

Image courtesy of FMC Technologies

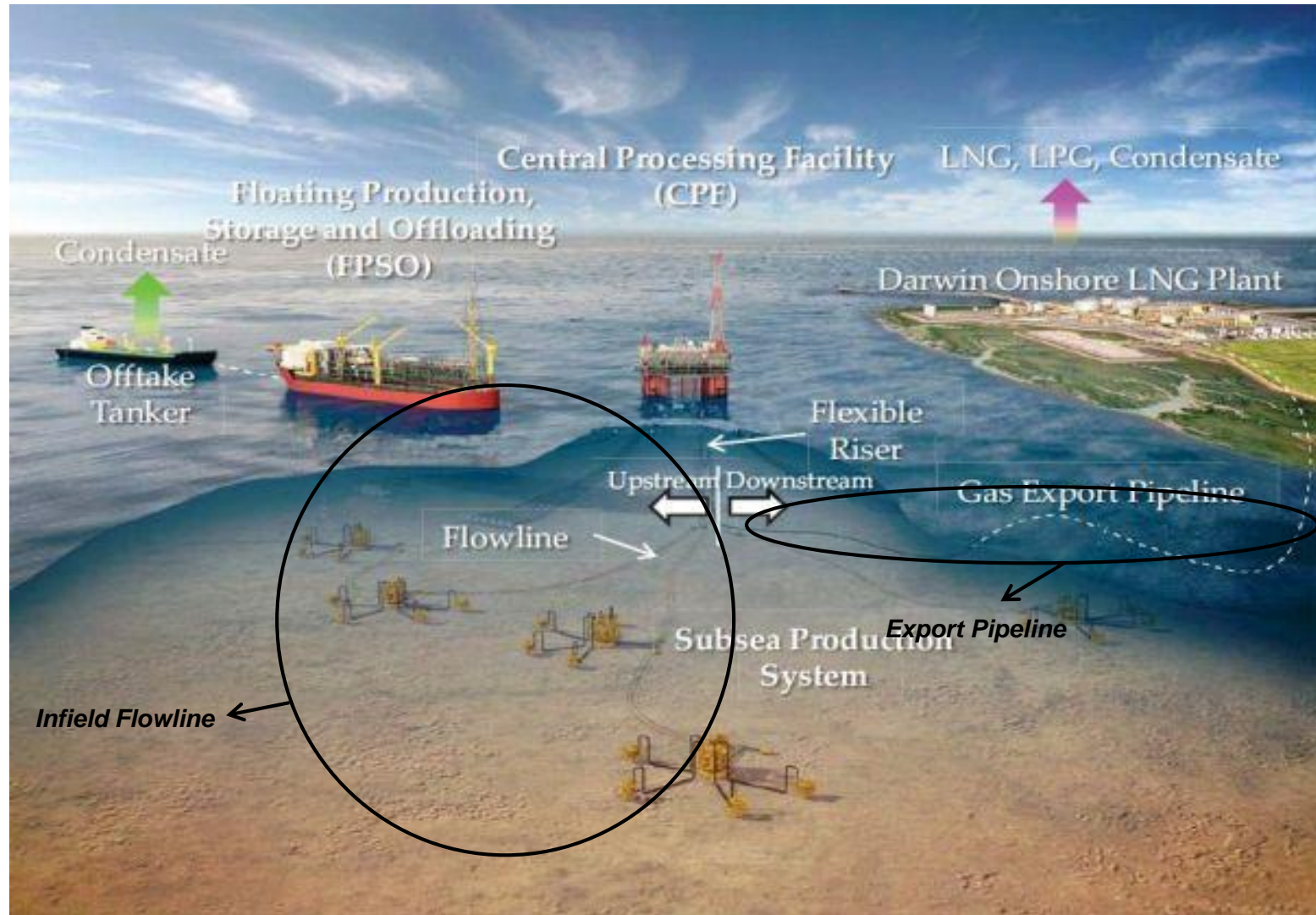
해저 공학

서유탉

1. 해저 생산 시스템 설계 절차

Pipeline System (1) : Oil and Gas Production

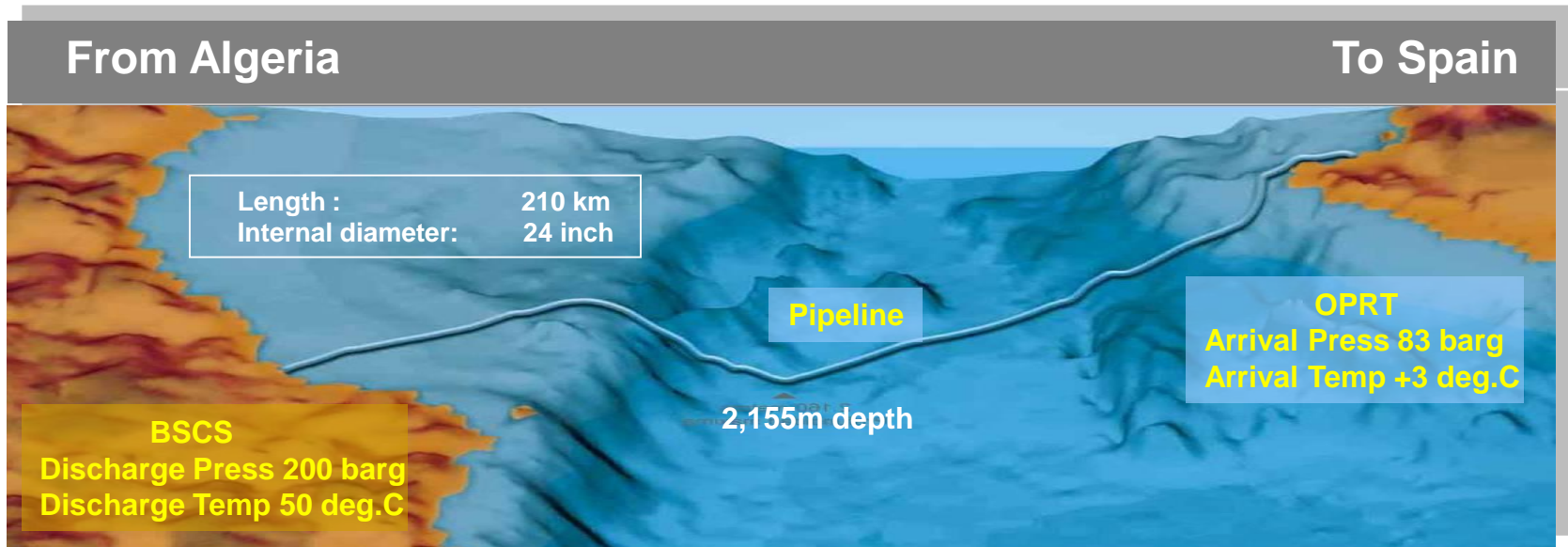
Ex) Gas and Condensate Production for Darwin LNG Project (AU)



Source : Darwin LNG Project (Australia), <http://subseaworldnews.com>

Pipeline System (2) : Gas Transportation

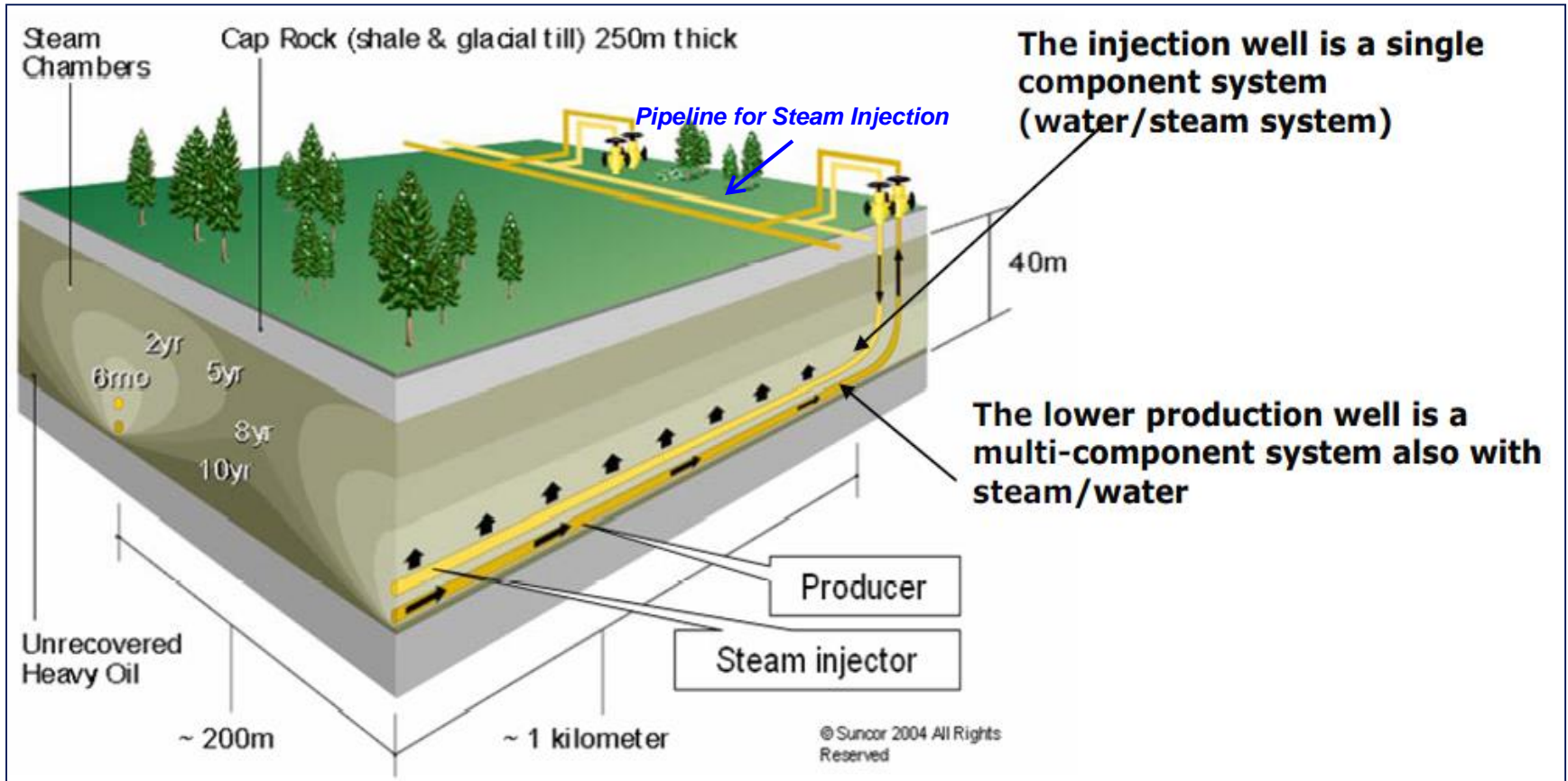
Ex) Gas Transportation from Algeria to Spain for LNG Feed



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

Pipeline System (3) : Extra-Heavy Oil Production

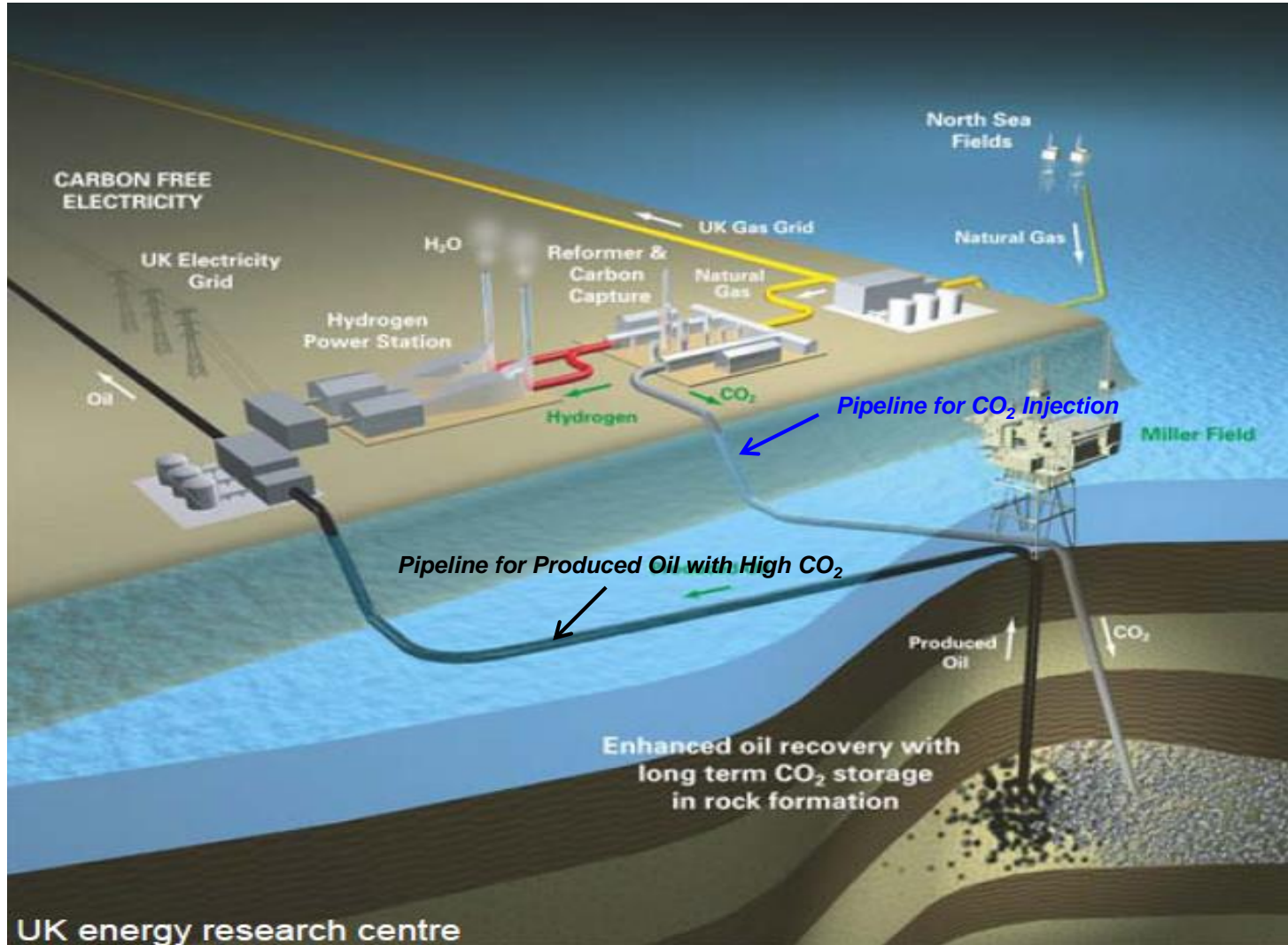
Ex) Steam Injection for Bitumen Production (SAGD)



