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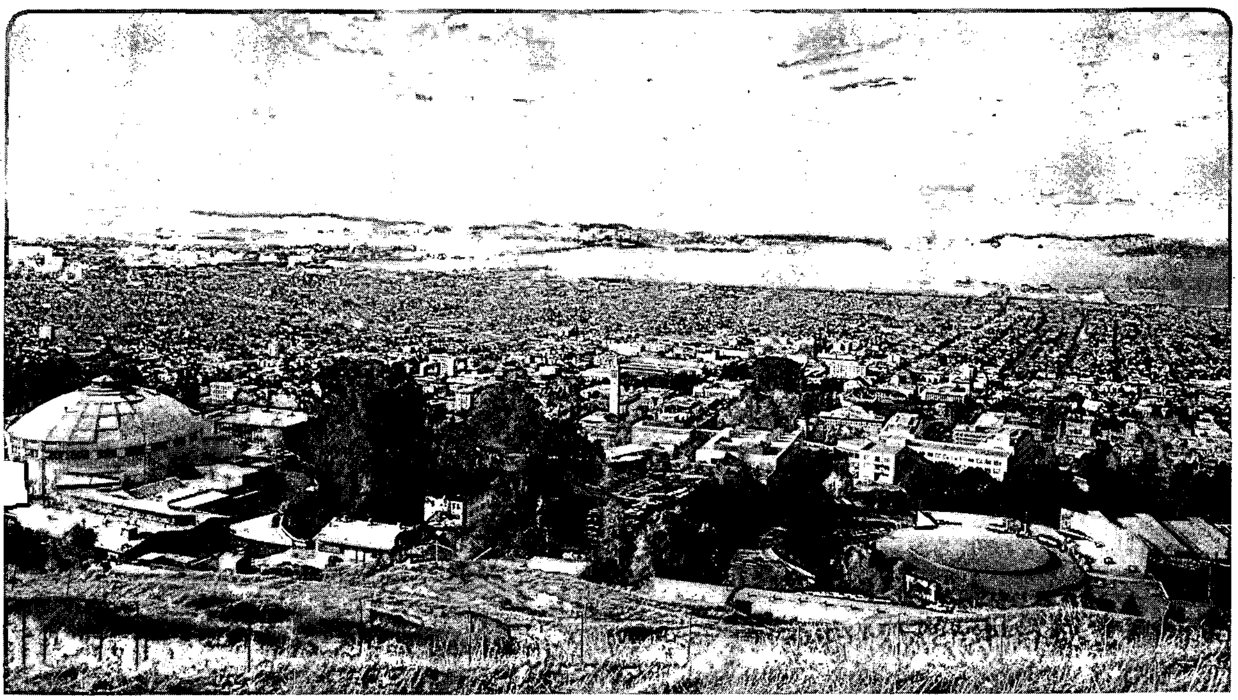



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# Coupling of a Reservoir Simulator and a Wellbore Simulator for Geothermal Applications

*Teklu Hadgu, Robert W. Zimmerman, and Gudmundur S. Bodvarsson*

Earth Sciences Division
Lawrence Berkeley Laboratory
University of California
Berkeley, CA 94720

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# COUPLING OF A RESERVOIR SIMULATOR AND A WELLBORE SIMULATOR FOR GEOTHERMAL APPLICATIONS

Teklu Hadgu, Robert W. Zimmerman and Gudmundur S. Bodvarsson

Earth Sciences Division, Lawrence Berkeley Laboratory, University of California, Berkeley, CA 94720

## ABSTRACT

Coupling of the reservoir simulator TOUGH and wellbore simulator WFSA is presented. A brief description of the structure of the two computer codes is given. TOUGH was developed at Lawrence Berkeley Laboratory by Pruess (1987). WFSA was developed at Auckland University, New Zealand by Hadgu and Freeston (1990). A new module COUPLE has been written to serve as an interface between TOUGH and WFSA. Two sample problems, involving single-phase flow, two-phase flow, and multiple feedzones, are solved using the coupled simulators. This new procedure should allow more accurate simulations of geothermal reservoir behavior under exploitation.

