IMPACTS OF GAS PIPELINE INTERNAL COATING ON SYSTEM CAPACITY AT GHANA NATIONAL GAS PLANT, ATUABO

by

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DECLARATION

I hereby declare that this project work is my own work towards the award of Professional Masters in Engineering with Management and that, apart from sources acknowledged, this project contains no material previously published by another person nor which has been accepted for the award of any other degree in any institution.

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ABSTRACT

Pipelines play an extremely important role throughout the world as a means of transporting gases and liquids over long distances from their sources to the ultimate consumers. Transmission pipelines are made of steel and generally operate at pressures ranging from 500 to 1,400 pounds per square inch gauge (psig). Pipelines for gas transportation are coated primarily to ensure that the pipeline does not corrode. In addition to anticorrosion, some pipelines are internally lined typically with a liquid epoxy or Fusion Bonded Epoxies (FBE) system to enhance the flow characteristics of the natural gas or oil travelling through the pipeline. The main types of pipeline coatings in use today include coal tar enamel, polymeric tapes, fusion-bonded epoxy (FBE), spray-applied liquid coatings, and two- and three-layer polyolefin coatings.

The main objective of this research was to determine impacts friction and transmission factors of both coated and uncoated pipelines have on flow rates. The AGA and Colebrook-White equations were both used to determine these impacts on system capacity. Using both AGA equations and Colebrook–White equations, it was observed that the coated pipe was able to transport 8.91% and 9.42% more flow rate Q respectively than the uncoated pipe. It is therefore concluded that decreasing the pipe roughness directly results in a throughput or efficiency increase in a pipeline. Thus, smoother pipe surface leads to increased flow capacity.

Internal flow coating can also make a significant difference in reducing pumping or compression costs over the lifetime of the pipeline. These reduced energy costs can provide a financial payback within some years of service. Internal coating of steel pipe is also vital to ensure the long term integrity of the pipeline and reasonable long-term reliability.

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D	=	Pipe diameter (mm)
E1	=	Upstream nodal elevation (m)
E2	=	Downstream nodal elevation (m)
L	=	Pipe length (km)
P1	=	Upstream nodal pressure (Pa)
P2	=	Downstream nodal pressure (Pa)
Pb	=	Base pressure (Pa)
Pave	=	Average pressure (Pa)
Q	=	Flow rate (E3m3/day)
E	=	Elevation correction
SG	=	Specific gravity
Tb	=	Base temperature (K)
Zavg	=	Average compressibility
J12	=	Joule-Thomson coefficient
J	=	Conversion factor (1 Nm/J)
m	=	Mass flow rate (kg/hr)
M	=	Molecular weight (kg/kg-mol)
T1	=	Upstream nodal temperature (K)
T2	=	Downstream nodal temperature (K)
Tavg	=	(T1 + T2)/2 (K)
f	=	Fanning friction factor
Ke	=	Effective roughness (μm)
Df	=	Drag factor
NRe	=	Reynolds number
μ	=	Viscosity (Pas)
R	=	Gas constant
(ROW)	=	Right of Way
AFUDC	=	Allowance For Funds Used During Construction
AGA	=	American Gas Association
FBE	=	Fusion-bonded epoxy
ARO	=	Abrasion-resistant overlay
RTU	=	Remote terminal units
Ke	=	Effective roughness
Ks	=	Surface roughness
Ki	=	Interfacial roughness
Kd	=	Roughness due to bends welds fittings, etc.

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CHAPTER ONE

1.0 Introduction

1.1 Background

In oil and gas production, hydrocarbon is taken from the wellhead manifolds and delivers stabilized marketable products, in the form of crude oil, condensate or gas. The mixture of crude oil, gas and condensate from the well is separated on the surface. The condensate is disposed off and the crude oil and gas are treated, tested, measured and transported. Hydrocarbon among other applications, are used to produce electrical power. In fulfilling the supply of oil and gas for power production and other applications, pipelines are built for transportation from their source of supply to their consumers. These pipelines supported by compressor/pump stations are mostly buried. The pipelines carry billions of cubic meters of natural gas, crude oil and other products to consumers. The selection of piping system is an important aspect of system design in any energy consuming system. The selection issues such as material of pipe, configuration, diameter, insulation, nature and volume of fluid to be transported, the length of pipeline, types of terrain traversed, environmental constraints etc. have their own effects on the overall energy consumption and capacity of the system.

Plate 1.1: Typical gas pipeline

1.2 Natural Gas Production and Transportation

Natural gas exists in wells or reservoirs as non-associated natural gas, associated natural gas or gas-cap natural gas. The non-associated natural gas in a well or reservoir is the gas which does not have any contact with oil. The associated natural gas in a well or reservoir is the natural gas in which the gas is dissolved in the crude oil at the reservoir conditions, and the gas cap natural gas is the gas overlying the crude oil phase in the well or reservoir. According to Obanijesu *et al* (2011), the non-associated natural gas constitute about seventy two percent (72%) of the world-wide reserves, leaving the associated natural gas and gas-cap natural gas compositions of eight point five (8.5%) and nine point five (9.5%) respectively. Natural gas is drilled thousands of meters underground.

In addition to methane, ethane, pentane and butane, natural gas from the reservoirs contain other heavier hydrocarbons in low concentrations. The natural gas in the reservoirs may also be made up of hydrogen, nitrogen, water, carbon-dioxide, hydrogen sulphide, helium, mercury and arsenic. Natural gas transmission system which include primarily of pipelines are connected to transmit the natural gas from the offshore or onshore fields to flow stations for various gas separation processes based on customer composition requirements and finally to the consumers. Offshore natural gas reservoirs are generally deep depending on the depth of the water, which are categorized into shallow or deep offshore waters.

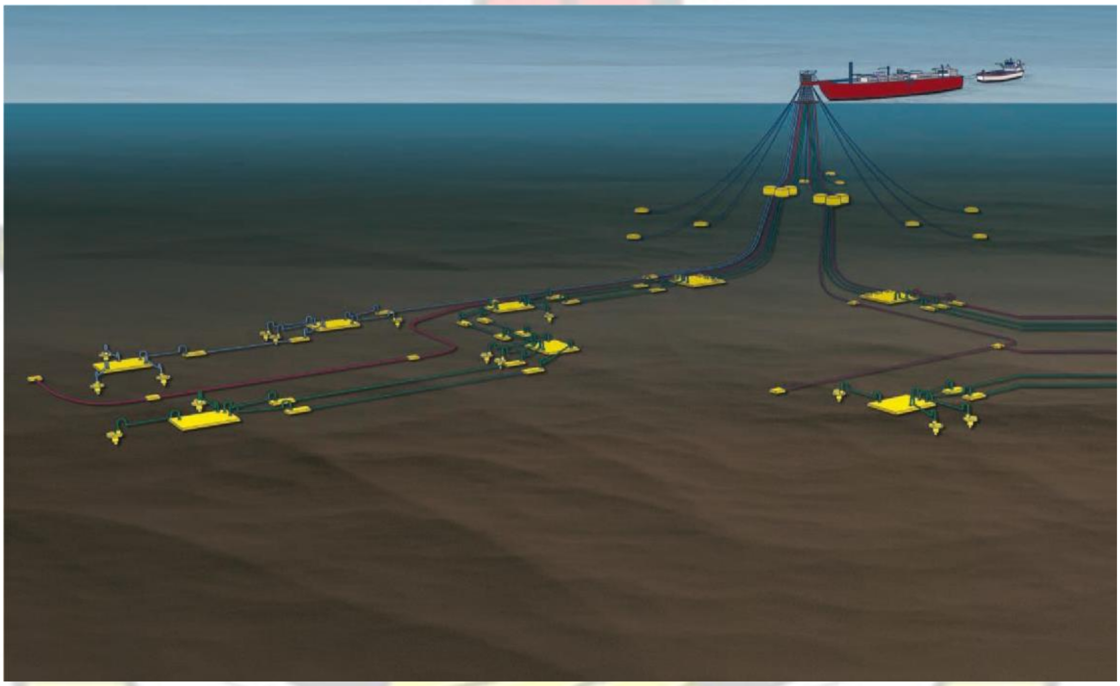

Plate 1.2: Underground reservoirs and pipelines

Generally, pressure differential between the inlet and outlet of the pipelines enable gas to flow through pipes. Frictional and gravitational forces in pipeline systems impact the flow of the gas from one point to another. These forces reduce the pressure or energy of the gas as it moves down the pipe. Compressors are mostly used to overcome these frictional and gravitational forces in the pipes. Compressors help to sustain pressure differential between any point in the pipe and the terminal point and ultimately meet the delivery requirement of the customers. According to Asante (2013a), two main types of compressors are widely used in the natural gas industry: the reciprocating and centrifugal compressors. The reciprocating compressors boost the natural gas pressure by directly reducing the natural gas volume using the displacement actions of its pistons. On the other hand, the centrifugal units increase the natural gas pressure using the double actions of its rotating blades or impellers and velocity reduction of its stationary diffusers.

