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History Matching with the use of Qualitative 4D Seismic Data Application to Norne Field

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Dedication

This work is dedicated to my wife Gloria Kanyika and my daughter Angel Kenedy

Disclaimer

The views expressed in this thesis report are the views of the author and do not necessarily reflect the views of Statoil and the Norne license partners.

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Abbreviation

ANTHEI	Angolan, Norwegian and Tanzanian Higher Education Initiative
API	American Petroleum Institute
EnKF	Ensemble Kalman Filter
FGOR	Field Gas Oil Ratio
FGORH	Field Gas Oil Ratio History
FOPR	Field Oil Production Rate
FOPRH	Field Oil Production Rate History
FOPT	Field Oil Production Total
FOPTH	Field Oil Production Total History
FPSO	Floating Production Storage and Offloading
FWCT	Field Water Cut
FWCTH	Field Water Cut History
FWPT	Field Water Production Total
FWPTH	Field Water Production Total History
GOC	Gas Oil Contact
HM	History Matching
HUTS	History-matching Using Time-lapse Seismic
MULTFLT	Keyword used to modify the transmissibility (and diffusivity) across a fault previously defined using the FAULTS keyword
MULTIPLY	Keyword that multiply array by a constant in current box
MULTNUM	Keyword that defines regions for applying inter-region transmissibility multiplier
MULTREGT	Keyword that multiplies the transmissibility between the flux or MULTNUM regions
MULTZ	Keyword that specifies transmissibility multipliers in Z-direction
NTNU	Norwegian University of Science and Technology
OWC	Oil Water Contact
PERMX	Keyword that specifies the permeability values in the X-direction
PERMZ	Keyword that specifies the permeability values in the Z-direction
PEM	Petro-elastic Model
PSO	Particle Swarm Optimization
PVT	Pressure Volume and Temperature

SG	Specific Gravity
TVD	True Vertical Depth
UKCS	United Kingdom Continental Shelf
UDSM	University of Dar es Salaam
1D	One Dimension
2D	Two Dimensional
3D	Three Dimensional
4D	Four Dimensional

Nomenclature

A, B,C	weight vectors
B_{gi}	Initial gas formation volume factor
B_{oi}	Initial oil formation volume factor
CO_2	Carbon dioxide
C	Covariance matrix that accounts for the measurements errors, correlations and weights
C_d	Covariance matrix of the data
C_X, C_Y, C_Z	Covariance matrices
C_α	Covariance matrix of the parameters of the mathematical model
d^{obs}	Observed data
d^{sim}	Simulated data
F	Function
H_2S	Hydrogen sulfide
$k_H h$	Flow capacity where k_H is horizontal permeability and h is thickness
k_v/k_H	Vertical permeability to horizontal permeability ratio
P_b	Bubble pressure
P_{res}	Reservoir pressure
Q(x)	Objective function
q_{prior}	Objective function for a-prior information (to add petrophysical constraints to the variations of reservoir parameters)
q_{prod}	Objective function for production data
q_{seis}	Objective function for seismic data
T_{res}	Reservoir pressure

W	Diagonal matrix that assign individual weights to each measurement
Y(x)	Simulated data
Y^{obs}	Observed data
Z(x)	Simulated seismic data
Z^{obs}	Observed seismic data
β	Weighting factor which express the relative strength of a belief in the initial model
α	Model
α_{prior}	Prior model

Units

cP	centipoise
Kg/m^3	Kilogram per cubic meter
m	Meter
mD	Millidarcy
Rm^3/Sm^3	Reservoir cubic meter per standard cubic meter
Sm^3	Standard cubic meter
Sm^3/Day	Standard cubic meter per day
Sm^3/Sm^3	Standard cubic meter per standard cubic meter
^oC	Degree centigrade

ABSTRACT

History matching is a very important activity performed in reservoir management since it helps to improve and validate reservoir simulation model and hence obtain reliable reservoir performance forecast. History matching can either be done manually, automatically or computer assisted. This study was focused on purely manual history matching of the Norne field using production and qualitative 4D seismic data. History matching the Norne field using quantitative 4D seismic data was not done since it is based on computer assisted history matching approach that requires high technical investment and time; therefore only the literature part of it was covered in this study.

Results showed that the final best matched (improved) simulation model during history matching using production data is obtained when wide vertical transmissibility of layer 15 is reduced (made more prominent), local vertical transmissibility of layer 8 is increased and local vertical transmissibility of layer 15 and RFT D_-H is reduced; transmissibility of fault CD_B3 is reduced while transmissibility of fault E_01, C_01, C_02, C_10, D_05 and G_07 is increased; and horizontal permeability of layer 5, 6, 7 and 8 is increased while horizontal permeability of layer 18 and 20 is reduced.

The results from history matching the Norne field (segment E) using qualitative 4D seismic data showed that the oil water contact from simulation model is matched to oil water contact from seismic data when fault transmissibility multiplier of fault E_01 is decreased, local vertical permeability of layer 8, 9 and 12 is decreased, and local vertical permeability of layer 11 is increased.

Based on the results from this study, the Norne reservoir simulation model has been improved after history matching using both production and 4D seismic data

It is recommended to carry out further study by performing history matching using qualitative seismic data on the other Norne field segments, and history matching using quantitative seismic data in order to obtain more realistic Norne field simulation model. Furthermore, history marching at a well level should be performed.

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CHAPTER 1

1. INTRODUCTION

Reservoir management, sometimes referred to as asset management is considered to be a very important aspect of petroleum production operations (Fower et al., 1996). The main objective of a reservoir management team is to make sure that the reservoir is exploited in such a way that economic recovery is maximized while minimising investments and operating costs. The management process is done from the discovery of a reservoir through production to depletion and abandonment. The best reservoir management approach is the team based approach which involves integration of geoscience and engineering professionals, tools, technology and data. Reservoir management involves collecting, analysing, validating and integrating reservoir description data and performance data into an optimal reservoir development and depletion plan (Trice & Dawe, 1992), (Satter et al., 1994).

One of the tools that cannot be taken out of picture in reservoir management is reservoir simulation. Reservoir simulation is a key tool used by reservoir engineers to obtain reservoir performance predictions under different operating conditions (scenarios). Reservoir engineers usually perform simulation of numerical models. These numerical models are a set of mathematical equations that describe the physical behaviour of the processes in a reservoir. The models are constructed based on the rock properties and fluid properties of a given reservoir. The models can be grouped into geological models and reservoir simulation models. The geological models represent the physical appearance (size, shape and physical characteristics) of a given reservoir whereas the reservoir simulation models (also referred to as dynamic models) represent the flow of fluid through porous media (Dake, 1978).

The simulated reservoir performance in most cases is not accurate since it relies on the models which were constructed based on parameters that are not certain (assumptions have to be made due to lack of enough information). The parameters are obtained from methods such as core analysis, well log analysis and other exploration techniques. However, through these methods it is not possible to get information that is representative of each point of a reservoir since the collected data represents only an infinitesimal portion of the actual space of a given reservoir. For example the log measurement available at present may cover few meters from the well therefore the information beyond the coverage of the tool is not well captured and hence most of the time assumptions have to be made. The common parameters that are not certain include permeability, transmissibility, fault information, aquifer condition, compressibility, gas cap condition, and formation volume factor.

As part of reservoir management; estimated reservoir performance should be compared to the production data (which are the real measured/observed data of a given field). Usually, the estimated results will differ from the measured/observed production data because the estimated data are based on the parameters of which most of them are not certain.

Since the observed production data represent the real characteristic of a reservoir, then they can be used to modify and improve the initial reservoir model that was constructed based on uncertain parameters. The process of improving reservoir model using observed production data is called history matching (HM) (Ertekin et al., 2001).

HM is a very important activity in reservoir management and it has been growing and advancing day after day. In earlier days history matching activity was only done manually. Later came automatic history matching and then computer assisted history matching (Cancelliere et al., 2011).

Reservoir HM has normally been performed using only production data; however this traditional way of performing HM has some setbacks because production data provides information observed from the well only. In an effort to improve HM, nowadays repeated seismic acquisitions (4D seismic data) is included in the HM processes. Repeated seismic (4D seismic) data provides information over large area hence helps in better characterization of the reservoir and hence obtain good (reliable) reservoir models (Fahimuddin et al., 2010).

1.1 Objectives

1.1.1 Main Objective

The main objective of the study is to history match Norne full field using production data, qualitative 4D seismic data and quantitative 4D seismic data in order to improve reservoir model for better future production forecast.

1.1.2 Specific Objective

The specific objectives of the study are to:

i. Determine the effect of adjusted uncertain parameters (fault transmissibility, vertical transmissibility of the stratigraphic barriers, horizontal and vertical permeability) on the Norne full field reservoir simulation model.
ii. Modify and improve the Norne full field reservoir simulation model for better future production forecast.

1.2 Scope of the Study

This study is mainly focused on history matching the Norne field using production data and 4D seismic data. The study was based on manual history matching approach. In history matching using production data; the parameters adjusted in the study were vertical transmissibility of the stratigraphic barriers, fault transmissibility, vertical permeability and horizontal permeability whereby the parameter that were matched were field water cut (FWCT), field water production total (FWPT), field oil production rate (FOPR), field oil production total (FOPT) and field gas oil ratio (FGOR).

History matching using 4D seismic data is categorised into matching using qualitative 4D seismic data and matching using quantitative 4D seismic data. In this study history matching will be done for qualitative 4D seismic data whereby the parameter to be matched is the oil water contact (OWC) and the parameter to be adjusted are fault transmissibility and vertical permeability. History matching using quantitative 4D seismic data needs more time and normally it is done using computer assisted history matching. Therefore, since this study is purely manual history matching, then only the literature of matching using quantitative 4D seismic data has been presented.

CHAPTER 2

2. HISTORY MATCHING

2.1 Introduction to History Matching

Reservoir management is an important aspect in petroleum industry. The solely objective of reservoir management is to make sure that hydrocarbons (oil and gas) are extracted at maximum recovery as possible while minimising investment and operating expenses. To achieve this, management should be a continuous process that starts from discovery, development, and production/depletion to final abandonment. Reservoir management involves several activities and operations whereby history matching is one of them (Schiozer et al., 2005). History matching is defined as a process of adjusting uncertain variables in a reservoir simulation model in order to honour observations of rates, pressures, saturations, and other variables observed at individual wells (Gu & Oliver, 2005). History Matched models are important to ensure reliable future forecasts (i.e. helps to improve and validate the reservoir simulation model), to give better understanding of the reservoir processes (i.e. geological and reservoir models), to improve the reservoir description and data acquisition programs and to identify unusual operating conditions (Almeida Netto et al., 2003), (Ertekin et al., 2001).

Generally; it is known that in order to find a solution, a model is used to estimate performance of a given reservoir. This is called forward solution method. However in history matching, the solution approach is different because observed/measured reservoir behaviour is used to estimate reservoir model variables that caused the behaviour. Hence history matching is considered to be an inverse solution problem (Oliver & Chen, 2010). The primary goal of history matching is to find a better (improved and more realistic) reservoir simulation model such that the discrepancy between the performance of the base simulation model (initial model) and the history of a reservoir is minimized (Tavassoli et al., 2004). In the tradition perspective, the key target of adjusting the variables (history matching) is to minimise the mismatch between the measured (observed) data and the computed data thus enabling prediction of future performance with confidence and optimization of production of a given reservoir (Rwechungura et al., 2011). Furthermore, it is important to perform history matching because it is a fundamental step in uncertainty quantification (Cancelliere et al., 2011).

History matching is not a onetime activity but it is a continuous process throughout reservoir's life. This is because as production activities continue, real production data are obtained. These production data are usually different from the simulated results hence necessitate conducting of history matching. Generally in reservoir, at the beginning (before starting production) a base reservoir simulation model is run to predict the performance of a given reservoir. After a certain period of production, history matching is then carried out to validate the base reservoir model. The matched model is then used to predict the future performance of a reservoir. Then production is carried out for certain period and again history matching is performed. This process goes on throughout the reservoir's life.

2.1.1 Parameters to be Matched and Parameters to be Adjusted

As stated earlier, the production data is used to validate the reservoir model, however selection of the production data to specify during history matching depends on the stage of history match (pressure match or saturation match stage) and type of hydrocarbons, availability and quality of data. Common production data to be matched include pressure match (static and flowing pressure), saturation match (water-oil ratio, gas-oil ratio, oil production rate, water production rate, gas production rate, water-cut, breakthrough times, log-derived fluid saturations) and 4D seismic data match (qualitative and quantitative) (Ertekin et al., 2001).

One among of the important task in history matching is the selection of reservoir parameter to adjust. The common parameters that can be adjusted during history matching are aquifer (size, connectivity & strength), vertical permeability barriers, flow capacity ($k_H h$), total system compressibility, vertical and horizontal permeability ratio (k_V/k_H), pore volume, relative permeability curves, fault transmissibility, vertical transmissibility and net to gross ratio (Ertekin et al., 2001). There are no specific rules in choosing parameter to adjust; but it is important to be careful when choosing parameters because the same production history could be fit by different reservoir scenarios (Tomomi, 2000). It is recommended by (Lind et al., 2013) that parameters to be modified should be those that are most uncertain in a given reservoir and the given situation.

Although in history matching one can freely change any parameter that is not certain, there are some parameters that some author recommend not to be changed. For example (Cheng, 2014) recommend that reservoir fluid properties, initial fluid contacts and initial reservoir pressure, initial water saturations, porosity and structure/thickness, major faults, and historical rates should not be changed.

The general procedures to be followed in history matching is as follows (Ertekin et al., 2001)

1. Set the objectives of the history matching process.
2. Determine the method to use in the history match. This should be dictated by the objectives of the history match, company resources available for the history match, the deadlines for the history match, and data availability.
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 the reservoir data that can be adjusted during the history match and the confidence range for these data. The data chosen should be those that are the least accurately known in the field but that have the most significant impact on reservoir performance. This step should be performed in conjunction with the reservoir engineers, geologists, and field operations staff working on the field under study.
5. Run the simulation model with the best available input data.
6. Compare the results of the history match with the historical production data chosen in step 3.
7. Change the reservoir data selected in step 4 within the range of confidence.
8. Continue with steps 5 through 7 until the criteria establish in step 3 are met.

2.2 Reservoir Simulation Model

Reservoir simulation is an important part in reservoir engineering. It is considered to be the most powerful predictive tool available to the reservoir engineer because it considers much more geologic and reservoir data than any other reservoir predictive technique (Ertekin et al., 2001). According to (Ghoniem et al., 1984), "Simulation of petroleum reservoir performance refers to the construction and operation of a model whose behaviour simulates actual conditions. The model itself is either physical or mathematical. A mathematical model is simply a set of equations that subject to certain assumptions, describes the physical process active in the reservoir". These mathematical models are broadly used in the prediction of the performance of a reservoir.

Since these mathematical models are constructed based on certain assumptions, then they should be validated through history matching. The traditional approach is to compute the past reservoir performance and then compare the computed results with the observed behaviour of the reservoir. If the comparison between the two is not satisfactory, the estimates are then continually adjusted until an acceptable match is obtained (Ghoniem et al., 1984), (Veatch & Thomas, 1971). In other words, history matching is used to determine how closely a given model can reproduce certain characteristics of observed or measured data (Parish et al., 1993).

Normally a petroleum reservoir is characterized by fundamental laws and models which are relevant to the dynamics and seismic responses of the given reservoir. These laws and models are combined to build mathematical model and results in a system of differential equations and matrices. The laws and models are; mass conservation law, Darcy's laws, equation of state, relative permeability and capillary pressure relationships, Gassmann equation, Hertz-Mindlin model, Wood's law, 1D seismic reflectivity modelling (matrix propagation techniques) and Fourier transforms (Rwechungura et al., 2011)

2.3 Types of History Matching

The process of adjusting variables (history matching) can be done in two ways either manually or automatically as it is shown in Figure 2.1 below.

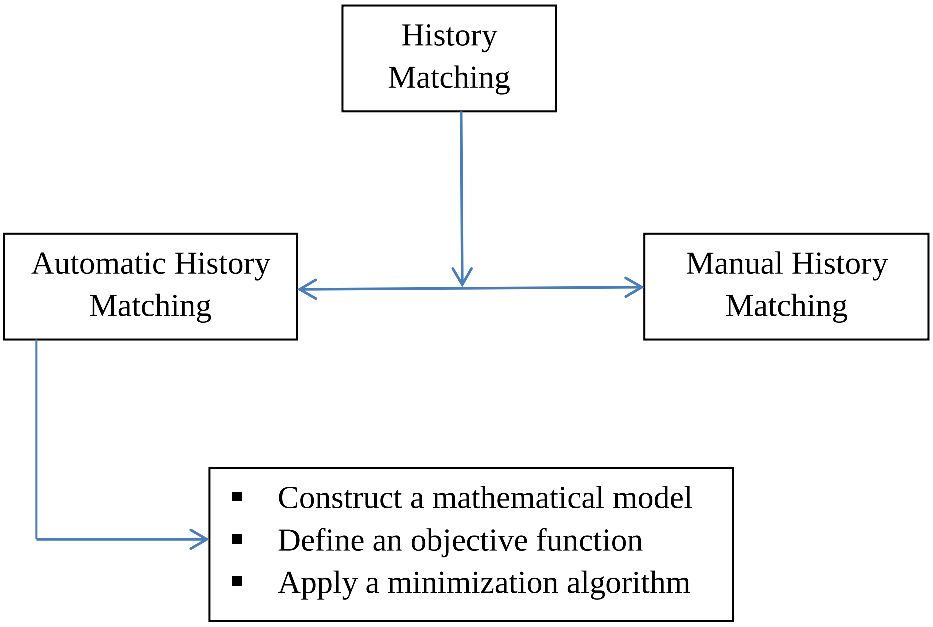


Figure 2.1: History matching (Rwechungura et al., 2011)

2.3.1 Manual History Matching

The procedures involved in manual history matching starts with running the simulation model for the historical period and then comparing the simulation results with the actual reservoir field (observed/measured) data. Finally adjustment of simulation input variables is done to improve the match (Ertekin et al., 2001). Note that in manual history matching the selection of input variables to be adjusted is based on knowledge and experience of an individual i.e. a team of reservoir engineers sit down and analyse the difference between simulated results and measured/observed data and manually adjust one or few parameters at a time in hope of improving the match (Rwechungura et al., 2011).

Manual history matching is said to be subjective, labour-intensive, time-consuming, expensive and often frustrating and quality of the match depends largely on the knowledge and experience of the team members involved in a given reservoir study, the amount of budget, quality of the reservoir model, quality and quantity of various input and observed data and the results are not unique (too many possible solutions with good history match but with incorrect predictions) (Denney, 2003), (Cheng, 2014). The mentioned setbacks of manual history matching are because of many uncertain parameters that have to be adjusted during the matching process (Lind et al., 2013). Therefore there has been effort to do research on “automatic” or “computer assisted history matching” in order to solve the challenges faced in manual history matching (Cancelliere et al., 2011). However, despite of its tedious process and low precision, manual history matching has been and still is commonly used in petroleum industry (Zhang et al., 2011).

Another challenge of doing manual history matching is that, matching process involves one factor at a time adjustment of the reservoir parameters i.e. only one factor is adjusted at a specific time. In other words, manual history matching does not allow multiple parameters adjustment at a time (Denney, 2003). Therefore, since reservoirs are heterogeneous and also there are hundreds of thousands of grid blocks in a typical reservoir simulation model to estimate reservoir parameters; manual history matching is therefore often not reliable for long periods of simulation and is always associated with many uncertainties (Rwechungura et al., 2011).

2.3.2 Automatic History Matching

Manual history matching has setbacks due to the fact that it is a trial and error procedure that consumes considerable computer time and money and therefore the effort is to develop tools that will speed up the history matching process (Denney, 2003), (Veatch & Thomas, 1971). In effort to automate the procedure, some individuals have invested in investigation of iterative adjustment and regression techniques, linear and nonlinear programming methods, and energy dissipation analysis (Veatch & Thomas, 1971). The fundamental concept in automatic history matching is that, the constructed algorithms takes control of the parameter adjustment process and obtain the best possible match (MacMillan et al., 1999).

The underlying idea in automatic history matching is treating history matching as an optimization process; the process that involves defining an objective function and then minimization of the objective function. The minimization process of the objective function can be done by using appropriate optimization algorithm (Cancelliere et al., 2011). Description of the objective function is given in section 2.4 below.

The steps to be followed in automatic history matching can be summarized as follows (Rwechungura et al., 2011):

i. Construction of a mathematical model based on the physics of the problem that is capable of reproducing the reservoir performance.
ii. Defining an objective (error) function which measures the misfit between the observed reservoir performance and the behaviour predicted (simulated) by the model.
iii. Applying a minimization algorithm that is capable of finding the model parameters that result in a minimum value of the objective function.

(Cancelliere et al., 2011) explain that "the selection of the most adequate optimization algorithm among those available in the technical literature is not trivial, and the number of independent variable involved in complex reservoir simulation does not make the solution of the optimization problem a standard procedure. In fact, the main criticalities of a history matching process change for each analysed reservoir. As a consequence, the identification of an optimization methodology appropriate for a wide variety of reservoirs is impossible. Therefore, automatic history matching remains a dream and more realistically, assisted history matching can be the target".

(Denney, 2003), (MacMillan et al., 1999) point out that most published automatic history matching algorithms are impractical for large reservoir simulation models because they require excessive computational time, and therefore they are applicable to small problems such as well test analysis or adjusting relative-permeability curves to match a laboratory core flooding experiments.

The techniques employed in automatic history matching include; gradient-based optimization techniques, optimal control theorem, stochastic modelling techniques, sensitivity analysis techniques, and gradual deformation techniques. These techniques provide great time-saving benefits over conventional trial-and-error (manual history matching) approaches (Tavassoli et al., 2004).

2.3.3 Computer Assisted History Matching

The shortcomings of automatic history matching have given rise to computer assisted history matching. As in Automatic history matching, also Computer Assisted history matching uses optimization process. The goal of this optimization process is to find the minimum of the objective function that represents the quality of the reservoir model (Reis et al., 2009). The approach in computer assisted history matching is similar to that used in automatic history matching. However, the difference between automatic history matching and computer assisted history matching is that in computer assisted history matching, the reservoir engineers are still in control of reservoir adjustment process, but they can rely on reliable optimization tools to better explore the parameter space and to speed up the convergence to one or more solutions (Cancelliere et al., 2011).

It is important to note that the choice of history matching approach (manual, automatic or computer assisted) to be used in a given history matching study will depend on the objectives of the history match, the company resources invested in the history match, and the deadlines of the study. Furthermore, based on several studies that has been done it has been observed that no history matching approach (manual, automatic or computer assisted) that will guarantee a successful history match that meets all history matching objectives. However, if unexpected difficulties arise during the history match, both methods should be attempted to achieve the required matching objectives. (Ertekin et al., 2001).

2.4 The Objective Function

History matching is achieved through minimization of an objective function. This objective function measures the differences between the observed and simulated data. There are three different known methods for calculating objective function. These are least-square, weighted least-square and generalized least-square formulation method.

1. Least-Square method

$$F = \left(d^{obs} - d^{sim}\right)^T \left(d^{obs} - d^{sim}\right) \quad \text{...} \quad (1)$$

2. Weighted Least-Square method

$$F = \left(d^{obs} - d^{sim}\right)^T w \left(d^{obs} - d^{sim}\right) \quad \text{...} \quad (2)$$

3. Generalised Least-Square method

$$F = \frac{1}{2}(1-\beta)\left\{\left(d^{obs} - d^{sim}\right)^T C_d^{-1}\left(d^{obs} - d^{sim}\right)\right\} + \frac{1}{2}\beta\left\{\left(\alpha - \alpha_{prior}\right)^T C_\alpha^{-1}\left(\alpha - \alpha_{prior}\right)\right\} \quad (3)$$

Where d^{obs} represents the observed data, d^{sim} represents the simulated data, w is a diagonal matrix that assigns individual weights to each measurement, β is a weighting factor which express the relative strength of a belief in the initial model, C_d is the covariance matrix of the data (it provide information about the correlation among the data), C_α is the covariance matrix of the parameters of the mathematical model, α is the model and α_{prior} is the prior model (Rwechungura et al., 2011).

2.5 History Matching Methods

The methods that can be used in history matching falls under two categories, gradient based methods and non-gradient based methods. It is important to note that many methods can be used in minimization of the error function. However, the difference in these methods depend on the assumptions of whether the error function is linear or nonlinear with changes to the reservoir data and on the technique used in the minimization of the error function. (Ertekin et al., 2001)

2.5.1 Gradient Based Methods

Gradient (downhill) based methods uses deterministic algorithms and traditional optimization approaches to find the local minimum of the objective function. This process is done through the following steps (1) calculating the gradient of the objective function, (2) determining the direction of the optimization search (3) and final let the function converge towards the local minimum The challenge associated to the process of finding the local minimum is that there is no guarantee that the obtained minima is a global minimum because the objective function can have many minima (Bjørke & Rørvik, 2010).

The following are the gradient-based methods:

- Steepest descent method
- Gauss-Newton method
- Levenberg-Marquardt algorithm
- Conjugate gradient method
- Sequential quadratic programming

Steepest descent method is one of the oldest and most widely known methods for solving smooth optimization problems (Papa Quiroz et al., 2007). The method is based on the principle that the response changes fastest in the direction of the optimum, so it is mainly necessary to find out the gradient and use it to determine the direction of the next point. The method requires only the gradient to be calculated and a step size that relates to how far away the new point is from the old one (Brereton, 2009). Steepest descent method has the drawback of progressing very slowly in the vicinity of the minimum.

Gauss-Newton method involves solving sensitivity coefficients matrix. This matrix is formulated using the derivatives of the simulated data with respect to the reservoir parameters (Rodrigues, 2006). Detailed description of history matching using Gauss-Newton method is given by (Tan, 1995).

Levenberg-Marquardt method can be considered as a version of Gauss-Newton with a modification to the Hessian to improve convergence and avoid the need for estimating the step length (Oliver & Chen, 2010).

Conjugate gradient method is a minimization method which requires only the computation of gradient of the objective function but tend to converge much more slowly than Gauss-

Newton methods. Despite the relatively slow convergence, they are frequently more efficient in total computation time for large-scale history matching problems where the number of data and model parameters are so large that it is not feasible to compute all sensitivity coefficients (Ruijian et al., 2003). In the conjugate gradient method, the search directions are conjugate to each other and next search direction is a linear combination of the current residue and all previous search directions. (Oliver & Chen, 2010).

2.5.2 Non-gradient Based Methods

Usually gradient based methods are used to handle simple optimization problems and therefore they are not good tools for solving complex history matching problems. The effort has been put to develop algorithms that can handle complex problems. The developed algorithms are non-gradient based methods and they can be grouped in two categories: stochastic samplers methods and particle filter methods. Stochastic population-based algorithms are often seen as good option to solve history matching problems because they adaptively search for multiple good models and are less likely to get trapped in local minima (Hajizadeh, 2010). It is also very important to note that, despite the fact that the stochastic methods such as simulated annealing and genetic algorithms are very useful, they are associated with a challenge that they require large number of iterations to converge and this become expensive because a single simulation run may require several hours of computing time depending on the size of the given reservoir model (Gomez et al., 2001).

1. The stochastic methods are
    - Evolutionary algorithms
        - Genetic Algorithms
        - Evolutionary Strategies
    - Simulated annealing
    - Scatter search
    - Tabu search
    - Particle swarm optimization
    - Neighbourhood algorithm
    - Hamiltonian and Marker chain Monte Carlo
    - Chaotic optimization
2. Particle filter method
    - Ensemble Kalman filter method

Evolutionary algorithms are based on nature. They are population-based optimization algorithms inspired by process occurring in biological evolution i.e. each new generation inherits characteristics (progress, growth and development) of the previous generation and passes the same characteristics to the next generation. An evolutionary algorithm uses the principal of “survival of the fittest” (Mohaghegh, 2000). An evolutionary algorithm applied in history matching might use mutations and recombinations of individual reservoir models to generate new models and a fitness function that is based on data mismatch to determine which models survive and which are eliminated from a pool of candidate reservoir models. There are two most common types of evolutionary algorithms for history matching which are genetic algorithms and evolutionary strategies. A genetic algorithm uses random uniform sampling for mutation of parameters and use recombination of variables for reproduction. Whereas, evolutionary strategies are similar to genetic algorithms with the exception that they allow co-evolution of evolutionary parameters such as mutation step size; in this way, the algorithm can be made to converge in the neighbourhood of a minimum in the objective function (Oliver & Chen, 2010).

Simulated annealing is a probabilistic algorithm for the global optimization problem in a large search space; meaning that it is used to find global minimum of an objective function which have several local minima. This method exploits the physical process happening in metallurgy whereby a metal is slowly cooled so that when eventually its crystal structure is “frozen”, this happens at a minimum energy configuration. In the process of computing solution; the current solution is replaced by a nearby solution, chosen with a probability depending on the difference between the corresponding function values (Bjørke & Rørvik, 2010), (Ouenes et al., 1993).

Tabu Search is a meta-heuristic algorithm that guides a local heuristic search procedure to explore the solution space beyond local optimality. It uses adaptive memory to create more flexible search behaviour. This method is based on procedures designed to cross boundaries of feasibility or local optimality, instead of treating them as barriers (Glover & Marti, 2006). The principle of Tabu Search is to pursue Local Search whenever it encounters a local optimum by allowing non-improving moves. In this method, cycling back to the previously visited solutions is prevented by the use of memories, called tabu lists, that record the recent history of the search, a key idea that can be linked to artificial intelligence concepts (Gendreau, 2002).

Scatter Search is an optimization algorithm that works on a set of solutions (reference set). The goal is to improve the overall quality of the reference set after each new iteration. New solutions are generated by a non-convex combination of reference solutions. The scatter search is a hybrid metaheuristic method that combines some elements of evolutionary algorithms and other elements from the tabu search method. From evolutionary algorithms, scatter search inherits the concept of population, in the form of the reference set, and the reproduction scheme, where two or more solutions from the reference set are combined to generate new trial solutions. From tabu search, the scatter search adopts the tabu list concept, which is a list of solutions that are marked not to be used in the generation of new trial solutions, a diversification strategy. A solution remains in the tabu list for a fixed number of iterations known as the tabu duration (de Sousa, 2007)

Particle Swarm Optimization (PSO) is a multi-agent optimisation algorithm that uses a population of particles to search for the optimal position in a multidimensional problem space. In PSO, a population of particles (a swarm) are initially placed at random positions in the search space, moving in randomly defined directions. The directions of particles are influenced by their own previous successes and the successes of their neighbours, searching in regions that have proven relatively successful and potentially discoverage even better regions with lower objective function. The method is fast, simple and effective with superior global optimisation ability compared to other stochastic algorithms (Mohamed et al., 2010).

Ensemble Kalman filter method (EnKF) is one of the efficient methods used in computer assisted history matching which was introduced by (Evensen, 1994) as a sequential data-assimilation algorithm. The method is a Monte Carlo type where error function is represented by an ensemble of realizations. In this method, the prediction of the estimate and uncertainty is done by ensemble integration using the reservoir model and therefore the error estimates is based only on the information from the ensemble. Thus the EnKF is said to be independent of the simulator. In EnKF, the reservoir model condition and parameters are updated sequentially in time based on the information from pressure and rate measurements from production wells; hence this makes it possible to always have an updated model conditioned on the most recent production data (Haugen et al., 2006), (Evensen et al., 2007).

2.6 Challenges of History Matching

One of the challenges associated with history matching is that the matched model is not always the correct one (not always unique); because the historical production can be fit by several reservoir scenarios. In most cases, the solution of an inverse problem (for example history matching) is associated with non-uniqueness. Therefore it is not always correct to assume that “a good history-matched model is a good representation of the reservoir” (Tavassoli et al., 2004), (Tomomi, 2000). This problem cannot be avoided, however matching as much production data as available and adjusting only the least known reservoir data within acceptable ranges should yield a better match (Ertekin et al., 2001).

Another challenge of history matching is the presence of uncertainties during simulation. Usually, in history matching, porosity and permeability are allowed to vary independently at each grid block used in the finite-difference. This may result to uncertainties because of the large number of unknowns compared to the limited available data (Gavalas et al., 1976).

(Lind et al., 2013) state that “the errors in measured and allocated history data are frequently overlooked. For example water production need not originate from the reservoir but can come from mechanical problems (casing leaks, poor cement bond)”

Therefore, due to the fact that history matching is a challenging process and also because of the uncertainties associated with the simulation results of a given reservoir, it is important to carry out an assessment of the quality of the data both observed and the given reservoir description model before starting history matching activity (Parish et al., 1993).

2.7 Introduction to Seismic Data

Seismic survey is one of the exploration method used in petroleum industry to determine the location of hydrocarbon bearing reservoir and to understand their characteristics (geological structures and rock properties). The method is said to utilise the elasticity nature of the rock. Seismic data plays an important role in reservoir field development (reservoir management) since the interpretation and conclusion from seismic data can be integrated with the analysis of other source of data such as well logs, pressure tests, core analysis, geological depositional knowledge and other information from exploration and appraisal wells to make decision on the commercial integrity of a given reservoir. The process of obtaining seismic data starts with acquisition followed by processing and finally interpretation of the results (CSEG & Chief Geophysicists Forum, 2011).

Seismic acquisition involves sending elastic waves (vibrations) down to the targeted area of the earth’s surface and allowing the waves to interact with the target. Due to variations in the physical properties of the geological layers, seismic wave signals can be reflected or refracted at the boundaries of the geological layers. The reflected wave signal propagates back to the surface and hence recorded and processed to generate images of the subsurface layers and to give estimates of other physical properties such as wave velocity. Seismic processing involves reconstruction of the process of wave propagation, including its reflection point and ray paths while seismic interpretation involves the estimation of geometry and properties of the earth (geological features). The process of data acquisition, processing and interpretation are connected to each other (Al-Ali, 2007).

Seismic data can be categorized into three types which are two-dimensional (2D) seismic survey, three-dimensional (3D) seismic survey and four-dimensional (4D) seismic survey.

2.7.1 Use of 4D Seismic Data in History Matching

Four-dimensional (4D) or time-lapse seismic survey is defined as the process whereby standard 3D seismic survey is repeated over time in order to make snapshots of the fluid and pressure fronts during production (i.e. pressure and saturation change due to production or injection) (Amundsen & Landrø, 2007).

4D seismic data finds several applications in the petroleum industry. According to (Amundsen & Landrø, 2007), some of the applications are "in monitoring reservoir fluid movements with time, in identification of drained and undrained reservoir compartments, in optimising well placement, in reducing uncertainty in reservoir development and production decisions, to differentiate between reservoir fluid and pressure changes, in distinguishing between compacted and non-compacted reservoir sections, identifying stretching and stress changes in overburden, and in monitoring CO_2 sequestration".

The first most important activity that must be done before 4D seismic data is used in history matching is data quality accuracy (repeatability) check-up. This is because 4D seismic data depends on the differences between corresponding amplitudes in seismic surveys taken at different times. Therefore data accuracy is more important than with conventional seismic. Repeatability check-up is done to make sure that the seismic response changes are due to production or injection and not from noise. Acquisition-dependent processing technique may be applied to reduce the effects of non-repeatability. For example, application of high-frequency imaging to optimize vertical resolution of 4D seismic data is becoming a standard procedure (Stein et al., 2006). Example of a repeatability measurement is shown in Figure 2.2 below.

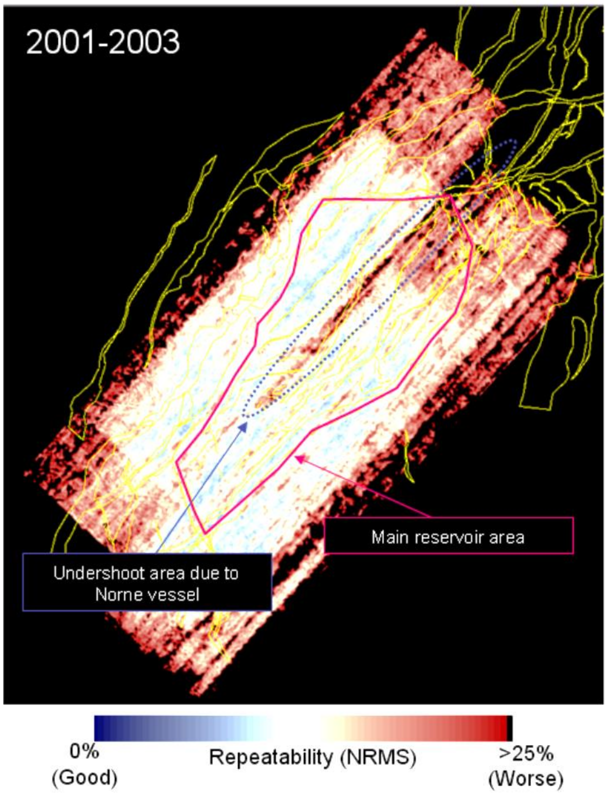


Figure 2.2 Example of time-lapse repeatability measurement between seismic survey 2001 and survey 2003. The white/blue area indicates where the 4D seismic data quality is good whereas the red/black area indicates the opposite. A significance zone around the Norne production vessel is indicated to be less repeatable but still acceptable (El Ouair et al., 2005)

History matching has always been done using production data only. However this approach is associated with some challenges that the upscaling is done at the fluid flow simulator scale only and the fine-grid geological model is not updated because of the lack of appropriate tools and methodologies. The use of 4D seismic data in history matching allows updating of both fluid flow model and geostatistical model (Roggero et al., 2012). The other challenge of using production data in history matching is that the production data are obtained at discrete locations (the well) and therefore lacks the areal coverage necessary to accurately constrain dynamic reservoir parameters such as permeability and effect of faults. On the other hand, 4D seismic data provides information beyond the well i.e. 4D seismic data provide information at the field scale (large area) (Fahimuddin et al., 2010).

Furthermore, 4D seismic data are more useful in history matching over the tradition use of production data because they allow direct imaging of rock properties that are closely related to vertically averaged fluid saturations and pressure. Usually, seismic images are said to be sensitive to the spatial variation of two distinct types of reservoir properties (Dong & Oliver, 2003):

- Non-time-varying static geologic properties such as lithology, porosity, cementation, and shale content
- Time-varying dynamic fluid-flow properties such as fluid saturation and pore pressure.

2.7.2 Qualitative use versus Quantitative use of 4D Seismic Data in History Matching

The 4D seismic data can be used either qualitatively or quantitatively. The qualitatively use of 4D seismic data refers to what kind (quality) of changes has occurred whereas quantitatively use of 4D seismic data refers to how much (quantity) of the change has occurred on saturation and pressure (Fahimuddin, 2010).

For long time the use of 4D seismic data has been focused on qualitative seismic data as it has been reported by several authors that qualitative use of seismic data is very simple and direct. For example (Fahimuddin, 2010) reports that the qualitative monitoring of reservoir changes due to production is done by identifying regions in which the amplitude or impedance has changed with time and attributes these changes to changes in saturation, pressure or temperature. Therefore now the effort and focus is to consider the use of quantitative seismic data; although some authors have reported that it is very difficult to use 4D seismic data in quantitative way.

Although qualitative use of 4D seismic data has been very useful in history matching process, it has disadvantage that it ignores the constraints on saturation and pressure imposed by mass conservation and flow relationships (Dong & Oliver, 2003). However, with the introduction of computer assisted history matching, it is now possible to quantitatively use 4D seismic data in history matching (Fahimuddin, 2010).

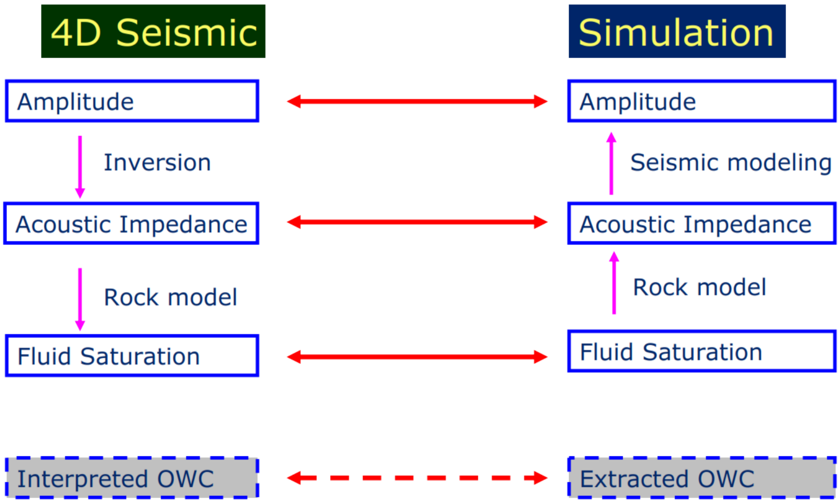


Figure 2.3: History matching with the use of 4D seismic data (Cheng & Osdal, 2008)

2.7.3 Approaches of Using 4D Seismic Data in History Matching

Several works have been done by different authors on how the 4D seismic data can be used in history matching. For example (Kretz et al., 2002) presents two approaches of using 4D seismic data:

- The first approach uses interpreted 4D seismic data. In this approach, the seismic data are interpreted in order to directly point out the changes of fluid saturation, impedance or elastic properties between the surveys. In this case only one forward simulator is used in the inversion process which is fluid flow simulator as it can be seen in Figure 2.4 below. This approach is common practice of qualitative use of 4D seismic data. In this case it is possible to perform manual history matching.

- The second approach does not use interpreted seismic data. But in this case, seismic data is considered as another set of matching data. In this approach, the inversion process uses fluid flow simulator and forward seismic wave propagation simulator as indicated in Figure 2.5 below. This approach is commonly applied in the quantitative use of 4D seismic data. Generally, the seismic data is integrated in the matching process. In this approach it is not possible to perform manual history matching; therefore the assisted history matching is applied.

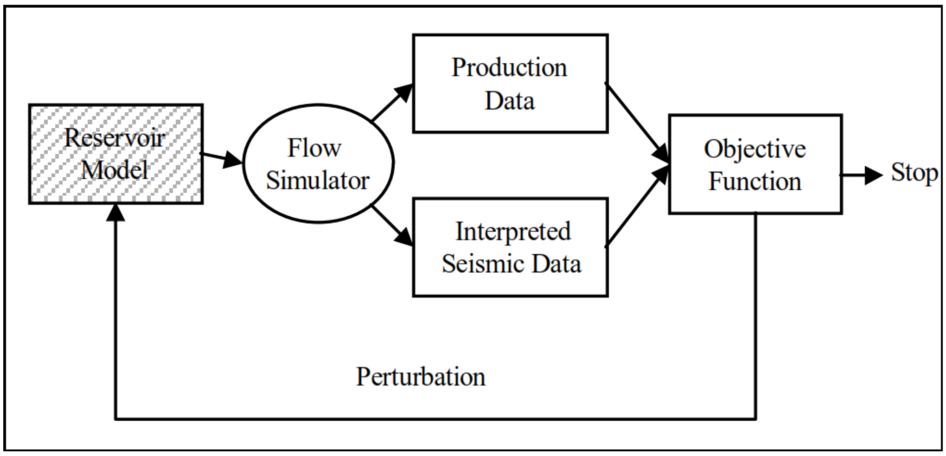


Figure 2.4: History matching with 4D seismic data: 1st approach (Kretz et al., 2002)

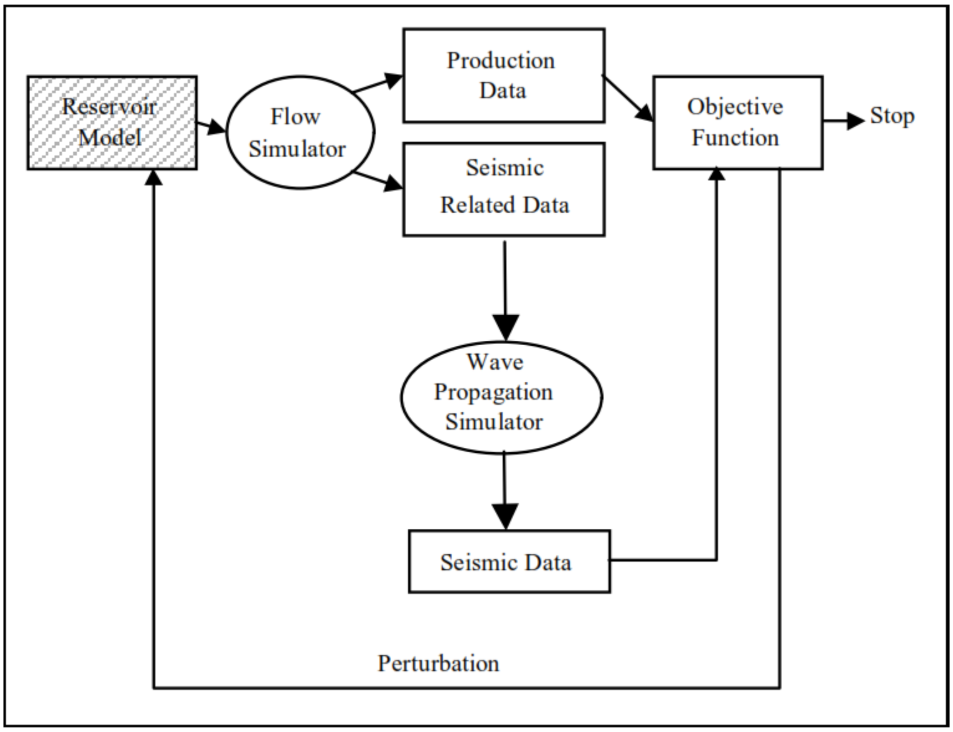


Figure 2.5: History matching with 4D seismic data: 2nd approach (Kretz et al., 2002)

2.7.3.1 Quantitative 4D seismic data history matching based on Petroelastic Modelling

In effort to match 4D seismic data in quantitative way, several methods have been proposed by different authors. One of the methods is the integration of Petroelastic model (PEM) with a dynamic flow simulator proposed by (Gosselin et al., 2003), (Falcone et al., 2004). The method proposed is the result of a two-year project sponsored by the European Commission. The proposed HUTS (History matching Using Time-lapse Seismic) approach uses an iterative, gradient-based optimisation method to adjust the initial reservoir parameters.

