International Journal of Scholarly Research in
Engineering and Technology
Journal homepage: https://srrjournals.com/ijsret/
ISSN: 2961-3280 (Online)

(RESEARCH ARTICLE)

Check for updates

Pipeline design for transportation of gas in Niger delta

Nnorom Obinichi *, Odafiagwuna Friday and Ameme Clinton

Department of Mechanical Engineering, University of Port Harcourt, Choba, Nigeria.

International Journal of Scholarly Research in Engineering and Technology, 2026, 07(02), 001-019

Publication history: Received on 02 March 2026; revised on 11 April 2026; accepted on 13 April 2026

Article DOI: https://doi.org/10.56781/ijsret.2026.7.2.0014

Abstract

The study is to develop an optimized pipeline system design for transportation of gas in Niger Delta was investigated. Hydrocarbon Gas is moved from central storage facilities over long-distance trunk lines to refineries or other storage facilities. Hydrocarbon Gas trunk lines operate at higher pressures than flow lines and could vary in size from 6 inches in diameter to as large as 4 feet. In order to design a suitable pipeline for transporting gas for the Agbada I and Agbada II Fields, the following methods were employed in this work; considering the minimum required parameters in the design of onshore and subsea pipelines but not limited to temperature of flow lines; 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. In conclusion, the hydrate formation temperature obtained from the hydrate phase envelope at a defined pressure of 2 555 psia is approximately 73 ^oF, in flow line 1 and 2, as distance increases the pressure of 8 ins pipe, 10 ins pipe, 12 ins pipe and 14 ins pipe decreases. In flow line 1, as distance increases the flow rate of Gas 120mmscfd and Gas150mmscfd decreases, then increase exponentially and decrease with total distance and in flow line 2, as distance increases the flow rate of Gas 120mmscfd and Gas150mmscfd decreases, then remain constant with total distance. Finally, the increase in distance increases the parallel line capacity increases flow rate and the increase in distance increases the parallel line capacity increase flow rate.

Keywords: Pipelines; Design; Transportation; Gas; Niger Delta; Hydrocarbon

1 Introduction

Pipeline transportation is a long-distance transportation of liquid and gas materials using pipelines as a means of transportation. It is a special transportation method for transporting petroleum, coal and chemical products from the production place to the market, and it is a special part of trunk transportation in the Niger Delta region, even all over the country. Since most existing pipelines are not performing optimally, a large number of choices need to be made, both with respect to the configuration and the pipeline operation, such as Routing, Pipe diameter, pipe wall thickness, material properties, maximum production, high pressure vs low pressure (Nagham, 2011).

Principally industrial fuel oils are gotten from repressed crude or atmospheric residue, with vacuum residuum occasionally involved as well. These constituents are frequently mixed with lighter fractions obtained in the refinery, e.g. heavy gas oil, to increase their quality and meet the craved spec (Nagham, 2011). The main characteristics of fuel oils are flash point, pour point, ash content water, sediment, viscosity, heat of combustion and carbon residuum. Fuel oils are grouped into various grades depending on their densities and viscosities. The grades are commonly classified as light, medium and heavy types for various applications or numerated from 1 to 6 depending on their boiling range, as stipulated by American specifications (Akbar & Geelen, 2018). A lot of challenges are caused by storing, burning or selling commercial fuel oils, majority comes from negligence to meet the actual spec. The high rate of carbon-to-hydrogen ratio, pour point, sulfur content, and viscosity are the primary reasons for disobedience (Akbar & Geelen,

* Corresponding author: Nnorom Obinichi

2018). Nevertheless, a chemical upgrading process known as visbreaking is used to decrease the high rate of pour point or viscosity (Nagham, 2011). It is a fact that as the temperature rises the viscosity of the heavy crude fractions reduces. Hence, in the oil industry, heavy crude fractions are heated to reduce their viscosity and enhance better flow in pipeline. The demerits of this process are the energy required, added cost of heating devices and the insulation of pipelines. Phases of heating should be used for long-distance conveyance of such oils, which markedly raises cost. Hence, it is preferred implement the heating process in the refineries. In cases where much quantities of oil have to be conveyed; it is at the beginning of the pumping station that heating process can be carried out. (Solan et al., 2019). Exact rates of viscosity for residuum fuel oils and their mixtures as a function of composition and temperature are important for pipeline conveyance, burning, engineering calculations and handling of fuel oils (Chhabra & Sherh, 2019; Heric & Brewer, 2017). Many empirical and semi-empirical correlations have been formulated to explain the viscosity dependence of heavy crude fractions on composition and temperature (Chhabra & Sherh, 2019).

2 Materials and methods

2.1 Materials

The materials required for the design of pipeline for the transportation of quality crude oils and simulation processes are listed below:

2.1.1 Software:

PIPESIM: For process simulation, modeling, and analysis of crude oil quality transportation in a pipeline.

Data Visualization Tools: Microsoft Excel spreadsheet for data presentation, such as: graphs and chart to visualize the dynamics behavior of crude oil quality transportation in a pipeline.

2.2 Methods

2.2.1 Methods of Data Collection

The below ways were adopted in this work to design an appropriate pipeline for conveying condensate gas for the Agbada I and Agbada II sites: looking at the least expected parametric quantities in the design of undersea pipelines, but not restricted to temperature of flow lines; composition and properties of gas, pressure losses of pipeline,; elevation at exporting terminal (FPSO), rate of flow of expected mass, Pipesim, equation of Weymouth, and distance between exporting terminal and the accepting facility (Tese, 2018; Ugwunna, et al., 2019). These factors are crucial for accurate design and efficient operation of subsea pipelines, as they influence the pipeline's hydraulic and thermal performance, as well as the overall safety and cost-effectiveness of the transportation system (Witkowski, et al., 2014). The Weymouth equation is commonly used to estimate pressure losses in pipelines based on factors such as flow rate, pipe diameter, and gas properties (Kamari, et al., 2013). Additionally, the use of software tools like Pipesim helps to simulate and optimize the pipeline design by considering a variety of operational and environmental parameters (Naseer & Brandstatter, 2011).

Pipeline Design Parameters

Table 1 Relevant Field Data of the Research Places

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: Indorama 2015

Data, such as annual water temperature and information on the Agip Gas Processing Plant (AGPP), were got from Agip Company Nigerian Limited's website (Agip Company Nigerian Limited, 2020). Also, Data on gas entry pressure, composition, and properties were collected from the 2013 Agbada Site reports and literature (Agip Company Nigerian Limited, 2013). Table 1 displays secondary data collected from the relevant research sites. Nevertheless, data on Agbada II gas composition were collected from the 2014 Environmental Impact Assessment (EIA) report of the Agbada II Project (Environmental Impact Assessment Report, 2014).

Temperature of Flow Lines

Flowline 1 guessed the temperature of Ghana's sea-water to get the surrounding temperature of the pipeline; Flowline 2 guessed an average onshore environmental temperature of 80.6 °F. The temperature profile of the seawater along the coast of Ghana was applied to get the temperature at different depths of concern for Flowline 1 (Anon, 2009).

Pipeline Pressure Losses

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

Gas Composition and Properties

The data on the composition and properties of gas were collected from varying sources, involving Agip Oil Nigerian Limited. The average compositional values of gas were applied for this work.

2.2.2 Method of Delta Analysis

Pipesim Computation

Pipesim app was applied to get the non-conductive thickness, envelope of hydrate phase, pipe size, and the heating temperature of the DEH system. The entry of the constituents of pure gas and the addition of the characterized weighty hydrocarbon constituent is required by app, to create the phase envelope of the fluid composition. The size of the pipeline was defined by calculating FPSO temperature and inlet pressure as source requirements, the design rate of flow, the roughness, the overall heat convey coefficient and environmental temperature, some pipe diameters, and the ground non-insulation (Schlumberger, 2021).