Source : Presentation Material for OLGA User Seminar (2011)

Pipeline System (4) : Gas (CO₂, N₂, HC) Injection

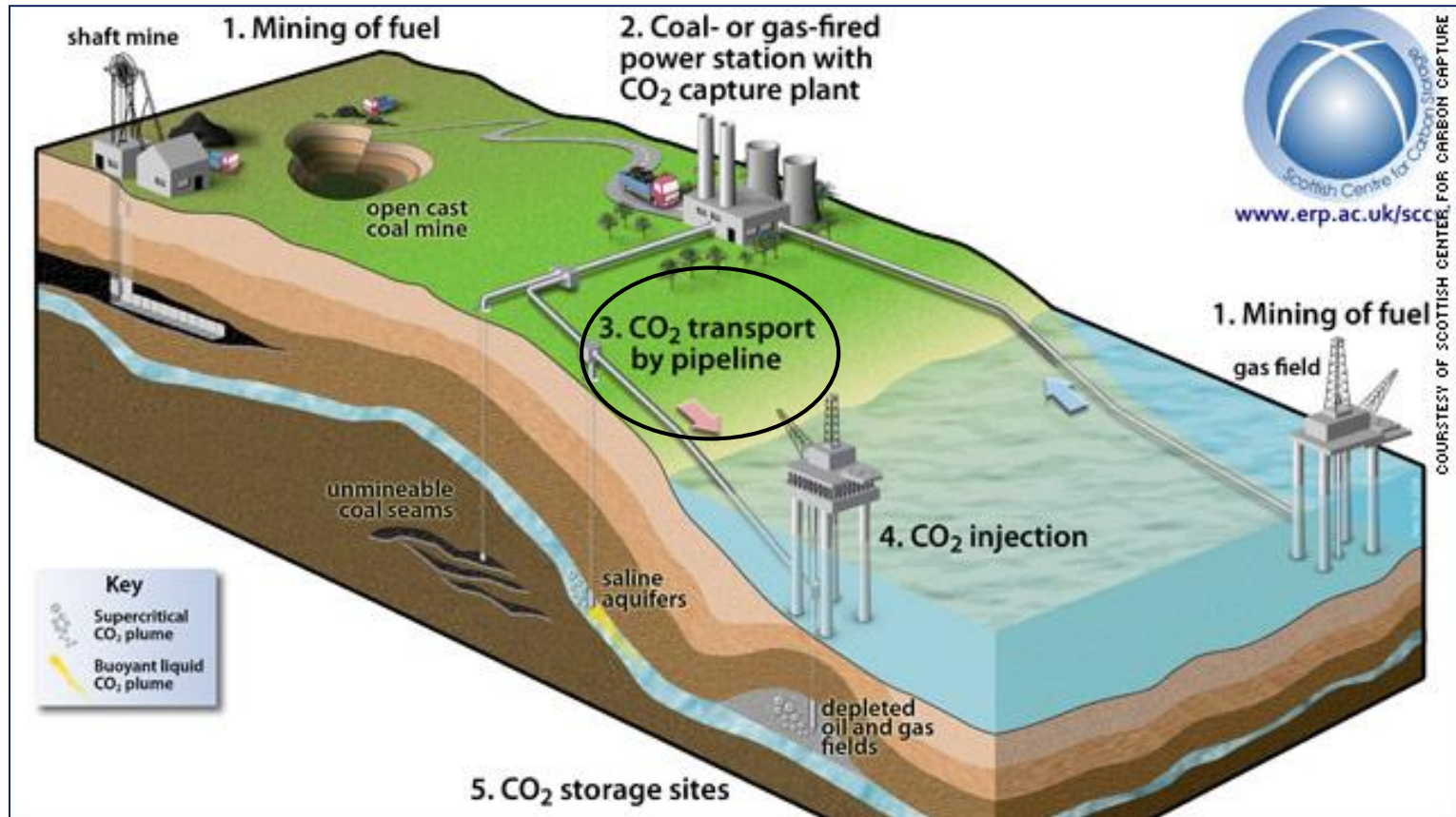
Ex) CO₂ Injection to Oil Reservoir for EOR (Enhanced Oil Recovery)



Source : Presentation Material for OLGA User Seminar (2011)

Pipeline System (5) : CO₂ Storage for CCS

Ex) CO₂ 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

*With Pipeline
Geometry and
Operation
Requirement*

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***

2. Design (1) : for Flow Assurance

What is Flow Assurance?

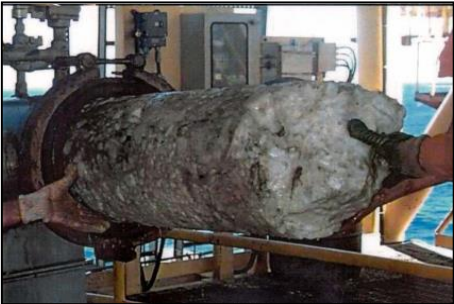
Flow assurance is a relatively new term in oil & gas industry. It refers to ensuring successful and economical flow of production fluid from reservoir to the point of sale. The term was coined by Petrobras in the early 1990s in Portuguese as *Garantia do Escoamento*, meaning literally “Guarantee of Flow”,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

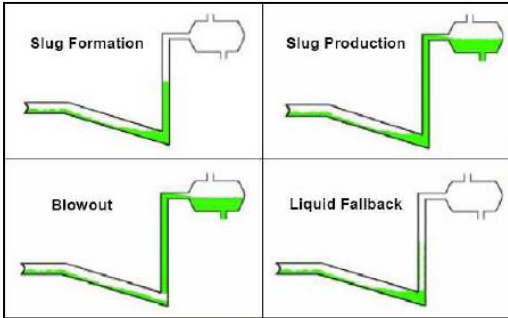
As well as oil / gas production system, steam / condensate and CO₂ transportation network for enhanced oil recovery need to do flow assurance study.

Flow Assurance (FA) Issues

Hydrate Plugging



Liquid Slug



Wax (C17+) Deposition



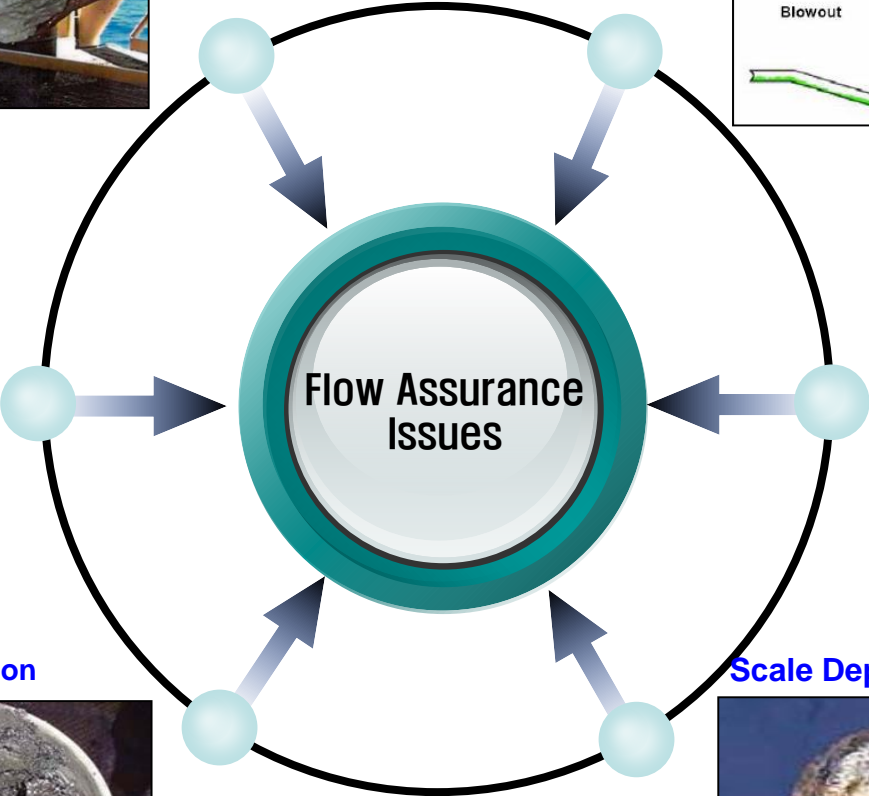
Sand Plugging (especially at CV)



Asphaltene Deposition



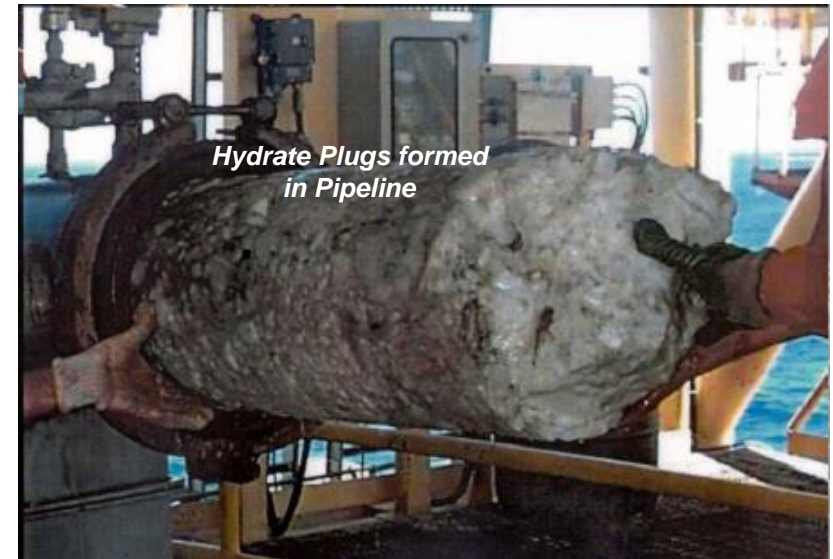
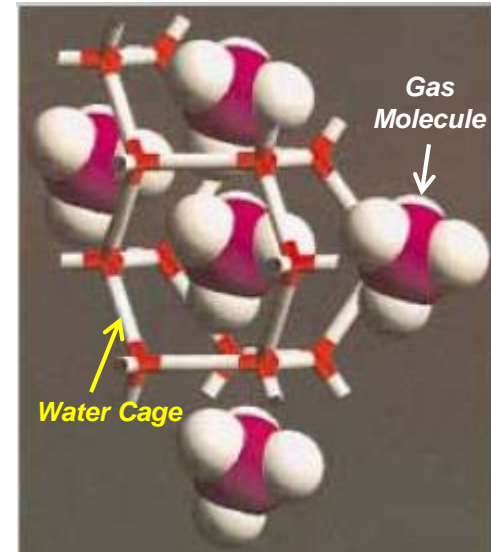
Scale Deposition



2-1. Hydrate Inhibition

What is Hydrate?

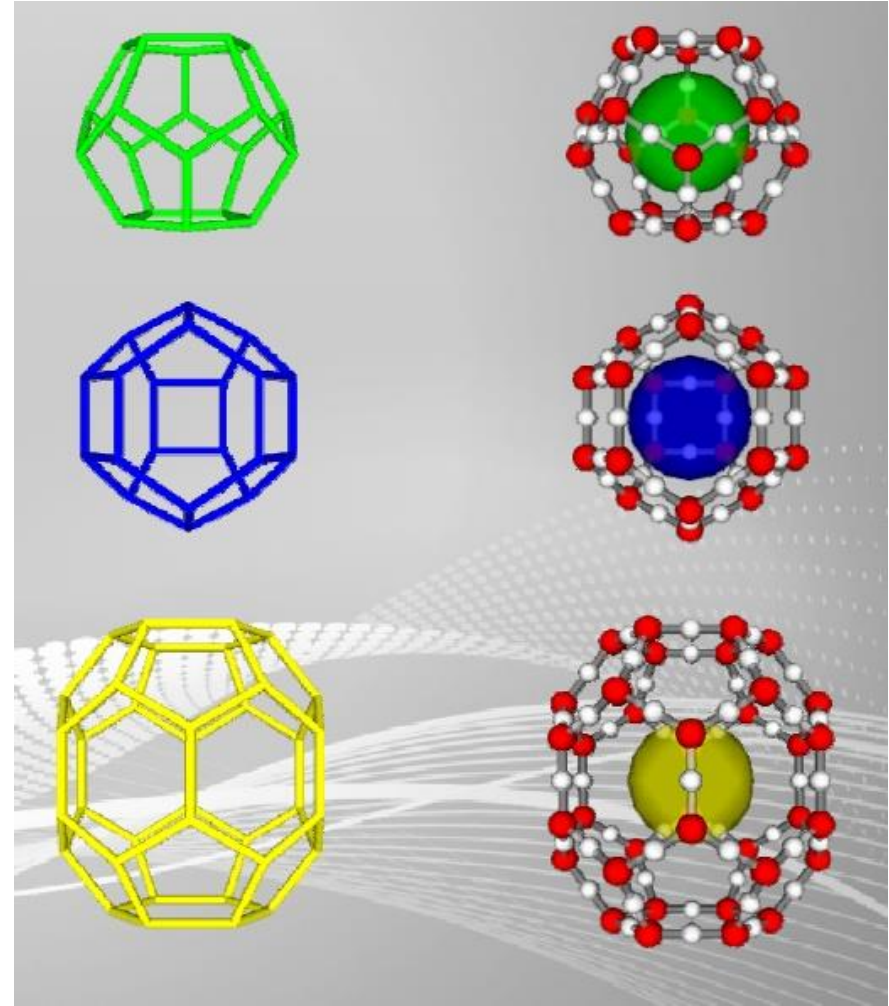
- Ice-like solids that form due to the presence of water. Hydrocarbons are trapped in a lattice of frozen water.
- Can form and be stable at or near normal operating temperatures, resulting in potential for a blocked system.
- May be an issue during steady state production, and more commonly during shutdown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



Clathrates – “Cage-like” Structures

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.

