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Flow Assurance Studies for Subsea Pipeline Systems

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ABSTRACT
The transportation of multiphase fluids in flowlines across these fields from the reservoir along low temperature seabed up through the risers to the topside facilities causes major subsea production problems. The problems and management strategies of hydrate, wax, slugging and in multiphase operations were reviewed with particular focus on optimized design For Subsea Pipeline Systems. A field was investigated and analysed on the issue of diameter selection, erosion check, establishment of hydrate formation condition, insulation level and configuration, and terrain slugging in the pipeline riser system. From the analysis and results, line size of 0.241m ID did not satisfy the initial pressure criterion, and was therefore eliminated. Line sizes of 0.292 and 0.343m were carried forward to erosion analysis, and the fluid mean velocities were found to be acceptable to avoid erosion; however, the erosion limit set by Pipesim as presented was higher and as such not conservative compared to the critical velocity to initiate erosion from API RP 14E. Hydrate formation analysis yielded a hydrate formation temperature of 8.82℃ applying the maximum operating production pressure of 24.1bar, as the critical pressure since hydrate formation is most likely to occur at high pressures. This was matched along with the specified wax formation temperature of 25℃ for the selection of the critical temperature at which production fluid is expected to stay above; thus, the wax formation temperature was selected as the threshold (or critical temperature) since wax formation will be encountered before hydrate in terms of temperature. From this temperature, the OHTC, U value was determined manually to be 1.104 W/m^2K against U value establish from Pipesim as 1.0 W/m^2K**.** The U value from Pipesim (latter) is more conservative. By selecting a single layer Polyurethane Foam (wet insulation) as the insulation type with thermal conductivity of 0.03 W/m℃, and carbon steel as pipeline material having thermal conductivity of 40 W/m℃, and applying the U value of 1.0 W/m^2K, an insulation thickness of 35mm was established to deliver the required temperature. Terrain slugging analysis satisfied the specified slug handling capacity of the 1st separator of $8.5m^3$. However, severe slugging occurred at both liquid rates for 1 and 4 wells flowing respectively, for both inlet and outlet pressures. Later field life analysis and results signified significant pressure drop, requiring gas lift for all liquid rates.

KEYWORD: Hydrate, Wax, Terrain Induced and Severe Slugging

I. INTRODUCTION

As the world's energy consumption soars, so does the price of oil. The surge in the price of oil and its demand drives oil companies to uncharted, unexplored territories otherwise known as deepwater or ultra deep waters in order to find and recover this elusive "black gold" to fuel the emerging economies of tomorrow. This is especially true for developing countries such as India, China and Brazil etc whose energy consumption is said to soar in the coming years. As per the International Energy Agency (IEA) forecast it is estimated that the world's oil consumption would rise by 1.4 million barrels a day to 89.1 million barrels.

Flow assurance was first used in Brazil in the early 1990's as "Garantia de fluxo", which literally means "Guarantee the flow" is a term derived by the Brazilian renowned oil company Petrobras, Which was subsequently translated to give the well-known expression, Flow Assurance (Watson., et al, 2003). It originally referred to as only thermodynamic and production chemistry issues encountered during oil and gas production .Although, the term is relatively new, the problems related to flow assurance have been a critical issue in the oil and gas industry from the early days (Q. Bai and Y.Bai, 2010). Multiphase fluids produced from subsea oil and gas fields are composed of mixtures of oil, gas and water, sometimes laden with solid particles, and often also contain corrosive components. These produced multiphase fluids are potential sources of many subsea production problems as the possibility for deposition of both inorganic and organic solids is increased while they are been transported via flow-lines over long distances as tie-backs to existing processing infrastructures to serve simultaneously several new fields. The multiphase flow-line system used in exporting these fluids are designed with consideration of the characteristics of the reservoir fluid being transported, flow conditions, topology of the pipeline and the topography of the seabed as well. These ensure a certain degree of flow assurance required to enable fluids continue to flow throughout the life of the field.

