

Effect of Pressure on CO₂ Corrosion of Pipeline Conveying Hydrate-Prone Natural Gas: A Simulation Approach

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Abstract

Natural gas is most often transported from its production sites to distant locations. To move the gas, pipelines are widely used to convey it to its destination. This is normally done by compressing the gas. Moving gas at high pressure can cause hydrate formation and pipeline corrosion. In this study, a gas pipeline was simulated under operating conditions offshore the Niger Delta to determine the extent to which pressure affects CO₂ corrosion in a pipeline conveying hydrate-prone natural gas. Hydrate formation was simulated using Unisim R380, while the NORSOK M-506 standard model was used to calculate the corrosion rate. The following were considered: the CO₂ corrosion-temperature relationship at different operating pressures; the CO₂ corrosion-temperature relationship at varying wall shear stress; the effect of temperature on CO₂ corrosion at varying operating pressures; and the effect of temperature on mixture viscosity at varying fluid pressure. The results showed that at 78°C, CO₂ corrosion was 4.35 mm/year at a pipeline operating pressure of 60 bar; 5.44 mm/year at 80 bar; and 6.40 mm/year at 100 bar. The study also showed that for temperatures below 78°C, at every incremental wall shear pressure, CO₂ corrosion of the pipeline increased.

Keywords: Pressure; Corrosion; Unisim; Pipeline; Norsok.

1. Introduction

Across the world, due to environmental concerns, there has been a strong drive to reduce the consumption of fossil fuels. Fossil fuels are known to yield, upon combustion, the harmful by-products; carbon dioxide CO₂ and carbon monoxide CO. Carbon dioxide CO₂ is an infrared-active greenhouse gas that causes global warming [1]. Carbon monoxide, on the other hand, is a poisonous gas with up to 250 times the affinity for haemoglobin as oxygen, making inhaling even a very small amount very dangerous for humans [2].

The sustainable alternative sources of energy for powering machines and equipment in this very busy world are the renewables: solar, wind, and hydro. However, renewable energy generators are expensive to build or start compared with their fossil fuel counterparts. The technologies for harnessing renewable energy are also less developed than those for fossil fuels. These economic concerns and technological issues have led to a slow pace of adoption of renewable energy as a primary energy source, especially in developing countries. To move towards an era of clean energy utilisation, a transition period has been created that harnesses a cleaner energy (natural gas) than traditional fossil fuels (petroleum, diesel, coal).

Natural gas, which is either an immediate or semi-finished resource, is used both domestically and industrially [3]. Remarkably, it is estimated that up to 85% of all the natural gas produced is utilised far from where it is produced, hence the need for transportation [4]. Natural gas is commonly transported by compressing it and transmitting it through high-pressure pipelines [5]. Nevertheless, natural gas is also transported using ocean-going vessels and tankers.

One key theme in the pipeline transportation of natural gas is flow assurance. As such, the roles of flow assurance professionals are critical and sensitive in the planning and execution of hydrocarbon field development projects, as flow assurance is a key component of both capital and operational expenditures [6].

Hydrate formation tends to reduce the pipeline flow circumference and, in extreme cases, can cause complete blockage, with implications for pump and separator damage [7]. Hydrate formation leads to a build-up of pressure between the upstream and downstream sides of the hydrate plug [8]. When removing hydrate plugs, if the force acting on a plug exceeds the force holding it to the internal walls of the pipe, the plug may become a projectile [9]. Another problem in the pipeline transportation of natural gas is pipeline corrosion. Corrosion is a challenge for the subsea transportation of natural gas using carbon steel pipelines at high CO₂ partial pressure and a wellhead at high temperature [10].

High pressure, temperature, and gas composition play key roles in both hydrate formation and CO₂ corrosion of natural gas pipelines. For instance, research using NORSOK M-506 showed that CO₂ corrosion increased with increasing CO₂ fugacity, and this behaviour persisted until the temperature reached 79°C [11].

Corrosion can also be caused by acid gases such as H₂S and CO₂ present in natural gas and gas hydrates. When these gases are absorbed into water, the risk of internal corrosion in pipelines that carry them increases [12].

The economic cost of CO₂ corrosion is very high. For instance, in 2014, the cost of CO₂ corrosion to the U.S. production and manufacturing sector was quantified at \$34.4 billion; of this amount, the oil and gas industry accounted for 50% [13].

The relationship between corrosion rate and wall shear stress is linear. Also, the relationship between CO₂ corrosion rate and operational pressure was linear, with the rate increasing with pressure [14]. Interestingly, hydrate chips formed in natural gas pipelines bombard the pipe wall, causing erosion-corrosion [15].

