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Modelling Long Distance Tie-Back in Niger Delta Flow Assurance in Deep Offshore

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Abstract
This study focused on some typical flow assurance issues in deep offshore, Niger Delta, Nigeria, which are pressure losses, erosion, hydrate formation and wax formation. Erosion impacts system integrity, wax formation results in blockage, and arrival pressure are required because of the topside separator requirement. These are important considerations because maintenance and cost (direct and indirect) of replacement offshore are extremely expensive. PIPESIM tool was used to model the system at early life (4500 psia and 150°F), mid life (2500 psia and 130 °F) and late life (1500 psia and 115°F). The results show that flow rates (STB/d) are almost the same (for both the wet insulation and Pipe in Pipe insulation) for dual flow lines of 3 miles (4.828 km) in length connected to a riser of 1 mile horizontal distance. For wet insulation, flow rates are 59550 STB/D, 65809 STB/D and 21527 STB/D at early life, mid life and late life respectively whereas flow rates for Pipe in Pipe insulation are 58436 STB/D, 65388 STB/D and 28440 STB/D at early life, mid life and late life, respectively. Choke size varies between 1.58in to 1.595in at early life and between 2.5in to 2.55in at mid life for both insulations. This study concludes that the arrival temperature in Pipe in Pipe insulation (PiP) is significantly higher because change of insulation does not have much effect on pressure drop. In addition, subsea choking is needed at a water depth of 5000ft and finally, Pipe in Pipe (PiP) insulation increases tie-back distance.

Key words: *Tie Back, Wet insulation, Pipe in Pipe insulation, Early life, Mid life, Late life*

1. Introduction

Interest has shifted to deep water exploration and production, following the reduction of reserves located both onshore and offshore shallow-water. The challenges in deep water exploration and production are ever increasing as oil and gas industry advances into deeper waters (Yong and Bai, 2010). Over the years, despite the challenges, it has become possible through a combination of floating and subsea production units to exploit the hydrocarbons offshore. Early in the 21st century, there was increase in Offshore Exploration and Production due to high oil prices, with subsea wells drilled beyond 3,000 m depth and tie-back distances reaching hundreds of kilometres (Figure 1).

With the increasingly long subsea tie-backs capability, deep offshore oil and gas wells are drilled and completed to transport hydrocarbon from its original location inside the reservoir (deep offshore) to surface facility or to the sales point through flowlines. Consequently, many flow assurance problems occur within subsea flowlines and/or production facilities due to pressures and temperatures variation. The most typical flow assurance problems encountered are pressure losses in the system, erosion, hydrate, waxes, asphaltenes and scale deposition. Often, the production rate of a well is constrained by the performance of the components forming the subsea production facilities.

Flow Assurance is about guaranteeing successful and economical flow of hydrocarbon stream from reservoir to production facilities. From a survey performed in 2001, 48% of oil companies ranged flow assurance as technical challenge number 1 or 2 for deep-water developments (TechnipFMC, 2017). Hence, the necessity to design the production system to avoid potential flow assurance issues becomes necessary.

The mission of the Flow Assurance engineer is to guarantee transport of hydrocarbons from the reservoir to the host facility or offloading tanks throughout the life of the field by predicting,

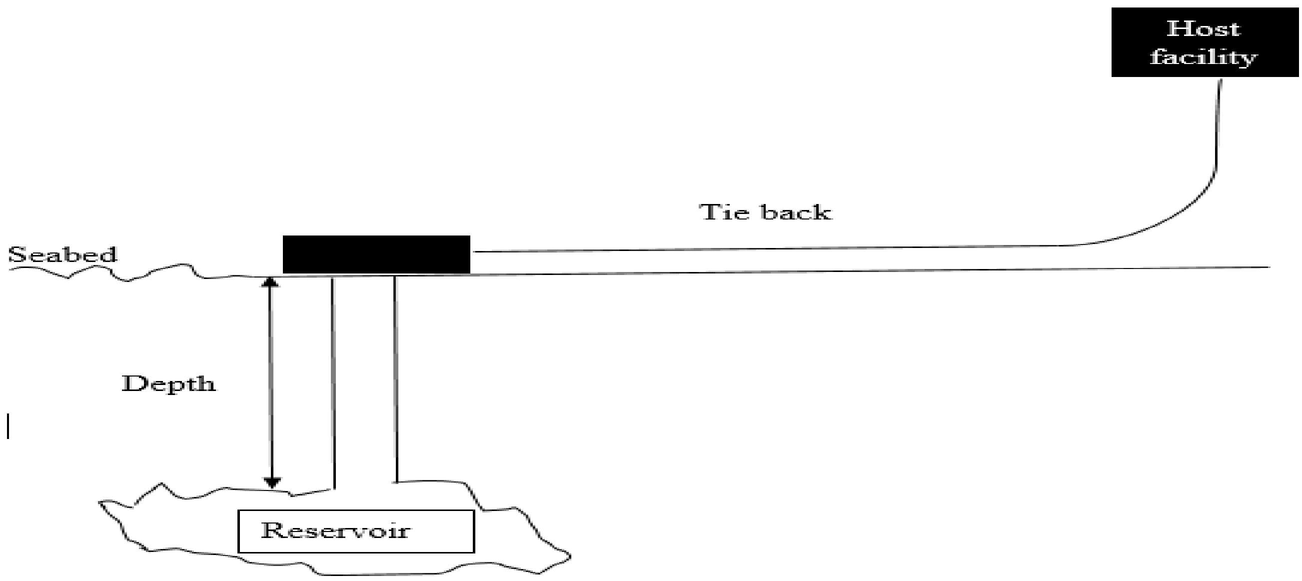

Figure 1: Reservoir depth and tie-back distance

preventing, and solving problems originated by the behavior of the transported fluids (Lullo, 2017)

The increase in tie-back distance, increases the effects of erosion, wax formation and pressure drop This is because erosion affects system integrity, wax formation results in blockage and arrival pressure is required because of the topside separator requirement. Maintenance and cost (direct and indirect) of replacement offshore are extremely expensive. Pressure, temperature and velocity vary along a subsea pipeline and as a result, the inability to predict this system leads to hydrate and wax formation, and very high erosion rate in subsea pipelines making maintenance or replacement necessary.

