THE FLOW ASSURANCE DILEMMA: RISK VERUS COST?

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Introduction

The principal theme of this article is the dilemma encountered in Flow Assurance design when trying to balance the perceived risks of a new oil and gas development with the required capital expenditure. To any practicing engineer, this conflict is quite familiar and is aptly summarised by Sir Hugh Ford's definition of Engineering:

"Essentially decision taking in the creation of artefacts fit for their purpose to meet the perceived need at an acceptable price in a competitive market against a background of incomplete knowledge and uncertain boundary conditions with limited resources of materials, man power, time and money."

We first consider the meaning of the term Flow Assurance as understood in the industry before examining the reasons why the subject has come to the fore in recent years. We then explore the difficult decision making process which embodies the trade-off between capital investment and risk acceptance and the role that Flow Assurance plays in this process. Finally we make some tentative recommendations about how the process could be improved.

What is Flow Assurance?

For those working in the global oil and gas industry, the term Flow Assurance is all too familiar term, having been adopted as a universal marketing cry by engineering design and construction companies alike. We understand that the term was coined by Petrobras in the early 1990s in Portuguese as Garantia de Fluxo, meaning literally Guarantee the Flow, which was subsequently translated to give the well-known expression Flow Assurance. The term originally covered only the thermal hydraulic and production chemistry issues encountered during oil and gas production.

In recent years however, Flow Assurance has become a vogue subject and with this popularity has come a broadening to include a multiplicity of other issues which can affect the extraction of oil and gas. As a result, the term is now synonymous with wide range of issues, for example:

- System Deliverability – pressure drop versus production, pipeline size & pressure boosting
- Thermal Behaviour – temperature changes, insulation options & heating requirements.
- Production Chemistry – hydrates, waxes, asphaltenes, scaling, sand, corrosivity & rheology.
- Operability Characteristics – start-up, shutdown, transient behaviour (e.g. slugging) etc.
- System Performance – mechanical integrity, equipment reliability, system availability etc.

The Growing Importance of Flow Assurance

While the term Flow Assurance is relatively new, the problems it encompasses are not and have been a thorn in the industry's side from the very early days. For example, hydrates were first observed causing blockages in gas pipelines as early as the 1930s which motivated the pioneering work of Hammerschmidt into the mitigation and remediation of hydrate blockages using chemical inhibitors.

More recently however, the Flow Assurance problems encountered in oil and gas production have become more onerous, leading to an increased overall awareness in the industry. This is particularly the case in the offshore sector, where the low temperatures, remote locations and often great water depths of subsea environments conspire to exacerbate problems such as blockages through hydrate formation or wax deposition or topsides' facilities shutdowns due to severe slugging. Moreover, the ramifications of these events can be very serious incurring significant intervention costs and substantial losses in production revenues.

But why have Flow Assurance difficulties worsened recently? Well the explanation lies in the changing face of the offshore industry. In mature provinces, such as the North Sea, the average field size has decreased markedly such that small fields, typically of the order of 10 million barrels, are the main stay of activity. For such small accumulations, economic hurdles can only be met if development costs are kept very low compared to historical levels. As a result these small fields are often developed with long subsea tiebacks to existing infrastructure that push the boundaries of Flow Assurance design.

At the other end of the spectrum are the frontier deepwater provinces, such as the Gulf of Mexico or West Africa, where the field size is much larger (typically 250-1000 million barrels) and able to support a much higher level of capital investment. However, the Flow Assurance difficulties are still quite pronounced due to the inherent difficulties in producing from great water depths, often in excess of 1000 metres.

