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COLD FLOW IN LONG-DISTANCE SUBSEA PIPELINES

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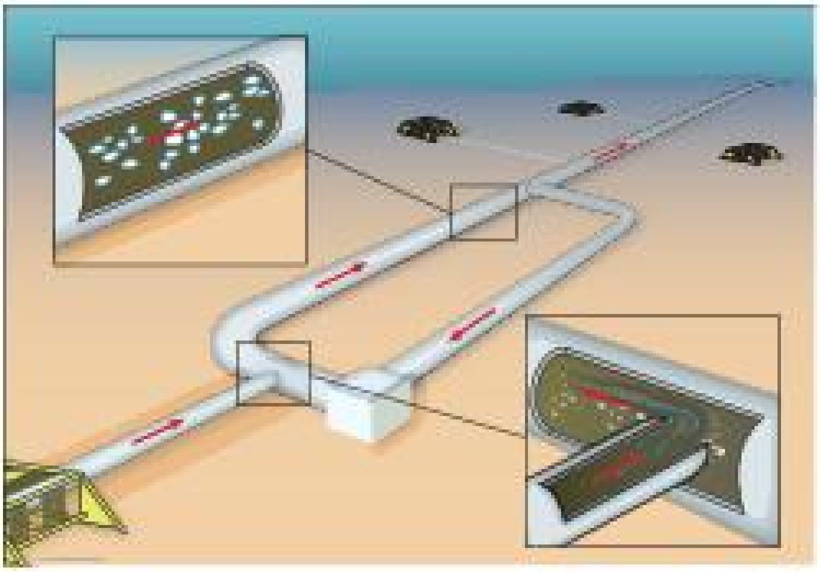

MOSES GIDEON AKPABIO

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I remain a debtor in gratitude to all others whom I may forget to mention here due to space or the lack of it.

ABSTRACT

As the world's appetite for energy continues to grow, oil and gas developments are moving to ever deeper subsea environments, thereby causing hydrates-related issues to become a growing concern for the industry. Hydrates blockages, beyond the safety risk they represent, result in time-consuming and costly mitigation and remediation operations. Most hydrate experiences found in the literature, and the corresponding prevention and remediation strategies, concern subsea pipelines. This work relates a novel technology for hydrate mitigation in subsea pipelines. This is the cold flow technology. A detailed review of the cold flow technology, its main component equipment, the concepts by different organizations on the technology, as well as the advantages and disadvantages of each proposal has been done.

A qualitative research method is used, which is suitable when exploring a new phenomenon. Six cases of different technologies were chosen which include: chemical inhibition (THIs and LDHIs), direct electrical heating system and three potential emerging cold flow technology concepts for ensuring flow assurance in long pipelines. The technical, environmental and economical evaluations of the different technologies have been done. In order to obtain information on these cases, observation and documental studies (archives) were chosen as research methods. These methods however do not give me all the needed information about the various cases and this is a weakness of the results.

Cold flow technology was compared with the conventional technology currently used for tackling hydrate and wax problems. It was found out that the cold flow technology offers a more robust means of eliminating the problem in a cost and environmentally effective manner especially over long distances greater than 200 kilometers. The lessons learned from this experience are presented here and are currently being used as a basis for improving operation guidelines and hydrates prevention strategies for deepwater transportation pipelines.

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1. Introduction

The increase in demand for energy has seen the oil industry moving into more challenging environment (offshore and ultra-deep water), due to the depletion of the conventional onshore and shallow water sources of hydrocarbon. Offshore and ultra-deep water exploration and production is now going from deepwater (3,000 to 6,000 ft) towards ultra deepwater (6,000 to 10,000 ft), Bell et al. 2005. The subsea environment which involves low temperatures as well as high pressures, high water cuts and longer transfer times provide conditions that are ideal for hydrates and wax formation, and other solids deposits. These are the fundamental impediments to production of oil and gas through long distance subsea pipelines, especially at shut-down and restart situations. Though the existing Subsea processing and transportation facilities enable this exploitation, but adequate flow assurance is needed.

Pipeline, among other means of transporting oil and gas guarantees delivery from the wellhead to the processing plants and from there to the customers. Subsea pipelines represent at least 25% of the total project cost and it's one of the reasons for the flow assurance studies (Nava et al. 2011). To ensure flow assurance in relatively short pipeline length (say 5-10 km), both insulation and electrical heating can be used. When the pipeline length is medium (say 10-100 km), antifreeze chemical can be injected to prevent gas hydrate formation and fine (specialized) chemicals can be injected to prevent paraffin wax formation, or rather, keeping wax particles from agglomerating. However, for long pipeline length (say 100-200 km), the same chemicals can also be used, but considerable volumes of antifreeze need to be used, resulting in large increases in both CAPEX and OPEX. Specialized chemicals (additives) are also expensive and may pose an environmental problem at the receiving end of a subsea pipeline (landing site) (Gudmundsson 2012).

These existing flow assurance techniques have limitations on preventing hydrates and wax deposition and are becoming less economical and practical for production from subsea environments. Cold Flow Technology (CFT) is the new technology suggested as an alternative to the use of anti-freeze, insulation, and heating of pipeline for flow assurance to be ensured. Though this technology is under development and testing, yet it promises to be a potential solution of flow assurance challenges in longer distance subsea pipelines which is very challenging for existing and traditional technologies.

The focus of this thesis research work is to study the new cold flow technologies (CFT) as proposed by organizations and companies. This work will also focus on explaining how this technology will work as well as identifying the main equipment. A comparison between the existing (established) technologies mentioned above and the new CFT will be done based on technical, environmental, and economical evaluations. Moreso, the oil and gas provinces of the world where CFT will be of greatest benefit and potential if successfully implemented, will be identified. Technical and other challenges that needs to be solved before CFT can be implemented in subsea production of oil and gas will also be evaluated.

I have divided the problem into several parts to include: studying first the major flow assurance problems in subsea production pipelines, the existing technologies of tackling flow assurance problems, and then, the new cold flow technology. The advantages and disadvantages of each technology is also addressed. This is to enable possible comparison of the different technologies which is one of the purposes of this study.

A theoretical approach was adopted and the following research questions were set to be a guiding light in this study:

- What are the technical, environmental and economical challenges of the different technologies of hydrate and wax prevention method especially over long distance transportation of hydrocarbon?
- What are the deficiencies of the current prevention techniques?
- Can the potentially emerging cold flow technology, if successfully implemented be economically viable to handle the problems facing technologies currently in use, especially over long distances?
- What technical and other challenges of the potentially emerging cold flow technology should be solved to bring about its successful implementation? And, are there any technical or technological option that can be adopted or utilized in solving this problem?

2. Method

Methods are procedures used or ways of doing things. In this chapter, I will present the method adopted in this research work.

2.1 Method Selection and Description

In this work, I have chosen a qualitative and descriptive method to investigate my research questions. The reason for this choice is simply due to its uniqueness and to utilize both inductive and deductive procedures (Ringdal 2001). The inductive procedure was used in exploring the new technology of cold flow concepts, since there is little research on it and the existing technologies. The deductive procedure was used in analyzing the results of the research, where comparisons have been made based on the findings. However, access to relevant quantitative data concerning the technologies considered in this work is very scarce.

Qualitative research method was found suitable because, it concerns the understanding of a phenomenon which is unique in my case. This provides a researcher with an exploring technique. This method provides an overall perspective of a complex and detailed picture of a case of study, thus making the data collection method flexible and sensitive (Ringdal 2001).

There are five main research strategies which include: experiments, surveys, archival analysis, histories and case studies, and these can be used for three main purposes: exploratory, descriptive or explanatory. Each strategy has a distinctive characteristic, but there are no clear boundaries between them, thus, they may well overlap (Yin 1989).

In this paper, I have chosen a case study because most of the requirements proposed in Yin (1989) are relevant in my case. I have chosen to analyze six cases based on the posed research problems. I have utilized both the intrinsic and collective case studies. The later provides the understanding of the case itself being the primary objective of the study and the former, enhances the comparison and analysis done in this work.

2.3 Case Study

According to Stake (1994), a case study is not a method but a choice of objects to be studied. It is the technique used in collecting data from the case which are the methods. Case study can also be defined as an "empirical inquiry that investigates a contemporary phenomenon within its real-life context; when the boundaries between phenomenon and context are not clearly evident; and in which multiple sources of evidence are used" (Yin 1989).

A case study can involve one or several cases and different levels of analysis. It is of advantage because; different types of data collecting methods can be combined. These include methods such as archives, interviews, surveys and observations (Yin 1989; Eisenhardt 1989).

In this work, my major sources of information were archives and observations. Observation is what a person notices as everyday's life is revealed. However, it does not reveal what is going on inside the observed people's minds. Hence, the observers can only come up with potential solutions (Dingwall 1997). On the other hand, archives provide a large amount of background information that complements observations. The use of internet (world wide web) was the basic source for the archival investigations. The two methods were combined to reduce the possibility of misinterpretations and to help validate the results. I have chosen observation as one of the data collecting method in this work because, interviews with the companies and industry people were not feasible for me here in Nigeria.

To understand the subject matter of this research, I commenced my thesis work by reading the available literature particularly on cold flow technologies, since I had little knowledge on the subject. I developed some questions based on the description of the research work by my supervisor that guided me during this research. As the work progressed, I modified most of the questions that help me shape my thoughts so as to get a better work done.

2.4 Critique of the Method

Qualitative research method which I have adopted in this work has many limitations. This is because the ground for judgment in this case could be biased. My findings were based on limited information which may be erroneous. It was therefore difficult to draw general conclusions (Stake 1994).

Another limiting issue was the analyses part. Focusing on some concept than others can result in generalization to an extent that it obstructs the understanding of the specific case (Stake, 1994).

Observation is also a biased method. The researcher's theoretical sensitivity influences what is observed. To sort the validity of observation findings, I have worked in tandem and also referred to documental investigations or studies. In addition, I could have used interviews with the companies, the experts and users of the technologies in the field in order to confirm and validate my observations. In future research, I hope to use interviews to improve my investigations on these subjects.

However, limitations regarding the potential quality of this work will be presented in chapter 9.2.

3. Flow Assurance Challenges

The phrase “Garantia de Fluxo” was coined by Petrobras, meaning “Guarantee the Flow” in the early 1990s (Trick 2005). Flow assurance deals with the risks and problems arising from the challenging properties and behavior of the produced hydrocarbons, associated fluids, and solids. It is an evaluation process that ensures that produced fluids from the wells are delivered safe to its desired location. It is a structured engineering analysis process that utilizes the in-depth knowledge of fluid properties and thermal-hydraulic analysis of the system to develop strategies for control of solids such as hydrates, wax, asphaltenes, and scale (Kaczmarski and Lorimer 2001).

As earlier said, deepwater production environment and transportation through longer tiebacks, pipelines, and flowlines provides conditions that brought about flow assurance challenges. These flow assurance challenges are as illustrated in Figure 1. The challenges posed in this environment can also be complicated due to the changes in the prevailing conditions and production profiles over the field’s life. It is worthy to also note that for effective subsea production, it is important to identify the potential for and quantify the extent of any solid deposition in the system.

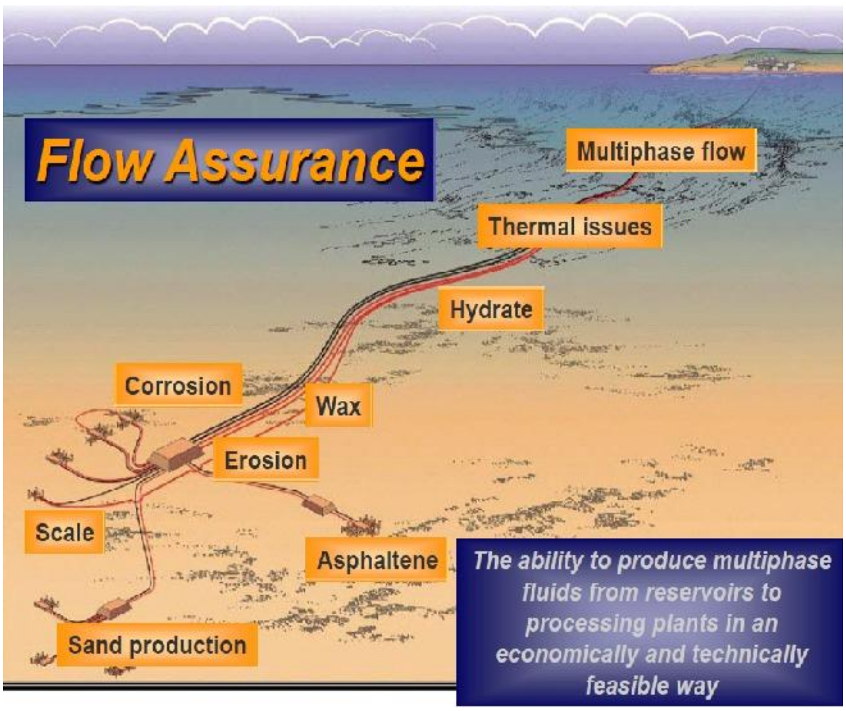


Figure1: Typical Flow Assurance Challenges (Hadne 2012)

It is difficult and costly to remove a plug in a pipeline especially in subsea environment. As the industry is moving into deep and ultra-deepwater environment which is more remote, the need for a technology that will enhance cost effective flow assurance becomes very imperative. This is so because development of new fields will demand long distance tiebacks to an existing infrastructure or onshore facility for processing.

The present solutions used today are losing their value particularly when it comes to longer distance step out. A potentially emerging technology (cold flow technology) with a high value proposition would provide a subsea field development concept for hydrocarbon transportation in a bare steel pipeline over long distances. Thus, increase in oil field developments will be enhanced.

In this chapter, I will discuss on some flow assurance challenges such as hydrates and wax formation and deposition on subsea pipeline. Asphaltenes and scales deposition problems will also be presented briefly only in this section, but will not be considered as major problem in further studies in this work.

3.1 The Gas Hydrate Problem

This section will look at the history of Natural gas briefly, the components of natural gas, a brief history of natural gas hydrates, the structure of gas hydrates, and the conditions that are necessary for hydrates formation, as well as hydrate formation and growth in pipeline.

3.1.1 Brief History of Natural Gas

The history of natural gas can be traced back to the ancient Mesopotamia, or the cradle of civilization that is known today as the Middle East. Natural gas has been observed since ancient times (Ingersoll 1996). However, it was until a few centuries ago that countries such as Great Britain, China, and USA, among others, started using natural gas as a means of supplementing their need for energy (Mokhatab et al. 2006). Moreover, the construction of a sustainable gas infrastructure, including storage, pre-processing and transport facilities allows natural gas to become commercially available throughout the world (Sanchez 2010).

According to Mokhatab et al.(2006), the Chinese drilled the first known natural gas well in 211 B.C. A few centuries later (around 500 B.C.), they employed crude bamboos as a means to transport natural gas. In Europe, even though the British discovered natural gas in the middle of the 17th century, it was until the late 18th century (around 1785) that they started trading natural gas obtained from coal seams for lighting of houses and streets (Rojey et al. 1994).

An intriguing factor that caused a faster expansion of the use of natural gas around the world in the last decade of the 19th century was the fact that many cities began replacing their gas lamps with electric lamps. Thus, the gas industry was required to look for new markets, perhaps far away from their usual customers (Sanchez 2010).

Natural gas had been clearly extinguished by electricity. However, at that time the real problem was certainly the lack of a pipeline infrastructure to transport and distribute natural gas, as well as the lack of facilities to store it (Chapoy 2004).

3.1.2 Typical Components of Natural Gas

Natural gas is a non-renewable resource that is expected to be widely expanded in the decades to come. It is considered a very safe energy source when transported, stored and used. It is a mixture consisting mainly (70-95 %) of methane (CH_4, a covalent bond composed of one carbon atom and four hydrogen atoms), as shown in the Figure 2. It also contains other gaseous hydrocarbons such as ethane (C_2H_6), propane (C_3H_8), normal butane (n-C_4H_{10}), isobutane (i-C_4H_{10}), and pentane (C_5H_{12}), among other higher molecular weight hydrocarbons (Sanchez 2010).

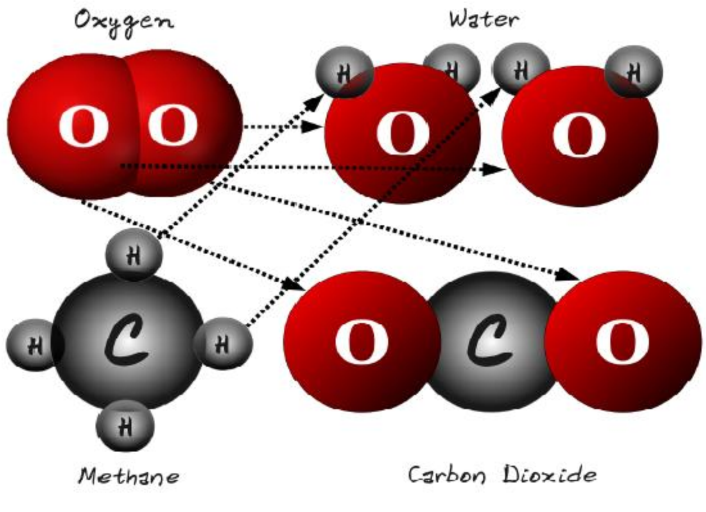


Figure 2: Natural Gas Typical Molecule: Models of molecules of oxygen (O_2), water (H_2O), methane (CH_4) and carbon dioxide (CO_2) (Sanchez 2010).

Natural gas also contains impurities or contaminants that have to be removed before it can be used as a consumer fuel after its extraction from the reservoir. These impurities include acid gases, such as hydrogen sulfide (H_2S), carbon dioxide (CO_2), mercaptans (methanethiol – CH_3SH, and ethanethiol – C_2H_5SH), nitrogen (N_2), helium (He), and water vapor (H_20). Sometimes, mercaptans are kept or added for safety reasons (Sanchez 2010). However, a typical composition of natural gas is given in Table 1.

Table 1: Typical Natural Gas Components, (Chapoy 2004).

Hydrocarbons		**Non – Hydrocarbons**	
Components	Mole %	Components	Mole %
Methane	70 - 98	nitrogen	Trace - 15
Ethane	1 -10	Carbon dioxide	Trace – 20
Propane	Trace – 5	Hydrogen sulphide	Trace – 20
Butane	Trace – 2	Helium	Up to 5 (non usually)
Pentane	Trace – 1		
Hexane	Trace - 0.5		
Heptane+	Trace		

In the reservoir, oil and natural gas normally coexist with water. Water comes as the wetted phase and from the sub-adjacent aquifer. The presence of water also causes crystallization of salts after hydration due to salt concentration increase (when water is consumed).

Furthermore, when gas is produced offshore, the separation of liquid fractions and the removal of water are not always carried out before the production stream is sent into pipelines. Consequently, the unprocessed hydrocarbon stream coming from a production field can contain water and light hydrocarbon molecules (methane, ethane, propane and other components). Given the correct temperature and pressure conditions, (particularly large temperature gradients which leads to higher pressure), these can lead to hydrate formation during transport through pipelines. The next section will briefly delve into the history of natural gas hydrates.

3.1.3 History of Natural Gas Hydrate

Gas hydrates were first identified in 1810 by Sir Humphrey Davy and their composition established by Faraday, Koh (2002). They are crystalline compounds formed by chemical combination of natural gas and water under pressure and temperature considerably above the freezing point of water (Sloan 1998). Hammerschmidt, in 1934 determined that the plugging of natural gas pipelines was not due to ice formation but to formation of clathrate hydrates of natural gas (Gaillard et al. 1999). They had it that, this discovery was the determining factor in causing a more pragmatic interest from oil and gas companies.

The first algorithm to calculate the amount of methanol necessary to prevent or inhibit a stable hydrate formation was presented by Hammerschmidt in 1939. In 1965, Makogon discovered natural gas hydrates as energy source (Makogon 1997). Hydrates, having been recognized as a possible source of highly undesirably costs arising from the operational problems caused in technical applications, has turned from a mere curiosity into a real troublemaker in natural gas industry. From here, there was an urgent need to go into systematic research activities to understand the conditions: pressure, temperature, gas compositions, under which natural gas hydrates form (Oellrich 2004). As said earlier, natural gas hydrates in oil and gas pipelines may block the pipelines, facilities and instruments. These can cause flow and pressure monitoring errors, reducing gas transportation volume, increasing pipeline pressure differences and damaging pipe fittings. The nature of an hydrate plug removed from a subsea pipeline is as shown in Figure 3.

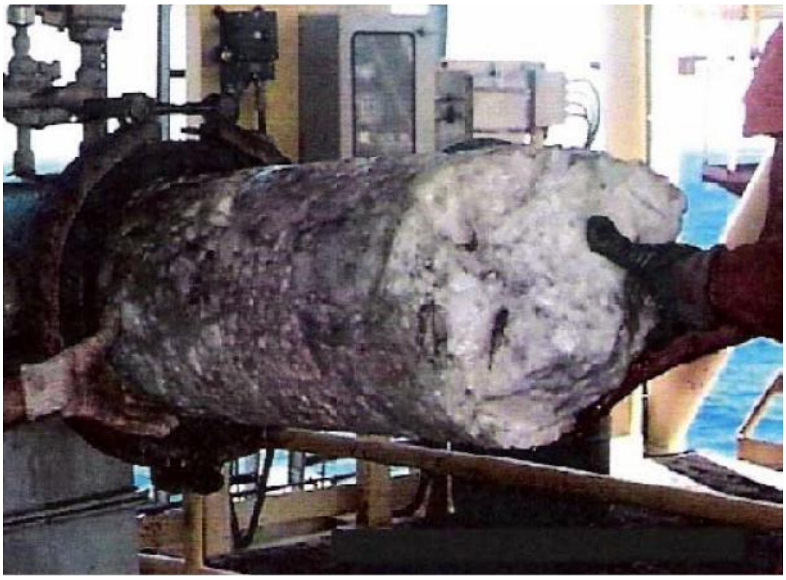


Figure 3: Hydrate Plug Removed from a Gas Pipeline (Zarinabadi and Samimi 2011).

3.1.4 Structure of Natural Gas Hydrates

Hydrates are solid crystalline compounds, which have a structure wherein guest molecules are entrapped in a cage like framework of the host molecule without forming a chemical bond. Thus, hydrates form as a result of hydrogen bond with water. The hydrogen bond causes the water molecules to align in regular orientations. The presence of certain compounds causes the aligned molecules to stabilize, and a solid mixture precipitates. The water molecules are referred to as the host molecules, and the other compounds, which stabilize the crystal, are called the guest molecules. The hydrate crystals have complex, three dimensional structures in which the water molecules form a cage and the guest molecules are entrapped in the cages.

The structures of the crystals fall into the class of clathrates with the water molecules forming a hydrogen-bonded cage-like structure which is stabilized by ‘guest’ molecules located within the lattice, Makogon (1997) and Sloan (1998). Gas hydrates which are crystalline ice-like solids are formed from water and a range of lower molecular weight molecules, typically methane, ethane, and propane. The water molecules are referred to as the ‘host molecules’ and the other compounds which stabilize the crystal are called, the ‘guest molecules’. The hydrate crystals have complex, three-dimensional structures in which the water molecules form a cage and the guest molecules are entrapped in the cages as shown in Figure 4.

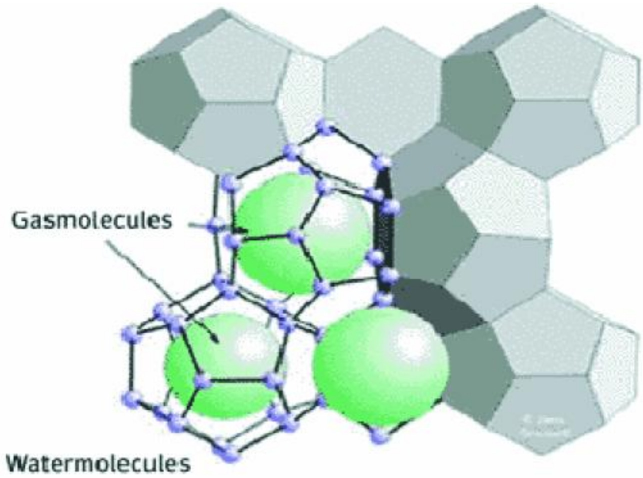


Figure 4: Host molecules (water) and guests (Gas), (Zarinabadi and Samimi 2011).

There are three known hydrate structures referred to as structures I, II and H (abbreviated as sI, sII and sH) as contained in Pickering et al. 2001. The schematics of the three different structures are presented in Figure 5.

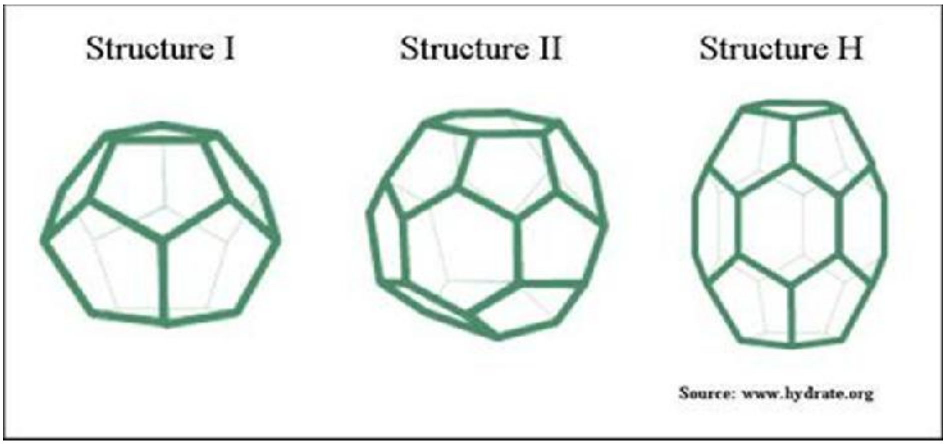


Figure 5: Schematics of Structure I, II, and H Gas Hydrates (FEESA 2011).

Structure I hydrates contain 46 water molecules per 8 gas molecules giving a hydrate number of 5.75. The water molecules form two small dodecahedral voids and six large tetra-decahedral voids. The sizes of the voids are relatively small meaning that the guest molecules are restricted in size to essentially methane and ethane (Pickering et al. 2001).

Structure II hydrates contains 136 water molecules per 24 gas molecules giving a hydrate number of 5.67. The water molecules form 16 small dodecahedral voids and 8 large hexakaidecahedral voids. The larger voids are able to accommodate molecules including propane, isobutane, cyclopentane, benzene and others. However, while the larger cavities can accommodate larger molecules, the structure is only stable if small 'help' molecules are available to fill the smaller lattice cavities (Pickering et al. 2001).

Structure H hydrates contains 34 water molecules for every 6 gas molecules giving a hydrate number of 5.67. The structure has three cavity sizes with the largest cavity able to accommodate larger molecules than both sI and sII. Once again, stability is only possible in the presence of smaller 'help' molecules such as methane or nitrogen (Pickering et al. 2001). Table 2 lists the properties of the three common unit crystals.

These three structures commonly contain only one non-polar guest molecule within each cage. The guest molecule size has to be big enough to be stabilized in cavity, but not too big to fill the cavity (Christiansen and Sloan 1994). Therefore, under unusual conditions of very high pressure they can have multiple cage occupancy with unusually small guest molecules, example hydrogen and noble gasses (Sloan 2003).

Table 2: The three common hydrates unit crystal structures. Nomenclature: $5^{12}6^{4}$ indicate a water cage composed of 12 pentagonal and four hexagonal faces. The numbers in squares indicate the number of cage types. For example, the structure I unit crystal is composed of two 5^{12} cages, six $5^{12}6^{2}$ cages and 46 water molecules. (Sloan Jr., 2003)

Hydrate crystal structure	**I**		**II**		**H**		
Cavity	Small	Large	Small	Large	Small	Medium	Large
Description	5^{12}	$5^{12}6^{2}$	5^{12}	$5^{12}6^{2}$	5^{12}	$4^{3}5^{6}6^{3}$	$5^{12}6^{2}$
Number of cavities per unit cell	2	6	16	8	3	2	1
Average cavity radius (Å)	3.95	4.33	3.91	4.73	3.91	4.06	5.71
Coordination number	20	24	20	28	20	20	36
Number of waters per unit cell	**46**		**136**		**34**		

3.1.5 Conditions Necessary for Hydrates Formation

There are four major conditions necessary for hydrate formation (Zarinabadi and Samimi 2011). These, as shown in Figure 6 include:

- Water as the liquid phase condensing out of the hydrocarbon.
- Hydrate formers. These are small gas molecules such as methane, ethane, and propane (gas composition).
- The right combination of low temperature and,
- High pressure.