The major aim of this paper is to properly size the subsea flow line and riser system at the base case and maximum length tie-back distance, for natural flow, using PIPESIM.

2. Contextual information

The hydrocarbon in a reservoir, for a new field flows to the surface by the reservoir pressure. The flowing wellhead pressure reduces over time as the pressure in the reservoir reduces. Pressure drop is a major parameter to consider early at the Front End Engineering Design (FEED) phase as well as over the life of the field (TechnipFMC, 2017).

2.1. Pressure loss in single phase flow

Pressure loss/drop is the result of losses due to friction, gravity and kinetic. Higher friction factor, density, pipe length and velocity increase the pressure drop, while larger internal diameter decreases the losses. Higher friction factor such as in flexible pipes increases the friction loss and these results to high pressure loss. In deep water, it is sometimes necessary to use flexible composite risers, but to reduce the friction factor; the internal diameter of the riser will increase. However, increase the internal diameter of the riser, will increases the top tension of the riser and rig capacity. One outcome of a large riser is reduced flowing speed, which may result in flow assurance issues such as wax and hydrate formation because the temperature will drop (Bozorgmehrian, 2013).

2.2. Pressure loss in multiphase flow

The application of Homogeneous and separated flow models, in the prediction of two phase frictional pressure loss is limited. Treating the mixed liquid phase as a single entity, consequently, has been proposed for prediction in gas–liquid flows in horizontal pipe using empirical correlations. (Spedding et al, 2006). Spedding et al. (2006) reported that for particular flow regimes, pressure drop prediction methods are useful only when used for two and three phase pipe flow. This report was made when detailed experimental data (2 and 3 phase) was compared with measured/predicted pressure drop from different flow correlation models such as Lockhart–Martinelli, Dukler–Wicks–Cleveland, Beggs–Brill correlation, Friedel, Beattie–Whalley, Muller Steinhagan–Heck, etc.

2.4. Wax formation

Extensive studies and research have been reported on waxes in past decades. These studies were performed based on operational difficulty posed by the complexity of waxes and issues with impact on Capital Expenditure (CAPEX) and Operating Expenditure (OPEX) (Reistle, 1928). Interestingly, it has become very important, for subsea pipelines, to solve the issues of wax formation as large scale oil production in colder regions will be prone to severe wax precipitation (Smith and Ramsden, 1978; Asperger et al., 1981). Waxes are hydrocarbons that exist as natural components of any crude oil, when the temperature of the crude oil goes below the Wax Appearance Temperature (WAT). Wax formation increases pressure drop, due to continuous deposition of the wax on the inner wall of the pipe. The deposition gradually reduces the inner diameter of the pipe, up to a point when the pipe completely blocks. Wax control strategy are necessary for pipelines carrying waxy crude. Often, the wax control strategy consists of monitoring temperature, and removing the wax from the pipe wall by pigging.

2.5. Erosion

Erosion is a mechanical wear process, whereby material is gradually removed by repeated deformation and cutting actions caused by solid particle impingement. Consequences of erosion include loss of corrosion protection layer, loss of functionality for choke valves or loss of pipe integrity/containment in the most severe case (Islam and Farhat, 2014). Erosion depends on the pipeline material, particle feed rate, temperature, impact angle of the particle, velocity of fluid, and on the properties of the impinging particle such as density, hardness, size and shape. Spherical particles are less erosive than abrasive particles. The equation below represents the relationship for calculating erosion rate.

$$E_{rate} = \frac{\dot{m}_p\left(1-\left(\frac{D_2}{D_1}\right)^2\right) K U_p^n f(\alpha)}{\frac{\pi}{4.Sin\,\alpha}\left(D_1^2-D_2^2\right)\rho_t} C_2 \qquad (1)$$

where E_{rate}, $f(\alpha)$, K, n, ρ_t, $\dot{m}_p$, and U_p are Erosion rate (thickness of material removed per second), angle function, material constant, velocity exponent, material (pipeline) density, mass rate of erosive particle, and velocity of particle.

$$C_2 = \left(\frac{10^6 d_p}{30(\rho_m)^{1/2}}\right) for \left(\frac{10^6 d_p}{30(\rho_m)^{1/2}}\right) < 1 \qquad (2)$$

$$C_2 = 1\, for \left(\frac{10^6 d_p}{30(\rho_m)^{1/2}}\right) \geq 1 \qquad (3)$$

where d_p and ρ_m are diameter of particle and mixture (fluid) density respectively.

Erosion are caused by solids (inorganic, insoluble, particulate material), frac sand, proppants, drill mud, cement fines, etc. Erosion can also be caused by liquid droplets.

2.6. Hydrates formation

Hydrates are crystalline compounds that are formed when hydrocarbon molecules mix with water at a temperature below the hydrate formation temperature. Figure 2 shows hydrate formation curve for distance tie back project, executed by Chevron West Africa (TechnipFMC, 2017). Hydrates are formed whenever there is a favourable condition: Free water (water in liquid form), high pressure, low temperature, hydrate formers like methane, ethane, propane, n-butane and carbon dioxide.

