

Hydrates Wax Erosion



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1 Introduction

Management of production chemistry issues requires the prediction of system temperature and pressure profiles together with fluid composition and flowing conditions. The same is true for erosion management. Pressure profiles have already been discussed, this next section will analyse temperature prediction in steady state and transient conditions.

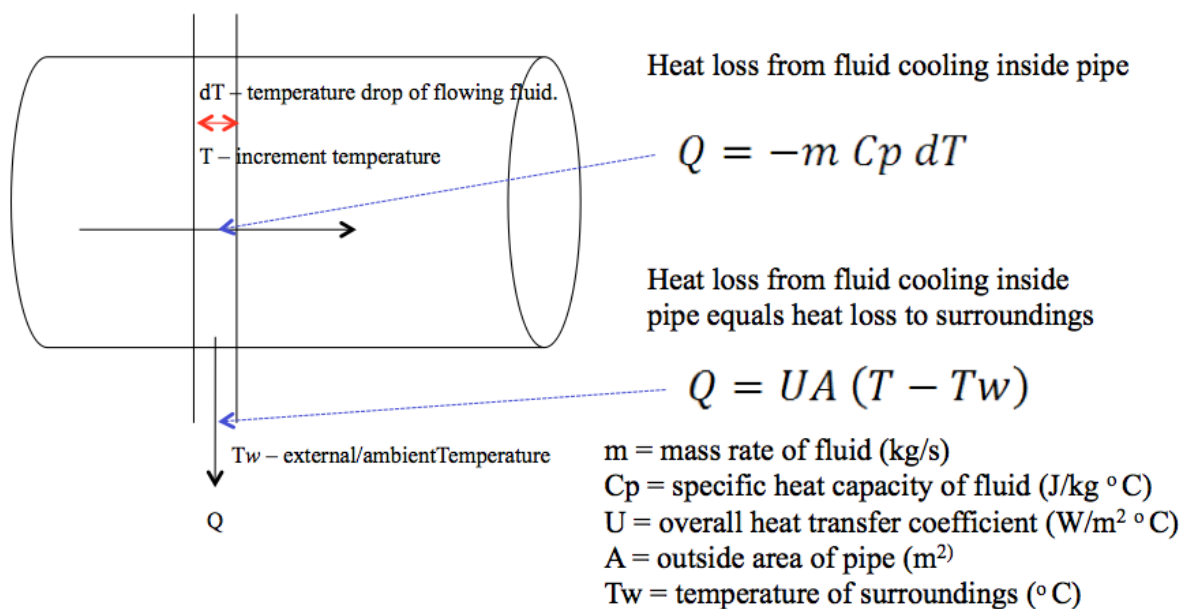
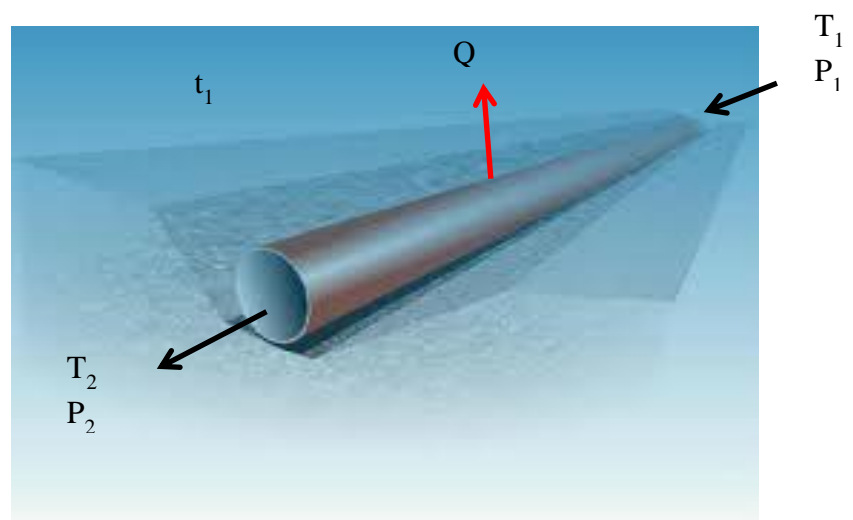
Formation prediction of hydrates, wax and asphaltene is presented. Options for their prediction and control are reviewed.

Erosion is discussed and modelling techniques are also reviewed.

2 Pipeline Heat Balance

A coupled pressure-temperature analysis is required for flow assurance assessments

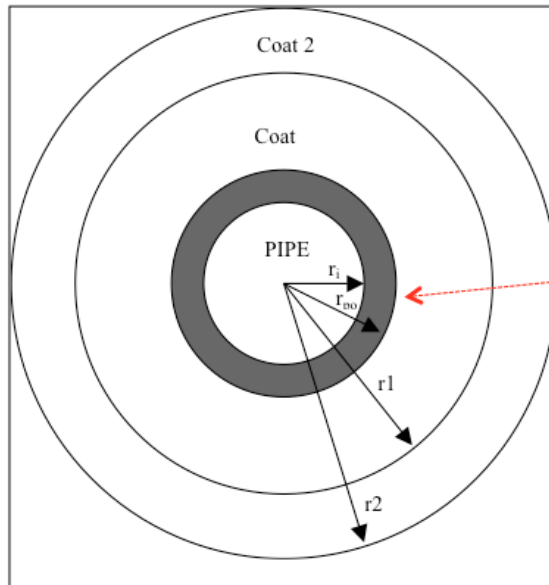
This requires the solution of the complete energy balance. This is usually conducted in an incremental manner solving for P and T.



2.1 Overall Heat Transfer Coefficient, U

The overall heat transfer is calculated as follows.

$$\frac{1}{U} = \frac{r_p}{r_i h_i} + \frac{r_p \ln(r_p / r_i)}{k_p} + \frac{r_p \ln(r_1 / r_p)}{k_1} + \frac{r_p \ln(r_2 / r_1)}{k_2} + \frac{r_p}{r_2 h_a}$$



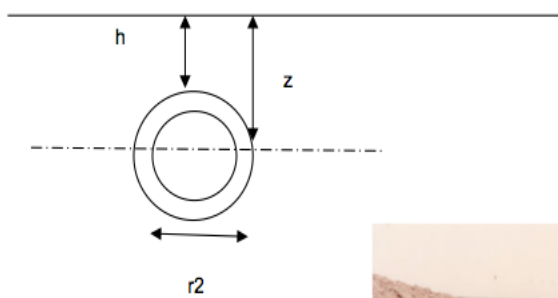
Be careful with reference area for heat transfer. In the above formula the reference area is the outside of the pipe = $r_{po} = r_p$

$$A = \Pi \cdot 2 \cdot r_p \cdot L$$

k – thermal conductivity
 h – film coefficient

Pipeline burial adds an eccentric geometry and is accounted for by a shape factor as follows.

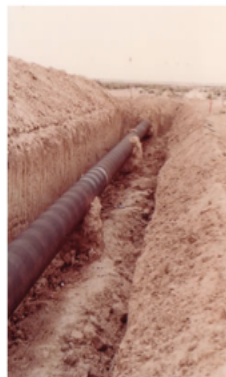
$$\frac{1}{U} = \frac{r_p}{r_i h_i} + \frac{r_p \ln(r_p / r_i)}{k_p} + \frac{r_p \ln(r_1 / r_p)}{k_1} + \frac{r_p \ln(r_2 / r_1)}{k_2} + \frac{r_p}{r_2 h_a}$$



The outside coefficient is given by the following expression which reflects the eccentric nature of the geometry;

$$h_g = \frac{k_g}{r_2 \cdot \cosh^{-1} \left(\frac{z}{r_2} \right)}$$

k_g is the soil thermal conductivity



Analogous with heat transfer within a heat exchanger tube, a log mean temperature difference is used in the heat transfer equation. The film coefficients are calculated using the same as that used in exchanger design.

The log mean temperature difference (ΔT_{lm}) is calculated from the terminal temperature differences: the difference in the fluid temperatures at the inlet and outlet ends of the pipe:

$$\Delta T_{lm} = [(T_1 - t_2) - (T_2 - t_1)] / \ln [(T_1 - t_2)/(T_2 - t_1)]$$

T_1 = inlet inside fluid temperature

T_2 = outlet inside fluid temperature

t_1 = inlet outside temperature

t_2 = outlet outside temperature

For subsea pipelines cooling to the surrounding ambient, $t_1 = t_2$, the seabed temperature.

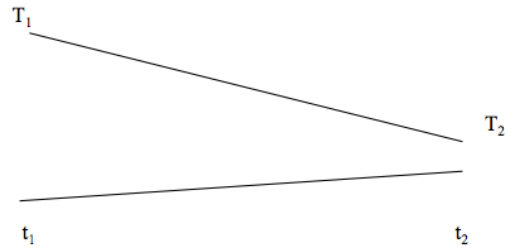
Thus, for a subsea pipeline with a constant ambient temperature;

$$\Delta T_{lm} = (T_1 - T_2) / \ln [(T_1 - t_1)/(T_2 - t_1)]$$

T_1 = inlet inside fluid temperature

T_2 = outlet inside fluid temperature

$t_1 = t_2$ outside ambient temperature



Equating heat loss from pipeline to the heat lost by the mass, m , of internal fluid.

$$m.C_p. (T_1 - T_2) = U.A. \Delta T_{lm}$$

Solving for T_2 , knowing that

$$\Delta T_{lm} = (T_1 - T_2) / \ln [(T_1 - t_1)/(T_2 - t_1)]$$

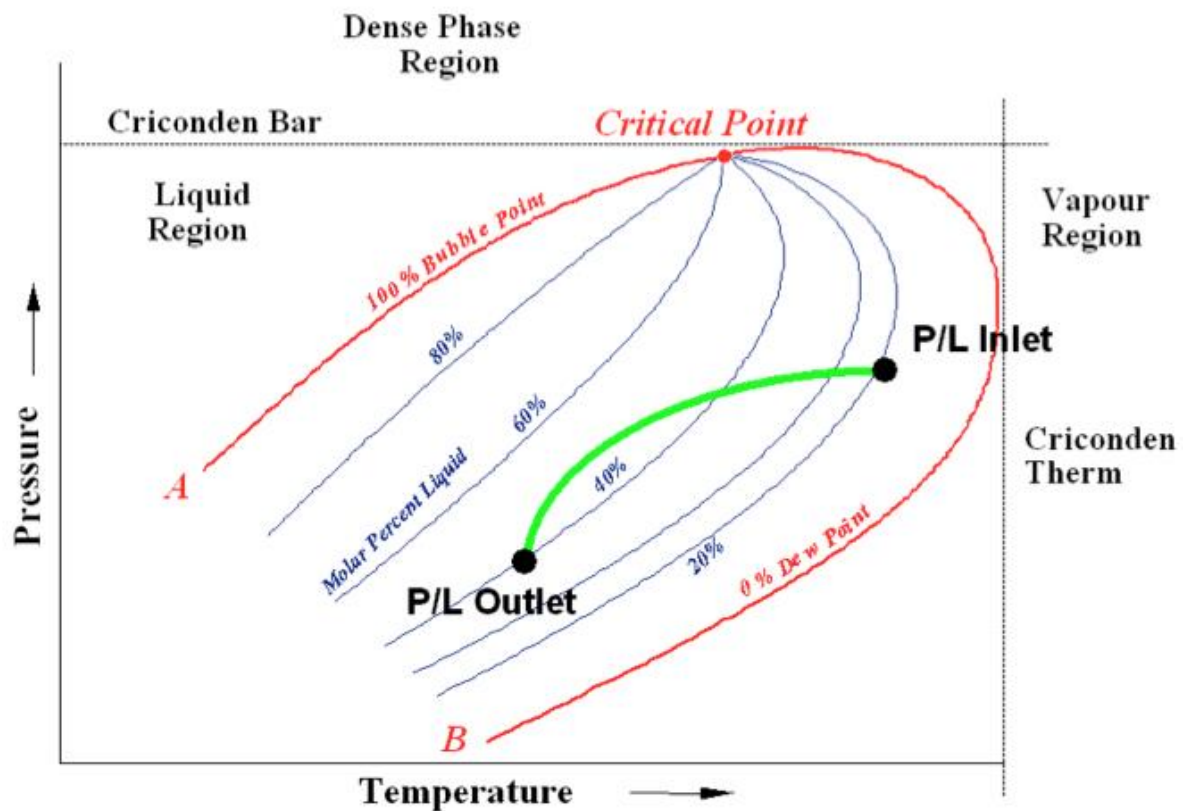
Gives;

$$T_2 = (T_1 - t_1) / (\exp(U.A/m.C_p)) + t_1$$

The above equation can be used to estimate pipeline temperature profiles.

2.2 Phase Behaviour and Physical Properties

The solution of a pipeline pressure and temperature profile requires a further coupling of the energy equation to a phase behaviour and physical property model. As pressure and temperature change, physical properties and liquid to vapour ratios change.



2.3 External Insulation Systems

To retain heat, many pipelines are insulated. The main materials used in the insulation industry consist of polymer materials such as polypropylene, polyurethane and epoxy. These insulation materials come in four main forms as follows:

- Solid
- Blown foam
- Syntactic foam

Solid insulation materials mainly consist of the polymer material on its own in solid form without any reinforcements or modifications to its physical structure. Solid insulation materials are relatively dense compared to other insulation materials; solid polypropylene has a density of approximately 900kg/m³ and is therefore almost neutrally buoyant.

Blown foams are produced by introducing air bubbles into a material. This provides a material with a very low density (typically between 50 and 300 kg/m³). Blown foams are limited by water depth where the compressive force of the liquid head can distort the foam.

Syntactic foams have been specifically developed for deepwater applications. These materials offer the advantage of high strength and low density.

Syntactic foams generally consist of small hollow spherical structures called microspheres incorporated into a solid polymer matrix. It is the microspheres which provide high hydrostatic strength to the polymer.

