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Hydrate Remediation in Deepwater Gulf of Mexico Dry-Tree Wells: Lessons Learned

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Abstract

Hydrate plugs were formed above the mud line in two dry tree oil wells in the Gulf of Mexico. The plugs were formed when trying to open the downhole safety valve with crude to return the wells to production after they were shut-in due to hurricane evacuation. Several attempts to melt the hydrate blockage included pumping methanol through a chemical injection line below the plug and lubricating in glycol above the plug were performed without success. As a last attempt, before utilizing coiled tubing, injecting hot oil into the tubing-casing annulus was considered. Transient simulations were performed to determine the required injection temperature, rate, and time. Well integrity issues were mainly associated with the compatibility of the hot oil with the elastomers and possible asphaltene or paraffin precipitation in the annulus. Sensitivity studies show that with 1 bbl/min injection rate and 150^{o}F injection temperature, the pressure-temperature condition inside the tubing located 3000 ft below the sea level will come out of the hydrate formation region within 4 hours. However, as the section goes deeper the warm-up time increases and at some point the conditions will not warrant being out of the hydrate region even after several days of injection time. Hydrate plugs in two dry tree wells melted after 6 and 60 hours of injection time, respectively. A revised restart procedure has been implemented to eliminate the hydrate problem in future startups.

Introduction

After being shut-in due to hurricanes, two dry tree oil wells in the Gulf of Mexico were suspected to have hydrate plugs formed above the mud line. Even though an anti agglomerate low dosage hydrate inhibitor (AA LDHI) was injected into the wells prior to shut-in, a hydrate plug was suspected to have formed inside the production riser above the mud line. Further analysis showed that an inadequate amount of LDHI was injected due to unknown problems with the injection skid. Hydrate formation was supported by the pressure build-up in the tubing when trying to open the surface controlled subsurface safety valve (SCSSV) by injecting crude. Estimated hydrostatic pressure and temperature inside the wellbore after shut-in were compared against the hydrate dissociation curve and shown to be favorable for hydrate formation.

Several attempts to melt the hydrate blockage were performed including pumping methanol through the chemical injection line below the plug and glycol above the plug, but without success. Before going to a coil tubing option, injecting hot oil into the tubing-casing annulus was considered as the last attempt.

Thermal-hydraulic transient analyses were performed to determine injection temperature, pumping rate, and pumping time to inject hot oil through the annulus. The transient simulation results confirmed that the existing topside facilities were adequate to support the operation. Well integrity issues were mainly associated with the compatibility of hot oil with elastomers and possible asphaltene or paraffin precipitation in the wellbore annulus.

Hydrate Issues in a Dry Tree Well

Under favorable conditions of high pressure and low temperature, hydrocarbons and water can combine to form crystalline solids, which resemble wet snow or ice, what are also called hydrates. The crystal structure is composed of cages of hydrogen bonded water molecules which surround 'guest' hydrocarbon molecules such as methane, ethane and propane. These ice-like structures agglomerate to block tubing, flowlines, and/or facilities.

To determine the conditions of temperature and pressure under which hydrates can form, the best approach is to conduct experimental measurements on the appropriate hydrocarbon/water mixture. However, this is not always practical. Thus, the method for predicting hydrate behavior using thermodynamic models is more common. A thermodynamic model is used to calculate the hydrate equilibrium curve, also know as the hydrate disassociation curve. This is a prediction of temperature, at a given pressure, above which hydrates will not form.

In a dry tree well the most critical area that is subjected to hydrate formation, particularly during extended shut-in and cold startup, is along the wellbore above the mud line since the production riser is in direct contact with the sea ambient. During an extended shut-in, phase segregation in the wellbore causes a gas cap to form and depending on gas-oil ratio and pressure the gas cap may extend down to the mud line. If water is introduced into this cold gas column either due to