REGIONAL PROBABILTY PERTURBATION METHOD APPLIED TO A REAL RESERVOIR

Todd Hoffman & Jef Caers
Stanford University
May, 2004

Abstract

Production data from a North Sea hydrocarbon reservoir is used to improve the description of the reservoir simulation model. In the reservoir, there exist a number of lenticular calcite with very low permeability. It is likely that these bodies inhibit vertical fluid flow, and it is possible that they could funnel flow in certain horizontal layers. The location and proportion of the bodies are generally unknown. This work attempts to stochastically model these bodies, and then perturb their local proportion and position so that the reservoir model more accurately reproduces the field production data.

The regional probability perturbation method (RPP) is used to model and modify the configuration of the bodies. RPP allows the perturbation of discrete bodies such as the calcite ones observed in this reservoir. The simulation model is changed in such a manner that the geologic concept is always conserved, and although the perturbations are done with a region-wise approach, no artifacts are created at the region borders. This method improves the production data match and ensures the geology is honored.

The current work matches 5 ½ years of historical oil and water flow rate data and RFT pressure data. The original non-history-matched (NHM) simulation model is not able to reproduce the water rates and breakthrough times of a few wells in the reservoir. The calcite bodies have a considerable impact on fluid flow in the reservoir, and by perturbing these bodies the water rate match is improved over the NHM model especially in the wells that initially had poor matches. The pressure data match is also improved over the NHM model; however, its improvement is less dramatic than the water rate’s improvement. With this case study, the importance of having an adequate conceptual geologic model in history matching is demonstrated; specifically, including the calcite bodies in the correct grid layers is shown to be of vital importance.
Introduction

The reservoir has a moderately faulted layered structure. The faults are primarily vertical and are generally not fully sealing. There are four segments separated by the faults; however, there is pressure communication aerially among all of the segments. Figure 1 shows the top of the structure and the general location of the four segments. The reservoir is at a depth of 2500 m and is about 230 m thick.

![Figure 1: Top of the structure is shown along with the four segments. The yellow line a-b corresponds to the subsequent cross section map (Figure 2).](image)

Vertically, there are five major formations. An impermeable shale layer (Horizon 2) isolates the top formation from the bottom three formations. Although the furthest right fault in Figure 2 appears to have open communication between Horizon 1 and Horizon 3, the fault shear is likely sealing as there is no indication from production data that communication exists between the two layers.

![Figure 2: Vertical cross section showing five horizons, oil-water contact, and gas-oil contact.](image)
A gas cap exists in the reservoir and makes up a large portion of the top formation. Below the shale layer, there is only a small amount of free gas present. The water zone accounts for the principal amount of Horizon 5 (Figure 2).

Twenty-two wells delineate the reservoir. There are 8 injection wells that vertically intersect the reservoir. Five injectors have been strictly under water injection, while the other three have injected both water and gas. Most of the 14 production wells are either horizontal or deviated (10 wells). Figure 3 shows where the wells intersect the top of the reservoir. Wells with letter I are injection wells; wells with P are producers. Wells I-1, I-3 and I-4 have injected both water and gas. Figure 3 is rotated 90° to the right compared to Figure 1.

A significant number of very low permeability nodules are found in the reservoir. They were created by the diagenesis of calcite and tend to have a lenticular shape. They typically have an areal extent of a few meters to tens of meters. Where clusters of these bodies are found, they can have a large detrimental affect on vertical permeability. By inhibiting vertical flow, they may also cause channeling of flow in the horizontal direction. Figure 4 shows three separate zones in which bodies are thought to occur with enough quantity to alter vertical flow. Observed well log and core data suggests that the lower section of Horizon 3, the top of Horizon 4, and the bottom of Horizon 4 have a large amount of calcite bodies.
The main goal of this work is to produce a simulation model that matches the historical production data and honors the geology of the reservoir. Predictions from geologically unrealistic models likely are less reliable than predictions from models that include both the production data and the geology. It is apparent that the low permeability calcite bodies can have an influence on fluid flow and are to be included in the model. Since the location and proportion of the bodies is highly uncertain, they provide an important model parameter to modify during history matching. The regional probability perturbation method of Hoffman & Caers (2003A, 2003B) is well suited to solve this type of history matching problem. Other model parameters such as porosity, permeability, fault transmissibility, relative permeability, and others will also be explored to see if modifying them can improve the reservoir model.
Review of Methodology

