Flow Assurance in Subsea Pipeline Design - A Case Study of Ghana's Jubilee and TEN Fields*

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Abstract

The increasing exploration and production activities in the offshore Cape Three Point Blocks of Ghana have led to the discovery and development of gas condensate fields in addition to the oil fields which produce significant amount of condensate gas. These discoveries require pipelines to transport the fluids avoiding hydrates and wax formation. This paper focuses on subsea pipeline design using Pipesim software that addresses flow assurance problems associated with transporting condensate gas from the Jubilee and TEN Fields to the Atuabo Gas Processing Plant. It also considered an alternate design that eliminates the need for capacity increase of flowlines for the futuristic highest projected flow rates in 2030. The design comprises of two risers and two flowlines. Hydrate formation temperature was determined to be 72.5 ˚F at a pressure of 3 000 psig. The insulation thickness for flowlines 1 and 2 were determined to be 1.5 in. and 2 in. respectively. The pipe size for flowlines 1 and 2 were determined to be 12 in. and 14 in. respectively. The maximum designed flow rate was determined to be 150 MMSCFD. To meet the highest projected flow rate of 700 MMSCFD in the year 2030 at the processing plant, a 16 in. ID pipeline of 44 km length was placed parallel to the 12 in. ID flowline 1. This parallel pipeline increased the designed flow rate by approximately 4.7 times (705 MMSCFD). The alternate design employs 18 in. and 20 in. ID pipes for flowlines 1 and 2 respectively.

Keywords: Condensate Gas, Flowline, Flow Assurance, Hydrate, Pipesim

1 Introduction

Pipeline in the oil and gas industry refers to a long line of connected segment of pipe with pumps, valves and other facilities needed for operating the system. Pipelines usually have a minimum diameter of 0.1 m and a minimum length of 1.6 km unless stated (Guha and Berrones, 2008). As the demand for energy continues to increase globally, exploration and production firms adapt to operational practices to meet the world's energy demand. This energy demand has led to the growing development of oil and gas activities offshores of many countries including that of Ghana, which requires safe and guaranteed means of transporting both crude and natural gas (condensate gas). Other means of transporting natural gas include use of tankers, conversion into Liquefied Natural Gas (LNG), Compressed Natural Gas (CNG), and gas to solid among others. However, transportation using pipelines are considered safe, economical, friendly to the environment and highly reliable (Singh and Nain, 2012). Although pipelines better guarantee continuous delivery and assures lower operating and maintenance cost, more challenges arise when transporting natural gas from offshore to onshore processing plant because temperature and pressure variations affect the physiochemical properties of the fluid transported (Ayala and Adewumi, 2003).

The subsea environment, which involves low temperatures as well as high pressures, high water cuts and longer transfer time provide conditions that are ideal for hydrates and wax formation and other solid deposits. These are the fundamental impairments to production of oil and gas through long distance subsea pipelines, especially at shutdown and restart situations (Akpabio, 2013). Hydrate related issues, severe riser slugging, wax formation, pressure and temperature losses, in natural gas pipelines have become a growing concern for the industry. In the quest to avert the above issues, Marfo *et al.* (2018) designed a subsea pipeline that transports natural gas from Gazelle Field in Côte d'Ivoire to a processing platform located 30 km to predict the conditions under which hydrate will form so as to be avoided. Their work anticipated hydrate to form at a temperature of 65 °F for an arrival pressure of 800 psia thereby recommending flowline insulation thickness of 0.75 in. with specific pipe size of 10 in. to satisfy the arrival pressure condition. Similarly, this paper covers the design of a subsea pipeline system that addresses issues associated with transporting condensate gas from a satellite platform to a processing plant.

1.1 Background of the Study Areas

This research was conducted on the offshore waters of Ghana which covers Ghana's Jubilee Field, West Cape Three Points, and Tweneboa Enyerra Ntomme (TEN) Field. The pipeline covers a distance of about 59 km from the FPSO Kwame

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Nkrumah, with 44 km section of the pipeline positioned on the sea bed and the remaining 15 km on the water surface to the Onshore Receiving Facility (ORF) which is the Atuabo Gas Processing Plant. Brief description of the study areas are discussed:

1.1.1 West Cape Three Point (WCTP) Discoveries

The WCTP is located at the Tano basin in the Gulf of Guinea, covering an area of 457 294 776 gross m^2 with water depth ranging from 50 – 1798 m. The discoveries by Kosmos Energy made at the block include; The Jubilee Oil Field, 2007, the Mahogany Oil Field, 2008, the Teak Oil and Gas condensate Fields, 2011 and the Akasa Oil Field, 2011 (McLaughlin, 2012).

1.1.2 Jubilee Field

Jubilee oil Field is located in deep-water of about 1100 – 1700 m depth and an approximate distance of 60 km from the nearest coast in the Western Region of Ghana. The field covers an area of 109 265 220 gross m^2 and a total gross resources of 600 MMbbl with upside. The production from the field averaged approximately 102 000 bopd. The field underlies portions of the West Cape Three Point and Deep-water Tano License Blocks. The field start-up occurred on November 28, 2010 and production has continued to ramp up as additional phase one wells has been brought online. The phase 1 development programme consists of 17 wells, 9 producers, 6 water injectors, and 2 gas injectors which target the lower and upper Mahogany reservoirs (McLaughlin, 2012).

1.1.3 TEN Field

The Jubilee partners discovered a significant gas condensate accumulation at the Tweneboa Field in 2009, followed by the Enyenra oil Field in 2010. Further drilling success resulted in the discovery of oil at the Ntomme Field, and oil and gas condensate at Wawa in 2012. Initial development of the discoveries on the Deep-water Tano block focused on the Enyenra and Ntomme oil fields, utilising a Floating Production, Storage and Offloading (FPSO) vessel. Production from Tweneboa, Enyenra, and Ntomme (TEN) began in August 2016 (Anon, 2014).

1.1.4 The Floating, Production, Storage and Offloading Vessel (FPSO)

The FPSO Kwame Nkrumah which is named after the first president of Ghana was installed in November 2010, at a water depth of 1 100 m. It is designed to operate for 20 years. The facility processes 120 000 bpod and 160 Mscfd of gas, and has a storage capacity of 1.6 million bbl of oil (Anon, 2013; Anon, 2014). Table 1 shows the production ranges for the operating parameters and specification of FPSO Kwame Nkrumah.

1.1.5 The Atuabo Gas Processing Plant (AGPP)

The Atuabo gas processing plant or the Ghana Gas Company located at Atuabo in Western Region of Ghana is designed to receive natural gas from the fields in Ghana. The plant has a capacity of 140 MMSCFD of natural gas. It is designed to process a minimum of 140 000 000 kg of Liquefied Petroleum Gas (LPG) for domestic use and deliver about 46 000 000 kg of condensate and about 150 000 000 kg of isopentane (Anon, 2014). The associated gas from all the Cape Three Points Fields have to be channeled to the gas plant for further processing.

The study area is shown in Fig 1.

