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An Offshore Natural Gas Transmission Pipeline Model and Analysis for the Prediction and Detection of Condensate/Hydrate Formation Conditions

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Summary: *The purpose of this paper is to model and analyze an existing natural gas transmission pipeline – the 24-inch, 5km gas export pipeline of the Amenam-Kpono field, Niger Delta, Nigeria – to determine properties such as pressure, temperature, density, flow velocity and, in particular, dew point, occurring at different segments of the pipeline, and to compare these with normal pipeline conditions in order to identify the segments most susceptible to condensation/hydrate formation so that cost-effective and efficient preventive/remedial actions can be taken. The analysis shows that high pressure and low temperature favor condensation/hydrate formation, and that because these conditions are more likely in the lower half of the pipeline system, remedial/preventive measures such as heating/insulation and inhibition injection should be channeled into that segment for cost optimization..*

I. Introduction

Natural gas is a hydrocarbon mixture consisting primarily of methane CH_4 (70-90% v/v) and other hydrocarbons such as ethane, propane and butane. Non-hydrocarbon impurities such as H_2O, CO_2, N_2, and H_2S can also be found in small amounts [1]. Natural gas is the cleanest fossil fuel and can be used everywhere, from households to high-energy-demand industries [1, 2]. This is the reason natural gas pipeline networks have been developed for the transportation of gas throughout the world. Appendix 1 shows the whole chain of natural gas production, processing, and the transmission and utilization pathways. Transportation usually involves long-distance pipeline, with the attendant danger of condensation and hydrate formation. The adverse consequences of this phenomenon include line blockage, and explosion – which may be accompanied by fire [2, 3, 4].

Thus, accurate measurement of hydrocarbon dew points is of great importance in achieving safe and effective utilization of natural gas pipelines designed for single phase transportation [5,6]. However, since it is not feasible, along a typical long-distance pipeline, to empirically determine segmental variations in pressure, temperature, density, viscosity, etc., we must predict these measurements by applying thermodynamic and conservation principles.

Thus, there follows a model and analysis of an existing natural gas transmission pipeline, which aims to determine properties such as pressure, temperature, density, flow velocity and in particular the dew point, occurring along different segments of the pipeline, so as to compare with normal pipeline conditions in order to identify the segments most susceptible to condensation/hydrate formation, so that cost effective and efficient preventive/remedial actions can be taken.

II. Modeling

For a gas stream at a given pressure, the dew point is the temperature that marks the onset of condensation. Thermodynamically, it is the temperature that satisfies the following relation:

$$\sum Z_i/K_i = 1 \qquad (1)$$

Thus for a gas mixture with composition Z_i, for each component, K_i is the equilibrium constant.
The use of equilibrium constant K values in phase equilibrium analysis, including dew point determination, has been documented extensively. Thermodynamically, it is found from the equilibrium relationship:

$$K_i = \gamma_i P_i^0 / \varphi_i P \qquad (2)$$

Where:
γ_i is the activity coefficient of component i
φ_i is the fugacity coefficient of component i
P_i^0 is the vapor pressure of component i
P is the system pressure

For non-polar hydrocarbon mixtures, such as in this case, γi=1, hence the equation becomes:

$$K_i = P_i^0/\varphi_i P \quad (3)$$

Pi^0 is given in terms of the Antoine equation as:

$$\log P = A - B/(T + C) \quad (4)$$

Sometimes the natural logarithm is used instead of the base-10 logarithm, or Celsius temperature is used instead of Kelvin. A, B, and C are Antoine constants.

The fugacity coefficient of component i in a mixture, φi, is calculated from the equation:

$$RT \ln \phi i = \int_V^{\infty} \left(\left\{ \frac{\partial P}{\partial ni} \right\}_{T,V,nj\neq i} - \frac{RT}{V} \right) dV - RT \ln Zn = \int_0^{p} \left(Vi - \frac{RT}{P} \right) dP \quad (5)$$

where V_i is the partial molar volume of component i in the mixture.