The most common polymer materials used for thermal insulation are polyurethane (thermoplastic and elastomeric), epoxies (amine or anhydride cured) and polypropylene. Other polymers used include PVC, polyester, rubbers and polystyrene. In addition to polymer foams, a wide range of pipe-in-pipe (PIP) insulation materials have been used including fly-ash, foamed cement, mineral wool, gels, silica gels, aerogels and vacuums.

Insulation systems are provided for subsea structures, flowlines, steel risers, manifolds, wellheads and trees.

The main types of insulation systems can be classified as follows:

- Layer insulation
- Pipe in pipe (PIP) insulation
- Bundle insulation

Note that pipeline burial also achieves a degree of insulation.



2.3.1 Insulation Layer Thermal Conductivity

Thermal conductivity is the key parameter for insulation systems as it dictates the insulation capability of the material. The thermal conductivity progressively decreases from solid to syntactic foam, to blown foam. For example the thermal conductivities of solid polypropylene, syntactic polypropylene and polypropylene foam are typically in the order of 0.22, 0.16 and 0.14-0.18 W/m^{°K}, respectively.

The key role of the insulation designer is to ensure that thermal conductivity requirements are kept throughout the service life. Several factors lead to increases in thermal conductivity during the lifetime of the product. Generally the thermal conductivity of a material increases

with temperature so that it is important for an insulation manufacturer to measure the thermal conductivity of a material at the intended service temperature and account for maximum temperatures to which the system may be exposed. Ingress of water into the material also increases the thermal conductivity.

Material	Btu/hr ft °F	W/m °C
Concrete	1.18	2.04
FBE (fusion bonded epoxy)	0.114	0.2
Coal Tar Enamel	0.114	0.2
Neoprene	0.156	0.27
Polyurethane Foam	0.017	0.03
PVC Foam	0.023 – 0.04	0.04 – 0.7
Syntactic PU	0.07	0.12

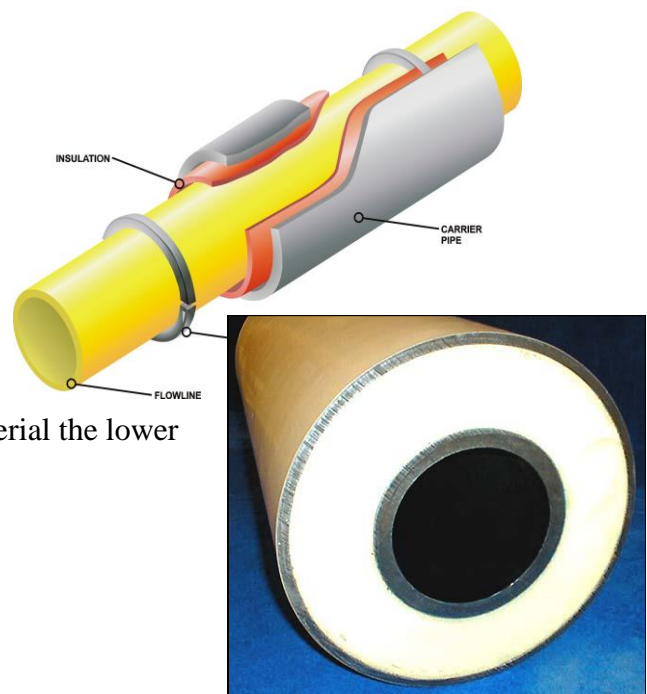
Metal conductivities follow;

Material	Metal Temperature (°C)	Thermal Conductivity (W/m °C)
Aluminium	100	206
Carbon Steel	100	45
12% Cr Stainless Steel	0 - 100	16
Copper	100	378
90/10 CuNi	0 - 100	45
Titanium	0 - 100	16

2.3.2 Pipe in Pipe Insulation

This system comprises of an inner flowline with an outer carrier pipe. The annulus is filled with insulation. The outer pipe provides protection to the insulation from the compressive forces of the surrounding hydrostatic head.

This system provides the highest level of insulation the industry can provide. Clearly the lower the conductivity of the insulating material the lower the heat transfer coefficient.



One material which provides a very low thermal conductivity is an aerogel. Aerogels are among the lightest solid materials known to man. They are created by combining a polymer with a solvent to form a gel, and then removing the liquid from the gel and replacing it with air. Aerogels are extremely porous and very low in density. They are solid to the touch. The material was developed by NASA and has the lowest thermal conductivity of any known substance.

For a highly insulated system such as pipe in pipe the inside and outside convective coefficients are negligible. Heat transfer is dominated by the very low conductivity of the insulating material and the other thermal resistances can be ignored.

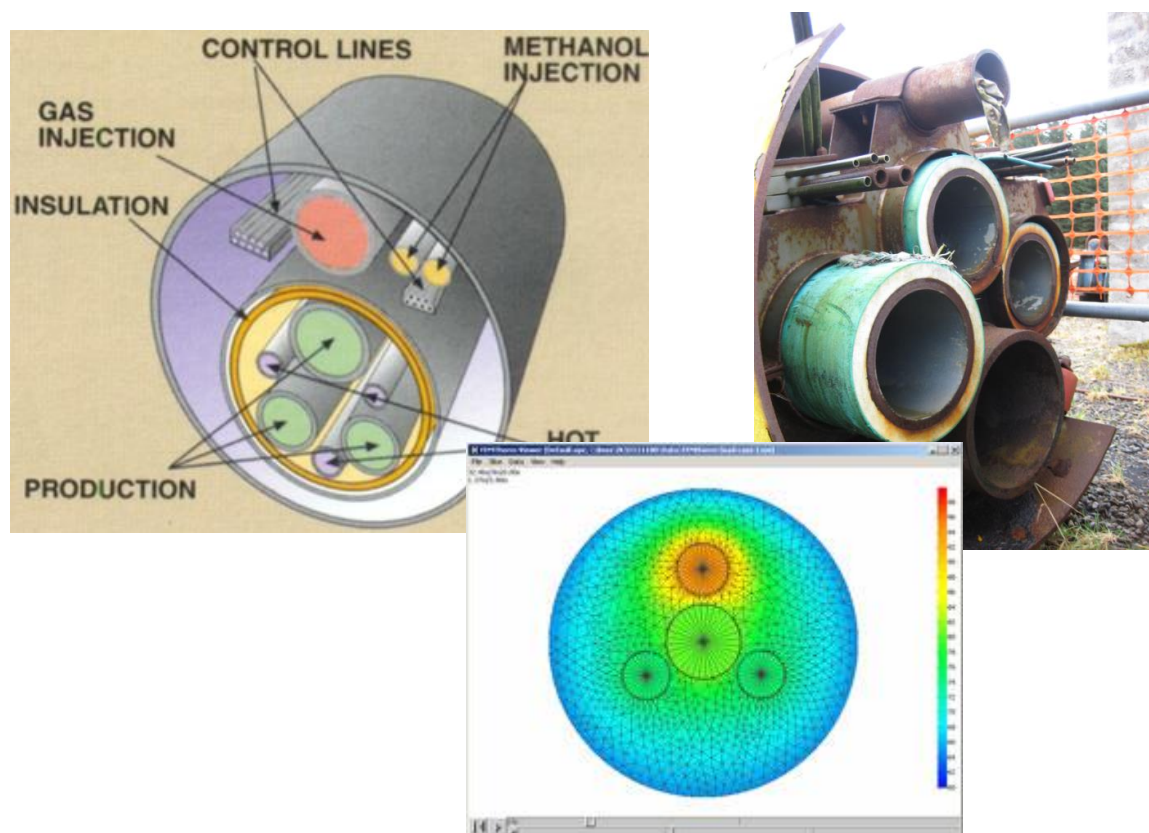
$$\frac{1}{U} = \frac{\cancel{r_p}}{\cancel{r_i h_i}} + \frac{\cancel{r_p \ln(r_i/r_1)}}{\cancel{k_p}} + \frac{r_p \ln(r_1/r_p)}{k_l} + \frac{\cancel{r_p \ln(r_2/r_1)}}{\cancel{k_p}} + \frac{\cancel{r_p}}{\cancel{r_2 h_a}}$$

2.3.3 Bundled Systems

There are two main types of bundles, passive and actively heated bundles.

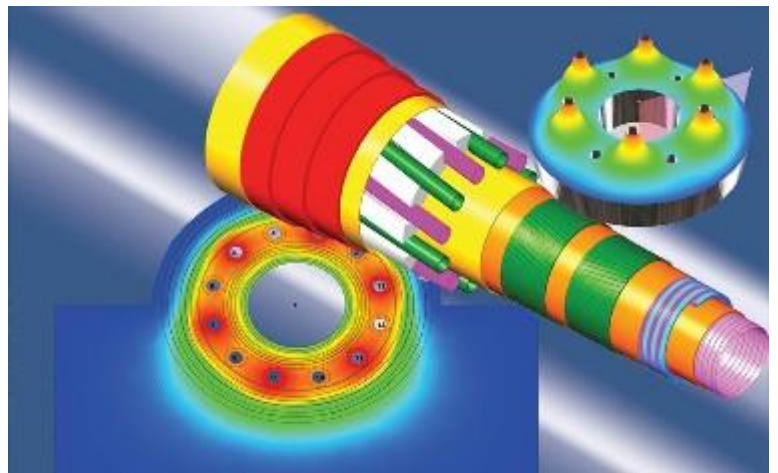
The bundle consists of the flow lines, test lines, gas lift, water injection, methanol/chemical lines and umbilicals together inside of a larger carrier pipe. The void between the pipes can be filled with a heat transfer gel. Furthermore, the bundle contents can be heated by passing a hot fluid through one of the pipes.

Except for the simple pipe-in-pipe, bundles require specialized finite element modelling to accurately simulate the heat transfer in the system, particularly for transient operations such as start-up and shutdown.



Finite element heat transfer (FEHT) was originally designed to facilitate the numerical solution of steady-state and transient two-dimensional conduction heat transfer problems. Many practical conduction heat transfer problems can not be solved analytically. As a result, numerical solutions provide the only feasible way in which these problems can be solved. There are two common approaches: finite-difference and finite-element methods. In both approaches, the governing partial differential conduction equation subject to specified boundary (and for transient problems, initial) conditions is transformed into a system of ordinary differential equations (for transient problems) or algebraic equations (for steady-state problems) which are solved to yield an approximate solution for the temperature distribution. In the finite difference method, spatial discretization of the problem using a set of nodal points followed by application of energy balances and rate equations for each of the discrete segments directly results in a system of equations which are solved to obtain the temperature at each nodal point.

There are numerous commercially available packages for FEHT. In many applications FEHT is coupled with Computational Fluid Dynamics (CFD).



2.3.4 Insulation Temperature Limits

Insulation materials degrade at known temperatures. Typical values are shown.

Material	Max. Temp (°C)
Bitumen	60
Neoprene	100
EPDM	120
Low density PE	70
Medium density PE	85
High density PE	100
PU	80
PUF	80
High Density PUF	80
Syntactic PU	120
PVC	70
PVC Foam	70
Polypropylene	120
Foamed PP	120
Syntactic PP (Carizite)	120

2.3.5 Pipeline Trenching and Backfill

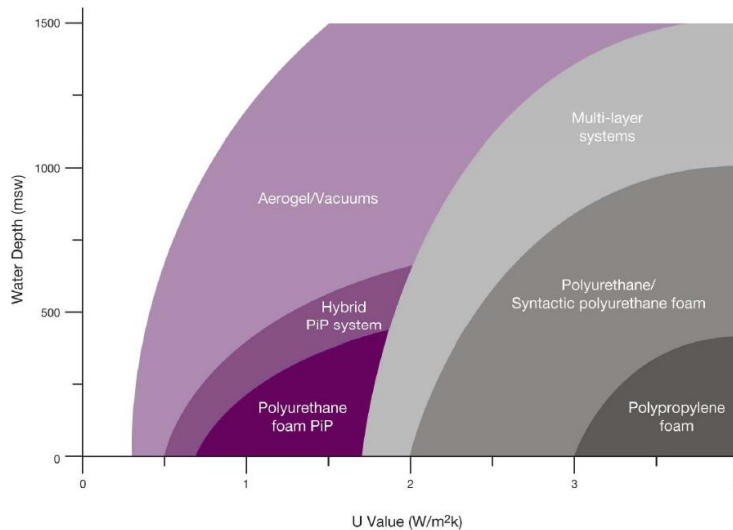
Burial increases insulation levels through the thermal properties of soil.

Note that there are instances reported where backfill has not been effective hence thermal performance can be much poorer than design calculations would suggest.



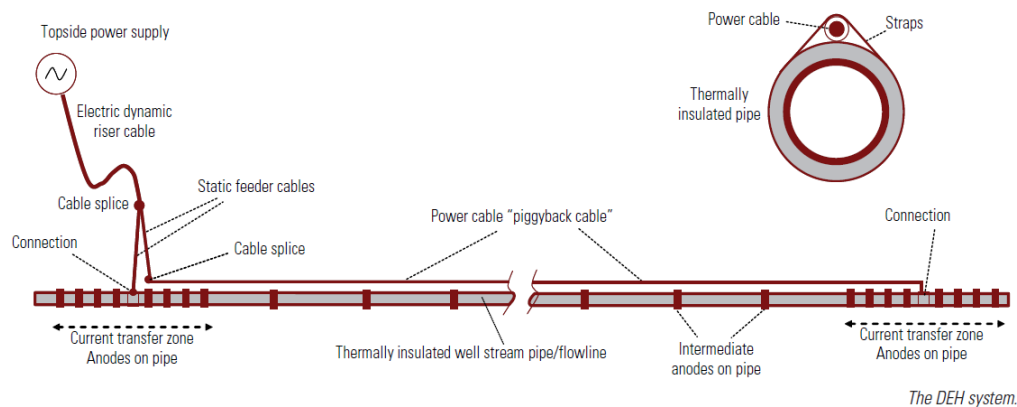
2.3.6 Effect of Water Depth

Increasing water depth makes it more difficult to protect the insulation from the effects of the water head. Typical limits are shown.



2.3.7 Direct Electric Heating

Here an electrical current is passed through the pipe wall and heat is generated by resistive current losses. This allows the pipeline inner wall to be maintained above critical temperatures – hence preventing wax deposition and hydrate formation.



2.3.8 Subsea Cooling

HP/HT (high pressure, high temperature) reservoirs are being produced subsea, here subsea flowing wellhead temperatures of 160 -180 °C can be experienced. Such high temperatures may cause mechanical and material problems such as upheaval buckling. To avoid this the fluids are cooled subsea prior to entering the pipeline.

Note a spool can also be used for pipeline warm up avoiding low temperatures from Joule-Thomson expansion on well start up.

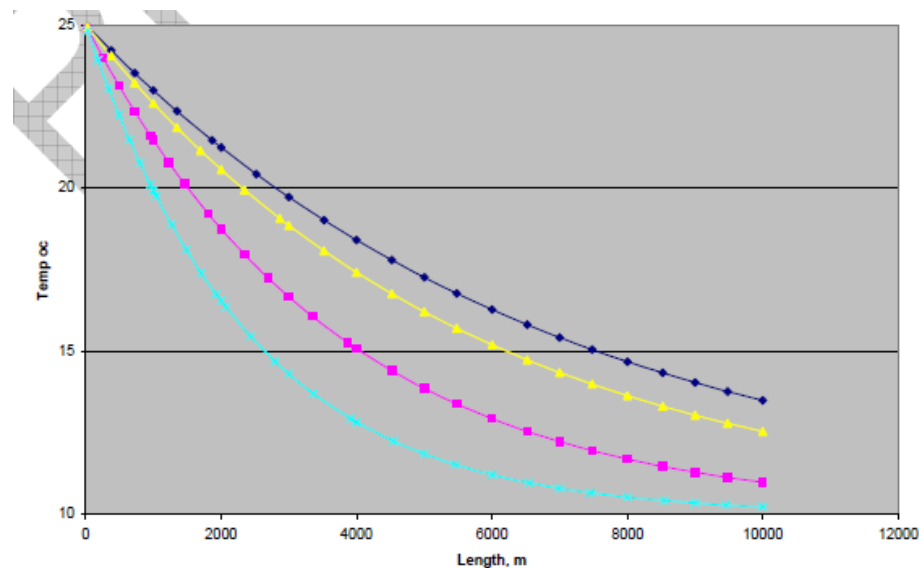
2.3.9 Uninsulated Components

Whilst introducing little temperature drop during steady state flow, uninsulated sections can cause problems when the system is shutdown. The uninsulated section will quickly cool to ambient conditions resulting in local hydrate and wax deposition problems.



2.3.10 Pipeline Thermal Analysis

A steady state analysis will provide information required to identify the insulation level required. A typical analysis of differing insulation levels is shown. Subsea insulation is very costly hence significant effort is expended in thermal analysis. However, it must be emphasized that a steady state analysis alone is NOT sufficient for a final design of the insulation. Transient simulation is essential.



2.3.11 Transient Operations

In addition to the steady state design cases a multi-phase, subsea systems must be assessed against all operating modes. These are;

Rate Changes – a sudden change of rate into a multi-phase pipeline e.g. well start up can cause a surge of liquid at the receiving installation. The increased flow ‘sweeps’ liquid from the pipeline.

Turndown – as flowrates reduce temperatures reduce with production chemistry concerns such as wax and hydrate formation. Fluid velocities will change hence flow patterns can change. Severe slugging is often initiated at reduced rates.

Shutdown – when a pipeline stops flowing it will cool to the ambient conditions. This can result in wax and hydrate concerns. The liquid will also drain to the low points which can be the pre-cursor to instabilities at the next start up.

Start up – the pipeline may have solidified due to wax deposition. If a well is closed it will act as a separator – gas will migrate to the top. The pipeline fed by the wells may for operational reasons have been depressured. When the well is opened up the gas expands into a low pressure system resulting in Joule Thomson cooling. The cold temperatures could prejudice material integrity and also result in hydrate formation.

Blowdown – pressure reduction to avoid hydrate formation.

All of the above operating modes have to be analysed to ensure multi-phase systems can be successfully and safely operated.

Analysis of the aforementioned is usually undertaken using complex dynamic simulators such as OLGA.

3 Hydrates

A hydrate is a physical combination of water and other small molecules to produce a solid. The hydrate has an “ice-like” appearance but possesses a different structure than ice. Their formation in gas and/or NGL systems can plug pipelines, equipment, and instruments, restricting or interrupting flow and create safety concerns.

There are three recognized crystalline structures for such hydrates. In both, water molecules build the lattice and hydrocarbons, nitrogen, CO₂ and H₂S occupy the cavities. Smaller molecules (CH₄, C₂H₆, CO₂, H₂S) stabilize a body-centered cubic called Structure I. Larger molecules (C₃H₈, i-C₄H₁₀, n-C₄H₁₀) form a diamond-lattice called Structure II. Normal paraffin molecules larger than n-C₄H₁₀ do not form Structure I or II hydrates as they are too large to stabilize the lattice. However, some isoparaffins and cycloalkanes larger than pentane are known to form Structure H hydrates.

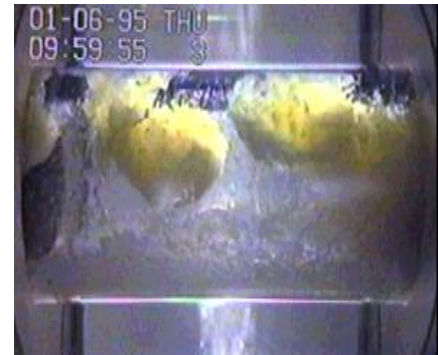
Gas composition determines structure type. Mixed gases will typically form Structure II.

Limiting hydrate numbers (ratio of water molecules to molecules of included gaseous components) are calculated using the size of the gas molecules and the size of the cavities in the H₂O lattice.

From a practical viewpoint, the structure type does not affect the appearance, properties, or problems caused by the hydrate. It can, however, have a significant effect on the pressure and temperature at which hydrates form.

Structure II hydrates are more stable than Structure I. This is why gases containing C_3H_8 and $i-C_4H_{10}$ will form hydrates at higher temperatures than gas mixtures which do not contain these components. The presence of H_2S in natural gas mixtures results in a substantially higher hydrate formation temperature at a given pressure. CO_2 , in general, has a much smaller impact and often reduces the hydrate formation temperature at fixed pressure for a hydrocarbon gas mixture.

The appearance of gas hydrate crystals is similar to that of ice. Individual crystals are transparent (as ice crystals) but agglomerates of hydrate crystals are white (similar to snow, which is a porous agglomerate of small ice crystals). A hydrate deposit which was formed in a system containing water, condensate and gas under conditions of turbulent flow is shown in the left hand figure. Much like wet snow, water-wet hydrate crystals tend to stick to each other forming hydrate accumulations which may eventually block a pipeline. Hydrates can form as chunks of water/hydrate/condensate slush which are carried by the slug of condensate.



3.1 Hydrate Physical Properties

The physical properties of gas hydrates depend on the composition of the hydrate which in turn is determined by the composition of the production stream and the temperature and pressure at which the hydrate is formed. The physical properties of gas hydrates which are formed at specified conditions can be estimated using commercial simulators.

Typically, the density of gas hydrates typically ranges between 900 and 950 kg/m³.

One cubic meter of liquid water will, when combining with gas to form hydrates, result in the formation of around 1.2 m³ of hydrates.

Characteristic properties of hydrates are low thermal conductivity and large heats of dissociation i.e. the amount of energy required to transform solid hydrates to vapour.

Approximately 450-500 kJ of heat is needed to dissociate 1 kg of hydrates into liquid water and gas at atmospheric pressure and zero degrees centigrade. This is approximately 1.5 times the heat required to convert ice into liquid water.

The thermal conductivity of gas hydrates is approximately 0.5 W/Km, which is one quarter of the thermal conductivity of ice.

There are 140 molecules of methane per 860 molecules of water in a methane hydrate.

From this information we can determine the volume of gas in the methane hydrate.

1 m³ of hydrate has a mass of 913 kg. Converting this to moles $913/17.74 = 51.45$ kmole of hydrate, of which 7.257 kmoles are methane. The ideal gas law can be used to calculate the volume of gas when expanded to standard conditions (15°C and 1 atm or 101.325 kPa)

$$V = nRT/P = (7.257)(8.314)(15+273)/101.325 = 171.5 \text{ Sm}^3$$

Consider a solid hydrate being heated – this process will liberate a significant amount of gas which could be very hazardous.

3.2 Hydrate Formation and Dissociation

The three main conditions required for hydrate formation in offshore pipelines and processes are:

- a) Free water and natural gas are needed. Gas molecules ranging in size from methane to butane are typical hydrate components, including CO₂ and H₂S. The water in hydrates can come from free water produced from the reservoir, or from water condensed by cooling the gas phase.
- b) Cold temperatures. The system temperature need not be below 0 °C for hydrates to occur. The ocean bottom temperature is remarkably uniform 2-4 °C. Pipelined gas and oil readily cools to this temperature within a few miles of the wellhead in an uninsulated system. Hydrates form readily at 2-4 °C at high pressure.
- c) High pressures. At 2-4 °C, common natural gases form hydrates at pressures as low as 7 bara; at 100 bara, common gases form hydrates at 18 -20 °C. Since pipelines typically operate at higher pressures, hydrate prevention will clearly be a primary consideration in developing an appropriate subsea architecture.

Unlike ice, hydrates can form at much higher temperatures than 0 °C.

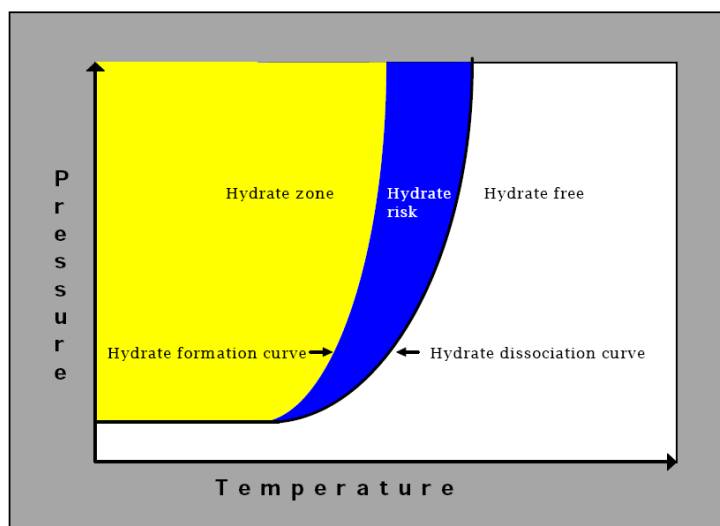
Note that hydrate blockages can occur very rapidly. Transient operations such as start-up, shutdown and blowdown are very susceptible to hydrate blockages because this is often when the production system conditions are likely to drop into the hydrate formation region.

The hydrate dissociation temperature is defined as the highest temperature at which thermodynamically stable hydrates can exist in a system of known composition and at a given pressure. In general, the higher the pressure, the higher the temperature at which stable hydrates can exist. A plot of the hydrate dissociation temperature versus the pressure is called a hydrate equilibrium curve. All predictive methods calculate hydrate dissociation temperatures, not hydrate formation temperatures. The hydrate dissociation temperature is a well-defined thermodynamic entity.

The hydrate formation temperature is quoted as being a sharply defined temperature at which hydrates will actually form when a system gradually cools from a temperature above the hydrate dissociation temperature to a temperature below the hydrate dissociation temperature. When a system enters the hydrate region because of gradual cooling (either at fixed pressure or at fixed volume), the first hydrates do not usually form as soon as the hydrate dissociation temperature is reached. On the contrary, hydrates usually form at lower temperatures. This results from the time required to form the first stable hydrate crystals. The difference between the hydrate formation temperature and dissociation temperature is difficult to quantify and is system specific. It will depend upon the rate of cooling, the degree of turbulence and the presence of crystal nucleation sites.

Although it is known that some systems operate within the hydrate region without hydrate plugs forming there are no models which can predict this with any degree of confidence.

Hence most flow assurance engineers will utilise the hydrate dissociation temperature as the basis for the system design.



3.3 Hydrate Prediction

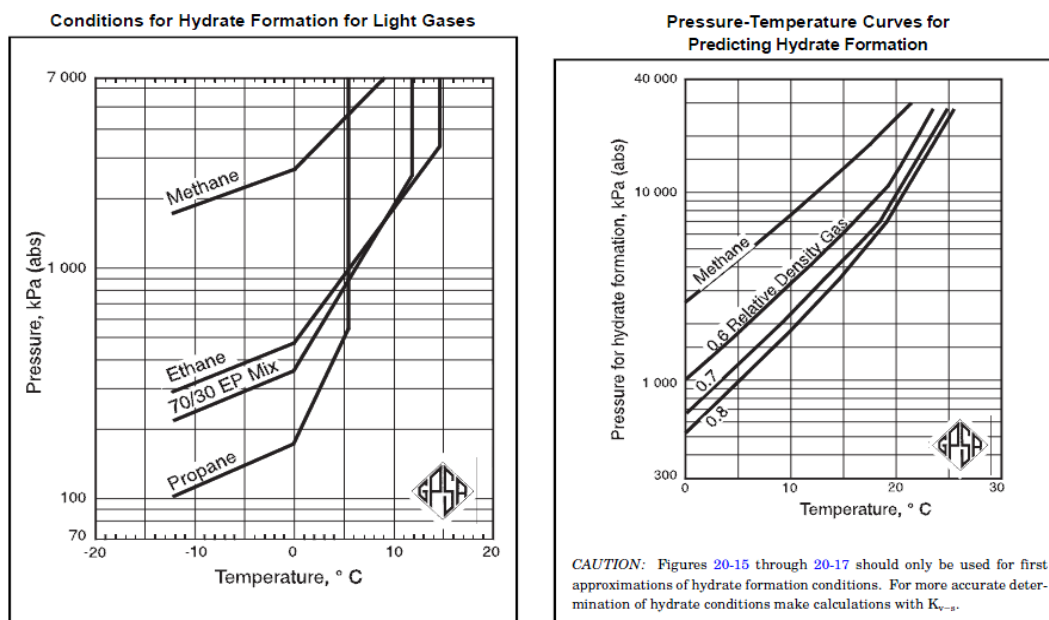
The region of hydrate risk represents an area where hydrates may form but due to slow nucleation may not represent a risk. This area is very difficult to predict.

Hydrate formation conditions can be estimated by the following methods;

- Hydrate Curves
- Equilibrium calculations using K values – similar to previous dew point calculations
- Equations of state

3.3.1 Hydrate Curves

Use of hydrate curves produced for example by GPSA can be used as a first estimation.



Recall - relative gas density is the gas molecular weight/ molecular weight of air (29)

Heavier hydrocarbon gases, such as ethane, propane, butane lower the pressure at which hydrates will form for a given temperature.

For example, at 1000 psia (69 bar), the hydrate formation temperature of pure methane is about 48°F (9°C). By adding 1% ethane and 1% propane to the mixture, the hydrate formation temperature increases to 57°F (14°C).

3.3.2 Hydrate K Factors

The Katz K value method utilises vapour solid equilibrium constants;

$$K_{vs} = y/x_s$$

K_{vs} is the vapour solid constant

x_s is the composition of the species in the solid hydrate

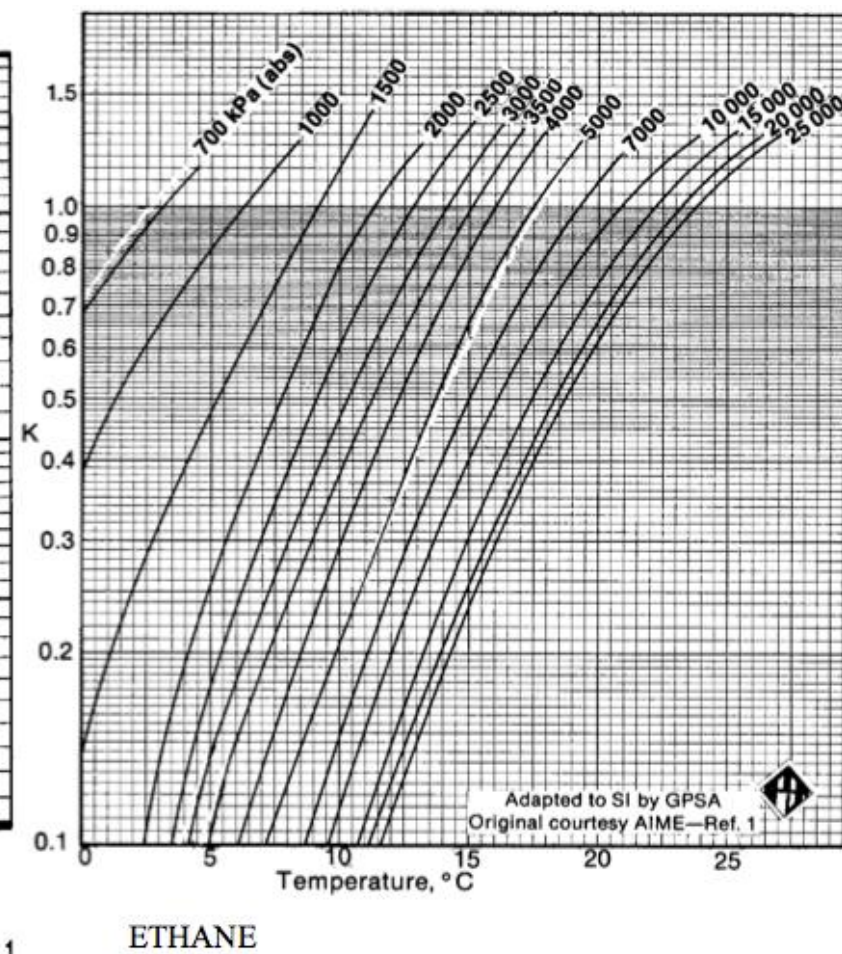
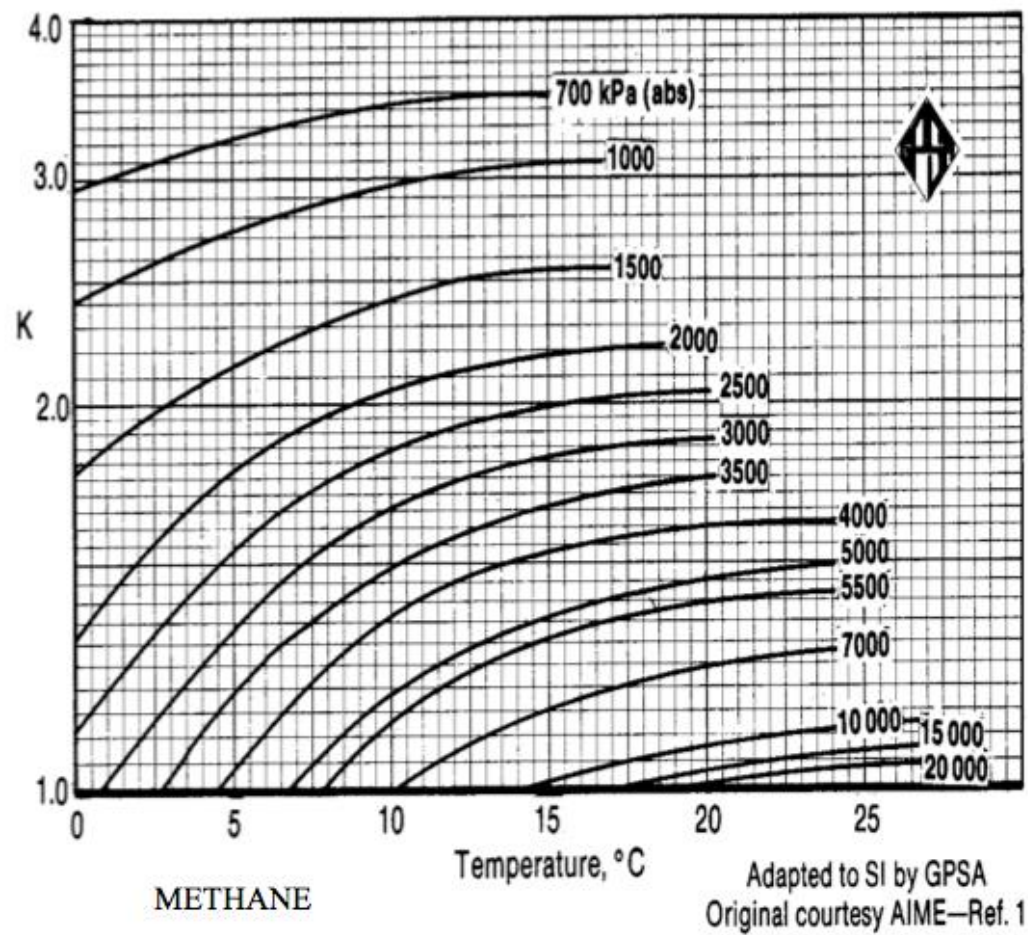
y is the composition of the species in the gas in equilibrium with the hydrate

The K_{vs} values are used in a “dewpoint” equation to determine the hydrate temperature or pressure. The calculation is similar to a conventional dewpoint calculation and is iterative until convergence is achieved when the following objective is satisfied;

$$\sum_{i=1}^{i=n} \left(\frac{y}{K_{vs}} \right) = 1$$

For calculation purposes, all molecules too large to form hydrates have a K-value of infinity. These include all normal paraffin hydrocarbon molecules larger than normal butane. Nitrogen is assumed to be a non-hydrate former and is also assigned a K-value of infinity. Prudence should be exercised when some higher molecular weight isoparaffins and certain cycloalkanes are present as they can form Structure H hydrates.

K value charts from GPSA are shown.



Example

Calculate the pressure for hydrate formation at 10 Deg C for a gas with the following composition.

Component	Mole Fraction in Gas	2070 kPa (abs)		2760 kPa (abs)	
		K_{vs}	y/K_{vs}	K_{vs}	y/K_{vs}
Methane	0.784	2.04	0.384	1.75	0.448
Ethane	0.060	0.79	0.076	0.50	0.120
Propane	0.036	0.113	0.319	0.072	0.500
Isobutane	0.005	0.046	0.109	0.027	0.185
n-Butane	0.019	0.21	0.090	0.21	0.090
Nitrogen	0.094	*	0.000	*	0.000
Carbon dioxide	0.002	3.0	0.001	1.9	0.001
Total	1.000		0.979		1.344

* Infinity Interpolating linearly, $\Sigma y/K_{vs} = 1.0$ at 2100 kPa (abs)

The experimentally observed hydrate-formation pressure at 10°C was 2240 kPa (abs).

3.3.3 Equations of State

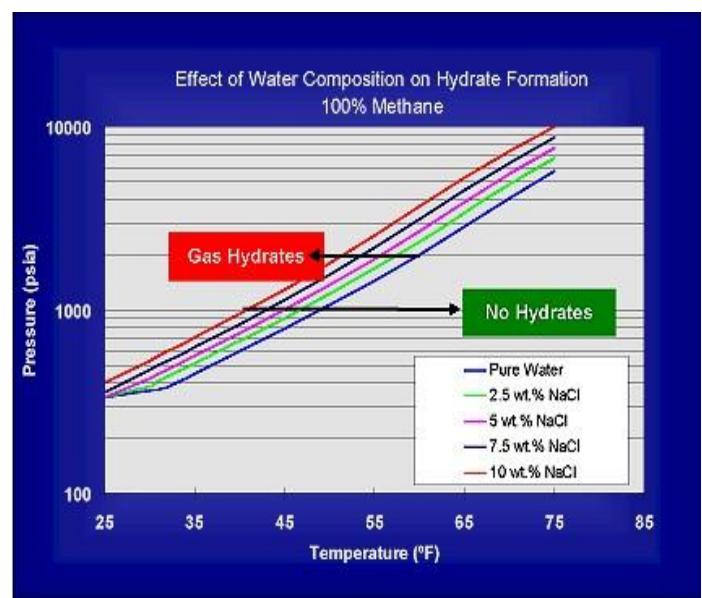
Most modern methods are based upon the work of Van der Waals and Platteeuw. This model assumes that firstly liquid water solidifies to form an empty hydrate lattice. This is followed by gas molecules being adsorbed into the lattice. Peng Robinson and CPA (cubic plus association) models are widely used for hydrate prediction.

3.4 Hydrate Inhibition

Hydrate inhibition was covered in Gas Treatment where alcohols such as methanol and glycol will suppress hydrate formation. Suppression can be predicted using Hammerschmidt or more accurately using commercial simulators such Aspen Hysys.

3.4.1 Salt Inhibition

Salts inhibit hydrate formation in the same manner that salt depresses the freezing point of pure water - salting winter roads. Hence a produced water analysis will allow a less conservative estimate of the hydrate formation conditions. Standard hydrate



prediction models can be used to establish the effect of salts.

3.5 Hydrate Management

There are generally three prevention methods:

1. Water removal

Free water is removed through separation, and water dissolved in the gas is removed by drying with tri-ethylene.

Glycol or a molecular sieve to obtain water contents which are sufficiently low to prevent water from condensing as the pipeline contents cool. Clearly this option would not be possible for a subsea development where unprocessed reservoir fluids are transported to a host installation.

2. Maintaining high temperatures

High reservoir fluid temperature may be retained through insulation and pipe bundling, or additional heat may be input via hot fluids or electrical heating.

3. Addition of hydrate inhibition chemicals

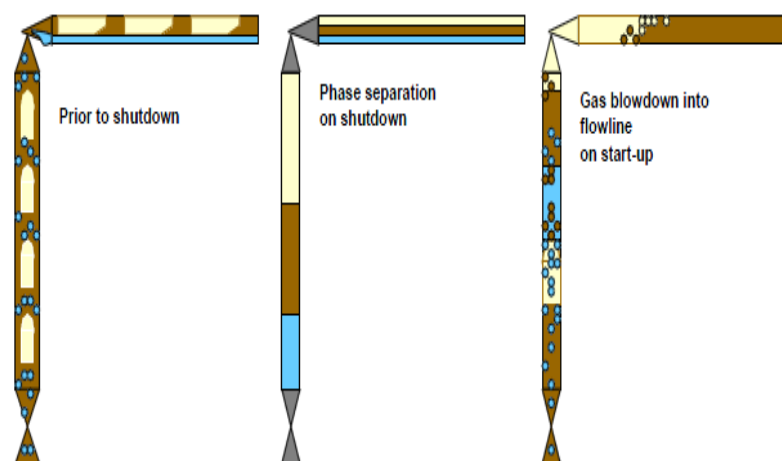
Chemicals such as methanol (MeOH), mono-ethylene glycol (MEG) or Threshold Hydrate Inhibitors (THI) can added. These chemicals suppress the formation of hydrates or prevent hydrates forming blockages.

A particular concern is on well start up where a high pressure gas pocket may be present at the top of a well. The expansion

of high pressure gas across a subsea choke valve can lead to cold downstream temperatures due to Joule Thomson expansion.

Methanol or glycol is therefore often injected upstream of subsea choke valves. Gas expansion across a valve follows an isenthalpic path. Gas expansion can result in choke downstream

temperatures considerable below the surrounding sea temperature. Low Temperatures can result in ice and hydrate formation. Methanol is frequently injected at start up to prevent hydrate where appropriate.



3.5.1 Methanol Inhibition

Methanol has the following advantages.

- Easily vaporised into the gas phase so methanol condenses when free water condenses.
- Used for removing flowline and topside plugs.
- Methanol depresses the hydrate formation temperature more than glycol per unit mass so it is often preferred over glycol.
- Easier to recover from salty solutions.

Disadvantages are;

- High losses into the vapour and condensate phase.
- The loss of methanol to the vapour and condensate phase should be taken into account when calculating required injection rates.
- Reduced price for hydrocarbon liquids if contaminated with methanol.

3.5.2 Mono Ethylene Glycol (MEG)

Advantages

- Low volatility into the gas and condensate phases – less losses.
- Less hazardous.

Disadvantages

- High viscosity inhibits flow in umbilicals and injection lines.
- Possibility of salt precipitation and fouling.
- Remains in the aqueous phase.
- Glycol has a transportability problem because it does not vaporise, it is viscous, and tends to accumulate at the bottom of the pipe.

The final selection will be a balance between cost, operability and safety.

3.6 Threshold Hydrate Inhibitors (THI)

These are inhibitors developed over the past decade. There are three general classes of THI - threshold hydrate inhibitors.

3.6.1 Kinetic Inhibitors

Kinetic inhibitors prevent hydrate crystal nucleation and growth without emulsifying water into the hydrocarbon phase. Prevention of nucleation prevents hydrate crystals from growing to a critical radius. Growth inhibition maintains hydrates as small crystals, inhibiting progress to larger crystals. Kinetic inhibitors are commonly polymers. Each of the chemicals has a polyethylene backbone, connected to pendant groups typically containing an amide ($-N-C=O$)

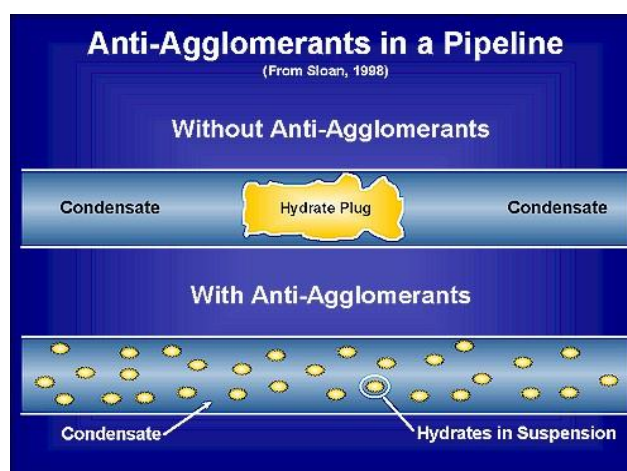
linkage, frequently within a five or seven member ring. As the inhibitor adsorbs on the hydrate crystal, the pendant group penetrates specific sites (cages) of the hydrate crystal surface while the polymer backbone extends along the surface. In order to continue growing, the crystal must grow around the polymer; otherwise the crystal growth is blocked. Typically the measure of the effectiveness of the kinetic inhibitor is the degree of subcooling a system can operate without forming hydrates. Subcooling (ΔT) is the measure of the lowest temperature that the system can be operated relative to the hydrate formation temperature at a given pressure. The degree of subcooling appears to be pressure independent; however, it is a function of the type of polymer, molecular weight of the polymer and the amount of salt, glycol, and alcohol present. Typically 12°C can be achieved – note methanol can achieve much higher suppression levels.

It should also be noted that there is a time effect associated with KHIs where their effect reduces with time.

3.6.2 Emulsion Additives (Slurry Additives or Anti-Agglomerates)

The figure shows a schematic of the method by which anti-agglomerants prevent hydrate plugs. In the top pipeline, hydrates form a large mass and can grow to a sufficient size to plug the pipeline.

In the second pipeline, an emulsification additive has been introduced to the system to cause the water to be suspended as small droplets in the condensate. While hydrates still form in this situation, the hydrates are prevented from



agglomerating to larger hydrate masses capable of plugging a pipeline. Emulsification additives are particularly effective in preventing hydrate plugs or flow stoppages during shut-ins, with subsequent cooling and restarting issues.

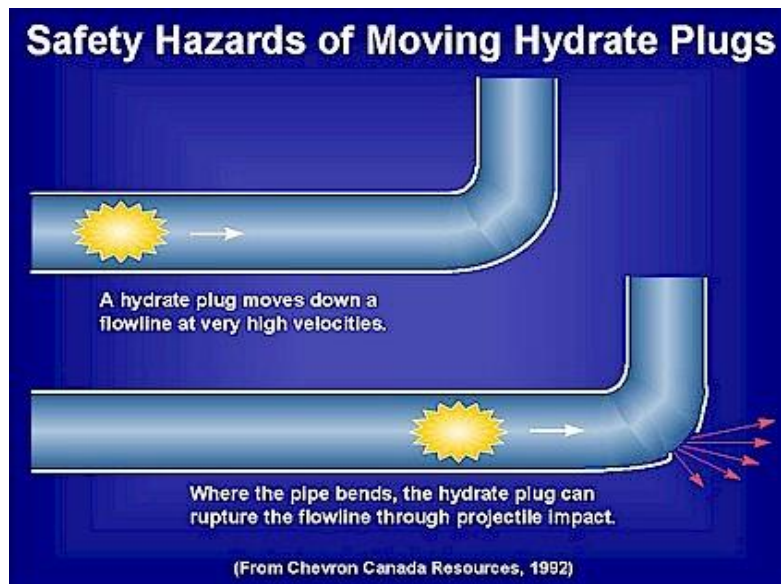
Anti-agglomerates are surfactant molecules which have one end that is water-attractive and one end that is oil-attractive. In conditions with excess oil (a water-to-oil ratio of less than 40:60), a surfactant causes the water phase to be suspended as emulsified droplets. At higher water cuts, the emulsion may be reversed and water will be the external water phase, thus eliminating the effectiveness of the anti-agglomerant.

3.6.3 Crystal Growth Inhibitors

These operate at the crystal surface to limit the hydrate crystal size. This is in contrast to emulsion additives which attempt to limit crystal size by entraining water in the liquid organic phase. The growth inhibitors result in a mass of small hydrate crystals dispersed in the dense hydrocarbon phase.

3.7 Hydrate Safety Issues

Hydrate formation in a production system can result in serious, and sometimes fatal, accidents. Hydrates have densities like ice. A dislodged hydrate plug can be a projectile. The projectile can cause failure at a pipeline constriction (valve or orifice) or at a sharp change in direction (bend, elbow, or tee).

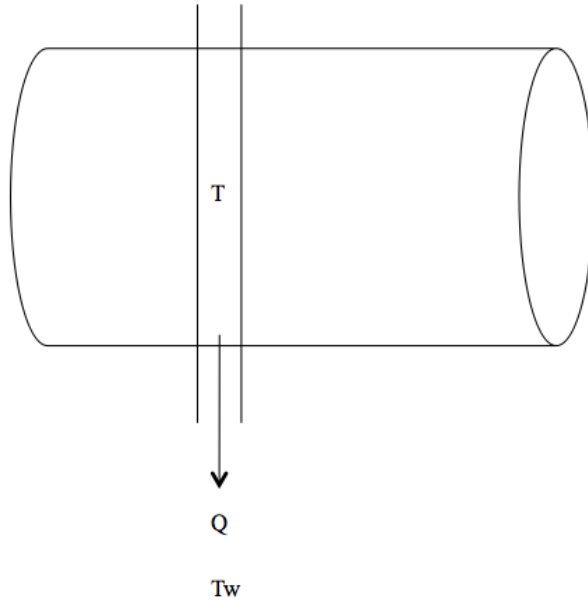


A hydrate plug can be as effective as a closed valve in blocking flow. A trapped hydrate can present a hazard if it is heated and the light gases trapped in the lattice are released. If the released gases have no place to expand into the pressure will rise which could lead to a pipe failure.

3.8 Survival Time to Hydrate

Insulation will allow a flowing pipeline to be operated outside the hydrate formation region. However if the flow is stopped then the fluids within the line will begin cool and the pipeline pressure will settle out at a pressure between the flowing inlet and outlet pressure. The pipeline temperature will in time drop to the local ambient when flow ceases. The pipeline contents are then at risk to hydrate formation. The time taken to reach hydrates – the survival time - can be a key factor in determining the pipeline insulation level.

Survival times can be estimated using a transient heat balance.



Heat lost by fluid cooling in pipe;

$$Q = -m C_p dT/dt$$

m = mass of in segment

C_p = specific heat capacity of fluid (J/kg °C)

U = overall heat transfer coefficient (W/m² °C)

A = outside area of pipe (m²)

T = temperature of fluid inside the pipe (°C)

T_w = temperature of surroundings (°C)

Heat loss to surroundings;

$$Q = UA (T - T_w)$$

Equating;

$$\int \frac{-UA}{mC_p} dt = \int \frac{dT}{T - T_w}$$

Integrating gives;

$$T = T_w + (T_i - T_w) e^{-\frac{UA}{mC_p}t}$$

where;

m = mass of fluid within segment (kg)

C_p = specific heat capacity of fluid (J/kg °C)

U = overall heat transfer coefficient (W/m² °C)

A = outside area of pipe (m²)

T_w = Temperature of surroundings (°C)

T_i = initial average temperature of pipeline fluids at time zero (°C)

T = Temperature at time t

t = times (s)

In a cooldown instance, the pipeline fluid is static hence the heat transfer from the internal fluid to the cooler pipe wall will be controlled by natural convection. For natural convection the Nusselt number is correlated to Rayleigh's Number.

$$Nu = 0.55Ra^{0.25}$$

$$Ra = g\beta\Delta TL^3/(\nu\alpha)$$

$$Nu = hiD/k$$

Where;

h_i = film coefficient for fluid in pipe, W/m²°C

β = coefficient of thermal expansion (1/°K)

α = thermal diffusivity (m²/s) = $k/(\rho \cdot C_p)$

ν = kinematic viscosity (m²/s) = μ/ρ

g = gravity = 9.81 m/s²

L = Characteristic length – diameter (m)

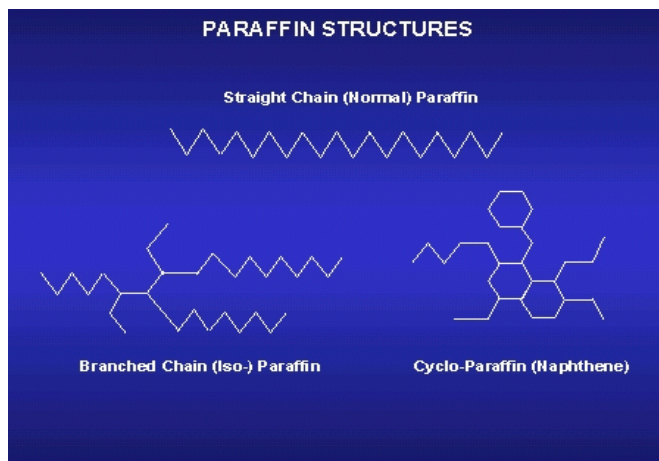
ΔT = temperature of fluid – external ambient (°K)

D = pipeline diameter (m)

Should cooling continue into the hydrate region the pipeline operator is likely to depressurise the pipeline to avoid hydrate formation. This may be at the expense of the associated gas flaring requirement.

4 Wax

Wax is not a single compound but a range of high molecular weight paraffins (C17+) that solidify from crude oil. Waxes consist of straight chain, normal paraffins or may be branched or cyclic paraffins. The temperature where the first crystals occur is called the Cloud Point or Wax Appearance Temperature (WAT) of the crude oil. At the WAT only a tiny fraction of waxes crystallise; however, as the temperature continues to drop, more and more waxes crystallise.



The primary factor affecting wax crystallisation is temperature, pressure effects are secondary. Light ends (propane, butane etc.) act as solvent for waxes and are at their highest concentration in the crude oil at the bubble or saturation point, consequently the WAT is lowest at the bubble point. Below the bubble point, light ends are removed from the liquid phase as the pressure drops, therefore the WAT increases as the pressure decreases below the bubble point.

The wax content defines the weight percent of wax in a crude sample.

Wax content as a function of temperature can be obtained via filtration, NMR (Nuclear Magnetic Resonance) or inferred from the DSC (Differential Scanning Calorimetry)

Crude Oil	Wax Content (wt percent)
Beatrice	17
Forties	6
Indonesia	30
Gulf of Mexico	2-4

The wax content is only useful as a guide for comparing different crude oils, e.g. highly waxy crudes with wax contents of over 10% are likely to be more viscous and to suffer from restart problems. Crudes such as Beatrice in the North Sea and many Indonesian and Chinese crudes fall into this category.

Crudes with low wax contents are less likely to suffer flow problems, however, even crudes with wax contents of less than 1% wax have been known to cause blockages via wax depositing on pipe walls.

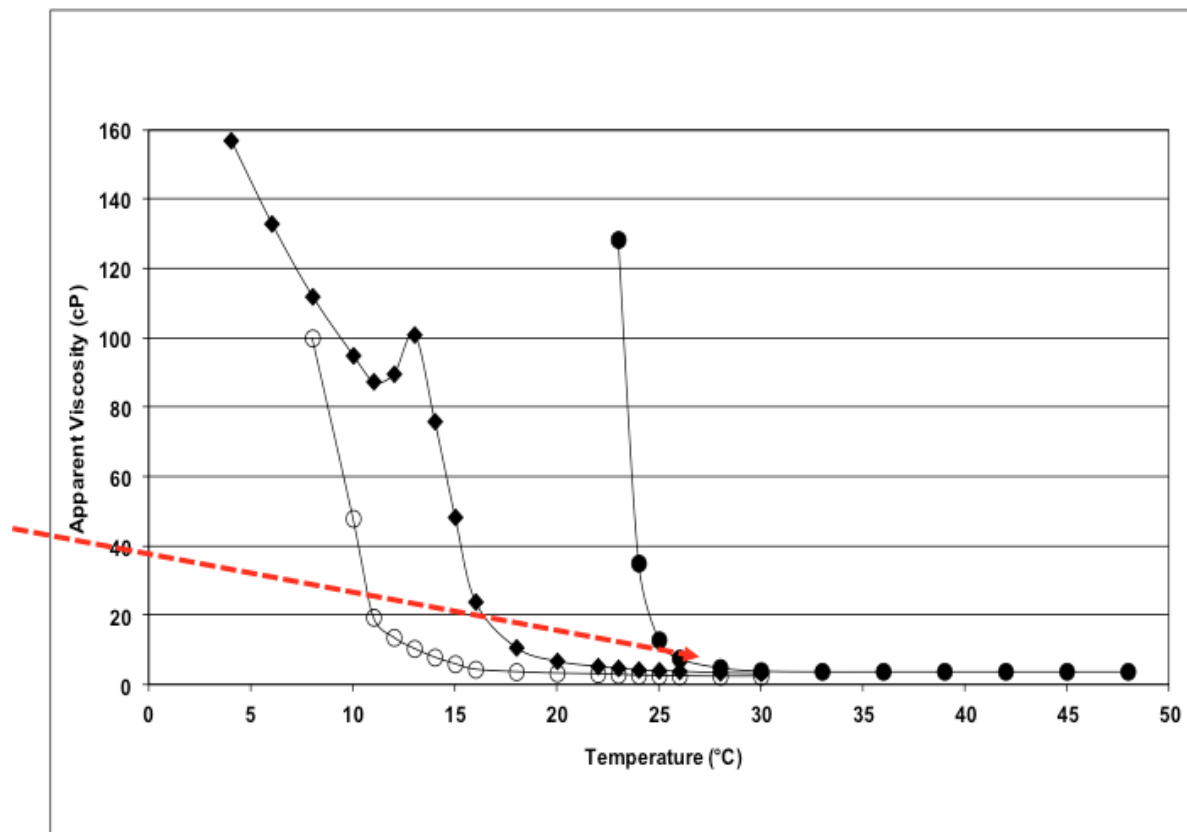
Wax deposits will reduce flow area and in the extreme can plug a pipeline.

4.1 Wax Appearance Temperature (WAT)

As stated the cloud point or Wax Appearance Temperature (WAT) is the temperature at which the first waxes crystallise from the crude oil. As soon as the pipe wall temperature drops below the WAT, wax can deposit on pipe walls even though the bulk fluid temperature is still higher than the WAT. The WAT can be used along with production profiles and thermal modelling of the production scenarios to determine if, when and where waxes may cause operational problems.

When the fluid temperature falls below the wax appearance temperature the fluid viscosity will generally increase due to the nature of the wax crystals.

Viscosity is often used as a surrogate for determining the wax appearance temperature; when crystals of wax form the viscosity rises.



4.2 Pour Point

Oil at a temperature significantly below its Wax Appearance Temperature (WAT), can lead to wax crystals interacting to form a matrix structure – a solid or gel.

Under static conditions, the structure may eventually extend throughout the entire pipeline, gelling the crude oil. Once this occurs, the crude is said to be below its Pour Point.

The Pour Point is defined as the lowest temperature at which the oil can be poured under force of gravity.



If a pipeline is shutdown and the fluid cools to below the pour point, a semi-solid gel will form which requires an initial yield force to be applied before the gel structure breaks and the fluid begins to flow. This is known as the gel strength or breakaway yield stress (BAYS).

The gel strength (or yield stress) is the force required to break down the wax structure formed below the pour point and typically determines the differential or pumping pressure required to re-establish flow in a gelled system. The temperature of fluids before shutdown and final fluid temperature may all be significant in impacting the amount of precipitated wax, the gel structure and the gel strength. The gel strength is typically expressed in terms of the pressure per unit length required to restart flow.

Gelled fluid poses different design and operational problems as many gels exhibit non-Newtonian behaviour. They tend to be shear thinning, meaning that the viscosity reduces as shear is applied.

In pipeline situations the application of a pressure differential (which will vary for different systems) is required to mobilise the fluid. This can be limiting if for example the wellhead pressure is not sufficient to mobilise the gel. Gel strength could be a very serious issue and in the extreme may prevent the field from being developed.

For a waxy crude sample, the Breakaway Yield Stress, measured in pa or psi, is a means of estimating the pressure driving force required to restart a line filled with the crude. The BAYS is usually obtained from laboratory experiments.

It is given by the following equation:

$$\tau = D \cdot \Delta P / (4 \cdot L)$$

Where;

τ = yield stress (pa)

D = pipeline diameter (m)

ΔP = differential pressure (pa)

L = pipeline length (m)

As an example, wax breakaway yield stress is measured as 5Mpa, for a 100 km long, 0.3m diameter pipeline. The required pressure differential to break the gel would be;

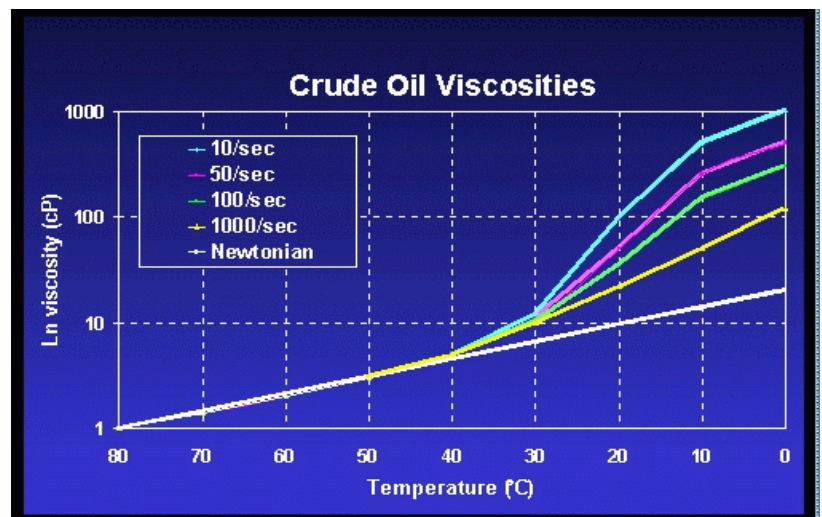
$$5 \times 4 \times 100000 / (0.3 \times 1000) = 67 \text{ bar.}$$

Should the system not have the ability to provide a 67 bar differential then the wax plug will remain and prevent production.

4.3 Viscosity Effects

Viscosity is a vital parameter for predicting pipeline pressure drops and consequently, for designing and sizing pipeline systems.

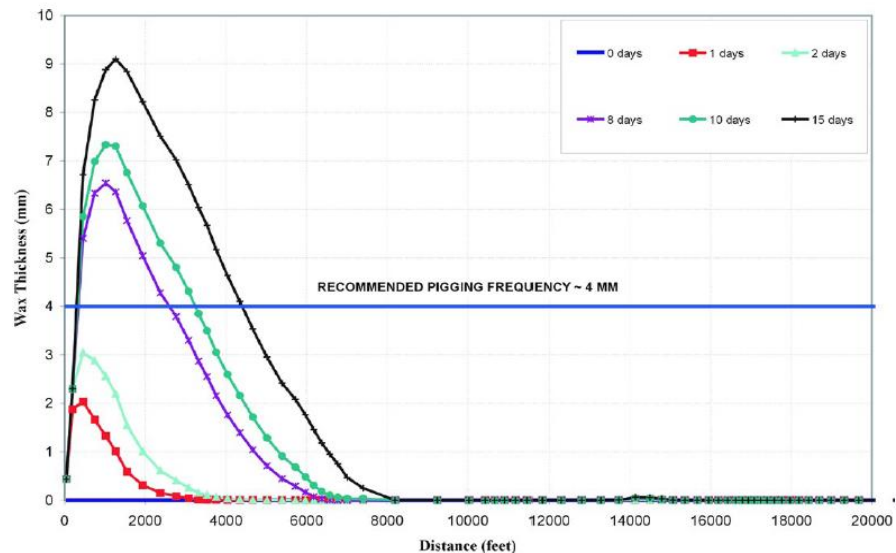
The dynamic viscosity is a measure of fluid resistance to flow and is a strong function of temperature. At temperatures above the WAT the viscosity of a crude oil is only a function of temperature (Newtonian behaviour). Below the WAT however, the wax crystals can begin to influence the viscosity, resulting in the viscosity being not only a function of temperature but also of shear rate (non-Newtonian).



The figure demonstrates the difference between Newtonian and non-Newtonian behaviour. When the crude oil is non-Newtonian, the viscosity increases rapidly as the temperature decreases and is highest at low shear rates.

4.4 Wax Deposition Modelling

Models are currently available for predicting where, when and how much wax will deposit. Given good information about the producing conditions, the heat transfer environment and a laboratory measured WAT, models can



predict the pipeline location where wax deposition will occur.

Beyond that, given laboratory data for wax deposition rates, a model can indicate the magnitude of the wax deposition problem and its impact on production operations.

For the example, given a maximum tolerable wax thickness of 4 mm, from the enclosed figure the pigging frequency would be approximately every 3 days.

4.4.1 Deposition Mechanism

There two main mechanisms for wax deposition are:

- Molecular diffusion
- Shear dispersion

Molecular diffusion is often considered to be the dominant mechanism in laminar flow operations. In these cases the shear dispersion effect is negligible. This diffusion effect results from the temperature gradient between the bulk fluid and the pipe wall.

In turbulent flow and particularly for multiphase systems, the shear dispersion effect is far more significant.

The deposition rate is usually referred to as the accumulation thickness of wax on a pipe wall per unit time, where wax deposition in this context relates to gradually building a wax layer around the inner pipe wall. The rate of deposition is known to be directly proportional to the heat flux. A range of other factors will also influence both deposition rates and whether wax is in fact a problem at all in any given situation. Foremost of these would be flow regime and shear rate. In general, where flow is multiphase, the dominant factor governing wax build up will be the shear stresses that help to strip away the depositing wax as it forms. Fluid gas oil ratio can have a great influence on waxing behaviour. Deposition from a stabilised oil system

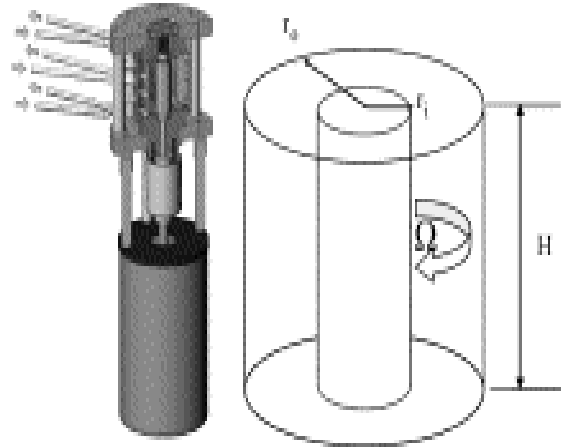
may be far higher than from one containing appreciable light ends. The light ends act as wax solvents.

Flow loops and deposition cells are available to test live oil wax characteristics at a range of heat fluxes and shear rates that would be expected in the flowline during actual production.

The loop is used to determine the WAT of the oil sample, assess efficiency of inhibitors (see later), and estimate the wax deposition rate according to flow conditions. It also enables estimations of pigging frequency for wax

removal and pipeline restart pressure for gel breaking.

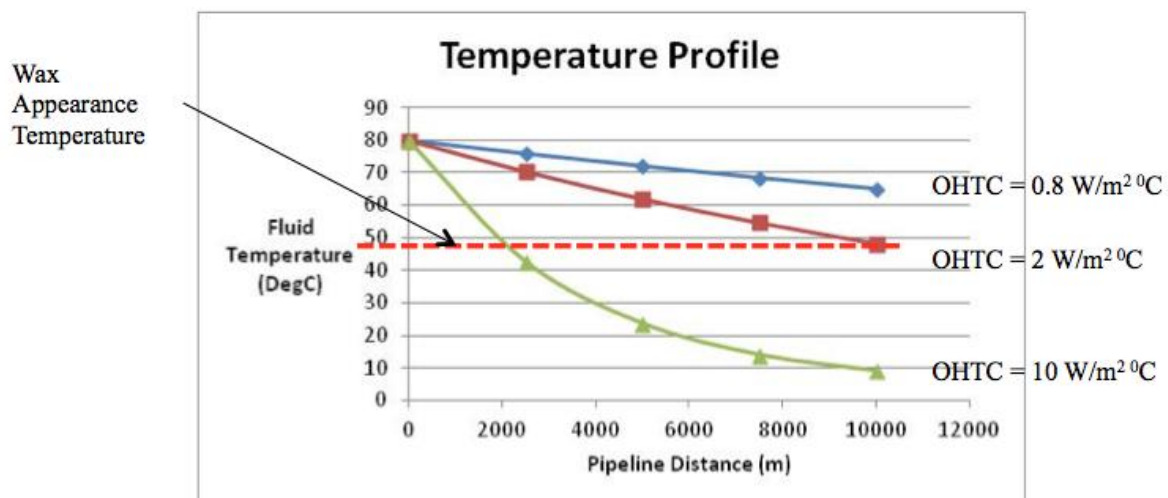
In a wax deposition cell the fluid is inserted into an annulus containing an inner cylinder. The inner cylinder is cooler than fluid temperature. The cylinder is rotated to mimic shearing and the rate of wax deposition on cylinder is measured at different shear rates and heat fluxes.



4.5 Wax Management

4.5.1 Insulation

The most obvious way of avoiding wax deposition is to maintain the system temperature above the wax appearance temperature using insulation. A U value is determined to maintain temperature as shown.

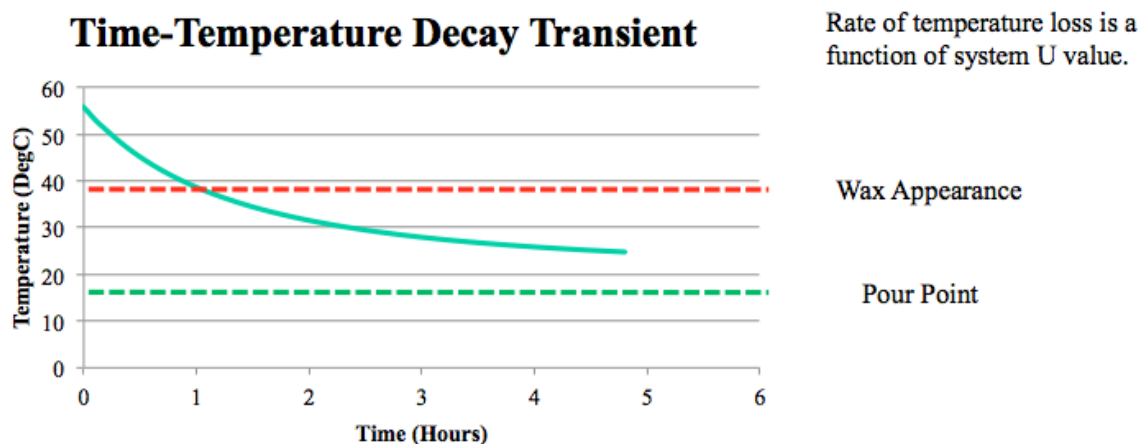


A WAT of 48⁰C is indicated on the temperature profile for a 10km pipeline. As can be seen a U of 10 W/m²⁰C would not achieve the required profile – 2 W/m²⁰C would be the maximum required.

Whilst this can be economic for shorter pipelines. Insulation may not be practical for many pipelines, particularly over long distances and other techniques would have to be deployed such as scrapper pigs.

Similar to hydrate formation issues during a shutdown, the key issue associated with wax gelation is maintaining the produced fluid temperature above the pour point for a sufficient time to either restart the system or treat the produced fluids. In many respects, the wax gelation issues can be much more severe than hydrate formation, given the remediation alternatives.

The cooldown time to the pour point may be quite short, preventing the operators to react early enough to clear the process upset and restart the system.



4.5.2 Thermal Removal

Hot oiling and hot water washes

Hot oiling and hot water washes have been used extensively for remediating onshore wellbores and pipelines. Transient, thermal modelling of the process should be performed to determine if the fluid will remain sufficiently warm to remove the deposit. As a rule of thumb, for wax to dissolve the temperature requires to be 10 ⁰C above the deposition temperature.

In-situ heat generation method (SGN) developed by Petrobras.

Two compounds in a solvent carrier are pumped down a flowline or wellbore. The two compounds react exothermically to generate heat, nitrogen gas and salty water. Sufficiently high temperatures can be achieved to melt wax deposits. The melted wax remains

dissolved/dispersed in the carrier solvent and flows back to the platform. One primary concern is that the generation of large quantities of nitrogen gas could lead to potential problems. The chemical reaction must be carefully controlled for the process to be safe and operable.

4.5.3 Chemical Removal

A variety of chemical methods are available for managing wax problems. Performance and suitability varies enormously and needs to be assessed on a case by case basis.

The methods act in four different ways:

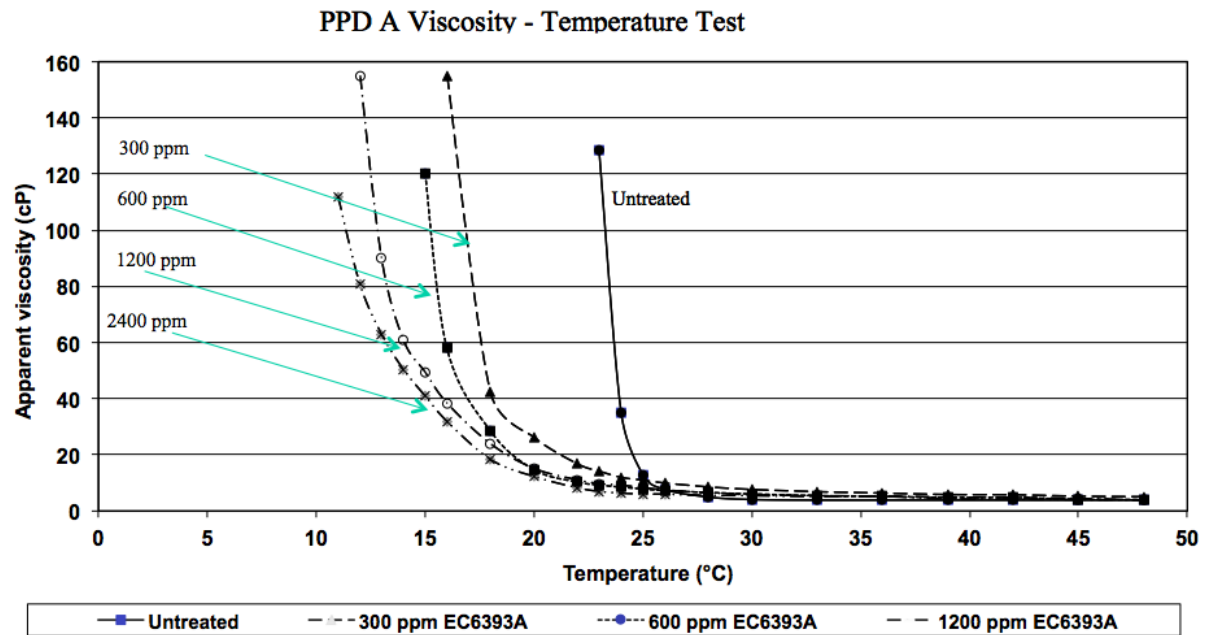
- Pour Point Depression
- Wax Deposition Inhibition
- Wax Crystal Dispersion
- Dissolution of Wax

The first two methods above are concerned with routine management of wax issues, either reducing the risk of high viscosities and gelling impacting on operations or simply reducing the rate at which wax deposits in the system. The final two methods primarily concern chemical remediation approaches once a wax problem has occurred and can no longer be tolerated. Laboratory testing is usually required to determine the type and dosage of chemicals required to generate a given effect.

Pour Point Depression

Although pour point depressants (PPD's) may have some beneficial effects at reducing wax deposition, they are primarily chosen where pour points are high relative to ambient conditions and there is a high risk of fluid gelling somewhere in the system. They are typically applied to export oil systems. In many waxy oil export lines, viscosities can become very high as fluid approaches the pour point and, of course, there is the risk of fluid gelling, especially during a shutdown. Pour point depression is typically used in these cases to maintain the pumpability of oil at low temperatures.

A typical laboratory test output is shown. Here the effectiveness of differing concentration of proprietary PPD is being assessed.



Wax Deposition Inhibition

Wax or paraffin inhibitors are high molecular weight polymers specifically designed to reduce the quantity of wax deposited in both pipeline and topside systems. Chemicals selected for this purpose may also be chosen to achieve a pour point depressant effect but this will depend on each application. In some cases, wax deposition is a problem but pour points are very low and are not the primary concern. Chemical selection should target specific needs, since trying to meet both objectives may restrain choice and performance in one aspect or the other. Commercial inhibitors can be wax crystal modifiers or inhibitors, dispersants, surfactants or a combination of these. Crystal modifiers prevent the formation of large wax crystals by co-crystallising part of the wax crystal. This prevents further crystal growth and also reduces the adhesiveness of the crystals. The inclusion of a wax crystal inhibitor helps to reduce the deposition rate.

Inhibitor chemicals are not, however, completely effective and there are no universal inhibitors. Extremely careful selection is required before production begins for developments at risk of wax deposition problems. This typically requires a significant degree of fluid testing in advance, especially for difficult oils. Although optimisation may be achieved in the field, the primary chemical selection should be made beforehand.

Since crystal modifiers are less effective once crystals have started to form, wax inhibitor chemicals usually have to be injected above the fluid cloud point to achieve maximum performance. This will not always be practical, however, and predicted performance impacts of not doing so should be assessed during fluid testing and chemical selection.

In many cases, selected chemicals may combine a number of features in one product, the inhibitor co-crystallising with the wax to prevent crystal structures sticking to the pipe wall, a dispersant coating wax crystals to prevent them from agglomerating and a surfactant acting to water-wet the crystals so that they do not adhere to each other or the pipe wall. Wax inhibitors are very oil specific. Performance may also be temperature dependent and they may reduce deposition in part of the cooling range better than another. It is important in the selection process to assess how this behaviour may impact performance. Specifically, the type of wax depositing at different temperatures may vary considerably.

Wax Crystal Dispersion

Wax crystal dispersants have the effect of reducing physical adherence of small wax crystals by chemically coating the particles, allowing them to remain in suspension in the crude oil. Dispersants also have strong spreading effects, which allow them to penetrate accumulated paraffin deposits and free individual particles. Dispersants are typically applied as a remediative tool rather than as a continuous chemical addition, although a wax inhibitor chemical that may be injected continuously can incorporate some dispersant properties. Predominantly for topside systems, provision should be made for waxy systems for injection of dispersant upstream or into equipment particularly susceptible to wax blockage. Dispersant used in this manner would be dosed on line to try and clear any flow restriction that had been identified.

Dissolution of Wax

Wax is soluble in many organic solvents. Solubilities are low, however, and large quantities of solvent may be required, particularly at low temperatures. A variety of solvents for dissolving wax deposits are commercially available. To remove a build-up from a pipeline, the solvent is typically pumped into the line and allowed to soak for a period of time. Unfortunately high molecular weight waxes are relatively insoluble in most solvents except at higher temperatures so the most that can be hoped for is that the solvent works to break down or soften the wax deposit so that it can be flushed out when flow is re-established. Solvents can be hazardous chemicals. The best performance is usually achieved when the wax can be periodically soaked in solvent. This will be better still if heat can be added. Although a wide range of common solvents is available for managing wax deposits, a number of these have major environmental concerns. One of the more effective solvents falling into this category is xylene, however, as a result of environmental and health concerns, many operators will not use Xylene. Selection of a suitable wax solvent should be addressed in exactly the same

manner as selection of a wax inhibitor chemical. This should be done well before production commences, testing a variety of chemicals to identify that best able to dissolve sample wax deposits (typically those laid down during flow loop testing).

4.5.4 Mechanical Removal

Pigging

Pigging is commonly used method for removing wax deposits that have accumulated in flowlines and pipelines. Pigging can be a very successful, cost effective method for managing paraffin deposition in flowlines and pipeline providing that a regularly scheduled pigging program is initiated upon commissioning; optimised based upon field experience; and followed religiously unless producing conditions change.

Pigs can become stuck in wax deposits, but that occurs when too much wax has been allowed to accumulate.

The pig is unlikely to remove the entire wax deposit, but leaves behind a smooth layer which can reduce the pipe wall friction and pressure drop.

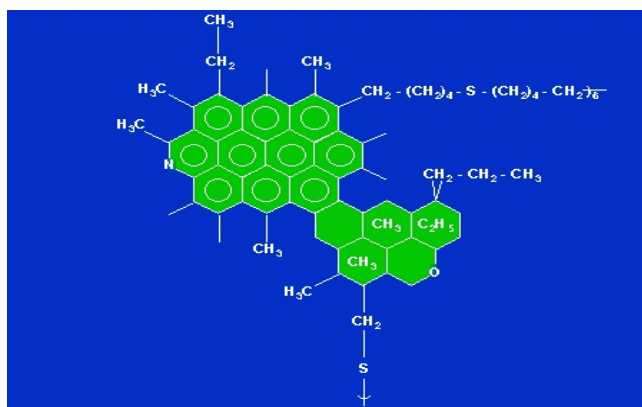


5 Asphaltenes

Asphaltenes are defined by the ASTM D-3279-90 (American Standard Test Method) test or IP143/90 (Institute of Petroleum) as a solid that precipitates when an excess of n-heptane or n-pentane is added to a crude oil.

Heptane/Pentane acts as a solvent for the resins which stabilise the asphaltenes.

Chemically, asphaltenes are high molecular weight, polynuclear aromatic, polar compounds containing carbon, hydrogen, oxygen, nitrogen, sulphur and some heavy metals such as vanadium and nickel. The diagram gives a representation of an asphaltene molecule; however, asphaltenes do not have a single, unique structure or molecular weight.



Asphaltenes are dark brown to black solids. They can deposit in reservoirs, wellbore tubing, flowlines, separators, etc. Unlike waxes, asphaltenes do not melt. Consequently, thermal methods such as insulation, hot oiling, etc. do not work to prevent or remediate asphaltene deposition.

Asphaltenes can deposit due to a drop in pressure however waxes primarily deposit due to a drop in temperature.

Asphaltenes can flocculate due to an acidizing or stimulation job or due to the mixing of different fluids (e.g. high and low aromatic crudes). Asphaltene flocculation may be irreversible. That means if asphaltenes have flocculated in a sample container, it may not be possible to return the asphaltenes completely back in solution.

Gas lifting can exacerbate an asphaltene deposition problem due to solvent vapourisation.

Asphaltenes are very soluble in aromatic compounds such as xylene.

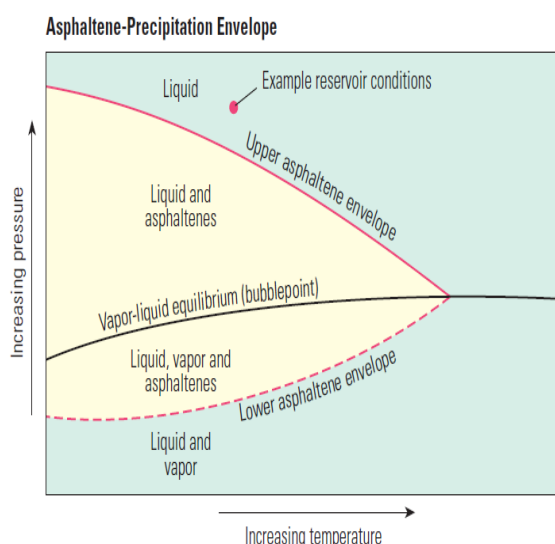
An asphaltene precipitation envelope is often prepared to evaluate asphaltene risks. The

asphaltene-precipitation envelope (red curve) delimits the stability zones for asphaltenes in solution. For the given example reservoir conditions (red dot), primary depletion causes the pressure to decrease. When the pressure drops to the upper asphaltene-precipitation envelope, also known as the asphaltene-precipitation onset pressure, the least-soluble asphaltenes will precipitate. As pressure continues to decrease, more asphaltenes

will precipitate, until the bubble point pressure is reached, and gas is released from solution. With continued pressure decrease the crude oil may begin to re-dissolve asphaltenes at the lower asphaltene-precipitation envelope.

Asphaltene inhibitors are polymeric dispersants which help stabilise the micelles which prevents the asphaltenes from flocculating.

The inhibitors act in the same manner as the resins interacting with the asphaltenes and stabilising the asphaltene micelles in the crude oil. Asphaltene inhibitors have a stronger association with the asphaltenes than the natural resins and are able to stabilise the asphaltenes through greater changes in pressure, temperature, shear and chemical environment. Asphaltene inhibitors can be squeezed into the formation or continuously



injected downhole. Squeezing the inhibitor into the reservoir can prevent deposition of asphaltenes in the near-well bore area. It is important that the asphaltene inhibitors are added to the crude oil before the asphaltenes become destabilised and flocculation occurs.

6 Erosion

Erosion is defined as the wastage of material due to mechanical removal of the material surface by a flowing environment causing damage to equipment and piping systems with consequent loss of containment being a primary concern. It is most extreme when solids are present in the environment. To mitigate against erosion, velocity limits and therefore production limits can be imposed



Four mechanisms termed erosion are presented:

- Erosion by non-corrosive fluids through liquid droplet impact
- Pure solids erosion by a non-corrosive fluid carrying solid particles
- Erosion-corrosion by a corrosive medium in the absence of solids
- Erosion-corrosion by a corrosive medium containing solids

Factors which affect erosion are;

FLUID PROPERTIES

Viscosity, density

FLOW PROPERTIES

Velocity, flow regime

PARTICLE PROPERTIES

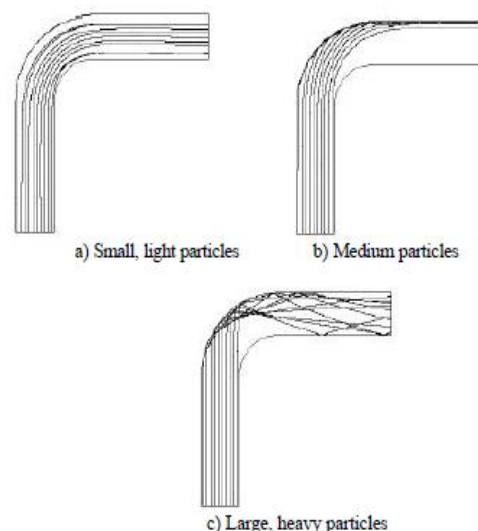
Amount, size, shape, density

MATERIAL PROPERTIES

Hardness, yield strength

GEOMETRIC PROPERTIES

Pipe elbow, tee, straight pipe, flow constrictions etc.



6.1 Liquid droplet erosion

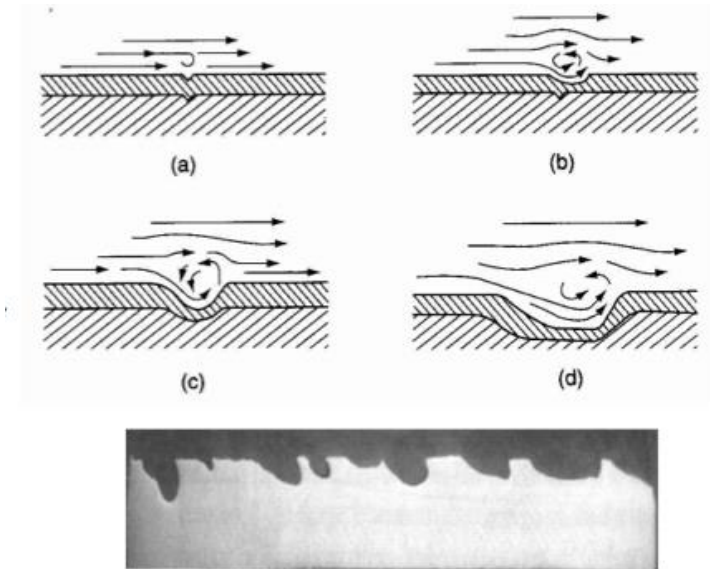
This form of erosion is produced when the liquid droplets impinge on the pipe wall.

6.2 Erosion-corrosion

Erosion-corrosion occurs in environments that have the potential to be both erosive and corrosive. The erosion and corrosion can be either independent, in which case the total wastage is the wastage produced by each mechanism in isolation, or synergistic, in which case the total wastage is greater than the sum of the independent mechanisms of erosion and corrosion.

High velocity fluid flow can often disrupt adherent surface films and deposits that would otherwise offer protection against corrosion. Thinning or removal of surface films by erosion from the flowing stream results in accelerated corrosion, called erosion-corrosion. The attack is accelerated at elbows, tube constrictions, burrs, and other structural features that alter flow direction or velocity, and increase turbulence.

Erosion-corrosion takes the form of grooves, waves, gullies and teardrop-shaped pits.

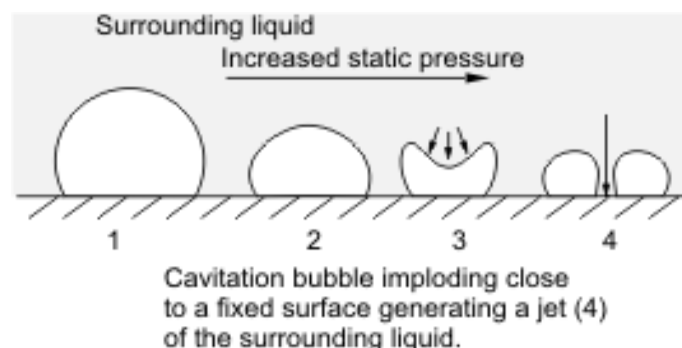


Photograph of erosion-corrosion showing individual teardrop shaped pits with undercutting in the downstream direction.

6.3 Cavitation – erosion

Cavitation is caused by the high energy collapse of vapour bubbles (or cavities) in a liquid flow stream as a result of pressure recovery following pressure reduction to a value below the vapour pressure (bubble point) of the liquid at the flowing temperature. Solid boundaries in the vicinity are likely to be eroded. This is a complex phenomenon and, like other forms of erosion, it can exacerbate corrosion effects if materials are susceptible.

Cavitation erosion is not caused by the impact of solid particles or liquid droplets, but by the impact of a very high velocity liquid pulse onto the solid boundary from a collapsing



bubble. Cavitation emits a characteristic noise by which its presence and severity (incipient or full cavitation) can be recognised. Cavitation may be caused by other features of the flow passage causing a sharp change in the flow direction e.g. a tight-radius 90-degree elbow, in

which the pressure falls below the vapour pressure. Pump impellers may also initiate cavitation.

Appropriate erosion resistant materials (stellite, tungsten carbide, etc.) are often used locally in the area where cavitation is expected to occur. Austenitic stainless steels, martensitic stainless steels, and nickel alloys are more resistant than carbon steel, but materials which are highly resistant to other forms of erosion, such as satellite, etc., are many times more resistant to damage.

6.4 Erosion Models

6.4.1 Accuracy of erosion models

All of the models used for calculation of erosion damage levels are based, in the main, on laboratory test programmes. Hence they are likely to be at their most reliable for simple flow conditions in non-corrosive environments. Agreement between the erosion models is relatively poor, particularly for flow conditions that are substantially removed from those for which experimental work has been completed, e.g. large versus small diameter pipework. At best, each erosion rate model is typically no more accurate than a factor of 2, i.e. +100% to – 50%, which reflects the scatter in experimental results in multiphase flow of gas, liquid, and solid particles.

All of the erosion rate models suffer from limited comparison with field experience.

6.4.2 Computational Fluid Dynamics (CFD)

The erosion prediction models are only applicable for estimating erosion damage levels of the most commonly used pipe fittings, e.g. elbows and bends. Whilst erosion models can predict the level of erosion damage, they do not predict the location(s) of the damage. For example, changing gas-liquid ratios in multiphase flows is known to alter the site(s) of greatest erosion damage on elbows and bends. Various degrees of subtlety, such as the influence on the flow into a manifold by the fluids already flowing in the manifold, cannot be represented by the erosion prediction models.

Complex geometries can be addressed by the use of CFD modelling. CFD modelling by itself should not be used to predict the likely rate of erosion. It is usually coupled with an erosion model. A coupled model should provide the most accurate means for assessing erosion damage.

6.4.3 API RP 14E

The API (American Petroleum Institute) Recommended Practice 14E defines a critical velocity above which erosion may occur, and recommends that the maximum velocity in the system be limited to this critical velocity, effectively sizing flowlines, production manifolds, process headers and other lines transporting gas and liquid in two-phase flow.

The critical velocity is defined by the empirical equation:

$$V_m^* = C / \sqrt{\rho_m}$$

Where C = an empirical constant normally 100 (see later)

ρ_m = the **no slip** gas/liquid mixture density at operating temperature and pressure, lb/ft³

V_m^* = the maximum allowable mixture erosional velocity, ft/s

Metric equivalent

$$V_m^* = 1.22 C / \sqrt{\rho_m}$$

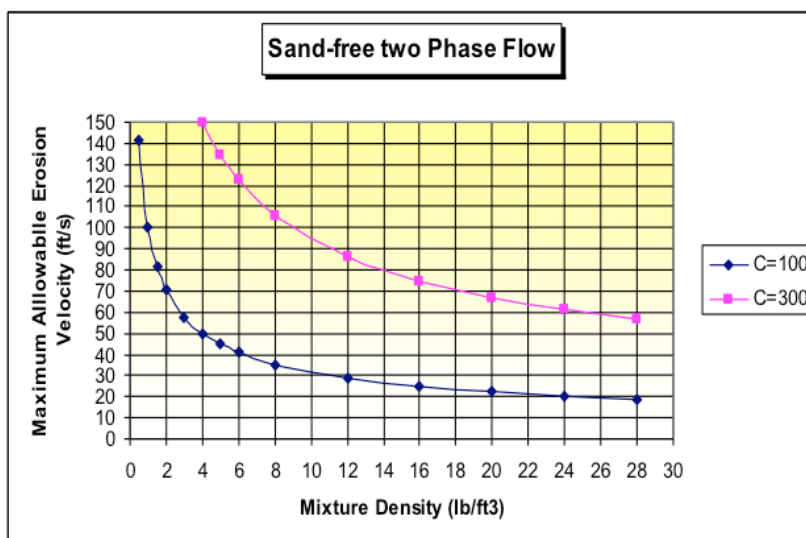
The equation is widely used throughout the industry, however it should be noted that:

- only applies to gas/liquid flow
- does not apply to flow containing solids (e.g. sand).
- the constant C can be varied depending on the material properties.

Although simplistic, the API method is used by many flow assurance engineers.

6.4.4 Salama and Venkatesh

Salama and Venkatesh (1983) presented a critical review of API RP 14E. They concluded that the C values recommended in the API publication are too conservative and they suggested that for sand free two-phase flow C=300 is more appropriate or stainless steels.



Operator experience suggest C values of:

- 135 for carbon steel
- 300 for 13% Cr
- 350 for duplex stainless steel.

6.5 Erosion in Presence of Solids

When sand is produced there are erosion models that attempt to determine the rate of erosion for the particular circumstances. These include:

- Salama Model
- Tulsa University Model

The variables considered in these equations are:

- Velocity
- Pipe Diameter (to define the area of impact)
- Solids/sand Loading

The equations take a similar form:

$$\text{Wastage rate} = \text{Constant} * MV^2/d^2$$

Where;

M is the solids production rate

V is the mixture velocity

d is the pipe diameter

6.5.1 Salama Model

$$ER = W \cdot V_m^2 d / (S_m \cdot D^2 \cdot \rho_m)$$

where:

ER is the erosion rate (mm/year)

W is the solid particle flow-rate (kg/day)

V_m is the mixture velocity (m/s)

d is the particle diameter (microns)

D is the pipe internal diameter (mm)

ρ_m is the fluid mixture density (kg/m³)

S_m is a geometrical constant

This equation was calibrated against the published results of several multiphase flow loop tests that covered a broad range of liquid-gas ratios and solid particle concentrations to produce different values of the constant S_m (depending on the particular pipe geometry) as follows:

$S_m = 5.5$ for pipe elbows/bends

$S_m = 68$ for tees (liquid-gas flow)



$S_m = 1,379$ for tees (gas flow)

6.5.2 Tulsa Model

The Tulsa 'Sand Production Pipe Saver' Model was based on theoretical work evaluating particle tracking. The model was built up piece by piece with laboratory experiments validating the model at each step. The resulting model is claimed to have a wide range of applicability.

The model defines an erosion rate E as follows:

$$E = C \times S \times F \times V^{1.73}$$

where

V is the mixture velocity

F is a scaling factor

S is the sand concentration

The empirical constant, C , is dependent on material, pipe geometry and flow regime.

7 Key Learnings

1. Requirement to couple pressure loss with overall energy balance.
2. Pipeline steady state heat balance.
3. Pipeline U value.
4. Pipeline insulation systems.
5. Hydrate formation and conditions required.
6. Use of hydrate curves and K values to predict hydrate formation.
7. Hydrate management using Methanol, Glycols and Threshold Hydrate Inhibitors.
8. Safety issues with formed hydrate plugs.
9. Transient temperature decay for static pipeline.
10. Wax appearance temperature, pour point and breakaway yield strength.
11. Wax management techniques.
12. Erosion models and application of API 14E