SUT - US

Flow Assurance

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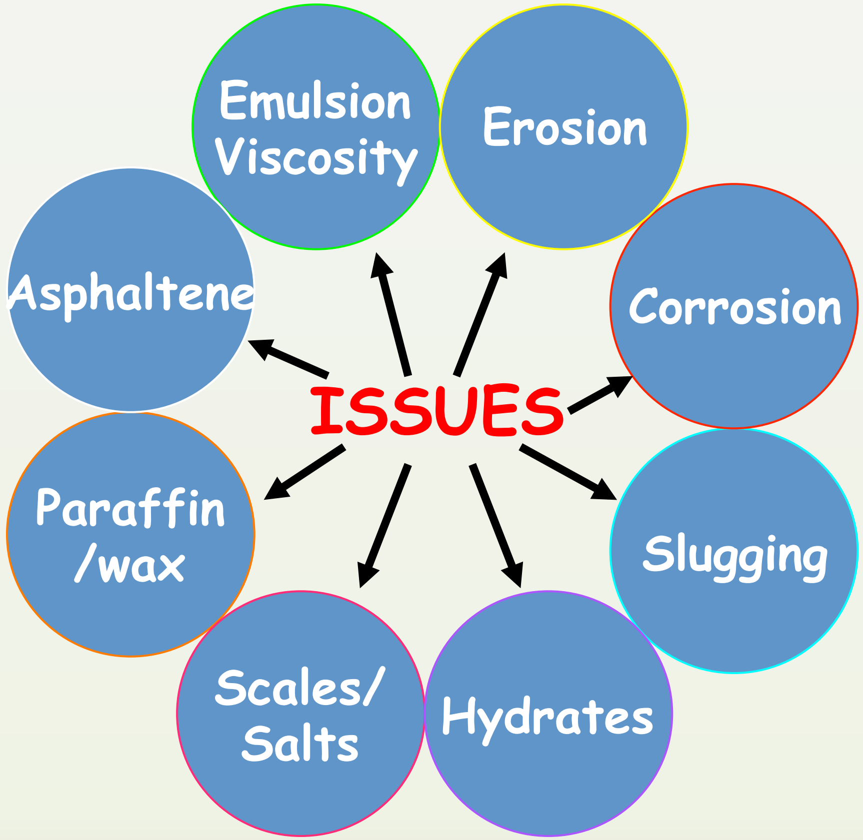
SUT-US Subsea Awareness Course

Flow Assurance

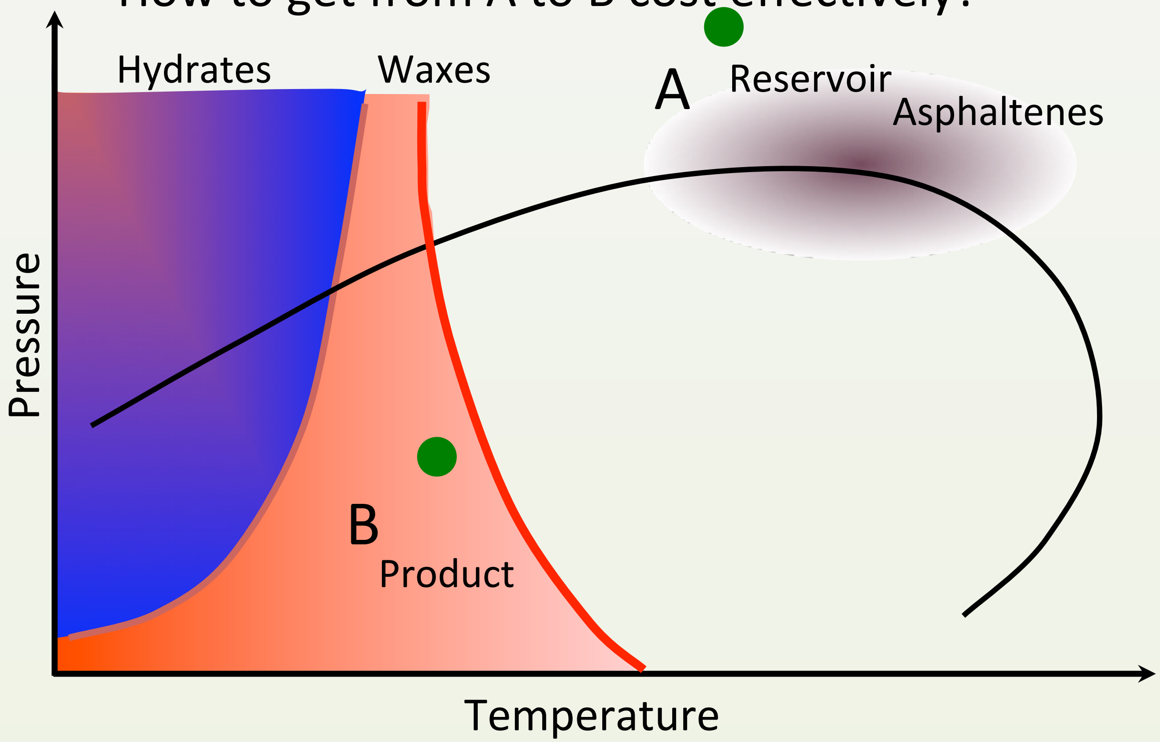


Flow Assurance Overview

- What Is Flow Assurance?
- Fluids
- Flow Assurance Issues
- Hydraulics – Single & Multiphase Flow
- Thermal Design – Insulation, Heating Systems
- Flow Assurance Design Process
- Flow Assurance Role in Bigger Picture

Flow Assurance Definition

How to get from A to B cost effectively?



- Flow Assurance (FA) addresses all issues of importance which ensure transfer of production fluids from the reservoir to the point of sale
- Defined by Petrobras in the early 1990s as 'Garantia de Fluxo' which literally translates as 'Guarantee the Flow', or Flow Assurance.

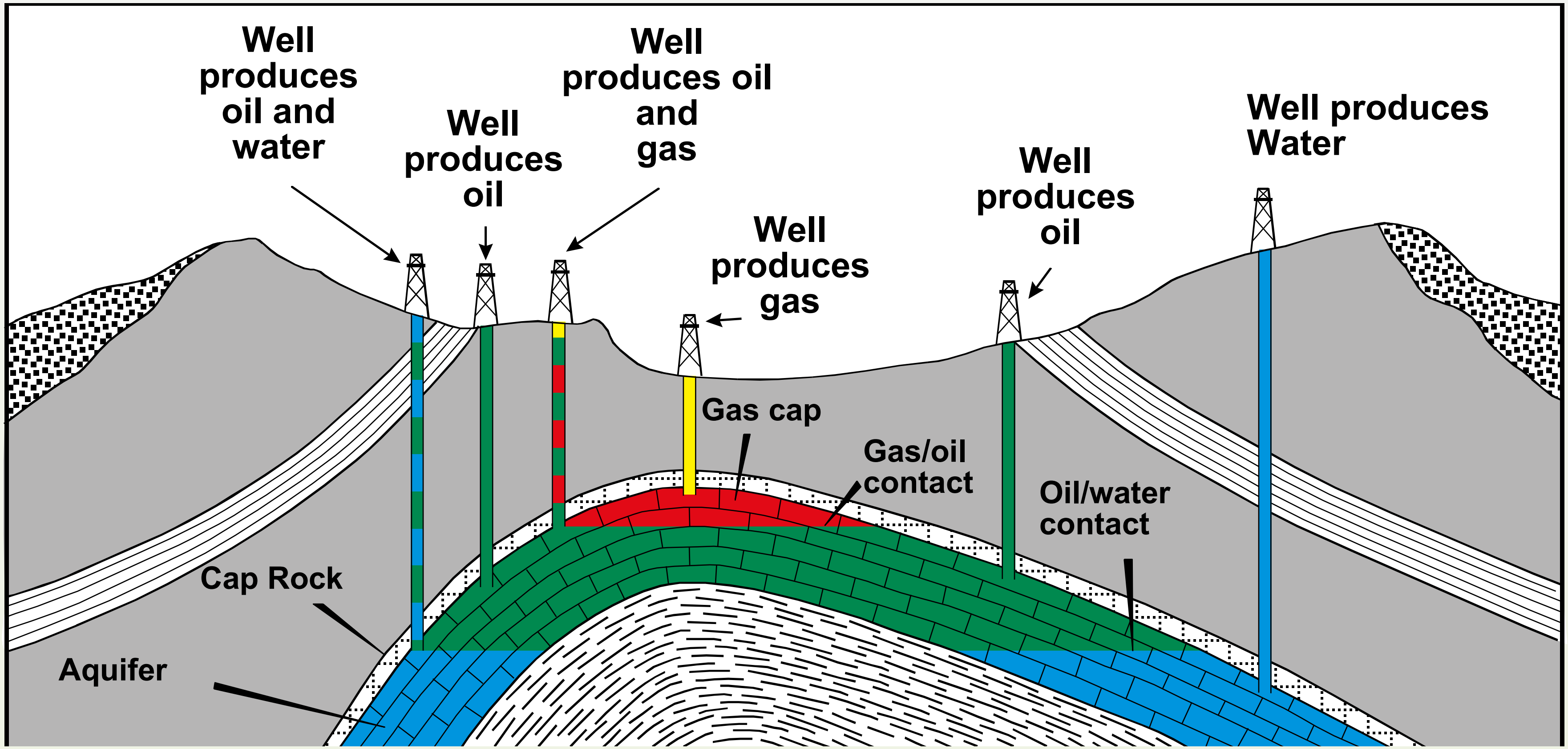
FA facilitates operability by the development and implementation of strategies to manage key areas of concern, such as:

– Hydraulic and thermal performance

– Hydrate formation and wax deposition

– Other production chemistry related issues

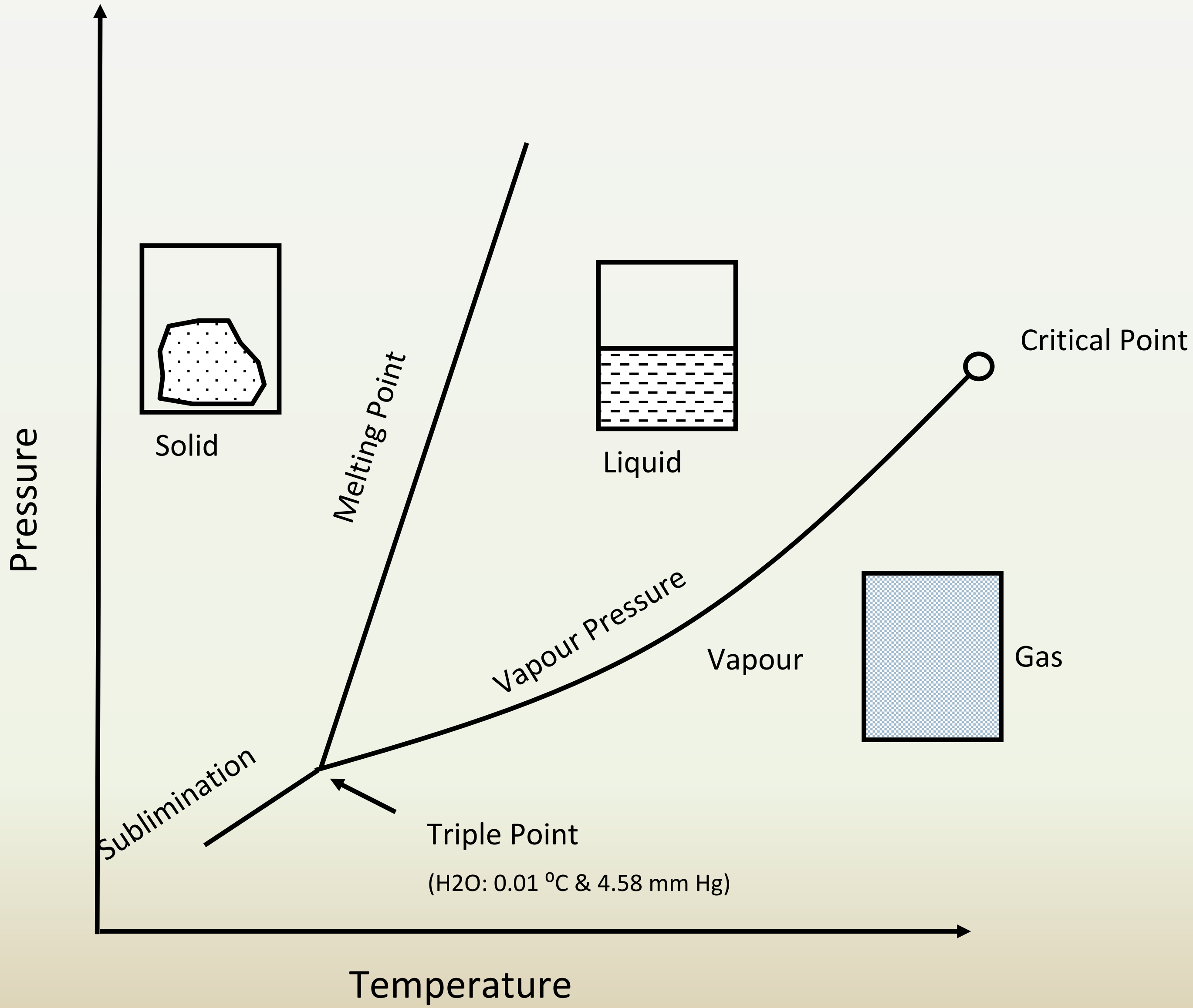
A Typical Hydrocarbon Reservoir



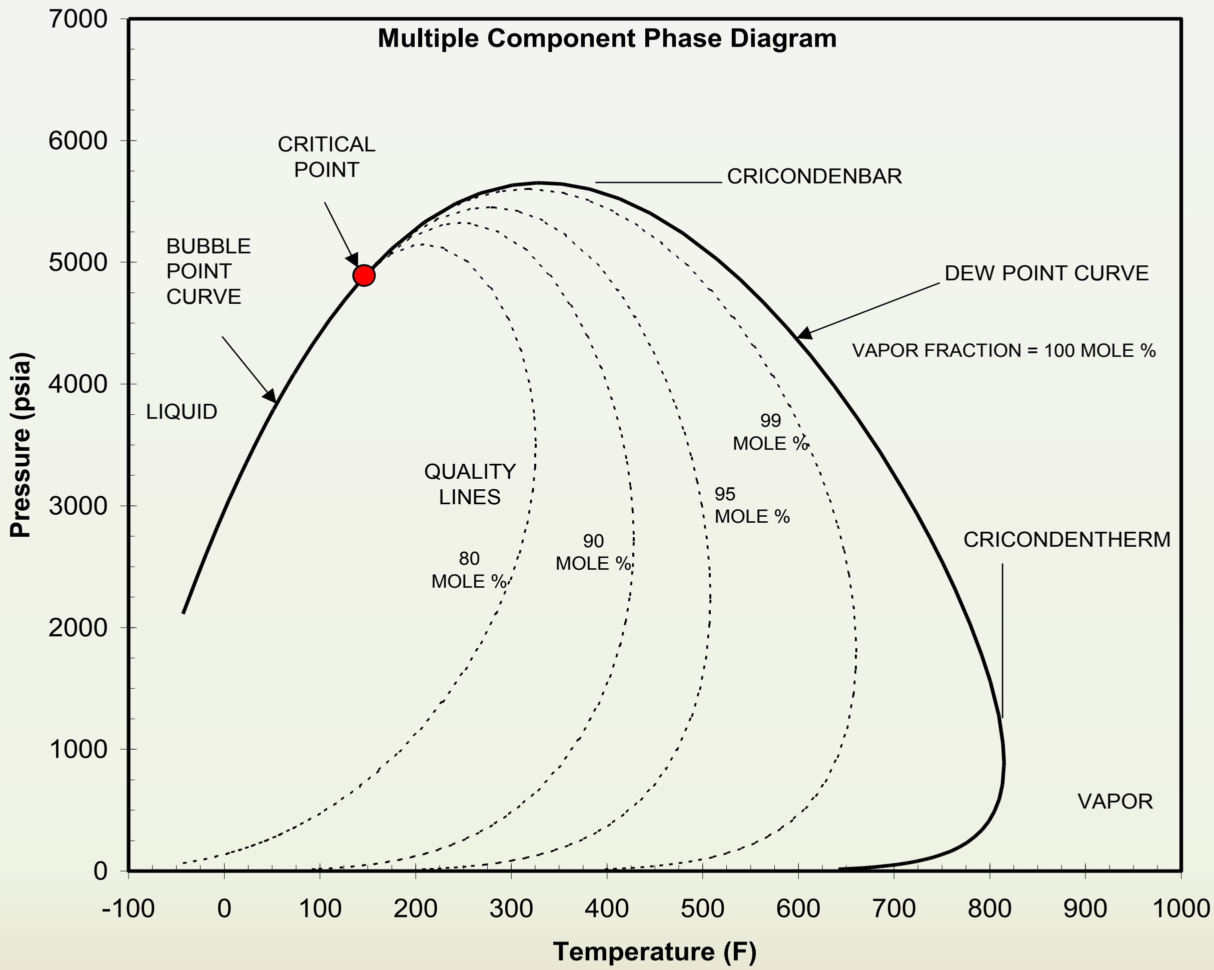
Hydrocarbon reservoirs produce oil, gas, condensate, water

Flow Assurance and Production Chemistry ensure that the fluids can flow from the reservoir to where they are processed and to export

Phase Diagram – Single Component

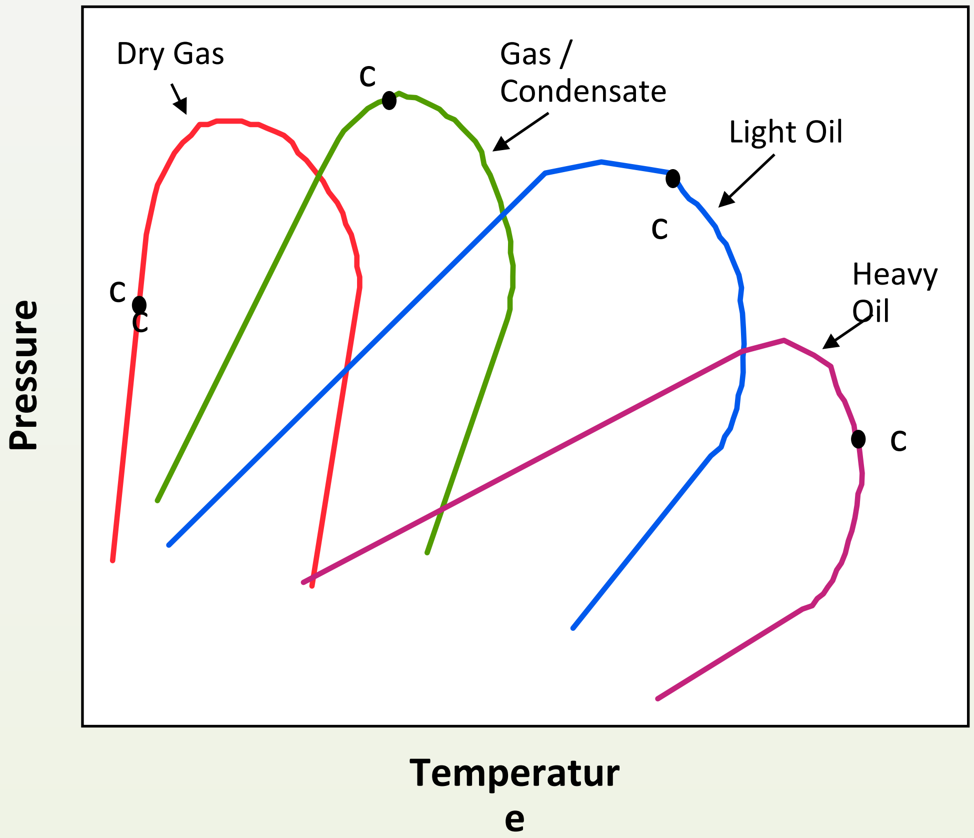


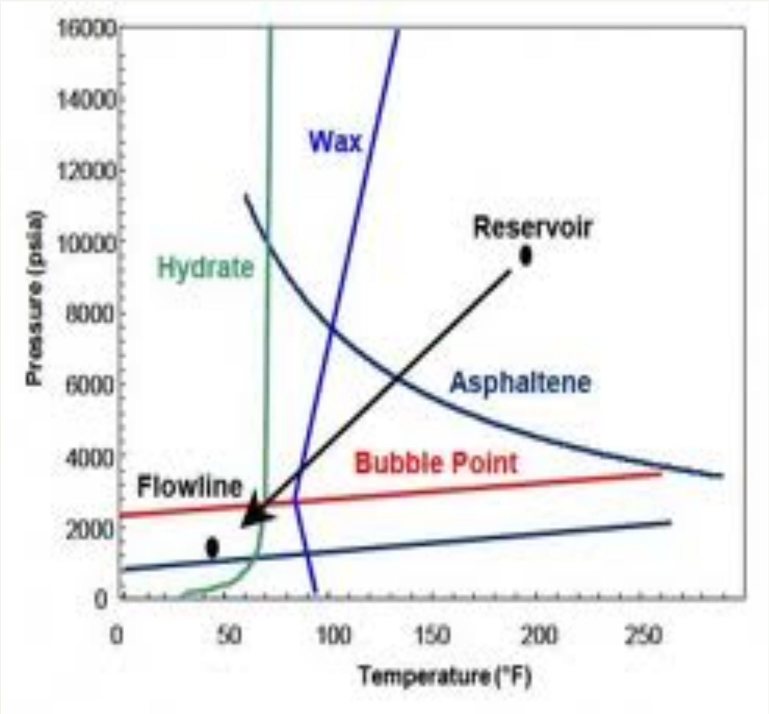
Fluid Phase Envelopes



- Modelling work requires knowledge of fluid properties and phase behaviour as functions of system temperature and pressure
- Phase behaviour determines vapour-liquid split, how the fluid will behave under temperature and pressure
- Experimental data likely to be limited so prediction is required
- The PVT Report is structured to provide the much of the black oil model information together with limited compositional data
- Uncontaminated representative (@ reservoir conditions) fluid samples are necessary for good FA issue prediction

Fluid Phase Envelopes





Fluid Modeling

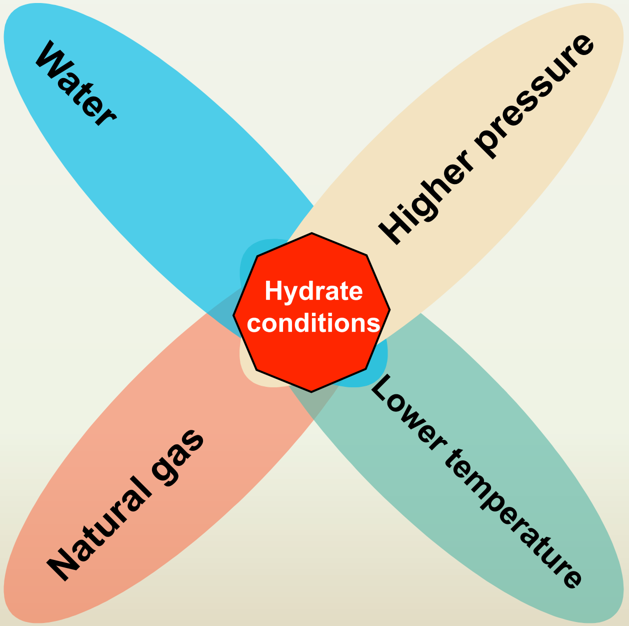
- **Black Oil Model:**
  - Predicts fluid properties using empirical correlations
  - Requires the following minimum information:
    - Stock tank oil API gravity
    - Gas gravity
    - Total producing GOR
    - Water cut and water gravity, if water present
- **Compositional Model:**
  - Predicts gas and liquid physical properties using an equation of state (EOS)
  - Requires detailed knowledge of composition and pseudo-components
  - Two of the most popular EOS are Soave-Redlich-Kwong (SRK) and Peng-Robinson (PR)
  - Transport properties such as viscosity require other models
- **EOS characterization:**
  - Obtain experimental data from a range of experiments
  - Input to PVT property package
  - Use software to tune pseudo-component critical and binary interaction parameters to minimize error between experimental data and predictions

Hydrates

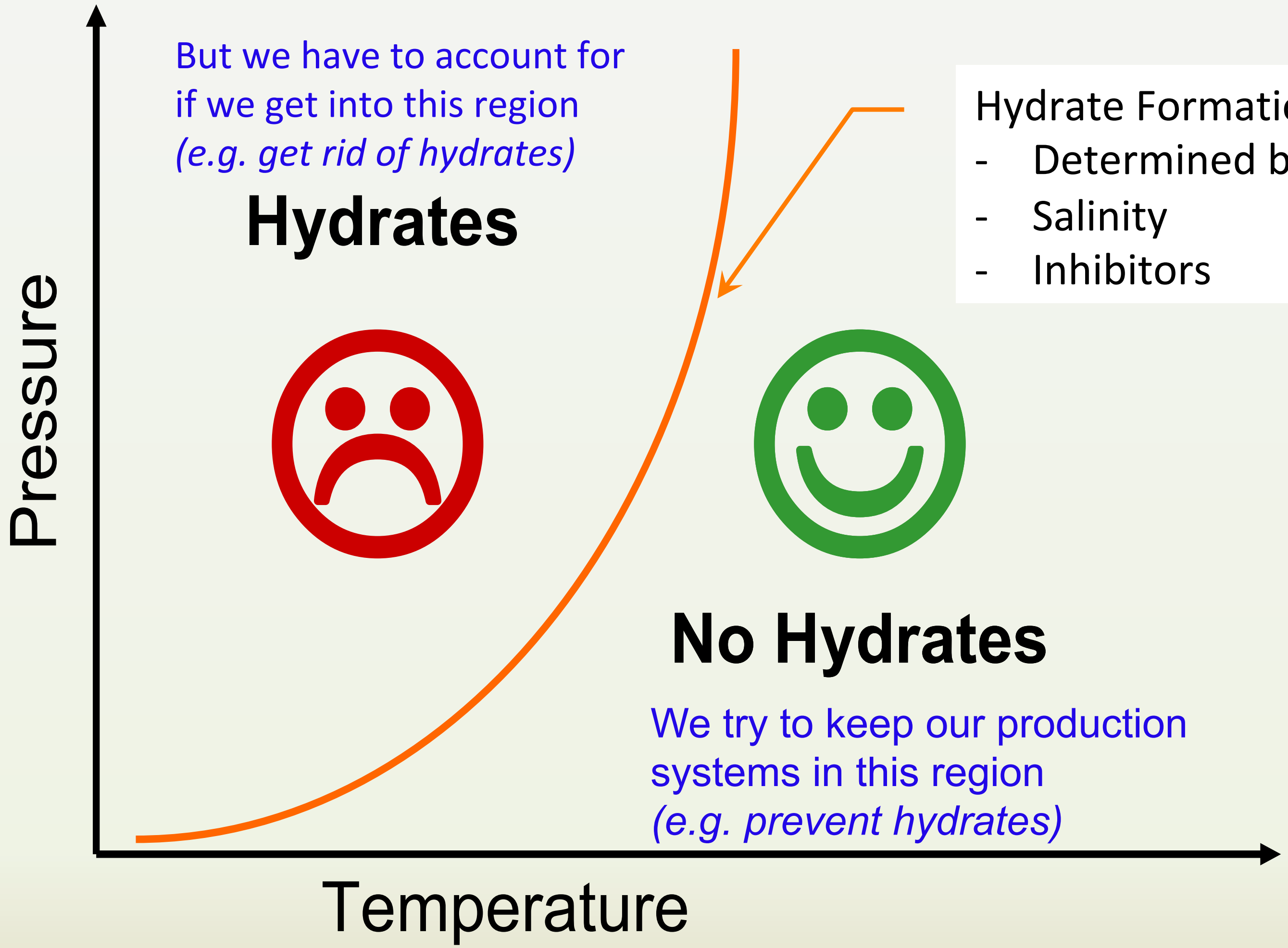
Crystalline “ice-like” solids composed of water & gas molecules

Requirements for Hydrate Formation

- To form hydrates requires four essential ingredients:
  - Natural **gas** components (e.g. methane, ethane, propane, CO2 ...)
  - A sufficient amount of **water**
  - The right combination of (low) **temperature** and (high) **pressure**
- Hydrate formation is enhanced by:
  - Presence of free water
  - Effective mixing
  - Solid surfaces to aid crystallisation
- But it does **not** require a free gas phase
- Hydrates can form in gas, gas-condensate and black oil systems, given the right conditions.