The Mathematical Equations Required for the Process

The Weymouth Equations

The Weymouth expression for perpendicular flow was applied for this work. The cause is that the fluid guesses a high-Reynolds-number flow where the Moody friction factor is just a function of relative roughness. It is speculated that the elevation Δz is unequally sloped; flowlines temperature stays constant at designated nodes, and also the flow in the pipe is steady-state flow (Weymouth, 1912; Moody, 1944).

Weymouth Equation for Flow Rate

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

$$L_e = \frac{(e^2-1)L}{S} \tag{2}$$

$$S = \frac{0.0375\gamma_g\Delta z}{\bar{T}\bar{z}} \tag{3}$$

$$N_{Re} = \frac{Du\rho}{\mu} \tag{4}$$

Moody friction factor, f

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

Where;
P_1 = upstream pressure, psi
P_2 = downstream pressure, psi
T = average temperature, R
Z = $(P_1$- $P_2)/2$
T_b, P_b = operating temperature and pressure
q_h = rate of flow measured at the base requirements, MCFD.
N_{Re} = Reynolds Number
f = friction factor
$\bar{z}$ = gas deviation factor at T and P
u = fluid velocity, ft/sec
ρ = fluid density, lbm/ft3
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

- **Weymouth Expression for Parallel Capacity Rise**

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

Where;
q_t = total rate of flow MMSCFD
q_1 = former rate of flow MMSCFD
D_1 = interior diameter of flow line 1
D_2 = interior diameter of parallel linked flow line
D_3= interior diameter of flow line 2

Slugging Calculation

$$\text{Slug Length} = \frac{\text{Riser height}}{\text{P}_1\text{−SS Number}} \qquad (7)$$

Where;
P_1 −SS = Slug number P_1 – SS number not more than 1 denotes extreme slugging
P_1 – SS number not less than 1 denotes no slugging

Pipeline Sizing

Determination of Pipe Diameter

Ugwunna, et al (2019)

$$D = \sqrt{\frac{3.5\ x\ Qh\ x\ TA}{PA}} \qquad (8)$$

Where D = Pipe Diameter, Qh= Flowing Capacity (MSCF/D)

TA = Absolute Temperature, PA = Absolute Pressure

Where, Qh= 35MSCF,

T_A= 72.2°F + 460 =532.2°F, P_A= 1104 + 14.7 =1,118.7Psia

$$D = \left[\frac{3.5 \text{ x } 35 \text{ x } 532.2}{1{,}118.7}\right]^{\frac{1}{2}} = 7.6'' \qquad (9)$$

7.06” + 1” allowance= 8.06”. Hence the diameter of the pipe = 8 inches (152.4mm)

Determination of Pipe Nominal Thickness

The nominal wall thickness can be computed by applying the Barlow’s expression.

Ugwunna, et al (2019)

$$t_{NOM} = \frac{P_d D}{2 f_w \eta \delta_y F_t} + C_a \tag{10}$$

Where;

t_{NOM}=Nominal wall thickness, mm, Pd= Design Interior pressure
C_a =Corrosion thickness allowance
f_w= Weld efficiency factor. It is 1.0 for seamless, Arc weld (SAW or DSAW)
δ_y= Specified Minimum Yield strength, ή= design Factor, which is 0.72 for pipeline.
F_t= Temperature derating factor, which is 1 for temperature not above 250°C

Let the Corrosion thickness allowance be 4.00mm

$$= \frac{152.4\text{mm } 1104\text{psi}}{1\ 0.72\ 1\ 20{,}000\text{psi } 2} + 4.00\text{mm}$$

= 5.842mm + 4.00mm
= 9.84mm = 10mm

Determination of Pipe Schedule Number.

Ugwunna, et al (2019)

$$S = 1000\ x\ \frac{P}{S} \tag{11}$$

S= 20,000 psig, got from char

:. S=1000x1104/20,000 = 55.2, Roughly, 60.

From (Nominal Pipe sizes chart), 8” nominal size, schedule 60 has a thickness of 10.33mm

This is in compliance to the computed thickness applying Barlow’s formula.

Determination of Reynolds Number and Frictional Factors.

$$N_{Re} = \frac{20 q_h G}{\mu D} = \frac{0.68\ 35\ 20}{0.0121 \text{ x } 8} = 4{,}917.355 \tag{12}$$

Since, N_{Re} > 2,100. The flow is turbulent.

Determination of Delivery PressureP_2, using Weymouth Equation.

Ugwunna, et al (2019)

$$Q_g = 1.1 d^{2.67} \left[\frac{{P_1}^2 - {P_2}^2}{LZGT_1}\right]^{\frac{1}{2}} \tag{13}$$

Where, T1= (72.4 +460)°R,= 532.4 °R, P1= 1104psi, P2=? d= 8”-2(0.3937) =7.213”
G = 0.68, L= 14 KM = 14 x 3280.84ft= 45,931.8ft, Z = 0.88, Qg = 35MSCF

$$35 = 8^{2.67}\left[\frac{1104^2 - P_2{}^2}{45{,}931.8 \text{ x } 0.88 \text{ x } 0.68 \text{ x } 532.4}\right]^{\frac{1}{2}} \quad (14)$$

$222{,}865.5801 = 1104^2 - P_2{}^2$

$P_2 = 997.972 = 998psia$

Determination of gas pipeline design pressures
Ugwunna, et al (2019)

1. Maximum allowable pipeline operating pressure (MAOP)
MAOP = 2 x f x SMYS x t/D (15)
= 2 x 0.72 x 60,000 Psi x 10mm/203.2mm
= 4,251.969 psi
2. Pipeline Bursting Pressure (Bp)

B_p =0.5(SMYS + SUTS)2 x t/D (16)
= 0.5(60,000 + 75,000) 2 x 10/203.2
=8,858.2677 Psi
3. Plastic collapse pressure, Py

P_y = 2 x SMYS x t/D (17)
= 2 x 60,000 Psi x 10mm/203.2mm
= 5,905.512 Psi
4. Hydrotest pressure (HT)

H_p =1.25 x MAOP (18)
= 1.25 x 4,251.969 psi
= 5,314.96 Psi.
5. Pressure drop, Dp

D_p = PI – P2 =1104 – 998= 106 Psia

API Gravity

Density is the mass of a unit volume of substance at a given temperature. It's unit is grams per cubic centimeter. Initially, density was the main specification for crude oil products. Nevertheless, the obtained associations between the density and its fractional composition were only valid if they were used for a particular type of crude oil.

A typical characteristic, which is specific gravity, it is the ratio of the density of oil to the density of water and is based on two temperatures: those at which the densities of the oil sample and the water are measured. The specific gravity equals the density in the CGS system (centimeter-gram-second system), as the water temperature is 4°C (39°F), due to the volume of 1 g of water at that temperature is, 1 mL. The standard temperatures for specific gravity in the crude oil industry in North America are 60/60°F and 15.6/15.6°C all over the world. Hence, the density of water, for instance, changes with temperature, while its specific gravity is always unity at equal temperatures.

Albeit, density and specific gravity are applied greatly in the oil industry, the API gravity is seen as the accepted property. It is expressed as;

$$API = \frac{141.5}{Y} - 131.5 \quad (19)$$

where γ is the oil specific gravity at 60°F (15.6°C). Hence, in this system, a liquid with a specific gravity of 1.00 has an API of 10 deg. A greater API gravity denotes a lighter petroleum product, whereas a low API gravity means a weighty petroleum product (Bratakh, et al., 2015).