A history-matching algorithm proposed by Hoffman & Caers (2003A) allows facies bodies to be perturbed in a reasonably efficient manner while honoring the geologic concept of the reservoir. The algorithm starts by creating an initial realization using a geostatistical simulation technique. This realization will honor all types of static information that are known about the reservoir including well logs, cores, seismic, geologic model and others. Initially, the production data will rarely match the historical field data. The realization will have to be perturbed in some manner until the simulated data matches the field data. Directly perturbing gridblock properties may potentially destroy the geological continuity of the initial realization. Therefore, we propose to perturb the “probability distribution” used to create the geostatistical realization. The probability distribution, P(A|B), is the probability of an unknown gridblock property, A, given some static information, B. For example, the unknown property could stand for “calcite body occurs” or “permeability is less than 100 mD” and the other information, B, could be well-log data, seismic information, and/or geologic knowledge of the reservoir. By perturbing the probability distribution, the static information, including the geologic model, is maintained in all realizations. Thus, when a realization is found that adequately matches the production data, it will necessarily honor the previous reservoir information also.

Real reservoirs are complex, both geologically and from a well delineation standpoint. To be able to history match a real reservoir, different amounts of perturbations are necessary for different parts of the reservoir; thus, the reservoir must be divided into separate regions. Nevertheless, the regional perturbations should not create geologic artifacts at the region boundaries. While a number of different techniques are available to define the shape of the regions, using streamlines to define regions has been shown to work effectively for complex reservoirs (Milliken, et al. 2001; Gross, 2003; Hoffman & Caers, 2003A). Once regions are defined, the probability distribution, P(A|B), can be perturbed by different amounts in each region.

The probability distributions are modified using a set of perturbation parameters, \( \{r_{D1}, \ldots, r_{DK}\} \), that can range from 0.0 to 1.0. K stands for the total number of regions and k indexes a particular region. When a parameter, \( r_{Dk} \), is close to 0.0, P(A|B) in that region is perturbed by a small amount, and in the resulting realization, the bodies in that region are distributed very
similarly to the initial realization. Conversely, when a perturbation parameter is 1.0, \( P(A|B) \) is maximally perturbed in that region. Although the geologic continuity model remains the same, the location of bodies differs from the initial realization (Hoffman & Caers, 2003A).

After flow simulation, all regional perturbation parameters are updated based on how well their regional production data matches the field data. Regions that match well will be attached a low perturbation parameter, and regions that match poorly will get a high perturbation parameter. After all perturbation parameters are updated, a new realization is generated and flow simulation is completed on the entire updated reservoir model.

One advantage of using a perturbation parameter to modify the probability distribution is that the history-matching problem can be optimized using a set of straightforward parallel 1D optimizations. An objective is calculated for each region, which is simply some measure of difference between the simulated production data and the observed field data for that region. Using the current regional objective, the previous regional objectives and the previous \( r_{Dk} \), a new \( r_{Dk} \) can be calculated for each region. Once the \( r_{Dk} \) for all regions are updated, a new realization is created and flow simulation is run for the updated model. The efficiency advantage lies in the fact that only one flow simulation is needed per iteration, yet all regions can be improved during every iteration.