Hydrate formation is favoured by low temperatures and high pressures typically 20 °C and 100 bara.

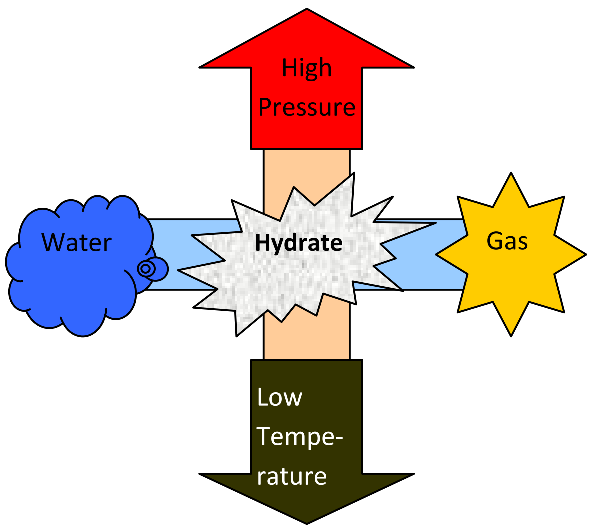


Figure 6: Hydrate Formation Conditions Combination (Author)

Solids formation phase diagram in the pressure-temperature plane is as shown in Figure 7. The right hand region covers pressures and temperatures at which hydrates are thermodynamically unstable and is therefore 'hydrate free' as indicated. On the left hand, the temperatures and pressures favour hydrate formation. In the 'hydrate region', the degree of subcooling is sufficient enough to promote hydrate formation spontaneously (Estefen et al. 2005).

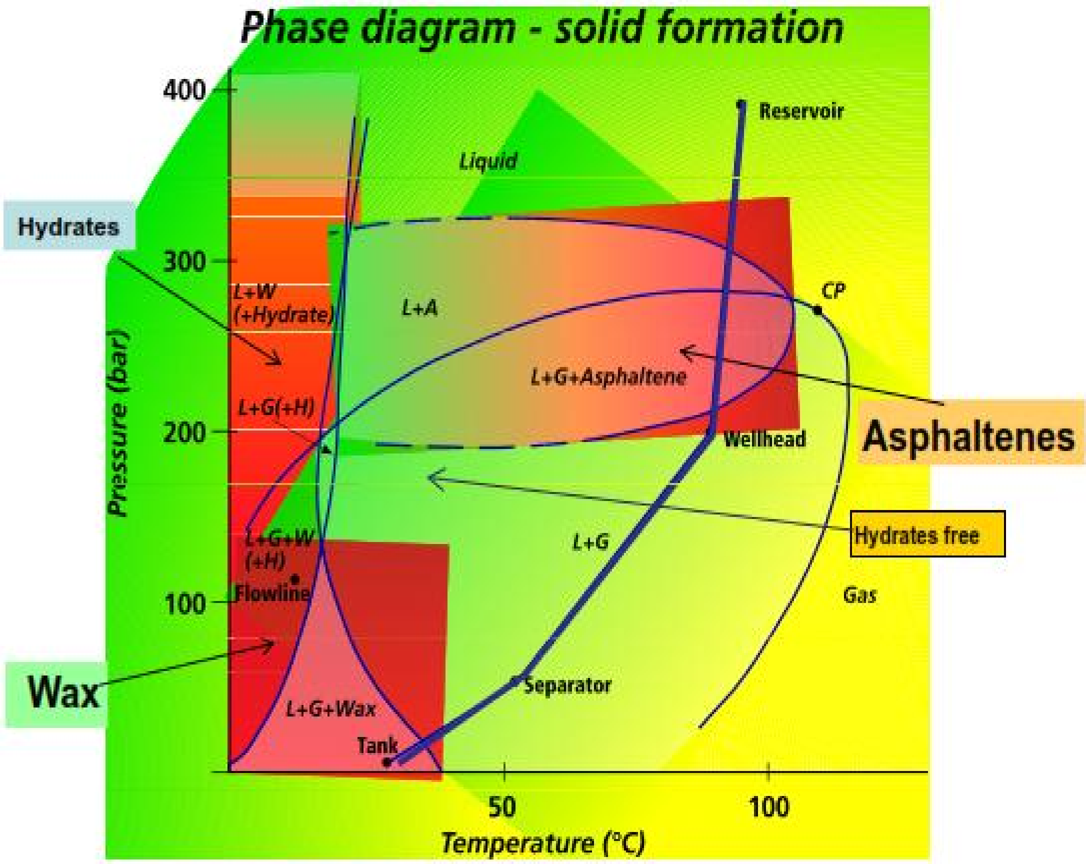


Figure 7: Phase diagram showing typical pressures and temperatures for solid formation (Time 2011).

Gas hydrate forms in water phase from gas molecules dissolved in that phase. Consequently, H_2S and CO_2 increase the temperature at which hydrates will form since they are more soluble in water than most hydrocarbons. Hydrate formation is enhanced during flow particularly in turbulence producing conditions (for example; flow through orifice meters, reduced port valves). However, hydrate also forms under static conditions.

Therefore, factors which contribute to the initiation of hydrate particles formation include:

- **Degree of subcooling** – hydrates may not begin to form immediately upon reaching the hydrate point. As much as 5 °C to 10 °C of subcooling is needed to form the first seed crystals of hydrates.
- **Presence of artificial nucleation sites** – This is a point where a phase transition is favored, and in this case the formation of a solid from a fluid phase. Good nucleation sites for hydrate formation include an imperfection in the pipeline, a weld spot, or a pipeline fitting (elbow, tee, and valve). Scale and sand all make good nucleation sites as well.
- **Degree of mixing** – system geometry and flow regime. This is to say that hydrate formation is favored in regions where the fluid velocity is high. This is because, there is high velocity while natural gas is passing through the narrowing in the valve and mixing in a pipeline, process vessel, and heat exchanger, enhances hydrate formation. There is also a high temperature drop when natural gas is choked through a valve due to Joule-Thompson effect (CAPP 2007 and Carroll 2009).

Furthermore, once crystallization has begun, time is needed for the crystals to agglomerate (clump) and actually block the flow (CAPP 2007). In other words, hydrate formation is a transient process. Also, the exact hydrate formation point depends on the composition of the fluids involved; gas composition and water as well as brine composition. In Figure 8, the conceptual representation of hydrate formation is shown schematically as temperature drops along a pipeline with time in oil dominated system. It starts with a shell and then grows up to a hydrate plug (Sloan et al. 2009). Hydrate formation phenomenon in a pipeline will be further discussed in the next sub-section.

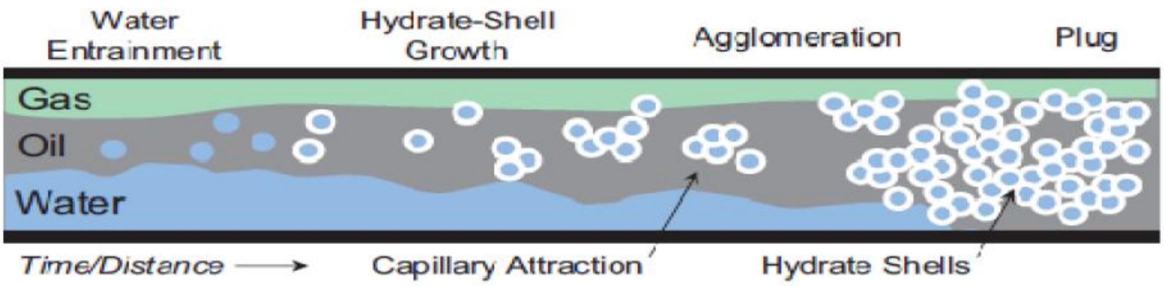


Figure 8: Conceptual representation of hydrate formation in an oil-dominated system. Sloan et al. 2009.

3.1.6 Hydrate Formation and Growth in Pipeline

Hydrate formation begins when temperature drops below a certain level and starts to nucleate close to the hydrocarbon phase on a water droplet in gas, oil or condensate phases. Along the surface of a droplet, hydrate will grow until it is completely covered with a thin hydrate layer. Then, from the interior of the water droplet to the surface of the hydrophilic hydrate, water will penetrate next to the hydrocarbon phase through microperforations or small cracks in the hydrate film as shown in Figure 9. Hydrate formation rate will decrease with the increase in the thickness of the hydrate layer, depending on the shear forces on the droplets and the hydrate formation driving force, within a relatively short time (Larsen et al. 2003).

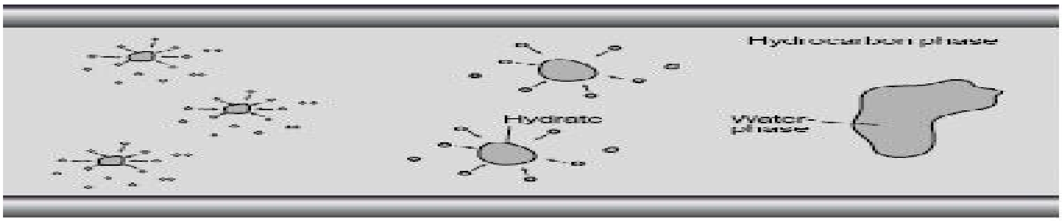


Figure 9: Agglomeration of water droplets after hydrate initiation (Larsen et al. 2003).

When the water droplets covered by a hydrate film hits the pipe or a reactor's wall in a turbulent system, the impact created may create a large crack in the film. The subcooled water inside the droplet will then drain out through these cracks, and spread on the dry hydrophilic hydrate film, creating a sticky film. This can often result in hydrate deposition on the wall of a pipeline.

The water phase in turbulent liquid systems are often distributed in the hydrocarbon phase as rough, unstable water-in-oil emulsions. As the surface tension of the droplets increase due to the hydrate layer, the water droplets agglomerate to larger droplets in order to minimize surface area, as shown in Figure 10.

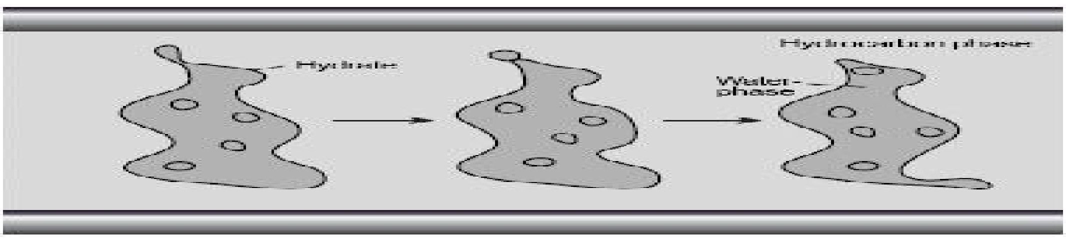


Figure 10: Hydrate covered with water droplet inside larger water lumps. The start of slush like flow behaviour (Larsen et al. 2003).

The surface area and the volume of water lump will continuously change its form in a turbulent liquid systems. This will result in breaking down of the thin hydrate layer on the water lump, giving new water-hydrocarbon interfaces where more hydrates form quickly. Also, the turbulent forces would as well create small hydrate covered with water droplets as shown Figure 11. These droplets will be absorbed in the water lumps giving a slush-like appearance due to hydrophilic nature of the hydrate surface.

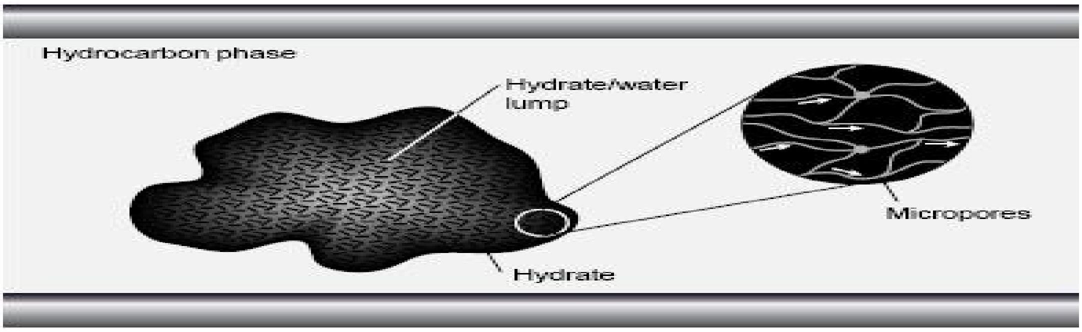


Figure 11: Conversion of water to hydrate by water transport to surface of large lumps (Larsen 2003).

Further growth and particle accumulation will cause the outer area of the lumps to stiffen. When these lumps collide with one another and the walls of the pipe, free water from the lump interior will spread out to the surface of the hydrate and will act as glue to enhance agglomeration in further collisions. The hydrate layer covering lumps or plugs increases in thickness until internal pressure gradients due to capillary forces and volume changes, break it down to smaller hydrate particles as shown in Figure 12 and Figure 13. This process continues until the lumps have been broken down to a powder-like appearance, assuming that the flow conditions can be maintained throughout the process. In a reality, the pipeline will likely be plugged before this stage is reached (Larsen et al. 2003).

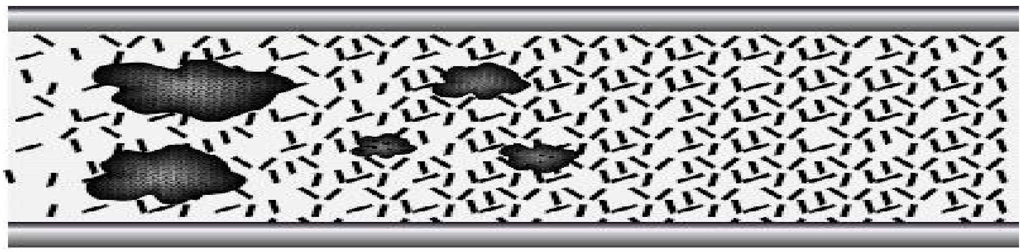


Figure 12: Break-up of large hydrate lumps (Larsen et al. 2003)

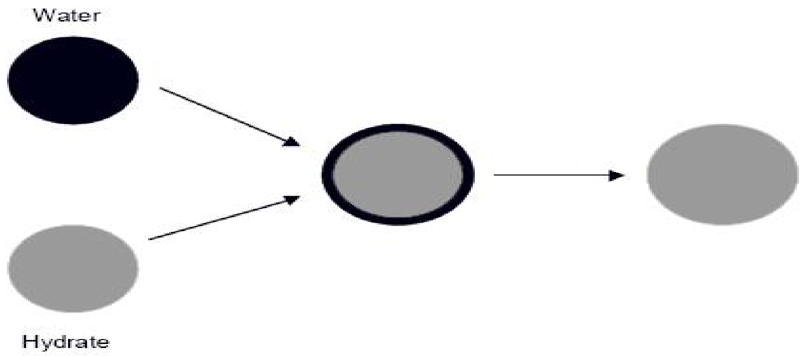


Figure 13: A water droplet & a dry hydrate particle. After wetting, the water layer is converted to hydrates from the existing hydrate surface and outwards (Larsen et al. 2003).

3.2 Wax Problem

Wax is another important solid formation and deposition in subsea pipelines that causes flow assurance problems. Wax deposition and blockage can cause loss of production as well as income to the industry. In this section, wax description, precipitation, deposition and wax gelation will be looked into.

3.2.1 Wax Description

Wax consists of high molecular weight n-paraffin and asphaltenes components of crude. They are mainly long-chain alkanes with 20 to 50 carbon atoms, but also contain minor quantities of branched and cyclic hydrocarbons. Typical content in North Sea oils is 1 - 15 weight percent (Time 2011). However, Nigerian crude had a typical wax content of 6 – 10 weight percent (Oseghale et al. 2012). Wax deposits on a pipe's cross section are as illustrated in Figure 14.

Figure 14: Wax deposits on a pipe's section (Time 2011)

Wax precipitation and deposition are important issues in natural gas and condensate production and transportation on land, offshore, and deepwater production. Paraffin waxes are predominantly heavy hydrocarbons, which are contained in natural gas condensate. As shown in the phase envelope, see Figure 7, it is clear that wax formation and deposition strongly depends on temperature and less of pressure. Wax precipitation begins when the flowing stream is cooled down, for example, in long pipelines, and then it deposits on the pipe's wall.

Wax just like hydrates, precipitates and deposits on subsea pipelines. When it builds up, it could lead to problems such as higher pressure drops, decrease in flow rates and even clogging of pipelines, thus resulting in revenue loss. Siljuberg 2012, defines wax as an oil field cholesterol.

3.2.2 Wax precipitation

As oil is cooled down through the production system, wax starts to precipitate as a solid phase typically around 30 to 40 °C, but may be as high as 50 to 55 ^{o}C (Time 2011). The temperature at which paraffin wax begins to precipitate is referred to as the Wax Appearance Temperature (WAT) or cloud point. It is dependent on the wax content, the amount of solvents including dissolved gases, and to a smaller extent on the pressure (Tordal 2006). The precipitated wax from a petroleum fluid consists primarily of normal paraffins, isoparaffins, and naphthenes, while the aromatics do not precipitate (Ronningsen et al. 1991).

The WAT is a very important design parameter in field development, particularly in subsea environment. The solubility of wax is strongly dependent on temperature. Wax is totally dissolved in most oil reservoirs and there may be exceptions like some very shallow reservoirs. For example, in the Pechora Sea (Northern Russia) there are reservoir temperatures as low as 28 – 30 °C. On the other hand, such reservoirs often contain biodegraded oil with low wax content (Tordal 2006).

A typical wax precipitation curve shows the amount of paraffin wax precipitated from condensate, as illustrated in Figure 15. It depends on the extent to which the paraffin wax mixture is cooled down below the WAT. In crude oil and condensates, wax precipitation depends on its solubility. The heaviest waxes are least soluble and they precipitate first and upon further cooling, the lighter ones precipitates.

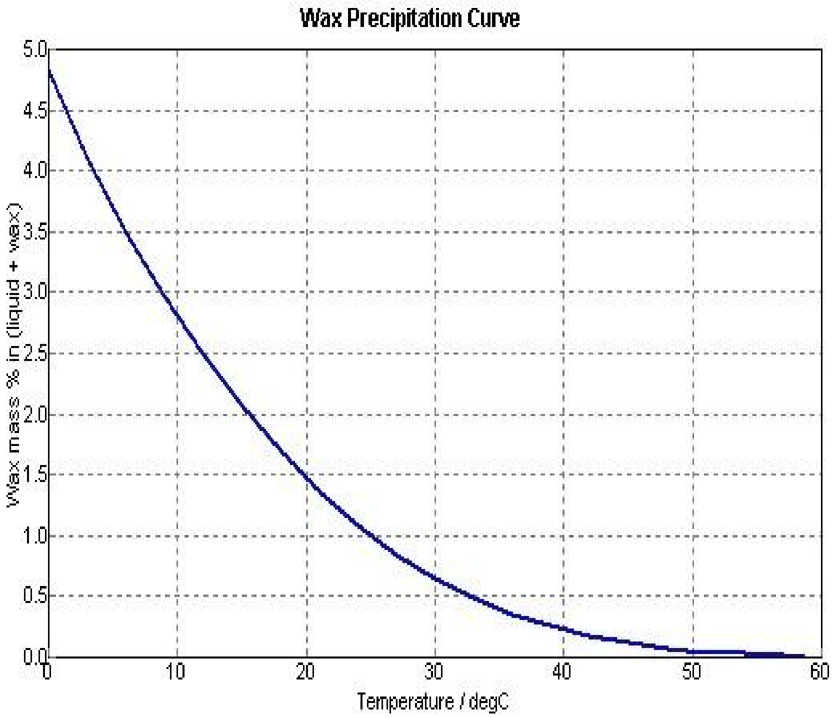


Figure 15: Wax Precipitation Curve (Infochem 2012)

The wax crystallization process develops in three stages:

(a) **Nucleation** – this is the appearance of the first nuclei which promotes further crystallization and growth in a clear solution. Nucleation process can be primary or secondary. The former occurs when there are no crystals present in the solution to start with and crystallization is occurring for the first time, while the later occurs if there are some crystals already present in the system over which, further crystallization can occur. Primary nucleation process requires a sufficiently high concentration of supersaturated solution, whereas secondary nucleation can occur at relatively lower concentrations (Majors 1999).

(b) **Growth** – this is the stage at which crystal mass is transported from the solution toward the nuclei. It is a dynamic process during which crystallization continues through molecular diffusion of paraffin components from the liquid solution to the nuclei interface. At this point, the paraffin chain becomes incorporated into the crystalline lattice structure. Crystal growth follows nucleation process and it continues till a steady state is reached.

(c) **Agglomeration** – this is the stage at which the developed crystals join together and bigger crystals are formed.

However, the crystals of wax or paraffin start to liquefy as their temperature reaches the pour point. (Chin 2001).

3.2.3 Wax Deposition

Wax precipitation is necessary but not a sufficient condition for wax deposition (Hammami et al, 2003). Deposition would not occur if there are no wax crystals in the solution. The initial crystals that appear in solution during cooling to WAT will be suspended in solution and will form a gel when up to 1 – 2 percent weight. These crystals are formed under super cooling conditions (Ronningsen et al. 1991; Kane et al. 2003).

Deposition rates can be attributed to many factors including paraffin content, fluid viscosity, flow rates, gas and oil ratio and the overall heat transfer coefficient (U-value) (Golczynski and Kempton 2006). Diffusion of wax particles from the liquid – solid interface to the pipe wall under temperature and subsequent concentration gradients, result in the formation of solid deposit on the pipe wall. However, wax will only deposit on the pipe wall when the wall temperature is below the cloud point and colder than the bulk fluid. Deposition of wax from oil results in a gradual reduction of production due to plugging of wells and pipelines. However, in an extreme case, this can cause a pipeline or production facility to be abandoned (Singh et al. 2011).

3.2.4 Wax Gelation

At temperatures lower than the pour point, complete gelation of the system occurs. Pour point is the temperature where sufficient amount of wax (about 4 weight percent) is precipitated to make the oil take on a solid-like (gel) structure. The pour point of North Sea oils may be as high as 35 °C and lower than -50 °C. Pour point temperature is a principal factor in gel formation, because it defines the temperature at which gels form. Below the pour point, the oil has a yield shear stress. This implies that the oil would not flow unless it is subjected to a certain minimum shearing force (shaking or pumping) (Time 2011). During a long shutdown for instance, after the production fluid has been cooled to the ambient temperatures, a pipeline can become completely blocked or significant difficulties will be encountered when being restarted (Golczynski and Kempton 2006).

Wax gelation is less common in steady state than is wax deposition. This can have greater impact if, during production system shutdowns, fluid temperatures cool below the fluid pour point, thus allowing the formation of a “candle” or solid wax column (Golczynski and Kempton 2006). The melting point of wax deposits is normally about 20 °C higher than the cloud point. Figure 16 is a schematic of wax plug removed from a subsea pipeline.

Figure 16. Wax plug removed through pigging (Time 2011)

However, wax precipitation and deposition in offshore environment poses a great challenge such that remediation costs becomes very significant or humongous. Thus, this is a key issue for the oil industry in analyzing the economics of waxy crude production in the cold environments.

3.3 Scale Problem

Scale is a precipitation of inorganic salts (minerals) in production equipment such as carbonates and sulphates of barium, strontium or calcium. Scale may also be salts of iron like sulphides, carbonates and hydrous oxides (Time 2011). Oilfield scales are deposited from oilfield brines when there is a disturbance in the thermodynamic and chemical equilibrium that may result in certain degree of super saturation. The disturbance in thermodynamic and chemical equilibrium can be a change in pressure, temperature, pH and ionic composition (Jordan and Mackay 2005). They reduce the flow capacity of pipelines or flowlines and other problems when they are deposited. Figure 17 is a schematic of scale deposits on a pipeline cross section.

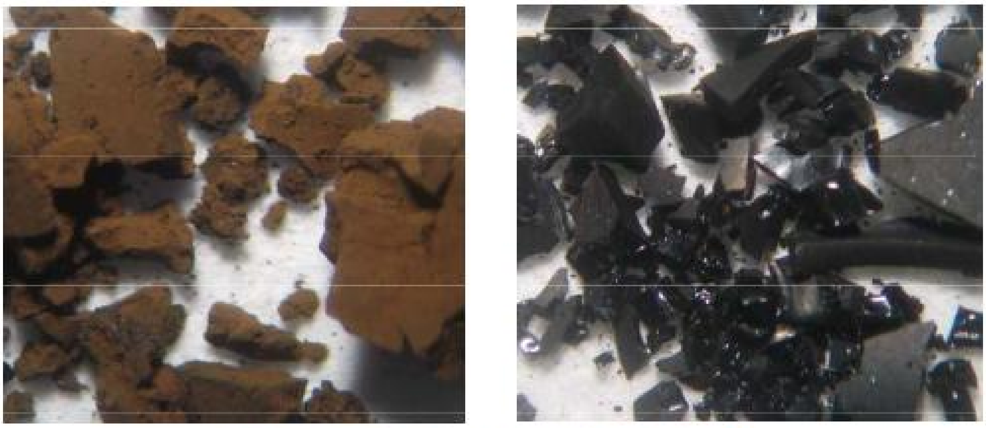
Figure 17: Scale deposits on a pipe's section (Time 2011).

Formation of oil field scale can be in one of these two ways: the formation water (brine) may undergo change in conditions such as temperature or pressure. This generally gives rise to carbonate scales. Also, when two incompatible waters for example, formation water rich in calcium, strontium and barium and sea water rich in sulphate mixes together. This generally gives rise to sulphate scales (Time 2011). The mechanism of mineral scales formation is dependent upon the degree of supersaturation of the water with respect to a particular mineral, the rate of temperature change and changes in the pressure as well as the pH of the water .

3.4 Asphaltenes Problem

Asphaltenes are high molecular weight polycyclic organic compounds with nitrogen, oxygen and sulphur in their structure, in addition to carbon and hydrogen. The presence of asphaltenes in the petroleum fluids is also defined as a fraction of petroleum fluid or other carbonaceous sources such as coal. They are soluble in benzene and the deposits, by addition of a low-boiling paraffin solvent. Asphaltenes do not crystallize upon deposition from the petroleum fluids. This is why its phase transition from the liquid to solid does not follow the same path as paraffin. It is also not easily separated into individual purified components or fractions. Resins are strongly adsorbed by asphaltenes, thus their extreme analyses are not significant and quantitative, and they are easily separated from them. Figure 18 presents a schematic of asphaltenes from a production facility (Time 2011).

Asphaltenes can cause problems in oil production, transportatipon, and processing facilities. The asphaltene contents in oil is less important than their stability. Their stability is dependent on their properties and solvent properties of the oil. Light oils with small amounts of asphaltenes are more likely to cause problems than heavy oil with larger amounts of material in the asphaltene fraction. Heavier oil contains intermediate components that are good asphaltene solvents whereas the light oil consist largely of paraffinic materials in which by definition, asphaltenes have very limited solubility. Asphaltenes in heavier oils can also cause problems if they are destabilized by mixing with another crude oil during transportation or by other steps in oil processing. It can alter surface wetting properties or accumulate and plug well bores and flowlines. The first step toward predicting and avoiding any of these problems is knowing how to evaluate asphaltene stability (Time 2011). In general, asphaltenes cause little or no operational problems because most of asphaltic crude oils contain stable asphaltenes.



http://baervan.nmt.edu/Petrophysics/group/intro-2-asphaltenes.pdf

Figure 18: Asphaltenes appearance separated from Mars-P crude oil with an excess of n pentane (n-C5) and n-heptane (n-C7) (Time 2011)

This work will however focus mainly on hydrates and wax problems. Thus, the succeeding chapter will highlight and review related literature on the traditional technologies used in tackling hydrates and wax flow assurance problems.

4. Hydrate and Wax Prevention Techniques

In everyday business, there must be ways of proper management and control of processes to ensure profitability. Remediation of hydrates or wax in flowlines and pipelines poses greater challenge and loss of money to the oil industry. This is because, blockage point location is a difficult job itself at first, and if blockage is far away from an access point, such as riser, it may be difficult to reach it with chemicals or remediation tools especially at subsea location (Kaczmarski and Lorimer 2001). Most of the remediation and prevention tools and technologies are as shown in Figure 19 and Figure 20. Since reduction of risk factors is the scientific basis for primary prevention and control, and for flow assurance to be ensured, the industry has adopted several techniques considering technological, environmental, and economics of the different technique.

