PSIG 2123

Pigging and Hydrate Tracking in a Gas Pipeline

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ABSTRACT

Gas pipelines want to provide transportation flexibility to meet demand, but are always focused on operational safety, reliability, system integrity, and environmental issues. Transportation networks need to ensure the components of gas are acceptable for delivery to end users. Local distribution companies want to meet customer demand and have no existing capacity to remove or extract hydrocarbons from their system. This paper introduces a method for calculating hydrate formation and the phase transfer between gas and liquid to allow the user to know how much liquid exists in a pipeline and the appropriate pigging scenario for the liquid fallout. The paper focuses on determining pigging and how the gas transfers to liquid and the amount of liquid hold up that occurs in the pipeline. Using these mathematical models and algorithms can allow an operator to know the correct timing for pipeline inspection and where in the pipeline system liquid is building up for potential safety monitoring.

INTRODUCTION AND BACKGROUND

Cleaning a pipeline during operation is a maintenance procedure that needs to be done on a regular predetermined frequency using pigs adequately designed for the proper cleaning application. The pigging operation will almost always increase the flow efficiency and reduce operating expenses. In pipelines that have low flow conditions it is more prevalent to see an increase in the collection of free water in the bottom of the pipeline, even in crude oil lines. In low flow conditions you need a mechanical means (pigs) to remove both the solids and liquids that collect in the bottom of the pipeline to help prevent the process of internal corrosion. When a pipeline goes online 100% efficiency cannot be expected, but a routine pigging can keep a pipeline operating at 90 – 95 percent capacity. A pigging requires manual labor and adds cost to the pipeline. An algorithm is needed to estimate the amount of liquid in a pipeline at any given moment and allow the user to know that it is time to pig the pipeline to help alleviate the issues of free water or condensate that is staying in the pipeline. Previous papers have already gone over how the simulation flow and gas condensation work in a gas pipeline. Below is the mathematical procedure to estimate the liquid hold up along with the amount of piggable liquid that is in the pipeline to give a better time to pig a pipeline.

APPROACH

The pipe segment is used to simulate a wide variety of piping operating modes ranging from single or multiphase piping with rigorous heat transfer estimation, to a large capacity looped pipeline problem. The pipeline is divided into several sections, where pressure and composition are assumed constant within one section. Calculations are performed in each section. For each segment the inlet temperature, inlet fluid composition, inlet flow and outlet pressure are specified. Algorithms determine the pressure drop, the energy and mass balances, segment fluid inventory, and the outlet flow. Each section is computed independently as properties change is reported to next section (e.g. changes in density, pressure, temperature, etc). All sections are simulated sequentially starting from beginning of the pipeline. The calculation continues down the length of the pipeline until the flow to consumer is determined. All sections are computed within one full system computation cycle.

The fluid flow mathematical model is described by a system of nonlinear partial differential equations of four state variables:

- Pressure (P)
- Temperature (T)

- Density (ρ)
- Mass Flow (M)

By solving these equations, the behavior of fluid parameters is obtained throughout the pipe network. The algorithms to solve the 4 nonlinear partial differential equations have been explained in previous papers and can be found in previous papers. This paper focuses on the liquid hold up and the amount of liquid in a pipeline in each segment.

LIQUID HOLDUP

The liquid holdup (H_L) along a section of pipe is defined as the ratio of the volume of liquid that is contained in that section of pipe to the volume of that section of pipe. Its value varies from zero for single-phase gas flow to one for single-phase liquid flow. An accurate prediction of H_L is required to compute the pressure drop that occurs in a liquid/gas mixture as it travels through a pipeline. Numerous empirical methods have been developed to compute H_L from the gas and liquid properties, the pipe diameter (D), the inclination angle of the pipe (Θ), and the qualitative nature of the flow of the liquid/gas mixture (i.e. the flow regime). The Beggs-Brill method[1] is used because it is one of the most reliable and robust methods of predicting both the liquid holdup and the pressure drop that occurs in wells and in hilly-terrain pipelines.

Before a value can be evaluated for the liquid holdup, it is necessary to identify the flow regime that characterizes the motion of the liquid/gas mixture. The Beggs-Brill method assigns the flow of the mixture to one of the following regimes: segregated flow; intermittent flow; distributed flow; or transition flow.