Pipelines for gas transportation are generally coated to prevent pipe corrosion once buried underground. They are also coated for the purpose of preventing corrosion during storage, hydrostatic testing and construction-induced defects. According to Romano e*t al* (2005 a) pipelines are also internally coated especially with a liquid epoxy or fusion bonded epoxy (FBE) materials to enhance the flow efficiency of the natural gas or oil travelling through the pipeline. Thus, the coating ensures the surface roughness of a coated pipe remain relatively unchanged during its service life. This implies lower operating cost of transmission for the coated pipeline. Internal coatings have also played an important role in resistance against scale formation in oil and gas production and paraffin build up in oil production. Typical pipeline coatings in use today include coal tar enamels, polymeric tapes, fusion-bonded epoxies (FBE), sprayapplied liquid coatings, and two- and three-layer polyolefin coatings.

Plate 1.3 Typical externally coated pipeline

Plate 1.4: Liquid epoxy used for inside pipe

1.3 Problem Definition

Natural gas transmission in pipelines encounters two main flow regimes used to determine, among other factors, the decision to coat the pipeline internal surfaces. They are partially turbulent and fully turbulent regimes. The flow regimes are used to determine the friction factors and consequently the transmission efficiency of the gas. In partially turbulent flow regimes, pipelines do not need internal coating to enhance transmission efficiency because the gas flow rates are not high enough to induce full turbulence. The viscous sub-layer close to the pipe wall surrounds a turbulent core of fluid and this act as a natural protective coat of the pipe internal surface. Drag-inducing components such as girth welds, fittings and bends affect partially turbulent flow behaviour.

Pipelines operating in the fully turbulent regime are suitable for pipeline internal coating. This is because in fully turbulent flow regime, flows are typically high enough to induce complete turbulence across the entire pipe cross-section and consequently, the viscous sub-layer that surrounds the pipe walls are non-existent. The pipe internal surface is exposed. This also exposes the gas to additional drag due to the pipe surface roughness. This phenomenon of fully turbulence and pipe surface roughness affects the efficiency of gas transmission and consequently the system capacity. The impact of coating the internal surface of the pipeline on system capacity will be determined.

1.4 Research Objectives

The overall objective of this research is to determine the impact that pipeline internal coating has on the system capacity.

Specific Objectives

The following are the specific objectives to be achieved by this study:

- Determine the friction factors, of coated and uncoated pipelines
- Determine the transmission factors, of coated and uncoated pipe
- Determine the impact on flow rates, Q

1.5 Justification

- Pipeline flow lining or coating makes a significant impact on the cost of pumping or compression during the lifespan of the pipeline project. The cost or energy savings from reducing pumping or compression cost can be used as a financial payback during the pipeline project lifetime.
- Reducing the compressor stations, size and capacity can also provide some savings. Thus, fuel cost will be reduced along that length of pipeline as compared to the uncoated pipeline of the same pipe length.
- Internal flow lining of steel pipe is very important to ensure the long term integrity of the pipe and reasonable long-term reliability.

1.6 Project Main Outline

This research work has been organized into five main chapters. The introduction gives a brief review of the research topic. It also states the objectives and defines the problems and justification for the study. The literature review discusses the technical and economic parameters to assess the impacts of internally coated pipelines.

In the research methodology, gas pipeline data collected from the Ghana Gas Company Limited is used to evaluate the technical impact of internal coating of gas pipeline on system capacity. The results and findings of the thesis shall be presented and discussed in Chapter Four. Finally in Chapter 5, the overall conclusion and recommendation will be presented.

CHAPTER TWO

2.0 Literature review

2.1 Introduction

In natural gas transmission systems, pipelines and compressor stations constitute important part of the transmission system that supports transportation of large volumes of gas to various destinations. Pipelines are extremely important component of the natural gas transmission system that moves fluids along a long stretch of pipelines from their production point to their customers. According to

Beavers *et al* (2006 a) the first oil pipeline was constructed from Bradford to

Allentown, Pennsylvania in 1879.The pipelines were constructed 175 km in length and 152 mm in diameter. Almost all natural gas and crude oil pipelines have been made of welded steel since the late 1920s. In the 1960s, larger diameter pipelines ranging from 32 to 36 in. were built.

2.2 Natural gas transmission system

The transmission system for natural gas is made up of mainly of steel pipes, compressors, city gate stations, and storage facilities used for transporting natural gas via pipelines. Natural gas transmission pipelines typically operate at pressures ranging from 500 pounds per square inch gauge to 1,400 pounds per square inch gauge

(psig).The pipelines can measure typically from 6 inches to 48 inches in diameter. Some components of pipeline sections can be made of smaller-diameter pipes (thus, as small as 0.5 inch in diameter). According to Folga (2007 a) the mainline pipelines are usually between 16 inches and 48 inches in diameter and the smaller-diameter pipes (between 6 and 16 inches in diameter) are usually used for gathering, distribution and control–line purposes. Gas transmission pipelines are generally buried in the ground at varying depths.

The depths depend on the local geography along which the pipeline is routed. The pipelines are normally buried at a depth of 2 feet to 4 feet to the top of the gas pipelines.

2.2.1 Compressor Stations

According to (Folga, 2007 b) natural gas is highly pressurized as it is transported through any pipeline. To ensure that the natural gas flowing through any one pipeline remains pressurized, compressor stations which are mounted at specified interval along the pipeline, compress the natural gas periodically. The compressors are typically mounted 40 miles to 100 miles interval along the length of the pipelines. Turbines, motors or engines compressed the natural gas as it enters the compressor station.

2.2.2 Metering Stations

Metering stations like in many other metering systems are mounted at specified locations along the natural gas pipelines. According to Folga (2007 c) the metering stations enable local distribution companies or organisations to essentially measure the flow of gas along the pipeline and tracking the gas as it is transmitted or transported along the pipeline. Specialised metering equipment is employed to measure and track the natural gas as it is transported along the pipeline without impeding its flows.

Plate 2.1 Typical Metering Stations

2.2.3 City Gate Stations

According to (Folga, 2007 d) the natural gas is fed through one or more city gate station received from the transmission pipeline. The primary function of the city gate stations are for metering or controlling the gas flow rates and its pressure from the transmission pipelines through the city gate stations and maintaining the required pressure and flow rates in the distribution systems.

2.2.4 Valves

Pipelines include a great number of valves along their entire length. They are usually opened and allow natural gas to flow freely, but they can be used to stop gas flow along a certain section of pipe for emergency shutdown and maintenance.

Plate 2.2 City Gate Gas Measurements and Regulation Station

2.2.5 Pig Launching and Receiving Facilities

Pigging facilities consist of pig launching or receiving equipment and allow the pipeline to accommodate high-resolution internal inspection tools. According to (Folga, 2007e) a pig is an equipment or device that is inserted into a pipeline using launchers and receivers to clean the internal surface of the pipeline. A pig is also used to study or monitor the activities occurring in the pipeline and external condition.

2.2.6 SCADA Centres

To account for the gas that is transported along the potentially lengthy pipeline, sophisticated control systems (SCADA) are mounted on the pipeline network at required positions to monitor the gas transmission and to ensure the end users receive timely supply of the product. According to (Folga, 2007 f), these systems are essentially sophisticated communications systems that take measurements and collect data along the pipeline and transmit the data to the centralized control station. Control and monitoring of the natural gas transmission are carried out using remote terminal units (RTUs) at locations such as pumping or compressor stations, city gate stations, underground storage fields etc. The remote terminal units RTUs collect information from the SCADA equipment which are used to monitor and measure flow rate, pressure, temperature and heat content of the gas and send this information to pipeline engineers. This enables pipeline engineers to quickly react to all equipment malfunctioning and unusual activities.

2.3 Properties of Gas

Gas is a homogenous fluid. Gas easily expands to occupy the space in the container that retains the gas. Gas molecules are spaced farther apart compared with a liquid and, therefore, little changes in pressures and temperatures affect the density of gas molecules more than that of the liquid molecules. Gas, therefore, has higher compressibility than liquid. Hence, gas properties such as density, viscosity and compressibility factors change with change in pressure and temperature.

2.3.1 Density and Specific Gravity

Density of any gas can be referred to as the amount of gas in a specified volume. Density, therefore, is measured in mass per unit volume. Specific gravity of a gas, also known as gravity, is a measure of how heavier the gas is compared to air at a particular temperature. Specific gravity of a gas can also be termed as the relative density. Relative density of a gas is expressed in terms of the ratio of the gas density to the density of air. This is dependent on the gas composition. The heavier hydrocarbons contribute significantly to the overall specific gravity of the mixture (Menon, 2005 a).

2.3.2 Viscosity

The viscosity of a fluid is defined as its resistance to flow. According to Menon (2005 b) viscosity can also be described as the internal friction among the gas molecules that resist movement or flow. It varies with temperature, density and pressure. The higher the viscosity of the gases, the more resistant the gases flow in pipelines. Gas viscosity, though has a small number than liquid, the gas viscosity has important components in determining the nature of flows in pipelines.

2.3.3 Reynolds Number and Velocity

The Reynolds number is a dimensionless term or parameter used to categorise flow regimes in pipes. Reynolds numbers depend on the flow rate, pipe internal diameter, gas viscosity, temperatures, and pressures. The velocity of gas flows in pipelines refer to the speed at which the gas molecules travel from one point to another. The highest velocity of gas molecules will be at the downstream end, where the pressure is the lowest. Conversely, the lowest velocity will be at the upstream end, where the pressure is highest. Generally, the flow rate is inversely proportional to the square root of the gas gravity (Menon, 2005 c).

