



Flow Assurance in Wellbores and Pipelines: What You **NEED** to Know

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Outline

- What is Flow Assurance?
- Why Model?
- The Basics of Multiphase Flow
- Multiphase Models for Vertical and Horizontal Flow
- The Importance of Fluid Properties
- Matching Measured Pressure Losses
- Tubing Performance Curves
- Minimum Stable Flow Rate
- Conclusions

What is Flow Assurance ?

- Flow Assurance is making sure the gas/oil/water from the wells makes it to the delivery location.
- Concerns:
 - Pipeline or wellbore rupture from corrosion
 - Pipeline blockage by hydrates or wax
 - Severe slugging in riser destroys separator
 - Well can't lift its liquids and dies
 - Separator flooded by liquids
 - Large pressure losses in pipelines cause flow rates to be lower than should be

What is Flow Assurance ?

- “Garantia de Fluxo” \Rightarrow “Guarantee the Flow”
–coined by Petrobras in the early 1990’s
- All aspects of production from the reservoir through to the plant inlet
 - Hydraulic Analysis - pressure loss
 - Thermal Analysis - heat loss
 - Operability - cooldown, slugging
 - Blockages - hydrates, wax, scale, sand
 - Phase behaviour & viscosity
 - Mechanical Integrity - corrosion, erosion
 - Mitigation - chemical injection, choking

How to Ensure Flow Assurance ?

- Ensure the gas/oil/water from the wells makes it to the delivery location by:
 - Calculating mixture composition in pipeline
 - Calculating flowing temperature
 - Calculating flowing pressure
 - Comparing the above to the conditions required for corrosion, hydrates, wax, severe slugging, and liquid loading
 - Determining how these items change with depletion and with operating conditions

Why Model ?

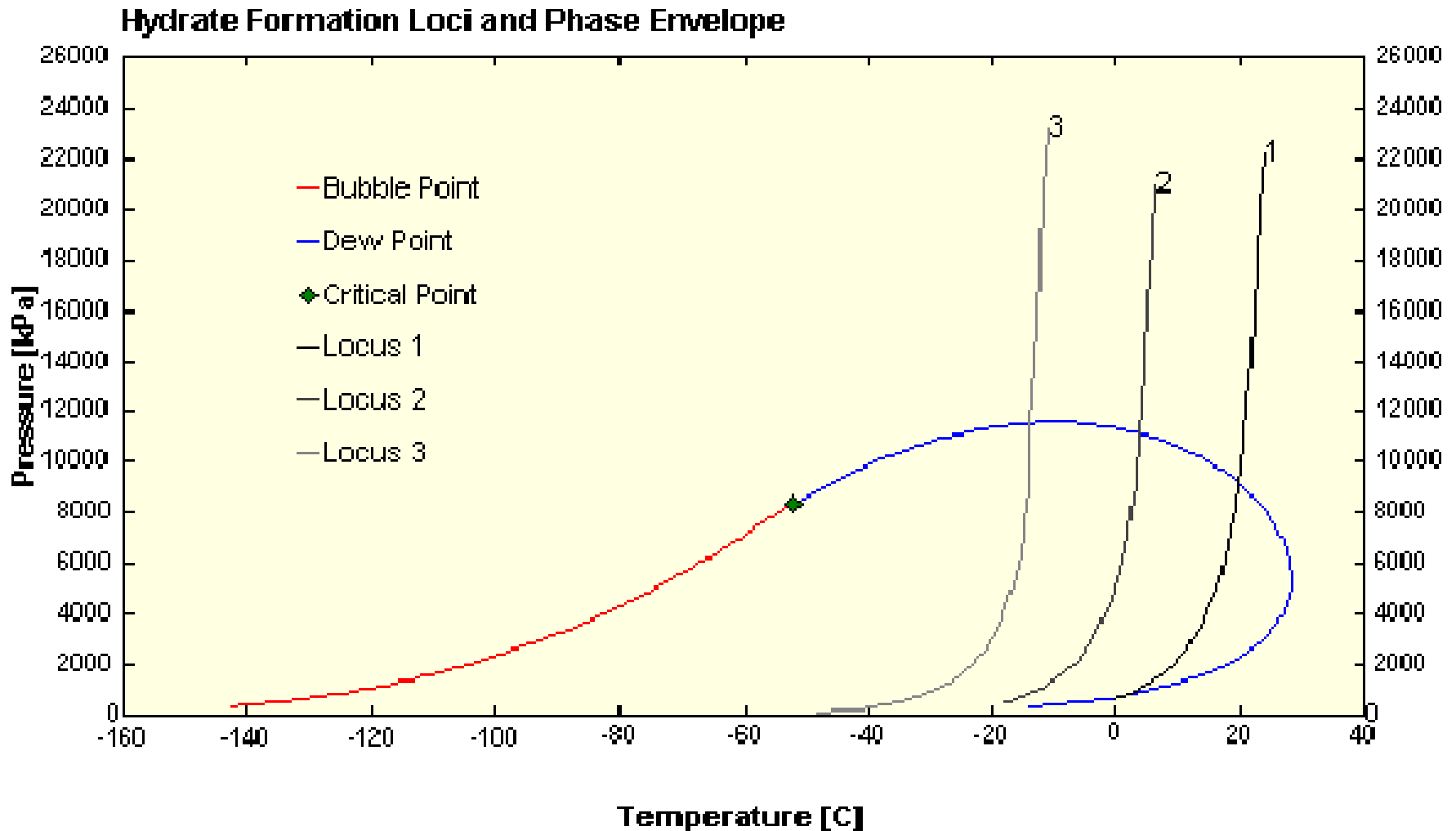
- The aim of modeling is to describe mathematically
 - what has happened
 - what is happening
 - what will happen in a physical system.

