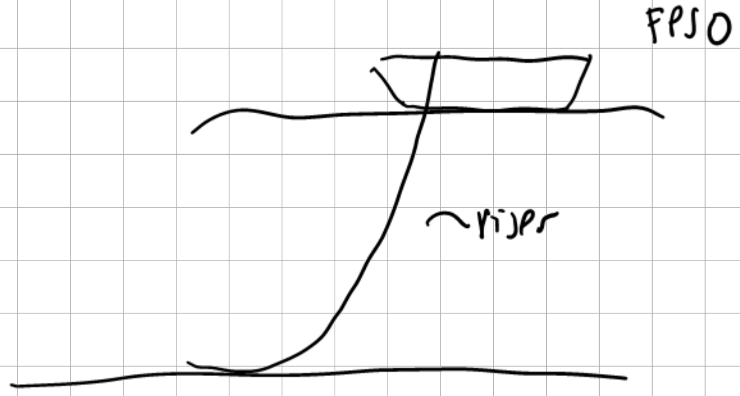
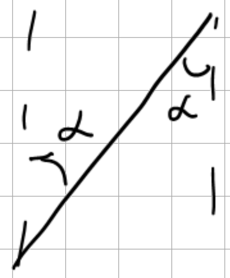


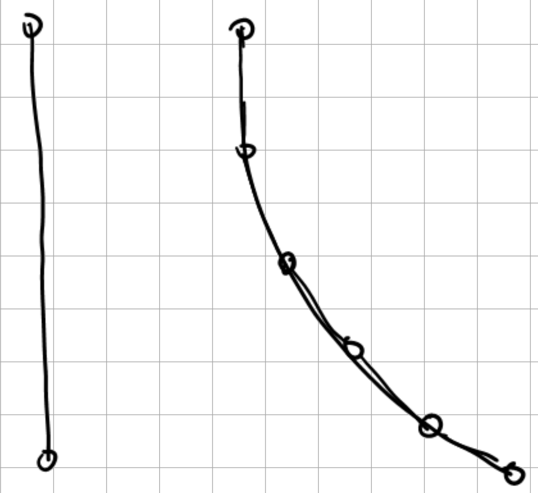
$C_{PL}, C_{FL}, C_{riser}$ $\quad p_1 \rightarrow p_2$

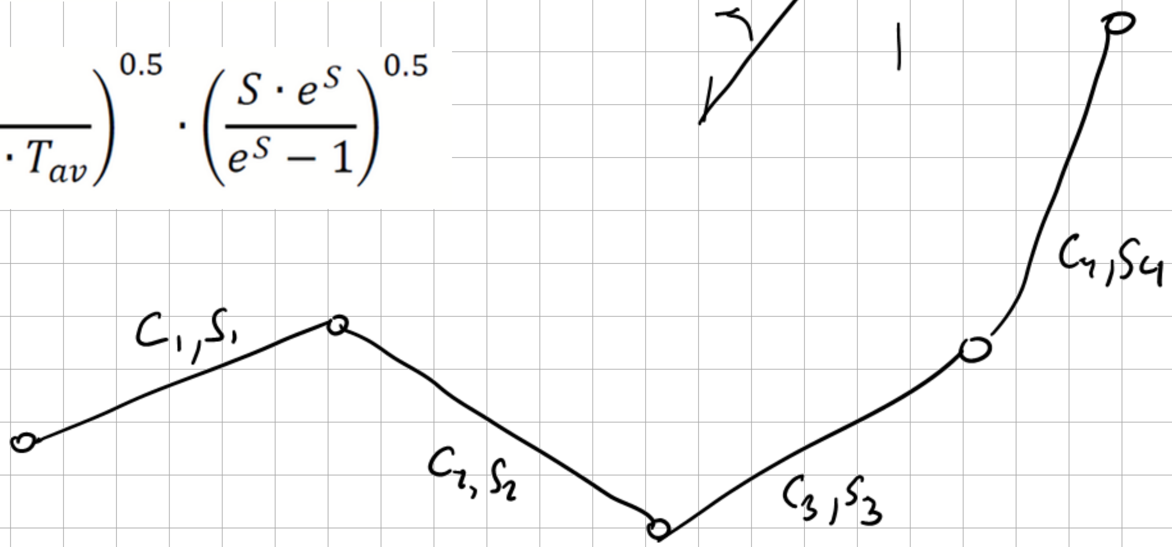
$$q_{sc} = C_T \cdot \left[\left(\frac{p_{wf}^2}{e^S} - p_t^2 \cdot\right)\right]^{0.5}$$

$$S = 2 \cdot L \cdot C_a = 2 \cdot \frac{M_g}{Z_{av} \cdot R \cdot T_{av}} \cdot L \cdot g \cdot \cos(\alpha)$$



$$C_T = \left(\frac{\pi}{4}\right) \cdot \left(\frac{R}{M_{air}}\right)^{0.5} \cdot \left(\frac{T_{sc}}{p_{sc}}\right) \cdot \left(\frac{D^5}{f_M \cdot L \cdot \gamma_g \cdot Z_{av} \cdot T_{av}}\right)^{0.5} \cdot \left(\frac{S \cdot e^S}{e^S - 1}\right)^{0.5}$$





Special case of horizontal pipe $\quad S=0$

however when calculating C $\rightarrow \dfrac{S \cdot e^S}{(e^S - 1)}$ $\quad S=0 \quad \dfrac{0 \cdot 1}{(1-1)^{\to 0}} = \dfrac{0}{0}$

use L'Hopital rule

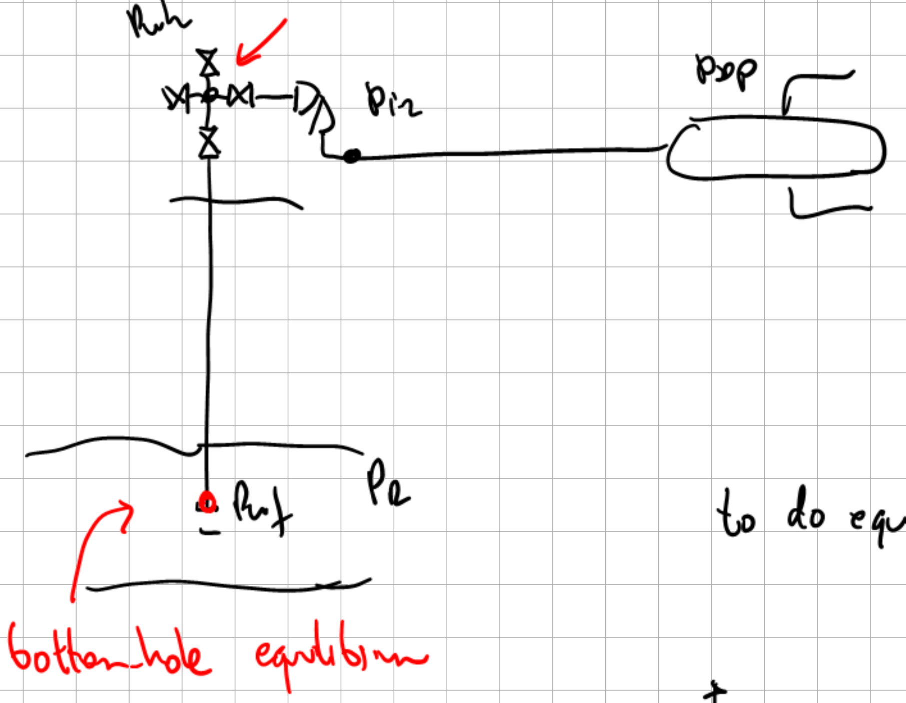
$$\lim_{x \to 0} \frac{f(x)}{g(x)} \rightarrow \text{undefined}$$

$$\lim_{x \to 0} \frac{f'(x)}{g'(x)} \quad \frac{(e^S + Se^S)}{(e^S)} \overset{S \to 0}{=} \frac{1+0}{1} = 1$$

in horizontal pipe $\dfrac{Se^S}{(e^S - 1)} = 1$

if $\phi \uparrow \rightarrow C_{FL} \uparrow \rightarrow$ lower Δp (or larger rate)

if $L \uparrow \rightarrow C_{FL} \downarrow \rightarrow$ higher Δp (or lower rate)

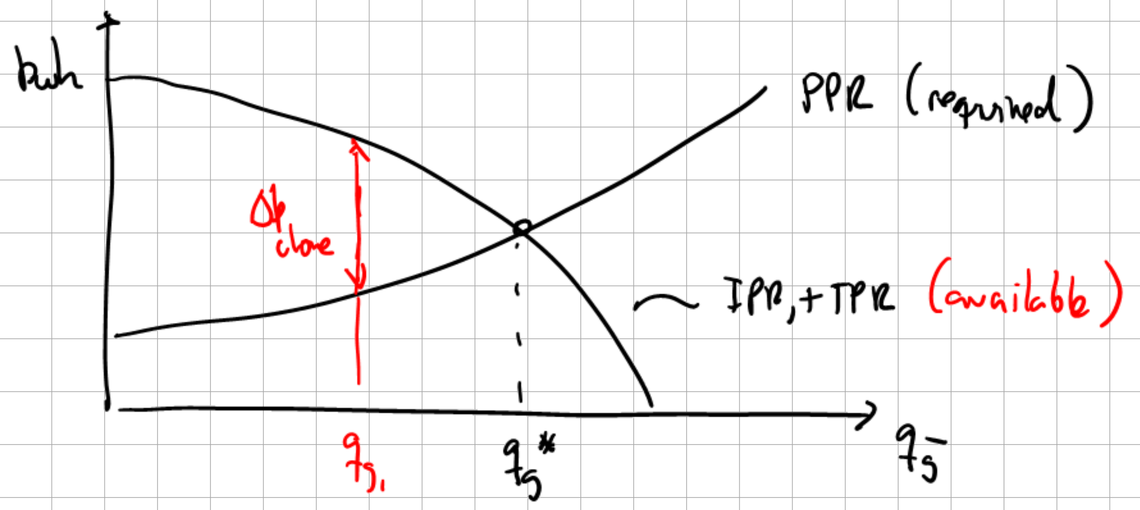


$\Delta p_{choke} = (P_{wh} - P_{in})$

when $\Delta p_{choke} = 0$

$p_{wh} = p_{in}$

to do equilibrium with flowline



p_R, Res pressure	304	bara	
C_R	104	Sm3/d/bar^2n	
n, exponent	0.9		
C_t, tubing	4.25E+04	$Sm^3/d/bar$	
s, elevation	0.155		
C_{fl}, flowline	1.25E+05	4.00E+04	$Sm^3/d/bar$
p_{sep}	40	bara	