Table 1 Jubilee FPSO Function Specification

Parameters	Jubilee Production
Total fluid rate	160 000 BLPD
Oil production rate	120 000 BOPD
Produced water rate	80 000 BWPD
Produced gas rate	160 MMSCFD
Topsides arrival pressure	34.5 – 55.2 BAR (500 – 800 psig)
Arrival temperature	49 – 60 ˚C (120 -140 ˚F)
Flowline shut-in pressure	414 BAR (6000 psig)
Water injection pressure	345 BAR (500 psig)
Water injection rate	232 000 BPD minimum
Gas injection pressure	5 500 psig
Gas injection rate	160 MMSCFD
Gas export rate	707 BAR (3 000 psig)
Gas export rate	160 MMSCFD

(Source: Weinbel and Araujo, 2012)

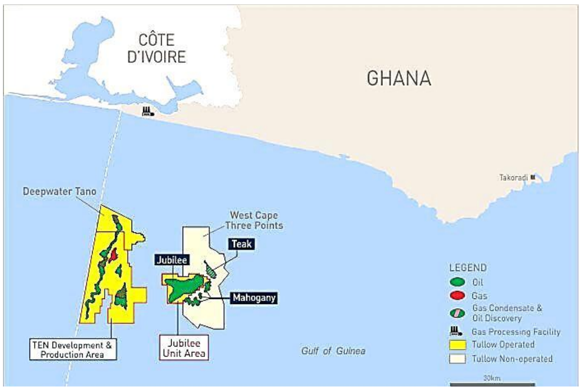

Fig 1 West Cape Three Points, Jubilee Field, TEN Field and Atuabo Gas Plant (Source: Anon, 2014)

1.2 Overview of Flow Assurance

Flow assurance refers to ensuring successful and economical flow of hydrocarbon stream from a reservoir to the point of sale. Flow assurance includes thermal investigation of pipelines, ensuring temperature is above hydrate's formation temperature (Anand and Anirbid, 2015). Blocked oil and gas pipelines, is one of the industry's challenges, resulting in loss of revenue. It has therefore been important to find solutions for oil and gas pipelines to avoid such incidents (Sum, 2013). Flow assurance is considered a critical task during subsea transportation of natural gas because of the anticipated high pressure and low temperature (Obanijesu *et al*., 2010). The following are some of the challenges that results in flow assurance problems in subsea transportation of condensate:

1.2.1 Hydrate Formation

There are three different forms of hydrate structures. These are; the cubic structure I (s1), cubic structure II (sII) and hexagonal structure H (sH). Gas such as methane (CH_4) and carbon dioxide (CO_2) mostly form s1 hydrates while natural gas form sII hydrates (Mokhatab *et al.*, 2006; Ripmeester *et al.*, 1987). Hydrates are solid crystalline compounds whose structure is made of a hydrogen bonded water molecules and a gas molecules (Gabitto and Tsouris, 2010). Gas hydrate causes many flow assurance problems which include; reduction of the pipe internal diameter, flow restriction, increased pumping pressure, reduced throughput and increased surface roughness (Broni-Bediako *et al*., 2017). There are a number of factors, which contribute to gas hydrate formation. The major ones include; free water condensing out of a gas, hydrate formers such as methane, ethane, propane, isobutane, nitrogen, hydrogen sulphide, and carbon dioxide; low temperature and high pressure conditions (Ameripour, 2005). The determination of hydrate formation conditions in a pipeline is one of the major operations the oil and gas industry is concerned with, as subsea conditions favour hydrate formation. Due to the conditions under which gas hydrate forms, there is no unique method of preventing its formation. Gas hydrate formation can be prevented in the following ways; by preventing free water in the gas, either dehydrating the gas or increasing the temperature to vaporise more water; introducing chemical inhibitors such as methanol, ethanol and glycol into the pipeline system (Covington and Collie, 1997).

1.2.2 Wax Deposition and Gelation

Wax formation and deposition is one of the major problems associated with pipeline transportation of crude oil and condensates. Wax deposition can foul the internal surface, which results in increasing pressure drop. Wax deposition depends more on a flow temperature since it only deposits on the walls of a pipe when the wall's temperature is below the cloud point and colder than the bulk fluid (Akpabio, 2013). Waxes that precipitate out of the flow stream consist of normal paraffin and naphthenes (Theyab and Diaz, 2016). According to Karen and Rønningsen (2003), wax precipitation within pipelines at and below the cloud point of the fluid can cause gelling inhibiting flow. Factors such as fluid viscosity, paraffin content, flow rate, gas-oil ratio, and the overall heat transfer coefficient affect the deposition rate of wax (Golczynski and Kempton, 2006).

1.2.3 Pipeline Slugging

Slugs can cause damage to facilities, separator flooding, increased corrosion, starving compressors and high backpressure. There are different forms of slugs such as hydrodynamic slugs, terrain induced slugs, turn up slugs, and pigging slugs. Terrain induced slugging normally occurs when liquid is trapped in the pipeline at low spots. Riser slugging is a type of terrain induced slugging which occurs at the riser base and normally depend on the flow rate (Mokhatab *et al*., 2006).

1.2.4 Temperature Losses Control Mechanisms

The transportation of condensate gas through a pipeline over a long distance requires a set temperature to be maintained in order to avoid hydrate formation, wax formation and deposition and wax gelation. Due to this regard, temperature losses across the distance of the pipeline are of paramount concern (Nikhar, 2006). According to Okologume and Appah (2015), thermal insulation of subsea pipeline is of essential need in the design and operation of subsea pipelines since it helps preserve heat and maintains the operating temperature beyond the hydrate region. Direct Electrical Heating (DEH) is a flow assurance technology developed to safeguard the well stream through the pipeline to the platform. The pipe is heated by running alternating current through the steel in the pipe (Nexans, 2015). DEH has really proved to be cost effective, highly reliable, and flexible. Industry partners have used DEH at selected fields since 2000, and the method has proved very good under various operating conditions. So far, the method is used up to 1 km water depth and approximately 45 km pipeline length (Nysveen *et al.*, 2005). DEH system is, effective and efficient over short distances and it is environmentally friendly than chemical inhibition. Over longer distances, both chemical inhibition and DEH may not be economically viable to be utilised (Akpabio, 2013).

2 Resources and Methods Used

In order to design a suitable pipeline for transporting condensate gas for the Jubilee and TEN Fields, the following methods were employed in this work; considering the minimum required parameters in the design of subsea pipeline but not limited to temperature of flowlines; pipeline pressure losses; gas composition and properties; desired mass flow rate; elevation at exporting terminal (FPSO); distance between exporting terminal and the receiving facility; Weymouth equation and Pipesim.

2.1 Pipeline Design Parameters

Data on gas composition, properties and gas entry pressure were taken from the 2013 Jubilee Field reports and literature. Other data such as annual water temperature, data on the Atuabo Gas Processing Plant (AGPP) were obtained from Tullow Ghana Limited's website. However, data on TEN gas composition were taken from 2014 Environmental Impact Assessment report of the TEN Project. Table 2 presents secondary data taken from the relevant study areas.

2.1.1 Temperature of Flowlines

To determine the ambient temperature of the pipeline, flowline 1 assumed the temperature of Ghana's seawater. Temperature profile of the seawater (Fig 2) along the coast of Ghana was used to determine the temperature at various depths of interest for flowline 1 (Anon, 2009). Flowline 2 assumes an average onshore ambient temperature of 80.6 ^oF.