This paper describes some of the subsea production problems that can emerge in multiphase operations due to flow assurance issues. A range of possible solutions currently being applied by operators are also discussed. It also presents a framework of model-based flow assurance management strategy in handling the aftermath of slugging using PIPESIM. The PIPESIM model indicates where slugging can occur in the pipeline and rate at which it occurs. With that achieved, precautions are then taken determine the best 6.
approach to take in order to avoid the effect of slugging in transient state. Also it is a known fact that production of oil and gas offshore are prone to flow assurance issues such as wax deposition, hydrates, scaling, corrosion and so on and so therefore Flow assurance issues is a major challenge in the Nigerian oil and gas industry, and require prompt steps to tackle and ensure that subsea pipeline systems (Flowline, pipelines, and risers) are designed to withstand the action of the problems, so as to ensure it is fit-for-purpose.

II. MATERIALS/METHODS

1. The methodologies employed are the conventional flow assurance methods for performing pipeline designs. The API RP 14E method shall be applied to erosional design/check.
2. Hydrate formation conditions will be performed with the K values method using series chats.
3. The determination insulation configuration will be based upon Fourier equation and Dittus Boelter equation.
4. While the method/correlation of Scott, Shoham and Brill shall be utilized in terrain slugging; and severe slugging will conform to the Boe criterion.
5. Finally, the Beggs and Brill revised correlation shall be used for both vertical and horizontal flow; and DBR PVT Equation of state will be applied for system thermodynamics.

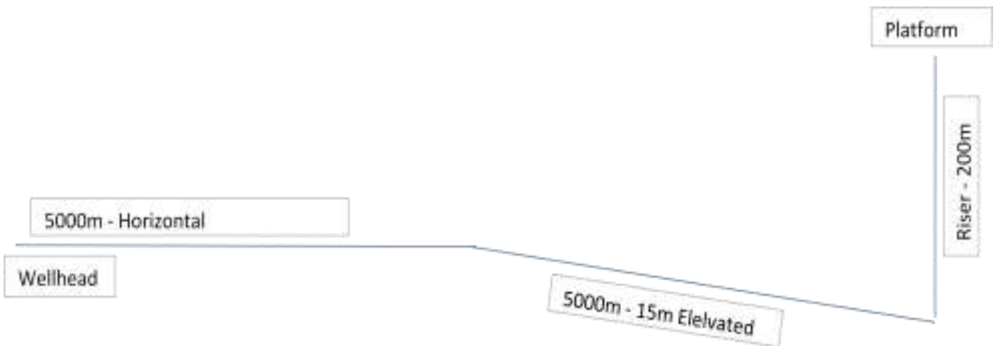

Figure 1; Schematic of subsea Pipeline Architecture of an offshore field.

Boundary conditions (input)

Separator slug handling capacity = 8.5m^3; wall thickness = 0.0127m; roughness = 0.0254mm; Line sizes to be considered are 0.241, 0.292, 0.343m internal diameter; volume flow rates are 3280, 2460, 1640, and 820 sm^3/day, for 4, 3, 2, and 1 wells flowing in the pipeline respectively; assumed initial U value = 10 W/m^2 °C. Also, the rate of undulations is Assume zero (Pipesim input).

Table 1: Design data

Fluid inlet pressure at wellhead	24.1 **bar**
Fluid inlet temperature at wellhead	50°C.
Four (4) well liquid flow rate	3280 **m^3/day**
Maximum turndown	820 **m^3/day**
Minimum outlet pressure at platform	10.3 **bar**
Minimum outlet temperature at platform	T°C.
Wax formation temperature	25°C.
Ambient Temperature	4°C.

1. Erosion Design/Check

The API RP 14E specified the critical velocity for erosion analysis, defined by the empirical equation:

$$v_m^* = \frac{c}{\sqrt{p_m}}$$

(1)

And the metric

$$v_m^* = \frac{1.22c}{\sqrt{p_m}}$$

Where

C= an empirical constant normally 100, V_m^* = maximum allowable mixture erosion velocity, ρ_m = no-slip mixture density at operating temperature and pressure

2. Vapour-Solid Equilibrium Ratio Method

The Vapour-Solid Equilibrium Ratio (K-value) method is an early method for calculating hydrate forming conditions using vapour-solid equilibrium constants. Katz reasoned that hydrates were the equivalent of solid solutions and not mixed crystals. They postulated that hydrate-forming conditions could be calculated from empirically determined vapour-solid equilibrium constants:

$$k_{vs} = \frac{y}{x_s} \quad (2)$$

Where

y = mole fraction of a hydrocarbon in the gas on a water-free basis.

xs = mole fraction of the hydrocarbon in the solid on a water-free basis.

