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A New Modular Approach to Comprehensive Simulation of Horizontal Wells

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Abstract

The development in drilling and completion technology for horizontal wells has created new demands for enhanced comprehensive simulation methods. Wellbores with complex flow geometries are not easily implemented in commercially available simulation tools. A modular, comprehensive modelling of well and reservoir is proposed in this paper. The model consists of a detailed horizontal well flow simulator coupled to a reservoir simulator. The wellbore simulator is based on a network model which is capable of solving a broad range of possible flow configurations in the horizontal part of the well. The modular approach is facilitated by a coupling technique that reduces the requirement for iteration between the modules. The simulator is applied to high flowrate horizontal wells in thin oil zones with high permeability. Due to the flexibility in wellbore configuration, the simulator may be used to optimize well location, well path and completion approach. The coupling provides a detached wellbore simulation module which is reservoir simulator independent. The new simulation approach should be considered for horizontal wells where frictional pressure loss or geological inhomogeneities along the well are of importance to a well's production performance. The simulator will be used to evaluate completions with a complex flow configuration, potential cross-flow and for optimization of production and injection performance of wells in heterogeneous reservoirs.

Introduction

Optimizing the inflow to long horizontal wells has been recognized as a critical research area with a high potential for increased production rates.[1,2] New completion designs for horizontal wells have recently been proposed for improved well productivity and reduced production problems[1,2]. A typical inflow control liner design for use in high permeability, thin oil zones is shown in Figure 1. Efficient use of these completion designs requires that the flow inside the completion can be calculated in a more detailed way than what is possible with available reservoir simulation packages. Thus, a detailed flow simulator for horizontal well completions was developed for modular integration with reservoir simulators. The modular simulator approach is illustrated in Figure 2. The implementation of a detailed near wellbore simulator as indicated in the figure is recognized to be of great importance for prediction of local geology effects on the inflow, but was not within the scope of this study.

A modular, comprehensive simulation of the reservoir and the well has shown to be feasible through a coupling project involving a detailed horizontal wellbore simulator (HOSIM)[3] and a 3D, two phase reservoir simulator (FRONTSIM)[4]. Based on the experience from this coupling project, a modular, iterative coupling approach was developed between HOSIM and a general black oil reservoir simulator, which we refer to as RESIM.

Enhanced Wellbore Simulation

The horizontal wellbore simulator (HOSIM) is based on a general network solver for calculation of steady state flow through wellbore completions. The network solver which was originally developed[5] for use with gas pipeline systems has been modified to perform steady state simulation of horizontal wells. As the network solver also is capable of determining the direction of flow, the simulator can be used for injection

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References and illustrations at end of paper.

wells as well as for indicating cross flow between formations. In this paper, production wells are being considered. An illustration of the elements involved in the calculations is given in Figure 3.

Due to the flexibility provided by the network approach, a variety of completion flow geometries can be calculated using single and multiphase pressure loss models. A typical flow problem configuration is shown in Figure 4. Flow through the reservoir and completion is defined as a network of flow paths intersecting in nodes and commingled into a single flow path at the tubing. A set of equations combining the mass and momentum balance for the system is used to simultaneously solve for the unknown pressures and flowrates. The outlet boundary condition for the flow problem is specified by defining the total well flowrate or the system outlet pressure. Towards the reservoir, a simple reservoir model based on phase productivities permits the boundary conditions to be specified by providing flowrates or pressures at each reservoir boundary node. If flowrates are specified into the system, the pressure may be specified as the outlet boundary condition. If pressures are specified at the system inlet, either outlet pressure or flowrate may be specified.

HOSIM can be used for wells with different quality and proportions of fluids entering the wellbore from pay zones with different pressure regimes. The phase productivities and a classification of the fluids entering the well are specified for each reservoir connection. A mixing module maintains the volume balance for oil, water and gas within the flow system and black oil correlations are used to handle the mass transfer between phases and to evaluate the fluid properties.

Current multiphase flow models are OLGAS[6], Xiao[7] and the no-slip model. For single phase flow, experimentally obtained friction factors[8] for real size pre perforated liners are available within the program. Hydrostatic pressure loss is calculated to account for the effects of undulating wellbores and to extend the use of HOSIM to the surface.

The accelerational pressure loss as well as secondary effects from radial influx along the well has not been accounted for in the simulations. Volumetric average properties between water and oil are used when calculating the liquid phase properties.

Reservoir Simulator

In the black oil reservoir simulator, the well control modelling is based on the specification of a target value for a selected (primary) flow variable.

Additional constraints can be imposed on other (secondary) variables. The set of such flow variables includes rates for oil, gas, water, liquid and total reservoir fluids, bottom hole and tubing head pressure. Within the framework of this project, we do not focus upon the flexibility of this well control scheme. Instead, we assume throughout the discussion that a time dependant total reservoir fluid rate or systems outlet pressure is specified and that any other specification of well control parameters can be converted to this format, which is consistent with the modelling of boundary conditions in both HOSIM and RESIM. In other words, the discussion on coupling of HOSIM and RESIM presented below is based on a known value for total flowrate Q^n_T or systems outlet pressure $\mathbf{P}^n_{out}$ on each time level n.

