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Transient Pressure Analysis of Gas Wells in Unconventional Reservoirs

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Abstract

Unconventional gas reservoirs have shown the potential to be the next world primary energy resource and have received a lot of attention in the past few years in the world. Even with the significant progress that has been made world-wide towards commercial development of natural gas from these unconventional resources, understandings or modeling tools of gas flow in these extremely low-permeability reservoirs are far behind the industry needs. In this paper, we present a numerical model for modeling transient gas flow behavior and its application to well testing analysis in unconventional gas reservoirs. Specifically, the numerical model simulates realistic reservoir gas flow processes, including Klinkenberg effect, non-Darcy flow behavior, and adsorption under reservoir flow condition, in addition to well bestorage and skin effect. We use the numerical model to generate various type-curves for nonlinear gas flow for well testing analysis in unconventional porous and fractured reservoirs and demonstrate the conventional well testing analysis approach may still be applicable for analysis of unconventional gas reservoirs.

Introduction

This paper presents our continual effort in developing simulation models and tools for quantitative studies of unconventional gas reservoirs (Wu and Fackahroenphol, 2011; Wu et al. 2012). Specifically, we explore the possibility of performing well testing analysis using a numerical modeling approach. The numerical model simulates realistic unconventional reservoir gas flow processes, including Klinkenberg effect, non-Darcy flow behavior, and adsorption under single-phase and two phase flow condition. In addition, we also include wellbore storage and skin effect in gas production wells in the pressure transient analysis. We use the numerical model to generate various type-curves for nonlinear gas flow for well testing analysis in unconventional porous and fractured reservoirs.

Even though significant progresses has been made towards commercial development of gas and oil from these unconventional resources (Denny, 2008; Bybee, 2008; King, 2010) in the past few years, characterization of gas flow in unconventional gas reservoirs, such as flow in shale gas or tight gas formations, remain a challenge. This is primarily because there exist so many co-existing nonlinear processes, Klinkenberg effect (Klinkenberg, 1941), nonlinear adsorption/desorption (Silin and Kneafsey, 2011), strong interactions between fluid (gas and water) molecules and solid materials within tiny pores as well as severe heterogeneity on any scales of unconventional formations, such as various scaled fractures. As a result, gas flow through unconventional reservoirs is more nonlinear, compared to that in conventional gas reservoirs, even under single-phase flow condition. Therefore well testing analysis for gas wells in unconventional gas reservoirs cannot rely entirely on traditional, analytical based analysis approaches and may have to be carried out by a numerical approach in general.

This paper describes application of a two-phase flow model for simulating both gas and water flow in shale gas and tight gas reservoirs (Wu et al. 2012), in which single-phase gas flow is handled as a special case and used for simulation of transient flow and well testing analysis in this work. The unconventional gas flow model incorporates many of the important nonlinear gas physical processes in unconventional reservoirs, such as non-Darcy flow, Klinkenberg effect, and nonlinear sorption. The main outcome of the work is to provide a series of type curves for transient pressure responses in gas production wells for reservoir engineers to use in well testing analysis in unconventional reservoirs. The results can be used for quantitative studies of transient gas flow behavior and effects of non-linear flow or gas production processes.

Mathematical Model and Numerical Formulation

The mathematical model, on which this work is based, has been presented in several SPE papers of ours (e.g., Wu and Fackahroenphol, 2011; Wu et al. 2012). Here we present a brief description of the flow model, as follows, to make this paper a standalone article.

Flow Model: Two phase (gas and water) flow, in an isothermal system containing two mass components of gas and water and subject to sorption, is described in an arbitrary flow region of a porous or fractured domain for flow of phase β ($\beta = g$ for gas and $\beta = w$ for water),

$$\frac{\partial}{\partial t} (\phi S_{\beta} \rho_{\beta} + m_{k}) = -\nabla \bullet (\rho_{\beta} \mathbf{v}_{\beta}) + q_{\beta}$$
⁽¹⁾

where ρ_{β} is the density of fluid β ; \mathbf{v}_{β} is the volumetric velocity vector of fluid β ; \mathbf{S}_{β} is the saturation of fluid β ; ϕ is the effective porosity of formation; t is time; \mathbf{m}_{k} is the adsorption or desorption term for gas component (k=g only) per unit volume of formation; and \mathbf{q}_{β} is the sink/source term of phase (component) β per unit volume of formation.

