Risk-Based Hydrate Management for Offshore Oil & Gas Developments

Alicia Park

John Boxall, Kecheng Shen
School of Mechanical and Chemical Engineering

CEED Client: Woodside Energy Ltd.

Abstract

Natural gas hydrate formation can cause significant operational problems, resulting in production losses in the order of multi-million dollars and major safety risks. As the oil and gas industry expands to deeper water developments, the risk of hydrate formation and consequent impacts has increased. Traditionally, a risk avoidance strategy has been adopted for management of hydrates. Due to the increasing complexity and costs associated with the avoidance strategies, however, there has been a desire within the industry towards acceptance of a more risk- based hydrate management, through better understanding of various factors influencing hydrate blockage.

Risk-based hydrate management evaluates potential causes and consequences of hydrate plug formation. Adequately employed, it can reduce CAPEX and OPEX without imposing significantly increased risks. Investigation of different hydrate management methods including chemical inhibitors can assist in identifying their limitations and potentials to reduce hydrate risks. This project aims to investigate hydrate inhibition technologies available and develop a risk-based methodology for selection of hydrate management strategies for offshore oil and gas developments.

1. Introduction

1.1 Hydrate Plugs

Hydrate plugs can cause significant operational problems resulting in considerable economical losses. The plugs can form quite abruptly in operating conditions, and the remediation can take downtimes of days or months. This can incur production losses in the order of multi-million dollars, as well as imposing major safety risks.

Natural gas hydrates are crystalline solids composed of water and gas. When accumulated, hydrates form ice-like solid plugs blocking flowlines. Due to the consequences following a hydrate blockage, companies typically design for complete avoidance of hydrate formation using different strategies. To date, chemical inhibitors have been commonly applied. Thermodynamic hydrate inhibitors (THI's) such as methanol and monoethylene glycol (MEG) shift the thermodynamics of hydrate curve outside the operating range. Depending on the water rate, a deepwater offshore system can use 2,500 – 10,500 gallons of methanol per day, costing approximately $ 4 – 15m annually (Agizah *et al.*, 2010).

Fig.1 (Notz, 1994) shows the hydrate formation pressure and temperature as a function of methanol concentration for a given development. The operating conditions relative to hydrate curve depends on numerous factors such as the composition of hydrocarbon, initial fluid temperature from the reservoir, ambient seabed temperature, and the level of insulation applied to the pipeline, etc. The bold line indicates the pipeline length from a deep water petroleum well. When no methanol inhibitor is injected, the system enters the hydrate forming region at approximately 9 miles (14.5km) from the wellbore. With a higher dosage of methanol concentration, the hydrate curve is thermodynamically moved to the left, and outside the operating range.

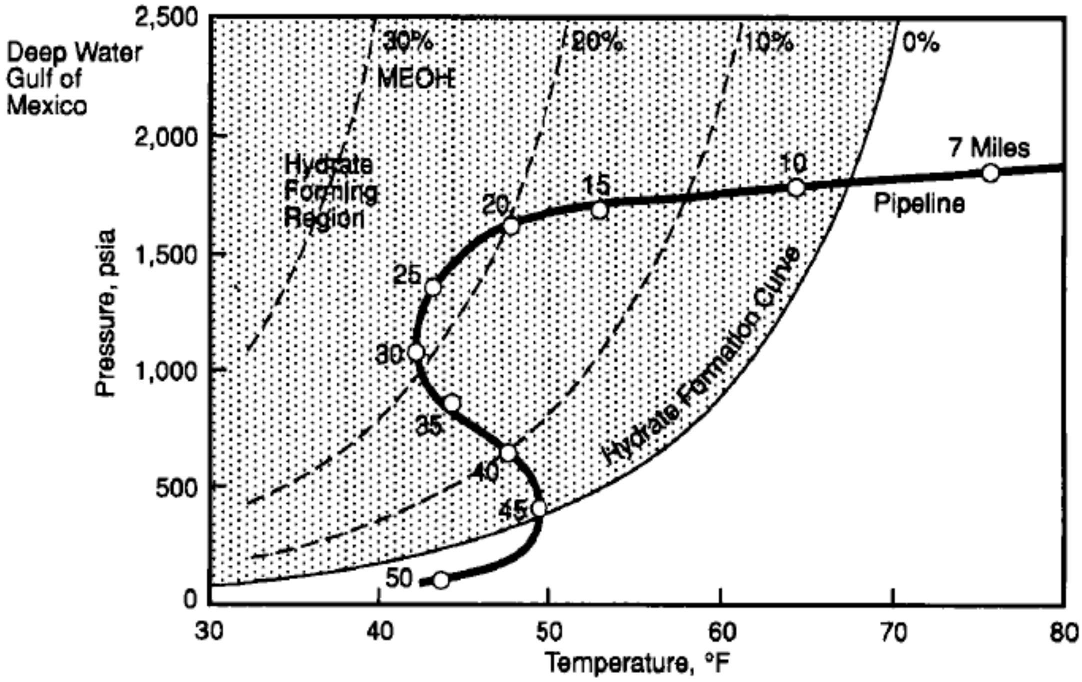

Fig. 1 Hydrate-formation pressures and temperatures (Notz, 1994)

