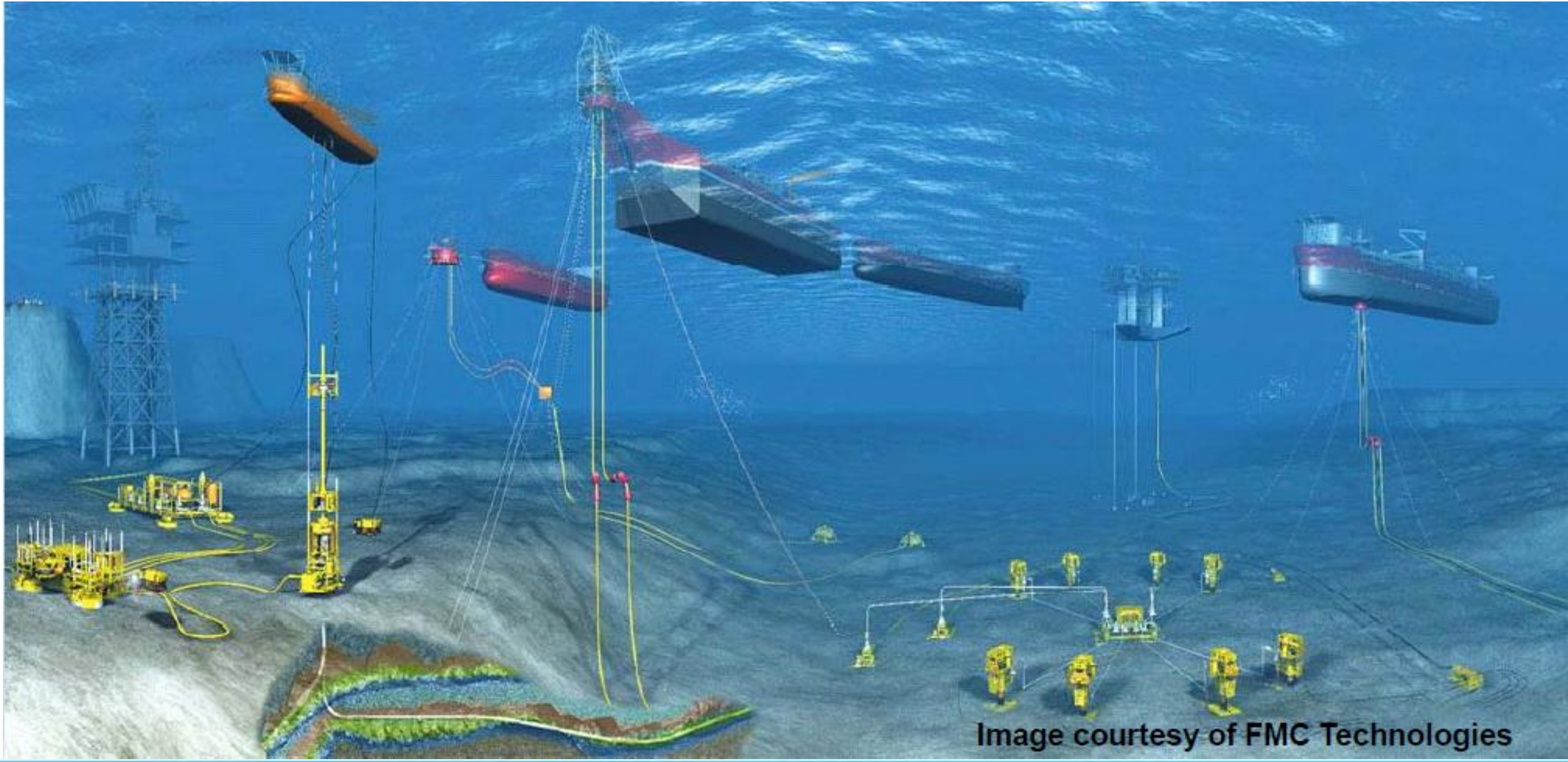
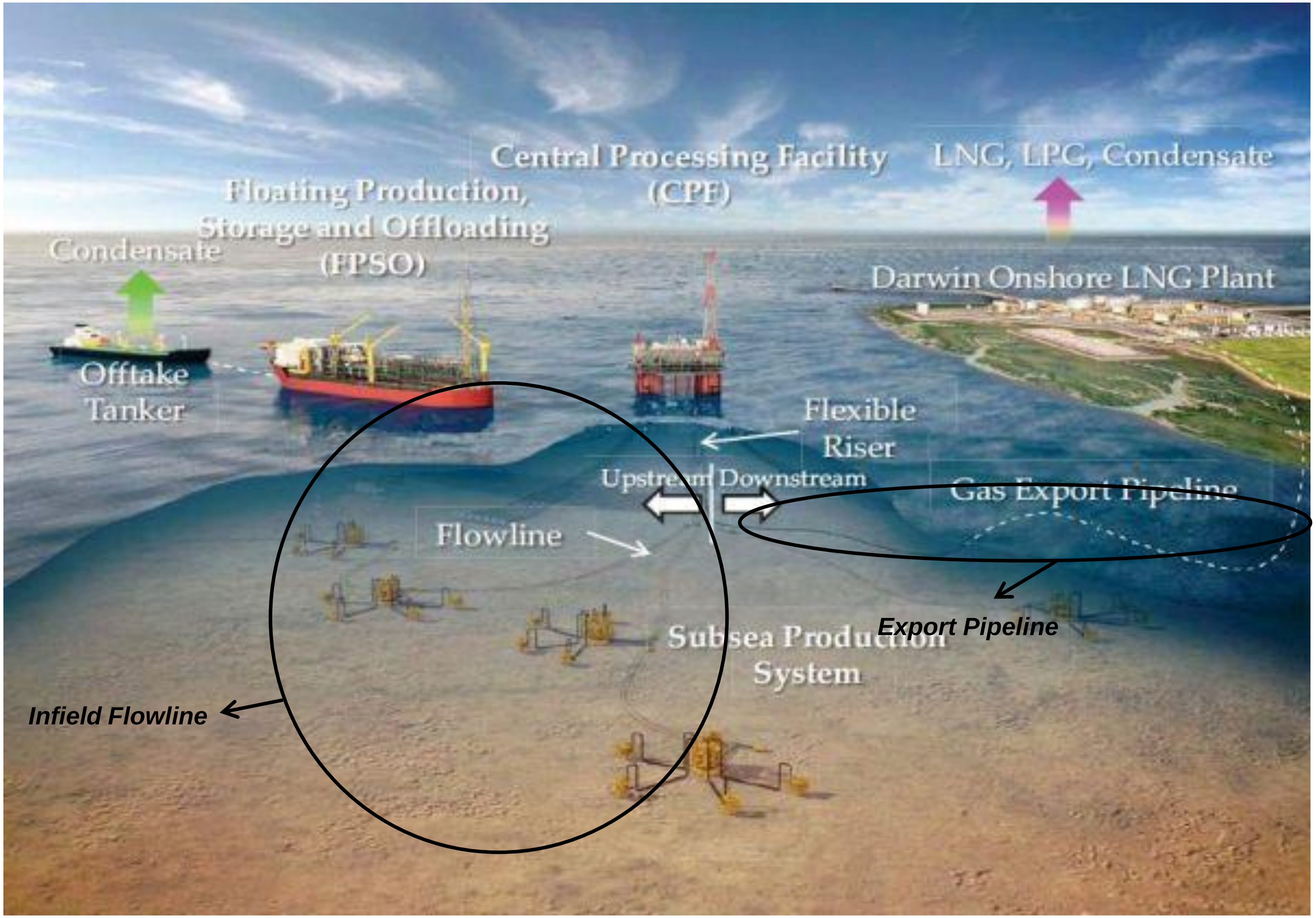


Subsea Engineering

Yutaek Seo

Pipeline System (1) : Oil and Gas Production

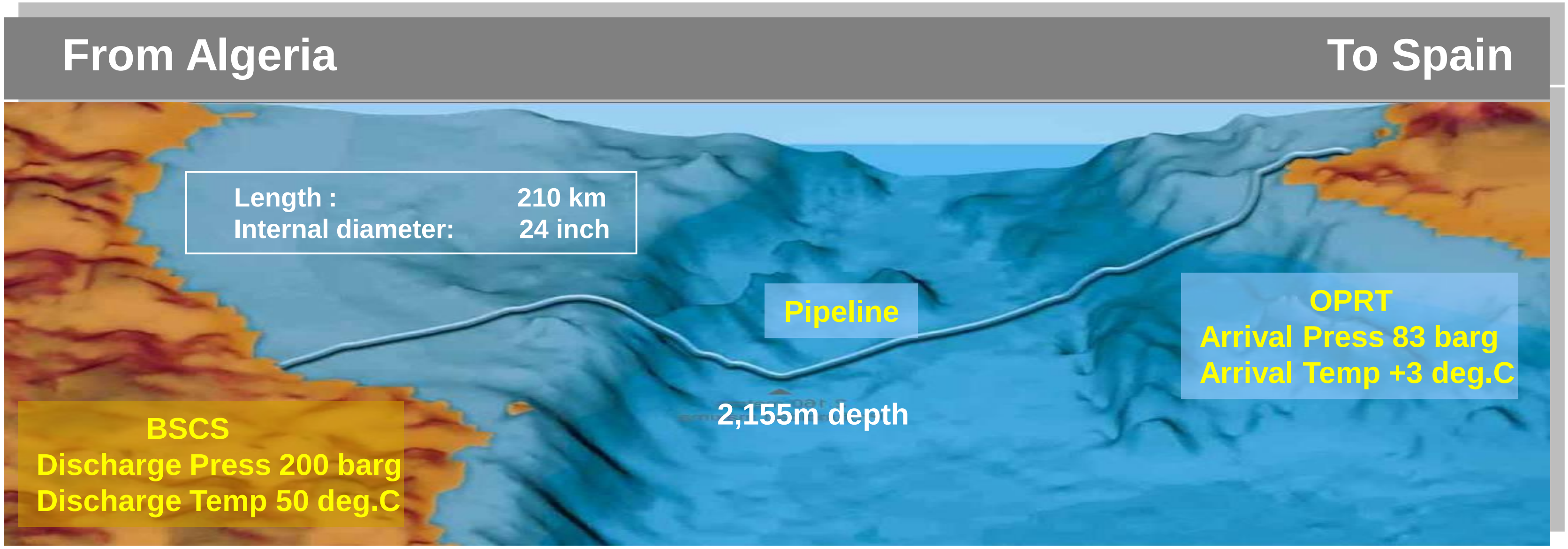
Ex) Gas and Condensate Production for Dawin LNG Project (AU)



Source : Darwin LNG Project (Austrailia), http://subseaworldnews.com

Pipeline System (2) : Gas Transportation

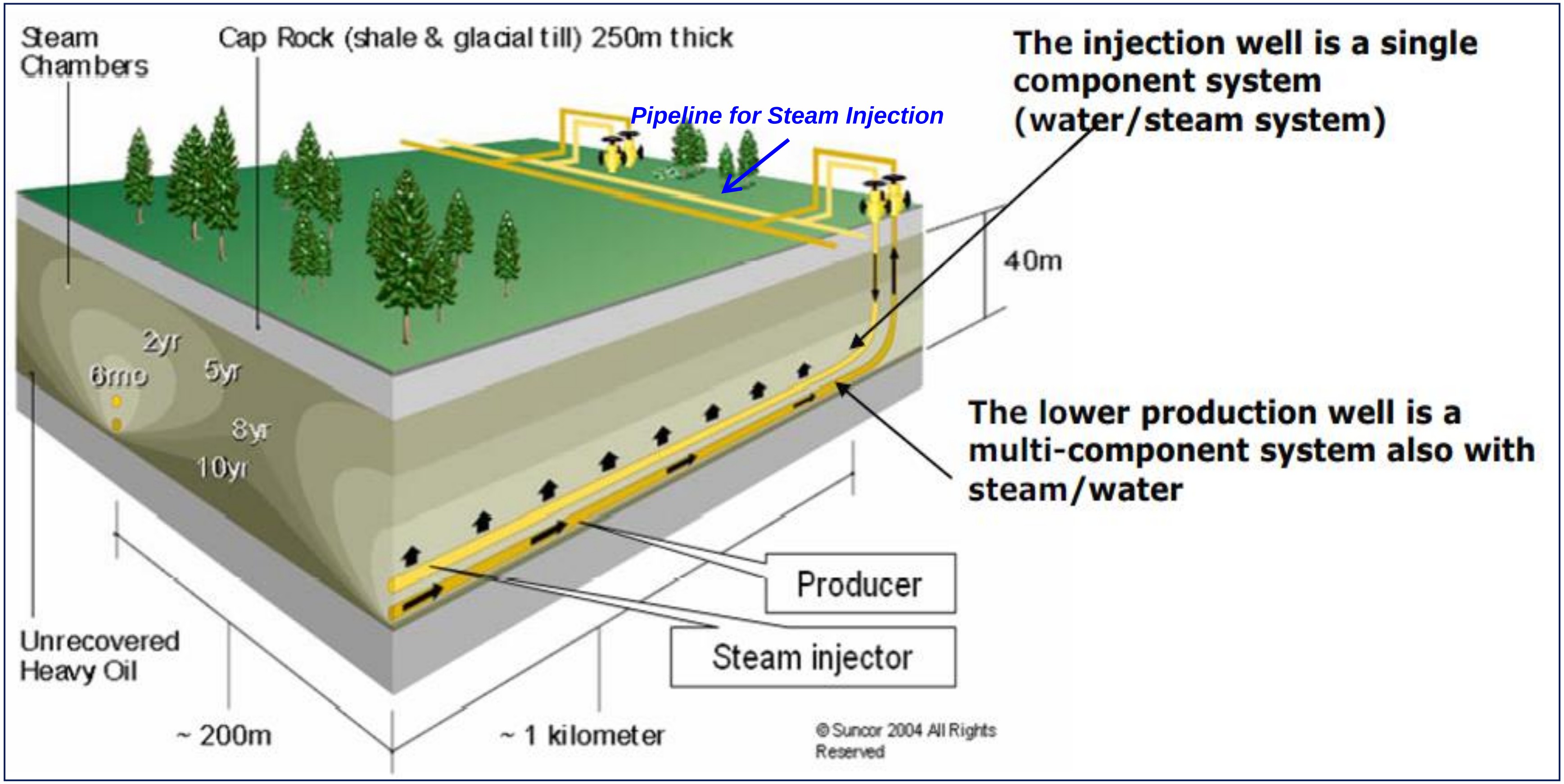
Ex) Gas Transportation from Algeria to Spain for LNG Feed



Source : Education Materials for Pipeline Engineering, Held by JP Kenny (2012)

