Uncertainty Assessment of SAGD Performance Using a Proxy Model Based on Butler's Theory

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Steam Assisted Gravity Drainage (SAGD) is an efficient method for thermal recovery of bitumen from the vast reserves available worldwide and particularly from the oil sands in western Canada. Flow simulators are available for predicting SAGD performance and are used to support reservoir management decisions; however, the high computational time associated with the use of such complex flow simulation makes it impractical for all locations especially when reservoir uncertainty and variable operational parameters are included in the making decision process. The use of a simpler analytical model as a proxy for the reservoir simulator is shown to be a feasible alternative to flow simulation. A proxy model based on the Butler's SAGD theory is developed to predict the oil flow rate, cumulative oil production and cumulative steam injection profiles during both: the rising and spreading steam chamber periods for a confined SAGD well pair. Modifying factors are used to fit the proxy to flow simulation results to account for conformance and reservoir heterogeneity among other factors. A critical aspect of the proxy model is a realistic parameterization of geological heterogeneity. Monte Carlo Simulation (MCS) and the proxy model permit an efficient transfer of the uncertainty in reservoir and operational parameters through to performance variables such as oil production and steam oil ratio. An example application for a single well pair showed the efficiency of the methodology in terms of computation time. The results permit improved reservoir management of complex SAGD projects. This paper has been published as SPE 115662.

Introduction

Current high oil prices are boosting the feasibility of bitumen production projects supported by the availability of tested exploitation technology as well as the vast bitumen reserves available worldwide. An important part of these vast resources are in western Canada. According to the Energy Resources Conservation Board[1], at 2007 the established bitumen reserves in Alberta are 27.45×10^9 m^3 and about 82% is considered recoverable by in-situ methods. The successful application of SAGD process as thermal recovery method is one of the pillars in which Canadian oil industry is supporting the exploitation of the in-situ recoverable bitumen leading to a massive expansion around all Alberta oil's sands.

SAGD is a thermal recovery process based on steam injection coupled to horizontal well technology. Common implementation consists of two horizontal parallel wells, the first drilled near the bottom of the reservoir with the second located at a short distance, typically 5 to 10 m above it. The upper well provides continuous steam supply into the reservoir and the lower one allows the continuous production of bitumen, gas and condensed water. During the SAGD process, the cold oil is essentially immobile; therefore, an initial preheating stage is necessary to create a uniform thermo-hydraulic communication between the well pair. In this start-up period, steam is injected in both wells to preheat the reservoir between the wells. Once mobility has been established, steam is injected continuously into the upper well and rises within the reservoir, developing a steam chamber. The injected steam will reach the chamber interface, heating the surrounding cold oil sand. The heated oil and condensed water will drain by gravity along the chamber-to-reservoir interface to the lower well in which the fluids are continuously produced. The process follows an initial rising period where the steam chamber rises up to the overburden and then the spreading period which is characterized by the lateral growth of the interface along the well pair.

High steam generation costs together with the lower price of bitumen makes the economical feasibility of SAGD projects more sensitive to operational conditions and reservoir variables than conventional light oil projects; consequently less margin of error is available during the reservoir management making decision process. On top of this, the always present uncertainty of reservoir/fluid properties makes the SAGD production performance always uncertain. The natural way to face the challenge of selecting better reservoir management decisions is through a probabilistic analysis in which the decisions should be made considering the stochastic character of reservoir/fluid and operational variables. Geostatistics tools are available to provide multiple equi-probable realizations of geological variables honoring all available data.

These different geological realizations, together with proper probability distribution functions attached to other operational and fluid variables, are used to generate the model of reservoir uncertainty. Monte Carlo Simulation sampling is then used to transfer this uncertainty to SAGD production performance indicators by means of transference functions such as reservoir flow simulators.

The compositional nature and transient temperature behavior of the SAGD process makes the numerical simulation of such problem highly expensive in terms of simulation times. Excessive simulation times might result either in delaying the decision making process or in biased forecasts and therefore in sub-optimal decisions, due to the impossibility of considering a representative number of development possibilities for a SAGD process. Therefore, the transference of uncertainty from the reservoir and operational parameters to the forecast variables during a SAGD process using numerical simulation is nowadays almost an impossible and very expensive task.

An alternative to overcome such challenge is the use of simpler models to predict SAGD performance. The use of proxy models in reservoir simulation studies is justified basically by the decreasing of CPU time in getting an accurate result of any output of the reservoir simulator. The basic idea is to use outcomes from specific simulator outputs or from a relationship of them to calibrate a pre-selected simple model, which is function of some simulator inputs. The model will be built using a relative small sample of time-consuming simulation cases and it will be valid in the space domain defined by the range of input values used during the simulation work.

Little has been found in the technical literature about application of proxy-models in SAGD problems. One of the works found so far was done by Queipo et al[2], 2001. They proposed a solution methodology including the construction of a “fast surrogate” of the reservoir simulator for the optimization of vertical spacing, steam injected enthalpy, injection pressure and subcooling aiming to maximize the weighted sum of cumulative oil and cumulative steam injected for a synthetic 2-D reservoir model. The methodology is based on neural networks and a kriging surface to interpolate the residuals. An adaptive method to improve the sampling in the search of optimal parameters was implemented.

Reservoir static measures have been proposed to be used as performance indicators in order to optimize a particular operational or geometric parameter in presence of reservoir uncertainty without the expense of doing flow simulation. An example of this strategy is presented by McLennan et al[3]. They maximized oil recovery by optimizing the vertical depth of the horizontal production well in a SAGD well pair, having fixed its horizontal location. Several 3-D geological realizations of geological properties were generated and cut-offs values were used to create pairs of top and bottom continuous bitumen (TCB / BCB) surfaces. For each realization the maximum recovery was found by the minimization of the difference between total possible recovery and actual recovery through an objective function given by TCB / BCB position along the well pair, producer well depth and two indicators used to include the effect of well effectiveness. The optimization was done using a simulated annealing algorithm. At the end, the uncertainty of the maximum recovery was reported.

In other work McLennan et al[4] shows a complete framework to transfer the reservoir uncertainty to oil flow rate and steam oil ratio (SOR) within a SAGD production area, through the use of calibrated reservoir static measures. They defined a measure of the local connectivity and assessed the connected resource for a given number of geologic realizations, then the drainage volume of potential SAGD well pairs were determined for each realization. A downscale was performed for each SAGD drainage volume focusing the reservoir flow simulation. The fine-scale geological realizations were ranked based on a sand volume ranking parameter and the low, medium and high cases were selected for flow simulation input. Finally, after performing the flow simulations the oil flow rate and SOR were calibrated to the geological ranking parameter. Thus, the reservoir uncertainty can be transfer to the oil rate and SOR through the calibrated geologic ranking parameter. Although this strategy accomplishes this task successfully, it doesn’t aim the transference of the uncertainty in the other parameters that also affect the SAGD performance as it’s the case of fluid properties, thermal rock/fluid properties and well pair operation constraints.

Another strategy for the efficient transference of the uncertainty of reservoir, operational and fluid properties parameters to the SAGD production performance was proposed by Vanegas et al[5,6]. They used the Design of Experiments (DOE) techniques to first identify the most influential variables over the Net Present Value (NPV) of a SAGD project, based on the range of variation of some input reservoir simulation variables. Then, Response Surface Methodology was used to fit a simple second order function defined by the variables selected in the previous stage, using a specific experiment design matrix of runs. Monte Carlo Simulation (MCS) and the second order function allowed the transference of uncertainty from the most influential variables to the NPV without any extensive simulation work. This strategy fails in including the influence of the variability of the geologic variables along the reservoir into the response surface function, as well as in including the time dependent characteristics of the SAGD performance response.