The flow velocity \mathbf{v}_{β} in Eq. (1) will be evaluated (1) using the Darcy's law with Klinkenberg effects (for gas flow); (2)

using the nonlinear flow models to describe non-Darcy flow behavior (e.g., Wu, 2002); and (3) flow condition where flow may not occur until the pressure or potential gradient reaches a certain threshold value (Wu and Pruess, 1998).

In Eq. (1), gas adsorption terms are handled using the Langmuir isotherm (Silin and Kneafsey, 2011). As observed, adsorbed mass of gas can provide significant fraction of gas reserves and recovery from gas shales formations and is included in the flow model using measured nonlinear isotherms from laboratory or field studies.

Numerical Model: The numerical approach of this work follows the general methodology for reservoir simulation, i.e., using numerical approaches to simulate gas and water flow, following three steps: (1) spatial discretization of mass conservation equations (Eq. 1); (2) time discretization; and (3) iterative approaches to solve the resulting nonlinear, discrete algebraic equations.

Discrete Equations: The gas and water component mass-balance Equations (Eq.1) are discretized in space using a control-volume or integrated finite difference concept (Pruess et at. 1999; Wu, 2004). The control-volume approach provides a general spatial discretization scheme that can represent a one-, two- or three-dimensional domain using a set of discrete meshes. Each mesh has a certain control volume for a proper averaging or interpolation of flow and transport properties or thermodynamic variables. Time discretization is carried out using a backward, first-order, fully implicit finite-difference scheme. The discrete nonlinear equations for components of gas and water at gridblock or node i can be written in a general form:

$$\begin{cases} M_{i}^{k,n+1} - R_{i}^{k,n+1}\Delta t - M_{i}^{k,n} \\ \end{cases} \frac{V_{i}}{\Delta t} = \sum_{j \in \eta_{i}} flow_{ij}^{k,n+1} + Q_{i}^{k,n+1} \\ (k = 1, 2) \text{ and } (i=1, 2, 3, ..., N) \end{cases}$$
(2)

where superscript k serves also as an equation index for two mass components with k = 1 (gas) and 2 (water); superscript n denotes the previous time level, with n+1 the current time level to be solved; subscript i refers to the index of gridblock or node i, with N being the total number of nodes in the grid; Δt is time step size; V_i is the volume of node i; η_i contains the set of direct neighboring nodes (j) of node i; M_i^k and R_i^k are the accumulation and reaction (absorption or desorption) terms,

respectively, at node i; $flow_{ij}^k$ and Q_i^k are the component mass "flow" term between nodes i and j, and sink/source term at node i for component k, respectively. The "flow" is defined below.

The "flow" terms in Eq. (2) are mass fluxes by advective processes and is described, for example, by a discrete version of Darcy's law with a two-point flux approximation or integrated finite difference scheme, i.e., the mass flux of fluid phase β along the connection is given by

$$flow_{\beta,ij} = \lambda_{\beta,ij+1/2} \gamma_{ij} \left(\Phi_{\beta j} - \Phi_{\beta i} \right)$$
(3)

where $\lambda_{\beta,i j+1/2}$ is the mobility term to phase β , defined as

$$\lambda_{\beta,i\,j+1/2} = \left(\frac{\rho_{\beta}k_{r\beta}}{\mu_{\beta}}\right)_{ij+1/2} \tag{4}$$

In Eq. (3), γ_{ij} is transmissibility, e.g., defined for the integrated finite approach (Pruess et al. 1999; Wu, 2004). The flow potential term in Eq. (3) is defined as,

$$\Phi_{\beta i} = P_{\beta i} - \rho_{\beta, i j + 1/2} g Z_i$$
(6)

where Z_i is the depth to the center of block i from a reference datum.

In addition to multiphase flow Darcy's law, our model formulation also includes (1) Klinkenberg effect on gas flow permeability; (2) "Non-Newtonian" flow, i.e., gas and/or water flow is subject to a threshold potential gradient; (3) Non-Darcy flow; and (4) generalized modeling approaches for handling various type fractures, from hydraulic fractures and various scaled natural frcatures, using continiuum, discrete, or a hybrid modeling conceptual models.