If we assume that a horizontal well is penetrating a cartesian grid in the x-direction, the modelling of local inflow performance in RESIM is based on the Pieceman formulae

$$q_\alpha=\frac{a\Delta x(K_zK_y)^{\frac{1}{2}}k_{r\alpha}}{B_\alpha\mu_\alpha(\log\frac{r_o}{r_w}+S)}(P_o-p_w)\ , \qquad .....(1)$$

where r_o is the equivalent Peaceman radius defined by

$$r_o=0.28\frac{[(\frac{K_y}{k_z})^{\frac{1}{2}}\Delta Z^2+(\frac{K_z}{k_y})^{\frac{1}{2}}\Delta y^2]^{\frac{1}{2}}}{(\frac{K_y}{K_z})^{\frac{1}{4}}+(\frac{K_z}{K_y})^{\frac{1}{4}}}\ , \qquad .....(2)$$

where P_o is the grid block pressure and p_w is the wellbore pressure in that grid block.

For multiphase flow problems with horizontal wells in heterogeneous reservoirs, the above formulas are not valid. For a thorough discussion, see ref. 9. Improvements represent an active area of research[9,10,11]. It is emphasized here that the objective of this paper is to perform a coupling of HOSIM and RESIM, and that an improvement of the inflow performance modelling within the reservoir simulator is beyond the scope of the paper.

Coupling Approach

In this coupling approach, pressure has been used as the boundary condition in HOSIM at the reservoir side to provide the possibility of defining either total flowrate or system outlet pressure in HOSIM. Connection flowrates vs. connection point pressures are specified to HOSIM implicitly by transmitting information to build inflow performance relationships for each phase and connection point. These inflow performance relationships are being used during the HOSIM calculation procedure to maintain a representative relationship between pressure and flow at the sand face for the calculated time step. Thus, a certain simulation overlap exists between the two models as updated, static reservoir responses at each time step are passed over for use in HOSIM. This overlap is illustrated in Figure 5.

The Interface HOSIM / RESIM

The system outlet boundary condition in HOSIM is either total flowrate Q_T or pressure p_{out}. The boundary conditions used in HOSIM at the system inlet are reference pressures $P_{\infty k}$. These are given implicit from RESIM through the transfer variables as the reference pressures can be obtained by extrapolating the connection pressures p_k to receive zero flowrates at the connection points.

To extrapolate these reference pressures in HOSIM, it is necessary to obtain the flowrates $q_{\alpha k}$ for the relevant connection pressures p_k, in addition to the derivatives of the flowrates with respect to pressure $\delta q_{\alpha k}/\delta p_k$. These variables, called transfer variables, will vary with time. Based on this information and an assumption of steady state flow in the wellbore, HOSIM calculates the corrected connection pressures p_k as transfer variables back to RESIM in addition to the corresponding flowrates $Q_{\alpha k}$. By comparing the flowrates obtained from HOSIM to the flowrates obtained from the reservoir simulation, the conservation of mass between the two simulators can be verified.

The most important parameters, the connection point flowrates vs. connection points pressure from the reservoir simulation, are always maintained as points on the IPRs used by HOSIM. This is an important aspect of the coupling approach as it assures that only the correct solution can be found.

The connection flowrates and pressures can clearly be passed between RESIM and HOSIM in an iterative procedure. However, the partial derivatives $\delta q_{\alpha k}/\delta p_k$ may represent a problem. Below we first discuss a general scheme for coupling HOSIM to RESIM, where we assume known values for $\delta q_{\alpha k}/\delta p_k$ when calling HOSIM. Thereafter, we discuss several possible approaches for generation of the partial derivatives.

General Iterative Coupling Scheme

Let

$$RESIM(p_k, S^{old}_{\alpha ij}, P^{old}_{\alpha ij}) \rightarrow p^{new}_{\alpha ij}, S^{new}_{\alpha ij}, q_{\alpha k}, \delta q_{\alpha k}/p_k \qquad .....(3)$$

denote one time-step execution with RESIM, using (initial) reservoir pressures $P^{old}_{\alpha ij}$ and initial phase saturations $S^{old}_{\alpha ij}$, together with given pressures p_k inside the wellbore as boundary conditions. The output variables from this computation are new fluid distributions and pressures ($S^{new}_{\alpha ij}$, $P^{new}_{\alpha ij}$) and phase rates in addition to the derivatives of phase rates with respect to pressure ($q_{\alpha k}$,$\delta q_{\alpha k}/\delta p_k$) at each connection point.

Similarly, we let

$$HOSIM(p_k, q_{\alpha k}, \delta q_{\alpha k}/\delta p_k) \Rightarrow p_k, Q_{\alpha k} \qquad .....(4)$$

denote a computation using HOSIM with connection pressures p_k, fluids rates $q_{\alpha k}$ and connection rate derivatives with respect to connection pressures $\delta q_{\alpha k}/\delta p_k$ as transfer variables from RESIM. In addition the outlet boundary condition, which may be either pressure p_{out} or total flowrate Q_T , is specified. By using the transfer variables, and assuming a constant fluids rate derivative, reference pressures at $q_{\alpha k}=0$ can be extrapolated linearly in HOSIM for each connection point. Assuming a linear productivity is satisfactory for iteration close to the calculated connection point rates where the productivities are representative. The extrapolated reference pressures can then be used in HOSIM as inlet boundary conditions.

