GOR-W_C combination falls on an unfeasible region, this indicates that probably the hydrate slurry will have too high effective viscosity. This indicates that subsea processing must be used (e.g., subsea water separation) to ensure transportability.

Model details

Figure 1 shows a diagram of the cold flow unit. The hydrate cold flow unit receives mass flow streams of gas, oil and water and outputs mass flow streams of gas, oil, water, and inert hydrate particles. The hydrate particles at the outlet are dispersed in the liquid phase.
In this work it is assumed the pressure change in the unit is minimum. The temperature is reduced to a value close to the temperature of the cooling media (seabed water in this case).

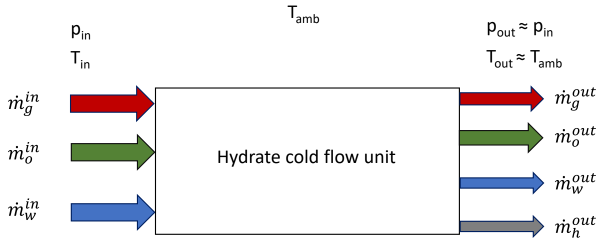

Figure 1. Block diagram of the hydrate cold flow unit

The unit could operate in two ways, depending on the inlet conditions:

- Water-limited reaction: Most water will be converted to hydrates and hydrate-forming light components will be leftover. In this case the resulting slurry will consist of a dispersion of hydrate particles and some salty water in an oil continuous phase.
- Hydrate former-limited reaction: Most hydrate-forming light components will be converted to hydrate and some free water will be leftover. In this case the resulting slurry will consist of oil-water multiphase flow with hydrate particles in oil, water, or both.

Assumptions:

- It is assumed that the cold flow unit dissipates the heat generated by the hydrate reaction to the surrounding ambient.
- It is assumed there is a fixed (input) stochiometric relationship between hydrate formers, water and hydrates. This stochiometric relation is expressed in terms of mass fraction. In this work, it is assumed 0.86 kg of water join with 0.14 kg of hydrate-forming components to form 1 kg of hydrate.
- The hydrate formation model does not include the reaction kinetics.
- It is assumed that almost all components that end up in surface gas (standard conditions rate $q_{\bar{g}}$) could potentially form hydrates. Therefore, the formation of hydrates effectively reduces the surface gas-oil-ratio of the hydrocarbon mixture that enters the cold flow unit
- It is assumed the salinity of the water is equal to zero
- Water dissolved in reservoir gas entering the wellbore is neglected.

Calculations details

Calculations are performed based on 1 Sm3/d of oil. The standard condition volumetric rates of gas and water are calculated from the flowing gas-oil ratio (R_p) and the water cut (W_c).

1. The mass flow rate of surface water and surface gas are calculated using the standard conditions volumetric rates and standard conditions densities.
2. The hydrate reaction is computed, assuming that a fraction “F” (in this work, equal to 0.94) of the surface gas converts to hydrates. This gives remaining mass flow rates of surface water, surface gas and hydrates
3. Remaining mass flow rates of surface gas and water are converted back to standard conditions volume rates
4. The standard conditions volumetric rates obtained in step 3 and black oil properties (Appendix 2) are used to calculate local volumetric rates of oil, gas and water (as indicated in Appendix 1) at two locations:
   a) the outlet of the cold flow unit and
   b) at the receiving separator
   Since the temperature in the transportation pipeline downstream the cold flow unit is constant, these two locations give the lower and upper bound of operating pressure and thus the upper and lower bound of fluid volume fractions.
5. The local volumetric rates are used to estimate volume fractions of hydrates in liquid.

The procedure described above was programmed into a function (called “cold flow unit” function) that receives as inputs the GOR and W_C and outputs:

- The hydrate volume fraction in liquid at separator conditions
- The hydrate volume fraction in liquid at the outlet of the cold flow unit
- An integer indicating if the hydrate reaction is water-limited or hydrate-former limited
- The gas volume fraction at separator conditions
- The gas volume fraction at the outlet of the cold flow unit

Operational maps

There are two types of plots generated in this study, 1. Color maps and 2. Envelopes. A brief description of how these two are generated is provided next.