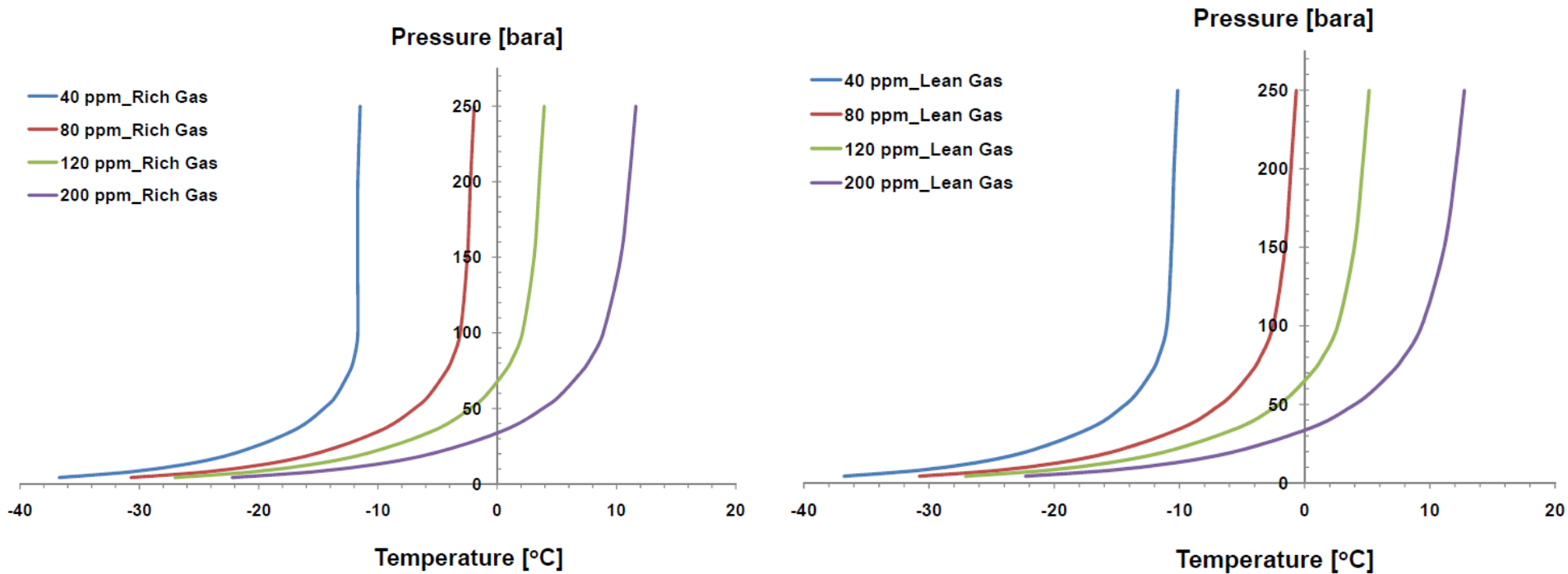
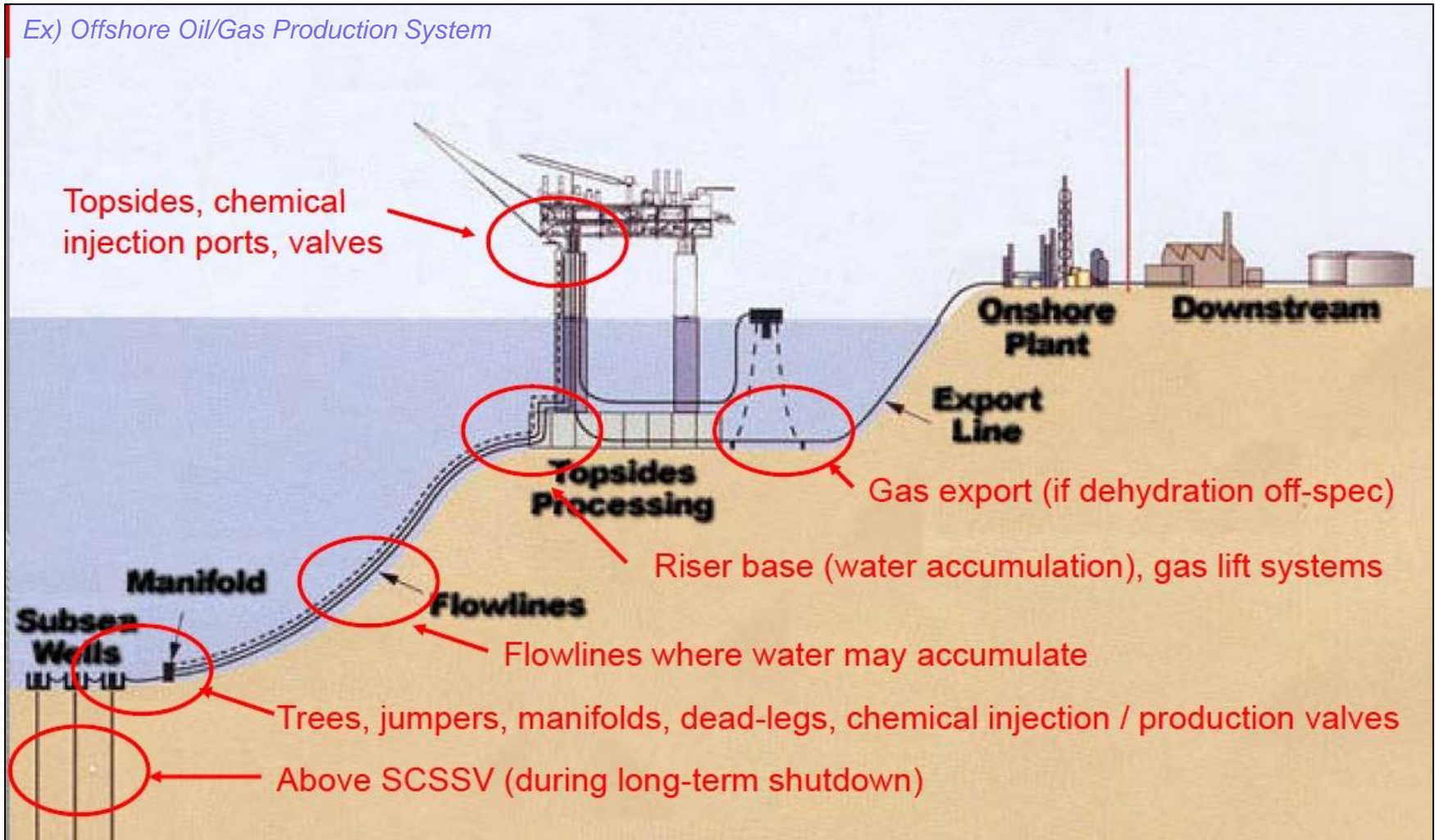


Figure. Hydrate Formation Curve for Great Sunrise Gas Field located on Timor Sea

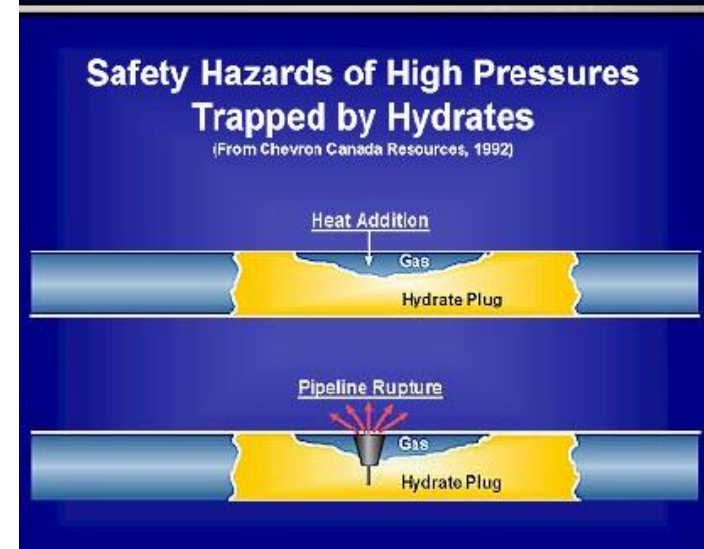
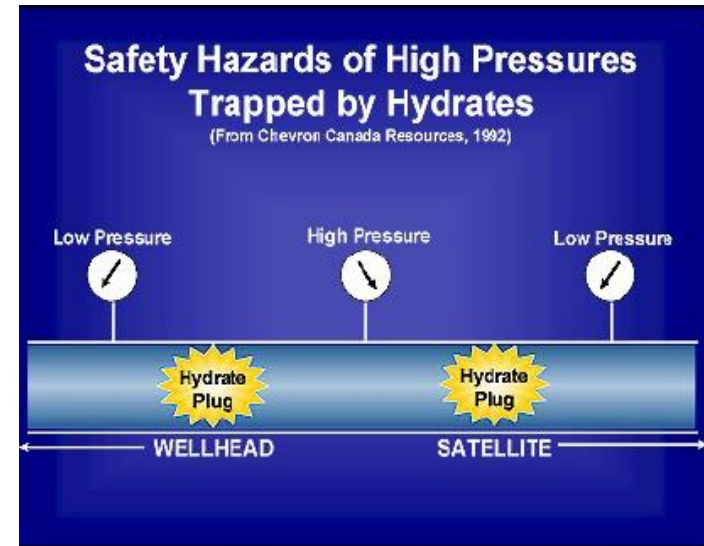
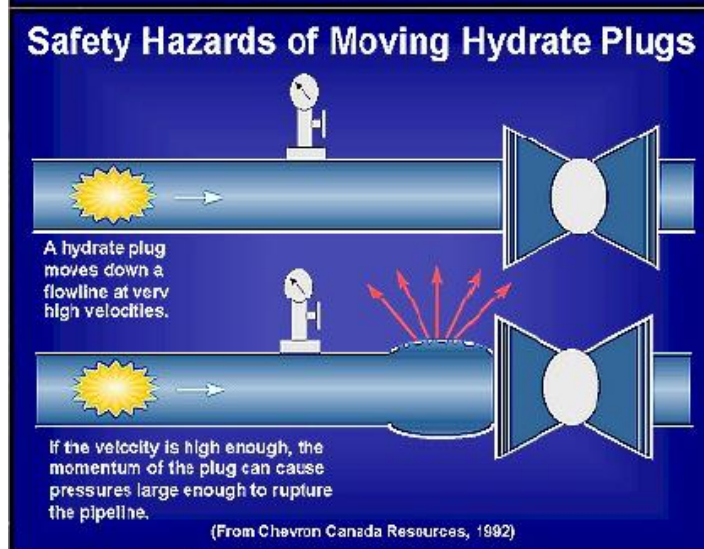
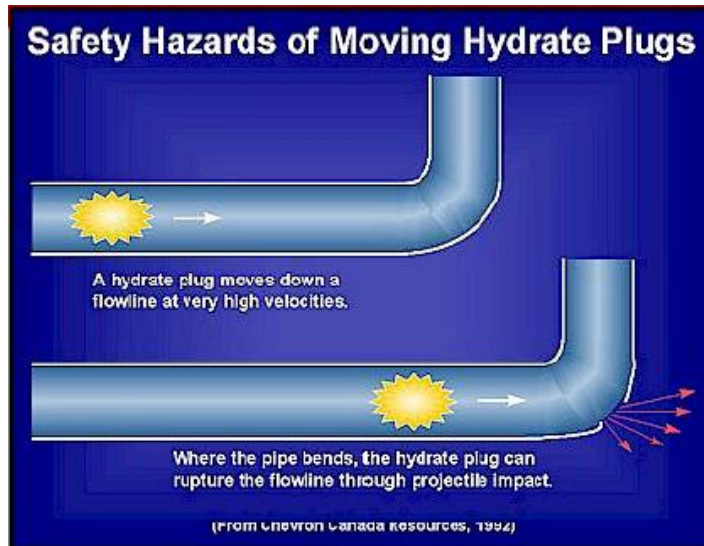
Hydrate Formation (II)

Where can hydrate be formed?

Ex) Offshore Oil/Gas Production System



If hydrate plugging occurs..

