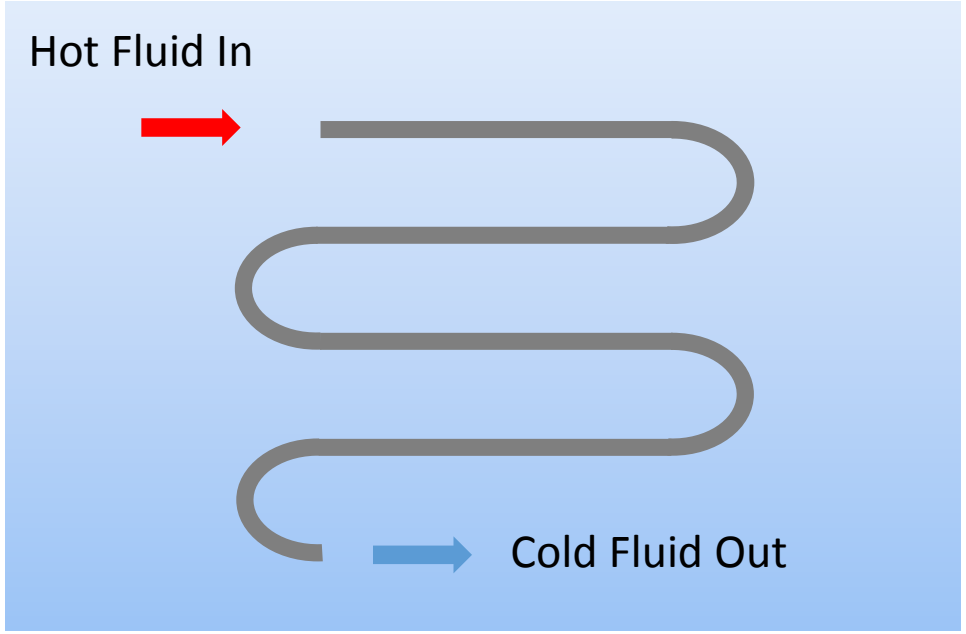
High Pressure High Temperature Multiphase Subsea Cooling - A Cost Reducer for Greenfields, an Enabler for Brownfields

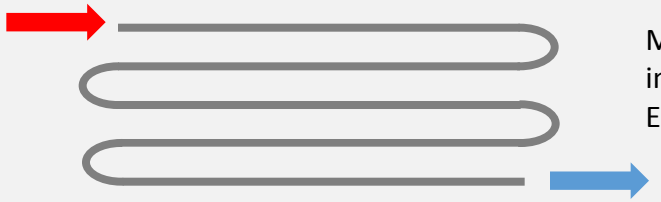
Mattias Gillis Winge Rudh
FMC Technologies

Subsea Coolers



Surrounding sea acts as heat sink

Cooling Spool (Passive)



Mature Technology, first installation 1995
East Spar Development

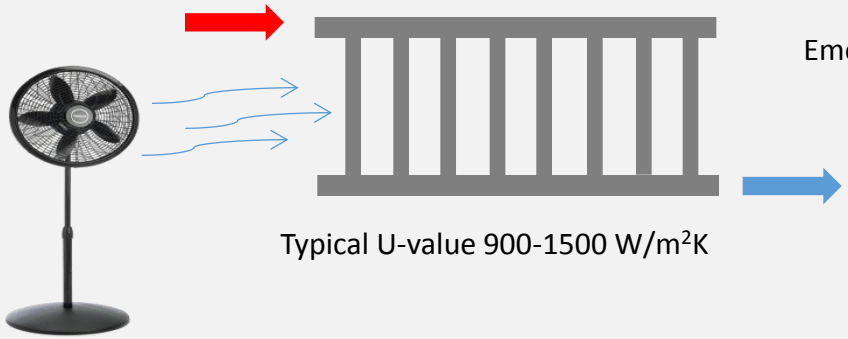
Typical U-value 400-700 W/m^{2}K

Manifold Cooler (Passive)

New technology, first installed 2014, Åsgard

Typical U-value 600-900 W/m^{2}K

Active Cooler



Emerging Technology

Typical U-value 900-1500 W/m^{2}K

Cooler Equipment

Passive Cooler
- No moving parts
- Robust
- Pipe

Active Cooler

Active Cooler
- Active transport of sea water (pumping)
- Control System
- Shell & Tube

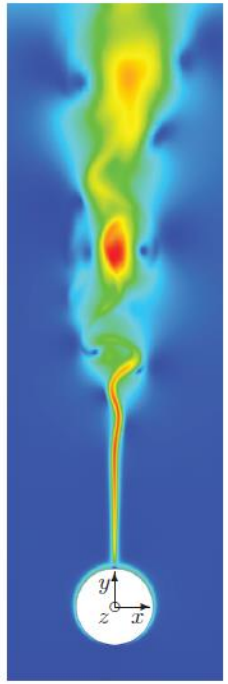
Cooling Loop

Manifold Cooler

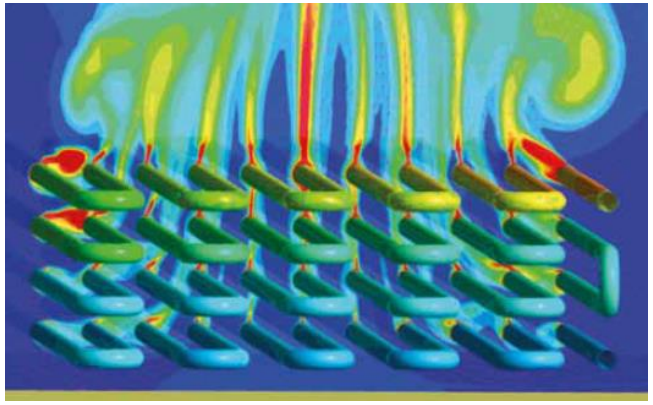
Qualification Specimen from the Åsgard Cooler TQP

Cooler Operation

Passive Cooler



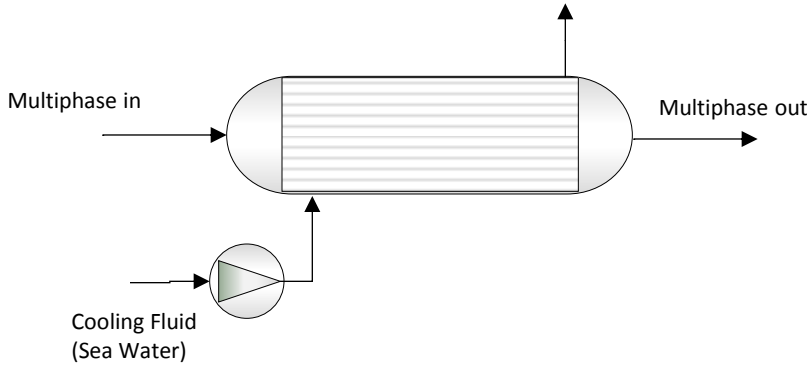
An external flow of sea water is generated by the hot pipes.



