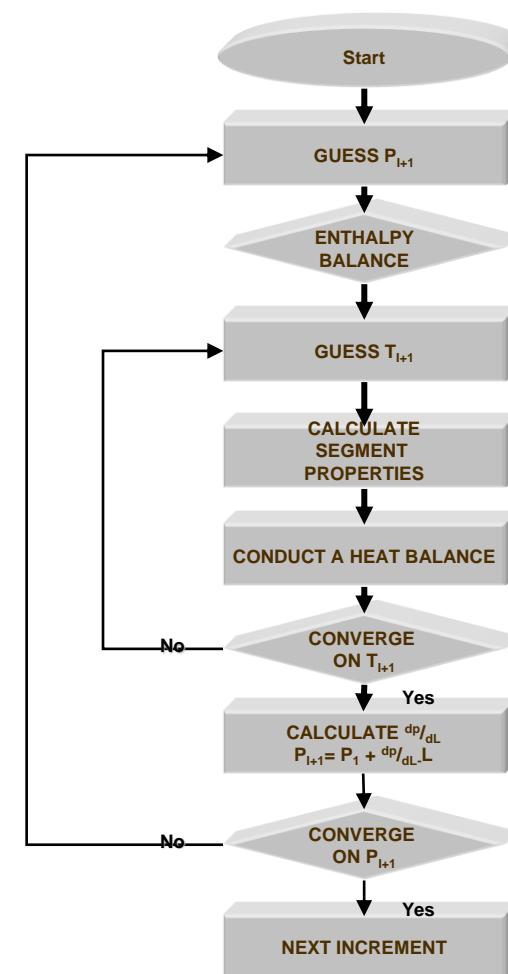
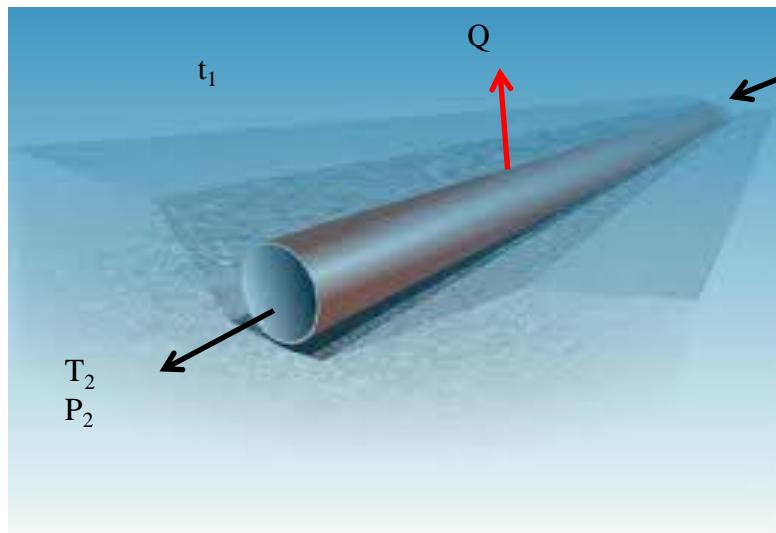
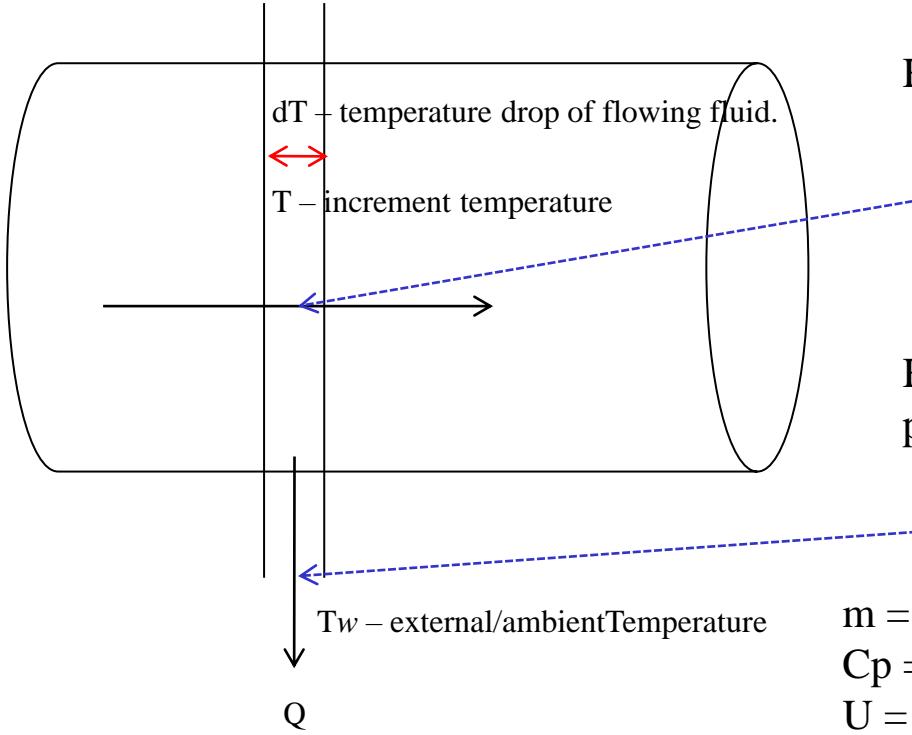

8. Hydrates, Wax and Erosion

Pipeline System Energy Balance

A coupled pressure – temperature analysis is required for pipeline systems.



Pipeline Heat Balance



Heat loss from fluid cooling inside pipe

$$Q = -m C_p dT$$

Heat loss from fluid cooling inside pipe equals heat loss to surroundings

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

m = mass rate of fluid (kg/s)

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

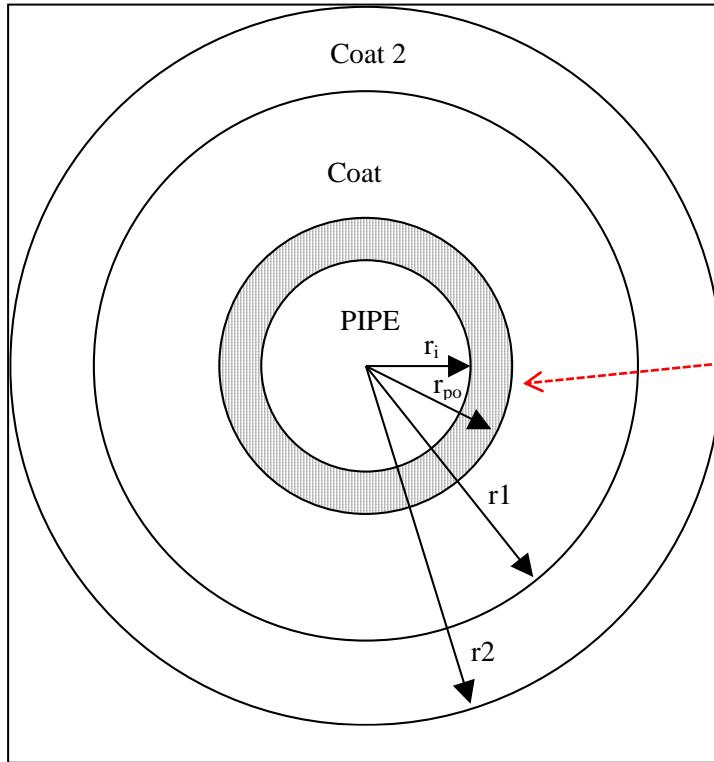
U = overall heat transfer coefficient (W/m² °C)

A = outside area of pipe (m²)

T_w = temperature of surroundings (°C)

Overall Heat Transfer Coefficient, U

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



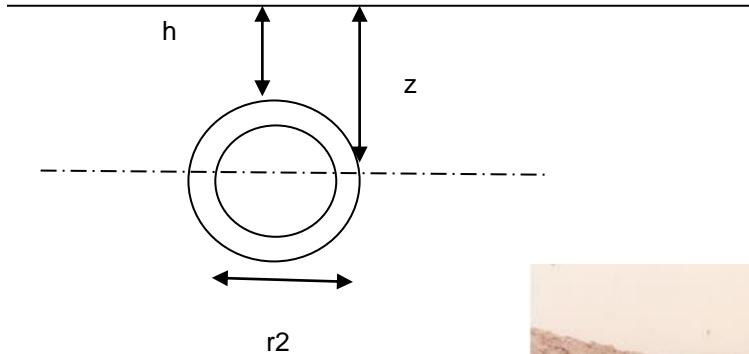
Be careful with reference area for heat transfer. In the above formula the reference area is the outside of the pipe = $r_{po} = r_p$

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

k – thermal conductivity
h – film coefficient

Overall Heat Transfer Coefficient, Buried Pipe

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



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

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

k_g is the soil thermal conductivity

Temperature Difference

Analogous with heat transfer within a heat exchanger tube, a log mean temperature difference is used in the heat transfer equation.

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:

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

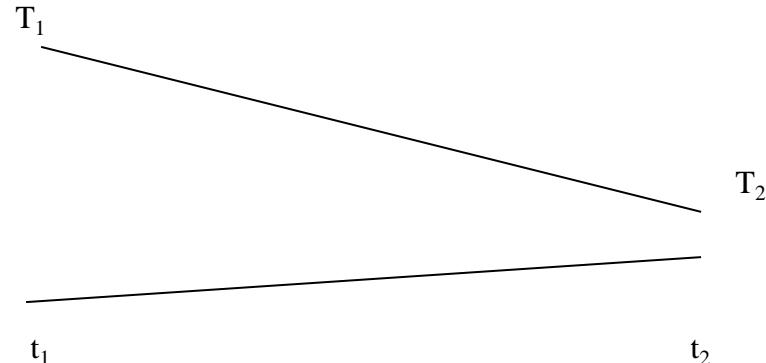
T_1 = inlet inside fluid temperature

T_2 = outlet inside fluid temperature

t_1 = inlet outside temperature

t_2 = outlet outside temperature

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



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

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

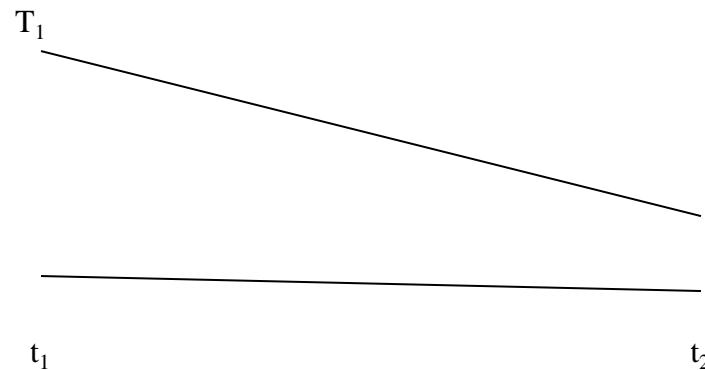
T_1 = inlet inside fluid temperature

T_2 = outlet inside fluid temperature

$t_1 = t_2$ outside ambient temperature

Pipeline Heat Balance

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



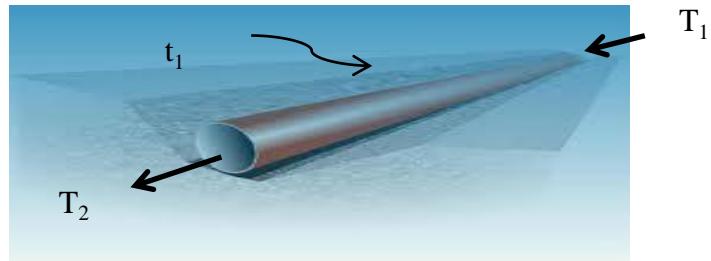
Solving for T_2 , knowing that

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

Gives;

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

This equation can be used to predict subsea pipeline temperature profiles.



Worked Example

Calculate the outlet temperature from a subsea pipeline with following conditions:

OHFC, $U = 2 \text{ W/m}^2 \text{ }^\circ\text{C}$ based upon pipeline 0.0

Mass flowrate, $m = 10 \text{ kg/s}$.

Fluid specific heat, $C_p = 2.8 \text{ kJ/kg } ^\circ\text{C} = 2800 \text{ J/kg } ^\circ\text{C}$.

Outside temperature, sea, $t_s = 4^\circ\text{C}$

Pipe ID = 0.2 m.

Pipe wall thickness = 0.02 m.

Pipe length = 1000 m

Inlet temperature, $T_i = 80^\circ\text{C}$

Worked Example

For outlet temperature use formula:

$$T_2 = (T_1 - t_1) / \exp\left(\frac{UA}{MC_p}\right) + t_1 \quad - \textcircled{1}$$

Calculate pipe area:

$$\begin{aligned} \text{Pipe } 0.4 &= 0.2 + 2 \times 0.02 \\ &= 0.24 \text{ m} \end{aligned}$$

$$\begin{aligned} \text{Pip heat transfer area} &= \pi \times 0.24 \times 10000 \quad (\text{m} \cdot \text{W}) \\ &= 7540 \text{ m}^2 \end{aligned}$$

$$\text{Calculate } \frac{UA}{MC_p} = \frac{2 \times 7540}{10 \times 2800} = 0.538$$

$$\begin{aligned} \text{From } \textcircled{1}, \text{ calculate } T_2 &= (80 - 4) / e^{0.538} + 4 \\ &= \underline{\underline{48.4^\circ C}} \end{aligned}$$

Worked Example

Calculate temperature profile down pipeline.

Distance (m)	$\frac{UA}{MC_p}$	T_2 ($^{\circ}\text{C}$)
0	0	80
2500	0.134	70.4
5000	0.269	62.5
7500	0.402	54.7
10000	0.538	48.4

Worked Example

Repeat for $U = 0.8 \text{ W/m}^2\text{°C}$

Distance (m)	$\frac{UA}{MC_p}$	T_2 (°C)
0	0	80
2500	0.0536	76.0
5000	0.1072	72.2
7500	0.1608	68.7
10000	0.2144	65.3

Worked Example

Repeat calculation at various mass rates with $U = 2.0 \text{ W/m}^2\text{°C}$

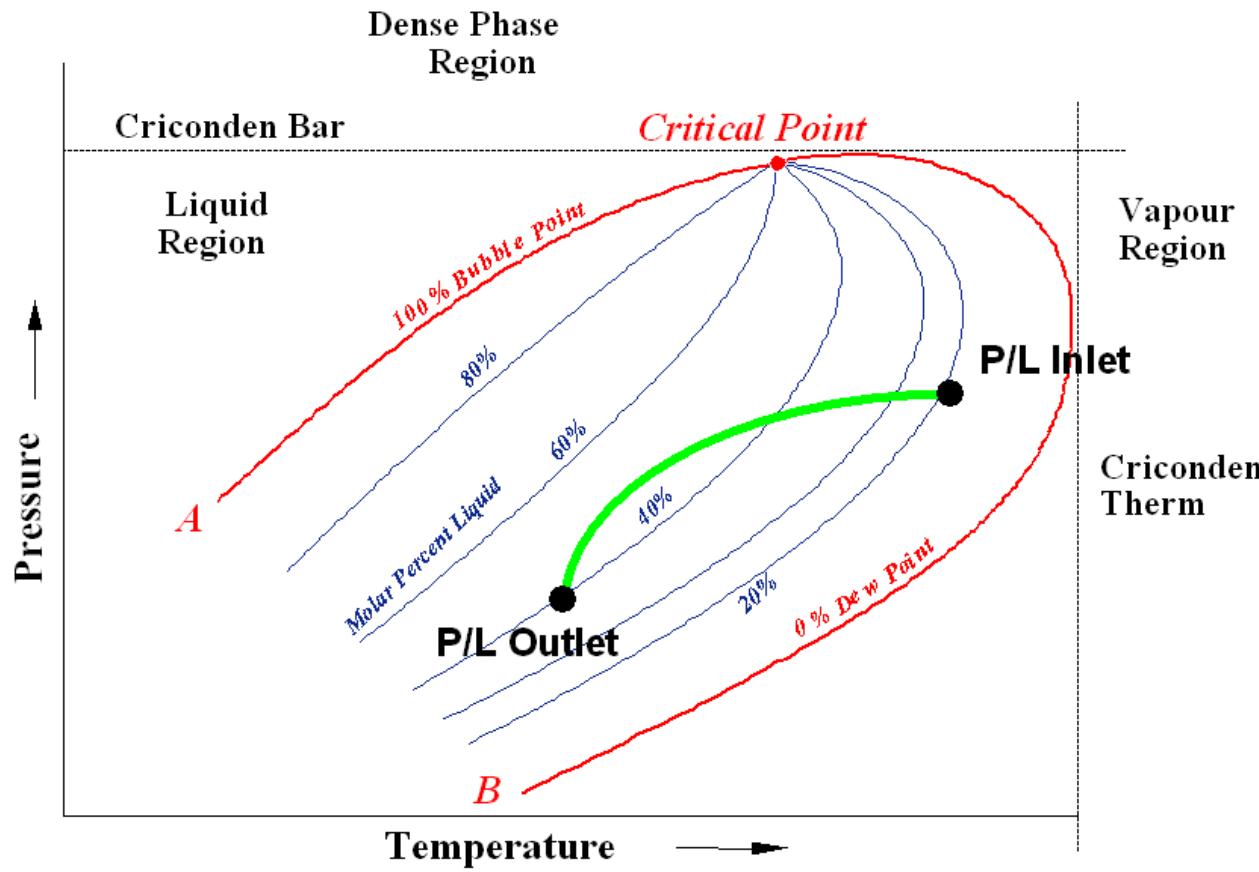
5.

Mass flowrate, $m = 10, 7.5, 5, 2.5 \text{ kg/s}$

Calculate outlet temperature, T_2 .

Mass flowrate, m (kg/s)	UA/mC_p	T_2 (°C)	$= (T_1 - t_1) / \exp\left(\frac{UA}{mC_p}\right) + t_1$
2.5	2.15	12.8.	$= (80 - 4) / \exp\left(\frac{UA}{mC_p}\right) + 4.$
5.0	1.08	29.9	
7.5	0.72	41.0	
10.0	0.54	48.3	

Flow path of fluids through the Phase Envelope.



The solution of a multi-phase pipeline pressure drop 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.

External Insulation Systems

Solid

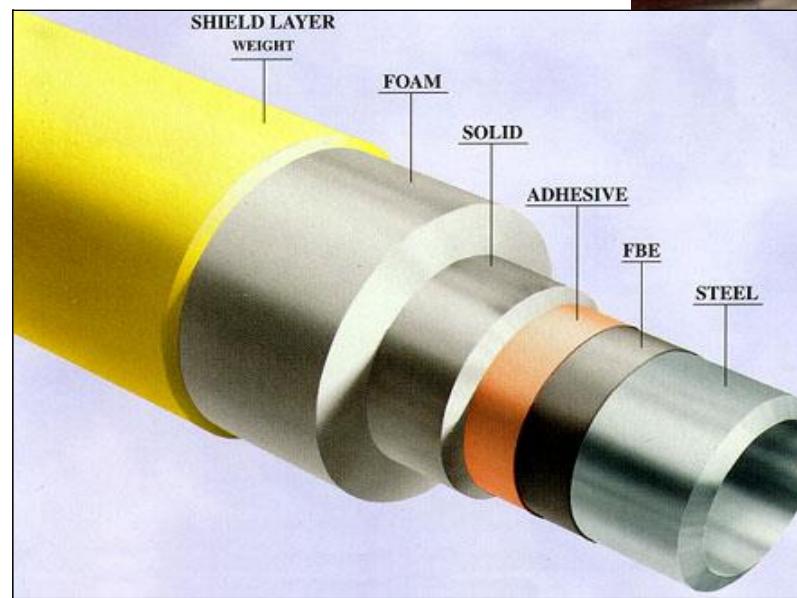
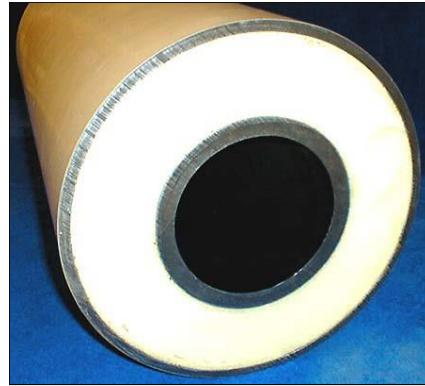


Blown foam

Syntactic foam



External Insulation Systems



Insulation 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/mK, 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.

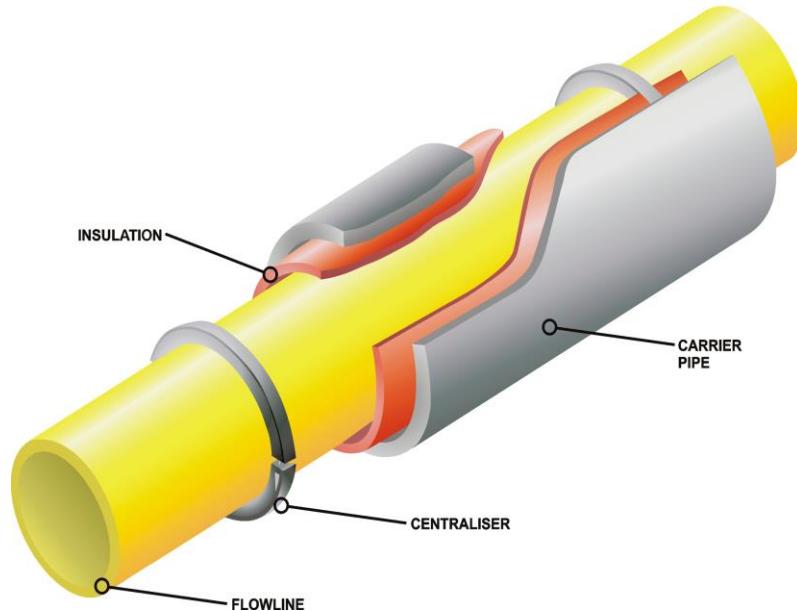
Material	Btu/hr ft $^{\circ}$ F	W/m $^{\circ}$ C
Concrete	1.18	2.04
FBE (fusion bonded epoxy)	0.114	0.2
Coal Tar Enamel	0.114	0.2
Neoprene	0.156	0.27
Polyurethane Foam	0.017	0.03
PVC Foam	0.023 – 0.04	0.04 – 0.7
Syntactic PU	0.07	0.12

Metal Thermal Conductivity

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

Note Carbon steel has a much higher conductivity than alloyed steel.

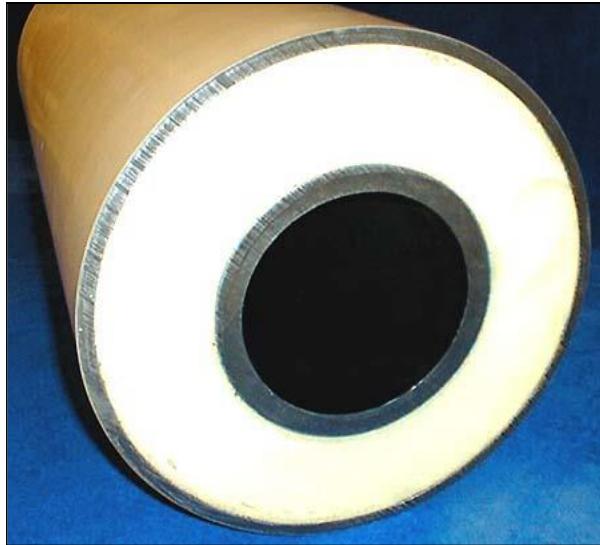
Pipe in Pipe – U Values 1 W/M²K or less



An inner flowline with an outer carrier pipe. The annulus is filled with insulation. The outer pipe provides protective to the insulation for the compressive forces of the surrounding hydrostatic head.

For every 10m of water depth the hydrostatic head is approximately 1 bar.

Pipe in Pipe – U Values 1 W/m²K or less

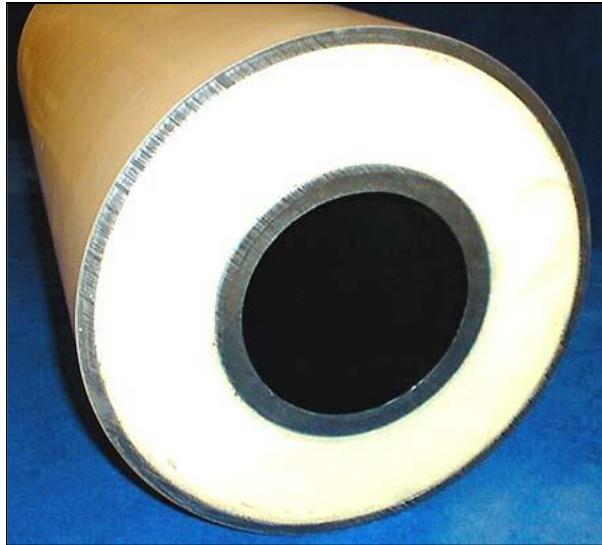


Outer pipe provides mechanical protection for insulating material.



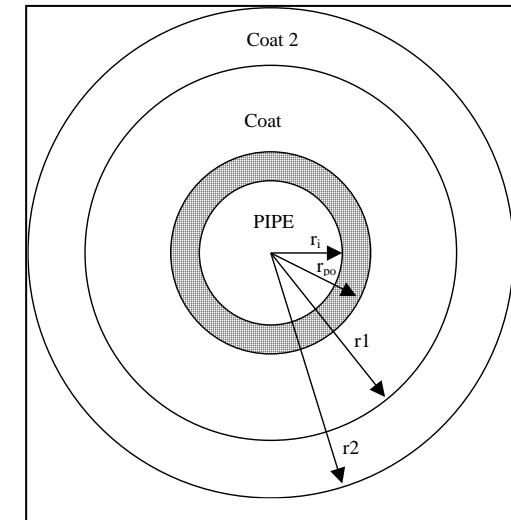
Aerogels are being utilised as an insulant. Aerogels are among the lightest solid materials known to man. They are created by combining a polymer with a solvent to form a gel, and then removing the liquid from the gel and replacing it with air. Aerogels are extremely porous and very low in density. They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

Pipe in Pipe – U Values 1 W/m²K or less



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.