Defining the Hydrate Region



Hydrate Formation Curve:
- Determined by composition
- Salinity
- Inhibitors

Hydrate Control: The Principles

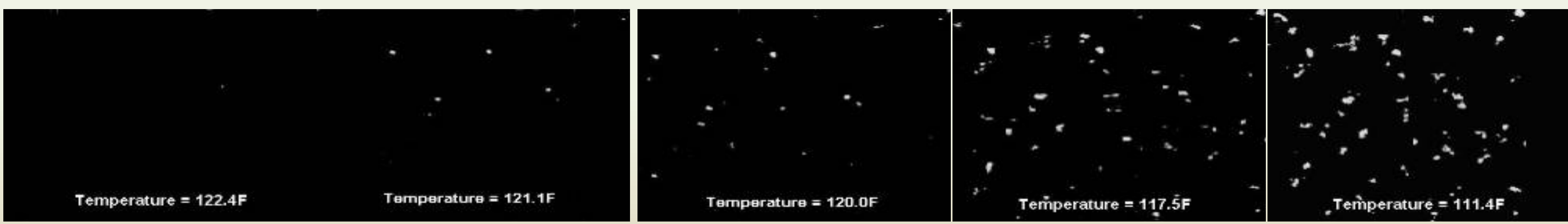
- Move the target conditions outside the hydrate region
  - Keep the system warm (insulation, heating)
  - Drop the pressure (depressurization)
- Shift the hydrate curve
  - Remove the water and/or gas (dehydration, displacement, bull heading)
  - Use thermodynamic inhibitors (methanol, MEG)
- Operate inside the hydrate region, but
  - Buy some time: kinetic inhibitors
  - Let hydrates form but not lead to a blockage: AA's
- Shut-in / restart issues will vary with the method chosen.

Hydrate Management Strategy

- Developments often rely upon a combination of tools. A common deep-water approach is to have:
  - Sufficient insulation to provide a reasonable no-touch time - Most shutdowns are <5 hours
  - A displacement strategy: Remove hydrate formers either as the system cools, or to minimise risk on start-up
  - Flood vulnerable locations with hydrate inhibitor chemicals: Injection of hydrate inhibitors during start up until flowing temperatures are re-established
- Remediation techniques are similar to prevention techniques
  - Depressurization
  - Chemical treatment
  - Thermal methods
  - Mechanical methods

Wax

- Long carbon chains become less soluble in oil as temperature falls in the system
- Wax Appearance Temperature (Cloud Point) is the temperature at which the first wax crystals appear. At the WAT solubility is exceeded and wax crystallizes. As the temperature continues to drop, more and more waxes crystallize
- Pour Point is the lowest temperature at which a crude oil can be poured under force of gravity
- Yield Stress (Gel Strength) is the force required to break down the wax structure developed below the pour point. It determines the pumping pressure required to restart flow in a line
- Wax Melting Point is the temperature at which solid wax melts - used to define the temperature to which pipe walls may need to be heated in order to remove solid deposits or sludge's



122.4 °F 121.1 °F 120 °F 117.5 °F 111.4 °F

Consequences of Wax Deposition

- **Blockages / restrictions in flowlines / risers / wells / pipelines**
  - Reduced system throughput
  - Increased system downtime
  - Effect can be catastrophic if planning is wrong
  - Tubing restrictions and impaired equipment operation
  - Increased Pumping pressure needs
  - Reduced revenue and removal costs

- **Reduction in equipment performance and risk to facilities**
  - Potential to impair valve operation and level controls
  - Produced water quality problems
  - Storage tank fouling
  - Increased pigging frequency

- **On shutdown**
  - Initial wax deposition rate increases because of localized effects
  - Later, rate drops as temperature approaches that of the pipe's wall
  - There is insufficient wax to block the pipeline with wax deposits
  - Wax crystals can combine into a matrix structure containing oil which can gel in the pipeline
  - Gel can be broken down on startup with sufficient pressure

Control of Wax Deposition

- **Management by Prevention or Avoidance**
  - Operate at above wax appearance temperature - Heat trace, insulate, preheat oil
  - Minimize heat transfer to reduce driving force to deposition - Insulation, burial
  - Deposition rate inhibitors, Thermodynamic inhibitors, Wax crystal modifiers, Dispersants/surfactants
- **Management by Removal**
  - Periodic mechanical removal - Pigging, increase shear stress (flowrate)
  - Periodic thermal removal - Hot oiling, hot solvent, heat line, chemical reaction
  - Chemical - Solvents and dissolvers, e.g. xylene
- **Monitoring for Wax deposition Direct/Indirect**
  - Look for evidence in cold dead spots e.g. waxed up instrument lines
  - Pigging- Measure DP when pig is in line, Examine evidence of solids in pig trap
  - Hot oiling - Measure temperature in and returning, wax content of incoming fluids
  - Chemicals - Confirm chemicals perform under some field conditions but not a universal panacea

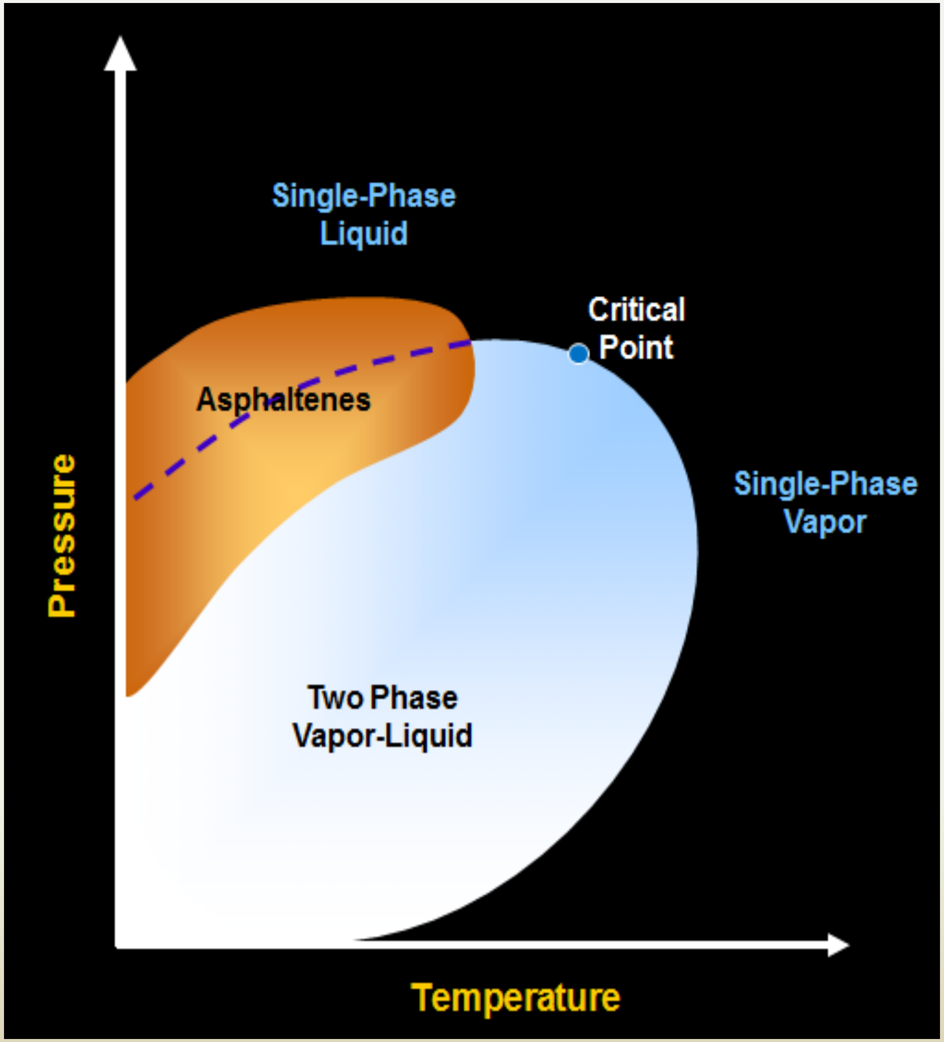
Asphaltenes

- Asphaltenes are dark brown to black solids
- Do NOT melt, unlike waxes
- Can form due to:
  - Drop in pressure (When reservoir pressure below bubble point)
  - Change in composition – mixing of different fluids miscible flood with CO_2 or natural gas, gas lifting
- Very soluble in aromatic compounds, e.g. xylene
- In general, a low asphaltene content crude oil has a higher potential for asphaltene deposition than a high asphaltene content crude oil
- Fluid specific, Relatively rare
- Identify by Lab work or Statistical – De Boer Plot
- Lack of reliable precipitation/deposition models available

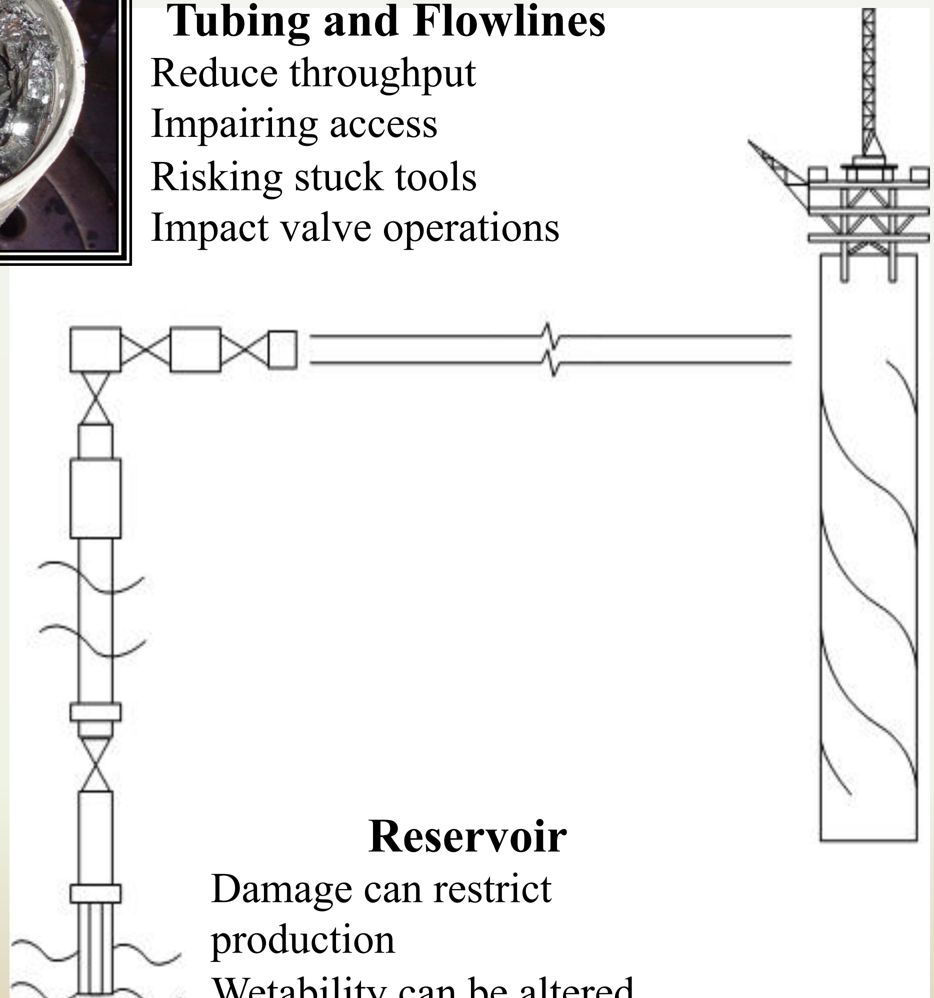
Asphaltenes – Phase Behavior

Asphaltene flocculation envelopes may take up a variety of shapes and sizes depending on the composition of the asphaltene micelles and, more importantly, the host oil. The asphaltene flocculation envelope often extends into both the single-phase and two-phase regions of the typical phase diagram.

Since the boundaries of the envelope is often unknown, subsurface sampling is recommended.



Where Can Asphaltenes Precipitate?