From S. Grafsrønningen, PhD Dissertation 2012

Msi Kenny Cooling Spool

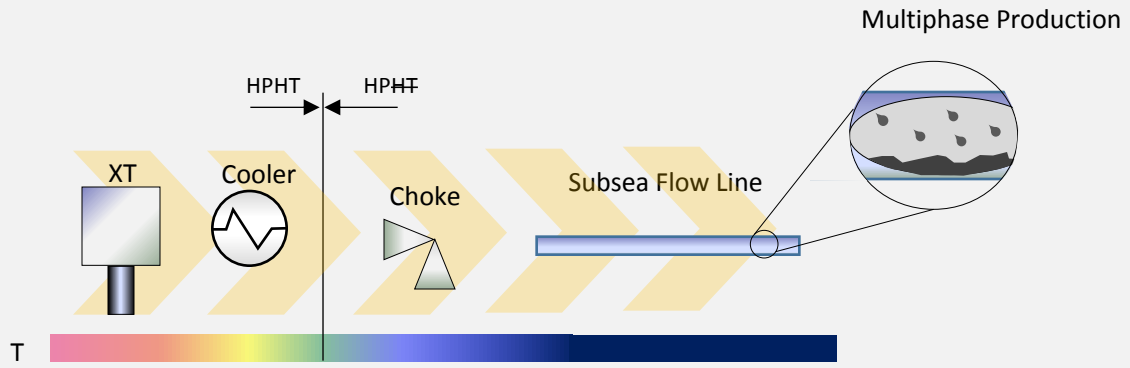
Active Cooler

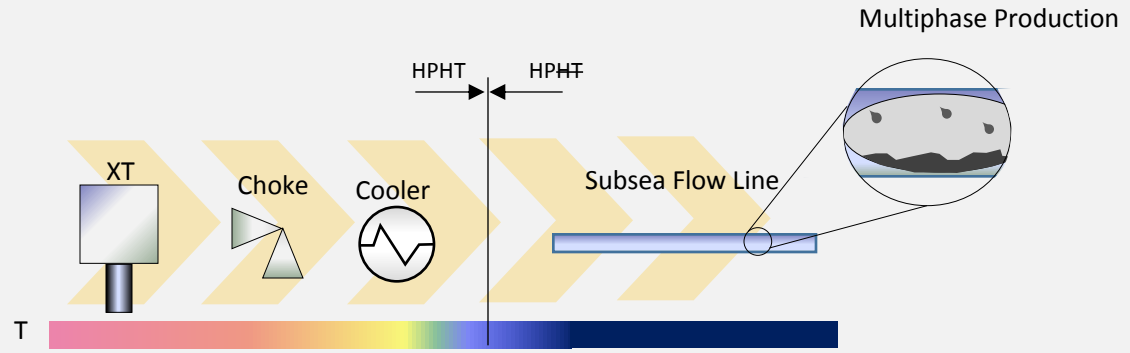


An external flow of cooling fluid (sea water) is generated by a pump.