Why Model ?

Modeling is a very cost effective way to

- Enable safe operation
- Optimize new and existing systems
- Reduce downtime
- Enable rigorous screening of various options in existing and potential systems
- Reduce uncertainty

Hydrate Formation



Wax Formation

- Depend on Composition:
 - Cloud Point
 - Wax Appearance Temperature
 - Pour Point
- Thickness of wax layer depends on:
 - Composition of oil
 - Temperature
 - Pressure
 - Velocity of fluid

Internal Corrosion

- Internal corrosion depends on
 - Composition, CO₂, pH
 - Location and amount of water (at low points)
 - Velocities and shear rates
 - Flow pattern
 - Pressure and temperature

All of which can be calculated with multiphase pressure and temperature calculations

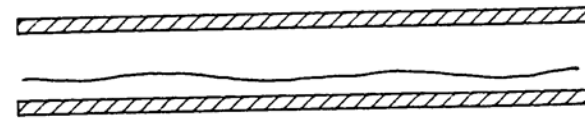
Temperature

- Fluid properties depend on mixture composition, pressure and temperature (e.g. Joule Thomson effects)
- Fluid temperature depends on:
 - Surroundings temperature
 - Surroundings conductivity (limestone, sea water, air)
 - Insulation
 - Inside film conductivity
 - Residence time

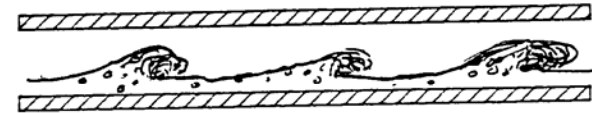
The Basics of Multiphase Flow

- Total pressure loss =
 - hydrostatic + friction + kinetic
- Flow pattern
- Input liquid fraction < liquid in situ (holdup)
- Most correlations model 2 phase (not 3 phase) flow