2.3.4 Compressibility factor

The compressibility factors of a gas refer to correction factors which account for deviation from ideal behaviour for the pressure-volume-temperature relationship of real gases. Compressibility factors are dimensionless quantities which are independent of the masses of the gases but varies significantly with pressure, temperature and composition of the gases. The compressibility factors could be determined from the

Real Gas Law as: $Z = PVnRT$ or more accurately from thermodynamic equations of state such as the Benedict-Webb-Rubin-Starling (BWRS) equation of state (Asante, 2013 b).

2.4 The General flow equation

The steady-state isothermal flow equation in a gas pipeline is the basic equation for relating the pressure drop with flow rate (Menon, 2005 d).The general flow equation was derived from a general energy balance taken from fluid moving through a pipeline under steady-state flow and thermodynamic equilibrium conditions. The steady-state isothermal flow equations correlate three important design variables: flow rate, pressure drop and pipe diameter. The choice of a particular flow equation has a direct impact on the facility requirements (Asante 2013 c).The equation is commonly expressed in terms of flow rate, pressure, pipeline internal diameter, gas properties and temperature as follows:

$$Q = C\left[\frac{P_1^{\,2}-P_2^{\,2}-E}{GLTZ}\right]^{0.5} D^{2.5}\sqrt{\frac{1}{f}}$$ ....Equation 2.1

$$Q_b = C_1\frac{T_b}{P_b}\sqrt{\frac{1}{f}}\left[\frac{P_1^{\,2}-P_2^{\,2}-E}{GLTZ}\right]^{0.5} D^{2.5}$$ ....Equation 2.2

Where;

$$\sqrt{\frac{1}{f}} = 4\,log_{10}\left[\frac{3.7D}{K_e}\right]$$ ....Equation 2.3

2.4.1 Gas Flow Regimes

Two main flow regimes are generally encountered in natural gas transmissions. These are partially turbulent and fully turbulent gas flow regimes. In partially turbulent flow regime, a viscous sub-layer close to the pipe wall surrounds a turbulent core of fluid (Figure

2.1), and this acts as a natural coat protecting the internal pipe surface. This according to Asante (1993 a), the pipe surface roughness has negligible effect on flow behaviour. Draginducing components such as girth welds, bends, fittings, etc. affect partially turbulent flow behaviour.

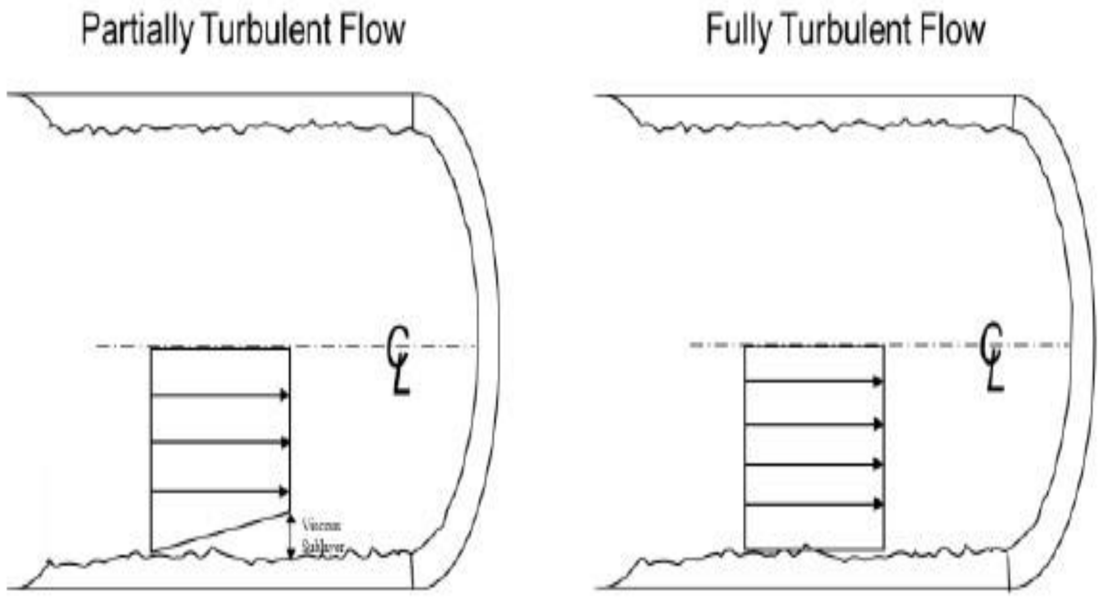

Figure 2.1 Turbulent flow regimes in gas transmissions

Where CL – centre Line

In fully turbulent flow regime, pipelines are affected by both the pipe surface roughness and the drag inducing forms. Gas transmission in fully turbulent flow regimes is typically high enough to induce complete turbulence in the entire pipe cross section. No viscous sub-layer exists close to the pipe wall. (Asante, 1993 b).The pipe wall are exposed and the gas stream experience drag along the pipe due to the pipe surface roughness. In the fully turbulent regime, effective roughness of transmission reflects the frictional resistance of the pipe wall and the drag-inducing elements. The effective roughness could be represented as:

Ke = Ks + Ki + Kd..Equation 2.5

.

2.4.2 Friction factor

This is a dimensionless parameter that depends on the Reynolds number of flow. In a turbulent flow regime, it is a function of the Reynolds number, inside diameter, and surface roughness of the pipeline. Researchers have put forth many empirical formula or relationships for determining the friction factor and the more commonly used relationships are the Colebrook-White and American Gas Association AGA equations. The AGA equation is the standard equation recommended for hydraulic analysis. AGA provides the best fit to the operating data for both the partially turbulent and fully turbulent flow regimes. The Colebrook-White equation shows lower transmission factors than the AGA equation and consequently predicts higher pressure drops (Menon, 2005 e).

2.4.3 Colebrook-White equation

The Colebrook-White equation is a correlation between the friction factors, pipe inside diameters, pipeline surface roughness and the Reynolds number.

$\frac{1}{\sqrt{f}} = -2 \log_{10} \left(\frac{e}{3.7D} + \frac{2.51}{Re\sqrt{f}}\right)$ for Re > 4000…………………..........Equation 2.6 In determining the friction factor f in equation 2.6, we must use a trial-and-error method since f appears on both sides of the equation. We first assume a value of *f* and substitute it in the right-hand side of the equation which will yield a second approximation for *f*, which can then be used to calculate a better value of *f*. For smooth pipelines in turbulent flow in Colebrook Equation 2.6, the first term within the square brackets is negligible compared to the second term. Hence, for smooth pipes in turbulence flow, the friction factor equation becomes:

$$\frac{1}{\sqrt{f}} = -2\ \mathrm{Log}_{10}\left(\frac{2.51}{Re\sqrt{f}}\right) \quad \text{...Equation 2.7}$$

In a similar manner, for fully rough pipelines in turbulent flow in the Colebrook Equation 2.6, having Reynolds number *Re* being a large number, *f* depends largely on the surface roughness *e*. Hence, the friction factor equation becomes:

$$\frac{1}{\sqrt{f}} = -2\ \mathrm{Log}_{10}\left(\frac{e}{3.7D}\right) \quad \text{...Equation.2.8}$$

2.4.4 American Gas Association (AGA) Equations

The American Gas Association AGA equations are used to determine transmission factors F for natural gas pipes, and substituted in the gas flow equation. Two different equations are used to determine the Transmission factors F. Firstly, the transmission factors F are determined for rough-pipe law. For high gas flow rates, where turbulence is fully developed, theory and experiments have shown that the friction factor is independent of flow rate. Thus friction factor is a function of relative roughness only, D/ke. For the AGA fully turbulent flow equation, however, the roughness is defined as the effective or operating roughness. Thus as opposed to the rough-pipe law, where k is defined as absolute roughness and reflects only the internal condition of the pipe wall, the fully turbulent relationship reflects the composite effect of the internal roughness and roughness induced by drag forms such as bends, beads welds, fittings etc.(Menon ,2005 f). The fully turbulent flow equation is expressed as:

$$Q_b = 38.77\frac{T_b}{P_b}\left[\frac{P_1^2 - P_2^2 - E}{GLTZ}\right]^{0.5} \left[4\ \log\frac{3.7D}{k}\ \right] D^{2.5} \quad \text{...Equation 2.9}$$

Where;

Ke is the effective roughness.

Secondly, the transmission factors F are determined for smooth pipe law. For turbulent flow at low gas flow rates, the friction factors are dependent on the Reynolds's number; and for high flow rates the friction factors are functions of the relative roughness of the pipelines. For partially turbulent flows, the friction factors are constant multiples of that for the Smooth-Pipe Law. The constant of proportionality is a function of the drag factor, Df, and it reflects the contribution to frictional pressure loss of the fittings, bends, welds, beads, terrain etc. in the pipeline system. The drag factor varies typically from 92% - 98% depending on the number and degree of the draginducing elements. The friction factor equation for partially turbulent flow is an implicit expression (Menon, 2005 g). When substituted in the general flow equation, the partially turbulent flow equation is obtained:

$$Q_b = 38.77\frac{T_b}{P_b}\left[\frac{{P_1}^2-{P_2}^2-E}{GLTZ}\right]^{0.5}\left[4\log\frac{Nre}{1.4\sqrt{1/f}}\right]D^{2.5}$$

........................Equation 2.10

2.4.5 Reynolds number of flow

The Reynolds number is used to define the type of flow in a pipeline. The flow types are laminar, turbulent and critical flow. Reynolds number of a flow is a nondimensional parameter applied to determine the friction factors in pipe flows. Reynolds number is a function of flow rates, pipe internal diameter, gas density and viscosity.According to Menon (2005 h) most natural gas pipelines operate in the turbulent flow regions. Turbulent flows in pipelines are categorised into three main regions or regimes as: Turbulent flows in rough-pipes, Turbulent flows in smooth-pipes and Transition flows. In smooth pipe flows, the friction factors depend only on the Reynolds numbers. Friction factors in fully rough-pipes depend largely on the pipe surface roughness and very little on the Reynolds number. Friction factors in the transition flows or zones (thus flows between smooth pipes and fully rough pipes) depend on the pipe diameter, surface roughness and Reynolds numbers.