Non-Darcy's Flow: Non-Darcy flow may occur between and among the continua in tight or shale gas reservoirs. The flow velocity, \mathbf{v}_{β} , for non-Darcy flow of each fluid may be described using the multiphase extension of the *Forchheimer* equation (e.g., Wu, 2002),

$$-\left(\nabla \Phi_{\beta}\right) = \frac{\mu_{\beta}}{k_{r\beta}} k \mathbf{v}_{\beta} + \beta_{\beta} \rho_{\beta} \mathbf{v}_{\beta} |\mathbf{v}_{\beta}|$$
(7)

where β_{β} is the effective non-Darcy flow coefficient with a unit m⁻¹ for fluid β under multiphase flow conditions. Under the non-Darcy flow condition of Eq. (7), the flow term (flow $_{\beta,ij}$) in Eq. (2) along the connection (i, j), between elements i and j, is numerically defined as (Wu, 2002),

$$flow_{\beta,ij} = \frac{A_{ij}}{2(k\beta_{\beta})_{j+1/2}} \left\{ -\frac{1}{\lambda_{\beta}} + \left[\left(\frac{1}{\lambda_{\beta}} \right)^2 - \overline{\gamma}_{ij} \left(\Phi_{\beta j} - \Phi_{\beta i} \right) \right]^{1/2} \right\}$$
(8)

in which the non-Darcy flow transmissivity is defined as,

$$-\frac{\gamma_{ij}}{\rho_{ij}} = \frac{4\left(k^2 \rho_\beta \beta_\beta\right)_{ij+1/2}}{D_i + D_j}$$
(9)

Adsorption: Natural gas or methane molecules are adsorbed mainly to the carbon-rich components, i.e. kerogen (Silin and Kneafsey, 2011. In our model, the mass of adsorbed gas in formation volume V is described using the Langmuir isotherm (Langmuir, 1916; Wu et al. 2011),

and

$$m_{g}(V) = \rho_{K}\rho_{g}f(P)\overline{S_{k}}V$$
⁽¹⁰⁾

$$f(P) = \frac{V_L P_g}{P_g + P_L}$$
(11)

In Eqs. (10) and (11), ρ_K is kerogen density, ρ_g is gas density at standard condition, $\overline{S_k}$ is the average volume relative of kerogen in bulk volume, $m_g(V)$ is the adsorbed gas mass in bulk formation volume V. In Eq. (7), f(P) is the adsorption isotherm function, V_L is the Langmuir volume (the maximum adsorption capacity at a given temperature), and P_L is the Langmuir pressure (the pressure at which the adsorbed gas content is equal to $\frac{V_L}{2}$).

Klinkenberg Effect: Klinkenberg effect (Klinkenberg, 1941) may be too significant to be ignored when modeling gas flow in low-permeability formation and/or low pressure reservoirs (Wu et al. 1998). Klinkenberg effect is expected to be larger in unconventional reservoirs, because of small size pores and low permeability associated. Under such flow conditions, absolute permeability for the gas phase is written as a function of gas pressure as,

$$k_{g} = k_{\infty} \left(1 + \frac{b}{P_{g}} \right)$$
(12)

where k_{∞} is constant, absolute gas-phase permeability under very large gas-phase pressure (where the Klinkenberg effect is minimized); and b is the Klinkenberg factor, depending on the pore structure of the medium and formation temperature.

Numerical Solution: In our model, we use the fully implicit scheme to solve the discrete nonlinear Eq. (2) with a Newton iteration method. Let us write the discrete nonlinear Eq. (2) in a residual form as,

$$R_{i}^{k,n+1} = \left\{ M_{i}^{k,n+1} + \Delta t R_{i}^{k,n+1} - M_{i}^{k,n} \right\} \frac{V_{i}}{\Delta t} - \sum_{j \in \eta_{i}} flow_{ij}^{k,n+1} - Q_{i}^{k,n+1} = 0$$
(13)
(k = 1, 2; i = 1, 2, 3, ..., N).

Eq. (13) defines a set of $2 \times N$ coupled nonlinear equations that need to be solved for the balance equation of the two mass components, respectively, which are solved using the Newton iteration.