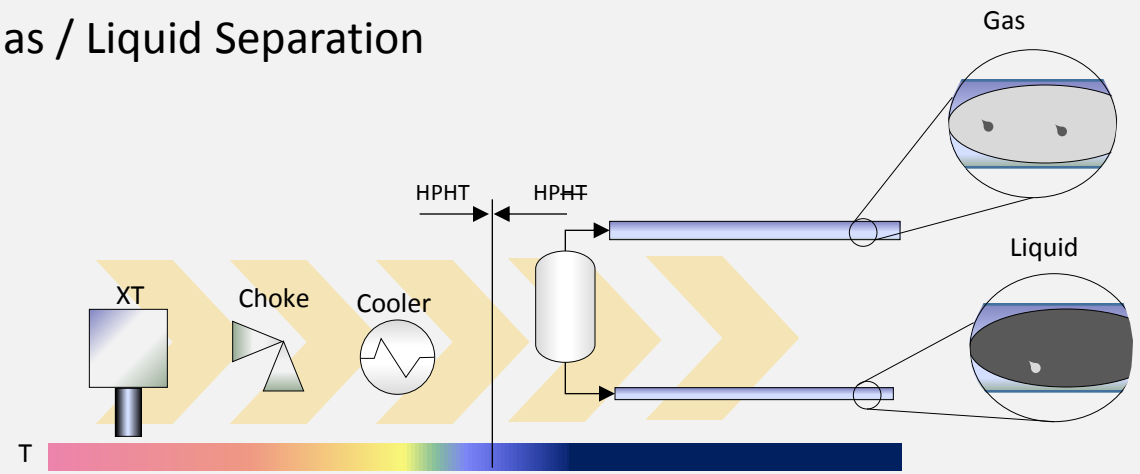
Subsea Cooler Applications

Enabling lower temperature rated equipment

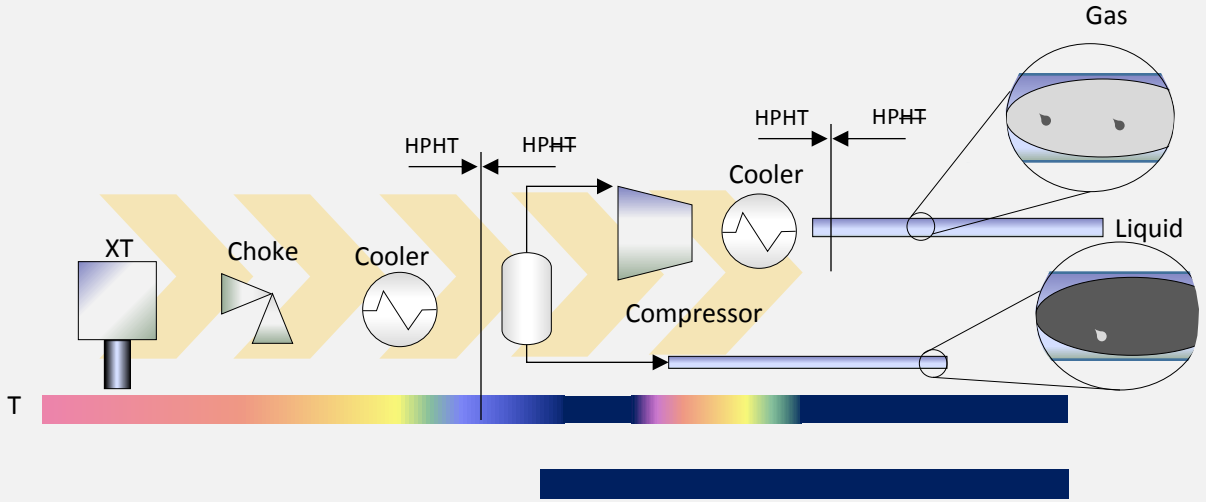




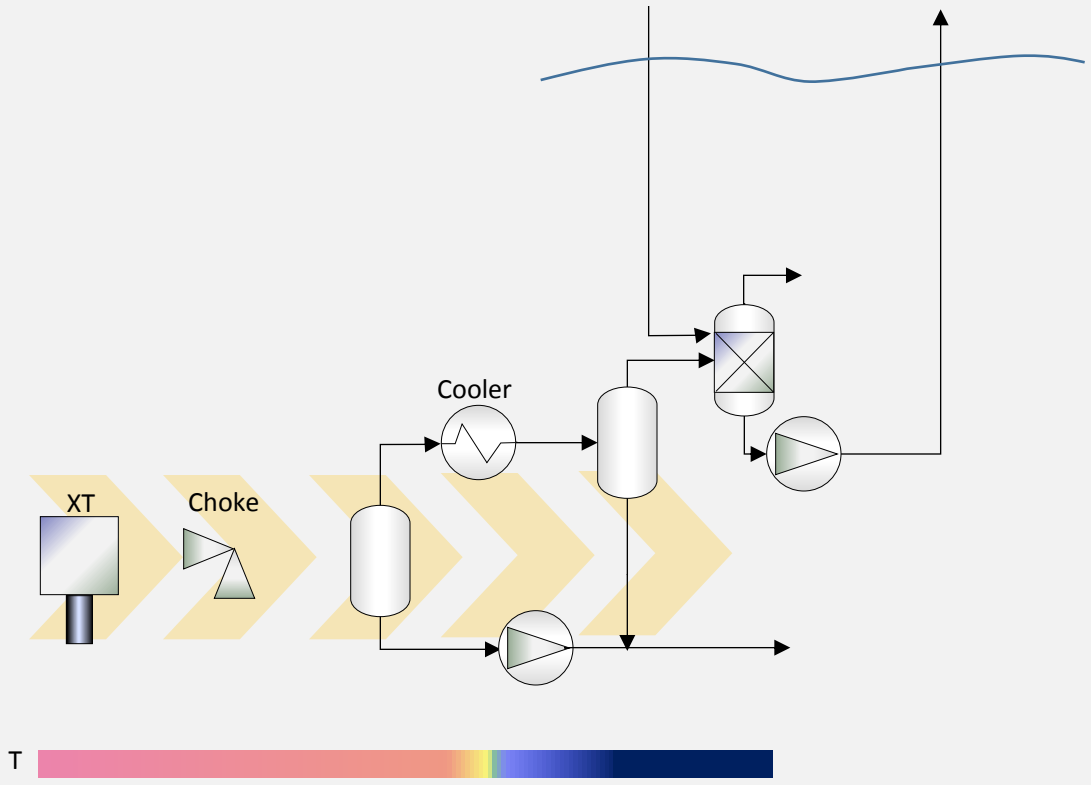
Gas / Liquid Separation



Subsea Gas Compression



Subsea Applications – Gas Dehydration



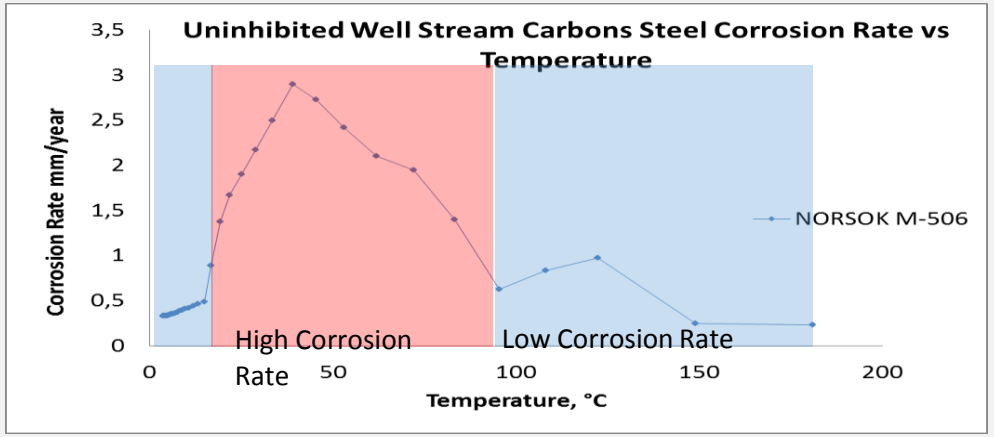
FMC Patented Dehydration Process

Subsea Gas Dehydration

- 2 Stage separation with in-between cooling to maximize liquid removal
- Gas dehydration (topside glycol regeneration).
- Cooling only on gas stream - > more efficient cooling design.
- Subsea gas export quality

