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Development of Effective Numerical Model for Heavy Oil Production Using Steam-Assisted Gravity Drainage

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Abstract

One of the modern technologies for heavy oil and bitumen recovery is SAGD (Steam Assisted Gravity Drainage), which use two horizontal wells, one above the other with spacing 5-10*m*. Upper well is used for steam injection and creating the high-temperature steam chamber (SC). On the SC boundary the steam is condensing and water together with the heated oil flow downward into production well.

Pressure and temperature (P/T) measurements in injection and production well are used to control production process. This data contains only indirect information about the steam chamber parameters and oil inflow profile along the well length, therefore various mathematical models should be used to interpret measurement results.

P/T measurements interpretation, optimization of steam injection regime and analysis of reservoir heterogeneity influence on SAGD parameters are commonly performed on 3D models, which need tremendous computational resources and provide results within an inapplicable time (several days and even weeks) for field usage.

Present work is devoted to development of the effective SAGD numerical model. It is based on the well admitted in literature assumption, that horizontal steam flow along the injection well prevail over the horizontal steam flow along the reservoir. Thus 3D simulation can be substituted for by the 1D simulations for the injector/producer connected with N 2D cross section reservoir models which are connected only through injection and production boreholes (an example is in paper[4]). Injection well model provides steam pressure/temperature profiles for 2D cross section models. In turn these models calculate profile of steam injection rate which is an input data for injection well model. Developed 1D + N*2D SAGD model can be used for fast SAGD simulation and for injectivity profile inversion from P/T data recorded in injection well.

1D model of injection well with tubing inside the well for steam injection at the heel and/or at the toe was developed. It assumes two phase (water/vapor) flow with ‘drift flux’ and heat exchange between tubing and annulus flow. Nevertheless, analysis of field data recorded by DTS in injector shows that assumption of joint flow of the water and vapor along the injector, and hence simultaneous injection of the vapor and the water in reservoir can be violated in some cases. Modification of the 1D injection well model with separated distributed vapor/water injection in the reservoir was developed. Simulation results obtained obtained with modified model are able to reproduce qualitatively field data behavior.

Introduction

Heavy oil and bitumen account for more than double the resources of conventional oil in the world. Recovery of heavy oil and bitumen is a complex process requiring products and services built for specific conditions, because these fluids are extremely viscous at reservoir conditions (up to 1500000 *cp*). Heavy oil and bitumen viscosity decreases significantly with temperature increases and thermal recovery methods seems to be the most promising ones.

Steam Assisted Gravity Drainage (SAGD)[1] offers a number of advantages in comparison with other thermal recovery methods. Typical implementation of this method requires a pair of parallel horizontal wells drilled near the bottom of the reservoir one above the other. Steam is circulated in both wells to preheat the reservoir between the wells. Once mobility has been established, the upper well, "injector", is used for steam injection and forming the steam chamber, the lower well, "producer", is used for production of the heated oil. SAGD provides greater production rates, better reservoir recoveries, and reduced water treating costs and dramatic reductions in Steam to Oil Ratio (SOR).

SAGD method has complications due to the lack of control of steam chamber growth along the horizontal well section. This lack of control leads to the possibility of the steam breakthrough to the producer. To handle this problem the production process requires complicated operational technique, based on downhole pressure and temperature (P/T) monitoring. P/T monitoring data itself does not provide information about production well inflow profile, possible steam breakthrough and location of steam breakthrough zone. High accurate reservoir simulation is required to describe the steam chamber forming and flow of bitumen and condensed steam especially in heterogeneous reservoirs. Due to essentially 3D geometry of the problem, the most accurate way of the SAGD simulation is based on 3D modeling. Nevertheless, application of the full scale SAGD simulation to the problem of P/T measurements interpretation can not provide solution in acceptable computational time for the real time monitoring applications. Hence the problems of SAGD monitoring require development of fast and accurate SAGD simulator – an alternative to full scale 3D simulation.

