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# Permeability Updating of the Simulation Model Using 4D Seismic Data

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## Abstract

In this paper we present a practical methodology for updating the reservoir simulation model by incorporating permeability derived directly from time-lapse seismic data. The proposed method builds new permeability distributions by integrating the prior 3D simulation model with 2D permeability maps from the time-lapse seismic results. Application of this approach to a West of the Shetland Isles turbidite field under waterflood shows that the misfit to the water cut data can be improved. The updates using this procedure appear to provide a good alternative to those obtained using a conventional gradient based history matching tool on its own. The main advantage of our methodology is the ease of implementation but also that the largely uncertain petroelastic model can be avoided when history matching to the time-lapse seismic data.

## Introduction

New high resolution 4D seismic acquisition techniques have led to many advances, especially in static reservoir property estimation. A common question in the reservoir engineering context is how far can time-lapse seismic go when it is used to refine the flow simulation model. After years of significant research into the time-lapse analysis of reservoir properties such as fault location, flow barriers or high permeability pathways (Floricich et al. 2008), time-lapse seismic is now extending its value from the qualitative to the quantitative. This is of considerable benefit as time-lapse seismic can play a unique role in providing measurements across the field with a favorable resolution compared to conventional tools such as well testing. For the quantitative route, although time-lapse seismic seems to be progressing in solving the challenges such as pressure/saturation change separation (Landrø 2001, MacBeth et al. 2006) fewer researchers have been successful in estimating reservoir properties such as permeability. Permeability is a reservoir property that has a first order of impact on simulation model predictions, and is important for optimising the simulation model predictions. In recent years, much research has been devoted to the development of a history matching process (Villegas et al. 2006) or seismic history matching process (Mezghani et al. 2004, Stephen and MacBeth 2006) to estimate the permeability in an iterative fashion using an objective function matched exactly to the seismic data. However fewer authors have investigated the direct transform of time-lapse seismic attributes into average permeability maps of the reservoir. Updating the permeability of simulation models using this approach has been investigated before based on the trajectories but without using prior reservoir simulation models (Vasco et al. 2004). Direct estimation of reservoir properties from 4D seismic, by transformation procedures similar to those used to carry out the estimation of properties like porosity and net-to-gross, now appears to be one viable approach (Al-Maskeri and MacBeth 2006; Johann et al. 2009). However one major drawback of all approaches is that the permeability is defined as a 2D map and not a 3D volume. The current work addresses this challenge by designing a scheme to effectively integrate the depth-averaged, mapped estimates from seismic to update the 3D permeability field from the simulation model. To examine the benefits of this approach, we compare our results with the conventional history matching of production data.

## Reservoir description

The proposed updating procedure and field application of methods have been implemented on a dataset from the UK continental shelf. More details of this field and the relevance of seismic interpretation and integration are presented in Parr et al. (2000). This seismic data has been previously studied for pressure and saturation change separation and seismic history matching Stephen and MacBeth (2006). For the current investigation, post-stack migrated 3D seismic volumes from 1999 (monitor survey, time T1) and 1993 (base survey, time T0) are available. Prior to our study, the seismic data are cross-

equalized and the results are found to be sufficiently good to enable further accurate studies. The producing interval of specific interest in our study is the T31 sand in which compartments and faults are noticeable. The southernmost sector of the field is chosen, separated from the other sectors by a sealing normal fault. In this sector of our study there are four active wells, two injectors and two producers, in the time period between the base (time T0) and monitor (time T1) surveys. Water flooding has been applied in order to maintain the pressure and sweep the remaining oil. The initial reservoir pressure is close to bubble point pressure, but gas does not exsolve from solution during the time period of interest. Figure 1(a) shows the changes in the seismic signature between the time T0 and T1. The average permeability map of the reservoir from the simulation model is also displayed in the Figure 1(b) for reference. The map in Figure 1(b) is the result of harmonic averaging of the values in the first four layers of the numerical simulation model corresponding to the 4D seismic vertical coverage.