Temperature Effect on Subsea Equipment Design

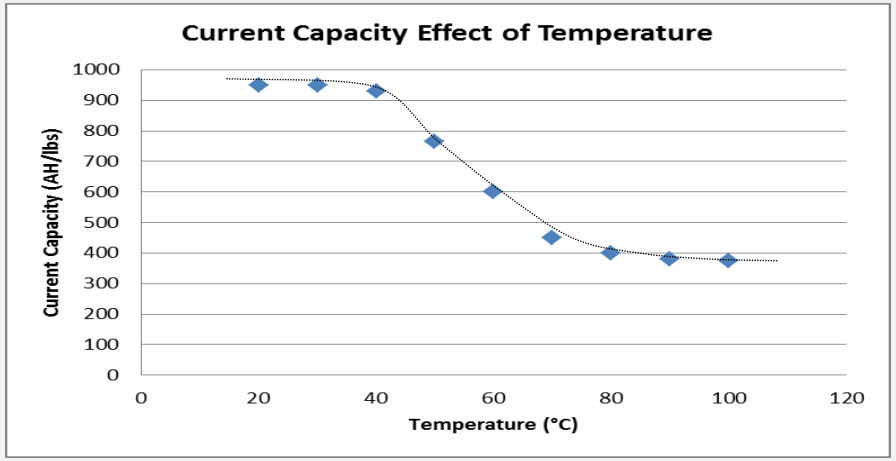
Corrosion Rate



Conditions

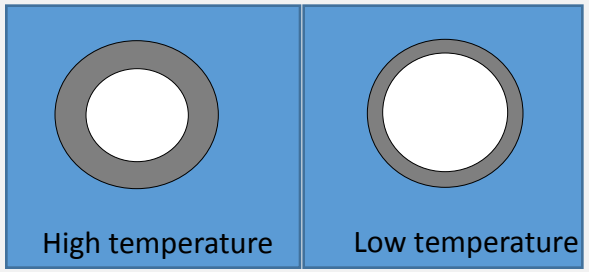
P=40 bar, P_{CO2}=2.7 bar, ID=800mm, Q_G=6843 Am^3/h, Q_L=130 m^3/h

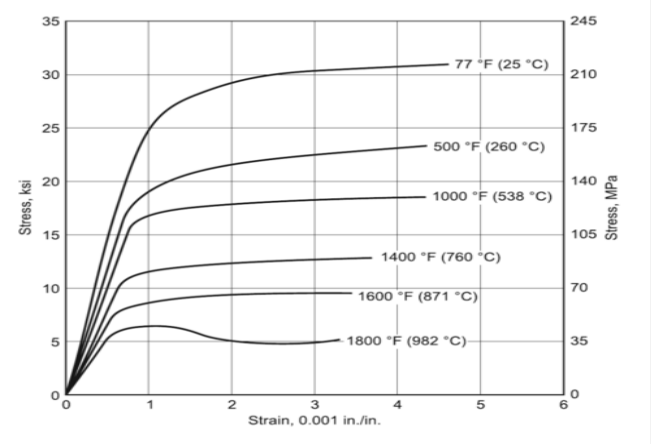
Cathodic Protection



Data from: Schreiber, C.F. and R.W. Murray, "Effect of Hostile Marine Environments on the A1-Zn-In-Si Sacrificial Anode", paper no. 32 Presented at CORROSION/97, March 1988, St.

Material De-Rating

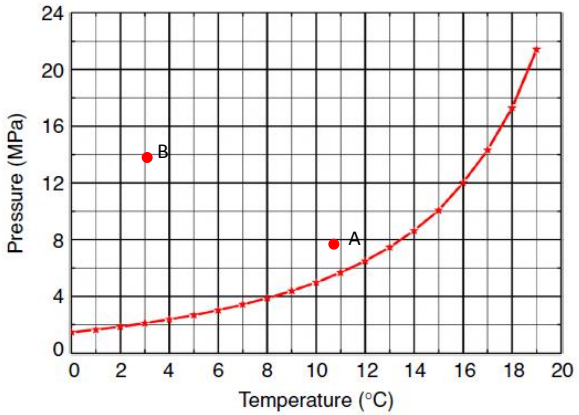




Source: T.W. Gibbs, W. Kyros, and C.L. Theberge, "Development of a Resistance Heating Facility for the Determination of Tensile Properties of Aircraft and Missile Alloys," RaD. TM-63-8, Avco Corp., Feb 1963. As published in *Structural Alloys Handbook*, Vol 2, CINDAS/USAF CRDA Handbooks Operation, Purdue University, 1994, p 33

Hydrate Formation

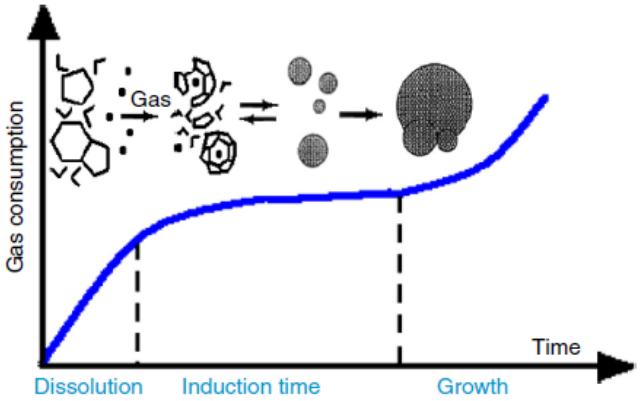
Typical Hydrate Equilibrium Curve



«Equilibrium between hydrate formation and dissociation»

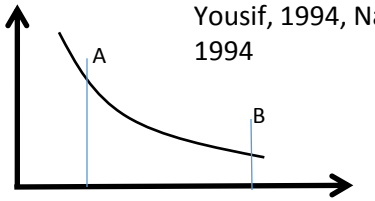
$$4CH_4 + 23H_2O \rightleftharpoons 4CH_4 \bullet 23H_2O$$

Kinetics of Hydrate Formation



Lederhos J.P., Long J.P., Sum A., Christiansen R.L., Sloan E.D. Jr (1996) Effective kinetic inhibitors for natural gas hydrates, Chemical Engineering Science 51, 8, 1221-1229

Induction Time



Skovborg 1993, Monfort and Nzihou, 1993, Yousif, 1994, Natarajan, Bishnoi and Kalogerakis, 1994

«Driving Force» for hydrate formation

Some Literature Data

Lv, X. F et al Oil and Gas Science and Technology 2015

High Pressure Flow Loop
Induction Time **0.5 – 3 hrs**

F.S. Merkel et al Int. J. Chem. Eng. 2015

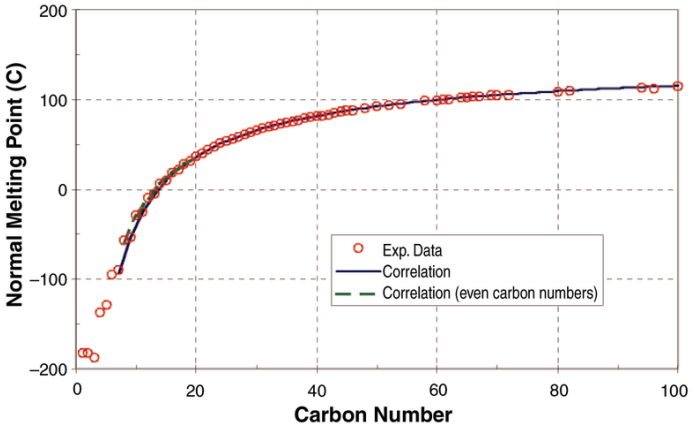
High pressure reactor
Induction Time **1 – 50 h**

Induction Time in a real system?