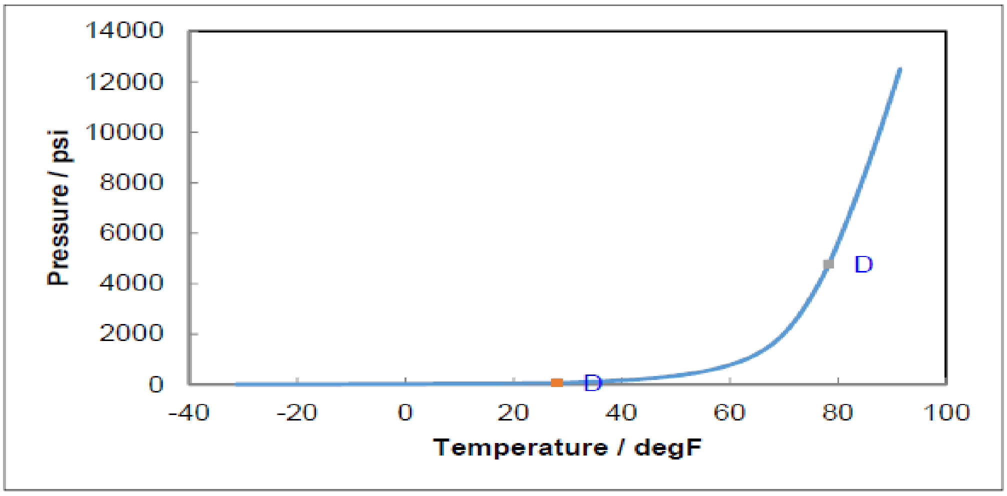

Figure 2: Hydrate Formation Curve (TechnipFMC, 2017)

3. Materials and methods

The software used in this work was PIPESIM which has the capability to model equipment sizing in order to reduce erosion, wax formation and pressure loss at base case (3 miles) and as the tie-back distance is increased. In utilizing the software, steady-state flow assurance was implemented. The sensitivity template in the software was utilized to optimize the design of flowlines and risers and the effects of changes in parameters was assessed. The Beggs and Brill method for pressure loss calculation in multiphase flow applies was utilize in this work for both horizontal and vertical flow. PIPESIM has algorithms for the Beggs and Brill correlation. It takes into consideration different flow regimes. The Froude number, which is dimensionless, was used to define the flow regime.

$$N_{FR} = \frac{{V_{ns}}^2}{g.D} \qquad (4)$$

where V_{ns}, g and D are no slip velocity, gravitational constant and inner diameter respectively.

Segregated if; $N_{FR} < L_1$, *Intermittent if;* $L_1 < N_{FR} \leq L_2$, *Distributed if;* $N_{FR} > L_2$ *and* $N_{FR} \geq L_1$

$$L_1 = exp(-4.62 - 3.757X - 0.481X^2 - 0.0207X^3) \qquad (5)$$

$$L_2 = exp(-1.061 - 4.602X - 1.609X^2 - 0.179X^3 + 0.635X^5) \qquad (6)$$

$$X = \ln(\frac{Q_L}{Q_L+Q_G}) \qquad (7)$$

where Q_L and Q_G are liquid and Gas volumetric flow rate.

The gravitational pressure losses per unit length is defined:

$$(\frac{dP}{dZ})_g = \frac{H_L\,\rho_L + (1.0-H_L)\rho_G.g.Sin\theta}{144 g_c} \qquad (8)$$

where ρ_m, θ, ρ_L, ρ_G, and H_L are mixture density (a function of the liquid holdup), angle of inclination, liquid density, Gas density and liquid holdup respectively.

The frictional pressure drop losses per unit length is defined:

$$-\left(\frac{dP}{dZ}\right)_f = \frac{f_{tp} G_m V_{ns}}{2 g_c D} \qquad (9)$$

where f_{tp}, G_m, V_{ns}, and D are “two phase friction factor”, “mixture mass flux”, “no slip velocity” and internal diameter respectively (Saleh, 2002).

3.1. Model system and input parameters

The system in the model comprise of a wellhead (in a manifold), a choke, dual flowlines/riser and a Riser base. The hydrocarbon flow from the choke through the manifold and flowline. The model input parameters are summarized in Table 1. Figure 3 shows the model set up, which is a tie-back system connecting subsea manifold to a surface production platform/topside facility (fixed or floating) via a flow line, a riser base and a riser. The tie-back refers to the flowline and the tie-back distance refers to the flowline length. The tie-back distance (flowline length) shall be increased in steps of 0.1 miles.