2.1.2 Pipeline Pressure Losses

This includes the inlet pressure at the FPSO exporting terminal, the length of the pipeline, the flow regime, the operating flow rate, the roughness of the pipes, the outlet pressure of the onshore receiving terminal at the gas processing plant (Table 2). The average inlet pressure of the gas exported from the FPSO used for this work is 3 000 psig. The pressure drops to 2 400 psig after a distance of 44 km and then, 700 psig at the Onshore Receiving Facility (ORF) (Anon, 2013).

2.1.3 Gas Composition and Properties

The average gas compositional values were used for this work. The data on the gas composition and properties were taken from different sources including Tullow Oil Ghana Limited. Table 3 provides a comprehensive data on gas composition from the Jubilee and TEN Fields while Table 4 giving a yearly projected flow rate to Atuabo Gas Processing Plant (AGPP) (Anon, 2014).

2.2 The Weymouth Equations

The Weymouth equation for non-horizontal flow was used for this work. The reason being that, the fluid assumes a high-Reynolds-number flow where the Moody friction factor is merely a function of relative roughness. It is assumed that the elevation Δz is uniformly sloped; flowlines temperature remains constant at designated points and also the flow in the pipe is steady state flow (Weymouth, 1912; Moody, 1944).

2.2.1 Weymouth equation for flow rate:

$$q_h = \frac{3.23T_b}{P_b}\sqrt{\frac{(P_1{}^2 - e^S P_2^2)D^5}{f\gamma_g \bar{T}\bar{z}L_e}} \qquad (1)$$

$$Le = \frac{(e^2 - 1)L}{S} \qquad (2)$$

$$S = \frac{0.0375\gamma_g \Delta z}{\bar{T}\bar{z}} \qquad (3)$$

$$N_{\mathrm{Re}} = \frac{Du\rho}{\mu} \qquad (4)$$

Moody friction factor, f

$$\frac{1}{\sqrt{f}} = 1.14 - 2\log\left(e_D + \frac{21.25}{N_{\mathrm{Re}}}\right) \qquad (5)$$

where;

P_1	=	upstream pressure, psi
P_2	=	downstream pressure, psi
T	=	average temperature, ^oR
Z	=	(P1- P2)/2
T_b, P_b	=	operating temperature and pressure
q_h	=	flow rate measured at the base conditions, MCFD.
N_{Re}	=	Reynolds Number
f	=	friction factor
$\hat{z}$	=	gas deviation factor at T and P
u	=	fluid velocity, ft/sec
ρ	=	fluid density, lbm/ft^3
D	=	pipe diameter, in
γ_g	=	gas gravity

µ	=	fluid viscosity, ibm/ft-sec
Le	=	effective pipeline length, ft
L	=	pipe length, ft
S	=	slope
e	=	base for natural logarithm (2.718)
e_D	=	relative roughness

2.2.2 Weymouth equation for parallel capacity increase

$$\frac{q_t}{q_1} = \frac{\sqrt{D_1^{16/3}} + \sqrt{D_2^{16/3}} + \sqrt{D_3^{16/3}}}{\sqrt{D_1^{16/3}}} \quad (6)$$

where;

q_t = total flow rate MMSCFD
q_1 = initial flow rate MMSCFD
D_1 = internal diameter of flowline 1
D_2 = internal diameter of parallel connected flowline
D_3 = internal diameter of flowline 2

2.2.3 Slugging calculation

$$Slug\ \text{length} = \frac{\text{Riser height}}{PI - SS\ \text{number}} \quad (7)$$

where;

PI –SS = Slug number PI – SS number less than 1 means severe slugging
PI – SS number greater than 1 means no slugging

2.3 Pipesim Computation

Pipesim software was used to determine the hydrate phase envelope, pipe size, insulation thickness and the heating temperature of the DEH system. The software requires the input of the pure gas components and the addition of the characterised heavier hydrocarbon components, to generate the phase envelope of the fluid composition. The size of the pipeline was determined by computing FPSO inlet pressure and temperature as a source conditions, the design flow rate, the roughness, the overall heat transfer coefficient and ambient temperature, the ground conductivity and a range of pipe diameters.

Table 2 Relevant Field Data of the Study Areas

Parameters	Value	Parameters	Value
Water Depth (m)	1100	ORF Inlet Pressure (psig)	1015
Subsea Temperature (˚F)	41	ORF Inlet Temperature (˚F)	74
FPSO Inlet Pressure (psig)	3000	Gas Density (API)	37
FPSO Inlet Temperature (˚F)	160	Gas Viscosity (cP)	0.16
Current Gas Production (MMSCFD)	160	ORF current capacity (MMSCFD)	300
Gas Gravity	0.64		

(Source: Anon, 2013)

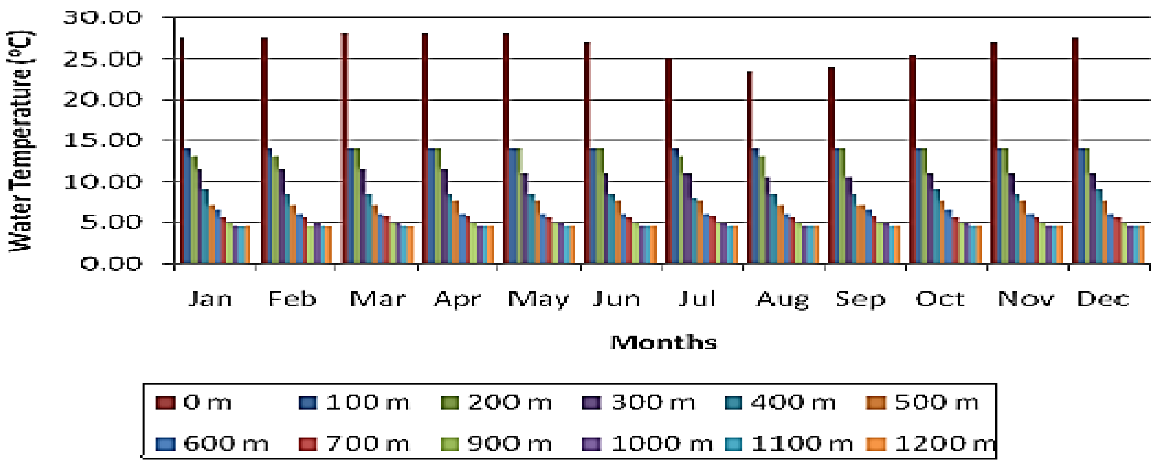

Fig 2 Profile of Water Temperature Offshore Ghana (Source: Anon, 2009)

Table 3 Data on Gas Composition

COMPONENT	JUBILEE	JUBILEE	TEN	TEN	AVERAGE
C1	77. 65	79.197	76.392	76.645	77.440
C2	6.344	5.265	6.943	5.867	6.105
C3	5.387	2.583	4.241	4.125	4.084
C4	0.677	0.241	0.994	0.705	0.594
IC4	0.167	1.665	2.198	0.283	1.257
C5	0.325	0.378	0.453	0.315	0.418
IC5	0.409	0.301	1. 005	0.177	0.384
C6	0.005	0.023	0.278	0.357	0.115
C7+	7.394	7. 534	7.003	9.822	7.938
N_2	0.385	0.0995	0.466	0.336	0.241
CO_2	1.424	1.415	1.442	1.314	1.424
H_2S	0.003	0.0074	0.00004	0.013	0.0004

Table 4 Yearly Projected Flow Rate to AGPP

YEAR	FLOW RATE
2014	120 MMSCFD
2015	150 MMSCFD
2016	300 MMSCFD
2017	300 MMSCFD
2018	450 MMSCFD
2019	450 MMSCFD
2020	560 MMSCFD
2025	640 MMSCFD
2030	700 MMSCFD

3 Results and Discussion

To address the major flow assurance problems while minimising cost and satisfying the field operating conditions, two pipeline designs were considered. For the purpose of simplicity, the two final designs are presented in a tabular form. Table 5 outlines the initial design specifications while Table 6 outlines the specifications of the alternate design. The two risers have the same specifications in both designs. Fig 3 shows orientation of the full design, indicating Source 1 (FPSO) and S1 (ORF, Atuabo Gas Processing Plant). The designs limitation and the necessary solution for efficient delivery are also presented.

