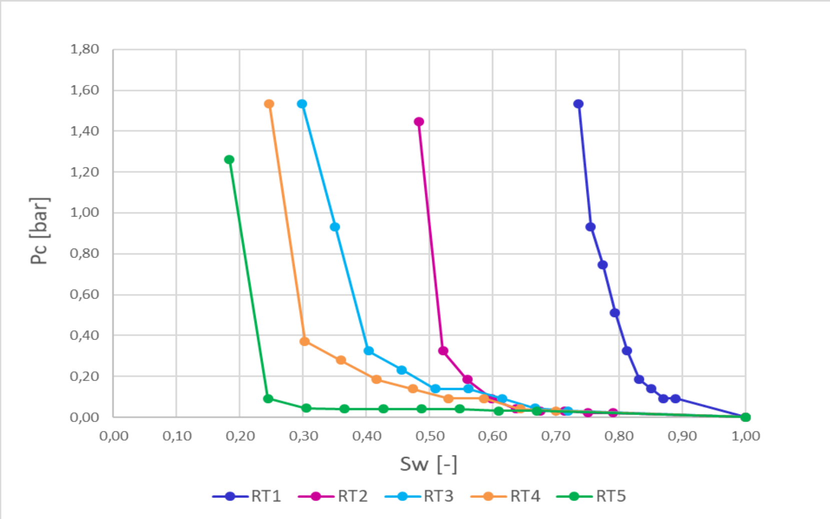

Figure 11: Capillary pressure curves regarding 5 defined rock types, Dynamic model internal report 2015

4.2.3 Relative Permeability

As relative permeability experiments were never conducted on the cores in this field, a generic Corey function model was applied to identify relative permeability classes. Critical water saturations are determined based on irreducible water saturations, which were employed to identify capillary pressure curves. The oil relative permeability approaches zero at irreducible oil saturation corresponding to a recovery factor of 0.5. Connate and critical water saturations were established as an equal value. Additionally, the oil irreducible saturation to water and gas are set up identical. The Corey function parameters are shown in the **Table 14**. **Figure 12** and **Figure 13** have demonstrated oil-water relative permeability and gas-oil relative permeability regarding 5 specified rock types, respectively.

Table 14: Corey Function Parameters Dynamic model internal report 2015

K class [mD]	<1	<10	<100	<1000	>1000
Kro(@Sw_irr)	0.8	0.8	0.8	0.8	0.8
Krw(@So_irr)	0.5	0.5	0.5	0.5	0.5
Krw(@Sw=1)	1	1	1	1	1
Krg(@Sw_irr)	0.9	0.9	0.9	0.9	0.9
Krg(@So_irr)	0.8	0.8	0.8	0.8	0.8
Sw_irr	0.736	0.483	0.298	0.246	0.183
So_irr	0.11	0.21	0.28	0.3	0.33
Sg_critical	0.05	0.05	0.05	0.05	0.05
CoreyExp. Water	4	4	4	4	4
CoreyExp. Oil	3	3	3	3	3
CoreyExp. Gas	6	6	6	6	6

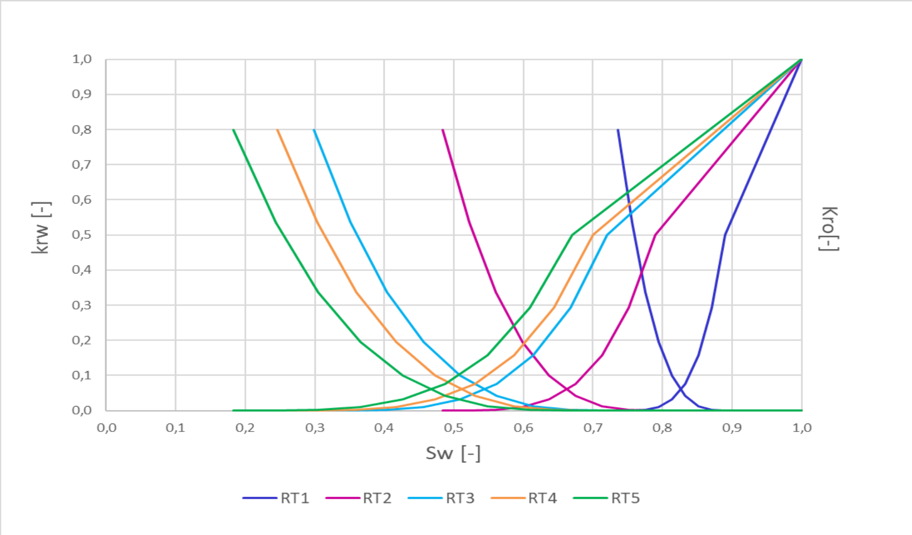

Figure 12: Water oil drainage relative permeability curves regarding 5 defined rock types, Dynamic model internal report 2015

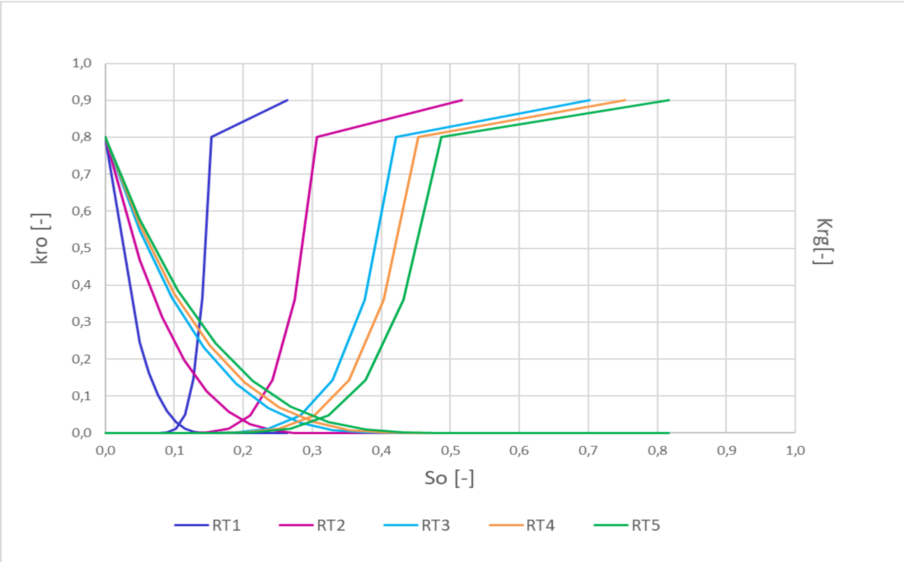

Figure 13: Gas oil drainage relative permeability curves regarding 5 defined rock types, Dynamic model internal report 2015

4.2.4 Well data & Production-injection data

Data collection and quality control of available data are carried out in the first stage of study in order to create more precise schedule files. Production and injection historical data are extracted from ''Finder Data Base'' again and compared with the existed old dynamic model_2015. As the consistency of all received data files are in doubt, quality control of data is regarded a fundamental step to dynamic model. Making a Pivot chart for all available historical data in Excel file , can be used to visually look at production and injection flow rates, a well by well or by particular group to ensure data accuracy. Accordingly, some remedial correction should be applied to avoid any inconsistency of data. If logical proofs are founded to justify this substitution during the history matching process, this alteration can remain in the same way, otherwise it should be again revised. Multiple terms are subjected to changes as following:

- If there is a particular month missing, the missing months are manually added and noted as a comment. It is essential to figure out about the reason why the production data is not reported for that particular months and what data should be accounted in that months.
- QC on well efficiency factor (WEFAC). This value cannot be specified out of range of zero to one. If this problem is encountered, it must be certainly corrected and remarked as a comment including the description of the reasons and accounted process.
- If any abnormality is detected in production (suddenly increasing or decreasing) trend (**Figure 14**), those month(s) must be highlighted as the observed discrepancies. Afterwards, it should find out why such abnormality is appeared in production data and eventually, taking the precise value or measurement from accurate data sources.

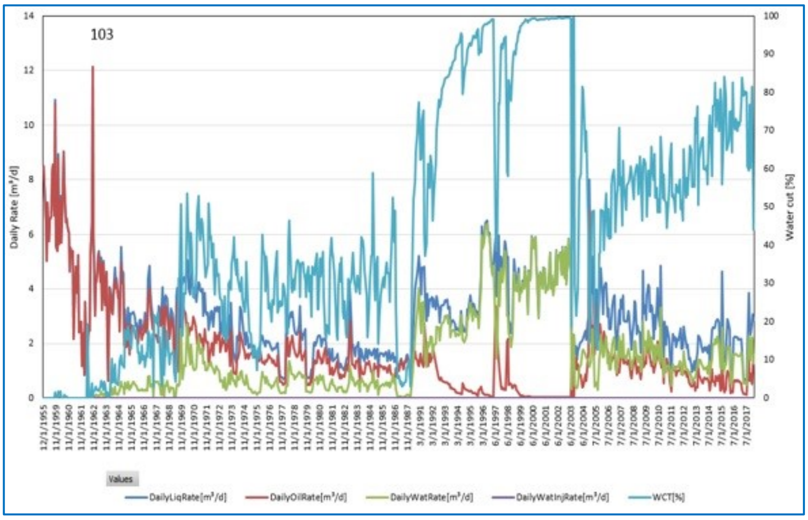

Figure 14: Abnormality in production data_ WO-103

- In addition, finding abnormality in injection data is accounted in the similar way.
  The significant discrepancy occurred in the injection historical data of EO field. In August 1993, a drastic increment is observed in injection rate looked as if it is manipulated to indicate the uncommon rate. Indeed, compared to overall liquid rate, injection rate is significantly shifted to upper level (**Figure 15**). To reach the same trend in the neighboring months, using multiplier is a best solution to eliminate the impact of this irregular trend. Several multipliers are examined to accomplish the similar past trend. In old dynamic model_2015, the injection rate was multiplied by 0.1. However, in this thesis, in order to modify the trend, this multiplier is eventually changed to 0.7 (**Figure 16**).

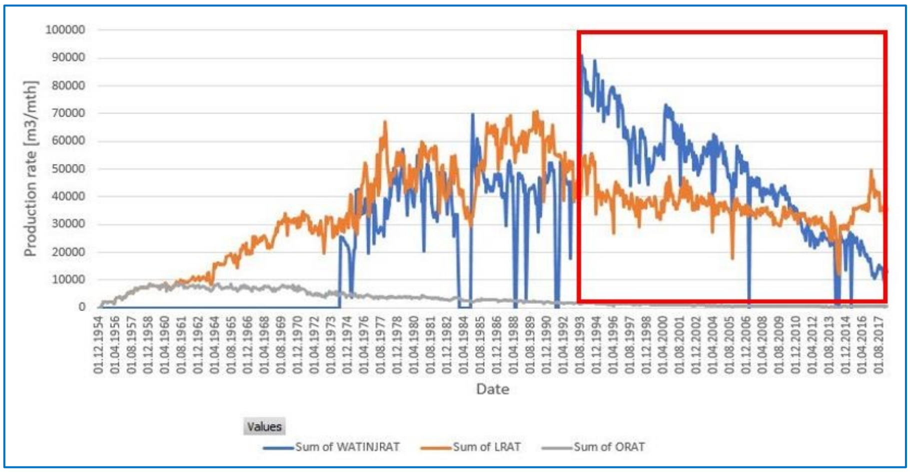

Figure 15: Abnormality in injection data in EO field

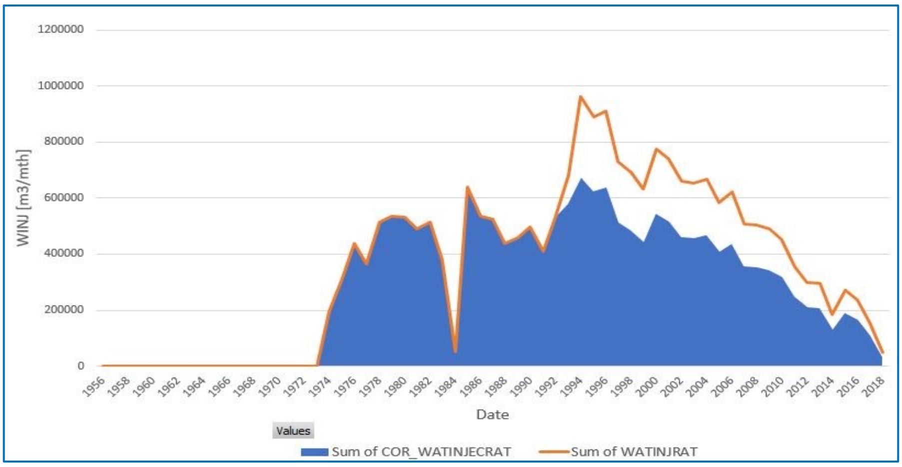

Figure 16: Using multiplier 0.7 in injection rate after August 1993 to modify the injection trend of EO field

- If the presence of sidetracks are confirmed in data source, historical data must be allocated to sidetrack wells being in operation instead of parent wells because almost none of parent wells could reach the target reservoir.
- There was no measurement for skin. At the beginning of simulation, the skin value for the whole wells are assumed +2; however, in proceeding the matching process it could be adjusted as per well requirements.
- QC of perforation interval and check if there is any different interval in one date are reported.
- QC of perforation date which must be reported before starting of production date. To prepare data input file to simulator, the majority of perforation date are established in the first date of production due to simulator issue.
- Check perforation reports to figure out about well completion, if it is reported squeezing job or re-perforating, plug-in some parts of perforated interval or extended length of perforation.

4.2.5 QC of Exported File from Static Model (Petrel software)

The rescue file is used to export data file from static model to enable importing any simulator. Since the geological model was constructed in Petrel version 2015, the rescue file must be exported in the exact same version. Otherwise, it will become a big hassle if the generated static model opens in another version of PETREL and export rescue file. The big discrepancy is appeared in the beginning of building dynamic model due to this problematic issue.

- QC of rescue file revealed that there was a significant shifting between the position of made horizons and the structural framework. Hence, the majority of perforation intervals could not show the distributed reservoir properties. Additionally, the reservoir horizon illustrated the complete flatted horizon without any fluctuation in depth. This issue arises implicitly due to use another version of petrel software.
- Well trajectory of sidetracks were missing in the exported rescue file (from static model), adding well survey of missing wells to data file and assigning well event and historical data were performed.
- Total wells were not included in the rescue file or even static model, the required data is extracted form old dynamic model_2015 or another source.

4.2.6 Flow rate and Pressure Data

The export rates of the WO field and its neighboring fields are measured together, and then allocated to individual fields. Thus, the biggest uncertainty is the quality of this allocation as it is calculated on the basis of a historic formula and not measurements. The change of error with the time cannot be tracked under this uncertainty. Moreover, it is worthy to note that the field flow rates are allocated to individual wells according to the measurements carried out each 2 to 6 months. Even though, monthly three phase flow rates have been reported for the whole field, there is considerable mistrust in the collected data and there is no way to check or even correct its accuracy. Gas rates have never been measured in the field and the reported gas rates are absolutely established upon estimations and PVT sample of early field life. It should bring to mind the results of the whole study are imposed by this effect.

Pressure surveillance was performed based on the fluid level measurements through the field life either static or dynamic pressure. The default reference depth is basically used to calculate the bottom hole pressure (BHP) either static or dynamic, the depth is referenced to the datum depth of 750 mTVDss to plot. There is no available commented data to describe whether the well was shut-in and for how long.

Looking at the pressure graphs (**Figure 17**), some wells are not trustworthy to use in the history matching process as the result of the WO-90 has indicated the eccentric fluctuation in the flowing pressure curve; meanwhile the static pressure shows steadily growing in the trend.

Liquid level measurements are totally excluded, as their behavior is completely erratic in many cases. The value only can be used when production data are not reported regarding Dynamic report_2015.

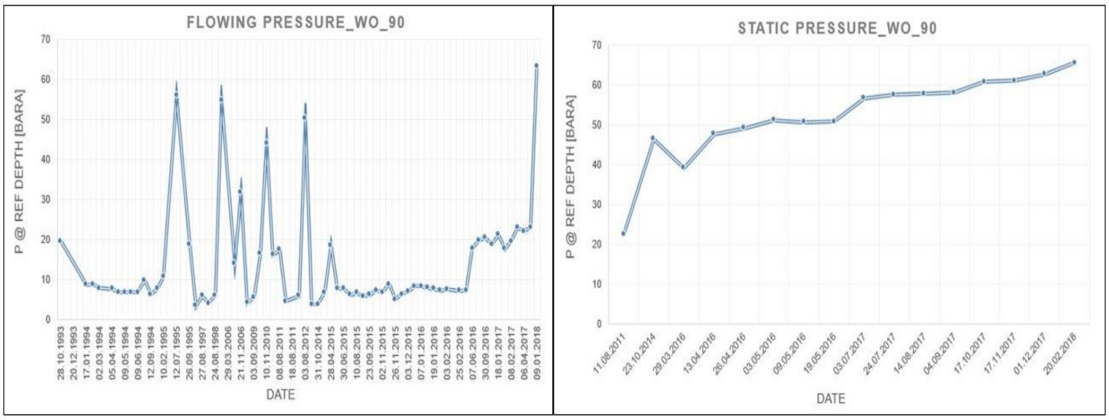

Figure 17: Static and flowing pressure abnormality in WO-90

4.2.7 PVT Data

Only one fluid sample, WO-8 well, was taken from WO field and two samples from EO field. The oil samples illustrated similar behavior in terms of bubble point, FVF. Meanwhile, gravity, GOR and especially gas composition and gravity demonstrated significant variation. However, the similar oil properties made allowance for considering the homogeneous oil for the whole reservoir. The analysis of WO-8 well is utilized to apply in PVT modeling with the low degree of alteration in some properties to match. The reported results are based on estimations and early field life PVT samples (B.1.2). The oil properties and gas compositions from downhole oil sample are tabulated as **Table 15** & **Table 16**:

Table 15: Oil properties, downhole oil sample form WO-8 well

Measuring Depth	m	818
Reservoir Temperature	°C	37.7
Bubble Point Pressure	Barg	37.6
Formation GOR	Sm3/Sm3	13.5
FVF at bubble point	Rm3/Sm3	1.041
Dead oil gravity	Sp.Gravity	0.869
Gas gravity	Sp.Gravity	0.616
Viscosity at P_i	cp	24.5

Table 16: Gas composition _ downhole oil sample form WO-8 well

Gas Composition	Unit	value
C5	Vol%	-
C4		2.11
C3		2.41
C2		1.68
C1		93.8
Co2		-
Na frei		-
Gravity		0.616

4.3 Simulation Model

4.3.1 Introduction to Simulator

Reservoir simulation is a widely used tool in the field development. In this thesis, TNavigator software has recently developed is utilized to build the dynamic reservoir model incorporating to model designer, geological designer, PVT designer and assisted history-matching modules. Despite the fact that this software is very user friendly, it should deem to be the most challengeable part of this thesis. It will be discussed further the challenge and issue involved in this recent developed simulator which is introduced as an integrated software package.

4.3.2 Assumptions and uncertainties

It is essential to be aware of the inherent uncertainties and assumptions in WO reservoir model during simulation and interpretation of results. It is important to deal with the difficulty to quantify all of the assumptions and uncertainties in the reservoir model as the most pronounced presumption and uncertainties in this dynamic model are listed as below. Further discussion related to this topic will be addressed later in the thesis where is found appropriate.

- Maximum permeability is assumed to be 3600 md.
- Lateral permeability is equal (Kx=Ky)
- Vertical permeability may be too low since presumed to be a fraction of lateral permeability. In the begging, it is considered to be 0.1 *PERMX.
- Aquifer strength: Pressure maintenance is constrained by a large aquifer with good connectivity
- Boundaries in the model are not flux boundaries.
- Skin value is assumed to be +2 for all wells in the beginning.
- Relative permeability used in the reservoir simaultion model based on core samples.

- According to core properties, water oil capillary pressure is regarded to define permeability classification. The J-Function utilization neglected due to inaccurate group definition.
- The used fluid properties involve a noticeable uncertainty due to the only sample taking from early production time in January 1955.
- 5 different rock types are defined to cover the wide range of irreducible water saturation.
- There is substantial uncertainty fully dependent on the reservoir properties propagation biased to facies and non-biased since the trend of sand and shale line are not clarified. The facies trend could be smoothed or even deviated from defined sand and shale lines. Non-biased property distributions cannot be indicative of dispositional environment. In this work, the usage of non-biased properties are neglected due to time limitation.
- The degree of compartmentalization is in doubt.
- The main uncertainty is accounted fault compartmentalization. The considerate question will arise whether the major fault is elongated in the right position or not with respect to be important to determine WOC regions. Fault displacement and non-juxtaposition of neighboring segments, sealing fault or even the degree of fault transmissibility should be evaluated to diminish the uncertainty during history matching process.
- Rock compressibility is 4.5e-4 at reference pressure 90 bar

4.3.3 Design Model

There is a functional module in TNavigator called ‘’Model Designer’’ which must be used to design the whole framework of dynamic reservoir model. The model is set up based on Metric system. After data validation, all input data consists of rescue file form static model, well events, performance historical data, fluid properties, capillary pressure and relative permeability curves are imported to Model Designer.

4.3.4 PVT Modeling

The creation of fluid model is conducted by “PVT Designer” in TNavigator being capable of simulating PVT and phase behavior of reservoir fluids. PVT Designer allows to model either Black oil or Compositional, however, this work will focus on Black oil model. PVT tables are created from standard correlation types. **Table 17** and **Table 18** provide all correlation parameters for oil, gas respectively that PVT Designer needs to build the PVT model. Additionally water properties are used to generate PVT model is described in **Table 19**. Oil properties are shown in dependence of dissolved gas content that contains combination of the saturated branch and undersaturated branch (**Appendix Figure 9**). Besides, gas model is shown in B.2.1**Appendix Figure 10**.