Pipeline System (3) : Extra-Heavy Oil Production

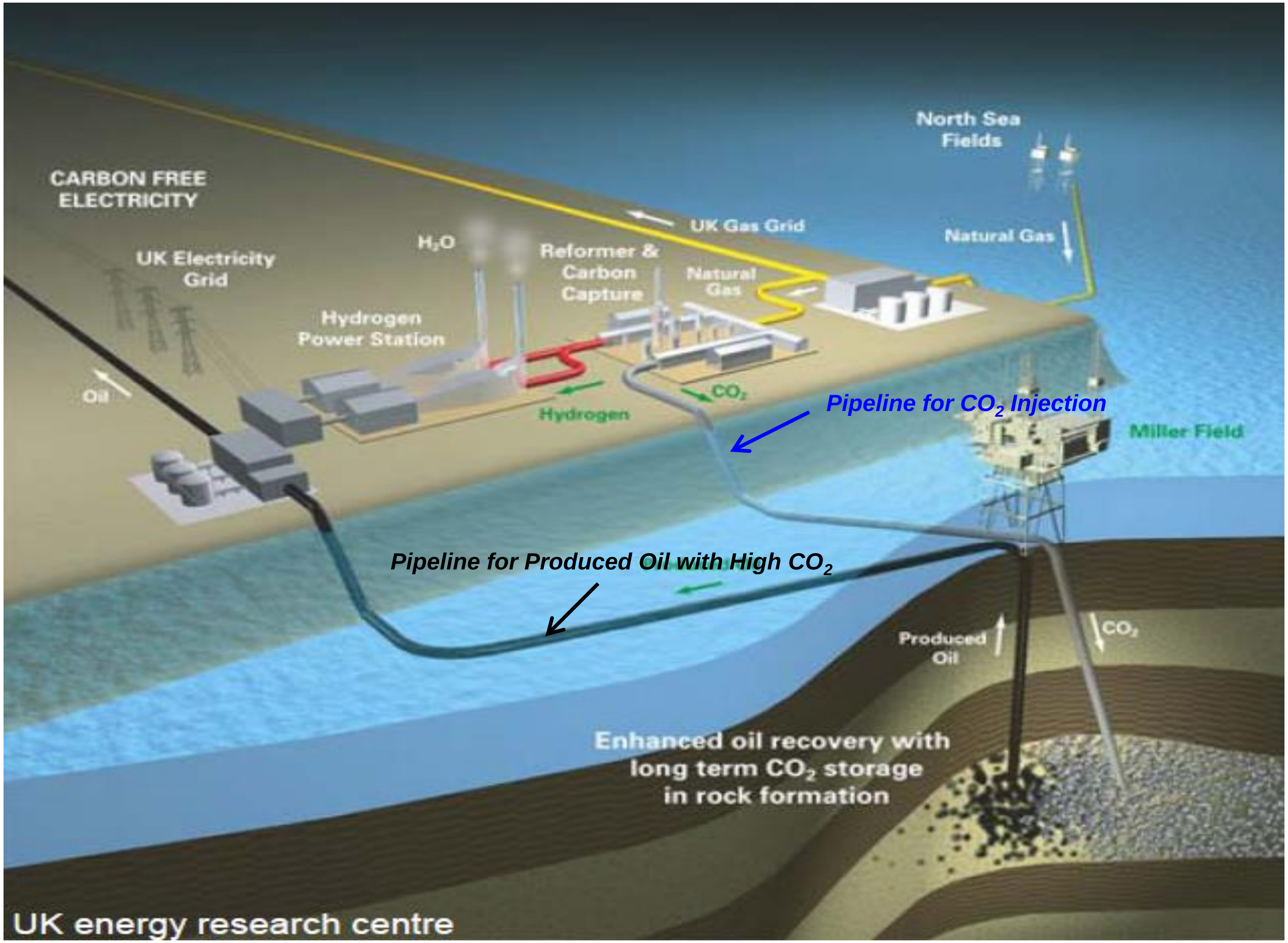
Ex) Steam Injection for Bitumen Production (SAGD)



Source : Presentation Material for OLGA User Seminar (2011)

Pipeline System (4) : Gas (CO_2, N_2, HC) Injection

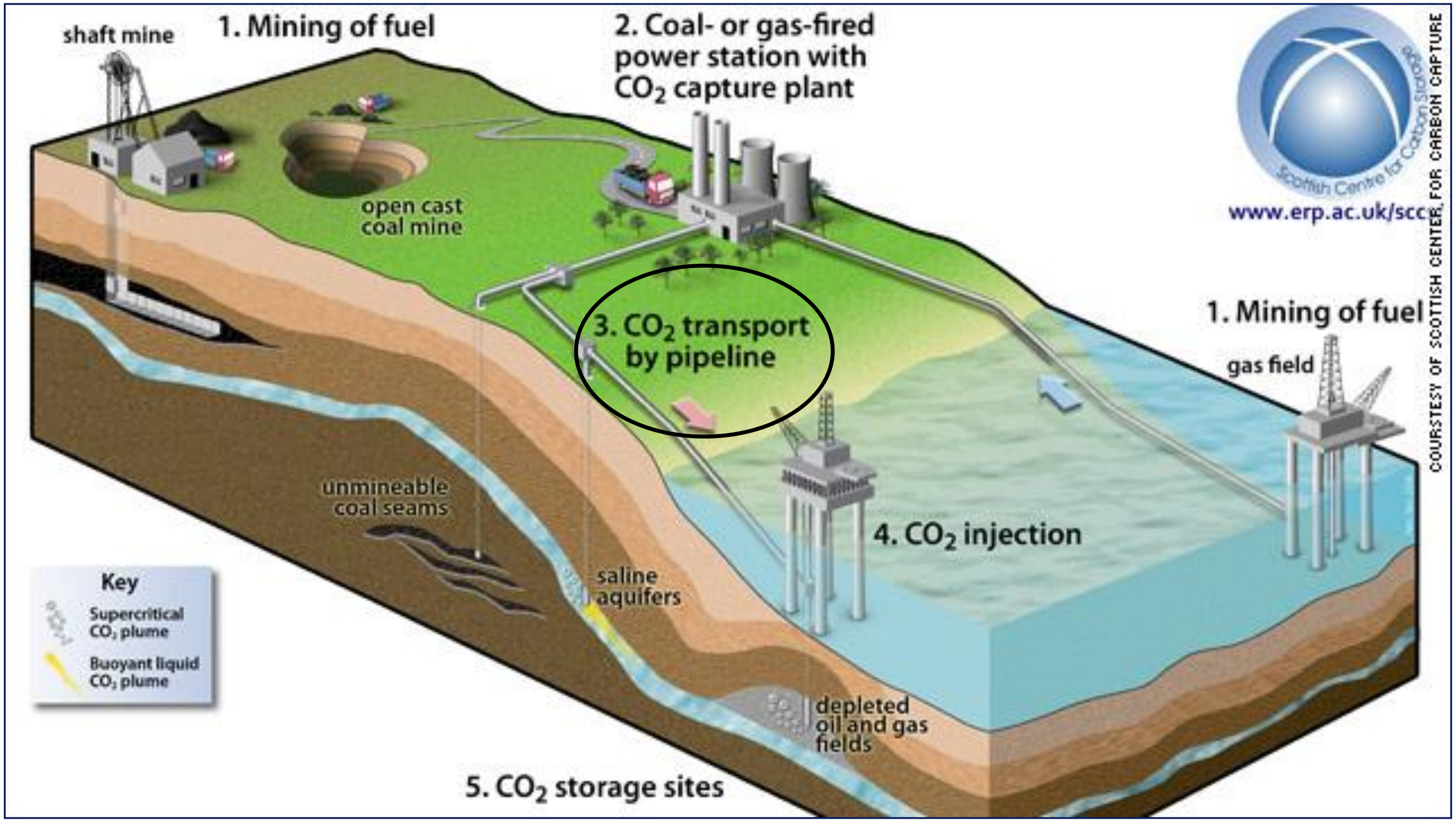
Ex) CO_2 Injection to Oil Reservoir for EOR (Enhanced Oil Recovery)



Source : Presentation Material for OLGA User Seminar (2011)

Pipeline System (5) : CO_2 Storage for CCS

Ex) CO_2 Storage System



Source : http://edition.cnn.com/2010/TECH/04/07/coal.capture.storage/index.html

Approach to Pipeline Design

Fluid Characterization

① Production fluid characteristics (especially on pseudo-component)

② Solid characteristics (ex. hydrate, wax, scale, asphaltene)

③ Checking characterized fluid property with experiment data

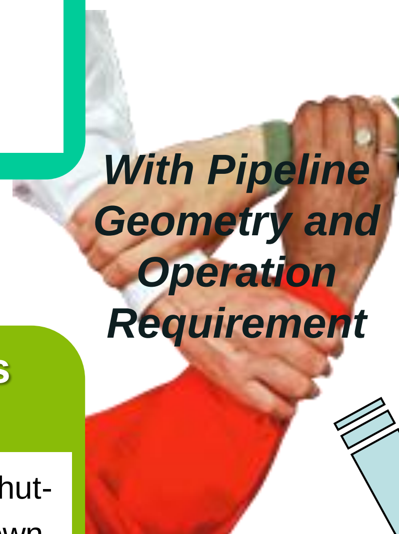
Steady State Analysis

Estimating PIPELINE SIZE suitable for ;

① Pipeline condition requirement

② Physical pipeline stability free of erosion and corrosion problem

③ Flow assurance for inhibiting solid formation and controlling severe liquid slug



Transient (Dynamic) Analysis

1. Checking operation scenarios (ex. Shut-down, Ramp-up, Ramp-down, Turn-down, Restart, Pigging)
2. Determining liquid surge volume of slug catcher and establishing operating philosophy for chemical injection rate, pigging period and so on

Optimized Pipeline Design

What is Flow Assurance?

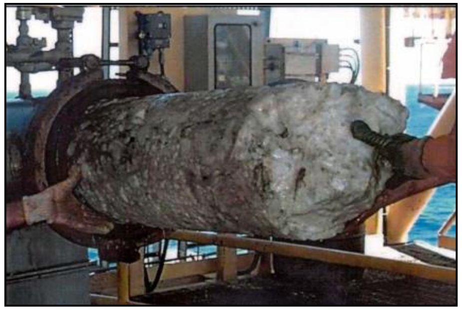
Flow assurance is a relatively new term in oil & gas industry. It refers to ensuring successful and economical flow of production fluid from reservoir to the point of sale. The term was coined by Petrobras in the early 1990s in Portuguese as *Garantia do Escoamento*, meaning literally “Guarantee of Flow”, or Flow Assurance.

Flow assurance involves effectively handling many solid deposits, such as gas hydrates, asphaltene, wax, scale and some solids from erosion & corrosion, and severe liquid slug problem.

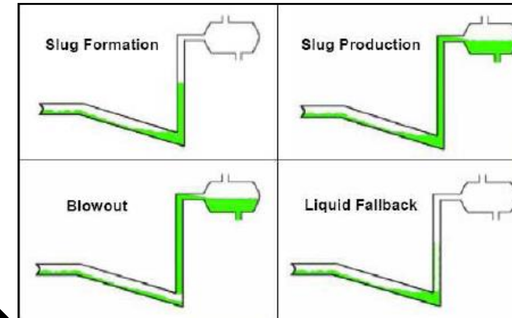
As well as oil / gas production system, steam / condensate and CO_2 transportation network for enhanced oil recovery need to do flow assurance study.

Flow Assurance (FA) Issues

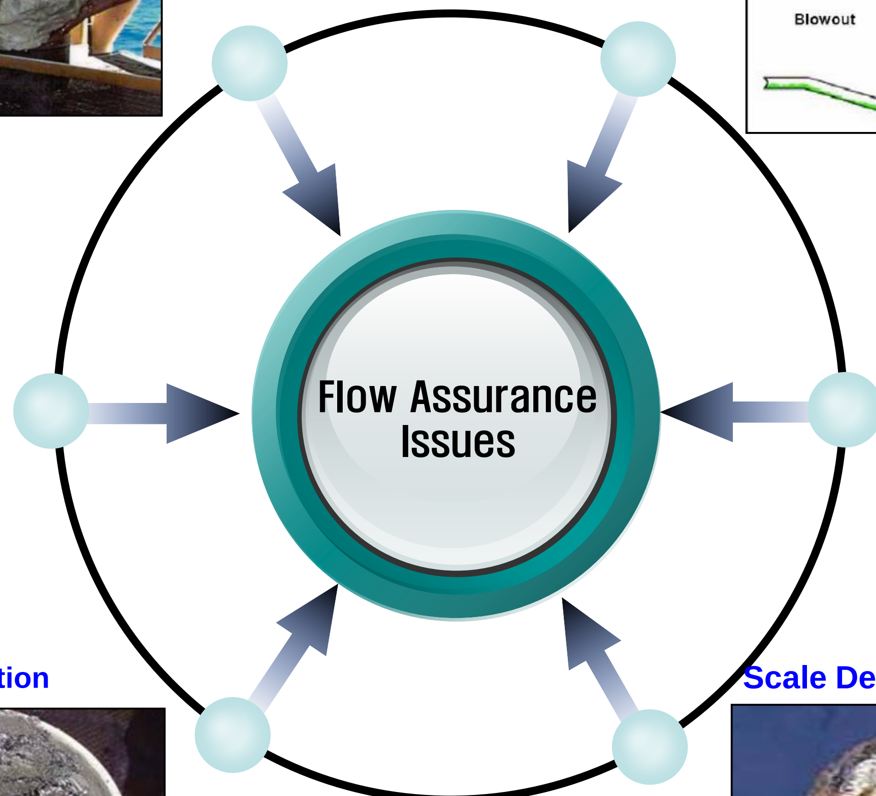
Hydrate Plugging



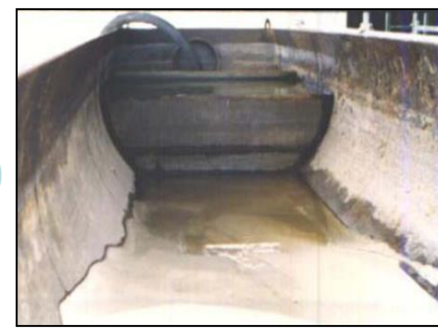
Liquid Slug



Wax (C17+) Deposition



Sand Plugging (especially at CV)

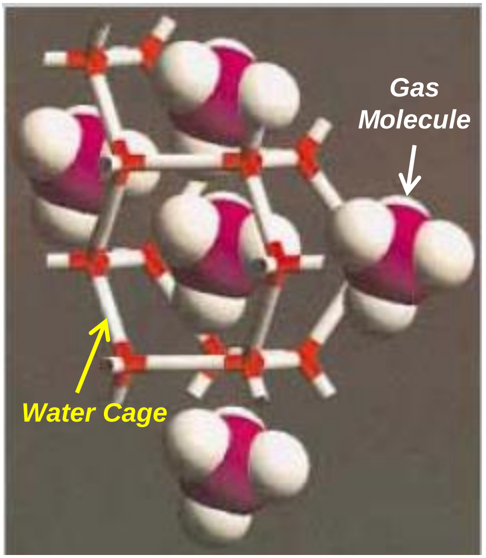


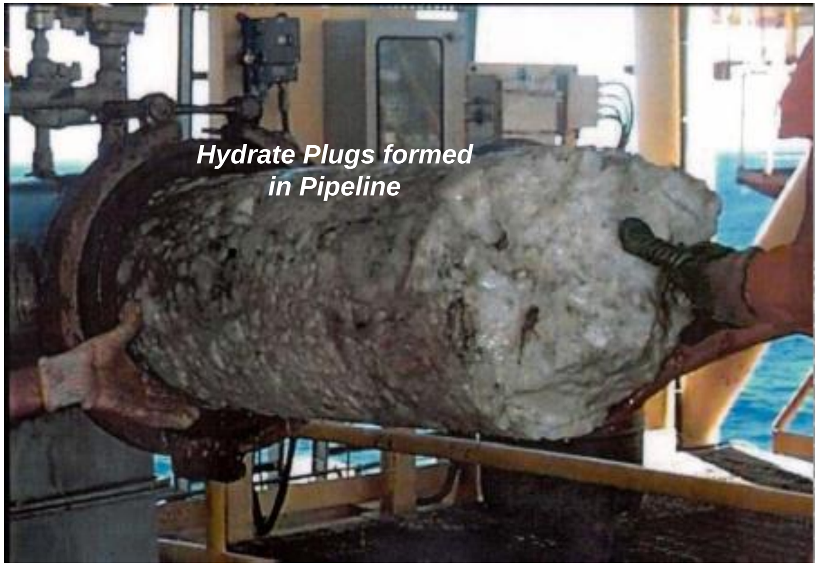
Asphaltene Deposition

Scale Deposition

What is Hydrate?

