CAPITAL COST OPTIMIZATION OF OFFSHORE GAS CONDENSATE GATHERING NETWORK

BY

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Master of Technology

(Pipeline Engineering)

By

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CERTIFICATE

This is to certify that the work contained in this thesis titled "CAPITAL COST OPTIMIZATION OF OFFSHORE GAS CONDENSATE GATHERING NETWORK" has been carried out by Vutla DurgaRao under my supervision and has not been submitted elsewhere for a degree.

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Abstract

This project focuses on developing a simulation model to perform capital cost optimization for the Gas Condensate Gathering pipeline network system. A simplified model has been developed by using software support to calculate the physical parameters like operating pressures, pressure drop, holdups and few others. Network fluid consists of Water, Oil and Gas. Presence of liquid causes trouble to fluid flow; Separator is used to separate liquids in a pipeline. Since it is a 3-phase flow, prediction of flow regimes should be done with the help of Weisman correlation based on superficial liquid velocity and superficial gas velocity. After completing simulation part, we can see pressure in each pipe leg doesn't cross its own MAOP and flow rate meets requirement, pressure imbalance are within given precision. Once the simulation part is completed with acceptable results, Capital cost optimization should be performed. SQP (Sequential Quadratic Programming) method is used to optimize the gathering networks. The sequential quadratic programming (SQP) methods are widely regarded as the most effective methods for nonlinearly constrained programming (NCP) problem. Capital cost optimization is done without causing any disturbance to network operating parameters and physical parameters
.

Acknowledgement

I am immensely grateful to my advisor Mr. Bhalachandra Shingan for his inspiring, supervision and sharing of my excitement as well as ideas in this work. Without his constant support, encouragement and guidance, this work wouldn’t be possible.

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Units of Measurement

Length	:	km
Diameter	:	in
Wall Thickness	:	in
Roughness	:	in
Thickness of Insulation	:	in
Temperature	:	F
Pressure	:	bar
Flow Rate	:	m^3/hr
Specific gravity	:	kg/m^3
Water Conductivity	:	w/m.c
Water velocity	:	km/hr
Fluid Conductivity	:	w/m.c
Pipe Conductivity	:	w/m.c
Soil Conductivity	:	w/m.c
Insulation Conductivity	:	w/m.c
Density	:	kg/m^3
WGR	:	$m^3/MM\ m^3$
CGR	:	$m^3/MM\ m^3$
Estimated Flow rate	:	$MM\ m^3/hr$

Elevation change	:	m
Efficiency	:	Percentage
Heat transfer Coefficient	:	$w/m^2.c$
Over all U factor	:	$w/m^2.c$
Gas holdup	:	MM m^3
Liquid holdup	:	m^3
Mixed velocity	:	m/s
Gas velocity	:	m/s
Superficial gas velocity	:	m/s
Superficial liquid velocity	:	m/s

1. Introduction

1.1. Gas Condensate:

Gas Condensate is a low-density mixture of hydrocarbon liquids that are present as gaseous components in the raw natural gas produced from many natural gas fields. It condenses out of the raw gas if the temperature is reduced to below the hydrocarbon dew point temperature of the raw gas. The natural gas condensate is also referred to as simply condensate, or gas condensate, or sometimes **natural gasoline** because it contains hydrocarbons within the gasoline boiling range.

Raw natural gas may come from any one of three types of gas wells

- Crude oil wells: Raw natural gas that comes from crude oil wells is called *associated gas*. This gas can exist separate from the crude oil in the underground formation, or dissolved in the crude oil. Condensate produced from oil wells is often referred to as *lease condensate*.

- Dry gas wells: These wells typically produce only raw natural gas that does not contain any hydrocarbon liquids. Such gas is called *non-associated* gas. Condensate from dry gas is extracted at gas processing plants and, hence, is often referred to as *plant condensate.*

- Condensate wells: These wells produce raw natural gas along with natural gas liquid. Such gas is also *non-associated* gas and often referred to as wet gas.

Composition:

There are many condensate sources worldwide and each has its own unique gas condensate composition. However, in general, gas condensate has a specific gravity ranging from 0.5 to 0.8, and is composed of hydrocarbons such as propane, butane, pentane, hexane, etc. Natural gas compounds with more carbon atoms (e.g. pentane, or blends of butane, pentane and other hydrocarbons with additional carbon atoms) exist as liquids at ambient temperatures.

Condensate Gas Ratio:

Ratio of total amount of condensate produced to amount of surface gas leaving the facility. A maximum CGR corresponds to maximum liquids yield at stock tank. Since CGR is inversely proportional to GOR (Gas Oil Ratio)

Water Gas ratio:

Ratio of total amount of water injected to total amount of gas producing. The amount of water injected increases as the age of well increases and gas production decreases.

1.2. Problem Statement:

In Offshore fields, gathering network is often constrained by capital cost, operating parameters, and fluid handling capacity facilities. This project aims at develop optimized gas condensate gathering network without affecting operational parameters and production rate. The major considerations of this project is modeling a gathering network, undergo simulation to evaluate it and finally to perform capital cost optimization. Considerations for optimization are objective function, decision variables, and constraints.

1.3. Approach:

The problem requires simultaneous allocation of fluid data, pipeline data, heat transfer data, and few others. Robust procedure for such a task is not available; hence the software requirement is much needed. Here, in this project PIPEPHASE a multi-phase simulation and analysis software is used. Modeling, simulation and analysis are performed by using PIPEPHASE. In optimization case it is necessary to optimize all control variables simultaneously subject to constraints. NETOPT is a fluid flow network optimizer allows you to optimize network performance by defining an objectives while satisfying both physical and user imposed constraints. Mainly helpful at the design state to minimize the capital cost. The target problem is a non-linear constrained optimization problem with decision variables. A SQP (Sequential quadratic programming) method is used to perform optimization.

2. Literature Review

Applications of optimization techniques in the upstream oil and gas industry began in the early 1950s and have been flourishing since then. Applications have been reported for recovery processes, planning, history matching, well placement and operation, drilling, facility design and operation and so on. Optimization techniques employed in these applications cover almost all subfields in mathematical programming, such as linear programming, integer programming, and nonlinear programming.

With the continuously growing development and demand scale of natural gas, the gas gathering pipeline network becomes much bigger and more complicated, which makes it much more difficult to understand. After completion of pipeline project, pipe structured parameters cannot be changed, so initial care must be taken at the modeling stage to reduce capital cost. Gas Gathering system consists of well platforms, and a process platforms mainly. The collected fluid at well platforms is gathered at process platforms via feeder subsea pipelines to undergo process. After finishing the required process mainly separating liquid from the fluid, gas is transported through export pipelines.

At present there are two aspects to simplify the network simulation: simplify the network model or use an algorithm. This project follows simplifying network model with the help of simulation software.

The basic elements of the gas gathering and transportation pipeline network system are pipeline, node, platform, source and sink. When gas flows through these elements simulation is performed. After ensuring the simulation results are précised, network optimization should be started. Here in this project NETOPT multi-phase fluid flow network optimizer is used. It is mainly capable of optimizing capital cost of pipeline networks.

2.1. Constrained Optimization Methods:

The optimum of a constrained optimization problem is characterized by a certain set of conditions. These conditions were first established by Kuhn and Tucker in 1951 and they are often called the Kuhn-Tucker conditions or optimality conditions. Constrained optimization methods are developed to find a point that satisfies these conditions. The major constrained optimization methods include sequential quadratic and linear programming methods, reduced-gradient methods, and methods based on augmented Lagrangians, penalty, and barrier functions.

In this project SQP is used. The sequential quadratic programming (SQP) methods are widely regarded as the most effective methods for nonlinearly constrained programming problem. The SQP methods have a structure of major and minor iterations. Every major iteration involves formulating a quadratic programming (QP) sub problem to obtain the search direction and using a line search procedure to obtain the step length.

2.2. Optimization of Gathering System design and operations:

Traditionally, optimization of Gas gathering design and operation in a petroleum field has been performed by nodal analysis combined with trial and error. NETOPT is a commercial network optimizer that combines a general multiphase network simulator with a SQP method. NETOPT is a very general tool, and can be interfaced with PIPEPHASE a multi-phase flow simulator, and be used to optimize design, capital cost, and operational problems.

Barua et al. discussed the general usage of NETOPT in the optimization of production operations. Heiba et al. applied NETOPT to devise optimal strategies for a cyclic steam stimulation project. Because NETOPT employs SQP, a derivative-based optimization algorithm, it locates only local optima and accepts only continuous decision variables. The performance on individual optimization problems is not guaranteed and care has to be taken to ensure reasonable results. Zhang and Zhu minimized the total cost of a gas distribution network by adjusting the diameters of pipelines of a fixed network layout.

3. Modeling of Gas Gathering Network

A network system that collects and transfer the fluid to the place for processing is normally called Gathering System. Oil or Gas is collected from well heads and they feed into subsea pipelines to transfer fluid to a process platform where fluid separation takes place. Later gas is transported through export pipelines.

As mentioned, natural gas gathered from wells and flows to a well header with name of manifolds. Also most natural gas production requires some treatment to remove undesirable components before the commodity goes to market. Treatment facilities can range from settling tanks that remove sediment and water, to billion-dollar plants that remove sour (hydrogen sulfide [H2S]) gas, carbon dioxide, nitrogen and water, and separate out major products, including condensate, natural gas liquids (NGLs) and sulfur. Gas-gathering and transmission lines are required to transport raw gas to processing plants and marketable gas to other transmission lines and customers. NGLs are collected by main gathering systems and transported to refineries for processing.

Major elements:

- Well head Platforms
- Feeder subsea Pipelines
- Gathering Gas junction/node
- Process Platform
    - ✓ Gas-Liquid Separation
    - ✓ Gas Compression
- Transportation Pipelines

- ## Well Head Platforms:

Generally Four-legged unmanned platform consisting of spider deck, cellar deck, main deck and helideck. A typical well head platform consists of 3 to 32 wells. Well head platform also called unmanned platforms. They are designed to operate remotely under normal operations, only to be visited occasionally for routine maintenance or well work. Well servicing (work over) is done by jack up rigs or by modular rigs that are assembled over the platform.

- Feeder Subsea Pipelines:

Individual well streams are brought into the main process facilities over a network of gathering pipelines. The duty of feeder subsea pipelines is to gather the fluid from the wellhead platforms to the process platforms. Usually the diameter of these pipelines varies from 8inch to 12in pipes.

- Gas Gathering Junction/Node:

Well fluid from various well platforms is collected via feeder subsea pipelines at junction /node. From this node fluid is passed to process platforms for processing. Here in this project from node fluid is passed to process platform.

- Process Platforms:

3-Phase or 2-phase fluid is received from well platforms and processed at large process platforms.

Generally consisting of following 4-major processing modules:

- Separation (oil, gas and produces water) and Oil dispatch
- Gas Compression & Dehydration
- Produced water conditioning
- Sea water processing and Injection system

These process complexes also have Fire detection and suppressing system, power generation, well services, drilling modules, water makers, utilities, sewage treatment and living quarters.

a. Separation:

Well fluids from various well platforms reaches process platforms through subsea pipelines. Some wells have pure gas production which can be taken directly to gas treatment/compression. More often well fluids are usually 2-phase or 3-phase fluids consisting of oil, gas and water. This well fluid reaches inlet separator. Separator is a vessel in which 3-phase separation of well fluid into oil, gas and water occur. Separated gas is routed to gas compression and dehydration module. Separated oil flows to oil manifold and exported through trunk lines. Separated water flows to water conditioning manifold and diverted to produced water conditioning unit. Separated gas is diverted to gas compression module and exported via pipelines to onshore processing plant.

b. Gas Compression:

Gas from a pure natural gas wellhead might have sufficient pressure to feed directly into a pipeline transport system. Gas from separators generally lost so much pressure that it must be recompressed to achieve a pressure about 90-100 kg/cm^2 as per the requirement. Normally centrifugal compressors are used. Natural gas processing consists of separating all of the various hydrocarbons and fluids from natural gas to produce what is known as ‘pipeline quality’ dry natural gas. Compressed gases are dehydrated to avoid hydrate formation. Major transportation pipelines usually impose restrictions on the makeup of natural gas that is allowed into the gas pipeline. That means that before the natural gas can be transported it must be purified.

- Transport Pipeline:

After completion of separation process i.e., separating oil and water from well fluid pure gas is transported via export pipeline to gas processing plant for further purification and distribution. Here in this network a good insulation is provided to avoid the formation of hydrates, such the temperature of pipeline should be maintained at above 20^{o}c.

3.1. Field description:

An offshore gas condensate field is considered. It consists of 8-well platforms and 1-process platform. Well platform collects fluid at certain temperature and pressure. A network includes source, sink, links, separators, compressors and nodes. Links refer to any device or facility across which pressure changes. A link can be pipeline. A node represents a flow junction or the terminal point of a link. Duty of process platform is to separate liquids from gas and transport gas only. Sink pressure is fixed and flow rate is obtained.

Well Head Platforms – A, B, C, D, E, F, G, H

Process Platform – E1 to E2

GASP – Gas Processing Plant

L001 to L0012- Gathering Lines

01 – Transport pipeline

02 – Onshore Pipeline to Gas processing Plant

3.2. Network Diagram:

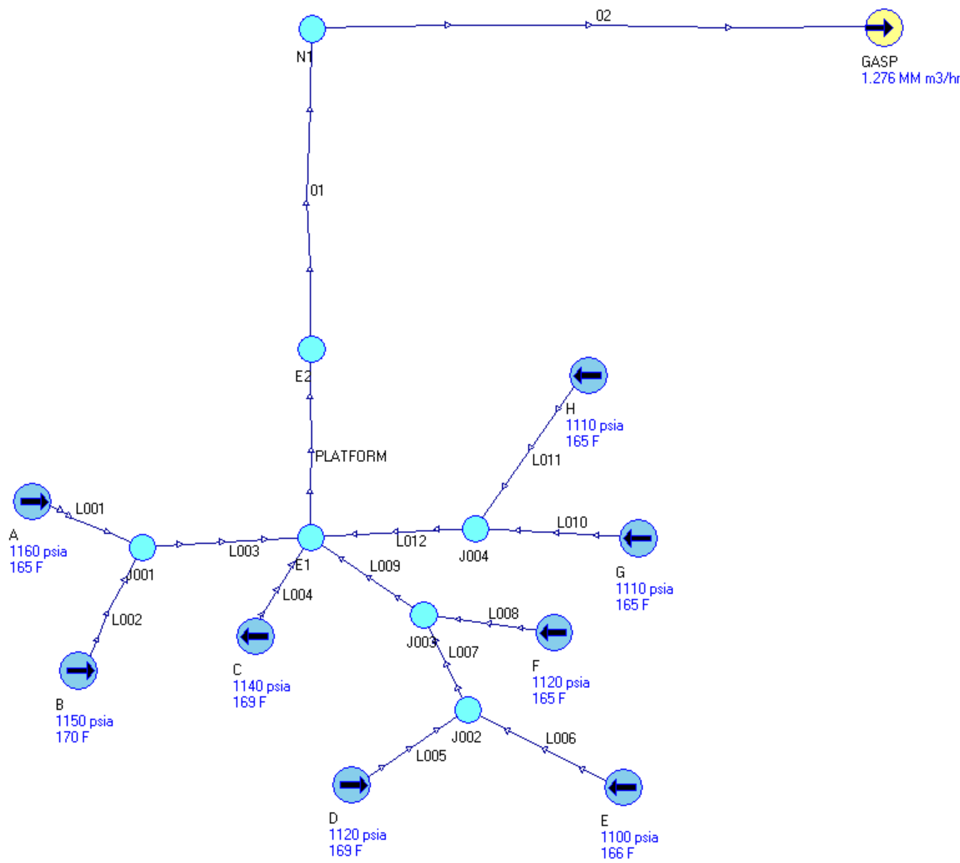


Fig.no: 01: Offshore Gas Condensate Gathering Network

4. Simulation of Gas Gathering Network

A typical oil field contains a gathering system, a fluid distribution network, and an injection network. The gathering system collects the fluids from production wells and delivers them into separation units. The separated fluids are then distributed to different destinations for storage, sale, disposal, injection, or further processing. The multiphase flow problems in the gathering, distribution and injection network belong to network flow problems that have special properties. For the capital cost optimization problem considered in this work, a model is required to simulate the multiphase flow in the gathering system. The distribution and injection networks are ignored.

The network problem with single-phase flow is relatively easy to solve compared to multiphase. There are two major solution approaches. Both approaches formulate the network problem according to the requirements of mass balance and Kirchoff's law. The first approach is to formulate the network problem as a set of system equations and solve the system equations by the Newton-Rapshon method or one of its variations. The second approach is to formulate the network problem as an optimization problem and solve it using appropriate optimization algorithms.

However, the multiphase network problem is much more difficult than the single phase network problem for the following reasons: Firstly, the system equations are more difficult to construct, because we need to determine the fluid compositions in a link before the pressure loss along the link can be evaluated. This is not easy in complex systems where the flow directions are unknown and phase splitting ratios at junctions are hard to determine. Secondly, the Newton-Raphson method may not converge or converge slowly due to the complex nature of the multiphase flow. Finally, mathematically, multiple solutions exist for the multiphase network problem and not all of them are physical. Results show that even for a simple system with two wells, the solution method can take more than ten Newton iterations to converge unless a good initial guess is available.

In this study, we consider gathering system network. The gathering system can include such components as wells platforms, pipes, separators, compressors, heaters, junction points, source and sink. The fluids in the system can include oil, gas, and water phases. Fluid properties are represented by the Non-compositional model.

In order to simulate the pipeline as real as has been constructed in seabed and offshore platform the changes of its elevation along pipeline distance with considering pipeline material and insulation should be taken into account. Furthermore governing equation should be considered to calculate the physical parameters.

4.1. Network Simulation:

In this section, we first discuss about required data. Source pressure is fixed pressure, Fluid data is provided at initial stage, Heat transfer data, separator is used for fully separation of gas and liquid fluids, duty of compressor is to increase pressure, but should not increase beyond MAOP of pipe. Sink flow rate is fixed. After providing all required data, governing equations should be given.

Simulation is done such that pipeline pressure should be less than 90 bar and temperature should be greater than 20^{o}c. Flow rate should be 1.274 MM m^3/hr.

4.2. Simulation for Thickness of Insulation calculation:

Insulation thickness is determined giving an initial assumed value and by running a simulation and observing the temperature profile. To avoid unnecessary conditions and formation of gas hydrates, pipeline should be maintained at temperature above 68 F.