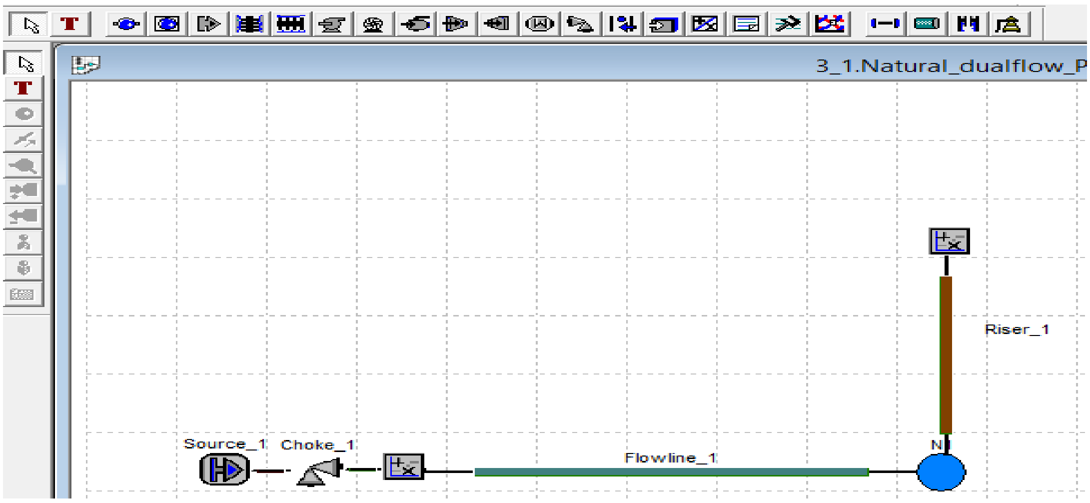

Figure 3: PIPESIM model set up

Table 1: Property values

Properties		Unit	Value
Flowing WellHead Temperature	Late Life	^{O}F	115
	Mid Life	^{O}F	130
	Early Life	^{O}F	150
C factor for Erosional Velocity Ratio (EVR) Calculation		$(ft/s)(ib/cuft)^{0.5}$	150
EVR < 1	Seabed Temp	^{O}F	39
	MSL Temp	^{O}F	77
Roughness		in	0.0018
Water Cut	Late Life	%	40
	Mid Life	%	20
	Early Life	%	0
Wet Insulation (U value)		$Btu/hr/ft^2/^{O}F$	0.8
PiP (U value)		$Btu/hr/ft^2/^{O}F$	0.2
Gas Oil Ratio (GOR)		Scf/STB	900
API		Degree	30
Gas Specific Gravity		Dimensionless	0.7
Water Depth		Dimensionless	1.02
Water Depth		ft	5000
Flowline (outside diameter)		in	8.625 (Dual Flowlines)
Flowline (wall Thickness)		in	0.8125 (Dual Flowlines)
Flowing WellHead Pressure	Late Life	psia	1500
	Mid Life	psia	2500
	Early Life	psia	4500
Topsides Arrival Pressure		psia	400
Wax Appearance Temperature		^{O}F	75
Number of flowlines			2

3.2. Sensitivity analysis

The sensitivity analysis on pressure and temperature (Table 2) was carried out using PIPESIM, and for each insulation case (Wet insulated and PiP) at each point in time (Early, Mid and Late), a sensitivity plots for the systems were generated.

Table 2: Simulation matrix for Sensitivity Analysis

Time	Pressure (psia)	Temperature (^{O}F)
Early Time	4500	150
Mid Time	2500	130
Late Time	1500	115

4. Results and discussion

These are results from the simulation of oil flow from wellhead to separator at topside. There is a choke in the wellhead, a riser and a dual flowline connecting the wellhead to the riser. The flowline has an internal diameter, 7 inches, with insulation, which is either wet insulated or Pipe in Pipe (PiP). First the flow rate reaching separator (topside) at 400 psia without choking was found, then checked if the Erosional Velocity Ratio (EVR) was greater than one (1). Once the EVR is greater than 1, the flow was choked by adjusting the bean size, and finally checked if arrival temperature is okay.

4.1. Base case with wet insulation (Early life 3 miles)

Figure 4 was plotted for base case (3 miles) when choke was fully open (bean size of 5 inch) at Early life for dual flow lines having wet insulation. It shows a production flow rate of about 149375 STB/d at a topside arrival pressure of 400 psia. Figure 5 is a plot for base case (3 miles) when choke was fully open (bean size of 5 inch) at Early life for dual flow lines having wet insulation. The above shows that at a flow rate of 149375 STB/d, there is an EVR of 2.54 and this EVR is greater than 1. The EVR is too high and so there is need for choking.

4.2. Mid life

Figure 6 was plotted for base case (3 miles) when choke was fully open (bean size of 5 inch) at Mid life for dual flow lines having wet insulation. This shows a production flow rate of about 81669 STB/d at a topside arrival pressure of 400 psia. Figure 7 was plotted for base case (3 miles) when choke was fully open (bean size of 5 inch) at Midlife for dual flow lines having wet insulation.

This shows that at a flow rate of 81669 STB/d, there is an EVR of 1.24 and this EVR is also greater than 1. So, there is need for choking.

4.3. Late life

Figure 8 was a plot for base case (3 miles) when choke was fully open (bean size of 5 inch) at Late life for dual flow lines having wet insulation. This result shows a production flow rate of 21527 STB/d at a topside arrival pressure of 400 psia. Figure 9 was a plot for base case (3 miles) when choke was fully open (bean size of 5 inch) at Late life for dual flow lines having wet insulation. At a flow rate of 21527 STB/d, there is an EVR of 0.28 and this EVR is less than 1, hence the flow is not choked with the arrival temperature of 82.3 °F and arrival pressure of 400 psia. There is elevation and frictional pressure drop of 989 psia and 107 psia respectively.

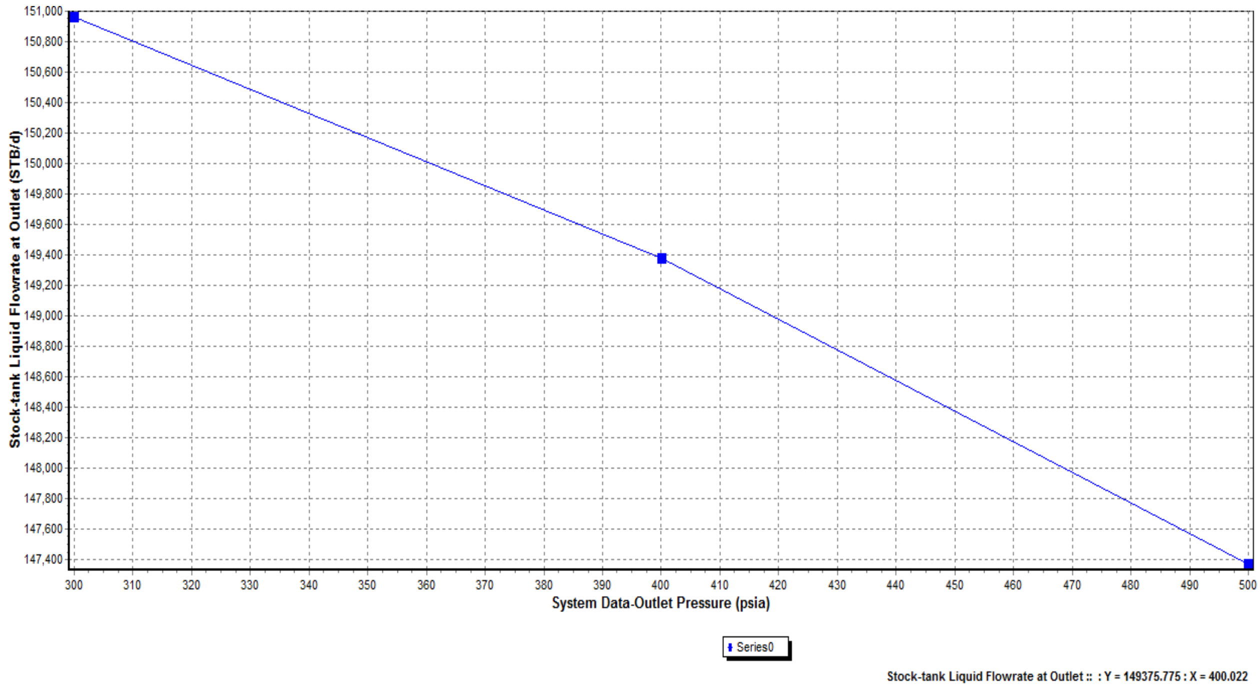

Figure 4: Stock-tank liquid volume versus arrival pressure (fully open choke)