2.2.3 Characterization Factors

Characterization factors are applied in the crude oil industry to show the crude class. It is also called Correlation indexes. There are many correlations between yield and type of crude in terms of paraffinicity and aromaticity. The two commonly used expressions are:

- Watson characterization factor:

Bratakh, et al (2015)

$$K_w = \frac{T_b^{\frac{1}{3}}}{\gamma_a} \quad (20)$$

- U.S. Bureau of Mines Correlation Index:

$$Ind = T_b - 87.552 + 473\,.7.\gamma_a - 456.8 \quad (21)$$

where γ_a - is the specific gravity at 60 °F (15.6 °C) and Tb is the mean average boiling point (oR). The Watson factor is from 10.5, for highly naphthenic petroleum, to 12.9, for the paraffinic type British Petroleum Handbook, BP Company Ltd, London, (2017).

3 Results

3.1 Field Data Collations

Table 2 Relevant Field Data of the Research Places

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: Indorama 2015

Table 2 indicates the relevant Field data of the study area, which showed the floating production and offloading (FPSO) as well as the onshore receiving facility (ORF) parameters that FPSO Inlet Pressure (psig) and ORF Inlet Pressure (psig) are respectively as 3000 psig and 1015 psig, FPSO Inlet Temperature (˚F) and ORF Inlet Temperature (˚F) of 160 ˚F and 74 ˚F and FPSO Current Gas Production (MMSCFD) and ORF current capacity (MMSCFD) of 160 MMSCFD and 300 MMSCFD at the water depth of 1100m.

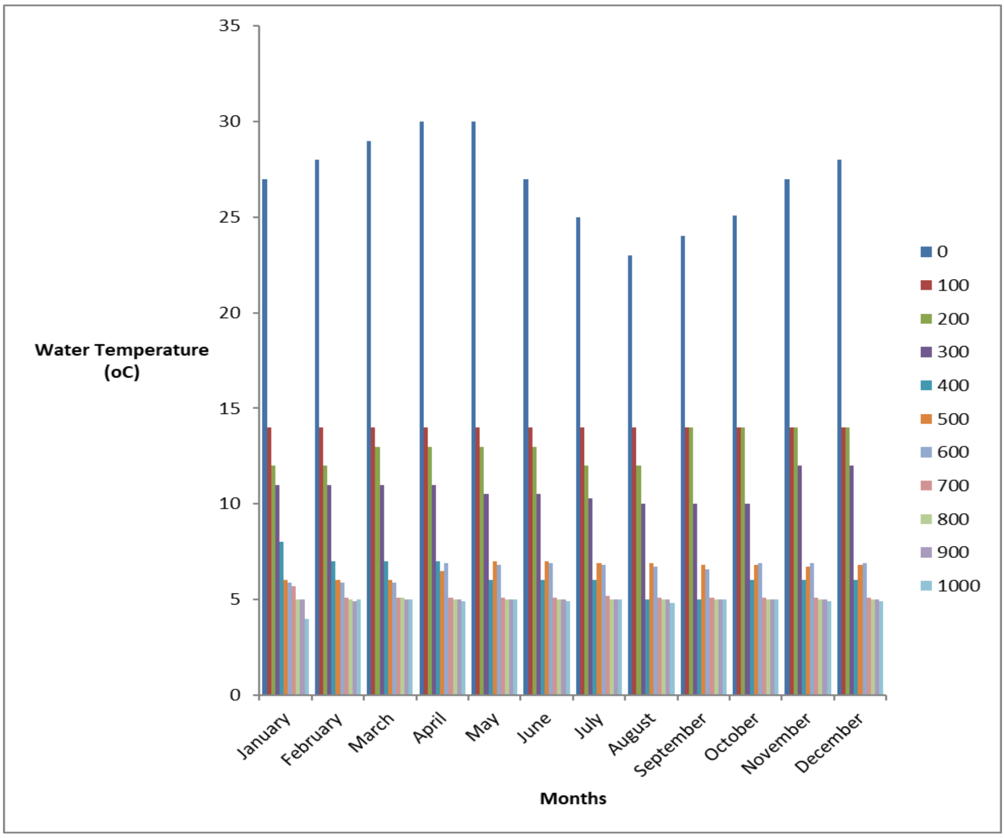

Figure 1 Graph of Profile of Water Temperature Offshore Nigeria (Source: Agip, 2010)

Figure 1 displays the link between temperature of water and months at varying distances. The order of decrease is 900m < 800m < 700m < 600m < 500m < 400m < 300m < 200m < 100m < 0m from December to January.

Table 3 Data on Gas Composition

Component	Agbada I	Agbada I	Agbada II	Agbada II	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

4 Discussions

The two last designs are shown in a two-dimensional form just for ease. To take care of the actual flow assurance challenge while reducing cost and meeting the functioning conditions of field, two pipeline designs were looked at. The two risers have the same specifications in the designs. The design restrictions and the necessary answer for efficient delivery are also displayed. The pressure and temperature of hydrate formation were obtained from the temperature which hydrate will form is 72.5 ˚F from the hydrate phase envelope.

4.1 Addressing Flow Assurance Challenges and Hydrate formation

The hydrate formation temperature obtained from the hydrate phase envelope at a defined pressure of 2 555 psia is approximately 73^{o}F. Wax formation was not detected at the minimum subsea temperature of 41^{o}F.

Table 5 Effect of Ambient temperature of flow line 1 and 2

Pipeline	Pipe Size	Satisfy Boundary Condition(Distance)	Effect on Ambient temperature	Remark
Flowline 1, 2	12”/14”	44Km, 15km	Raised from 41^{o}F to 80^{o}F	The insulation of the pipe has a direct effect on the flow rate.

Table 6 The effect of pressure and distance on the pipe sizes of flow line 1 and 2 and the effect of temperature and distance on the flow rate of line 1 and 2.

Flowline 1	12”	44Km	2800psig	8 in. pipe size for flow line 1 **did not** meet output pressure required to flowing the gas through riser 2 and flow line 2 to the ORF.
Flowline 2	14”	15km	1010psig	14 in. was selected for flow line 2 instead of 12 in. because the 12 in. pipe **did not** meet the inlet pressure of the ORF.

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.

4.2 Parallel Pipe Capacity Increase Flow Rate

The maximum flow rate of the design is 150 MMSCFD which does not meet the projected flow rates. The highest flow rate from the fields to the processing plant is projected to be 700 MMSCFD in 2030. Hence, requires a capacity increase in the flow lines. The capacity increase in flow line 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 6 shows the output of the capacity increase in Flow line 1

4.3 Results/Findings Discussion

4.3.1 Selection of Optimal Pipeline Sizes

Some of pipe sizes were modeled to define the least pipe size that satisfies the requirements of pressure at the intended points, which will sustain a greater rate of flow. The size of pipe chose for flow line 1 shall meet boundary criteria of 44 km length and a pressure over 2,800 psig, whilst the size of pipe for flow line 2 shall meet boundary criteria of 15 km length and a pressure over 1,010 psig . The least size of pipe that met the boundary criteria for flow line 1 was 12 inches, while that of flow line 2 was 14 inches. This is because the 10 inches size of pipe for flow line 1 did not satisfy the resultant pressure expected to flow the gas via riser 2 and flow line 2 to the ORF. Hence, a 12 inches size of pipe was used alternatively. Likewise, 14 inches pipe was used for flow line 2 alternatively rather than of 12 inches due to the fact that 12 inches pipe did not satisfy the inlet pressure of the ORF.