As a new alternative this work proposes a SAGD semi-analytical model as a proxy for the reservoir simulator. The proxy model is based on the Butler's SAGD theory described in a 1987[7] paper and also with more detail in Rose's PhD thesis, 1993[8]. The proxy-model allows the prediction of oil flow rate, cumulative oil production and cumulative steam injection time-profiles during both: the rising and spreading steam chamber periods for a confined SAGD well pair. Modifying factors are applied in order to fit the proxy either to flow simulation results or to field measurements and account for steam chamber conformance and reservoir heterogeneity among other factors. The model is based on the description of the hot interface advance through a 2-D section of a confined well pair, using conduction as a heat transference mechanism. The reservoir heterogeneity was explicitly included in the proxy by taking advantage of the steam chamber-to-reservoir interface discretization used by the Butler's model. During the spreading period the interface is divided in short segments and according to their position within the input geological grid, an average of the reservoir properties is calculated along the entire interface and used it to find the SAGD production response for the current time-step. Thus, a new interface position can be determined and a new set of average reservoir properties defined. The calculations are repeated up to a given production time.

A computer code was written to implement the modeling strategy and to generalize the application of the proxy-model for 3-D well pair descriptions in areas of more than one well pair and in a total probabilistic calculation scheme. Thus, different geological realizations can be used together with probability distribution functions attached to operational and fluid properties variables in order to transfer the reservoir uncertainty model to the SAGD production variables using MCS. The results are presented as deciles specified by the user of cumulative oil production, cumulative steam injection and oil flow rate. At the end a band of uncertainty is defined as a function of time for each of the previous production variables at a feasible computational cost. An additional program was written to determine the modifying factors that best fit a set of simulation results. The simulated annealing algorithm was used to accomplish this optimization task.

This paper describes a new methodology for the transference of the reservoir/fluid and operational uncertainty using a physical founded proxy-model fitted to some simulation results. The methodology was applied to a single synthetic SAGD well pair case. A set of 100 realizations of porosity, horizontal permeability, vertical permeability, oil saturation and rock type (shale or sand) were generated to describe the geological uncertainty. The Original Oil in Place (OOIP) was then used as ranking parameter to select the P10 to P90 deciles in order to perform flow simulation and fit the proxy-model. Finally the uncertainty of cumulative oil production, oil flow rate and cumulative steam injection was determined as a function of time.

Model Description

The model used in this work is a modification of that presented by Butler in 1987[7]. Later, in 1993 Rose[8], in his PhD thesis, showed all the details related to such model and proposed a modified one, by coupling the rising-steam-chamber, modeling proposed earlier by Butler[9] to the Butler's new approach (1993), for an unconfined well pair. The proxy here also couples both the rising period and spreading period using a different criterion to that used by Rose but for a confined well pair. Besides, the proxy-model includes: a calculation for the average relative permeability as a function of the instantaneous steam oil ratio for each time-step from either a given relative permeability table or from a cubic function of mobile saturations[10]; suitable correlations proposed by Butler[9,10] for the calculation of fluid properties as well as the option of use tabulated fluid properties; the use of the reservoir heterogeneity for calculation of average reservoir properties along the interface; adjusting factors to fit the model to field measurements or flow simulation results; and the implementation of the MCS sampling using different geological realizations as well as proper probability distribution functions attached to the other rock/fluid properties and operational parameters. A brief description of the Butler's spreading period and rising period models, as well as the modifications added in this work are presented below.

Spreading Steam Chamber Modeling.
In his well-known "GravDrain's black book"[9], Butler shows the approaches to the development of a SAGD process model. He assumed a small cross section of the chamber-to-reservoir interface such as that shown in **Fig. 1**, where the temperature of the steam chamber T_s is constant (the interface is also at T_s), T_r is the reservoir temperature at some distance away from the interface, θ is the angle of the interface from the horizontal, and at some distance ξ from the interface, the oil has a kinematic viscosity ν. The heat transfer beyond the interface to the colder oil-sand was assumed to be dominated by conduction normal to the interface. The advance of the hot interface was considered at a constant an unspecified velocity U assuming that the temperature distribution beyond the interface would correspond to the steady state condition. In other words, the heat used to warm up the reservoir ahead of the interface is run over by the advance of the interface due to the drainage of oil parallel to the interface. Under the previous assumptions the temperature distribution is given by **Eq. 1**.

$$T^* = \frac{T - T_r}{T_s - T_r} = e^{\left(-\frac{U\xi}{\alpha}\right)} \quad \text{.....(1)}$$

Where, α is the thermal diffusivity of the oil-sand. In order to find an expression for the oil rate, Darcy's law was used for a differential element of width $d\xi$ and length equal to one, (along the well pair), **Eq. 2**.

$$dQ = \frac{kg\sin\theta}{\nu} d\xi \quad \text{.....(2)}$$

Where k is the effective permeability to oil and g is the gravity acceleration. To solve the respective integral Butler proposed a convenient relationship for the oil viscosity and temperature which in turns implicitly describes the dependency of ξ and temperature, **Eq. 3**.

$$\frac{\nu_s}{\nu} = \left(\frac{T - T_r}{T_s - T_r}\right)^m \quad \text{.....(3)}$$

Where, ν_s is the kinematic oil viscosity at T_s, and m a dimensionless parameter defined by the viscosity and temperature relationship in **Eq. 4**.

$$\frac{1}{m\nu_s} = \int_{T_r+\delta}^{T_s} \frac{dT}{\nu(T - T_r)} \quad \text{.....(4)}$$

The parameter δ is used to be able of solving the integral and avoid the inclusion of the cold flow[10] in the model. Given a viscosity table, m can be calculated by solving this integral numerically. After applying Darcy's law and solving the integral using **Eq. 3** the expression for the oil flow rate is defined as in **Eq. 5**.

$$Q = \frac{kg\sin\theta}{m\nu_s U} \quad \text{.....(5)}$$

Butler noticed that this strategy does not allow a proper description of the interface advance since it predicted an interface movement away from the production well, while at the top the interface goes to infinity. He identified two main reasons to this poor performance: the steady state assumption in the temperature profile beyond the interface and the assumption of constant velocity along the interface, which clearly fails to describe its stationary condition at the production well, however it seems to be a reasonable assumption close to the center portions of the interface.

Although the solution of the transient heat conduction of an advance front can allow better predictions, the complexity of that solution makes it harder its practical application. As alternative Butler proposed a much simpler differential equation, which allowed for a efficient computational estimation of the degree of heat penetration γ, **Eq. 6**.

$$\frac{d\gamma}{dt} = \frac{2}{\pi}\left(\frac{\alpha}{\gamma} - U\right) \quad \text{.....(6)}$$

Where, the degree of heat penetration γ is defined[7] as the depth to which heat would have penetrate if there was no temperature gradient and the hot region would have remain at T_s.

Eq. 6 was derived from the result of the temperature gradient for two extreme cases: 1) the steady state case where U is constant and ($d\gamma/dt$) is zero and 2) the no advancing interface with reservoir temperature as initial condition. The approximation gives the exact solution for the temperature gradient at those two limiting cases and for other any situation, it is assumed that the temperature gradient varies linearly with the velocity between those two cases. Butler also considered that the **Eq. 5,** as a function of the degree of heat penetration, is a reasonable approximation for the temperature distribution to other conditions different that the steady state condition for which it is the exact solution.