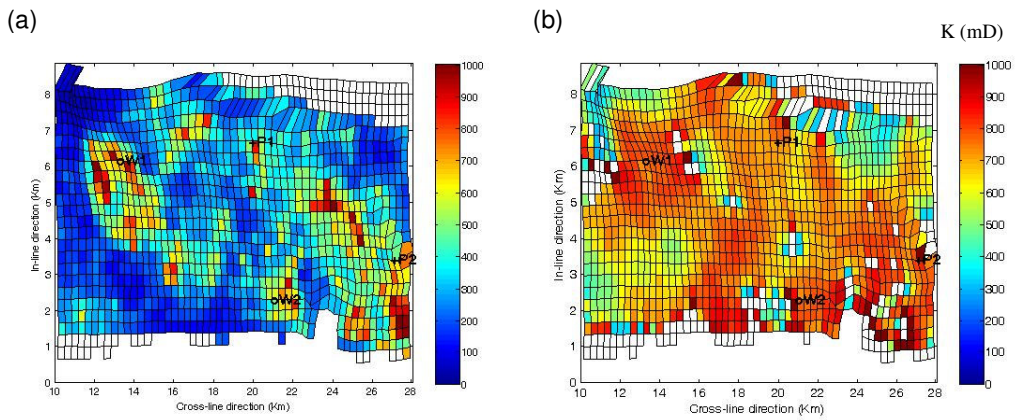


**Figure 1. (a) Normalized difference in the seismic maximum amplitude attribute between 1993 and 1999. Values are drawn on the simulation model grid. (b) Average permeability from the simulation model.**

## Application of proposed method

The formulation of MacBeth and Al-Maskeri (2006) is used to estimate the mapped 2D permeability distribution, $K$, using time lapse seismic data. This model is derived from the single phase diffusivity equation

$$K_0 = \frac{c_f \mu}{\Delta T} \phi \left\{ \frac{|\Delta A|}{\left[ \frac{\partial^2 \Delta A}{\partial x^2} + \frac{\partial^2 \Delta A}{\partial y^2} \right]} \right\} \tag{1}$$

where $c_f$ is the total compressibility, μ is the fluid viscosity and ϕ is the effective porosity (porosity x net to gross). $\Delta A$ is the seismic attribute difference between the two seismic measurements (one survey by necessity must be the baseline survey), assumed to be dominated by the pressure changes. The permeability defined in (1) has the potential to enhance a history match as the Laplacian in the denominator is capable of detecting edges of channels and discontinuities related to compartmentalization in the field, similar to that used in evaluating seismic curvature. This is in contrast to the permeability in the base case model which is derived from stochastically distributed facies trends. Applying the explicit scheme shown in (1) we get the permeability distribution displayed in the Figure 2(a). To generate this map it was necessary to implement a numerical scheme that applies a regularization to smooth the data and to incorporate prior information in the form of the prior trend of permeability versus porosity. The regularization technique is applied to correct discontinuous values arising in the numerical implementation of the Maskeri-MacBeth method, and to ensure the function has smooth derivatives. The average permeability map obtained after applying their formulation will be used as the initial map ($K_0$) during the regularization process. Here we use the numerical scheme proposed by Gonzalez et al. (2005) to obtain a physically consistent and regularized permeability distribution.

$$\frac{\partial K}{\partial t} - \beta \left( \frac{\partial^2 K}{\partial x^2} + \frac{\partial^2 K}{\partial y^2} \right) = (K_0 - \alpha K) \tag{2}$$

This is achieved by considering that the term $(K_0 - \alpha K)$ is a time dependent source term and the boundary conditions are of Neumann type. After $n$ iterations of the smooth regularization process and application of (2) we get the following initial and boundary conditions:

$$\frac{K^{(n+1)} - K^{(n)}}{\theta} \begin{array}{l} K(0) = K_0 \\ = \beta \Delta K^{(n)} - (K_0 - \alpha K^{(n)}) \\ \nabla K_{\partial\Omega} . \vec{n} = 0 \end{array}$$

(3)

where α is a weighting for the initial model, β the smoothing factor and ϑ the step size. It takes 10 iterations for the procedure to converge. In order to incorporate the essential prior information, we compare the permeability-porosity trend of our model with the cross plotted data corresponding to the reservoir simulation model. We modify the permeability-porosity trend obtained in order to align the maximum and minimum values with those of the prior data to ensure our trend remains consistent with the original data.

