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Inference of near-borehole permeability and water saturation from time-lapse oil-water production logs

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A B S T R A C T

The conventional interpretation of production logs (PL) acquired in time-lapse mode helps petrophysicists to detect the advancement of fluid contacts in the near-borehole region. Without inclusion of a dynamic reservoir model, conventional time-lapse interpretation remains limited to describing time variations of fluid inflow rates produced from or injected into fluid-producing rock formations. However, proper reservoir management requires quantifying depth variations of near-borehole properties (e.g., formation damage and fluid saturation) over time to construct reliable field-scale reservoir models.

This paper develops a new borehole-formation fluid flow model capable of simulating oil-water production measurements acquired from vertical and deviated boreholes. We implement an iteratively coupling flow algorithm to explicitly interface a borehole fluid flow model to a reservoir multiphase flow simulator. The specific application considered in this study invokes the coupled borehole-formation fluid flow model to estimate near-borehole permeability and water saturation from time-lapse oil-water production measurements.

Borehole fluid flow simulation is based on an isothermal two-fluid formulation that applies separate mass and momentum conservation equations to the oil and water phases. When solving momentum conservation equations, we compute interfacial drag and buoyant forces based on the assumption of spherical oil or water droplets with negligible interfacial mass transfer. Subsequently, the spatial distribution of droplet diameter associated with the discontinuous fluid phase is dynamically modified to accurately account for variations of slip velocity across fluid-producing layers. Linkage of the borehole and formation fluid flow models is next carried out by introducing additional source terms into the borehole mass conservation equations.

In a synthetic reservoir model supported by an infinite-acting aquifer, the coupled flow algorithm integrates production logs acquired in time-lapse mode to construct a near-borehole reservoir model that describes depth variations of skin factor over the elapsed time. Feasibility studies show that the estimated petrophysical properties can be adversely influenced by the large volume of investigation associated with PL measurements. Moreover, undetectable fluid production across low-permeability layers decreases the sensitivity of production logs to layer incremental flow rate, thus increasing estimation uncertainty. Despite these limitations, estimated fluid saturation and permeability across high-permeability layers are within 15% and 20% of the corresponding actual values, respectively. The developed interpretation algorithm additionally integrates well logs and production logs acquired in an oil-water field example to construct a PL-calibrated near-borehole reservoir model. Results enable (a) the differentiation of low-permeability layers from highly-damaged formations, (b) the identification of layers accountable for high water production, and (c) the quantification of the added value of remedial workover operations to isolate water-producing layers. In addition, the coupled model is used to study sensitivity of production logs to near-borehole petrophysical properties. We show that production logs are mainly sensitive to formations' absolute and relative permeabilities, water saturation, and pressure.

1. Introduction

Fluid withdrawal from a hydrocarbon reservoir usually starts under single-phase conditions. However, over time, fluid movement in the reservoir gives rise to production of multiphase fluid. In oil-water flowing systems, aquifer encroachment, or advancement of the water from injector wells incrementally change the near-borehole water saturation. The alteration of near-borehole water saturation, accompanied by near-borehole formation damage, considerably decreases the inflow performance of the borehole. An established method to quantify

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Acronyms

1D	one dimensional
3D	three dimensional
MD	measured depth
PL	production logs
PLTs	production logging tools
PVT	pressure volume temperature

