

Preventing the Formation of Methane Hydrates in Natural Gas Transmission Pipelines—A Comprehensive Review

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Abstract

Hydrates are usually formed during the transportation and treatment of natural gas, resulting in hydrate plugging of pipelines. Hydrates are crystal like structure being formed from the mixture of gas and water. They occur at low temperature and high-pressure conditions. These hydrate plugs cost the oil and gas industry significant amounts in revenue cuts and is a major problem for the industry. There are many preventive measures that can be implemented such as inhibitors to avoid the formation of hydrates. This paper aims to highlight the different measures and analyse their effectiveness for hydrate-plug prevention.

One such method for the reduction of hydrate formation is the removal of existing hydrates by using different types of inhibitors. The most common method of hydrate prevention in deep-water developments is injection of thermodynamic inhibitors, which include methanol, glycols, and others. If hydrate prevention methods are unsuitable and hydrates are liable to form, the process of dehydration can be used wherein the water gets removed from the gas stream. Electrical heating is also used as a way to dehydrate the pipe. This paper compares a variety of inhibitors and various hydrate preventive methods and discusses their influence in the mitigation of hydrate formation in gas pipelines.

Introduction

The increase in demand for energy is continuously forcing gas producers to work at higher pressures. The natural gas industry began to face the issue of unforeseen pipeline blockages at the beginning of the twentieth century. Hammer Schmidt showed in 1934 that the blockages that seemed to be ice were actually gas hydrates. If not quickly removed, this formation will plug the flow line in order to collapse the structure. This topic has cost the oil and gas industry billions of dollars in sales losses. Hydrate output along the natural gas pipeline has also been described as a major challenge to the sustainability of the oil and gas industry. Clathrate hydrates are

non-stoichiometric mixtures of water and natural gas in which the gas molecules are trapped in polygonal crystalline structure made of water molecules [1]. The water molecules arrange themselves around the gas molecules in an orderly manner, thereby trapping them. Such gas hydrates have the appearance of ice but can form at high pressures well above the freezing point of water. As you can see below in figure 1, the water molecules arrange themselves in an orderly manner around the gas molecules, thus entrapping them and these gas hydrates have the appearance of ice but can form well above the freezing point of water at high pressures.



Figure 1: Hydrates Formed on a Pipeline.

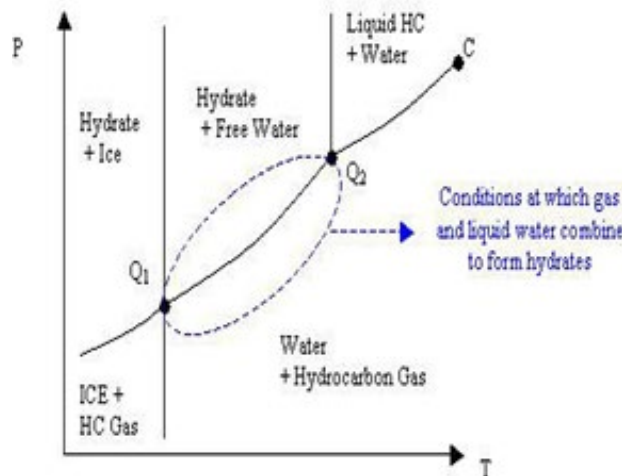


Figure 2: Phase Diagram Depicting the Formation of Hydrates. (Adewumi, 2018)

Natural gas pipelines always have some moisture content as the gas from the formations reach the well head saturated with water [3]. During the cold season, the ground temperatures are lower resulting in the temperature drop of the pipeline content. If the gas temperature falls below the saturation temperature corresponding to the water dew point, water vapour condensation will begin. In straighter sections of the pipeline, the condensate begins to collect due to gravity at the base of the pipe. At the base of the sagging/uphill parts of the pipe, the accumulation can increase. Hydrate nucleation processes are initiated if enough water is present and the thermodynamic conditions are acceptable. In the figure 2 above, gas hydrate phase diagram showing the depth and temperature conditions suitable for the formation of gas hydrate under various conditions of permafrost depth, geothermal gradient, gas chemistry, and a pore-pressure gradient of 9.795 kPa/m is shown.

