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A Quick-Look Model to Predict Gas Hydrate Formation in Gas Pipelines using Modified Navier-Stokes Correlation

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Authors' contributions

This work was carried out in collaboration among all authors. Author AOO designed the study, wrote the protocol and wrote the first draft of the manuscript. Authors OOO and IOS managed the analyses of the study. Author OOO managed the literature searches. All authors read and approved the final manuscript.

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ABSTRACT

Major challenges associated with the smooth production operations in the oil and gas industry that has raised technical curiosity are formation of natural gas hydrates in production facilities and flow lines which introduces significant cost to operators. Accurate modeling is therefore paramount; most existing models are based on constitutive conservation laws neglecting other dissipative energy types.

To predict "if" and "where" gas hydrate would be formed in gas pipeline, the Navier-Stokes equation was modified by incorporating dissipative forces of viscosity and gravity; the equation that emerged was solved analytically to determine the hydrate formation pressure (HFP) and the position of hydrate formation along gas pipelines.

The developed model, used as a quick-look tool for where and if hydrates will form revealed that when the predicted HFP is positive hydrates was formed but when it is negative hydrates were not formed. The model also showed that HFP is a function fluid composition, mass flowrate, changes in fluid and surrounding conditions and changes in elevation and direction confirming the results of earlier work done.

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ABBREVIATIONS

D : Pipeline diameter
f : Frictional Factor
g : gravitational acceleration
L : Pipeline transmission length,
P : Pressure
Re : Reynolds Number
U : Fluid Velocity
Θ : Pipeline Inclination
A : Volume Fraction
P : Fluid density
ϵ : Kinematic viscosity
q : volumetric flow rate
ϕ : porosity
μ : fluid viscosity
HFP : Hydrate Formation Pressure

1. INTRODUCTION

Over the years, oil and gas companies have been faced with several challenges in producing hydrocarbon fluids from the source to the surface facilities where they are separated to gas, oil and water phases. Natural gas production is faced with operational challenges which majorly stems out from blockages in wells and pipelines. In their study authors [1,2] concluded that these blockages were either structure-related or fluid-related. Structure related blockages involve damage to pipeline infrastructure such as pipe deformation, valve malfunction, and deposition caused by corrosion, which can all be avoided by proper maintenance and regular inspection. However, the fluid related blockages are more persistent and difficult to handle, they involve formation and/or deposition of solids such as asphaltene, wax or gas hydrates in natural gas pipeline. The most troublesome of these is gas hydrate deposition, which introduces significant cost to operators. The crux of this study focuses on hydrate formation in pipelines.

Hydrates are ice-like crystalline solids in nature formed when gas (guest) molecules contact free water (host) at low temperature and high pressure [3]. In the presence of free water, hydrates form when the temperature is below hydrate temperature which in turn is less than or equal to the dew point temperature of the hydrate forming gas. These hydrates are known as Clathrates to distinguish them from stoichiometric hydrates found in inorganic chemistry [4]. The cages are stabilized by van der Waals forces between the water molecules and hydrate formers (methane, ethane, propane, butane, carbon dioxide, hydrogen sulphide and nitrogen and some heavy hydrocarbon). In 2005, Sharareh [5] classified hydrate formers into organic and inorganic compounds. The presence of the guest molecules provides stability to the crystal structure which enables the hydrates to subsist at much temperature than ice and no bonding exist between the guest molecules and the host molecules [6,7], consequently, guest molecules are free to rotate inside the cages built by the host molecules. The free space of the crystalline grid is clocked up with hydrocarbon molecules which are attached to the water molecules by weak chemical bonds. These researchers [8-11] presented a theoretical and conceptual model of hydrate formation stages as nucleation, growth, agglomeration, and plugging based on crystallization theories. The period of the nucleation is measured by the induction time [6,12]. In their review work on clathrate hydrate nucleation Khurana and his associates [13] gave an in-depth insight into nucleation types and characteristics, nucleation pathways and nucleation rates; they also proposed four major conceptual theories of hydrate nucleation as: Classical Nucleation Theory (CNT), Labile Cluster Hypothesis (LCH), Nucleation at Interface Hypothesis (NIH) and Local Structuring Mechanism (LSM). In 1810 the first discovery of hydrate structures was accredited to Sir Humphrey Davy, in his work, he observed that the ice-like solid formed at temperatures above the freezing point of water and that it composed of more than just water [14,15] while in 1934, Hammerschmidt found out that the formation of gas hydrate blocked pipelines rather that ice that was original believed to have plugged pipelines [14]. It was in the late 19th and early 20th century that the first hydrocarbon hydrate was discovered by Villard and de Forcrand, respectively [15-17]. von Stackelberg and Muller in their work studied the hydrate structure using x-ray diffraction methods [18], their work along with work of Claussen in 1951 identified two hydrate structures, structure I and structure II [19]. There are majorly three main types of hydrate structures which depend largely on the size of the guest molecules, they are called types I, II and H [15,17,20-22]; and there is the fourth type known as Trigonal ST formed by dimethyl ether [11,23].

