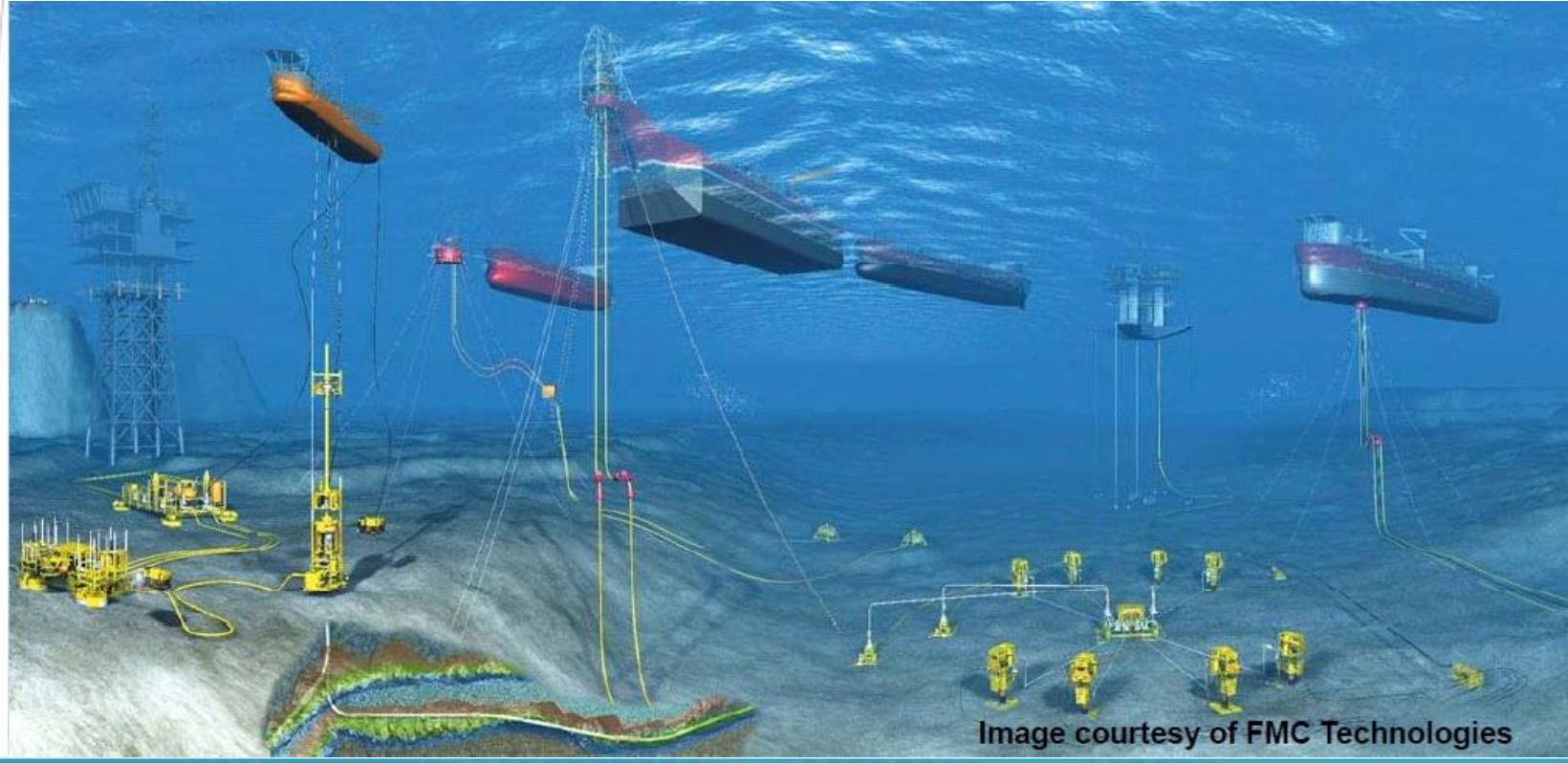


Introduction to Offshore Platform Engineering

Yutaek Seo

HW 2. Thickness

- Internal pressure 4,000 psi, 16” OD, X-65 grade pipe
- For pipeline, DF = 0.72

$$t \geq \frac{4{,}000 \times 16}{2 \times 65{,}000 \times 0.72} = 0.684''$$

- For riser, DF = 0.5

$$t \geq \frac{4{,}000 \times 16}{2 \times 65{,}000 \times 0.5} = 0.985''$$

HW 2. Collapse check

- Internal pressure = 4,000 psi, water depth 3,000 ft (1,333.3 psi), 16” OD, 0.684” wall thickness, X-65 grade seamless pipe, E = 29,000,000, M = *v* = 0.3

$$\left| P_o - P_i \right|_{max} \le f_o P_c$$

$$P_c = \frac{P_y P_e}{\sqrt{P_y^2 + P_e^2}}$$

$$P_y = 2S\left(\frac{t}{D}\right)$$

$$P_e = 2E\frac{\left(\frac{t}{D}\right)^3}{(1-v^2)}$$

$$P_y = 2 \times 65{,}000 \times \left(\frac{0.684}{16}\right) = 5{,}558\,\text{psi}$$

$$P_e = 2 \times 29{,}000{,}000 \frac{\left(\frac{0.684}{16}\right)^3}{(1-0.3^2)} = 4{,}980\,\text{psi}$$

$$P_c = \frac{5{,}558 \times 4{,}980}{\sqrt{5{,}558^2 + 4{,}980^2}} = 3{,}709 \text{ psi}$$

$$f_o P_c = 0.7 \times 3{,}724 = 2{,}596 \text{ psi}$$

$$P_o - P_i = 1{,}333.3 - 0 = 1{,}333.3\,\text{psi} \quad \text{during installation (empty pipe)}$$
$$P_o - P_i = 1{,}333.3 - 4{,}000 = -2{,}666.7\,\text{psi} \quad \text{during operation}$$

Collapse check is only OK during installation (i.e. empty pipe)
During operation, Po-Pi = 2666.7 > 2596 psi.
But there will be no burst due to external pressure.

HW 2. Buckle propagation check

- Internal pressure = 4,000 psi, water depth 3,000 ft (1,333.3 psi), 16” OD, 0.684” wall thickness, X-65 grade seamless pipe,

$$P_p = 24\,S\left[\frac{t}{D}\right]^{2.4}$$

If $[P_o - P_i]_{max} \geq 0.8\,P_p$ then, buckle arrestor is required

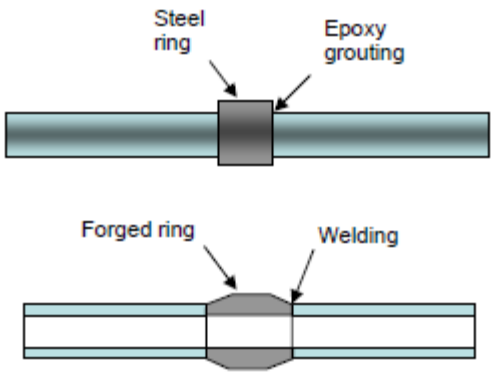
Therefore,

$$P_p = 24 \times 65{,}000\left[\frac{0.684}{16}\right]^{2.4} = 808\,\text{psi}$$

$$0.8\,P_p = 0.8 \times 808 = 646\,\text{psi}$$

$$[P_o - P_i]_{max} = 1{,}333.3\,\text{psi}$$

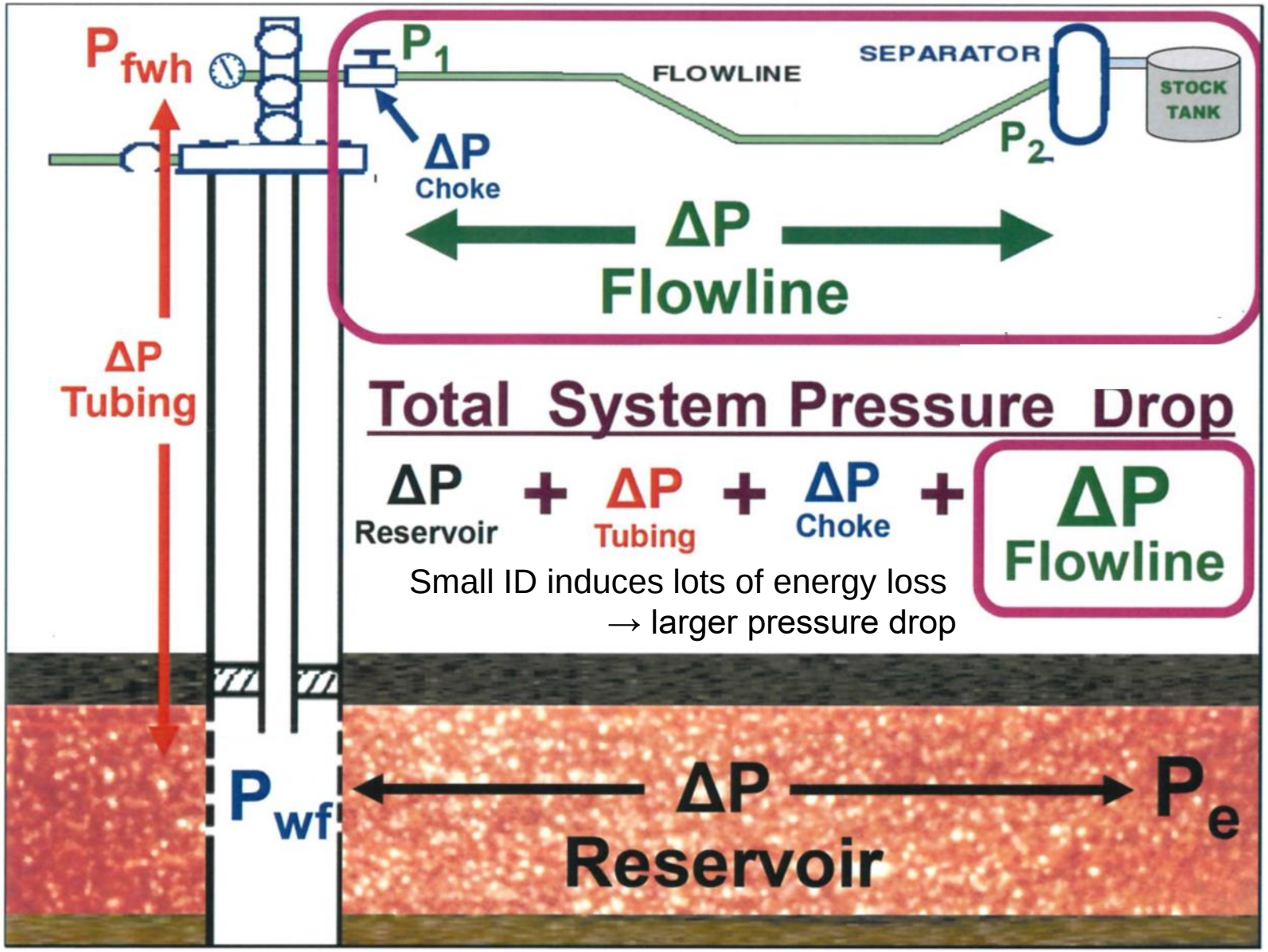
$\therefore [P_o - P_i]_{max} \geq 0.8\,P_p \quad \therefore$ buckle arrestor is required



Flow Assurance
: Interface with Reservoir Evaluation and Topsides Design

- Production profiles; FWHP, FWHT, WI rates
- Reservoir depth, temperature, and pressure
- Required topside arrival pressure (separator pressure + ~50 psi) and temperature
- Separator and slug catcher capacities
- Capacities and pressure ratings of
  - : Export pumps and compressors
  - : Gas lift compressors
  - : Chemicals pumps
  - : Hydraulic fluid pumps
- Topside piping/equipment – temperature ratings
- Topside storage capacities for oil, diesel, chemicals and water

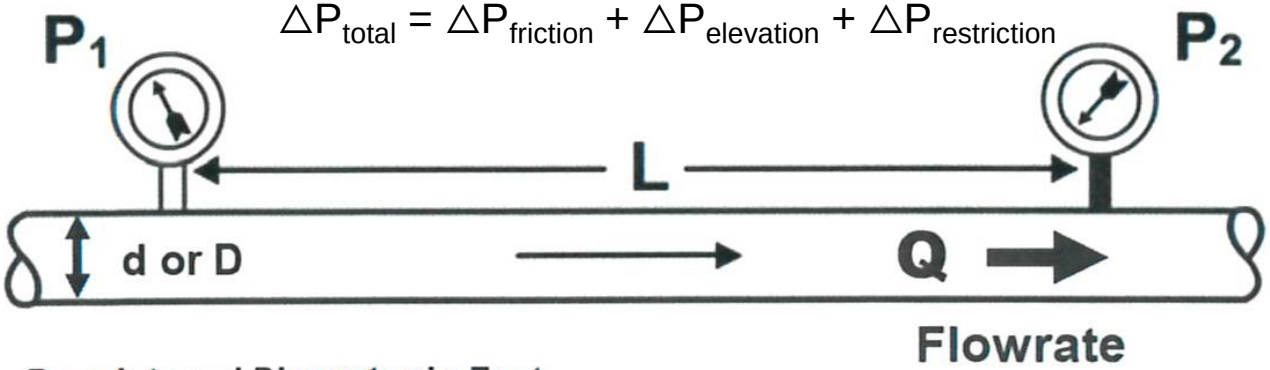
Gathering system



Pressure drop vs. Flowrate in oil field flowlines

$$\Delta P = P_1 - P_2$$

$$\triangle P_{total} = \triangle P_{friction} + \triangle P_{elevation} + \triangle P_{restriction}$$