Gas Hydrates

Gas hydrates form in untreated multiphase flows when water molecules crystallize around guest molecules at certain pressure and temperature conditions. The most common guest molecules are methane, ethane, propane, isobutane, normal butane, nitrogen, carbon dioxide and hydrogen sulphide, of which methane occurs most abundantly in natural hydrates [4]. While many factors influence hydrate formation, the two major conditions that promote hydrate formations are (1) the gas being at the appropriate temperature and pressure, and (2) the gas being at or below its water dew point. Other factors that affect hydrate formation include mixing, kinetics, type of physical site, surface for crystal formation, agglomeration and the salinity of the system [5].

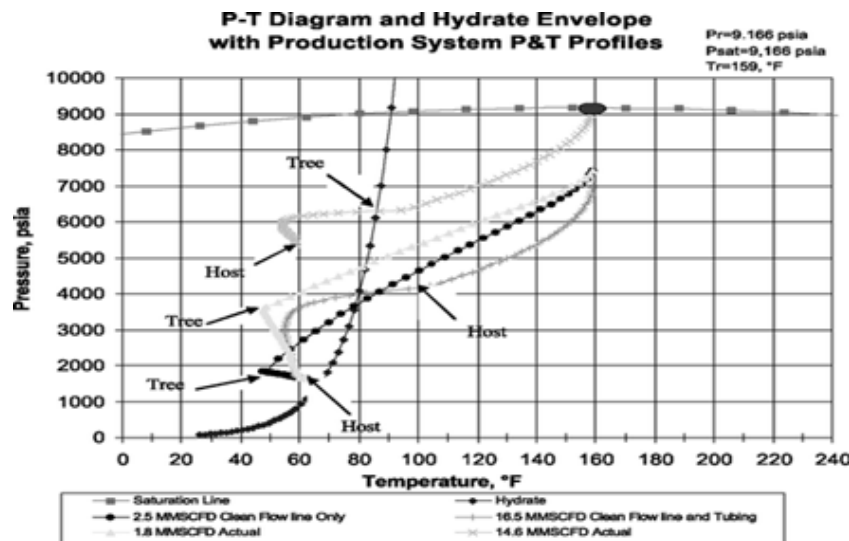


Figure 3: Typical Gas Hydrate Envelope of Gulf of Mexico

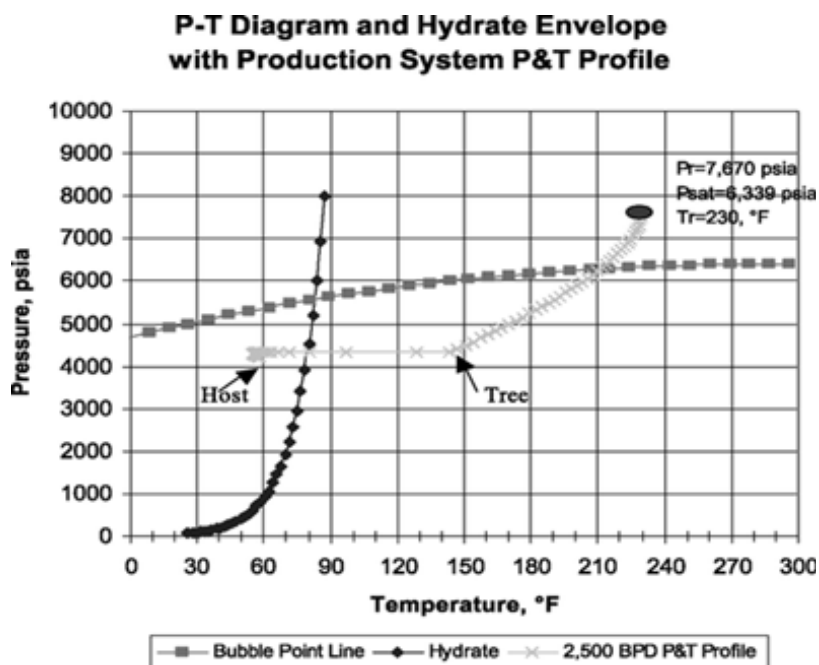


Figure 4: Typical Oil Hydrate Envelope of Gulf of Mexico

Hydrates are reported to occur when at higher pressures and reduced temperature, the natural gas and water coexist. In deep-water oil and gas fields, high pressures and low temperatures are normal, providing ideal conditions for the formation of hydrates. In general, as the multiphase fluid generated at the wellhead flows through the subsea pipelines, it becomes colder, which implies that at some point in their operating envelope, most subsea pipelines will experience hydrates. Moreover, shut-in and start-up are also primary times when hydrates form. On shut-in, the line temperature cools to that of the ocean floor so that the system is almost always in the hydrate region if the line is not depressurized [6]. At that condition, multiple hydrate plugs can form. Figures 3 and 4 above show the hydrate envelope (HE) examples for gas and oil respectively. The hydrate curve represents the thermodynamic boundary between hydrate stability and dissociation. The figure also shows an example of these curves, which shows the stability of natural gas hydrates as a function of pressure and temperature. To the right of the dissociation curve is the region in which hydrates do not form; operating in this region is safe from hydrate blockages. To the left of hydrate formation curve is the region where hydrates are thermodynamically stable and have the potential to form. This does not mean that hydrates will necessarily form or that formed hydrates will cause operational difficulties. The stability of hydrates increases with increasing pressure and decreasing temperature. There is often a delay time or the temperature must be lowered somewhat below the hydrate stability temperature in order for hydrates to form [7]. The tree and the host in the figure reflect a sense of differentiation of the set of barrels per day produced to the left and right of the hydrate curve. Hydrate does not form at the hosts and has a higher chance of forming at the tree.

Brief History of Hydrates

The historical background of gas hydrates can be traced back to Humphrey Davy, a scientific expert from Cornwall, England, who recognised chlorine as a component in 1810. Throughout the early 1800s, Davy and his collaborator, Michael Faraday, started experimenting with chlorine, combining the green gas with water and cooling the mixture to low temperatures [8].

At that point, during the 1930s, petroleum gas excavators started to complain of an icelike material obstructing pipelines exposed to cold temperatures. Researchers established that this material was not unadulterated ice, however ice formed over methane. They wasted no time attempting to discover approaches to keep hydrates from forming and went essentially to synthetic compounds, for example, methanol or monoethylene glycol [9]. From that point forward, mining organizations have added these materials to their flammable gas pipelines to restrain hydrate arrangement.