Color map

To produce a color map, the “cold flow unit” function is triggered for several combinations of interest of producing gas-oil ratio and water cut, using a regular grid. The output is recorded for all combinations and plotted on a 2D plot of GOR vs WC. The value of the variable of interest (e.g., hydrate volume fraction in liquid at separator conditions) is shown using a color bar.

Operating envelope

The operating envelope depicts the following boundaries:

- A line separating "feasible-unfeasible” operating regions (i.e., a threshold in volume fraction of hydrate in liquid is reached)
- A line separating the regions of water-limited reaction versus hydrate former-limited reaction

These two boundaries were found using the method of bisection on the “cold flow unit” function. The first boundary was found using as objective the hydrate volume fraction in liquid at separator conditions, while the second boundary was found using the integer indicating if the hydrate reaction is water-limited or hydrate-former limited.

Costs Analysis

A cost comparison between alternative flow assurance methods is made to see how the cold flow technology compares with other technologies. Cost estimates for conventional technologies are based on experience from earlier field developments.

Results and Discussion

Methods Applied on Field Case

The method is tested on a field case with transport distance to host of about 100 km. The API of the crude is 39. The specific gravity of surface gas is 0.86. Two reservoir recovery strategies are considered: gas injection and water injection.
It is considered the pressure of the cold flow unit is 110 bara, separator pressure is 15 bara, and the ambient temperature is of 4 °C. These two points fall inside the hydrate equilibrium region. The cold flow operational envelope is provided in Figure 2 when using a hydrate volume fraction in liquid (HVFL) threshold of 30 %.

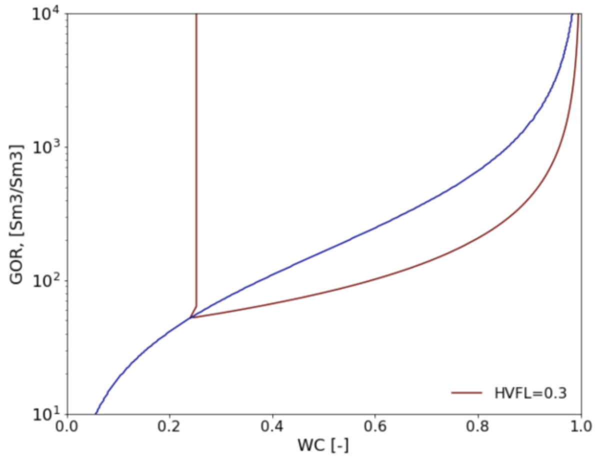

Figure 2: Operational envelope of cold flow for different combinations of GOR and W_C, using HVFL@sep =0.3 as threshold. Separator conditions are 15 bara, 4 °C.

Figure 3 is similar to Figure 2, but using three values of HVFL at separator conditions, 0.1, 0.2, 0.3. Results show that if hydrate content tolerance is stricter (e.g. the slurry viscosity increases significantly with hydrate volume fraction) then the feasible area shrinks considerably.

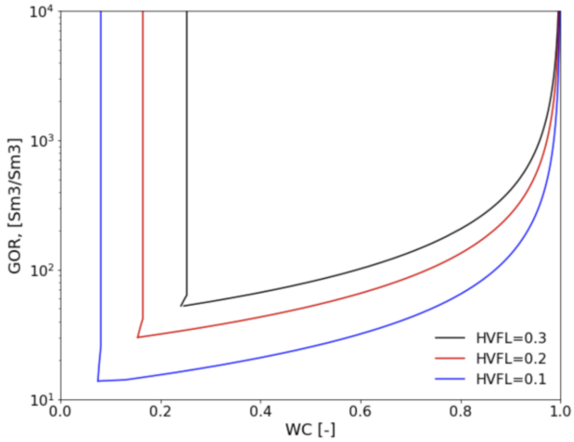

Figure 3: Operational envelope of cold flow for different combinations of GOR and W_C, using HVFL@sep=0.3,0.2,0.1 as thresholds. Separator conditions are 15 bara, 4 °C.

GOR-W_C profiles calculated from production data were over-imposed on the operational envelope. Figure 4**Figure** shows the results for the gas injection case and Figure 5 for the water injection case. The results show the cold flow method is most suitable for the gas injection case, since the GOR-W_c pairs of the production profile are outside the “unfeasible” region.

