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Predicting Wellbore Stability in SAGD Infill Wells Using 3D Finite Element Modeling

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In Steam Assisted Gravity Drainage (SAGD), multiple vertically spaced well pairs (injector and producer) are drilled from a pad. Due to continuous steam injection, a steam chamber around each well pair is formed which expands with time. After a few years of production, steam chambers between the adjacent well pairs can comingle and eventually overlap. This leaves a wedge of unproduced oil between the adjacent well pairs at the base of the reservoir. One way to access this unswept area is to drill "**infill wells**". An infill well is a single horizontal well, drilled on the center-line between the two SAGD well pairs. Usually there is no injector on an infill well since the stranded bitumen in the unswept area has already been partially mobilized due to heat from adjacent injectors. Infill wells have been show to increase recovery by up to 10% with no additional steam. However, positioning of infill wells needs careful planning to maximize reserves recovery and to minimize risk of steam release and wellbore stability problems caused by various geomechanical effects.

One of the biggest challenges in drilling infill wells is positioning them appropriately within the wedge area and at a sufficient distance from existing steam chambers. Since infill wells are generally drilled several years after the initial development of SAGD well pairs, the knowledge of the size and position of the steam chamber around the existing wells is less certain. The nearer an infill well is drilled to the high temperature, high pressure front of a stream chamber, the greater the risk of an unintended steam release. To avoid contacting the steam chamber, drilling infill wells requires a precise understanding of steam chamber development and geometry. For this reason, the Alberta Energy Board defines any well within 1000 m of a steam injector well as "at risk", and requires blowout preventer (BOP) on the wellhead during drilling operations.

Another challenge is predicting wellbore instabilities during the drilling of the infill wells caused by altered state of stresses due to steam injection in the existing wellbores (SAGD injector wells). Continuous steam injection triggers complex coupled thermal and hydraulic processes, which can dramatically alter the in-situ stresses, reduce rock strength, induce new fractures or re-activate existing fractures and/or faults. Steam injection increases formation pressure (i.e. pore pressure) which in turn decreases the effective stresses. At low effective stresses (near fracturing conditions), shear strength of rock can decrease significantly leading to potential shear movement and shear stability issues at within the reservoir, sand/shale interface and in overlying formations. In order to capture these dynamic changes in stresses and rock properties, an integrated geomechanics approach which explicitly couples reservoir simulation (thermal fluid flow) with geomechanical modeling (changes in stress, strain and dilation) has been developed and successfully used to predict wellbore stability in infill wells.

In this paper, we present a case study which utilized integrated geomechanics approach to predict wellbore instabilities in drilling horizontal infill wells and to recommend appropriate drilling parameters for safe drilling. The analysis was performed using data from six offset wells. We model the virgin and altered stress state using a 3D finite element based reservoir geomechanics software, VISAGE™ and the variation in formation pressure and temperature using the reservoir modeling software, ECLIPSE™. Thermal effects on fluids are considered by ECLIPSE™ and thermal effects on solids are considered by VISAGE™. We analyzed the sensitivity of wellbore stability to various key parameters such as variations in mud weights, injection plan, proximity of infill well to thermal front and steam chamber.

Results of this analysis indicate that not only the magnitude of injection pressure but also the resultant induced stresses control the direction and size of the steam chamber growth. Therefore, understanding the altered state of stress is a key to predicting steam chamber growth and thereby predicting wellbore stability of infill fills. Changes in the state of stress can be estimated accurately with the coupling of a geomechanical model with a reservoir simulation model. By predicting the steam chamber growth pattern, operators can optimize on the orientation and placement of infill wells to minimize wellbore instabilities while drilling these wells and during subsequent production.