For the initial algorithm development, a constant conceptual geologic model (CGM) was assumed known, and only the facies’ locations were perturbed (Hoffman & Caers, 2003A). Due to uncertainty, the CGM will never exactly match the reservoir heterogeneity. Rather, the CGM depicts an idea about what type of geology is in the reservoir (e.g. the direction of channels or amount of shale). Voelker (2003) showed that achieving a history match with this method depends largely on the CGM assumed. Indeed, if the CGM does not accurately represent flow in the reservoir (for example some important geologic features (flow connectivities or barriers) are omitted), the proposed method will fail to history match. No matter how many realizations are generated, none will match the production data because all of them have the same “wrong” geologic model. When this is the case, certain aspects of the CGM need to be parameterized and perturbed as part of the history matching process.
One aspect of the geologic model that is important for a large number of applications is the local proportion of certain (flow) facies. The local proportion (LP) is the amount of a certain facies in a region expressed as a fraction or percentage of the total region. A region is smaller than the entire model and could be defined as the area that influences a well’s production or a set of wells’ production. Because of limited measurements and imprecise knowledge of the geology, there is often a large range of uncertainty on the local facies proportion. Moreover, the LP of these facies bodies can be significantly different for various parts of the reservoir. Therefore when history matching, the LP must be perturbed by varying amounts in different reservoir regions (Hoffman & Caers, 2003B).

If the production data in a region closely matches the historical field data, only small changes need to be made to the LP, however for a poorly matched region, larger changes are in order. Therefore, the set of regional perturbation parameters, \{r_{D1}, \ldots, r_{DK}\}, are well suited to help perturb the LP. When the production match is good, \(r_{Dk}\) decreases, and the LP is forced to remain similar to the initial model. When the production does not match well, \(r_{Dk}\) increases, and the LP is forced to change considerably. Equation (1) demonstrates how such changes in LP can be obtained using \(r_{Dk}\).

\[
LP_k^{NEW} = LP_k^{OLD} + i_k \cdot (r_{Dk}) \cdot Fc \quad \text{for } k = 1, \ldots, K
\]  

where \(K\) is the total number of regions. \(Fc\) is a user-defined constant that characterizes the amount of change allowed each step. Since the values of \(r_{Dk}\) range from 0 to 1, when \(r_{Dk}\) equals 1, \(LP_k^{OLD}\) is either increased or decreased by an amount equal to \(Fc\). Typical values for \(Fc\) range from 1\% to 10\%. Too much or too little change per iteration may decrease the efficiency of the method. By linking the perturbation of \(LP_k\) to the parameter \(r_{Dk}\), the dimensionality of the optimization problem does not increase.

The indicator term, \(i_k\), determines whether the LP should increase or decrease and is defined as follows:

\[
i_k = \begin{cases} 
1 & \text{if increase in local proportion is desired} \\
-1 & \text{if decrease in local proportion is desired} 
\end{cases} \quad \text{for } k = 1, \ldots, K.
\]  

(2)
For simple cases where the relationship between the amount of facies bodies and the production data is well understood, $i_k$ can be determined prior to running flow simulation (Hoffman & Caers, 2003B). Consider an example where a series of high permeability bodies are located between an injector and a producer. If the model is over predicting the water cut at the producer, then the proportion of bodies needs to be reduced, and if it is under predicting, the amount of bodies needs to be increased. However, one can imagine that in some cases the relationship between facies proportion and production data is not as trivial. For example if a reservoir has channels that run both North-South and East-West, increasing the LP may increase or decrease water production from a production well located North of an injector. Likewise if facies bodies have low permeability, they may inhibit (i.e decrease) flow, or they may channelize (i.e. increase) flow between a producer/injector pair. Hence, increasing the LP can lead to an increase or decrease in flow. In these cases a different approach must be used (Kim & Caers, 2003). The probability perturbation method is still utilized, but since it is not known whether the LP should be increased or decreased, one simulation is completed where the LP is increased and one simulation is ran with a decreased LP. Then the simulation that best matches the field data is selected to continue the perturbation algorithm.
Application to the Reservoir

Reservoir Model

A non-history-matched (NHM) reservoir model was provided to us, and most of the data that is discussed in the following section comes from that model. The reservoir model is a structured stratigraphic model with 39 cells in the x-direction, 98 cells in the y-direction, and 41 cells in the z-direction. The z direction has been refined from a previous model that has 26 z-direction blocks. The 41 grid layers delineate 5 horizons. There are just over 150,000 total gridblocks in the model and about half of them are active. The active gridblocks are displayed in Figure 5. The vertically refined layers appear as thick black layers in the figure.