Relative roughness of a pipeline is a dimensionless term which is calculated as a ratio of the absolute pipe roughness (e) and the pipe inside diameter (D) as follows: Relative roughness = e/D

2.4.6 Transmission factor

The transmission factor F, according to Menon (2005 i) can be described as the direct measure of how much gas can be transported or transmitted through the pipeline. The transmission factor is inversely proportional to the friction factor. Thus as the friction factor increases, the transmission factor decreases and the gas flow rate also decreases. In other words, the higher the transmission factors of the gas, the lower the friction factors and, therefore, the higher the flow rate. The transmission factor F of a gas is correlated with the friction factor *f* as follows:

$$F = \frac{2}{\sqrt{f}}$$

Where f = friction factor

F =transmission factor

$$f = \frac{1}{F_f}$$

Where f_f is the Fanning friction factor

2.5 Pipe-Coating Materials

The nature of pipeline surface affects the longevity and reliability of sub-sea and buried oil and gas pipelines throughout the world. As a result, the pipelines are designed and constructed with an external corrosion resistant coating and protected simultaneously with an effective cathodic protection system (Guan *et al, 2005).*In addition to corrosion prevention, gas pipelines are internally coated to increase the flow rate of the gas or oil transported through the pipeline**.** Coatings materials vary significantly in their long-term performance. In the olden days, steel pipelines were coated with specialized coal tar enamel but currently steel pipelines are coated with a fusion bonded epoxies FBE or extruded polyethylene materials simultaneously with cathodic protection system. Cement Lining and epoxy systems are two commonly used internal coating systems. Two commonly used external coatings systems are Fusion bonded epoxy and three layer polyolefin according to Varughese Kuruvila (Internal and External coatings for water transportation pipelines).

2.5.1 Liquid Epoxies

Liquid Epoxies are pipeline coating systems used basically on larger-size pipes when the epoxies should provide better resistance to required temperature or the conventional pipe coating systems may not be available. Generally, liquid epoxies contain an amine or a polyamide curing agent. In the coal-tar epoxies, coal-tar pitch is added to the epoxy resin. A low-molecular–weight amine is used to cure the coal-tar epoxy and this helps to make it resistant to an alkaline environment especially on a cathodically-protected structure (Beavers *et al*, 2006 b).

Steel pipes that are internally coated using epoxy-based liquid are basically done to improve the fluid transmission by reducing the surface roughness of the pipes. It is also done to offer anticorrosive protection in the pipelines. The surface of the pipeline is thoroughly cleaned. The epoxy-based paint is used on the cleaned pipe's inner surface using an airless guns system. Typically, the thickness of the internal coating system for a pipe ranges from 60 and 100μm for gas transportation pipelines (Socotherm, 1999 a).

Plate 2.4 Liquid Epoxies

2.5.2 Concrete Weighting Coating

Concrete weighing coating was developed to offer an economical form of internal corrosion and abrasion protection for oilfield tubular and line pipes. Concrete mortar lining is used primarily in water injection and disposal lines (Hactfeld, 2015 a). Mortar linings have the longest history of use in offering protection against corrosion in in wrought irons or steel pipes. The alkalinity of the concrete mortar lining CML enhances the production of protective iron oxide layers or films on the steel pipelines. Generally, external applications are used over corrosion-resistant coatings for armour protection (Beavers *et al*, 2006 c).The CML consists of a mixture of sand, plus gravel or iron ore, cement and water in the right proportions. The CML is applied directly to the pipe surface and a wire mesh is simultaneously applied to offer reinforcement. To ensure suitable curing, a film of polyethylene is also applied (Scotherm, 1999 b).

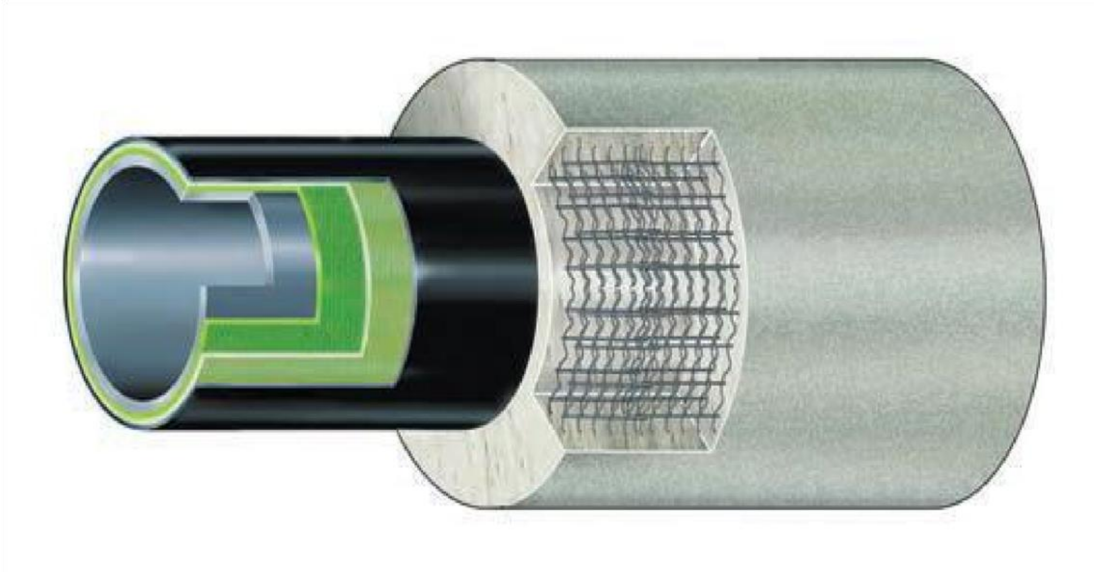

Plate 2.5 Concrete Weighting Coating

2.5.3 Bituminous enamels

According to Beavers *et al* (2006 d) these are obtained from petroleum asphalt or coal-tar pitch. For more than 65 years, bituminous enamels have been used as protective coatings but in recent years the use of enamels has reduced because of health and environmental concerns. There are other accepted alternative products on the market. Bituminous enamel can provide efficient long-term corrosion protection in pipelines when correctly selected and used. Enamel coating is affected by both hydrocarbon and ultraviolet light from the sun. Enamel coating must be white-washed to protect it.The use of a barrier coat is recommended for protecting the enamel when known contamination exists.

2.5.4 Asphalt mastic

Asphalt mastic pipe coating is made of a dense mixture of components such as crushed limestone, sand and fibre bound together with select air-blown asphalt. It has been used for over 50 years. The asphalt mastic materials are available with various types of asphalts. The selection of the mastic materials is dependent on operating temperatures of the materials and climatic conditions to obtain optimum operating characteristics. The mastic coating is dense that results in seamless corrosion coating. A suitable operating temperature for the asphalt mastic systems ranges from 4.4 to 88 degrees Celsius. Asphalt mastic coatings are affected by both ultraviolet rays and hydrocarbon. The asphalt mastic is white-washed to protect it from hydrocarbon and ultraviolet light from the sun. The whitewash also protect the asphalt mastic during storage and so the coating material should be applied when in storage. According to Beavers *et al* (2006 e) asphalt mastic materials were not designed to be installed or applied on pipelines above the ground and in environments contaminated with hydrocarbon.

2.5.5 Fusion-bonded epoxy

According to Beavers *et al*, (2006 f), fusion-bonded epoxy (FBE) coatings are heatactivated, chemically cured coating systems and furnished in powdered form. It was introduced in 1959 and was first used as an external pipe coating in 1961. Presently, FBE coatings are most commonly employed in new installations of large-size pipes**.** These coatings are applied to preheated pipe surfaces. Some fusion bonded epoxy systems may require a primer system; others require post heating for complete cure. The fusion bonded epoxy coatings have very good adhesive, physical and mechanical properties. Chemical resistance and flexibility for fusion-bonded epoxies are very high. Fusion bonded epoxies are better resistant to acids, alkalis and hydrocarbons. The benefits of the FBE pipe coatings are that they cannot hide apparent surface deposits or defects; therefore, the steel pipeline surface can be inspected after it has been coated. FBE provides a clean internal surface with corrosion protection for pipelines (Hachfeld, 2015 b).