$$q_g = c(p_R^2 - p_{wf}^2)^n$$

Tubing performance relationship (TPR)

$$p_{wh} = p_2 = \left(\frac{p_1^2}{e^s} - \frac{q_g^2}{C_T^2}\right)^{0.5}$$

Flowline performance relationship (FPR)

$$\boxed{q_{\bar{g}} = C_{FL} \cdot \left(p_{in}^{\ 2} - p_{out}^{\ 2}\right)}$$

assumed

IPR-qg

pwf [bara]	qg-IPR [Sm3/d]	pwf-TPR [Sm3/d]	WPR [Sm3/d]	PPR - 1 [bara]	PPR - 2 [bara]
304	0.00E+00	43			
250	1.11E+06	52			
200	1.84E+06	64			
150	2.38E+06	74			
100	2.76E+06	82			
50	2.99E+06	87			
0	3.06E+06	89			
84.378937	2.85E+06	84			

wellhead performance relationship

$p_{wf} \rightarrow p_{wh}$

TPR

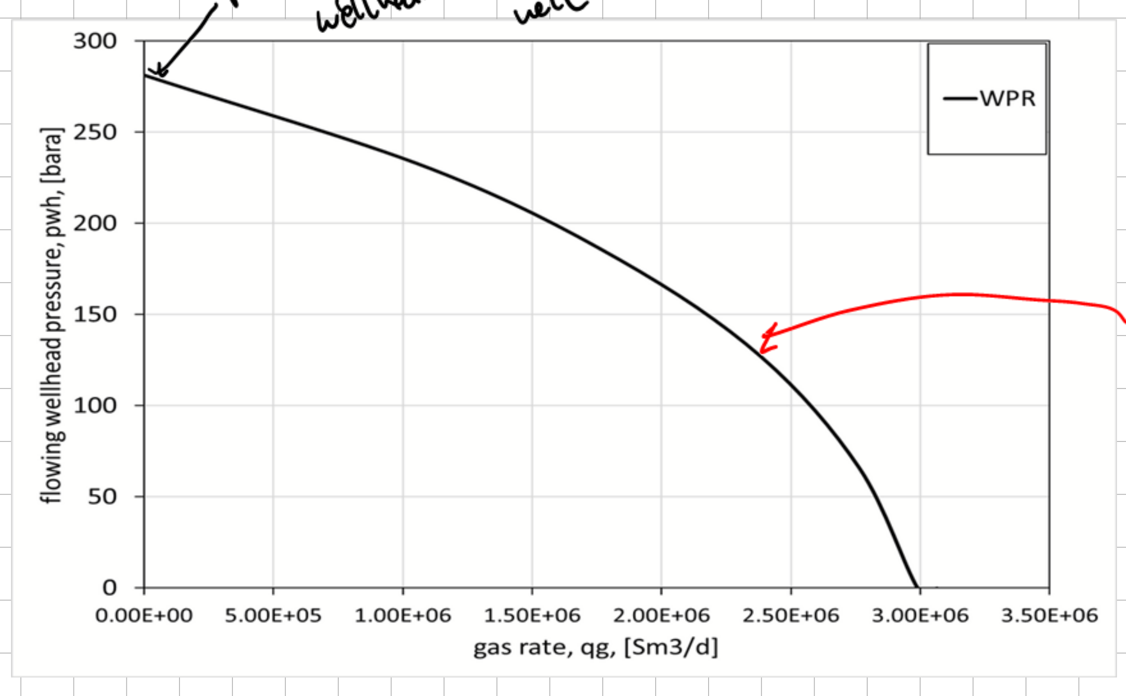
required, with TPR, assuming Pwh = 40 bara

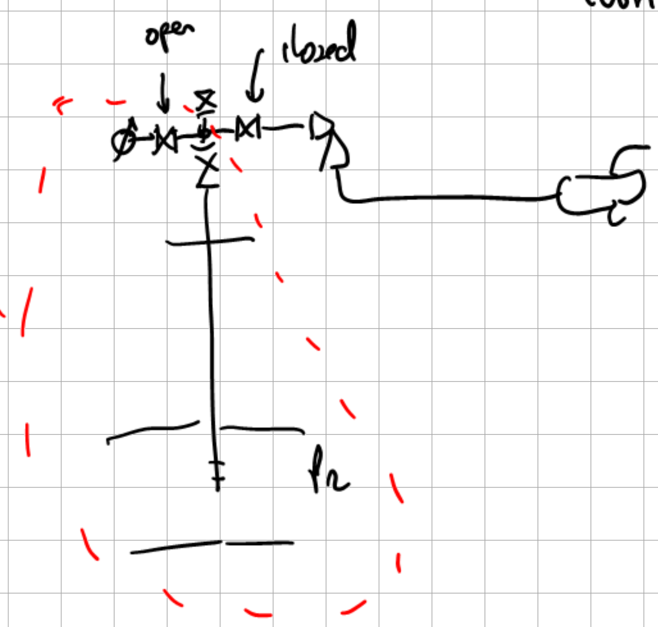
tubing_qg (P_1, P_2)

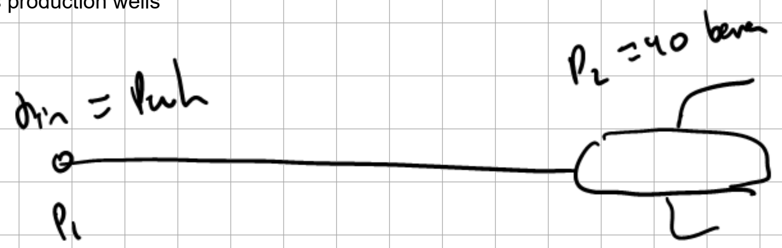
calculated → tubing_P_1 (P_2, q_g)

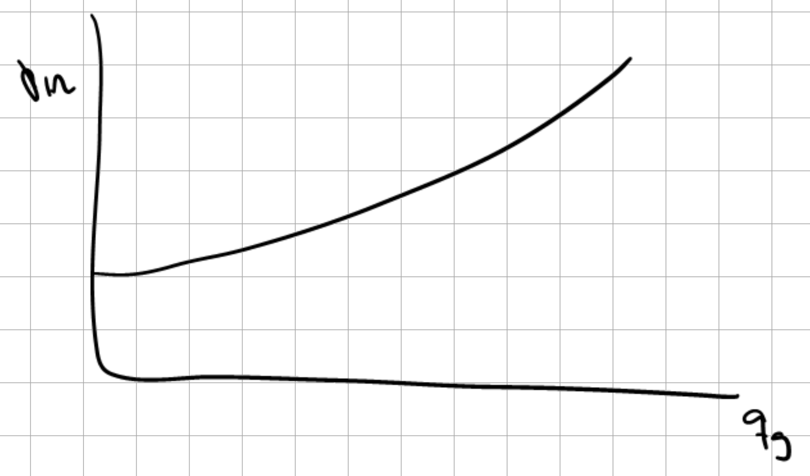
tubing_P_2 (P_1, q_g)

pressure necessary at wellhead with closed well









$$q_g = C_{FL} \cdot \left(\frac{p_1^2}{e^s} - p_2^2\right)^{0.5}$$

horizontal $s \to 0$

$$q_g = C_{FL} \left(p_1^2 - p_2^2\right)^{0.5}$$

required pressure

$$p_1 = \sqrt{p_2^2 + \left(\frac{q_g}{C_{FL}}\right)^2}$$

```
Function Linep1(Cfl, p2, qg)
Linep1 = (p2 ^ 2 + (qg / Cfl) ^ 2) ^ 0.5
End Function
```

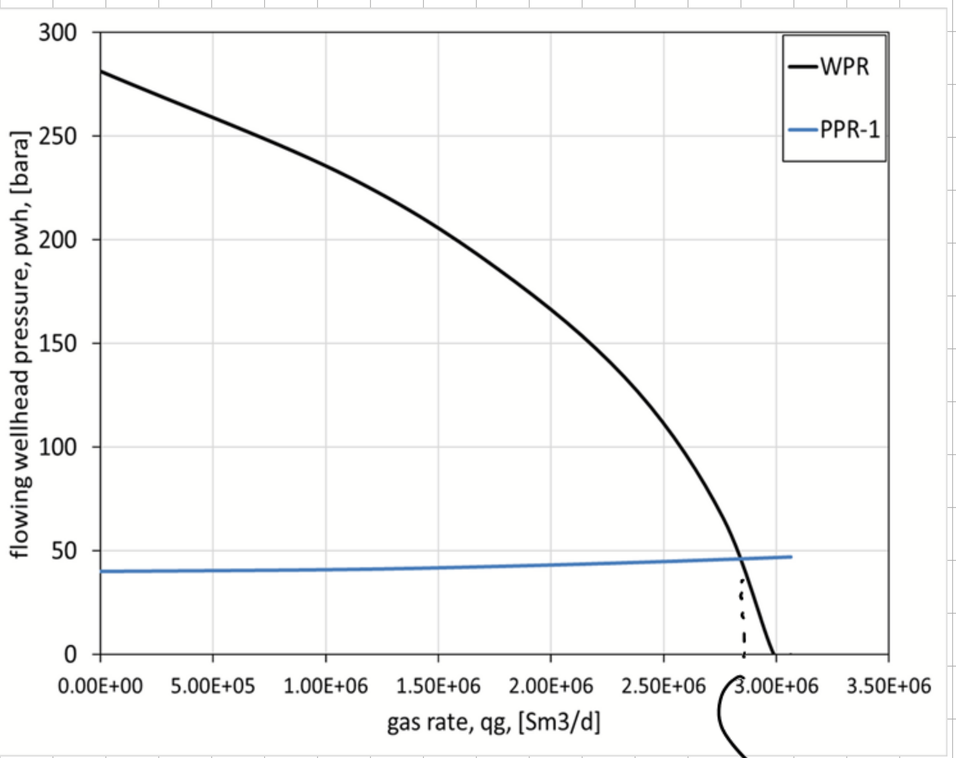
pwf [bara]	qg-IPR [Sm3/d]	pwf-TPR [Sm3/d]	WPR [Sm3/d]
304	0.00E+00	43	281
250	1.11E+06	52	230
200	1.84E+06	64	180
150	2.38E+06	74	127
100	2.76E+06	82	66
50	2.99E+06	87	#VALUE!
0	3.06E+06	89	#VALUE!