- For 0.5 in thickness:

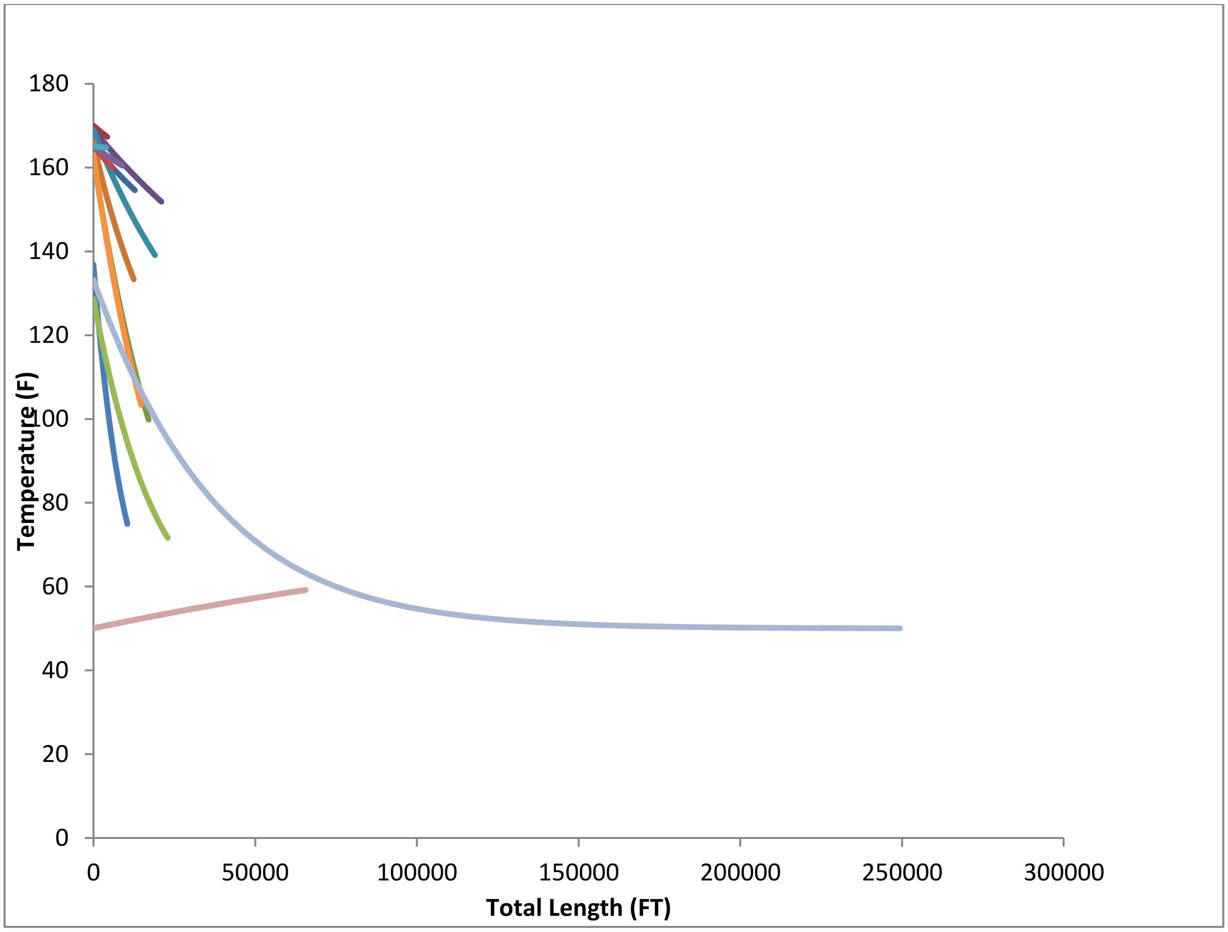
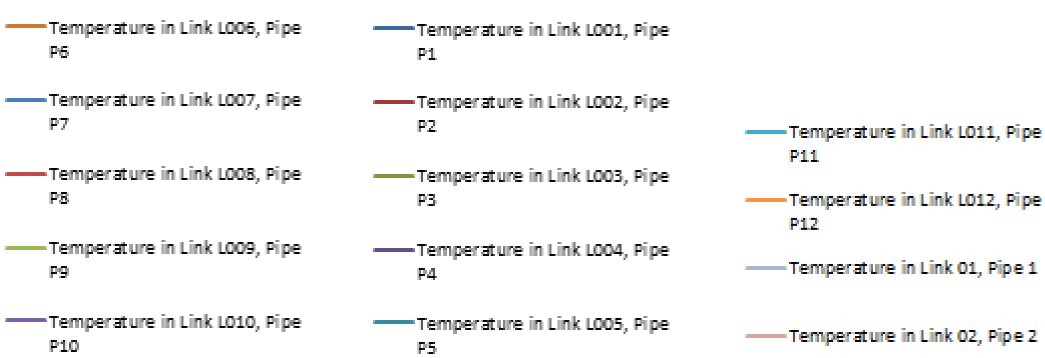


Fig no: 02: Temperature profile for insulation thickness 0.5in

As we seen from graph the temperature of pipeline-01 reaches ambient temperature.



- For 1.0 in thickness:

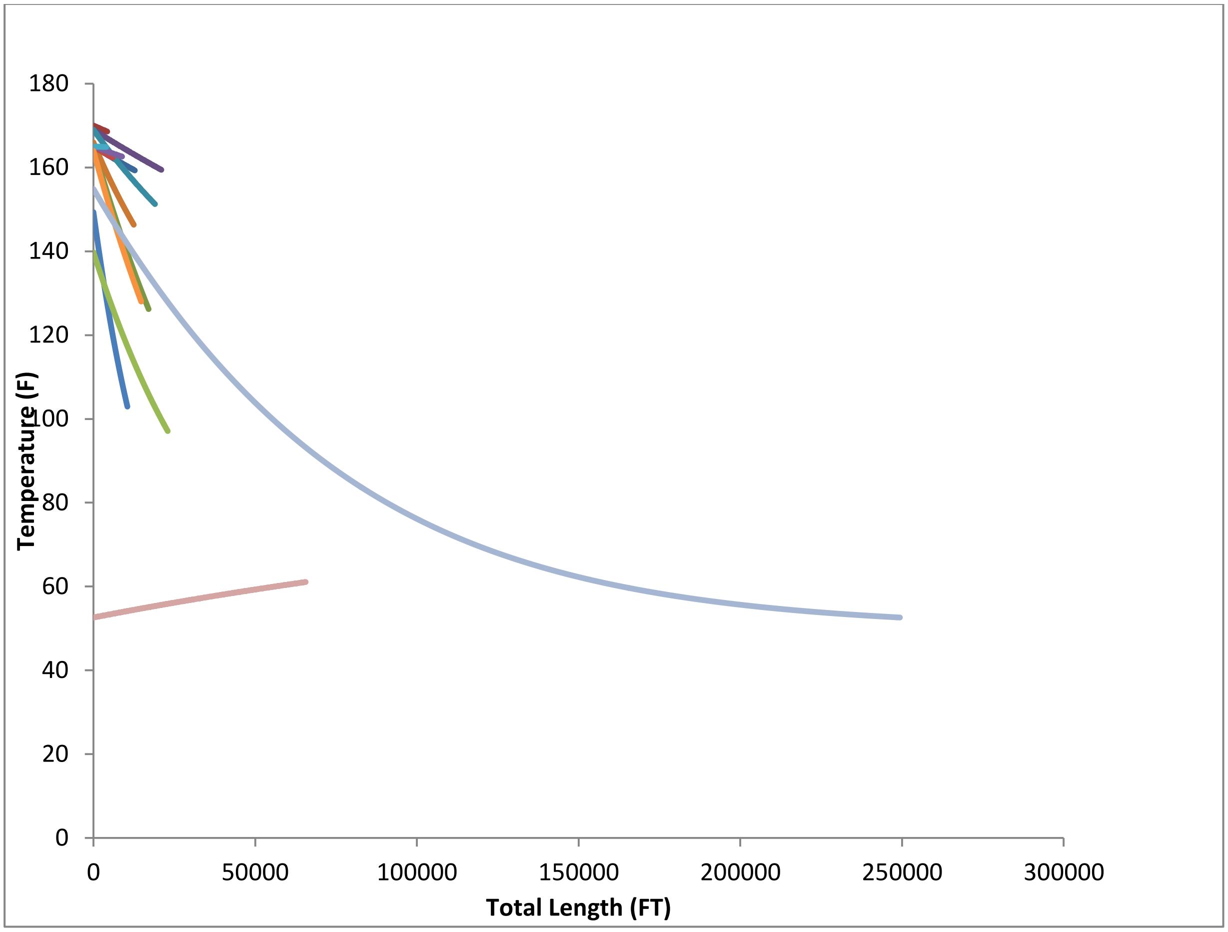
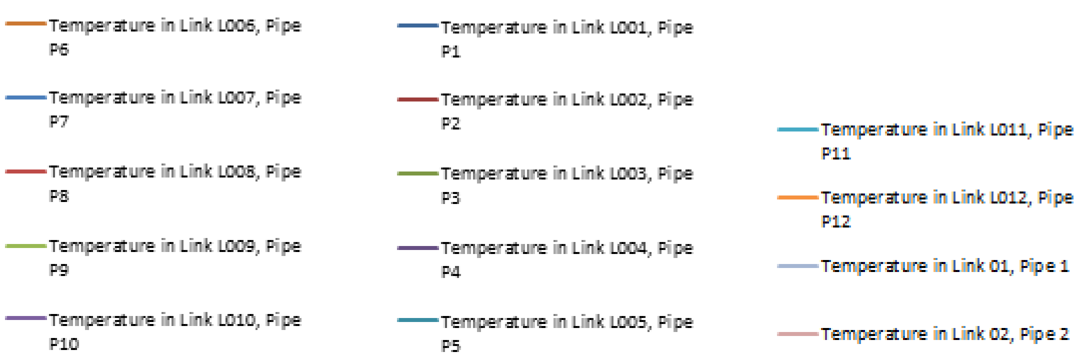


Fig no: 03: Temperature profile for insulation thickness 1.0 in

As we seen from graph the temperature of pipeline-01 reaches ambient temperature.



- For 1.5 in thickness:

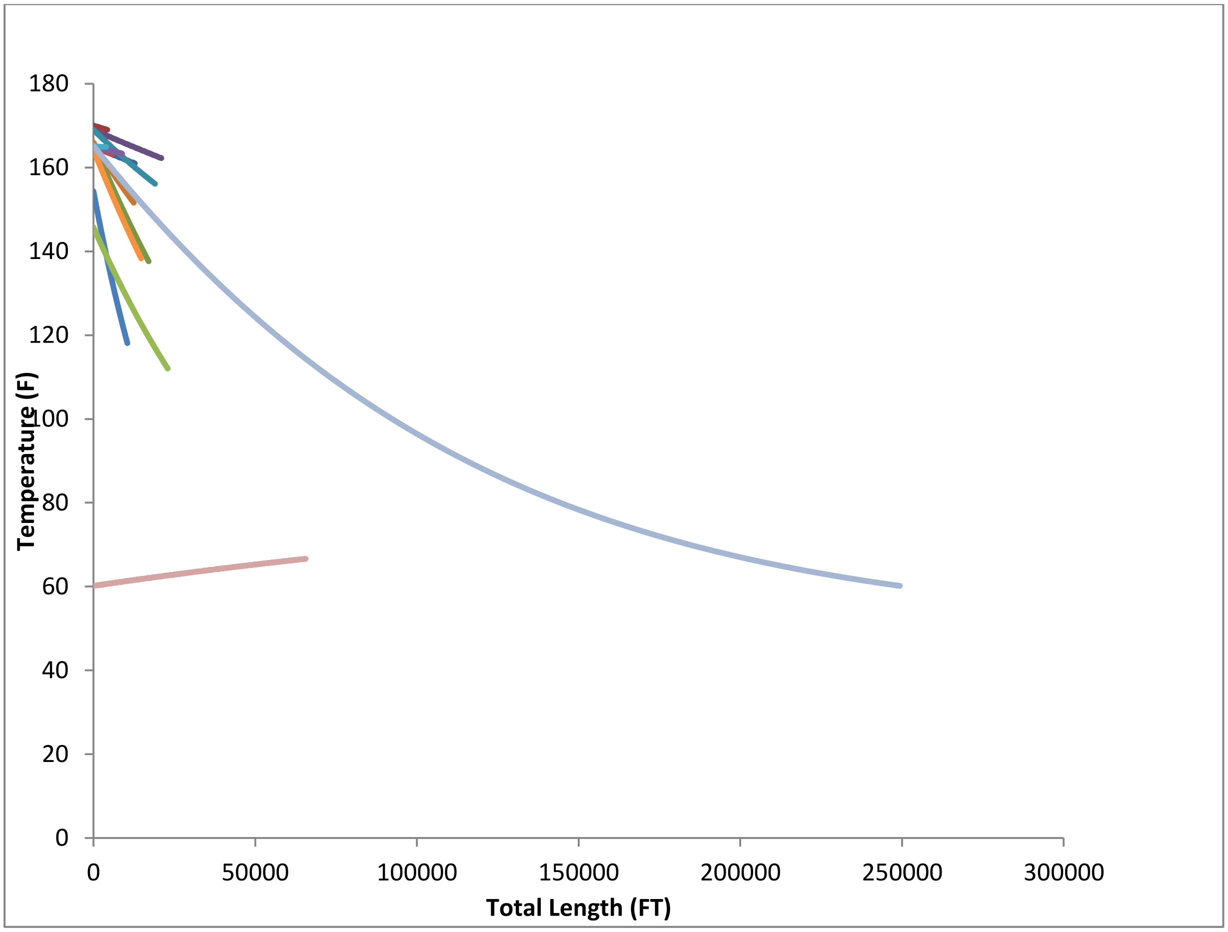
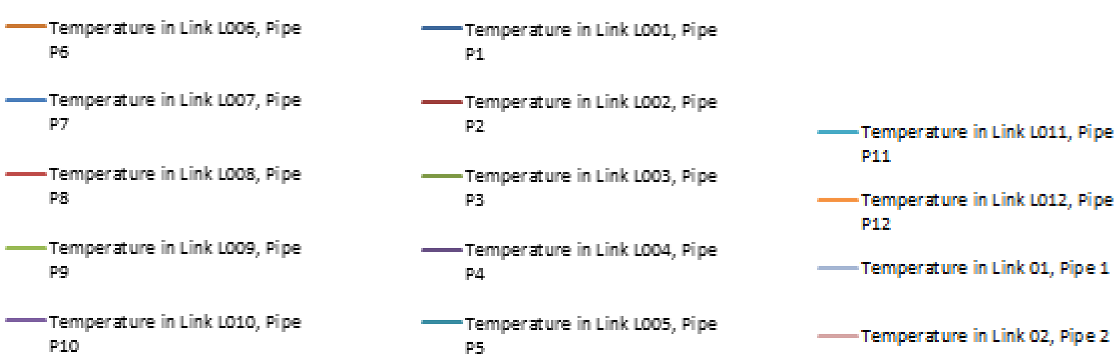


Fig no: Fig no: 04: Temperature profile for insulation thickness 1.5 in

As we seen from graph the temperature of pipeline-01 reaches ambient temperature.



- For 1.8 in thickness:

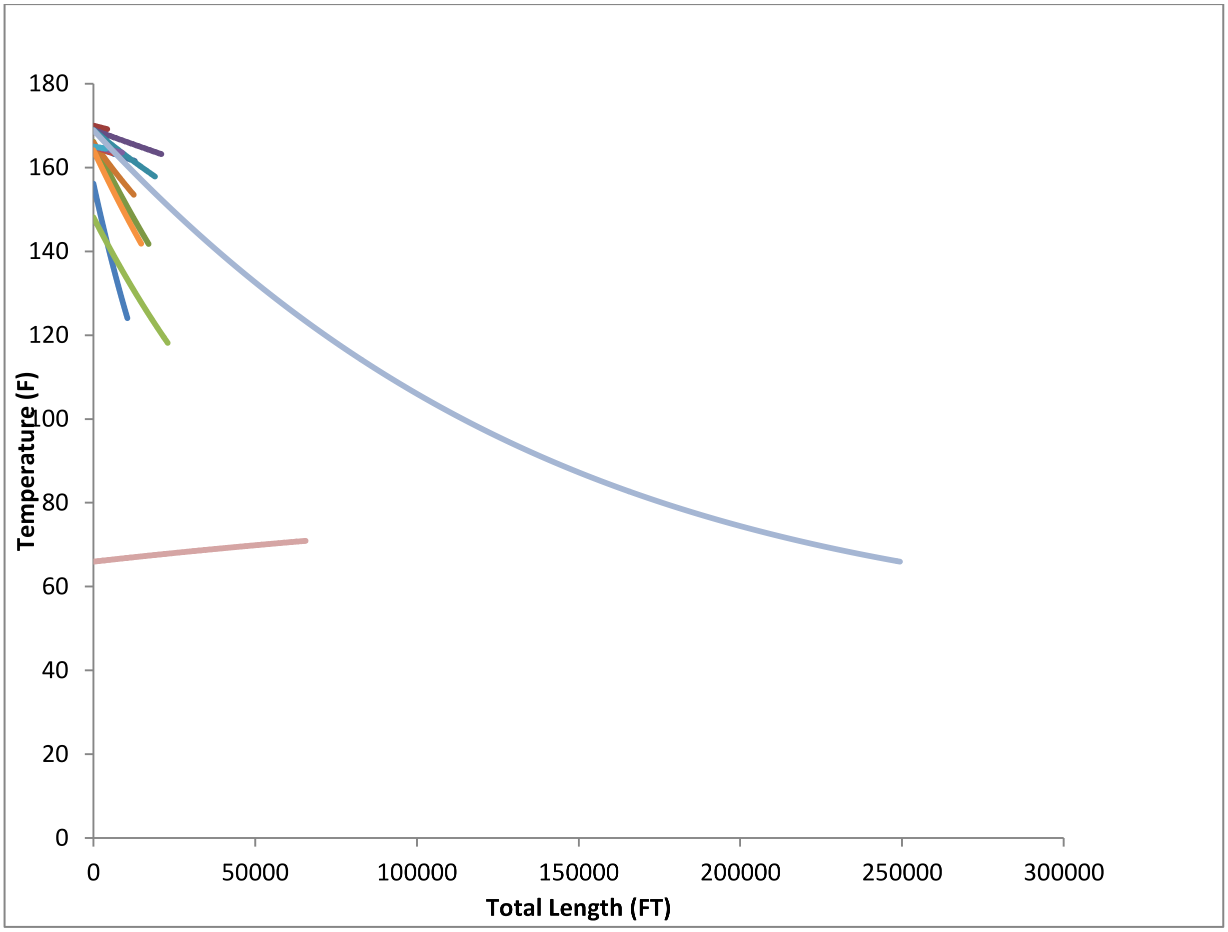
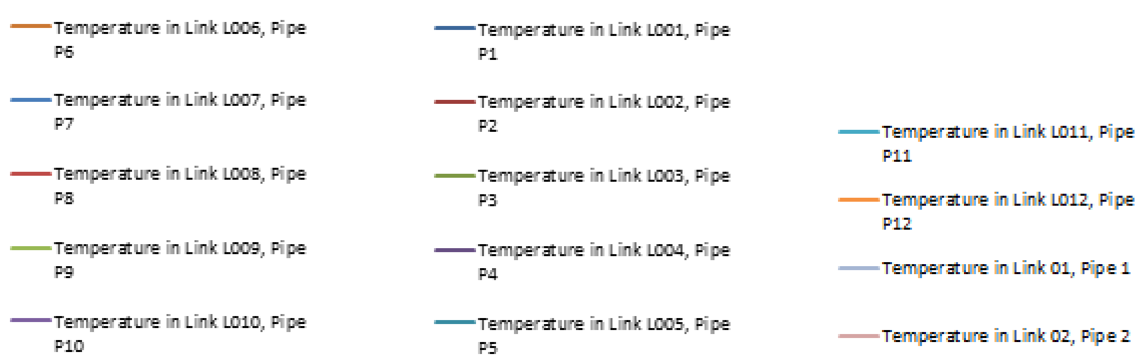


Fig no: 05: Temperature profile for insulation thickness 1.8in

As we seen from graph the temperature of pipeline-01 reaches less than 68 F.