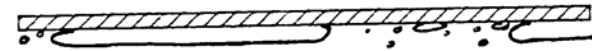
Flow Patterns in Horizontal Flow



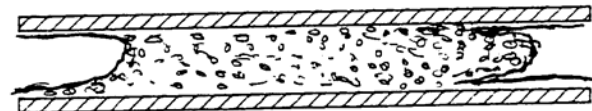
STRATIFIED



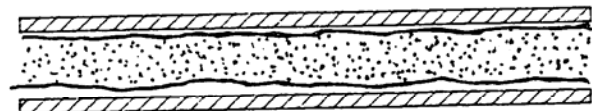
WAVE



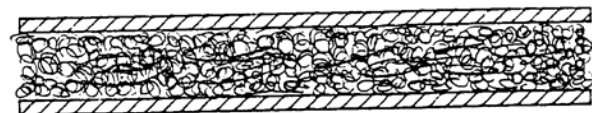
ELONGATED BUBBLE



SLUG

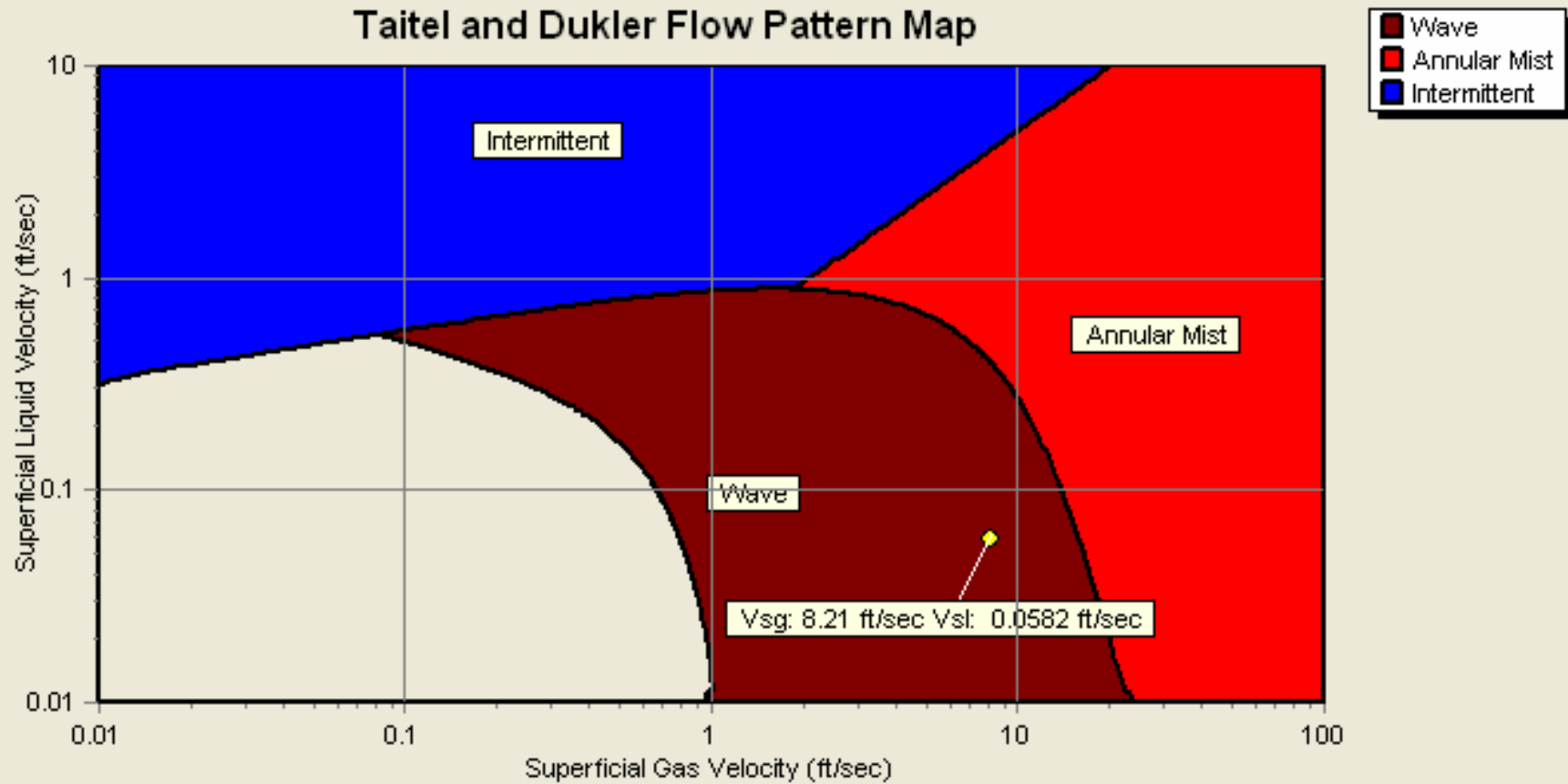


ANNULAR-MIST



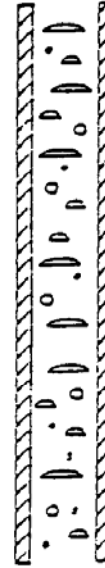
DISPERSED BUBBLE

Horizontal Flow Taitel and Dukler Flow Pattern Map



Flow Patterns in Vertical Flow

BUBBLE



SLUG



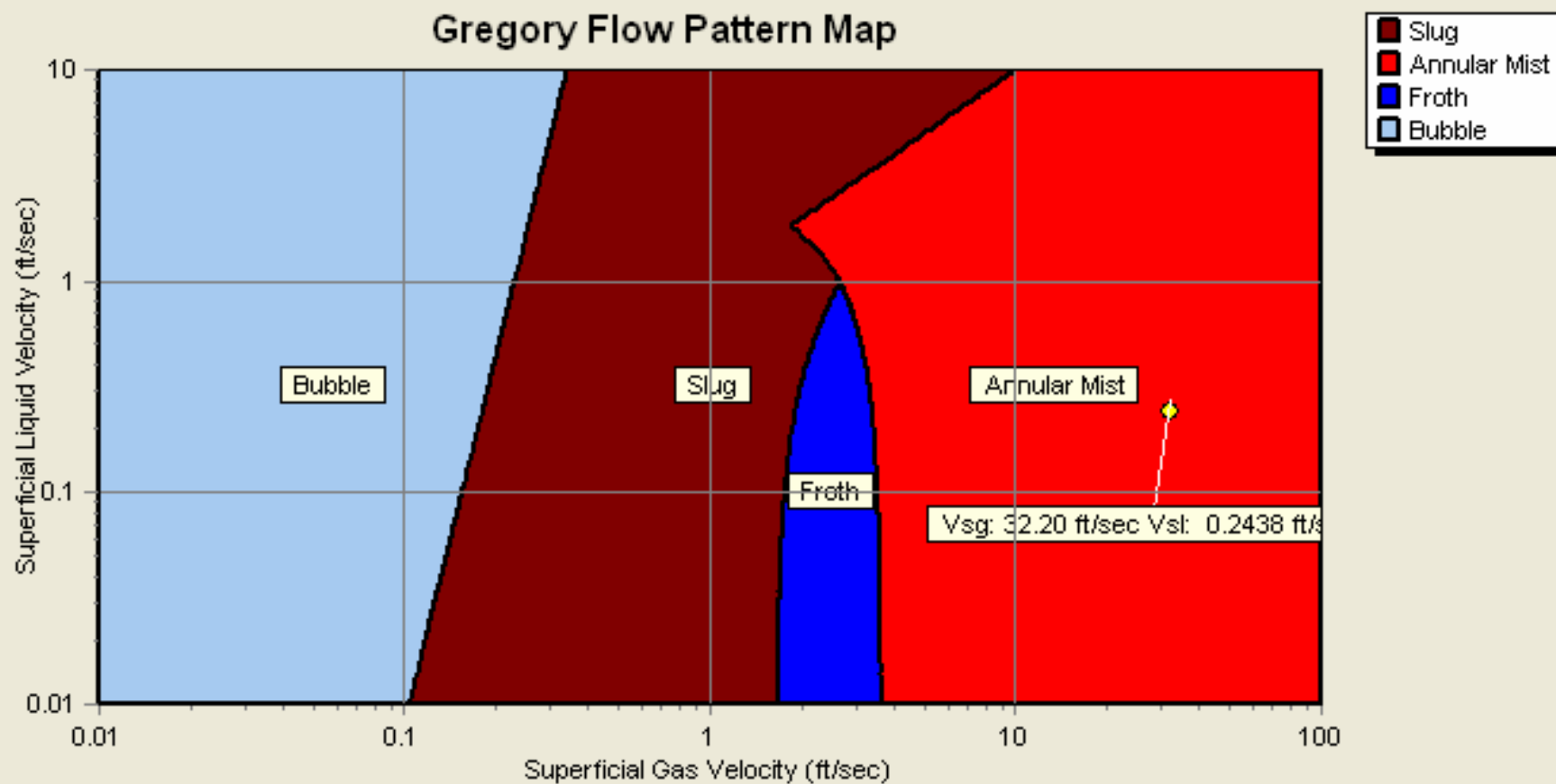
TRANSITION



**ANNULAR
MIST**



Vertical Flow Gregory Flow Pattern Map



Hydrostatic Pressure Loss

- Going uphill, lose mixture head

$$\Delta P_{HH} = \Delta z (\rho_G E_G + \rho_L E_L)$$

- Going downhill, only recover the gas head

$$\Delta P_{HH} = \Delta z \rho_G$$

- All of the ups and downs are important
- Under low flow rates, large pipes going uphill will have LARGER pressure losses than smaller pipes

Horizontal Empirical Models

- Flanigan (1958)

Drastically underpredicts pressure losses for more than 50 bbl/MMscf of liquids

- Beggs & Brill (1973)

- Built for all angles of inclination but uses only a horizontal flow pattern map
- Uses exponents based on flow pattern
- Gives poor results, especially for gas-condensate

Horizontal Empirical Models

- Eaton (1967) for holdup and Oliemans (1976) for frictional pressure loss
 - Eaton does not include angle of inclination and can underpredict holdup in hilly terrain
 - Eaton - Oliemans recommended for gas-condensate or gas-water systems
 - OK for gas-oil
 - Flanigan head factor can help for hydrostatic pressure losses in hilly areas

Horizontal Empirical Models

- Hughmark (1962) & Dukler (1964)
 - Hughmark overpredicts holdup for gas-condensate but is OK for gas-oil
 - Recommended for oil-gas systems but overpredicts for gas-condensate
- Lockhart and Martinelli (1949)
 - Best correlation for laminar flow
 - Overpredicts in turbulent flow

Horizontal Mechanistic Models

- Oliemans (1987)
 - Includes angle of inclination
 - Only for stratified or wave flow
 - Better at liquid holdup than Eaton
- OLGAS (1991, 2000) from Scandpower
 - Handles all angles of inclination
 - Excellent liquid holdup prediction
 - Especially good for hilly terrain
 - Recommended