Table 17: Correlation parameters for oil

Pressure	Number of stage	20
	Minimum	1.01325
	Maximum	250
Table type	Live oil	
Correlation Type	Rs (Scf/STB)	Standing
	Oil FVF saturated	Standing
	Oil FVF undersaturated	Standing
	Dead oil viscosity	Standing
	Live oil viscosity saturated	Standing
	Live oil viscosity undersaturated	Standing
Correlation Option	Temperature (°C)	37.7
	Specific oil gravity	0.91
	Specific gas gravity	0.645
	Bubble point pressure (bars)	38.6
	Isothermal compressibility (1/bars)	8.513e-5
	Rs	13.5

Table 18: Correlation parameters for gas

Pressure	Number of stage	20
	Minimum	1.01325
	Maximum	250
Table type	Dry gas	
Correlation Type	Gas FVF	Standing
	viscosity	Lee et al
Correlation Option	Temperature (°C)	37.7
	Specific gas gravity	0.645
	Z factor	0.9

Table 19: Water properties

Reference Pressure (bars)	90
Reference FVF (m^3/m^3)	1.014
Compressibility (1/bars)	4e-05
Reference viscosity (cp)	2.0121347
Viscosibility (1/bars)	0
Water specific density (kg/m^3)	1100

4.3.5 Initialization

Two regions (EQLNUM) are used to initialize the reservoir model. This is performed to honor the two encountered water contacts. WO-110 found water up to 1014 m TVDSS and WO-108 oil down to 971 m TVDSS. Hence, the oil water contact of north part is interpreted to be approximately at a depth of 980 m TVDSS. The rest part of reservoir is determined at a depth of 920 m TVDSS as encountered by WO-14 at 917 m TVDSS.

The WOC regions are determined regarding the major fault position in new structural model, However, further investigation demonstrates the significant uncertainty involved to the position of this major fault. This fault is used to make a boundary to define WOC regions. As in **Figure 18** can be seen, the place of this main fault is shifted towards the east part and extended to EO field as well. The significant discrepancy is observed in initialization model in liquid rate and total that could not be justified with any reasonable criteria. In addition, this new WOC definition is confirmed by old dynamic model 2015. **Table 20** shows parameters specification in the new definition of WOC regions.

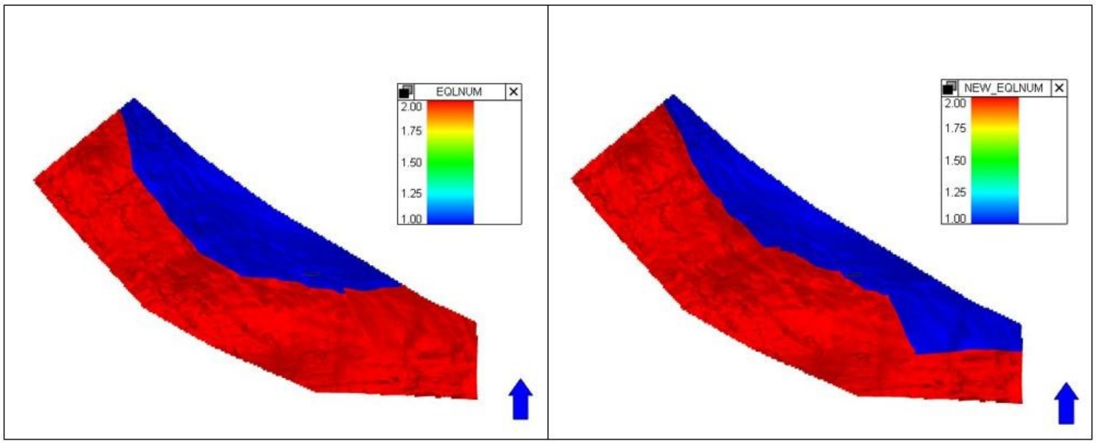

Figure 18: Primary EQULNUM left side & Corrected EQLNUM in right side (WOC Definition)

Table 20: parameters specification in two WOC regions

EQLNUM	Datum depth (m)	Datum Pressure (barsa)	WOC depth (m)
Region 1	750	90	920
Region 2	750	80	980

After initialization of the reservoir model, oil in place is in accordance with obtained oil in place form static model that is approximately 17.2 MM sm^3.

4.3.6 Comparing the Initial Model with historical performance

For such simulation, it is possible to assess how well the simulation model matched the historical performance data and at the same time obtain indications of what changes are required to reach better model. First glance is given to whether field injection and liquid production could be achieved or whether they could be reduced due to BHP control limits.

To run first simulation, liquid rate is selected as a well control for producers due to the fact that the export rates (liquid) are collected from three fields and then allocated back to individual fields. Moreover, water injection rate is chosen to control injector wells. Hence, in the preliminary simulation run the impact of BHP as control limit is evaluated and the results show the big discrepancy between simulated and original data (**Figure 19**).

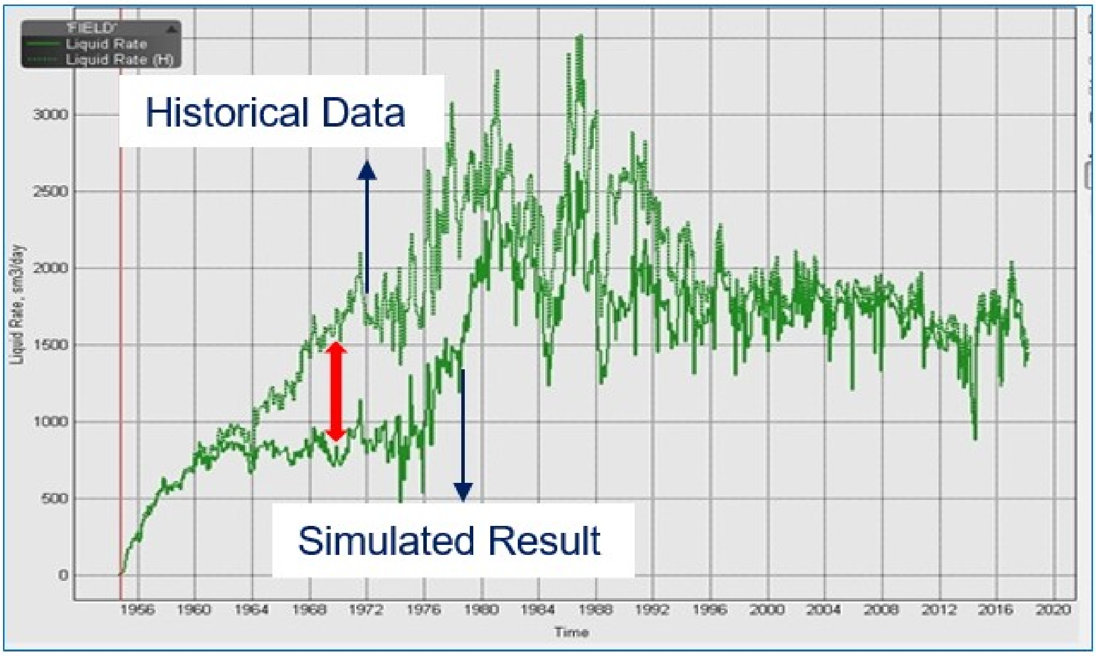

Figure 19: Liquid production rate no BHP well control

Subsequently, aquifer is attached to this initial model; otherwise, a significant gap between rates or total volume plots are appeared. The first aquifer set up based on zero capillary pressure, which indicates fully water saturated part (**Appendix Figure 11**).

To modify the base case model, additional constraint, BHP, is added to control production and injection wells, which set in the value of 20 and 110 bars, respectively. As it can be seen in **Figure 20**, water injector rate is experienced to have a major mismatch rather than water and oil or even liquid rates. Water cut as a saturation function has matched well from the beginning.

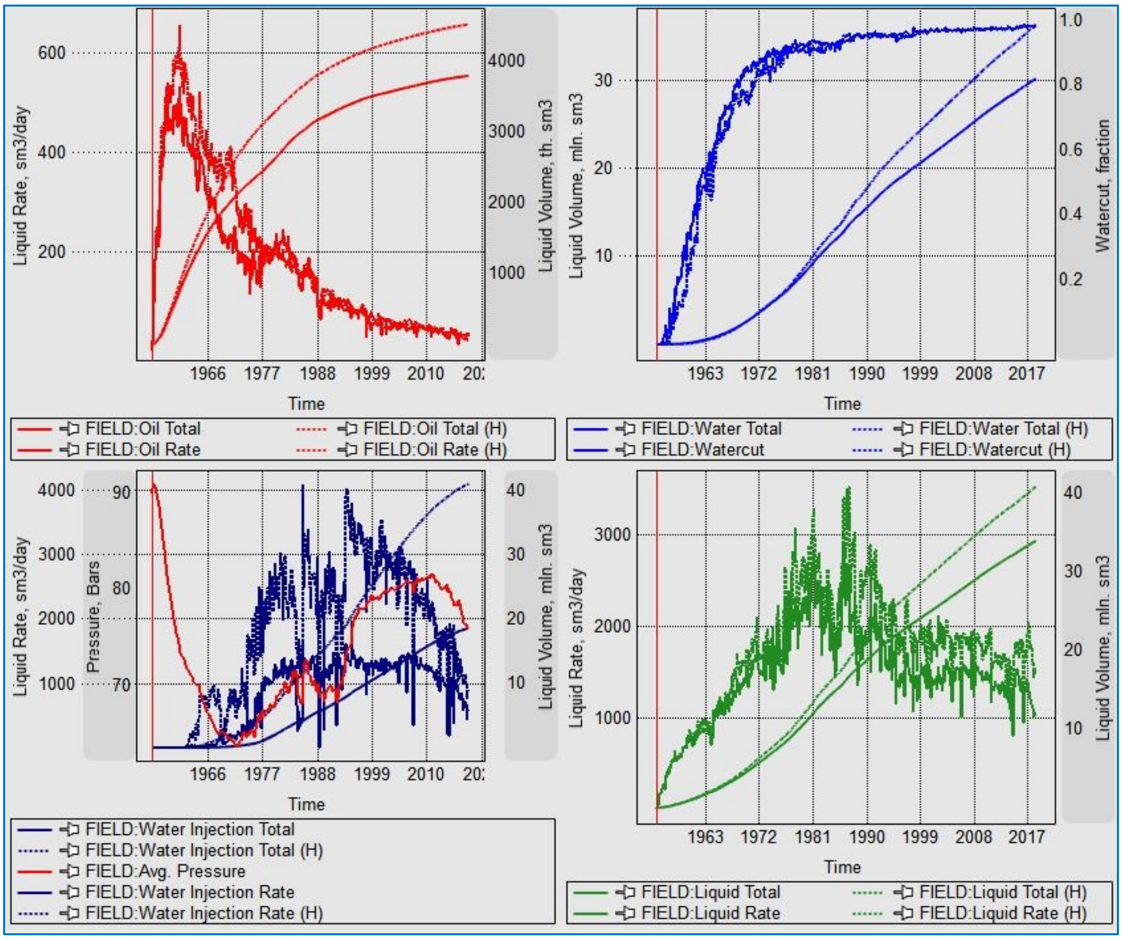

Figure 20: Initial model rate and total results without parameter changes

Secondly, the field pressure average needs to inquire into in terms of unlikely high or very low-pressure values and following the measured pressure trend in wells. Pressure distribution map illustrates some compartments fully isolated (**Appendix Figure 12**). Pressure is falling down less than bubble point pressure so that this area cannot get any support from any injectors or even aquifer.

4.3.7 Manual History Matching & Result

Prior to commence history-matching process, it will be wise to work out a set of study objectives and choose the important parameters that need to change. In this approach, even though perturbations have been made in trial and error fashion, they will not be randomly made but based on knowledge of the field and the geological understanding obtained from various sources. The most alterations have been applied globally or to individual layers. Although, the startup of the model calibration is global matching and then to proceed the advance matching, it should be pointed out to dive into varied parameters around individual wells is done in the next step. The selection of which parameters to perturb is focused on the uncertainty basis. If a parameter has a high degree of uncertainty but negligible effect on model response, it should disregard to change in the model. All of the sensitive parameters are investigated in this thesis showing in **Figure 21**.

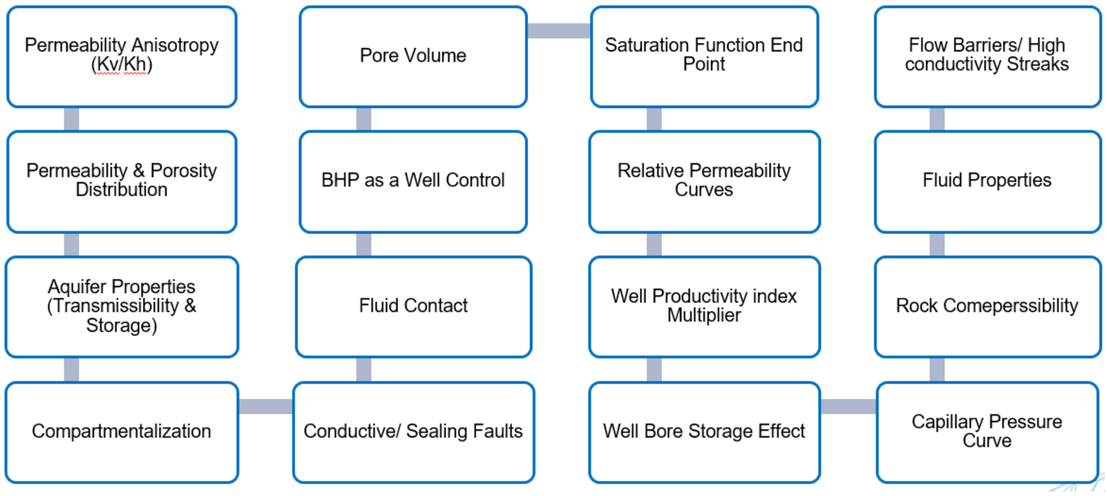

Figure 21: Sensitive parameters in this field of study

4.3.7.1 Permeability Anisotropy

Permeability is principally considered as the main matching parameter. Two different approaches can propose to assess the permeability calibration in this procedure (**Table 21**).

- Scenario 1: Using 3 facies trend distribution (**Appendix Figure 13** to **Appendix Figure 19**)
- Scenario 2: Using 5 facies trend distribution

Table 21: Sensitivity analysis on permeability modification (red value: final trial)

Rock type		**1**	**2**	**3**	**4**	**5**
Perm. range		K<1	1<K <10	10< K <100	100<K <1000	1000< K
Facies	Facies trend	Shale		Shaly sand	Sand	
Scenario 1:	No change in facies trend	Hetero. Perm.		Hetero. Perm.	Hetero. Perm.	
		10		200-300	500-700	
	Smoothness of facies trend	10		200-300	500-700	
Scenario 2:	No change in facies trend	-	-	*3 (1.2 to 5)	*3 (1.2 to 5)	-
		Kz=0.25*Kx (range of variation of multiplier from 0.1 to 1) Kx=Ky Max value Kx=3600 md Min value=0.001 md (range of variation from 0 to 500 md)				

As a conclusion of scenario 1, it seems to smooth the facies trend can be more matched to the reservoir description. Since this facies trend was determined based on the depositional knowledge regardless of any seismic attribute, it can be nonetheless modified to be further indicative of the reality. This will be highly recommended to the geologist to reconsider this issue.

In scenario 2, as **Figure 22** has illustrated, minimum value of permeability are predominated in shale division (SATNUM 1&2). Meanwhile, rock type 3 and 4 are dominant in the main part of the reservoir, which is rather oil saturated. From geological point of view, this overall change of permeability can be justified by underestimating of this property in the main part of the reservoir to be responsible for producing oil (**Appendix Figure 20**). Permeability difference histogram indicates the shifting of low value to higher value and correspondingly this mutation is substituted by better rock type (**Appendix Figure 21**).

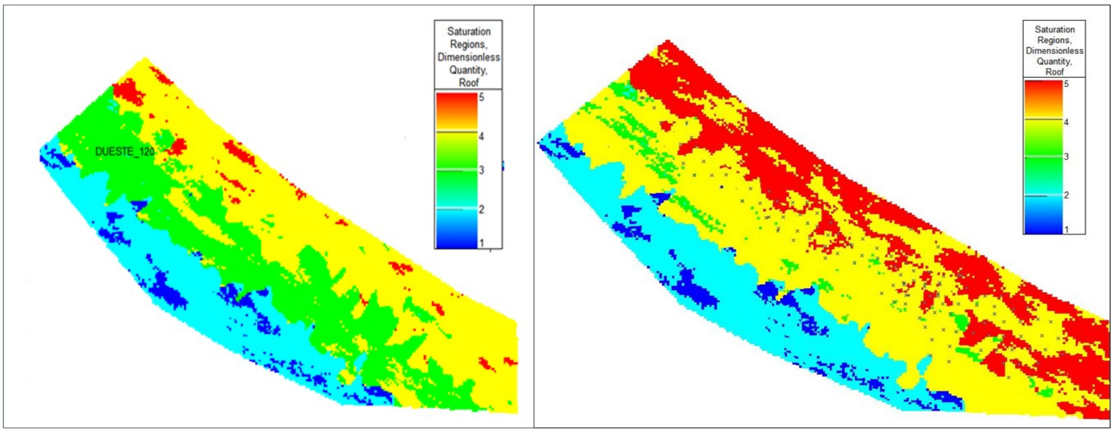

Figure 22: Rock type distribution, left side prior to permeability change &right side according the last alteration criteria.

4.3.7.2 Aquifer Strength

As water derive is determined as the main encroachment mechanism, the numerical simulation model should be associated to aquifer model in addition to the reservoir and fluid properties. Thus, the next step is to add an aquifer to the reservoir model to supply pressure to produce oil. The huge underlying aquifer will have the potential of water encroachment into production wells immediately. Aquifer modeling is a method of simulating large amount of water connected to the reservoir, whereby it is not necessary to know about fluid movement in it but rather how to influence on the reservoir response. To simulate aquifer, several aquifer models can be proposed including numerical, Carter Tracy, Fetkovich, constant flux, constant pressure and rainfall. Each aquifer model will have its own set of parameters and the capability of connection to the grid cells in different directions consisting of top down, bottom up, grid edges and or fault edges.

The aquifer model is one of the complex and sensitive parameter in history matching process. The variety of change in size and properties can be applied in analytical model aquifer regardless the alteration of productive area. The most appropriate aquifer properties for alteration, in approximate order of reducing uncertainty are aquifer storage and transmissibility.

In TNavigator to add an aquifer model, the interest area should be selected and add aquifer setting parameters and its direction. TNavigator aquifer models are limited to numerical model, also Carter Tracy and Fetkovich as analytical model. By changing related parameters in analytical and numerical aquifer model and running simulation, different aquifer models are evaluated with respect to pressure distribution analysis in the reservoir to find the evidence for heterogeneous aquifer properties and nonuniform water influx. Moreover, looking for the difference pressure distribution in the model and in the actual data from field that imply the presence of sealing faults, pinch out or even poor communication between zones or compartments and migration from nearby reservoir. Numerical and Carter Tracy aquifer model are neglected to build final aquifer model after the observed result.

Since the Fetkovich is approached to establish an optimal aquifer model, this method refers how to deal with the water influx issue without knowing the reservoir aquifer geometry. The developed model is mainly empirical and assumes a pseudo steady state flow behavior, which means a finite aquifer with a short transient period. With minor aquifer strength adjustment, the result is showing significantly improvement. Aquifer productivity index ranges investigated between 100 to 500 sm^3/day/bars. In addition, the extent of the aquifer is varied to achieve a best match. All terms necessary to determine the optimal analytical aquifer parameters based on Fetkovich approach are given in **Table 22**. **Appendix Figure 22** is indicative of different trial of aquifer extension in the entire field. **Figure 23** is final aquifer model which extended in WO and also EO fields.

Table 22: Aquifer setting parameters

Datum Depth (m)	750
Initial Pressure on datum (barsa)	95
Total Aquifer Compressibility (1/bars)	0.000145504
Aquifer productivity index (sm^3/day/bars)	150
Aquifer influx multiplier (m^2)	1
Aquifer size, Initial water volume in Aquifer (sm^3)	10^9
Aquifer Connectivity	+/-j, +/-k, -i

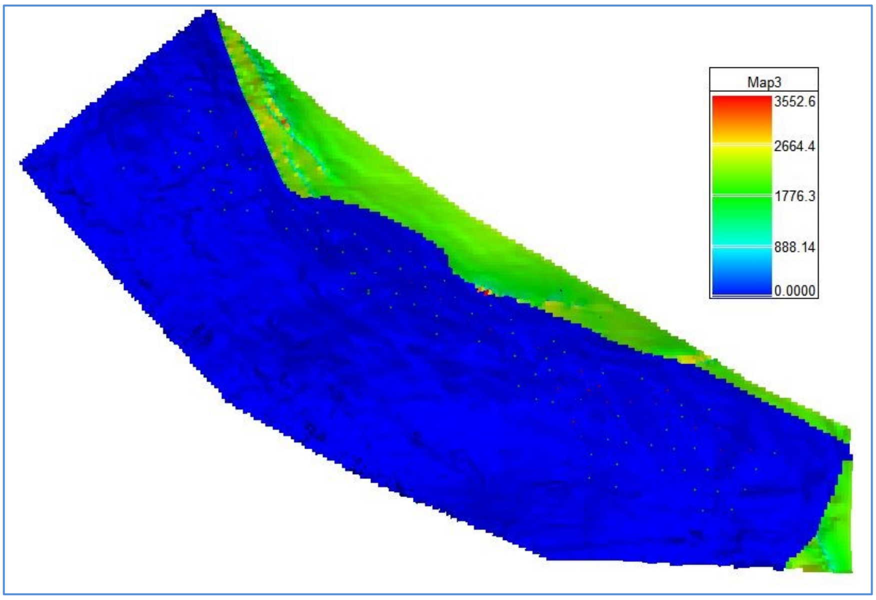

Figure 23: Finalized aquifer model in terms of extension

4.3.7.3 Faulting compartmentalization

The reservoir compartmentalization is recognized as the key global issue in this field (**Figure 24**). Accurate characterization of connectivity and compartmentalization of permeable reservoir or reservoir fluid-unit architecture is the necessity of any reservoir. Compartmentalization in the WO field is attributed to combine stratigeraphic and structural mechanisms. Lateral extensive stratigraphic barrier (Shale towards crest) and shale interbeded are diagnosed in this area; whilst large throw faults compartmentalize the reservoir laterally. The common goal is to characterize this compartmentalization with sufficient resolution so that fluid flow can be correctly moved throughout the reservoir. Besides, it can help to define right pressure maintenance in compartments.