- For 2.0 in thickness:

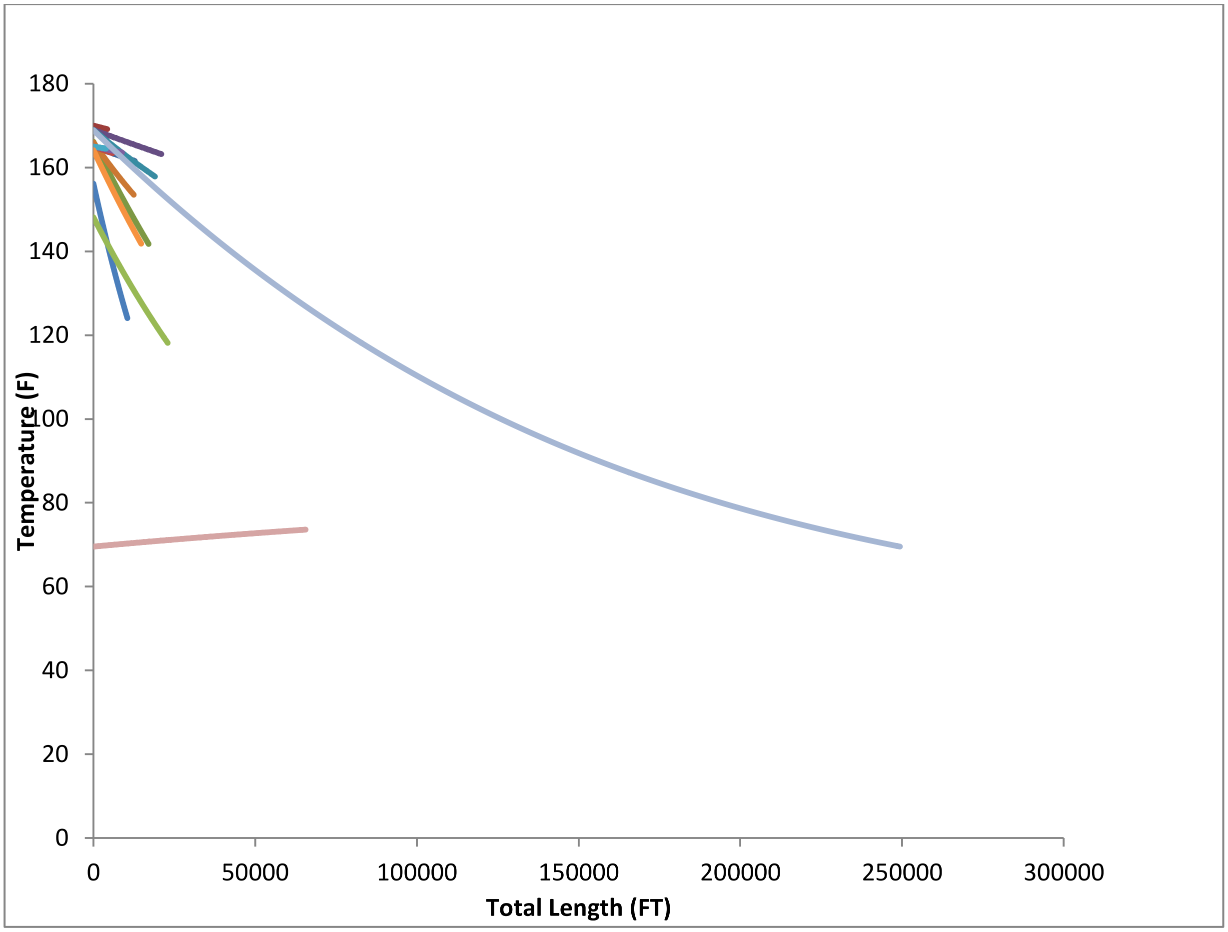
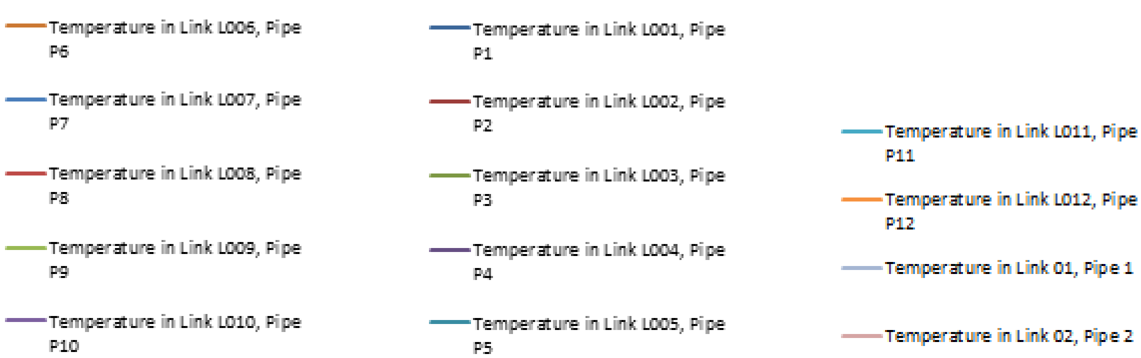


Fig no: 06: Temperature profile for insulation thickness 2.0 in

As we seen from graph the temperature of pipeline-01 maintains at safer temperature i.e., above 68 F



4.3. Simulation for Compressor power calculation:

Compressor power is estimated by simulation and analysis process. Firstly an assumed (initial) value of set power is provided and obtained simulation results are observed. Simulation is continued by providing set power a required amount. The set power value is increased until the sink pressure is reached as per estimated.

- For set power 7500 HP, 10000 HP & 11000 HP delivery pressures obtained are observed through pressure profiles and required set power is calculated through simulation and analysis procedure:

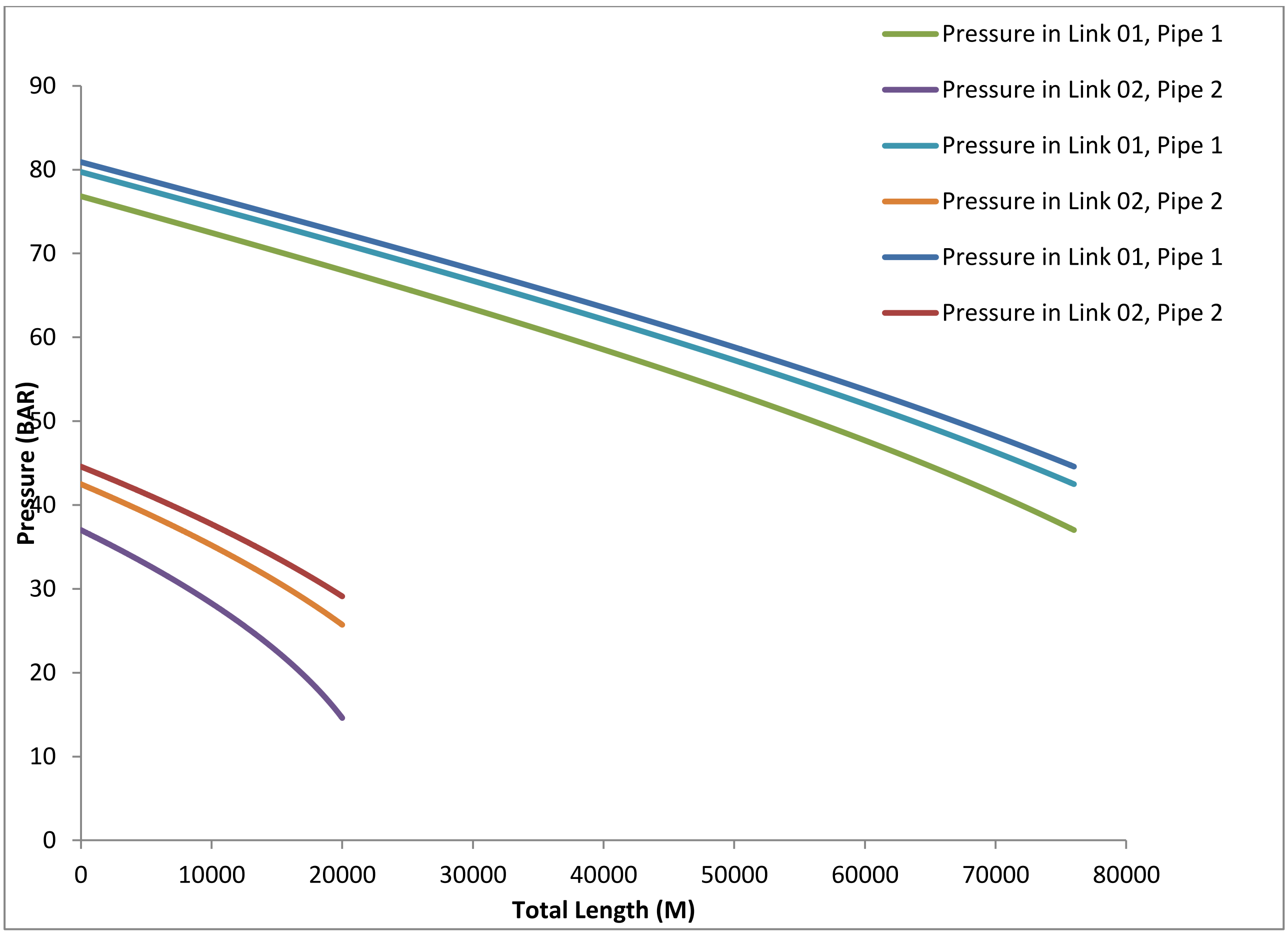


Fig no: 07: Pressure profile for 7500HP, 10000 HP, 11000 HP compressors in Link01 and Link02.

Since Compressor with 11000Hp is not available, compressor of nearest set power should be installed

4.4. Pressure Gradient Equation:

As, energy balance taken around a steady state given a flow rate and the pressure at one end of a pipe, the pressure loss (or gain) in the pipe can be computed by integrating the pressure gradient along the pipe. Consider gas/liquid two-phase flow in a pipe without perforations, the total pressure gradients along the pipe can be decomposed into three parts.

Equations:

$$\underset{total}{(dP/dL)_t} = \underset{friction}{(dP/dL)_f} + \underset{elevation}{(dP/dL)_e} + \underset{acceleration}{(dP/dL)_{acc}}$$

The pressure drop consists of a sum of three terms:

- Reversible conversion of pressure energy into a change in elevation of the fluid,
- Reversible conversion of pressure energy into a change in fluid acceleration, and
- Irreversible conversion of pressure energy into friction loss.

The individual pressure terms are given by:

$$(dP/dL)_f = f_{tp}\rho_{tp}v_{tp}^2/2g_c d$$

$$(dP/dL)_e = g\rho_{tp}\sin\phi/g_c$$

$$(dP/dL)_{acc} = \rho_{tp}v_{tp}/g_c(dv_{tp}/dL)$$

ρ_{tp} = fluid density = $\rho_l H_L + \rho_g H_g$

H_L, H_g = liquid and gas holdup terms subscript *tp* refers to the two-phases.

Where $\frac{dp}{dL}$ = flow pressure gradient, L is pipe length, ρ is fluid density, V is flow velocity, f is friction factor of flow, D is internal diameter of pipeline, Ө is inclination of angle, g is gravitational acceleration and g_c is gravitational constant. The subscripts are “tot” for total, “ele” for elevation, “fri” for friction loss, “acc” for acceleration change terms and “tp” for two- and/or three-phase flow

4.4.1. Dukler-Eaton-Flanigan (DEF):

Dukler-Eaton-Flanigan correlation is used to calculate pressure drop and holdup correlations. It is best suited for low condensate gas systems. It uses Dukler correlation for friction calculation, Eaton correlation for liquid holdup calculation and elevation term is neglected.

Holdup, velocity, temperature, pressure and fluid property details are requested in the output report. Link pressure, link temperature and phase envelope plots are requested in the output report.

This method uses the Dukler correlation to calculate the friction term. The friction factor is given by:

$$y = -\ln(\lambda_L)$$

$$f_n = 1 + y / \left(1.281 - 0.478y + 0.444y^2 - 0.094y^3 + 0.0084y^4\right)$$

$$f_n = 0.0056 + 0.5 N_{Re}.$$

Where:

N_{Re} = Reynolds number

The liquid holdup, H_L, used in calculating the mixture density, ρ,in the friction term is computed using the Eaton correlation. In this correlation, the holdup is defined as a function of several dimensionless numbers.

The elevation term is calculated using equation (3). The mixed density, ρ, however, is calculated not by using the Eaton holdup, but by using the liquid holdup calculated by the Flanigan correlation:

$$H_L = 1 / \left(1 + 0.326 v_{sg}^{1.06}\right)$$

The acceleration term is calculated using the Eaton correlation:

$$(dP/dL)_{acc} = W_1 \left(\Delta v_1\right)^2 + W_g \left(\Delta v_g\right)^2 / \left(2 g_c q_m \Delta L\right)$$

where:

W= mass flow rate

v = fluid velocity

v_{sg}= superficial gas velocity

q_m= mixture flow rate

q_m subscripts g and l refer to the gas and liquid phases

4.5. Flow Regime Prediction:

Prediction of flow regimes is very difficult, thus it requires a most established and recognizable method. Weisman in 1979 studied the effect of fluid properties and pipe diameter on flow pattern transitions. Weisman correlation is used to accurately predict the flow regimes in Offshore Gas condensate Gathering Network. In their experiments, they systematically varied liquid viscosity, liquid density, interfacial tension, and gas density. Flow regimes vary depending on operating conditions, fluid properties, and flow rates. They observed the following flow patterns: annular, slug, plug, wavy, stratified, bubble and dispersed flow.

To distinguish between flow patterns, they coupled visual observations with measured pressure drop fluctuations. They found that the flow pattern is determined primarily by the relative volumetric flow rates of gas and liquid. They proposed a flow regime map with property and diameter corrected superficial liquid and vapor velocities as the co-ordinate axes. However, they suggested that the effects of these corrections on the transition lines are insignificant compared to the influence of superficial velocities.

Horizontal Flow Pattern Maps:

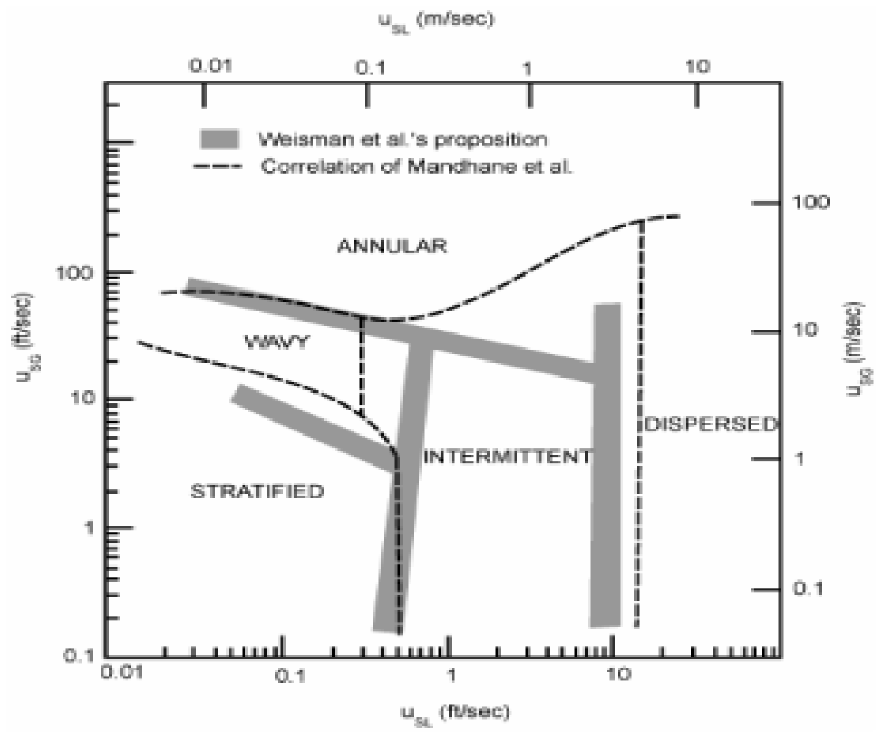


Fig no: 08: Weisman map to predict flow pattern based on superficial gas velocities and superficial liquid velocities.

4.5.1. Types of Flow Pattern:

For horizontal flow, the phases tend to separate due to differences in density, causing a form of stratified flow to be very common. This makes the heavier (liquid) phase tend to accumulate at the bottom of the pipe. When the flow occurs in a pipe inclined at some angle other than vertical or horizontal, the flow patterns take other forms. In these situations, a form of slug flow is very common. The effect of gravity on the liquid precludes stratification. The common flow patterns for horizontal and slightly upward inclined flows in a round tube are given below. Flow patterns that appear here are more complex than those in vertical flow because the gravitational force acts normal to the direction of the flow rather than parallel to it, as was the case for the vertical flow, and this results in the asymmetry of the flow. As the quality, *x*, is gradually increased from zero, the flow patterns obtained are:

Stratified Flow:

Stratified flow consists of two superposed layers of gas and liquid, formed by segregation under the influence of gravity. Note that this flow pattern does not usually occur; the interface is almost smooth. Usually occurs at low gas velocities.

Wavy Flow:

Increasing the gas velocity in a stratified flow leads to the formation of waves on the interface. These travel in the direction of flow. However crest of this wave does not touch the top of the tube. The wave amplitude increases as the gas velocity increases.

Annular Flow:

At even larger flow rates, the liquid forms a continuous annular film around the perimeter of the tube, the film is thicker at the bottom than the top. The interface between liquid interface and vapor core is distributed by small amplitude waves and the droplets may be dispersed in the gas core.

Plug Flow:

The individual small gas bubbles have coalesced to produce long plugs. In the literature sometimes the flow pattern observed at very low flow quality, prior to the plug flow, is referred to as **Bubbly flow**. In this situation the gas bubbles tend to flow along the top of the tube.

Slug Flow:

At higher velocities, diameter of the elongated bubbles become similar to the channel height. The liquid slug separating such elongated bubbles can also be described as large amplitude waves.

Dispersed Bubble:

At high liquid rates and low gas rates, the gas is dispersed as bubbles in a continuous liquid phase. The bubble density is higher toward the top of the pipeline, but there are bubbles throughout the cross section. Dispersed flow occurs only at high flow rates and high pressures. This type of flow, which entails high-pressure loss, is rarely encountered in flow lines

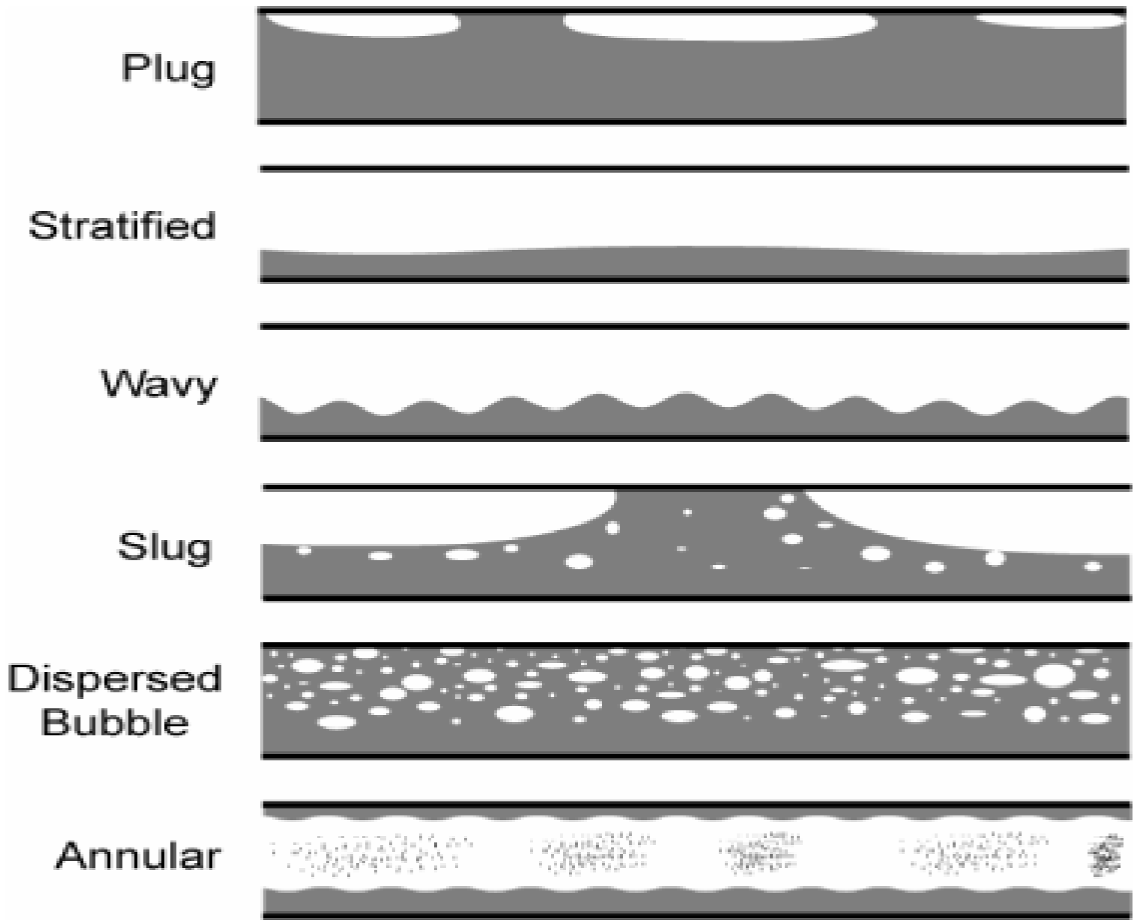


Fig: no: 09: Types of Horizontal flow regimes

4.6. Calculation of Physical Parameters:

- Gas Density:

An important property of any gas is its density. **Density** is defined as the mass of an object divided by its volume. Gas density varies with pressure within the pipeline.

- Superficial Velocity:

The superficial velocity is the velocity of one phase of a multiphase flow, assuming that the phase occupies the whole cross section of pipe by itself. It is defined as follows:

$$V_{SW} = \frac{Q_W}{A}$$

$$V_{SO} = \frac{Q_O}{A}$$

$$V_{SG} = \frac{Q_G}{A}$$

Where $A=A_W+A_O+A_G$

A = Total C/S area of the pipe

Q_G= Gas Volumetric flow rate

Q_O = Oil Volumetric flow rate

V_{SG} = Superficial gas velocity

V_{SO} = Superficial oil velocity

V_{SW} = Superficial water velocity

- Multi-Phase flow mixture velocity:

Mixture velocity is the sum of phase superficial velocities:

$$V_M=V_{SW} + V_{SO} + V_{SG}$$

Where V_M is multiphase mixture velocity

- Holdup:

Holdup is the cross-sectional area, which is locally occupied by one of the phases of a multiphase flow, relative to the cross-sectional area of the pipe at the same local position.

