

OPTIMISING LONG-DISTANCE GAS-CONDENSATE FLOWLINES

Abstract

This case study is drawn from a conceptual study carried out for an independent UK based Oil and Gas company. The flowline was sized by combining an integrated reservoir/flowline simulator with simple discounted cash flow economics. The operability of the flowline was also an important issue as the speed at which it could safely alter its production rate was stipulated in the Gas Sales Contract (GSC). The study demonstrates how many conceptual issues in gas-condensate systems can be studied using steady state simulators, thus allowing transient simulation to be deferred until the later phases of design.

The System

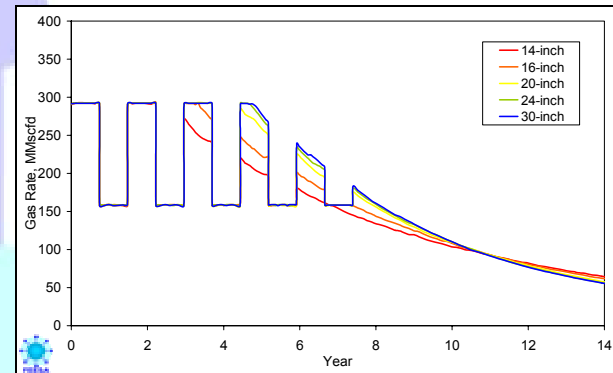
The system of interest was a large offshore field tied back to shore through a long-range wet gas-condensate flowline. The flowline was more than 100km in length and is situated in Northern Europe. As typifies such systems, the seasonal change in demand for gas is reflected in the production profile; in this case twice the flow of gas is required October - March than for the rest of the year. The price per unit volume of gas is subject to both seasonal fluctuations and system responsiveness, as defined in the GSC.

Flowline Sizing

For this development, pipeline capital costs represented a major part of the capital investment, meaning that the economics of the development is a strong function of the pipeline design. Motivated by this, the system was optimised based on pipeline size. Simulations were performed for a range of pipeline sizes using an integrated reservoir-flowline model. Using the model the impact of pipeline size on system deliverability was evaluated through field life. Illustrative results are presented in Figure 1 for a range of pipeline sizes.

The simplified square-wave shape of the fluctuating seasonal demand can clearly be seen. Production rates are forced to follow this demand by choking, until the pressure in the reservoir is no longer able to deliver the required flow rate of gas. The arrival pressure was constant throughout field life, i.e. no onshore compression was used in these cases.

Figure 1 Production Profile as a Function of Diameter



As can be seen in Figure 1, the 16-inch case is unable to meet the demand for gas from the winter of year 3 onwards, as the pressure drop is too high for the remaining pressure in the reservoir. In the following year, a 24-inch diameter pipe is able to meet peak demand but only for about half of the winter period. It is interesting to note, that increasing the pipeline size to 30-inch in this period does little to improve the situation in the fourth winter. This is because during this period the flow rate is constrained by formation and tubing pressure drops.

From this parametric Life-of-Field analysis, it is clear that larger pipelines lead to higher flow rates and greater ultimate recoveries. However, larger pipelines are more costly than smaller ones, and over 100km, the differences can be very significant.

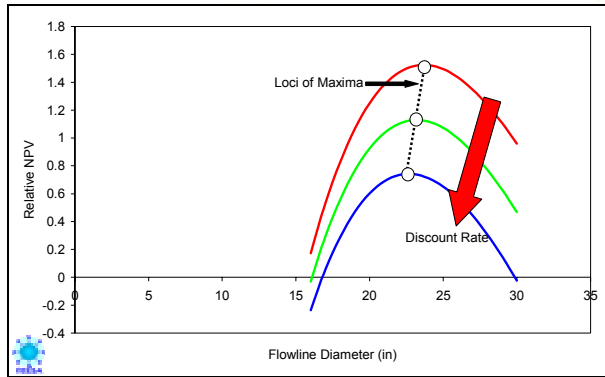
One can clearly see the ‘law of diminishing returns’ taking effect, which implies that increasing the pipeline size does not lead to a proportionate increase in the incremental value of the gas. The explanation is that the flow rate becomes constrained by some other part of the production system, e.g. the well or formation pressure drops.

So which diameter is best? This question can be answered by calculating some economic measure (or econometric) of the system and seeing how it changes with diameter. Commonly used values are the Net Present Value (NPV) or the Internal Rate of Return (IRR).

