Department of Chemical Engineering

TKP4580 - Chemical Engineering Specialization Project

Multiphase Flow Modelling for Virtual Flow Metering Applications

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1 Introduction

1.1 Background and Motivation

Flow measurement is critical in the oil and gas industry as it directly determines the revenue generated. It is important to be aware of flow rates of oil, water and gas of each individual well in a network in order to fix production rates which affects both long-term as well as daily operations. The use of multiphase flow meters, especially in subsea systems, introduces complications during installation and maintenance as well as uncertainty in measurements **handbook˙mpfm**.

Virtual Flow Metering(VFM) is a data analysis tool that uses mathematical models to predict flow rates using readily available data from fields. Sensors that are cheap and easy to install, such as temperature and pressure sensor, are part of most oil and gas wells. The data that these sensors provide can be leveraged to help predict flow rates of the production that flows out of their respective wells Amin 2015. A VFM model can be tuned using existing field logs to be able to predict flow rates based on real-time readings from the sensors installed. Since VFM is based on mathematical modelling, the uncertainty of these sensors can also be offset in the calculations.

There have been mainly two types of VFM models: hydrodynamic and statistical/data-driven. Data-driven models directly feed the field data into a purely statistical model which predicts the flow rates. This type of VFM is much easier and quicker to build as it does not require any knowledge of flow calculations. However, these predictions lack physical basis and cannot be made without historical data.
A hydrodynamic VFM, on the other hand requires a multiphase flow model which performs flow dynamic and thermodynamic calculations and actually calculates flow rates and respective pressures and temperatures. This also enables the VFM to calculate several other parameters at various points in the flowline/well tubing Andrianov 2018. This produces a more robust prediction algorithm that is not limited to the application of flow measurement.

1.2 Problem Formulation

The goal of this project is to aid the development of a hydrodynamic VFM based on a first-principles model. The objective of the first-principles model is to use some parameters from the field data (such as temperature, outlet pressure) in order to calculate the remaining parameters (inlet pressure, flow rate profiles). Discrepancies between the model's calculations and field data may occur due to many reasons such as usage of different closure laws, different thermodynamic models different criteria for switching between flow regimes and so on. Thus, the first-principles model needs to be tuned to the field data.
The field data necessary for the tuning can be collected experimentally or by modelling the specific well/network on existing flow modelling software. This data needs to be updated in a timely manner as various parameters associated with oil networks, such as fluid properties, bottom-hole pressures and temperatures and production profiles, change throughout the life of a well/reservoir. Thus it is easier and more practical to have a virtual model replicating the 'real plant' and supply the necessary field data Bikmukhametov 2020.

This project aims to build a model of an oil and gas network on multiphase flow modelling software. This model will serve as a 'real plant' to provide field data which can be used to tune a first-principles model.

2 Methodology

2.1 Software - OLGA

The software OLGA (Version 2015) from Schlumberger was chosen to carry out the multiphase flow modelling of the oil and gas network. OLGA is an industry standard multiphase flow simulator which uses one dimensional modelling. It uses a three-phase model, that is it applies the conservation equations to the three phases separately.
The solver includes a steady-state pre-processor which generates its own initial conditions. The solver starts with a fully filled flowline based on these initial conditions and then converges to the required steady-state.
Each flowline is divided into discrete pipe sections and segments. The model solves the mass conservation equations for each phase separately as well as for oil and water droplets in the gas phase. Similarly, it solves momentum conservation equations for each discrete phase. In addition, the phases are linked by mass transfer (gas-condensate equilibrium). An energy balance equation is also solved assuming that the temperature is constant across the phases Schlumberger 2015.
The Black-oil composition feature has been used in this project where the specific gravity of each phase is input to OLGA and the rest of the PVT properties are generated by the solver itself using a set of in-built Black-oil correlations. Based on the chosen values of oil specific gravity, the Lasater correlation was selected Lasater 1958. why choose OLGA - merits and features

2.2 Network Model

The model consists of a subset of a typical oil and gas network Y. Bai and Q. Bai 2018. Two well-tubings with well-head choke valves. The wells join a subsea manifold which terminates at a topside separator operating at fixed pressure. The manifold joins the separator through a riser. All pipe section were considered to be in carbon steel. The properties of the material are default in-built in the software. The schematic of the network is shown in Figure 1.