For Liquid Phase:

$$H_L = \frac{A_L}{A} = \frac{A_W + A_O}{A} = H_W + H_O$$

For Gas Phase:

$$H_G = \frac{A_G}{A}$$

Where the parameter H is the phase holdup and subscripts are L for the liquid and G for the gas phase. Although "holdup" can be defined as the fraction of the pipe volume occupied by a given phase, holdup is usually defined as the in-situ liquid volume fraction whereas the term "void fraction" is used for the in-situ gas volume fraction.

- Phase Velocity:

Phase velocity (in-situ velocity) is the velocity of a phase of a multiphase flow based on the area of the pipe occupied by that phase. It may also be defined for each phase as follows:

$$V_L = \frac{V_{SL}}{H_L} = \frac{V_{SW} + V_{SO}}{H_L}$$

$$V_G = \frac{V_{SG}}{H_G}$$

- No Slip

If there is no slip between the phases, V_L=V_G, and by applying the no-slip assumption to the liquid holdup definition, it can be shown.

$$H_{L,\text{no-slip}} = \lambda_L = \frac{V_{SL}}{V_M}$$

Investigators have observed that the no-slip assumption is not often application. For certain flow patterns in horizontal and upward inclined pipes, gas tends to flow faster than the liquid (positive slip). For some flow regimes in downward flow, liquid can flow faster than the gas (negative slip).

5. Optimization of Gas-Condensate Gathering network

Objective: Usually, the objective is to minimize the capital cost and calculate the operating conditions and physical parameters for the optimized gas-condensate gathering network. Doing optimization is a complicated issue that requires intensive study in its own right. To keep this research focused, we restricted our attention to simple objective functions. The flow rate and other operational parameters are checked during optimization such that no disturbance should occur beyond to operation.

Objective function involves cost of pipeline per kilometer including fitting, valves, regulators insulation and other miscellaneous costs.

Optimization option: Minimization of Objective function

Taking Pipeline cost per kilometer as 0.435 MM \$/inch diameter

Cost of Compressor per 1000 HP is 4.66 MM \$

Equation:

Total Capital cost:

$$\sum_{i=1}^{12}(0.436 * \text{Internal Diameter}) + \sum_{i=1}^{2}(0.436 * \text{Internal Diameter}) + (0.00466 \text{ x Compressor Power})$$

i= Pipe Number

Control Variables: The decision variables are compressor power, pipe diameters, flow rates. Compressor is used at process platform to increase the pressure for gas transportation. Usually the duty of compressor is to increase pressure up to 90 to 100kg/cm^2 in gas transportation pipeline.

Constraints: Sink pressure act as constraint, since delivery is always fixed at the gas processing plant and compressor outlet pressure is another constraint. Outlet pressure must be less than maximum allowable pressure to avoid the unnecessary accidents.

6. Results

Pressure drop Results:

Table: no: 01: Pressure drop Results in Link001 to Link012, L01 & L02

Link Name	From Node	To Node	Flow Rate	Pressure IN	Pressure OUT	Pressure Imbalance
L001	A	J001	143154.493	79.98	76.98	0.000
L002	B	J001	217893.737	79.29	76.98	0.000
L005	D	J002	91643.433	77.22	75.22	0.000
L006	E	J002	58636.851	75.84	75.22	0.000
L007	J002	J003	150280.285	75.22	74.29	0.000
L008	F	J003	219793.512	77.22	74.29	0.000
L010	G	J004	129100.146	76.53	74.70	0.000
L011	H	J004	201584.570	76.53	74.70	0.000
L003	J001	E1	361048.230	76.98	68.60	0.000
L004	C	E1	212481.173	78.60	68.60	0.000
L009	J003	E1	370043.796	74.29	68.60	0.000
L012	J004	E1	330684.716	74.70	68.60	0.000
Platform	E1	E2	1274257.91	68.60	80.91	0.000
01	E2	N1	1274257.91	80.91	44.58	0.000
02	N1	GASP	1274257.91	44.58	29.10	0.000

Maximum Pressure Imbalance: 0.0000002 bar at node E1.

Node Summary:

Table: no: 02: Node Summary Results at each node

Node	Pressure	Temperature
A	80.00	165.00
B	79.310	170.00
J001	77.00	166.20
C	78.60	169.00
D	77.24	169.00
E	75.86	166.00
J002	75.2413	156.20
F	77.24	165.00
J003	74.3103	148.10
G	76.55	165.00
H	76.55	165.00
J004	74.724	164.20
E1	68.6137	139.00
E2	80.9310	168.90
N1	44.5931	69.50
GASP	29.11	73.60

Compressor Report:

Table: no: 03: Compressor detailed Report

Suction Pressure	Outlet Pressure	Outlet Temperature	Head MHD	Efficiency	Power/stage
994.90	1173.50	168.90	3150	80	11000

Flow Regime Results:

Table: no: 04: Flow Regime Results in Link001 to Link012, L01 & L02

Link No	SLV	SGV	Flow Regime
L001	0.02	7.65	Annular
L002	0.03	11.83	Annular
L003	0.03	13.23	Annular
L004	0.01	12.25	Annular
L005	0.01	5.045	Annular
L006	0.00373	3.24	Stratified
L007	0.0099	5.16	Stratified
L008	0.01	12.22	Stratified
L009	0.02	10.20	Annular
L010	0.02	7.18	Stratified
L011	0.02	11.28	Annular
L012	0.025	12.26	Annular
01	0.00	14.60	1-phase
02	0.00	22.50	1-phase

SLV: Superficial liquid velocity

SGV: Superficial gas velocity

Amount of water removed: 19.890 m^3/hr

Amount of oil removed: 22.582 m^3/hr

Gas Density:

Table: no: 05: Gas density Results in Link001 to Link012, L01 & L02

Link No	Gas Density		
	Initial	Middle	Final
L001	0	41.04126	40.35862
L002	0	40.35393	39.76623
L003	0	38.73899	37.2832
L004	0	38.25689	35.66555
L005	0	39.82074	39.69241
L006	0	39.73875	40.04163
L007	0	41.00395	42.04032
L008	0	39.49599	38.75711
L009	0	39.66985	39.15062
L010	0	39.41038	38.97008
L011	0	39.37574	38.89957
L012	0	38.15456	37.22683
L01	0	38.22639	27.77301
L02	0	23.12833	17.54716

Gas Holdup:

Table: no: 06: Gas holdup Results in Link001 to Link012, L01 & L02

Link No	Gas Holdup		
	Initial	Middle	Final
L001	0	0.000142	0.000291
L002	0	$4.85*10^{-5}$	$9.71*10^{-5}$
L003	0	0.000301	0.000602
L004	0	0.00024	0.000479
L005	0	0.000216	0.000433
L006	0	0.000142	0.000284
L007	0	0.000185	0.00037
L008	0	$6.74*10^{-5}$	0.000135
L009	0	0.000527	0.001053
L010	0	0.000101	0.000202
L011	0	$4.49*10^{-5}$	$8.97*10^{-5}$
L012	0	0.000255	0.000522
L01	0	0.016618	0.033237
L02	0	0.004373	0.008746

Liquid Holdup:

Table: no: 07: Liquid holdup Results in Link001 to Link012, L01 & L02

Link No	Liquid holdup		
	Initial	Middle	Final
L001	0	2.708326	5.406735
L002	0	0.903444	1.803615
L003	0	5.422984	10.81255
L004	0	3.823388	7.577562
L005	0	4.261828	8.523646
L006	0	2.608718	5.228902
L007	0	3.523705	7.084666
L008	0	1.073899	2.142209
L009	0	8.973147	17.96993
L010	0	1.830434	3.65685
L011	0	0.765913	1.529255
L012	0	4.429531	8.870658
L01	0	0	0
L02	0	0	0

Pressure:

Table: no: 08: Pressure Results in Link001 to Link012, L01 & L02

Link No	Pressure		
	Initial	Middle	Final
L001	79.97903	78.49097	76.98183
L002	79.28957	78.14271	76.98183
L003	76.98183	72.85992	68.59617
L004	78.60009	73.73477	68.59617
L005	77.22114	76.22269	75.22056
L006	75.84219	75.53206	75.22056
L007	75.22056	74.75069	74.28945
L008	77.22114	75.76543	74.28945
L009	74.28745	71.46109	68.59614
L010	76.53166	75.62232	74.7048
L011	76.53166	75.62257	74.7048
L012	74.7048	71.69067	68.59617
L01	80.90788	64.49749	44.58039
L02	44.58039	37.70832	29.10099

Temperature:

Table: no: 09: Temperature Results in Link001 to Link012, L01 & L02

Link No	Temperature		
	Initial	Middle	Final
L001	165	163.2598	161.5681
L002	170	169.5268	169.1559
L003	166.1731	153.3846	141.7548
L004	169	166.0491	163.2042
L005	169	163.1563	157.8492
L006	166	159.408	153.4946
L007	156.1611	138.7154	124.0535
L008	165	164.2076	163.4255
L009	148.1311	139.9989	118.1494
L010	165	164.2848	163.5773
L011	165	164.7657	164.532
L012	164.1584	152.4996	141.8261
L01	168.9269	100.4764	67.54784
L02	69.54784	71.71917	73.59583

No-slip Holdup:

Table: no: 10: No Slip holdup Results in Link001 to Link012, L01 & L02

Link No	No –slip hold up.		
	Initial	Middle	Final
L001	0	0.002218	0.002192
L002	0	0.002813	0.002773
L003	0	0.00255	0.002519
L004	0	0.001143	0.00107
L005	0	0.002239	0.002257
L006	0	0.001151	0.001187
L007	0	0.001983	0.00211
L008	0	0.00117	0.001149
L009	0	0.001579	0.001617
L010	0	0.002234	0.002216
L011	0	0.002003	o.001987
L012	0	0.00218	0.001987
L01	0	0	0
L02	0	0	0

Flow mixture velocity:

Table: no: 11: Flow mixture Results in Link001 to Link012, L01 & L02

Link No	Mixture velocity		
	Initial	Middle	Final
L001	0	7.66306	7.79247
L002	0	11.8696	12.04454
L003	0	13.21717	13.75127
L004	0	12.18879	13.07342
L005	0	5.056131	5.072568
L006	0	3.238242	3.213859
L007	0	5.194579	5.06716
L008	0	12.21135	12.4439
L009	0	10.17994	10.31533
L010	0	7.19686	7.27044
L011	0	11.24487	11.38224
L012	0	12.28654	12.59363
L01	0	12.70908	17.49261
L02	0	21.00551	27.68666

Superficial liquid velocity:

Table: no: 12: Superficial liquid velocity Results in Link001 to Link012, L01 & L02

Link No	Superficial liquid velocity		
	Initial	Middle	Final
L001	0	0.016997	0.017081
L002	0	0.033387	0.033403
L003	0	0.033699	0.03464
L004	0	0.013933	0.013982
L005	0	0.011319	0.011449
L006	0	0.003728	0.003813
L007	0	0.010301	0.01069
L008	0	0.014282	0.014303
L009	0	0.016071	0.016129
L010	0	0.016077	0.016129
L011	0	0.022523	0.022519
L012	0	0.026778	0.02837
L01	0	0	0
L02	0	0	0

Superficial gas velocity:

Table: no: 13: Superficial gas velocity Results in Link001 to Link012, L01 & L02

Link No	Superficial gas velocity		
	Initial	Middle	Final
L001	0	7.646062	7.775389
L002	0	11.83621	12.01114
L003	0	13.18348	13.71663
L004	0	12.17485	13.05944
L005	0	5.044812	5.05647
L006	0	3.234514	3.210046
L007	0	5.184278	5.05647
L008	0	12.19707	12.4296
L009	0	10.16386	10.29865
L010	0	7.180783	7.261916
L011	0	11.22235	11.35972
L012	0	12.25976	12.565226
L01	0	12.70908	17.49261
L02	0	21.00551	27.68666

Gas flow rate:

Table: no: 14: Gas Actual flow rate Results in Link001 to Link012, L01 & L02

Link no.	Gas Actual Flow rate		
	Initial	Middle	Final
L001	0	0.143154	0.143154
L002	0	0.217894	0.217894
L003	0	0.361048	0.361048
L004	0	0.212481	0.212481
L005	0	0.091643	0.091643
L006	0	0.058637	0.058637
L007	0	0.15028	0.15028
L008	0	0.219763	0.219763
L009	0	0.370044	0.370044
L010	0	0.1291	0.1291
L011	0	0.201584	0.201584
L012	0	0.330685	0.330685
L01	0	1.274257	1.274257
L02	0	1.274257	1.274257

Gas velocity:

Table: no: 15: Gas velocity Results in Link001 to Link012, L01 & L02

Link No	Gas Velocity		
	Initial	Middle	Final
L001	0	7.788035	7.919222
L002	0	12.05616	12.23352
L003	0	13.42033	13.96127
L004	0	12.36751	13.26194
L005	0	5.144249	5.160845
L006	0	3.294119	3.26947
L007	0	5.283545	5.154284
L008	0	12.39099	12.62616
L009	0	10.33738	10.47477
L010	0	7.310965	7.393239
L011	0	11.41361	11.55267
L012	0	12.4684	12.77938
L01	0	12.70908	17.49261
L02	0	21.00551	27.68666

Optimization Results:

Decision variables:

Table: no: 16: Decision variables data

Link No	Variable	Lower Bound	Current Value	Upper Bound	Move	Shadow Price
L001	PIPE ID	8.00	11.7464	30.00	-0.5056	-0.3774
L002	PIPE ID	8.00	14.3623	30.00	2.1103	1.5877
L005	PIPE ID	8.00	17.0056	30.00	1.7536	0.2852
L006	PIPE ID	8.00	13.9339	30.00	1.6819	0.00
L007	PIPE ID	8.00	11.7464	30.00	-0.5056	-4.4715
L008	PIPE ID	8.00	11.7464	30.00	-0.5056	-0.0054
L010	PIPE ID	8.00	14.3897	30.00	-0.8623	-0.2854
L011	PIPE ID	8.00	13.8123	30.00	1.5603	0.00
L003	PIPE ID	8.00	16.8397	30.00	-0.5383	0.00
L004	PIPE ID	8.00	11.7464	30.00	-0.5056	0.00
L009	PIPE ID	8.00	13.1015	30.00	0.8495	0.7695
L012	PIPE ID	8.00	15.4104	30.00	0.1584	0.00
Platform	SET POWER	0.00	15637.27	50000.00	4637.27	0.00309
01	PIPE ID	18.00	28.0582	30.00	-1.3197	-24.2985
02	PIPE ID	18.00	28.0251	30.00	-1.3529	-3.9936

Constraint Variables:

Table: no: 17: Constraint variables data

Name	Type	Lower Bound	Current Value	Upper Bound	Move	Shadow Price
GASP	Pressure	20.6896	25.20	51.72	-56.6752	-0.0286
Compressor	Outlet Pressure	1.0	89.35	172.00	122.17	0.00

Objective function Summary:

Value of Objective function after Optimization: 1508.361 Million $

Value of objective function after Optimization: 1458.37 Million $

Change from value at start: - 49.991 Millions $

Best optimized results are obtained after 30th cycle.

Separator required in this network is a three phase separator. Cost of 3-phase separator for separation of oil, gas and water is $ 50,000.

Overall capital cost involves cost of pipeline construction from purchasing to laying per kilometer, cost of compressor per thousand HP, cost of separator.

Therefore, total optimized capital cost of this project is 1458.42 Million $

Pressure drop results:

Table: no: 18: Pressure drop Results in Link001 to Link012, L01 & L02

Link Name	From Node	To Node	Flow Rate	Pressure IN	Pressure OUT	Pressure Imbalance
L001	A	J001	143154.493	79.98	76.98	0.000
L002	B	J001	217893.737	79.29	76.98	0.000
L005	D	J002	91643.433	77.22	75.22	0.000
L006	E	J002	58636.851	75.84	75.22	0.000
L007	J002	J003	150280.285	75.22	74.29	0.000
L008	F	J003	219763.512	77.22	74.29	0.000
L010	G	J004	129100.146	76.53	74.70	0.000
L011	H	J004	201584.570	76.53	74.70	0.000
L003	J001	E1	361048.230	76.98	68.60	0.000
L004	C	E1	212481.173	78.60	68.60	0.000
L009	J003	E1	370043.796	74.29	68.60	0.000
L012	J004	E1	330684.716	74.70	68.60	0.000
Platform	E1	E2	1274257.91	68.60	80.91	0.000
01	E2	N1	1274257.91	80.91	44.58	0.000
02	N1	GASP	1274257.91	44.58	29.10	0.000

Maximum Pressure Imbalance: 0.0000002 bar at node E1.

Node Summary:

Table: no: 19: Node Summary at each node.

Node	Pressure	Temperature
A	80.00	165.00
B	79.3103	170.00
J001	77.358	167.00
C	78.62	169.00
D	77.24	169.00
E	75.86	166.00
J002	75.58	156.20
F	77.24	165.00
J003	75.28	151.00
G	76.55	165.00
H	76.55	165.00
J004	75.28	164.20
E1	70.83	140.00
E2	89.35	183.00
N1	45.91	74.00
GASP	25.20	77.00

Flow Pattern summary:

Table: no: 20: Flow Pattern Results in Link001 to Link012, L01 & L02

Link No	SLV	SGV	Flow Regime
L001	0.02	6.86	Annular
L002	0.03	11.73	Annular
L003	0.03	11.93	Annular
L004	0.01	10.89	Annular
L005	0.0098	4.43	Annular
L006	0.0017	0.74	Stratified
L007	0.0056	2.45	Stratified
L008	0.01	10.35	Annular
L009	0.01	8.73	Annular
L010	0.01	5.61	Stratified
L011	0.02	9.43	Annular
L012	0.02	10.23	Annular
01	0.00	11.79	1-phase
02	0.00	18.86	1-phase

Amount of water removed: 20.867 m^3/hr

Amount of oil removed: 22.084 m^3/hr

7. Conclusions and Recommendations

A comprehensive offshore gas condensate gathering network is designed for this study. Based on analysis of data, comparison with literature, and physical parameters the proposed network is completely viable and obtained acceptable results. The major part is performing capital cost optimization; during this changes occurred in pressures, temperature. Changed valued are completely with in limit and acceptable. After capital cost optimization cost of project get reduced by 49.991 Million $.Total capital cost of project after optimization is1458.42 Million $.

Recommendations for Future work:

1. In this study only capital cost optimization is performed, project can be extended to work on operational cost
2. At platform only separation and gas compression is done. Since in above mentioned network gas hydrates possibility is ruled out by providing thick insulation. One can perform Gas hydrates chances and mitigation techniques
3. By reducing the pressure drop capacity increasing studies can be performed.

Appendix: A

Network Data:

Calculation options:

Run Type	Network
Fluid Type	Condensate

Base Conditions:

Standard Temperature	60.00
Standard Pressure	1.00

Limits:

Maximum Pressure	1725
Minimum Pressure	1.00
Maximum Temperature	800.00
Minimum Temperature	-60.00

Segmentation Options:

Maximum No. of Segments	2000
Length Change (horizontal)	10

PVT data summary:

Gravity of condensate	0.85
Gravity of gas	0.60
Gravity of water	1.00

Solution Methods/Tolerances:

Network solution method	Pressure Balance
Maximum Iterations	2000
Absolute Pressure Tolerance	6.896×10^{-7}
Method of Initial solution estimate	Flow = 2

Water Properties:

Conductivity	0.519
Velocity	0.4469
Density	999.0110
Viscosity	0.001

Source Data:

Source	Estimated rate	WGR	CGR	Pressure	Temperature
A	0.145	20.00	16.80	80	165
B	0.219	30	16.78	79.31	170
C	0.210	10	11.2	78.62	169
D	0.0932	25	11.6	77.24	169
E	0.06	10	9.7	75.86	166
F	0.22	10	10.7	77.24	165
G	0.129	10	33.7	76.55	165
H	0.2	10	28.9	76.55	165

Sink Data: At GSPA

Pressure	27.035
Flow	1.270

Pipeline Structure Data:

Flow Code: Weisman correlation

Ambient Temperature: 50 F

Link no	ID	Length	Elevation Change	Roughness	Wall Thickness
L001	12.2520	3.9	18	0.0018	0.375
L002	12.2520	1.3	20	0.0018	0.375
L003	15.2520	5.2	17	0.0018	0.375
L004	12.2520	6.4	27	0.0018	0.375
L005	12.2520	5.8	15	0.0018	0.375
L006	12.2520	3.8	20	0.0018	0.375
L007	15.2520	3.2	12	0.0018	0.375
L008	12.2520	1.8	22	0.0018	0.375
L009	17.3780	7	12	0.0018	0.375
L010	12.2520	2.7	16	0.0018	0.375
L011	12.2520	1.2	17	0.0018	0.375
L012	15.2520	4.5	12	0.0018	0.375
01	29.3780	76	22	0.0018	0.4380
02	29.3780	20	5	0.0018	0.4380

Compressor Data:

No of Stages	01
Power	11000
Adiabatic Efficiency	80.00 %

Separator:

Condensate and water separator

Condensate to be removed	100 %
Water to be removed	100 %

Heat Transfer Data:

Here, in this project Heat Transfer Data is same for all pipes in a pipeline.