To evaluate equation 5 above requires the knowledge of the PVT behavior of the system in analytical form: the so-called Equation of State (EoS). Usually the cubic Soave-Redlich-Kwong (SRK) and Peng-Robinson (PR) EoS are used [7.8]. The parameters of the equations are shown in Table 1 below:

Table 1: SRK and PR EoS equations/parameters

SRK	PR
$P = \frac{RT}{V-b} - \frac{a}{V(V+b)}$	$P = \frac{RT}{V-b} - \frac{a}{V(V+b)+b(V-b)}$
$a = 0.42748 \frac{(RT_c)^2}{P_c} a(T)$	$a = 0.42748 \frac{(RT_c)^2}{P_c} a(T)$
$a(T) = \left[1 + m(1 - T_r^{0.5})\right]^2$	$a(T) = \left[1 + m(1 - T_r^{0.5})\right]^2$
$m = 0.48508 + 1.55171 \cdot \omega - 0.15613 \cdot \omega^2$	$m = 0.37464 + 1.54226 \cdot \omega - 0.26992 \cdot \omega^2$
$T_r = \frac{T}{T_c}$	$T_r = \frac{T}{T_c}$
$b = 0.08664 \frac{RT}{P_c}$	$b = 0.0778 \frac{RT_c}{P_c}$

In this case, several mixing rules have been employed to depict the parameters a and b of a cubic EoS for mixtures. The traditional Van der Waals one-fluid mixing rules stipulate the parameters of a mixture through the following expressions:

$$a_M = \sum_i \sum_j z_i z_j (a_i a_j)^{0.5} (1 - K_{ij}), .. \quad (6)$$

$$b_M = \sum_i z_i b_i, .. \quad (7)$$

where z_i and z_j represent the mole fractions of components i and j in the mixture and kij is the binary interaction parameter – usually recovered by using the experimental data. For natural gas mixtures, kij=0.

As the traditional van der Waals mixing rules fail to model the excess Gibbs energy over a wide range of pressures, further improvements in the mixing rules are required. The following rules account for this:

(i) Mixing Rules of Huron and Vidal (HV)

$$a = b\left[\sum x_i \left(\frac{a_i}{b_i}\right) + \frac{G^E}{C^*}\right] \quad (8)$$

(ii) The linear combination of Huron-Vidal and Michelsen Models (LCVM)

$$a = bRT\left[\left(\frac{\lambda}{C^*} + \frac{1-\lambda}{q_1}\right)\frac{G^E}{RT} + \frac{1-\lambda}{q_1}\sum_i x_i \ln\left(\frac{b}{b_i}\right) + \sum_i x_i \ln\left(\frac{a_i}{b_i RT}\right)\right] \tag{9}$$

(iii) Predictive Soave-Redlich-Kwong Model (PSRK)

$$a = bRT\left[\sum_i x_i \frac{a_i}{b_i RT} + \frac{1}{A_0}\left(\frac{G^E}{RT} + \sum_i x_i \ln\left(\frac{b}{b_i}\right)\right)\right] \tag{10}$$

In the above relations GE is the excess Gibbs energy; Co and Ao are EOS-dependent parameters. For the PRSV EoS, their values are -0.62323 and -0.64663 respectively. λ is an adjustable parameter that determines the relative importance of the combined rules. Suggested values are 0.36 for the original UNIFAC for low pressure systems, and values in the range from 0.65 to 0.75 for the modified UNIFAC for high pressure systems; b is the same in the above mixing rules as in the van der Waals mixing rule.

In the past, gas pipeline networks were designed based on simple formulas such as Weymouth and Panhandle[10,11], but in recent years, the use of engineering softwares such as PRO II and HYSYS has increased. In general, for the prediction of flow rate, pressure and temperature variation of gas along pipelines, three equations of mass, momentum and energy balance are solved simultaneously. These equations for a pipeline with angle θ from horizontal are as follows[8].