3. Insulation level

$$C_{Pm} = (\lambda_L . C_{PL} + \lambda_g . C_{Pg}) \quad (3)$$

Where

C_{Pm} = Mixture fluid specific heat, C_{PL} = Liquid specific heat, C_{Pg} = Vapour specific heat.

$$A_{ref} = \pi . D . L \quad \textbf{(4)}$$

Where

A_{ref} = Flowline heat transfer area, L= Total length of flowline

D= Outer diameter, OD= ID +2(Wall thickness).

4. Insulation Properties: Internal Fluid Properties:

$$k_m = \lambda_L K_L + \lambda_g k_g \quad (5)$$

Where;

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$k_{m=}$ no-slip fluid thermal conductivity, $k_{L=}$ Liquid thermal conductivity, $k_{g=}$ Gas thermal conductivity, From Dittu Boelter Eqution

$$h_i = A\left(\frac{k_m}{D}\right)\left(\frac{Dv_m\rho_m}{\mu_m}\right)^a\left(\frac{c\rho_m\mu_m}{k_m}\right)^b \quad (6)$$

$$\text{Reynolds number} = \left(\frac{Dv_m\rho_m}{\mu_m}\right) \quad (7)$$

$$\text{Prandtl number} = \left(\frac{C\rho_m\mu_m}{K_m}\right) \quad (8)$$

Where

ρ_m= No-slip mixture density, $V_{m=}$ No-slip fluid mixture velocity, μ_m=No-slip fluid mixture viscosity, $k_{m=}$ No -slip fluid thermal conductivity, D = internal diameter, Fluid film coefficients: A, constant= 0.027

5. Terrain Induced and severe slugging

Invoking the correlation of Scott, Shoham and Brill Correlation, given below as:

$$In(L_m) = -2.663 + 5.441\left[\ln(D)\right]^{0.5} + 0.059\left[\ln V_m\right] \quad (9)$$

Where

L_m = mean slug length, D = pipe diameter, V_m = mixture velocity

For severe slugging will occur if $\Pi_{ss} < 1$

$$\Pi_{ss} = \left(\frac{dp}{dt}\right)_{flowline} / \left(\frac{dp}{dt}\right)_{Riser} \quad (10)$$

$$\left(\frac{dp}{dt}\right)_{flowline} = P_{inlet} * (Q_L / V_{gas}) \quad (11)$$

$$\left(\frac{dp}{dt}\right)_{Riser} = \rho_L * g * V_L \quad (12)$$

Where

$Q_{L=}$ Liquid Mass Flow Rate, ρ_L= Density of Liquid, $V_{L=}$ Liquid velocity, g = Acceleration due to gravity, P_{inlet} = Inlet pressure.

III. RESULTS AND DISCUSSION

Values from Tables 1 and Boundary conditions were inputted into PIPESIM to generate the following results: diameter selection, erosion check, establishment of hydrate formation condition, insulation level and configuration, and terrain slugging in the pipeline riser system. Results obtained are as follows;

Diameter Selection

From Table 2, 0.241m internal diameter did not satisfy the delivery pressure criterion. Thus, it has been permanently eliminated and the default diameter is set to 0.292m in Pipesim.

Table 2: Summary of the results

	LIQUID FLOW RATES(M^3/DAY)			
LINE SIZES (M)	3280 m^3/day	2460 m^3/day	1640 m^3/day	820 m^3/day
0.241	1.29 bar	12.446 bar	16.342 bar	14.883 bar
0.292	15.08 bar	16.859 bar	16.551 bar	12.824 bar
0.343	17.407 bar	16.709 bar	13.86 bar	12.009 bar

Erosion Check

Note: comparing the output data, the highest density at the inlet of flowline_1 was selected as it gives the lowest critical velocity, V_m^*; as allowable which is safe and better than a higher limit from erosion viewpoint. The critical velocity using data **from Appendix A** is then calculated thus:

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$$V_m^* = 1.22\,x\,\frac{100}{\sqrt{161.94}} = 9.59\ m/s$$

Comparing values of Table 3 to the calculated critical velocity of 9.59 m/s, showed that both line sizes satisfied erosion criterion, and as such will be moved forward to the next analysis. However, the maximum erosion velocity established using Pipesim presented a higher limit (maximum) of 11.45 and 10.53 m/s for line size of 0.292 and 0.343 m at liquid of 3280 sm3/day. Thus, the calculated critical velocity of 9.59 m/s is safer and conservative in terms of erosion.