The Dilemma: Risk versus Cost

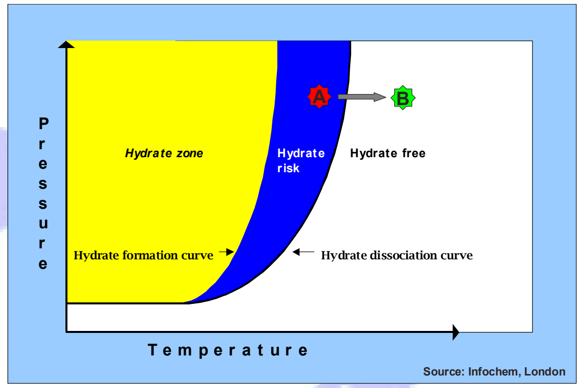
All oil and gas fields can be developed to minimise Flow Assurance problems and maximise the overall production and availability. But it is well-known that increasing the robustness of a system to very high levels, implies increased equipment costs which ultimately makes the project uneconomic. Hence, it is necessary to strike a satisfactory balance between the capital investment requirement and the level of acceptable risk. Unfortunately this is very easy to say but in practice very difficult to achieve principally because of the subjective nature of risk and varying perceptions of risk among those involved in the design process.

For example, it may be anticipated that a new field development will operate inside the hydrate risk zone (Figure 1, Position A) in the first year of production because of low production rates and hence operating temperatures. This could be a temporary state because in later years the number of producing wells will have increased as more wells are drilled, the average water cut will increase and the operating temperatures will rise moving the system away from the hydrate risk zone.

Because of the temporary nature of the risk, and the low levels of water early in field life making the formation of a hydrate blockage unlikely, some will argue that this is acceptable. However, other more cautious types, mindful of the sensitivity of the overall economics to successful early production, may take the contrary view. They may recommend that the levels of insulation on the subsea pipelines are increased to move the system outside the hydrate risk zone (Figure 1, Position B) thus reducing the risk.

In this example, the obvious next question is who is right? Well the answer to this is highly subjective and really impossible to answer before the event; which way you vote depends very much on your level of exposure to the potential risk. Furthermore, the willingness to accept risk also varies with the economics of a particular project and it is commonplace for marginal projects to accept an often uncomfortable level of risk if the project economics dictate that no more money is available for further expenditure.

Figure 1 Hydrate Risk Diagram



Another example of the subjective nature of evaluating Flow Assurance risks is in the design of flowline-riser systems for stable operation free from slug flow. In offshore developments, a common configuration is a multiphase pipeline transporting gas and liquid supplied by a number of production wells at one extremity to a central processing facility at the other extremity. The fluids are conveyed from the seabed to the processing facility via a production riser.

These systems are susceptible to a form of instability which can lead to large surges in the liquid and gas production rates, and if the topsides processing facilities are not adequately sized this can result in equipment trips and unplanned shutdowns. Indeed, in some circumstances the magnitudes of these surges can render a system inoperable necessitating costly equipment modifications such as the retrofitting of a larger slug catcher.

This instability has various names in the industry, including ‘severe slugging’, ‘riser-base slugging’ and ‘riser-induced slugging’. Figure 2 presents a schematic of the process of severe slugging. The base of the riser is periodically blocked with liquid which prevents flow. After a period of time (usually of the order of hours) the pressure in the flowline has increased to a sufficient level to expel the liquid in the riser in one large liquid slug. This is then followed by a large gas surge produced as the pipeline blows down to a low pressure. As the gas rate drops off, the liquid then begins to accumulate at the base of the riser and the cycle is repeated.