In validation of input data section is confirmed the structural model requires realistically updating in terms of adding fault and situating the major fault beyond the predefined one. It should be noticed that one fault is manually supplemented to structure model between WO-71 and WO-46 play as a barrier to reduce the effect of aquifer support.

As primary attempt to eliminate the impact of soluble gas in isolated compartments obtained from the initialized model, non-neighboring grid cells should be connected to allow moving further fluid flow. Hereupon, using keyword NNC can help to connect grid cells along the faults. However, the definition of non-neighboring connection encounters some difficulty in this work. Since grid cells in the structural model is not specified in the appropriate direction, thus distorted grid cells with incomplete shape are mainly appeared along faults. It will be definitely proposed to reconstruct the structural model based on corner grid point or zigzag fault to have full shape of grid cell.

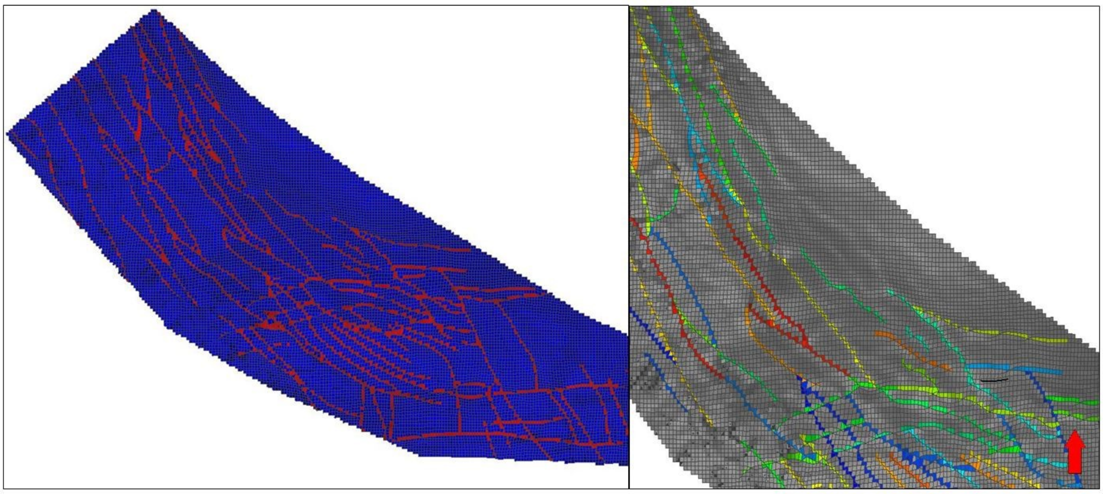

Figure 24: Fault compartmentalization, 54 segments

For some compartments, non-neighboring connection is corrected to preserve pressure after initialize the model. Thus, the issue related to the isolated compartments with drastic pressure dropping below bubble point pressure is literally solved.

During the adjustment of historical data and simulated result, transmissibility between segments should be tuned by keyword MULTFLT in order to prospect the fault transmissibility in the reservoir in terms of sealing fault, partial or full transmissible faults.

4.3.7.4 BHP as a well control

The impact of BHP as a control limit is presented in the base case model. To seek individual well pressure how well-treated regarding the predefined BHP in the base case model, Figure 49 shows that assigned value could not be sufficient in some wells to simulate well pressure properly. It is obvious that the BHP alteration can improve the strange fluctuated behavior. The range of BHP for producer is varied between 10 to 20 bars, meanwhile for injection wells, the variation is assumed from 110 to 150 bars to exclude instability in well pressure trend. The identical value cannot be finally fixed since well pressure plots illustrate the same behavior same as **Figure 25** again in spite of using 10 bar for producers and 150 bar for injectors that are really unrealistic. It is supposed that for these injectors and producers should undergo other reservoir properties to remove this spike. Even though, the specific order of magnitude is preserved for the main producers and injectors respect to 15 and 130 bars. Particularly, 150 bar as BHP is computed for two injectors, WO-H1 and WO-H2, which are exactly situated in the flank of the reservoir and drilled into aquifer.

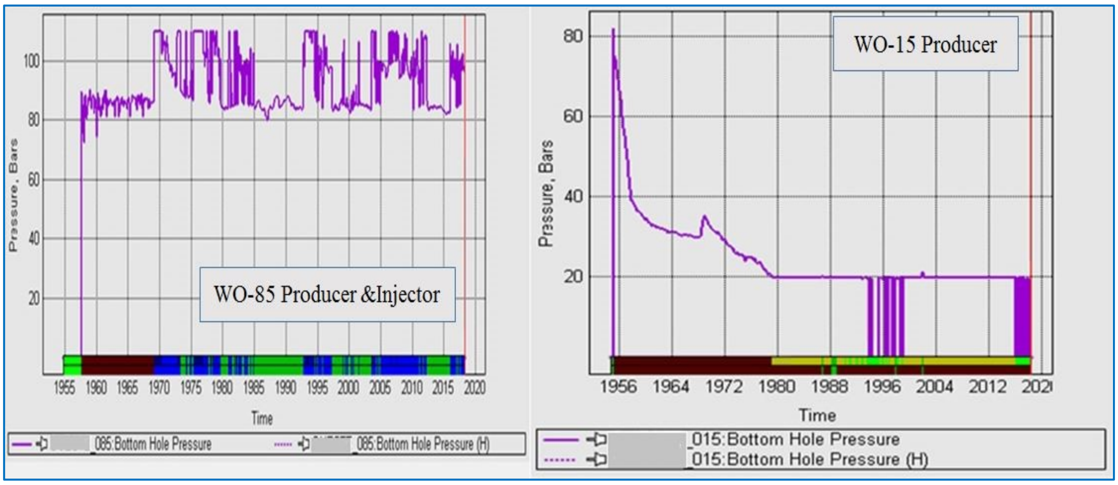

Figure 25: BHP pressure as a well constraint

4.3.7.5 Global History matching Result

A final match is obtained after several simulation runs, looking at the pressure distribution map in the first and last time step can show the issue related to isolated compartments in the initialization model are completely disappeared (**Figure 26**).

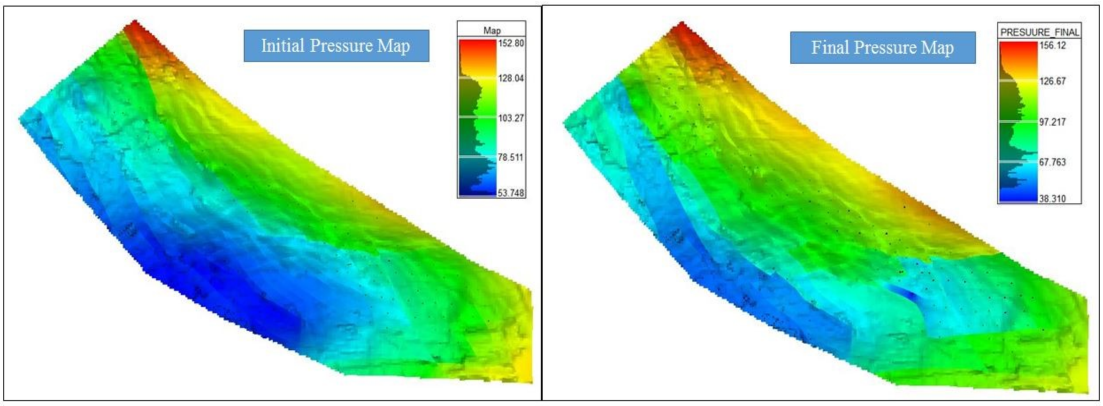

Figure 26: Pressure distribution map in the first and last time step

The final match is tested on the scenarios under consideration, namely: oil, water and liquid rats and their total production, water injection rate and total water cut and pressure. As it can be seen in **Figure 27**, Nonetheless, water cut and oil rate are required more investigation in detail and individual wells to achieve the precise adjustment, a very good match has obtained in water, oil and liquid total as well as liquid rate and water injection rate and total. In this work, the major parameters can contribute on result including, permeability modification, aquifer size, extent and connectivity, fault transmissibility in different compartments and BHP as well constraint. Other parameters consist of PVT data, rock compressibility, viscosity, saturation functions, gas solution ratio and porosity might have low degree of effect. The closeness of final match model to the historical model is an indication that the manual history matching method used is quite successful. Making the multiple perturbations by combinations and permutation, an appropriate match can be possibly achieved.

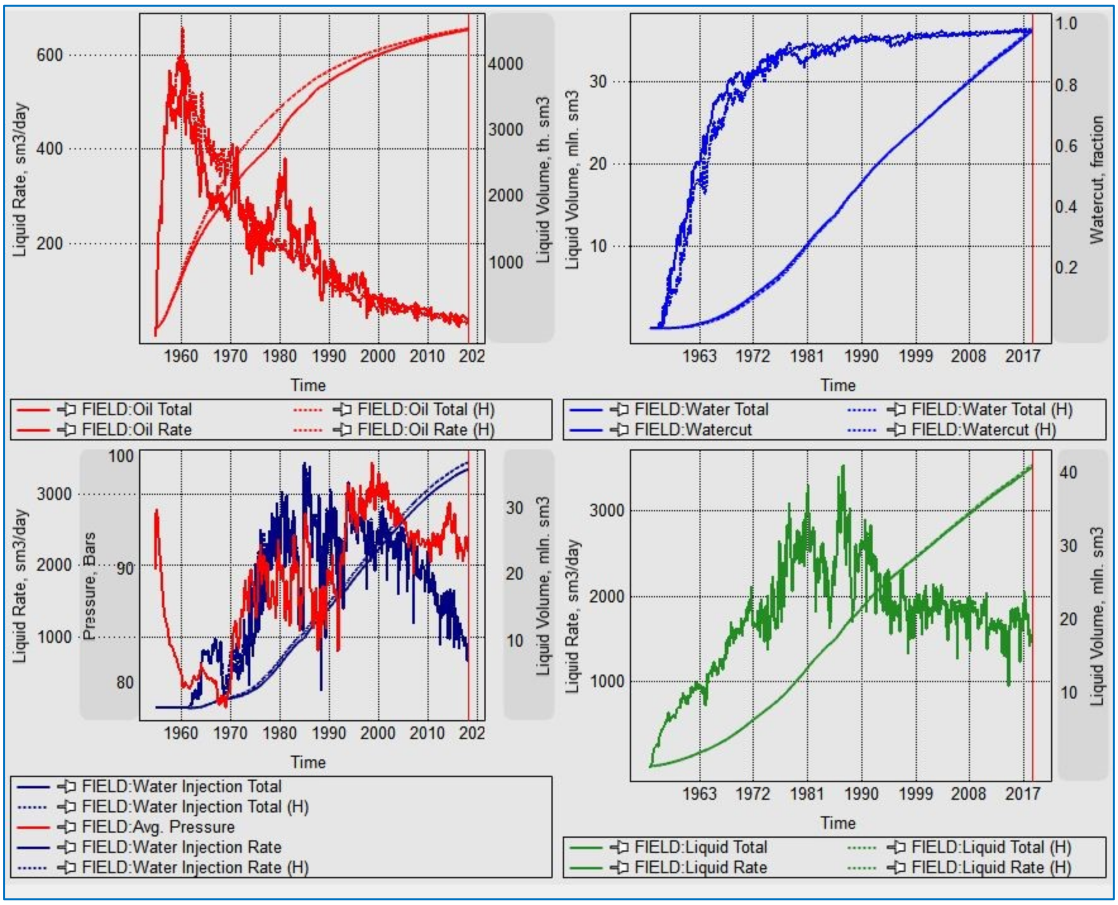

Figure 27: Rate and total results in the last running simulation (Global History Matching)

4.3.8 Assisted History Matching & Result

4.3.8.1 Optimization method

After global history matching, assisted history matching is employed to improve the calibration of historical performance and simulated one. Assisted history matching tools can be helpful to obtain multiple history-matched models, an order of magnitude faster than manual history matching process. Due to numerous uncertain parameters involved in this procedure, a primary screening deems to be essential. In order to seek the most sensitive ones should consider the history matching criteria and possibly to reduce the variation of variable. This is a pre-processing step of assisted history matching.

4.3.8.2 Variable Definition

To implement optimization approach, a sensitivity study is the preliminary step to scan the whole range of static and dynamic uncertain parameters. Only the most sensitive parameters with respect to an objective function quantifying the mismatch between the observations and simulation results are retained for the subsequent step. To design optimization model in assisted history matching, some effective variable are selected including vertical permeability, permeability multiplier for SATNUM 3 to 5 and additionally relative permeability and capillary pressure for mentioned SATNUM will the basis of perturbation (**Figure 28**). Regarding reservoir knowledge, other important parameters must be involved; however, there is a limitation to define some another variable in TNavigator particularly aquifer strength, well bore storage, BHP, etc. Moreover, determination of multiply fault transmissibility for all or even some of compartments will lead to crash the simulator.

Variable	Int.	Base	Min	Max	Values
✓ KV_KH		0.1	0.1	1	Alg. Defined
✓ M_PERM_SATNUM_3		1	0.1	2	Alg. Defined
✓ M_PERM_SATNUM_4		1	0.1	1.5	Alg. Defined
✓ M_PERM_SATNUM_5		1	0.1	1.1	Alg. Defined
✓ SATNUM_KRORW_S_3TO5		0.8	0.7	0.9	Alg. Defined
✓ SATNUM_KRO_S_3TO5		0.8	0.7	0.9	Alg. Defined
✓ SATNUM_KRWR_S_3TO5		0.5	0.4	0.6	Alg. Defined
✓ SATNUM_KRW_S_3TO5		1	0.9	1.1	Alg. Defined
✓ SATNUM_PCW_S_3TO5		-1.5324	-1.6324	-1.4324	Alg. Defined

Figure 28: Variable definitions to design optimization method

4.3.8.1 Optimization Result

The methods benchmarked are Response Surface, Differential Evolution, Particle Swarm Optimizer and Simplex Method. To benchmark consistently these techniques, a fixed set of variable is identified to examine all methods. Parteo chart of 4 methods are shown in **Figure 29**; optimization methods by changing the variable in the specified range indicate different positive and negative correlations. As it can be seen, the better results can be mainly affected by multiplier for SATNUM 5 and SATNUM 4 presented as positive correlation.

It is important to get the acceptable match for all identified objective functions including production and injection rates and total. To justify which optimization method will conclude the better result, it is required to compare different optimization methods in optimization plot regarding defined objective function. The best predictions in each optimization method are chosen to infer the best outcome (**Appendix Figure 23** to **Appendix Figure 26**).

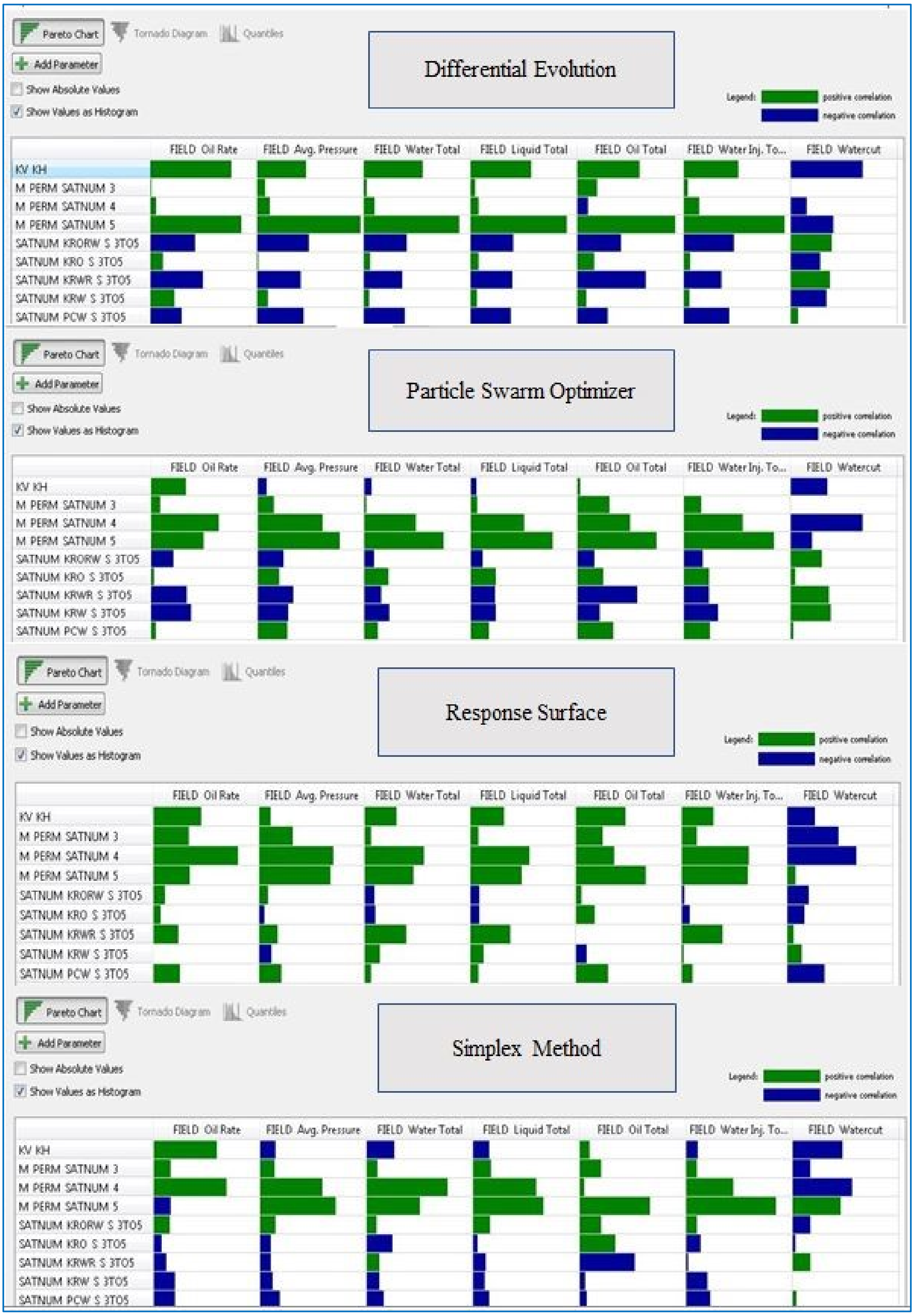

Figure 29: Comparison of Pareto chart of different optimization methods

From Response Surface approach can derive the best result (**Figure 30**). However, the problem of getting match in water cut and oil rate has still remained, not real enhancement appears by using assisted history matching. The main hassle comes up during the assisted history matching process related to determine variables in TNavigator. There is no possibility to generate variable to involve the broad range of matching criteria. Variables are dependent on aquifer transmissibility, aquifer storage, aquifer extent, skin, rock compressibility, or even BHP. Besides, one of the chief drawback of TNavigator is to specify variables for all segments in terms of mutation of fault transmissibility. Several attempts to perform are failed due to high number of compartmentalization.

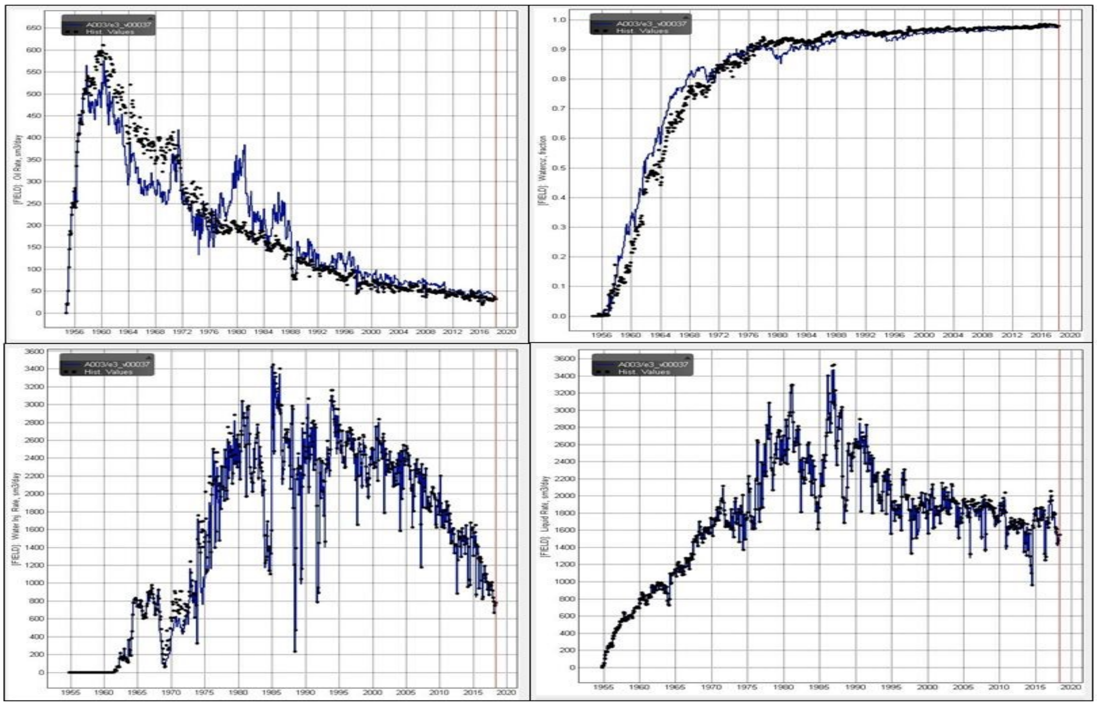

Figure 30: Best-obtained rate result based on Response Surface optimization method

Parteo chart of best obtained result from Response Surface indicates by multiply permeability of SATNUM 5; oil total showing positive correlation but having negative effect on water injection and production and liquid total. However, in SATNUM 4 illustrates completely the reversed impact (**Figure 31**)

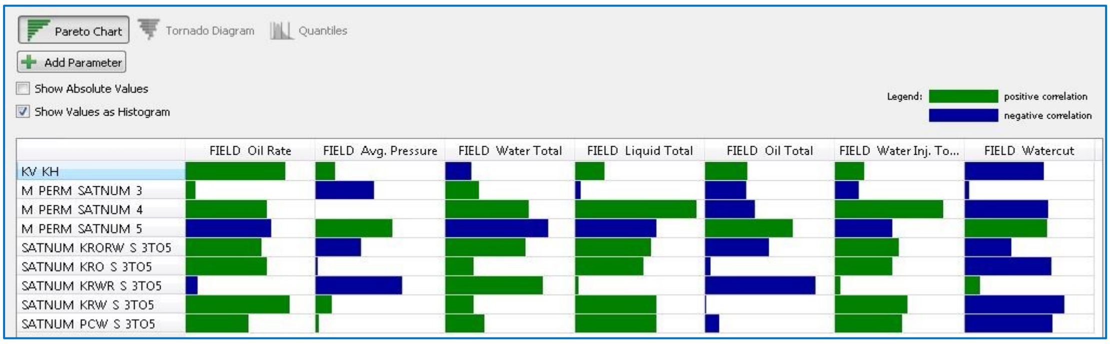

Figure 31: Pareto chart of best-obtained result based on Response Surface optimization method

Chapter 5

Modeling Tracer Application

5.1 Multi Well Test (MWT) Location

A location was selected for MWT based on successive meetings with operational people, geologist and reservoir engineers. A potentially suitable area constitues WO-22 as well injector and WO-73 and WO-140 as well producers in the field of interest. As mentioned previously, the WO field is a sandstone reservoir with a shale content gradient increasing from east towards west of field and average water cut of 97 %. The selected wells have produced more than 60 years with the perforation depth around 950 m (Alkan H., 2015). The properties of oil and water phase sampled from studied field and tracer components are given in **Appendix Figure 27**.

