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Abstract

Uncertainty in the building of a 3D geo-model process is a result of our limited knowledge of the actual condition (Bratvold, R. B. and Begg, S. H., 2010). Many interpretations, analogues, estimations and simplifications are made when one get into the subsurface matters. Besides, the information gathered to reduce uncertainty has its own limitation, for example scale and resolution (Barkve, 2013). In the volumetric oil in place calculation, reservoir geometry and spatial properties uncertainty have been accounted to yield probabilistic outcomes. While in reservoir simulation, deterministic single geo-model was often used. Due to different software applications used in geo-model building and reservoir simulation, only limited calibrations in spatial properties are allowed. Reservoir geometry alteration is avoided which can cause looping back to the geo-modeling process. Otherwise, trial and error of building geo-model to run simulation is inevitable. Considering reservoir study's time and budget, a reservoir engineer would try to solve the history matching problem even with unphysical calibration to compensate impractical access to all uncertain parameters. Still, the result is bias and unreliable single model solution.

The synthetic field model used in this study has two faults. These faults positions movement are modifiers for history matching process. The number of modifiers is set to two to enable proxy model visualization in a surface plot. A combination of automated geo-model rebuilding, geo-model – reservoir simulation bridging tool and assisted history matching allows multiple solutions to be performed.

The proxy model result substitutes the traditional reservoir simulation within acceptable accuracy range which makes it reliable in structural history matching. It also provides the result within superior time which makes it practical to implement. Unphysical values in some regions of the proxy model had no accuracy implication rather than visual look of the graphs. Minimization algorithms worked very well in reducing uncertainty of production performance, oil in place and indirectly in bulk rock volume (BRV).

Key words: structural uncertainty, assisted history matching and proxy model

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Abbreviation

AHM	Assisted history matching
ANN	Artificial neural network
BHP	Bottom-hole pressure
Bo	Oil formation volume factor
BRV	Bulk rock volume
CDF	Cumulative distribution function
GOR	Gas-oil ratio
GRV	Gross rock volume
HCPV	Hydrocarbon pore volume
NPD	Norwegian Petroleum Directorate
NPV	Net present value
NTG	Net to gross ratio
OWC	Oil-water contact
OOIP	Original oil in place
PDF	Probability density function
RF	Recovery factor
Rs	Solution gas-oil ratio
SRM	Surrogate reservoir model
TVD	True vertical depth
WC	Water cut
Wp	Cumulative water production
wwct	Well water cut
wwpt	Well water production total

Chapter 1 Introduction

1.1 Study background

Uncertainty is a function of human knowledge. Probability as representation of uncertainty is a state of mind due to subjectivity to who analyze it (Bratvold, R. B. and Begg, S. H., 2010). We pay some cost on information to reduce uncertainty so that we can bear the bad consequence of possible outcomes, well-known as risk. Transferring risk to other party with compensation has become its own industry. In certain cases, we just accept risk.

The petroleum industry historically has shown a varying trend in terms of activity levels. More to this is that its projects are capital intensive in nature. From exploration, production to the abandonment phase or from subsurface and surface facility to petroleum economics which deals with fluctuating oil and gas price.

To be able to justify the economics of a discovered field, it is important to understand reservoir geometry and its behavior. The geometry is used to quantify the initial amount of oil and its behavior is used to estimate the amount of producible oil (reserves). Furthermore, selecting field development concept, anticipating drilling challenges, designing surface facility, planning schedule maintenance and anticipating tax regulation changes are list of tremendous jobs required to assess a discovered field whether profitable or not.

Dealing with uncertainty

Predicting the amount of oil or gas in a field is very important. Companies should allocate their investment based on the most “attractiveness score” after screening and assessment of opportunities and risks (Leonard, M. S. and Ozkaynak, F., 2000). In 2000, evaluation of Norwegian exploration drilling stated that Bulk Rock Volume (BRV) is the most important parameter to get amount of oil in reservoir accurate, then followed by initial percentage of water content in a porous rock (Fosvold, L., Thomsen, M., Brown, M., Kullerud, L., Ofstad, K., and Heggland, K., 2000). BRV (known also as Gross Rock Volume/GRV) is influenced by structural shape and hydrocarbon fluid contact. The structural parameters are top reservoir surface, base reservoir surfaces, and fault position. Fault properties are used to determine compartmentalization whether the layer on both side of fault is sealing or leaking. Fluid contact is oil-water contact or gas-water contact for a gas field. These parameters are acquired through seismic interpretation in which the seismic data itself required filtering and processing from the original one. It is expected that results are inexact. In addition, seismic data is noisy and unclear at faulted area as shown in Figure 1 (Røe, P., Abrahmsen, P., Georgsen, F., Syversveen, A. R., and Lia, O., 2010). The shattered area or volume of fault absorbs energy from seismic and poorly reflected to receivers on surface.

Recoverable oil is the amount of oil that technically and economically able to be produced. This performance represented in percentage so-called recovery factor (RF). In the very early phase of a project, recovery factor is usually arbitrary number based on assumptions. It could be average number from statistics in a well-known area or from corporate guideline for frontier area. The reservoir geometry is further investigated after acquiring extensive data from different disciplines and reservoir behavior is predicted under various operating strategies. Production performance profile may change when model’s assumptions are changed. Figure 2 from Norwegian Petroleum Directorate (NPD) website is showing an example of a newly discovered oil reservoir in the Barents Sea area with recoverable oil uncertainty between seven and ten million standard cubic meters.

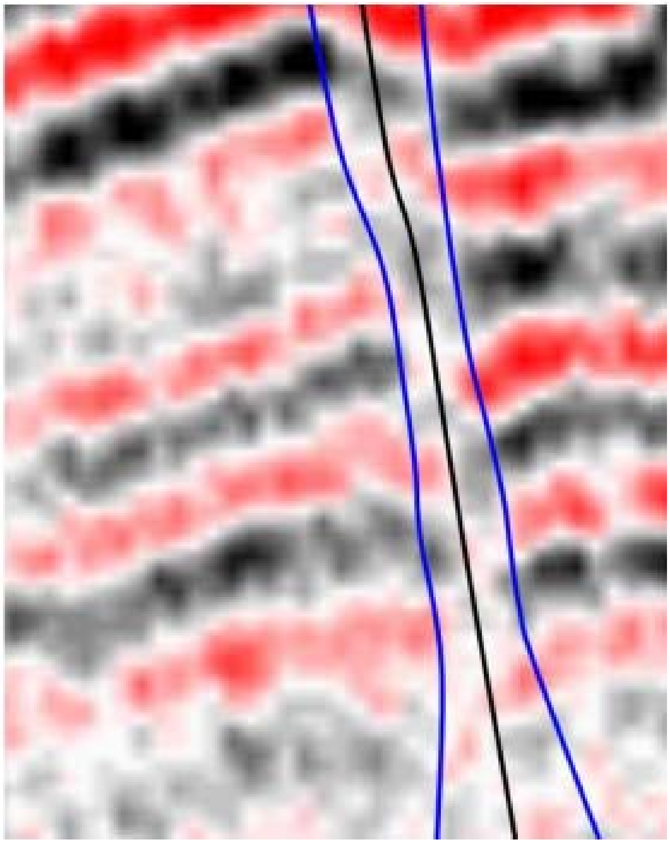

Figure 1: Noisy and unclear faulted area (Røe, P., Abrahmsen, P., Georgsen, F., Syversveen, A. R., and Lia, O., 2010)

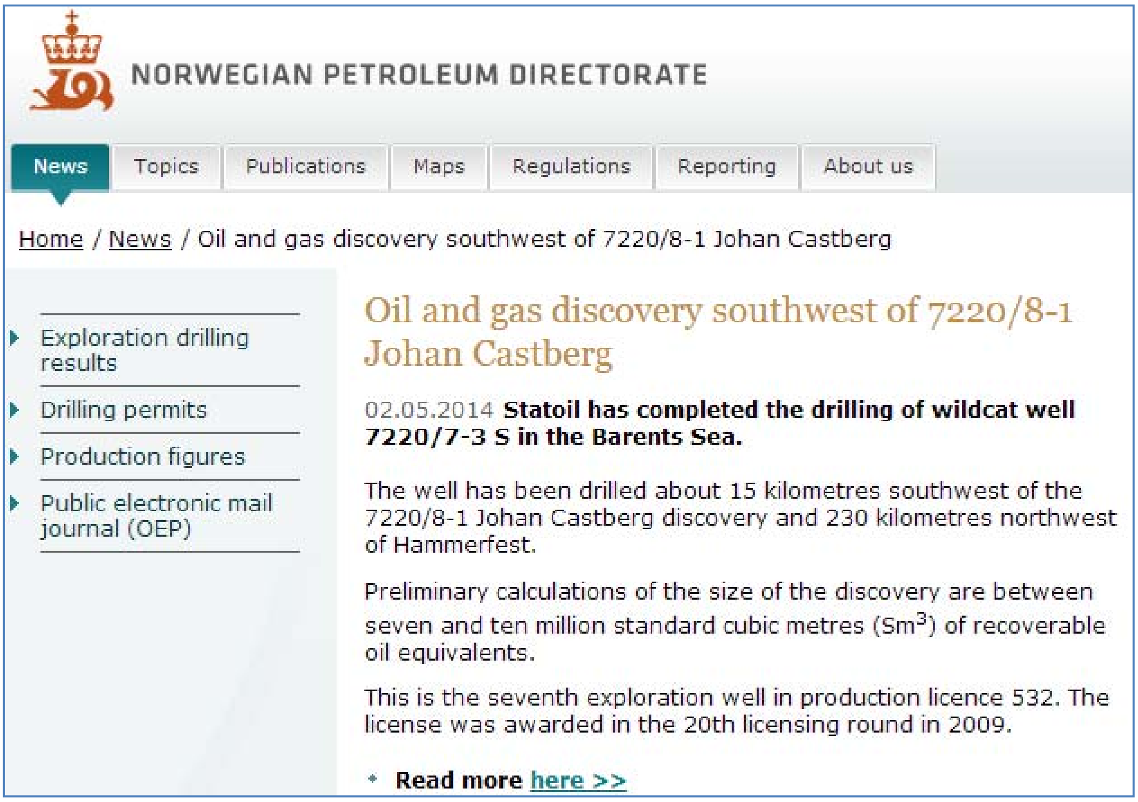

Figure 2: Exploration result in the Barents Sea area with preliminary recoverable reserves

A model is a simplified version of real system with many assumptions to eliminate the complexity. Geological model visualizes the conditions of a subsurface reservoir. It is the only model that honors 3D data from all disciplines. The model should be updated as new data acquired. Having a realistic model is critical to a project that spans several decades. Available resources, budget and time are usually the constraints for the 3D reservoir study. Many interpretations, analogues, estimations and simplifications are made when one get into the subsurface matters. It is common if the model, numbers or recommendation are varied as much as the number of groups, given the same data to do the same analysis. As new data becomes available, it is not unusual that the concepts and model would undergo any change. Highly appreciated data is one that capable of reducing uncertainty and changing one decision (Bratvold, R. B. and Begg, S. H., 2010).

In oil reserves calculation, it is common to take into account uncertainty whether by corporate policy or regulation from government. One of the examples is by varying fluid contact, P90 for lowest tested oil, P50 for lowest known oil, and P10 for lowest structural contour (closure). A decade ago, it was done manually three times. It was uncommon to have many geological models that have structural parameters variation. This inefficient work process was due to unavailability of method and tool which accommodate workflow automation (Seiler, A., Rivenæs, J. C., Aanonsen, S.I., and Evensen, G., 2009). As the software technology advanced, model building automation process was developed and varying horizons were able to be implemented. Varying horizons parameter was relatively straight forward compared to varying fault positions, thus the latter was never considered since it required manual model building (Gringarten, 2012). Recently, this obstacle was overcome and it is easier to produce hundreds to thousands of geological models by taking into account both structural and petrophysical uncertainty in volumetric calculation. Reservoir simulation is a technique to estimate recoverable oil under various production and injection scenarios. This tool assists decision maker to select the most profitable way of draining oil before further investment is made to drill wells or build production facilities. Traditionally, it can be a tiresome process for the reservoir engineer when single simulation run could take hours or days. Hence it was preferable if the geo-modeler handed over only a single geological model to be exported into the flow simulation model.

The advancement in hardware computer technology enables reservoir simulation load distribution into the multiple core processors and multiple CPU. The advancement in history matching process, so-called assisted history matching, is an alternative solution in realizing multiple simulations runs in reasonable time while reservoir engineers have more time to analyze the results. It also enables probabilistic outputs which quantify uncertainty rather than questionable deterministic solution. Uncertainty anticipation means readiness to its consequences, either good or bad. This technology trend has been predicted in 1997 (Watts, 1997).

Multiple static and dynamic reservoir modeling

Static reservoir models or often called geo-models are ideally the combined effort of a geophysicist, geologist and petrophysicist work with input from reservoir engineer. The terminology static refers to very small or negligible changes over time (e.g., hydrocarbon trapped event is a dynamic process which takes place in a scale of millions of year). It consists of seismic processing and interpretation, velocity modeling to convert time to depth, facies architecture modeling, petrophysical distribution to all studied area, fluid contacts definition and rock properties analysis. The end result of this stage is an estimation of hydrocarbon volume in place. Uncertainty in the building of 3D model process is a result of our limited knowledge of the actual condition (Bratvold, R. B. and Begg, S. H., 2010). While the information gathered to reduce uncertainty has its own limitation, for example scale and resolution (Barkve, 2013). Figure 3 shows comparison of different type of data sources scale (probe, core, log and seismic data) and observed sediments scale in nature (laminae, beds and parasequences). Reservoir geometry and spatial properties uncertainty are accounted to yield probabilistic outcomes of hydrocarbon volume in place or known as hydrocarbon pore volume (HCPV). A typical case of exception is seen in shallow onshore reservoirs with many wells that cover most of the area. In this case, a deterministic model may be applied.

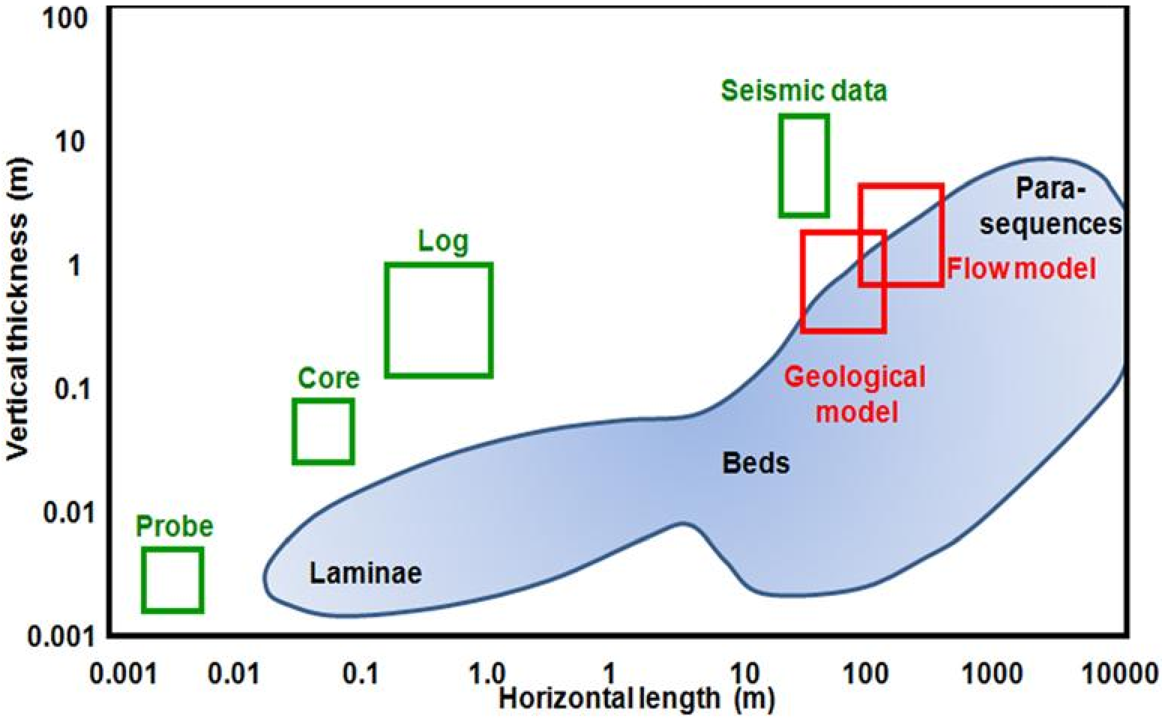

Figure 3: Comparison of different type of data sources scale and observed sediments scale in nature (T. Barkve adapted from Pickup and Hern, 2002)

Dynamic reservoir modeling, also identical to reservoir simulation, is used to qualify geo-model representing actual condition. The geo-model is expected to produce oil, water, gas and generate pressure as close as the measurement from the field. Calibration to the geo-model is allowed to match the actual data. This process is done by considerable trial and error of reservoir modification. It required extensive level of commitment and focus from an experienced reservoir engineer to observe and then get familiar with reservoir behavior in response to parameters adjustment. It is arguable whether calibration should only be done within geological sense. Traditionally, calibrations are done by modifying petrophysical parameters such as permeability, transmissibility, relative permeability or even porosity and capillary pressure as shown in Figure 4. This process is done on reservoir simulation software application. Reservoir engineer would try to solve the history matching problem without looping back to the geo-modeling process for the sake of time, money and energy. Nowadays, using computer automation in building new geo-model in reasonable time helps bridging the gap between reservoir engineer and geo-modeler interest. Figure 5 shows involvement of structural position uncertainty in history matching process. Structural movement is causing grid reconstruction hence required reservoir modeling and simulation software integration. The proxy model or response surface techniques as substitution of full reservoir simulation allows multiple calibration scenarios in short of time (Eide, A., Holden, L., Reiso, E., and Aanonsen, S. I., 1994). In this study, surface response plots are created to assess the most influent parameter and quality check estimation values. On the later stage, these multiple history matching solutions are used as basis for risk assessment of probable hydrocarbon rate (or volume) expected in the future.

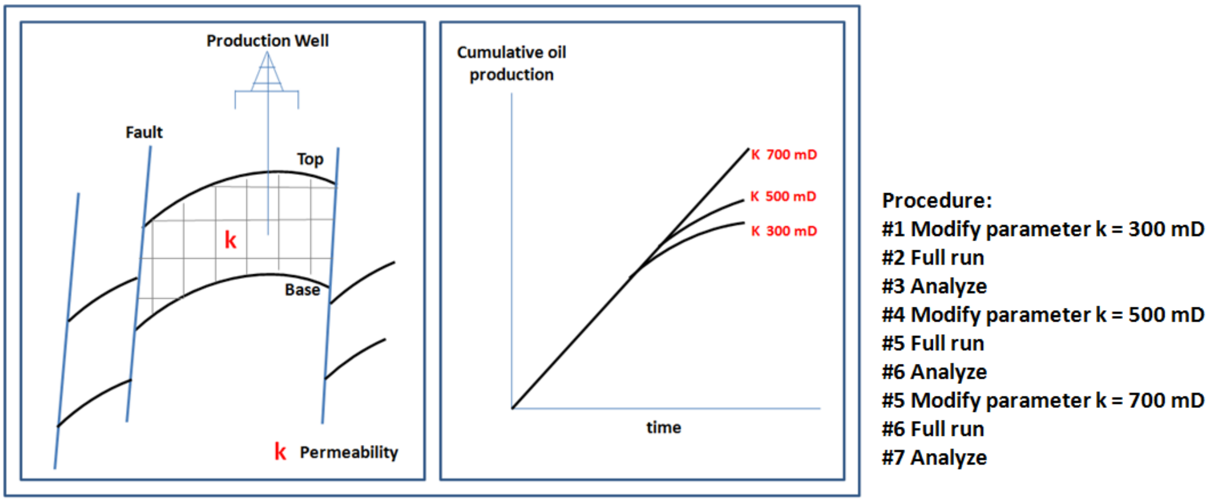

Figure 4: Traditional history matching

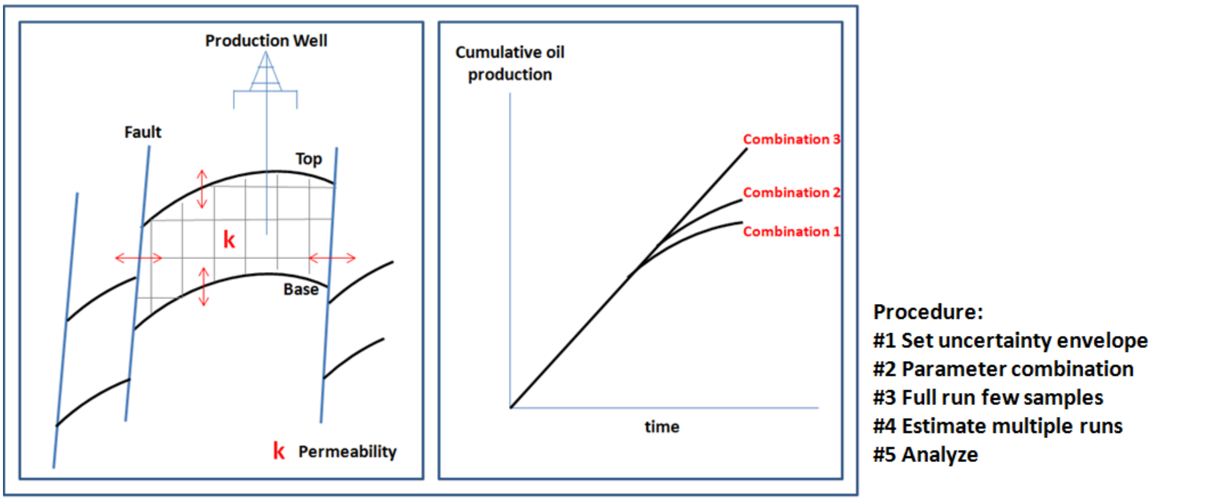

Figure 5: Assisted history matching with structural uncertainty

1.2 Study objectives

The available tool for automated 3D model building and assisted history matching enable multiple cases to be run in reasonable time. This advancement opens the opportunity to take into account structural parameters such as horizons or fault positions uncertainty into the history matching process.

This master thesis builds and tests the application of fault positions uncertainty on the history matching process across different software applications. RMS for geological modeling and Tempest ENABLE for assisted history matching tool from Roxar are used. The work is applied on a synthetic model while the effect of facies geometry as a result of fault position alterations is excluded. The reliability and practicality of the proxy model generated from structural uncertainty are investigated.

1.3 Outline

In Chapter one, background of the study is elaborated. Bulk Rock Volume (BRV) is the main parameter required to be correctly predicted. The revolutionary approach of modeling automation and assisted history matching (AHM) unlock easier multiple solutions to static and dynamic reservoir modeling.

Chapter two presents important terminologies in this work, focusing on dynamic reservoir modeling part. The background for selection of objective function, measurement tolerance and measurement presentation are discussed. Parameterizations for fault uncertainty are listed. Latin Hypercube sampling as standard experimental design methods nowadays is illustrated in an easy way to understand. The proxy model or response surface as substitution of full reservoir simulation run is described. Some minimization algorithm methods are listed with combination of gradient-based and genetic algorithm are used in this study.

Chapter three shows a comparison of traditional and modern integrated reservoir study from software applications point of view. This chapter also provides insight of each process of the work, from automated geo-model rebuilding workflow to assisted history matching diagram steps.

An initial structural model provided by Roxar and the following set up for Base Case is discussed in Chapter four. The Base Case model consists of two faults and four zones. Two producer wells are placed in the middle of structure while three injector wells are placed on the flank. The Base Case model sensitive to water cut is used. “TRUE” observed (measurement) data are generated by using specific Fault 1 and Fault 2 positions. The observed data is added with noise to represent measurement tool fluctuation. Afterwards, smoothed observed data is used in history matching with range of noise set as tolerance.

The Base Case and assisted history matching results are presented in Chapter five. Initialization result is compared with initial oil in place from geo-model. Then the final results of history matching are presented to describe proxy model usage reliability and practicality in structural history matching. Summary findings are listed as point of conclusions in Chapter six. Suggestions for possible future work are presented in the end of this chapter.

Chapter 2 Theoretical background

2.1 Introduction

The geo-model is expected to generate fluid and pressure as close as the measurement from the field prior to prediction of reservoir performance. Initially, it is normal that this model will yield deviation results. Model calibration or so called history matching is conducted to verify if geo-model reproduces the observed conditions. While the measurement itself has uncertainty on tools or methods, there is certain degree of acceptance in the history matching process.

Automatic history matching has been an ambition as computer hardware and software applications advance in last few decades. The challenges such as sophisticated minimization algorithm and insufficient robustness to all reservoir settings made influence from reservoir engineers are still required (Cancelliere, M., Verga, F., and Viberti, D., 2011). Then a more reasonable expectation on terminology called assisted history matching emerges. On the following sections, the common terminologies used in assisted history matching are described.

2.2 Objective function

In the history matching stage, simulations do generally not generate the exact observation. There is a reasonable tolerance which is determined based upon probability function of measurement tool accuracy or measurement methods. The methods could be back-allocation calculation over certain period of time, commingle production, tank-volume measurement over certain period of time, visual estimation/intuitions (for flare gas measurement) or rule of thumb in a field. In other words, observed data is subject to uncertainty.

The observed data has uncertainty due to measurement tool’s accuracy or resolution. The objective function for history matching is the difference between observed data and the simulated value. The difference is divided with tolerance interval and then squared to prevent unphysical value. An observed data point on a well variable is called estimator point at the software ENABLE. A few estimator points should be specified to reduce the workload and to help focus on the key aspects of production data of each well. Later on, ENABLE will prioritize these values for matching. Objective function used in the history matching process is shown below:

$$Objective\ function = \sum_{i=1}^{n} \left(\frac{Observed\ i - Simulated\ i}{Tolerance\ i} \right)^2$$

Here, n is the number of estimator points and subscript i is the number of the estimator point. It doesn’t take into account a weighing factor since this study has no preference on specific matching parameter over others.

In an assisted history match process, uncertain-parameter modifiers are varied within defined set values. Various simulated values are estimated with proxy to find minimum objective function. The objective function below-one implies that good quality history match has been achieved since the observed-simulated difference is within tolerance range. Ideally, this quality should be applied to all data and all wells. If objective functions are not satisfied, one may increase the tolerance, for example two times existing values.

Tolerance value may be associated with standard deviation. In a normal distributed data, one standard deviation refers to 68.2% of observed data laid on upper and lower side of mean data. Two and three standard deviations refer to 95.4% and 99.7% of data respectively. Figure 6 is showing tolerance as standard deviation in history matching process.

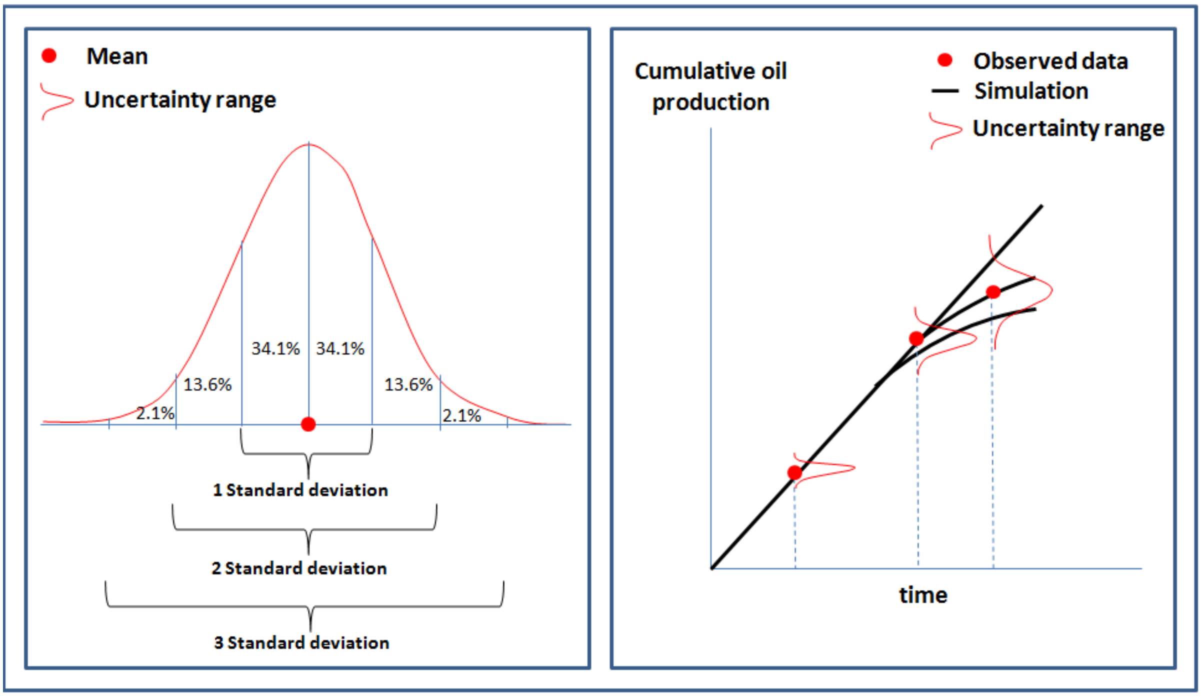

Figure 6: Tolerance as standard deviation in history matching process

2.3 Selection of production constraint

Production constraint settings on reservoir simulation depend on how reliable our data is. In a case where water production measurement is inaccurate, one may choose oil rate as production constraint in simulation. In this study, both oil and water measurements are assumed accurate, while small amount of gas production is flared and unconsidered. Liquid rate, sum of oil and water rate, is preferred as constraint. The simulator will honor pre-defined volume of liquid at each time step and then proportion of oil and water are tried to match with observed data.

2.4 Parameterization

Parameterization is the chosen method to calibrate initial reservoir model in order to produce measurement production and pressure data. In traditional history matching process, only few parameters are taking into account due to different applications of geological model software and reservoir simulation software. They are usually spatial distribution of petrophysical parameters such as porosity, horizontal permeability, vertical permeability, permeability multiplier or net to gross (NTG) values which are possible to be modified on reservoir simulation software. Some of traditional parameterization methods are individual grid block properties, region grid blocks properties and global grid blocks properties. A method called pilot points from hydrogeology was proposed by Marsily in 1978, later on adapted in petroleum industry. Gradual method was proposed by Roggero et al (1998) to control stochastic reservoir property distribution within historical production data (Roggero, F. and Hu, L. Y., 1998). Few years later, Ravalec-Dupin and Hu (2007) combined pilot point and gradual deformation to avoid extreme values usually assigned on pilot point (Dupin, M. R. and Hu, L. Y., 2007). An elastic grid approach was proposed by Seiler et al (2010) to be used in structural geometry updating (Seiler, A., Aanonsen, S. I., Evensen, G., and Lia, O., 2010). Some of parameterization options on fault uncertainty are listed below (Røe, P., Abrahmsen, P., Georgsen, F., Syversveen, A. R., and Lia, O., 2010):

- Fault position
- Fault angle
- Fault throw
- Fault length
- Fault volume (fault as 3-dimensional structure)

Excluding fault volume, all these parameters are requiring grid reconstruction which should be handled on reservoir modeling software. The results will be called by ENABLE software for reservoir simulation.

Currently, faults are modeled as areal-based while actually volume structures (Røe, P., Abrahmsen, P., Georgsen, F., Syversveen, A. R., and Lia, O., 2010). More extensive research required to accommodate this parameter as this will cause transmissibility alteration within fault structures. In association with fault length, this parameter represents full flow-barrier, half flow-barrier or flow-conduit. Fault throw may be divided by stratigraphic and vertical throw. Stratigraphic throw is top formation displacement between hanging wall and foot wall. While vertical throw is true vertical depth (TVD) between top formation on hanging and foot wall. Fault angle variation could be dip or strike. As shown in Figure 7, there are two types of fault position displacement, laterally and perpendicularly. In this study, only the later is used.

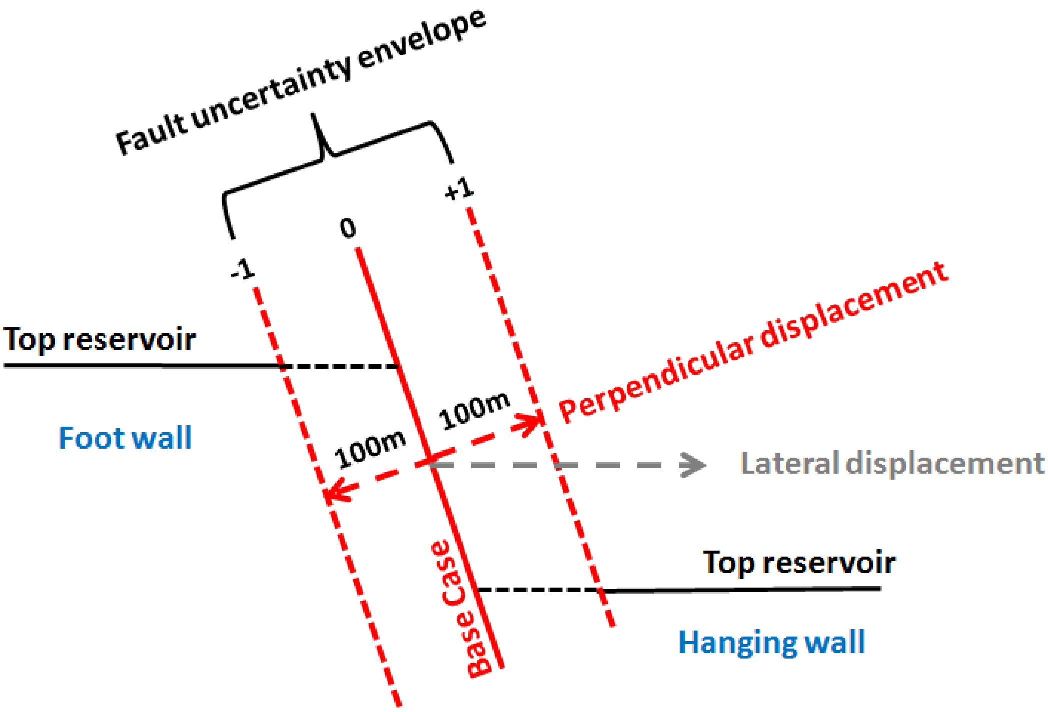

Figure 7: Fault displacement types

2.5 Experimental design

Experimental design is a statistic-based sampling technique used when one deal with a large number of data. The sampling method has purpose to extract as many information within minimum number of experiments or simulations. This strategy is a very efficient way of covering search space to obtain representative information required to be able estimate results from un-sampled values accurately. The sampled values of parameter to be fully simulated will be used later on to construct proxy. More into this will be discuss in the next section. The principle of experimental design was developed by Fisher for agriculture industry in the 1926. Plackett and Burman presented their work on optimum multi-factorial experiments in 1946 while working in Ministry of Supply. In 1960, Box and Draper introduced response surface construction based on an analytical function. In early 1970s, this topic started to evolve on literature of petroleum industry such as factorial design (Saxena, U. and Vjekoslav, P., 1971). McKay et al (1979) was the first who introduced Latin Hypercube method. Since then, this method became popular and standard method in uncertainty studies.