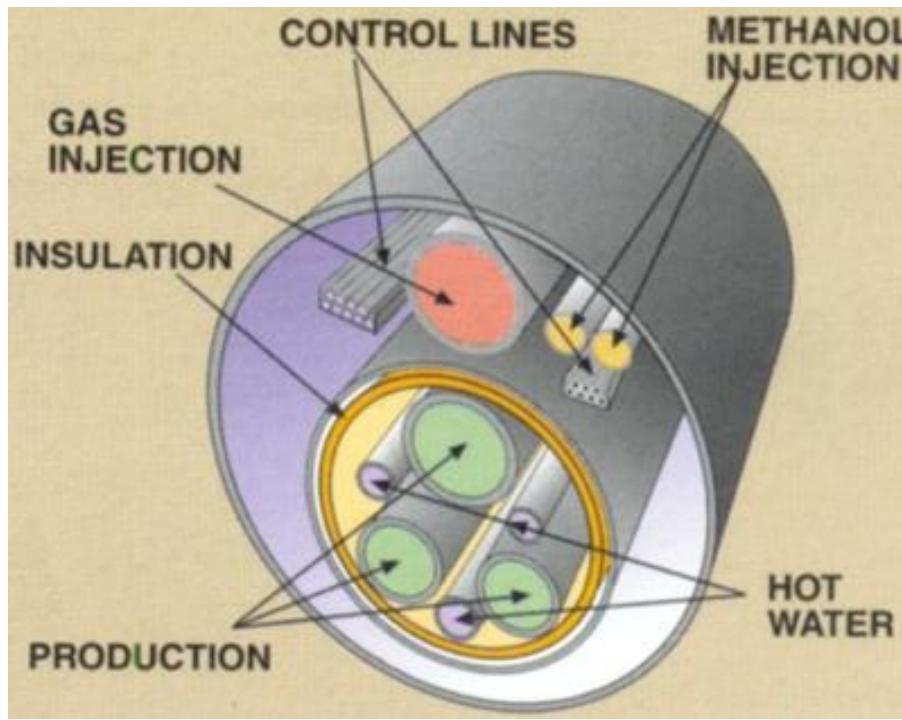
$$\frac{1}{U} = \frac{\cancel{r_i h_i}}{\cancel{k_p}} + \frac{r_p \ln(r_1/r_i)}{\cancel{k_p}} + \frac{r_p \ln(r_1/r_p)}{k_1} + \frac{\cancel{r_p \ln(r_2/r_1)}}{\cancel{k}} + \frac{\cancel{r_p}}{\cancel{r_2 h_a}}$$



Bundled Flowlines

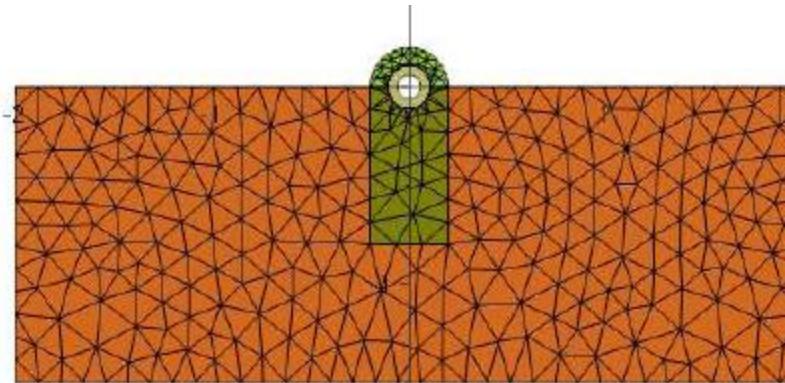
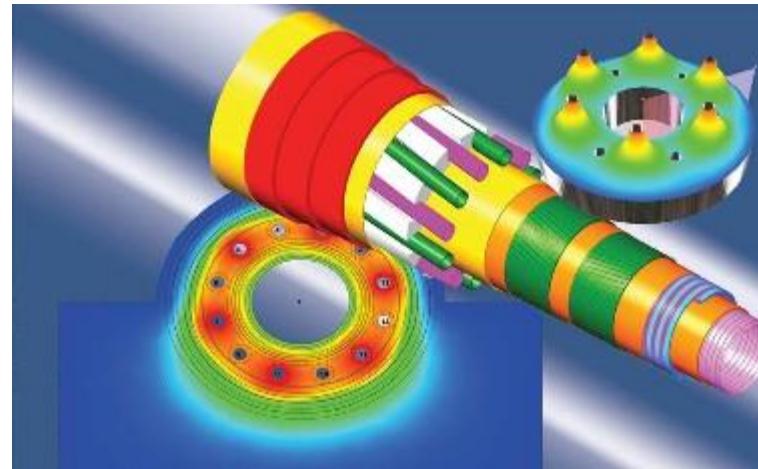
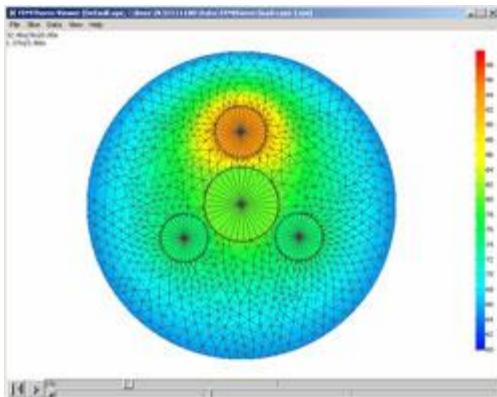
There are two main types of bundles, passive and actively heated bundles.

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



Finite Element Analysis

For complex geometries finite element analysis is used to establish temperature profiles.



External Insulation Systems

Temperature Limits

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

Trenching and Backfill

Method of increasing insulation levels through thermal properties of soil.

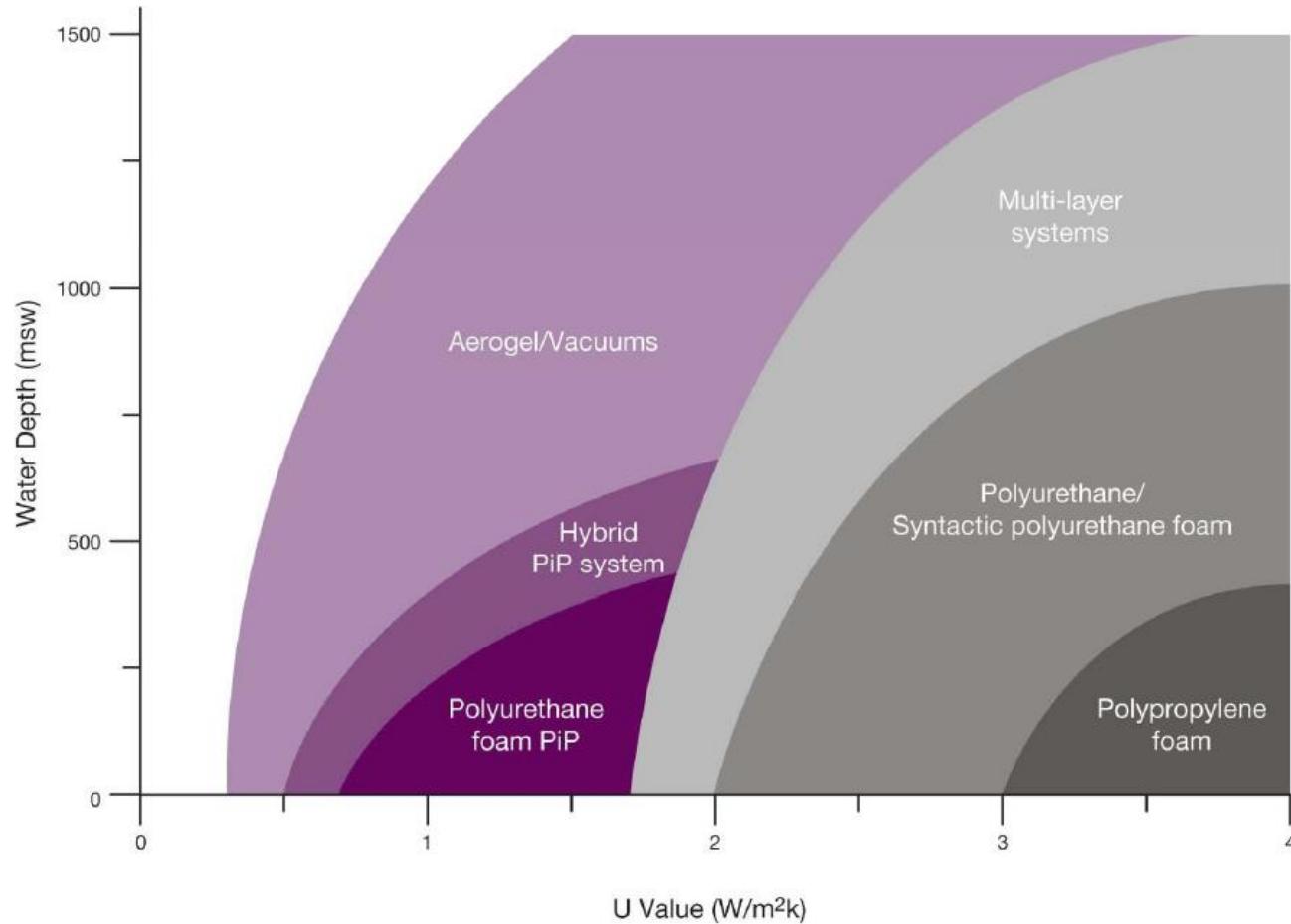
Instances reported where backfill has not been effective hence thermal performance much poorer than design



Backfill Plough

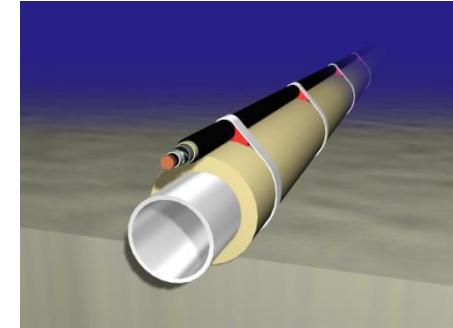
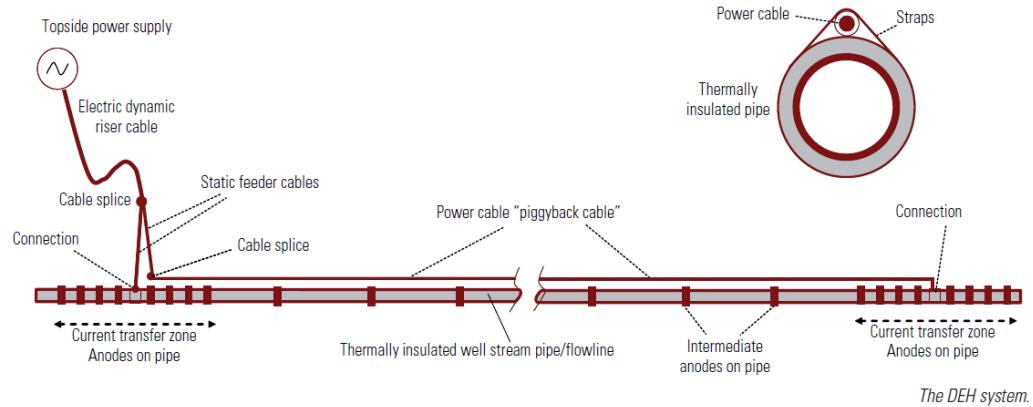


OHTC vs Water Depth



Alternatives to Insulation

Direct Electric Heating (DEH)



Flow assurance by actively controlling the temperature on the pipe.

Electrical current is passed through the pipe wall.

Heat is generated by resistive current losses,
uniform heat distribution for same pipe
properties.

The pipeline inner wall is at all times kept above
critical temperatures – wax deposition, hydrate
formation.



Subsea Cooling

HP/HT (high pressure, high temperature) reservoirs are being produced subsea. Subsea flowing wellhead temperatures of 160 -180 DegC can be experienced. Such high temperatures may cause mechanical and material problems – upheaval buckling.

To avoid this the fluids are cooled subsea prior to entering the pipeline.

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



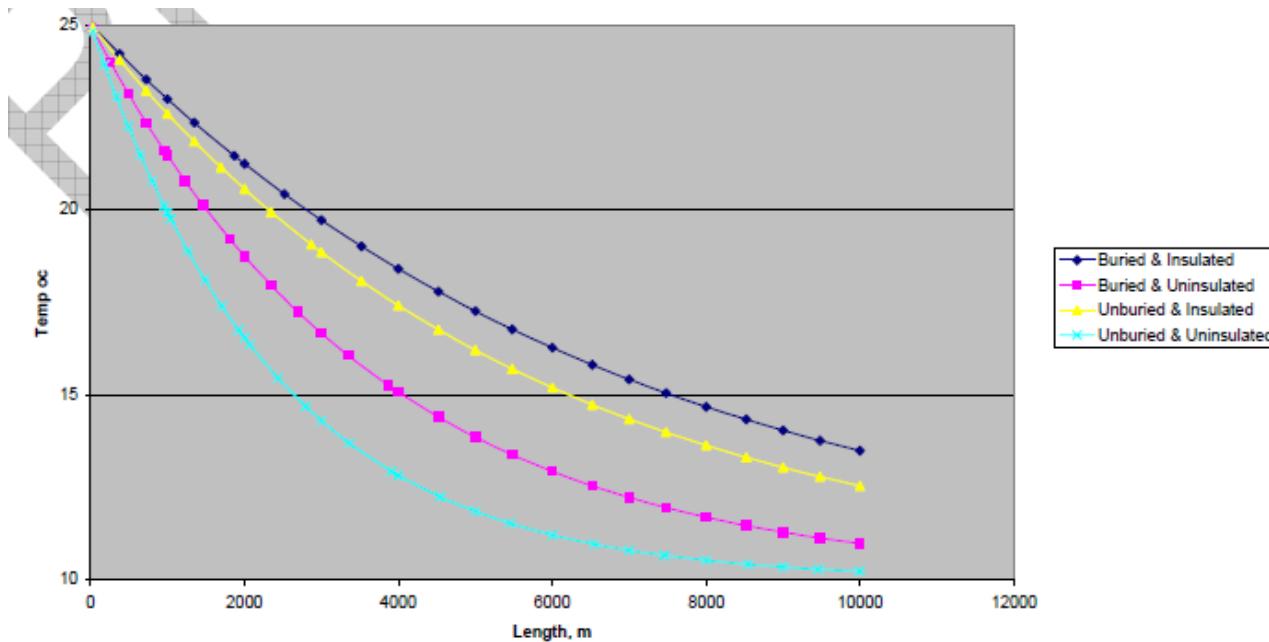
Subsea Cooling Spool

Watch for 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.

Pipeline Thermal Analysis



A steady state analysis will give an indication of the insulation requirements and a cost estimate. However, it must be emphasized that a steady state analysis alone is NOT sufficient for a final design of the insulation. Transient operations such as start-up, shutdown and blowdown will dictate the final insulation design. This requires use of a transient model.

Transients/Operating Procedures

In addition to the steady state design case a multi-phase, subsea systems must be assessed against all operating modes across the field life. 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 result in hydrate formation.

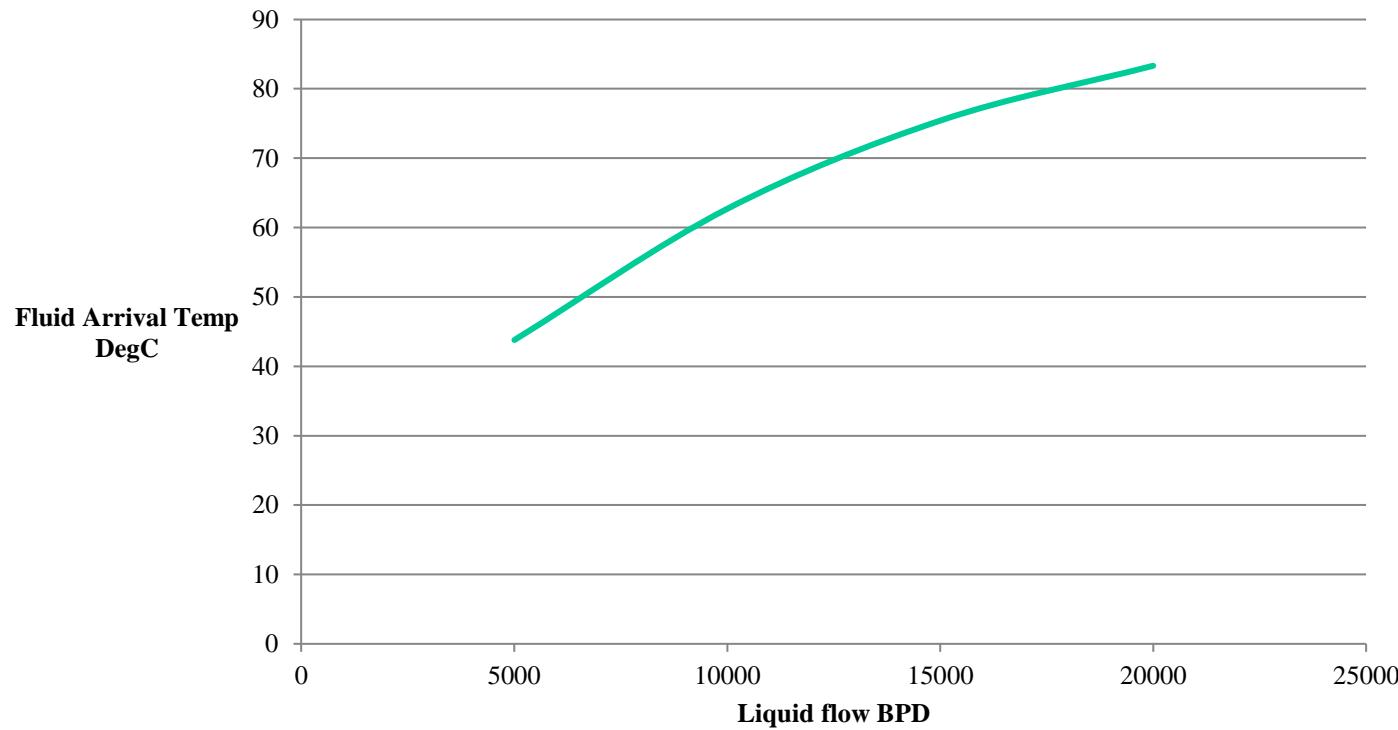
Blowdown – pressure reduction to avoid hydrate formation.

All of the above 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.

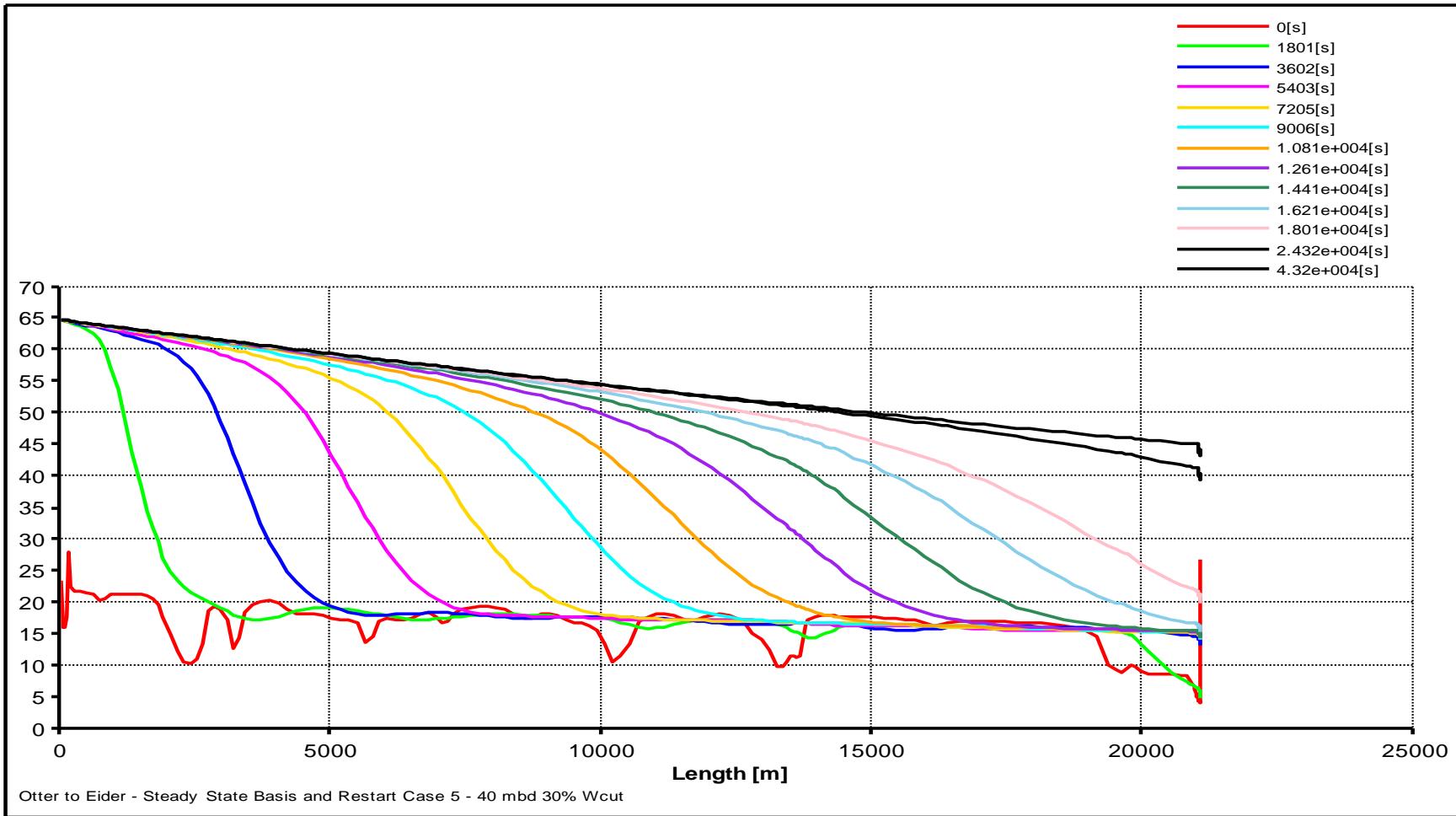
Transients/Operating Procedures

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 .



Typical Olga Transient – Pipeline Warm Up

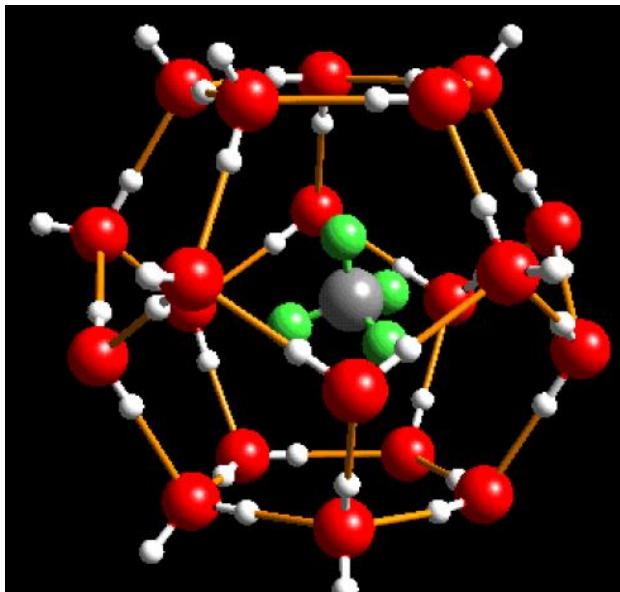
INNER WALL SURFACE TEMPERATURE, BRANCH-PIPE [C]



Hydrates

Natural gas hydrates (clathrates) are crystalline compounds formed by water with natural gases and associated liquids at high pressures and low temperatures.

Solid ice-like crystals composed of cages of hydrogen bonded water molecules surrounding/trapping small ‘guest’ gas molecules such as methane, ethane, propane

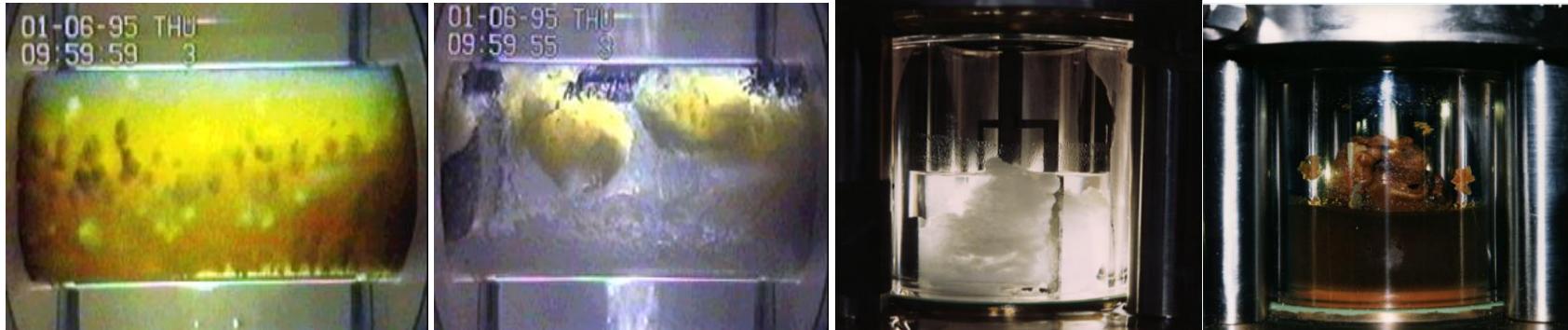


Hydrate Formation

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. Below about 1000m of water depth, the ocean bottom (mudline) 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.

Hydrate Appearance



Volume of Gas in Hydrate

The following are the properties of the methane hydrate:

density: 913 kg/m³

molar mass (molecular weight): 17.74 kg/kmol

methane concentration: 14.1 mole per cent

There are 141 molecules of methane per 859 molecules of water in the 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)

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

Hydrates

In summary, the conditions which affect hydrate formation are:

Primary Considerations

- Gas or liquid must be at or below its water dew point or saturation condition
- Temperature
- Pressure
- Composition

Secondary Considerations

- Mixing
- Kinetics
- Physical site for crystal formation and agglomeration such as a pipe elbow, orifice, thermowell, or line scale
- Salinity

Like pure ice, hydrates can block any type of flowline, production tubing, and pipeline. However, unlike ice, hydrates can form at much higher temperatures than 0 DegC.

One cubic metre of hydrates can contain approximately 180 standard cubic metres of gas.

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 is likely to drop into the hydrate formation region.

Hydrates Dissociation and Formation

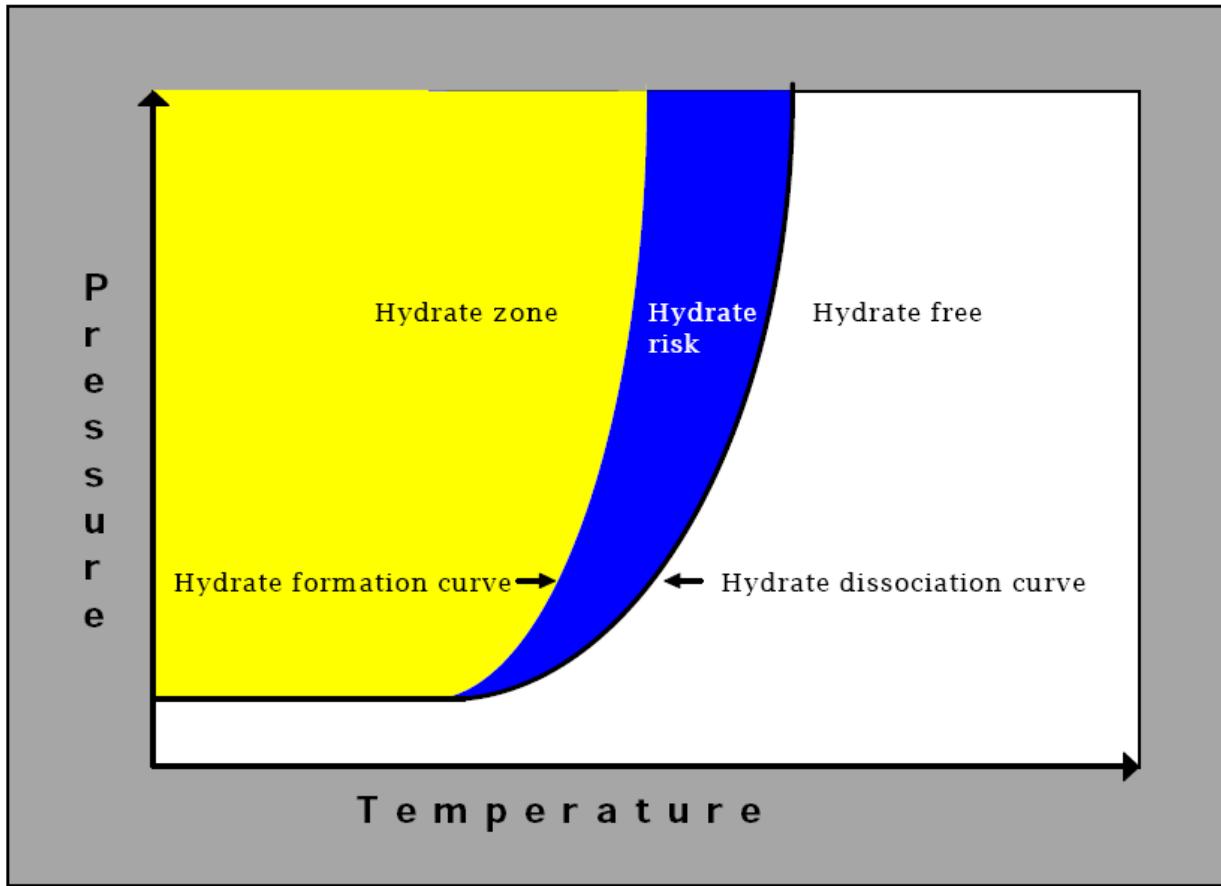
The hydrate dissociation temperature is defined as the highest temperature at which thermodynamically stable hydrates can exist in a system of known composition and at a given pressure. In general, the higher the pressure, the higher the temperature at which stable hydrates can exist. A plot of the hydrate 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 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.