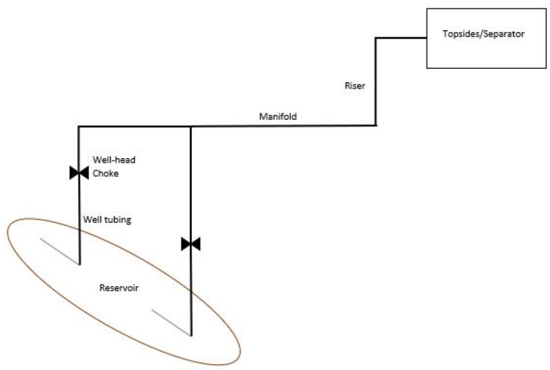


Figure 1: Schematic of the network

The inputs to the OLGA model are:

- Outlet Pressure
- Standard Oil Flow Rate at Inlet
- Gas-Oil Ratio (GOR) and Water-cut
- Fluid Temperature at Inlet
- Black-oil Properties

2.2.1 Assumptions

In order to simplify the first-principles model and make the tuning process more feasible a few assumptions were made with respect to the model.
Temperature calculations were modified in order to ensure an isothermal model. Due to flow friction, pressures usually decrease along the length of a horizontal flowline in the direction of flow. This decreasing pressure may cause some of the oil to enter the gas phase resulting in lowering of temperature. This was offset by setting the temperature calculations to isothermal mode.
The steady-state pre-processor was used to ensure that the model reached steady state, avoiding any transient state data.
Additionally, different flow rates were tried to ensure that there is none/minimal slug flow in the model as a first-principles model built for stratified flow cannot handle slug flow. The 'ID' feature in OLGA was also used to ensure stratified flow Schlumberger 2015.

3 Results

3.1 Model Parameters

All the different flowline and fluid parameters used in the model are listed in Tables 1, 2 and 3. In order to maintain uniformity with the first-principles model and simplify the tuning process the parameters have been referenced from Bikmukhametov 2020. A horizontal section of length 100 m is added to the end of each flowline to aid convergence of the solver.
The solver was set to run for 5 hours of simulation time with the minimum and maximum time-step set to 0.1 seconds and 1 second, respectively.

Flowline	Length (m)	Diameter (m)	Roughness (m)
Tubing 1	1100	0.1	$3e-5$
Tubing 2	1200	0.1	$3e-5$
Manifold	1000	0.2	$3e-5$
Riser	450	0.2	$3e-5$

Table 1: Flowline Parameters

Parameter	Value
Outlet Pressure	10 bara
Inlet Temperature	25 deg C

Table 2: Network Parameters

Parameter	Value
Oil Specific Gravity	0.867
Water Specific Gravity	1.020
Gas Specific Gravity	0.814
GOR	50 sm^3/sm^3
Watercut	0.3