In this study, Latin Hypercube sampling is used as the only option in the software used. The advantage of this method is that one may set number of samples desired independent of number of uncertain parameters. For samples position that is contained in a squared search space, there is only one sample in each row and column.

Uncertain parameter values are equally divided into the probabilistic interval and then randomly selected. Uniform distribution is applied for uncertain parameters such as fault position in this study. This type of distribution is selected to represent very limited knowledge on possible value except the minimum and maximum values. The selected values for one parameter then pair randomly with results from another parameter. Figure 8 below shows example of two dimensional of Latin Hypercube sampling for four samples.

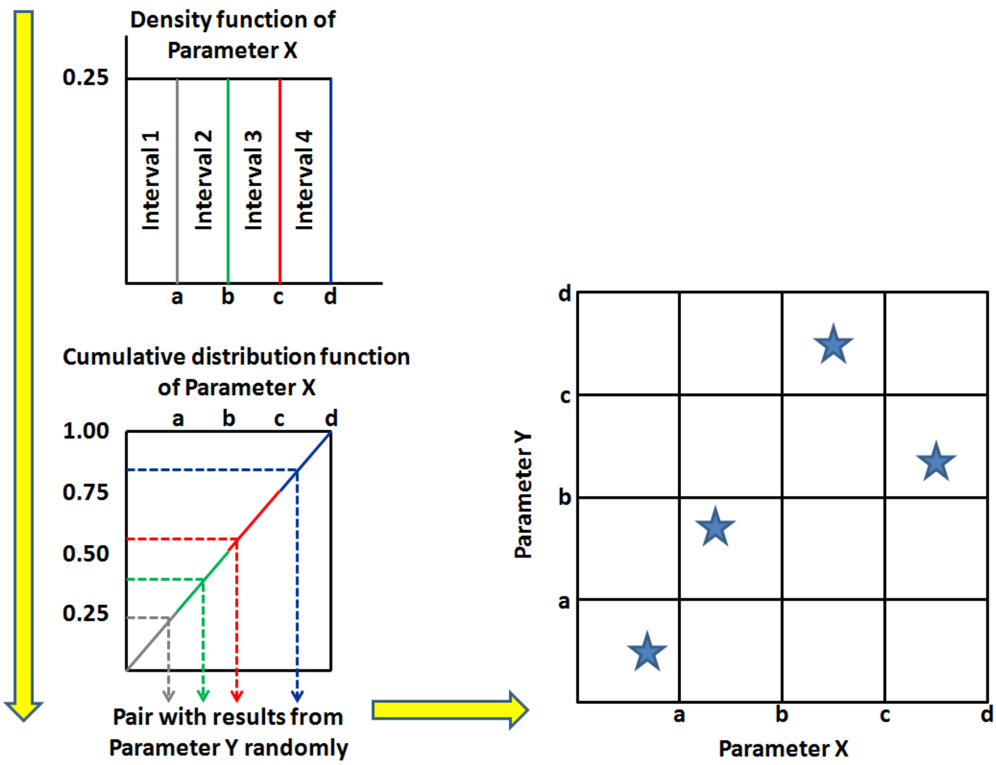

Figure 8: Latin Hypercube sampling

A prior model is an initial geological model without taking into account observed (measured) production and pressure data. A prior model that influenced by observed data becomes a posterior model. This posterior model serves as a prior model when new information or data is available to be included on model validation.

2.6 Proxy model

Proxy means representation or substitution to real simulation. In literature, it is also called surrogate reservoir model (SRM) or response surface. It is constructed based on equation which fit the results from simulated sampled value of parameters. This proxy will estimate results from un-sampled value of parameters in a very fast way since it eliminates running full simulation.

Some of proxy methods are linear, polynomial (least squares), kriging, splines and artificial neural network (ANN). A comparison study in 2005 suggested that quadratic polynomial, kriging and splines give better accuracy in predicting probabilistic uncertainty and the most influential parameter (Yeten, B., Castellini, A., Guyaguler, B., and Chen, W.H., 2005). Among these methods, only kriging that reproduces outcome at sampled points. Another study in 2009 didn't recommend the use of proxy for history matching, particularly for large number of uncertain parameters (Zubarev, 2009). In this study, proxy was built based on polynomial and kriging method. Polynomial up to 3rd order provides a trend surface model while kriging ensures proxy model agrees precisely with outcomes obtained by full simulation runs. Local part of the proxy model will be refined to meet objective functions defined.

Assisted history matching using the proxy model has advantage in predicting result in nearly no time. Nevertheless, one should aware of error that may contain on the estimation as it doesn't run the actual simulation. Blind test could be performed to check the accuracy of the proxy model. One of the sample points excluded from building proxy model. This single sample point is run and compared to proxy model as validation. Another way of validation test is by visualizing the proxy model. Figure 9 shows example of the 1-dimensionalal proxy model plotting.

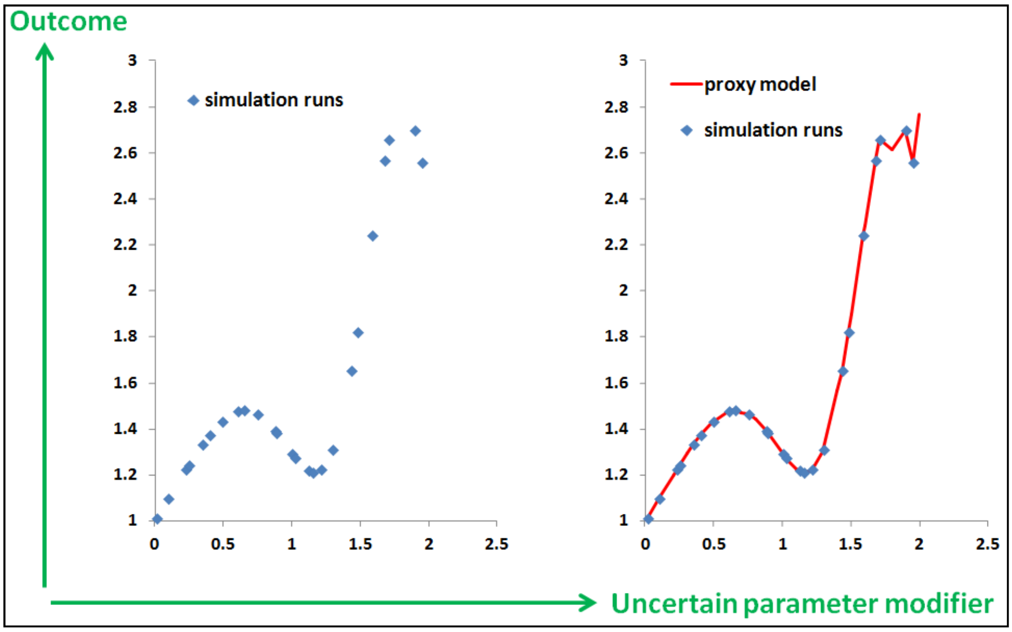

Figure 9: The proxy model plotting example

2.7 Minimization algorithm

The proxy models built without influence of any information data are called the prior models. While the posterior proxy models are constructed after taking into account information data. The information data is observed (measurement) production data with tolerance interval. The sampling points for building posterior proxy models are populated at local area where the prior proxy model and tolerance value are intersected. This area is called the history match area or the plausible area. Later on, the proxy model will be updated in this area iteratively. Each iteration of the models used to reduce the uncertainty range. Figure 10 illustrates expectation from posterior run after applying minimization algorithm on specified objective function.

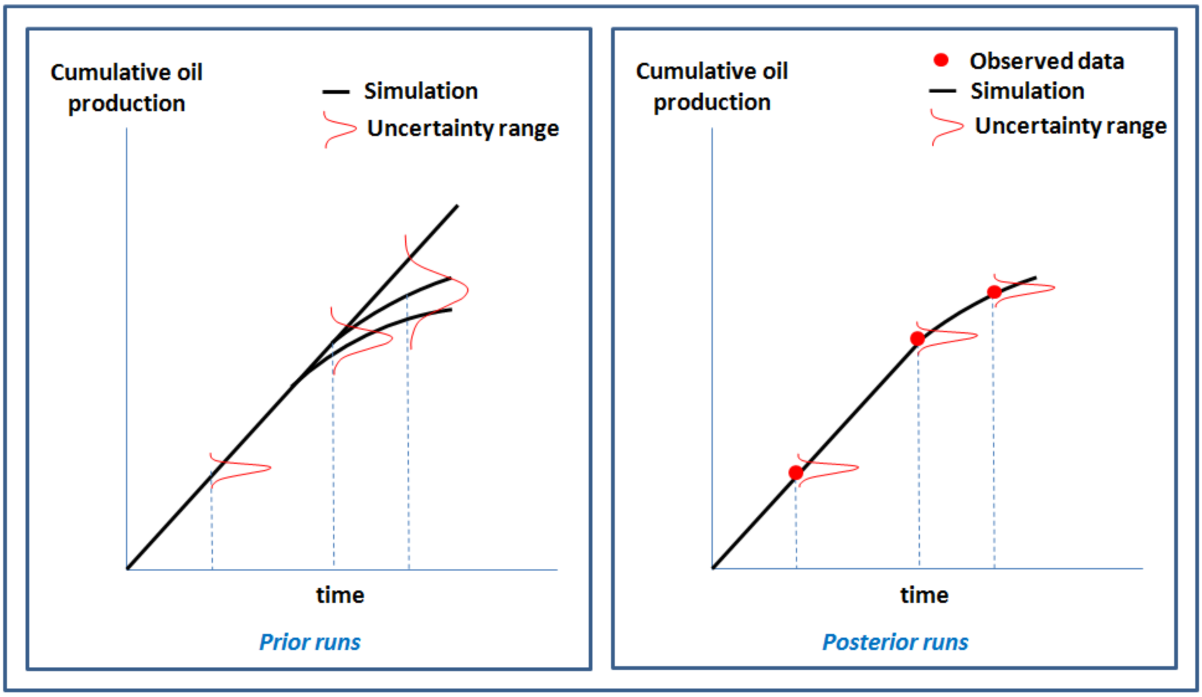

Figure 10: Prior and posterior runs comparison

Some of minimization algorithms are gradient-based method, simulated annealing, direct search, global search, genetic algorithm. They are mainly classified either deterministic or stochastic methods (Islam, M. R., Moussavizadegan, S. H., Mustafiz, S., and Abou-Kassem, J. H., 2010). Deterministic approach is based on inverse problem theory. From the model parameters available, information or data is tried to be extracted. While stochastic method is based on forward problem using random input to eventually obtain satisfied outcome. The stochastic method is almost the same process with traditional history matching, finding solution by trial-and-error.

Gradient-based methods are examples of deterministic methods. These methods require computation on the gradients of the mathematical model with respect to the parameterization in order to minimize the objective function. The advantage of this method is fast convergence but unable to resolve local minima convergence issue. Hence, history match quality becomes low if one uses it solely in a real reservoir case known as a complex and non-linear.

Different from deterministic methods, stochastic methods avoid unsuccessful history matching but slower rate of convergence is expected. Simulated annealing and genetic algorithm are common examples of stochastic based methods.

The simulated annealing is a probabilistic method aim to find global solution from discrete large search space by accepting worse solution than the current best one. The concept originally came from metallurgy industry where annealing metal requires heating and cooling processes. Different from gradient-based method that always moves downward, this method has occasional upward moves or so called hill-climbing algorithm to avoid local minima trap. Another advantage of this method is capable of handling large number of uncertain reservoir parameters. In petroleum industry particularly history matching, this method was proposed in 1993 for determining uncertain parameter at simplified gas reservoir case (Ouenes, A., Brefort, B., meunier, G., and Dupere, S., 1993). In 1994, infill drilling study was performed by applying this method for carbonate oil reservoir characterization (Sultan, A. J., Ouenes, A., and Weiss, W. W., 1994). The study using this method concluded improvement of recovery factor for the studied field with heterogeneity challenge.

Noticeable from its name, genetic algorithm is a method inspired by evolution theory introduced by Charles Darwin (1859). His observation on natural selection is driven by survival of the fittest. The processes of genetic algorithm are:

- Initialization
- Evaluation
- Selection
- Crossover
- Mutation
- Repetition

In 2000, genetic algorithm method was applied for history matching process (Romero, C. E., Carter, J. N., Gringarten, A. C., and Zimmerman, R. W., 2000). This method tends to find global solution by applying those processes to population of individual solution, iteratively. The processes will be terminated once predefined objective function is met. Since objective function has interval tolerance, one could expect the solution is close to global solution. This method is capable of handling large number of parameters which is very important nowadays as more uncertain parameters are included in history matching process.

This study used combination methods from deterministic and stochastic approach. Gradient-based method is used for local minimization. To ensure the solution obtained is the best one within entire search space, genetic algorithm is added as combination.

There are many other methods which their descriptions are out of the scope of this study. Many hybrid methods also could be found on literatures. For guided stochastic methods, Particle Swarm Optimization (Mohamed, L., Christie, M., and Demyanov, V., 2009), Ant Colony Optimization (Hajizadeh, 2010) and Differential Evolution (Hajizadeh, Y., Christie, M., and Demyanov, V., 2010) were introduced in 2010. For data assimilation approach, Ensemble Kalman Filter (EnKF) is the best known method (Nævdal, G., Johnsen, L. M., Aanonsen, S. I., and Vefring, E. H., 2003) (Evensen, G., Hove, J., meisingset, H. C., Reiso, E., Seim, K. S., and Espelid, Ø., 2007). A comparison studies suggested that selection of parameterization, sampling technique and minimization algorithm may be affect range of uncertainty and our decision on field development (Erbas, D. and Christie, M. A., 2007).

Chapter 3 Modern integrated reservoir study

3.1 Software applications

Software is used as a tool to integrate all the data coming from different sources and translate it into a decision. It is inevitable that subsurface team work with different software applications. Although the trend shows that these tools become more integrated nowadays.

Figure 11 shows traditional integrated reservoir study workflow. Geophysicists, geologists, petrophysicists and reservoir engineers are working together in static reservoir modeling phase. This phase aims to model reservoir geometry and properties in the geo-modeling software. The end result of this collaboration is volumetric calculation of the geo-model, for example oil in place. Then the geo-model is exported to dynamic reservoir modeling for further work. Reservoir simulation software is used by reservoir engineers to compare reservoir behavior in the past and simulated behavior from the geo-model. The geo-model will be calibrated to mimic reservoir behavior in the past (history matching) prior to be used in predicting future behavior. Reservoir engineer has high degree of independence in calibrating dynamic reservoir properties such as rock and fluid properties. In contrary, only limited static reservoir properties could be changed from this software. For example, permeability values could be changed but not the permeability distribution trend direction. When history matching is found very challenging and reservoir geometry requires modification then looping back process to geo-modeling software is inevitable. Some members of the team could be reluctant to re-work this model after considering it finished when oil in place calculation generated. A good integrated reservoir study team will modify it and handed over to reservoir engineer. Reservoir engineer will set up and try to solve history matching with updated model. If the result still doesn't satisfy reservoir engineer, another looping back may be required. This trial and error process is impractical and difficult to be implemented. This is the reason why traditional integrated reservoir study often comes up with single model solution which is bias and unreliable.

In comparison to traditional way, modern integrated reservoir study workflow is shown in Figure 12. A tool that capable of bridging geo-modeling software and reservoir simulation software is introduced. This tool also accommodates the uncertainty of many input parameters from both software applications. The advantage of this feature is avoiding excessive trial and error processes by performing simulations for the defined range of uncertainty from the beginning. Reservoir geometry uncertainties, reservoir property uncertainties and dynamic reservoir properties uncertainties are combined and simulated. Thus, some different geo-models could match the same observed data. As uncertainty has been quantified, prediction reservoir behaviors become more reliable. To implement multiple geo-models building and simulations, automated geo-model rebuilding and assisted history matching are introduced in geo-modeling software and reservoir simulation software, respectively. The advantage of this feature is transferring a labor work on models set up to the computer so that the team members have more time on the analyzing the results. More into this will be discussed in the next section.

Three different software applications were used in this study. RMS for geo-modeling, Tempest for reservoir simulation and ENABLE for assisted history matching tool. The later also used to bridge geo-modeling and reservoir simulation software. The latest version of ENABLE used in this study has been integrated into the Tempest.

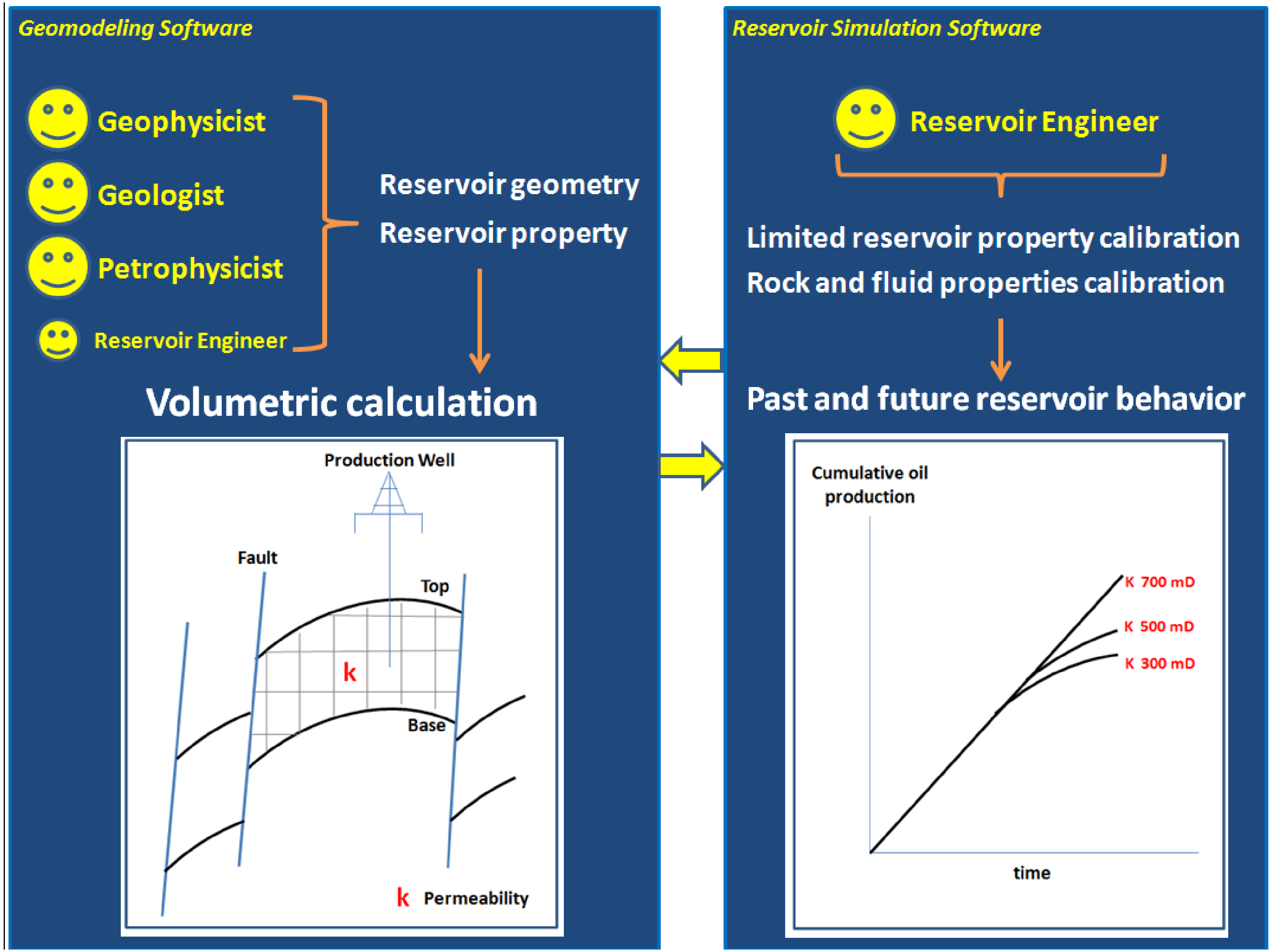

Figure 11: Traditional integrated reservoir study

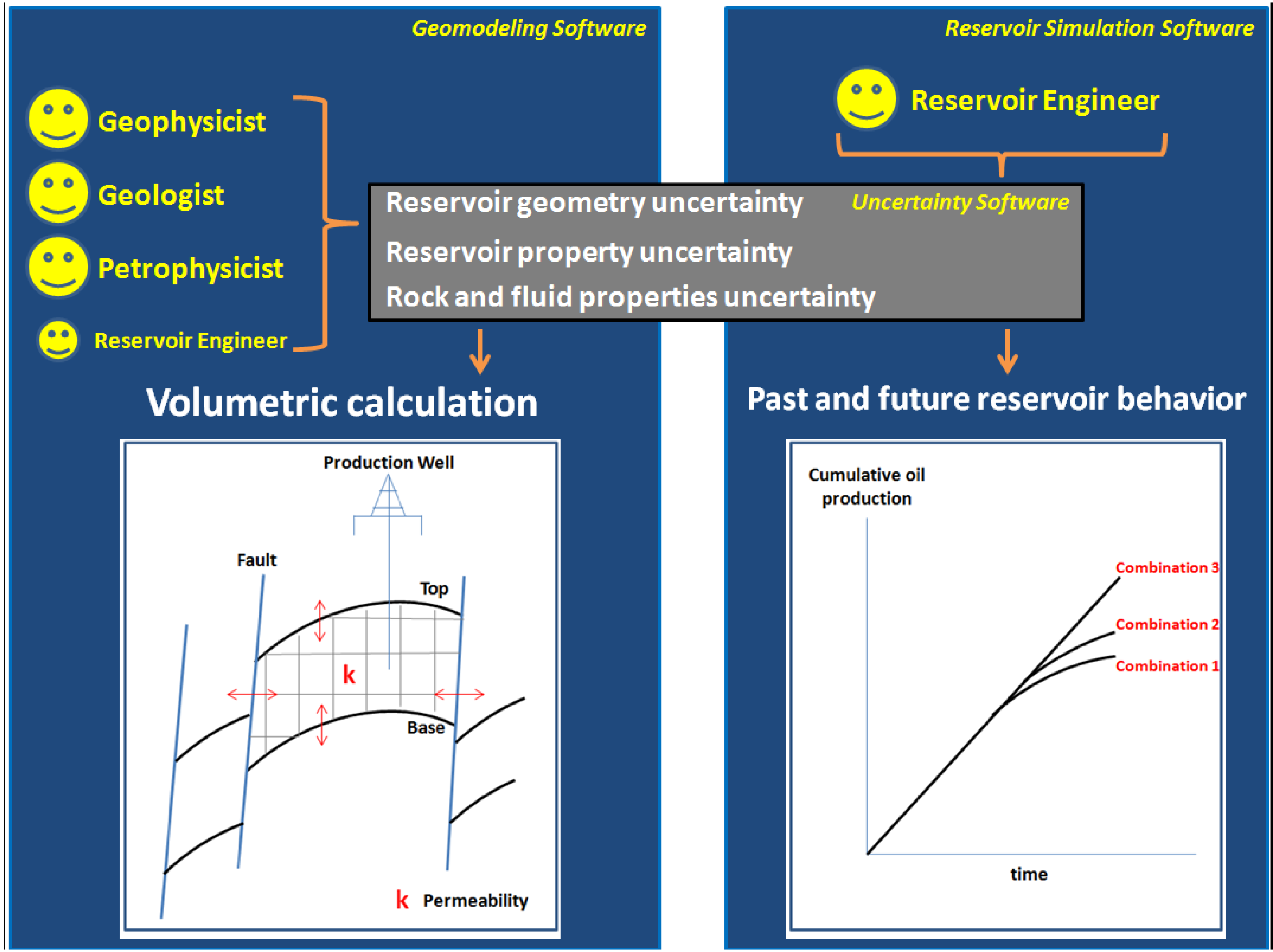

Figure 12: Modern integrated reservoir study

3.3 Workflow

Base Case geo-model is built and simulated to observe its sensitivity to structural parameter variations. Fault position uncertainty is selected to be parameterization in this study. There are two faults on Base Case allow to move perpendicularly on specified range. Figure 13 below shows the automated geo-model rebuilding workflow on RMS.

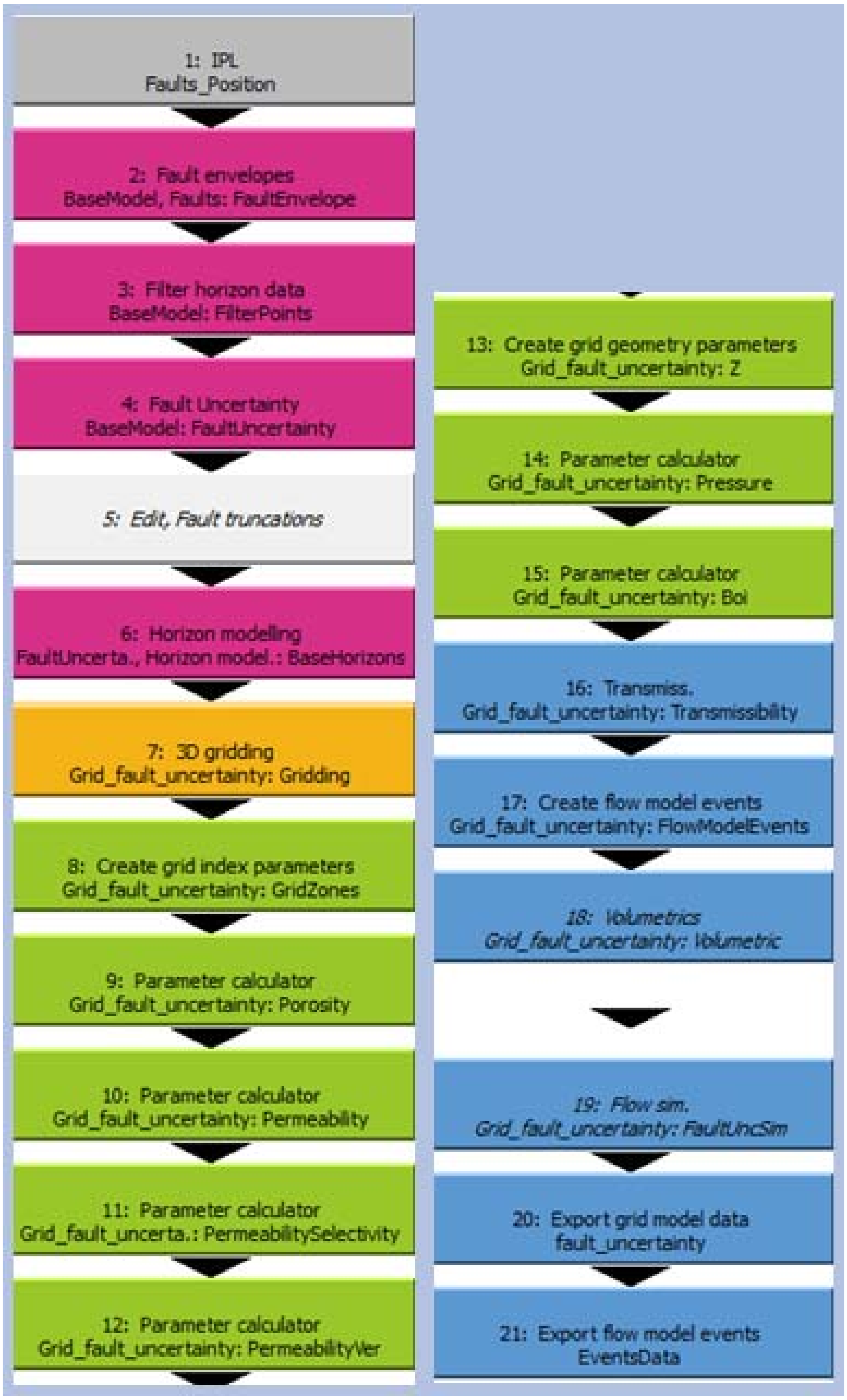

Figure 13: Automated geo-model rebuilding workflow on RMS

Assisted history match uses proxy as reservoir simulation substitution. The proxy is built on equations that match outcome from sample simulation runs. The chosen simulation runs are based on Latin Hypercube sampling method called scoping runs. This study used 20 scoping runs to build the proxy model although manual of ENABLE suggested 25 runs for real field model. The proxy model at this stage is called prior model.

Subsequent to prior model building, initial analysis results are required. At this point, observed data are involved. A good prior model is obtained when scoping run bracket observed data. If the observed data are out of coverage or different in shape to scoping runs then uncertain parameters range might be enlarged. Tornado chart and the proxy model plots are used to identify the most and least sensitive parameters. This situation could initiate looping-back process when discussion with geophysicist, geologist and petrophysicist suggesting uncertain parameter alteration.

Refinement runs are iteration process similar to previous steps at local area only. This local area also called history match area or plausible area. ENABLE has algorithm to search most likely range of uncertain after comparing the prior proxy model with observed data. Some observed data points with tolerance interval were picked as estimator points. The tolerance intervals are indicator of our acceptance to outcome of history matching. In this study, noisy observed data are smoothed and set the range of noise as tolerance. Eighty refinements were performed to satisfy history match quality. Figure 14 shows reservoir simulation workflow using assisted history match technique.

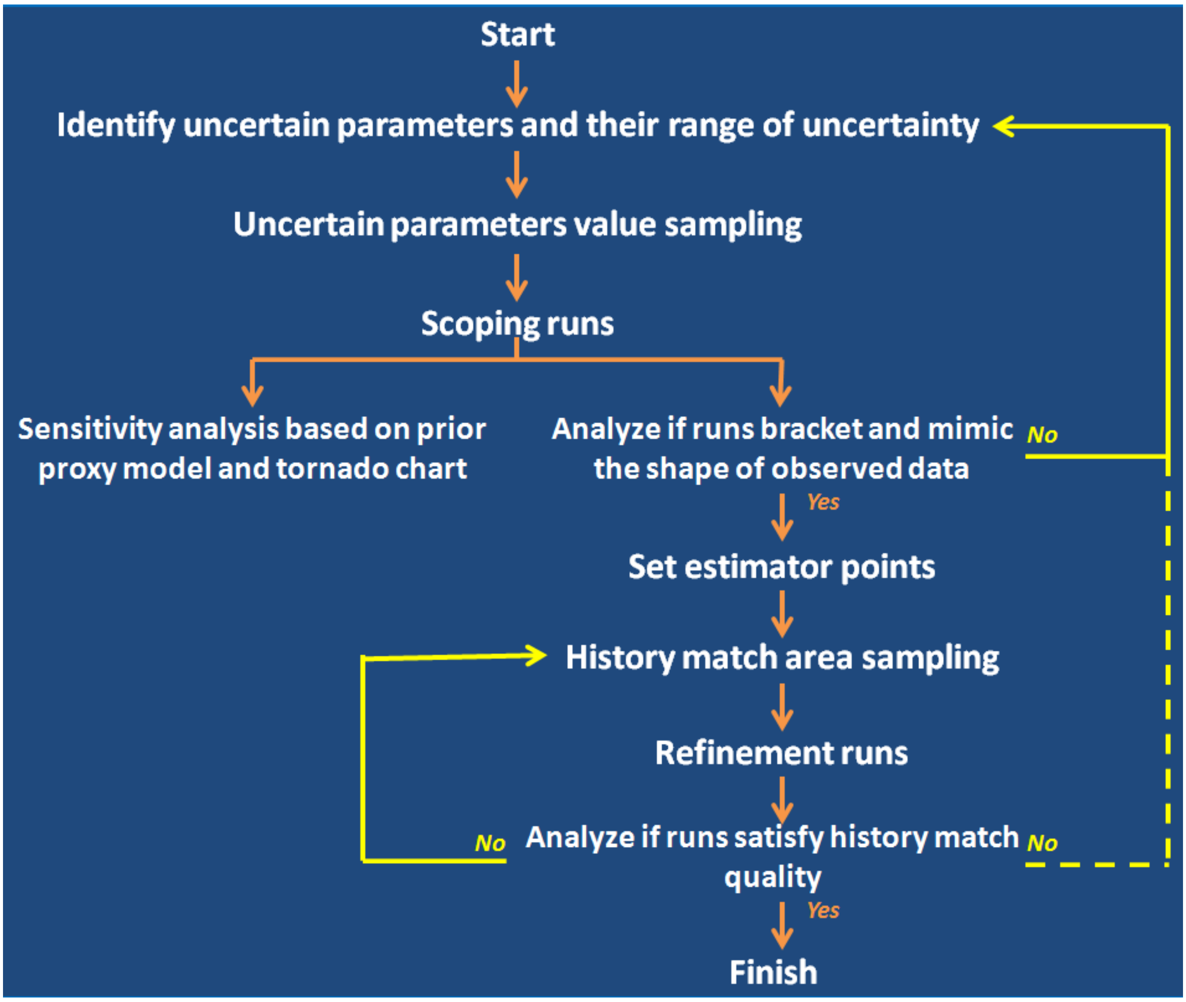

Figure 14: Assisted history match workflow on Tempest ENABLE

Some decisions that should be done by reservoir engineer together with subsurface team are the need for data modification, satisfactory criteria judgment and initial results analysis. More complete on these are listed below:

- If observed data smoothing is required
- If initial parameterization sufficient to reach satisfactory history match
- If initial uncertainty range sufficient to reach satisfactory history match
- If there is any information to focus on certain uncertainty range
- Estimator point location selection
- Number of runs

Chapter 4 Model description

4.1 Initial structural model

A synthetic field was built and set up to be used on this study. Initial structure and grid model is provided by Roxar. The model consists of:

- Total cells : 30000
- Grid dimensional : 50 x 50 x 12
- Grid size : 159 m x 159 m
- Number of faults : 2
- Number of layers : 12
- Number of zones : 4

The model contains two non-intersecting faults. They are communicating with the surround structures. All of the zones consist of three layers each. The first zone located on top while last zone located on bottom. The first and third zones have 5 m thickness while the rest have 10 m thickness, each. Figure 15 shows the initial structure and grid model.