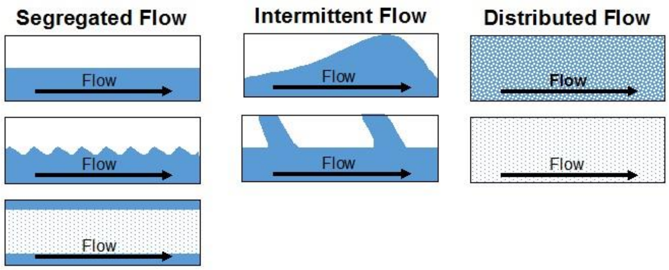

Figure 1 – Flow regime classifications for Beggs-Brill method

- Segregated Flow - The liquid and gas phases are separated from one-another and move (mostly) independent of each other. Furthermore, the relative amount of volume each phase occupies remains fairly constant.
- Intermittent Flow - The liquid and gas phases are separated from one-another. However, the relative volumes of the liquid and gas phases fluctuate, coupling their motions.
- Distributed Flow - The liquid and gas phases are mixed together and move collectively.
- Transition Flow -. The liquid/gas mixture is transitioning from segregated flow to intermittent flow.

The flow regime of the two-phase fluid is determined from the following three step procedure:

Step 1. Compute the mixture's liquid content, λ_L , and Froude number, N_{Fr}

$$\lambda_L = \frac{q_l}{q_l + q_g} \tag{1}$$

$$N_{Fr} = \frac{v_m^2}{gD} \tag{2}$$

Where q_g *and* ql are the volumetric flow rates of the gas and liquid phases. The superficial velocity of the mixture (v_m) is

$$v_m = v_g + v_l \tag{3}$$

and

$$v_g = \frac{q_g}{0.25\pi D^2} \tag{4}$$

and

$$v_l = \frac{q_l}{0.25\pi D^2} \tag{5}$$

v_g and v_l are the superficial velocities of the gas and liquid phases, and g = 9.80665 m/s^2 = 32.1740 ft/s^2 is the acceleration due to gravity.

Step 2. λ_L and N_{Fr} are used to compute four additional parameters that are needed to identify the flow regime

$$L_1 = 316\lambda_L^{0.302} \tag{6}$$

$$L_2 = 0.0009252\lambda_L^{-2.4684} \tag{7}$$

$$L_3 = 0.1\lambda_L^{-1.4516} \tag{8}$$

$$L_4 = 0.5\lambda_L^{-6.738} \tag{9}$$

Step 3. The flow regime is identified by the following criteria:

1. Segregated Flow
   - Either: $\lambda_L < 0.01$ and $N_{Fr} < L_1$
   - or: $\lambda_L \geq 0.01$ and $N_{Fr} < L_2$
2. Intermittent Flow
   - Either: $0.01 \leq \lambda_L < 0.4$ and $L_3 < N_{Fr} \leq L_1$
   - or: $\lambda_L \geq 0.4$ and $L_3 < N_{Fr} \leq L_4$
3. Distributed Flow

- Either: $\lambda_L < 0.4$ and $N_{Fr} \geq L_4$
- or: $\lambda_L \geq 0.4$ and $N_{Fr} > L_4$

4. Transition Flow
   - $L_2 < N_{Fr} < L_3$

Now that the flow regimes have been identified and algorithm knows which flow regime is happening the liquid hold up can be calculated.

For the segregated, intermittent, and distributed flow regimes a reliable prediction of liquid holdup can be obtained through the following two step process:

Step 1. The value of the liquid hold up for horizontal flow, H_L (0), is determined by the following equations:

$$H_L(0) = \frac{a\lambda_L^b}{N_{Fr}^c} \; when \; \frac{a\lambda_L^b}{N_{Fr}^c} \geq \lambda_L \quad (10)$$

$$H_L(0) = \lambda_L \; when \; \frac{a\lambda_L^b}{N_{Fr}^c} < \lambda_L \quad (11)$$

Where a, b, and c are parameters specific to the flow regime. The parameters can be found in the table below.