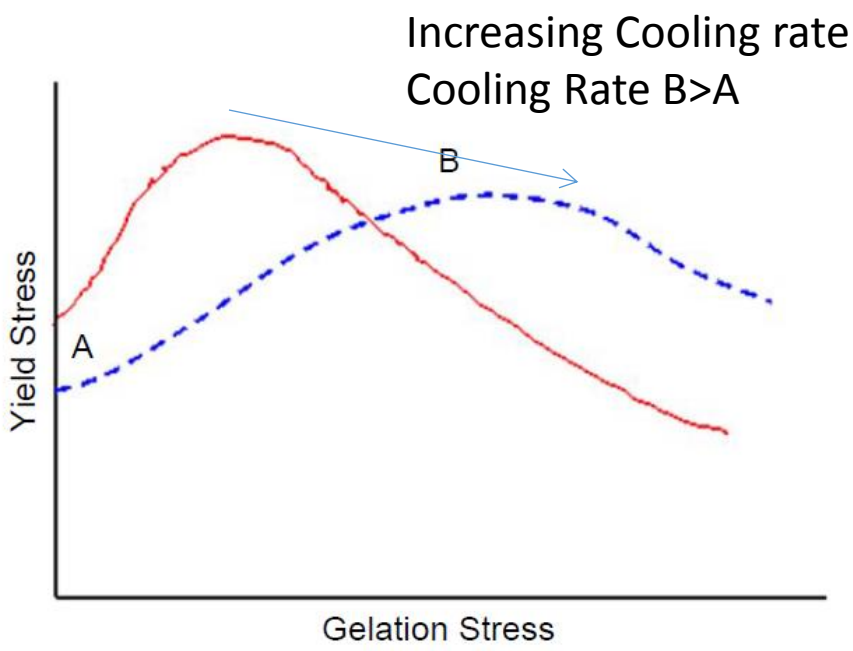
Difficult to say
Predictive model fair,
Experimental testing required, however for a real subsea system **the time scale is probably >> residence time in any subsea cooler!**

Wax

- Wax forms when a phase change occurs in long chained hydrocarbons.
- Complex mechanism dependent on composition
- Small «contaminants» can have significant impact on the WAT
- Predictive models generally poor, laboratory tests required.
- High cooling rate leads to lower wax yield strength.



NIST. 1997. TRC Thermodynamic Tables—Hydrocarbons. College Station, Texas: Thermodynamics Research Center/NIST.
Brandrup, J. and Immergut, E.H. ed. 1989. Polymer Handbook, third edition. New York: John Wiley & Sons.
Marano, J.J. and Holder, G.D. 1997. General Equation for Correlating the Thermophysical Properties of n-Paraffins, n-Olefins, and



R. Venkatesan, Chem. Eng. Sci 60 (2005)

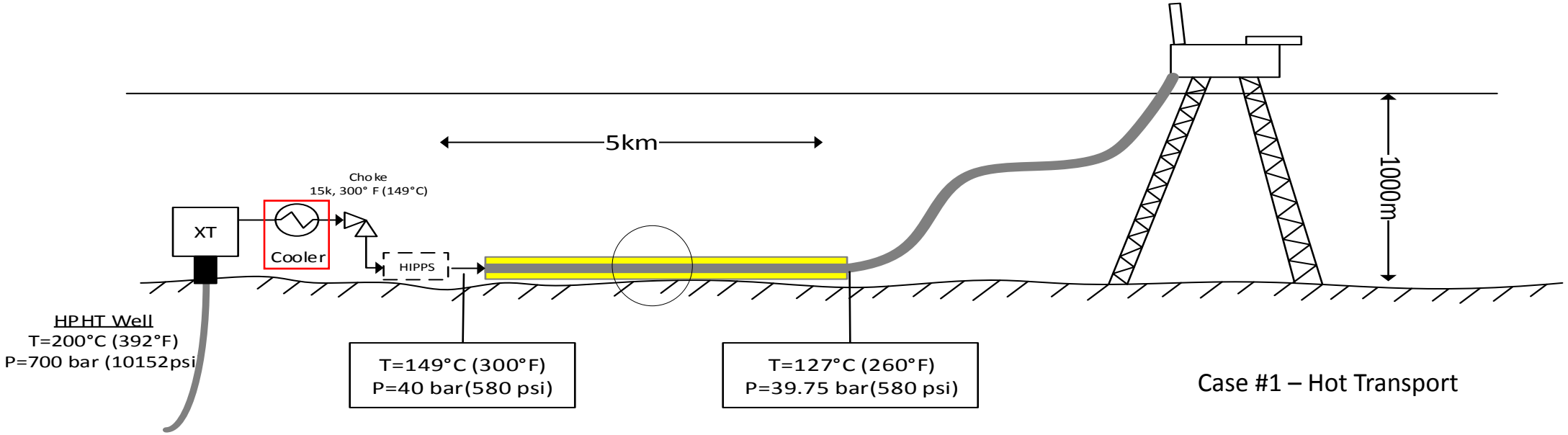
Green Field - Case Study #1 – Hot Transport

Development of a Gas Condensate HPHT well

- Generic Gas Condensate Composition
- P=700 bar, T=200°C
- 1000m water depth
- 5km subsea tie back to host

Reducing the temperature upstream the choke enables → lower temperature rated choke.