The following relationship applies:

$$P_{\alpha ref.} = P_k - \frac{q_{\alpha k}}{\delta q_{\alpha k}/\delta p_k} \qquad .....(5)$$

Both connection rate and connection pressure are in this way implicitly implemented as boundary conditions by constructing the inflow performance relationships for each phase and at each connection point as below:

$$q_{\alpha k} = (-\frac{\delta q_{\alpha k}}{\delta p_k})(P_{\alpha ref.} - p_k) \qquad .....(6)$$

Adjusted wellbore connection pressures p_k together with adjusted phase rates at each connection point are output from HOSIM. The total fluids rate Q_T will in this case also be calculated as an output from HOSIM, but is only used for checking the continuity of mass flow as a convergence criteria between RESIM and HOSIM. As conservation of mass is maintained in HOSIM, the following relationship is valid:

$$\sum_k \sum_\alpha Q_{\alpha k} = Q_T \qquad .....(7)$$

To advance the coupled simulation from one time level n to the next time level n+1, an iterative procedure must be invoked. Let m be the iteration index. The procedure is illustrated in Figure 6 and can be described as follows:

A $m:=0; p_k^{n+1,m}:=p_k^n; P_{\alpha ij}^{n+1,m}:=P_{\alpha ij}^n; S_{\alpha ij}^{n+1,m}:=S_{\alpha ij}^n; Q_{\alpha k}^{n+1,m}:=Q_{\alpha k}^n; q_{\alpha k}^{n+1,m}=q_{\alpha k}^n$

B $RESIM(p_k^{n+1,m}, S_{\alpha ij}^{n+1,m}, P_{\alpha ij}^{n+1,m}) \rightarrow P_{\alpha ij}^{n+1,m+1}, S_{\alpha ij}^{n+1,m+1}, q_{\alpha k}^{n+1,m+1}, (\frac{\delta q_{\alpha k}}{\delta p_k})^{n+1,m+1}$

C $HOSIM(p_k^{n+1,m}, q_{\alpha k}^{n+1,m+1}, (\frac{\delta q_{\alpha k}}{\delta p_k})^{n+1,m+1}) \Rightarrow p_k^{n+1,m+1}, Q_{\alpha k}^{n+1,m+1}$

D $IF: \sum_k \sum_\alpha [q_{\alpha k}^{m+1} - Q_{\alpha k}^{m+1}]^2 \leq \epsilon : n; = n+1; GOTO(A); ELSE: m:=m+1; GOTO(B)$

A variety of termination criteria may replace the one given in (D) above.

Evaluation of The Partial Derivatives

We next consider different approaches to evaluate the partial derivatives appearing in the HOSIM call in (C) above.

Evaluation Based on Productivity Indices

In simple flow problems it may be adequate to identify fluids inflow performance in a section of a well, with analytical steady state solutions for drainage from infinite volumes. Specially, in such cases where the inflow behaves as

$$q_{\alpha k}=(PI)_{\alpha k}(P_{\alpha\infty}-p_k) \quad .....(8)$$

where $P_{\alpha\infty}$ is a (phase) reservoir pressure at a sufficiently remote point, such that $P_{\alpha\infty}$ is constant with respect to wellbore pressure and where k is representing a connection in the section of the well associated with $P_{\alpha\infty}$. With reference to the notation used in the iterative procedure, a productivity for each phase and connection point can be derived:

$$(-\frac{\delta q_{\alpha k}}{\delta p_k})^{n+1,m+1} \approx PI = \frac{q_{\alpha k}^{n+1,m+1}}{P_{\alpha\infty}^{n+1,m+1} - p_k^{n+1,m}} \quad .....(9)$$

However, the approximation

$$-(\delta q_{\alpha k}^{n+1,m+1}/\delta p_k) \approx (PI)_{\alpha k} \quad .....(10)$$

is rather questionable, and improved methods are required for efficient convergence in coning situations. Unlike the more general approach, this method is based on estimating productivities from a provided reference pressure rather than extrapolating reference pressures from provided productivities. Thus, a larger uncertainty in the productivities may be expected together with a slower convergence.

Evaluation Based on Internal RESIM Data Structure

Since production terms usually can be treated implicitly in most reservoir simulators, the derivatives needed in step (C) are evaluated internally in such codes. This approach is expected to give the highest quality coupling, but was not tested in this work.

Evaluation Based on Sensitivity Simulations

The derivatives can always be obtained by brute force, simply by perturbing the wellbore pressures $p_k^{n+1,m}$ occurring in the RESIM call in step (B) and repeating the call. However, this is time consuming and should be avoided. A more sophisticated method based on analytical methods can improve the efficiency of such sensitivity calculations considerably[12]. However, this has not been considered in this paper.

Evaluation Based on Iteration Variables

An estimation of the derivatives based on internal iteration variables can be defined as follows:

For m > 1, use

$$(\frac{\delta q_{\alpha k}}{\delta p_k})^{n+1,m+1} = \frac{q_{\alpha k}^{n+1,m+1} - q_{\alpha k}^{n+1,m}}{p_k^{n+1,m} - p_k^{n+1,m-1}} \quad .....(11)$$

If n=0 and m=1, use the productivity factor in formula (1). For m=1, use $\delta q_{\alpha k}/\delta p_k$ from the previous time step.

Possible Enhancements to Speed up Convergence

The ultimate goal is to reduce number of iterations between HOSIM and RESIM to a minimum. Although the proposed coupling approach considerably limits the need for iteration, additional means to enhance the speed of the computation can be implemented. The following method has not yet been implemented in the calculation procedure.