Fluid thermal Conductivity	0.027
Thermal Conductivity of Pipe	50.191
Thermal Conductivity of Soil	1.385
Effective Outside heat Transfer Coefficient	877.273
Thickness of Insulation	2.0
Thermal Conductivity of Insulation	0.1660
Overall U Factor	4.34

Optimization Data Input:

Control Variables:

Link No	CLASS	NAME	Variable	Lower Bound	Upper Bound	Variable perturbation	Objective coefficient
L001	PIPE	P1	PIPE ID	8.00	30.00	0.001	1.6961
L002	PIPE	P2	PIPE ID	8.00	30.00	0.001	0.5600
L005	PIPE	P3	PIPE ID	8.00	30.00	0.001	2.2610
L006	PIPE	P4	PIPE ID	8.00	30.00	0.001	2.7832
L007	PIPE	P5	PIPE ID	8.00	30.00	0.001	2.5227
L008	PIPE	P6	PIPE ID	8.00	30.00	0.001	1.6528
L010	PIPE	P7	PIPE ID	8.00	30.00	0.001	1.3918
L011	PIPE	P8	PIPE ID	8.00	30.00	0.001	0.7826
L003	PIPE	P9	PIPE ID	8.00	30.00	0.001	3.0446
L004	PIPE	P10	PIPE ID	8.00	30.00	0.001	1.1739
L009	PIPE	P11	PIPE ID	8.00	30.00	0.001	0.5219
L012	PIPE	P12	PIPE ID	8.00	30.00	0.001	1.9572
Platform	COMP	C001	SET POWER	0.00	50000.00	0.001	4.66×10^{-3}
01	PIPE	1	PIPE ID	18.00	30.00	0.001	33.0540
02	PIPE	2	PIPE ID	18.00	30.00	0.001	8.6992

Constraints:

Class	Name	Type	Lower Bound	Upper bound	Feasibility Tolerance
Node	GASP	Pressure	20.68	51.724	0.01
Compressor	C001	Outlet pressure	1.00	172.413	0.01

Optimization options:

Minimization Objective function:

Maximum number of cycles	30
Default fractional perturbation	0.00100
Tolerance in objective function	0.00010
Tolerance in decision variable	0.00100
Tolerance in constraints	0.01000
Number of damped cycles	05
Damping Factor	04

Appendix: B

Graphs:

1. Gas Density:

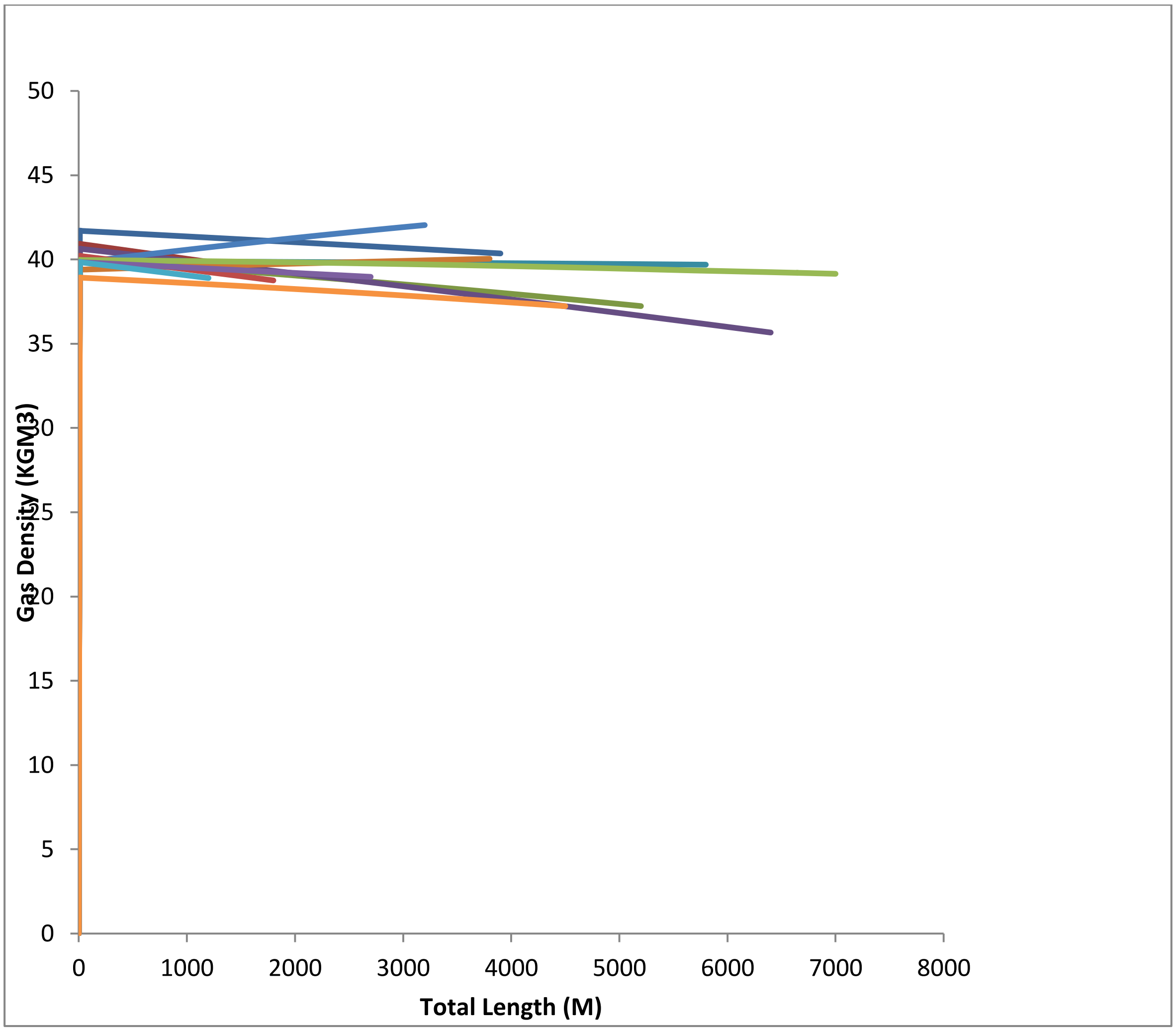


Fig: 10: Gas density profile for L001 to L0012

Gas Density in Link L001, Pipe P1
Gas Density in Link L002, Pipe P2
Gas Density in Link L003, Pipe P3
Gas Density in Link L004, Pipe P4
Gas Density in Link L005, Pipe P5
Gas Density in Link L006, Pipe P6
Gas Density in Link L007, Pipe P7
Gas Density in Link L008, Pipe P8
Gas Density in Link L009, Pipe P9
Gas Density in Link L010, Pipe P10
Gas Density in Link L011, Pipe P11
Gas Density in Link L012, Pipe P12

ii. Gas Holdup:

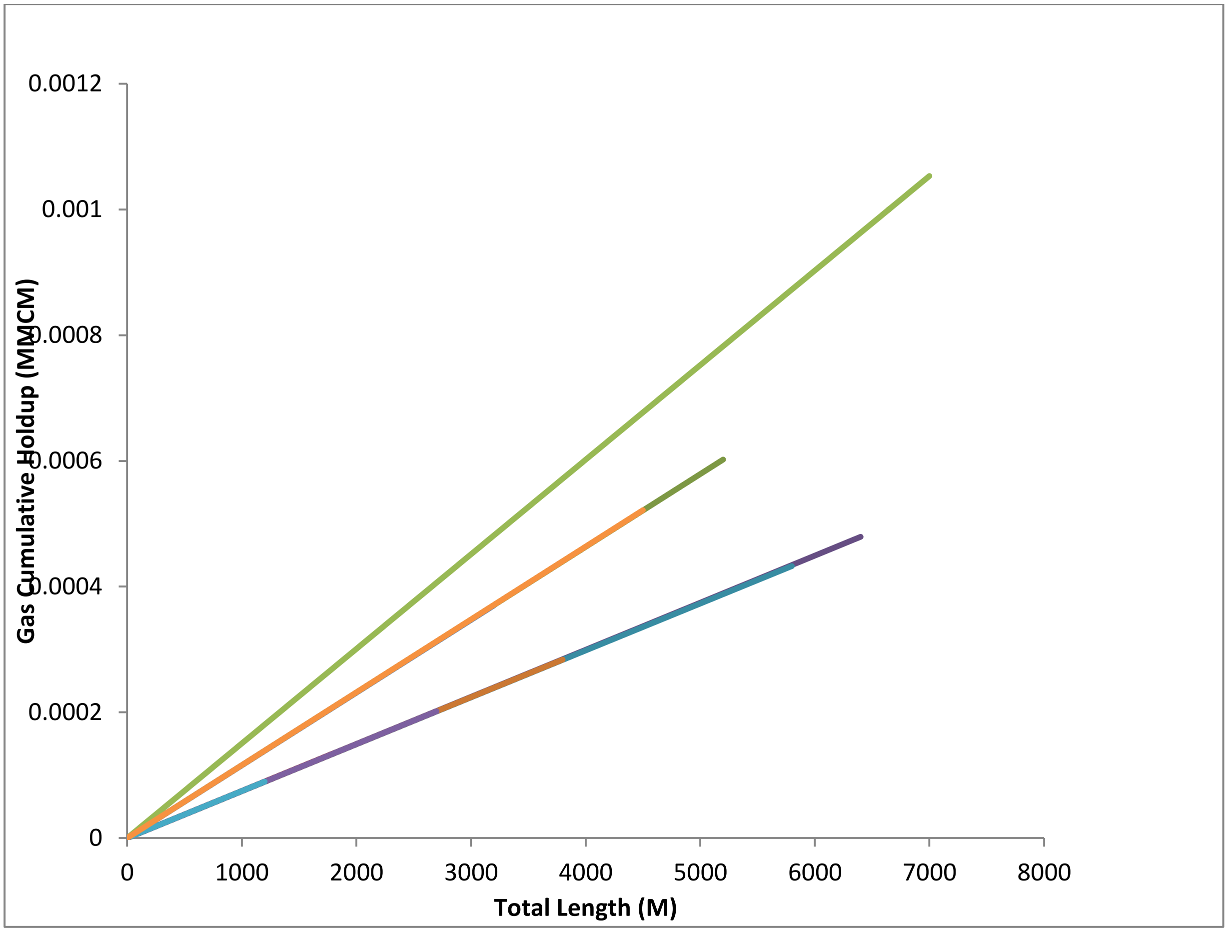
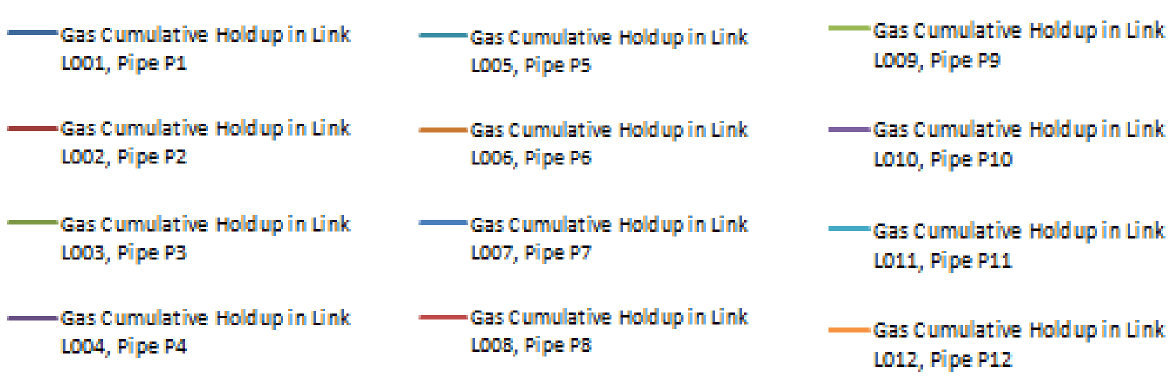


Fig: 11: Gas holdup profile for L001 to L0012



iii. Liquid Hold Up:

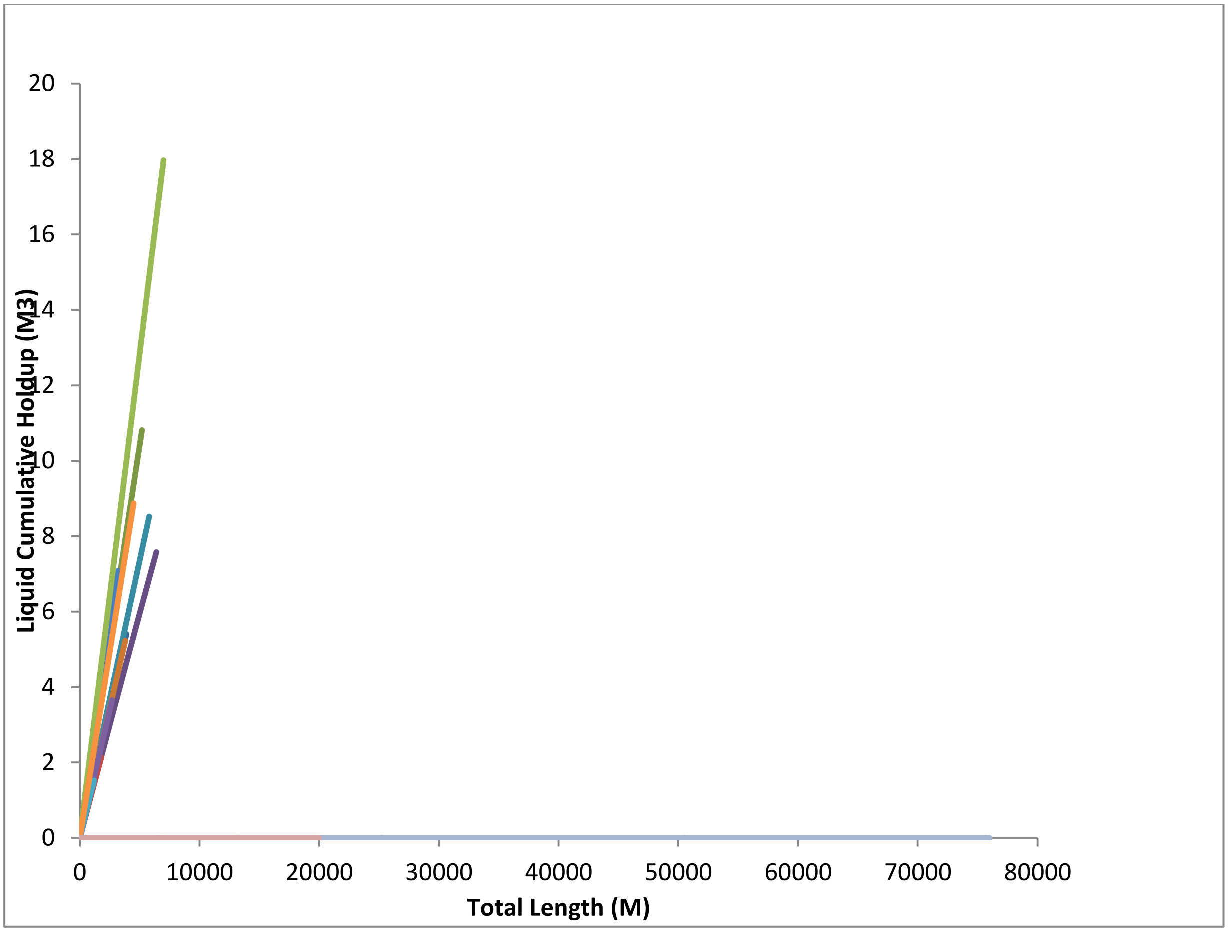
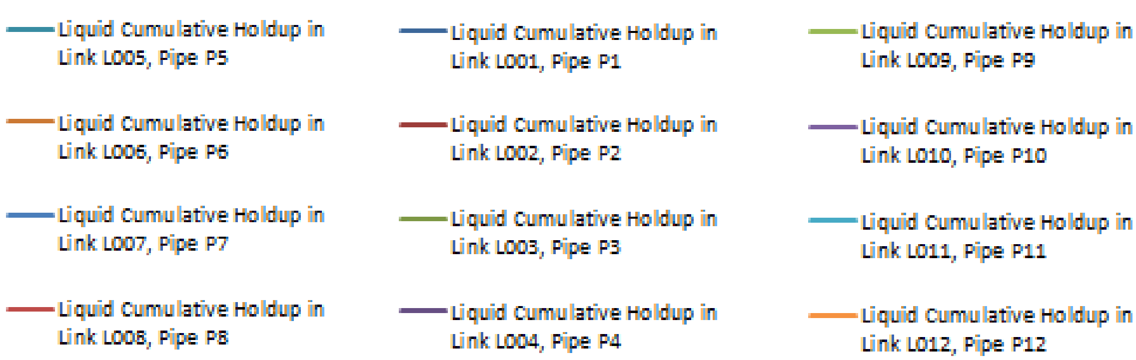


Fig: no: 12: Liquid holdup profile for L001 to L0012



iv. Pressure plot:

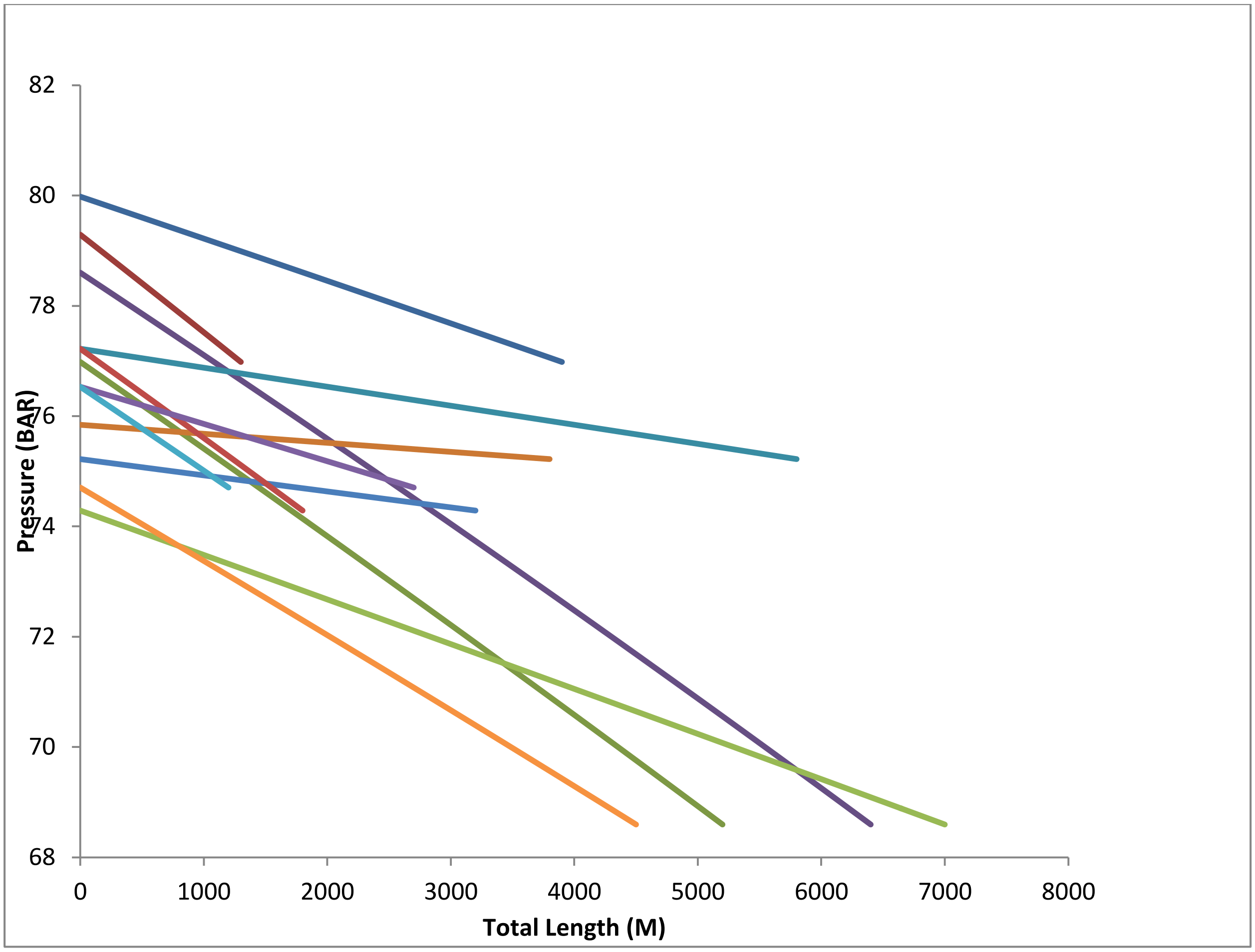
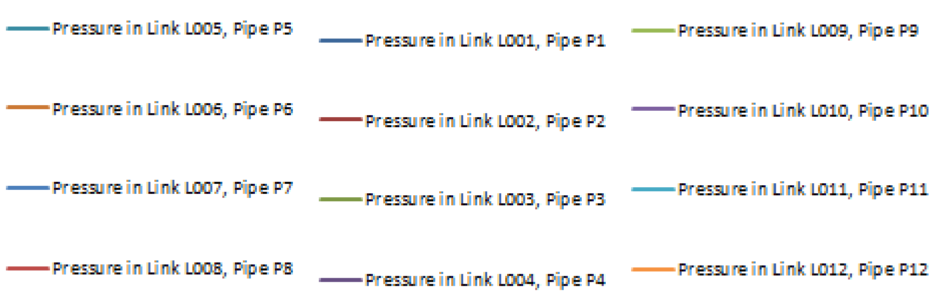