Mass balance equation

$$\frac{\partial \rho}{\partial t} + \frac{\partial(\rho u)}{\partial x} = 0 \tag{11}$$

Momentum balance equation

$$\frac{\partial(\rho u)}{\partial t} + \frac{\partial(\rho u^2 + P)}{\partial x} = -\rho g \sin\theta - 2\frac{f\rho u|u|}{D} \tag{12}$$

Energy balance equation

$$q\rho A dx = \frac{\partial}{\partial t}\left[(\rho A dx)\left(C_v T + \frac{u^2}{2} + gz\right)\right] + \frac{\partial}{\partial x}\left[(\rho A u\, dx)\left(C_v T + \frac{u^2}{2} + gz + \frac{P}{\rho}\right)\right] \tag{13}$$

In the above equations, the density of the real gas can be estimated as follows:

$$\rho = \frac{P}{ZRT} \tag{14}$$

III. Simulation

A range of numerical methods, such as explicit and implicit finite difference, the method of characteristics and the method of lines can be used to solve the equations above. At steady state these partial differential equations are converted to ordinary differential equations, and an initial value method such as Euler or Runge-Kutta can be used for the calculation of pressure and temperature along the pipeline. In HYSYS software, the explicit finite difference method is used for dynamic gas pipeline calculations, while the Euler method is used for steady state gas pipeline calculations. Thus, using the PRO II and HYSYS software, along with the EoS equation and parameters of Table 1 above, equations 1 to 14 are solved with the following inputs(Table 2):

Table 2: Pipeline Parameters

Pipe
Nominal external diameter (mm): 622.2
Nominal wall thickness (mm): 20.7

Profile (Pipe Profile input file)
Elevation (m): 0
Horizontal distance (m): 540
Overall heat transfer coeff (W/m²K): 38.36935
Number of divisions/segments: 30

Operating Conditions
Gas flow rate (MMSCFD): 749.8656
Inlet temperature (°C): 60
Inlet pressure (bar): 147.5
Ambient temperature (°C): 15

Gas Properties
Gas gravity (kg/m³): 0.182
Gas specific heat capacity (J/kg.K): 2170

Compound	Molar mass g/mole	mole %
Nitrogen	28.013	**0.09**
Carbon dioxide	44.01	**0.48**
Methane	16.043	**81.05**
Ethane	30.07	**9.57**
Propane	44.097	**5.38**
Iso-Butane	58.124	**1.30**
n Butane	58.124	**1.36**
Iso-Pentane	72.151	**0.19**
n-Pentane	72.151	**0.33**
n-Hexane	86.178	**0.26**

IV. Results and Analysis

Table 3 below is the output of the simulation showing the pressure, temperature, velocity, density and dew point profiles along the natural gas pipeline.

Table 3: Simulation Results

Pipeline Length (km)	Horizontal Distance (km)	Elevation at node relevant to inlet (m)	Pressure (bar)	Temperature (°C)	Velocity (m/s)	Density (kg/m³)	dew point (°C)
0	0	0	147.5	60	7.69	22.84	19.12849
0.022	0.022	0	147.5	59.33	7.67	22.89	19.06045
0.043	0.043	0	147.5	58.67	7.65	22.94	18.99336
0.065	0.065	0	147.49	58.02	7.64	22.99	18.9272
0.086	0.086	0	147.49	57.38	7.62	23.04	18.86191
0.108	0.108	0	147.49	56.75	7.61	23.09	18.79764
0.13	0.13	0	147.49	56.13	7.59	23.13	18.73432
0.151	0.151	0	147.49	55.52	7.57	23.18	18.67196
0.173	0.173	0	147.48	54.92	7.56	23.23	18.61054
0.194	0.194	0	147.48	54.32	7.54	23.28	18.54902
0.216	0.216	0	147.48	53.74	7.53	23.32	18.48953
0.238	0.238	0	147.48	53.16	7.51	23.37	18.42993
0.259	0.259	0	147.47	52.6	7.5	23.41	18.37239
0.281	0.281	0	147.47	52.04	7.49	23.46	18.31476
0.302	0.302	0	147.47	51.49	7.47	23.5	18.25809
0.324	0.324	0	147.47	50.94	7.46	23.55	18.20136
0.346	0.346	0	147.47	50.41	7.44	23.59	18.14667
0.367	0.367	0	147.46	49.88	7.43	23.63	18.09189
0.389	0.389	0	147.46	49.36	7.42	23.67	18.03815
0.41	0.41	0	147.46	48.85	7.4	23.72	17.98537
0.432	0.432	0	147.46	48.35	7.39	23.76	17.93355
0.454	0.454	0	147.46	47.85	7.38	23.8	17.88166
0.475	0.475	0	147.45	47.37	7.37	23.84	17.83186
0.497	0.497	0	147.45	46.88	7.35	23.88	17.78093
0.518	0.518	0	147.45	46.41	7.34	23.92	17.7321
0.54	0.54	0	147.45	45.94	7.33	23.96	17.68315
0.99	0.99	0	147.41	30.83	6.94	25.32	16.08715
1.98	1.98	0	147.32	23.1	6.73	26.07	15.25238
2.97	2.97	0	147.24	19.14	6.63	26.47	14.8196
3.96	3.96	0	147.16	17.12	6.58	26.67	14.59752
4.95	4.95	0	147.07	16.09	6.56	26.77	14.48387

