CRANFIELD UNIVERSITY

JOSEPH OTU INOK

INJECTABLE VENTURI FOR SLUG CONTROL

SCHOOL OF WATER, ENERGY AND ENVIRONMENT
PhD in Energy and Power

DOCTOR OF PHILOSOPHY (PhD)
Academic Year: 2016 - 2019

Supervisor: Dr Liyun Lao
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This thesis is submitted in partial fulfilment of the requirements for the degree of Doctor of Philosophy

ABSTRACT

Severe slugging is a cyclic flow regime which causes intermittent delivery of oil and gas, which could lead to flow separator flooding, production reduction, platform trips and plant shutdown. The large and rapid variation in flow reduces the average flow output, which could be as large as 50 %. This relative inefficiency results in substantial profit losses. This study presents novel methods for severe slugging mitigation. It describes the use of a Venturi and an injectable Venturi for the improvement of system stability, increase in production and hydrocarbon recovery.

An injectable Venturi is a Venturi tube that has an opening at its throat, and a pipe inclined at 45° is inserted into this opening. Thus, gas is injected counter to the flow coming from upstream of the injectable Venturi to choke the working fluid passing through the throat of the injectable Venturi.

Flow regimes maps, stability maps, stability curves, severe slug envelopes and Hopf bifurcation maps were generated and used to demonstrate the performance of the Venturi and the injectable Venturi in mitigating severe slugging in a pipeline-riser system. The results from the experiment show that with the Venturi or injectable Venturi coupled to the pipeline-riser system, severe slugging was mitigated, the severity of severe slugging was reduced, the operating region of severe slugging was reduced, and stability was achieved at a larger valve opening and lower riser base pressure. Practically, these results imply an improvement to the stability of the system and increase in oil and gas production. Also, these results indicate that oil and gas production can proceed more smoothly, thus, enhancing flow assurance. Potentially, these results will help to extend the operational life of a reservoir further, thus enhancing oil recovery, safe and continuous production of low-pressure wells.

Keywords:

Venturi, Injectable Venturi, Severe slug mitigation, Increased production, Enhanced recovery, Bifurcation map, Flow assurance, Stability study

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CAPEX	Capital Expenditure
FOPTD	First-Order-Plus-Time-Delay
ISC	Inferential Slug Controller
KH	Kelvin-Helmholtz
LabVIEW	Laboratory Virtual Instrument Engineering Workbench
NMSE	Normalized Mean Square Error
OPC	OLE for Process Control
OPEX	Operation Expenditure
PCA	Principal Component Analysis
PCV	Pressure Control Valve
PDF	Probability Density Function
PSD	Power Spectral Density
PVSC	Pneumatic Valve Service Compressor
SCADA	Supervisory, Control and Data Acquisition

NOMENCLATURE

Symbol	Description	Unit
A_E	Effective area of the throat of the injectable Venturi during injection	m^2
A_G	Gas flow area	m^2
A_L	Liquid flow area	m^2
A_1	Cross sectional area of the converging section of the injectable Venturi	m^2
A_2	Actual cross sectional area of the throat of the injectable Venturi	m^2
A_3	Cross sectional area of the diverging section of the injectable Venturi	m^2
B	Productivity index	-
$C_{d,i}$	Inlet coefficient of discharge	-
$C_{d,o}$	Outlet coefficient of discharge	-
D_E	Injectable Venturi equivalent throat diameter	m
D_1	Injectable Venturi inlet diameter	m
D_2	Injectable Venturi throat diameter	m
D_3	Injectable Venturi outlet diameter	m
g	Acceleration due to gravity	m/s^2
h_G	Height occupied by the gas phase	m
K_{vt}	Effective area ratio	-
n	Empirical index	-
P_{bh}	Well bottom-hole pressure	barg
P_{HYD}	Hydrostatic pressure	barg
P_p	Pipeline pressure	barg
P_r	Reservoir pressure	barg
P_1	Injectable Venturi inlet pressure	barg
P_2	Pressure at the throat of the injectable Venturi	barg
P_3	Injectable Venturi inlet pressure	barg
q	Well production rate	kg/day
Q_g	Volumetric flow rate of gas injected into injectable Venturi	m^3/s
Q_G	Volumetric flow rate of gas	m^3/s

Q_L	Volumetric flow rate of liquid	m^3/s
Q_m	Mixture flow rate	m^3/s
V_{sg}	Gas superficial velocity	m/s
V_{sl}	Liquid superficial velocity	m/s

Greek Letters

Symbol	Description	Unit
α_L	Liquid hold-up	-
β	Ratio of the throat diameter to the inlet diameter	-
β_E	Ratio of the equivalent throat diameter to the inlet diameter	-
β_*	Ratio of the throat diameter to the outlet diameter	-
ΔP^*	Normalised differential pressure	-
ε_i	Inlet expansibility factor	-
ε_o	Outlet expansibility factor	-
θ	Angle of inclination of the pipeline	°
ρ_G	Density of gas phase	kg/m^3
ρ_L	Density of liquid phase	kg/m^3
ρ_m	Mixture density	kg/m^3

1 INTRODUCTION

1.1 Background

The oil and gas industry continually seeks effective means to explore and extract hydrocarbons due to the depletion of conventional wells. Companies have to penetrate greater depths to access ultra-deepwater (greater than 5000 feet) oil. This increase in depth has led to longer multiphase transport pipelines from the well clusters and wellhead platforms into the production platforms. The increase in brownfields due to diminishing reserves of oil from reservoirs once their natural pressure drops have made oil recovery more difficult. Thus, oil and gas companies have been engaged in various methods to enhance oil recovery. These low-pressure wells, increased length of multiphase transport pipeline and greater depths have led to more flow-related problems. They impose additional challenges for the smooth extraction and transportation of fluids to the processing platforms. One of the major challenges is a phenomenon called severe slugging.

Severe slugging is a cyclic flow regime that is characterised by intermittent flows and surges of gas and liquid, which causes flow and pressure oscillations during hydrocarbon extraction and transportation. Severe slugging is problematic for oil production systems because it leads to unwanted flaring, separator flooding, production reduction, platform trips and plant shutdown (Havre et al., 2000). Due to low-downhole pressure, wells are often considered to have reached the end of their useful life sometimes before they actually are. The cyclic fluctuations caused by severe slugging reduces the average flow output and causes several operational setbacks in the oil and gas industry.

Yocum (1973) was the first to identify the threat of severe slugging to the production platform and the different approaches for severe slug mitigation. Since then, several attempts have been made to mitigate severe slugging. The major techniques can be grouped into two categories viz.: passive slug mitigation and active slug mitigation. Active techniques involve the use of actuators or external interferences for the implementation of slug control, whereas passive techniques usually take the form of design changes to the facility itself and no actuators are involved.

Typical active approaches are external gas lift and smart or dynamic choking. External gas lift has been reported to be effective in mitigating severe slugging, enabling continuous production and ensuring smooth start-up of a pipe system that has been shut down (Yocum 1973; Schmidt et al. 1979, 1985; Hill 1989,1990). However, its major drawback is the large amount of gas required to achieve stabilisation and additional cost to CAPEX (CAPital EXpenditure) due to compressor cost. The use of controllers (dynamic choking), has been reported to be able to help alleviate this problem by stabilizing the system at a larger valve opening (Stasiak et al., 2012; Henriot et al., 1999; Jansen et al., 1996; Godhavn et al., 2005; Storkaas and Skogestad, 2004; Ogazi et al., 2009, 2010; Siahaan et al., 2005; Storkaas and Skogestad, 2007; Ehinmowo and Cao, 2015). However, it is difficult to use the choke valve to eliminate severe slugging without reducing the production rate.

Passive techniques are less flexible as they may be difficult to do any modification once the system has been commissioned. Typical approaches includes installing flow conditioners, intermittent absorber, self-gas lifting and using permanent choking to suppress the influence of slugs on the separator unit (Schmidt et al., 1979, 1980; Taitel, 1986; Farghaly, 1987; Taitel et al., 1990; Jansen et al., 1996; Kaasa, 1990; Prickaerts et al., 2013; Adedigba et al., 2006; Adedigba, 2007; Xing et al., 2013a, 2013b, 2013c; Almeida and Gonçalves, 1999, 2000; Ehinmowo et al., 2016). However, these methods have their peculiar disadvantages; self-gas lifting and flow conditioning require subsea pipeline changes which are often technically difficult, and economically costly. Permanent (constant) choking is effective; however, in practice, over-chocking often occur. The valve is closed down more than required in order to ensure severe slugging is mitigated, hence oil production could be significantly reduced due to the valve’s restriction (Havre, Stornes and Stray, 2000). Consequently, a robust and effective severe slug mitigation approach that would stabilise the system and increase production is needed.

This research presents novel passive and active severe slug mitigation techniques which are used to stabilise and increase the overall production. Two cases for severe slug mitigation are investigated: (a) A Venturi tube is embedded into a pipeline-riser system upstream of a choke valve before the topside two-phase (passive technique); (b) similarly, an injectable Venturi is embedded into a pipeline-riser system upstream of a choke valve before the topside two-phase (active technique). A series of experiments were conducted on the 2″ pipeline-riser system with and with no Venturi for the first case and with and with no the injectable Venturi for the second case. Furthermore, the application of active control to the two devices (Venturi and injectable Venturi) and associated processes is also conducted.

1.2 Motivation

The oil and gas companies will be out of business without a proper or adequate flow assurance strategy. A key aspect or classical problem for flow assurance is how to mitigate severe slugging and at the same time, maximise production and enhance oil recovery. The motivation for this research is to improve our understanding of the fundamental aspects of severe slugging phenomena. In addition, find an efficient and robust strategy for severe slug control that will enhance oil recovery, increase production and improve flow assurance quality. Furthermore, a technique that would be economical in order to increase the profitability margins of the oil and gas production company.

1.3 Aim and Objectives

This study aims to develop a novel approach for severe slug mitigation that will stabilise the system and increase the overall production. To achieve this aim, the research objectives were:

1. Evaluation of the effect of Venturi and injectable Venturi on severe slugging
2. Investigation of the potential of the Venturi, and the injectable Venturi to increase production in a pipeline-riser system
3. Improvement of the performance of the Venturi and injectable Venturi through the application of active control

1.4 Overview of Methodology

This section provides an overview of the method adopted in this study. This project employed both experimental and modelling approaches.

1.4.1 Modelling of the Injectable Venturi

A simplified model of the injectable Venturi was developed using physical first-principles such as Bernoulli and continuity equations in order to make the model less complex. The model was implemented in MATLAB. The goal of the model is to simulate the throat and the output pressures from the injectable Venturi, and the differential pressure across the injectable Venturi given the values of the input pressure from the experiment. Using the normalised mean square error (NMSE) fitness metric, the tuned MATLAB model was validated against the experimental data.

1.4.2 Experimental Work on Severe Slugging in an S-shape Pipeline-Riser System

The Cranfield University 2" rig was used for the experimental investigation, and a test matrix was set for the experiment. Sensitivity studies were implemented to determine the most efficient and effective amount of gas to be injected into the throat of the injectable Venturi. Experiments were run for the pipeline-riser, the pipeline-riser system with the Venturi applied, and the pipeline-riser system with the injectable Venturi applied. Experimental data were collected from the Delta V and LabVIEW data acquisition programs. The data were analysed using flow regime maps, Hopf bifurcation maps, stability curves, stability maps and severe slug envelopes. The flow regime maps were developed objectively using Probability Density Function (PDF) and Power Spectral Density (PSD).

To design the controller, critical valve opening was determined through bifurcation analysis and the reaction curve for the plant was obtained from the stable operating points through step response for the pipeline-riser-Venturi and the pipeline-riser-injectable Venturi systems. These reaction curves were used to determine the plant models from where model parameters (process gains, time constants and time delays) for each experiment were obtained. Ziegler-Nichols open-loop tuning was used to determine the controller gains and inferential slug control approach was used to control and stabilise the system beyond these critical valve openings.

1.4.3 Approaches to Severe Slug Mitigation

The approaches used for severe slug mitigation are:

1. Parameter variation
2. The Venturi
3. The injectable Venturi
4. Active control

1.4.4 Proofs of Concepts

Four proofs of concepts were used to show the effectiveness and performance of the Venturi and the injectable Venturi in attenuating severe slugging and at the same time maximising production:

1. Flow regime identification
2. Hopf bifurcation
3. Gas perturbation
4. Active control

1.5 Thesis Outline

Figure 1-1 illustrates the thesis structure, as well as the relation between the contents and the objectives introduced in Section 1.2.

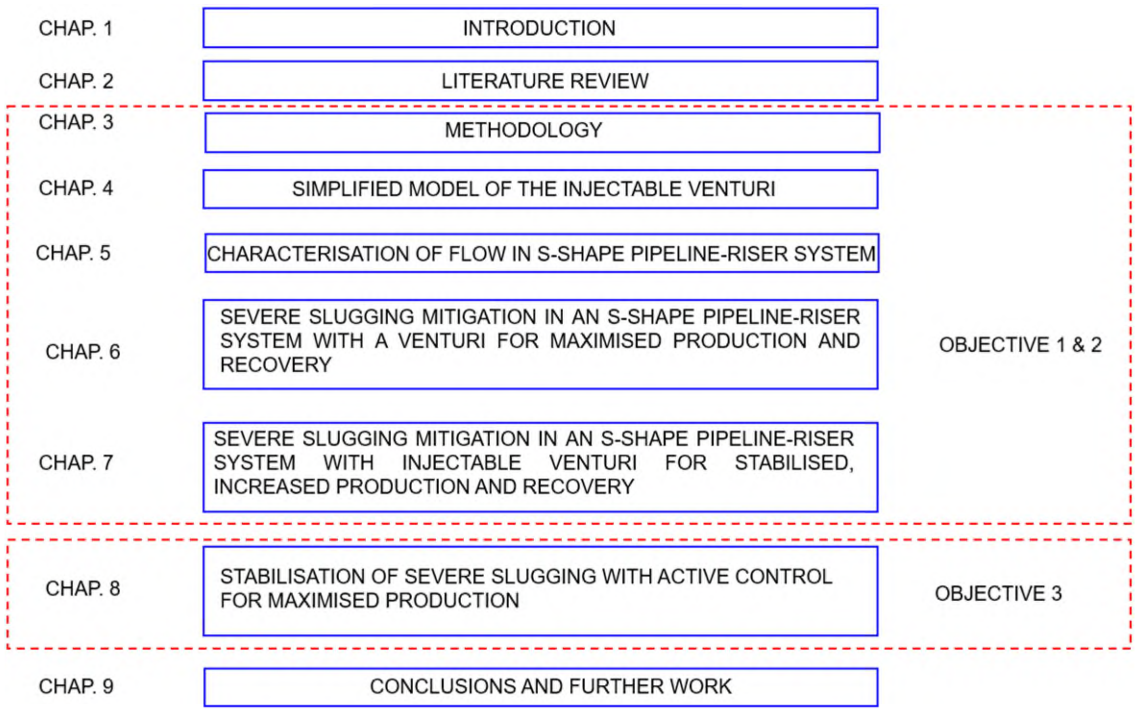

Figure 1-1 Outline of the thesis structure

The work presented in this thesis is outlined according to the chapters as follows:

Chapter 2 presents a literature review on multiphase flow with emphasis on severe slug flow and severe slug flow control. Active and passive severe slug mitigation methods were critically reviewed. Their limitations and challenges are also discussed.

Chapter 3 describe the methodology adopted to achieve the objectives set out in section 1.3. The Cranfield University multiphase experimental facility used for the experimental studies, experimental flow loops, experimental procedures, instrumentations were explained.

Chapter 4 presents the simplified injectable Venturi two-phase homogeneous flow model implemented in MATLAB. The model was validated by comparing its simulation data to the data obtained during the experiment.

Chapter 5 is devoted to the characterisation of flow regimes in a 2" S-shape riser within the test matrix investigated in this experiment. This chapter details how these flow regime maps were developed.

Chapter 6 presents the critical evaluation of the severe slug attenuation potential of the Venturi in the pipeline-riser system and the determination of its production increase potential in pipeline-riser systems.

Chapter 7 is devoted to critical evaluation of the severe slug attenuation potential of the injectable Venturi in the pipeline-riser system and the determination of its production increase potential in pipeline-riser systems.

Chapter 8 focuses on the design of the active controller and the implementation of active control to improve severe slug attenuation and increase in production capacity of the Venturi and the injectable Venturi.

Chapter 9 presents a summary of the key findings, the contribution to knowledge and the potential impact of this study. In addition, it suggests recommendations for future work.

1.6 Publications

The following publications have resulted from this work:

1. Inok, J., Lao, L., Cao, Y., Whidborne, J., Severe slug mitigation in an S-shape pipeline-riser system by an injectable Venturi. Chemical Engineering Research and Design Journal (2019), doi: https://doi.org/10.1016/j.cherd.2019.08.008

2. Inok, J., Lao, L., Cao, Y., Whidborne, J., 2019. Severe slugging mitigation in an S-shape pipeline-riser system with injectable Venturi for stabilised and increased production, in: Proceedings of the 19th International Conference on Multiphase Production Technology, 5-7 June, Cannes, France, pp. 375–388

3. Inok, J., Lao, L., Cao, Y., Whidborne, J., 2019. Severe slug mitigation in an S-shape pipeline-riser system by a Venturi. International Journal of Multiphase Flow (In Review)
4. Inok, J., Lao, L., Cao, Y., Whidborne, J., 2019. Severe slugging mitigation in an S-shape pipeline-riser system with a Venturi for increased production and recovery, in: Proceedings of the Offshore Technology Conference Brazil 2019, 29-31 October, Rio de Janeiro, Brazil (To be presented)

2 LITERATURE REVIEW

2.1 Introduction

This chapter presents a brief but critical literature review on gas-liquid two-phase flow with a focus on severe slug flow control. Firstly, a general overview of gas-liquid two-phase flow is presented in Section 2.2; gas-liquid slug flow is discussed in Section 2.3. Section 2.4 presents the various severe slug control techniques with a critical review of their respective claims. Finally, the chapter is concluded in Section 2.5.

2.2 Gas-Liquid Two-Phase Flow

Two-phase flow is the simultaneous flow of gas-liquid, gas-solid, liquid-liquid or liquid-solid in the same conduit, such as a pipe. Amongst the various two-phase flows, the gas-liquid flow has the most complication due to the compressibility and deformability of the gas phase (Ghajar, 2005). The gas and liquid phases in the gas-liquid two-phase flow form several flow regimes due to the simultaneous interaction by surface tension and gravity force. Gas-liquid two-phase flow exists in different flow patterns. These flow patterns are the physical distribution of the phases within the flow enclosure. Hence, it could be classified into different flow patterns called flow regimes.

2.2.1 Gas-Liquid Two-Phase Flow Regimes

Flow regime or flow pattern is a term commonly used in multiphase flow studies to classify the different geometric features of phase distribution, which occur during multiphase flow through pipes (Baker, 1954). This complex interaction between the various phases often results in the distribution of gas and liquid in the pipe in such a pattern that is observable and can be represented using a flow map called flow regime map. However, flow regime maps are only relevant to the system (operating condition, pipeline dimension and fluid type) applied in generating it; these play a significant role in establishing the flow regime obtainable in the system (Brennen, 2005). Thus, there is no generalised flow regime that can be used to understand flow regime in all flow systems. Schicht (1969) and Weisman and Kang (1969) unsuccessfully attempted such generalisation which was geared towards generalising flow regime map coordinates. This did not work because the transition in majority of flow pattern maps and the associated instabilities depend on different properties of the fluid. Examples of gas-liquid two-phase flow regime maps are shown in Figures 2-1 and 2-2 for horizontal and vertical flow configurations respectively.

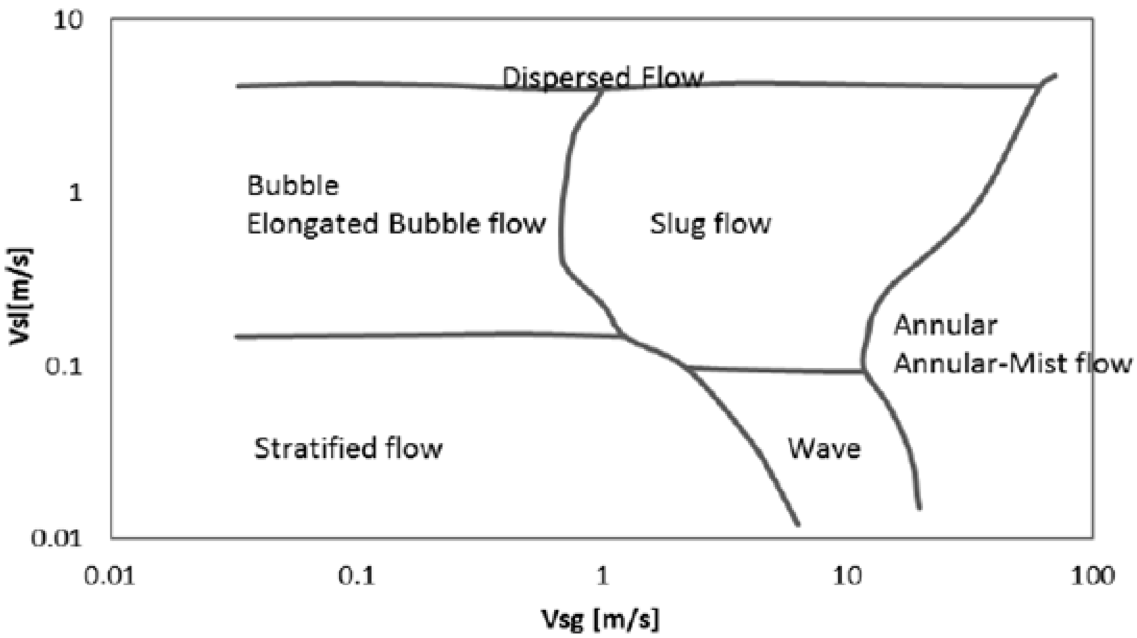

Figure 2-1 Horizontal multiphase flow regime map (Mandhane et al., 1974)

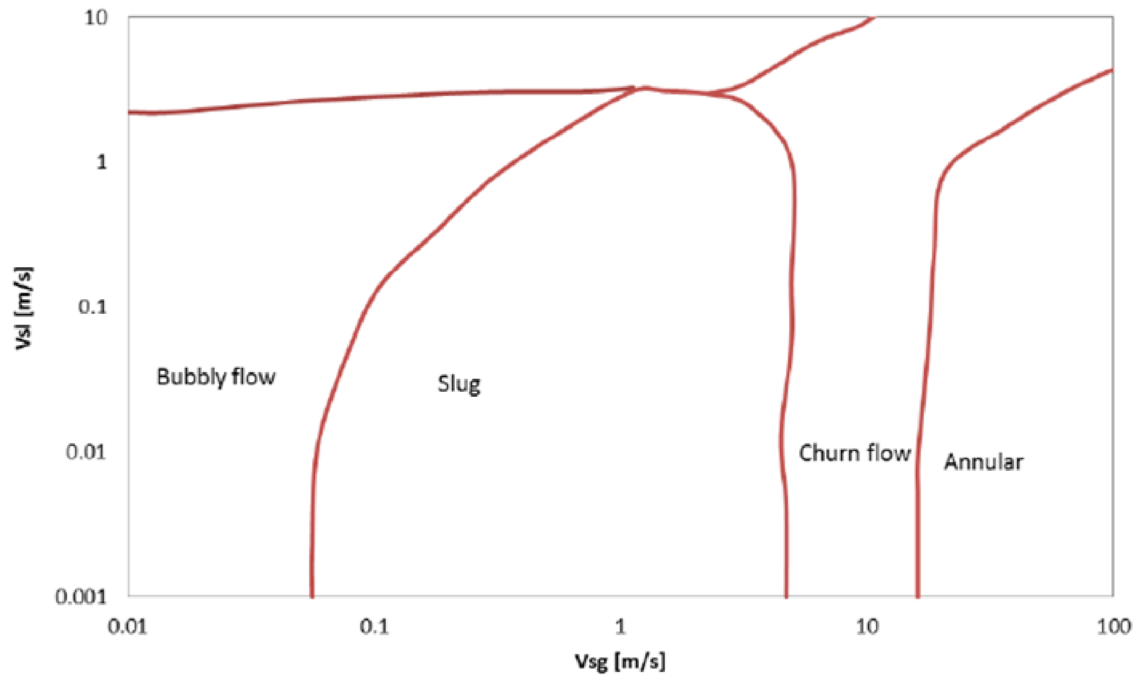

Figure 2-2 Vertical multiphase flow regime map (Barnea, 1987)

2.2.1.1 Gas-Liquid Two-Phase Flow in Horizontal Pipeline

Earlier studies by Taitel et al. (1979) and Weisman (1983) have shown that flow regime common in a vertical pipeline vary from that of the horizontal pipeline. Weisman (1983) classified typical flow regimes predominant in the two-phase gas-liquid multiphase flow in a horizontal pipe as shown in Figure 2-3 as bubble, slug, plug, annular, stratified, wavy, and dispersed.

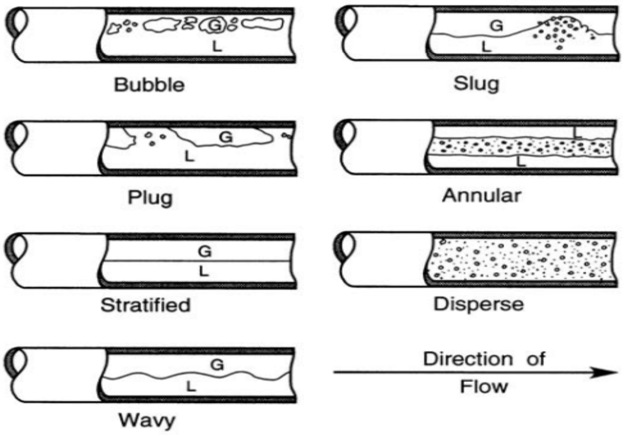

Figure 2-3 Typical flow patterns in a horizontal pipeline (Weisman, 1983)

2.2.1.2 Gas-Liquid Two-Phase Flow in Vertical Pipeline

Figure 2-4 shows the typical flow regimes predominant in the two-phase gas-liquid multiphase flow in a vertical pipe. Weisman (1983) classified them as bubble, slug, churn, annular and disperse.

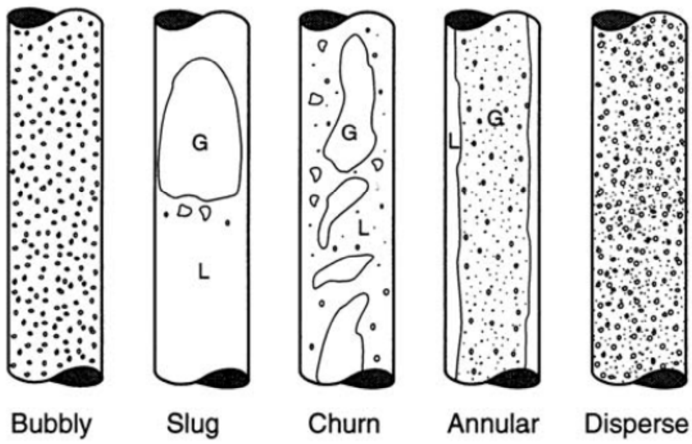

Figure 2-4 Typical flow patterns in a vertical pipeline (Weisman, 1983)

2.3 Severe Slugging

Severe slugging usually occurs in brownfields or matured oil wells approaching the end of operational life. At a late stage in the field life of an oil well, the reservoir pressure is usually low, and consequently, production will be reduced. Severe slugging occurs due to low gas and liquid flow rate; when downward inclined or undulating horizontal pipeline flows into an upward incline pipeline or vertical riser (Jansen and Shoham, 1994).

This phenomenon is common in offshore production systems and is often related to issues such as high instantaneous flow rates, which causes instabilities in the system and may eventually lead to the shutdown of operations. In addition, it causes high average backpressure at the wellhead, which reduces the production rate and could also cause unwanted plant shutdown. Furthermore, it causes reservoir flow oscillations, which could damage equipment worth millions of dollars (Baliño, 2014).

2.3.1 Severe Slugging in Vertical Riser

Severe slugging in vertical riser has been investigated experimentally by several researchers (Malekzadeh et al., 2012; Linga, 1987; Taitel, 1986; Taitel, 1990; Xie et al., 2017; Zhou et al., 2018; Schmidt, 1977; Schmidt et al., 1980). Schmidt (1977), was the first to identify severe slugging in vertical riser. The initial study on severe slugging on vertical riser by researchers centred on establishing the mechanism and the general features of severe slugging. They classified severe slugging into classical severe slugging (Severe Slugging Type I), Severe Slugging Type II and Transitional Severe Slugging.

Further studies focused on the effects of severe slugging on production. However, the preference of most producing companies to use Floating Production Storage and Offloading (FPSO) vessels due to their economic value have made risers with complex geometry more popular. These vessels are less expensive than traditional offshore oil and gas platforms, more flexible, safer, and time-efficient.

2.3.2 Severe Slugging in Complex Geometry

Severe slugging in complex riser such as S-shape riser has been investigated experimentally by several researchers (Li et al., 2017; Tin, 1991; Li et al., 2013; Tin and Sarshar, 1993; Ye and Guo, 2013; Park and Nydal, 2014). They also had similar classification to that of the vertical riser.

Tin (1991) was the first to report an experimental study of severe slugging in S-shape riser. However, his results were mainly times series recordings of the riser base pressure. They showed the cycling behaviour characteristics of the riser base pressure during severe slugging. He did not consider the pressure across the riser or any other sections of the riser. Besides, riser base pressure could be affected by downstream pressure fluctuation. Hence, it would not give an accurate reflection of what is happening within the riser. Furthermore, a method that is not objective (visual observations) was used to discriminate the results. 56

Tin and Sarshar (1993) characterise flow regimes in S-shape riser and presented various flow pattern maps showing the boundaries of severe slugging and unstable flow regions. However, the maps did not show experimental data-points. Thus, the transition lines could be assumed arbitrary since the relative distinction between each flow regime region cannot be established.

Recently, investigations (Li et al., 2017; Li et al., 2013; Ye and Guo, 2013; Park and Nydal, 2014) have focused on the objective characterisation of flow and the effects of choking on S-shape riser. Li et al. (2013) did a comparative study on vertical and S-shaped riser. They used the flow pattern developed in their S-shaped riser experiment to compare with experimental data from Malekzadeh et al. (2012) vertical riser experiment. Figure 2-5 shows the comparison of a vertical riser to an S-shape riser. This comparison shows the differences between complex geometry riser (S-shape) and vertical riser. Thus, the flow through a vertical and an S-shaped riser exhibit different characteristics.

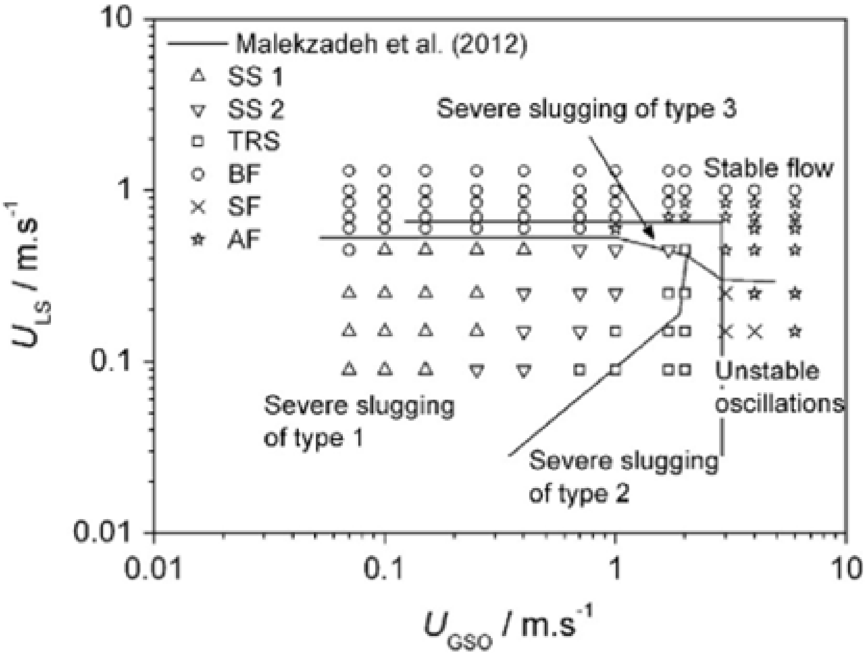

Figure 2-5 Comparison of the vertical riser with S-shape riser (Li, Guo and Li, 2013)

Several of these researchers used objective methods such as Probability Density Function (PDF) and Power Spectral Density (PSD). However, they characterise the flow based on measurements from different sections of the riser such as the differential pressure measurements across different sections of the riser (lower limb, downcomer and upper limb). They did not consider the entire length of the riser.

2.3.3 Severe Slug Formation

Multiphase flow pipelines are used to transport a mixture of water, gas and oil (three-phases) or gas and liquid (two-phase) simultaneously. The liquid phase usually accumulate in the low points of the pipeline due to the terrain topography and the local flow conditions. Hence, long liquid bridges are formed, which could be blown out from one pipeline section to the next by the gas pressure (De Henau and Raithby, 1995). Various authors (Sarica and Tengesdal, 2000; Montgomery, 2002; Schmidt et al.,1985; Montgomery and Yeung, 2002) have described severe slug formation process. However, early studies by Taitel (1986) describe the severe slug formation of a gas-liquid two-phase flow as a four-stage cyclic process. The four-stage cyclic process is shown in Figure 2-6 and highlighted as follows:

1. ***Slug formation stage:*** In this stage, the liquid gathers in the bottom of the riser due to the lack of ability to raise the dense liquid through the entire length of the riser at once. Hence, it blocks the passage of the gas and causes the gas to compress
2. ***Slug production stage:*** This stage starts once the slug front reaches at the riser top. The liquid blocks the gas at the riser base. As more fluids enter the pipeline, the bottom pressure increases; thus, the riser section will be filled with liquid
3. ***Slug blowout stage:*** As the blocked gas accumulates, after a while it builds up pressure sufficient enough to overcome the hydrostatic pressure. Thus, the gas blows the liquid out of the riser into the separator at a fast velocity
4. ***Liquid fall back stage:*** After the blow-out, the remaining liquid in the riser falls back to the bottom of the riser. Thus, the liquid will start to build up in the bottom of the riser, and the cycle repeats itself.

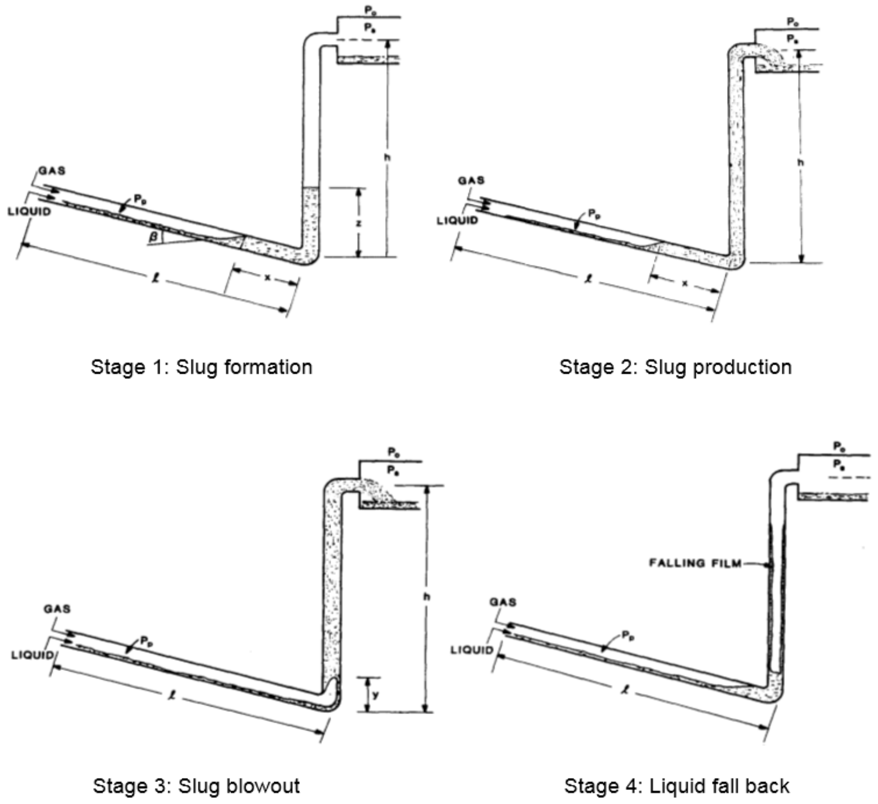

Figure 2-6 Severe slug four-stage cyclic formation process (Taitel, 1986)

2.3.3.1 Severe Slug Classification

Severe slugging can be classified according to the observed flow regime, as follows (Tin and Sarshar, 1993):

1. ***Severe Slugging 1 (SS1):*** Earlier studies by Taitel (1986) described the cyclic formation of SS1 in four stages viz., slug formation, slug movement into the separator, blowout, and liquid fall- back. However, to point out the distinctions between all types of severe slugging Malekzadeh et al. (2012) describe the cyclic formation of SS1 in five stages viz., blockage of the riser base, slug growth, liquid production, fast liquid production and gas blowdown. Thus, the major difference is that for SS1 the liquid slug length is greater than or equal to the riser length. Also, the maximum pipeline pressure is equal to the hydrostatic head of the riser when the friction pressure drop is considered negligible.

