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Challenges for Waterflooding in a Deepwater Environment

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Abstract

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Big reservoirs in deepwater Gulf of Mexico typically produce at world-class rates. The scale of investment is likewise world-class.

The energy industry's drive to invest in enhanced oil recovery from deep-water basins is sustainable in a world of volatile oil prices and increasing demand for energy. However, project economics will continue to depend on accurate risk assessment, risk mitigation strategies, and more fundamentally, progressive deployment of evolving technologies in ‘brownfield’ deepwater secondary recovery projects.

Details of well geometry and design optimizations may prove to be minor sensitivities in high cost deepwater developments, however rig rate has a major impact on economics. The assessment required to minimize the number of injectors and ensure their proper placement logically takes more time than exotic choices of injection patterns. With such major constraints in mind, an optimal design for wells and materials has to take precedence. Accepting this as a given, additional, more common, challenges would then follow.

The waterflood study team for the deepwater Ursa-Princess field, in the Gulf of Mexico, has spent appreciable time and effort evaluating various potential challenges affecting the surface and subsurface aspects of the development plan. The design for an optimum injection rate was a bottom-up process starting from the reservoir up to the topsides injection facilities. Reservoir sweep efficiency and reservoir pressure distribution logically dictated injection well designs and injection pump sizing. Subsurface risks, such as reservoir souring and hydrate formation, dictated materials selection and completions design.

This paper addresses the challenges primarily affecting the design of the deepwater subsea injection wells. In addition to the well cost, several other underlying factors have played an influential role in defining the boundary conditions for the injectors design.

Background

Industry-wide experience in the execution and the operation of waterflood projects in deepwater environments is relatively limited. With a relatively few analogues, the Ursa and the Princess fields are set to embark on major facilities expansion and subsea development. The aim is to deliver a high rate of specific quality water though four subsea injection wells into a vast and, largely thirsty, reservoir.

Ursa and Princess reside 100mi SSE of the Mississippi River mouth in the Mars Basin, Gulf of Mexico (GOM). The Ursa field was discovered in 1990 and has been on production since 1999. The Princess field was discovered in 2000 and has been producing since December 2003 through a subsea tieback to Ursa. The fields have their main reservoirs in common and are in pressure communication. The working interest in the Ursa and Princess fields are Shell (45.4% - operator), BP (22.7%), ExxonMobil (16%), and ConocoPhillips (16%).

The Yellow reservoir is the main reservoir at both Ursa/Princess and Mars, the other major field in the Mars basin. It is a world class Upper Miocene turbidite reservoir that stretches across the Mars Basin, including the Mars Field. This 12,000-acre reservoir is charged with light oil type, though with slight variations in properties as indicated by the analysis results of the abundant PVT samples.

Due to limited TLP well availability, high cost of subsea wells and the limitations of the subsea system to handle large water cuts, the waterflood will use relatively few injectors. The proposed base plan has four water injectors (WI): 2 into Princess and 2 into Ursa.

Producing wells will include three Princess subsea wells, and four Ursa TLP wells. Five TLP wells are to be sidetracked updip or recompleted at a later stage.

High injection rates are required to replace voidage and maintain reservoir pressure above bubble point. Initial injection rates per well (annual average) of 30-40K BWPD are required. This injectivity can only be maintained by creating fractures. With the wide well spacing relative to fracture length, this is not expected to negatively impact sweep efficiency. However, due to the uniqueness of well spacing and reservoir volumes, there is a lack of analog data points to calibrate the outcomes.

Parallel evaluation of the viability of artificial lifting has shown that TLP Waterflood (WF) producers would benefit