There are numerous faults in the model, and Figure 5 reveals that some of the displacements are rather significant. Most of the faults tend to have reduced permeability, though none of them are impermeable over the entire fault. Areally, there are four separate segments, and they are depicted in Figure 6. The individual segments correspond to different fault blocks; however, horizontally none of the segments are entirely isolated because none of the faults are completely sealing. Vertically, there is isolation because the second horizon is an impermeable shale layer that separates the top horizon from the lower three horizons (Figure 2).
Figure 6: Four areal segments.

There is an aquifer present and the water contact in the model varies from 2575 to 2694 meters in depth depending on the segment and whether above or below the shale barrier. There is also a gas cap in the reservoir, and above the shale barrier, it is rather large. However, below the shale layer, where most of the oil reserves are, there is only a small amount of free gas present.

The porosity and horizontal permeability initially provided in the model are shown in Figure 7.

Figure 7: Porosity and permeability for initial simulation model.

The porosity is mapped using a kriging algorithm. From these two graphics, it can be seen that a linear transformation is used to calculate the permeability from the porosity. The x and y direction permeability are equal, but the z direction permeability has been reduced for different
layers and different areas of the reservoir. Porosity and permeability vary considerably layer to layer, but within each layer little variation exists.

The initial pressure in the reservoir was around 270 bars. There are 18 separate relative permeability regions where the values are calculated from Corey type curves with different exponential coefficients and end points. The 18 water-oil relative permeability curves are displayed in Figure 8.

![Water/Oil Relative Permeability](image)

Figure 8: Relative permeability curves.

In addition to the faults, there are also calcite bodies in the reservoir that influence fluid transmissibility. Since the bodies are relatively thin, they are given no vertical thickness in the simulation model, and they are modeled as z direction transmissibility barriers. Gridblock containing a body or a cluster of bodies will get a reduced or zero transmissibility. So for this case, LP is not a volumetric value of proportion, but rather the proportion of gridblocks that have a reduced vertical permeability due to the presence of the calcite bodies. For example if the LP is 30%, this does not mean that 30% of a region’s volume is calcite. It means that 30% of the gridblocks in the region have reduced vertical permeability.

**Geostatistics Model**

While the probability perturbation method can be used with any geostatistical method, the framework of multiple-point geostatistics is convenient when the method is used in the context of reservoirs with discrete facies bodies (SNESIM; Strebelle, 2002). To describe the geology of a reservoir, most traditional geostatistics techniques such as SGSIM (Deutsch and Journel, 1998) make use of a variogram and are good at reproducing continuous variables. However,
variograms, which only use the correlation of two points in space, can not reproduce well-connected curvi-linear features such as channels or discretely shaped bodies. SNESIM relies on the concept of multiple-point statistics, where the probability distribution, $P(A|B)$, is directly inferred from a training image. A training image is a non-conditional and purely conceptual depiction of the geological patterns deemed relevant for a particular subsurface. The training image used for the current work is shown in Figure 9, and it only needs to be 2D because these bodies are modeled with no z dimension. 30% of the cells in this training image are low permeability bodies.

![Figure 9: Training image.](image)

Little information is known about the bodies’ shape and distribution; therefore, the bodies are randomly dispersed as shown in the training image (Figure 9). Although the size and shape of the bodies is not precisely understood, we are assuming that where clusters of bodies occur, their effects are over a minimum area of 0.04 km$^2$. On average the gridblocks have a length around 100 m in the x and y directions, so the size of the bodies in the training image is typically two gridblocks square. SNESIM allows the proportion of bodies in the realizations to be significantly different than the training image while still honoring the essential patterns of the training image.
**DE Segment**

During the first phase of this study, only a part of the full field model is considered. A reduced model was selected in an attempt to speed up the development of the history matching method. The full field model took approximately 1-½ hours to complete on the available computers, whereas the reduced model took around ½ hour. More time could be focused on creating and improving the history matching algorithm and less time waiting for simulations to finish. Once the method is investigated on the smaller model, it will be expanded to the full model. This initial study area is termed the DE segment, and it contains 6 production wells and 3 injection wells (Figure 10).