Literatures are replete on comprehensive studies of thermodynamic models [24-29] in the analysis of gas hydrate, these models were based on the theory proposed by van der Waals and Platteeuw in 1959 [24]. Jamuluddin and his co-workers used compositional characterization of fluid samples and several screening techniques to determine the thermodynamic conditions for various forms of hydrocarbon solid formation [30]. It was discovered that these techniques were time consuming, expensive and not accurate in determining where the solid hydrocarbons would be formed. An early warning signal to detect initial signs of hydrates formation and also to identify a hydrate safety margin has been developed [10,31], tracking of the rate of hydrate formation in pipelines was the main goal of the techniques.

The pressure transient analysis technique is also very useful in the detection of early partial blockage, this technique is cost effective and less invasive. Adewumi and his co-workers developed a mathematical gas dynamics model that describes the propagation of a pressure pulse through a natural gas pipeline containing multiple partial blockages [32,33]. Their model monitored and analyzed pressure variations at the pipe inlet caused by reflected pressure waves. They succeeded in determining the location and the severity of the blockages along a straight pipe. In 2007 Chen and fellow researchers investigated into the practicability of blockage characterization by pressure transient analysis, they used the theoretical developments of the work of Adewumi [32,33] to a laboratory experimental setup [34]. They discovered that blockage length and location can be predicted with high level accuracy, but blockage severity was rated too low by almost 50%. In 2015, Akinsete and Isehunwa developed an analytical model which was extended to check the behavior of different methane fraction component in natural gas stream to hydrate growth and blockage severity [10]. They found out that a simple analytical method can be used to resolve the nonlinear partial differential equation that describes the fluid flow problems in natural gas pipeline systems. They used the model as a predictive tool for early warning signal to prevent the risk and catastrophes resulting from hydrate agglomeration and plugging of gas pipeline. Blockage of gas pipeline by hydrates is a serious threat to the economics of the operations as well as the safety of the personnel [31].

2. METHODOLOGY

Most transport equations have been successful in considering only the basic constitutive conservation laws of mass, momentum and energy; neglecting other dissipative forces or energy types. In this work, the Navier-Stokes dissipative equation, such as due to viscosity, gravity, and other dissipative losses, was adopted for the prediction of “if” and “where” gas hydrates would be formed in a natural gas pipeline.

The Navier–Stokes equations describe the motion of viscous fluid substances, it rise from applying Isaac Newton's second law to fluid motion, together with the assumption that the stress in the fluid is the sum of a diffusing viscous term (proportional to the gradient of velocity) and a pressure term—hence describing viscous flow. The main difference between them and the simpler Euler equations for inviscid flow is that Navier–Stokes equations also factor in the Froude limit (no external field) and are not conservation equations, but rather a dissipative system, in the sense that they cannot be put into the quasilinear homogeneous form.

2.1 Viscid Flow Model

The Navier-Stokes equation that describes the flow of incompressible fluids is given as:

$$\rho\left(\frac{\partial v}{\partial t} + v \cdot \nabla v\right) = -\nabla P + \nabla \cdot T + f \qquad (1)$$

The left-hand side (LHS) of equation (1) is the acceleration of a small region of fluid while the right-hand side (RHS) is the forces that act on it (i.e. pressure, stress and internal body forces). Both sides of equation (1) did not balance, to balance it we rewrite the equation (1) as:

$$(\rho v)_t + \nabla \cdot (\rho v v) + \nabla p - \mu \nabla^2 v = HYDRATE\ FORMATION\ PRESSURE \neq 0 \qquad (2)$$

Where

$$\rho = density\ of\ the\ natural\ gas, p = pressure\ v = flow\ velocity, and\ \mu = viscosity$$

