Introduction to Offshore Platform Engineering

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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 = ν = 0.3

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

\[
P_e = 2 \times 29,000,000 \times \left( \frac{0.684}{16} \right)^3 = 4,980 \text{ psi}
\]

\[
P_c = \left( \frac{5,558 \times 4,980}{\sqrt{5,558^2 + 4,980^2}} \right) = 3,709 \text{ psi}
\]

\[
f_c P_e = 0.7 \times 3,724 = 2,596 \text{ psi}
\]

\[
P_o - P_i = 1,333.3 - 0 = 1,333.3 \text{ psi} \quad \text{during installation (empty pipe)}
\]

\[
P_o - P_i = 1,333.3 - 4,000 = -2,666.7 \text{ psi} \quad \text{during operation}
\]

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 \([P_o - P_i]_{\text{max}} \geq 0.8 P_p\) then, buckle arrester is required

Therefore,

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

\[
0.8 P_p = 0.8 \times 808 = 646 \text{ psi}
\]

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

\[\therefore [P_o - P_i]_{\text{max}} \geq 0.8 P_p \quad \therefore \text{buckle arrester is required}\]
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

Small ID induces lots of energy loss → larger pressure drop
Pressure drop vs. Flowrate in oil field flowlines

\[
\Delta P = P_1 - P_2 \\
\Delta P_{\text{total}} = \Delta P_{\text{friction}} + \Delta P_{\text{elevation}} + \Delta P_{\text{restriction}}
\]
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

\[ \Delta P = \frac{\rho \ f \ L \ v^2}{144 \ D \ 2g} \]

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

\( f: \) Friction factor
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

\[
Re = \frac{\rho D v}{\mu_e}
\]

\(\rho: \text{lb/ft}^3\) \(D: \text{ft}\) \(v: \text{ft/sec}\) \(\mu_e: \text{lb/ft} - \text{sec}\)

- \(Re < 2000 = \text{Laminar flow}\)

\[
\text{Liquid: } Re = 92.1 \frac{SG_L Q_{BPD}}{d \mu}
\]

\[
\text{Gas: } Re = 20100 \frac{SG_G Q_{MMCFD}}{d \mu}
\]

d: inches, \(\mu\): 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: \( \varepsilon / D \)

- For complete turbulence
  - \( f_m \) a function of \( \varepsilon / D \) only
Note: Absolute Roughness units are in feet. Relative Roughness is Dimensionless.

ε for Steel Pipe = 0.0015 feet
LIQUID:  \( Re = 92.1 \ S_{GL} \ \frac{Q_{BLPD}}{d_{\mu}} \)

GAS:  \( Re = 20,100 \ S_{Gg} \ \frac{Q_{MMCFD}}{d_{\mu}} \)

Re: REYNOLDS 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 = \text{SG}_L Q / d \mu
Pressure drop: Transitional and Turbulent

- Liquid

\[ \Delta P_{\text{psi}} = 11.5 \times 10^{-6} \frac{f_m L_f t Q_{BPD}^2 S G_L}{d_{in}^5} \]

- Gas

\[ P_1^2 - P_2^2 = 25.1 \frac{f_m L_f t Q_{MMCFD}^2 S G_G Z T_R}{d_{in}^5} \]
Exercise $\Delta P$: Liquid flow in Pipe

- What is the friction pressure drop in 10,000 ft of 2 inch ID pipe flowing 50 BPD of 35 $^\circ$API crude oil ($\mu=1.2$ cp and $\text{SG}_L=0.85$)?

1. First calculate Reynold’s number to determine flow regime:

   $\text{Re} = 1,631$ so flow is Laminar

2. Use the equation for

$$\Delta P_{\text{psi}} = 7.95 \times 10^{-6} \mu \frac{L}{\text{ft}} \frac{Q_{\text{BPD}}}{\text{inch}}$$

$$\Delta P_{\text{psi}} = 0.3 \text{ psi}$$
Exercise: Increasing flow rate 3000 BPD

1. First calculate Reynolds’s number to determine flow regime:

   \[ Re = 97,856 \]
   \[ Re > 2000 \] so flow is Non-Laminar.

2. Use the equation for Turbulent Transitional:

   \[
   \Delta P_{psi} = 11.5 \times 10^{-6} f_m L ft Q_{BPD}^2 SGL d_{in}^5
   \]

3. Determine \( f_m \) using chart:

   \[ \Delta P_{psi} = \]

   \[ \Delta P_{psi} = \]
$f_m$ for Steel Pipe
(ID & Re)

$d = 2''$
$	ext{Re: } = 97,856$

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

GAS: $Re = 20,100 \frac{SG_g \cdot Q_{MMCFD}}{d \cdot \mu}$
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**
  \[
  \begin{align*}
  \text{Liquid: } & \Delta P_{\text{psi}} = 7.95 \times 10^{-6} \mu_{cp} L_{ft} Q_{BLPD} / d_{\text{inch}}^4 \\
  \text{Gas: } & \Delta P_{\text{psi}} = 0.40 \mu_{g} L_{ft} T Z Q_{MMCFD} / P_{\text{psi}} d_{\text{inch}}^4
  \end{align*}
  \]