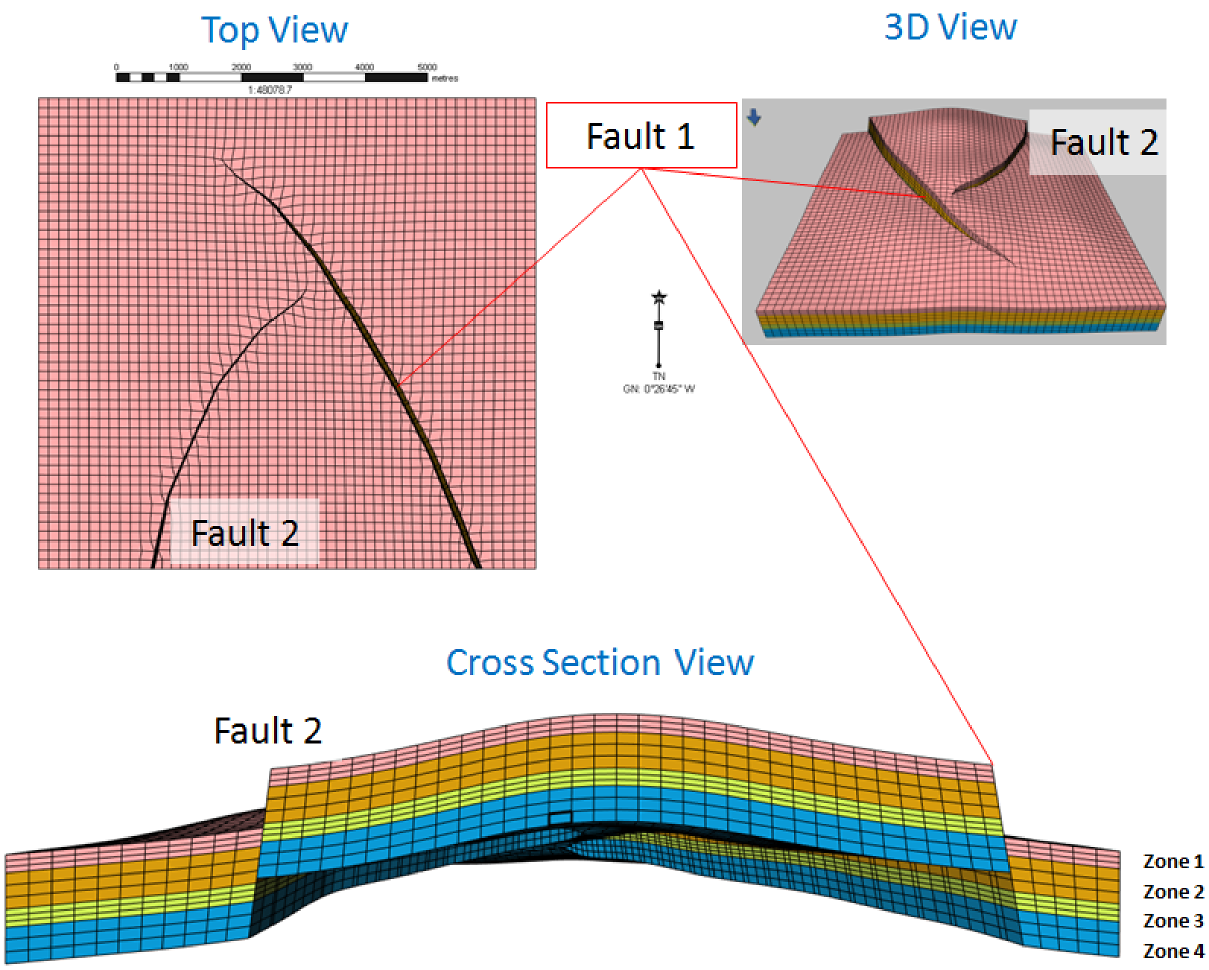

Figure 15: Initial structure and grid model

Fault 1 and Fault 2 have uncertainty range of 100 m to each opposite direction. Parameterization used in this study is shown in Table 1. Figure 16 describes the fault movement direction within fault uncertainty envelope.

Table 1: Parameterization

Parameters	Minimum	Maximum
Fault 1	100 m toward inner side	100 m toward outer side
Fault 2	100 m toward inner side	100 m toward outer side

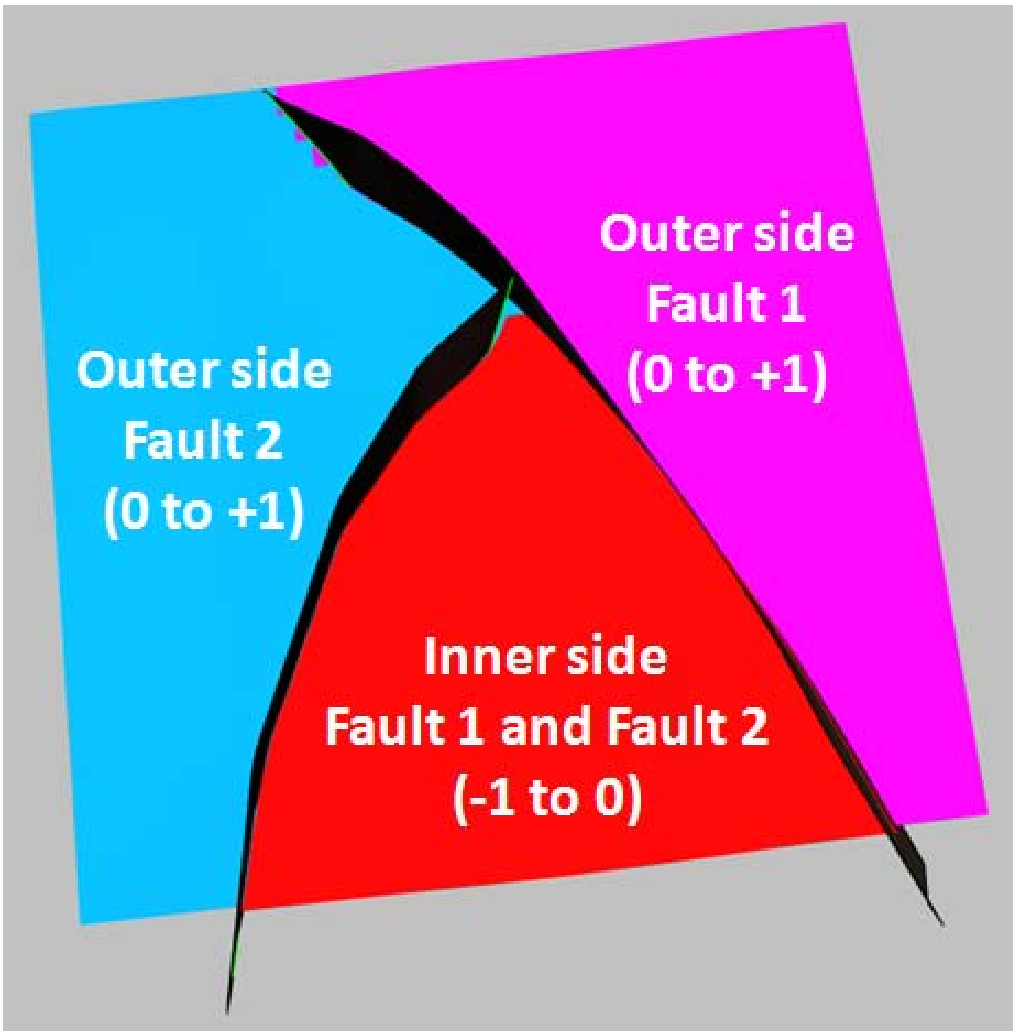

Figure 16: Fault movement direction within fault uncertainty envelope

The faults are built with low angle. In combination with perpendicular movement, they have consequence will not intersected with model and disappear. Figure 17 show the illustration of fault disappearance as a consequence of low angle fault combined with perpendicular movement. The problem of non-intersected model is solved by extending the length of the faults.

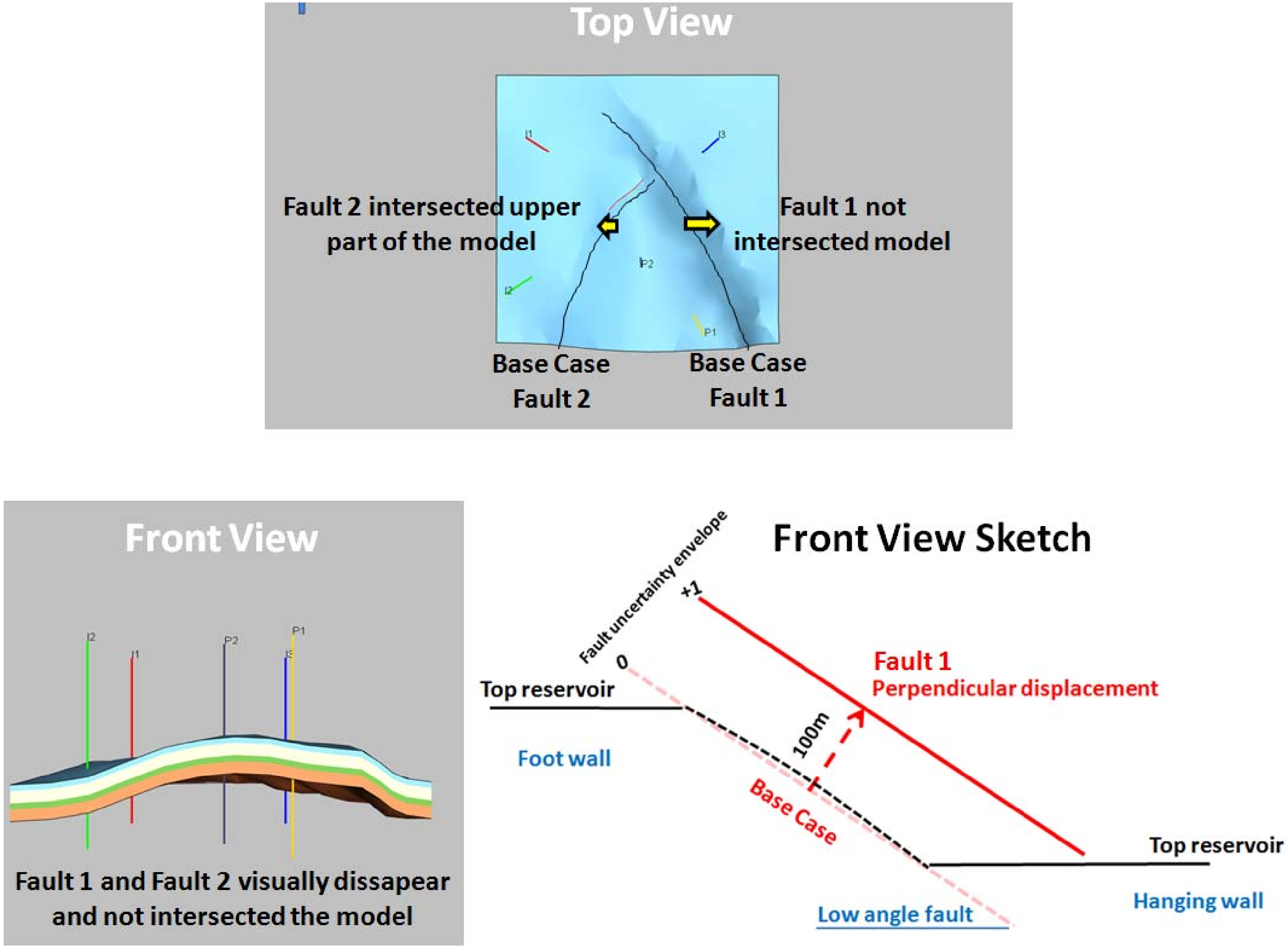

Figure 17: Fault disappearance as a consequence of low angle fault combined with perpendicular movement

4.2 Base Case model set up

Base Case set up is selected for geo-model and then reservoir simulation. The building Base Case from synthetic field requires trial and error set up of reservoir property and perforation intervals, to come up with a case suitable to demonstrate this study's objective. Top reservoir model is located at 1039 m and bottom reservoir model at 1110 m. A two-phase system of oil and water is chosen to simplify later history match process. The oil reservoir is saturated and contained with a very low solution gas-oil ratio (Rs). Hence the gas rate, gas cumulative and gas-oil-ratio (GOR) are omitted. Subsequently, oil and water contact (OWC) set to 1070 m. Two vertical producers (well P1 and well P2) are placed in the middle structure while three injectors (well I1, well I2 and well I3) are placed on the flank where contain 100% water. These injectors act as pressure support to prevent significant pressure drop. Figure 18 and Figure 19 show location of wells from different angle of views. Porosity is assumed to be homogenous with value 25%. The horizontal permeabilities set up are listed as follow:

- Thinner zone (layer 1 & 3) : 500 mD
- Thicker zone (layer 2 & 4) : 50 mD

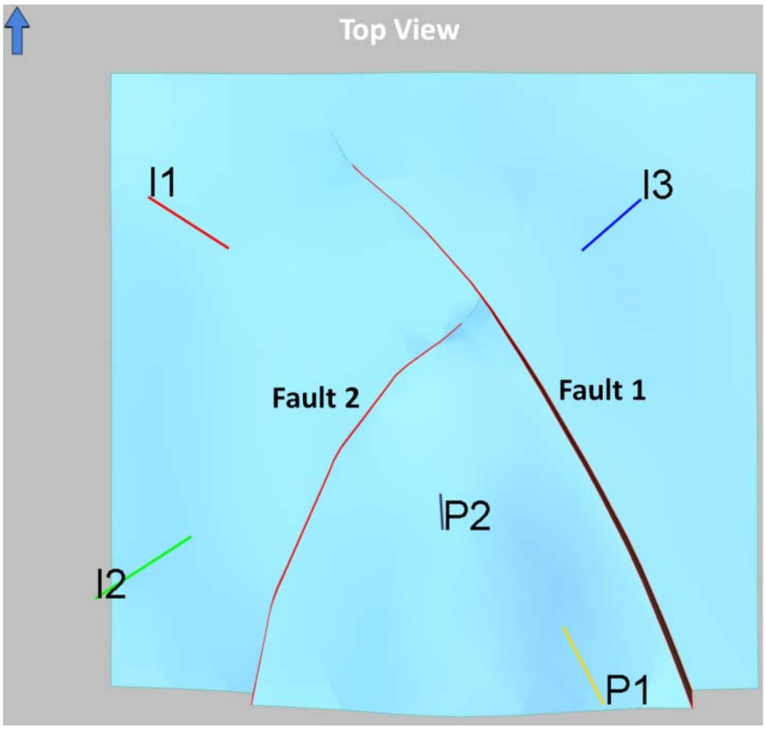

Figure 18: Geo-model with wells from top view

Net-to-gross ratio set to 1 for the entire grid, while water saturation set to 0.2 above the OWC. To convert reservoir to surface volume, oil formation volume factor ranging from 1.1916 to 1.1965 are used. Table 2 shows volumetric calculations for geo-model Base Case:

Table 2: Volumetric calculation for geo-model Base Case

Zone	Bulk Volume (krm^3)	Net Volume (krm^3)	Pore Volume (krm^3)	HCPV (krm^3)	STOIIP (ksm^3)
1	105.69	105.69	26.42	21.14	17.68
2	158.84	158.84	39.71	31.77	26.58
3	61.12	61.12	15.28	12.22	10.23
4	37.85	37.85	9.46	7.57	6.34
Totals	363.50	363.50	90.88	72.70	60.83

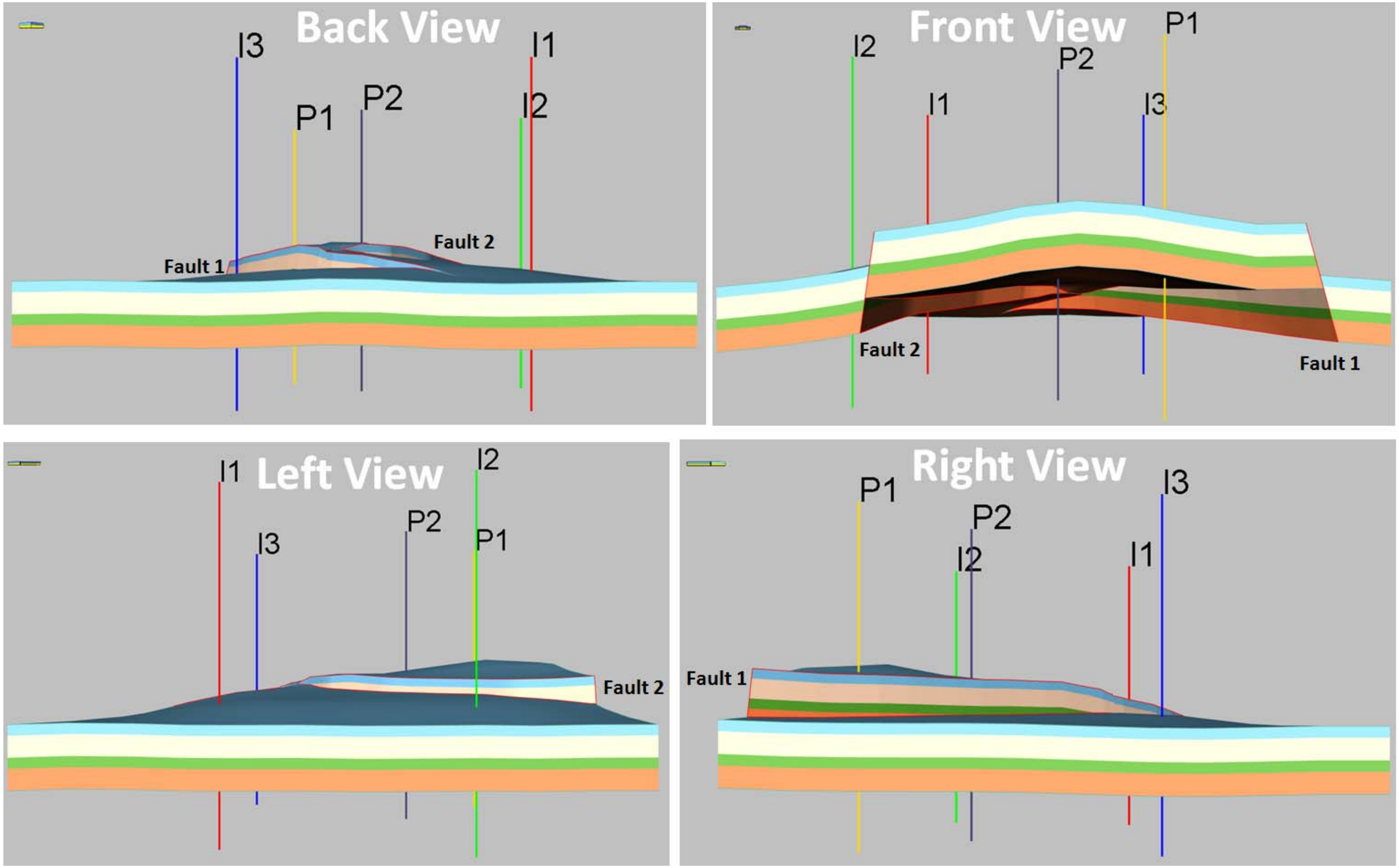

Figure 19: Geo-model with wells from back, front, left and right views

Vertical permeability was initially set to a factor of 0.5 multiplied by horizontal permeability. The following reservoir simulation results by varying fault positions didn't show significant difference. Water breakthrough from water zone, also known as water coning, was dominating. Later on, vertical permeability value is decreased to a factor of 0.1 multiplied by horizontal permeability. This geo-model is agreed as Base Case to be used on following process. In addition to delay water coning effect, perforations are lifted up. For producer wells, perforation set far above OWC at 1047-1054 m. While for injector wells, perforation were kept just below the OWC at 1072-1082 m. The effect of varying fault position in water cut performance is represented in three realizations. Figure 20 shows oil rate and water cut performance between well P1 and well P2.

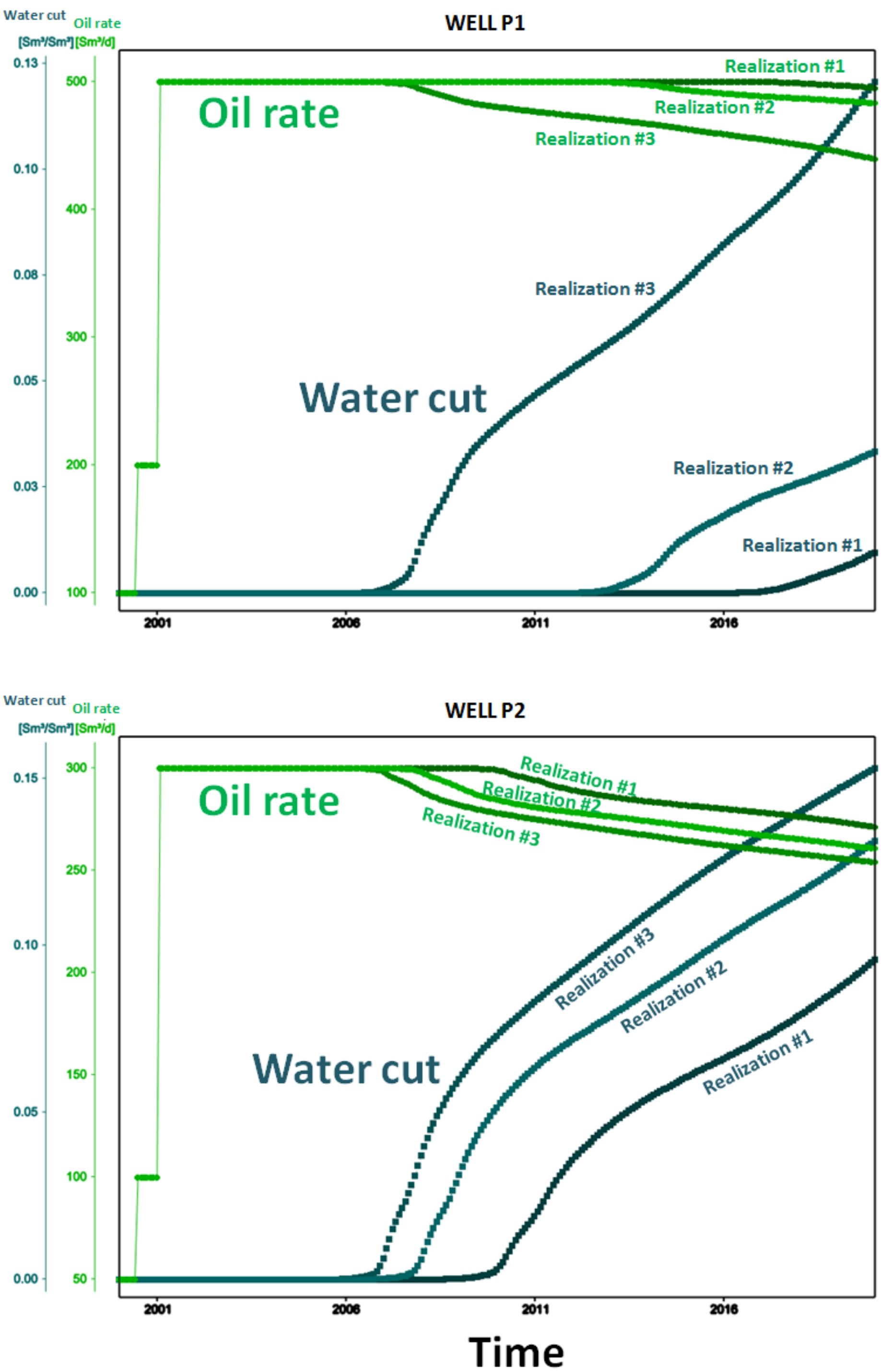

Figure 20: Oil rate and water cut from well P1 and P2

Reservoir simulation is performed for 20 years from 01/01/2000 until 01/01/2020. Time step for simulation is 1 month. Initial reservoir pressure set to 200 bar at reference depth 1000 m. Bottom-hole pressure data are available as we assume there is permanent down-hole gauge on each well.

For producer wells, liquid production target (oil + water) is chosen as constraint so that history matching focuses on oil-water proportion. For injector wells, water injection target is a parameter that could be controlled in field. To avoid BHP exceeds formation fracture pressure, 210 bar is selected as constraint which is not far from initial reservoir pressure. Initial completion events to generate reference or true observed data set as shown in Table 3:

Table 3: Initial production events to generate reference or true observed data

Time	Well	Primary constraint (m^3)		Secondary constraint (bar)	
01/01/2000	P1	Liquid Production Target	100	-	
	P2	Liquid Production Target	50	-	
	I1	Water Injection Target	300	BHP	210
	I2	Water Injection Target	300	BHP	210
	I3	Water Injection Target	300	BHP	210
01/06/2000	P1	Liquid Production Target	200	-	
	P2	Liquid Production Target	100	-	
	I1	Water Injection Target	400	BHP	210
	I2	Water Injection Target	400	BHP	210
	I3	Water Injection Target	400	BHP	210
01/01/2001	P1	Liquid Production Target	500	-	
	P2	Liquid Production Target	300	-	

"TRUE" observed (measurement) data are generated by using Fault 1 position at 72 m toward outer side and on Fault 2 position at 23 m toward inner side. For position movement toward outer side, zero and positive-sign are used. While negative-sign is used to represent movement toward inner side. For Fault 1, movement to the right is considered outer side while for Fault 2 is the opposite. The following observed data are generated:

- Well P1: Bottom-hole pressure, oil rate and water rate
- Well P2: Bottom-hole pressure, oil rate and water rate
- Well I1: Bottom-hole pressure
- Well I2: Bottom-hole pressure
- Well I3: Bottom-hole pressure

The observed data are added noise to represent actual measurement fluctuation. Figure 21 shows the equation used to add noise.

Final value = Initial value * (1 + % noise * [Random Number - 0.5])

Where,

% noise for oil and water rate = 10%

% noise for BHP = 5%

Figure 21: Equation used to added noise on observed data

A comparison of a history match using original observed data and smoothed observed data is performed. The result is not sensitive to smoothed data. Data smoothing is applied to:

- Interval of time when the condition is the same (on production at the same choke size)
- Interval with clear trend

Then smoothed observed data is used in history matching with range of noise set as tolerance. Figure 22 shows example of smoothed data for oil rate measurement from well P1. Complete smoothed data for well P1 and P2 can be found in Appendix A.

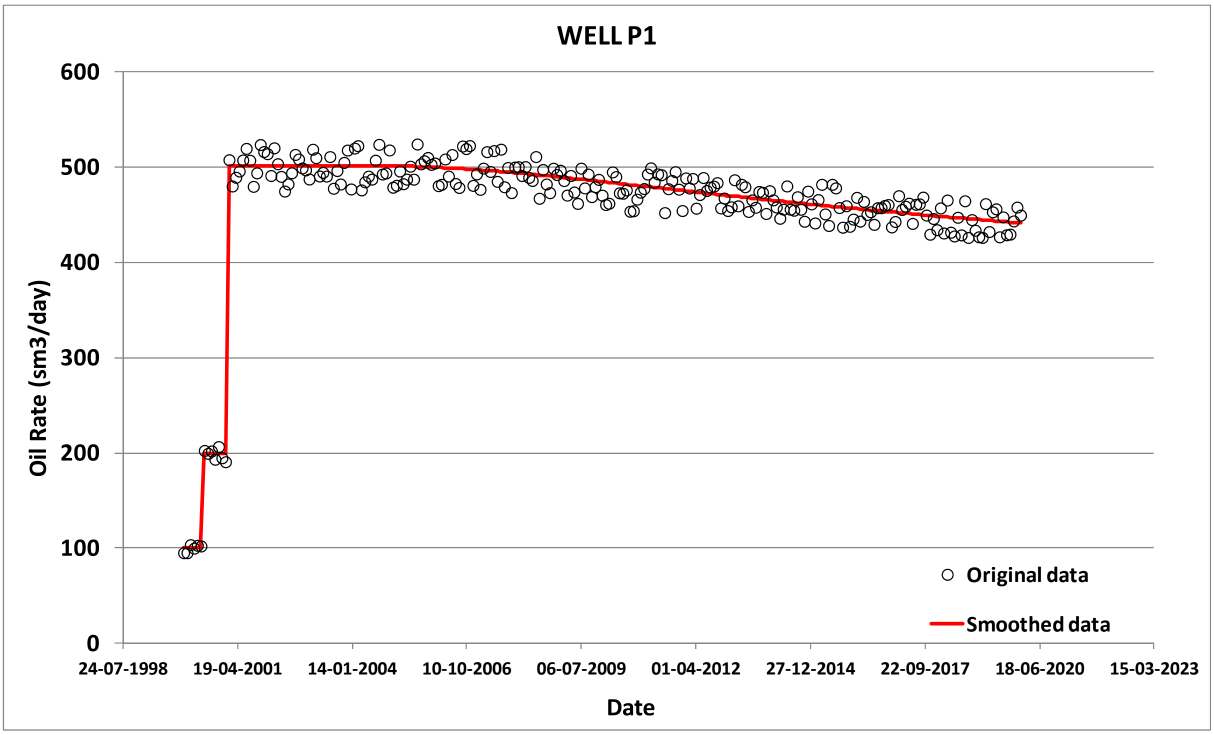

Figure 22: Example of smoothed data

The reference depth for simulated pressure set to 1040 m for all wells. This way, pressure data from all wells can be compared without bias of different perforations depth. Production and pressure data constraints are following smoothed data.

The formation volume factor (Bo) is a function of pressure while pressure itself is a function of depth. In reservoir simulation set up, Bo set to 1.1992 at 200 bar which correspond to 1000 m. This value will be interpolated to mid-point grid from 1039 m to 1110 m. Rock and other fluid input properties are presented on Appendix B.

Manual from ENABLE suggested picking two or three observed data points for matching prioritization. These points should be able representing trend or shape of production profile. After picking certain time step on a well variable, tolerance interval is defined. In the software application, these points are called estimator points. As the history match got challenging, a few points can be added. The estimator points shouldn't be placed in the beginning or at the first point where significant changes occur. In general, trend of performance curves are captured at:

- 1 Jan 2008: at 40% of total data
- 1 Jan 2015: at 75% of total data
- 1 Jan 2020: at 100% of total data

Selected estimator points with tolerance are shown in Table 4. In a real field case with many wells, it will not be practical to pick estimator points manually. This input section should have options to choose whether user-defined, data percentile or other innovative algorithm. For newly producing wells, an estimator point is sufficient. Thus, all the wells should be grouped based on number of available observed data. For example, three estimator points are assigned to upper-group. Upper-group is for those wells with more than 67% of total number of data. Subsequently, middle and lower-group are assigned with two (between 33% and 67% of total number of data) and one (less than 33% of total number of data) estimator points. Different treatment might be applied to infrequent pressure data such as bottom-hole pressure.

Table 4: Estimator points with tolerance

Well	Variable	Time	Tolerance
P1	wbhp	01-Jan-15	4 bar
P1	wopt	01-Jan-15	139.6 ksm^3
P1	wwpt	01-Jan-15	8 ksm^3
P1	wbhp	01-Jan-08	4 bar
P1	wwct	01-Jan-08	0.006
P1	wwct	01-Jan-20	0.006
P2	wbhp	01-Jan-15	4 bar
P2	wopt	01-Jan-15	72.1 ksm^3
P2	wwpt	01-Jan-15	8.1 ksm^3
P2	wbhp	01-Jan-08	4 bar
P2	wwct	01-Jan-08	0.006
P2	wwct	01-Jan-20	0.006

Remarks:
wbhp: well bottom-hole pressure
wopt: well oil production total
wwpt: well water production total
wwct: well water cut

Chapter 5 Discussion of results

This chapter will present and discuss results from Base Case and assisted history matching. The first section will compare Base Case result and observed data to show initial deviation prior to any history matching effort.

The second section will present assisted history matching processes from sampling, proxy model building to uncertainty reduction. Latin Hypercube sampling for both scoping and refinement runs will be shown in tabulation. Afterwards, the most influent modifier is discussed using diagnostic plot and proxy model plot. Consequence in unphysical proxy model values in some regions and suggestion to solve this finding will be analyzed. Final result of history matching in graphical and proxy model plot are presented including uncertainty reduction in production performance, initial oil in place, recovery factor and indirectly bulk rock volume. Number of runs to finalize the study is determined using estimator statistics plot as describe in the last part of this chapter.

5.1 Base Case result

Base Case simulation result is compared to observed data to show initial deviation in graphical plots. Prior to these results, consistency of initial oil in place should be checked. It is normal to have a small difference between calculation from RMS geo-model and Tempest reservoir simulation software applications. A difference up to 10% is still acceptable in some cases. The main differences are from input parameters such as water saturation and oil formation volume factor (Bo). Table 5 below shows comparison of initial oil in place from different applications. Stability run could be performed to check equilibrium of reservoir model.

Table 5: Comparison of oil in place from RMS and Tempest

Source	Oil in Place (ksm^3)
RMS - Geomodel	60.83
Tempest - Initialization	60.59
difference	0.40%

Figure 23 to Figure 30 show reservoir simulation results from Base Case. Compare to observed data with interval tolerance, well P1 deviated more than well P2. This also means that fault position variation less influent to well P2. Well P1 located nearer to Fault 1 than well P2. This preliminary analysis implied that Fault 1 position was the most sensitive parameter to production performance. In terms of variable, bottom-hole pressure (BHP), water cumulative production (Wp) and water cut (WC) required more effort in the history matching process.