Hence, the focus of this chapter will be on reviewing and describing the different technologies of hydrates and wax prevention. These descriptions will consequently form the basis of further analysis (comparison) and discussion in subsequent chapters. There are several technologies used today to achieve flow assurance in subsea transportation through pipelines.

I have chosen to focus on six technologies. These technologies are believed to have high potential values and in agreement with my supervisor. These technologies are chemical inhibition which includes the thermodynamic hydrate inhibition (THI) and low dosage hydrate inhibition (LDHI), electrical heating system, and three cold flow concepts which are developed by SINTEF-BP, Gudmundsson and Heriot-Watt University respectively.

There are other technologies that are also evaluated at the end of the existing technologies, but will not be part of my evaluation in this study. These technologies are also presented here to give a picture of these technologies, but will not be further analyzed.

The different technologies are evaluated based on the research description from my supervisor. The issues are as follows: technical evaluation, environmental, and economical evaluations, and advantages and disadvantages of the different technologies. Under technical description and evaluation of the different technologies, I have generally tried to look at the technical issues like viscosity, water cut, GOR, subcooling, pipeline distance it can effectively and economically cover, among other issues based on their performances.

However, cold flow technology which is a potentially emerging new technology will be presented in detail in the subsequent chapter while the existing technologies will be presented in the following sub-sections.

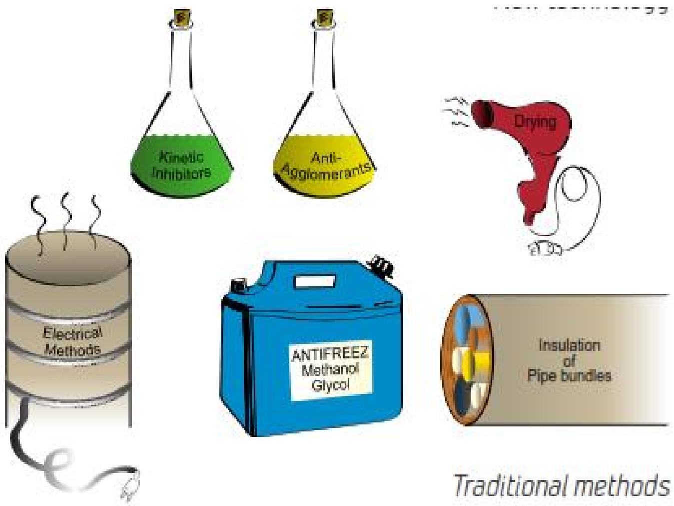


Figure 19: Traditional Methods of hydrate and wax prevention (SINTEF 2010).

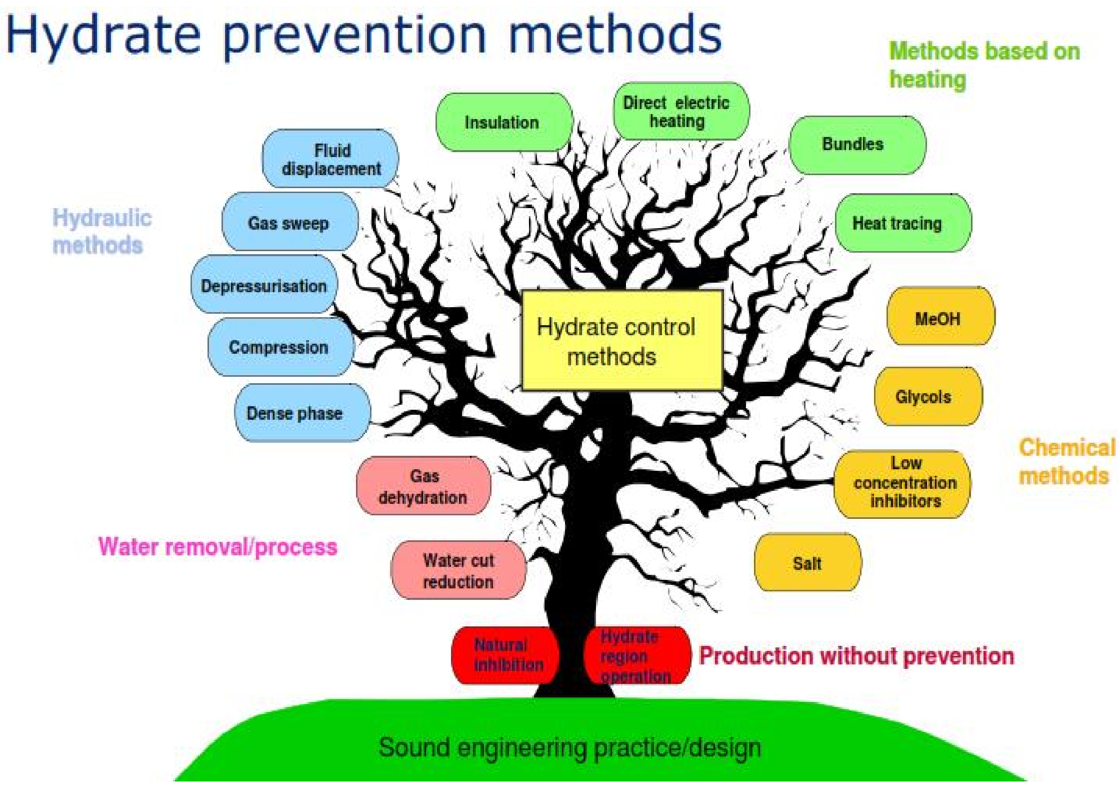


Figure 20: Hydrate prevention methods (Labes-Carrier 2007)

4.1 Prevention with Chemical Injection

Hydrate inhibition using chemical inhibitors remains the most widely used method in the industry. The development of cost effective alternative and environmentally acceptable hydrate inhibitors is a technological challenge for the oil and gas industry (Lederhos et al. 1996). Inhibitors are added into processing lines to inhibit the formation of hydrates. Injection of chemical is used for pipelines with length ranging from 10 km to 250 km (Gudmundsson 2012 and Ilahi 2006).

There are two main categories of chemical inhibitors: thermodynamic hydrate inhibitors (THIs), and low-dosage hydrate inhibitors (LDHIs), Paez et al. 2001. These would be discussed in the succeeding sections.

4.1.1 Thermodynamic Hydrate Inhibition – Technical Evaluation

The thermodynamic hydrate inhibitors (THIs) have been used for a long time in the industry and they act as antifreeze. The most commonly used THIs are methanol and mono-ethylene-glycol (MEG) (Boxall and May 2011). Other chemicals such as diethylene glycol (DEG), and triethylene glycol (TEG) are also used but will not be specifically considered in this work.

The main principle behind this method is that, it prevents hydrate formation by shifting the equilibrium conditions so that lower temperatures and higher pressures are required to form hydrates (Huo 2001). This implies that with the addition of THIs (methanol or MEG), hydrate equilibrium curve will be shifted to the left (lower temperature and higher pressure). This alters the thermodynamic equilibrium of water and hydrocarbon molecules and reduces the risk of hydrate formation in the system. This is essentially because, the chemical potentials of hydration are reduced and correct volumes of injection must be ensured. They do not affect the nucleation of hydrate crystals and the growth of crystals into blockage. They only change the temperature and pressure conditions, thereby shifting operating conditions out of stable hydrate region, as illustrated in Figure 21.

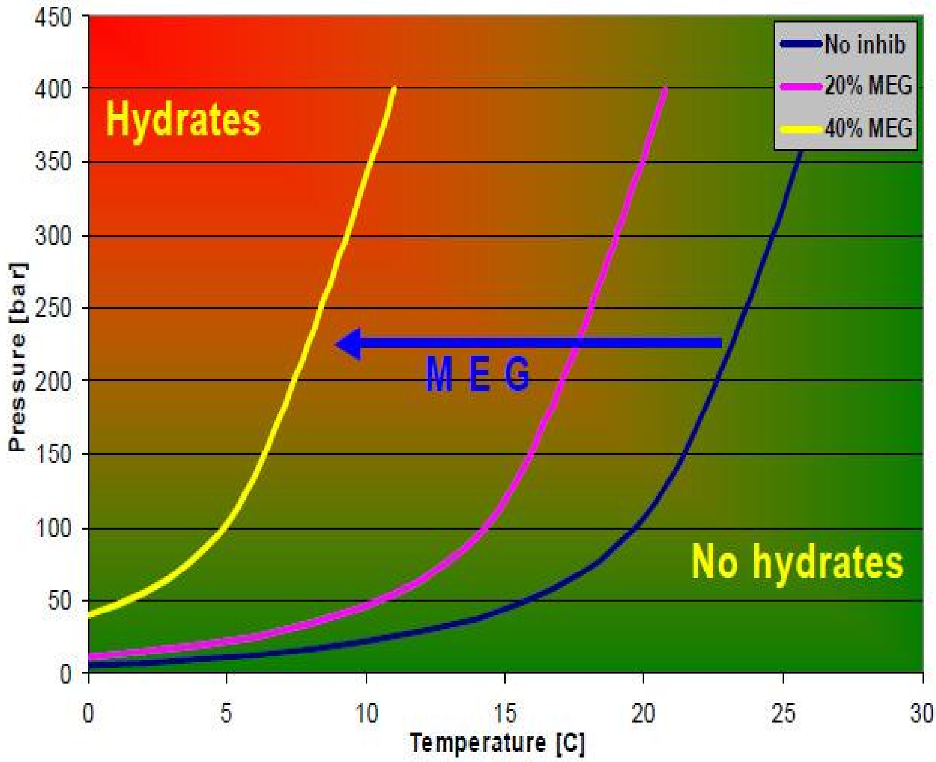


Figure 21: Gas hydrate equilibrium curve (Sandengen 2010)

A typical hydrate management strategy with chemicals is based on continuous injection of a thermodynamic hydrate inhibitor (typically mono-ethylene-glycol, [MEG]) with little or no insulation of the subsea system (Estefen et al. 2005). THIs are rarely used in oil systems because high concentrations will be involved to provide hydrate prevention (Sloan 1998). Injection is also done during start up and shut down periods only, since the steady state system is designed to operate outside hydrate risk conditions (Mehta and Klomp 2005). They are used mostly in gas and condensates and multiphase system. The chemicals are delivered through small diameter pipeline in opposite direction to the production stream from the fixed tanks on the seabed or at topside.

THIs are typically used when the water cut in the system is in the range of 20 to 40 weight percent, but theoretically, it can be used at all water cuts (Tvedt 2005). The subcooling effect of THIs (methanol) could be as high as up to about 30 ^{o}C for 50 weight percent at the pressures between 0 and 170 bar (Pickering et al. 2001). The viscosity of petroleum is always affected with the addition of THIs. With the addition of methanol, the petroleum produced will be thicker while glycols make it thinner, but this is difficult to predict (Tvedt 2005). However, the amount of hydrate up to 30 percent does not necessarily give measurable change in the viscosity of the fluid (Gudmundsson 2002). Thus, thermodynamic hydrate inhibitors required to control hydrate formation is not impacted by the quantity of hydrate forming particles and GORs. With high water cuts and high GOR, it becomes difficult to transport the fluid notwithstanding the quantity of chemical inhibitor added (Tvedt 2005).

Glycols are extensively used in the oil and gas industry, especially in the production of natural gas. When methanol and MEG are used as gas hydrate inhibitors, their loss in hydrocarbon phase is the most significant disadvantage, especially for methanol. MEG are more preferred because they are easier to regenerate and do not pollute oil like methanol (Tvedt 2005). Its boiling point is higher than methanol and also, its evaporation loss is negligible as well as being suitable for stations where natural gas is to be treated. Also, effective THIs content is less than up to 6 percent of the gas to be treated (Wu et al 2007). Conventional regeneration systems are typically used to boil off water at conditions close to atmospheric pressure. The operational temperature depends on the required lean MEG content. The mode of operation of regeneration process and the main components of the MEG regeneration system include a column equipped with a reboiler and a lean/rich MEG heat exchanger (EET 2011) as illustrated in the Figure 22, and Figure 23 is a picture of the regeneration and reclamation unit. However, methanol is not usually regenerated (Mehta and Klomp 2005).

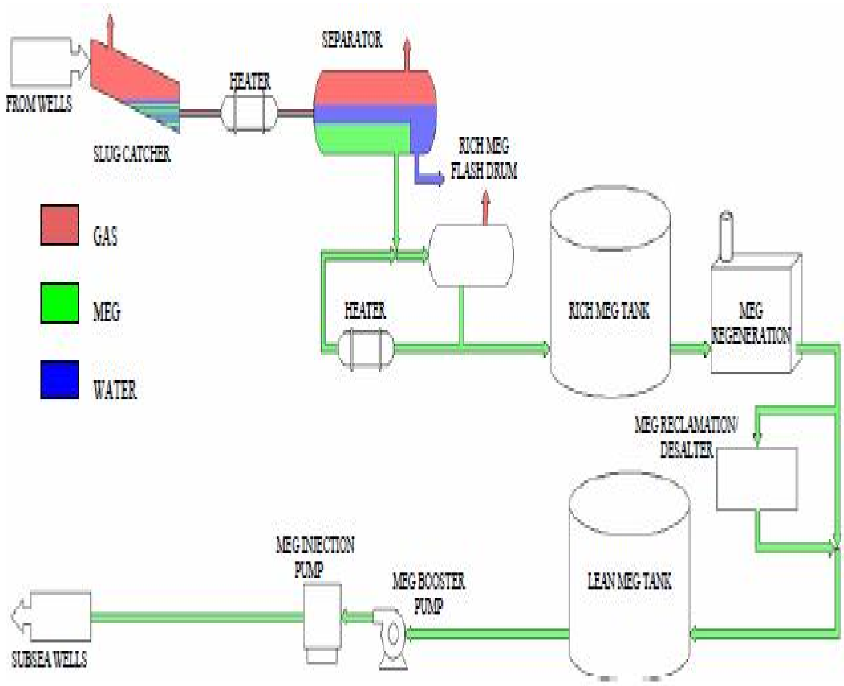


Figure 22: MEG Reclamation Process Schematics. (Estefen et al. 2005)

The main benefits of the thermodynamic hydrate inhibitors (THIs) include their effectiveness, reliability (provided sufficient quantities are injected) and proven track-records. However, these benefits are outweighed by significant limitations, including high volumes, high associated costs (both CAPEX and OPEX), toxicity and flammability (Pickering et al. 2001).

Figure 23: Photograph of Glycol Regeneration & Reclamation Unit (Son and Wallace 2000).

4.1.2 Environmental Evaluation of THIs

In subsea environment, THIs (methanol and MEG) are sensitive to changes in system subcooling, thus, injection rates are set to correspond with the subcooling effect. This leads to large quantities or volume (30 – 60 percent by volume) needed to prevent hydrates formation (Patel and Russum 2010) as water cut increases. Over inhibition results in high costs and negative impact on the environment. This may be attributed mainly to the fact that the process and production engineers do not have any means to quantitatively measure the degree of inhibition within which the flow system should be actually operated, although some experience-based tactics have been suggested to rationalize hydrate inhibitor injection (Willmon and Edwards 2006).

There are many restrictions associated with the use of THIs. Among these include environmental concerns based on the discharge limits and safety considerations. Based on the fact that they are harmful to the environment, significant disposal into the environment is well prohibited (Pickering et al. 2001). Glycol reclamation processes can generate a solid waste or a concentrated liquid waste product, which is primarily salt for disposal. These salts are toxic. In methanol recovery processes, there is no solid waste generated (Son and Wallace 2000), but there exist the risk of handling.

Regeneration units installed for the purpose of recovering most of the injected THIs can aggravate scaling problems by lowering the solubility of scaling salts in water, cause salting out of total dissolved brines and contamination of the exported oil especially methanol (Patel and Russum 2010). Regeneration and disposal of THIs poses a serious environmental issue (Campbell & Company 2003). Moreso, the large volume of THIs required can cause damage to wildlife, aquatic lives and plants in a local area if there leakage or undesirable discharge.

4.1.3 Economic Evaluation of THIs

Hydrate prevention with methanol or MEG can be very expensive due to high effective dosages required, 20 to 50 percent of the water phase (Szymczak et al. 2005). The cost of methanol per unit volume is less than that of MEG although its price varies significantly while MEG is fairly stable (Son and Wallace 2000). MEG is usually recovered downstream and recycled while methanol is not usually recovered. But the selection of either methanol or MEG for deepwater hydrate inhibition usually involves comparison of many factors such as capital and operating costs, site-specific conditions and previous experiences (Son and Wallace 2000).

Methanol is less expensive per gallon than MEG. Typically, methanol is used without regeneration because it reacts with the gas phase and its total volume can be as high as twice the volume of water (Tvedt 2005). This results in the allocation of large amount of storage and transportation volumes (Mehta and Klomp 2005). As earlier said, it needs to be injected in very large quantities, from 30 weight percent to 60 weight percent. This can cause price escalation around $60,000 per day for using THIs. The respective cost of Methanol, MEG and TEG is NOK 3, 5 and 7 per litre (Tvedt 2005).

On the other hand, the price of MEG is fairly stable. The controlling factor is the product of chemical cost and gallons consumed. Thus, chemical losses rather than price per gallon can have the greatest bearing on chemical costs (Son and Wallace 2005). MEG is added in equal amount to the amount of water in the petroleum. This drives the cost for MEG injection system up, in addition to a costly pipeline diameter (Tvedt 2005). MEG is recovered, regenerated and reused when utilized for hydrate inhibition. For subsea production systems, separation of produced water on the sea floor is not normally possible as salt water associated with the produced gas will distribute into and be separated with the rich glycol phase (Son and Wallace 2005). Since all the MEG cannot be regenerated, extra cost will be acquired as MEG will be reclaimed and new MEG slowly added.

MEG is generally associated with high CAPEX because of the equipment needed to regenerate it. The size of subsea transportation lines ranges from 14 inches to 36 inches (Tvedt 2005). Ormen Lange has a pipeline diameter of 30 inches, which transports gas with only water as vapour in small amount (Bostrøm et al. 2010). An oil system will need even larger pipeline diameter, thus increasing the price of the pipelines. It is normal to use an insulated pipeline in combination with injection of methanol. The price of a thermal insulated pipeline is around $1 million per kilometer. Also, a large portion of heat is required to regenerate MEG, as all the water needs to be boiled out and this again can add to the cost acquired (Tvedt 2005).

However, since large quantities may be necessary to suppress the equilibrium temperature below the lowest operational temperature expected in the system, the infrastructure cost may add up to significant or humongous amounts. Necessary considerations to make when designing for a hydrate strategy with thermodynamic inhibitors are storage volumes and regeneration facilities. It will cost from around $7,000 million and upwards for a system with regeneration facilities. Depending on the regeneration needed, the cost will be from $180 million and up and cost will reduce without a regeneration system (Tvedt 2005).

The reinjection pipeline cost can be calculated relative to length and diameter of other pipelines. Moreover, the need for injection valves, a tank to store the chemicals and powerful pumps will also add to the cost of the system. This would cost around $1 million,

$27 million and $1.6 million for a system equal in size to Ormen Lange respectively (Tvedt 2005).

4.1.4 Advantages of THIs

Methanol has a lower viscosity and hence requires less pump horsepower for injection (Son and Wallace 2000). MEG is reliable, requires low capital and operating cost (Low CAPEX & OPEX). It is very flexible with low molecular weight. MEG is also recoverable (regeneration and reclamation).

Both chemicals have deepwater proven track record and can provide the necessary inhibition in a properly designed system. They are effective, well understood, and predictable (Chandragupthan et al. 2011).

4.1.5 Disadvantages of THIs

Methanol is volatile and some of it is lost into the gas phase, as opposed to the aqueous phase where it should be inhibiting hydrates (Son and Wallace 2000). Methanol also promotes corrosion problems and reduces the efficacy of some corrosion inhibitors due to the dissolve oxygen in it (Scott-Hagen 2010).

MEG regeneration requires large heat. It may also foam with oil and condensate with limited dew point reduction (Chandragupthan et al. 2011).

Moreover, the major challenge with using thermodynamic hydrate inhibitors is the high concentrations (10 – 60 weight percent in the aqueous phase) required, with a large attendant costs. They are toxic and hazardous and environmentally harmful (Chandragupthan et al. 2011).

4.2 Low Dosage Hydrate Inhibitor (LDHI) – Technical Evaluation

Low-dosage hydrate inhibitors (LDHIs) have recently been developed and their usage modifies the rheology of the system rather than changing its thermodynamic state. The low-dosage hydrate inhibitor is divided into kinetic hydrate inhibitors (KHIs), and anti-agglomerants (AAs). These types of chemicals would be considered in this section.

Low dosage hydrate inhibitors (LDHIs) was coined because they can be used at comparatively low concentration levels (0.25 – 0.50 percent by volume in produced water) (Clark and Anderson 2007), when compared to the higher concentrations required of more traditional thermodynamic inhibitors such as methanol. LDHIs do not significantly change the hydrate equilibrium curve unlike thermodynamic inhibitors. They rather work at low concentrations, lower than or equal to one (1) weight percent. Therefore, the use of this technique reduces the environmental concerns and since no regeneration units are required, it results in reduction of capital cost (Pickering et al. 2001). LDHI was initially produced to prevent hydrate formation in deepwater, and also to transport multiphase hydrocarbon. But is now also used when transporting wet gas in pipelines in the Middle East since hydrate can easily form due to the condensation of water from the gas (Mehta and Klomp 2005).

A kinetic hydrate inhibitor (KHI) delays hydrate formation for a period of time, also known as the induction period. This period is system specific and as such, KHIs are designed to meet individual facility requirements. It can delay the onset of hydrate formation time from hours to days (Paez et al. 2001). Residence time should be shorter than the induction time (Tohidi 2011) as illustrated in Figure 24. This implies that, as induction time is increased to a value higher than the residence time, hydrate will not be formed during its passage through the pipeline. But if the transit time through the pipeline is sufficiently long, and during shutdown for instance, hydrates will be formed and plugged the pipeline.

KHIs are typically most effective in low-to-moderate hydrate formation conditions. They are applicable to both gas and oil systems and are able to prevent hydrates up to around 18 -20 °F subcooling. Subcooling is the difference in temperature between the actual working conditions of a system to the hydrate formation point. The first generations of KHI were very effective in controlling hydrates up to 8 °C subcooling and with extension of induction time to 24 hours (Clark et al. 2008). For the latest technology, the application window has expanded to 13 °C subcooling and for at least a 48 hours shut-in protection (Fu et al. 2005). The limit of subcooling for best KHI is 14 – 15 ^{o}C (Peytavy et al. 2008). KHIs have subcooling limits rather than water-cut limits, and can work even at 100% water cut (Patel and Russum 2010). KHIs are not limited by GOR and water cut experienced in the produced fluids (Clark et al. 2008), but high water cut and high GOR, will result in difficulty of fluid transportation.

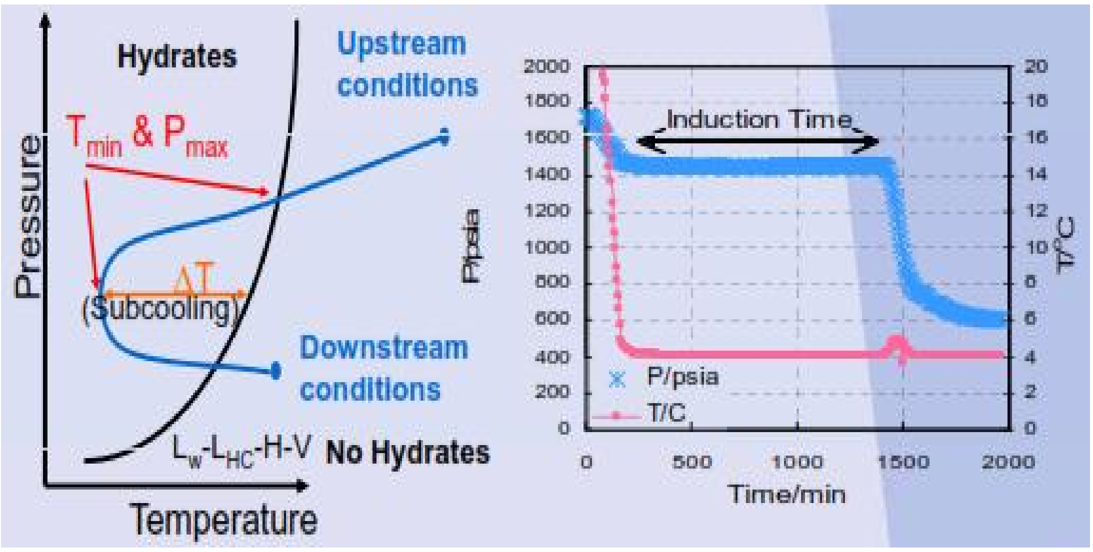


Figure 24: Hydrate prevention with KHIs (Tohidi 2011)

KHIs are commonly water-soluble polymers which delays the nucleation and growth of hydrate crystals until the produced fluids are brought to a zone where hydrates are unstable. Some KHIs also are incompatible with corrosion inhibitors. Kinetic hydrate inhibitors are injected in much smaller quantities compared to thermodynamic inhibitors. Therefore it offers a significant potential costs savings, depending on the pricing policies of major chemical suppliers (Pickering et al. 2001). A hydrocarbon liquid phase as a carrier is not necessary for KHIs, as it is not limited by the water cut as long as it is in sufficient amount in the aqueous phase (Mehta and Klomp 2005), but 20 – 30 percent of water cut is preferred in normal operations for KHIs (Tvedt 2005).

Two different methods are usually adopted in the application of KHI blends. One method is to apply the blend neat without a supplementary methanol injection. Another method is to apply it along with methanol, either through separate injection points or mixed into methanol and applied as a single injection (Scott-Hagen 2010). He added that, KHIs used as an additive to methanol injection provides both an increase to the subcooling tolerance of the treatment while routinely reducing the overall injection rate by 40 – 60 percent to that of methanol alone, or more, depending on the system treated. The selection of injection method is based primarily upon cost-to-treat and the required effectiveness of the program. Typical examples of KHIs include: polyvinylpyrrolidone (PVP) and polyvinylcaprolactam (PVCap) (Kelland 2006).

Anti-agglomerants (AAs) are surface active chemicals (surfactants). They allow hydrate crystals to form but prevent them from agglomerating and adhering to pipe walls (Klomp et al. 2004). This means that, they allow hydrates to form, but as tiny, non adherent particles that are easily dispersed into the liquid hydrocarbon phase. As the viscosity remains low, this will allow the hydrates formed to be transported with the produced fluids. AAs do not have subcooling limitations but have been found to be effective in low to extreme hydrate stable regions, even during extended shut in periods (Scott-Hagen 2010).

The design of the AA molecule is similar to foaming surfactants used for gas well deliquification. A foaming surfactant has a hydrophilic (water-attracting) head and a hydrophobic (water-repelling) tail. The molecule's head is attracted to the hydrate and becomes part of the hydrate crystal. The tail portion is dispersible in hydrocarbon liquids and causes the crystal to be dispersed into a hydrocarbon phase. The dispersion hinders the formation of larger crystals which would then be less likely to cause plugs (Clark et al. 2005). Since hydrate crystal is formed and dispersed, subcooling or residence time limitations has been eliminated, as shown in Figure 25.

There are two classes of AAs commercially in use. These include; pipeline or production AAs and gas well AAs. The former allows formation of hydrates as transportable non-sticky slurry particles dispersed in the liquid hydrocarbon phase while the later disperses hydrate particles in excess water (Kelland 2009). However, as a side effect on dispersion requirement, AAs requires the presence of a liquid hydrocarbon phase to provide effective inhibition. Typically, the water cut must be below 25 – 50 percent for AAs to be effective. It also shows a gas-to-liquid (GOR) limitation. Above this range, hydrate particles concentration in the slurry becomes so high that AAs are no longer able to allow the transport of the suspension. A rule of thumb for AAs to be effective is that a GOR should be less than 100,000 scf/stb (Clark et al. 2005).