List of symbols

A_c	acentric factor
a_{ip}	interfacial area concentration, 1/ft
$\hat{a}_{ip}$	dimensionless interfacial area concentration
C_1	cost function for permeability estimation, fraction
C_2	cost function for saturation estimation, fraction
C_3	cost function for the third minimization loop, fraction
C_D	drag coefficient
C_o	oil-phase isothermal compressibility, μsip
C_w	water-phase isothermal compressibility, μsip
D	borehole diameter, in
D_h	pipe hydraulic diameter, in
$\boldsymbol{e}_1$	data residuals for permeability estimation, fraction
$\boldsymbol{e}_2$	data residuals for saturation estimation, fraction
$\boldsymbol{e}_3$	data residuals for the third minimization loop, fraction
F_{Dp}	interfacial drag forces per unit volume, lb_f/ft^3
f_p	fluid-phase wall friction factor
g	gravitational acceleration, ft/s^2
$\boldsymbol{K}$	unknown layer permeability vector, mD
K	permeability, mD
K_h	horizontal permeability, mD
K_v	vertical permeability, mD
K_{ff}	far-field permeability, mD
K_{nw}	near-borehole permeability, mD
k_r	relative permeability, fraction
K^{ref}	reference permeability, mD
k_{ro}	oil-phase end-point relative permeability, fraction
L	Laplace length, in
$\hat{L}$	dimensionless Laplace length
N_{mp}	number of borehole pressure measurements
N_{wp}	number of borehole depth windows to estimate permeability
N_{ws}	number of borehole depth windows to estimate water saturation
P	borehole pressure, psia
P^m	measured borehole pressure, psia
P^s	simulated borehole pressure, psia
P_c	capillary pressure, psi
P_c^{ref}	reference capillary pressure, psi
P_{crit}	critical pressure, atm
R_d	droplet diameter, in
r_s	radius of near-borehole region, in
r_w	borehole radius, in
S	total skin factor
$\boldsymbol{S_p}$	vector of fluid-phase saturations, fraction
S_p	fluid-phase saturation, fraction
S_v^m	measured slope of mixture velocity, 1/s
S_v^s	simulated slope of mixture velocity, 1/s
S_α^m	measured slope of oil holdup, 1/ft
S_α^s	simulated slope of oil holdup, 1/ft
S_w	water-phase saturation, fraction
S_{wir}	irreducible water saturation, fraction
t	time, s
T_{crit}	critical temperature, ^oK
V_{crit}	critical volume, $m^3/kgmol$
V_m	mixture velocity, ft/s
V_o	oil-phase velocity, ft/s
V_p	fluid-phase velocity, ft/s
V_w	water-phase velocity, ft/s
$\boldsymbol{W}_1$	data-weighting matrix for permeability estimation
$\boldsymbol{W}_2$	data-weighting matrix for saturation estimation
z	borehole axial position, ft
α_o	oil-phase volume fraction, fraction
α_p	fluid-phase volume fraction, fraction
γ	rescaling coefficient of permeability field
Γ_p^{for}	mass influx from formation per unit volume, $lb_m/day\ /ft^3$
ε_p	energy dissipation rate per unit mass, ft^2/s^3
$\hat{\varepsilon}_p$	dimensionless energy dissipation rate per unit mass
θ	borehole deviation angle, degree
λ	regularization multiplier, $1/mD^2$
μ_p	fluid-phase viscosity, cp
μ_o	oil-phase viscosity, cp
μ_w	water-phase viscosity, cp
ρ_p	fluid-phase density, g/cc
ρ_o	oil-phase density, g/cc
ρ_w	water-phase density, g/cc
ϕ	porosity, pu
ϕ^{ref}	reference porosity, pu

borehole productivity is the analysis of surface measurements that estimates an average skin factor associated with the fluid-producing rock formations. Despite its reliability, interpretation of surface production measurements does not quantify depth variations of skin factor. To circumvent this limitation, downhole production logs are acquired and interpreted to identify highly-damaged rock formations and layers accountable for high water production. The latter method enables production engineers to design and evaluate adequate remedial workover operations (e.g., water shut-off) to enhance borehole inflow performance.

Production measurements acquired in time-lapse mode provide valuable information regarding time variations of near-borehole petrophysical properties. Quantifying those variations requires a dynamic borehole-formation fluid flow model that simulates and compares the spatial distribution of borehole production measurements acquired at various time lapses. This paper describes the development and application of a borehole two-phase fluid flow model hydraulically connected to an in-house reservoir simulator for reliable simulation and interpretation of production measurements. The novelty of this work is the new ability to constrain the reconstruction of production logs to the physics of fluid flow in reservoir rocks when estimating relevant petrophysical properties of rock formations. This modeling approach enables one to estimate a near-borehole reservoir model that honors borehole production logs. Under single-phase flowing conditions, as an example, one could estimate formations' permeability to reconstruct borehole fluid velocity and pressure (Frooqnia et al., 2011).

A review of documented technical contributions indicates that borehole fluid flow modeling is commonly performed based on the following approaches: (a) homogeneous models, (b) drift-flux models, and (c) two-fluid models. Homogeneous models replace multiphase fluid with a single-phase fluid whose properties are represented by effective fluid mixture properties (Sharma et al., 1996; Holmes et al., 1998). Applying single-phase fluid flow equations only to the fluid mixture significantly simplifies the numerical implementation of homogeneous models. However, in the case of large discrepancies between fluid-phase properties (e.g., density), fluid homogenization gives rise to inaccurately simulated properties of individual fluid phases. As a modification to homogeneous models, drift-flux models