Hydrate Formation



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 Estimation

Hydrate formation conditions can be estimated by the following methods;

Hydrate Curves

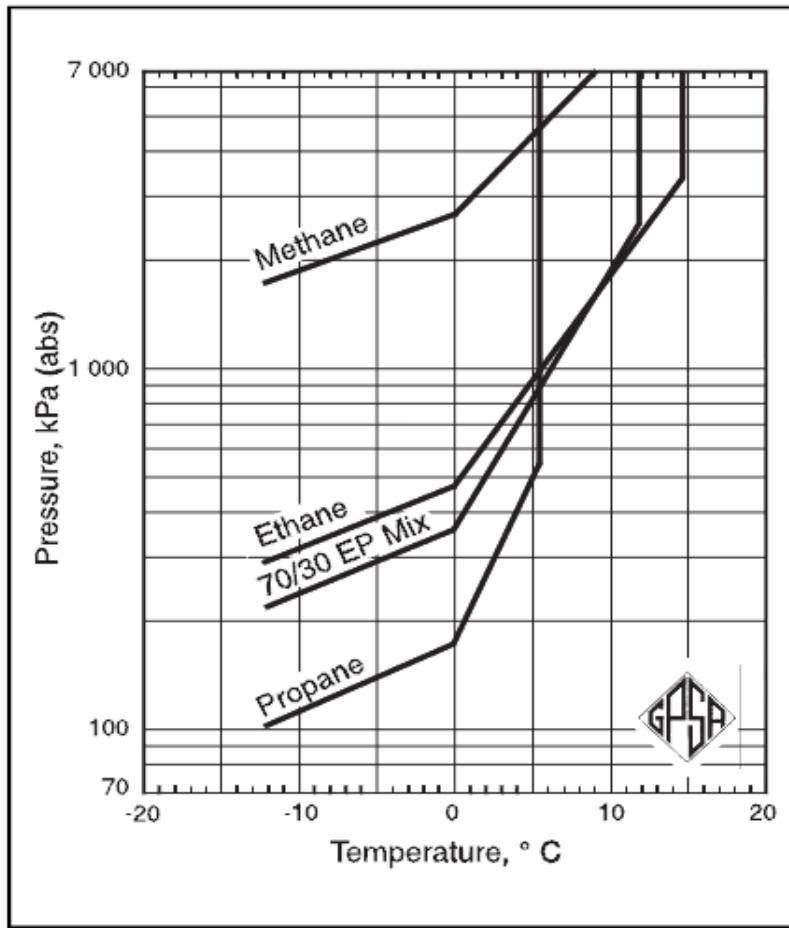
Equilibrium calculations using K values – similar to previous dew point calculation

Equations of state – contained within flow simulators.

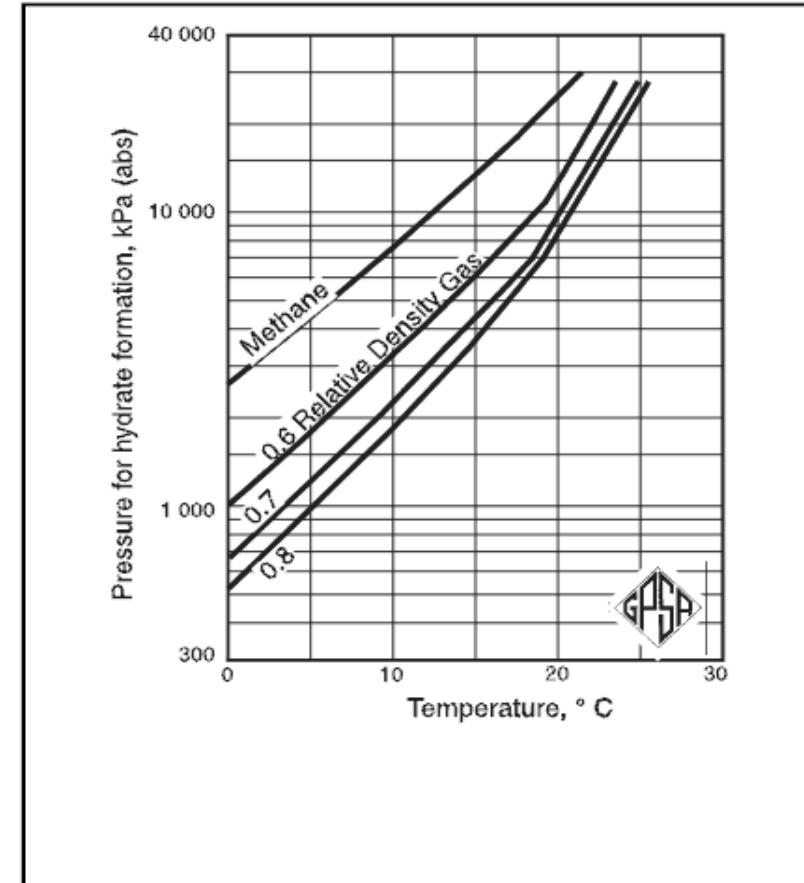
Hydrate Formation Curves

Use as first approximation only

Conditions for Hydrate Formation for Light Gases

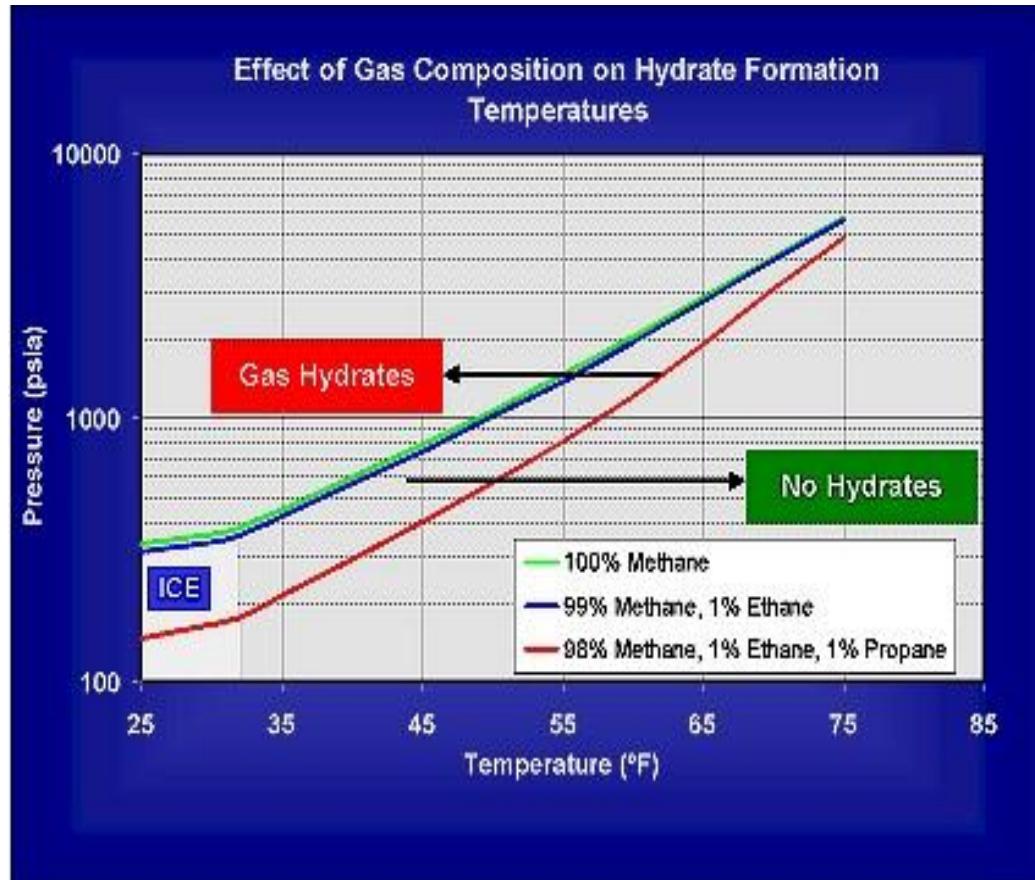


Pressure-Temperature Curves for Predicting Hydrate Formation



Relative gas density is the gas molecular weight/ molecular weight of air (29)

Effects of Gas Composition on Hydrate Formation



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 (9C).

By adding 1% ethane and 1% propane to the mixture, the hydrate formation temperature increases to 57°F (14C).

A hydrate model can predict the effects of the gas composition.

Hydrate Prediction

The Katz K value method utilises vapour solid equilibrium constants;

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

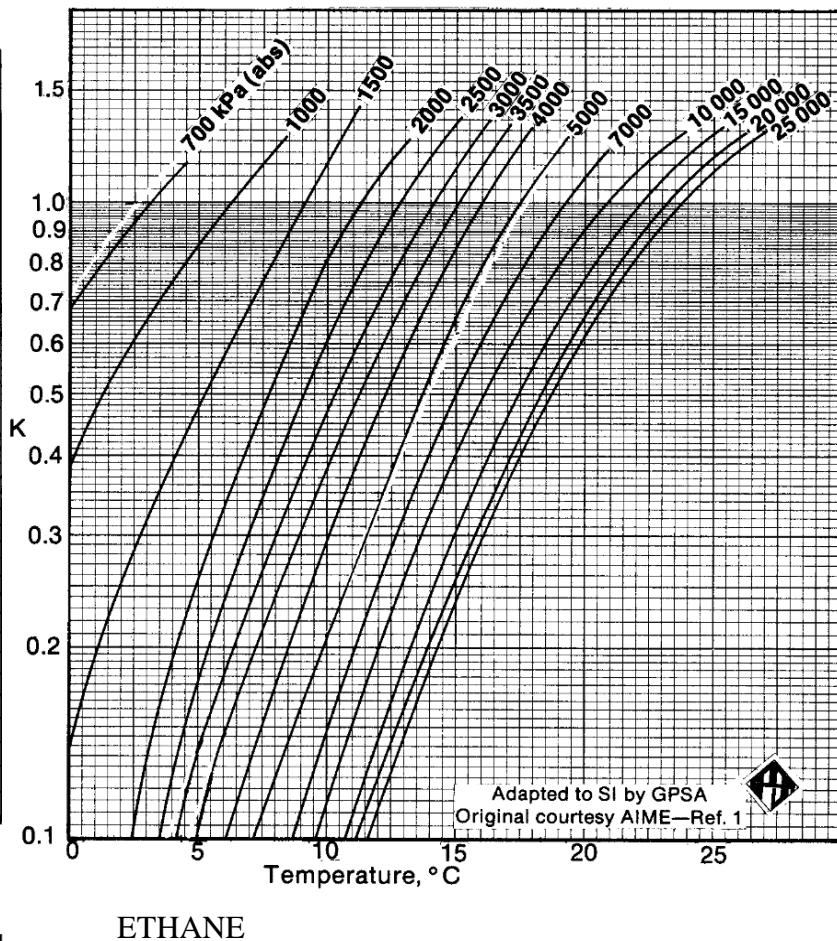
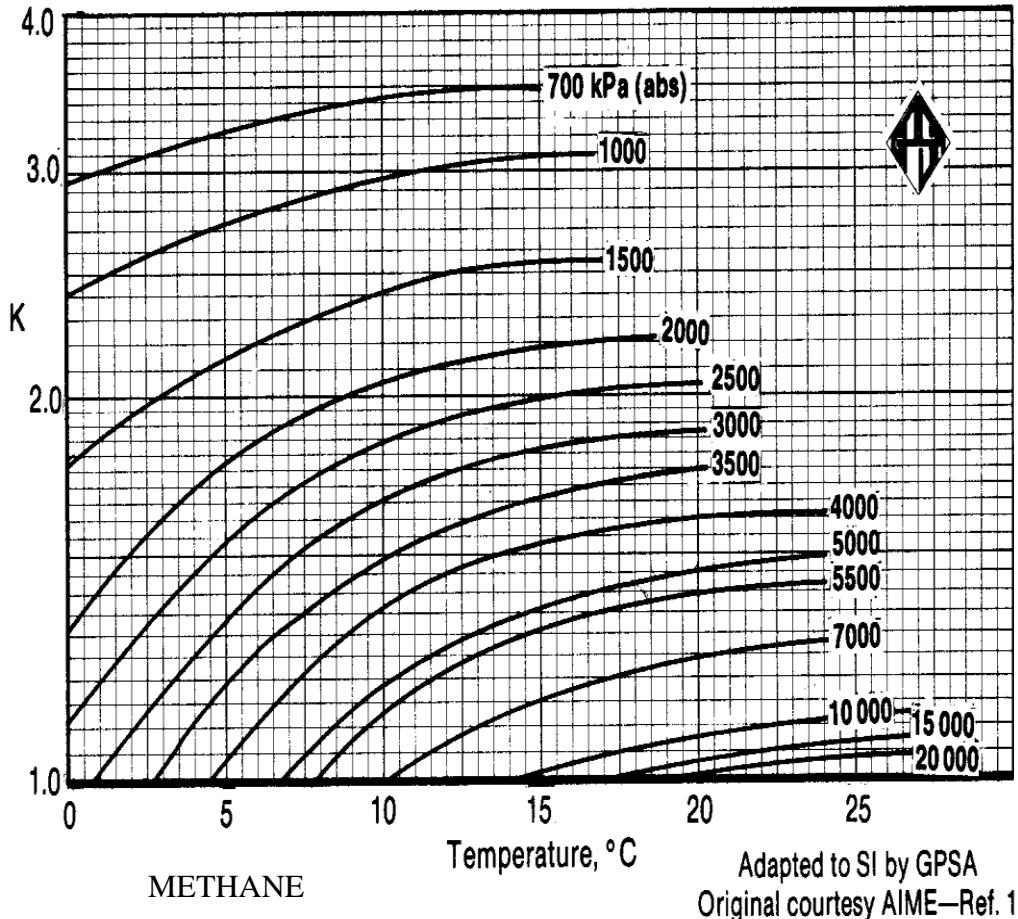
The applicable K-value correlations for the hydrate forming molecules (methane, ethane, propane, isobutane, normal butane, carbon dioxide, and hydrogen sulphide) are shown in the following charts. Normal butane cannot form a hydrate by itself but can contribute to hydrate formation in a mixture.

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.

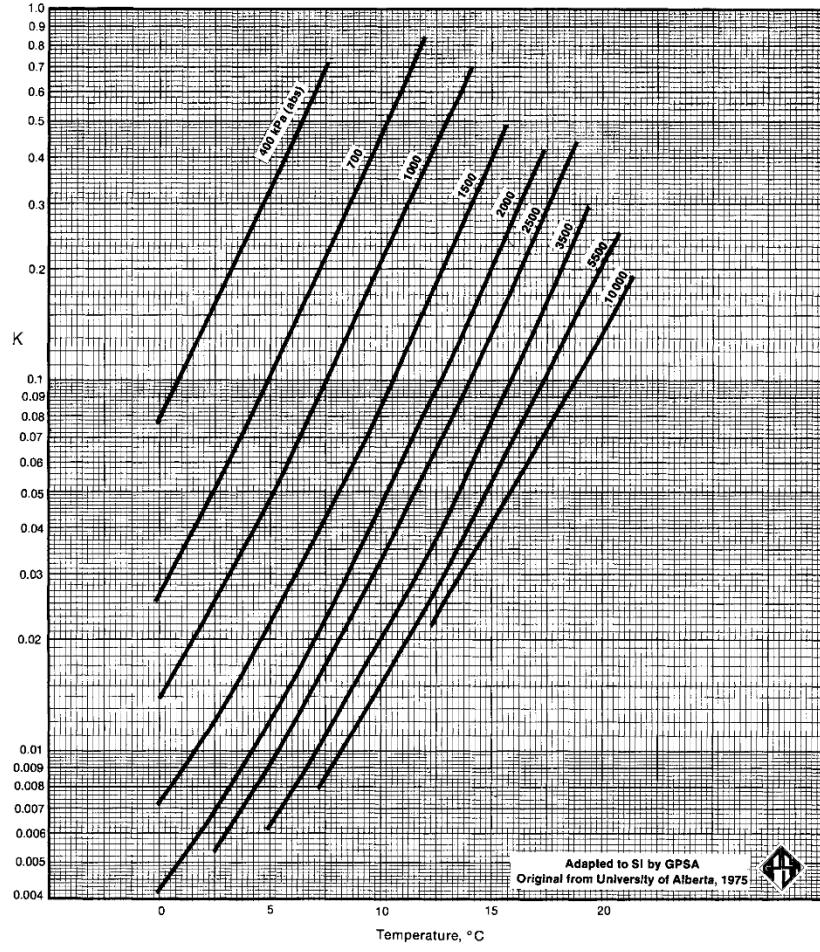
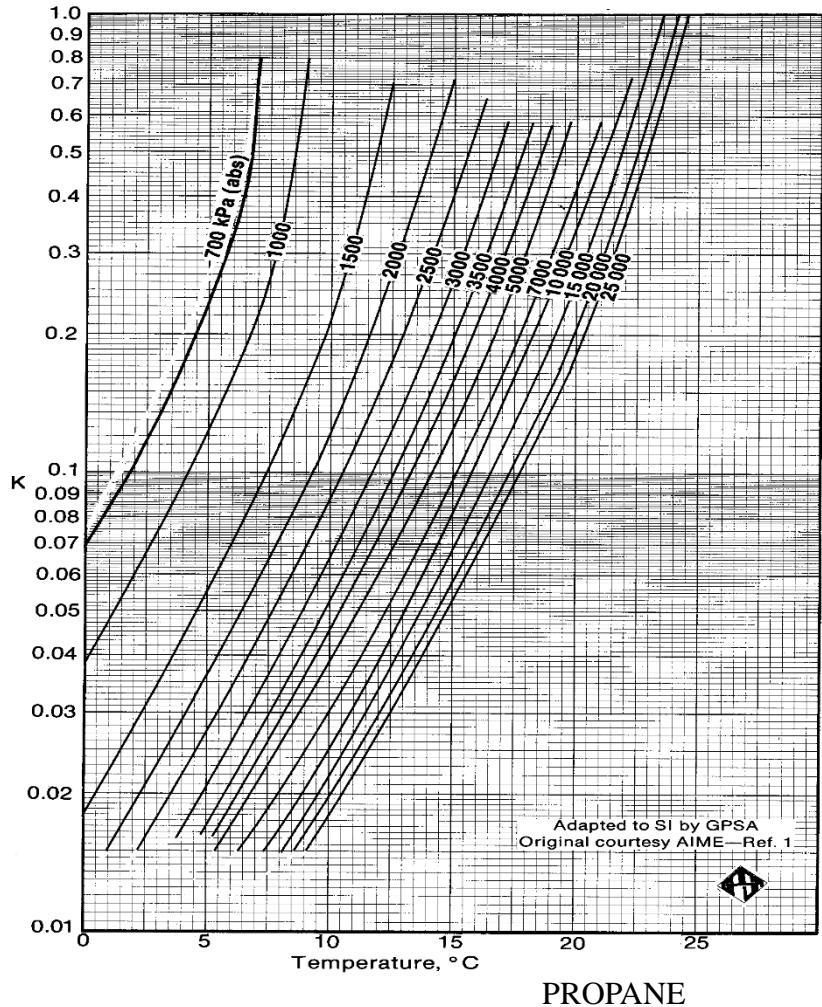
The K_{vs} values are used in a “dewpoint” equation to determine the hydrate temperature or pressure. The calculation is similar to a conventional dewpoint calculation and iterative until convergence is achieved when the following objective function is satisfied;

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

Hydrate K values

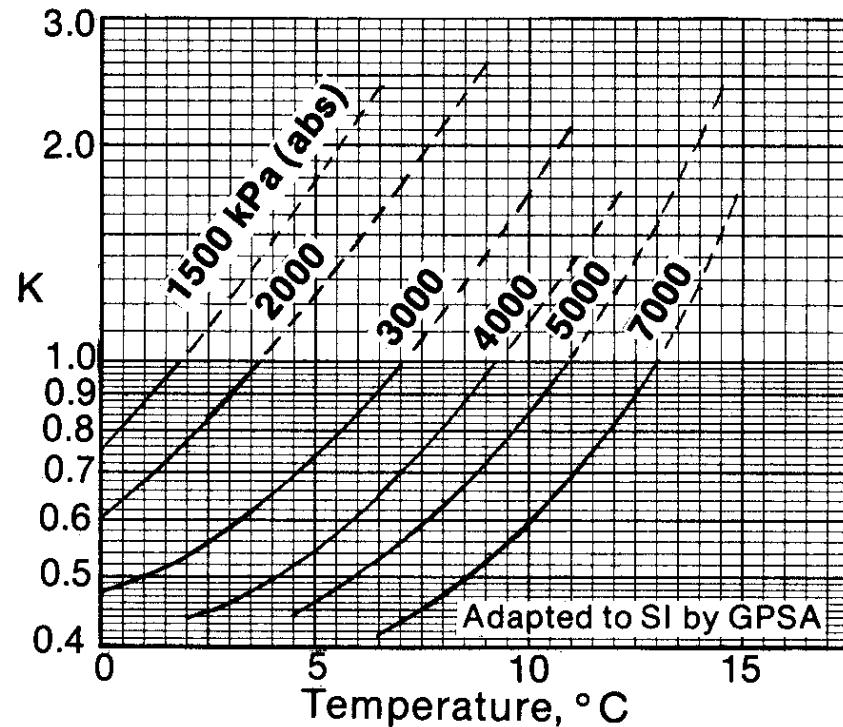
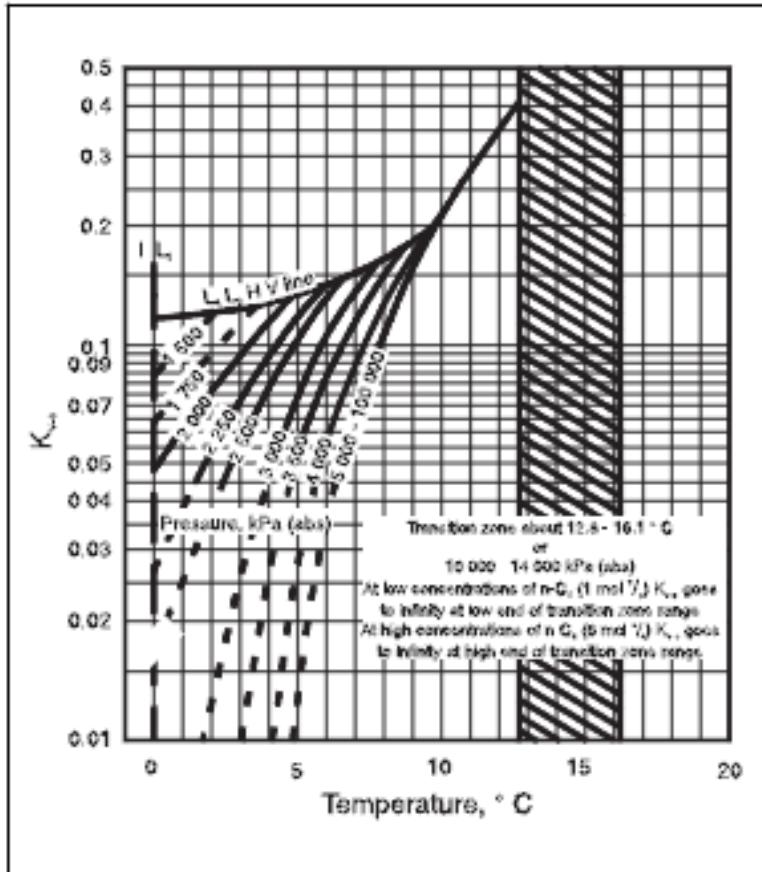


Hydrate K values



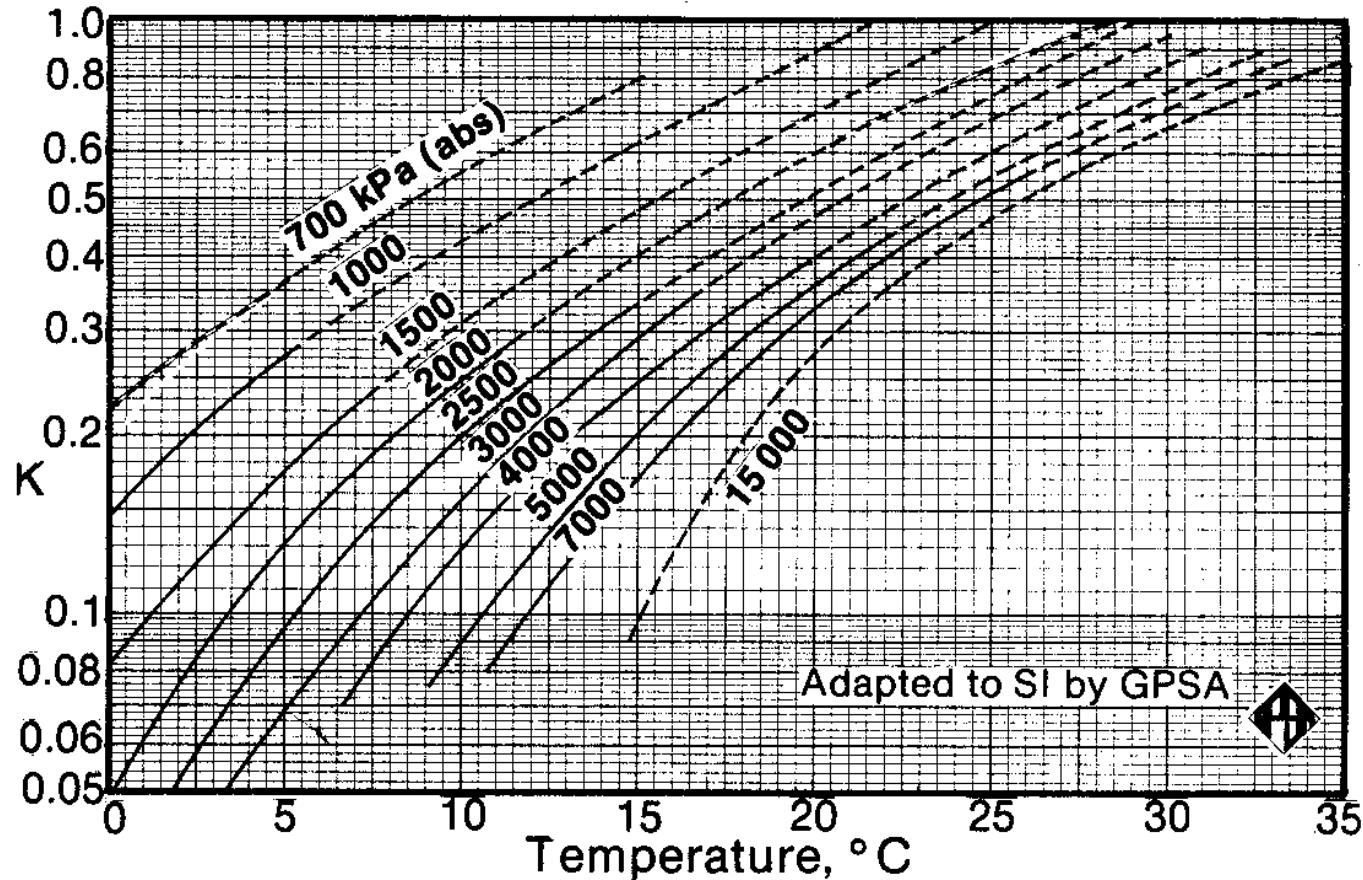
Hydrate K values

Vapor-Solid Equilibrium Constants for N-Butane



CARBON DIOXIDE,
CO₂

Hydrate K values



HYDROGEN SULPHIDE, H_2S

Hydrate Prediction Example

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

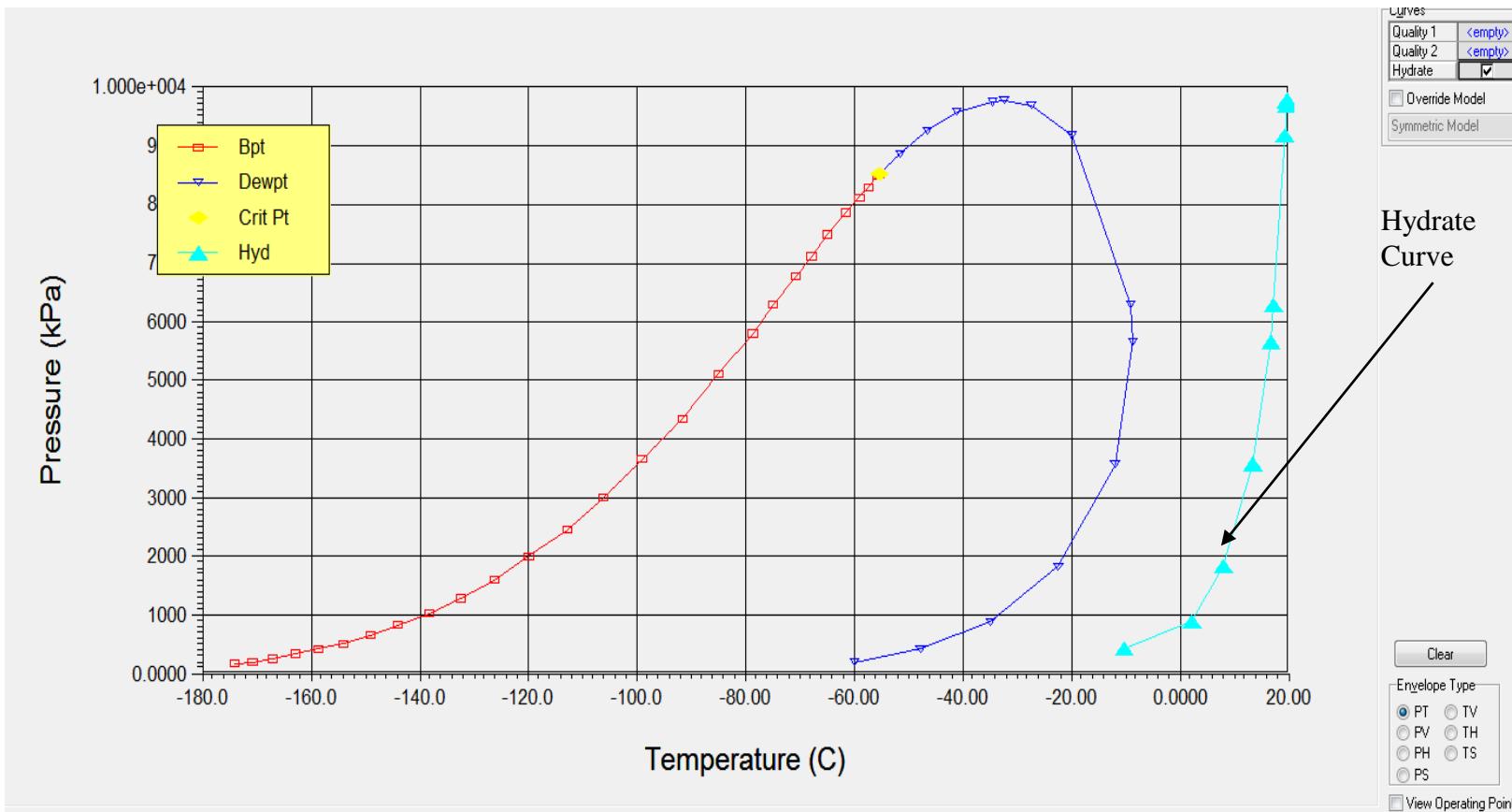
Component	Mole Fraction in Gas	2070 kPa (abs)		2760 kPa (abs)	
		K _{vs}	y/K _{vs}	K _{vs}	y/K _{vs}
Methane	0.784	2.04	0.384	1.75	0.448
Ethane	0.060	0.79	0.076	0.50	0.120
Propane	0.036	0.113	0.319	0.072	0.500
Isobutane	0.005	0.046	0.109	0.027	0.185
n-Butane	0.019	0.21	0.090	0.21	0.090
Nitrogen	0.094	*	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).