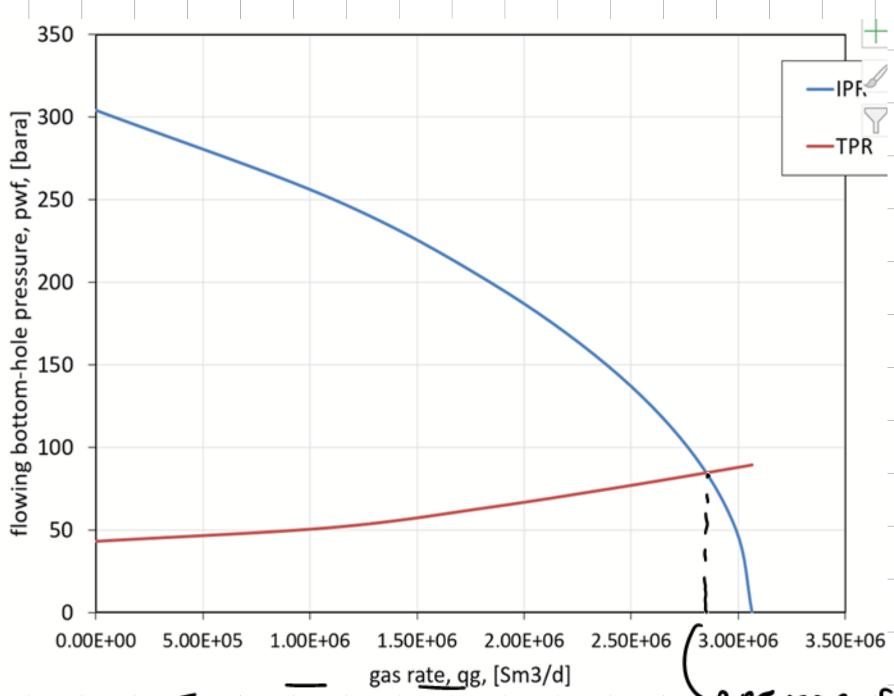
$$q_g = C_T \left(\frac{p_{wf}^2}{e^s} - p_{wh}^2\right)^{0.5}$$

$$p_{wh} = \sqrt{\underbrace{\frac{(p_{wf})^2}{e^s} - \left(\frac{q_g}{C_T}\right)^2}}$$

(+)

(−)



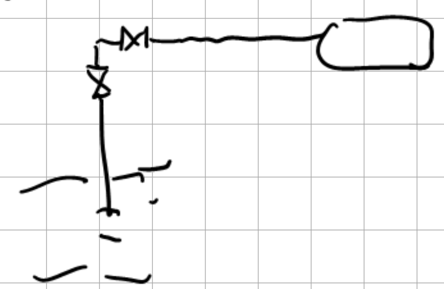


a bit lower

2.85E06 Sm³/d

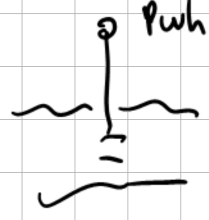
$p_{sep} = 40$ bara

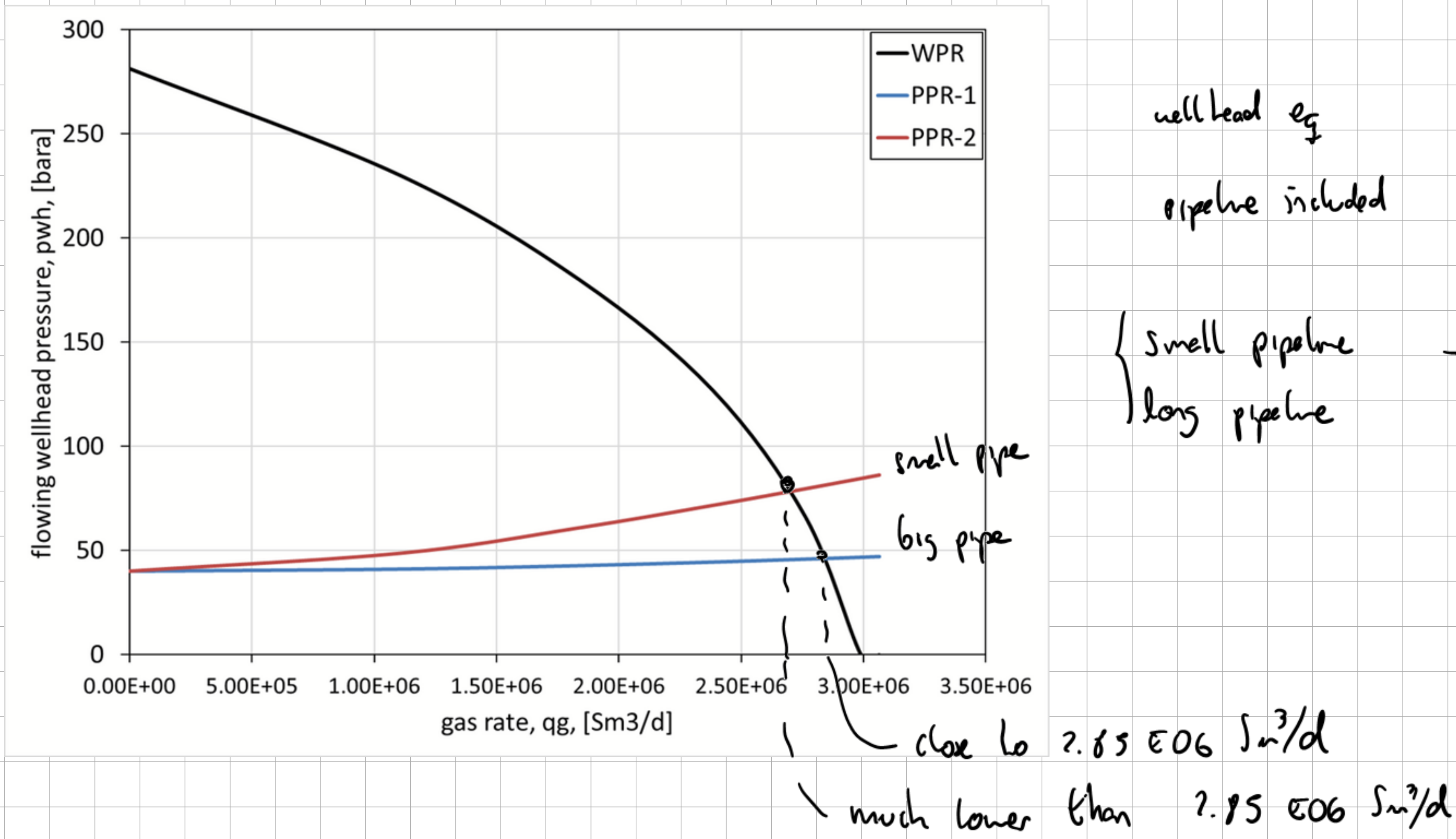
wellhead eq



bottom-hole eq

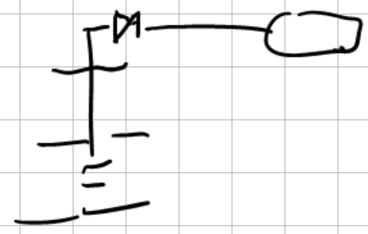
$p_{wh} = 40$ bara





wellhead eq

pipeline included

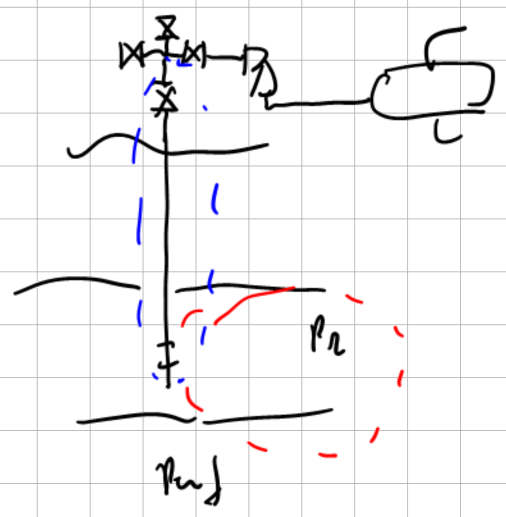


small pipeline

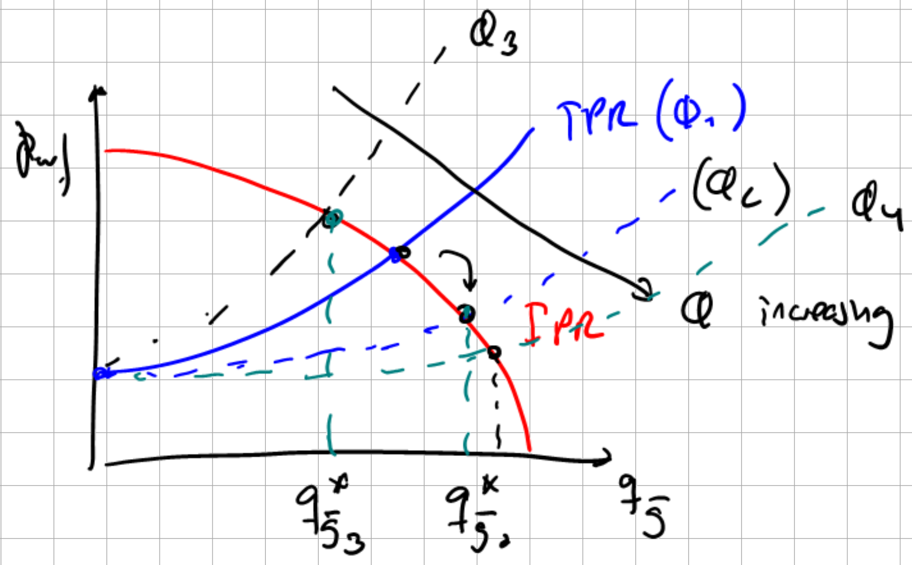
long pipeline

Tubing size considerations: (Φ)

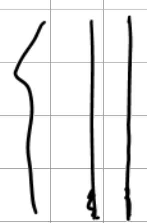
∘ Maximize q_o, q_g → increase equilibrium rate
↳ revenue