As like other history matching approaches, HUTS approach aimed at finding the best reservoir model, i.e. the one with a minimum mismatch between observed data and simulated data. The following is the description of the objective function as proposed by (Falcone et al., 2004)

$$Q(x) = \frac{1}{2}\left\|Y(x) - Y^{obs}\right\|_C^2 \quad \text{...} \, (4)$$

Where $Q(x)$ is the objective function, $Y(x)$ is the simulated data, Y^{obs} is the observed data and C is the covariance matrix that accounts for the measurements errors, correlations and weights.

The objective function can also be written as:

$$Q(x) = a.q_{prod} + b.q_{seis} + c.q_{prior} \quad \text{...} \, (5)$$

Where:

$$q_{prod}(x) = [A \cdot R(x)]^t \cdot C_Y^{-1} \cdot [A \cdot R(x)] \quad \text{..} \, (6)$$

$$q_{seis}(x) = [B \cdot S(x)]^t \cdot C_Z^{-1} \cdot [B \cdot S(x)] \quad \text{...} \, (7)$$

$$q_{prior}(x) = [C \cdot M(x)]^t \cdot C_X^{-1} \cdot [C \cdot M(x)] \quad \text{..} \, (8)$$

With:

$$R(x) = Y(x) - Y^{obs} \quad \text{..} \, (9)$$

Y: production data (i.e. oil rate, gas rate, water cut, gas-oil ratio)

$$S(x) = Z(x) - Z^{obs} \quad \text{..} \, (10)$$

Z: seismic data (i.e. absolute values or variations of elastic properties)

$$M(x) = X - X^{prior} \quad \text{..} \, (11)$$

X: a-priori information (to add petrophysical constraints to the variations of reservoir parameters)

A, B, C are weight vectors, whileC_Y, C_Z , C_X are covariance matrices.

Note that, the observed elastic properties (absolute values or time-lapse change) and associated uncertainties are calculated by inversion of the 4D seismic data.

The illustration of the HUTS workflow is given in Figure 2.6 below. The figure also shows where the PEM intervenes.

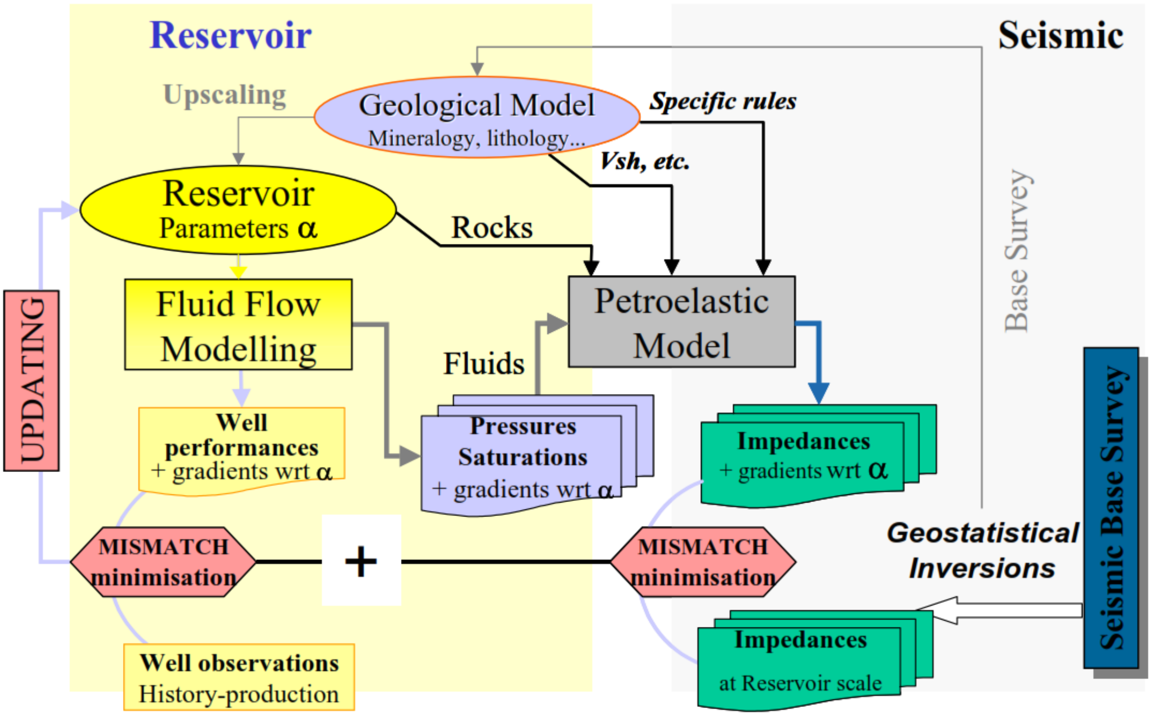


Figure 2.6 The HUTS workflow (Falcone et al., 2004)

Petroelastic Modelling

A PEM converts fluid properties (i.e. pressure, saturation, fluid density and fluid elastic modulus) and rock properties (i.e. porosity, clay content, lithology and rock frame elastic modulus) into simulated elastic parameters (P- and S- velocities and density or impedances). PEM provides the link between the reservoir domain (flow simulation) and elastic domain (wave propagation). The link intervenes in both forward and inversion procedures. The forward approach is the one which starts from the reservoir domain to the elastic domain. The conversion performed in PEM is based on general theoretical principles applied to the specific field under study. Also, it consists of both analytical formulae and empirical laws calibrated with log and core data (Falcone et al., 2004), (Gosselin et al., 2003).

To better understand the various components of a PEM, it is proposed to characterise a PEM as a chain of calculations (tree) split into levels. Whereby on each level, there are relationships (rules) such as Gassmann's equation and Wood's equation (to calculate the bulk modulus of the fluid mixture), and empirical correlations (signature) that describe the mechanical properties of elementary constituents (porosity, density of oil as a function of pressure, temperature and depth, compressibility of shale as function of overburden, etc.). A tree of rules develops from the signature (Falcone et al., 2004).

Other proposed methods

The following are some of the other proposed methods to match 4D seismic data

i. Several works have been done by different author to use Ensemble Kalman Filter (EnKF) in history matching of 4D seismic data, for example (Skjerrvheim et al., 2005), (Haugen et al., 2006), (Trani et al., 2012) and (Abadpour et al., 2013). According to (Skjerrvheim et al., 2005), "EnKF is a Monte Carlo type sequential Bayesian inversion method that provides an approximate solution to the combined parameter and state estimation problem". This method is said to be able to handle complex problems and uncertainties. Further explanation of EnKF is given in Chapter 2.5.2

ii. (Stephen et al., 2005) proposed a method to match 4D seismic data using multiple model history matching based on simultaneous comparison of spatial data from seismic, and individual well production data. This method was applied to a UKCS turbidite reservoir.

iii. Another method for 4D seismic data history matching is the Streamlines-based simulation approach where a fluid flow simulation is run and the flow properties (porosity, permeability etc.) are adjusted along the streamlines so that the computed fluid fronts match with the observed fluid fronts derived from 4D seismic. This method was proposed by (Kretz et al., 2004).

iv. The other method that was proposed by (Roggero et al., 2007) is the use of advanced parameterization technique to constrain the fine scale geostatistical model. This is done through gradual deformation method which allows smooth transformations of the facies model realization while conserving the overall statistical characteristics.

2.7.4 Processing and Interpretation of 4D Seismic Data (Norne field case study)

In order to have a good interpretation of 4D seismic data, a careful processing of the seismic is very essential. For example in Norne field, the best OWC is interpreted from seismic difference data and therefore this requires careful 4D seismic processing to enhance the production-related 4D seismic differences. During processing, it is important to test processing algorithms on all vintages so that 4D seismic difference displays can be analysed and compared. There are two approaches that can be used in processing; adaptive processes and deterministic processes. It is recommended to use the deterministic processes. Also in processing the 4D seismic data, it is necessary to conduct 4D binning. Furthermore, in order to obtain good repeatable 4D seismic data, it is recommended to select the pair of traces between two vintages that best match in terms of source and receiver locations as demonstrated in Figure 2.7 below. Pairs of traces between two vintages that do not match in acquisition geometry will degrade the 4D seismic difference. (Osdal et al., 2006).

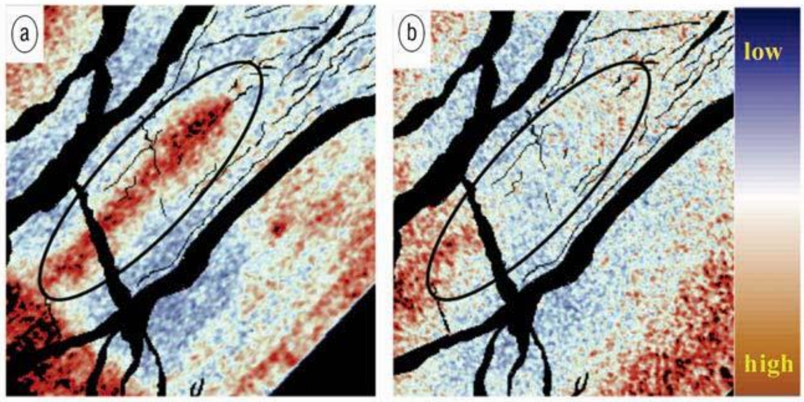


Figure 2.7 The nrms map showing an overfold area with (a) all data used in the processing and (b) 4D binning applied and nonrepeating traces thrown away (Osdal et al., 2006)

The interpretation of seismic data in Norne field is presented in Figure 2.8 below. Figure 2.8a shows seismic modelling (stacks) of varying rise of the OWC (0-70 m), it can be seen that it is almost impossible to locate the new OWC on these stacks. However, if the 4D differences are used, the geology can be cancelled and the new and original OWC are left in the data as presented in Figure 2.8b below. Figure 2.8c shows a 2003 seismic line through water injector well whereby it is clear that the OWC cannot be interpreted from the line. The 2003 OWC can be interpreted in the 2001-2003 seismic difference as shown in Figure 2.8d. Figure 2.8e shows some synthetic modelled difference data in the injector based on repeated saturation logging in 2000 and 2002. The left curves in Figure 2.8e show the relative change in acoustic impedance between base and 2000 (blue) and base and 2002 (black) surveys. A complete flushing of the oil with water causes an acoustic impedance change of 7-8% (Osdal et al., 2006).

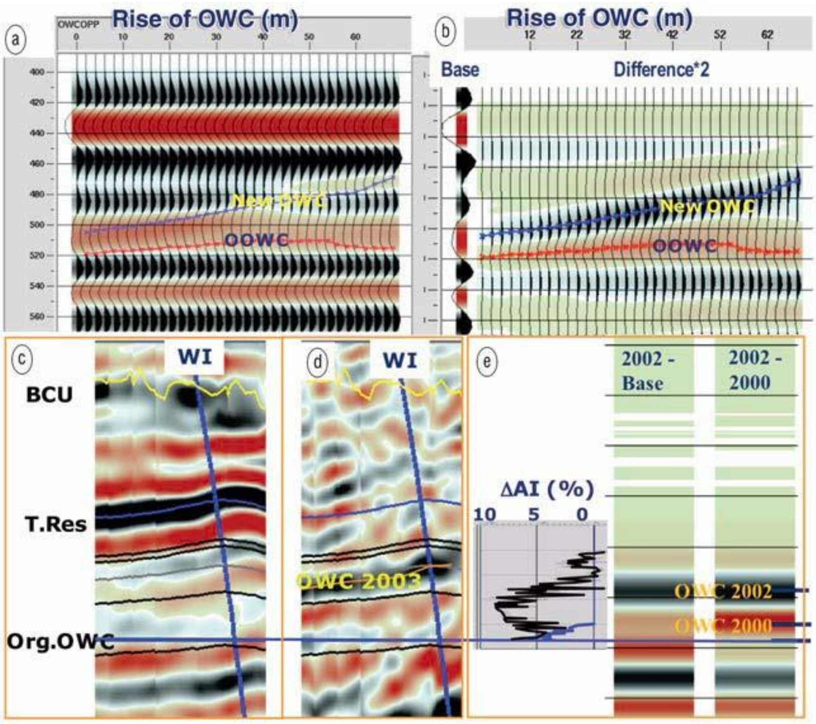


Figure 2.8 (a) Seismic modelling for varying rise of OWC from 0-70 m. (b) Seismic differences for varying rise of OWC and the first base trace. (c) 2003 4D data around an injector (d) 2001-2003 4D difference around same injector. The 2003 OWC can clearly be interpreted here. (e) Left curves show change in acoustic impedance in % from base to 2000 (blue curve) and base to 2002 (black curve). Seismic modelling on the right shows differences between base and 2002 and 2000-2002 (Osdal et al., 2006)

CHAPTER 3

3. NORNE FIELD OVERVIEW

3.1 General Information of the Norne Field

Norne is an oil field which is located in blocks 6608/10 and 6508/10 on a horst block in the southern part of the Nordland II in the Norwegian Sea. This horst block is said to be approximately 9 km x 3 km (IO Center-NTNU, 2010c), (IO Center-NTNU, 2010d). The field comprises of two separate oil sections, which are Norne Main structure (consisting of segment C, D and E) and the North-East segment (segment G). Discovery of Norne Main structure was in December 1991 and the measurement and analysis showed that it contains 97 % of oil in place (Lind, 2006). Norne field is a conventional reservoir with oil, gas and water. Furthermore, the water depth is 370 to 390 m (Steffensen & Karstadt, 1996).

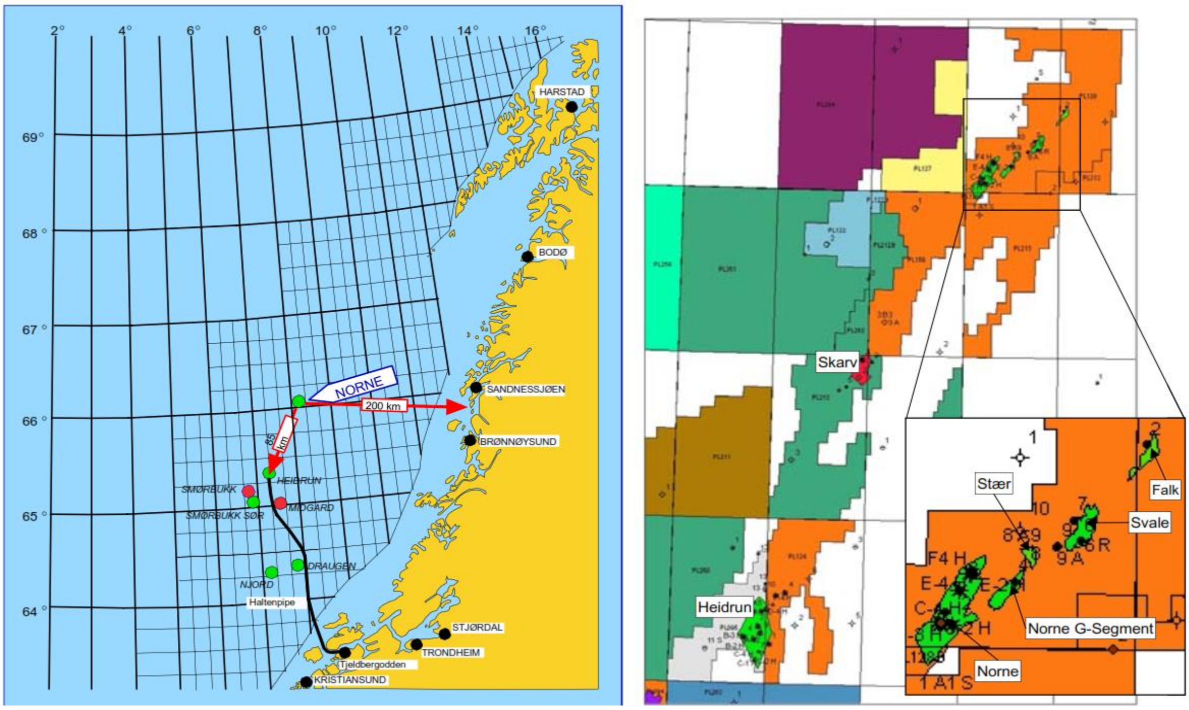


Figure 3.1: The location of Norne field (Steffensen & Karstadt, 1996)

Measurement further showed that the field contains a total hydrocarbon column of 135 m of which 110 m is oil and 25 m is gas cap (Lind, 2006). The discovered oil and gas is in the rocks of Lower and Middle Jurassic age (IO Center-NTNU, 2010d). Furthermore, according to the geological reports, it has been pointed out that the Norne field consists of four formations from top to base which are Garn, Ile, Tofte and Tilje (Lind, 2004). However, there is also a shale (non-reservoir) formation named Not formation which separates and prevents communication between Garn and Ile formations. This non-reservoir formation is expected to be continuous throughout the field however it is locally broken by major faults (Gjerstad et al., 1995). Ile and Tofte formation contain approximately 80 % of oil in place of the Norne field whereas gas is found in the Garn formation (IO Center-NTNU, 2010c). The gas is reported to be above the non-reservoir Not formation (Gjerstad et al., 1995)

Simulation model showed that the amount of initial oil in place in this field is about 160.6 million Sm^3 whereas the geological mode showed that initial oil in place is 160.8 million Sm3 (IO Center-NTNU, 2010a). The total gas in the field is approximately 29 billion Sm3 of which 18 billion Sm3 is associated gas and 11 billion Sm3 is in the gas cap (Gjerstad et al., 1995).

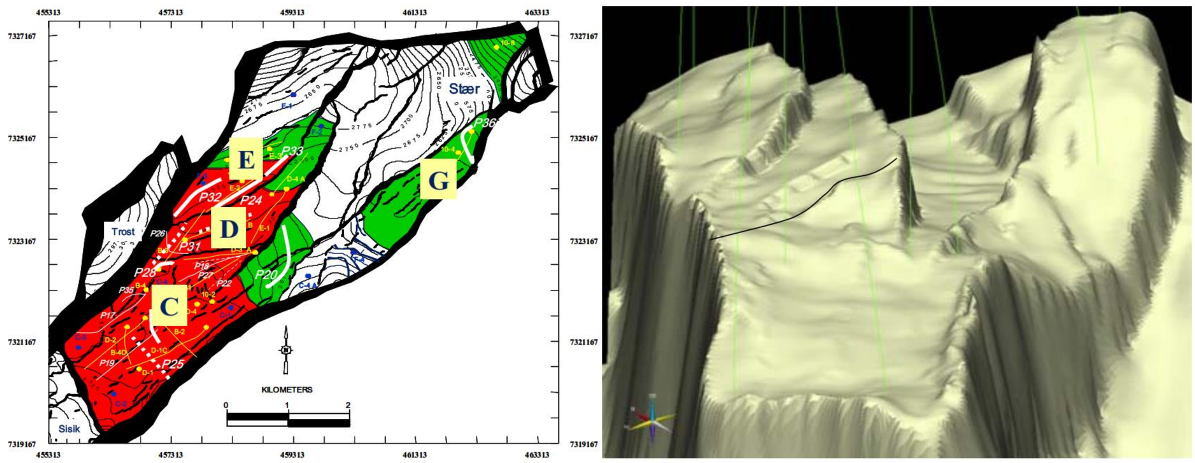


Figure 3.2: The Norne field segment and wells (Lind, 2004)

Table 3.1 below shows fluid contacts (the initial gas-oil contact (GOC) and oil-water contact (OWC)) in the different formations and segments as used in 2004 Norne reservoir simulation model

Table 3.1: Gas-oil and oil-water contacts as used in 2004 Norne reservoir simulation model

Datum (m)	**Pressure (bar)**	**WOC Depth (m)**	**GOC Depth (m)**	Segment	Formation
2582.0	268.56	2692.0	2582.0	C + D	Garn
2500.0	263.41	2585.5	2500.0	G	Garn
2582.0	269.46	2618.0	2582.0	E	Garn
2200.0	236.92	2400.0	2200.0	G	Ile – Tilje
2585.0	268.77	2693.3	2585.0	C + D + E	Ile – Tilje

3.2 Geological Description of the Norne Field

It has been reported that the location of hydrocarbons in this reservoir is in Lower to Middle Jurassic sandstones. Moreover, the sandstones are characterized by fine-grained and well to very well stored sub-arkosic arenites and they are reported to be buried at a depth of 2500-2700 m and are affected by diagenetic processes (IO Center-NTNU, 2010d), (IO Center-NTNU, 2010b).

The Norne field source rocks are Spekk formation from late Jurassic and coal bedded Åre formation from early Jurassic. The cap rock which seals the reservoir and keeping the fluids in place is the Melke formation. The entire reservoir thickness, from Top Åre to Top Garn formations, varies over the field – from 260 m in the southern parts to 120 m in the northern parts due to the increased erosion to the north, causing the Ile and Tilje formations to decrease in thickness (IO Center-NTNU, 2010b).

3.2.1 Reservoir communications

Norne field is characterised by both faults and stratigraphic barriers which affect vertical and lateral fluid flow. However, despite the fact that these barriers are not expected to be important in a field-wide scale, it is important to consider their effect on the fluid flow to enhance drainage strategy. The lateral extent and thickness variation of these stratigraphic barriers has been assessed using cores and logs. Table 3.2 below shows the continuous intervals which restrict the vertical fluid flow within the Norne field (IO Center-NTNU, 2010b).

Norne field has faults (major and minor faults) whereby major faults can be identified through studying the seismic data. The illustration of cross sections through the Norne field with fluid contacts and faults is shown in Figure 3.5 below. The geological description reports of the Norne field state that each sub-area of the fault planes has been assigned transmissibility multipliers. Furthermore, to describe the faults in the reservoir simulation model, the fault planes are divided into sections which follow the reservoir zonation. These are functions of the fault rock permeability, fault zone width, matrix permeability and the dimensions of grid blocks in the simulation model (IO Center-NTNU, 2010b).

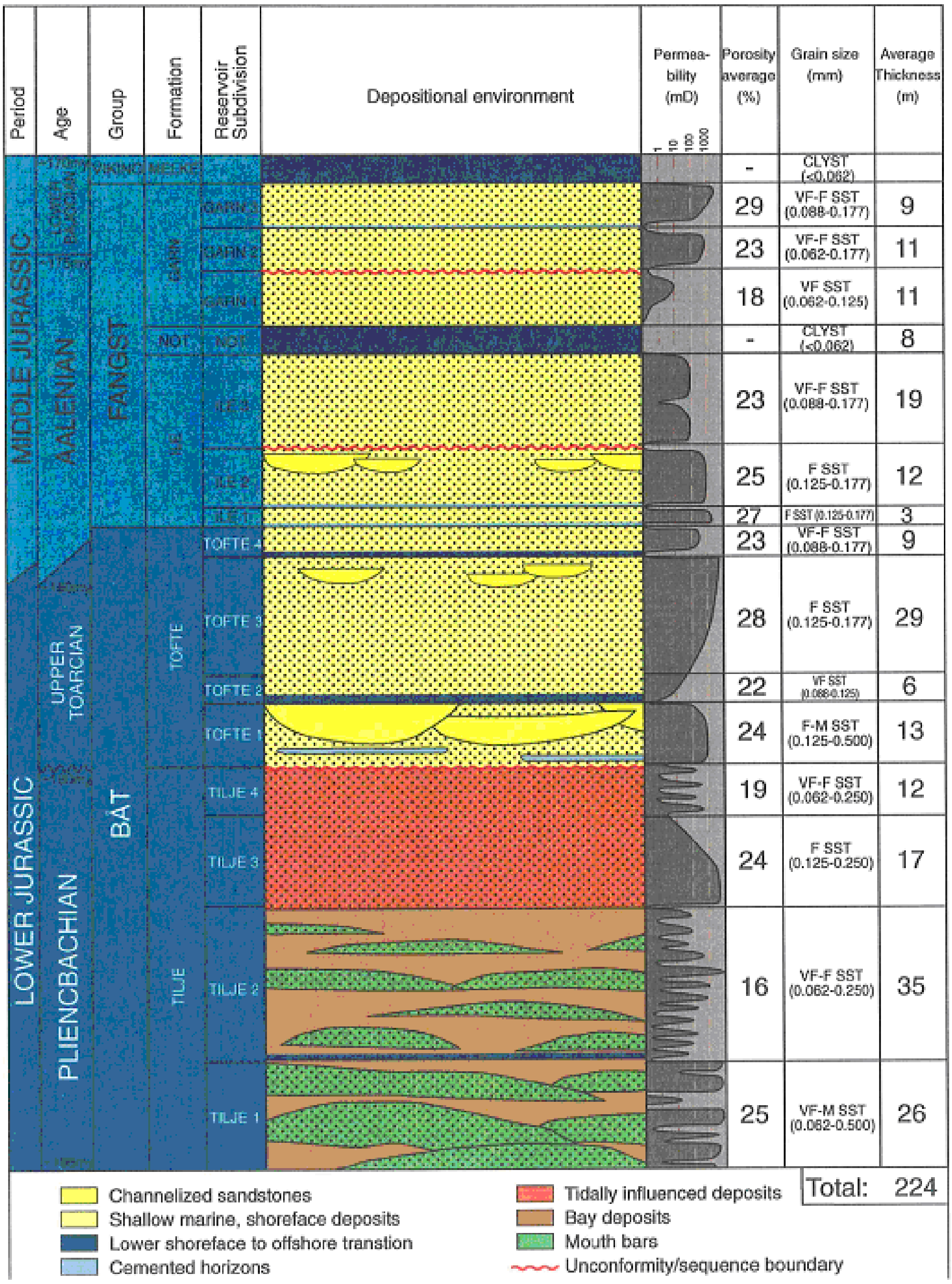


Figure 3.3: Stratigraphical sub-division of the Norne reservoir (IO Center-NTNU, 2010d)

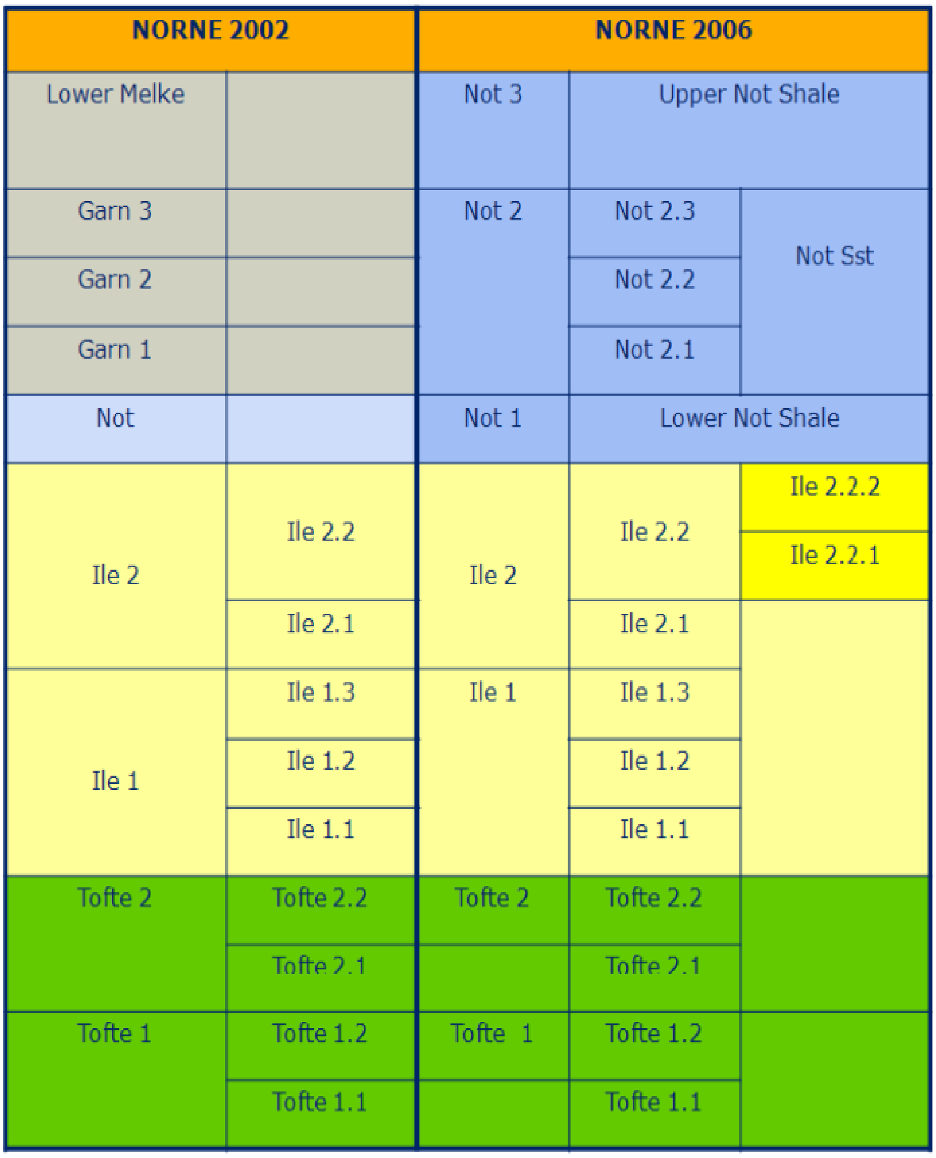


Figure 3.4: Old and new zonation (IO Center-NTNU, 2010d)

Table 3.2: Location of the stratigraphic barriers in the 1999 and 2004 geological zonation (Morell, 2010)

Geological zonation		**Comment**
1999 model	**2004 model**	
Garn 3/Garn 2	Garn 3/Garn 2	Carbonate cemented layer at top Garn 2
Not Formation	Not Formation	Claystone formation
Ile 3/Ile 2	Ile 2.1.1/Ile 1.3	Carbonate cementations and increased clay content at base
Ile 2/Ile 1	Ile 1.2/Ile 1.1	Carbonate cemented layers at base Ile 2
Ile 1/Tofte 4	Ile 1.1/Tofte 2.2	Carbonate cemented layers at top Tofte 4
Tofte 2/Tofte 1	Tofte 2.1.1/Tofte 1.2.2	Significant grain size contrast
Tilje 3/Tilje 2	Tilje 3/Tilje 2	Claystone formation

3.3 Norne Field 4D Seismic Data

As part of reservoir management strategy/plan, a total of 6 seismic surveys have been carried out on the Norne field, starting with the first conventional base survey carried out in 1992 using a dual source, and three streamers separated by 100m. Then five monitoring surveys were conducted using a Q-marine vessel in 2001, 2003, 2004, 2006 and 2008. The first monitoring survey was done in 2001 covering 40 km^2. This survey was named ST0113 and it was intended to monitor oil-water contact and drainage of the field. A second Q-marine survey acquired in June 2003, covering 85 km^2, was named ST0305. This survey was carried out as identically as possible to ST0113. Then in July 2004, a third Q-marine survey was acquired and named ST0409. This survey covered a larger area (146 km^2) and was acquired as identical as possible to ST0113 and ST0305 surveys. Then the 4^{th} Q-marine survey was shot in July/August 2006 and named ST0603. This survey was acquired as identically as possible to the 2004 survey. Note that in all the monitor surveys, a single source and six steerable streamers separated by 50 m were used (IO Center-NTNU, 2010d), (Rwechungura et al., 2010).

3.4 Development and Drainage Strategy

In petroleum industry there are several production strategies that can be selected depending on the nature and characteristics of the given reservoir. In the Norne Field the employed production strategy is the use of Floating Production Storage and Offloading vessel (FPSO). It has been reported that, the Norne field has six wellhead templates at the sea bottom connected to a floating production storage and offloading vessels which are B, C, D, E, F and K as it can be seen in Figure 3.6 below. Template K was placed on the sea bottom in 2005, south of B, C and D templates and it has 4 slots available; 3 for production and 1 for injection or production (IO Center-NTNU, 2010c).

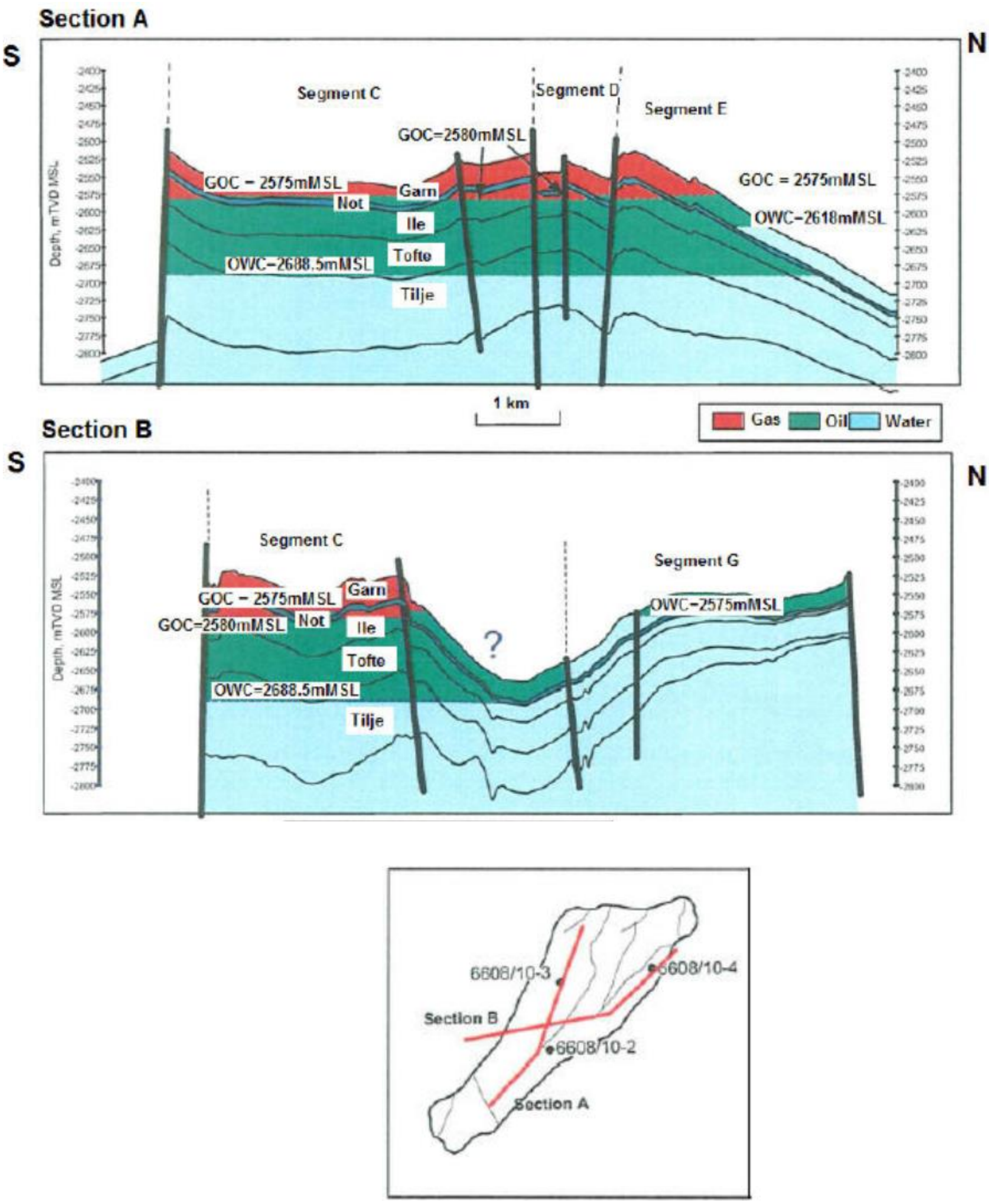


Figure 3.5: Structural cross sections through the Norne field with fluid contacts (IO Center-NTNU, 2010d)

In August 1996 development drilling in the Norne field was started, and in 6th November 1997 the oil production was started (Lind, 2004). As stated earlier that the Norne field is being produced using FPSO vessel, then the production from each well (well stream) is transported by flexible risers to the FPSO vessel, which rotates around a cylindrical turret anchored to the sea floor. Furthermore, this FPSO vessel has storage tanks which are used for storing stabilized oil and also it has a processing plant which is located on the deck of the ship (IO Center-NTNU, 2010c).

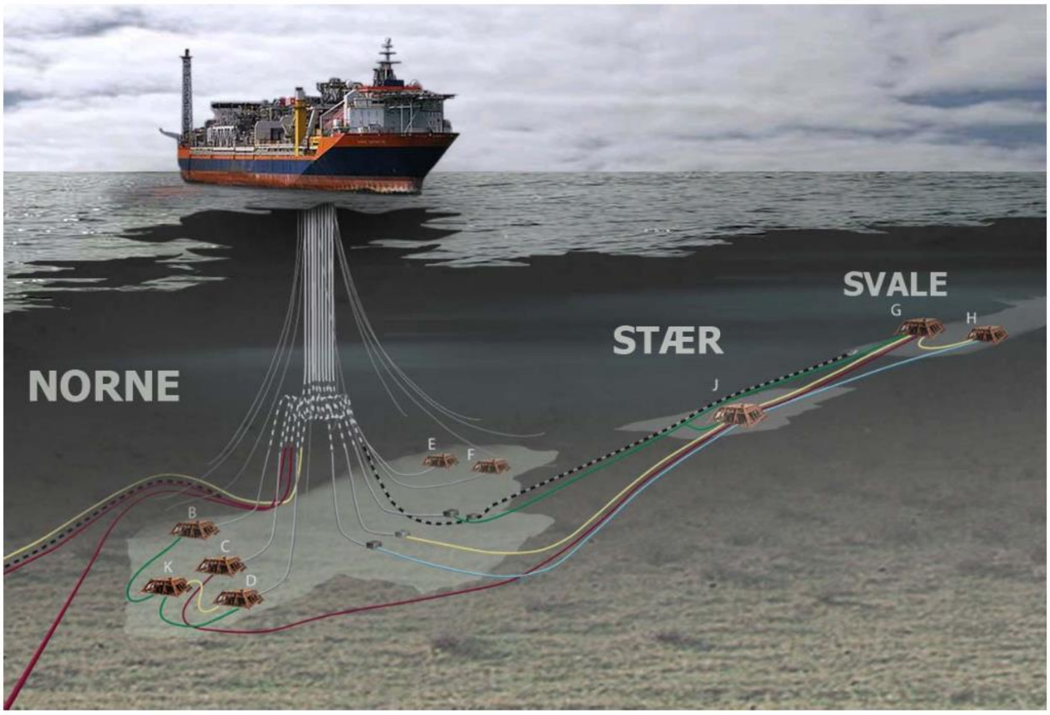


Figure 3.6: The development of the Norne field and Urd field (Norne satellites Stær and Svale) (Lind, 2006)

As like other fields; the main goal in the Norne field was to develop it in such a way that the economic optimum production profile is attained. Currently; the Norne field is developed only with horizontal producers. However, to accelerate the build-up of well potential until plateau production was reached, some of the first producers were drilled vertical and some deviated. All these wells have been side-tracked to horizontal producers (Lind, 2006).

The Norne field reservoir pressure was initially planned to be maintained by re-injecting produced gas into the gas cap and injecting water into the water zone. However, during the first year of production it was experienced that the Not shale is sealing over the Norne Main structure, and therefore the strategy was changed to inject gas in the water zone and the lower part of the oil zone. Finally, in 2005 the gas injection was ended as it can be seen in Figure 3.8 below (Lind, 2006). The change in pressure maintenance strategy was successful however this led to more complications and uncertainties in the prediction of gas flow in the reservoir. A higher GOR than predicted caused the production to be restricted by gas handling capacity, therefore gas export was started in order to get a balanced gas and water injection strategy, and prevent further increase in GOR (Morell, 2010).

During its commissioning on 6th November 1997, it was estimated that Norne field will produce until 2014 but now the company (Statoil ASA) plans to extend production to 2030. As of January 2015, the field has produced 700 million barrels of oil equivalent and attained recovery factor of 56.5 % which is considered to be a top result worldwide for production from subsea fields. The target is to increase the recovery factor to 60% thus accessing the remaining resources which is estimated to be 300 million of oil equivalent (Statoil, 2015).

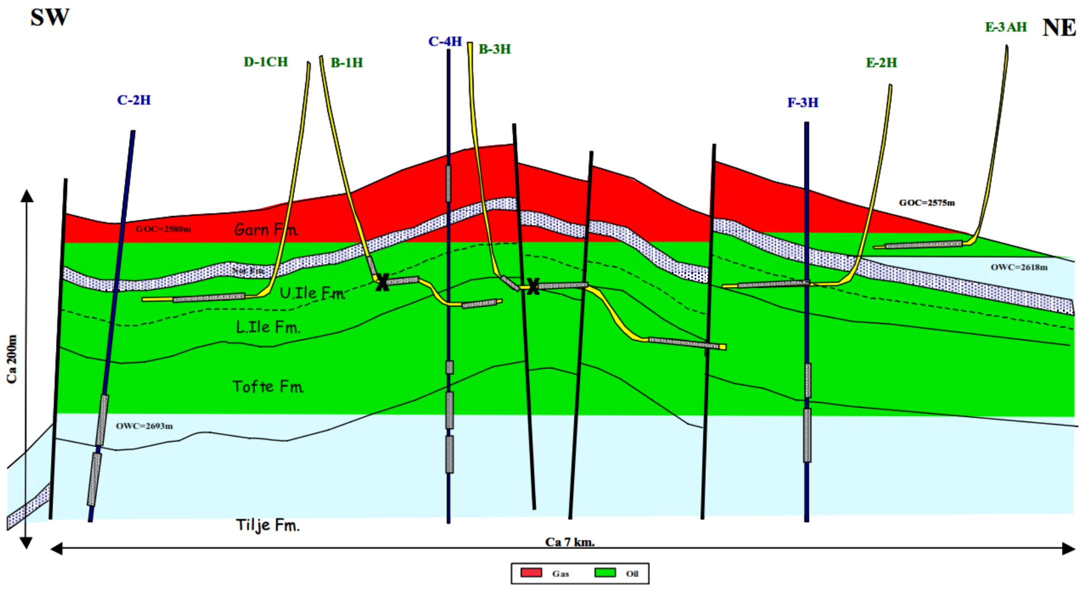


Figure 3.7: NE-SW running structural cross section through the Norne field with initial fluid contacts and current drainage strategy (Lind, 2004)

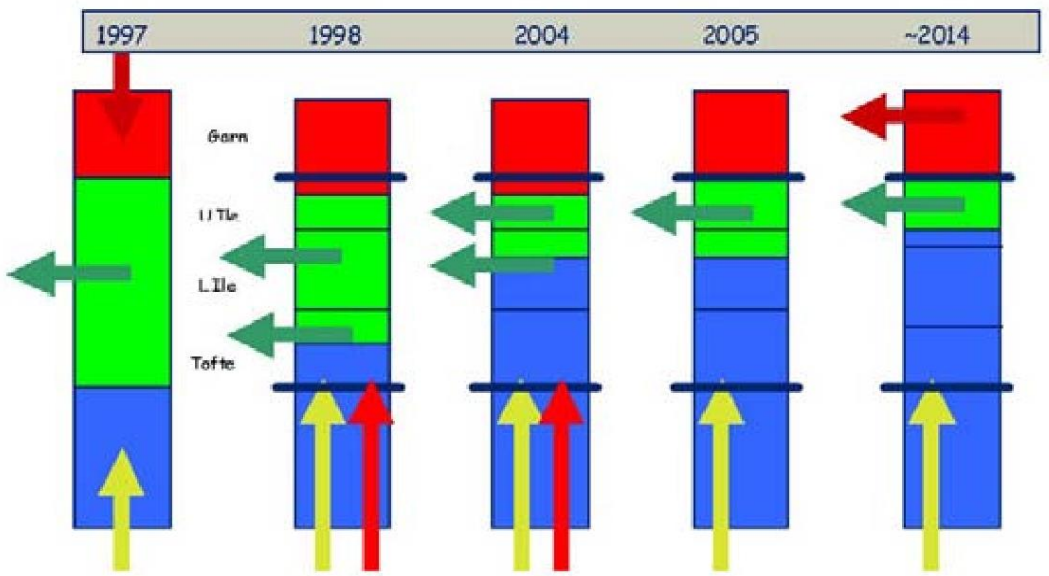


Figure 3.8: The drainage strategy for the Norne field from pre-start and until 2014 (IO Center-NTNU, 2010a)

CHAPTER 4

4. METHODOLOGY

To achieve the objectives of this study, firstly the literature review was done to get knowledge and insight of history matching and what has been done in Norne field by other researchers so far. History matching can either be done manually, automatically or computer assisted. This study was focused on purely manual history matching of the production data and 4D seismic (qualitative) data.

In history matching the Norne field using production data; the parameters that have been considered uncertain and hence selected for adjustment were vertical transmissibility of the stratigraphic barriers, fault transmissibility, vertical permeability and horizontal permeability. Whereas parameters that were matched were field water cut, field water production total, field oil production rate, field oil production total, and field gas oil ratio.

History matching using 4D seismic data can be done either qualitatively, quantitatively or both. In this study, qualitative 4D seismic data history matching was done whereby oil water contact from simulation model was manually matched with the oil water contact from 4D seismic by adjusting fault transmissibility and vertical permeability.

Black oil simulator was used in this study which is the Eclipse 100 of 2014.1 and its interpretation software's which are FloViz and Office. The other software used in this study is Petrel 2015.

The data used in this study is the Norne full field data whereby permission (username and password) was granted to access the data available at http://www.ipt.ntnu.no/~norne/Full-Norne/.

The key steps followed in history matching using production data are:

1. Reviewing the Norne full field reports and information.
2. Running the Norne full field base case reservoir simulation model and then evaluating the difference between the simulated results and historical production data.
3. Evaluating uncertain reservoir parameters that have resulted into difference between simulated results and historical production data.
4. Choosing the parameters to adjust and parameter to match.