Hydrate Prediction Example

UniSim Calculation



Hydrate Prediction Example

Recall procedure for calculating a mixed gas molecular weight.

Com	in Gas
Methane	0.784
Ethane	0.060
Propane	0.036
Isobutane	0.005
n-Butane	0.019
Nitrogen	0.094
Carbon dioxide	0.002
Total	1.000

Molecular weight of above gas = $\sum y_i \cdot Mw_i$

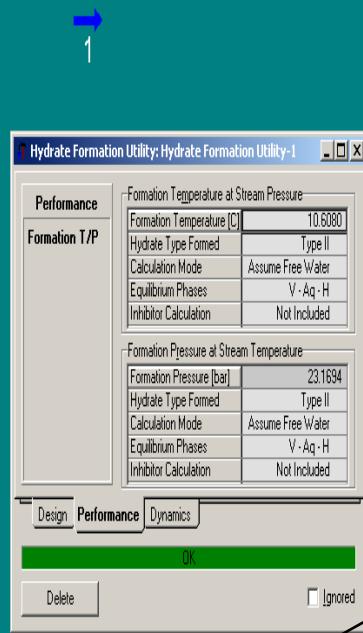
$$0.784 \times 16 + 0.06 \times 30 + 0.036 \times 44 + 0.005 \times 58 + 0.019 \times 58 + 0.094 \times 28 + 0.002 \times 44 = 20$$

Gas relative density, MW/MW of Air = 20/29 = 0.691

Number	Compound	Formula	Molar mass (Molecular weight)	Number	Compound	Formula	Molar mass (Molecular weight)	Number	Compound	Formula	Molar mass (Molecular weight)
1	Methane	C_4H_{10}	16.043	22	n-Octane	C_8H_{18}	114.231	31	Ethene(Ethylene)	C_2H_4	28.054
2	Ethane	C_2H_6	30.070	23	Diisobutyl	C_8H_{18}	114.231	32	Propene(Propylene)	C_3H_6	42.081
3	Propane	C_3H_8	44.097	24	Isooctane	C_8H_{18}	114.231	33	1-Butene(Butylene)	C_4H_8	56.108
4	Isobutane	C_4H_{10}	58.123	25	n-Nonane	C_9H_{20}	128.258	34	cis-2-Butene	C_4H_8	56.108
5	n-Butane	C_4H_{10}	58.123	26	n-Decane	$C_{10}H_{22}$	142.285	35	trans-2-Butene	C_4H_8	56.108
6	Isopentane	C_5H_{12}	72.150	27	Cyclopentane	C_5H_{10}	70.134	36	Isobutene	C_4H_8	56.108
7	n-Pentane	C_5H_{12}	72.150	28	Methylcyclopentane	C_6H_{12}	84.161	37	1-Pentene	C_5H_{12}	70.134
8	Neopentane	C_5H_{12}	72.150	29	Cyclohexane	C_6H_{12}	84.161	38	1,2-Butadiene	C_4H_6	54.092
9	n-Hexane	C_6H_{14}	86.177	30	Methylcyclohexane	C_7H_{14}	98.188	39	1,3-Butadiene	C_4H_6	54.092
10	2-Methylpentane	C_6H_{14}	86.177	40	Isoprene	C_5H_8	68.119	41	Acetylene	C_2H_2	26.038
11	3-Methylpentane	C_6H_{14}	86.177	42	Benzene	C_6H_6	78.114	43	Toluene	C_7H_8	92.141
12	Neohexane	C_6H_{14}	86.177	44	Ethylbenzene	C_7H_8	106.167	45	c-Xylene	C_8H_{10}	106.167
13	2,3-Dimethylbutane	C_7H_{16}	86.177	46	m-Xylene	C_8H_{10}	106.167	47	p-Xylene	C_8H_{10}	106.167
14	n-Heptane	C_7H_{16}	100.204	48	Synthetic	C_6H_{14}	104.152	49	Isopropylbenzene	C_9H_{12}	120.194
15	2-Methylhexane	C_7H_{16}	100.204	50	Methyl alcohol	CH_3O	32.042	51	Ethyl alcohol	C_2H_5O	46.069
16	3-Methylhexane	C_7H_{16}	100.204	52	Carbon monoxide	CO	28.010	53	Carbon dioxide	CO_2	44.010
17	3-Ethylpentane	C_7H_{16}	100.204	54	Hydrogen sulfide	H_2S	34.082	55	Sulfur dioxide	SO_2	64.065
18	2,2-Dimethylpentane	C_7H_{16}	100.204	56	Ammonia	NH_3	17.0305	57	Air	$N_2 + O_2$	29.9625
19	2,4-Dimethylpentane	C_7H_{16}	100.204	58	Hydrogen	H_2	2.0159	59	Oxygen	O_2	31.9986
20	3,3-Dimethylpentane	C_7H_{16}	100.204	60	Nitrogen	N_2	28.0134	61	Chlorine	Cl_2	70.9054
21	Tripane	C_7H_{16}	100.204	62	Water	H_2O	18.0153	63	Helium	He	4.0026
				64	Hydrogen chloride	HCl	36.461				

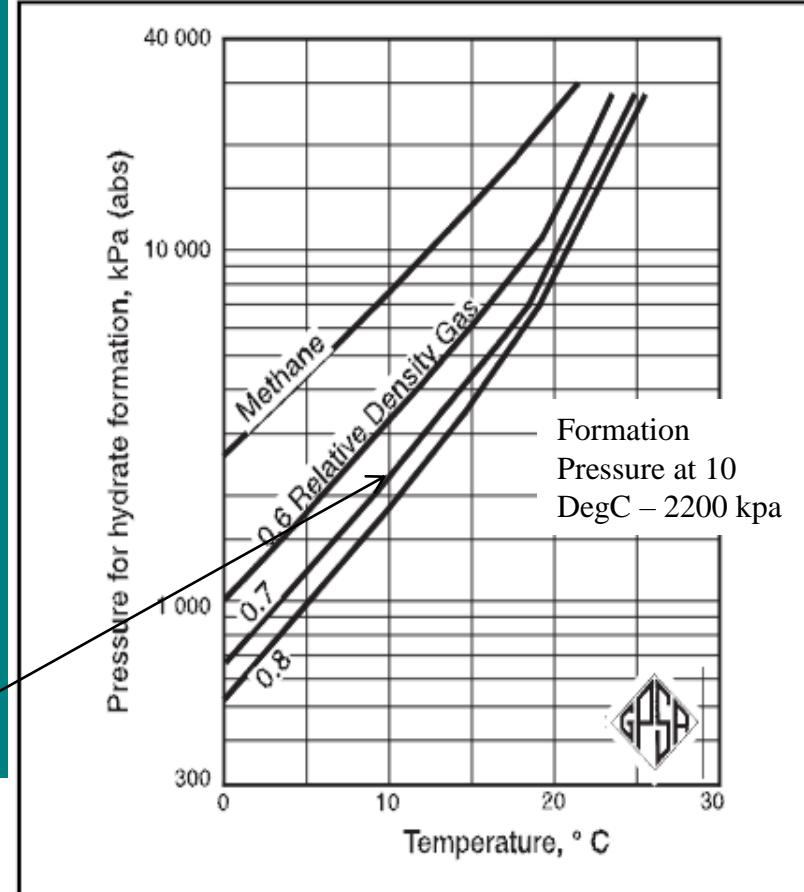
Hydrate Prediction Example – Unisim and Simple GPSA Chart

1		
Temperature	10.00	C
Pressure	25.00	bar
Molar Flow	100.0	kgmole/h
Master Comp Mole Frac (Methane)	0.7840	
Master Comp Mole Frac (Ethane)	0.0600	
Master Comp Mole Frac (Propane)	0.0360	
Master Comp Mole Frac (i-Butane)	0.0050	
Master Comp Mole Frac (n-Butane)	0.0190	
Master Comp Mole Frac (Nitrogen)	0.0940	
Master Comp Mole Frac (CO ₂)	0.0020	



Gas Molecular Weight – 20 ; Relative Density = 0.69

Pressure-Temperature Curves for
Predicting Hydrate Formation



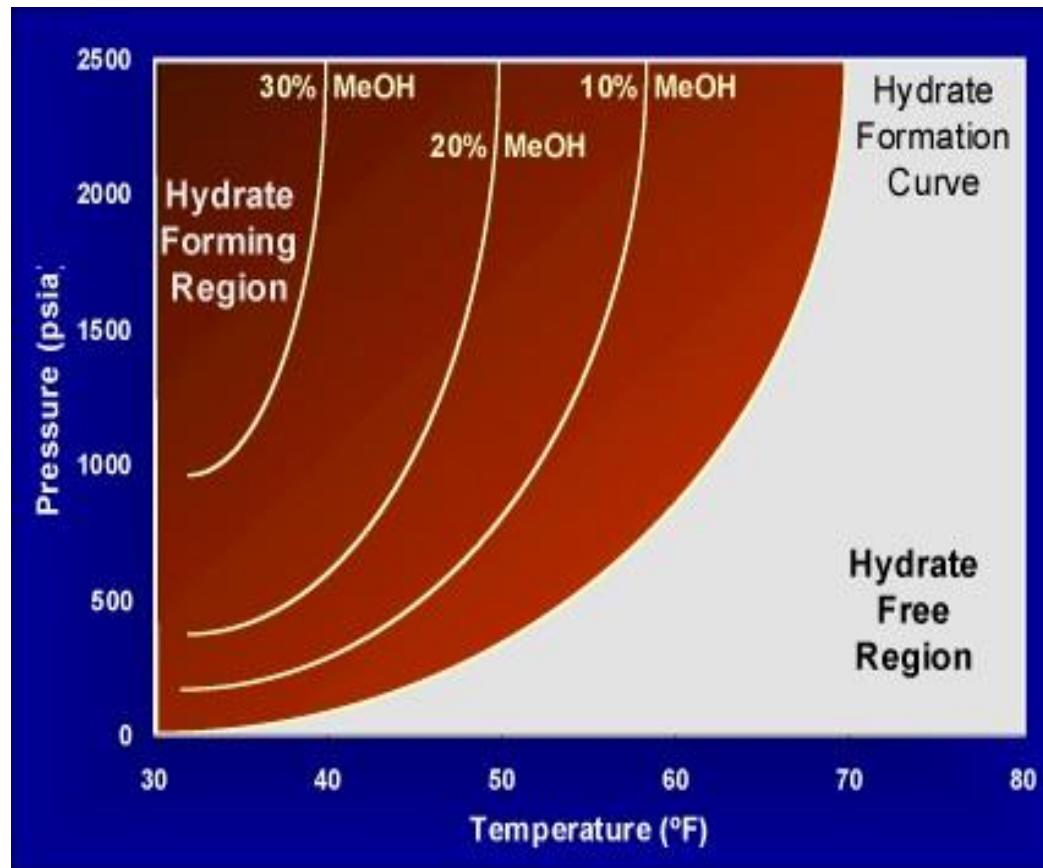
Hydrate Formation Envelope

Operating conditions within the grey region, no hydrates will form.

Operating conditions (either steady state or transient) in the red region, hydrate formation is possible. And more likely the further into the red region

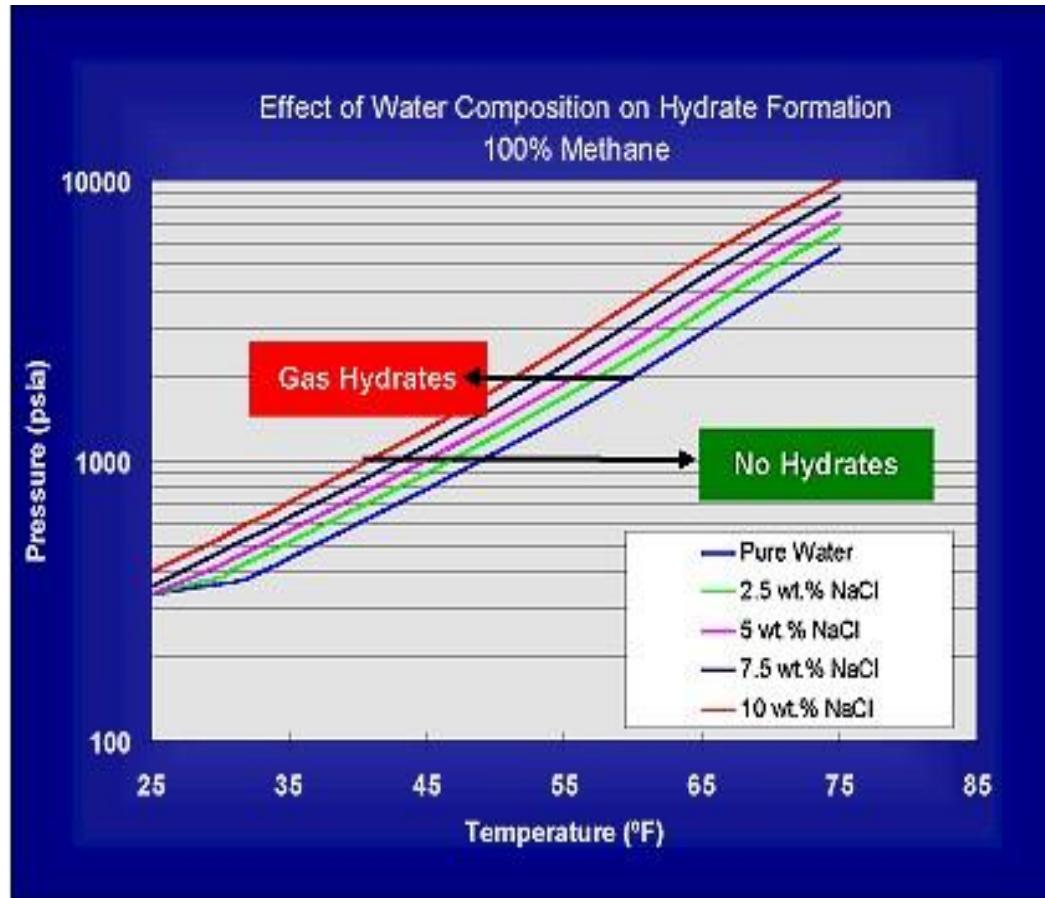
The figure also shows the hydrate formation curve for 10, 20 and 30% methanol inhibition. A hydrate model can also be used to predict these curves.

Injection of methanol lowers the temperature at which the hydrate will form.



A hydrate formation envelope for a Gulf of Mexico fluid.

Effects of Water Composition on Hydrate Formation –Effect of salinity



The effect of NaCl on the hydrate formation curve of pure methane.

Salts inhibit hydrate formation in the same manner that salt depresses the freezing point of pure water - salting winter roads.

A produced water analysis will allow a less conservative estimate of the hydrate formation conditions. Standard hydrate prediction models can predict the effect of salts.

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

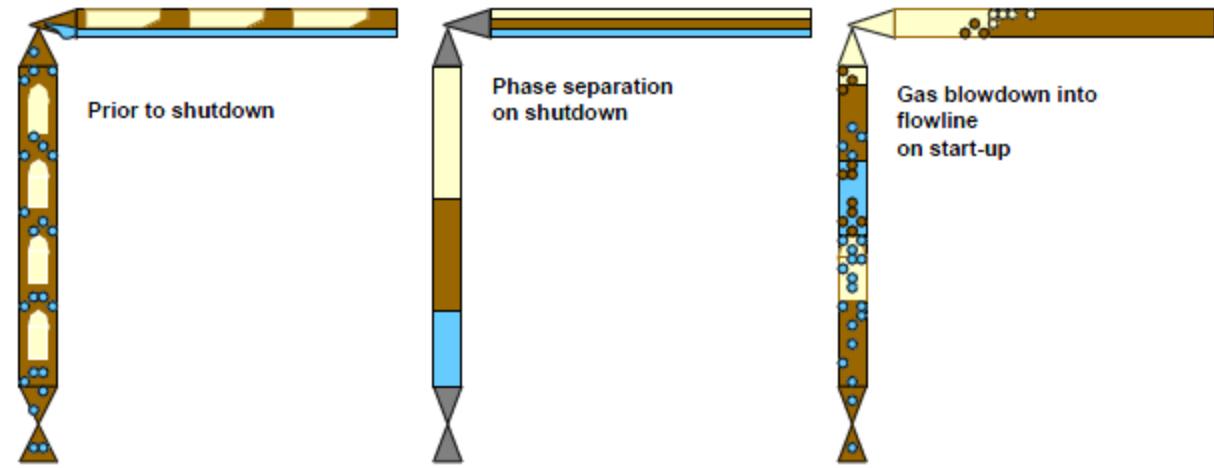
Chemicals such as methanol (MeOH), mono-ethylene glycol (MEG) or Threshold Hydrate Inhibitors (THI) can be added. These chemicals suppress the formation of hydrates or prevent hydrates forming blockages.

Conventional Hydrate Inhibitors

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.

Start Up Low temperatures

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.



Methanol as a Hydrate Inhibitor

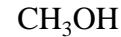
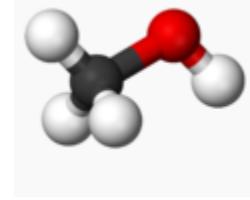
Advantages

Easily vaporised into the gas phase so methanol condenses when free water condenses.

Used for 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

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.

MEG as a Hydrate Inhibitor

Advantages

Low volatility into the gas and condensate phases.

Disadvantages

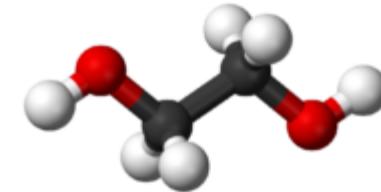
High viscosity inhibits flow in umbilicals and injection lines.

Possibility of salt precipitation and fouling.

Remains in the aqueous phase.

It may be difficult to design a glycol system applicable for start-up since it does readily vapourise. The glycol may not be available when free water condenses from the vapour phase

Glycol has a transportability problem because it does not vaporise, it is viscous, and tends to accumulate at the bottom of the pipe.



Mono Ethylene Glycol
 $\text{HO}-\text{CH}_2\text{CH}_2-\text{OH}$

THI - Threshold Hydrate Inhibitors

These are inhibitors developed over the past decade.

There are three general classes of THI - threshold hydrate inhibitors.

Kinetic Inhibitors

Do not thermodynamically lower the hydrate formation temperature.

They prevent crystals from forming (i.e., they prevent nucleation) and thereby **temporarily** allow the fluids to be supercooled (cooled below the actual freezing point without crystallisation). Typically the best kinetic inhibitors will allow up to 12°C of supercooling.



Emulsion Additives (Slurry Additives or Anti-Agglomerates)

Do not thermodynamically lower the hydrate formation temperature but attempt to prevent agglomeration of hydrate crystals and thereby enable transport of hydrates.

By forming an emulsion they limit the droplet size available for hydrate formation.

Crystal Growth Inhibitors

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.

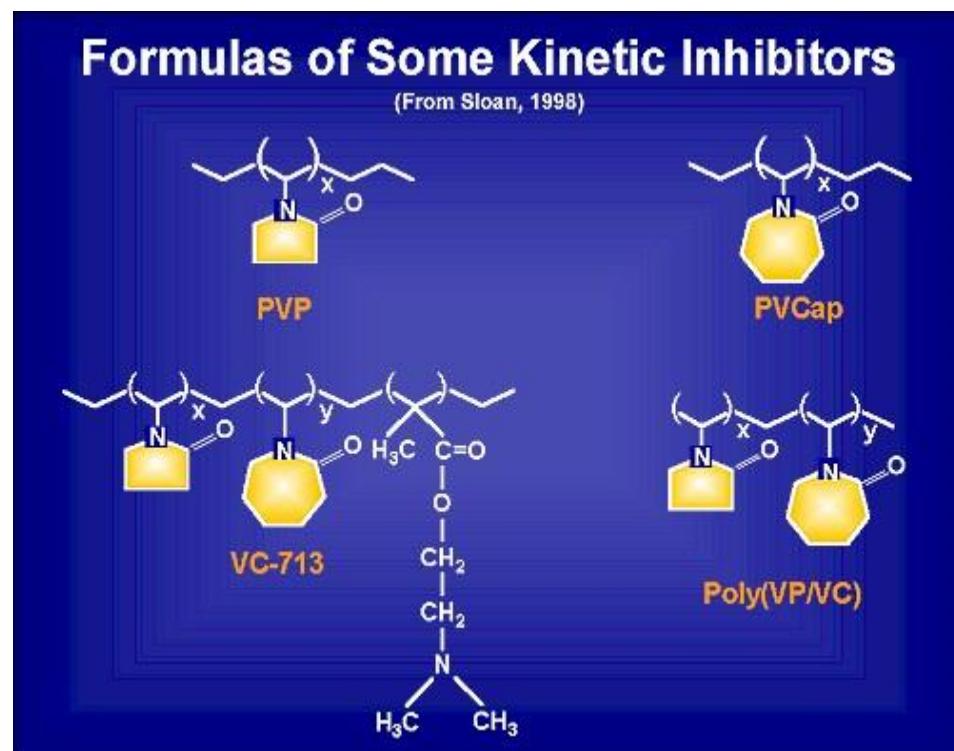
The growth inhibitors may ultimately result in a mass of small hydrate crystals dispersed in the dense hydrocarbon phase.

The Ice Fish – protein in blood was basis for new range of hydrate inhibitors

Kinetic Hydrate 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.

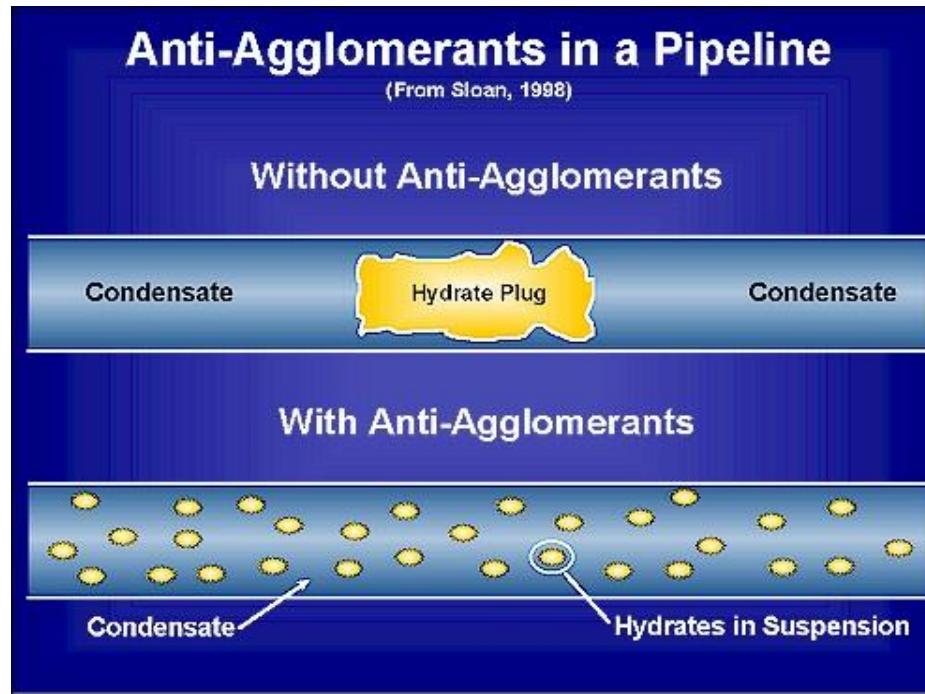
Kinetic inhibitors are commonly polymers. Each of the chemicals has a polyethylene backbone, connected to pendant groups typically containing an amide ($-N-C=O$) linkage, frequently within a five or seven member ring. As the inhibitor adsorbs on the hydrate crystal, the pendant group penetrates specific 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.



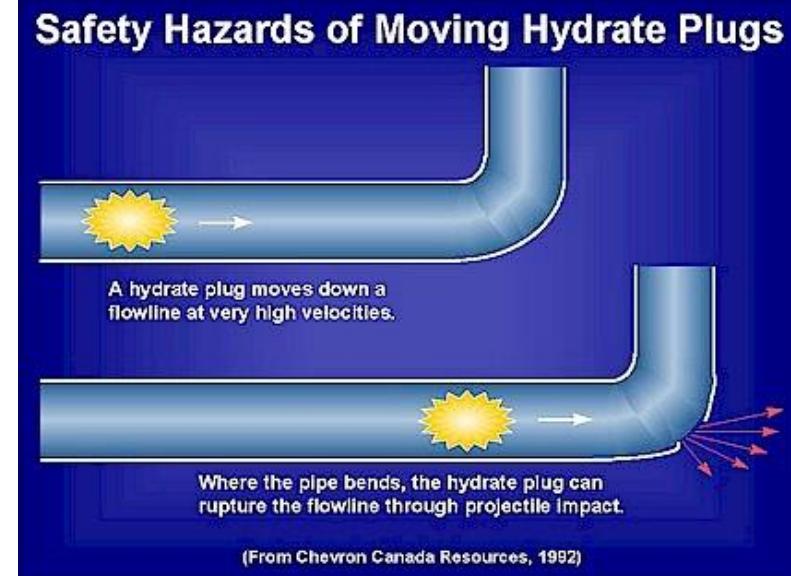
Typically the measure of the effectiveness of the kinetic inhibitor is the degree of subcooling a system can operate without forming hydrates. Subcooling (ΔT) is the measure of the lowest temperature that the system can be operated relative to the hydrate formation temperature at a given pressure. The degree of subcooling appears to be pressure independent; however, it is a function of the polymer, molecular weight of the polymer and the amount of salt, glycol, and alcohol present.