Extrapolating Inflow Performance Relationships

The reservoir simulator requires a starting value for the connection pressures as an entry point for the iterative calculations. Analytically derived connection pressures, or the connection pressures from the last time level, is used as a default to guess the pressure profile along the well for the current time level. As the decline in productivity and reservoir pressure for a large part follows a trend during a simulation, information is available from simulation of previous time levels to reduce the number of iterations for a large percentage of the time steps during a simulation.

HOSIM can be used to produce an improved first estimate of the connection pressures at the current time level by applying extrapolated inflow performance relationships in the calculations. The inflow performance relationships can be extrapolated into the current time level using stored information. This approach requires that the transfer variables (connection pressures p_k, connection fluids rates $q_{\alpha k}$ and connection rate derivatives with respect to connection pressures, $\delta q_{\alpha k}/\delta p_k$) are stored for the last three to four time levels. If the IPRs for the current time level follows the same trend as the previous, an improved first estimate for the pressure profile will be obtained.

This approach will clearly not allow prediction of unexpected dynamic reservoir behavior like a sudden gas or water breakthrough. Thus, for these conditions the default iteration procedure as described above applies.

Example Calculations

The functionality of the coupling approach was tested by applying a dummy reservoir simulator in the coupled simulations. The dummy module generated new inflow performance relationships (IPR) for each phase and connection point at each time level. To test the robustness of the coupling approach, the IPR had an nonlinear relationship between connection pressure and flowrate. Both the slope of the IPR and the reference pressures varied with time as can be seen from Figure 7. An 800m long / 6"internal diameter well was configured with 8 equally distributed connection points to the dummy reservoir simulator. The well resembled a continuously perforated liner as the roughness was set to 0.3 mm. The well produced at a total liquid rate of 2500 Sm^3/d with 50% water cut and a free gas production of 1250 Sm3/d. An oil with a bubble point of 159 bar and a solution GOR of 65 Sm^3/Sm^3 at reservoir conditions of 159 bar and 69 °C was used.

Figure 8 shows some of the results from the calculations given by converged connection pressures and oil flowrates for each 4th. time level. A pressure loss of 0.6 bar along the liner was typically calculated for all time levels. The effect of the pressure loss on the inflow along the well can be seen by the curves in the lower part of Figure 8 which show uneven distribution of inflow.

The required accuracy for the calculations was set to be a maximum of 1 % error in the material balance between the dummy reservoir simulator and HOSIM. This condition was met within two iterations except from for the first two time levels which required 6 and 5 iterations, respectively. The convergence scheme is illustrated in Figure 9 by showing how the calculations advanced from time level n=3 to n=4 for a connection point located 550 m from the toe of the well. In the following discussion, local productivity is understood as the connection point productivity at a certain connection point pressure.

As no extrapolation of IPR to the next time level is applied in these calculations the converged connection pressure from time level n=3 is directly applied when performing the first iteration of reservoir calculations for time level n=4. The reservoir simulator returns a calculated rate for this connection point pressure. The local productivity to be used in HOSIM is found by correcting the simulated productivity (based on simulated reference pressure and a linear IPR) with the proportion of the local productivity to the productivity (based on simulated reference pressure and a linear IPR) experienced at the previous time level. The local productivity is then applied in combination with the connection point pressure and the simulated connection point flowrate to construct a linear IPR for time level n=4. This linear IPR is fitted through the first simulated point on the IPR for time level n=4.

The next HOSIM derived solution of connection point pressure and rate will be located on this linear IPR, but now with an improved solution for the rate. The magnitude of the error experienced at this point highly depends on the nonlinearity of the real IPR. For these calculations more than one iteration was necessary and a new point on the IPR is found by repeating the procedure using the HOSIM calculated connection point pressures. It can be seen from the figure that the corrected local productivity is significantly improved in the second iteration.

Example Simulations

Simulations using HOSIM and Frontsim were carried out to illustrate the performance of the coupled model. FRONTSIM is a reservoir simulator based on front-tracking methods for the solution of the saturation equations. The simulator applies new mathematical concepts in the field of hyperbolic conservation laws in order to avoid numerical dispersion. The simulator uses an IMPES formulation and the pressure equation is solved by finite element method. The simulator currently handles two phase immiscible flow in three dimensions using a simple PVT model for oil/gas systems with constant bubble point pressure. Both gravity and compressibility are included in the model.

In the simulated cases, an 800m long, 0.1m internal diameter horizontal well was located 14.5m below the gas oil contact. A high roughness of 3 mm was applied to the wellbore to increase friction. Thirty layers of 3 by 20 simulation grid blocks were used in the 250m by 1000m reservoir model. The horizontal and vertical permeabilities were 500 and 50 md, respectively. A light oil with an initial gas saturation of 65 Sm^3/Sm^3 and a bubble point pressure of 159 bar at 69 °C (initial reservoir conditions) was used in the simulations and an overlaying large gas cap was modelled to provide sufficient pressure support throughout the simulations. A constant bottom hole pressure of 155 bar at the heel of the well was applied to control the flowrate, and one day time steps were applied throughout the simulations. The reservoir model was simplified as the functionality of the coupling approach rather than the functionality of the applied reservoir simulator is the issue of this paper. The following discussion of the case study is therefore focused on the coupling:

No frictional pressure loss along the wellbore

The simulations were performed by applying a wellbore diameter of 1 m in HOSIM. The oil production and GOR before and after time of gas break through can be seen from Figure 10. With a bottom hole pressure of 155 bar, an oil production rate in excess of 14000 Sm^3/d gave gas break through at 37 days into production.