The hydrate formation temperature and pressure were determined from the hydrate phase envelope generated by the addition of water content to the inputted fluid composition. Fig 4 shows the hydrate phase envelope generated. From the hydrate phase envelope, the temperature below which hydrate will form is 72.5 ˚F.

3.1 Selection of Optimal Pipeline Sizes

A range of pipe sizes were simulated to determine the minimum pipe size that meets the pressure requirements at the designated points which will maintain a higher flow rate. The pipe size selected for flowline 1 must satisfy a boundary conditions of 44 km length and a pressure above 2 800 psig whilst the pipe size for flowline 2 must satisfy a boundary conditions of 15 km length and a pressure above 1 010 psig (Fig 5 and Fig 6 respectively). The minimum pipe size that met the boundary conditions for flowline 1 was 12 in. while that of flowline 2 was 14 in. This is because the 10 in. pipe size for flowline 1 did not meet output pressure required to flow the gas through riser 2 and flowline 2 to the ORF. Therefore, a 12 in. pipe size was selected instead. Similarly, a 14 in. was selected for flowline 2 instead of 12 in. because the 12 in. pipe did not meet the inlet pressure of the ORF.

3.2 Optimal Insulation for Pipelines

The optimal insulation thickness for flowline 1 was determined to be 1.5 in. while that of flowline 2 was 2 in. The ambient temperature of flowline 1 was raised from 41 ^{o}F to 80 ^{o}F using Direct Electrical Heating (DEH). Fig 7 shows a range of flow rate for flowline 1 when an insulation thickness of 1.5 in. was used and Fig 8 shows a range of flow rates when an insulation thickness of 2 in. was used for flowline 2. The insulation of the pipe has a direct effect on the flow rate. The insulation improves the flow rate of the gas. A better insulation gives a higher flow rate. The insulation material used in the design has a thermal conductivity of 0.15 Btu/hr/ft/°F. The insulation thickness for flowline 1 was 1.5 in. whilst that for flowline 2 was 2 in. In order to operate above the hydrate formation temperature, a Direct Electrical Seating (DEH) system was, incorporated into the design to raise the temperature of flowline 1 above the hydrate formation temperature due to the low subsea temperature. Flowline 1 was insulated and then heated using the DEH to raise the ambient subsea temperature of 41 ^{o}F to 80 ^{o}F.

3.3 Addressing Riser Slugging Challenges

The initial design has a minimum PI-SS number (slug number) of 4.95 (Table 8) and that of the alternate design was 1.6 (Table 9). Both designs have their PI-SS number greater than 1 indicating no liquid slugging at the riser base will occur.

A PI-SS number or slugging value greater than 1 means an absence of liquid slugging at the riser base whilst a PI-SS number less than 1 means that there is a possibility that liquid slugging will occur. Severe riser slugging can be determined from the PI-SS number using equation 7. A PI-SS or slug number of 4.95 (Table 8) was obtained for the initial design and a 1.6 (Table 9) for the alternate design. Both designs have their PI-SS number greater than 1 indicating no liquid slugging at the riser base. Since the PI-SS values obtained indicate no liquid slugging at the riser base, it also means that severe riser slugging will not occur.

3.4 Addressing Flow Assurance Challenges

The hydrate formation temperature obtained from the hydrate phase envelope at a defined pressure of 2 555 psia is approximately 73 ^{o}F (Fig 4). Wax formation was not detected at the minimum subsea temperature of 41 ^{o}F as shown in Fig 4. The absence of wax precipitation and deposition in the flowlines was due to the absence of heavier hydrocarbon components and the increased surrounding temperature by the direct electrical heating system.

The maximum flow rate of the design is 150 MMSCFD which does not meet the projected flow rates from the year 2016. The highest flow rate from the fields to the processing plant is projected to be 700 MMSCFD in 2030 (Table 4). This therefore requires a capacity increase in the flowlines. The capacity increase in flowline 1, was computed to obtain the smallest pipe size which when run parallel to the 12 in. pipe will increase the design flow rate of 150 MMSCFD to 700 MMSCFD or more. Table 7 shows the output of the capacity increase in Flowline 1.

Table 5 Specification of the Design

PARAMETER	FLOWLINE 1	FOWLINE 2	RISER 1	RISER 2
Pipe length (m)	44 000	15 000	1100	1100
Pipe size (in)	12	14	10	10
Pipe thickness (in)	1.0	1.0	0.5	0.5
Ambient temperature (˚F)	41.0	80.6	68.0	68.0
Thermal insulation thickness (in)	1.5	2.0	0.0	0.0
Temperature by DEH (˚F)	40.0	0.0	0.0	0.0
Roughness	0.001	0.001	0.001	0.001
Pipe conductivity (Btu/hr/ft/˚F)	50	50	35	35
Flow rate (MMSCFD)	150			