## INTRODUCTION

A geothermal production system consists of the reservoir, the wellbores, the surface fluid gathering system, and the power/energy production stage. The geothermal fluid passes through these various stages on its way to produce energy. An efficient usage of the resource requires a thorough study of these various stages and interactions between them.

The fluid gathered at the surface passes through the wellbore as it moves upwards from the reservoir. The thermodynamic conditions of the fluid at the wellhead depend on the reservoir and wellbore characteristics. The pressure difference between the reservoir and the wellhead is a combination of the pressure drawdown in the reservoir, and the pressure drop in the wellbore. Currently, many reservoir simulators exist that are intended to model flow processes occurring in the subsurface (e.g., TOUGH, Pruess, 1987; TETRAD, Vinsome et al., 1991). These models typically ignore the details of flow in the wellbore, and treat the well in a very simplified manner. Likewise, several wellbore simulators exist which model the internal flow in the wellbore, with varying degree of accuracy and sophistication (e.g., HOLA, Bjornsson and Bodvarsson, 1987; WFSA and WFSB, Hadgu and Freeston, 1990). These models usually require input parameters that would typically be found as output of a reservoir simulator (e.g., flowrate and enthalpy). In this paper, we discuss the coupling of a reservoir simulator and a wellbore simulator. A coupled reservoir/wellbore model will allow for more accurate simulation of the exploitation of geothermal resources.

## RESERVOIR SIMULATOR TOUGH

TOUGH (Pruess, 1987) is a multi-phase flow numerical code designed to model the coupled transport of fluid and heat, in porous as well as fractured media. It is a three dimensional code which solves the equations of motion by discretizing them in space using the integral finite difference method. Time is also discretized, in a fully implicit manner, as a first-order finite-difference.

Darcy's law is used to describe flow of single- and two-phases with interference between phases represented by relative permeability functions. Thermodynamic and transport properties of water substance are obtained from steam table equations reported by the International Formulation Committee (1967). Heat flow is represented by conduction, convection and binary diffusion. Thermal conductivity of the rock-fluid system depends on saturation, using an equation that interpolates between the conductivity at zero liquid saturation and the conductivity at full liquid saturation. TOUGH solves mass and energy balance equations for each gridblock, at each time step.

TOUGH has options for describing fluid/heat injection or withdrawal from the reservoir, treated as source/sink terms. TOUGH also has a deliverability option to evaluate well output based on specified wellbottom pressure and productivity index (Coats, 1977). Details of the structure of the code, along with sample problems, can be found in the user's guide (Pruess, 1987).

## FLOW FROM THE RESERVOIR TO THE WELLBORE

Flow from the reservoir into the wellbore is often treated as steady-state, because it is assumed that flow equilibrates in the block containing the well faster than in the reservoir as a whole. Pritchett and Garg (1980) compared steady and unsteady flow solutions for an infinite reservoir of uniform properties and constant thickness, containing a single-fully penetrating well. Their results showed that for times greater than about ($4\phi c\mu r^2/k$) after a flowrate change, the solutions are equivalent, where r is the radius of the block containing the well, k is the permeability, $\phi$ is the porosity, $\mu$ is the viscosity, and c is the compressibility. For single phase conditions this time is typically on the order of seconds, but can become significant for two-phase flow, due to the large compressibility of a two-phase mixture (Grant et al., 1982).

It is assumed that the flow into the well is steady and horizontal, and governed by Darcy's law. With the additional assumptions that flowrates are low, the fluid is single-phase (liquid) and the reservoir is homogeneous and isothermal, the governing equations can be integrated to give

$$p_r - p_{wb} = \frac{W\mu}{2\pi\rho kh}\ln\left(\frac{r_e}{r_w}\right) \qquad (1)$$

where W is mass flowrate (injection or production), $p_{wb}$ is pressure in the wellbore, $r_w$ is radius of the wellbore, h is reservoir thickness, $\rho$ is fluid density, and $p_r$ is pressure in the reservoir at a distance $r_e$ from the well. For cases when well damage is important, the additional pressure drop due to skin is included:

$$\Delta p_{skin} = \frac{W\mu}{2\pi\rho kh} s \qquad (2)$$

where s is the dimensionless skin factor. Adding the pressure drop due to skin given by equation (2) to equation (1) and solving for W gives