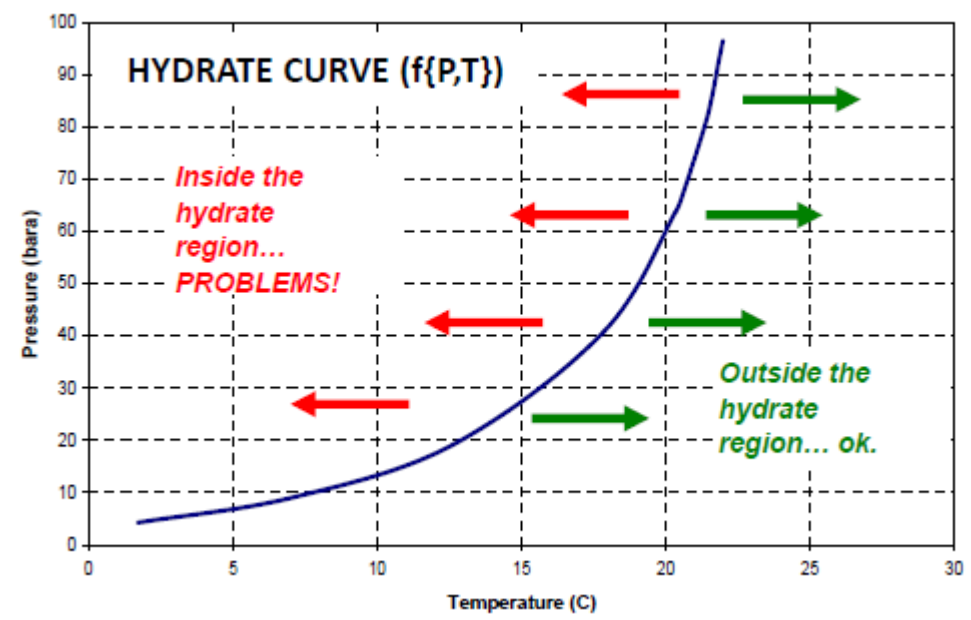
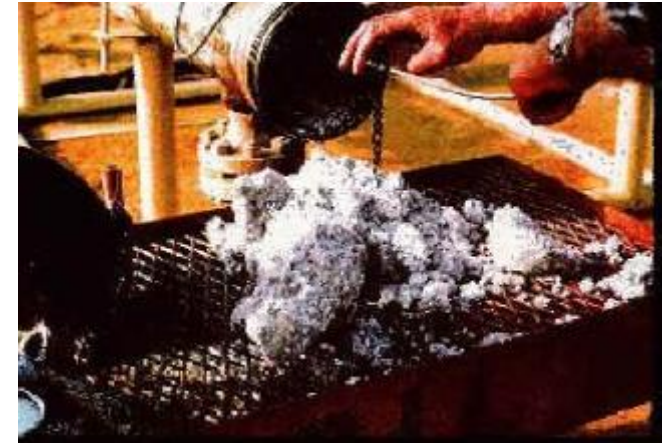


Source : Education Materials for Pipeline Engineering, Held by JP Kenny (2012)

For Hydrate Inhibition

Strategy

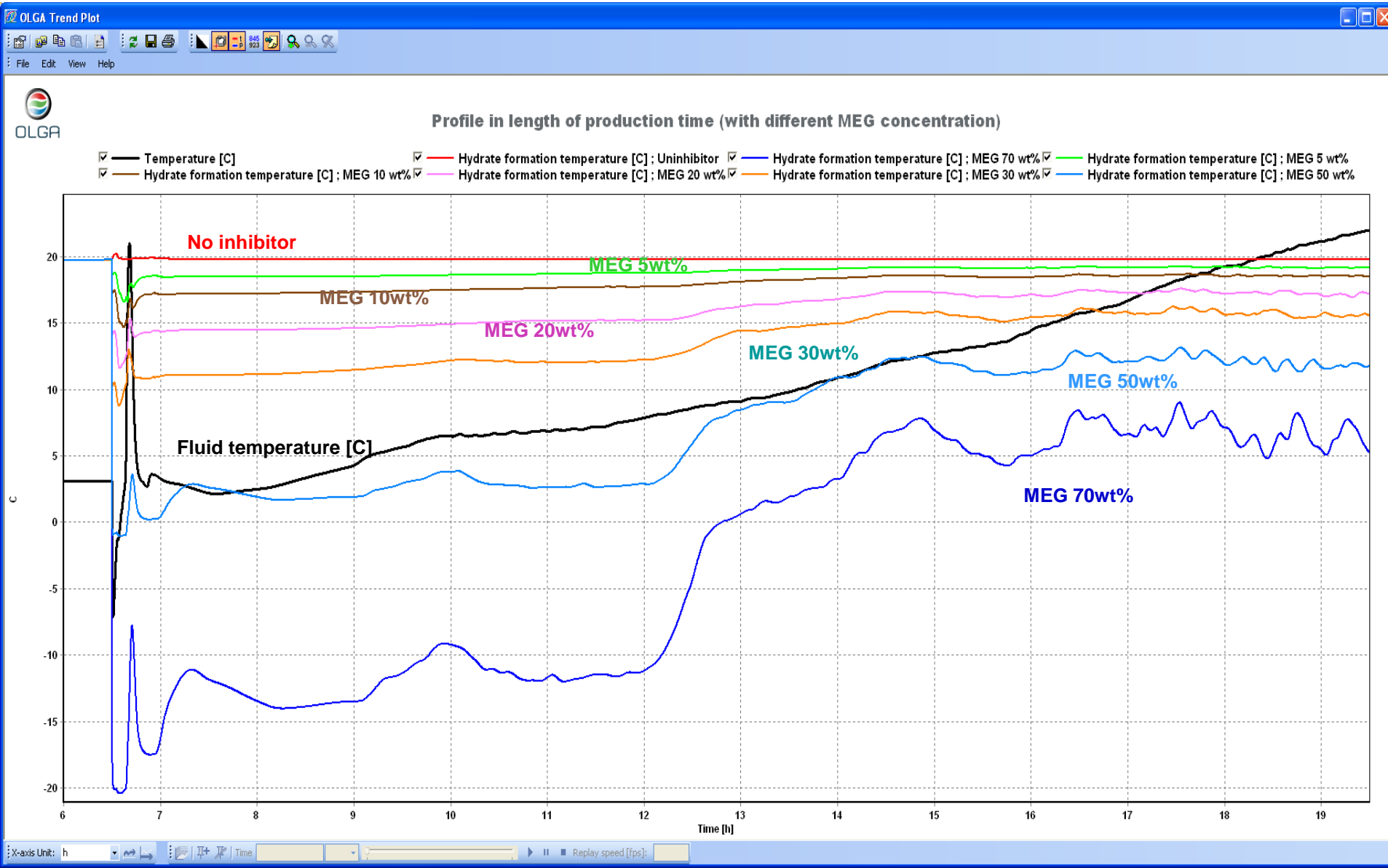
- Maintaining system temperature outside the hydrate formation region
 - use of insulation, heating and pressure limitations
 - use of thermodynamic hydrate inhibitors (THI's)
 - chemicals that reduce the hydrate formation temperature of the system (ex. MEG, Methanol)
- LDHI : Kinetic hydrate inhibitor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

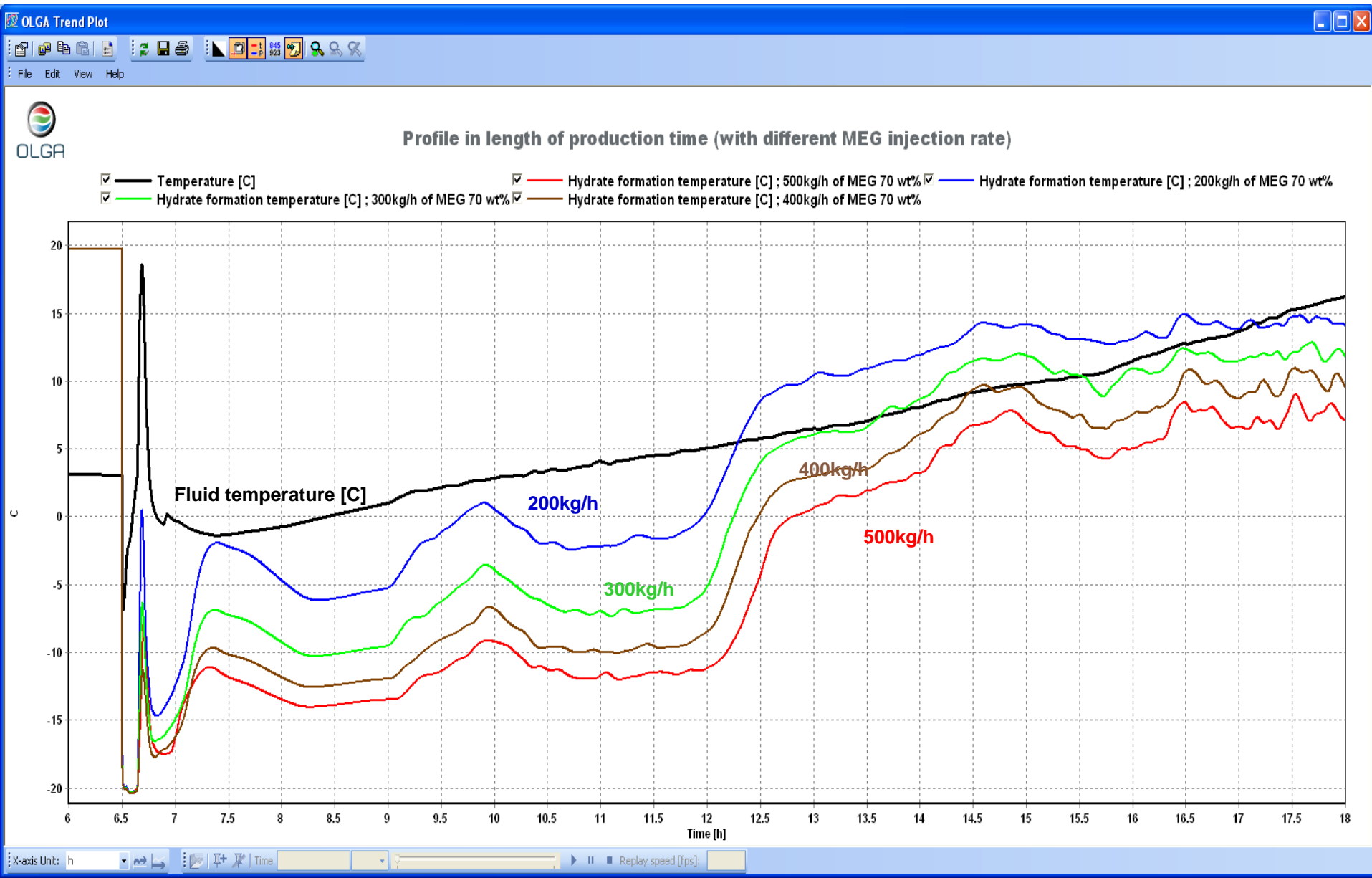
Example – Hydrate Inhibition Mitigation

Ex) Degree of Hydrate Inhibition according to THI Concentration



Example – Hydrate Inhibition Mitigation

Ex) Degree of Hydrate Inhibition according to THI Mass Flowrate

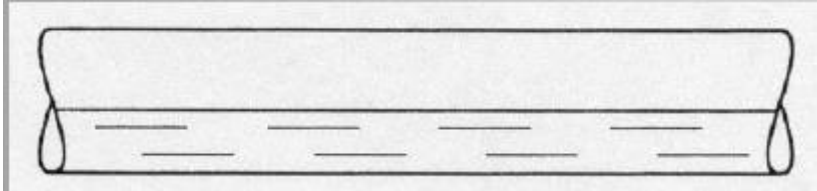


2-2. Slug Control

Flow Regimes (I)

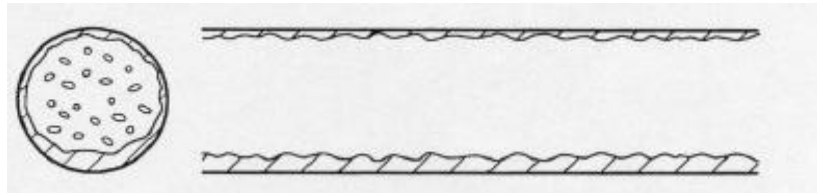
Horizontal pipeline

Stratified / Wavy



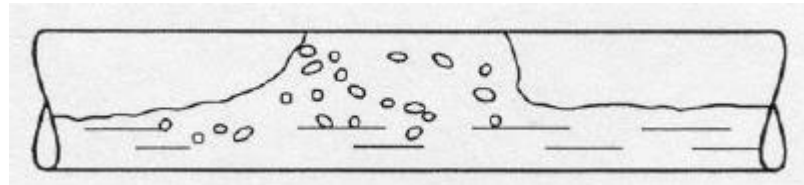
- ① **Stratified Flow** : Liquid flows along pipeline, gas flows over top with 'smooth' interface
- ② **Wavy Flow** : Higher velocity gas than stratified flow, with waves at interface traveling at high velocity

Annular / Mist



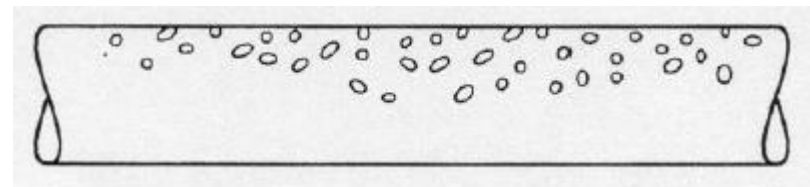
- ③ **Annular Flow** : Liquid flows as thin film along pipeline, with gas flowing in middle ('core')
- ④ **Mist Flow** : Very high gas velocities, entrain nearly all liquid

Slug



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

Bubble / Dispersed

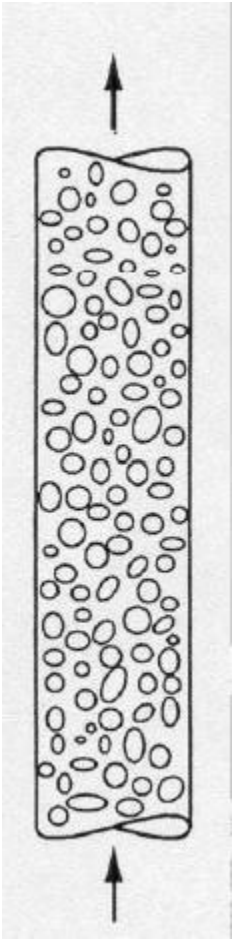


- ⑥ **Bubble Flow** : Gas dispersed as bubbles, move at velocity similar to liquid
- ⑦ **Dispersed Flow** = Definition of **Mist Flow**

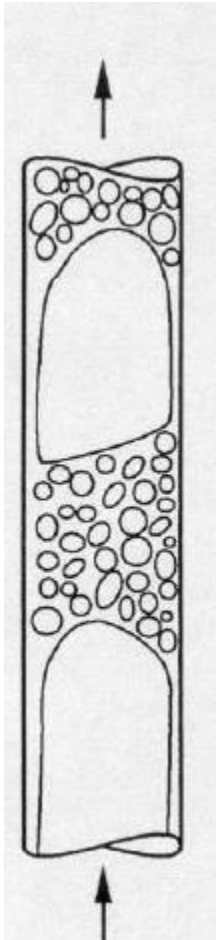
Flow Regimes (II)