![Figure 10: (A) Plan view and (B) 3D view of DE segment model.](image)

To achieve the reduction in modeling time, a flux boundary model was created for the smaller section of the reservoir (i.e. the DE segment). During one full field simulation, flows across the boundary of the DE segment are written to a file. This file is read during the reduced field runs to reproduce the appropriate boundary conditions (Schlumberger, 2003). Perturbations can be performed on the reduced model until a history match is achieved for the wells inside the smaller section.

**Production Data**

The flow data used to match is the water rate. In the model, wells have fixed liquid rates, hence if water rates are correct, oil rates are also correct as are the water cuts. The available pressure data comes from RFT pressures taken at 12 wells when they were first drilled. For each well there are numerous measurements taken throughout the reservoir column. The objective
function is simply defined as the square difference between the simulated production and measured production data. Depending on when a well came on-line and went off-line there is between 17-44 months of production for each well. Equal weight is given to each point of data, not to each well, so theoretically, a well that is producing for 40 months will have twice the influence of one that has been producing only 20. Likewise, a well with RFT measurements taken over 200 m will have twice the influence as a well where only 100 m were measured; however, most wells had similar distance intervals measured. The pressure data is weighted such that it comprises about 40% of the total objective, and water rate data account for the other 60%.

The water rates from the six production wells in segment DE are displayed in Figure 11 as the solid blue lines. The water rates from the provided non-history-matched (NHM) model are also shown in the figure as red lines. Although continuous lines are shown, the data used to match is actually monthly data. Figure 11 only shows the water rates, but oil and gas rates for the producers along with injection rates for the injectors are given in Appendix A.

Of the six wells, two are of primary concern, P-3 and P-4. The other four are matched quite well. For well P-3 the water breaks through to the producer too early and too much water is produced in the model. Although the well is mainly in the D segment, the water that is produced primarily comes from the E segment. It crosses the fault along the bottom where the fault is not sealing, and due to the pressure depletion caused by P-3, water travels up to the well.

Conversely, for well P-4 the water breaks through too late in the simulation model. This well is also in the D segment, but most of the produced water at this well comes from the aquifer portion of the D segment.
Figure 11: Water rate for the six production wells in DE segment and the modeled water rate from the NHM simulation.

Pressure versus depth data is available for four wells in the DE segment (Figure 12). Pressure from the NHM model is also plotted on the graphs. The original match is good for wells P-13 and I-7, but it is not as good for wells I-5 and I-6.
The pressures in Figure 12 above 300 bars that are at shallow depths are pressures in Horizon 1. These pressures are higher than the rest of the horizons, and they remain higher throughout the production period. This clearly demonstrates that Horizon 1 is isolated from the lower three formations.

**Reservoir Regions**

To perform history matching with the probability perturbation method, a method for defining regions in the reservoir is required. Streamlines are well suited for the job because they directly show the flow paths by which fluid enters a production well. These paths identify the gridblocks that, if changed, will have an obvious impact on a well’s production. All blocks hit by the set of streamlines entering a well define the “drainage zone” for that well. The various drainage zones will define the geometry of the regions used for history matching. As the model is perturbed and new realizations are generated, the facies distribution will change. Consequently, the drainage
area of the production wells will be different for different realizations, and the streamline-defined regions will have to be updated. The region definitions for one realization are displayed in Figure 13.

Figure 13: Streamline defined regions in 3D and for two selected layers.