In the 1960s, the researchers found that methane hydrate, or "solid natural gas," was present in the Messoyakha gas field in western Siberia. This was noteworthy in view of the fact that normally occurring gas hydrates had never been detected. Geologists and physicists landed in a large basin bowl and began to examine the conditions under which the hydrates were formed. They found that subpermafrost residues were rich in hydrates and began to look for similar deposits in other high-scope locations. Before long, another group of analysts discovered methane hydrate in dregs covered far beneath the North Slope of Alaska. (Kvenvolden, 1999).

In view of these early discoveries, the U.S. Geological Survey (USGS) and the Department of Energy National Energy Technology Laboratory directed broad research between 1982 and

1992, uncovering that methane hydrate deposits could be found in offshore sediments also. All of a sudden, what had once been an anomaly and an industry problem seemed as though it may be a critical asset. In the mid-1990s, Japan and India led the methane hydrate research package, with the goal of finding further deposits and developing a monetary approach to extracting captured methane. Researchers have since discovered methane hydrate deposits in various areas, including the Mackenzie River Delta in Canada and the Nankai Trough off the coast of Japan. By 1955, today's technology had been developed and used by the petroleum industry [10].

Location of Gas Hydrates

Gas hydrates can be formed in any location where a free gas, water, the appropriate temperature and pressure exist, in the atmospheres of planets, inside the planets, and in the technical systems of production, transportation, and processing of gasses. In real conditions, the technological hydrates form in the layer prior to putting the development of a deposit in the well-bottom zone of a layer, if the deposit is located in the hydrate formation zone. Hydrates also form when the fluid temperature falls below the equilibrium temperature as a result of large recess or during the pumping of water having a temperature below hydrate equilibrium into the well bottom zone of a gas or a gas-oil well [11].

The forming hydrates can completely plug the wellbore during the long shutdown of wells in northern or offshore fields, even damage the well construction under some conditions and lead to an emergency fountain. Hydrates may form in the long-distance transport systems and in the underground storage and distribution of gases and a large fraction of liquid hydrocarbons in any segment of the technical gas collection and pre-treatment line [11].

The gas structure, salt content of water, and vapour composition in the gas phases before and after hydrate forming, the equilibrium pressure and temperature conditions of hydrate formation, and the successful adjustment of pressure and temperature must be understood to determine the location of hydrate formation. During the reduction of the temperature below equilibrium, hydrates will form and begin to accumulate. Several hydrate plugs can form in a series in a gas pipeline. Many variables decide the speed of hydrate aggregation, the most important being the state of water, the degree of subcooling and instability of the flow rate of the formation of a gas-water free interface, the strength of diffusion of hydrate formers, and other variables [11].