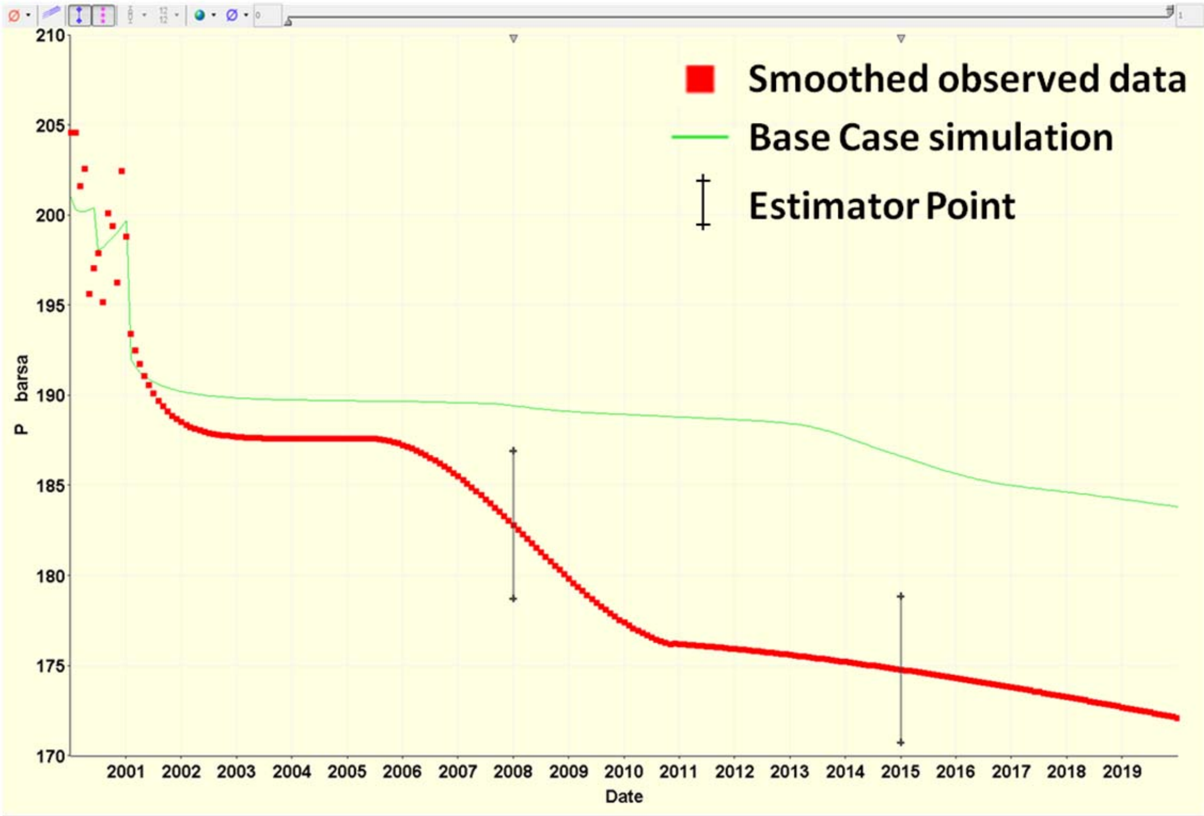

Figure 23: Comparison of smoothed observed data and Base Case result - BHP well P1

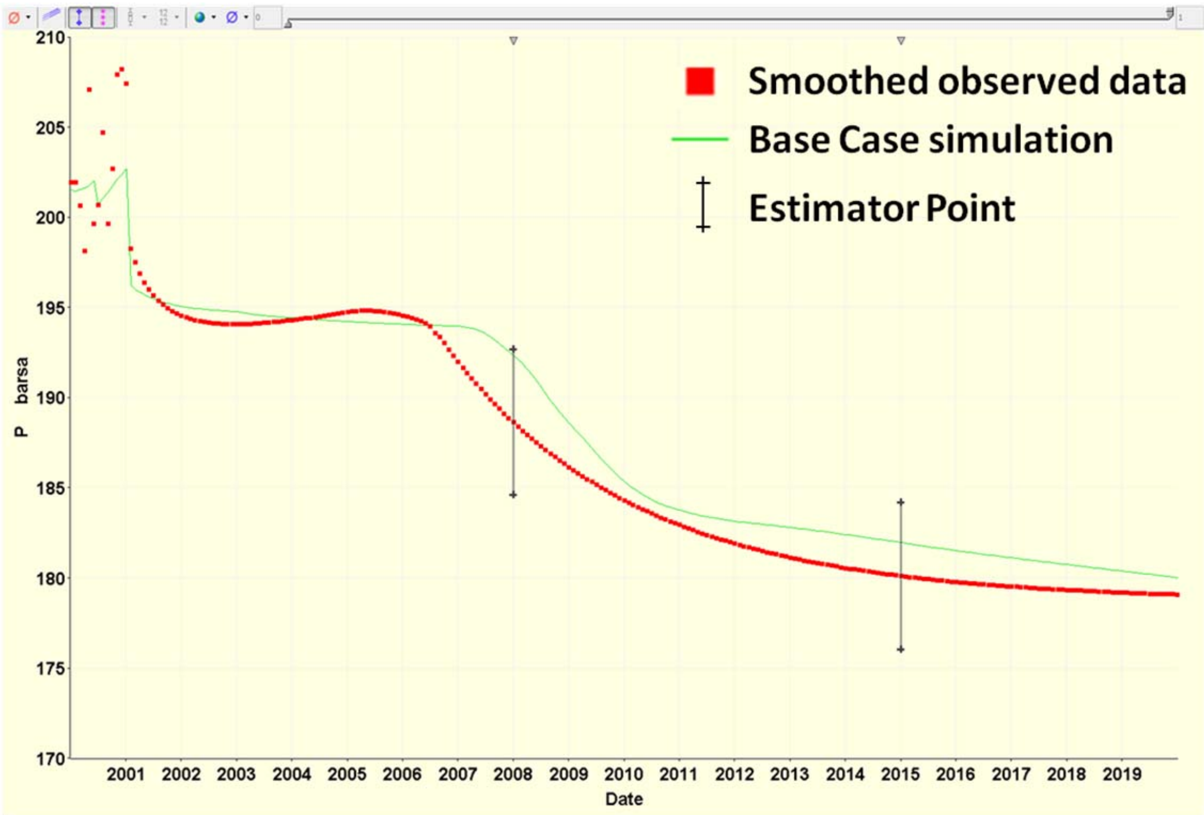

Figure 24: Comparison of smoothed observed data and Base Case result - BHP well P2

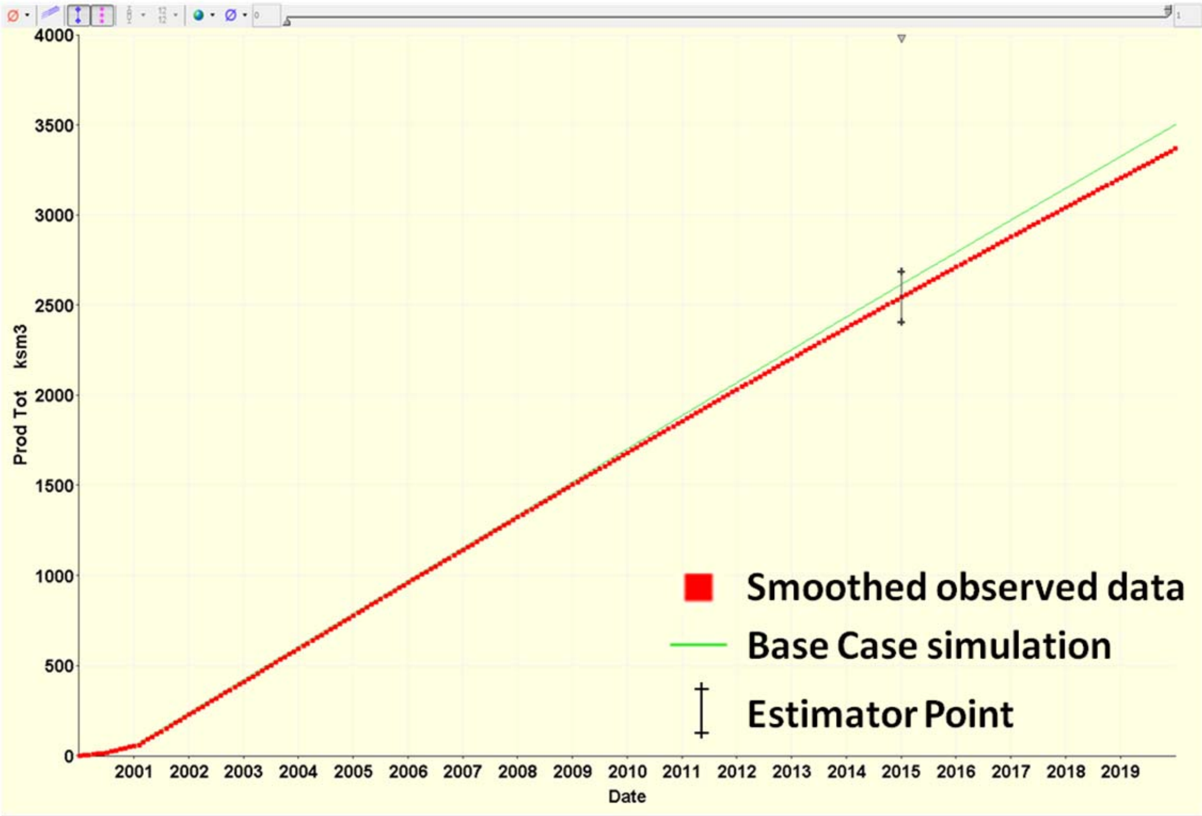

Figure 25: Comparison of smoothed observed data and Base Case result – Cumulative oil production well P1

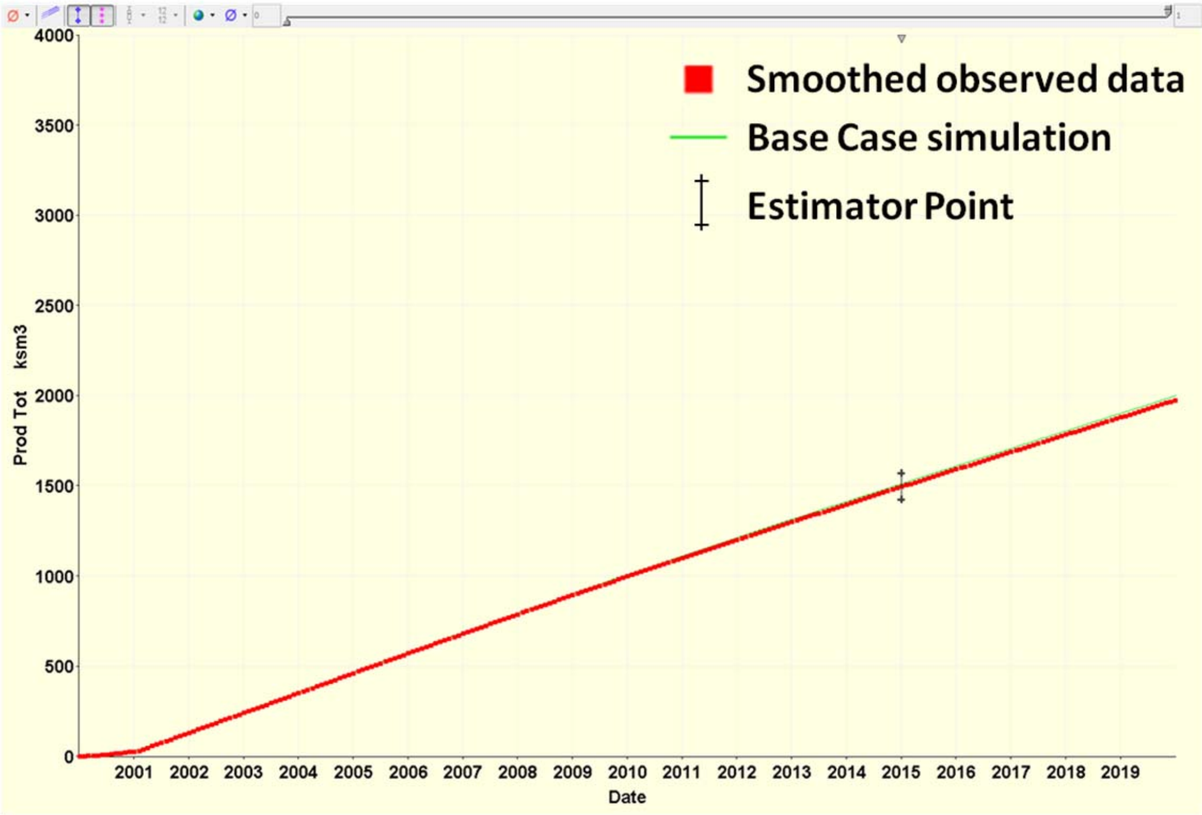

Figure 26: Comparison of smoothed observed data and Base Case result – Cumulative oil production well P2

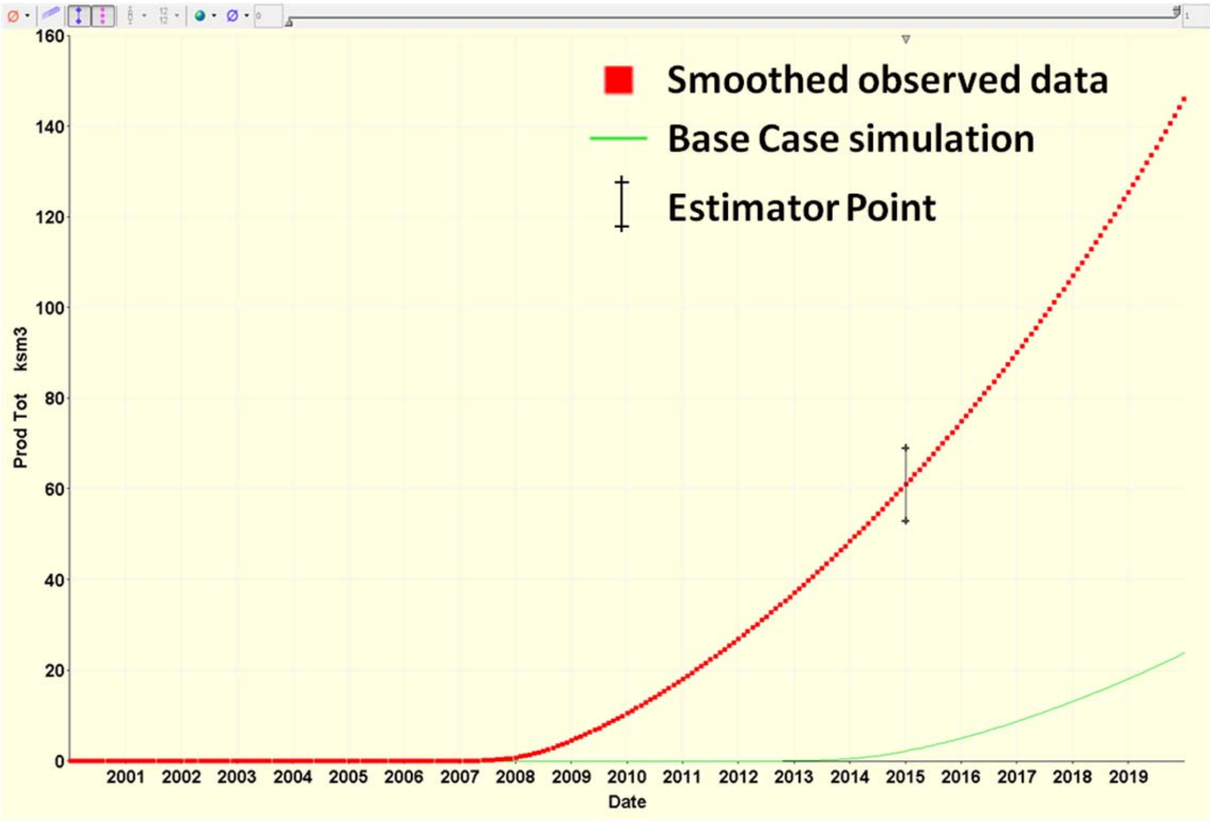

Figure 27: Comparison of smoothed observed data and Base Case result – Cumulative water production well P1

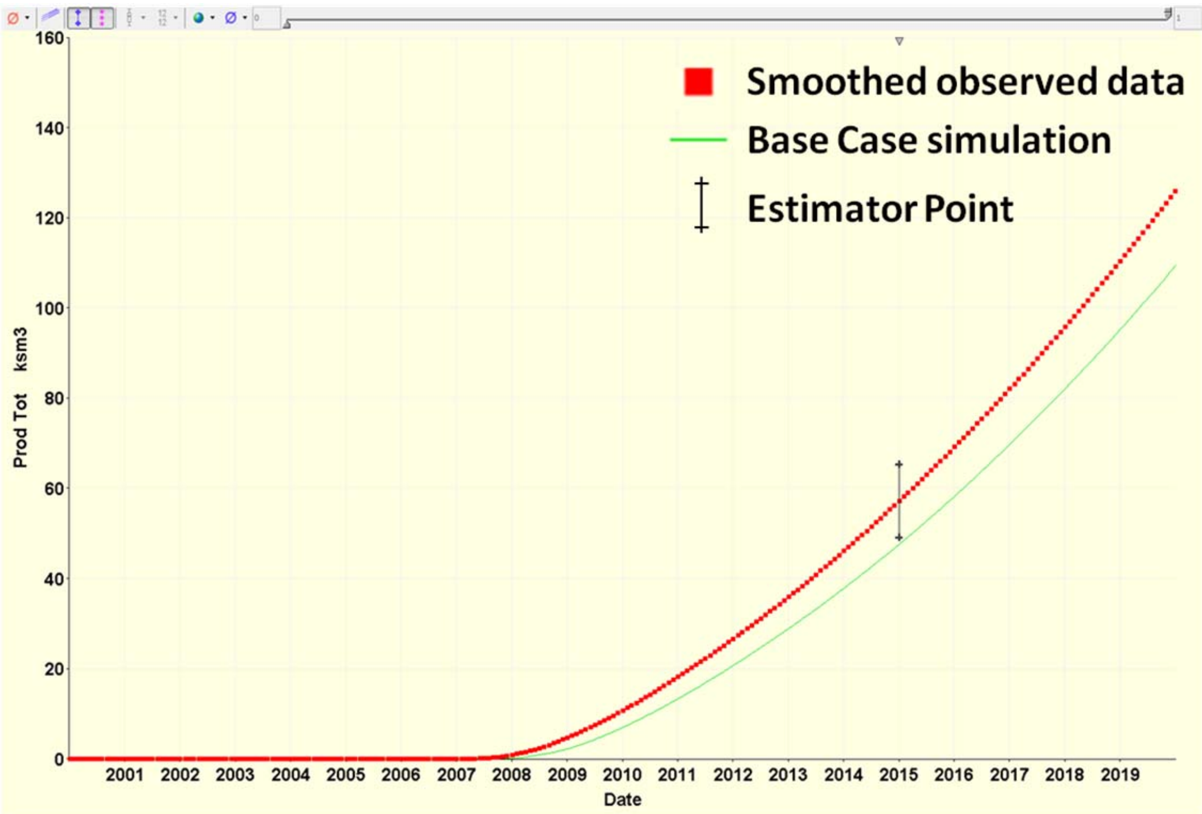

Figure 28: Comparison of smoothed observed data and Base Case result – Cumulative water production well P2

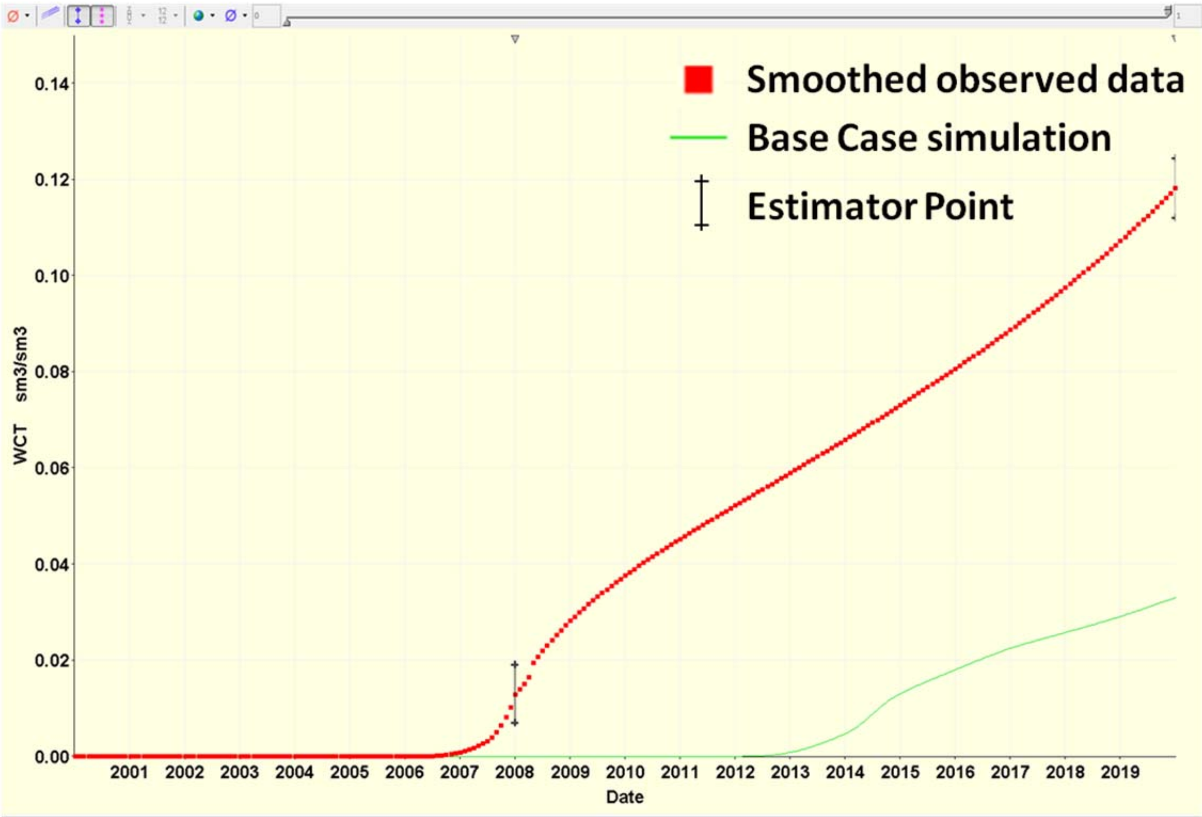

Figure 29: Comparison of smoothed observed data and Base Case result – Water cut well P1

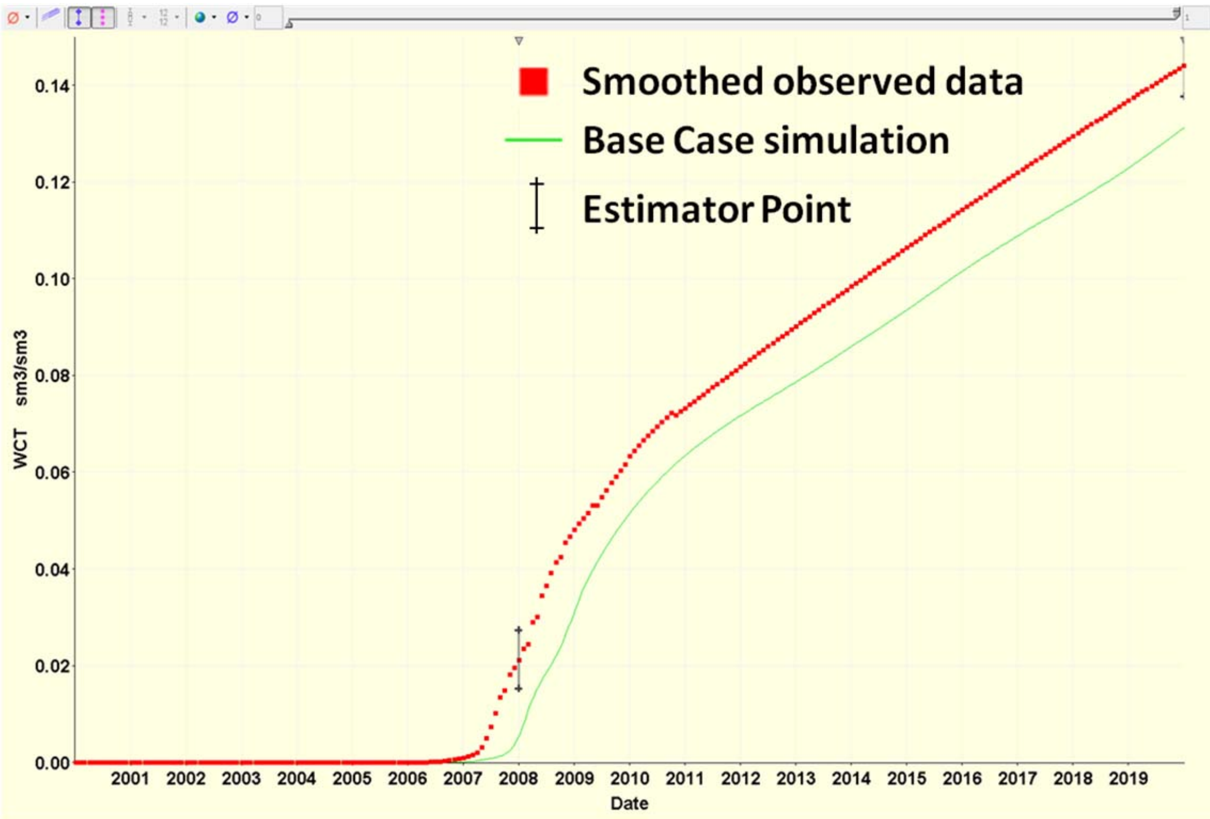

Figure 30: Comparison of smoothed observed data and Base Case result – Water cut well P2

5.2 Assisted history matching result

Experimental design with Latin Hypercube sampling for scoping and refinement runs are shown in Table 6. As scoping runs bracket the observed data, it means selected parameterizations were sufficient to reach satisfactory history match. The most influential parameter modifier was analyzed with tornado chart and the proxy model plot. Number of modifiers set to two to enable visualization of response surface of proxy model in 2 dimensional and 3 dimensional plots.

Figure 31 shows tornado chart of water cut in well P1 on 1 January 2020. It clearly describes high correlation between Fault 1 and water cut of well P1. In fact, Fault 2 position movement would never deliver acceptable history match quality. Both upper (positive) and lower (negative) values range of uncertainty would increase water cut. To match tolerated observed data (0.11817 ± 0.00621), a high positive range of Fault 1 position is expected. This is consistent with the prior proxy model that showed high influence from Fault 1 with visual range between 0.5 and 1 would intersect observed data. On the other side, Fault 2 position remained uncertain. The prior proxy model for this estimator point is showed in Figure 32.

Another result example was bottom-hole pressure well P2 on 1 January 2008. The observed data is 188.64 bar with tolerance ± 4 bar. Figure 33 shows a tornado chart of the bottom-hole pressure in well P2 on 1 January 2008. Fault 1 is still a dominating parameter while Fault 2 position movement is intersected with tolerance interval. Both Fault 1 and Fault 2 give negative correlation. It means upper (positive) value would give lower BHP value and the opposite. The prior proxy model for this estimator point is shown in Figure 34 to support the analysis. Increasing Fault 1 position value will generally decrease BHP value. The proxy model intersects observed data in the range of Fault 1 between 0.5 and 1. BHP becomes sensitive to Fault 2 position particularly in the region of upper value of Fault 1.

The version of software used is producing unphysical proxy model values in some regions. These occurred for the following estimator points:

- Well P1 for wwpt on 1 Jan 2015
- Well P1 for wwct on 1 Jan 2008
- Well P1 for wwct on 1 Jan 2020
- Well P1 for wwct on 1 Jan 2008

The Base Case model is built with sensitive to water production. At certain fault positions, it would produce very low water production. One of the equations that build the proxy model is polynomial equation. This equation oscillates at low water production and then down to below zero. At the other region of fault positions, the proxy models increase and intersect with observed values. There is no accuracy implication rather than visual look of the graphs. Suggestion for the future version of the software is applying truncation rule to obtain non-negative values.

After setting estimator points, Latin Hypercube sampling for the first 20 refinement runs are performed. The algorithm within ENABLE would lead the sampling on local (plausible) area where estimator points intersected with the proxy models. This area also called plausible area where sampling points represented by yellow dots on following figures. A total of 80 refinement runs in 4 steps were performed to satisfy history match quality.

Table 6: Sampling points

Scoping runs

User Modifier	Scope1	Scope2	Scope3	Scope4	Scope5	Scope6	Scope7	Scope8	Scope9	Scope10	Scope11	Scope12	Scope13	Scope14	Scope15	Scope16	Scope17	Scope18	Scope19	Scope20
F2position	0	-0.793251	0.972467	-0.136018	0.150838	0.641775	0.0415749	0.216935	0.564418	-0.262522	-0.320031	0.709364	-0.483907	0.812078	0.407622	-0.0461717	-0.517333	0.363659	-0.825509	-0.626489
F1position	0	0.303521	0.714948	-0.612203	-0.217382	0.0342203	0.81189	0.171613	0.677422	0.916984	0.529145	-0.325125	-0.46227	0.257268	0.420594	-0.939455	-0.0561897	-0.896855	-0.147224	-0.723142

1st step refinement runs

User Modifier	Refine21	Refine22	Refine23	Refine24	Refine25	Refine26	Refine27	Refine28	Refine29	Refine30	Refine31	Refine32	Refine33	Refine34	Refine35	Refine36	Refine37	Refine38	Refine39	Refine40
F2position	0.554959	0.520895	0.504089	-0.322574	-0.269958	-0.240801	-0.248675	-0.259599	-0.238295	-0.251528	-0.180848	-0.357876	-0.299267	-0.216121	-0.251949	-0.174156	-0.154823	-0.285926	-0.265221	-0.251634
F1position	0.670564	0.642858	0.635322	0.524281	0.622784	0.631855	0.619072	0.656195	0.670351	0.661879	0.648022	0.668617	0.684046	0.656078	0.66177	0.648714	0.643131	0.679241	0.661638	0.661614

2nd step refinement runs

User Modifier	Refine41	Refine42	Refine43	Refine44	Refine45	Refine46	Refine47	Refine48	Refine49	Refine50	Refine51	Refine52	Refine53	Refine54	Refine55	Refine56	Refine57	Refine58	Refine59	Refine60
F2position	-0.256052	-0.307451	-0.357152	-0.243272	-0.283796	-0.28497	-0.324273	-0.212673	-0.190705	-0.283793	-0.187435	-0.264952	0.0570842	-0.239188	-0.262631	-0.281165	-0.319404	-0.192918	-0.154249	-0.283794
F1position	0.652897	0.682752	0.67636	0.786223	0.677737	0.835667	0.692432	0.656117	0.643053	0.677709	0.639442	0.666837	0.78482	0.641195	0.660351	0.674599	0.689727	0.595481	0.51118	0.677709

3rd step refinement runs

User Modifier	Refine61	Refine62	Refine63	Refine64	Refine65	Refine66	Refine67	Refine68	Refine69	Refine70	Refine71	Refine72	Refine73	Refine74	Refine75	Refine76	Refine77	Refine78	Refine79	Refine80
F2position	-0.175963	-0.322624	-0.405616	-0.299789	-0.294076	-0.302217	-0.240049	-0.3539	-0.238243	-0.236444	-0.368093	-0.281365	-0.36186	-0.370959	-0.285409	-0.101768	-0.220641	-0.306917	-0.232653	-0.236448
F1position	0.653431	0.677808	0.683054	0.682265	0.671137	0.679259	0.637609	0.640537	0.615613	0.63855	0.676508	0.660924	0.63534	0.638039	0.657891	0.684358	0.605111	0.681881	0.664747	0.638539

4th step refinement runs

User Modifier	Refine81	Refine82	Refine83	Refine84	Refine85	Refine86	Refine87	Refine88	Refine89	Refine90	Refine91	Refine92	Refine93	Refine94	Refine95	Refine96	Refine97	Refine98	Refine99	Refine100
F2position	-0.285222	-0.340641	-0.29341	-0.227976	-0.303811	-0.334326	-0.376757	-0.188393	-0.359801	-0.206015	-0.379709	-0.285218	-0.313564	-0.284516	-0.304041	-0.132886	-0.257044	-0.21324	-0.275916	-0.202992
F1position	0.66482	0.679947	0.68954	0.668223	0.689348	0.685932	0.685678	0.66263	0.649852	0.66927	0.689801	0.66419	0.681753	0.67001	0.691263	0.674453	0.668367	0.673668	0.683849	0.669478