5. Adjusting the uncertain parameters to obtain a best matched simulation model.

The key steps followed in history matching using 4D seismic data are:

1. The best matched simulation model during history matching using production data was considered as the base model for history matching using 4D seismic data.
2. Loading the simulation model into the Petrel
3. Loading the seismic survey into the simulation model in Petrel and choosing the seismic line with good quality.
4. Locating the seismic line path in the simulation model
5. Zooming into E segment
6. Interpreting the oil water contact in both simulation model and seismic data
7. Comparing the oil water contact from simulation model and seismic data to see if they match.
8. Adjusting uncertain parameters (fault transmissibility and vertical permeability) in the simulation model and running simulation using Eclipse
9. Repeating step 2 to 8 until the oil water contact from simulation model is matched to the oil water contact from seismic data.

CHAPTER 5

5. THE NORNE FIELD RESERVOIR SIMULATION MODEL

The reservoir simulation model used in this study is that of 2004. This simulation model is based on the geological model built in 2004. The geological model has 20 structural maps while reservoir simulation model has grid dimensions of 46x112x22 (Husby, 2005) and it is based on a 2004 interpretation of the 4D seismic surveys ST0103, ST0305 and ST0409 (Morell, 2010). Of the 113344 grid cells; 44927 have been reported to be active (Rwechungura et al., 2010). The layer zonation of the model is as show in Table 5.1 below

The 2004 reservoir model show a total of 21 producing wells and 9 injection wells. These production wells are B-1BH, B-1H, B-2H, B-3H, B-4BH, B-4DH, B-4H, D-1CH, D-1H, D-2H, D-3AH, D-3BH, D-4AH, D-4H, E-1H, E-2AH, E-2H, E-3AH, E-3CH, E-3H, E-4AH and K-3H. Injection wells are C-1H, C-2H, C-3H, C-4AH, C-4H, F-1H, F-2H, F-3H and F-4H.

It has been reported that in constructing the Norne reservoir simulation model; porosity, permeability and net-to-gross ratio were imported from the geological model. Also in the model, vertical permeability is given as a ratio of horizontal permeability. As explained earlier in Chapter 3 that the field contain vertical stratigraphic barriers then; in the reservoir model the vertical barriers are implemented as MULTZ-maps imported from the geological model. The maps are generated from well and pressure data (Husby, 2005).

The following is the summary of the Norne reservoir properties (Cheng, 2015), (IO Center-NTNU, 2010d)

- Porosity = 24-28 %, Permeability = 100 – 3000 mD
- Initial reservoir pressure, P_{res} = 273 bar @ 2639 m TVD; Reservoir temperature, T_{res} = 98 ^oC.
- Bubble pressure, P_b = 250 bara; Gas oil ratio, GOR = 111 Sm^3/Sm^3
- Oil specific gravity, SG = 0.7; Oil viscosity = 0.5 cP
- Oil density = 859.5 kg/m^3, API = 32.7^o; Gas density = 0.854 kg/m^3; Water density = 1033 kg/m^3.
- Initial oil formation factor, B_{oi} = 1.32 Rm^3/Sm^3; Initial gas formation factor, B_{gi} = 0.0047 Rm^3/Sm^3.

- Pore Compressibility = 4.84 x 10^{-5} bar^{-1} at 277 bar.
- Rock wettability: mixed

Furthermore, compositional and PVT analysis show that the Norne field is characterized by one common hydrocarbon system and CO_2 and H_2S content is reported to be 0.9 mole% and 0-4 ppm, respectively (Gjerstad et al., 1995).

Table 5.1 Layer zonation in 2004 reservoir simulation model (IO Center-NTNU, 2010d)

Layer number	Layer name	Layer number	Layer name
1	Garn 3	12	Tofte 2.2
2	Garn 2	13	Tofte 2.1.3
3	Garn 1	14	Tofte 2.1.2
4	Not	15	Tofte 2.1.1
5	Ile 2.2	16	Tofte 1.2.2
6	Ile 2.1.3	17	Tofte 1.2.1
7	Ile 2.1.2	18	Tofte 1.1
8	Ile 2.1.1	19	Tilje 4
9	Ile 1.3	20	Tilje 3
10	Ile 1.2	21	Tilje 2
11	Ile 1.1	22	Tilje 1

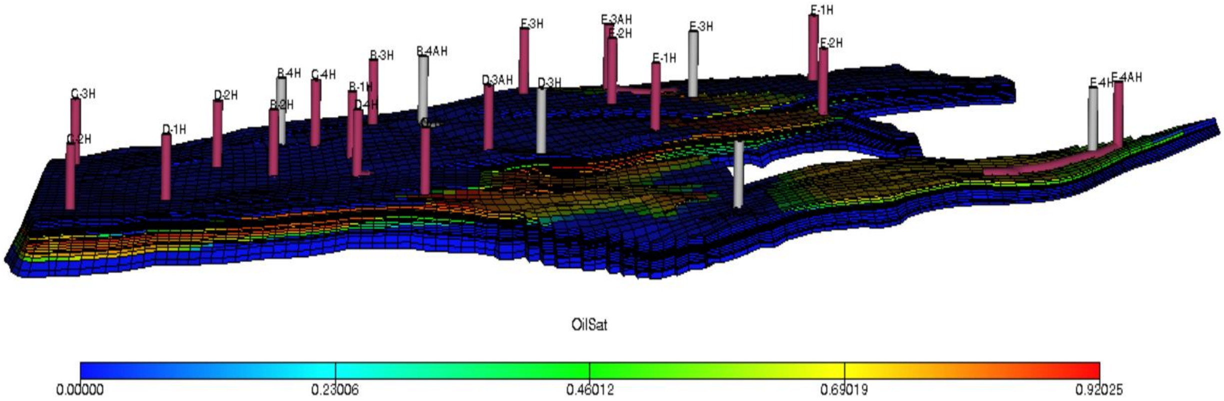
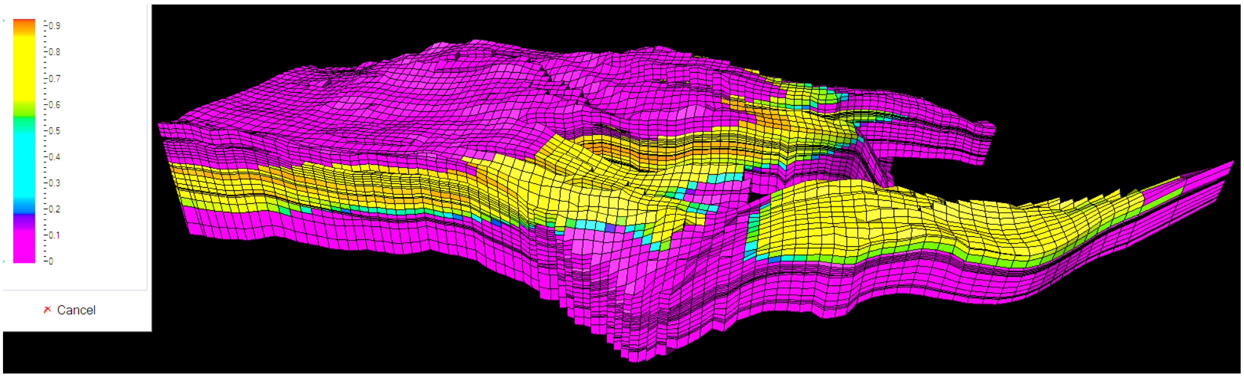
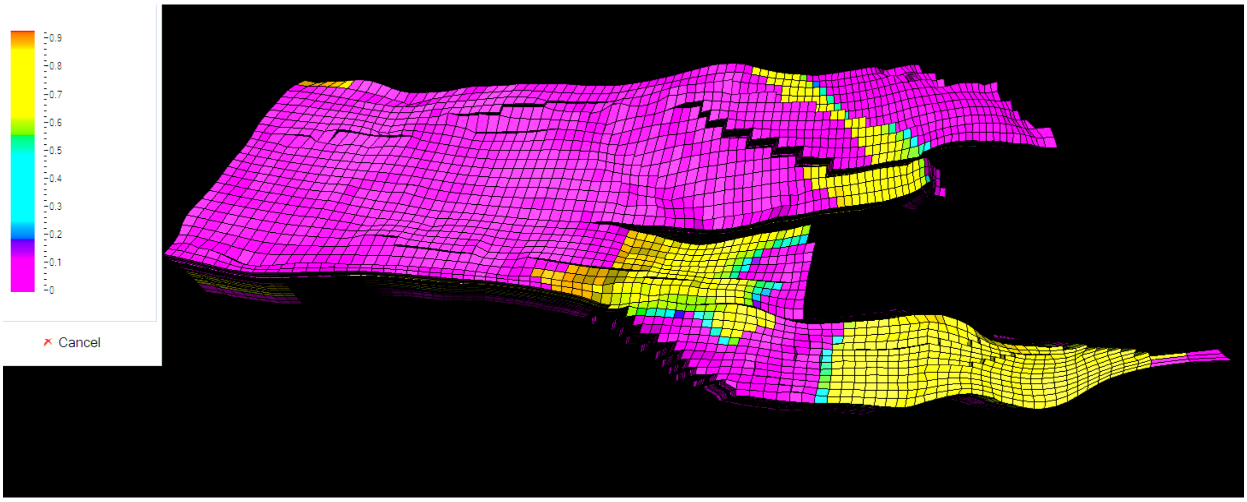


Figure 5.1 Norne field reservoir simulation model of 2004 showing wells in July 2001



(a)



(b)

Figure 5.2: Norne field initial oil saturation distribution (in November 1997). (a) showing the model with layers (b) showing the top surface of the model.

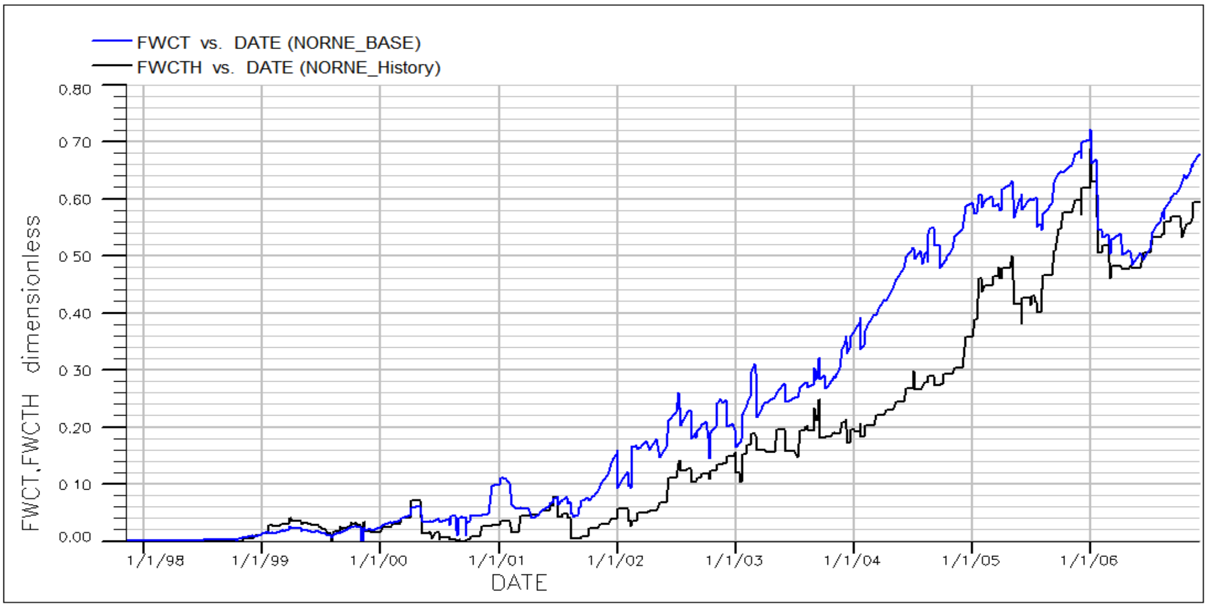


Figure 5.3 Field water cut where blue is the simulated result and black is the historical performance

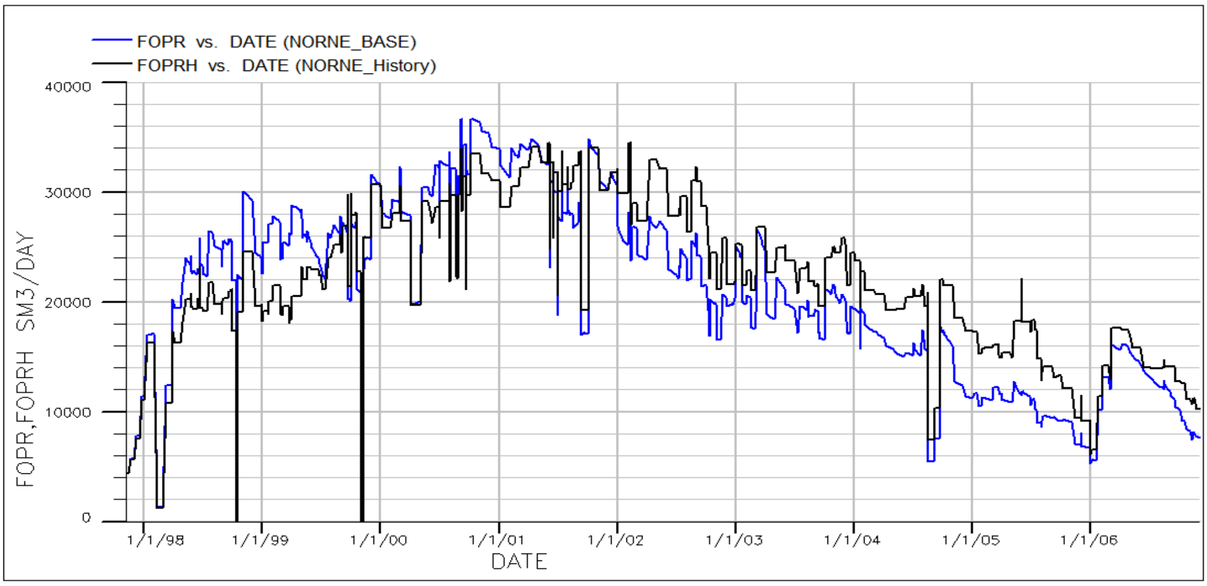


Figure 5.4 Field oil production rate where blue is the simulated result and black is the historical performance

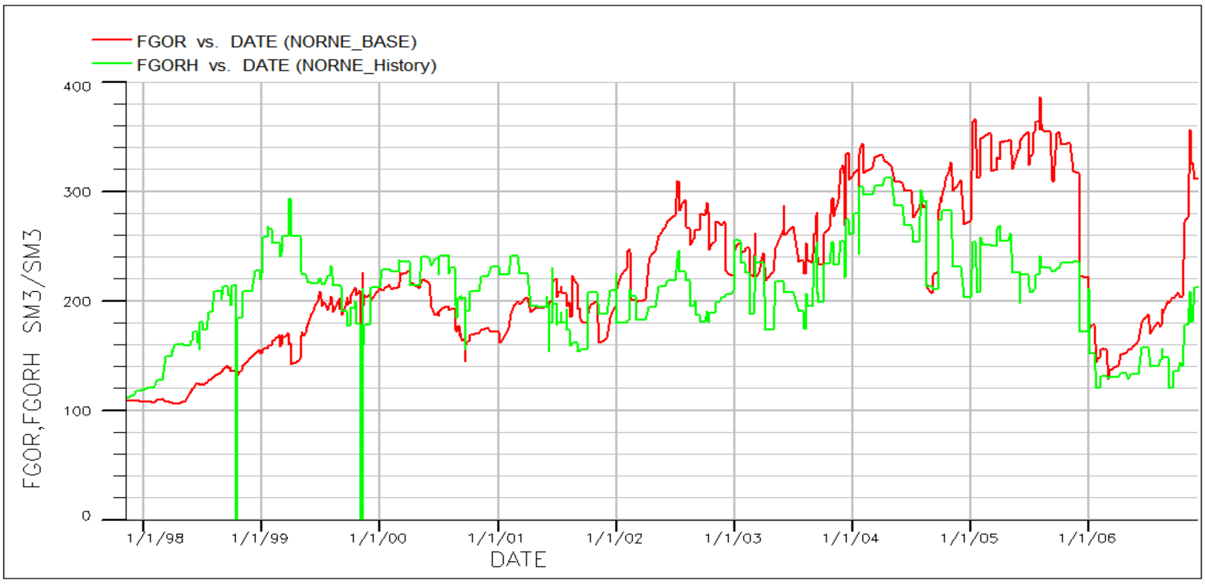


Figure 5.5 Field gas oil ratio where red is the simulated result and green is the historical performance

As it can be seen in Figure 5.3 to Figure 5.5, there is difference between the simulated field production performance (water cut, oil rate and gas oil ratio) and the observed (history) performance. The differences in the results might be due to parameters that are not certain such as fault transmissibility, vertical transmissibility of the stratigraphic barrier, permeability (horizontal and vertical) etc. Due to the observed differences, there is a need to adjust and update the uncertain parameters in order to obtain a reservoir simulation model of the Norne field that better match the historical performance.

CHAPTER 6

6. HISTORY MATCHING THE NORNE FULL FIELD MODEL USING PRODUCTION DATA

As described in chapter 5 above that there is difference between the simulated and historical results, therefore there is a need to history match the Norne field simulation model. The parameters that have been selected to be matched in this study are field water cut, water production total, oil production rate, oil production total, and gas oil ratio. Whereas the parameters that have been selected for adjustment in this study are vertical transmissibility multiplier of the stratigraphic barriers, fault transmissibility multiplier, vertical permeability, and horizontal permeability.

6.1 Adjusting Vertical Transmissibility Multiplier (MULTZ) of the stratigraphic barriers

Stratigraphic barriers in petroleum are those geological phenomenons that reduces the permeability laterally up the dip. They are common either as the chief trapping agency, or as an auxiliary trapping agency. The stratigraphic barriers are formed as results of depositional, erosional or diagenetic processes. For example; facies change, truncation, and overlap, cementation, solution and fracturing are the common causes of permeability variations that result in petroleum pools. It is not necessary that permeability be completely eliminated (Das & Baruah, 1997).

In Norne field, the stratigraphic barriers are mostly carbonate cemented layers and claystone layers as shown in Table 3.2. Vertical transmissibility multiplier (MULTZ) is a parameter that is used in reservoir simulation to represent vertical communication between geologic layers (including stratigraphic barriers). MULTZ varies from zero to one; and when it is set to zero, a permeability barrier blocks vertical flow between layers (Schlumberger, 2014).

According to 2004 Norne reservoir simulation model; the reservoir has been modelled with MULTZ of the field wide stratigraphic barriers as shown in Table 6.1 below. Furthermore, the model includes local modifications to the field-wide MULTZ barriers as shown in Appendix 1.

Since stratigraphic barriers are said to affect vertical communication and hence fluid flow; then adjustment to both field-wide and local MULTZ was done to find the values that best represent the vertical fluid flow across the barriers.

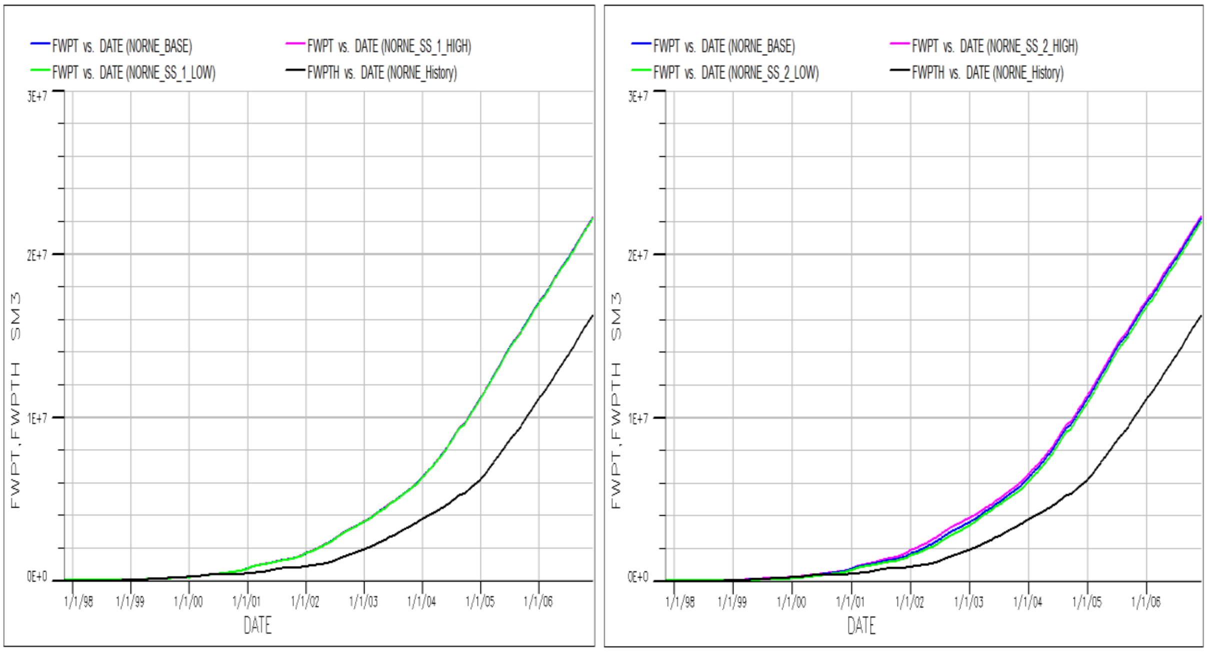
Table 6.1 Field wide MULTZ barriers as used in 2004 Norne field reservoir simulation model

Layer	Stratigraphic barrier	MULTZ
1	Garn 3 / Garn 2	0.01
4	Not	Inactive
15	Tofte 2.1.1 / Tofte 1.2.2	0.05
18	Tofte 1.1 / Tilje 4	0.001
20	Tilje 3 / Tilje 2	0.00001

6.1.1 Adjusting field wide MULTZ stratigraphic barriers

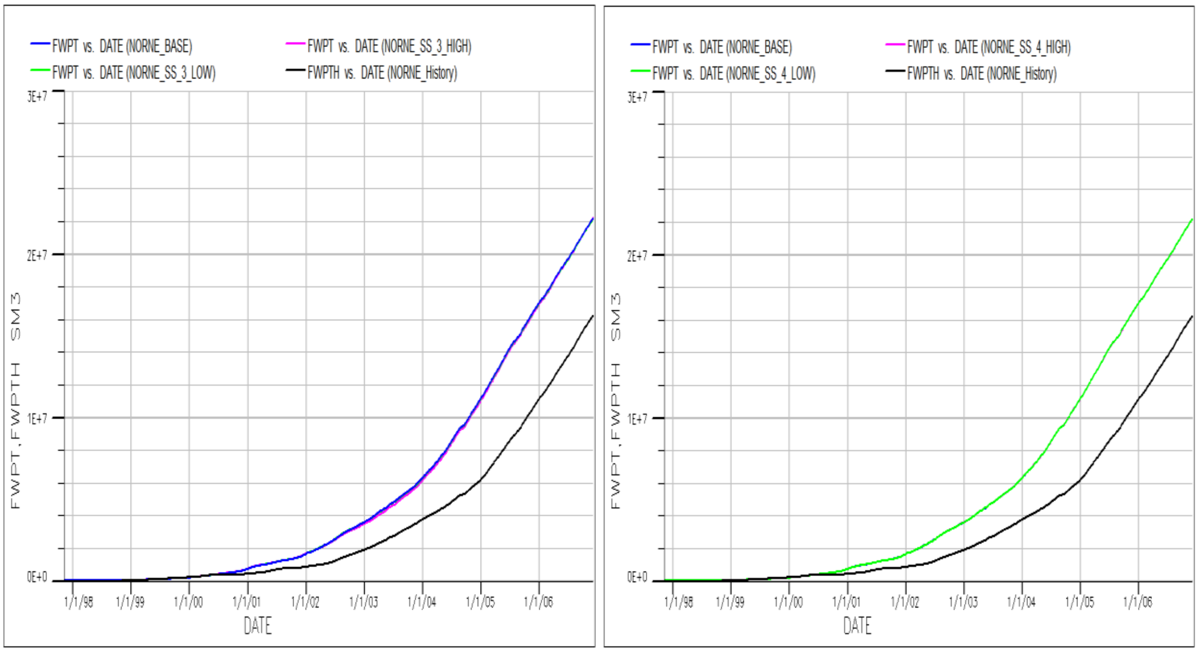
Sensitivity analysis was done to layer 1, 15, 18 and 20 by multiplying their MULTZ values by low factor of 0.1 and high factor of 10 to see how the adjustment to MULTZ will affect production performance. The result from the analysis is as presented in Figure 6.1 and Figure 6.2 below.

The results of sensitivity analysis for layer 1 (Figure 6.1a), layer 18 (Figure 6.2a) and layer 20 (Figure 6.2b) shows that there is no difference in water production profile for base case, low case and high case. This observation has implication that any modification to MULTZ for layer 1, 18 and 20 will not bring any changes to the field production profile. However, the result of sensitivity analysis for layer 15 (Figure 6.1a) shows that there is a difference in field water production profile for the base case, low case and high case. Therefore this observation necessitate further modification of MULTZ for layer 15 to find the best value for MULTZ that will result to a better match.



(a) (b)

Figure 6.1 Sensitivity analysis for field water production total when changing MULTZ of (a) layer 1 (b) layer 15. Where blue is base case, green is low case (factor of 0.1), purple is high case (factor of 10) and black is the history production.



(a) (b)

Figure 6.2 Sensitivity analysis for Field water production total when changing MULTZ of (a) layer 18 (b) layer 20. Where blue is base case, green is low case (factor of 0.1), purple is high case (factor of 10) and black is the history production.

Further modification to MULTZ of layer 15 was done and it was observed that a best match is obtained when MULTZ of layer 15 is multiplied by factor of 0.01 (i.e. setting MULTZ value to 0.0005). The observed results are presented in Figure 6.3 and Figure 6.4 below. The obtained result implies that the stratigraphic barrier of layer 15 should be made more prominent to depict the water historical production profile.

Using simple calculation presented in Appendix 7 and visual analysis of the field water cut and field water production total of the best matched model presented in Figure 6.3 and Figure 6.4, it can be seen that by reducing the wide MULTZ of layer 15; the field water cut and field water production match is improved by approximately 5% compared to the base case model.

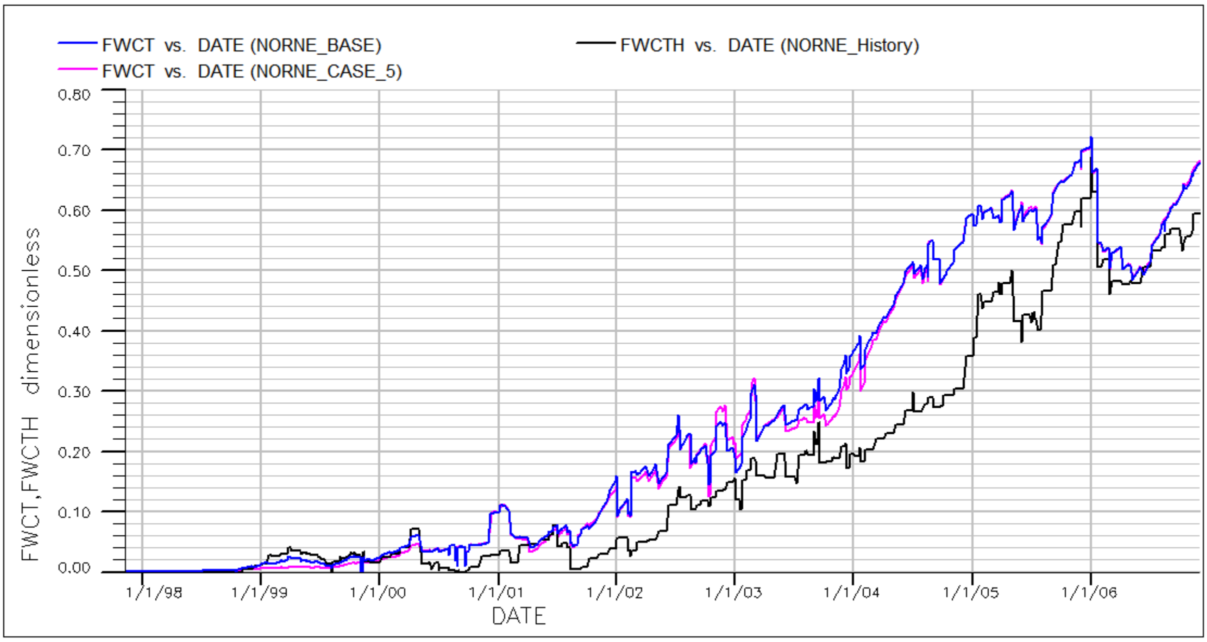


Figure 6.3 Field water cut where blue is base case, black is the history and purple is case 5 which is the matched case (multiplying MULTZ of layer 15 by 0.01)

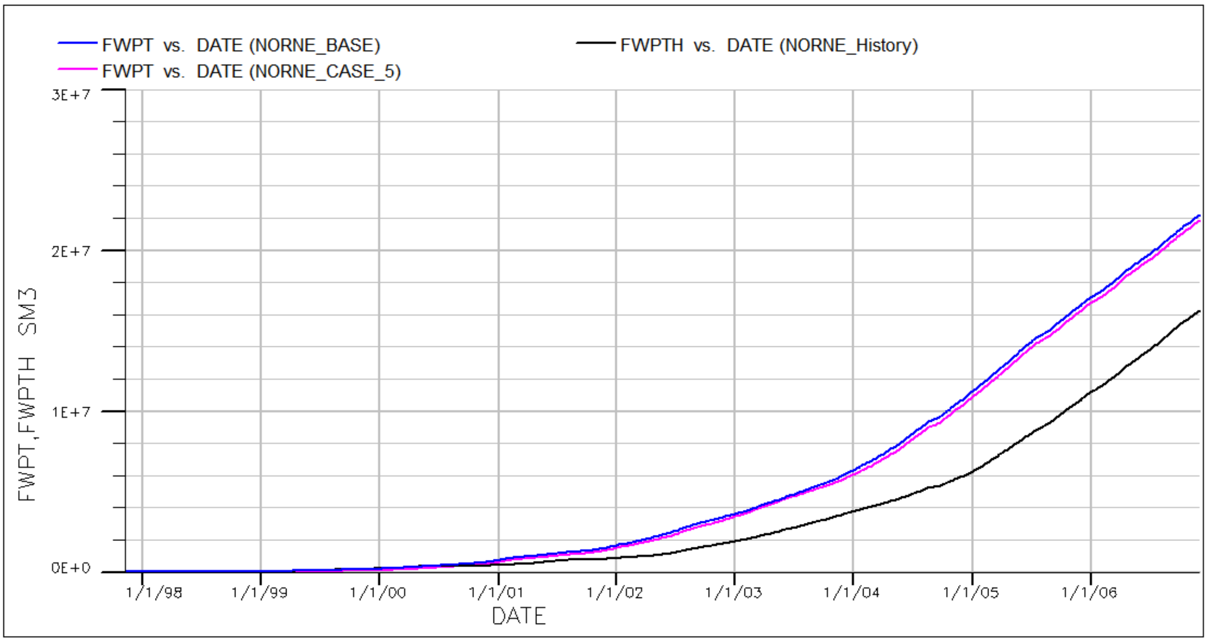
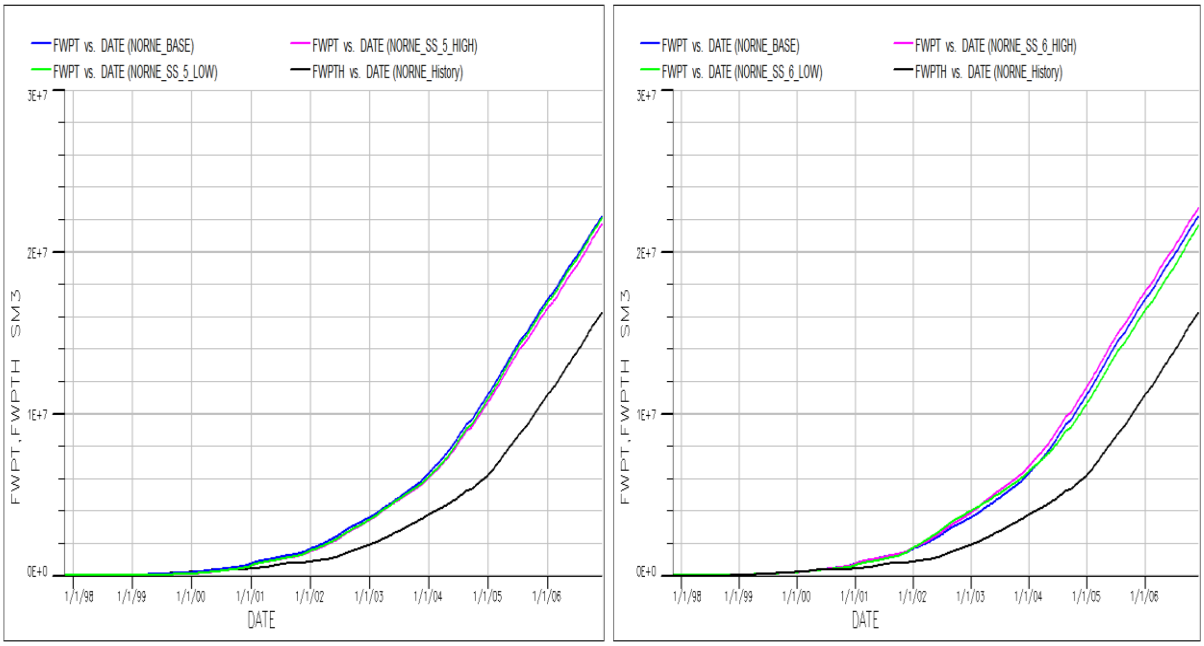


Figure 6.4 Field water production total where blue is base case, black is the history and purple is case 5 which is the matched case (multiplying MULTZ of layer 15 by 0.01)

6.1.2 Adjusting local MULTZ values of the field-wide stratigraphic barrier

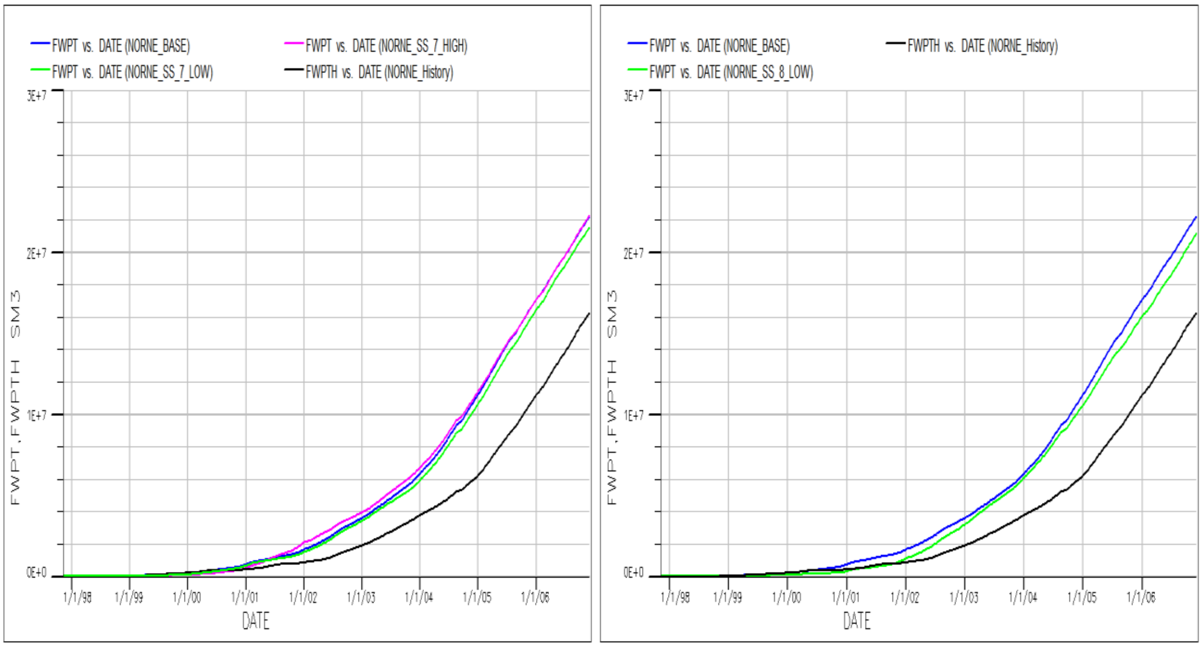
Norne field 2004 reservoir simulation model shows that the local MULTZ values are for layer 8, 10, 15; D-1H; B-1 & B-3 and RFT D_-H as it can be seen in Appendix 1. Sensitivity analysis was done to the local MULTZ values by multiplying them with low factor of 0.1 and high factor of 10. The results from the sensitivity analysis are as presented in Figure 6.5 to Figure 6.7 below.

Sensitivity analysis results for local MULTZ of layer 8 (Figure 6.5a) shows that water production profile is improved when local MULTZ is multiplied by high factor (10). Whereas sensitivity analysis for local MULTZ values of layer 10 (Figure 6.5b), layer 15 (Figure 6.6a), D-1H water (Figure 6.6b) and RFT D_-H (Figure 6.7b) show that the water production profile is improved when the local MULTZ is multiplied by low factor (0.1). Sensitivity analysis for local MULTZ of B-1 & B-3 water as presented in Figure 6.7a show that by multiplying with low factor (0.1) there is no improvement in the match (i.e. the adjustment results to poor match when compared to base case). Note that in Figure 6.6b, Figure 6.7a and Figure 6.7b it can be seen that there is no results for high factor, this is because the values of local MULTZ for D-1H water, B-1 & B-3 water and RFT D_-H exceeds 1 when multiplied by 10 which is not realistic, therefore they were only multiplied by low factor (0.1).



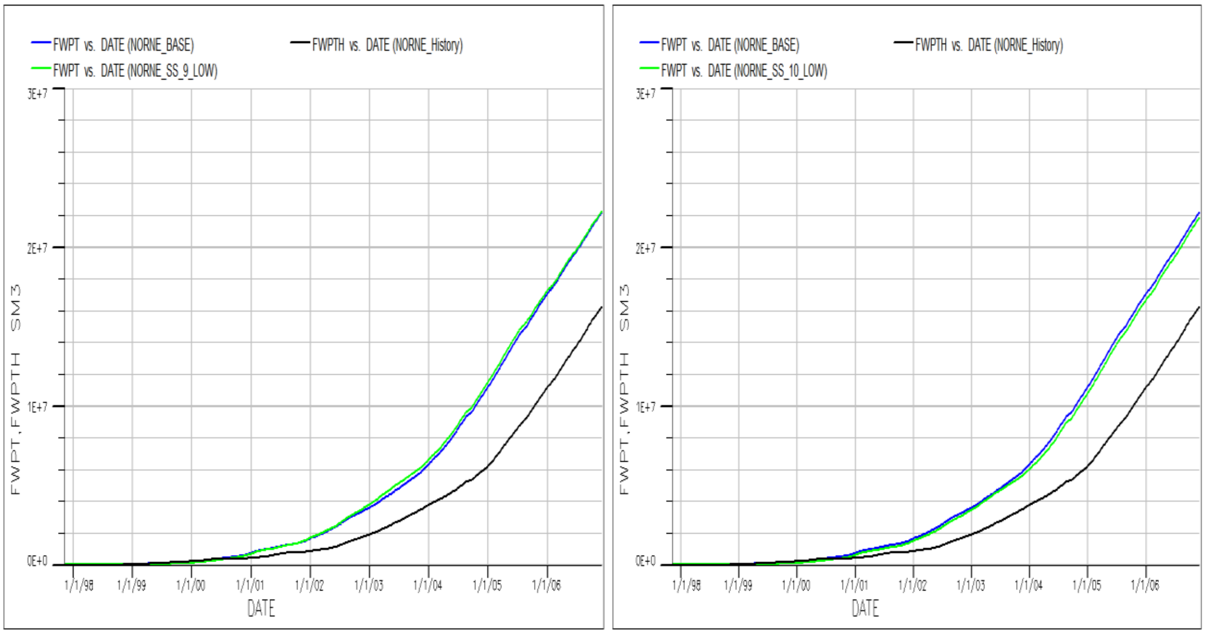
(a) (b)

Figure 6.5 Sensitivity analysis for field water production total when changing local MULTZ for (a) layer 8 (b) layer 10. Where blue is base case, green is low case (factor of 0.1), purple is high case (factor of 10) and black is the history production



(a) (b)

Figure 6.6 Sensitivity analysis for field water production total when changing local MULTZ for (a) layer 15 (b) D-1H water. Where blue is base case, green is low case (factor of 0.1), purple is high case (factor of 10) and black is the history production



(a) (b)

Figure 6.7 Sensitivity analysis for field water production total when changing local MULTZ for (a) B-1 & B-3 water (b) RFT D_-H. Where blue is base case, green is low case (factor of 0.1) and black is the history production.

Following the observation from sensitivity analysis as presented in Figure 6.5 to Figure 6.7 above, all the individual adjustments of local MULTZ were combined together with the adjusted wide MULTZ and further adjustment was done to obtain a best match presented in Figure 6.8 to Figure 6.10 below.

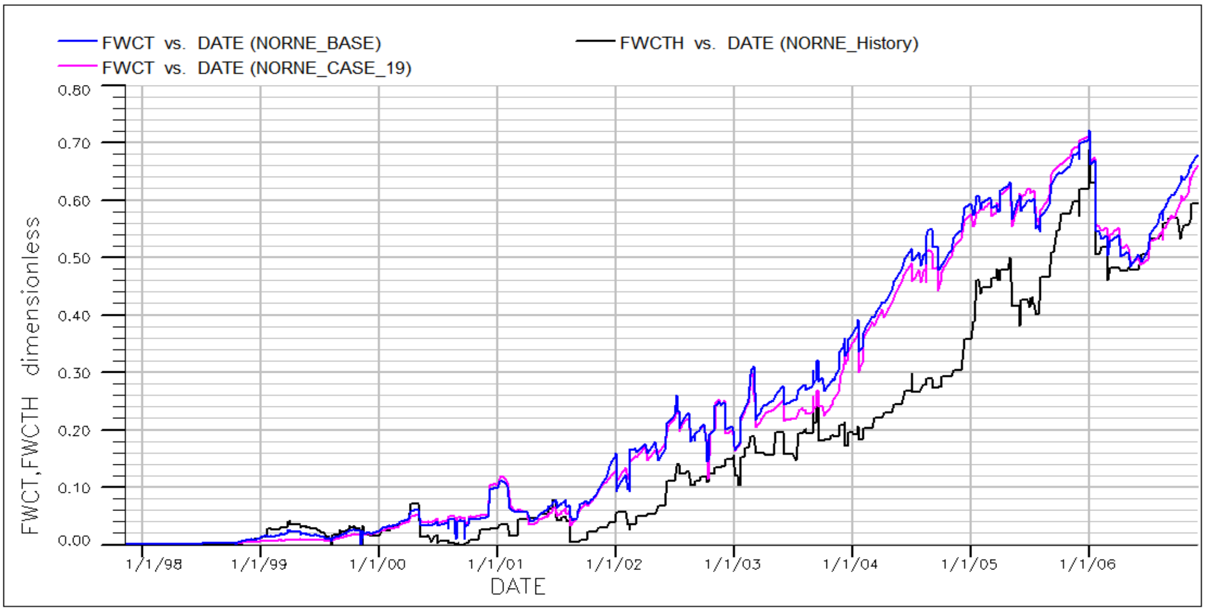


Figure 6.8 Field water cut where blue is the base case, black is the history and purple is the best match in adjusting MULTZ

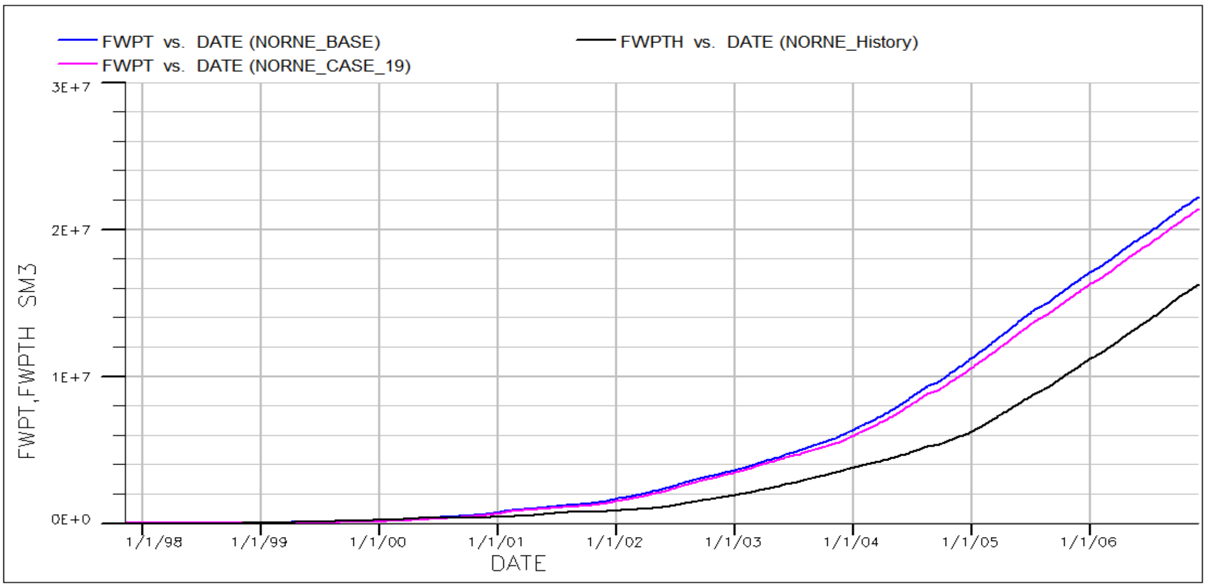


Figure 6.9 Field water production total where blue is the base case, black is the history and purple is the best match in adjusting MULTZ

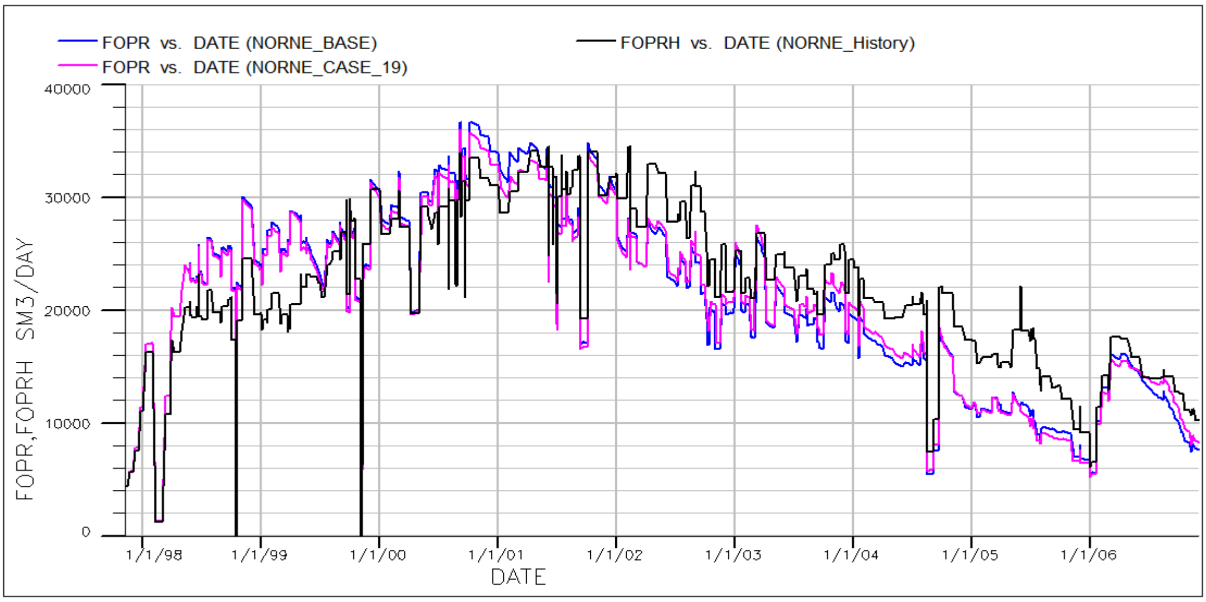


Figure 6.10 Field oil production rate where blue is the base case, black is the history and purple is the best match in adjusting MULTZ

It was observed that the best match is obtained when local MULTZ of layer 8 is increased by factor of 10 and reducing the local MULTZ of layer 15 and RFT D_-H by factor of 10. The adjusted local MULTZ values of the field wide stratigraphic barrier are presented in Appendix 2. Through simple calculation presented in Appendix 7 and visually analysing the field water cut and field water production total of the best matched model presented in Figure 6.8 and Figure 6.9, it can be seen that by reducing the wide MULTZ of layer 15 together with increasing the local MULTZ of layer 8, and reducing the local MULTZ of layer 15 and RFT

D_-H; the field water cut and field water production match is improved by approximately 10% compared to the base case model. Field oil production rate (Figure 6.10 above) and field gas oil ratio (Figure A.6 in Appendix 8) is also improved, however it can be seen that in year 2005, the field gas oil ratio profile is poor than the base case.