Consequently, AAs effectiveness is dependent on the type of oil/condensate, the salinity of the formation water and the water cut. Pipeline operation can also be of importance as dispersion of small hydrate crystals will be favored by higher velocities. At low flow rates and during shutdown conditions, the crystals may settle out and agglomerate when the oil density difference is sufficient. The anti-agglomerants provide protection up to 40:60 water oil ratios (Chandragupthan et al. 2011). Typical examples of AAs include alkyl aromatic sulphonates or alkylphenylethoxylates (Pickering et al. 2001)

As such, AA inhibitor is an economically attractive option under severe hydrate-forming conditions and is also very effective where production is shut-in for extended periods.

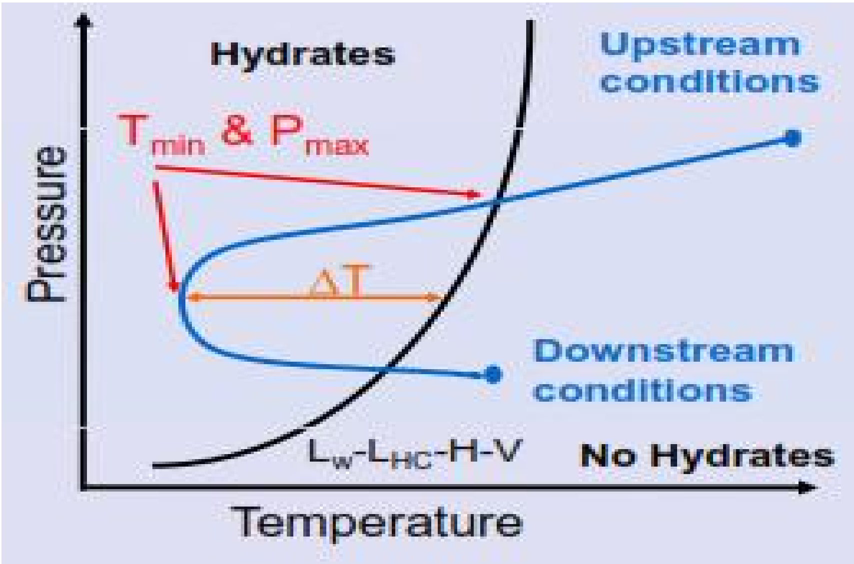


Figure 25: Hydrate Prevention with AAs (Tohidi 2011)

4.2.1 Environmental Evaluation of LDHIs

LDHIs have a low-toxicity characteristic and smaller volumes requirement for treatment makes it environmentally desirable over a long term. The leakages from storage, treatment, and transport facilities are also reduced, since there is no recovery stage required. LDHIs minimizes environmental footprint from the reduced storage and injection requirements. And, they are also effective under severe temperature conditions as well as complying with some environmental standards (Schlumbeger 2011).

Currently, LDHIs are now widely used in the industry and as such can be regarded as proven technology, following a number of successful trials and field experience. The usage of KHI was primarily limited to onshore fields and relatively shallow offshore system, but several deepwater projects have now been considered (Frostman and Crosby 2003). This inhibitor has successfully offered protection for long subsea flowlines length of up to 40 km long (Champion 2012).

However, LDHI have been successfully deployed in some fields, for example, in the South-Par phase 2 & 3 in Iran (Glénat et al. 2004) and also, Champion 2012, had it that they have successfully deployed AAs in the Gulf of Mexico. Some LDHIs are incompatible with some production-system materials, processing fluids, and production chemicals, thus, LDHIs are not allowed everywhere. LDHIs are banned from usage on the Norwegian continental shelf by the Norwegian government and also from other sea zones because of their toxicity (Tvedt 2005). Statoil, according to Tvedt 2005, said that they will not use LDHIs due to their toxic nature and poor ability to dissolve.

4.2.2 Economical Evaluation of LDHIs

LDHIs are more cost effective than THIs, and the shift from THIs to LDHIs is driven by economics. Among these economic drivers include: facilitation of higher production rates in THIs (Methanol) volume-limited system, CAPEX and OPEX reduction through system designs where fewer umbilical lines, smaller and lighter storage capacity, and smaller pumps are required. Drastic reduction in volumes required of LDHIs leads to a whole host of potential cost savings when compared to Methanol (Frostman et al. 2003). Insulated pipeline are normally used with chemical injection which costs around $1 million per kilometer (Tvedt 2005).

Though the chemicals are expensive, only less than one percent by weight is required of LDHIs to prevent hydrate formation. LDHIs cost approximately NOK 65 to 100/ kg or $4 – 6/lb. (Tvedt 2005). It takes 0.5 weight percent of LDHI to treat 11 ^{o}C subcooling which is equivalent to using 25 weight percent methanol or about 40 weight percent MEG (Kelland 2006). Also, an average cost KHIs is $5 – 6 per Litre, which makes it nearly the same as operational expenditure as using THIs (Clark et al. 2008).

The selling prices of specialty chemical LDHIs are significantly higher than the commodity chemicals (Methanol and MEG). LDHIs are typically sold for tens of dollars per gallon, whereas Methanol is typically $0.30 - $0.90/gal and MEG is typically $1.75 - $3.75/gal (Frostman et al. 2003).

4.2.3 Advantages of LDHIs

LDHIs are used in multiphase, gas condensate, and crude oil production. They can extend the life of wells and its ultimate recovery through higher water production rates from subsea wells and because of continuous flow, the problem of liquid-hold up in gas wells are minimized. They are also capable of delaying water-cut related curtailment, as such, wells may not be shut down because of hydrates or other high water cuts related problems (Singh et al. 2006; Frostman et al. 2003).

They are typically non-toxic and environmentally friendly. Requirement for manpower is reduced because less stock is needed to be handled. They also save potential cost (CAPEX & OPEX), since lower volumes are required (less than one percent weight) and less pump maintenance resulting from smaller dosing rates. KHIs is now becoming field proven (Pickering et al. 2001; Frostman et al. 2003). And, the absence of subcooling limitations for AAs.

4.2.4 Disadvantages of LDHIs

LDHIs are system specific and thus requires adequate testing prior to implementation or deployment. For new field development, production fluids may not be readily available for testing. They also lack an established model for the prediction of their effectiveness, thus posing difficulties for field developers in the application of these chemicals (Pickering et al. 2001; Chandragupthan et al. 2011).

KHIs have limited subcooling (time dependent). They interact with other chemical inhibitors (for example corrosion inhibitors) which reduce their effectiveness and this should be accounted for in testing programmes (Graham et al. 2001). They also have limited experiences in oil systems (Chandragupthan et al. 2011). Anti-agglomerants (AAs) are limited to low water cuts due to the continuous hydrocarbon phase that is required and it also has limited experience (Chandragupthan et al. 2011).

However, the summary of these chemical applications, benefits, and their limitations according to Pickering et al. (2001) is presented in Table 3.

Table 3: Summary of Applications, Benefits & Limitations of Chemical Inhibitors (Pickering et al. 2001)

Thermodynamic Hydrate Inhibitors	**Kinetic Hydrate Inhibitors**	**Anti-Agglomerants Inhibitors**
Applications		
1. Multiphase 2. Gas & Condensate 3. Crude oil	1. Multiphase 2. Gas & Condensate 3. Crude oil?	1. Multiphase 2. Condensate 3. Crude oil
Benefits		
1. Robust & effective 2. Well understood 3. Predictive 4. Proven track-record	1. Lower OPEX/CAPEX 2. Lower volume (<1wt. %) 3. Environmentally friendly 4. Non toxic 5. Tested in gas system	1. Lower OPEX/CAPEX 2. Lower volume (<1wt. %) 3. Environmentally friendly 4. Non toxic 5. Wide range of subcooling
Limitations		
1. Higher OPEX/CAPEX 2. High volumes (10-60wt. %) 3. Toxic / hazardous 4. Environmentally harmful 5. Volatile – losses to vapour 6. ‘Salting out’	1. Limited subcooling (< 10 ^{o}C) 2. Time dependency 3. Shutdowns 4. System specific – testing 5. Compatibility 6. Precipitation at higher temperature 7. Limited experience in gas systems 8. No predictive models	1. Time dependency? 2. Shutdowns? 3. Restricted to lower water cuts 4. System specific – testing 5. Compatibility 6. Limited experience 7. No predictive models

4.3 Prevention by Insulation and Electrical Heating Method of Hydrates

Thermal methods of hydrate prevention include heat retention and or active heating in order to maintain or keep the produced fluids out of hydrate forming conditions. Heat retention is achieved through insulation (that is, either through external coating, pipe-in-pipe system, bundling, and burial) (Oram 1995, Hunt 1996). These methods can be successfully applied depending on the type of fluid transported, topside capabilities of the host platform, and tieback distance. Heat retention system design of such typically seeks a balance among the high cost of the insulation, the intended operational flexibility of the system, and their acceptable risk level (Fidel-Dufour and Herri, 2002). However, active heating involves hot fluid heating (indirect heating) and direct heating through electricity

(Bai and Bai 2005). Thermal management is a key issue in long tiebacks, and the use of electrical heating can be considered as an alternative to fluid circulation for preservation purposes (Decrin et al. 2011).

In this section, I therefore choose to focus on direct heating with direct electrical heating (DEH): an active control of hydrate challenges in subsea pipelines.

4.3.1 Direct Electrical Heating System (DEHS) – Technical Description

Direct heating by application of electric current in the pipe is noted to have been in use since 1970's in shallow waters and it has the potential of preventing hydrate formation as well as wax deposition along the entire length of a pipeline (Bai and Bai 2005). As oil and gas production moves into deeper water, direct electrical heating systems (DEHS) have been developed and qualified for heating of flowlines and pipelines in subsea, for example DEHS installed in North Sea (Lenes et al. 2005) as shown in Figure 26.

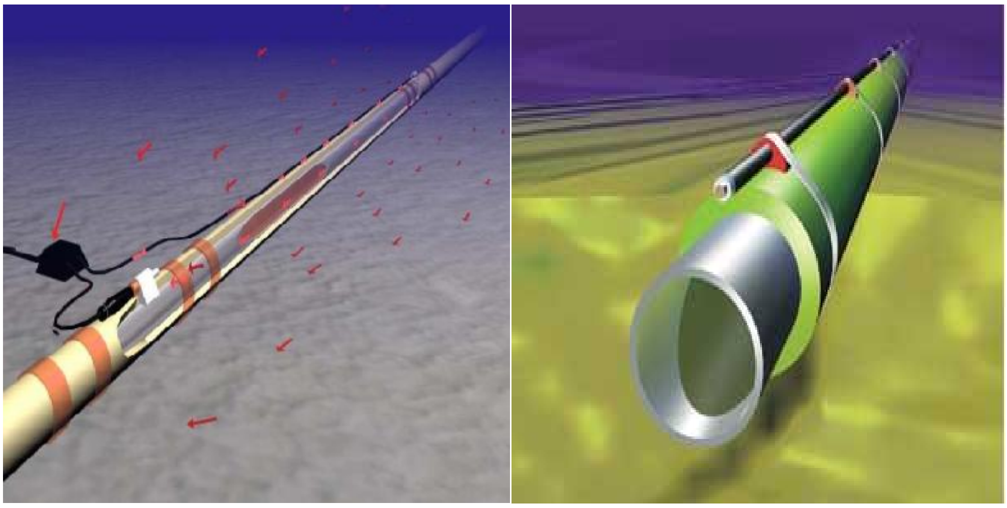


Figure 26: DEHS on seabed (Kulbotten 2008; Clase and Ystad 2009)

The basic principle in DEHS involves passing a large electric current through the pipeline wall to generate heat. It is the most attractive and reliable option for deepwater field operation of transport flowlines (Nysveen et al. 2007; Lenes et al. 2005). DEHS is such a system and was proposed by SINTEF Energy Research. It has the potentials of reducing investments of recovery plants for chemical residual products and depressurization systems (Kullbotten and Lervik 2007).

DEHS is based on using an alternating current (AC) through a metallic conductor to generate heat. The pipe to be heated is an active conductor in a single phase electric circuit with a single core power cable which acts as a forward conductor. The cable is located in parallel with and close (piggyback) to the heated pipeline. Power is supplied from the platform through two riser cables. One of the two single core riser cables is connected to the near end of the pipe, and the other to the forward piggyback cable connected to the far end of the pipe (Kullbotten and Lervik 2007) as illustrated in Figure 27. This implies that, it has two cables connected to each pipeline's end, creating a closed circuit. As current is added, an ohmic force is encountered and thus, an energy loss in this process heats up the pipeline. Larger pipeline diameter up to 30 inches or more can be used for DEHS (Nysveen et al. 2007).

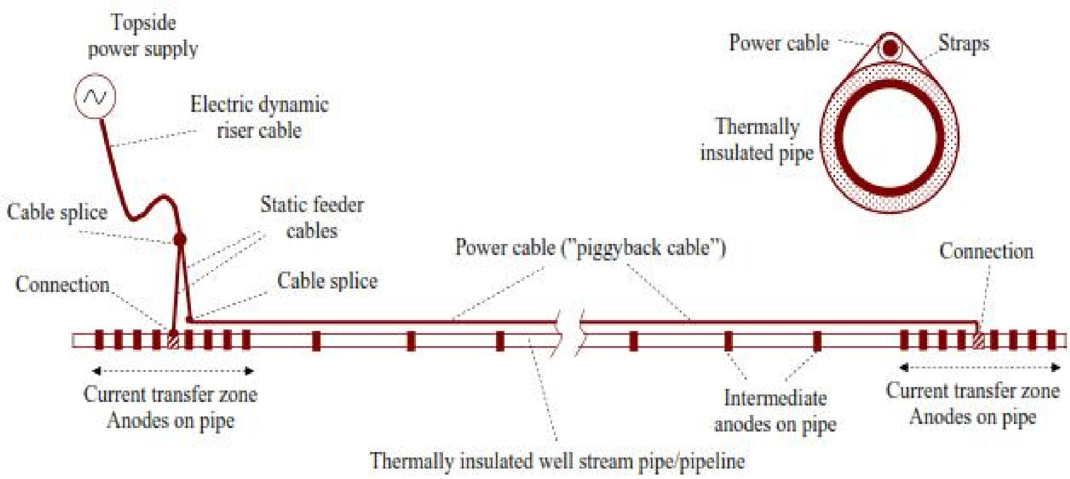


Figure 27: Working principle schematic of the DEHS (Kulbotten and Lervik 2007).

Through several sacrificial anodes, the heating system is electrically connected (that is, earthed) to the surrounding sea water (that is, an open system) for safety and reliability purposes. The pipelines are thermally insulated. The sea water acts as an electric conductor in parallel to the pipe by direct contact between pipe and sea water at both ends of the heated pipeline. Thus, this implies that the current will be transferred by either the pipeline or through the water and through the anodes in the transfer zones. The transfer zone length is measured on full scale test directly on the pipeline and is typically 50 m at 50 Hz. The currents that leaves the individual anodes initially has a radial direction as shown in Figure 28. DEHS also has a potential of protecting the pipeline against corrosion through the anodes as long as the insulation remains undamaged (Kulbotten and Lervik 2007; Nysveen et al. 2007).

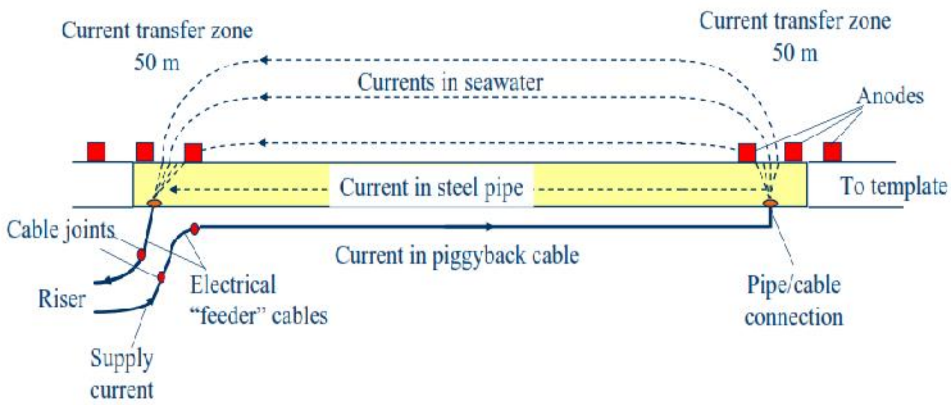


Figure 28: Electric current distribution in DEHS (Kulbotten 2008)

The DEHS are generally designed such that the temperature of the produced fluid is maintained above hydrate formation temperature (25 ^{o}C) during shutdowns, as well as increasing its temperature from ambient temperature (6 ^{o}C) within a specified period of time. Thus during steady state flow, continuous heating may not be required. However, for longer step out pipeline distance like 500 km or during tail production, continuous heating of the pipeline will be necessary (Kulbotten 2008; Tvedt 2005). The estimated power required to maintain a steady state pipe temperature above hydrate formation temperature (25 ^{o}C) is 100 – 150 W/m on a single 8 to 12 inches pipe (Kulbotten and Lervik 2007).

DEHS is also proposed for application on long pipeline distance like 100 to 200 km and at water depths greater than 1500 m. There is no conceptual showstopper for longer distances when the system is divided into sections. For a longer distance pipeline, this means that an increase in number of sections will also raise the cost for the system.

The concept has many engineering challenges like electromagnetic, mechanical and cable issues. Cable issues include: intermittent operation, elongation in the cable and impact loads. It is good to note that, the highest system voltage in DEHS is 52 kV. However, there is an improvement in the design of DEHS from the traditional DEHS method as proposed in Lervik and Nysveen, 2011. These improvements include: reduced power cable dimensions, simplified electrical connections to the pipelines, reduced number of anodes, reduced interactions with neighbouring pipelines and infrastructure (Kulbotten and Lervik 2007; Lervik and Nysveen 2011 & Delebecque et al. 2008). Though subsea transportation over long distance is expensive, but with today's technology, 200 km might be the limit (Tvedt 2005). DEHS installed has proven easy operation with high reliability for flow assurance. This makes DEHS a simple concept (Lenes et al. 2005). DEHS are designed based on factors like pipeline materials, operational parameters, and design criteria.

Direct electrical heating (DEH) concept is not dependent on field conditions. This implies that, the oil, gas, and water rates do not make any difference to the system. They are not needed in the area of the pipeline where temperature is high because, high temperature will affect the cables (Tvedt 2005). Most flow assurance problems like hydrate, wax, scales, and others are handled proficiently by DEHS. It is also good to note that, for longer shutdown period, the produced stream may cool down to the extent of hydrate forming conditions. Hydrates if formed, may plug the pipeline and by heating through DEHS, they will melt and unplug the pipeline (Kulbotten 2008).

For over 10 years of application of DEHS for flow assurance, several projects have confirmed its reliability, flexibility, and cost effectiveness. It has been deployed on several pipelines in the North Sea and has been proved on sixteen (16) pipelines in the North Sea. New fields are now developed with several pipelines and of deepwater fields as DEHS is becoming more attractive. The world's first installation of a DEHS took place in year 2000 for Åsgard on the Norwegian continental shelf, where it is designed to heat the flowlines from 42.8 ^{o}F (6 ^{o}C) up 56 to 80 ^{o}F (27 ^{o}C) to prevent hydrate formation (Bjørnstad 2004). The longest installation of DEHS is the 43 km long pipeline which connects the Tyrihans field and Kristin field (Kulbotten and Lervik 2007).

The experience with DEHS is generally good. Most of the encountered problems emanate from the installation and commissioning phase of the projects, but these have been fixed along with other minor operation problems (Nysveen et al. 2007). The installed DEHS equipment has been tested and verified of its rating and thermal performance. Thus, it has proved to be in good compliance with basic theory and system calculations (Nysveen et al. 2007). Therefore, this concept can be regarded as proven technology on shorter distances. The market penetration of DEHS is relatively small, being a new concept of which its value still needs to be proved before it becomes a globally accepted standard (Tvedt 2005). Nevertheless, this technology is becoming more interesting to most oil companies as they have investigated it and this seems to be most cost efficient in today’s market. Also, DEHS has a long track record, simple and it is reliable (Heggal 2012).

Cable failure in DEHS utilization is the greatest risk involved as this can cause damage to the pipeline (Nysveen et al. 2005). This implies a short circuit that might cause a hole in the pipeline. Also, a crack in the pipe's insulation can cause unwanted current going into the sea, and corrosion due to high temperatures are other risks involved. However, these risks are controlled using the sacrificial anodes (Kulbotten and Lervik 2007).

4.3.2 Environmental Evaluation of DEHS

DEHS eliminates the use of chemicals which is mostly used to control hydrate formation in subsea pipelines. This makes DEHS very attractive and environmentally friendlier than chemical usage. Environmental pollution is greatly reduced and production stream contamination is eliminated as opposed to the use of chemicals.

This system is user friendly. DEHS gives the operator adequate time for sorting out of failure situations before prevention of hydrate activities is started, and the field's production regularities will be increased. Heat is generated immediately after the system is activated (Dretvik and Børnes 2001).

4.3.3 Economic Evaluation of DEHS

Prevention of hydrate formation and wax deposition in subsea pipeline during oil production through DEHS has proved to be possible economically. Investigations have shown that the concept design, planning and implementation is very economical. The installation of DEHS in the North Sea was based on its technical and economical advantages (Børnes 2011).

Statoil has done a project with a 9 km pipeline and a pipe diameter of 13 inches (Tvedt 2005). He had it that, the project has the following cost: Cable and related equipment is about $7.7 million, extra installation cost due to DEHS is $1.5 million, DEHS riser installation is $0.8 million, and DEHS topside equipment is around $1.5 million. He also added that the cost of thermal insulated pipeline is around $1 million per kilometer and that a bundled pipeline starts at $1.5 million upwards.

Consequently, this means that cost of installing DEHS and operation is better and more efficient when compared to the chemical facilities for regeneration and costs in managing hydrates and wax problems. But, according to Tvedt (2005), the cost of laying the cables with extra protection on the cables against fishing nets and other dangers varies from project to project.

4.3.4 Advantages of DEHS

DEHS has no shutdown limitation period as opposed to a passive heating and chemical system. It is more environmentally friendlier solution to the expensive chemical injection prevention method of hydrates and wax problems in subsea pipelines.

The risk of depressurization is greatly reduced, restart operations are simplified and it enhances immediate remediation of hydrate and wax precipitation and blockages. Also, there is optimization of the riser thermal insulation system, as opposed to an extensive insulation coating system, such as pipe-in-pipe or bundles (Halvorsen et al. 2000 and Chandragupthan et al. 2011).

4.3.5 Disadvantages of DEHS

Cable failure may cause damage to the pipeline as it creates a short circuit for current flow. This, depending on the intensity can harm the aquatic lives. Also, insulation's crack exposes the pipeline to corrosion especially when the anodes and power supply system fault protection fails.

For long pipeline, high power consumption is required. This would add cost to system as it will be applied to the pipeline in section of 50 km and this may not be economically feasible (Nysveen et al. 2007; Kulbotten and Lervik 2007). However, the CAPEX for long subsea pipeline DEHS installation can be very enormous.

4.4 Prevention by Cold Flow

In the early 1990's, NTNU (Norwegian University of Science and Technology) carried out a work which showed that natural gas hydrate slurry (the liquid phase was water or diesel fuel) in a circulation loop did not deposit on pipe walls in a constant temperature laboratory. The gas hydrate particles produced in a CSTR (continuous stirred tank reactor) were small (1-10 [µm]) and stayed suspended in the liquid phase, even allowing shut-in for a day. The idea of cold flow emerged (evidence that others worked so early on similar ideas have not be found).

In cold flow, hydrate particles suspended in the liquid phase at constant temperature subsea pipelines, will not deposit on the pipe wall (the precipitated particles will not deposit). Before entering the pipeline the natural gas hydrate particles must be produced and cooled down to the surrounding (seawater) temperature (Gudmundsson 2012).

However, for a more detailed study on cold flow, the different concepts proposed and evaluations, the reader is referred to chapter 5 of this work.

4.5 Other Hydrates and Wax Control Methods

In this section, I will highlight and review some other method used in tackling hydrate and wax problems. These will not be considered in comparison and evaluation with the new technology (cold flow technology) proposed for tackling hydrates and wax problems in subsea long distance pipeline.

There are other techniques used in the industry to prevent and manage the formation of gas hydrates and wax deposition. It is good to note that once hydrates are detected in the system, it can be controlled and managed by thermal, chemical, compositional management. The following are the other ways used to prevent and control hydrate and wax formation:

- Removal of the water phase from the system.
- Depressurization.
- Mechanical pigging.
- Other Chemical Treatment of Wax.

4.5.1 Water Removal

Removal of water which is the host molecule will cause hydrate instability. This is because the dew point of the system is lowered. Water can be removed either by mechanical methods or through the reaction of water with added chemicals. Dehydration of gas entering the transmission line to a dew point low enough to prevent hydrate formation in the system would have been a satisfactory method, but this is impossible in subsea environment (Chandragupthan et al. 2011). Therefore, Molecular sieves (solid adsorbent), -glycol dehydration (liquid desiccant) are often used.

Molecular sieves are solid crystalline materials containing tiny pores of a precise and uniform size. They are capable of providing the lowest dew point, high adsorption of water without being damaged by water unlike silica gel. They are typically used in low temperature process plant like subsea systems (Ilahi 2006).

4.5.2 Depressurization of Pipeline

Hydrate blockage of subsea pipeline can also be managed through pressure reduction of the pipeline system. There are three methods of pressure reduction to manage hydrate problems. These include:

- Isothermally, as with infinitely slow pressure reduction.
- Isenthalpically, as with rapid pressure reduction (Joule-Thomson expansion) without heat transfer.
- Isentropically, as with pressure reduction through an ideal turbo expander without heat transfer (Chandragupthan et al. 2011).

4.5.3 Mechanical Pigging

This involves running in of pigs into a pipeline to scrap off wax buildup on the internal wall of pipeline that can plug flow at some interval frequency. Subsea pigging systems are difficult to access due to its complex and costly operations, which requires high-reliability equipment, facilities and procedures. Dual-size scraper pigs and optimized pipeline layouts help sustain production in cold subsea conditions (Mokhatab and Towler 2009).

Modern pigs have many functions, but the main one remains pipeline cleaning. They are also used to remove liquid accumulations in the flowlines, removal of salts, scale, et cetera, which are important for the proper operation of a pipeline. Pig is not usually used to clean hydrates from a line, but with pigs the potential nucleation site for hydrate formation is removed. Pig is transported along with the fluid and its launching is always scheduled to prevent solids formation from becoming problematic (Carroll 2009). Figure 29 is a picture of a pig used for cleaning oil pipeline.

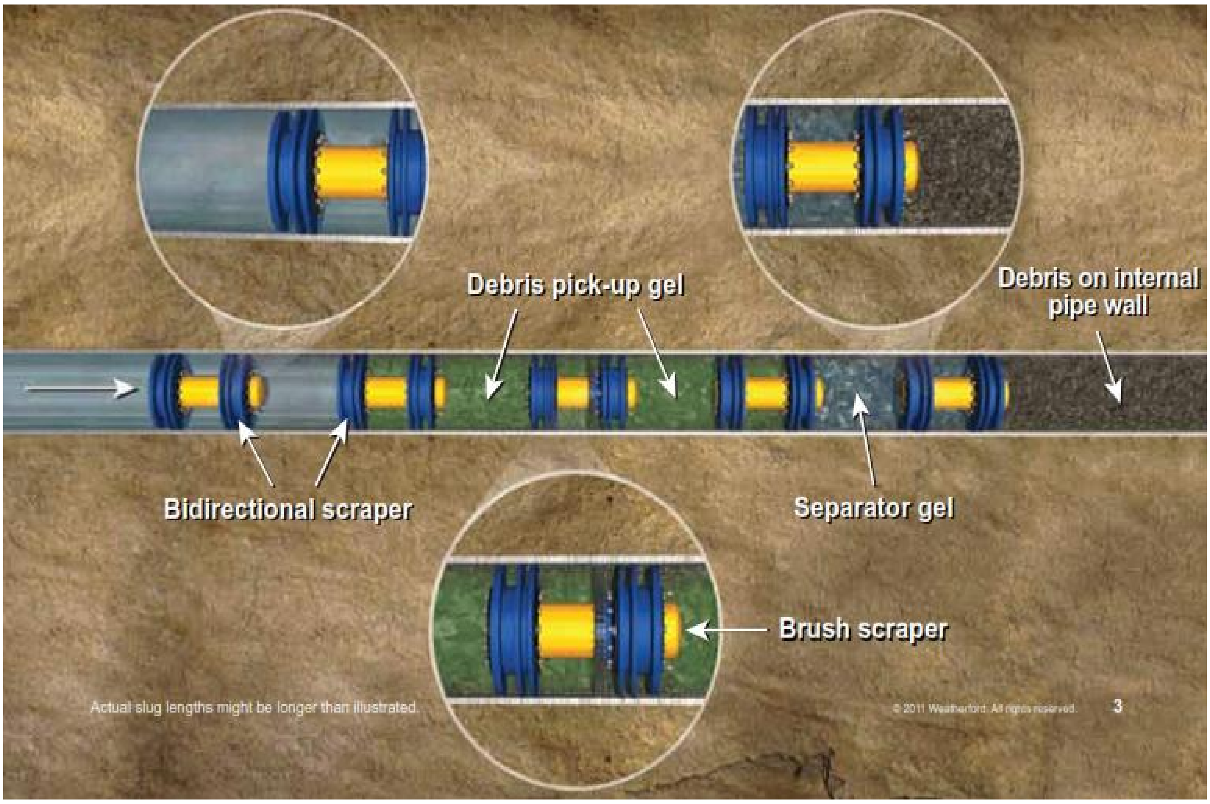


Figure 29: Picture of a Pipeline Pig (Weatherford 2011)

4.5.4 Other Chemical Treatment of Wax

There are other chemicals used in treatment of wax problems. These are divided into four (4) groups which include: solvents, emulsion breakers, special chemicals and pour point dispersants (PPDs) (Fan and Liave 1996, and Nikhar 2006). Solvents are usually used to dissolve existing deposits, example diesel and xylene mixtures. They have been found to be very effective in dissolving of paraffin and some solvents can cause problems to crude oil refining. The most important factor is that, solvent that will penetrate and dissolve wax deposition is of high specific gravity. Chlorinated hydrocarbon causes poisoning of downstream process. Aromatic solvents have low specific gravities and it is difficult to use them on the well bottoms, they also have low flash points and handling becomes difficult (Fan and Liave 1996).