The streamline simulation (StreamSim, 2003) is needed only to define regions (i.e. find the main gridblocks that influence flow at a well); not for deducing water and oil rates. Thus, the actual streamline simulation model is different from the finite difference model. The grid dimensions, porosity and permeability are the same for both models, but the streamline model is incompressible; its gas phase is not treated, and simplified relative permeability curves (x-curves) are used in the streamline model. Nonetheless, the biggest difference between the streamline and finite difference models is how the wells are modeled. In the reservoir (and the finite difference model), wells come on line at different times over the 5½ years; however in the streamline simulation model, all wells are included at the initial time. This is necessary to ensure that each region contains gridblocks that are most consequential for flow to the well in that region. In the NHM model, the wells have fixed liquid rates that are constant over the wells’ life, so those values are used in the streamline model (P-3 = 6000, P-4 = 6000, P-10 = 7500, P-11 = 6000, P-12 = 1000, P-13 = 3000 m³/day). Because streamlines change very little when the well boundary conditions are constant and the streamline simulation is only used to define regions, the streamline simulation only needs to be run for a short duration (10 days).
Although some calcite bodies are present throughout the entire reservoir, there are three vertically defined zones that are thought to have a higher concentration of bodies as observed from well log and core data (Figure 4). Zone 1 is located near the bottom of Horizon 3 and accounts for layers 11-17 in the simulation model. Zone 2 is at the top of Horizon 4 and corresponds to layers 18-25, and the third zone is at the bottom of Horizon 4, layers 32-37. Figure 14 shows where the zones are in the simulation model.

Figure 14: Three zones that are thought to have a significant proportion of calcite bodies.
For the first history matching run, bodies are included in all three vertically described zones and all six streamline-defined regions. The location of the bodies as well as the local proportion (LP) is perturbed per region. The LP was perturbed using the method of Hoffman & Caers (2003B) where if the model was over predicting the water rate for a region, the LP for that region is increased and vice versa. (Note that this is slightly different than the original development by Hoffman & Caers because they demonstrated the method with high permeability bodies, and in the current case, there are low permeability bodies.) The initial LP for all regions is 30%, and it is maintained between 10% and 60%. If a perturbation causes the LP to go outside these bounds, then the LP is reset to the boundary value. The specifications for all history matching runs that are discussed in the paper are presented in Table 1.

Table 1: Specifications for history matching runs.

<table>
<thead>
<tr>
<th>Run #</th>
<th>Run Specifications</th>
<th>Figures</th>
</tr>
</thead>
</table>
| NHM   | • provided model – non-history matched  
       | • bodies only placed deterministically based on well log information | Figures 11, 12 |
| Run 1 | • bodies in grid layers 11-25, 32-37  
       | • range of proportions 10% - 60%  
       | • local proportion (LP) perturbed based on over/under predicting field data  
       | • initial $r_{Dk} = 0.50$; initial LP = 30%  
       | • sensitivities include (a) bodies only in grid layers 11-25  
       | • (b) bodies only in grid layers 32-37 | Figure 15 |
| Run 2 | • bodies in grid layers 26-28 - Only Region P-3  
       | • fixed proportion = 90%  
       | • no perturbations | Figure 17 |
| Run 2a| • bodies in grid layers 32-37 - Only Region P-3  
       | • fixed proportion = 90%  
       | • no perturbations | Figure 18A |
| Run 2b| • bodies in grid layers 26-28 - Only Region P-3  
       | • fixed proportion = 60%  
       | • no perturbations | Figure 18B |
| Run 3 | • bodies in grid layers 11-37  
       | • range of proportions 1% - 99%  
       | • local proportion (LP) perturbed based on increasing/decreasing and keeping the best matched in each region for 3rd flow simulation  
       | • initial $r_{Dk} = 0.75$; initial LP = 80% for region P-3 & 20% for other regions | Figures 20, 22 |

For Run 1 some improvements, like in well P-4, are observed; however, most of the wells’ water rates either did not improve over the NHM model, or they got worse (Figure 15). The breakthrough time for well P-3 continues to be over two years too early and well P-11 does not match as well as the NHM model. Additional cases (not shown) are completed where the bodies
are only placed in Zone 3, or only placed in Zones 1 and 2. These cases show some minor regional improvements, but the breakthrough time for well P-3 remains a problem.

![Graphs showing water production from field and model](image)

**Figure 15:** Water production from field and model

After a number of unsuccessful attempts to rectify this problem, a different approach is attempted. In the three layers that are directly below P-3’s lowest perforations, the vertically impermeable bodies are placed with a proportion of 90% (Figure 16).
Recall that this does not mean there is 90% calcite in this region, only that 90% of cells in this region have their vertical permeability affected by the bodies. The bodies are only put in region P-3; the other five regions have no bodies. This is called Run 2 in Table 1. The water breakthrough time for well P-3 is reasonable and the match for well P-4 improved as well (Figure 17). The match for the other four wells did not change significantly.