2. ***Severe Slugging 2 (SS2):*** When compared to SS1; SS2 has a shorter slug length. Although it is qualitatively similar to SS1 in terms of transition to severe slug; the liquid slug length is shorter than the riser's height, with intermittent gas penetration at the riser base.

3. ***Severe Slugging 3 (SS3):*** SS3 is characterised by a growing long aerated liquid slug in the riser. This aerated liquid slug is followed by the gas blow down stage and its cyclic formation is in four stages viz., transient slugs, aerated slug growth, fast aerated liquid production, gas blowdown (Malekzadeh et al., 2012). There is continuous penetration of gas at the bottom of the riser. The flow in the riser was observed to resemble normal slug flow, but critical look at pressure, slug lengths and frequencies reveal cyclic variations of smaller periods and amplitudes when compared to SS1.

2.3.3.2 Severe Slug Models

Modelling multi-phase flow dynamics are challenging processes. The dynamics of flow has been investigated for many years, and it is still ongoing. A number of steady-state models (Goldzberg and Mckee, 1987; Pots et al.,1985; Taitel and Dukler, 1976; Taitel, 1986) and transient models (Fabre et al., 1987; Moe et al., 1989; Sarica, C. and Shoham, 1991; Schmidt et al., 1980) have been developed to predict the occurrence of severe slugging in a pipeline-riser system over the years. Severe slug models have sought to answer two basic questions associated with severe slug flow:

1. When or at what conditions will severe slugging occur?
2. What are the characteristics of severe slugging?

Steady-state models are often used to answer the first question. These models predict the likelihood of severe slugging occurring. Hence, these are termed criteria for severe slugging. Schmidt et al. (1980) asserted that for severe slugging to occur, stratified flow must be present in the pipeline approaching the riser base. Previous work by Taitel and Dukler (1976) predicted this stratified flow; thus, it is employed as the first criterion for severe slugging.

Taitel and Dukler (1976) developed a criterion to predict stratified flow regime in horizontal and near-horizontal pipelines. Although this criterion is not explicitly developed as a severe slug criterion, it has been used by several authors (Bøe, 1981; Pots et al., 1985; Taitel, 1986). By applying the inviscid Kelvin-Helmholtz theory in which shear stress is neglected (Kordyban and Ranov, 1970), the condition developed is given as:

$$U_G > \left[\frac{g(\rho_L - \rho_G)h_G}{\rho_G}\right]^{\frac{1}{2}} \quad \textbf{(2-1)}$$

where U_G is the superficial gas velocity, h_G is height occupied by the gas phase, ρ_G and ρ_L are the density of gas and liquid phases respectively.

If U_G, has a lower value than that obtained by evaluating the right-hand-side (RHS) of Equation (2-1), a stratified flow regime is obtained in the pipeline, and severe slugging can occur in the pipeline-riser system. Figure 2-7 shows the Taitel and Dukler (1976) criterion plot. Below the transition line (unstable flow) in Figure 2-7 is the region were stratified flow occurs in the pipeline.

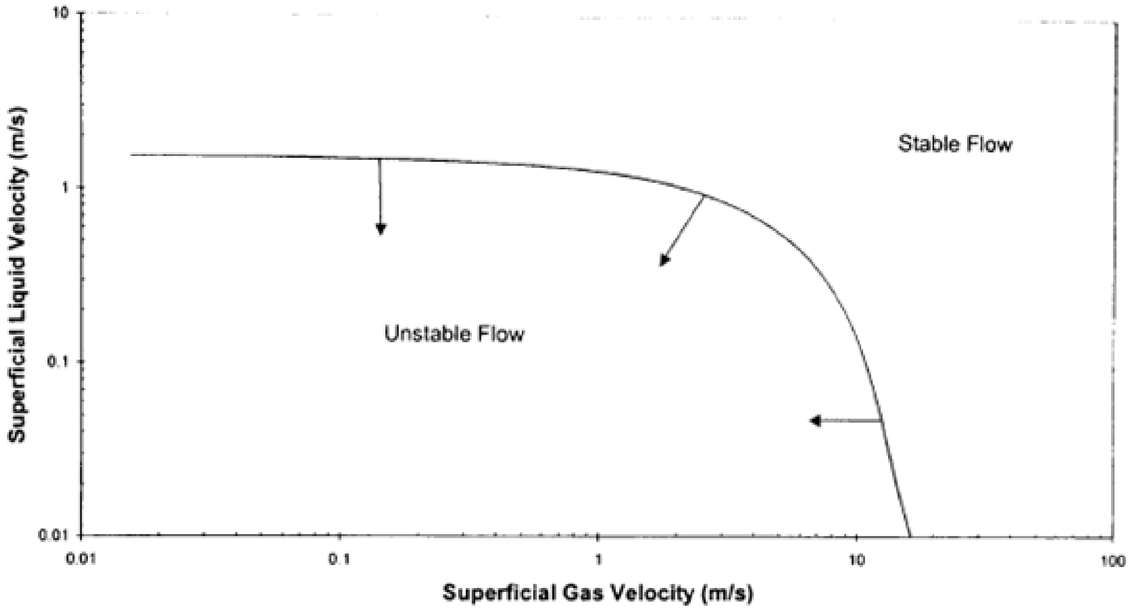

Figure 2-7 Taitel and Dukler Stratified Flow Criterion Plot (Taitel and Dukler, 1976)

Goldzberg and Mckee (1987) also developed a criterion based on the Taitel and Dukler criterion for the formation of slug in a pipeline dip through the sweeping out of the accumulated liquid in the pipeline dip. Their criterion was analysing the Bernoulli equation over the liquid surface. Consequently, the criterion obtained by Goldzberg and McKee is given as:

$$U_G < C_2 \left[\frac{g(\rho_L - \rho_G) cos\theta A_G}{\rho_G \frac{dA_L}{dh_{LP}}} \right]^{\frac{1}{2}} \tag{2-2}$$

where A_L is the liquid flow area, A_G is the gas flow area, $C_2 \approx A_G/A_L$ and θ is the angle of inclination of the pipeline.

Bøe (1981) developed another criterion for severe slugging, which is based on the assertion that the rate of pressure head accumulation at the riser base must be greater than the rate of pipeline gas pressure increase for a severe slug to form. This criterion is summarised as:

$$\frac{\partial(\Delta P_{HYD})}{\partial t} > \frac{\partial\left(P_p\right)}{\partial t} \tag{2-3}$$

where P is the pressure and the subscripts HYD and P are the hydrostatic and pipeline pressure respectively, and t is the time. Under constant inlet fluid flowrates, a pressure balance over the riser and the mass balance of gas in the pipeline, the criterion given in Equation (2-3) was resolved to give:

$$U_L \geq \frac{P_p}{\rho_L(1-\alpha_L)\sin\theta} U_G \tag{2-4}$$

where P_p is the pipeline pressure, U_L is the superficial liquid velocity, θ is the angle of inclination of the pipeline and α_L is the liquid hold-up. In the initial work by Bøe the condition for the pipeline liquid hold-up was used and is given as:

$$\alpha_L = \frac{U_L}{U_L + U_G} \tag{2-5}$$

For severe slugging to occur, the condition in equation (2-4) must be satisfied. Figure 2-8 shows the Bøe (1981) criterion plot. Above the straight line (unstable flow) in Figure 2-8, severe slugging occurred.

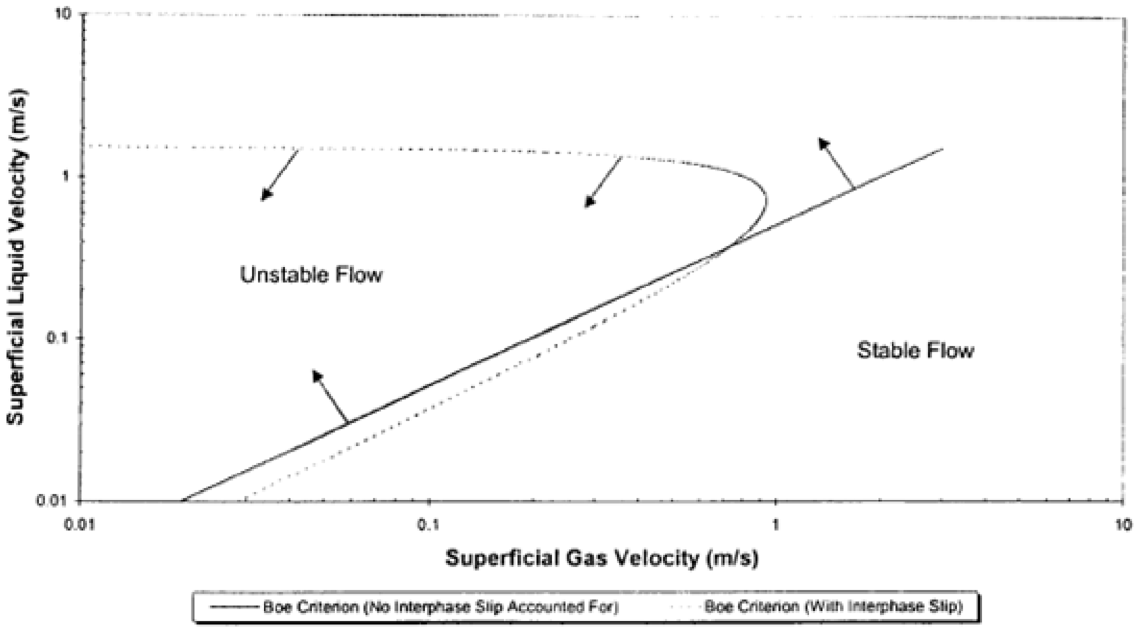

Figure 2-8 Bøe Criterion Plot (**Bøe, 1981)**

Pots et al. (1985) developed another criterion similar to the Bøe criterion for predicting the occurrence of severe slugging. They considered the liquid build-up stage of severe slugging and presented a criterion based upon the balance between the rate of hydrostatic pressure head build-up across the riser and the gas accumulation in the pipeline. The criterion was developed assuming that there is no mass transfer between the liquid and gas phase, the riser is vertical, and there is no liquid fall back. They assumed that severe slug in the riser was formed by all the liquid entering into the pipeline. The criterion is given as:

$$\Pi_{ss} = \frac{ZRT/M_G m_G}{g \alpha_L L m_L} \quad \textbf{(2-6)}$$

where Z is the gas compressibility factor (-), R is the gas constant (J/mol K), T is the temperature (K), M_G is the gas molecular weight (kg/kmol), L is the length of the pipeline (m), and m_L and m_G are the mass flow rate of liquid (kg/s) and gas (kg/s) respectively. For severe slugging to occur, the rate of hydrostatic pressure head build-up across the riser must be greater than the rate of accumulation of gas in the pipeline. Thus, severe slugging will occur if Π_{ss} < 1.

Another criterion for the occurrence of severe slugging was developed by Taitel (1986). The aim of this criterion was to quantify the effect of separator pressure on the likelihood of severe slugging. Taitel's criterion considered the blowout stage of the severe slugging cyclic formation process and the net force across the riser during the blowout stage. The Taitel (1986) condition for instability (severe slugging) to occur is given as:

$$\frac{\partial(\Delta F)}{\partial y} > 0 \qquad \textbf{(2-7)}$$

where ΔF is the net force over the riser column as the gas bubbles penetrate the riser at the base, y is the height of the gas bubble penetrating the riser. The ΔF is given by:

$$\Delta F = \left[(P_s + \rho_L g H_R)\frac{\alpha_G L}{\alpha_G L + y\alpha_G^{'}}\right] - [P_s + \rho_L g(H_R - y)] \qquad \textbf{(2-8)}$$

where P_s is the topside separator pressure, H_R is the riser height, α_G is the gas holdup in the pipeline, L is the length of the pipeline and $\alpha_G^{'}$ is the gas hold- up in the gas bubble penetrating the riser. By combining Equations (2.7) and (2.8), the final form of the criterion is given as (when referenced to atmospheric conditions):

$$\frac{P_s}{P_0} < \frac{\left(\frac{\alpha_G}{\alpha'_G}\right) L - H_R}{P_0/\rho_L g} \tag{2-9}$$

The analysis of this criterion shows that it depends on the pipeline-riser geometry and operating condition. The gas holdup is assumed to be equal to a constant value of 0.89 for vertical flow. Figure 2-9 shows the Taitel (1986) criterion plot. Below the straight line (unstable flow) in Figure 2-9, severe slugging occurred. Fuchs (1987) also developed a severe slug criterion model, which was based on the severe slug blow out stage analysis.

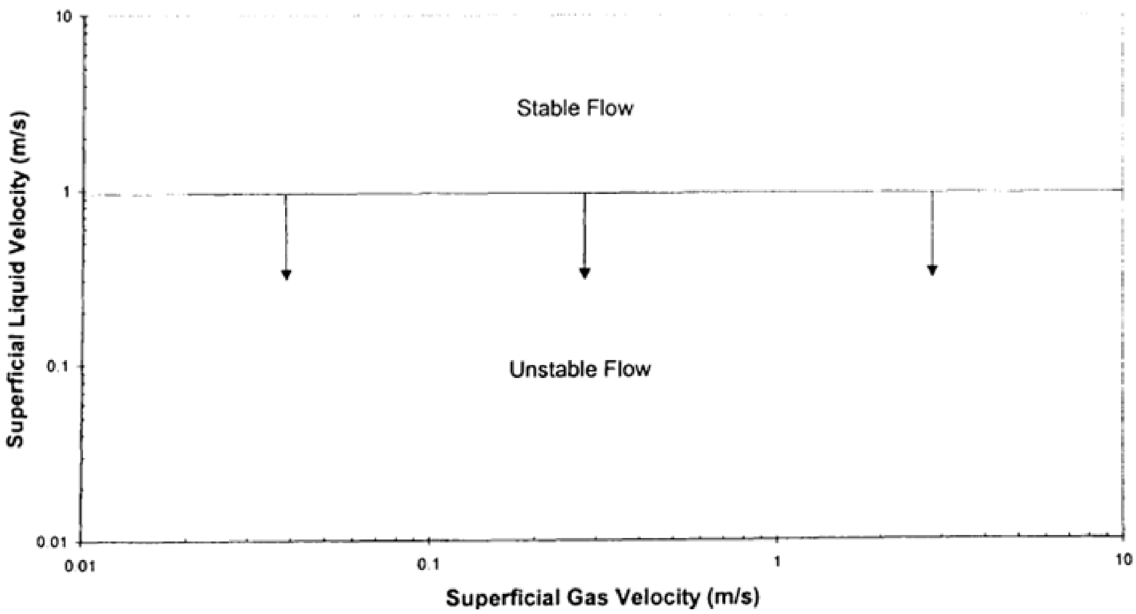

Figure 2-9 Taitel (1986) criterion plot

Schmidt et al. (1980) presented the first model of severe slugging attempting to predict the slug length and the slug build up time. They developed a transient model based on mass and pressure balances on the pipeline-riser system with a focus on the liquid build-up stage. The aim of their model was to predict the time for slug build-up and the slug length. Their model prediction showed good agreement with their experimental result. However, the model's ability to be generalised was very limited due to the closure model. The closure model was developed as an empirical correlation generated from their experimental facility.

Schmidt et al. (1980) developed another transient model for predicting severe slugging. The model was developed with a focus on predicting all the stages in the severe slugging cyclic process. Different mass and pressure balances were used for each stage in the cycle. The gas-liquid interface was used to define the transition between each stage in the severe slugging cycle. The simulation results obtained from this model was reported to agree closely when compared to the experimental data of Schmidt et al. (1980). This model has been used in subsequent work by Hill (1987).

The main issue of severe slug modelling is that most models are based on the mass balance principle, which requires the liquids and gasses injected into the system to be known. In reality or practice, this is not often the case. The limitation of these older models is that they were developed to simulate flow in the pipelines and not developed for slug control. Hence, they cannot be validated with manipulated variables in a closed-loop.

Commercial computational multiphase flow simulation programs such as OLGA, CFD and Leda flow have been used to develop control-oriented models. They are based on continuity equation and have been proven to be reliable. Many researchers have used them in modelling and validation of their experiment (Xing et al., 2013c; Malekzadeh et al., 2012; Jahanshahi and Skogestad, 2011; Tang and Danielson, 2006; Nemoto et al., 2015; Enilari and Kara, 2015; Takei et al., 2010).

2.4 Severe Slug control

Considerable advancement has been made in the study of severe slug flow regime, its avoidance and mitigation. Early studies by Yocum (1973) identified different process changes which are still being used in some plants today to mitigate severe slugging. Since then, various severe slugging mitigation methods have been proposed and implemented. However, only a few of these techniques such as Inferential slug control (Cao, 2011) patented by (Cao et al. 2013) and other methods reported in Courbot (1996), Hill, (1989), Kovalev et al. (2003) and Havre et al. (2000) have been deployed for industrial use. The mitigation methods can be grouped into two major categories viz.; passive slug mitigation and active slug mitigation.

2.4.1 Passive Slug Mitigation

The passive slug mitigation methods usually take the form of design changes to the facility itself, and no actuators are involved. Yocum (1973) identified different passive slug mitigation methods, although other passive mitigation methods have been identified since then. Passive mitigation methods can be categorised into five groups:

1. Reducing the incoming line diameter near the riser in order to establish a new stable flow regime (using flow conditioners)
2. Using dual or multiple risers or pipelines
3. Inducing a minimum excessive back pressure on the riser in order to eliminate slug
4. Using fluid remixing device. This devices mix fluids at the riser or riser base in order to avoid liquid accumulation, thus, preventing stratified flow from progressing into severe slugging
5. Riser outlet downstream adjustment. This involves design modification of downstream processing facilities in order to mitigate severe slugging

Various passive techniques have been implemented over the years with mixed results. These five initiatives are the fundamental principles of all the methods explained in this section.

2.4.1.1 Design Modification of Downstream Facilities

Slug catchers are static enclosed vessels which are specially designed and installed at the end of a pipeline or a riser to provide buffer and storage volume for the fluids coming from the well in the upstream oil production system (Cadei et al., 2015). It manages the intermittent slug flow and optimises the operating condition of the upstream and downstream facility. Thus, allowing the maximisation of oil production. Also, they provide the first stage of separation between gas and liquid phases; hence, they are often referred to as pre-separators. As a severe slug mitigation system, they do not prevent severe slug formation. Figure 2-10 shows the schematic diagram of a horizontal slug catcher.

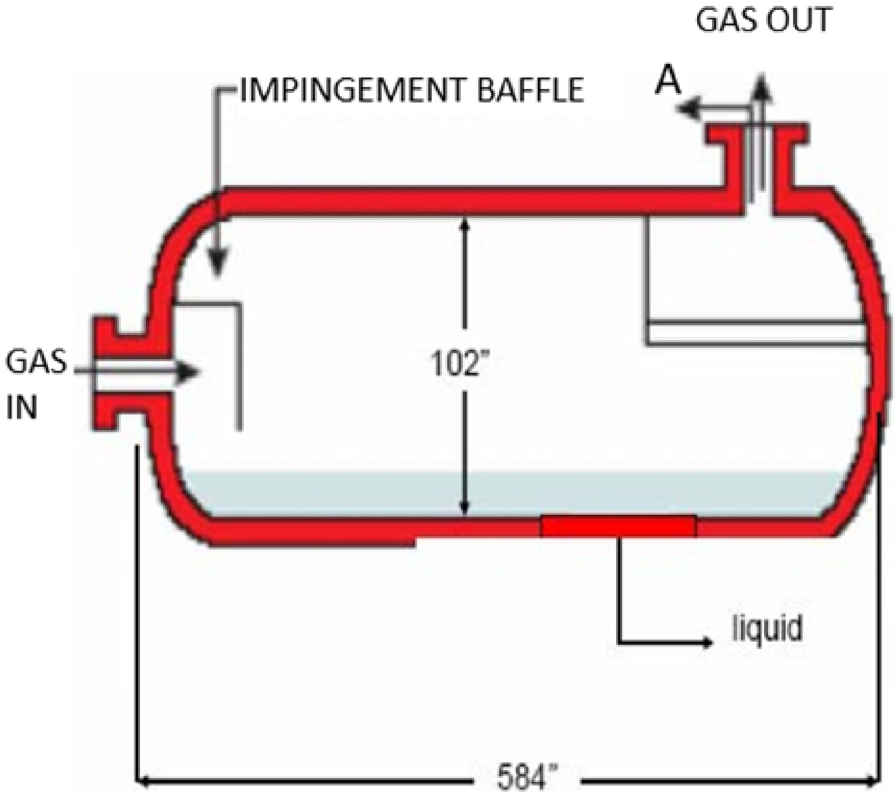

Figure 2-10 Vessel type slug catcher (Vergara and Foucart, 2007)

McGuinness and Cooke (1993) implemented this at the top of the well. The idea was to prevent having multiphase flow completely from the transportation line. They claimed that segregation of gas and liquid into separate flows offered an effective way of avoiding the slugging problem. This method is effective, but it will significantly increase CAPEX and OPEX due to the requirement of multiple subsea installations, single-phase pipelines and increase in the frequency of pigging operations. Generally, slug catchers (deployed at the top of the well or just before the processing system) are very good at mitigating severe slug. However, due to space and weight limitations at platforms, it is very expensive to implement. Also, it is not able to deal with all slug sizes due to its limited buffer volume. Furthermore, determination of the actual slug catcher size that will accommodate all slugs and optimise the process is also a very difficult and serious challenge.

2.4.1.2 Permanent or Fixed Choking

Permanent or fixed choke is a choke that is manipulated manually without any active control base on real-time changes of the system variables. Schmidt et al. (1979) were the first to suggest or recognised that choking could eliminate severe slugging. An experimental study was later performed in Schmidt et al. (1980), where they stated that choking was an effective method for severe slug elimination. However, no complete analysis of choke valve behaviour was presented. To better understand the process Taitel (1986) employed stability concept to theoretically show the possibility of stabilising the flow by increasing the backpressure of the separator (employing a manually manipulated choking at the pipe exit).

Jansen et al. (1996) undertook an experimental and theoretical investigation by performing a stability analysis of the system and extending the quasi-equilibrium model presented by Taitel et al. (1990). Thus, they proposed permanent choking as an effective way to avoid and eliminate slugging. The study was extended to a real offshore pipeline at the Upper Zakum field were fixed choking was used to manipulated the riser topside valve; which increased the backpressure in the system, thereby eliminating slug (Farghaly, 1987).

In conclusion, most of these studies have been focused on vertical risers. Generally, the main idea of permanent choking is to stabilise the flow by increasing backpressure in order to break down severe slugging in the pipeline-riser. However, due to the non-linearity of multiphase flow, fixed choking will be ineffective during sudden changes or variations in fluid velocities, which could either make the system stable or unstable. Besides, it does not provide an optimal solution in terms of production optimisation even if the valve is choked to the optimal point (open-loop bifurcation point).

2.4.1.3 Multiple or Dual Risers

This method involves the use of subsea separation facilities to separate the fluid into single phases of liquid and gas. Thus, two separate pipelines are often required for the process and a subsea pump to supply the required pressure head need to deliver the liquid to the surface (Sarica and Tengesdal, 2000). A subsea slug catcher with T-splitter was used to distribute gas and liquid into two risers in order to prevent or eliminate severe slugging (Kaasa, 1990). Severe slug behaviour in a multiphase flow pipeline leading to a dual riser was also investigated by Prickaerts et al. (2013). This pipeline was split into two risers with the aid of a non-symmetric branch T-splitter. Figure 2-11 shows the dual risers.

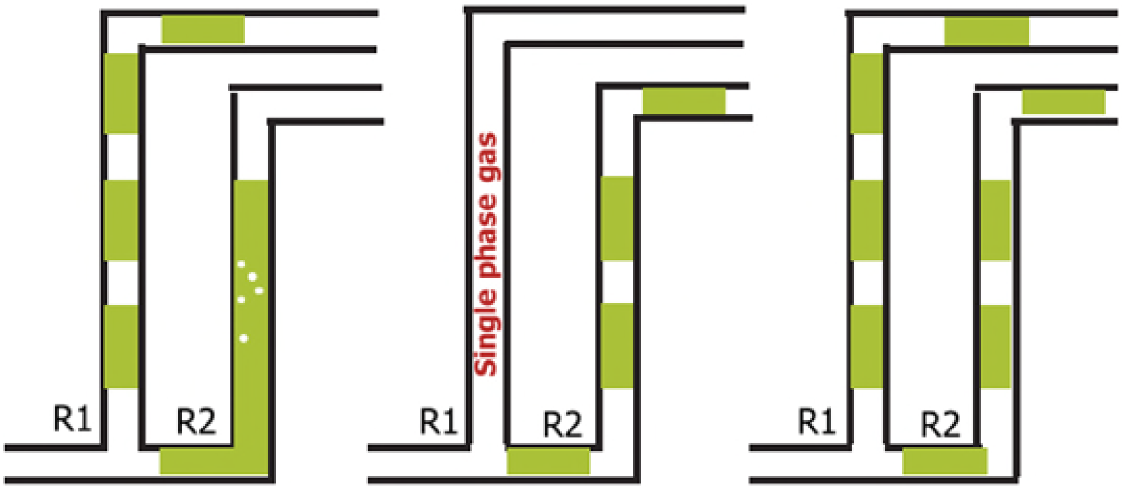

Figure 2-11 Dual risers (Prickaerts et al. 2013)

In general, this method is viable since it does not impose backpressure on the system. The main idea here is to avoid having multiphase flow completely in the pipeline riser in order to avoid severe slugging. However, there is a possibility of some liquid being carried into the gas riser; this raises questions over the effectiveness of this technique reported in Kaasa (1990). Prickaerts et al. (2013) technique is challenged by the need to determine an appropriate T-splitter that will achieve optimum separation of phases into the riser. Generally, both methods are not economical as they will significantly increase CAPEX and OPEX due to design changes, subsea deployment, the requirement of multiple single-phase pipelines, and increase in the frequency of pigging operations.

2.4.1.4 Flow Conditioners

Flow conditioners are specific devices installed in a multiphase flow pipeline with the aim of affecting the original flow regime. Schmidt et al. (1980) gave three conditions for severe slugging to be formed in a pipeline-riser system. These conditions must simultaneously exist for the occurrence of severe slugging, one of such conditions is that the pipeline upstream the riser must be in stratified flow regime for severe slug to occur. Generally, flow conditioners are installed upstream the riser base and are designed or implemented to avoid this condition.

Adedigba et al. (2006) and Adedigba (2007) implemented this with a novel helical pipe. It was shown that at certain superficial air and water velocities, the stratified flow prevailed in the straight pipeline while bubble flow occurred in the helical pipe. Thus, the helical pipe converted stratified flow into bubble flow. It was proved that the severe slug region in the flow regime map could be reduced by the use of a helical pipe. Also, the severity of severe slugging could be reduced in the severe slug operating region. This technique shows good potential for severe slug mitigation. However, the major drawback is in the very expensive installation cost due to subsea. Figure 2-12 shows the helical pipe in operation.

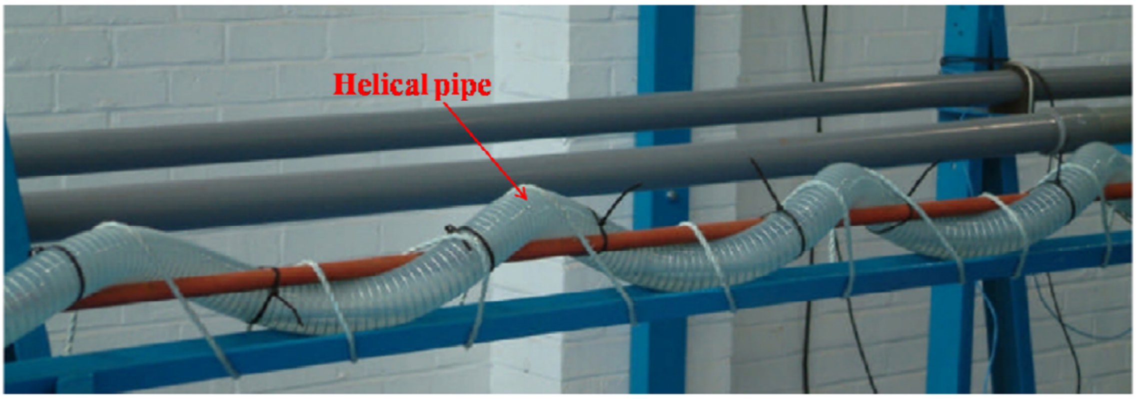

Figure 2-12 Helical pipe (Adedigba, 2007)

Xing et al. (2013a, 2013b, 2013c) followed the condition stated by Schmidt et al. (1980) and implemented it with the wavy pipe, both numerically and experimentally. They carried out studies to investigate the effects of the wavy pipe on the flow behaviour in a pipeline-riser system and to verify its effectiveness in severe slugging mitigation. They claimed the wavy pipe is effective in mitigating severe slugging in a pipeline-riser system. Also, they claimed the severe slugging region and the severity of the severe slugging in terms of fluctuation of the pressure in the pipeline and liquid production out of the riser can be reduced with a wavy pipe applied. However, the major setback for this method is the very expensive installation cost and maintenance for offshore operations. Figure 2-13 shows the wavy pipe in operation.

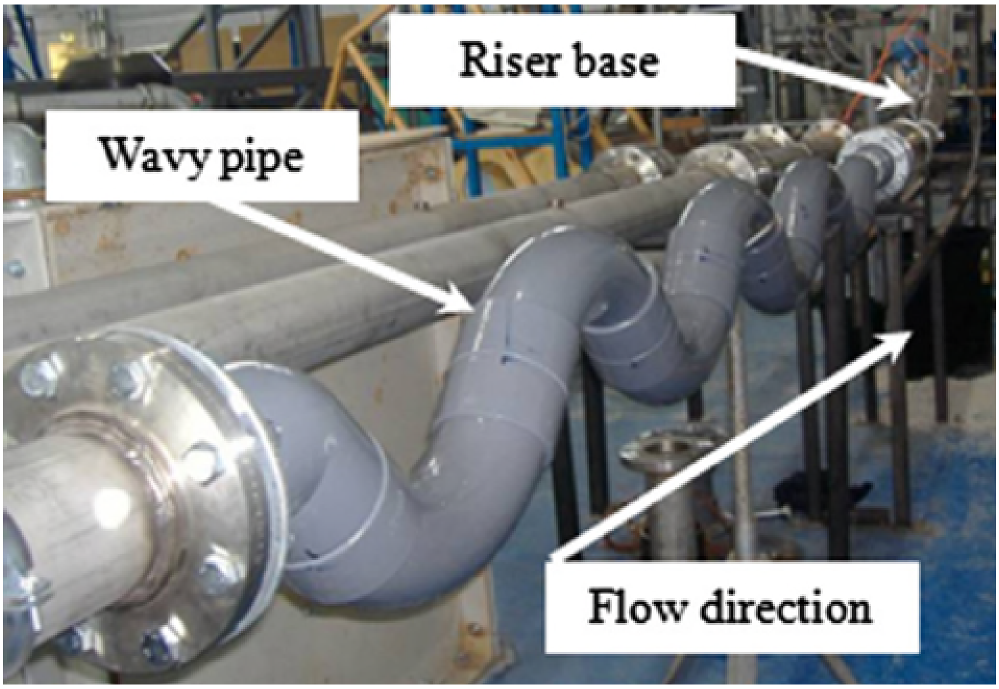

Figure 2-13 Wavy Pipe Installed in the pipeline (Xing et al., 2013b)

Makogan and Brook (2007) patented another type of flow conditioner for mitigating severe slugging in a pipeline-riser system. The device is made up of a short upward inclined pipe which leads to a horizontal pipe and a downward inclined pipe; the whole combination adds a small trapezium bend to the pipeline. This is connected back to the pipeline upstream the riser. They claimed the technique reduced the length of severe slug by creating a shorter high-frequency slugs which are transported through the riser to the topside facilities. Consequently, severe slugging could be changed into plug flow or intermittent flow. The major limitation of these devices is their inability to eliminate all slugs. In addition, installing these devices offshore will be very expensive due to the requirement of subsea deployment. Furthermore, determining appropriate sizes of these devices that will achieve optimum slug control or elimination is also a concern. Figure 2-14 shows the pipe device proposed by Makogan and Brook (2007).

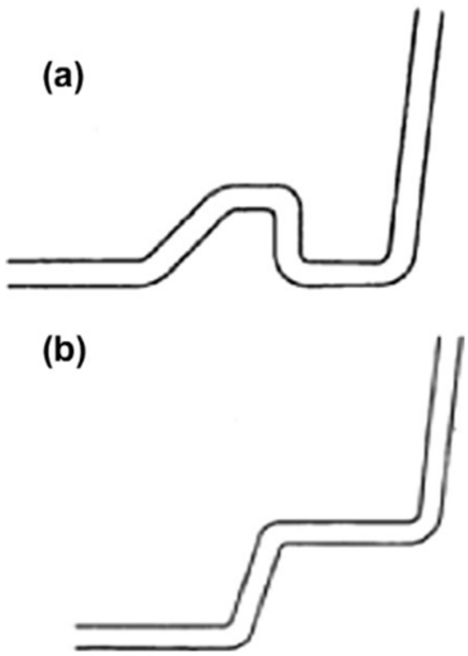

Figure 2-14 Pipe devices (a) Upward/downward pipe sections (b) Upward/horizontal pipe sections (Makogan and Brook, 2007)

Almeida and Gonçalves, (1999, 2000) proposed and patented a Venturi device which interior has a convergent nozzle section and a divergent diffuser section. Thus, creating a geometric configuration that introduces pressure drop. They claimed this device converted the stratified flow into a non-stratified flow (annular, bubble, etc.). Consequently, the device prevented the formation of severe slugging. However, this technique requires subsea pipeline changes which are often technically difficult, and economically costly. In addition, the sudden reduction in pipe size through the Venturi device would also cause problems for pigging operations. Figure 2-15 shows the Venturi-shaped device proposed.

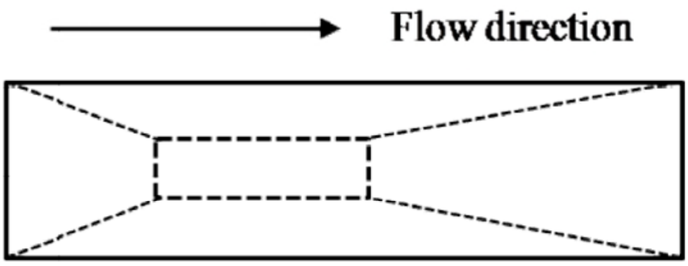

Figure 2-15 Venturi-shaped device (Almeida and Gonçalves, 1999, 2000)

Makogon et al. (2011) proposed a non-intrusive technique that is comprised of 'ups and downs' undulating pipes of the same diameter as the multiphase pipeline diameter. These pipes were placed immediately upstream of the riser pipe. The main idea behind the configuration and placement of these pipes is to achieve better mixing. The configuration shown in Figure 2-16 was claimed to have a better mixing effect, and thus, better severe slug mitigation than the configuration shown in Figure 2-17. They claimed the devices might be an effective non-intrusive solution to reduce backpressure on the production system normally caused by severe slugging. Thus, the life of the field could be extended, and the recovery factor for the reservoir increased. The adverse effects of this method toward operation were investigated. They suggested the use of sweeping pigs and smart pigs for the pipeline maintenance and inspection respectively. However, no test was conducted to validate this claim. Thus, the negative effects of this method to pigging operations is still a concern. Also, the cost associated with subsea deployment and extra pipelines will significantly increase CAPEX and OPEX.