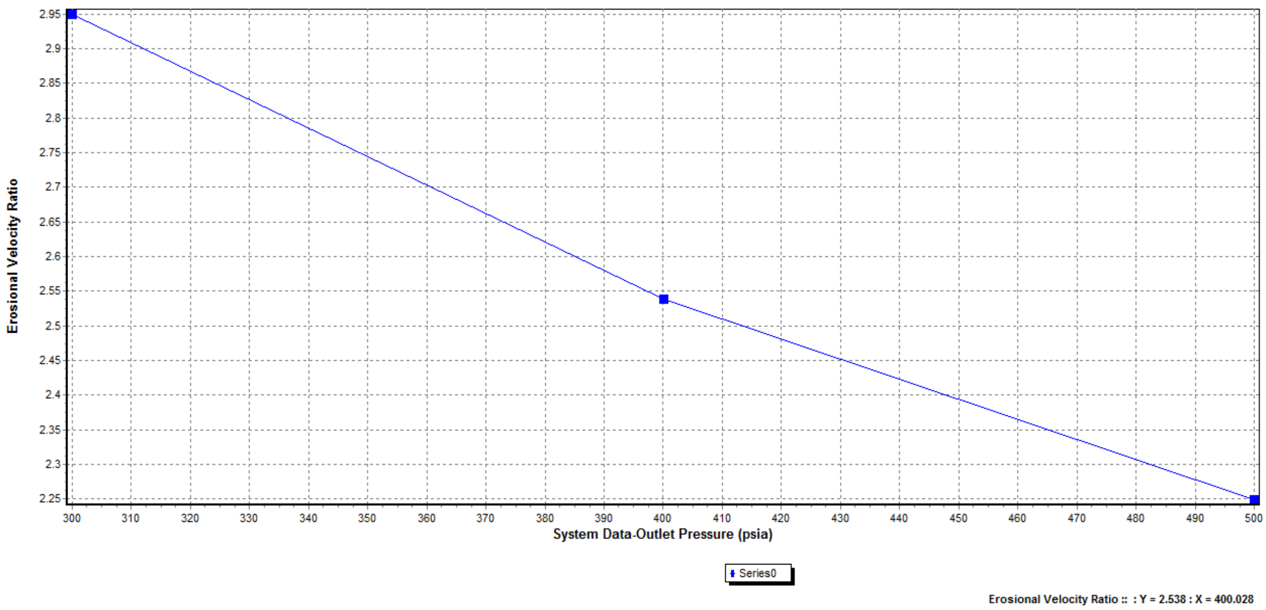

Figure 5: EVR versus arrival pressure (fully open Choke)

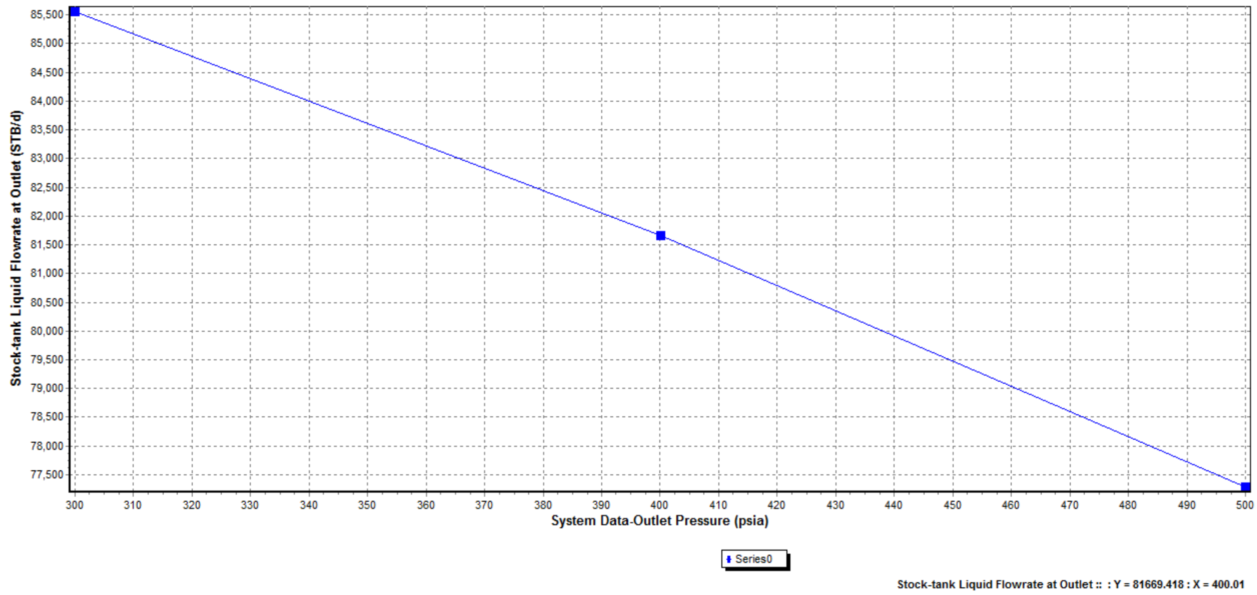

Figure 6: Stock-tank liquid volume versus arrival pressure (fully open choke)