No-slip correlations applied in the wellbore

The development in oil production rate and GOR can be seen from figure 11. Again with a bottom hole (heel) pressure of 159 bar, a stable oil production rate of 2500 Sm3/d was maintained until gas break through occurred 86 days into production. The oil rate from FRONTSIM then drops off to approximately 1950 sm3/d and stabilizes at this level. The oil flowrate calculated by HOSIM after gas breakthrough differs from the flowrate calculated in Frontsim by a stepwize decline in rate as new connection points detect gas entering the wellbore at different times into the simulation. The oil rates from FRONTSIM and HOSIM approach the same magnitude as gas has coned into the second connection point. As convergence of calculated oil flowrate in HOSIM was confirmed for the time of discrepancy and since the flowrate can only converge to the correct solution, the discrepancy between the two derived oil flowrates immediately after gas break through has been identified as an artifact and should not be considered a weakness of the coupling approach.

OLGAS correlation applied in the wellbore

Figure 12 shows oil production rate and GOR development for case 3. By applying a bottom hole (heel) pressure of 155 bar, a somewhat higher oil production rate compared to the no-slip case gave a time of gas break through at 78 days. The increased production rate indicates lower wellbore friction. As stratified flow occur in the wellbore before gas breakthrough, a smaller pressure loss will be calculated with a correlation that accounts for slip between the phases. However, a larger drop in oil production rate after gas breakthrough is experienced in case 3 than in case 2 due to slug flow occurring in the heel of the well. This is explained by a higher pressure loss calculated by the slug model in OLGAS than by the no-slip model

Again, the discrepancy between the two calculated flowrates immediately after gas break through can be explained in the same way as for case 2.

Convergence

In the comprehensive simulations, the simplest of the described convergence schemes was applied. A reference pressure at the flank of the reservoir and connection productivities were used as transfer variables from Frontsim to HOSIM. The connection productivities were calculated from the simulated connection point flowrates, connection point pressures and reference pressure. The simulations did not have a convergence criteria put into effect and 10 iterations were allowed on each time step to observe the convergence. of HOSIM calculated oil flowrates.

The % deviation from the converged oil flowrate at each iteration is shown in Figure 13 for three different times into the simulation of case 3. The rate at a time before gas break through (62 days) immediately converges to the correct oil flowrate. This rapid convergence can be expected as the reservoir before gas breakthrough has a linear inflow performance like the one used in the coupling.

At time 78 days into the simulations, gas breakthrough is experienced and the error in oil flowrate is for the first iteration close to 1.3 %. At the second iteration, the error has decreased to less than 0.1 % and converges to the correct solution occurs by iteration 7. The slower iteration after gas breakthrough is caused by the nonlinearity of the simulated inflow performance. As described in the general coupling approach and the example calculations above, this may be accounted for by using various schemes to approximate the local (connection point rate and pressure) connection point productivity.

Simulator Application to New Completions

As the level of detail in wellbore simulations increases due to the complexity of the completions (inflow control, stinger completions, gravel pack, perforations, zonal isolation, undulating wellbores) it has been shown to be more feasible to develop simulators for wellbore purposes as stand alone modules rather than as an integrated part of the reservoir simulator. New completion designs based on controlling the inflow from the reservoir require that the wellbore calculations are performed with a network approach rather than by nodal analysis. The comprehensive simulator with a detailed horizontal wellbore model is therefore required for efficient completion design and development, and for production optimization.

Conclusions

To be able to efficiently optimize the completion design in long horizontal wells, detailed network calculations of the wellbore are necessary. Detailed wellbore simulations are not easily performed implicitly in the reservoir simulator. Thus, a modular simulation approach was found to be the most feasible path of development.

Comprehensive simulations of reservoir and wellbore are necessary for long horizontal wells due to the high level of interaction between the reservoir and the wellbore. A coupling scheme has therefore been developed to allow for comprehensive modular simulation of wellbore and reservoir.

The functionality of the coupling scheme has been verified both by applying a dummy reservoir module and a reservoir simulator coupled to the horizontal wellbore simulator. Simulations with satisfactory convergence were performed for a high permeability reservoir after breakthrough of free gas into the wellbore.

Several methods for speeding up convergence have been described. One method that adjusts PI for linear IPR to local productivity (at a certain connection pressure and rate) by applying the proportion between these two productivities in the last time step was tested with good results to account for the nonlinearity of the IPR.

Nomenclature

q, Q :flowrates (q=estimated, Q=actual / derived)
a :conversion factor in formula (1)

$\Delta x, \Delta y, \Delta z$:grid block dimensions

K :permeability
k_r :relative permeability
P :reservoir pressure
$P_{ref.}$:reference (pressure at q=0)
P_{out} :outlet pressure (at heel or wellhead)
p :wellbore pressure
B :formation volume factor

μ :viscosity

r_o :equivalent Pieceman radius formula (2)
r_w :wellbore radius
S :saturation, skin

ϵ :error limit

n :time level ($t = n \Delta t$)

m :iteration index
PI :productivity index

P_∞ :reservoir boundary pressure

Subscripts

T :total

α :phase - oil, gas, water

x, y :areal coordinates
z :vertical coordinate
k :connection index
i j :grid block index
w :well
$(\ )^n$:final (converged) values on time level n
$(\ )^{n,m}$:iterative values on time level n