6.2 Adjusting Fault Transmissibility

Faults are common features in oil and gas reservoirs. They play an important role in reservoir performance since their presence has effect on fluid flow and pressure communication within a faulted petroleum reservoirs. They most commonly act as barriers for fluid flow, but also they can act as conduits, or they can act as combined conduit-barrier systems. Therefore in order to perform a reliable production performance forecast, it is important to have detailed understanding of their behaviour. These faults generally occupy a negligible fraction of the total volume of a given petroleum reservoir, and their thicknesses are significantly smaller than cell dimensions used in reservoir models, therefore they are modelled as membrane-like two-dimensional slip surfaces (Soleng et al., 2007). Also, the presence of faults as flow conduits may not always be economically advantageous because they can sometimes cause large losses of expensive drilling mud and result in premature water production (Fisher & Knipe, 2001).

It is important to note that the process of handling faults is a very difficult and challenging task because of their complexity nature and the fact that their contribution to fluid flow varies widely. The variation is due to the fact that each fault has its own geometry (orientation, dimensional and properties), spacing, distribution, connectivity, and hydraulic properties, which result either to enhancement or impeding fluid flow (Aydin, 2000).

Norne field is characterized by several faults as they can be seen in Figure 6.11 and Figure 6.12 below. In conventional flow models, transmissibility multipliers represent the fault sealing effects and MULTFLT keyword is used in Eclipse simulator to modify the transmissibility (and diffusivity) across a fault previously defined using the FAULTS keyword. In addition the keyword MULTREGT is used to control transmissibility between defined flow regions. Table 6.2 below shows faults of the Norne field with their respective MULTFLT values.

For a reservoir with several faults like the Norne field, it is likely that there are uncertainties associated with characterization of these faults; therefore the accurate representation of these faults in the reservoir flow simulation model is very important if realistic predictions of the production performance are to be attained. History matching can be done to modify these faults to obtain a more realistic representation (characterization). There are three possible things that can be done during history matching of the faults. The first one is to define new faults, the other one is to re-define geometry (orientation, dimension and properties) of the faults, and the last one is to adjust fault transmissibility multiplier (MULTFLT) values of the fault. In this study, the option that was taken is to adjust the MULTFLT values.

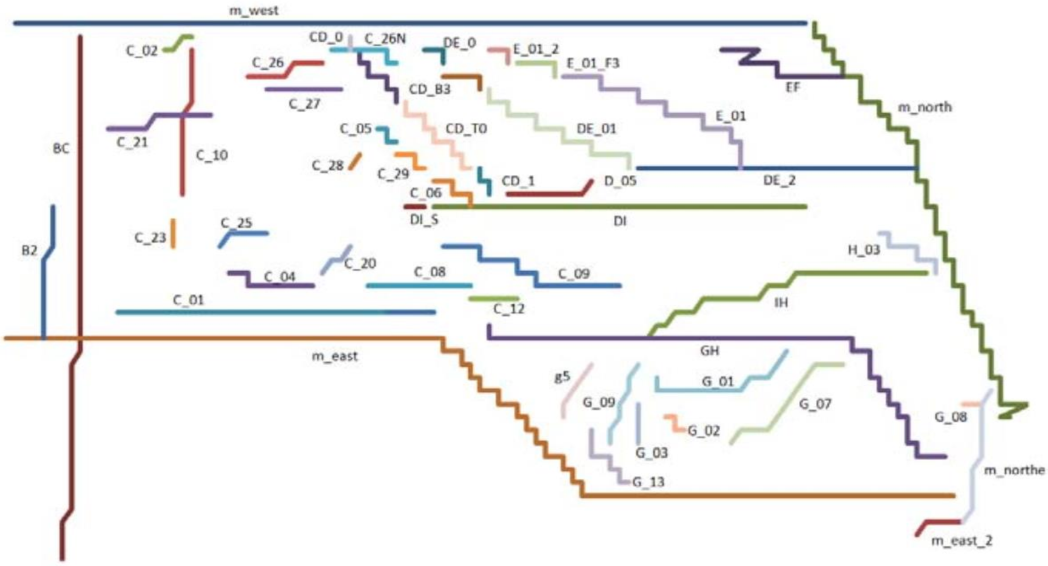


Figure 6.11 Schematic diagram showing faults zonation and names in the 2004 reservoir simulation model of Norne field (Morell, 2010)

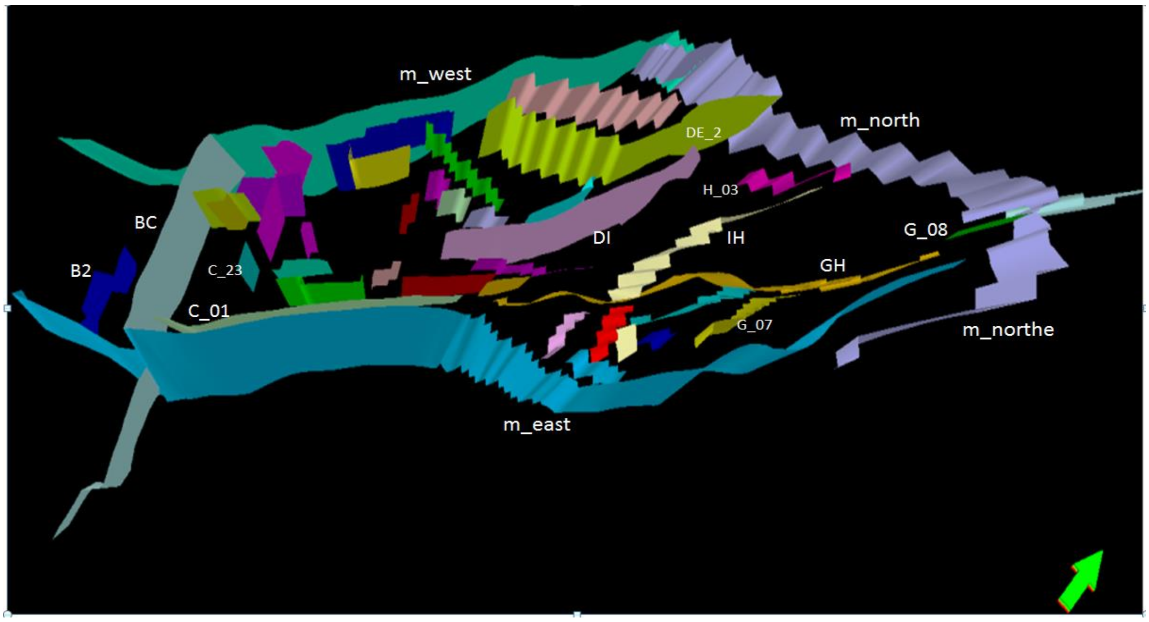


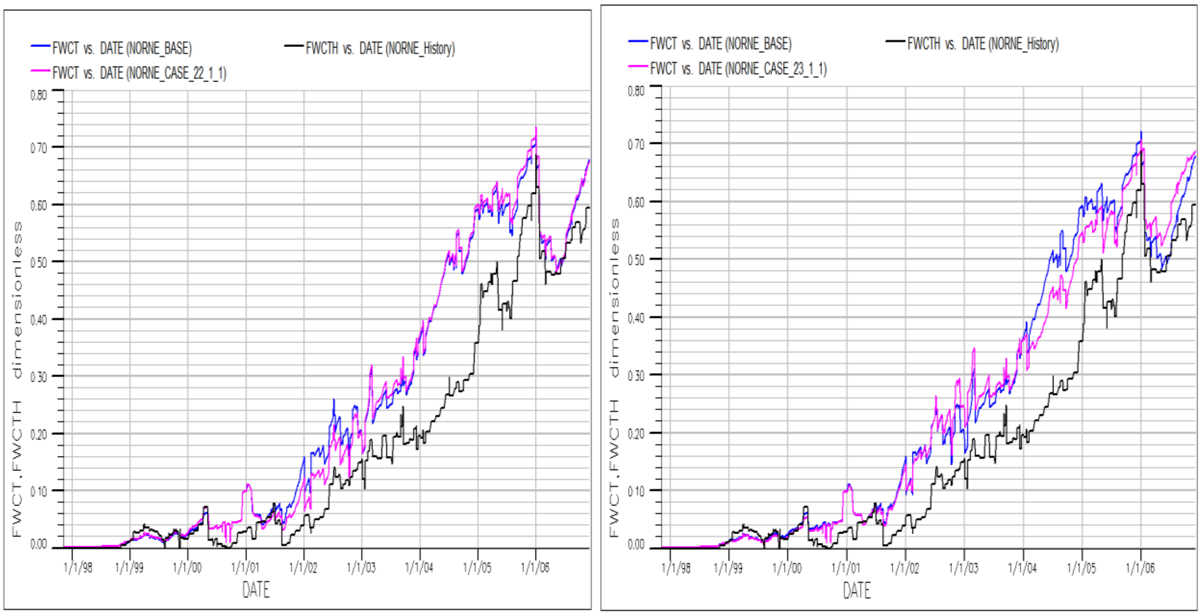
Figure 6.12 Faults of the Norne 2004 reservoir simulation model as seen from Petrel software.

Table 6.2 Fault transmissibility multiplier **(**MULTFLT) values as used in the Norne 2004 reservoir simulation base case model

Fault name	**MULTFLT value**	**Fault name**	**MULTFLT value**
E_01	0.01	C_21_Ti	0.001
E_01_F3	0.01	C_22	0.001
DE_1	3.9	C_23	0.1
DE_1_LTo	0.01	C_24	0.1
DE_B3	0.00075	C_25	0.1
DE_2	0.015	C_26	0.1
DE_0	20	C_26N	0.001
BC	0.1	C_27	0.05
CD	0.1	C_28	1.0
CD_To	0.01	C_29	0.1
CD_B3	0.1	DI	0.1
CD_0	1.0	DI_S	0.1
CD_1	0.1	D_05	0.01
C_01	0.01	EF	1.0
C_01_Ti	0.01	GH	1.0
C_08	0.01	G_01	0.05
C_08_Ile	0.1	G_02	0.05
C_08_S	0.01	G_03	1.0
C_08_Ti	1.0	G_05	0.5
C_08_S_Ti	1.0	G_07	0.05
C_09	0.1	G_08	0.05
C_02	0.01	G_09	0.05
C_04	0.05	G_13	0.05
C_05	0.1	H_03	1.0
C_06	0.1	IH	1.0
C_10	0.01	m_east	1.0
C_12	0.1	m_east_2	1.0
C_20	0.5	m_north	1.0
C_20_LTo	0.5	m_northe	1.0
C_21	0.001	m_west	1.0

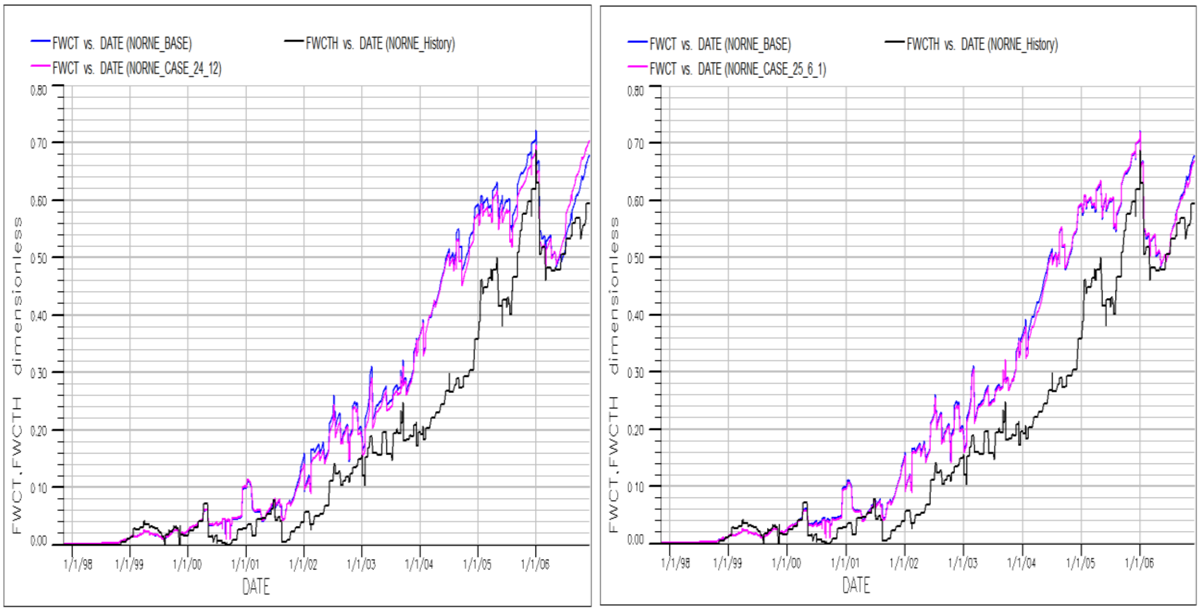
Sensitivity analysis to Fault Transmissibility Multipliers

Sensitivity analysis to fault transmissibility multipliers values of all the faults defined in Table 6.2 above was done to test whether the faults should be made more sealing (non-communicating), partially sealing or conductive (communicating) and how any adjustment affect production profile (recovery). In order to test the effect of fault on production performance; fault transmissibility multipliers (MULTFLT) were adjusted and then results were analysed and compared to the base-case model. It was observed that during adjustment, most of the faults did not show any significant change in production profile (specifically water cut) while few faults showed significant change in water cut production profile. Figure 6.13 to Figure 6.15 shows water cut profile for adjustment of faults with significant change.



(a) (b)

Figure 6.13 Sensitivity analysis to Field water cut for (a) fault E_01 (b) fault C_01. Where blue is base case, black is the history and purple is for adjusted MULTFLT values



(a) (b)

Figure 6.14 Sensitivity analysis to Field water cut for (a) fault CD_B3 (b) fault C_10. Where blue is base case, black is the history and purple is for adjusted MULTFLT values

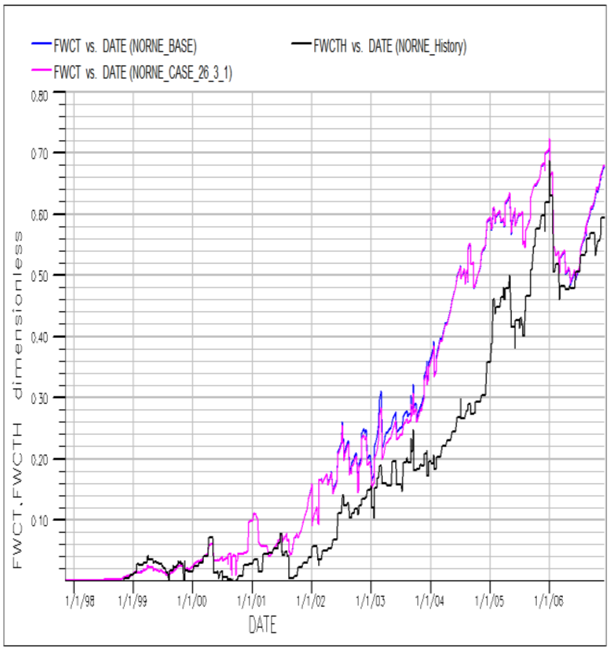


Figure 6.15 Sensitivity analysis to Field water cut for fault D_05. Where Blue is the Base case, Black is the history and Purple is for adjusted MULTFLT values

In order to obtain the best match during fault transmissibility adjustment; further tuning to the MULTFLT values was done to those faults with significant change and it was observed that best match is obtained when using MULTFLT values shown in Table 6.3 below

Table 6.3 Adjusted faults with their respective old and new MULTZ values

Fault Name	Old MULTFLT value	Modified MULTFLT value
E_01	0.01	0.02
C_01	0.01	0.1
CD_B3	0.1	0.01
C_02	0.01	0.1
C_10	0.01	0.1
D_05	0.01	0.1
G_07	0.05	0.5

The values presented in Table 6.3 above means that in order to obtain a best match; fault CD_B3 should be made more partially sealing while faults E_01, C_01, C_02, C_10, D_05, G_07 should be made more conductive. These modified values of the faults were all included in the model to obtain a best match presented in Figure 6.16 to Figure 6.18 below.

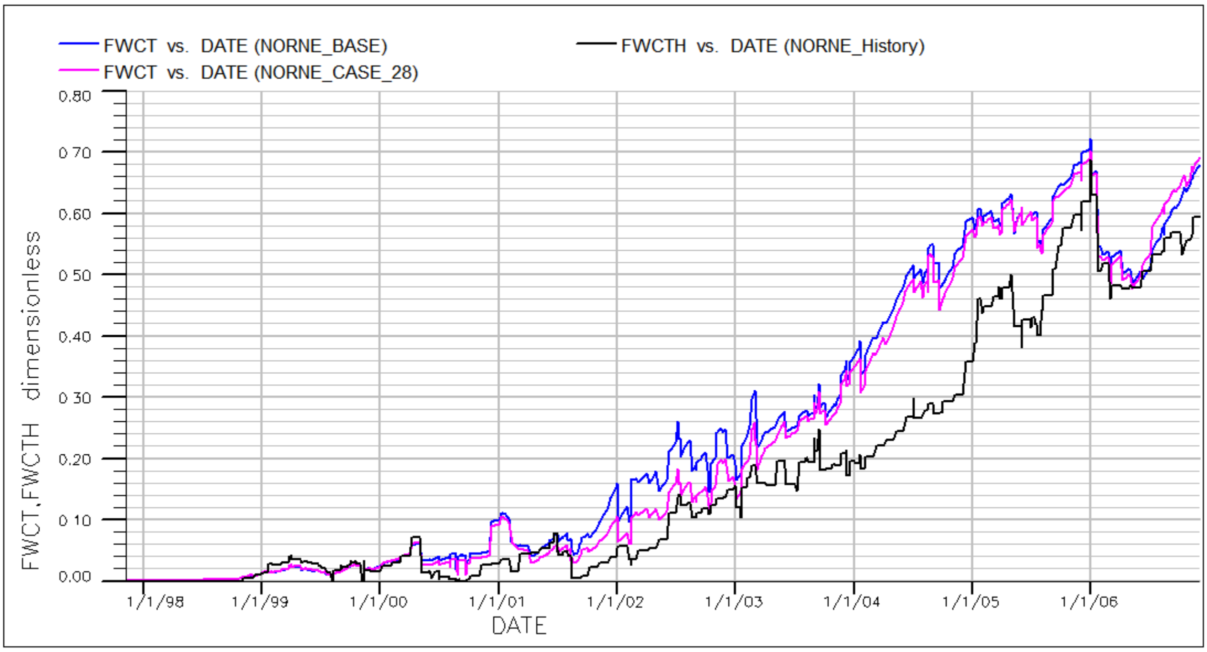


Figure 6.16 Field water cut where blue is the base case, black is the history and purple is the best matched model for MULTFLT adjustment.

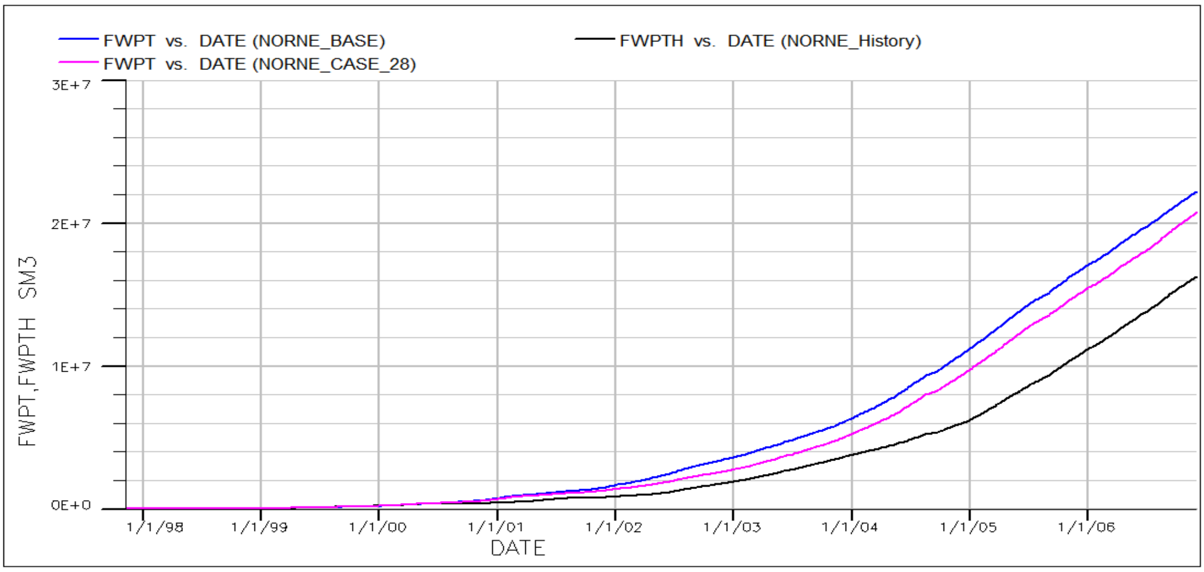


Figure 6.17 Field water production total where blue is the base case, black is the history and purple is the best matched model for MULTFLT adjustment.

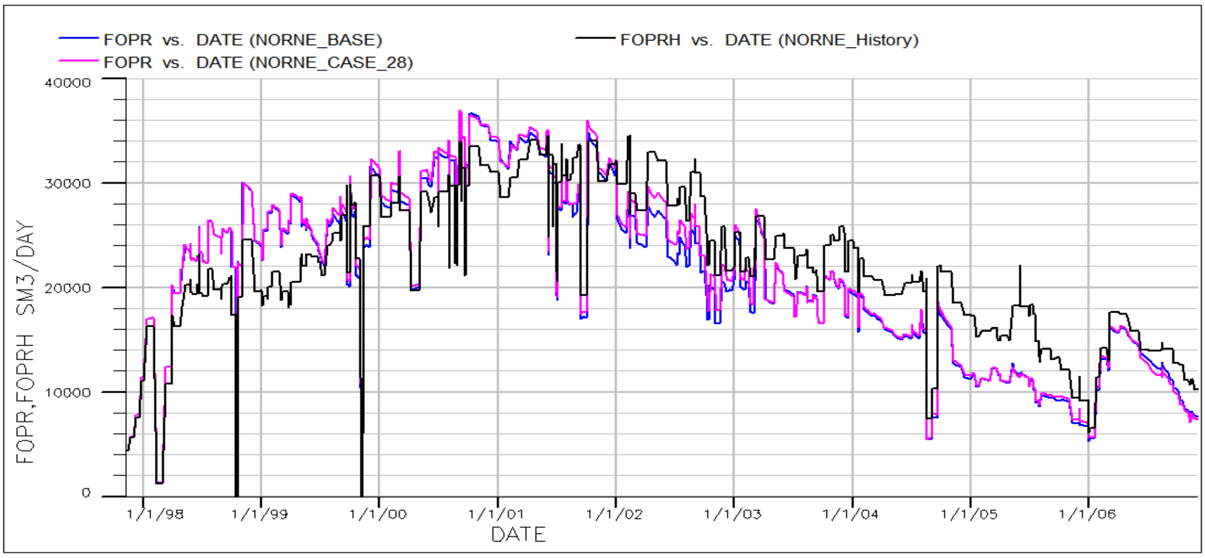


Figure 6.18 Field oil production rate where blue is the base case, black is the history and purple is the best matched model for MULTFLT adjustment.

Through simple calculation presented in Appendix 7 and visually analysing the field water cut and field water production total of the best matched model presented in Figure 6.16 and Figure 6.17, it can be seen that by reducing the fault transmissibility multiplier of fault CD_B3, and increasing the fault transmissibility multiplier of fault E_01, C_01, C_02, C_10, D_05 and G_07 as presented in Table 6.3; the field water cut and field water production match is improved by approximately 30% compared to the base case model. Furthermore, the result show that there is no significant improvement for field oil production rate (Figure 6.18 above) and field gas oil ratio (Figure A.7 in Appendix 8)

6.3 Combining adjustment of MULTZ and MULTFLT

By combining the adjusted MULTZ values of stratigraphic barrier and the modified MULTFLT values presented in Table 6.3; it was observed that the production profile presented in Figure 6.19 to Figure 6.21 below has better improvement compared to the matched cases when adjusting MULTZ alone and adjusting MULTFLT alone.

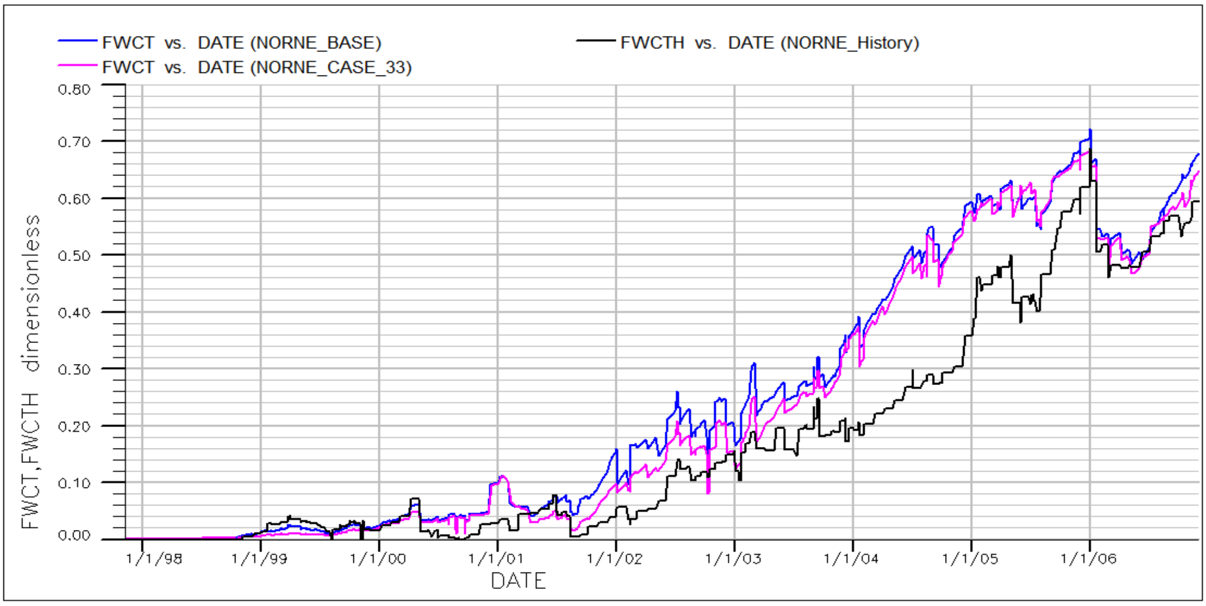


Figure 6.19 Field water cut where blue is the base case, black is the history and purple is the best matched model for combined MULTZ and MULTFLT adjustment

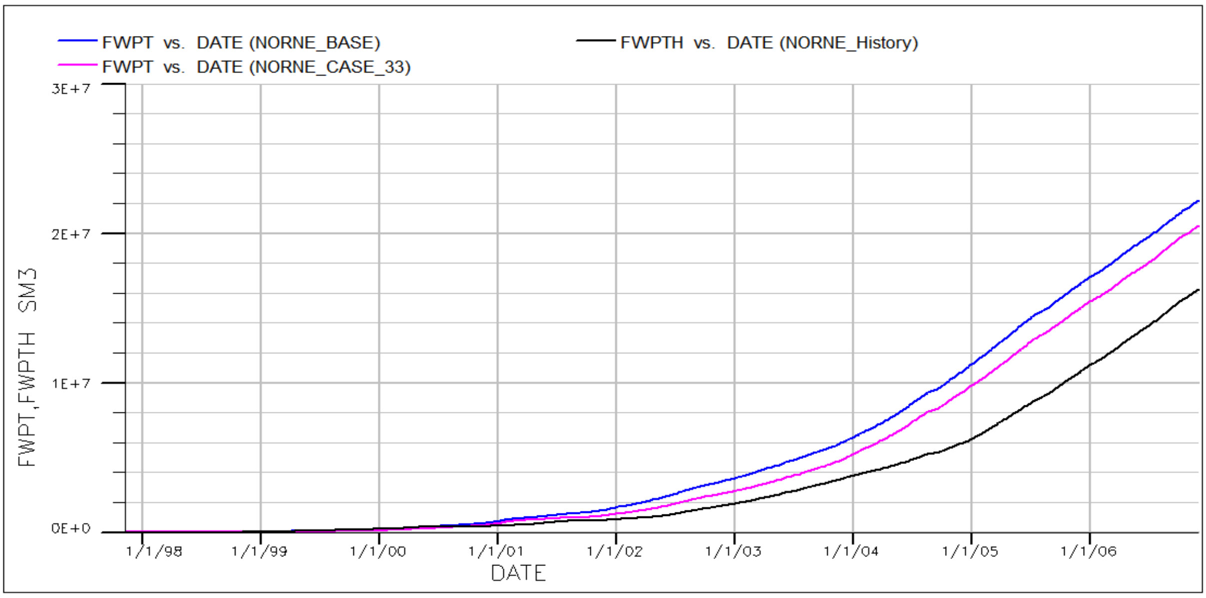


Figure 6.20 Field water production total where blue is the base case, black is the history and purple is the best matched model for combined MULTZ and MULTFLT adjustment

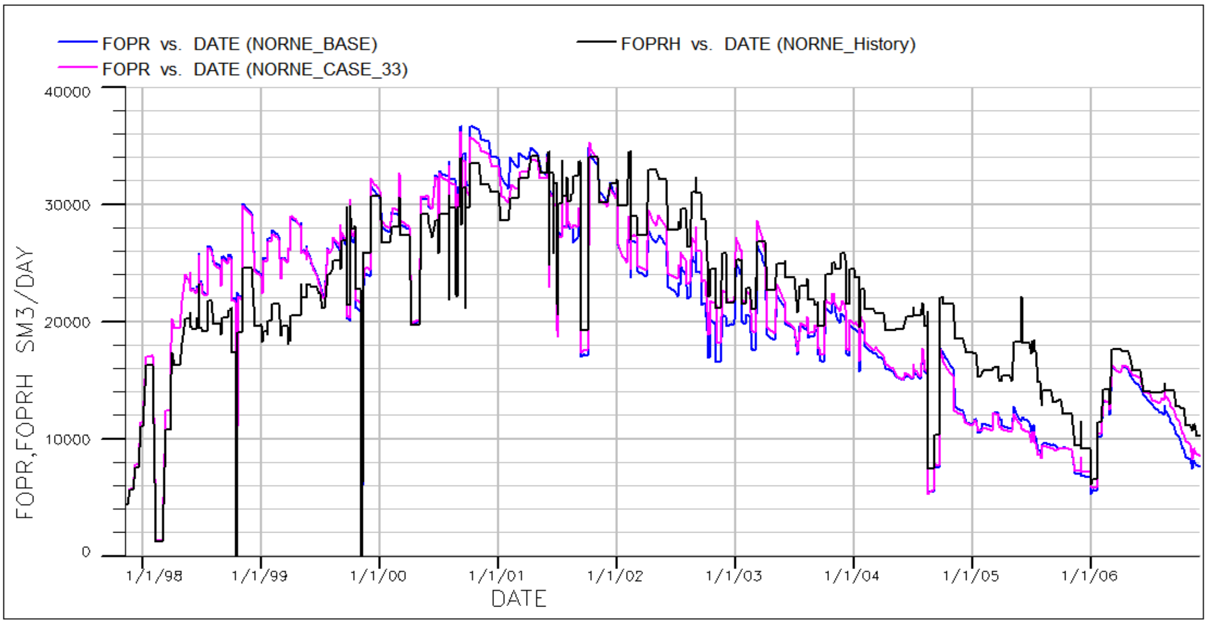


Figure 6.21 Field oil production rate where blue is the base case, black is the history and purple is the best matched model for combined MULTZ and MULTFLT adjustment

Using simple calculation presented in Appendix 7 and visual analysis of the field water cut and field water production total of the best matched model presented in Figure 6.19 and Figure 6.20, it can be seen that by combining the adjustment of fault transmissibility multiplier and transmissibility multiplier of the stratigraphic barrier; the field water cut and field water production is improved by approximately 35% compared to the base case. The match is also better when compared to adjusting MULTZ alone and adjusting MULTFLT alone. The field oil production rate (Figure 6.21 above) and field gas oil ratio (Figure A.8 in Appendix 8) is somehow improved with the exception that in year 2005 field gas oil ratio profile is poor than the base case.

6.4 Adjusting Permeability

Permeability is defined as a capacity of a given reservoir rock to transmit fluids (oil, gas or water) under pressure. The permeability of a reservoir rock depends on the size and shape/geometry of the openings (pore spaces) in it, the connectivity of the pore spaces (how pore space communicate to one another), capillaries and fractures present in a given reservoir rock. Permeability is among the important parameters that are used to classify a given rock as a potential reservoir rock (Fettket & Copeland, 1931). It is a very important formation parameter that is used to determine whether a well should be completed and brought into production, or abandoned. Generally, permeability controls the amount of hydrocarbon that is recovered from a given reservoir (Zahaf & Tiab, 2000).

In many reservoir rocks, permeability is almost directly proportional to the rock's porosity, which is the fraction of the rock's total volume that is occupied by pores, or voids. However, this is not an absolute rule. Textural and geologic factors determine the magnitude of permeability by increasing or decreasing the cross-sectional area of open pore space. These factors affect the geometry of the pore space and are independent of fluid type (Schlumberger, 2014).

Permeability is one of the parameters in the reservoir that is commonly not certain (it is usually one of the least well-known reservoir properties). Therefore in most history matching cases, the permeability must be adjusted in order to obtain more accurate model that depict the observed (history) reservoir performance. The permeability can be absolute, vertical or horizontal. In this study both vertical permeability and horizontal permeability were adjusted.

6.4.1 Adjusting Vertical Permeability

Vertical permeability in Norne reservoir simulation model is given as a ratio of horizontal permeability as it can be seen in Appendix 3. Vertical permeability in Eclipse simulator is defined using a keyword PERMZ (a keyword that specifies permeability values in Z-direction).

Vertical permeability is a very important parameter that has influence in recovery for reservoir with vertical fluid flow such as water or gas coning, gravity drainage, displacement by water or gas in an anisotropic formation. It is also an important factor in determination of productivity gains to be expected from horizontal wells (Bourdarot & Daviau, 1989). Vertical Permeability is also essential in overall reservoir management and development, for example, for the determination of optimal drainage points and production rate, optimization completion and perforation design, and planning Enhanced Oil Recovery (EOR) patterns and injection conditions (Zahaf & Tiab, 2000).

Sensitivity analysis to vertical permeability (PERMZ)

Vertical permeability multiplier factor for each layer (22 layers) was adjusted to see how the adjustments affect production performance profile. The results from the sensitivity analysis showed that the adjustment to PERMZ for most of the layers has no effect on the production profile. Just few layers showed an effect on production performance as presented in Figure 6.22 to Figure 6.25 below.

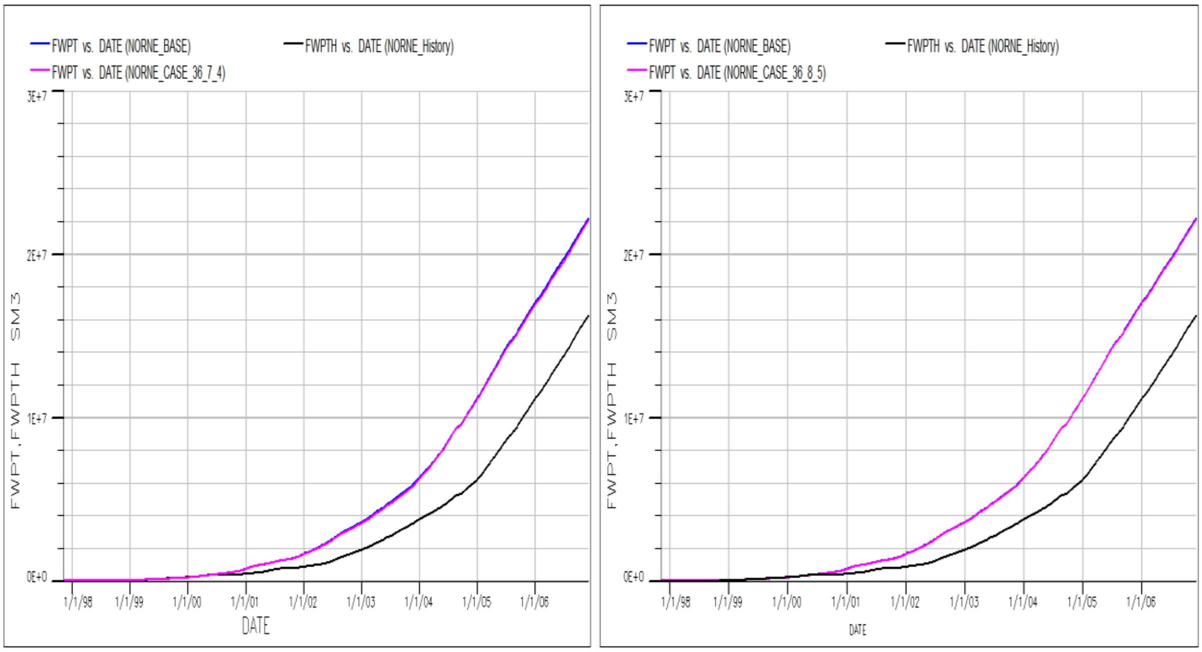


Figure 6.22 Sensitivity analysis for PERMZ for (a) layer 8 (b) layer 9. Where blue is base case, black is the history and purple is the adjusted PERMZ

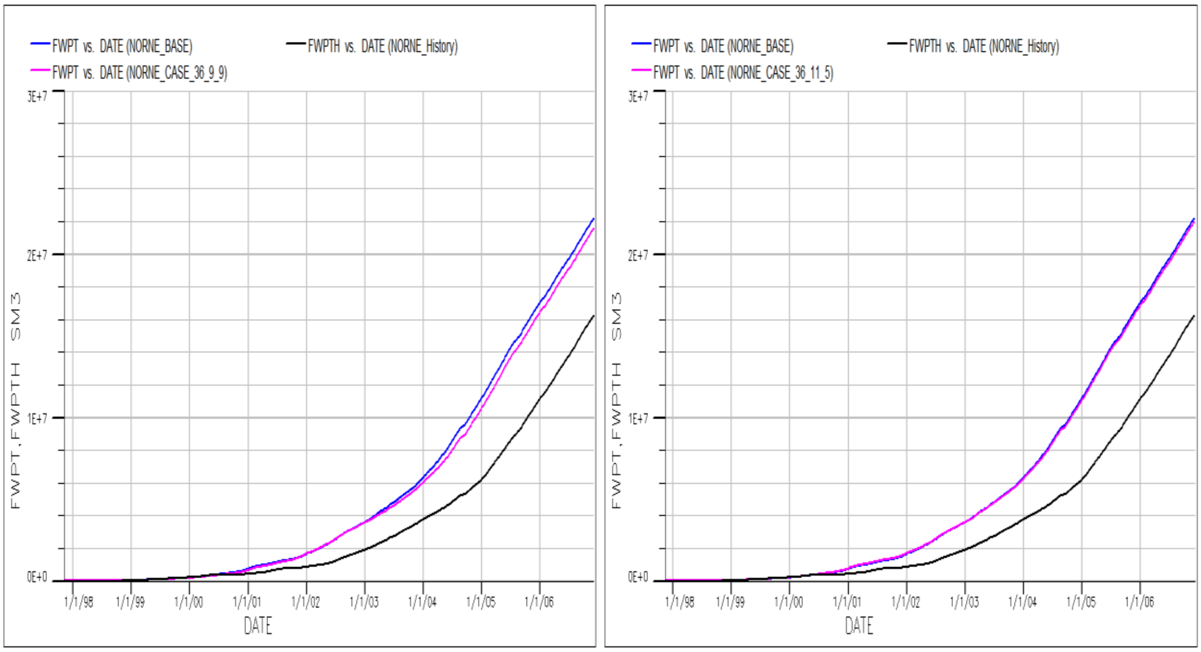


Figure 6.23 Sensitivity analysis for PERMZ for (a) layer 10 (b) layer 12. Where blue is base case, black is the history and purple is the adjusted PERMZ

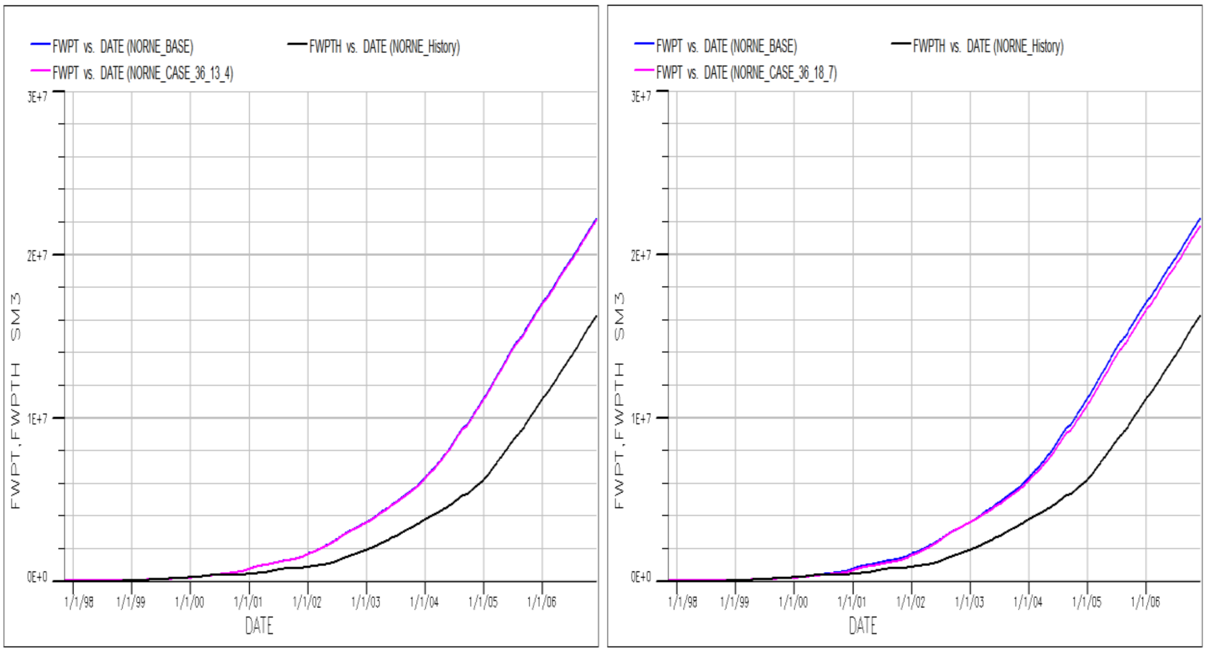


Figure 6.24 Sensitivity analysis for PERMZ for (a) layer 14 (b) layer 19. Where blue is base case, black is the history and purple is the adjusted PERMZ

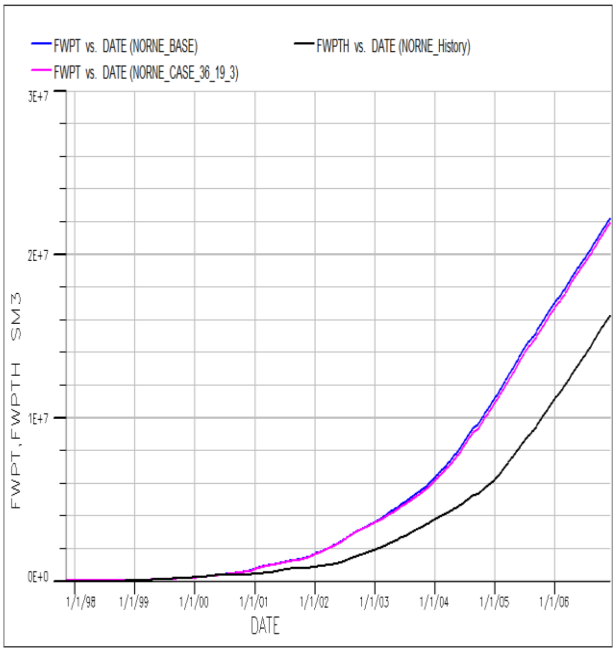


Figure 6.25 Sensitivity analysis for PERMZ of layer 20. Where blue is base case, black is the history and purple is the adjusted PERMZ

To obtain a best match in vertical permeability adjustment, further tuning to PERMZ of the layers that showed changes in production profile was done and it was observed that the best match is obtained when using PERMZ factor presented in Table 6.4 below and Appendix 4. Figure 6.26 to Figure 6.28 shows the matched model for vertical permeability adjustment.