The next stage is to convert this mapped property into adjustments to the 3D model. The problem of seismic resolution and the associated issues of incorporating seismic mapped data into 3D models is well documented (for example, Behrens and Tran, 1999). Here we adopt the approach of Gorell (1995) and make use of the concept of multipliers. Figure 2(b) gives multiplier values defined by comparing the average simulation values with the results of the permeability transformation from the time lapse seismic data.

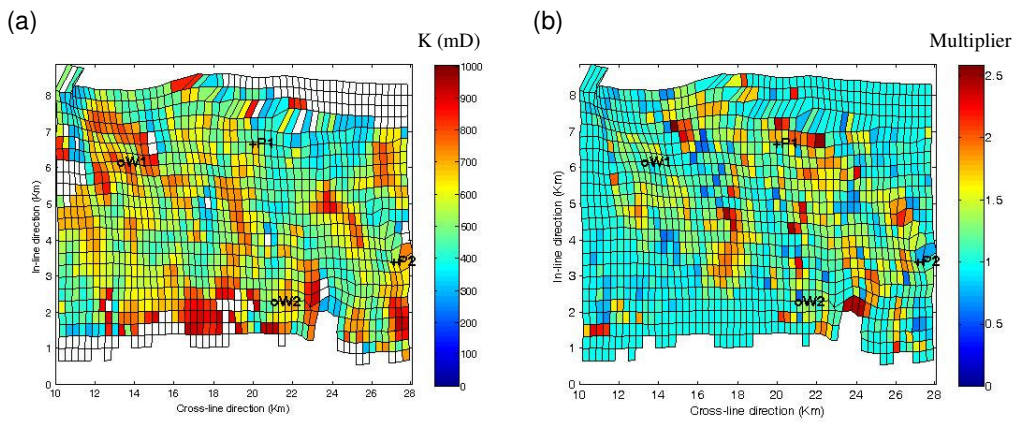


**Figure 2. (a) Regularised permeability map from the time lapse seismic data, transformed onto the simulation model grid. (b) Corresponding multiplier values.**

In order to get an updated permeability model, we make use of the multipliers of Figure 2(b). These multipliers are fixed for each horizontal location and applied vertically throughout each layer of the reservoir simulation model as perturbing factors. To apply the multipliers in each layer of the 3D reservoir simulation model, it is necessary to interpolate the multiplier values located in the seismic grid to the horizontal positions of each cell in the corner point grid. Once we find the multipliers in each 3D grid position, we apply it directly to the 3D prior permeability distribution to create a new volume. Only the area of the simulation model covered by the seismic data can, of course, be updated in this fashion. Figure 3 shows the comparison between the base case model permeability and the new updated permeability values for each layer of the model.

## History matching

In order to evaluate the accuracy of the new permeability volumes we consider a fit to the dynamic data via the history match. Therefore we define the residual operator (J) as a vector in the data space which contains the differences between the real and the simulated water production rate, the bottom-hole pressure and GOR. The objective function is defined as the least square data misfit:

$$J = \sum_{N} \frac{\left(Q_W - Q_{W_{OBS}}\right)^2}{\sigma_{Qw}^2} + \frac{\left(P_W - P_{W_{OBS}}\right)^2}{\sigma_P^2} + \frac{\left(GOR_W - GOR_{W_{OBS}}\right)^2}{\sigma_{GOR}^2} \qquad (4)$$

where $Q_{wOBS}$ , $P_{wOBS,}$ and $GOR_{wOBS}$ are the water production rate, bottom hole pressure and Gas to oil ratio from the history data, and $Q_w$ , $P_w$ and $GOR_w$ are the simulated data resulting from running the forward simulation with a specific 3D permeability. $\sigma^2_{Qw}$ is the standard deviation of the water production rates measurements $\sigma^2_P$ that for the pressure measurements, and $\sigma^2_{GOR}$ for the Gas oil ratio measurements. The values of the objective function using the base case model and the 4D seismic updated model are 1.66 and 1.67 respectively. The data misfit appears not to have changed by incorporating the 4D seismic updates.