Plate 2.6 Fusion-bonded epoxy

2.5.6 Tape coatings

According to Beavers *et al* (2006 g), for normal construction conditions, prefabricated cold-applied tapes are employed as a three-layer system consisting of primers, corrosion-preventive tapes (inner layers), and mechanically-protective tapes (outer layers). The functions of the primers are to provide bonding media between the pipe surfaces and the adhesives or sealants on the inner layers. The inner-layer tapes consist of plastic backings and adhesives. These layers are the corrosion-protective coatings; therefore, the layers must provide high electrical resistivity, low moisture absorptions and permeability, and effective bond to the primed steel surfaces. The outer-layer tapes consist of plastic films and adhesives composed of the same types of materials used in the inner tapes or materials that are compatible with the inner-layer tapes. The purpose of the outer-layer tapes are to provide mechanical protections. The outer-layer tapes have been designed and engineered to withstand normal handling, outdoor weathering, storage, and shipping conditions (Beavers *et al*, 2006 h).

2.5.7 Three-Layer Polyolefin

In the 1990s, the three-layer polyolefin pipeline coatings were developed to bond the excellent adhesive nature of Fusion-Bonded Epoxies FBE with the damage resistance of tape wraps and extruded polyethylene materials. The three–layer polyolefin consist of Fusion-Bonded Epoxy primers, intermediate copolymer layers, and topcoats. The topcoat can either be polyethylene materials or polypropylene materials (Beavers *et al,* 2006 i).The intermediate copolymers are used to bond the Fusion-Bonded Epoxy primers with the polyolefin or polypropylene topcoats. Polypropylene materials have higher temperatures than the polyolefin resistance but the polyethylene materials are more expensive. The polypropylene is more expensive because of its raw materials and the requirement for higher temperatures for it application according to Beavers *et al*, (2006 j).

Plate 2.7 Three-Layer Polyolefin

2.5.8 Wax coatings

Wax coating according to Beavers *et al* (2006 k), has been in existent for over fifty (50) years. Wax coatings are currently used on limited bases. Wax coatings typically applied together with protective wrapper or overwraps. The coatings are applied on gas pipelines to serve as waterproof membranes on the pipes, and the overwraps protect the wax coatings from contact with the corrosive substance or soil. The coatings also protect the pipeline from mechanical damage. The most common applications of wax coatings are the over-the ditch. These are done in one operation with a combination equipment that cleans, coats, wraps, and fixes the pipes into the ditch.

2.6 Economic Impact

Beside flow rate and pipe surface roughness, economic analysis is carried out to determine optimum choice between coated and uncoated pipe parameters. Cost of service is used to find the costs incurred in the transportation of the gas or liquid as well as the return on the capital invested.The annual cost of service is calculated for each year of the project. Components of the cost of service include: Capital costs, Operating and maintenance costs, Taxes, and Return on rate base. Using the cost of service components, the two scenarios of coated and uncoated pipeline internal surfaces are compared and the economic impacts are determined. The cost of services difference between coated and uncoated pipelines is primarily the cost of coatings of the pipeline.

2.6.1 Capital and related costs

Capital and related costs are all costs associated with activities necessary to bring a project to a full service or operation. It is the best estimate of the total cost required to put a facility in service. This cost includes the costs of equipment, material, labour, and commissioning. Pipelines, compressors, valve stations and meter stations, telecommunication cost, supervisory control and data acquisition (SCADA) cost, engineering and construction management cost, environmental and permit costs, rights of way (ROW) cost, legal or regulatory costs, Allowance for Funds Used During Construction (AFUDC) and contingency constitute the major elements that make up the initial capital cost in natural gas pipeline system.

Plate 2.8 Pipeline Construction

Also according to Asante (2013 d), the pipeline cost include pipe materials, pipe coatings, pipeline fittings and labour cost. When given the cost per ton of pipeline materials, the total pipeline materials amount can be determined. Actual labour costs are generally obtained from contractors but given the pipeline construction cost per unit length, the actual labour costs for installing the pipeline can be determined. Contractors take into consideration some factors such as the nature of trenching work, installation and back-filling the ditches. The sum of the total pipeline cost and the labour cost is the total pipeline capital cost. Generally, the major costly components of any pipeline capital cost are the pipeline and compressor stations. They constitute the bulk of any pipeline capital cost.

Another major component is the mainline valve stations. These are installed at specified length or sections of the pipelines to isolate the pipes for maintenance, repair and safety reasons. In events of defective pipeline sections, the pipelines are isolated by shutting off the mainline valves on each side of the damaged section. The cost of the mainline valve station at a specified interval is determined by construction contractors.

Metering stations installed on the pipelines are used for measuring the gas flow rate. Components of the metering stations include meters, valves, control and instrumentations. The cost of metering stations can be estimated using materials for the meter station and labour for a particular location. Other components such as pressure regulating stations, environmental and permit costs etc. can be estimated as a lump sum figure per site. The lump sum figure for other components are summed together with the total pipeline capital cost.

According to Asante (2013 e) the environmental and permitting costs involve the costs that enable the project to operate in an environmentally-safe conditions. It ensures the facilities do not damage the ecosystems. These costs may range between 10 and 15% of total project costs. The right of way (ROW) is acquired from private ownership and local government for a fee.

According to Menon (2005 i) engineering costs involve the preliminary and detailed engineering design and preparation of drawings, development of specifications, purchase of document and other associated costs which include material acquisitions. Other costs such as the construction management cost, legal cost, rental facilities, transportation, contingency cost, Allowance for Funds Used During Construction (AFUDC) cost are also very important part of the total pipeline project cost which must be considered.

The Operating and Maintenance (O&M) costs include the administrative and general expenses (A&G), actual operating and maintenance expenses of facilities (field and technical) and fuel costs. It is a recurring annual cost over the service life of the project. Operating and Maintenance cost is a major part of cost of service. A&G expenses relate to payrolls and general and administrative cost. Technical O&M which refers to direct costs associated with the functioning of the facilities (e.g., operating labour and electricity costs of compressor stations). Field O&M relate to indirect costs of facilities (e.g., general upkeep of stations, servicing equipment, line inspection, repairs, inspection of pipeline, permitting, leasing, rental, right of ways, etc.).

CHAPTER THREE

3.0 Methodology

3.1 Introduction

In this chapter, the methods for determining the various objectives stated in the introductory chapter will be presented. The methods shall be grouped into technical and economic. In the technical methodology, the AGA and Colebrook-White equations will be used to determine impacts of pipeline internal coating on system capacity. Cost of service will be used to determine the economic impact. In the economic analysis, the difference between cost of services of coated and uncoated pipeline internal surface is essentially the cost of coating the gas pipeline.

3.2 Case Study at Atuabo, Ghana Gas Development Project

Pipelines in the Ghana Gas Infrastructure Development project is used as case study in determining the impact of pipeline internal coating on system capacity. The onshore pipeline (Fig.3.1) from Atuabo Gas Processing Plant to Takoradi Thermal Power Plant (TTPP) in the Western Region of Ghana used for the case study consists of 111 km of 20-inch diameter mainline. The Gas Processing Plant supplies the mainline with 150 MMScfd of gas to Takoradi Thermal Power Plant. The onshore pipeline also entails 75 km of 20-inches diameter pipeline from Essiama to Prestea, also in the Western Region of Ghana (Ghana Gas Company, 2013).

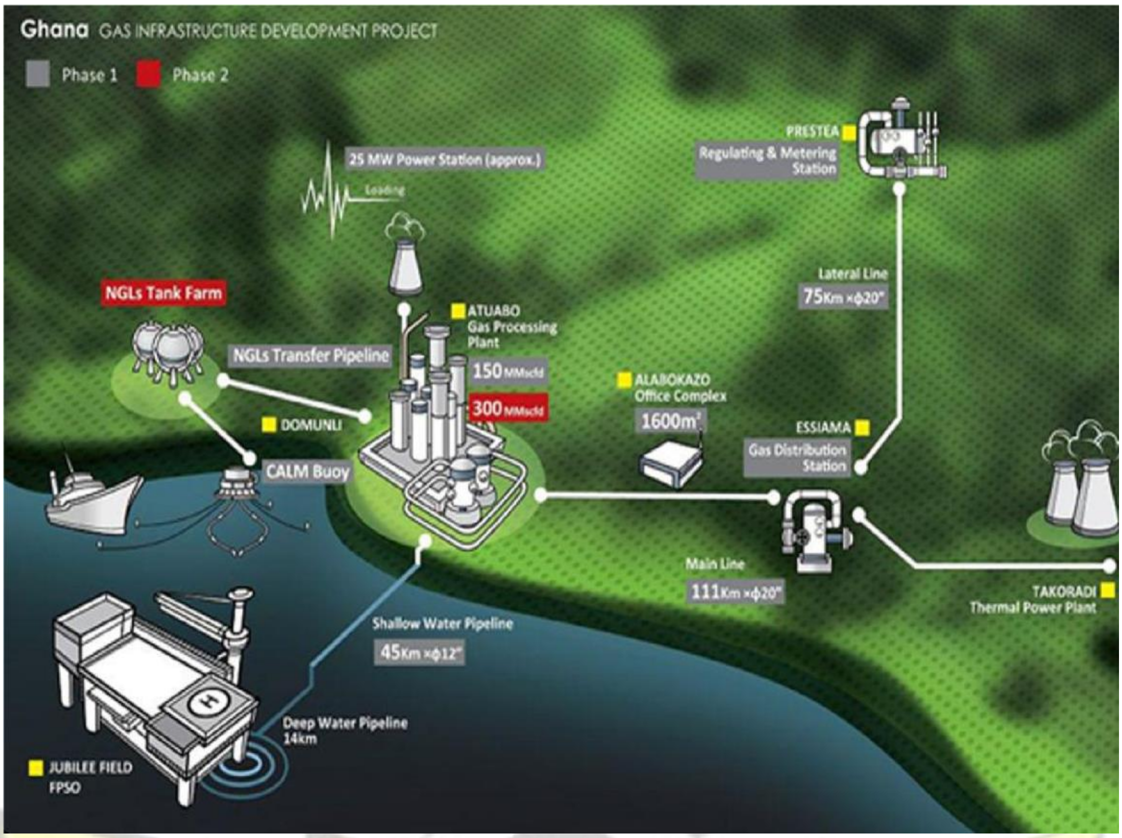

Plate 3.1: An Illustration of the Gas Infrastructure Project (Ghana Gas project)