In order to simplify the calculation and generalize the applicability of the model, Butler rewrote the equations in terms of some dimensionless variables. Dimensionless distances were expressed as ratios to the reservoir thickness H and areas as ratios of H^2. The dimensionless flow rate Q^* is expressed:

$$Q^* = \frac{Q}{\alpha\phi\Delta S_o B_3} \quad \text{...(7)}$$

Where, Q is the oil flow rate; ϕ the effective reservoir porosity; and ΔS_o is the initial oil saturation minus the residual oil saturation. A dimensionless variable, B_3 was defined as, **Eq. 8**.

$$B_3 = \sqrt{\frac{kgH}{\alpha\phi\Delta S_o m \nu_s}} \quad \text{...(8)}$$

The dimensionless time was determined by **Eq. 9**.

$$t^* = \frac{B_3 \alpha t}{H^2} \quad \text{...(9)}$$

Where, t is the time. The **Eq. 5** in terms of dimensionless variables and as a function of the dimensionless depth of heat penetration γ^* is given by **Eq. 10**.

$$Q^* = \gamma^* B_3 \sin\theta \quad \text{...(10)}$$

Eq. 6 becomes **Eq. 11**.

$$\frac{d\gamma^*}{dt^*} = \frac{2}{B_3 \pi}\left(\frac{1}{\gamma^*} - B_3 U^*\right) \quad \text{...(11)}$$

Where the dimensionless interface velocity U^* is given by **Eq. 12**.

$$U^* = -\frac{\partial Q^*}{\partial L^*} \quad \text{...(12)}$$

L^* is the dimensionless length of an element of interface. The displacement of the interface is calculated from material balance relationships at an interface element, considering that in order to have an advance of the interface, oil must be flowing out of the interface element faster than that flowing in. **Eq. 13** and **Eq. 14** show those relationships in terms of dimensionless variables.

$$\left(\frac{\partial Q^*}{\partial y^*}\right) = -\left(\frac{\partial x^*}{\partial t^*}\right) \quad \text{...(13)}$$

$$\left(\frac{\partial Q^*}{\partial x^*}\right) = \left(\frac{\partial y^*}{\partial t^*}\right) \quad \text{...(14)}$$

Using an explicit calculation sequence, discretizing the time in small time-steps, the previous equations can be implemented in a computer program to determine the oil flow rate, cumulative oil production and interface shapes for a defined set of input parameters. The initial condition considers a vertical fracture as interface at T_s along and above the well pair. The interface is discretized in small elements and those elements move along the reservoir width as the drainage process progresses. The equations are implemented in their difference form and the sequence calculation is given by 1) selection of arbitrary small γ^*; 2) calculation of the flow rate for all nodes of the discretized interface, using **Eq. 7.** The oil rate at the top node of the element located right below of the overburden is considered equal to zero and at the initial condition, θ is 90°; 3) calculation of flow rate change for each interface element; 4) **Eq. 13** or **Eq. 14** are used to define the advance of the interface in x^* or y^*; 5) Trigonometry relationships are used to find L^*

and the new θ; 5) **Eq. 12** is used to define the dimensionless interfacial velocity; 6) **Eq. 11** gives the new dimensionless heat of penetration used for the next dimensionless time-step which is given by **Eq 9**. All the sequence is repeated up to a given dimensionless production time.

On other hand, the Cumulative Steam Oil Ratio (CSOR) was defined by Rose[8] as **Eq. 15**,

$$\mathrm{CSOR} = \frac{\text{total heat transferred/unit volume of oil}}{\text{enthalpy of steam/unit volume of water}} \quad (15)$$

Eq. 15 can be written in terms of the dimensionless cumulative consumptions of heat as in **Eq. 16**.

$$\mathrm{CSOR} = \frac{(T_s - T_r)\left(C_r\rho_r Q_c^* + C_r\rho_r Q_r^* + C_o\rho_o Q_o^*\right)}{Q_c^*\Delta H_w \phi \Delta S_o} \quad (16)$$

Where ΔH_w is the enthalpy contained in the injected steam; and C_r, C_o, ρ_r and ρ_o are heat capacities and densities of reservoir and overburden respectively. Those quantities are assumed to be constant in the range of temperature T_r to T_s. Butler[7] defined the heat consumption as three additive components: 1) the cumulative heat to the chamber and produced oil Q_c; 2) the cumulative heat to the reservoir, Q_r; and 3) the cumulative heat lost by conduction to the overburden, Q_o. **Eq. 17** and **Eq. 18** give the definition of the dimensionless form of cumulative heat to the chamber, Q_c^*, and cumulative heat to the reservoir Q_r^*.

$$Q_c^* = \frac{Q_c}{H^2 C_r \rho_r (T_s - T_r)} \quad (17)$$

Where Q_c^* is obtained by integrating the dimensionless flow rate over time.

$$Q_r^* = \frac{Q_r}{H^2 C_r \rho_r (T_s - T_r)} \quad (18)$$

Where Q_r^* is defined by the numerical integration of the dimensionless heat penetration along the interface. The cumulative heat lost to overburden for a spreading hot zone is calculated using **Eq. 19**.

$$Q_o = \frac{4}{3} K_o (T_s - T_r) A \sqrt{\frac{t}{\pi \alpha_o}} \quad (19)$$

Where K_o and α_o are thermal conductivity and thermal diffusivity of the overburden respectively; and A is the area of the hot zone at time t. The dimensionless form Q_o^* of the heat to overburden is given by **Eq 20**.

$$Q_o^* = \frac{Q_o}{H^2 C_o \rho_o (T_s - T_r)} \quad (20)$$

During the SAGD operation, patterns of well pairs are used in order to improve the thermal efficiency by decreasing the area of exposition of the steam chamber to the overburden, thus, the heat losses are reduced and the CSOR improved. For a given well pair spacing, after certain time, the steam chambers of two well pairs will collapse and a non flow boundary between them will be formed. In that way, the reservoir of each well pair will be confined and a non flow boundary condition can be applied to the calculation procedure explained previously. The calculation sequence remains the same up to half way of the well spacing, then, the nodes are respaced evenly and fixed along the x direction and the change in the position of the interface is calculated as function of the change in y direction. Rose[8] shows all details about the implementation of this procedure.For a confined well pair the heat lost to overburden after the interface reaches the non flow boundary at time t_1 is given by **Eq. 21.**

$$Q_o = \frac{4}{3} \frac{K_o (T_s - T_r)\dot{A}}{\sqrt{\pi \alpha_o}} \left[t^{0.5} - (t - t_1)^{0.5}\right] \quad (21)$$

Where $t > t_1$ and $\dot{A}$ is the rate of growth of the spreading hot zone.

Rising Steam Chamber Modeling.

Rose[8] noticed that the assumption of a hot vertical fracture as initial condition of a SAGD process doesn't represent adequately the reality. He proposed a more realistic model by coupling the Butler's model for the rising steam chamber and the previous modeling strategy. Thus, the proposed procedure predicts oil flow rates and interface positions during the rising period and when the interface reaches the reservoir top the algorithm will switch to the calculation sequence of spreading period using as initial condition the final interface coordinates and heat penetration of the rising period. Rose presented the dimensionless form of the Butler's equations for the rising period by the **Eq. 22** to **Eq. 24**. The dimensionless flow rate for the rising period is given by,

$$Q^* = 1.5 t^{*^{1/3}} \quad \text{………………………………………………………………(22)}$$

The dimensionless oil production during the rising period is,

$$Q_c^* = 1.125 t^{*^{1/3}} \quad \text{………………………………………………………………(23)}$$

The dimensionless height at the top of the steam chamber, h^*, as function of dimensionless time is calculated from:

$$h^* = 2 t^{*^{2/3}} \quad \text{………………………………………………………………(24)}$$

In the development of these equations, Butler assumed that the flow rate would follow a similar formulation of that in the spreading period. He used two empirical factors, one to adjust the cross sectional area of the rising steam chamber and another to adjust the available head for the rising process. He noticed that the chamber grows at an approximately constant angle of 58° with the horizontal. An example of the dimensionless production rate versus dimensionless time using the coupled model reported by Rose[8] for an unconfined reservoir is illustrated in **Fig. 2**. The plot shows a dramatic drop in the oil flow rate during the transition between the rising and spreading periods. No reports have been found about that oil rate behavior in SAGD applications and neither has it appeared in reported simulation works. It seems that the oil flow rate behavior pointed by Rose is not realistic.