Hydrate Prevention Techniques

A variety of methods can prevent the formation of gas hydrates. The permanent solution is to extract water prior to transport by pipeline, such as using an offshore dehydration or subsea separation facility, which is not always the most cost-effective solution. Another way to avoid hydrate plugs is to maintain pressure and temperature conditions outside the hydrate-forming zone. But all in all, there are four methods to prevent hydration: [12].

- Injection of chemical inhibitors (these inhibitors avoid the formation of hydrates and are used in other methods).
- Control of the pressure (lower pressure, less hydration, but in gas transporting lines, it is impossible to raise the gas pressure for transporting it)
- Control of the temperature (heating of the system by electrical heating in order to prevent it from reaching the hydrate point of formation)
- Removing water (water in the pipe line should be removed). However, there is still some water in the pipe line.

Inhibitors

Two major classes of chemical inhibitors are available: thermodynamic and synthetic inhibitors. Traditionally, adding large quantities of methanol, ethylene glycol, or diethylene glycol (at a high enough concentration) to the gas/water stream has become the most common practical method to avoid hydrate formation in gas production systems. These chemicals are referred to as "thermodynamic inhibitors" and have the effect of pushing the loci of hydrate formation to the left, allowing the hydrate formation loci to the left, which causes the hydrate formation point to be displaced to a lower temperature and/or a high pressure. Such inhibitors are very costly, toxic and environmentally damaging. They have elevated uncertainty as well [13].

Synthetic inhibitor stimulates the growth of crystals and traps hydrocarbons in the net of ice crystals, impacting them by adsorbing molecules of water and preventing the chemical connection between molecules of gas and water. These inhibitors are added to gas lines at a low density [13].

As we can see below, figure 5 presents the systematic study done in context of implementation of gas hydrate inhibitors that are obtained via naturally occurring amino acids (L-Alanine, Glycine, L-Histidine, L-Phenylalanine and L-Asparagine). These materials are tested for methane (CH₄) hydrate inhibition purposes from both thermodynamically and kinetically perspectives at wide process conditions. Gas hydrate experiments were carried out by using rocking cell apparatus, from which pressure, temperature equilibrium data were obtained at recorded time and these data were translated into inhibitor performance evaluation from both thermodynamics and kinetic inhibition perspectives. Therefore, the figure below shows the effect of solubility limitation of studied amino acids, the effect of inhibitor concentration effect on the thermodynamic shift of the hydrate equilibrium curve, the role of side chain in amino acids in kinetic hydrate inhibition, the hydrophobic interactions of alkyl chain in water for synergistic point of view. The results done on the study showed that the suitability of amino acids combined with synergistic materials for high kinetic inhibition performance, which provided an additional time shift up to 35 hours in hydrate formation at moderate process conditions up to 55 bars, specifically when L-Alanine was used [14].