4.3.2 Optimal Insulation for Pipelines

Direct Electrical Heating (DEH) was used to increase the surrounding temperature of flow line 1from 41 °F to 80 °F. The best non-conductive thickness for flow line 1 was defined to be 1.5 inches, while that of flow line 2 was 2 inches. The non-conductivity of the pipe has a direct impact on the rate of flow. The non-conductivity advances the rate of flow of the gas, as suitable non-conductive outputs in a maximum rate of flow. The non-conductive substance applied in the design has a heat non-insulation of 0.15 Btu/hr/ft/°F. While non-conductive thickness for flow line 1 was 1.5 inches, that for flow line 2 was 2 inches. In order to function over the temperature of the hydrate formation, a Direct Electrical Heating (DEH) system was introduced into the design to high the temperature of flow line 1 over the temperature of the hydrate formation because of the minimum undersea temperature. Applying the DEH to increase the surrounding undersea temperature of 41 °F to 80 °F, Flow line 1 was non-conductive and then heated.

4.3.3 Addressing Riser Slugging Challenges

The designs have their PI-SS number more than 1, depicting no liquid slugging at the riser base will happen. The former design has a least PI-SS number (slug number) of 4.95 (Table 8), and that of the alternate design was 1.6. A PI-SS number smaller than 1 means that there is a possibility that liquid slugging will take place, as a PI-SS number or slugging value more than 1 means no presence of liquid slugging at the riser base. Extreme riser slugging can be got from the PI-SS number using Equation 7. A PI-SS or slug number of 4.95 was chosen for the former design, and 1.6 for the alternate design. Both designs have their PI-SS number not less than 1, denoting no liquid slugging at the riser base. It that implies that extreme riser slugging will not take place since the PI-SS values got show no liquid slugging at the riser base.

4.3.4 Addressing Flow Assurance Challenges

Wax formation was not noticed at the least undersea temperature of 41°F. The temperature of the hydrate formation taken from the hydrate phase envelope at a stated pressure of 2,555 psia is roughly 73°F. The no presence of wax precipitation and deposition in the flow lines was as a result to the no presence of heavier hydrocarbon components and the raised environmental temperature by the direct electrical heating system. The highest rate of flow of the design is 150 MMSCFD, which does not satisfy the anticipated rate of flow from the year 2016. The greatest rate of flow from the fields to the processing plant is anticipated to be 700 MMSCFD in 2030. This needs a capacity rise in the flow lines. The capacity rise in flow line 1 was computed to get the least pipe size which, when operated parallel to the 12 in. pipe, will boost the rate of flow of the design to 700 MMSCFD from 150 MMSCFD or even more.

Selection Criteria- Values and Trade-Offs.

Table 7 Size Selection Criteria- Source SPDC- Ubie Nag DG3 2024.

Criteria	**8"**	**10"**	**12"**	**14"**	**Remarks**
Economics	\$305mln	\$320mln	\$356mln	\$391mln	Larger pipelines will require more materials
Gas Flow	< 150MMscf/d	< 150MMscf/d	>150MMscf/d	>150MMscf/d	
Future expansion	No	No	Yes	Yes	More capacity-based Forecast
EVR	>1 @150Mscf	>1 @150Mscf	<1 @ >150Mscf	<1 @>150Mscf	
Selection			Selected for F1	Selected for F2	

4.3.5 Discussion

12" Size is selected for flow line 1 over 14" Pipe Size because of less CAPEX and offer more economic benefit than 14". Although 14" provides more capacity future expansion but 12" can also accommodate forecast quantity. Oversized pipeline can present risk of significant liquid/condensate accumulation, solid deposition and corrosion and pigging difficulties