Proposed Modifications to the SAGD modeling

Some modifications to the Rose's modeling strategy were implemented in this work in order to apply it as surrogate model for the reservoir simulator. Those modifications include: 1) a more realistic coupling of both stages of a SAGD process; 2) inclusion of the reservoir heterogeneity; 3) calculation of average relative permeability at each time-step; 4) generalization of the model to include 3D-well pair geometries in multi-well pair cases; and 5) implementation of the stochastic calculation scheme. A brief description of some of those modifications appears in the next sections.

Coupling Strategy. The first modification to the Rose model was the application of a different strategy to the coupling of rising and spreading models. The proxy-model proposed here followed a particular recommendation made by Butler in his black book[9]. He pointed out that for practical applications the transition between both stages can be approximated by the intersection of the oil flow rate versus recovery factor curves of both rising and spreading periods. Thus, the rising model will be used until the predicted flow rate reaches that predicted by the spreading model in an oil rate versus recovery factor (or cumulative production) curve. The time to reach the same cumulative production might be different for both models; therefore, the coupled model needs an adjustment to take into account this time difference.

Fig. 3 shows the oil flow rate versus time curve after using the proxy model proposed in this work, with same input data and same conditions (unconfined well pair) as in **Fig. 2**. There is clearly a more realistic representation of the oil flow rate time-profile.

Reservoir Heterogeneity. An important aspect of a proper proxy for reservoir simulation is the capacity of handling the geologic heterogeneity. McLennan et al[3] mentioned it as one of most influential aspect into the production performance of a SAGD process, since the relative position of shales to the well pair have an important influence in the conformance of the steam chamber along the well pair reducing the effective reservoir volume to be drained.

The proxy-model proposed in this work takes into account the reservoir heterogeneity in two different ways. The first of them is by superimposing the interface discretization used in the spreading steam chamber modeling to the spatial discretization of the reservoir variables for each vertical section along the well pair, as it is shown in **Fig. 4**. This figure shows a map of horizontal permeability in a vertical section of a reservoir to be drained by a SAGD well pair together with the interface position calculated by the previously mentioned model, after certain production time. At each time-step, during the calculation procedure, an average of the reservoir properties along the interface is calculated by using the properties of the geologic blocks that each segment of interface is crossing through. Those average properties will defined a new position for the interface at the next time-step. In that way, the model will find the production behavior for a "new reservoir" defined by the average of the reservoir variables along the interface at each small time-step up to a given production time.

In a preliminary stage the absolute permeability of each cell is calculated as the geometric average of the vertical and horizontal permeabilities which are given as gridded input data. An arithmetic average weighted by the distance of the interface segment within each block is calculated for porosity, oil saturation and permeability. Distance weighted averages of reservoir thermal properties as heat capacity, thermal conductivity and thermal diffusivity are calculated according to the type of rock defined at each block that the interface crosses through. The thermal properties of those rock types and the gridded rock type indicator are part of the input data to the proxy-model. Only sand and shale were considered as rock types to represent the lithology distribution in the reservoir.

The second way to represent the heterogeneity was by the determination of an Effective Volume Factor, *EVF*. This factor was defined as the fraction of porous volume which is vertically connected within a single vertical section along a SAGD well pair, **Eq. 25**.

$$EVF = \frac{\sum_{i=1}^{nb_h} \sum_{j=1}^{nb_{vsi}} VP_{ij}}{Total\ VP} \qquad (25)$$

Where nb_h is the number of blocks in the horizontal direction of the reservoir vertical section; nb_{vsi} is the number of blocks below the first shale in the vertical direction, at the i^{th} block of the horizontal direction; VP_{ij} is the porous volume of the block *ij*; and Total *VP* is the total porous volume of the reservoir vertical section. The *EVF* was used then to correct the oil flow rate given by the model.

Average Oil Relative Permeability. The permeability used in the previous models is the oil effective permeability. To include the effect of simultaneous flow of condensed water and oil during the drainage process is necessary to use an oil relative permeability value. Butler[10] showed that 40% is a reasonable value to represent the average of the oil relative permeability during a SAGD process. He pointed out that for clean sands the oil relative permeability can be given as a function of the fractional flow of water, $\mathbf{f_w}$**,** by using a cubic function of the relative permeabilities and the mobile fluid saturations, **Eq. 26**.

$$k_{ro} = \frac{1}{\left(\left[\left(\frac{1}{f_w} - 1 \right) \frac{\mu_o}{\mu_w} \right]^{-1/3} + 1 \right)^3} \qquad (26)$$

Where μ_w and μ_o are the water and oil dynamic viscosities at steam temperature; k_{ro} is the oil relative permeability. The fractional flow of water can also be given as a function of the water oil ratio, *WOR* by:

$$f_w = \frac{1}{1 + \frac{1}{WOR}} \qquad (27)$$

In this work the average of the oil relative permeability was calculated at each time-step by assuming a value for the ratio between the *WOR* and the instantaneous *SOR*. Thus, the *SOR* can be calculated by applying **Eq. 16** using the heat consumptions during each small time-step and a value of *WOR* can be obtained from the assumed ratio *WOR /SOR*; then, **Eq. 27** and **Eq. 26** are used to find an average of k_{ro} at a given time-step.

After running some simulation cases could be noticed that the ratio *WOR/SOR* remains close to 1 during almost all SAGD production time. In other words, the steam injected in terms of condensed water remains approximately the same that the produced water. It is important to notice that, those simulations didn't consider the presence of gas during the production of the SAGD well pair. As example, **Fig. 5** shows the *WOR* and *SOR* curves for a particular simulation case.

The option of using a relative permeability table instead of the cubic function of mobile fluid saturations was also implemented.

The SAGD modeling strategy was then generalized for 3-D well pairs geometries using the assumption that the production behavior of each vertical section in a 3-D model of a SAGD well pair is independent each other. It implies that there is not horizontal flow between blocks of different vertical sections, although, in real situations, pressure gradients might be developed in the reservoir along the well pair due to temperature gradients within the steam chamber and to reservoir heterogeneity.

The proxy is also able to predict the SAGD performance over areas with multiple well pairs under the assumption that each well pair will drain a given volume specified by the net thickness, well pair spacing and well pair length. Thus, there is not overlapping between the drainage volumes of adjacent well pairs. This assumption would require of certain symmetry in the heterogeneity of each half of reservoir volume between two adjacent well pairs and this is not the case in actual applications.

During the flow simulation of SAGD process, usually the start-up period is emulated by placing a heat source along both: injector and producer wells. The source will heat the well pair up to a temperature setting and it will remain at this temperature by a given period of time, then the SAGD operation will start. The proxy emulates this start-up period by delaying the oil production for the same period of time.

Finally, a complete MCS simulation scheme was implemented in order to transfer the reservoir uncertainty represented by a defined number of geological realizations given as gridded input data of rock type, absolute horizontal permeability, absolute vertical permeability, porosity and oil saturation, to SAGD production variables including oil flow rate, cumulative oil production and cumulative steam injection. The uncertainties in the reservoir/fluid thermal properties, residual oil saturation, steam injection pressure, steam quality, oil API and start-up time were considered by selecting samples of values, per geological realization, from specific probability distribution functions. This probabilistic SAGD performance tool was named as: Forecasting Analytical SAGD model for Transference of Reservoir Uncertainty (FastRun).

Fitting Process

Although, the SAGD production model used in this work was developed based on the physics of the process, some of the assumptions simplify a lot the complexity of the process; on other hand, there were other aspects inherent to the physical process that weren't included in the model.