  **Non-Laminar**
  \[
  \begin{align*}
  \text{Liquid: } & \Delta P_{\text{psi}} = 11.5 \times 10^{-6} f_{m} L Q_{BLPD}^{2} SG_{L} / d_{\text{inch}}^5 \\
  \text{Gas: } & (P_1)^2 - (P_2)^2 = 25.1 f_{m} L Q_{MMSCFD}^{2} SG_{g} Z T / d_{\text{inch}}^5
  \end{align*}
  \]
What if pipeline is not horizontal?
Pressure drop due to Elevation

- Liquid: $\Delta P$ due to Elevation

$$\Delta P_{E(psi)} = \frac{\rho_L (lb/ft^2) H_E(ft)}{144} = 62.4 \cdot \frac{SG_L H_E(ft)}{144}$$

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

- Gas: $\Delta P$ due to Elevation

$$\Delta P_{E(psi)} = \frac{\rho_G (lb/ft^2) H_E(ft)}{144} = 2.70 \cdot \frac{SG_G P_{psi}/T_o R Z H_E(ft)}{144}$$

$$\Delta P_{E(psi)} = 0.188 \cdot \frac{SG_G P_{psi}}{T_o R Z H_E(ft)}$$
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 $\Delta P$ without using Friction Factor

- **Empirical equations**
  - Useful for quick calculation before use of PCs
  - Commonly accepted empirical equations
    - Hazen-Williams empirical equation (Liquid flow)
      \[
      \Delta P = 0.7 \times 10^{-6} \frac{Q^{1.85} L SG_L}{d^{4.87}}
      \]
      ($\Delta P$ in psi, $Q$ in BLPD, $L$ in feet, $d = ID$ in inches)
    - Weymouth formula (gas flow)
      \[
      P_2^2 = P_1^2 - \left[ \frac{0.8 L_{ft} T_R Z SG_G Q_{MMCFD}^2}{d_{in}^{5.334}} \right]
      \]
      - most common for oil field use
      - good for IDs between 0.75 inch & 16 inch
      - at Laminar rates, calculated $\Delta P$ is too low
    - Panhandle empirical equation (gas flow)
Panhandle: A & B Empirical equation

- For estimating $\Delta P$ without friction factor

**A:**

$$Q_{MMCFD} = \left[ \frac{0.020 \ E \ (P_1^2 - P_2^2)^{0.51}}{(SG_G^{0.853} zT^o_R L_{mi})^{0.539}} \right] d^{2.62}$$

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

**B:**

$$Q_{MMCFD} = \left[ \frac{0.028 \ E \ (P_1^2 - P_2^2)^{0.51}}{(SG_G^{0.961} zT^o_R L_{mi})^{0.51}} \right] d^{2.53}$$

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

$\Delta P$ 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
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 direction

- Stratified smooth flow (SS)
- Stratified wavy flow (SW)
- Elongated bubble flow (EB)
- Slug flow (I)
- Dispersed bubble flow (DB)
- Annular (wavy) flow (A-AW)
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 $\approx 20\%$ common
  - Use simulation software and experience
- API RP 14 E gives following simplified method
  - Assumes: $\Delta P < 10\%$, bubble / mist flow, $f=0.015$

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

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

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

First Generation of Steel-Bodied Pipeline PIGs
Introduced by T. D. Williamson Inc. in 1943
to Remove Paraffin from Large Diameter P/L
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**
  1. maintaining temperature above hydrate formation conditions (Insulation, DEH, etc)
  2. Decreasing the pressure outside the area of possible hydrate formation (for remediation)
  3. Removing the water (Subsea processing)
  4. 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, (°F):

\[ \Delta T = \left( \frac{2335}{MW} \right) \times \left( \frac{X}{1 - X} \right) \]

Where \( \Delta T \) 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 \( \Delta T \) was 5%.
Cubic Equation of State (1980’)

- Thermodynamic equilibrium

\[ f_{\text{Gas}} = f_{\text{LiqHC}} = f_{\text{Aq}} = f_{\text{Hyd}} \]
Effect of adding inhibitor

Cluster formation by hydrogen bonding:
- Lowering fugacity coefficient of water in aqueous phase
Inhibition Point

Hydrate Stability Zone

Hydrate Free Zone

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)
    \[ Kv = \exp (5.706 - 5738 \left( \frac{1}{T(°R)} \right)) \]
  - MeOH loss to liquid HC (correlation for CH₄, C₃H₈, n-heptane)
    \[ Kv = \exp (5.90 - 5404.5 \left( \frac{1}{T(°R)} \right)) \]
- 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 by corrosive water
  - \( \text{Fe} = \text{Fe}^{++} + 2\text{e}^- \)
  - Variables
    - Material
    - \( \text{H}_2\text{S} \) and \( \text{CO}_2 \) 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

![Corrosion diagram](image-url)
### Example treating chemicals properties and levels

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

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!