Vertical Pipeline

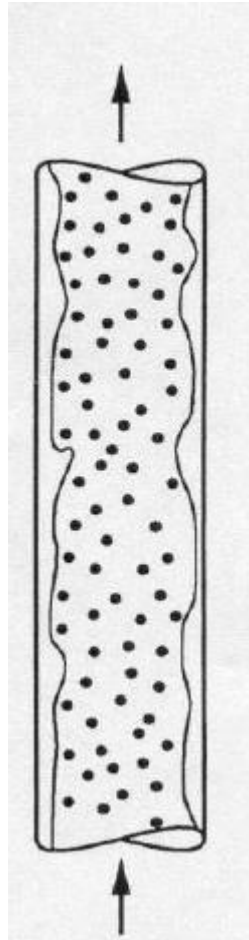
Bubble



Slug



Annular



① Stratified Flow

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

② Wavy 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

Severe Slug Formation

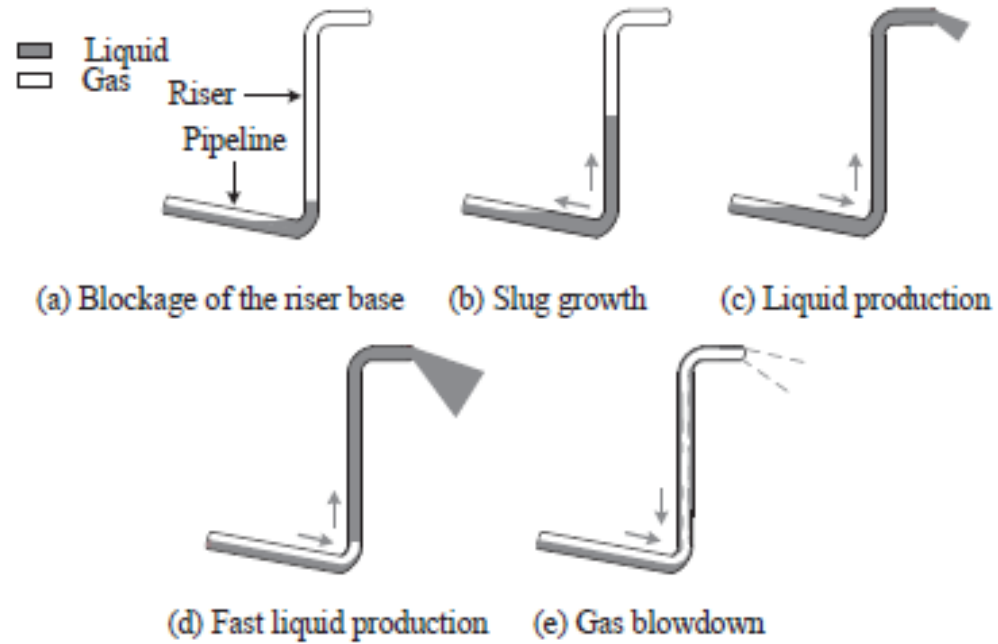


Figure. *The Buildup and Generation of Severe Slug*

What can Liquid Slug lead to?

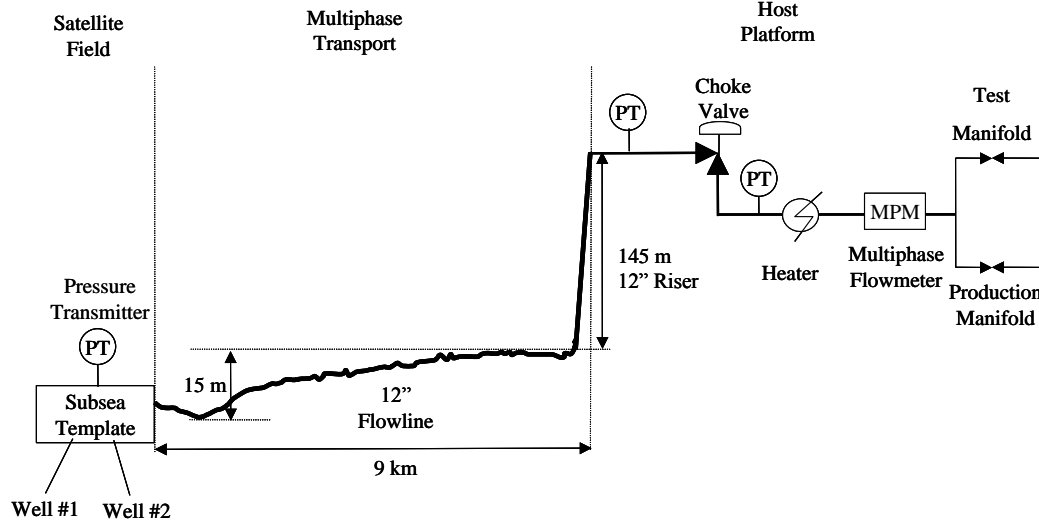


Figure. Schematic Overview of the Offshore Process (operated by STATOIL)

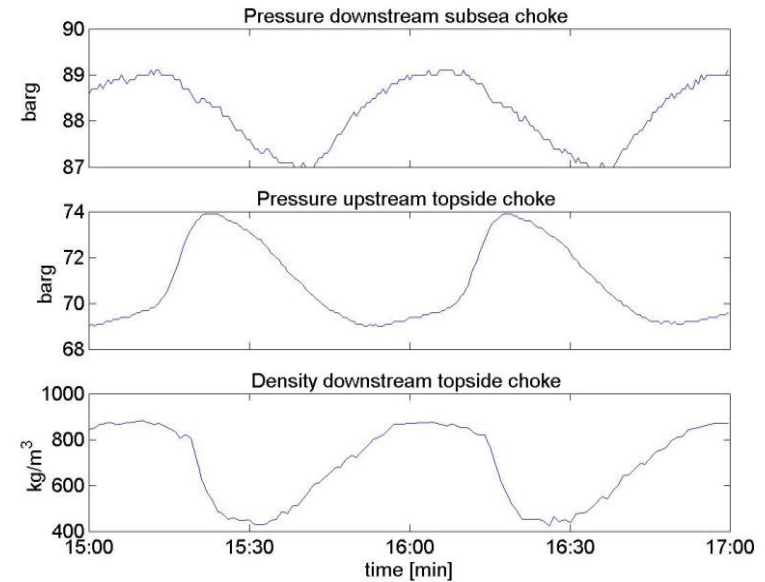


Figure. Measurements Indicating Liquid Slug Problem

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

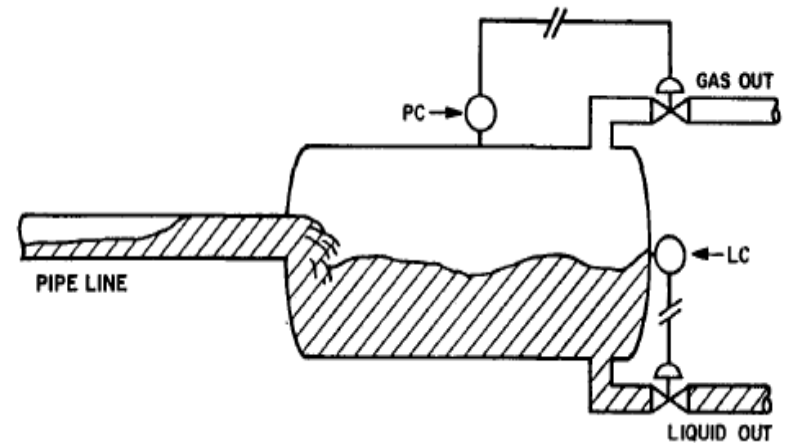
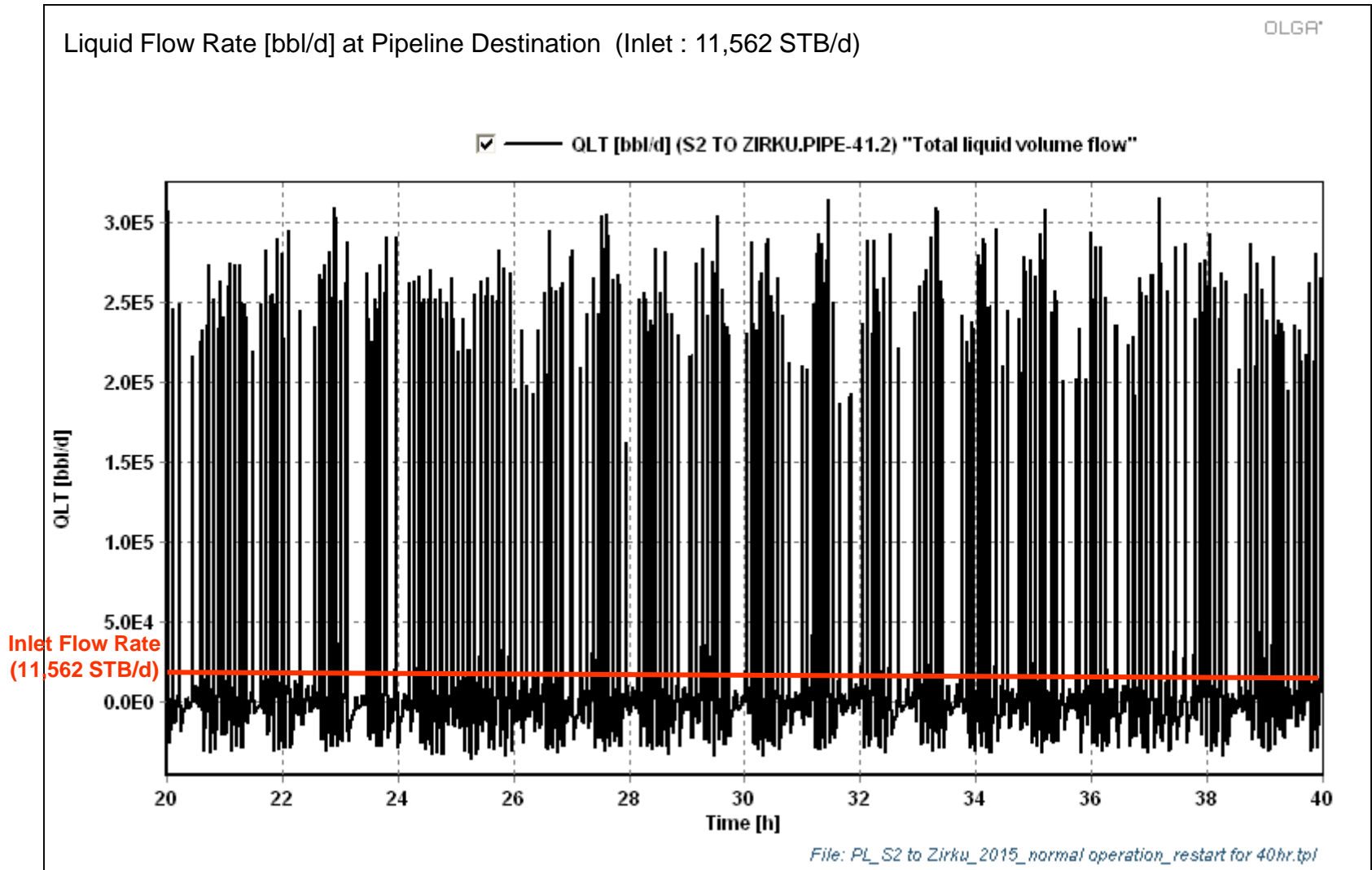


Figure. Slug Catcher System

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

Example (1) – Normal Operation

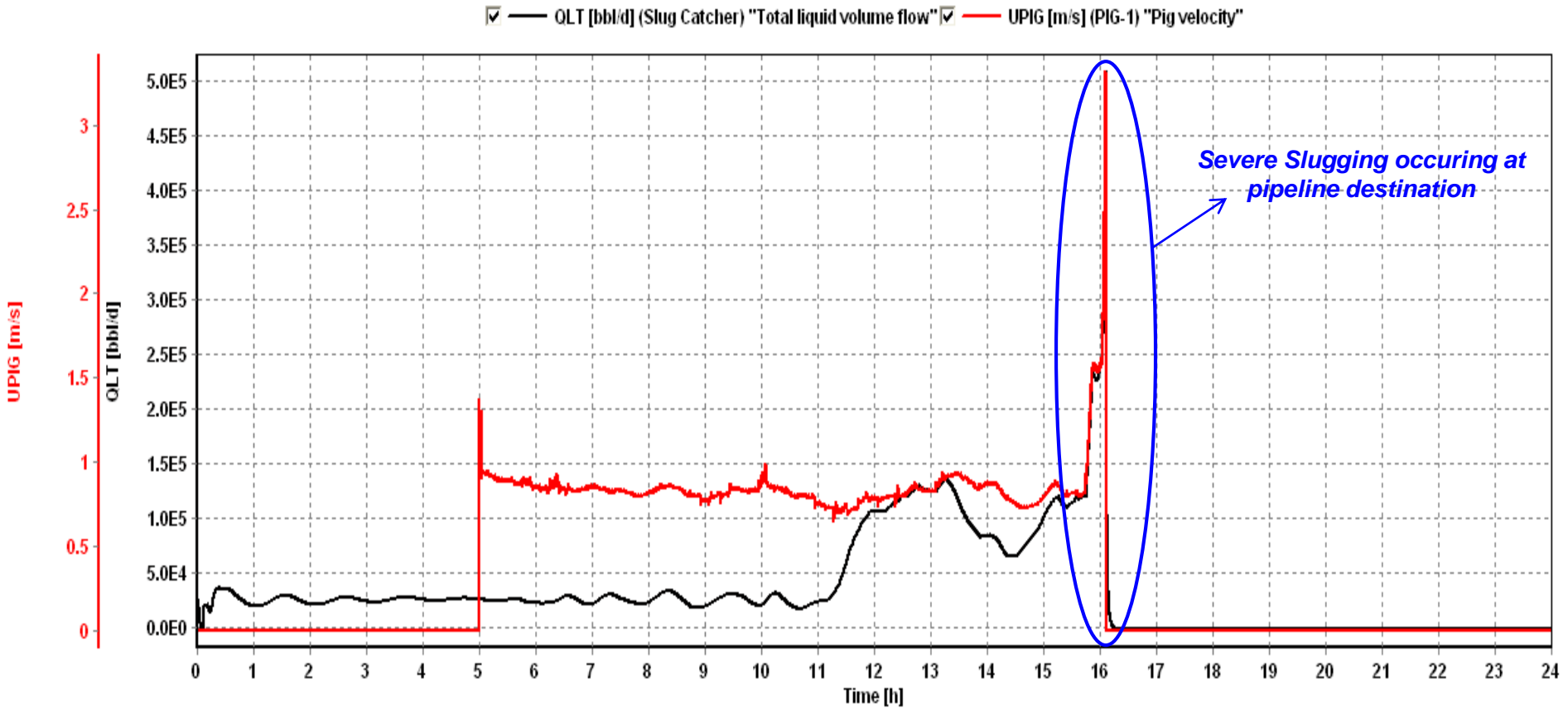
Ex) SARB-4_Offshore Pipeline (Total Length : 33 km)