Summary of the fluid mean velocities established from Pipesim are presented in Table below:

Table 3: Summary of fluid mean velocity

	LIQUID FLOW RATES (M^3/DAY)			
LINE SIZES (M)	3280 m^3/day	2460 m^3/day	1640 m^3/day	820 m^3/day
0.292	4.024 m/s	2.606 m/s	1.723 m/s	1.112 m/s
0.343	2.462 m/s	1.883 m/s	1.496 m/s	0.865 m/s

Establishment of Hydrate Formation Condition

This task involves the determination of hydrate formation conditions from the K-Value method. These conditions will involve using the maximum pressure (24.1 bar) to determine the minimum allowable temperature. Hydrate is known to form at high pressure, thus the maximum pressure was selected as the critical pressure to determine the temperature at which hydrate will form. This will also account for Joule Thompson expansion and cooling at the inlet. The calculation process is presented Table 1.0A in Appendix B:

Using Data from Appendix B and Interpolating for y/Kvs = 1.0,
gives: 8.82℃ for 24.1 bara, thus hydrate formation temperature = 8.82℃.

Comparing the hydrate formation temperature of 8.82℃ to the wax appearance temperature of 25℃, the critical temperature governing both wax and hydrate formation is set at 25℃. Using the evaluated critical temperature, the insulation level (OHTC, U value) from Pipesim is adjusted (or iterated) to achieve a delivery temperature above the critical temperature along the pipeline to manage and avoid both wax and hydrate formation. The iteration process yielded a **value of 1.0 W/m^2 K** achieving a delivery temperature of 41.68℃ and 41.45℃ for line sizes of 0.292 and 0.343m respectively for liquid rate of 3280sm^3/day. Also, liquid rate of 820sm^3/day recorded a delivery temperature of 27.745℃ and 25.164℃ for line sizes of 0.292 and 0.343m respectively.

$$U = \frac{m}{A} C_p \left[ln\left(\frac{T_{1-t_1}}{T_{2-t_1}}\right)\right]$$
(13)

Where T_1, T_2, and t_1 are the inlet, outlet and ambient temperatures respectively.

Using fluid data from Appendix gives,

$$U = \frac{8.679}{10170.84}\,x\,1650\left[ln\left(\frac{323-277}{298-277}\right)\right] = \mathbf{1.104}$$
W/m^{2}K.

The calculated value is in close agreement with the PIPESIM U value; however, the value from PIPESIM is more conservative for design purposes.

Insulation Level and Configuration

From Appendix D, the insulation configurations established are: Insulation thickness, **t_{ins} = 0.034 m ≅ 35mm; insulation outer radius, r_1 =0.1937m = 193.7mm;** and the selected insulation type is a **single layer Polyurethane Foam (wet insulation).**

Terrain Slugging

Calculation for Terrain induced and severe slugging are presented in Appendix E, and the results extracted and presented in Table 4 for Terrain induced and severe slugging From Table 4, terrain slugging will not occur considering a zero level of undulation, intermittent flow pattern (from output file) in the upstream section (not stratified), stable flow in the downstream section and sufficient slug handling capacity of 8.5 m^3, greater than the mean slug volume for both 1 and 4 wells. Also, severe slugging will occur since the severe slugging number for 1 and 4 wells flowing are$<$ 1.