Equation (2) was further simplified to give:

$$\rho \frac{\partial v^x}{\partial t} + \rho v^x \frac{\partial v^x}{\partial x} - \mu \frac{\partial^2 v^x}{\partial x^2} + \frac{\partial P}{\partial x} \neq 0 \qquad (3)$$

Using traditional variable u for v^x, equation (3) becomes:

$$\rho\frac{\partial u}{\partial t} + \rho u\frac{\partial u}{\partial x} - \mu\frac{\partial^2 u}{\partial x^2} + \frac{\partial P}{\partial x} \neq 0 \quad (4)$$

From first principle

$$\dot{m} = \frac{m}{t} = \rho Q = \rho A u \quad (5)$$

$$\frac{m}{t} = \rho A u \quad (6)$$

Differentiating equation (6)

$$\frac{\partial}{\partial t}\left(\frac{m}{t}\right) = \frac{\partial}{\partial t}(\rho A u) \quad (7)$$

Taking $m, \rho \text{ and } A \text{ as functions independent of } t$, we have:

$$m\frac{\partial}{\partial t}\left(\frac{1}{t}\right) = \rho A\frac{\partial u}{\partial t} \quad (8)$$

$$m(-t^{-2}) = \rho A\frac{\partial u}{\partial t} \quad (9)$$

$$\frac{\partial u}{\partial t} = -\frac{m}{\rho A t^2} \quad (10)$$

Applying product rule to equation (4) gives:

$$\rho\frac{\partial u}{\partial t} + \rho u\frac{\partial u}{\partial t}.\frac{\partial t}{\partial x} - \mu\frac{\partial^2 u}{\partial x^2} + \frac{\partial P}{\partial x} \neq 0 \quad (11)$$

Substituting equation (10) into equation (11) becomes:

$$\rho\left(-\frac{m}{\rho A t^2}\right) + \rho u\left(-\frac{m}{\rho A t^2}\cdot\frac{\partial t}{\partial x}\right) + \frac{\partial P}{\partial x} - \mu\frac{\partial^2 u}{\partial x^2} \neq 0 \quad (12)$$

But, $u = \frac{\partial x}{\partial t}$ (13)

Substituting equation (13) into equation (12), we have:

$$-\frac{2m}{At^2} + \frac{\partial P}{\partial x} - \mu\frac{\partial^2 u}{\partial x^2} \neq 0 \quad (14)$$

Rewriting equation (14) in terms of weight and volume of gas, gives

$$-\frac{2W_{gas}}{V_{gas}} + \frac{\partial P}{\partial x} - \mu\frac{\partial^2 u}{\partial x^2} = HFP \quad (15)$$

In terms of mass flowrate equation (15) becomes:

$$-\frac{2\dot{m}_{gas}\, g}{Q} + \frac{\partial P}{\partial x} - \mu\frac{\partial^2 u}{\partial x^2} = HFP \quad (16)$$

Equation (16) for an inclined pipeline gives:

$$-\frac{2\dot{m}_{gas}\, g\cos\theta}{Q} + \frac{\partial P}{\partial x} - \mu\frac{\partial^2 u}{\partial x^2} = HFP \quad (17)$$

Hagen-Pouiselle Equation a dissipative viscous force is given as:

$$\mu\frac{\partial^2 v}{\partial x^2} = \frac{\Delta P}{L} = \frac{8\mu Q}{\pi R^4} \quad (18)$$

Substituting equations (18) into (17) gives:

$$-\frac{2\dot{m}_{gas}\, g\cos\theta}{Q} + \frac{dP}{dx} - \mu\frac{8Q}{\pi R^4} = HFP \quad (19)$$

Equation (19) is the fully coupled equation for predicting Hydrate Formation Pressure (HFP)

$\frac{dP}{dx}$ in equation (19) could be calculated using any of the gas equation depending on mode of operation of gas pipeline, but in this work the simplified gas formula equation (20) was used.

$$\frac{dP}{dx} = \frac{(P_1 - P_2)}{L} = 25.2\left(\frac{\gamma Q_g^2 ZTf}{d^5(P_1 + P_2)}\right) \quad (20)$$

Substituting equations (20) into (19) gives:

$$-\frac{38640\dot{m}_{gas}\, g\cos\theta}{Q} + 25.2\left(\frac{\gamma Q_g^2 ZTf}{d^5(P_1 + P_2)}\right) - \mu\frac{2.8\times10^{-7}Q}{\pi R^4} = HFP \quad (21)$$

For a given operating Q and given conditions, if HFP is negative, gas hydrate is unlikely to be formed and if it is positive, gas hydrate is likely to be formed.