The ability to predict internal corrosion in steel exploration and production facilities with a high degree of accuracy is very useful, especially for Front End Engineering Design (FEED) and for the management and corrosion control of existing facilities [16].

The development and deployment of a predictive model using field or existing laboratory data and theoretical models can be used to assess the CO₂ corrosion rate [17]. To study CO₂ corrosion of pipelines, IFE, in collaboration with oil majors, has used 16 models to assess the validity of their claims and predict CO₂ corrosion. Some of these patented models are: Casandra by BP, Hydrocor by Shell, Multicorp by Ohio University, KSC by IFE [18].

The NORSOK M-506 standard model, an empirical CO₂ corrosion prediction model patented by the Norwegian oil and gas industry, is reputed for providing a good representation of the maximum corrosion rate in a CO₂-corrosion-controlled system. The NORSOK M-506 is very reliable, supported by extensive laboratory data and designed to account for the effect of protective film on the CO₂ corrosion mechanism at higher temperatures and higher pH, more than many other prediction models [19-20].

2. Method

The simulation for hydrate formation for hydrate prone natural gas from offshore Niger Delta transported via pipeline was done, using Unisim R380. On the other hand, the CO₂ corrosion prediction for the natural gas pipeline was performed in MATLAB using the NORSOK M-506 model. Executable scripts were written in the Graphical User Interface (GUI). The sequence of actions taken in this work is given in Figure 1.

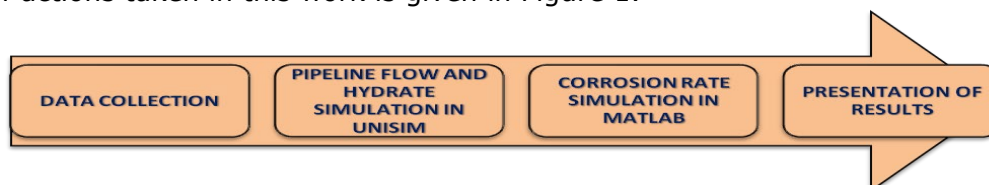


Figure 1. Work flow for the simulation.

Results were exported to EXCEL for graphical representation and visualization. The CO₂ corrosion rate equations for temperatures between 5°C and 150°C are given in equations 1-3, and the input data for the corrosion rate equations are given in Tables 1 and 2.

For T= 5°C:

$$Cr_{CO_2} = K_T * f_{CO_2}^{0.36} * f(pH)_T \quad (1)$$

where: Cr_{CO_2} is the CO₂ corrosion rate, mm/year, K_T is a constant which depends on operating temperature; f_{CO_2} = CO₂ fugacity, mPa; $f(pH)_T$ = a temperature dependent pH function.

For T=15°C:

$$Cr_{CO_2} = K_T * f_{CO_2}^{0.36} * \left(\frac{S}{19}\right)^{0.146+0.0324 \log(f_{CO_2})} * f(pH)_T \quad (2)$$

For temperature range: T≤20°C≤150°C:

$$Cr_{CO_2} = K_T * f_{CO_2}^{0.62} * \left(\frac{S}{19}\right)^{0.146+0.0324 \log(f_{CO_2})} * f(pH)_T \quad (3)$$

$$S = 0.5 \times f \times \rho_m \times U_m^2 \quad (4)$$

where: S= the pipe wall shear stress. Pa; f = the friction factor at the pipe wall; ρ_m is the density of the fluid mixture in kg/m³; U_m is the velocity of the fluid mixture in m/s.

$$f = 0.001375 \left[1 + \left(20000 \frac{k}{D} + 10^6 \frac{\mu_m}{\rho_m U_m D} \right)^{0.33} \right] \quad (5)$$

where: k is the pipe roughness in inches; D is the pipe diameter in mm; μ_m is the viscosity of the fluid mixture in Ns/m².

Table 1. Pipeline operating parameters used in the study.

Parameters	Value
Ambient temperature	20°C
Operating temperature	From 0°C to 150°C
Operating pressure (mPa)	6, 8, 10, 12, ……20
Fluid velocity, m/s	1, 2, 3, 4, 5
Fluid flowrate, MMscfd	5
pH range	3.5 - 6.5
Pipe internal diameter, in	12, 18, 24, 30, 36, 42, 48
Pipe roughness	0.0018 inches

Table 2. Constant K_T at different temperatures.

Temperature (°C)	K_T value (dimensionless)	Temperature (°C)	K_T value (dimensionless)
5	0.42	80	9.949
10	1.59	90	6.250
20	4.762	120	7.77
40	8.927	150	5.203
60	10.695		

3. Results

The results of the gas hydrate formation simulation showed that both type I and type II hydrate formed; this is illustrated in Figure 2. The result of the influence of pressure on CO₂ corrosion of natural gas pipeline conveying hydrate-prone natural gas is here presented as follows.