- Ice-like solids that form due to the presence of water. Hydrocarbons are trapped in a lattice of frozen water.
- Can form and be stable at or near normal operating temperatures, resulting in potential for a blocked system.
- May be an issue during steady state production, and more commonly during shutdown and cooldown of a production system.



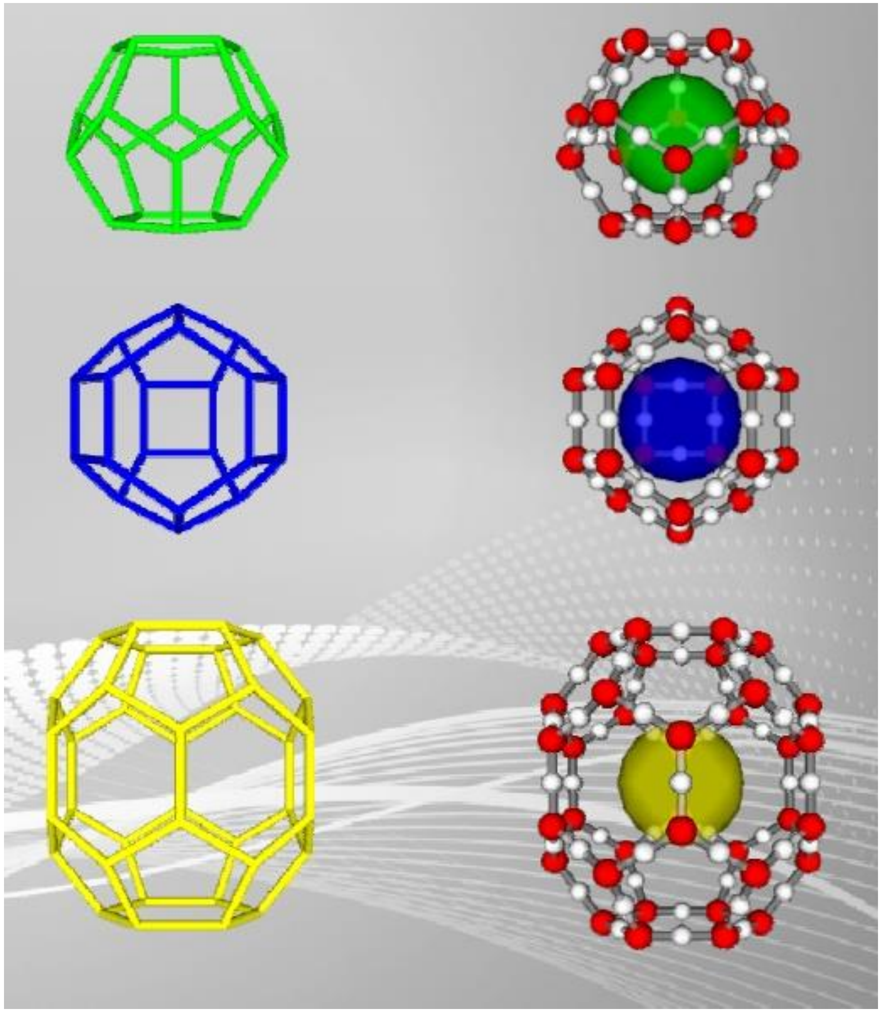


Clathrates – "Cage-like" Structures

Source : Education Materials for Pipeline Engineering, Held by JP Kenny (2012)

Hydrate Type

- Crystalline shapes & components determine the hydrate type
- Most low molecular weight gases (including O_2, H_2, N_2, CO_2, CH_4, H_2S, Ar, Kr and Xe), as well as some higher hydrocarbons and freons will form hydrates at suitable temperatures and pressures.
- Type I : include CO_2 & CH_4
- Type II : include O_2 & N_2
- Type III : include hydrocarbon



Source : Education Materials for Pipeline Engineering, Held by JP Kenny (2012)

Hydrate Formation (I)

When can Hydrate be formed?

: Favor conditions for hydrate formation are 1) High Pressure, 2) High Water Content and 3) Low Temperature.

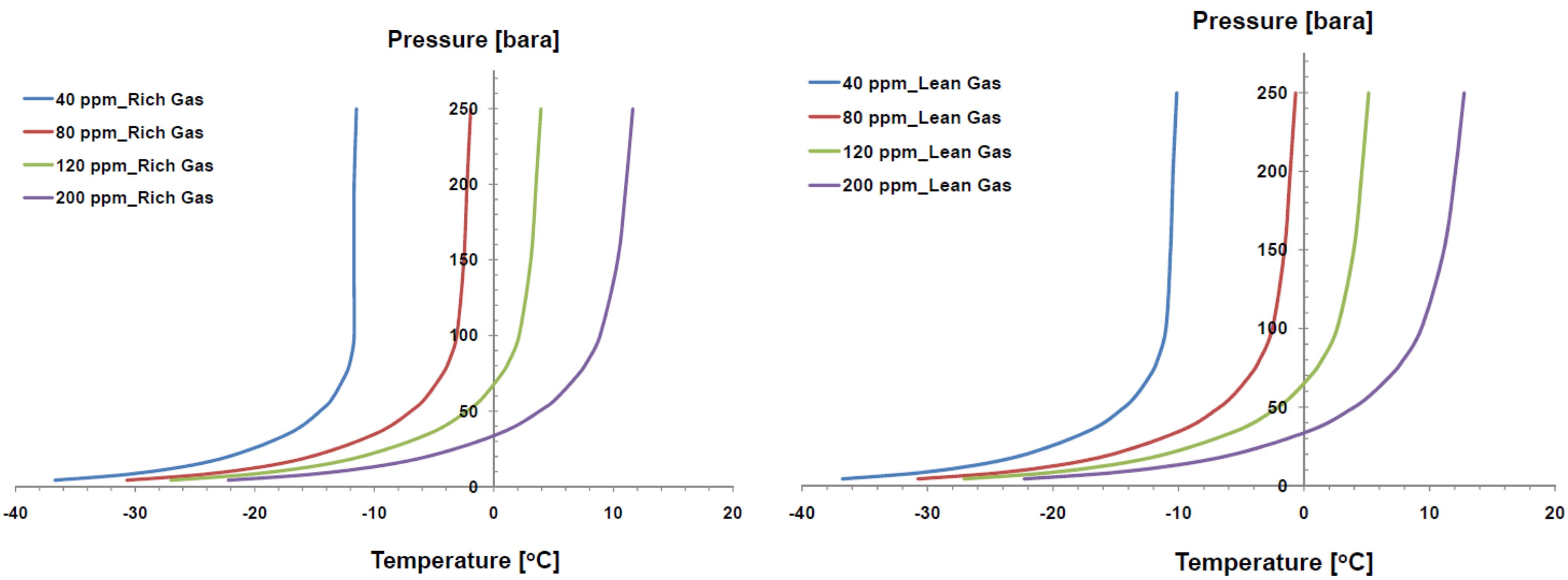
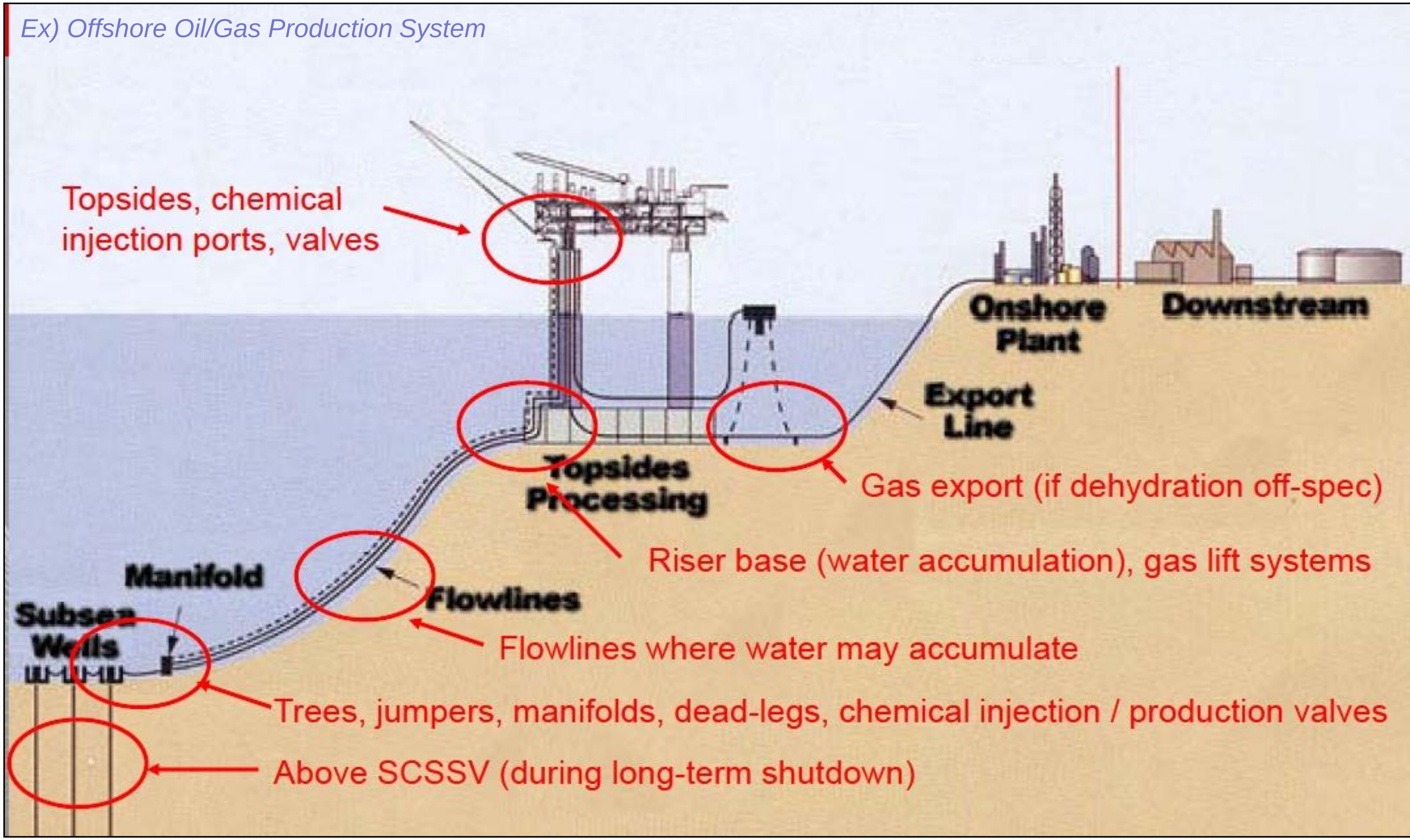


Figure. *Hydrate Formation Curve for Great Sunrise Gas Field located on Timor Sea*

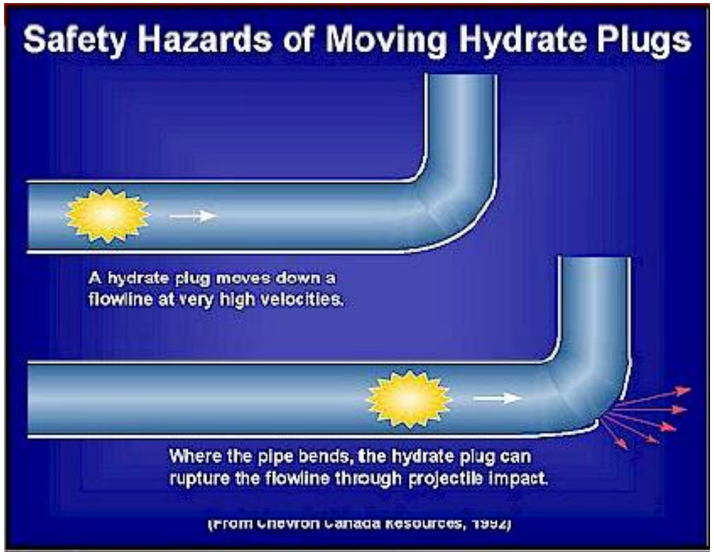
Hydrate Formation (II)

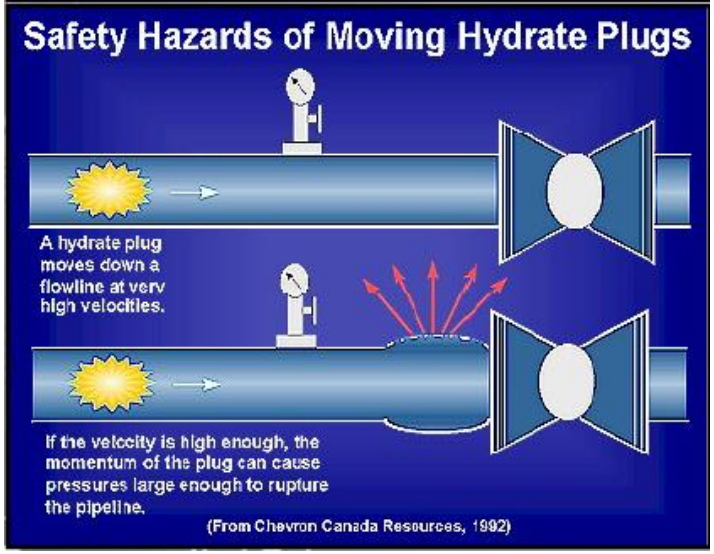
Where can hydrate be formed?