3.3 Technical Analysis

The general steady-state isothermal flow equation in a gas pipeline is given by:

$$Q_b = C_1 \frac{T_b}{P_b} \sqrt{\frac{1}{f}} \left[\frac{P_1^{\,2} - P_2^{\,2} - E}{GLTZ}\right]^{0.5} D^{2.5}$$ ……………………………………………Equation 3.1

Using Nikuradse's Rough-Pipe equation given by:

$Q_b = 38.77\frac{T_b}{P_b}\left[\frac{P_1^2-P_2^2-E}{GLTZ}\right]^{0.5}\left[4\log\frac{3.7D}{k}\right]D^{2.5}$, flow rate for the uncoated pipeline can be determined.

Nikuradse's Rough-Pipe equation states that the friction factor is a function of the cross-sectional area of flow only. Thus, it depends on the relative roughness of the pipe (ratio of diameter to surface roughness) and not on the fluid properties or flow rate. The rough pipe equation predicts ideal fluid behaviour in the fully rough flow regime. The absolute roughness, k, should be defined in terms of an effective (or operating) roughness before the rough pipe equation could be applicable to real systems.

Prandtl-von Karman smooth–pipe equation given by:

$Q_b = 38.77\frac{T_b}{P_b}\left[\frac{P_1^2-P_2^2-E}{GLTZ}\right]^{0.5}\left[4\log\frac{Nre}{1.4\sqrt{1/f}}\right]D^{2.5}$, is used to determine the flow rate for coated pipeline scenario.

The Prandtl-von Karman Smooth-Pipe equation states that the friction factor is dependent on the Reynolds number alone. A viscous sub-layer is usually formed on the wall which surrounds a turbulent core of gas. The smooth pipe equation reflects ideal conditions only and drag factors are used with the smooth pipe equation to predict fluid behaviour for actual pipeline systems operating in the partially rough flow regime.

3.4 Economic Analysis

Cost of service is used to find the costs incurred in the transportation of the gas or liquid as well as the return on the capital invested. It is used to determine the economic impact of pipeline internal coating. Components of the cost of service are capital and related costs, Operating and maintenance costs, Taxes, and Return on rate base. Adding all the individual factors together provides the annual cost of service (COS):

COS = (Capital Cost + OM + Taxes +Rate of Return)……..........................Equation 3.2

The difference between the cost of services of coated and uncoated pipelines is the primarily the cost of coating the pipelines. The internal surface of steel pipelines is coated using epoxy–based liquid.

CHAPTER 4

4.0 Results and Analysis

4.1 Introduction

Using the mainline from the gas processing plant at Atuabo to the Takoradi Thermal Power Plant (TTPP) in the Western Region of Ghana, gas is transported through the pipeline of length 111 km and diameter 20 inches. The gas plant processes 150 MMScfd of gas.

4.2 Case Studies – Technical analysis

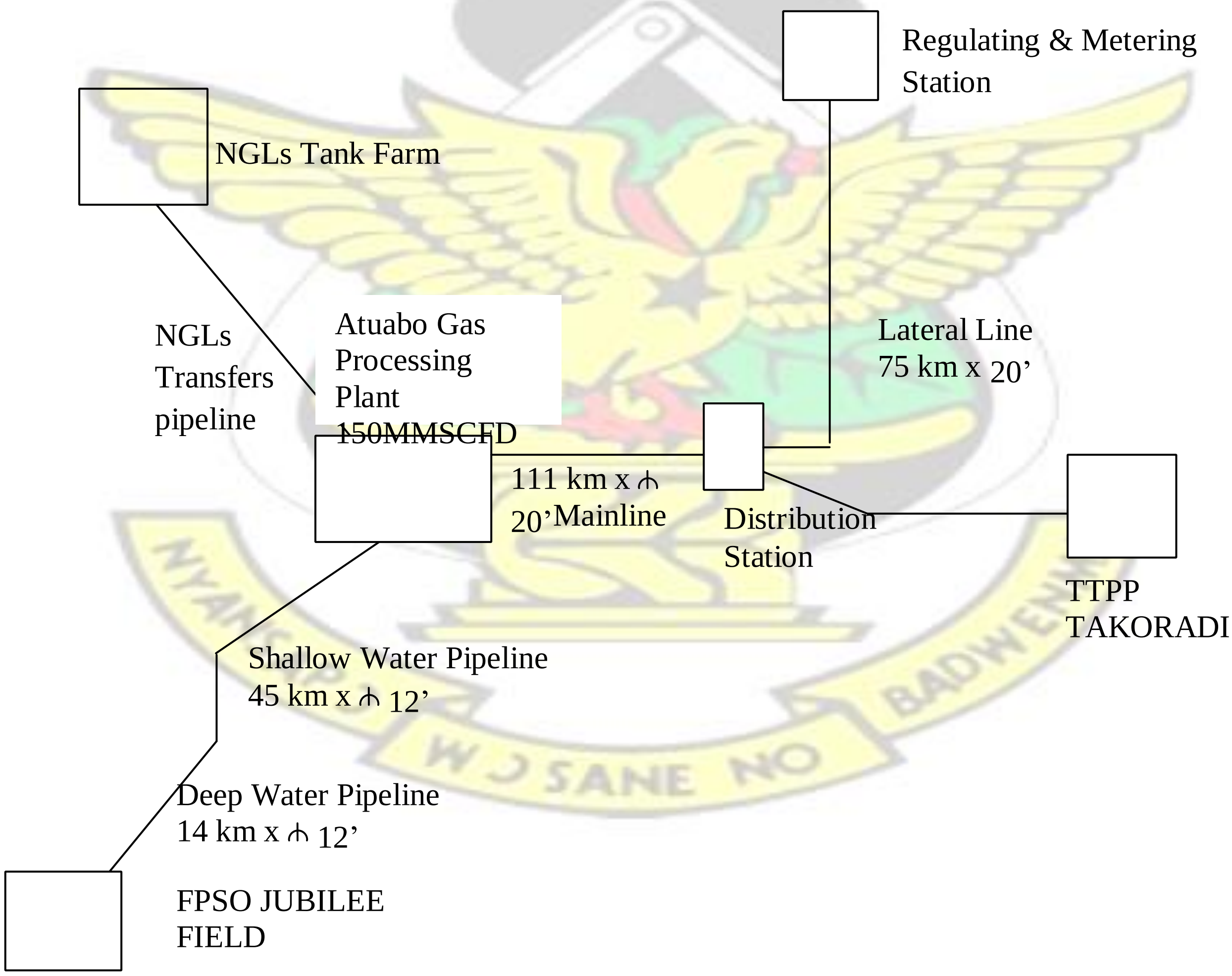

Figure 4.1 Schematic of Ghana Gas Pipeline layouts

4.2.1 Assumptions

The following assumptions were made in determining the friction factors and transmission factors for both coated and uncoated pipelines:

1. The flow is assumed to be steady along the section of the pipeline.
2. The flow is assumed to be isothermal or almost approaching isothermal condition.
3. The gas compressibility is assumed to remain constant along the length of the pipeline.
4. The change in kinetic energy in the pipeline is assumed to be negligible; hence the kinetic energy term can be eliminated.
5. The friction factor f is assumed to be constant along the entire length of the pipe.
6. Effective roughness equals the surface roughness of the pipe.
7. Pipe thickness is 0.50 inches
8. Bend index for all fittings and bends is 60 degrees
9. Specific gas gravity(air =1.0) = 0.6
10. Viscosity of gas = 0.000008 lb/ft-sec