Pour point dispersants are polymeric materials which prevent paraffin deposition by disrupting nucleation, co-crystallizing. PPDs have been used with great success for several decades. They can also be plagued by crude oil specificity, large package treating rates, and waxy components that can be hard to apply. Wax-control additives, which include crude oil

PPDs, are polymers with pendant hydrocarbon chains that interact with paraffin in the crude and, thus, inhibit the formation of large wax crystal matrices. The interaction retards crystal formation and growth, alters the paraffin's heat of crystallization and, subsequently, depresses the crude's pour point while affecting crystal size and shape (Fan and Liave 1996, Nikhar 2006).

5. Cold Flow Technology

Cold flow technology is a new developing technology that can serve as an alternative technology for hydrate and wax blockage control on subsea pipeline in steady conditions. It is based on hydrate and wax particles slurry transport in thermodynamic equilibrium with the surroundings over long distances. Cold flow technology (CFT) is different from the chemical-based, insulation and heating technology for hydrate prevention in that, a non-heated, uninsulated pipeline is intended to be used to transport oil-water mixture in cold, subsea environment. It concerns cost effective flow of produced fluid (oil, gas and water) mixtures from the wellhead to the processing facility through subsea production pipelines, without the constant use of chemicals to prevent hydrate formation as well as wax deposition (Gudmundsson 2002; Bai and Bai 2005).

The Cold Flow technology (CFT) promises low costs in terms of maintenance, and low system complexity in long transport distances to the existing facilities onshore (Gudmundsson 2002; Turner and Talley 2008). The basic principle in this technology is that, hydrate formation is permitted through cooling down of the produced fluid, yet hydrate is carried by the fluid stream in the slurry form, thus avoiding further agglomeration of hydrate particles that can plug the pipeline.

Essentially, the CFT is described as a system in which the hydrocarbon fluid produced are flowing in bare steel pipelines at thermodynamic equilibrium with the surrounding seawater without chemical modifiers and heat (passive or active heating or heat retention schemes) (Larsen et al. 2007). Cold flow is based on the fact that while solids formation may be present in the liquid that is transported, their depositions' driving forces are eliminated or well minimized through the cooling process. The slurry created is easily transported, and has the potentials of going through long-lasting shut-ins, and re-dispersing at restart without plugging the pipeline (Wolden 2008).

CFT also has potentials for longer distance transfer (greater than 200 km) from the wellhead to the processing facilities on seabed, topside, or to beach (onshore) as earlier said. An example of long distance to an existing infrastructure in Arctic and cold harsh environment include Skrugard which is 200 km offshore of Northern Norway in Barents Sea and Mizzen, 500 km offshore of Newfoundland, Canada. The development of fields with small reservoirs, subsea tie-back to hubs where platforms are not economically feasible will also be possible with cold flow technology (Hoffman 2012).

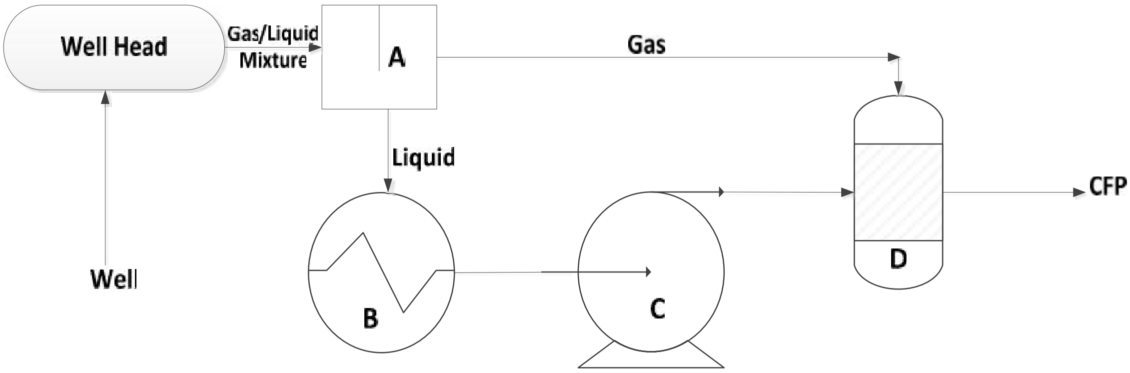
CFT was initially developed for hydrate plugging control, but wax deposition during slurry creation, recirculation and production of waxy crude oil, has deemed it necessary for wax control in the loop. However, Regular pigging and heating have been suggested to be the possible solution for wax control in the loop though this may be risky and costly (Hoffman 2012).

5.1 Principle of Cold Flow Technology

As earlier described, cold flow technology is based on allowing hydrate particles to form in the produced stream, but preventing their agglomeration and pipeline blockage. This is done by cooling down the bulk flow to be in equilibrium with the seawater temperature. However, the brief principle of cold flow technology (how it intends to work) presented here is based on Gudmundsson's cold flow concept, illustrated in Figure 30.

The hot production stream (gas-liquid mixture) with temperature ranging from 40 to 80 ^{o}C, leaves the wellhead and enters a mechanical device (separator) that separates the liquid phase from the gas phase. The liquid phase is then transported to the heat exchanger system and the gas phase is passed directly to the reactor system. A bare steel pipeline is utilized in this technology and a multi-phase pump may be necessary in this system to pump the cooled fluid.

In the heat exchanger system, the hot liquid phase of the production stream is cooled down to the surrounding seawater temperature (4 ^{o}C). The cold liquid phase are then moved to the reactor system, where they are mixed up with gas at conditions that favour solids (slurries) formation. The slurries formed and the remaining reservoir fluid (liquid or gas) would be sent into the cold flow pipeline (CFP) for transportation. Once the ambient temperature is reached, the precipitated solids flow in thermodynamic equilibrium without being deposited on the pipeline and the dangers of plugging eliminated. (Gudmundsson 2002). This can be attributed to the fact that the thermal flux, which is believed to be the main driving force for deposition has been eliminated or minimized.



Nomenclature: A= Separator, B= Heat Exchanger, C= Pump, D= Reactor, CFP= Cold Flow Pipeline

Figure 30: Principe of Cold flow Technology (re-drawn after Gudmundsson's Concept 2002)

5.2 Main Components of Cold Flow System

The following are the main components of cold flow system for hydrates and wax control:

- A reactor,
- A separator,
- An heat exchanger system,
- A bare steel pipeline,
- And, a centrifugal pump among other components (Gudmundsson 2002).

It also may be comprised of wax monitoring system as well as controlled heating system for removal of wax deposit into the cooled stream in the cooling down section of the system and long distance power transmission (Hoffman 2012). Some of these components are as shown in Figure 31.

At the subsea separator as said earlier, the production stream would be separated into the liquid-phase and the gas-phase. The established design of subsea separator methods can be used to design the separator unit for cold flow technology (Gudmundsson 2002). However, subsea separator has been successfully designed and implemented. For example, Statoil Tordis Subsea Separation, Boosting and Injection (SSBI) project on the Norwegian continental field at 650 feet water depth (Kliewer 2008). Separation equipment is very important in the oil and gas production process for splitting of the well streams into oil, gas, and water.

In the cool down section (heat exchanger unit), the liquid phase is cooled down close to seabed temperature. Wax deposition may occur in this section (Hoffman 2012).

At the reactor, the liquid-phase and the gas-phase are mixed up again. The prevailing conditions in the reactor are suitable for hydrate particles formation in cold flow process. The created slurries are then transported in cold flow pipeline to the receiving terminal or processing platform.

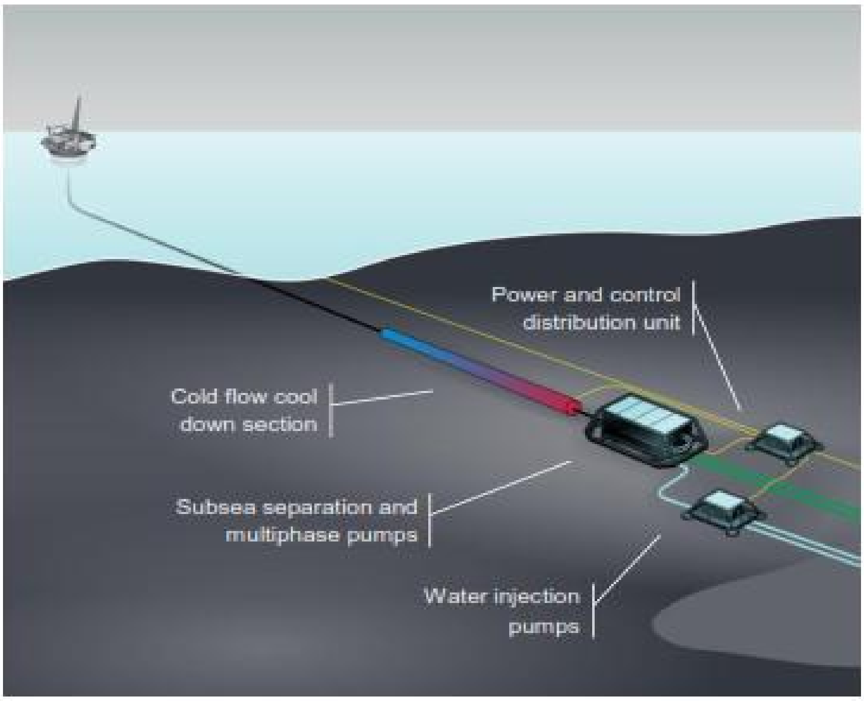


Figure 31: Some Cold Flow Components (Hoffman 2012)

5.3 Benefits of Cold Flow Technology

It is worthy to note and outline the main benefits of cold flow technology. These benefits cut across the capital and operational costs, value and health, safety and environmental issues according to SINTEF (2010). These include:

- No high cost of pipeline insulation or heating (passive and active) solutions.
- Direct production from subsea to shore.
- Cost of long tie-backs are greatly reduced.
- Eliminates deepwater surface piercing structures (Example: TLP, fixed bottom platform and production risers).
- No Chemical injection and harmful discharge (methanol, glycols, and LDHIs) to the sea.
- Carbon dioxide (CO_2) emission reduced.
- Reduction of required energy for heating of pipelines
- Tail-end production and recovery rates extension.
- Reduced number of offshore personnel
- No need for MEG usage, injection line, and regeneration plants

- No hydrate or wax blockage and potential personnel risks.
- Improved production
- Increased asset value as well as number of viable projects.
- Simple system operation, steady and lower maintenance cost.

5.4 Cold Flow Technology Concepts

Hydrates risk management in subsea transportation pipeline is the main idea of developing cold flow concept. Cold flow technology (CFT) has received several attention from various research organizations and companies.

In the succeeding sections, I will present the concepts developed by different organizations. This will include SINTEF-BP concept (initially developed internally at SINTEF Petroleum Research, Tvedt 2005), NTNU concept (Norwegian University of Science and Technology, developed by Gudmundson) and HYDRAFLOW concepts (developed at the Centre for Gas Hydrate Research, Heriot Watt University). The technical description of the different concepts, environmental, and economical evaluation of each of these concepts will also be presented.

5.5 SINTEF-BP Cold Flow Concept – Technical Description

The initial development of this concept was done internally by SINTEF Petroleum Research and BP later become a partner after a couple of years. This concept is patented to SINTEF (Tvedt 2005). Currently, StatoilHydro is also partner in this project (Larsen 2011).

SINTEF-BP cold flow concept allows hydrates to form in a fast but controlled condition with the water content from the production stream close to the well. The hot production stream from the wellhead are rapidly mixed with the cooled well stream of dry hydrate particles to form a wet hydrate slurry that would be transported through long subsea cold flow pipeline (CFP). The dry hydrate particles act as seed crystals that eat up the free water droplets in the production stream coming from the wellhead. Therefore, as free water is eaten up and hydrate slurries are formed, further reaction is hindered as the flowing fluid temperature in the pipeline and the surrounding temperature are in equilibrium. The hydrates formed would continue to grow and consume all the free water in the stream. This causes the fluid to flow down the pipeline without further formation of hydrates that can plug off the pipeline (Larsen et al. 2003; Knott 2004) as shown in Figure 32.

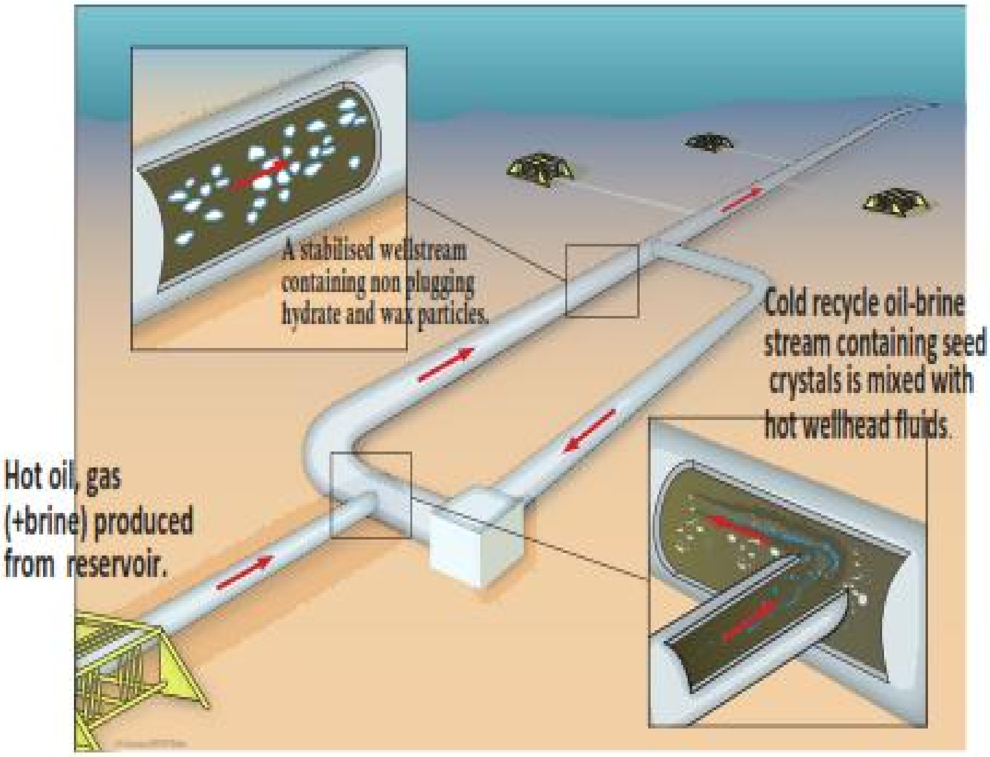


Figure 32: SINTEF-BP Cold Flow Concept Solution (SINTEF 2010)

SINTEF-BP cold flow concept has the following basic component units: a reactor, an extra pipeline for the pipe loop, a splitter, and a pump. Additionally, a potentially free water knock out unit could be used (Larsen et al. 2003).

The production stream from the subsea well is first passed through a separator (a free water knockout), where the unwanted water content of the production stream is separated. The water content is reduced to not more than 20 percent. This will help to avoid further formation of hydrates later down the flow. After this, the production stream containing free water droplets are pumped down and mixed with the cooled well stream. With the right temperature conditions, the water will quickly coat the dry hydrate particles (seeds) with a thin water film and converts to hydrates by growing from the existing hydrate surface outwards as illustrated in Figure 32. The cooling process is done in a bare steel pipeline loop which provides quick cooling of the stream and bring the system to the surrounding temperature. Therefore, as the system is in thermodynamic equilibrium with the surrounding, further condensation in the pipeline is eliminated (Larsen et al. 2003).

The mixtures of the hydrate particles formed and the hydrocarbon fluids reach the splitter where they are split off and re-circulated, with the recycled cold well stream being within the range of 50 – 90 percent of the main well stream. The water in the stream is converted to hydrates particles before they get to the splitter. The essence of the splitter is to ensure that, most of the production stream proceeding downstream is converted to a stable (inert) hydrate slurry before sending it into pipeline for final transportation. The hydrate formed would be seen as a powder flowing along with the production stream (Larsen et al. 2003).

When the transported stream gets to the end of the system where the temperature rises again and pressure drops, the hydrate particles will not melt back to free water and natural gas. These particles can be separated mechanically with a sieve or by gravity in a separator. The gravity method would depend on the density of the particles (Larsen et al. 2003).

SINTEF-BP's cold flow concept can be used to produce cold hydrate slurry from a well, or a chain of wells, or from an entire field. If more than one well is involved, then the loop may be enlarged so that only one splitter or recirculation loop is needed (Larsen et al. 2003) as shown in Figure 33. The percentage of the recycled fluid would depend on the number of wells that are producing. The more wells are included the less the cold hydrocarbon fluid that is needed in recycling the flow.

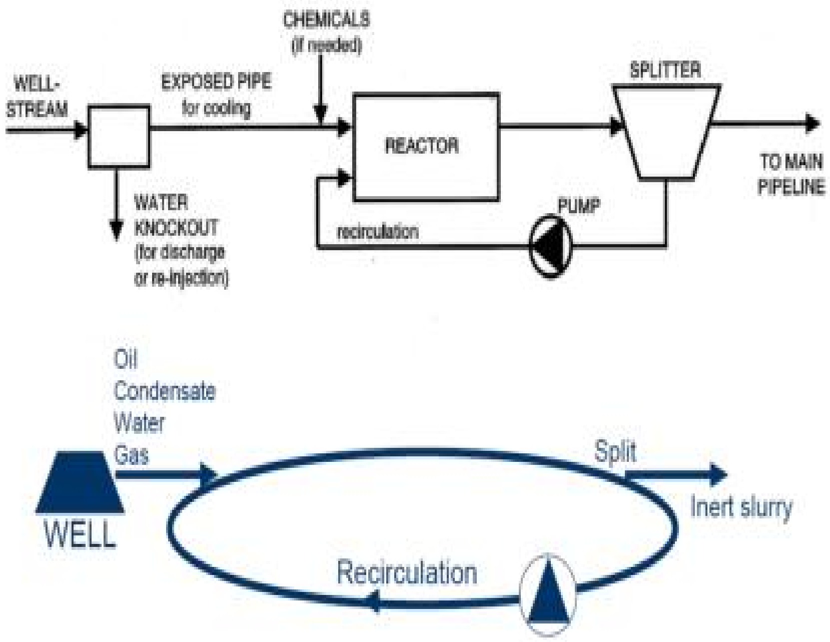


Figure 33: SINTEF-BP cold flow reactor (Larsen et al. 2003)

This concept will be faced with a challenge of flexibility regarding dealing with different petroleum at different conditions (Tvedt 2005). Tvedt (2005) in his Personal communication with Senior Research Scientist Roar Larsen, SINTEF Petroleum Research, puts that the variation in viscosity will be a limitation on transport over long distances in that, high viscosity will lead to large pressure drop. However, Gudmundsson and Andersson (1999) showed that the amount of hydrates up to 30 percent does not really give a measurable change in the viscosity of the fluid, though different types of oil would demand flexibility in the operational conditions, from their experiment.

The concept was developed with oil fields as initial target with some amount of gas, but gas and condensate fields would be incorporated in the future (Tvedt 2005). The concept has flexibility regarding transport of the slurry provided either all the water or gas is completely used up to avoid further formation and problem during flow over long distances. That is, if there be a high GOR, hydrate formation will be high as well, but provided either all the gas or water is completely gone, there would not be any problem. This concept has been experimented with a range of GORs of oil field. SINTEF-BP concept is designed to prevent both wax and hydrates. But there is not enough evidence to prove that wax will not be problematic (Tvedt 2005).

The concept has other engineering challenges like cooling process which is based on heat transfer from the pipeline to the surrounding seawater. The heat transfer is dependent on the overall heat transfer coefficient, and this is lower for concrete coated and buried pipeline. Practically, this is uncertain regarding the application of this concept (Tvedt 2005). Ilahi (2005), has it that SINTEF-BP uses 100 W/m^2K in their calculations of the overall heat transfer coefficient, while the industry value on the other hand, ranges from 15-20 W/m^2K. Thus, this uncertainty is an important issue that has to be resolved (Tvedt 2005).

Other challenges that need attention include:

- Subsea Pump – This has to be redesigned to meet subsea usage as most pumps are used onshore.
- Sand production – This is not really considered as a high risk because of its attribute to nucleate during hydrate formation.

- Other solids formation – The formation of solids like asphaltenes or scales should be taken into consideration. However, SINTEF-BP considered this not really a challenge as they have run a test in the laboratory which demonstrate that wax formation was six times lower than without cold flow system (Tvedt 2005).

SINTEF-BP has carried out test on this concept on a test loop using different oil from oil fields operated by BP in Norway. They have proved this concept experimentally, see Figure 34. They have planned to build up a 75 mm diameter pipe pilot at SINTEF to conduct a scale up test, in view of getting this technology ready for implementation and commercialization as soon as possible (Tvedt 2005). The concept is flexible since it can be deployed on an existing infrastructure by adding an extra pipeline, but it is primarily developed for an operation in a new field (Larsen et al. 2003). Figure 35 illustrates field implementation of SINTEF-BP cold flow concept.

Figure 34: SINTEF Cold Flow test loop (Trondheim, Norway) (Wolden 2008)

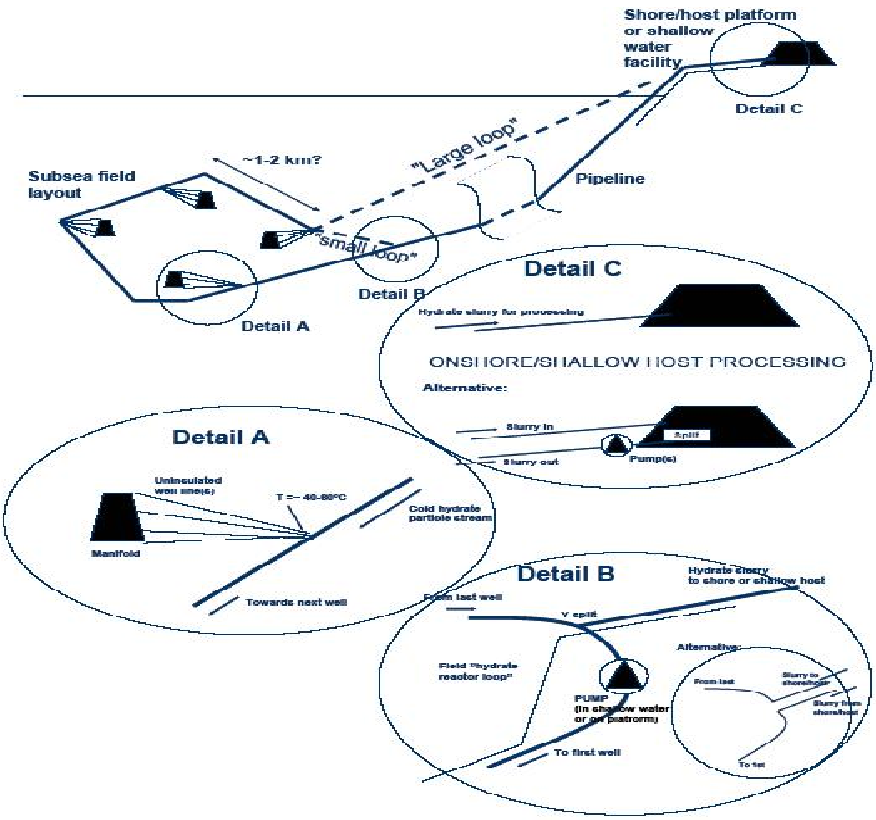


Figure 35: Implementation schematic of SINTEF-BP cold flow concept (Larsen et al. 2003).

5.5.1 Environmental Evaluation of SINTEF-BP Concept

Cold flow concept generally promises positive effect on the environment and humans as it reduces the need for usage of chemicals (Larsen et al. 2003). With cold flow technology, it is also possible to transport the subsea production stream directly to shore, thus elimination of surface piercing structures (for example; production risers, production platforms like tension leg platform (TLP), fixed bottom platform, and Spars) that may influence the environment is possible as well. Environment can be affected if hurricanes occurs and destroy the production risers which can result in pollution. Furthermore, this can result in the reduction in the number of people needed for deepwater offshore operations and less disruption of wildlife (Larsen et al. 2003).

However, at the end of the subsea transportation to shore, the hydrate slurry needs to be melted back to free water and hydrocarbons. This requires a large usage of energy and CO_2 will be evolved in the process and this must be dealt with onshore (Tvedt 2005).

5.5.2 Economical Evaluation of SINTEF-BP Concept

Cold flow technology (CFT) offers high cost savings when compared to other conventional or traditional solutions like chemical injection and insulations to flow assurance challenges. Tvedt (2005) from his personal communication with the Senior Research Scientist Roar Larsen, of SINTEF Petroleum Research, puts that BP's calculations shows a reduction in CAPEX up to 30 percent and OPEX savings, around 10 percent. Knott (2004) also holds that all the savings could cut off to the order of $100 million off the cost of subsea development. CFT work has been done so far on small scale, but up to about NOK 20 million have been spent on the development of this concept (Tvedt 2005).

CFT is also beneficial because of its ability in regards to pipeline diameter reduction, since large volumes of chemical usage have been eliminated. Also, the possibility of using a bare steel pipeline. However, the deployment of the bare steel pipeline in subsea environment would cost between $0.5 million per kilometer and $0.8 million per kilometer instead of around $1 million per kilometer for insulated pipelines. This cost is proportional with the length and the diameter of the pipe (Tvedt 2005).

5.5.3 Advantages of SINTEF-BP Concept

CFT offers both environmental and economical benefits as the use of chemicals as well as pipeline insulation and heating are eliminated. There is also an elimination or reduction of deepwater surface structures that influences the environment as well as less disruption of wildlife. The need for regeneration unit for chemicals like MEG is eliminated, and less number of platform personnel would be required.

Also, SINTEF cold flow concept promises to handle both hydrate and wax problem in that, paraffin wax will precipitate out in the bulk (not on wall) of the flow along with the natural gas hydrate. However, extensive laboratory testing indicates that the SINTEF cold flow concept tackles both natural gas hydrate and paraffin wax simultaneously (Gudmundsson 2012).

A bare steel pipeline will be used. The cold flow loop is flexible, thus it can be enlarged to incorporate (tie backs) small reservoirs and wells, thus allowing for development of more deepwater field. Its operation will be simple, with lower maintenance as well as ensuring steady state operations. Moreover, CFT can be mounted on an existing infrastructure. Production can also be made directly from subsea to onshore. These among other things would result in reduced CAPEX and OPEX for the installation and operation of CF system if successfully implemented (SINTEF 2010).