D = Internal Diameter in Feet

d = Internal Diameter in Inches

Darcy – Weisbach Formula

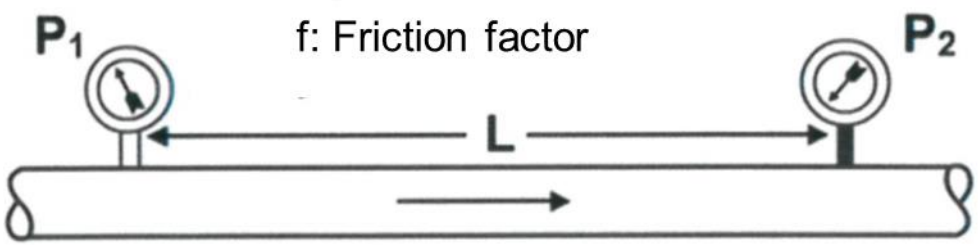
- Pressure drop expressed in feet of fluid head

$$h_{ft} = \frac{f\ L\ v^2}{D\ 2g}$$

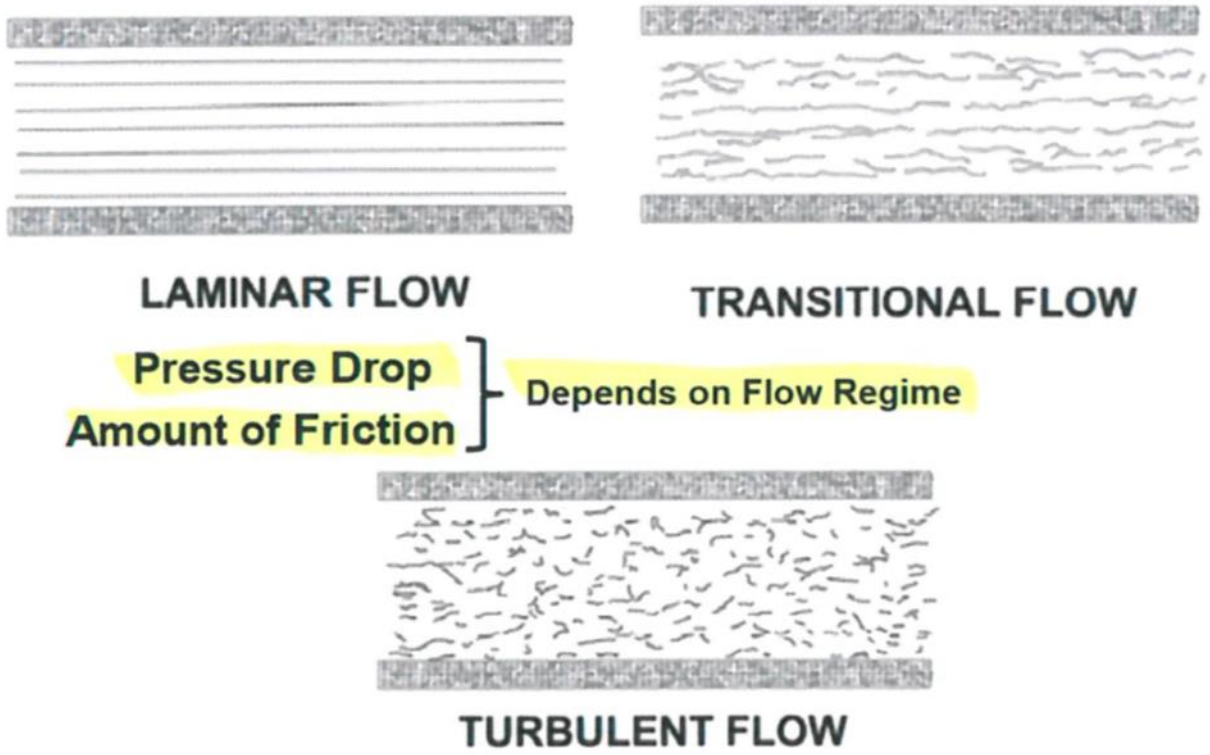
- Pressure drop expressed in psi

$$\triangle P = \frac{\rho\ f\ L\ v^2}{144\ D\ 2g}$$

g: correction factor
not gravity acceleration
(= 32.2 ft/s^2 = 9.81 m/s^2)



Flow regime in pipe



- Gas dominant stream is mostly turbulent
- Flow regime determined by Reynolds number

Reynolds number

- Dimensionless parameter
  : Ratio of Inertia forces to Viscous forces

$$R_e = \frac{\rho D v}{\mu_e}$$

ρ : lb/ft^3 D : ft v : ft/sec μ_e : lb/ft - sec

- Re < 2000 = Laminar flow

$$Liquid: Re = 92.1 \frac{SG_L Q_{BPD}}{d\ \mu}$$

$$Gas: Re = 20100 \frac{SG_G Q_{MMCFD}}{d\ \mu}$$

d: inches, μ: centipoise

Friction factor

- f = Dimensionless factor of proportionality

  f_m = Moddy friction factor

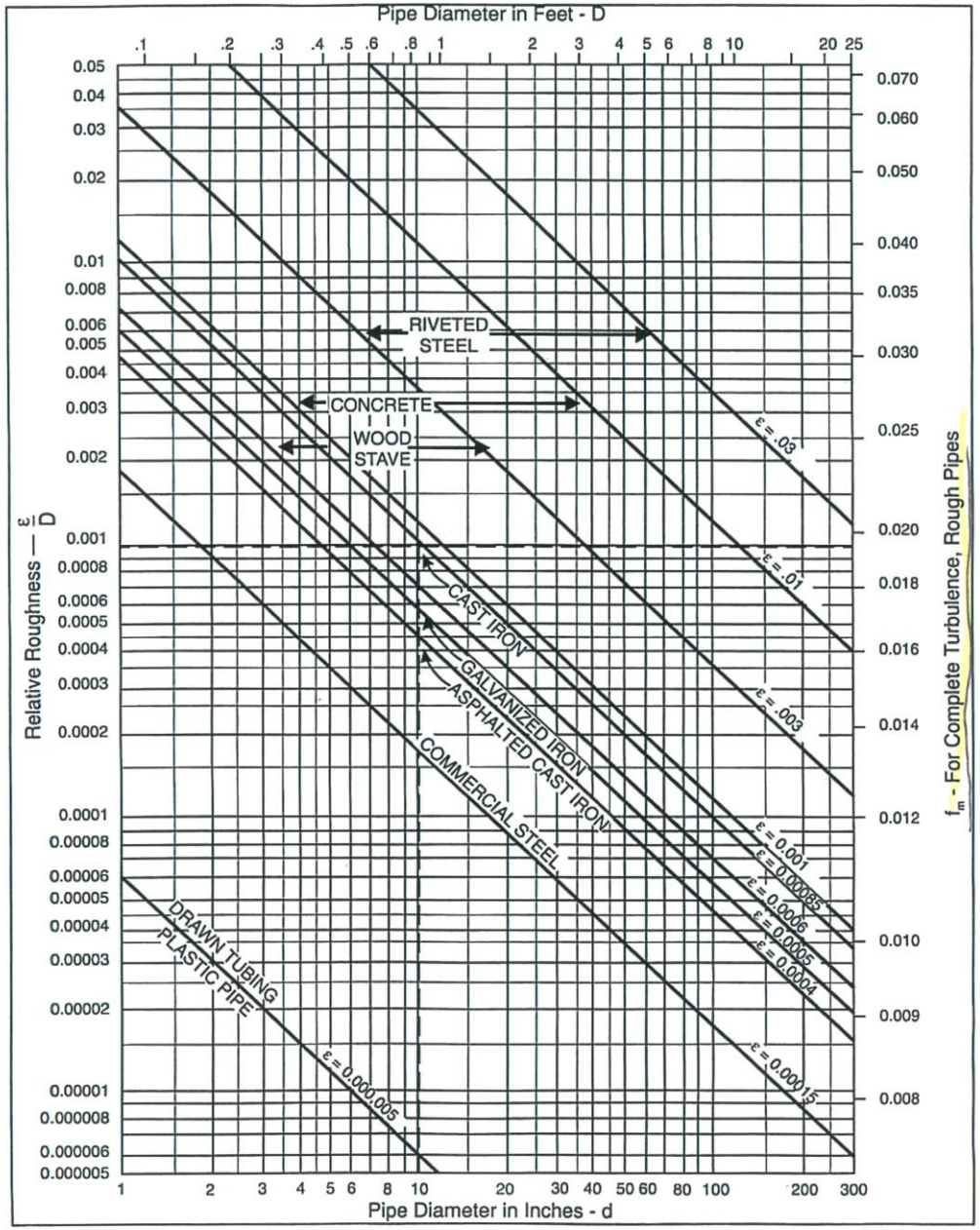
  f_f = Fanning fraction factor ($f_f = 1/4\ f_m$)

- Laminar flow: $f_m = 64 / Re$

- For transitional and turbulent flow
  - f_m a function of Re
  - Relative roughness: ε / D

- For complete turbulence
  - f_m a function of ε / D only

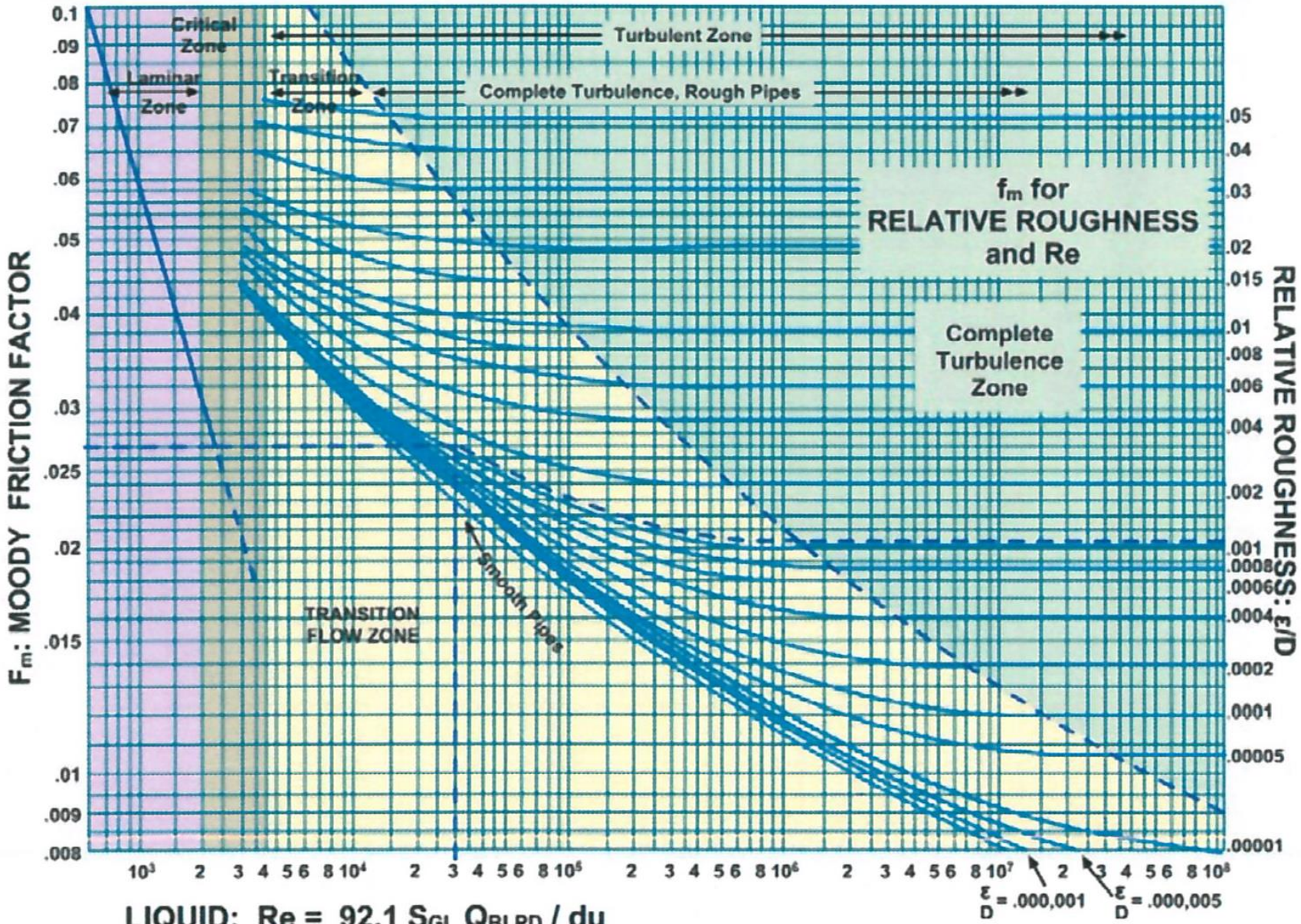
(Do NOT use right hand scale for f_m unless you KNOW flow is FULLY TURBULENT)



Gas Processors Suppliers Association

Note: Absolute Roughness units are in feet.
Relative Roughness is Dimensionless.