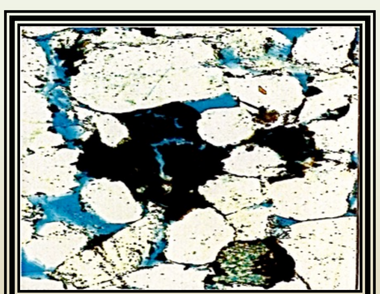


Tubing and Flowlines

Reduce throughput
Impairing access
Risking stuck tools
Impact valve operations

Production

Where incompatible fluids mix
- Chokes
- Vessels
- Export Lines



Reservoir

Damage can restrict production
Wetability can be altered

Asphaltene Remediation

- Operations
  - Operational Change
  - Pigging
  - Coiled Tubing
  - Wireline Cutting
- Solvents
  - Periodic Aromatic Flushes (e.g. Xylene)
  - Common use for production tubing deposits
- Inhibitors or dispersants
  - Injection in production tubing
  - Squeeze applications
  - Use via lift gas

Scale

- Scale is a deposit of inorganic mineral components of water
- Formed in two ways:
  - Precipitate out from brine as is changes in temperature and pressure
  - Precipitate out when two incompatible waters e.g. seawater (rich in sulphates) and formation water (rich in calcium, strontium and barium) mix – generally sulphate scales
- Common Types:
  - Calcium Carbonate, $CaCO_3$ - Most commonly occurring scale, often occurs with pressure drop, Solubility decreases with increasing temperature
  - Calcium Sulfate - Gypsum, $CaSO_4 \cdot 2H_2O$ associated with lower temperatures, or Anhydrite, $CaSO_4$ - associated with higher temperatures
  - Barium Sulphate, $BaSO_{4}$ - Extremely insoluble, Likely to form at low concentrations of species, Solubility increases with increasing temperature, often found in conjunction with Strontium and Radium (radioactive & leads to disposal issues)
  - Strontium Sulfate, $SrSO_4$ - Similar to Barium Sulphate, but twice as soluble
  - Iron compounds, Iron comes from formation water &/or corrosion, may form carbonates, sulphides even hydroxides

Scale Operational Problems

- Suspended scales may cause formation plugging
- Adherent scales can restrict flow in pipes and damage equipment, e.g. pumps
- Corrosion and microbial activity may be accelerated under scale deposits
- Scaling maybe encountered if injection water is incompatible with formation water
- HP/HT reservoirs – typically have:
  - TDS = 300,000+ ppm
  - Temperature > 350^{o}F
  - Pressure > 15,000 psi

Managing Scale Problem

- Treat to prevent deposition using scale inhibitors
  - Added upstream of problem area
  - Present on a continuous basis
- Allow scale to form and remove it periodically
  - Chemically
  - Mechanically
- Pre-treat to remove dissolved and suspended solids
  - Ion exchange, filtration …

Corrosion

- **Corrosion:**
  - Reaction of carbon steel with CO_2 in the presence of water
  - Reaction of carbon steel with H_2S (hydrogen induced cracking and sulphide stress corrosion cracking)
  - Corrosion rates increase significantly at higher temperatures temperature Operational Problems – material loss leading to leaks / rupture, replacement of piping / pipeline
- **Identify Problem** - Monitor material loss / wall thickness, examine solids produced from pipelines and present in vessels (iron counts in water), model anticipated corrosion rate
- **Manage Problem** - Select materials of construction, minimize pockets / dead legs in system design, chemical inhibitors

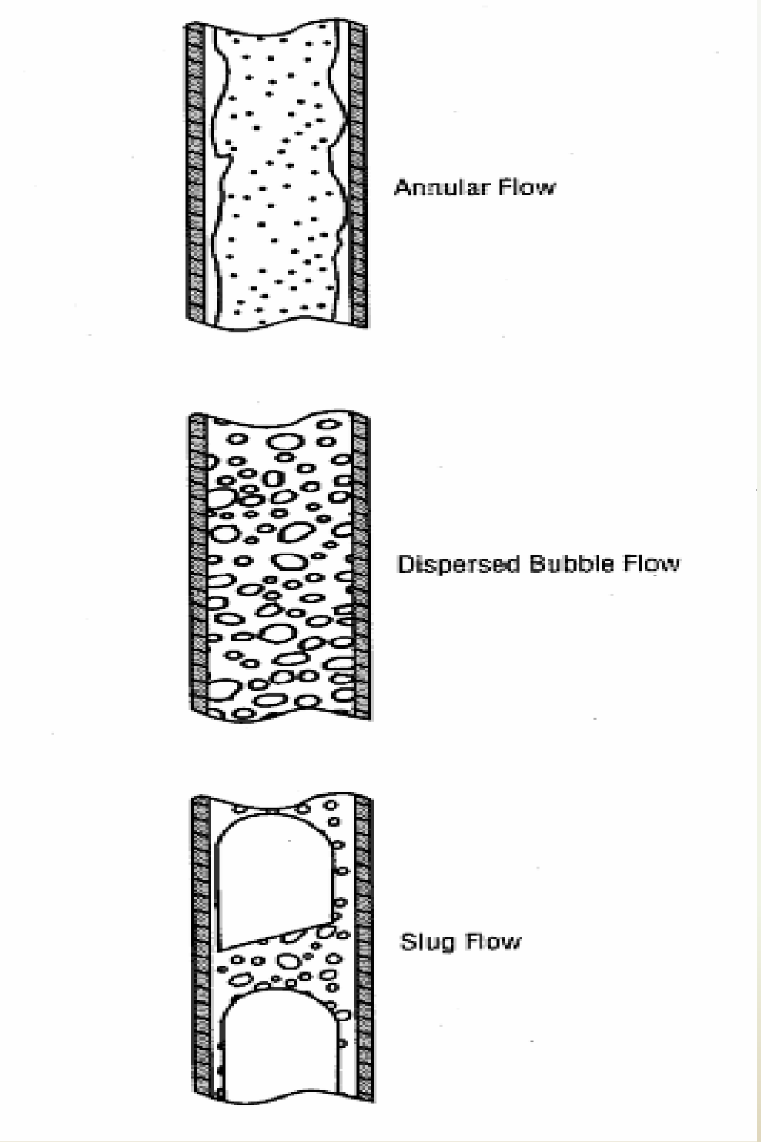
Main FA Hazard Areas

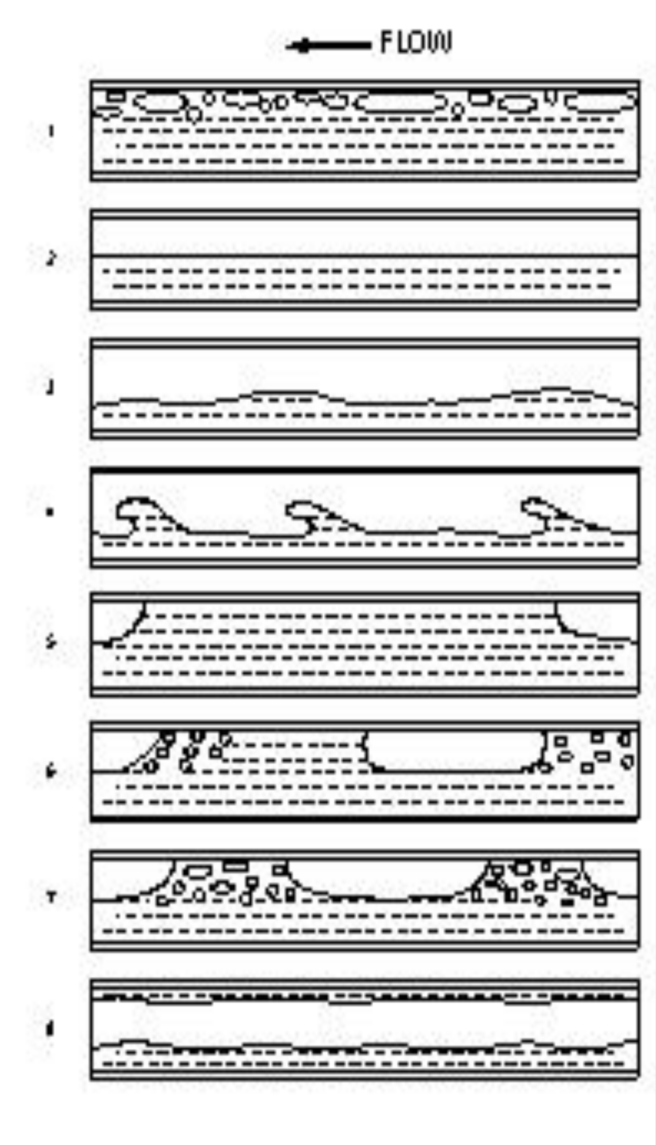
- **Reservoir** - Asphaltenes and scales
- **Wellbore** - Scales, asphaltenes and paraffin waxes
- **Trees & Manifold** - Hydrates, scales and paraffin waxes
- **Flowline /Riser** - Hydrates, paraffin waxes and pour point
- **Processing facilities** - Hydrates, scales and separation (emulsions)

Hydraulics - Flow Types

- **Single Phase Flow**
  - Liquid - incompressible
  - Gas - compressible
- **Two - Phase Flow**
  - Liquid and Gas
- **Multiphase Flow**
  - Liquid and Gas, plus water

Multiphase Flow





Bubble flow

Stratified - smooth

Stratified - wavy

Stratified – rolling waves

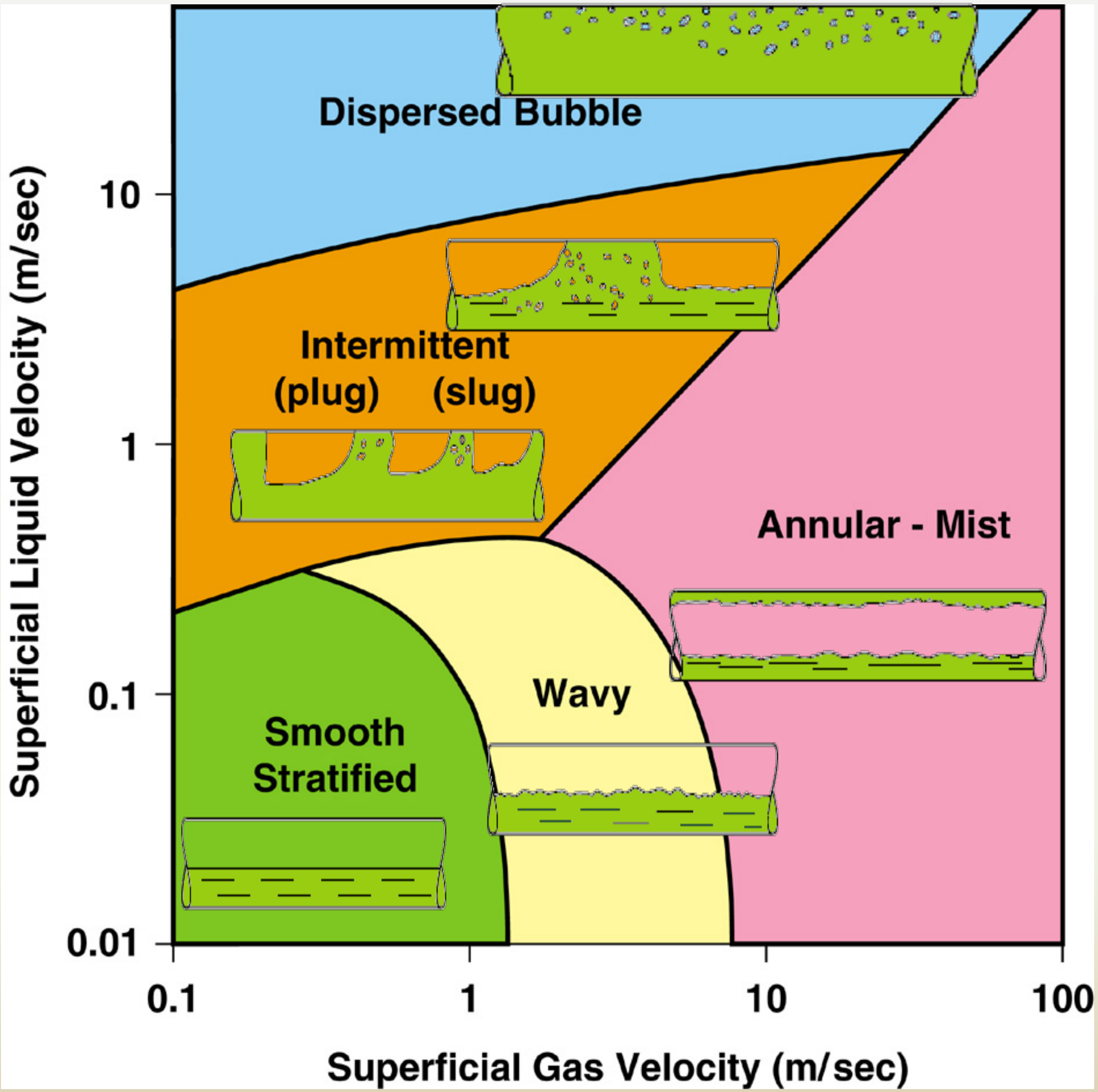
Plug flow

Slug flow

Pseudo-slug flow

Annular

Multiphase Flow Regimes



- The superficial velocity, is the velocity the phase would have occupied the entire cross sectional area of the pipe
- Which flow pattern occurs depends on the in situ flowing velocity of the gas and liquid phases
- Different flowmaps for Vertical, Horizontal, Downhill etc.

