Multi-Phase Flow Modeling of Liquid Loading

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Summary

• Offshore liquid loading gas rate typically exceeds Turner by 20% up to 100%

• (Multi-phase) flow modeling provides various explanations, linked to parameters such as temperature gradient, inflow performance and deviation

• Transient multi-phase flow modeling offers new insights into mechanism of liquid loading e.g. onset of liquid loading is triggered by film flow reversal rather than droplet flow reversal

• Multi-phase flow modeling increases insight into role of different parameters such as deviation, tubing size and inflow performance
Offshore Field Data

Turner is lower limit
Actual can be 2x higher

\[ v_p (\text{water}) = \frac{5.62 \left( 67 - 0.0031p \right)^{1/4}}{(0.0031p)^{1/2}} \] \hspace{1cm} (7)

\[ q_g (\text{MMcf/D}) = \frac{3.06 \, p \, v_p \, A}{T_z} \] \hspace{1cm} (9)

Dunning, EGWDC2008
Steady State Flow Modeling (1)

- Original Turner equation has been modified
  - Coleman et al. (SPE20280): -20%
  - Guo et al. (SPE94081): +10%
    - Minimum kinetic energy
  - Abbas et al. (EGWDC2008): +30%
    - Minimum kinetic energy
- Temperature gradient influences location and magnitude of Turner rate (Sutton et al., EGWDC2008)
  - Bottom hole Turner rate higher at low FTHP and low temperature gradient: maximum +15% for offshore data set

FTHP = Flowing Tubing Head Pressure

**Dry Gas Case**
(2.441 Tubing)

<table>
<thead>
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<th>Wellhead Pressure, psia</th>
<th>Turner Ratio</th>
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Southern North Sea
~1.5 °F/100 Ft
FTHP>70 psia

In this presentation Turner refers to wellhead conditions!
Steady State Flow Modeling (2)

• Inflow performance influences minimum stable rate (Veeken, Belfroid et al., Sutton et al.)
  – $Q_{\text{min}}$ depends on interaction between outflow and inflow relations, impact increases with tubing size: maximum +100%

• Outflow relation influences deviation dependency
  – Captured by correction factor based on laboratory test results (0.05 m ID, air-water system)
    • Oudeman (SPE19103), modified Gray: maximum +31% at 45 degrees $(1 + 0.31 \sin(2 \times D))$
    • Belfroid et al. (SPE115567), modified Turner: maximum +35% at 37 degrees $\sin(1.7 \times (90 - D))^{0.63/1.74}$
  – Reflected as transition in flow pattern, $Q_{\text{min}}$ depends on outflow relation, inflow relation and tubing size: maximum +400%
A = $\frac{(P_{res}^2 - P_{bh}^2)}{Q}$

**Q_{min} Vs Deviation (A=0, THP=50 bara)**

- **Flow pattern changes at 45 degrees**
- **Straight & uniform wellbore**
- **MG=Modified Gray**
- **FRM=Flow Regime Map**

Graph showing Q_{min} vs. Deviation (in degrees) with different wellbore diameters and flow patterns.
Transient Multi-Phase Flow Modeling

- Apply software developed for modeling transient flow in pipelines to model heavily inclined pipelines a.k.a. wells
- Assume simple i.e. straight and uniform wellbore configuration, constant FTHP and water of condensation
- Slowly reduce reservoir pressure and record liquid loading point (gas rate, reservoir pressure, bottomhole flowing pressure, wellhead flowing temperature)
- Monitor flow regime, holdup, total water flow and film water flow along wellbore
- Vary deviation, tubing size and inflow performance
0.1 m ID, 50 bar FTHP, A=2.69, 0 deg

\[ A = \frac{\left(P_{\text{res}}^{2} - P_{\text{bh}}^{2}\right)}{Q} \]

- \( P_{\text{res}} : 70 \Rightarrow 65 \text{ bar in 100 days} \)
- \( Q_{\text{min}} = 130 \times 10^3 \text{ m}^3/\text{d} \)
- \( P_{\text{ab}} = 67.5 \text{ bar} \)
- \( P_{\text{min}} = 64.7 \text{ bar} \)

\( Q_{\text{gas}} = \text{gas rate (e}6\text{m}^3/\text{d)} \)

\( Q_{\text{water}} = \text{water rate (m}^3/\text{d)} \)

- FBHP = flowing bottomhole pressure (bar)
- FTHT = flowing tubing head temperature (degC)
3 km deep, 10 deg deviation, 0.1 m tubing, 50 bar FTTHP, annular flow, droplet flow and film flow both important

Near-Vertical

Flow regime = Annular

Holdup = 0.007

Gas = 0.184e6 m³/d

Total water = 3.2 m³/d

Water film = 1.7 m³/d
Liquid loading starts when film flow “flips” i.e. changes from upward to downward, generally starts at wellhead.