3.1. Effect of temperature on corrosion rate for varying pressure

The relationship between temperature and CO₂ corrosion rate at different operating pressures of the pipeline carrying a hydrate prone gas is shown in Figure 3. For every increase in the operating pressure of the gas system that was simulated, there was corresponding increase in CO₂ corrosion rate.

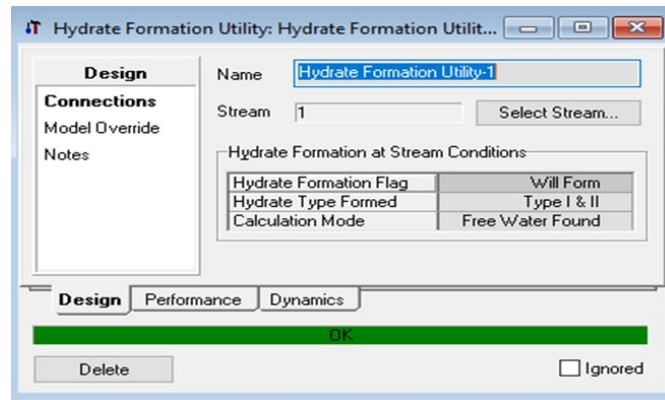


Figure 2. Unisim Design window showing Hydrate formation utility for the gas sample.

Figure 4 shows the effect of temperature on CO₂ corrosion rate for varying wall shear stress at a pH of 3.5. Again, from the result, there is an increase of CO₂ corrosion rate for each incremental temperature, at all wall shear stress the simulation was done, for temperatures below 78°C. It is also clear that CO₂ corrosion rate increased for every increase in wall shear stress. The effect of temperature on density for varying operating pressure is shown in Figure 5. At incremental pressure, density was higher. Generally, the relationship between temperature and density is inverse. The result of the effect of temperature on mixture viscosity for varying fluid pressure is shown in Figure 6. Accordingly, Figure 6 shows that at each pressure, the viscosity of the natural gas reduced when temperature increased. At every incremental pressure, viscosity was higher.

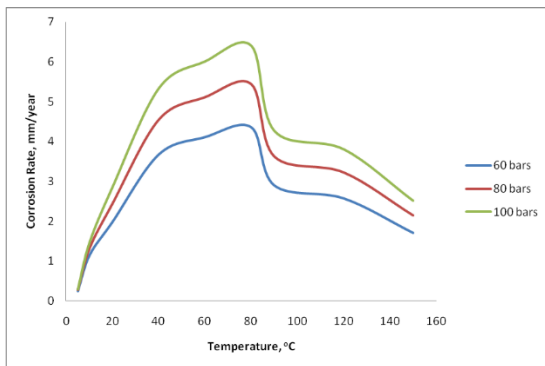


Figure 3. Plot of temperature against corrosion rate for varying pressures.

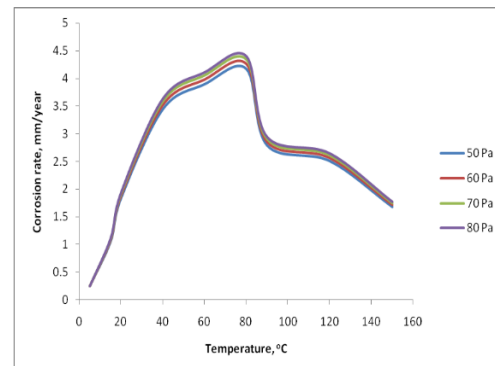


Figure 4. Effects of temperature on corrosion rate for varying wall shear stress at pH=3.5.

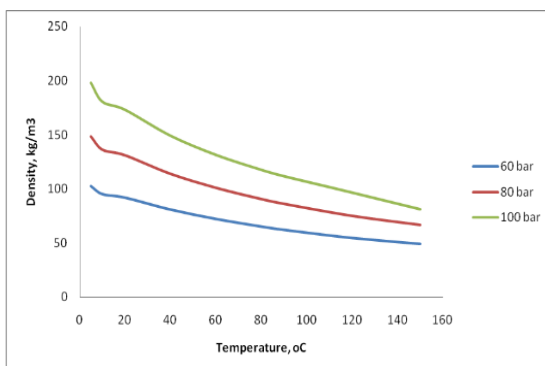


Figure 5. Plot of temperature against density for varying operational pressures.