Figure 2-16 Non-intrusive passive device severe slug attenuation device (Makogon et al., 2011)

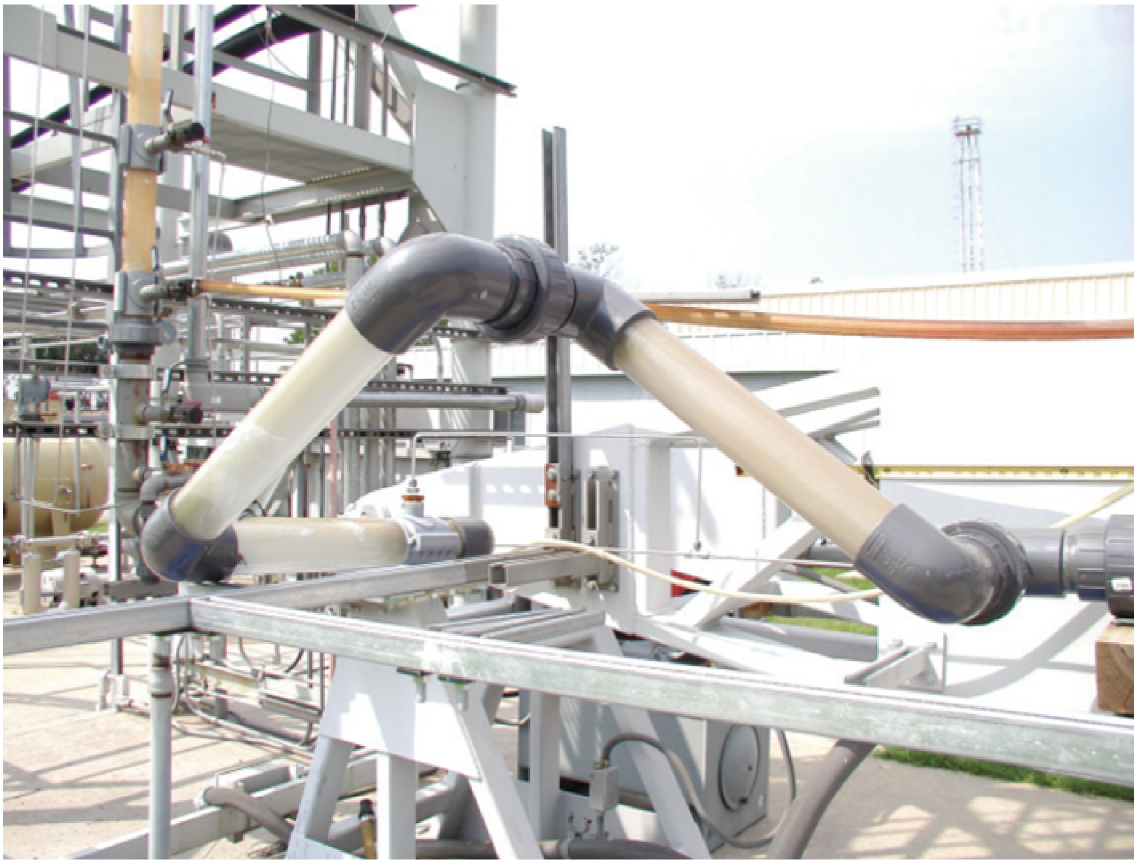

Figure 2-17 Non-intrusive passive device severe slug attenuation device alternative configuration (Makogon et al., 2011)

Yao et al. (2019) proposed the use of a quasi-plane helical device for mitigating severe slugging in the pipeline-riser system. Experimental study was conducted on a long pipeline-riser system with two-phase flow. To evaluate the effectiveness of the quasi-plane helical pipe device on severe slugging mitigation, comparisons were made between conditions with and without the quasi-plane helical pipe device on aspects of flow pattern, differential pressure and liquid production. Figure 2-18 shows the quasi-plane helical pipe device.

Figure 2-18 Schematic of the quasi-plane helical pipe (Yao et al., 2019)

They stated that the quasi-plane helical pipe device could induce shorter slugs to increase the frequency of liquid slugs and decrease the fluctuation amplitude of the differential pressure across the riser by breaking the stratified flow coming from upstream the riser, thus reducing the severity of severe slugging. They claimed the device could mitigate severe slugging, reduced the severe slugging region on the flow pattern map, reduced pressure fluctuation in the pipeline-riser system, and reduced the intermittency of liquid outflow. However, the major drawback for this method is the very expensive installation cost and maintenance due to subsea deployment.

In conclusion, flow conditioning techniques usually require subsea pipeline changes which are often technically difficult, and economically costly. Besides, these investigations were implemented on vertical riser. There is a need to validate these claims on risers with complex geometry. The popularity of FPSO amongst production companies has made this vital since most FPSO uses risers with complex geometry.

2.4.1.5 Intrusive Devices

Intrusive devices are devices that are inserted into the pipeline for slug attenuation. Over the years, different devices have been proposed. Schrama and Fernandes (2005) proposed the use of the bubble breaker for slug mitigation. This device was designed to convert the severe slug flow regime into dispersed flow. It is normally introduced into a vertical pipe to generate more void fraction after the fluid flow through it. They claimed the device was able to postpone the transition from bubbly to slug flow. Also, the device broke up spherical caps and slugs into finely dispersed bubbles, which were sufficiently small to prevent them from re-coalescing, even far downstream of the bubble breaker. They investigated the efficiency of the device through experiment and field trial. They claimed the use of the device on field trials gave a 10 % increase in production. However, this method would significantly affect pigging operations and may not be able to attain this claimed increase in other flow conditions outside the experiment and field trial due to the pressure drop it caused in the system. Figure 2-19 shows the bubble breaker device.

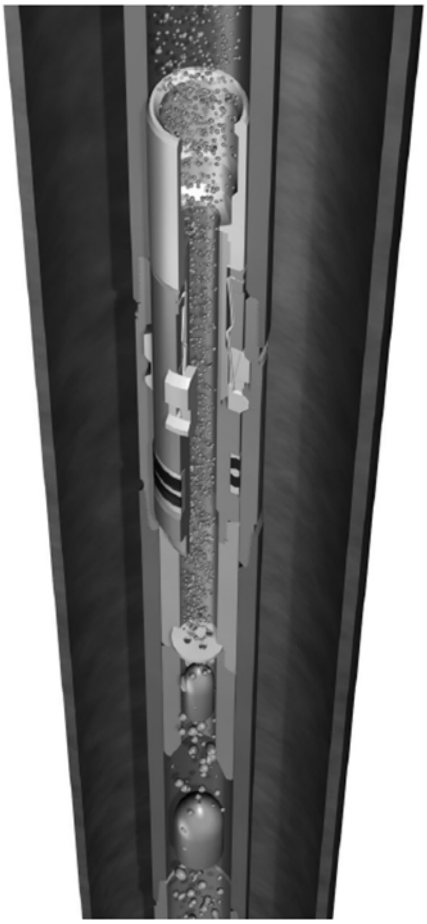

Figure 2-19 Artist impression of bubble breaker (Schrama and Fernandes, 2005)

Brasjen et al. (2013) proposed the use of four different mixing devices (choke, perforated liners, swirl, and mixer) for slug elimination. These devices were introduced into different positions in the pipeline. Their investigations revealed that positioning them near the exit of the pipeline achieved the best performance. They claimed that these devices offered up to 16 % reduction in pressure fluctuation. However, these do not eliminate severe slugging completely as the dissipated slugs quickly reformed downstream the devices. Besides, it increases the total pressure drop of the system and would cause problems for pigging operations. Figure 2-20 shows the mixing device.

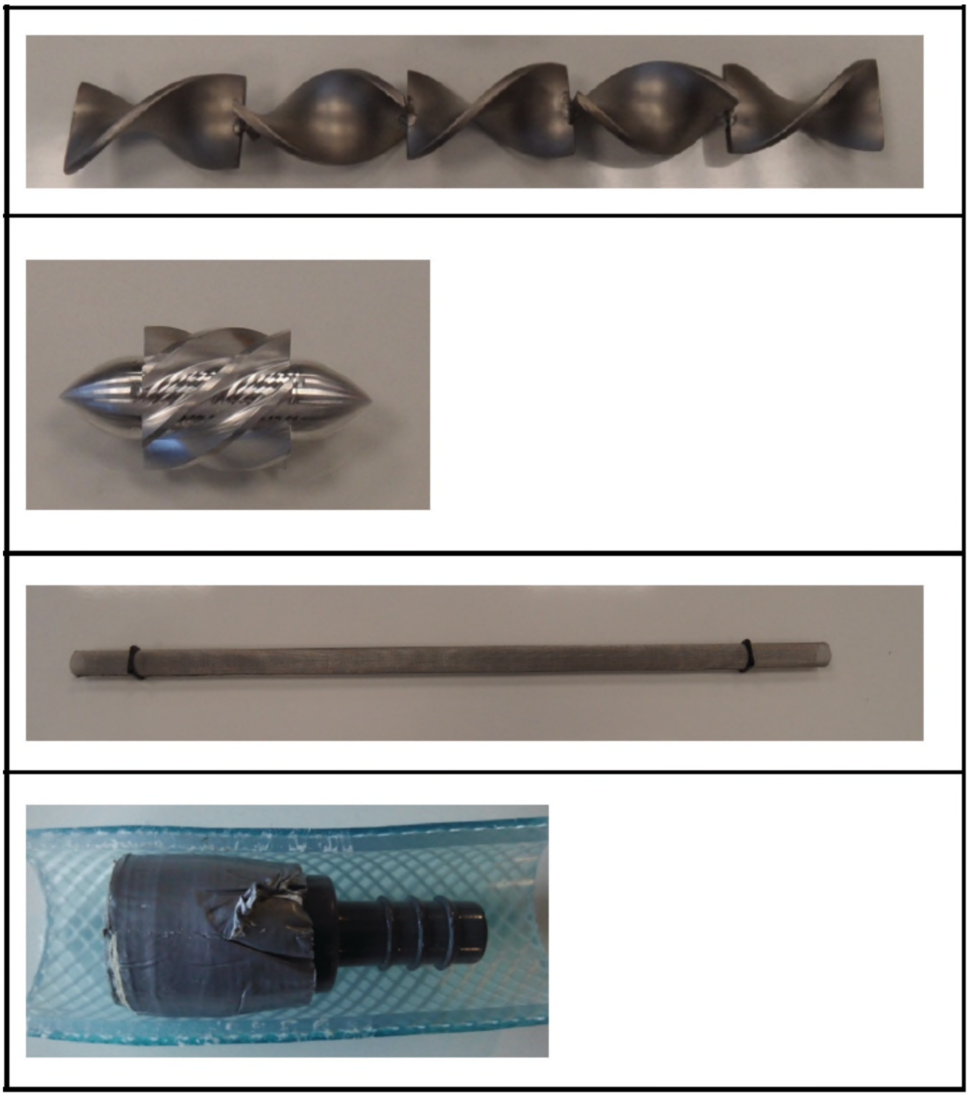

Figure 2-20 Mixing devices (Brasjen et al., 2013)

In conclusion, these devices cause problems for pigging operations and do not eliminate severe slugging completely as the dissipated slugs quickly reformed downstream the devices. Also, there is a need to extend this study to riser with complex geometry to validate their effectiveness.

2.4.1.6 Intermittent Absorber

Ehinmowo et al. (2016) proposed the use of an intermittent absorber for severe slug attenuation at large valve opening. They investigated the potential of the intermittent absorber in attenuating severe slugging in a pipeline-riser using experimental and numerical methods. These two approaches were used to validate this proposed method. They claimed the intermittent absorber was able to attenuate slug and stabilise the flow at larger valve opening when compared to the conventional choke valve. However, designing and seizing an appropriate intermittent absorber that will achieve optimum slug attenuation or elimination is difficult. Besides, it will be difficult for the intermittent absorber to accommodate large slugs or variations in flow.

2.4.1.7 Self-Gas Lifting

This method involves the re-injection of gas separated upstream the riser into the riser in order to break or reduce the size of severe slugs. The re-injection is possible due to the pressure difference, and the system is designed to be self-stabilising, thus, this enhances slug elimination.

Sarica and Tengesdal (2000) proposed this technique to lessen or eliminate severe slugging in pipeline-riser systems applicable to all water depths. Two methods were considered: External by-pass and Small diameter pipe insert. The claimed the gas transfer process would reduce both the hydrostatic head in the riser and the pressure in the pipeline. Thus, severe slugging will be lessened or eliminated. Experimental investigation of the external by-pass method was later done by Tengesdal et al. (2003), they were able to validate their earlier claims: model and simulation reported in Sarica and Tengesdal (2000). Figure 2-21 show the self-gas lifting devices.

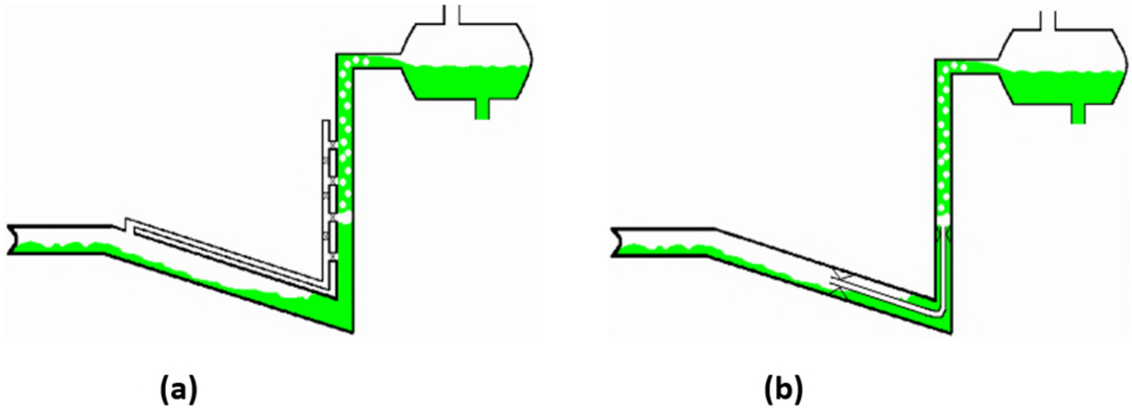

Figure 2-21 Self-gas lifting (a) External by-pass (b) Smaller diameter pipe insertion (Sarica and Tengesdal, 2000)

This method is very advantageous since the re-injected gas reduces the hydrostatic pressure created by the liquid in the riser. Also, since no external gas lift supply is required. However, the cost of installation and maintenance will significantly increase CAPEX and OPEX due to subsea pipeline changes which are often technically difficult, and economically costly. Besides, it will complicate flow assurance due to its effects on pigging operation. Furthermore, this method has much complexity; thus, implementing this method on risers with complex geometry such as S-shape riser will very difficult.

2.4.2 Active Slug Mitigation

Active slug mitigation involves the use of actuators or external interferences for the implementation of slug control or mitigation. Generally, some automatic feedback control strategy is used to manipulate some actuators for the implementation of active slug mitigation. This anti-slug control system uses measurements such as pressure and flow rate as control variables and the various control valves as the manipulated variable. Although in some cases, both active and passive approaches are combined, i.e., actuators are being used, while process changes are also implemented. These methods are also generally classified as an active mitigation method.

2.4.2.1 Smart Choking or Dynamic Choking

Earlier studies by (Schmidt et al. 1979; 1980) gave more understanding into choking as a viable method for severe slug control. This method was generally accepted and used in the industry. In the 1990s, the emphasis shifted from stability analysis of choking towards controllability analysis of choke valve and how to optimise choking as a viable severe slug mitigation method (Jahanshahi et al., 2012). Controllable valve choking methods are the most investigated active slug elimination approach. Various models, numerical methods and experiments have been investigated and implemented over the years. The use of controller has been reported to ease this problem by stabilising the system at larger valve opening, thus, maximising production and total oil recovery from oil producing fields (Ogazi et al., 2009, 2010; Sivertsen et al., 2009; Ehinmowo et al., 2016; Ehinmowo and Cao, 2015). However, most of these studies have been focused on vertical risers.

Dynamic choking has become generally accepted in the oil and gas industry. In practice, the industry has used this method for many years. Basically, active or dynamic choking is similar to fixed choking. The major difference is its flexibility to process changes and its ability to achieve stability beyond the critical stability point of fixed choking. The aim is to stabilise the flow at operating conditions, which without control would lead to instability in the system (severe slugging). The control valves could respond to the various feedback control signal by either closing or opening in order to overcome any form of instability introduced into the system. The idea here is to stabilise the flow by efficiently creating the minimum required back pressure needed to stabilise the system per time. Active choking enables the system to be operated at the unstable operating region, i.e. beyond the open-loop stable point of the system.

Hopf Bifurcation maps are often used to determine critical point after which the further opening of the valve will lead to instability. The bifurcation maps are generated by keeping the flow rate constant and varying the valve opening. These maps help to identify the stable flow regions with the associated pressures contributed by the valves to stabilise the system at the critical valve opening. Controllers are then designed and used to operate the system beyond this critical value at larger valve opening while still maintaining stability. Thus, this is the main aim of smart choking.

Active valve choking methods are the most investigated active slug elimination approach. In Jahanshahi et al. (2012), an investigation was carried out on both subsea and topside control valves. However, slug control using the topside choke valve has been studied and implemented more due to its ease in operation and flexibility. Typical work can be found in Ogazi et al. (2009,2010); Havre et al. (2000); Havre and Dalsmo (2001); Di Meglio et al. (2012); Storkaas and Skogestad (2007); Jahanshahi et al. (2012). Havre et al. (2000) used the slug controller structure shown in Figure 2-22 for flow stabilisation.

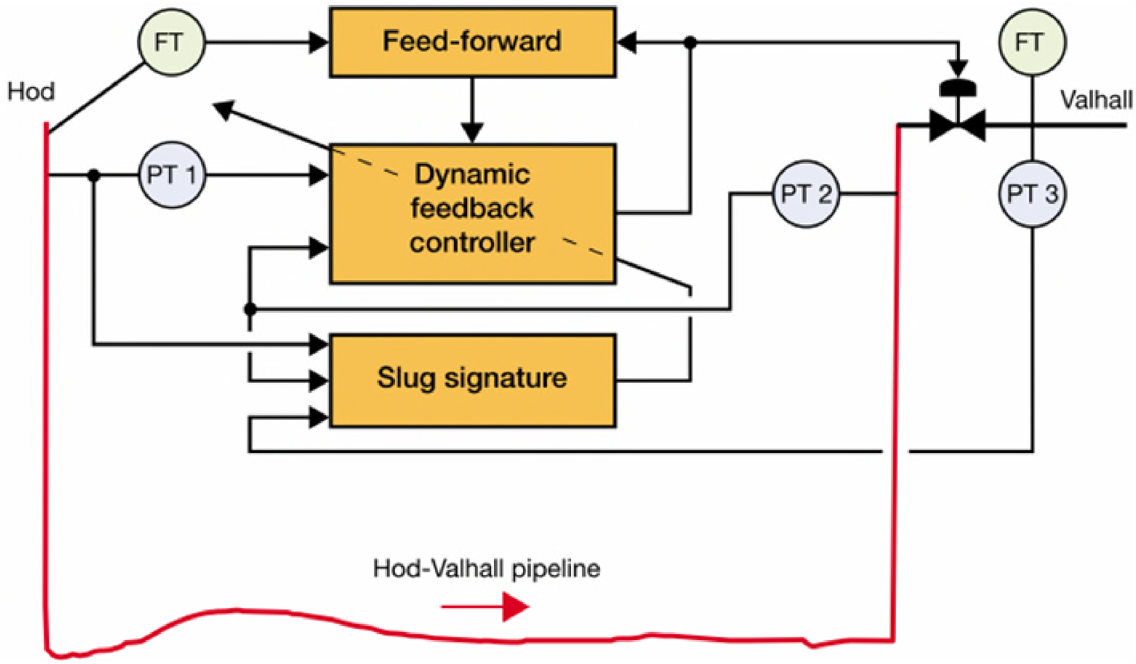

Figure 2-22 Slug controller feedback structure for flow stabilisation (Havre et al., 2000)

Numerous control techniques such as active feedback, feedforward and cascade control systems have been investigated and applied in smart choking for slug control (Stasiak et al., 2012; Henriot et al., 1999; Jansen et al., 1996;

Godhavn et al., 2005; Storkaas and Skogestad, 2004; Ogazi et al., 2009, 2010; Siahaan et al., 2005; Storkaas and Skogestad, 2007; Ehinmowo and Cao, 2015). Various controllers have also been designed and optimised to improve the robustness of slug control systems. Most works used detailed dynamic models and only proved stability linearly, whereas Kaasa et al., (2008); Jahanshahi et al. (2013); Siahaan et al. (2005) proved nonlinear stability with simplified dynamic models. The first field execution of this method was reported in Havre et al. (2000). Campos et al. (2015) also commission and implemented this active control method.

Generally, smart choking methods are more flexible, easier to implement, less expensive. However, choking increase the backpressure and this leads to reduction in production rate. Thus, it is difficult to use the choke valve to eliminate severe slugging without reducing the production rate.

2.4.2.2 External Gas Lifting

External gas lifting method has been one of the most popular severe slugging elimination method in the oil and gas industry over the years. In Brazil, it is responsible for more than 70 % of the total oil production (Plucenio et al., 2012). Generally, it is implemented in brownfields and depleted reservoirs where low pressures are paramount. The gas is usually injected at the bottom of the well in order to increase the pressure, hence, boost production. Also, it is injected at the riser base in order to prevent severe slugging, which is common in mature fields.

The primary benefit of gas injection is to reduce the hydrostatic weight in the riser and, thus, reduce the pipeline pressure. The injected gas also tends to carry the liquid and keep the liquid moving up the riser. When sufficient gas is injected the liquid will be continuously lifted, and a steady flow will occur

This method was first proposed by Yocum (1973); Schmidt et al. (1979, 1985) also considered it in their work. The effect of gas injection at riser base on severe slugging characteristics in a pipeline-riser was later studied by Pots et al. (1987); Hill (1989,1990). Basically, the major aim of this method is to accelerate or increase the velocity of the fluid around the riser base to avoid liquid accumulation in the riser. Thus, this will reduce the hydrostatic weight in the riser, reduce the cycle time and also reduce the pipeline pressure (Henriot et al., 1999; Jansen and Shoham, 1994; Jansen et al., 1996). These reductions enable more continuous liquid production, and when the injected gas is sufficient enough, the liquid will be lifted and steady flow will occur (Jansen and Shoham, 1994).

It has been proven over the years through theoretical, numerical, experimental and field investigations that external gas-lifting is also an effective approach for mitigation of severe slugs (Pots et al., 1987; Hill 1989,1990; Jansen and Shoham, 1994; Jansen et al., 1996; Plucenio et al., 2012).

Hill (1989,1990) reported from his study that gas lift helps in attenuation of slugging enabling more continuous production, and also helps to ensure smooth start-up of a pipe system that has been shut down. Jansen and Shoham (1994); Jansen et al. (1996) in their studies showed that external gas lift is an effective method to eliminate severe slugging. However, a large amount of injected gas was required to completely stabilise the system when compared to the flow rate of gas in the pipeline. They discovered that for steady flow to be achieved the riser flow needed to approach annular flow conditions. They claimed that injected gas aerated the riser, increase the velocity of the fluid, reduced liquid holdup in the riser, reduce the system pressure and stabilise the flow along the axis of the superficial gas velocity. Also, they claimed it enabled continuous lift of the liquid, causing shorter slug lengths and shorter cycle times which leads to an increase in production.

Pots et al. (1987) in their study of effects of gas injection suggested that pipeline injection may be preferable to riser base injection if more than 300 % of the inlet gas rate is needed for riser base injection. Jansen and Shoham (1994) also noticed this during their study and proposed that two possibilities exist for gas injection location: gas injection at the riser base, and gas injection into the pipeline at some distance upstream the riser bend. They stated that for the latter, it could be assumed that the effect will be similar to increased gas injection needed to stabilise the former. Henriot et al. (1999) validated these claims (Pots et al., 1987; Jansen and Shoham, 1994) during their study on the effects of gas injection positioning and the effectiveness of gas injection.

Johal et al. (1997) developed a new method for lifting called multiple riser base lift (MRBL) system which they claimed was better than the traditional riser base gas lift (RBGL) system and added considerable benefits in terms of CAPEX and OPEX. The traditional RBGL was noted to cause technical problems such as low-temperature effects resulting from Joule-Thompson cooling (a change of temperature for fluid when it flows through a valve) of the gas across the control valves and required hydrate inhibition during deepwater field operations. They claimed their method overcomes these issues. The main concept of this method is to divert flow from a stable multi-phase flow production line to the nearest pipeline-riser system where severe slugging is experienced in order to break them up the static head in the riser. The additional hot gas reduces the fluid density, consequently reducing the back pressure on the well. However, despite their claim in the reduction to OPEX and CAPEX; the additional pipelines and the associated increase in pigging operations makes these claims questionable.

Over the years; various devices have also been patented to enhance this process (Schmidt, 1998; Johal and Cousins, 2001). Investigations have now been shifted towards stabilisations of gas lift risers and wells (Plucenio et al., 2012; Aguilar et al., 2011). External gas lift is generally accepted in the oil and gas industry due to its associated benefits. However, its major limitation is the large amount of gas required to achieve stabilisation and economical cost due to subsea deployment. Furthermore, the additional cost to CAPEX due to compressor cost, and lack of injection capabilities have made some operators to avoid this method.

2.4.2.3 Combination of External Gas Lift and Topside Choking

The combination of external gas lift and choking has been claimed to be the most effective method for eliminating severe slugging in Jansen and Shoham (1994). The main idea is to combine the benefits of both methods, while their negative tendencies are largely reduced in order to stabilise the system better and hence, maximise production.

Jansen and Shoham (1994) showed that gas lift and choking complement each other in eliminating severe slugging. The former stabilises the flow in the direction of increased gas velocity, whereas the latter mainly stabilises the flow in the direction of increased liquid velocity. Thus, the best features of both methods can be utilised by an operator to establish the best practical approach to achieve optimum operating conditions. They observed that the cycle times and the slug lengths were greatly reduced for flows where cyclic motion still existed. Hence, this resulted in a stable flow and continuous production. They claimed this method reduces the degree of choking and the amount of injected gas needed to stabilise the flow. In addition, they claimed it gives the operator more degree of freedom in changing the gas injection rate or choke setting in order to meet operational changes. Furthermore, they claimed this method would allow smooth operation of the system, including start-up, and also ensure safe and continuous production of low-pressure wells.

Recent study of this method has been to automate the process. Enilari and Kara, (2015) investigated this method in their study using OLGA simulator to control slug and demonstrate the system behaviour. They claimed that the method eliminates both hydrodynamic and severe slugging effectively, increases stability of liquid flow, and allows smooth operation. Thus, a continuous production flow rate was sustained.

Generally, the combination of gas-lifting and topside choking has been hailed for its effectiveness. However, the associated cost due to compressor cost, subsea installations and additional pipeline will significantly increase OPEX and CAPEX. Besides, this method still needs validation

2.4.2.4 Combination of Self-Gas Lift and External Gas Lift

The combination of self-gas lift and external gas lift has been used for mitigating severe slugging in deepwater (Okereke et al., 2018). The main idea is to combine the benefits of both methods, while their negative tendencies are largely reduced in order to stabilise the system better and hence, maximise production.

Okereke et al. (2018) proposed severe slug mitigation technique which involves combining self-lift and external gas lift. Their methodology involved validating field data by comparing field pressure data with OLGA simulation based on input data from the field. They claimed that their approach stabilised the flow in the riser column and that the horizontal topside section experienced stratified flow. Also, they claimed their study has the potential of moderating the high compressor cost associated with external gas-lift in deepwater scenario. Despite these claims, it is not economical to implement this method, the associated cost due to compressor cost additional pipeline, and the cost of subsea installation and maintenance will significantly increase OPEX and CAPEX.

2.4.2.5 Homogenising the Multiphase Flow

This method basically involves the mixture of the liquid and gas to form a homogeneous fluid. Forcing the liquid and gas into a homogeneous fluid is believed to eliminate severe slug flow regime since it is associated with non-homogeneous multiphase flow. Hassanein and Fairhurst (1998) proposed homogenising multiphase fluid by injecting a surfactant. The idea was to reduce the surface tension of the fluid. This changed the fluid into foam, hence making the fluid homogeneous. However, no detailed information on the technique was provided.

Sarica et al. (2014) carried out an experimental investigation on the use of surfactants as a severe slugging mitigation technique and proposed a method for quantifying its elimination potential. The surfactant was observed to mitigate severe slugging at different levels for different flow conditions as shown in Figure 2-23. Their investigation shows the potential for total slug elimination at some flow rates, shows partial attenuation at others and it was unable to mitigate severe slugging at low flow rates.

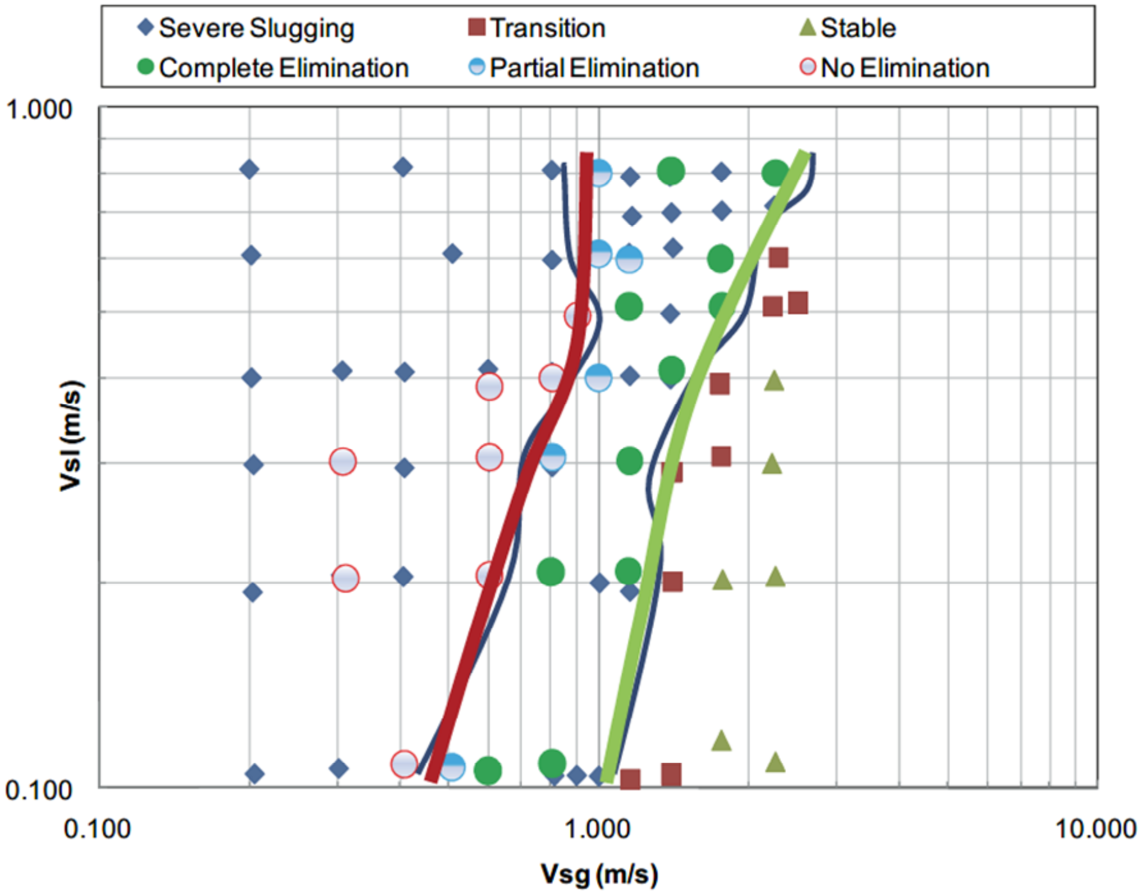

Figure 2-23 Severe slugging map with surfactant tests (Sarica et al.,2014)

However, the major drawback is the requirement on removal of the surfactant at the topside separation process and the additional cost of injecting the foaming agent. In addition, determining the optimum dosage rate of the surfactant is also a concern. Furthermore, the product quality may be adversely affected due to the remaining surfactant on the multiphase fluid.

2.4.2.6 Combination of Surfactants and External Gas Lift

A feasibility analysis of the combination of external gas lift and surfactants as a severe-slugging-suppression technique was conducted by Sarica et al. (2015). Thirty tests were conducted, and their results analysed to investigate the effectiveness of the combination of surfactants and gas lift in severe slugging suppression. The surfactant used was a foaming agent capable of forming stable foams in all brines for a wide range of pH values. The combination of surfactant and external gas lift was observed to mitigate severe slugging at different levels for different flow conditions as shown in Figure 2-24.

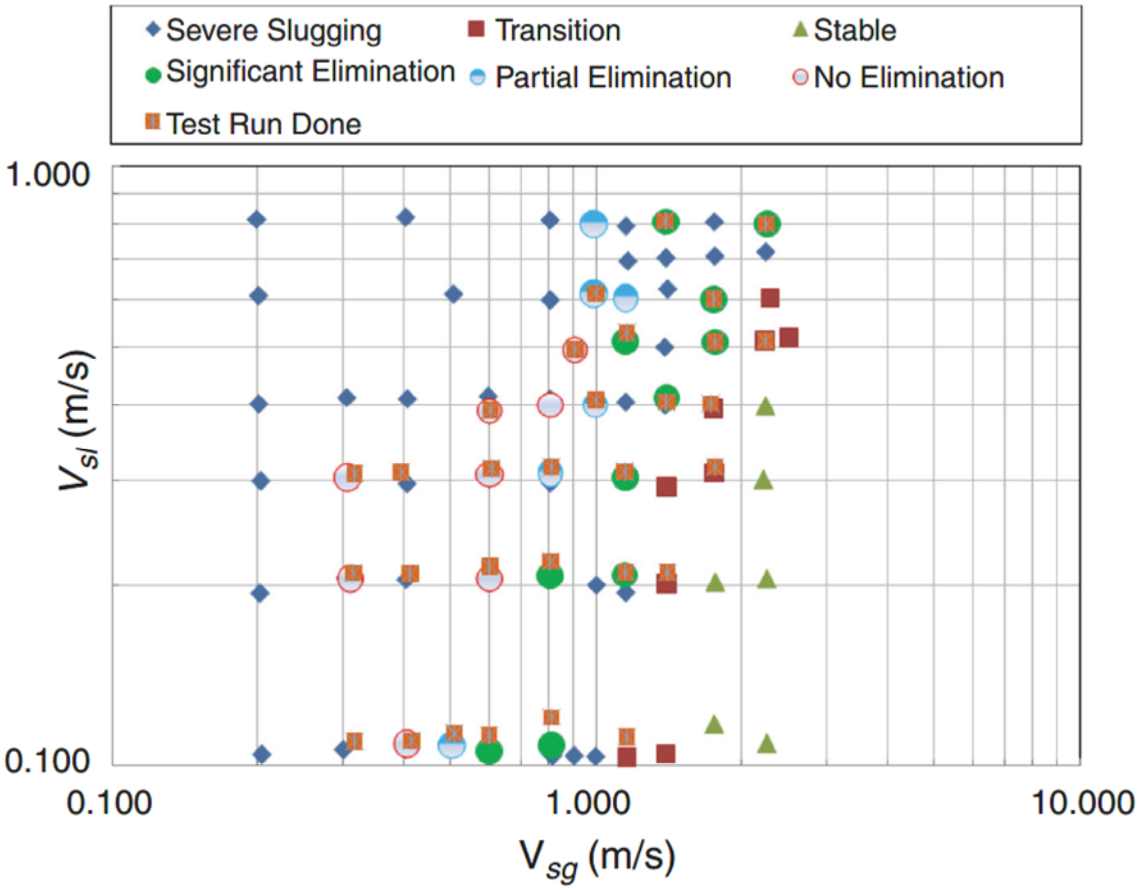

Figure 2-24 Severe slugging map with surfactant and external gas lift tests (Sarica et al., 2015)

The data obtained from the experiment were analysed for the severe slugging suppression of the combination of surfactant and gas lift, the effect of gas lift on surfactant injection, and the effect of the surfactant on the reduction of the gas lift gas. They claimed the combination of the technique with the highest gas lift rate completely eliminated the severe slugging for all tests conducted. Also, they claimed there were reductions in the gas lift rate from the original maximum gas lift injection rate (i.e. without surfactants) for all the tests conducted with surfactant injection. The minimum reduction was 32 %, while the maximum reduction was 100 %. However, the requirement on removal of the surfactant at the topside separation process and the additional cost of injecting the foaming agent will significantly increase CAPEX and OPEX. In addition, determining the optimum dosage rate of the surfactant is also a concern. Furthermore, the product quality may be adversely affected due to the remaining surfactant in the multiphase fluid.

2.4.2.7 Slug Suppression System (S^3)

Slug suppression system (S^3) was designed by Shell and used for slug elimination as reported by (Kovalev et al. 2003). The S^3 slug control system is made up of a topside mini separator with two automatic control valves at the outlets. One for the gas pipeline and the other for the oil pipeline. This system helps in the accurate determination of gas and liquid flow rates; it also acts as a mini-automated slug catcher since it provides buffer and storage volume to the system. The gas injection into the first stage separator is controlled and used to compensate for potential slugs. The liquid injection is also controlled in order to stabilise the height of the liquid. The gas and liquid streams from the mini-separator are later recombined and introduced into the first stage separator which would have likely by affected by slugging without this system upstream. Figure 2-25 shows the slug suppression system.