Source : Education Materials for Pipeline Engineering, Held by JP Kenny (2012)

If hydrate plugging occurs..





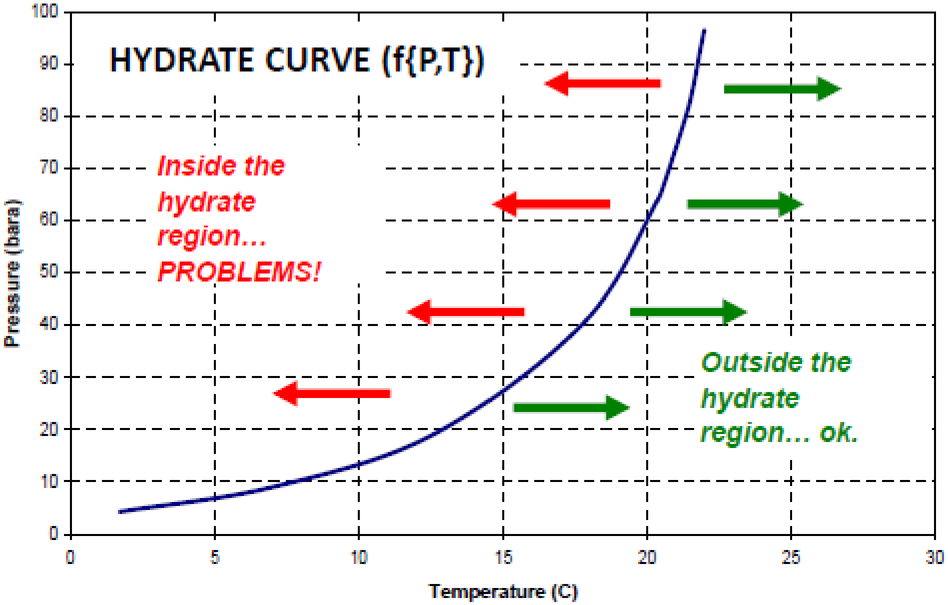
Source : Education Materials for Pipeline Engineering, Held by JP Kenny (2012)

For Hydrate Inhibition

Strategy

- Maintaining system temperature outside the hydrate formation region
  - use of insulation, heating and pressure limitations
  - use of thermodynamic hydrate inhibitors (THI's)
  - chemicals that reduce the hydrate formation temperature of the system (ex. MEG, Methanol)

- LDHI : Kinetic hydrate inhibitor (KHI's)
  - chemicals that reduce the speed of hydrate formation
- LDHI : Growth inhibitor (Anti-Agglomerates)
  - chemicals that limit the size of hydrate solid, resulting in a slurry rather than a blockage

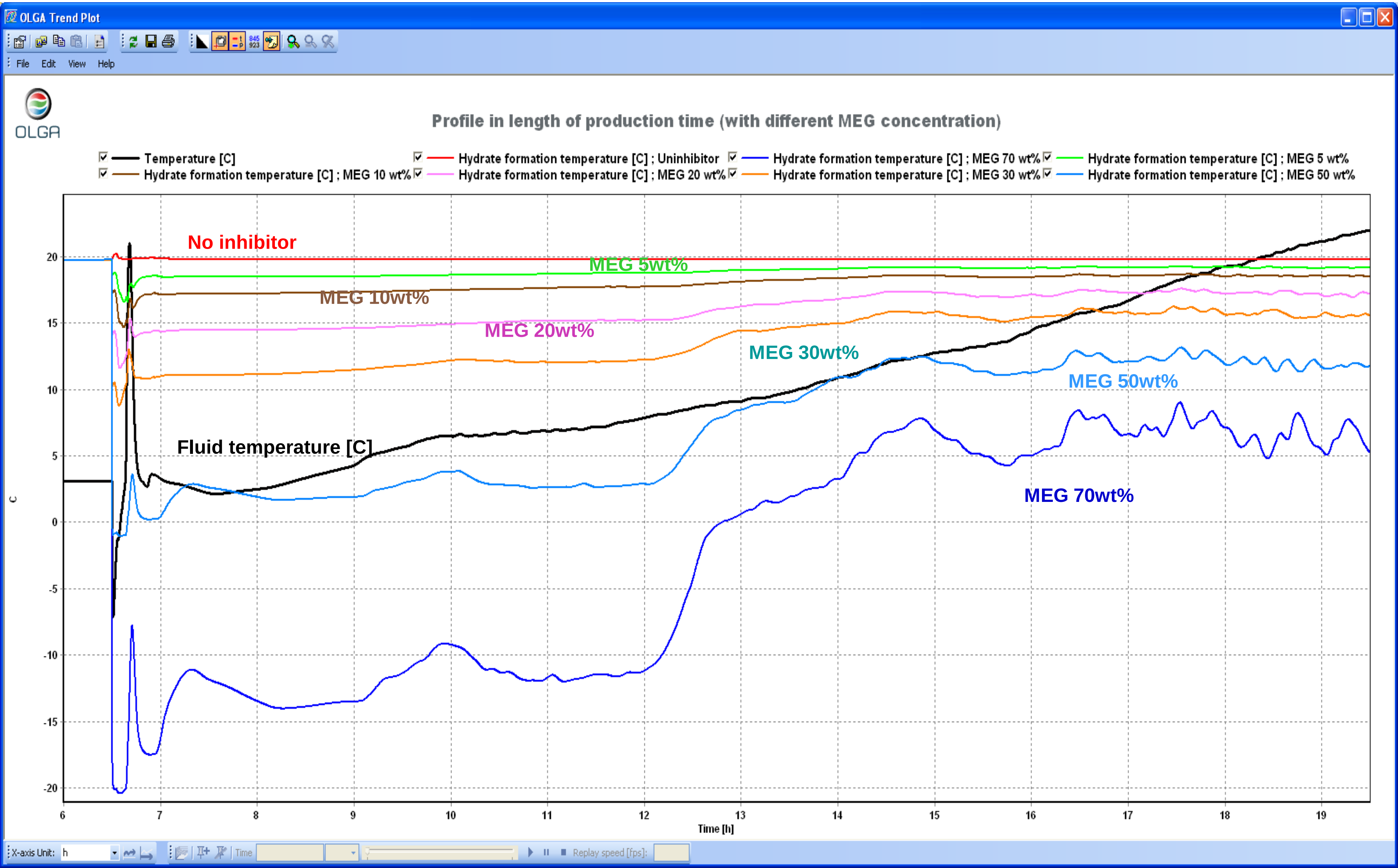


*** LDHI : Low Dosage Hydrate Inhibitor**

Source : (1) CSIRO, (2) Education Materials for Pipeline Engineering, Held by JP Kenny (2012)

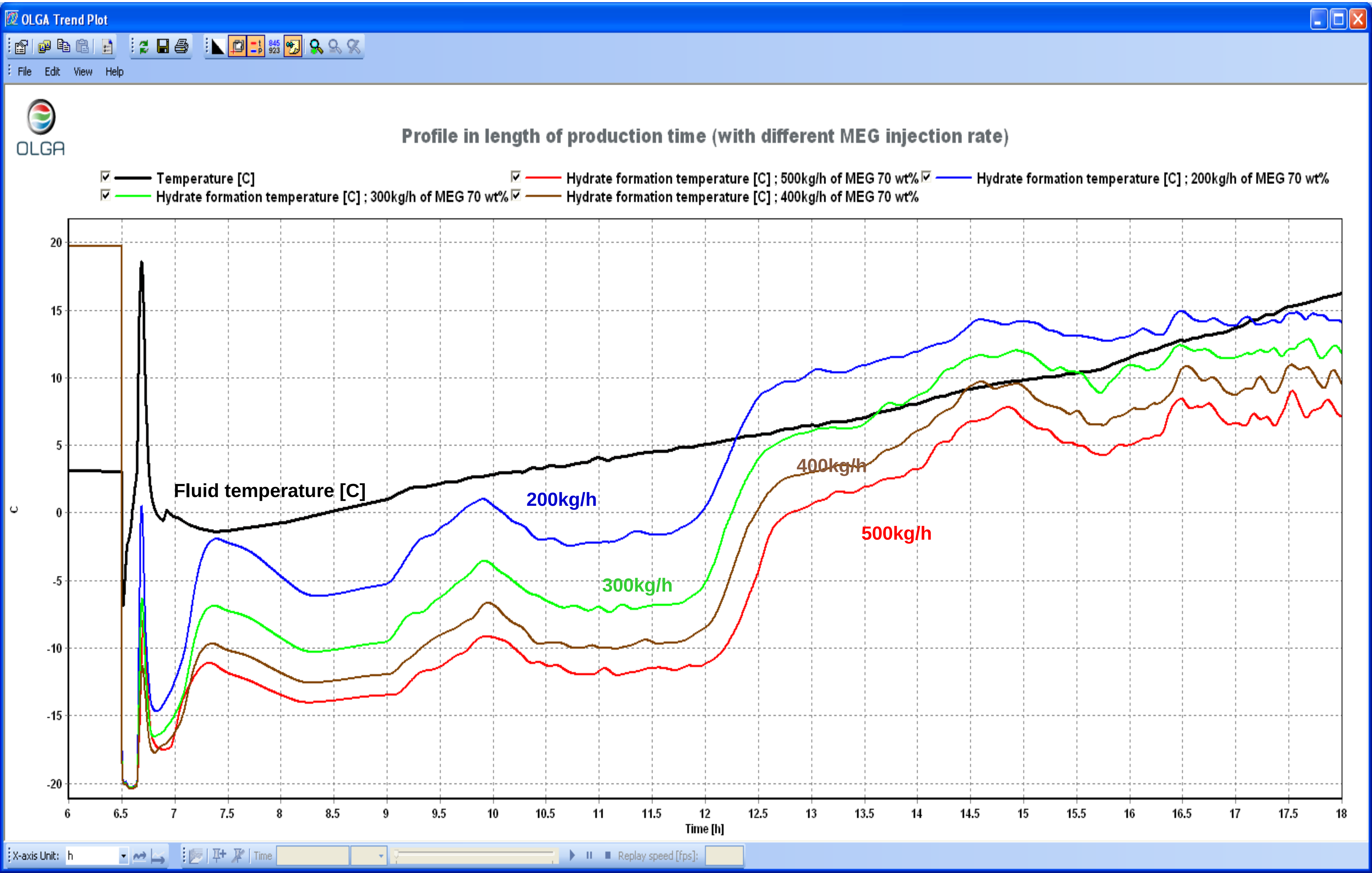
Example – Hydrate Inhibition Mitigation

Ex) Degree of Hydrate Inhibition according to THI Concentration



Example – Hydrate Inhibition Mitigation

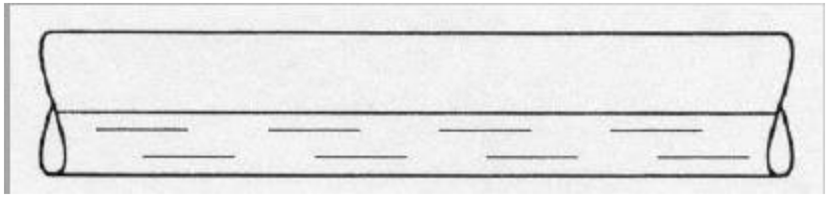
Ex) Degree of Hydrate Inhibition according to THI Mass Flowrate



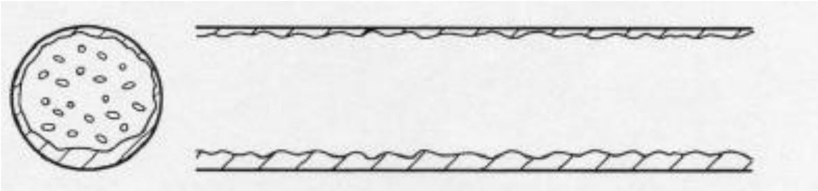
Flow Regimes (I)

Horizontal pipeline

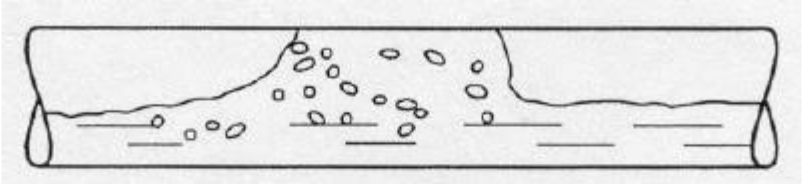
Stratified / Wavy



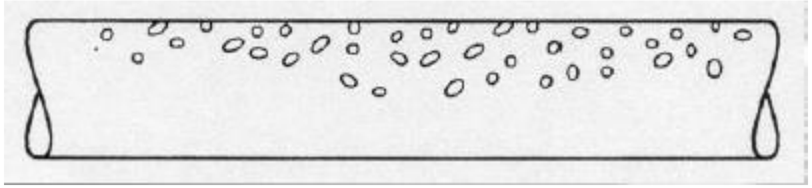
Annular / Mist



Slug



Bubble / Dispersed



① **Stratified Flow** : Liquid flows along pipeline, gas flows over top with 'smooth' interface

② **Wavy Flow** : Higher velocity gas than stratified flow, with waves at interface traveling at high velocity

③ **Annular Flow** : Liquid flows as thin film along pipeline, with gas flowing in middle ('core')

④ **Mist Flow** : Very high gas velocities, entrain nearly all liquid

⑤ **Slug Flow** : Intermittent periods of gas / liquid flow. Liquid characterized by high velocity and high momentum flows

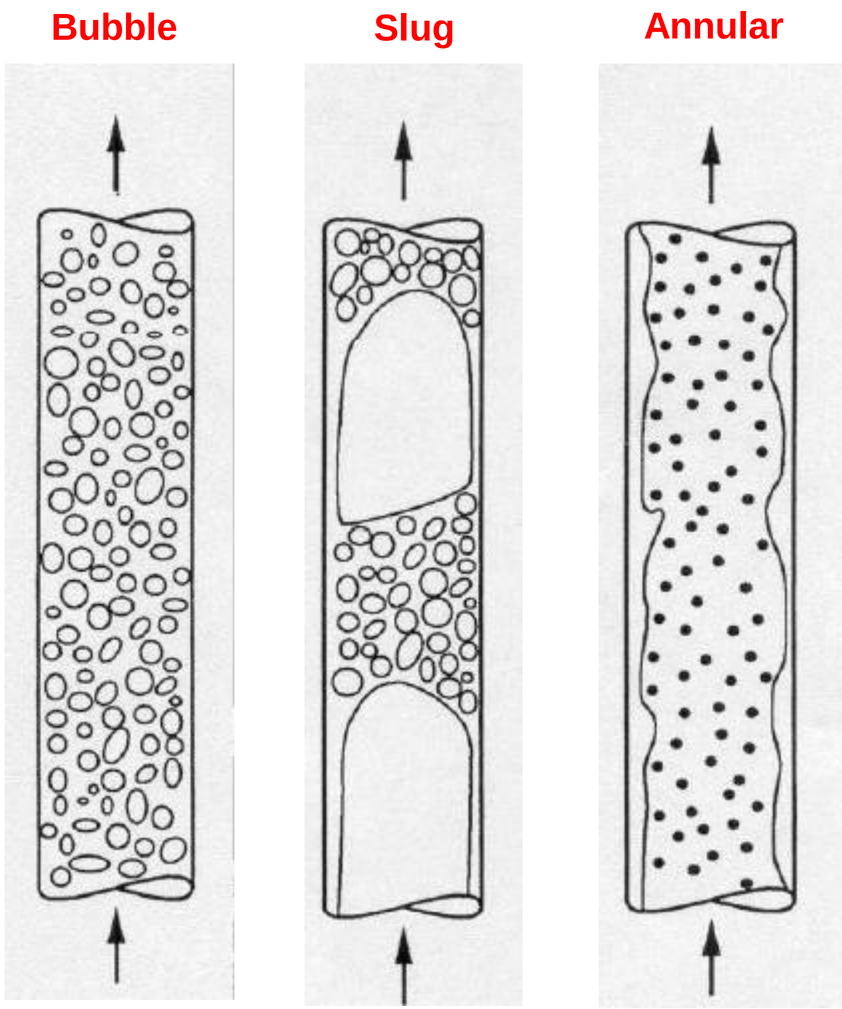
⑥ **Bubble Flow** : Gas dispersed as bubbles, move at velocity similar to liquid

⑦ **Dispersed Flow** = Definition of **Mist Flow**

Source : Education Materials for Pipeline Engineering, Held by JP Kenny (2012)

Flow Regimes (II)

Vertical Pipeline



① **Bubble Flow**

- Liquid is continuous with gas phase.
- Small bubbles with limited frictional pressure drop impact.