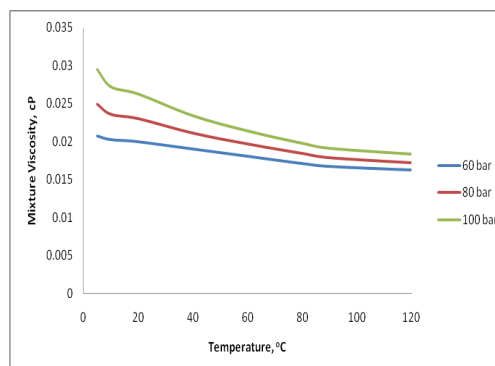


Figure 6. Plot of temperature against mixture viscosity for varying operational pressures.

4. Discussion

The result, as shown in Figure 3, indicates that for every temperature below 78°C, an increase in the pipeline system's operating pressure corresponded to an increase in CO₂ corrosion of the pipeline. At 78°C, CO₂ corrosion was 4.35 mm/year at 60 bar, 5.44 mm/yr at 80 bar, and 6.40 mm/year at 100 bar. The maximum corrosion occurred at 78°C across all pressures for which this study was conducted. This can be understood by applying the theory of protective film formation on the internal walls of the pipeline at a given temperature. The film formed a compact ferrous shield on the pipeline walls against corrosion; hence, the reduction in corrosion activity after 78°C, the temperature at which the film formed.

From Figure 4, the results showed that CO₂ corrosion increased with increasing wall shear stress at temperatures below 78°C. Wall shear stress is either due to residual internal stress within the pipe or to stress applied to the exterior of the pipeline. Wall shear stress can also be attributed to the formation of natural gas hydrate in the pipeline.

Figure 5 shows the relationship between temperature and density for different pressures. As shown, at a given pressure, every increase in temperature led to a decrease in the fluid's density. This can be explained by Charles' Law, which states that at constant pressure, the volume of a given mass of gas is directly proportional to temperature. According to this law, at high temperatures, gas molecules are sparsely distributed, resulting in a lower density.

The gas mixture viscosity temperature relationship for different pressures is shown in Figure 6. Mixture viscosity decreased as temperature increased. This can be explained by the fact that as the temperature of the gas increases, the molecules will stay as far away from each other as possible, but with an increase in pressure, at a given constant temperature, the molecules will be much more closely packed (more viscous), causing them to collide more easily.

5. Conclusion

The results of the simulation study of the effect of pressure on CO₂ corrosion of a hydrate-prone natural gas pipeline show that pressure plays a very big role in CO₂ corrosion. When a natural gas pipeline is operated at higher pressure, the system not only risks the formation of gas hydrate, but also faces the risk of increased CO₂ corrosion of the pipeline. The wall shear stress also impacted on the CO₂ corrosion of the pipeline. For temperatures lower than 78°C, the higher the wall shear stress, the greater the corrosion at a particular temperature. Pressure also impacts on other fluid properties such as viscosity and density: as the pressure increases (at a particular temperature) the higher the viscosity and the density. Of course both mixture density and viscosity are important when considering wall shear stress, while viscosity is critical when considering friction factor.

Nomenclature

°C	Degree Celsius (a temperature scale)
Bar	Unit of measurement of pressure
BP	British Petroleum
C_{rCO_2}	CO ₂ corrosion rate
D	Internal diameter of pipe
f	Friction factor
FEED	Front End Engineering Design
F_{CO_2}	CO ₂ Fugacity
$f(P^H)_T$	function of pH and temperature
GUI	Graphical User Interface
IFE	Institute for Energy Technology
IR	Infrared
k	Pipe roughness
K_T	operating temperature-dependent constant
MATLAB	Matrix Laboratory
Mm	millimeter
m/s	metre per second
MMscfd	Million Standard cubic feet per day

MPa	Mega Pascal (a measurement scale of pressure)
NORSOK M-506	CO ₂ corrosion prediction model
Ns/m ³	Newton's second per cubic metre
Pa	Pascal
P _{CO₂}	Partial pressure of CO ₂
p ^H	Hydrogen potential
S	Wall shear stress
T	Temperature
U _m	Velocity of fluid mixture
Unisim R380	Equation-oriented simulation software package
ρ _m	Mixture density
μ _m	Viscosity of the fluid mixture in Ns/m ²

Credit author statement

George G. Ononien: Conceptualisation, Methodology, Investigation, Writing, Analysis; Nnaemeka Uwaezuoke: Review and Editing; Ifeanyichukwu M. Onyejekwe: Supervision.

Declaration of competing interest

The authors declare that they have no competing financial interests or personal relationships that could have influenced the work reported here.

Data Availability

Gas composition and other simulation data were obtained from an offshore field in the Niger Delta region.

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