Prior to the pilot project, three main activities were investigated to prepare wells for the pilot. The well integrity assessment remarked as the first activity to make certain of the injection fluid to the target reservoir. The second important activity was the injectivity test which must be conducted to verify the wellbore characteristics. The last one was fall off test which to certify the reservoir properties; thus, it can be applied to fine-tune the reservoir simulation model and operation parameters (Admita P., 2017).

As a numerical simulation has been an inevitable part of a field application, the production performance was predicted in the pilot project by the numerical implementation established and validated by Wintershall using CMG-STAR (Alkan H., 2015). This MEOR model was calibrated with laboratory data consisting of growth curves, measured metabolite properties and dynamic experiments which are upscaled to the field scale (Alkan, 2016).

Three wells including two producers and one injector were assigned to be more investigated in terms of corresponding to the field test: two producers, WO-140 and WO-73, which are placed at 427 and 252 meters from WO-22 as an injector, respectively (**Figure 32**).

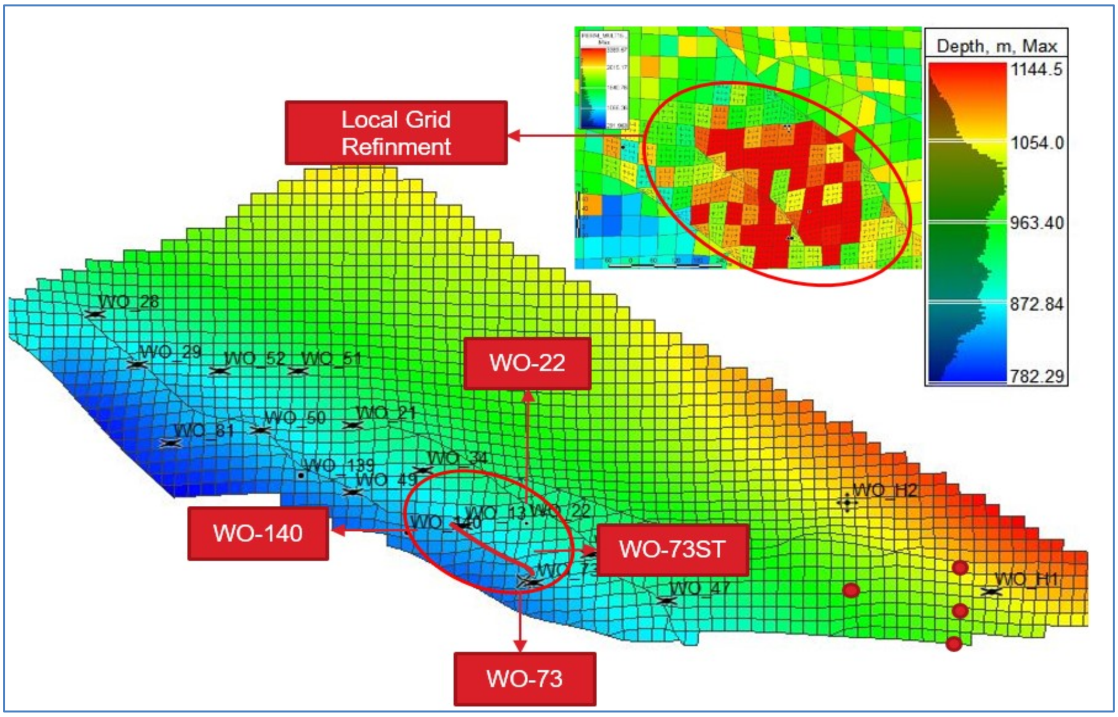

Figure 32: Map of the MWT location

5.1.1 Tracer Application

Prior to multi well test in the field test, as a part of the comprehensive monitoring and surveillance program for MEOR pilot project, the tracer injection was designed and implemented to verify reservoir connectivity between injector and producers and additionally water breakthrough time. The tracer injection was performed on 7th Feb 2017 to identify the connectivity between the selected wells for MEOR MWT operation.

The chemical structure of the used tracer was reported in a general form as ‘’organic acids and derivatives/ salts acids’’ which was coded by company as IF-WT-12 product. As a matter of fact, the tracer components are compatible in both aqueous fluid as salts and in organic based fluid as acids.

5.2 Tracer Simulation

A sector model is cropped from full field reservoir model, which is calibrated preliminary to the historical performance of the field being representative of multi well test location. To choose sector boundaries, it should avoid splitting the model in the areas with high phase flow.

Otherwise, intensive flow problems can bring about either incorrect model behavior with no flow or inconsistency during model boundary updates. It is important to rerun the simulation after splitting to create influx boundary. **Appendix Figure 28** to **Appendix Figure 33** have illustrated reservoir characteristic in the sector model. Moreover, specific area was regarded for grid refinement because following the tracer concentration are expected to be apparent. **Table 23** describes the reservoir properties in the cropped section.

Table 23: Reservoir properties of the cropped sector reservoir model

Properties in MWT	
Injector	WO-22
Producers	WO-73, WO-73ST, WO-140
Porosity Range	19%-24%
Permeability range	600-1600 mD
Average Depth	800-870 mTVDSS
Average Pressure	110 bar
Distance from Injector	WO-73 ~ 240m
	WO-73ST ~ 120m
	WO-140 ~ 420m

An inter-well tracer project was conducted in the pilot area to validate the need of a conformance treatment to improve the understanding of the reservoir connectivity. Subsequently, a simulation approach is taken in TNavigator to model tracer injection operation and focused on predicting the breakthrough time of the tracer in producers WO-140 and WO-73 and a proposed sidetrack well, WO-73ST .

No tracer breakthrough was observed in the neighboring production wells after 10 months (The end of November 2017). Whilst, forecasting of the last tracer modeling approach indicated that the tracer breakthrough time in WO-73 was by the end of July 2017 and in WO-140 was by the end of November 2017. Therefore, the previous tracer prediction result cannot correspond to the actual tracer concentration in production wells. It can prove the presence of an apparent heterogeneity or flow barrier that were not anticipated at the beginning of the pilot.

The understanding of the field connectivity and heterogeneity had evolved since the static model was updated in 2015, and then simulated production flow was matched to the real historical production data in the full field simulation model in 2015. According to the tracer result, inter-well connectivity predictions suffered from some loss of accuracy with the old simulation model, but the another predictions nonetheless provided useful information. To diminish the observed mismatch between flow simulation model and actual reservoir response, the seismic survey was reinterpreted and used to construct a new static model, and finally delivered to reservoir engineer in July 2018 in order to create a new reservoir simulation model. The new structural interpretation has reflected slightly change in the fault patterns which also confirmed the existence of one fault NW-SE oriented in the MEOR pilot area between injector and 2 producers. Hence, the next phase of MEOR for implementing multi well test can be affected by the presence of new interpreted fault. The new detected fault in seismic reinterpretation showing more than 10 meters throwing can lead to less connection in neighboring cells. Accordingly, the connectivity between producers and injector can be remarkably influenced by this fault.

5.2.1 New well objective and consideration

Since one of the biggest issue in MEOR pilot project is flow connection between production and injection wells, drilling of one sidetrack which deviated from WO-73 is approached to cope with the faced issue. The main objective of the sidetrack is to provide flow connection in the MEOR pilot area. A couple of consideration about positioning and target entry point should be taken into account:

- ✓ The entry point should be preferably situated approximately 150 m away from the injector well, to obtain better results for the multi-well MEOR test.
- ✓ The sidetrack well from WO-73 has already designed to be located at least 50 meters away from a mapped fault.
- ✓ The target point should be positioned as close as possible to the currently existing WO-73 well.
- ✓ The target point should be situated as preferential as possible with regards to the flow direction coming from well WO-22.

5.2.2 Methodology

The new reservoir simulation model in accordance with updated seismic interpretation was set up to model the tracer. Briefly, to optimize the simulations and reduce simulation time without reducing the numerical accuracy (Huseby E. S., 2012), the number of grid blocks was minimized by using sector model; However, the area of interest was locally refined to increase the consistency of dynamic flow in reality.

The new tracer model was generated using RESTART file from the base case model and was run until the February 2019 (2 years prediction). In this case, 5 Kg of detectable active tracer components is used to estimate the tracer concentration in the model instead of 67 liters of injected tracer. Moreover, the tracer injection duration was specified for 30 minutes (**Table 24**).

Table 24: Tracer injection operation in well WO-22

Injection Well	**WO-022**
Tracer	IFE-WT-12
Ave. WO_022 injection rate	~ 180sm3/day
Tracer concentration input to the simulator	0.001333
Weight, active component	5 kg
Volume	~ 67 Liter
Injection Duration	~ 30 minutes
Injection Date	7 February 2017

The tracer adsorption on a rock and decay of tracer with time can be ignored with regard to the used components of tracer. WTRACER is used as a keyword to enable simulating the tracer that specifies the value of concentration of the tracer in the injection streams of its associated phase for flooding. An obvious use of tracer data is thus to obtain information on the mass transport of the injected fluid to easily track in the target reservoir.

5.2.3 Interpretation of Tracer result

By using Tnavigator to develop the tracer injection model, the interpretation of the tracer breakthrough time is carried out on the basis of the calculated tracer production concentration rather than the interactive cross-sectional profile. Using cross sectional profile could lead to mislead since the predicted result has been constrained by the palette coloring (set values) which does not necessarily represent the actual detection limit of the tracer concentration.

5.3 Streamline analysis

In all the simulations, flow is considered to be compressible. PVT properties in black oil system can be identified as a robust function of pressure, and voidage replacement ration (reservoir volume in/out) can deviate considerably from unity either locally or on a field basis leading to strong pressure change. The correct initial condition can be mapped into the streamlines, particularly the conditions at the end of the previous step and moved forward to in time numerically. Two important assumptions in particular are worth mentioning: first assumption is to know source and sinks corresponding wells. Indeed, all streamlines must start in the source (an injector) and end up in the sink (producers). The second one describes the flow rate along each streamline to be constant. The second assumption is particularly substantial as it implies that transport along streamline. In compressible flow, streamlines can initiate or terminate in any grid block, which act as a source or sink due to the compressible nature of system as well (Marco R., 2001).

The single most attractive feature is the visual power of streamlines in outlining flow pattern. Streamlines can clearly show how wells, reservoir geometry and heterogeneity interact to dictate where flow is coming from (injector) and additionally, where flow is going to (producer). It is not eccentric to observe wells communicating with other wells far from the expected pattern. Meanwhile, such behavior might be attributable to any error or wrong interpretation in geological model (Marco R., 2001).

In this case, streamlines start in the aquifer or injector and end up in producers. As time increases and the pressure transient moves further out, the streamlines will cover a large area of the reservoir. Flow visualization reveals that WO-22 as the injector can particularly support WO-73 & WO-73ST but not much WO-140. According to new seismic interpretation, the impact of the defined fault with 0.5 fault transmissibility is clear in streamline pattern. Thus, the observed pattern can conform the expected distribution of the fluid in the reservoir. **Figure 33** and **Figure 34** can show the effect of new detected fault in streamlines.

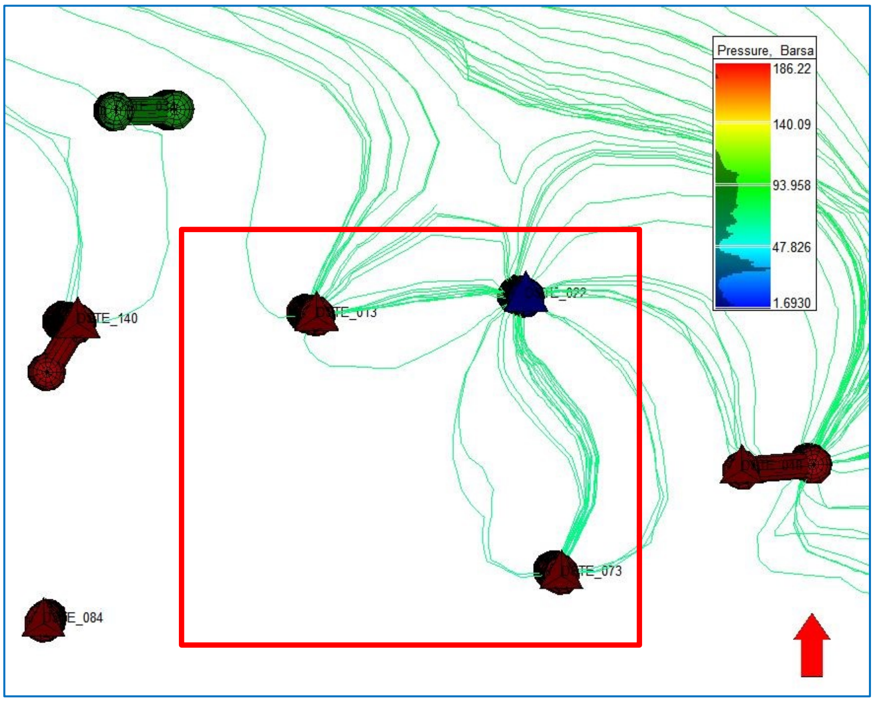

Figure 33: Streamline pattern in MWT location before adding fault

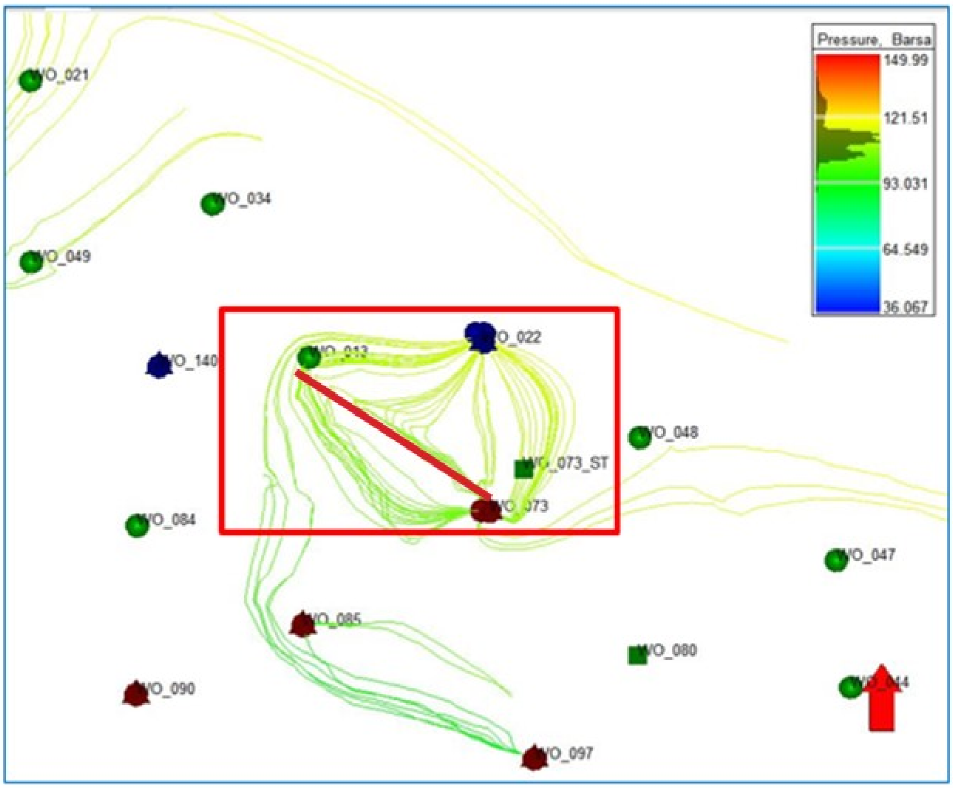

Figure 34: Streamline pattern in MWT location after adding fault with transmissibility 0.5

5.4 Sensitivity Analysis

This section is described the sensitivities of the injected tracer and will elaborate the interpretation results. In principle, two different scenarios are followed with respect to new findings in the reservoir characterization. New tracer modeling is essentially set up in the new simulation model associated with new detected fault in MEOR pilot area.

The first scenario will investigate the tracer breakthrough time in two producers, WO-73 and WO-140, those predictions are subject to validate results from the real case. Furthermore, the longer forecast time is established regarding the variation of fault transmissibility to observe the tracer breakthrough if it could be achieved until the end of prediction period. The production data is updated until April 2018. The prediction of tracer in sidetrack well is basically considered as a second scenario and the response of spatial distribution of permeability heterogeneities should be mainly investigated. It is noteworthy to mention that the short breakthrough time is an indicative of the presence of major conduits or high permeability in tracer analysis. Whilst, the longer breakthrough time is a representative of high degree of tortuosity, the presence of faults, change of facies or even better volumetric sweep (Modiu Sanni L., 2017).

5.4.1 Scenario 1: Producers WO-73 & WO-140

Appendix Table 1 to **Appendix Table 3** are the result of simulation run regarding the scenario 1, **Figure 35** and **Figure 36** are illustrative of production concentration in two interest producers. By taking the typical peak concentration of 5 ppb into consideration, no breakthrough time cannot be distinguished in the simulated case. The only reason might be the fault throwing which can create discontinuity along the faults and have a leading impact on transient flow between the injector and producers.

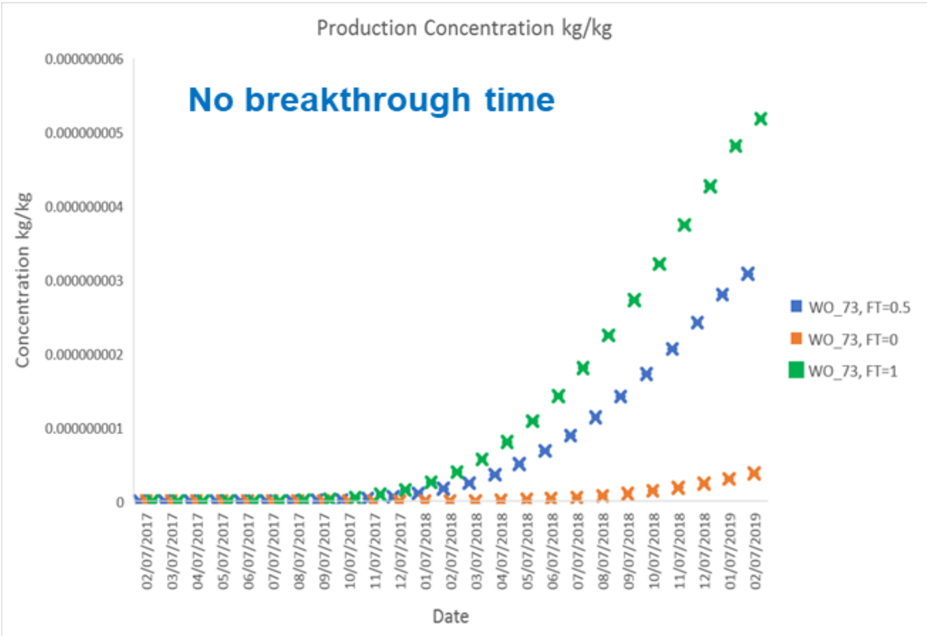

Figure 35: schematic of tracer concentration curve in WO-140 well

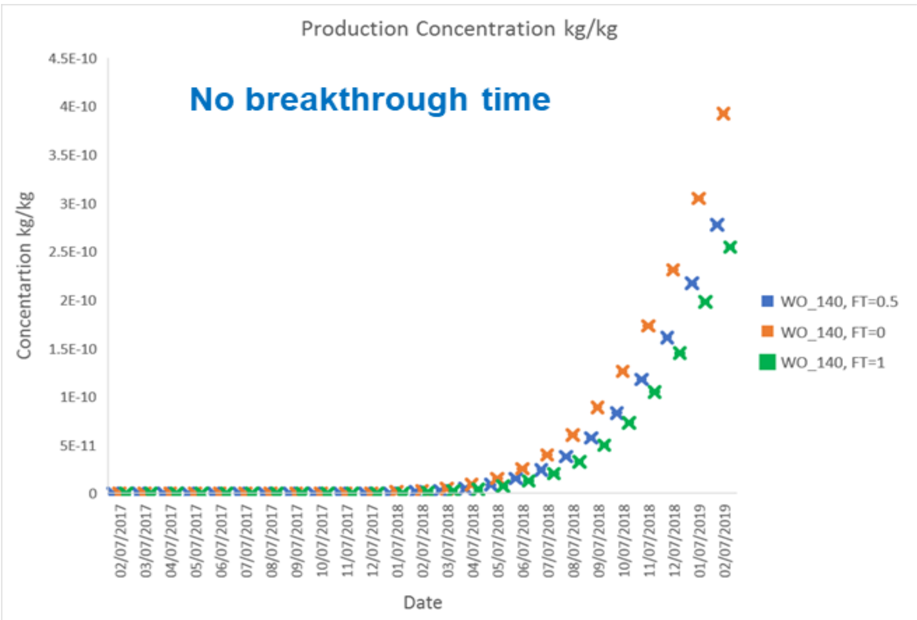

Figure 36: schematic of tracer concentration curve in WO-73 well

5.4.2 Scenario 2: Proposed producer, WO-73ST

- No change in permeability distribution (Base case)
- Increase permeability regarding facies transition (PERM*1.5)
- Decrease permeability regarding facies transition (PERM*0.5)
- Vertical permeability change (PERMZ*5)

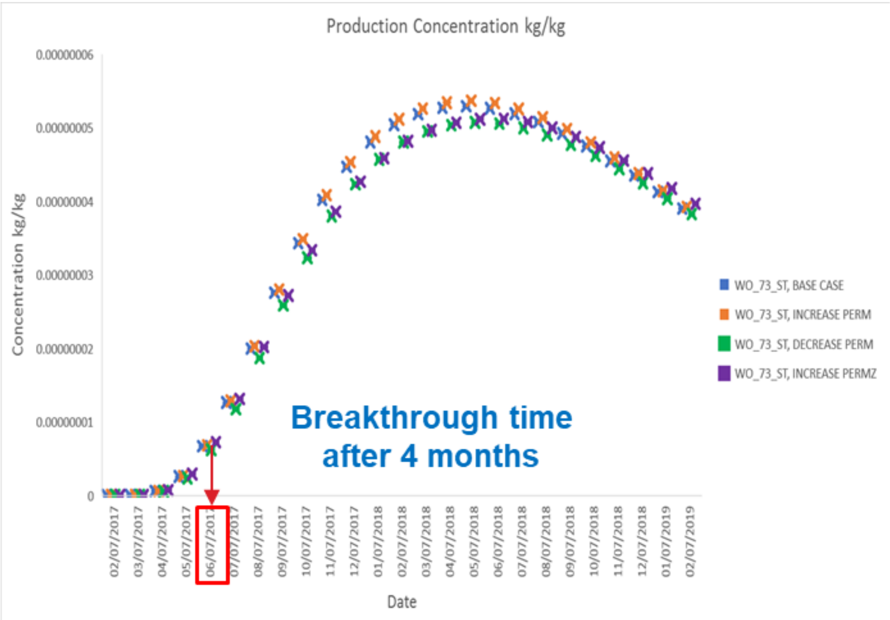

Figure 37: schematic of tracer concentration curve in WO-73ST well

Tracer curve analysis (**Figure 37**) in the case of adding the designed sidetrack indicates the connectivity pattern between injector and producer pair. Tracer breakthrough time is recognized for all cases at the same month, June 2017 with respect to the typical peak concentration of 5 ppb (**Appendix Table 4**). As a conclusion, heterogeneity of the reservoir cannot substantially influence on the tracer result in this case since the distance of production and injection wells is chosen as close as possible.