Table 2 – Flow Regime Parameters for level pipe

Flow Regime	a	b	c
Segregated	0.98	0.4846	0.0868
Intermittent	0.845	0.5351	0.0173
Distributed	1.065	0.5824	0.0609

Step 2. The value of the liquid holdup for a nonhorizontal flow, H_L (θ), is computed by multiplying H_L (θ) by β (θ), a correlation factor that depends on the inclination angle of the pipe (θ)

$$H_L(\theta) = \beta(\theta)H_L(0) \quad (12)$$

The value of B (θ) is obtained from the following expression.

$$\beta(\theta) = 1 + \beta\,(sin(1.8\theta) - \frac{1}{3}sin^3(1.8\theta)) \quad (13)$$

Where

$$\beta = (1-\lambda_L)ln(a\lambda_L^b N_{LV}^c N_{Fr}^d) \quad (14)$$

And

$$N_{LV} = v_l(\frac{\rho_l}{g\sigma_{ST}})^{0.25} \quad (15)$$

Where N_{LV} is the liquid velocity number, ρ_l is the density of the liquid phase, σ_{ST} is the surface tension that exists between the liquid and gas phases, and *a*, *b*, *c*, and *d* are parameters that are specific to the flow regime and the uphill/downhill direction of the flow. The formula for N_{LV} assumes that ρ_l , σ_{ST}, and v_l are expressed in units of kg/m^3, N/m , and m/s, respectively. For many industries it is more convenient to express ρ_l, σ_{ST}, and v_l in units of lb/ft^3, dyn/cm, and ft/s.

Table 3 – Flow Regime Parameters for Uphill pipe

Uphill Flow	a	b	c	d
Segregated	0.011	-3.768	2.539	-1.614
Intermittent	2.96	0.305	-0.4473	0.0978
Distributed	β= 0			

For distributed flow β=0 so it is not necessary for any flow parameters.

Table 4 – Flow Regime Parameters for Downhill pipe

Downhill Flow	a	b	c	d
All Regimes	4.7	-0.6392	0.1244	-0.5056

For the transition flow regime, H_L (θ) is computed as a weighted average of liquid holdup values that were determined for the segregated, $H_L(\theta)_S$, and the intermittent, $H_L(\theta)_I$, flow regimes:

$$H_L(\theta) = w_s H_L(\theta)_S + w_I H_L(\theta)_I \quad (16)$$

Where

$$w_s = \frac{L_3 - N_{Fr}}{L_3 - L_2} \quad (17)$$

and

$$w_I = 1 - w_s \quad (18)$$

Now that the hold up is determined a pigging simulation and calculation can be added to the system.

PIGGING

Pigging is a standard maintenance procedure that involves the transfer of a object (referred to as a pig) through sections of a pipeline. Pigs are typically cylindrical objects with widths that are slightly smaller than the width of the pipe it travels through. The primary goal of pigging is to clean the inner surface of the pipes to avoid buildup of congealed wax, precipitated hydrides, and sand.

The terms used to compute Pig position are as follows (also refer to Figure 2).

- $Q = Q_{In} = Q_{Out}$: Fluid volumetric flow rate along the pipe.
- L_1 and A_1: Length and cross-sectional area of Pipe 1 (the pipe that currently holds the pig at time t_{n-1})
- L_2 and A_2: Length and cross-sectional area of Pipe 2 (the pipe immediately downstream of Pipe 1)
- $x(t_{n-1})$ and $x(t_n)$: Pig position at time t_{n-1} and t_n
- V_1 and V_2: Pipe 1 and 2 internal volumes

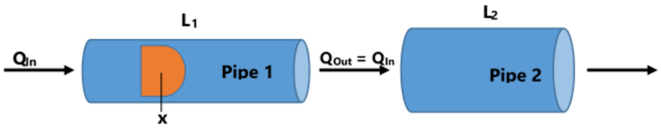

Figure 2 – Pig Position Terms

Based on these terms, the following procedure is used to update the Pig position.

Step 1. Compute the initial volume of liquid that exists between the start of Pipe 1 and the Pig using Equation (19).

$$V_{n-1} = A_1 \times x(t_{n-1}) \tag{19}$$

Step 2. Compute the final volume of liquid that exists between the start of Pipe 1 and the Pig using Equation (20).

$$V_n = V_{n-1} + \eta_{Slip} \times Q \times \Delta t, \tag{20}$$

where η_{Slip} is the Pig volume transfer efficiency, i.e., the ratio of the volume that the Pig traveled over the volume that it would have traveled if there were no slippage.