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Table 4: Terrain Induced and Severe Slugging

Liquid Rate m^3/day	Mean Slug Length (m)	Mean Slug volume (m^3)	$\prod_{ss} = Severe\ slugging\ number$
3280	119.81	8.02322	0.1541
820	110.40	7.3928	0.1525

Later Life of Field Assessment

Towards the end of field life, the produced fluids will be 90% water as against the initial zero; however, the liquid rate will remain at 3280 m3/day. The impact of this increase in water content with respect to pressure drop was accessed using Pipesim and the plot of the pressure profile against total distance for the later field life is as presented below

Table 5: Summary of Delivery Pressure with respect to distance

	LIQUID FLOW RATES (M^3 /DAY)	
LINE SIZES (M)	3280 m^3/day	820 m^3/day
0.292m	11.204 bar	7.968 bar
0.343m	10.511 bar	7.77 bar

The delivery pressures from liquid flow of 820 m^3/day were less than the allowable minimum pressure delivery design pressure of 10.3 bar; however, the delivery pressures for 3280 m3/day were slightly higher than the prescribed outlet pressure/threshold. Following the analysis and results, it will be pertinent to introduce gas lift to attain a delivery pressure adequately above the allowable delivery pressure of 10.3 bar. Furthermore, the fluid mean velocity was also found to reduce significantly from a maximum of 4.24 m/s to 1.2 m/s, leading to a corresponding reduction in the erosion velocity from 11.5 to 5.8 m/s (Pipesim). These changes (reduction) were occasioned due to the reduction in pressure for the same flow rates.

Thus, gas lift will be required in the later field life to achieve delivery pressures adequately above the threshold of 10.3 bar for all flow rates. However, the composition of the gas lift to be provided by the topside should meet the dew point control requirement; also, injection location should be based on optimization, effectiveness and cost.

IV. DISCUSSION

From the analysis and results, line size of 0.241m ID did not satisfy the initial pressure criterion, and was therefore eliminated. Line sizes of 0.292 and 0.343m were carried forward to erosion analysis, and the fluid mean velocities were found to be acceptable to avoid erosion; however, the erosion limit set by PIPESIM as presented was higher and as such not conservative compared to the critical velocity to initiate erosion from API RP 14E.Hydrate formation analysis yielded a hydrate formation temperature of $\mathbf{8.82}$℃ applying the maximum operating production pressure of 24.1 bar, as the critical pressure since hydrate formation is most likely to occur at high pressures. This was matched along with the specified wax formation temperature of $\mathbf{25}$℃ for the selection of the critical temperature at which production fluid is expected to stay above; thus, the wax formation temperature was selected as the threshold (or critical temperature) since wax formation will be encountered before hydrate in terms of temperature. From this temperature, the OHTC, U value was determined manually to be $\mathbf{1.104}$ **W/m²K** against U value establish from Pipesim as $\mathbf{1.0}$ **W/m²K.** The U value from Pipesim (latter) is more conservative. By selecting a single layer Polyurethane Foam (wet insulation) as the insulation type with thermal conductivity of 0.03 W/m℃, and carbon steel as pipeline material having thermal conductivity of 40 W/m℃, and applying the U value of 1.0 W/m^2K, an insulation thickness of 35mm was established to deliver the required temperature. Terrain slugging analysis satisfied the specified slug handling capacity of the 1st separator of 8.5m^3. However, severe slugging occurred at both liquid rates for 1 and 4 wells flowing respectively, for both inlet and outlet pressures. Later field life analysis and results signified significant pressure drop, requiring gas lift for all liquid rates.

V. CONCLUSION

Following the design, line sizes 0.292 and 0.343m were found to pass for all analysis and design carried out herein; however, recommend the selection of line size of 0.292m in terms of cost as the smallest of both. Also, the bulk of the analysis were done based on 0.292m after pressure based analysis; this also presented a conservative design should there be any need to fall back to line size of 0.343m following detailed design and considering other operational modes (transient states) towards design finalization. Finally, recommend a design factor of 1.1 – 1.2% to be applied to insulation thickness as factor of safety and considering a wet insulation. I will also recommend the following mitigation strategies for the severe slugging: Reduction/elimination of the inclination of the flowline_2 from Figure 1.0 at the riser base to the horizontal or 2-5% positive slope; Higher flow rates to mitigate slugging and instability; Higher pressure and providing choke system at the riser top to control and hold-down back pressure.