The one-dimensional character in which the heat conduction was assumed; the simplification of one dimensional flow for the oil parallel to the interface; conduction being the only transference mechanism in the process; the character pseudo-transient of the model; the use of correlations for the fluid properties; the lack of modeling of geomechanical effects into the reservoir; the lack of modeling the presence of top/bottom water/gas layers; a proper model for the initial warm-up of the well pair; and the assumption of no gas within the reservoir during the SAGD process, among others, are factors that affect the proper representation of the reality during the SAGD production.

Perhaps the lack of this detail is helpful in the sense that the proxy-model makes the calculations simple enough that allows it to be used as a probabilistic forecasting tool for the SAGD performance, which would not be possible by using a numeric reservoir simulator. The great degree of detail in a complex numeric solution doesn't allow the successful integration of the uncertainty analysis into the decision making process of SAGD projects. In the same line of thought, Bos[11] mentioned that when trading-off model precision versus degree of uncertainty modeling, the latter is more important than the former, mainly when the uncertainties are large. Therefore, approximate models should be used to make more sound decisions by integrating the uncertainty analysis to the decision process.

One step required to the use of a proxy-model towards the integration of uncertainty analysis into the reservoir making decision process is its calibration to a more detailed solution or even to actual production data. The calibration aims to complement the modeling deficiencies by inserting some empirical factors that adjust the proxy performance to more truthful production information. The proxy should be adjusted over a set of different and probable production scenarios, particularly over a range of the equi-probable geological realizations of the reservoir in order to make a solution of more global applicability.

Four adjusting factors were included in FastRun; two of them allow fitting the oil production during the rising and spreading periods; a third factor permits the adjusting of the steam injection and the last one allows a control in the degree of declination of the production during the entire process. The fitting process was implemented in a complementary computer program focusing the minimization of square error of the cumulative oil production and cumulative steam injection using a simulated annealing type of optimization algorithm.

As illustration purpose **Fig. 6a** shows a comparison of the cumulative oil production and the cumulative steam injection results between a 2-D reservoir simulator model of a SAGD process and the FastRun after finding and applying the respective adjusting factors; **Fig. 6b** shows the map of horizontal permeability used to generate the results. The simulation time for the reservoir simulator was 25 minutes while FastRun ran the same case in 8 seconds. The results along with the calculation time show the good performance of the proxy-model for a highly heterogeneous SAGD well pair model. This result encouraged a more complete application case shown in the next section.

Application Case

A synthetic 2-D case for a single SAGD well pair was prepared to illustrate the application of the previous probabilistic model. A set of 100 geological realizations of rock type, horizontal permeability, vertical permeability, porosity and oil saturation was generated as reservoir uncertainty model. A geological grid of 161x1x36 blocks with 1 m in *i* and *k* directions; and 900 m in *j* direction was used to discretize the reservoir domain.

An example of the degree of reservoir heterogeneity within the drainage volume of the SAGD well pair appears in **Fig. 7,** where the maps of the reservoir variables are shown for the first geological realization. The average proportion of shale within the reservoir SAGD well pair is 10%, and **Fig. 8** shows the histograms of the reservoir variables for the sand lithology along with some summary statistics. The values of the reservoir variables for shale were considered deterministic, using a porosity of 0.05; horizontal and vertical permeability of 100 md and 50 md respectively; and an oil saturation of 0.2. In general, the reservoir is a clean sand with porosity and oil saturation being roughly homogeneous and having almost all reservoir heterogeneity represented by the heterogeneity in the directional permeabilities.

The realizations were ranked using the OOIP as ranking parameter, then the P10 to P90 deciles were selected to fit the proxy to the results of a commercial thermal reservoir simulator. It was assumed that the 9 deciles are enough to fit the proxy over the entire range of variability of the geological model. The Cumulative Distribution Function of OOIP, (CDF) depicted in **Fig. 9** shows the uncertainty in the ranking parameter.

Nine flow simulation models were created using the geological realizations corresponding to the 9 deciles from the ranking procedure. The SAGD simulation cases considered two parallel and horizontal wells of 900 m length oriented in *j* direction, within a reservoir with top at 200 m depth, with no dipping, and 1,500 kPa of initial pressure. Initial temperature was 18 °C and all surfaces of the model have a no flow boundary but heat loss is assumed at the overburden.

No aquifer and gas cap zones were considered. A two component model was assumed with no gas at any time in the reservoir. 95% quality steam was injected at 200 °C. Maximum bottom-hole pressure of 1,510 kPa was defined as steam injection constraint, while the production bottom-hole pressure was always 10 kPa below the maximum injection pressure. The steam flow rate at the producer well was constrained at a maximum of 0.5 m^3/d.

Simulations were performed using a two-dimensional model in the pseudo—compositional and thermal reservoir simulator STARS®[12] All simulation cases were run over a period of 15 years and each simulation case lasted in average 30 minutes using a 2.33 GHz, 2.00 GB of RAM, Centrino® Duo PC. The calibration was performed over the 9 data sets. After 367 interactions, the annealing schedule converged in approximately 8 hours of time machine. **Fig. 10** shows a comparison of the cumulative oil production and cumulative steam injection between FastRun and the reservoir simulator for the P50 geological realization. This was the best visual fitting result and it gives a rough idea of the good quality of the fitting.

The quality of fitting is illustrated in **Fig. 11**. The two plots at the top of that figure show the cumulative oil production and steam injection calculated by the simulator after 3000 days versus the OOIP, the ranking measure to represent the geological variability. Because the static aspect of the OOIP a single production point in time was selected to construct those plots. The time was chosen assuming that the highest variability between the simulation results would appear around half of the production time. A first attempt to transfer the reservoir uncertainty might be the use of the OOIP as static measure of the SAGD well pair performance, however, the very low correlation coefficient values found on the scatter plots, 0.312 for cumulative oil production and 0.123 for cumulative steam injection, indicate that it is not the best strategy.

The two plots in the middle of **Fig. 11** show the cumulative oil production and steam injection from the reservoir simulator versus the ones from FastRun without applying any adjusting factors. In contrast to OOIP, the dynamic nature of the results from FastRun allows including all reported times to make the diagnostic of the proxy prediction quality. The results at all production times were used for the calculation of the statistics and just 31 of them plotted for illustration. The high values of the correlation coefficients for the unfitted proxy-model, 0.979 and 0.984 for oil production and steam injection respectively, indicates its high consistency to represent a more detailed flow simulation model. This very good correlation is mainly due to the strong physical foundation in which FastRun was developed. However, the proxy predictions for the cumulative oil production are systematically lower than those from the reservoir simulator. Thus, a subsequent adjustment is necessary in order to apply it as probabilistic prediction tool.

The two bottom plots of **Fig. 11** show the quality of the fitted model for the prediction of cumulative oil production and steam injection. It can be noticed that although the correlation coefficients didn't change substantially, 0.981 and 0.978 for oil production and steam injection respectively, the predictions of the proxy-model are considerably closer to the ones from the simulator than the predictions using the unfitted model. This good performance encourages the application of the fitted proxy-model as an efficient substitute of the reservoir simulator for the transference of the reservoir uncertainty to the dynamic description of the cumulative oil production and steam injection of SAGD projects.

The fitted proxy was subsequently used to find the uncertainty of the cumulative oil production and steam injection by running all 100 geological realizations along with deterministic values of fluid properties and operational parameters listed in the likeliest column of **Tab. 1**. **Fig. 12** shows the band of uncertainty generated by the P10 and P90 deciles of the mentioned variables as a function of time. The figure shows how the uncertainty band increases with time; this is basically due to the cumulative nature of the variables.

A second set of runs was done, this time adding the other input reservoir/fluid properties and operational parameters as random variables to the 100 geological realizations in order to perform a fully stochastic calculation of the SAGD performance. **Tab. 1** shows the parameters of the each triangular probability distribution selected to perform the Monte Carlo Simulation. **Fig. 13** shows the band of uncertainty for the performance variables after running a sample of 50 reservoir/fluid properties and operational parameters values per geological realization. An increase in the amplitude of the band of uncertainty can be noticed in both performance variables; however a bigger increase in the uncertainty related to the cumulative steam injection can be noticed compared to the increase of the uncertainty in the cumulative production.