Example (II) – Pigging Operation

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

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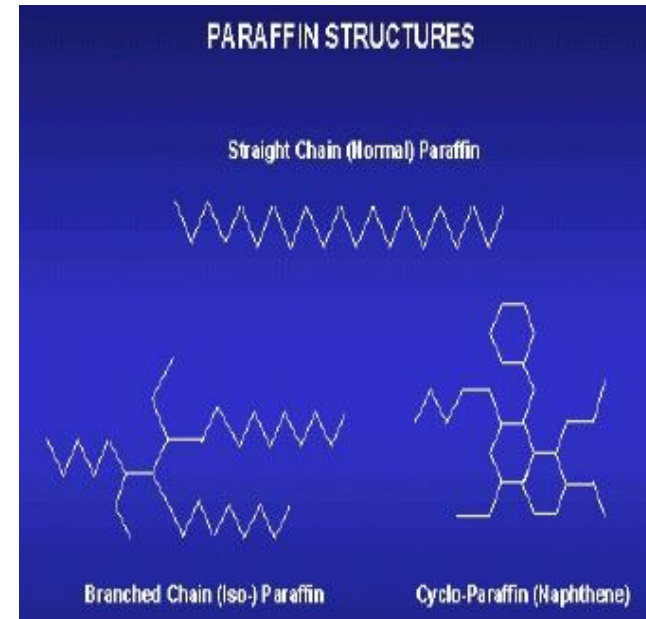
File: PL_S1 to Zirku_pigging_2015_pig slug off-5s.tpl

2-3. Wax Deposits Inhibition

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 °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)

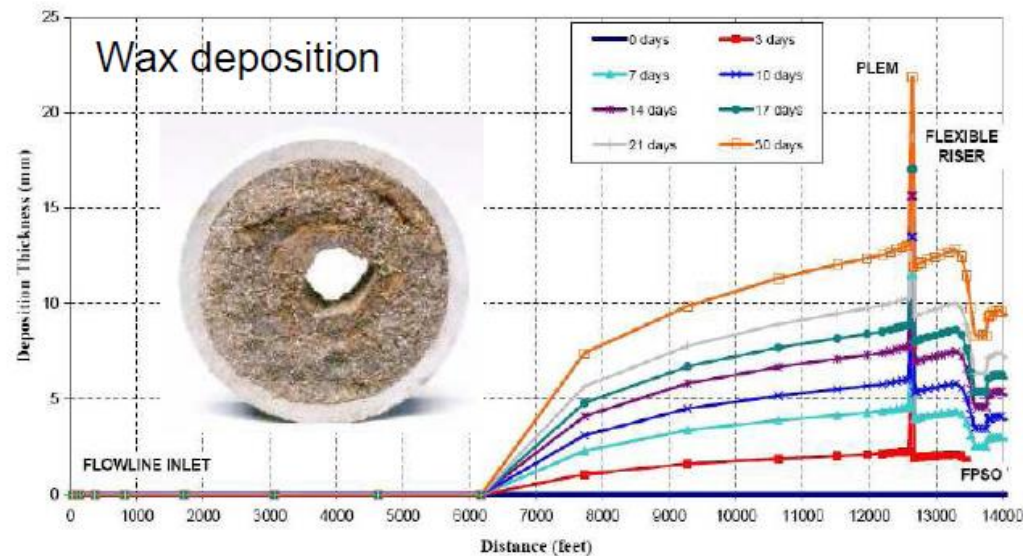
Wax Inhibition

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

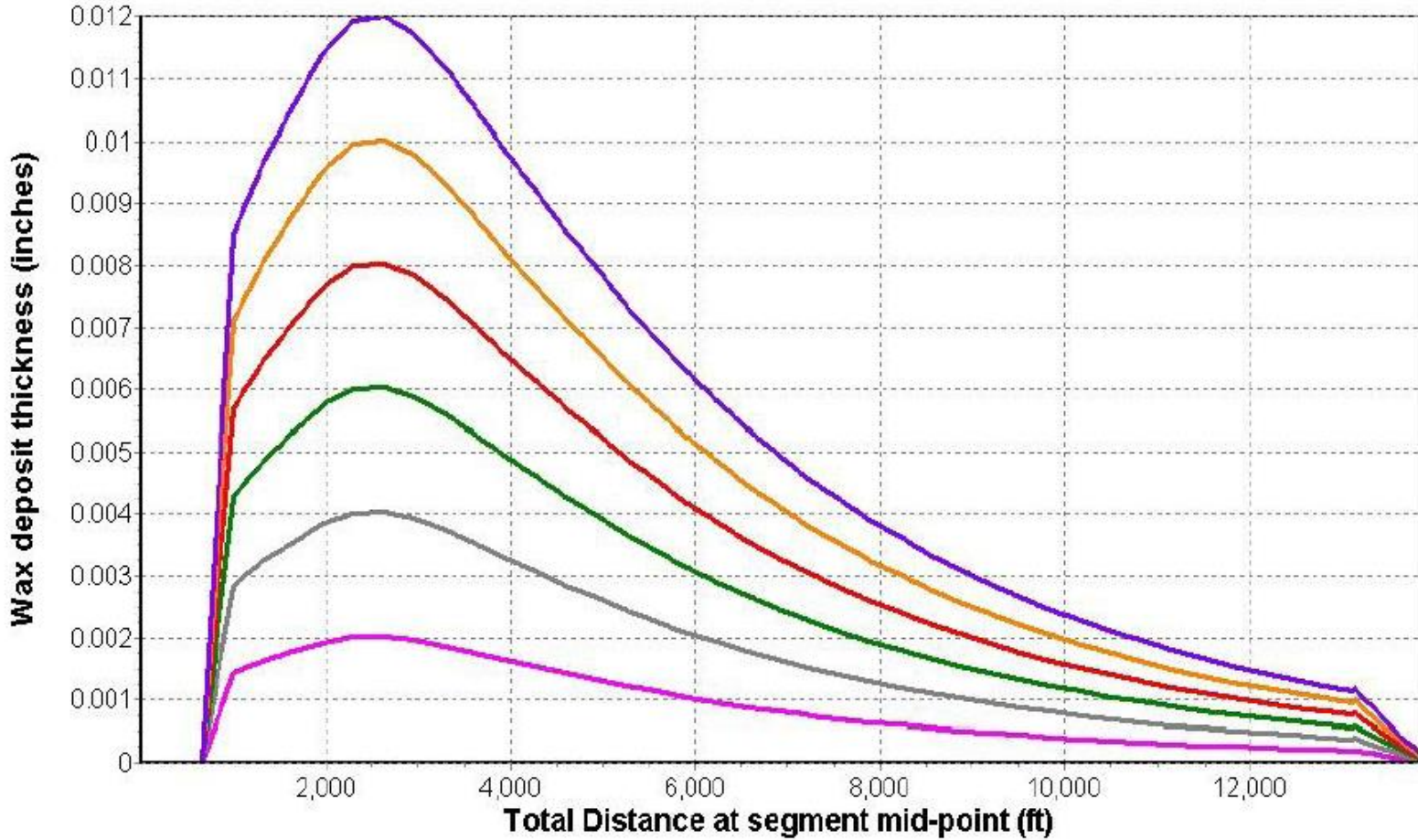


Source : Education Materials for Pipeline Engineering, Held by JP Kenny (2012)



Source : Seminar Material, CSIRO

Example – Wax Deposition Analysis



Production Time — TIME=0 — TIME=12 — TIME=24 — TIME=36 — TIME=48 — TIME=60 — TIME=72

Schlumberger
Created by Schlumberger on 19/04/04 11:02:30

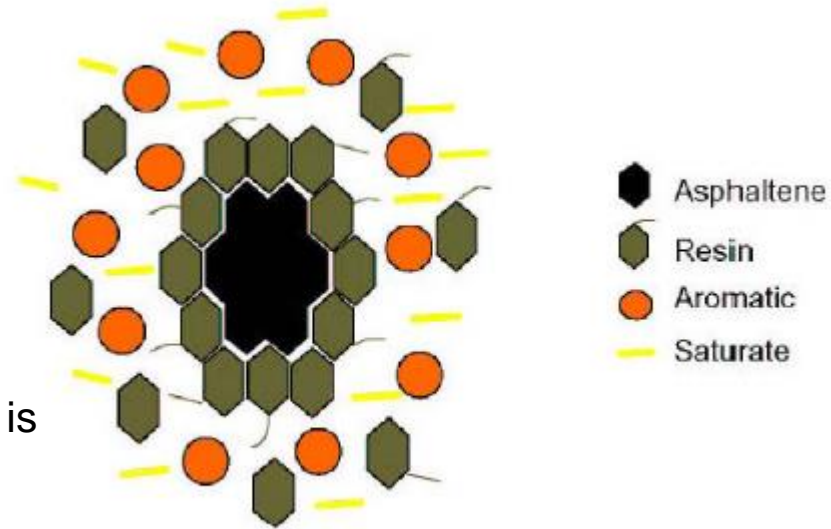
Source : PIPESIM S/W Seminar (2009)

2-4. Asphaltene / Scale Deposit Inhibition

Asphaltene Deposition

What is Asphaltene?

- High molecular weight 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

Scale Problem?

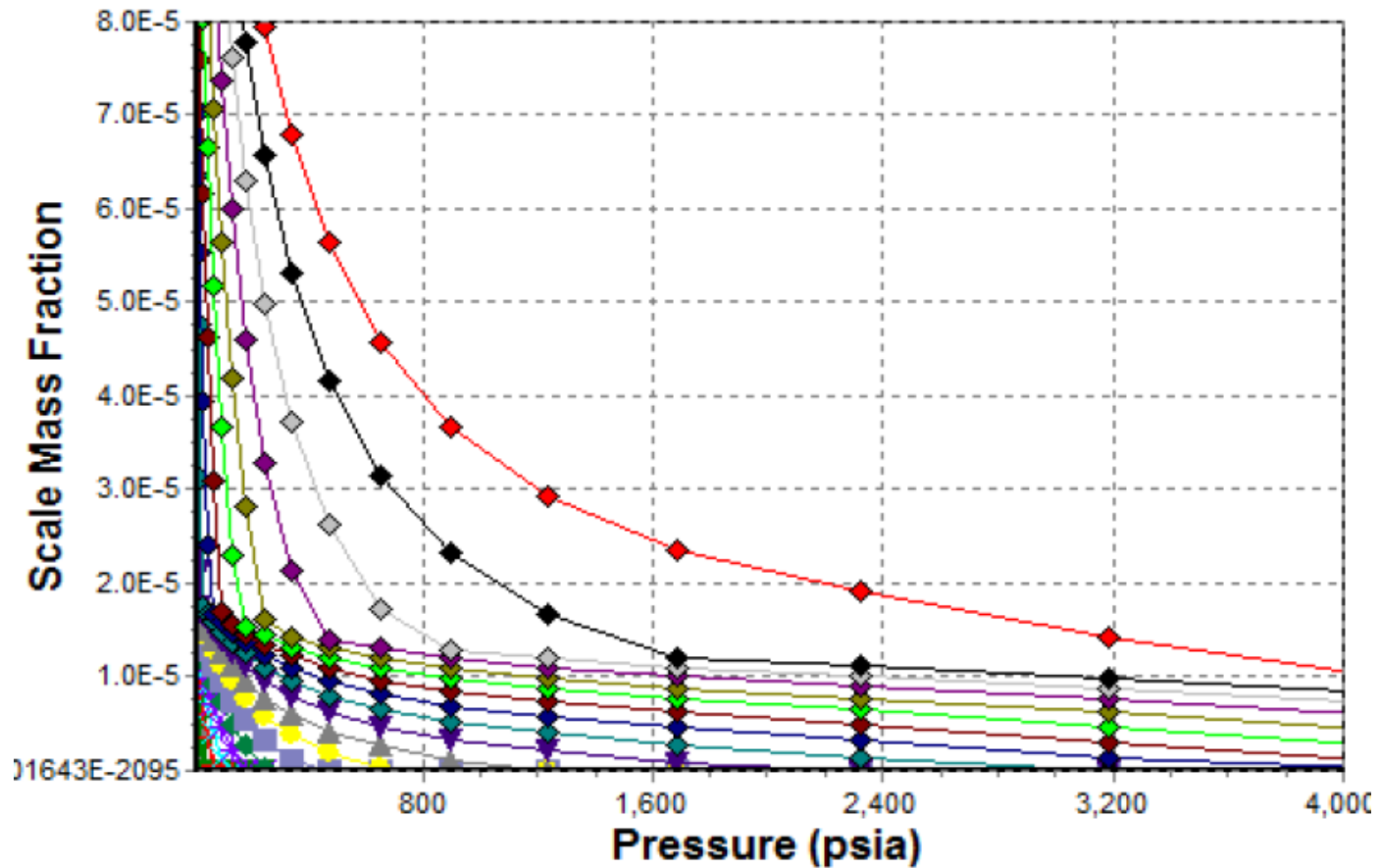
- Reduction in flow area
- Change in wall friction (increased pressure drop)
- Equipment fouling, increased corrosion, increased emulsion potential and so on