5.5.4 Disadvantages of SINTEF-BP Cold Flow Concept

SINTEF cold flow concept would have a challenge of heat balance. The recycled liquid provides direct cooling by mixing but the pipeline cooling will be a slow process, and this will require long pipelines. The temperature driving force in subsea pipeline is limited and this implies that the cooling pipelines need perhaps, to be mounted above the sea bottom and fitted with enhanced heat transfer fins. Moreover, it should be noted that subsea pipelines have a steel-reinforced concrete layer to make them heavy for not to float during laying and to stay fixed at the bottom, and this can result in a low overall heat transfer coefficient (Gudmundsson 2012).

At the end of the transportation, melting of the slurry may require a substantial amount of energy (Tvedt 2005). However, the concept has no field experience and it has not proven field wise.

5.6 Gudmundsson Cold Flow Concept – Technical Evaluation

Gudmundsson cold flow concept has been exclusively developed at the Department of Petroleum Engineering and Applied Geophysics at NTNU. It has some similarities with the SINTEF concept. This concept's solution is based on forming small hydrate particles from an associated gas and water before they enter the pipeline. The hydrate will then flow with oil in a three-phase flow from there to shore (production site) together with surplus gas (Gudmundsson 2002). This will eliminate the problems of hydrate and wax deposit in the pipeline in a steady state. In this concept, the production stream has to be cooled at the heat exchanger unit, and hydrates created, before it reaches the pipeline.

As mentioned earlier in chapter 5.2, Gudmundsson cold flow concept has the following major component units: the wellhead unit (WHU), the separator unit (SU), the heat exchanger unit (HXU), and the reactor unit (RU). The set of these major components required are dependent on parameters like GOR, WC, and other fluid properties (Gudmundsson 2002) as illustrated in Figure 36.

Gudmundsson's concept utilizes natural cooling process such that the hot fluid mixture from the WHU of 40 to 80 ^{o}C can be cooled close to the ambient sea temperature of –2 to 4 ^{o}C. But this requires very large cooling areas. An alternative method would be an active cooling process in a smaller equipment to achieve cooling to the ambient surrounding temperature of the seabed outside the pipeline. However, more work is needed to determine what kind of active cooling would be suitable for deepwater production conditions (Gudmundsson 2002).

The hot production stream produced from the reservoir in subsea well flows into the wellhead unit (WHU). The gas and the liquid mixture will be separated as it reaches the separator unit (SU) into liquid and gas. The liquid phase goes into the HXU while the gas moves directly into the RU where it meets the cooled liquid phase. Both gas and the cooled liquid phases would be mixed up and hydrate slurry would occur, which would be sent to CFP (Gudmundsson 2002).

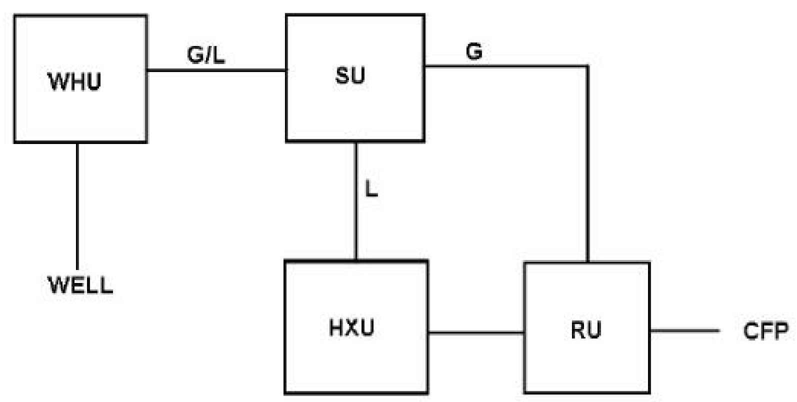


Figure 36: NTNU cold flow concept, illustrating various component units (Gudmundsson 2002).

The hot production stream from the WHU is lead into the subsea SU where the associated gas is split from the liquid phase at high temperature. The separator would be a two-phase separator which separates the liquid-phase, consisting of water and oil, from the associated gas. The water content required however, would not be more than 15 percent in the liquid phase after separation (Gudmundsson et al. 2002).

The liquid phase from the SU is cooled down in the HXU which utilizes two units for cooling. HXU consist of a normal tube heat exchanger unit and a refrigeration unit, see Figure 37 and Figure 38. The two cooling units are potentially necessary because there is a reasonable limit for how much heat one unit can transport away from another medium given the surrounding conditions without becoming too extensive. In the tube heat exchanger, the liquid will not be cooled down to the ambient seawater temperature, but it can be cooled to at least 10 ^oC. The remaining cooling to the ambient sea temperature will be done in refrigerator unit and should be done with the aid of a compressor. Gas cooling is not necessary since it requires less effort (Gudmundsson 2002; Gudmundsson et al. 2002).

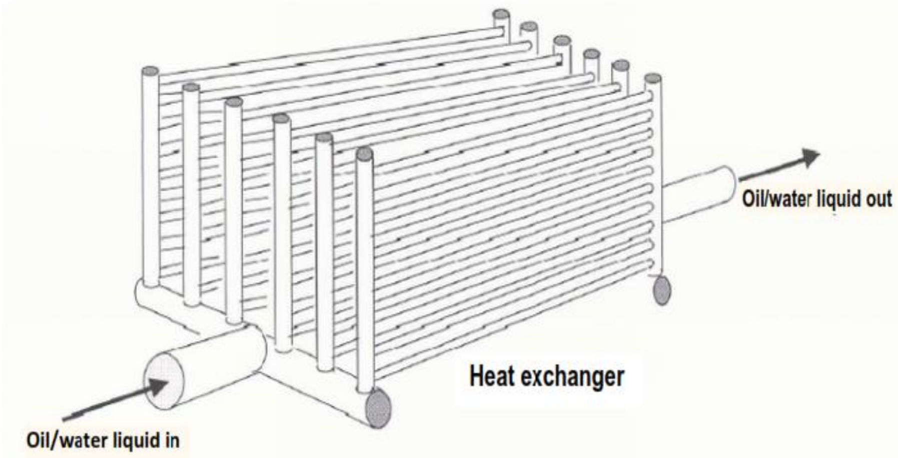


Figure 37: Tube heat exchanger unit of NTNU concept (Gudmundsson et al. 2002)

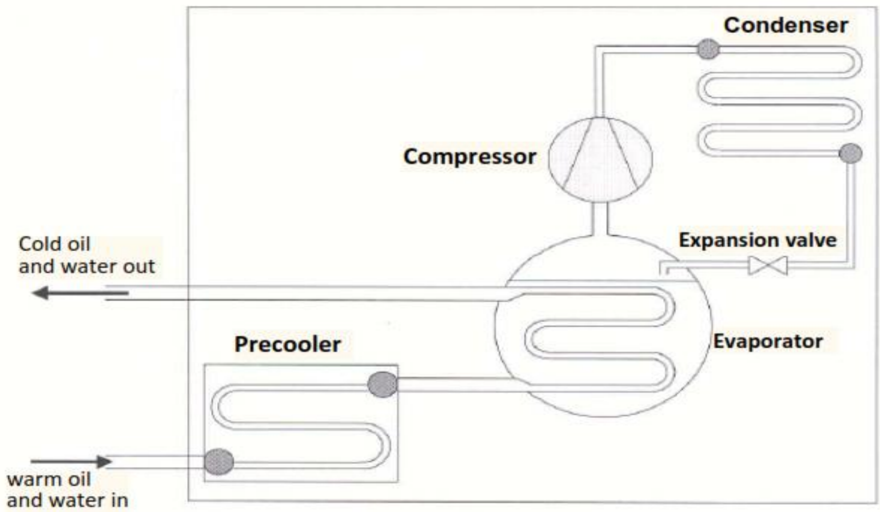


Figure 38: Refrigeration unit of NTNU concept (Gudmundsson et al. 2002)

Hydrate formation takes place in the reactor unit (RU). Here, the cooled liquid-phase are mixed with the gas-phase (free gas or associated gas), and hydrates slurries are formed as a result of high pressure with low temperature. Hydrate formation would occur between the cooled liquid and the associated gas in controlled conditions as a result of turbulent mixing. All the water will either eat up the gas or all the gas will eat all the water to form hydrates and, the surplus of either gas or water will flow along with oil phase in the pipeline to shore or production site without causing problems. This is so because, there is an elimination of one of the necessary hydrate former conditions, and the stable hydrates already formed will flow with the rest of the production stream without dangers of pipe plugging (Gudmundsson 2002; Gudmundsson et al. 2002).

At the receiving terminal onshore or production site, this concept proposes the use of conventional technology as an end solution for the slurry separation. The produced crude (oil, gas, and water) are separated as the slurry stream is continuously fed to the heating and melting units. The receiving terminal however, can also be integrated into an existing refinery complex or being incorporated from the beginning (Gudmundsson et al. 1999).

This concept still need an extensive engineering work to polish it to a finished unit, which can be put down on the seabed. For the subsea system operations, there would be a necessity for power supply. This would not really be a problem, because it can be provided through a cable from an onshore facility (Tvedt 2005).

Water cut is usually present in oil and gas production, and it always increases as the well matures. In this concept, according to Tvedt (2005), variable water cut would not be a problem. However, in a situation where most of the water is not required, a free water knockout unit could be used in the system between the wellhead and the SU. The free water knockout will reduce the water content to around 20 percent (Tvedt 2005).

Also, in this concept, different fractions of hydrate forming particles can be handled. This is because either all the gas or all the water will be consumed up in the process. However, different test shows that hydrate forming particles should be below 50 percent. The cooling medium provides a limit of subcooling effect, but this is not more than 5 – 10 ^{o}C above the cooling medium per cycle (Tvedt 2005). It can also manage or treat GOR at all oil field's condition, but would be a problem in gas and condensate fields. Also, a high GOR and WC would make transportation of fluid difficult, just as in SINTEF-BP concept (Tvedt 2005).

In Gudmundsson concept, an HXU that can perform the needed cooling process in subsea is a challenge. Though similar equipment has been used onshore, a marinised heat exchanger suitable for deepwater production must be developed (Tvedt 2005). Moreover, it has been concluded that the cooling process is feasible (Gudmundsson et al. 2002).

High viscosity in the pipeline is another risk and this could result in high pressure drop in the pipeline during transfer over long distances. To indemnify this, it will require a larger pipe diameter, and the increase in size could probably be around 5 – 10 percent. However, the risk involved in this case is not bigger than the risk of chemical usage in a bare steel pipe, which will also require a much larger pipeline diameter (Tvedt 2005).

Other risks include the protection of the wellhead and other equipment during planned shutdowns. This could be achieved through isolation of the fragile units or loading with chemicals. Nevertheless, if chemicals and additional water are needed for the process, it could be supplied or delivered from a buoy on the water surface or through a cable, during steady state to the system. The options for solving these problems are many, and relatively straightforward. There will also be a sufficient power supply option for controlling and running of the needed equipment. For instance, powering of the Ormen Lange subsea compressor of capacity 12.5 MW, demonstrates that power supply for the needed processes will not be an issue (Tvedt 2005).

An equipment like a reactor unit in subsea could also be at risk (Tvedt 2005). He had it that, the experience concerning new subsea equipment development and barriers before a unit is sent to subsea will marginalize this risk. Wax formation in pipeline is another risk factor in Gudmundsson's concept. Chemicals can be used to treat wax deposition in a situation where cold flow concept alone cannot handle it, but this is not preferable, as well as for scales and asphaltenes (Tvedt 2005).

Just like SINTEF-BP cold flow concept, Gudmundsson concept have also been tested and proved experimentally. Several tests done at the Natural Gas Hydrate Laboratory at NTNU on hydrates and their properties have been positive (Gudmundsson 2002).

5.6.1 Environmental Evaluation of Gudmundsson Concept

Gudmundsson's Cold Flow concept will have the same environmental consequences as the SINTEF-BP cold flow concept. The consequences will therefore not be discussed again. Refer to Chapter 4.4.1 for environmental evaluation of SINTEF-BP cold flow concept.

5.6.2 Economic Evaluation of Gudmundsson Concept

According to Tvedt (2005), the earlier work on Gudmundsson's cold flow technology also includes some calculation on costs. He had it that a real case with five fields at a water depth of 1500m and seawater temperature of about 4 °C, was used to establish rough cost estimates. The following costs were calculated for the needed equipment (Gudmundsson et al. 2002):

•	Refrigerator system:	$ 106 million
•	Liquid flow cooling system	$ 96 million
•	Separator units:	$ 96 million
•	Reactor units:	$ 96 million
	Total:	$ 394 million (€1.2 = $1)

Pipeline prices come additionally. A bare steel pipeline deployed subsea cost between $0.5 million per km and $0.8 million per km as earlier described in SINTEF concept. The length and the pipeline diameter cost is directly proportional and there will be an additional price with a free water knockout unit (Tvedt 2005).

To reduce the size of the total separation system and the use of centrifugal pump downstream, there is need for optimization in the use of cold flow concept. For example, the usage of hydro cyclones for pre-separation. However, this will offer a possibility for operation at a lower abandonment pressures. This implies improved performance and increased recovery with cold flow concept (Gudmundsson et al. 2002).

5.6.3 Advantages of Gudmundsson's Concept

This concept will have similar merits as SINTEF-BP cold flow technology concept. Therefore, the reader should refer to chapter 5.4.3 for the advantages of cold flow technology.

5.6.4 Disadvantages of Gudmundsson's Concept

Refer to chapter 5.4.4, since this concept is similar to SINTEF-BP concept. However, the issue of heat balance and need for long pipelines for cooling is not a case in Gudmundsson concept as it utilizes cooling through a heat exchanger.

5.7 HYDRAFLOW Cold Flow Concept

HYDRAFLOW is a new, patented cold-flow-assurance technology developed at the Centre for Gas Hydrate Research, Heriot-Watt University, Edinburgh. The project started in September 2005 with support from the Scottish Enterprise Proof of Concept Program. Recently, a high pressure flow loop was constructed and commissioned with partial support from the Scottish Funding Council. The plan is to test and prove the concept at simulated-pipeline conditions, initially with support from Scottish Enterprise and then through a joint-industry project (JIP), for which four companies have confirmed their support (Azarinezhad et al. 2010).

HYDRAFLOW concept is based on allowing most or all of the gas-phase into hydrates in the presence of excess water but preventing their agglomeration and pipeline blockage by use of low doses (few percent by mass) of chemical anti-agglomerants where necessary (Tohidi 2006). The hydrates formed are transferred in slurry form in the pipeline (Azarinezhad et al. 2008).

The name, HYDRAFLOW is used to distinguish it from the dry hydrate concepts. It is also referred as a WET cold flow concept, because of the presence of free aqueous phase desired to convert the gas phase into hydrate particles. In this concept, it is proposed that where produced water is insufficient for maximum hydrate formation, excess water such as seawater can be added. The use of anti-agglomerants (AAs) and other additives may be necessary to control the hydrate-crystal size as well as preventing solids blockage in these systems. Hydrate slurry viscosity can also be adjusted by adjusting the amount of water (Azarinezhad et al. 2008, 2010).

In this concept, it is also proposed that all or part of the liquid and the aqueous phase can be recycled where possible as part of a loop concept. This is because, the recycled fluid will play the role of carrier fluid, collecting produced fluids from various wells, reacting them with the gas phase to form hydrates, and transporting them as hydrate slurry in oil and or water to production facilities as shown in Figure 39. The hydrate slurry is then transported in the cold flow pipeline to shore or platform for processing.

The main components of HYDRAFLOW concept include: the separation unit and water recycling unit, pipeline loop system connecting the various wells, injection lines for the chemicals and the excess water and a single phase pump located at the receiving facilities. HYDRAFLOW concept utilizes subsea bare pipeline as the reactor where the produced stream (oil, gas and water) mixes together to formulate hydrate slurry. The presence of excess water and low dose chemical if necessary helps in controlling the slurry density and prevent its agglomeration as it will be transported. It can also eliminate the need for subsea and remote multiphase pumps for circulating hydrate seed nuclei (Azarinezhad et al. 2008 and 2010).

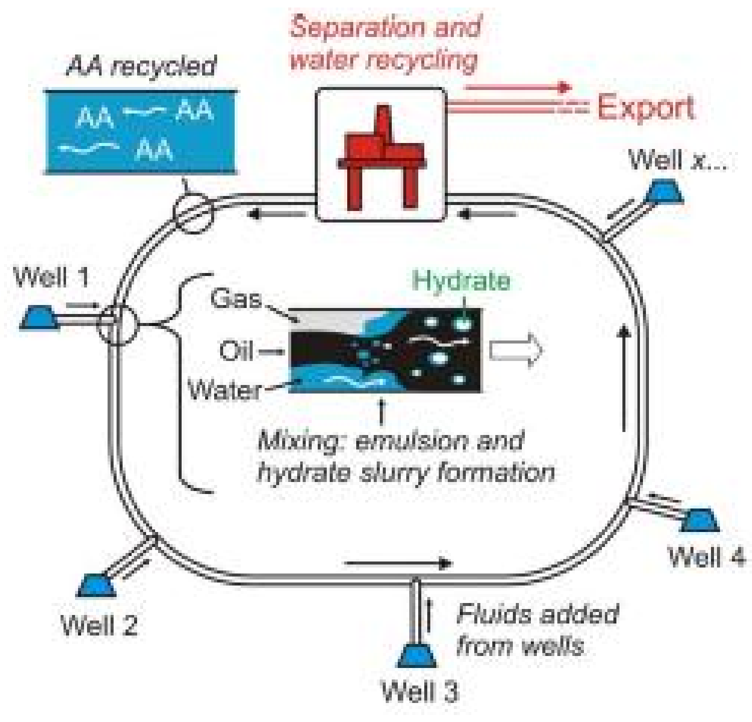


Figure 39: HYDRAFLOW pipeline concept (Azarinezhad et al. 2008)

The proposed HYDRAFLOW cold flow concept unlike other cold flow concepts, promises a reduction or elimination of risks of hydrate blockage. The density difference between the phases (water, oil, hydrates) will be greatly reduced by converting the gas phase into hydrates. This will help to minimize pipeline slugging problems, hence reduction in CAPEX and OPEX. HYDRAFLOW concept also has the potential of reducing pipeline costs by eliminating the need for heating and insulation, while reducing operating pressures (or increasing capacity). Furthermore, it could have the extra benefit of reducing chemicals and disposed water treatment costs through aqueous phase recycling as well as reducing environmental impact. These chemicals could include: corrosion, scale, wax, asphaltene inhibitors.

Moreover, the importance of the HYDRAFLOW concept is also that it has the potential of reducing wax deposition problems by maintaining the fluid temperature for a longer time through exothermic hydrate formation reaction, and by providing solid seeds for wax nucleation in the flowing liquid phase rather than on pipeline walls, and by abrasion of deposited wax through turbulent movement of hydrate particles (Azarinezhad et al. 2008).

HYDRAFLOW concept has been tested and proven through various laboratory experiments. The details of the experiment procedure on this concept can seen in the papers of Azarinezhad et al. (2008 and 2010). In their experiment, the effect of salts, effect of AAs (including the type, concentration, partitioning, and biodegradable AAs), have been tested at subzero conditions corresponding to the seabed temperature. They have also carried out a test to measure the viscosity and the transportability of water in-oil emulsions and hydrate in-water and oil slurries. Various systems of low to high GOR (350 to 4200 scf/b) of oil systems, gas systems, and high water cuts (WC) representing mature fields and production scenarios of shut-in and start-up conditions has also been well tested (Azarinezhad 2008 and 2010). In their experiments, various real crude oil, North Sea natural gas and commercial AAs were used. Figure 40 is a picture of the high pressure kinetic rig designed and constructed in-house and used in their experiments.

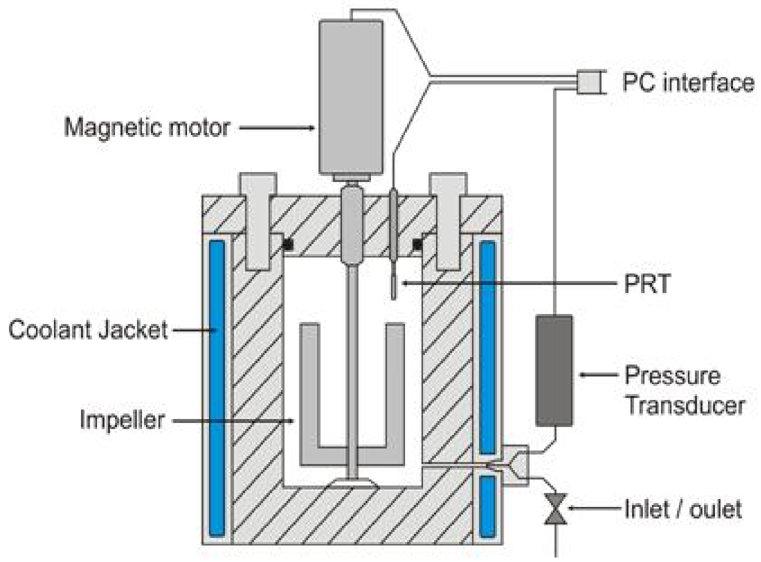


Figure 40: High pressure autoclave cell used for slurry-rheology studies (Azarinezhad et al. 2010)

However, from their various tests they concluded that, the presence of salt improves the performance of tested AAs in both low and high water-cuts (20 and 60 percent). The rate of hydrate formation is affected by all studied parameters including degree of subcooling, heat transfer and mixing rates. However, any increases in mixing rate above a certain value say 400 revolutions per minute did not change the hydrate formation rate in low GOR oil system. The degree of subcooling had more effect on hydrate formation rate than the mixing and heat transfer rate at the tested conditions. And, the high GOR oil system showed more sensitivity against any changes in mixing and heat transfer rates (Azarinezhad et al. 2008).

The fundamental requirement for developing this technology is the availability of reliable data to predict how hydrates form and how rapidly they will grow. The transportability of hydrate slurry needs thoroughly understanding of rheological behavior of hydrates and the effect of the various additives. Rheological properties for various oil and gas systems in the presence or absence of AAs have been investigated and results of previous studies have proved that this concept is viable, at least under laboratory conditions (Azarinezhad et al. 2008).

In this concept, when the hydrate slurry (that is, hydrates plus oil and, or free water) reaches the receiving facilities onshore or on a platform, the hydrates can be dissociated through depressurization and, or heating and introducing the fluid system to a separator to recover the oil and gas, depending on the specific conditions (after partial or total separation of free-water phase) (Azarinezhad et al. 2008).

HYDRAFLOW cold flow concept is under development process. There are plans to scale up the wet cold flow concept studies at the Centre for Gas Hydrate Research, Heriot-Watt University and modeling of the pipeline pressures, taking into account hydrate kinetics and rheological properties (Azarinezhad et al. 2008, 2010) as shown in Figure 41. The plan is to upscale the small (autoclave) equipment to a large scale (flow loop) study to test and prove the concept at different simulated pipeline conditions. The planned flow loop has the following characteristics:

- 2.5 cm / 1" diameter
- 40 m / 130 ft length
- 200 bar / 2900 psi pressure
- -15 to +20 ^{o}C temperature range
- Moineau pump system
- Interchangeable 'test section'.

Figure 41: HYDRAFLOW concept upscaling plan (Azarinezhad et al. 2009)

5.7.1 Environmental Evaluation of HYDRAFLOW Cold Flow Concept

HYDRAFLOW cold flow concept will have similar environmental impact as other cold flow concepts except for the fact that low doses of chemical AAs would be used which may add complexity to the system. However, this concept proposes the usage of chemical AAs in low doses of few percent by mass, in place of high doses of thermodynamic chemical inhibitors used in the traditional methods of preventing gas-hydrate problems (Azarinezhad et al. 2010). This perhaps, can pose some environmental hazards during associated water disposal and treatment if not properly handled as well as adding extra cost to the system.

Nevertheless, Azarinezhad et al. 2010 puts it that, the loop concept will reduce environmental impacts through reduction of chemical (AAs) usage and associated disposed-water treatment costs through partial recycling of the aqueous phase. This could also result in recycling other chemicals such as corrosion, scale, wax, and asphaltene inhibitors.

5.7.2 Economical Evaluation of HYDRAFLOW Cold Flow Concept

HYDRAFLOW cold flow concept will have similar economic value like other cold flow concepts because it proposed utilizing a bare pipeline and loop system among other things. It also proposes an elimination of a reactor system for creation of hydrate slurry and the use of subsea or remote multiphase pumps. These will result in reduced CAPEX and OPEX.

With the use of chemical (AAs), there is reduction in the size of storage and pumping facilities and the associated footprint. The availability of excess water (seawater), when the produced water is insufficient and its potentials in reducing pipeline slugging problems also makes it economically attractive (Azarinezhad et al. 2008, 2010).

5.7.3 Advantages of HYDRAFLOW Concept

This concept has potential benefits just like other cold flow concepts. It proposes utilizing non-heated and non-insulated pipeline, reduction in chemical costs as only little or no AAs and no reactor system would be required and recycling of all or part of AAs and other chemicals in a loop system.

Environmental impact will be reduced or eliminated through reduction in chemical use and its discharge. In addition, it also proposes the use of bio-degradable AAs where necessary. Hydrate plugging risk would be minimized as well as pipeline slugging problem (Azarinezhad et al. 2009).

5.7.4 Disadvantages of HYDRAFLOW Concept

In this concept, it can be envisaged that the chemicals, though it would be recycled can cause pollution if not properly handled. It is also known that these chemicals (AAs), though it would be used in small quantity are more costly than the thermodynamic inhibitors. Therefore, these may lead to an increase in OPEX of the system. However, the design of this concept to include the storage and pumping facilities can as well increase its CAPEX.

5.8 Comparison of the Cold Flow Concepts

The differences and similarities of SINTEF and Gudmundsson's cold flow concepts have already been analyzed in Tvedt (2005) and Ilahi (2006). I will in this section, repeat them so as to compare them with HYDRAFLOW concept also reviewed in this work. Therefore, the differences and similarities of these three concept include:

- All are based on the same principles of allowing an inert hydrate slurry to form to avoid hydrate blockage of pipeline.
- They all proposed the use of bare steel pipeline exposed to the surrounding ambient sea temperature.
- Hydrate slurry creation: In SINTEF concept, hydrate slurries are created through the introduction of dry hydrate particles to the production stream, while in Gudmundsson concept, hydrate slurries are created by mixing the cooled liquid phase with the gas phase to create hydrate slurries, and in HYDRAFLOW concept, creation of hydrate slurries will utilize chemical AAs.
- Cooling method: SINTEF and HYDRAFLOW concepts utilize bare pipeline loop, while Gudmundsson utilizes heat exchanger arrangement.
- Wax problem: SINTEF concept would handle other flow assurance issues, including wax problem. Gudmundsson concept has no published solution for wax problem, but

proposes use of chemical where CFT cannot handle it and HYDRAFLOW would solve wax problems and other issues with chemicals (AAs).

- All targets oil fields with some gas. However, gas and condensate fields would be incorporated in the future.

5.9 World Oil and Gas Provinces Suitable for Cold Flow Technology

Deepwater production has been in operation in places such as offshore Mid-Norway, West of Shetlands, Gulf of Mexico, offshore Brazil and West Africa and is likely to expand considerably in the coming decades (Gudmundsson 2002). Figure 44 shows some areas of the world where deepwater oil production is going on. These oil and gas provinces are areas where CFT would have the greatest benefits and potential if successfully implemented for the following reasons:

(a) Each of the regions mentioned play host to deep offshore fields that promote the occurrence of hydrates and waxes as flow assurance challenges.

(b) Each of the regions produce and transport the oil in the deepwater environment through subsea pipelines to the receiving terminal, topside, or to onshore processing facilities.

(c) A number of reactive measures have been adopted in the past to resolve the problems caused by hydrate and wax deposition in these regions for instance the Niger Delta fields of Nigeria. Some of these methods included pigging, solvent soaking, and wax cutting. These techniques had yielded little positive results as their application was characterized by sudden increase in production with subsequent gradual production loss. This calls for a more effective mitigation strategy (Sulaimon, et al. 2010).

(d) There have been a number of methods for tackling hydrate problems but these methods are not without limitations. For example the chemicals are expensive and environmentally hazardous. They are also very sensitive, and can work effectively only on specific crudes. Thermal treatment such as hot oiling can cause formation damage and contraction and expansion of facilities. This makes the cold flow technology a potential in these regions.