Table 8 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			

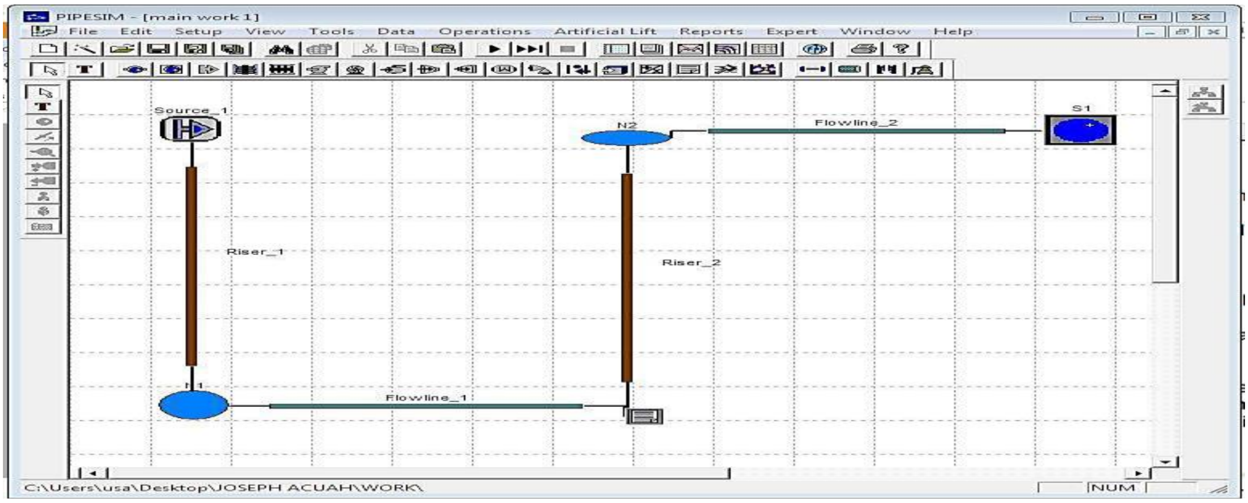

Figure 2(a): Pipesim Interface Showing the Full Design Orientation

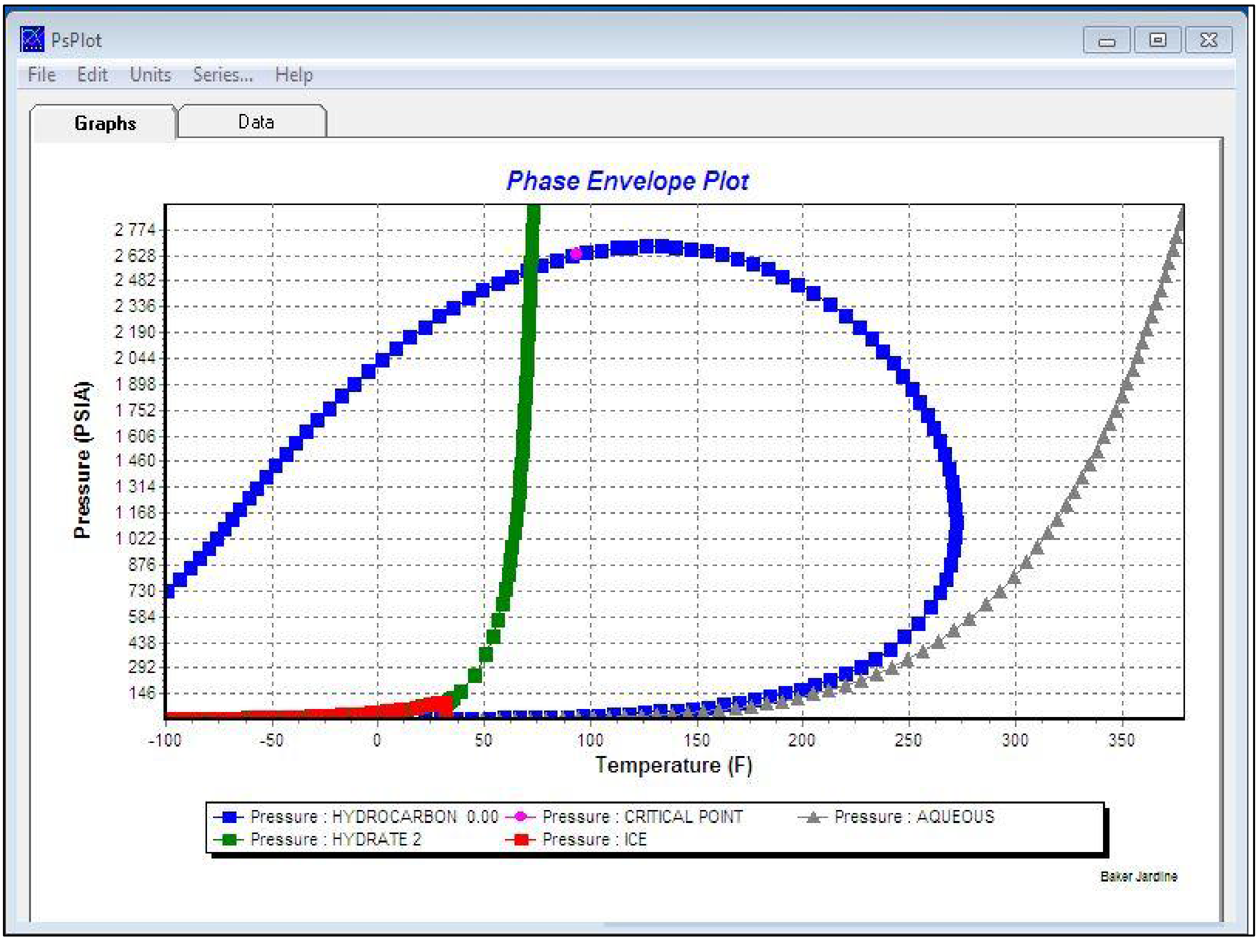

Figure 2 (b): Graph of Hydrate Phase Envelope displaying Temperature of Hydrate Formation

The temperature of the hydrate formation got from the envelope of the hydrate phase at a specified pressure of 2 555 psia is roughly 73 ^{o}F.

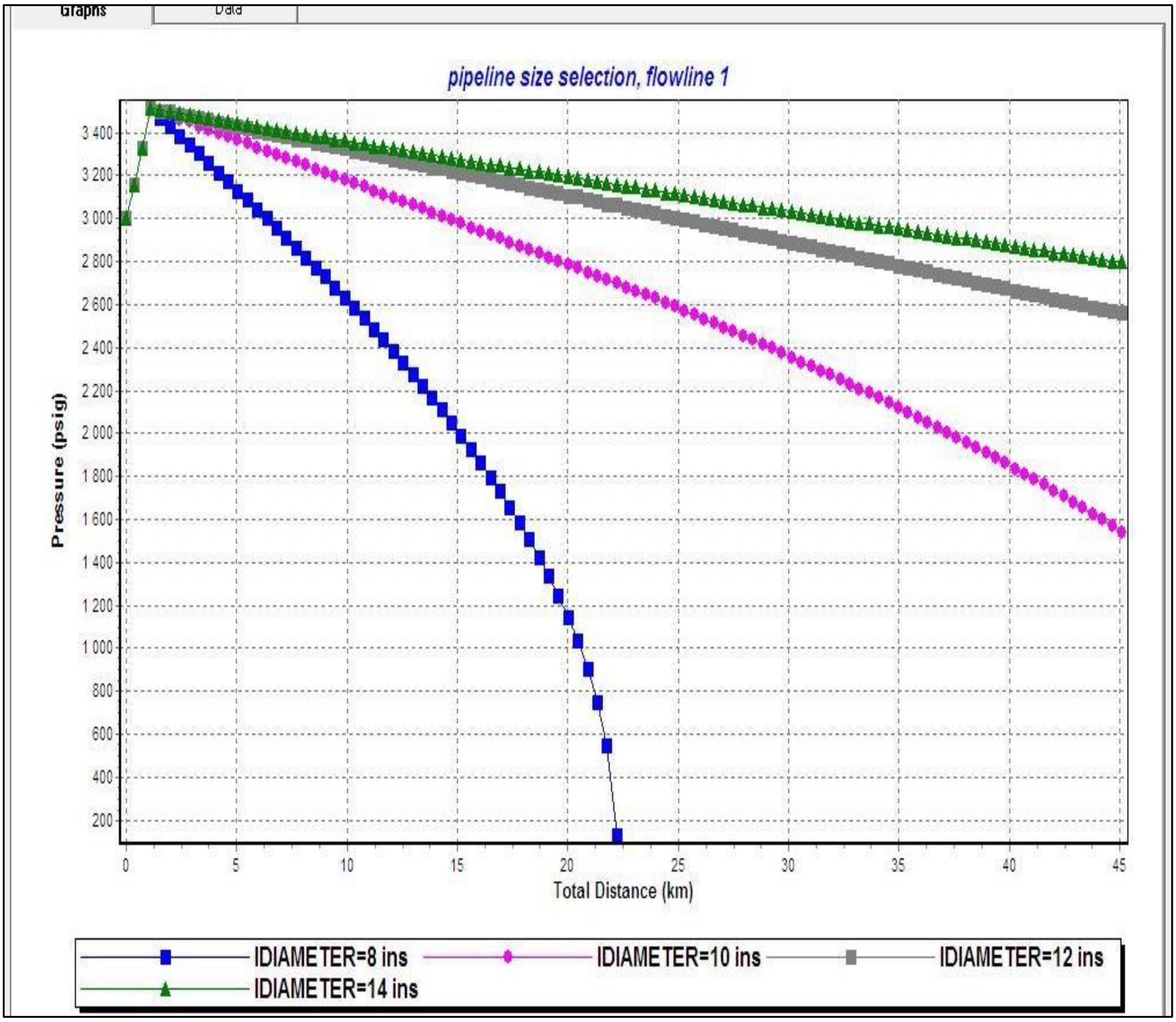

Figure 2(c): Graph of Pressure – Distance Plot Displaying Sizes of Pipe for Flow line 1

Figure 2(c) shows the relationship between pressure and total distance showing the pipe sizes for flow line I. As distance increases the pressure of 8 ins pipe, 10 ins pipe, 12 ins pipe and 14 ins pipe decreases. The decrease may be attributed to the sizes of pipes. The order of decrease is 8 ins pipe < 10 ins pipe < 12 ins pipe < 14 ins pipe