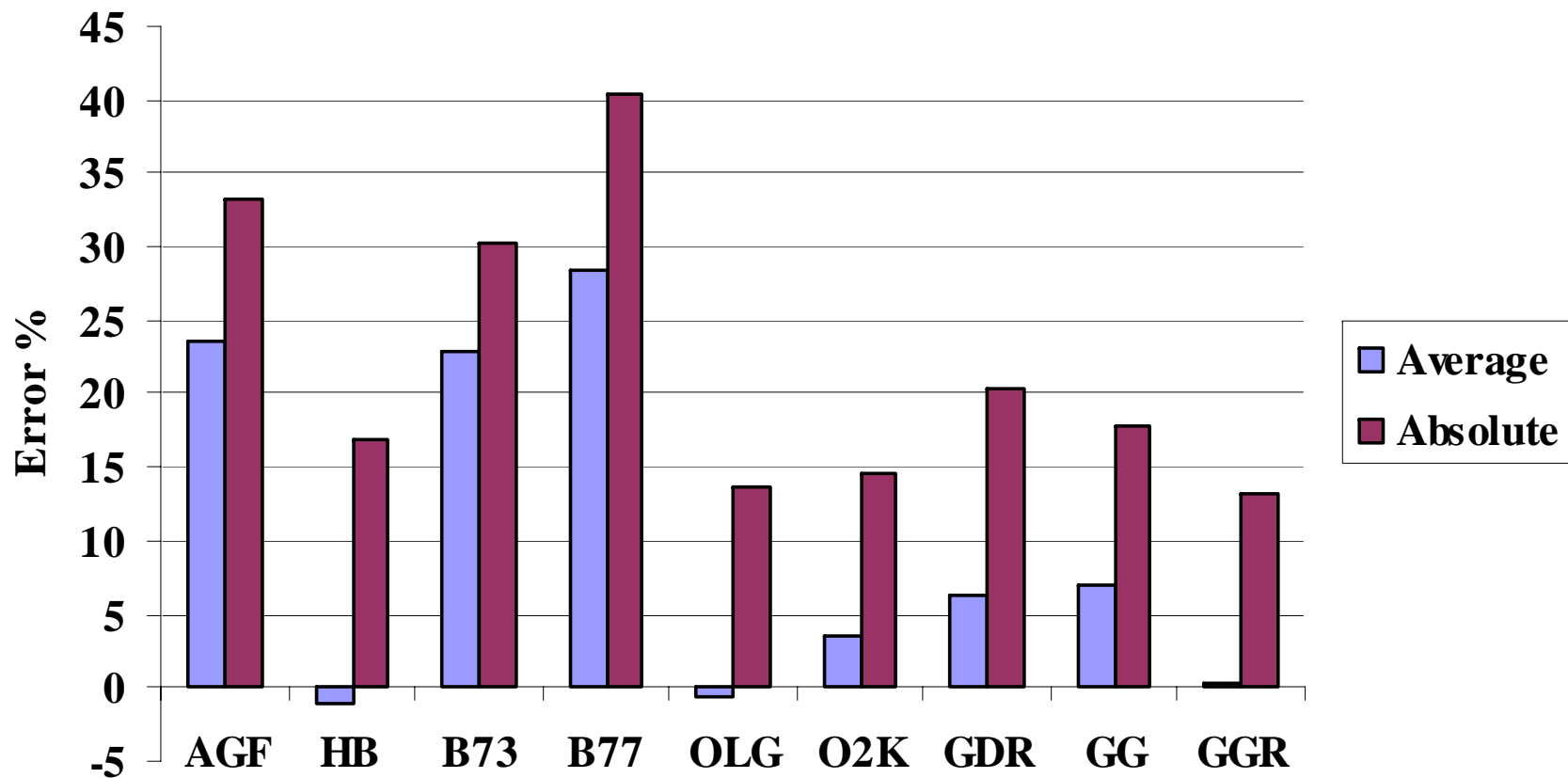
Vertical Empirical Models

- Beggs & Brill (1973, 1977)
 - Very poor results, especially for gas-condensate
- Gray (1978)
 - Does not use flow pattern or Reynolds number
 - Only for wet gas wells at high flow rates
- Hagedorn & Brown (1965)
 - Only total pressure loss was measured
 - No flow pattern thus can't predict minimum stable flow rate

Vertical Mechanistic Models

- Aziz, Govier and Fogarasi (1972)
 - Overpredicts minimum stable flow rate for gas/water and gas/condensate wells
 - With homogeneous flow in AMF works well for oil wells
- Gregory (1989)
 - Based on AGF with better transition to AMF
 - Allows choice in AMF: of Duns & Ros (1963) and Gray (1978)
- OLGAS (1991), OLGAS 2000
 - Excellent

Comparison: 109 Gas-condensate & 13 Gas-Water Wells (2003)