These grid layers (layers 26-28) did not include bodies in Run 1. Grid layers 26-28 are in Horizon 4, but they are between the two vertically defined zones (Zone 2 and Zone 3) where calcite bodies were included. To check if the large proportion of bodies and not their location caused the improved match, a similar case (Run 2a) is completed where 90% proportion is placed in the original Zone 3, layers 32-37 (Figure 18A). This, however, did not have the same beneficial effect as the Run 2 (Figure 18C). To test if the location (and not the high proportion of bodies) is the reason for the improved match, a case (Run 2b) where only 60% proportion of
bodies is put into the three layers 26-28 (Figure 18B). Although the match is better than Run 2a, it does not show the same improvement (especially regarding breakthrough time) as Run 2 (Figure 18C). These two examples demonstrate that it is both the locations and proportions of bodies that kept the model from matching the data in Run 1 (Figure 15).

The match of production data shown in Figure 17 is acceptable; however it is not geologically realistic to have the situation illustrated in Figure 16: in a small area, 90% of the gridblocks have very low vertical transmissibility; elsewhere, none of the gridblocks are altered. Thus, the conceptual geologic model must be altered so the bodies can be stochastically modeled in a more geologically realistic manner. Although the calcite bodies are present to some extent in most of the reservoir, it was thought that they only existed with enough quantity to affect flow in the three previously defined zones. The preceding analysis (Run 2) demonstrates that, at least in the region around well P-3, bodies are also a factor in the middle of Horizon 4. Therefore, bodies will be allowed in layers 26-31 (between Zones 2 and 3) in the next history matching runs. Consequently, all gridblocks in layers 11 to 37 will be able to have their z transmissibility reduced due to the low-permeability calcite bodies.

A further modification to the algorithm is necessary with regard to how the LP is updated. In Run 1 the LP of the calcite bodies are perturbed as follows. If the model’s water rate is greater than the observed rate, the proportion of bodies is increased in an attempt to reduce flow to the well, and if the model is under predicting the field data, the proportion of low-permeability bodies is decreased. This works for some wells such as P-3, but for others such as P-10, this logic actually makes the match worse. Because P-10 is completed in the upper layers, an
increase in vertical flow barriers allows less water to travel down by gravity. In this situation, the presence of calcite bodies “funnels” the water to the well and causes an earlier breakthrough (Figure 19). The LP may need to be increased for some regions and decreased for others, and it is not immediately known from production data, which one will lead to a better match.

![Well P-10](image)

**Figure 19:** Comparing water rate for models with 30% LP and 90% LP.

Therefore, a different method for perturbing LP, similar to one proposed by Kim and Caers (2003) is used. First, the LP for all regions is increased (i.e. \( i_k \) in Eq. 1 is +1 for all k) and flow simulation is run. Then, the LP is decreased for all regions (\( i_k = -1 \) for all k) and flow simulation is again completed. The regional objectives are compared for the two cases. Some regions may have a better match for an increased LP, while other regions will match better for the decreased LP. On this basis it is decided whether to increase or decrease the LP in a region (i.e. whether \( i_k \) should be -1 or +1 for each k). Finally, a new model is created that contains the various regional increased and decreased LPs, and a third simulation is run. The global mismatch will be calculated from this third simulation and compared with the best previous mismatch in the optimization routine.

Other changes to the method allowed a larger space of possible LP values to be searched and the values to be searched in a faster manner. First, the LP was allowed to vary more during each perturbation. \( F_c \) is set to 10%, hence the average LP perturbation is around 5%. Second, a set of higher initial \( r_{Dk} \) values started each inner iteration (0.75 instead of 0.50). Hoffman and Caers (2003A) show that increasing the initial \( r_{Dk} \) values increases the initial convergence rate. Third,
the search space of the local proportion was expanded from 10% - 60% to 1% - 99%. Finally, the initial LP for region P-3 is 80%, and it is 20% for the other five regions.