4.2.2 Case Study 1 – AGA Equation

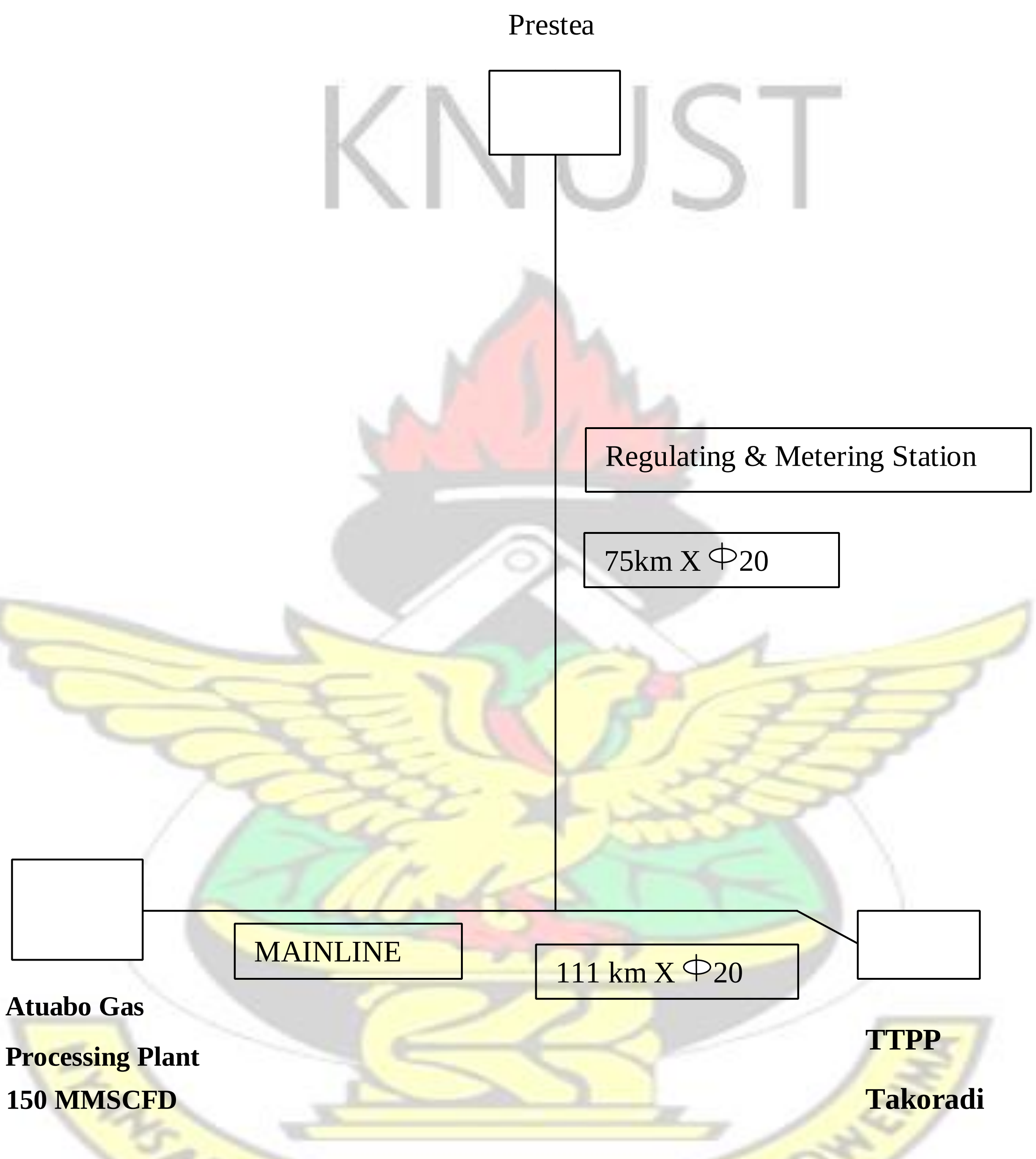

Figure 4.2 Schematic of pipeline - case study

A) For uncoated pipelines

Using the Von Karman rough pipe flow equation:

$$Q = 38.77 \frac{Tb}{Pb} \frac{P^2 - P_1^2 - E}{GLTZ}][^{0.5} \text{ X } D^{2.5} \text{ X} \sqrt{\frac{1}{f}}$$

$$\sqrt{\frac{1}{f}} = 4 \log \frac{3.7D}{Ke}$$

Using effective roughness (Ke) for uncoated pipelines = 700 micro inches (Menon, 2005)

$$Q = 38.77 \frac{Tb}{Pb} \frac{P^2 - P_1^2 - E}{GLTZ}][0.5 \text{ X } D2.5 \text{ X } \sqrt{4 \log \frac{3.7D}{Ke}}$$

Since Q $\propto$ T in the general steady-state isothermal flow equation,

$$T = 4 \log \frac{3.7D}{Ke}$$

Nominal Diameter OD = 20

1D = 20 – 2 (0.5)

Inside Diameter 1D = 19 inch

Tu (Transmission factor for uncoated pipeline) = $4 \log \frac{3.7D}{Ke}$

$$Tu = 4 \log \frac{3.7(19)}{0.0007}$$

$$Tu = 4 \log \frac{70.3}{0.0007}$$

Tu = 20.010

Hence the Transmission factor for uncoated pipeline Tu = <u>20.010</u>

The corresponding friction factor f (fanning friction factor):

$$f = \frac{1}{\sqrt{f}}$$

$$\sqrt{f} = \frac{1}{T}$$

$$= \frac{1}{20.01}$$

f = 0.0024975

Hence the friction factor f (fanning friction factor) is <u>0.0024975</u>

B) For coated Pipeline

Using the rough pipe flow equation (Von Karman):

$$Q = 38.77\ \frac{Tb}{Pb}\ \frac{P^2 - P_1^2 - E}{GLTZ}][^{0.5}\ X\ D^{2.5}\ X\sqrt{\frac{1}{f}}$$

$$\sqrt{\frac{1}{f}} = 4\ \log\ \frac{3.7D}{Ke}$$

Using effective roughness (Ke) for coated pipelines = 250 micro inches (Asante et al, 1993 c)

$$Q = 38.77\ \frac{Tb}{Pb}\ \frac{P^2 - P_1^2 - E}{GLTZ}][0.5\ X\ D2.5\ X\ \sqrt{4\ log\frac{3.7D}{Ke}}$$

Since Q $\propto$ T in the general steady-state isothermal flow equation,

$$T = 4\ log\frac{3.7D}{Ke}$$

Nominal Diameter OD = 20

1D = 20 – 2 (0.5)

Inside Diameter 1D = 19 inch

Tc (Transmission factor for coated pipeline) = 4 log $\frac{3.7D}{Ke}$

$$Tc \quad = 4\ \log\ \frac{3.7(19)}{0.00025}$$

$$Tc \quad = 4\ \log\ \frac{70.3}{0.00025}$$

$$Tc \quad = 21.796$$

Hence the Transmission factor for coated pipeline Tc = 21.796
The corresponding friction factor f (fanning friction factor):

$$f \quad = \frac{1}{\sqrt{f}}$$

$\sqrt{f} \quad = \frac{1}{T}$

$= \frac{1}{21.796}$

f $\quad$ = 0.00210497

Hence the fanning friction factor f is 0.00210497

Since Q $\propto$ T in the general steady-state isothermal flow equation;

$Q = 38.77 \frac{Tb}{Pb} \frac{P^2 - P_1^2 - E}{GLTZ}]^{0.5} \times D^{2.5} \times \sqrt{T}$

The coated pipeline will transmit;

$\frac{Tc - Tu}{Tu} \quad \frac{21.80 - 20.01}{20.01} =$

$= \frac{1.79}{20.10}$

= 0.08905

= 8.905%

= 8.91%

Hence the coated pipeline will be able to transport about **8.91%** more gas than the uncoated pipelines.

4.2.3 Case 2 – Colebrook-White Equations

A) For Uncoated Pipeline Using the

Colebrook-White equation;

$\frac{1}{\sqrt{f}} = -2 \log \left[\frac{Ke}{3.7D} \quad \frac{2.51}{Re\sqrt{f}} + \right]$

Ke = 700µin = 0.0007in

Nominal Diameter =20 in Inside Diameter

= 20 – 2(0.5) = 19in

Relative roughness $\frac{ke}{D}$ $\frac{700 \ x \ 10^{\wedge}-4}{19}$ =

= $\frac{0.0007}{19}$

Reynolds number Re = 0.0004778 (Pb/Tb) (GQ/UD)

Re = 0.0004778 (14.73/520) (0.6 x 150 x 10^6/ 8 x 10^{-6} x 19)

Re = $\frac{633{,}419.46}{0.07904}$

Re = 8,013,910.172

Substitution Re = 8,013,910.172 into the Colebrook equations;

$$\frac{1}{\sqrt{f}} = {}_{-2}\log \left[\frac{0.0007}{3.7(19)} \quad \frac{2.51}{8{,}013{,}910.172\sqrt{f}} + \right]$$

Solving for f

Assuming f = 0.01 and substitute into equation;

$$\frac{1}{\sqrt{f}} = -2 \log \left[\frac{0.0007}{3.7(19)} \quad \frac{2.51}{8{,}013{,}910.172(\sqrt{0.01})} + \right]$$

$$= -2 \log \left[9.957 \times 10^{-6} + \frac{2.51}{801391.0172} \right]$$

$$= -2 \log [9.957 \times 10^{-6} + 3.13 \times 10^{-6}]$$

$$= -2 \log [1.3089 \times 10^{-6}]$$

$$\frac{1}{\sqrt{f}} = 9.76618$$

$$f = \left(\frac{1}{9.76618} \right)^2$$

f = 0.01048

Hence the friction factor f for the uncoated pipeline is <u>0.01048</u>

The corresponding Transmission factor T, using Darcy friction factor:

$$Tu = \frac{2}{\sqrt{f}}$$

$$Tu = \frac{2}{\sqrt{0.01048}}$$

$$= 19.53236$$

$$Tu = 19.53236$$

Therefore the transmission factor for the uncoated pipeline is 19.53236

B) **For coated pipeline** Using

the Colebroke equation;

$$\frac{1}{\sqrt{f}} = -2 \log \frac{Ke}{3.7D} \quad \frac{2.51}{Re\sqrt{f}} +$$

Re = 8,013,910.172

Relative roughness for coated pipeline $\frac{Ke}{D}$ $\frac{100 \; x \; 10^{\wedge}-4}{19}$ =

$$\frac{1}{\sqrt{f}} = -2 \log \frac{100 \; x \; 10^{\wedge}-4}{3.7(19)} \quad \frac{2.51}{8{,}013{,}910.172\sqrt{f}} +$$

