Flow Assurance in Brazil's Deepwater Fields

Significant oil reserves are in ultradeepwater fields (water depth greater than 1500 m). In these fields, flow assurance plays a crucial role because of high pressures and low temperatures. Strategies on flow-assurance issues for short- to near-term projects are based on specific field experiences as well as on the foreseeable technologies. Current R&D in flow-assurance activities is discussed.

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Introduction

Flow assurance has been relevant to field-development teams in Brazil since the mid-1980s with the discovery of the deepwater Albacora and Marlim fields. The pilot production systems for these fields used floating production units (FPUs), subsea wells, flexible flowlines, gas lift for artificial lift, and waterflood for enhanced oil recovery. Because of high heat losses in multiphase flow, wax deposition in the flowlines was severe, especially in Albacora, becoming, at that time, the main challenge. Application of corrective techniques, especially the nitrogen-generating system, an exothermal-chemical-reaction method to dissolve wax deposits, and round-trip pigging, was decisive for the operational continuity of these pilot production systems. However, cost/benefit analyses showed that preventive solutions would provide better economic results for the development phases of these fields, as well as for other new deepwater fields. These analyses also took potential hydrate issues in the multiphase flowlines into account.

Increased offshore heavy-oil activity has encouraged R&D to assure maximum future throughput from these fields. Therefore, special attention was given to investigating water-in-oil emulsion and its effect on the viscosity of the produced fluid.

Current Design Criteria

Although other flow-assurance aspects are considered in the design criteria, hydrates and wax deserve special consideration. Because of the existing low temperatures at the seafloor, the widespread use of subsea wells, and the adoption of waterflood for enhanced oil recovery, the risk of blockages is great.

Hydrate. The design criteria are prediction, prevention, and remediation. For prediction, the dissociation curve is calculated on the basis of gas composition at separator conditions. This determination is conservative because gas composition at the separator is richer in heavier-hydrocarbon components than elsewhere and, thus, more prone to stabilize hydrate. Some crude oils can transport hydrate particles as slurry and delay hydrate formation. Therefore, laboratory tests must verify if the oil has a blockage tendency. These laboratory tests are still in the R&D phase. There also are guidelines concerning how to obtain the thermal/hydraulic performance, either for steady-state or transient flow.

For prevention, the design criteria take into account heat retention, heat addition, pressure control, fluid removal, and thermodynamic inhibition. The most important is heat retention by use of appropriate insulation. Flowlines, risers, and subsea equipment must have an insulation level that complies with criteria governed by oil characteristics. For systems handling nonplugging oils, an insulation level is required that keeps the fluid pressure and temperature outside the hydrate envelope during steady-state flow and provides a cool-down time of at least 2 hours before entering the hydrate envelope after a shut-in. For plugging-oil systems, the cool-down time requirement increases from 2 to 8 hours. The cool-down time can be used for depressurizing the line or for replacing the fluids in the production line.

Heat addition to the trapped fluids is possible, but so far, no systems are equipped with it. One ongoing project aims at installing an electrically heated pipe-in-pipe (PIP) flowline in Roncador field by 2007.

Pressure control should be designed into the topside facilities to enable simultaneous blowdown of the production lines from at least four wells within a 2-hour period. Similarly, topside facilities should be designed to allow fluid removal and replacement of produced fluids from flowlines of 6 wells within a 4-hour period. Diesel fuel usually is used for this purpose. If the amount of diesel fuel required for this operation exceeds the available volume stored in the FPU, then alternative methods must be considered (e.g., remove the produced fluids by lift gas).

Injection of thermodynamic inhibitors, such as methanol or ethanol, is discouraged. Preliminary laboratory tests suggested that injection in the subsea tree during shut-in may not be effective, because it is difficult to promote adequate mixing of the inhibitor and segregated water. Thus, thermodynamic inhibition is considered only as contingency for prevention.

For remediation, it is recommended that sufficient space be available on the FPU topside to receive the equipment for blockage location and eventual operations of riser depressurization through coiled tubing.

Wax. Several characterization tests are performed to predict potential wax-deposition problems: wax-appearance temperature (WAT) obtained by differential scanning calorimeter, pour point, wax content, yield stress, static simulation of organic deposition (cold-finger method), and wax solubility as a function of temperature. The results are interpreted qualitatively by comparing data with similar data from producing fields that have wax problems. Typically, there is excellent agreement between the prediction of wax-deposition problems and field behavior. Several joint industry projects are in progress to develop a wax-deposition-modeling tool. Although commercial models are available, they tend to overpredict wax deposition.

For prevention, heat retention, heat addition, and chemical inhibition are considered. The priority is heat retention through appropriate heat insulation. The requirement is to assure flowing temperatures at least 3°C greater than the WAT. Pigging also is considered for critical cases in which keeping the fluid temperature at the required level is not feasible. Alternatively, chemical inhibition can be considered.

For remediation, the requirements are the same as for hydrate: topside surface areas should be made available to accommodate the equipment for locating blockages and eventual operations with coiled tubing.