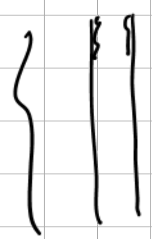
$P_{wh} = p_{sep}$



∘ minimize cost ↓Φ, ↓ cost



tubing comes in discrete sizes Φ → { Φ_1, Φ_2, Φ_3



tubing according to API specs

used in pipe flow calculations

Tubing Size		Nominal Weight						Threaded Coupling					Joint Yield Strength		Capacity Table	
									Coupling Outside Dia.							
Nom. in.	OD in.	T & C Non-Upset lb/ft	T & C Upset lb/ft	Grade	Wall Thick-ness in.	Inside Dia. in.	Drift Dia. in.	Non-Upset in.	Upset Reg. in.	Upset Spec. in.	Col-lapse Resis-tance psi	Internal Yield Pres-sure psi	T & C Non-Upset lb	T & C Upset lb	Barrels per Linear ft	Linear ft per Barrel
3/4	1.05	1.14	1.20	H-40 J-55 C-75 N-80	0.113	0.824	0.730	1.313	1.660		7,200 9,370 12,250 12,710	7,530 10,360 14,120 15,070	6,360 8,740 11,920 12,710	13,300 18,290 24,940 26,610	0.0007	1516.13
1	1.315	1.700	1.800	H-40 J-55 C-75 N-80	0.113	1.049	0.955	1.660	1.900		6,820 8,860 11,590 12,270	7,080 9,730 13,270 14,160	10,960 15,060 20,540 21,910	19,760 27,160 37,040 39,510	0.0011	935.49
1 1/4	1.660	2.300	2.400	H-40 H-40 J-55 J-55 C-75 N-80	0.125 0.140 0.125 0.140 0.140 0.140	1.410 1.380 1.410 1.380 1.380 1.380	1.286	2.054	2.200		5,220 5,790 6,790 7,530 9,840 10,420	5,270 5,900 7,250 8,120 11,070 11,810	15,530 21,360 29,120 31,060	26,740 36,770 50,140 53,480	0.0019 0.0018 0.0019 0.0018 0.0018 0.0018	517.79 540.55 517.79 540.55 540.55 540.55

Non-API tubing (tubulars)

VAM – Vallourec (French)

	VAM® 21	VAM® 21 HT	VAM TOP ®	VAM TOP ® HT	VAM TOP ® HC	VAM® HTTC	VAM® HP	VAM® HW ST	VAM® LOX	VAM® BOLT-II	VAM® HTF-NR	VAM® FJL	VAM® MUST	VAM® SG	VAM® EDGE SF	VAM® SLIJ-II	VAM® LIFT	DINO VAM®	BIG OMEGA ®	VAM TOP ® FE	VAM® TTR
2 3/8			✓									✓									
2 7/8			✓									✓									
3 1/2	✓		✓			✓						✓									
4			✓									✓									
4 1/2	✓	✓	✓	✓	✓	✓					✓	✓		✓		✓					
5	✓	✓	✓	✓	✓	✓		✓			✓	✓		✓	✓	✓					
5 1/2	✓	✓	✓	✓	✓	✓		✓			✓	✓	✓	✓	✓	✓					
5 3/4			✓																		
6	✓	✓	✓	✓	✓																
6 5/8	✓	✓	✓	✓	✓	✓		✓			✓	✓				✓				✓	
6 7/8																✓					
7	✓	✓	✓	✓	✓	✓	✓	✓			✓	✓				✓		✓		✓	
7 5/8	✓	✓	✓	✓	✓		✓	✓			✓	✓	✓			✓				✓	
7 3/4	✓		✓		✓						✓					✓				✓	
8																				✓	
8 1/8												✓									
8 5/8	✓		✓				✓					✓				✓				✓	✓
8 3/4	✓																				
9							✓														
9 3/8											✓	✓									
9 5/8	✓	✓	✓			✓		✓			✓	✓				✓		✓		✓	✓
9 3/4																✓		✓			
9 7/8	✓		✓								✓	✓				✓		✓		✓	
10	✓		✓													✓					
10 1/8	✓		✓				✓			✓						✓					
10 1/2							✓														
10 3/4	✓		✓				✓	✓				✓	✓			✓		✓		✓	✓

tub

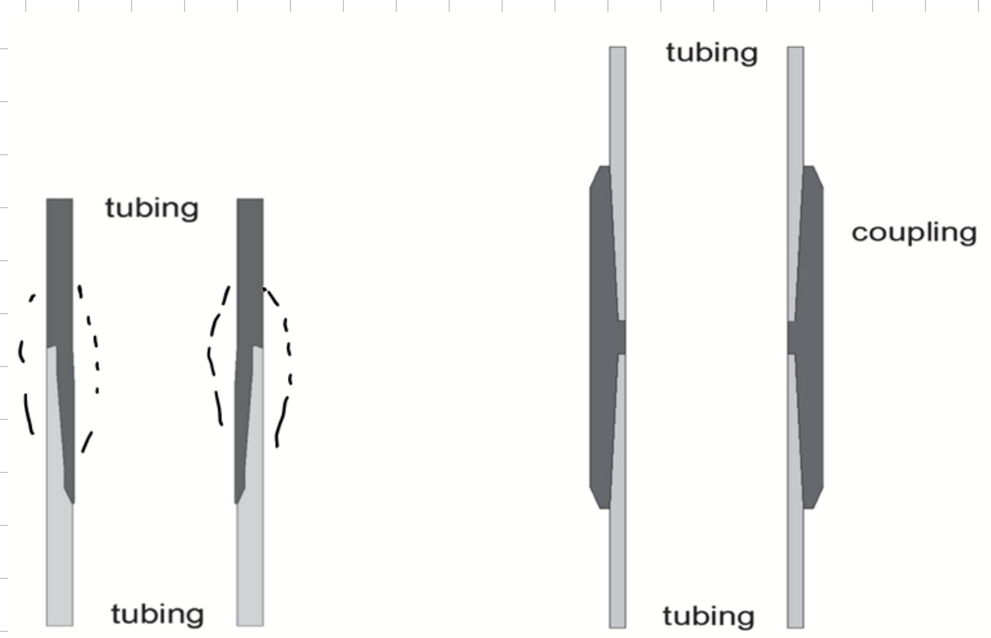
casing

riser flowline

⋮

26

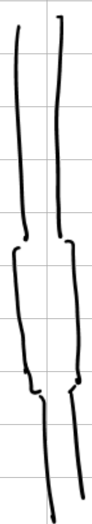
7''	-	32#	-	P-110	-	BTC/LTC
nominal size		weight per length pound per foot ppf		steel "type" grade resistance		type of thread



integrated joint

Coupling

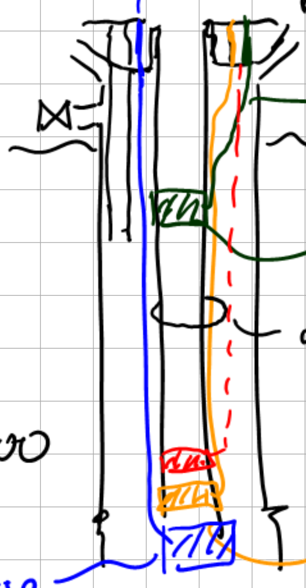
- tubing hanger considerations



DHSV (100-200 m below wellhead)

Power and signal

tubing hanger



hydraulic line (to keep open)

Downhole safety valve

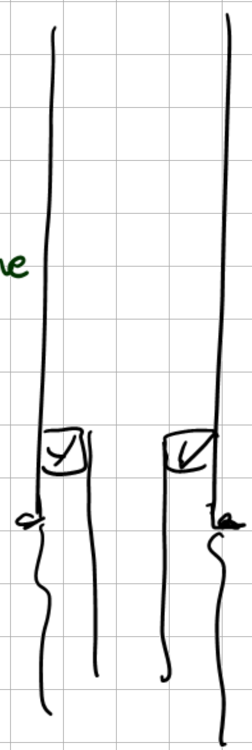
clamp*

downhole pressure gauge

ESP

electric submersible pump

9 5/8''



*

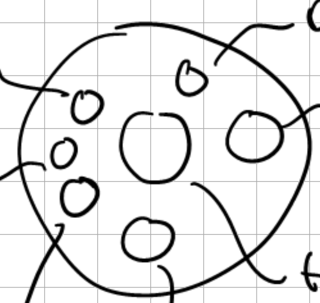
(ESP

chemical injection

DHSV

annulus

downhole valve (ICV)

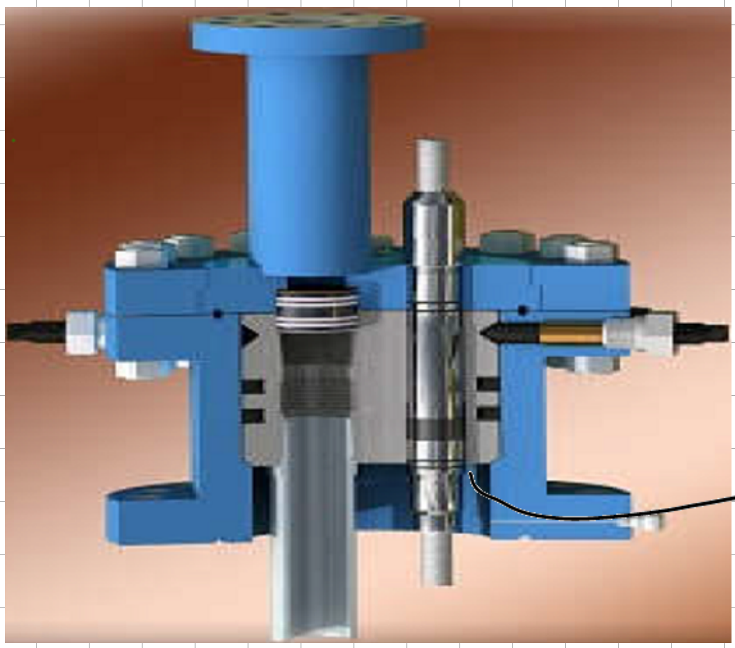


downhole pressure gauge

tubing

electric ESP cable

→ structurally "solid"