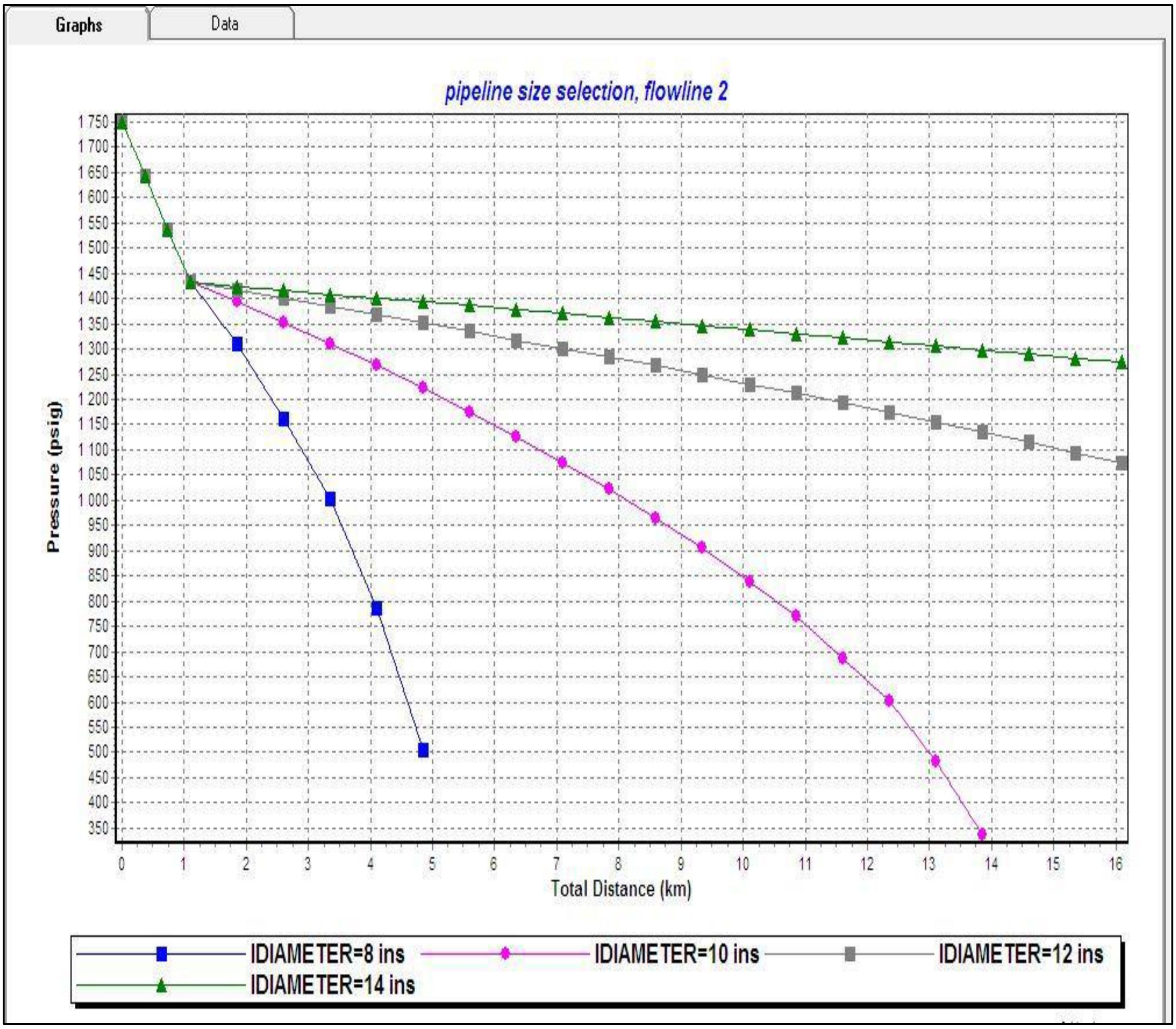

Figure 2(d): Graph of Pressure – Distance Plot Displaying Sizes of Pipe for Flow line 2

Figure 2(d) illustrates the relationship between pressure and total distance showing the pipe sizes for flow line II. As distance increases the pressure of 8 ins pipe, 10 ins pipe, 12 ins pipe and 14 ins pipe decreases. The decrease may be attributed to the sizes of pipes. The order of decrease is 8 ins pipe < 10 ins pipe < 12 ins pipe < 14 ins pipe

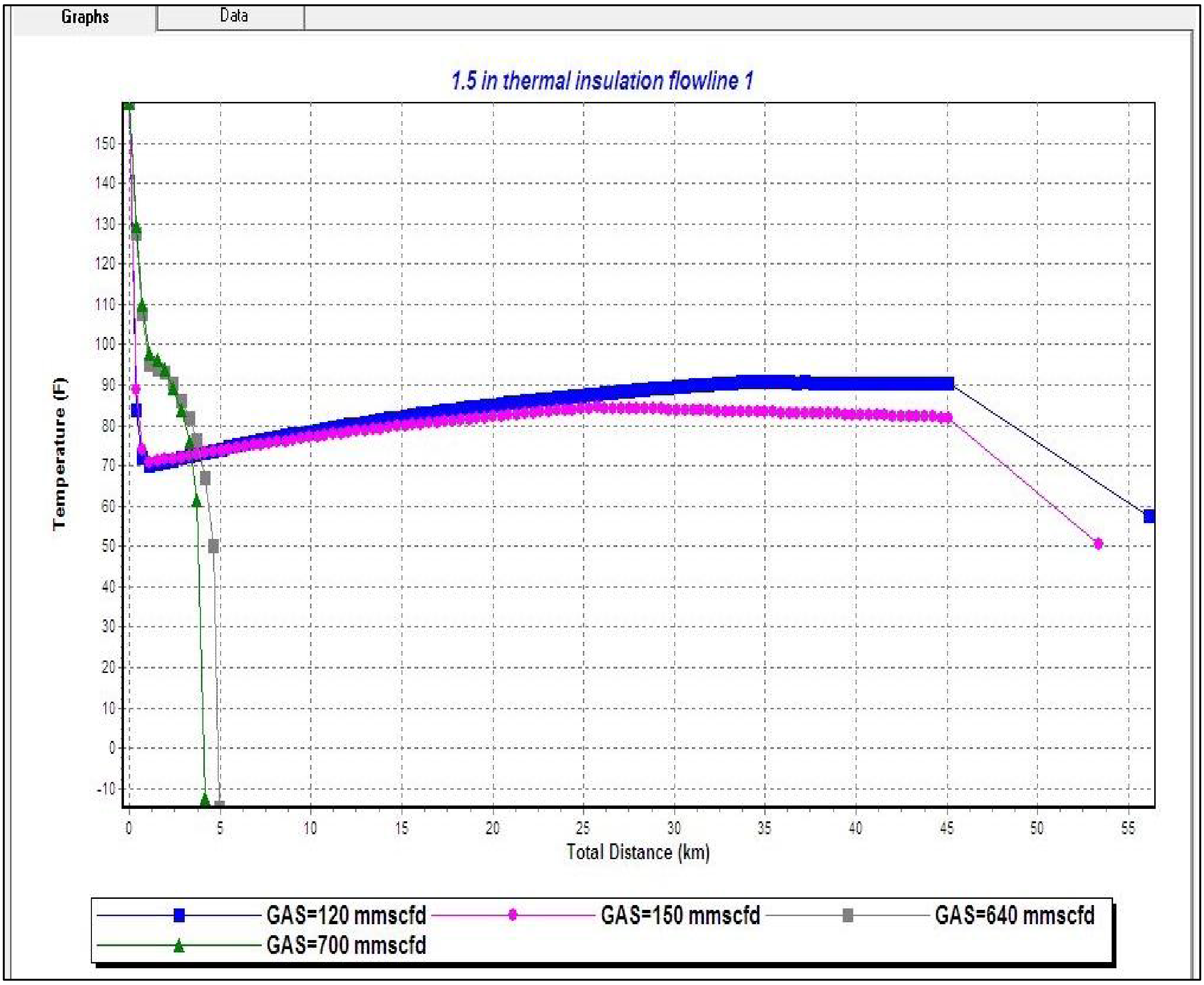

Figure 2(e): Graph of Temperature – Distance Plot Displaying the Rates of Flow for Flow line 1

Figure 2 (e) demonstrates the relationship between temperature and total distance showing the pipe sizes for flow line I. As distance increases the flow rate of Gas 120 mmscfd and Gas150mmscfd decreases, then increase exponentially and decrease with total distance. The order of decrease, increase and decrease are Gas 120 mmscfd > Gas150mmscfd. While Gas 640 mmscfd and Gas 700mmscfd decrease exponentially with total distance in the order of Gas 640 mmscfd > Gas 700mmscfd.