If X be the length or position (in miles) from the pipeline's entry section at which hydrate begins to form; Interpolation (between X=0 and X=L) technique was used to get the value of position X as shown in equation (22) below:

$$X = L\left(\frac{(\Delta P_{HYDRATE\ FORMATION = zero}) - (\Delta P_{HYDRATE\ FORMATION\ when\ P1=P2})}{(Calculated\ \Delta PHYDRATE\ FORMATION) - (\Delta P_{HYDRATE\ FORMATION\ when\ P1=P2})}\right) \quad (22)$$

3. RESULTS AND DISCUSSION

Data was collected from Natural Gas Pipeline transmission company "Alpha", and the hydrate formation pressure (HFP) was calculated using the developed model. We have written a program in MATLAB called HPP. HPP takes in the input data in raw form and very flexible in that it could be used for multiple number of pipelines; here we have used only 10 pipeline data. HPP calculates and plots several graphs or figures for different

analysis. HPP allows for a robust sensitivity analysis on how these several input parameters would affect the hydrate formation pressure.

3.1 Distance or Position of Hydrate Formation along Pipeline

The model was able to calculate the expected position of hydrate formation as shown in Figs. 1-5 and Tables 1-2. From Table 1: Pipelines 1, 6, 7, 8 and 10, in which hydrates were formed had their distances as 62.01, 2.88, 2.26 and 71 miles respectively. Pipelines 2,3,4, 5, and 9 in which hydrates were not formed gave outrageous values of distances or position, some of the values exceeding the total pipeline's length (100 miles) as in the cases of Pipelines 2, 4 and 9.

3.2 Sensitivity Analysis

Sensitivity analysis results are shown in Table 2. Pipelines 1 and 2 with the same flow parameters but different upstream pressures; Pipeline 1 has a higher upstream pressure compared to pipeline 2 and the predicted Hydrate Formation Pressure is Positive showing a greater probability of hydrate formation (Fig. 3). The hydrate was formed at distance of 98.2 miles in the pipeline.

Pipelines 6 and 7 with the same flow parameters but different angle of inclination (different theta values), with Pipeline 6 inclined at 30° to the horizontal against the horizontal Pipeline 7. Pipeline 6 has a positive predicted Hydrate Formation Pressure (i.e. hydrate was formed) compared with a negative predicted value for horizontal Pipeline 7, making Pipeline 6 more vulnerable to hydrate formation (Fig. 4).

Pipelines 8 and 9 with the same flow parameters but different mass flow rate values with a higher value for Pipeline 8. Result as shown in (Fig. 5) revealed that a higher mass flow rate does not induce the formation of hydrate when compared with a Pipeline 9 with lower mass flow rate where hydrate is formed.