1.2 Current State of Arts and Environment

With an increasing demand for oil and gas resources, the industry has expanded exploration fields into deeper water in recent years, ranging from 3000 to 5000 ft. As a result of the extreme conditions, the risk of hydrate formation and demand on current hydrate management strategies increases. Due to the increasing complexity and associated cost of current strategies, there has been a desire within the industry towards acceptance of a more risk-based management.

A risk-based hydrate management evaluation considers both the likelihood and potential consequences when screening hydrate management strategies. The objective of risk-based management is to reduce development and operating costs (CAPEX and OPEX) without imposing significantly increased financial, environmental, social or safety risks. This is achieved through increased understanding of the factors influencing hydrate blockage formation, evaluation of likelihood and consequences of hydrate blockage, and selection of appropriate management strategies.

Investigation of various hydrate management strategies can also enhance the risk analysis. One of such strategies is the low dosage hydrate inhibitors (LDHI's), including kinetic hydrate inhibitors (KHI's) and anti-agglomerants (AA's). KHI's delay the induction time of the hydrate nucleation, whereas AA's prevent the hydrate particles from joining or agglomerating, and instead facilitates slurry flow of the fluid. LDHI's can be applied at a significantly lower dosage than THI's –typically applied at 0.25-5 vol.% of produced water (Clark *et al*., 2005) in comparison to 30-50 vol.% for THI's (Agizah *et al.* 2010). However, LDHI's also have several limitations that need to be addressed in a risk-based decision.

1.3 Objectives

The main objective of this project is to develop a methodology for risk-based assessment of hydrate management strategies. The methodology will serve as a guideline to design engineers to assist in screening and selecting hydrate management strategies. Understanding of hydrate kinetics as well as thermodynamics will be critical in assessing hydrate blockage potential, or quantifying the associated risk.

2. Analysis Process

The main objective was further broken down into the following:

- Analyse the current hydrate management practiced in the industry
- Evaluate causes and consequences of hydrate plugs, and costs of inhibition methods
- Investigate LDHI implementations and other technologies for hydrate management

This was achieved in a series of literature reviews (e.g. Carroll, 2003; Sloan, 2000), followed by a close examination of the hydrate management strategies employed within Woodside. Shell's Hydrate Guideline (Klomp, 2008) was reviewed to gain understanding of industry practice. Collection of knowledge from literature reviews and the gained industry experience was then used to evaluate factors necessary to create a risk analysis of hydrate formation.

The flowchart below summarises the investigation plan.