A comparison of **Fig.12** and **Fig. 13** leaves the idea that for this specific case the steam injection is much more sensitive to the uncertainty of operational parameters and reservoir/fluid properties (the ones listed in **Tab. 1**) than the cumulative oil production. This is probably because for long production times the cumulative oil production will be limited mainly by the in-situ resources while the steam injection doesn't have any volume limitation.

A summary of the uncertainty in bitumen reserves, CSOR, OOIP and recovery factory at the end of 15 years of SAGD production, in terms of the P10, P50 and P90 deciles, for the fully stochastic application case is shown in **Tab. 2**.

In total, 5,000 different cases were run to assess the uncertainty of the cumulative oil production and the cumulative steam injection during 15 years of operation of a single SAGD well pair. The time machine to perform this task was around 9 hours. Assuming the same computer resources the reservoir simulator would take around 100 days to accomplish the same task. The fitted proxy-model allows a drastic reduction of the computer effort even when a simple 2-D geometry is used for the flow simulation modeling of a SAGD well pair. This reduction would be even more remarkable if a more detailed 3-D model would be used within the uncertainty analysis framework showed in this work.

On other hand, reservoir flow simulation of large scale SAGD projects is extremely expensive and nowadays, it is practically impossible use it to perform uncertainty analysis. It is in this context that a tool as FastRun can find its best applicability.

Conclusions

A proxy-model for the forecasting of SAGD performance is proposed in this work based on a Butler's semi-analytical solution of the process. The model is based on the description of the hot interface advance through a 2-D section of a confined well pair. Some modifications to the original model were implemented in order to improve its applicability as a surrogate of a thermal reservoir simulator into the uncertainty analysis framework. Among other considerations, the heterogeneity of the reservoir was explicitly contemplated by a convenient averaging of the reservoir properties along the discretized interface taking advantage of the time discretization used in the original model. Modifying factors were included aiming the adjustment of the proxy to more reliable information.

The proposed proxy-model was successfully tested as a tool to assess the uncertainty of SAGD performance variables without extensive reservoir flow simulation in a single SAGD well pair. Therefore, the application of this tool allows the efficient integration of the uncertainty into the decision making process of SAGD projects. The proper application of the proxy requires a preliminary fitting process over a set of different and probable production scenarios to improve its global applicability. The fitting process should include a set of geological realizations that reflect the uncertainty of the spatial distribution of the geological variables within the reservoir. The proxy-model methodology will find the highest applicability when the uncertainty of some reservoir and operational parameters is a significant constraint to the development decisions of a SAGD production project.

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Table 1. Parameters of the triangular distribution functions for some input reservoir/fluid properties and operational variables used in the proxy-model.

Input Variable	Minimum	Likeliest	Maximum
Sand thermal conductivity, J/m.d-C	9.31E+04	1.33E+05	1.73E+05
Shale thermal conductivity, J/m.d.C	9.31E+04	1.33E+05	1.73E+05
Water thermal conductivity, J/m.d-C	2.73E+05	3.90E+05	5.07E+05
Oil thermal conductivity, J/m.d-C	9.31E+04	1.33E+05	1.73E+05
Overburden thermal conductivity, J/m.d.C	1.03E+05	1.47E+05	1.91E+05
Sand heat capacity, volumetric, J/m3-C	1.67E+06	2.39E+06	3.11E+06
Shale heat capacity, volumetric, J/m3-C	1.67E+06	2.39E+06	3.11E+06
Oil fluid heat capacity, J/Kg-C	1466	2094	2722
Heat capacity of overburden, volumetric, J/m3-C	1.64E+06	2.35E+06	3.06E+06
Oil API density, deg	7.91	11.3	14.7
Residual oil saturation, fraction	0.2	0.22	0.24
WOR/SOR for calculation fractional flow of water, fraction	0.95	1	1.05
Steam chamber pressure, kPa	1057	1510	1963
Injeciton Steam quality, fraction	0.82	0.9	0.98
Temperature of production fluids, deg C	130	150	170
Start up time, days	100	120	140

Table 2. Summary of the uncertainty for some SAGD production variables.

	mean	P10	P50	P90
Reserves (MM m3/d)	0.812	0.737	0.815	0.893
CSOR over well life	2.339	2.076	2.333	2.606
SAGD OOIP (MM m3/d)	1.085	1.074	1.085	1.097
Recov. Factor	0.749	0.682	0.75	0.819

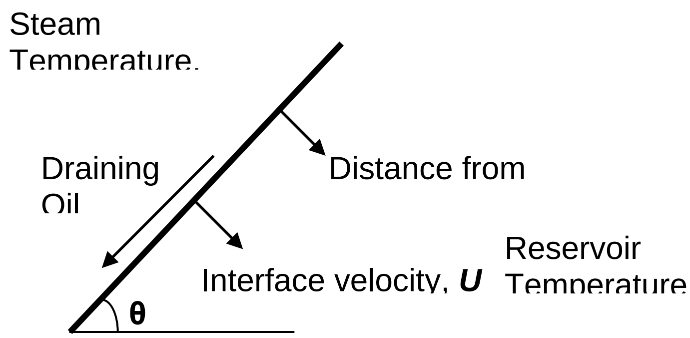

Figure 1. Small vertical section of steam-chamber to reservoir interface

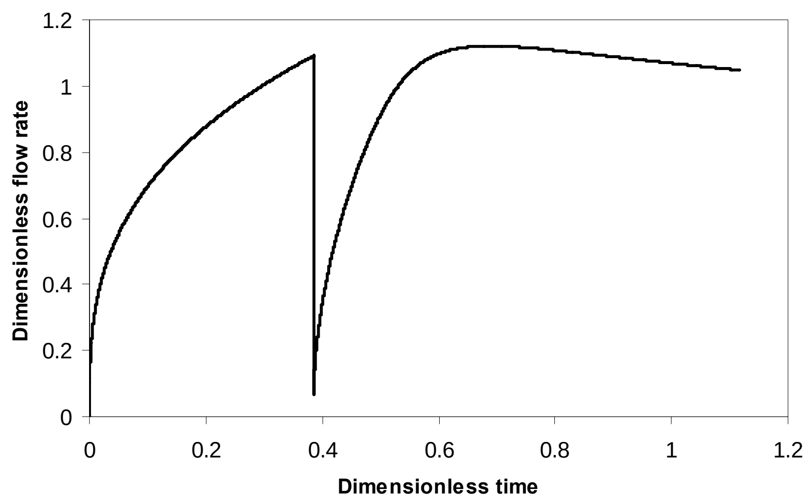

Figure 2. Dimensionless production rate as a function of dimensionless time, after Rose[8], 1993.

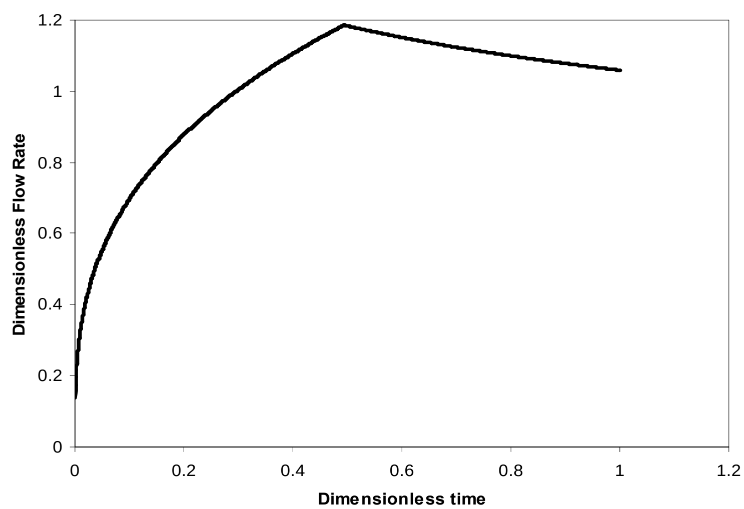

Figure 3. Dimensionless production rate as a function of dimensionless time, using proxy-model proposed in this work.