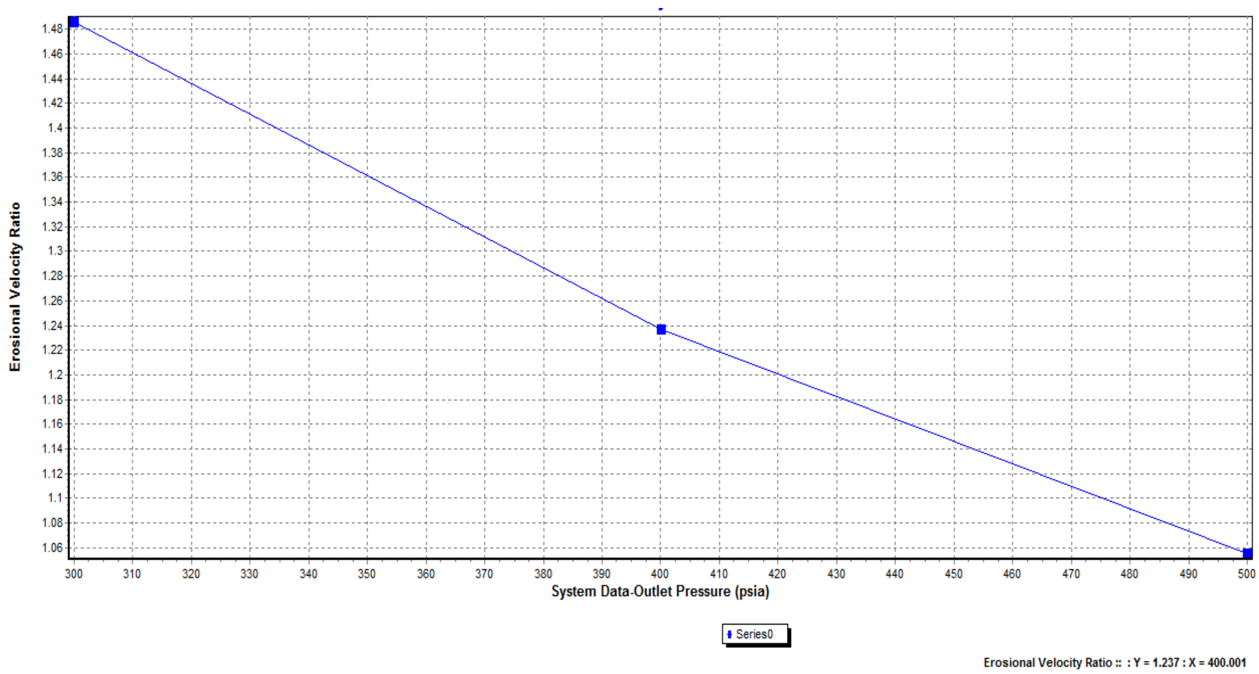

Figure 7: EVR versus arrival pressure (fully open choke)

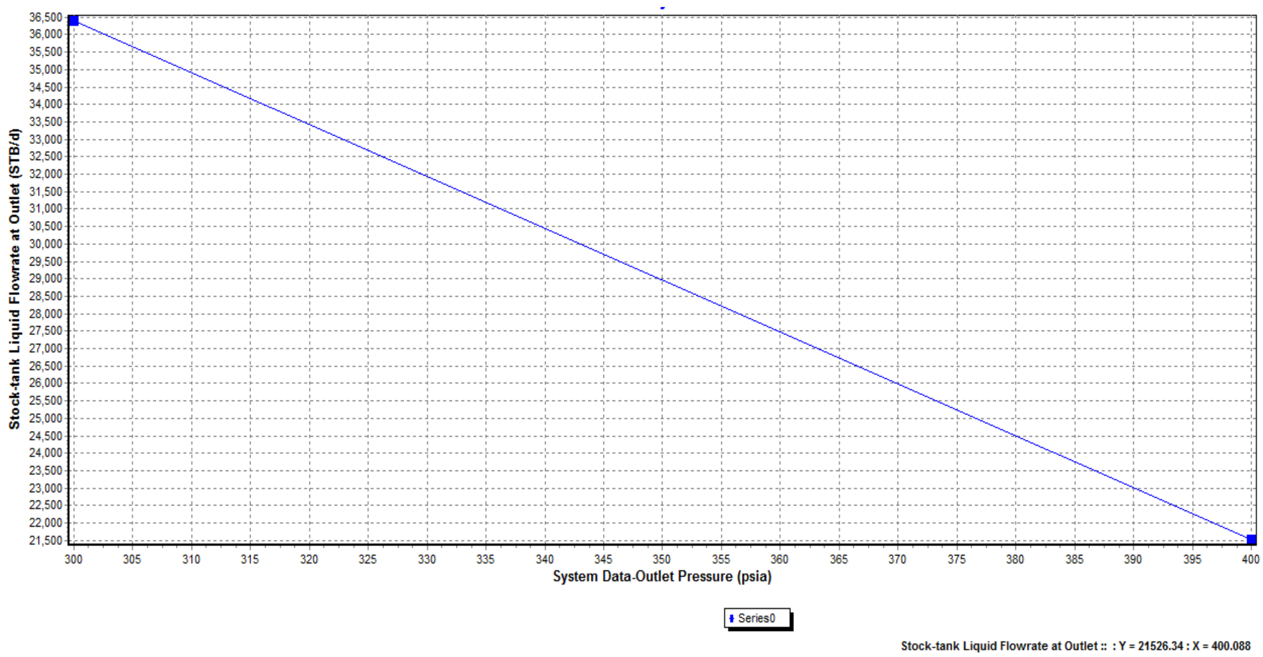

Figure 8: Stock-tank liquid volume versus arrival pressure (fully open choke)