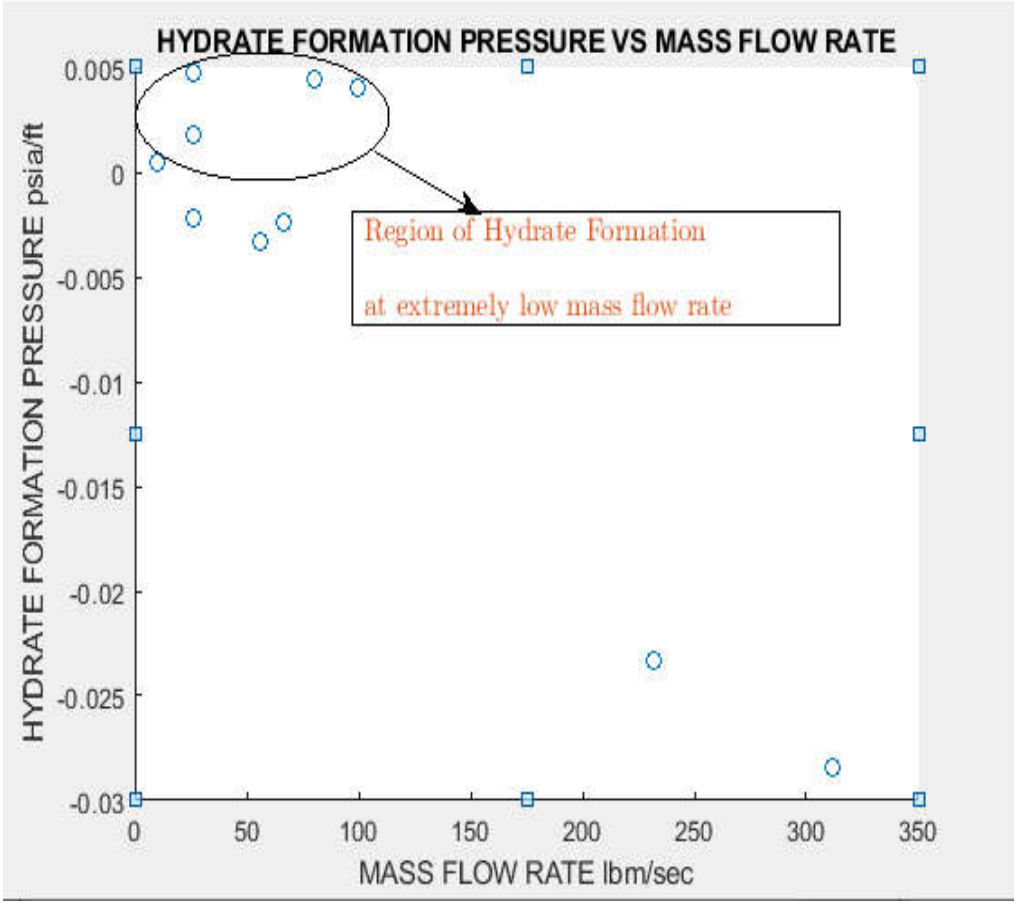

Fig. 1. Hydrate formation pressure (psi/ft) versus mass flow rate(lbm/sec)

Table 1. Results showing where and when natural gas hydrate formation in pipeline

Pipeline	**1**	**2**	**3**	**4**	**5**	**6**	**7**	**8**	**9**	**10**
Mass Flow Rate (lbm/sec)	26.5	55.8	66.9	231.5	312	100	80.32	26.5	26.5	10
Volumetric Flow Rate (cu.ft/day)	3.64E+08	3.64E+08	3.64E+08	3.64E+08	3.64E+08	3.64E+08	3.64E+08	3.64E+08	3.64E+08	3.64E+08
θ°	0	0	0	0	0	30	-30	0	0	0
P_1 (psia)	3000	2000	847	1000	847	900	900	1000	1000	1000
P_2 (psia)	600	600	600	325	600	600	600	600	700	200
Viscosity(cp)	0.02	0.002	0.002	0.06	0.002	0.002	0.03	0.002	0.002	0.03
Length (ft)	528000	528000	528000	528000	528000	528000	528000	528000	528000	528000
Radius(in)	12.1	12.1	12.1	24	24	24	12.1	12.1	12.1	12.1
HFP (psi/ft)	0.00170	-0.00327	-0.00242	-0.02329	-0.02842	0.004045	0.004322	0.004761	-0.00225	0.000409
Hydrate Formation Distance (miles)	62.0140	223.6703	15.1858	1938.569	70.7657	2.8802	2.2698	3.7102	499.6229	71.3004
REMARK	HYDRATE FORMED	HYDRATE NOT FORMED	HYDRATE NOT FORMED	HYDRATE NOT FORMED	HYDRATE NOT FORMED	HYDRATE FORMED	HYDRATE FORMED	HYDRATE FORMED	HYDRATE NOT FORMED	HYDRATE FORMED

Table 2. Sensitivity analysis (with different upstream pressures, inclinations and mass flow rates)

Pipeline	**1**	**2**	**3**	**4**	**5**	**6**	**7**	**8**	**9**	**10**
Mass Flow Rate (lbm/sec)	26.5	26.5	26.5	26.5	26.5	26.5	26.5	40.0	5.0	100.0
Volumetric Flow Rate (cu.ft/day)	3.64E+08	3.64E+08	3.64E+08	3.64E+08	3.64E+08	3.64E+08	3.64E+08	3.64E+08	3.64E+08	3.64E+08
θ°	0	0	0	0	0	30	0	0	0	0
P_1 (psia)	3000	2000	847	847	847	900	900	1000	1000	847
P_2 (psia)	1500	1500	600	600	600	600	600	600	600	600
Viscosity(cp)	0.02	0.02	0.03	0.02	0.02	0.01	0.01	0.02	0.02	0.01
Length (ft)	528000	528000	528000	528000	528000	528000	528000	528000	528000	528000
Radius(in)	13	13	12.1	12.1	12.1	12.1	12.1	12.1	12.1	12.1
HFP (psi/ft)	0.006647	-0.001887	-0.002389	-0.02374	-0.02374	0.0001194	-0.002258	-0.003517	0.0001968	-0.010157
Hydrate Formation Distance (miles)	98.2	294.5	591.3	591.3	594.5	73.7	492.2	538.2	68.0	2264.7
REMARK	HYDRATE FORMED	HYDRATE NOT FORMED	HYDRATE NOT FORMED	HYDRATE NOT FORMED	HYDRATE NOT FORMED	HYDRATE FORMED	HYDRATE NOT FORMED	HYDRATE NOT FORMED	HYDRATE FORMED	HYDRATE NOT FORMED