Wellbore Storage Effect: Wellbore storage is afterflow of fluids into the wellbore after the well is shut-in at the wellhead. During the early flowing time, reservoir responses are often masked or distorted by wellbore storage effect. During that short time of wellbore store (buildup) or unload (drawdown) fluids, the transient pressure response is not the true reservoir response to be analyzed for formation properties. The duration of wellbore storage effect is primarily dependent on three factors: the wellbore volume, the formation permeability and the fluid compressibility. The wellbore storage coefficient (C) may be defined as the ability of the wellbore to store or unload fluid per unit change in pressure. In single-phase fluid flow the wellbore storage coefficient (C, m³/Pa) may be defined as

$$C = V_{wb} c_{wb} \tag{14}$$

where V_{bw} is the volume of the wellbore in m³ and c_{wb} is the compressibility of the wellbore fluid in Pa⁻¹. In our numerical simulation, wellbore storage effect is incorporated by computing an equivalent element (gridblock) volume, $V_{wb-element}$, for a given value of C and c_{wb} (Al-Otaibi and Wu, 2010), as follows:

$$V_{wb-element} = C / (\phi c_{wb})$$
⁽¹⁵⁾

Then this computed volume, $V_{wb-element}$, is input to the numerical model as the volume of the well element or gridblock in the reservoir grid system to actually represent the wellbore and its storage effect.

Skin Effect: Treatment for a real well should consider skin effect because of (1) damage to the near-wellbore formation; (2) well only drilled through a portion of the reservoir formation thickness; (3) the reservoir interval may consist of a number of layers with different permeabilities; and (4) presence of fractures which intersect the well. Skin effect factor is a dimensionless parameter or additional dimensionless pressure drop, caused by the additional flow resistence. There are several ways to take into account the skin effect in the numerical model. For example, the skin zone (damaged or stimulated) can be numerically simulated by adjusting rock permeability in control volume elements near the wellbore. For a given value of skin factor (S), wellbore radius (r_w), and reservoir permeability (k); the permeability of the skin zone (k_s) is calculated using the following equation for any skin zone radius (r_s) for a fully penetrating vertical well (Hawkins, 1956; Al-Otaibi and Wu, 2010):

$$k_{s} = \frac{k}{\left(S/\ln\frac{r_{s}}{r_{w}}\right)+1}$$
(16)

Then, the calculated skin zone permeability (Eq. 10) is input to the numerical simulator as a rock property for the gridblock near the wellbore. Following the strategy above, it has shown the skin effect can be easily included in a numerical model using r-z type grids and excellent agreement was obtained between the numerical model and analytical solution for all values calculated for skin factors using this approach (Al-Otaibi and Wu, 2010).

Dimentionaless Variables: Pseudopressure (i.e., pseudo gas pressure, known as real gas potential) is used for the transient well testing analysis of unconventional gas wells. It is defined as,

$$m(P) = 2 \int_{P_0}^{P} \frac{P'}{\mu Z} dP'$$
(17)

where P_0 is referenc pressure; gas pressure-viscosity, gas pressure-Z factor, and gas pressure-gas density relationships, as used

in this study, are shown in Fig.1 and Fig. 2, in which the methane gas properties are used.



Fig.1 Pressure versus viscosity and pressure versus Z factor Relationship



Fig.2 Pressure verus density relationshp

Dimensionless pseudopressure, time and raduis are defined as:

$$m_{\rm D} = \frac{T_{\rm sc} kh}{Q_{\rm sc} TP_{\rm sc}} [m(P_{\rm i}) - m(P)]$$
⁽¹⁸⁾

$$t_{\rm D} = \frac{kt}{\phi(\mu c)_i r_{\rm W}^2} \tag{19}$$

$$r_{\rm D} = \frac{r}{r_{\rm w}} \tag{20}$$

where P is gas pressure, T is temperature, Q is well gas production rate, h is formation thickness, c is gas compressibility factor; subscript sc is for surface, standard condition, and subscript i denotes the initial reservoir condition.

Application

In this section, we demonstrate the use of the proposed mathematical model for modeling transient pressure responses during gas production from a shale gas reservoir. Here we present gas flow problems in a nonfractured well in a single porosity reservoir and a hydraulically fractured well in a double-porosity, naturally fractured reservoir as examples to illustrate gas flow and transient pressure behavior.