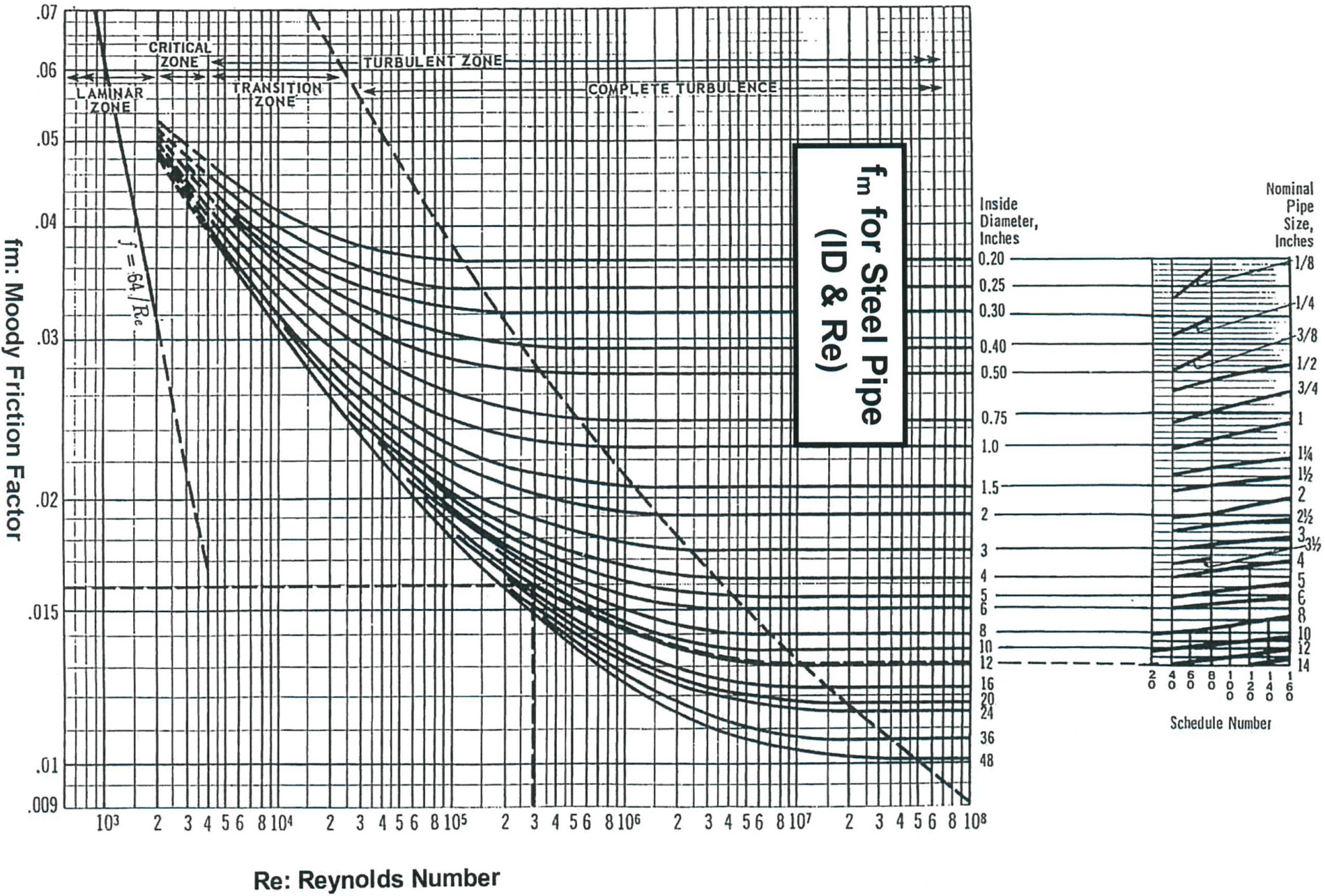
ε for Steel Pipe = 0. 00015 feet



LIQUID: $Re = 92.1\ S_{GL}\ Q_{BLPD} / d\mu$

GAS: $Re = 20{,}100\ SGg\ Q_{MMCFD} / d\mu$

Re: REYNOLDS NUMBER


fm for Steel Pipe (ID & Re)
LAMINAR ZONE
CRITICAL ZONE
TRANSITION ZONE
TURBULENT ZONE
COMPLETE TURBULENCE
f = 64 / Re
fm: Moody Friction Factor
Re: Reynolds Number
Inside Diameter, Inches
Nominal Pipe Size, Inches
Schedule Number

Pressure drop: Laminar flow (Re < 2000)

- Liquid

$$\Delta P_{psi} = 0.00068 \frac{\mu_{cp} L_{ft} V_{ft/sec}}{d_{in}^2}$$

$$\Delta P_{psi} = 7.95 \times 10^{-6} \frac{\mu_{cp} L_{ft} Q_{BPD}}{d_{in}^4}$$

- Gas

$$\Delta P_{psi} = \frac{0.040\ \mu_{cp} L_{ft} T_{^oR} Z Q_{MMCFD}}{P_{psi} d_{in}^4}$$

No "f_m" since f_m = 64/Re and Re = SG_L Q / d μ

Pressure drop: Transitional and Turbulent

- Liquid

$$\Delta P_{psi} = 11.5 \times 10^{-6} \frac{f_m L_{ft} Q_{BPD}^2 SG_L}{d_{in}^5}$$

- Gas

$$P_1^2 - P_2^2 = 25.1 \frac{f_m L_{ft} Q_{MMCFD}^2 SG_G Z T_R}{d_{in}^5}$$

Exercise ΔP: Liquid flow in Pipe

- What is the friction pressure drop in 10,000 ft of 2 inch ID pipe flowing 50 BPD of 35 ^{o}API crude oil (μ=1.2 cp and SG_L=0.85) ?

1. First calculate Reynold's number to determine flow regime

   :

2. Use the equation for

$$\Delta P_{psi} =$$

Exercise: Increasing flow rate 3000 BPD

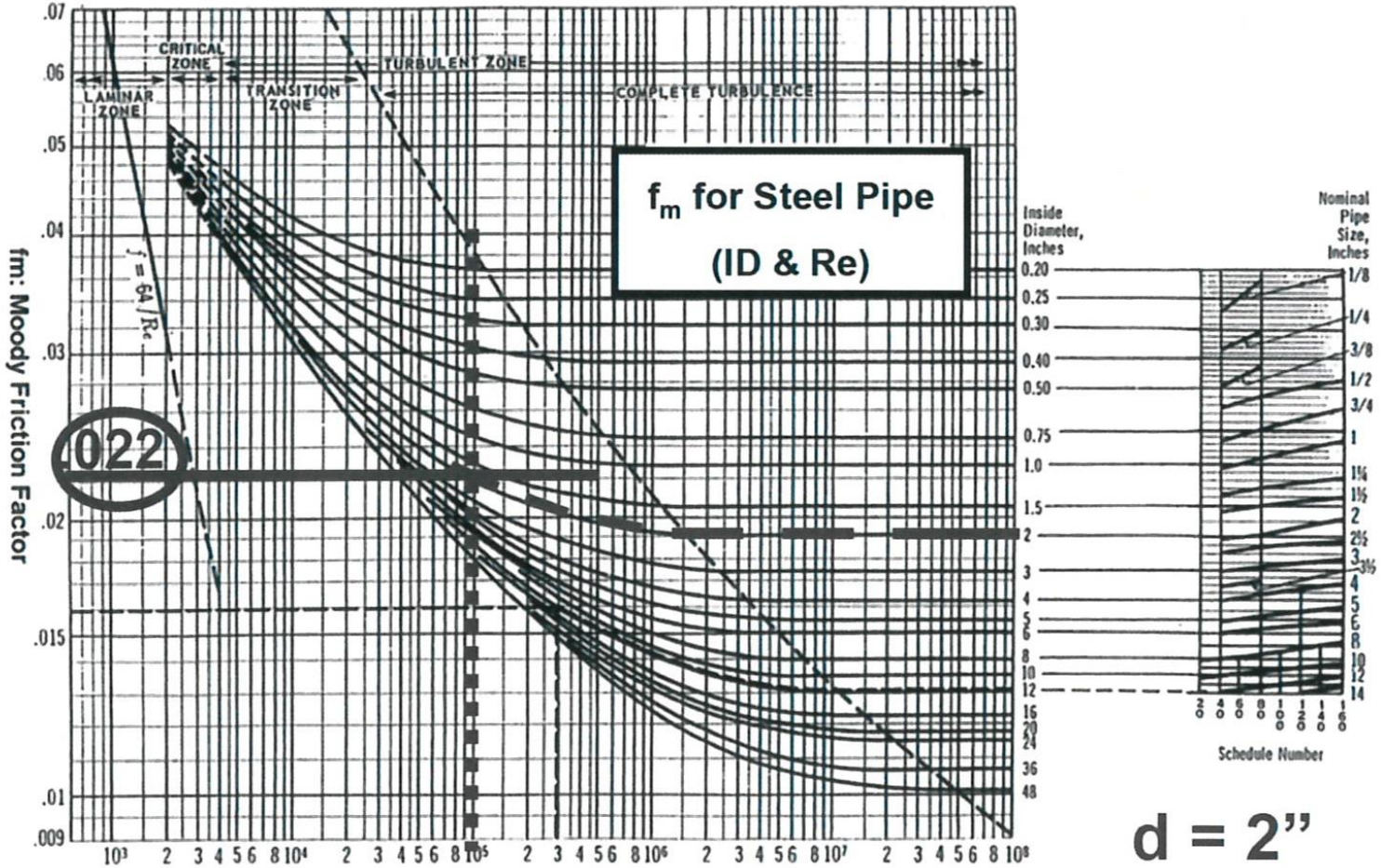
1. First calculate Reynold's number to determine flow regime

   :

2. Use the equation for

3. Determine f_m using chart

$\Delta P_{psi} =$



d = 2”

Re: = 97,856

LIQUID: $Re = 92.1\ SG_L\ Q_{BLPD} / d\ \mu$

GAS: $Re = 20{,}100\ SG_g\ Q_{MMCFD} / d\ \mu$

Pipeline sizing Summary

- **Consider Fluid Velocity**
  - Noise / Corrosion / Erosion
  - Liquid / Solids Build-Up
- **Contain Internal Pressure**

$$P = 2\,S\,t\,F\,E\,T / d$$

- **Pressure Drop: Horizontal Pipeline**

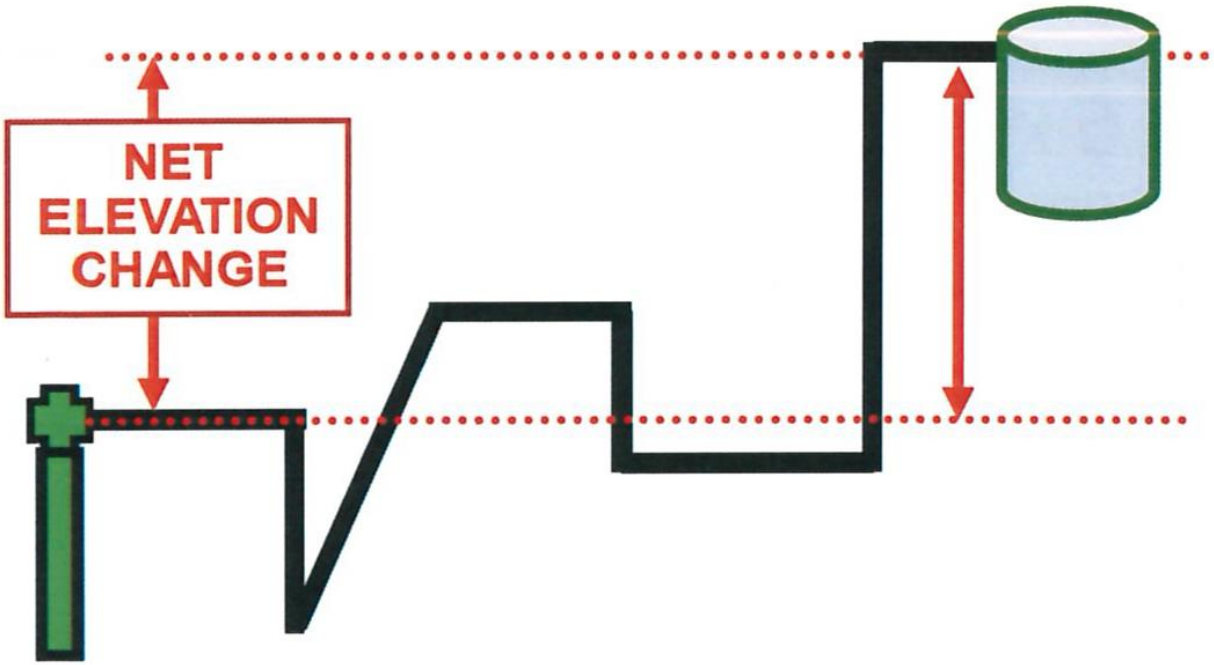
Laminar

$$\begin{cases} \text{Liquid}: \Delta P_{psi} = 7.95 \times 10^{-6}\ \mu_{cp}\ L_{ft}\ Q_{BLPD} / d^4_{inch} \\ \text{Gas}: \Delta P_{psi} = 0.40\ \mu_g\ L_{ft}\ T\ Z\ Q_{MMCFD} / P_{psi}\ d^4_{inch} \end{cases}$$

Non-Laminar

$$\begin{cases} \text{Liquid}: \Delta P_{psi} = 11.5 \times 10^{-6}\ f_m\ L\ Q^2_{BLPD}\ SG_L / d^5 \\ \text{Gas}: (P_1)^2 - (P_2)^2 = 25.1\ f_m\ L\ Q^2_{MMSCFD}\ SG_g\ Z\ T / d^5 \end{cases}$$

What if pipeline is not horizontal?