Step 3. If $V_n \leq V_1$, compute $x(t_n)$ using Equation (21).

$$x(t_n) = \frac{V_n}{A_1} \tag{21}$$

Step 4. If $V_n > V_1$, compute $x(t_n)$ relative to the start of Pipe 2 using Equation (22).

$$x(t_n) = \frac{(V_n - V_1)}{A_2} \tag{22}$$

Currently, the influence the Pig has on the pressure change across the pipe is determined by multiplying the pressure change across the pipe segment where the pig is located by a user-specified correction coefficient.

Piggable liquid is defined as the amount of liquid that can be collected by a pig, this is a portion of the total liquid contained in the pipeline and is influenced by η_{Slip}, the pig volume transfer efficiency. The calculation of piggable liquid is as follows, we start of with the initial input data:

- $Area$ - the cross-sectional area of the pipe segment
- M_{total} - the total mass flow rate of the Condensate/Water/Gas mixture that travels through the pipe segment
- P - the pressure of the pipe segment
- T - the temperature of the pipe segment
- ρ_o and ρ_w - the densities of the condensate and water components of the Condensate/Water/Gas mixture
- x_o, x_w, and x_g - the mass fractions of the condensate, water, and gas components of the mixture
- The mole fraction composition of the gas phase of the Condensate/Water/Gas mixture
- η_{Slip} - an auto-tuning correction coefficient for the flow rate of the pig
- $Mass_o$ and $Mass_w$ - the total mass of condensate and water stored inside the pipe segment
- Vol_o, and Vol_w - the total volume of condensate and water stored inside the pipe segment

After the initial data is configured, we can now calculate the piggable liquid.

1. Correct the values of x_o, x_w, and x_g to account for gas condensation.
2. Correct the mole fractions of the gas phase to account for gas condensation.
3. Use standard subroutines to compute the density of the gas, ρ_g.
4. Use standard subroutines to compute the liquid holdup which is explained in the previous section.
5. Compute the liquid density using the following expression.

$$\rho_L = \frac{x_o}{x_o + x_w} \cdot \rho_o + \frac{x_w}{x_o + x_w} \cdot \rho_w \tag{23}$$

6. Compute the Liquid Velocity through the following procedure.

$$M_L = M_{total} \cdot (x_o + x_w) \tag{24}$$

$$Q_L = \frac{M_L}{60 \cdot \rho_L} \tag{25}$$

$$v_L = \frac{Q_L}{LH \cdot Area} \tag{26}$$

7. Compute the Pig Velocity through the following procedure.

$$M_g = M_{total} \cdot x_g \quad (27)$$

$$Q_g = \frac{M_g}{60 \cdot \rho_g} \quad (28)$$

$$v_g = \frac{Q_g}{(1-LH) \cdot Area} \quad (29)$$

$$v_{pig} = \eta_{Slip} \cdot \max(v_g, v_L) \quad (30)$$

8. Compute the total mass and volume of liquid within the pipe segment.

$$Mass_L = Mass_o + Mass_w \quad (31)$$

$$Vol_L = Vol_o + Vol_w \quad (32)$$

9. Finally using the following expressions to compute the pigged liquid mass and pigged liquid volume for the pipe segment.

$$(Pigged\ Mass)_{seg} = Mass_L \cdot \left(1 - \frac{v_L}{v_{pig}}\right) \quad (33)$$

$$(Pigged\ Vol)_{seg} = Vol_L \cdot \left(1 - \frac{v_L}{v_{pig}}\right) \quad (34)$$

Now that the piggable liquid has been calculated the alogirthm can be applied to a test case.

CASE STUDY

The proposed modeling and simulation techniques were applied to a 56" pipeline that is about 76km long. The pipeline runs in the ground and is a relatively flat pipeline as the elevation data shows in the figure below.