Near-Term Flow-Assurance Issues

One challenge is that of increasing exploitation of heavy-oil fields (oil density less than 20°API) in deep and ultradeep water. The physical properties of heavy oil are considerably different from those of lighter crudes, common in offshore fields elsewhere. These differences cause greater pressure losses that result in lower production rates and require new technologies to enable economical production of such oils, especially from deepwater fields.

Another concern is increased water production from mature fields. Thus far, oils produced from deepwater fields have antiagglomerant properties that avoid flowline blockage by hydrate. Nevertheless, questions need to be answered. Will these oils be able to avoid hydrate blockage even for higher water contents? What is the water-content limit above which hydrate problems are expected? How is this water content determined? What action should be taken when this limit is exceeded?

Heavy Oil and Water-in-Oil Emulsion. The main differences between heavy and light oils in regard to fluid flow in pipes are viscosity, gravity, and pour point. The first two make heavy-oil flow through pipelines more difficult than for light oils. Higher viscosity means greater pressure drop, thus a need for more-powerful artificial-lift methods and export pumps and for larger-diameter pipelines with higher-pressure rating. Some heavy oils also may exhibit non-Newtonian behavior. The higher the oil gravity, the greater the pressure gradient in the uphole sections such as the wellbore and riser. Finally, the pour point can add flow-assurance concerns in cases of cold startup of pipelines or wells.

Emulsion is a dispersion of one liquid phase in another, and it occurs when the liquids are mixed under shear, presenting non-Newtonian behavior. In heavy-oil reservoirs, the water production usually starts early in the field's life. Thus, knowledge of emulsion behavior is very important for designing the production system. The apparent viscosity of the emulsion is related to several variables, such as fluids composition, shear stress, temperature profile, and shearing period. Emulsions also may present shear-thinning behavior. Another issue still not well understood is the emulsion-inversion point, or the limit above which free water starts to appear. This issue affects the fluid viscosity and could increase the risk of hydrate blockage in the presence of free water. The inversion point is related to oil and water compositions but also depends on the flowing conditions from the wellbore to the FPU.

Hydrate-Slurry Transportability. Some crude oils show the ability to transport hydrate particles as slurry, preventing pipeline blockage. Polar compounds in crude oils (such as asphaltenes) stabilize water-in-oil emulsions and may provide the oil with antiagglomerant properties concerning hydrate or delay hydrate formation. The design criteria concerning hydrates depend on the oil's blockage tendency. A current R&D project aims to establish a set of laboratory tests to assess an oil's tendency to prevent hydrate agglomeration.

The formation of a stable emulsion is seen as a necessary condition for the oil to present good hydrate-transportation properties. Once established that certain oils form stable water-in-oil emulsions, it is important to assess the water-content limit below which the emulsion will still be stable.

Wax-Deposition Modeling. Slow buildup of wax layers in pipelines and flowlines is caused by the solidification of the paraffinic fractions because of cold seabed temperatures. The deposition rate depends mainly on crude-oil characteristics, the heat flux through the pipeline, and the shear stress at the wall. Several R&D efforts are studying this phenomenon and working to improve the prediction methods.

Some waxy oils may have pour-point temperatures greater than the typical seabed temperature of 4°C. This situation could present difficulties for starting up pipelines after the crude oil reaches the equilibrium temperature. Such situations may require heating the pipeline before its startup. Rheology techniques are being developed that enable prediction of the required pressure for pipeline startup at a given temperature.

Heat Management—Insulation. The PIP configuration is being studied for deep- and ultradeepwater applications. Considering the current fields and new discoveries, with water depth reaching 2500 m, this configuration is analyzed with respect to manufacturing, installation method, carrier, insulation and pipe materials, structural aspects, and special topics such as water stoppers and buckling arrestors. These studies are applied to both flowlines and risers.

Heat Management—Heat Addition. Flexible, rigid, and PIP subsea pipelines, heated by either electricity or hot water, are some of the options to add heat to the produced fluids. One application targets a 6-km-long production flowline in 1900 m water depth. This project will use a subsea electrical submersible pump for artificial lift, and the flowline will be an electrically heated PIP. The electrical power will be delivered to the lift system during normal operation and to the flowline during shut-in and restart.

Other Initiatives. Several initiatives aim at minimizing flow-assurance drawbacks in deepwater developments. Methods include use of dual-diameter pigs, a subsea gas/liquid separation system, and plug location and removal.

One conceptual project comprises installation of a subsea system to separate produced water from satellite wells at the seafloor. Even though its main goal is to increase liquid-handling capacity of the FPUs, a side benefit of such a system is the reduced hydrate-formation risk and reduced viscosity of the produced fluid.

Although several techniques can be applied to mitigate wax- and hydrate-plugging potential, it is not possible to eliminate the risk of eventual blockages completely in deepwater production. Thus, it is important to develop special techniques and tools for blockage location and remediation in subsea pipelines. Two methods to locate blockage are based on the detection of pressure-pulse echoes reflected from the blockage and detection of the pipeline-diameter variation as a function of the pipeline pressure. Blockage-removal methods include heating, chemical solvents, mechanical tools, and depressurization. The selection of the most appropriate technique will depend on the specific blockage. JPT

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