ENGINEERING PRACTICE

VOLUME 9 NUMBER 36

JANUARY 2023

IACPE
INTERNATIONAL ASSOCIATION OF
CERTIFIED PRACTICING ENGINEERS

WWW.IACPE.COM

Empirical Approach to Hydrate Formation in Natural Gas Pipelines

Jayanthi Vijay Sarathy

Natural Gas Pipelines often suffer from production losses due to hydrate plugging. For an effective hydrate plug to form, factors can vary from pipeline operating pressure and temperature, presence of water below its dew point, extreme winter conditions & Joule Thomson cooling. In the event hydrates form in the pipeline section, their consequence depends on how well the hydrates agglomerate to grow and form a column. If the pipeline section temperature is only at par with the hydrate formation temperature, the particles do no agglomerate; instead they have to cross the metastable region which is of the order of 50C to 60C, before hydrate formation accelerates to block the pipeline.

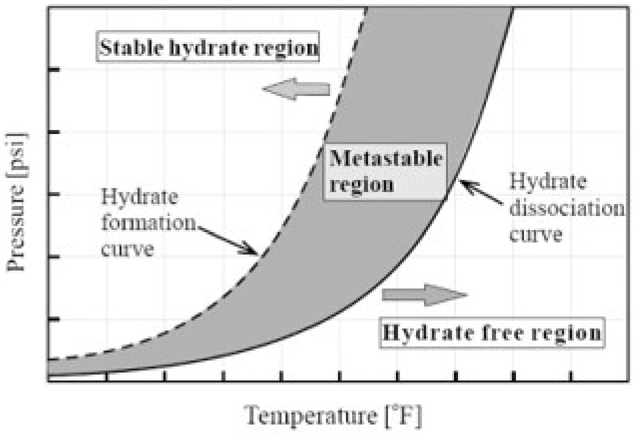


Figure 1. P-T Hydrate Curve [1]

Although engineering softwares exist to estimate pipeline process conditions and also generate a P-T hydrate curve, the following article provides a guidance summary to estimate the expected pipeline temperature profile and the associated hydrate formation temperatures.

PROBLEM STATEMENT

A DN 14", 20 km hydrocarbon line carrying natural gas at the rate of 85,000 kg/h, 40 bara and 250C is fed to a receiving station. The total pipeline pressure drop per km [DP/km] is taken to be 1 bar/km. The overall heat transfer coefficient is taken to be 25 W/m2.K. The ambient temperature is 120C. The hydrate formation temperature for the composition is experimentally estimated to be 500F at 325 psia. It is required to estimate the pipeline exit A DN 14", 20 km hydrocarbon line carrying natural gas at the rate of 85,000 kg/h, 40 bara and 250C is fed to a receiving station. The total pipeline pressure drop per km [DP/km] is taken to be 1 bar/km. The overall heat transfer coefficient is taken to be 25 W/m2.K. The ambient temperature is 120C. The hydrate formation temperature for the composition is experimentally estimated to be 500F at 325 psia. It is required to estimate the pipeline exit temperature & the hydrate formation temperature along the pipeline. For the estimates, the Joule-Thomson coefficient is assumed to be an average of 0.560C/bar throughout the pipeline. The natural gas composition is as follows,