For the history matching we use the commercial tool of Schlumberger (Simopt) which involves an automatic gradient based history matching approach. The gradient, estimated by using Simopt, is defined as the adjoint of the Frechet derivative applied to the residuals in the following way:

$$\delta K^{(n)} = -R'[K^{(n)}]^* R(K^{(n)}) \tag{5}$$

In the equation $\delta K$ is the gradient estimated by Simopt, $R'[K]^*$ is the adjoint of the Frechet derivative and $R(K)$ is the norm.

$$K^{(n+1)} = K^{(n)} + \omega \delta K^{(n)} \tag{6}$$

where ω is a step-length chosen appropriately (in our case it was estimated by using a line search criteria).

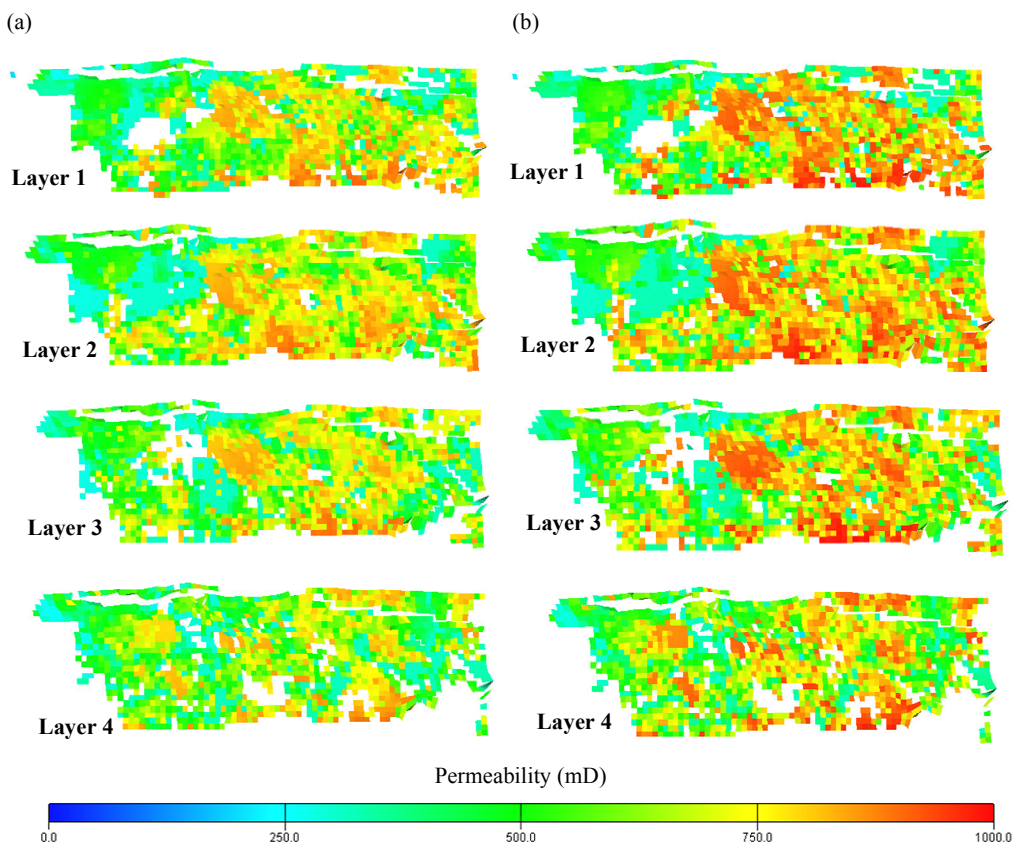


**Figure 3. (a) Base case simulation model, and (b) the new updated model (right) after applying the multipliers of Figure 2(b). Figures from top to bottom refer to the first four layers of the model.**

The permeability results of this process are shown in Figure 4, where the updates to four individual layers in the model are shown before and after the updating and history matching procedures. The objective function evaluations using these new models, before the history matching processes, are 1.66 for the base case, 1.67 for the 3D model updated using the 4D seismic information, and after 10 iterations in history matching are 1.53 for the history matched base case using SimOpt, and 1.34 for history matching using the updated model. Thus, although the 4D seismic updates did not change the misfit significantly, they have changed the rate of convergence and the final history matched model misfit. Individual fits to water cut, total field gas production and bottomhole pressure are shown in Figures 5 and 6. The main improvement for the history matched updated model is in the fit to the water cut at individual wells, whereas the history matched base case model fits the total field gas production better. The bottomhole pressure is matched by both models equally well, showing a slight improvement in both cases.