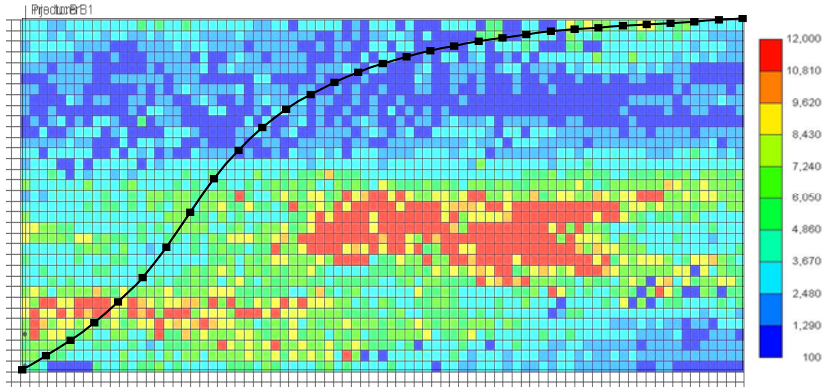

Figure 4. Example of the superimposition of the interface position to the reservoir heterogeneity. The map corresponds to the horizontal permeability (md) of a reservoir vertical section of a SAGD well pair.

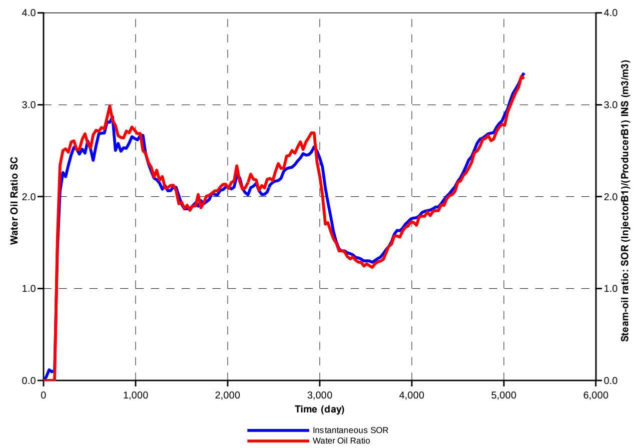

Figure 5. Water oil ratio and instantaneous SOR results from a flow simulation example of a SAGD well pair.

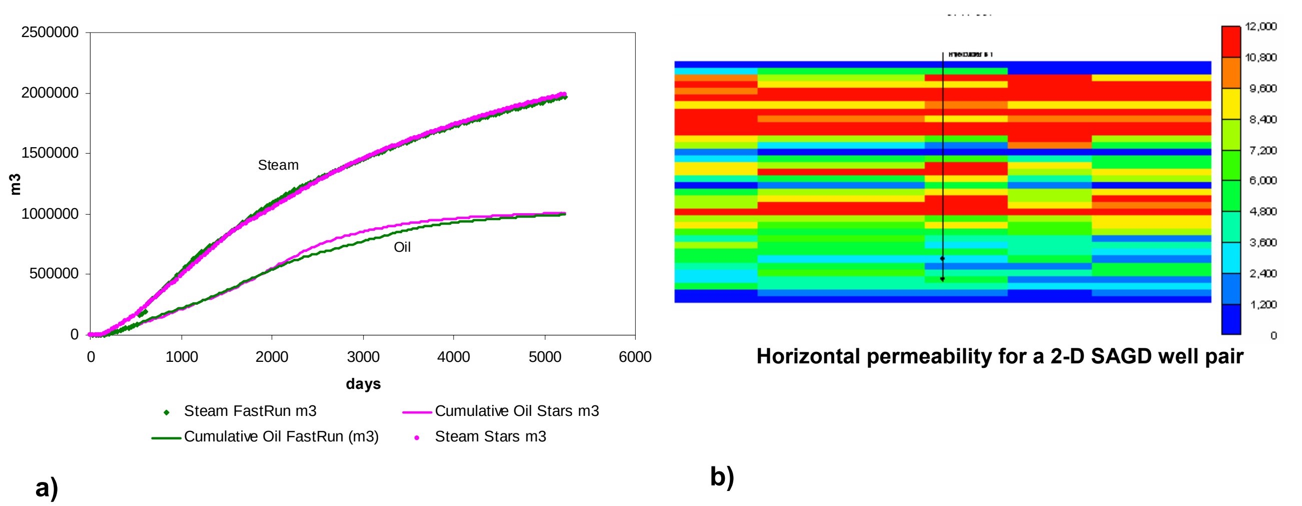

Figure 6. Comparison of cumulative oil production and stem oil injection curves for the proxy-model and reservoir simulator. A 2-D geometry and heterogeneous permeability were used for the predictions.

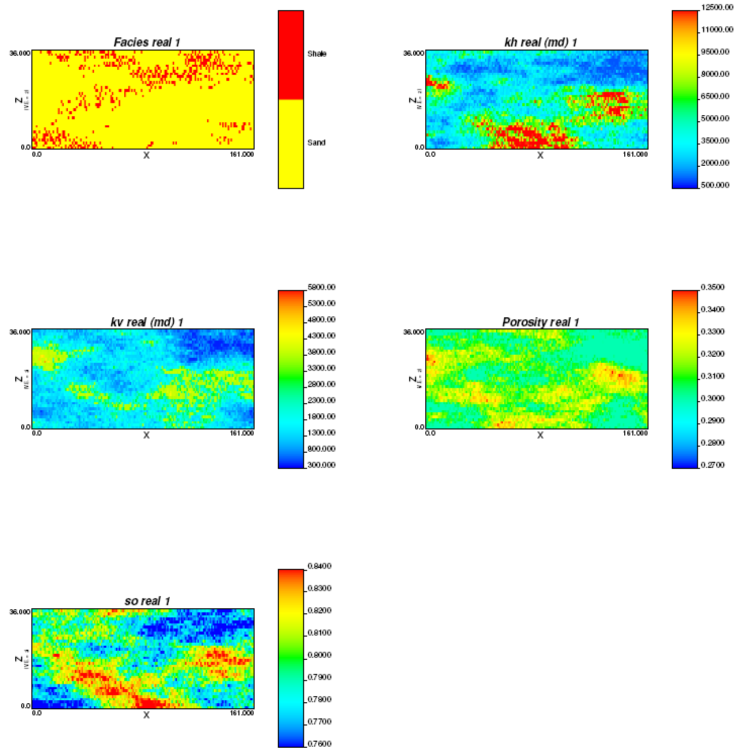

Figure 7. First of geological realizations used as input data in the application case.