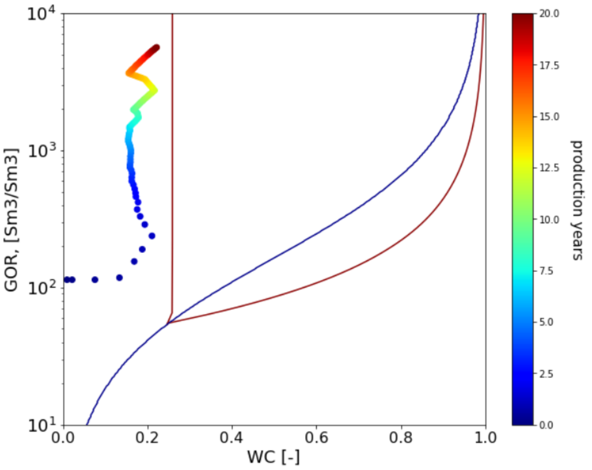

Figure 4: Gas injection case plotted over the field lifetime. Separator conditions are 15 bara, 4 °C

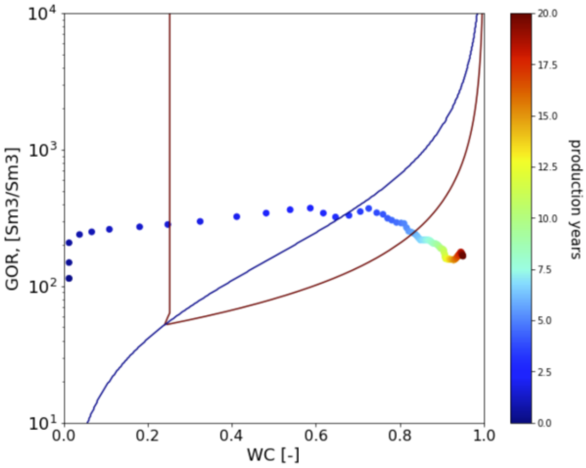

Figure 5: Water injection case plotted over the field lifetime. Separator conditions are 15 bara, 4 °C

For the water injection case, several of the GOR-W_C points during early field life fall into the region of high slurry viscosity.
Figure 6 shows the value of HVFL at separator conditions for both cases, gas injection and water injection, in time. For the water injection cases, there is a period between 2-6 years where values are significantly higher than 0.3.

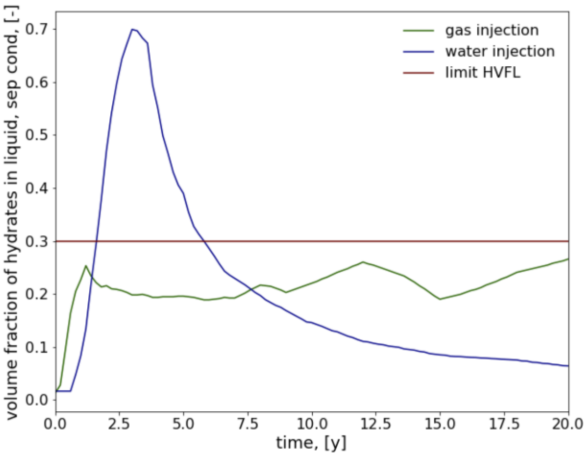

Figure 6: HVFL at separator conditions (15 bara, 4 °C) in time for the water and gas injection cases.

If a subsea water separator is installed upstream the cold flow unit to limit the water cut to 0.2, then it would be possible to operate in the feasible region. The new operational envelope is presented in Figure 7.

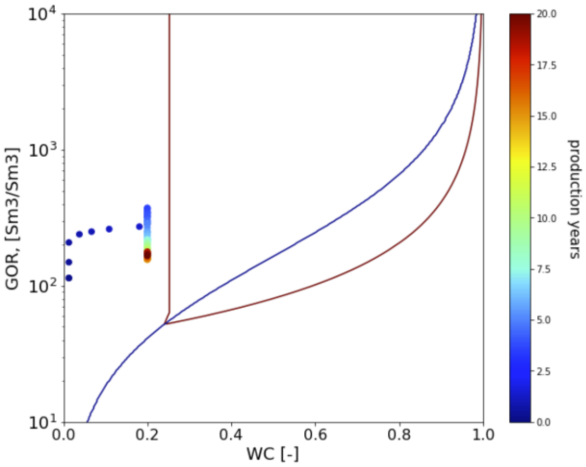

Figure 7: Water injection case with water separation upstream the cold flow unit plotted over the cold flow envelope. Separator conditions are 15 bara, 4 °C.