Pressure drop due to Elevation

- Liquid: ΔP due to Elevation

$$\Delta P_{E(psi)} = \frac{\rho_{L(lb/ft^2)} H_{E(ft)}}{144} = 62.4 \frac{SG_L H_{E(ft)}}{144}$$

$$\Delta P_{E(psi)} = 0.433\ SG_L H_{E(ft)}$$

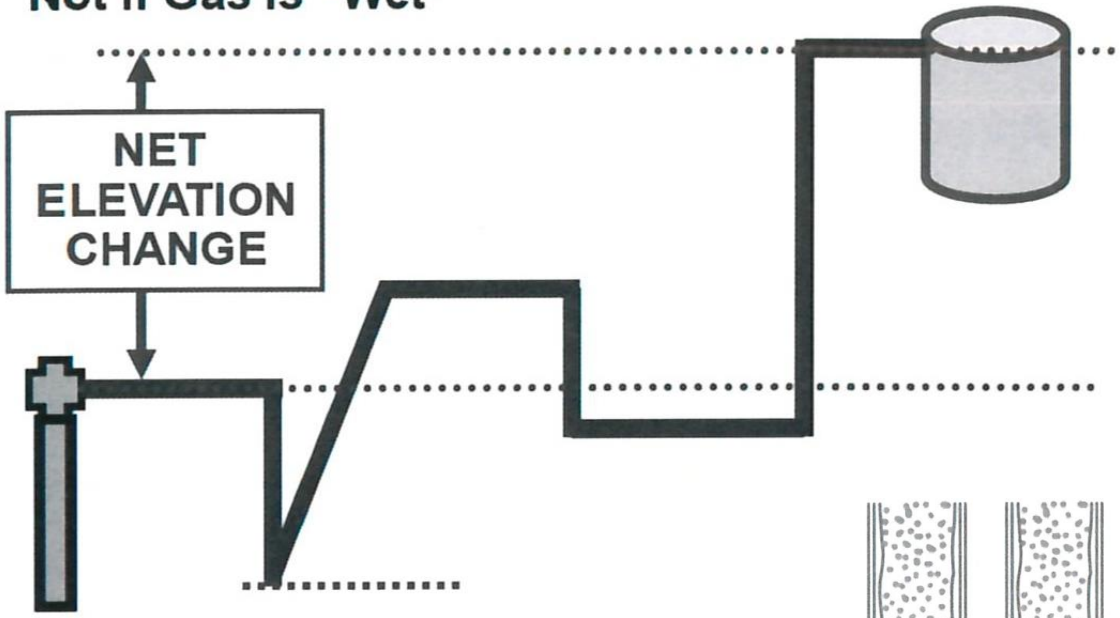
- Gas: ΔP due to Elevation

$$\Delta P_{E(psi)} = \frac{\rho_{G(lb/ft^2)} H_{E(ft)}}{144} = 2.70\ \frac{SG_G P_{psi}/T_{^oR} Z H_{E(ft)}}{144}$$

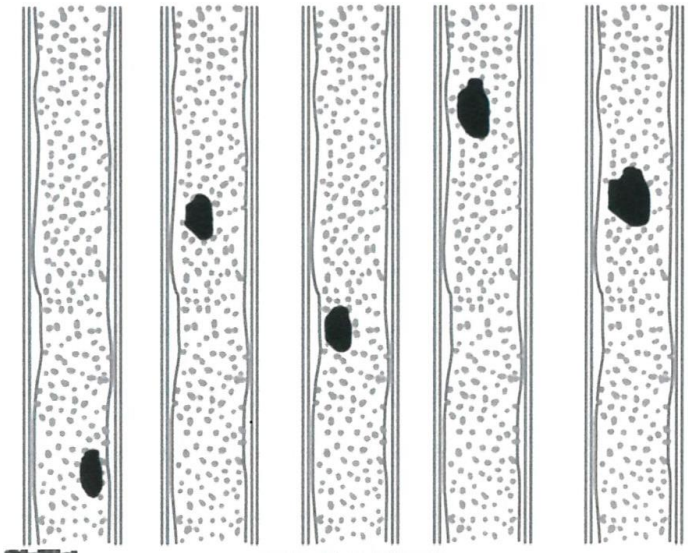
$$\Delta P_{E(psi)} = 0.188\ \frac{SG_G\ P_{psi}}{T_{^oR}\ Z\ H_{E(ft)}}$$

Not always true for gas flow

- Not if Gas is "Wet"

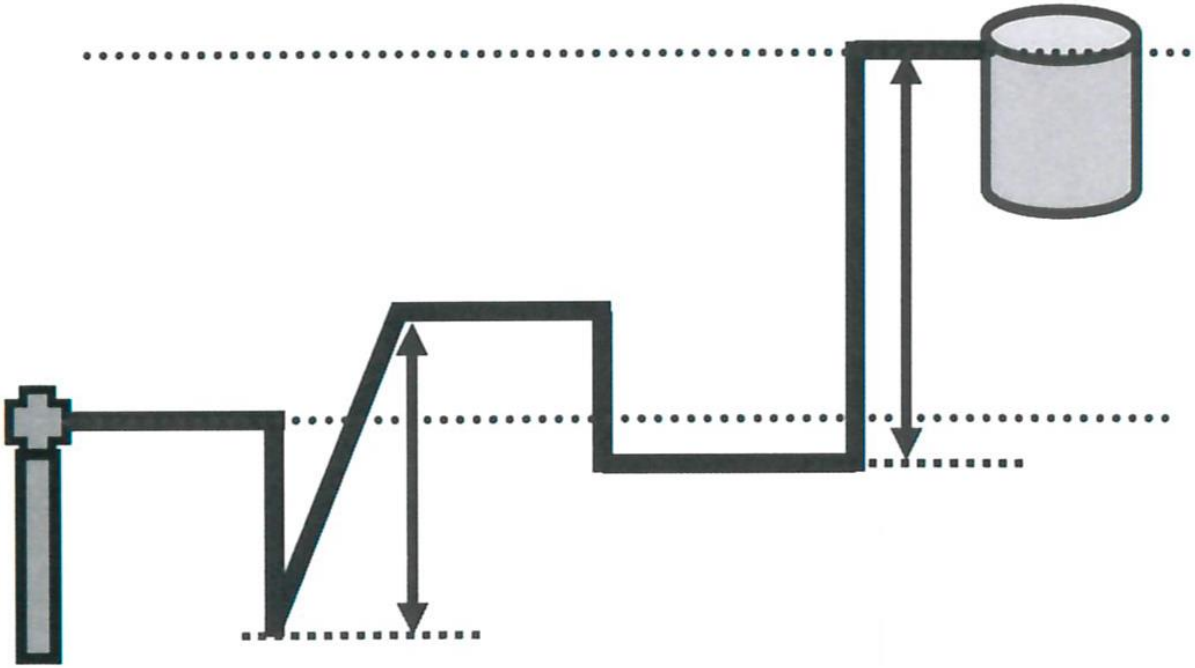


- Big liquid droplets for annular flow



Pressure drop for Wet gas

- Sum the “Ups”



Estimating ΔP without using Friction Factor

- Empirical equations
  - Useful for quick calculation before use of PCs
  - Commonly accepted empirical equations

    : Hazen-Williams empirical equation (Liquid flow)

$$\Delta P \quad = 0.7 \times 10^{-6} \frac{Q^{1.85} L\, SG_L}{d^{4.87}}$$

$$(\Delta P\ in\ psi, Q\ in\ BLPD, L\ in\ feet, d = ID\ in\ inches)$$

    : Weymouth formula (gas flow)

$$P_2^2 = P_1^2 \quad - \left[\frac{0.8\, L_{ft} T_R Z\, SG_G Q_{MMCFD}^2}{d_{in}^{5.334}} \right]$$

    - most common for oil field use
    - good for IDs between 0.75 inch & 16 inch
    - at Laminar rates, calculated ΔP is too low

    : Panhandle empirical equation (gas flow)

Panhandle: A & B Empirical equation

- For estimating ΔP without friction factor

A: $$Q_{MMCFD} = \left[\frac{0.020\ E\left(P_1^2 - P_2^2\right)^{0.51} d^{2.62}}{\left(SG_G^{0.853} z T^o{}_R L_{mi}\right)^{0.539}}\right]$$

- For IDs between 6 inch and 24 inch
- Re between $5*10^6$ and $15*10^6$

B: $$Q_{MMCFD} = \left[\frac{0.028\ E\left(P_1^2 - P_2^2\right)^{0.51} d^{2.53}}{\left(SG_G^{0.961} z T^o{}_R L_{mi}\right)^{0.51}}\right]$$

- For IDs between 6 inch and 24 inch
- Re > $15*10^6$

ΔP in psi, Q in MMCFD, L_{mi} in miles, d = ID in inches

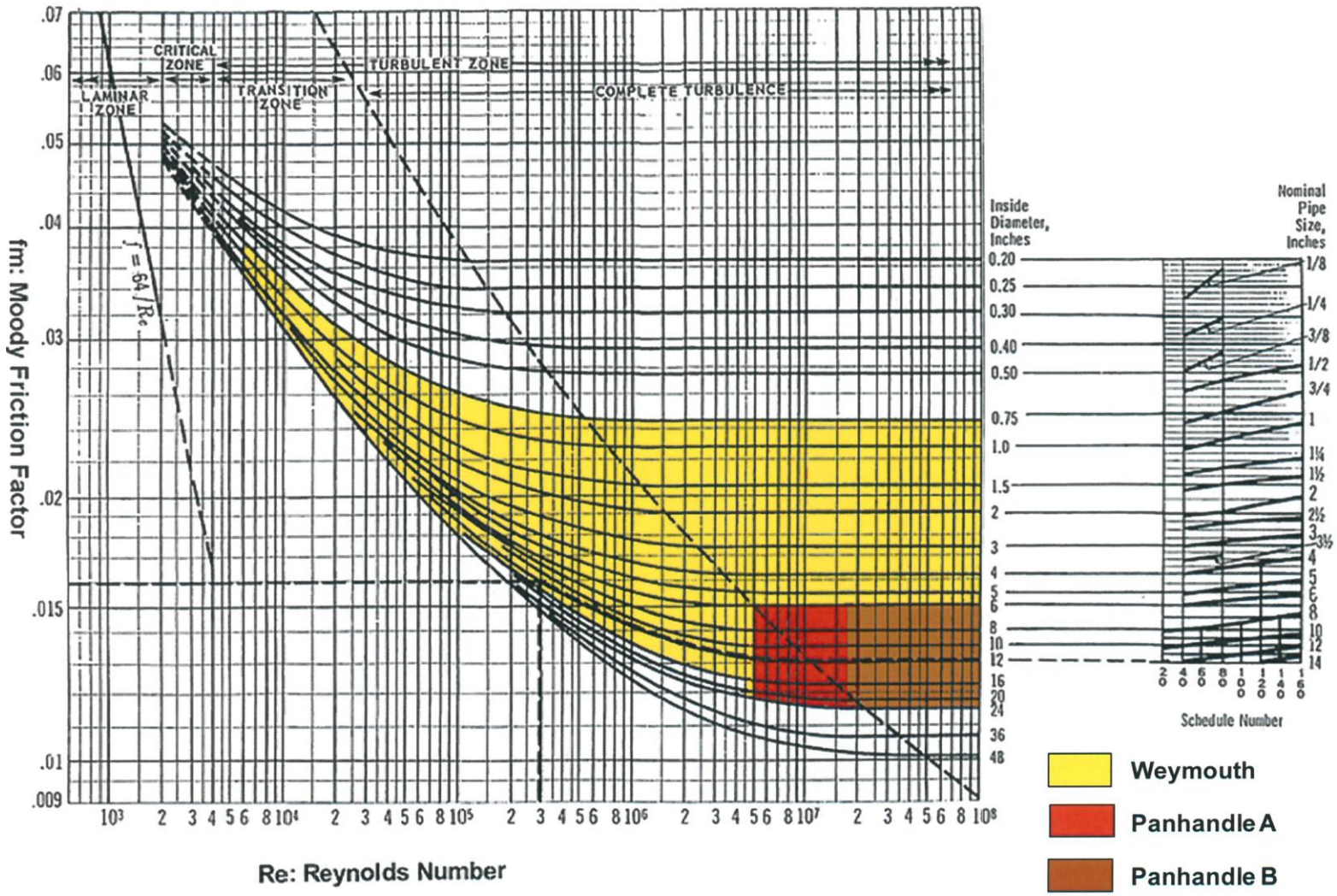
E factor : E = 1.00 for new pipe

= 0.95 for good condition

= 0.92 for average condition

= 0.85 for old pipe

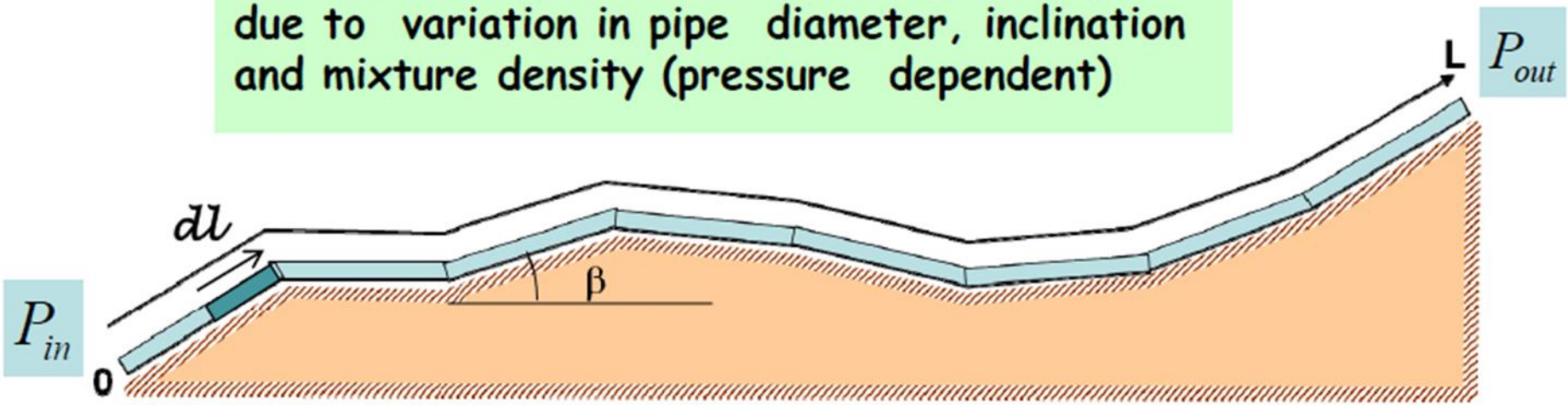
= 0.75 for corroded pipe


CRITICAL ZONE
LAMINAR ZONE
TRANSITION ZONE
TURBULENT ZONE
COMPLETE TURBULENCE
f = 64/Re
fm: Moody Friction Factor
Re: Reynolds Number
Inside Diameter, Inches
Nominal Pipe Size, Inches
Schedule Number
Weymouth
Panhandle A
Panhandle B