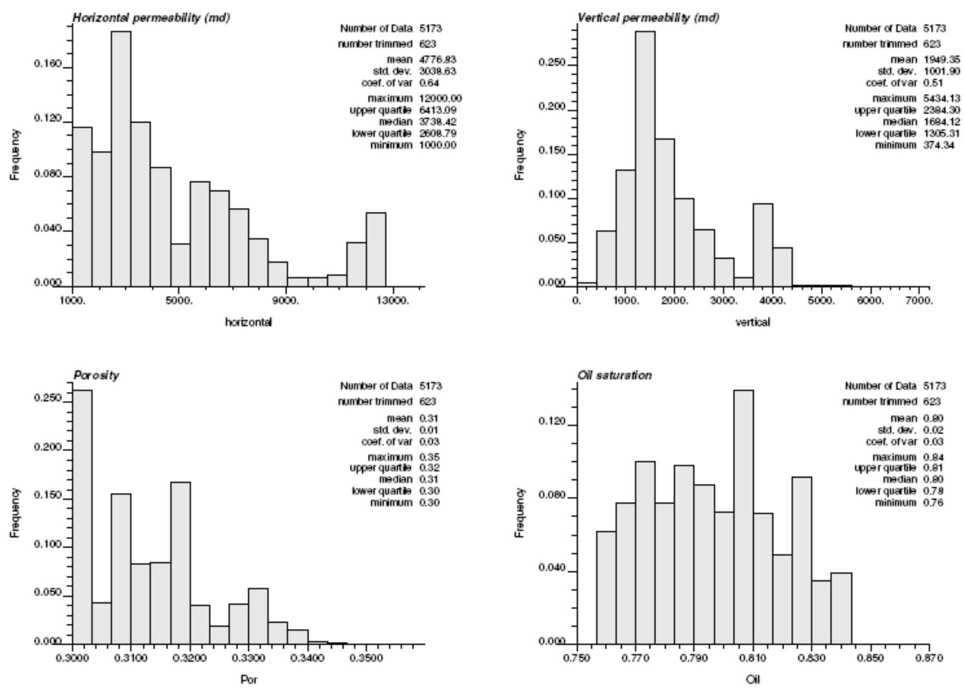

Figure 8. Histograms of geological variables used in the application example.

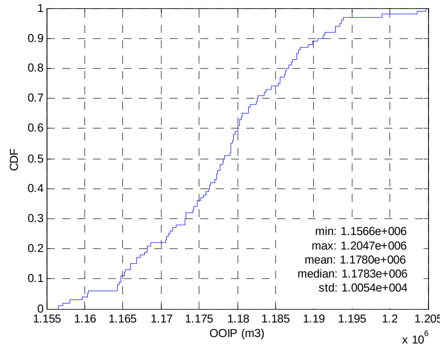

Figure 9. CDF of the ranking parameter: OOIP.

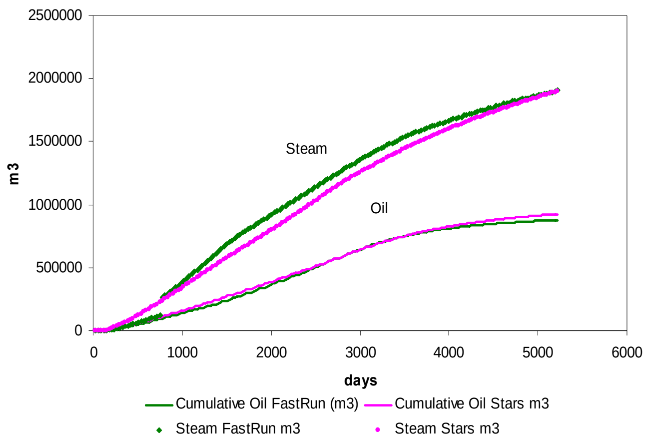

Figure 10. Comparison of cumulative oil production and stem oil injection curves for the proxy-model and reservoir simulator, for the P50 geological realization after fitting process.

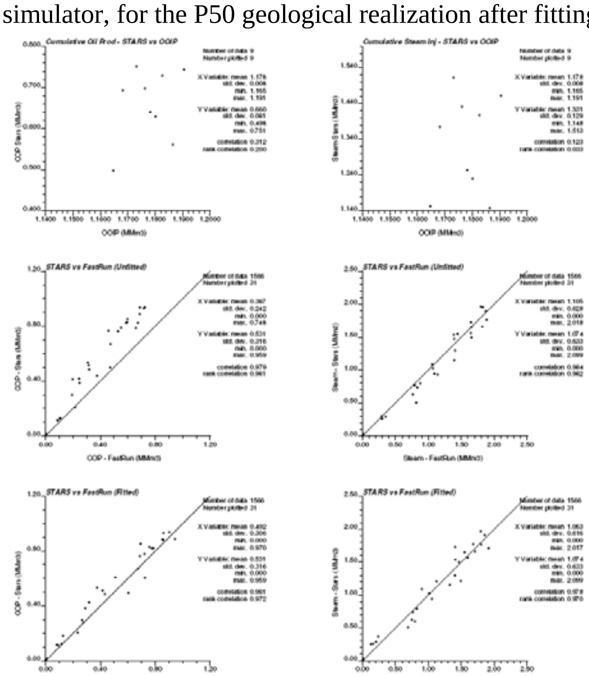

Figure 11. Quality of the SAGD performance predictions using FastRun for the application example. In the top plots the production performance is compared to the ranking parameter. The plots in the middle are using the unfitted proxy-model and the bottom plots using the fitted one.

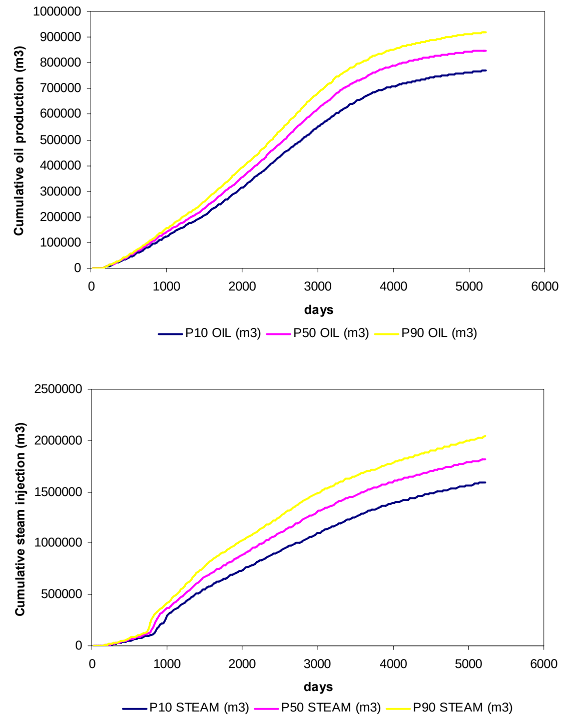

Figure 12. Uncertainty of the cumulative oil production and steam injection for the SAGD application case. The uncertainty illustrated in this figure is due to the reservoir uncertainty.

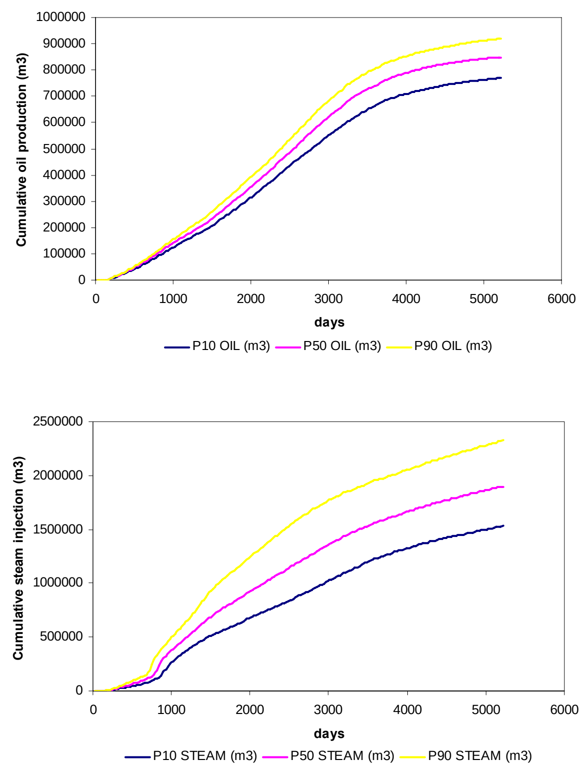

Figure 13. Uncertainty of the cumulative oil production and steam injection for the SAGD using a fully stochastic calculation.