Table 3: Fluid Properties

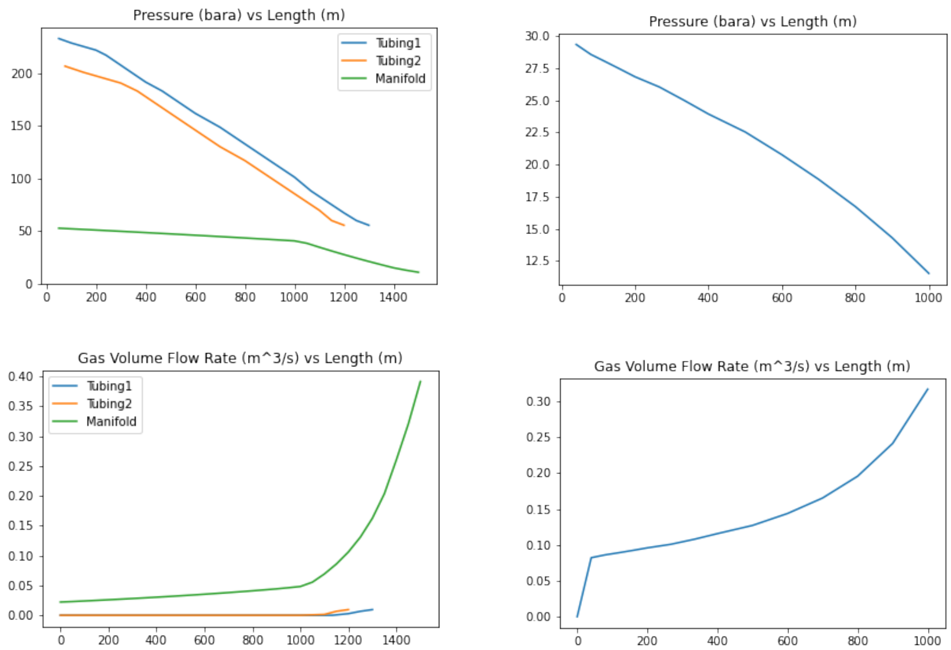
In addition to the network model, another model of a single horizontal flowline terminating in a separator without a riser was also created (will be referred to as single-line model). The same fluid and solver parameters as above are used in the model and the flowline 'Manifold' from Table 1 is used. This model was created as a first step of tuning for the first-principles model before near-vertical risers are incorporated.

3.2 Plots and Flow Data

A range of standard oil flow rates were tested on both the network model and the single-line model. Flow rate that caused slug flow were avoided. Due to a fixed GOR and Watercut, only the oil flow rates needed to be changed for each case, more specifically the standard oil volume flow rate. Eight different cases with increasing oil flow rates were run on both models. In each case, both wells produce an equal amount fluid but show different pressure profiles as the tubings have different lengths. The cases are identified by the total amount of oil that flows through the Manifold.
The main parameters to be matched were the inlet pressure at the Manifold and the Gas Volume Flow Rates throughout the same flowline. Other parameters such as Standard Volume Flow rates of gas and water and Volume Flow Rates at flowing Conditions for all three phases were compared to help troubleshoot the first-principles model. A compilation of these values for different flow rates can be found in the Appendix. The pressure at the inlet and the resulting pressure drop in the Manifold was all cases have been tabulated in Table 4. A sample of the plotted results for Case 4 is shown in Figure 2

		Inlet Pressure ($bara$)		Pressure drop (bar)	
Case	Standard Oil Flow Rate (sm^3/s)	With Riser	Without Riser		
1	0.0417	30.42	16.2	20.42	6.2
2	0.0556	35.61	20.15	25.61	10.15
3	0.0694	41.05	24.61	31.05	14.61
4	0.0833	46.74	29.36	36.74	19.36
5	0.0972	52.16	33.96	42.16	23.96
6	0.1111	57.57	37.85	47.57	27.85
7	0.125	63.17	41.8	53.17	31.8
8	0.1389	68.93	45.83	58.93	35.83

Table 4: Manifold pressures for different cases



Profiles from Network Model Profiles from Single-Line Model

Figure 2: Pressure and Gas Volume Flow Rate at flowing conditions for Case 4

As expected, increasing flow rates cause greater and greater pressure drops in the Manifold as well as the tubing. It is observed that in some cases, there is no gas flow in the tubings. Since the tubings are near-vertical flowlines, there is a large pressure build-up especially towards the base causing pressure to exceed the bubble point pressure of the gas. Due to this, gas flow only begins towards the end of the tubings in many of the cases.

The model itself is a key part of the results. As it is easy to manipulate the parameters of the model, it can be modified to varying levels of complexity as the first-principles model develops.

4 Future Work

A virtual model was chosen to provide the real plant data due to the ease of interfacing and accessibility of data. This can be further improved upon by creating an Open Platform Communications (OPC) server which can send results directly from the OLGA interface to the VFM algorithm without any user intervention. Upon setting up an OPC server, the first-principles model can also be replaced by the OLGA model, removing the extra step of tuning a first-principles model.
In addition, the current OLGA model, with a few changes, can also be used to generate data which can serve as a training set to the VFM algorithm.