Chapter 6

Discussion and Results

6.1 Static Model and Seismic Interpretation

- The important concern in this study is compartmentalization and fault definition in terms of fault displacement, fault positioning, and degree of compartmentalization. Due to high fault throw in some segments, some compartments are fully isolated and cannot get any pressure support. Several compartments cover only small parts of the reservoir, in order to eliminate the effect of this fault compartmentalization, the merging of these compartments to neighbors could infer the faster converge to the match and more accurate structural definition.
- Besides, seismic re-interpretation will require modifying in terms of reservoir characterization. Since the defined major fault is used to determine regions with respect to two distinct OWC regions, the position of this main fault is not precise. With regard to the inappropriate definition of WOC regions, the significant gap between observed data and simulated one can be illustrative thus the impact of this definition is approved during history matching process. The boundary, which can separate two regions (EQLNUM), is manually changed in this work to be representative of actual water oil contact regions. Moreover, the boundary is extended to involve some parts of EO field.
- According to production data, one minor fault is manually added to reservoir simulation model. It should be better to update structural model for further simulation study.
- It this thesis, only properties biased to facies are involved to use in the process of history matching simulation model, it is recommended to use stochastic distribution properties to assess the outcome. Moreover, the necessity of modifying facies trend is

highly recommended. As a matter of the fact, reservoir properties are populated based on facies trend and therefore, the transition from shale to sand (shale and Sand lines) has significant contribution on the reservoir description and eventually the adjustment of historical reservoir performance to the simulated one.

- As permeability anisotropy is regarded as a main uncertainty, the evaluation of permeability distribution during the match process indicates that the permeability range cannot be indeed as low as the propagated one and underestimated. Thus, it is required to multiple the permeability at least in production part of the reservoir not only due to allow more drainage around the well bore but also due to pressure maintenance that is supported by aquifer term or injectors.
- Moreover, it is highly recommended to run different realizations in static model to create different property distribution either biased or non-biased to facies. Therefore, it can be helpful to provide an alternative history match and assess the quality of different reservoir property distribution during history matching process in terms of better reservoir characterization.
- It is proposed to modify geometry of grid cells in terms of using appropriate direction along major faults and eliminate intentionally the cut shape of grid cells by using another method of pillar gridding to benefit the complete shape of grid cells.
- This should be worthy to mention that if the static model is generated in any version of PETREL software, the rescue file or any other exported file must be derived from the exact same version. This hassle came up in the beginning of this work; it took huge time to figure out what was the main reason of appeared inconsistency.

6.2 Dynamic Reservoir Model

- A global history matching is successfully achieved by making perturbations in a trial and error fashion. However, all alterations have been made in accordance with available information and geological understanding of the reservoir. The verification of input data and data preparation to import to simualtor is very tedious and tough to perform. However, this step is considered as a main step to reduce somewhat the uncertainty in the reservoir. It is noteworthy to mention that all of mutations made to WO-EO fields are realistic or at least possible regarding the initial non-matched model. However, there is nonetheless some discrepancy between the calibrated model and historical data, which should be elaborated.
- Stochastic property propagation is one of main reason existing slightly mismatch, as the concept of stochastic models biased to facies are highly heterogeneous and

uncertain, thus there is no capability to model more homogenous sand (sand part of reservoir) and continuous channels that may be present in the reservoir architecture.

- The obtained match can be one of several possible solutions due to non-unique nature of history matching problems. Thus, multiple equi-probable history matched models might be expected in addition to the presented one in this thesis. It is believed that injection historical data has been erroneously allocated in EO-Field due to sharp increment in August 1993.
- Incorporate new production and injection data to keep the history matched update. In addition, continue the history matching for individual wells to obtain the better match more locally. The more reliable match can provide accurate predictions in order to utilize in the purpose of drilling new wells or MEOR pilot plan in the reservoir.
- One of the biggest challenges is facing the issue related to calculated BHP and THP due to regarded inconsistency. It seems to be unlikely the whole computed flowing and static pressure being capable to utilize in the improvement of history matching.
- Relative permeability and capillary pressure curves might be required to change slightly with respect to the result of optimization method. Although, any alteration of end point saturation or even relative permeability curve might be poorly resulted in global behavior of matching.
- The manual history matching is most preferable in this compartmentalized reservoir due to the weakness of assisted history matching workflow in Tnavigator.
- Using assisted history matching tools cannot significantly improve the achieved history matching. Nevertheless, the best outcome is resulted in Response Surface as a optimization method.

6.3 Tracer Simulation

- Monitoring the injected tracer and validating to actual response of the tracer concentration have provided valuable information concerning the impact of faulting and reservoir properties on fluid migration within the reservoir, which has been used to guide calibration of updating model.
- The tracer data have been used to reduce uncertainty attributed to inter-well communication and vertical barrier and lateral heterogeneity. Combining tracer and simulation allows the highlighting of possible issues, and what possible solution or remedial actions can be applied.
- Accordingly, the designed well sidetrack can obviously detect tracer; therefore, it will substantially be a best candidate to investigate for MEOR pilot project.

- To predict the reliable tracer breakthrough times with simulators, history matching must be captured for individual wells in one bigger sector with neighboring wells and particularly in wells of MEOR study.
- Aquifer plays a significant role in the field behavior specifically MEOR section due to vicinity to aquifer. Geometry and fault transmissibility as important parameters to perform history matching should bring into account to optimize MEOR strategy planning.
- Analyze streamlines shows each well how to behave as a source and sink when is near to aquifer or imposed by injectors.
- Advanced tracer analysis is highly recommended to use compositional model and streamline together due to the fact that the compositional simulation model can be more reflective of the flow dynamic of phases in the reservoir; thus, the different breakthrough time either earlier or later can be acquired in the compositional model in terms of the importance of well placement strategy.

6.4 Reservoir Simulator (TNavigator)

- The last but not least subject is the software challenge being problematic issue in this thesis. Even though, TNavigator is user friendly in some manners, there is a variety of visualization bugs that should be modified. Some efforts are made to realize about software obstacle and how to overcome. That is indeed time consuming to find out the appropriate solution in the case of encountering difficulties.
- Although, model designer in TNavigator can provide an easy way to create the simulation model, it is exhausting to use model designer to update or modify some works in the most cases.
- Another obstacle is how to apply some particular keywords or whether it can have a negative or positive effect on the reservoir model. Besides, the some methods or keywords are described in the tutorials; meanwhile they cannot be implemented as simple as illustrated ones. It is almost always required to keep in touch with supportive team and reported any obstacle.
- When the newest version is launched, opening the reservoir model in new version can remove some defined parameters; therefore, quality control is substantial. It should be worthy to note that rescue file derived from PETREL model must be crosschecked, in addition another input data to ensure about the validation of imported data.

Chapter 7

Conclusion

- Static model must be revised for in terms of structural definition, reservoir property distribution.
- Global history matching on the full field model is successfully achieved by changing most sensitive parameters which are elaborated in the beginning of history matching process.
- As the manual HM model is already good enough, the assisted history matching can not help to improve history matching.
- Proposed well WO-73ST shows the connectivity of injector and producer in MWT.
- New proposed well can be used in next work package of MEOR studies regarding implementation of MWT.
- It is highly recommended to proceed individual history matching to obtain locally better adjustment.

Chapter 8

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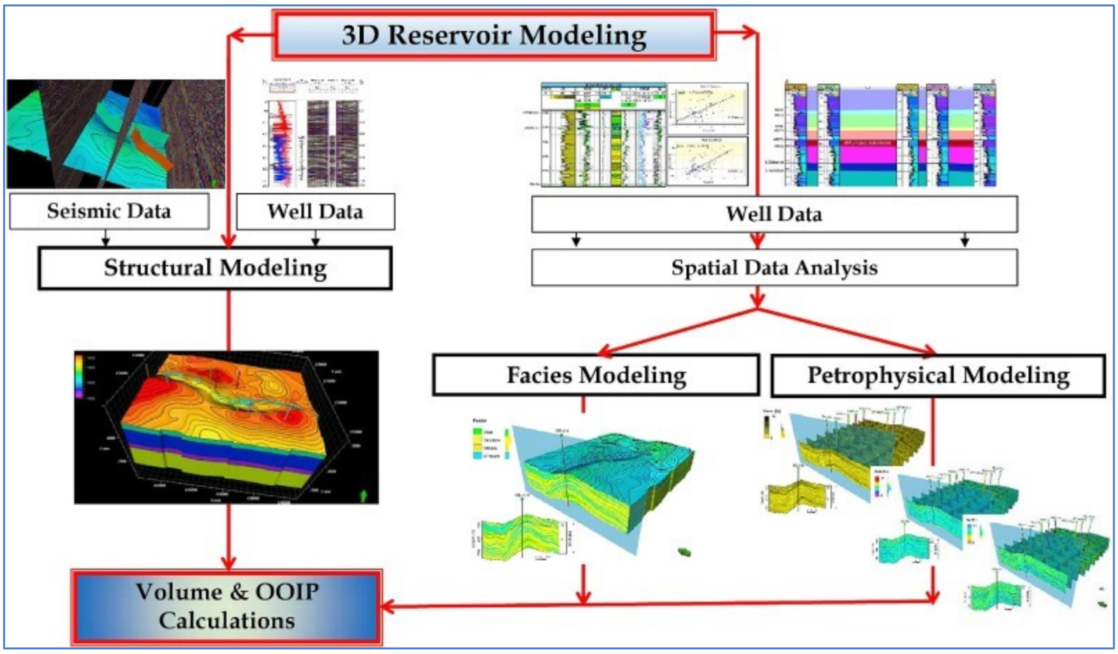
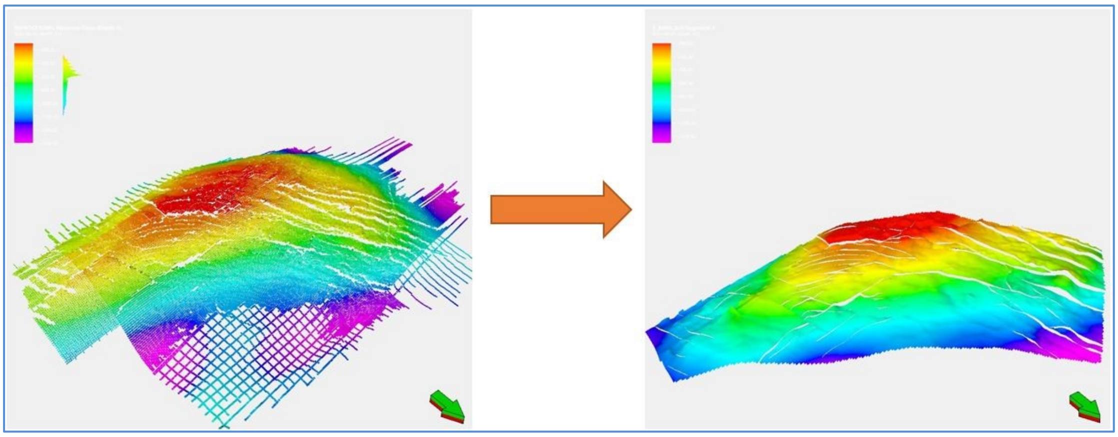
Appendix A

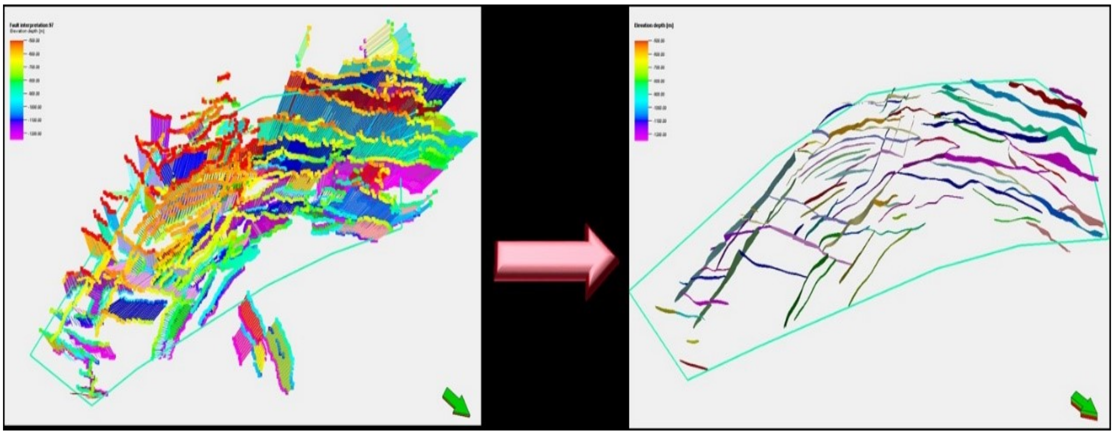
A.1 Static Model



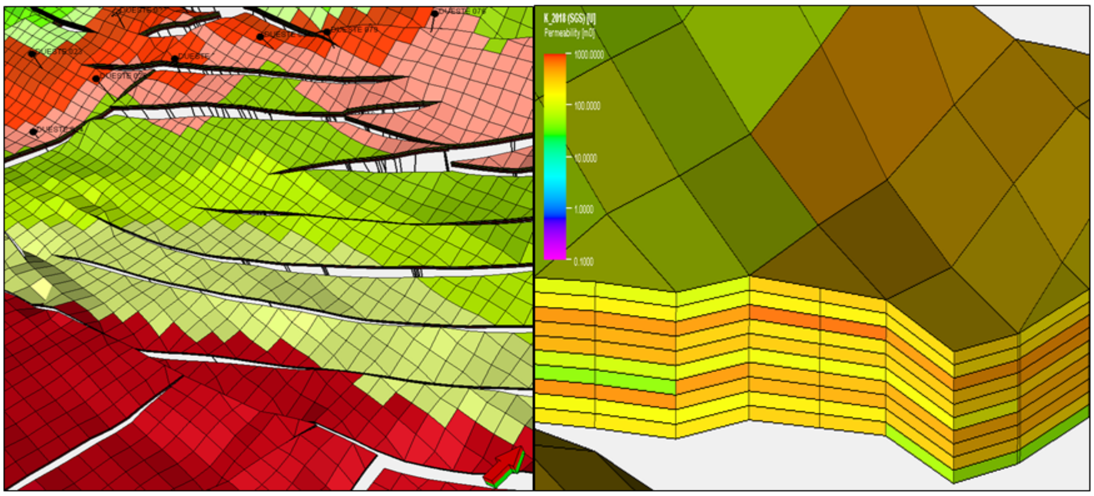
Appendix Figure 1: General Workflow of static model



Appendix Figure 2: Seismic horizon interpretation on the left and the structural model in the right side



Appendix Figure 3: Seismic Fault interpretation on the left and the structural model in the right side

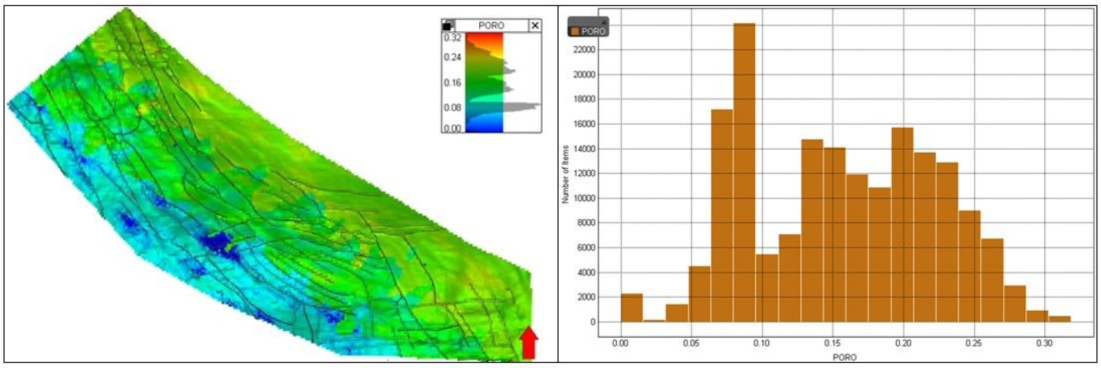


Appendix Figure 4: Proportional layering building from top to the base of reservoir

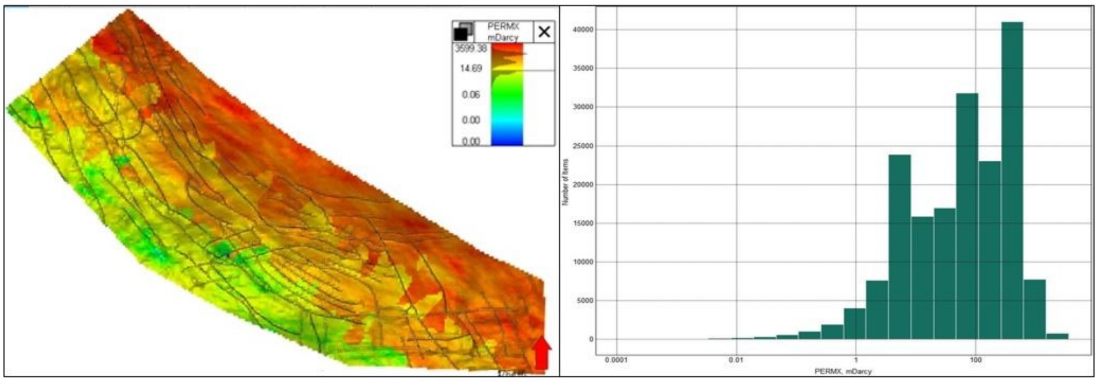
Appendix B

B.1 Validation of data

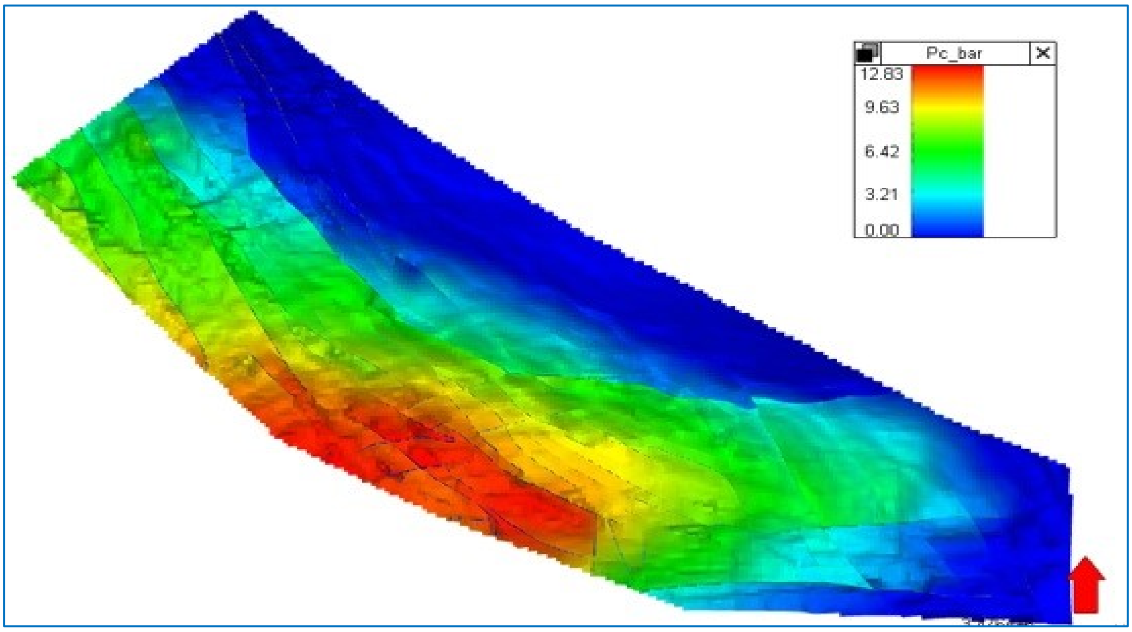
B.1.1 Porosity and permeability



Appendix Figure 5: Porosity distribution map and histogram

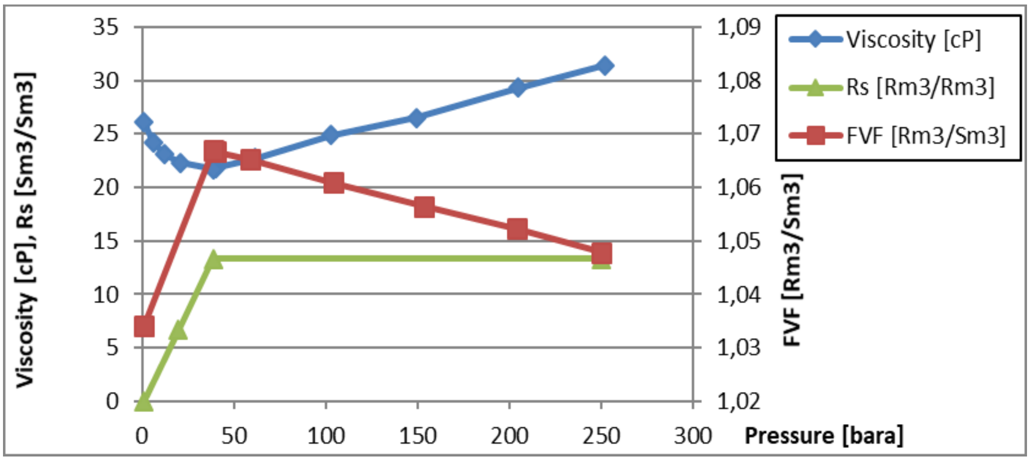


Appendix Figure 6: Permeability distribution map and histogram



Appendix Figure 7: Capillary pressure distribution map regarding 5 defined rock types