Model description

This paper considers an alternative to 3D approach to fast and accurate SAGD simulation. It is based on application of the 1D injection well model decoupled from the bitumen drainage processes. Injection well model provides steam pressure/temperature profiles that are boundary conditions for a set of N 2D cross-sectional SAGD models of steam, water and bitumen flow in layers perpendicular to the injection well axis. In turn, these models calculate profile of steam injection rate which is an input data for injection well model.

The developed 1D model uses approach of the multi-segment well model similar to implemented in Eclipse Thermal simulator. A description of the Eclipse Multi-Segment Well model was published in[3], application of it to the Thermal simulation was described in[6]. This model takes into account heat transfer between the tubing and annulus, annulus and formation. Input parameters are: variable steam injectivity profile and the steam injection rates specified at the heel and toe. This model solves the material balance equations for each phase and calculates the pressure drop equation that takes into account the local hydrostatic, friction and acceleration pressure gradients. We consider the case of long-term steam injection and well developed SC when heat losses from the annulus to surrounding formation are negligible. The pressure drop is calculated either from the homogeneous flow model where all the phases flow with the same velocity or with the 'drift flux' model that allows slip between the phases.

Modification of the developed model was done in order to have ability of taking into account independent injectivity profiles for water and vapour phase in pressure drop calculations. This modification of 1D injection well model is based on the system of steady state flow equations for two-fluid model for water and vapour phase for the horizontal well[2,5]. Important application of this modification of the 1D injection well model is estimation of the steam injection profile basing on P/T data recoded in injection well.

The main problem for this modification of the model was the estimation of the influence of separated water and vapour outflow. Therefore the simple injection well model for steam injection at the heel only was considered. It was assumed that water flows from the annulus to formation due to gravity and SC volume (or production rate) is large enough to take this water.

If denote the flow rate of water flowing along the annulus bottom as m_w (*kg/s*), then relation for the liquid phase flow (*kg/m/s*) from the annulus to formation can be written as

$$\frac{dm_w}{dx} = -\Delta r \cdot \rho_w{}^2 \cdot \frac{k \cdot k_w}{\mu_w} \cdot g \tag{1}$$

where Δr (we assume $\Delta r \approx r_w$) is the width of the seepage zone, k reservoir permeability, k_w water relative phase permeability, ρ_w water density, g gravitational acceleration and μ_w water viscosity at the reservoir temperature.

Taking into account that under the well bottom the oil saturation is residual and gas saturation is small (as water film at the well bottom isolates it from the vapour) it can be assumed that k_w is large enough ($k_w \approx 0.5 \div 0.8$).

m_w value does not include droplet water phase that is transferred in the gas core. Fraction f_E of water droplet phase was estimated using the correlation from Wallis (1969)[8]:

$$f_E = 1 - e^{-0.125(\phi - 1.5)} \tag{2}$$

where $\phi = 10^4 \frac{v_{SV}\mu_V}{\sigma}\left(\frac{\rho_V}{\rho_W}\right)^{0.5}$, σ is surface tension, μ_v is the vapour viscosity, ρ_v is the vapour density, ρ_w is water density, $v_{SV} = q_V / A$ is vapour superficial velocity, A is the well crossection area, q_v is the vapor volumetric flow rate.

Pressure profile along the well is calculated using well known formulas for two phase flow[2,5] with varying vapour and water flow rates. Along the well flow pattern was determined basing on well known flow maps generated using experimental data[2,5], and water/vapour flow rates.

At the relatively low steam injection rate the flow regime in injector is stratified-smooth exhibiting the low pressure gradient. With the increasing of the injection rate the flow pattern changes to stratified-wavy, this transition increases the pressure gradient. At higher rates the flow pattern becomes annular in which the vapour phase flows in the high-velocity core and may contain significant amount of entrained liquid droplets; the liquid flows as a thin film around the pipe wall. The interface between phases is wavy. The film at the bottom is thicker than one at the top. All this regimes are possible for the realistic steam injection rates varying from 50 to 500 *m3/day*.

The separate water and vapour outflow can result in the presence of dry vapour in wellbore after several meters. In this case the friction pressure losses are determined using the simple formula:

$$\frac{dp}{dx} = -\frac{\xi_{FV}\rho_V v_V^2 S}{2A} \tag{3}$$

where v_v is the vapour phase velocity, A is a cross-sectional area of well, S is the flow perimeter, ξ_{FV} is a vapour friction factor.

Input data of the model are vapour injection profile and output data are pressure and temperature profiles.

SAGD injection well completion and operating conditions

Adequate model of steam injection well should take into account its typical geometry and operation conditions. The injection well geometry is dependent on the length of the well horizontal section, steam injection rates, injection pressure and steam quality. Average diameter of the liner varies from 7″ to 8.6″ or even 9.6″. For very long wells (1000 *m* or more) or very high rate wells (700 *m3/day* or more of steam injection) the size of the liner reach 10.7″ (as mentioned in[7]). Larger liners reduce the pressure drop in the liner annulus, and improve reservoir performance through a more uniform steam injection distribution and uniform production inflow characteristics.

To obtain the operational flexibility the injection well is often designed with tubing inside the wellbore (**Fig.1**). This allows steam injection at the heel or at the toe or both at toe and heel. This design provides more uniform steam injection, but it suffers from the counter current heat transfer between the fluid flowing in the annulus and the tubing and significant pressure losses in tubing.

Further for calculations we use the following parameters of injection well: length of horizontal section 500 *m*, the values of internal and outer diameters of the annulus and tubing: ID tubing 3″, OD tubing 3.5″, ID casing 8.625″, OD casing 9.5″. The heat capacity of tubing / casing is 1.5 *kJ/kg/K*, thermal conductivity of tubing / casing is 45 *W/m/K*, the wellbore wall effective roughness 0.001 *m*. Typical injection rates are about 100-500 *m3/day* (in liquid water volume). Value of steam quality at the inlet of the horizontal well section is varied from 0.6 to 0.85.

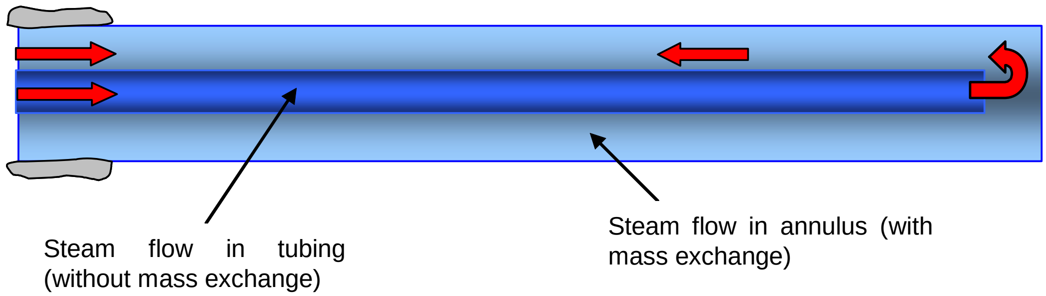

Fig. 1. Injection well completion

Simulation results

The developed model was evaluated using DTS data for Athabaska tar sands. The reservoir model was homogeneous with permeability equal to 5 *Darcy* and the steam injectivity profile was assumed to be linear. Well model for annulus and tubing was consisted of 20 sections; each section was 25 meters long. Injected steam from each section was recovered by separate outlet with fixed production rate. Steam was injected into the reservoir at the heel and at the toe of the well. Injection rate at the well heel was 32.5 *m3/day* of steam with steam quality equal to 0.85. Injection pressure was equal to 16 *Bar*. Injection rate at the well toe was 50 *m3/day* of steam. The steam quality at the inlet of the tubing was equal to 0.85, injection pressure was equal to 17.7 *Bar*.

The simulated pressure profiles along the tubing and annulus are presented on the **Fig.2**. Pressure drop in the tubing is about 1.7 *Bar*, in annulus about 0.3 *Bar*. Minimum pressure in the annulus is at the distance ~150 *m*, where heel and toe flows meet.

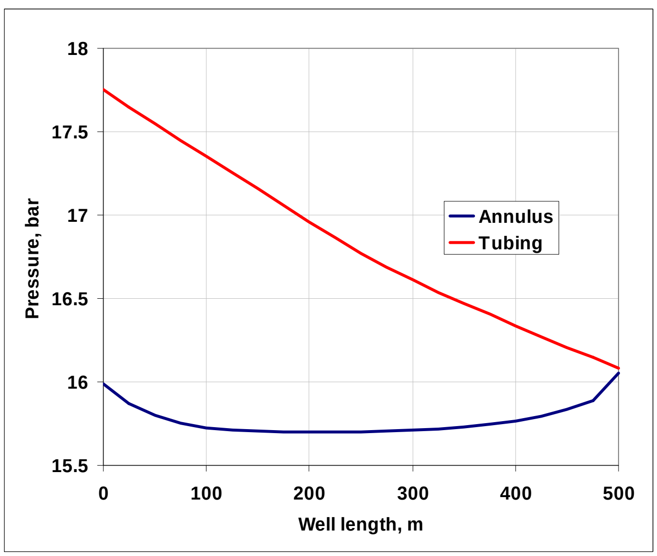

Fig. 2. Pressure distribution in injection well for injection through heel and toe

Steam quality along the tubing drops from 0.85 to 0.35 and increase in the annulus section because of the counter-current heat transfer between the fluid flowing in the annulus and the tubing (**Fig.3**). At the depth interval 75-200 *m* there is the superheated steam in the annulus.

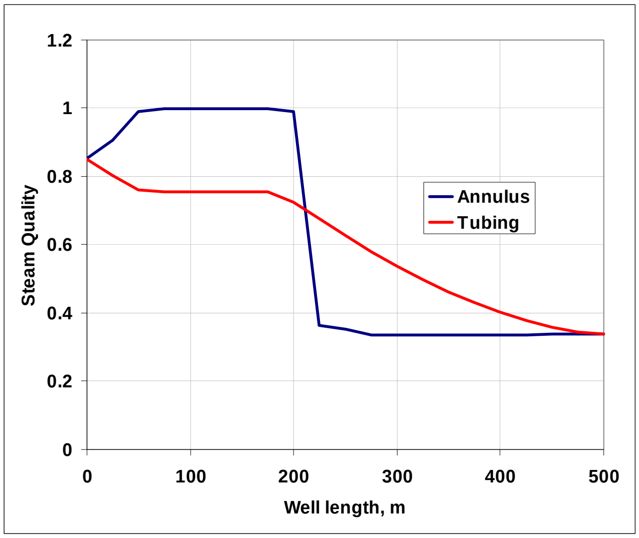

Fig. 3. Steam quality profile in injection well for injection through heel and toe

The presence of the superheated steam in the annulus one can see from calculated steam quality profile presented in **Fig.3**. **Fig.4** shows that temperatures drop in the tubing is about 4.5 *K* in agreement with saturated steam pressure decrease. Temperature in annulus also decrease with pressure decrease (200-500 *m*, **Figs.2,4**), but in the well section with the superheated steam (75-200 *m*), temperature in annulus is practically equal to the tubing temperature.

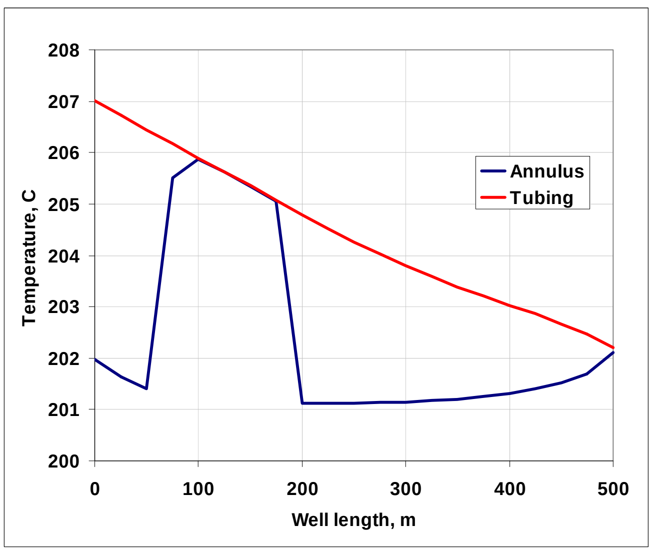

Fig. 4. Temperature profiles in injection well for injection through heel and toe

Obtained results for temperature distribution along the annulus section of the injection well were compared with the DTS data recorded in annulus of the injection well located in the Athabasca tar sands field (**Fig.5**). This plot shows that temperature in the annulus starts to grow near the outlet of the tubing in spite of the friction pressure drop. It means that steam becomes superheated close to the outlet of the tubing. It can not be explained by heat transfer from the tubing as near the outlet of the tubing its temperature is close to the annulus flow temperature. This effect can be explained by the rapid outflow of liquid water from the annulus to the reservoir. This water drains down to the producer due to the gravity. Only in this case heat flow from the tubing can provide notable heating of dry vapour close to the tubing outlet. This effect cannot be modeled if it is assumed that equal fraction of each phase goes out from the wellbore to the formation..

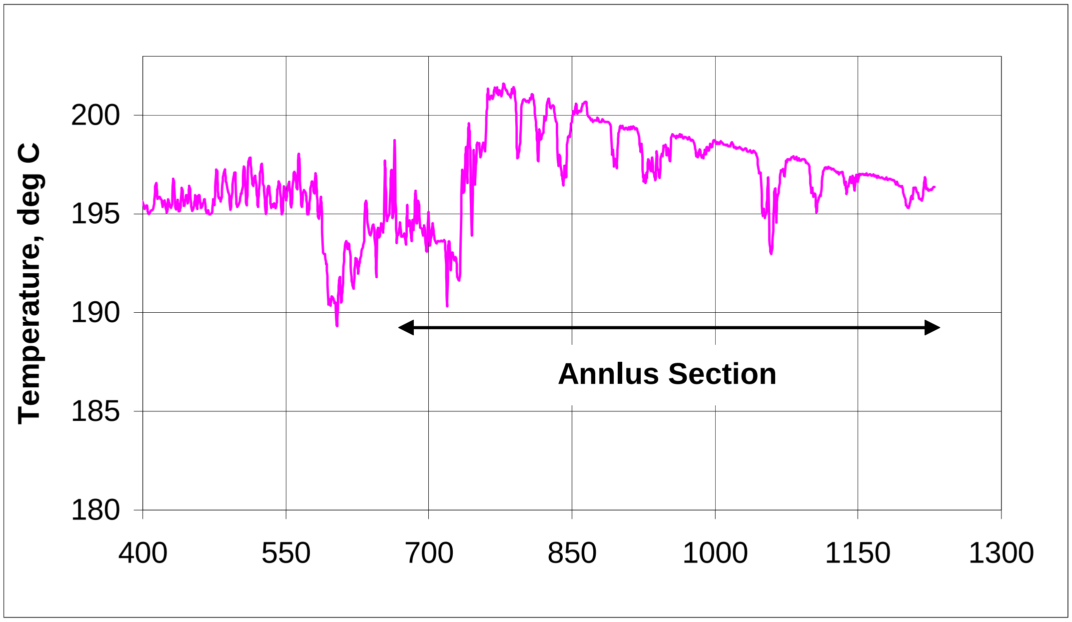

Fig. 5. SAGD injection well DTS data

Results of simulations using modified wellbore model are shown on **Figures 6-8.** The main problem for this modification of the model was the estimation of the influence of separated water and vapour outflow. Therefore the simple injection well model for steam injection at the heel only was considered.

Simulations were done for the following set of parameters: rate of the steam injection 100 - 500 *m3/day*, steam was injected into the reservoir at the heel of the well, steam quality 0.8, well length 500*m*, OD tubing 3.5″, ID casing 8.625″, OD casing 9.5″, wellbore wall roughness 0.001*m*. Reservoir has uniform permeability 5 Darcy, water relative permeability 0.8. Calculated pressure profiles are presented in the **Fig. 6**. Steam quality profile along the well is presented in **Fig.7**. Temperature profile is given in **Fig.8**.

The calculated parameters for the 100 *m3/day* steam injection: inlet vapour velocity is 5.35 *m/s*, water velocity 0.34 *m/s*. The flow-pattern is stratified-wavy. Initial entrainment fraction at the inlet is 0.0052.After the 10 meters the water phase disappears and flow becomes one-phase as presented on **Fig.7**.

The calculated parameters for the 200 *m3/day* steam injection: inlet the vapour velocity is 10.7 *m/s*, water velocity 0.69 *m/s*. The flow-pattern is stratified-wavy. Initial entrainment fraction at the inlet is 0.18. After the 19 meters the water disappears.

The calculated parameters for the 300 *m3/day* steam injection: inlet the vapour velocity is 16 *m/s*, water velocity 1.04 *m/s*. The flow-pattern is stratified-wavy. Initial entrainment fraction at the inlet is 0.32. After the 29 meters the water disappears.

The calculated parameters for the 400 *m3/day* steam injection: inlet the vapour velocity is 21.4 *m/s*, water velocity 1.4 *m/s*. The flow-pattern is stratified-wavy. Initial entrainment fraction at the inlet is 0.44. After the 38 meter the water disappears.

The calculated parameters for the 500 *m3/day* steam injection: inlet core velocity is 26.7 *m/s*, film velocity 0.77 *m/s*. The flow-pattern is annular dispersed. Initial entrainment fraction at the inlet is 0.53. After the 14 meters the flow regime change to the stratified-wavy with water velocity 1.42 m/s, vapour velocity 25.7 *m/s*. After 47 *m* the water phase disappears.

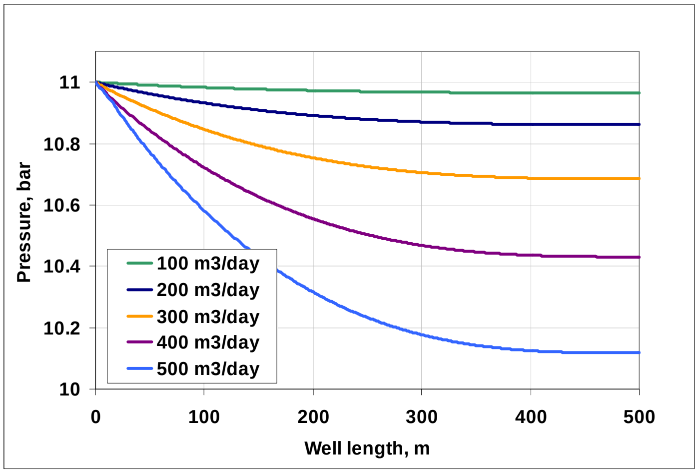

Fig. 6. Pressure distribution for injection at heel

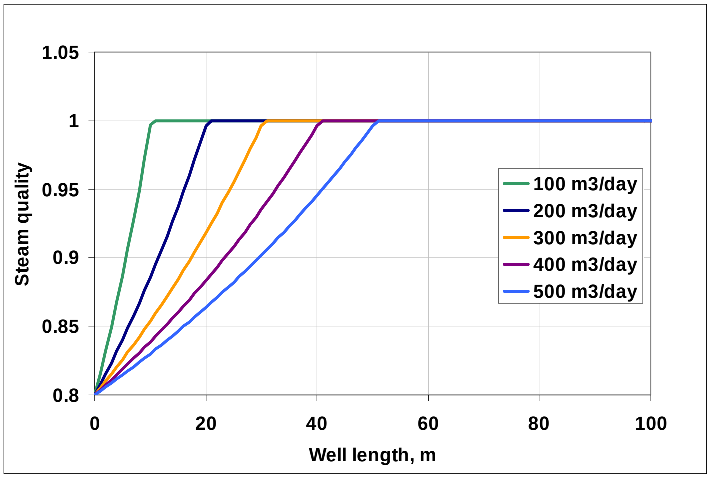

Fig. 7 Steam quality distribution for injection injection at heel

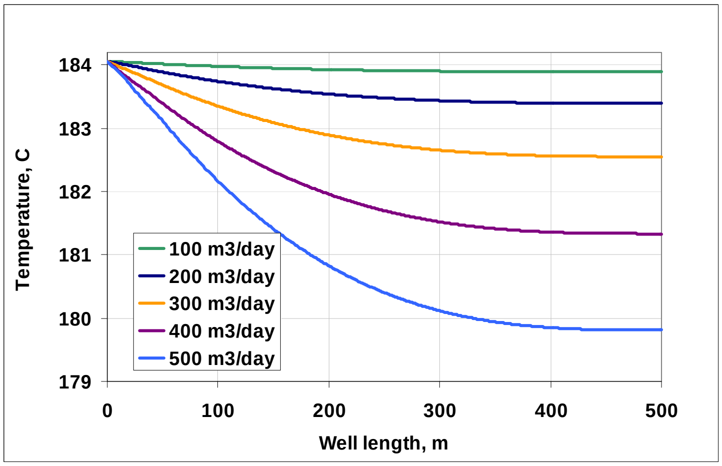

Fig. 8 Temperature in injection well for injection at heel

Presented results show that the two main flow regimes took place near the inlet of injection well: stratified-wavy and annular. If initial the flow pattern is Annular with flow rate decreasing it changes to stratified-wavy.

Test cases show that at the distance 10-50 *m* from the inlet (depending on flow rate value) liquid water phase drainage from the annulus down to the reservoir due to the gravity and in the main part of the annulus we have dry overheated vapour. Temperature decrease in this well section is caused by the dry vapour adiabatic expansion.

Conclusions

Approach for fast SAGD process simulation, alternative to the 3D model was considered. This approach is based on application of the 1D injection well model and a set of N 2D cross-sectional SAGD models of steam, water and bitumen flow in layers perpendicular to the injection well and connected only through injection and production boreholes. Injection well model provides steam pressure/temperature profiles that are boundary conditions for a set of N 2D cross-sectional SAGD models. In turn, these models calculate profile of steam injection rate which is an input data for injection well model. As the result, the steam chamber characteristics and production well inflow are obtained. Developed 1D + N*2D SAGD show significant decrease in computational time in comparison with 3D SAGD models. 2D model for each layer are independent and can be run separately on cluster node. Number of 2D layers is a model input parameter. Computational time for one 2D model doesn't exceed 3 hours, computational time for 1D model is several minutes. Developed approach can be used for real SAGD field tasks including DTS data interpretation, production period optimization even in cases of heterogeneous reservoir.

It was shown that the injector well model based on assumption of joint flow of the water and vapor along the injector, and hence equal fraction of each phase (vapour and water) goes out from the annulus flow can be violated for some cases and model are not able to reproduce qualitatively the field data recorded by DTS. To overcome this problem the modification of the 1D injection well model with ability to simulate independent injection of the vapour phase into the steam chamber and water drainage down to the reservoir due to the gravity was developed.

Test cases show that at the distance 10-50 *m* from the inlet (depending on flow rate value) liquid water drainage from the annulus and in the main part of the annulus we have dry overheated vapour. In this case the friction pressure losses are determined using the simple formula for one phase flow.

Acknowledgments

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Nomenclature

A - *well crossection area*

f_E - *water fraction in droplet phase*

g - *gravitational acceleration*

k - *reservoir permeability*

k_w - *water relative permeability*

m_w - *flow rate of water flowing at the annulus bottom*

p – *pressure*

q_v – *vapour volumetric flow rate*

r_w - *well radius*

Δr- *width of seepage zone*

S -*flow perimeter*

v_{sv} - *vapour superficial velocity*

v_v - *vapour velocity*

μ_v – *vapour viscosity*

μ_w- *water viscosity at the reservoir temperature*

ξ_{FV} – *vapour friction factor*

ρ_v – *vapour density*

ρ_w - *water density*

σ – *water surface tension*

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