4.1 Variations of the Model

As mentioned in the Results, the model can be modified to include more complexities in the future to make the field data more accurate. Temperature calculations can be turned on to include temperature data. Dynamic simulations can also be carried out to study different operating scenarios. Additionally, a PVT characterization software can be utilised to generate thermodynamic data for more realistic fluid compositions. This data can then be input to the OLGA simulation, avoiding the need for a Black-oil model.
As the first-principles model develops and can handle more complex calculations, the OLGA model can also be modified to produce more accurate data.

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Appendix

A Terminology and Conventions

Definition of Gas-Oil Ratio (GOR)

GOR at standard conditions is the ratio of the Standard Gas Volume Flow Rate (sm^3/s) to the Standard Oil Volume Flow Rate (sm^3/s). It has the units (sm^3/sm^3).

$$GOR = \frac{StandardGasVolumeFlowRate}{StandardOilVolumeFlowRate}$$

Definition of Watercut

WAtercut at standard conditions is the ratio of the Standard Water Volume Flow Rate (sm^3/s) to the Standard Liquid Volume Flow Rate (sm^3/s). It has no units, however it can expressed as a percentage.

$$Watercut = \frac{StandardWaterVolumeFlowRate}{StandardWaterVolumeFlowRate + StandardOilVolumeFlowRate}$$

Standard Conditions

By convention, standard conditions are fixed to be 60 F temperature and 1 atm pressure. In SI units, this corresponds to 15.56 degC and 1.01325 bar pressure.

B Result Plots and Tables

B.1 Tabulated Data Points

The Standard volume flow rates are constant across the length of a pipeline as it is unaffected by the ambient pressure. Thus only one value is reported for each phase in the network models. This value corresponds to the flow in the Manifold. The flow rate would be halved in each of the well tubings.
Due to large pressure drops in the flowlines, a single value of gas flow rate cannot be reported. Hence, these values are plotted across the lengths of the flowlines and presented in the next section. The oil and water flow rates, however, do not vary drastically making it possible to report a single value for each flowline.

Case	Inlet Pressure ($bara$)			Gas Rate (sm^3/s)	Oil Rate (sm^3/s)				Water Rate (sm^3/s)			
	Tubing 1	Tubing 2	Manifold	Standard	Standard	Tubing 1	Tubing 2	Manifold	Standard	Tubing 1	Tubing 2	Manifold
1	130.92	111.85	30.42	2.0832	0.0417	0.0233	0.0233	0.0437	0.0179	0.0089	0.0089	0.0179
2	151.26	130.55	35.61	2.7776	0.0556	0.031	0.031	0.0588	0.0238	0.0119	0.0119	0.0239
3	174.11	151.39	41.05	3.472	0.0694	0.0387	0.0388	0.0742	0.0298	0.0148	0.0148	0.0298
4	199.91	174.8	46.74	4.1664	0.0833	0.0465	0.0465	0.0898	0.0357	0.0178	0.0178	0.0358
5	228.39	200.53	52.16	4.8608	0.0972	0.0542	0.0542	0.1056	0.0417	0.0207	0.0207	0.0418
6	260.08	229.03	57.57	5.5552	0.1111	0.0619	0.0619	0.1217	0.0476	0.0236	0.0236	0.0477
7	294.5	259.83	63.17	6.2496	0.125	0.0696	0.0696	0.1381	0.0536	0.0265	0.0266	0.0537
8	333.02	294.3	68.93	6.9463	0.1389	0.0773	0.0773	0.155	0.0595	0.0294	0.0295	0.0596

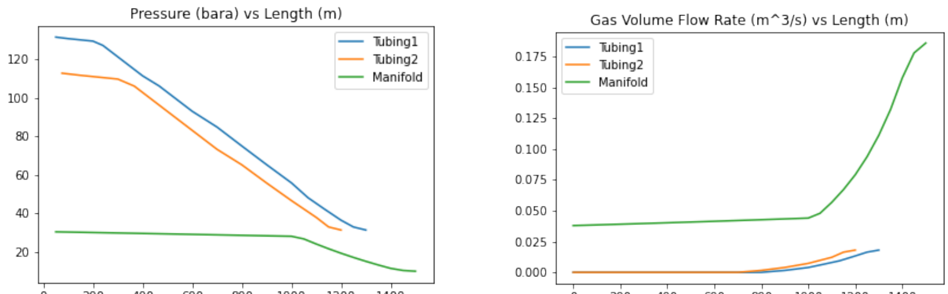
Table 5: Results from the Network Model

Case	Inlet Pressure ($bara$)	Pressure Drop (bar)	Gas Rate (sm^3/s)	Oil Rate (sm^3/s)		Water Rate (sm^3/s)	
			Standard	Standard	Flowing	Standard	Flowing
1	16.2	6.2	2.0832	0.0417	0.0428	0.0179	0.0179
2	20.15	10.15	2.7776	0.0556	0.0574	0.0238	0.0239
3	24.61	14.61	3.472	0.0694	0.0722	0.0298	0.0298
4	29.36	19.36	4.1664	0.0833	0.0873	0.0357	0.0358
5	33.96	23.96	4.8608	0.0972	0.1026	0.0417	0.0418
6	37.85	27.85	5.5552	0.1111	0.118	0.0476	0.0477
7	41.8	31.8	6.2496	0.125	0.1336	0.0536	0.0537
8	45.83	35.83	6.944	0.1389	0.1493	0.0595	0.0597

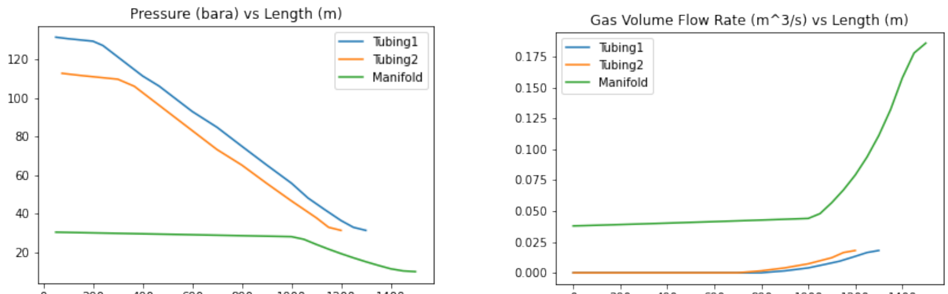
Table 6: Results from the Single-Line Model

B.2 Plotted Results

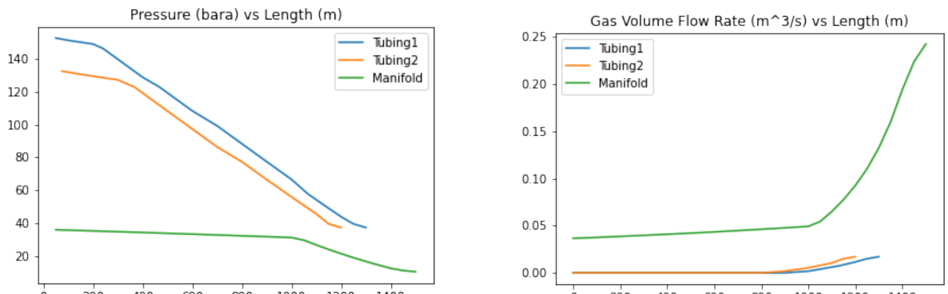
The variations in pressure and gas flow rates across the lengths of flowlines for both the models are plotted and presented in this section for all cases.



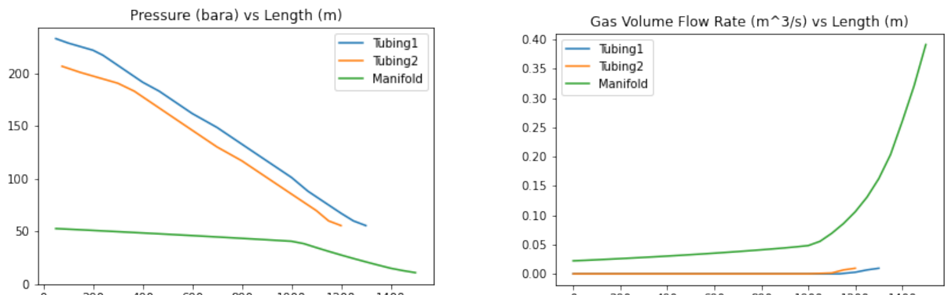
Case 1



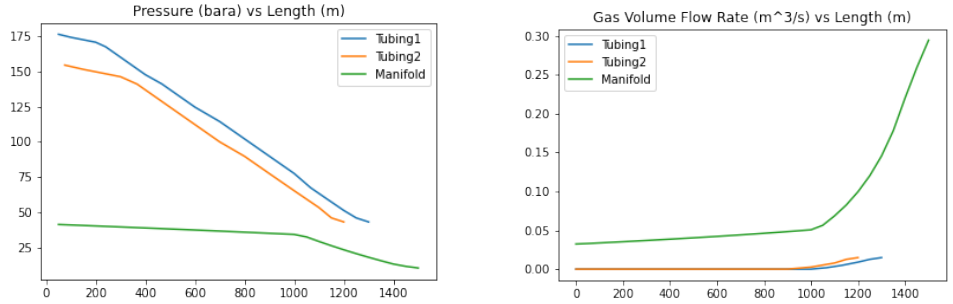
Case 2



Case 3



Case 4



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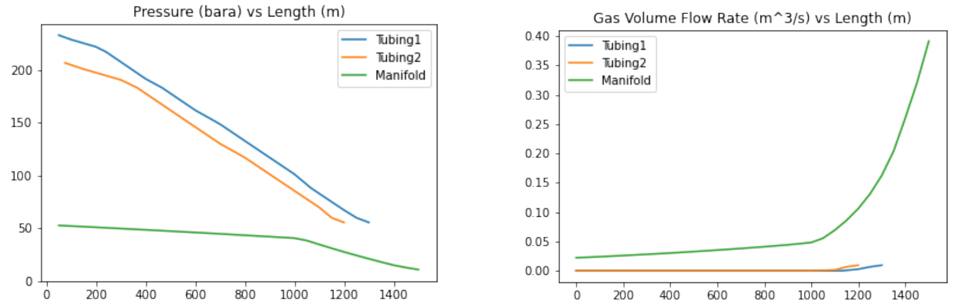

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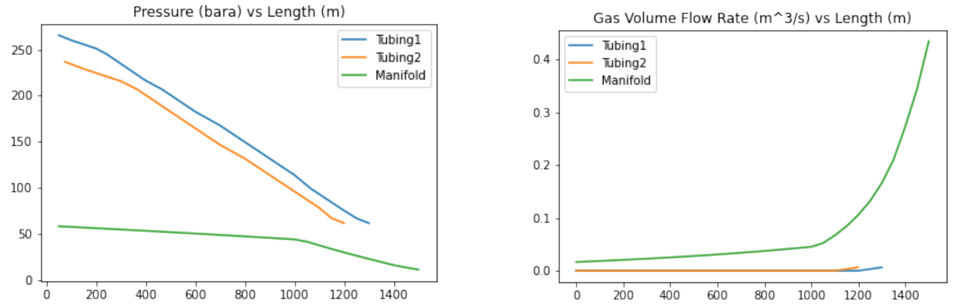
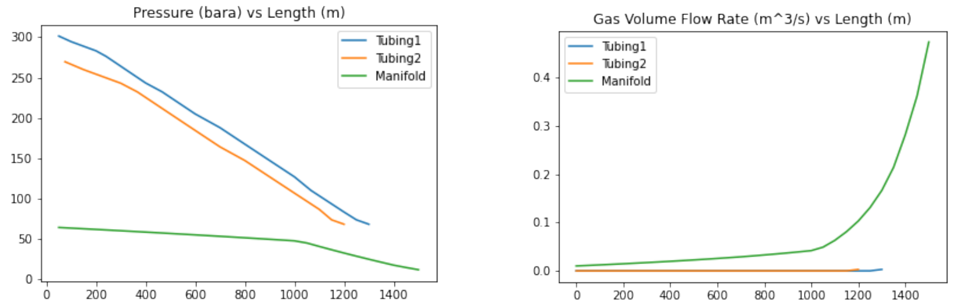
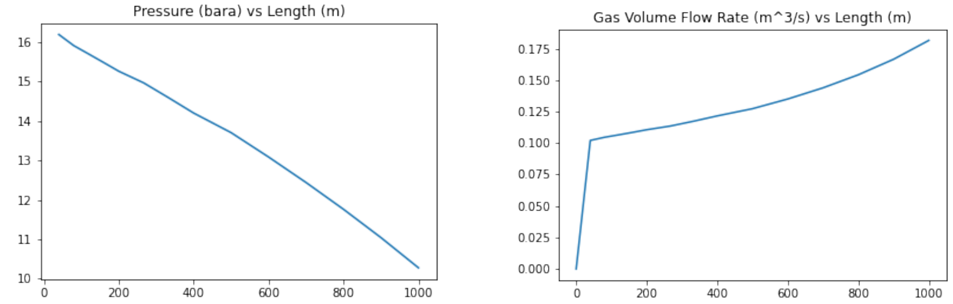


Case 7

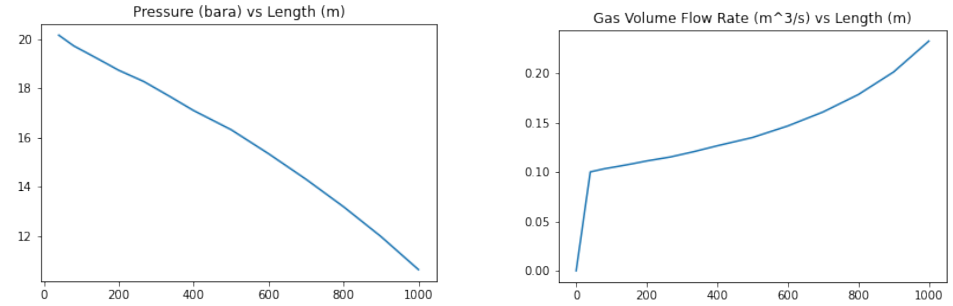


Case 8

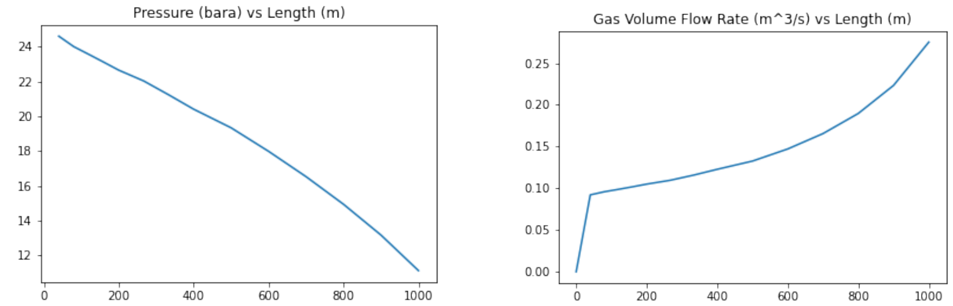
Figure 4: Plotted results from the Network Model.



Case 1



Case 2



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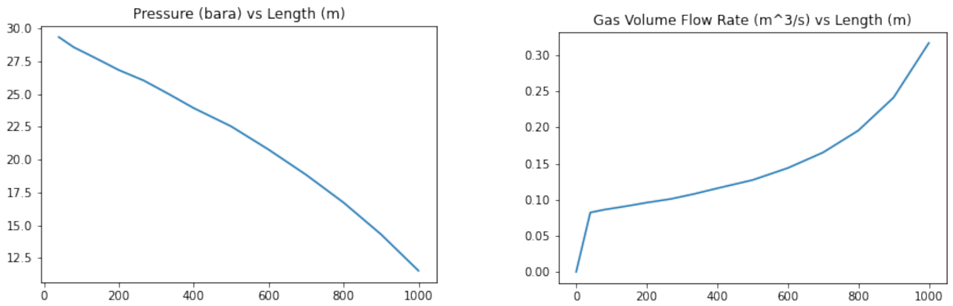