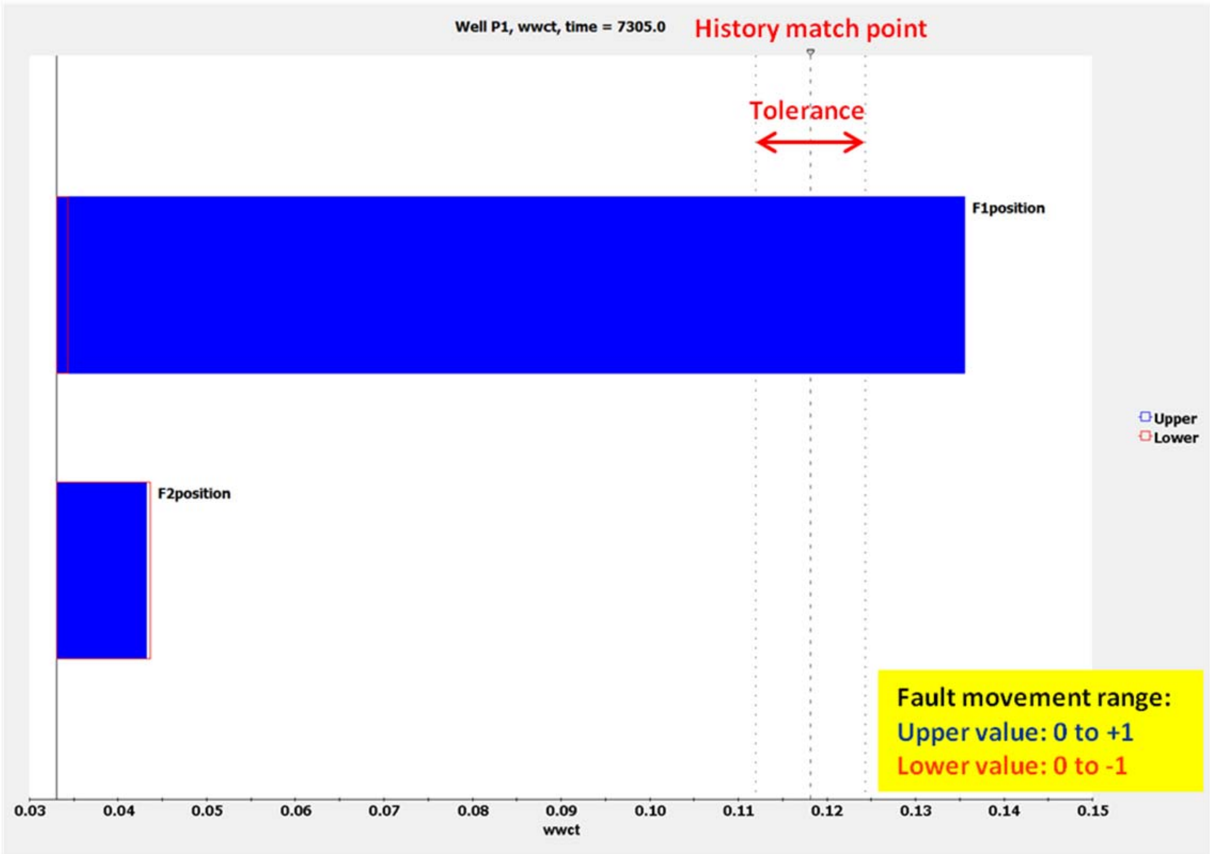

Figure 31: Tornado chart of water cut well P1 on 1 January 2020

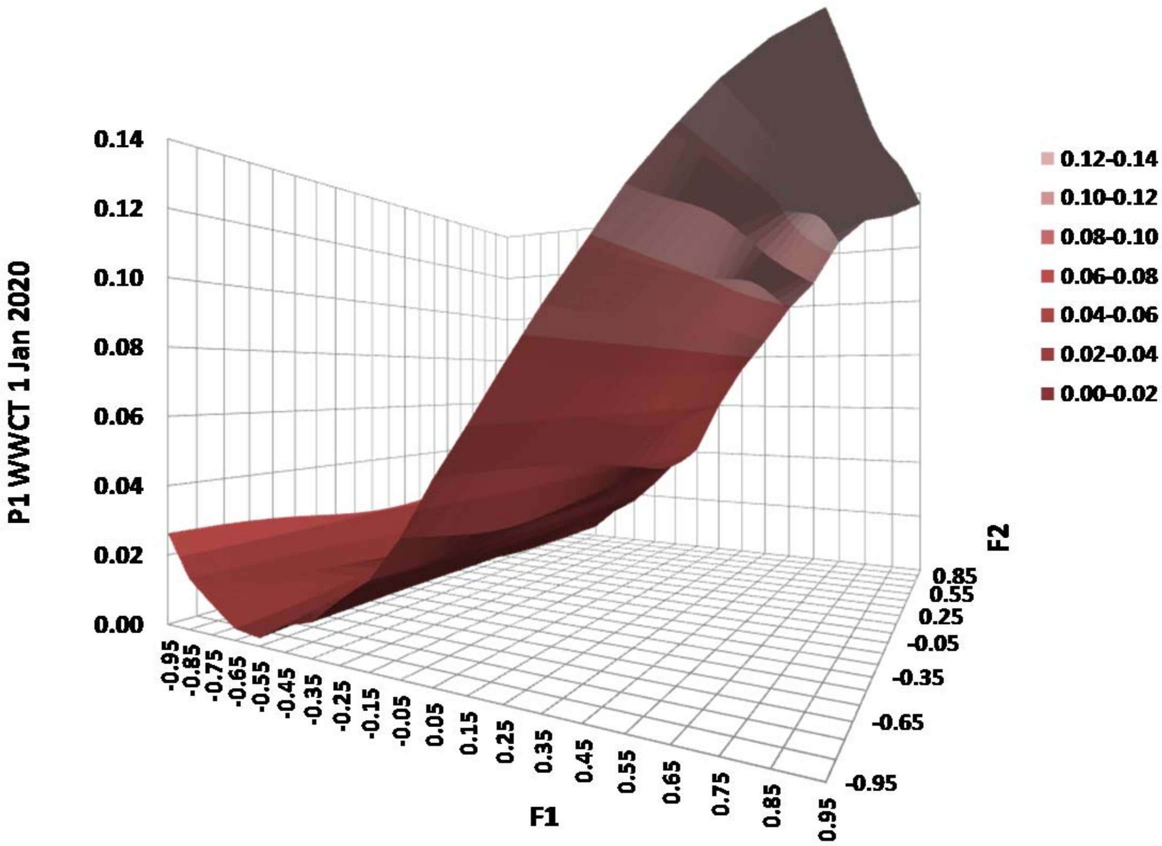

Figure 32: The prior proxy model of water cut well P1 on 1 January 2020

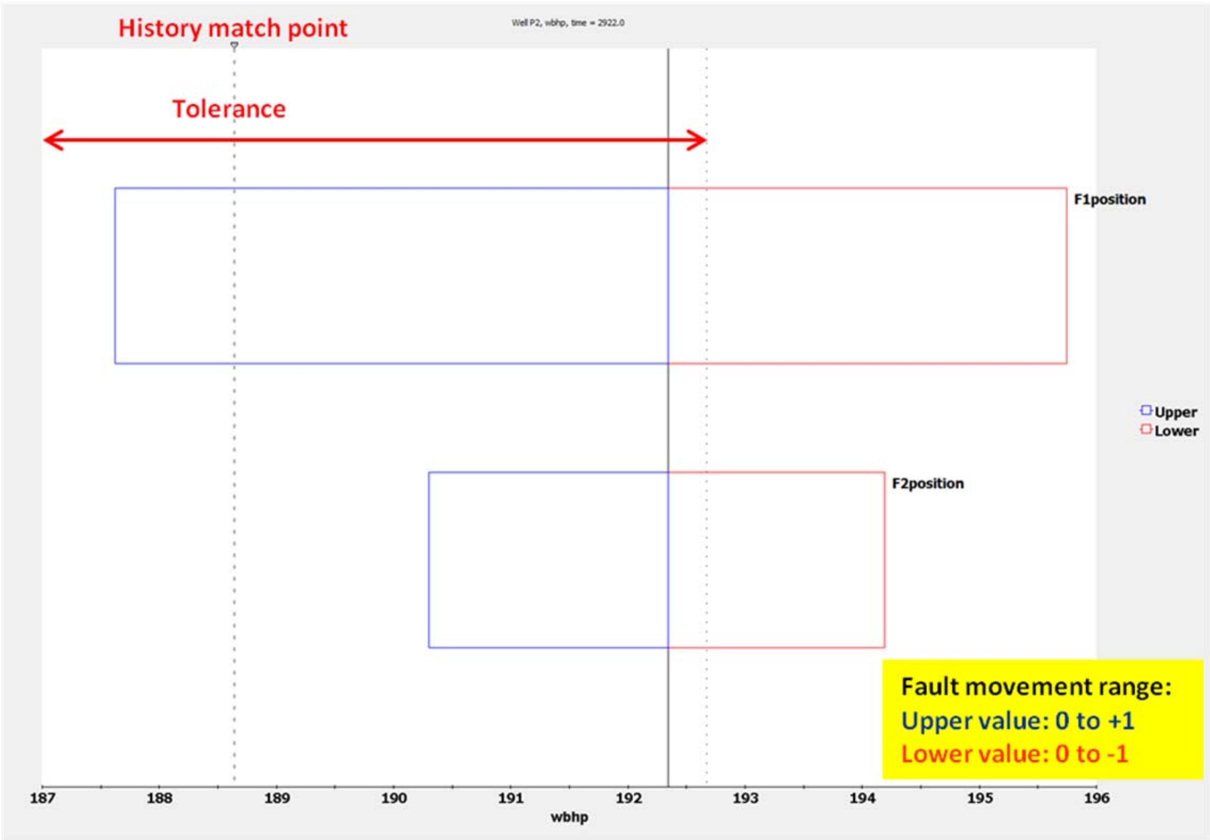

Figure 33: Tornado chart of BHP well P2 on 1 January 2008

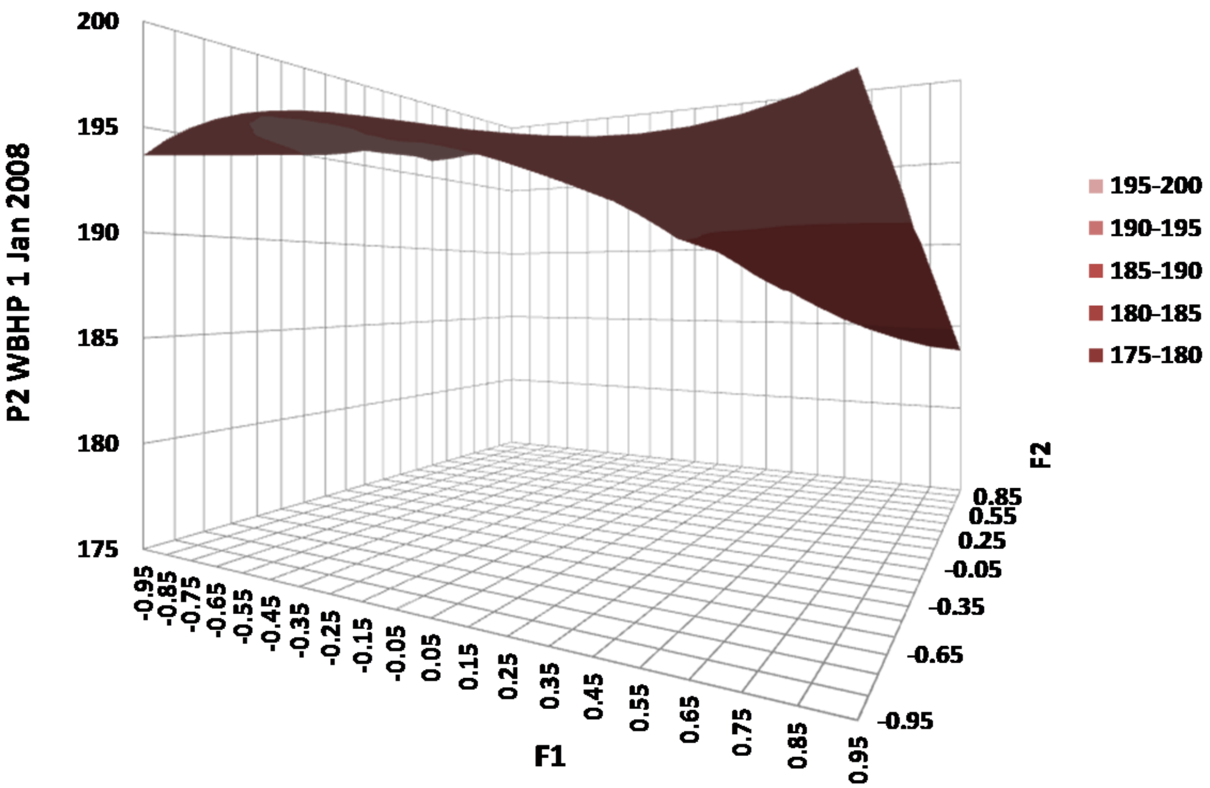

Figure 34: The prior proxy model of BHP well P2 on 1 January 2008

Figure 35 to Figure 37 show result of assisted history match processes. Their differences are on display-method of scoping and refinement runs. The first figure displays results in graphical then followed by proxy (response surface) model in 3D and 2D map (overlaid with sampling points), respectively. A complete graphical comparison between 20 scoping and 80 refinement runs is presented in Appendix C.

Final results of history matching are considered from the 4^{th} step of refinement runs (run 81 to run 100). Comparisons of last refinement and smoothed observed data are presented in Figure 38 to Figure 45. Visually, these simulations are matching almost perfectly for all variables. Exception for bottom-hole pressure, even though the match is within tolerated area but smoothing process has changed the shape of the curve.

The minimization algorithm works very well on reducing uncertainty, once scoping runs bracket the observed data. Uncertainty reduction of water cut profile from well P1 on 1 January 2008 is showed on Figure 46. The prior model has range from 0 to 0.0243 while posterior model reduced to level from 0.00795 to 0.1309.

The “TRUE” observed data (Fault 1 at 72 m towards outer side and Fault 2 at 23 m towards inner side) is overlaid on diagnostic plots. The first diagnostic plot, cross-plot, is shown in Figure 47. Based on this plot, Fault 1 and Fault 2 have uncertainty range around 40 m. The subsequent plots are modifier distribution plots as shown in Figure 48. The plots consisted of probability density function (PDF) and cumulative distribution function (CDF) for both faults. Prior PDF shows uniform distribution from -1 to 1. Posterior PDF for both modifiers have been altered within smaller range. For Fault 1, range of probability is 0.5779 to 0.7912 or equal to 57.79 m to 79.12 m towards outer side (moves to the right). While for Fault 2, the range is -0.3619 to -0.1531 or equal to 36.19 m to 15.31 m towards inner side (moves to the right). Although the “TRUE” observed data are not falling into the mean or P50, the proxy models are capable of alternating full reservoir simulation within acceptable probability range.

Oil in place for “TRUE” case is 67.60 ksm^3 or 7 ksm^3 more than Base Case initialization as shown in Figure 49. The last refinement runs (4^{th} step) reduce the difference down to 1-1.5 ksm^3 as shown in Figure 50. Since the model’s properties are constant, this means bulk volume uncertainty has been reduced. To avoid volumetric effect on production performance display, recovery factor as a function of time are also plotted. Figure 51 and Figure 52 show a recovery factor comparison of scoping and 4^{th} step refinement runs against “TRUE” observed data (before added with noise). In scoping runs, the “TRUE” observed data is located in lower quartile with uncertainty range 7.67% to 10.74%. In comparison, last refinement runs almost perfectly overlaid the “TRUE” observed data with uncertainty range from 8.05% to 8.14%.

Estimator statistics plot describe uncertainty against number of runs. This diagnostic plot could be used as decisions tool whether to continue another set of refinement runs or finish the simulation. Figure 53 shows estimator statistic plot which uncertainty for all estimator points reduced approaching zero. This study finished at 80 refinement runs out of total 100 simulation runs (including scoping runs). There won’t be much improvement if another iteration of refinement runs is performed.

Full simulation runs for 20 scoping runs and 20 refinement runs are performed within 20-30 minutes CPU time. For comparison, 400 case outcomes estimated from the proxy model only require less than 50 seconds CPU time.

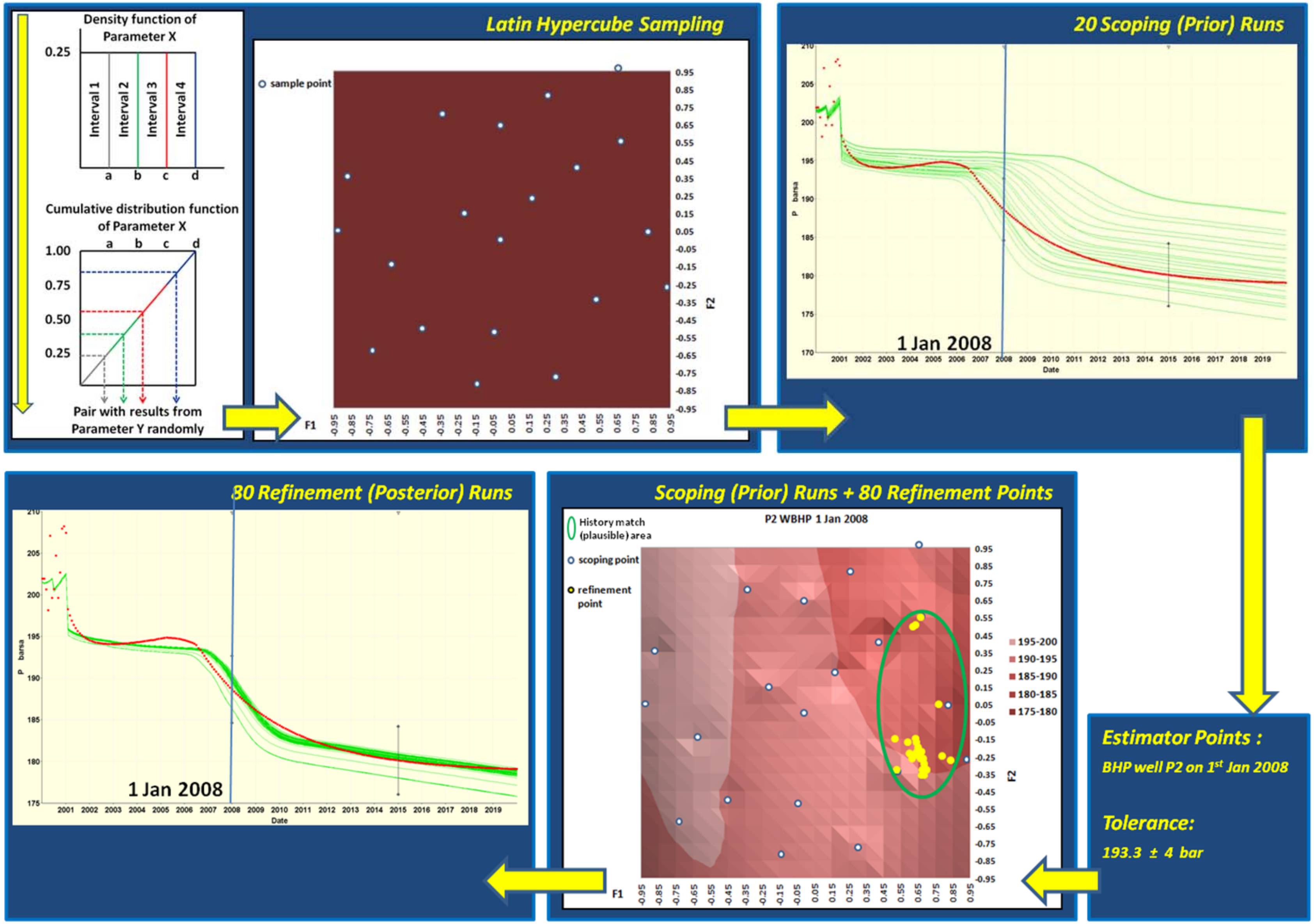

Figure 35: Assisted history matching result – graphical

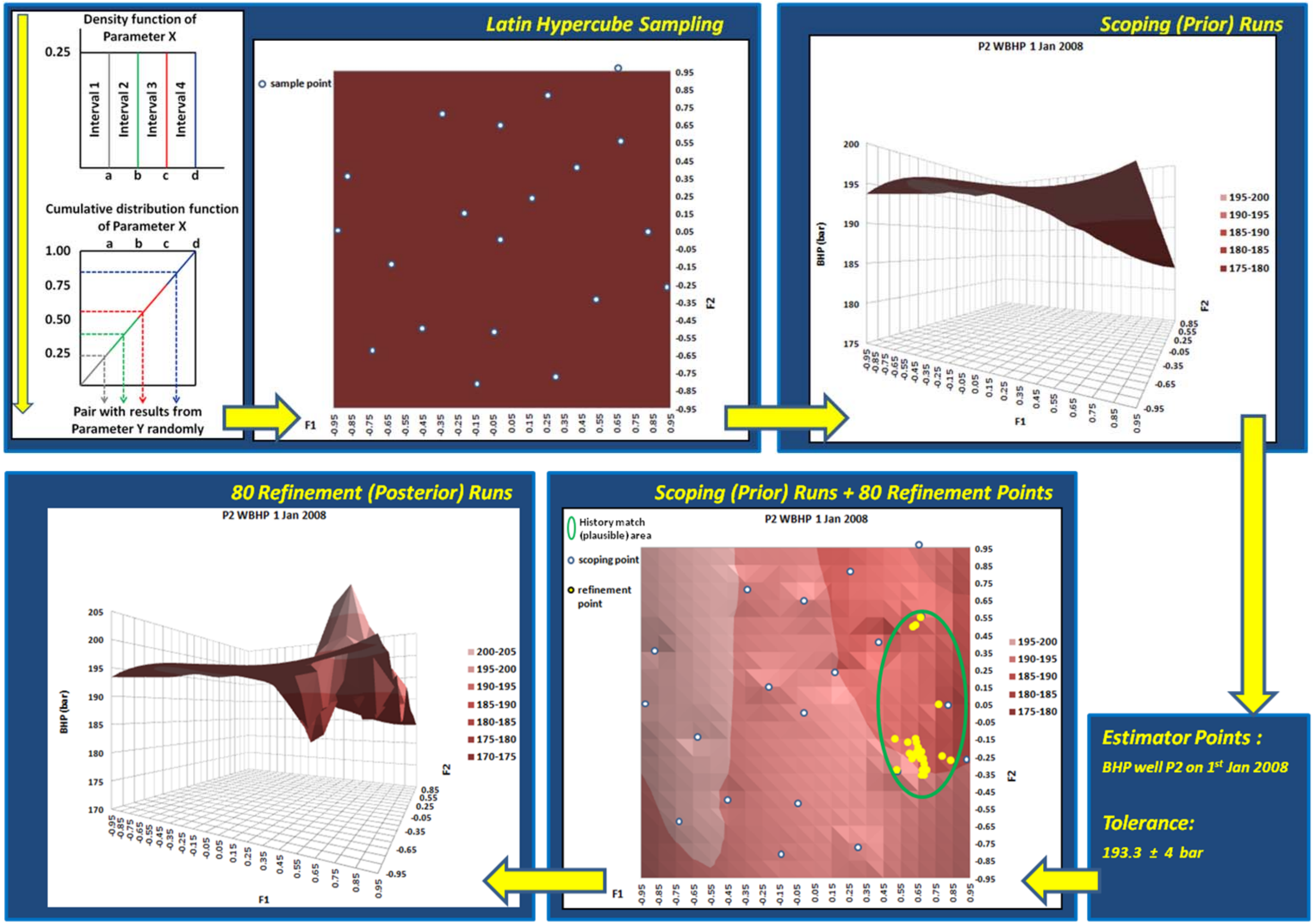

Figure 36: Assisted history matching result – Proxy (response surface) model in 3D

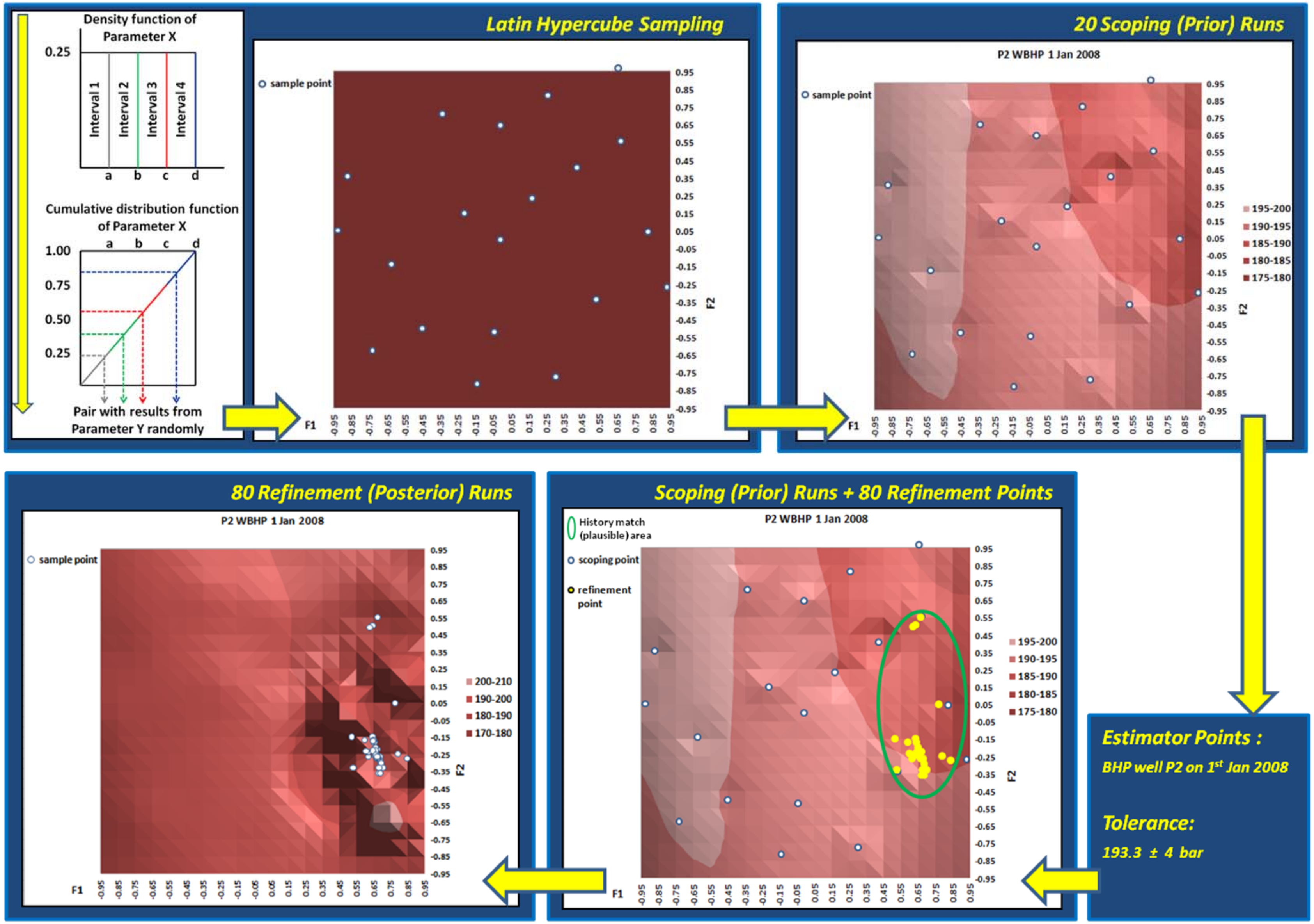

Figure 37: Assisted history matching result – Proxy (response surface) model in 2D map (overlaid with sampling points)

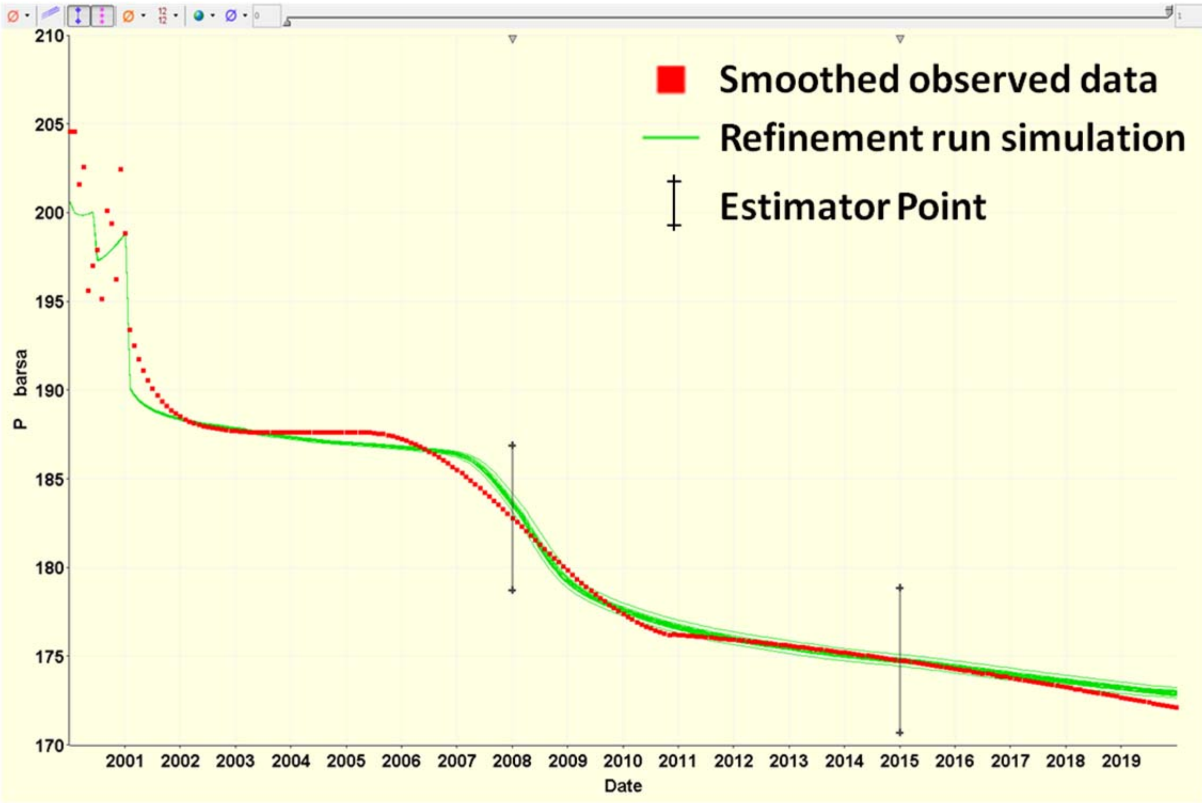

Figure 38: Comparison of smoothed observed data and 4th step refinement runs - BHP well P1

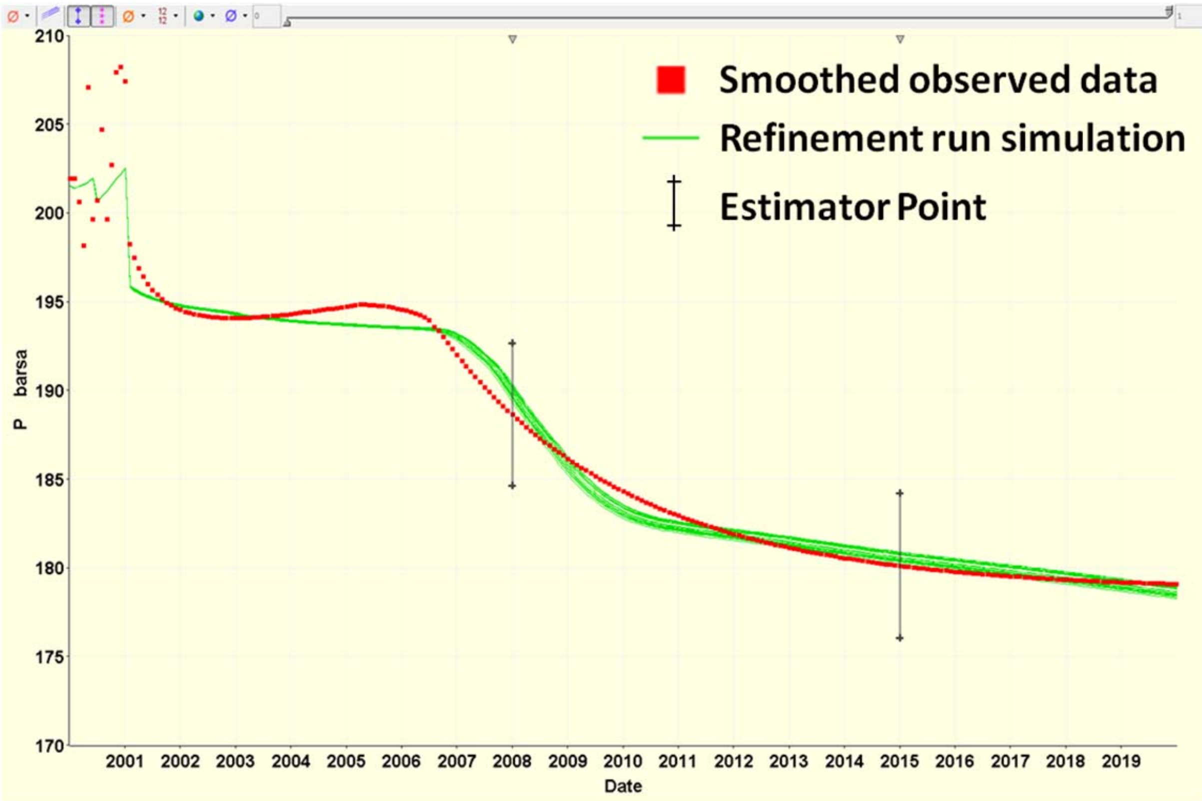

Figure 39: Comparison of smoothed observed data and 4th step refinement runs - BHP well P2

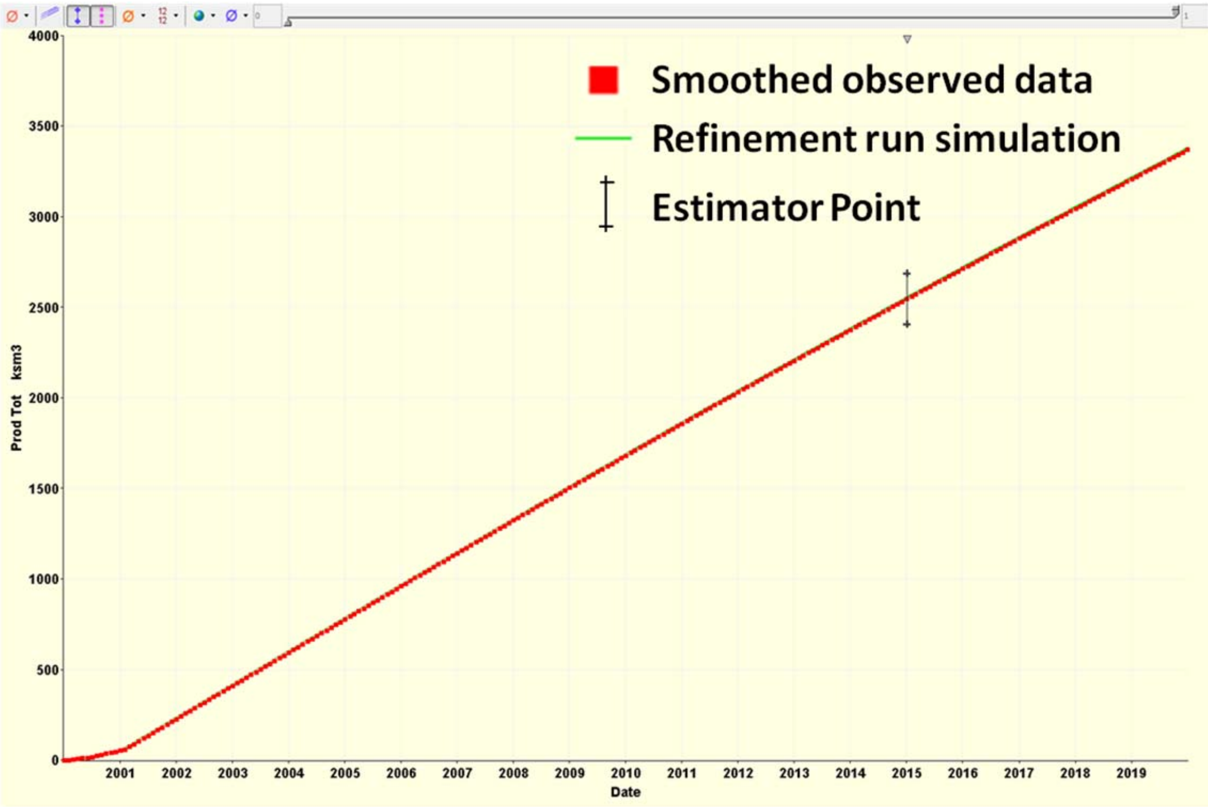

Figure 40: Comparison of smoothed observed data and 4th step refinement runs - Cumulative oil production well P1

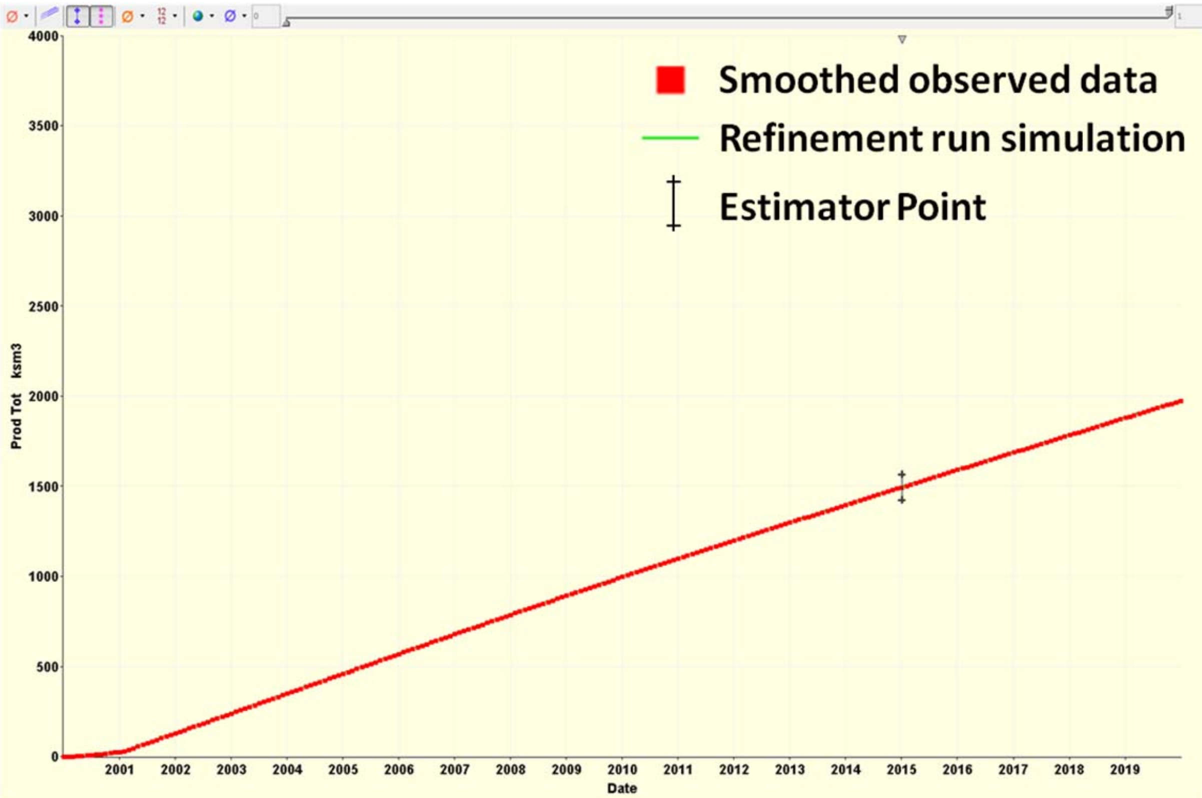

Figure 41: Comparison of smoothed observed data and 4th step refinement runs - Cumulative oil production well P2