penetrator

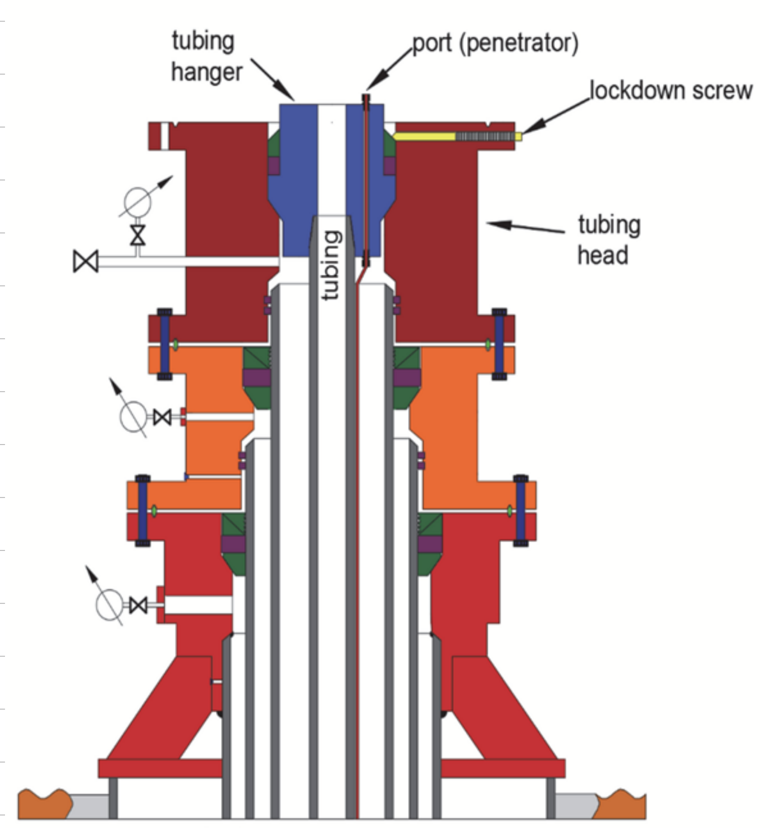
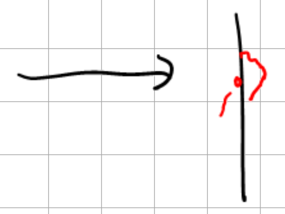


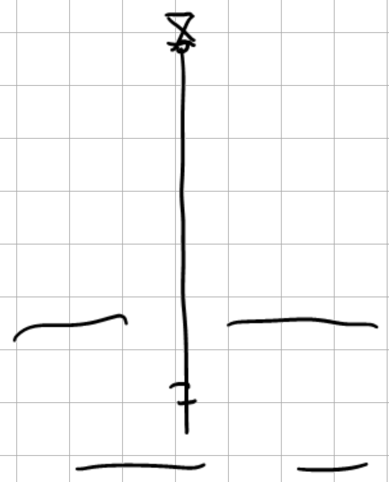
FIGURE 6-10. FINAL CONFIGURATION OF THE WELLHEAD

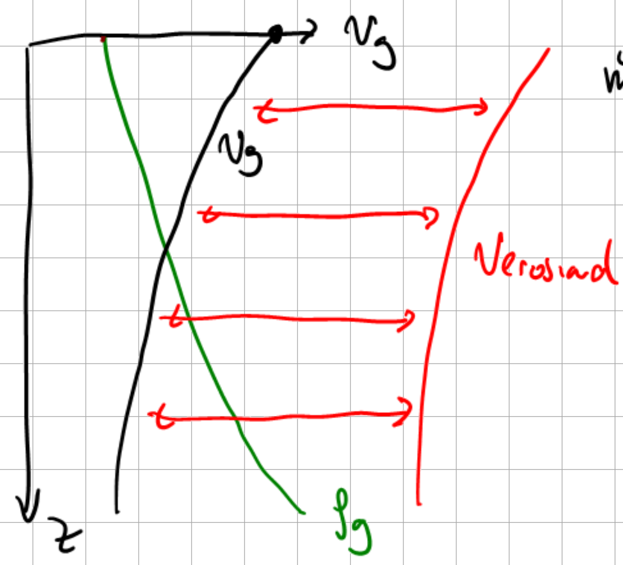
- erosional velocity

$v_f < \underbrace{V_{erosional}}$ velocity



gas well $\quad v_f = v_g = \dfrac{q_g}{A}$





$\dot{m}_g = \rho_g q_g = q_g \cdot \rho_g = v_g \cdot A \cdot \rho_g$

$v_g = \dfrac{\rho_g q_g}{A \rho_g}$ constant with depth

API 14E $\sim$ $V_{erosional} = \dfrac{C}{\sqrt{\rho_m}} \rightarrow (100 - 125)$ "severe" $\left[ft/s \right]$

conservative

$\sqrt{\rho_m} \sim \left[lb/ft^3 \right]$

$\rho_m = f(\rho_L, \rho_g)$

eg $\quad \rho_m = \dfrac{q_o \rho_o + q_g \rho_g + q_w \rho_g}{q_o + q_g + q_w}$

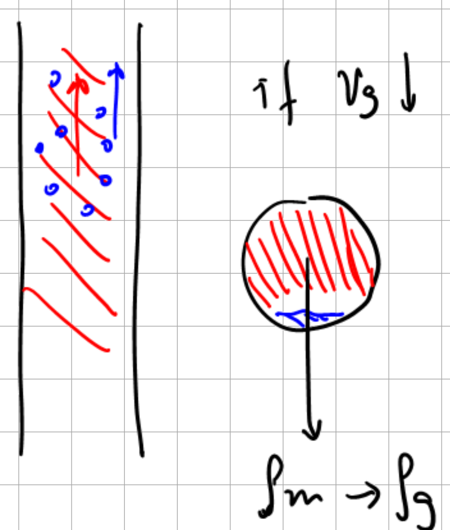
what happens if there is more than 1 fluid in the tubing?

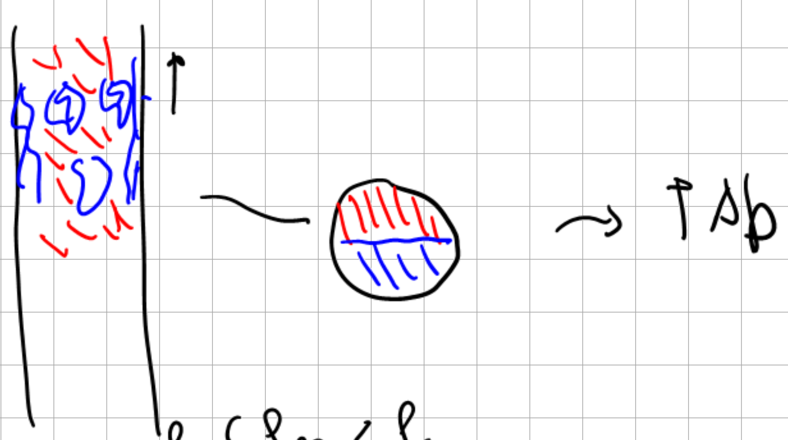
o + g + w

$v_m = \dfrac{(q_o + q_g + q_w)}{A} = \underbrace{\dfrac{q_o}{A}}_{u_{so}} + \underbrace{\dfrac{q_g}{A}}_{u_{sg}} + \underbrace{\dfrac{q_w}{A}}_{u_{sw}}$

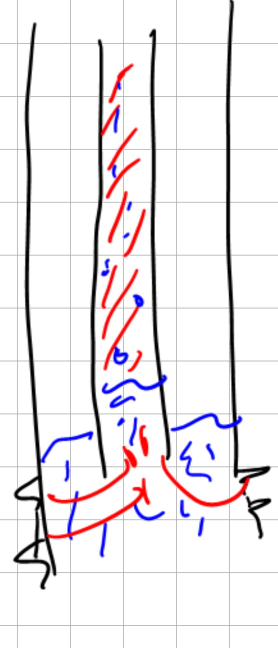
↳ superficial velocity

- only in gas wells → avoid liquid loading



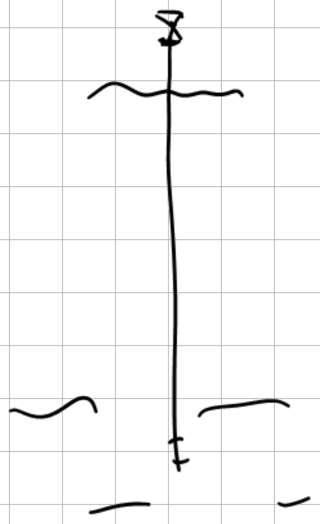


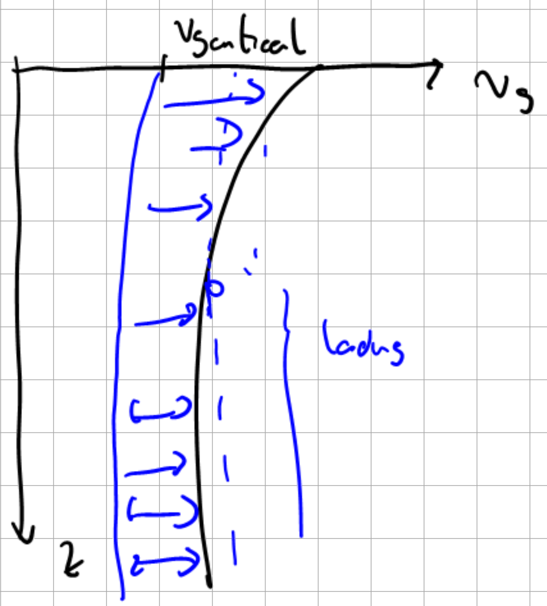
$H_L = \dfrac{A_L}{A} \qquad \rho_m = (H_L)\rho_L + (1-H_L)\rho_g$



in general $H_L \neq \frac{q_L}{q_L + q_g}$

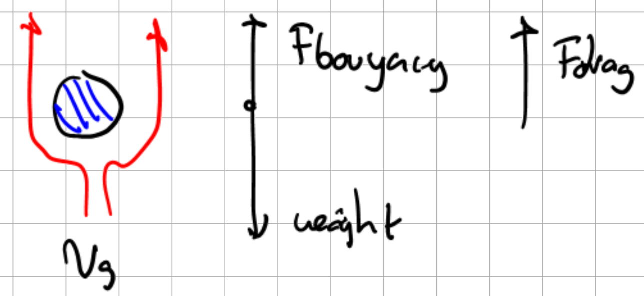
$v_g > v_{critical}$ for all tubing depths



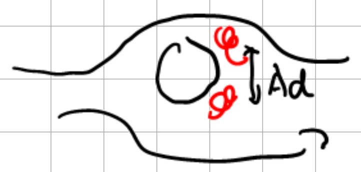


How to calculate $v_{critical}$?