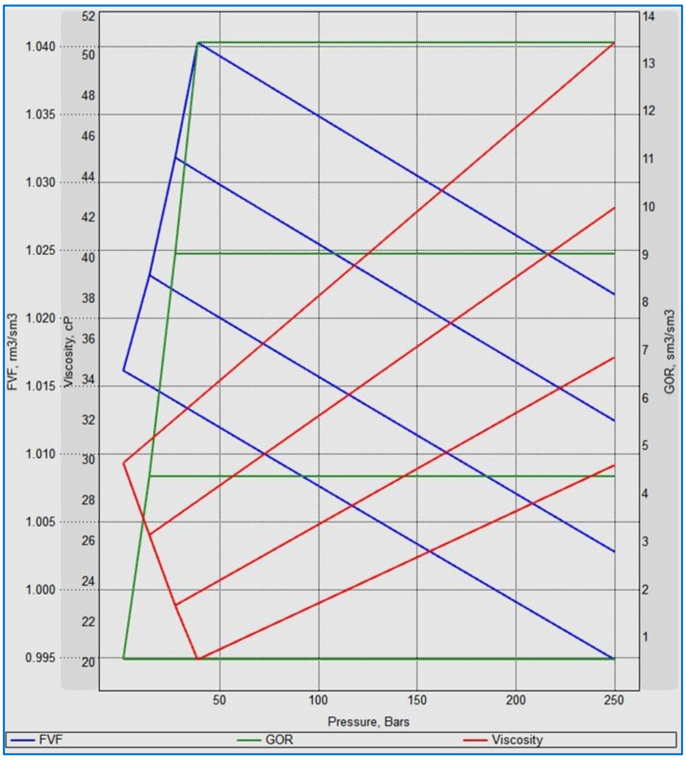
B.1.2 PVT Data



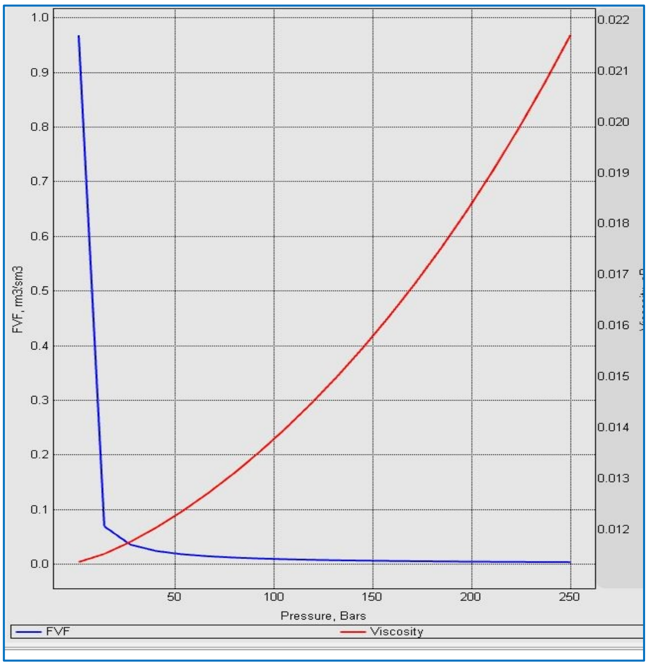
Appendix Figure 8: oil viscosity, Rs and FVF Lab results for a downhole sample taken in WO-8 well (January 1955)

B.2 Simulation Model

B.2.1 PVT Model

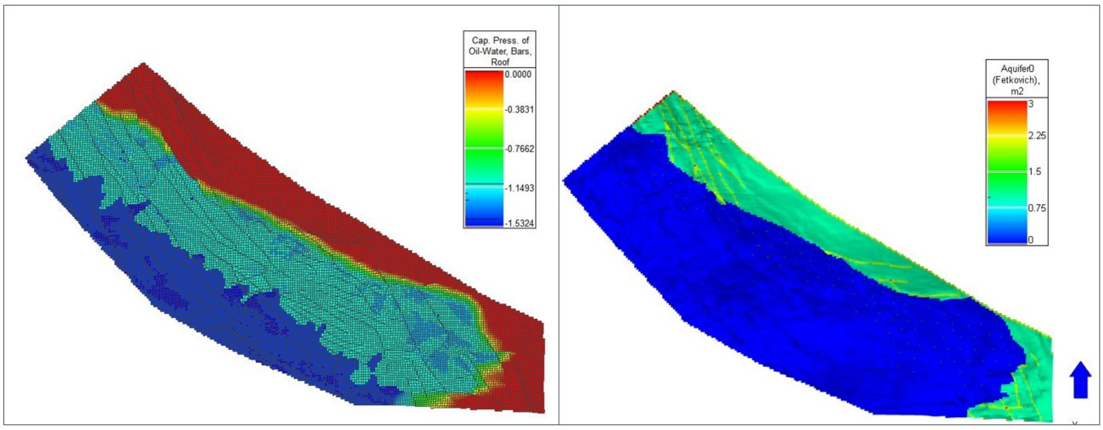


Appendix Figure 9: PVT Model for oil

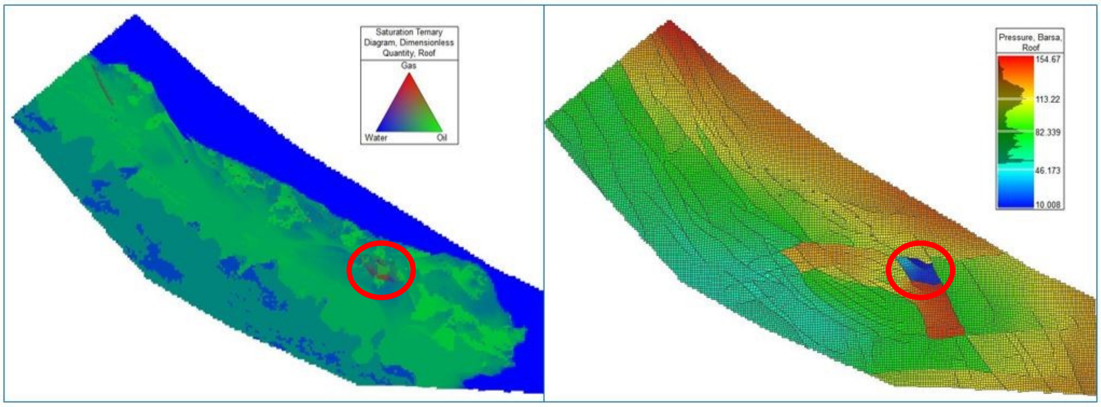


Appendix Figure 10: PVT Model for gas

B.2.2 Initialization



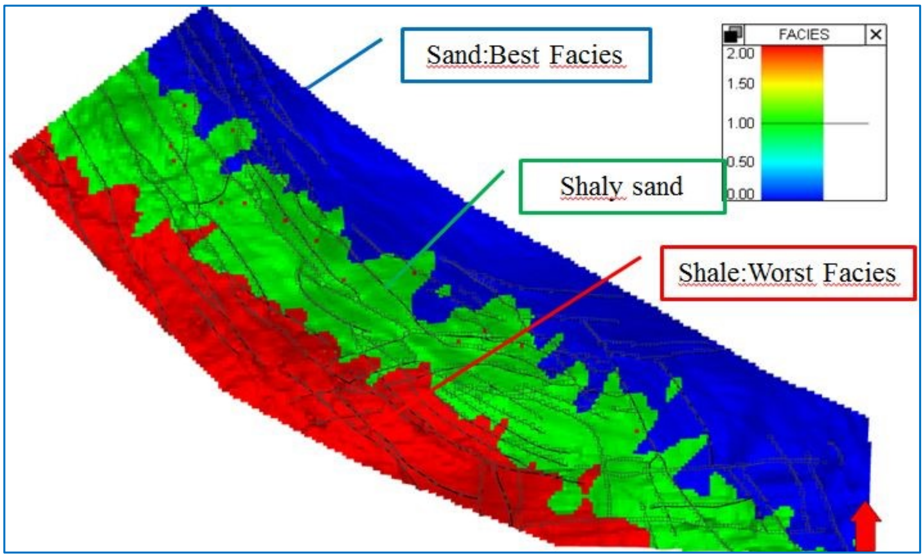
Appendix Figure 11: Primary aquifer map based on FWL area



Appendix Figure 12: Pressure Distribution in first simulation run

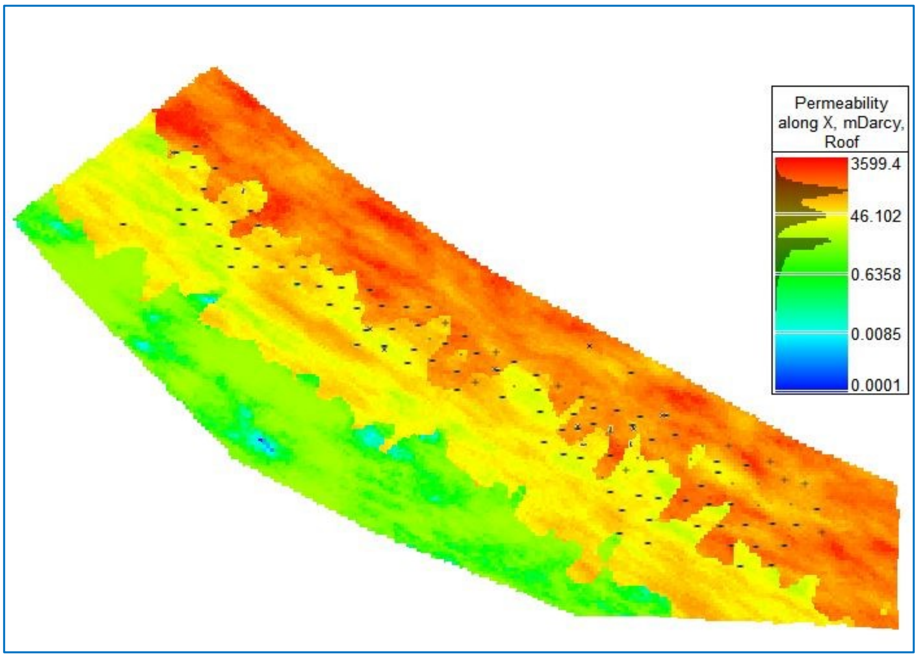
B.2.3 Manual History Matching

- **Scenario 1: Using 3 facies distribution**

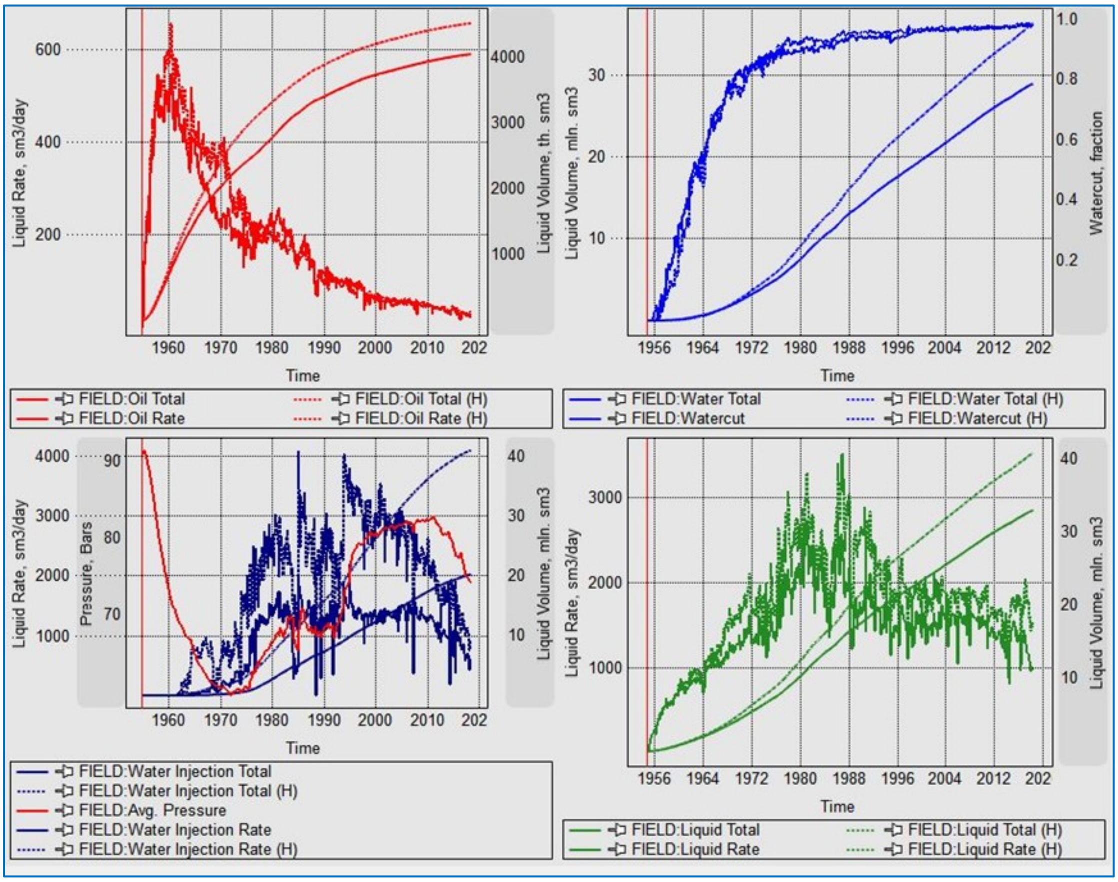


Appendix Figure 13: Facies trend distribution

✓ **Scenario 1_a: No change in facies trend with heterogeneous permeability**

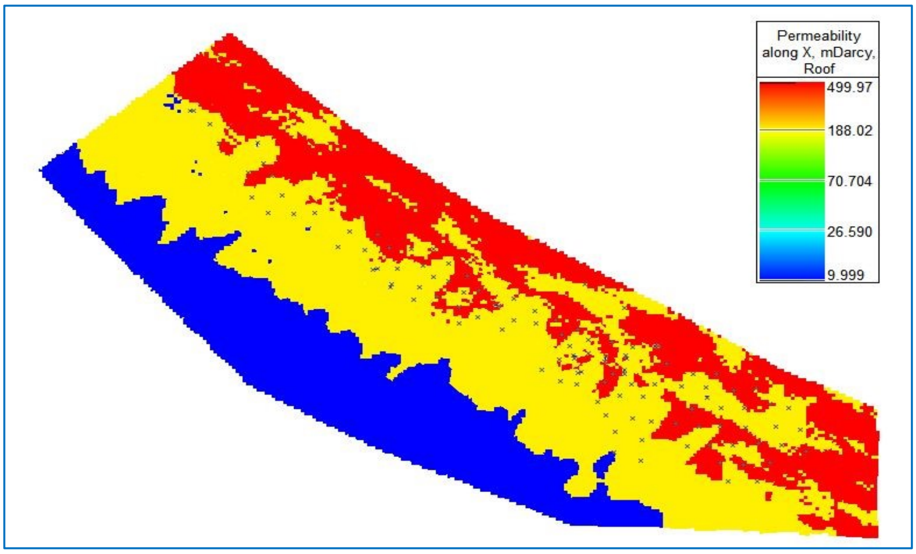


Appendix Figure 14: Heterogeneous permeability distribution biased facies trend

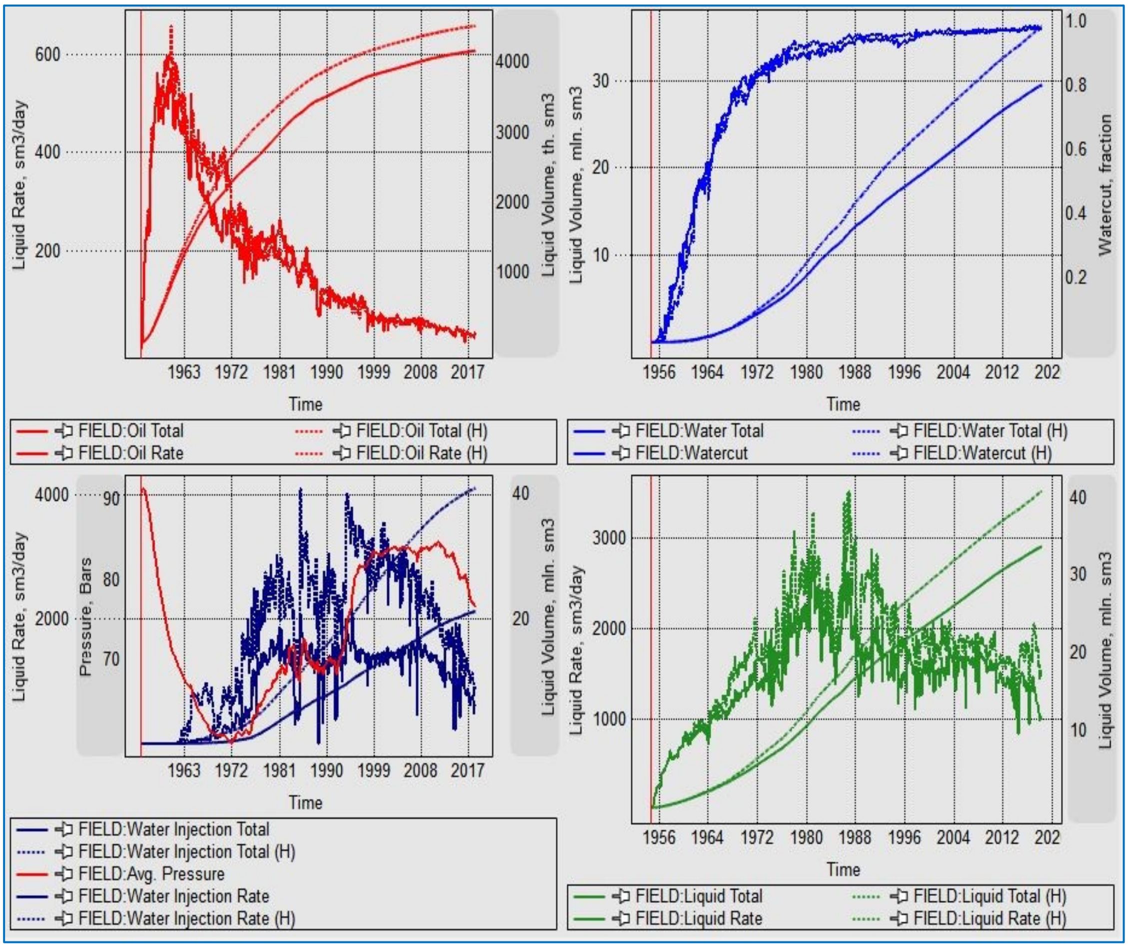


Appendix Figure 15: Rate and total results with heterogeneous permeability biased facies trend