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Data From the output file of Pipesim, for Erosion Analysis;

No-Slip Liquid Holdup,
λ_L = 0.2207167; and No-Slip gas Holdup, $\lambda_G = 1-\lambda_L$ = 0.7792833;Liquid superficial velocity, V_{SL} = 0.65599 m/s; and Gas superficial velocity, V_{SG} = 2.3161 m/s
Liquid/gas mixture velocity,
$V_M = V_{SL} + V_{SG}$ = 2.97209 m/s

APPENDIX

Recall that the No-slip holds can be derived using the superficial velocities as V_{SL} / V_M, and V_{SG}/ V_M
And the Density of Liquid, ρ_L = 669.92 Kg/m^3, and the Density of Gas, ρ_G = 18.066 Kg/m^3
Then the No-Slip is:
$\rho_m = \rho_L . V_{SL} + \rho_G V_{SG}$ = (0.2207167x669.92) + (0.7792833x18.066) = 161.94 Kg/m^3

Table 1.0A: Detailed calculation for Hydrate formation conditions

		24.1 bar: for 10°C		24.1 bar: for 5°C	
Components	Mole Fraction (y)	Kvs	y/Kvs	Kvs	y/Kvs
Methane (C1)	0.365	1.85	0.197297	1.55	0.235484
Ethane (C2)	0.044	0.6	0.073333	0.19	0.231579
Propane (C3)	0.026	0.09	0.288889	0.028	0.928571
Isobutane (IC4)	0.0063	0.035	0.18	0.0095	0.663158
Butane (NC4)	0.0013	0.2	0.0065	0.1	0.013
Isopentane (IC5)	0.0067	*	0.00	*	0.00
Pentane (NC5)	0.0083	*	0.00	*	0.00

Hexane (NC6)	0.027	*	0.00	*	0.00
C7+	0.5154	*	0.00	*	0.00
Total			0.74602		2.071792

Fluid Properties (Pipesim Output and Calculated) For U value Calculation

No-slip liquid holdup, $\lambda_L = 0.2207167$, No-slip gas holdup, $\lambda_G = 0.7792833$ Critical Outlet temperature, $T_2 = 298$ K, Liquid specific heat, $C_{PL} = 1.81E{+}03$ J/Kg K, Vapour specific heat, , $C_{Pg} = 1.61E{+}03$ J/Kg K

Mixture fluid specific heat,

$C_{Pn} = (\lambda_L .C_{PL} + \lambda_g C_{Pg}) = 1.6543E{+}03$ J/Kg K

Outer diameter, OD = 0.292 + 2x0.0127 = 0.3174 m,

Total length of flowline = 10200m

Flowline heat transfer area, $A_{ref} = \pi x D x L = \pi\ x\ 0.3174 x 10200 = 10170.84\ m^2$

Data from Pipesim output file for estimation of Insulation Properties: Internal Fluid Properties:

Liquid thermal conductivity, $k_L = 0.1$ W/mK; and gas thermal conductivity, $k_g = 0.0351$ W/mK

Therefore, no-slip fluid thermal conductivity, $k_m = (\lambda_L .k_L + \lambda_g k_g) = 0.04935$ W/mK

Liquid viscosity, $\mu_l = 3.07E-05$ Kg/m.s; and Vapour viscosity, $\mu_g = 1.25E-05$ Kg/m.s

Therefore, No-slip fluid mixture viscosity, $\mu_m = 1.65E-05$ Kg/m.s, Fluid film coefficients: A, constant = 0.027; coefficient of Reynolds number, a = 0.8; coefficient of Prandtl number, b = 0.33;

Recall from critical velocity calculation, no-slip mixture density, $\rho_m = 161.94109$ Kg/m^3 and

No-slip fluid mixture velocity, $V_m = 2.97209$ m/s; thus,

$$R_e = \left(\frac{dv\rho}{\mu}\right) = \frac{161.94109 \times 2.97209 \times 0.292}{1.65E-o5} = 8497111.234;\text{ and}$$

$$\text{Prandtl number}, = \left(\frac{C_p\mu}{k}\right) = \frac{1.6543E{+}03 \times 1.65E-05}{0.04935} = 5.53E{-}01$$