Turner criteria



$F_{drag} + F_{bouyancy} = F_{weight}$



$$\frac{1}{2}\rho_g C_D v_g^2 A_d + V_d \rho_g g = V_d \cdot \rho_L \cdot g$$

$C_D \to 0.44$

$$V_d = \frac{\pi \phi^3}{6} \qquad A_d = \frac{\pi \phi^2}{4}$$

$$\frac{1}{2}\rho_g\, 0.44\, v_g^2 \frac{\pi\phi^2}{4} = (\rho_L - \rho_g) g \frac{\pi \phi^3}{6}$$

Analysis and Prediction of Minimum Flow Rate for the Continuous Removal of Liquids from Gas Wells

R. G. Turner, SPE-AIME, Baker Oil Tools, Inc.
M. G. Hubbard, SPE-AIME, U. of Houston
A. E. Dukler, U. of Houston

1969

$$v_{crit} = \sqrt{\frac{4}{3} \frac{(\rho_L - \rho_g)}{\rho_g} \frac{\phi \cdot g}{0.44}}$$

$$N_{We} = \frac{\rho_g u_g^2 d}{\sigma_{gL}}$$

Drag

interfacial tension

Weber

Fundamentals of the Hydrodynamic Mechanism of Splitting in Dispersion Processes

J. O. Hinze, Royal Dutch Shell-Laboratory, Delft, Holland

1955

$N_{We} = 30 \to \phi_{max}$

$$30 = \frac{\rho_g u_g^2 \phi}{\sigma_{Lg}}$$

$$\phi = \frac{\sigma_{Lg}\, 30}{\rho_g u_g^2}$$

for every depth in tubing

$v_g \geq v_{crit}$

$$v_{crit} = 5.46 \left[\frac{\sigma_{Lg}^{0.25} (\rho_L - \rho_g)^{0.25}}{\rho_g^{0.5}}\right] \quad [m/s]$$

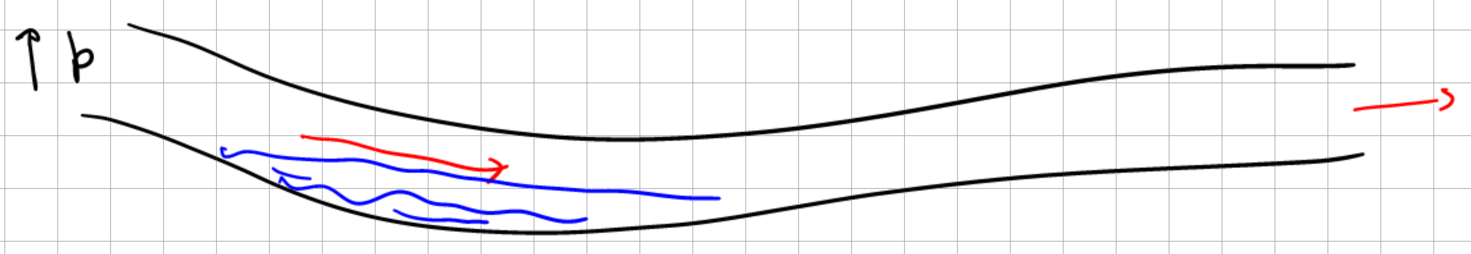
σ in $\left[\frac{N}{m}\right]$

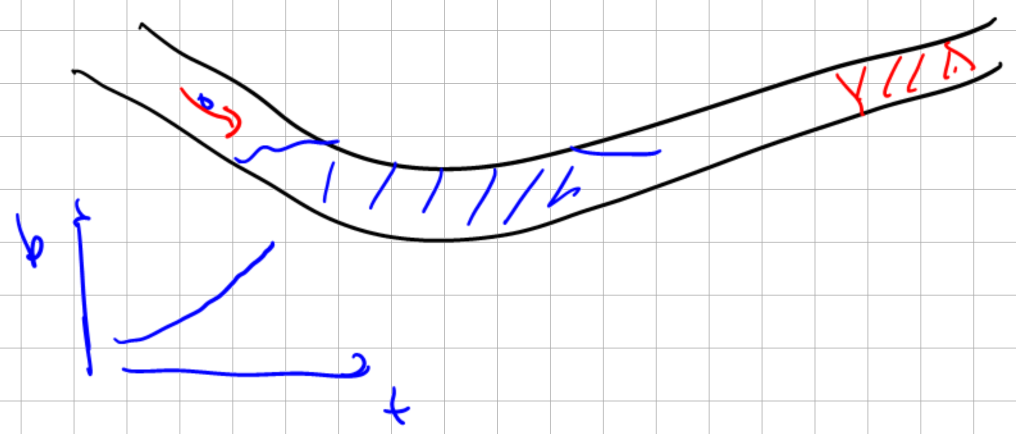
ρ in $\left[kg/m^3\right]$

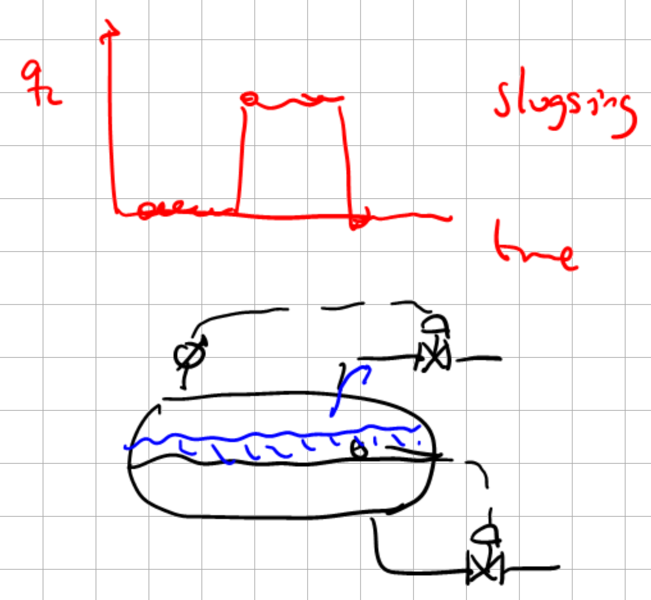
- pipeline sizing considerations

  $\uparrow q_{fs}$, $\uparrow q_{fo}$ $\downarrow$ cost

- v_g high enough to avoid accumulation of liquid (gas condensate pipeline)