② **Slug Flow**

- Intermittent periods of gas and liquid flow.
- Gas velocity higher than liquid velocity
- Impacted by downward force of gravity on slug gravity

③ **Annular Flow**

- Liquid film wetting pipe wall, with some liquid droplets entrained in gas phase

Source : Education Materials for Pipeline Engineering, Held by JP Kenny (2012)

Severe Slug Formation

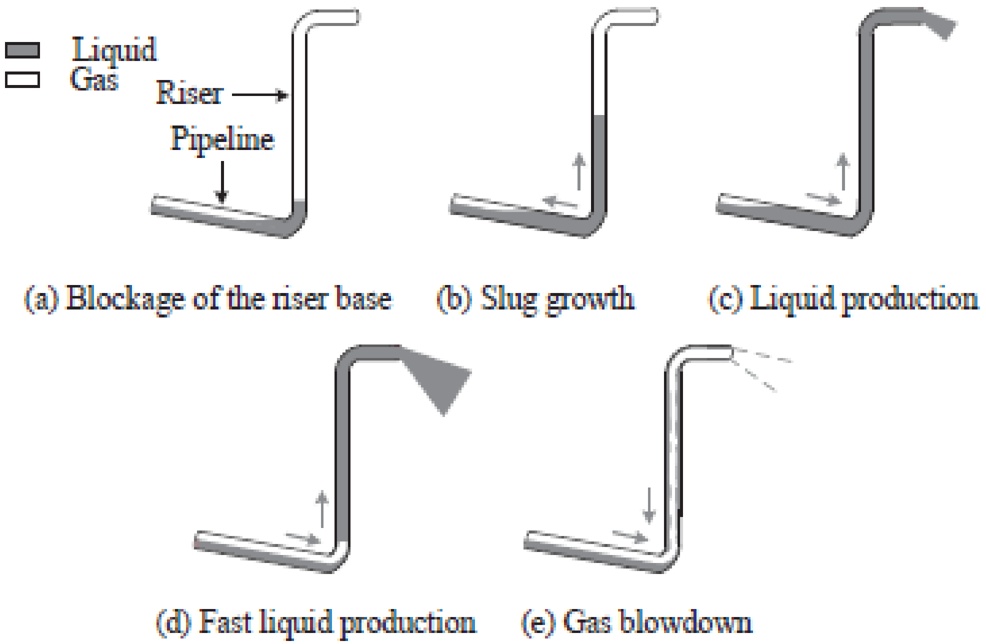


Figure. *The Buildup and Generation of Severe Slug*

Source "Stability of Severe Slugging", In. J. Multiphase Flow Vol. 12, No. 2, pp 203 (1986)

What can Liquid Slug lead to?

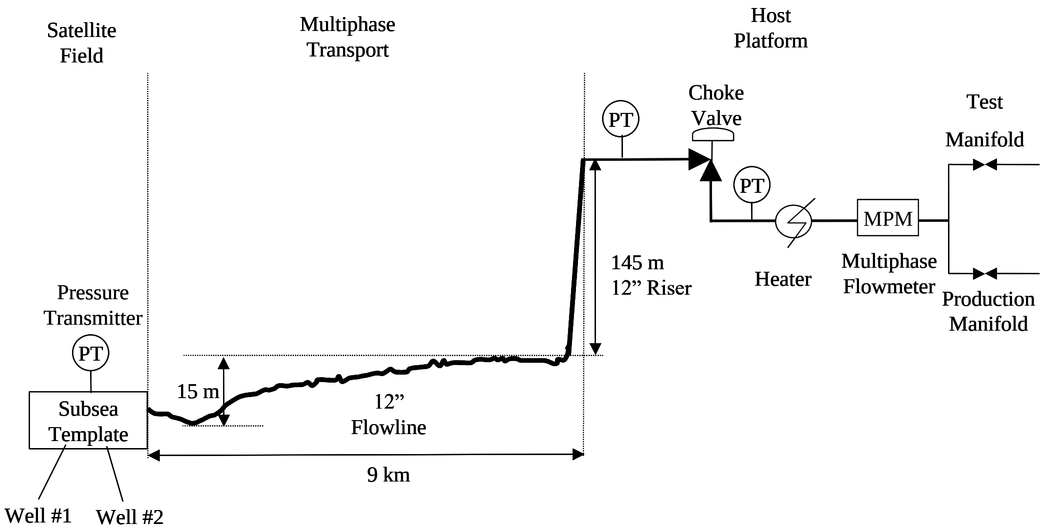


Figure. Schematic Overview of the Offshore Process (operated by STATOIL)

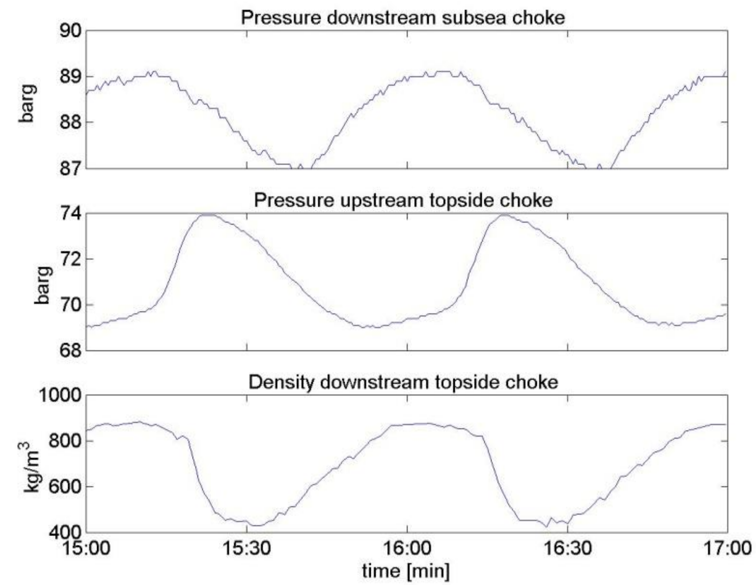


Figure. Measurements Indicating Liquid Slug Problem

Source : Slug Control of Production Pipeline, published by STATOIL

Liquid Slug Problem?

- Liquid slug can initiate **oscillations at choke valve / pipeline vend position** and this is unfavourable with respect to separation / operation for gas/oil treating process.
- The **wear and tear of equipment** increases as long as the liquid slug problem exists.

Liquid Slug Control

Strategy

- Increase fluid flow rate (playing with choke valve)
- Slug catcher installation at pipeline destination
  - Gas/Oil/Water Separation
  - Handling liquid slug

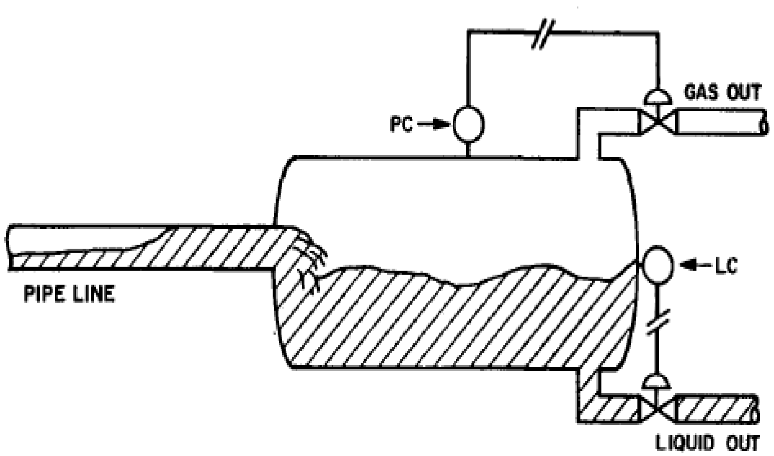
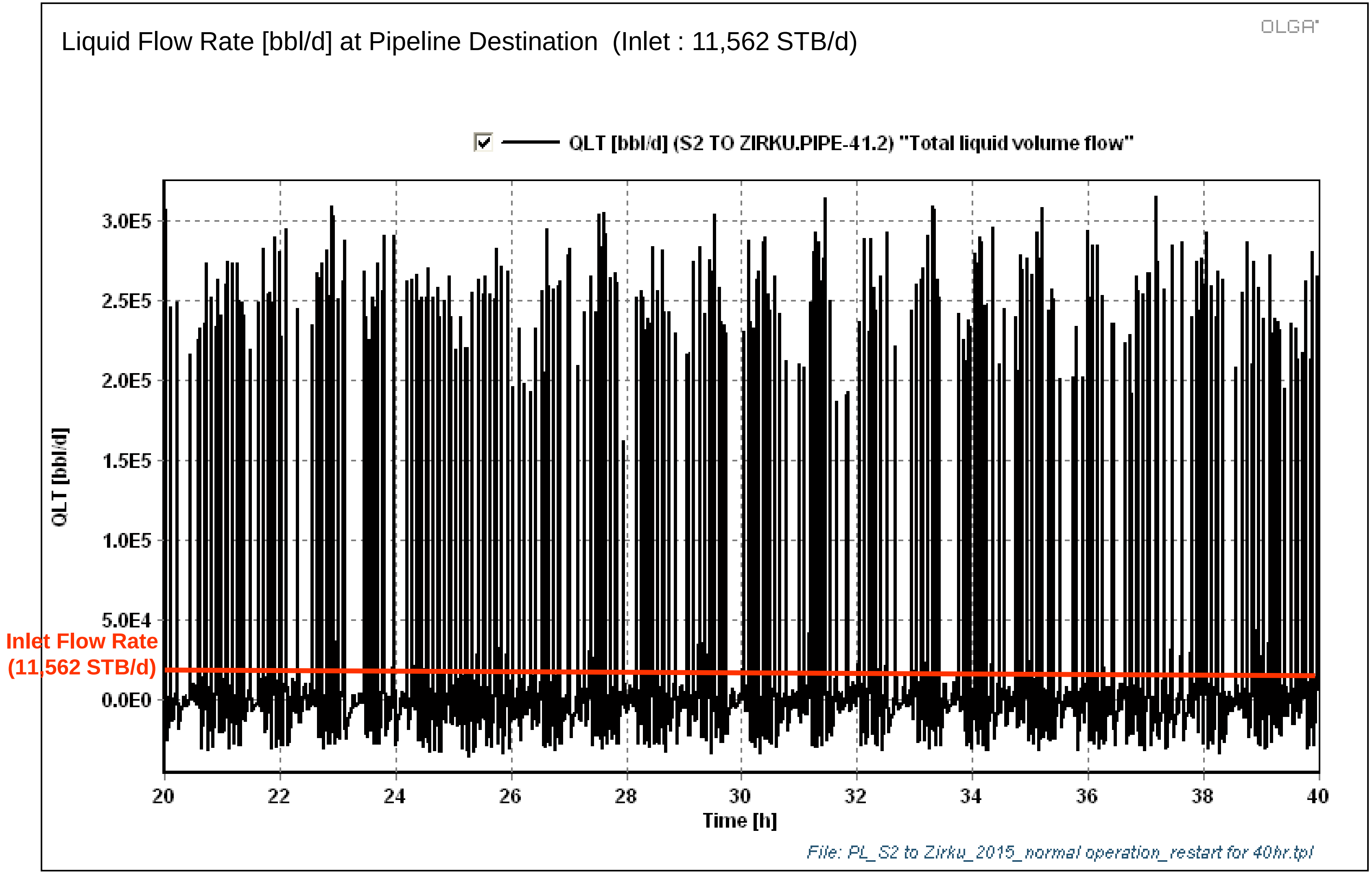