Pressure drop in pipe: Two phase flow

- With liquid and gas both flowing
  - Two phase flow results various flow patterns
- Horizontal flow patterns
  - Noise produced with bubbles
  - Using superficial velocities for gas and liquid

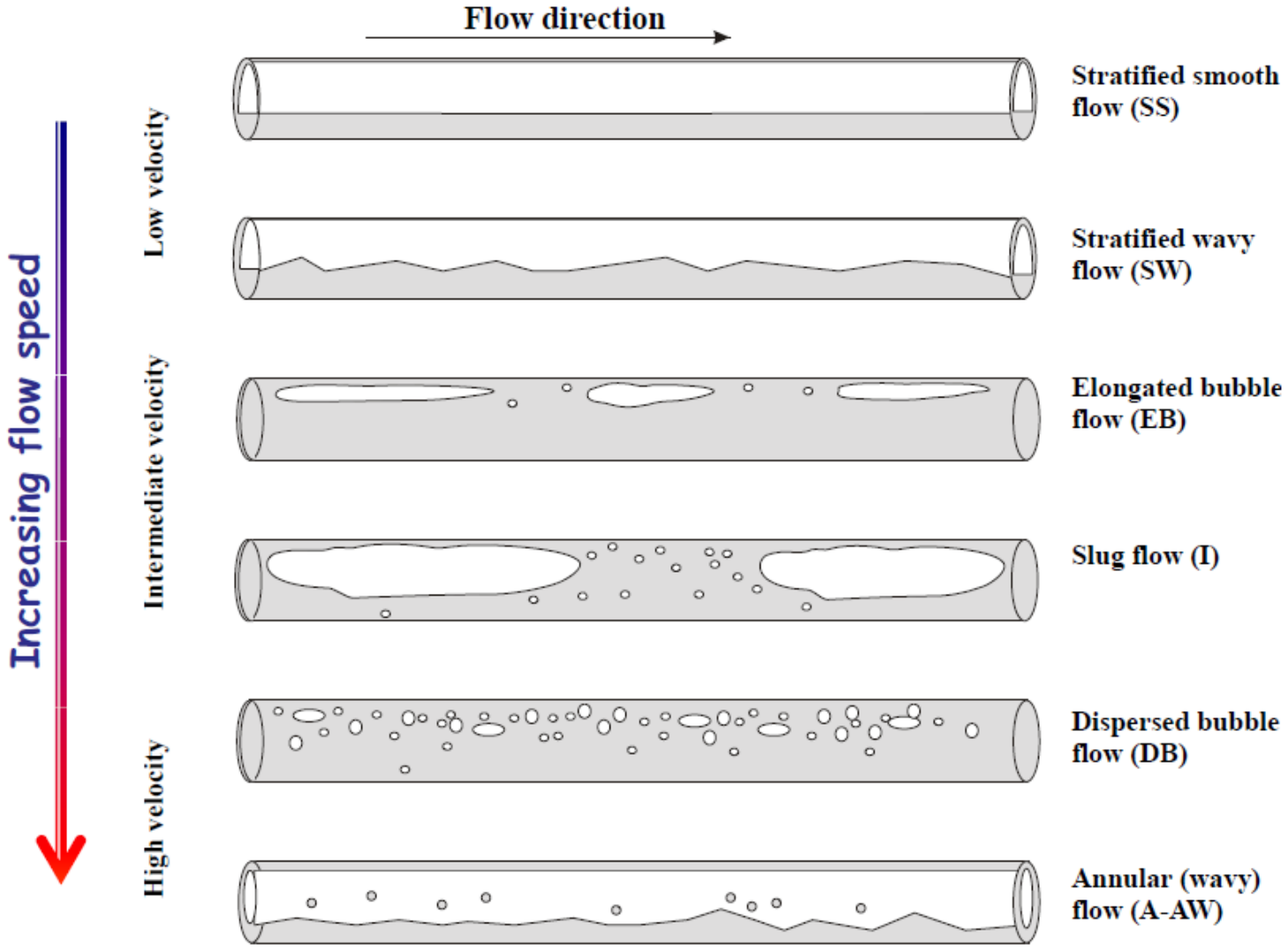
The pressure gradient varies along the pipe due to variation in pipe diameter, inclination and mixture density (pressure dependent)



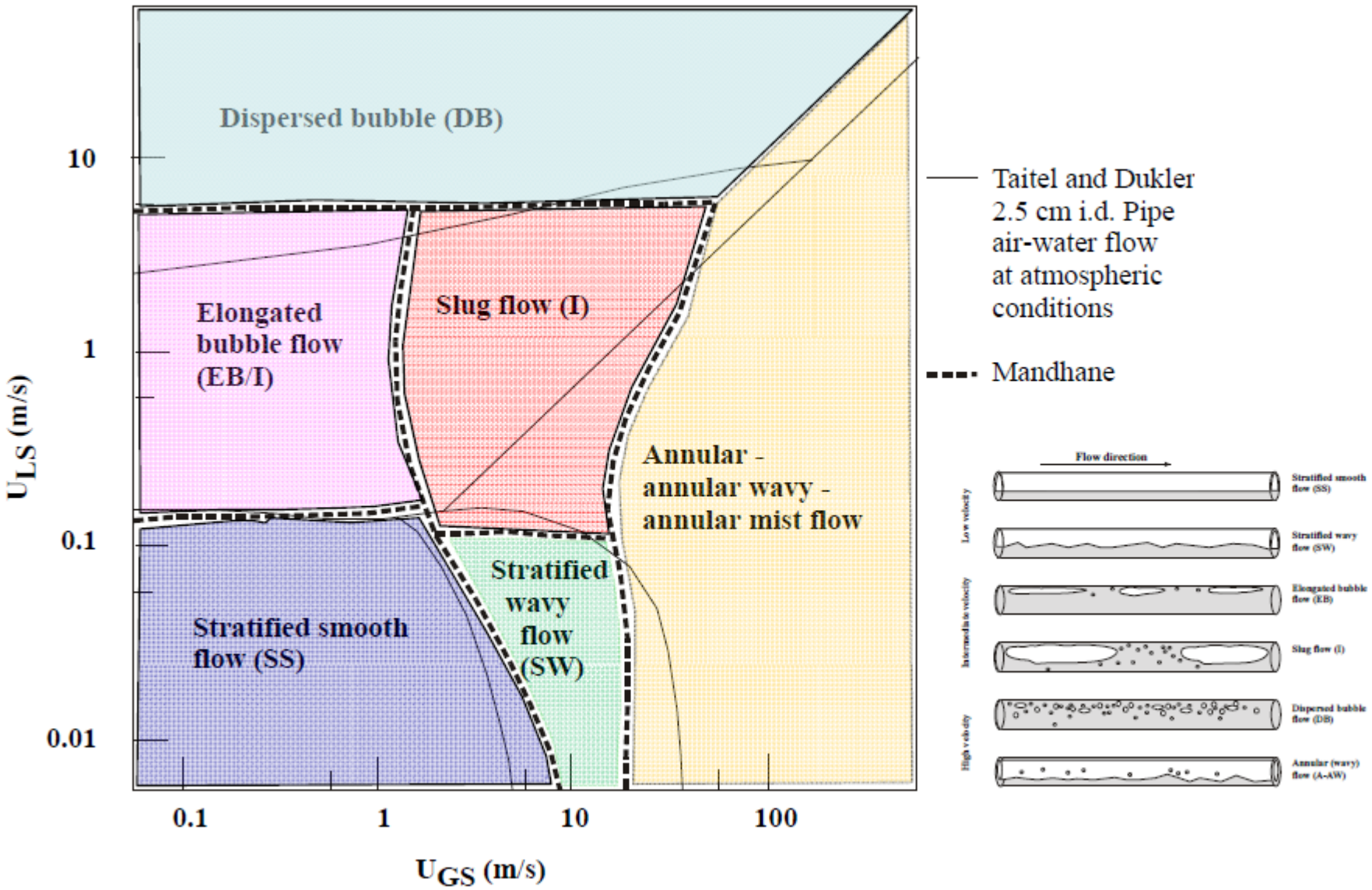
Pressure at exit: $P_{out} = P_{in} + \Delta P$

Gas liquid flow regimes

- In horizontal and near horizontal pipelines

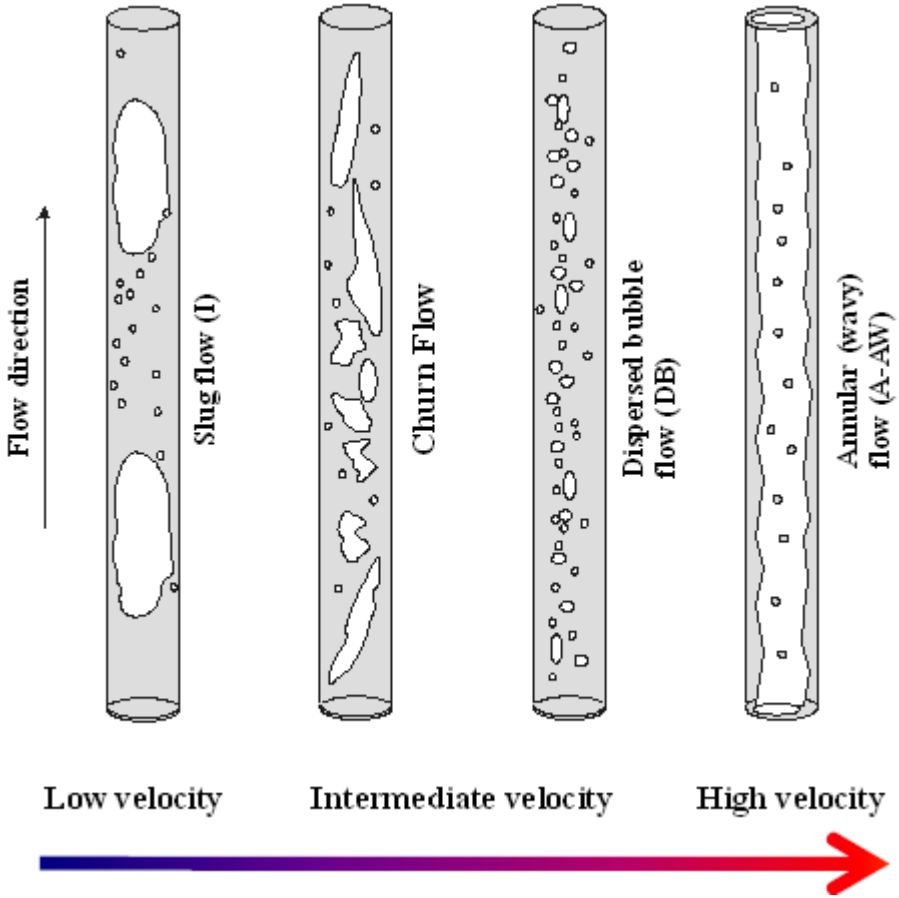


Flow regime map – horizontal pipe

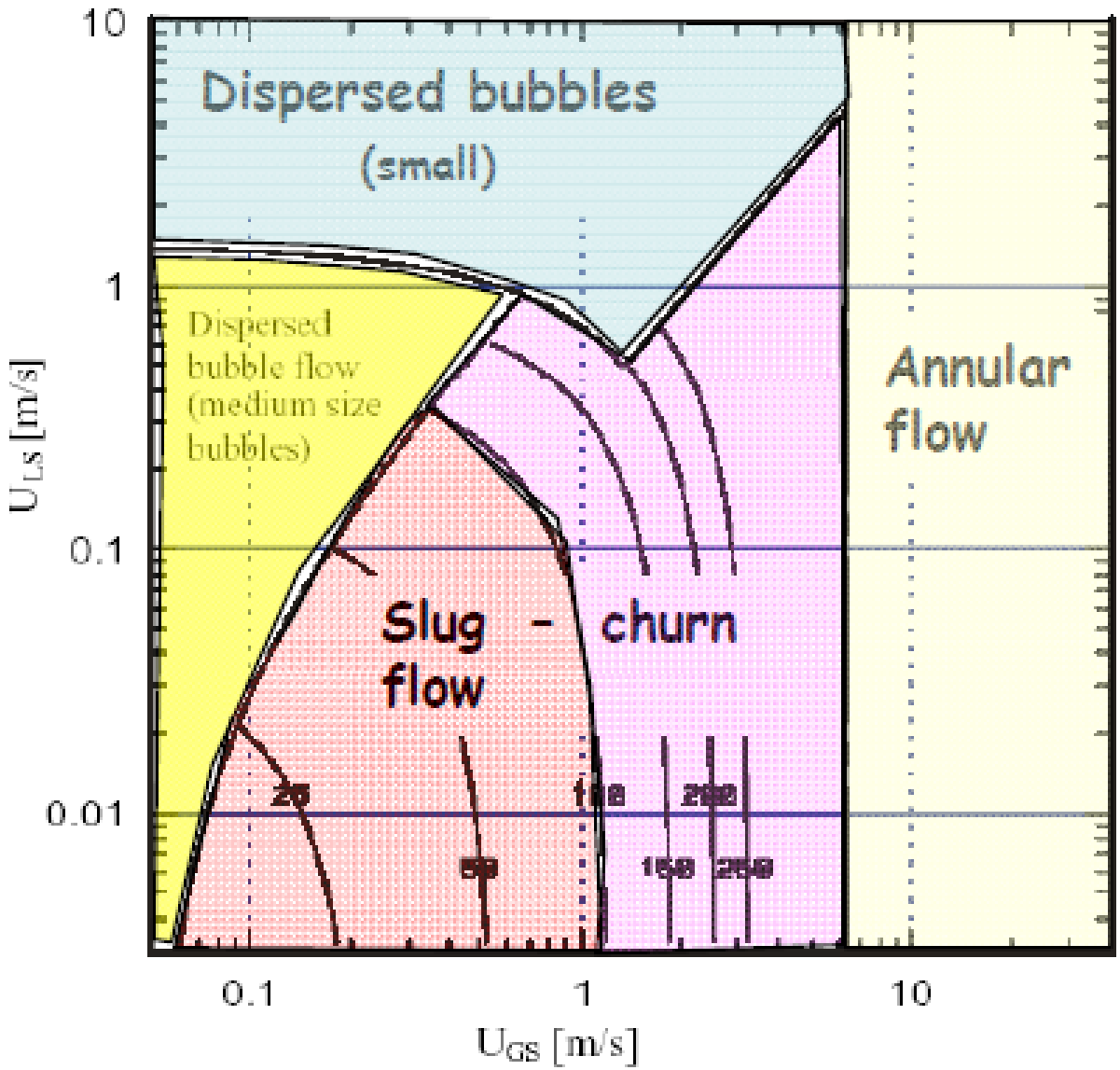


Vertical two-phase flow regimes

- In up-ward vertical pipeline



Flow regime map – vertical pipe



Pressure drop for two-phase flow

- Very complex: errors ≈ 20% common
  - Use simulation software and experience
- API RP 14 E gives following simplified method
  - Assumes: ΔP < 10%, bubble / mist flow, f=0.015