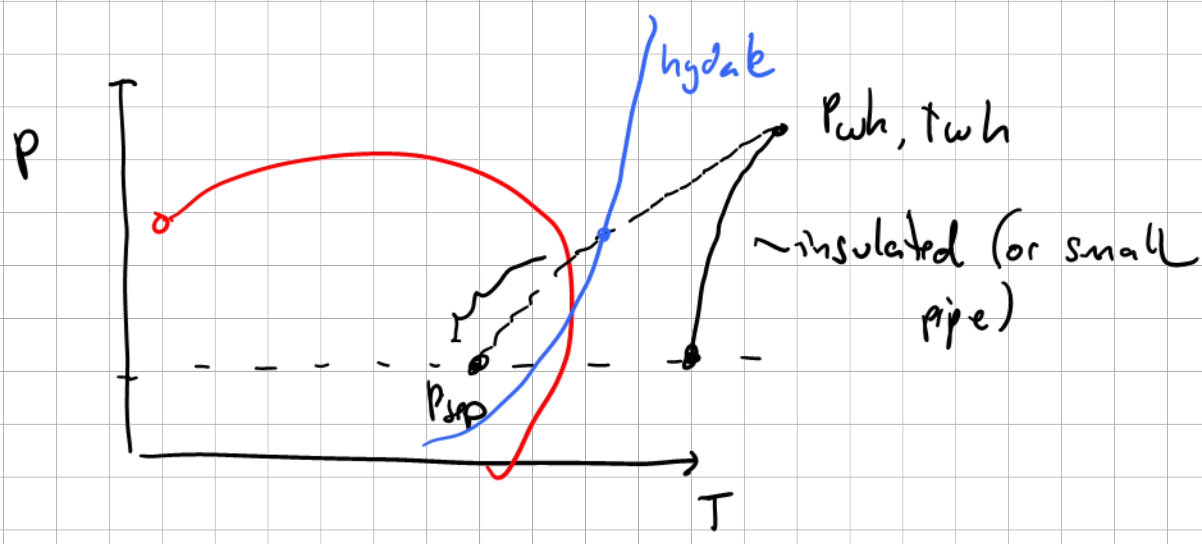
- heat transfer

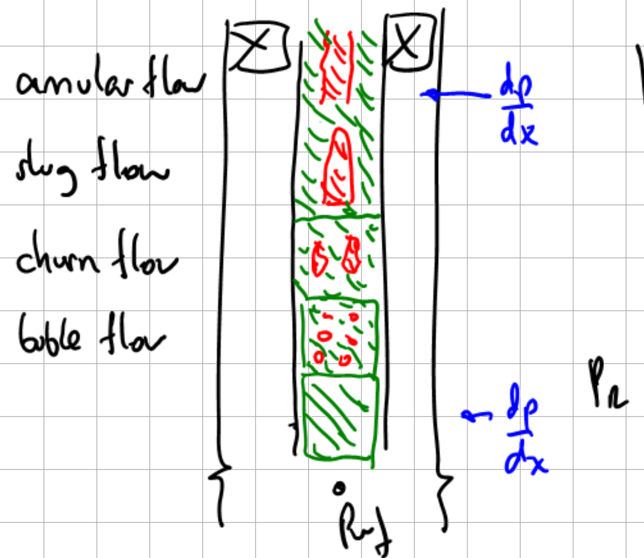
$$\dot{q} = A \cdot U (T_f - T_{amb})$$

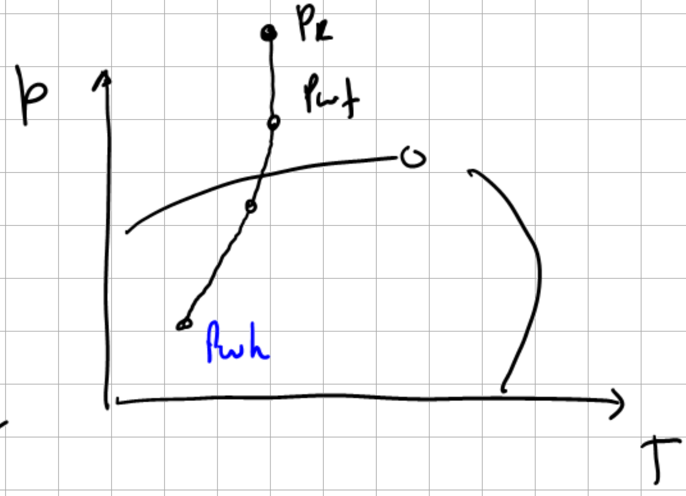
$$\pi D \cdot L \, U (T_f - T_{amb})$$

$$\phi \uparrow \quad \dot{q} \uparrow \quad T_f \rightarrow \downarrow$$

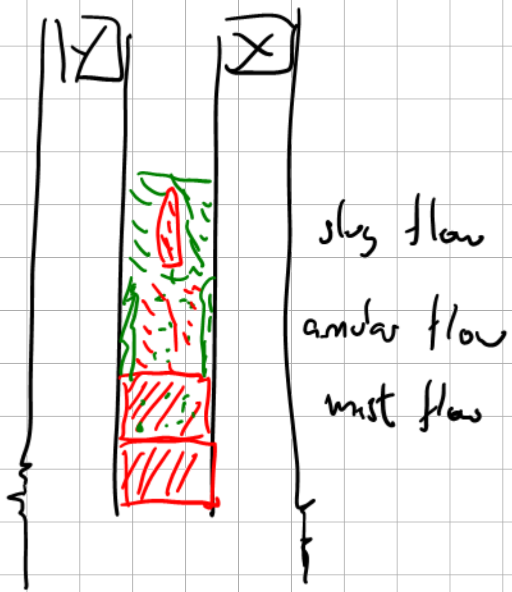
can also cause hydrate formation

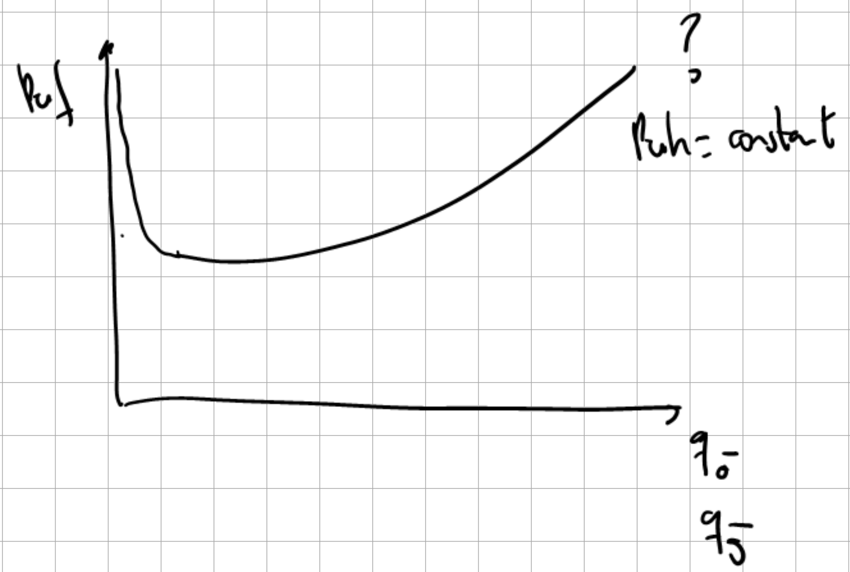


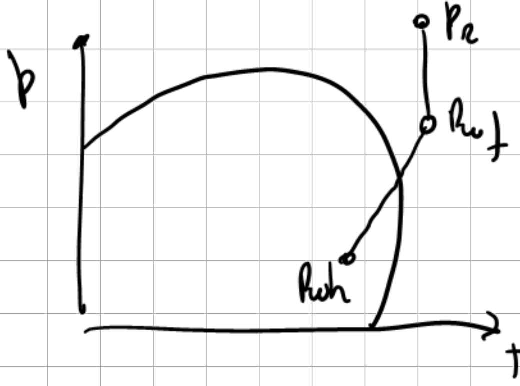




flow patterns

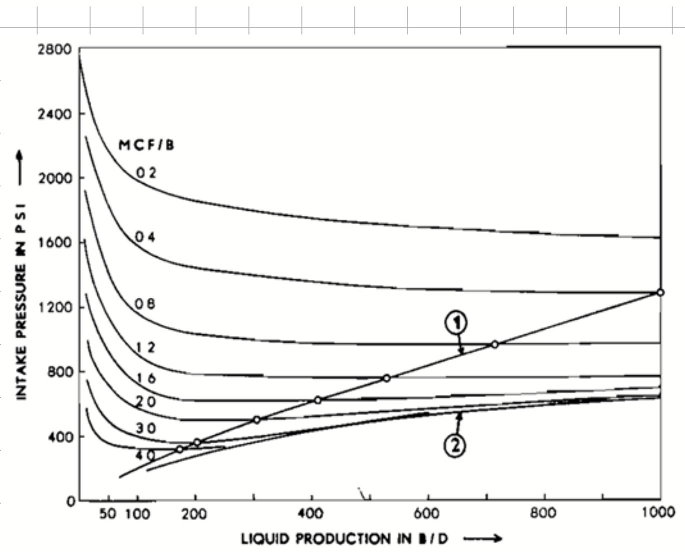






Flowing and Gas-lift Well Performance†

W. E. GILBERT*



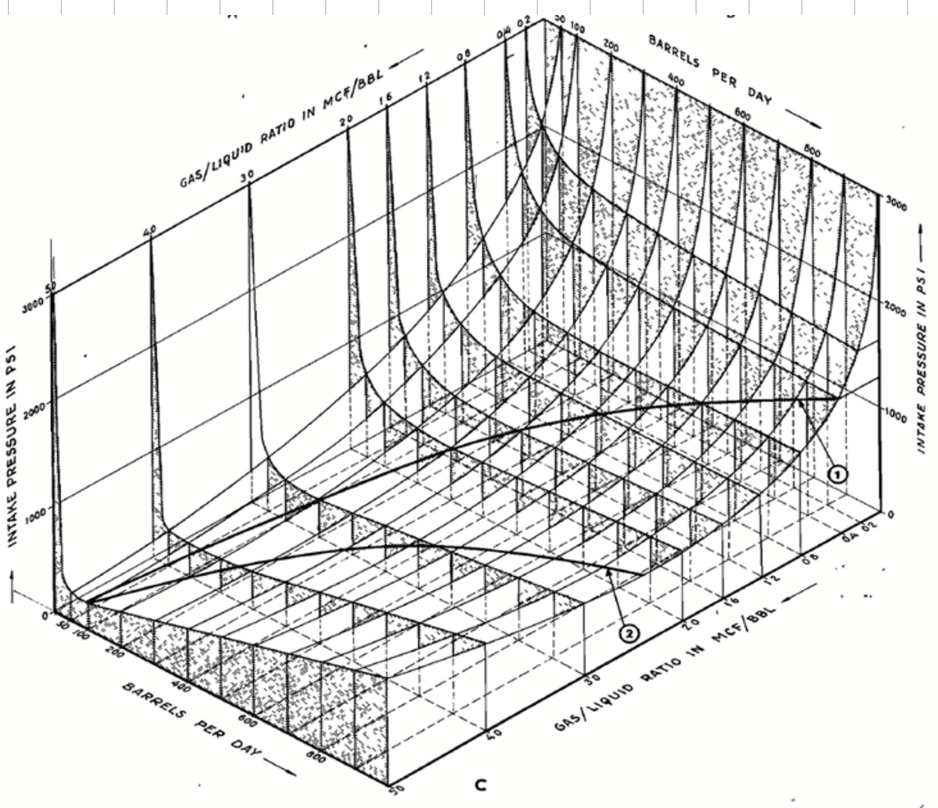
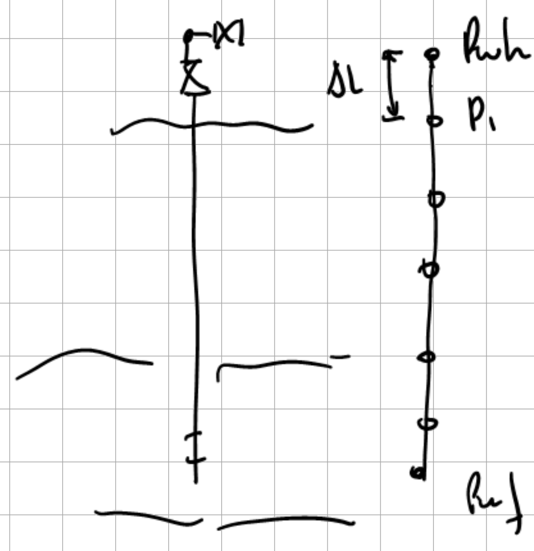


Fig. 6–The Two-phase Vertical-lift Function for 2.875-in. Tubing Set at 8,000 Ft
(Tubing Pressure = Zero Psi Gage)

$$\Delta p_{tubing} = \Delta p_{Hydrostatic} + \Delta p_{friction}$$



$$\left.\frac{dp}{dx}\right|_{P_{wh}} \rightarrow P_1$$

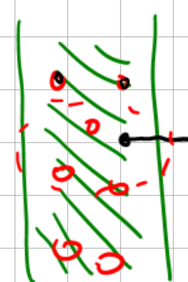
$$P_1 = P_{wh} + \left.\frac{dp}{dx}\right|_{P_{wh}} \cdot \Delta L$$

?