(e) Each of these regions have potentially untapped reserves in deepwater and ultra-deepwater location which the present technology may not be economically feasible for their exploitation. Therefore, successful implementation of cold flow technology will really enhance and promote the development of these resources economically and profitable.

Figure 42: Deepwater Basins Worldwide (Nikhar 2006)

5.9.1 West Africa: Applicability of Cold Flow Technology

Exploration and production of oil and gas is moving into deepwater (>500 m) and ultra deepwater (>2000 m) which often requires complex subsea production systems and floating platforms especially in Africa. According to INTSOK (2005), countries like Nigeria and Indonesia are trying to attract investors to their deepwater potential resources. Also, a reduction in production of oil from conventional sources and demand for energy has increased the focus of the industry on the less accessible sources like ultra deepwater. However, most of the new discoveries offshore are in deep and ultra deep waters. This environment requires a technology that could cost effectively develop the untapped resources with less risk, and cold flow technology promises to achieve these feat.

Cold flow technology if successfully implemented however, would be of potential benefit and use in West Africa, especially in Nigeria. This is because of the reasons mentioned above and those stated in chapter 5.9. This makes Nigeria a potential market for this potential emerging technology.

There are a lot of deepwater oil production projects going on in the Nigerian coast. Some examples of these deepwater projects in Nigeria are presented below:

(a) Bonga field is the first deepwater oil field discovery in Nigeria. It lies 120 kilometer off Nigerian coast with water depths, ranging from 900 m to 1,150 m. The field is produced to spread-moored floating production storage and offloading (FPSO) vessel with the capacity to produce 225,000 barrels of oil a day and 150 million cubic feet of gas and water treatment facility. Currently there are 16 oil producing and water injection wells on the field. Oil produced from the field is stored on the FPSO for transport to markets through tanker while the gas is exported via a pipeline to the Nigerian Coast for liquefied natural gas (LNG). In Bonga field, hydrate risks are overcome through inhibitor (Methanol) injection to the subsea tree and jumper, insulation and pre-heating of flowlines through hot oil circulation during cold start-up of the system (Schoppa et al. 2007; Shell in Nigeria 2012).

(b) Agbami field is another offshore oil field in Nigeria. It was discovered in late 1998, and it was the second major deepwater oil field discovered off the Niger Delta. The field is located in nearly 1,500 meters (4,800 ft) of water and 112 km off the coast of Nigeria. The field is jointly operated by the Star Deep Water Limited, an affiliate of Chevron, Famfa Oil, an indigenous oil company, Petrobras (Brazil), Statoil (Norway), and NNPC (the national oil company of Nigeria). It produces over 70,000 barrels per day (11,000 m^3/d) with peak production estimated to be at approximately 250,000 barrels per day. It produces to FPSO unit which cost over 4 billion US dollars to build (Famfa 2008). It has six subsea production systems each, configured as a four well cluster with a central manifold to commingle production from each well. The manifolds are tied back to the FPSO by dual 8-inch insulated flowlines and risers (Intecsea -). Thus, insulation of the flowlines prevents hydrate blockage of the pipeline during production.

(c) AKPO field is another offshore field in Nigeria. It was discovered in January 2000 and production started ahead of schedule in March 2009 in block of Offshore Mining License (OML) 130, 200 km offshore Nigeria in 1400 m of water. AKPO at plateau production, was planned to produce and export 175,000 B/D of condensate and to export gas at startup of 320 MMscf/D of gas to Bonny NLNG plant, onshore Nigeria. AKPO reservoirs characteristics have greatly influenced the development scheme while still making it technically and economically viable. It reservoirs consist of a 620-million-recoverable-barrels accumulation of a critical fluid made of very light oils up to 53°API and classified as condensate, with well head shut-in pressures up to 400 bars, fluid temperature up to 116°C at wellhead, and very high gas liquid ratio (GLR). It is not only a giant condensate field, but also a gas field with 1 Tcf planned gas export. It produces to an FPSO. It utilizes a passive wet insulation with conventional flowlines to control hydrate since the reservoir fluid has high temperature (Rafin et al. 2008).

6. Comparison of the Different Technologies

The different technologies and concepts presented in chapter 4 and chapter 5 will be compared in this section. These will include: cost estimate of the different technologies and qualitative comparison of the different technologies.

6.1 Cost Estimate Comparison

The cost estimate of the different technologies and concepts presented here is based on the values obtained in both chapters 5 and 6 of economical evaluations, and it is done in the order of Tvedt (2005) since most of these values were gotten from his paper. HYDRAFLOW concept equipment cost estimates are not available in the open literature and the assumptions made in this case and for other technologies are presented in Appendix III. Table 4 is an extract of the cost estimates of the different technologies, but more detailed Tables on cost estimates of each case are in Appendix IV.

Table 4: Cost Estimate profile for the different technologies

All numbers in ($) million		**50km**	**100km**	**200km**	**500km**	**1000km**
Insulated Pipeline	**$**	52	102	202	502	1002
Glycol	**$**	7117	14204	28379	70899	141767
LDHI	**$**	544	1088	2185	5435	10870
DEHS	**$**	62	112	213	516	1021
SINTEF-BP	**$**	91	116	166	316	566
Gudmundsson	**$**	107	132	182	332	582
HYDRAFLOW**	**$**	174	323	619	1510	2993

A glance through these cost estimates of the different technologies for enhancing flow assurance in subsea pipelines reveal that chemical inhibition technologies can be very high even at short distances. The cost also escalate at long distances and this may results to not considering its usage especially over long distances as it may not be economically feasible over long distances which the industry is looking at for subsea / deepwater field development.

DEHS which is an emerging technology indicates its economical viability with low cost values. It is considered economically viable for pipeline distance up to 200 kilometers.

A comparison of an insulated pipeline, DEHS, SINTEF-BP, Gudmundsson, and HYDRAFLOW concept is also illustrated in Figure 43. It may be argued here that the DEHS would compete with cold flow concepts at about some distance say 150 to 200 kilometers and above this limit, may not outwit cold flow based on some technical reasons like high power requirement.

And, comparison of the three cold flow concepts is as shown in Figure 44. It may also be argued here that HYDRAFLOW concept would have less economical value than SINTEF and Gudmundsson concept due to use of AAs in creation of the hydrate slurries.

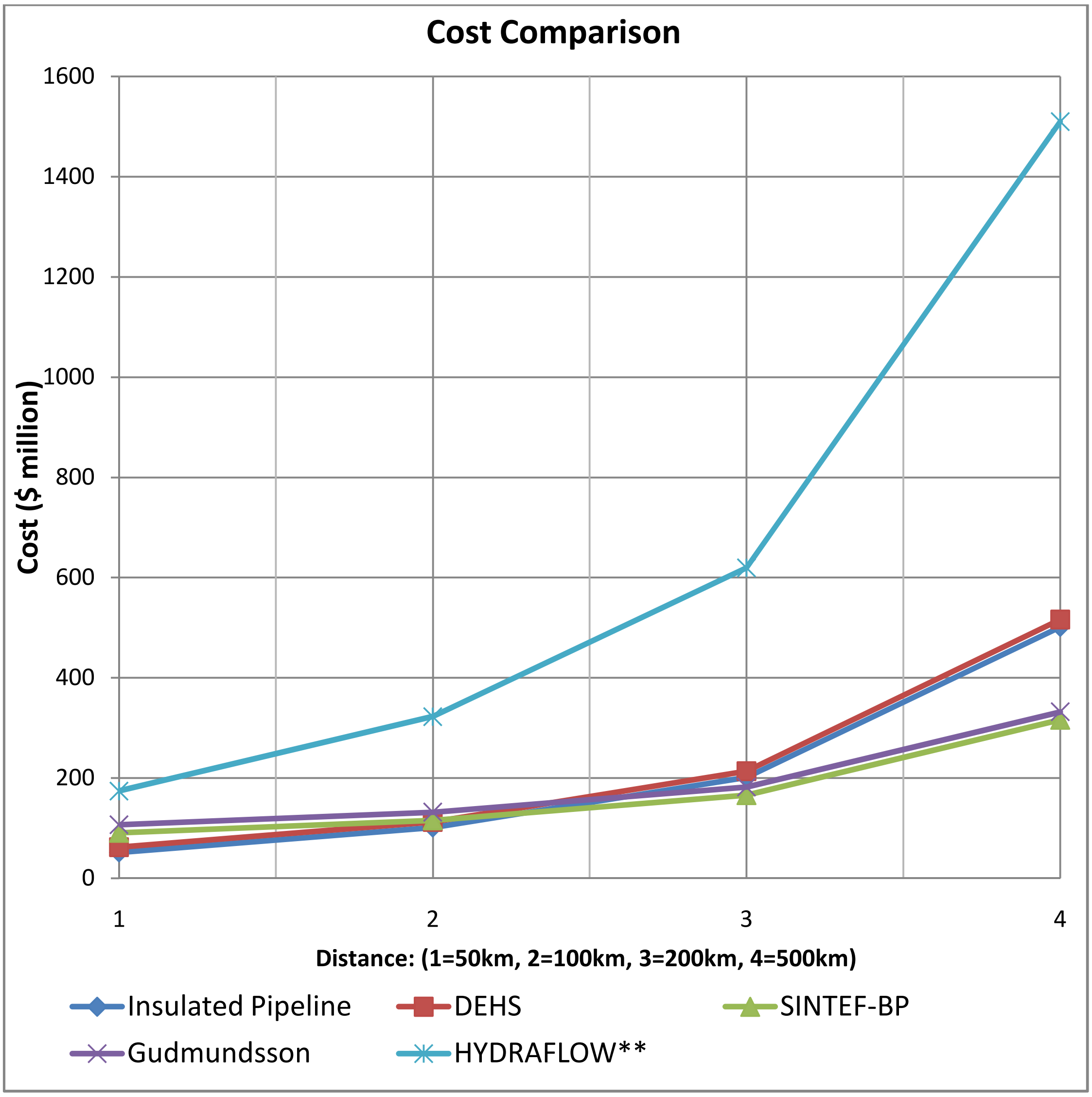


Figure 43: Cost Estimate Comparison of the different technologies

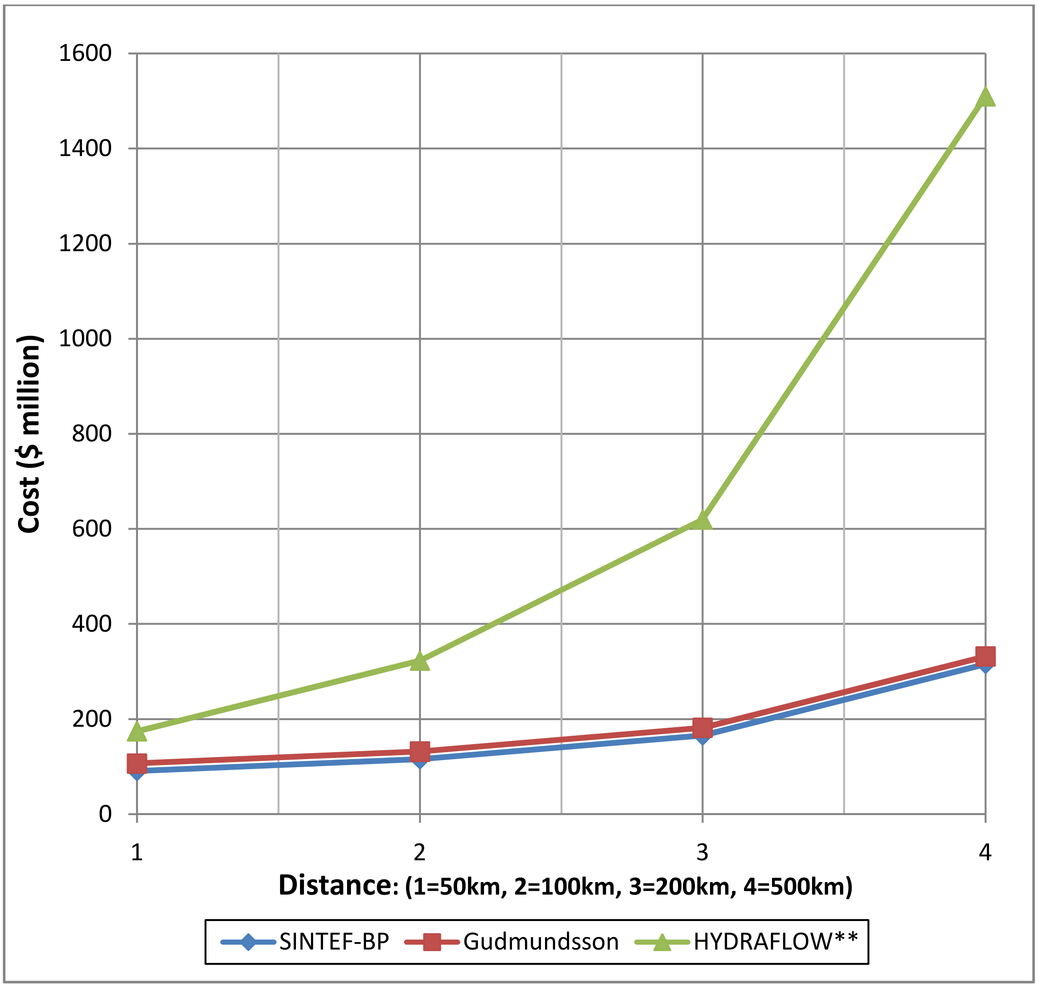


Figure 44: Cost Estimate Comparison of the three Cold Flow Concepts

6.2 Qualitative Comparison of the Different Technologies

The qualitative comparisons of the different technologies are presented in Tables 5(a) & (b). These are based on the technical, environmental and economic evaluations of the different technologies considered in this work in both chapter 4 and 5.

Under technical issues the following are considered: system application, subcooling, water-cut, GOR, pipe distance range, chemical requirements, important infrastructures, and flow assurance problems solved. Waste issues and pollution are considered under environmental issues and CAPEX and OPEX of each concept are compared under economical issues.

Table 5(a): Qualitative comparison of the different technologies

	Chemicals		
	THIs	LDHIs	
	MeOH & MEG	KHIs	AAs
Technical issues			
System application	Oil, gas & condensate, multiphase	Oil, gas & condensate, multiphase	Oil, gas & condensate, multiphase
Subcooling	Copes up to 30 ^oC, but depends on WC & Pressure	Limited to 8 – 14 ^oC	No limitation.
Viscosity	Up to 30%, but not problematic	Up to 30%, but not problematic	Up to 30%
Water cut	Handles all WC, but 20-40 % is normal	No limit, provided sufficient quantity is added. But 20-30% is normally preferred.	Normally below 25-50 %, but practically, 20-30 %, because of liquid h/c phase needed.
GOR	No effect. High GOR & WC makes transportation difficult.	No limit, but high GOR & WC can cause difficulty in fluid transport.	< 100,000 scf/stb. High GOR makes transportation difficult
Pipeline distance range	10-200 km. With insulation	10-200 km. With insulation	10-200 km. With insulation
Chemical requirements	10-60% by volume. High volume required for high WC	< 1% by vol. (usually 0.25-0.5% by vol. of produced water)	< 1% by vol. (usually 0.25-0.50% by vol. of produced water)
Important Infrastructures	Regeneration / reclamation facility, large storage tank, umbilicals, high horse power pump.	Fewer umbilicals, Smaller storage facility, Smaller pump horse power & no regeneration facility.	Fewer umbilicals, Smaller storage facility, Smaller pump horse power & no regeneration facility.
Flow Assurance problem solved	Hydrate: solved Wax: solved with other chemicals	Hydrate: solved at certain conditions. Wax: solved with other chemicals	Hydrate: solved under certain conditions. Wax: solved with other chemicals.
Environmental issues			
Waste issues & Pollution	Toxic & Contaminates oil and environment.	Less toxic	Less toxic
Economical issues			
CAPEX	Very high	High	High
OPEX	Very High	High	High

Table 5(b): Qualitative Comparison continuation

		COLD FLOW		
	DEHS	SINTEF	NTNU	HYDRAFLOW
Technical issues				
System application	Oil, gas & condensate, multiphase	Multiphase. Initially - Oil fields. Gas & Condensate fields to be incorporated	Multiphase. Initially - Oil fields. Gas & Condensate fields to be incorporated.	Multiphase. Oil. Gas & Condensate?
Subcooling	No effect	No limit.	Cooling medium dependent. Not more than 5-10 ^oC above cooling medium per cycle.	Copes with subcooling up to 20 °C
Viscosity	No effect	High pressure drop may lead to difficulty in transportation with high viscosity.	High viscosity due to low temperature & high pressure drop may lead to difficulty in transportation	Not a problem. Can be adjusted by adding water & AAs.
Water cut	No effect	No limit. But minimum of 20% is preferred	No limit. But a free water knockout may be needed as field matures.	Handles high WC. 20-60 %, simulating mature field.
GOR	No effect	High GOR & WC will cause difficulty in transportation. It covers all oil fields' GOR.	High GOR & WC will cause difficulty in transportation. It covers all oil fields' GOR.	Low to high GOR. 350-4200 scf/stb
Pipeline distance range	Presently up to 50 km. 200 km – Maximum	200 km & above. Extra pipeline for cooling loop	200 km & above.	200 km & above. Extra pipeline for cooling loop may be needed.
Chemical requirements	Not required	Not required	May be needed for WH protection during planned shut-downs.	Special LDHIs (biodegradable AAs)
Important Infrastructures	Power source	Non-insulated pipeline, reactor, splitter, pump.	Non-insulated pipeline, reactor, separator, pump.	Non-insulated pipeline, separator, pump.
Flow Assurance problem solved	Hydrate: solved Wax: solved	Hydrate: solved Wax: not a problem, but it has not enough proof.	Hydrate: solved during steady state. Wax: risky, & no published solution or may be solved with chemicals	Hydrate: solved Wax: solved due to turbulent flow & chemicals
Environmental issues				

Waste issues & Pollution	No pollution, but large energy demand	High energy demand to break the slurry. No chemical, no pollution.	High energy demand. Chemical need will be very minimal. Non hazardous & no pollution.	Minimal discharge due to recycling loop. May be hazardous.
Economical issues				
CAPEX	Low	Low	Low	Low
OPEX	Low	Low	Low	Moderate

7. Discussion and Evaluation

Cold flow technology is still under development because there are some technical gaps that must be closed before successful field trial and implementation can be achieved. Until now, it is still acknowledged as the future technology for the industry.

In this chapter I will discuss and compare the advantages and disadvantages of the different technologies considered in this work. This will be based on the description of the different technologies in both chapter 4 and chapter 5. Evaluation of the cold flow technological gaps with various technological concepts or options developed in quest of solving or could be utilized to solve these challenges.

7.1 Advantages and Disadvantages of the Different Technologies

Solids (hydrate and wax) formation and deposition prevention and remediation strategies are often based on the technical, environmental, and economical considerations in oil and gas production. The strategy adopted at times are influenced by the reserves base, and composition of the produced fluid especially in subsea location.

In this section, I will base my discussion on the capability of each technology to handle flow assurance problems considering the technical, environmental and economical issues. I will give attention to pipeline distance of 200 km and above. This is because the industry is today moving towards developing new fields with long and multiple subsea tiebacks to a central unit or to an onshore processing facility with the aim of reducing the demand for expensive infrastructure usage.

7.1.1 THIs

Thermodynamic hydrate inhibition (THIs) technology has been in use in oil and gas industries for several decades now. Its valuable contributions in enhancing flow assurance cannot be over emphasized. It is usually used with insulated pipelines to maintain the produced fluid temperatures above hydrate formation conditions.

It can be argued that this technology can be economically viable below 50 km of pipeline. This is due to the fact that longer distances would require higher volumes of chemical, which will result in high economics of a project.

Methanol is usually used in non-regeneratable systems while glycols are used in a continuous regeneratable processes. Though methanol is usually cheaper than MEG per unit volume, the fact that MEG is regeneratable justifies its usage over methanol. Also, methanol being volatile is lost to the gas phase instead of the aqueous phase where it should be inhibiting hydrates. Methanol also promotes pipeline corrosion due to the dissolved oxygen, and also reduces the efficacy of some corrosion inhibitors. These give MEG more value over methanol. Their usages in short distance transportation in subsea location would be very efficient. They are well understood and have proven records.

There have been optimization of chemical inhibition technology, but these do not really enhance its cost effectiveness in the industry over long distance transport. This is because large volumes would be required for longer distance transport considered in the case of THIs. Furthermore, their negative impact on the environment also adds to THIs limitations. Therefore, for longer distance transfer, THIs becomes inefficient economically to handle flow assurance problems.

7.1.2 LDHIs

The drawbacks set by THIs leads to the search for an alternative to the thermodynamic hydrate inhibition chemicals necessitated by the enormous overall cost and high volumes required, many at times in the natural gas processing and transportation. This results in the development of LDHIs. LDHIs have higher value than THIs because small volume (less than 1 weight percent) are required to inhibit hydrate blockage of pipeline. The use of LDHIs in the industry has proven to be cost effective, with the absence of chemical regeneration facilities. This results in low CAPEX and OPEX of the system. LDHIs also leads to hydrate risk management rather than prevention.

The major disadvantage of KHIs is that, they can only be used in low to moderate subcooling (less than 14 ^{o}C) conditions and the AAs are limited by high water cut in the system. However, better but economically efficient results would be obtained in pipeline of distance between 10 to 100 kilometers. The LDHIs are usually very expensive, thus increasing the cost of hydrate and wax prevention for distances up to 200 km. And, due to this high cost, the cost of prevention (OPEX) may escalate close to that of THIs especially over long distances. Also, they are less toxic and environmentally friendly, though they are prohibited in some areas of the world like Norwegian coast.

7.1.3 DEHS

The need for a more technical and economical method for enhancing flow assurance also leads to the development of insulation and electrical heating of subsea pipelines. DEHS has really proved to be cost effective, highly reliable, and flexible. This has given it a higher value over traditional chemical methods for flow assurance.

With DEHS, planned and unplanned shutdown can be managed through application of different heat input requirements to the pipeline. Hence, keeping the pipe content above hydrate formation temperature, reheating from cold conditions and wax melting are always possible with DEHS. Moreover, heating during tail production with adjustable heat input adapted to production rate and thermal properties or conditions, and elimination of depressurization risks for avoiding hydrate formations which is not always feasible particularly in deep water fields. It is environmentally friendly, economically feasible for distances less than 200 km with reduction in CAPEX and OPEX.

The only limitation of DEHS is the distance it can cover which is not above 200 km of pipeline length, for technical and economical purposes like high power requirement. Also, voltage difference between the sea and the pipeline will result in the need for high voltage (HV) insulation at the platform and some distance along the pipeline.

Currently, utilization of DEHS for transportation of hydrocarbon is limited to 50 km. And, it has not yet occupied the market like chemical inhibition technologies. It can be argued that in the next few decades, it will outwit chemical inhibition in the market based on its good track and proven records together with improvement of DEHS.

7.1.4 Cold Flow Technologies

As flow assurance develops from hydrate avoidance to risk management, this has lead to development of a new concept of cold flow technology. Though this technology has not yet been implemented, it promises to be highly valuable than all other methods for flow assurance, especially for longer distance transport of oil and gas in subsea pipelines. This is true because, it proposes an elimination of chemical usage, electrical heating of pipelines, pipeline insulation, risk of pipeline blockage and that of offshore personnel, as well as improving production and promoting production of small reserves. It will also simplify subsea operations, with low maintenance of the system, resulting in low CAPEX and OPEX. CFT as a potential emerging technology would only outsmart DEHS over longer distances as considered here and because of its high demand for power, if it performs as promised on all distances.

Nevertheless, cold flow technology may also face some technical challenges like heat balance of the system. Melting of the hydrate slurry into oil and gas may also require large amount of energy at the end of the transportation.

However, the two cold flow concepts of SINTEF and Gudmundsson will have higher value than the HYDRAFLOW concept. It can be argued that the proposed use of AAs chemical in HYDRAFLOW concept, though it would be recycled, would affect cost significantly. This is because, over longer distances, sufficient volume must be involved to keep the cooled fluid continuously dispersed. Whereas, in SINTEF and Gudmundsson concepts, chemicals may only be needed during start-up and shut-in periods.

And, the summaries of the advantages and disadvantages of the different technologies are also present in Table 6, see Appendix I.

7.2 Technical Challenges Facing Cold Flow

Achieving cold flow will improve and simplify transportation of oil and gas both on land and offshore. This is still acknowledged as the future for the industry, but to make it happen, the industry has to crack the nuts that are yet unturned. This is due to some technical challenges that must be solved before it can be successfully implemented.

The following technical gaps were identified. There are some subsea technological options that can be utilized, but I will only evaluate some options developed or proposed to handle wax deposition in the cool down section of cold flow technologies especially, that which could be utilized in SINTEF concept. These technical gaps include:

- Wax deposition in the cool down section.
- Cold flow pump system.

- Separator system

7.2.1 Wax Problem in Cool-down Section

In the cool down section, there is no need to actively control temperature because, the fluid in the recirculation or cooling loop cannot go below the temperature of the surrounding seawater. Thus, free water may precipitate out of the hydrocarbon stream. This will lead to formation of hydrates that will be transported in the production stream before it enters the cold flow pipeline, but wax precipitation and deposition in this section is a task that must be managed, to prevent blockage of this section.

As explained in chapter 5.5, wax deposition on the pipe walls in the cooling section of cold flow technology is one of the major challenges that need to be fixed, if cold flow technology is to be successfully implemented. Once the seawater, production stream flow, and the pipeline have the same temperature (thermodynamic equilibrium), solid particles (hydrate and wax) would not get build up. This way, cold flow transportation of the production stream would be successful.

From the economical and technological benefits which cold flow technology promises, some technological options have been developed and proposed which can handle this challenge. The currently proposed options (potential solutions) that can be adopted in solving the challenge of wax deposition in the cooling section will now be presented and discussed below.

(a) Statoil, a partner with SINTEF has proposed that in the cool-down section, heat pulse can be used in removing the wax. Since there is need to deal with wax deposition, heat pulse system will provide periodic and control heating of the pipe wall. The warm pipe wall will reduce the adhesive forces of wax to steel, and the deposited wax will not be melted rather, the heat supplied will improve the ripping off action by the turbulent shear forces. The wax deposits removed will then be transported downstream as solid particles in the cold bulk stream into the cold flow pipeline. Thus, the solid wax in the cold bulk stream would not deposit on the cold flow pipeline wall (Hoffman 2012). With the use of heat pulse on the cool down section, re-start of production after shut-in would be possible.

Being that the cool-down section is small compared to the pipeline length, the heat should be applied to this section and wax deposition in the cool-down section can be monitored continuously with a heat pulse system. If this system could be installed in a subsea pipeline, it would be possible to make continuous measurement of the wax build-up. This will in turn, allow for a much more efficient use of wax control technique. In this technology, the equipment is located outside the pipeline, such that it could be possible to add it to an existing pipeline. To determine when to remove wax deposition by heat pulse, the preferred solution is the use of fiber optic distributed temperature sensing (DTS) system, to measure the change in outer wall temperature with respect to the thermally insulated wax (Hoffman 2012), see Figure 45.

Fiber-optic distributed temperature sensing (DTS) system is a permanent monitoring technology that can provide measurements over the complete length of the optical fiber on a pipeline. This technology provides highly sensitive and accurate measurements that identify the source of changes in well performance as they occur and systems are monitored at the surface in real time (Schlumbeger 2013). The thermal profiles obtained from DTS system can be used for effective management of key assets (cooling section). This would not only prevent overheating of the pipe but also predict and monitor the thermal rating in real-time. According to Peck and Seebacher (2000), the economic benefits of using DTS from fault minimization and better asset utilization significantly outweigh the marginal costs of installing optical sensing. However, what is uncertain to me here is the material component of the pipeline.

(b) Another technology underdevelopment that can be employed to utilizing cold flow technology is the EMPIG flow assurance technology system. EMPIG AS is a Trondheim based company established in 2011 and the winner of both DNB NOR innovation award and Establishment stipend from Adolf Øiens fund in 2011 and also a nominee for ONS Innovation in 2012. EMPIG is a patented processing plant for the removal of wax and hydrate deposits in pipelines in the cold flow regime. EMPIG is building on the 12 years of SINTEF R&D (Saturn Cold Flow project). EMPIG technology solution to achieve cold flow has been developed in collaboration with SINTEF, Smart Motor AS, Inventas AS, HIST and NTNU.