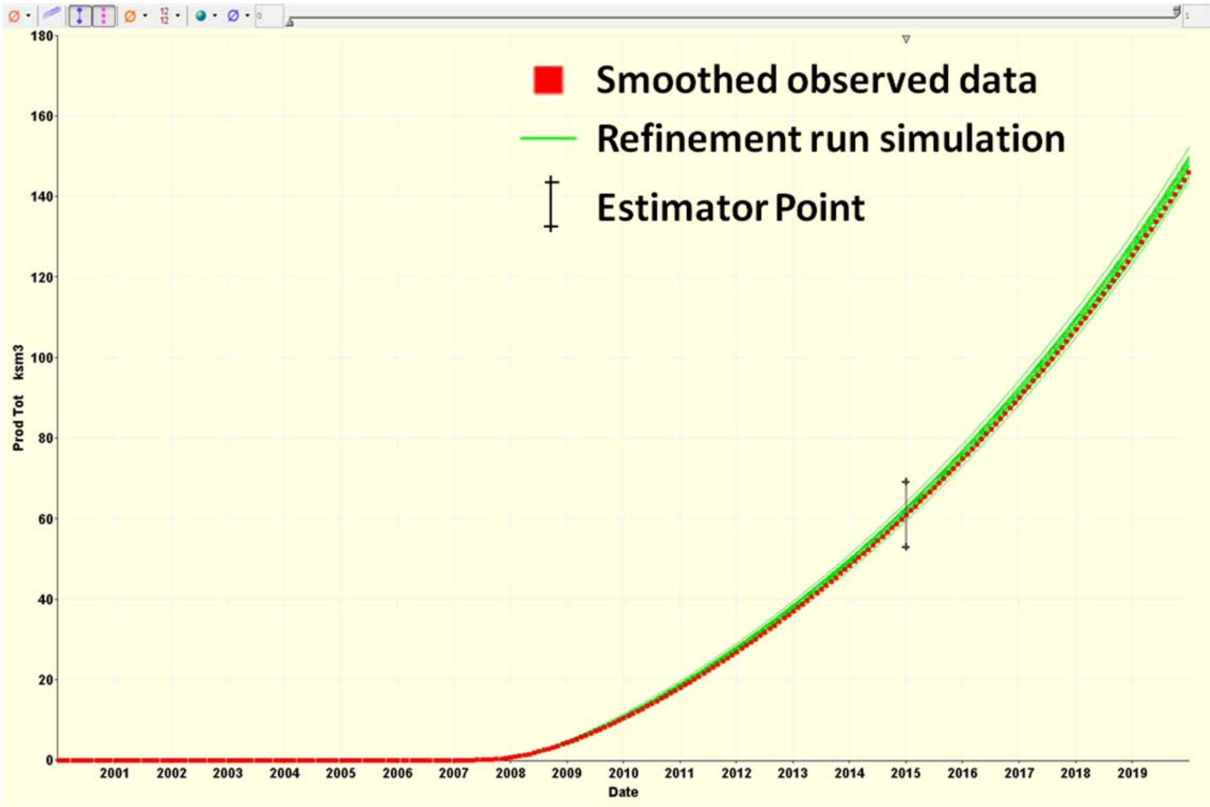

Figure 42: Comparison of smoothed observed data and 4th step refinement runs – Cum. water production well P1

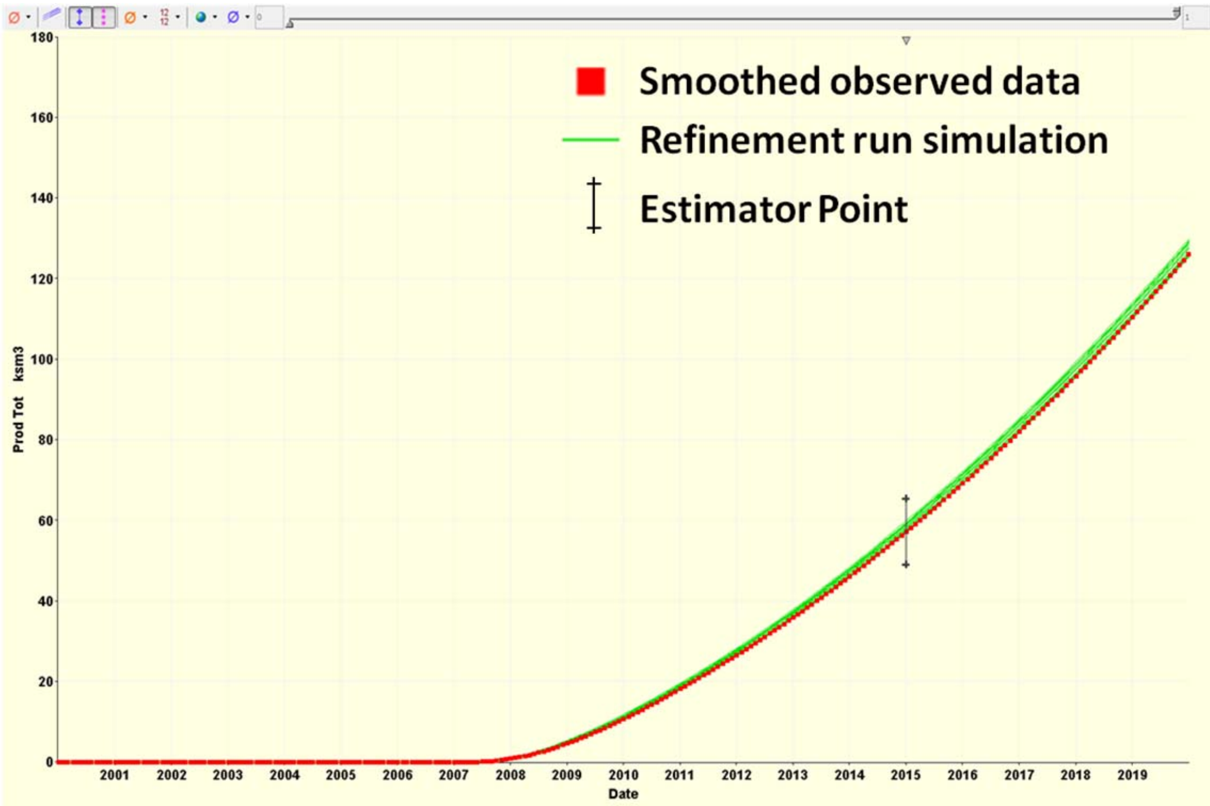

Figure 43: Comparison of smoothed observed data and 4th step refinement runs – Cum. water production well P2

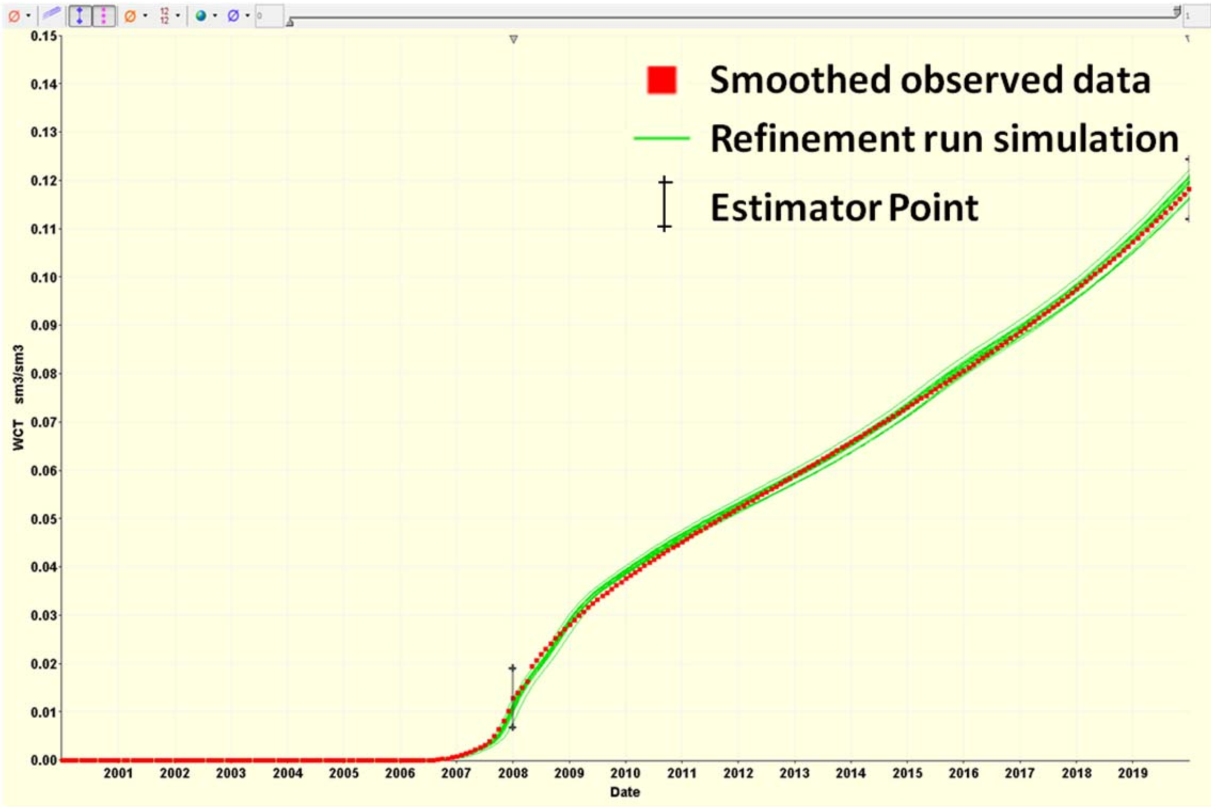

Figure 44: Comparison of smoothed observed data and 4th step refinement runs – Water cut well P1

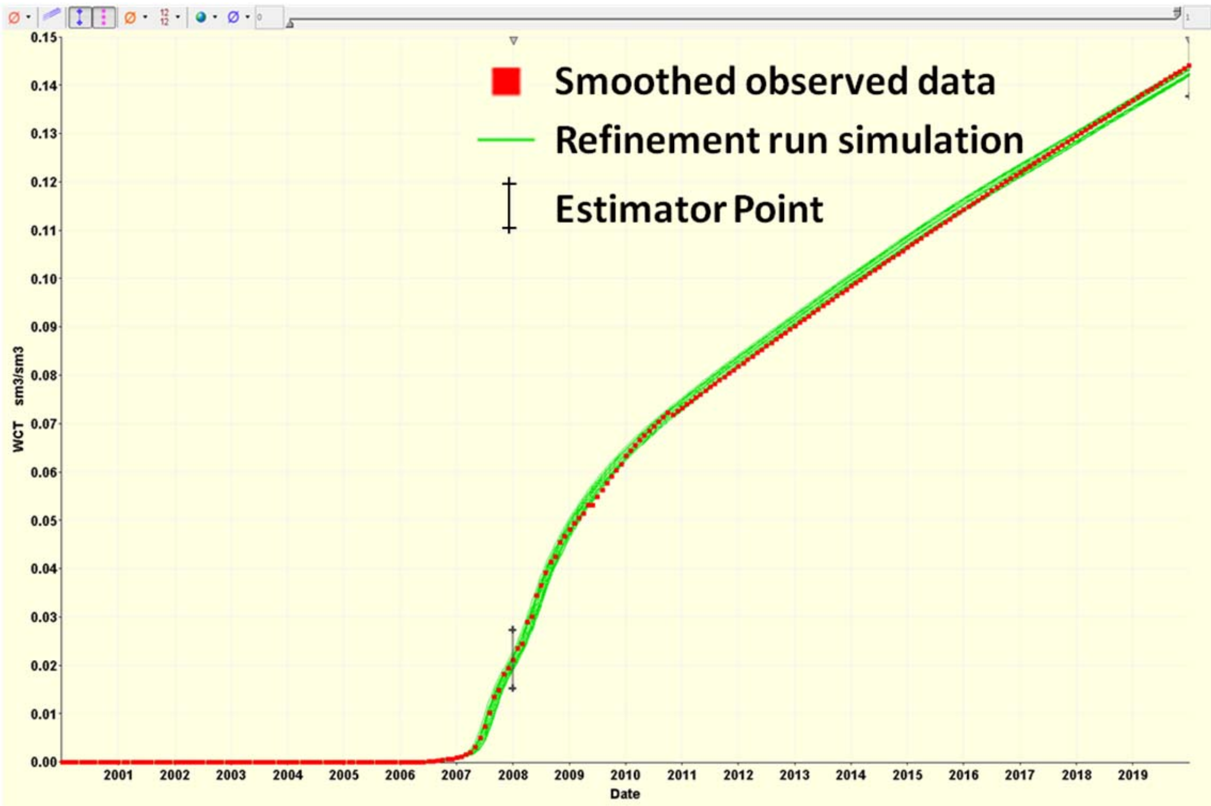

Figure 45: Comparison of smoothed observed data and 4th step refinement runs – Water cut well P2

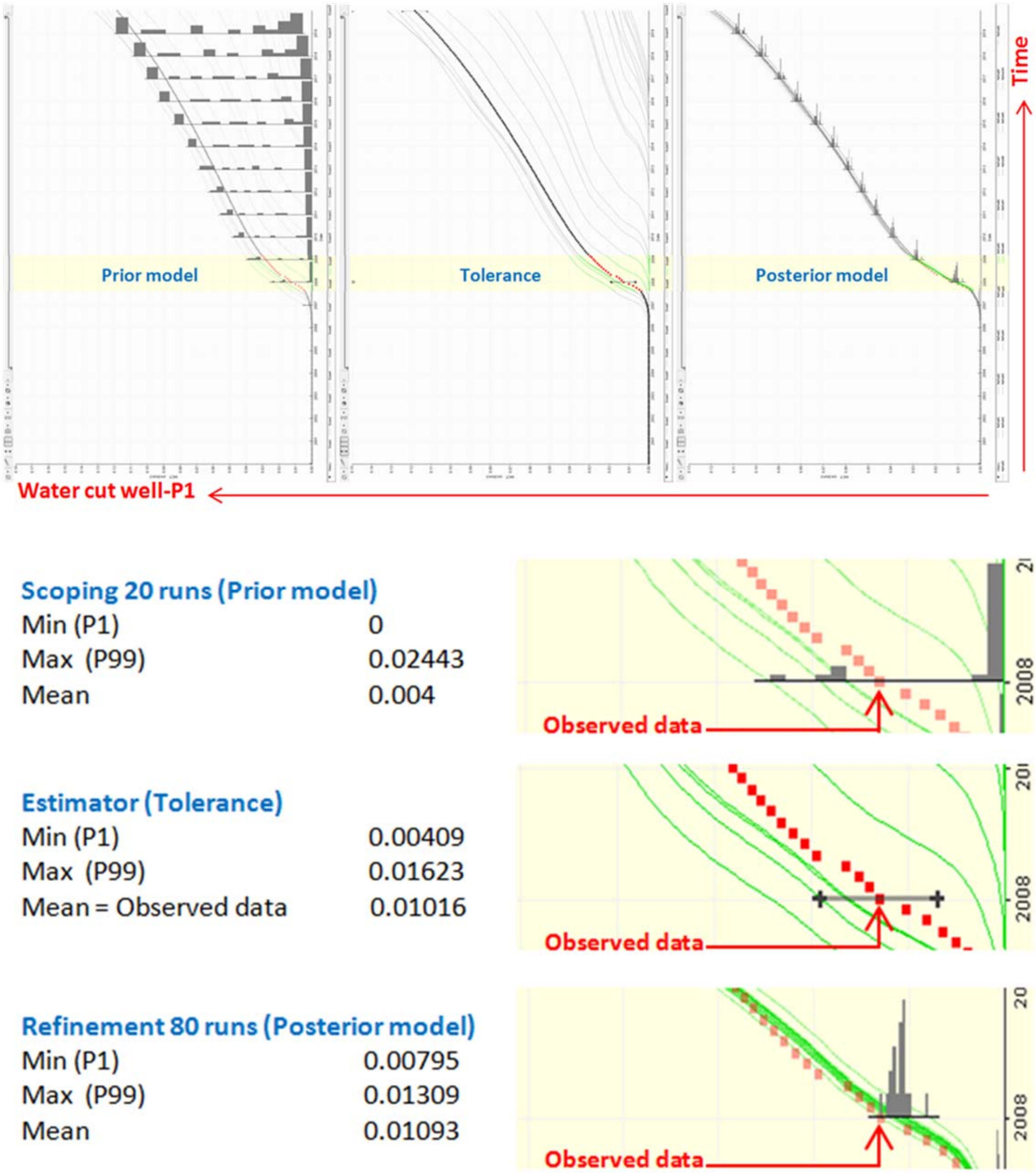

Figure 46: Uncertainty reduction of water cut profile from well P1 on 1 January 2008

F1 uncertainty: (0.511 to 0.917) x 100m = 40.6m
F2 uncertainty: (0.057 to -0.406) x 100m = 46.3m

Figure 47: The "TRUE" observed data was overlaid on cross-plot

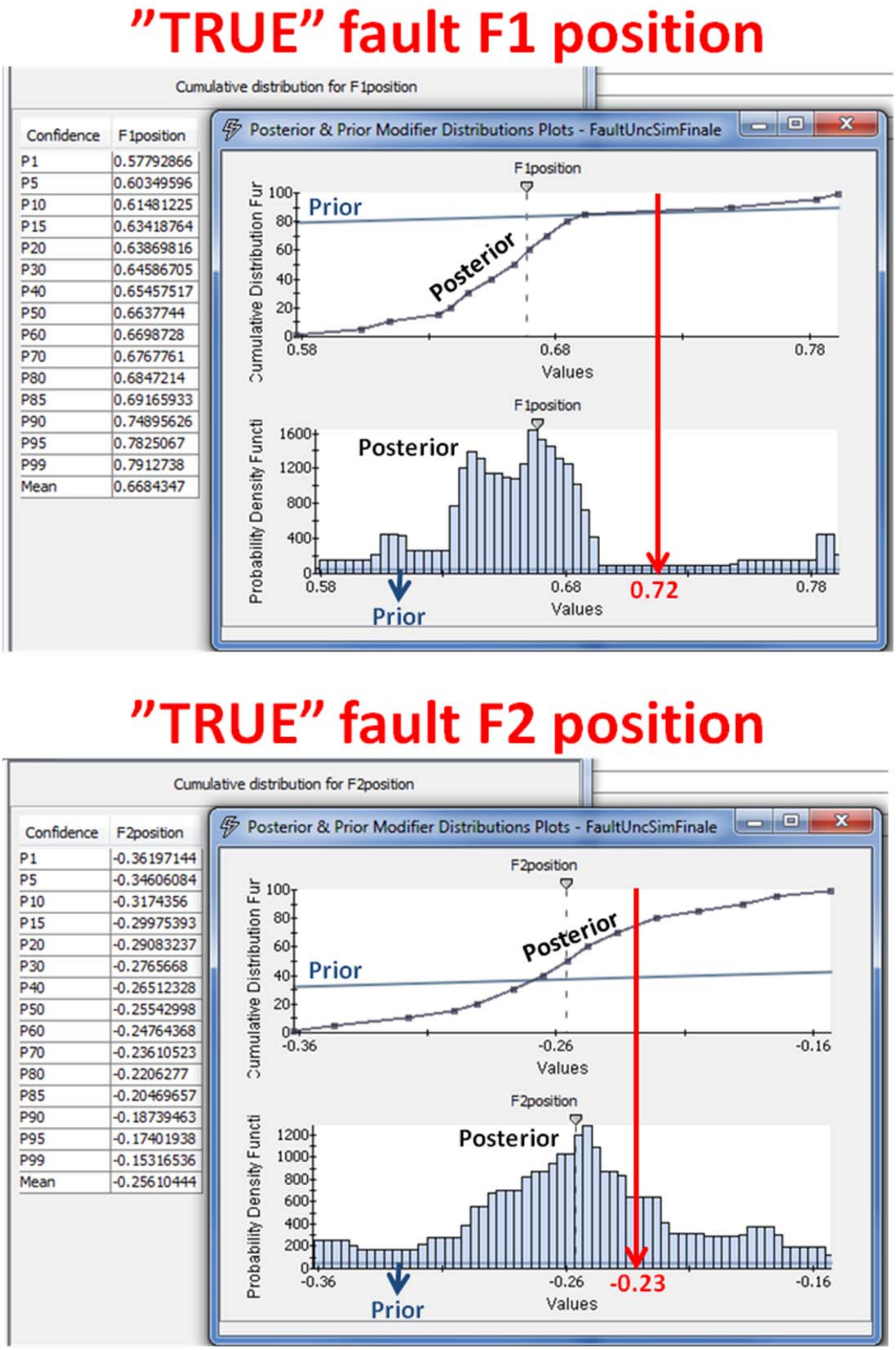

Figure 48: The "TRUE" observed data was overlaid on modifier distribution plot

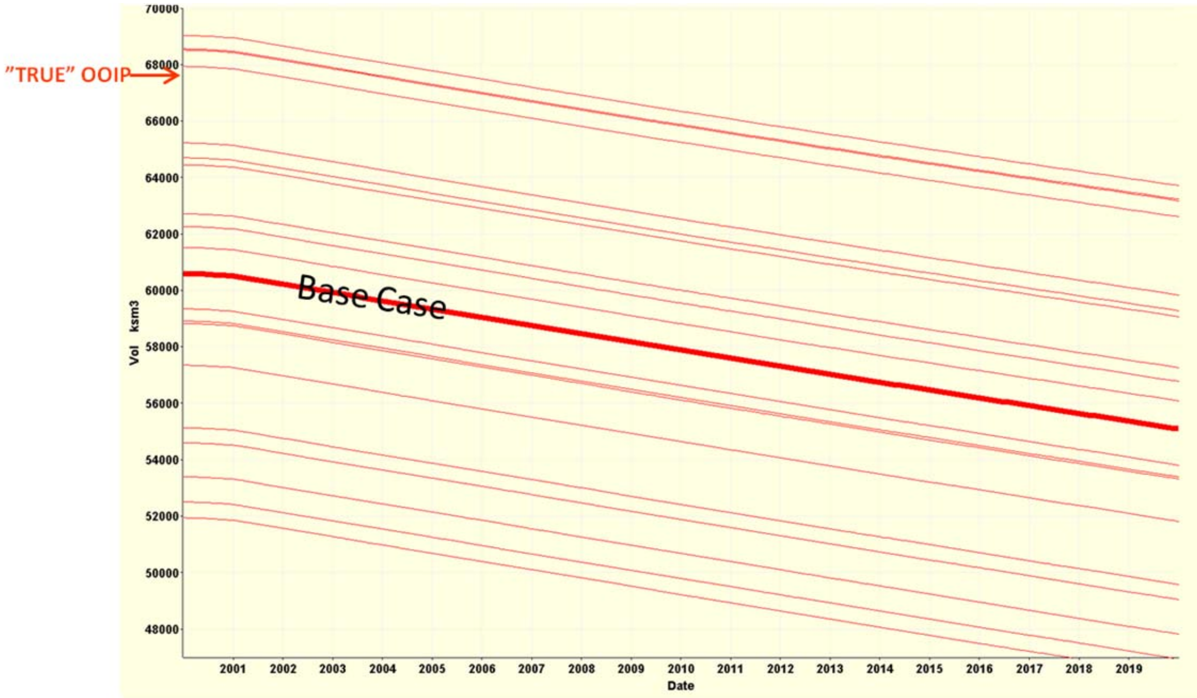

Figure 49: OOIP of scoping runs

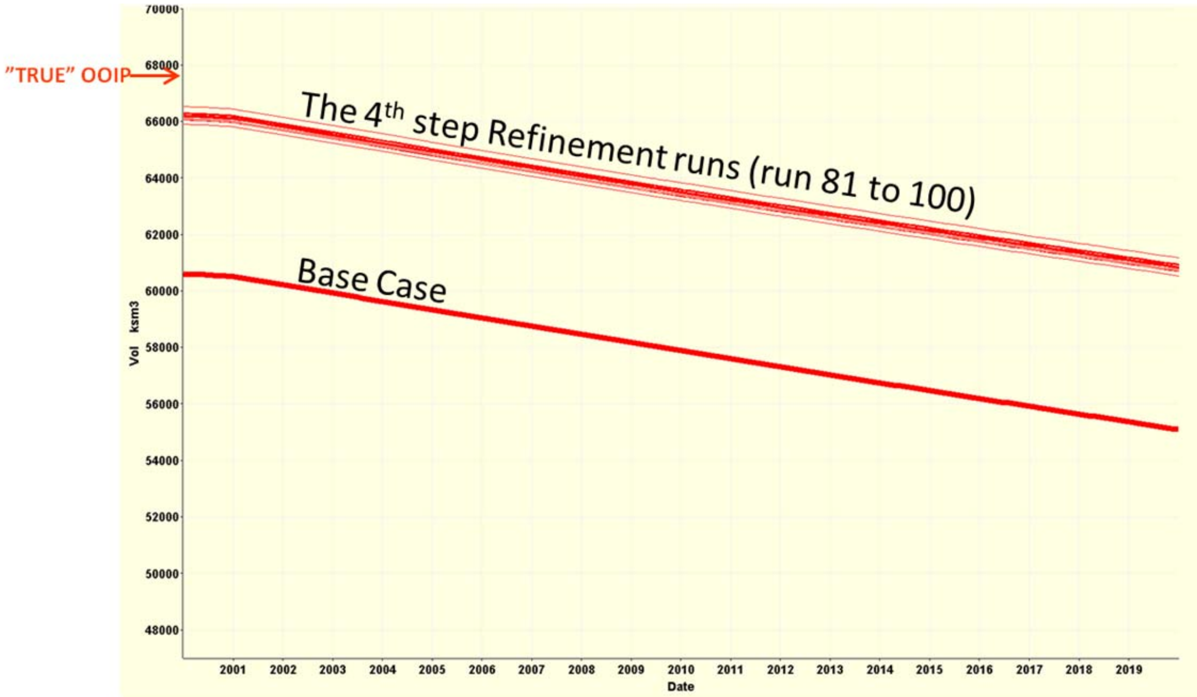

Figure 50: OOIP of the 4th step refinement runs

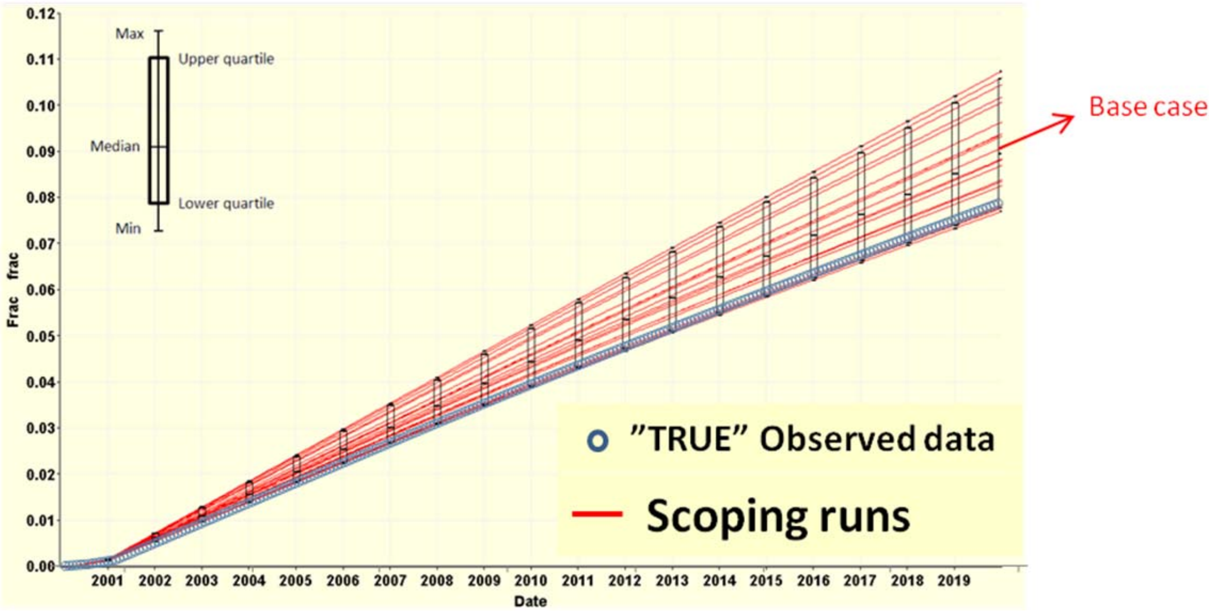

Figure 51: Recovery factor comparison of scoping runs against "TRUE" observed data

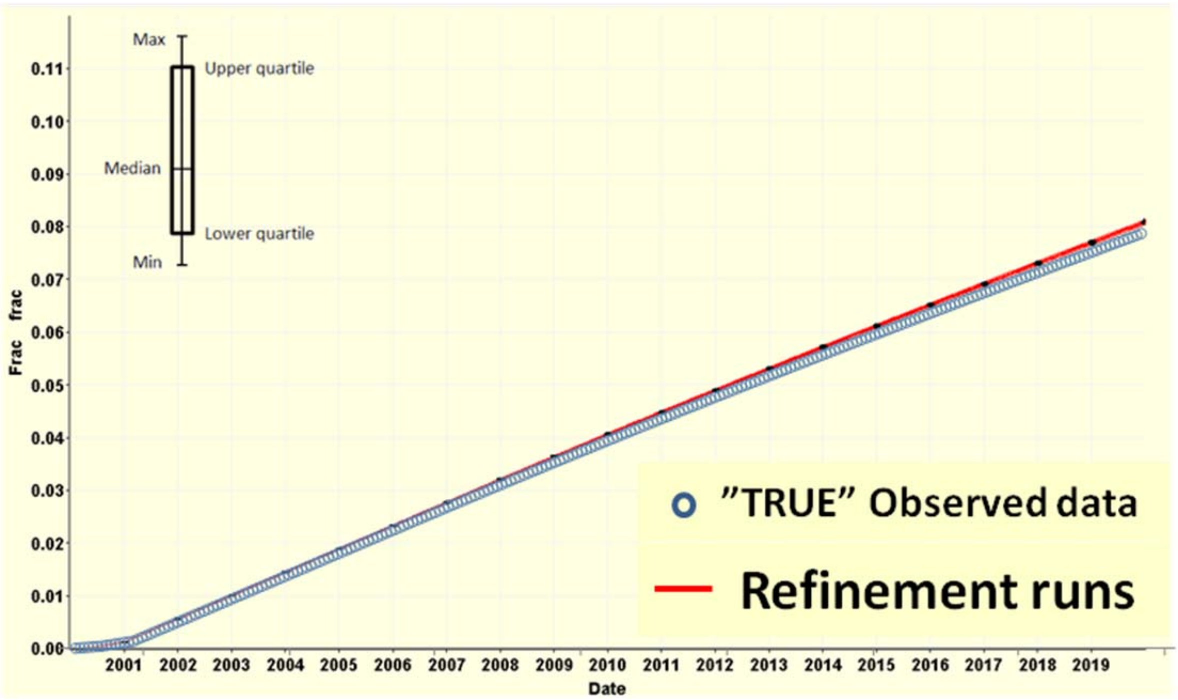

Figure 52: Recovery factor comparison of 4th step refinement runs against "TRUE" observed data

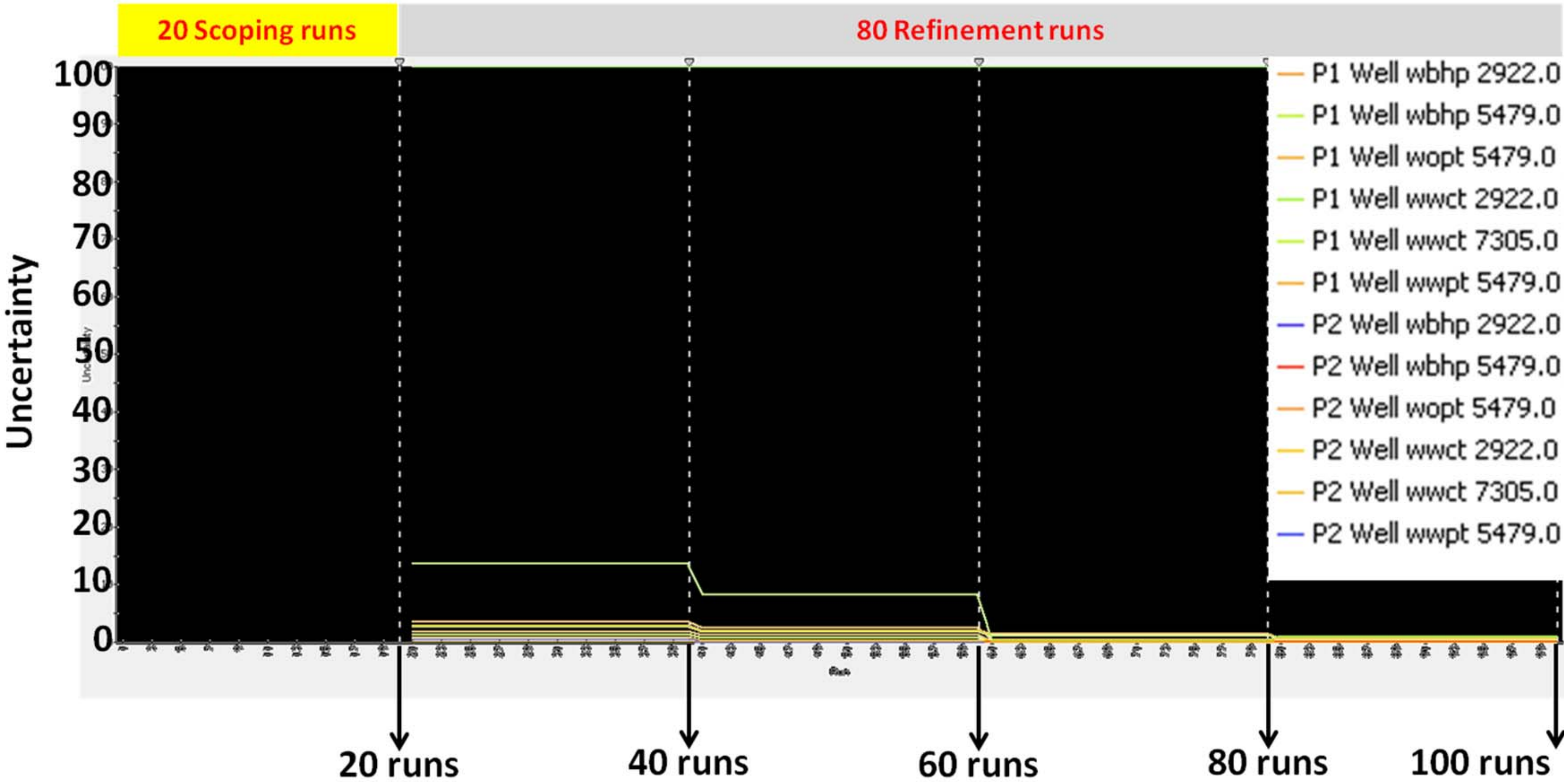

Figure 53: Estimator statistic plot

Chapter 6 Conclusions and future work

6.1 Conclusions

This work presents a synthetic field case involving structural parameter uncertainty in the history matching process. A total of 100 full simulation runs are performed to build and fine-tune the proxy model. The following conclusions can be drawn for the case studied in this work:

a) The model used in this study has two faults. These faults positions movement are modifiers for history matching process that affect production performance. The number of modifiers is set to two to enable proxy model visualization in a surface plot.
b) The proxy model is reliable and practical in structural history matching. It substitutes traditional reservoir simulation within acceptable accuracy range and superior time.
c) The unphysical proxy model values in some region have no accuracy implication rather than visual look of the graphs.
d) A total of 80 refinements with four step iterations satisfied the history match quality. Minimization algorithm worked very well on reducing uncertainty of production performance, oil in place and indirectly on bulk rock volume (BRV).
e) A combination of automated geo-model rebuilding, geo-model-reservoir simulation bridging tool and assisted history matching allows multiple solutions to be performed and better integration of interdisciplinary teams.