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

Anti-Agglomerants or Emulsion Additives



Hydrate Formation in Flowlines



Hydrate Formation in Flowlines

Hydrates contain as much as 180 volumes (STP) of gas per volume of hydrate. When the plugs are dissociated by heating, any confinement causes rapid gas pressure increases which can lead to pipeline ruptures

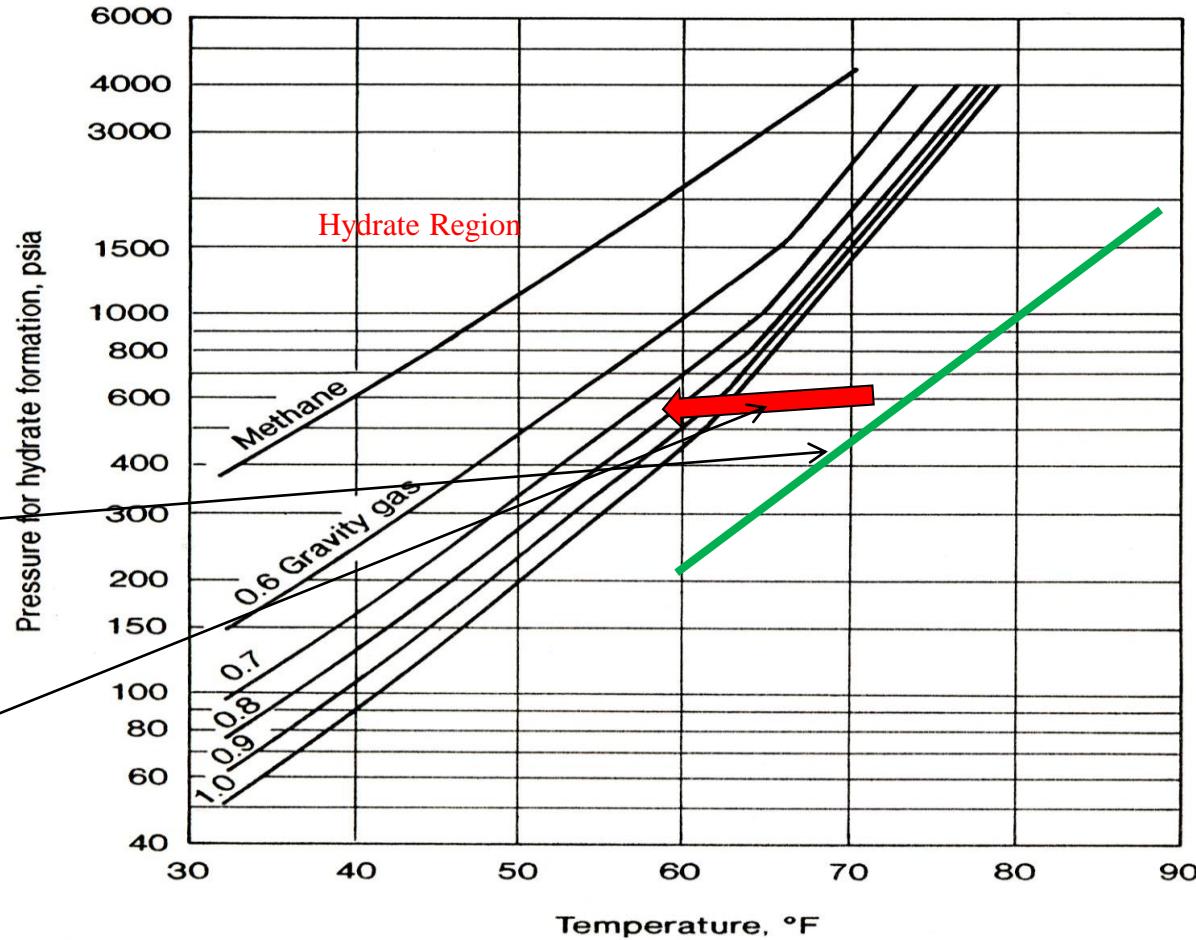


Survival Time to Hydrate

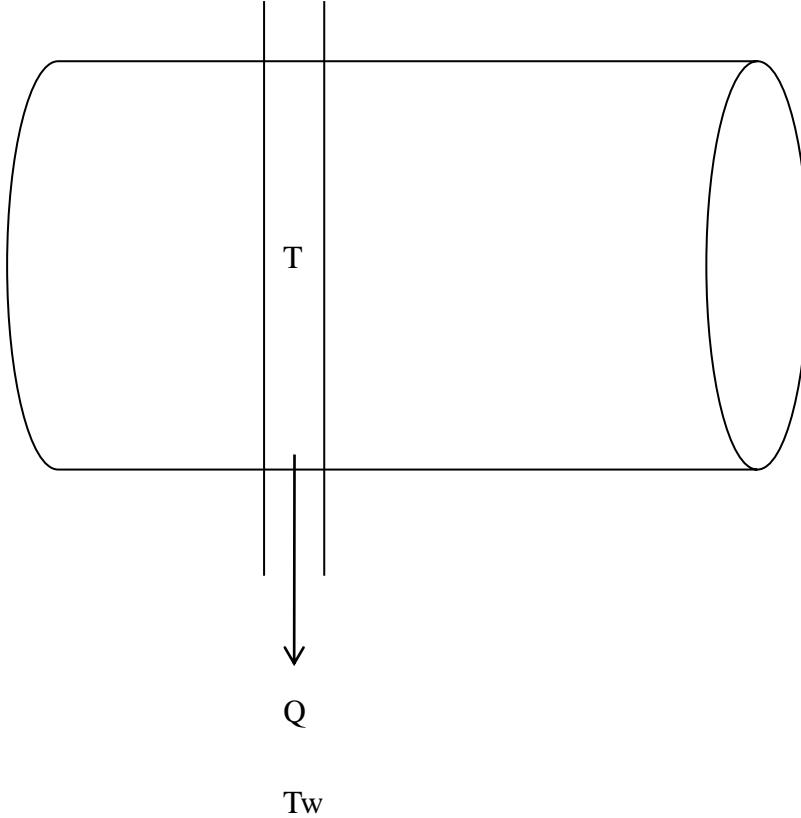
Whilst insulation will allow a flowing pipeline to be operated outside the hydrate formation region. If the flow is stopped then the fluids within the line will begin cool and the pipeline pressure will settle out at a pressure between the flowing inlet and outlet pressure.

Steady State pressure temperature profile of pipeline

Pipeline temperature reduces to local ambient when flow ceases. The pipeline contents are at risk to hydrate formation. The time taken to reach hydrates can be a key factor in determining the pipeline insulation level.



Pipeline transient temperature decay – static pipe



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 ($J/kg \text{ } ^\circ\text{C}$)

U = overall heat transfer coefficient ($\text{W}/\text{m}^2 \text{ } ^\circ\text{C}$)

A = outside area of pipe (m^2)

T = temperature of fluid inside the pipe ($^\circ\text{C}$)

T_w = temperature of surroundings ($^\circ\text{C}$)

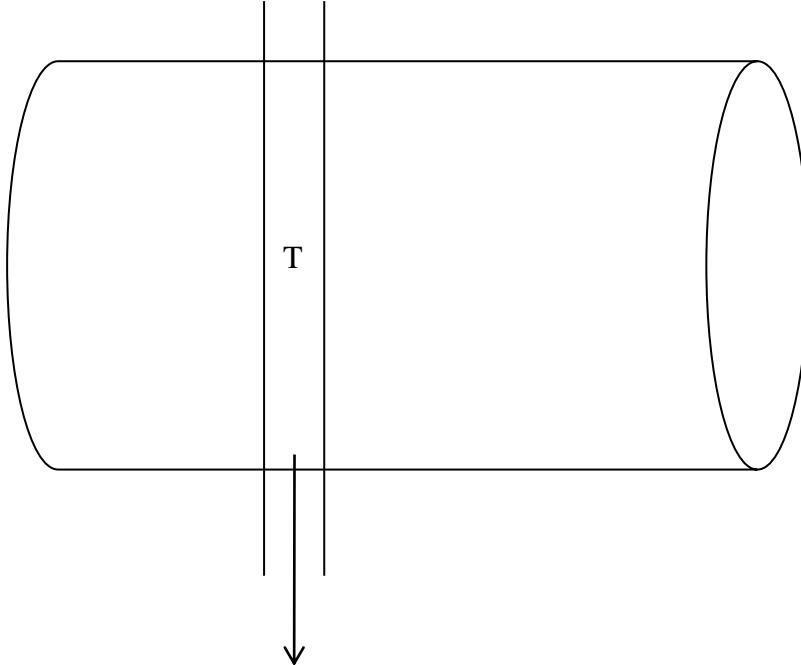
Heat loss to surroundings;

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

Equating;

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

Pipeline transient temperature decay



Integrating from t_i to t

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

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 temperature at time zero (°C)

T = Temperature at time t

t = time (s)

Inside film heat transfer coefficient, h_i

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.

Where

h_i = film coefficient for fluid in pipe, $\text{W}/\text{m}^2\text{°C}$

β = coefficient of thermal expansion ($1/\text{°K}$)

α = thermal diffusivity (m^2/s) = $k/(\rho \cdot C_p)$

v = kinematic viscosity (m^2/s) = μ/ρ

g = gravity = 9.81 m/s^2

L = Characteristic length – diameter (m)

ΔT = temperature of fluid – external ambient ($^\circ\text{K}$)

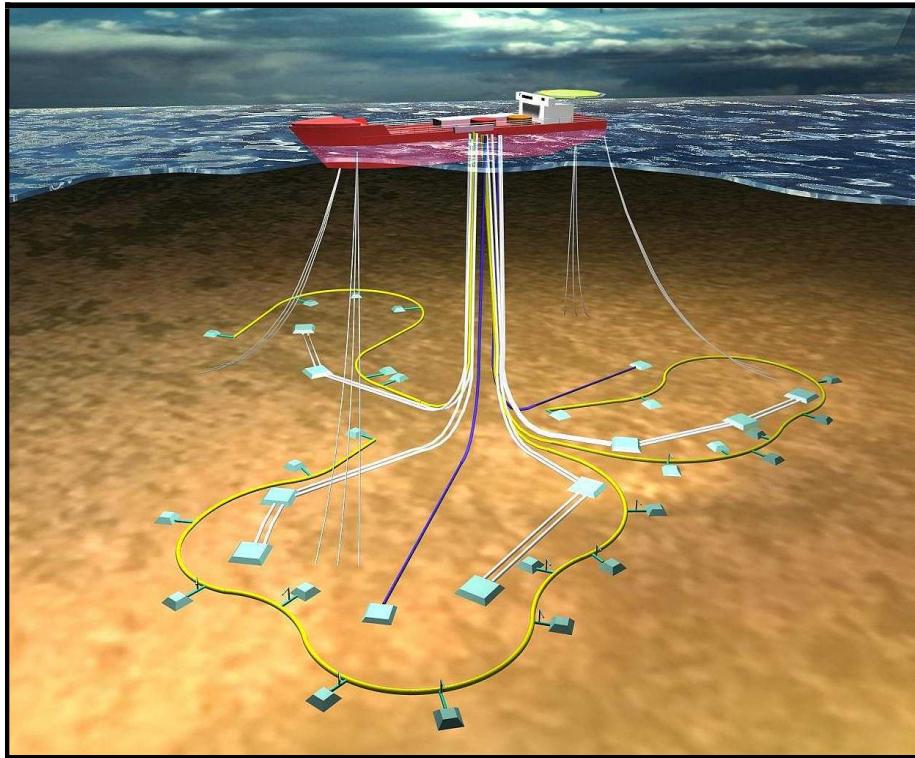
D = diameter (m)

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

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

$$Nu = h_i D / k$$

Hydrate Plug Removal



There are four main methods which may be applied in the removal of hydrate plugs:

- Hydraulic methods – Depressurisation
- Chemical methods – injection
- Thermal methods – direct heating

Wax



Wax

Wax is not a single compound but a range of high molecular weight paraffins(C17+) that solidify from crude oil.

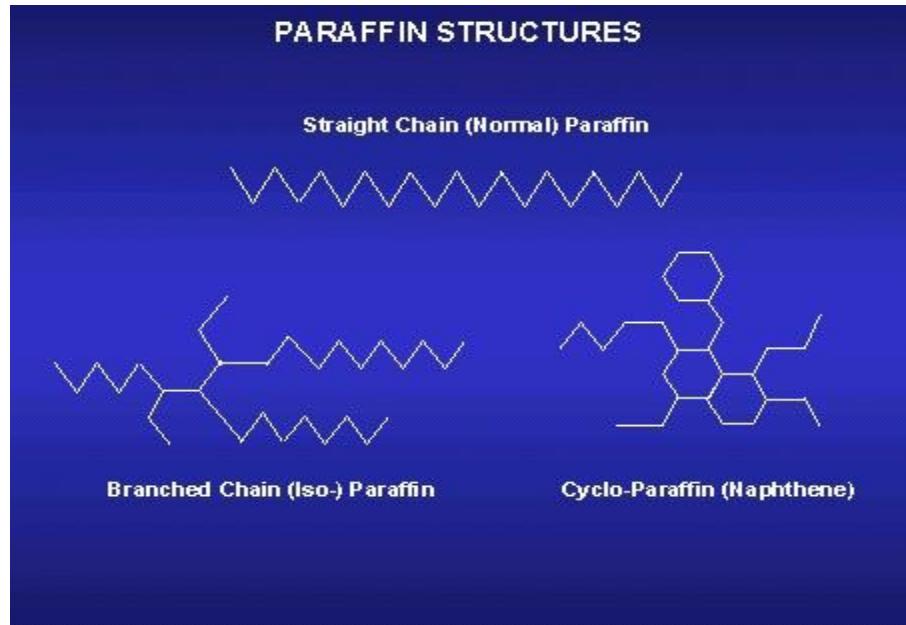
Waxes consist of straight chain, normal paraffins or may be branched or cyclic paraffins.

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.



Operational Issues



Wax can deposit on pipe walls



Wax can increase the viscosity



Wax can cause the crude oil to gel

Reduced throughput of system due to reduced diameter and increased roughness

Difficult to restart after prolonged shutdown due to gelling

Corrosion under hard wax, wax is a nucleation site for hydrates

Wax Appearance Temperature (WAT)

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.

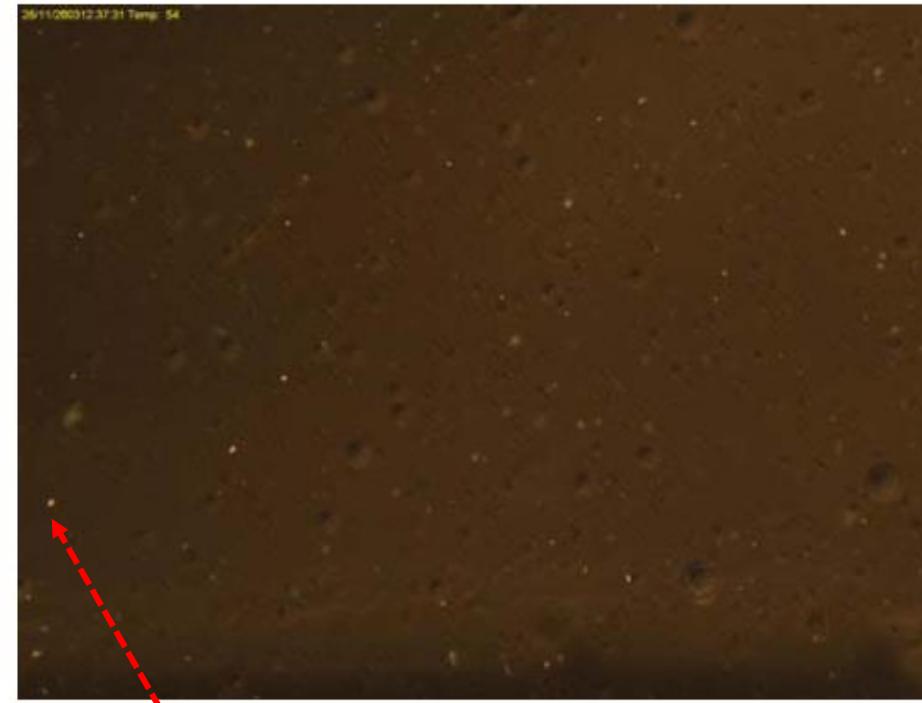
The WAT can be used along with production profiles and thermal modelling of the production scenarios to determine if, when and where waxes may cause operational problems.

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

Wax Appearance Temperature Visual observations



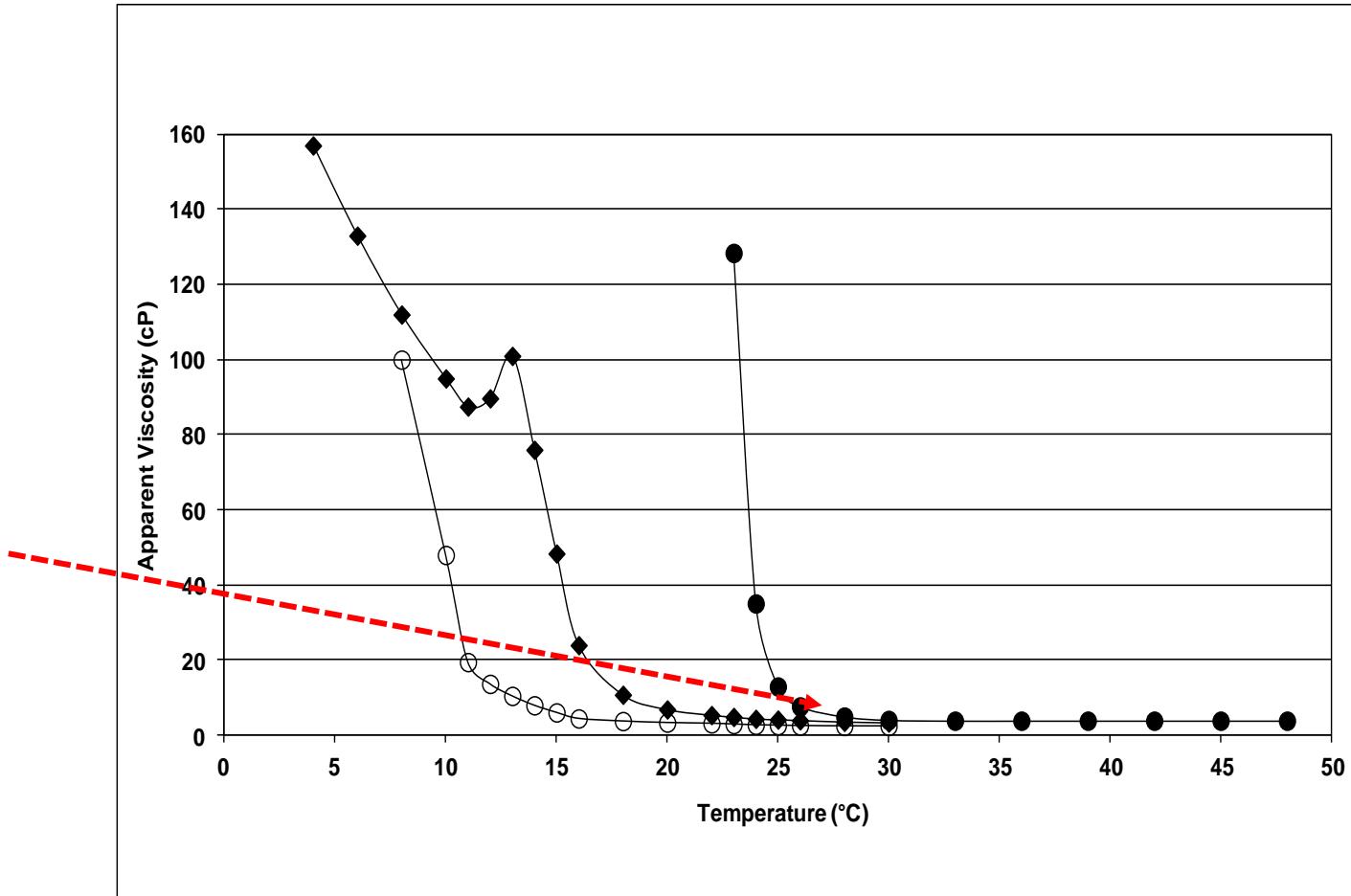
55.9°C :No visual wax



54°C Wax first appearing

Wax Appearance Temperature Comparison North Sea Fields

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



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).



Gel Strength

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.

Breakaway Yield Stress

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)

Breakaway yield stress is measured as 5Mpa. For a 100 km long, 0.3m diameter then 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 gel plug will remain and prevent production.

Effect of Wax on Viscosity

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

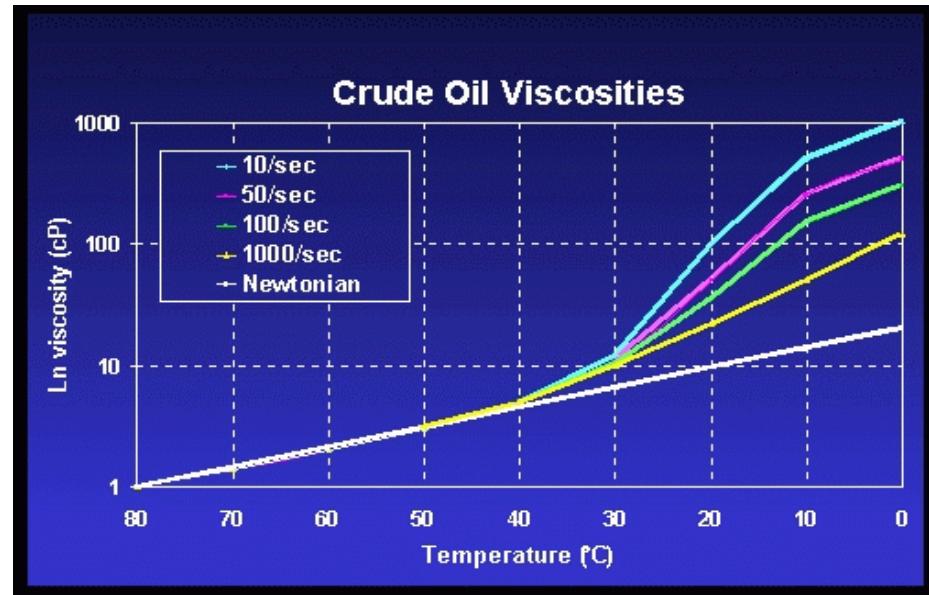
The dynamic viscosity is a measure of the fluid's resistance to flow and is a strong function of temperature.

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 at the right 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.



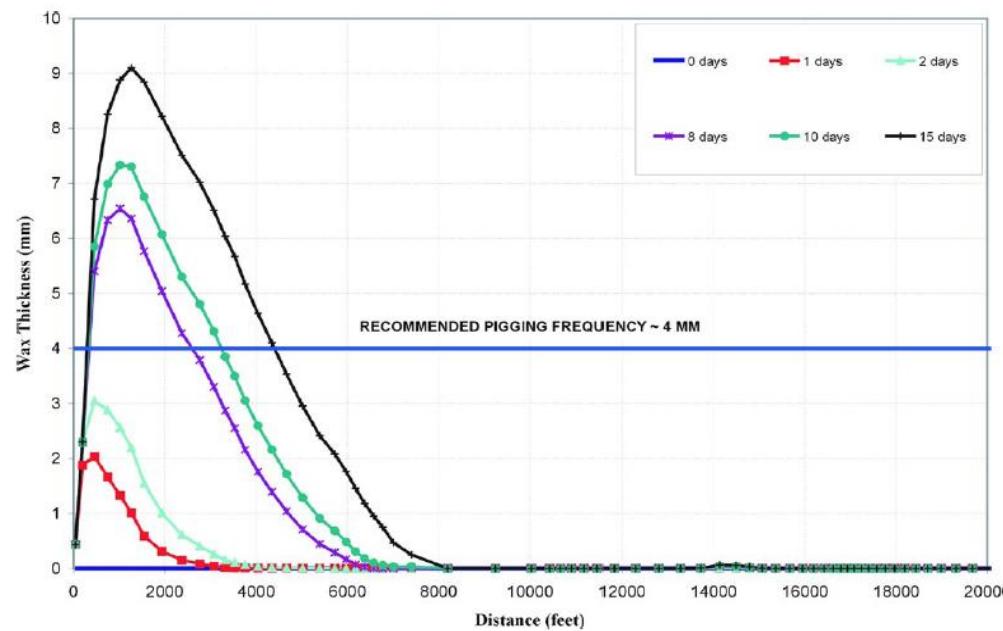
Wax deposition modelling

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 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 opposite, given a maximum tolerable wax thickness of 4 mm has been identified, the pigging frequency would be approximately every 3 days.



Deposition mechanisms

There two main mechanisms for wax deposition are:

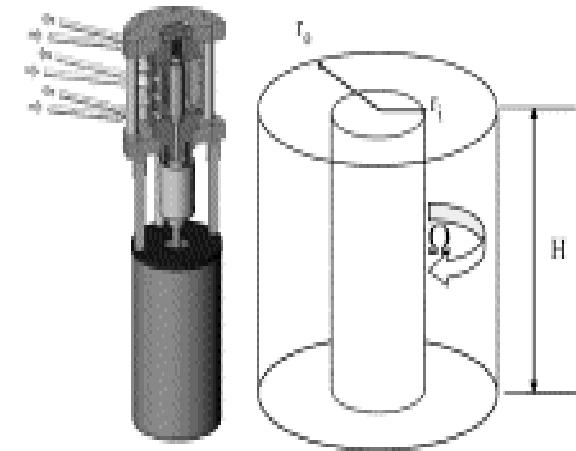
- Molecular diffusion
- Shear dispersion

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 operations, on the other hand, and particularly for multiphase systems, the shear dispersion effect is far more significant.

Deposition Rate

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.

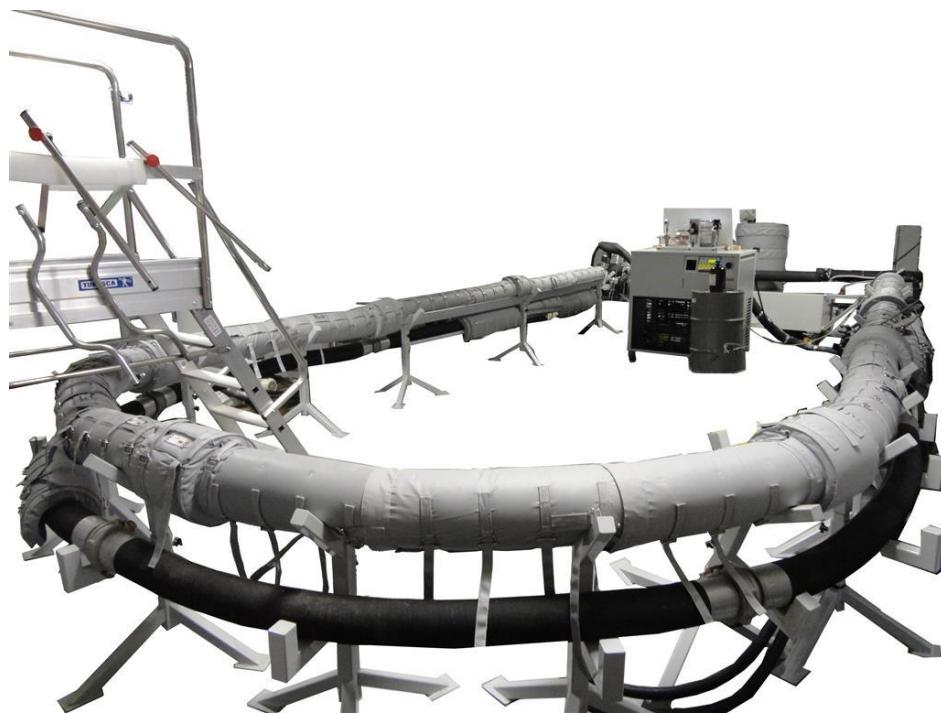


Wax deposition cell.