From Dittus Boelter equation, we have:

$$h_i = A\left(\frac{k}{d}\right)\left(\frac{dv\rho}{\mu}\right)^a\left(\frac{C_p\mu}{k}\right)^b$$

$$= 0.027\ \left(\frac{0.04935}{0.292}\right)\ (8497111.234^{0.8})(5.53E-010.33 = 1311.6037\ W/m^2K$$

Seawater Properties (with reasonable assumptions):

Thickness of insulation, t_{ins} =?; insulation outer radius, r_1 =?A, constant = 0.38; seawater density, $\rho_w = 1025$ Kg/m^3; seawater velocity, V_w =0.2 m/s;Seawater viscosity, $\mu_w = 0.001$; seawater specific heat, Cp = 4200 J/Kg.K; Seawater conductivity, $K_w = 0.7$ W/mK; coefficient of Reynolds number, a =0.56; coefficient of Prandtl number, b = 0.3; thus,

$$\text{Prandtl number}, = \left(\frac{C_p\mu}{k}\right) = \frac{4200\ x0.001}{0.7} = 6$$

Assuming pipeline material as carbon steel, then, thermal conductivity, $k_p = 45$ W/mK; and selecting Polyurethane foam as insulation type with thermal conductivity, $k_1 = 0.03$ W/mK.

The Reynolds number is based on the outer diameter of the insulation, thus the required thickness. Therefore, inputting same in the equation below and iterating using excel for thickness (in-terms of radius r_1 and for Reynolds number) to achieve the estimated U value of 1.0 W/m^3 K, gives the thickness as shown:

$$\frac{1}{1.0} = \frac{0.1587}{(0.146 x 1311.6037\ )} + \frac{0.1587 \ln\left({}^{0.1587}/_{0.146}\right)}{45} + \frac{0.1587 \ln\left({}^{r_1}/_{0.1587}\right)}{0.03} + \frac{0.1587}{(r_1.h_0)};$$

Thus giving an insulation thickness, $t_{ins} = 0.034$ m ≅ 35mm; insulation outer radius, r_1 =0.1937m = 193.7mm; and the selected insulation type is a single layer Polyurethane Foam (wet insulation).

Design for Terrian Induced and Severe Slugging (Terrian Induced Slugging – 3280 m^3/day)

Invoking the correlation of Scott, Shoham and Brill Correlation, given below as:

$$\ln(L_m) = -2.663 + 5.441\,[\ln(d)]^{0.5} + 0.059[\ln V_m]$$

Where L_m = mean slug length ft, d = pipe diameter (in); and V_m = mixture velocity (ft/sec)

As before, internal diameter, d = 0.292m = 11.496 in; no-slip mixture velocity, $V_m = 2.97209$ m/s; then,

$$\ln(L_m) = -2.663 + 5.441\,[\ln(11.496)]^{0.5} + 0.059[\ln 9.7508]$$

= 393.0585 ft = 119.81 m

And the mean slug volume = 119.81 x 0.0669662 = 8.02322 m^3 from the given: existing 1-st stage separator has a 8.5 m^3 slug handling capacity, thus adequate. Terrain slugging will not occur considering a zero rate of undulation, intermittent flow pattern (from output file) in the upstream section (not stratified), stable flow in the downstream section and sufficient slug handling capacity.

Terrian Induced Slugging – 820 m^3/day

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From output file, superficial liquid velocity, V_{sl} = 0.164 m/s; superficial gas velocity, V_{sg} = 0.57902 m/sAnd no-slip mixture velocity,

$V_m = V_{sl} + V_{sg} = 0.164 + 0.57902 = 0.74302$ m/s = 2.4377 ft/sec'

$\ln(L_m) = -2.663 + 5.441\,[\ln(11.496)]^{0.5} + 0.059[\ln 2.4377] = 362.1893$ ft = 110.3966 m

And the mean slug volume = 110.3966 x 0.0669662 = 7.3928 m^3

This is also less than the existing 1-st stage separator slug handling capacity of 8.5 m^3, thus adequate.