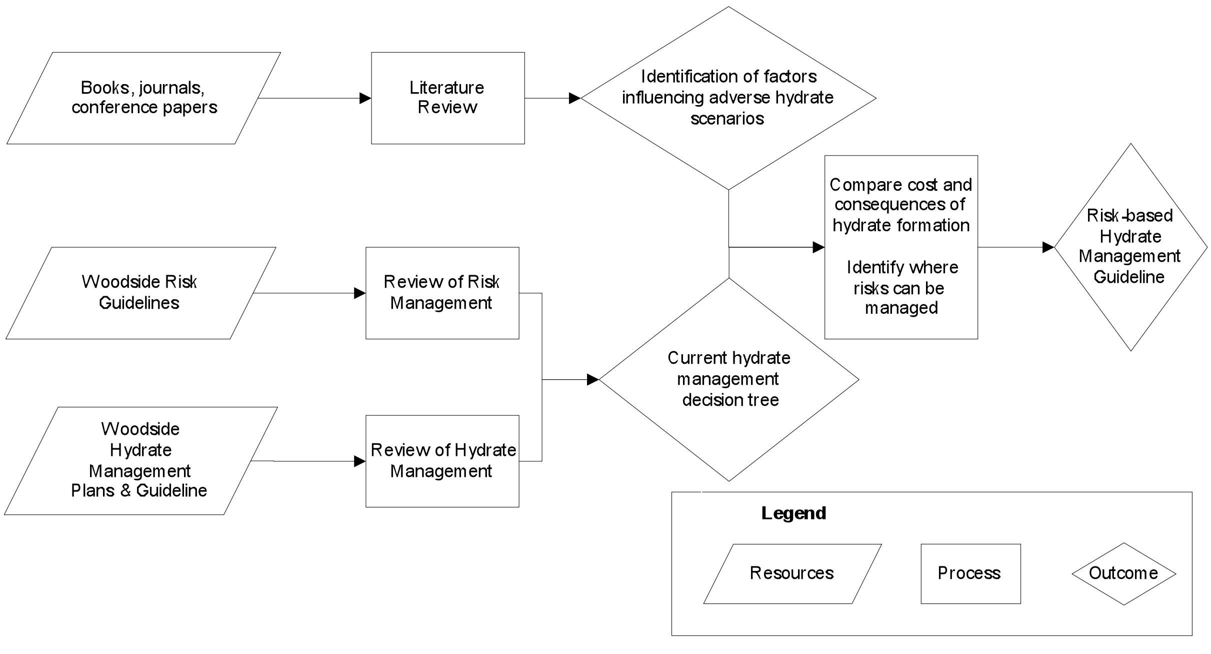

Fig.2 Flowchart of investigation plan

3. Results and Discussion

3.1 Risk-Based Management

In order to develop a risk-based management methodology, and potentially to quantify the risk, various operational scenarios and hydrate management methods were analysed in detail. Some of the key elements influencing a system to exhibit adverse hydrate condition are:

- Depth of water – determines the ambient temperature and hydrostatic pressure, affecting the P-T hydrate curve; influences the ease of accessibility
- Length of the pipeline – longer exposure to the ambient temperature reduces the fluid temperature; extended length affects overall cost of insulation
- Water production rate – promotes hydrate formation; increases the volume of chemical inhibitors required; influences the effectiveness of different hydrate management (e.g. DEH or dehydration may be justified)

Hydrate incidents mostly occur as a result of operational abnormalities –such as a failure of an inhibitor injection system, sudden increase in water cut, or restarts of flowline following extended shut-ins. Root cause analysis of these abnormalities and failures hence is beneficial to identifying which parts of the system leads more to a susceptible hydrate environment. Mobley (1999) describes the methodology of fault tree analysis in detail, with evaluation guidelines for common machineries and equipments. Modelling of event tree analysis is found in Vinnem (1999).

3.2 Chemical Hydrate Inhibitors

The literature review suggests that there have been numerous successful implementations of KHI's and AA's to reduce or replace traditional THI's (e.g. Agizah *et al*., 2010; Clark *et al*., 2005; Frostman, 2000). For some applications, the use of LDHI's reduced the operating costs (purchase, transportation and storage of chemicals), it also allowed incremental production capacity that was previously foregone due to the hydrate forming thermodynamic condition. Other benefits of LDHI's include combined usage with chemicals used for other flow assurance issues, such as corrosion inhibitors and paraffin inhibitors.

Frostman (2000) compares the transient effects of THI, KHI, AA, and no inhibitor conditions.

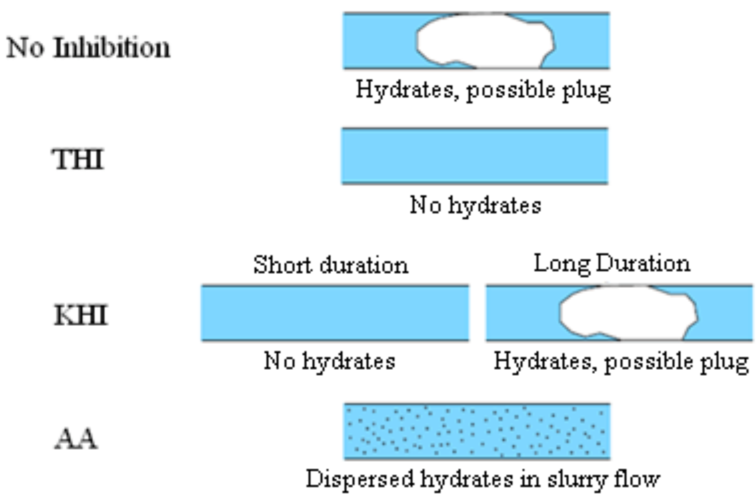

Fig.3 Transient effects of chemical hydrate inhibitions (Frostman, 2000)

Despite potential in reducing the overall cost (depending on water production rate) and improved safety, LDHI's have certain limitations. The effectiveness of KHI's is time-dependent and still heavily limited by the subcooling temperature, typically under 20°F (11°C). In fact, if the flowline temperature falls below the subcooling allowance, hydrate forms more rapidly than it would in an uninhibited line. In case of AA's, the promotion of slurry flow may result in erosion or other mechanical problems downstream. Neither KHI's nor AA's offer permanent solutions to hydrate inhibition, and in sensitive scenarios, such as a restart of flow following a long shut-in, THI's are often the only effective means of hydrate inhibition.