Multiphase Hydraulics

The total pressure drop over a pipeline system, ΔP_T is given by:

$$\Delta P_T = \Delta P_f + \Delta P_{el} + \Delta P_{acc}$$

where:

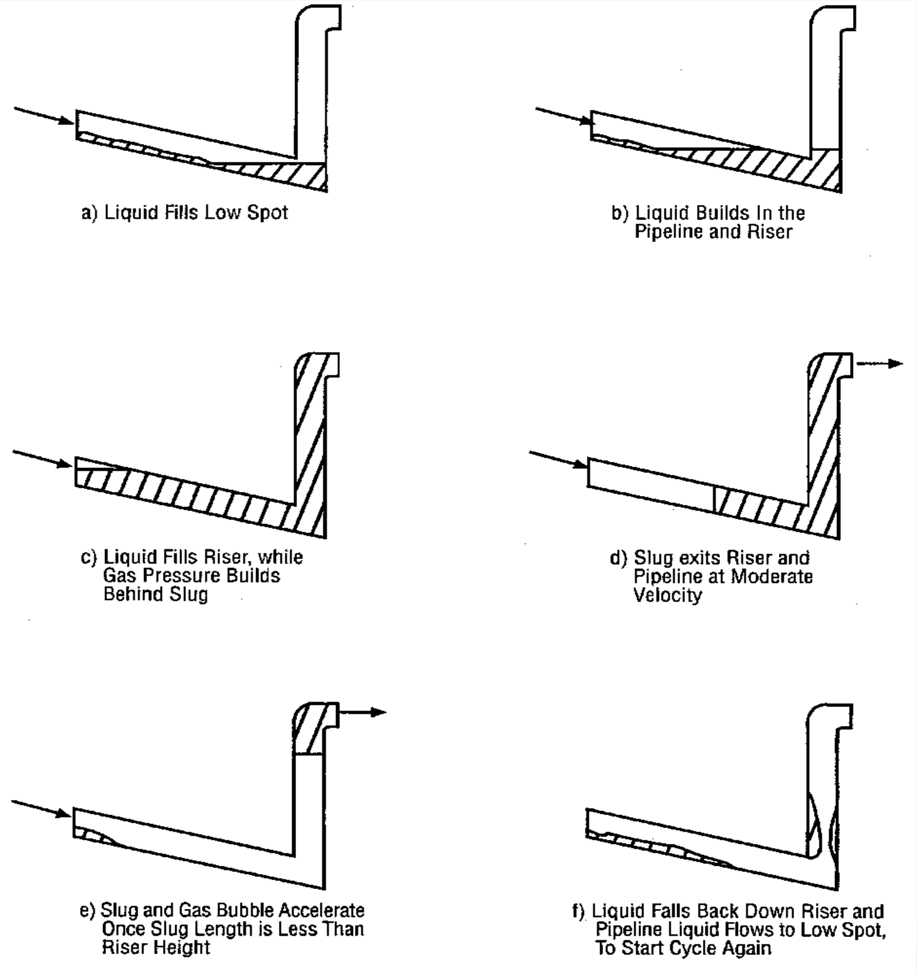
ΔP_f = frictional pressure loss

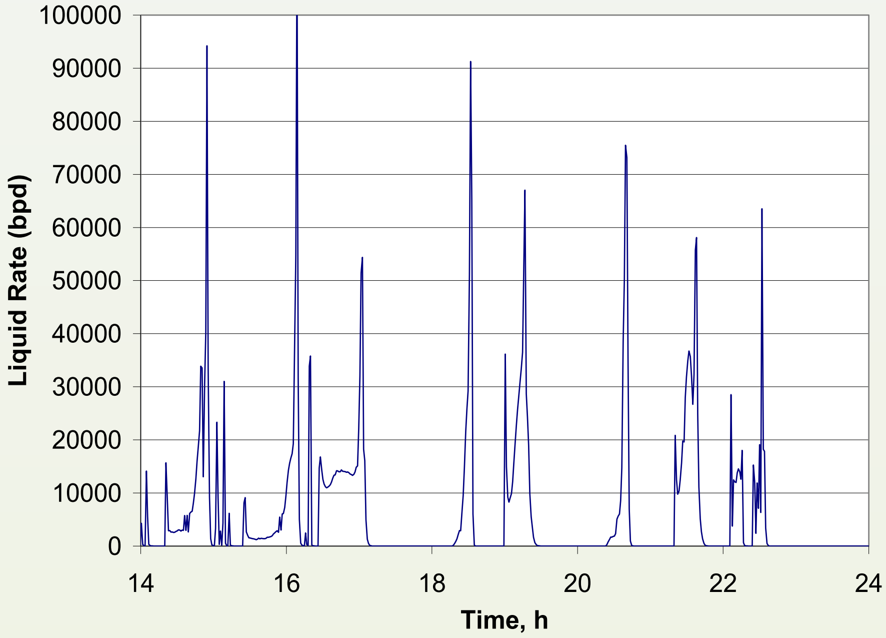
ΔP_{el} = pressure drop caused by elevation changes

ΔP_{acc} = pressure drop required to accelerate fluids eg at a change in cross-section. This is usually small unless at high velocity.

- In most 2-phase pipelines the gas travels faster than the liquid, under these conditions there is said to be slippage between the phases. For multiphase flow pressure drop computations, there are 2 models used to predict pressure drop:
  - homogeneous flow (no-slip model)
  - separated flow (slip model)
- Both use an analogous calculation method to that used for single phase flow
- Liquid hold-up H_L has a major influence on the type of flow that will occur & pressure drop
- The value of H_L is normally determined by use of an empirical correlation
- This calculation is complex routinely done by software packages rather than by hand!

Slugging – (terrain or riser base)

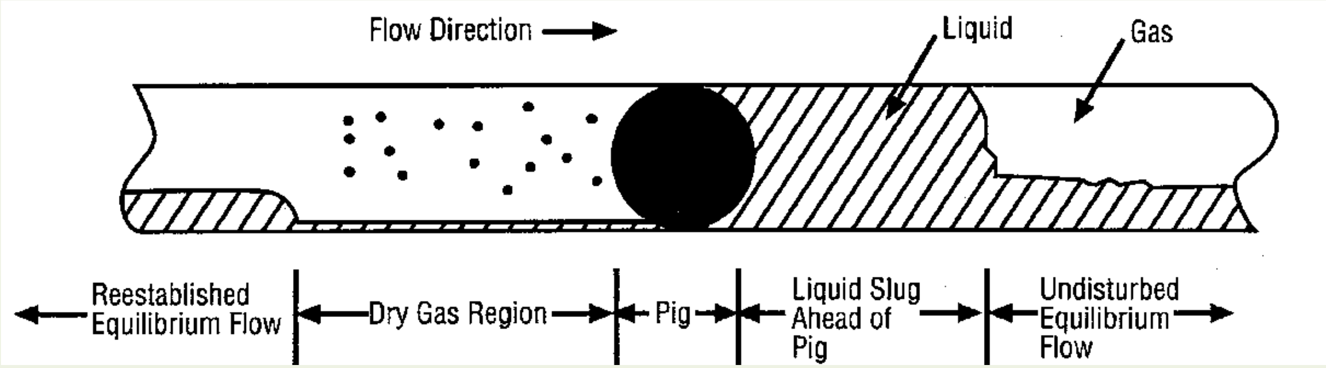




Slugging Issues

- May severely affect downstream process facilities: Trip HIPPS, flood separators and starve compressors
- May increase corrosion/erosion rates
- Can cause vibration problems in piping
  - Hydrodynamic Slugging
  - Terrain Slugging
  - Pigging
  - Rate Changes
  - Startup

Slugging Due to Pigging

- A pig, dropped near entrance of line, sweeps liquid from pipeline
- Pigging slugs very large in gas/condensate pipelines
- 

Velocity Guidelines

- Maximum design velocity:
  - API RP 14E outdated
  - Sand Erosion Limits – University of Tulsa, Salama (Erosion on pipe bends), etc – 0.1mm/yr target erosion rate
  - Corrosion Inhibitor stripping ~ 70 ft/s
  - Droplet Erosion – 230 ft/s (DNV)
- Minimum velocity limits are also important as:
  - Water may accumulate at low spots and the risk of corrosion increases if CO_2 or H_2S are present
  - Liquid holdup may increase at low mixture velocities and accumulations of liquid may cause problems if the line is pigged or the flow rate is changed rapidly
  - Low velocities may cause slugging in hilly terrain and riser systems
  - Sand Deposition – stuck pigs, possible corrosion

Thermal Modeling

- Temperature prediction is important:
  - Influences the physical characteristics of the fluid and the depositional potential e.g. hydrate formation, wax deposition etc.
  - Corrosion is also a strong function of temperature
  - In gas/condensate lines temperature loss due to Joule-Thomson (J-T) expansion can be significant, resulting in operating temperatures lower than the surrounding ambient temperatures
  - In many oil systems the temperature change due to J-T expansion is positive

System Thermal Design

- The following information is required:
  - System configuration, including coating, insulation and burial details (applies to wells and pipelines)
  - Material properties, i.e. thermal conductivity, density and specific heat capacity
  - Ambient environmental fluid details, including temperature and velocity
- Then possible to calculate the overall heat transfer for the system, U value using:

$$\frac{1}{u} = \frac{1}{h_{in}} + \frac{1}{L_1 / k_1} + \frac{1}{L_2 / k_2} + \ldots + \frac{1}{h_{ex}}$$

$Q = U\ A\ \Delta T_{lmtd}$ $\qquad$ $Q = m\ C_p\ \Delta T$

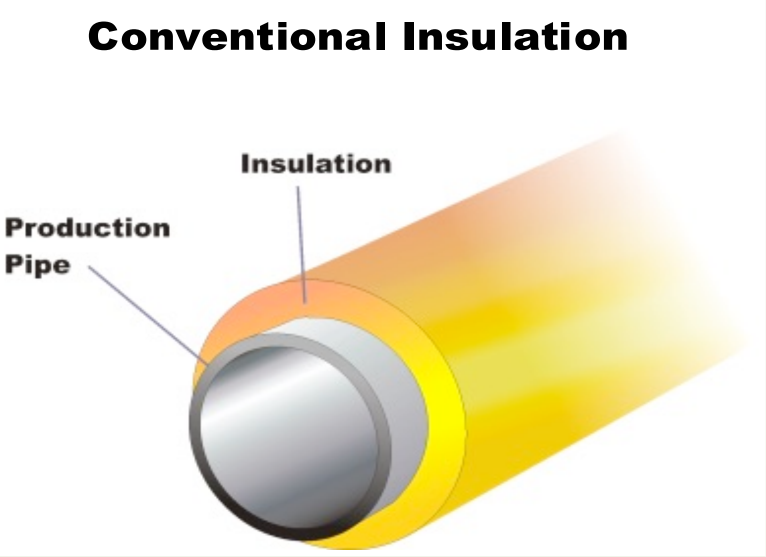
Insulation Drivers

- Insulation may be provided for one or more of the following reasons:
  - Avoid or limit hydrate formation (cooldown time)
  - Avoid or limit wax deposition
  - Minimize oil or emulsion viscosity to avoid excessive pressure drop
  - Maintain fluids warm enough to avoid or limit the requirement for heating at the processing plant

Insulation Systems - Passive

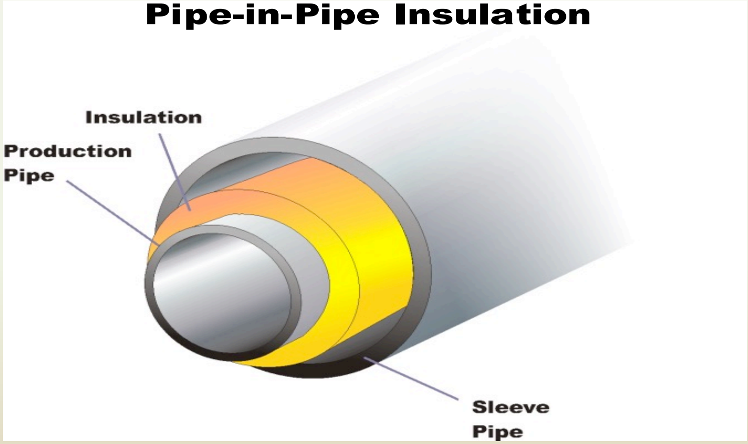
Wet Insulation

- Typical U Values: 0.4 – 0.6 Btu/ft²/hr/°F



Dry Insulation

- Pipe-in-Pipe System
- Typical U Values: 0.1 - 0.2 Btu/ft²/hr/°F

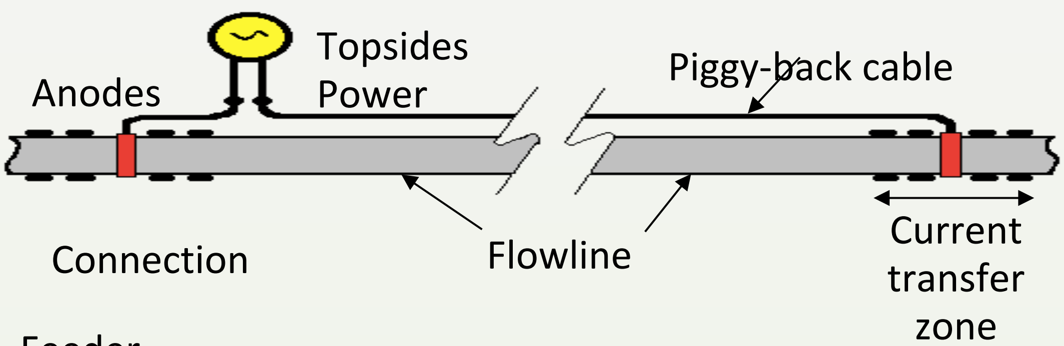


Buried Pipe

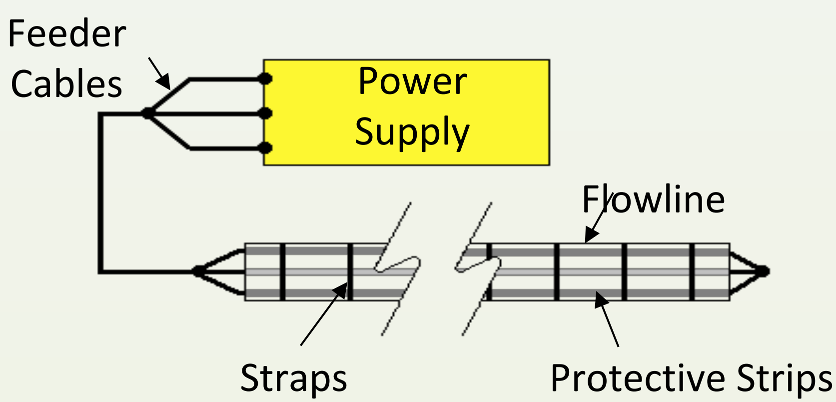
- Typical U Values: 1 - 2 Btu/ft²/hr/°F

  (depends on soil type & burial depth)