Figure 2 Severe Slugging in Flowline-Riser Systems

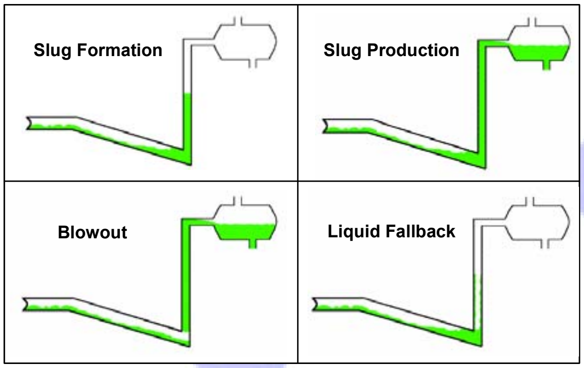
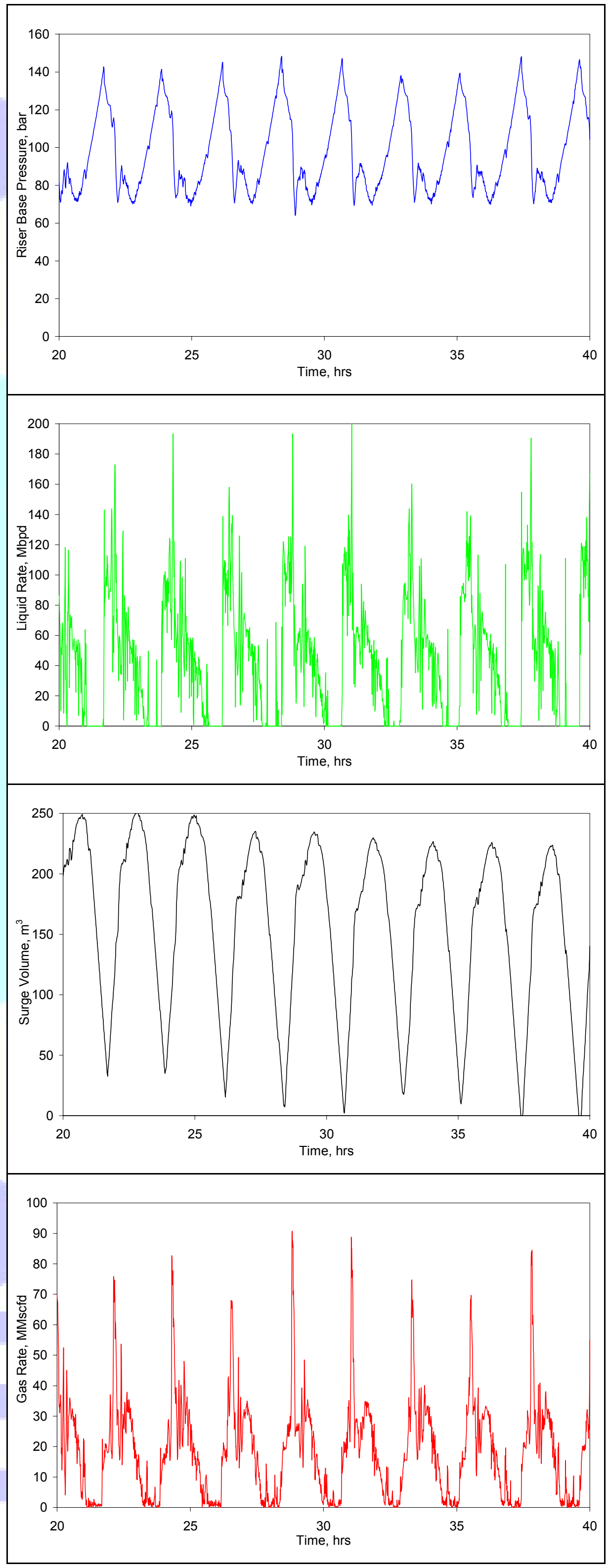


Figure 3 shows some predicted time traces generated from transient simulations with a leading multiphase flow simulator applied to a deepwater oil and gas production system. The example shows the large surges in gas and oil flow rates accompanying this phenomenon. Clearly such large transient variations could present difficulties for topsides facilities unless they are designed to accommodate them. However, designing the topsides facilities to accept these transients may dictate large and expensive slug catchers with compression systems equipped with fast responding control systems. This may not be cost-effective and it may be more prudent to design the system to operate in a stable manner, perhaps by the incorporation of gas lift injection at the base of the riser or by the reduction of the flowline size, both of which have a stabilising effect.