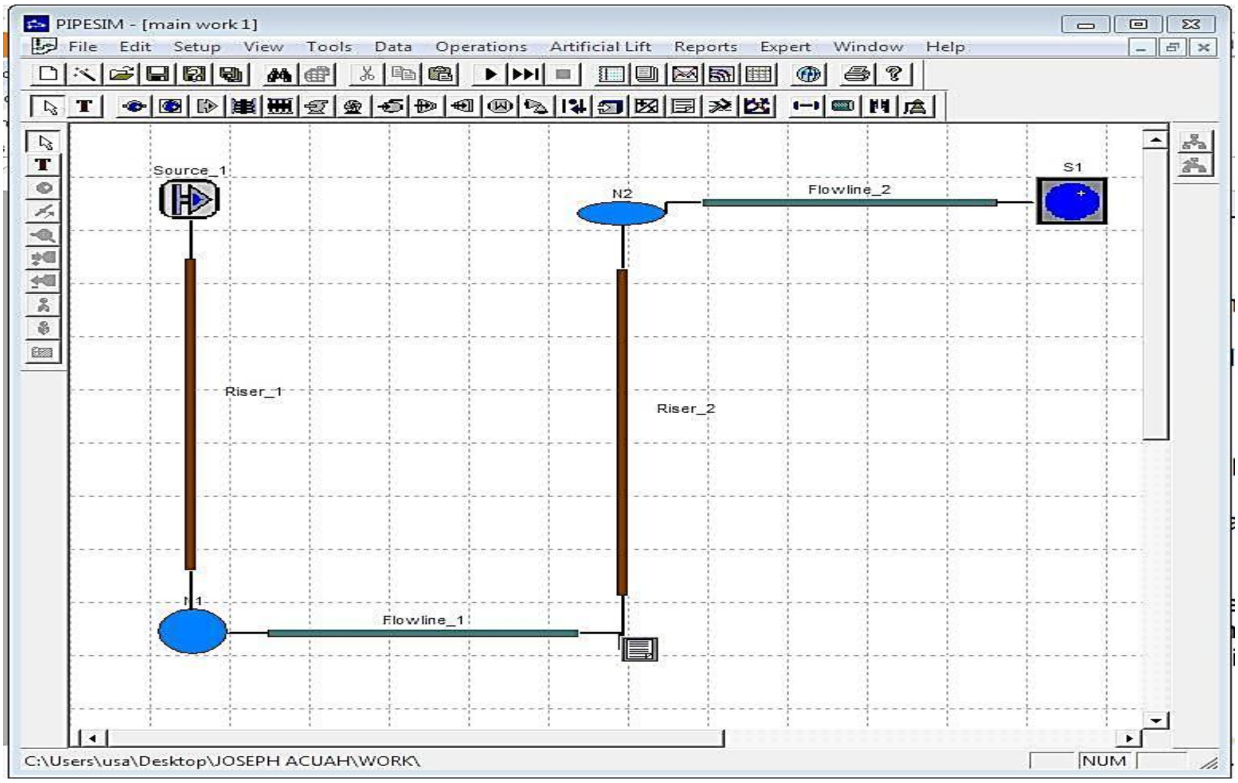

Fig 3 Pipesim Interface Showing the Full Design Orientation

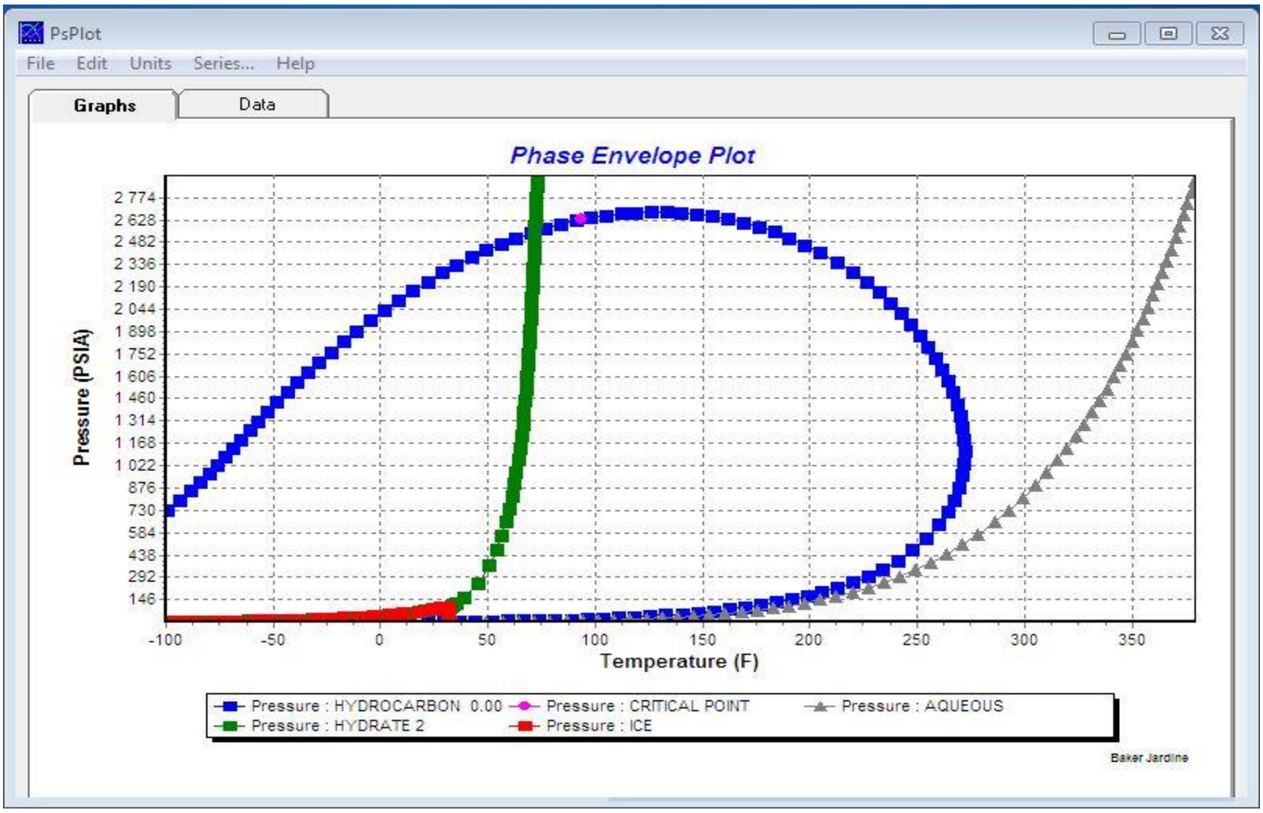

Fig 4 Hydrate Phase Envelope Showing Hydrate Formation Temperature

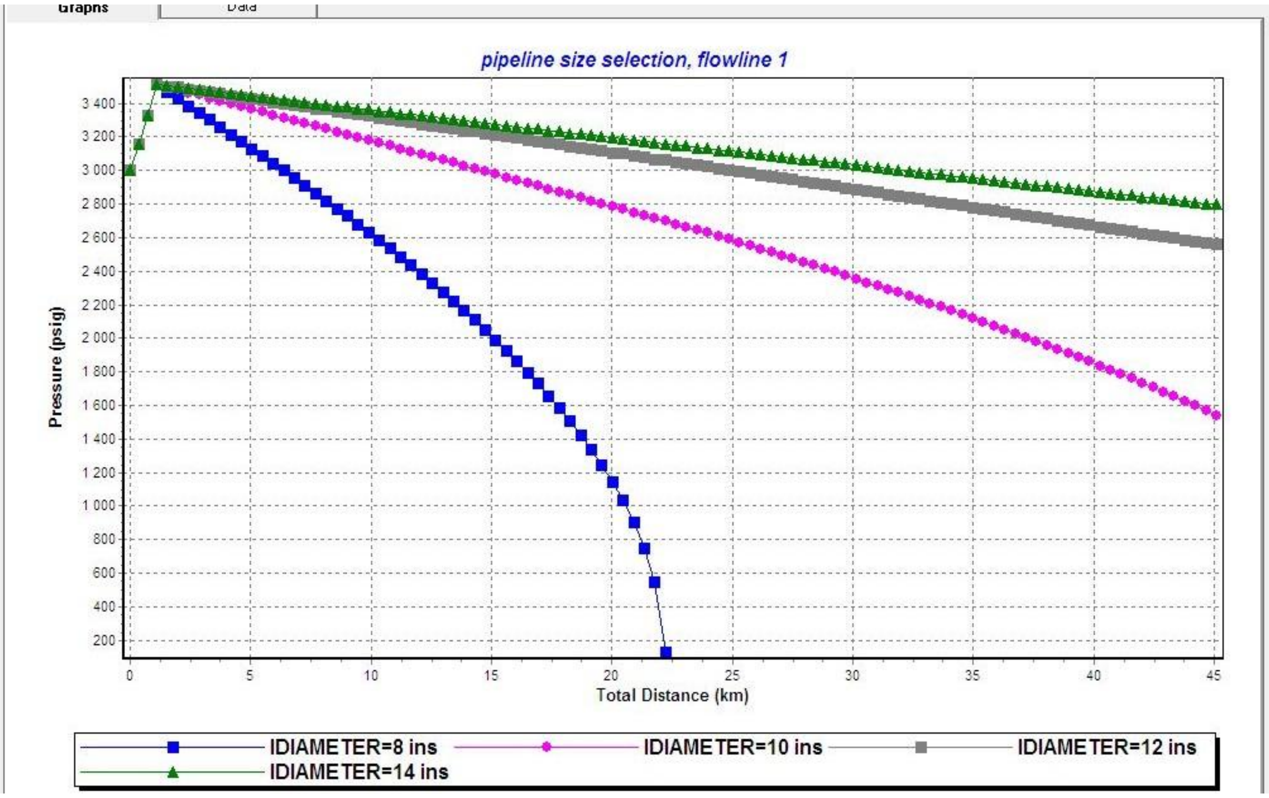

Fig 5 Pressure – Distance Plot Showing Pipe Sizes for Flowline 1

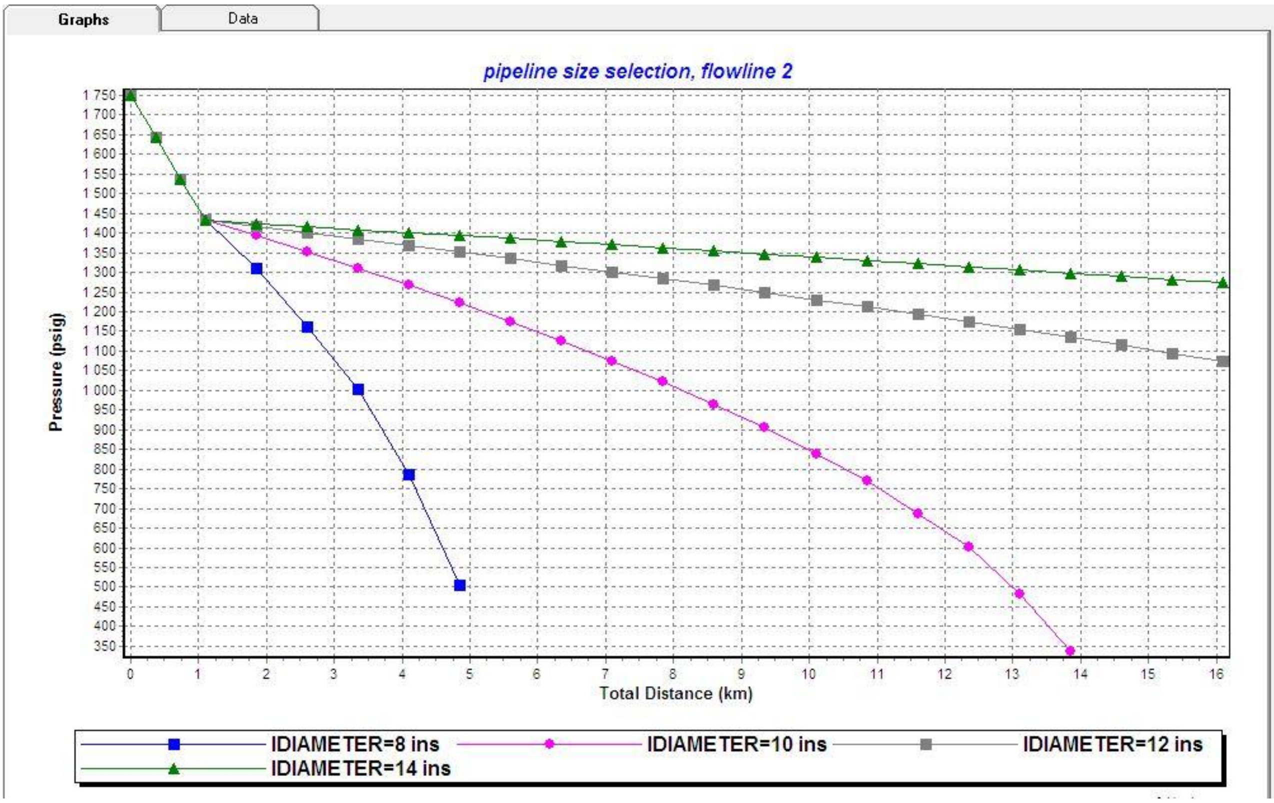

Fig 6 Pressure – Distance Plot Showing Pipe Sizes for Flowline 2

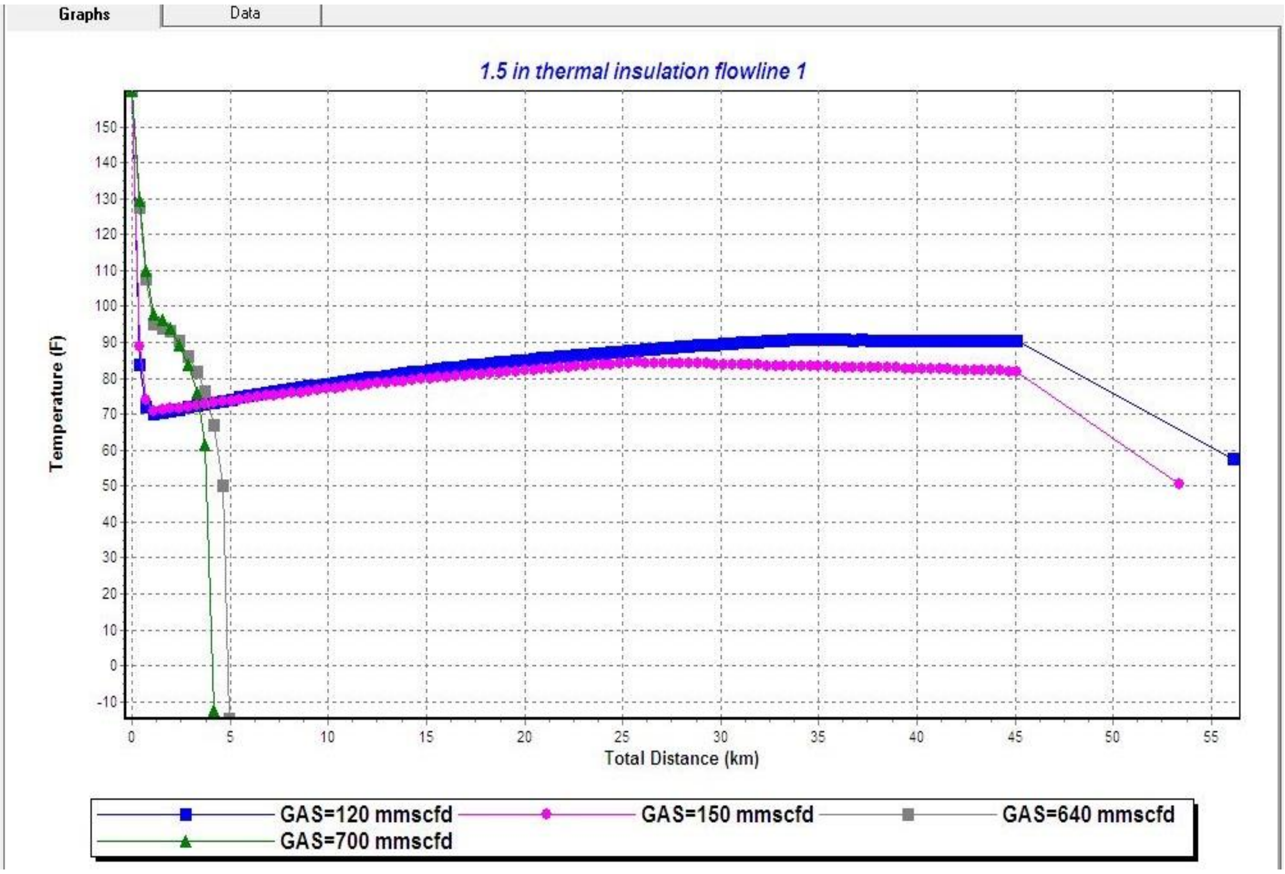