✓ **Scenario 1_b: No change facies trend with homogenous permeability**

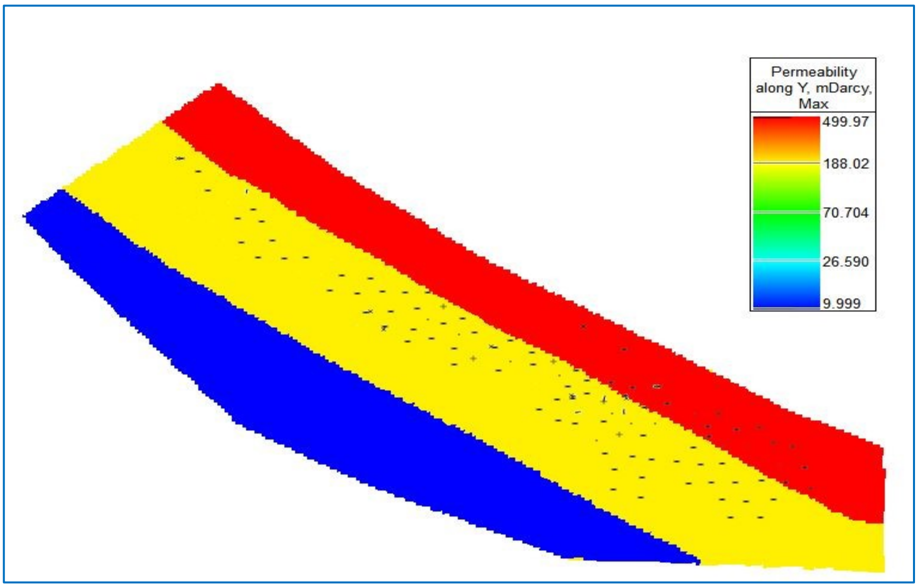


Appendix Figure 16: Homogeneous permeability distribution biased facies trend

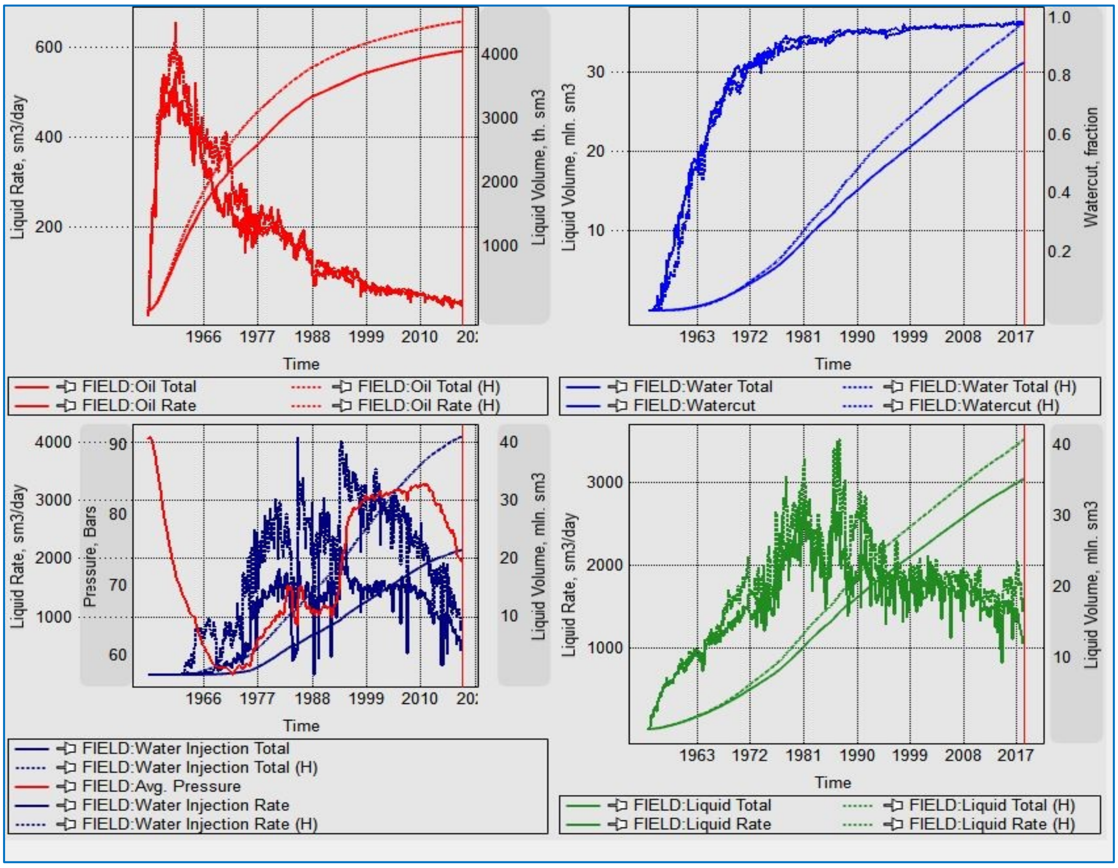


Appendix Figure 17: Rate and total results with homogeneous permeability biased facies trend

- ✓ **Scenario 1_C: Smoothness of facies trend with homogenous permeability**

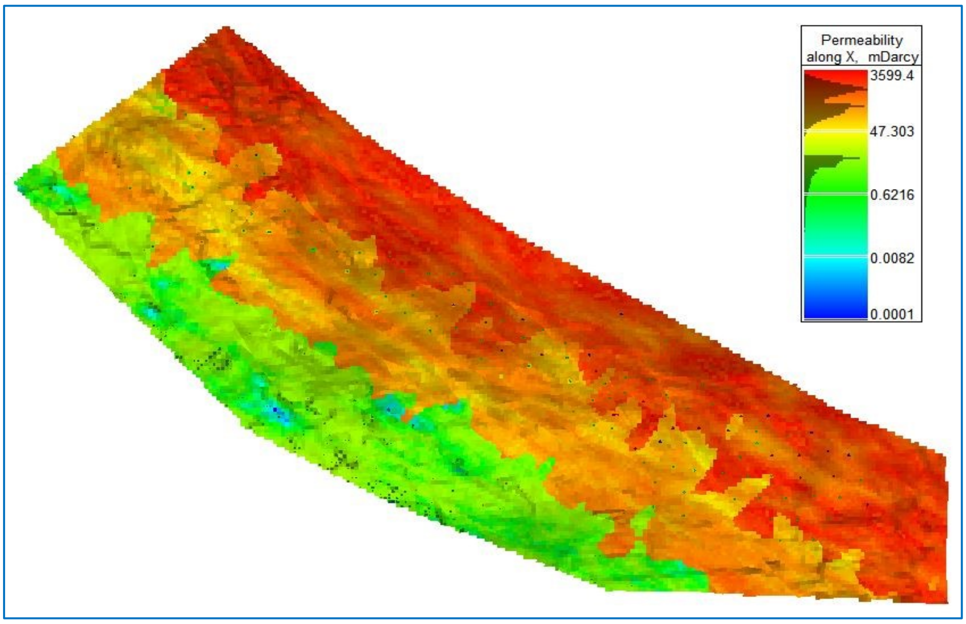


Appendix Figure 18: Homogeneous permeability distribution biased smoothed facies trend

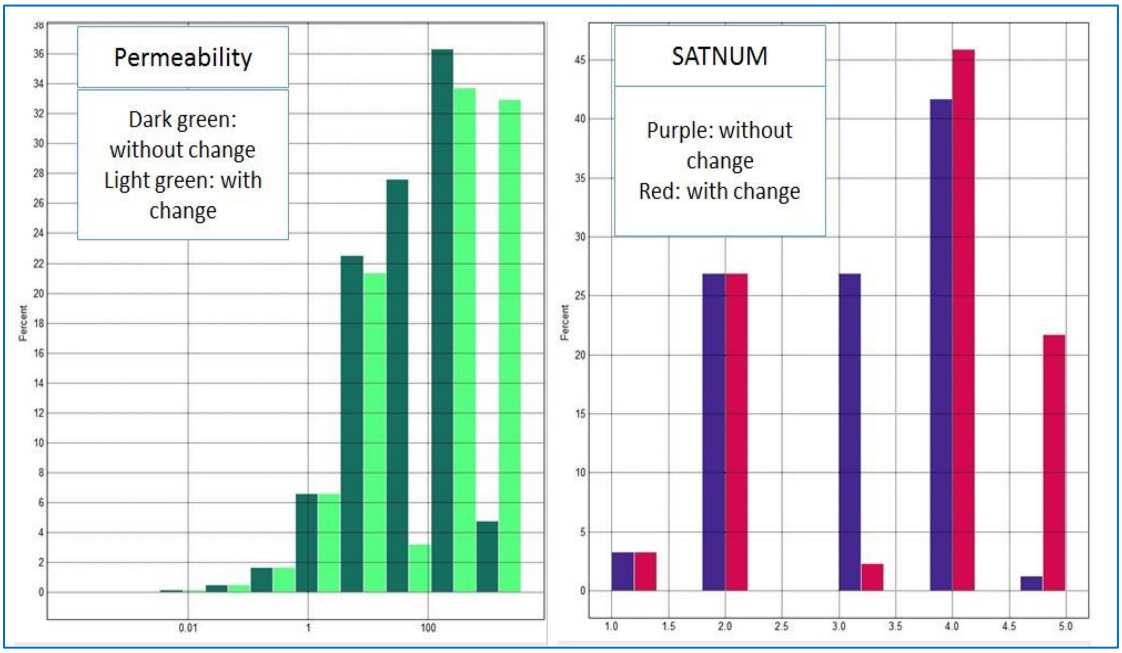


Appendix Figure 19: Rate and total results with homogeneous permeability biased smoothed facies trend

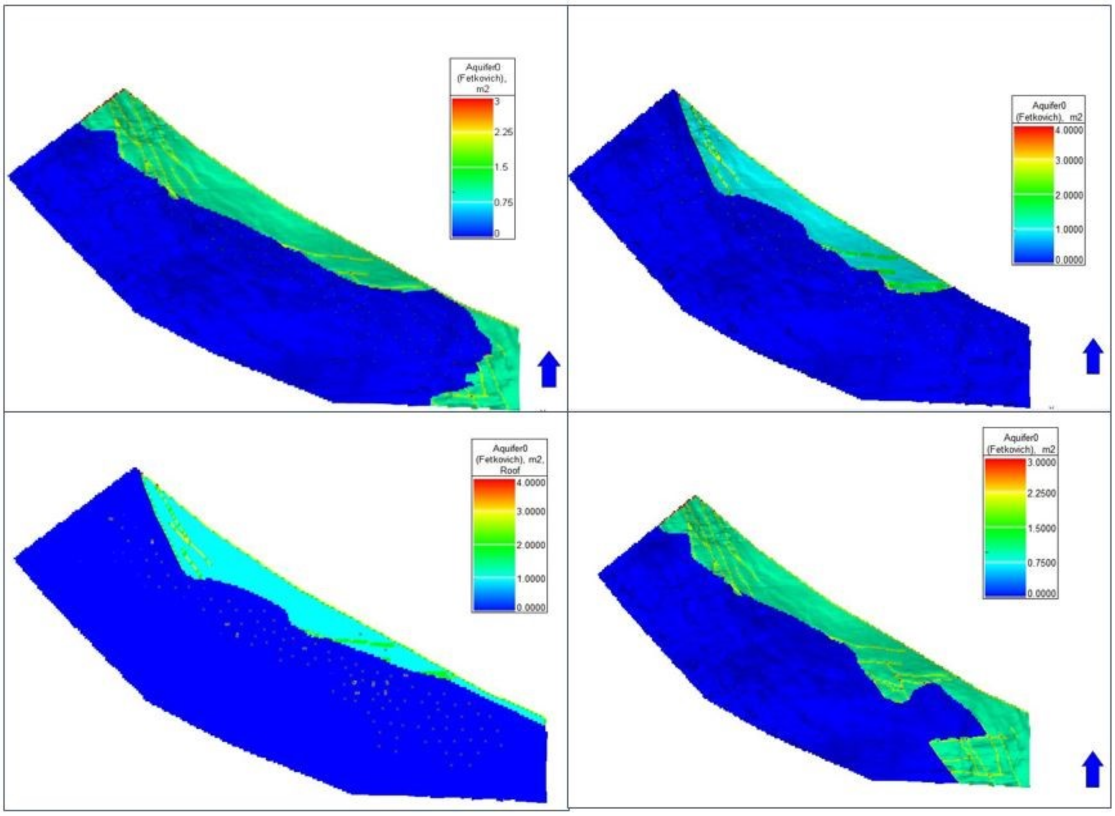
- **Scenario 2: Using 5 facies distribution**



Appendix Figure 20: Permeability modification map in the entire field

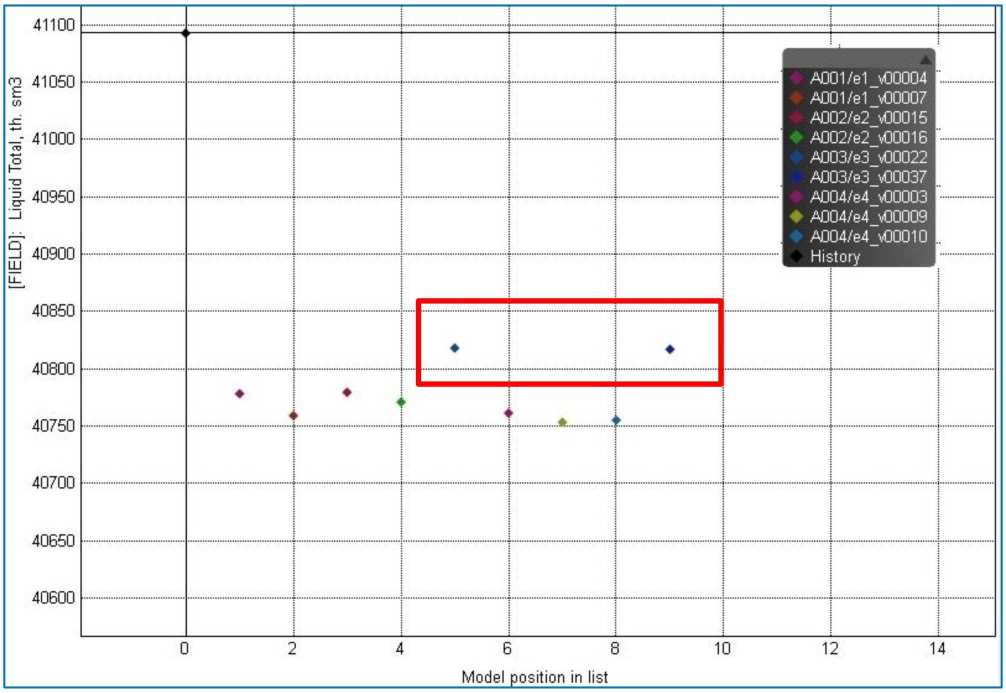


Appendix Figure 21: Permeability and SATNUM difference histogram after permeability modification

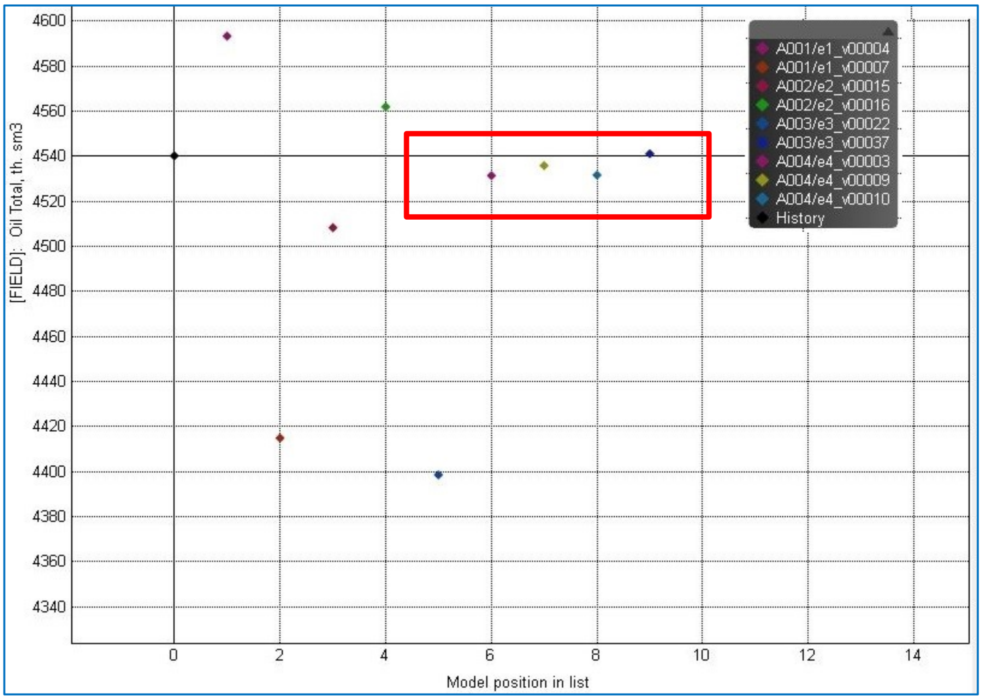


Appendix Figure 22: Different trial of aquifer extent

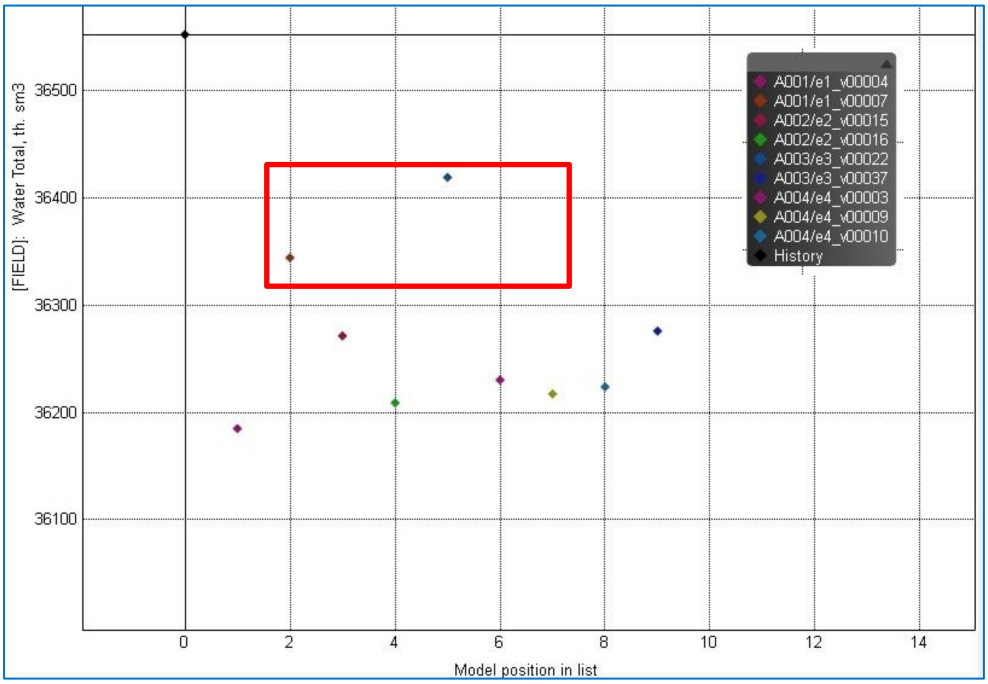
B.2.4 Assisted History Matching



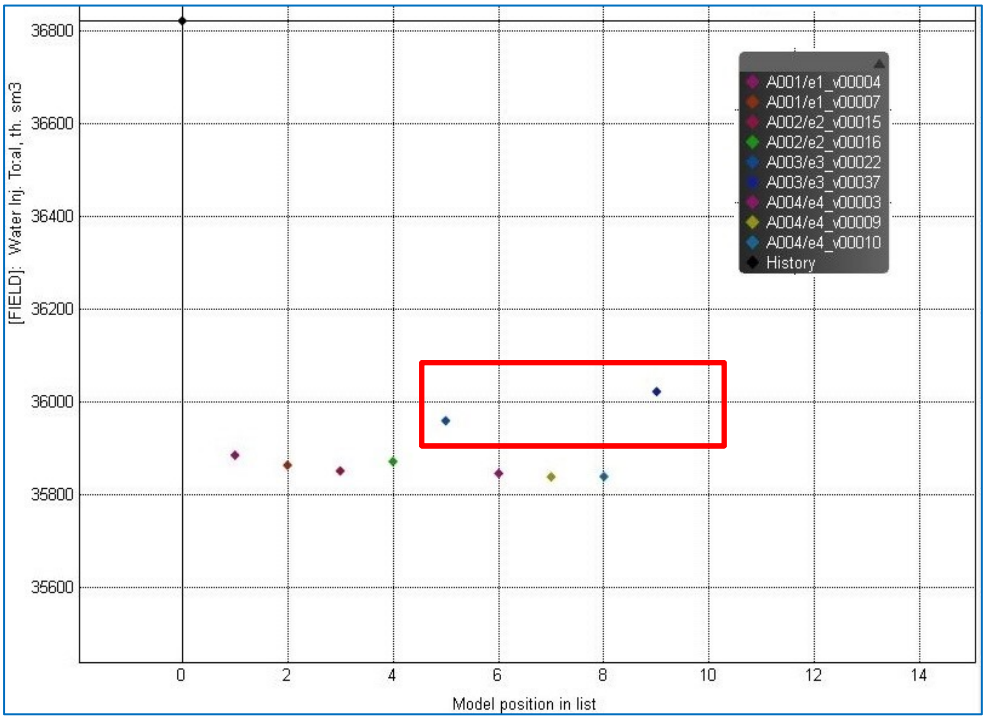
Appendix Figure 23: Comparison of different optimization methods regarding liquid total production



Appendix Figure 24: Comparison of different optimization methods regarding oil total production



Appendix Figure 25: Comparison of different optimization methods regarding water total production