These values are represented in Figures 1 to 5 below, respectively:

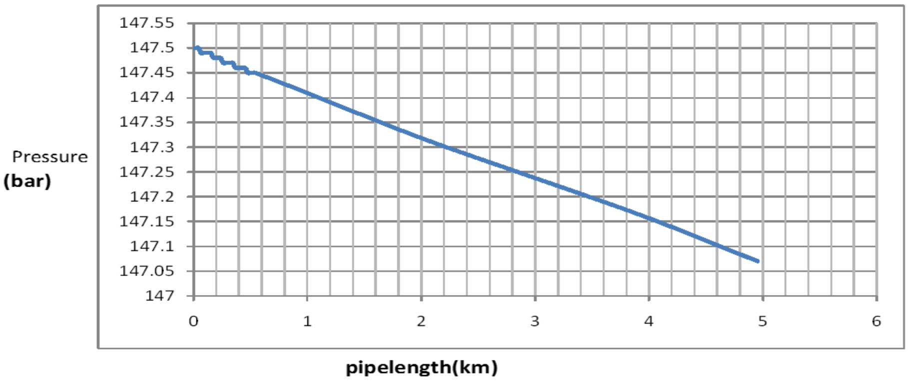

Fig.1: Pressure profile in a natural gas transmission pipeline

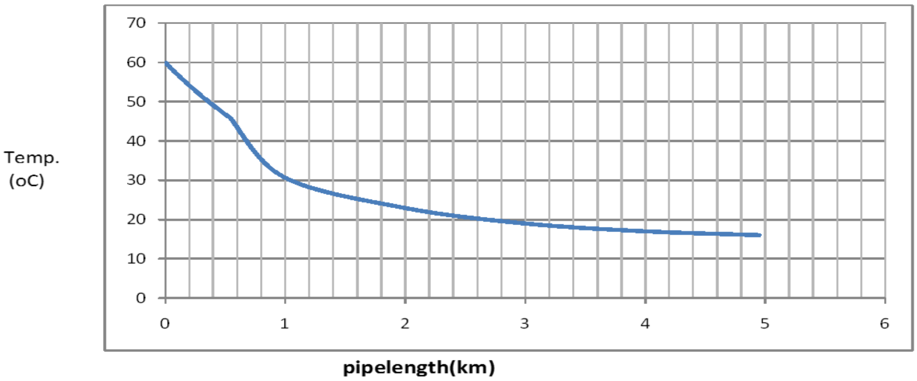

Fig.2: Temperature profile in a natural gas transmission pipeline

s

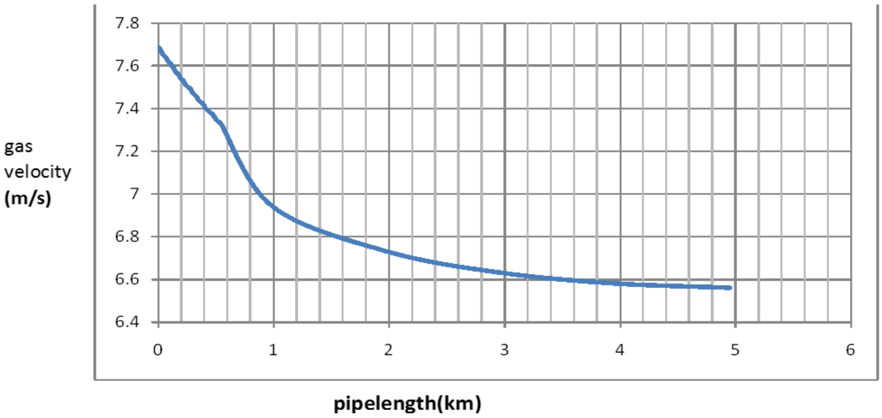

Fig.3: Velocity profile in a natural gas transmission pipeline

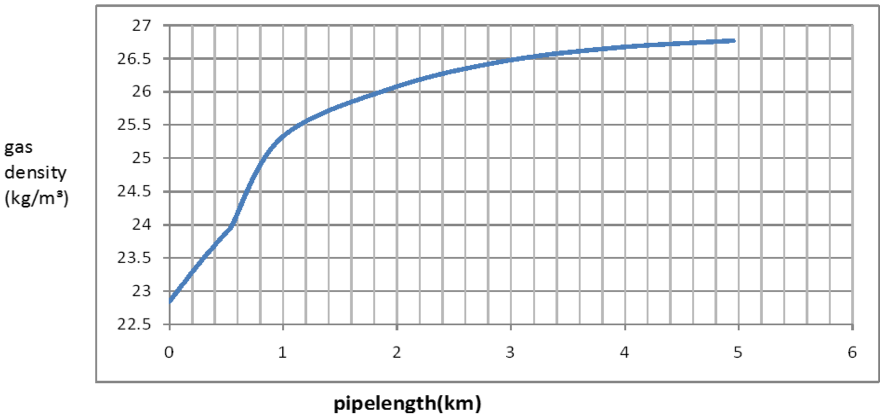