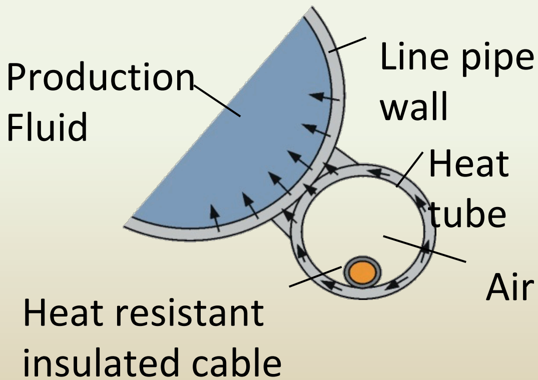
Electrical Heating Systems



Direct Electrical Heating (DEH) - Heat is generated by resistance when an AC current flows through a metallic conductor

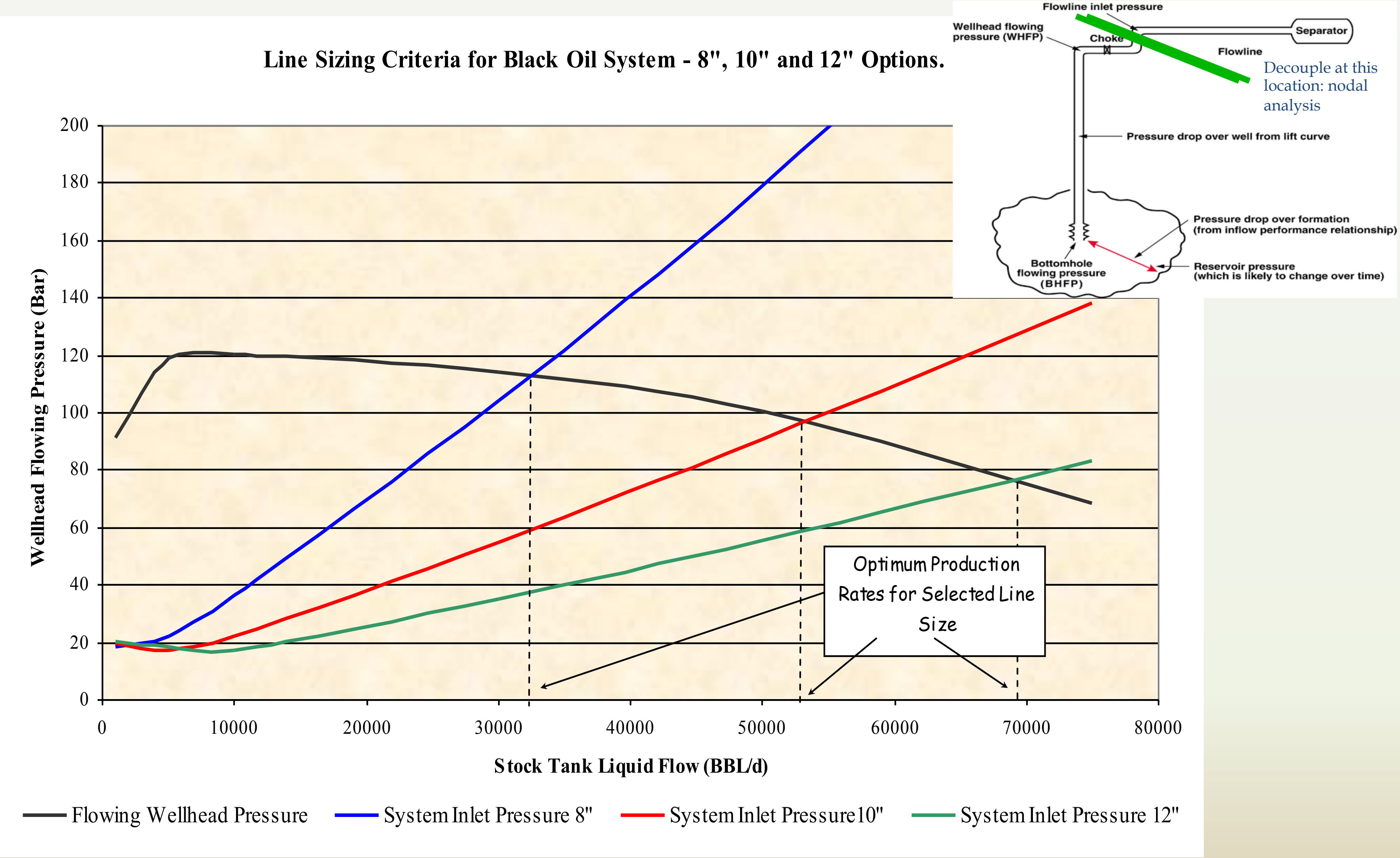


Indirect Heating – Electric current flow through a heating element attached to the pipe

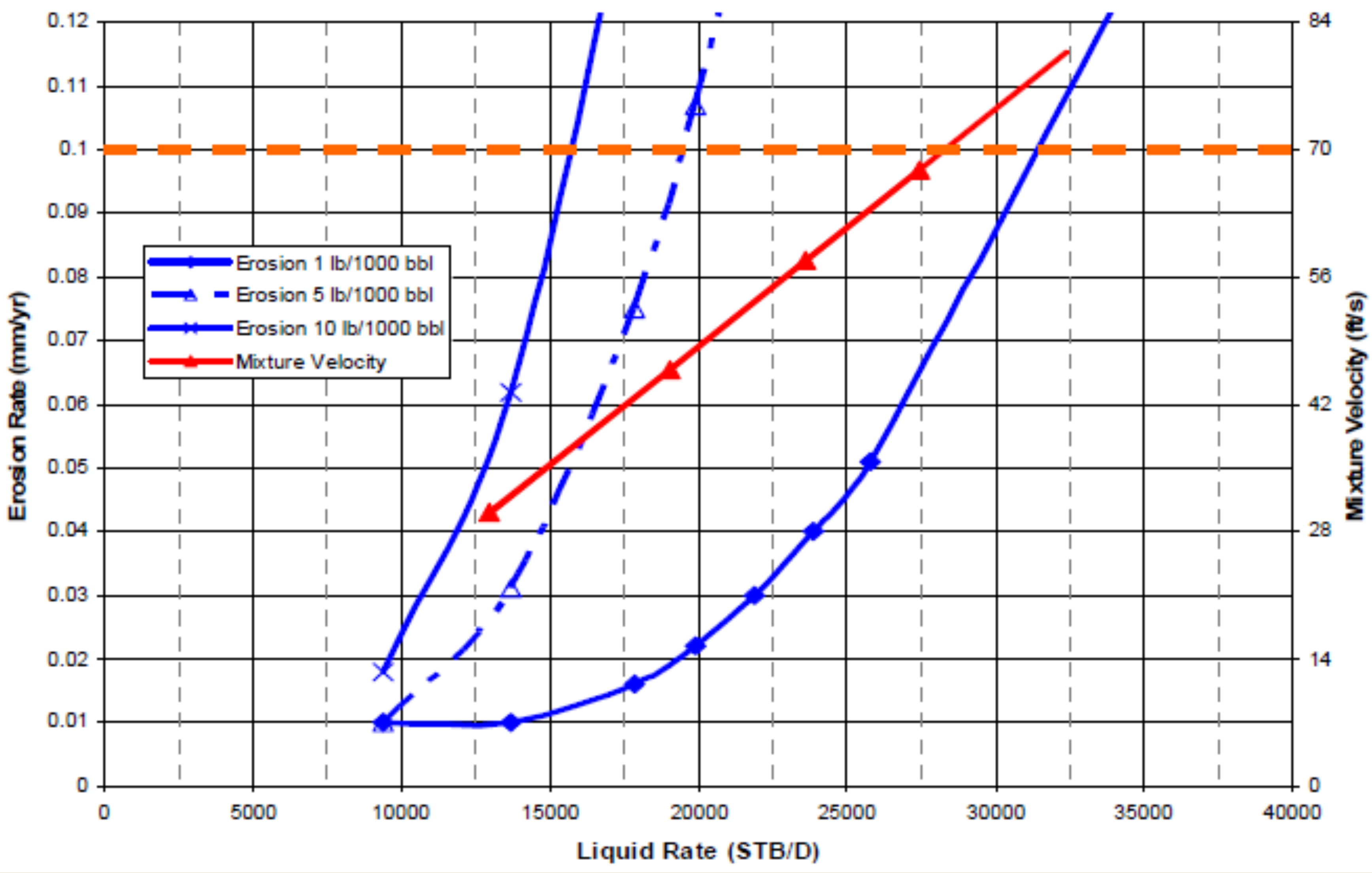


Skin Effect Trace Heating - AC current flows through the heat cable generates heat by skin effect. The heat is then transferred to the production line at the points of contact of the steel tube with the flowline