Fluid is inserted into annulus. Inner cylinder is cooler than fluid temperature. Cylinder is rotated to mimic shearing. Rate of wax deposition on cylinder can be measured at different shear rates and heat fluxes.

Wax Deposition Flow Loop

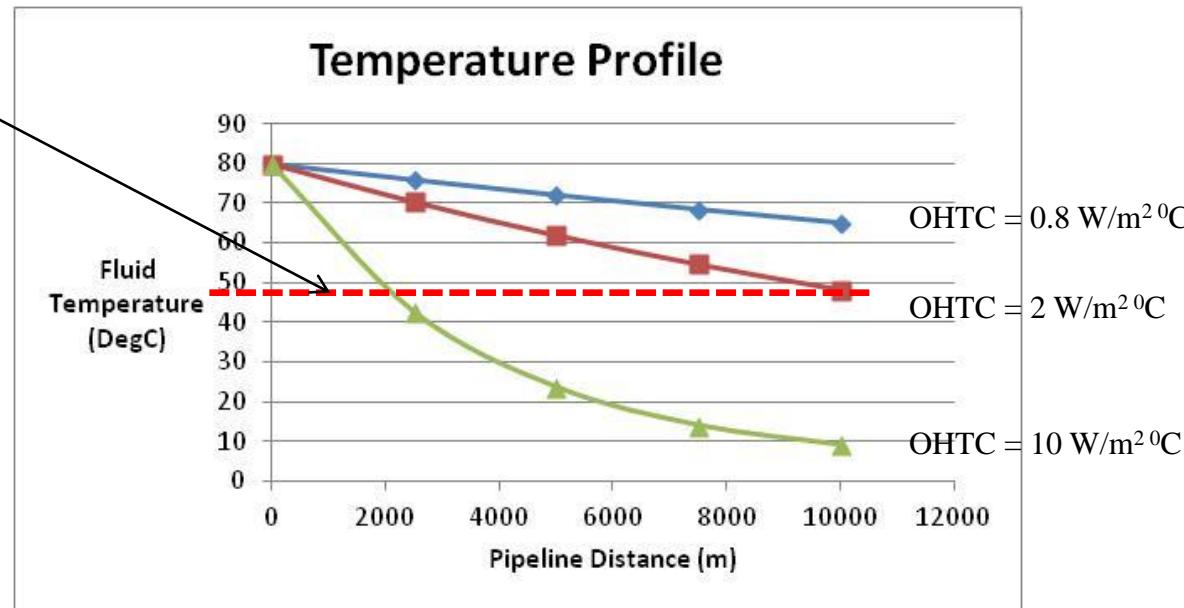
Flow loops are available to test live oil wax characteristics at a range of heat fluxes and shear rates that would be expected in the flowline during actual production. The loop is used to determine the WAT of the oil sample, assess efficiency of inhibitors, and estimate the wax deposition rate according to flow conditions. It also enables estimations of pigging frequency for wax removal and pipeline restart pressure for gel breaking.



Wax Management – Maintain Temperature above WAT

Maintain temperatures above the Wax Appearance Temperature – insulate the pipeline.

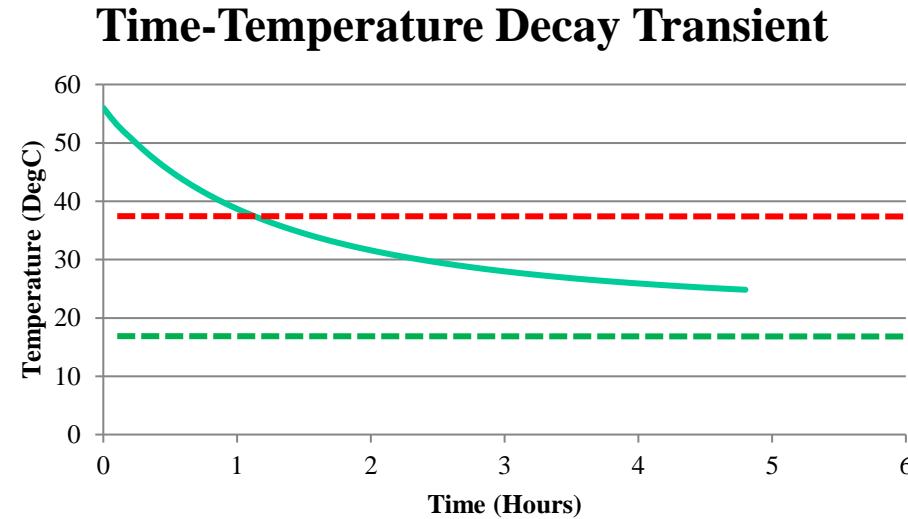
Insulation may not be practical for many pipelines, particularly over long distances.



Pipeline Cooldown

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.

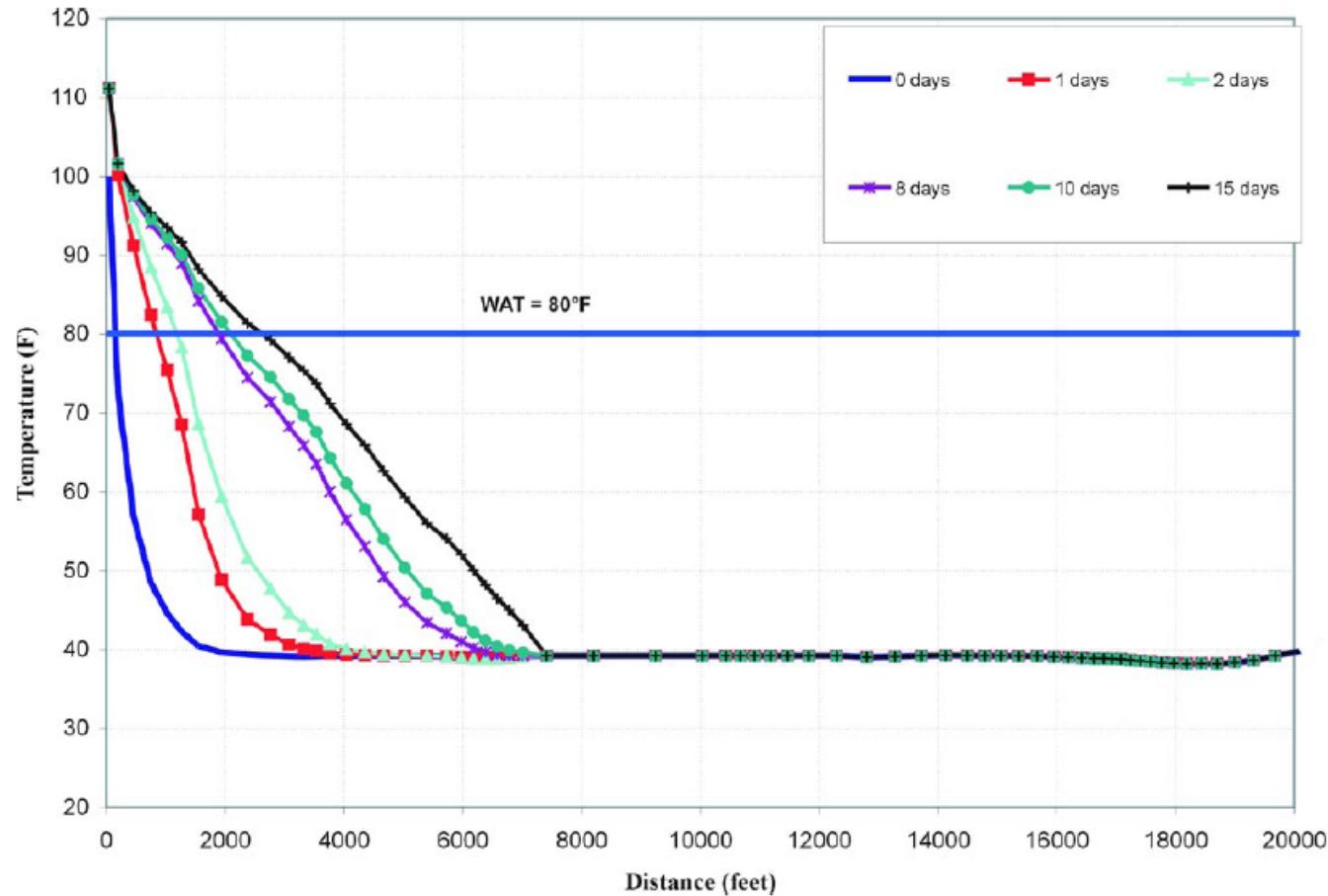


Rate of temperature loss is a function of system U value.

Wax Appearance

Pour Point

Wax Deposition with Time



Thermal Methods for Remediating Wax Deposition

Hot oiling and hot water washes

Hot oiling and hot water washes have been used extensively for remediating onshore wellbores and pipelines.

They can be an effective, economic remediation method.

Transient, thermal modelling of the process should be performed to determine if the fluid will remain sufficiently warm to remove the deposit.

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

Two compounds in solvent carrier are pumped down the 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 work properly.

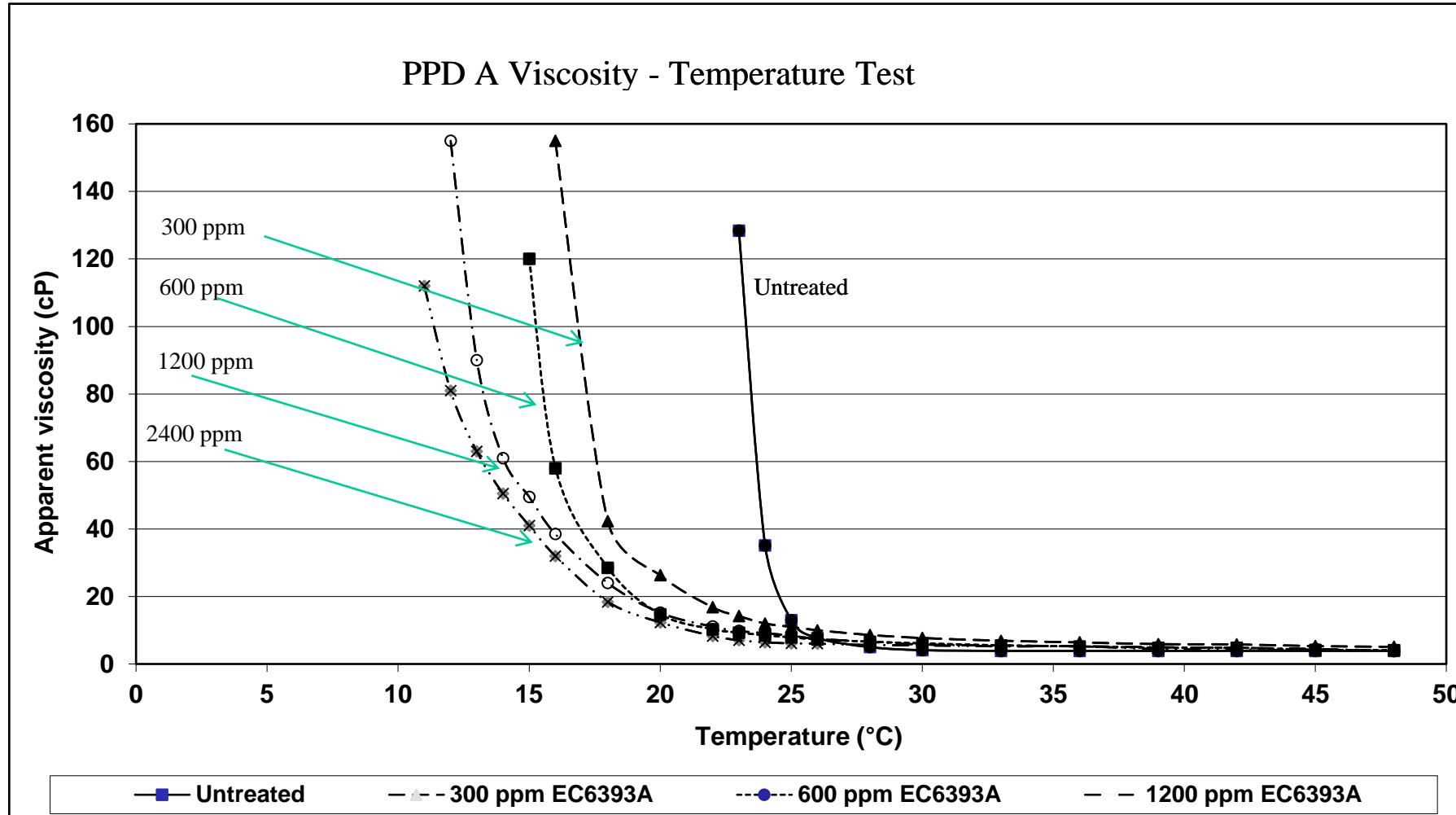
Chemical Methods for Remediating Wax Deposition

A variety of chemical methods are available for managing wax problems. Performance and suitability varies enormously and need 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

Typical Laboratory Results



Mechanical Methods for Remediating Wax Deposition

Pigging

Pigging is the most 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 pipelines 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.

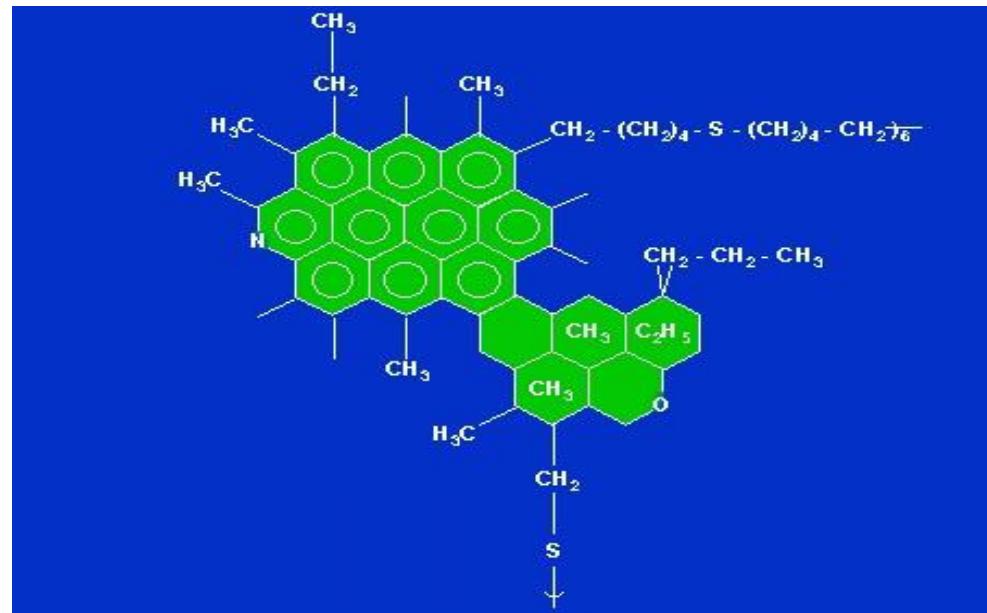
The pig is unlikely to remove the entire wax deposit, but leaves behind a smooth layer which can reduce the pipe wall friction and pressure drop.



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

Asphaltenes are dark brown to black solids.

Asphaltenes 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 are believed to be solids suspended by resins as micelles in the crude oil.

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

Asphaltenes can deposit due to a miscible flood with CO₂ or natural gas.

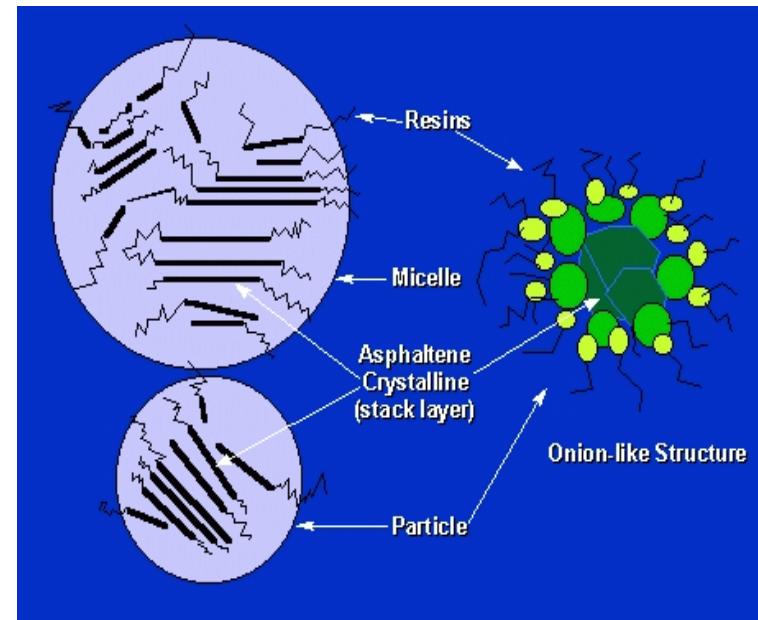
Asphaltenes can flocculate due to an acidizing or stimulation job.

Asphaltenes can flocculate due to the mixing of different fluids (e.g. high and low aromatic crudes).

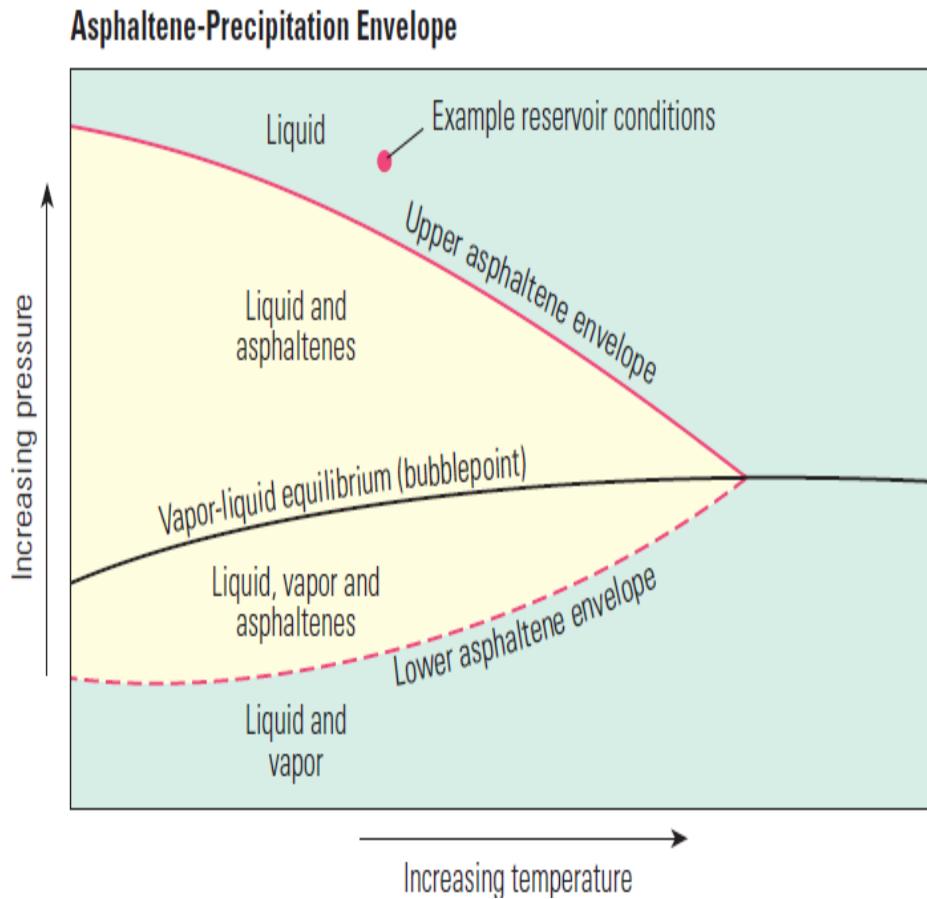
Gas lifting can exacerbate an asphaltene deposition problem.

Asphaltenes are very soluble in aromatic compounds such as xylene.

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.



Asphaltene Precipitation Envelope



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

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.

Erosion

Erosion

Erosion can be defined as:

The wastage of material due to mechanical removal of the material surface by a flowing environment.

- Most extreme when solids are present in the environment
- Damage to equipment/pipes results
- To mitigate against erosion, velocity limits and therefore production limits can be imposed
- Conservative limits lead to losing production
- Optimistic limits lead to
 - risk of erosion damage
 - consequential loss of production
 - increased maintenance costs
 - possible loss of system integrity.

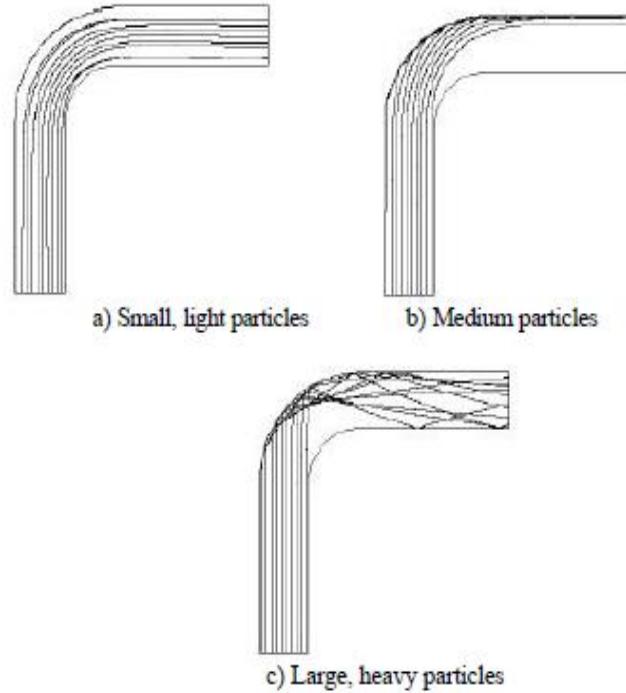


Four mechanisms termed erosion:

- 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 affecting Erosion

- 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.*



Erosion Mechanisms

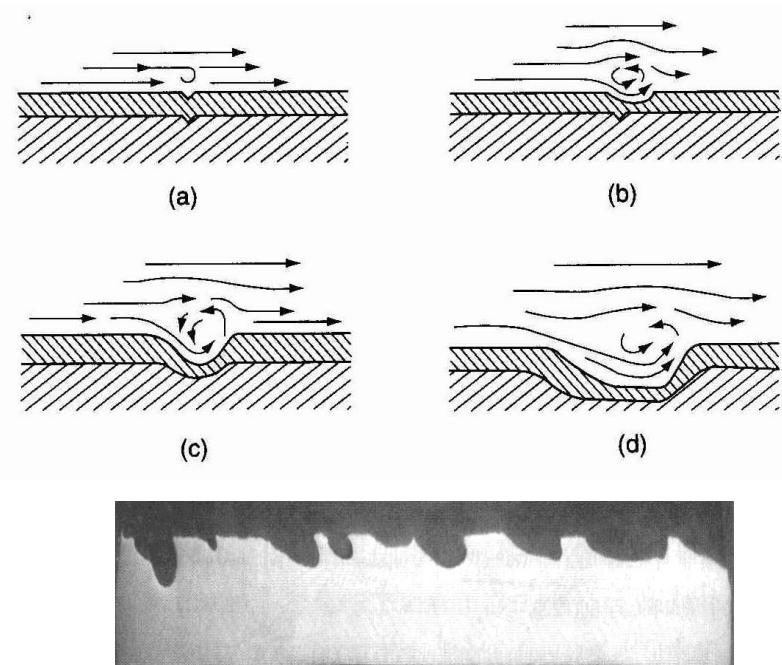
Liquid droplet erosion

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

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.



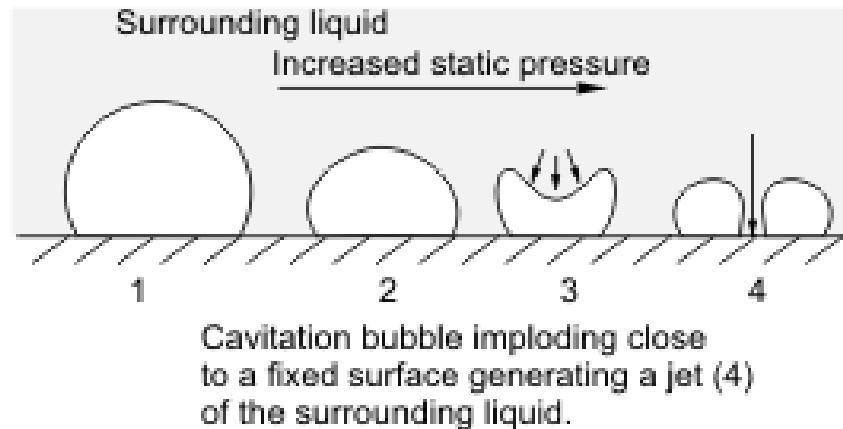
Photograph of erosion-corrosion showing individual teardrop shaped pits with undercutting in the downstream direction.

Erosion Mechanisms

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 stellite, etc., are many times more resistant to damage.



Erosion Models

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.

Use of Computational Fluid Dynamics (CFD) to assess erosion

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.

Erosion in Sand Free System

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:

- It only applies to gas/liquid flow
- It 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.

Erosion API 14E Example

What is the maximum permissible fluid velocity given the following pipe conditions.
Compare permissible velocity with actual pipe velocity.

Given:

Liquid density = 670 kg/m³

Gas density = 18 kg/m³

Fraction of liquid by volume = 0.22

Volume flowrate = 0.27 m³/s

Pipe ID = 0.292 m (pipe CSA = 0.067 m²)

Calculate;

Mixture Density = $670 \times 0.22 + 18 \times (1 - 0.22) = 161.4 \text{ kg/m}^3$

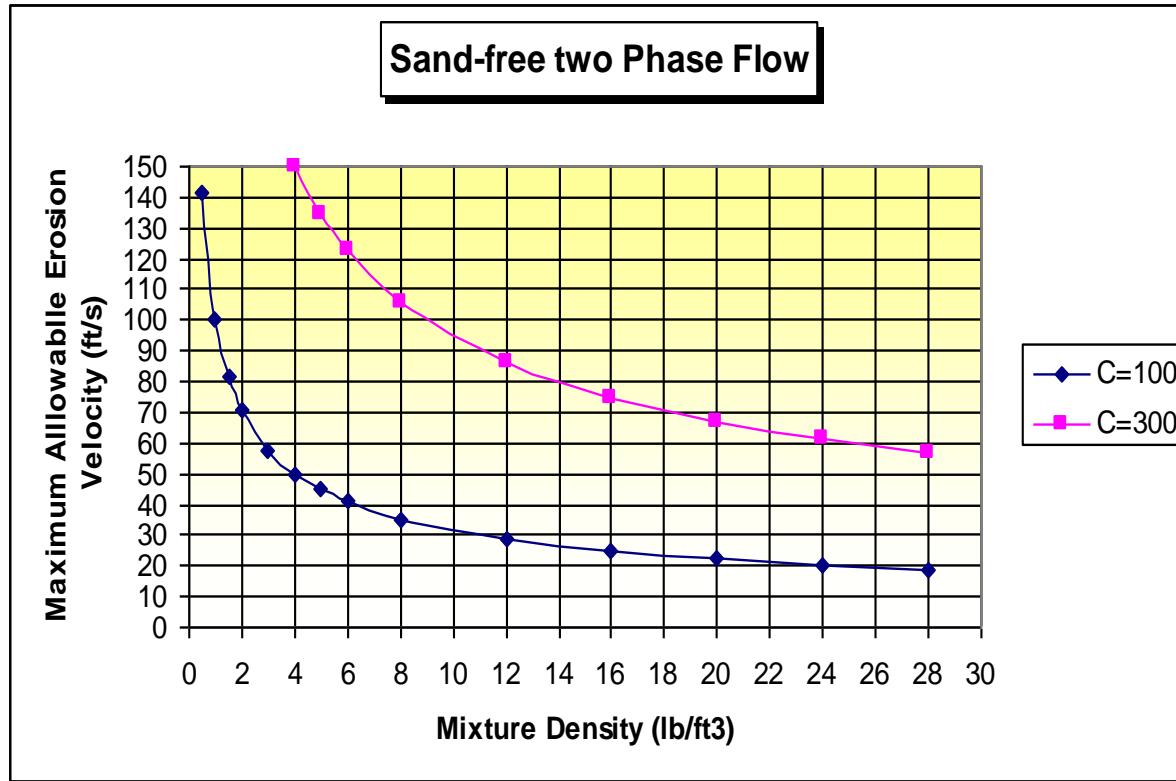
$V_m = 1.22 \times C / \rho_m = 1.22 \times 100 / (161.4)^2 = 9.6 \text{ m/s}$ (assume C = 100)

$V_m = 0.27 / 0.067 = 4 \text{ m/s}$ – actual velocity

Hence velocity acceptable from an erosion standpoint.