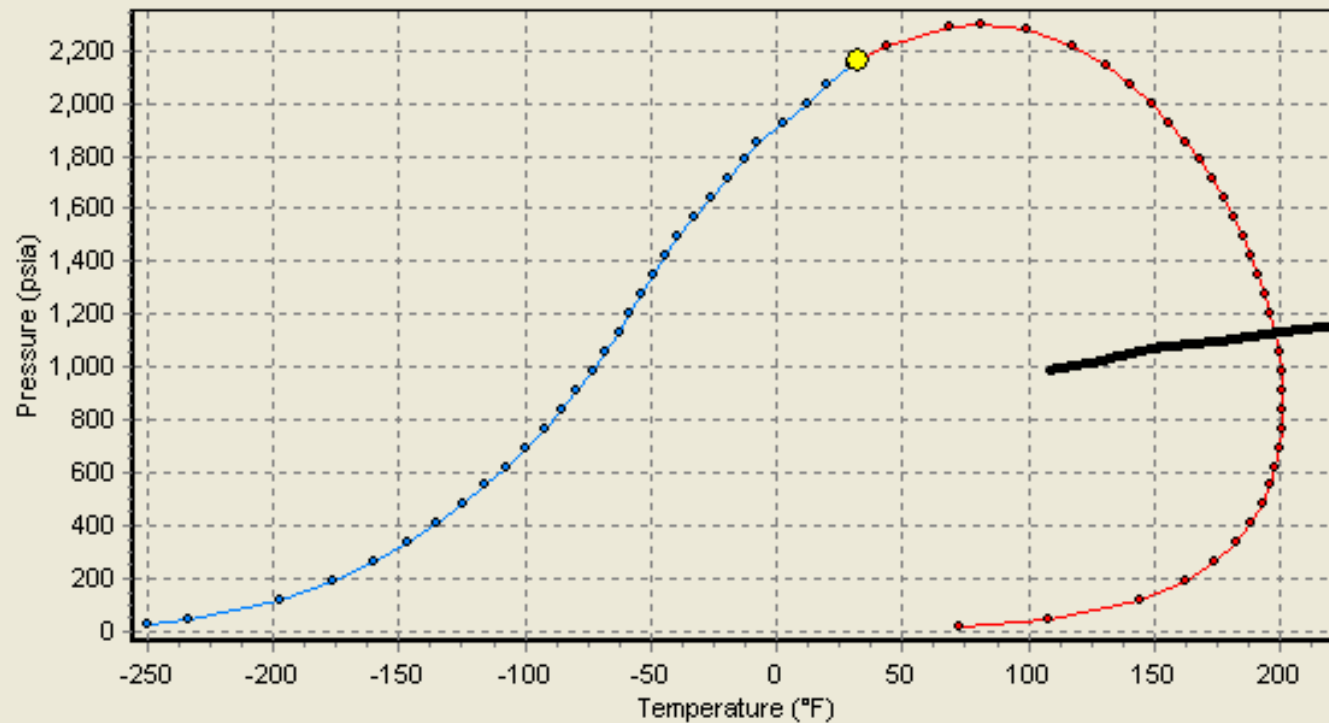
Don't Use the Wrong Model

- Use vertical correlations only for vertical
- Don't use vertical production correlations for multiphase injection
- Only OLGAS and Beggs & Brill can be used for all pipe inclinations
- Use Gray only for annular mist flow
- Avoid use of Beggs and Brill, especially for gas-condensates

Importance of Fluid Properties

- Multiphase correlations are very sensitive to density, viscosity and surface tension
- Presence or absence of liquid is the most important, not the relative amounts
- Significant liquid is $1 \text{ bbl/MMscf} = 5.6 \text{ m}^3/10^6 \text{ m}^3$
- For gas-water, need to determine how much water is liquid and how much is vapour
- For gas-condensate, need flash calculations to determine if there is condensate

Phase Envelope



- Dew Point Curve
- Bubble Point Curve
- Critical Point
- Pipeline P vs. T Curves

Cricondenbar: 2298 psia
Cricondenbar: 2298 psia
Critical Temperature: 32.5 °F
Critical Pressure: 2162 psia