Additional comments

Slurry viscosity and slurry transportability

In this study the value of hydrate volume fraction in liquid at separation conditions has been used to define the transportation feasibility of the slurry. However, it would be more appropriate to use the viscosity of the slurry. Unfortunately, un-tuned hydrate slurry rheology models are usually highly uncertain and have poor predictability [6]. Moreover, for conditions where there is water leftover, the hydrate wettability and the dynamics of the oil-water flow significantly affect the rheology of the slurry. Usually, extensive laboratory experiments are required to customize models and ensure they have an acceptable accuracy. Because of these reasons in this study, it was decided to work considering hydrate volume fraction in liquid only.

The amount of gas in the pipe is also an aspect that affects the “transportability” of the hydrate slurry in the pipeline. Usually, high amounts of gas (high gas volume fraction, GVF) at high speed allow to transport viscous liquids efficiently. Figure 8. shows a color map depicting the GVF at the outlet of the cold flow unit for several combinations of GOR and W_C. Figure 9 shows a color map depicting the GVF at separator conditions for several combinations of GOR and W_C. Locations where the GVF is high, could probably transport viscous liquid better.

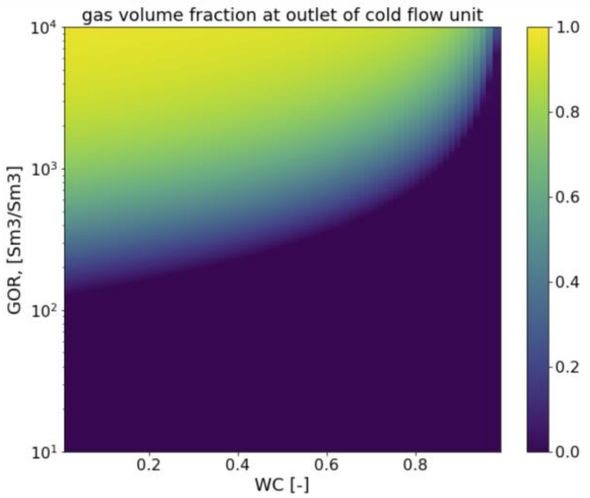

Figure 8. Color map depicting gas volume fraction at outlet of the cold flow unit (110 bara, 4 °C) for several combinations of GOR and W_C.

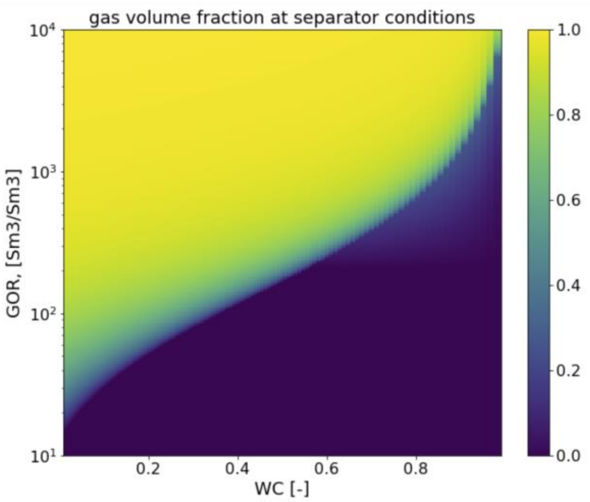

Figure 9. Color map depicting gas volume fraction at separator conditions (15 bara, 4 °C) for several combinations of GOR and W_C.

Hydrate melting downstream the cold flow unit

In this study it was the case that the pressure and temperature conditions in the transportation pipeline fall inside the hydrate formation region. However, it could occur that, as pressure is reduced in the pipeline, the pressure-temperature conditions fall outside the hydrate formation region, causing hydrate melting. These situations were not studied in this article. However, in these cases, the hydrate volume fraction in liquid will be reduced, thus the procedure proposed can still be useful as a conservative estimate.