Severe Slugging – 3280 m^3/day

L_{Riser} = 200m; $L_{pipeline}$ = 10000; ID = 0.292m; P_{inlet} = 24.1 bar

Recall:Density of Liquid, ρ_L = 669.92 Kg/m^3, and the Density of Gas, ρ_G = 18.066 Kg/m^3

From output file:Water cut in liquid = 0; water specific gravity, γ_w = 1.02; Oil specific gravity, γ_o = 0.722435; gas specific gravity, γ_g = 0.812382; Liquid specific gravity, γ_L = 0.722435;Liquid mass flow rate, m_L = 29.429 Kg/s; and gas mass flow rate, m_g = 2.8021 Kg/s

Thus, Liquid Mass Flow Rate,

$Q_L = m_L / \rho_L$ = 29.429/669.92 = 0.0439291 m^3/s, and Gas Mass Flow Rate,

$Q_g = m_g / \rho_g$ = 2.8021/18.066 = 0.1551035 m^3/s, and CRA = 0.0669662

Consider Riser:

Assuming the riser is filling with liquid only, then liquid velocity in riser becomes;

Liquid velocity, V_L = Q_L /CRA = 0.0439291/0.0669662 = 0.655989141 m/s

$(dp/dt)_{Riser}$ = ρ_L x g x V_L =669.92 x 9.81 x 0.655989141

= 4649.0523 Pa/s or 0.046491 bar/s

Considering the flowline feeding the Riser:

Recall: no-slip gas holdup, λ_G = 0.7792833, And volume of flowline:

$V_{flowline}$ = A x $L_{flowline}$ = 0.0669662 x 10000= 669.662 m^3; therefore, volume of gas in the flowline,

V_{gas} = $V_{flowline}$ x λ_G = 669.662 x 0.7792833 = 521.8564 m^3;

evoking the ideal gas law to the flow condition, then volume input of gas will cause a corresponding proportional increase in the rate of pressure rise of the gas section in the flowline. Hence, for the given inlet pressure of 24.1 bar,

$(dp/dt)_{Flowline}$ = P x Q_L / V_{gas} = 24.1 x 0.1551035/521.8564 = 0.007162879 bar/s, or 716.2879 Pa/s.

Recall slugging condition: for severe slugging to occur, if the rate of pressure rise of the gas section in the flowline is less than the rate of pressure rise as liquid fills the riser,

$(dp/dt)_{Flowline}$ /$(dp/dt)_{Riser}$< 1.

Wherem $(dp/dt)_{Flowline}$ /$(dp/dt)_{Riser}$ is known as the slug number, $\prod_{ss}$

If $\prod_{ss} < 1$, then slugging will occur.Therefore, from our calculation,

$(dp/dt)_{Flowline}$ /$(dp/dt)_{Riser}$= $\prod_{ss}$ = 716.2879/ 4649.0523 = 0.1541, **thus severe slugging will occur.**

For checks, considering the outlet allowable pressure,

$(dp/dt)_{Flowline}$ = P x Q_L / V_{gas} = 10.3 x x 0.1551035/521.8564 = 0.0030661313 bar/s, or 306.1313 Pa/s

Then,

$(dp/dt)_{Flowline}$ /$(dp/dt)_{Riser}$ = 306.1313/4649.0523 = 0.06584, more severe condition.

Severe Slugging – 820 m^3/day

For the same line size, the No-slip holdups and densities remain the same,

From output file, Liquid and gas mass flow rate, m_L = 7.3573 kg/s, and m_g =0.70053 kg/s

Then, Liquid Mass Flow Rate,

$Q_L = m_L / \rho_L$ =7.3573/669.92 = 0.010982 m^3/s, and Gas Mass Flow Rate,

$Q_g = m_g / \rho_g$= 0.70053/18.066 = 0.038776 m^3/s,

Consider Riser:

As before, Liquid velocity,

V_L = Q_L /CRA = 0.010982 /0.0669662 = 0.163993179m/s

$(dp/dt)_{Riser}$ = ρ_L x g x V_L = 669.92 x 9.81 x 0.163993179= 1174.0814 Pa/s or 0.01174081 bar/s

Considering the flowline feeding the Riser:

$(dp/dt)_{Flowline}$ = P x Q_L / V_{gas} = 24.1 x 0.038776 /521.8564 = 0.001790726 bar/s, or 179.072553 Pa/s.

Therefore,

$(dp/dt)_{Flowline}$ /$(dp/dt)_{Riser}$= 179.0725/1174.0814 = 0.1525, **thus severe slugging will occur**