Figure. *Slug Catcher System*

Source : "Dynamic Simulation of Slug Catcher Behavior", SPE 18235

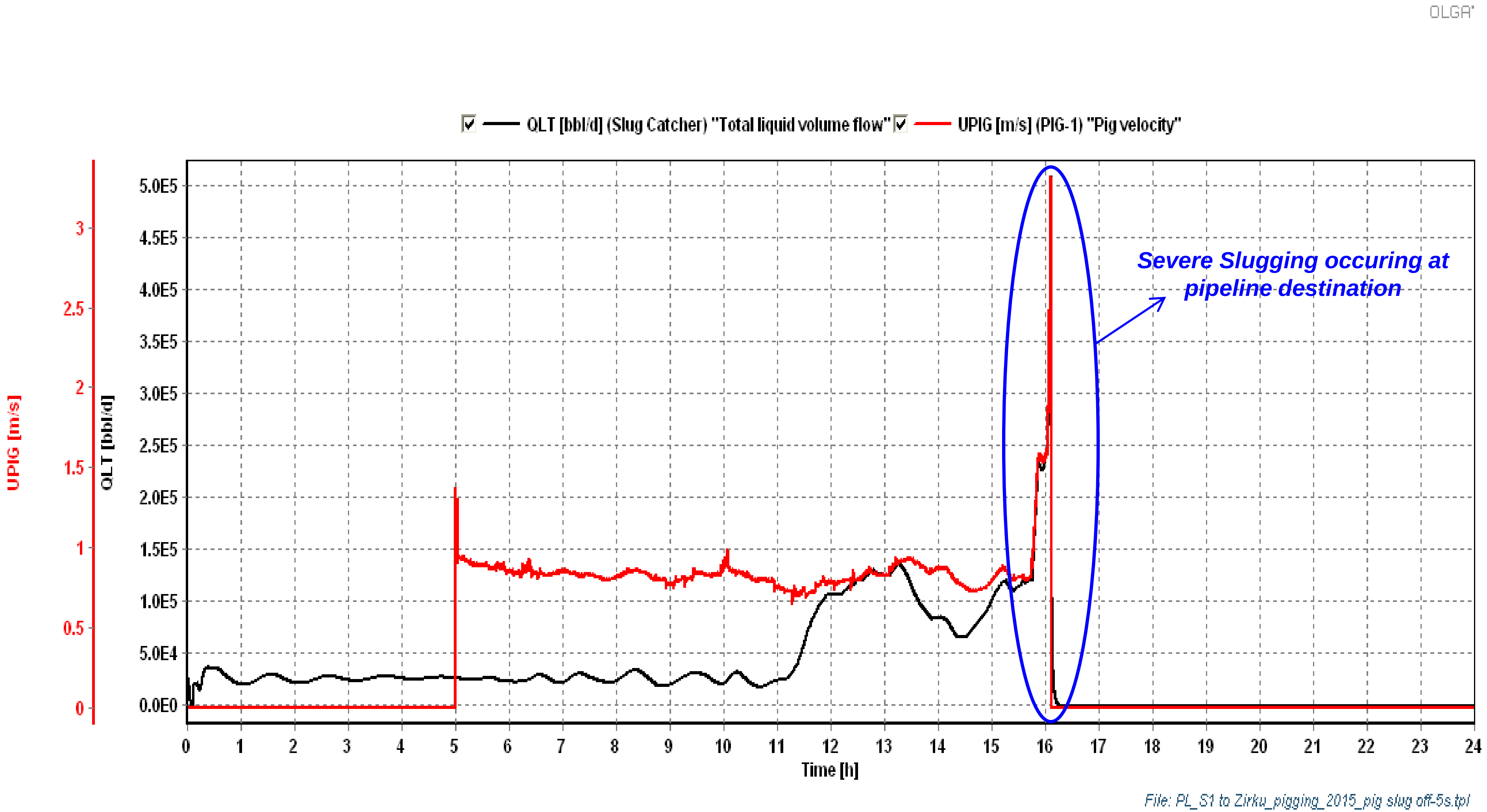
Example (1) – Normal Operation

Ex) SARB-4_Offshore Pipeline (Total Length : 33 km)



Example (II) – Pigging Operation

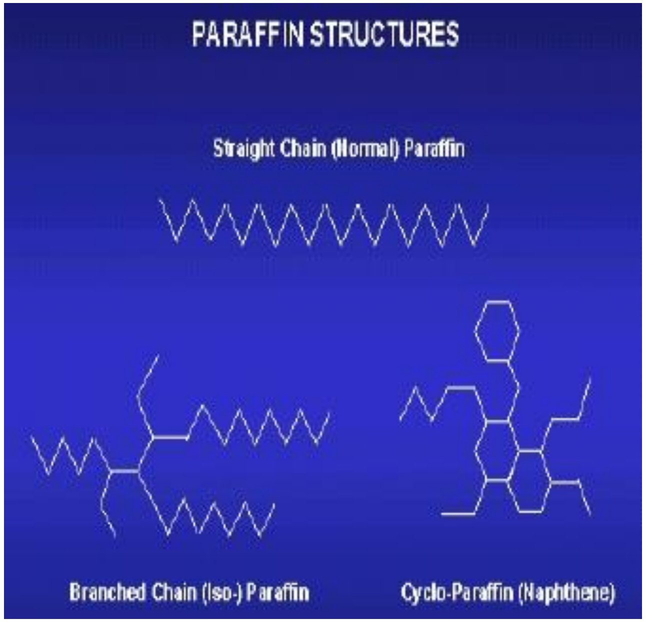
Ex) SARB-4_Offshore Pipeline (Total Length : 33 km)



What is Wax (C17+ Paraffin)?

What is Wax?

- High molecular weight paraffin (C17+) that precipitates
- Wax deposition
  - Wax appearance temperature (WAT) > Fluid Temperature
  - Temperature gradient required
- Melts at elevated temperature (20 ^{o}F above the WAT)



Wax Deposition Problem

- Reduction in delivery
  - Reduction in flow area
  - Change in wall friction and fluid viscosity (increased pressure drop in pipeline)

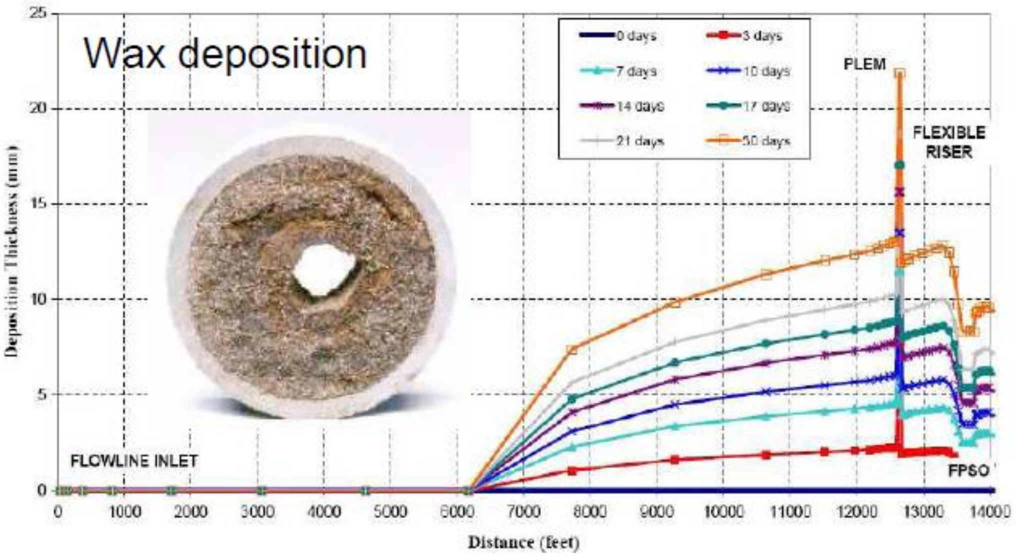
Source : Education Materials for Pipeline Engineering, Held by JP Kenny (2012)

Wax Inhibition

Strategy

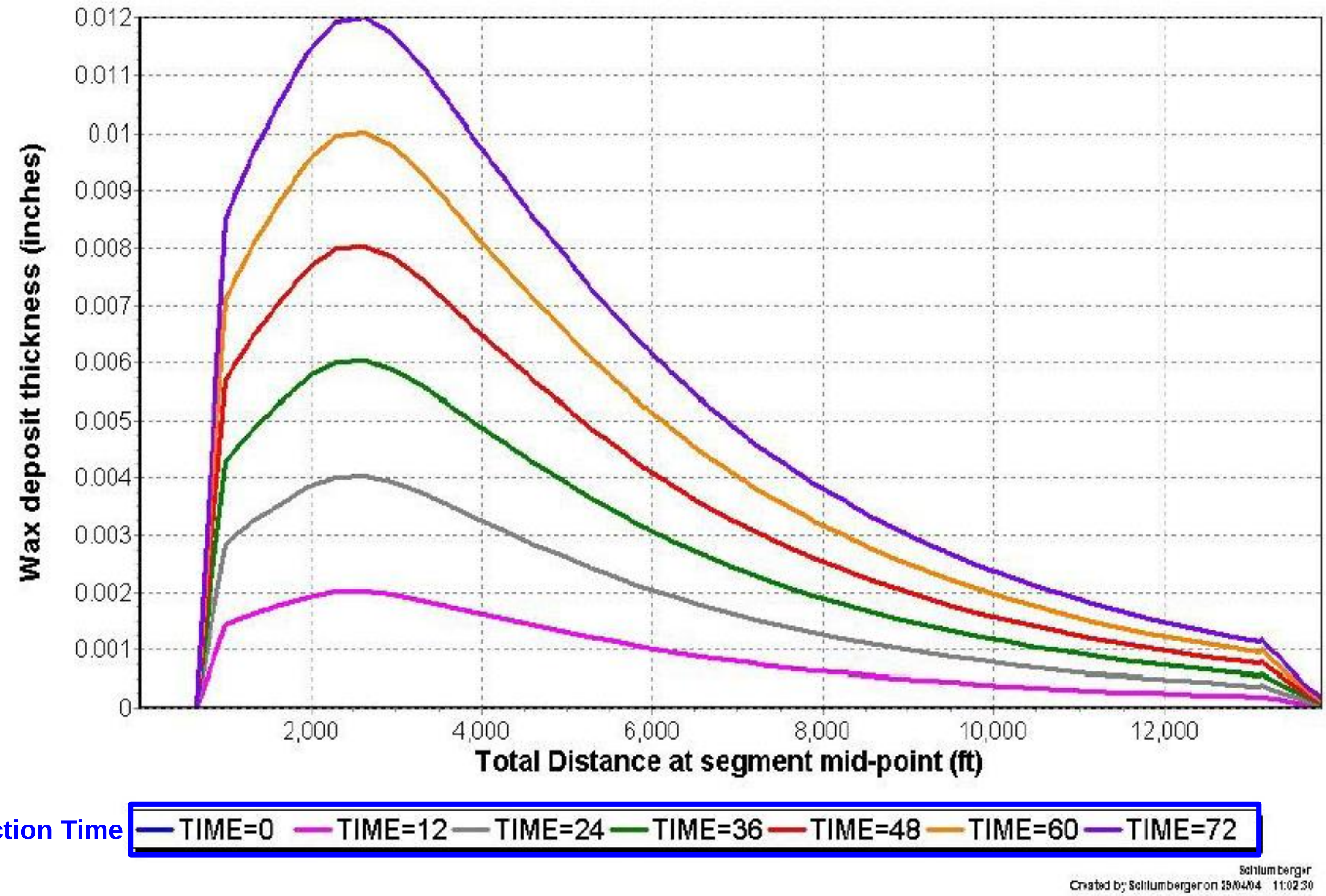
- Major factors : WAT, fluid temperature, pipeline U-value, n-paraffin content
- Maintain the system temperature above WAT
- Physical removal by Pigging
  - Rate of deposition can be predicted to calculate pigging frequency.
- Wax inhibitor injection

Source : Education Materials for Pipeline Engineering, Held by JP Kenny (2012)



Source : Seminar Material, CSIRO

Example – Wax Deposition Analysis



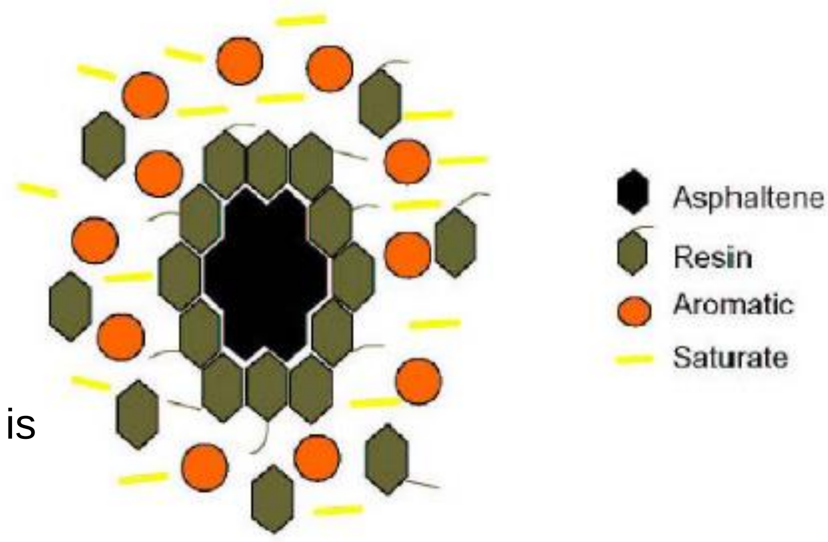
Production Time

Source : PIPESIM S/W Seminar (2009)

Asphaltene Deposition

What is Asphaltene?

- High molecular weigh compounds
- The heavy polar aromatic fraction
- Organic part not soluble in straight-chain solvents
- Asphaltene flocculation can occur when reservoir P is significantly above the bubble point



Asphaltene Deposition Problem

- Resulting blockage in pipeline
- Reduction delivery

Control Strategy

- Inhibitor (for flocculation) / solvent injection
- Physical method : pigging, wireline cutting, coiled tubing

Source : website of london-nano (www.london-nano.com)

Scale Deposition

What is Scale?

- Inorganic mineral deposits (carbonates or sulphates of calcium, strontium and barium) from free water
- Form due to
  - solubility change (temperature/pressure)
  - mixing of two different water
  - MEG / MeOH injection
- $FeCaCO_3$, $CaCO_3$ scaling issues in MEG system
- Salt/Sulfate scaling issues in MeOH with high concentration

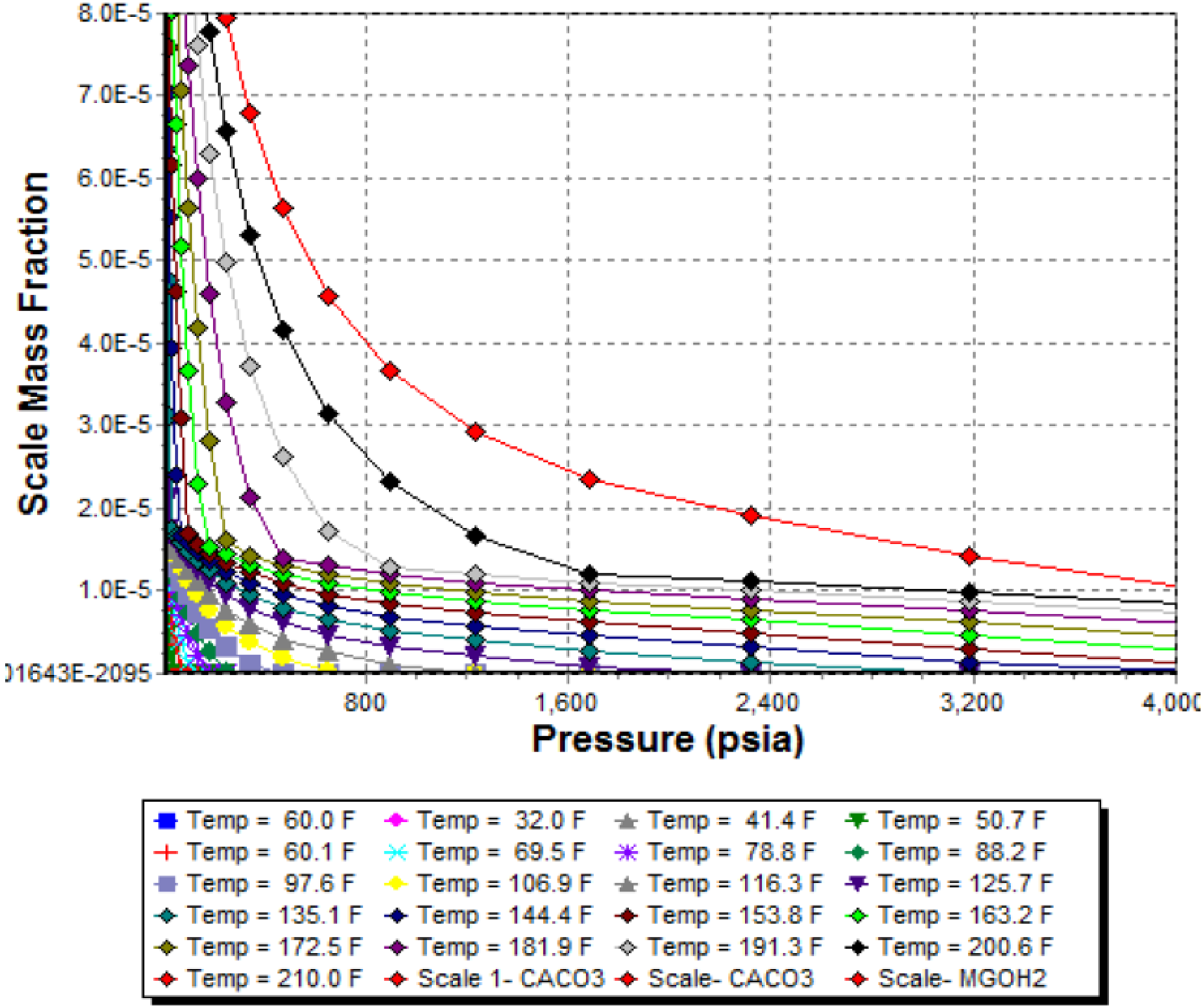
Source : SPT Group

Scale Problem?