Table 6.4 PERMZ multiplier values which result to a best match

Layer	Old PERMZ multiplier values	Modified PERMZ multiplier values
8	0.13	0.43
9	0.09	0.4
10	0.07	0.01
12	0.13	0.53
14	0.64	0.84
19	0.004	0.0001
20	0.004	0.0001

The values of vertical permeability presented in Table 6.4 implies that; to obtained a best match, vertical permeability values of layer 8, 9, 12, and 14 should be increased while that of layer 10, 19 and 20 should be decreased. Using simple calculation presented in Appendix 7 and visual analysis of the field water cut and field water production total of the best matched model presented in Figure 6.26 and Figure 6.27 below, it can be seen that by using the values of vertical permeability presented in Table 6.4; the field water cut and filed water production match is improved by approximately 25% compared to the base case model. The results also show that there is some improvement in field oil production rate (Figure 6.28 below) and field gas oil ratio (Figure A.9 in Appendix 8).

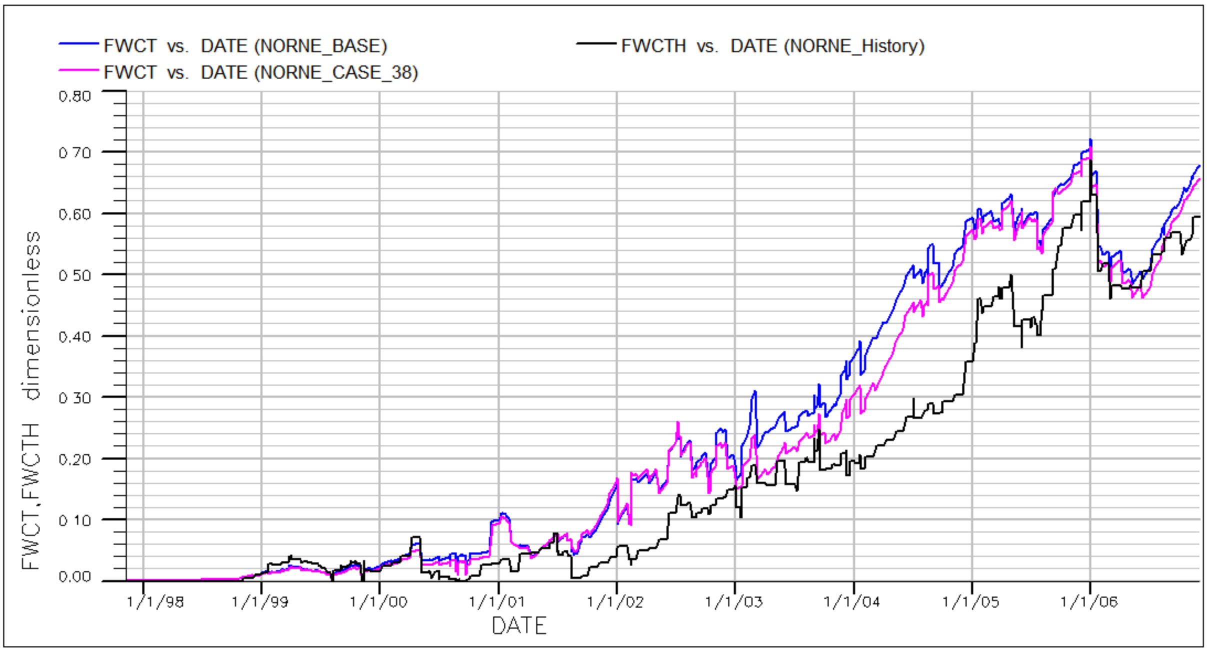


Figure 6.26 Field water cut where blue is the base case, black is the history and purple is the matched model for vertical permeability adjustment.

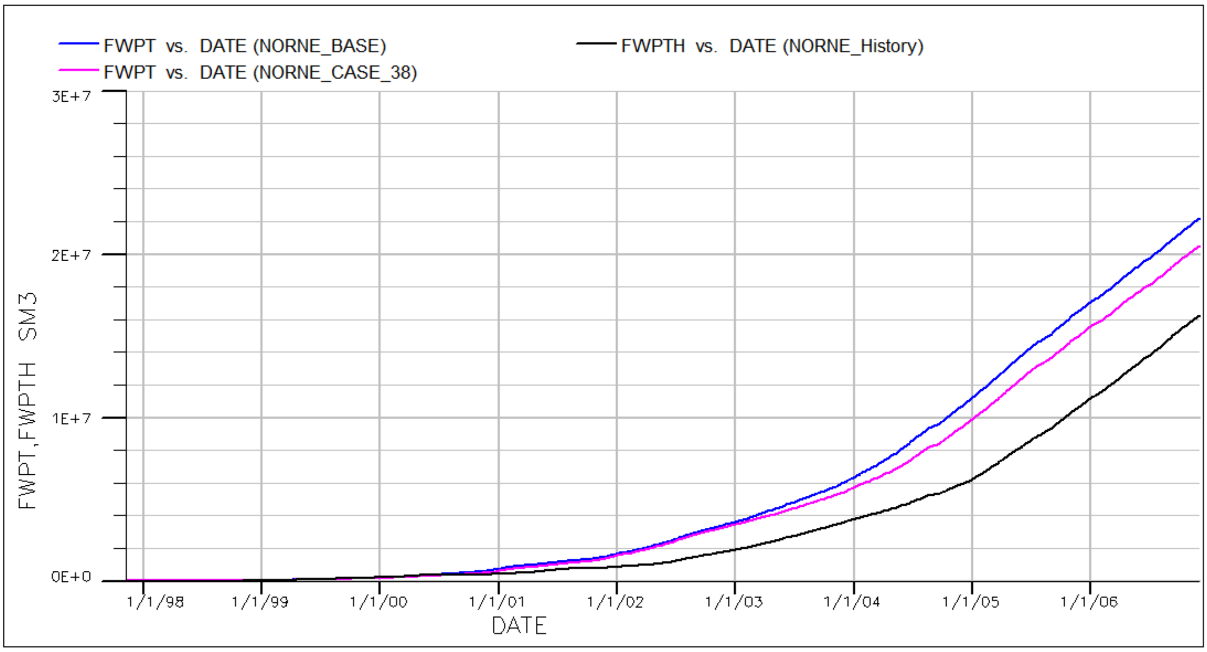


Figure 6.27 Field water production total where blue is the base case, black is the history and purple is the matched model for vertical permeability adjustment.

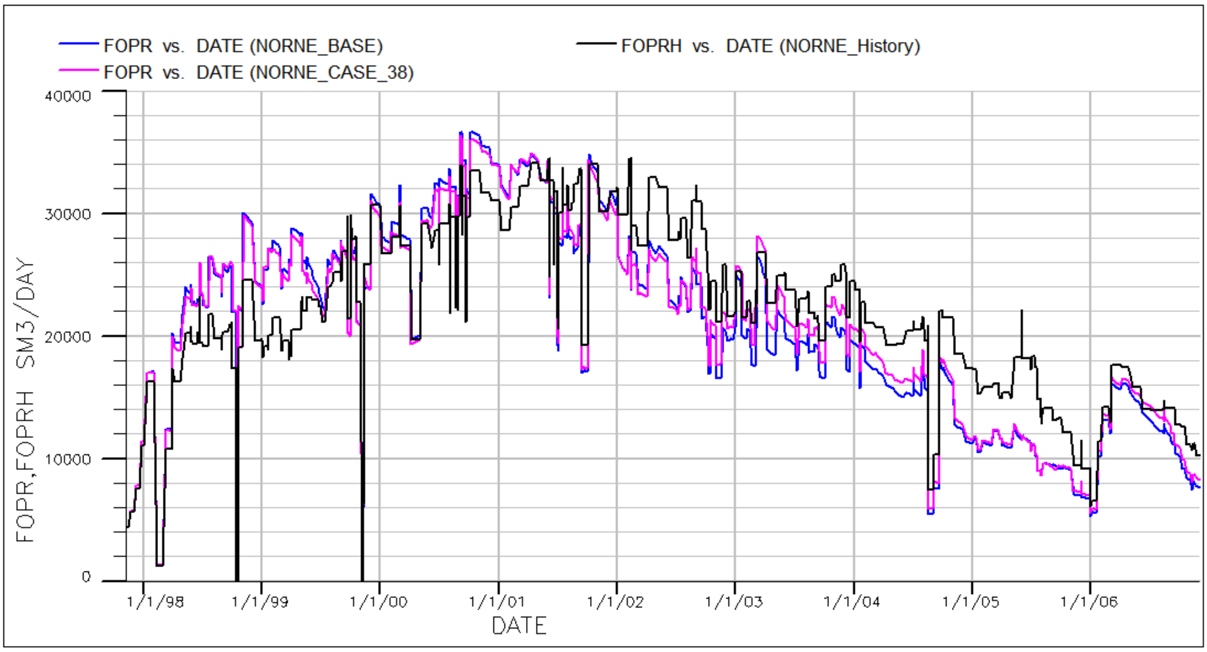
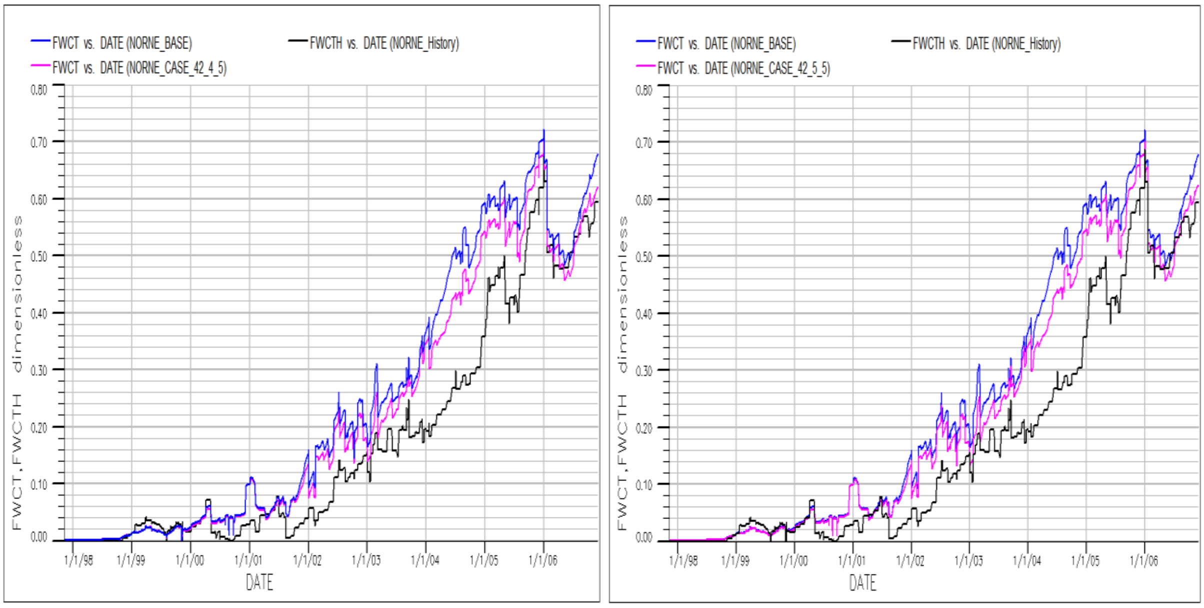


Figure 6.28 Field oil production rate where blue is the base case, black is the history and purple is the matched model for vertical permeability adjustment.

6.4.2 Adjusting Horizontal Permeability

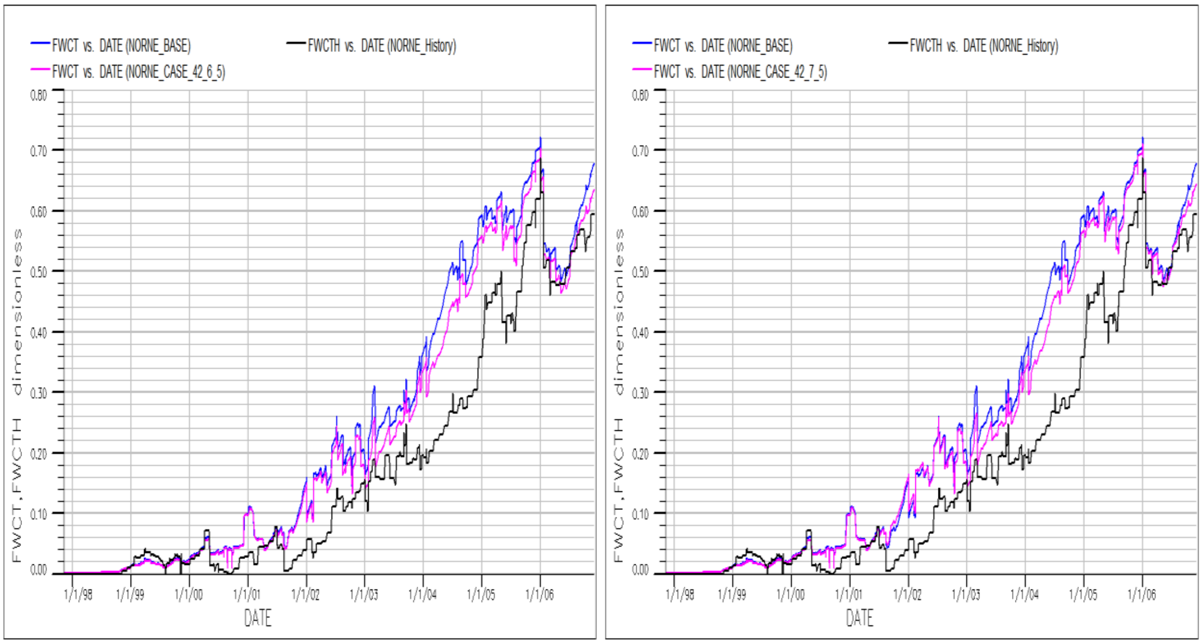
As like vertical permeability, horizontal permeability also plays an important role in reservoir's performance and it is associated with uncertainties in most cases; therefore it is important to adjust the horizontal permeability in order to find the most correct values that depict the reservoir performance. Horizontal permeability is generally part of the initial reservoir data obtained and it can be determined by analysing well test data and core measurements (Bourdarot & Daviau, 1989). In the Eclipse simulator, horizontal permeability is represented using the keyword PERMX (a keyword that specifies permeability values in X-direction)

Sensitivity analysis was done to all layers (22 layers) to see how the adjustment of horizontal permeability affects production performance. In performing sensitivity analysis, several PERMX multiplier factors were used which includes 0.025, 0.01, 0.1, 0.2, 0.5, 5, 10, 20, 30, 40 and 50. With except to layer 1, 2, 3, 21, and 22; the adjustment of horizontal permeability for all of the other layers showed a significant change in production profiles. Some of the layers with significant change, showed a positive change (an improved match compared to the base case) while the other layers showed a negative change (poor production profile when compared to the base case). Figure 6.29 to Figure 6.32 shows the results from sensitivity analysis for all layers with positive change and some layers with negative change.



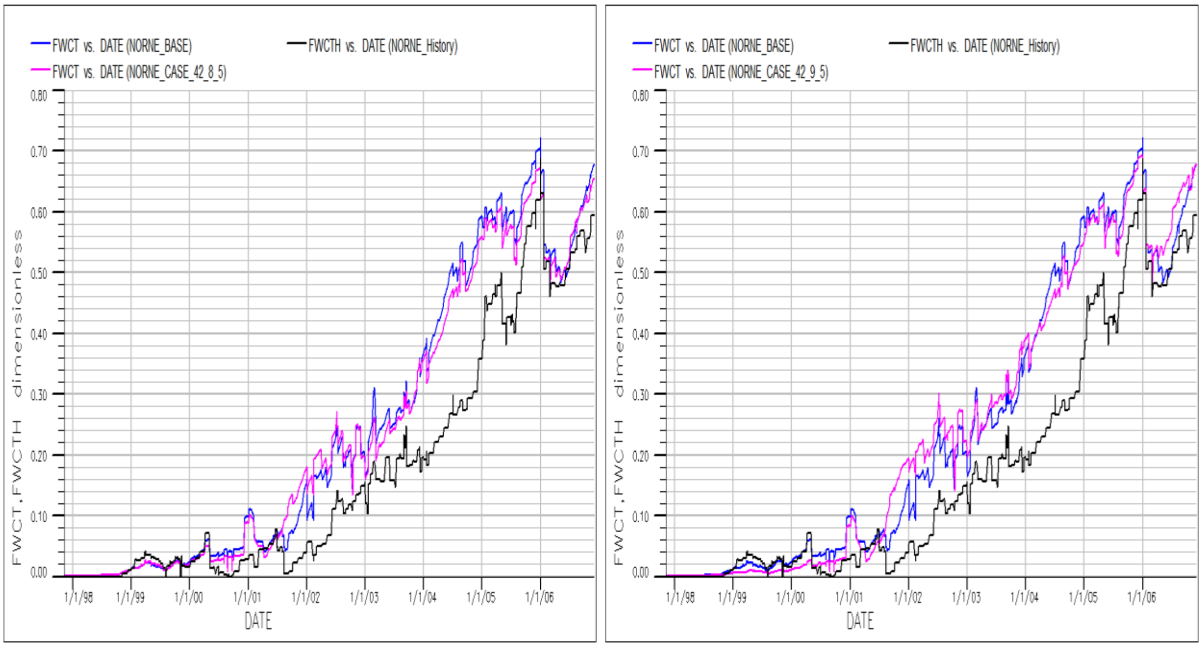
(a) (b)

Figure 6.29 Sensitivity analysis results for field water cut when adjusting PERMX for (a) layer 5 (b) layer 6. Where blue is the base case, black is the history and purple is the adjusted PERMX



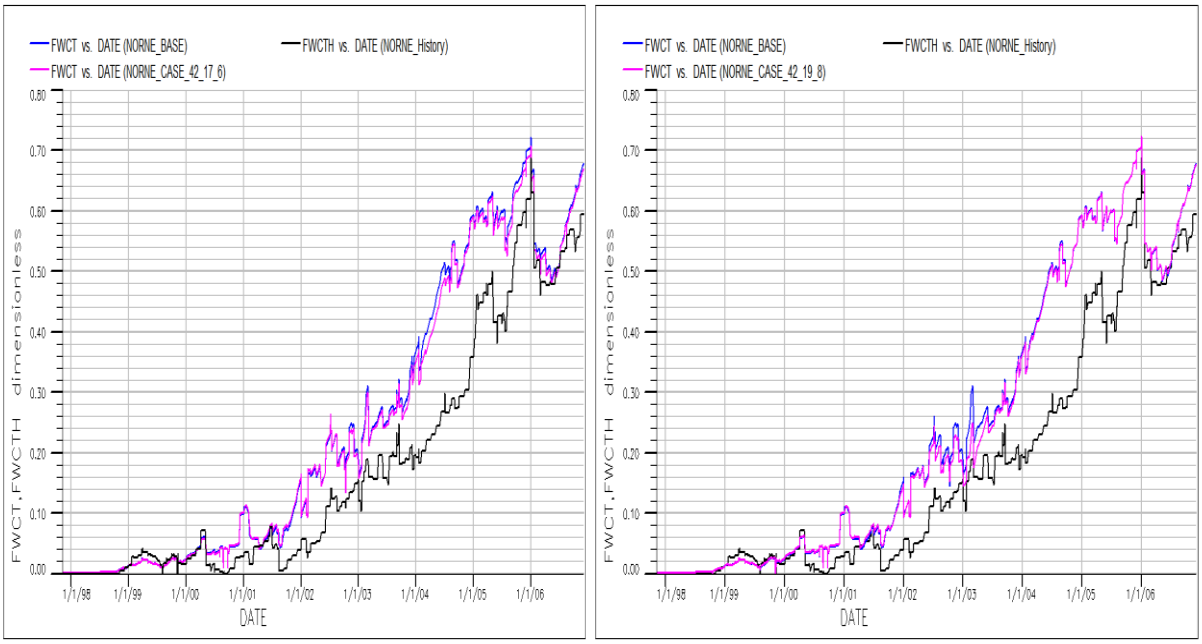
(a) (b)

Figure 6.30 Sensitivity analysis results for field water cut when adjusting PERMX for (a) layer 7 (b) layer 8. Where blue is the base case, black is the history and purple is the adjusted PERMX



(a) (b)

Figure 6.31 Sensitivity analysis results for field water cut when adjusting PERMX for (a) layer 9 (b) layer 10. Where blue is the base case, black is the history and purple is the adjusted PERMX



(a) (b)

Figure 6.32 Sensitivity analysis results for field water cut when adjusting PERMX for (a) layer 18 (b) layer 20. Where blue is the base case, black is the history and purple is the adjusted PERMX

The results for sensitivity analysis of Figure 6.29 (layer 5 and layer 6), Figure 6.30 (layer 7 and 8) and Figure 6.32 (layer 18 and 20) show an improved match whereas Figure 6.31 (layer 9 and 10) shows poor match.

Further adjustment to the layers with improved match was done to find the PERMX multiplier factors that will result to a best matched model. After the adjustments, it was observed that the best match is obtained when using the PERMX multiplier factor presented in Table 6.5 below and Appendix 5.

Table 6.5 PERMX multiplier factors which result to a best match

Layer	Modified PERMX multiplier factor
5	40
6	30
7	30
8	30
18	0.1
20	0.5

The PERMX multiplier factors presented in Table 6.5 above implies that horizontal permeability for layer 5, 6, 7 and 8 should be increased while that of layer 18 and 20 should be reduced to obtain a best match. The best match in adjusting horizontal permeability is as presented in Figure 6.33 to Figure 6.35 below.

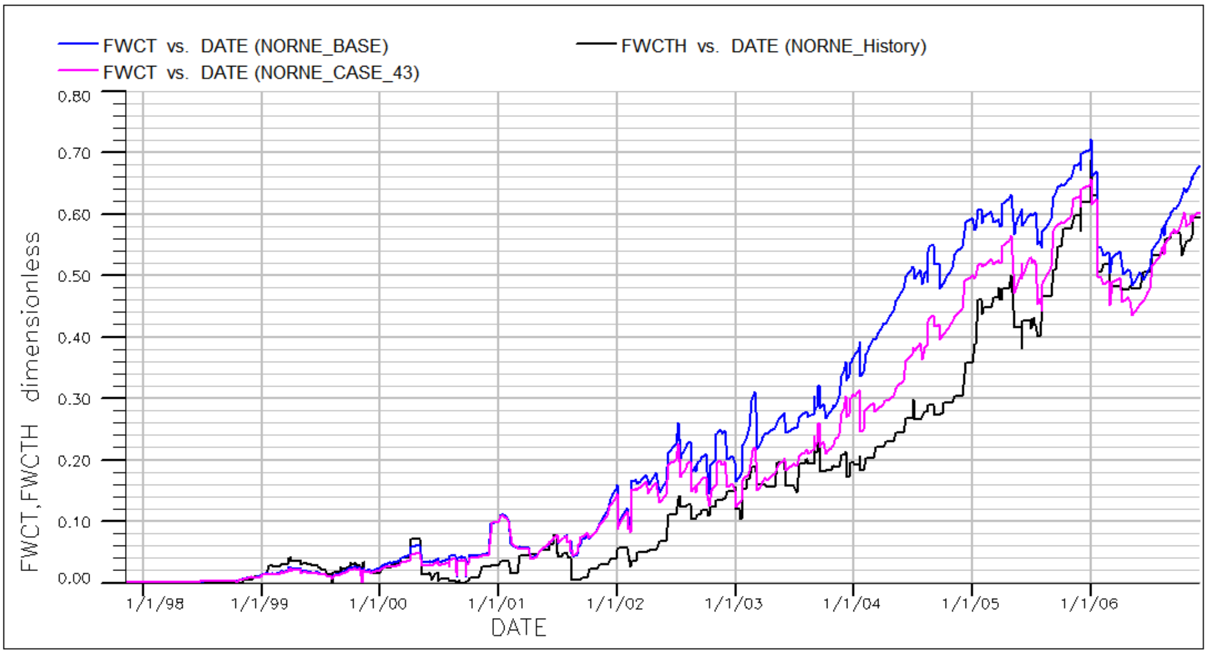


Figure 6.33 Field water cut where blue is the base case, black is the history and purple is the best match in adjusting PERMX

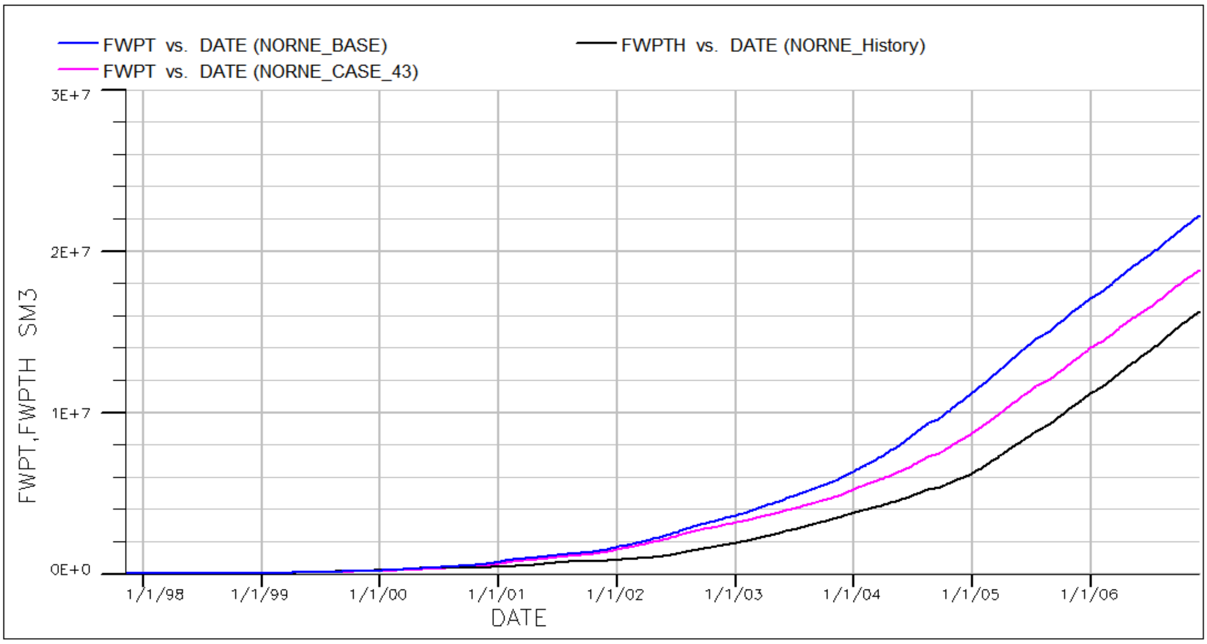


Figure 6.34 Field water production total where blue is the base case, black is the history and purple is the best match in adjusting PERMX

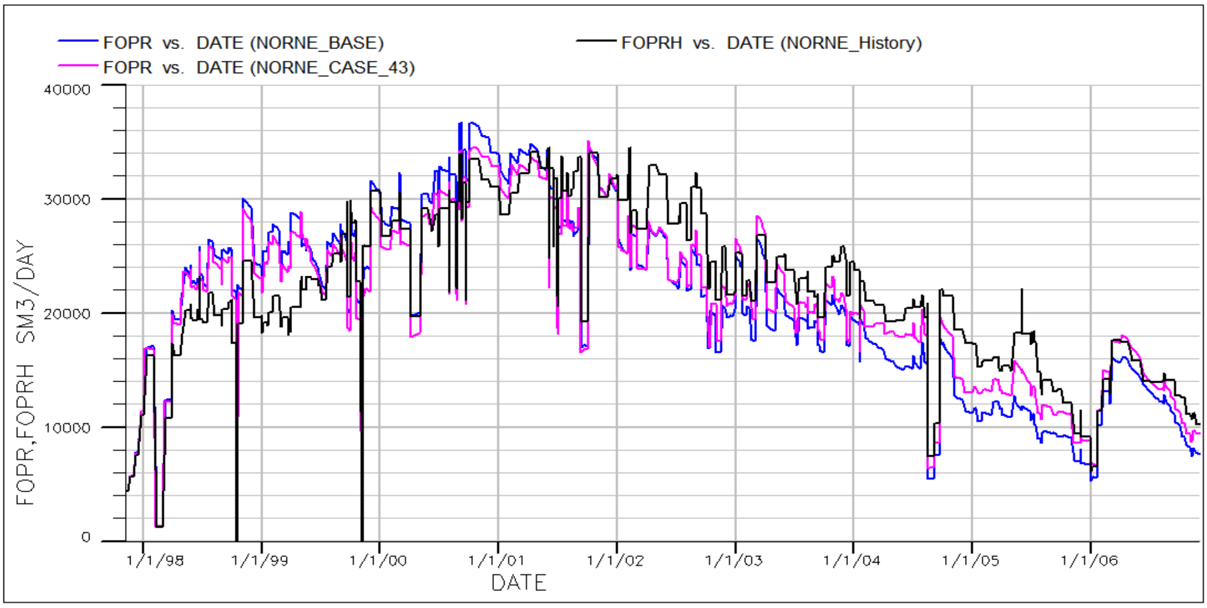


Figure 6.35 Field oil production rate where blue is the base case, black is the history and purple is the best match in adjusting PERMX

Using simple calculation presented in Appendix 7 and visual analysis of the field water cut and field water production total of the best matched model presented in Figure 6.33 and Figure 6.34, it can be seen that by adjusting horizontal permeability of layer 5, 6, 7, 8, 18 and 20; the field water cut and field water production match is improved by approximately 40% compared to the base case model. Also the result has shown that the adjustment of horizontal permeability results to a very significant improvement in oil production profile (rate and total) compared to all of the other adjusted parameters as it can be seen in Figure 6.35 above and Figure A.11 in Appendix 8. The field gas oil ratio (Figure A.10 in Appendix 8) is also improved.

6.5 Combining Adjustment of MULTFLT and PERMZ

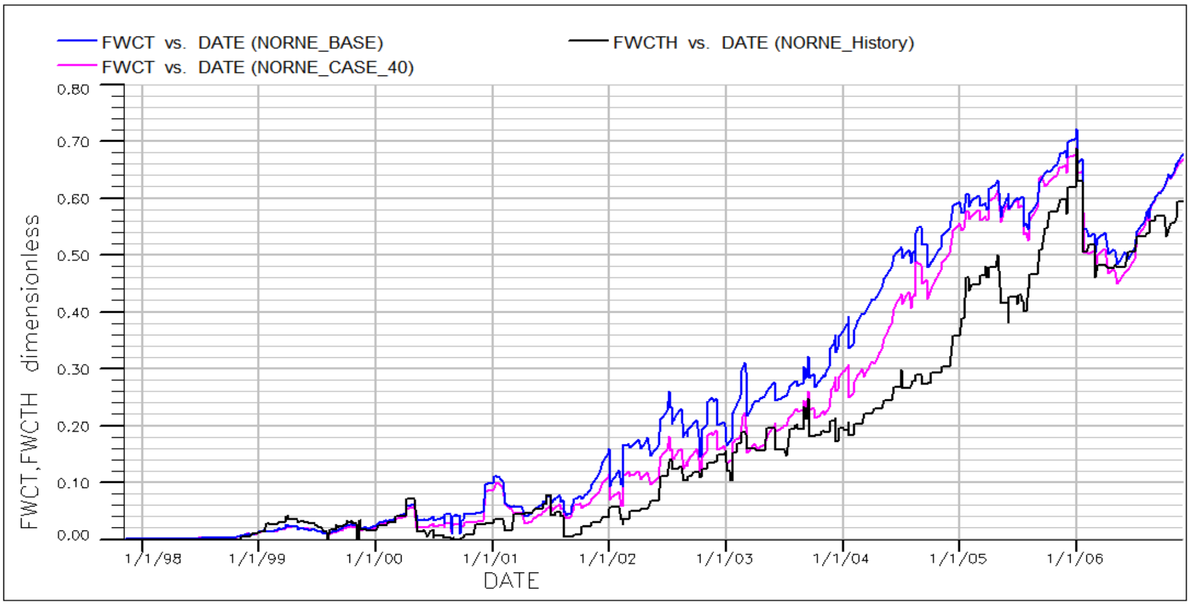


Figure 6.36 Field water cut where blue is the base case, black is the history and purple is the matched model for combining adjustment of fault transmissibility and vertical permeability

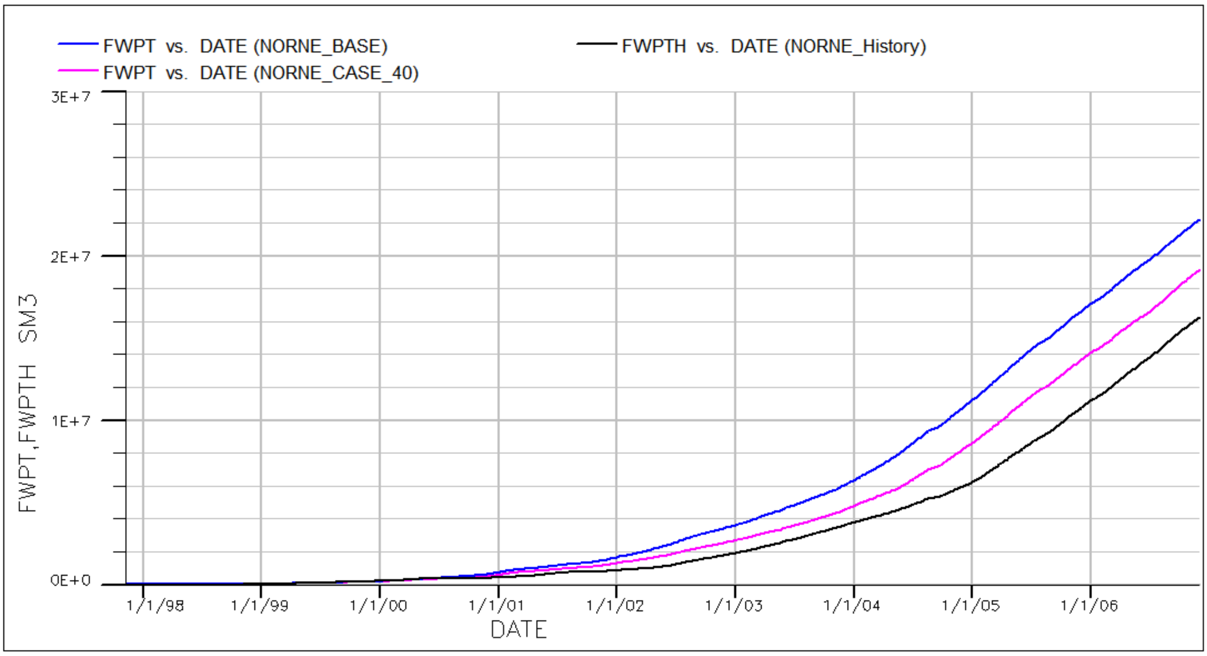


Figure 6.37 Field water production total where blue is the base case, black is the history and purple is the matched model for combining adjustment of MULTFLT and PERMZ

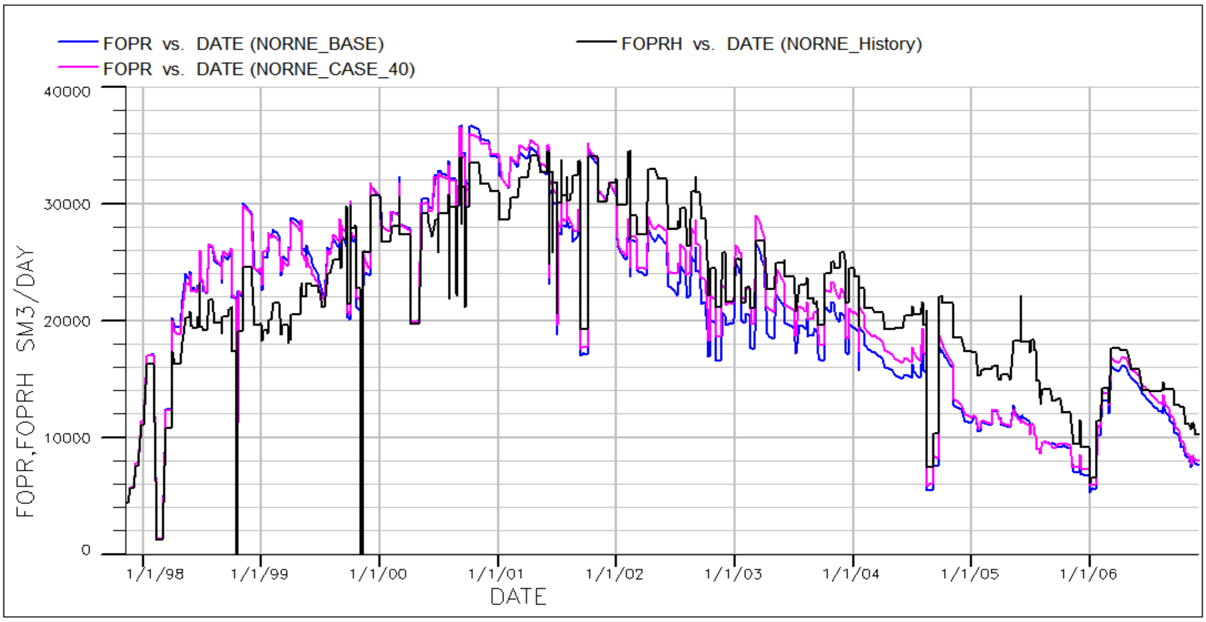


Figure 6.38 Field oil production rate where blue is the base case, black is the history and purple is the matched model for combining adjustment of MULTFLT and PERMZ

Using simple calculation presented in Appendix 7 and visual analysis of the field water cut and field water production total of the best matched model presented in Figure 6.36 and Figure 6.37, it can be seen that by combing adjustment of vertical permeability and fault transmissibility; the field water cut and field water production match is improved by approximately 50% compared to the base case. The match is also better compared to adjusting MULTFLT alone and adjusting PERMZ alone. The result also shows that there is some improvement in field oil production rate (Figure 6.38), specifically between year 2002 and 2005. There is no significant improvement in field oil gas ratio as it can be seen in Figure A.12 in Appendix 8.

6.6 Combining Adjustment of MULTZ, MULTFLT and PERMZ

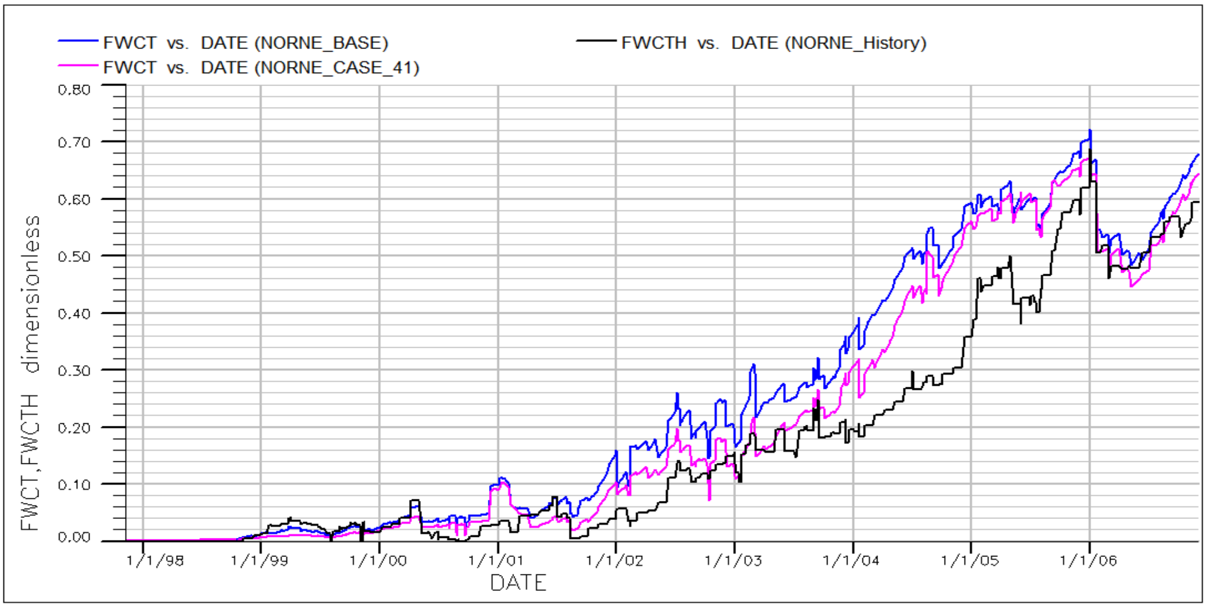


Figure 6.39 Field water cut where blue is the base case, black is the history and purple is the matched model for combining adjustment of MULTZ, MULTFLT and PERMZ

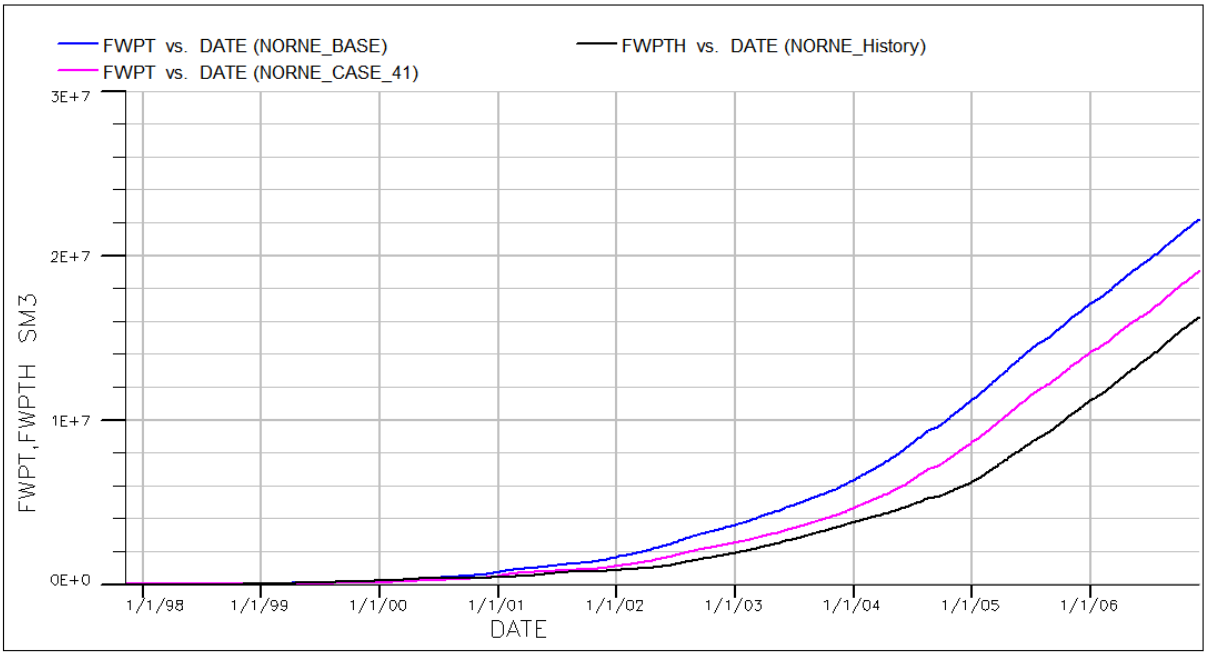


Figure 6.40 Field water production total where blue is the base case, black is the history and purple is the matched model for combining adjustment of MULTZ, MULTFLT and PERMZ

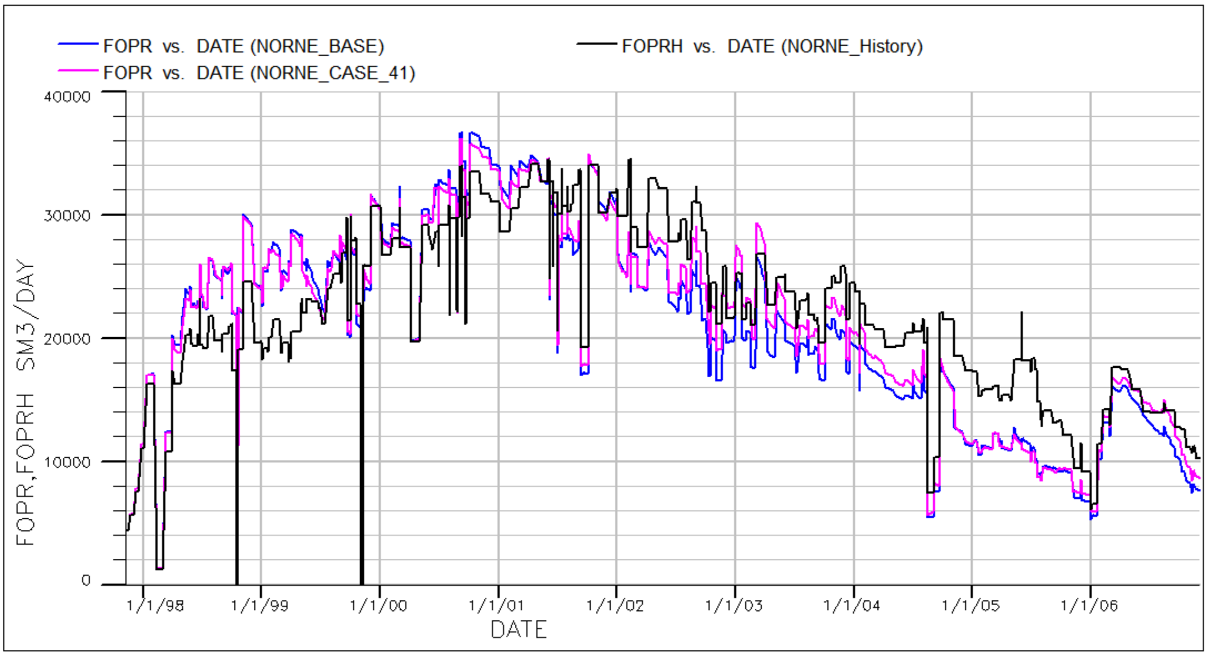


Figure 6.41 Field oil production rate where blue is the base case, black is the history and purple is the matched model for combining adjustment of MULTZ, MULTFLT and PERMZ

Using simple calculation presented in Appendix 7 and visual analysis of the field water cut and field water production total of the best matched model presented in Figure 6.39 and Figure 6.40, it can be seen that by combing adjustment of fault transmissibility of stratigraphic barrier, vertical permeability and fault transmissibility; the field water cut and field water production is improved by approximately 55% compared to the base case. Also the match is better than adjusting MULTZ alone, adjusting MULTFLT alone and adjusting PERMZ alone. From the result it can be seen also that field oil production rate (Figure 6.41 above) and field gas oil ratio (Figure A.13 in Appendix 8) is improved, however it can be seen that in year 2005, the field gas oil ratio profile is poor than the base.