## Conclusions

In this work we have updated the reservoir simulation model using a new methodology to build new 3D permeability distributions of the reservoir, by combining time lapse seismic data with the prior 3D reservoir simulation model of the field. In this methodology the fit to the water production data was significantly improved when we history match the simulation model which has been previously bump-started by the 4D seismic update process. It is possible that the permeability distribution assigned using the 4D seismic data generates a model which takes into account the representation of the possible channels connections and discontinuities. Such methodology is easy to implement and shows that it is possible to reduce the dynamic data misfit by incorporating the time lapse seismic information into our 3D permeability models without including the petroelastic model during the history matching process.

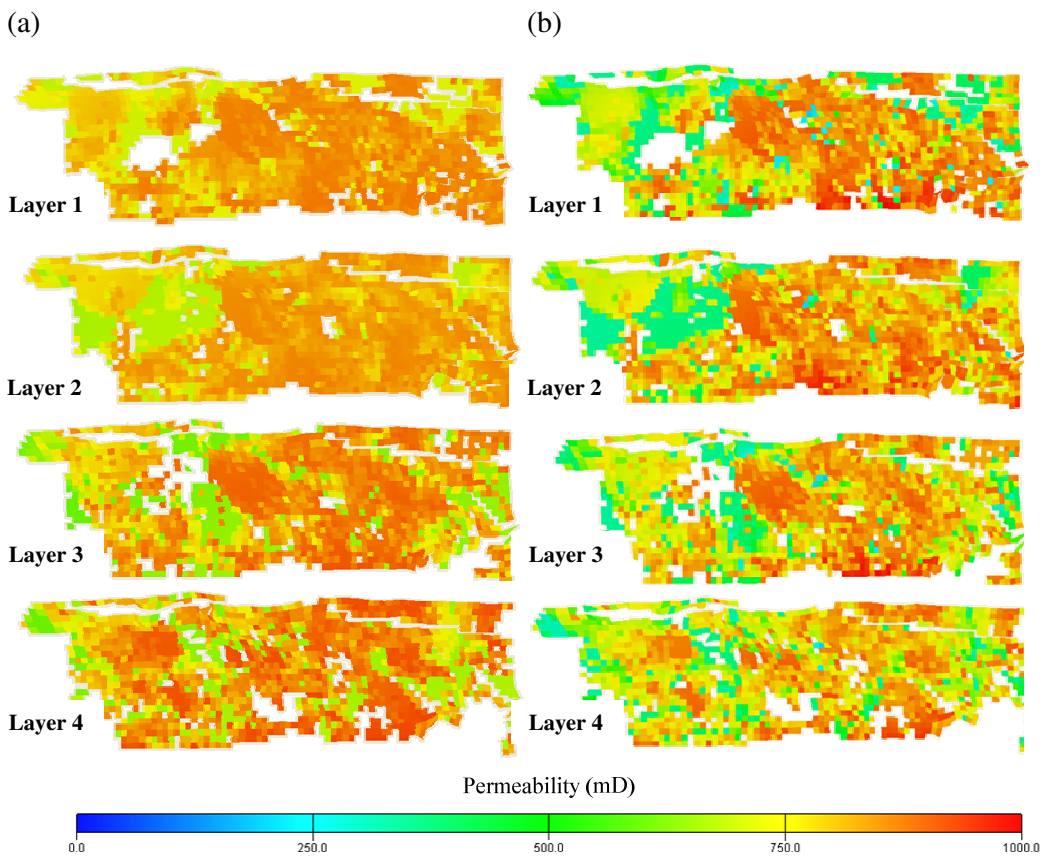


**Figure 4. Comparison of models after the history matching process (a) initiated from operator model and (b) initiated from the model with integrated 4D seismic permeability.**