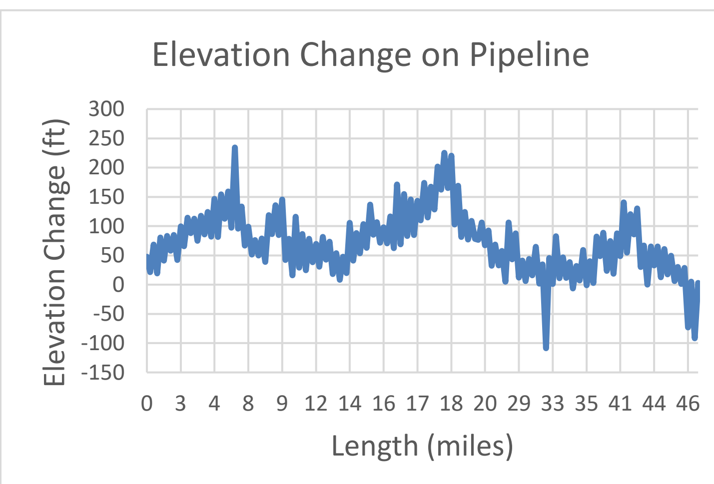

Figure 3 – Elevation profile

The pipeline has 3 producers where the pipeline receives flow from. The 3 producers are simply called Gas Producer 1 (GP1), Gas Producer 2 (GP2), and Gas Producer 3 (GP3). The gas pipeline then feeds two consumers and are called Gas Consumer 1 (GC1) and Gas Consumer 2 (GC2). For the producers GP1 normally runs around 200 mmscfd, GP2 normally rns around 700 mmscfd, and GP3 runs around 30 mmscfd. The total flow combined can run anywhere from 850 mmsfd to 1000 mmscfd. The gas properties are described in the table below for each Gas Producer as well.

Table 5 – Gas Properties from Gas Producer 1

Mole Fraction	Formula	Name	Cp/Cv
98.2766	CH4	Methane	1.31
0.0945	CO2	Carbon Dioxide	1.32
0.8438	C2H6	Ethane	1.19
0.3318	C3H8	Propane	1.14
0.0881	C4H10	i Butane	1.1
0.1016	C4H10	n Butane	1.09
0.0441	C5H12	i Pentane	1.08
0.0355	C5H12	n Pentane	1.08
0.0755	C6H14	N-Hexane	1.06
0.0419	C7H16	N-Heptane	1.05
0.0196	C8H18	n Octane	1.04
0.0028	C9H20	n Nonane	1.04
1.00E-05	H2O	Water	1.33
0.0443	N2	Nitrogen	1.4

Table 6 – Gas Properties from Gas Producer 2

Mole Fraction	Formula	Name	Cp/Cv
90.421	CH4	Methane	1.31
0.9043	CO2	Carbon Dioxide	1.32
3.455	C2H6	Ethane	1.19
2.4408	C3H8	Propane	1.14
0.5023	C4H10	i Butane	1.1
0.9406	C4H10	n Butane	1.09
0.3108	C5H12	i Pentane	1.08
0.2748	C5H12	n Pentane	1.08
0.2317	C6H14	N-Hexane	1.06
0.1413	C7H16	N-Heptane	1.05
0.0294	C8H18	n Octane	1.04
0.0047	C9H20	n Nonane	1.04

1.00E-06	H2O	Water	1.33
0.3409	N2	Nitrogen	1.4

Table 7 – Gas Properties from Gas Producer 3

Mole Fraction	Formula	Name	Cp/Cv
96.2331	CH4	Methane	1.31
0.1	CO2	Carbon Dioxide	1.32
1.9622	C2H6	Ethane	1.19
0.6281	C3H8	Propane	1.14
1.00E-05	C4H10	i Butane	1.1
0.1755	C4H10	n Butane	1.09
0.085	C5H12	i Pentane	1.08
0.0569	C5H12	n Pentane	1.08
0.1115	C6H14	N-Hexane	1.06
0.0606	C7H16	N-Heptane	1.05
0.0246	C8H18	n Octane	1.04
0.0011	C9H20	n Nonane	1.04
14.1392	H2O	Water	1.33
0.1032	N2	Nitrogen	1.4

Now that all the initial data is configured, and the baseline model is built. A simulation can be run to determine the amount of piggable liquid in the pipeline and compare with what is collected in real life.

RESULTS

Pigging operations are run monthly to keep the pipeline operating well and take out the liquid that sits in the pipeline. The main issue is sometimes when a pigging operation is done a little amount of liquid is collected and time and resources are wasted in the pigging operation. The purpose of the hydrate tracking in the pipeline is to give an idea of how much liquid is in the pipeline at a certain time. The overflow tank at the end of the pipeline can hold 2500 barrels of condensate, so it is important to not have more than 2500 barrels of liquid in the pipeline. Below you can see the results of the pigging operations over a 6-month period. The table represents the actual collected amount of liquid in the pipeline as well as the simulated amount of liquid that the algorithm states is in the pipeline based on the flow, pressure, and temperature in the pipeline. The main consumer pressure is also shown, since that is the main consumer and dictates the pressure on the entire pipeline.