This system is based on a bi-directional, non-intrusive, magnetic and hollow pig. The pig is controlled and moved from the outside of the pipe by an autonomous robotic sled, in which it is locked to magnetically, see Figure 46. The pig is independent of flow and can be moved both up or downstream even with full production rates. The pig is very robust and simple with no complicated parts and cannot form a plug. The pig does not contain sensitive electronics or mechanical parts that can malfunction (passive system) and the sleds are easily retrievable and replaceable through the use of a remotely operated underwater vehicle (ROV) and light intervention vessel. The sleds would only stop at the recharging dock station and a pulling force of over 1 kN can be achieved with a 1 m long pig. The pipeline is a standard austenitic stainless steel which is also non-magnetic.

The system is designed with a cooling zone of length, 500 – 1000 m long, depending on the nature of the field (fluid composition). This is only a small fraction of a normal pipeline full length. The cooling pipes are elevated from the seabed by a structural frame, and this will enhance the cooling process. The pipe diameter is 4 inches and are fitted in parallel, with the number dictated by flow rates. The system is adaptable and redundant, pipes can be closed individually. And, in the cold flow pipe, wax and hydrates are no longer a problem because, ambient sea temperature is reached. The sketch for this system is presented in Figure 47.

In this system, dry hydrate seeds would be introduced through a cold retour flow loop to accelerate and control the hydrate formation. The seeds act as a catalyst, dry hydrates develop, and not a sticky slurry, see Figure 48. The dry hydrates brake up into problem free particles in the flow, as explained in the SINTEF system. The introduced seeds are pumped through the retour flow pump. EMPIG is unique in solving both wax and hydrate challenges (Lund and Frøseth 2012).

With EMPIG, I can say that some challenges of SINTEF concept are solved. Initial creation or introduction of hydrate seeds in the case of SINTEF cold flow concept was one of the uncertain issues on how it would start before recycling of the cold stream for continuous creation of the inert slurry. But in the recent development of the EMPIG technology, this issue has been fixed up. Also, since the bare steel pipes are installed on a structural frame, I may argue that the issue of buoyancy effect which was before one of the challenges of

SINTEF concept can now be handled. These installed pipes may be towed as a complete structure to the site. This will enable new subsea developments and transport over longer distances than what is possible today.

(c) Another technology is a subsea heat exchanger or subsea cooler system to cool down the production stream, so as to achieve cold flow. Some of the subsea heat exchanger technological options include: Heat exchange side-by-side tubular structures or tube sections with manifold type header or header plate (Patented to FMC Kongsberg Subsea AS) (Jacobsen et al. 2012), and also a compact cooler with heating facility for the needed new heat exchanger design recommended by Hoffman (2012).

8. Conclusion

The oil industry is today moving towards developing new fields in deep and ultra deepwater environment due to the depletion of the conventional onshore and shallow water sources of hydrocarbon. For economical development of deepwater fields and profitable production, subsea fields are tied back to an existing infrastructure. This environment provides ideal conditions necessary for flow assurance problems (hydrates and wax formation) in subsea pipelines used for transportation of the produced fluids especially over long distances.

Currently, two solutions of tackling flow assurance problems include: chemical inhibition and direct electrical heating combine with pipeline insulation. Chemical inhibition is effective but over short distances and it is always associated with high attendance costs coupled with environmental concern. DEHS is also effective and efficient over short distances and it is environmentally friendly. DEHS performance is even better than chemical inhibition. Over longer distances, both chemical inhibition and DEHS may not be economically viable to be utilized. Cold flow technology is a novel technology proposed to tackle these flow assurance problems over longer distance.

Cold flow technology is a future technology for preventing hydrate and wax blockage of pipelines. It allows solids formation but will transport them in a slurry (multiphase) form over long distances. It promises to be cost effective, environmentally friendly and reliable in ensuring flow assurance over long distance transfer. With the elimination of pipeline insulation, heating and the use of chemicals, cold flow will outsmart DEHS especially over distances greater than 200 km and chemical inhibition. One of the main concerns of CFT is wax deposition in the cool down section during cooling process. There have been continuous effort on improving this technology which points out that in the next few decades, it may successfully be implemented once the main challenges are solved.

SINTEF-BP cold flow concept and Gudmundsson cold flow concepts are very similar and would have higher value than HYDRAFLOW concept being that HYDRAFLOW proposed to utilize chemicals (AAs) in hydrate slurry creation process. The three concepts propose to use bare steel pipeline. However, with successful implementation of this potential emerging technology, Nigeria would be one of the potential markets.

9. Recommendation and Limitation

9.1 Recommendations

There are other technical gaps that might have receive an attention in regards to bringing cold flow technologies to a reality, with regards to subsea pumping system, and separator. These were not evaluated and therefore, should be considered in further studies among other technical issues.

The rough estimate done here is a repetition of estimates performed by Tvedt (2005) in his paper. These, somehow may not have been comprehensive enough. This needs to be improved in subsequent studies, to include the installation cost, some operation costs, and cost benefit analysis of these different technologies.

In this kind of study, an interview would have been very relevant to obtain first hand information concerning the cases considered in this work. A broader evaluation would have also been possible. Hence, interviews would be necessary for an improvement in the next studies.

Also, combination of various analytical tools like PESTEL would have been useful. I discovered this late and in subsequent study, this should be considered for improvement of the analysis. I missed this because I was trying to make my work different from Tvedt's (2005) work.

An investigation of other means of transportation of oil and gas from subsea environments like LNG, and NGH should also be analyzed and compared.

9.2 Limitations

There are several limitations regarding my work. Firstly, it would have been very useful to me if I had access to the industry and experts on the field to interview them on the different technologies considered in this work. This has forced me to work on limited resources and basing most of my ideas on observations and documental studies. Hence, the limitations of other peoples works and views have really influenced my studies and results.

The method adopted in this work is biased and trying to make my work different from others has limit my reasoning on several issues. Also, getting to like one case than the other has limited my sense of judgment in this studies. However, generalization of the results become difficult as it based on observations from other people's ideas.

The economical estimate done in this work was first a repetition of Tvedt's (2005) work and then addition of the new concept of HYDAFLOW. There are no cost estimates for this concept, thus, several assumptions were made on the values and other issues. Therefore, the limitations regarding Tvedt (2005) cost estimates becomes relevant here, in addition with mine.

There might be several updates on costs or economical information for most of the cases considered in this work. However, my inaccessibility to these information also have some degree of limitation to the results and evaluation done in this work.

10. Abbreviations

B.C	–	Before Christ
CAPEX	–	Capital Expenditure
OPEX	–	Operating Expenditure
CF	–	Cold Flow
CFT	–	Cold Flow Technology
CFP	–	Cold Flow Pipeline
WAT	–	Wax Appearance Temperature
THIs	–	Thermodynamic Hydrate Inhibitors
LDHIs	–	Low Dosage Inhibitors
MEG	–	Mono-Ethylene Glycol
GOR	–	Gas-Oil Ratio
h/c	–	Hydrocarbon
WC	–	Water Cut
WH	–	Wellhead
TEG	–	Tri-ethylene Glycol
NOK	–	Norwegian Krone
$	-	US dollar
AAs	–	Anti-Agglomerants
DEHS	–	Direct Electric Heating System
WHU	–	Wellhead Unit
SU	–	Separator Unit
HXU	–	Heat Exchanger Unit
RU	–	Reactor Unit
G/L	–	Gas and Liquid Mixture
TLP	–	Tension Leg Platform
scf	–	Standard Cubic Feet
stb	–	Stock Tank Barrel

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12. Appendices

Appendix I: Summary of Qualitative Comparison of Advantages and Disadvantages of the Different Technologies

Table 6: Qualitative comparison of advantages and disadvantages of the different technologies (summary)

Methods	Description	Advantages	Disadvantages
THIs (Methanol & MEG)	Shifts the hydrate equilibrium conditions to favour lower temperature and high pressure. No effect on nucleation and growth of hydrate crystals into plug	1. Proven track record. 2. Effective and robust. 3. Predictable 4. Well understood	1. Environmentally toxic & harmful 2. Enhances corrosion especially methanol. 3. High volumes (10-60 wt. %). 4. Higher CAPEX & OPEX 5. Volatile – losses to vapour 6. Salting out
LDHIs (KHI & AA)	Modifies the rheology of the system. It delays crystal growth for a period that is longer than the residence time of free water in the system. It also creates a non-agglomerated slurry that is easy to transport.	1. Environmentally friendly 2. Delays water cut related curtailment. 3. Reduced manpower requirement 4. Less-toxic 5. Reduced CAPEX & OPEX 6. Lower volume (<1 wt. %) 7. No subcooling limitation.	1. Time dependency 2. No establish predictive model 3. System specific-testing required 4. Restricted to lower WC 5. Shut downs 6. Compatibility 7. Limited experience
DEHS	Passing of a large electric current through the pipeline wall to generate heat that will maintain a steady-state flow of fluid and prevents hydrate formation. It utilizes alternating current (AC).	1. Environmentally friendly 2. No chemical usage 3. No risk of depressurization 4. Simplified re-start operations. 5. Enhances immediate remediation of blockage 6. Low CAPEX & OPEX 7. No subcooling effect 8. Proven technology 9. Good track records	1. High power consumption for long distances 2. Insulation cracks and power failure can lead to pipeline corrosion. 3. Cable failure can result in pipeline damage and short circuiting of current flow.
Cold Flow	Allows solids formation and transportation in a slurry form at thermodynamic equilibrium with the surrounding seawater in a non insulated, non-heated pipeline and without the use of chemicals.	1. Environmentally friendly 2. No chemical usage 3. Reduced energy for heating of pipeline 4. Lower CAPEX & OPEX 5. Improves production 6. Promotes production of small reserves. 7. Reduced numbers of offshore personnel 8. Removes risks of blockage & that of potential	1. Large energy may be required in melting the hydrate slurry. 2. No field experience yet 3. Not yet proved

Methods	Description	Advantages	Disadvantages
		personnel 9. Simplified operations, steady & low maintenance.	

Appendix II: Cold Flow Solutions For Cooling Section Schematics

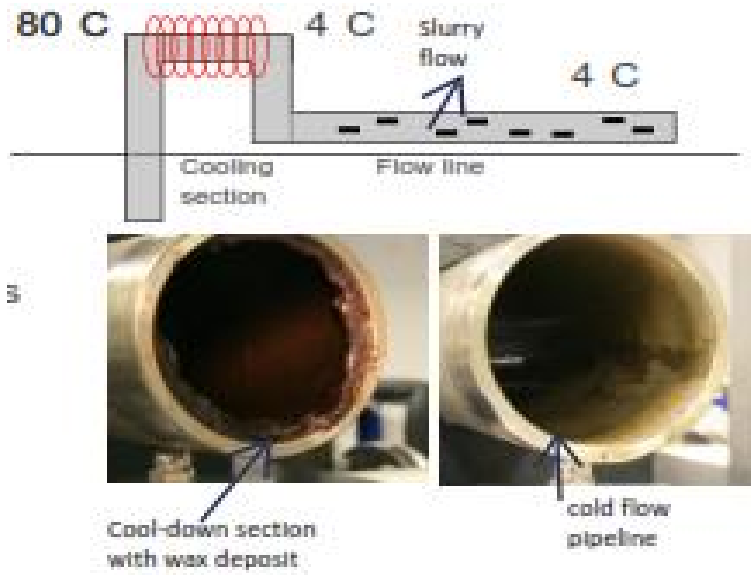

Figure 45: Cold flow principle with heat pulse (Statoil patented), (Hoffman 2012)

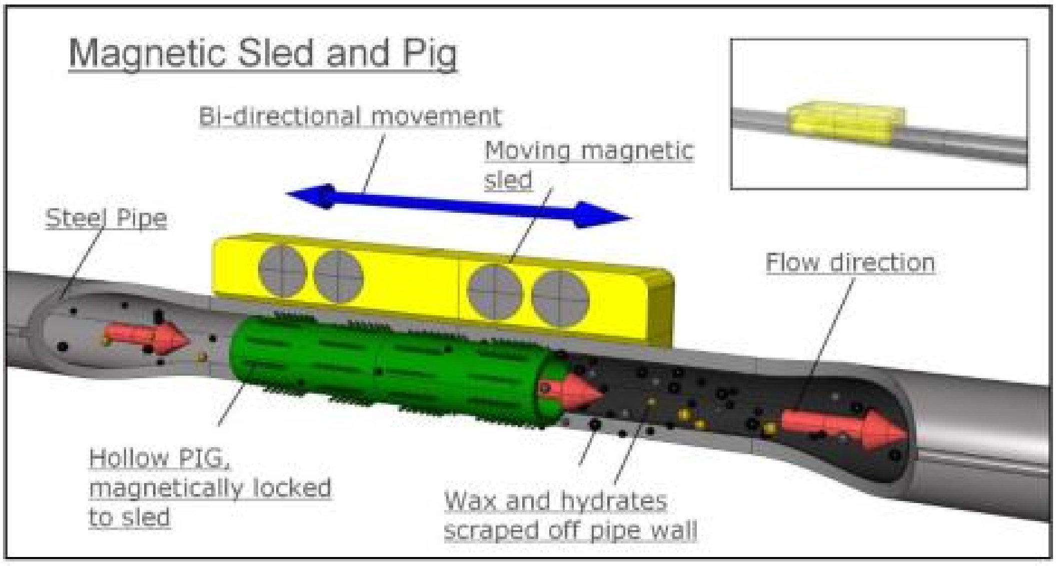

Figure 46: Schematics of Magnetic sled and Hollow pig

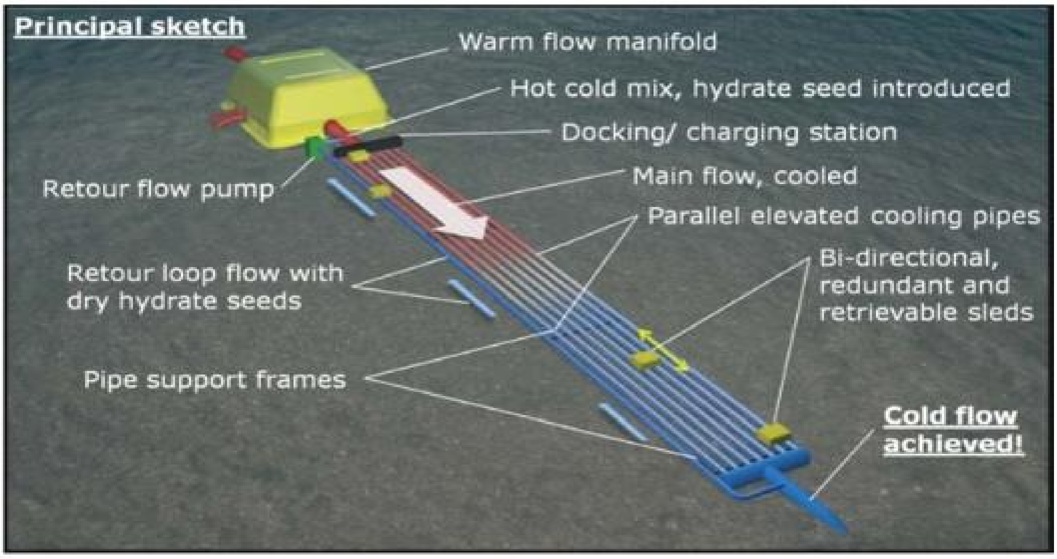

Figure 47: Schematic of Empig system principle

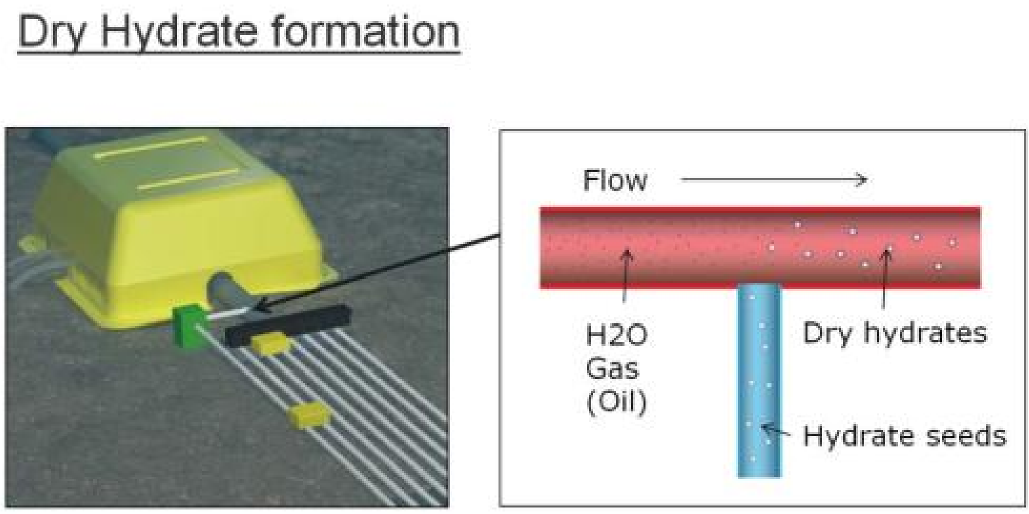

Figure 48: Dry hydrate formation

Appendix III: Cost Estimates Assumptions for Different Technologies Assumptions

In this Appendix, since I have repeated Tvedt (2005) work on cost estimates, all his assumptions remains valid. I will further include the assumptions I have made on HYDRAFLOW concept estimation. Hence, I present here Tvedt's assumptions first.

The assumption on the cost estimates for the different technologies done in the Tables is presented. Each technology including a baseline concept with a bare pipeline, will have its own assumptions. If numbers or assumptions are given earlier in the paper they will not be repeated here.

General Assumptions

All the figures have been calculated in US $ million, and the exchange rate between NOK and US $ have been 6.5. I considered using this instead of NOK 5.6 to a dollar because of inflation which can set in anytime. Further on, no installation costs have been added to the technologies because of limited resources to acquire these. These will vary between the different concepts, and could probably change the cost picture to some degree.

In general the assumptions taken to get some numbers to evaluate are based on some insight into the industry, but they are not to be regarded as accurate. Especially the number for chemical inhibiting could have been more accurate, but they give an impression of the cost size. For instance the amount of barrels per day will not fit with the scale of regeneration that is needed on Ormen Lange. The real number will probably be higher.

Insulated pipeline

Price per kilometer bare steel pipeline is assumed to be $1 million. This is for a 16-inches pipeline. This pipeline size is probably too small, but since this is only an estimate that is supposed to give a rough understanding it will be used for all pipelines unless otherwise said.

Chemical Inhibiting

I have assumed a production of 16 000 barrels per day, which is a low number, to get an impression of the amount of chemical needed. Further on, the injection pipelines are assumed to be of equal size to Ormen Lange, i.e. 6” and 8”, which is likely to be the closest comparison project today. Since the pipeline cost is proportional with length, diameter and weight of steel needed a very rough scaling on the diameter is done. This scaling is not accurate, but will give an impression of the cost. The cost of a chemical tank has been copied from the Ormen Lange project. The same goes for pumps and distribution network. The regeneration system is scaled to handle the amount of volume in the pipeline.

To find the amount of chemical need, I have calculated the amount of water in the pipeline that needs to be dealt with on 1:1 basis for MEG, and dividing that number again by 50 in accordance with figures given earlier in this paper for LDHI. Water cut on 1 percent, which is very low, is chosen. Since the chemical needs to be transported back again, I will assume doubling the needed amount required. The speed assumed is 6 m/s. For LDHI storage and injection facilities will be almost negligible, but is given the value of $1 million. These assumptions were made based on discussions with Gudmundsson.

DEHS

I have assumed a price on electricity at $0.045/kWh (30 øre/kWh), which should be a conservative assumption. During the last five years it has only once been this high for the power demanding industry and in 2004 it was $0.036/kWh (SSB 14.12.2005).

In addition, I have calculated continuous heating of the pipeline, but still with continuous heating this attributes do not affect the total price of the concept significantly.

Cold Flow Concepts

I have only managed to get numbers for Gudmundsson's concept, but since SINTEF- BP's concept is quite similar the same numbers have been used. The only exception is the cooling process where SINTEF-BP will use a cooling loop while Gudmundsson's concept will use active cooling. The pipeline used for cooling has bare steel pipes that cost $0.5 million per kilometer base on his discussion Roar Larsen.

The equipment prices' were originally given as total sums for five fields. I have divided the numbers from the referred paper with five since the referred paper only talked about the total price for the different equipment. This simple solution has been chosen because it gives an average sum on what kind of sums that could be expected when the system will have to be redesigned for each field.

HYDRAFLOW Concept**

The cost estimate of this concept is not available in the open literature. Based on its various components and mode of operation proposed, I therefore made assumptions related to other cold flow concepts and mode of its operation. I assumed the same cost of bare steel pipeline used in other concepts; storage tank and injection line for the proposed chemical (AAs) was assumed to be same as in the case of LDHIs storage tank. Refrigerated pipeline cost was assumed same as in other cold flow concepts. The cost of pump was reduced to $1 million since it is stated in the literature that a small horse power pump is proposed for use from onshore location. Also, since the chemical would be recycled, I chose to reduce the velocity by one quarter (1/4) for injection. The cost of chemical is assumed to be same as for LDHIs.

However, these assumptions may not be true of this concept but I believe it is relevant to some extent.

Appendix IV: Detailed Cost Estimates Tables for Comparison of the Different Technologies

Table 7: Cost Estimate for Insulated Pipeline

Baseline Insulated Pipeline Costs Insulated pipeline All numbers in $ Millions	**$**	**50 km**	**100 km**	**200 km**	**500 km**	**1000 km**
Overhead						
insulated pipeline	$	50	100	200	500	1000
Pigtrap (receiver and Launcher)	$	0.5	0.5	0.5	0.5	0.5
Pig	$	1	1	1	1	1
Total	**$**	**51.5**	**101.5**	**201.5**	**501.5**	**1001.5**

Table 8: Cost Estimate for MEG

Cost for insulated pipeline with MEG injection

Chemical: Glycol						
All numbers in ($) million		**50 km**	**100 km**	**200 km**	**500 km**	**1000 km**
Overhead						
Injection Pipelines	$	21.9	43.8	87.5	218.8	437.5
Chemical tank inclusive valves	$	27.6	27.6	27.6	27.6	27.6
Pump	$	1.6	1.6	1.6	1.6	1.6
Distribution network	$	1.0	1.0	1.0	1.0	1.0
Regeneration system	$	182.9	365.7	731.5	1828.7	3657.4
Assume regeneration:						
Minimum run-through time+reposition time (*2)		4.6 hour	9.3 hour	18.5 hour	46.3 hour	92.5 hour
Equivalent volume chemical this length pipeline		493 m^3/50km	987 m^3/100 km	1974 m^3/200 km	4934 m^3/500 km	9869 m^3/1000 km
Equivalent volume chemical this length pipeline		493441 litre/50 km	986882 litre/100 km	1973764 litre/200 km	4934410 litre/500 km	9868820 litre/1000 km
Volume rate glycol of water	%	1	1	1	1	1
Volume of chemical needed this length pipeline		4934.41 litre/50 km	9868.82 litre/100km	19737.64 litre/200 km	49344.1 litre/500 km	98688.2 litre/1000 km
Price per litre MEG	$	1.38	1.38	1.38	1.38	1.38
cost glycol this length pipeline	$	6832	13664	27328.4	68321	136642
variable						
Pipeline ($1million/km)		50	100	200	500	1000
Total		**7117.10**	**14203.90**	**28378.98**	**70898.70**	**141767.10**

Table 9: Cost Estimate for LDHIs

Chemical: LDHI						
All numbers in ($) million		**50 km**	**100 km**	**200 km**	**500 km**	**1000 km**
Overhead						
Storage tanks & Injection system	$	1.0	1.0	1.0	1.0	1.0
Not assuming regeneration:						
Minimum run-through time	$	2.3 hour	4.6 hour	9.3 hour	23.1 hour	46.3 hour
Equivalent volume chemical this length pipeline	$	246.7 m^3/50km	493 m^3/100 km	987 m^3/200 km	2467 m^3/500 km	4934 m^3/1000 km
Equivalent volume chemical this length pipeline	$	246720.5 m^3/50km	493441 m^3/100 km	986882 m^3/200 km	2467205 m^3/500 km	4934410 m^3/1000 km
Volume rate of LDHI of water	%	0.02	0.02	0.02	0.02	0.02
Volume of chemical needed this length pipeline	$	49.3 litre/50 km	986.9 litre/100 km	1973.8 litre/200 km	4934.4 litre/500 km	9868.8 litre/1000km
Price per litre LDHI	$ (Not in Million)	10.0	10.0	10.0	10.0	10.0
Cost LDHI this length pipeline	$	493.4	987	1973.764	4934.41	9868.82
variable						
Pipeline ($1million/km)		50	100	200	500	1000
Total		**544.4**	**1087.9**	**2184.8**	**5435.4**	**10869.8**

Table 10: Cost Estimate for DEHS

Direct electrical heating system (DEHS)						
All numbers in ($) million		**50 km**	**100 km**	**200 km**	**500 km**	**1000 km**
Overhead				Possible limit for DEHS		
DEHS Extra cost installation	$	1.5	1.5	1.5	1.5	1.5
Installation riser	$	0.8	0.8	0.8	0.8	0.8
Topside equipment	$	1.5	1.5	1.5	1.5	1.5
Cables and relevant equipment	$	7.7	7.7	7.7	7.7	7.7
Variable						
Insulated pipeline	$	50	100	200	500	1000
Power requirement	$	10 kW	20 kW	40 kW	100 kW	200 kW
Price per kW	$	0.05	0.05	0.05	0.05	0.05
Cost of electrical heating (OPEX)	$	0.46	0.92	1.84	4.60	9.20
Total	**$**	**62.01**	**112.47**	**213.39**	**516.15**	**1020.75**

Table 11: Cost Estimate for SINTEF-BP Cold Flow Concept

SINTEF-BP Cold Flow Concept						
All numbers in ($) million		**50 km**	**100 km**	**200 km**	**500 km**	**1000 km**
Overhead						
Reactor Unit	$	19	19	19	19	19
Separator unit	$	21	21	21	21	21
Refrigerated pipeline (10 km)	$	5	5	5	5	5
Liquid flow cooling system	$	21	21	21	21	21
Variable						
Pipeline ($1 million/km)	$	25	50	100	250	500
Total		**91.0**	**116.0**	**166.0**	**316.0**	**566.0**

Table 12: Cost Estimate for Gudmundsson Cold Flow Concept

Gudmundsson Cold Flow Concept						
All numbers in ($) million		**50 km**	**100 km**	**200 km**	**500 km**	**1000 km**
Overhead						
Reactor unit	$	19	19	19	19	19
Separator unit	$	21	21	21	21	21
Refrigerator unit	$	21	21	21	21	21
Liquid flow cooling system	$	21	21	21	21	21
Variable						
Pipeline ($1 million/km)	$	25	50	100	250	500
Total	**$**	**107.0**	**132.0**	**182.0**	**332.0**	**582.0**

Table 13: Cost Estimate for HYDRAFLOW Concept

HYDRAFLOW Concept **All numbers in ($) million**		**50 km**	**100 km**	**200 km**	**500 km**	**1000 km**
Overhead						
Separator		19	19	19	19	19
Storage tank & injection line		1	1	1	1	1
Refrigerated pipeline (10 km)		5	5	5	5	5
Pump		1	1	1	1	1
Not assuming regeneration						
Minimum run-through time	$	1.2 hour	2.3 hour	4.6 hour	11.6 hour	23.1 hour
Equivalent volume chemical this length pipeline	$	123.4 m^3/50km	247 m^3/100 km	493 m^3/200 km	1234 m^3/500 km	2467 m^3/1000 km
Equivalent volume chemical this length pipeline	$	123360.3 litre/50 km	246720.5 litre/100 km	493441 litre/200 km	1233603 litre/500 km	2467205 litre/1000 km
Volume rate of AAs of water	%	0.01	0.01	0.01	0.01	0.01
Volume of chemical needed this length pipeline	$	12.3 litre/50 km	246.7 litre/100km	493.4 litre/200km	1233.6 litre/500 km	2467.2 litre/1000 km
Price per litre AAs	$ (Not in Million)	10.0	10.0	10.0	10.0	10.0
Cost AAs this length pipeline	$	123.4	247	493.441	1233.603	2467.205
Variable Pipeline($1 million/km)	$	25	50	100	250	500
Total		**174.4**	**322.7**	**619.4**	**1509.6**	**2993.2**