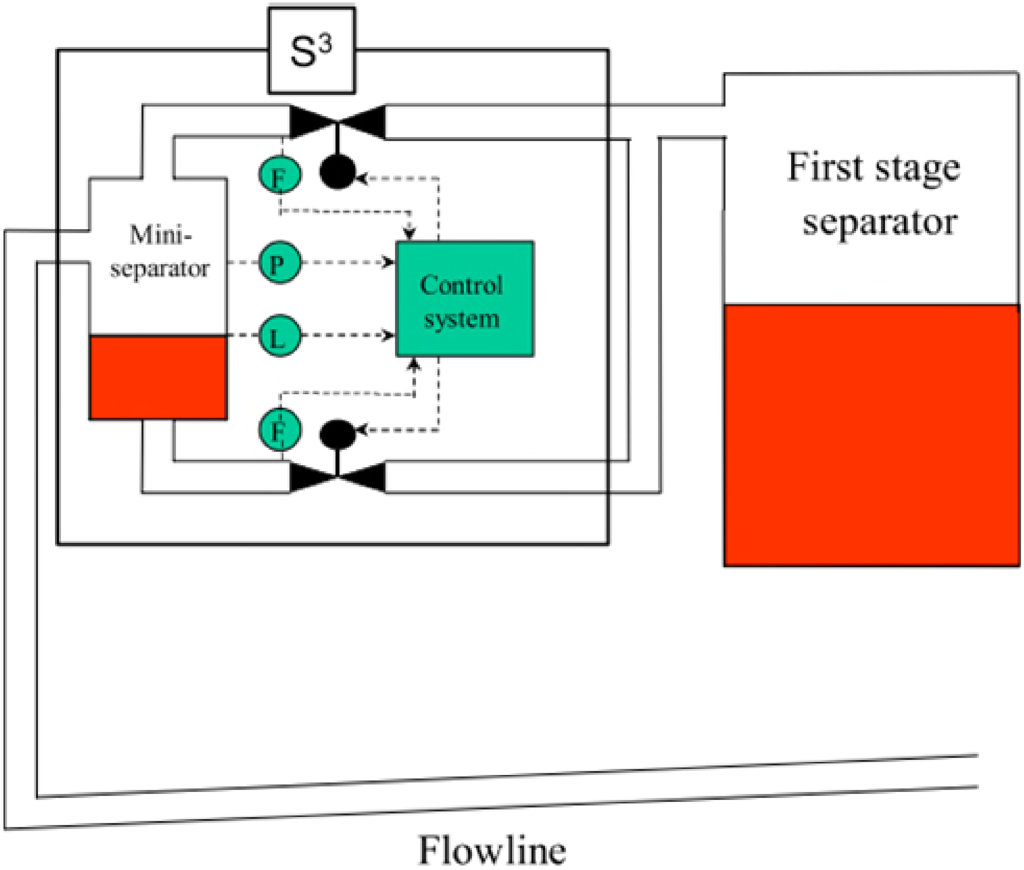

Figure 2-25 Schematic diagram of the Slug Suppression System (S^3) (Kovalev et al. 2003)

This system was implemented experimentally, installed and commissioned for field operation successfully. It was reported to successfully eliminate all types of slug and improved production rate for both oil and gas. However, the cost of extra equipment will significantly increase OPEX and CAPEX.

2.5 Chapter Summary

In this chapter, an overview of gas-liquid two-phase flow and its developments has been presented. Also, an overview of gas-liquid slug flow, severe slug modelling and severe slug control methods has been presented. Following from these, passive and active severe slugging mitigation techniques were critically reviewed. From the review conducted, the following observations could be summarised:

1. Previous studies of flow regime characterisation have not considered the entire length of the S-shape riser. Most studies have been focused on using either riser base pressure or using part of the differential pressure measurements across different sections of the riser (lower limb, downcomer and upper limb). The riser base is affected by downstream pressure fluctuations. Thus, it will not give an accurate representation for characterisation of flow within the riser

2. Most of the severe slug mitigation techniques have been implemented on vertical risers. Risers with complex geometry such as S-shape riser has not received much attention. Thus, there is a need to implement severe slug mitigation techniques on riser with complex geometry since their stability or transition lines are different from that of vertical risers

3. Despite the advances in using active control to mitigate severe slugging, most efforts have been concentrated on implementation on vertical risers. There is scarce information on its implementation on risers with complex geometry for severe slug mitigation purposes

4. Previous study of the use of Venturi for severe slugging mitigation has been based on deployment as a flow conditioner. It was deployed just before the riser base. There is no reported study of the use of Venturi at the topside (downstream the riser) for severe slugging mitigation

5. There is no reported study on the use of injectable Venturi for severe slug mitigation. In addition, the device has not been applied to dynamic flow behaviour investigation before. Furthermore, no model of the injectable Venturi has been developed before

This work is dedicated to addressing these gaps. The next chapter presents the methodology adopted in addressing the aim and objectives of this project.

3 METHODOLOGY

3.1 Introduction

This chapter describes the method adopted to achieve the objectives set out in Section 1.3. It explains the experimental facilities and procedures used in conducting the experiments, the acquisition of experimental data generated during the experiment and the different techniques used in analysing the experimental data acquired. Also discussed in this chapter are the various approaches used for severe slug mitigation and the approach used in modelling the injectable Venturi.

This study employs both modelling and experimental approaches. As a result, the methodology involves four major areas: experiments, modelling, simulation and validation. To ensure quality assurance the experiments, simulations and validation are repeated and checked for repeatability and reproducibility. In addition, all devices used for the experiment were calibrated. Furthermore, data were analysed and evaluated with MATLAB and Microsoft Excel software. The overview of the methodology structure is shown in Figure 3-1.

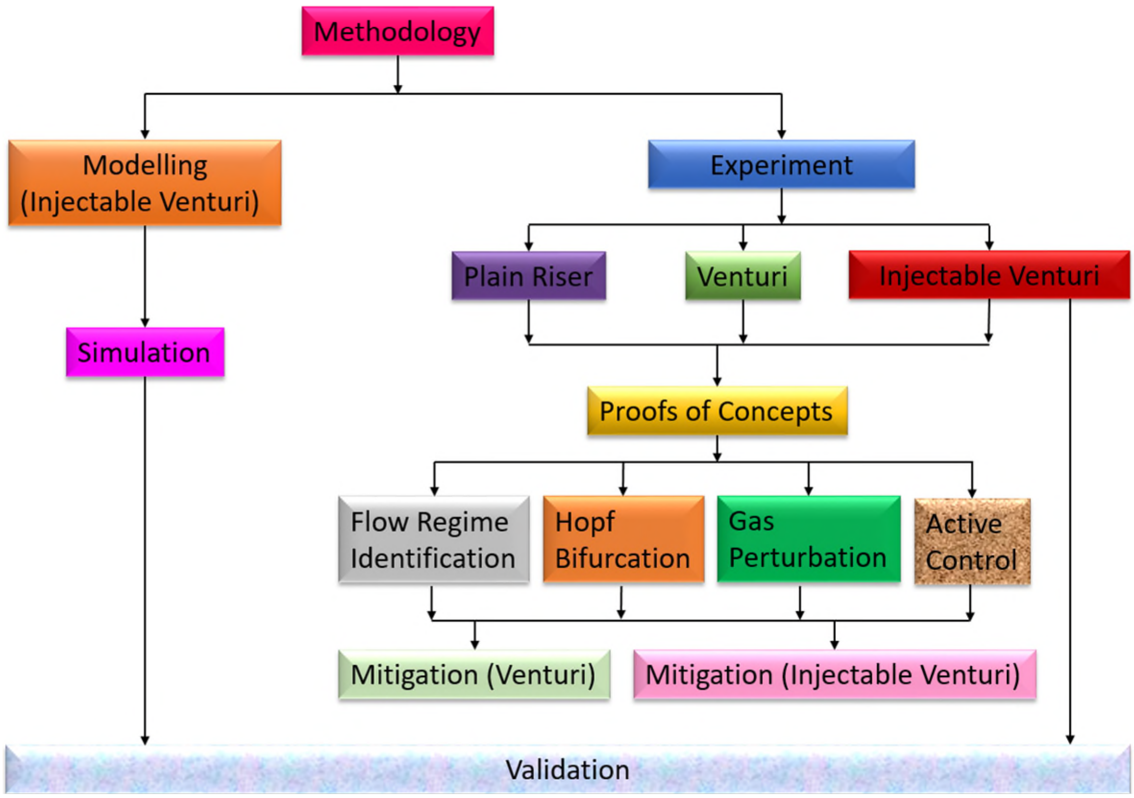

Figure 3-1 Overview of methodology structure

Section 3.2 gives an overview of the experimental facility. Section 3.3 presents the design of the injectable Venturi. Section 3.4 discusses the experimental procedures. Sections 3.5 presents the test matrix and operating condition. Section 3.6 describes the data collection methods, while Section 3.7 discusses the various techniques used for data analysis. Section 3.7 details the approach to severe slug mitigation. Section 3.8 presents the injectable Venturi numerical model while the chapter is concluded in Section 3.9.

3.2 The Multiphase Flow Facility

The Cranfield University Multiphase Flow Test Facility is a unique and fully automated high-pressure test facility designed to continuously and safely process multiphase fluid under different operating conditions at real-time and at a controlled and measured rate. The facility is near industrial scale and fully automated with a state-of-art industrial standard distributed control system. The schematic of the test facility is shown in Figure 3-2.

The test facility is rated to 20 barg, but the capability is currently limited by the maximum pressure of air from the compressors at 7 barg.

The test facility is controlled by DeltaV, a Fieldbus based supervisory, control and data acquisition (SCADA) software supplied by Emerson Process Management. The DeltaV SCADA system is used to remotely operate the test facility and perform the experimental procedure including pressurising and depressurising the system, control, shut down and data acquisition.

The test facility can be divided into five sections: the fluid supply section, the flow metering section, the valve manifold section, the test section and the phase separation section. Detailed description and operation of the test facility is given in Appendix A.

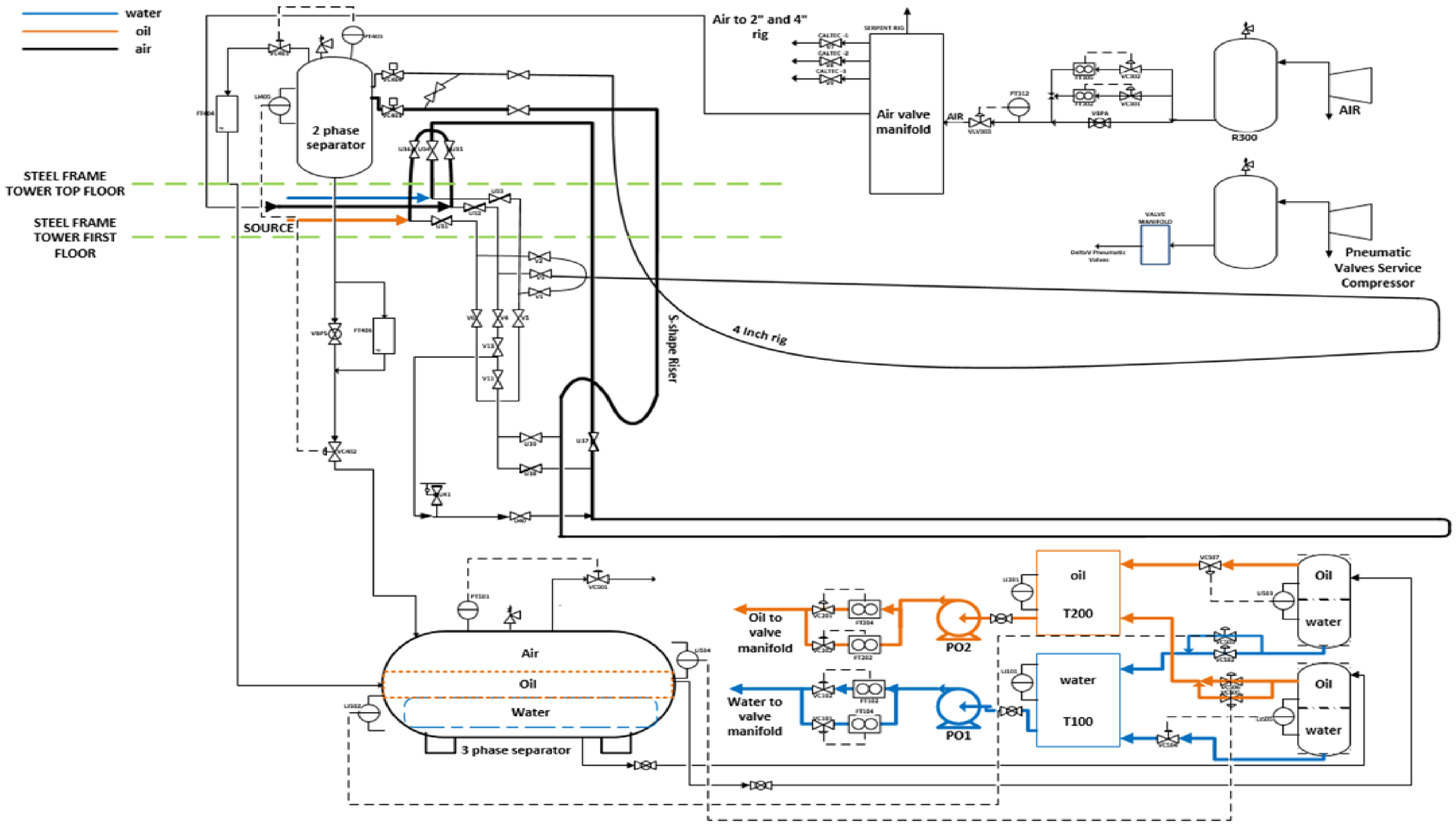

Figure 3-2 Schematic of the three-phase test facility: overall structure

3.2.1 Test Section

The test section of the multiphase flow facility comprises of two major loops the 4" and 2" flow loops. However, the project was executed with the 2" loop (primary loop) and the gas injection loop (secondary loop).

3.2.1.1 Primary Test Loop

The main test loop consists of three parts: a 40 m horizontal pipeline to ensure full development of multiphase flow; an S-shaped riser with total height of 11.75 m and upper limb, lower limb and downcomer of 6.28 (45°) m, 4.69 (90°) m and 0.8 (45°) m in height respectively; and a 5.2 m horizontal topside section. The horizontal topside section is connected to the two-phase separator where two-phase (air and liquid) separation takes place. A 2" control valve (choke valve) is installed on the horizontal topside section upstream the two-phase separator; this can be used to control the flow conditions in the test section. The schematic of the primary test loop is shown in Figure 3-3. Table 3-1 shows the description of the primary test loop items.

This configuration was used throughout the experiments; however, a Venturi and an injectable Venturi were incorporated upstream of the choke valve when there was need to study the effects of the Venturi and the injectable Venturi on severe slugging.

The injected gas supply from the secondary loop was cut off for the injectable Venturi without gas injection experiments. Thus, the hole in the injectable Venturi throat was sealed, and the device operated as a normal Venturi. The inner diameter of the choke valve is the same as for the pipeline (0.0548 m); thus, when the valve is fully opened, the pressure drop over the choke can be ignored.

All pipes of the 2" test section have an internal diameter of 0.0548 m and are made of stainless steel, except the riser which is made of transparent PVC pipe and the 0.4 m high transparent Perspex segment located at the riser base for visual observations of flow in the riser. Some sections of the 2" S-shape are shown Figures 3-4 to 3-5 respectively.

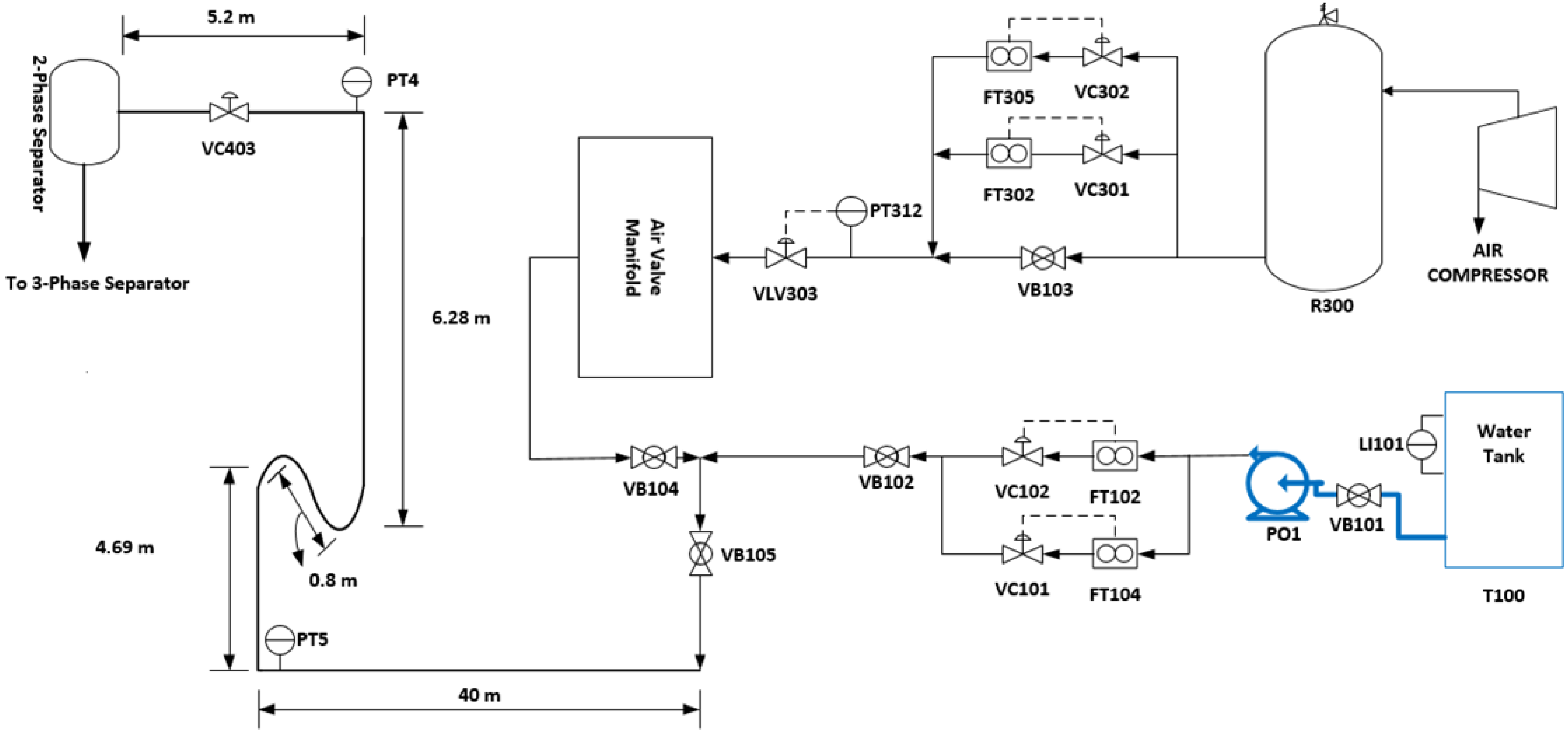

Figure 3-3 Schematic of the primary test loop

Table 3-1 Description of primary test loop items

Items	Description
PT4	Topside Pressure Transducer DN 15 from 0 - 6 barg
PT5	Riser Base Pressure Transducer DN 15 from 0 - 6 barg
PT1, PT2, PT3, PT4,	Pressure Transducer DN 15 from 0 - 6 barg
PT312	Pressure Transmitter
VC403	Pneumatic Control Valve (Choke Valve)
VC101, VC102, VC301, VC302	Pneumatic Control Valve
VLV303	Slam Shut Valve
FT102	Flow Transmitter from 0 - 1 kg/s
FT104	Flow Transmitter from 1 - 30 kg/s
FT302	Flow Transmitter from 0 - 150 Sm3/h
FT305	Flow Transmitter from 100 - 4250 Sm3/h
LI101	Level Indicator
VB101, VB102, VB103, VB104	Ball Valve
R300	Air Receiver
PO1	Water Pump with a duty of 100 m3/hr @ 10 barg
Air Compressor	Air Compressor Atlas Copco GA 55 with flow rate of 840 m3/hr FAD @ 7 barg

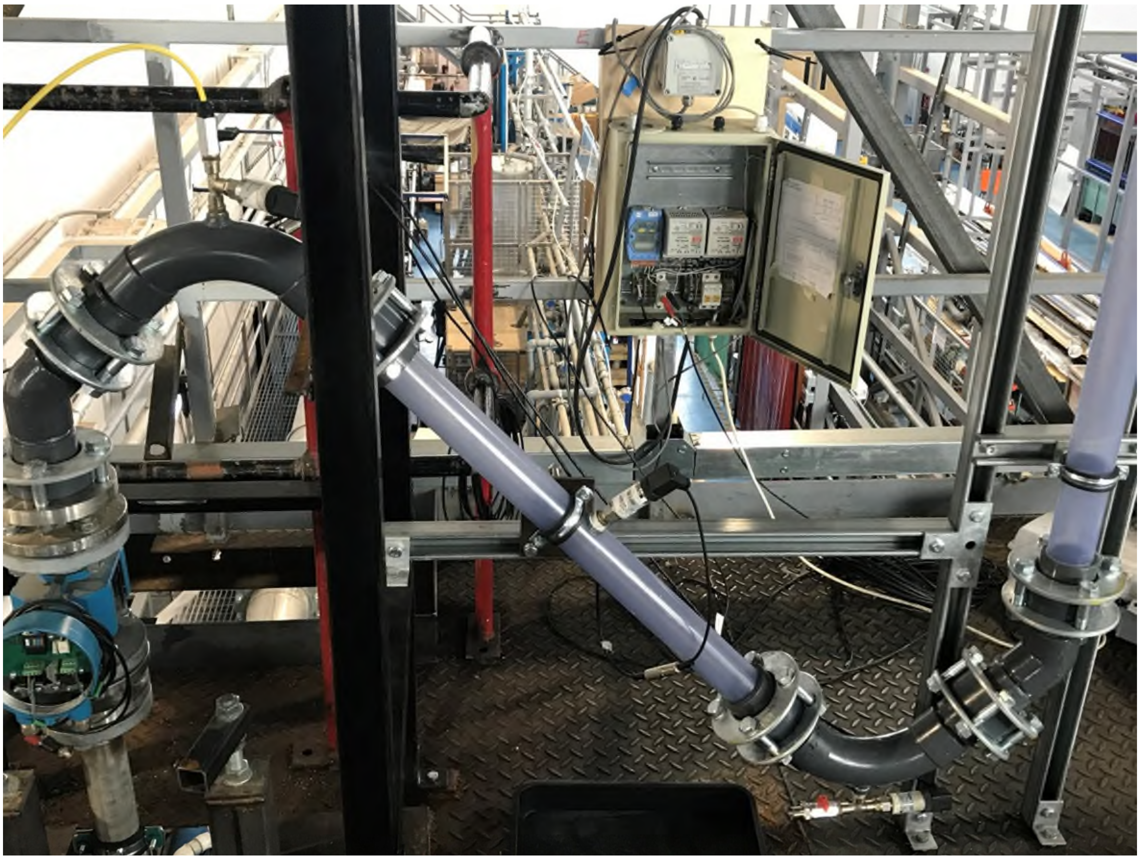

Figure 3-4 Downcomer part of the S-shape riser

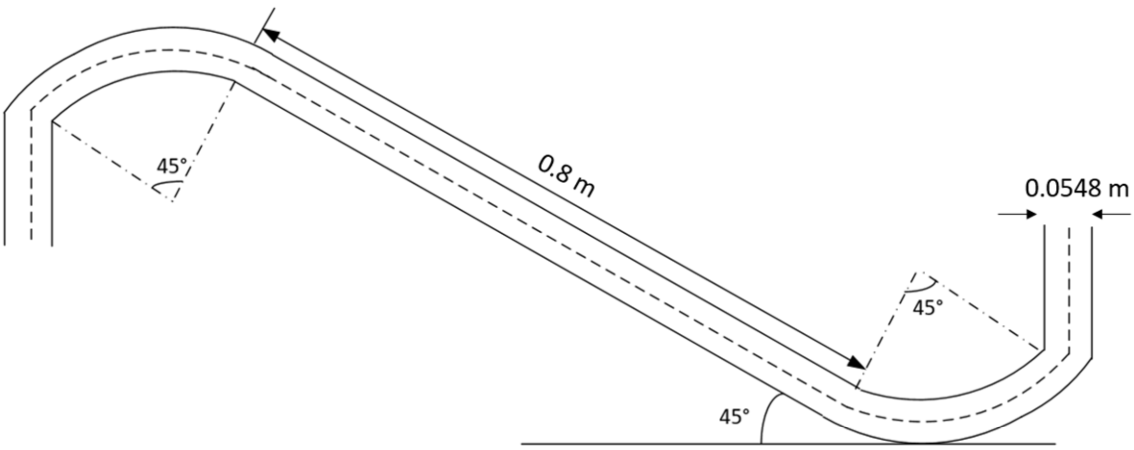

Figure 3-5 Isometric drawing of the downcomer part of the S-shaper riser

3.2.1.2 Secondary Test Loop

The gas injection flow loop consists of a stainless steel horizontal pipeline, a flexible tube, pressure regulator, pressure control valve, flow transmitter, pressure gauge, two ball valves and two non- return valves. The horizontal pipeline is 2 m long, and the flexible tube has a total height of 13 m, and they are both ½" diameter. The schematic of the secondary test loop is shown in Figure 3-6, and Figure 3-7 shows a section of the secondary test loop. Table 3-2 shows the description of the secondary test loop items.

The loop uses the same air supply as the primary test loop; however, the air is regulated by the pressure regulator, and the required amount of gas injected into the system is controlled by the pressure control valve (PCV). The PCV is controlled remotely by a LabVIEW program designed for this purpose, and the gas was injected at 50 m^3/hr. The flexible pipe is connected to the throat of the injectable Venturi at 45° such the gas injected counters the flow coming from upstream the injectable Venturi to the throat.

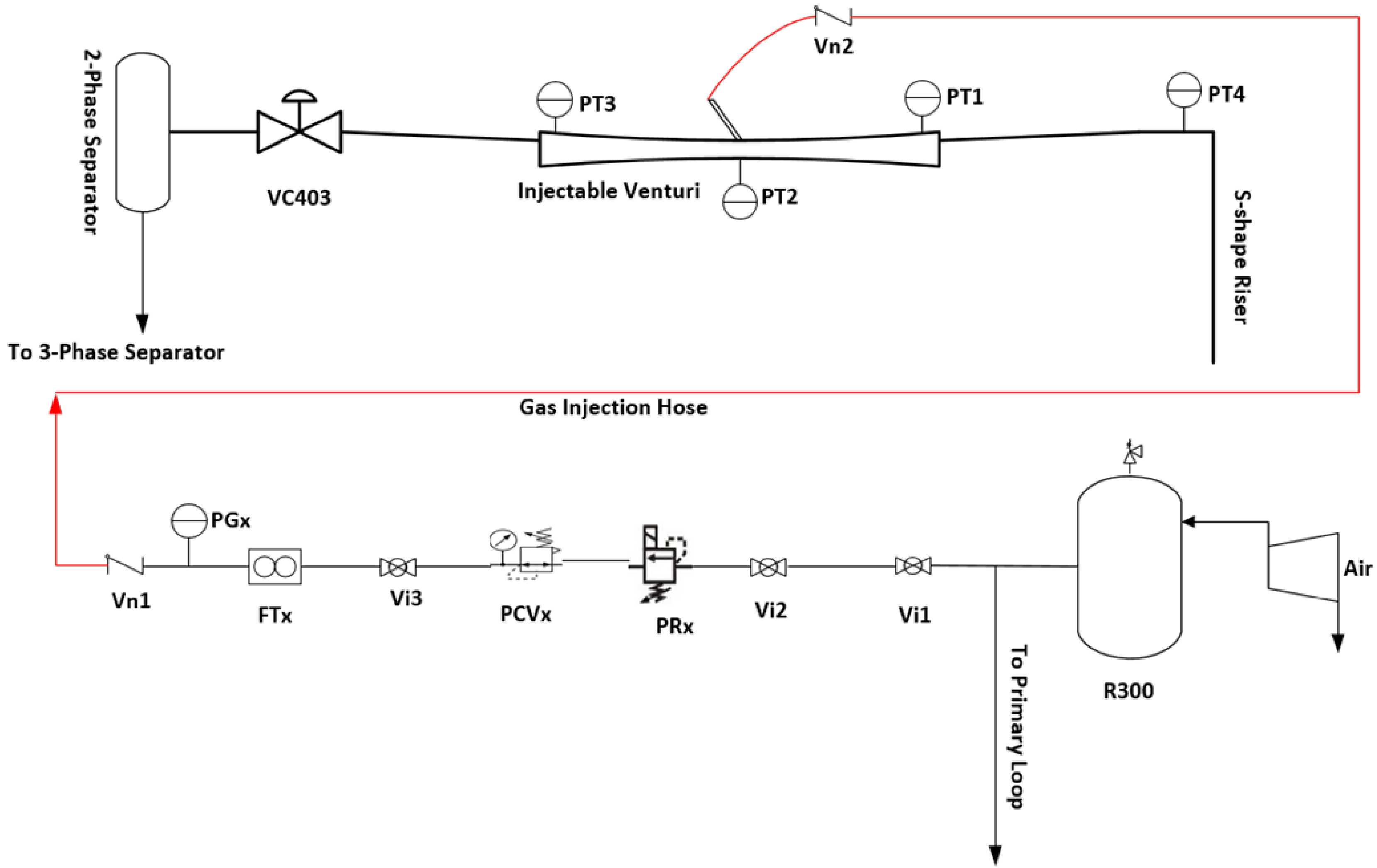

Figure 3-6 Schematic of the secondary test loop

Table 3-2 Description of secondary test loop items

Items	Description
Vi1, Vi2, Vi3,	Ball Valve
PT1, PT2, PT3, PT4,	Pressure Transducer DN 15 from 0 - 6 barg
VC403	Pneumatic Control Valve (Choke Valve)
R300	Air Receiver
PRx	Pressure Regulator
PCVx	Pressure Control Valve
Pgx	Pressure Gauge
FTx	Flow Transmitter
Vn1, Vn2	Non-Return Valve

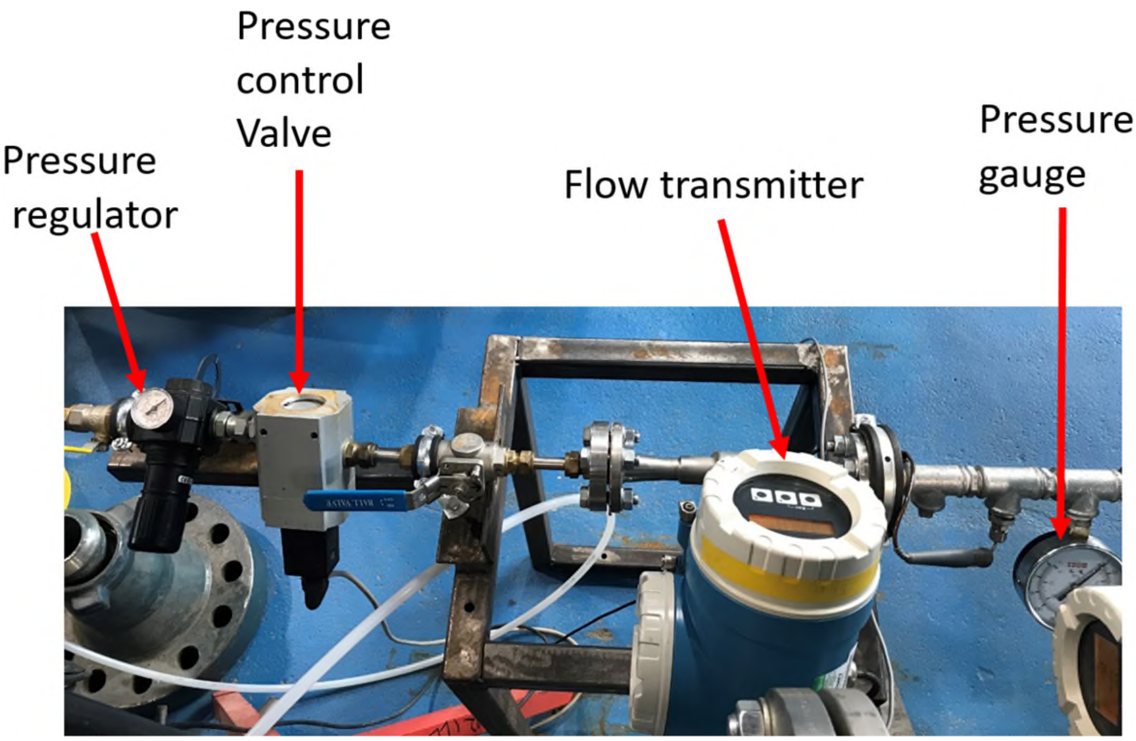

Figure 3-7 A section of the secondary flow loop

3.2.2 Test Fluids

The test fluids used in the study were air and water. The water was supplied from Cranfield University water network. It has viscosity and density values of 0.001 Pa.s and 998.2 Kg/m^{3}respectively. The gas-phase throughout the experimental campaigns was air. Table 3-3 shows the summary of the test fluid properties.

Table 3-3 Test Fluids Properties

Testing Fluid	Density (25°C, Kg/m^3)	Viscosity (Pa.s)	Surface Tension (25°C, Kg/m3)
Air	1.225	0.00001725	
Water	998.2	0.001	0.0728

3.3 Design of Injectable Venturi

Venturi here refers to a tube with convergent, throat, and divergent section that are generally used for measurement and flow regulation purposes. The Venturi effect is the reduction in fluid pressure which occurs when a fluid flows through a narrow constricted section of a pipe. The reduction in pressure results in an increase in velocity which agrees with Bernoulli's principle. It utilizes both the principle of continuity as well as the principle of conservation of energy.

The gradual flowing area contraction (converging section) followed by a gradual flowing area expansion (diverging section) of the Venturi helps in accelerating fluids and may account for the low loss of energy in a Venturi. Generally, a Venturi produces less permanent pressure losses and high-pressure recovery due to the converging section when compared to an orifice or nozzle. Thus, it saves energy.

An injectable Venturi is a Venturi tube that has an opening at its throat, and a pipe inclined at 45° is inserted into this opening. Thus, gas is injected counter to the flow coming from upstream of the injectable Venturi to choke the working fluid passing through the throat of the injectable Venturi. Basically, it operates as a Venturi and enjoys the benefits associated with a Venturi. However, gas is injected to regulate the size of the throat in order to further stabilise the flow. Figure 3-8 shows a picture of the tested injectable Venturi installed in the pipeline. Figure 3-9 shows the design dimensions for the injectable Venturi.

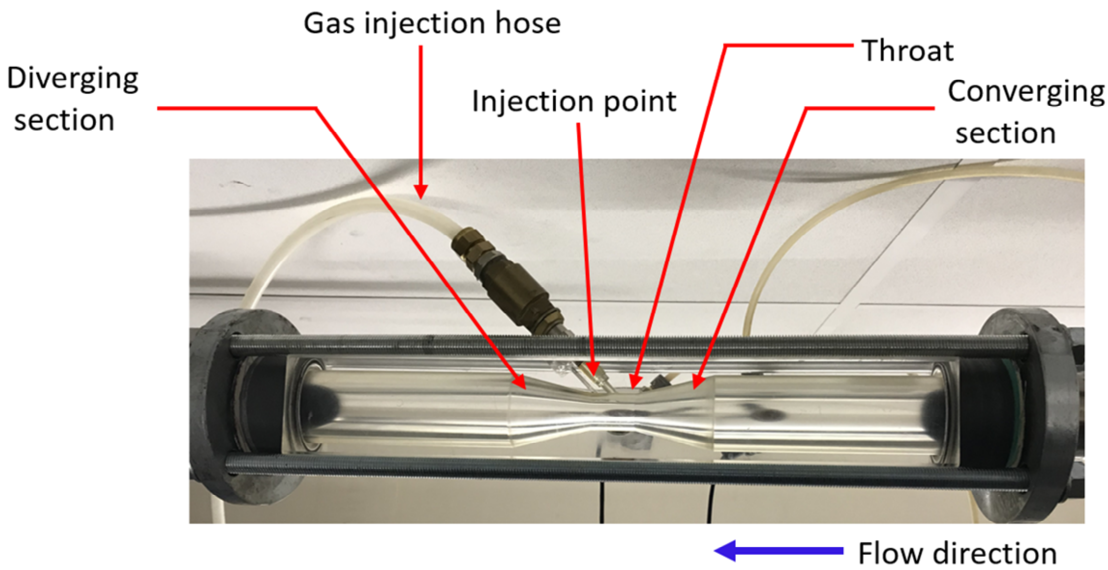

Figure 3-8 Injectable Venturi

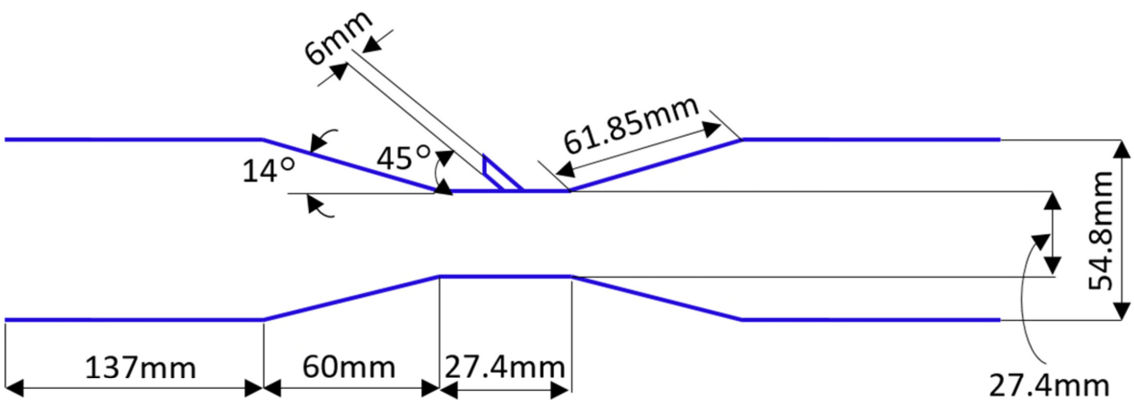

Figure 3-9 Design of injectable Venturi

3.4 Experimental Procedures

The objective of the experiments is to investigate the possibility of using the Venturi and injectable Venturi to stabilise the S-shape pipeline-riser system in operating conditions that will originally be unstable without these devices in order to mitigate severe slugging and increase overall production. This summarises the aim and objectives of this project. The five major aspects of the study, for which data were obtained in each experimental run are: flow regime identification, Hopf bifurcation, stability curve, stability maps and active control. The procedural steps for the entire experiments are stated in Sections 3.4.1-3.4.5.