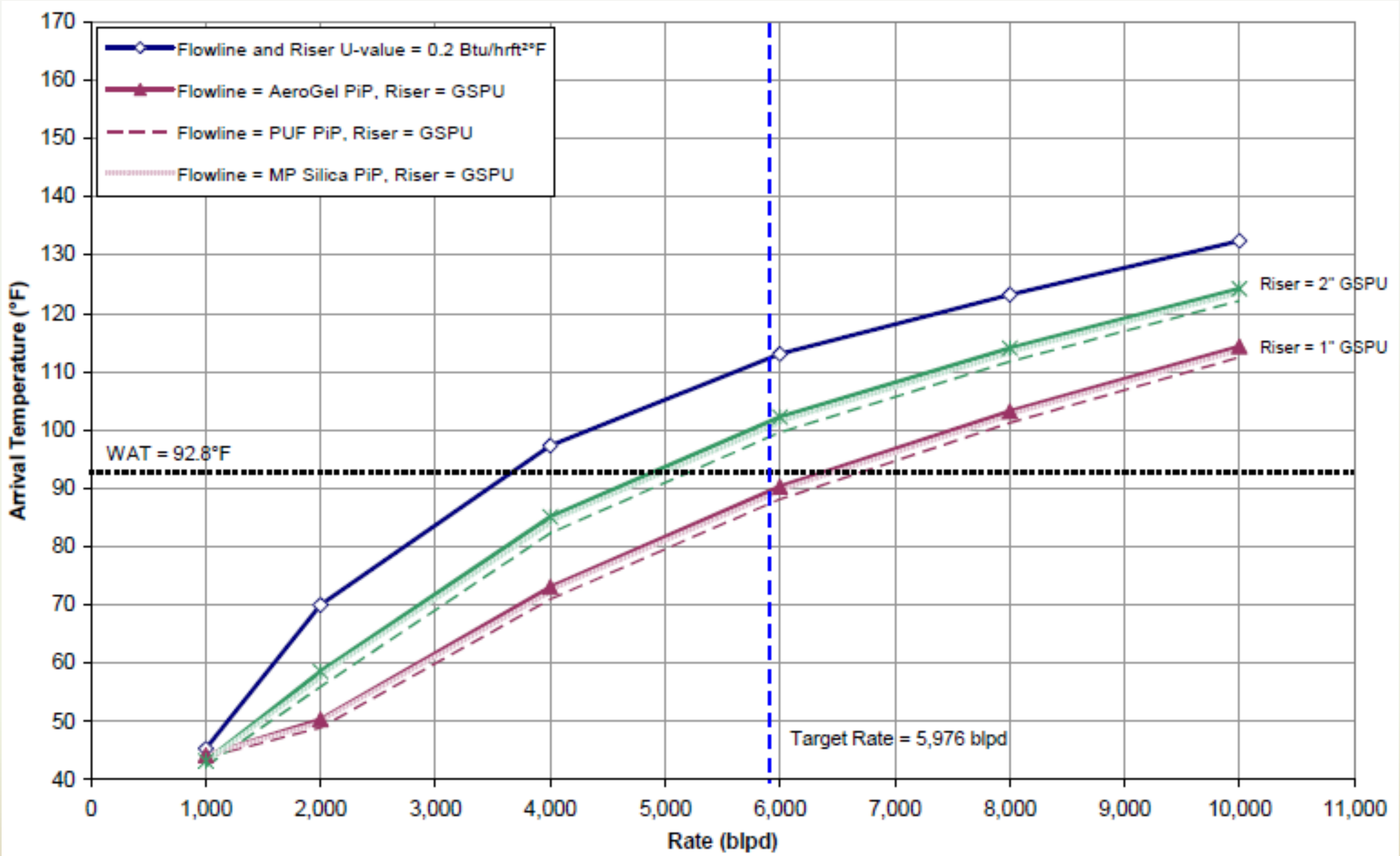
Flow Assurance Design – Line Sizing



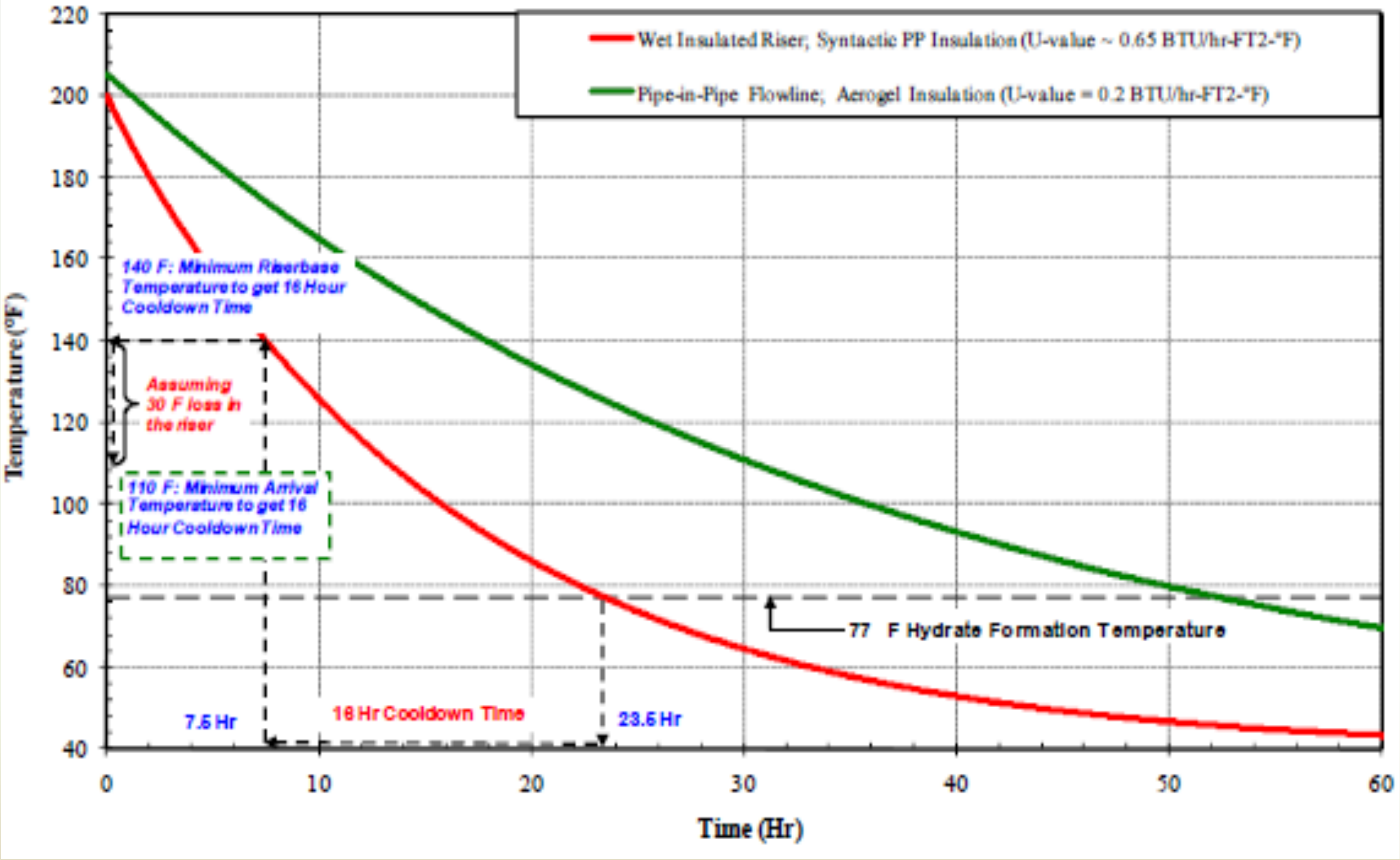
Flow Assurance Design – Max Flow



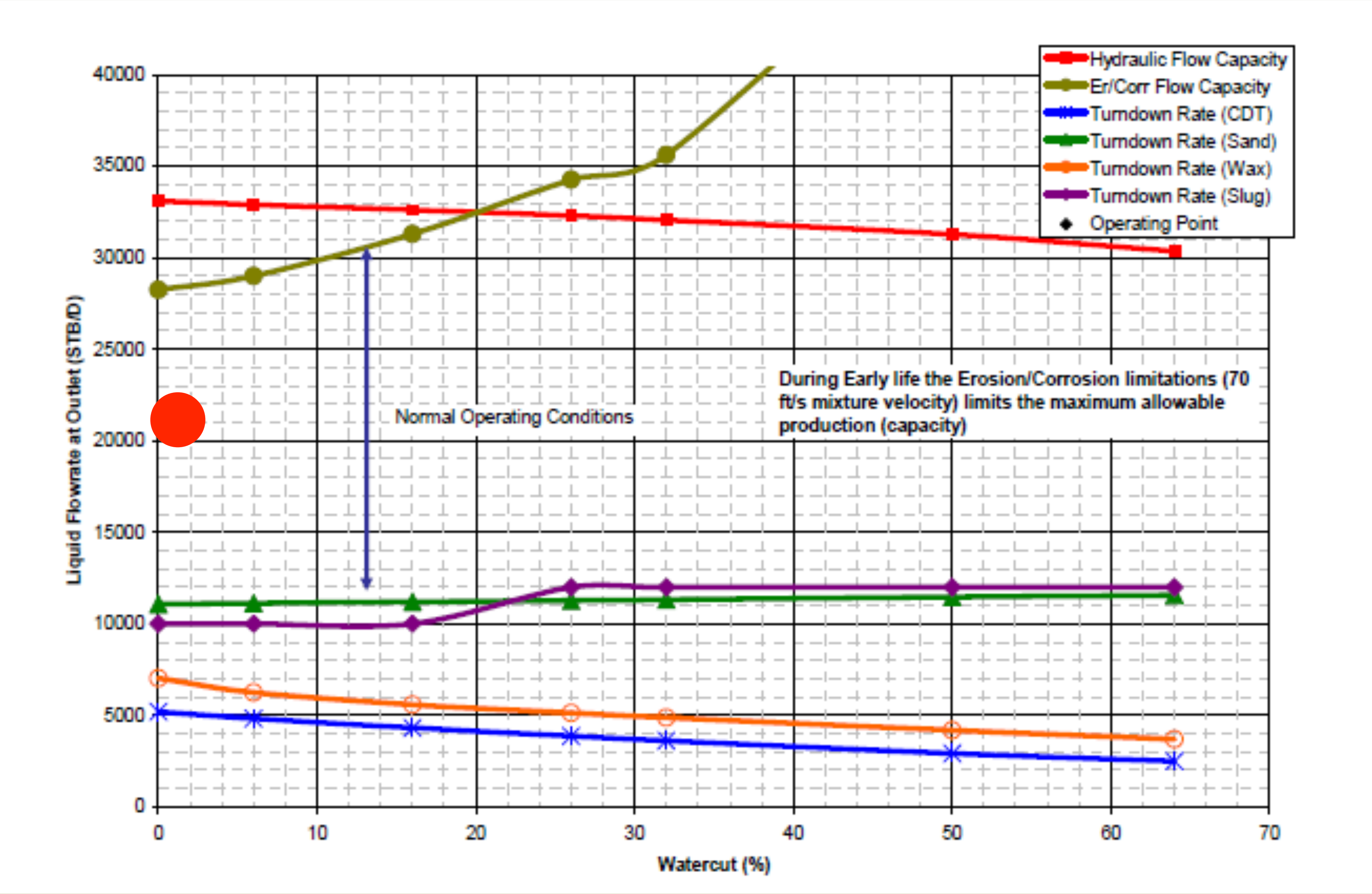
Flow Assurance Design – Thermal Performance – Steady State



Flow Assurance Design – Thermal Performance - Cooldown



Flow Assurance Design – Operating Envelope



Flow Assurance Design - Other Limitations

- SITHP – used to define system design pressure
- High temperature
  - Issue with coatings, riser flexjoints at high temperatures
  - CO_2 corrosion of carbon steel increases with temperature
- Low temperature, the main areas of concern are:
  - Hydrate formation
  - Wax deposition
  - High viscosities of some crudes and some oil/water emulsions
  - Material limits Chilly choke

Flow Assurance Design - Transient Operations (1)

- Transient simulations are performed to model abnormal operations such as:
  - Start-up (including well cleaning, J-T expansion cooling, …)
  - Shutdown (including depressurization, dead oil displacement, …)
  - Pigging
  - Rate changes
  - Slugging
  - Well testing
  - Pressure surges
  - Leaks and ruptures
- Both transient hydraulic and thermal aspects are modelled
- A range of the software packages available was presented later

Flow Assurance Design - Transient Operations (2)

- Start-Up – the main issues are:
  - Length of time required for hydrate mitigation, considering:
    - Start from ambient cold earth conditions
    - Restart from non-ambient (warm) conditions
  - Slugging: volumes displaced and time to stabilize flow
  - Single well start-up
  - Subsequent well start-up

Flow Assurance Design - Transient Operations (3)

- Shutdown and associated operations – the main issues are:
  - Length of time taken to fall within the hydrate formation region
  - Evaluation of various hydrate mitigation techniques, e.g. blowdown (depressurization), dead oil displacement, jumper flushing, heating systems etc.
- Rate changes (turndown and ramp-up) – the main issues are:
  - Time taken to re-stabilize flow, i.e. reach new steady state liquid holdup
  - Estimate of liquid volumes displaced, to size reception facilities

Flow Assurance Design - Transient Operations (4)

- Pigging transients – also used to size reception facilities or to define operating procedures
- Pressure surge transients – to ensure adequate design pressure of systems or to define the operating procedures (akin to water hammer in a water injection system)
- Leaks and rupture – used to assess safety and environmental risks and hazards

Other Flow Assurance Design Areas

- Wax deposition modelling
- Compositional tracking scenarios
- Chemical dosage rates & chemical qualification
- Chemical/material compatibility
- Umbilical sizing, injection locations
- Evaluation of boosting options – MPP, Gas Lift
- Process data for other engineering disciplines
- Input to operating procedures

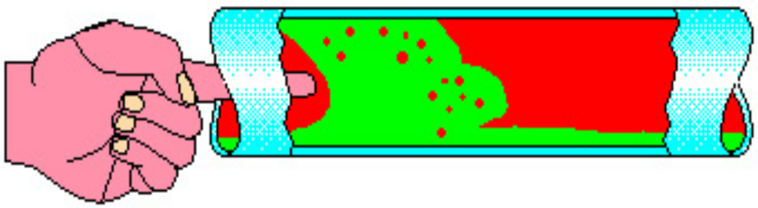
Software Tools

- **Fluid Characterization:**
  - PVTsim (CalSep)
  - Multiflash (InfoChem)
  - GUTS (MSI)
  - Some specialized software for Corrosion, Wax, Scale, Asphaltene

- **Hydraulic & Thermal Analysis:**
  - **Pipesim** (Multiphase Steady State)
  - **OLGA** (Multiphase Steady State and Transient)
  - Hysys/Unisim
  - Stoner (Single Phase Gas & Liquid Transients)
  - LedaFlow (Multiphase Steady State and Transient)
  - Pipephase (Steady State)

Key Technical Issues in Flow Assurance

Energy

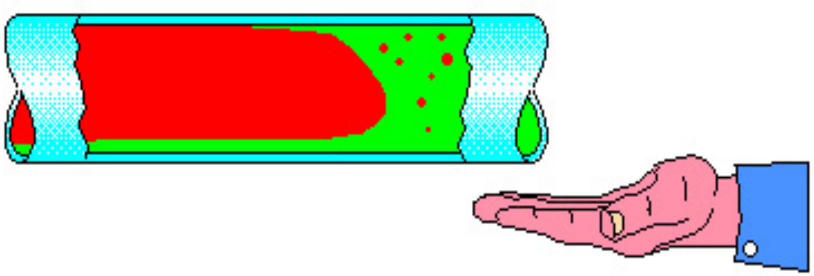


- Integration to reservoir performance.
- Boosting method selection.
- Gas lift.
- Pressure/temperature drop prediction

Integrity

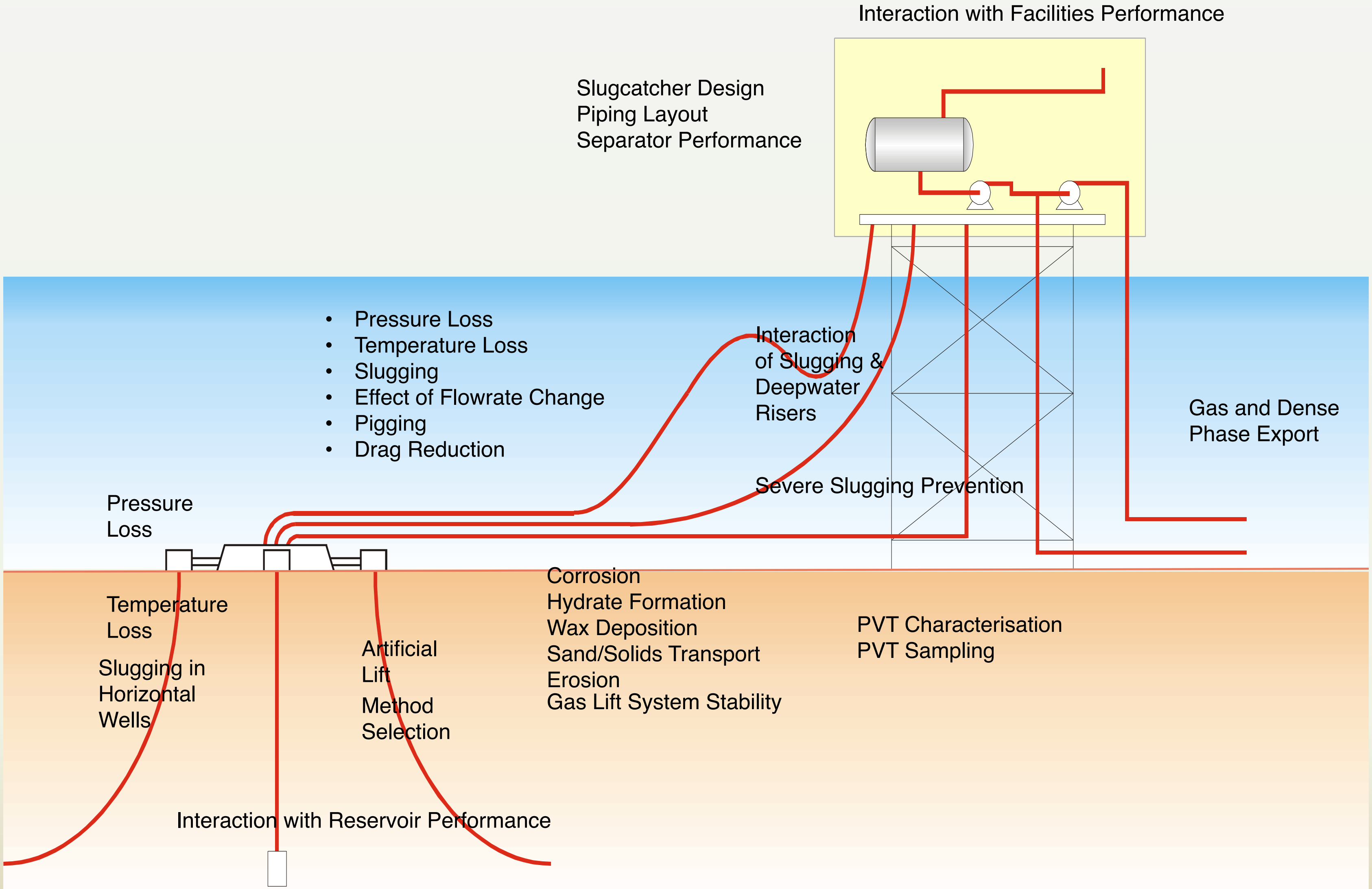
- Corrosion.
- Wax.
- Scale.
- Hydrates.
- Mechanical loads.

