OTC 19505

Two Field Studies Demonstrate That New AA LDHI Chemistry is Effective at High Water Cuts Without Impacting Oil/Water Quality

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This paper was prepared for presentation at the 2008 Offshore Technology Conference held in Houston, Texas, U.S.A., 5–8 May 2008.

Abstract

The second generation new anti-agglomerate low dosage hydrate inhibitor (AA-LDHI) chemistry is greater than 99% oil soluble and has proven performance to prevent hydrate blockages in both wet-tree and dry-tree applications. This new chemistry has been successful in field applications of water cuts up to 80%. The first generation AA-LDHIs are known to perform at low water cuts, such as less than 40%, and cause poor produced oil/water quality.

Hydrate crystals formed during a flowing condition and/or shut-in condition could form a hydrate blockage and result in a production shut-down. The remediation of such a hydrate plug involves lost revenue, risk for the safety of the personnel and a potential negative impact on the environment. The subcooling involved in deepwater applications is usually higher than 25°F, which would require the use of an AA type LDHI which can protect the production systems up to 50°F subcooling.

Two case studies, one for a wet-tree well and one for a dry-tree well will be presented. The results show a significant decrease in the total oil and grease (TOG) levels in the produced water and percent BS&W in the produced oil. The data will include the performance results, TOG data for long periods of time, toxicity/environmental testing data and shut-in/restart history.

A major benefit of this new chemistry is that the produced water quality is improved compared to the first generation chemistry in field applications. The oil-soluble nature of the new chemistry makes the produced water less toxic and can reduce the chemical costs involved in produced water polishing. The new chemistry can extend the production life of the wells by allowing it to produce at higher water cuts. Given the high crude oil sale price, the new chemistry could add significant value to the producers while not affecting the produced water quality.

Introduction

Hydrate management is a critical aspect of deepwater oil and gas production facilities. Producing wells and flowlines are susceptible to hydrate formation and ensuing blockage if they meet certain criteria. These criteria are the presence of natural gas and water at elevated pressures and low temperatures. The temperature below which hydrates can form increases with increasing pressure and can be as high as 86°F (Kelland 2006). Once formed, the hydrate blockage can take anywhere from a couple of days to months to dissociate, resulting in decreased revenue to the producer due to lost production and other costs associated with the dissociation. The remediation of a hydrate plug poses a significant risk to the safety of the personnel involved and for a potential negative impact on the environment. Dissociating a hydrate plug can cause pipeline/flowline rupture which could injure personnel and release hydrocarbons into the environment.

Flow assurance requirements such as the prevention of hydrate formation are often the basis of design for deepwater field developments. Methods for controlling hydrate formation can be thermal and/or chemical. The typical methods for controlling hydrate formation include pressure reduction, changing the temperature of the system by insulating flowlines and/or equipment, circulating hot oil through the system prior to start-up/re-start and the injection of anti-agglomerate, kinetic or thermodynamic inhibitors. The conventional chemical hydrate inhibition method is the use of thermodynamic inhibitors such as methanol and glycol. This method is a proven technology; however, the logistics of transportation and storage of large volumes of inhibitor for the facility have a significant impact on the OPEX and CAPEX of the field's development