$$W = \frac{(p_r - p_{wb})}{\nu K_{d1}} \qquad (3)$$

where $\nu$ is kinematic viscosity and $K_{d1}$ is the drawdown factor for laminar flow, defined by

$$K_{d1} = \frac{\ln(r_e/r_w) + s}{2\pi kh} \qquad (4)$$

The above analysis deals with fluid flow from a position at $r = r_e$ away from the well to $r = r_w$. The averasge reservoir pressure $p_r$ in the wellblock is thus defined at $r = r_e$, and not at the center of the wellblock. Researchers have studied the relationship between $r_e$ and the size of the wellblock. A criterion for choosing the value of $r_e$ is developed in the next section.

At high flowrates the flow in the reservoir near the wellbore tends to be turbulent, and Darcy's law is no longer applicable. Kjaran and Eliasson (1983) included turbulence in their analysis of flow into a wellbore. By including all the pressure drop components, one can arrive at the following equation for the overall pressure drop:

$$\Delta p = \nu\left(K_{d1}W + \frac{K_{d2}}{\rho}W^2\right) \qquad (5)$$

where $K_{d1}$ is drawdown factor for Darcy flow defined in equation (4), and $K_{d2}$ is drawdown factor for turbulent (non-Darcy) flow: $K_{d2} = f_c/4\pi h^2 r_w$, where $f_c$ is an empirical flow coefficient. The drawdown factor for Darcy flow can be evaluated using reservoir parameters as shown in equation (12). Evaluation of $K_{d2}$ is not as straightforward, as it requires knowledge of the flow coefficient $f_c$. For cases where turbulence is significant, equation (5) may be evaluated using data from discharge tests.

## NODAL PLACEMENT FOR THE WELLBLOCK

If a single well test is being modeled, a fine-meshed cylindrical grid would typically be used around the wellbore. For long term modeling of an entire geothermal field, a coarse-meshed rectangular grid would typically be used. In each case, a proper choice of nodal point placement must be made. One reasonable criterion for this choice is that the finite-difference calculations give the correct flux for, say, the case where the pressure distribution around the well is single-phase, quasi-steady-state, and radially symmetrical. For a cylindrical grid in which the grid boundaries are of the form $r_{i+1} = c\, r_i$, Aziz and Settari (1979) showed that, in order for the finite-difference transmissivity between gridblocks i and i+1 to agree with the exact steady state value, the nodal points $r_{di}$ must be located at (see Fig. 1 for definitions of the distance variables).

$$r_{di} = \frac{\ln c}{(c-1)} r_i \qquad (6)$$

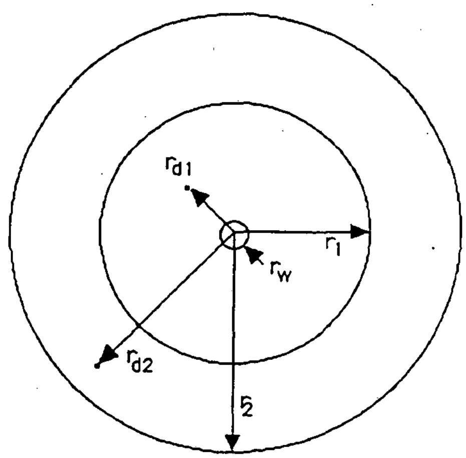


Fig. 1. Radial grid in cylindrical coordinates. $r_i$ is the outer radius of the ith gridblock; $r_{di}$ is the location of the nodal point in gridblock i, and $r_w$ is the radius of the wellbore.

For a rectangular grid, as is often used in large scale simulations (see Fig. 2), TOUGH's approximation of Darcy flow between two adjacent blocks is given by:

$$p_2 - p_1 = \frac{W\mu}{\rho k}\left[\frac{D_1+D_2}{A_s}\right] \qquad (7)$$

If we add up the flow from all four gridblocks adjacent to the wellblock (five-point finite difference scheme), then $A_s$=4Lh. As $D_1 = 0.5L - r_{d1}$ and $D_2 = 0.5L$, i.e., $D_2 + D_1 = L - r_{d1}$, we have

$$p_2 - p_1 = \frac{W\mu}{\rho k} \left[\frac{L - r_{d1}}{4Lh}\right] \qquad (8)$$