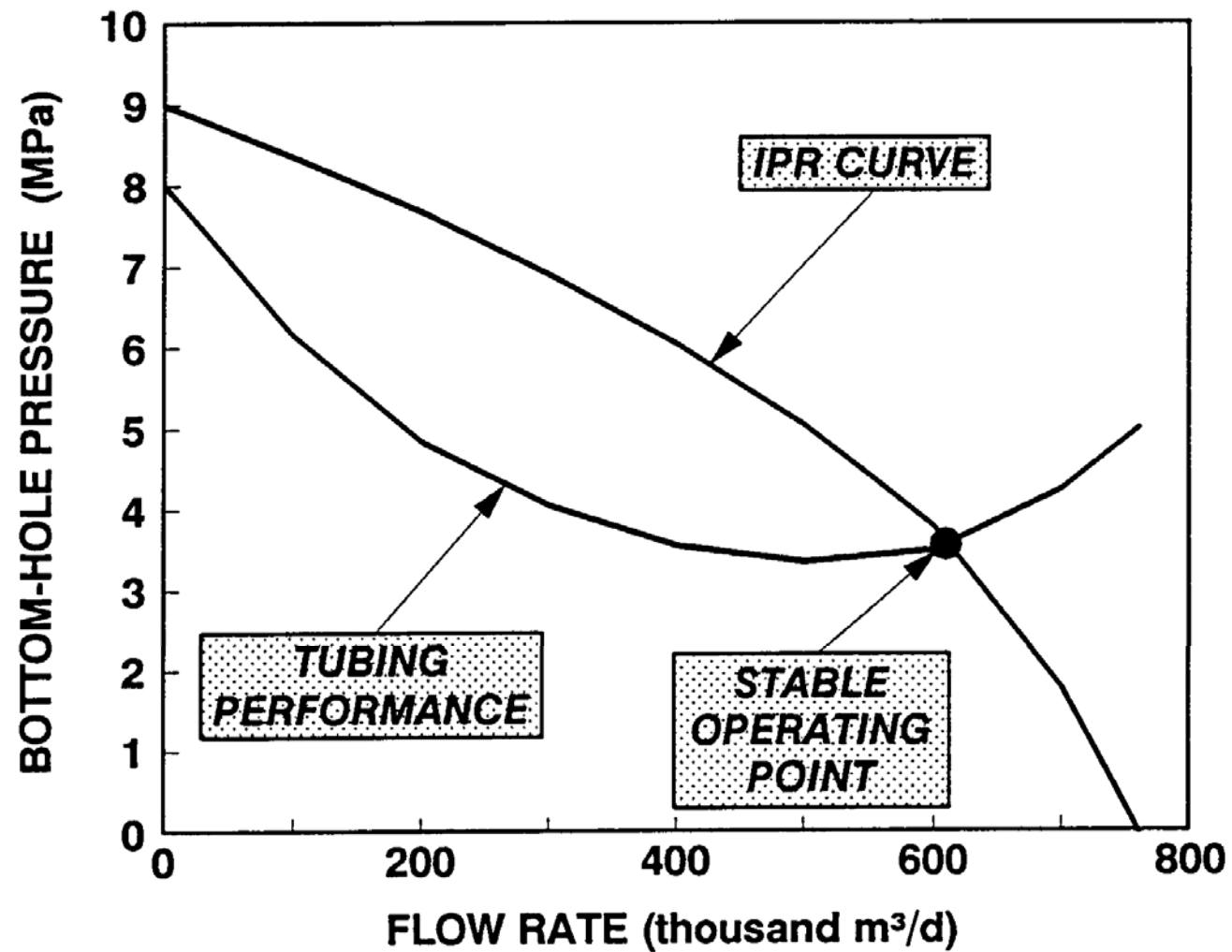
Matching Pipeline Pressures

- Match to within measurement tolerances
- Use Eaton (1967) - Oliemans (1976) for gas-condensate and Hughmark (1962) - Dukler (1964) for gas-oil
- Adjust roughness: 1/3 to 10 x average steel pipe roughness (0.0018 inch -or- 0.046 mm)
- Enter detailed elevation profile
- If not matching: try with/without Flanigan head factor, then try OLGAS 2000 2 phase from Scandpower
- Recheck input data

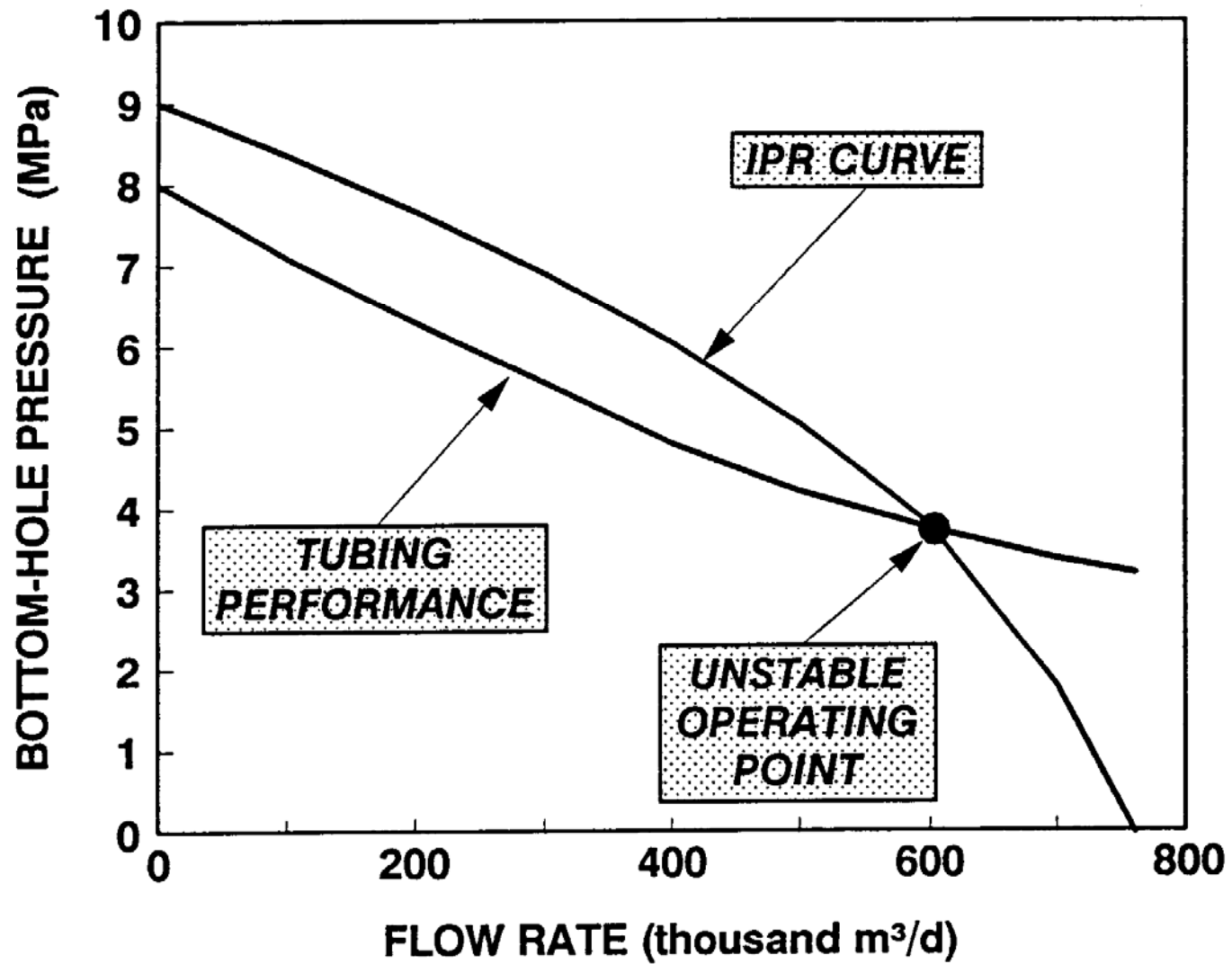
Matching Wellbore Pressures

- Match to within measurement tolerances
- Use Gregory with Gray revised for gas/water and gas/condensate
- Use AGF + Homogeneous flow for oil
- Calculate in the direction of flow
- Adjust roughness: 1/3 to 10 x average steel pipe roughness (0.0018 inch -or- 0.046 mm)
- OLGAS 2000 2 phase from Scandpower
- Recheck input data if not matching