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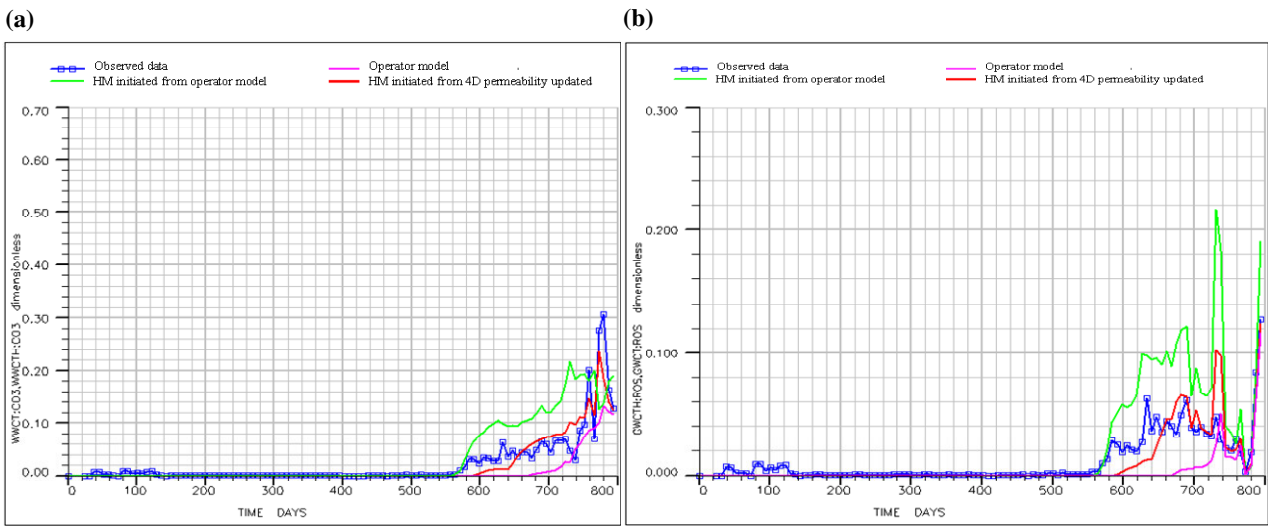


**Figure 5. (a) Water cut in the production well P1 and (b) in a group of production wells (P1 & P2), after history matching the base case and 4D seismic updated model.**

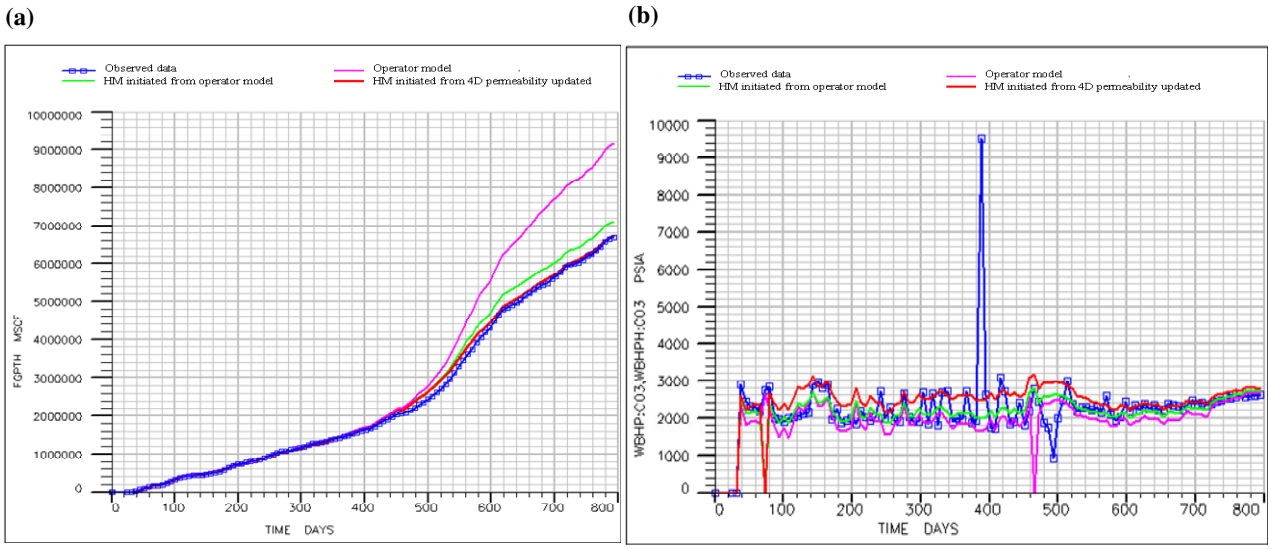


**Figure 6. (a) Total field gas production and (b) bottom-hole pressure for well P1 and corresponding fits.**

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