Fig.4: density profile in a natural gas transmission pipeline

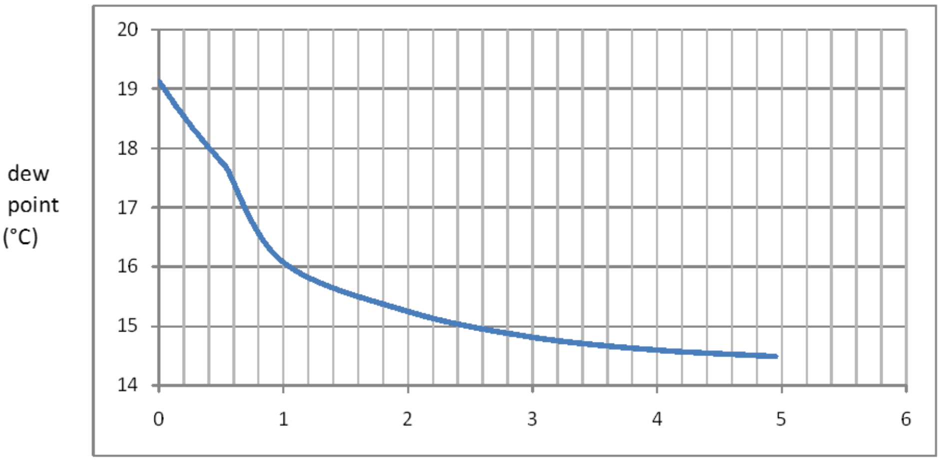

Fig.5: dew point profile in a natural gas transmission pipeline

The figures show that while the pressure, temperature, velocity and dew point profiles decrease with increasing distance of the pipeline from the point of departure, the density increases.
Fig.6 compares the gas temperature and dew point profiles of a natural gas transmission pipeline.

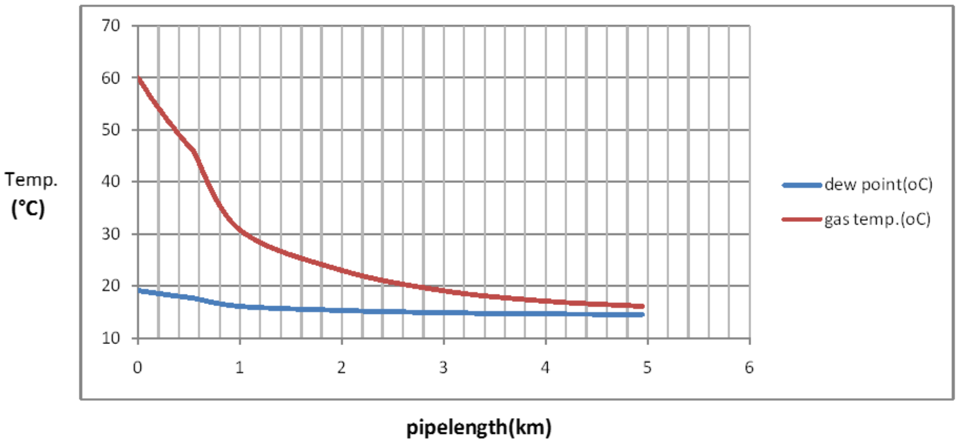

Fig.6: comparative plots of gas temperature and dew point profiles in a natural gas transmission pipeline

This shows that the difference between the two is greater at high temperature regions and less at low temperature regions. This trend was also observed with increasing gas density, as shown in Fig.7:

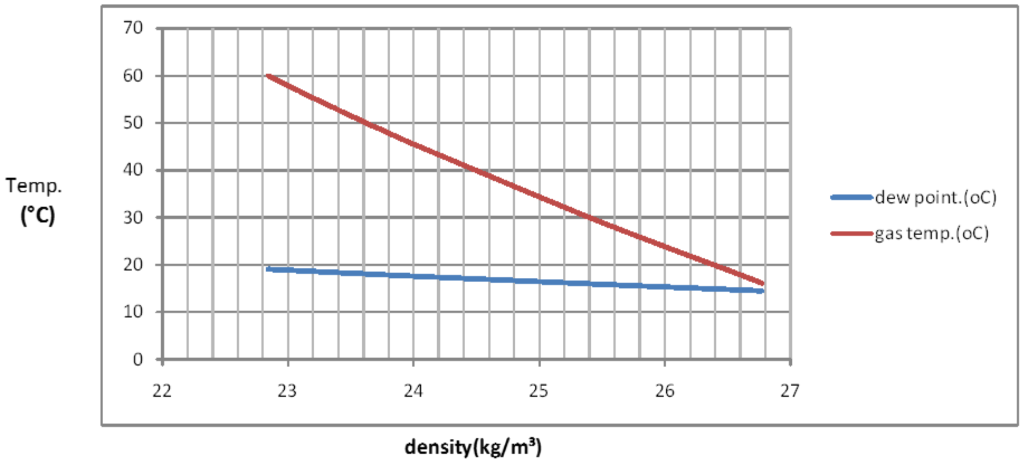

Fig.7: comparative plots of gas temperature and dew point profiles with gas density in a natural gas transmission pipeline

However, in the simulation results (Table 2 above), the pressure variation (max 147.5; min 147.07; range 0.43) is minimal compared to the temperature variation (max 60; min 16.09; range 43.91) which is very pronounced. This analysis shows that high pressure and low temperature favor condensation/ hydrate formation.

V. Conclusion

The above natural gas pipeline analysis can be used as a guide for forecasting condensation/gas-hydrate forming conditions and susceptible locations in long-distance pipelines, with and without inhibitors, and to design remediation and/or prevention schemes such as:

- Increasing the operating temperature, by insulating the pipelines or applying heat;
- Decreasing the operating pressure when possible;
- Adding a required amount of appropriate inhibitor to reduce the dew point/ hydrate-formation temperature and/or increase the hydrate-formation pressure.

For effective results and cost optimization in the case of this specific pipeline, these preventive/remedial actions should be implemented at the midpoint of the pipeline and onward, since this is the point at which gas temperature is close to dew point temperature, signaling the highest likelihood of condensation/hydrate formation.

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Appendix 1: Natural gas production, processing, and transmission and utilization pathways