Tubing Performance Curve - Stable



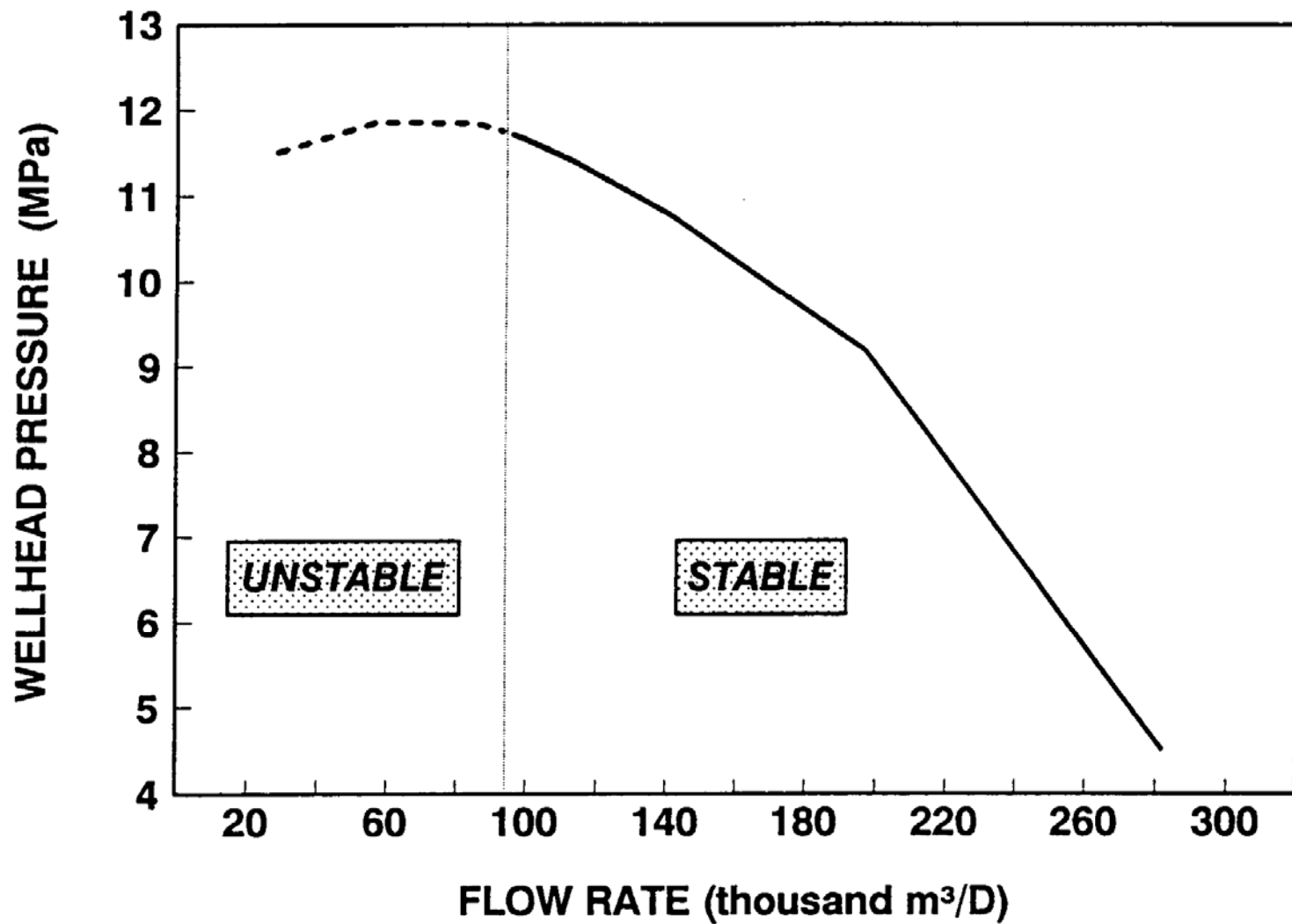
Tubing Performance Curve - Unstable



Minimum Stable Flow Rate

- Minimum stable flow rate is the minimum rate at which the gas can continuously lift the liquids
- Use tubing performance to calculate
- Will decrease as reservoir pressure decreases or with lower sandface deliverability because the lower the sandface pressure, the higher the gas velocity will be to lift liquids

Wellhead Deliverability Curve



Conclusions

- Calculating composition, pressure and temperature is necessary to determine if there will be hydrates, wax, corrosion, and excessive pressure losses, etc.
- Elevation is very important.
- Size matters. Bigger is NOT always better.
- Fluid properties are very important
- Presence or absence of liquid is more important than relative volume of liquids
- Use correlations only for which they were designed

Society of Petroleum Engineers



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