Sand Free Two-Phase Flow

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 for stainless steels.



Operator experience suggest C values of:

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

Erosion Rates in the presence of sand/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

Calculation of Erosion Rates

– 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)



Calculation of Erosion Rates

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.

Key Learnings

- 1. Requirement to couple pressure loss with overall energy balance.
- 2. Pipeline steady state heat balance.
- 3. Pipeline U value. Heat loss = $U \cdot A \cdot dT$
- 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

Subsea Technology

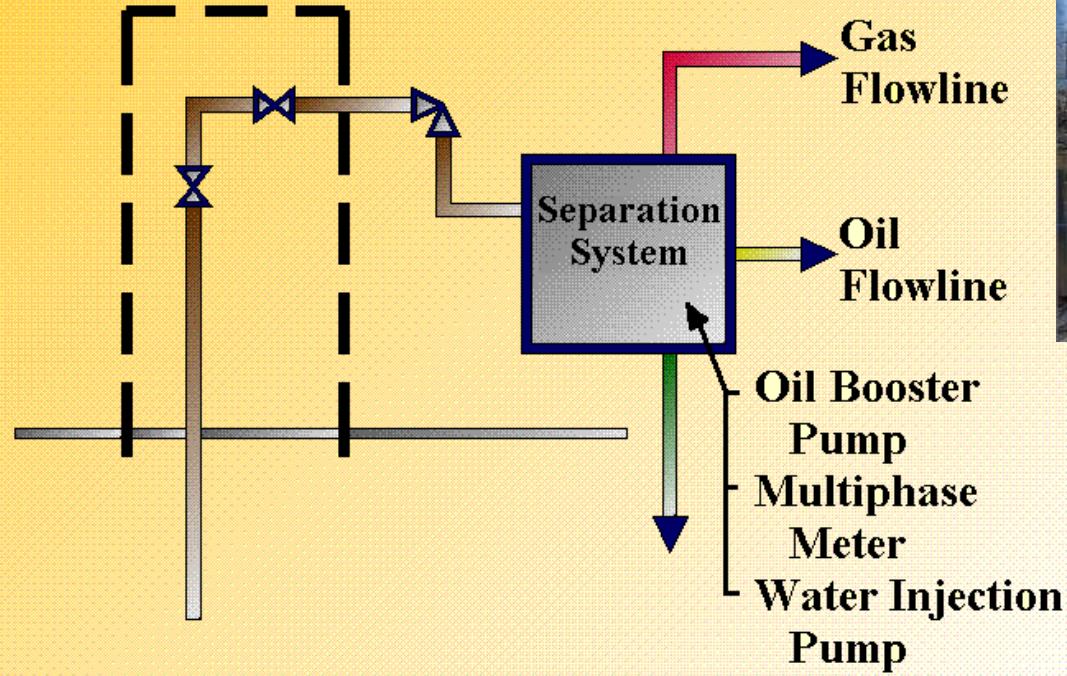
For information – not examinable:

Prime considerations for any subsea technology is;

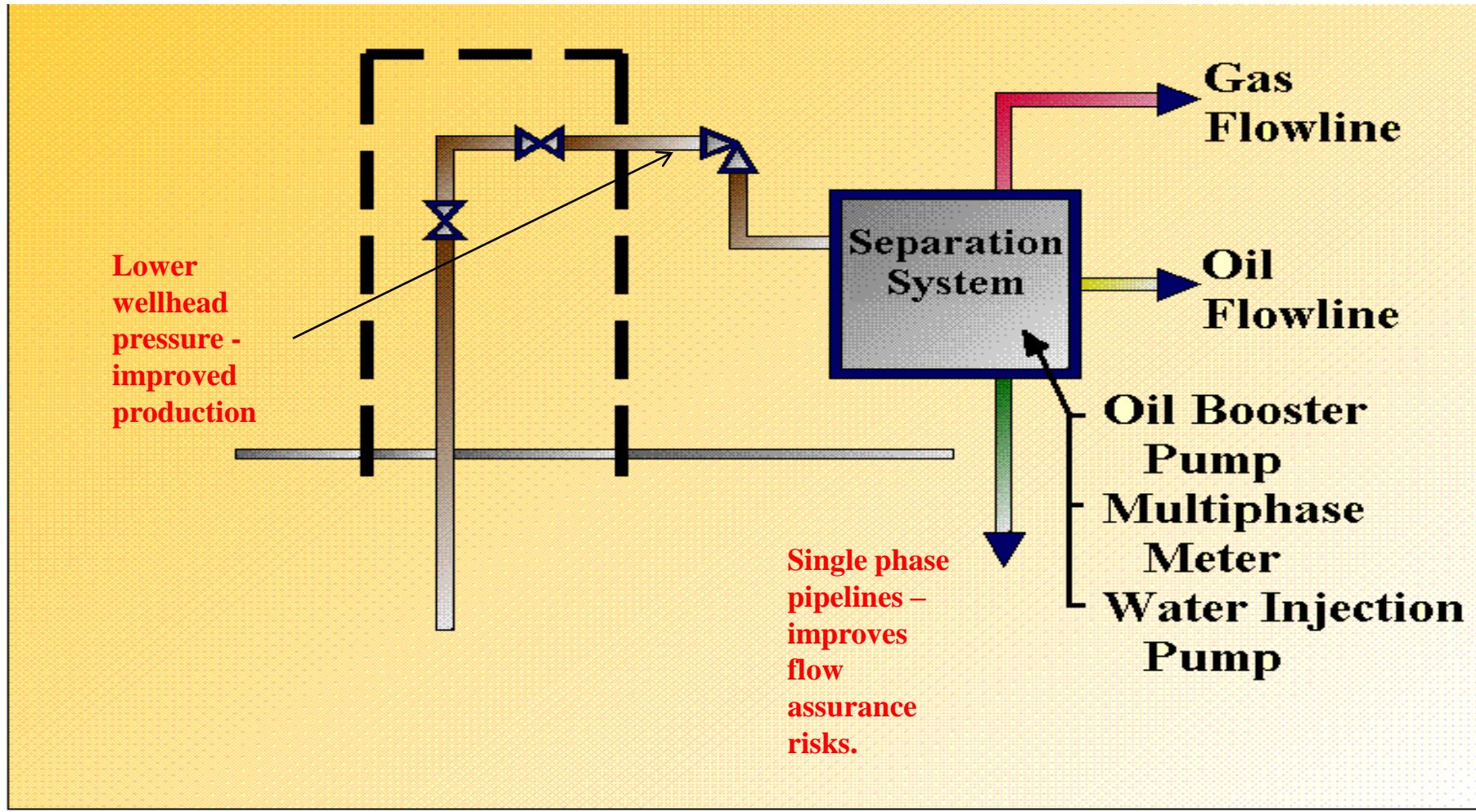
- Reliability
- Intervention frequency
- Intervention cost

Subsea Separation

Subsea Separation



Subsea Separation



Subsea Separation

A number of potential benefits derive from the use of subsea processing technologies. These are briefly outlined below.

Increased production rates and improved reservoir recovery

The primary advantage of subsea processing is to improve the recoverable reserves from a reservoir. A typical increase in oil production rates is often quoted as being in the range of 10 to 25%. Increases in production rate will also mean increased oil recovery from the reservoir and typically between 5 and 10% increase in oil recovery can be achieved with subsea processing.

Improved flow assurance

Separating produced water from the well fluid on the seabed reduces the risk of corrosion, scaling and hydrate formation in the pipeline. However, other flow assurance issues like wax and asphaltene deposition will still need to be managed. The effect of slugging may also be reduced when water is separated on the seabed. Seabed separation of gas and the bulk liquids could also mean that the multiphase nature of the tie-back could be eliminated and gas and liquid streams sent back to shore in separate single-phase pipelines.

Improvement in flowline / riser flow capacity

Water content in the well fluids can cause capacity constraints in flowlines and pipelines, which can restrict the production from the field. Additional wells cannot be tied-in to the production system unless some de-bottlenecking of the flowline system is carried out. Separating out water from the produced fluids on the seabed will free up spare capacity in the flowlines allowing production from new wells.

The application of subsea processing could also mean de-manning of platforms or platform-less development for green fields. The subsea to beach approach is being adopted for recent deepwater developments, for example, the Snohvit and Ormen Lange developments offshore Norway, in which the subsea field is tied-back directly to shore. This not only reduces OPEX on logistics, crew maintenance, etc., but also improves safety performance.

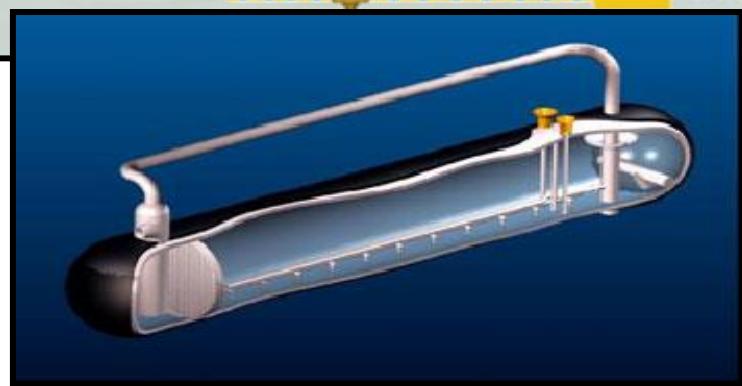
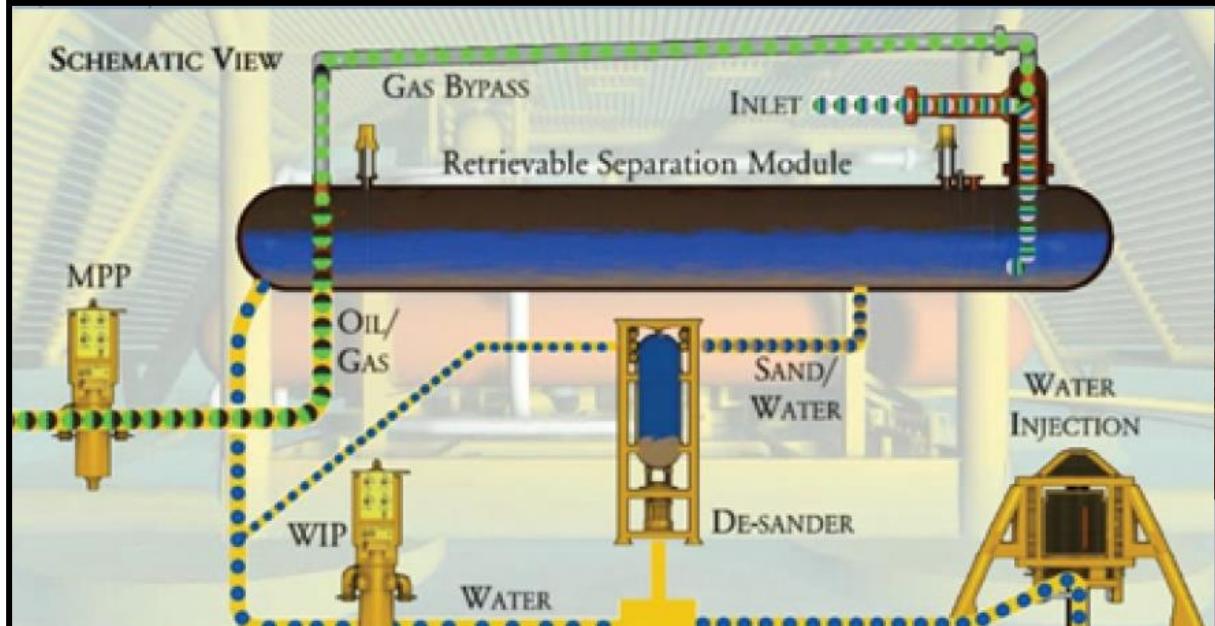
Tordis Field – Subsea Separation

The Tordis Subsea Separation, Boosting and Injection (SSBI) was installed in 2007. This system uses a horizontal separator vessel. A key feature is a patented gas by-pass system that separates the majority of the well fluid gas flow at the separator inlet and by-passes the vessel. The gas is recombined with the oil flow downstream of the separator .

A key advantage if this is it allows a significant reduction in the cross-sectional area of the separator vessel as a much smaller proportion of this area has to be given over to gas flow. A subsea separator has to be designed both for internal fluid pressures and for the external head from the water depth. The external pressure can dictate the vessel wall thickness and this is proportional to vessel diameter. Thus a reduction in vessel cross-sectional area results in a reduction in vessel wall thickness giving a saving in costs and weight of the assembly. The latter can be critical in terms of system installation as beyond a certain lift weight there is a step change in installation vessel costs.

<http://www.youtube.com/watch?v=apUgpNU-pC0>

Tordis

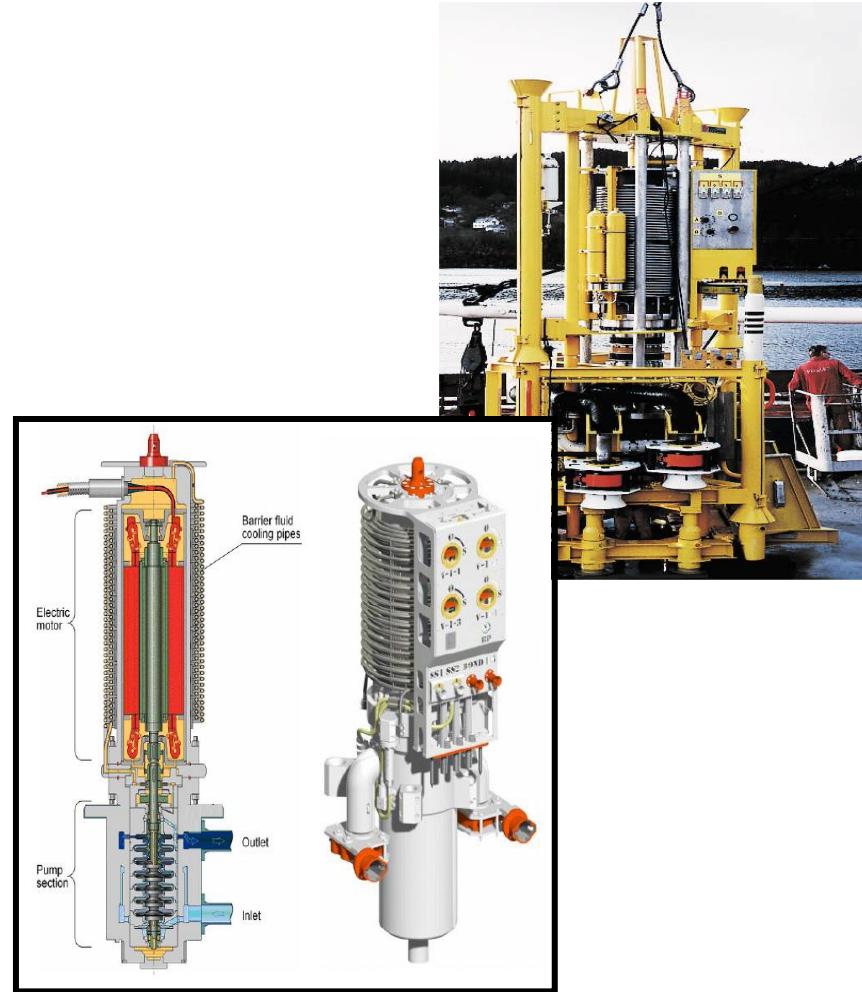


Subsea Water Injection

Subsea Water Injection Pumps are considered to be a mature technology. Several have been installed subsea and have therefore built up some operational experience. Pumps are typically multi-stage centrifugal type. Some examples of installed water injection pumps are:

- Norsk Hydro Troll Pilot 1.5MW Water Injection Pump (installed 1999, running 2001 through 2003, replaced after trip) [Framo]
- Columba E Raw Seawater Injection (pump installation 2007) [Framo]
- Statoil Tordis, 2.3MW Water Injection Pump (installation 2007)[Framo]
- Tyrihans, order placed for 2 x 2.9MW raw seawater injection pumps [AkerKvaerner LiquidBooster®]

Another application here is in the injection of raw seawater into a formation for pressure maintenance and sweep. Framo Engineering AS and Aker Kvaerner are leading the market in subsea raw seawater injection. The Aker Kvaerner developed unit is called the SeaBooster. Another player is Well Processing, who developed a Sea Water Injection and Treatment (SWIT) Facility.

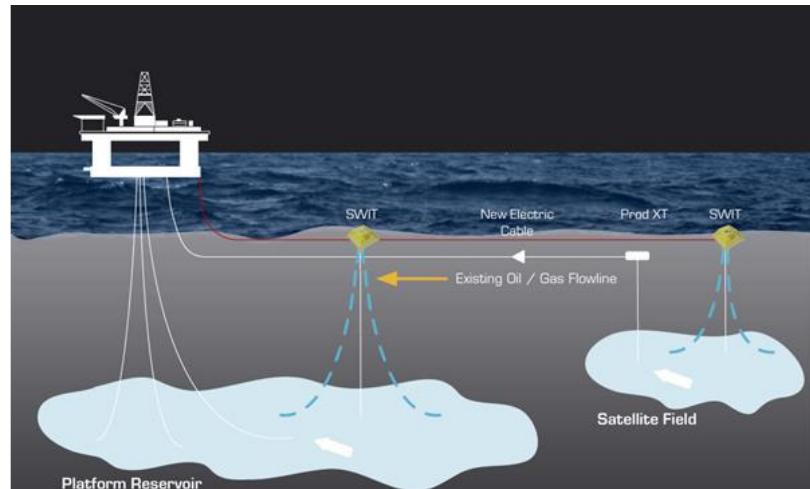
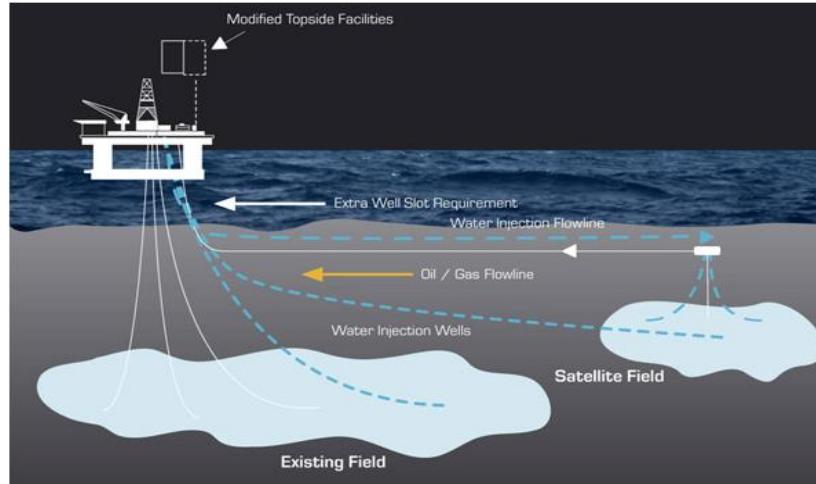


Subsea Water Injection and Treatment

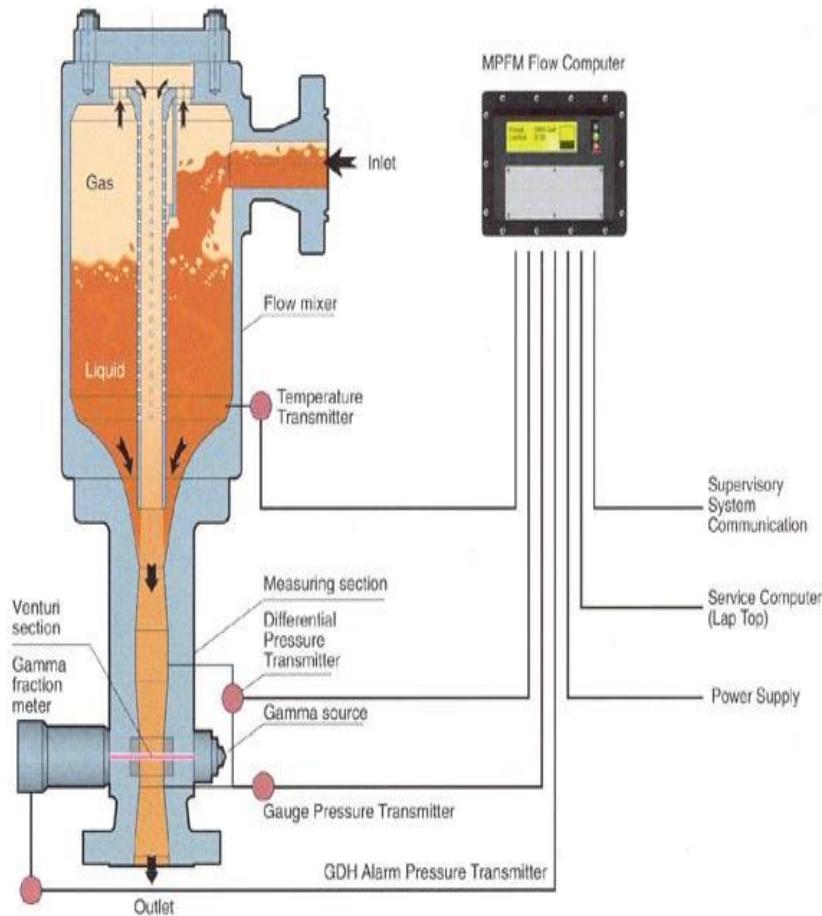
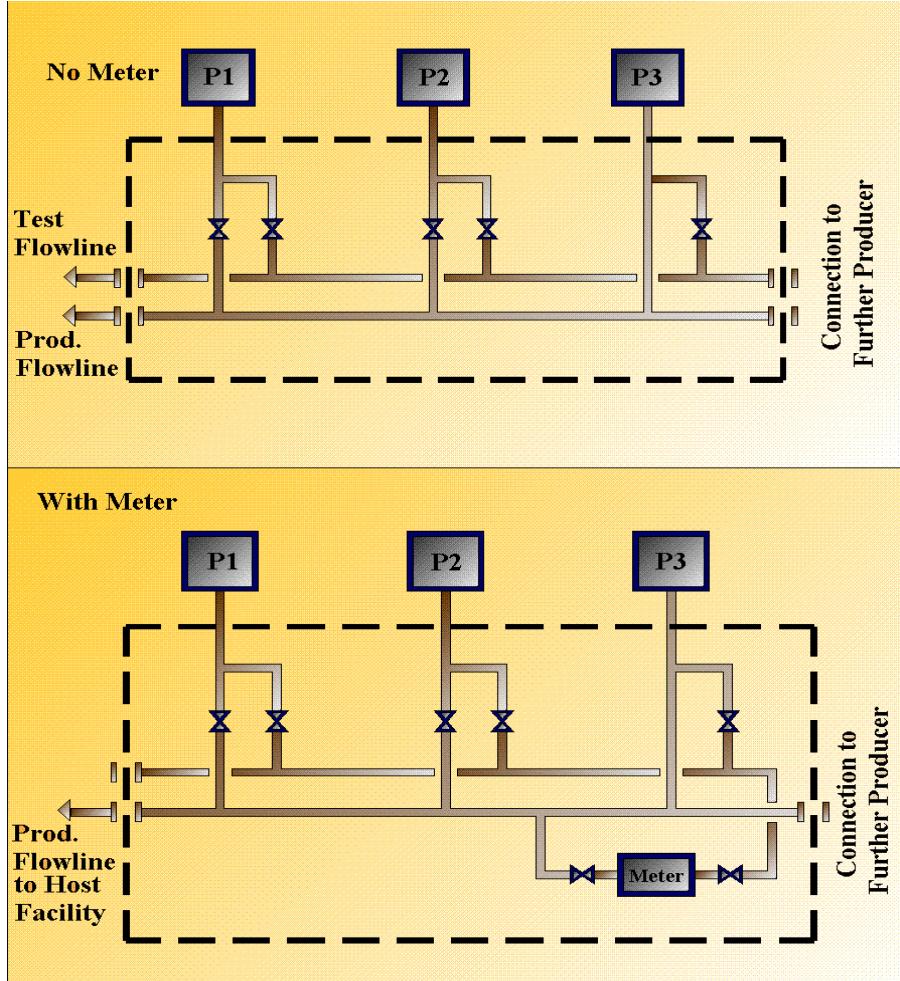
Traditional topsides plant includes;

- Filtration
- Deaeration
- Chemical treatment
- Pumping

Locate on seabed.



Multiphase Metering



Multiphase Metering

A subsea meter can save the investment in a separate test line.

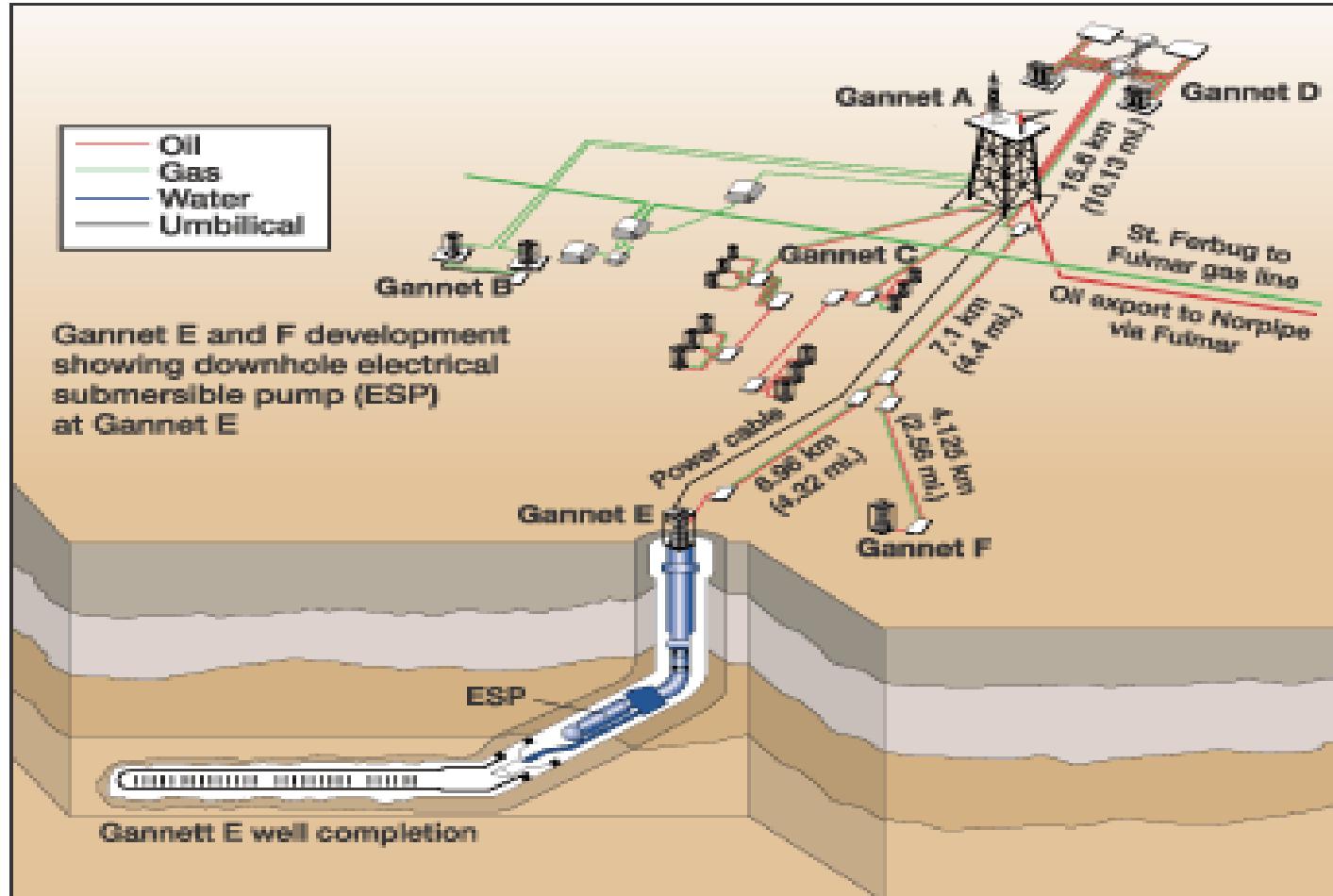
The fluids are separated into gas and liquid and then homogenised to prevent slippage between the phases. A venturi meter provides a measurement of volume flow.