Comparing equation (8) with the general equation for radial pressure distribution (see equation 1), and using $r_{d2} = L$, we get a relationship between nodal distances and the radius of the wellblock:

$$\frac{2\pi}{\ln(L/r_{d1})} = \frac{4L}{L - r_{d1}} \qquad (9)$$

Equation (9) can be solved to give $r_{d1} = 0.3747L$. A different approach was taken by Peaceman (1978) and Pritchett and Garg (1980), who placed the nodal point at the center of the wellblock, and then found an effective radius at which the wellblock pressure can be assumed to act. We interpret the pressure in the wellblock as being the mean pressure in the block, and then find the appropriate nodal point location.

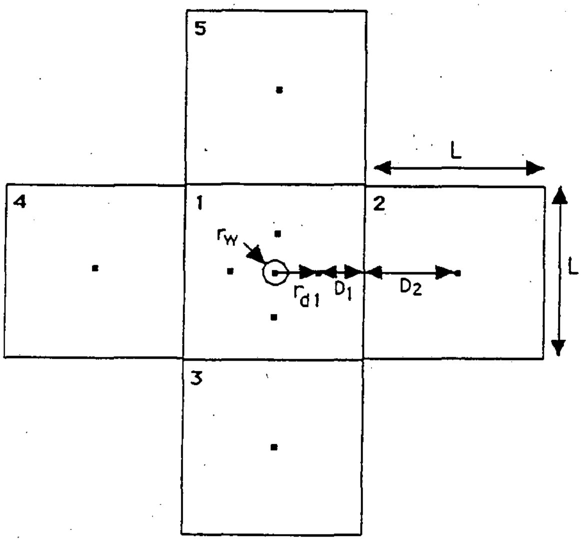


Fig. 2. Rectangular grid in cartesian coordinates. $D_i$ is the distance from the nodal point of gridblock i to the interface between two blocks.

For single phase flow, the flow between the reservoir and the wellbore as defined in TOUGH is

$$W = \frac{\rho}{\mu} PI_1 (p_1 - p_{wb}) \qquad (10)$$

where $p_1$ is pressure in the wellblock and $PI_1$ is the productivity index for Darcy flow. For Darcy flow between the reservoir and the wellbore, and assuming no skin effect (s = 0),

$$W = \frac{2\pi kh\rho}{\mu \ln(r_{d1}/r_w)} (p_1 - p_{wb}) \qquad (11)$$

The productivity index can then be found by equating (10) and (11):

$$PI_1 = \frac{2\pi kh}{\ln(r_{d1}/r_w)} \qquad (12)$$

where $r_{d1}$ is evaluated using the analysis described above. Thus, the drawdown factor $K_{d1}$ (equation 4) is the reciprocal of productivity index. For cases where turbulence is important, equation (5) must be used. This would require evaluation of the productivity index for turbulent flow, $PI_2$, which is the reciprocal of $K_{d2}$; $K_{d2}$ can be evaluated if an estimate of the flow coefficient $f_c$ is made. If measured data are available equation (5) can be used to evaluate $K_{d2}$.

## WELLBORE SIMULATOR WFSA

Flow of fluid in a wellbore is essentially flow in a vertical pipe with connections to the reservoir only at a few feed points. Thus it can be described using classical fluid mechanics and heat transfer methods for flow in a pipe. However, the presence of liquid water, steam, dissolved solids and non-condensable gases in a geothermal fluid constitutes a complex multi-phase flow problem. Other features such as radial heat flow, multiple feed zones, flow in the slotted liner, and deposition of chemicals (e.g., calcite) in the wellbore further complicate the problem.

Because of these complexities, many researchers use empirical methods to simulate the fluid flow. However, many of these empirical correlations were derived from the oil and gas industry, or other sources having applications that differ from geothermal wellbore flow. Some of the methods were developed from laboratory experiments using small diameter pipes of short length with air and water as media. Geothermal conditions, in contrast to the above, require large diameter pipes and steam-water flow (single component, two-phase). Despite the complexity of the problem and the simplifications required, some wellbore models developed have shown reasonable accuracy when used in geothermal wellbore simulation. Comparisons of some of these wellbore simulators were made by Freeston and Hadgu (1988), and recently by Probst et al. (1992). Both comparisons showed that none of the wellbore simulators were able to accurately model flow under all conditions. Their findings, however, showed that certain simulators performed better in specific conditions. Some researchers have attempted to use analytical and experimental methods along with state of the art fluid and heat flow research. However, due to lack of experimental data on steam-water flow at high temperatures in sufficiently long, large diameter pipes, empirical relations have been used to augment the models.