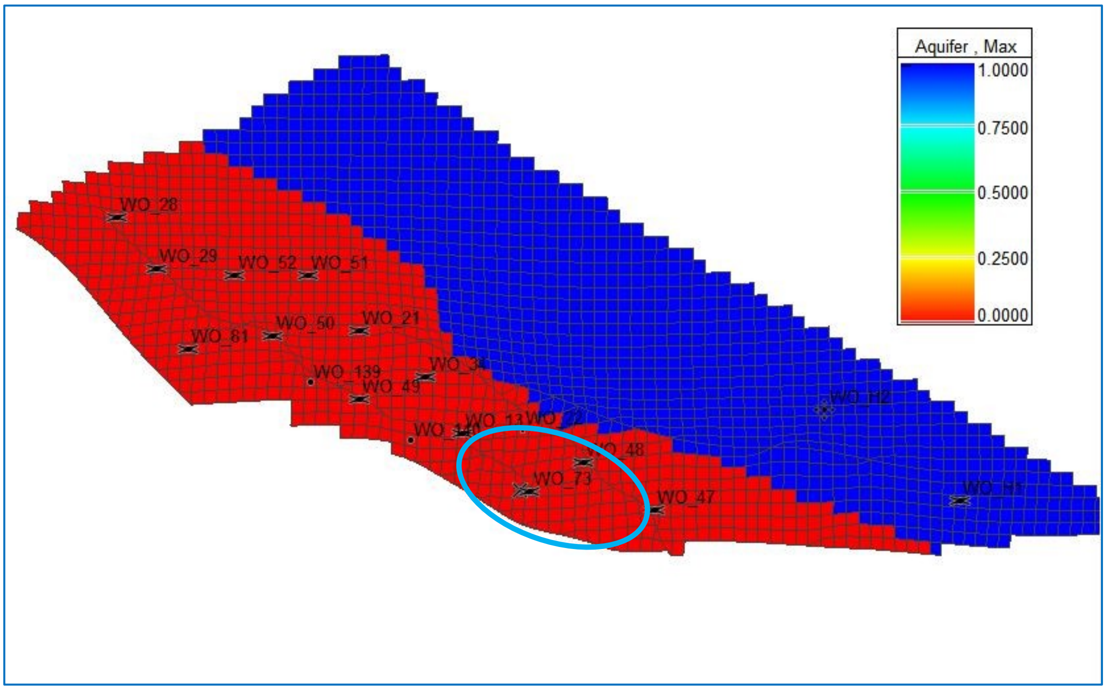
Appendix Figure 26: Comparison of different optimization methods regarding water total injection

Appendix C

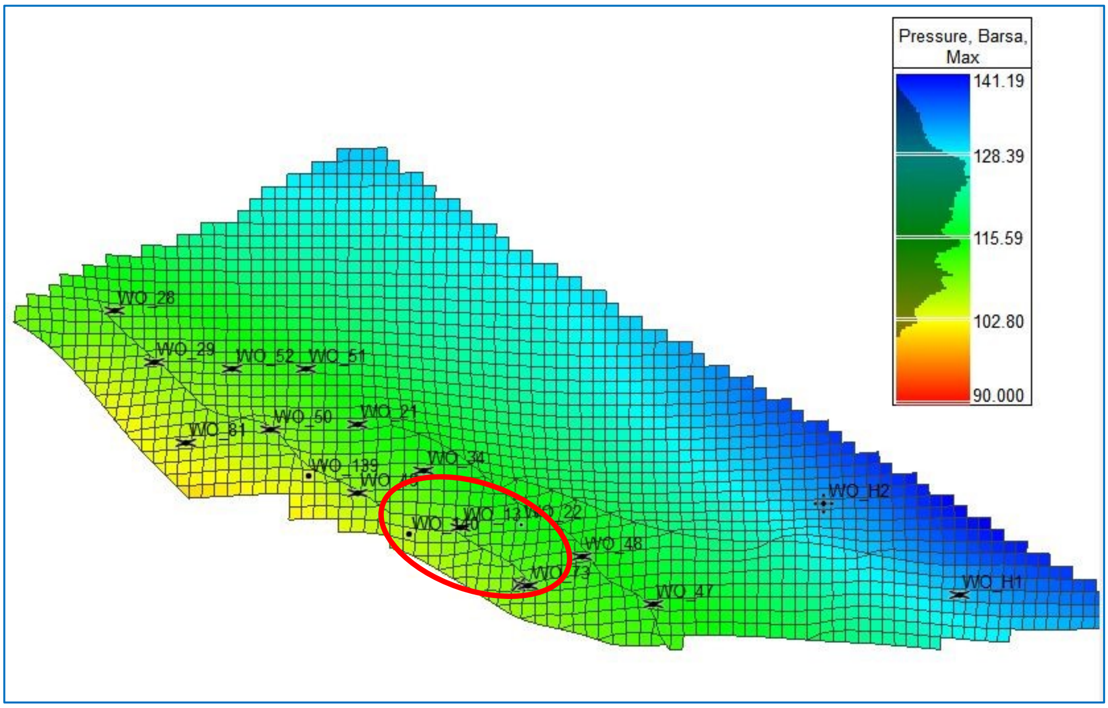
C.1 Modeling Tracer application

Property (Unit)	Measurement
Brine	
Density (kg/m^3)	1110
Salinity (g/L)	155
Viscosity @ 37°C (mPa.s)	1.18
Oil	
Density @ atm pressure (kg/m^3)	880
Viscosity @ atm pressure (mPa.s)	40
Viscosity @ res. pressure (mPa.s)	25
IFT_{wo} @ 37°C (mN/m)	40
Reservoir	
Initial temperature (°C @ *750 m tvdss*)	37
Current pressure (bar @ *750 m tvdss*)	30
Bubble point (bar)	37.6
Major injection water components (mg/L)	
Iron	86
Sulfate	66.5
Phosphate	<2
Nitrate	<1
Calcium	14000
Sodium	45900
pH	5.7

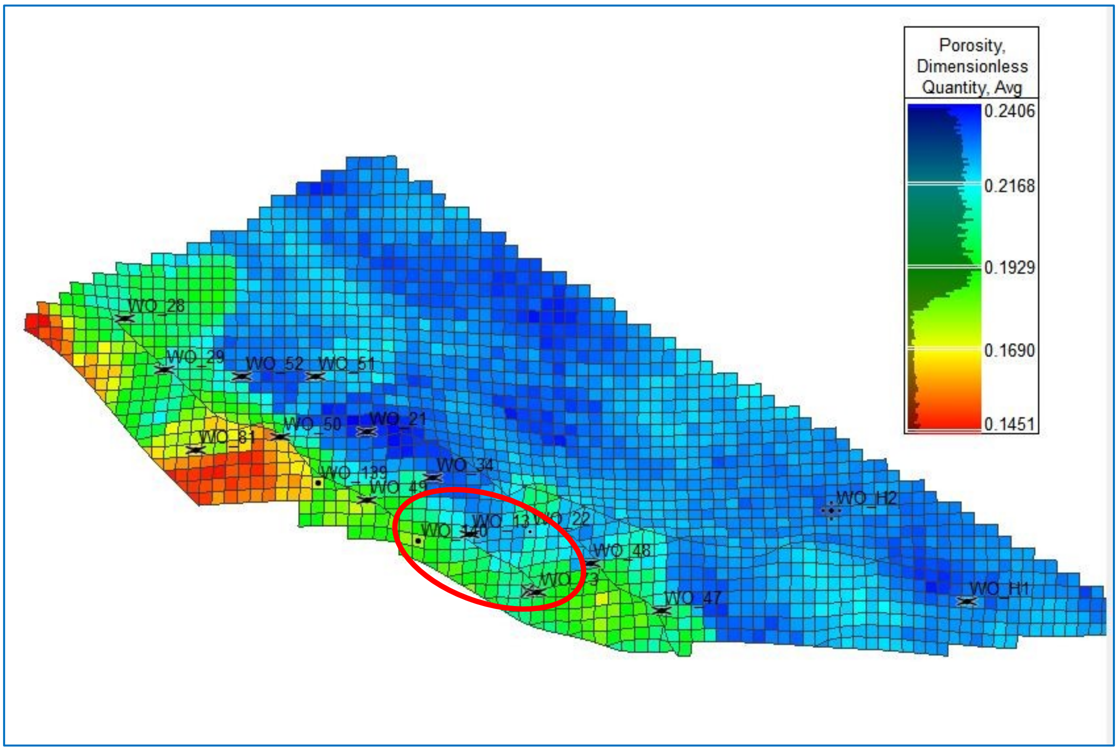
Appendix Figure 27: Reservoir and injection water characteristics of the chosen Wintershall Field (Alkan H., 2015)



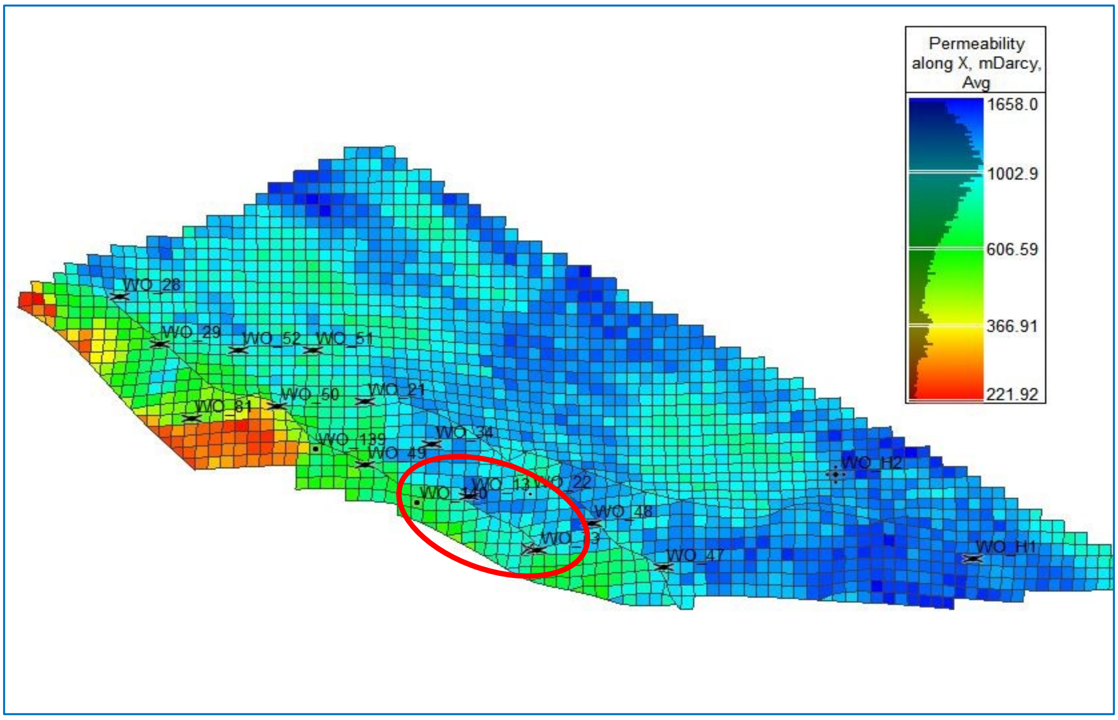
Appendix Figure 28: Aquifer definition map in Sector model



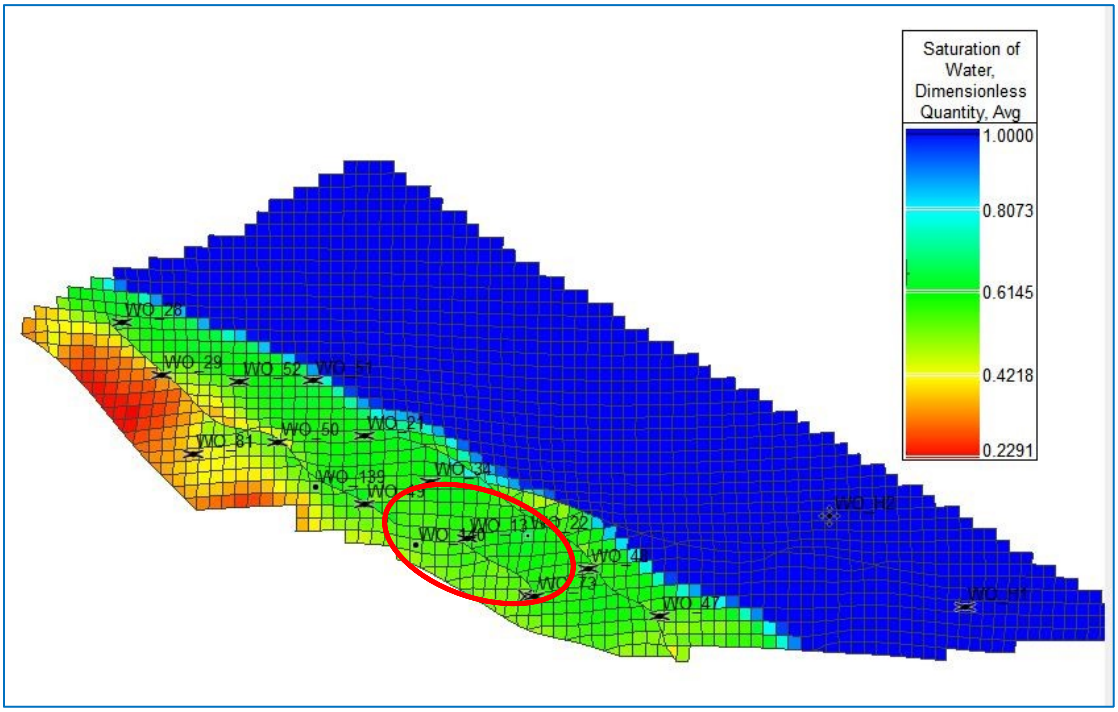
Appendix Figure 29: Pressure distribution map



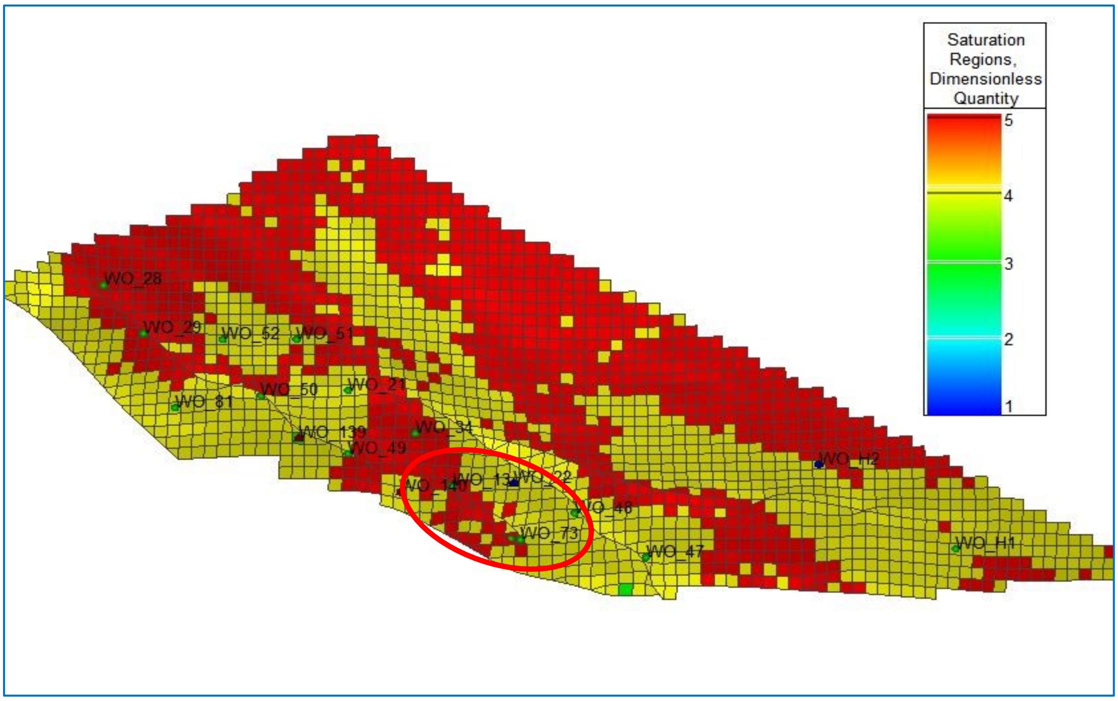
Appendix Figure 30: Average porosity map



Appendix Figure 31: Average permeability map



Appendix Figure 32: Average water saturation map



Appendix Figure 33: Rock type definition map

C.1.1 Scenario 1: Producers WO-73 & WO-140

1) Fault Transmissibility=0

Appendix Table 1: Tracer concentration in two producers regarding fault transmissibility zero

Wells	**WO_140**	**WO_73**
Date	**Tracer 'WATER_WO_022': Production Concentration, kg/kg**	
02/07/2017	0	0
03/07/2017	0	0
04/07/2017	0	0
05/07/2017	0	0
06/07/2017	0	0
07/07/2017	0	0
08/07/2017	0	0
09/07/2017	0	0
10/07/2017	0	0
11/07/2017	0	0
12/07/2017	0	1.02111E-12
01/07/2018	1.3021E-12	2.16726E-12
02/07/2018	2.72721E-12	4.26734E-12
03/07/2018	4.92004E-12	7.3709E-12
04/07/2018	9.02258E-12	1.28365E-11
05/07/2018	1.53436E-11	2.09223E-11
06/07/2018	2.53766E-11	3.31562E-11
07/07/2018	3.95165E-11	4.96935E-11
08/07/2018	6.02377E-11	7.28929E-11
09/07/2018	8.87329E-11	1.03613E-10
10/07/2018	1.26133E-10	1.44956E-10
11/07/2018	1.72849E-10	1.85732E-10
12/07/2018	2.30949E-10	2.39647E-10
01/07/2019	3.04769E-10	3.04585E-10
02/07/2019	3.92521E-10	3.78481E-10
	No Breakthrough	No Breakthrough

2) Fault Transmissibility=0.5

Appendix Table 2: Tracer concentration in two producers regarding fault transmissibility 0.5

Wells	**WO_140**	**WO_73**
Date	**Tracer 'WATER_WO_022': Production Concentration, kg/kg**	
02/07/2017	0	0
03/07/2017	0	0
04/07/2017	0	0
05/07/2017	0	0
06/07/2017	0	0
07/07/2017	0	2.96E-12
08/07/2017	0	8.72E-12
09/07/2017	0	2.17E-11
10/07/2017	0	4.57E-11
11/07/2017	0	8.87E-11
12/07/2017	0	1.55E-10
01/07/2018	0	2.56E-10
02/07/2018	1.14E-12	3.99E-10
03/07/2018	2.14E-12	5.68E-10
04/07/2018	4.11E-12	8.04E-10
05/07/2018	7.31E-12	1.08E-09
06/07/2018	1.26E-11	1.43E-09
07/07/2018	2.05E-11	1.81E-09
08/07/2018	3.25E-11	2.25E-09
09/07/2018	4.98E-11	2.72E-09
10/07/2018	7.28E-11	3.22E-09
11/07/2018	1.05E-10	3.74E-09
12/07/2018	1.45E-10	4.27E-09
01/07/2019	1.98E-10	4.81E-09
02/07/2019	2.54E-10	5.18E-09
	No Breakthrough	Last month Break through

3) Fault Transmissibility=1

Appendix Table 3: Tracer concentration in two producers regarding fault transmissibility 1

Wells	**WO_140**	**WO_73**
Date	**Tracer 'WATER_WO_022': Production Concentration, kg/kg**	
02/07/2017	0	0
03/07/2017	0	0
04/07/2017	0	0
05/07/2017	0	0
06/07/2017	0	0
07/07/2017	0	2.96E-12
08/07/2017	0	8.72E-12
09/07/2017	0	2.17E-11
10/07/2017	0	4.57E-11
11/07/2017	0	8.87E-11
12/07/2017	0	1.55E-10
01/07/2018	0	2.56E-10
02/07/2018	1.14E-12	3.99E-10
03/07/2018	2.14E-12	5.68E-10
04/07/2018	4.11E-12	8.04E-10
05/07/2018	7.31E-12	1.08E-09
06/07/2018	1.26E-11	1.43E-09
07/07/2018	2.05E-11	1.81E-09
08/07/2018	3.25E-11	2.25E-09
09/07/2018	4.98E-11	2.72E-09
10/07/2018	7.28E-11	3.22E-09
11/07/2018	1.05E-10	3.74E-09
12/07/2018	1.45E-10	4.27E-09
01/07/2019	1.98E-10	4.81E-09
02/07/2019	2.54E-10	5.18E-09
	No Breakthrough	Last month Break through

C.1.2 Scenario 2: Proposed producer, WO-73ST

Appendix Table 4: Tracer concentration in WO-73 ST regarding heterogeneity variation

Cases	**Base case**	**PERM*1.5**	**PERM*0.5**	**PERMZ *5**
Date	**Tracer 'WATER_WO_022': Production Concentration, kg/kg**			
02/07/2017	0	0	0	0
03/07/2017	2.80E-12	3.86E-12	5.80E-12	5.03E-12
04/07/2017	5.97E-10	6.10E-10	5.63E-10	7.13E-10
05/07/2017	2.55E-09	2.60E-09	2.37E-09	2.89E-09
06/07/2017	**6.70E-09**	**6.82E-09**	**6.22E-09**	**7.24E-09**
07/07/2017	1.26E-08	1.28E-08	1.17E-08	1.31E-08
08/07/2017	1.99E-08	2.03E-08	1.87E-08	2.02E-08
09/07/2017	2.75E-08	2.80E-08	2.58E-08	2.72E-08
10/07/2017	3.43E-08	3.48E-08	3.23E-08	3.33E-08
11/07/2017	4.02E-08	4.08E-08	3.80E-08	3.86E-08
12/07/2017	4.46E-08	4.53E-08	4.23E-08	4.27E-08
01/07/2018	4.81E-08	4.88E-08	4.57E-08	4.58E-08
02/07/2018	5.04E-08	5.12E-08	4.80E-08	4.81E-08
03/07/2018	5.18E-08	5.26E-08	4.95E-08	4.96E-08
04/07/2018	5.27E-08	5.34E-08	5.04E-08	5.07E-08
05/07/2018	5.29E-08	5.36E-08	5.07E-08	5.12E-08
06/07/2018	5.26E-08	5.33E-08	5.06E-08	5.12E-08
07/07/2018	5.19E-08	5.26E-08	5.00E-08	5.08E-08
08/07/2018	5.08E-08	5.14E-08	4.90E-08	5.00E-08
09/07/2018	4.92E-08	4.98E-08	4.77E-08	4.88E-08
10/07/2018	4.75E-08	4.80E-08	4.62E-08	4.73E-08
11/07/2018	4.55E-08	4.59E-08	4.44E-08	4.55E-08
12/07/2018	4.35E-08	4.37E-08	4.25E-08	4.38E-08
01/07/2019	4.13E-08	4.14E-08	4.04E-08	4.17E-08
02/07/2019	3.90E-08	3.92E-08	3.82E-08	3.96E-08