Fig: no: 13: Pressure profile for L001 to L0012



v. Temperature Plot:

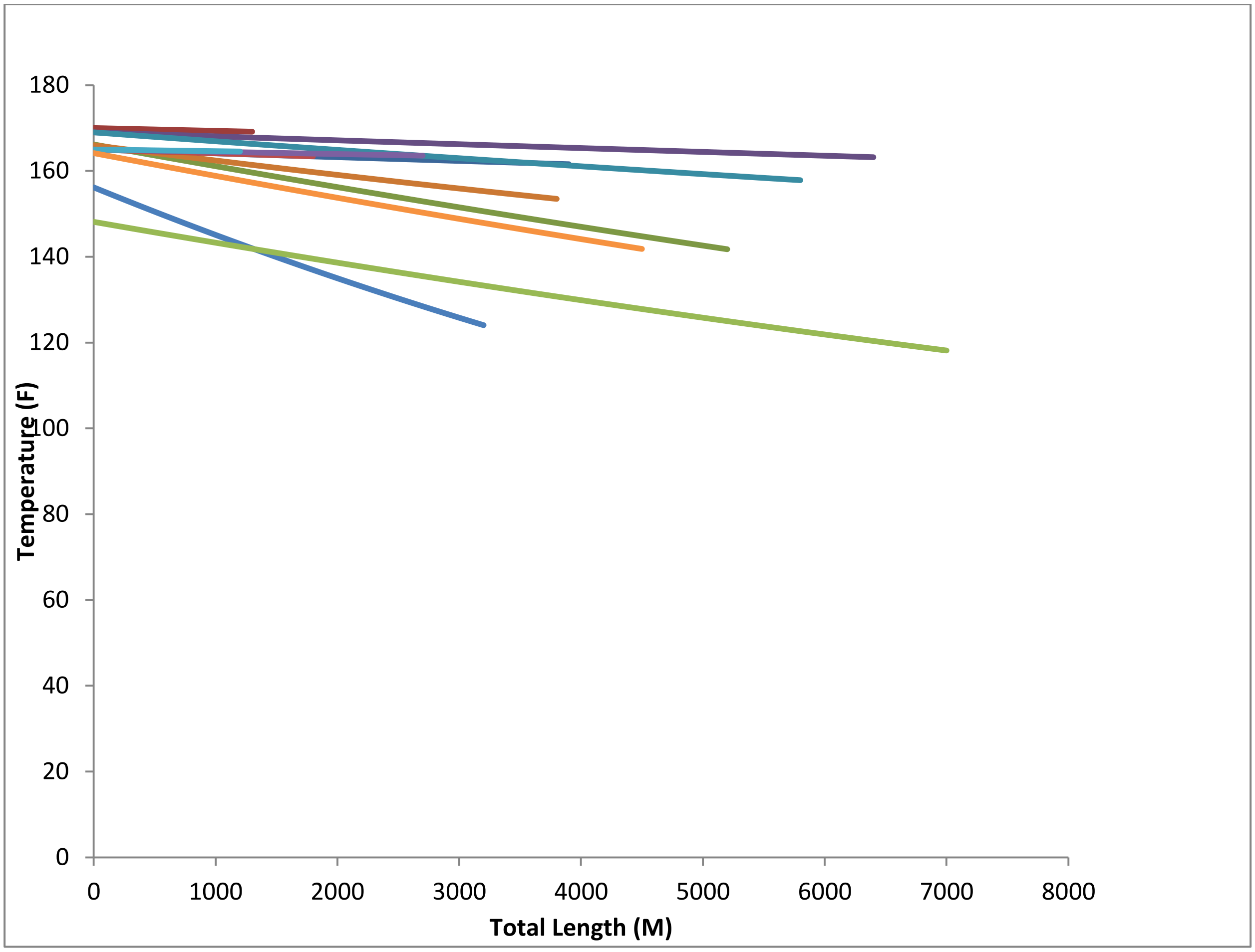
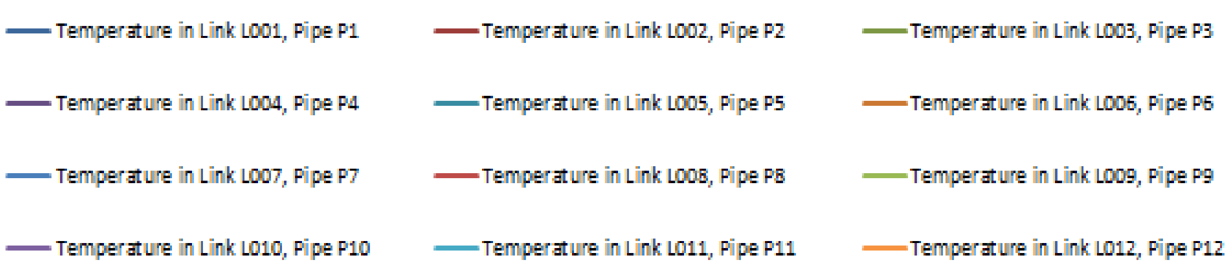


Fig: no: 14: Temperature profile for L001 to L0012



vi. No-slip holdup:

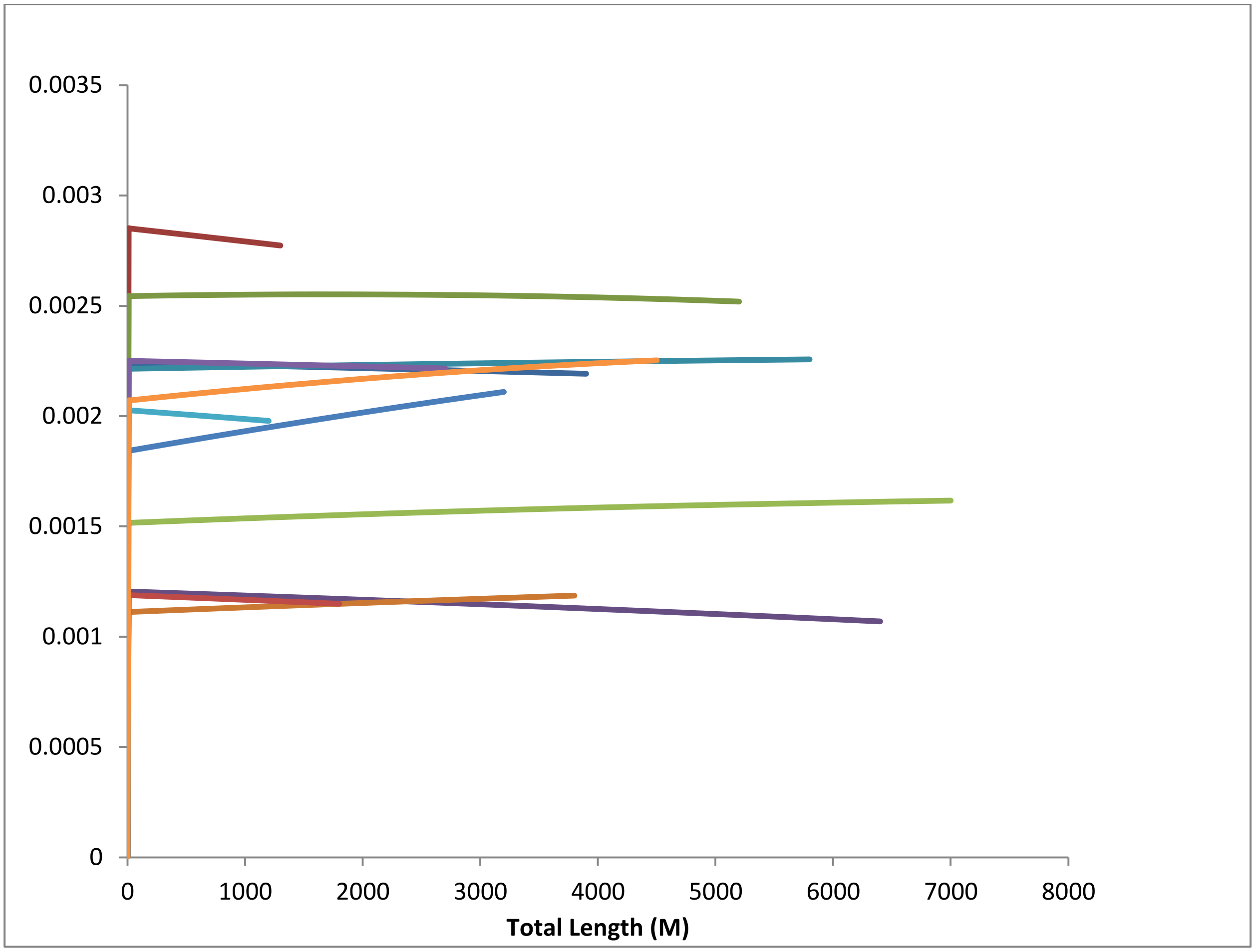
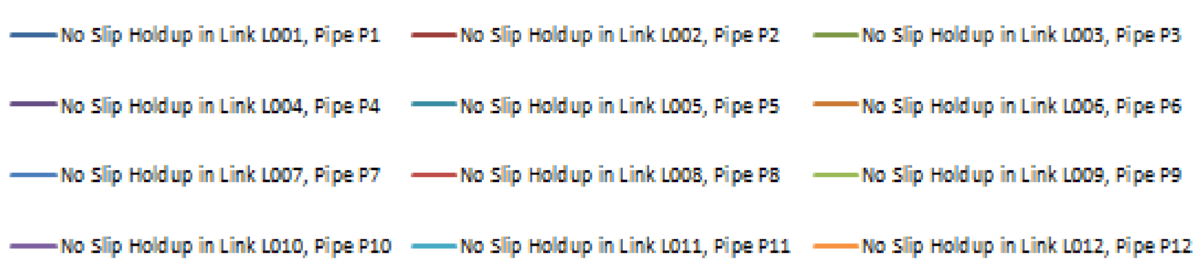


Fig: no: 15: No-Slip holdup profile for L001 to L0012



vii Mixed velocity

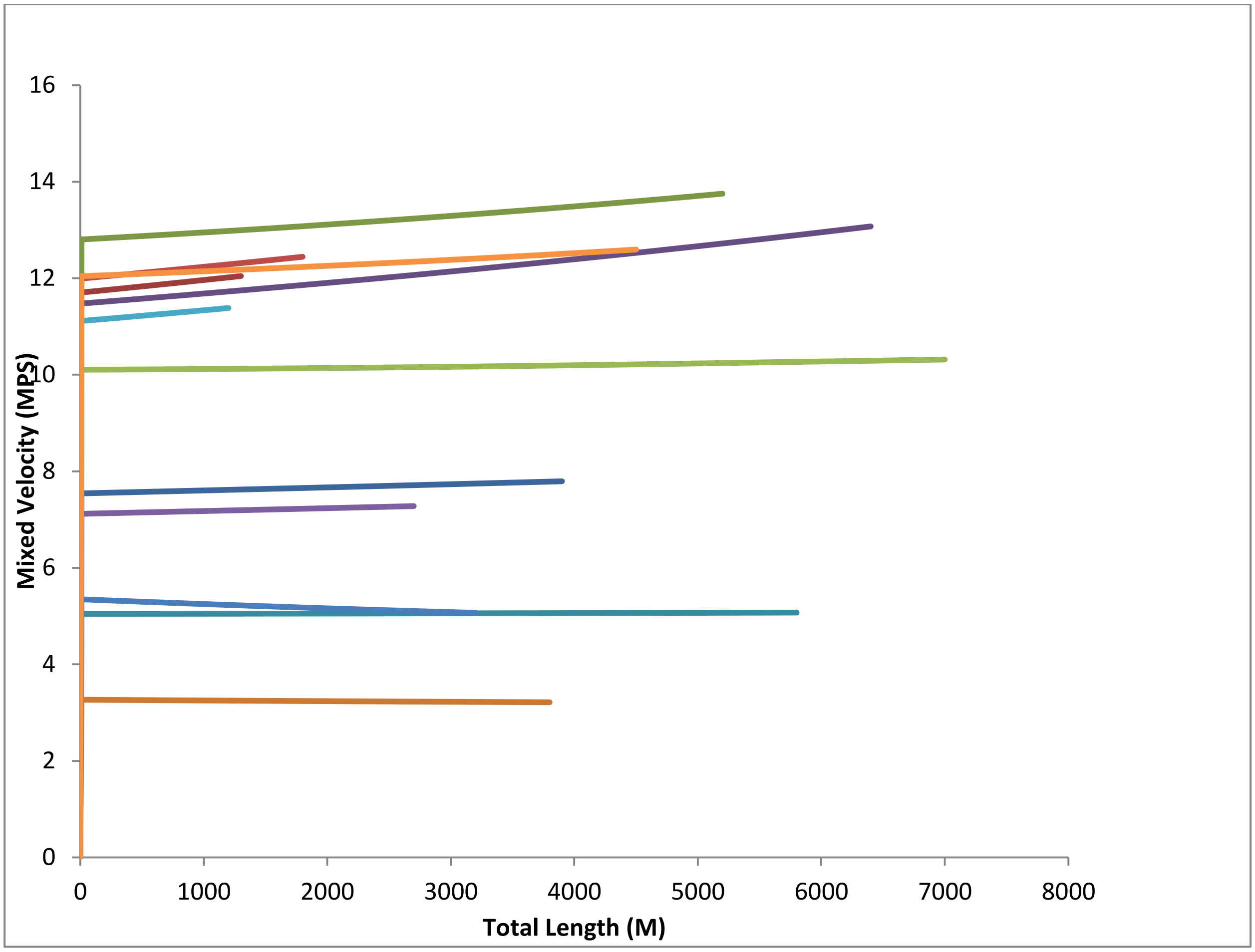


Fig: no: 16: Mixed velocity profile for L001 to L0012

Mixed Velocity in Link L005, Pipe P5
Mixed Velocity in Link L001, Pipe P1
Mixed Velocity in Link L009, Pipe P9
Mixed Velocity in Link L006, Pipe P6
Mixed Velocity in Link L002, Pipe P2
Mixed Velocity in Link L010, Pipe P10
Mixed Velocity in Link L007, Pipe P7
Mixed Velocity in Link L003, Pipe P3
Mixed Velocity in Link L011, Pipe P11
Mixed Velocity in Link L008, Pipe P8
Mixed Velocity in Link L004, Pipe P4
Mixed Velocity in Link L012, Pipe P12

viii. Superficial liquid velocity:

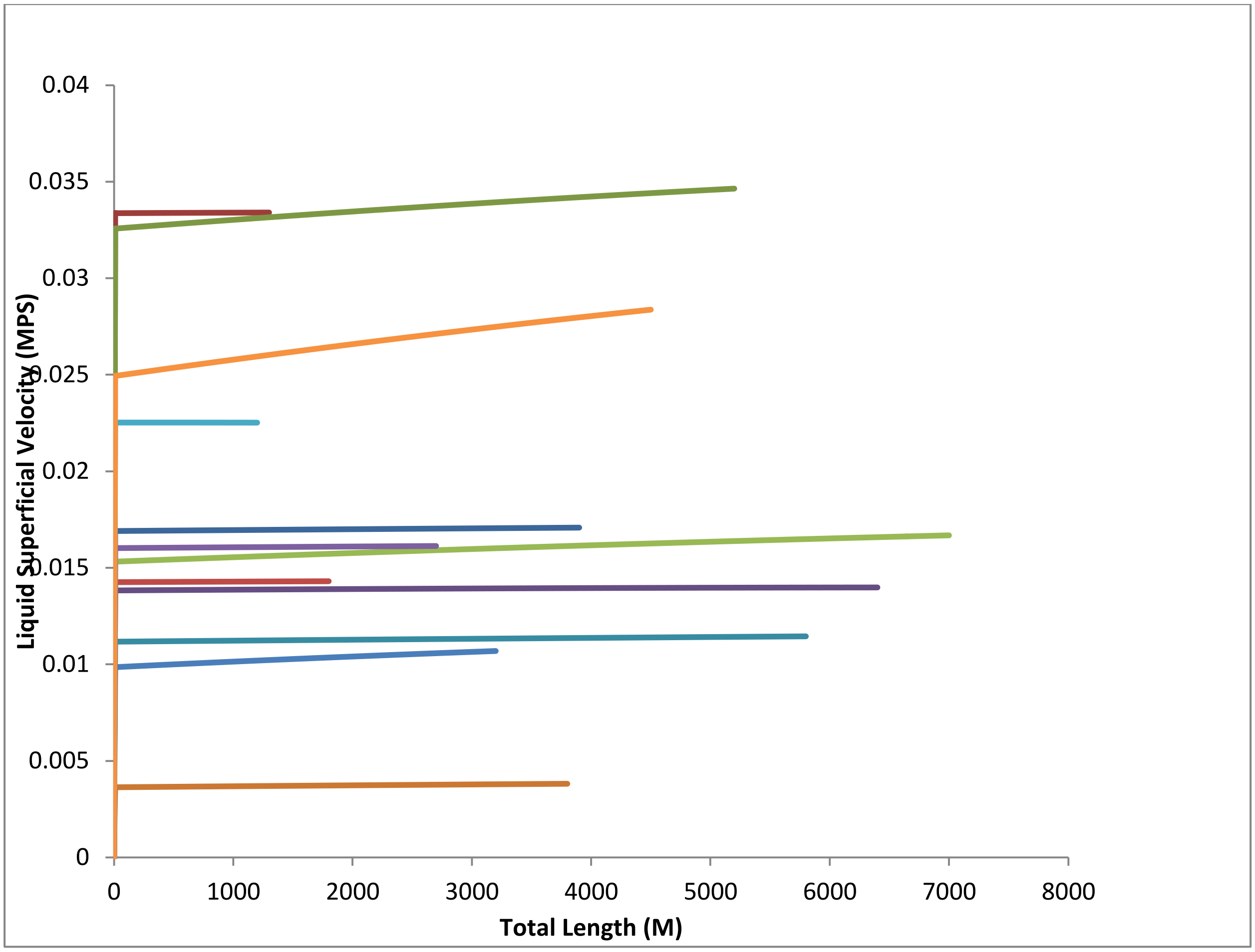
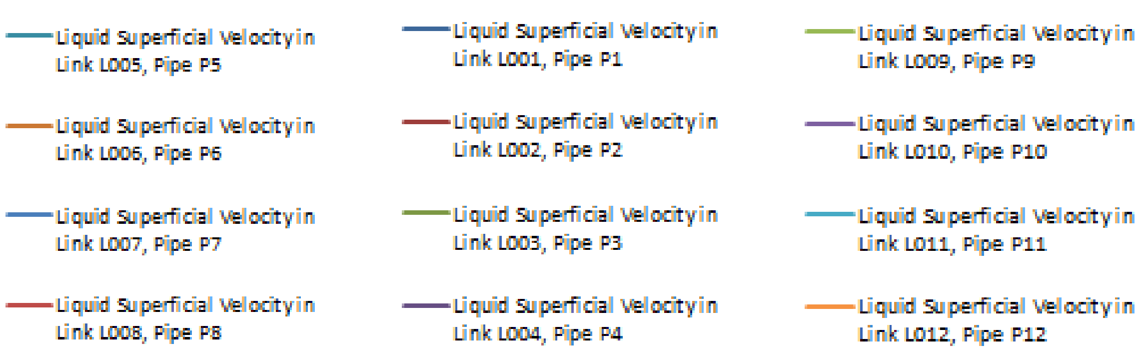