6.7 Combining Adjustment of PERMX and MULTFLT

The results presented in Figure 6.42 to Figure 6.44 below show that there is high improvement in the match when combining the adjustment of horizontal permeability and fault transmissibility. Using simple calculation presented in Appendix 7 and visual analysis of the field water cut and field water production total of the best matched model presented in Figure 6.42 and Figure 6.43, it can be seen that by combing adjustment of horizontal permeability and fault transmissibility; the field water cut and field water production match is improved by approximately 75% compared to the base case. Also the match is good when compared to adjusting PERMX alone and adjusting MULTFLT alone. Furthermore, it was observed from the results that there is very significant improvement in field oil production rate (Figure 6.44 below) and field gas oil ratio (Figure A.14 in Appendix 8).

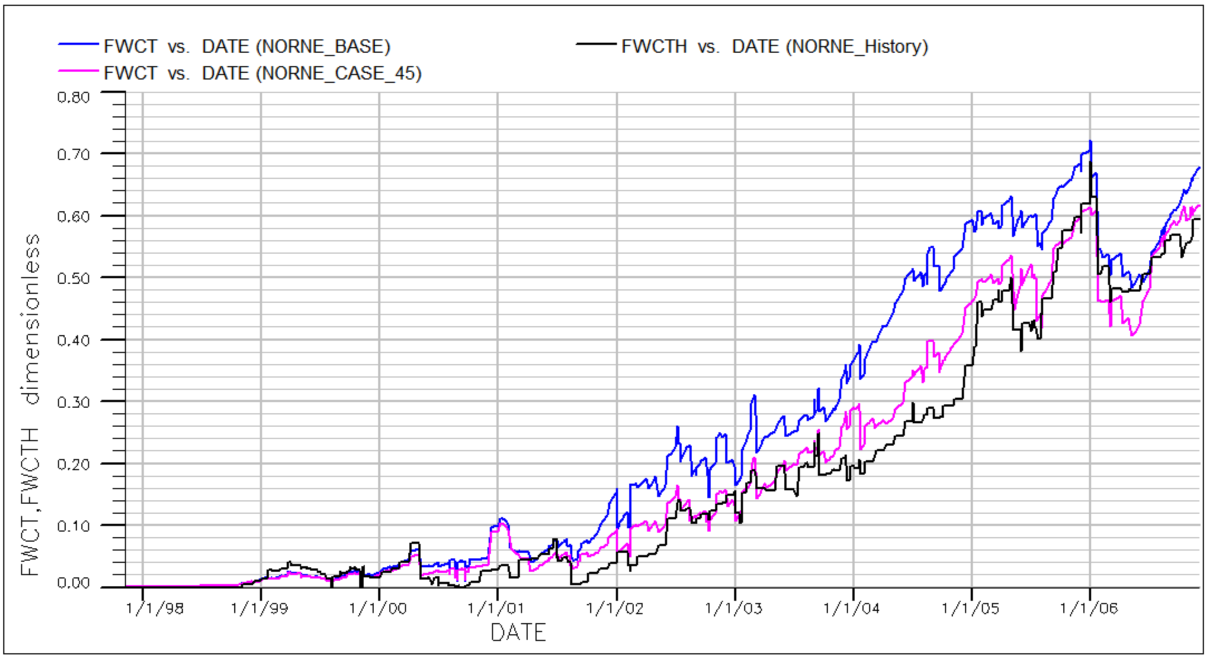


Figure 6.42 Field water cut where blue is the base case, black is the history and purple is the matched case for combing adjustment of PERMX and MULTFLT

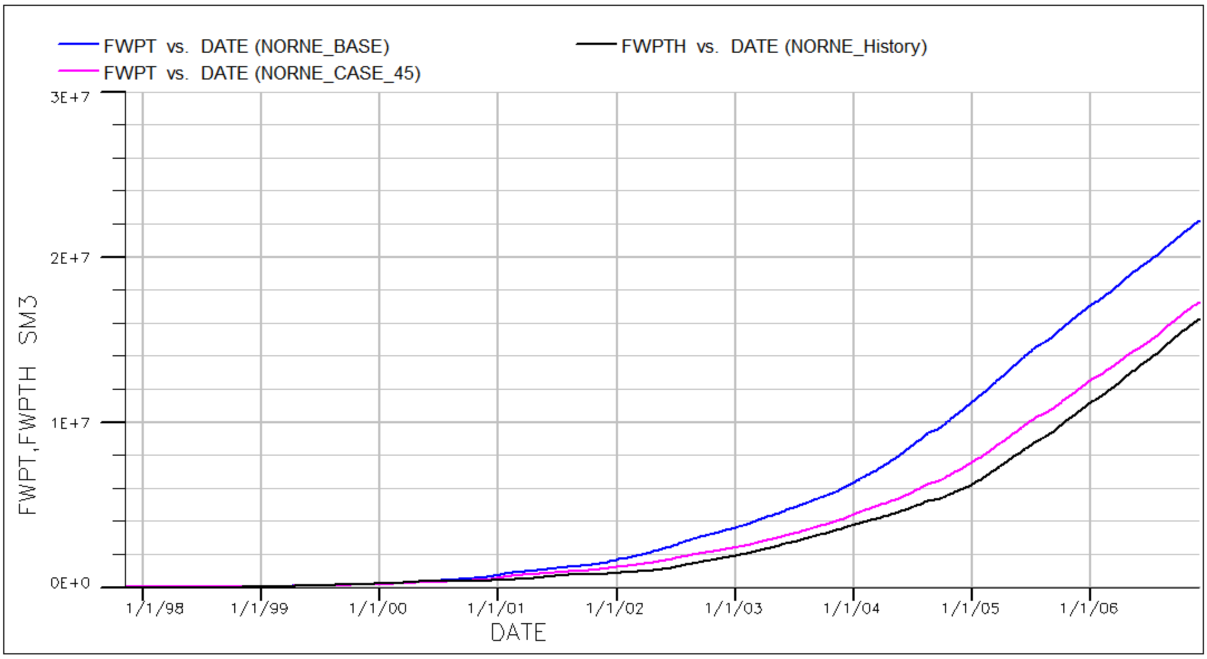


Figure 6.43 Field water production total where blue is the base case, black is the history and purple is the matched case for combing adjustment of PERMX and MULTFLT

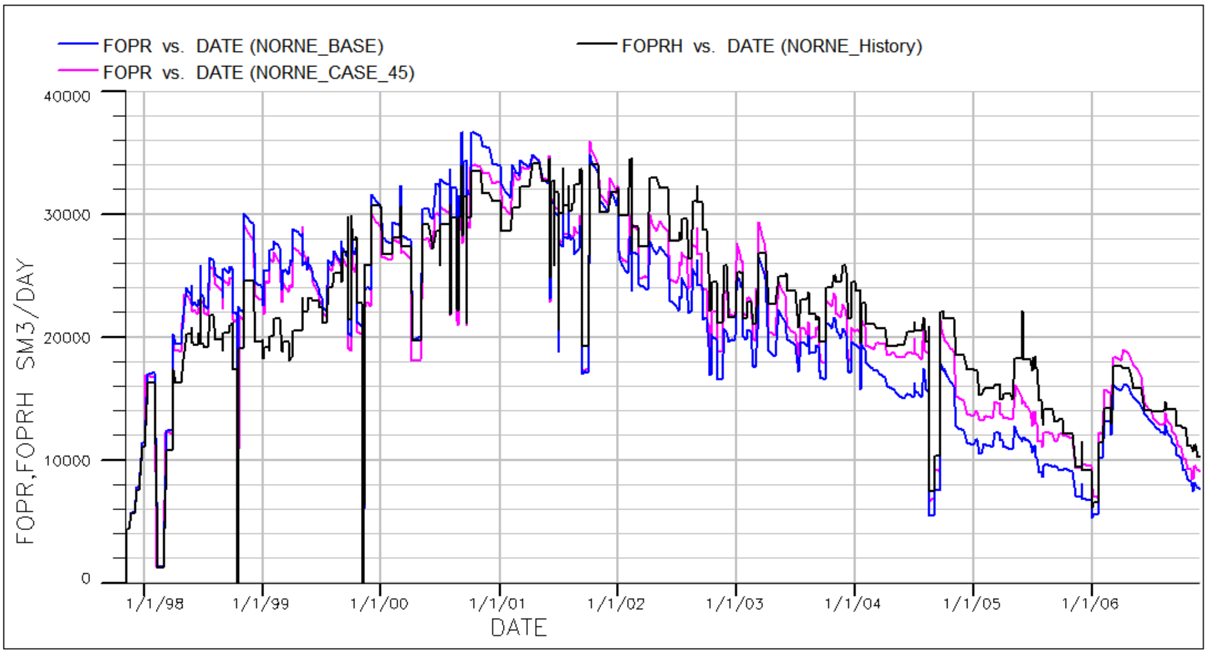


Figure 6.44 Field oil production rate where blue is the base case, black is the history and purple is the matched case for combing adjustment of PERMX and MULTFLT

6.8 Combining Adjustment of PERMX, MULTFLT and MULTZ

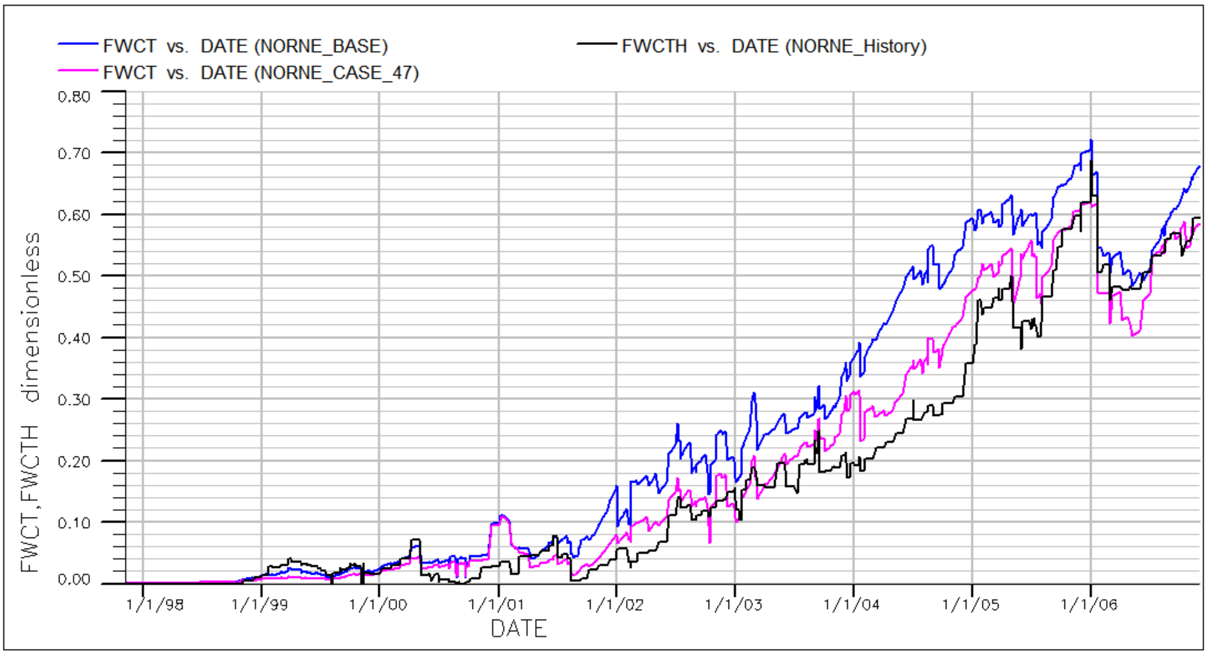


Figure 6.45 Field water cut where blue is the base case, black is the history and purple is the matched model for combining adjustment of PERMX, MULTFLT and MULTZ

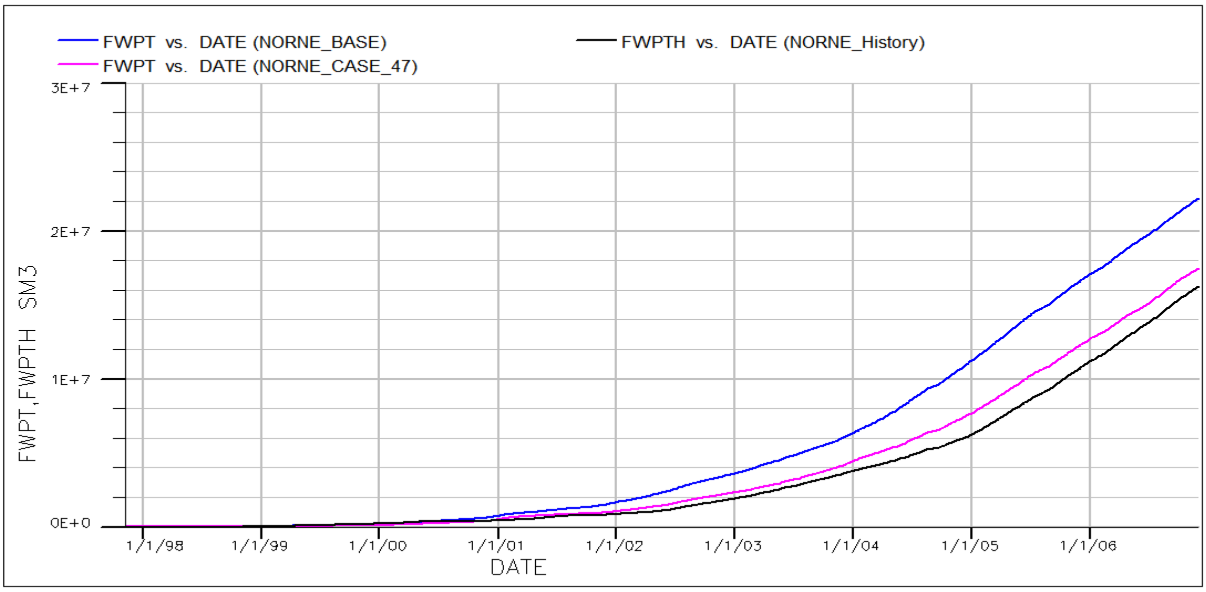


Figure 6.46 Field water production total where blue is the base case, black is the history and purple is the matched model for combining adjustment of PERMX, MULTFLT and MULTZ

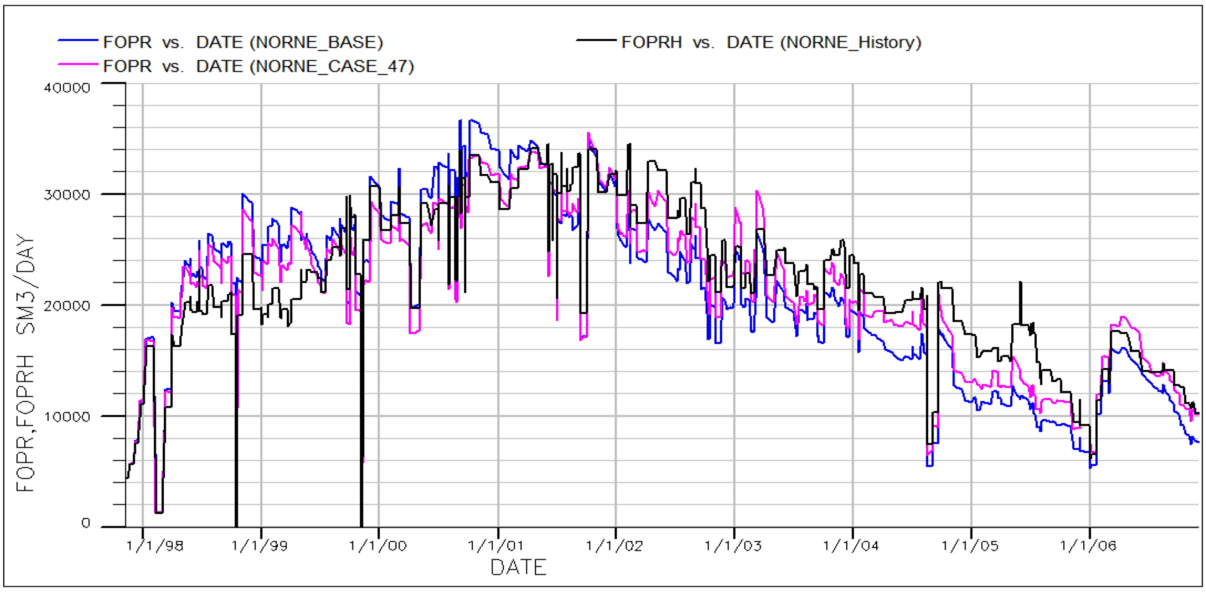


Figure 6.47 Field oil production rate where blue is the base case, black is the history and purple is the matched model for combining adjustment of PERMX, MULTFLT and MULTZ

By simple calculation presented in Appendix 7 and visual analysis of the field water cut and field water production total of the best matched model presented in Figure 6.45 and Figure 6.46, it can be seen that by combing adjustment of horizontal permeability, fault transmissibility, and vertical transmissibility of stratigraphic barrier; the field water cut and field water production match is improved by approximately 75% compared to the base case. Also the match is better compared to adjusting PERMX alone, adjusting MULTFLT alone and adjusting MULTZ alone. It was also observed that there is a very significant improvement in the field oil production rate (Figure 6.47 above) and field gas oil ratio (Figure A.15 in Appendix 8)

6.9 Final Matched Model in Adjusting Production Data

To get the final matched model, the results from different cases were analysed. These cases are: combining adjustment of (1) MULTZ and MULTFLT (2) MULTZ and PERMZ (3) PERMZ and MULTFLT (4) PERMZ, MULTZ and MULTFLT (5) PERMX and PERMZ (6) PERMX and MULTZ (7) PERMX and MULTFLT (8) PERMX, MULTFLT and MULTZ (9) PERMX, PERMZ and MULTFLT (10) PERMX, PERMZ, MULTFLT and MULTZ.

Of all the cases analysed, it was observed that the best match is obtained from two cases which are (1) combining adjustment of PERMX and MULTFLT (2) combining adjustment of PERMX, MULTFLT and MULTZ. It was observed that these two cases have very similar results with minor differences. Therefore further analysis as presented in Appendix 6 was done on the two cases to find a final matched model. After the analysis it was observed that the final best matched model is obtained when combining the adjustment of PERMZ, MULTFLT and MULTZ. Figure 6.48 to Figure 6.51 shows the results for the final matched model.

The results of the final best matched model suggest that adjustment of horizontal permeability is more important than adjustment of vertical permeability. Generally, in most of the reservoir, the horizontal permeability (parallel to bedding) is greater than vertical permeability (normal to bedding) by order of magnitude or more because of inherent nature of deposition (vertical changes in sorting and bedding laminations). The vertical permeability values in Norne field (Appendix 3) are low than horizontal permeability values confirming that reservoirs has high horizontal permeability compared to vertical permeability. In some cases, vertical permeability is high than horizontal permeability due to fractures or even burrowing that cuts across bedding. In stratified reservoir comprising multiple layers, limited vertical communication between adjacent layers might exist through discontinuous barriers; therefore in this case the horizontal permeability is of paramount importance in reservoir production performance (Johnston & Cooper, 2010), (AAPG WIKI, 2016). The Norne field is characterised by stratigraphic barriers (as explained in Chapter 3) hence limited vertical communication, therefore this could be the explanation to why adjustment of horizontal permeability results to a more better match compared to adjustment of vertical permeability.

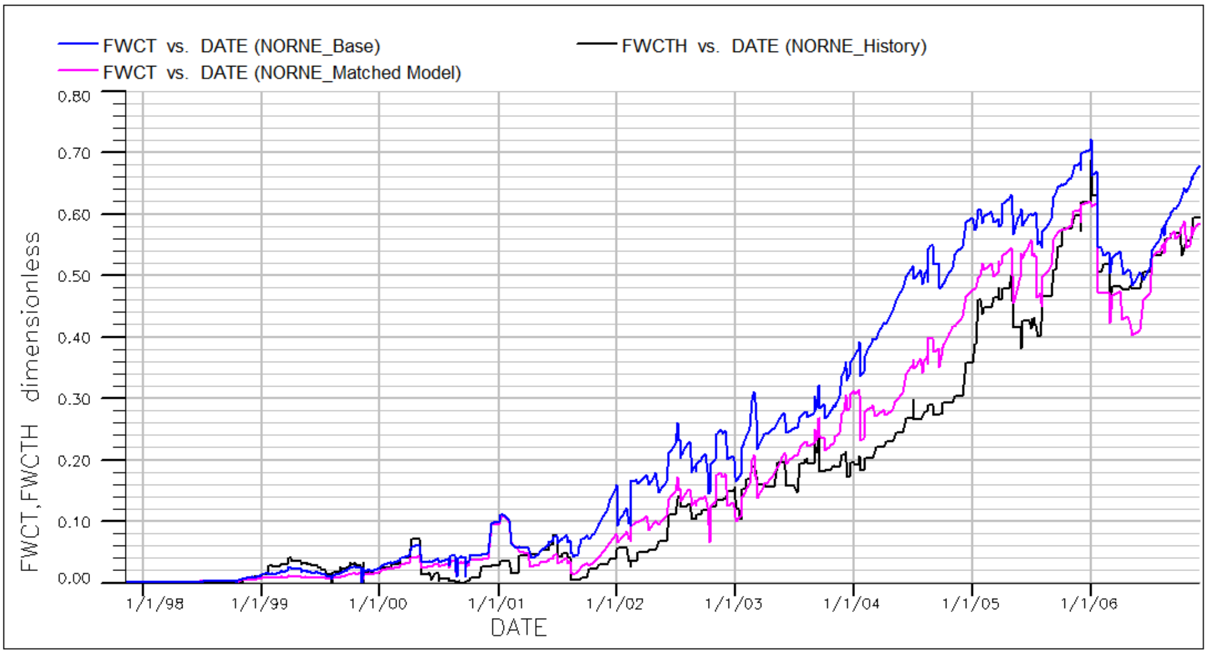


Figure 6.48 Field water cut where blue is the base case, black is the history and purple is the final matched model

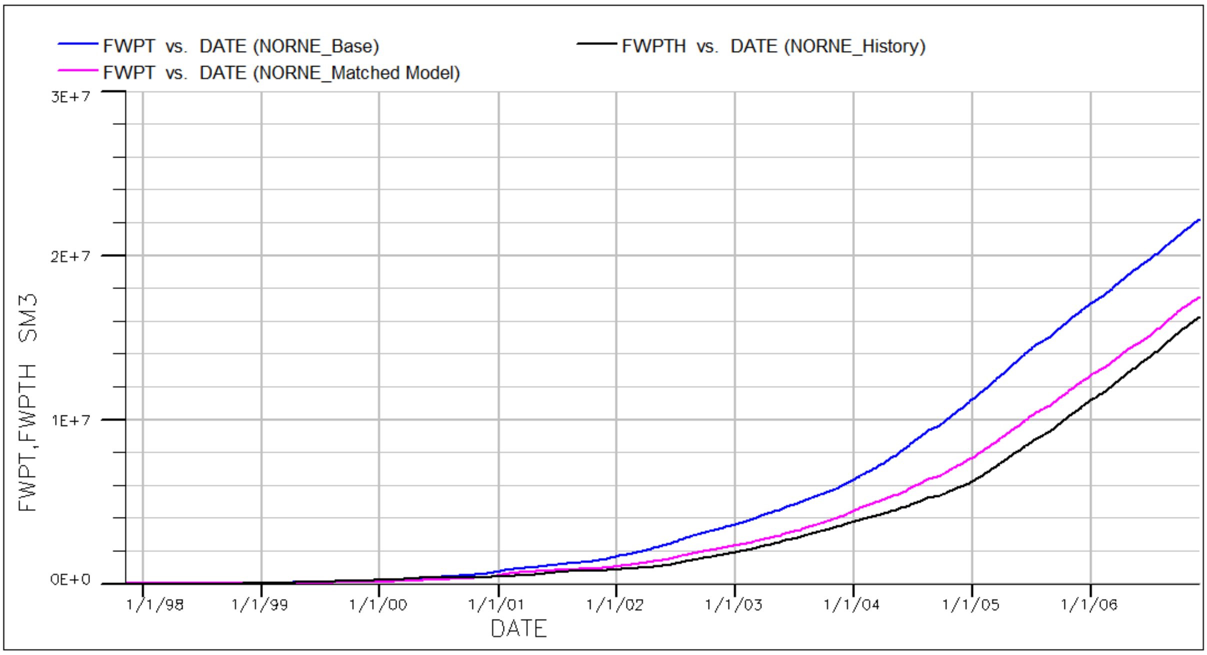


Figure 6.49 Field water production total where blue is the base case, black is the history and purple is the final matched model

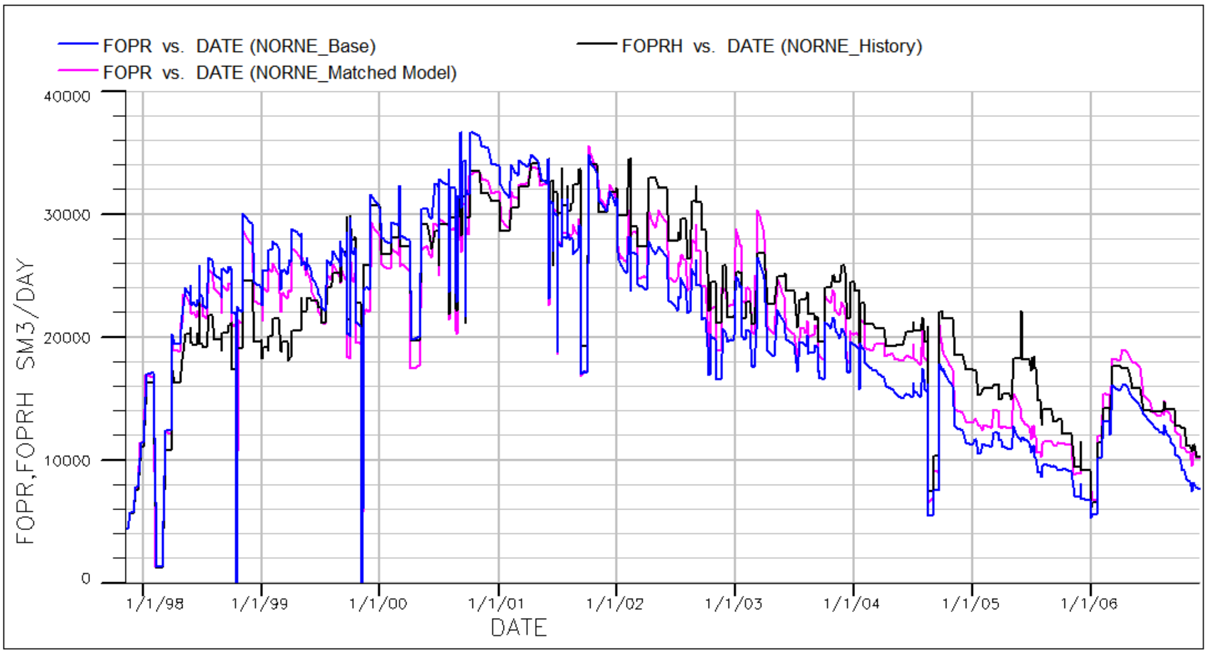


Figure 6.50 Field oil production rate where blue is the base case, black is the history and purple is the final matched model

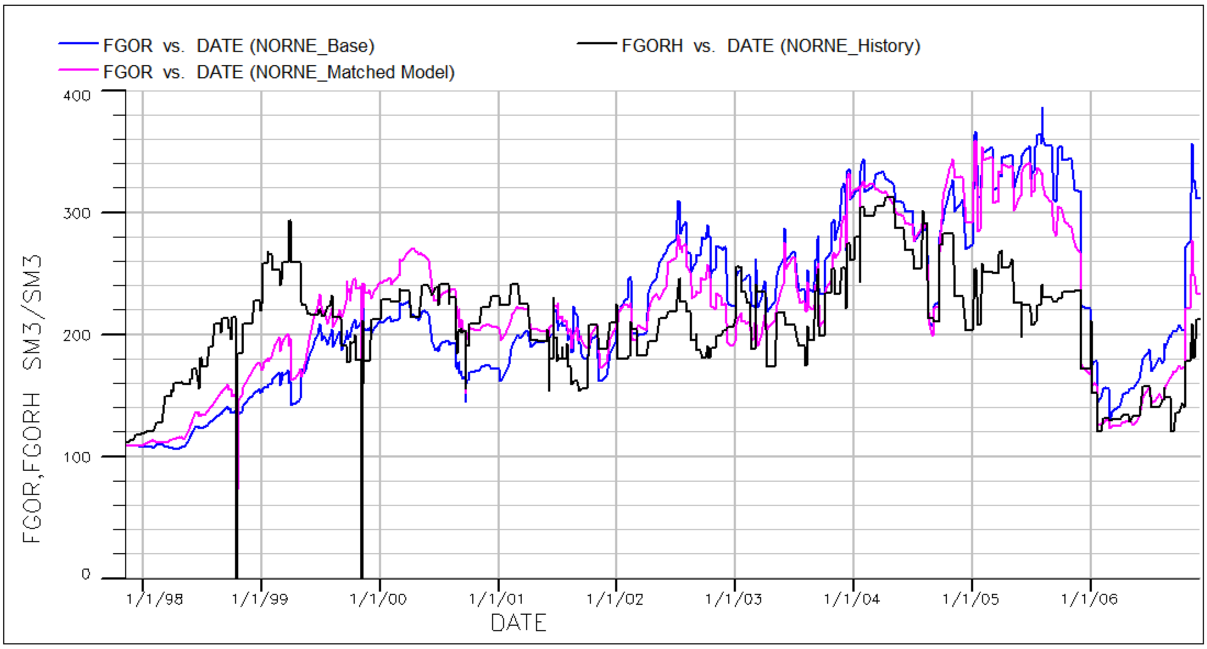


Figure 6.51 Field gas oil ratio where blue is the base case, black is the history and purple is the final matched model

CHAPTER 7

7. HISTORY MATCHING THE NORNE FIELD USING 4D SEISMIC DATA: CASE STUDIES BY STATOIL

7.1 Norne E-segment

The first case study is the Norne E-segment in which it was decided to drill an infill production well based on 4D seismic data acquired on 2003. The drilled well was named E-3CH. The analysis from the 4D seismic data of 2003 showed that there is a clear difference between the 4D seismic data and the reservoir simulation model. This comparison is as shown in Figure 7.1 below for a line through well E-3CH from the simulation model and the 4D seismic data (Osdal et al., 2006).

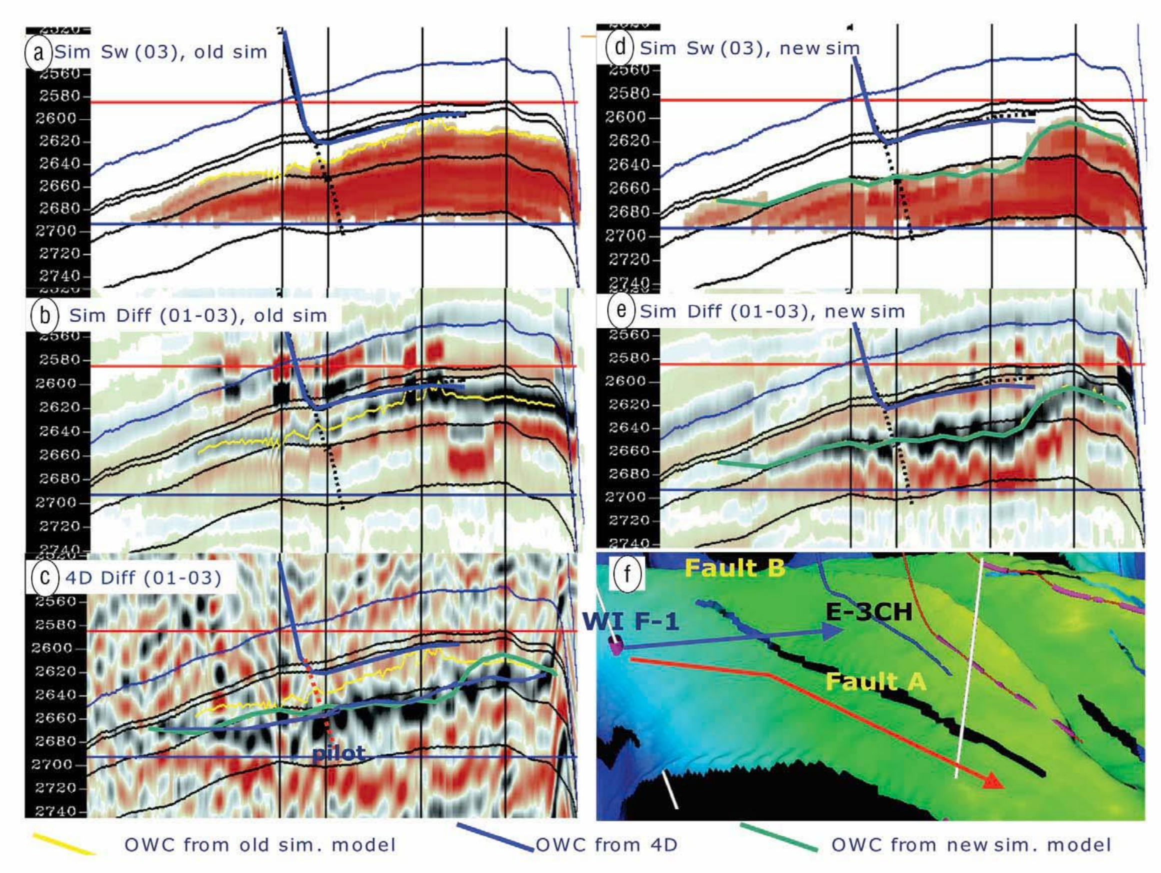


Figure 7.1 (a) Water saturation (red is high saturation) of old simulation model and (b) seismic modelling (4D difference) of old simulation model. (c) Real 4D difference data. (d) Water saturation (red is high saturation) of new simulation model and (e) seismic modelling (4D difference) of new simulation model. (f) Top reservoir map (Osdal et al., 2006)

Figure 7.1f shows the position of well E-3CH whereby Figure 7.1a shows the water saturation from the simulation model. The modelled seismic 4D difference of the simulation model is as shown in Figure 7.1b. Figure 7.1c shows the real 4D seismic difference data (2001-2003), where the OWC from 4D seismic data (blue line) can be clearly interpreted deeper than in the simulation model (yellow line). At that time, fault A (Figure 7.1f) was open in the reservoir simulation model and hence water flowed easily from the water injector F-1H through fault A. The 4D seismic data indicated that fault A was partly sealing and therefore most of the water from F-1H flowed along fault A instead of flowing through it (red arrow in Figure 7.1f). This is confirmed by tracer data in the area (Osdal et al., 2006).

Following this observation; a new simulation model was created by decreasing the fault transmissibility of fault A and extending if farther to the main fault (B). The new simulation model had a much better match with the 4D seismic data as it can be seen in Figure 7.1d and Figure 7.1e. The green line shows the OWC on the new simulation model and it matches the OWC from 4D seismic data (blue line). Also the location of well E-3CH was now good in the new simulation model (Osdal et al., 2006).

Furthermore, the water cut and pressure match from the new simulation model was also improved as it can be seen in Figure 7.2 below for two wells. Prior to drilling the production well, it was decided to drill a pilot well to check the OWC. The pilot well confirmed the OWC level as interpreted from the 4D seismic data and predicted from the new simulation model (Osdal et al., 2006).

Figure 7.3 below shows the summary of the results for well E-3CH after six months of production. This figure shows the comparison of the actual oil production and water cut with the prediction from the old and new simulation models. The new simulation model predicts the real observed production performance clearly better than the old simulation model (Osdal et al., 2006).

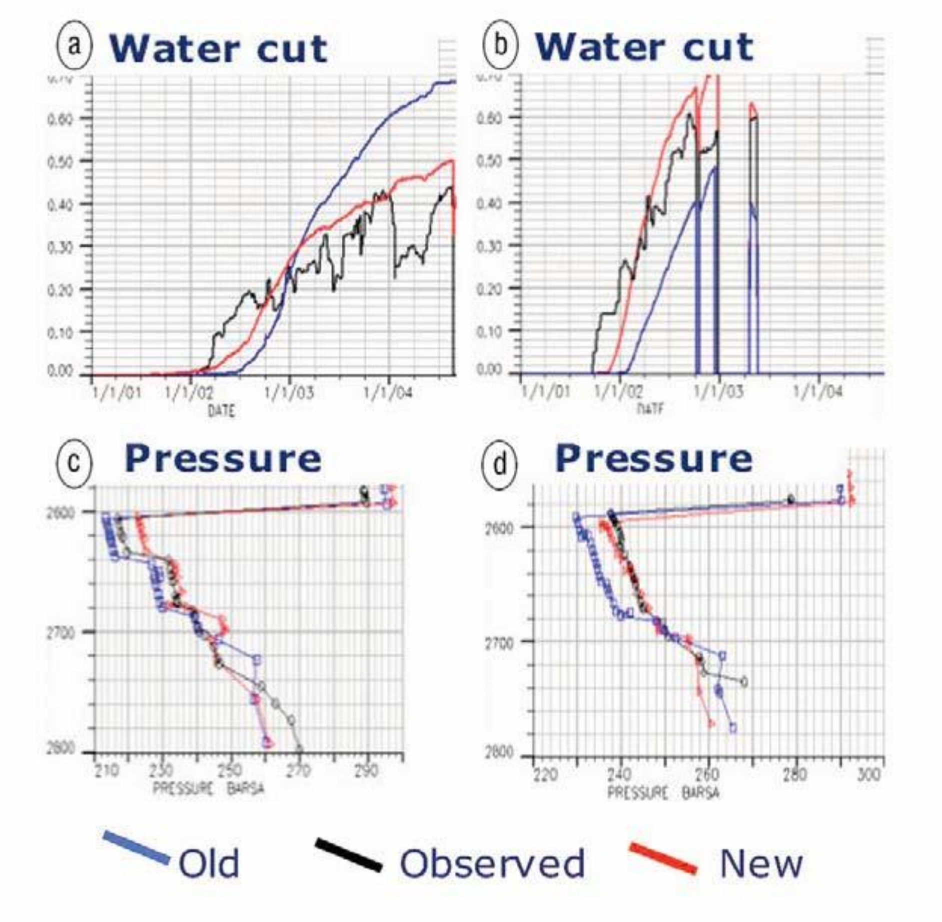


Figure 7.2 (a) and (b) water cut match (c) and (d) pressure match for two wells in the area using old and new simulation models (Osdal et al., 2006)

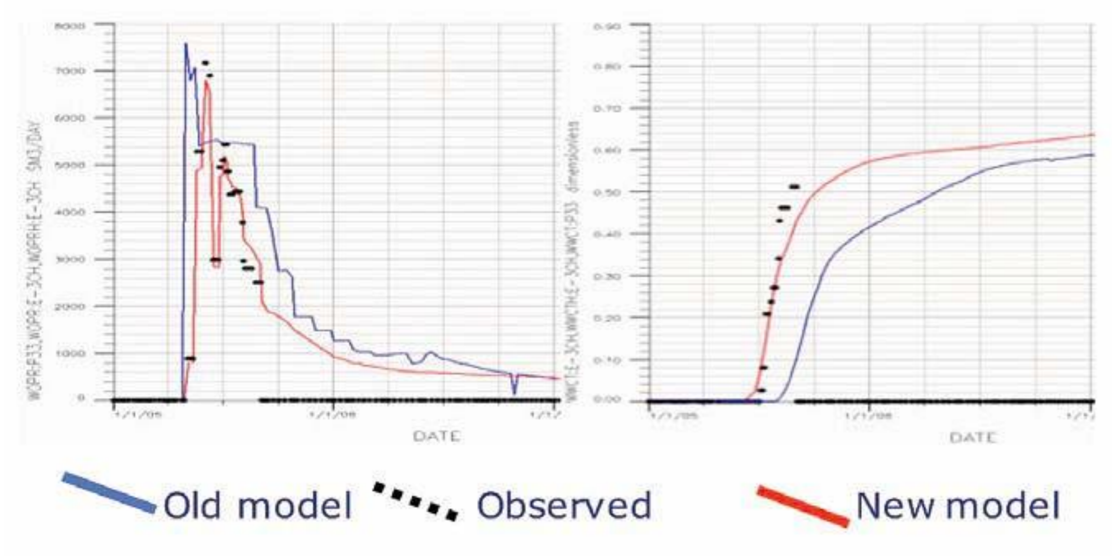


Figure 7.3 Left plot shows oil production, and right plot shows water cut for the well E-3CH. The new simulation model has predicted observations more accurately (Osdal et al., 2006)

7.2 Norne C-segment Southern Part

The other study is from Norne C-segment southern part of which its analysis is as presented in Figure 7.4 below. In this area, a horizontal producer well was drilled in 2003 where by its first planned location was based on the 4D seismic data acquired in 2001 and the reservoir simulation model of that time. Water saturation from the old simulation model of 2003 is as shown in Figure 7.4a. According to the geological information as presented in chapter 3, Norne field is characterized by several stratigraphic barriers. In Norne C-segment southern part there is a carbonate cemented barrier between Ile and Tofte formations (see Table 3.2). It was observed that there are pressure changes over the barrier in several wells in the area, and that it was expected to be a barrier for the water beneath. Therefore it was decided to place a first well in the highly porous and permeable Lower Ile formation above the carbonate cemented zone (Osdal et al., 2006).

Figure 7.4b below shows the 2001-2003 4D acoustic impedance difference data where red indicates an increase in impedance from 2001 to 2003. The increase in impedance is related to the scenario of water replacing oil. It is clear that the water certainly passed through the carbonate cemented zone and flooded the lower part of Ile Formation. Also it is evident that the toe of the originally planned well path seems to be in the water zone. Therefore to avoid early water production, the well location was moved upward and away from the water front (yellow line). The new well was successfully drilled in the oil zone and it produced with a rate of approximately 4000 Sm^3/d without water in the first year of production after start-up. (Osdal et al., 2006).