Delivery

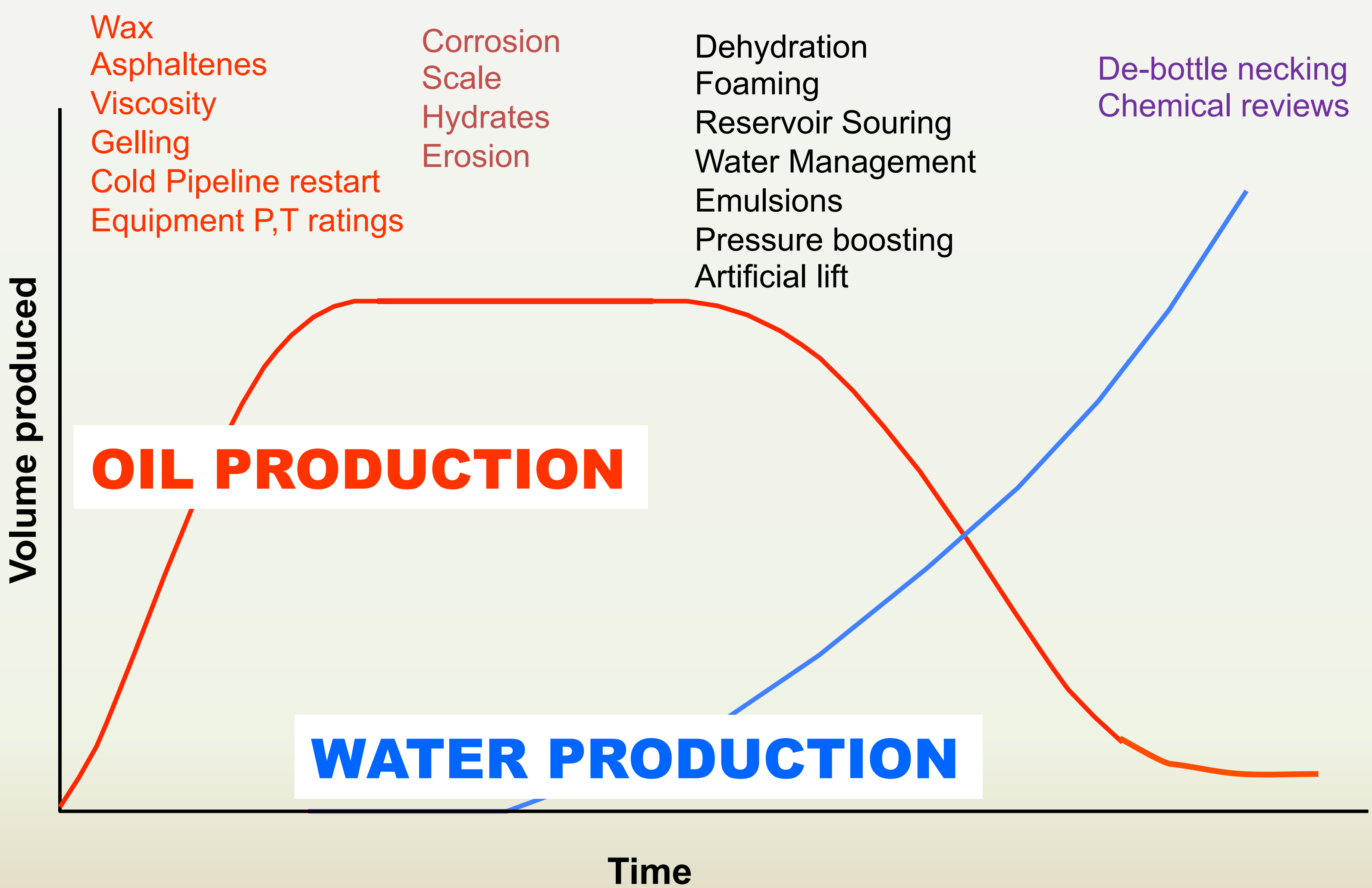


- Integration with process.
- Transient/steady state.
- Slug prediction.
- Slugcatchers.
- Effect of risers.
- Dynamic simulation.

Typical Production System – Flow Assurance Issues



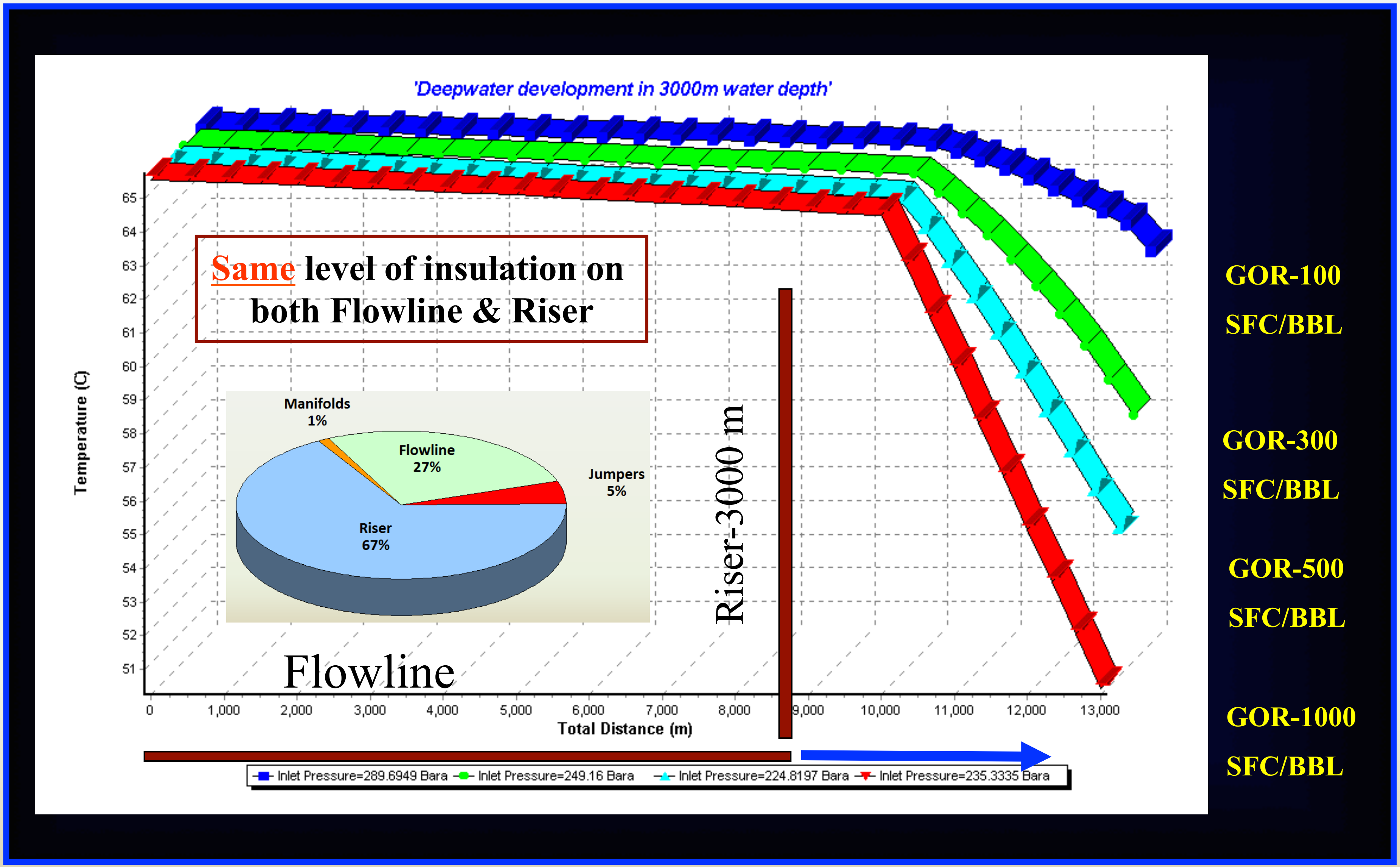
Fluid Related Concerns Throughout Production Life



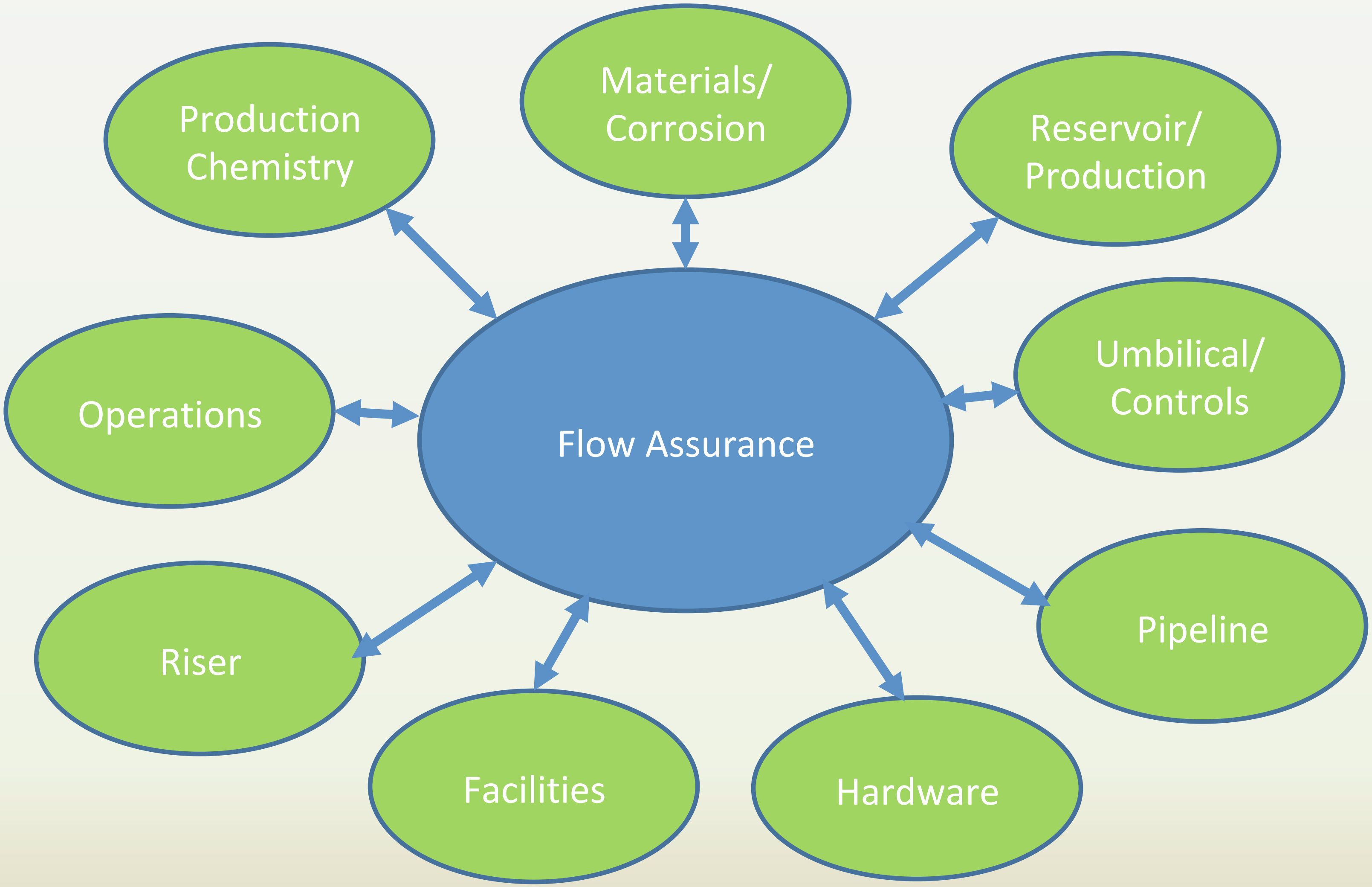
Flow Assurance for Deepwater

- Lower Seabed ambient temperatures, large riser temperature loss – better insulation systems
- Deepwater Column (higher hydrostatic pressure) – can’t depressurize must displace, longer tiebacks may need heated systems
- Remediation costs are very high – Flow Assurance becomes critical

Deepwater Development in 3000 m Water Depth
(Heat Loss In Riser Sections)



Flow Assurance Design – Interfaces



Flow Assurance has many interfaces with other engineering disciplines and is involved from concept development to first oil and operational support

Questions