Some of the research done with this line of reasoning can be found in Bilicki et al. (1981), Denver Research Institute and Coury and Associates (1981), Hadgu (1989) and Hadgu and Freeston (1990).

Simulator WFSA together with WFSB and STFLOW were developed at Auckland University, Auckland, New Zealand. Details of model development can be found in Hadgu (1989), and Hadgu and Freeston (1990). The codes WFSA, WFSB and STFLOW represent a multi-purpose geothermal wellbore simulator with features such as presence of dissolved solids, presence of gases, multiple feed zones, and fluid-rock heat exchange. These three sets were later combined to form a single simulator with all the above features. This simulator, WELLSIM Version 1.0, is discussed by Gunn and Freeston (1991) and Gunn et al. (1992). For the work reported in this paper, the simulator WFSA was used. Future work on the subject will include other features.

The main assumptions made in the development of WFSA are that flow is steady and one-dimensional; the phases are in thermodynamic equilibrium; fluid properties are constant within a selected interval; dissolved solids can be represented by NaCl; non-condensable gases can be represented by $CO_2$; and in the case of wells with multiple feedzones, either mass flowrate and enthalpy, or reservoir pressure, drawdown factor and enthalpy, are provided as input for each feed point. The governing differential equations are solved as an initial-value problem, starting from the known conditions at the wellhead or wellbottom. The equations, which represent conservation of momentum and energy, are integrated using a finite-difference discritization, and a forward-Euler algorithm. The models utilize analytical and experimental methods together with emperical correlations for closure.

## COUPLING SIMULATORS TOUGH AND WFSA

TOUGH's input includes sources/sinks. The various options available as to the type of sources/sinks are discussed by Pruess (1987). The options include the deliverability option, in which a constant wellbore pressure and productivity index are specified. For multiple layer completion (i.e., multiple feedzones) TOUGH requires a productivity index for each layer and a constant wellbore pressure for the uppermost layer. TOUGH then calculates wellbore pressures for the other layers based on the specified wellbore pressure in the uppermost layer. The assumption is made that wellbore pressures in other layers can be obtained by approximately accounting for gravity effects.

For this study the wellbore pressure of the uppermost layer is not required. The deliverability option in TOUGH is selected, but the calculations are performed in a separate subroutine (COUPLE) which couples TOUGH and WFSA. A schematic diagram of the coupled codes is shown in Fig. 3. The deliverability equation which connects the reservoir and the wellbore (i.e., either equation (10) or equation (5)) is applied at each feedzone. According to equations (10) and (5) the variables involved are feedzone productivity indices (drawdown factors), reservoir pressure ($p_r$), feedzone reservoir temperature ($T_r$), wellbore pressure ($p_{wb}$), feedzone mass flowrate (W), feedzone reservoir enthalpy ($h_r$), kinematic viscosity ($v_t$) and density ($\rho_t$). TOUGH uses conditions in the reservoir to evaluate fluid properties. The same procedure has been followed for this study. The main variables to be calculated are W and $p_{wb}$. TOUGH supplies, at each time step, the values of $p_r$ , $T_r$, $h_r$, $v_t$ and $\rho_t$ for each feedzone, and the total number of feedzones (layers) for a well. The wellbore simulator then evaluates W and $p_{wb}$ for each feedzone. It has been found that evaluating W and $p_{wb}$ at the beginning of each time step allows smoother convergence in TOUGH than implicit coding, and does not seem to cause stability problems.