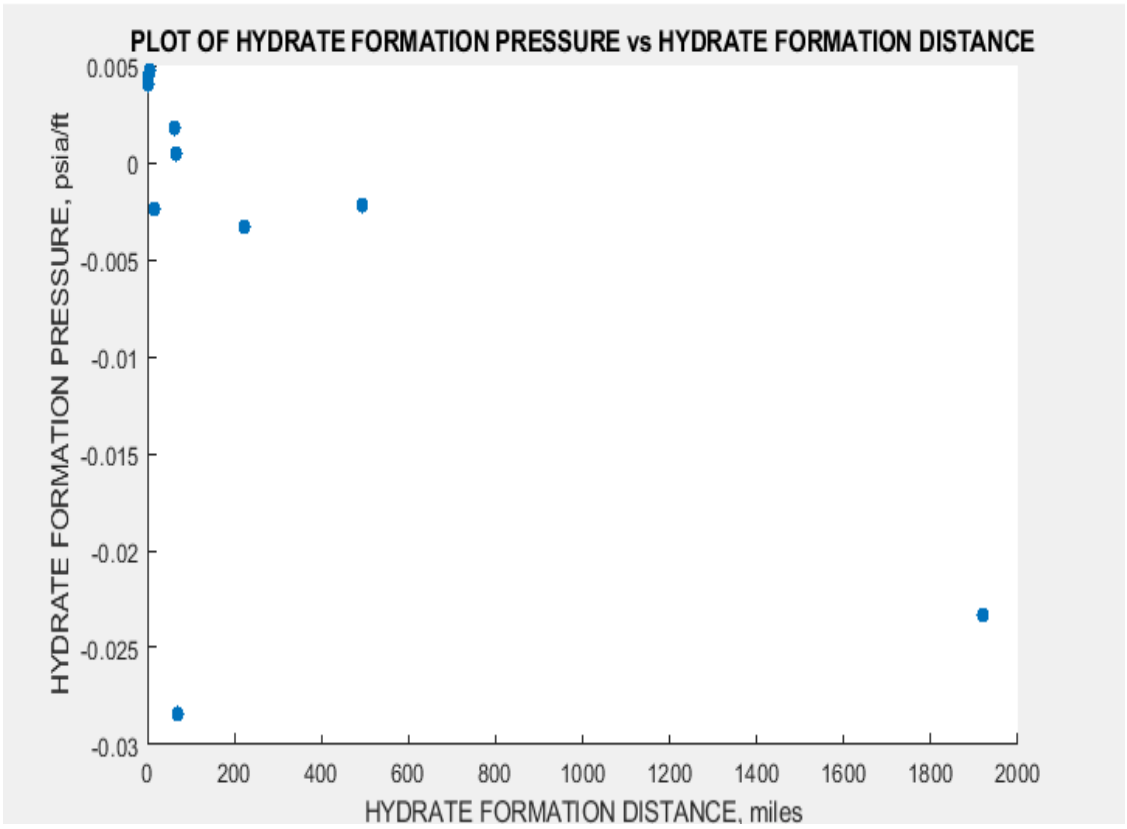

Fig. 2. Hydrate formation pressure (psi/ft) versus hydrate formation distance (miles)