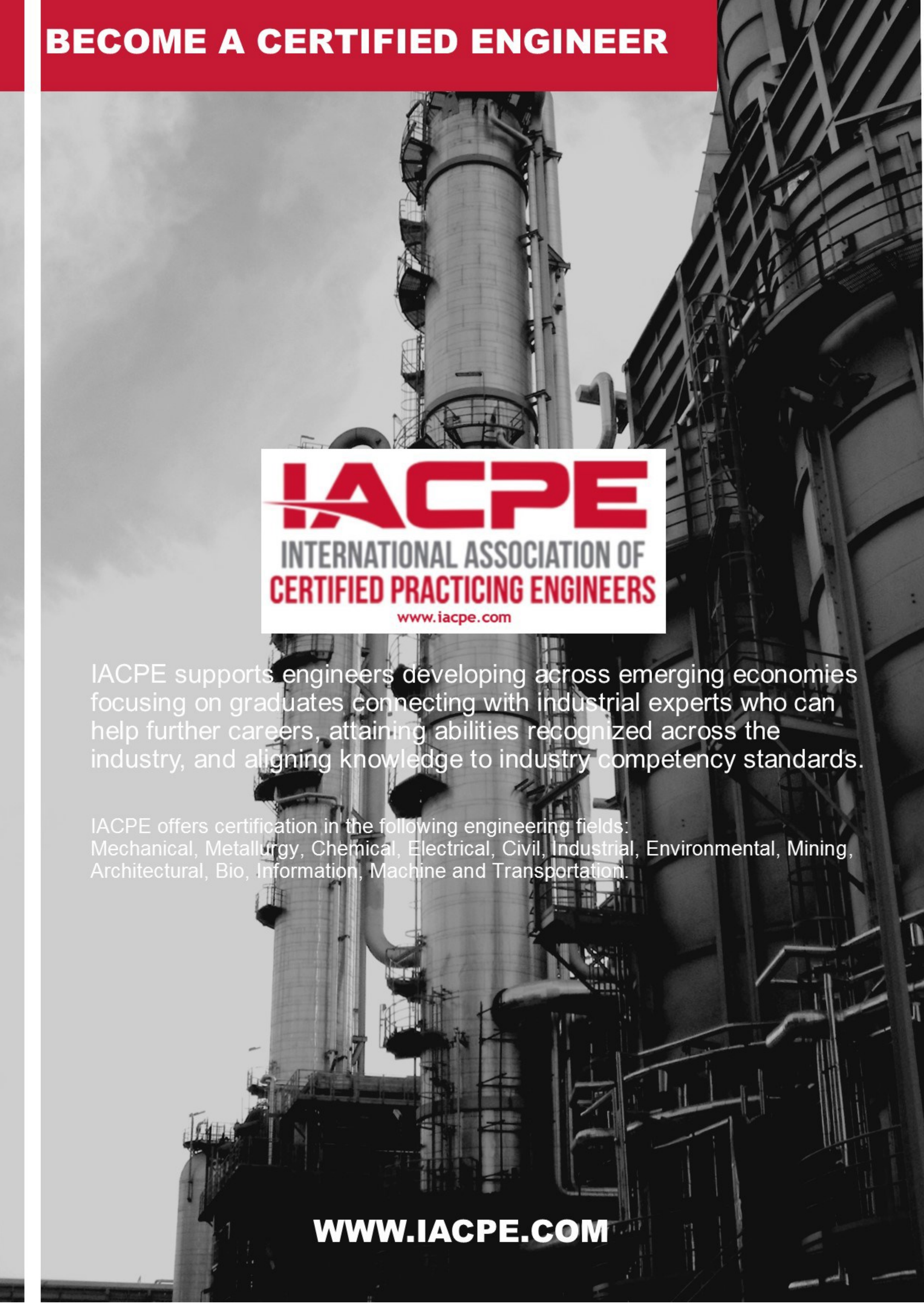
Table 1. Gas Mixture [GPSA, Sec 20, Page 20-15]

Component	Mol%	MW [M_i]	y_iM_i
	[%]	[kg/kmol]	[-]
Methane	78.40	16.04	12.58
Ethane	6.00	30.07	1.80
Propane	3.60	44.01	1.58
i-Butane	0.50	58.12	0.29
n-Butane	1.90	58.12	1.10
CO_2	0.20	44.01	0.09
N_2	9.40	28.01	2.63
Total	100.00	**MW [kg/kmol]**	**20.08**

METHODOLOGY

The pipeline temperature profile can be estimated based on Coulter & Bardon (1979) correlation [4]. The steady state temperature profile is calculated from the momentum equation, while omitting the potential & kinetic energy terms in the enthalpy equation.

$$\frac{dh}{dL} + \frac{dQ}{dL} = 0 \quad (1)$$


BECOME A CERTIFIED ENGINEER
IACPE
INTERNATIONAL ASSOCIATION OF CERTIFIED PRACTICING ENGINEERS
www.iacpe.com
IACPE supports engineers developing across emerging economies focusing on graduates connecting with industrial experts who can help further careers, attaining abilities recognized across the industry, and aligning knowledge to industry competency standards.
IACPE offers certification in the following engineering fields: Mechanical, Metallurgy, Chemical, Electrical, Civil, Industrial, Environmental, Mining, Architectural, Bio, Information, Machine and Transportation.
WWW.IACPE.COM

Where,

$$Q = \frac{\pi \times OD \times U \times \Delta L}{m}[T_0 - T_s] \quad (2)$$

$$dh = c_p dT - \mu c_p dP \quad (3)$$

Where,
U = Overall HTC [W/m^2.K]
ID = Pipeline OD [m]
m = mass flow rate [kg/s]
DL = Pipeline length [m]
T_0 = Fluid Temperature [K]
T_s = Surrounding Temperature [K]
m = Joule-Thompson Coefficient [^{0}C/bar]
C_p = Specific heat capacity [J/kg.K]
g_g = Gas Specific Gravity, MW/28.9625 [-]

Solving for pipeline temperature profile,

$$T[L] = \left[T_0 - T_s - \left(\frac{\mu}{a}\right)\left(\frac{dP}{dL}\right)\right]e^{-aL} + T_s + \left(\frac{\mu}{a}\right)\left(\frac{dP}{dL}\right) \quad (4)$$