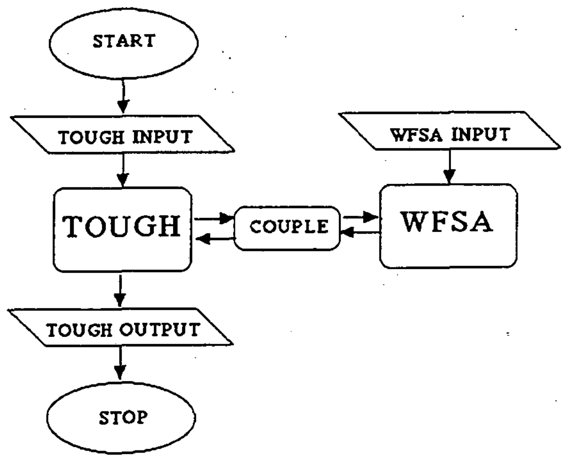


Fig. 3. Schematic diagram showing the coupled simulators. Subroutine COUPLE transfers information between TOUGH and WFSA.

The input to wellbore simulator WFSA was modified for this study, and now includes wellhead pressure, well geometry, calculation step and shut-in temperature profile. WFSA has its own subroutine to handle feedzones. Thus, calculations regarding feedzones other than the bottommost are handled in subroutine FEED. The procedure followed in WFSA is shown below.

(i) Obtain all input data from an input file, and from subroutine COUPLE.

(ii) Start with a guessed value for the wellbore pressure, along with mass flowrate and thermodynamic conditions of the bottom-most feedzone. Calculate flow parameters up the wellbore until the depth of the next feedzone is encountered.

(iii) At the next feedzone call subroutine FEED. The wellbore pressure is the calculated pressure at that depth. Subroutine FEED uses equation (10) or (5) to evaluate feedzone mass flowrate. A heat and mass balance is then performed to evaluate new thermodynamic conditions. If the calculated wellbore pressure in WFSA is larger than the feedzone reservoir pressure supplied by TOUGH, fluid will flow out of

the well into the feedzone. If the feedzone reservoir pressure is higher, the reverse will happen. WFSA assumes that the fluid entering the well from the feedzone flows upwards only.
(iv) Once the new mass flowrate and thermodynamic conditions are obtained, calculation continues to the next feedzone. The procedure is repeated at the next feedzone, and the calculations continue until the wellhead is reached.
(v) If the calculated wellhead pressure does not agree weith the specified wellhead pressure a new wellbore pressure for the bottommost feedzone is selected, and the integration process is repeated. This procedure is iterated until the calculated wellhead pressure agrees with the specified wellhead pressure to within a pre-selected tolerance.

The output from the coupled codes is similar to the standard TOUGH output, but it includes the additional output parameters and wellbore pressures at each feedzone.

## SAMPLE PROBLEMS

Both simulators have been individually tested and validated. For validation and testing please refer to Pruess (1987) for TOUGH, and Hadgu (1989) and Hadgu and Freeston (1990) for WFSA. Probst et al. (1992) also presented a comparison of WELLSIM Version 1.0 (WFSA) and other wellbore models with measured data. Following are two sample problems for the TOUGH-WFSA coupled models. These problems are only designed to demonstrate the type of information that might be obtained by coupling a wellbore simulator to a reservoir simulator. Actual validation of the coupled codes will require comparison with, say, field data, and will be attempted in future work. The results of the simulation, however, seem to be realistic given the input conditions. In all problems wells have an inside diameter of 0.2 m, and a calculation step of 10 m was taken for the wellbore flow calculation.

### Problem 1

A single well is completed in two layers (i.e., two feedzones) in a 9 x 9 rectangular mesh with gridblocks of 200 m length. The well is located at the center of the grid (i.e., in block x = 5, y = 5). The thickness of the bottom and top layers is 500 m each, and a cap rock of 500 m overlays the top layer. The wellblock nodal distance and productivity index were calculated using equations (9) and (12) to be 75 m and 9.49 x $10^{-12}$ $m^3$ respectively, for the bottom layer, and 75 m and 4.75 x $10^{-12}$ $m^3$ respectively for the top layer. Note that this assumes no skin effect at the well. The reservoir is initially single-phase with $p_i$ = 133.8 bars and $T_i$ = 190 °C for the bottom layer, and $p_i$ = 90.5 bars and $T_i$ = 190°C for the top layer. The permeability values used were 20 mD for the bottom layer, and 10 mD for the top layer. A porosity of 0.1 was used for both layers. Well parameters are: depth of the bottom feedzone = 1250 m, depth of the top feedzone = 750 m, and $p_{wh}$ = 7 bars.