See e.g. van ‘t Westende et al. in Int. J. of Multiphase Flow 33 (2007) 595-615.

**Near-Vertical**

- Gas = 0.129e6 m³/d
- Total water = 2.4 m³/d
- Water film = 0.0 m³/d
- Flow regime = Annular
- Holdup = 0.015

**Graph Details:**
- **Flow regime** indicator
- **Holdup** (Liquid Volume Fraction)
- **Gas Volume Flow at Standard Conditions**
- **Volumetric Flow Rate Water Film**
Downward film flow increases holdup and shifts holdup downward, increasing droplet flow upward partly compensates for film flow downward.

- Near-Vertical
- Holdup = 0.013
- Water film = -0.2 m³/d
- Total water = 1.5 m³/d
- Gas = 0.117e6 m³/d
- Flow regime = Annular
- Holdup = 0.013
At some point total water flow becomes downward.

- Gas = 0.104e6 m³/d
- Total water = 0.7 m³/d
- Water film = 0.0 m³/d
- Flow regime = Annular
- Holdup = 0.019

At some point total water flow becomes downward.
Near-Vertical

At high enough holdup flow regime changes from annular to slug flow, happens at bottom

- Gas = 0.082e6 m³/d
- Total water = 0.1 m³/d
- Water film = 0.0 m³/d
- Flow regime = Slug-Annular
- Holdup = 0.005
Eventually gas flow virtually stops and water accumulates at bottom (100% holdup)

Flow regime: Slug-Annular

Gas = 0.005e6 m³/d

Total water = 0.0 m³/d

Water film = 0.0 m³/d

Holdup = 0.000
0.1 m ID, 50 bar FTTHP, A=2.69, 45 deg

\[ P_{\text{res}} : 80 \Rightarrow 70 \text{ bar in 100 days} \]

\[ Q_{\text{min}} = 245 \times 10^3 \text{ m}^3/\text{d} \]

\[ P_{\text{ab}} = 76.4 \text{ bar} \]

\[ P_{\text{min}} = 72.0 \text{ bar} \]

\[ A = \frac{(P_{\text{res}}^2 - P_{\text{bh}}^2)}{Q} \]

\[ Q_{\text{gas}} = \text{gas rate (e}6\text{m}^3/\text{d}) \]

\[ \text{FBHP} = \text{flowing bottomhole pressure (bar)} \]

\[ \text{FTHT} = \text{flowing tubing head temperature (deg)} \]

\[ Q_{\text{water}} = \text{water rate (m}^3/\text{d)} \]
In this presentation Turner refers to wellhead conditions.

Q_{min} Vs Deviation (0.1 m ID, 50 bara FTHP)

Annular Flow
Stratified Flow

Flow pattern changes at 30 degrees
Tubing Size (50 bara FTHP)

Large impact of tubing size and inflow performance above 30 degrees.
Offshore Field Data (mostly 5” tubing)

Vertical wells: \( Q_{\text{min}} \approx Q_{\text{olga}} \approx 1.2 \times Q_{\text{Turner}} \)

Graph with data points and a linear fit:

\[ y = 0.0075x + 1.1985 \]
Mixed Trajectory (0.1 m ID, 50 bara FTHP)

Vertical at top, 45 degrees deviated at bottom Kick-off point impacts minimum stable rate.
Mixed Tubing Size (Vertical, 50 bara FTHP)

- Section with larger tubing size impacts $Q_{\text{min}}$ if it covers more than 5-10% of total length and governs $Q_{\text{min}}$ if more than 50%.

- Mix of 0.10 m and 0.15 m

![Graph showing mixed tubing size impact on $Q_{\text{min}}$]
Calculated Vs Actual $Q_{\text{min}}$

Compared to Turner the transient multi-phase flow model matches actual liquid loading better.

- $y = 1.15x$, $R^2 = 0.92$
- $y = 0.69x$, $R^2 = 0.90$
Conclusions

- In offshore wells the onset of liquid loading occurs at significantly higher rates than predicted by Turner.
- This can be explained qualitatively by the combined effect of well deviation and/or tubing size.
- It is reasonable to assume that an outflow relation based on flow patterns provides a more realistic description of liquid loading in deviated wells.
- The onset of liquid loading appears to be related to flow reversal of the liquid film rather than the liquid droplets.
- Compared to Turner the transient multi-phase flow model matches actual liquid loading better.
- (Transient) multi-phase flow modeling based on flow patterns is expected to generate new and useful insights into liquid loading and deliquification, especially for larger and deviated wells.
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