Where,

$$a = \frac{\pi \times OD \times U}{m \times C_p}$$

It is to be noted that the specific heat [C_p] and Joule-Thompson [J-T] co-efficient [m] varies with the pipeline pressure & temperature. But for computational purposes, is assumed to be constant. The purpose of including the J-T co-efficient is to account for cooling during gas expansion along the pipeline. The ideal mass specific heat [C_p], kJ/kg.K, of natural gas can be computed as,

$$C_p = [(-10.9602\gamma_g + 25.9033) + (0.21517\gamma_g - 0.068687)T + (-0.00013337\gamma_g) + 0.000086387)T^2 + (0.000000031474\gamma_g) - 0.000000028396)T^3]/MW \quad (5)$$

Where, T = Temperature [K]

HYDRATE FORMATION TEMPERATURE

To estimate the hydrate formation temperature [Th], Towler & Mokhatab (2005) [3], proposed the following correlation,

$$T_h[°F] = [13.47 \times ln(P)] + [34.27 \times ln(\gamma)] - [1.675 \times ln(P) \times ln(\gamma)] - 20.35 \quad (6)$$

Where,
P = Pressure [psia]
The validity of the above expression is for the
1. Temperature Range: 260 K to 298 K
2. Pressure Range: 1200 kPa to 40,000 kPa
3. MW: 16 g/mol to 29 g/mol (0.55 < g_g < 1.0)

RESULTS

Substituting the values to arrive at the pipeline temperature profile, the gas specific gravity is estimated as,

ANNEXURE: MS-EXCEL SPREADSHEET

$$\gamma_g = \frac{20.08}{28.9625} = 0.6933 \quad (7)$$

$$a = \frac{\pi \times \left[\frac{14 \times 25.4}{1000}\right] \times 25}{\left[\frac{85{,}000}{3600}\right] \times 2.071 \times 1000} = 0.0005711 \quad (8)$$

$$T[L] = 12.0195 \times e^{-0.0005711 \times L} + 286.1305 \quad (9)$$

The hydrate formation temperature [T_h] is,

$$T_h[°F] = [14.0835 \times ln(P, psi)] - 32.9023 \quad (10)$$

Plotting the above expressions, we get,

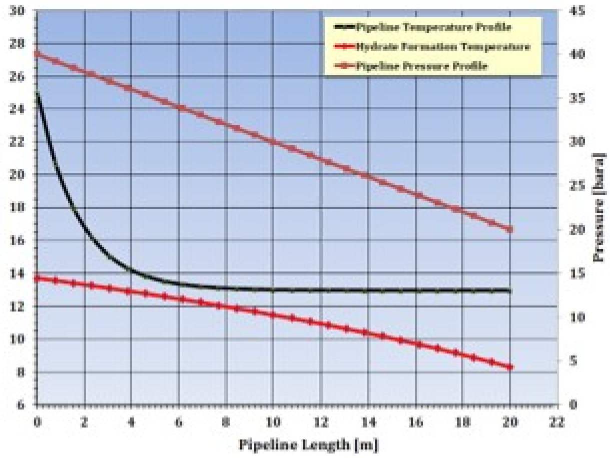


Figure 2. Hydrate Formation Temperature

From the plot, the pipeline temperature stays above the hydrate formation temperature. In practice, to increase the difference, the inlet gas can be either heated or hydrate inhibitors such as MeOH, MEG or TEG can be added.

Natural Gas Inlet Composition

Component	Mol% [%]	MW [M_i] [kg/kmol]	y_iM_i [-]
Methane	78.40	16.04	12.58
Ethane	6.00	30.07	1.80
Propane	3.60	44.01	1.58
i-Butane	0.50	58.12	0.29
n-Butane	1.90	58.12	1.10
i-Pentane	0.00	72.15	0.00
n-Pentane	0.00	72.15	0.00
C_6+	0.00	86.18	0.00
H_2O	0.00	18.02	0.00
CO_2	0.20	44.01	0.09
H_2S	0.00	34.08	0.00
N_2	9.40	28.01	2.63
Total	100.00	MW [kg/kmol]	20.08

Critical Properties - Sutton Correlation with Wichert & Aziz Correction

Parameter	Value	Unit
Inlet Pressure [P]	40.0	bara
Inlet Temperature [T]	25.0	^{0}C
Gas Specific Gravity [γ_g]	0.6933	-
Pseudocritical Pressure [P_{pc}]	664.2	psia
Pseudocritical Temperature [T_{pc}]	375.9	^{0}R
Deviation Factor [ε]	0.4410	^{0}R
Modified Pseudocrotical Pressure [P'_{pc}]	663.4	psia
Modified Pseudocrotical Temperature [T'_{pc}]	375.5	^{0}R
Modified Reduced Pressure [P_{pr}]	0.8863	-
Modified Reduced Temperature [T_{pr}]	1.4292	-
Modified Reduced Density [ρ_r]	0.1865	-
DAK EOS Convergence	*0.0000*	Calculate
Compressibility Factor [Z]	**0.8978**	**-**
Gas Density [ρ]	**36.09**	**kg/m^3**
Gas Viscosity [μ]	**0.0117**	**cP**