3.4.1 Calibration of Devices

The devices used for measurements in these experiments were all calibrated to ensure good performance. In this section, the focus will only be on the calibration of one device – the pressure transducer. The calibration process is similar for all other devices. This section outlines the procedure employed for calibrating pressure transducers by establishing a relationship between transducer output and change in voltage readings. From this relationship, the hysteresis, repeatability and linearity of the pressure transducer are determined. Also determined is the pressure **calibrating factor (sensitivity)** which is defined as the slope of the line relating the difference between observed voltage readings and the output from the pressure transducer to applied lateral pressure.

Hysteresis: This is the maximum difference between transducer output for the same applied pressure within a specified range. One reading obtained by increasing the pressure from zero to the upper calibration limit, and the other by decreasing the pressure from the upper calibration limit to the lower limit (zero).

Repeatability: This is the closeness of agreement (maximum difference) between transducer outputs for repeated pressures under identical loading and environmental conditions.

Linearity: This is the variation of transducer output from a straight line. In this procedure, measurements were obtained using a series of applied pressures over the total rated range of the pressure transducer.

3.4.1.1 Apparatus

Pressure Transducer: The pressure transducer is manufactured by GE Druck and is shown in Figure 3-10. The specification is shown in Table 3-4.

Figure 3-10 Pressure transducer

Table 3-4 Specification for pressure transducer

Transducer Type	PMP 1400
Range	6 barg
Serial Number	B01243/12
Output Voltage	0 - 5 Vdc
Non-linearity and Hysteresis	± 0.25 % BSL max

Pressure Source: ADT914 handheld pneumatic pressure test pump was used to apply pressure to the transducer and the electrical output measured, acquired and displayed by the LabVIEW data acquisition program. This device is capable of delivering and maintaining pressure up to the maximum rated pressure of the transducer. The pump is shown in Figure 3-11.

Figure 3-11 Handheld pneumatic pressure test pump

3.4.1.2 Precautions

The following precautions were taken during the calibration of the pressure transducer:

1. Physically examine the pressure transducer body to observe if there is any physical damage
2. Make sure connections are good, and the setup is free from external disturbance that may affect the output
3. Use the serial number for identification to avoid using the calibration results for another transducer

3.4.1.3 Procedure

The following procedural steps were taken in the calibration of the pressure transducer:

1. Mount the pressure transducer
2. Connect the signal cable which supplies power to the transducer and transfer voltage reading from the transducer to the National Instrument data acquisition box (NI-DAQ) that is linked to LabVIEW data acquisition program on the computer
3. Set the pressure on the pump to zero
4. Gently use the pump to change the pressure input level
5. Take both the pressure and voltage reading on the pump and LabVIEW data acquisition program respectively
6. Repeat step 4 and 5 for an increasing amount of input pressure value over the measuring range of the transducer (i.e. from the minimum to the maximum)
7. Then start the process in step 4 to 6 from the maximum to the minimum pressure value by releasing the pressure slowly, using the vent knob
8. Repeat steps 1 to 6 for repeatability check
9. Calculate the hysteresis to verify the condition of the transducer

10. Plot a graph of voltage readings versus pressure readings to determine the slope (m) and the intercept (c) form the equation of a straight line of the form

$$P = mV + c \tag{3-1}$$

Equation 3-1 may be rewritten in the form:

$$P = m(V - V_0) \tag{3-2}$$

Thus,

$$V_0 = -\frac{c}{m} \tag{3-3}$$

where V_0 is the offset.

The graph in Figure 3-12 shows the readings plotted, a regression line fitted and extrapolated back to show the intercept for the pressure transducer calibrated.

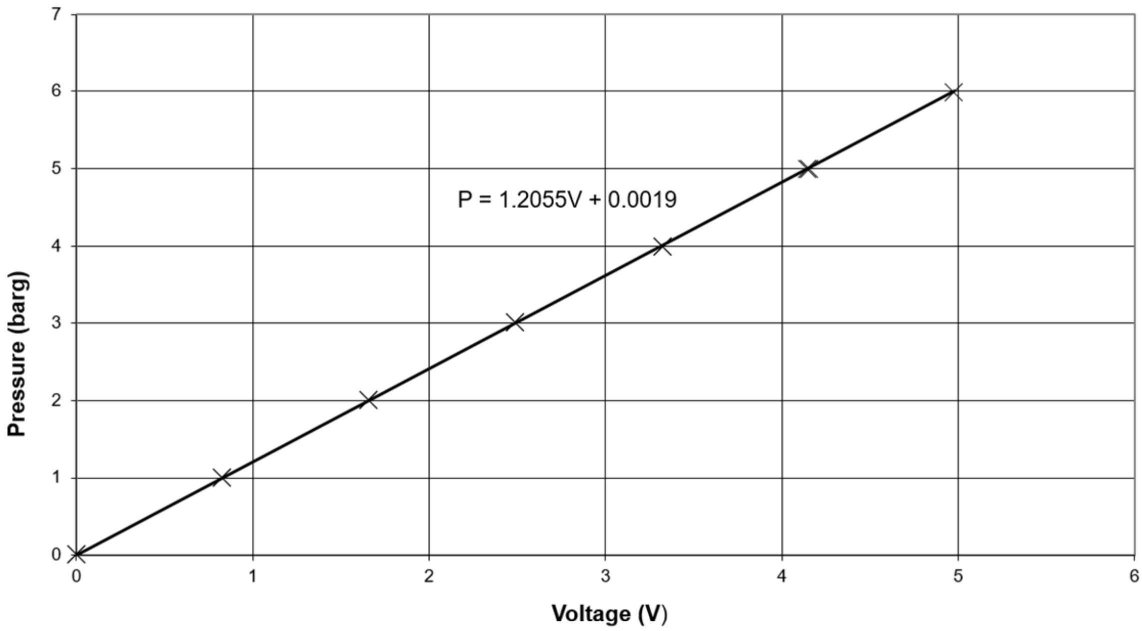

Figure 3-12 Calibration plot for the pressure transducer

The equation of the line is $P = 1.2055V + 0.0019$ where the slope is 1.2055 barg per volt, and the intercept is 0.0019 barg. The equation may be rewritten in the form: $P = 1.2055(V - V0)$, where $V_0 = -\frac{c}{m}$ = +0.0016.

3.4.2 Air-Water Test Procedure for S-shape Pipeline/Riser

The procedure followed for two-phase air-water flow tests experiments are outlined below:

1. Put the <2" RIG in OPERATION> sign on the notice board
2. Log into the DeltaV control system to check if there is any warning alarm and to make sure the system is in a good state to run
3. Visually check the readiness of the flow loop to operate
4. Switch on the pneumatic valve service compressor (PVSC) if it is off
5. Check the valve positions, and alter if necessary to correct any mismatch
6. Turn the cooler on. The temperature of the cooler has to be under +10 Celsius
7. Manually start the compressor(s)

8. Check the position of the slam shut valve (VLV303) and make sure it is open
9. Check the positions of topside choke valves at the outlet of both risers and ensure that the valve on the 4" flow loop is closed whiles that on the 2" flow loop is open
10. Open the operator interface on the Delta V control system and click the start-up button to pressurise the system
11. Set flow conditions after the start-up finishes
12. Record data when the flow stabilises

3.4.3 Air-Water Test Procedure for S-shape Pipeline/Riser/Venturi

The procedure of the two-phase air-water flow tests experiments for pipeline-riser with the Venturi applied is similar to that stated in Subsection 3.4.2. However, the major difference is the coupling of the Venturi upstream the topside choke valve which is before the test separator (two-phase separator).

All the experiments that have to do with the Venturi were run with this configuration.

3.4.4 Air-Water Test Procedure for S-shape Pipeline/Riser/Injectable Venturi

The procedure of the two-phase air-water flow tests experiments for pipeline-riser with the injectable Venturi applied is also similar to that stated in Section 3.3.2. However, the major difference is the coupling of the injectable Venturi upstream the topside choke valve which is before the test separator (two-phase separator) and the additional loop (secondary test loop) used for gas injection. This loop was discussed in Section 3.2.1.2.

All the experiments that have to do with the injectable Venturi were run with this configuration. The procedure followed in operating the secondary loop are outlined below:

1. Complete the start-up procedure for the 2" flow loop
2. Visually check the readiness of the secondary flow loop for operation
3. Check the valve positions, and alter if necessary to correct any mismatch
4. Open the operator interface on the LabVIEW control system set the gas injection flow rate
5. Click the start-up button to inject gas into the throat of the injectable Venturi

3.4.5 Slug Controller Implementation

Active control was implemented to improve the performance of the Venturi and injectable Venturi. The procedure for the experiments ran with the slug controller are similar to those discussed in Sections 3.4.2 – 3.4.4. However, the process was no longer controlled by the Delta V system but by the slug controller.

The active controller was developed with MATLAB Simulink; it communicated with the Delta V SCADA system through the OPC (OLE for Process Control) server. The procedure followed in operating the 2" flow loop (with and without the Venturi or the injectable Venturi) with active control are outlined below:

1. Complete the start-up procedure for the 2" flow loop and the secondary loop if required
2. Open the active control program and set it in manual operation
3. Set the appropriate control gain
4. Set the choke valve opening to be the same as that on the Delta V system
5. Click the run button to take control of the Delta V system
6. Switch to automatic control in order for the controller to take control of the process

3.5 Flow Rate and Operating Conditions

The flow rate and operating conditions used during all the experiments are summarised in Tables 3.5 and 3.6.

Table 3-5 Experiment test matrix

Test Matrix	
Air Flow Rate (Sm^3/hr)	Water Flow Rate (kg/s)
5 - 300	0.1 - 5

Table 3-6 Flow rate and operating conditions

Riser System	Two-phase Separator Pressure (barg)	3-Phase Separator Pressure (barg)	Air Source Type	Water Source Type
2"	1	1	Constant flow rate	Constant flow rate

3.6 Data Collection Method

Raw data acquired from online instrumentations, including the flowmeters and pressure transducers, were saved to desktop computers using Delta V data acquisition system and LabVIEW data acquisition system. Delta V is a Fieldbus based Supervisory, Control and Data Acquisition (SCADA) system supplied by Emerson Process Management. LabVIEW (Laboratory Virtual Instrument Engineering Workbench) is a system-design platform and development environment for graphical programming language supplied by National Instruments.

All signals were acquired in the Delta V Historian database and a high-speed multifunction National Instrument modules NI 9215 at a frequency of 1 Hz and

100 Hz respectively, which was sufficient for this study. These modules are housed by the National Instrument chassis NI cDAQ-9172 which transmitted the converted digital signals to the LabVIEW program. The sampling time of the signals was 600 seconds. A LabVIEW-based data acquisition and analysis program was used for data acquisition and processing. The DeltaV SCADA system is used to remotely operate the rig and perform the experimental procedure including pressurising and depressurising the system, control, shut down and data acquisition. The data retrieving form of the Delta V program and the data logging front panel of the LabVIEW program are shown in Figures 3-13 and 3-14.

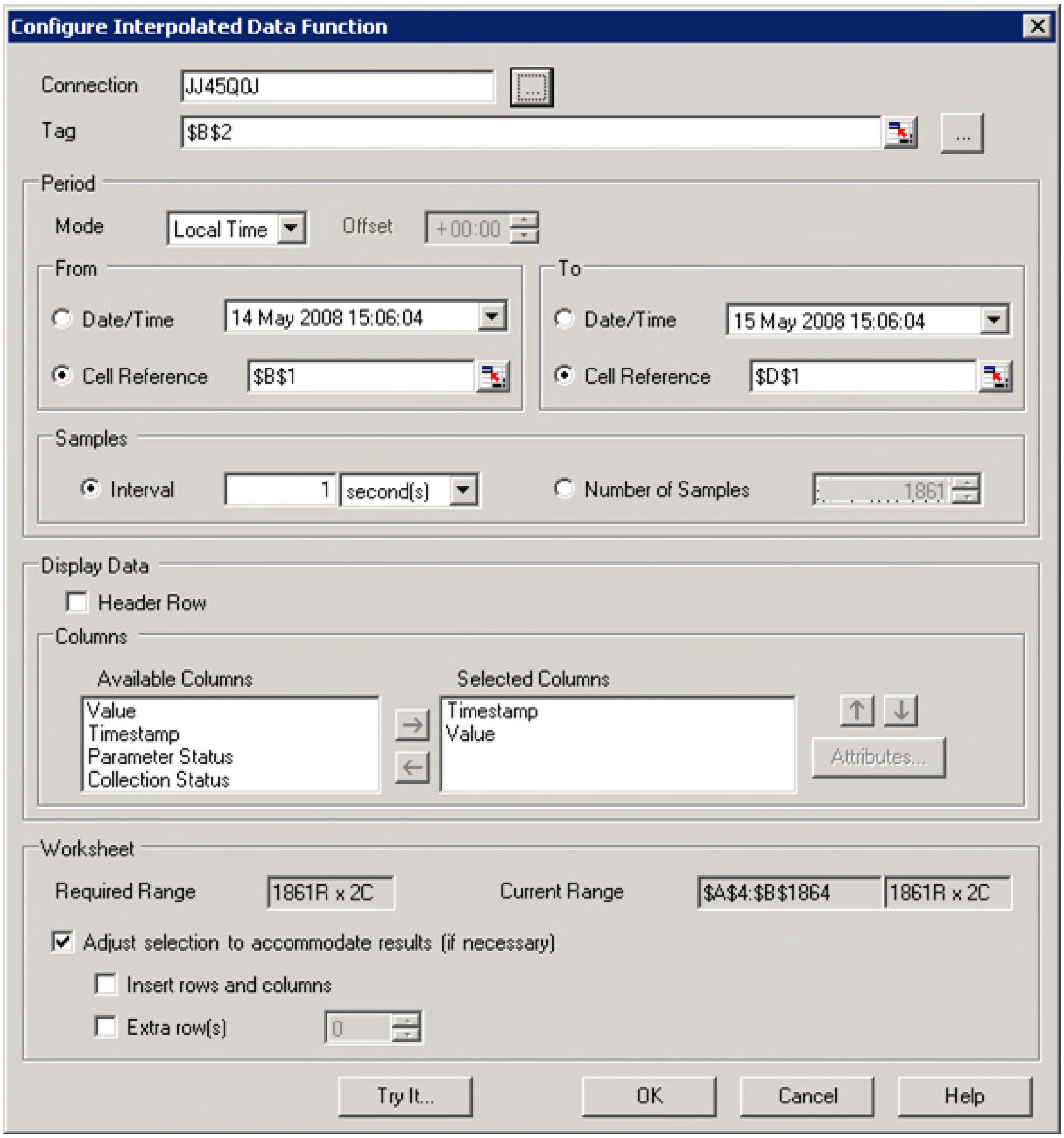

Figure 3-13 Delta V data retrieving form

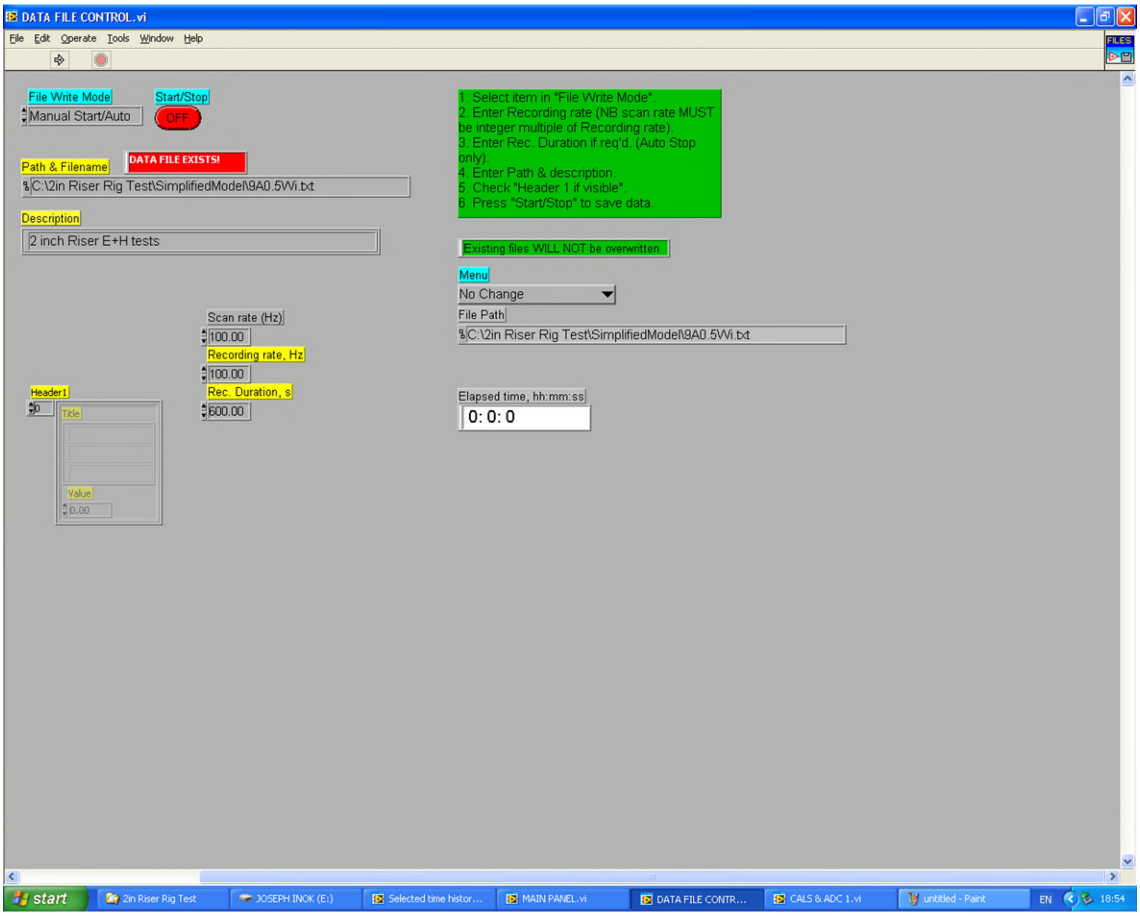

Figure 3-14 Data logging front panel of the LabVIEW program

3.7 Data Analysis

The data were analysed using flow regime maps, Hopf bifurcation maps, stability curves, stability maps and severe slug envelopes. These analyses and evaluation were executed with MATLAB and Microsoft Excel software.

3.7.1 Flow Regime Map

Flow regime map gives an overview over of which flow regimes we can expect for within a particular test matrix. It describes the geometrical distribution of multiphase fluid moving through a pipe. Different flow regimes are used to describe this distribution; the distinction between each one is qualitative. Probability Density Function (PDF) and Power Spectral Density (PSD) was used to objectively develop flow regime maps. This is discussed thoroughly in Chapter 5.

These maps were developed for the pipeline-riser set-up, pipeline-riser with the Venturi applied set-up and pipeline-riser with the injectable Venturi applied set-up, as shown in Chapters 5 – 7.

3.7.2 Hopf Bifurcation Map

This is a map that is developed through the parameter variation technique (Traditional choking of the topside choke valve) during experiments or simulations studies. This type of bifurcation occurs in a system when there is a loss of stability due to changes in an independent variable of the system (Thompson and Stewart, 1986). For a non-linear system like the pipeline-riser system, Hopf bifurcation can occur if a change in an independent variable such as the topside choke valve opening causes the system to become unstable at an operating point.

These maps were developed for the pipeline-riser set-up, pipeline-riser with the Venturi applied set-up and pipeline-riser with the injectable Venturi applied set-up, as shown in Chapters 5 – 7.

3.7.3 Stability Curve

Stability curves were developed through the gas perturbation technique for the pipeline-riser set-up, pipeline-riser with the Venturi applied set-up and pipeline-riser with the injectable Venturi applied set-up, as shown in Chapters 6 and 7. They show the general relationship between the riser base pressure as a function of increasing gas flow rate, with a constant liquid flow rate.

Usually, the liquid is kept constant while the gas flow rate is increased gradually. Initially, this will lead to a rapid decrease in riser base pressure until a nearly constant value at a low gas flow rate. However, when a minimum riser base pressure is attained, a further increase in gas flow rate will result in an increase in the riser base pressure. The regions to the left and right of the minimum value represent the unstable flow regimes and stable flow regimes regions respectively. This is discussed thoroughly in Chapters 6 and 7.

3.7.4 Stability Map

These maps were developed after flow regime characterisation by grouping severe slugging and transitional severe slugging test points from the flow regime map and re-classifying them as severe slugging. Thus, the stability maps are divided into two regions: unstable (severe slugging) and stable (stable flow).

These maps were developed for the pipeline-riser set-up, pipeline-riser with the Venturi applied set-up, and pipeline-riser with the injectable Venturi applied set-up, as shown in Chapters 5 – 7.

3.7.5 Severe Slug Envelope

Severe slug envelope is comparison tool used in creating stability boundary in order to measure and compare the severe slug elimination performance of the pipeline-riser with the Venturi applied to the plain pipeline-riser, and the pipeline-riser with the injectable Venturi applied to the plain pipeline-riser.

The stability maps were combined and used to develop severe slugging envelopes. These envelopes were created by tracing the outer severe slugging data points (stability boundaries) for each case. This is discussed thoroughly in Chapters 6 and 7.

3.8 Approach to Severe Slug Mitigation

To achieve the aim and objectives of this project, different approaches were employed to stabilise the system and increase the overall production. Approaches used for severe slug mitigation are parameter variation, the Venturi, the injectable Venturi and active control.

3.8.1 Parameter Variation Technique

The parameter variation technique involves varying the topside choke valve in order to alter the system behaviour. It employs the principle of changing a part to change the whole. The effect of such variation on severe slug flow regime in the pipeline-riser system was investigated and analysed using the Hopf bifurcation map.

3.8.2 The Venturi

Venturi produces less permanent pressure losses and high-pressure recovery due to the diffuser when compared to an orifice or nozzle. Thus, it conserves energy. These benefits associated with the Venturi were explored to mitigate severe slugging, stabilise the system and increase production. These were achieved by coupling the Venturi to the topside of the pipeline-riser, upstream the choke valve.

Figure 3-15 shows a simplified schematic of the pipeline-riser system with Venturi installed and Figure 3-16 shows the design dimension of the Venturi.

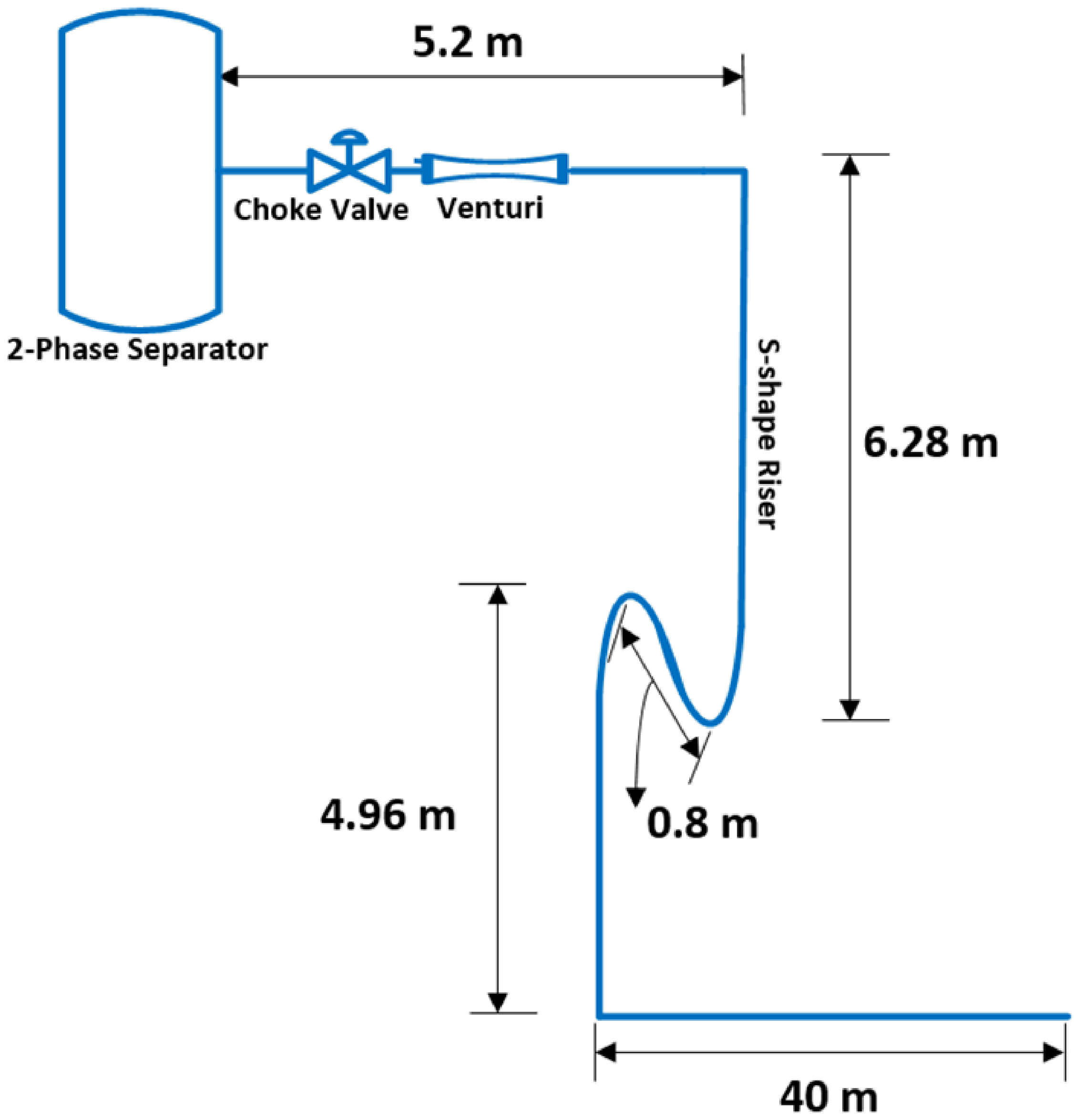

Figure 3-15 A simplified schematic of the pipeline-riser system with Venturi installed

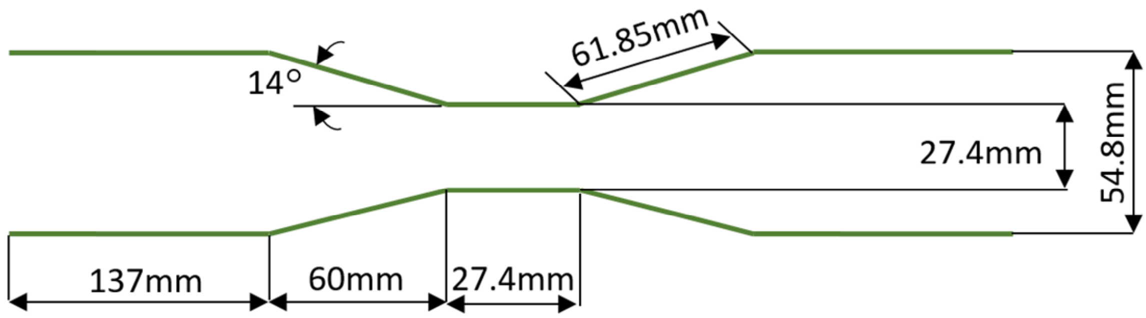

Figure 3-16 Design of the Venturi

3.8.3 The Injectable Venturi

The injectable Venturi is basically a Venturi that has an opening at its throat and a pipe inclined at 45° is inserted into this opening. The injectable Venturi also enjoys the benefits associated with the Venturi. However, gas is injected to regulate the size of the throat in order to further stabilise the flow. Thus, it was coupled to the pipeline-riser just before the topside choke valve in order to mitigate severe slugging, improve the stability of the system and increase overall production.

Sensitivity studies were implemented to determine the most efficient and effective amount of gas to be injected into the throat of the injectable Venturi. The gas was injected at 50 m^3/hr. This is the maximum gas injection rate allowable for the injectable Venturi due to safety concerns. Figure 3-17 shows a simplified schematic of the pipeline-riser system with injectable Venturi installed.

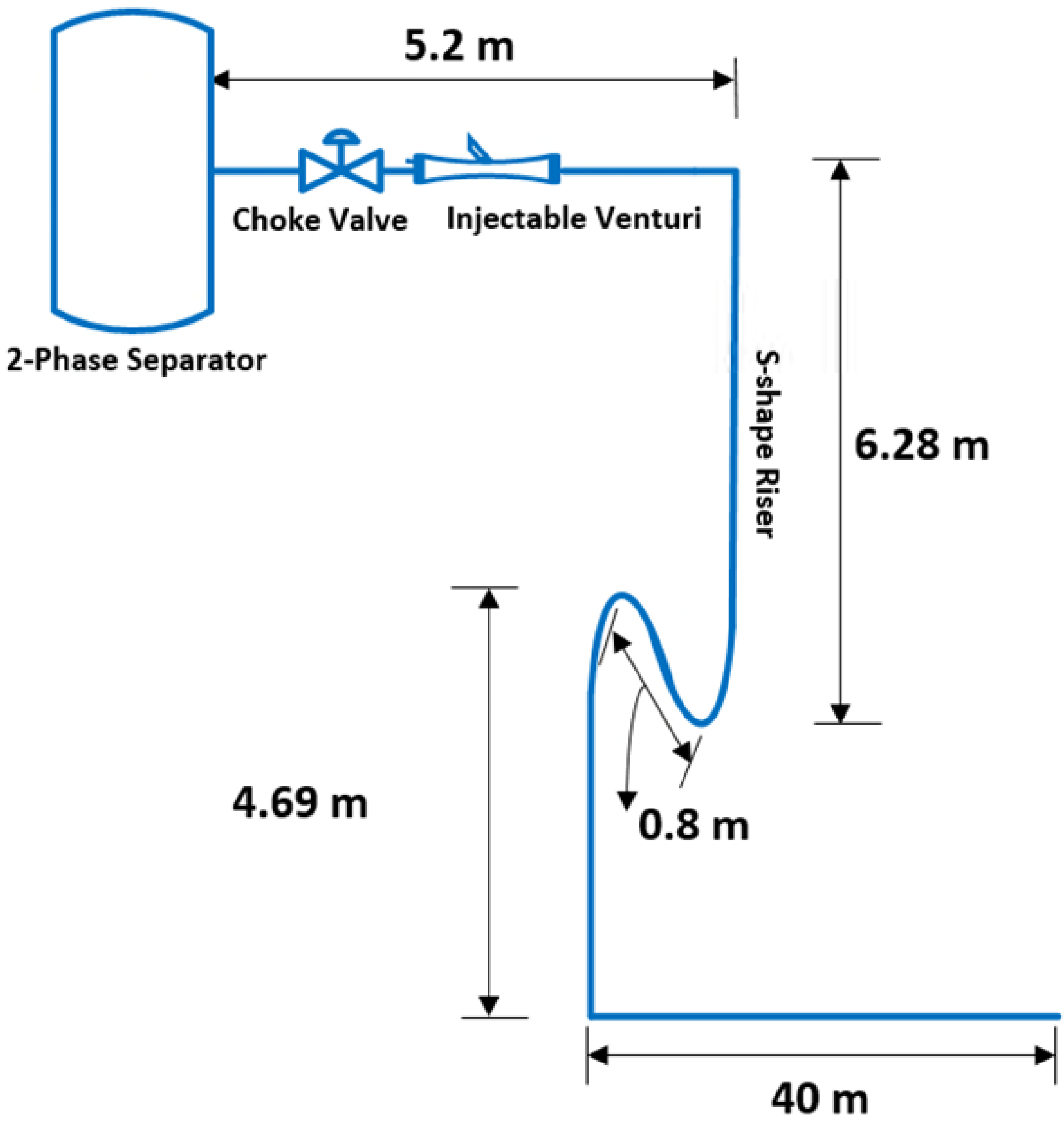

Figure 3-17 A simplified schematic of the pipeline-riser system with the injectable Venturi installed

3.8.4 Active Control

An active control system aims to stabilise the multiphase flow in the pipeline at operating conditions that, without control would lead to severe slugging. The primary aim of a slug controller is to stabilise the pipeline-riser system by mitigating severe slugging.

This technique was employed to further improve system stability and maximise production. The Venturi and injectable Venturi improved the system stability, and increased the overall production. However, their performance was enhanced by implementing active control.

3.9 Injectable Venturi Numerical Model

A simplified model of the injectable Venturi was developed using physical first-principles such as Bernoulli and continuity equations. The model was implemented in MATLAB. A correlation generated from the experiments was used in the development of the injectable Venturi model. The goal of the model is to simulate the output pressure from the injectable Venturi and the differential pressure across the injectable Venturi given the values of the input pressure from the experiment. Using the normalised mean square error (NMSE) fitness metric, the tuned MATLAB model was validated against the experimental data.

3.10 Chapter Summary

This chapter describes the methodology used for this study. The multiphase flow facility, equipment, and experimental arrangements employed to determine the severe slug mitigation, stability and production increase capability of the Venturi and the injectable Venturi have been discussed. In addition, the procedures for running each of these experiments have been explained. Furthermore, the operating conditions of the system and the mode of data collection have been presented.

The analytical methods used to interpret the experimental data were discussed. Also discussed was the approach to modelling the injectable Venturi and the approach used for severe slug mitigation. Descriptions and discussions of simulation results are presented in Chapter 4, while that of the experimental results is presented in Chapters 5 – 8.

4 SIMPLIFIED MODEL OF THE INJECTABLE VENTURI

Chapter Highlights

1. A new correlation is proposed and is successfully utilised for the calculations for K_{vt} (Effective area ratio)
2. A simplified injectable Venturi model has been developed from first physical principles
3. The new correlation achieved goodness of fit with the percentage of the average discrepancy between the predicted and the experimental result of 3.3 %

4.1 Introduction

This chapter describes the simplified model of the injectable Venturi under gas-liquid flow conditions in MATLAB. Bernoulli equations and continuity equations were used to develop the model. The developed model was validated using the experimental results with the model. Some correlations were developed for the calculations for K_{vt} (Effective area ratio).

This chapter seeks to address some part of the fifth gap in research identified in Chapter 2 of this thesis. The rest of the chapter is organised as follows. Section 4.2 outlines the pertinent first-principle equations for an injectable Venturi model. Section 4.3 presents the modelling of the injectable Venturi. Section 4.4 describes the implementation of these models using MATLAB, as well as the validation results. Section 4.5 presents the conclusions.

4.2 Simplified Model for Injectable Venturi

An injectable Venturi has a gradual flowing area contraction followed by a gradual flowing area expansion which helps in pressure recovery. Figure 4-1 shows a simplified schematic of the device. Sections (1), (2) and (3) of Figure 4-1 are the inlet (upstream), throat and outlet (downstream) of the injectable Venturi. During the experiment, pressure measurements were taken at the inlet, throat and outlet of the injectable Venturi. The simplified injectable Venturi model operates by taking the inlet experimental pressure measurement as input, computing it to give the pressure measurements at the throat and outlet respectively. These computed values are then compared with the actual experimental data. The differential pressure across the injectable Venturi obtained from the experiment, and that obtained from the simulation of the model are compared for goodness of fit in order to validate the model.