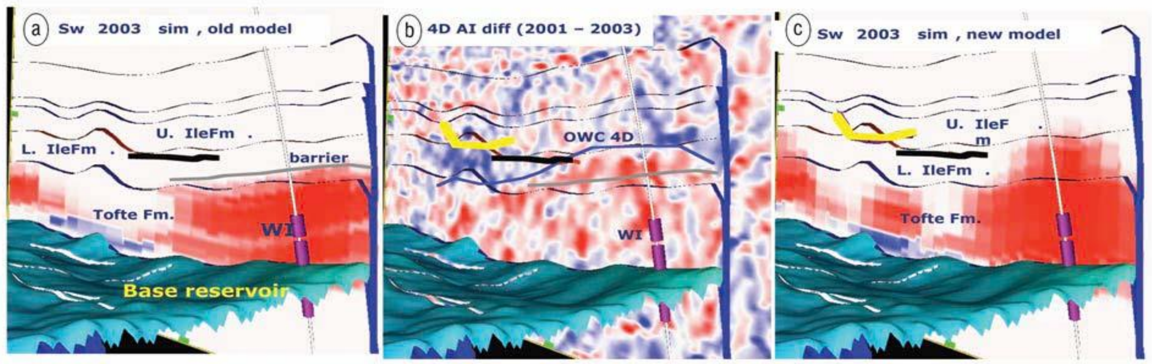


Figure 7.4 (a) Water saturation of old simulation model where red is high water saturation. (b) 4D acoustic impedance difference where red is increase in impedance from 2001 to 2003, indicating water replacing oil. (c) Water saturation of new simulation model where red is high water saturation (Osdal et al., 2006)

The reason for water to break through the carbonate cemented barrier can be that the area contains more small-scale faulting than what is observed in the seismic data. The carbonate cemented zone is also thin (approximately 20 cm) and tight, thus even small-scale faulting can break this barrier and allow water to flow through. Therefore by introducing more small-scale faulting into the reservoir simulation model, the observation from the 4D seismic data can be better matched as it can be seen in Figure 7.4c (Osdal et al., 2006).

7.3 Norne C-segment Northwestern Part

The other case study is Norne C-segment northwestern part which its analysis (4D amplitude and 4D difference data from a line through the well) is presented in Figure 7.5 below. 2003 and 2004 4D seismic data acquisition showed that the upper part of Tofte Formation was undrained, therefore a new producer well was scheduled to be drilled in the area in 2005.

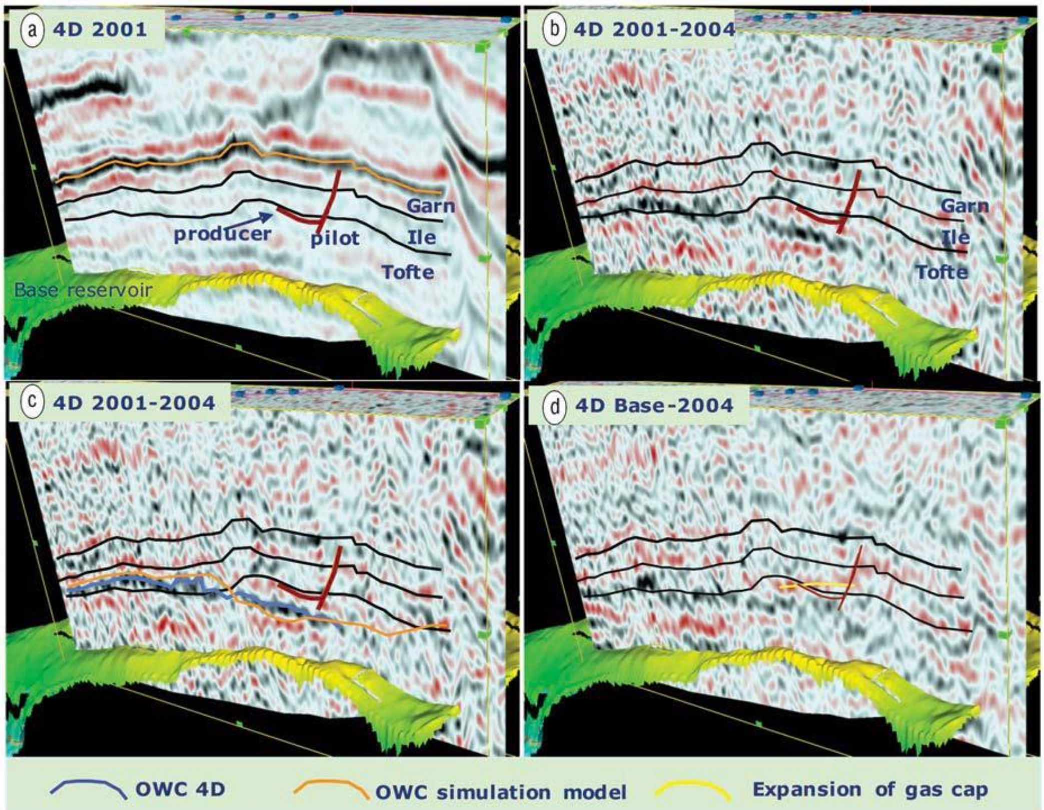


Figure 7.5 (a) 4D seismic data acquired in 2001. (b) 4D seismic data difference 2001-2004. (c) 4D seismic data difference 2001-2004 with OWC interpretation. (d) 4D seismic data difference Base-2004 with interpretation of gas cap expansion (yellow) (Osdal et al., 2006)

Figure 7.5a shows that the OWC is interpreted to be in the lower part of Tofte Formation and it is very difficult to interpret on each vintage. The OWC is much clearer and interpretable on the Q versus Q differences as can be seen in Figure 7.5b and Figure 7.5c. Prior to 2001 seismic acquisition, much gas was injected into the area and the gas is also seen in the area in 2004 seismic acquisition. This expansion of the gas cap is shown in the base-2004 4D seismic difference as it can be seen in Figure 7.5d (yellow line). Prior to drilling the horizontal producer well, a pilot well was drilled into Tofte Formation to check the OWC and to take pressure measurements. Due to high pressure in the lower part of the formation, the pilot well was stopped before reaching the OWC. However, the pilot well confirmed that the upper part of Tofte Formation is undrained as it was predicted by the 4D seismic data. Also the pilot well showed some gas cap expansion. Furthermore, it is likely that much of the water flooded into the area is coming from the north. By comparing the OWC from the 4D seismic data and the reservoir simulation model (blue and red lines) in Figure 7.5c, it can be seen that there is good match between the new reservoir simulation model and 4D seismic data. The horizontal producer began production in January 2006. By the end of February 2006, the well was producing approximately 5500 Sm^3/d with no water (Osdal et al., 2006).

7.4 Norne G-segment

The last case study is the G segment of which its analysis is presented in Figure 7.6 below. Well E-4 shown in Figure 7.6 began production in July 2000. When the first 4D seismic data was acquired in 2001, the pressure had already depleted below the bubble point to approximately 200 bars. Figure 7.6a shows the change in impedance between the base and 2001 surveys whereby blue is related to impedance decrease because of gas coming out of solution due to the pressure drop. This anomaly outlines the whole segment, and it shows that there is no pressure barrier between the E-4 producer well and the rest of the oil in the segment. Figure 7.6b shows the amount of gas in the new simulation model in 2001, which matches the 2001 4D seismic data (Osdal et al., 2006).

In autumn 2001, Well F-4 began water injection resulting to general pressure increase in the G segment. The change in acoustic impedance from 2001 to 2003 and from 2001 to 2004 is as shown in Figure 7.6c and Figure 7.6d respectively where a decrease in the impedance around F-4 and along the western main fault can be seen because of pressure increase due to injection. Also it can be seen that the most likely communication path from injection well F-4 to producer E-4 is along the western main fault. Furthermore, a pressure barrier (C) can be interpreted from the 4D seismic data. The opposite anomaly can be seen in the east of the pressure barrier. This anomaly is related to gas going back to the oil due to pressure increase. This anomaly could be due water flooding; however this explanation can be ruled out because there was no water production in production well E–4 in 2003. The pressure increase in this area must be less than the pressure increase along the western main fault. The water broke through to the E-4 producer in November 2003, but the effect of the water seems to be overprinted by the effect of gas going back to the oil on the 4D seismic data in Figure 7.6c and Figure 7.6d (Osdal et al., 2006).

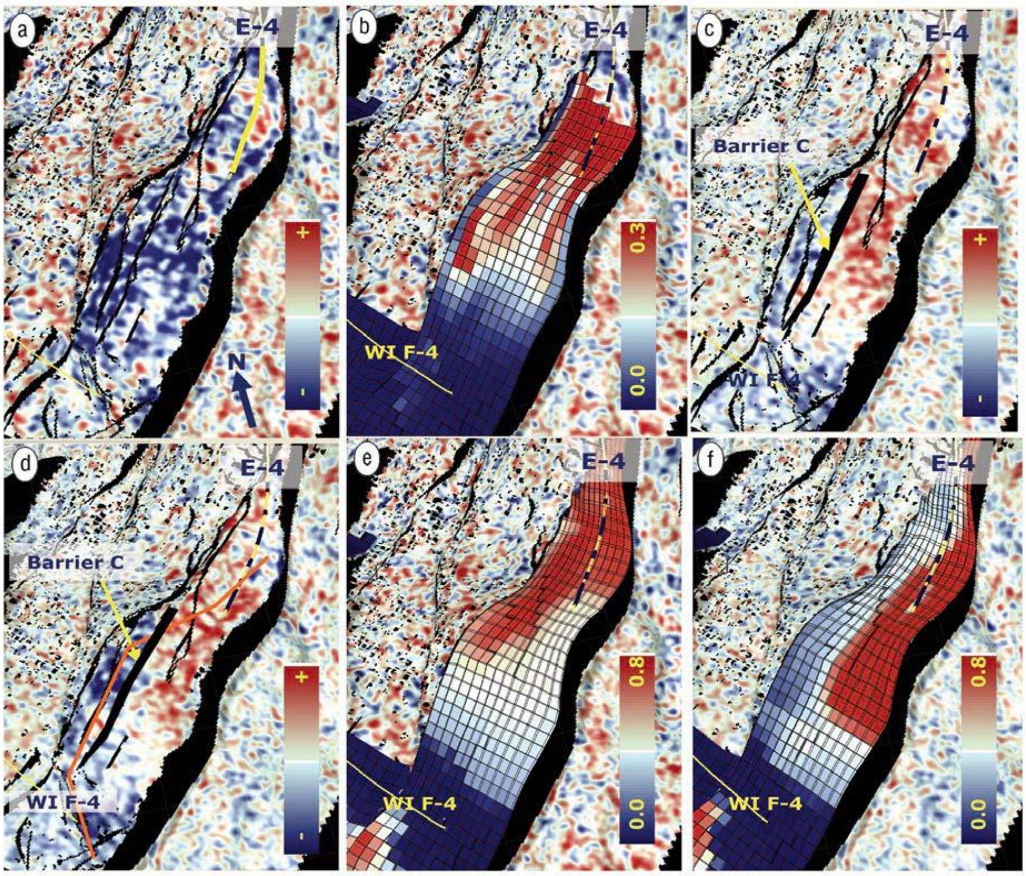


Figure 7.6 (a) Change in acoustic impedance base-2001 from 4D data. Blue is decrease in impedance related to gas out of solution due to pressure drop. (b) Gas saturation in 2001 from new simulation model put on top of the map in (a). (c) Change in acoustic impedance 2001-2003. (d) Change in acoustic impedance 2001-2004. Blue is decrease in impedance related to pressure increase due to water injection. Red is increase in acoustic impedance related to gas going back to the oil phase. (e) Oil saturation in 2004 from old simulation model. (f) Oil saturation from new simulation model (Osdal et al., 2006)

A seismic line through the observed anomalies is shown in Figure 7.7 where the top and base of the reservoir are shown in yellow. It can be seen that the 4D difference data between the Q data has much better quality than between the base and 2001 data. The location of the line is colored orange in Figure 7.6d. Figure 7.7d shows the measurement of the time shift below the reservoir between base and 2001 (red line) and 2001 and 2004 (black line). A clear 2–3 ms time shift is seen from 2001 to 2004 in the area with the strong pressure increase anomaly. A small time shift can be seen in the area with the gas back to oil anomaly. This is in accordance with the rock modelling shown in Figure 7.8. The left plot in Figure 7.8 shows velocity versus pore pressure from core plug measurement. Data recorded from injector F-4 shows pressure around 400–450 bar near the well; pressure in 2001 was approximately 200 bar. According to the left plot in Figure 7.8, this pore pressure increase will create a velocity decrease of 300–400 m/s, which corresponds to a time shift change of 2–3 ms in the 25–30 m reservoir. This time shift was also observed on the 4D seismic data (Figure 7.7d) (Osdal et al., 2006).

To better understand the 4D effect around producer well E-4 and the area east of barrier C, the Gassmann equations can be used to show the effect of gas going back to oil. According to Figure 7.8, the effect of gas going back to oil should be smaller (but opposite) than the effect of the pressure increase from 200 bar to 300 bar. This is not observed on the 4D seismic data in Figure 7.6c and Figure 7.6d. Here the gas back to oil dominates pressure increase. An explanation is that the velocity versus pressure curve can be flatter for pressures less than 300–350 bar, while it can be steep for higher pressures. The break on the curve is most likely related to fracturing of the rock that takes place at higher pressure. The uncertainty of core plug measurements is well known. Based on the 4D seismic observation and rock modelling, a better velocity versus pore-pressure curve is the black dotted curve in the left plot in Figure 7.8 (Osdal et al., 2006).

Figure 7.6e shows the oil saturation from the old simulation model. Here, barrier C is not included, and the water flows directly to the producer and floods the toe of well E-4 first. In Figure 7.6f, barrier C is included in the simulation model. The water will now flow along the western main fault area and flood the heel and mid part of well E-4 first. This new simulation model matches better the 4D seismic data than the old simulation model (Osdal et al., 2006).

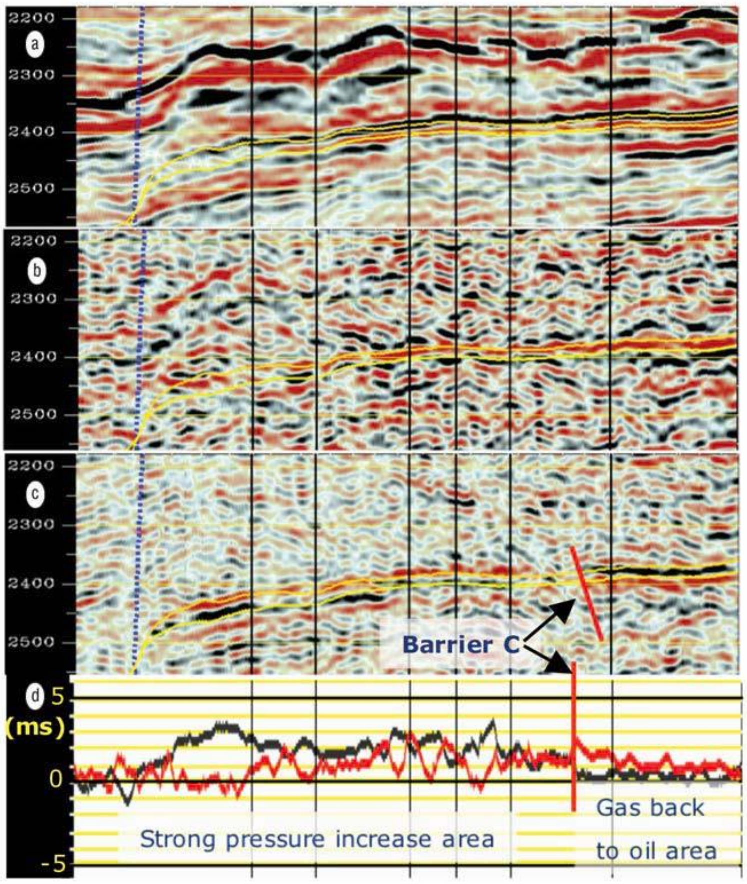


Figure 7.7 (a) 2001 4D data. (b) Base-2001 4D difference data. (c) 2001-2004 4D difference data. (d) Time shift in ms below reservoir for base-2001 (red curve) and 2001-2004 (black curve) (Osdal et al., 2006)

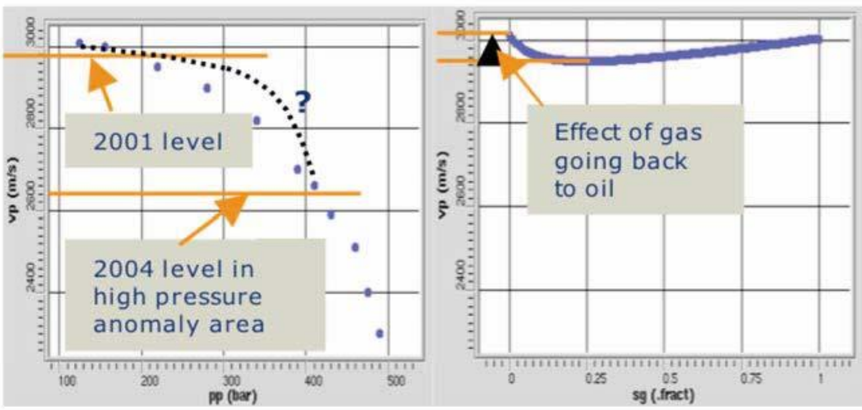


Figure 7.8 (left) P-wave velocity versus pore pressure from laboratory core plug measurement. Blue points are measurements. Black dotted curve is updated based on the 4D observations. (right) P-wave velocity versus gas saturation (Osdal et al., 2006)

CHAPTER 8

8. HISTORY MATCHING THE NORNE FIELD USING 4D SEISMIC DATA

As described earlier in Chapter 3 that Norne field comprises of four segments (C, D, E and G); then in history matching the Norne field using 4D seismic data, segment E was chosen due to its good quality 4D seismic data. Furthermore, the seismic line 1050 (with good quality seismic data) which cut across the E segment, was used. The interpretation of OWC from seismic line 1050 is as shown in Figure 8.1 below.

The Norne full field best matched model (Chapter 6.9) obtained during history matching using production data was taken as the base case for history matching using 4D seismic data.

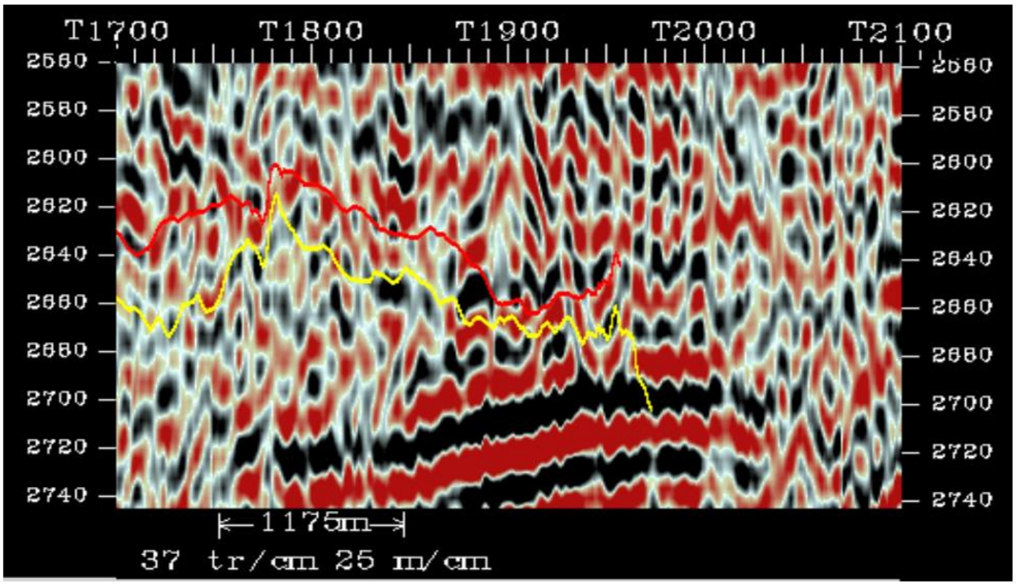


Figure 8.1 Interpreted seismic line 1050. The yellow horizon represents OWC from 2001, the red horizon represents OWC from 2004 (Rwechungura et al., 2012)

8.1 Procedures Followed

The following are the steps followed in history matching the Norne filed using 4D seismic data:

1. The first task was to locate the seismic line 1050 on the simulation model as shown in Figure 8.2 below.
2. The other task was to slice the simulation model across line 1050 and zoom in into segment E (Figure 8.3).

3. Interpretation of the OWC for both seismic data and simulation model was done on the sliced simulation model. Before interpretation, water saturation profile in the simulation model was time played into July 2001 and July 2004 to correspond the dates when the seismic data was acquired.
4. The last task was to adjust uncertain parameter (fault transmissibility and vertical permeability) in order to match the OWC from the simulation and 4D seismic data.

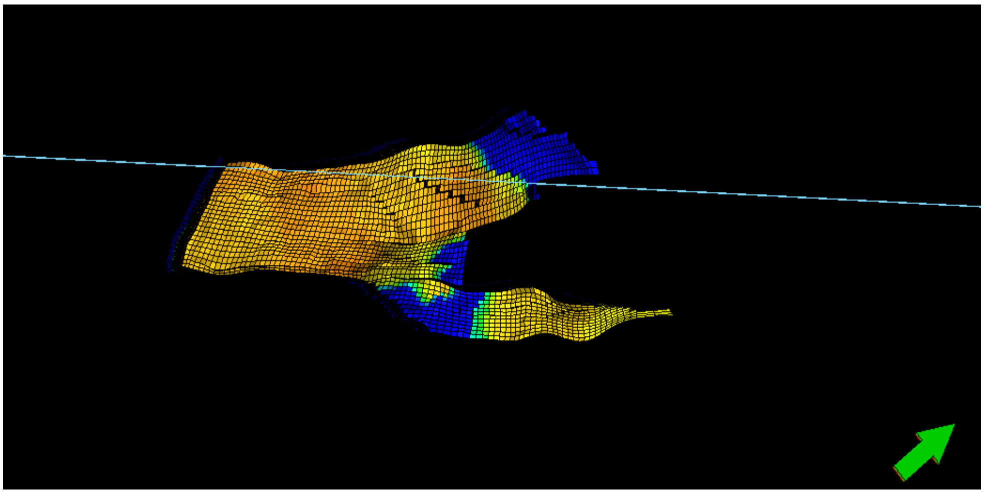


Figure 8.2 Location of seismic line 1050 on the Norne full filed reservoir simulation model

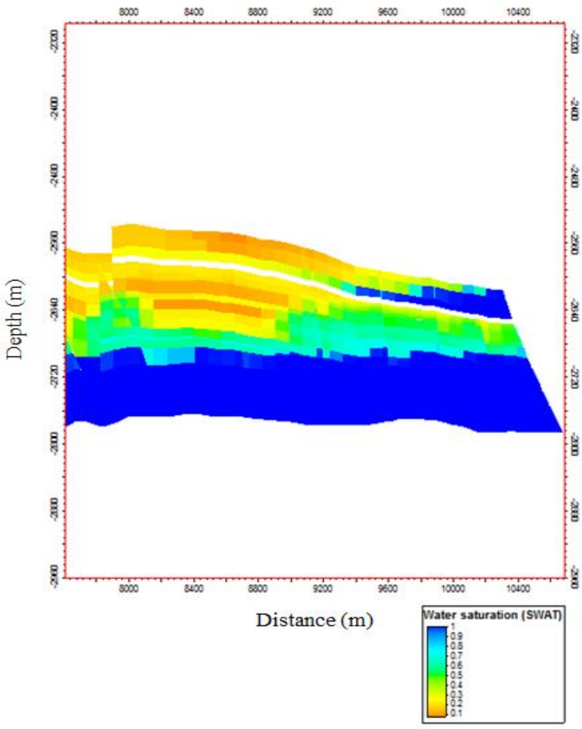


Figure 8.3 Sliced simulation model (in 2001) and zoomed in into E segment. This figure is as seen before interpretation of the OWC

Assumption made during interpretation of OWC on the simulation model

The zone which is dark blue was assumed to be 100% saturated with water. The zone which is light blue was assumed to be a transition zone. The area with green colour was assumed to be oil water contact.

8.2 Base Case Model

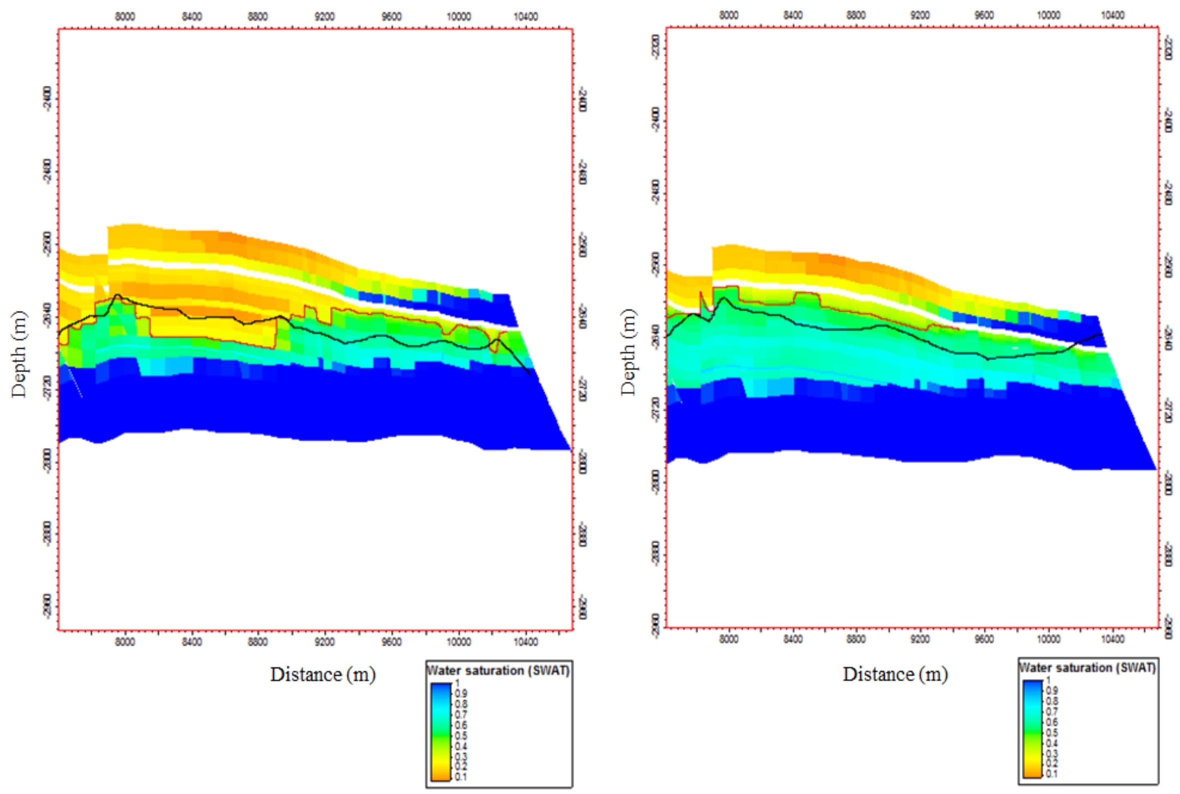


Figure 8.4 Comparison of the OWC for the base case obtained in 2001 (left) and 2004 (right). Where black is the OWC from seismic data, and red is the OWC from the simulation model

From the base case (Figure 8.4) it can be seen that the oil water contact interpreted from simulation model differs significantly from the oil water contact interpreted from 4D seismic data. It was expected that the difference could be slight since the base case model in Figure 8.4 was considered earlier (Chapter 6.9) as best matched model during history matching using production data. However the difference is significant. The difference might be due to the fact that in history matching using production data, the matching was done at field level (field production performance profile) while the 4D seismic data used in (Figure 8.4) is from segment E only. Therefore local adjustment should be performed in segment E in order to minimise the difference observed in Figure 8.4. The parameters that were local adjusted were fault transmissibility multiplier, and vertical permeability since they are among the main parameters that controls oil water contact movement.

8.3 The History Matched Model

Sensitivity analysis was performed to faults found in segment E (i.e. fault E_01, E_01_F3, DE_1, DE_B3, DE_1_LTo, DE_2 and DE_0) by adjustment their fault transmissibility multiplier. It was found that fault E_01 is the one that has significant effect on the oil water contact movement in segment E. Further adjustment to fault E_01 was done whereby it was observed that the best match in oil water contact is obtained if fault E_01 is made tighter (i.e. setting its MULTFLT factor to 0.0008). Furthermore, sensitivity analysis to local adjustment of vertical permeability in segment E was done for all layers whereby it was found that the best match is obtained when vertical permeability of layer 8, 9 and 12 is decreased by factor of 10 and that of layer 11 increased (assigned a value of 0.5) as shown in Appendix 9. Figure 8.5 below shows the history matched case whereby there is good match between oil water contact from simulation model to that from 4D seismic data.

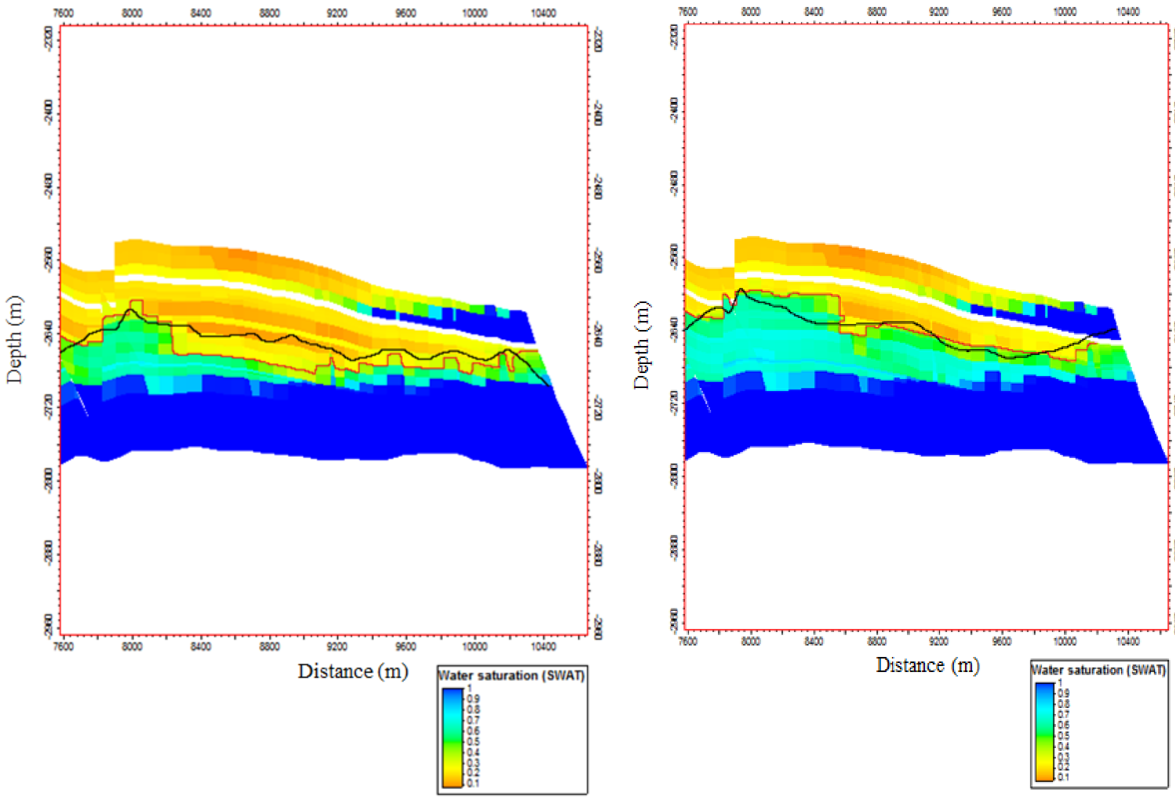


Figure 8.5 Comparison of the OWC for the matched model obtained in 2001 (left) and 2004 (right). Where black is the OWC from seismic data, and red is the OWC from the simulation model

CHAPTER 9

9. CONCLUSIONS AND RECOMMENDATIONS

The motivation to this study was mainly because the base Norne reservoir simulation model showed a significant difference between simulated results and the historical performance. The study was focused on history matching using both production and qualitative 4D seismic data. In history matching using production data; fault transmissibility, vertical transmissibility of the stratigraphic barrier, vertical permeability and horizontal permeability were manually adjusted to improve the Norne full field reservoir simulation model. To history match the Norne field using qualitative 4D seismic data; segment E was chosen because of its good quality 4D seismic data. Whereby fault transmissibility and vertical permeability were local adjusted in segment E to improve the match between oil water contact observed from 4D seismic data to that from simulation model. In accomplishing this study several challenges were faced mainly because of doing the thesis from abroad. Therefore extra effort was put to overcome these challenges and at the end the study has been accomplished with good success.

Based on the results from this study, the Norne reservoir simulation model has been improved after history matching using both production and qualitative 4D seismic data.

Field wide vertical transmissibility multipliers of stratigraphic barrier of layer 1, 15, 18 and 20 were adjusted and results showed that when reducing wide vertical transmissibility of layer 15 from 0.05 to 0.0005 the simulation model is improved. Also local vertical transmissibility multiplier factor of the barriers were adjusted and results showed that the best match is obtained when local vertical transmissibility of layer 8 is increased by factor of 10 and reducing the local vertical transmissibility of layer 15 and RFT D_-H by factor of 10.

Fault transmissibility multiplier factor of the faults in the Norne reservoir simulation model were adjusted and results showed that the best match is obtained if transmissibility of fault CD_B3 is reduced by factor of 10, transmissibility of fault E_01 increased from 0.01 to 0.02, transmissibility of fault C_01, C_02, C_10, D_05 and G_07 is increased by factor of 10.

Vertical permeability multiplier values for all 22 layers were adjusted and results showed that the best match is obtained if vertical permeability of layer 8 is increased from 0.13 to 0.43, that of layer 9 increased from 0.09 to 0.4, that of layer 12 increased from 0.13 to 0.53, that of layer 14 increased from 0.64 to 0.84, that of layer 10 reduced from 0.07 to 0.01, that of layer 19 reduced from 0.004 to 0.0001 and that of layer 20 reduced from 0.004 to 0.0001.

Horizontal permeability multiplier factor for all 22 layers were adjusted and results showed that the best match is obtained when horizontal permeability of layer 5 is increased by factor of 40, that of layer 6, 7 and 8 increased by factor of 30, while that of layer 18 reduced by factor of 0.1 and that of layer 20 reduced by factor of 0.5.

The final best matched (improved) model in history matching using production data is obtained when combining the adjustment of vertical transmissibility of the stratigraphic barrier, fault transmissibility multiplier and horizontal permeability.

Results from history matching the Norne field (segment E) using qualitative 4D seismic data showed that the oil water contact from simulation model is matched to oil water contact from 4D seismic data if fault transmissibility multiplier of fault E_01 is decreased (set to 0.0008), local vertical permeability of layer 8, 9 and 12 decreased by factor of 10, and local vertical permeability of layer 11 increased (set to 0.5)

To obtain a very best matched Norne field simulation model, it is recommended to carry out further study on history matching using qualitative 4D seismic data for the other segments in Norne field with good quality seismic data. Also, it is recommended that history matching using quantitative 4D seismic data (quantitative saturation and pressure change) be performed.

Furthermore, after obtaining the best matched model from history matching using 4D seismic data; it is recommended to perform history matching using production data at a well level.

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APPENDICES

Appendix 1: Local MULTZ values of the field wide stratigraphic barrier as used in Norne base case reservoir simulation model of 2004

```
-- Layer 8
EQUALS
  'MULTZ'  0.02    6 13 30 50  8  8 /
/
-- layer 10
EQUALS
  'MULTZ'   0.005  6  14  11  18  10  10  /  C-3H
  'MULTZ'   0.03  14  29  11  25  10  10  /  C south east
  'MULTZ'   0.05  14  25  26  30  10  10  /  C-segm mid/B-2H
  'MULTZ'   0.25   6  29  11  37  10  10  /  C-segm middle
  'MULTZ'   0.5   17  17  42  54  10  10  /  C north west
  'MULTZ'   0.5    6  12  38  39  10  10  /  C north west
  'MULTZ'   0.5    8  12  40  40  10  10  /  C north west
  'MULTZ'   0.5   10  12  41  43  10  10  /  C north west
  'MULTZ'   0.5   18  33  38  54  10  10  /  C1, D4 & D3
  'MULTZ'   0.5    6  13  44  52  10  10  /  B-4AH
  'MULTZ'   0.01  13  13  48  59  10  10  /  D-segm mid (B-4BH)
  'MULTZ'   0.01  14  14  49  59  10  10  /  D-segm mid (B-4BH)
  'MULTZ'   0.01  15  16  51  59  10  10  /  D-segm mid (B-4BH)
  'MULTZ'   0.05  17  19  55  99  10  10  /  E1
  'MULTZ'   0.05  14  14  60  62  10  10  /  E1
  'MULTZ'   0.05  15  15  60  65  10  10  /  E1
  'MULTZ'   0.05  16  16  60  69  10  10  /  E1
  'MULTZ'   0.005  6   9  52  60  10  10  /  F-3H/E-2H
  'MULTZ'   0.005  9   9  53  57  10  10  /  F-3H/E-2H
  'MULTZ'   0.005 10  10  54  58  10  10  /  F-3H/E-2H
  'MULTZ'   0.005 11  11  55  58  10  10  /  F-3H/E-2H
/

-- layer 15
EQUALS
  'MULTZ'   0.00003     6 29 11 21 15 15 / C south
  'MULTZ'   0.00005   6  29  22  39  15  15 /  C middle
  'MULTZ'   0.000001 19  29  39  49  15  15 /  C-1H
  'MULTZ'   1.0      19  29  38  45  17  17 /  C-1H
  'MULTZ'   0.005    16  19  48  61  15  15 /  E-1H/D-3H
```

```
  'MULTZ'   0.0008    8  18  40  40  15  15 /  C north
  'MULTZ'   0.0008    9  18  41  41  15  15 /
  'MULTZ'   0.0008   10  18  42  43  15  15 /
  'MULTZ'   0.0008   11  18  44  44  15  15 /
  'MULTZ'   0.0008   12  18  45  45  15  15 /
  'MULTZ'   0.0008   13  18  46  47  15  15 /
  'MULTZ'   0.0008   14  15  48  48  15  15 /
  'MULTZ'   0.0008   15  15  49  50  15  15 /

  'MULTZ'   0.01      12 12 46 56 15 15 / D-segm
  'MULTZ'   0.01      13 13 48 59 15 15 / D-segm
  'MULTZ'   0.01      14 14 49 62 15 15 / D-segm
  'MULTZ'   0.01      15 15 51 65 15 15 / D-segm
  'MULTZ'   0.01      16 19 62 69 15 15 / D-segm
  'MULTZ'   0.01      17 19 70 99 15 15 / D-segm
   MULTZ    0.0035     6  7 40 60 15 15 / D, E west
   MULTZ    0.0035     8  8 41 60 15 15 /
   MULTZ    0.0035     9  9 42 52 15 15 /
   MULTZ    0.0035    10 10 44 49 15 15 /
/

-- D-1H water
EQUALS
  'MULTZ'    1.0  22  24  21  22  11  11 /
  'MULTZ'    0.1  21  25  17  19  15  15 /
  'MULTZ'    1.0  22  24  17  19  17  17 /
  'MULTZ'    1.0  22  24  15  17  18  18 /
/

-- B-1 & B-3 water
EQUALS
  'MULTZ'    0.1 12  13  34  35  15  15 /
/

-- RFT D_-H
EQUALS
  'MULTZ'  0.1     16 19 47 53 18 18 /  D-3H
/
```

Appendix 2: Adjusted local MULTZ values of the field wide stratigraphic barrier

```
-- Layer 8
EQUALS
   'MULTZ'  0.2    6 13 30 50  8  8 /
/

-- layer 10
EQUALS
  'MULTZ'   0.005  6  14  11  18  10  10  /  C-3H
  'MULTZ'   0.03  14  29  11  25  10  10  /  C south east
  'MULTZ'   0.05  14  25  26  30  10  10  /  C-segm mid/B-2H
  'MULTZ'   0.25   6  29  11  37  10  10  /  C-segm middle
  'MULTZ'   0.5   17  17  42  54  10  10  /  C north west
  'MULTZ'   0.5    6  12  38  39  10  10  /  C north west
  'MULTZ'   0.5    8  12  40  40  10  10  /  C north west
  'MULTZ'   0.5   10  12  41  43  10  10  /  C north west
  'MULTZ'   0.5   18  33  38  54  10  10  /  C1, D4 & D3
  'MULTZ'   0.5    6  13  44  52  10  10  /  B-4AH
  'MULTZ'   0.01  13  13  48  59  10  10  /  D-segm mid (B-4BH)
  'MULTZ'   0.01  14  14  49  59  10  10  /  D-segm mid (B-4BH)
  'MULTZ'   0.01  15  16  51  59  10  10  /  D-segm mid (B-4BH)
  'MULTZ'   0.05  17  19  55  99  10  10  /  E1
  'MULTZ'   0.05  14  14  60  62  10  10  /  E1
  'MULTZ'   0.05  15  15  60  65  10  10  /  E1
  'MULTZ'   0.05  16  16  60  69  10  10  /  E1
  'MULTZ'   0.005  6   9  52  60  10  10  /  F-3H/E-2H
  'MULTZ'   0.005  9   9  53  57  10  10  /  F-3H/E-2H
  'MULTZ'   0.005 10  10  54  58  10  10  /  F-3H/E-2H
  'MULTZ'   0.005 11  11  55  58  10  10  /  F-3H/E-2H
/

-- layer 15
EQUALS
  'MULTZ'   0.000003     6 29 11 21 15 15 / C south
  'MULTZ'   0.000005   6  29  22  39  15  15 /  C middle
  'MULTZ'   0.0000001 19  29  39  49  15  15 /  C-1H
  'MULTZ'   1.0      19  29  38  45  17  17 /  C-1H
  'MULTZ'   0.0005    16  19  48  61  15  15 /  E-1H/D-3H
  'MULTZ'   0.00008    8  18  40  40  15  15 /  C north
  'MULTZ'   0.00008    9  18  41  41  15  15 /
  'MULTZ'   0.00008   10  18  42  43  15  15 /
```

```
  'MULTZ'   0.00008   11  18  44  44  15  15 /
  'MULTZ'   0.00008   12  18  45  45  15  15 /
  'MULTZ'   0.00008   13  18  46  47  15  15 /
  'MULTZ'   0.00008   14  15  48  48  15  15 /
  'MULTZ'   0.00008   15  15  49  50  15  15 /

  'MULTZ'   0.001      12 12 46 56 15 15 / D-segm
  'MULTZ'   0.001      13 13 48 59 15 15 / D-segm
  'MULTZ'   0.001      14 14 49 62 15 15 / D-segm
  'MULTZ'   0.001      15 15 51 65 15 15 / D-segm
  'MULTZ'   0.001      16 19 62 69 15 15 / D-segm
  'MULTZ'   0.001      17 19 70 99 15 15 / D-segm
   MULTZ    0.00035      6  7 40 60 15 15 / D, E west
   MULTZ    0.00035      8  8 41 60 15 15 /
   MULTZ    0.00035      9  9 42 52 15 15 /
   MULTZ    0.00035     10 10 44 49 15 15 /
/

-- D-1H water
EQUALS
  'MULTZ'    1.0  22  24  21  22  11  11 /
  'MULTZ'    0.1  21  25  17  19  15  15 /
  'MULTZ'    1.0  22  24  17  19  17  17 /
  'MULTZ'    1.0  22  24  15  17  18  18 /
/

-- B-1 & B-3 water
EQUALS
  'MULTZ'    0.1 12  13  34  35  15  15 /
/

-- RFT D_-H
EQUALS
  'MULTZ'  0.01     16 19 47 53 18 18 /  D-3H
/
```

Appendix 3: Vertical permeability as used in Norne base case reservoir simulation model of 2004

```
-- based on same kv/kh factor
MULTIPLY
  'PERMZ' 0.2     1 46 1 112  1  1 /    Garn 3
  'PERMZ' 0.04   1 46 1 112  2  2 /    Garn 2
  'PERMZ' 0.25   1 46 1 112  3  3 /    Garn 1
  'PERMZ' 0.0     1 46 1 112  4  4 /    Not      (inactive anyway)
  'PERMZ' 0.13   1 46 1 112  5  5 /    Ile 2.2
  'PERMZ' 0.13   1 46 1 112  6  6 /    Ile 2.1.3
  'PERMZ' 0.13   1 46 1 112  7  7 /    Ile 2.1.2
  'PERMZ' 0.13   1 46 1 112  8  8 /    Ile 2.1.1
  'PERMZ' 0.09   1 46 1 112  9  9 /    Ile 1.3
  'PERMZ' 0.07   1 46 1 112 10 10 /    Ile 1.2
  'PERMZ' 0.19   1 46 1 112 11 11 /    Ile 1.1
  'PERMZ' 0.13    1 46 1 112 12 12 /    Tofte 2.2
  'PERMZ' 0.64    1 46 1 112 13 13 / Tofte 2.1.3
  'PERMZ' 0.64    1 46 1 112 14 14 / Tofte 2.1.2
  'PERMZ' 0.64    1 46 1 112 15 15 / Tofte 2.1.1
  'PERMZ' 0.64    1 46 1 112 16 16 / Tofte 1.2.2
  'PERMZ' 0.64    1 46 1 112 17 17 / Tofte 1.2.1
  'PERMZ' 0.016  1 46 1 112 18 18 / Tofte 1.1
  'PERMZ' 0.004  1 46 1 112 19 19 / Tilje 4
  'PERMZ' 0.004  1 46 1 112 20 20 / Tilje 3
  'PERMZ' 1.0      1 46 1 112 21 21 / Tilje 2
  'PERMZ' 1.0      1 46 1 112 22 22 / Tilje 1
/
```

Appendix 4: Modified vertical permeability

```
-- based on same kv/kh factor
MULTIPLY
  'PERMZ' 0.2       1 46 1 112  1  1 /    Garn 3
  'PERMZ' 0.04     1 46 1 112  2  2 /    Garn 2
  'PERMZ' 0.25     1 46 1 112  3  3 /    Garn 1
  'PERMZ' 0.0       1 46 1 112  4  4 /    Not    (inactive anyway)
  'PERMZ' 0.13     1 46 1 112  5  5 /    Ile 2.2
  'PERMZ' 0.13     1 46 1 112  6  6 /    Ile 2.1.3
  'PERMZ' 0.13     1 46 1 112  7  7 /    Ile 2.1.2
  'PERMZ' 0.43     1 46 1 112  8  8 /    Ile 2.1.1
  'PERMZ' 0.40     1 46 1 112  9  9 /    Ile 1.3
```

```
  'PERMZ' 0.01     1 46 1 112 10 10 /    Ile 1.2
  'PERMZ' 0.19     1 46 1 112 11 11 /    Ile 1.1
  'PERMZ' 0.53     1 46 1 112 12 12 /    Tofte 2.2
  'PERMZ' 0.64     1 46 1 112 13 13 /Tofte 2.1.3
  'PERMZ' 0.84     1 46 1 112 14 14 /Tofte 2.1.2
  'PERMZ' 0.64     1 46 1 112 15 15 /Tofte 2.1.1
  'PERMZ' 0.64     1 46 1 112 16 16 /Tofte 1.2.2
  'PERMZ' 0.64     1 46 1 112 17 17 /Tofte 1.2.1
  'PERMZ' 0.016   1 46 1 112 18 18 /Tofte 1.1
  'PERMZ' 0.0001 1 46 1 112 19 19 /Tilje 4
  'PERMZ' 0.0001 1 46 1 112 20 20 /Tilje 3
  'PERMZ' 1.0       1 46 1 112 21 21 /Tilje 2
  'PERMZ' 1.0       1 46 1 112 22 22 /Tilje 1
/
```

Appendix 5: Modified horizontal permeability multiplier factor

```
-- Horizontal Permeability multiplier factor
MULTIPLY
  'PERMX' 1.0    1 46 1 112  1  1 /    Garn 3
  'PERMX' 1.0    1 46 1 112  2  2 /    Garn 2
  'PERMX' 1.0    1 46 1 112  3  3 /    Garn 1
  'PERMX' 1.0    1 46 1 112  4  4 /    Not       (inactive anyway)
  'PERMX' 40.0  1 46 1 112  5  5 /    Ile 2.2
  'PERMX' 30.0  1 46 1 112  6  6 /    Ile 2.1.3
  'PERMX' 30.0  1 46 1 112  7  7 /    Ile 2.1.2
  'PERMX' 30.0  1 46 1 112  8  8 /    Ile 2.1.1
  'PERMX' 1.0    1 46 1 112  9  9 /    Ile 1.3
  'PERMX' 1.0    1 46 1 112 10 10 /    Ile 1.2
  'PERMX' 1.0    1 46 1 112 11 11 /    Ile 1.1
  'PERMX' 1.0    1 46 1 112 12 12 /    Tofte 2.2
  'PERMX' 1.0    1 46 1 112 13 13 /   Tofte 2.1.3
  'PERMX' 1.0    1 46 1 112 14 14 /   Tofte 2.1.2
  'PERMX' 1.0    1 46 1 112 15 15 /   Tofte 2.1.1
  'PERMX' 1.0    1 46 1 112 16 16 /   Tofte 1.2.2
  'PERMX' 1.0    1 46 1 112 17 17 /   Tofte 1.2.1
  'PERMX' 0.1    1 46 1 112 18 18 /   Tofte 1.1
  'PERMX' 1.0    1 46 1 112 19 19 /   Tilje 4
  'PERMX' 0.5    1 46 1 112 20 20 /   Tilje 3
  'PERMX' 1.0    1 46 1 112 21 21 /   Tilje 2
  'PERMX' 1.0    1 46 1 112 22 22 /   Tilje 1
/
```

Appendix 6: Comparing results from combining adjustment of PERMX and MULTFLT versus combining adjustment of PERMX, MULTFLT and MULTZ

Combining adjustment of PERMX and MULTFLT (Case 45) gives a matched model which is almost similar to combining adjustment of PERMX, MULTFLT and MULTZ (case 47). Therefore it is important to compare them to find the best one.