Pipeline Temperature Profile & Hydrate Formation Temperature

Length [m]	Length [km]	T[L] [^{0}K]	T[L] [^{0}C]	Pressure [bara]	Towler & Mokhatab [^{0}C]
0	0.00	298.2	25.00	40.00	13.73
769	0.77	293.9	20.73	39.23	13.58
1,538	1.54	291.1	17.97	38.46	13.42
2,308	2.31	289.3	16.20	37.69	13.26
3,077	3.08	288.2	15.05	36.92	13.10
3,846	3.85	287.5	14.32	36.15	12.94
4,615	4.62	287.0	13.84	35.38	12.77
5,385	5.38	286.7	13.54	34.62	12.60
6,154	6.15	286.5	13.34	33.85	12.42
6,923	6.92	286.4	13.21	33.08	12.24
7,692	7.69	286.3	13.13	32.31	12.06
8,462	8.46	286.2	13.08	31.54	11.87
9,231	9.23	286.2	13.04	30.77	11.68
10,000	10.00	286.2	13.02	30.00	11.48
10,769	10.77	286.2	13.01	29.23	11.27
11,538	11.54	286.1	13.00	28.46	11.07
12,308	12.31	286.1	12.99	27.69	10.85
13,077	13.08	286.1	12.99	26.92	10.63
13,846	13.85	286.1	12.98	26.15	10.40
14,615	14.62	286.1	12.98	25.38	10.17
15,385	15.38	286.1	12.98	24.62	9.93
16,154	16.15	286.1	12.98	23.85	9.68
16,923	16.92	286.1	12.98	23.08	9.42
17,692	17.69	286.1	12.98	22.31	9.16
18,462	18.46	286.1	12.98	21.54	8.89
19,231	19.23	286.1	12.98	20.77	8.60
20,000	20.00	286.1	12.98	20.00	8.31

Pipeline Temperature Profile

Parameter	Value	Unit
Pipeline Grid Size	769.2	m
a = [π×OD×U]/[m×Cp]	0.0005711	[-]
((μ/a)*(dP/dL))	0.9805	[-]
Hydrate Formation Temperature [At Outlet]		
Towler & Mokhatab (2005)	**8.31**	^{0}C

Parameter	Value	Unit
Joule Thompson Coefficient [μ]	**0.56**	^{0}C/bar
Total Mass Flow Rate [m_T]	85,000	kg/h
Inlet Specific Heat [C_p]	**2.071**	kJ/kg.K
Pipeline Diameter [DN]	14.00	in
Pipeline Length incl. Fittings [L_e]	20,000	m
$T_{soil}/T_{water}/T_{ambient}$ [Above Ground/Buried]	12.0	^{0}C
Overall Heat Transfer Coefficient [U]	25	W/m^2.K
Pressure drop per Unit Length [dP/dL]	1.00	bar/km
Pipeline Exit Pressure	**20.00**	bara
Pipeline Exit Temperature	**12.98**	^{0}C

REFERENCES

https://www.sciencedirect.com/topics/engineering/hydrate-formation-curve

"Handbook of Natural gas Transmission and Processing", Saied Mokhatab, William A. Poe, John Y. Mak, 3rd Edition.

"Hydrate Formation Calculation in the Natural Gas Purification Unit", J A Prajaka et al 2019 IOP Conf. Ser.: Mater. Sci. Eng. 543 012084

Predicting Compositional Two Phase Flow Behaviour in Pipelines, H. Furukawa, O. Shoham, J.P. Brill, Transaction of the ASME, Vol 108, September 1986.

AUTHOR

Vijay Sarathy holds a master's degree in Chemical Engineering from Birla Institute of Technology & Science (BITS), Pilani, India and is a Chartered Engineer from the Institution of Chemical Engineers, UK. His expertise over 16 years of professional experience covers Front End Engineering, Process Dynamic Simulation and Subsea/Onshore pipeline flow assurance in the Oil and Gas industry. Vijay has worked as an Upstream Process Engineer with major conglomerates of General Electric, ENI Saipem and Shell.

KLM Technology Group is a technical consultancy group, providing specialized services and training to improve process plant operational efficiency, profitability and safety. We provide engineering solutions by offering training, technical services, best practices, and engineering designs to meet the specific needs of our partner clients. Since 1997, KLM Technology Group has been providing engineering, operations, and maintenance support for the hydrocarbon processing industry.

WWW.KLMTECHGROUP.COM

Engineering Solutions, Standards, and Software

KLM Technology Group