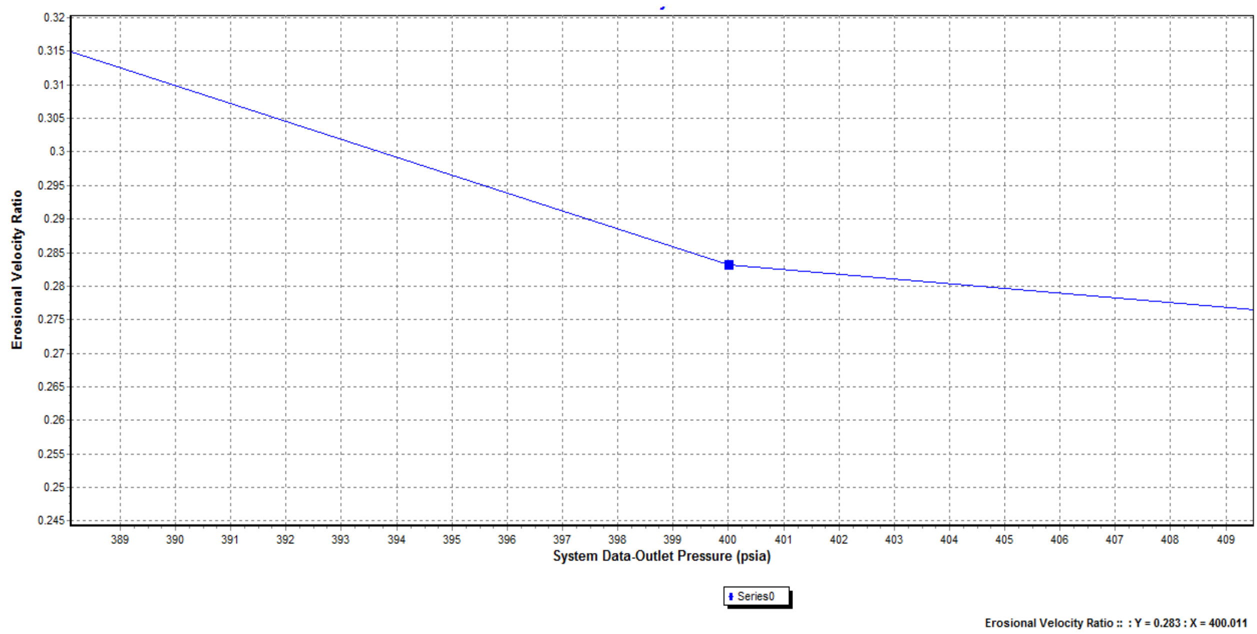

Figure 9: EVR versus arrival pressure (fully open choke)

4.4. Maximum flowline distance

Table 3 shows the maximum flowline distance that can achieve an arrival temperature of 75°F at late life. When compared with the results gotten at the base case, it shows arrival temperature is lower in late life while the values of other parameters tend to be very close to that of the base case.

The flow rate for PiP and wet insulation are almost the same for the base case (Figure 10). The major difference between the results for base case using PiP and wet insulation is the arrival temperature as shown in Figure 11. The main focus is on the result for late life when the flowline is at the maximum. Table 4 shows an arrival temperature at Late life when the flow line is extended to a distance of 9.9 miles.

In terms of field design, the choke bean size information is relevant for choosing the right type of choke in early engineering. The pressure loss across the choke is an important point to note. The maximum length of flowline informs the choice of the needed type of pipe insulation whether it is wet insulation or PiP. PiP is expensive but if the well has a tie-back distance of say 7 miles for example then PiP becomes the choice of Pipe insulation (Figure 12) which shows a maximum tie-back distance of 9.9 miles for PiP.

Table 3: Results for dual flow lines of 3.3 miles in length and having wet insulation

Pressure (psia)	Temp (^{O}F)	Flowrate (STB/d)	EVR	Arrival		Pressure Loss	
				Pressure (psia)	Temp (^{O}F)	Elevation	Friction
1500	115	18923	0.48	400	78.1	1007	91