The design of stable flowline-riser systems is particularly important in deepwater fields, for example the Angolan fields Dalia, Girassol, Greater Plutonio or Kizomba, since the propensity towards severe slugging is likely to be greater and the associated surges more pronounced at greater water depths. With the advancement in computing power and the increasing sophistication of the transient multiphase flow simulators, engineers in the oil and gas industry have recently begun to analyse the stability of these systems using computationally intensive parametric techniques. These techniques attempt to build a detailed picture of regions of stable and unstable behaviour in what is termed parameter space.

Figure 3 Example Time Traces of Surging During Severe Slugging

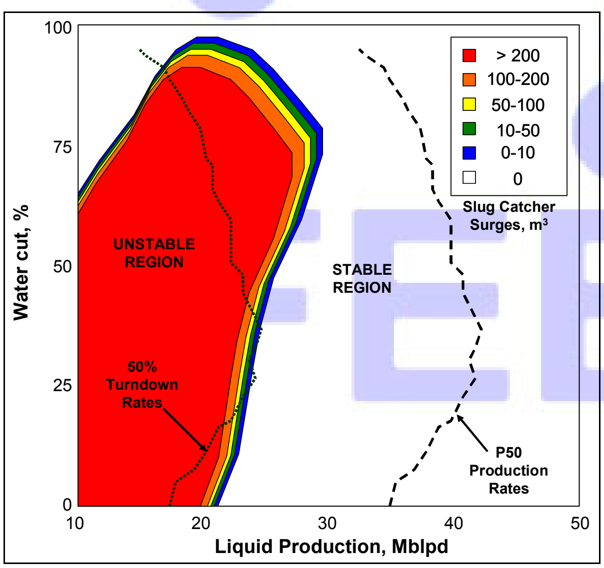


In Figure 4 an example stability map is shown for a flowline-riser system which shows regions of stable and unstable behaviour. By tracing the path of the P50 production profile on this plot, it is possible to assess the likelihood of instability under normal operation. The example chart shows that the system is stable under the expected production scenario through field life. Off-design cases can also be analysed using this approach by plotting an adjusted production profile. In the case shown, the path of 50% turndown rates is indicated which shows that system is predicted to be unstable when operated at these reduced rates.

This parametric approach to the design of stable flowline-riser systems is extremely powerful allowing a detailed picture to be established. But one should not be deluded by the rigour of this approach since considerable uncertainty exists in a number of areas. In particular, the basic data used to build a transient multiphase flow model is subject to uncertainty as is the outturn production history and hence the actual path that will be traced on the map. Moreover, other parameters can affect the location of the stability boundary such as the producing gas-oil ratio or the installed topography of the flowline. Finally, one should never overlook the inaccuracies of the multiphase flow simulators, for accurate prediction of transients in multiphase systems remains beyond the state-of-the-art.

Taking these factors into account, once again the design team is confronted by another subjective decision, in this case trading the risk of severe slugging against the capital expenditure in topsides and subsea facilities.

Figure 4 Example Stability Map (Watercut-Flow Rate Plane)



Conclusions & Recommendations

It is clear from only cursory consideration that the subject of Flow Assurance is extremely diverse, encompassing many discrete and specialised subjects and bridging across the full gamut of engineering disciplines. Therefore, implementation of Flow Assurance design practices leading to successful field developments, presents a significant challenge and necessitates good communication across all aspects of the design process.

The difficulties are further compounded by the lack of objectivity that exists in the decision making process due to the differing perceptions of Flow Assurance risk and the willingness to accept this risk. As a result, most field developments are sub-optimal and can be considered either over-engineered or under-engineered with respect to their Flow Assurance designs.

To address this situation, more comprehensive analysis of data from producing fields is required to evaluate the levels of conservatism in the design procedures and therefore the need for design margins. This analysis should be carried out across as wide a range of field types as is practicable and should include both successful developments and those plagued by Flow Assurance problems. Only through such a methodical approach, will it be possible to accurately quantify the levels of Flow Assurance risk and thus reduce the levels of subjectivity evident in today's industry.

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