3.3 Other Methods of Hydrate Inhibition

Another option to inhibit hydrate is to ensure that the system operates outside the hydrate forming region by increasing temperature or decreasing pressure. This can be done passively through burial or insulation of pipeline, and/or actively through direct electric heating (DEH). Insulation is normally applied to pipelines with a maximum length of 50 km, and may also benefit in wax inhibition and topsides processing. DEH is particularly useful in targeting sections prone to hydrate freezing without affecting the downstream process.

Pressure reduction is typically not feasible for large gas condensate developments, due to the high volumetric flows and operating pressures required. The reduced production rate may also affect revenue and cash flow of a project. Furthermore, the flow area can only be changed in the earlier designing stage, imposing inflexibility in later stages of production cycle.

Dehydration of production fluid removes the hydrate forming agent (water), thereby lowering potential to form hydrates. However, an offshore platform has limited space available and installation of a dehydration unit often requires additional platforms. Subsea dehydration technology is still in early stage of deployment, and may contain severe unforeseen problems.

3.4 Discussion

Jones (1995) names two difficulties with implementing risk-based management as 1) the need to accept the perception of risk, and 2) acquisition of sufficient quantity of quality data to extract the required frequencies or probabilities. In order to make risk-based decisions, risk acceptance criteria need to be identified according to the ALARP principle. These risk criteria exist in various dimensions -including personnel safety, asset economics, environmental and social reputations.

The infrequent occurrences of hydrate blockages make it difficult to compute probabilities and causes needed for an accurate risk analysis. The stochastic nature of hydrate formation also makes the prediction of the probability complex and difficult. Dejean (2005) attempts to compute the probability of hydrate incidence based on equipment reliability. His simulations suggest that the hydrate risk cannot be based on statistical information such as mean time between failure (MTBF) and mean time to repair (MTTR).

4. Conclusions and Future Work

The progress to date has found numerous successful applications of LDHI's and THI's. Other hydrate management methods using temperature increase, pressure reduction and dehydration were also explored. This identified benefits and limitations of various hydrate management strategies, which could assist in selection of an appropriate method. Some factors of adverse hydrate scenarios were also identified.

Currently, the project is undergoing the process of developing a fault tree and event tree of hydrate plug formation to combine into a bow-tie risk matrix. The bow-tie risk analysis can then be incorporated into the existing hydrate management guideline to produce a risk-based guideline. This will enable design engineers to make risk-based decisions.

Due to the insufficient records of hydrates currently available, the proposed selection methodology may have some limitations. It may be possible to rank the importance of root causes and quantify associated probabilities as more data becomes available. Similarly, the event tree can be re-evaluated to quantify consequences of hydrate plugging.

5. References

Agizah, F.A.L., Ali, T.A.R., Baydoon, M., Allenson, S. & Scott, A. 2010. Pioneer challenge Reduction of MEG consumption using KHI for hydrate control in a deepwater environment offshore Egypt.

Carroll, J. 2003. *Natural Gas Hydrates -A Guide for Engineers,* Burlington, MA, USA, Gulf Professional Publishing.

Clark, L.W., Frostman, L.M. & Anderson, J. 2005. Low Dosage Hydrate Inhibitors (LDHI): Advances in Flow Assurance Technology for Offshore Gas Production Systems. *International Petroleum Technology Conference.* Doha, Qatar: International Petroleum Technology Conference.

Dejean, J.P., Averbuch, D., Gainville, M. & Doux, F. 2005. Integrating Flow Assurance Into Risk Management of Deep Offshore Field Developments. *Offshore Technology Conference.* Houston, TX, USA.

Frostman, L.M. 2000. Anti-Agglomerant Hydrate Inhibitors for Prevention of Hydrate Plugs in Deepwater Systems. *SPE Annual Technical Conference and Exhibition.* Dallas, Texas: Copyright 2000, Society of Petroleum Engineers Inc.

Jones, R.B. 1995. *Risk-Based Management -a reliability-centered approach,* Houston, Texas, Gulf Publishing Company.

Klomp, U.C. 2008. Hydrate Guidelines. Amsterdam: Shell Global Solutions.

Mobley, R.K. 1999. *Root Cause Failure Analysis,* Woburn, MA, USA, Butterworth-Heinemann.

Notz, P.K. 1994. Discussion of the Paper "The Study of Separation of Nitrogen from Methane by Hydrate Formation Using a Novel Apparatus". *Annals of the New York Academy of Sciences,* 715**,** 425.

Sloan, E.D. 2000. Hydrate engineering. *SPE monograph series,* 21**,** 1-82.

Vinnem, J.E. 1999. *Offshore Risk Assessment,* Dordrecht, The Nedtherlands, Kluwer Academic Publishers.