In the single porosity model, the reservoir has no hydraulic fractures or natural fractures. The system is homogeneous and low-permeable with a vertical, full penetrating well at the center. A radial grid is built for the simulation (Fig. 3). The basic parameter set for the simulation is summarized in Table 1. The fracture system we model includes a single vertical hydraulic fracture in the drainage volume of a well in a 3-D setting and the reservoir is natural fractured. In both systems, fluids include gas and water, but water is at residual or immobile, so it is a single-phase gas flow problem. To simulate transient gas flow of this system using our model, the hydraulic fracture is represented by a discrete fracture with finite conductivity and the naturally-fractured reservoir is described by the double-porosity model. Since the system is symmetric, only a quarter of this hydraulically fractured reservoir system is modeled (Fig. 4). The basic parameter set for the fracture well system for the simulation is summarized in Table 2.

	Parameter	Value	Unit
	matrix porosity	$\phi_m = 0.15$	
	formation temperature	T = 50	°C
	permeability	$k = 9.87 \times 10^{-17}$	m ²
	reservoir radius	$r_{e} = 3000$	m
	reservoir thickness	h = 10	m
	well radius	$r_{w} = 0.1$	m
	initial reservoir pressure	$P_i = 2.07 \times 10^7$	Pa
	initial gas saturation	$S_{gi} = 0.98$	
	gas production rate	$Q_g = 1.0 \times 10^3$	m ³ /day
	skin factor	S = 0	
F: 2.0: 1		S = 5	
Fig. 3-Single porosity model		S = 20	
	dimensionlesswellbore		
	storage factor	$C_D = 1$	
		$C_{D} = 100$	
		$C_{D} = 1000$	

Table 1 Single porosity model parameters

Table 2 Fracture model parameters

Parameter	Value	Unit
matrix porosity	$\phi_m = 0.3$	
natural fracture porosity	$\phi_{nf} = 0.6$	
hydraulic fracture porosity	$\phi_{hf} = 0.5$	
matrix permeability	$k_m = 9.87 \times 10^{-17}$	m ²
natural fracture permeability	$k_{nf} = 9.97 \times 10^{-15}$	m ²
hydraulic fracture permeability	$k_{hf} = 9.87 \times 10^{-9}$	m ²
reservoir length	X = 500	М
reservoir width	Y = 500	М
reservoir thickness	Z = 5	m
hydraulic fracture length	$X_{hf} = 40$	m

hydraulic fracture width	$Y_{hf} = 0.02$	m
hydraulic fracture thickness	$Z_{hf} = 5$	m
matrix block thickness	$\Delta L_m = 5$	m
natural fracture volume fraction	$f_{Vnf} = 0.001$	
well radius	$r_{w} = 0.1$	m
initial reservoir pressure	$P_i = 3.45 \times 10^6$	Ра
initial gas saturation	$S_{gi} = 0.98$	
gas production rate	$Q_g = 2.8 \times 10^4$	m ³ /day

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Fig. 4 Fractured reservoir model

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Parameter	Value	Unit
standard gas density	$ \rho_{sg} = 0.68 $	kg/m ³
gas viscosity	$\mu = 1.64 \times 10^{-5}$	Pa s
klinkenberg coefficient	b = 0	Ра
	$b = 3.4 \times 10^{6}$	
	$b = 3.4 \times 10^{7}$	
	$b = 3.4 \times 10^{8}$	
non-darcy flow constant	$c_{eta}=0$	$m^{1.5}$
-	$c_{\beta} = 6.2 \times 10^{-6}$	
	$c_{\beta} = 3.1 \times 10^{-5}$	
	$c_{\beta} = 6.2 \times 10^{-5}$	
	$\beta = c_{\beta} / (k^{1.25} \Phi^{0.75})$	
Langmuir volume	$V_L = 0$	m ³
-	$V_L = 1.27 \times 10^3$	
	$V_{L} = 1.27 \times 10^{4}$	
Langmuir pressure	$P_L = 2.07 \times 10^6$	Pa

Table 3 Gas Properties

Fig. 5 shows the transient pressure responses at well in terms of dimensionless time versus dimensionless pseudo gas pressure for flow through the single porosity reservoir with Klinkenberg effect. The well is maintained at a constant rate gas production and the rapid pressure drop at a late time (~100 years) is due to the effect of the closed boundary.