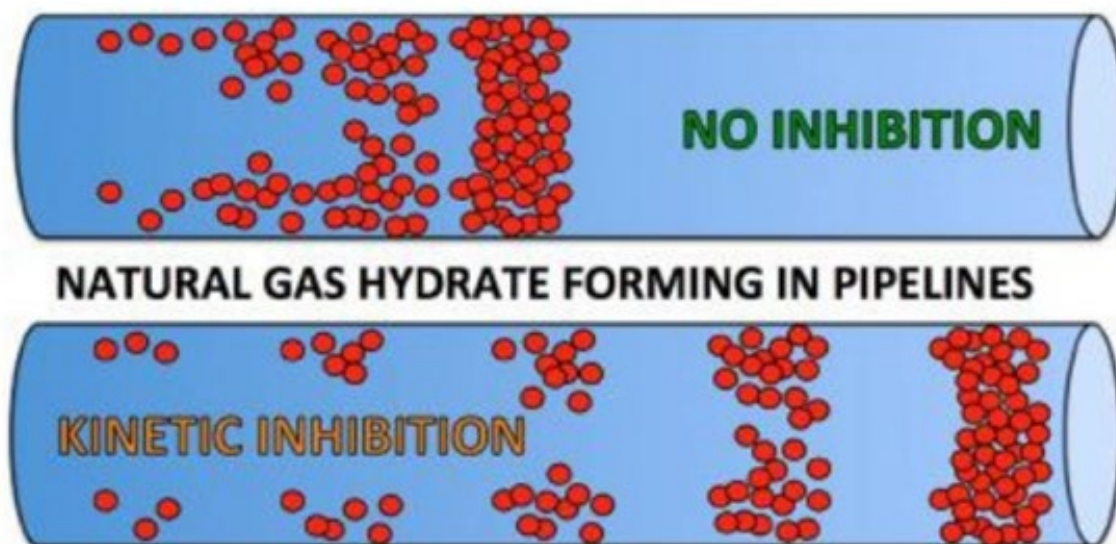


Figure 5: Natural Gas Hydrate Forming in Pipelines (Altamash, et al., 2017)

Low dosage inhibitors are an additional inhibitor newly discovered and used in the industry. Low-dosage inhibitors have been sufficiently developed in recent years to support their application in the field. Since they are one of the newest approaches to solving the problem of hydrate formation, they remain the least studied (both in the laboratory and in the field), the most poorly known and modelled, and the least applied, while implementations are reported in certain field conditions. Low dosage inhibitors have been tipped to be the greatest solution to hydrate inhibition in the coming years as they have just been introduced in the industry. They are more popular despite it being more expensive than conventional inhibitors (methanol and glycol) gained popularity because only small quantities are required to inhibit hydrate formation. It is expected that with the implementation of low-dosage inhibitors, environmental costs and capital expenditures would be reduced drastically. Methanol being toxic, needs to be removed from hydrocarbon stream before going into the market which requires the existence of a regeneration system. Low-dosage inhibitors, on the other hand, need not be removed from the product stream. Therefore, this removes the capital and maintenance costs involved with the isolation and recycling processes necessary for other families of chemical inhibitors are used. They are commonly non-toxic and/or biodegradable compounds that have infrastructure that is environmentally friendly. In some countries, however, some of these chemicals have not been licenced. When choosing and deploying this new technology, attention should be given to regional environmental regulations. Low-dose inhibitors are generally discussed in the literature under the subclassifications kinetic inhibitors and anti-agglomerants. Kinetic inhibitors are such where, in order to hold the polymer anchored around the hydrate-crystal surface, polymers with carbon backbones and pendant groups that

adsorb into partly formed hydrate cages. Rising hydrate crystals are pressured to expand around the polymer, which in the aqueous phase stabilises the hydrates as small particles. No liquid hydrocarbon need be present. Field tests have shown these chemicals to be effective at sub-cooling up to $\Delta T = 20^{\circ}\text{F}$, at dosages from 550 to 3,000 ppm in the water phase. Anti-agglomerants are discussed later in the report in detail [13].

Lower Pressure Gas Transformation

Centred on the hydrate dissociation curve, low pressure activity refers to the method of sustaining a device pressure that is smaller than the pressure equivalent to the atmospheric temperature. The pressure can need to be 300 psia (20 bar) or less for deep water with an atmospheric temperature of 39 F (4°C). Operating in the wellbore at such a low pressure is not feasible so pressure losses will be severe in a deep-water riser or long-distance tieback. The disparity between hydrate dissociation and operational temperatures (i.e. sub cooling) is minimised by the use of subsea choking and holding the output flow line at a lower pressure. This lower sub cooling can reduce the hydrate forming driving force and will limit the dosage of the inhibitor [16].

Removal of Water

Hydrate forming cannot occur if adequate water can be separated from the generated fluids. A typical hydrate protection technique applied to export pipelines is dehydration. For subsea production systems, subsea separation systems can reduce water flow in subsea flow lines [17]. Not only hydrate power, but also increasing reserve recovery and/or speeding recovery by making the generated fluid stream lighter and easier to lift, is the gain of applying subsea separation. Reduced top-side water storage, treatment, and

recycling is another plus.

As a new technology, subsea water separation/disposal systems are designed to separate bulk water from the production stream close to subsea trees on the seafloor. Basic components of such a system include a separator, pump to reinject water, and water injection well. Additional components include instrumentation, equipment associated with controlling the pump and separator, power transmission/distribution equipment, and chemical injection [17].