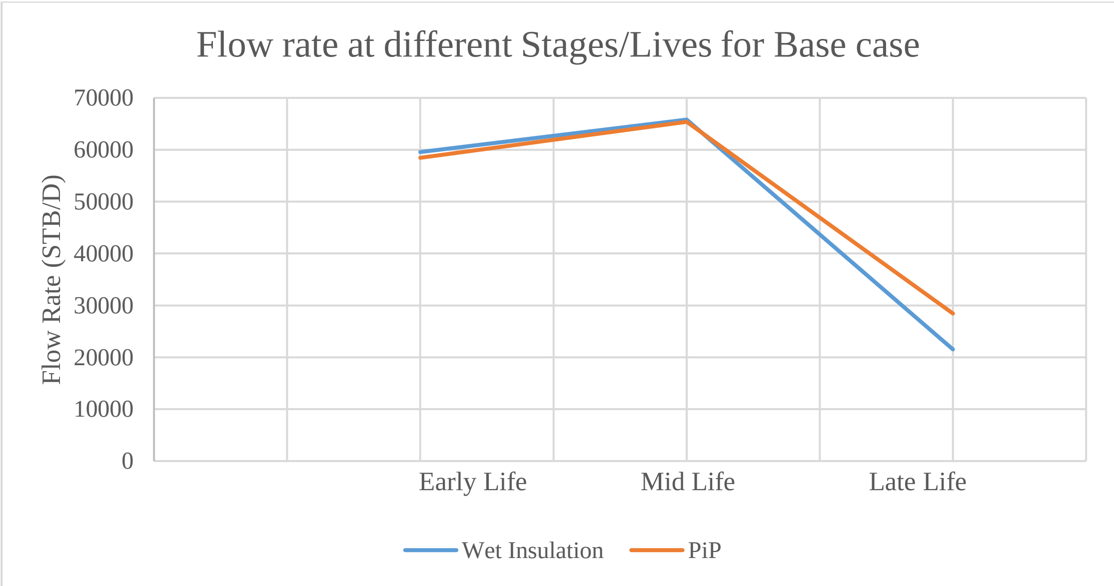

Figure 10: Flow rate at different lives for base case

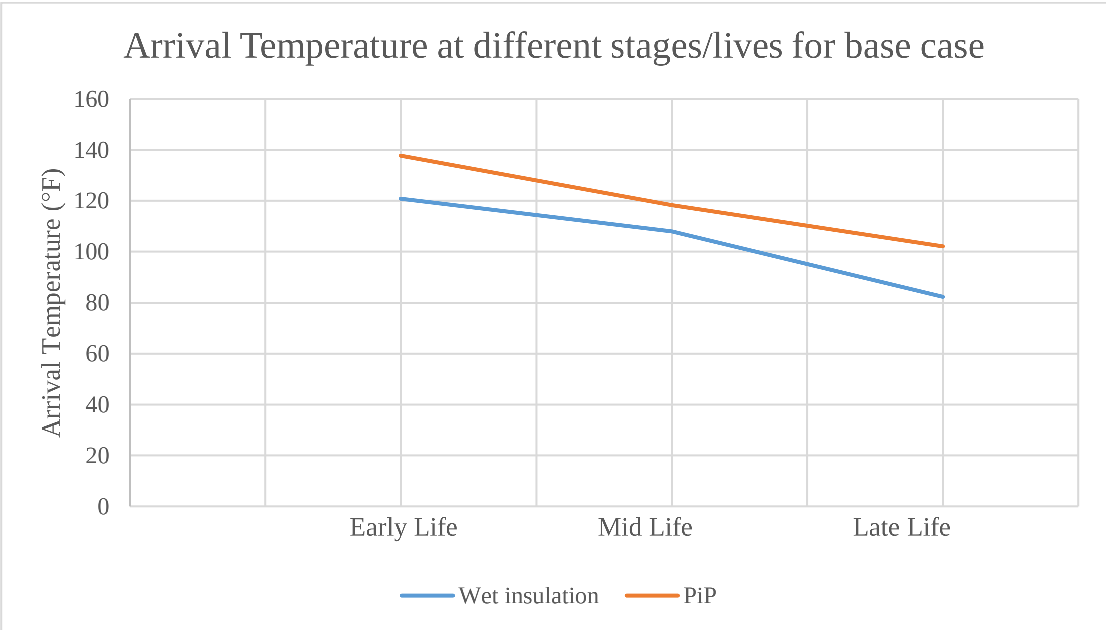

Figure 11: Arrival temperature at different lives for base case

Table 4: Results for dual flow lines of 9.9 miles in length and having PiP insulation

Pressure (psia)	Temp (^{O}F)	Flowrate (STB/d)	EVR	Arrival		Pressure Loss	
				Pressure (psia)	Temp (^{O}F)	Elevation	Friction
1500	115	10002	0.13	400	75.4	1027	72

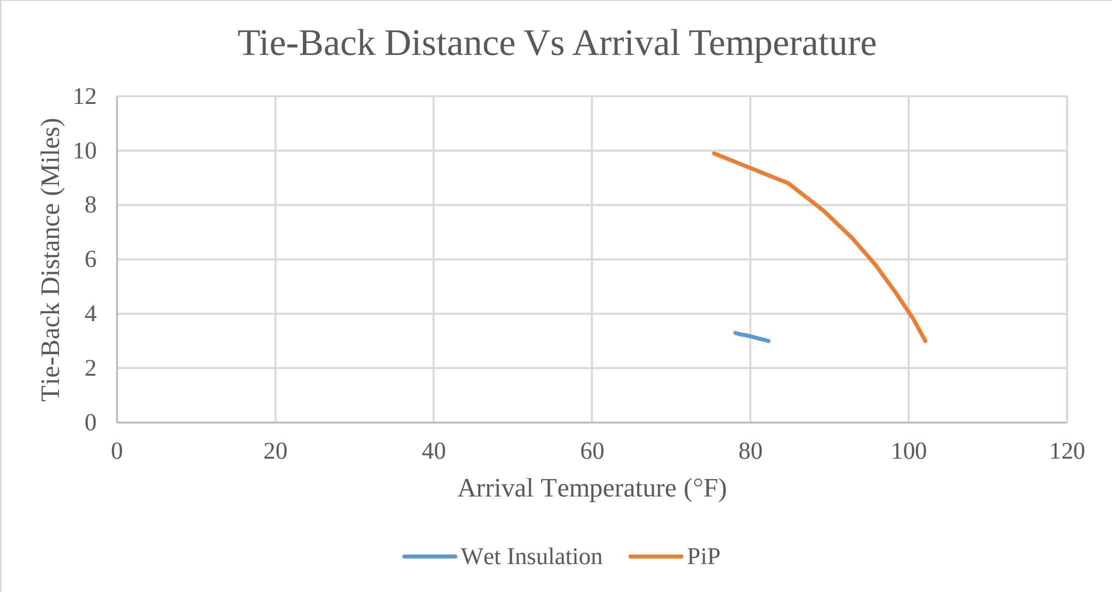

Figure 12 Tie-back distance versus arrival temperature

5. Conclusions

Flow Assurance challenges (Wax Appearance Temperature (WAT), Hydrate Formation), which affect production rates, tie-back distance and increase CAPEX and OPEX in deep offshore was studied in this work. Pressure drop and arrival temperature were determined to examine their effect on tie-back distance. Wet and Pipe in Pipe insulations, were used for the flowlines and for dual flowlines of 3 miles in length, connected to a riser of 1 mile horizontal distance and 5000ft depth, the flow rates (STB/d) are almost the same for both insulations. The arrival temperature in PiP is significantly higher than wet insulation, because change of insulation does not have much effect on pressure drop and PiP increases tie-back distance. Flow rate varies for both wet and pipe in pipe insulations at early, mid and late life. Choke size varies between 1.58in to 1.595in and between 2.5in to 2.55in at early and mid life for both insulation. Finally, at water depth of 5000ft subsea choking is needed.

Acknowledgement

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