Solving for f

Assuming f = 0.01 and substitute into equation;

$$\frac{1}{\sqrt{f}} = -2 \log \left[1.422 \text{ x } 10^{-6} + \frac{2.51}{8{,}013{,}910.172\sqrt{0.01}}\right]$$

$$= -2 \log [1.422 \text{ x } 10^{-6} + 3.13 \text{ x } 10^{-6}]$$

$$= -2 \log [4.552 \text{ x } 10^{-6}]$$

$$\frac{1}{f} = 10.6836$$

$$f = \left(\frac{1}{10.6836}\right)^2$$

$f = 0.008761$

Hence the friction factor f for the coated pipeline is 0.008761

The corresponding transmission factor T for the coated pipeline, using Darcy friction factor:

$$Tc = \frac{2}{\sqrt{f}}$$

$$Tc = \frac{2}{\sqrt{0.008761}}$$

$$= \underline{21.3675}$$

Since Q $\propto$ T in the general steady-state isothermal flow equation, the coated pipeline will transport gas:

$$\frac{Tc-Tu}{Tu} \quad \frac{21.37-19.53}{19.53} =$$

$$= 0.094214$$

$$= 0.094$$

$$= 9.42\%$$

Hence the coated pipeline will be able to transport about **9.42%** more gas than the uncoated pipelines

4.2.4 Summary Results

Table 4.1 Study Case 1- AGA Equation

	Friction Factor (f)	**Transmission Factor (T)**
Uncoated pipeline	0.00249750	20.010
Coated pipeline	0.00210497	21.796
% impact(increase) on flow rate, Q		**8.91**

Table 4.2 Study Case 2- ColebrookWhite Equation

	Friction Factor (f)	Transmission Factor (T)
Uncoated pipeline	0.01048	19.53
Coated pipeline	0.008761	21.37
% impact (increase) on flow rate, Q		**9.42**

CHAPTER FIVE

5.0 Conclusion and Recommendation

5.1 Conclusion

Using both AGA equations and Colebrook–White equations, it was observed that the coated pipe transported about 8.91% and 9.42% more flow rate Q respectively than the pipelines which are not internally coated, when other conditions remained constant. In AGA equation, transmission factors F were 20.010 and 21.796 respectively for uncoated and coated pipelines. Colebrook-White equation also achieved transmission factors F 19.53 and 21.37 respectively for uncoated and coated pipelines. This is true when the Reynolds number, Re, has slight or no effects on the friction factors f and the transmission factors F in the Colebrooke-White equations. However, in the AGA equations, increasing the pipe surface roughness has negligible impact on the friction factors f and the transmission factors F. Hence, decreasing the pipe surface roughness directly increases the efficiency in a pipeline leading to increased flow capacity.

For pipelines which are not internally uncoated, the surface will have a greater physical roughness which will increase turbulence resulting in greater friction being generated during the gas transmission. Internal linings are used among other reasons to increase the flow efficiency for natural gas pipelines and to mitigate corrosion damage to the pipe. Internal coatings help to maintain fluid purity by mitigating product interaction with the bare steel substrate which can result in harmful reaction products. Improved fluid purity enhances or increases the service life of pumping system while reducing their energy requirements. Flow efficiency or corrosion coatings typically consist of an epoxy liquid or fusion bonded epoxies that have sufficient thickness to coat the inside of steel pipeline. These coatings are used to reduce the frictions along the pipeline and enhance the gas flow conditions, hence increasing the efficiency of gas supply with less compressor stations or horsepower. This internal coating also promote the drying of the pipeline after hydrostatic testing, pigging, and cleaning, meaning an easier and quicker commissioning of the pipeline. It also improves movement of devices travelling along the pipeline which has been internally coated for robotic inspections. It increases transport capacity and reduces pig wear.

Flow efficient coating makes a significant impact on cost of pumping or compressing of the gas over the lifetime of the pipeline. The cost is significantly reduced. These savings on energy costs can be used as a financial payback during the lifetime of the project. Thus, compressor station situated along specified interval along the pipeline will have lower fuel costs on the coated length of the pipeline than on the pipeline which has not been internally coated.

5.2 Recommendation

While this study indicates a significant increase in flow capacity when pipeline are internally coated, it is generally recommended that even a one per cent (1%) increment in flow efficiency should be enough justification to internally coat the pipelines. Coating costs are usually 1-2% of the total installed cost of the pipeline. If the cost of service for the coated case is higher than that of the uncoated by 2% or less, internal coating is cost–effective.This phenomenon of gas pipeline internal coatings also referred to as internal flow efficient coatings, is essentially used to prevent the adverse impacts on pipeline capacity, pumping costs and operations which are caused by steel pipeline rough internal surfaces and corrosion. The pipeline transmission increases are more significant in systems where higher Reynolds numbers are high in turbulent flow regimes and smaller sized pipes.

5.3 Areas for Future Studies

The following topic areas are recommended for further studies:

1. Comparative analysis of onshore and offshore gas pipeline coatings 2. Impacts of drag-inducing elements on gas pipeline capacity

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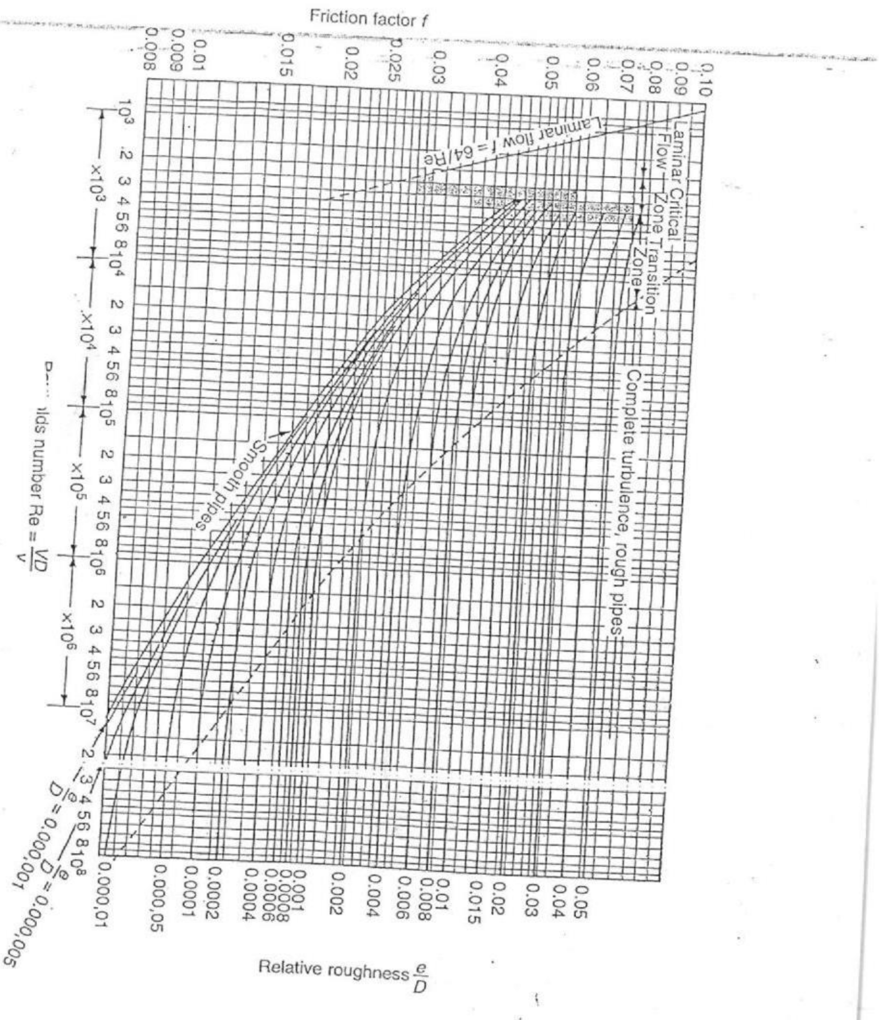
APPENDIX BE

APPENDICE

APPENDIX A

APPENDIX A



Friction factor f
Laminar flow $f = 64/Re$
Laminar Flow
Critical Zone
Transition Zone
Complete turbulence, rough pipes
Smooth pipes
Relative roughness $\frac{e}{D}$

APPENDIX B

Bend Index and Drag Factor

	Bend Index		
	Extremely Low 5° to 10°	Average 60° to 80°	Extremely High 200° to 300°
Bare steel	0.975–0.973	0.960–0.956	0.930–0.900
Plastic lined	0.979–0.976	0.964–0.960	0.936–0.910
Pig burnished	0.982–0.980	0.968–0.965	0.944–0.920
Sand blasted	0.985–0.983	0.976–0.970	0.951–0.930

Note: The drag factors above are based on 40-ft joints of pipelines and mainline valves at 10-mile spacing.