Two different level gamma energy sources direct a beam through the pipe walls and the fluid to detectors opposite. Gas, oil, condensate and water attenuate the gamma energy to different degrees, largely dependent on their densities. The gamma beams are emitted at two energy levels; the higher one is more sensitive to the gas to total liquid ratio and the lower one is more sensitive to oil or condensate to water ratio. When combined, the two energy attenuation measurements are used to calculate the fractions of the three phases. A third energy level can be used to determine the salinity of the water phase.

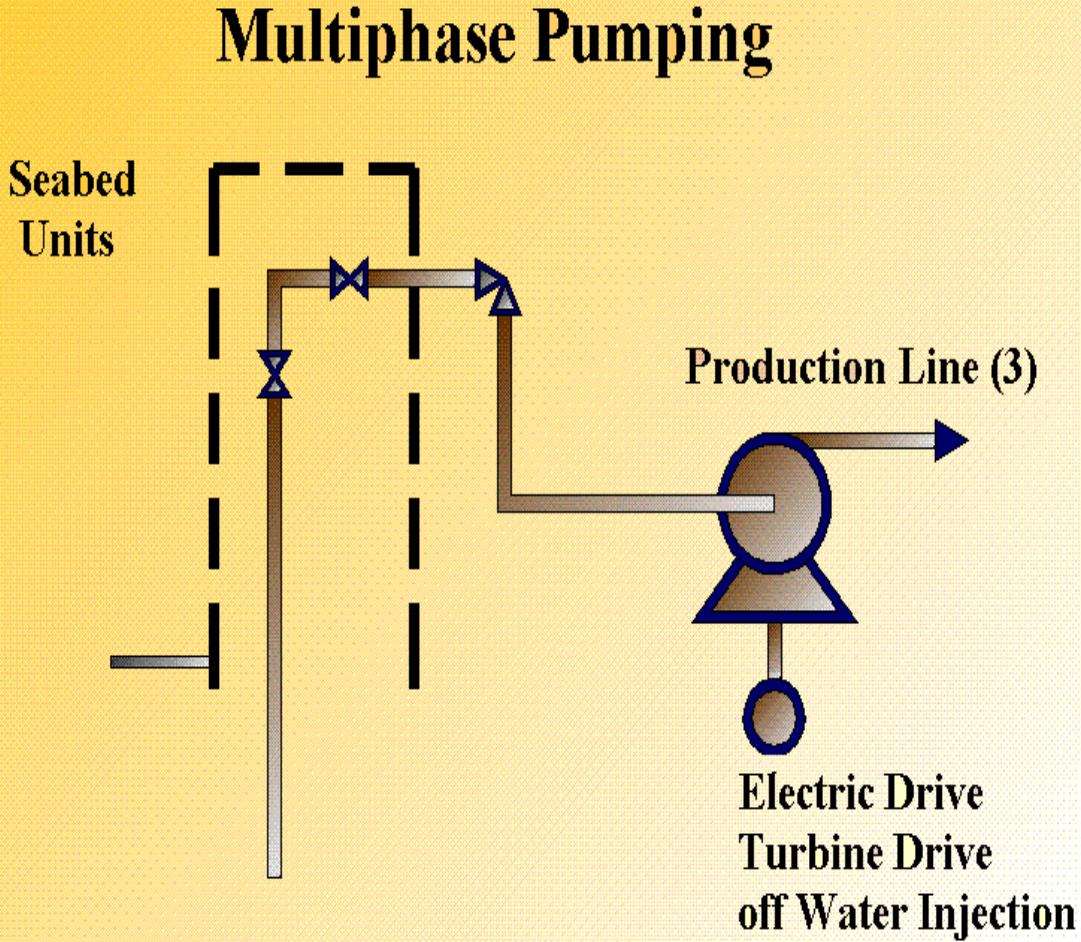
Nuclear (gamma ray) meters give large errors with salinity change because the minerals absorb much more of the energy than water.

Subsea Downhole Submersible Pump

Electric submersible installed in subsea well. Operates single phase. Power supplied by an electric subsea cable.



Seabed Multi-phase Pump



Multi-Phase Pumping

Multiphase pumping (MPP) reduces the back-pressure on producing wells thereby increasing production and final recovery. It can enable production transfer to a central processing facility via a single multiphase pipeline. Multiphase pumping is a relatively new area and there are a variety of different types of pump available, some still under development, but others are offered with significant operational experience.

Multiphase pumping is a very difficult duty. Designing a pump to handle a multiphase mixture presents numerous design problems.

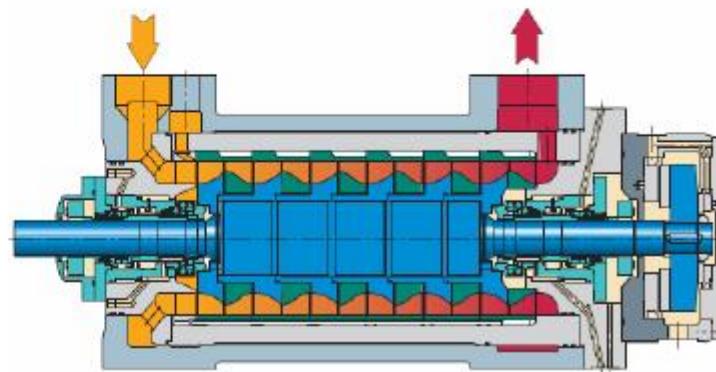
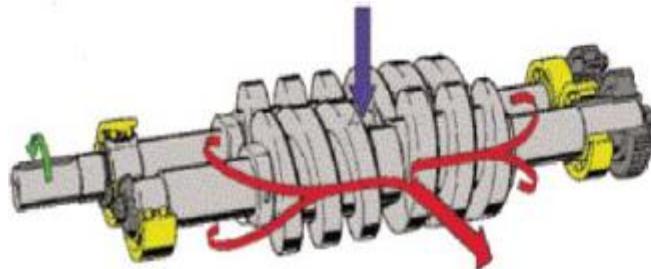
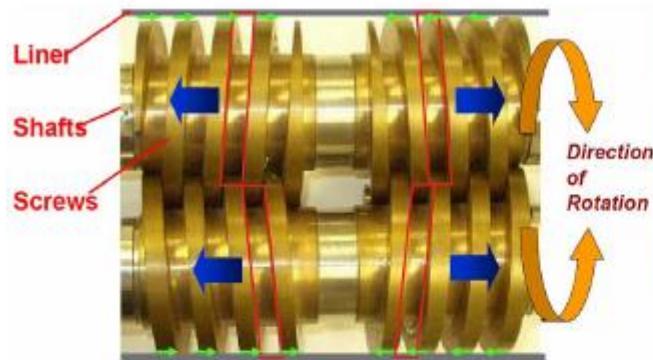
Multiphase pumps can be categorized as either **positive displacement or rotodynamic**.

The two main types offered by pump vendors are;

Helico-axial

Twin Screw

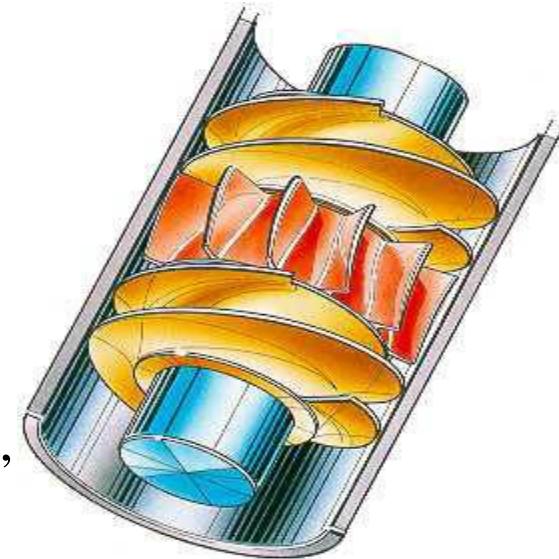
MPP Types



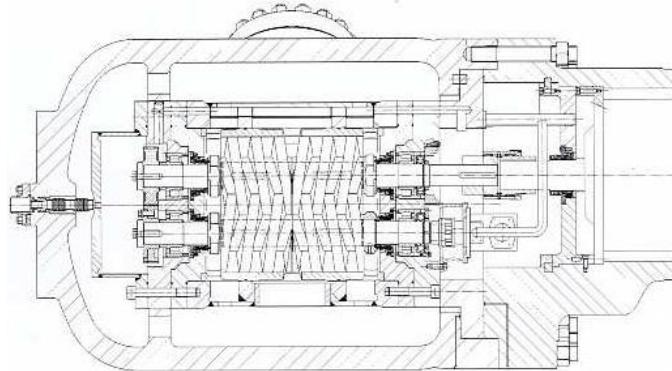
Helico Axial Multi-Phase Pump

Each compression stage consists of an impeller, mounted on a single rotating shaft, followed by a fixed diffuser. The impeller blades have a typical helical shape. The profile of the open type impeller and diffuser blading arrangement is specifically designed to prevent the separation of the gas-liquid mixture during the compression process. The hydraulic passages accommodate solid particles in suspension, and special care has been taken in the design to prevent their accumulation in the pump casing.

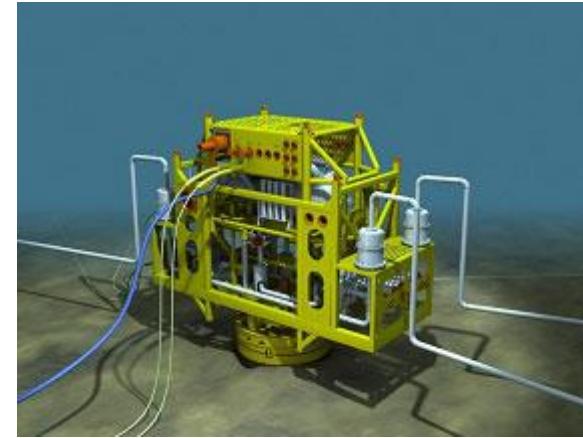
Due to the compression process the gas volumetric flow rate decreases as the fluid goes through the pump. Therefore the pump is generally equipped with different series of hydraulics, i.e. different series of geometries, whereby one series would have identical compression stages. The changing geometry from one series to the next provides adjustment for the decreasing volumetric flow rate.



Twin Screw Multi-Phase Pump



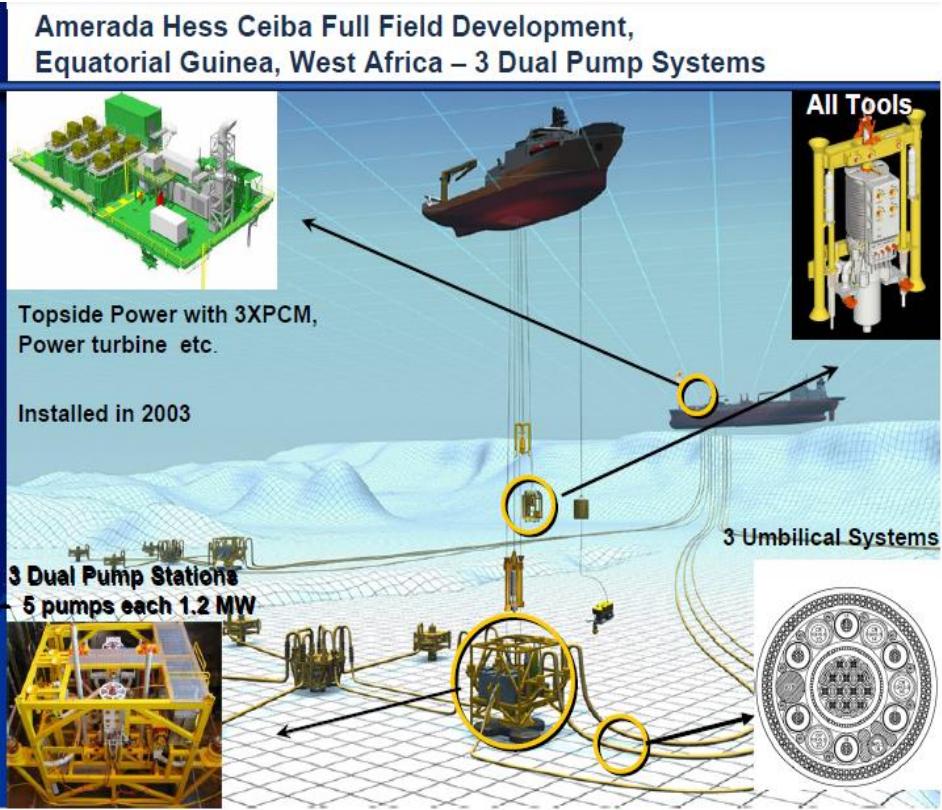
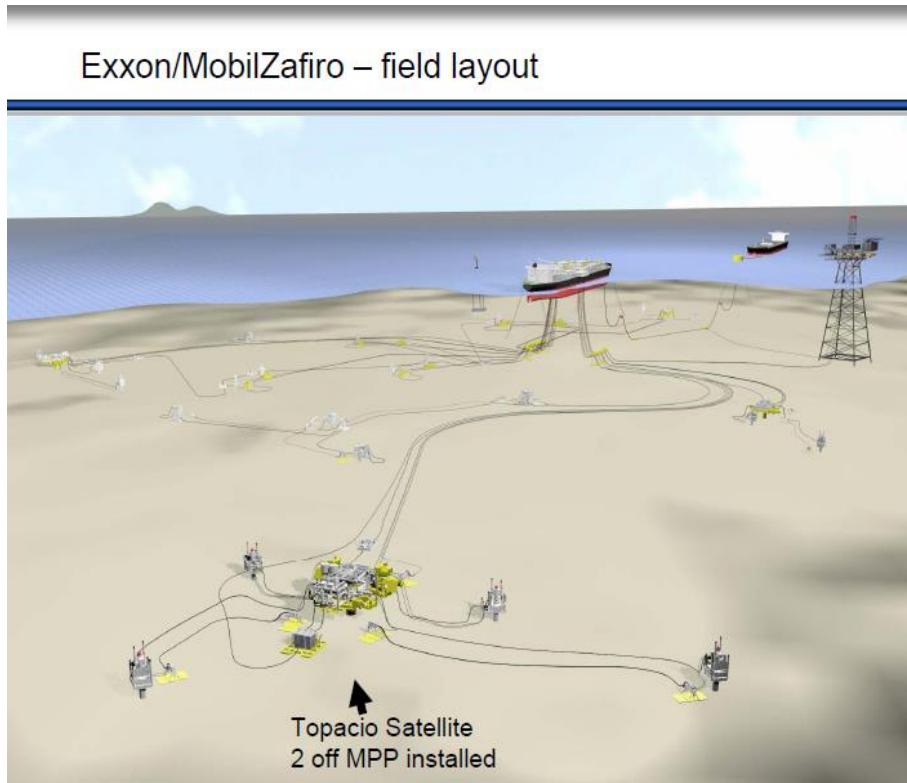
Lateral view of the multiphase pump.



In the twin-screw pump, produced fluids are fed into a closed chamber that contains two rotating, intermeshing screws, driven directly by a variable speed, oil-filled electric motor. The energy imparted to the fluid as it moves between the rotating screws provides the necessary boost in flow rate as the fluid leaves the chamber on to the production facility.

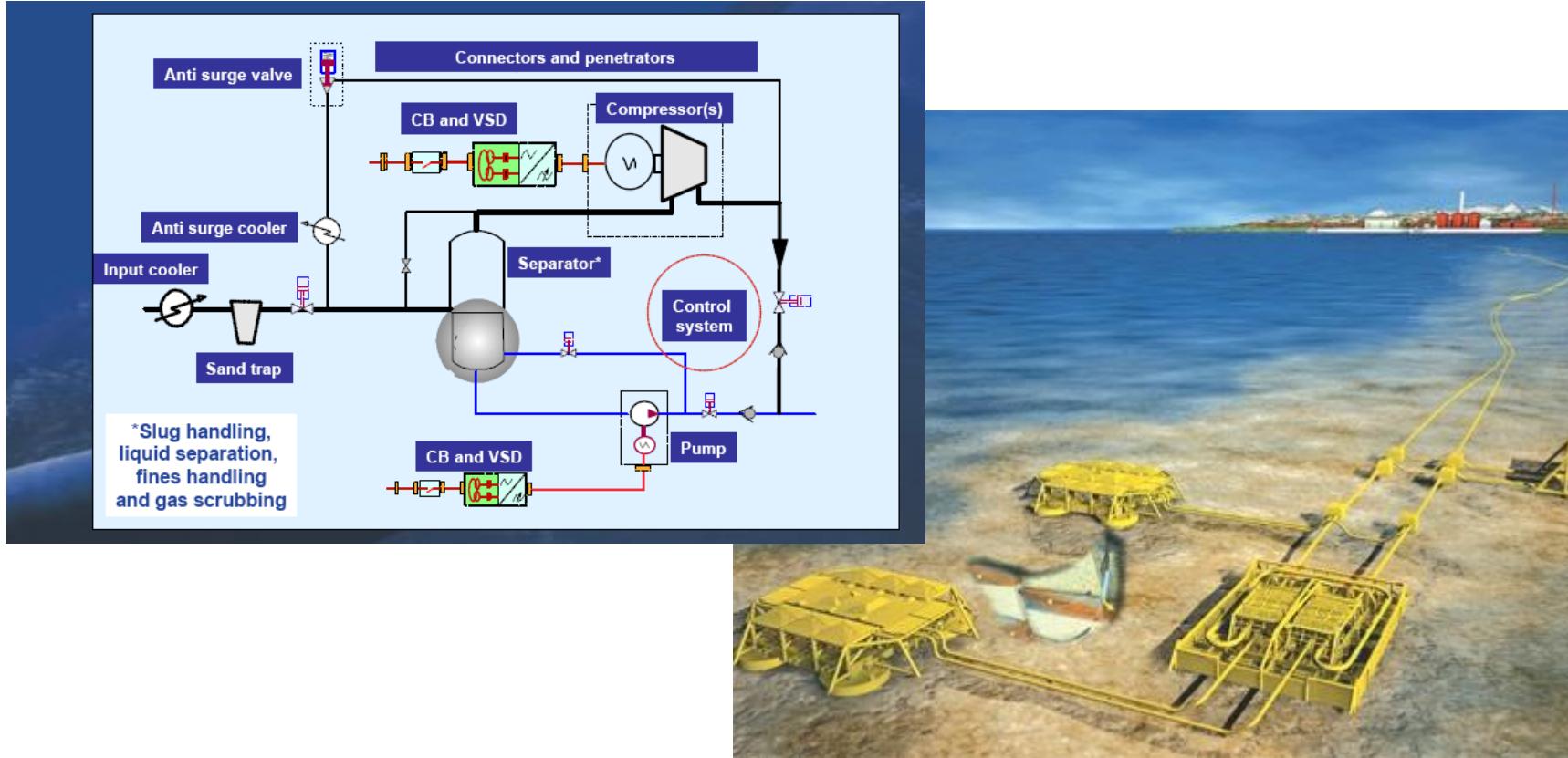
Twin-screw pumping systems have been shown to maintain high pressure boosts at high gas content (greater than 98% gas volume fraction), and efficiently dampen out slugging effects. They are low shear systems as well, thus reducing the tendency for emulsification of the produced fluids.

MPP Field Deployment



Subsea Compression

Wellhead pressure reduction allowing increased flowrate and improved recovery.



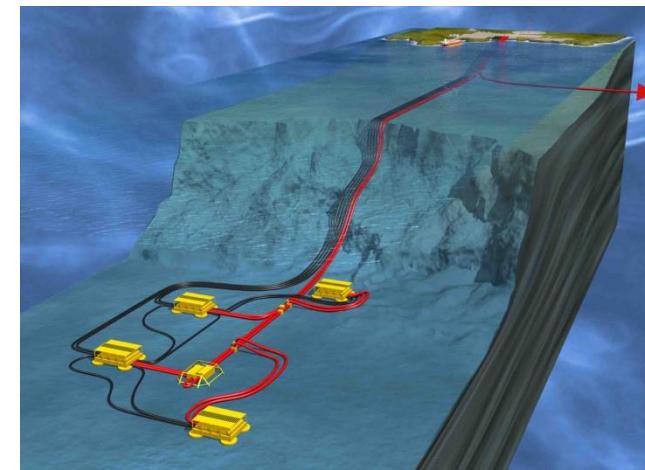
Subsea Compression

Ormen Lange

Developing Ormen Lange, the first deepwater discovery to be developed offshore Norway, represents a major challenge with a combination of water depth, extremely rough seabed conditions, long tieback distance, and demanding weather conditions. Fully developed, the Ormen Lange production system will consist of 24 subsea wells and multiphase transport to an onshore gas treatment terminal at Nyhamna. Gas export will be to Easington (UK) via the 1200-km long Langeled pipeline. Hydro is operator for Ormen Lange in the development phase. Norske Shell will take over operatorship at first production. The Ormen Lange field is located 120 km from the West Coast of Norway at a depth ranging from 800-1,100 m. First gas is planned for 2007 with an expected need for offshore compression in about 2014.

A subsea gas compression system is currently being evaluated as an alternative to topside compression on a floater. Subsea compression on Ormen Lange would represent a major technological advancement for subsea processing systems, as both the required step-out distance for power (120 km), the total installed power (exceeding 50 MW), and the system throughput (some 60 Mcm/d) are an order of magnitude larger than existing subsea processing systems in operation to date. The Ormen Lange license is currently executing the “Maturing of Technology Phase” of a multi-year technology qualification program.

Subsea compression is a novel and unproven technology, but with great potential for Ormen Lange and other subsea gas developments to reduce capex compared to a floater with topside compression. To capture this potential, investments are required to qualify the economical feasibility of the technology and to manage the uncertainty in the qualification process.



<http://www.youtube.com/watch?v=OtqqDSJP8uA>

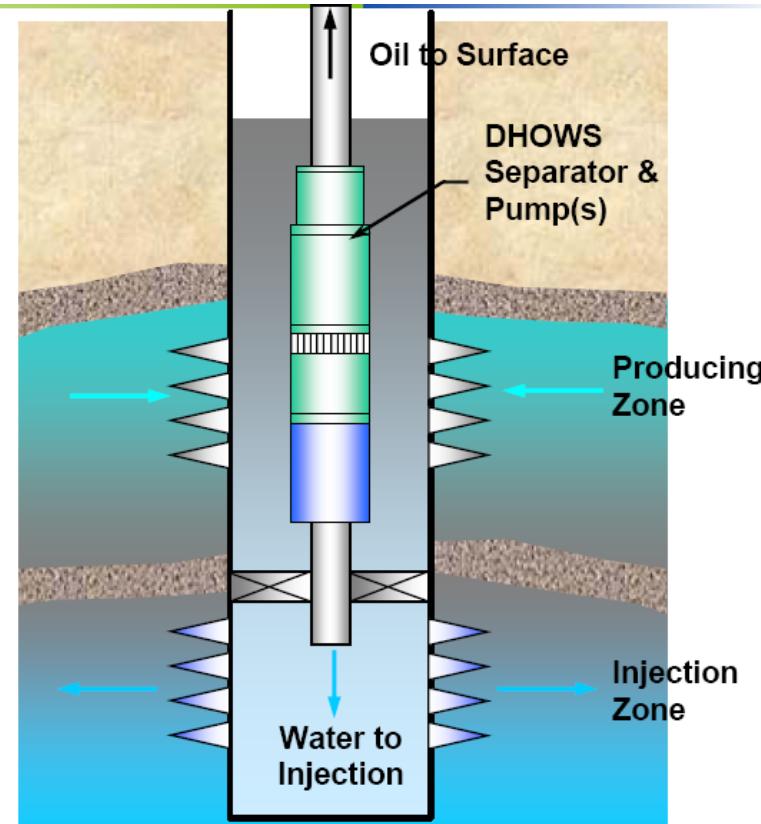
Downhole Oil Water Separation

Downhole oil–water separation technology (DOWS) is an emerging technology that separates oil and gas from produced water at the bottom of the well, and re-injects most of the produced water into another formation which is usually deeper than the producing formation, while the oil and gas rich stream are pumped to the surface.

A DOWS system includes many components but the two primary components are an oil/water separation system and a pumping/injection system used to lift oil to surface and inject the water into a deeper formation. Two basic types of DOWS system have been developed, one type uses hydrocyclones to mechanically separate oil and water and the other relies on gravity separation that takes place in the wellbore. Three basic types of pumping/injection system are used with the DOWS technology these include electrical submersible pumps, progressive cavity pumps and sucker rod pumps. Hydrocyclone separators are usually used with the electrical submersible pumps because of higher drawdown created with effective injection of water into the lower zone.

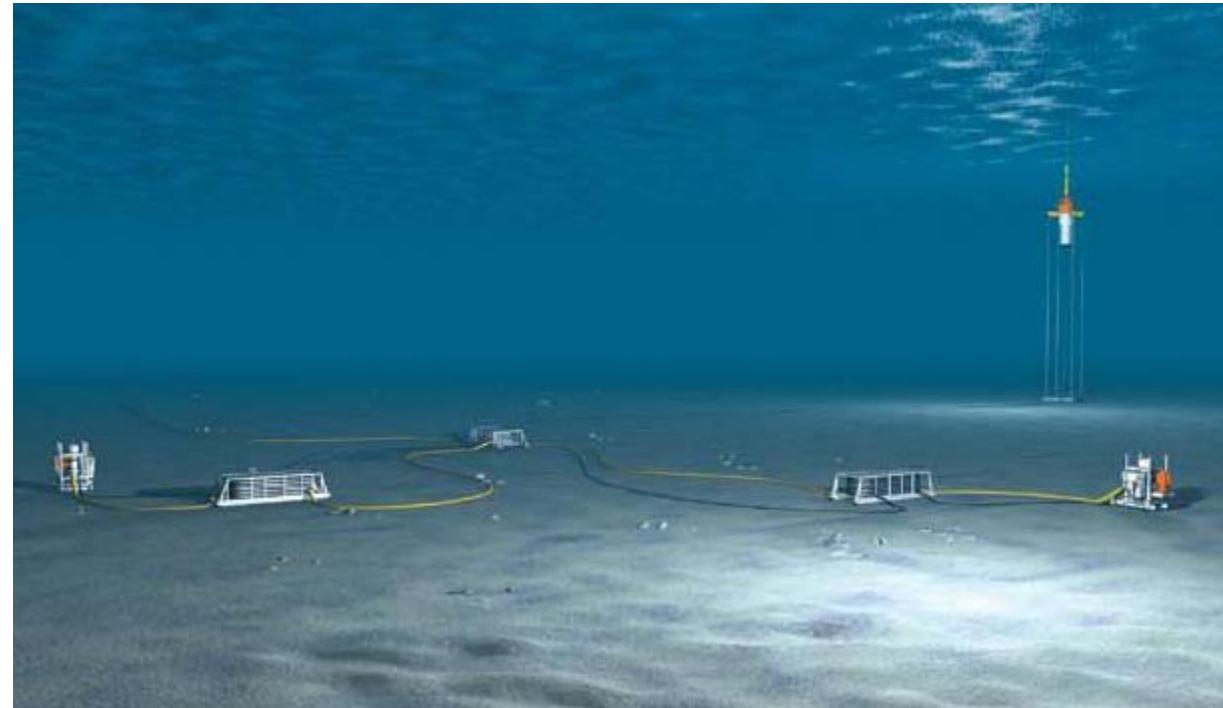
Downhole Oil Water Separation

- 1. Two zones:**
 - i. Producing zone
 - ii. Injection zone
- 2. Energy source to produce and inject (pumps)**
 - Artificial lift or reservoir
- 3. Downhole oil/water separator**
- 4. Isolation in wellbore and in reservoir**
 - Packer
 - Lithology/relative perm



Production Support Buoy

Buoy can provide power, control, chemicals and communications



Subsea Facilities and Equipment

