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New Flux Surveillance Approach for High Rate Wells

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Abstract

Wells in high permeability reservoirs requiring sand control are commonly completed either with a high permeability fracture (HPF) or a high rate water pack (HRWP). These prolific reservoirs are capable of delivering high production rates, but the downhole flow velocity becomes a limiting factor. The downhole velocity is one of the most important factors in completion failure. To determine a safe producing rate for prolific wells, the current best practice is to monitor flux to avoid completion failure due to screen erosion or destabilization of the annular pack. Flux is the flow velocity at a critical location in the completion: at the screen face to avoid screen erosion, or in the annular pack to avoid pack destabilization. The commonly applied method for mathematically estimating the flux from the mechanical skin relies on a number of parameters that cannot be uniquely quantified, including the proppant permeability, the proppant turbulence factor, and the fracture skin. The calculated flux is highly sensitive to these uncertain parameters. When the flux is overestimated, the well rate will be unnecessarily restricted. Underestimation of the flux risks completion failure.

Most practitioners assume values for uncertain parameters, calculate the flux, and back-calculate the number of flowing perforations. Sensitivity studies will show the potential pitfalls of this technique. Instead, this paper presents an alternative approach to determine the flux as the total flow rate divided by the flow area, which, in turn, can be related to the number of perforations effectively conducting fluid from the reservoir to the wellbore. For the HPF case, this means how many perforations connect the fracture to the wellbore, which is a function of the angle between the well trajectory and the far field plane of the hydraulic fracture. When the angle cannot be determined due to a lack of the necessary stress measurements or stress isotropy, the flux will be calculated based on the pressure drop across the perforation tunnels obtained from the mechanical skin. The method and its advantages over existing techniques will be demonstrated using field data from deepwater Gulf of Mexico (GOM) wells.

Introduction

When wells are drilled at an inclination, the intersection between a vertical fracture and the wellbore may be extremely limited and may complicate treatment execution and further restrict well productivity (Martins *et al.* 1992). In one reservoir, efforts to improve wellbore to fracture connectivity in deviated wells including 180 degree phased, oriented perforations, and aggressive tip screen out designs with high conductivity proppant were shown to compensate for these problems (Vincent and Pearson, 1995). However, superior treatment execution and well production are often achieved when fracturing vertical wells rather than inclined wells.

Reservoirs requiring sand control pose additional concerns regarding the limited intersection between an inclined wellbore and a vertical fracture. Maximum downhole fluid velocity must be constrained to avoid erosion of screens or destabilization of annular gravel packs. If the fracture has a limited area of intersection with the inclined wellbore, this concentration of flow will require the well to be operated at lower production rates or risk completion failure. Especially in deepwater (DW) wells requiring substantial investment, it is crucial to determine the maximum safe operating rate. Needless to say, any kind of well failure in DW reservoirs, whether caused by high velocity, or excessive drawdown, is not acceptable. A recent paper by Ehlig-Economides *et al.* (2008) reiterated the importance of alignment between the wellbore trajectory and the far field hydraulic fracture plane to ensure the well construction design is suitable for high production rates. This paper showed that misalignment between the wellbore trajectory and the far field fracture plane leads to concentrated flux through a few perforations. Resulting high velocities may be sufficient to erode the gravel pack (GP) screen. Although, Veeken *et al.* (1989) recommended that a well to be hydraulically fractured should be drilled with a vertical trajectory through the pay interval to ensure fracture to wellbore alignment, many hydraulically fractured wells are drilled with significant inclination. In most offshore developments