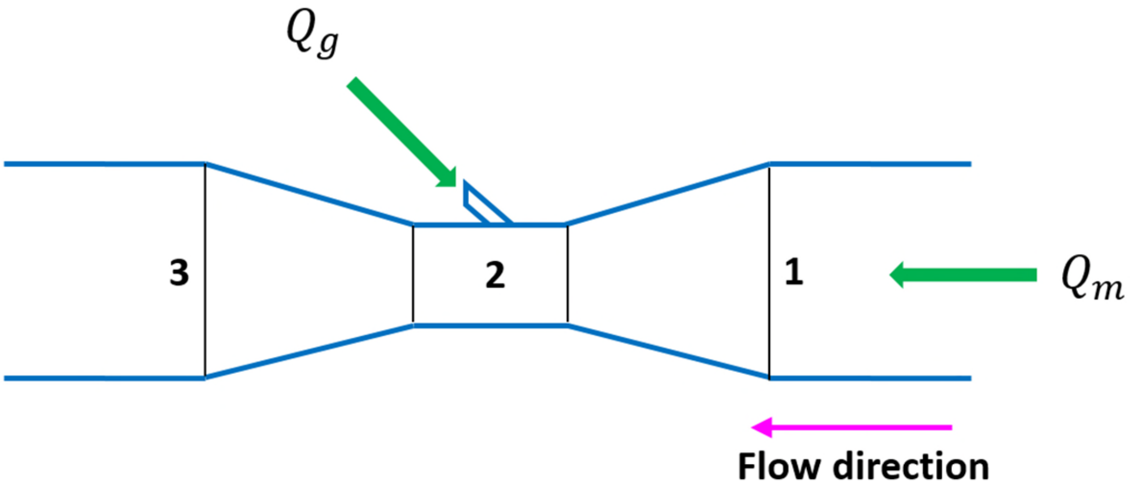

Figure 4-1 Simplified schematic of the injectable Venturi

In the injectable Venturi device, one cannot assume the density of the gas-liquid mixture is constant. However, for the initial part of the derivation, we first assume that it is. Later in the chapter, an expansion factor will be introduced to account for compressibility.

Assuming the flow going through the injectable Venturi is a two-phase homogenous flow. The injected gas (Q_g) is assumed to only change the effective area of the throat with negligible effect on the momentum of fluid flowing in the injectable Venturi (Q_m). Thus, in the model Q_g is accounted for by a function called the Effective area ratio (K_{vt}). K_{vt} is used to account for the change in the effective area of the throat in the model and is defined as

$$K_{vt} = \frac{A_E}{A_2} \tag{4-1}$$

where

A_E : is the effective area of the throat of the injectable Venturi during injection

A_2 : is the actual cross sectional area of the throat of the injectable Venturi

K_{vt} :   is the effective area ratio which ranges from 0 to 1

Also, given the geometries of the injectable Venturi are fixed, K_{vt} is the function of the related variables as follows:

$$K_{vt} = f(Q_g, Q_m, \rho_m, P_2) \quad \textbf{(4-2)}$$

where

ρ_m :   is the mixture density

Q_m :   is the mixture volumetric flow rate

P_2 :   is the pressure at the throat of the injectable Venturi.

4.2.1 Establishment of K_{vt} from Pressure Measurements

This section shows how K_{vt} was calculated and establishes the relationship between K_{vt} and pressure measurements in the injectable Venturi device. This results is going to be used for modelling of K_{vt} against flow conditions.

Assuming U_m is the mixture superficial velocity at the inlet of the injectable Venturi. The pressure difference between the inlet (1) and the throat (2) for without gas injection is given as:

$$\Delta P_{12\emptyset} = \frac{1}{2}\rho_m U_m^2 \left(\frac{1}{\beta^4} - 1\right) \quad \textbf{(4-3)}$$

where

$\Delta P_{12\emptyset}$: is $P_1 - P_2$ without gas injection into the injectable Venturi

P_1 : is the inlet pressure

P_2 : is the throat pressure

β : is the ratio of the throat diameter to the inlet diameter given as:

$$\beta = \frac{D_2}{D_1} \tag{4-4}$$

where

D_1 : is the inlet diameter

D_2 : is the throat diameter

The pressure difference between the inlet (1) and the throat (2) with gas injection is given as:

$$\Delta P_{12G} = \frac{1}{2}\rho_m U_m^2 \left(\frac{1}{\beta_E^4} - 1\right) \tag{4-5}$$

where

ΔP_{12G} : is $P_1 - P_2$ with gas injection into the injectable Venturi

β_E : is the ratio of the equivalent throat diameter to the inlet diameter given as:

$$\beta_E = \frac{D_E}{D_1} = \frac{D_E}{D_3} \tag{4-6}$$

where

D_E : is the equivalent throat diameter

D_3 : is the outlet diameter

Dividing Equation (4-5) by Equation (4-3) we have

$$\frac{\Delta P_{12G}}{\Delta P_{12\emptyset}} = \frac{\left(\frac{1}{\beta_E^4} - 1\right)}{\left(\frac{1}{\beta^4} - 1\right)} \qquad \textbf{(4-7)}$$

Simplifying further we have

$$\frac{\Delta P_{12G}}{\Delta P_{12\emptyset}} = \frac{\left(\frac{\beta}{\beta_E}\right)^4 - \beta^4}{1 - \beta^4} \qquad \textbf{(4-8)}$$

From Equation (4-8)

$$\left(\frac{\beta}{\beta_E}\right)^4 = \left(\frac{\Delta P_{12G}}{\Delta P_{12\emptyset}}\right)(1 - \beta^4) + \beta^4 \qquad \textbf{(4-9)}$$

From Equation (4-1)

$$K_{vt}^2 = \frac{A_E^2}{A_2^2} = \frac{A_E^2/A_1^2}{A_2^2/A_1^2} = \left(\frac{\beta_E}{\beta}\right)^4 \tag{4-10}$$

Hence,

$$K_{vt}^2 = 1/\left(\frac{\beta}{\beta_E}\right)^4 \tag{4-11}$$

Substituting Equation (4-9) into Equation (4-11) we have the K_{vt} from the inlet (1) to the throat (2)

$$K_{vt12}^2 = \frac{1}{\left[\left(\frac{\Delta P_{12G}}{\Delta P_{12\emptyset}}\right)(1-\beta^4) + \beta^4\right]} \tag{4-12}$$

Thus,

$$K_{vt12} = \left[\frac{1}{\left(\frac{\Delta P_{12G}}{\Delta P_{12\emptyset}}\right)(1-\beta^4) + \beta^4}\right]^{\frac{1}{2}} \tag{4-13}$$

A similar procedure was followed to obtain K_{vt32} for the throat (2) to the outlet (3) of the injectable Venturi.

Thus,

$$K_{vt32} = \left[\frac{1}{\left(\frac{\Delta P_{32G}}{\Delta P_{32\emptyset}}\right)(1-\beta_*^4) + \beta_*^4}\right]^{\frac{1}{2}} \qquad \textbf{(4-14)}$$

where

$\Delta P_{32\emptyset}$: is $P_3 - P_2$ without gas injection into the injectable Venturi

ΔP_{32G} : is $P_3 - P_2$ with gas injection into the injectable Venturi

P_3 : is the outlet pressure

β_* : is the ratio of the throat diameter to the outlet diameter given as:

$$\beta_* = \frac{D_2}{D_3} \qquad \textbf{(4-15)}$$

The total K_{vt} is calculated as follows:

$$K_{vt} = \sqrt{K_{vt12}K_{vt32}} \qquad \textbf{(4-16)}$$

4.2.2 K_{vt} Prediction from the Single Phase Flow Results

K_{vt} is an important parameter to characterise the injectable Venturi. The prediction of K_{vt} in two-phase flows is of great importance for designing, implementing, and optimising the two-phase flow control system using injectable Venturi. However, the establishment of K_{vt} in two-phase flows could be very challenging due to the complexity of the two-phase flow behaviour. A method is developed to predict the K_{vt} of two-phase flow from the K_{vt} of single phase flow conditions, and reported as follows.

4.2.2.1 Procedure and Data Set

Two cases were used for this study. The procedure used for K_{vt} measurement are as follows:

1. Experiments were run for Case (a) with air only ($V_{sg} = 2.0\ m/s$), water only ($V_{sl} = 0.25\ m/s$) and two-phase ($V_{sl} = 0.25\ m/s$ and $V_{sg} = 2.0\ m/s$) flows
2. Parameters from the experimental rig and pressure measurements obtained from running the experiment were used to calculate K_{vt}
3. The equations from Section 4.2.1 were used to calculate K_{vt}
4. Procedure (2) – (4) was repeated for Case (b) two-phase ($V_{sl} = 0.25\ m/s$ and $V_{sg} = 5.5\ m/s$) flows only

4.2.2.2 Development of the Correlation

Under different flow conditions K_{vt} is proposed as follows:

$$K_{vt(TP)} = K_{vt(L)} + [K_{vt(L)} - K_{vt(G)}]\left(\frac{Q_G}{Q_L + Q_G}\right)^n \quad \textbf{(4-17)}$$

where

$K_{vt(TP)}$: is the predicted K_{vt} for the two-phase flow

$K_{vt(L)}$: is the measured K_{vt} from the liquid (water) only flow

$K_{vt(G)}$: is the measured K_{vt} from the gas (air) only flow

Q_G : is the volumetric flow rate of gas

Q_L : is the volumetric flow rate of liquid

n : is an empirical index

The index was used to tune the predicted K_{vt} for goodness of fit. Figure 4-2 shows the results of the experiment for Case (a) and the predicted K_{vt} for the two-phase flow being fitted into the graph. It can be seen that the predicted K_{vt} curve closely match the measured K_{vt}. The percentage of the average discrepancy between the predicted and the experimental result is 5.6 %.

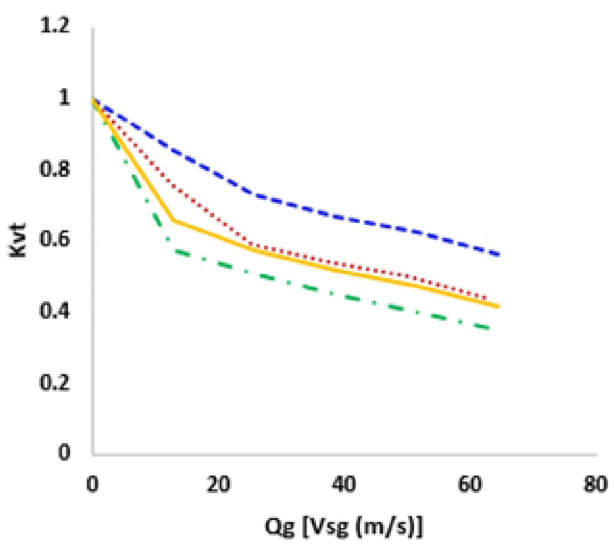

Figure 4-2 A plot showing the relationship between K_{vt} and Q_g for Case (a)

Figure 4-3 shows the results of the experiment for Case (b) and the predicted K_{vt} for the two-phase using the correlation developed from Case (a). It can be seen that the predicted K_{vt} curve closely match the measured K_{vt}. The percentage of the average discrepancy between the predicted and the experimental result is 3.3 %. Thus, this validated the correlations developed from the data set of Case (a).

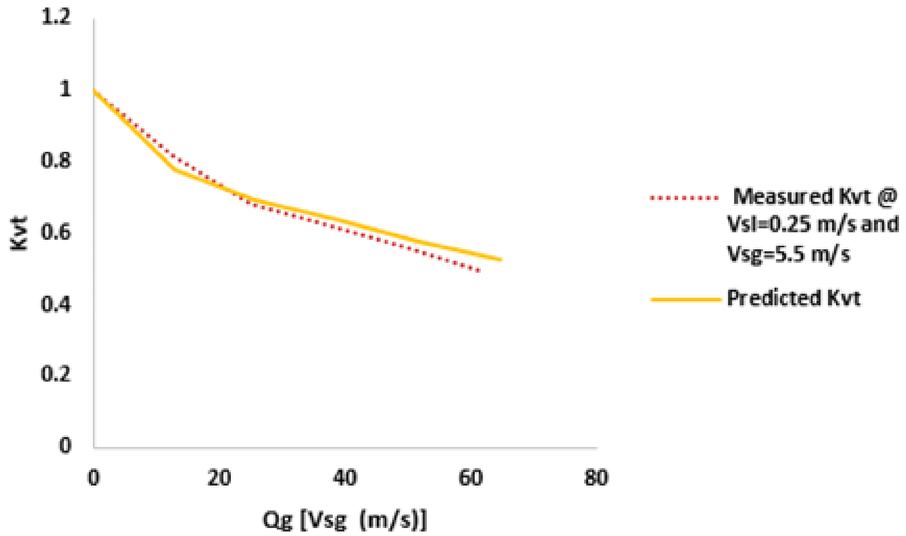

Figure 4-3 A plot showing the relationship between K_{vt} and Q_g for Case (b)

4.3 Modelling of the Injectable Venturi

The injectable Venturi is modelled with the combination of continuity equation and Bernoulli's equation. Recall from Equation 4-5 the pressure difference from the inlet (1) to the throat (2) with gas injected into the injectable Venturi is given as:

$$\Delta P_{12G} = \frac{1}{2}\rho_m U_m^2 \left(\frac{1}{\beta_E^4} - 1\right) \tag{4-18}$$

Also, the pressure difference from the throat (2) to the outlet (3) with gas injected into the injectable Venturi is given as:

$$\Delta P_{32G} = \frac{1}{2}\rho_m U_m^2 \left(\frac{1}{\beta_E^4} - 1\right) \tag{4-19}$$

In reality, there is a small loss of total pressure. Hence, Equations (4-18) (4-19) are divided by the discharge coefficient (C_d) to take this into account. In addition, since the fluid is compressible, there will be a change in density when the pressure changes from P_1 to P_2 on passing through the contraction section and P_2 to P_3 on passing through the divergent section. Thus, it is necessary to apply the expansibility factor. Hence, the Equations (4-18) (4-19) are divided by the expansibility factor (ε). The expansibility factor compensates for the fact that changes in the pressure of the gas as it flows through the Venturi result in changes in its density (Kinghorn, 1986). Thus, the actual pressure difference from the inlet (1) to the throat (2) and the throat (2) to the outlet (3) are given as:

$$\Delta P_{12G} = \frac{1}{2C_{di}\varepsilon_i}\rho_m U_m^2 \left(\frac{1}{\beta_E^4} - 1\right) \tag{4-20}$$

where

$C_{d,i}$: is the coefficient of discharge for the contraction section

ε_i : is the expansibility factor for the contraction section

$$\Delta P_{32G} = \frac{1}{2C_{do}\varepsilon_o}\rho_m U_m^2\left(\frac{1}{\beta_E^4} - 1\right) \tag{4-21}$$

where

$C_{d,o}$: is the coefficient of discharge for the divergent section

ε_o : is the expansibility factor for the divergent section

The coefficients of discharge ($C_{d,i}$ and $C_{d,o}$) and the expansibility factors (ε_i and ε_o) were used to tune the injectable Venturi model. From Equations (4-20) P_2 is given as:

$$P_2 = P_1 - \left[\frac{1}{2C_{di}\varepsilon_i}\rho_m U_m^2\left(\frac{1}{\beta_E^4} - 1\right)\right] \tag{4-22}$$

Also, from Equation (4-21) P_3 is given as:

$$P_3 = P_2 - \left[\frac{1}{2C_{do}\varepsilon_o}\rho_m U_m^2\left(\frac{1}{\beta_E^4} - 1\right)\right] \tag{4-23}$$

4.4 Injectable Venturi Model Simulation Results

The simplified model was simulated in MATLAB, and the tuning parameters were adjusted to validate the results against the experimental results using trial and error.

The MATLAB model takes the experimental pressure values, P_1 as input, computes the pressure P_2, and then computes the pressure P_3 as output using the equations in Sections 4.2 - 4.3. In the simulation, the actual dimensions of the injectable Venturi were also encoded.

To measure the goodness of fit of the MATLAB model results against the actual P_3 measurements, the normalized mean square error (NMSE) metric was used. The NMSE is defined as follows

$$NMSE = \left(1 - \frac{\left\|\boldsymbol{x}_{ref} - \boldsymbol{x}\right\|^2}{\left\|\boldsymbol{x}_{ref} - \overline{\boldsymbol{x}_{\boldsymbol{ref}}}\right\|^2}\right) \times 100\ \% \tag{4-24}$$

where $\boldsymbol{x}_{\mathrm{ref}}$ is the actual experimental data and $\boldsymbol{x}$ is the data produced by the model. The better the fit, the closer the value of NMSE to 100 %.

The K_{vt} used in the model was obtained experimentally as shown in Section 4.2.1 and 4.2.2. A subset of the tuning parameters, namely $C_{d,i}$ and $C_{d,o}$ were tuned first before estimating the expansibility factors, ε_i and ε_o, using MATLAB's fminunc optimization tool. The goal of fminunc was to maximise NMSE by changing ε_o and ε_i while keeping the other parameters fixed.

After tuning, simulation results are reported in Figures 4-4 to 4-9. In Figure 4-4, the simulated time series of the differential pressure across the injectable Venturi, $P_1 - P_3$, are superimposed with the actual differential pressure values at a test point of V_{sl} = 0.25 m/s and V_{sg} = 2.0 m/s. Figure 4-7 shows a similar result, however at a test point of V_{sl} = 0.25 m/s and V_{sg} = 5.5 m/s. It can be seen that the experimental and model results are closely matched. The high fluctuations seen in experiment data in the Figure 4-4 and 4-7 are due to noise present in the signals. Since the NMSE is 72 % for Figures 4-3 and 78 % for Figures 4-7 it can be said that the experiment is validated by the MATLAB model. Comparison plots are also included in Appendix B as Figure B1 and B2.

Probability Density Function (PDF) and Power Spectral Density (PSD) were also used to investigate how the model and the experiment data closely matched. The results for the two test points shown in Figures 4-6,4-8 and 4-9 show that the model and the experiment are a good fit. However, in Figure 4-5 as the normalised pressure increases the model becomes accurate.

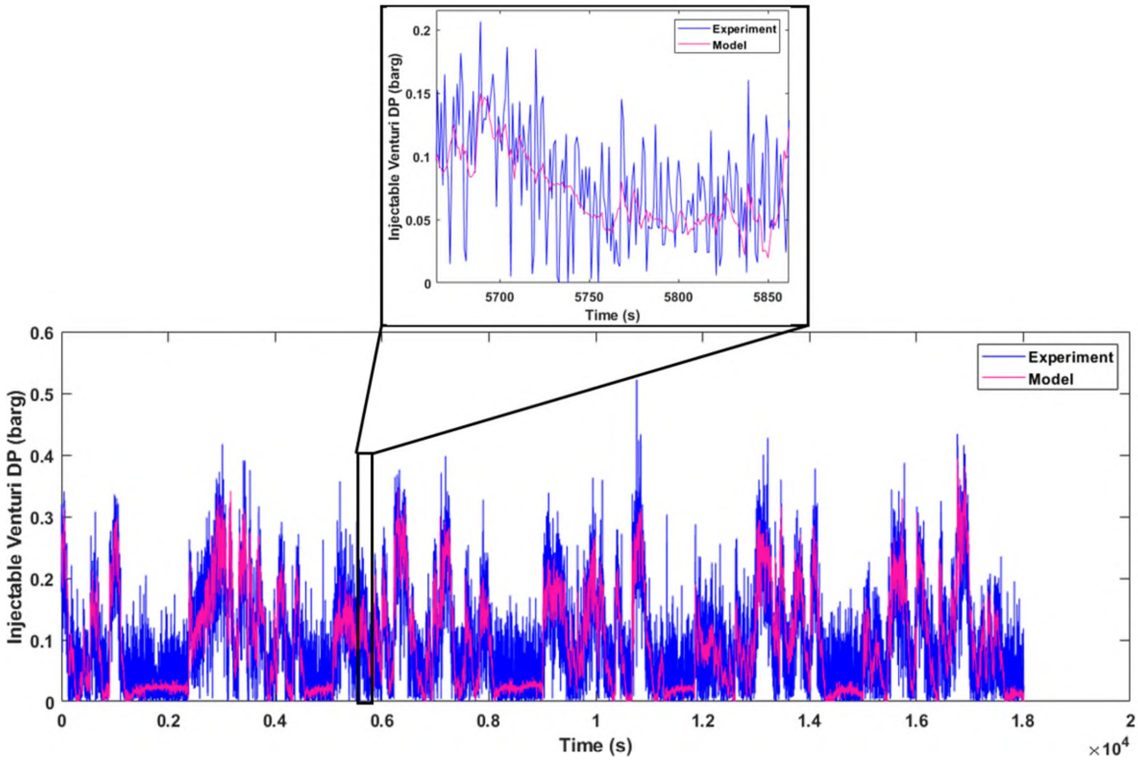

Figure 4-4 Differential pressure across the injectable Venturi (time series) for the experiment and model (V_{sl} = 0.25 m/s, V_{sg} = 2.0 m/s, Q_g = 50 Sm^3/hr and K_{vt} = 0.44).

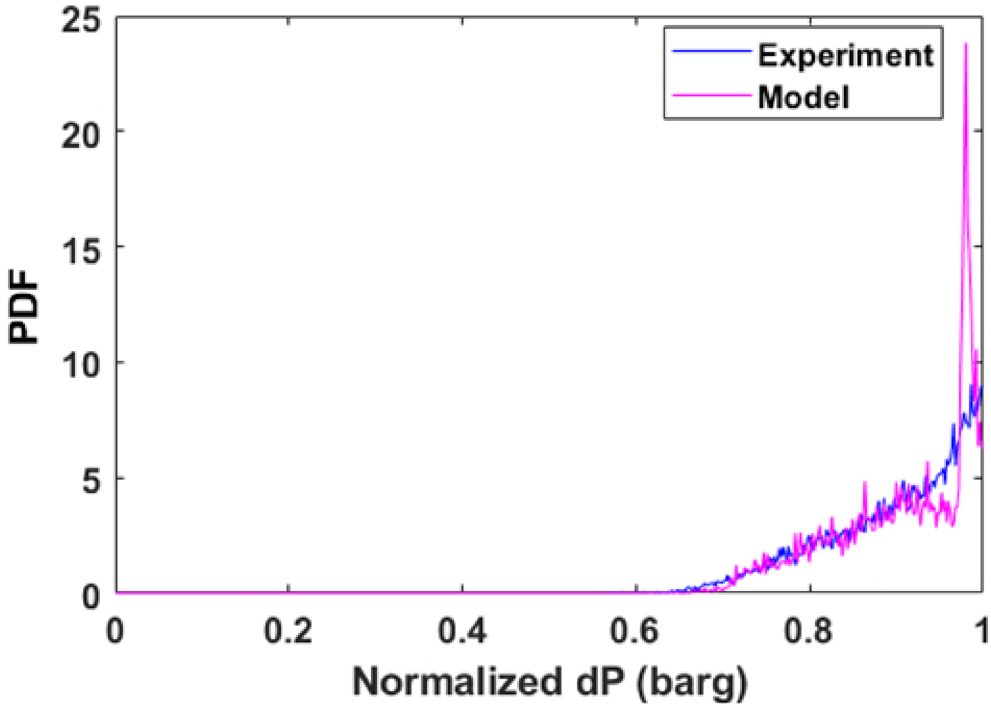

Figure 4-5 PDF of the differential pressure across the injectable Venturi (time series) for the experiment and model (V_{sl} = 0.25 m/s, V_{sg} = 2.0 m/s, Q_g = 50 Sm^3/hr and K_{vt} = 0.44)

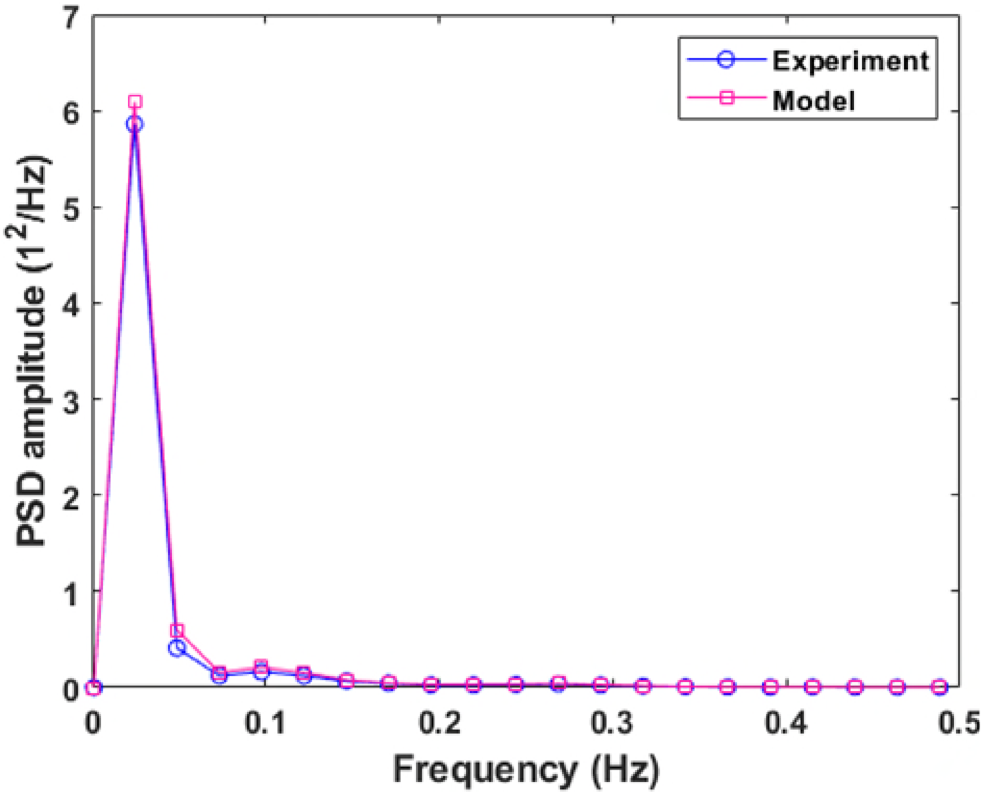

Figure 4-6 PSD of the differential pressure across the injectable Venturi (time series) for the experiment and model (V_{sl} = 0.25 m/s, V_{sg} = 2.0 m/s, Q_g = 50 Sm^3/hr and K_{vt} = 0.44)

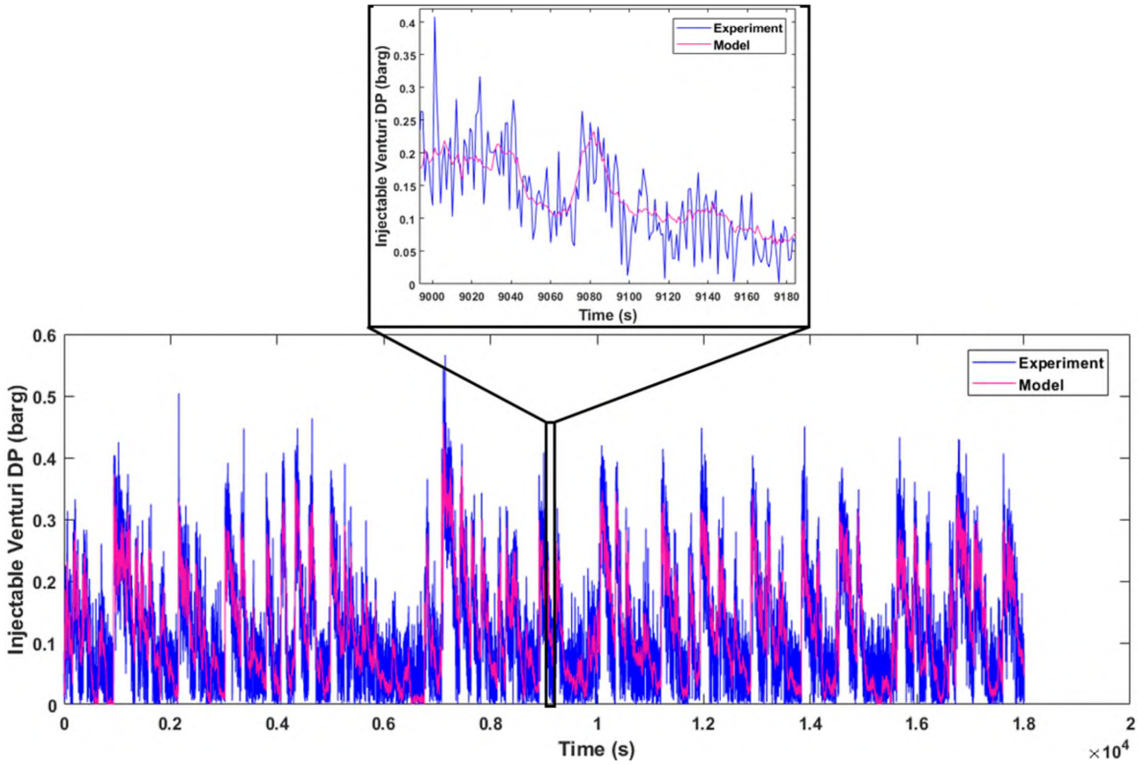

Figure 4-7 Differential pressure across the injectable Venturi (time series) for the experiment and model (V_{sl} = 0.25 m/s, V_{sg} = 5.5 m/s, Q_g = 50 Sm^3/hr and K_{vt} = 0.49).

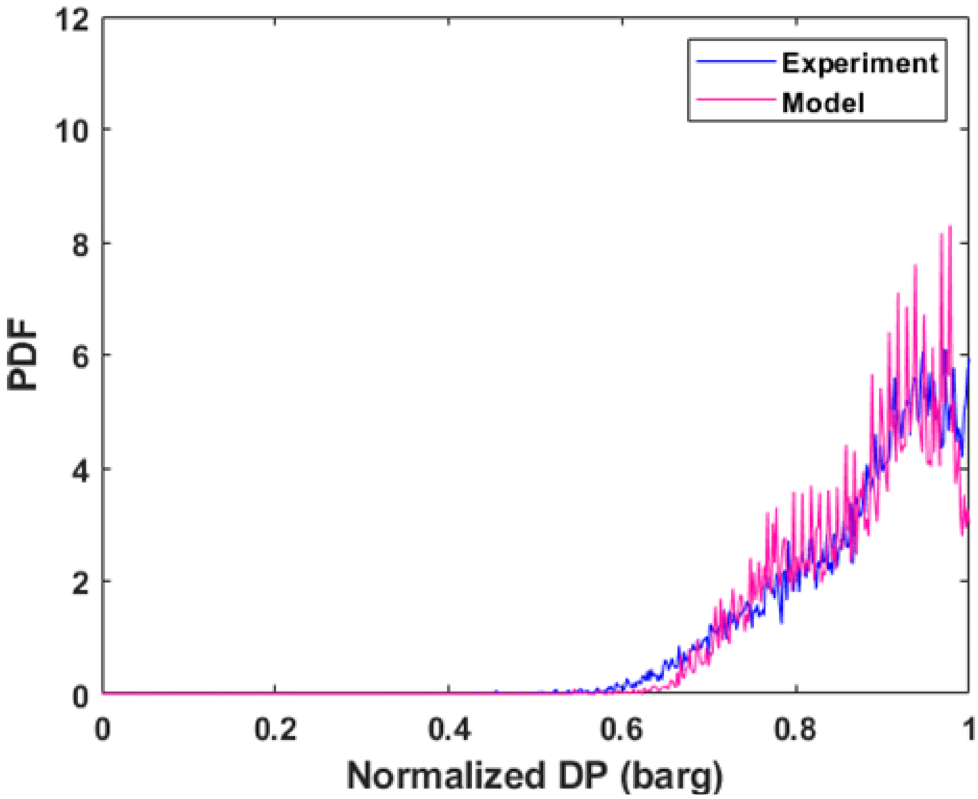

Figure 4-8 PDF of the differential pressure across the injectable Venturi (time series) for the experiment and model (V_{sl} = 0.25 m/s, V_{sg} = 5.5 m/s, Q_g = 50 Sm^3/hr and K_{vt} = 0.49).

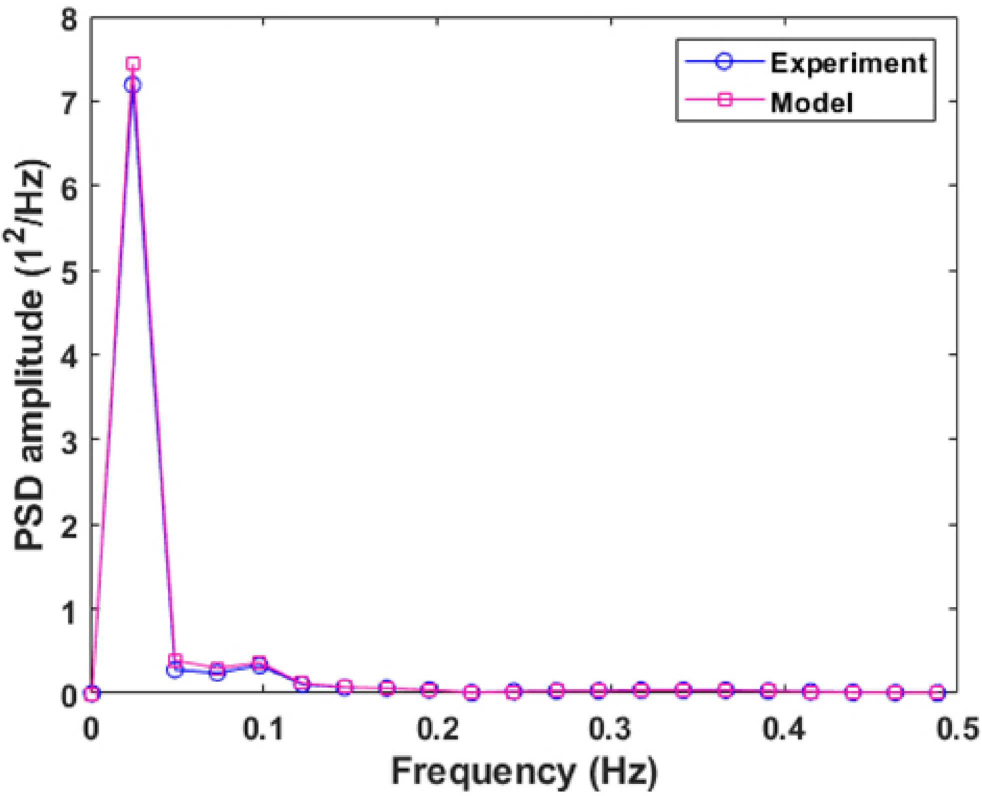

Figure 4-9 PDF of the differential pressure across the injectable Venturi (time series) for the experiment and model (V_{sl} = 0.25 m/s, V_{sg} = 5.5 m/s, Q_g = 50 Sm^3/hr and K_{vt} = 0.49).

4.5 Chapter Summary

In this chapter, a simplified model of the injectable Venturi was developed using physical first-principles such as a combination of Bernoulli and continuity equations. Also, correlations for the calculation of K_{vt} was developed. The predicted K_{vt} curve closely match the measured K_{vt}. The percentage of the average discrepancy between the predicted and the experimental result is 3.3 % for the cases considered. This new model were verified using experimental results and it showed a good agreement with experimental results.

The injectable Venturi model was implemented in MATLAB. Certain tuning parameters were used, in addition to fine-tuning using MATLAB's optimisation tools. The goal of the model is to simulate the pressures at the throat and outlet of the injectable Venturi, and the differential pressure across the injectable Venturi given the values of the input pressure from the experiment.

The main contributions of this chapter are summarised below:

1. A simplified model of the injectable Venturi has been developed from physical first-principles
2. Development of correlations for the calculation of K_{vt} from flow conditions
3. The predicted K_{vt} model showed good agreement with the measured K_{vt}
4. Development of simplified injectable Venturi two-phase homogeneous flow model in MATLAB
5. It has been shown that the simplified injectable Venturi model can compute the pressures at the throat and outlet of the injectable Venturi
6. An injectable Venturi model that simulates the differential pressure across the injectable Venturi has been established
7. The simplified injectable Venturi model simulation results have been established to be a good fit for the injectable Venturi experimental data

In conclusion, the predicted K_{vt} closely matched the measure K_{vt}. Also, using the NMSE fitness metric, the tuned MATLAB model was validated against the experimental data by achieving 78 % goodness of fit in one of the test point considered. Thus, the model closely matched the experimental results. Consequently, the experiment was validated by the simplified MATLAB model. The understanding provided by this study will enhance the understanding and proper design of the injectable Venturi and how it could be deployed for field operations.

5 CHARACTERISATION OF FLOW IN S-SHAPE PIPELINE-RISER SYSTEM

Chapter Highlights

1. Objective characterisation of flow regime map
2. Ten flow regimes identified
3. Characterisation of flow in the entire length of the riser

5.1 Introduction

This chapter describes the characterisation of flow regimes within the test matrix investigated in this study. Flow regime identification is one of the proofs of concepts of this work as stated in Chapter 1. This chapter details how flow regime map is developed. This map is used for data analysis as outlined in Section 3.6.1 and for achieving some of the objectives outlined in Section 1.3. Probability Density Function (PDF) and Power Spectral Density (PSD) were used to objectively develop flow regime maps.