The coupled codes were run using the data described above, and the results are shown in Figs. 4 and 5. The computation time was only marginally higher than for TOUGH simulations without coupling to the wellbore simulator. This was mainly due to the relatively high computational speed of WFSA, compared to TOUGH. The results show that the output of the top feedzone is lower than the bottom feedzone, mainly due to the lower productivity index of the top feedzone. As the well feeds from liquid feedzones, and flashing occurs in the well above the top feedzone, the frictional pressure gradient in the pipe length between the two feedzones is low compared to the gravitational gradient. Thus, flowrates are dominated by gravity effects. Fig. 4 shows the profiles of the average reservoir pressures in the wellblock, and the corresponding feedzone wellbore pressures. The reservoir pressures approach the wellbore pressures as time increases, which is due to the effect of the closed boundary. The flowrates decline in proportion to the difference between the reservoir and wellbore pressures, as shown in Fig. 5.

### Problem 2

This problem includes two-phase flow in the reservoir. A single well is located at the center of a radial grid with an outer radius of 464.4 m. The reservoir has a thickness of 100 m and is capped with a 500 m cap rock. Reservoir parameters are k = 1 Darcy, $\phi$ = 0.1, $T_i$ = 250°C, $s_{gi}$ = 0.001, and linear relative permeability functions with no residual saturations. The radial mesh was made using $r_{i+1} = c\, r_i$, with c = 1.29 and wellblock radius = 100 m. Using equations (6) and (12), the nodal distance for the wellblock and the productivity index were calculated to be 87.8 m and 9.27 x $10^{-11}$ $m^3$, respectively. Well parameters are: depth = 550 m and $p_{wh}$ = 10 bars. Figs. 6 to 8 show simulation results. Fig. 6 shows the average pressure in the wellblock, and the wellbore pressure at the feedzone. As the reservoir pressure declines the wellbore pressure follows it. Fig. 7 shows both vapor saturation and flowing enthalpy in the wellblock, both of which increase as a result the pressure decline in the reservoir. Fig. 8 shows the well discharge which seems stable for about eight months, and thereafter declines linearly with time.

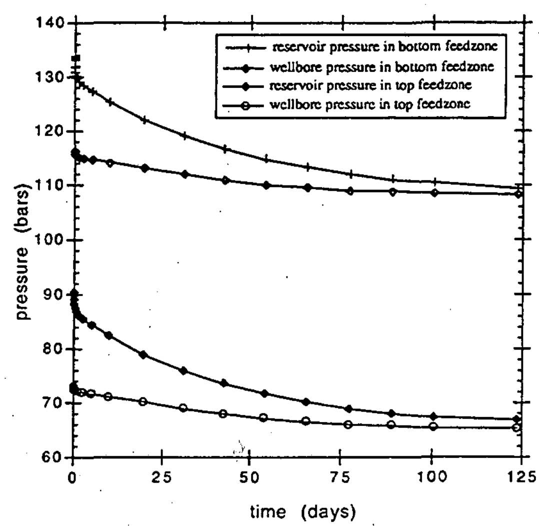


Fig. 4. Reservoir and wellbore pressures for Problem 1, which has a single cell completed in two layers (feedzones). Other details of the problem are described in the text.

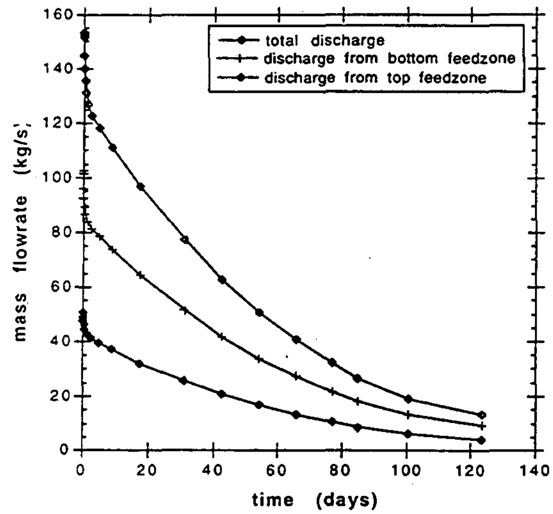


Fig. 5. Discharge rate for Problem 1. The figure shows discharge from the two feedzones and the total discharge at wellhead.