Fig.5 Type curves for Klinkenberg effect on transient well pressure responses in single porosity reservoir

As shown in Fig. 6 are the transient pressure responses with non-Darcy flow effect. The figure indicates that the larger non-Darcy flow coefficient (Cbeta of Table 3), the larger pressure drop at the well for maintaining the same production rate.



Fig.6 Type curves for non-Darcy flow effect on transient well pressure responses in single porosity reservoir

The most interesting results of this work perhaps are shown in Fig. 7, i.e., the effect of gas adsorption on flow or transient pressure drawdown. Fig. 7 shows a closed reservoir behavior as though the reservoir is subject to constant pressure condition at a later time if there is strong adsorption effect.



Fig.7 Type curves for gas adsorption effect on transient well pressure responses in single porosity reservoir

Fig. 8 presents type curves of well pressure responses under both skin and well storage effect.



Fig.8 Type curves for skin and wellbore storage effect on transient well pressure responses in single porosity reservoir

Fig. 9 shows the typical curves of pseudo pressure and its derivatives versus time in a log-log plot, subject to wellbore storage effect.



Fig.9 Transient pressure and its derivative curves in single porosity reservoir with skin and wellbore storage effect

An example of well testing analysis is demonstrated in Fig. 10, in which we use the conventional semi-log straight line approach (Chaudhry, 2003) without including Klinkenberg and non-Darcy flow effect. Here, we use a set of pressure drawdown testing data, generated by our numerical simulator, for single-phase gas flow into a well of constant production rate. Once the semilog slope is determined, as shown in Figure 10, we could calculate the formation permeability (note that we convert SI units to field units in the calculation), as follows:

$$m = 5.02 \times 10^{17} \left(\frac{Pa}{s}\right) = 1.0565 \times 10^{7} \left(\frac{psi^{2}}{cp}\right); \quad P_{sc} = 14.7psi; \quad h = 10m = 32.81ft$$

$$q_{sc} = \frac{1000 \text{ m}^{3}}{day} = 35.3147 \frac{Mscf}{day}; \quad T_{sc} = 520 \text{ R}; \quad T = 50^{\circ}\text{C} = 572\text{R};$$

$$k = \frac{57897q_{sc}P_{sc}T}{|m|hT_{sc}} = 0.097\text{md}$$

The actual value of permeability used in the numerical well testing is 0.1md. So the obtained permeability of the above is very accurate.



Fig.10 Semi-log analysis using numerical well testing data in single porosity reservoir (t in days)

Figs. 11, 12, and 13 show typical transient pressure responses in a hydraulically fractured well in a double-porosity, naturally fractured reservoir in terms of dimensionless time and dimensionless pseudo pressure. Fig. 11 displays the results of the Klinkenberg effect on flow behavior in the fractured well; Fig. 12 shows the significance non-Darcy flow effect may have; and Fig. 13 indicates the effect of adsorption on pressure drawdown, similar to a constant pressure boundary condition.



Fig.11 Type curves for Klinkenberg effect on transient well pressure responses in fracture reservoir



Fig.12 Type curves for non-Darcy flow effect on transient well pressure responses in fracture reservoir



Fig.13 Type curves for adsorption effect on transient well pressure responses in fracture reservoir

Summary

This paper presents a numerical model as well as modeling study of pressure transients of gas flow in unconventional reservoirs. The model incorporates many nonlinear flow processes, associated with gas production from low-permeability unconventional reservoirs, including Klinkenberg effect, non-Darcy flow, and nonlinear adsorption in addition to wellbore storage and skin effect. As application examples, we present a number of type curves for transient pressure drawdown tests in terms of dimensionless pseudo gas pressure and dimensionless time, incorporating Klinkenberg effect, non-Darcy flow and nonlinear adsorption in both porous media and fractured reservoirs. One interesting funding of this work is that the well transient pressure behaves as it is a constant-pressure flow system, if there is strong adsorption of gas on solids.

This work reports our continual research effort in modeling flow in unconventional oil and gas reservoirs. We will report the model application to analyze field data in the future.

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