6.2 Future work

a) It is suggested to apply truncation rule to prevent unphysical value resulted from polynomial equation when building the proxy model.
b) Investigate if there is any trend in the proxy model when one fault intersects with others.
c) Build automated estimator points selection to accommodate field with many wells. Having options to choose whether user-defined, data percentile or other innovative algorithm is suggested.
d) Incorporate or combine other variables on parameterization:
    - Other fault uncertainties (fault position with lateral movement, angle, throw, length, volume)
    - Horizon
    - Fluid contacts
    - Porosity
    - Transition zone or capillary pressure
    - Facies geometry
e) Real field case application

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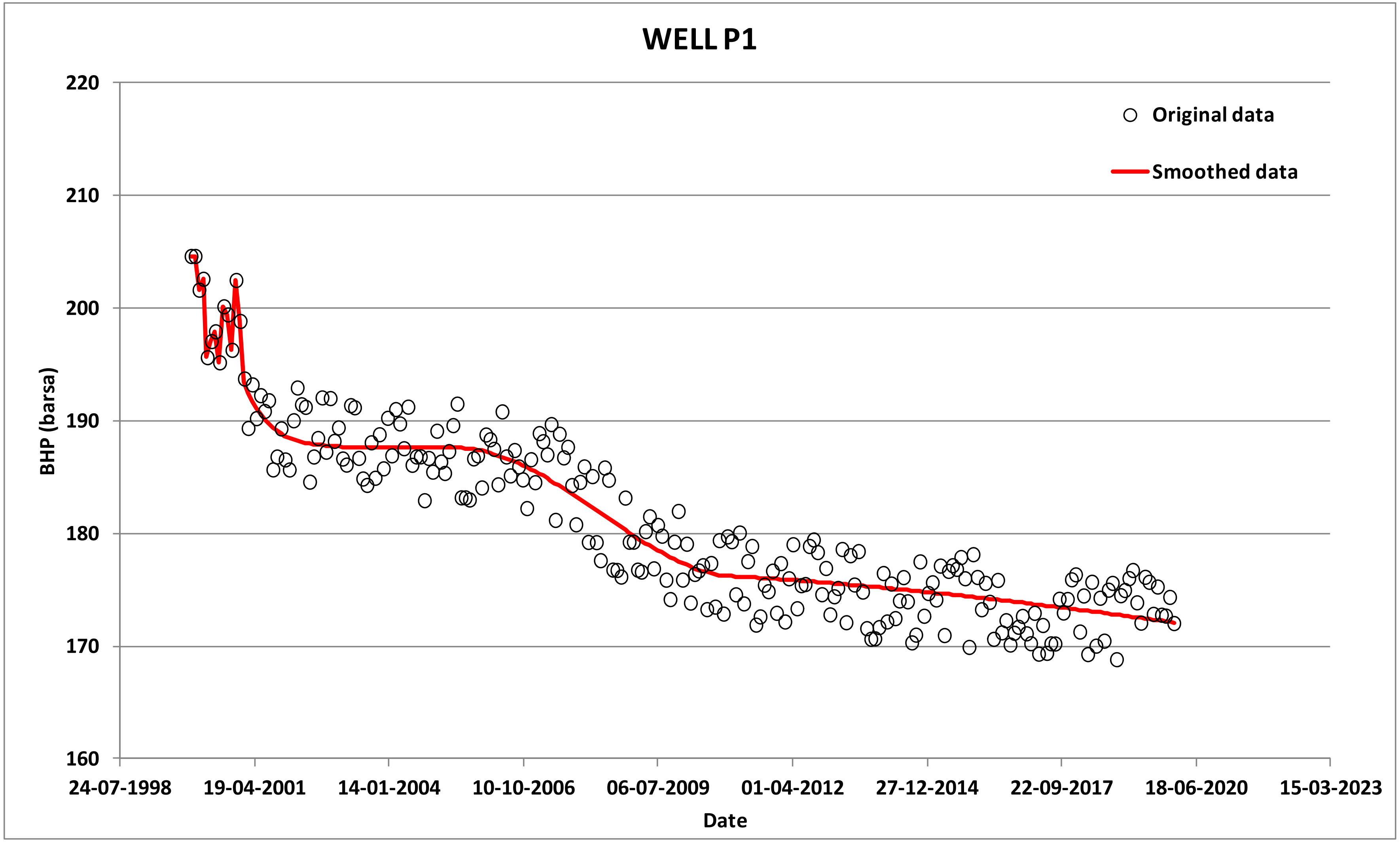
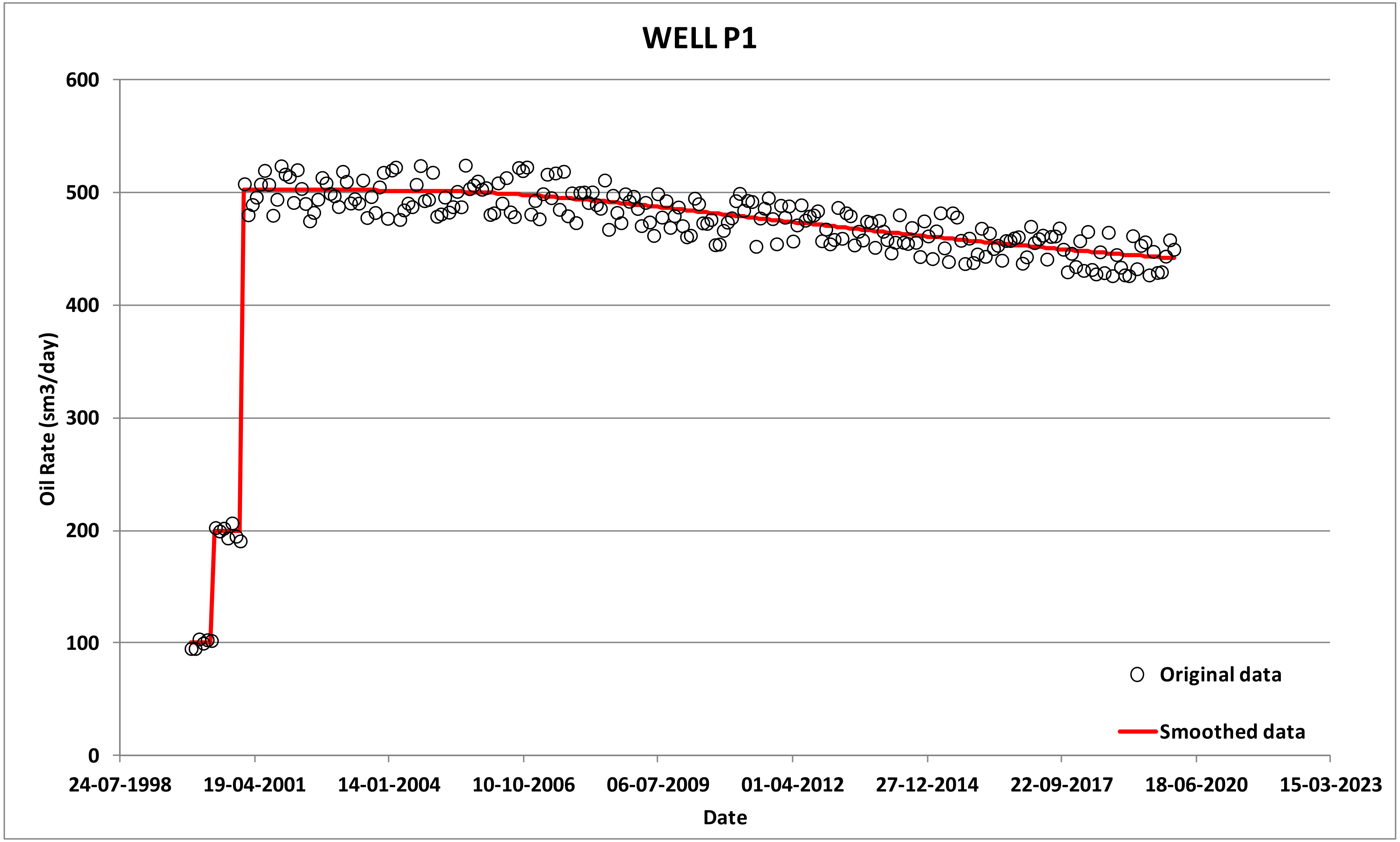
Appendix A

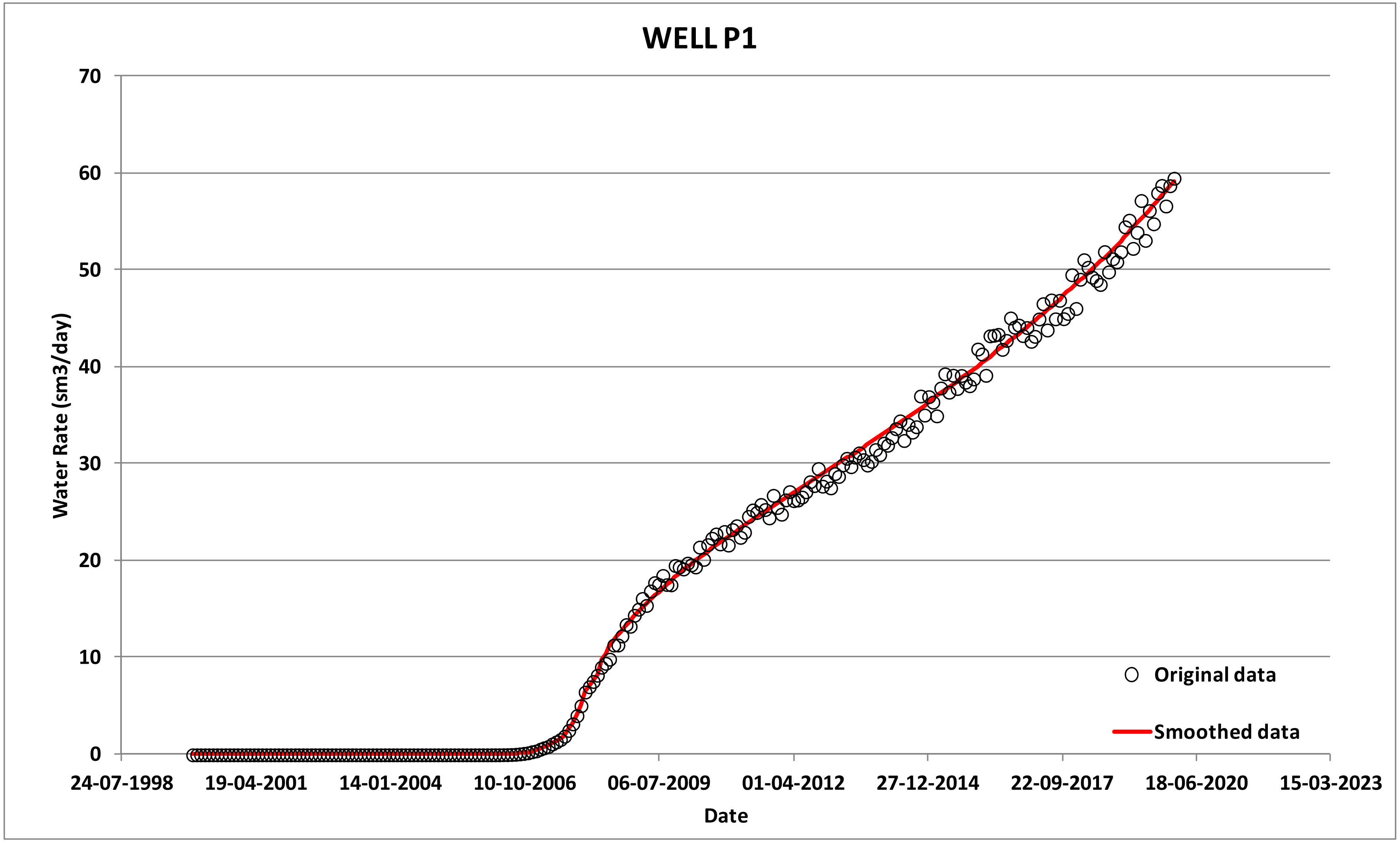
Data smoothing for BHP of well P1:



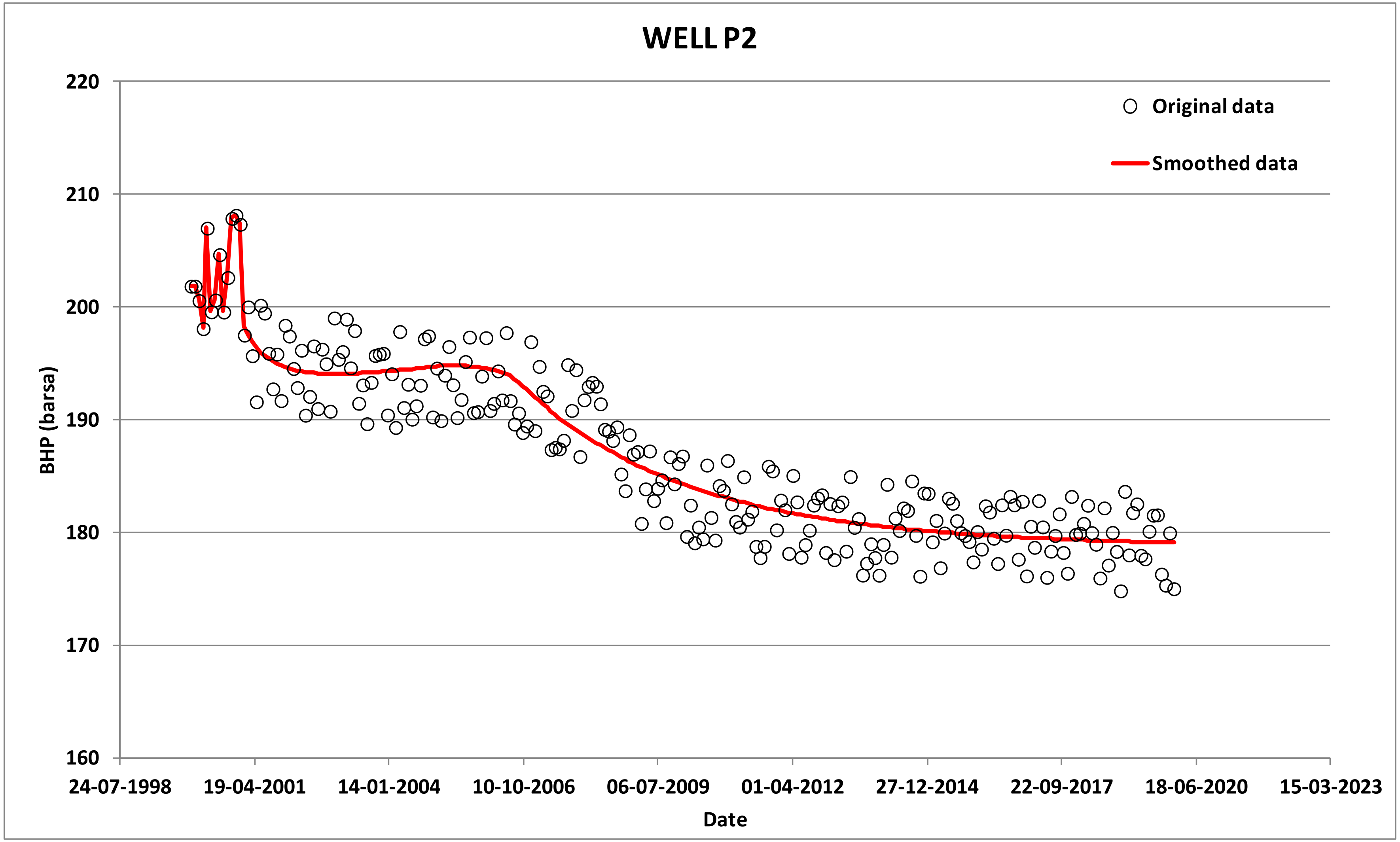
Data smoothing for oil rate of well P1:



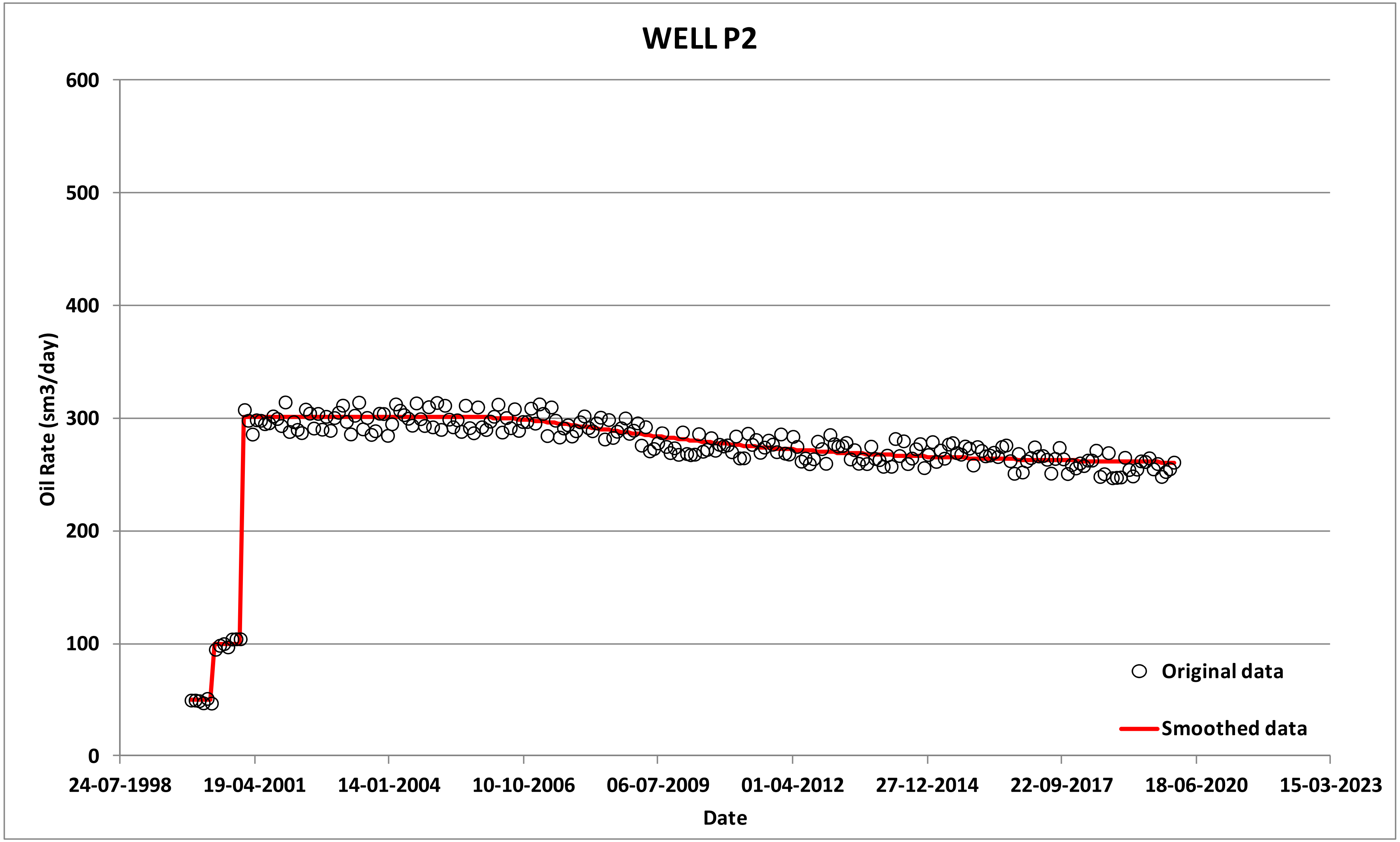
Data smoothing for water rate of well P1:



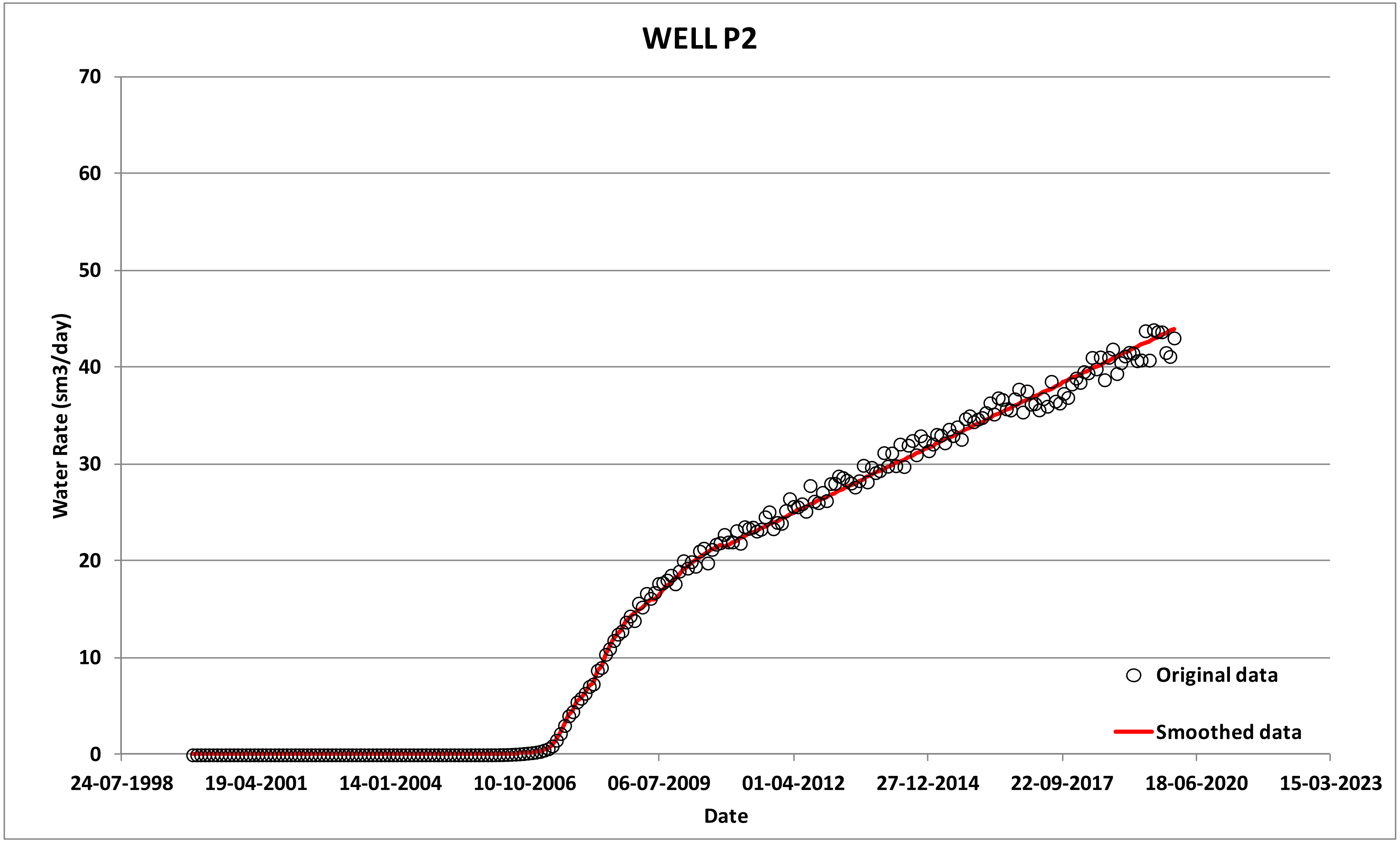
Data smoothing for BHP of well P2:



Data smoothing for oil rate of well P2:



Data smoothing for water rate of well P2:



Appendix B

Rock properties input:

```
KRWO
 0.20000  0.00000  1.00000  0.00000 /
 0.22000  0.00000  0.90330  0.00000 /
 0.24000  0.00001  0.81304  0.00000 /
 0.26000  0.00004  0.72900  0.00000 /
 0.28000  0.00013  0.65096  0.00000 /
 0.30000  0.00031  0.57870  0.00000 /
 0.32000  0.00064  0.51200  0.00000 /
 0.34000  0.00119  0.45063  0.00000 /
 0.36000  0.00202  0.39437  0.00000 /
 0.38000  0.00324  0.34300  0.00000 /
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 0.72000  0.22567  0.00237  0.00000 /
 0.74000  0.26244  0.00100  0.00000 /
 0.76000  0.30353  0.00030  0.00000 /
 0.78000  0.34927  0.00004  0.00000 /
 0.80000  0.40000  0.00000  0.00000 /
 1.00000  1.00000  0.00000  0.00000 /
/
```
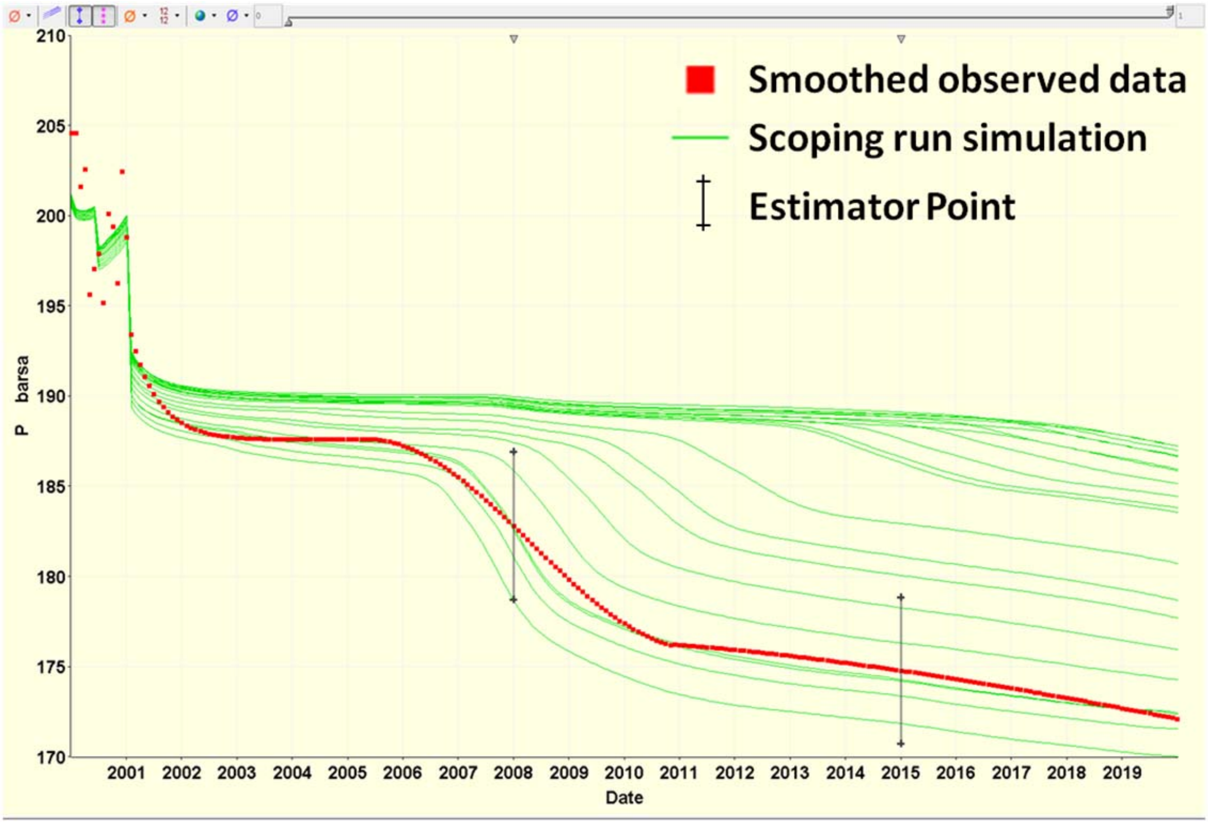

```
--* Set rock compressibility
CROC UNIF
CONS
 4.35113e-05 /

--* Set rock reference pressure
REFE UNIF
CONS
 2.00000e+02 /
```

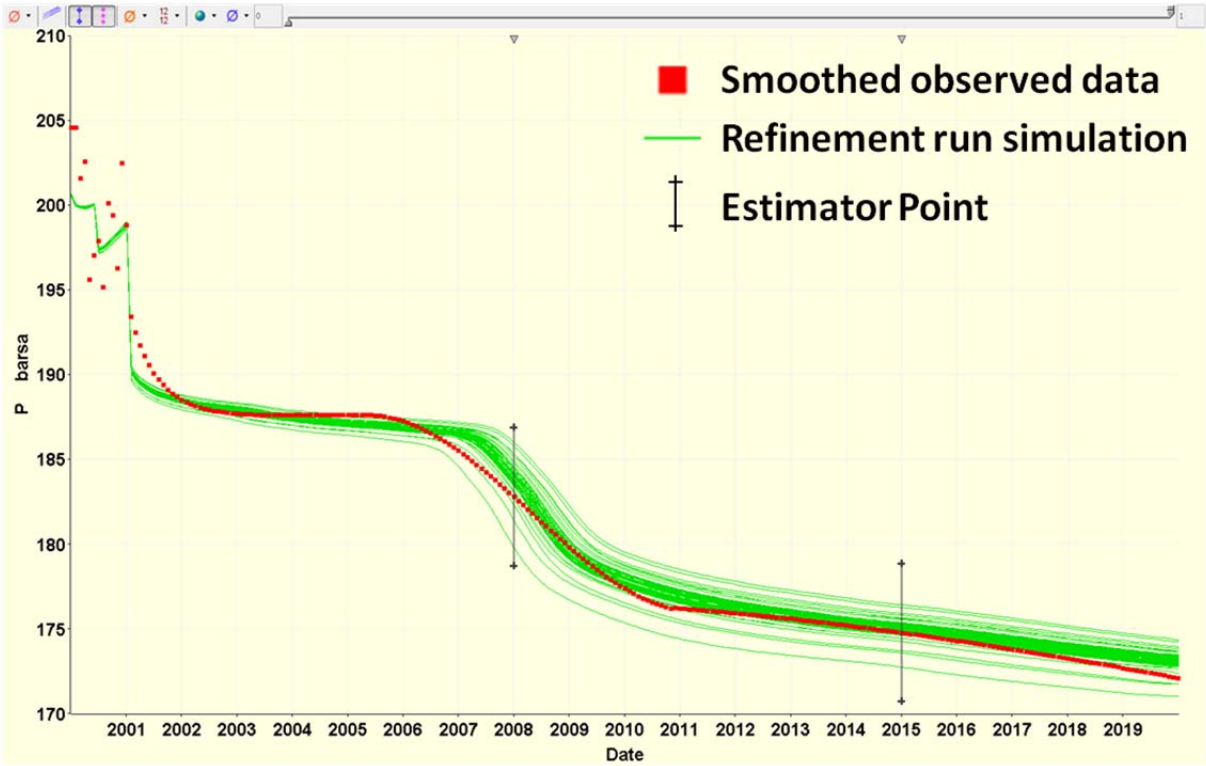
Fluid properties input:

```
CNAM OIL WATR

FLUID BLACKOIL
DENSITY
 8.00000e+02  1.10000e+03 1* /

TEMP  1.21111e+02

OPVT
 2.00000e+02  1.19920e+00  8.00000e-01  1.42486e-01  3.00000e-04 /
/

PVTW
 2.00000e+02  1.00000e+00  1.00000e-05  3.00000e-01 /
/
```