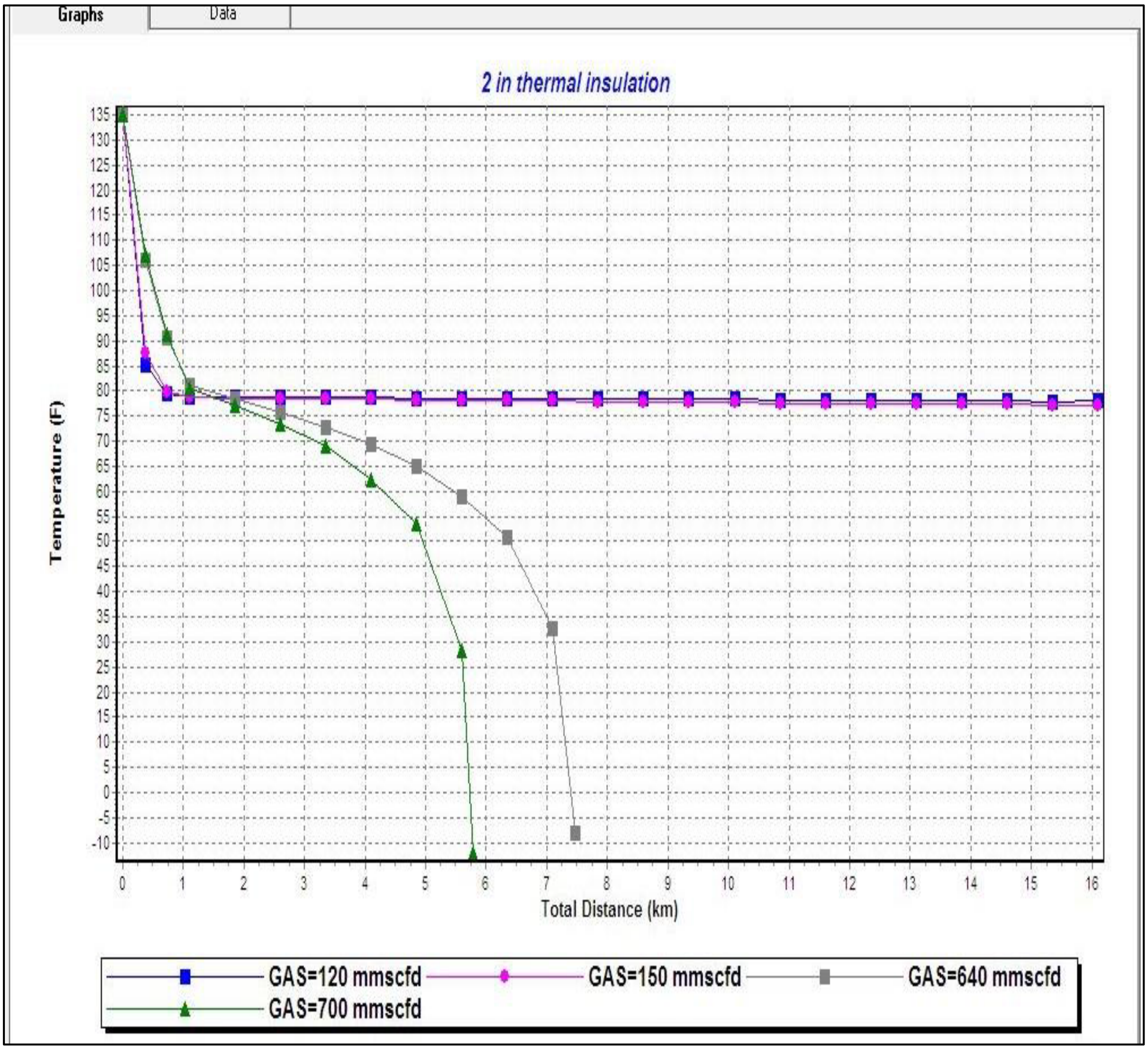

Figure 2(f): Temperature Graph - Distance Displaying the Rates of Flow for Flow line 2

Figure 2 (f) illustrates the relationship between temperature and total distance showing the pipe sizes for flow line 2. As distance increases the flow rate of Gas 120 mmscfd and Gas150mmscfd decreases, then remain constant with total distance. The order of decrease, increase and decrease are Gas 120 mmscfd = Gas150mmscfd. While Gas 640 mmscfd and Gas 700mmscfd decrease exponentially with total distance in the order of Gas 640 mmscfd > Gas 700mmscfd.

Table 9 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

Rise of Capacity of Flow line 1

Table 10 Capacity of flow line 1

PIPE ID (IN)		**PARALLEL PIPE CAPACITY RISE**		**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

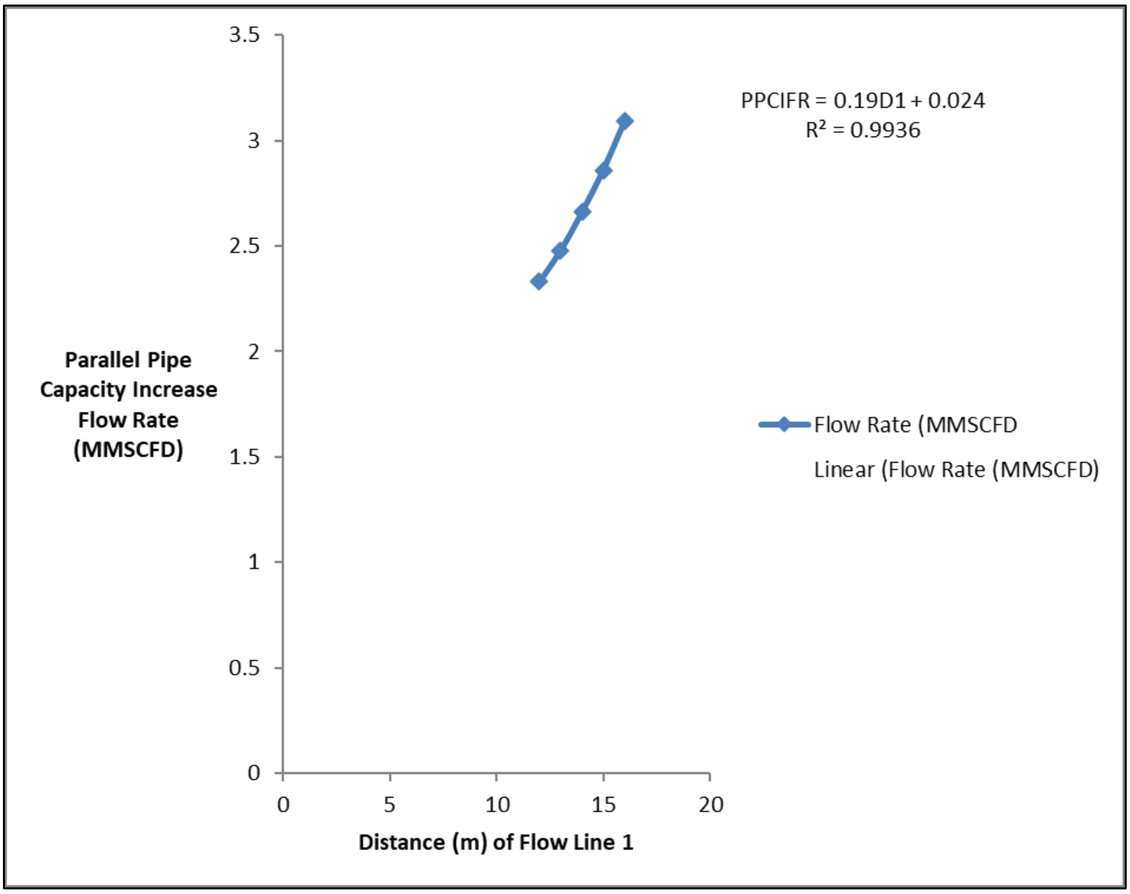

Figure 3(a): Graph of Parallel Pipe Capacity Increase Flow Rate against Distance of Flow Line 1