- Reduction in flow area
- Change in wall friction (increased pressure drop)
- Equipment fouling, increased corrosion, increased emulsion potential and so on

Control Strategy → Only scale inhibitor

Example – Scale Analysis



Source : PIPESIM S/W Seminar (2009)

Erosion Prevention

Why can Erosion occur on Pipeline Wall?

- Fluid velocity with high shear stress enough for erosion
- Fluid flowing with the components causing corrosion

Control Strategy

- Line sizing suitable for erosion inhibition
  - API 14E : Fluid velocity > Erosional Velocity

$$V_e = \frac{c}{\sqrt{pm}} \qquad \textbf{Eq. 2.14}$$

where:

V_e = fluid erosional velocity, feet/second

c = empirical constant

pm = gas/liquid mixture density at flowing pressure and temperature, lbs/ft^3

  - SALAMA Model not published

Figure. *Erosion Site on Pipeline Wall*

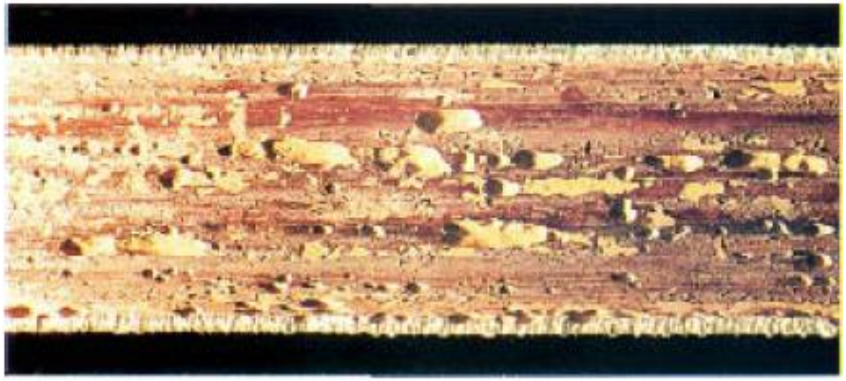
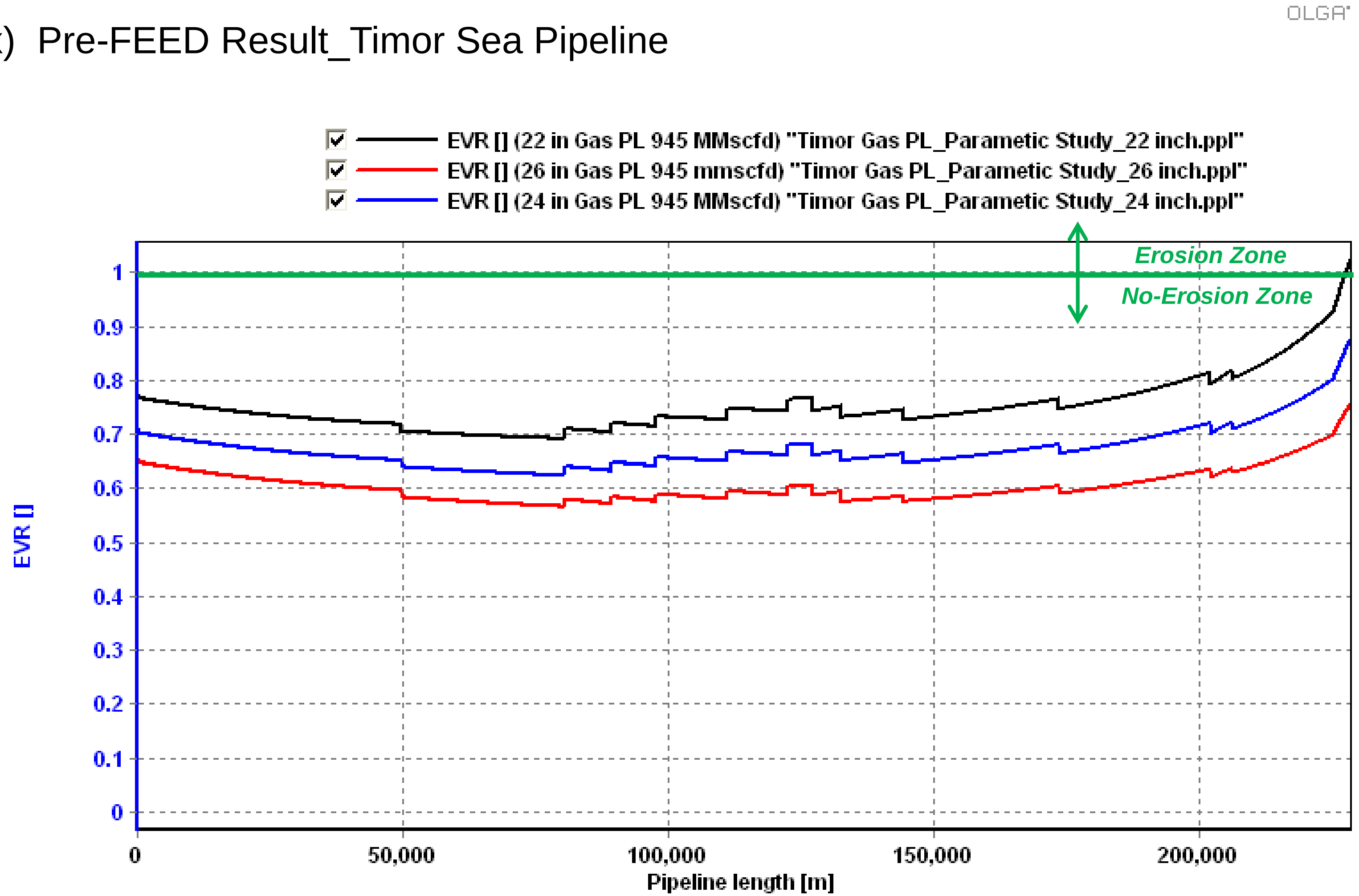


Figure. *Metal Loss from Erosion-Corrosion on Pipeline Wall*

Source : "The Nalco Guide to Cooling Water System Failure Analysis", Nalco Chemistry Company, McGraw-Hill

Example (I) – Erosion Prevention

Ex) Pre-FEED Result_Timor Sea Pipeline



※ EVR (Erosion Velocity Ratio) = Fluid Velocity / Erosional Velocity

Example (II) – Erosion Prevention

Ex) SARB-4_Offshore Pipeline (Total Length : 33 km)

Year	Max. EVR			Year	Max. EVR			
	C=200	C=150	C=100		C=200	C=150	C=100	
Pigging Operation								
2015 (S1)	0.28	0.37	0.55	2015 (S2)	0.30	0.40	0.60	
2016 (S1)	0.31	0.41	0.62	2016 (S2)	0.20	0.27	0.40	
2032 (S1)	0.26	0.35	0.52	2032 (S2)	0.21	0.28	0.42	
Ramp-up (25% → 100%) within 1 min								
2015 (S1)	0.39	0.52	0.78	2015 (S2)	0.24	0.31	0.47	
2017 (S1)	0.60	0.80	**1.20**	2016 (S2)	0.46	0.61	0.92	
2032 (S1)	0.63	0.83	**1.25**	2032 (S2)	0.65	0.87	**1.30**	**Erosion**
Ramp-up (50% → 100%) within 1 min								
2015 (S1)	0.34	0.45	0.68	2015 (S2)	0.23	0.30	0.45	
2017 (S1)	0.50	0.60	**1.00**	2016 (S2)	0.45	0.60	0.90	
2032 (S1)	0.63	0.83	**1.25**	2032 (S2)	0.56	0.75	**1.12**	**Erosion**
Normal Operation								
2015 (S1)	0.33	0.43	0.66	2015 (S2)	0.20	0.27	0.40	
2017 (S1)	0.55	0.73	**1.10**	2016 (S2)	0.45	0.60	0.90	
2032 (S1)	0.60	0.80	**1.20**	2032 (S2)	0.60	0.80	**1.20**	**Erosion**

Note 1) EVR (Erosion Velocity Ratio) = Fluid Velocity / Erosional Velocity
2) C values of 150 – 200 for corrosion inhibitor employment
3) C value of 100 for no corrosion inhibitor employment

Why can Erosion occur on Pipeline Wall?

- Corrosion is primarily due to the presence of CO_2/H_2S for well fluid pipeline and CO_2/O_2 for steam-condensate pipeline

- Corrosion is a chemical reaction whereby the metal in the pipeline is oxidized and is consequently removed.

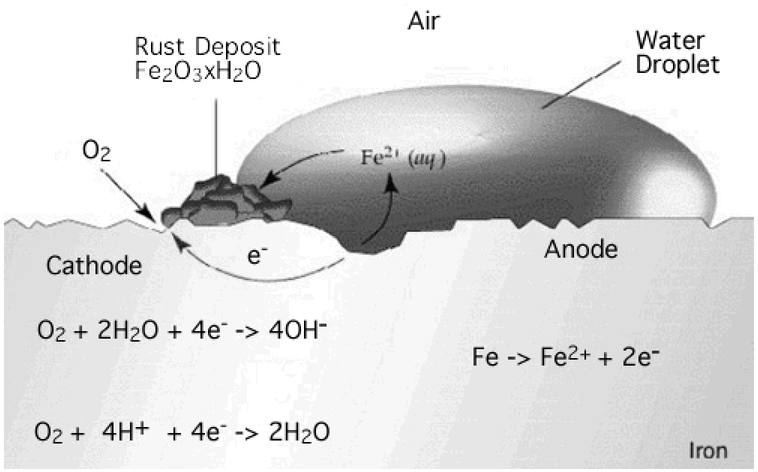
- Water is required for the corrosion mechanism.

Control Strategy

- Removing the chemical reactants (CO_2, H_2S or Water)

- Chemical treatments : Inhibitors, pH adjustment

- Specify more durable materials (ex. stainless steels)



Source : http://chemistry58.wikispaces.com

Hammering Prevention

Why can Hammering occur in Pipeline?

- Changes in pressure arise in pipelines when there is a change in fluid velocity. (ex. Pump swiching, valve operation)
- The greater the rate of change of velocity, the greater the pressure wave travelling along a pipeline.

Control Strategy

- A change in valve closure rates
- Provision of surge vessels or tanks
- Installation of surge protection valves