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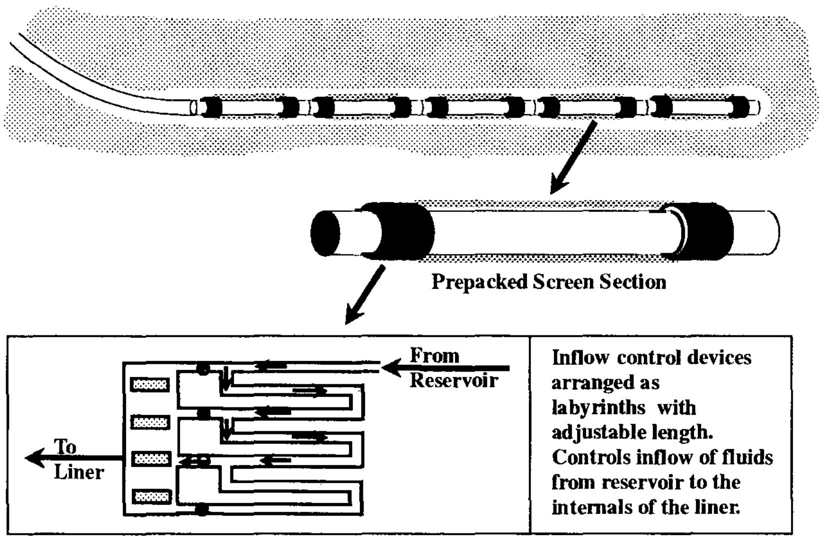