Fig 7 Temperature – Distance Plot Showing the Flow Rates for Flowline 1

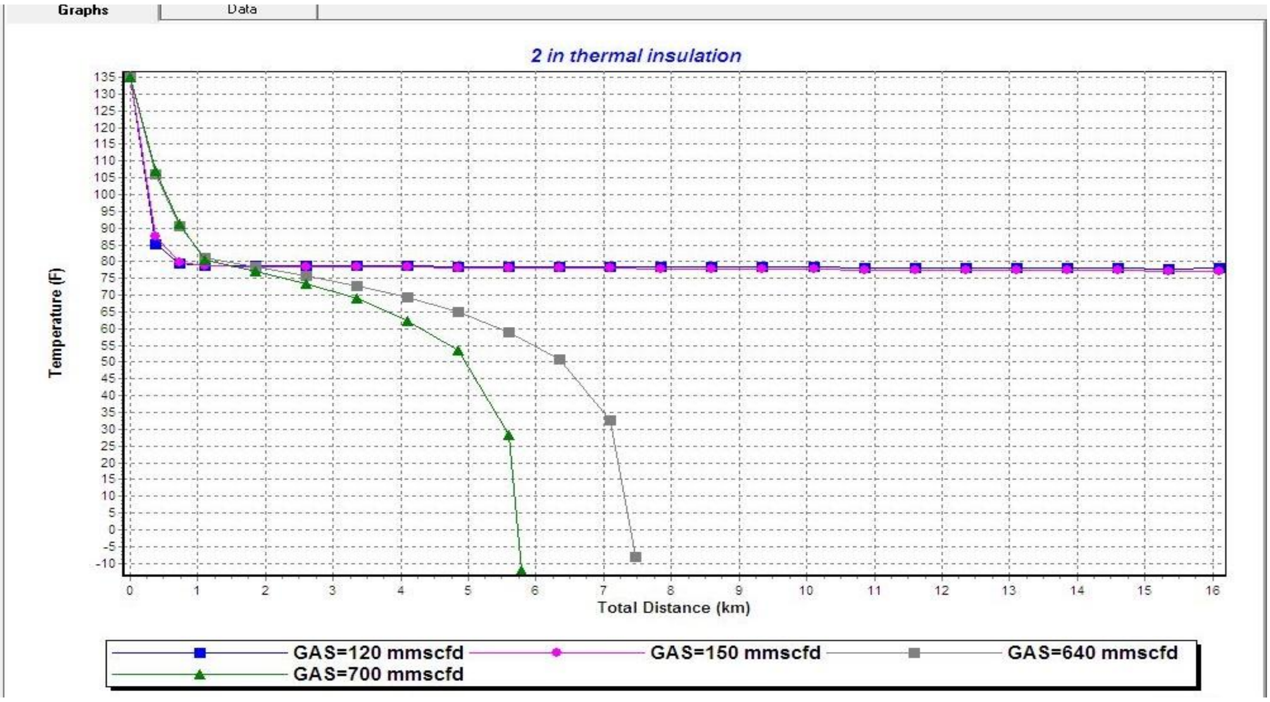

Fig 8 Temperature - Distance Showing the Flow Rates for Flowline 2

Table 6 Specification for an Alternative Design

PARAMETER	FLOWLINE 1	FOWLINE 2	RISER 1	RISER 2
Pipe length (m)	44 000	15 000	1100	1100
Pipe size (in)	18	20	10	10
Pipe thickness (in)	1	1	0.5	0.5
Ambient temperature (˚F)	41	80.6	68	68
Thermal insulation thickness (in)	1.5	2	-	-
Temperature by DEH (˚F)	40	-	-	-
Roughness	0.001	0.001	0.001	0.001
Pipe conductivity (Btu/hr/ft/˚F)	50	50	35	35

Table 7 Capacity Increase of Flowline 1

PIPE ID (IN)	PARALLEL PIPE CAPACITY INCREASE			YEARLY PROJECTED FLOW RATE	
	FLOWLINE 1 (M)	FLOWLINE 2 (M)	FLOW RATE MMSCFD	YEAR	FLOW RATE MMSCFD
12	3.51	2.33	526.0	2016-2017	300
13	3.75	2.48	562.5	2018-2019	450
14	4.02	2.66	603.0	2020	560
15	4.32	2.86	648.0	2025	640
16	4.70	3.09	705.0	2030	700