By comparing the field water cut (Figure A.1) it can be seen that in year 2001 and year 2006, case 47 has better match than case 45. Looking on year 2004 and year 2005, it can be seen that case 45 has better match than case 47.

Considering field oil production rate (Figure A.3) and field oil production total (Figure A.4), it can be seen that from year 2000 to 2003 case 47 has better match than case 45. Whereas from year 2004 to 2006; case 45 has better match than case 47.

Looking on the field gas oil ratio (Figure A.5) it can be seen that with exception to year 2005, the rest of the other years case 47 has better match than case 45.

Therefore based on these comparisons, Case 47 (combining adjustment of PERMX, MULTFLT and MULTZ) has better match than Case 45 (combining adjustment of PERMX and MULTFLT)

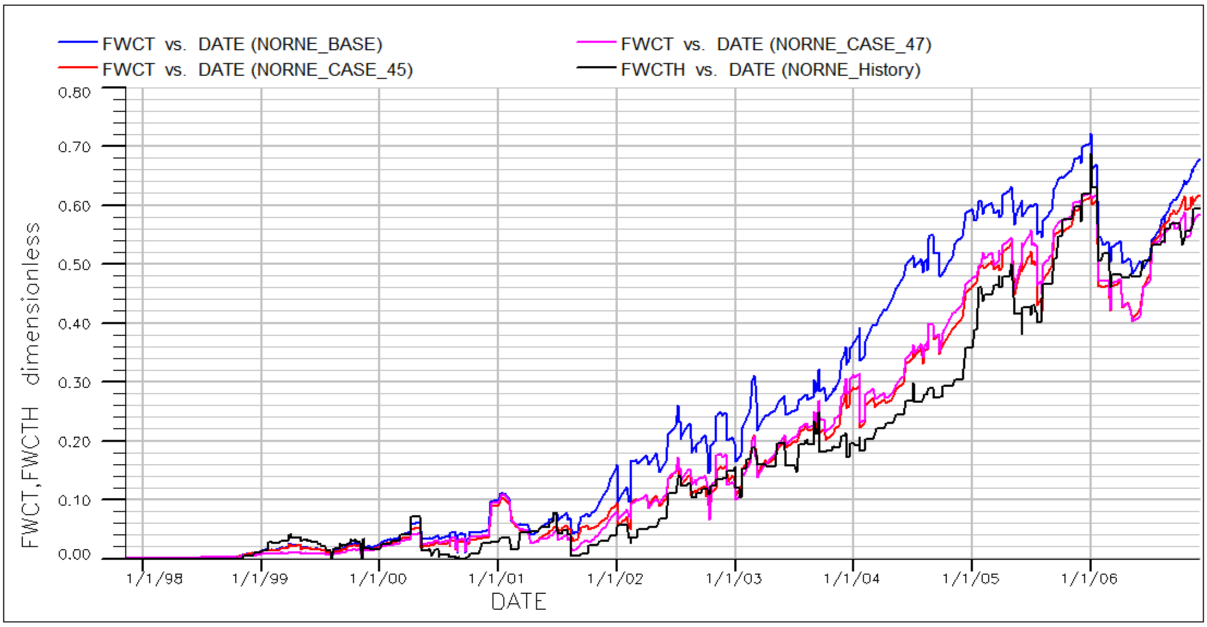

Figure A.1 Field water cut where blue is the base case, black is the history, red is case 45 (Combining adjustment of PERMX and MULTFLT) and purple is case 47 (Combining adjustment of PERMX, MULTFLT and MULTZ

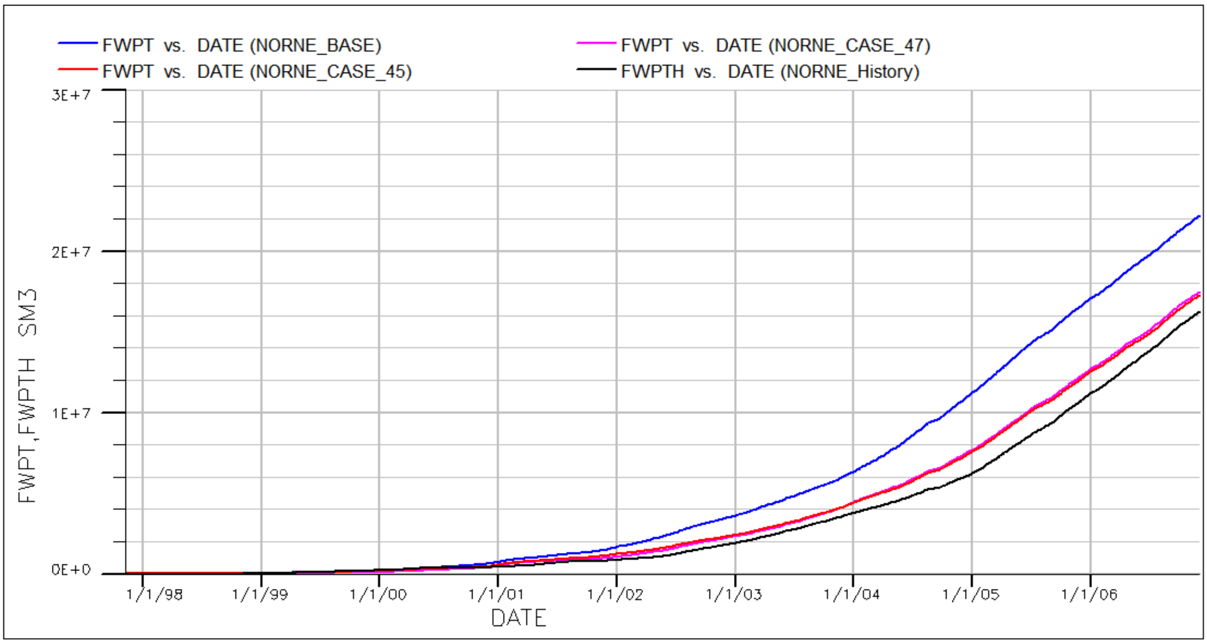

Figure A.2 Field water production total where blue is the base case, black is the history, red is case 45 (Combining adjustment of PERMX and MULTFLT) and purple is case 47 (Combining adjustment of PERMX, MULTFLT and MULTZ

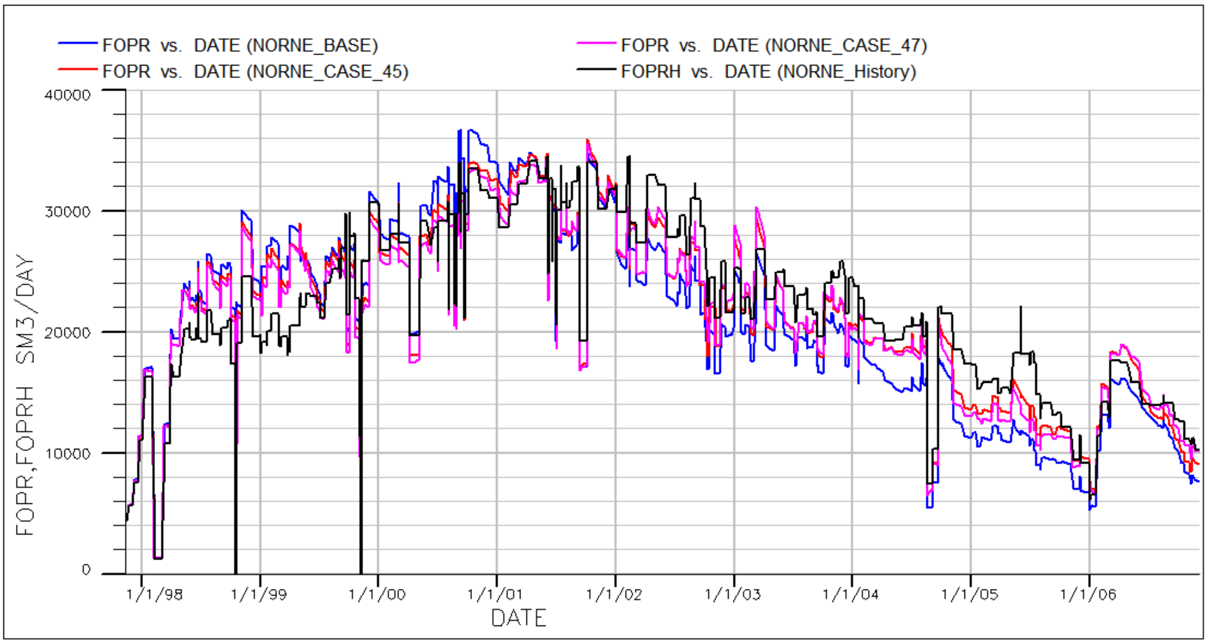

Figure A.3 Field oil production rate where blue is the base case, black is the history, red is case 45 (Combining adjustment of PERMX and MULTFLT) and purple is case 47 (Combining adjustment of PERMX, MULTFLT and MULTZ

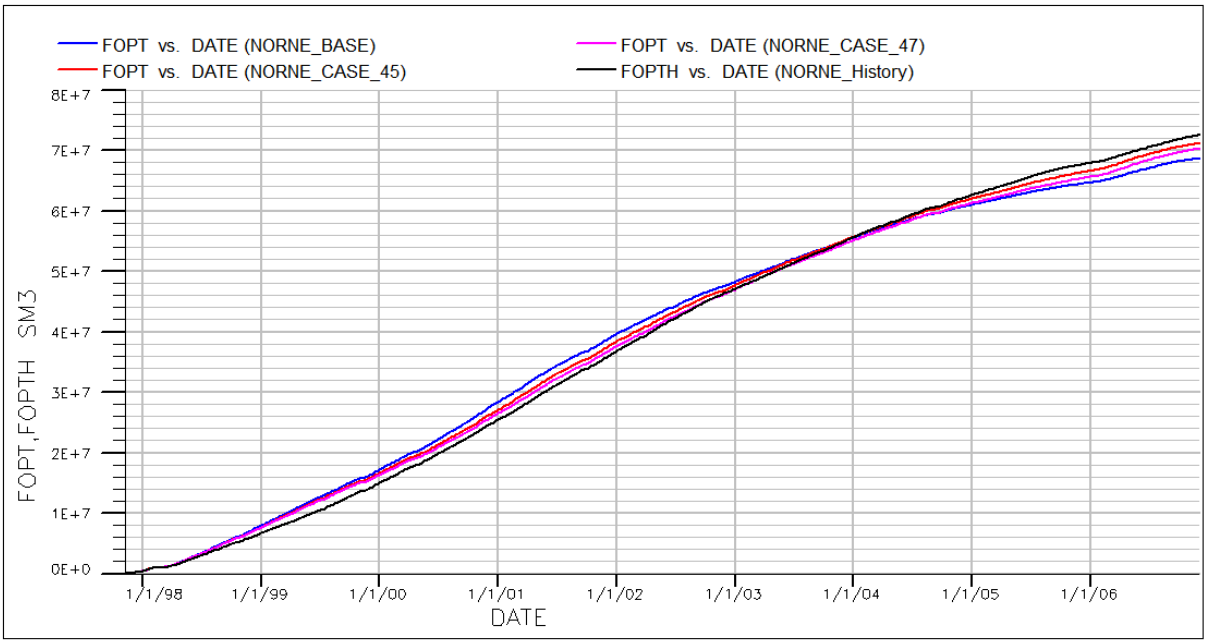

Figure A.4 Field oil production total where blue is the base case, black is the history, red is case 45 (Combining adjustment of PERMX and MULTFLT) and purple is case 47 (Combining adjustment of PERMX, MULTFLT and MULTZ

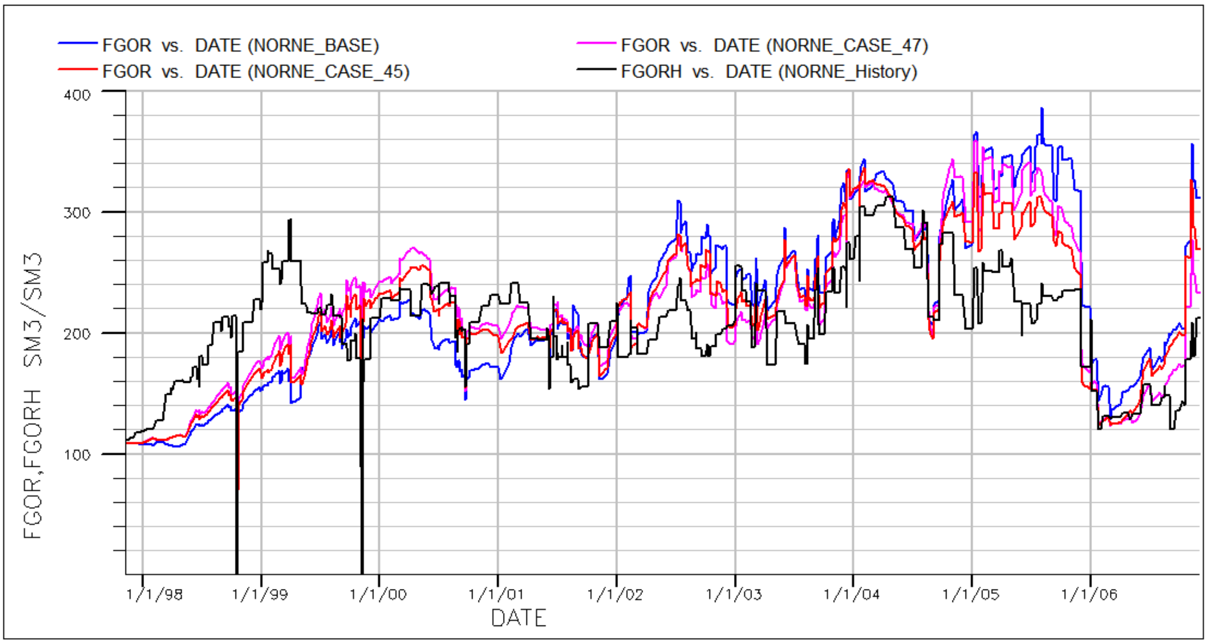

Figure A.5 Field gas oil ratio where blue is the base case, black is the history, red is case 45 (Combining adjustment of PERMX and MULTFLT) and purple is case 47 (Combining adjustment of PERMX, MULTFLT and MULTZ

Appendix 7: Finding the percentage of improvement in the match

This study is purely manual based history matching, therefore decision on the match has also been done manually i.e by visual analysis of the reservoirs production performance plot. In addition to the visual analysis, a simple calculation was used to decide the percentage in the improvement of the matched model. The calculation is based on the following steps

1. Choose a date to record the readings (e.g. water cut values)
2. Record the base case, history and matched model values
3. Calculate the difference between the history and the base case (Let the difference be D_1)
4. Calculate the difference between the history and the matched model (Let the difference be D_2)
5. Calculate $X = (D_2/D_1) \times 100\%$
6. Percentage improvement = 100 - X

Appendix 8: Other results

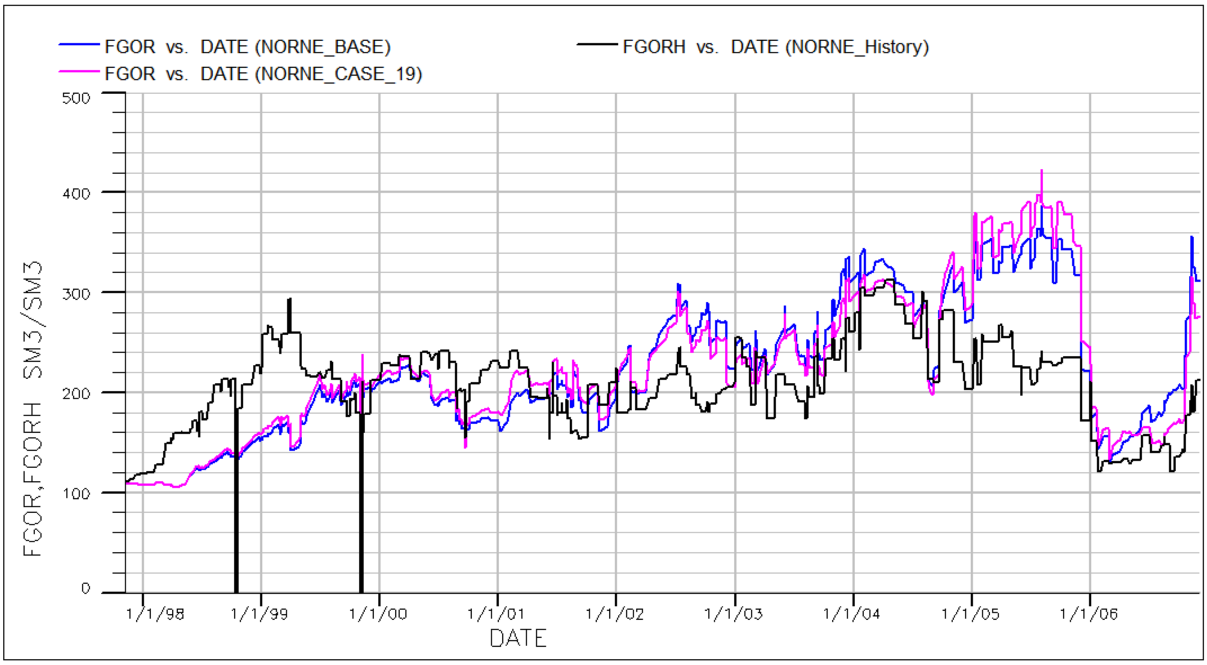

Figure A.6 Field gas oil ratio where blue is the base case, black is the history and purple is case 19 (adjusting MULTZ of the stratigraphic barrier)

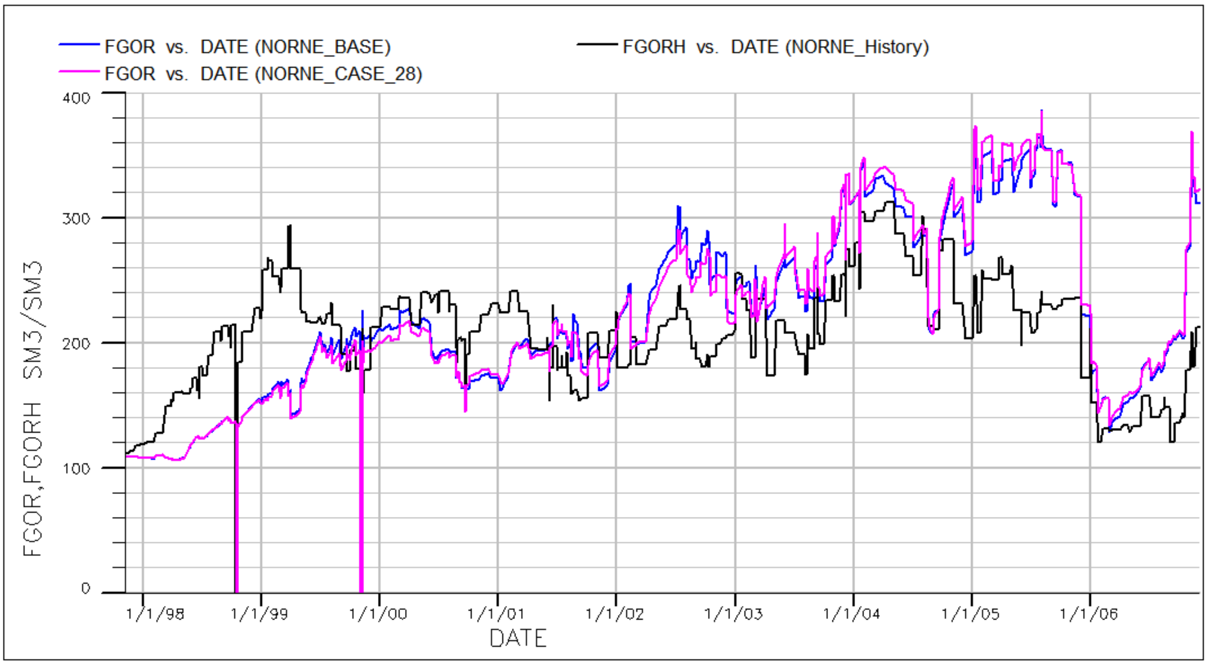

Figure A.7 Field gas oil ratio where blue is the base case, black is the history and purple is case 28 (adjusting MULTFLT)

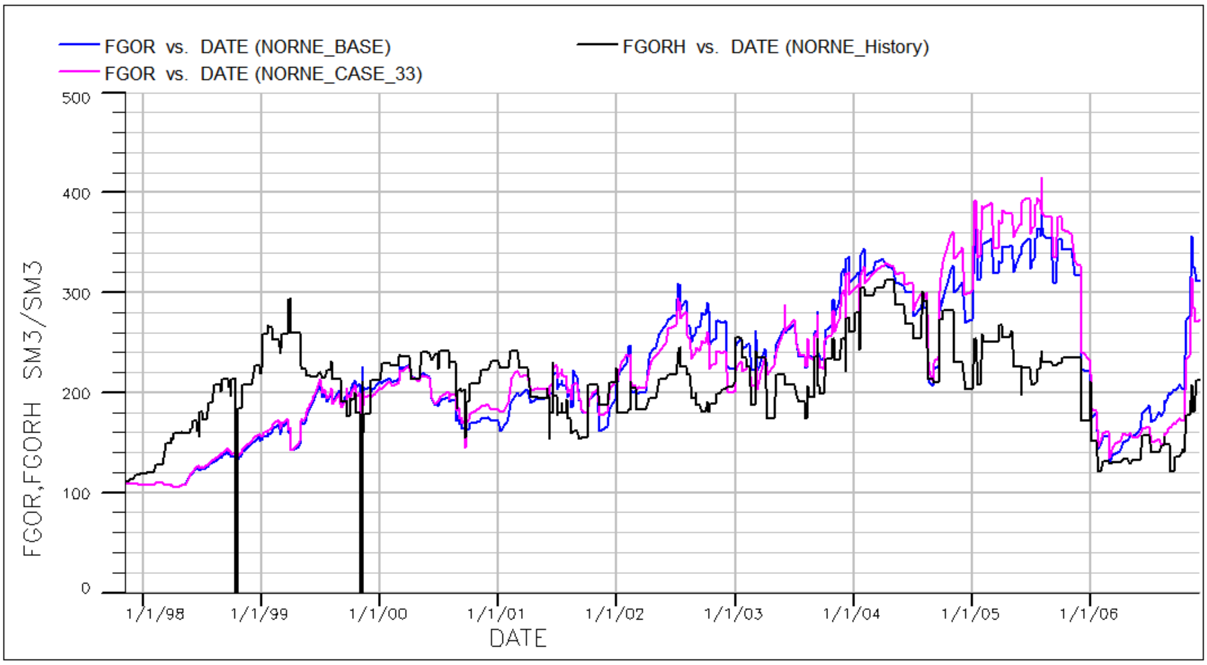

Figure A.8 Field gas oil ratio where blue is the base case, black is the history and purple is case 33 (combining adjustment of MULTZ and MULTFLT)

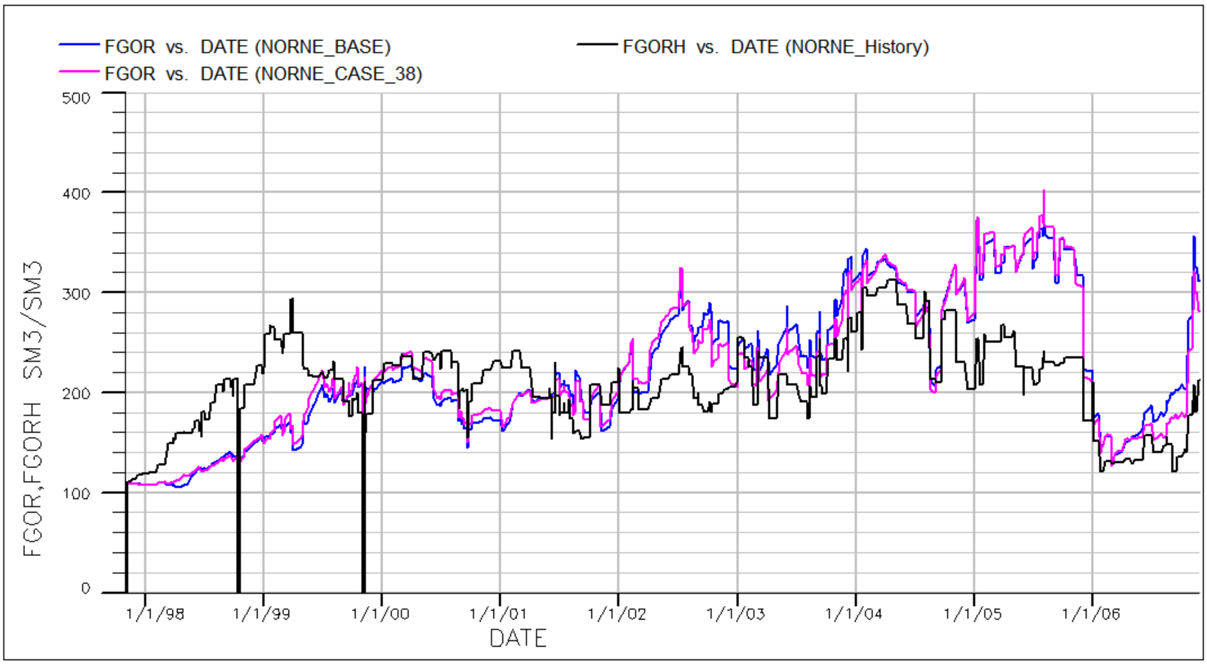

Figure A.9 Field gas oil ratio where blue is the base case, black is the history and purple is case 38 (adjusting PERMZ)

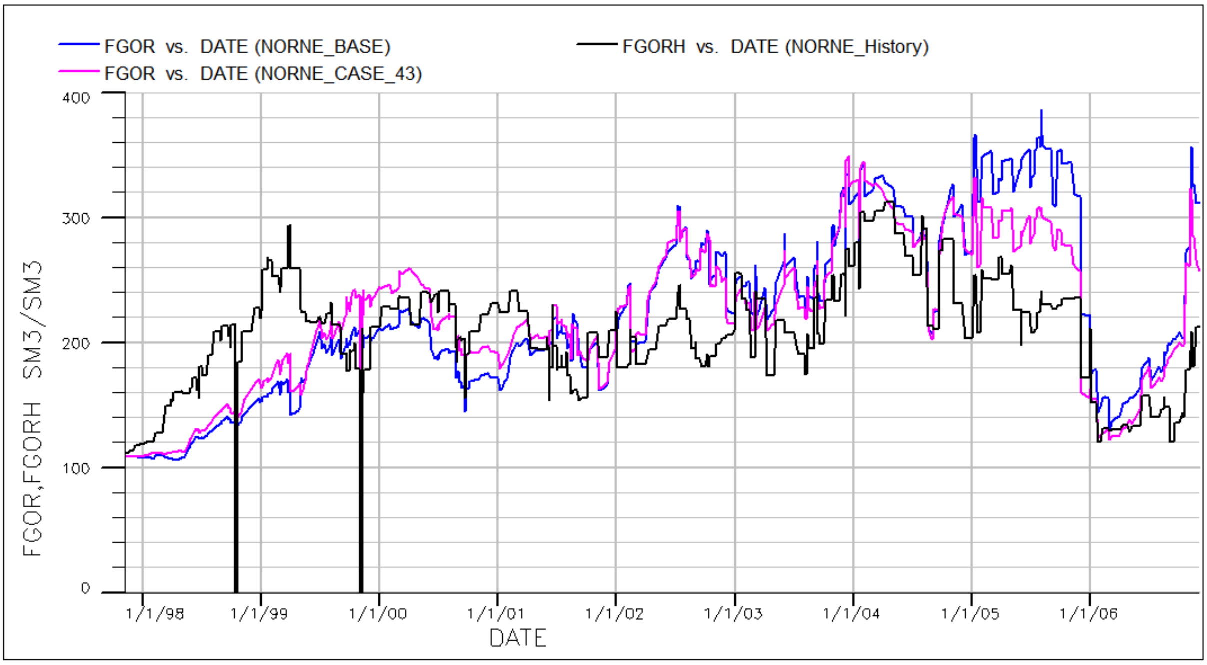

Figure A.10 Field gas oil ratio where blue is the base case, black is the history and purple is case 43 (adjusting PERMX)

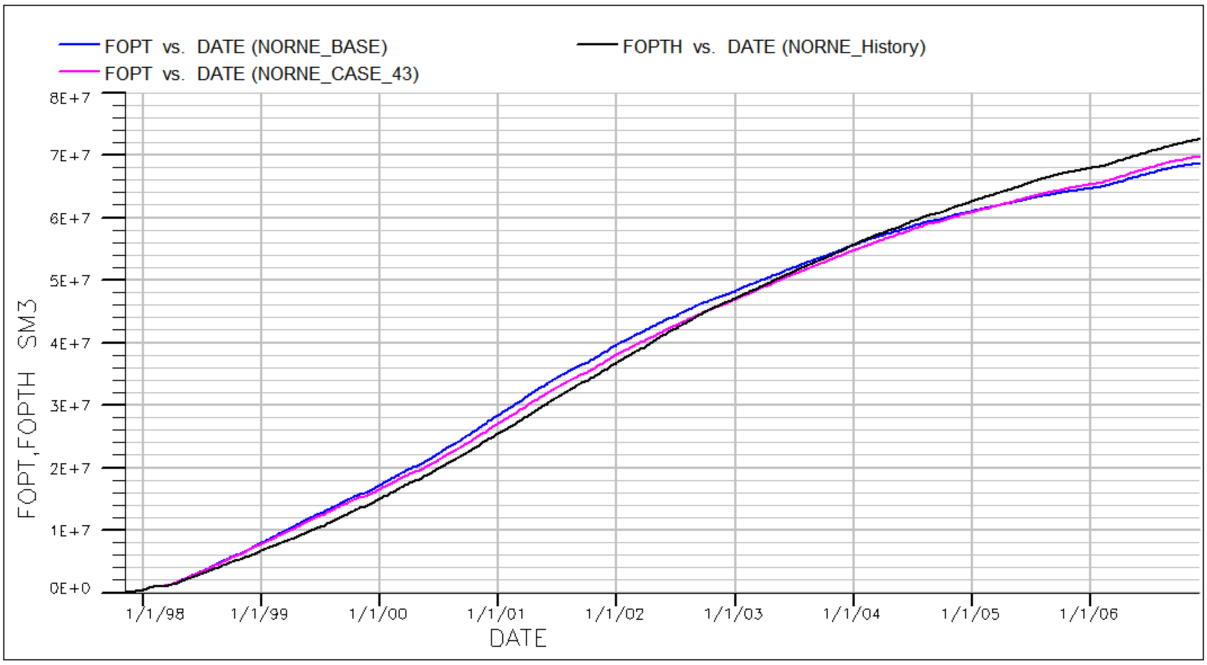

Figure A.11 Field oil production total where blue is the base case, black is the history and purple is case 43 (adjusting PERMX)

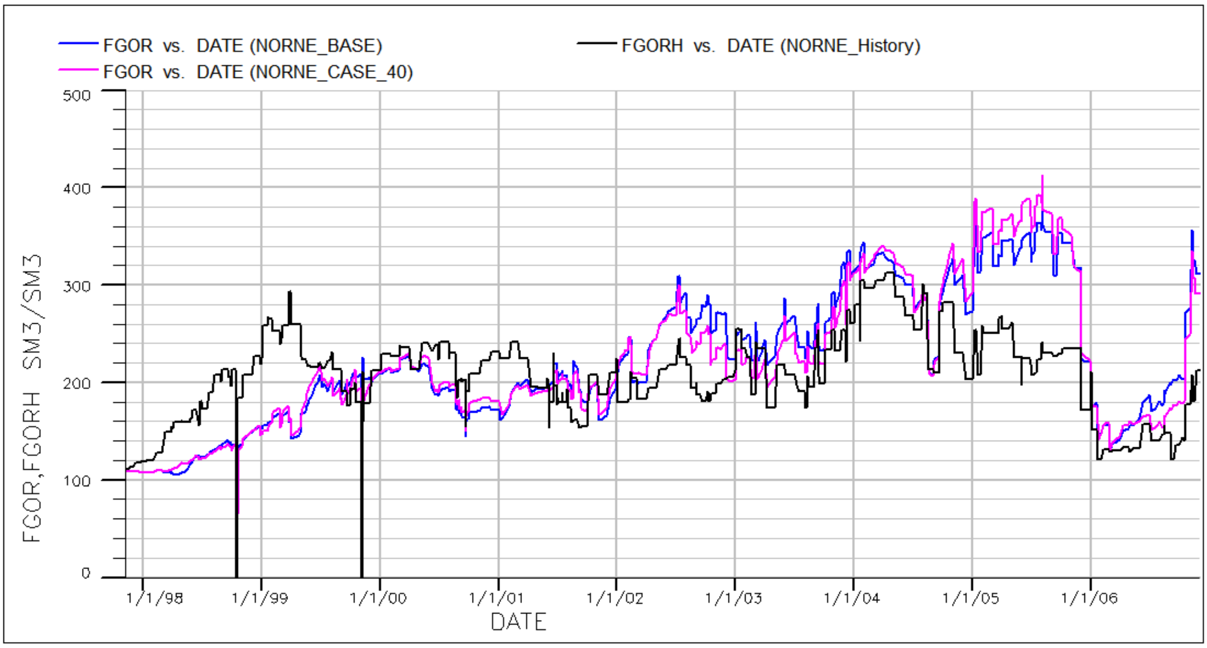

Figure A.12 Field gas oil ratio where blue is the base case, black is the history and purple is case 40 (combining adjustment of PERMZ and MULTFLT)

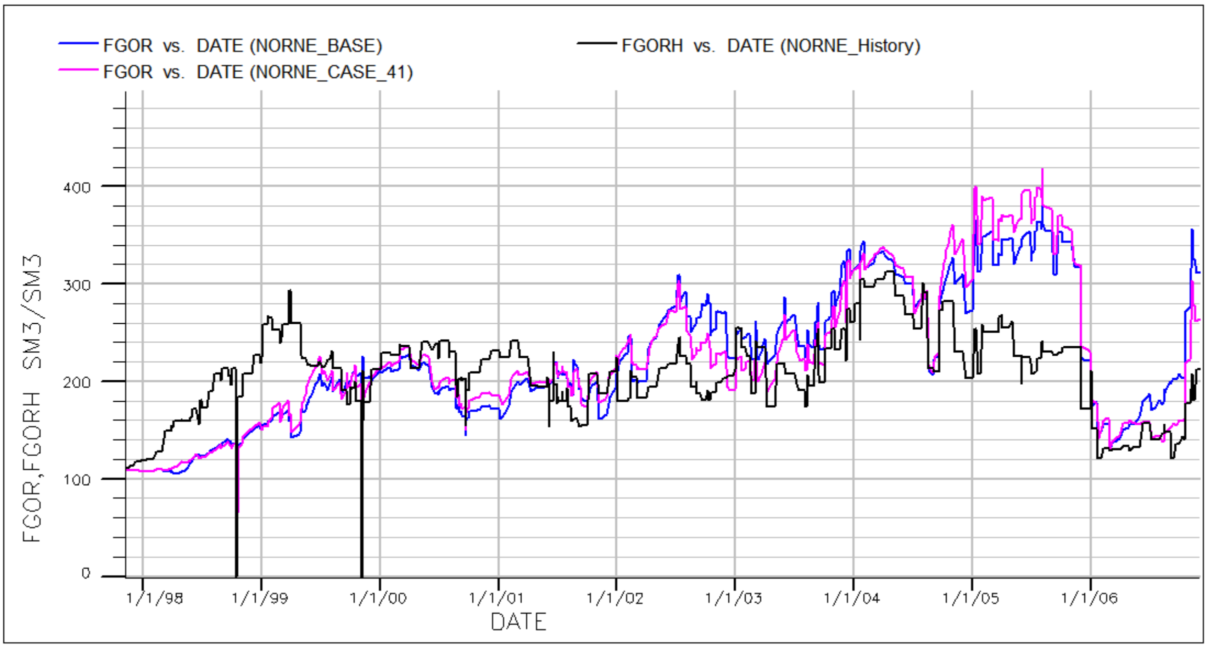

Figure A.13 Field gas oil ratio where blue is the base case, black is the history and purple is case 41 (combining adjustment of PERMZ, MULTZ and MULTFLT)

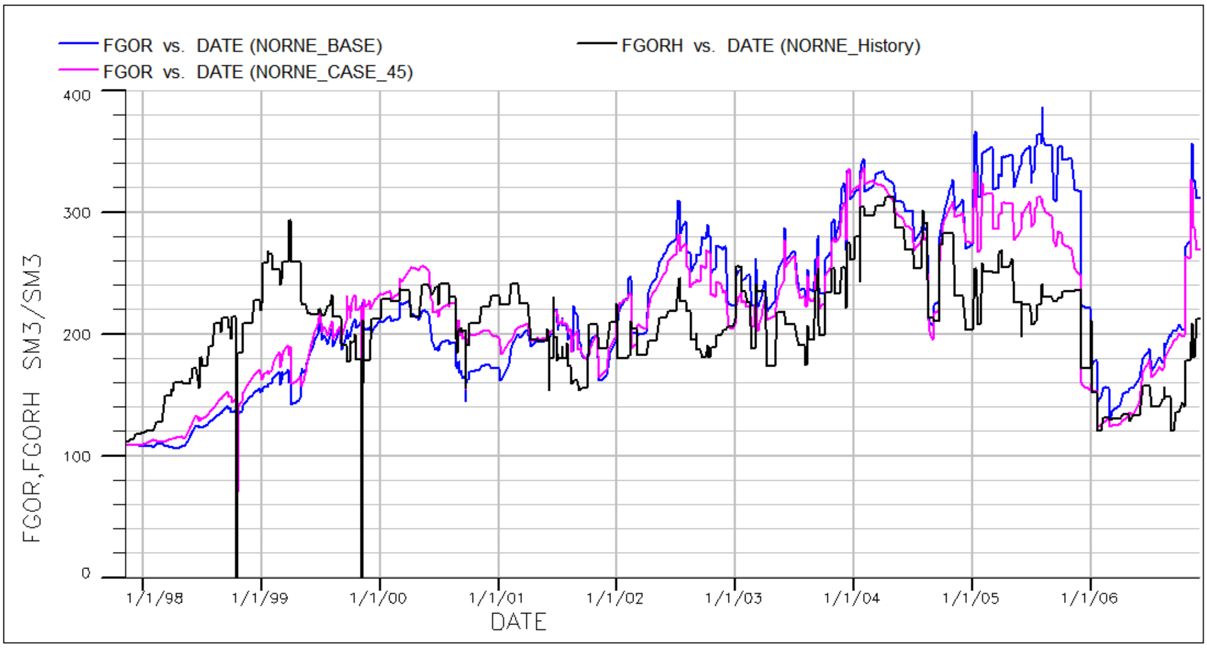

Figure A.14 Field gas oil ratio where blue is the base case, black is the history and purple is case 45 (combining adjustment of PERMX and MULTFLT)

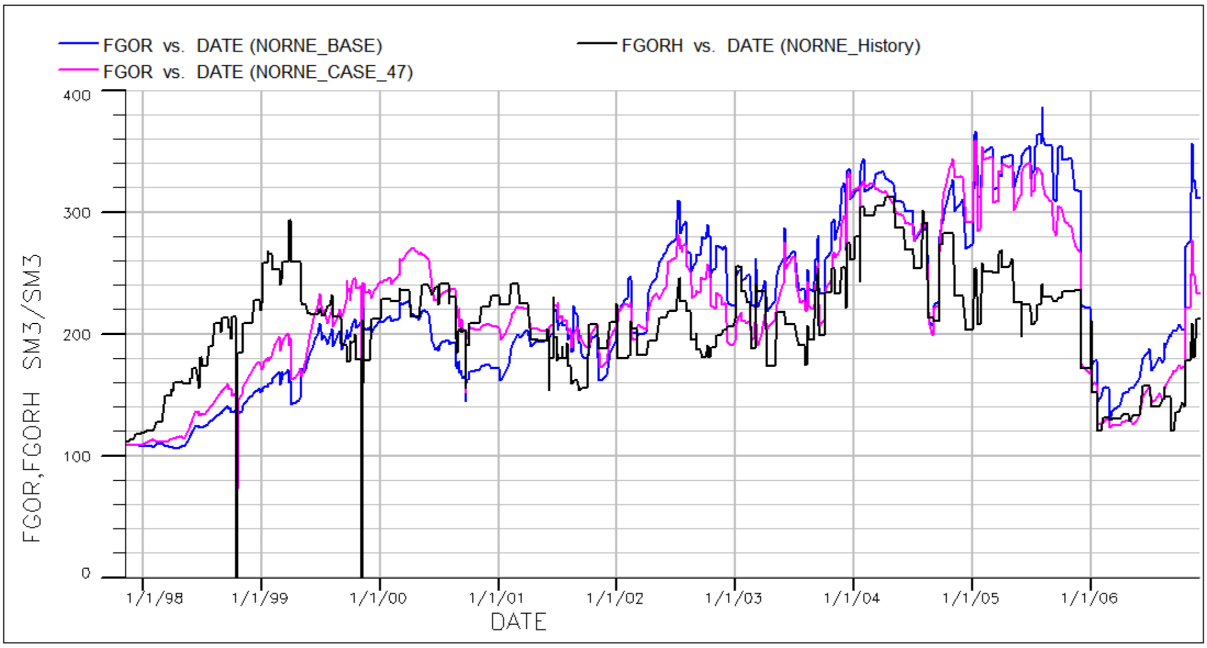

Figure A.15 Field gas oil ratio where blue is the base case, black is the history and purple is case 47 (combining adjustment of PERMX, MULTZ and MULTFLT)

Appendix 9: Local adjustment to vertical permeability in segment E

-- based on same kv/kh factor

MULTIPLY

```
   'PERMZ' 0.013   1 16 50 112  8  8 /     Ile 2.1.1
   'PERMZ' 0.009   1 16 50 112  9  9 /     Ile 1.3
   'PERMZ' 0.5     1 16 50 112 11 11 /     Ile 1.1
   'PERMZ' 0.013   1 16 50 112 12 12 /     Tofte 2.2
/
```