Figure 1: Inflow Control Liner Schematics

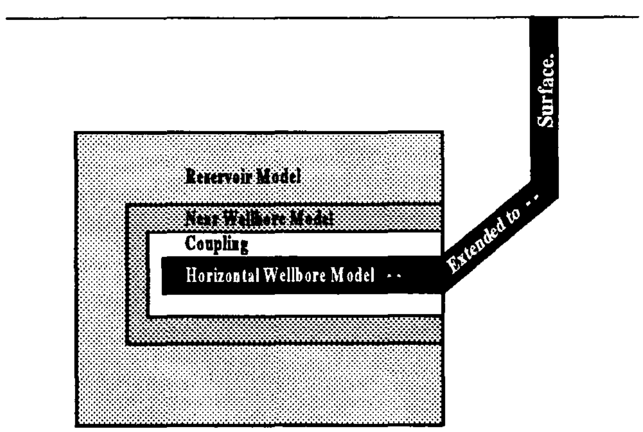

Figure 2: Coupled Simulator Layout

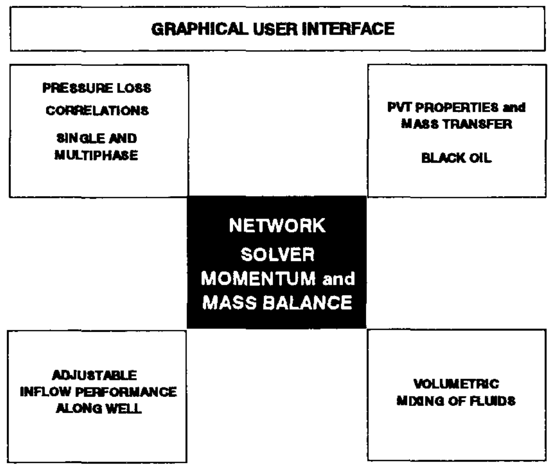

Figure 3: Wellbore Simulator Layout

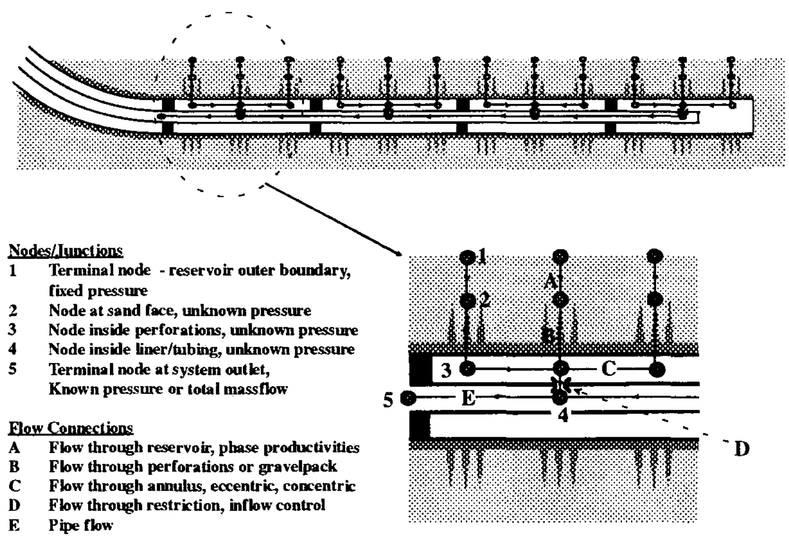

Figure 4: Typical HOSIM Problem Configuration

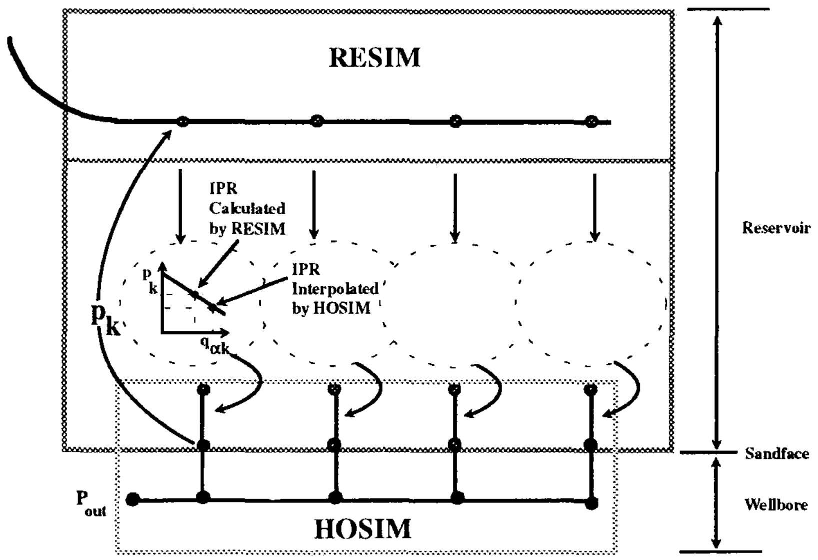

Figure 5: Simulator Interaction

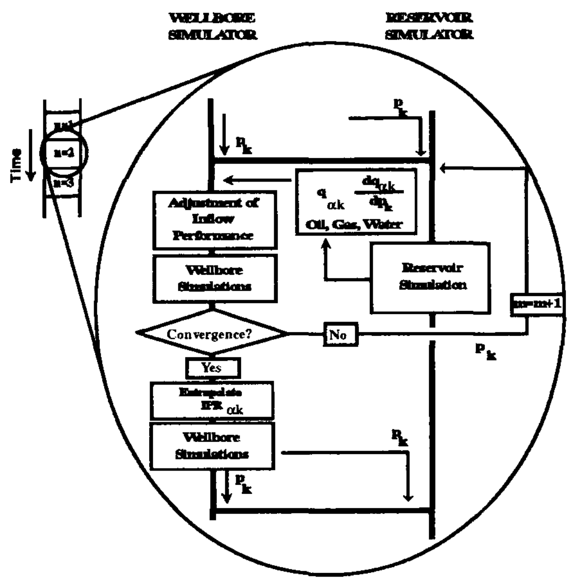

Figure 6: Iterative Coupling Scheme

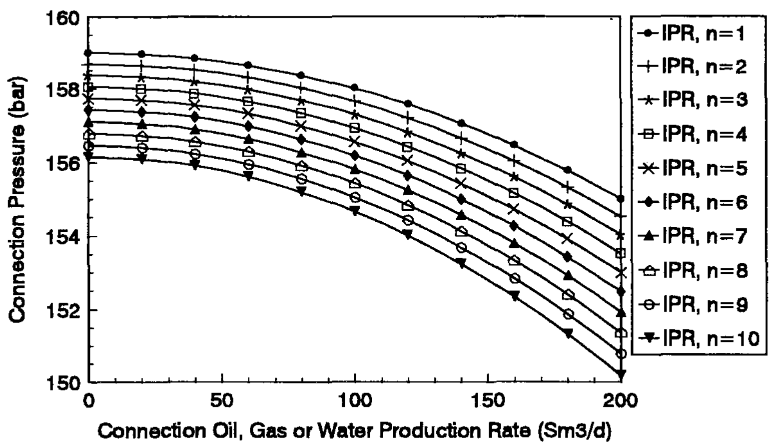

Figure 7: IPR Development Throughout the Calculations

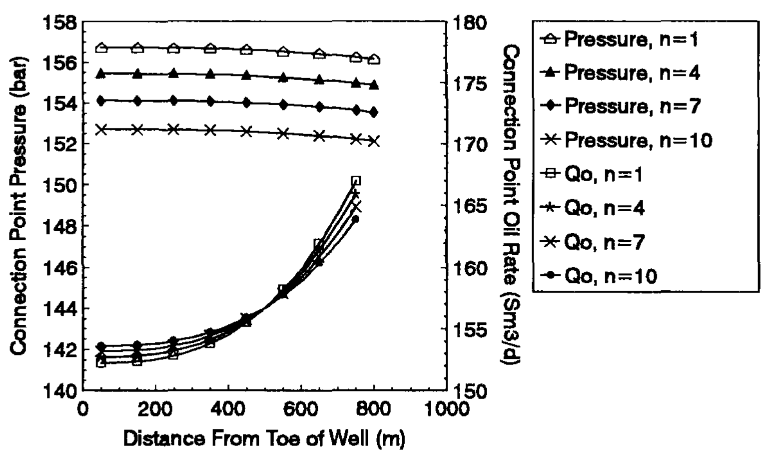