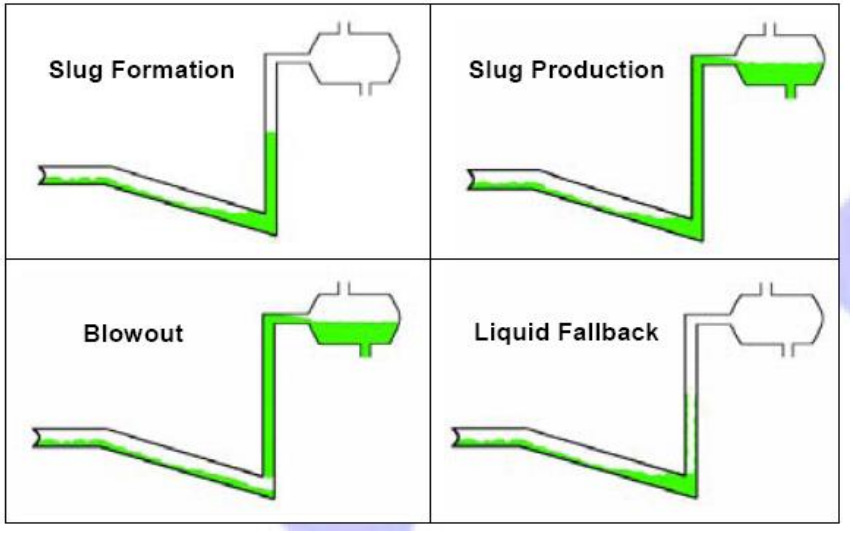
$$\Delta P = \frac{5 \times 10^{-8}\, L\, W^2}{d^5\ \ \rho_{mix}}$$

$$where,\ \text{W= 3180}\ Q_{MMCFD} SG_G + 14.6\ Q_{BPD} SG_L$$

$$and\ \rho_{mix} = \frac{12409\ SG_L P + 2.7\ R_{scf/bbl} SG_G P}{198.7\ P + R_{scf/bbl}\ T\ z}$$

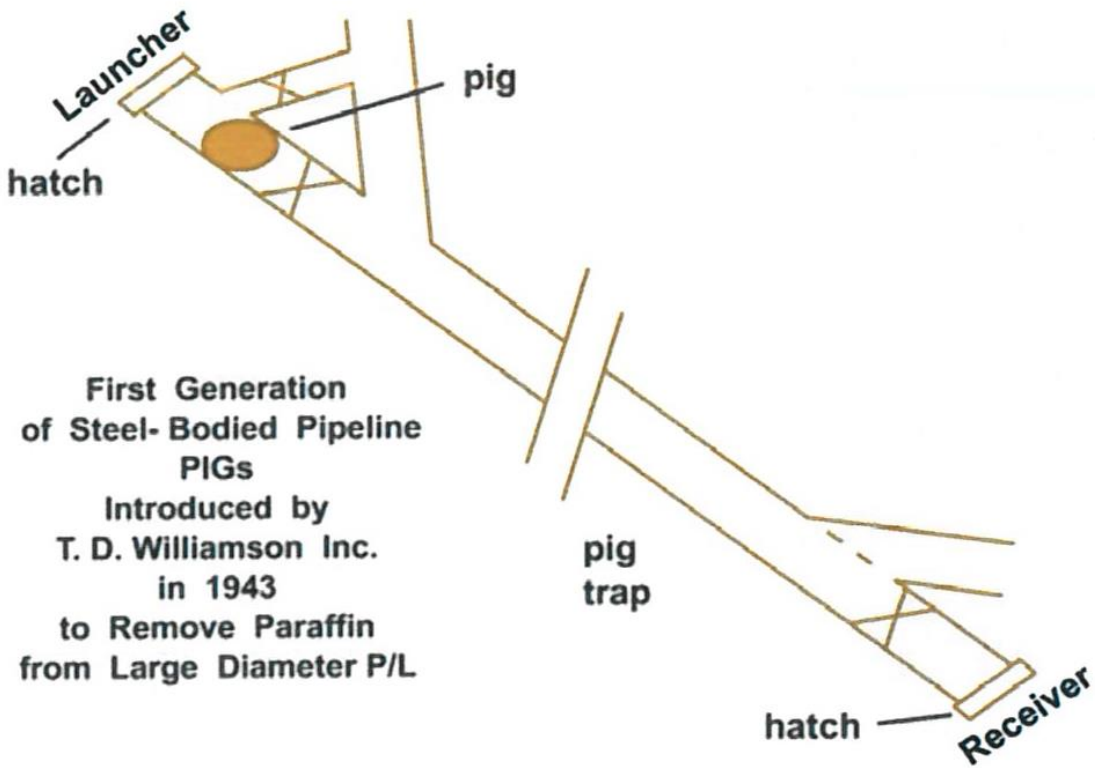
Slugging

- Slugging
  : Periods of low flow followed by periods of high flow (liquid bomb)
  : Occurs in multiphase flowlines at low gas velocities
  : Causes
    - Low fluid velocity
    - Seabed bathymetry
    - Riser type
- Control strategy
  : Increase flowrate
  (playing with topside valve)
  : Slug catcher
  : Gas lift / Gas recirculation



Pipeline Pigging System

- PIG: Pipeline Internal Gauge



Petroleum Industry PIG

- Pipeline Internal Gauge
  - Check internal condition for pipeline
  - Cleaning: Solids (wax, asphaltene etc)
  - Check or remove obstruction
  - Check for deformation / corrosion / erosion

- Intelligent PIG
  - Measure: Remaining wall thickness
  - Establish: Location and type of defects

- Foam Pigs for cleaning

- Bi-Di pigs: Gauging and Cleaning

Hydrate

- Hydrate

  An ice-like solid that forms when

  : Sufficient water is present

  : Hydrate former is present (C1, C2, and C3)

  : Right combination of P and T

- Control strategy

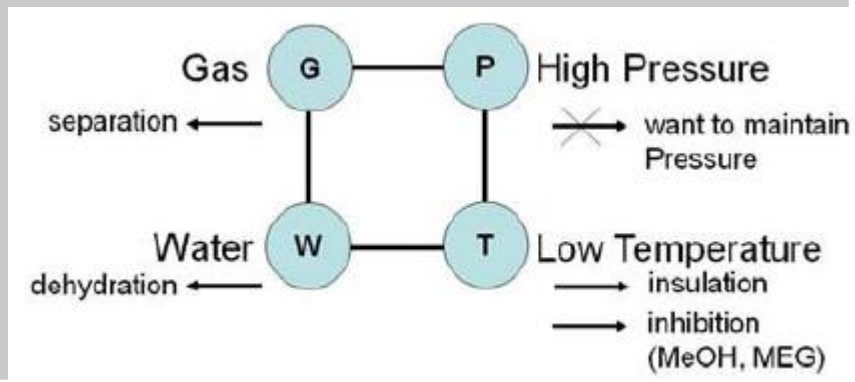
  i) maintaining temperature above hydrate formation conditions (Insulation, DEH, etc)

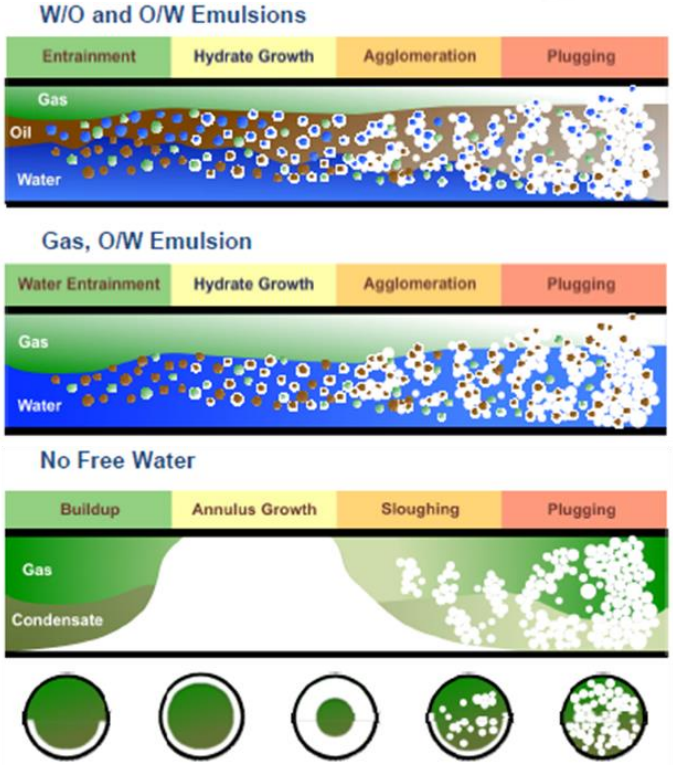
  ii) Decreasing the pressure outside the area of possible hydrate formation (for remediation)

  iii) Removing the water (Subsea processing)

  iv) Continuous injection of chemicals

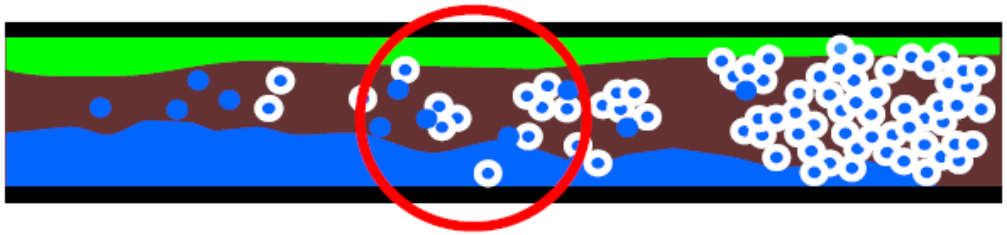
  : MEG is the most popular hydrate inhibition strategy for long distance tie-back systems



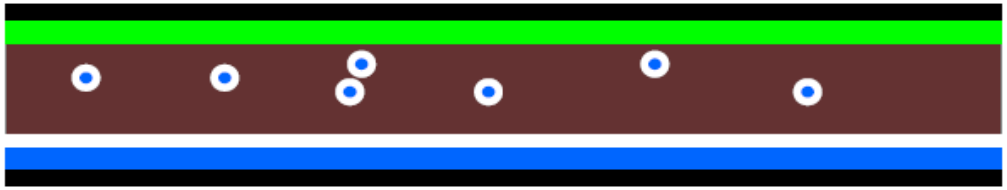


Hydrate formation mechanism

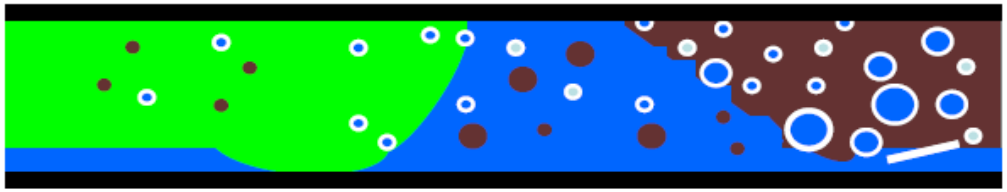
1. Normal Operation:



2. Shut-in:



3. Restart:



Question: When and where will hydrates form?