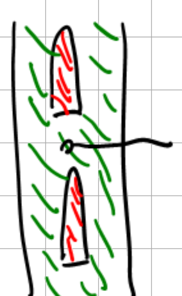
integration

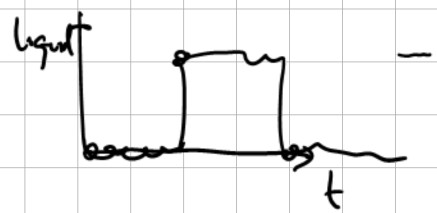
marching algorithm

$$P_2 = P_1 + \left.\frac{dp}{dx}\right|_{P_1} \cdot \Delta L$$



$$\frac{d}{dt} \neq 0$$





$x \qquad \bar{x} \quad \int_t x \, dt \qquad \bar{x} = \int_A x \, dA$

$\frac{dp}{dx} \rightsquigarrow$ pvt properties $(\rho_L, \rho_g, \mu_L, \mu_g, \sigma_{Lg}, x_g)$ mass fraction

$\rightarrow$ velocity (q_g, q_L)

$\rightarrow A, \phi, \theta, e$ roughness

Steady-State Multiphase Flow—Past, Present, and Future, with a Perspective on Flow Assurance

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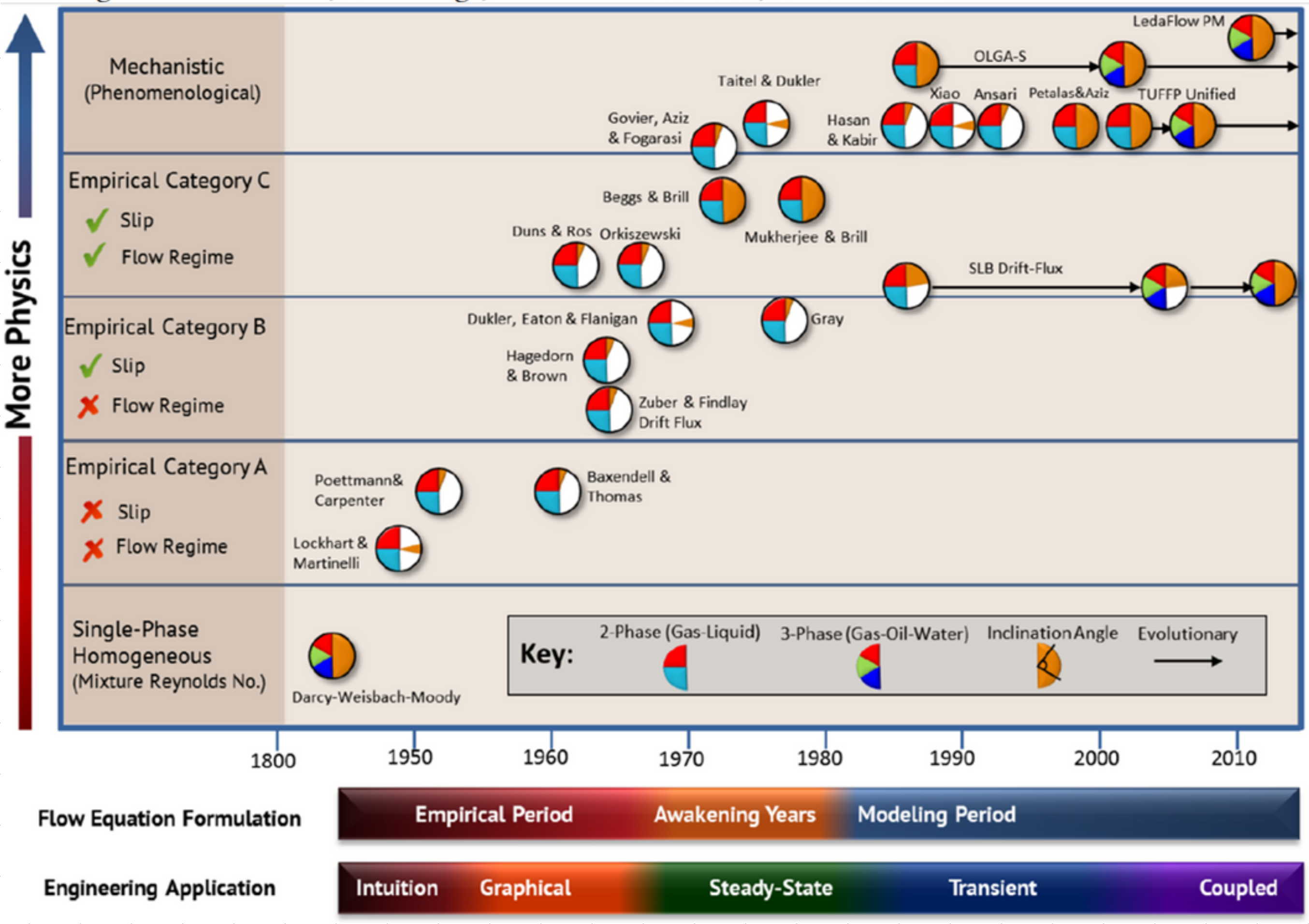
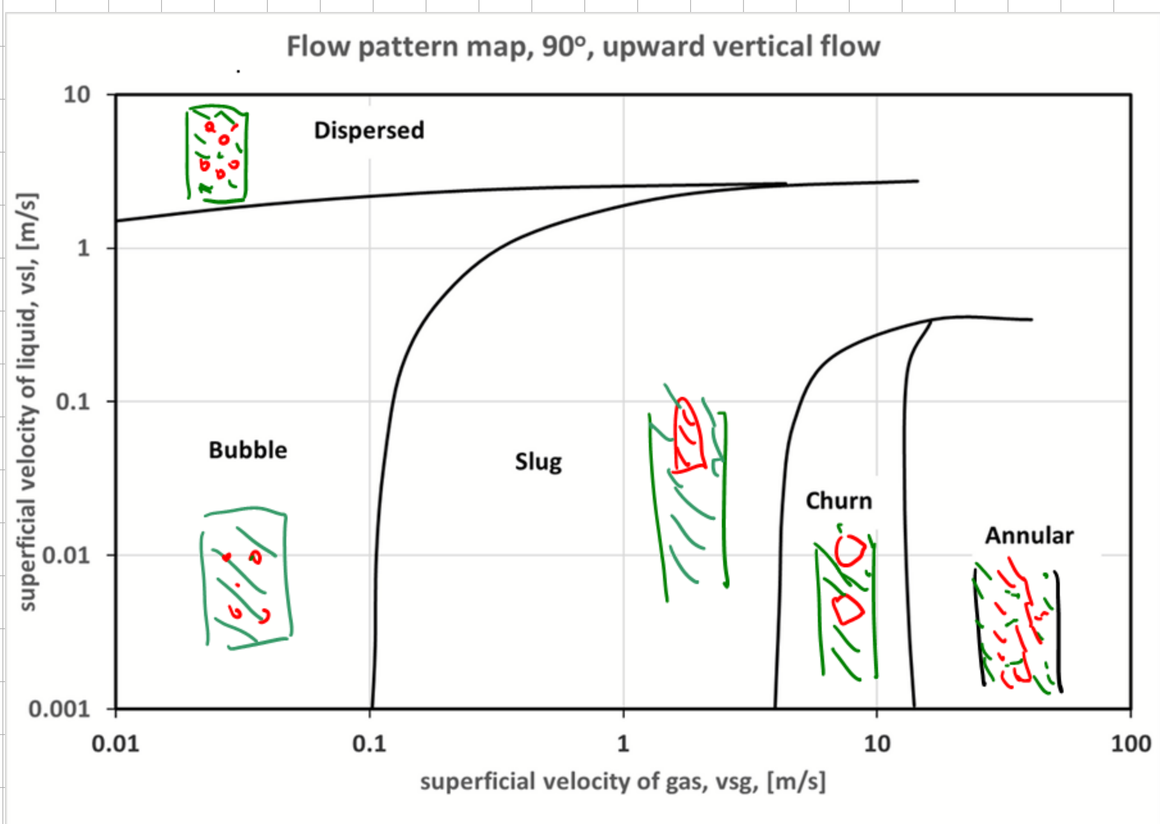


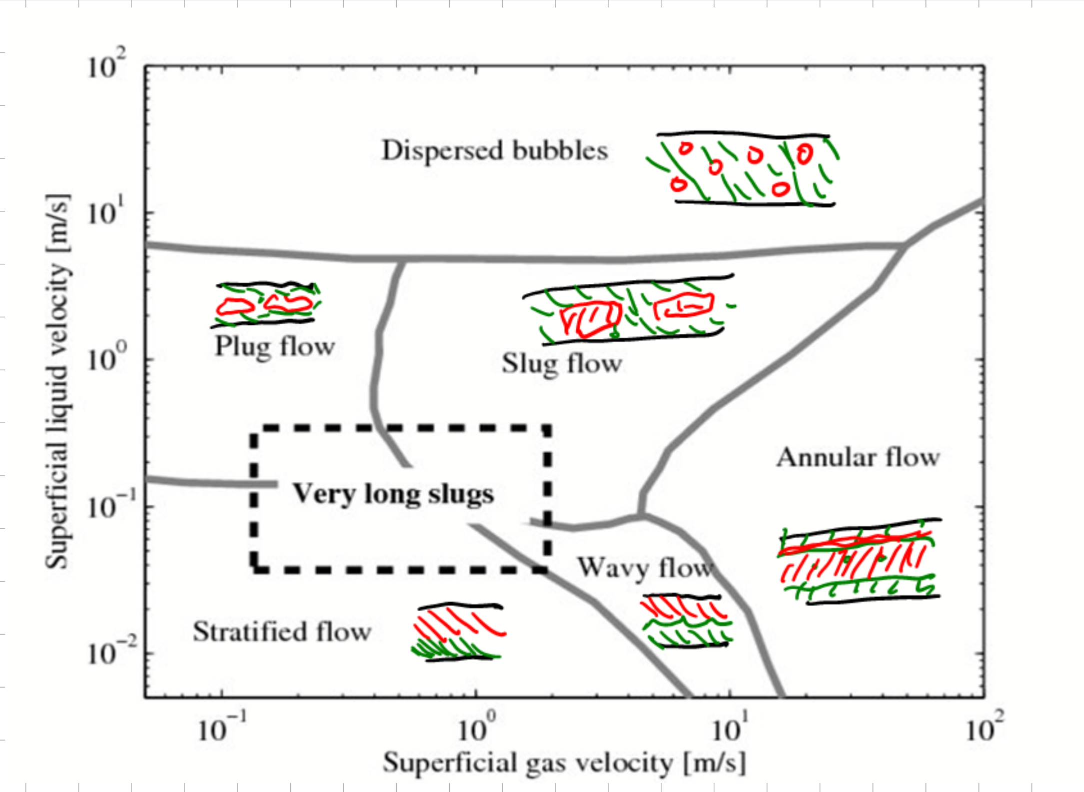
flow pattern map

for a given fluid, pipe, inclination, etc



$u_{sL} = \frac{q_L}{A}$

$u_{sg} = \frac{q_g}{A}$


Dispersed bubbles
Plug flow
Slug flow
Annular flow
Very long slugs
Wavy flow
Stratified flow
Superficial liquid velocity [m/s]
Superficial gas velocity [m/s]
10^{2}
10^{1}
10^{0}
10^{-1}
10^{-2}
10^{-1}
10^{0}
10^{1}
10^{2}