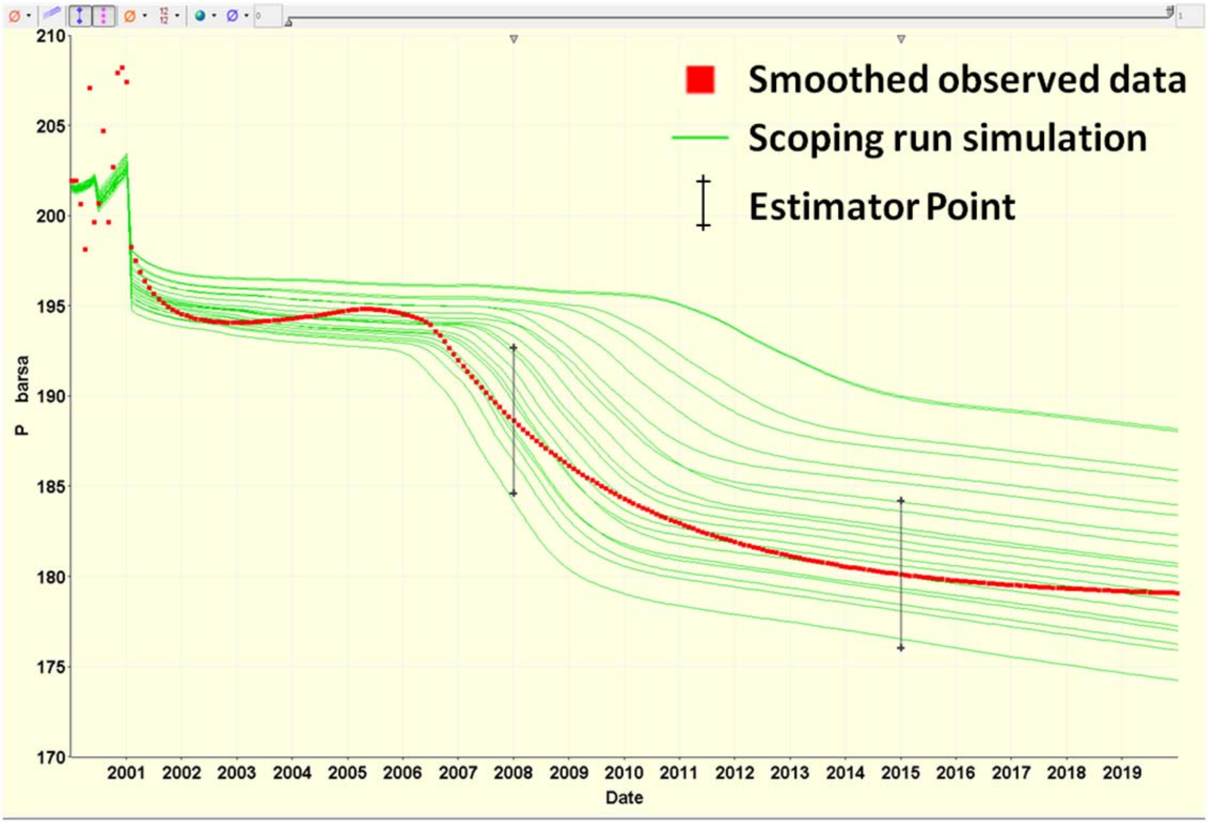
Appendix C

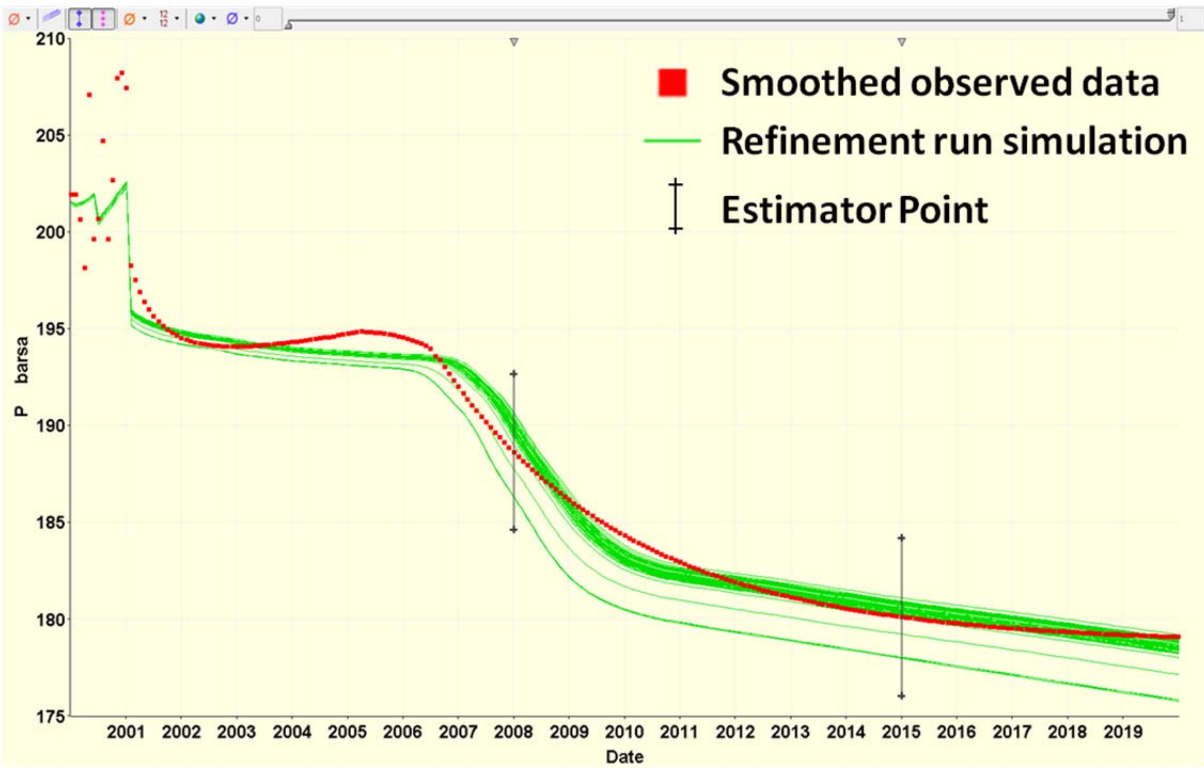
Comparison between scoping and refinement runs for BHP of well P1:



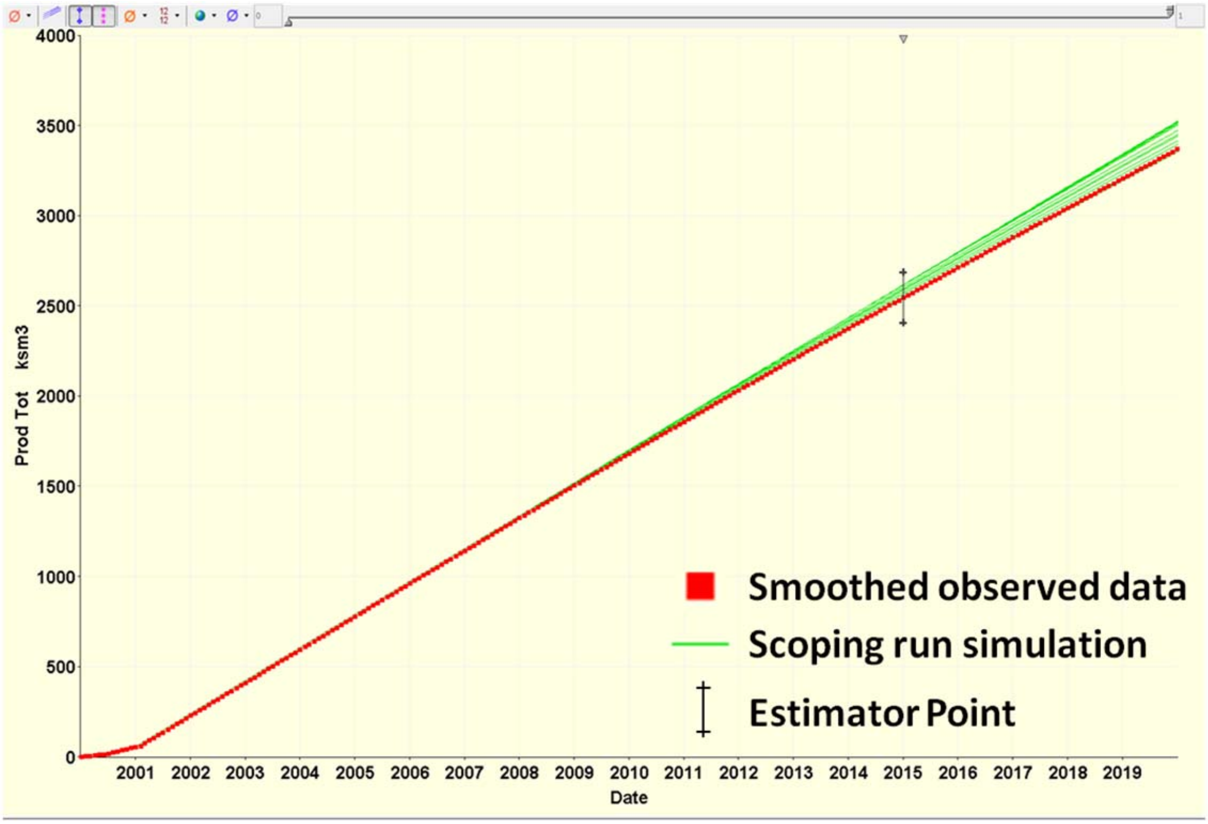


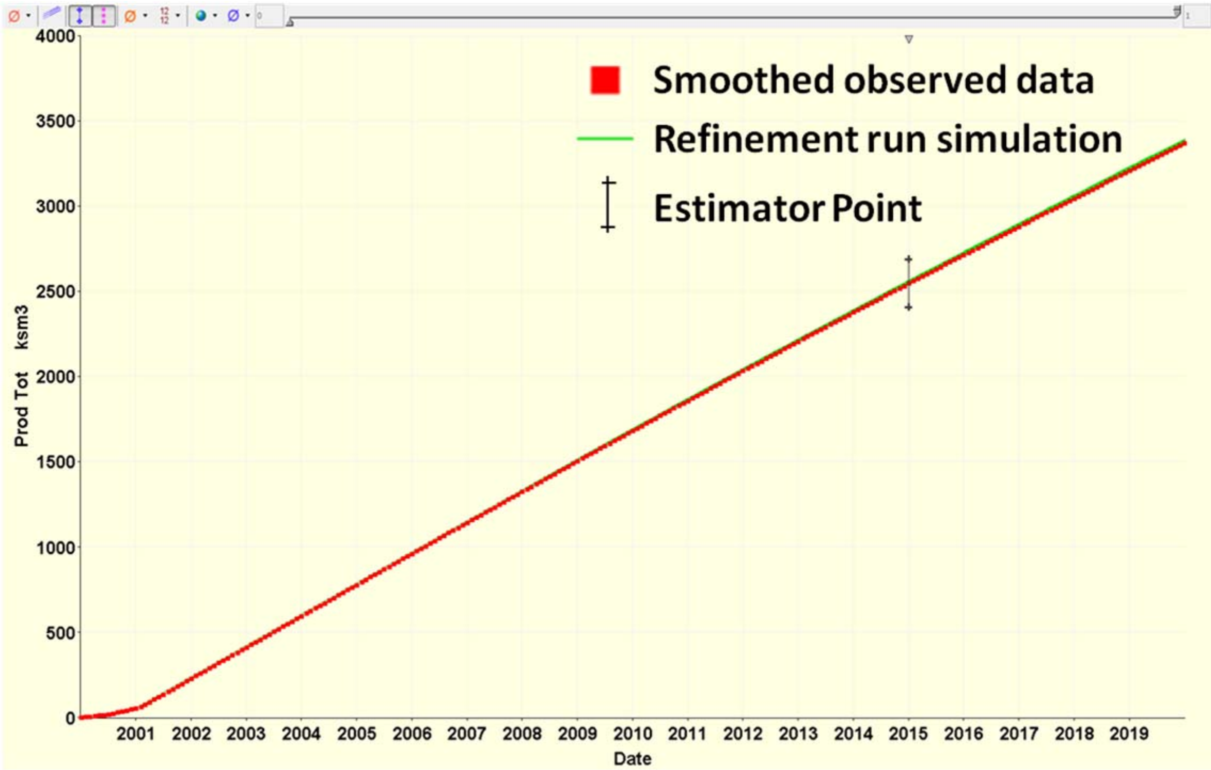
Comparison between scoping and refinement runs for BHP of well P2:



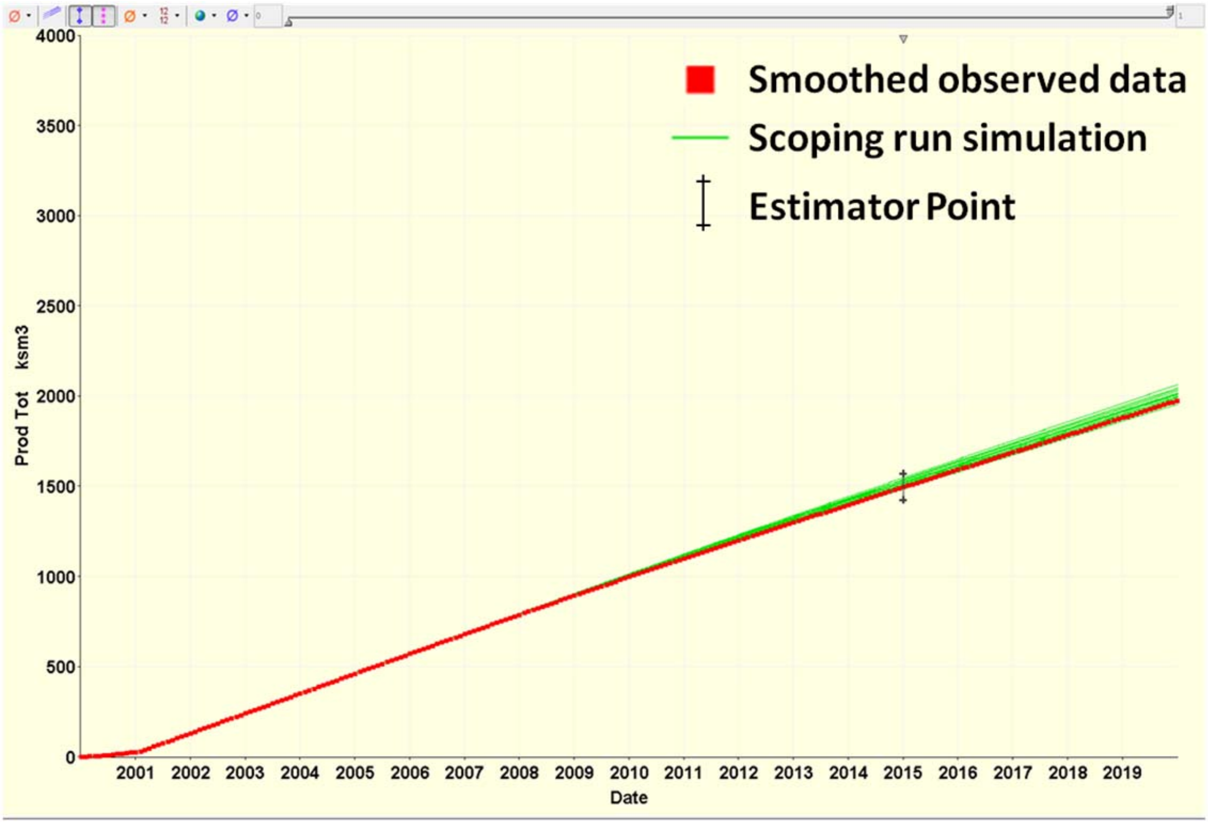


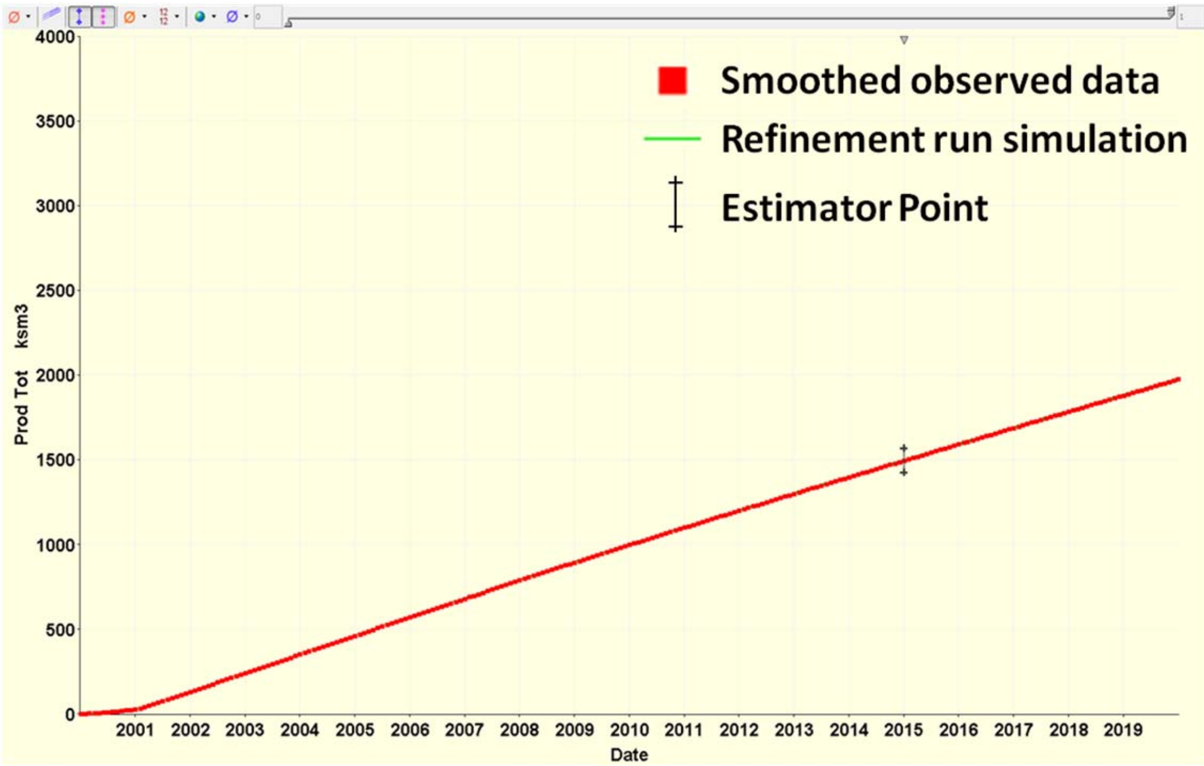
Comparison between scoping and refinement runs for cumulative oil production of well P1:



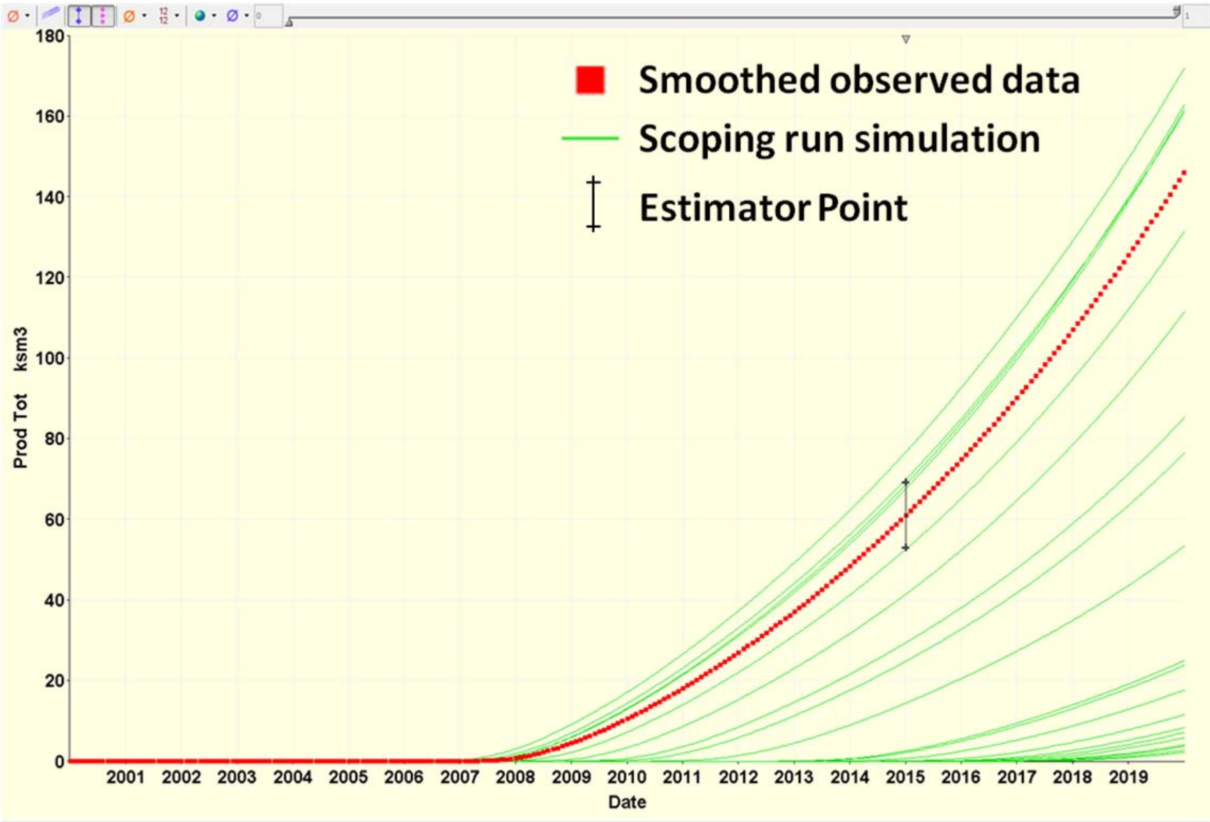


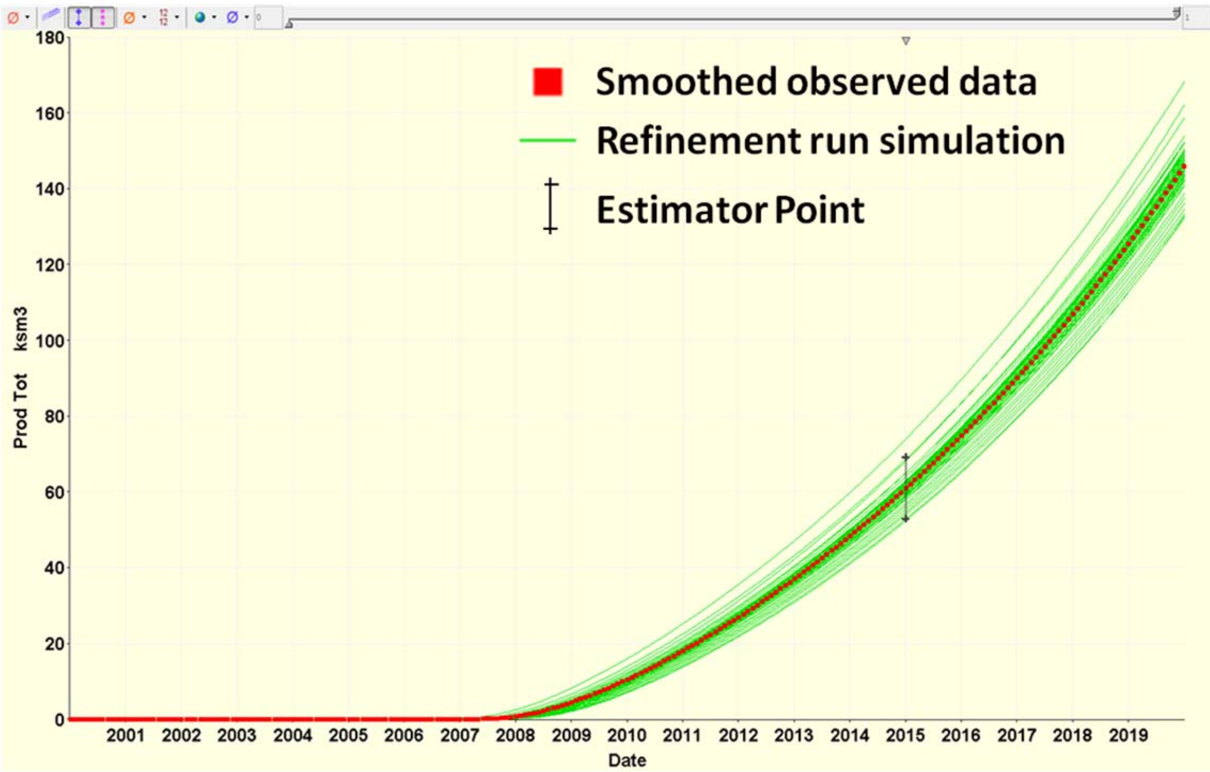
Comparison between scoping and refinement runs for cumulative oil production of well P2:



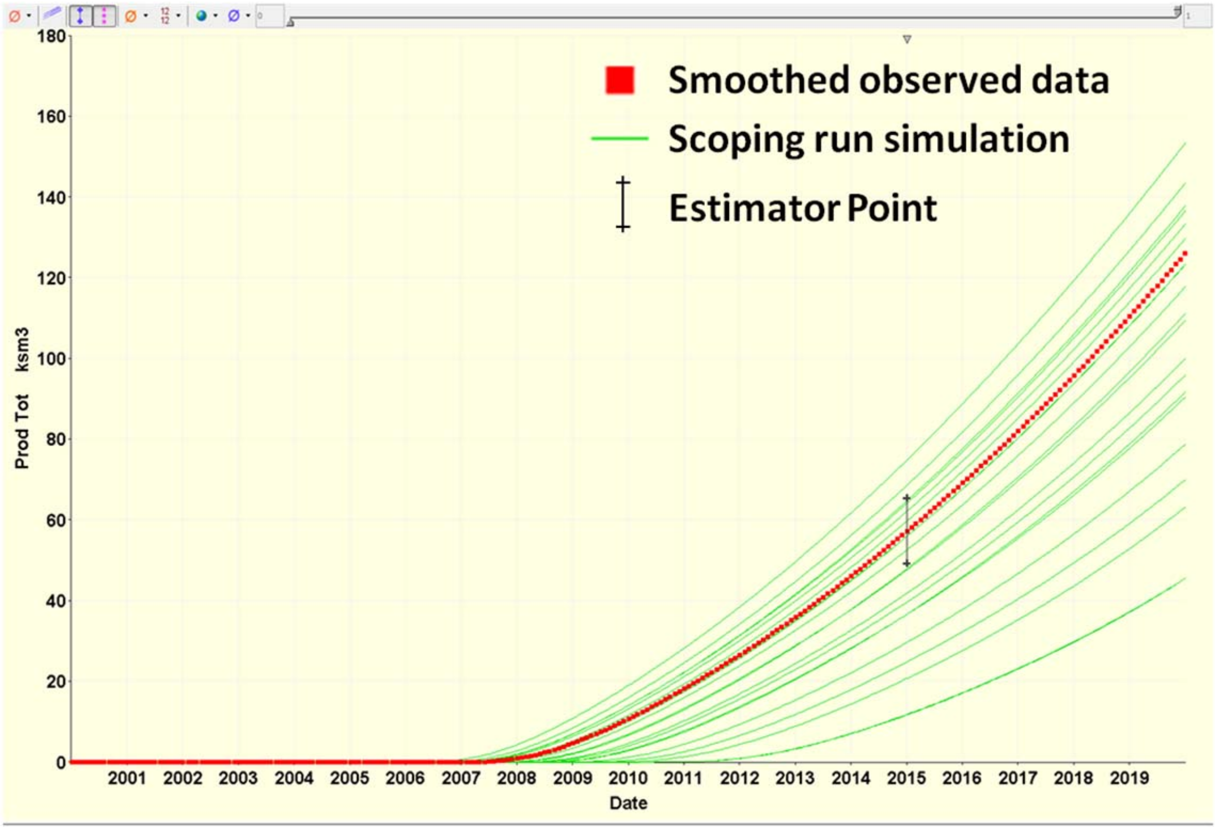


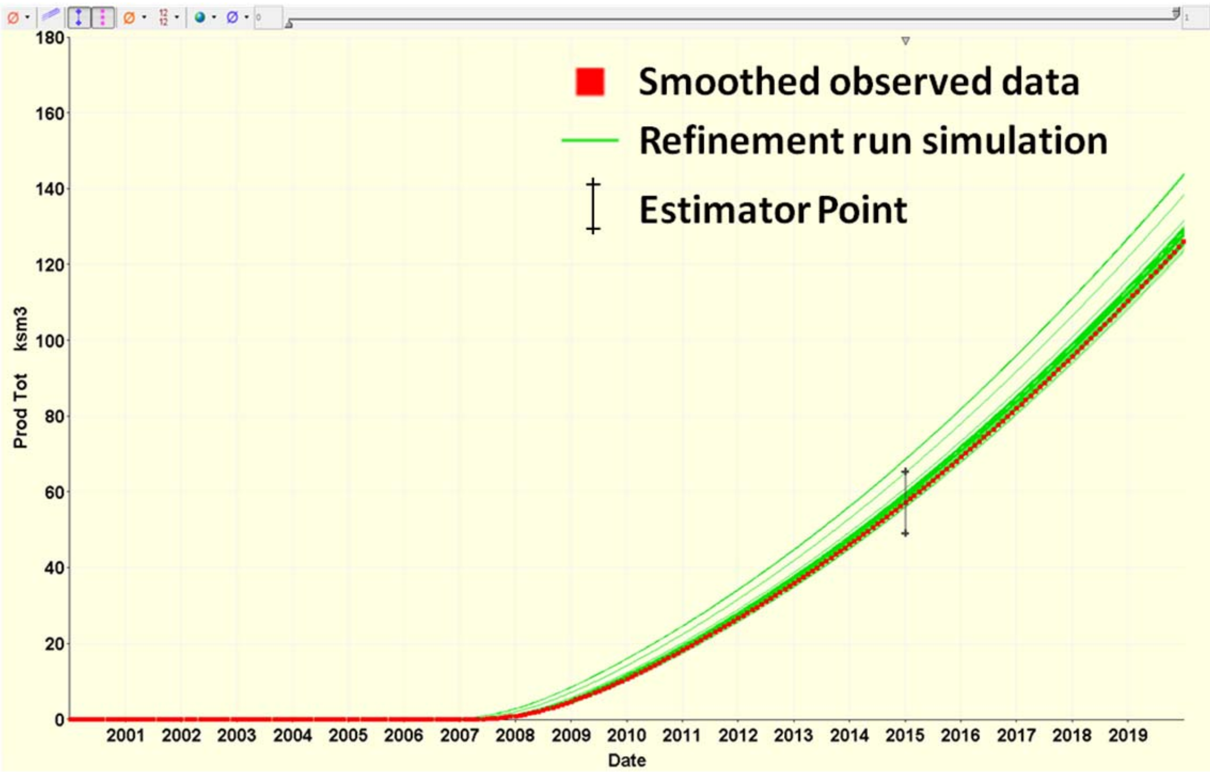
Comparison between scoping & refinement runs for cumulative water production of well P1:



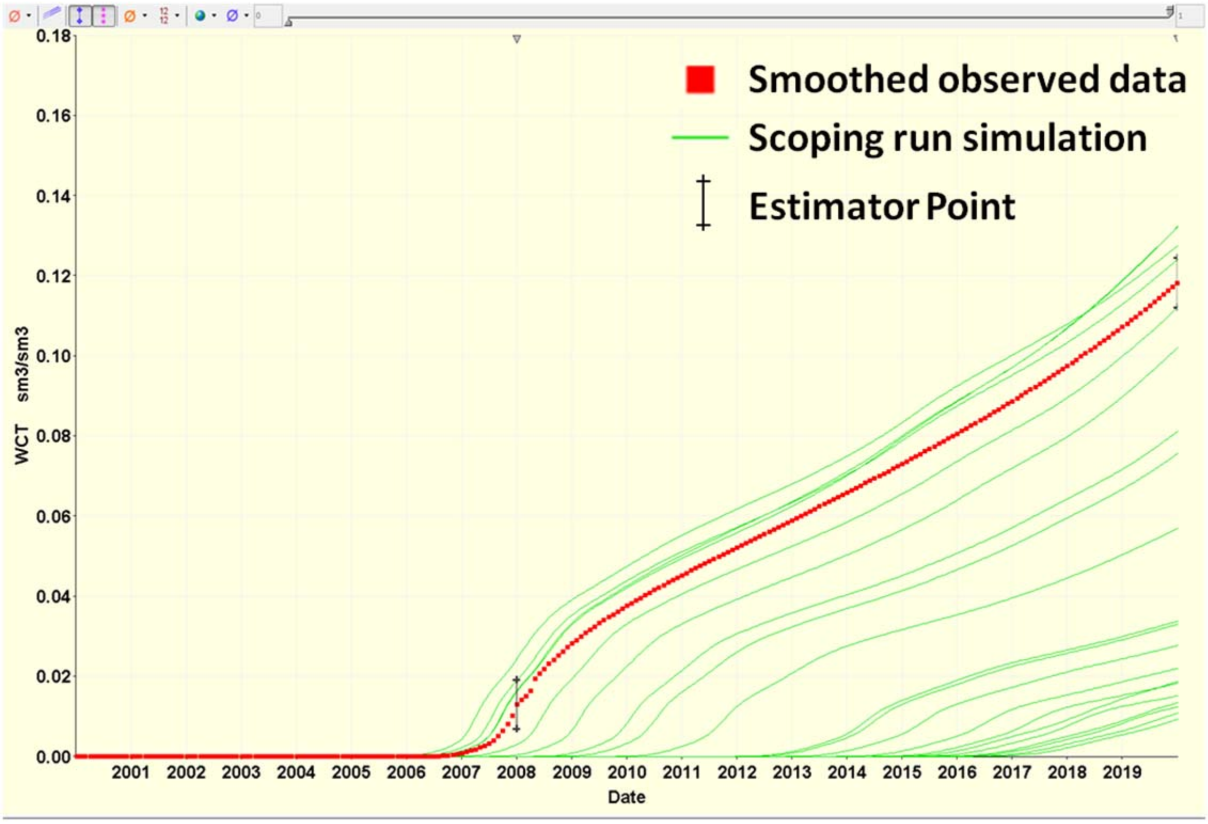


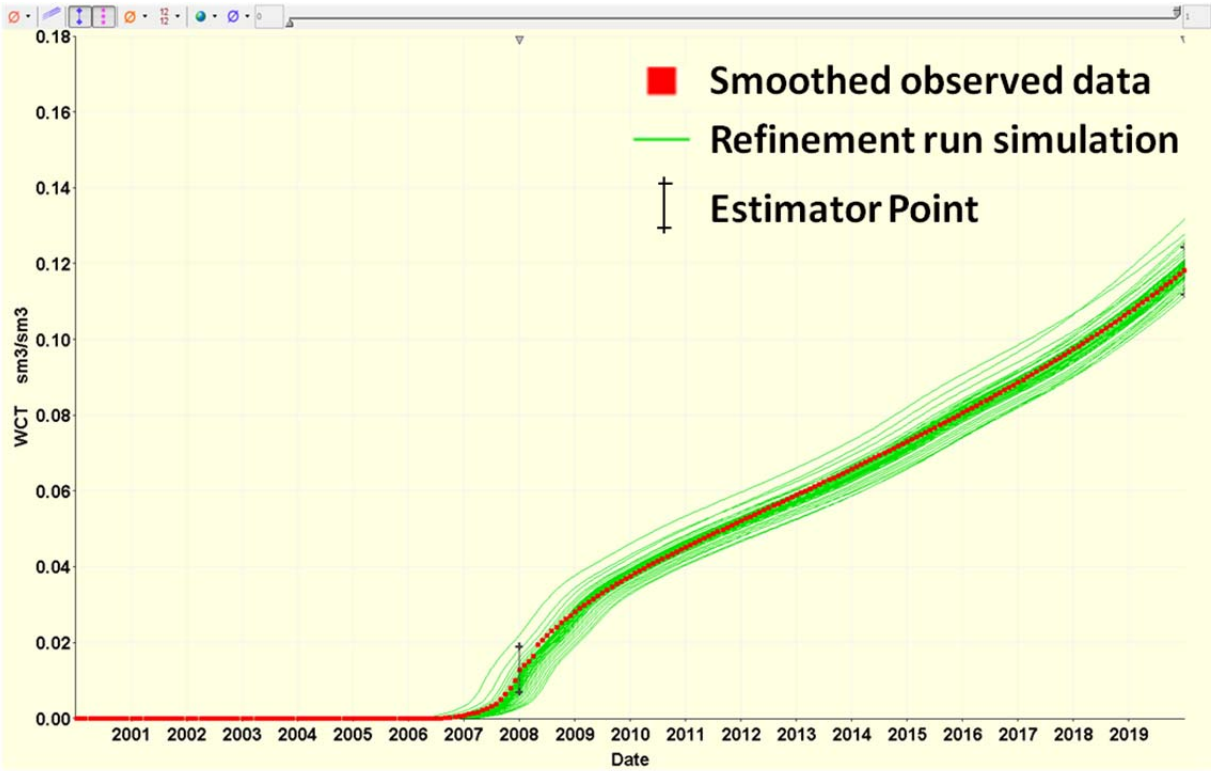
Comparison between scoping & refinement runs for cumulative water production of well P2:





Comparison between scoping and refinement runs for water cut of well P1:





Comparison between scoping and refinement runs for water cut of well P2: