Full Length Article

Wellbore modeling for hybrid steam-solvent processes

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ABSTRACT

The addition of hydrocarbon solvents to the cyclic steam stimulation (CSS) or steam assisted gravity drainage (SAGD) processes has recently gained significant interest from the petroleum industry. In these processes, a proper selection of solvent is critical: injected solvent must be in the vapor phase at the injection point in order to propagate inside the steam chamber and condense at the steam/oil interface to effectively reduce oil viscosity. Therefore, the wellbore have to deliver vaporized solvent near its dew point at perforation intervals.

This work provides a detailed numerical formulation to predict steam and solvent qualities, temperature, and pressure profiles along the wellbore. Four phases were considered: hydrocarbon liquid and vapor phases, and aqueous liquid and vapor phases. The mass, energy and momentum balance equations are integrated with drift-flux model and discretized over the wellbore domain. Unknowns and governing equations are divided into the sets of primary and secondary equation and unknowns are solved sequentially. The model was compared against previously published models and field data. The data from two steam injection wells and two gas condensate production wells were used for validation. Also, case studies are presented to investigate the temperature and condensation behavior of the solvent-steam mixture.

The use of this model will assist the industry in proper wellbore design and the engineering of injection constraints in hybrid steam/solvent injection processes.

1. Introduction

In hybrid steam-solvent injection processes, both steam and solvent are co-injected in different proportions to reduce the viscosity of heavy oil or bitumen by heating and dilution, which improves oil displacement, drainage, and consequently the production rate. To have a proper solvent placement at the edge of the steam chamber, the injected solvent must be in the vapor phase at the injection point in order to properly propagate inside the steam chamber. Also, the solvent needs to condense at the steam/oil interface to reduce oil viscosity effectively. Therefore, wellbore must deliver a vaporized solvent near its dew point to the perforation intervals. Predicting steam and solvent thermodynamic properties in the flowing wellbore can significantly improve the design of surface facilities, wellbore system, solvent selection, and injection constraints. When the solvent-steam mixture is injected into the wellbore, both the pressure and temperature of the injected fluid vary by time and depth. Heat exchange between the wellbore system and the lower temperature formation, change

in hydrostatic pressure, phase velocities, and friction determines the steam and solvent thermodynamic conditions at the sand face.

Thermal modeling of wellbore heat transmission dates back to the late 1950's, where Lesem et al. [1] *presented* an analytical model for calculation of bottom hole temperature in gas production wells. Similarly, Moss et al. [2] developed the solution to a system of equations predicting the temperature profile of the injected water in the wellbore based on some simplifying assumptions. Later on, Ramey [3] improved upon the previous studies on wellbore heat transmission. He developed an approximate solution considering a steady-state, non-compressible, and single phase fluid flow in the wellbore In his model, kinetic energy, and frictional pressure drop were neglected. To define an overall heat transfer coefficient, Ramey considered steady-state axial heat convection through the wellbore with transient heat conduction into the formation. This coefficient was assumed to be constant along the wellbore. Later, Willhite [4] improved the accuracy of the Ramey's model by considering depth-dependence overall heat transfer coefficient. Satter [5] extended the Ramey model to wet steam flow in the wellbore. In all of these models, it is assumed that there are no pressure changes with respect to the depth and only temperature and steam quality varies along the wellbore.

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Nomenclature

A	tubing inside area (ft^2)
A_p	area occupied by phase p (ft^2)
C_0	distribution coefficient (dimensionless)
d_t	inner diameter of tubing (ft)
f	friction factor (dimensionless)
$f_{c,p}$	fugacity of component c in the phase p (psia)
$f(t_D)$	time conduction function (dimensionless)
g	acceleration due to gravity (32.17 ft/s^2)
g_c	unit conversion factor (32.17 ft-lbm/lbf-s^2)
h_f	film coefficient of heat transfer between fluid inside pipe and the pipe (Btu/ft^2-day-°F)
h_{Pi}	coefficient of heat transfer across any deposits of scale or dirt at the inside wall of the pipe (Btu/ft^2-day-°F)
h_{Po}	coefficient of heat transfer across the contact between pipe and insulation (Btu/ft^2-day-°F)
$h_{rc,an}$	radiation and convection coefficient of heat transfer in the annulus (Btu/ft^2-day-°F)
$\dot{H}_p$	enthalpy rate per bulk volume of phase p (Btu/day-ft^3)
h_p	enthalpies per unit mass of phase p (Btu/lbm)
J_c	unit conversion factor (778 ft-lbf/Btu)
nc	number of hydrocarbon components
$\dot{n}_{c,p}$	molar flux of component c in phase p (lb-mole/day)
$\dot{n}_{h,c}$	total hydrocarbon molar flux in phase p (lb-mole/day)
$\dot{n}_{h,p}$	in-situ molar flux of hydrocarbon in phase p (lb-mole/day)
N_G	total number of wellbore grid blocks
$\dot{n}_{h,p}$	in-situ molar flux of hydrocarbon in phase p (lb-mole/day)
$\dot{q}_p$	molar rate per unit volume of phase p (ft/day)
$\dot{Q}_f$	heat loss rate per unit length (Btu/day-ft)
r_{Ea}	radius of altered zone in the formation near the wellbore (ft)
r_{ci}	inner radius of casing (ft)
r_{co}	outer radius of casing (ft)
r_i	inner radius of tubing (ft)
r_{ins}	insulation radius (ft)
r_o	outer radius of tubing (ft)
r_w	well radius (ft)
R	universal gas constant (psi-ft^3/(lbmol-°R))
R_h	average thermal resistance per unit length (ft-day-°F/Btu)
t	time (days)
T_a	ambient temperature (°F)
T_b	bulk temperature of the fluid flowing in the tubing (°F)
T_{EA}	surrounding formation temperature (°F)
t_D	dimensionless time (dimensionless)
u_p	internal energy per unit mass of phase p (Btu/lbm)
P_{hc}	hydrocarbon partial pressure (psia)
P_w	water partial pressure (psia)
P	wellbore Pressure (psia)
$z_{w,g}$	compressibility factor of steam (dimensionless)

$z_{h,g}$	compressibility factor of hydrocarbon (dimensionless)
T	temperature (°F)
v_d	drift velocity of gas in liquid (water) (ft/day)
v_l	liquid (water and oil) velocity (ft/s)
v_m	average velocity of the mixture (ft/day)
v_p	superficial velocity of phase p (ft/day)
$v_{p,i}$	velocity of phase p at the grid block i (ft/day)
v_{sg}	gas phase superficial velocity (ft/day)
v_{sl}	liquid phase superficial velocity (ft/day)
$v_{sh,g}$	hydrocarbon superficial velocity in gas phase (ft/day)
$v_{sh,p}$	superficial velocity of hydrocarbon in phase p (ft/day)
$v_{sw,g}$	superficial velocity of water in gas phase (ft/day)
$v_{sw,p}$	superficial velocity of water in phase p (ft/day)
$x_{c,p}$	hydrocarbon component mole fractions in the phase p (fraction)
$x_{w,g}$	mole fractions of water in gas phase (fraction)
$x_{w,w}$	mole fractions of water in water phase (fraction)
z	elevation or depth (ft)
z_c	overall hydrocarbon component mole fraction (fraction)

Greek letters

α_p	in-situ volume fraction of phase p (dimensionless)
α_l	in-situ volume fraction of liquid phase $(\alpha_o + \alpha_w)$ (dimensionless)
α_E	thermal diffusivity of the earth (ft^2/day)
θ	inclination of segment from horizon (radian)
λ_{ins}	thermal conductivity of insulation (Btu/ft-day-°F)
λ_P	thermal conductivity of pipe (Btu/ft-day-°F)
λ_{cem}	thermal conductivity of cement (Btu/ft-day-°F)
λ_E	thermal conductivity of earth (Btu/ft-day-°F)
λ_{Ea}	thermal conductivity of altered earth zone (Btu/ft-day-°F)
ρ	density (lb/ft^3)
$\dot{\varphi}_c$	molar flux of component c at the wellhead (lb-mole/day)
$\dot{\varphi}_{hc}$	total hydrocarbon Molar flux at the wellhead (lb-mole/day)

Acronyms

MSCF	thousand standard cubic feet
STB	stock tank oil barrel

Superscripts

c	component
g	gas
i	grid block index
m	mixture
o	oil
p	phase
w	water

Holst et al. [6] added the effects of frictional pressure drop in heat loss calculations to the model.

In 1969, Earlougher [7] employed two–phase flow pressure drop calculations (Hagedorn and Brown [8]) to account for the pressure changes for wet steam injection. In his calculations, slippage between phases was neglected. In 1981, Fontanilla and Aziz [9] presented a method to calculate steam quality and steam pressure by considering two-phase flow and slippage using the Beggs and Brill correlation [10]. Later, Farouq Ali [11,12] and Wooley [13] developed numerical models which were able to integrate a wider range of formation and well complexities. These models con-

sider directional heat transmission in the formation with different well operational constraints. Their studies showed the importance of vapor phase slippage and flow pattern for predicting the temperature, pressure drop, and steam quality during the downward wet steam injection. Sagar et al. [14] calculated the temperature of saturated steam in deviated wells using modified Ramey model. They also included the Joule-Thomson effect due to pressure drops in the tubing.

Stone et al. [15,16] extended the wellbore thermal models to integrate both the wellbore and the reservoir. In their formulation, fluid flow through the reservoir was approximated with