Control Strategy → Only scale inhibitor



Source : SPT Group

Example – Scale Analysis



Temp = 60.0 F	Temp = 32.0 F	Temp = 41.4 F	Temp = 50.7 F
Temp = 60.1 F	Temp = 69.5 F	Temp = 78.8 F	Temp = 88.2 F
Temp = 97.6 F	Temp = 106.9 F	Temp = 116.3 F	Temp = 125.7 F
Temp = 135.1 F	Temp = 144.4 F	Temp = 153.8 F	Temp = 163.2 F
Temp = 172.5 F	Temp = 181.9 F	Temp = 191.3 F	Temp = 200.6 F
Temp = 210.0 F	Scale- CACO3	Scale- CACO3	Scale- MGOH2

3. Design (2) : for Pipeline Stability (erosion / corrosion / hammering)

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

$$V_e = \frac{c}{\sqrt{\rho m}} \quad \text{Eq. 2.14}$$

where:

V_e = fluid erosional velocity, feet/second

c = empirical constant

ρm = gas/liquid mixture density at flowing pressure and temperature, lbs/ft³

- SALAMA Model not published



Figure. Erosion Site on Pipeline Wall

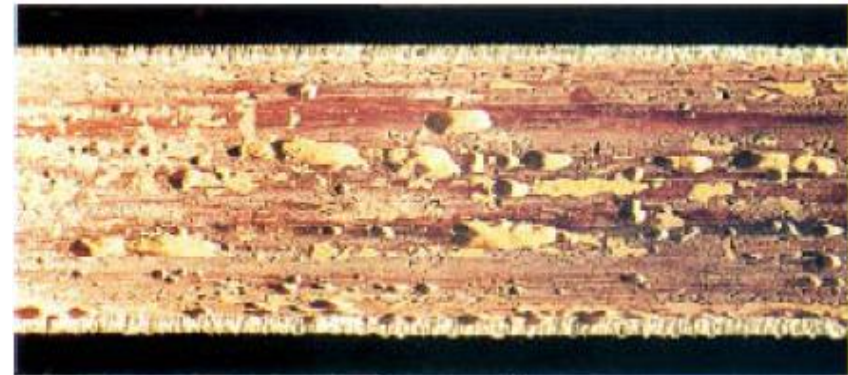


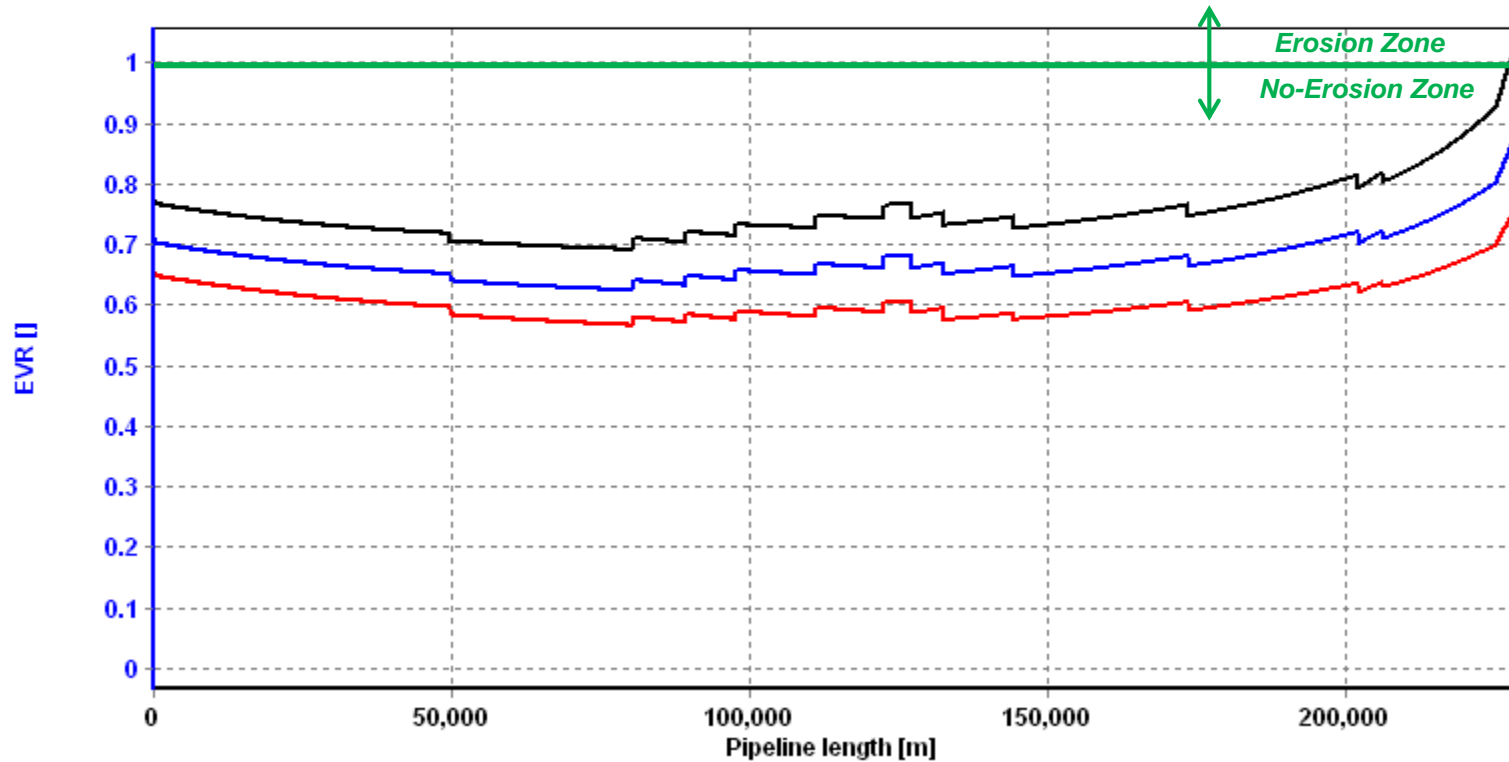
Figure. Metal Loss from Erosion-Corrosion on Pipeline Wall

Example (I) – Erosion Prevention

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Ex) Pre-FEED Result_Timor Sea Pipeline

- ✓ — EVR [] (22 in Gas PL 945 MMscfd) "Timor Gas PL_Parametric Study_22 inch.ppl"
- ✓ — EVR [] (26 in Gas PL 945 mmscfd) "Timor Gas PL_Parametric Study_26 inch.ppl"
- ✓ — EVR [] (24 in Gas PL 945 MMscfd) "Timor Gas PL_Parametric Study_24 inch.ppl"



※ 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
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
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

Erosion

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

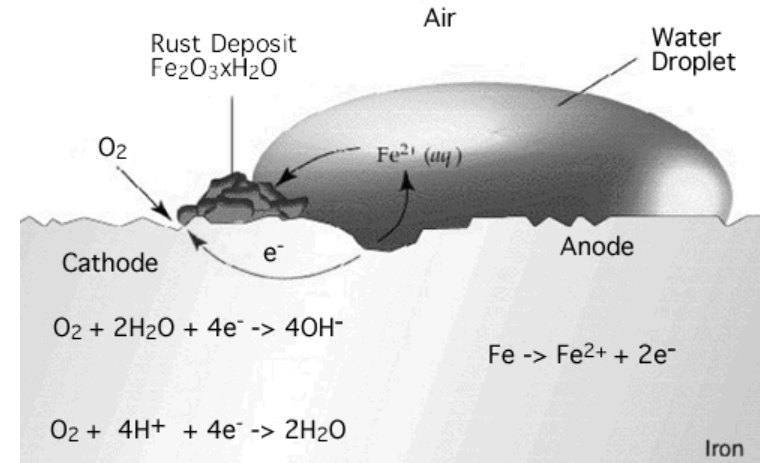
Corrosion Prevention

Why can Erosion occur on Pipeline Wall?

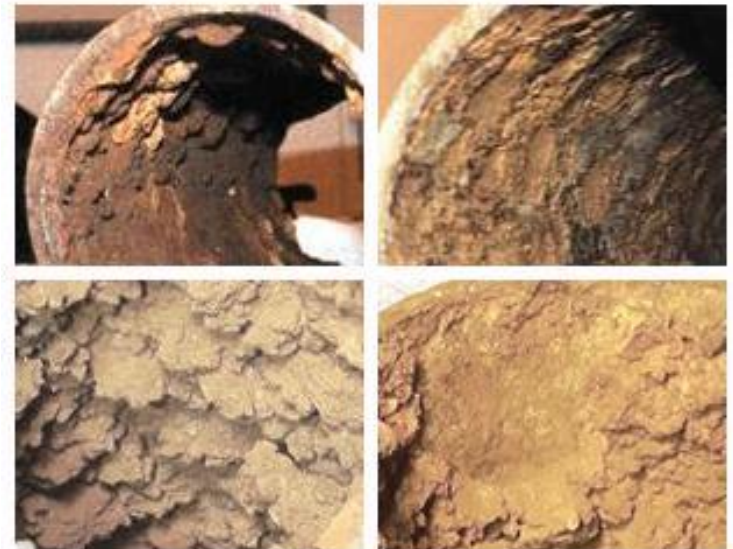
- Corrosion is primarily due to the presence of $\text{CO}_2/\text{H}_2\text{S}$ for well fluid pipeline and CO_2/O_2 for steam-condensate pipeline
- Corrosion is a chemical reaction whereby the metal in the pipeline is oxidized and is consequently removed.
- Water is required for the corrosion mechanism.

Control Strategy

- Removing the chemical reactants (CO_2 , H_2S or Water)
- Chemical treatments : Inhibitors, pH adjustment
- Specify more durable materials (ex. stainless steels)



Corrosion Problems



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 switching, 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

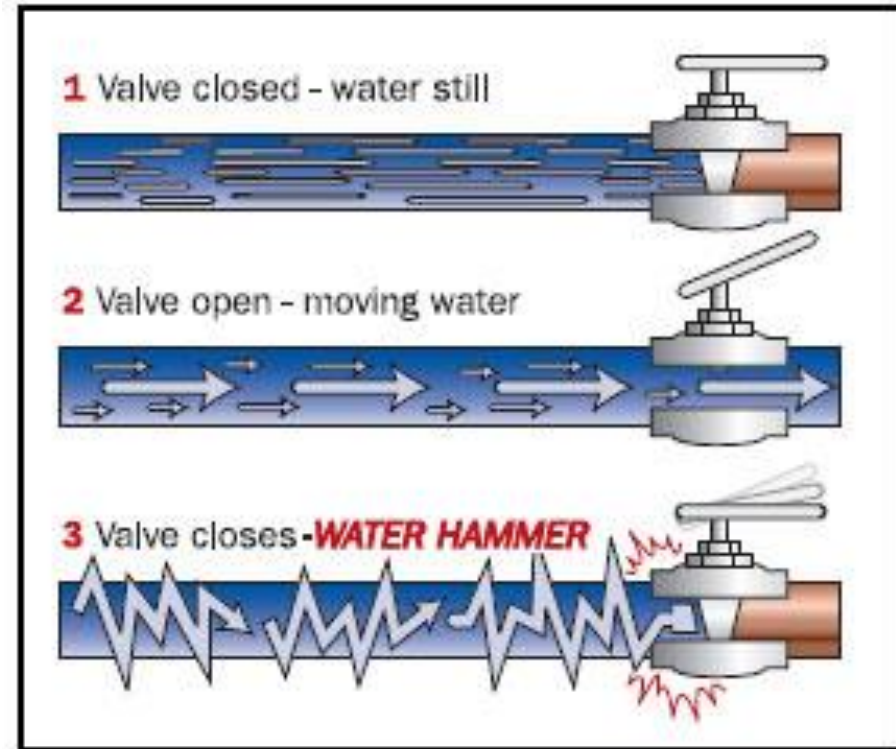


Figure. Water Hammering Mechanism

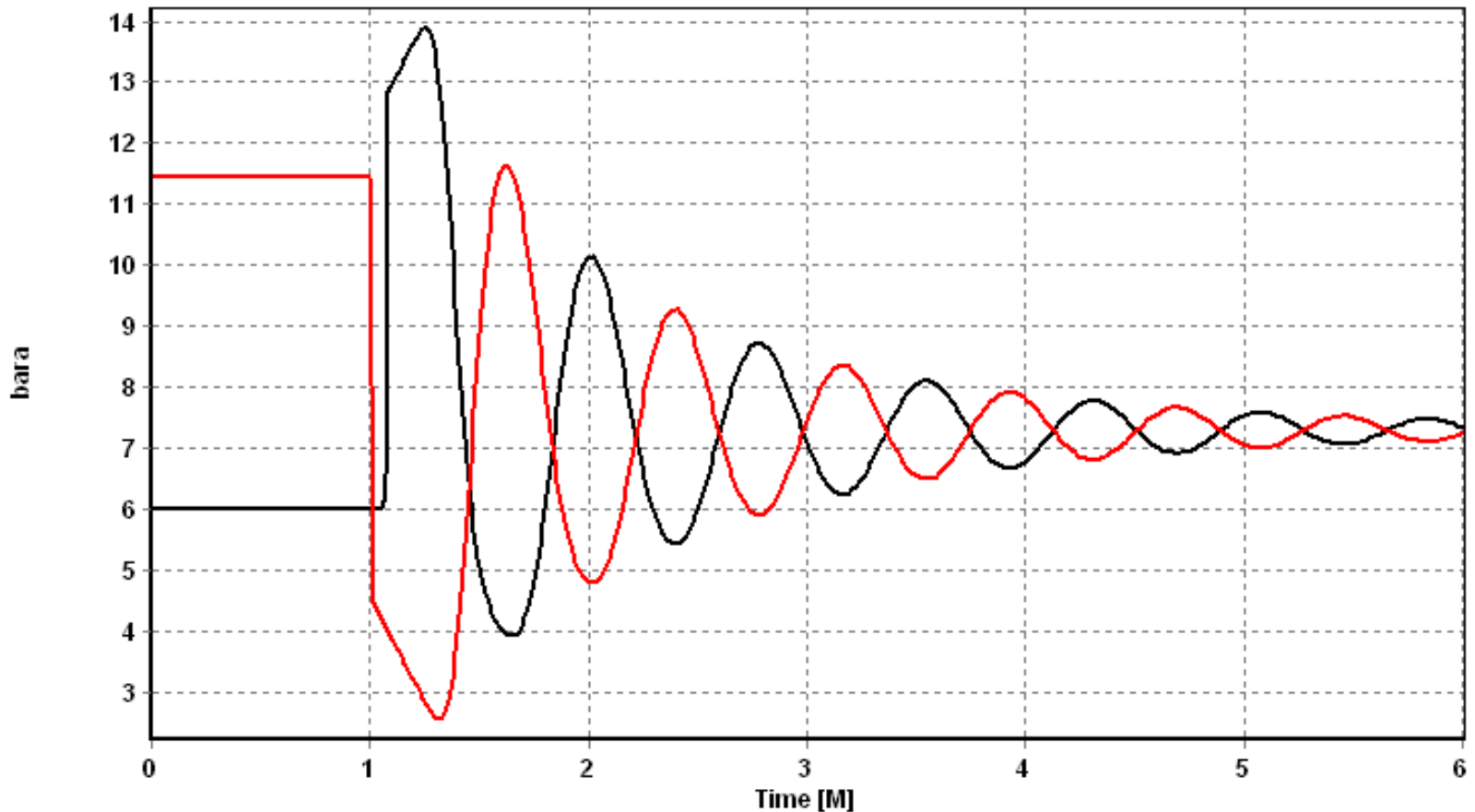
Example – Surge Analysis

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

OLGA[®]