Here, for illustrative purposes, we will use the incremental Net Present Value. This is calculated by trading the incremental CAPEX of a larger pipeline system against the incremental discounted net revenue associated with the additional gas production. A plot

of this econometric is provided in Figure 2 as a family of relative incremental NPV curves for different discount rates. From the figure, it is evident that the optimum pipeline size based on this single variable optimisation is 24-inch and under these assumptions this size would represent the most efficient use of capital.

Figure 2 NPV versus Flowline Size and Discount Rate



Clearly, applying optimisation techniques such as this, provides the system designer with a rigorous quantitative approach for selecting pipeline sizes.

Flowline Operability

Another important issue with long-range gas-condensate pipelines is the operability. Long-distance subsea gas-condensate flowlines have several interesting features.

Producing both water and hydrocarbon gas, there is invariably a risk of hydrate formation in such systems. There is usually insufficient enthalpy in the produced fluids to reach the end of the flowline without entering the hydrate envelope, even using expensive pipe-in-pipe insulation systems. Therefore, it is usual to select chemical inhibition for long gas-condensate flowlines, typically using inhibitors such as methanol or glycol to depress the hydrate formation temperatures. Such inhibitors are expensive and are often recovered from the fluids at the end of the flowline for reuse.

For gas-condensate flowlines, the flow regime is normally stratified. This is the flow regime where liquids travel along the bottom of the flowline and gas slips over the top, usually at a much higher velocity. The liquid velocity can be so low that the proportion of liquid to gas in the flowline can be many times greater than the producing Liquid Gas Ratio (LGR) from the reservoir. Consequently, significant quantities of hydrate inhibitor may need to be injected during the initial start-up phase before any are recovered from the outlet. As a result, the required storage volume for inhibitor may be considerable.

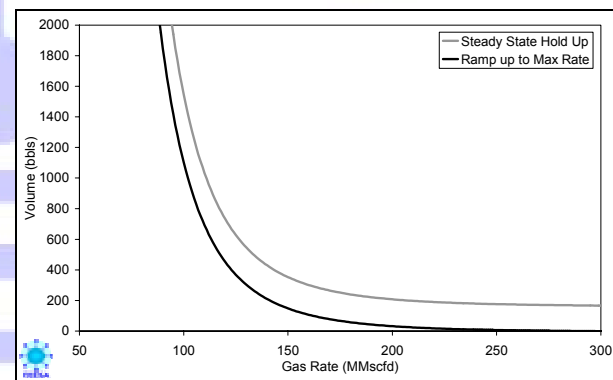
Another important operability issue in pipelines that operate in the stratified flow regime, is how the liquid content or *holdup* changes with flow rate. At low gas rates the fluids are at lower velocities, hence more liquid accumulates in the flowline and the total liquid content increases. Figure 3 illustrates this effect by presenting the variation of the steady state liquid holdup (total liquid content) with the gas rate. An operability problem therefore arises when moving from one steady state to another. If the final steady state has a much lower flowline liquid content than the initial state, (e.g. arising from a flow rate ramp-up operation), the excess liquids must be expelled from the flowline. If this excess liquid is expelled over a short duration, as can happen if the flow rate ramp-up is fast, then the resultant surge, known as a ramp-up surge, could well flood downstream equipment.

The ramp-up surge volume can be reduced by extending the time period over which the ramp-up takes place. However, a short ramp-up period may be a prerequisite of the GSC and a large slug catcher may therefore be necessary.

Also shown in Figure 3 is a ramp-up curve giving the estimated required slug catcher liquid surge volume for a ramp up operation taking into account the steady state holdup curve and the rate of ramp up. It was calculated using the Cunliffe method which only requires the results from the steady state simulator used in the integrated reservoir analysis discussed earlier.

As can be seen, ramp-up operations from flow rates greater than 150 MMscfd produce surges not exceeding 200 barrels. However, if the flowline operated at a steady state flow rate less than this, the surge volume could be very much greater if the flow rate was suddenly increased to the maximum rate.

Figure 3 Liquid Holdup Ramp-up Plots

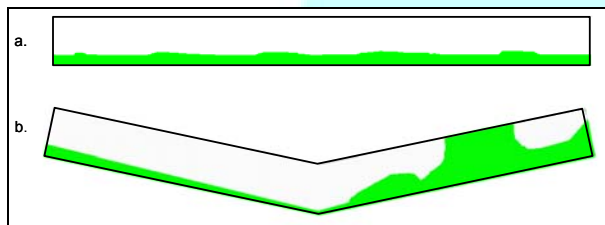


This minimum flow rate without encountering problems on ramp-up, is an important parameter in the operability of the system.