Hydrate mitigation

- Insulation
  - Pipe-in-pipe
  - Wet Insulation
- Active heating systems
  - Hot Water
  - Electric (DEH)
- Subsea Chemicals Injection
  - Methanol, MEG
  - LDHI
- Flowline Pressure Reduction
- Water removal (especially for Gas Export Pipeline)

Estimation of Hydrate Formation/Inhibition (Accurate to ±25%)

1. A pipeline pressure/temperature flow simulation should be done to determine the conditions between the wellhead and the pipeline discharge. (Pipesim, Olga, Leda, etc)

2. Hydrate formation conditions should be calculated, and pressures and temperatures of vapor and aqueous liquid inhibited by various amounts of THI should be considered. (Hammerschmidt eq., PVTSim, Multiflash, etc)

3. Calculate the amount of inhibitor injected into pipelines based on the amount of free-water phase

Hammerschmidt equation (1934)

- Hammerschmidt proposed the first empirical equation to find the required concentration of an inhibitor X, in an aqueous solution, for lowering the hydrate formation temperature by a given amount,(^{o}F):

$$\Delta T = \left(\frac{2335}{MW} * \frac{X}{1-X}\right)$$

Where ΔT temperature lowering, MW methanol molecular weight, X wt% methanol in aqueous phase. (For MEG, use 2000 instead of 2335)

- Extended equation for methanol (more accurate than the Hammerschmidt equation)

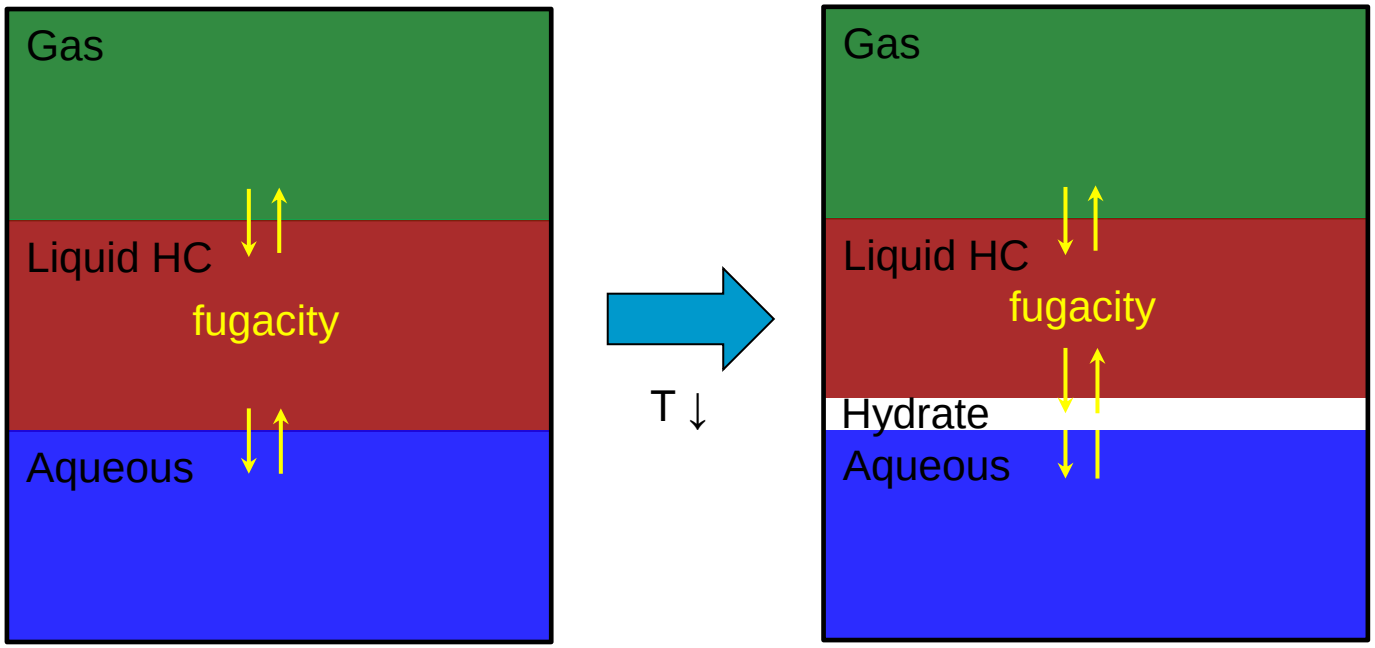
$$\Delta T = -129.6 \ln(1-N)$$

Where N mole fraction of methanol

- The accuracy the Hammerschmidt eq is surprisingly good; tested against 75 data points, the average error in ΔT was 5%.

Cubic Equation of State (1980')

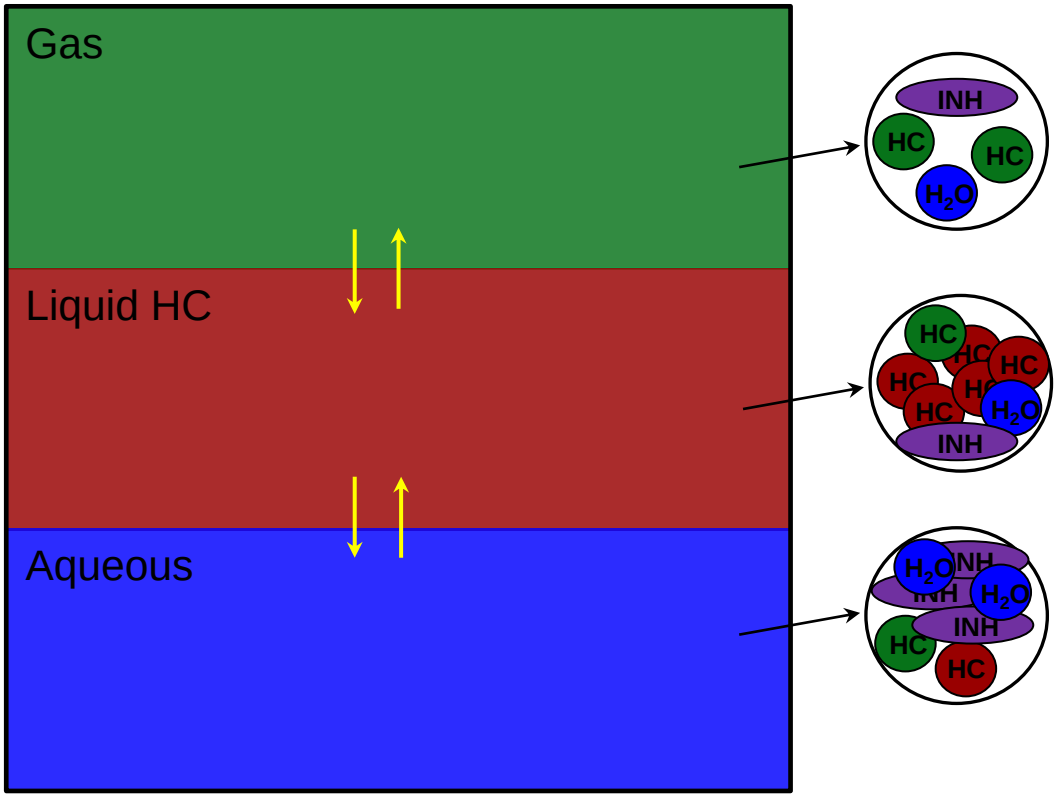
- Thermodynamic equilibrium



$f_{Gas} = f_{LiqHC} = f_{Aq}$

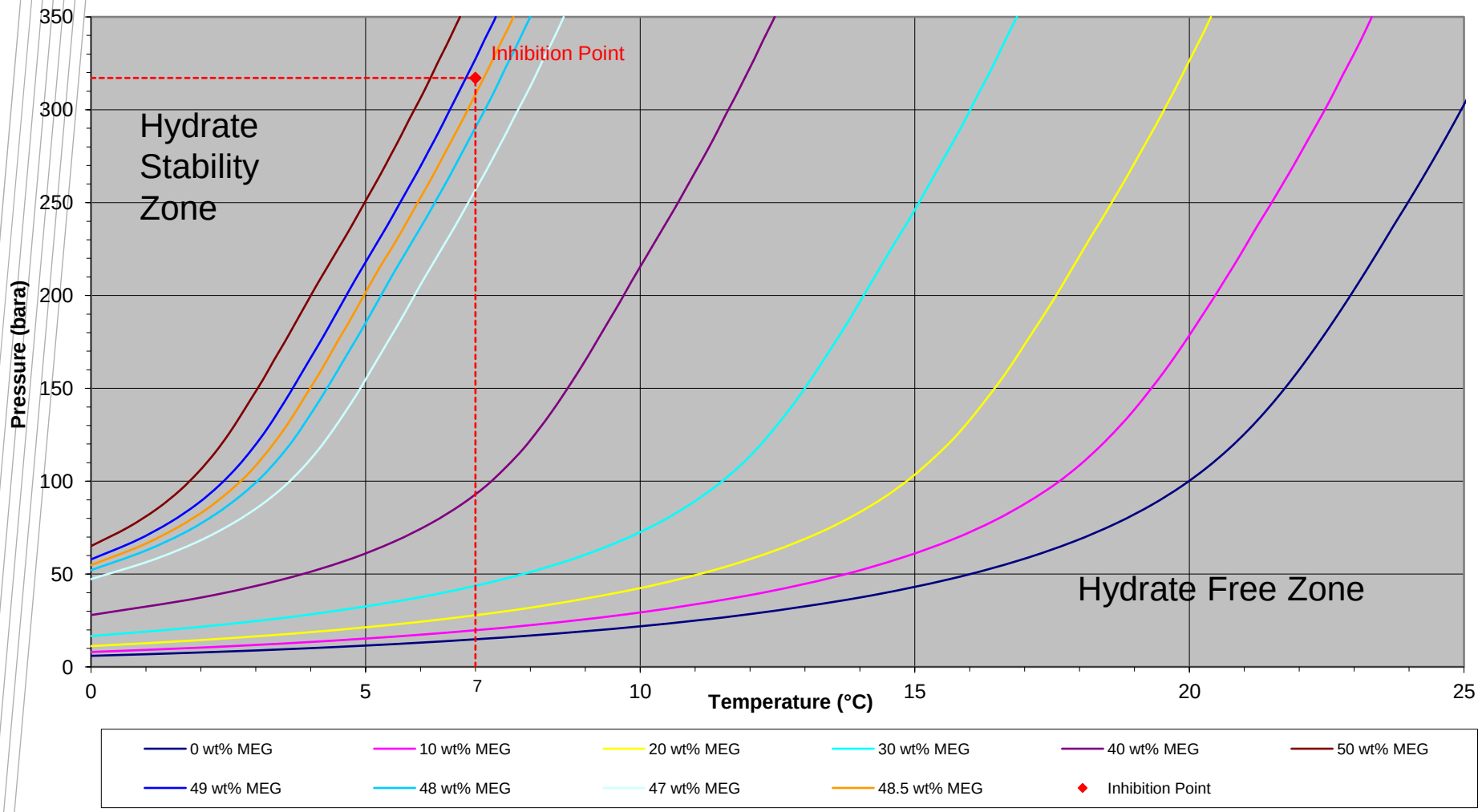
$f_{Gas} = f_{LiqHC} = f_{Aq} = f_{Hyd}$

Effect of adding inhibitor



Cluster formation by hydrogen bonding
: lowering fugacity coefficient of water in aqueous phase

Required MEG concentration



Amount of inhibitor lost to the gas and HC phase

- MEG loss to vapor is negligible
- MeOH

- At 39°F, P > 1000 psi, MeOH lost to vapor phase is 1 lbm MeOH/mmscf for every wt% MeOH in the free-water phase

  (i.e. 27 wt% MeOH indicates 27 lbm MeOH/mmscf lost to vapor)

- When the MeOH vapor loss can be substantially higher, ex) low water amount, it is recommended to use Kv for MeOH (=Yv/Xeq)

  $$Kv = \exp(5.706 - 5738\,(1/T(^{o}R)))$$

- MeOH loss to liquid HC (correlation for CH_4, C_3H_8, n-heptane)

  $$Kv = \exp(5.90 - 5404.5\,(1/T(^{o}R)))$$

- The total amount of MeOH injected to pipeline is therefore

  MeOH in aqueous phase + MeOH in gas + MeOH in condensate

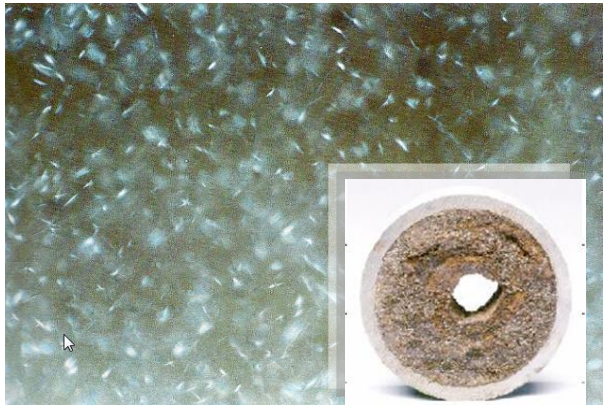
Wax

- Paraffinic hydrocarbons (candle?)