Controlling Temperature

In order to sustain the flowing mixture beyond the hydrate forming range, thermal methods use either the conservation or incorporation of heat. Conservation of heat is common practice and is achieved by insulation. Depending on the fluid being transferred, the tie back size, and host platform capacities, this approach may be feasible for certain subsea applications. Usually, the design of such conservation systems finds a balance between the high cost of the insulation, the system's expected operability and the appropriate level of harm. In addition to the high level of capital spending and technological difficulties, the implementation of the hydrate formation zone during a long-term shutdown would not be avoided. However, under normal operation conditions, it usually prevents hydrate formation.

A number of different concepts are available for introducing additional heat to a pipeline (Hansen et al., 1999). The simplest is an external hot-water jacket, either for a pipe-in-pipe system or for a bundle. Other methods use either conductive or inductive heat tracing (Lervik et al., 1998). There is real concern over the reliability of conductive systems. An electrical resistance heating system may be desirable for long offset systems, where available insulation is insufficient, or for shut-in conditions (Oram, 1995). The ability to heat during processing relies on the individual application of electrical heating. For pipeline depressurization, such devices have environmentally safe fluid temperature control without flaring. As there is no time wasted by excessive depressurizations, pigging, heating-medium circulation or elimination of hydrate blockage, the result is also an improvement in efficiency.

Other Methods Used

Thermal Insulation

Insulation provides hydrate power through preserving temperatures above hydrate forming conditions. Insulation also increases the cool down time until exceeding hydrate formation temperatures. The cooling down time provides operators time to either recover from the shutdown and restart a hot machine or ready the system for a long-term shutdown [18].

In general, insulation is not applied to gas processing systems, since the production fluid has a low thermal mass and can therefore be cooled by JT. Insulation is applicable to gas systems only for elevated reservoir temperatures and/or short tie-back distances. One benefit of an insulated production system is that it will allow

higher production of water, which with continuous inhibitor injection will not be economical [18]. However, shutdown and restart operations would be more complex. For example, long-term shutdowns will probably require depressurization.

The use of Polyurethane Foam thermal insulation (PUF) in a bonded pipe in the pipe principle is another such thermal insulation form. In accordance with criteria for low thermal losses, PUF thermal insulation is very useful for deep water flow lines. Jacket pipes of high-density polythene may be a viable alternative in shallow water - the combination may seem new for offshore flow lines, but in district heating systems it has a track record of 40 years and thousands of kilometers [19]. It is a material with astounding protecting properties and has a long history of use in building and aeronautic trade, particularly in pre-reinsulated pipelines for area warming heated water dispersion.

For over thirty years, syntactic foam thermal insulation has also been successfully used as an offshore buoyancy material, and today it is in use at depths of 3,000 meters or more. Thanks to its special fine-celled construction and high strength to weight ratio, its use as a Deepwater insulation device is increasing, giving it an advantage over other materials. Although having high resilience and ruggedness, it has low density and thermal conductivity. Other than its technical performance advantages, syntactic foam is often the least-cost effective solution to complex subsea problems. In comparison, no other material can successfully provide both buoyancy and insulation in a compact, volumetrically-efficient package [20].

Dehydrators

The use of dehydrators requires an alternate hydrate management system. The cost of the dehydration equipment, compressor, controls, valves and installation needed to efficiently control hydrate formation in wet sour gas is \$200,000, with continued running costs for diesel, glycol losses, operation and repair of the compressor [21]. Furthermore, it will just dehydrate the steam, leaving the sour condensate already soaked. It has been found from previous studies that hydrate conditions could indeed exist upon gas and condensate recombination. The supply of waste water handling and storage services will also require dehydration in this particular situation [21].

Active Heating

Active heating pipeline technologies have been developed to complement the thermal efficiency of wax and hydrate risk systems, particularly in shutdowns, start-ups and in some cases, in normal operations. Electrical heating and hot fluid circulation heating in a package are used in active heating. In flow lines and risers, thermal insulation must be added to active heating to reduce power requirements [18]. This flow line system is chosen specifically to provide a way of preventing and/or remediating the formation of hydrate during routine operations and shutdown conditions in the subsea production system. In addition, by sustaining device

temperatures above not only the hydrate formation temperature, but also the wax appearance temperature (WAT), the heated pipe configuration mitigates wax accumulation in the subsea flowlines,

essentially removing the need to run scraper pigs for wax build-up control [22].