Table 8 – Collected Pig Liquid vs. Calculated Liquid

Pigging Event	Collected (barrel)	Simulated (barrels)	Flow (mmscfd)	C1 Press (PSIG)
1	1276	4000	900	585
2	2161	4003	930	674
3	1180	4572	877	630
4	132	1951	850	635
5	478	1358	880	678
6	600	610	930	639
7	602	461	890	609

The biggest issue with the first few pigging events was the temperature readings we had in the pipeline were not in the right place and we were losing too much heat in the pipeline. Another item that happened was the pigs that were submitted for each pigging operation were different. The operator had 3 different pigs and when the alogorithm was updated to take into account which pig was being used in event 6 and 7 the piggable liquid was much more accurate.

CONCLUSIONS

With having the case study results, the algorithm can suggest how much liquid is in the pipeline and allow the operator to run pigging operations based on how much liquid is calculated in the pipeline and can help save pipeline operators manual hours and resources from futile pigging operations. Future work includes advancing the pigging calculation with estimated dynamic frictional forces in a straight pipe and mitre bend pipe along with differential pressure and acceleration with respect to time along with differential pressure, velocity, and acceleration with respect to distance of the starting point of the pig and the end point of the pig.

REFERENCES

1. H. D. Beggs and J. P. Brill, A Study of Two-Phase Flow in Inclined Pipes , J. Pet. Tech. 607-617 (May, 1973).

AUTHOR BIOGRAPHY

John Hooker is a controls engineer and the Engineering group manager at Statistics & Control, Inc. He has a Bachelor of Science in Aerospace Engineering from Iowa State University. Over the past 10 years, John has participated in several global projects in the oil & gas and power generation sectors and has implemented numerous applications for control solutions, equipment monitoring, design testing, data analysis, and brownfield optimization.

Dr. Daniel P. Theis is a software engineer working at Statistics & Control, Inc. He has a Bachelor of Science in Chemistry from

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FIGURES

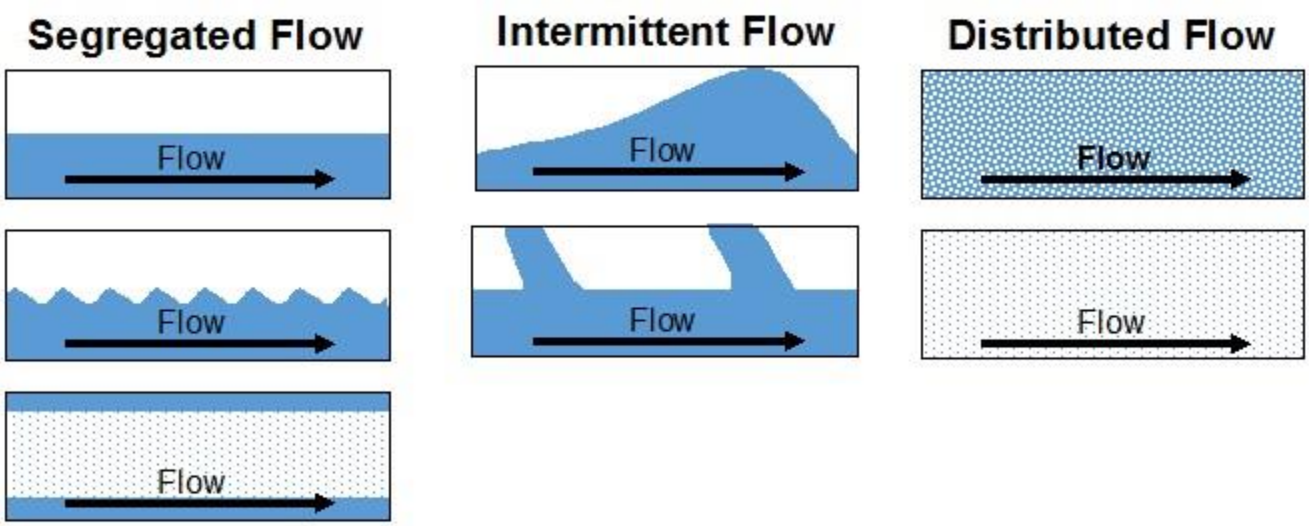

Figure 1 – Flow regime classifications for Beggs-Brill method

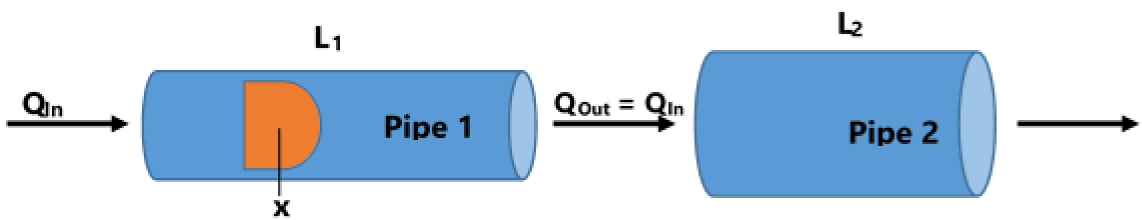

Figure 2 – Pig Position Terms

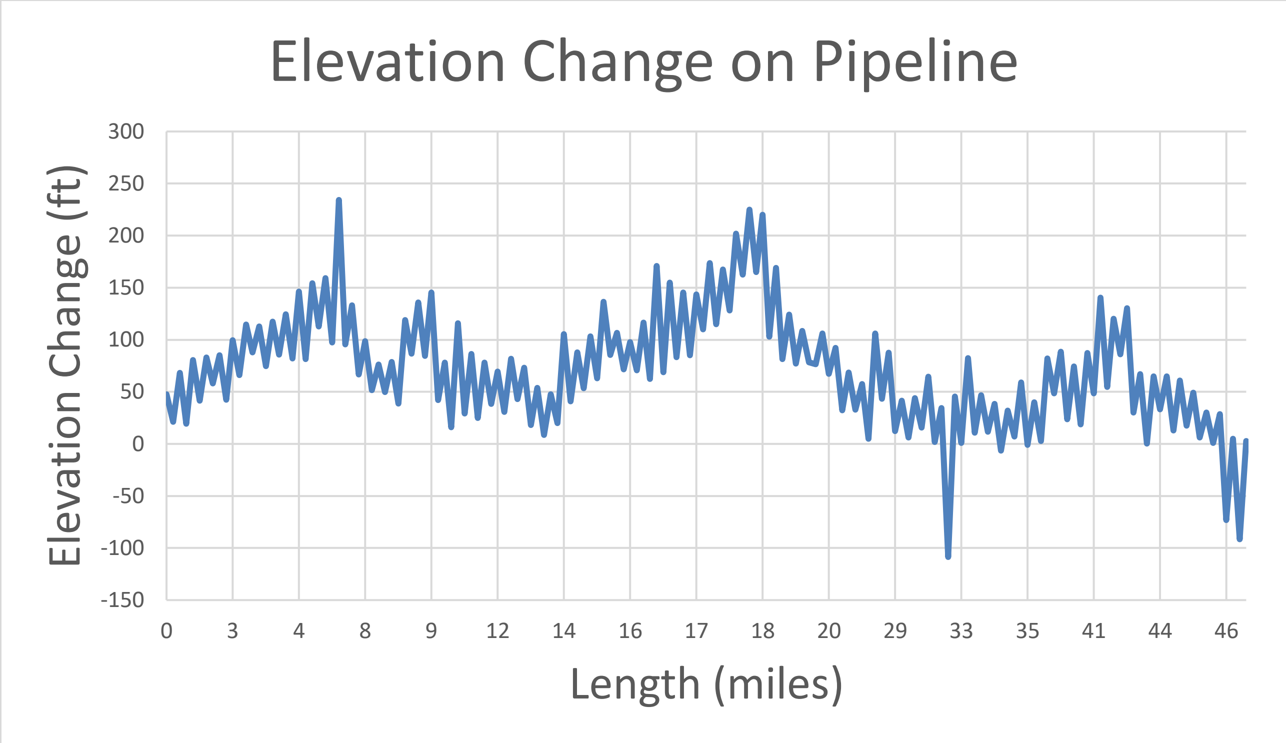

Figure 3 – Elevation Profile