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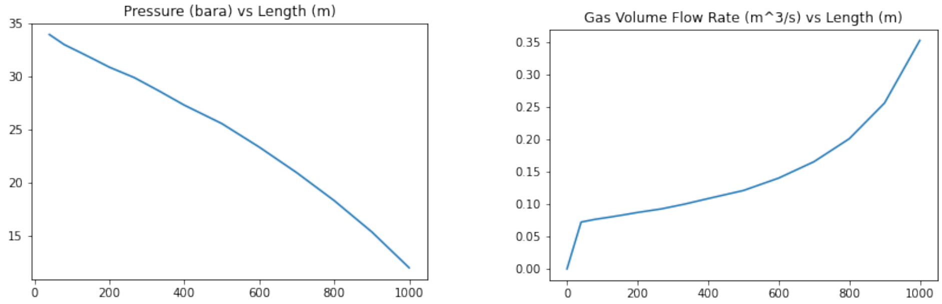

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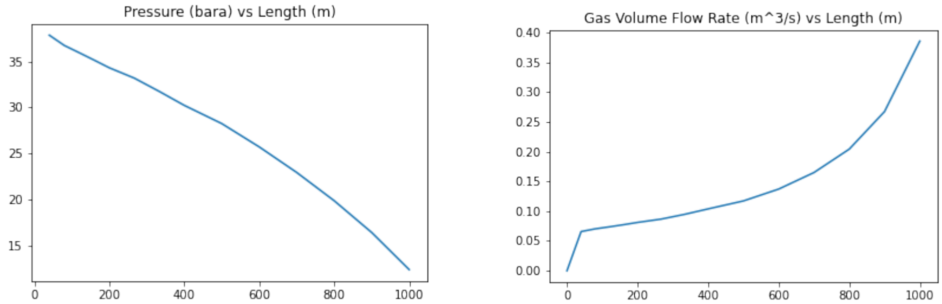

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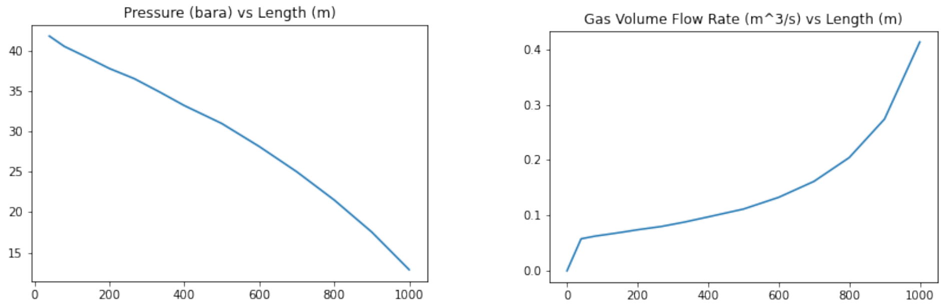

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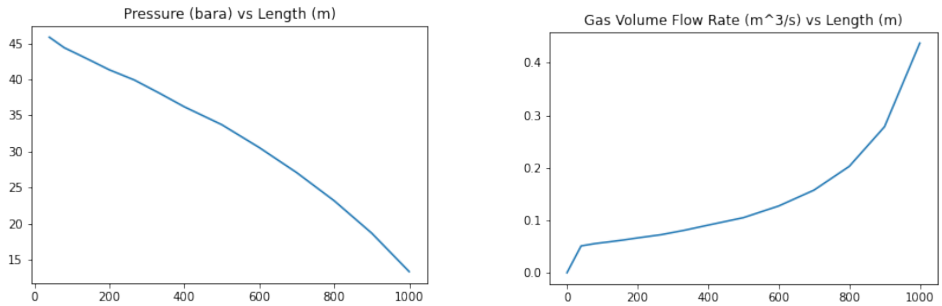

Case 8

Figure 6: Plotted results from the Single-Line Model.

C OLGA Files and Result Extractors

A sample of the network model and the single-line model each are attached with this report. The flow rate in the files can be changed to run any of the cases.
Running a cases produces a file with the extension '.ppl' which contains the results of the case. A python script also attached with this report can be used to extract the results and plots presented in this report. A different script is created for each of the models.