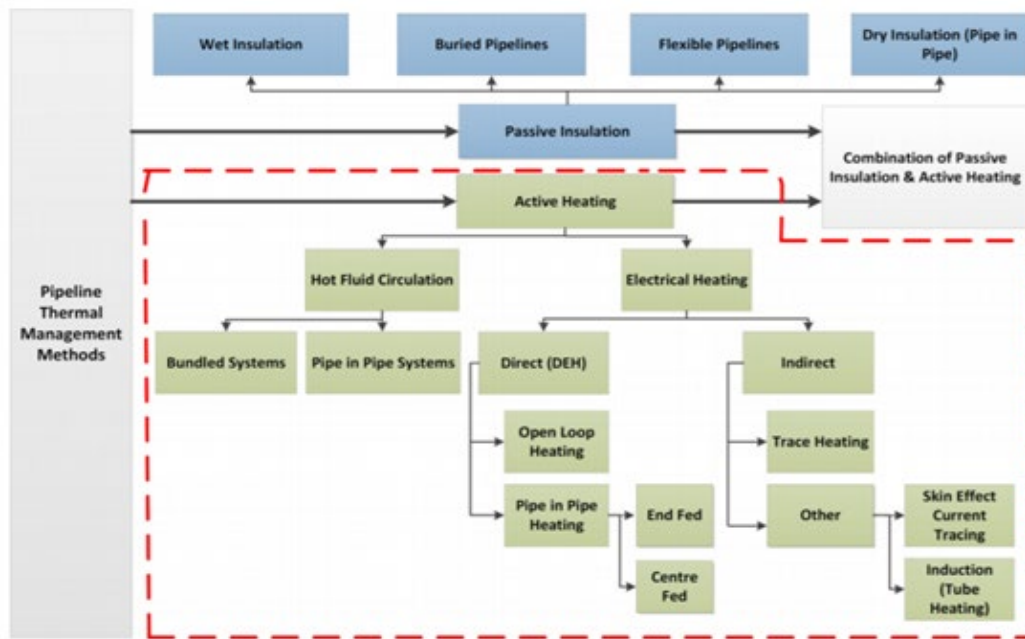


Figure 6: Summary of thermal management methods in subsea pipeline systems (McDermott & Sathanathan, 2014)

The figure (figure. 6) above shows the summary of thermal management methods in subsea pipeline systems. There are two such methods: Passive Insulation and Active heating. With Passive insulation, it uses materials of low thermal conductivity properties to minimize the heat loss from the produced fluid to the surroundings. It is further broken down to wet insulation, buried pipelines, flexible pipelines and dry insulations.

Active heating provides the capability to monitor and control the fluid temperature during start up, shutdown and turndown operations. Several electric and hot fluid circulation active heating systems are in operation as part of bundle or pipe in pipe systems. It is broken down into Hot fluid circulation and electrical heating which are further broken down into different set of systems and processes.

In low flow/turndown situations, this heating device can be used continuously to maintain the fluid temperature above either the WAT or hydrate structure temperature. Systems running with a long tie back distance in turndown conditions and/or fluids with a high WAT in nature would typically require heating of the flow line. The heating device should be placed online in the vent of a system shutdown prior to the start of solid forming to preserve the temperature of the fluid. The fluid can cool to room temperature af-

ter a prolonged shutdown. Until starting up or restarting, the fluids must be warmed up to reach the optimal flow line temperature. The needed time to reheat the device is a crucial design parameter that can determine the electrical heating systems' hot water circulation speeds or full power requirements [23]

Electrical Heating

Direct electric heating is a cost-effective and environmentally friendly form of flow assurance that substitutes chemicals for use. Thermally shielded flow is used in the electrical circuit as part of it which helps the electrical losses to heat the pipe contents. Electrical heating advantages include the removal of depressurizations of the flow line, simplification of restart activities, and the potential to rapidly remediate hydrate blockages [18]. Electrical heating techniques include:

- Direct heating, using the flow line as an electrical conductor for resistance heating;
- Indirect heating, using an EH element installed on the outer surface of flow line.

The figure (figure. 7) below shows direct electrical heating in pipes which combined with thermal insulation, provides interesting resolutions for wax melting and hydrate forming prevention. The power generation is in the range of 50-200 W/mm to satisfy the operating specifications for thermal insulated tubing [24].



Figure 7: Direct Electric Heating in pipes (Wärtsilä, n.d.)

Dispersants or Antiagglomerants

Low-dosage hydrate inhibitors of antiagglomerant cause hydrates to form but keep particles small and well distributed. The viscosity remains low, making it possible to move the hydrates with the fluids produced. Hydrate plugging rather than hydrate formation is avoided by antiagglomerant and it allows the formation of hydrates, but keep their particles small and well dispersed [26].