Surge analysis : Pressure distribution (valve closing time 5s)

— Pressure [bara] at the front of closing valve — Pressure [bara] at the rear of pump



File: Surge analysis_IRP_2_ADRD-ADIA_JET_close node_CT 5s.tpl

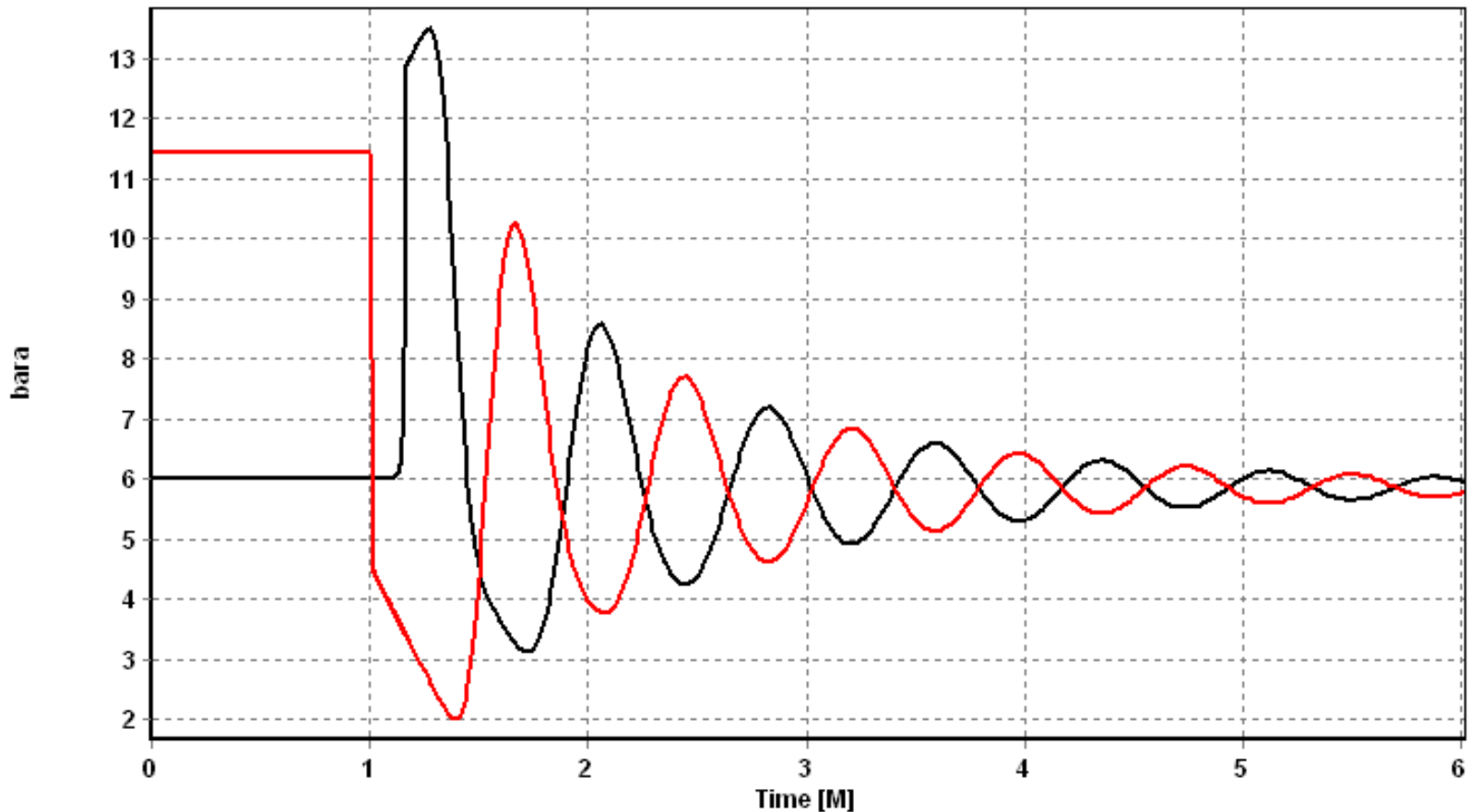
Example – Surge Analysis

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

OLGA®

Surge analysis : Pressure distribution (valve closing time 10 s)

— Pressure [bara] at the front of closing valve — Pressure [bara] at the rear of pump



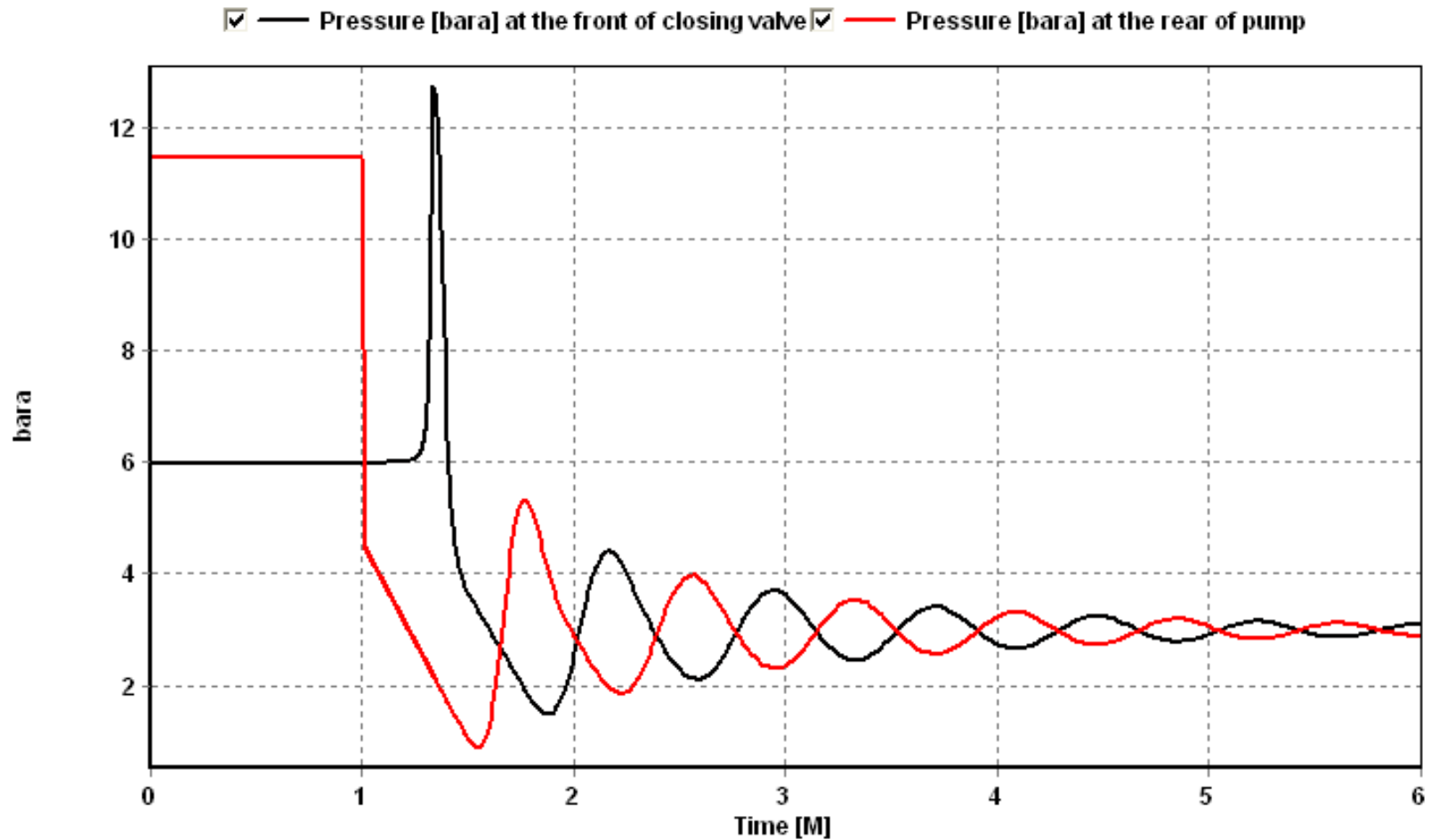
File: Surge analysis_IRP_2_ADRD-ADIA_JET_close_node.tpl

Example – Surge Analysis

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

OLGA*

Surge analysis : Pressure distribution (valve closing time 20 s)



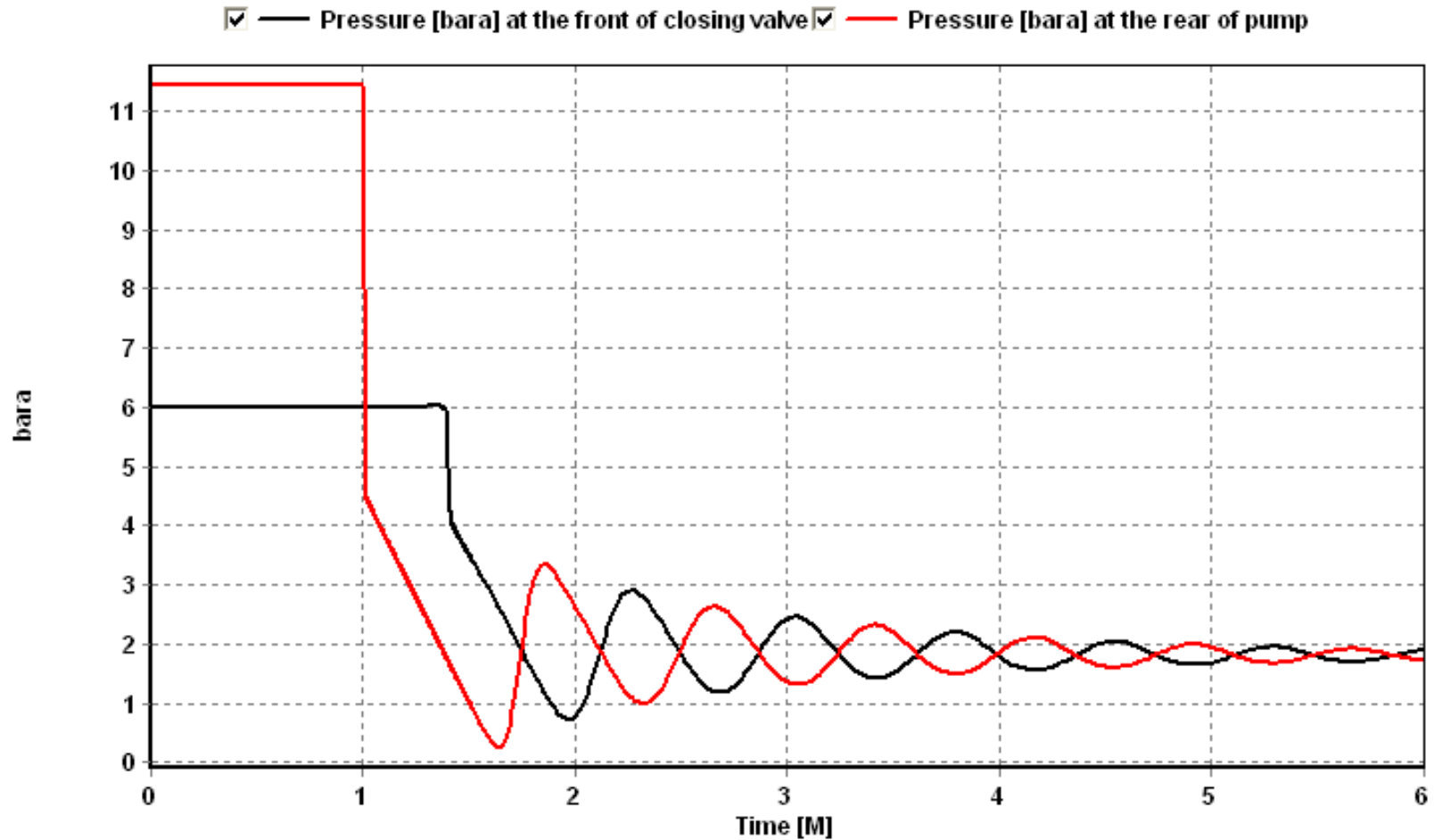
File: Surge analysis_IRP_2_ADRD-ADIA_JET_close node_CT 20s.tpl

Example – Surge Analysis

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

OLGA*

Surge analysis : Pressure distribution (valve closing time 30 s)



File: Surge analysis_IRP_2_ADRD-ADIA_JET_close node_CT 30s.tpl

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Thank you