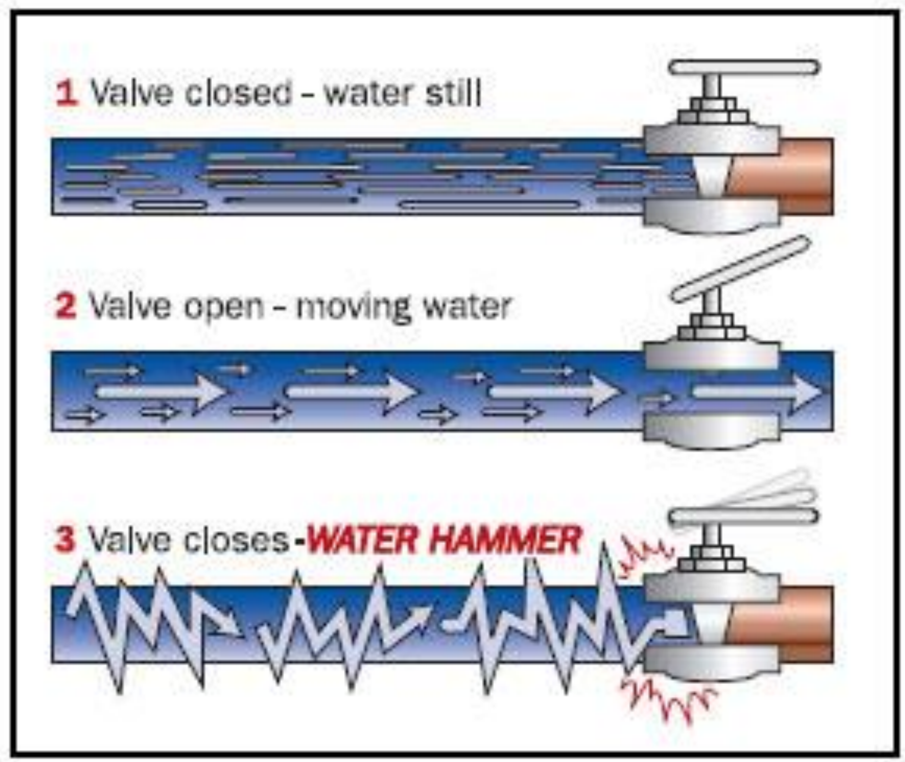
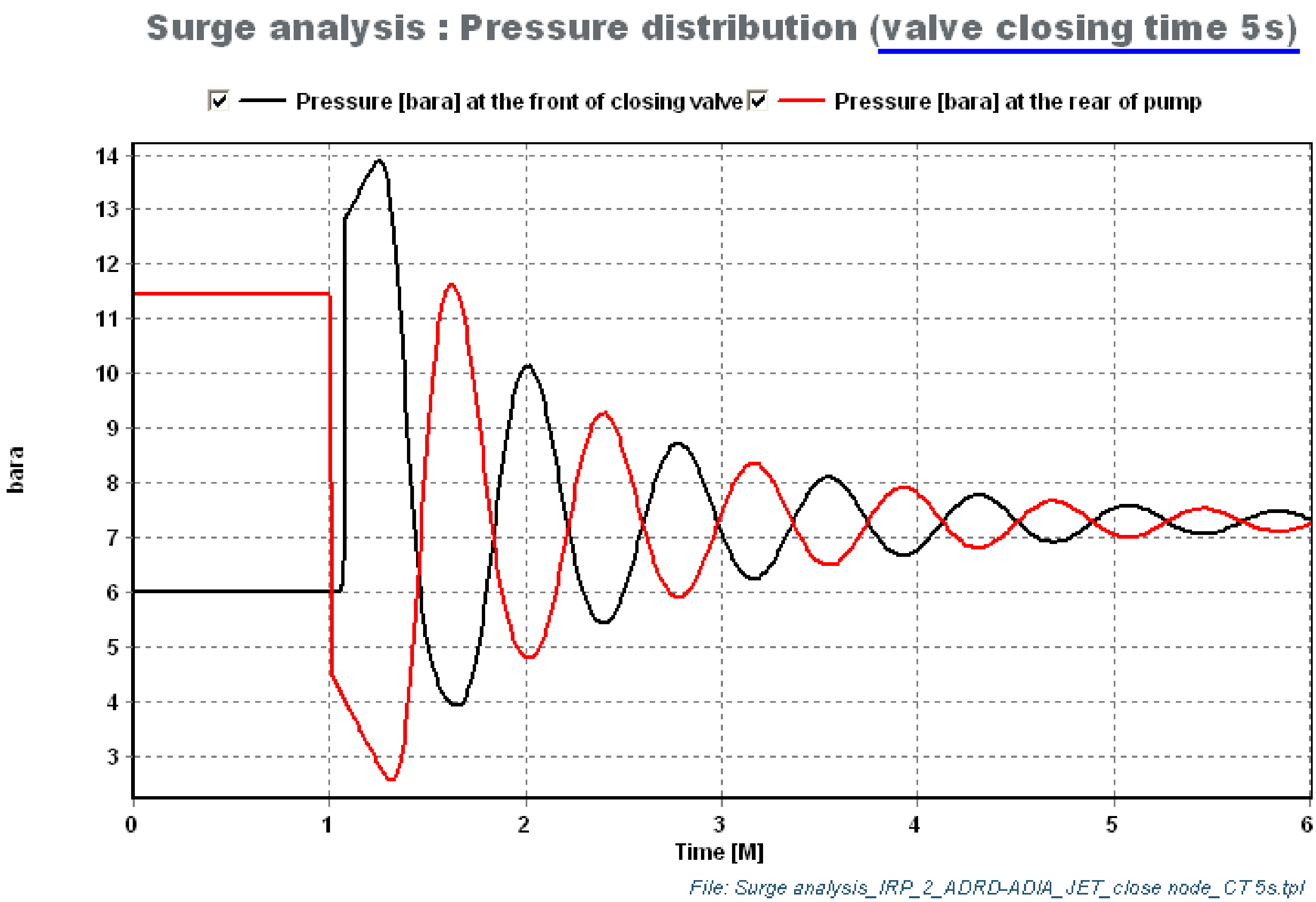


Figure. *Water Hammering Mechanism*

Source : http://www.maplesoft.com/applications/view.aspx?SID=129503

Example – Surge Analysis

Ex) IRP II_Pipeline for JET-A fluid (assuming Straight Pipeline 17km)



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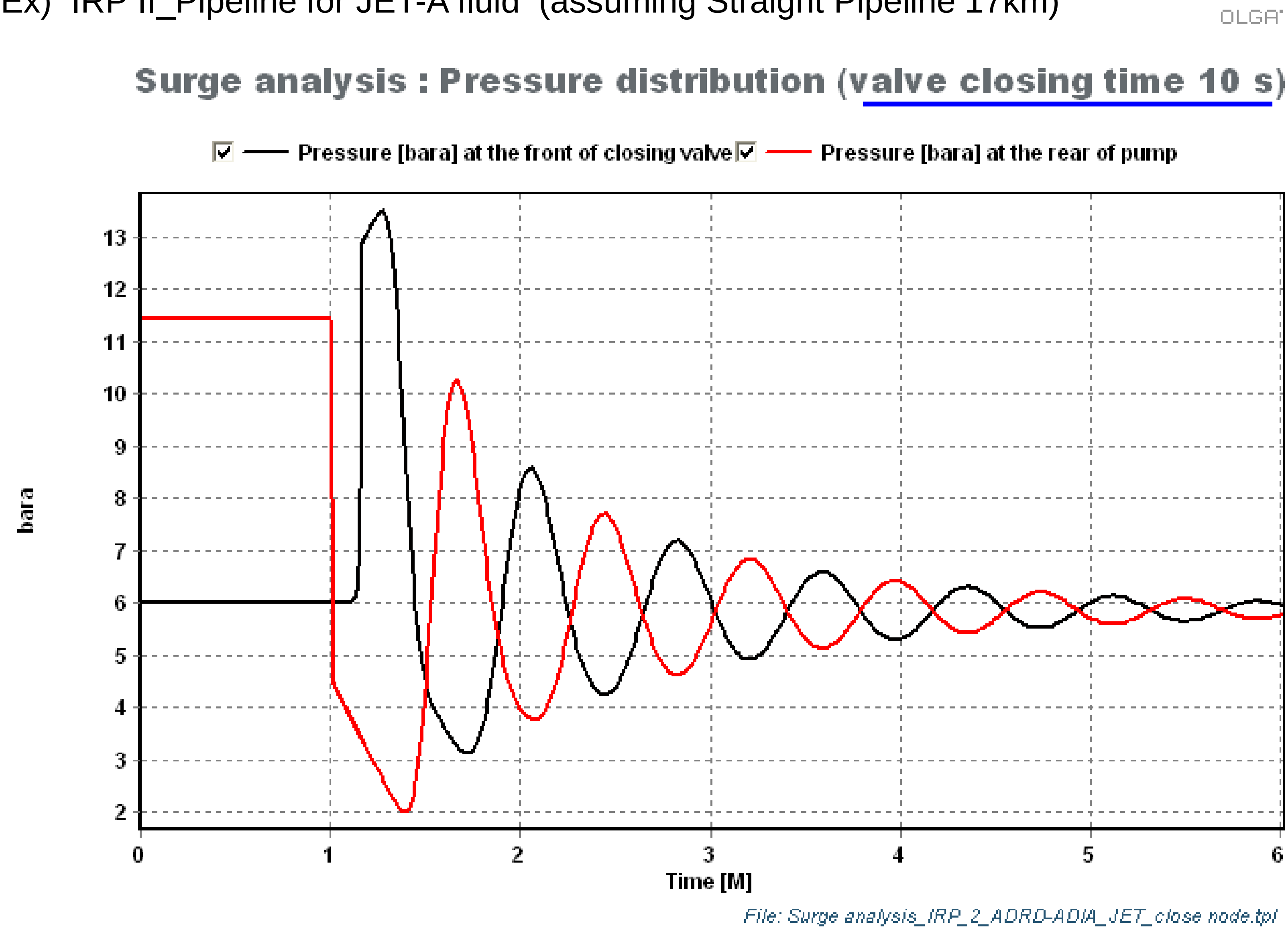

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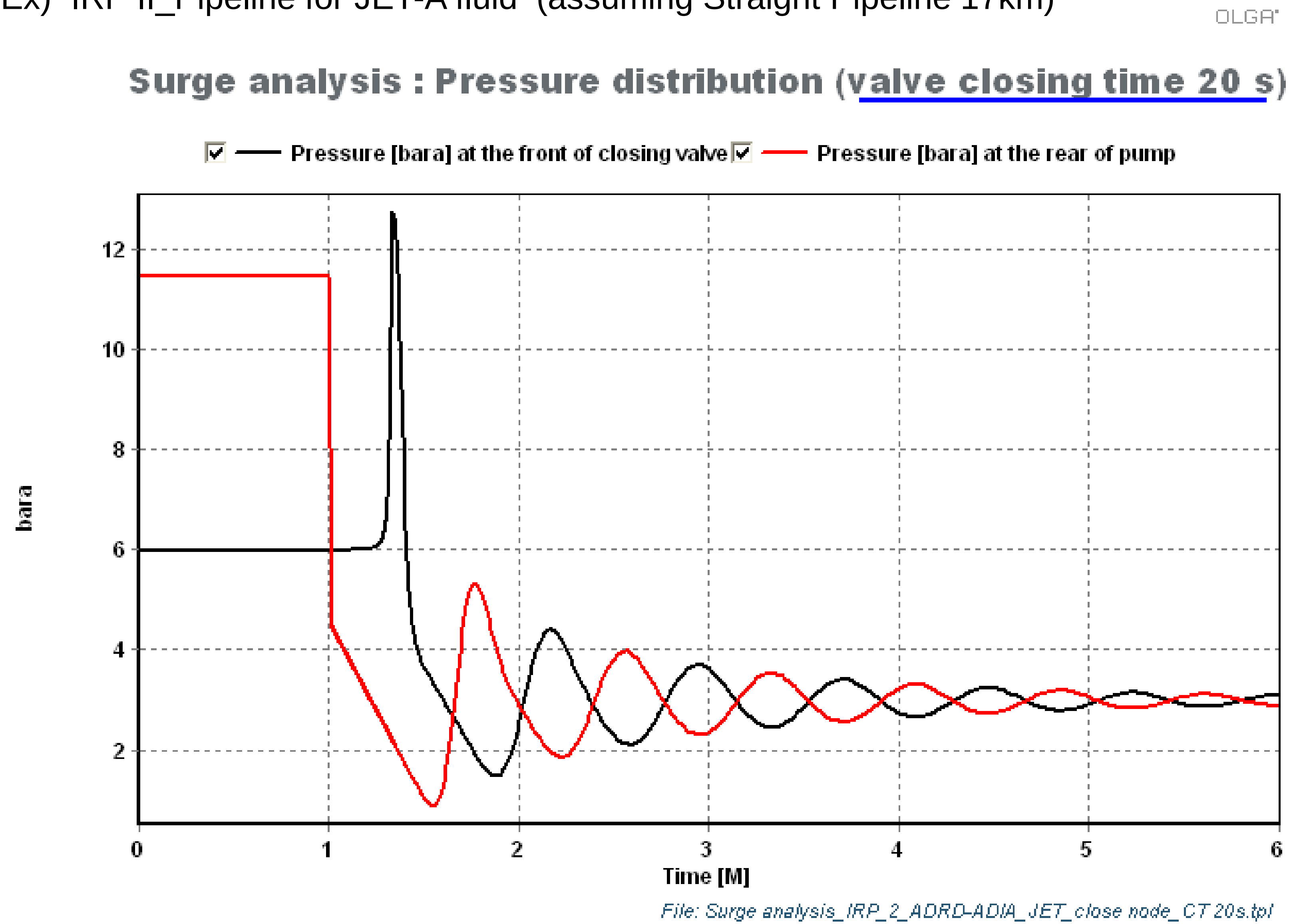

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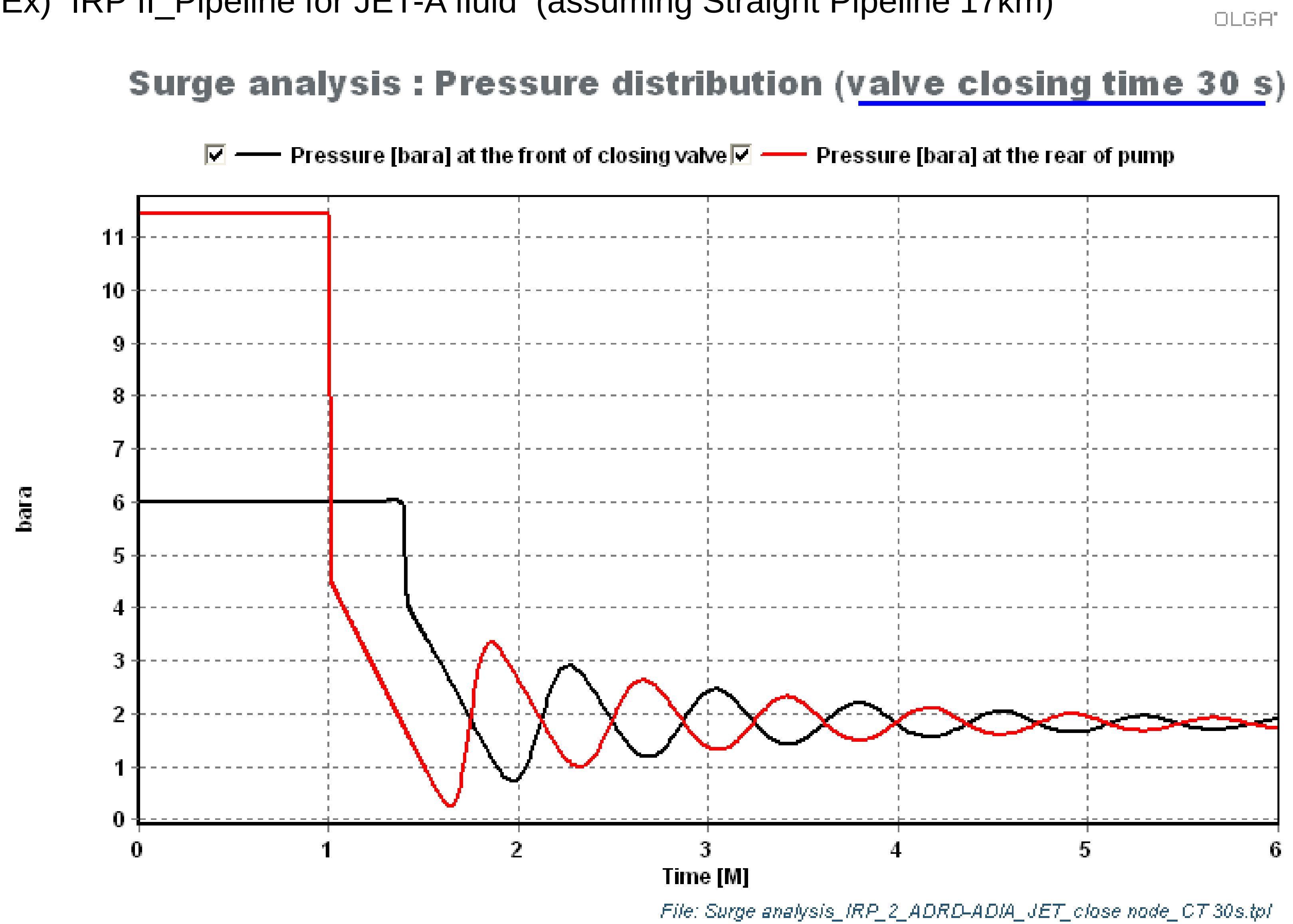

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Thank you