The objective of these chemicals is to convert water into finely dispersed hydrate particles that can be transported in a hydrocarbon liquid [27]. As long-chain quaternary ammonium salts, these industrial chemicals are embodied, essentially structuring hydrates, removing any component of both the water and visitor matrix frameworks. While as part of the hydrate system, three of the four divisions of a quaternary nitrogen salt shape, the fourth serves as a long tail that protrudes from the hydrate structure and stops the hydrates from being agglomerated into a greater mass. Substantial hydrocarbon liquid must be present to disperse the hydrates; the maximum water volume is 40% of the total liquid phase [27].

The commercial use of dispersants began in the Gulf of Mexico in 2001, after laboratory studies showing $\Delta T = 45^{\circ}\text{F}$ sub cooling [28]. For hydrate-plug protection on line shut-ins and restarts, these dispersants are especially useful. More comprehensive field work can however be undertaken. When these inhibitors come into commercial use, it would be important to address environmental issues regarding water purity.

Wax Deposition Mechanisms

A popular wax mitigation technique known as ‘pigging’ is used to regularly pig the pipeline to remove the deposited wax from

the pipe walls. Wax deposition is a complex problem involving various aspects of study such as fluid dynamics, mass and heat transfers, and during steady-state flows. For some subsea pipelines, especially export lines where hydrate is not a concern, pigging would normally be the main wax management strategy [29].

The pigging procedure is the solution for an air-free pipeline. The pig (pipeline inspection gauge) is a synthetic body, which lies tightly against the wall, is pushed through the pipeline with the medium water. Due to the space-filling closure up to the pipe wall, any air present is also pushed through the pipe and can escape at the other end of the pipe. The pig is also removed from the pipeline at this location. The pipeline is then completely filled with water and almost free of air. Only very small residual amounts of air, e.g. at pipe connections, can remain. There are numerous different sizes of pigs, depending on the requirements of the pipeline [30].

The pig is sent down from a pig launcher into the pipeline and is pushed by petroleum extraction or all other liquids, such as dead oil or coal. The pig scrapes the wax from the pipe wall manually and re-deposits it in front of the pig back into the crude. For the effectiveness of pigging activities, a regularly scheduled pigging program is very important. If the pigging process is not planned often enough, there could be too much wax accumulated on the wall of the vessel. A pig may get trapped inside the pipe during the pigging process because of the excess volume of wax in front of it. Based on wax deposition models, the pigging schedule software will be built and will be fine-tuned when the wax deposition rate is best understood in field operations [29].

Discussion & Conclusion (Initially Eliminated and Left Out)

There are many who contend that gas hydrates pose no significant production problem and that hydrate control technology was fully developed 25 years ago. While it is true that the basic techniques for gas hydrate control - application of heat, injection of ethylene glycol, and injection of methanol - remain essentially unchanged, some substantial improvements have been made during the last two decades.

Unlike methanol, Glycol gets easily contaminated with salt, and the water it picks up must be evaporated in order to regenerate and recover the glycol. Thus, glycol injection is not as well suited as methanol for controlling gas hydrates in high-pressure flow string or flow line. Nevertheless, glycol injection has numerous applications and its technology is very well-defined. Glycol injection would be enhanced by any process which will remove salt from the glycol and maintain its concentration at an acceptable level, say 0.5%. Some promise has been shown for new methods involving electro-dialysis.

Both cost and availability are matters of concern when larger quantities of methanol may be required to produce large wells flowing at high pressures and low temperatures. Although essentially all methanol is wasted in present day operations, it is believed that attention will be directed to recovering methanol from the gas phase, the oil phase and the water phase when the flow reaches the platform (or shore station) where it can be separated and treated.

Perhaps these are some of the more important and more urgent developments and improvements techniques of gas hydrate control. As the industry moves into deeper waters farther from shore and into the remote areas of the offshore Arctic with the attendant use of subsea completions and floating production systems demanded by these locations, costs associated with currently accepted hydrate control techniques are likely to become prohibitive. Economics, then, will eventually dictate the development of new methods or improvements on older methods which can be adapted to meet the requirements of these new environments. Surely there can be no doubt in advancements in the technology used in the offshore engineering field and we can expect improvements in the coming years.

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