This chapter seeks to address the first gap in research identified in Chapter 2 of this thesis. The chapter is organised as follows: Section 5.2 discusses flow regime identification and the different process used to objectively characterise the flow in the riser. Section 5.3 presents the results obtained from the experiment; analyses and discusses them. Section 5.5 concludes the chapter.

5.2 Flow Regime Identification

The flow regimes in a pipeline-riser system have been classified into different categories by different researchers (Schmidt et al., 1979, 1980; Matsui, 1984; Taitel et al., 1990; Tin, 1991; Malekzadeh et al., 2012; Montgomery and Yeung, 2002; Li et al., 2013; Ye and Guo, 2013; Park and Nydal, 2014; Li et al., 2017) as outlined in Chapter 2.

In this work pressure analysis was used for identifying flow patterns and defining the different stages of severe slugging cycle. Thus, the differential pressure of the entire riser length (riser base to top side) was used to analyse the various flow patterns present in the test matrix. The flow regimes observed in the 2" S-shape riser are classified into ten categories: severe slug type I (SS-I), severe slug type II (SS-II), severe slug type III (SS-III), transitional severe slug type I (SST-I), transitional severe slug type II (SST-II), oscillation flow (OSC), bubble flow, slug flow, churn flow and annular flow. They were further broadly categories as severe slugging, transitional severe slugging and stable flow.

To make the differential pressure signals results comparable, the differential pressure needed to be normalised.

5.2.1 Differential pressure normalisation

Pressure analysis was used for distinguishing flow patterns and defining the different stages of severe slugging cycle. Thus, the differential pressure of the entire riser length was used to analyse the various flow patterns within the test matrix. This differential pressure was normalised to make the differential pressure signal results comparable.

Firstly, the static differential pressure of the entire riser length of the empty riser was measured and recorded. Secondly, the riser was filled with water, and the static differential pressure recorded. Finally, the riser was emptied, and the static differential pressure of the empty riser was recorded again. The average of the two empty static differential pressure ($P_{air,ave}$) was calculated and subtracted from the static differential pressure value of when the riser was filled with (P_{water}) water to give the reference differential pressure ($\Delta P_{s,f}$) as:

$$\Delta P_{s,f} = P_{water} - P_{air,ave} \quad \textbf{(5-1)}$$

The reference differential pressure corresponds to the static fluid differential pressure of the riser. The differential pressure for each test point (ΔP) within the test matrix was recorded at a sampling rate of 100 samples per seconds for 600 seconds. The dimensionless normalised differential pressure ΔP^* was determined as:

$$\Delta P^* = 1 - \frac{\Delta P}{\Delta P_{s,f}} \tag{5-2}$$

According to Matsui (1984; 1986) for flows with negligible acceleration and friction pressure losses, ΔP^* would be indicative of the phase in the measurement section. Thus, the value of this dimensionless normalised parameter would be close to either 0 or 1 if the measurement volume between the two pressure taps were occupied by the liquid phase or gas phase, respectively (Shaban and Tavoularis, 2014). The normalised differential pressures were used to generate probability density function (PDF) and power spectral density (PSD) graphs, which were used to identify the various flow regimes objectively.

5.2.2 Calculation of PDF and PSD of Normalised Differential Pressure

PDF is used to specify the probability of a random variable falling within a particular range of values and is defined as:

$$Y(a \leq x \leq b) = \int_a^b D(x)dx \tag{5-3}$$

where $Y(a \leq x \leq b)$ is the probability that the variable x lies between a and b, and x is the normalised differential pressure across the entire riser length (ΔP^*).

The PDF was computed in a MATLAB program by separating the values of ΔP^* into 500 bins, each having a width of 0.002, which corresponded to a vector of 500 representative features.

The PSD is a frequency domain characteristic of a time series that is suitable for detecting the frequency components hidden in a stochastic process (Matsumoto and Suzuki, 1984). It can be used to reveal the distinctiveness in the signal of flow regimes present in a multiphase flow (Abbagoni and Yeung, 2016). Fast Fourier transform is used to create the PSD spectrum, which assumes that the processed signal (normalised differential pressure) is stationary and ergodic. The PSD function $D_x(f)$, of a discrete signal $x(n)$ is defined as the Fourier transform of the autocorrelation sequence $R_x(k)$ of the signal (Xie et al., 2004):

$$YD_x(f) = \sum_{k=-\propto}^{\propto} R_x(k) e^{-i2\pi f/f_s} \quad \textbf{(5-4)}$$

where f_s is the sampling frequency.

For an unlimited amount of data and real-valued continuous data, the autocorrelation sequence can be approximated by a time-average given as (Xie et al., 2004):

$$R_x(K) = \lim_{N\to\infty} \frac{1}{2N+1} \sum_{n=-N}^{N} x(n+k)x(n) \quad \textbf{(5-5)}$$

The signal was recorded for a finite time interval during the experiment; this may present some distortions to the spectrum. Consequently, a modified form of the PSD, called the Welch method, is adopted. Welch (1967) subdivided the signal sample into small length N-point overlapping segments, applied a window function to each data segment, calculated the periodogram of each of the segments and then averaged the periodograms in order to obtain the estimated power spectrum. Thus, the PSD of the ΔP^* was computed in MATLAB program using Welch's averaged periodogram method.

The PSD was estimated using a segment length which was computed as the next power of two greater than the number of samples and a Hanning window at 50 % overlap was applied in order to reduce the variance of the estimates.

5.3 Results and Discussion

This section presents the results obtained from the various test points within the test matrix ran during the experiment. It identifies and discusses the uniqueness of each flow regime within the test matrix. The typical riser differential pressure-time traces of the ten flow regimes in the S-shaped pipeline-riser system are included and used in combination with the PDF and PSD to objectively Identify the various flow regime.

5.3.1 Severe Slugging (SS)

Severe slugging typically exhibits cyclic behaviour and has been previously identified by several researchers (Tin, 1991; Li et al., 2013; Schmidt et al., 1985; Baliño et al., 2010; Malekzadeh, 2012; Montgomery, 2002). Generally, it is encountered at relatively low gas and liquid superficial velocity and can be described in four stages; the slug formation, slug production, bubble penetration, and gas blowdown and liquid fall-back. In this study, three types of severe slugging were identified in this study: SS-I, SS-II and SS-III.

5.3.1.1 Severe Slug Type I (SS-I)

This is the traditional severe slugging that typically exhibits the four stages cyclic behaviour; the slug formation, slug production, bubble penetration, and gas blowdown and liquid fall-back as shown in Figure 5-1(a). It has been identified previously by various researcher as classical severe or severe slugging (Baliño et al., 2010; Schmidt et al., 1985; Tin, 1991; Xing et al., 2013a; Ehinmowo et al., 2016).

A unique profile was observed for the PDF profile of the pressure difference over the riser during SS-I (Figure 5-1(b)). The PDF has a two-peak distribution where one peak occurs in the period of slug generation and the other peak in the period of slug production. The pressure impact when gas blowout occurs is manifested as the long tail of the distribution. The PSD (Figure 5-1(c)) exhibits two clear peaks; the lower frequency peak is more dominant and has a larger PSD amplitude.

5.3.1.2 Severe Slug Type II (SS-II)

This occurs when the gas velocity increases to the extent that bubble penetration occurs just when the slug front arrives at the top of the riser. The penetration of gas tends to accelerate the liquid slug into the separator and causes gas blowout. SS-II typically exhibits three stages in each cycle as can be seen in Figure 5-1(d). Thus, there is no stable slug production stage as in SS-I since the process of slug formation is followed immediately by bubble penetration.

The PDF (Figure 5-1(e)) has three-peak distribution with the smallest at lower pressure. The PSD (Figure 5-1(f)) has multiple peaks and a major peak with a large PSD amplitude that has a higher and strong dominant frequency than SS-I.

5.3.1.3 Severe Slug Type III (SS-III)

This manifested at higher flow rates when compared with SS-I. There is continuous gas penetration at the riser base during the slug production stage as can be seen in Figure 5-1(g). This is as a result of the higher friction of the fast-moving liquid carrying gas into the separator.

The PDF (Figure 5-1(h)) shows one major peak and two other peaks at pressures lower and higher than that of the highest peak. This corresponds to the pressure differences before and after the gas penetration. The PSD (Figure 5-1(i)) has a major peak with a strong dominant frequency and two other smaller peaks in the frequency domain. The PSD amplitude of the major peak is larger than that of SS-I and SS-II.

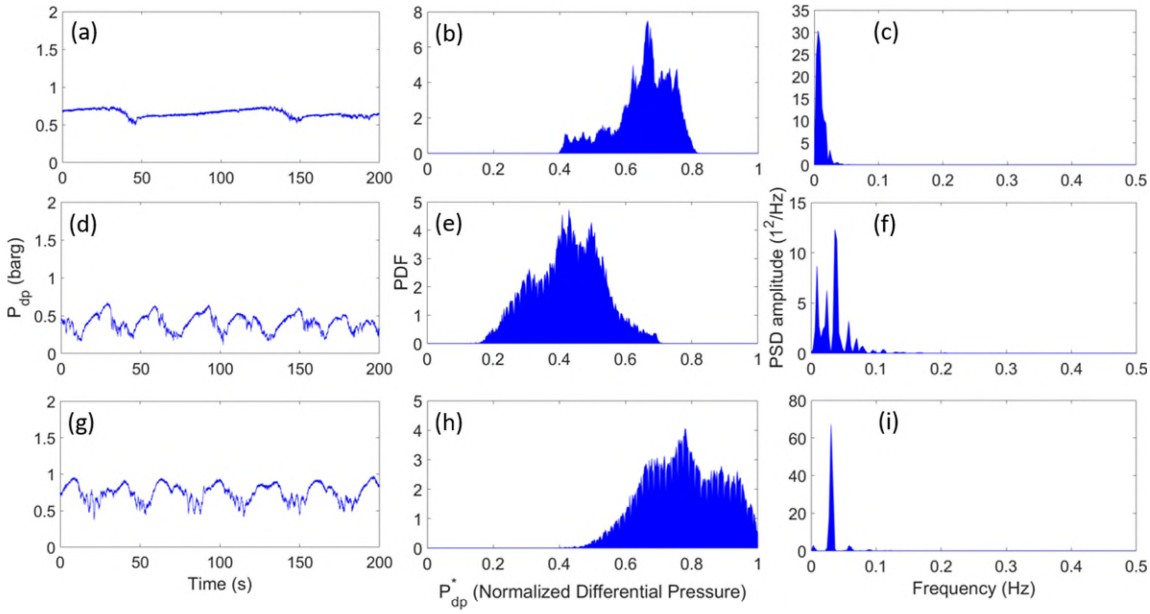

Figure 5-1 Differential pressure over the riser (time series), PDF and PSD of the differential pressure over the riser during different types of severe slugging flow (a,b,c) $V_{sl} = 0.05$ m/s, $V_{sg} = 0.44$m/s (SS-I); (d,e,f) $V_{sl} = 0.25$ m/s, $V_{sg} = 2.0$ m/s (SS-II); (g,h,i) $V_{sl} = 0.74$m/s, $V_{sg} = 0.81$ m/s (SS-III)

5.3.2 Transitional Severe Slugging (SST)

This severe slugging is a transitional flow regime between severe slugging and stable flow. The major difference between transitional severe slugging and severe slugging is that the dominant pressure difference over the riser is smaller for SST; thus, the slug length is less than one riser length. Three types of transitional severe slugging were identified in this study: SST-I, SST-II and OSC.

5.3.2.1 Transitional Severe Slug Type I (SST-I)

This tends to occur at higher gas and lower liquid flow rates. The pressure difference over the riser (Figure 5-2(a)) shows multiple gas penetration between two proportionately larger differential pressure leaps. The characteristics of SST-I are quite similar to those of SS-III, but with frequent gas penetration at the riser base and smaller pressure fluctuations.

The PDF (Figure 5-2(b)) has a two-peak distribution; the highest peak occurs at higher pressure, whereas the lower peak occurs at a lower pressure. The PSD (Figure 5-2(c)) has multiple peaks and a major peak with strong dominant frequency and PSD amplitudes smaller than those of SS-I, SS-II and SS-III.

5.3.2.2 Transitional Severe Slug Type II (SST-II)

This is observed at higher liquid and lower gas flow rates. The pressure difference over the riser (Figure 5-2(d)) shows more frequent gas penetration at the riser base and multiple smaller and larger differential pressure leaps.

The PDF (Figure 5-2(e)) shows a Gaussian-like distribution that is spread out almost evenly. The PSD (Figure 5-2(f)) has multiple components that spread throughout the frequency domain, and the highest peak occurs at a lower frequency than that of SST-I.

5.3.2.3 Oscillation Flow (OSC)

This transitional severe slug exists at higher gas flow rates than SST-II. The pressure difference over the riser (Figure 5-2(g)) shows frequent cyclic pressure fluctuations without the spontaneous vigorous blowdown.

The PDF (Figure 5-2(h)) shows a flattened peak, and the distribution spread out over higher pressures. The PSD (Figure 5-2(i)) has multiple high and low peaks spread throughout the frequency domain with the dominant frequency peak occurring at a higher frequency when compared to SST-II.

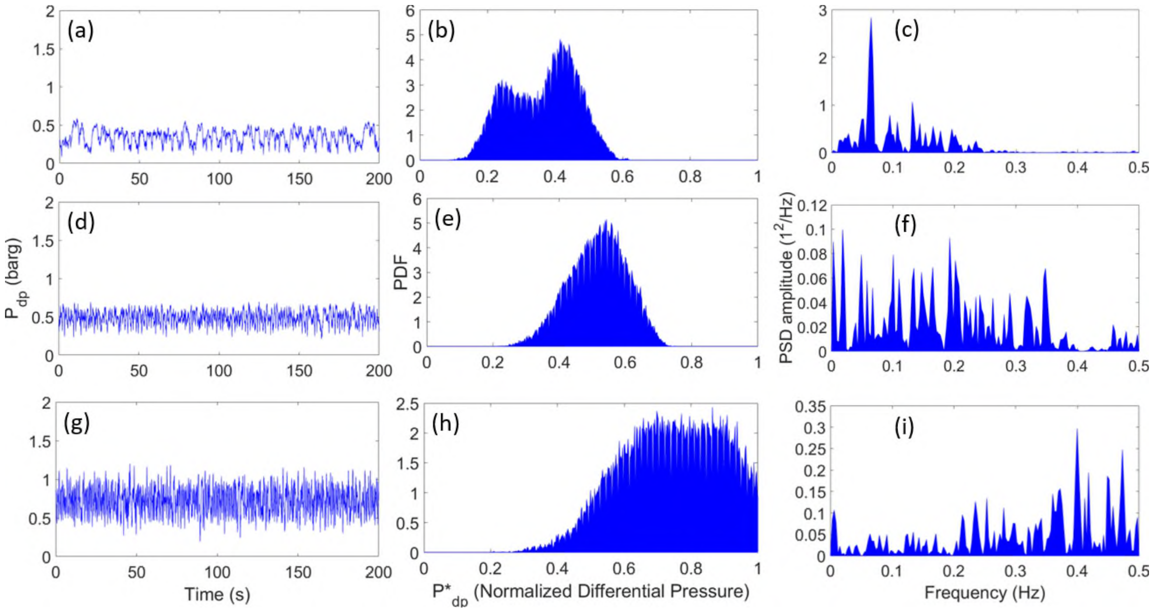

Figure 5-2 Differential pressure over the riser (time series), PDF and PSD of the differential pressure over the riser during different types of transitional severe slugging flow (a,b,c) $V_{sl} =$ 0.51 m/s, $V_{sg} =$ 5.21 m/s (SST-I); (d,e,f) $V_{sl} =$ 0.99 m/s, $V_{sg} =$ 4.71m/s (SST-II); (g,h,i) $V_{sl} =$1.73 m/s, $V_{sg} =$ 8.08 m/s (OSC)

5.3.3 Stable Flow (STB)

Stable flow is observed at a relatively high gas flow and liquid flow rates, the gas and liquid flow into the riser continuously without complete blockage of the pipeline. It has the lowest pressure amplitudes, its pressure trend over the riser profile remains roughly constant with smaller fluctuation. Four types of stable flow were identified in this study: bubble, slug, churn, and annular.

5.3.3.1 Bubble Flow

This occurs when the gas and liquid continuously flow through the riser with very small deviations as shown in Figure 5-3(a). It manifests as a continuum of liquid with dispersed gas bubbles.

The PDF (Figure 5-3(b)) shows a single peak with the largest normalised differential pressure when compared to other flow regimes in the stable category. The PSD (Figure 5-3(c)) has multiple peaks, and two peaks with dominant frequencies. The highest peak occurs at a lower frequency when compared to the other with dominant frequency and has PSD amplitude higher than the rest in the frequency distribution.

5.3.3.2 Slug Flow

Slug flow exhibits the largest pressure fluctuation amongst all the stable flow. This is evident with the intermittent nature of the liquid slug. It fluctuates more frequently and has a smaller amplitude than SST-I, SST-II and OSC as can be seen in Figure 5-3(d).

The PDF (Figure 5-3(e)) shows a Gaussian-like distribution that is spread out almost evenly at higher normalised differential pressure; it has the second-highest normalised differential pressure when compared to other flow regimes in the stable category. The PSD (Figure 5-3(f)) has multiple components spread throughout the frequency domain. It has two peaks with dominant frequencies, the major peak has a higher and stronger dominant frequency. This major peak occurs at a frequency higher than that of bubble flow.

5.3.3.3 Churn Flow

This flow is observed at a high gas flow rate and low liquid flow rates. Churn flow exhibits smaller amplitudes and fluctuates more frequently than the slug flow as shown in Figure 5-3(g).

The PDF (Figure 5-3(h)) also exhibits a Gaussian-like distribution that is spread out almost evenly; however, it occurs at lower normalised differential pressure when compared to slug flow. The PSD (Figure 5-3(i)) has multiple high and low peaks spread throughout the frequency domain. It has multiple peaks with dominant frequencies.

5.3.3.4 Annular Flow

This flow manifest at a higher gas flow rate and low liquid flow rates. As shown in Figure 5-3(j), annular flow exhibits very small amplitudes and fluctuates at very high frequency.

The PDF (Figure 5-3(k)) shows a single peak with the lowest normalised differential pressure when compared to other flow regimes in the stable category. The PSD (Figure 5-3(l)) has two major peaks with dominant frequency and other smaller multiple components in the frequency domain. The largest peak occurs at a lower frequency and exhibits the strongest dominant frequency.

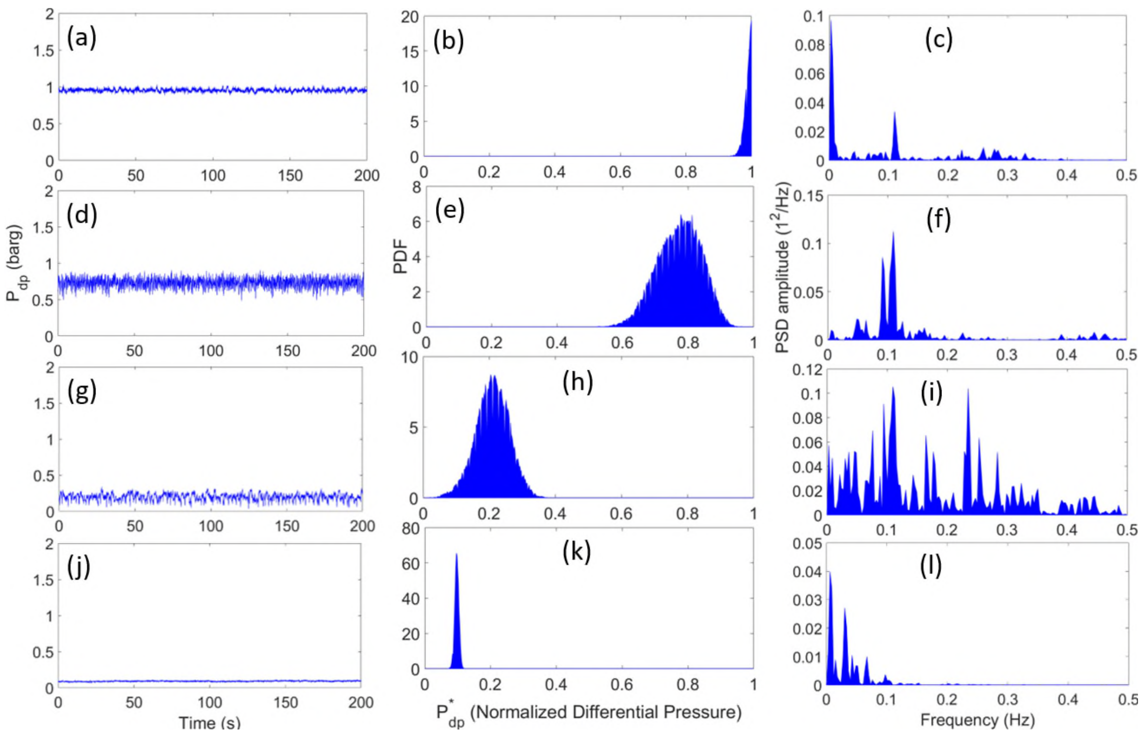

Figure 5-3 Differential pressure over the riser (time series), PDF and PSD of the differential pressure over the riser during different types of stable flow (a,b,c) $V_{sl} = 1.73$ m/s, $V_{sg} = 0.36$ m/s (Bubble flow); (d,e,f) $V_{sl} = 2.55$m/s, $V_{sg} = 2.44$ m/s (Slug flow); (g,h,i) $V_{sl} = 0.25$ m/s, $V_{sg} = 13.84$ m/s (Churn flow); (j,k,l) $V_{sl} = 0.05$ m/s, $V_{sg} = 18.88$ m/s (Annular flow)

5.3.4 Flow regime map

The experimental data were used to generate a flow regime map in order to obtain an overview of the different flow pattern within the test matrix. The flow regime map for the plain S-shape pipeline-riser is shown in Figure 5-4. This figure shows ten flow patterns which are present in the test matrix. These were further broadly classified as severe slugging, transitional severe slugging and stable flow.

The test points within the test matrix were converted to their respective superficial liquid and gas velocities and were used as coordinates to indicate the distribution of each flow pattern. The flow pattern regions obtained in this study are consistent with Tin's (1991) steep S-shape riser flow pattern map as shown in Figure 5-4. However, the discrepancies observed during the comparisons with experimental data may be as a result of the difference in test loops. In his study, Tin (1991) categorised his flow pattern map as severe slugging 1, severe slugging 1b, transition, oscillation and stable flow.

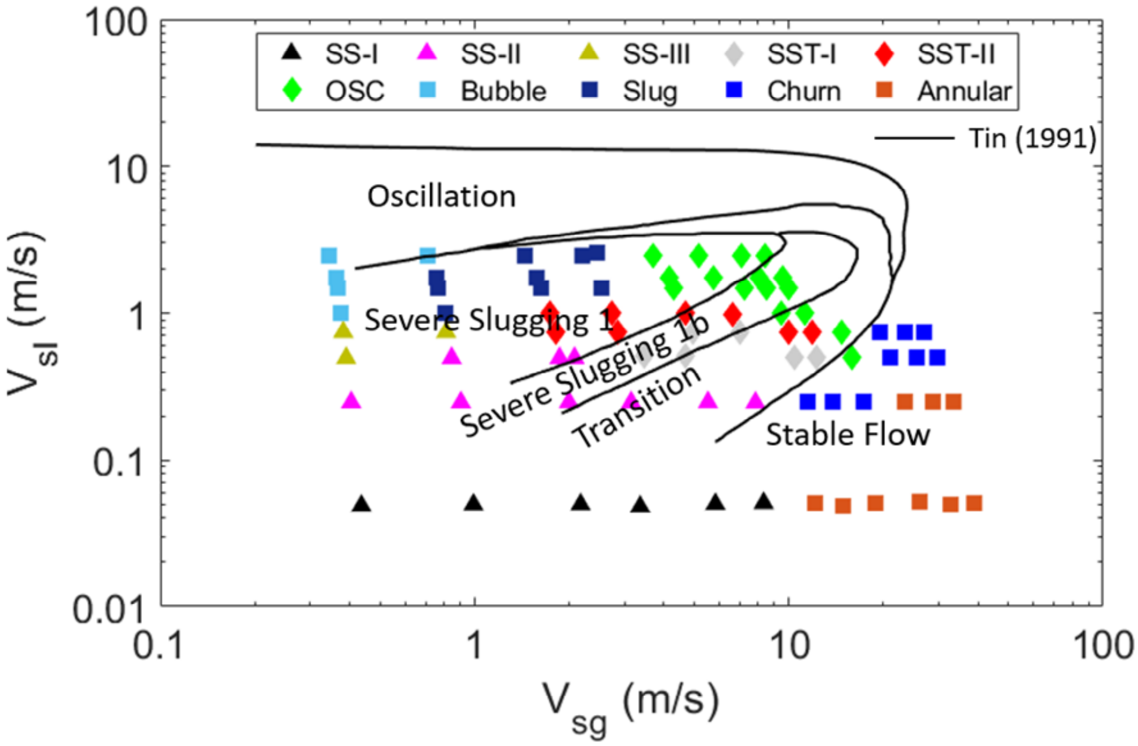

Figure 5-4 Flow regime map for the plain riser compared with steep S-shape riser flow regime map by Tin (1991)

5.4 Chapter Summary

This chapter covers flow regimes characterisation in an S-shape pipeline-riser system. Differential pressure measurements across the entire length of the riser were used to characterise the flow regime in the riser. The main contributions of this chapter are summarised as follows:

1. Flow regimes have been classified into ten categories viz.: severe slug type I (SS-I), severe slug type II (SS-II), severe slug type III (SS-III), transitional severe slug type I (SST-I), transitional severe slug type II (SST-II), oscillation flow (OSC), bubble flow, slug flow, churn flow and annular flow.
2. PDF and PSD were used to distinguish the flow regimes objectively. This aided the proper development of the flow regime map
3. Previous studies of flow regime characterisation have not examined the entire length of the S-shape riser. Most studies have been focused on using either riser base pressure or using part of the differential measurements across different sections of the riser (lower limb, downcomer and upper limb). However, this study has used pressure measurements across the entire riser to characterise flow regime.

In conclusion, flow regimes have been identified and classified in an S-shape riser. The understanding provided by this study will lead to proper flow regimes identification. Thus, Process Control Engineers can find useful information for implementing severe slugging control measure. Also, this will provide valuable information for Design Engineers in designing slug catchers and separators.

6 SEVERE SLUGGING MITIGATION IN AN S-SHAPE PIPELINE-RISER SYSTEM WITH A VENTURI FOR MAXIMISED PRODUCTION AND RECOVERY

Chapter Highlights

1. A novel passive severe slugging mitigation method is developed
2. Venturi is viable and effective in mitigating severe slugging
3. The Venturi is successfully applied to mitigate severe slugging through experimental study
4. Experimental results show that the Venturi can improve severe slug mitigation performance

6.1 Introduction

Severe slugging is a well-known flow assurance problem encountered during oil and gas extraction processes. It is a cyclic flow regime that causes intermittent delivery of oil and gas at the topside or processing facilities and may even cause platform trips and plant shutdown. More frequently, the large cyclic oscillations in the flow cause unwanted flaring and reduce the operating capacity of the separation and compression unit (Havre et al., 2000).

Schmidt et al. (1985) and McGuinness and Cooke (1993) stated that one of the necessary condition for severe slugging to occur in a pipeline-riser system is that multiphase flow in the riser must be unstable. Consequently, if a technique can stabilise the flow in the riser, severe slugging can be mitigated. This chapter presents a novel passive mitigation method for severe slugging in pipeline-riser systems. This novel technique is used to stabilise flow in the riser.

This study describes the use of a Venturi coupled to the S-shape pipeline-riser system upstream of the topside two-phase separator for severe slug mitigation and production maximisation. A series of experiments were conducted on the 2″ pipeline-riser system with and without the Venturi as described in Chapter 3.

The stabilising performance of this concept on severe slugging attenuation is shown using, flow regime maps, pressure trend graph (time series), stability maps, severe slug envelopes and stability curves. In addition, the production increase or maximisation capability of the technique is shown with Hopf bifurcation maps. Three out of the four proofs of concepts (Flow regime identification, Hopf bifurcation and Gas perturbation) listed in Chapter 1 were used in this chapter to show the effectiveness of this technique.

This chapter seeks to address the aim, the first and second objectives of this study stated in Chapter 1 (Section 1.3). Also, it aims to address the second and fourth gaps in research identified in Chapter 2 of this thesis. The chapter is organised as follows: Section 6.2 describes the Venturi and discusses the pressure recovery ability of the Venturi, and Section 6.3 presents the effects of Venturi on flow in a pipeline-riser system. Section 6.4 discusses the effects of Venturi on severe slugging and Section 6.5 presents the stability analysis of Venturi severe slug attenuation. Section 6.6 describes severe slug envelopes; Section 6.7 discusses the overall production benefit of the Venturi. Section 6.8 presents the impact of pressure on oil and gas production and Section 6.9 summarises the chapter.

6.2 Pressure Recovery of Venturi

Venturi are tubes with a gradual flowing area contraction (nozzle) followed by a gradual flowing area expansion (diffuser) which helps in accelerating fluids. The Venturi effect is the reduction in fluid pressure which occurs when a fluid flows through a narrow constricted section of a pipe. The reduction in pressure results in an increase in velocity which agrees with Bernoulli’s principle. It utilises both the principle of continuity as well as the principle of conservation of energy.

Figure 6-1 shows an orifice and the distribution of static pressure along the orifice. Similarly, Figure 6-2 shows a Venturi and the distribution of static pressure along the Venturi. Comparing Figures 6-1 and 6-2, it can be seen that Venturi produces less permanent pressure losses and high-pressure recovery due to the diffuser when compared to the orifice. The permanent head loss of an orifice is typically 60 % to 70 % of the differential pressure, whereas that of a Venturi is about 10 % of the differential pressure (Dryden,1982). Thus, Venturi conserves energy. The geometry of the Venturi may account for its low loss of energy.

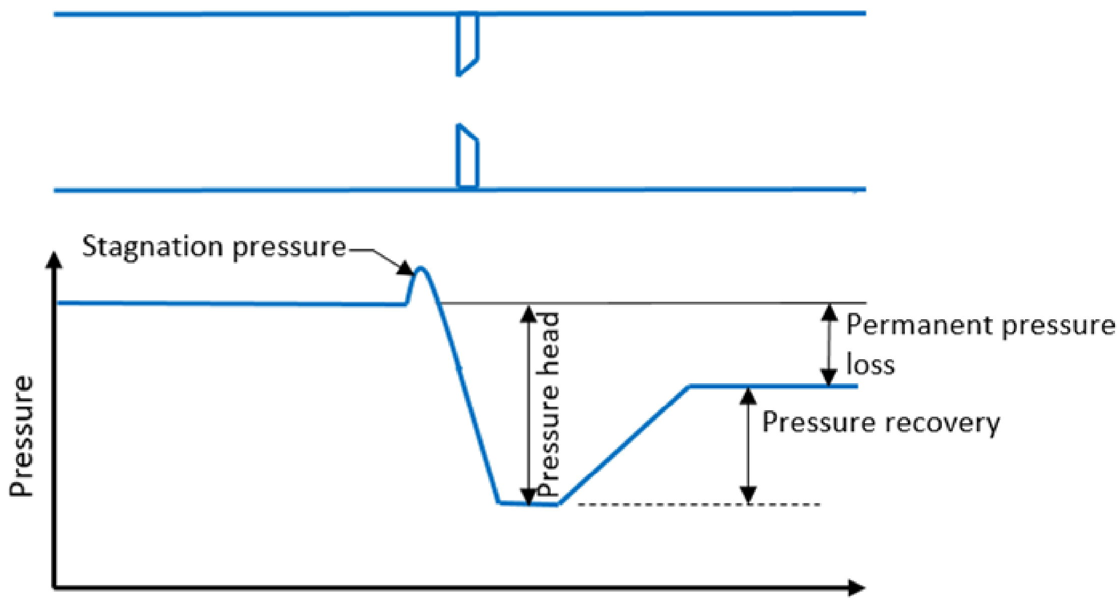

Figure 6-1 Schematic of an orifice and pressure profile along the central line

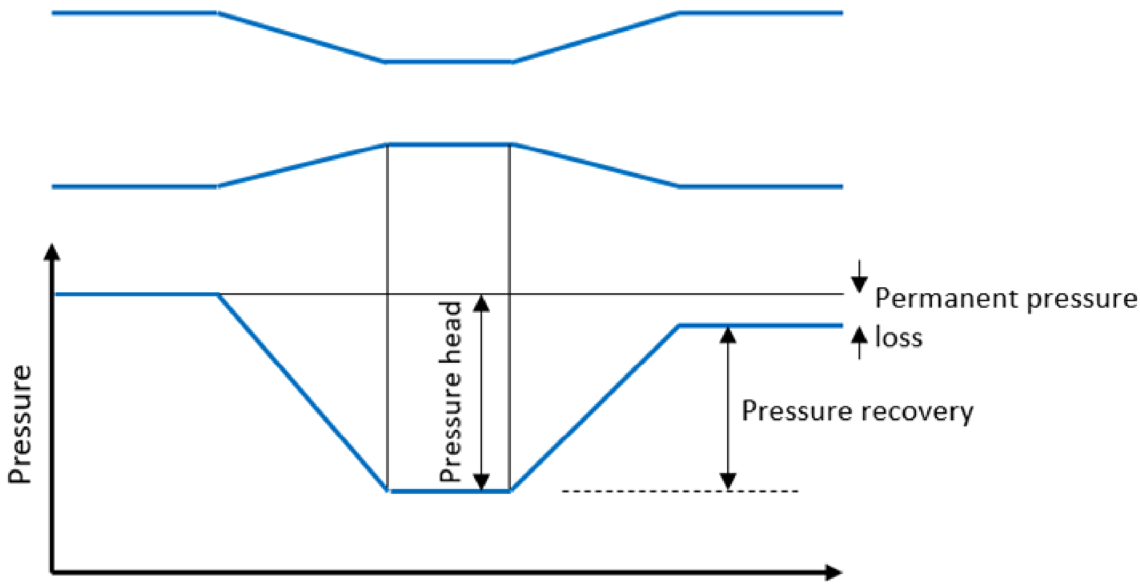

Figure 6-2 Schematic of a Venturi and pressure profile along the central line

6.3 Effects of Venturi on Flow in Pipeline-Riser Systems

The effects of the Venturi on the flow behaviour in pipeline-riser systems were investigated. Similar techniques used in developing the flow regime map for the plain pipeline-riser discussed in Chapter 5 were employed here to develop flow regime map for the plain riser with the Venturi applied. Figures 6-3 and 6-4 show the flow regime maps for the plain riser and the plain riser with the Venturi applied respectively.