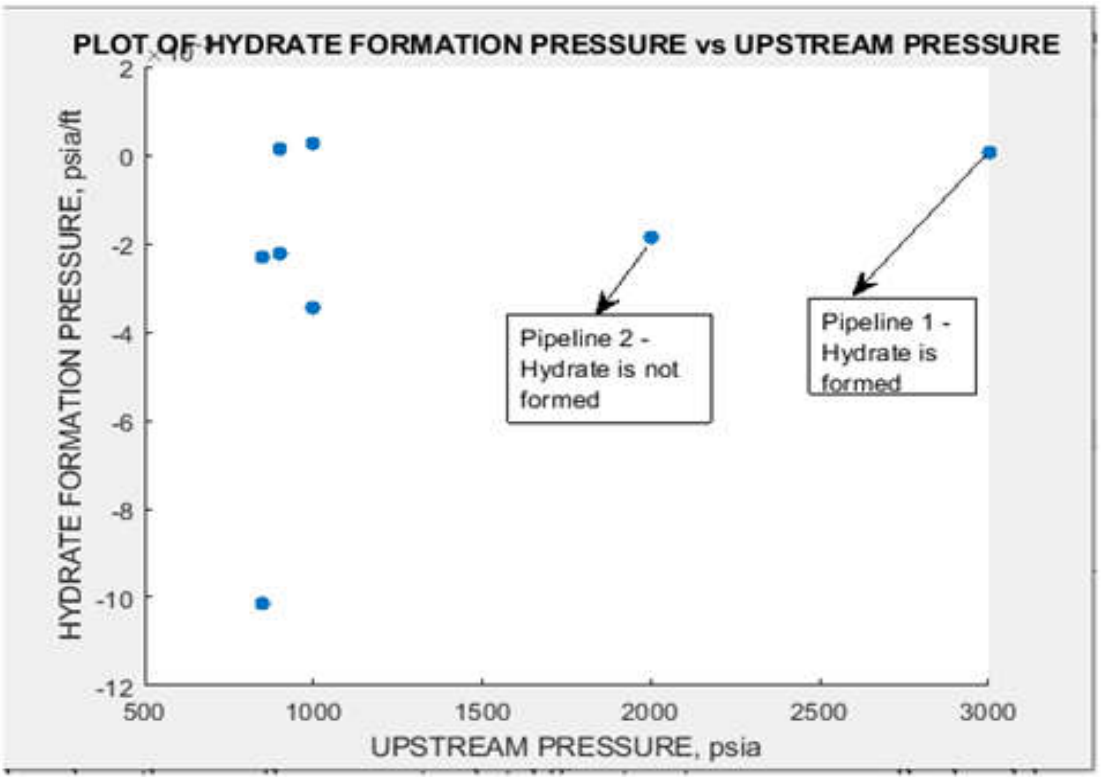

Fig. 3. Hydrate formation pressure versus upstream pressure

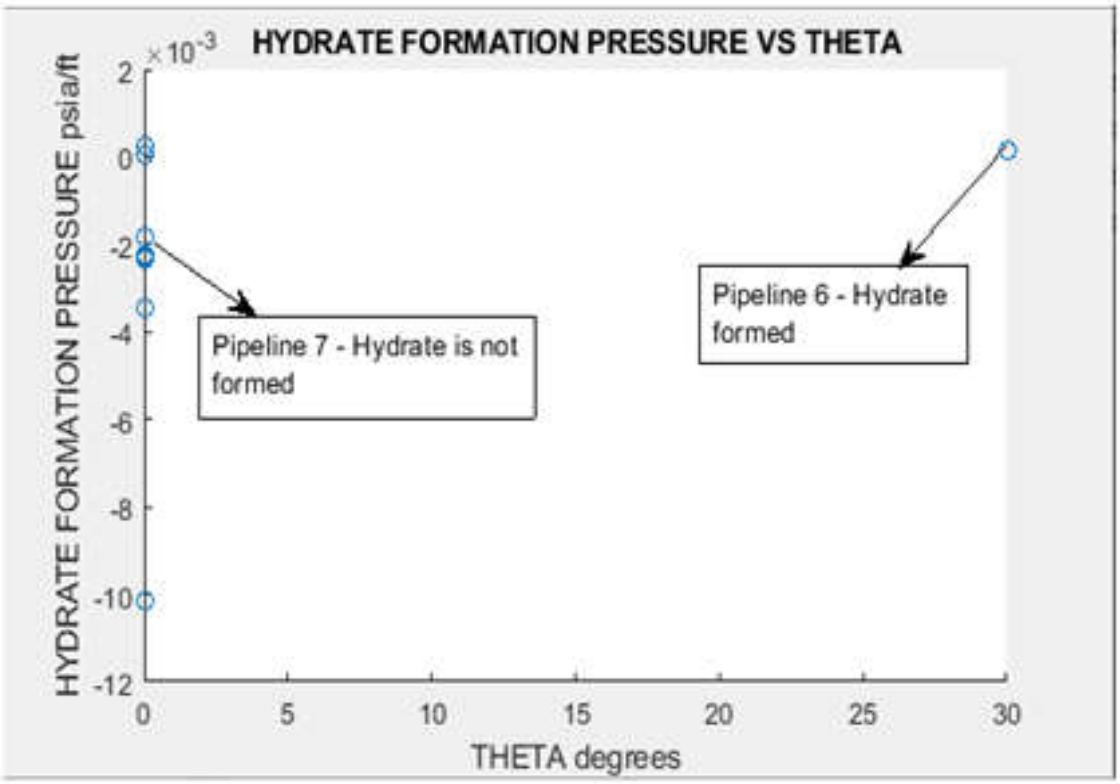

Fig. 4. Hydrate formation pressure versus angle of deviation

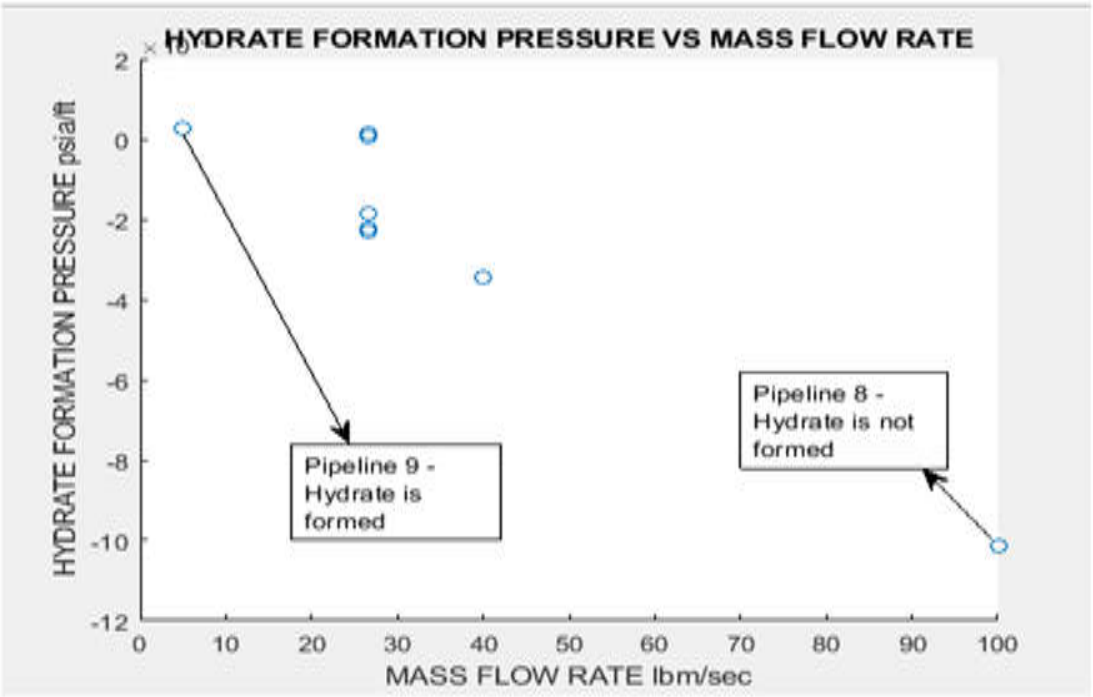

Fig. 5. Hydrate formation pressure versus mass flow rate

4. CONCLUSION

In this work, we made use of analytical method to modified the Navier-Stokes Equation by incorporating gravitational and viscous forces. This developed model was used to determine the pressure known as the Hydrate Formation Pressure (HFP), which was used as a quick-look tool to know "if" hydrate will form or not and the distance (i.e. where) it will form in gas pipelines.

The results of this model compared very much with that obtainable from the field, but with an underestimation. This underestimation is justified because of the robustness of the model obtained, having factored in viscous and gravitational forces. These forces are being overlooked in real field operations. We can easily see that the model input parameters of mass flow rate, volumetric flow rate, theta, upstream and downstream pressures, viscosities, desired length of pipeline and pipeline radius have different or varying effect as well as magnitude on the hydrate formation pressure.

COMPETING INTERESTS

Authors have declared that no competing interests exist.

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