Figure 3(a) illustrates the relationship between parallel pipe capacity increase flow rates against distance of flow line 1. The increase in distance increases the parallel line capacity increase flow rate. The equation of the line is PPCIFR = 0.19DI + 0.024 with R^2 = 0.9936

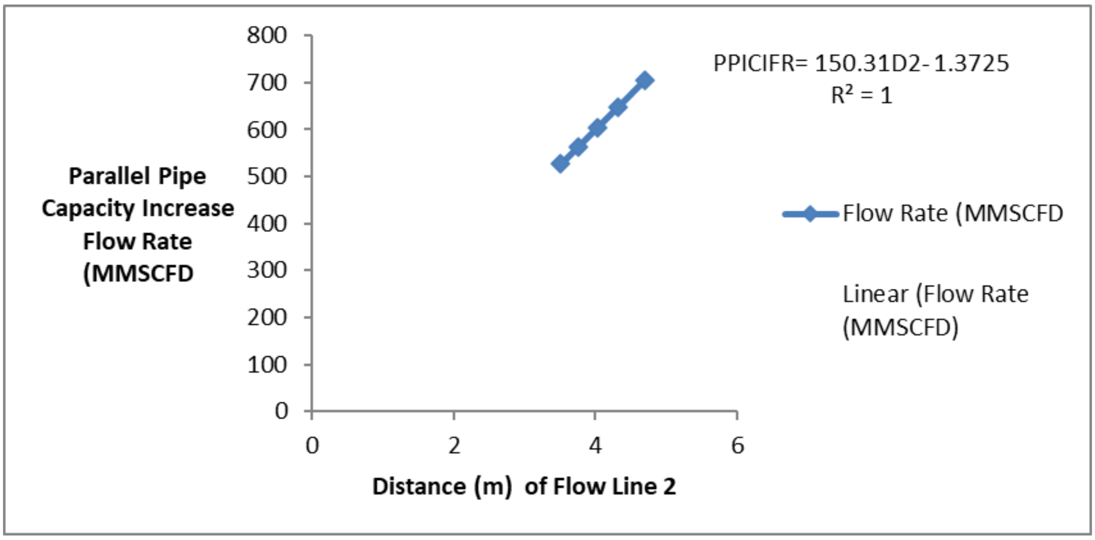

Figure 3(b): Graph of Parallel Pipe Capacity Increase Flow Rate against Distance of Flow Line 2

Figure 3(b) demonstrates the relationship between parallel pipe capacity increase flow rates against distance of flow line 2. The increase in distance increases the parallel line capacity increase flow rate. The equation of the line is $\text{PPCIFR} = 150.31D^2 - 1.3725$ with $R^2 = 1.0$

5 Conclusion

The outcome of this study is important in the movement of condensate gas from the offshore waters of Nigeria, specifically the Ikwerre Local Government Area, Agbada I Field, and Agbada II Fields, to the Agip Gas Processing Plant. Below are the conclusions got from this study:

5.1 Hydrate Formation Temperature

The hydrate formation temperature obtained from the hydrate phase envelope at a defined pressure of 2,555 psia is approximately 73°F. This temperature is crucial for understanding potential flow assurance issues related to hydrate formation in subsea pipelines

5.2 Pressure Drop with Distance in Flow Line 1 and Flow Line 2

In Flow Line 1, as distance increases, the pressure in 8-inch, 10-inch, 12-inch, and 14-inch pipes decreases. The order of decrease in pressure is 8-inch pipe < 10-inch pipe < 12-inch pipe < 14-inch pipe. Similarly, in Flow Line 2, pressure decreases with distance for all pipe sizes, with the same order of decrease. The pressure drop can be attributed to the larger pipe sizes, which affect the frictional losses along the length of the pipe.

5.3 Flow Rate Changes with Distance in Flow Line 1 and Flow Line 2

In Flow Line 1, as distance increases, the flow rate of Gas at 120 MMSCFD and 150 MMSCFD decreases, then increases exponentially, and then decreases again with total distance. The order of these changes is Gas 120 MMSCFD > Gas 150 MMSCFD. On the other hand, Gas at 640 MMSCFD and 700 MMSCFD decreases exponentially with total distance in the order of Gas 640 MMSCFD > Gas 700 MMSCFD.

In Flow Line 2, as distance increases, the flow rate of Gas at 120 MMSCFD and 150 MMSCFD decreases, then remains constant with total distance. The order of flow rate changes is Gas 120 MMSCFD = Gas 150 MMSCFD. Gas at 640 MMSCFD and 700 MMSCFD decreases exponentially with total distance in the order of Gas 640 MMSCFD > Gas 700 MMSCFD.

5.4 Parallel Pipe Capacity Increase and Flow Rate

The increase in distance results in an increase in the parallel line capacity and subsequently the flow rate. This relationship is a direct consequence of the additional flow area provided by parallel pipelines, which reduces the pressure losses and increases the overall gas flow to the processing plant.

Compliance with ethical standards

Disclosure of conflict of interest

"**Nnorom Obinichi, Odafiagwuna Friday, Ameme Clinton** declare that they have no known competing financial interests or personal relationships that could have appeared to influence the work reported in this paper."

Funding

This study was funded by the three authors "Nnorom Obinichi, Odafiagwuna Friday, Ameme Clinton is an employee of university of Port Harcourt.

Please, we have given you the consent to publish the manuscript in your journal paper.

References

[1] Abdulmutalib, A. and Abdulmalik, F. (2022) Investigation of Hydrate Formation in Natural Gas Transmission Pipelines. *International Journal of Advances in Engineering and Management* (IJAEM) 4 (5) 2040-2055.

[2] Broeker, R.J. (2014) A New Process for the Transportation of Natural Gas. *In:* Proceedings of the 1st International Conference on Liquified Natural Gas.

[3] Gray, B. ; Jones, E.C. Yvette Weatherton, Y.; Bussey, R.S. and Armstrong, H.(2013) Utilizing Pipeline Quality and Facility Sustainability to Optimize Crude Oil Supply Chains. *Int. J* Sup. Chain. Mgt 2(4) 9-16.

[4] Johnson, F.I.; Laing, R.; Bjeirmi, B. and Leon, M. (2022) Examining the Causes and Impacts of Pipeline Disasters in Nigeria. *AIMS Environmental Science,* 9(5): 636–657.

[5] Hermoso, J., Martínez-Boza, F. J., & Gallegos, C. (2017). Modeling pressure-viscosity behavior of oil-based drillingfluids. *Oil & Gas Science and Technology– Rev. IFP EnergiesNouvelles,* 72(4), 1-10. https://doi.org/10.2516/ogst/2017014.

[6] Kamari, E.; Mohammadi, S.; Ghozatloo, A. and Shariaty-Niassar, M. (2013) Journal ofChemical and Petroleum Engineering, University of Tehran, 47 (2) 115-127.

[7] Nagham, S.H.A.(2011) Improvement of Pipeline Transportation of Fuel Oil. AL-Nahrain University 1-117.

[8] Naseer, M. and Brandstatter, W. (2011) Hydrate Formation in Natural Gas Pipelines. WIT Transactions on Engineering Sciences, 70 261 – 270.

[9] Solan A., Ingham R. and Mann W.L., (2019.) First International Conference on "The Future of Heavy Crude and Tar Sands", 86, 719-726, Edmouton, Alberta, Conada.

[10] Tese, D. L. M. (2018) Carbon Dioxide Pipeline Transportation and Network. Politecnico Di Torino, 1 – 111.

[11] Ugwunna, A.D , Appah, D. and Evbuomwan, B.O. (2019) Design of Natural Gas Transmission Pipeline. Global Scientific Journal, 7 (2) 951 – 963.