Cost results

Total costs (CAPEX plus OPEX) for different flow assurance technologies are shown in Figure 5. The figure shows that the EMPIG cold flow technology [5] has 20-30 % less costs than direct electrical heating (DEH) at 100 km. For greater distances, cold flow is even more beneficial. The cost difference is mainly driven by lower CAPEX due to the use of a bare pipeline instead of a heated and insulated pipeline. A lower OPEX due to significant lower energy consumption is also an important contributor.

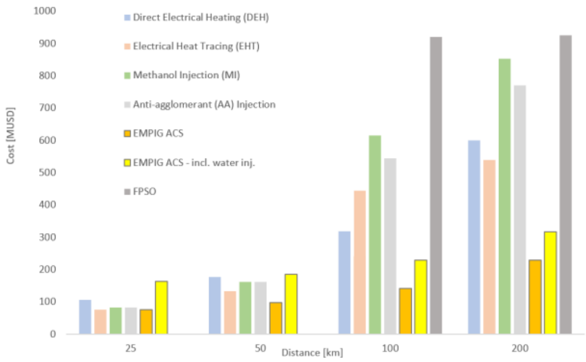

Figure 10: Subsea tieback costs (CAPEX plus OPEX) for different technologies and tieback distances.

Conclusions

Results of a real field study case show the cold flow operational envelope allows to evaluate the feasibility of producing using the cold flow technology and determine other necessary subsea processing equipment.
The use of cold flow technology introduces significant cost reductions compared to conventional flow assurance methods.

Responsibility Notice

The authors are the only responsible for the paper content.

Acknowledgments

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Appendix 1. Estimation of local flow rates of oil, gas and water at given pressure and temperature

The volumetric rates of oil (q_o), gas (q_g) and water (q_w), are computed with the surface condition rates ($q_{\bar{g}}$, $q_{\bar{o}}$, $q_{\bar{w}}$), and black oil properties (solution gas-oil ratio, R_s, oil volume factor, B_o and gas volume factor, B_g).
The local volumetric rate of gas:

$$q_\mathrm{g} = \left(q_{\bar{g}} - q_{\bar{o}} \cdot R_\mathrm{s}\right) \cdot B_g$$

Or, alternatively:

$$q_\mathrm{g} = q_{\bar{o}} \cdot (GOR - R_\mathrm{s}) \cdot B_g$$

Where GOR is the producing gas-oil ratio.
The volumetric rate of oil at the inlet:

$$q_\mathrm{o} = q_{\bar{o}} \cdot B_o$$

The volumetric rate of water (assuming water is incompressible):

$$q_\mathrm{w} = q_{\bar{w}} = q_{\bar{o}} \cdot \left(\frac{W_c}{1 - W_c}\right)$$

Appendix 2. Fluid model

Gas density
The gas volume factor B_g is calculated with the following expression:

$$B_g = \frac{p_{sc} \cdot Z \cdot T}{T_{sc} \cdot p}$$

The gas deviation factor Z has been calculated with the correlation of Hall and Yarborough [7]. The critical gas properties are estimated using the molecular weight (M_g) with the equations given by Sutton [8].
The molecular weight (M_g) used to compute the gas volume factor in this expression is the molecular weight of surface gas.
The solution gas-oil ratio, R_s, is calculated with Standing's correlation:

$$R_s = 0.571 \cdot \gamma_g \cdot 10^{0.0151 \cdot API - 0.00198 \cdot T} \cdot (0.797 \cdot p + 1.4)^{1.205}$$

The saturated oil volume factor, B_o, is calculated using Standing's correlation:

$$B_o = 0.9759 + 0.000952 \cdot \left[\left(\frac{\gamma_g}{\gamma_o}\right)^{0.5} \cdot R_s + 0.401 \cdot T - 103\right]^{1.2}$$

In these expressions, γ_g and γ_o are the specific gravities of surface gas and surface oil respectively. API is the crude API. Temperature (T) is input in K and pressure (p) in bara.