Table 8 Report on Initial Design

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      Dist.   Elev. Horiz. Vert.  Pres.   Temp.    Mean  Pressure Drop  Liquid   Free      Densities   Slug  Flow
                    Angle  Devn.                   Vel.      (psi)       Flow     Gas      (lb/ft3)   Number Pattern
     (feet)  (feet) (deg)  (deg)  (psia)    (F)   (ft/s)  Elev. Frictn. (bbl/d) (mmscfd)  Liquid    Gas (PI-SS)
RISER Riser_1
Topsides
  1  0.0000  0.0000 -90.0 0.000  3014.7  140.00  .97022  0.0000  0.0000  68.588  10.3615  61.491  16.650        ORK SLUG
  2  0.0000  -1203. -90.0 0.000  3174.0  123.63  .90218  -159.4  .03227  69.165  10.3550  61.765  17.912        ORK SLUG
  3  0.0000  -2406. -90.0 0.000  3342.6  112.12  .85249  -168.6  .03081  69.386  10.3518  61.950  18.963        ORK SLUG
  4  0.0000  -3609. -90.0 0.000  3519.1  103.76  .81442  -176.5  .02971  69.485  10.3500  62.081  19.856        ORK SLUG
RISER Riser_2
Riser Base
 106  0.0000  0.0000 90.00 0.000  3482.9  80.004  .77071  0.0000  0.0000  69.636  10.3465  62.373  20.991        ORK SLUG
 107  0.0000  1203.0 90.00 0.000  3294.7  76.565  .78020  188.15  .02832  69.645  10.3462  62.397  20.732   5.54 ORK SLUG
 108  0.0000  2406.0 90.00 0.000  3108.6  73.348  .78973  186.10  .02859  69.656  10.3460  62.418  20.479   5.24 ORK SLUG
 109  0.0000  3608.9 90.00 0.000  2924.4  70.335  .79930  184.10  .02885  69.669  10.3457  62.436  20.231   4.95 ORK SLUG
```

Table 9 Report on the Alternate Design

	Dist. (feet)	Elev. (feet)	Pipe I.D. (ins.)	Mean Slug Length (feet)	Mean Slug Freq (min-1)	1 in thousand Length (feet)	1 in thousand Freq (min-1)	1 in hundred Length (feet)	1 in hundred Freq (min-1)	1 in ten Length (feet)	1 in ten Freq (min-1)	Slug Number (PI-SS)	Flow Pattern
RISER Riser_1													
Topsides													
1	0.	0.0	10.000	–	–	–	–	–	–	–	–		–
2	0.	-600.0	10.000	0.0	0.000	0.0	0.000000	0.0	0.00000	0.0	0.0000		ORK BUBBLE
3	0.	-1200.0	10.000	0.0	0.000	0.0	0.000000	0.0	0.00000	0.0	0.0000		ORK BUBBLE
FLOWLINE Flowline_1													
Riser Base													
4	0.	0.0	18.000	–	–	–	–	–	–	–	–		–
5	1936.	52.2	18.000	0.0	0.000	0.0	0.000000	0.0	0.00000	0.0	0.0000	287.92	B/B SEGREGAT
6	3872.	65.6	18.000	0.0	0.000	0.0	0.000000	0.0	0.00000	0.0	0.0000	136.05	B/B SEGREGAT
7	5808.	117.8	18.000	0.0	0.000	0.0	0.000000	0.0	0.00000	0.0	0.0000	92.02	B/B SEGREGAT
8	7744.	131.2	18.000	0.0	0.000	0.0	0.000000	0.0	0.00000	0.0	0.0000	68.17	B/B SEGREGAT
9	9680.	183.4	18.000	0.0	0.000	0.0	0.000000	0.0	0.00000	0.0	0.0000	54.95	B/B SEGREGAT
10	11616.	196.9	18.000	0.0	0.000	0.0	0.000000	0.0	0.00000	0.0	0.0000	45.42	B/B SEGREGAT
11	13552.	249.0	18.000	0.0	0.000	0.0	0.000000	0.0	0.00000	0.0	0.0000	39.09	B/B SEGREGAT
12	15488.	262.5	18.000	0.0	0.000	0.0	0.000000	0.0	0.00000	0.0	0.0000	33.99	B/B SEGREGAT
13	17424.	314.6	18.000	0.0	0.000	0.0	0.000000	0.0	0.00000	0.0	0.0000	30.28	B/B SEGREGAT
14	19360.	328.1	18.000	0.0	0.000	0.0	0.000000	0.0	0.00000	0.0	0.0000	27.11	B/B SEGREGAT
15	21296.	380.3	18.000	0.0	0.000	0.0	0.000000	0.0	0.00000	0.0	0.0000	24.67	B/B SEGREGAT
16	23232.	393.7	18.000	0.0	0.000	0.0	0.000000	0.0	0.00000	0.0	0.0000	22.51	B/B SEGREGAT
17	25168.	445.9	18.000	0.0	0.000	0.0	0.000000	0.0	0.00000	0.0	0.0000	20.78	B/B SEGREGAT
18	27104.	459.3	18.000	0.0	0.000	0.0	0.000000	0.0	0.00000	0.0	0.0000	19.22	B/B SEGREGAT
19	29040.	511.5	18.000	0.0	0.000	0.0	0.000000	0.0	0.00000	0.0	0.0000	17.94	B/B SEGREGAT
20	30976.	524.9	18.000	0.0	0.000	0.0	0.000000	0.0	0.00000	0.0	0.0000	16.76	B/B SEGREGAT
72	131646.	2231.0	18.000	0.0	0.000	0.0	0.000000	0.0	0.00000	0.0	0.0000	3.51	B/B SEGREGAT
73	133582.	2283.1	18.000	0.0	0.000	0.0	0.000000	0.0	0.00000	0.0	0.0000	3.44	B/B SEGREGAT
74	135518.	2296.6	18.000	0.0	0.000	0.0	0.000000	0.0	0.00000	0.0	0.0000	3.39	B/B SEGREGAT
75	137454.	2348.8	18.000	0.0	0.000	0.0	0.000000	0.0	0.00000	0.0	0.0000	3.33	B/B SEGREGAT
76	139390.	2362.2	18.000	0.0	0.000	0.0	0.000000	0.0	0.00000	0.0	0.0000	3.28	B/B SEGREGAT
77	141326.	2414.4	18.000	0.0	0.000	0.0	0.000000	0.0	0.00000	0.0	0.0000	3.22	B/B SEGREGAT
78	143262.	2427.8	18.000	0.0	0.000	0.0	0.000000	0.0	0.00000	0.0	0.0000	3.18	B/B SEGREGAT
79	145198.	2480.0	18.000	0.0	0.000	0.0	0.000000	0.0	0.00000	0.0	0.0000	3.12	B/B SEGREGAT
80	147134.	2493.4	18.000	0.0	0.000	0.0	0.000000	0.0	0.00000	0.0	0.0000	3.08	B/B SEGREGAT
81	149070.	2545.6	18.000	0.0	0.000	0.0	0.000000	0.0	0.00000	0.0	0.0000	3.03	B/B SEGREGAT
82	151006.	2559.1	18.000	0.0	0.000	0.0	0.000000	0.0	0.00000	0.0	0.0000	2.98	B/B SEGREGAT
83	152942.	2611.2	18.000	0.0	0.000	0.0	0.000000	0.0	0.00000	0.0	0.0000	2.42	B/B SEGREGAT
84	154878.	2624.7	18.000	0.0	0.000	0.0	0.000000	0.0	0.00000	0.0	0.0000	2.29	B/B SEGREGAT
85	156814.	2676.8	18.000	0.0	0.000	0.0	0.000000	0.0	0.00000	0.0	0.0000	1.93	B/B SEGREGAT
86	158750.	2690.3	18.000	0.0	0.000	0.0	0.000000	0.0	0.00000	0.0	0.0000	1.85	B/B SEGREGAT
87	160686.	2742.5	18.000	0.0	0.000	0.0	0.000000	0.0	0.00000	0.0	0.0000	1.60	B/B SEGREGAT

4 Conclusions

The findings of this research are relevant in the transportation of condensate gas from the offshore waters of Ghana mainly the West Cape Three Points, Jubilee Field and TEN Fields to the Atuabo Gas Processing Plant. The following conclusions can be drawn from this study;

(i) A subsea pipeline for transporting condensate from the Jubilee and TEN fields to the Atuabo Gas Processing Plant has been designed. The design employs two subsea temperature control mechanism; insulation of the pipeline and the application of direct electrical heating to the pipelines in order to raise the surrounding temperature above the hydrate formation temperature.

(ii) The maximum designed flow rate is 150 MMSCFD. This is however possible only in the year 2014 and 2015 and will not meet the projected flow rate in the subsequent years where gas production is expected to increase. In order to meet the highest projected flow rate of 700 MMSCFD, a 16 in. ID pipeline of 44 km length should be run parallel to the 12 in. ID flowline 1 in order to meet the higher operating flow rate to the processing plant. The addition of 16 in. ID parallel pipeline will increase the design flow rate of 150 MMSCFD by approximately 4.7 times (705 MMSCFD) which meets flow capacity to the plant in the subsequent years.

(iii) An alternate design that eliminates the need for capacity increase of the flowlines for the higher projected flow rates in future was considered. This employs 18 in flow-line 1 and 20 in. flow-line 2 with a capacity of 700 MMSCFD, which meets the highest projected flow rate of 700 MMSCFD right from the start.

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