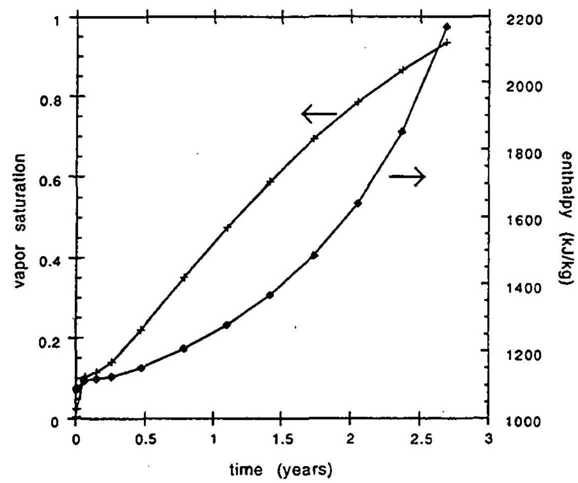


Fig. 7. Reservoir vapor saturation and flowing enthalpy for Problem 2.

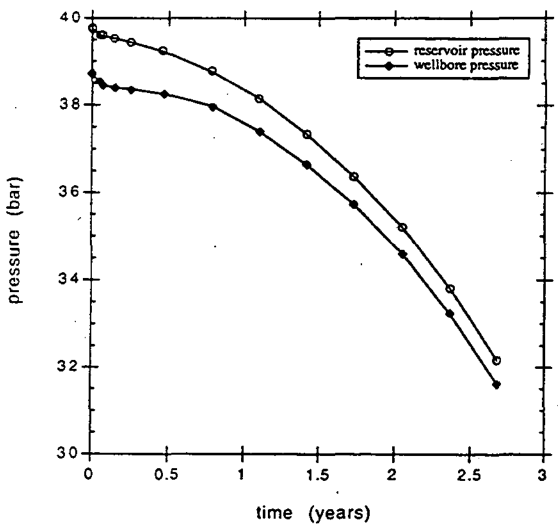


Fig. 6. Reservoir pressure and wellbore pressure for Problem 2, a single well completed in one layer (one feedzone). The reservoir initially contains near saturated liquid, and vapor saturation and flowing enthalpy increase due to drawdown.

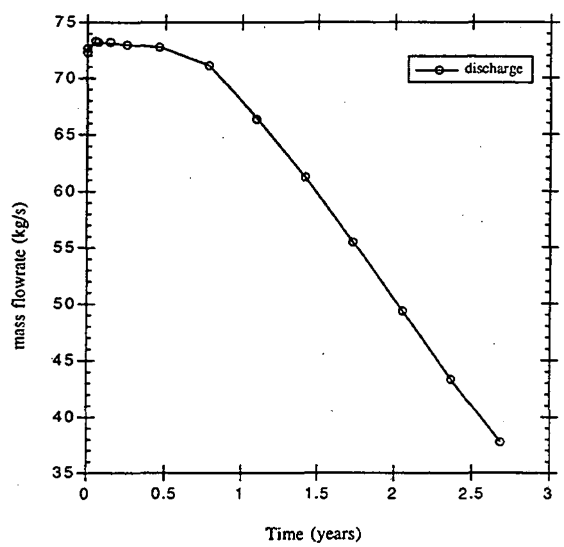


Fig. 8. Well discharge for Problem 2.

## CONCLUSIONS

A tandem usage of a reservoir simulator and a wellbore simulator has been demonstrated in this study. The study included analyses of the flow between reservoir and wellbore, and procedures for evaluating parameters are discussed. The reservoir/ wellbore coupling system includes Darcy and non-Darcy type flows provided that productivity indices are given as input. The coupled simulation was used on two sample problems, involving single-phase flow, two-phase flow, multiple wells and multiple feedzones. This study considered only the case where the wellhead pressure remains constant. Other options will be included in future efforts.

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UNIVERSITY OF CALIFORNIA
TECHNICAL INFORMATION DEPARTMENT
BERKELEY, CALIFORNIA 94720