Using the Cunliffe method to estimate the required slug catcher surge volume is very convenient since it is based on steady state simulation results which are comparatively cheap to generate. Moreover, the method is of reasonable accuracy and facilitates rapid sensitivity calculations. It is therefore very well suited to the conceptual engineering phase of oil and gas design when the accuracy of basic data does not warrant more sophisticated methods. However, in detailed engineering, when accurate design data are available (e.g. bathymetry results), the slug catcher should be sized using transient simulation tools.

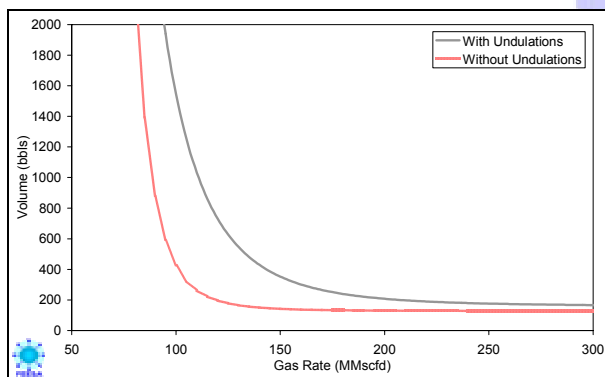
In order to predict holdup characteristics, it is important to have a representative model of the multiphase flowline, including an assessment of the likely topography along the proposed pipeline route. This is because liquid holdup is very sensitive to flowline inclination, particularly at low flow rates. Figure 4 illustrates the mechanisms.

Figure 4 The Effect of Undulation on Flowline Holdup



If a flowline is idealised as a perfectly horizontal pipe (Figure 4a), but actually has some undulation to it (Figure 4b), as many flowlines do, the liquid content of the flowline can be seriously underestimated. In the downhill sections of the undulation the holdup is slightly reduced compared to the horizontal case. However, in the uphill sections the holdup is markedly increased such that the flowline may even be operating in the slug flow regime. The net effect of modelling the undulations is a significant increase in the total predicted flowline liquid holdup.

Figure 5 The Effect of Undulation on Holdup Plot

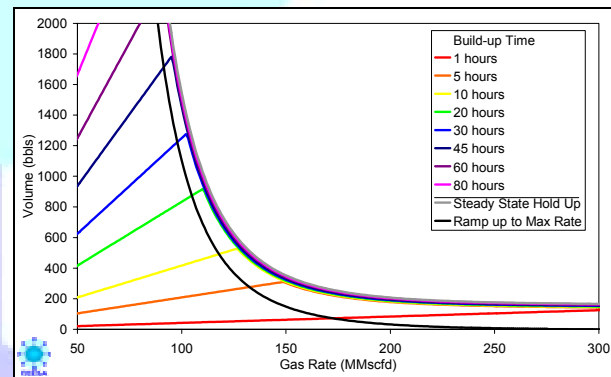


This difference in the predicted holdup also increases the predicted pressure drop in the system thus reducing the overall design deliverability.

Figure 5 shows how the inclusion of small scale undulations affects the predicted holdup curve. Clearly, the inclusion of undulations leads to a pronounced increase in the predicted holdup together with an increase in the minimum operating flow rate for a given slug catcher size. It is clear that good design practice should include sensitivity studies to quantify the effect of small scale undulations.

From Figure 1, it is evident that the flowline would not usually be operated at flow rates of less than 150 MMscfd. However, should this be required, it does not necessarily follow that large liquid surges will arise during ramp-up. Many gas-condensate systems have relatively low LGRs which implies that protracted periods of turndown operation are required in order to accumulate steady state liquid inventories. This time dimension is illustrated in Figure 6 as lines of liquid accumulation for various operating durations. For example, at 50 MMscfd it would take 20 hours to build up 400 barrels of liquid in the line and 80 hours to build up 1700 barrels of liquid. Thus it may be possible to operate for short periods without serious surge issues arising on ramp-up.

Figure 6 Ramp-up and Filling Time



Conclusions

Steady state simulations, used in conjunction with reservoir simulators, economic tools and an understanding of the key issues can be a great benefit in the analysis of long-distance gas-condensate flowlines. For conceptual studies, the use of elaborate transient simulators can be avoided using the techniques described. Thus, costly transient simulation can be deferred until the later stages of design when better design data are available justifying the application of these methods.