  : A solid paraffinic hydrocarbon which precipitate from a produced fluid

  : Forms when the fluid temperature drops below the Wax Appearance Temperature (WAT)

  : Melts at elevated temperature (20°F above the WAT)



- Control strategy

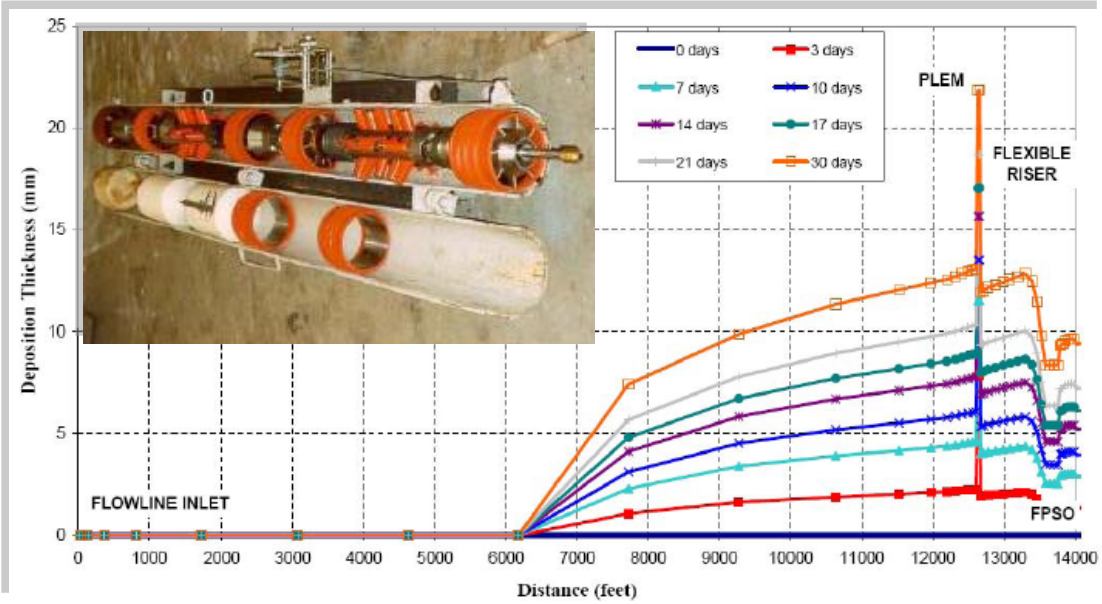
  : Rate of deposition can be predicted to calculate pigging frequency

  : Flowline insulation

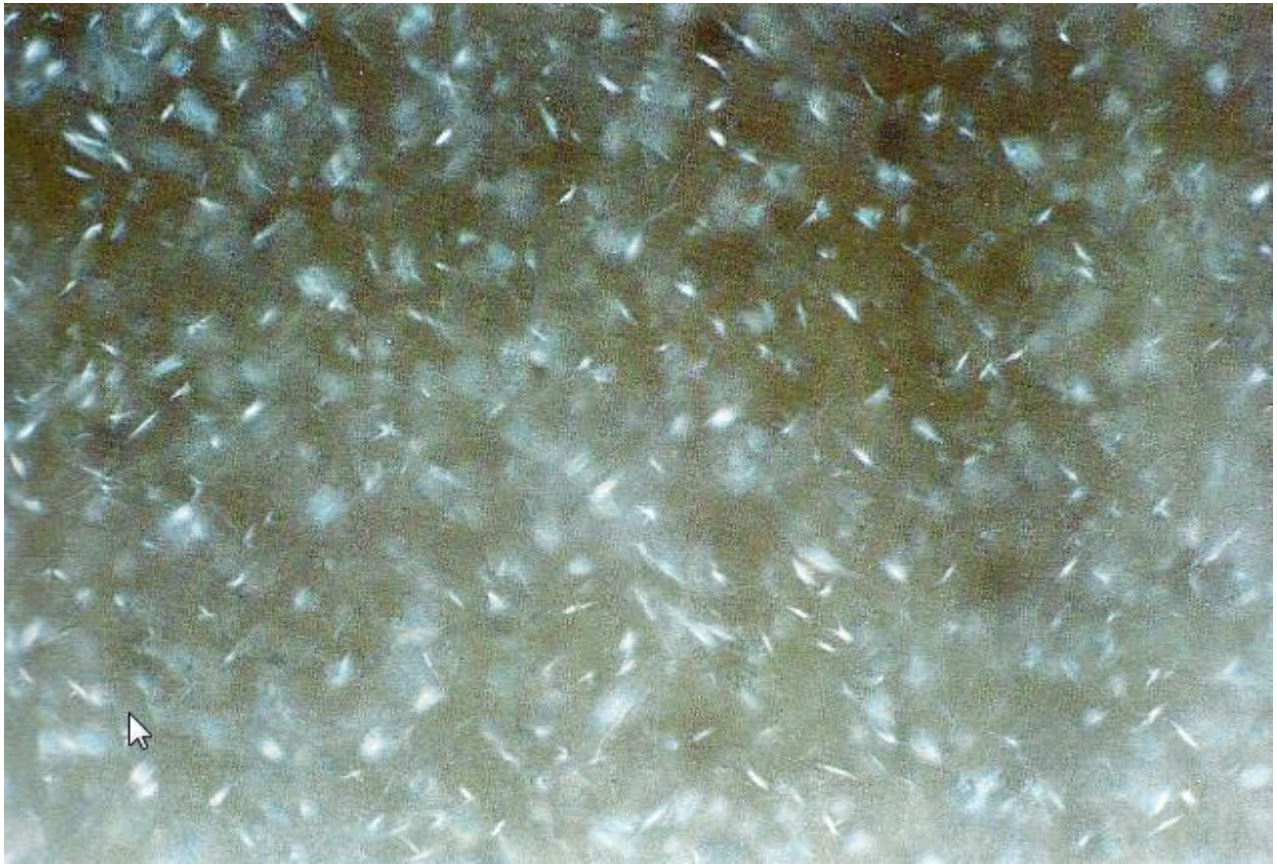
  : Wax inhibitor

  : Major factors

  - WAT
  - Fluid temperature
  - Overall U-value
  - Deposition rate

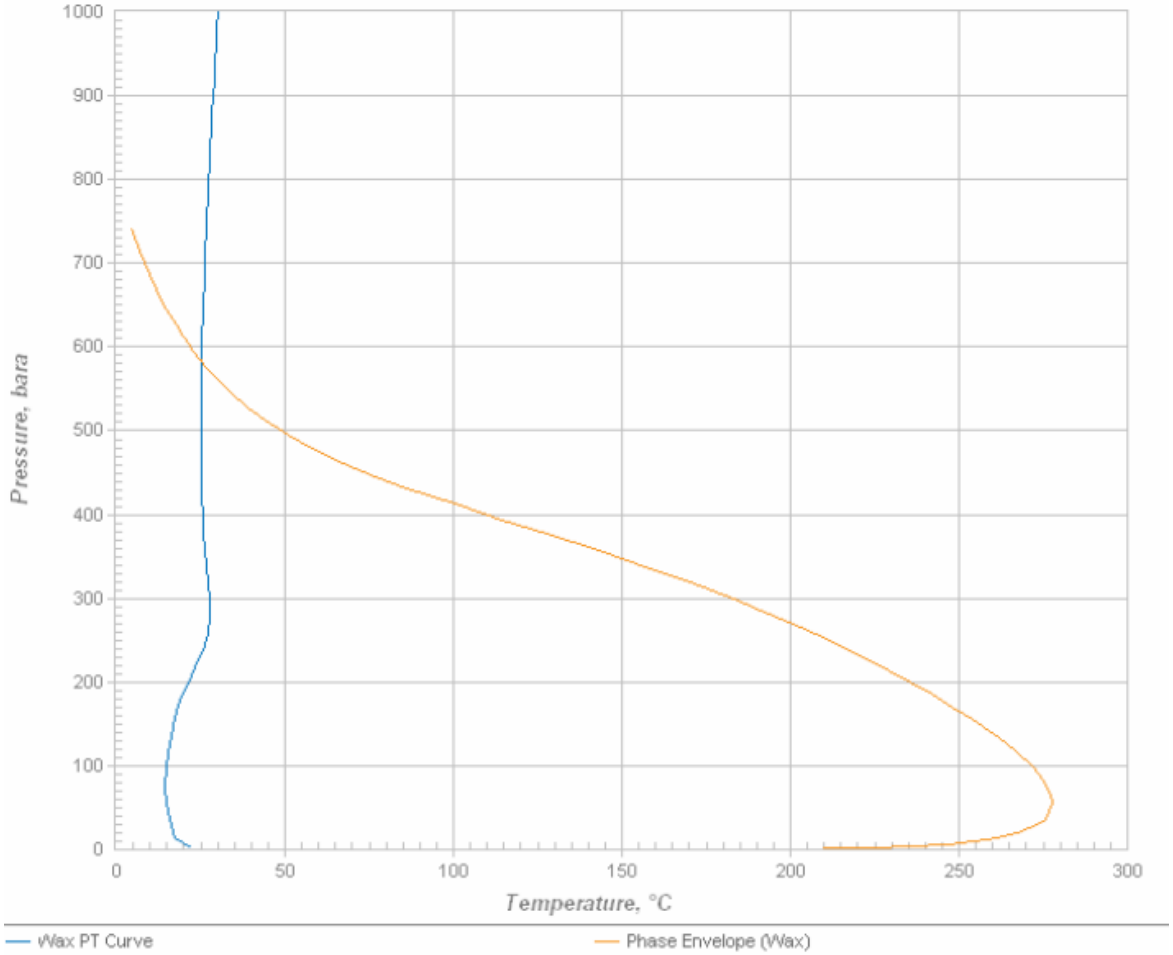


WAT by Cross Polar Microscopy



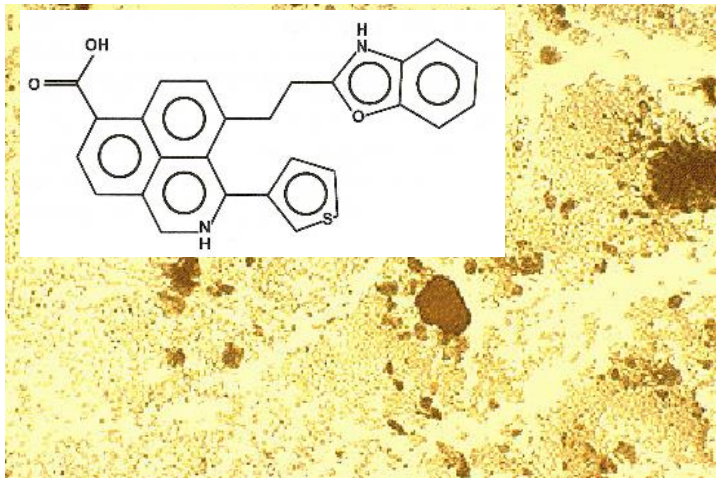
- Thermodynamic models can predict wax appearance Temperature (WAT) with
  - Detailed compositional analysis of oil
  - Quantitative n-paraffin analysis using high temperature (HTGC technique, C90+)
- The thermodynamic model may be combined with the model of flowline using software such as PIPESIM or OLGA to predict where wax deposits will occur, how fast wax will accumulate, and the frequency at which the line must be pigged.

- PVTSim prediction: Wax phase diagram



Asphaltenes and Scales

- Asphaltenes
  - : The heavy polar aromatic fraction
  - : Resulting blockage and formation damage
  - : The main causes are
    - A decrease in the system pressure
    - Mixing of incompatible crude oils
  - : Require asphaltene inhibitor injection



- Scales
  - : The carbonates or sulphates of calcium, strontium and barium
  - : $MgCO_3$, $CaCO_3$ scaling issues in the MEG system
  - : Require scale inhibitor injection

Corrosion

- Loss of metal

  : Metal loss caused be corrosive water

  : $Fe = Fe^{++} + 2e-$

  : Variables

  - Material
  - H_2S and CO_2 level in fluids
  - Water composition

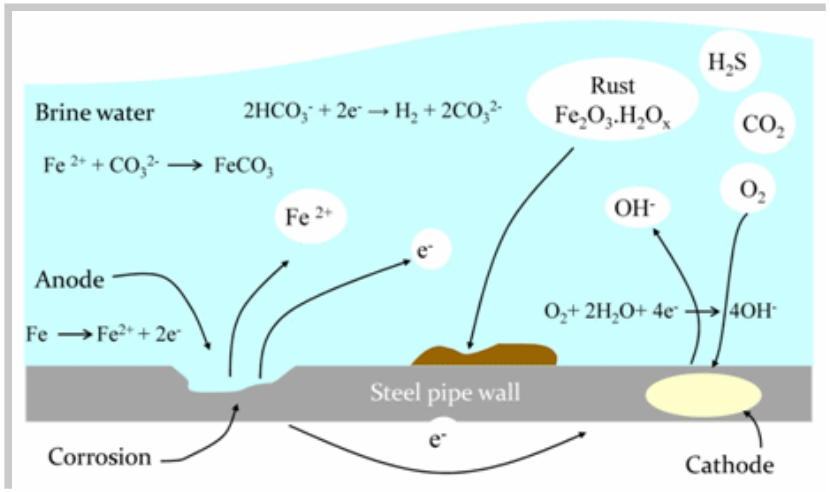
- Control strategy

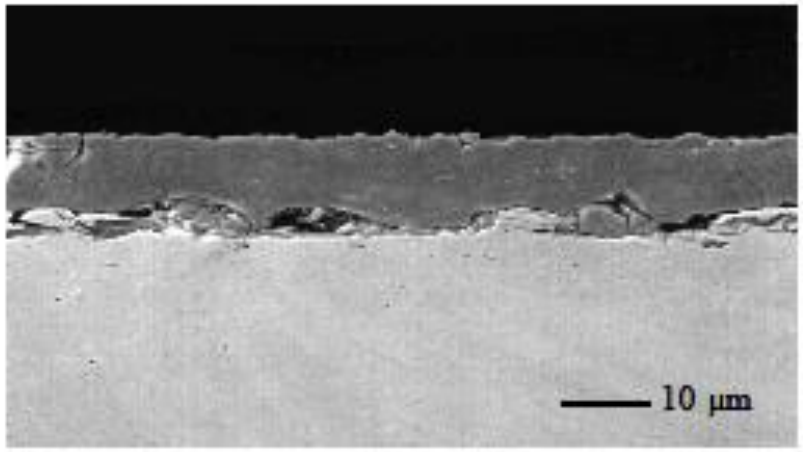
  : Alter chemical environment

  - Oxygen scavengers
  - Sulfide scavengers

  : Alter reactive surface of metal

  - pH control to form protective film
  - Corrosion inhibitors
  - Polymeric liners to flowlines





protective iron carbonate film formed at high pH (right).

Example treating chemicals properties and levels

Treating Chemical (& Injection location)	Viscosity at 40 oF (cP)	Density at 14.7 psia (g/cc)	P50 Treatment levels	
			(ppm-V)	basis
Paraffin Inhibitor (at tree)	4.1@ 14.7 psia 8.2 @ 10,000 psia	0.879 @ 60 oF	150	Oil
Scale Inhibitor (down hole)	37.8 @14.7 psia 41.5@10,000 psia	1.324@ 77oF	20	Water
Asphaltene Inhibitor (downhole)	12.4 @ 14.7 psi 35.3 @ 10,000 psi	0.926@ 60oF	250	Oil
Corrosion Inhibitor (at tree)	83.1 @ 14.7 psia 187.7 @ 10,000 psia	0.999@ 70oF	25	Oil + Water

Note: Treating chemicals from different suppliers (and different formulations from the same supplier, for the same function) can have greatly different physical properties and treatment levels.

Thank you!