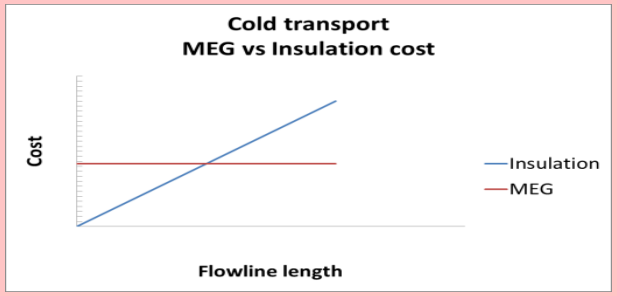
Insulated flowline



Case #1 – Hot Transport

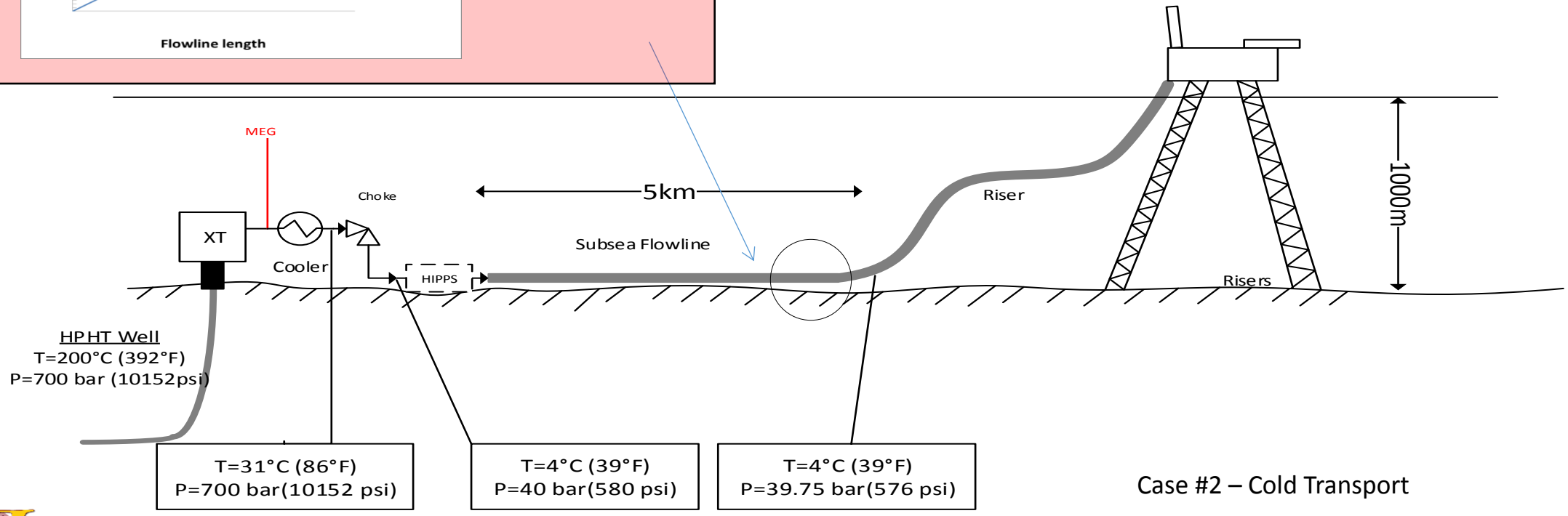
Green Field - Case Study #2 – Cold Transport

What is most cost effective, continuos MEG injection or insulation?



MEG injection upstream cooler

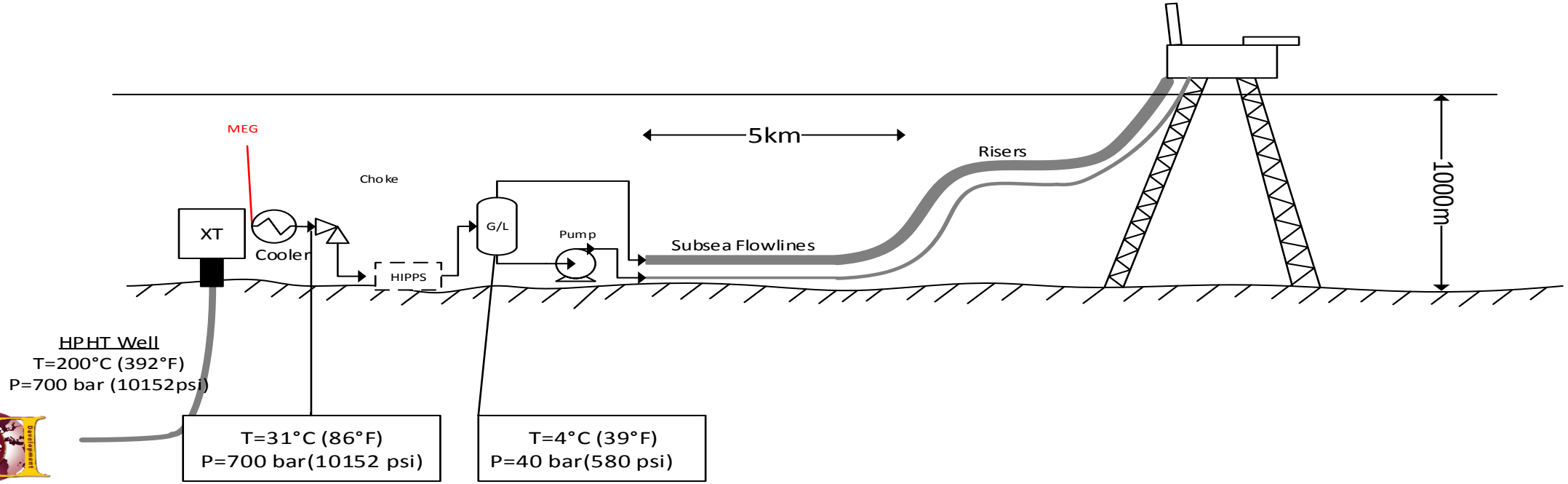
No insulation, cold transport



Case #2 – Cold Transport

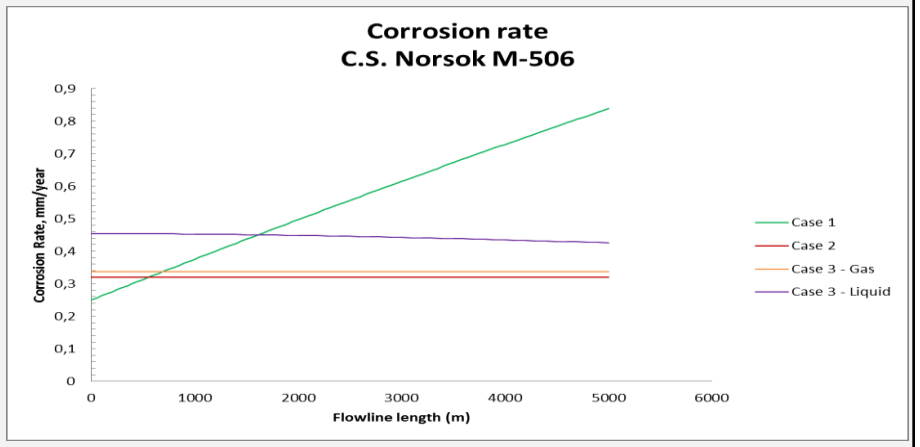
Green Field - Case Study #3 – G/L Sep

- MEG injection upstream cooler
- Separating liquid and gas at ambient conditions
- Cold transport of liquid and gas
- Dedicated liquid and gas transport pipe
- No further condensation will occur in the gas line