Figure 20 shows the water rate match achieved for the six wells. This is the best matched achieved to date and is rather good for all wells. The initial model is also displayed on the figure. This is not the NHM model; it is the first generated realization before any history matching perturbations are completed.

Figure 20: Match of simulation model data to field production data for DE segment.
For wells P-3 and P-4, the initial model already displays a vast improvement over the NHM model, and the perturbations only further improve the match but to a lesser degree. This demonstrates a point alluded to earlier: finding the correct conceptual geologic model is the most difficult and time-consuming part of history matching. It will be nearly impossible to achieve a history match with the wrong geologic model (unless the geologic data is invalidated altogether). However, once the correct geologic model is found, history matching is more straightforward.

For this reservoir, once bodies were placed in layers 26-31 and with high proportion in region P-3, history matching went smoothly.

This particular history matching run took only 22 flow simulations to achieve the outcome, and another history matching run that matched almost as well took only about 40 simulations to converge to its best solution. The final proportions for the six regions are 53% for P-3 region, 12% for both P-4 and P-10 regions, 1% for P-11 region, 13% for P-12 region, and 22% for P-13 region. The LP for region P-3 was expected to be higher as demonstrated by Figure 18; however, it ended up at a much more reasonable value below 60%. This is partially due to the fact that we are searching for a global match and the lower proportion of bodies in P-3 may help other wells match better. Although the breakthrough time is earlier for this run than Run 2, the amount of water produced stays lower longer for this run which helps the match quality.

The locations of the cells where the bodies influence vertical flow are shown in Figure 21. While most of the model has relatively few altered gridblocks, the region around P-3 (bottom left of grid) has a slightly higher proportion of bodies.

![Figure 21: Location of calcite bodies in two layers](image_url)
An adequate pressure match is also achieved for the model (Run 3), but the match is not exact for all wells (Figure 22). Well P-13 matches well for both the NHM model and the history matched model. Both wells I-5 and I-6 improve their match over the NHM model. Well I-6 is very closely matched while I-5 only improves its match to about half way between the NHM model and the field data. The pressure match for well I-7 is worse for the “matched” model than the NHM model, and pressures in the matched model are much higher than the observed pressure. The increase in pressure may have been due to the large proportion of bodies in region P-3. This could have reduced the amount of water flowing into the region and led to an increase in pressure around well I-7, which is located very close to region P-3. The boundary fluxes used for DE segment model might have also had an effect on I-7’s pressure because in the full field model this increase in pressure is no longer observed even when a high proportion of bodies is placed in region P-3.

![Figure 22: Pressure match for four wells.](image-url)
Conclusions

- A quality history match can be achieved on a real reservoir using the regional probability perturbation method. By stochastically modeling the locations and proportions of the calcite bodies, a reservoir simulation model is created that matches the production data much better than the initial model or the NHM model. In this manner a simulation model can be created that not only matches the production data but also honors the geologic conditions found in the reservoir.

- History matching in a geologically consistent manner necessitates that the correct conceptual geologic model is used. Indeed, if a wrong conceptual geologic model is used, no matter how efficient the algorithm, a match will not be achieved. A large portion of energy spent in history matching is in finding the correct conceptual geologic model.

- Future work consists of finishing the extension to the full field model. Both pressure and rates are matching well for all the wells except two or three. Similar to the method used to match well P-3, we are currently studying what can be done in these wells to improve the match and be geologically consistent. Some additional runs will be completed where other parameters are perturbed. The other parameters include fault transmissibility, relative permeability, absolute permeability, and porosity.

Acknowledgements

We would like to thank Statoil for providing us with this dataset and the support from various engineers, geologist in the field and in research to make the case successful.
References


Appendix A - Well Production (Oil, Gas and Water)

Well P-3

Oil

Gas

Water

Well P-4

NHM matched
Well P-12

Oil

Gas

Water

Oil

Gas

Water

Well P-13

Field

NHM

Matched
Water Injection

Well I-5

Well I-6

Well I-7

Water Injection

*Note there is no gas injection in the DE segment