Fig: no: 17: Liquid Superficial Velocity profile for L001 to L0012



ix. Superficial gas velocity:

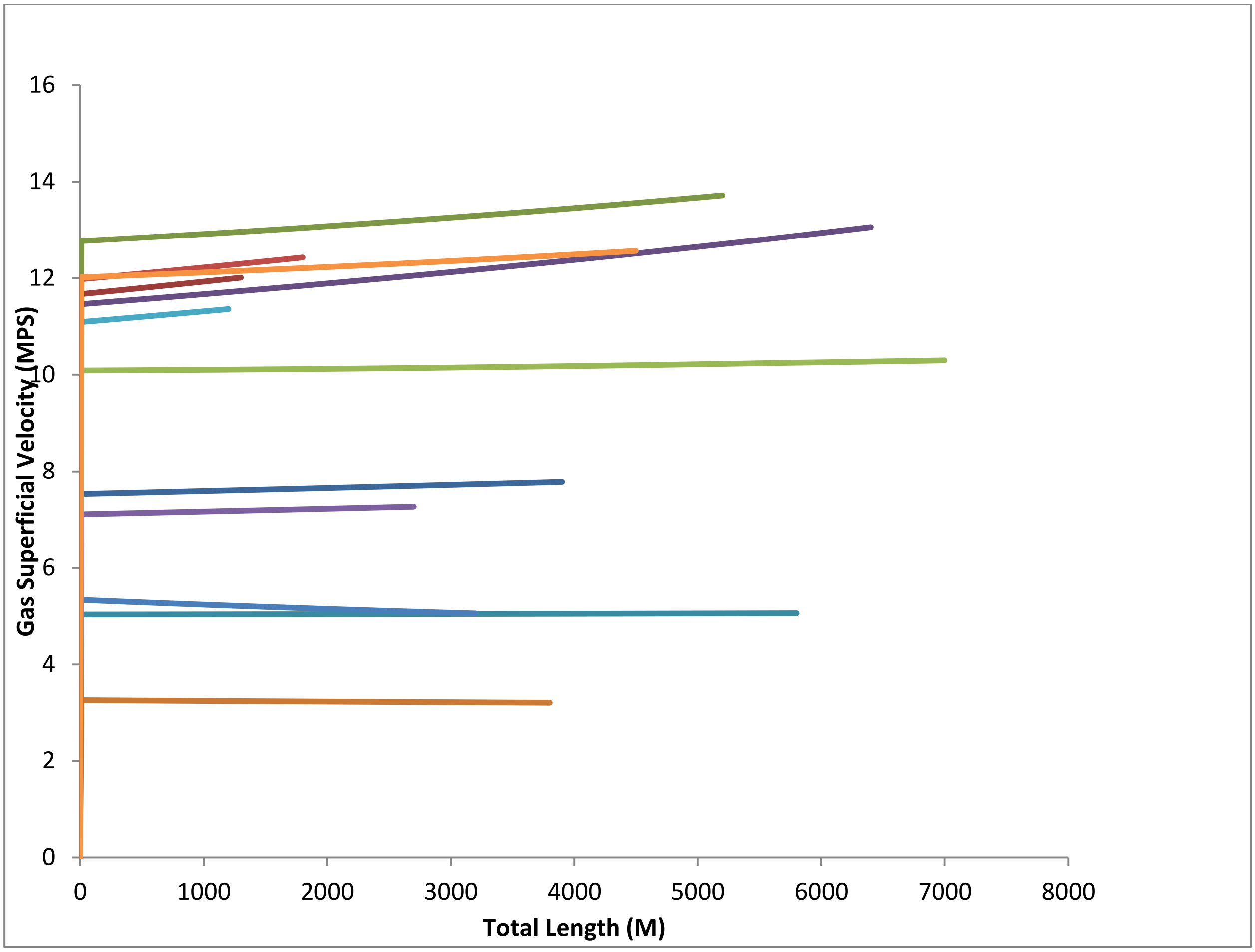
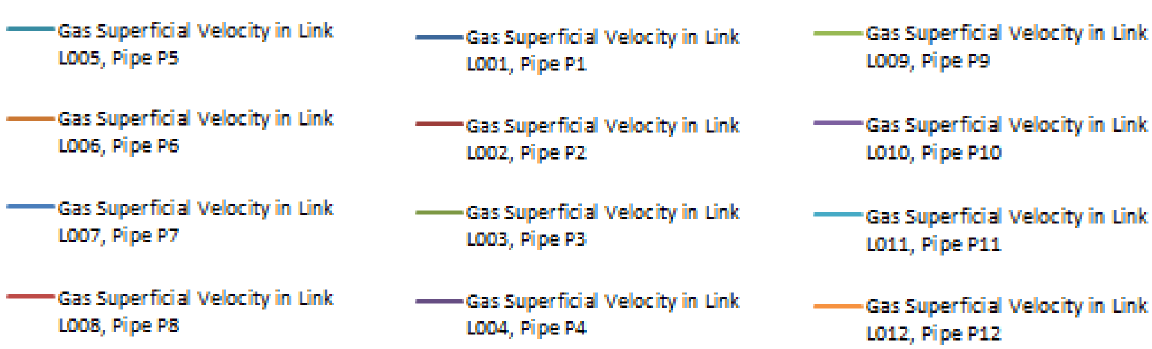


Fig: no: 18: Liquid Superficial Velocity profile for L001 to L0012



x. Gas velocity:

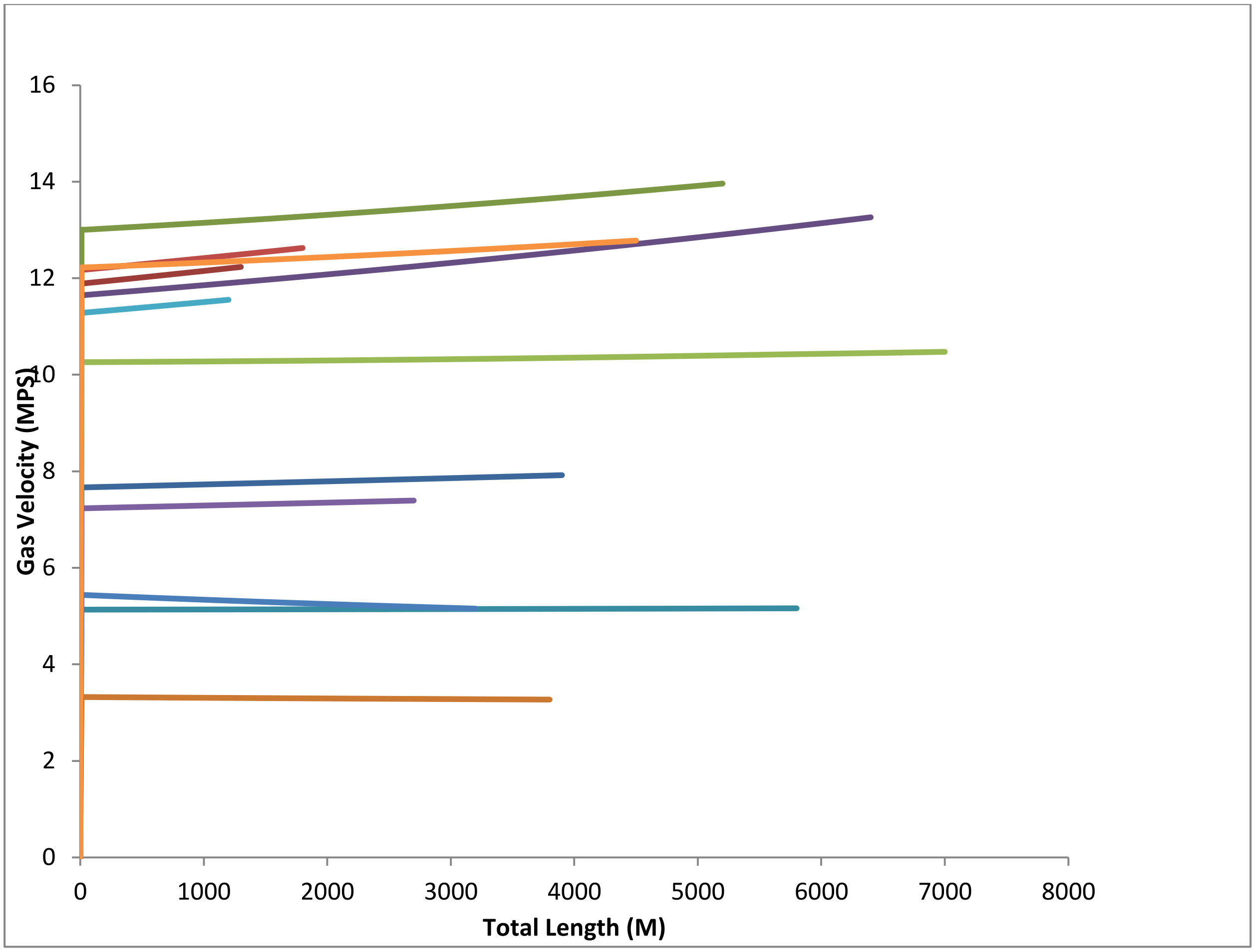
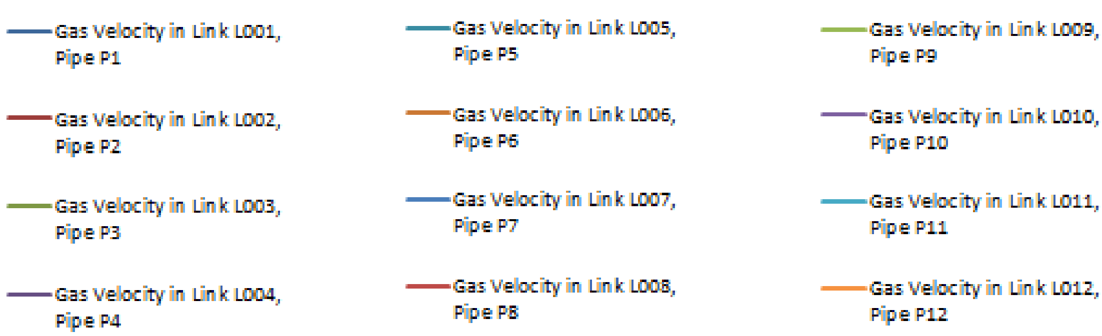


Fig: no: 19: Gas Velocity profile for L001 to L0012



xi. Gas flow rate:

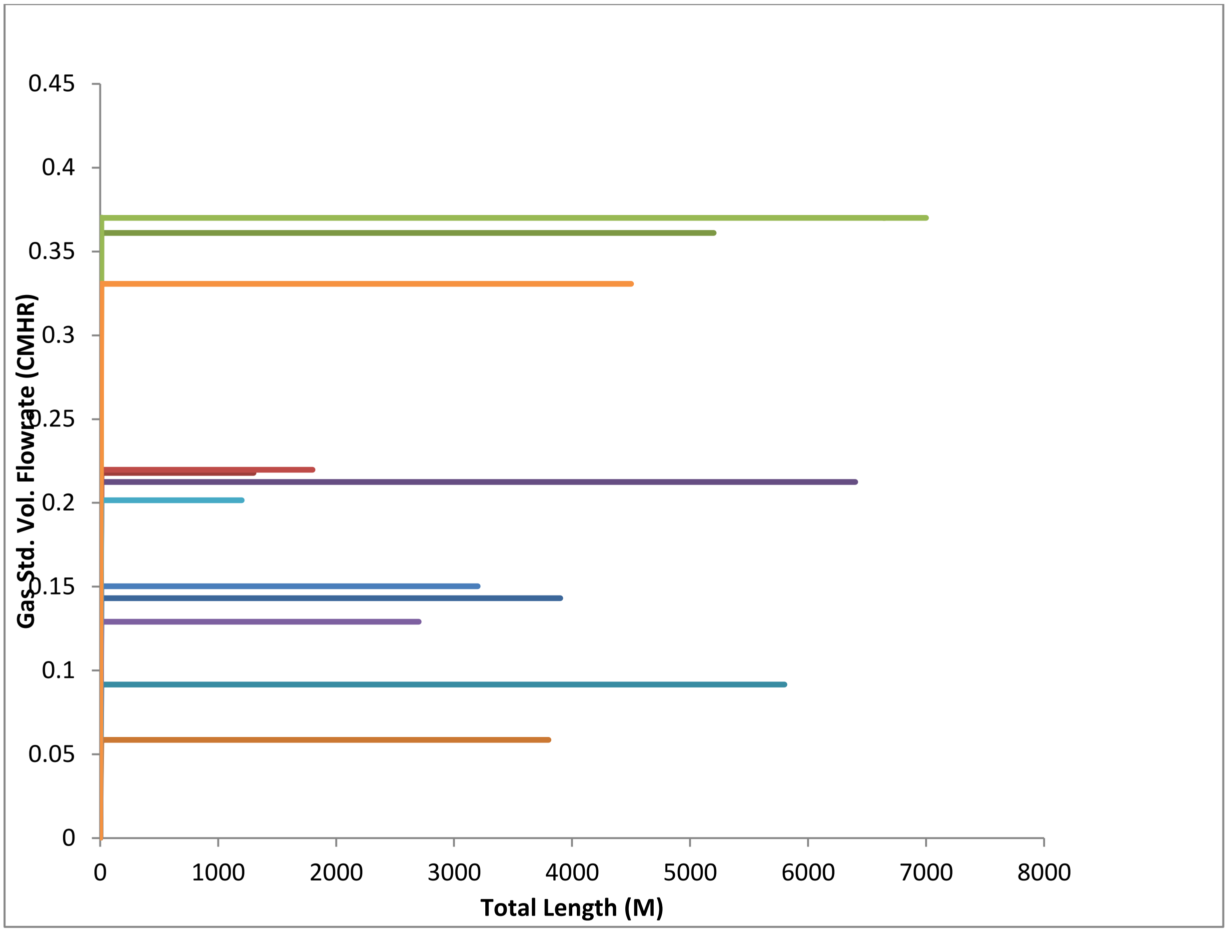


Fig: no: 20: Gas actual flow rate profile for L001 to L0012

Gas Std. Vol. Flowrate in Link L005, Pipe P5
Gas Std. Vol. Flowrate in Link L001, Pipe P1
Gas Std. Vol. Flowrate in Link L009, Pipe P9
Gas Std. Vol. Flowrate in Link L006, Pipe P6
Gas Std. Vol. Flowrate in Link L002, Pipe P2
Gas Std. Vol. Flowrate in Link L010, Pipe P10
Gas Std. Vol. Flowrate in Link L007, Pipe P7
Gas Std. Vol. Flowrate in Link L003, Pipe P3
Gas Std. Vol. Flowrate in Link L011, Pipe P11
Gas Std. Vol. Flowrate in Link L008, Pipe P8
Gas Std. Vol. Flowrate in Link L004, Pipe P4
Gas Std. Vol. Flowrate in Link L012, Pipe P12

Graphs:

i. Gas Density:

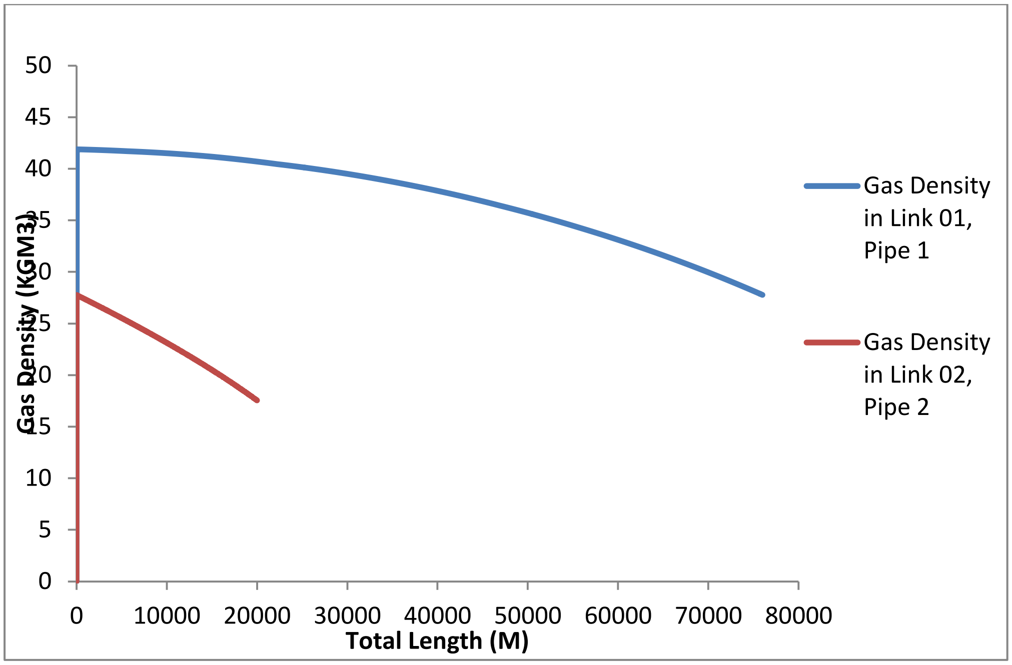


Fig: no: 21: Gas density profile for Link01 to Link02

ii. Liquid holdup:

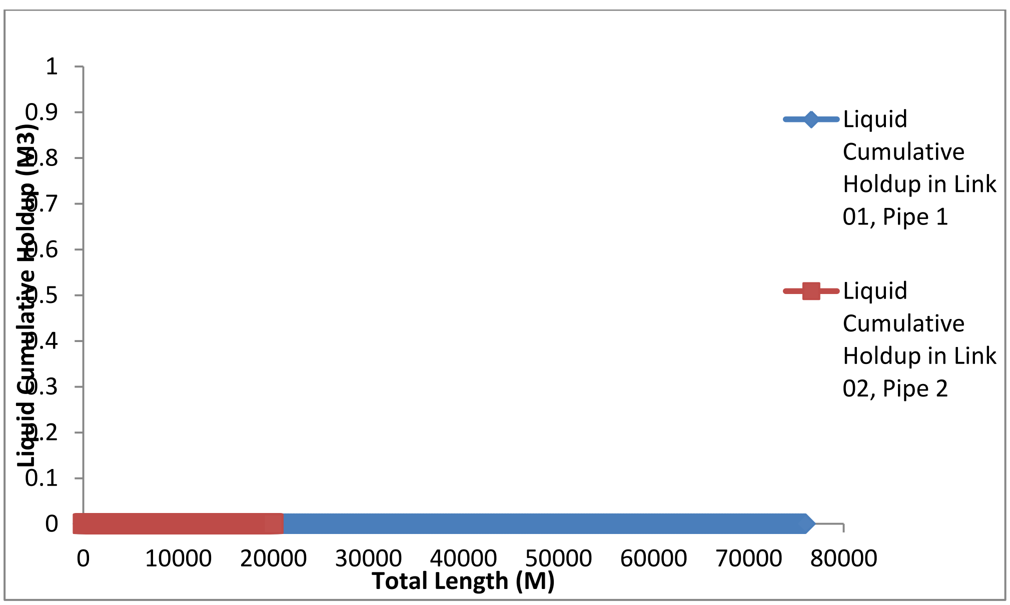


Fig: no: 22: Gas density profile for Link01 to Link02

iii. Gas Holdup:

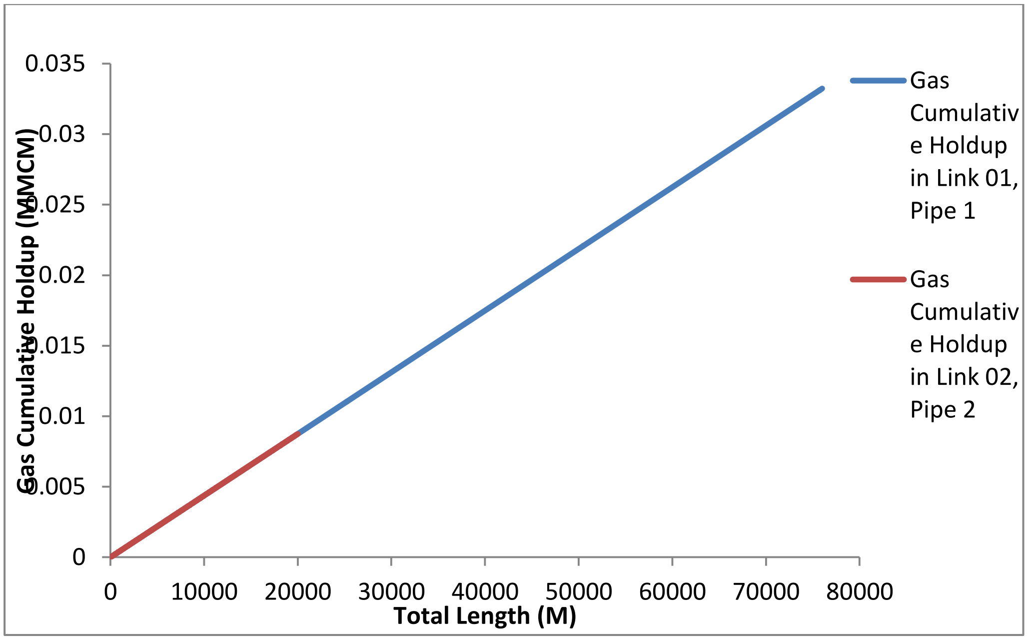


Fig: no: 23: Gas holdup profile for Link01 to Link02

iv. Pressure:

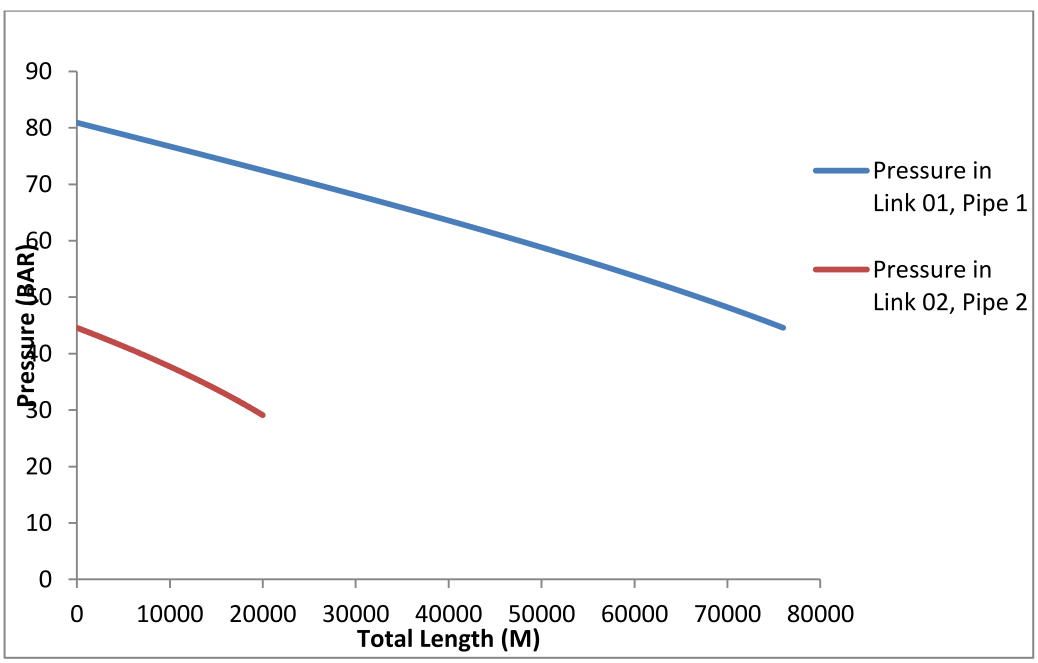


Fig: no: 24: Pressure profile for Link01 to Link02

v. Temperature:

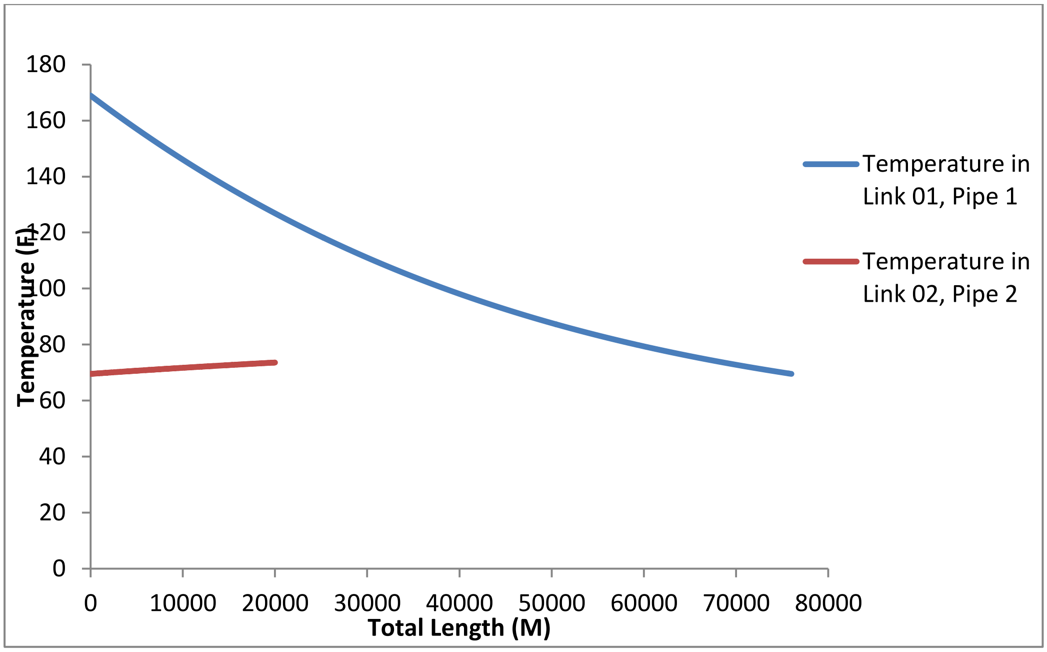


Fig: no: 25: Temperature profile for Link01 to Link02

vi: No Slip Holdup:

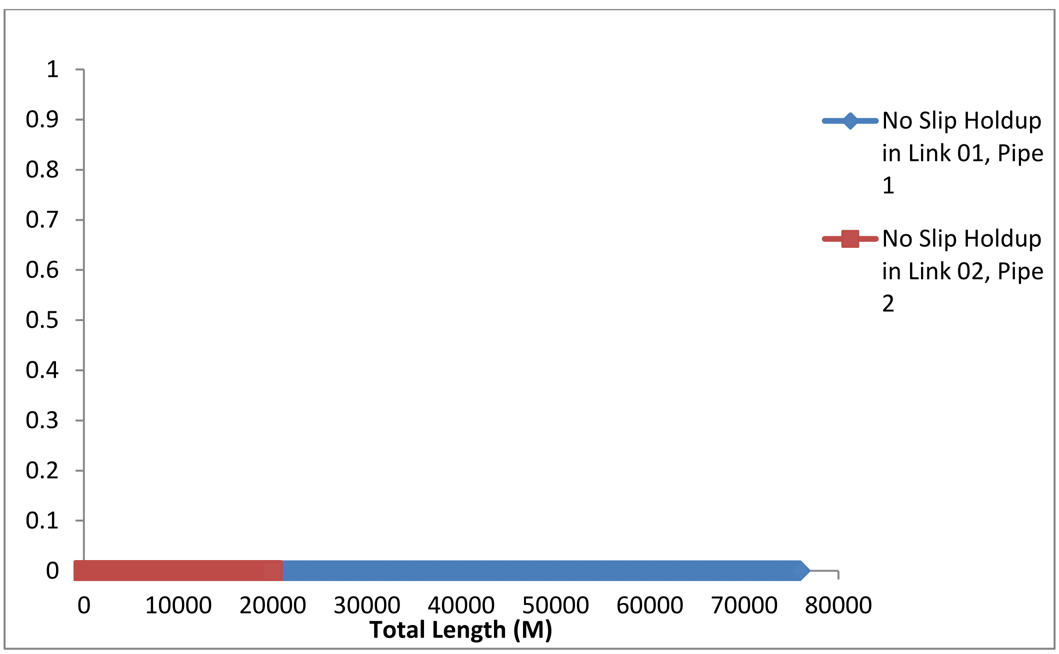


Fig: no: 26: No-slip holdup profile for Link01 to Link02 vii: Mixed Velocity:

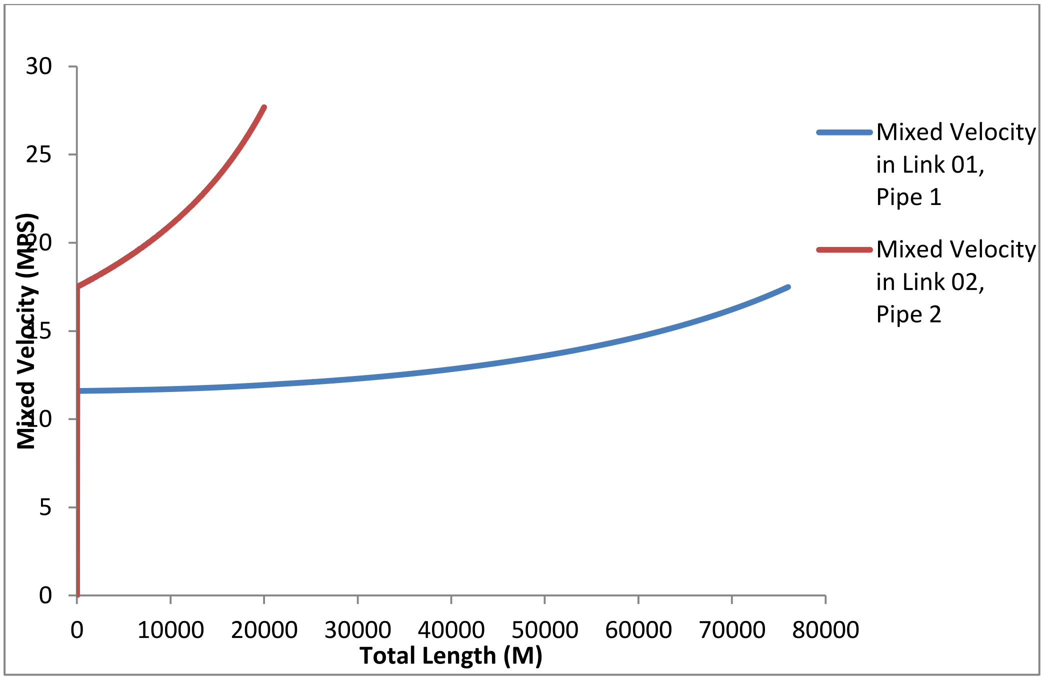


Fig: no: 27: Mixed velocity profile for Link01 to Link02

viii. Liquid Superficial Velocity:

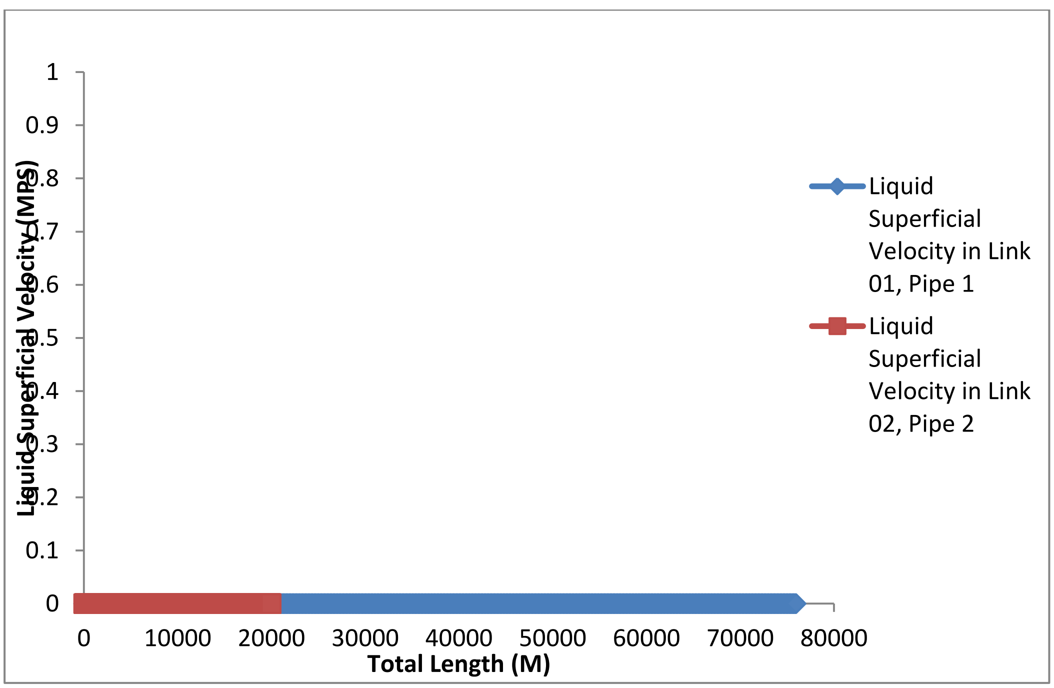


Fig: no: 28: Liquid superficial velocity profile for Link01 to Link02

ix. Gas Superficial Velocity:

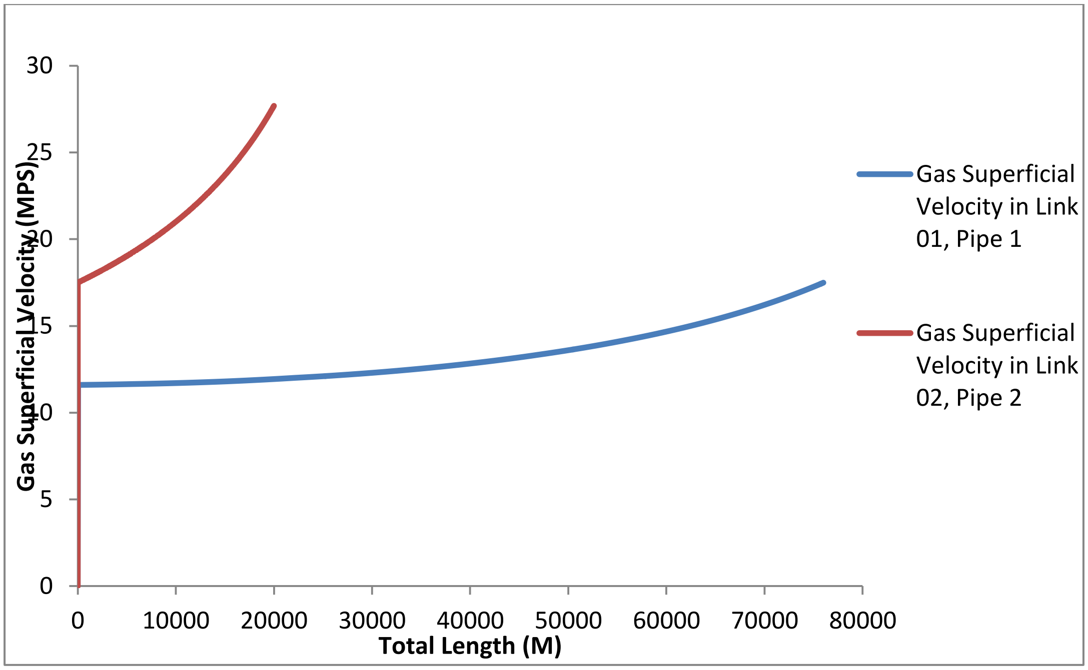


Fig: no: 29: Gas superficial velocity profile for Link01 to Link02

x. Gas Actual Flow Rate:

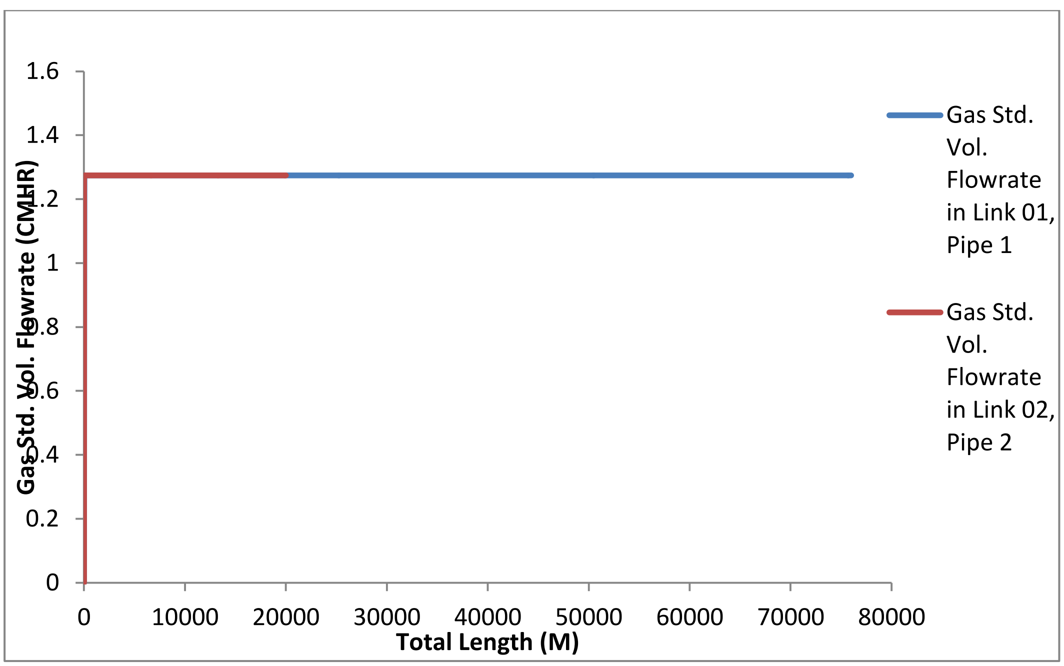


Fig: no: 30: Gas actual flow rate profile for Link01 to Link02

xi. Gas Velocity:

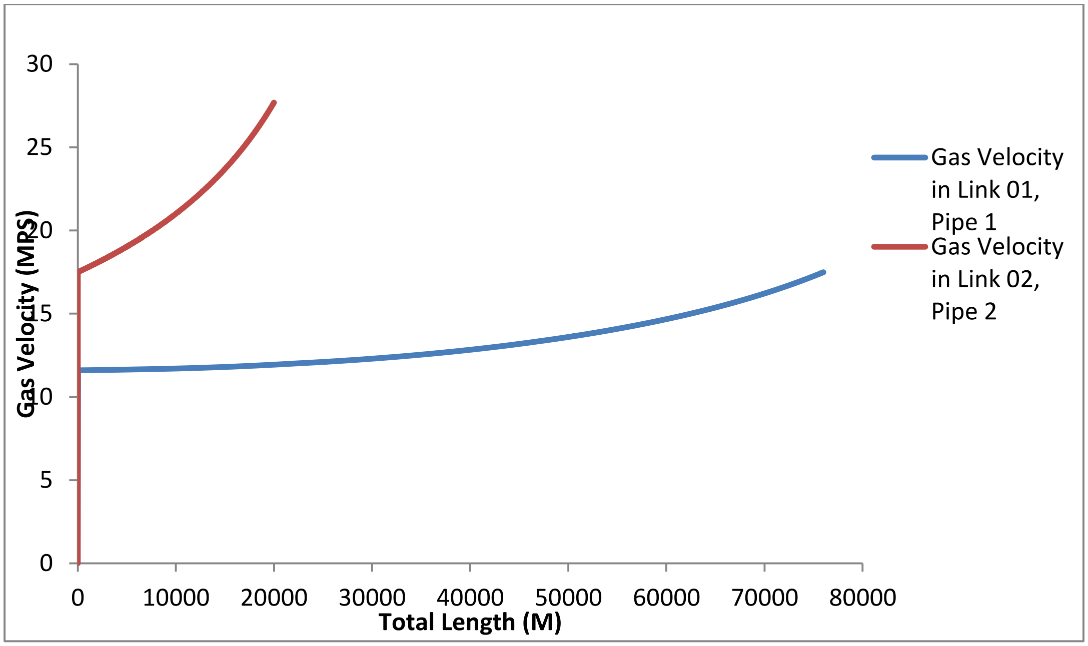


Fig: no: 31: Gas velocity profile for Link01 to Link02

Appendix: C

Diagrams

Well Platform:

Fig: no: 32.a: well Platform

Fig: no: 32.b: well platform

Process Platform:

Fig: no: 33: Process Platform

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