Comparison – Temperate Effects

Corrosion Rate

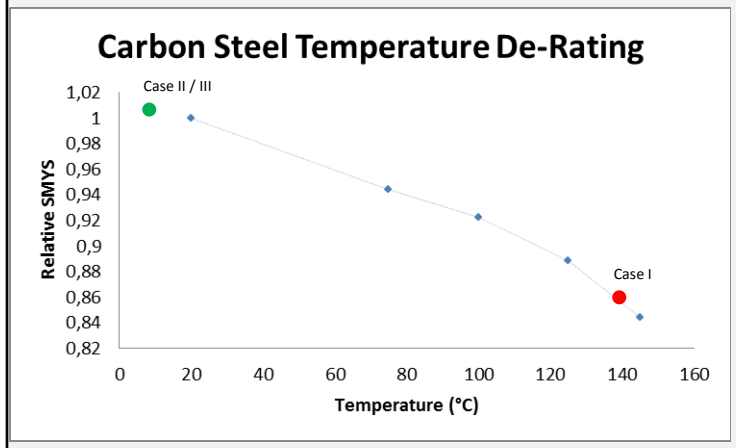


The corrosion rate is dependent of the temperature, the CO_2 content, wall shear stress and whether the system is saturated be $FeCO_3$ and or the presence of corrosion inhibitors.

The effect of adding MEG in Case II and III are incorporated in the corrosion rate calculation.

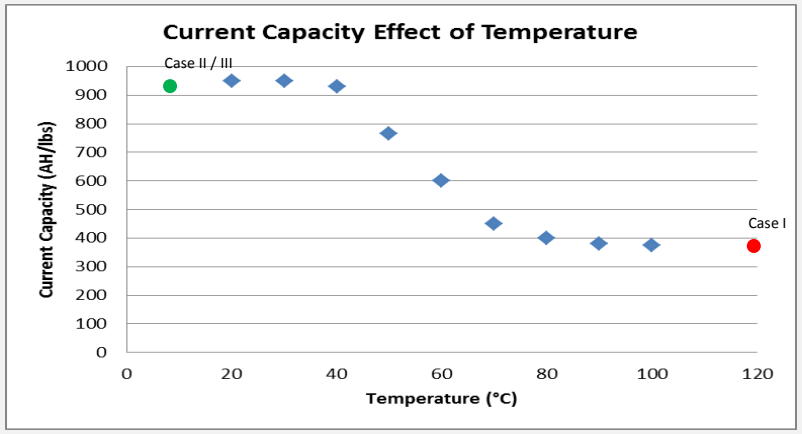
Case I gives the highest corrosion rate.

De-Rating



By using a higher design temperature the strength of the material needs to be de-rated=thicker pipe walls required for Case I.

Cathodic Protection

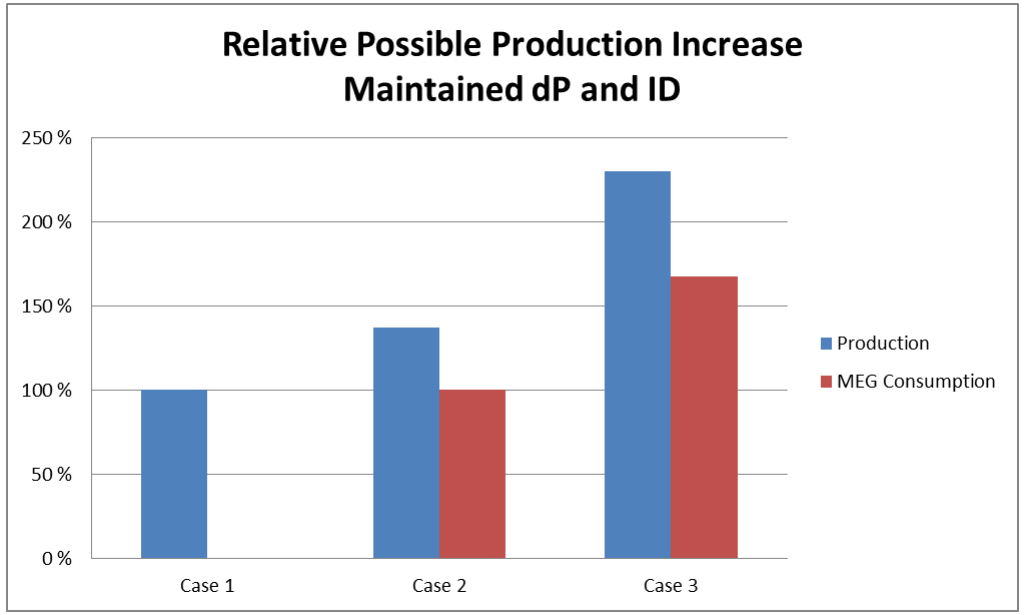


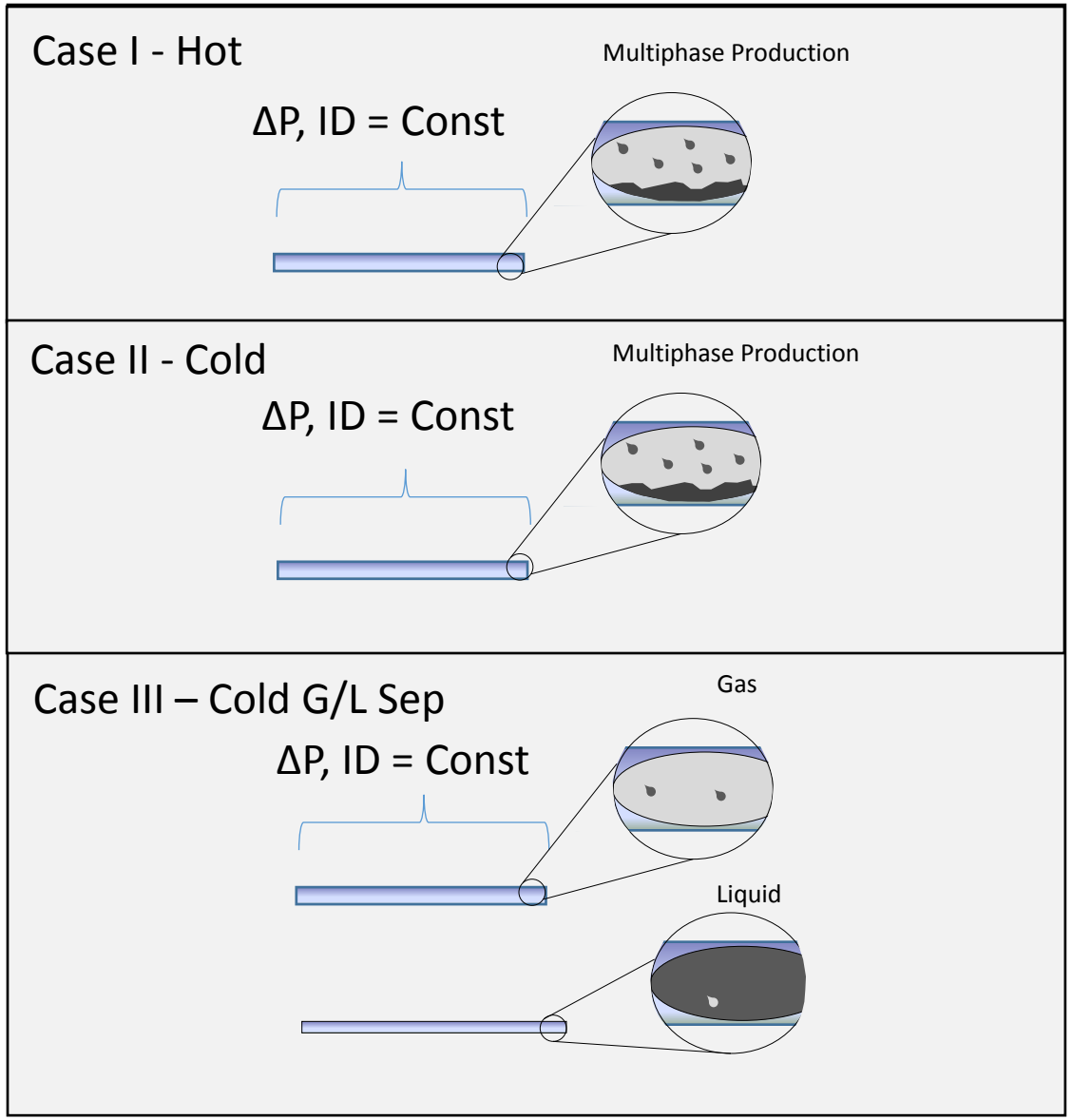
CP design for Case I would require approximately 3 times as large anode mass as for Case II and III compared to Case I.

Cooler Opportunities

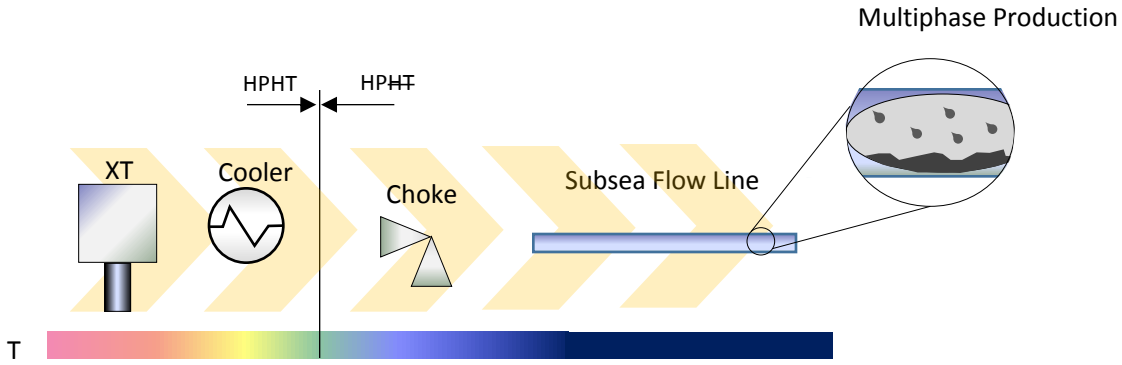
Case Comparison

When the temperature decrease, the gas volume is reduced and some components condensate. This leads to less frictional pressure drop **or a possible increased production while maintaining the same pressure drop.**

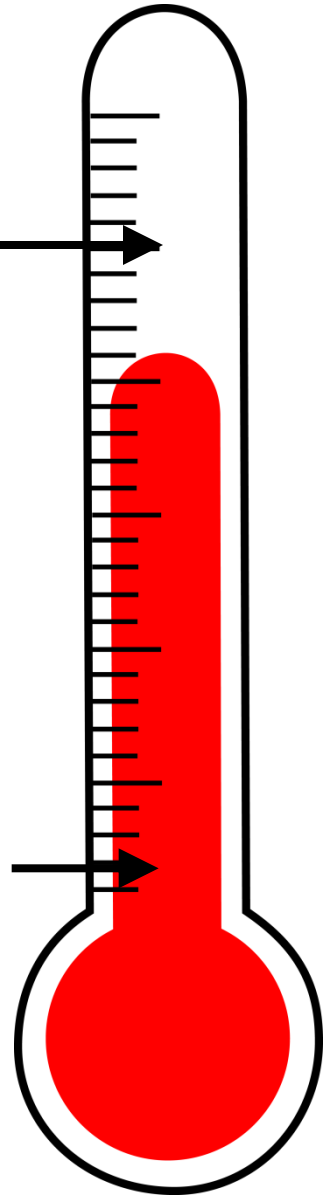




Summary



- Subsea Cooling enables the use of low(er) temperature rated downstream equipment.
- Subsea Cooling enhance G/L separation.
- Subsea Cooling enables subsea compression.
- Subsea Cooling enhance gas dehydration.
- A low(er) design temperature is favorable for the hardware design.



Favorable for:
Hydrate and Wax inhibition

Favorable for:
Corrosion, Mechanical strength, thermal stress, CP system, marine growth, scaling and production.