Figure 8: Pressure and Drainage Profile along Well

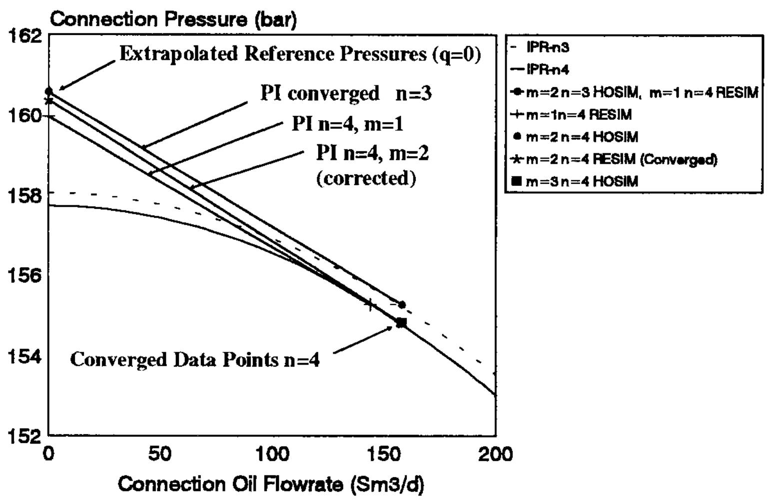

Figure 9: Iteration n=3 to 4, Connection 550 m from Toe of Well

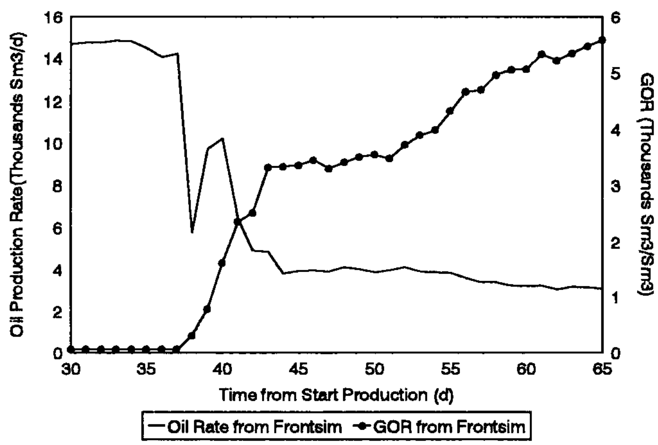

Figure 10: Case 1, Oil Rate and GOR vs. Time

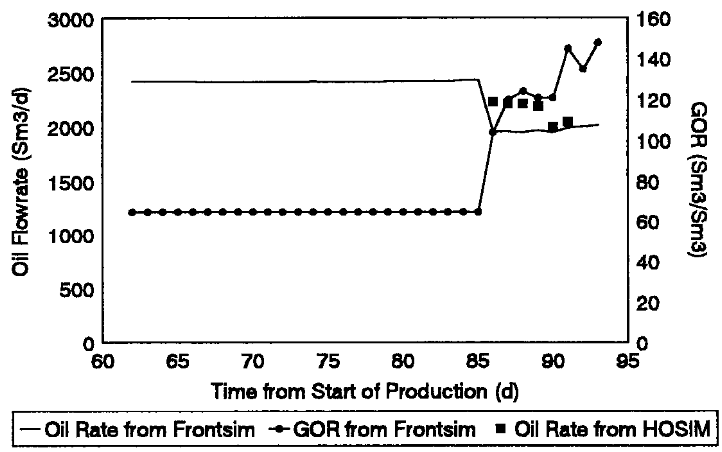

Figure 11: Case 2, Oil Rate and GOR vs. Time

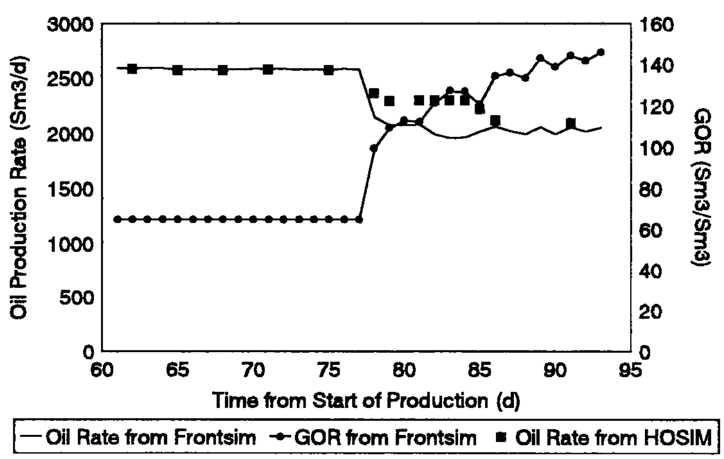

Figure 12: Case 3, Oil Rate and GOR vs. Time

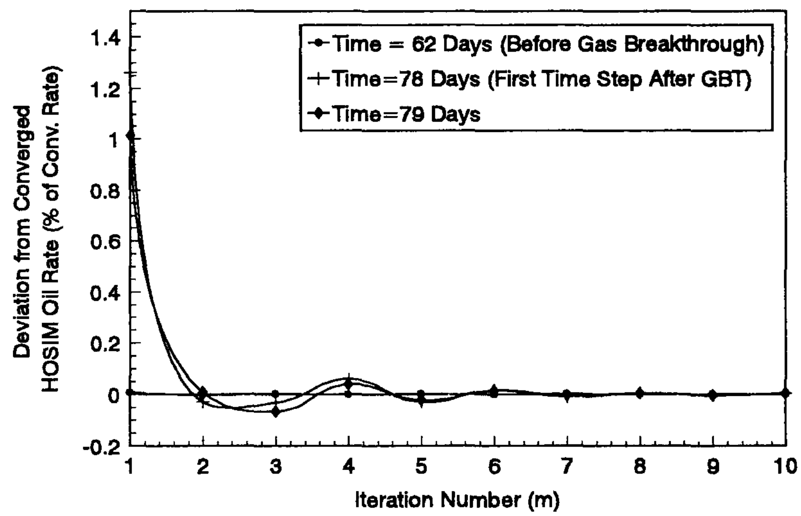

Figure 13: Case 3, HOSIM Oil Rate Convergence Before and Immediately After Gas Breakthrough