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Accidental field-scale testing for hydrate blockage criteria

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Abstract
The well under study typically maintained a water cut of 25%, and no hydrate prevention measures were implemented in its production line during shutdowns. Following an incident where the well remained closed for over 2 months with produced fluid present in the production line, the well was restarted as usual. However, 5 hours later, the well had to be shut down again, and a hydrate blockage was identified. Subsequent investigation revealed that during the 5 hours of production, the water cut had exceeded 40%, surpassing the threshold that would demand hydrate prevention measures during a shutdown. The event unintentionally confirmed the existing premise of a critical water cut for hydrate blockage formation. Consequently, as a result of the case analysis, an enhanced layer of protection was incorporated into the hydrate prevention procedures, specifically addressing water cut variations subsequent to prolonged shutdown periods.

Keywords
Hydrate; Field Operations

Introduction
In order to prevent hydrate blockages in subsea pipelines of oil-producing wells, specific procedures are typically carried out during production shutdowns [1]. These procedures aim to either replace the fluid within the pipeline or inhibit the water content in the fluid, thereby preventing that the contact between water and the produced gas results in hydrate blockage [2].

In Petrobras, not all wells undergo hydrate blockage prevention procedures. Typically, the decision to implement these procedures is based on criteria such as the water cut of the well, emulsion stability, or operational history. These factors are taken into consideration to assess the potential risk of hydrate formation and determine whether preventive measures are necessary.

These criteria are established based on laboratory tests, tailored to the specific fluid and production conditions of each asset. Field testing is not feasible due to the potential for significant costs associated with hydrate blockage dissociation.

However, with the production of multiple wells over many years, a robust criterion is developed, leveraging the operational history. This criterion incorporates conservative assumptions to mitigate the risk of hydrate blockages, ensuring the prevention measures are effectively implemented.

In the Petrobras asset under study, the hydrate blockage prevention procedures in the production line are typically conditioned by the water cut of the produced fluid. When the 40% water cut threshold is reached, hydrate prevention procedures are implemented during any production shutdown that lasts long enough for the production fluid to enter the hydrate envelope.

A literature-reported experiment stated that water cuts of 40–60% in decane show the largest increase in resistance-to-flow, and that increasing the water cut from 60% to 100% did not result in an increased risk of hydrate plug formation [3].

It is important to consider from an operational standpoint that as the water cut increases, there will eventually be a phase inversion in the system from oil-continuous to water-continuous. As the inversion point is approached, the viscosity of the oil-continuous phase tends to reach a maximum. [4][5].

Although extensive research has been conducted on the mechanics of hydrate plug formation in oil-continuous systems, there is a scarcity of data describing the process of hydrate formation near the inversion point [3].

This study will focus on an operational event that provided an opportunity to validate the water cut limit criterion for a producing well.

Methodology
The well under investigation, which typically has a water cut of 25%, remained closed for over 2 months with the fluid produced in the production line. The well was then successfully restarted but had to be shut down again after 5 hours due to topside issues. During the subsequent restart attempt, 2 days later, a blockage was detected in the production line.

In the well under investigation, as well as in other wells within the same field, an unexpected increase in water cut during production was observed following the scheduled shutdown. The water cut values reached levels that exceeded the threshold, requiring hydrate prevention measures. Some measurements indicated water cuts as high as 95%. It is highly probable that at the time of the second shutdown, which occurred 5 hours after the restart, the water cut value was slightly above 40%.

No sample was taken at the exact moment of the shutdown. However, based on the latest samples taken prior to the shutdown, the water cut was estimated to be around 45%.

As a result, a fortuitous field test scenario was inadvertently created, involving two production shutdowns in the same line. Both shutdowns utilized the same fluid but had different water cut levels, with one being below the critical threshold for hydrate prevention and the other surpassing it.

Results and Discussion

The investigation revealed that the first restart proceeded smoothly because the production line contained fluid from before the scheduled shutdown, with a water cut of 25%. Despite the fluid remaining stagnant in the line within the hydrate formation range for 2 months, no blockage occurred, and the well restarted without any issues.

After the scheduled shutdown, it was identified that the producing wells experienced an increase in water cut after a prolonged period of non-production. This led to a situation where, after the second shutdown, the well had been producing for 5 hours, resulting in a production line fluid with a water cut exceeding 40%, which is considered the limit for initiating hydrate prevention procedures, as illustrated in Fig. (1).

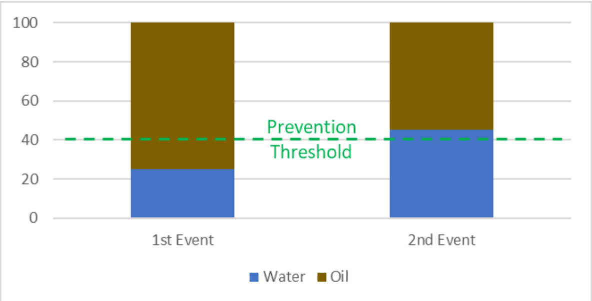

Figure 1. Water cut of the produced fluid in the 1st and 2nd events.

As a result, the well temporarily required preventive measures, but unfortunately, this condition went unnoticed at the time. After 36 hours, when an attempt was made to restart the well, a hydrate blockage had already formed.

Although unplanned, these events inadvertently served as confirmation that the operational criterion of a water cut limit for hydrate blockage prevention was accurately calibrated for the well.

Conclusions

Upon concluding the investigation of the incident, actions were implemented to prevent its recurrence. The first action involved revising the shutdown procedure for the well involved and similar wells. In the event of a shutdown lasting over 24 hours, the well would be deemed as a high water cut well, and hydrate prevention operations would be conducted if another shutdown occurred before the water cut had decreased below the limit.

The second action entailed updating the unit's operations manual to include provisions for an expected increase in water cut for all wells during extended shutdowns.

Furthermore, a recommendation was put forth to extend these measures to other Petrobras units. It emphasized the importance of identifying wells with a water cut below the limit but exhibiting a tendency for increased water cut following prolonged shutdowns. Additionally, it highlighted the need to consider scenarios where injection wells are opened before production wells, as this operational condition may temporarily raise the water cut in the production wells.

Subsequent events of a similar nature were recorded and served as further evidence of the effectiveness of these actions, as an increase in water cut was observed in the wells, and the prevention operations successfully prevented blockages from forming. As a result, the production efficiency of the unit was improved, leading to reduced production losses and greenhouse gas emissions.

Responsibility Notice

The authors are the only responsible for the paper content.

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