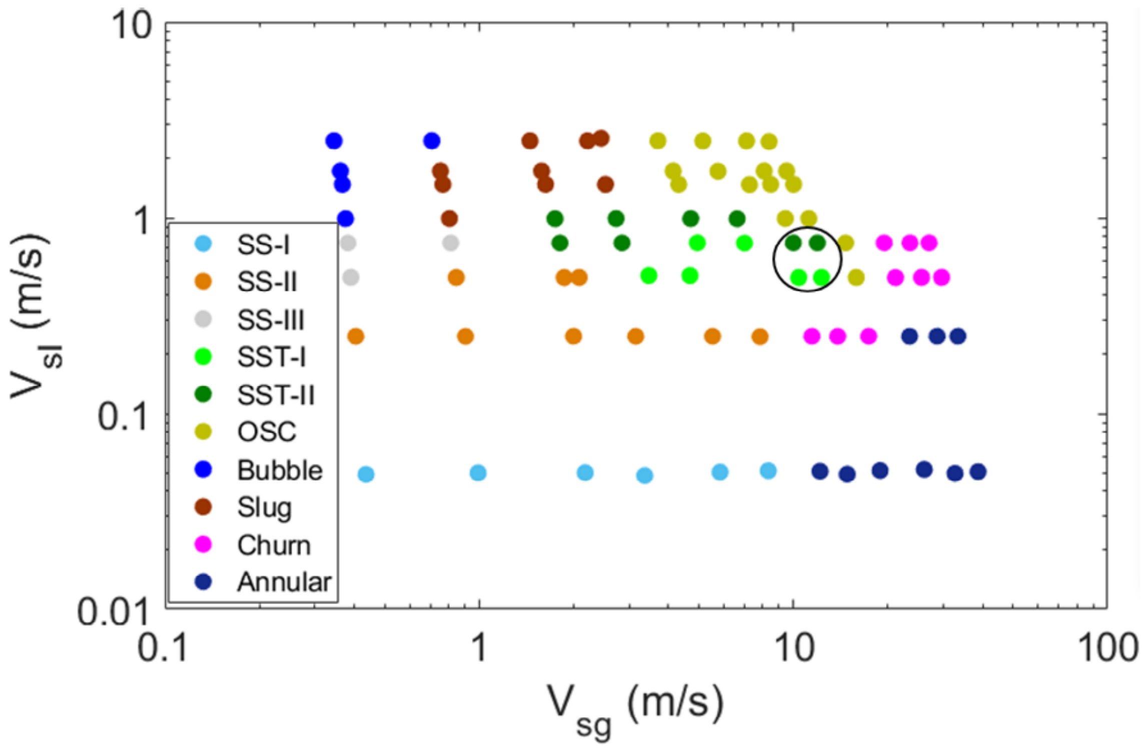

Figure 6-3 Flow regime map for the plain riser

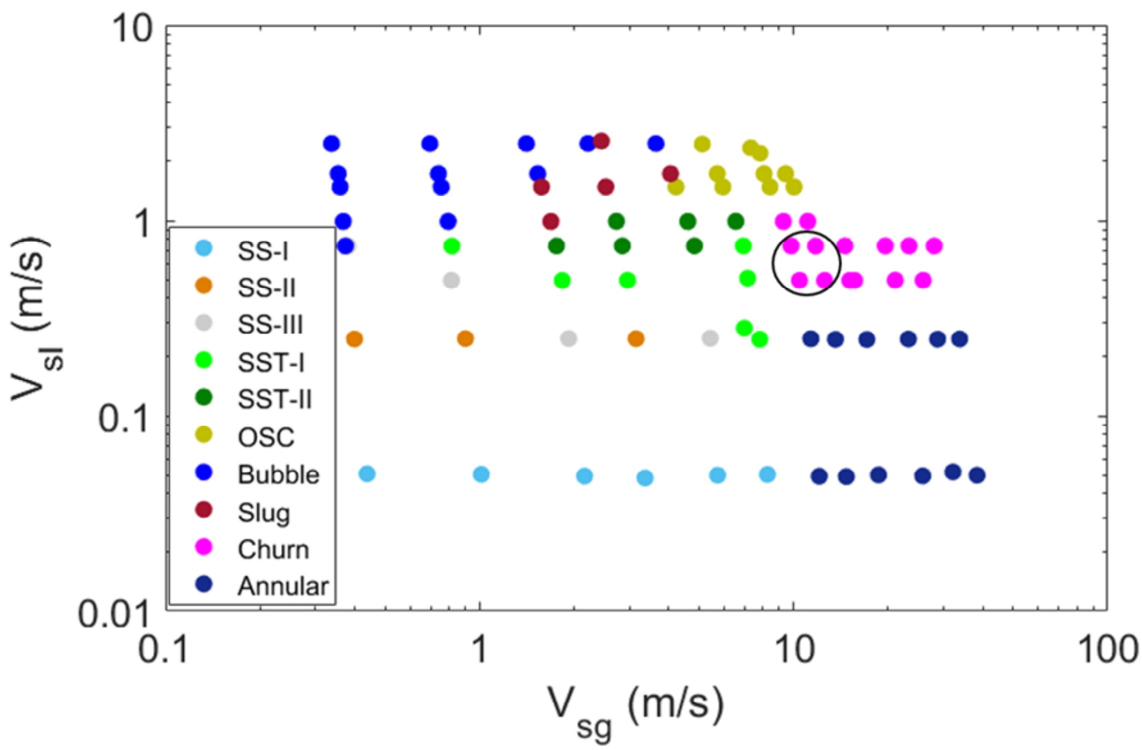

Figure 6-4 Flow regime map for the riser with the Venturi applied

From Figures 6-3 and 6-4 it can be seen that the severity of severe slugging and transitional severe slugging have been reduced as some test points have been converted from SS-I to SS-II, SS-II to SS-III, SST-I to SST-II and SST-II to OSC. In addition, some previously severe slugging and transitional severe slugging test points have been converted to stable ones. Also, some stable flow regimes have been converted to more stable ones. For example, the four data points circled in Figure 6-3 are two SST-1 and SST-II flow regime data points. However, with the Venturi applied to the riser they were both converted to churn flow as shown in Figure 6-3.

The gradual flowing area expansion (diverging section) of the Venturi helps in accelerating the two-phase flow in the pipeline-riser. Consequently, breaking down severe slugging, reducing its severity and in some instances converting them to stable flow. On the other hand, some stable flows were converted to more stable ones. In addition, Venturi produces less permanent pressure losses and high-pressure recovery; thus, it saves energy. These explain why the performance of the Venturi is better than that of the plain riser.

The Venturi reduced the severity of severe slugging in some test points. It also eliminated severe slugging in some test points, as we can see that some of these test points were converted to stable flow. This implies that severe slugging can be eliminated and the severity of severe slugging can be reduced by applying the Venturi to pipeline-riser systems. This practically translates to an improvement to the stability of the system, thus, enhancement of flow assurance.

6.4 Effects of Venturi on Severe Slugging

Pressure fluctuation in the riser has a chain reaction that could be felt upstream which would affect the bottom-hole pressure. The effectiveness of the Venturi, when applied to the pipeline-riser, was investigated and compared with the plain pipeline-riser.

Figure 6-5 compares the riser differential pressure for the plain riser and Venturi at $V_{sl} = 0.74$ m/s and $V_{sg} = 0.38$ m/s. It can be seen that severe slugging occurs with the plain riser. However, the fluctuation reduced drastically and the flow became stabilised when Venturi was coupled to the riser. Thus, severe slugging was eliminated.

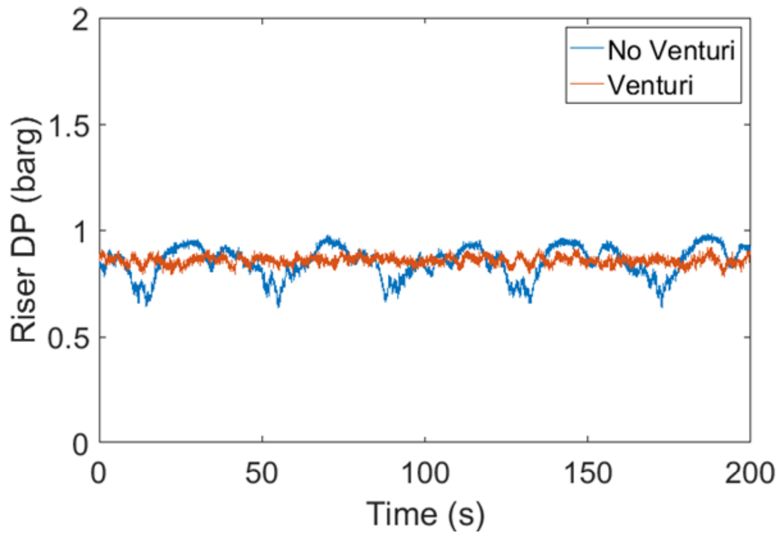

Figure 6-5 Riser differential pressure for the plain riser and the riser with the Venturi applied ($V_{sl} = 0.74$ m/s and $V_{sg} = 0.38$ m/s)

The standard deviations (SD) of the riser differential pressure for the plain riser and the Venturi were 0.0730 barg and 0.0197 barg respectively. The Venturi had the lowest SD. Thus, SD of the riser differential pressure reduced by 73 % when the SD associated with the Venturi was compared to that of the plain riser. The performance results are summarised in Table 6-1. Practically, these imply that the application of the Venturi to the top side of a pipeline-riser system may be an excellent alternative for severe slug elimination.

Table 6-1 Comparison of plain riser and Venturi with performance (Riser Differential Pressure)

Set-up	SD (barg)	Percentage Change (%)
Plain Riser	0.0730	73 % Reduction in of the riser differential pressure
Venturi	0.0197	

Figure 6-6 also compares the riser differential pressure for the plain riser and the Venturi at V_{sl} = 0.50 m/s and V_{sg} = 2.96 m/s. It can be seen that before Venturi was applied this particular test point was experiencing severe slugging (SS-II). However, with Venturi applied the severity was reduced and the flow was converted to transitional severe slug (SST-I) flow.

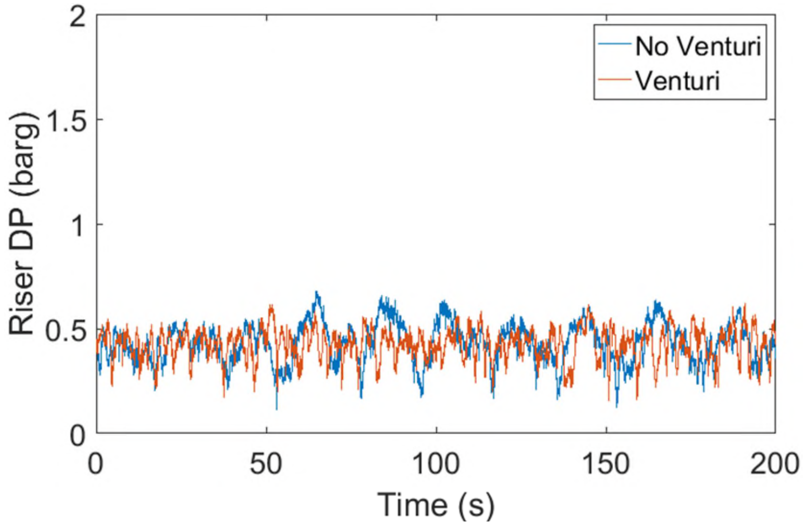

Figure 6-6 Riser differential pressure for the plain riser and the riser with the Venturi applied (V_{sl} = 0.50 m/s and V_{sg} = 2.96 m/s)

The standard deviations (SD) of the riser differential pressure for the plain riser and the Venturi were 0.095 barg and 0.075 barg respectively. The Venturi had the lowest SD. Thus, SD of the riser differential pressure reduced by 21 % when the SD associated with the Venturi was compared to that of the plain riser. The performance results are summarised in Table 6-2. This implies that the severity of severe slugging can be reduced by applying the Venturi to pipeline-riser systems.

Table 6-2 Comparison of plain riser and Venturi with performance (Riser Differential Pressure)

Set-up	SD (barg)	Percentage Change (%)
Plain Riser	0.095	21 % Reduction in SD of the riser differential pressure
Venturi	0.075	

6.5 Stability Analysis of the Venturi Severe Slug Attenuation

To further investigate the severe slug attenuation benefits of the Venturi, stability maps and stability curve were developed and used to study and determine the capability of the Venturi in stabilising the system.

6.5.1 Stability Maps

These maps were developed by grouping severe slugging and transitional severe slugging test points from the flow regime map and re-classifying them as severe slugging. The stable flow remains as it was previously defined in Section 5.3.3 in Chapter 5. Thus, the stability maps are divided into two regions: unstable (severe slugging) and stable (stable flow). Figures 6-7 and 6-8 show the stability maps for the plain riser and the riser with the Venturi applied respectively.

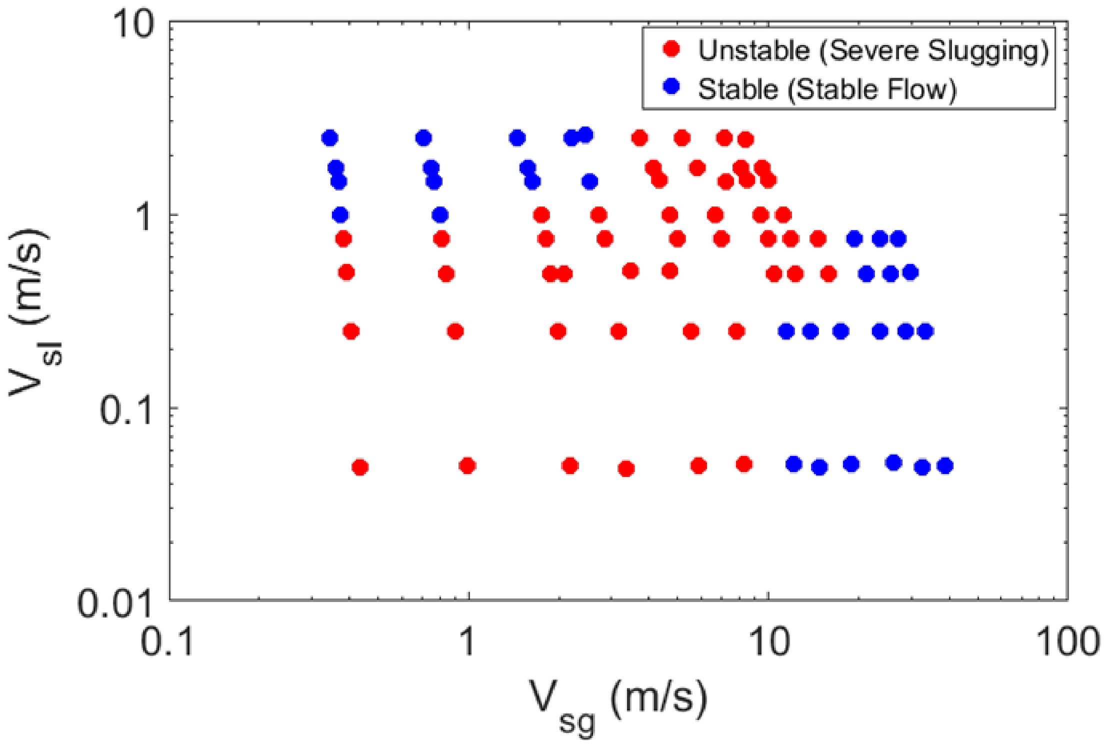

Figure 6-7 Stability map for the plain riser

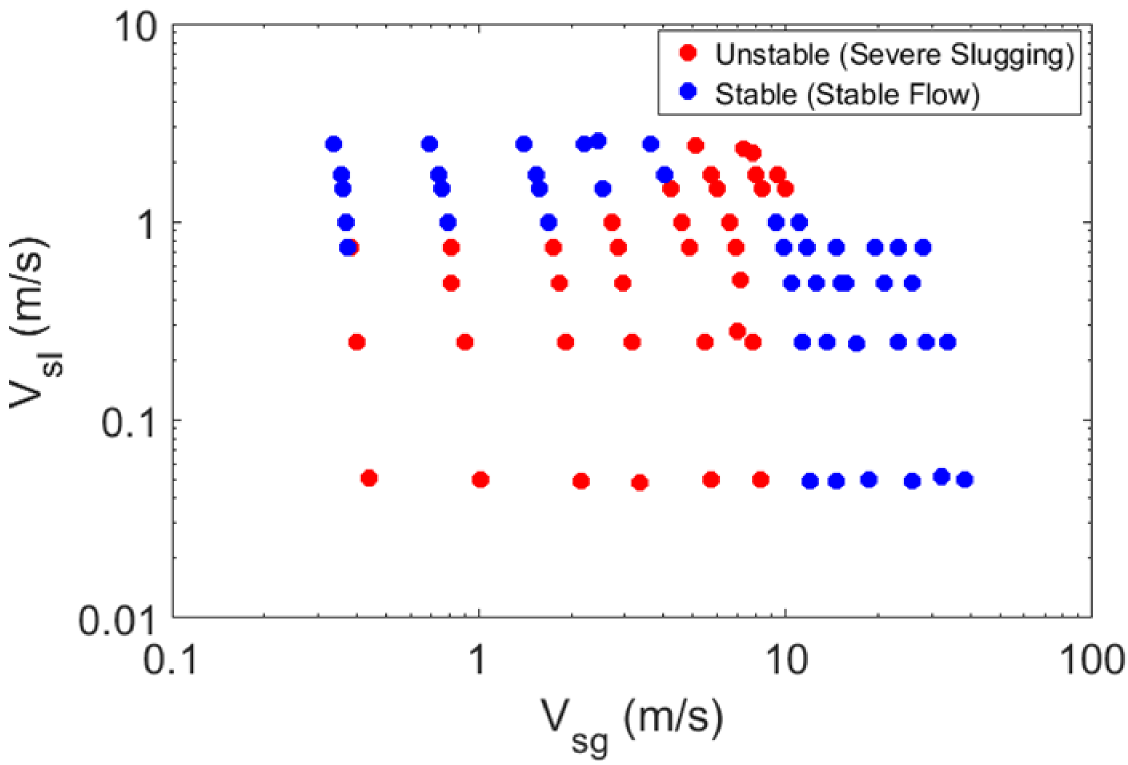

Figure 6-8 Stability map for the riser with Venturi applied

Comparing Figures 6-7 and 6-8, it can be seen that the plain riser has 48 unstable data points whereas with the Venturi applied to the riser the number of unstable data points reduced to 36. Thus, the application of the Venturi to the pipeline-riser has led to a 25 % reduction in the number of unstable data points and an increase in the stable operating region. This practically implies an improvement to the stability of the system, thus, enhancement of flow assurance.

6.5.2 Stability Curves

The instability caused by severe slugging is as a result of the change in geometry and compressibility of gas. Thus, an increment in gas flow rate could make a system gain or lose stability. Gas perturbation technique was used to develop a stability curve. Figure 6-9 shows the stability curve which displays the general relationship between the riser base pressure as a function of increasing gas flow rate, with a constant liquid flow rate.

From Figure 6-9, it can be seen that the riser base pressure decrease rapidly until a nearly constant value at a low gas flow rate for the plain riser and the Venturi. After some time, a minimum riser base pressure is attained, a further increase in gas flow rate resulted in an increase in the riser base pressure. The vertical lines are used to indicate where these minimum values occur for each case. The regions to the left and right of the minimum values represent the unstable flow regimes and stable flow regimes regions respectively. At low gas flow rate (below the minimum), any increment in the gas flow rate leads to an increase in frictional pressure loss that is less than the corresponding decrease in the hydrostatic pressure loss, and the riser base pressure decreases. In contrast, at higher gas rates (above the minimum), any increase in the gas rate leads to an increase in frictional pressure loss that is greater than the corresponding decrease in the hydrostatic pressure loss, and the riser base pressure increases. Hence, the unstable region results from the fact that any decrease in rate will lead to an increase in backpressure which drives a further decrease in rate (Ehinmowo and Cao, 2016).

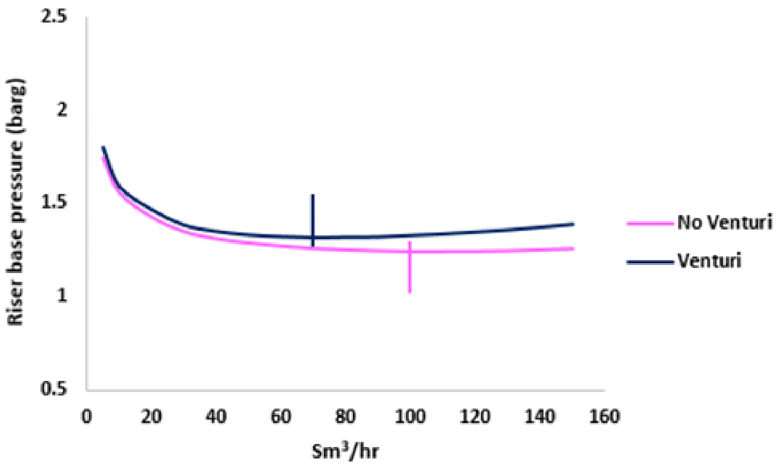

Figure 6-9 Stability curves for the plain riser and the riser with the Venturi

The performance of the pipeline-riser system with and with no Venturi was investigated for a constant water flow rate of 0.5 kg/s and increasing values of air flow rate. From Figure 6-9 it can be seen that with the Venturi applied to the pipeline-riser the system arrived at the stable operating point (minimum riser base pressure) at a lower gas flow rate and time than the plain riser. In addition, a lower amount of gas was required to achieve stability when compared to the plain riser. The Venturi system stabilised the flow with 70 Sm^3/h of air, whereas the plain riser could only stabilise the flow with 100 Sm^3/h of air. From the performance results summarised in Table 6-3, it can be observed that the Venturi has caused a 43 % reduction when the amount of gas required to stabilise flow in the case of the Venturi was compared to that of the plain riser. This practically translates to an improvement to the stability of the system, thus, enhancement of flow assurance.

Table 6-3 Comparison of plain riser and Venturi with performance (Stability Curve)

Set-up	Air (Sm^3/hr)	Percentage Change (%)
Plain Riser	100	43 % Reduction
Venturi	70	

6.6 Severe Slug Envelopes

The stability maps in Section 6.5.1 were combined and used to develop severe slugging envelopes. These envelopes were used as a yardstick to measure, demonstrate and compare the severe slug elimination performance of the pipeline-riser with the Venturi applied. The envelopes were created by tracing the outer severe slugging data points (stability boundaries) for the plain riser and the pipeline-riser with the Venturi applied.

It can be seen from Figure 6-10 that the severe slug envelope of the pipeline-riser system with the Venturi applied is smaller than that of the plain pipeline-riser. Thus, the application of Venturi has led to a reduction of the operating region of severe slugging within the test matrix. In addition, for some test points, severe slugging was eliminated and converted to stable ones. These test points would have required traditional choking to be converted to stable flow, which would require a reduction in choke valve opening. However, with the Venturi applied the choke valve will be fully (100 %) open at those test points. This practically implies that oil and gas production may be increased.

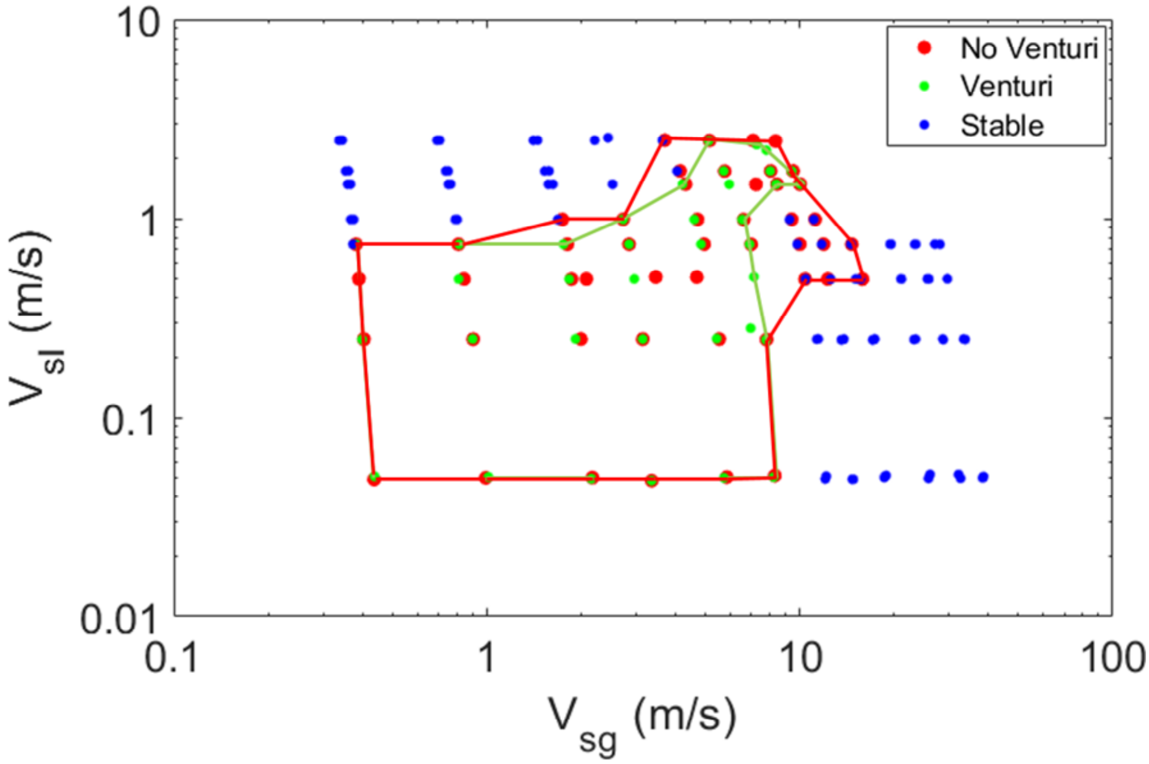

Figure 6-10 Severe slug envelopes for the plain riser with and riser with the Venturi applied

6.7 Oil and Gas Production Benefit of the Venturi

The increase in brownfields has made the need for better approaches to the enhancement of oil recovery to become vital. As a reservoir matures the well pressure declines, the differential pressure between the topside pressure and the well decreases. Consequently, the rate of production decreases. This imposes instability on the pipeline-riser system such that further action is required to stabilise the system. The main aim of any severe slug control technique is to mitigate severe slugging and stabilise the system. However, there is a need for such a technique to stabilise flow and increase production at the same time (Ogazi, 2011). Having shown the stabilising effects of the Venturi on the pipeline-riser system in Sections 6.3 - 6.5, the next objective is to investigate its overall production increase capability. Thus, the parameter variation (traditional choking) technique and Hopf bifurcation technique were combined and used to investigate the stability and production increase performance of the pipeline-riser with the Venturi applied. The study was conducted on a severe slugging condition of V_{sl} = 0.25 m/s and V_{sg} = 0.37 m/s for water and air respectively.

Figure 6-13 shows the riser base pressure bifurcation map for the severe slugging condition investigated for the plain riser. It was observed that as the pipeline-riser system is choked by reducing the valve opening the backpressure increases, the severity of slugging was reduced, and the flow condition changed from severe slugging to stable flow. Bifurcation (critical valve opening) occurred at 18 % valve opening and average riser base pressure value of 2.8 barg.

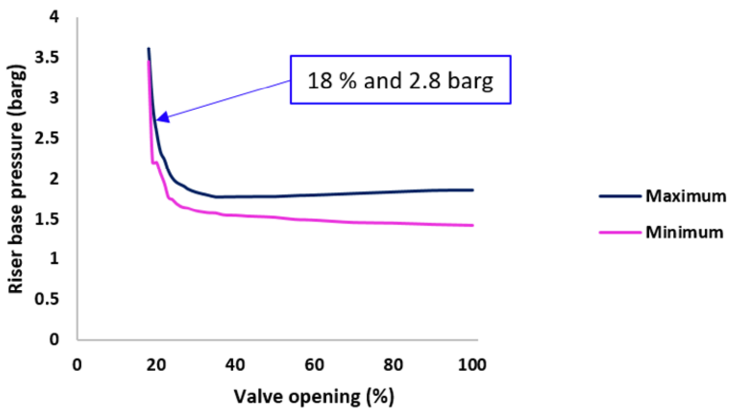

Figure 6-11 Riser base bifurcation map for the plain riser (V_{sl} = 0.25 m/s and V_{sg} = 0.37 m/s)

Figure 6-11 shows the riser base pressure bifurcation map for the severe slugging condition investigated for the Venturi. Similarly, it was observed that as the pipeline-riser system is choked by reducing the valve opening, the backpressure increases, the severity of slugging is reduced and the flow condition changed from severe slugging to stable flow. However, bifurcation occurred at a larger valve opening of 21 % and a lower average riser base pressure value of 2.5 barg.

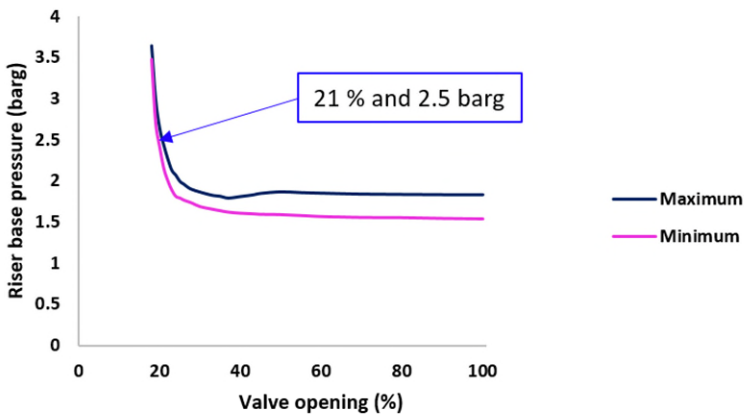

Figure 6-12 Riser base bifurcation map for the riser with the Venturi applied (V_{sl} = 0.25 m/s and V_{sg} = 0.37 m/s)

Comparing Figures 6-11 and 6-12, there was a 17 % increase in valve opening when the percentage of valve opening associated with the Venturi was compared to that of the plain riser. In addition, there was an 11 % reduction in the riser base pressure when the riser base pressure associated with the Venturi was compared to that of the plain riser. The performance results are summarised in Table 6-4, where it can be observed that the Venturi stabilised the system at a larger valve opening and lower rise base pressure. This reduction in backpressure achieved by coupling the Venturi to the pipeline-riser system leads to increase in production. These results suggest that the operational life of a reservoir might be extended by adopting this technique. Also, it practically implies an increase in oil and gas production.

The low loss of energy is due to the gradual change in geometry of the Venturi. This may account for its ability to achieve stability at a lower riser base pressure.

Table 6-4 Comparison of plain riser and Venturi performance (Bifurcation Map)

Set-up	Valve Opening (%)	Percentage Change (%)	Riser Base Pressure (barg)	Percentage Change (%)
Plain Riser	18	17 % increase in valve opening	2.8	11 % reduction in pressure
Venturi	21		2.5	

6.8 Impact of Pressure on Oil and Gas Production

In Section 6.7, the ability of the Venturi to stabilise the system at larger valve opening and lower pressure was shown. Thus, it is vital to analyse the impact of this low pressure on the oil production system. We have already established that a large valve opening translates to higher flow capacity and lower pressure drop and vice versa. The bottom-hole pressure is the sum of all the pressure drop downstream acting on the bottom-hole. Thus, any changes in the pressure of any section along the downstream have a chain reaction effect upstream, which directly impacts the bottom-hole pressure. The pipeline-riser system is part of the downstream production system; hence, it may contribute significantly to the bottom-hole pressure. Therefore, for increased oil and gas production, it is essential to have a large valve opening and lower pressure as shown in Section 6.7.

The dependence of production on pressure can be analysed by using pressure and production relationship from a linear well which can be shown mathematically using Darcy's law as given by (Abou-Kassem et al., 2006; Ogazi, 2011):

$$q = B(P_r - P_{bh}) \tag{6-1}$$

where q is the well production rate, B is the productivity index, P_r is the reservoir pressure P_{bh} is the well bottom-hole pressure and the pressure drop across the system is given by the expression $(P_r - P_{bh})$.

The relationship in Equation 6-1 implies that the well production rate is directly proportional to the pressure drop across the system. Consequently, a reduction in bottom-hole pressure will lead to an increase in the production rate and vice versa. Thus, to have maximum production, the downstream pressure that contributes to the bottom-hole pressure must be kept low. The study in Section 6.7 showed that with Venturi applied to the pipeline-riser system; the riser base pressure was reduced. The riser base pressure is part of the downstream pressure. This reduction will trickle to the well bottom-hole pressure and will make it reduce further than the reservoir pressure. As a result, the production rate will increase and the operation life of a reservoir might be extended.

6.9 Chapter Summary

In this chapter, a novel method for severe slug flow mitigation has been developed. The severe slug attenuation potential of the Venturi and its ability to increase the overall production in the pipeline-riser system have been investigated. The performance of the Venturi on severe slugging has been presented in terms of flow regime maps, stability maps, stability curves, severe slug envelopes and Hopf bifurcation. Experimental evidence from the study shows that the Venturi may be an excellent alternative to other known methods for severe slug mitigation.

The main findings in this chapter are summarised as follows:

1. The pipeline-riser system can be stabilised with the application of a Venturi
2. Venturi is effective in mitigating severe slugging
3. The application of the Venturi to the pipeline-riser system breaks down severe slugging and stabilises the system

4. It has been shown that with the Venturi applied to the pipeline-riser, the system arrived at the stable operating point (minimum riser base pressure) at a lower gas flow rate and time than the plain riser. Thus, the Venturi reduces that amount of gas required to stabilise the pipeline riser system

5. Venturi reduced the severity of severe slugging in a pipeline-riser system in some test points; thus, a Venturi can be used to reduce the severity of slugging in a pipeline-riser system

6. Venturi completely eliminate severe slugging in some test point within the test matrix; thus, a Venturi can be used to eliminate severe slugging in a pipeline-riser system

7. Severe slug operating region can be reduced by applying a Venturi to the pipeline-riser system

8. A Venturi coupled to a pipeline-riser system can stabilise flow at a larger valve opening and a lower pressure when compared to the plain pipeline-riser. This practically implies an increase in oil and gas production.

Venturi is a cheaper and viable severe slugging mitigation technique when compared to other methods that require expensive installation and maintenance, which will significantly increase CAPEX and OPEX. Its deployment at the topside is an additional advantage when compared with other methods that require subsea installation.

The combination of Venturi and manual choking imposes lower backpressure on the pipeline-riser system at the open-loop unstable operating point when compared to the high backpressure imposed by manual choking method alone. This reduction in backpressure achieved by applying Venturi to the pipeline-riser system leads to an increase in production. This result suggests that the operational life of a reservoir might be extended by adopting this technique. Thus, oil recovery in brownfields and flow assurance would be enhanced.

7 SEVERE SLUGGING MITIGATION IN AN S-SHAPE PIPELINE-RISER SYSTEM WITH INJECTABLE VENTURI FOR STABILISED, INCREASED PRODUCTION AND RECOVERY

Chapter Highlights

1. Development of a new flow regulation device, the injectable Venturi
2. The injectable Venturi extents the operation regime of conventional Venturi to make its flow characteristics adjustable during real-time operation
3. The newly invented injectable Venturi is successfully applied to mitigate severe slugging through experimental study
4. Experimental results show injectable Venturi can improve severe slug mitigation performance
5. Development of a novel active severe slugging mitigation method

7.1 Introduction

Severe slugging is a cyclic flow regime that causes pressure and flow oscillations which leads to intermittent delivery of liquid (oil and water) and gas to processing facilities during hydrocarbon extraction and transportation. Severe slugging is problematic for oil production systems because it leads to separator flooding, production reduction, platform trips and plant shutdown. These results in major profit losses for the oil and gas companies. Therefore, there is a need to handle severe slugs more efficiently. Thus, it is important to develop effective and efficient methods to mitigate or prevent such flow behaviour.

Gas injection or external gas lifting has been studied and used in the oil and gas industry over the years. Hill (1989,1990) reported from his study that gas lift helps in the attenuation of slugging; enables more continuous production, and

also helps to ensure smooth start-up of a pipe system that has been shut down. The main weaknesses of this technique, however, is the large amount of gas required to achieve stabilisation and the additional cost associated with the need for a compressor. In addition, some operators have avoided this method due to the lack of injection capabilities. Nevertheless, the recent changes in the oil and gas sector have made gas injection favourable. One of them is the “No flaring” environmental policy which enforces the availability of gas compression facilities to all new development for export or re-injection of gas.

This chapter presents a novel severe slugging mitigation technique which can stabilise and increase the overall production. It describes the use of an injectable Venturi coupled to the S-shape pipeline-riser system upstream of the topside test separator for severe slug mitigation, increase in production and enhance recovery of oil and gas. The availability of compressors or gas for injection would not be a challenge due to the No flaring policy. To ascertain the capability of the injectable Venturi in mitigating severe slugging and increasing production simultaneously, experiments were also carried out with the injectable Venturi with no gas injection.

A series of experiments were conducted on the 2″ pipeline-riser system with the plain riser, riser with injectable Venturi with no gas and with gas injection applied as described in Chapter 3. The design of the injectable Venturi can be found in Section 3.3 in Chapter 3. Sensitivity studies were implemented to determine the most efficient and effective amount of gas to be injected into the throat of the injectable Venturi. The gas was injected at 50 m^3/hr. This is the maximum gas injection rate allowable for the injectable Venturi due to safety concerns.

The ultimate aim of mitigating severe slugging is to achieve flow assurance, thus, a robust and effective severe slug mitigation technique that would be able to stabilise the system and increase production at the same time is desirable.

This chapter seeks to address the aim, the first and second objectives of this study stated in Chapter 1 (Section 1.3). Also, it aims to address the second and fifth gaps in research identified in Chapter 2 of this thesis. The remainder of this chapter is organised as follows: Section 7.2 presents the effects of the injectable Venturi on flow behaviour in pipeline-riser systems, and Section 7.3 describes the effects of the injectable Venturi on severe slug flow regime. Section 7.4 presents the stability analysis of Venturi severe slug attenuation, and Section 7.5 discusses severe slug envelope. Section 7.6 presents the production benefit of the injectable Venturi, and Section 7.7 discusses the effects of pressure on production, while Section 7.8 concludes the chapter.

7.2 Effects of Injectable Venturi on Flow in Pipeline-Riser Systems

The effects of the injectable Venturi on the flow behaviour in pipeline-riser systems were investigated. Similar techniques used in developing the flow regime map for the plain pipeline-riser discussed in Chapter 5 were employed here to develop flow regime map for the plain riser, the injectable Venturi with and with no gas injection applied. Figures 7-1, 7-2 and 7-3 show the flow regime maps for the plain riser, the injectable Venturi with no and with gas injection applied respectively.

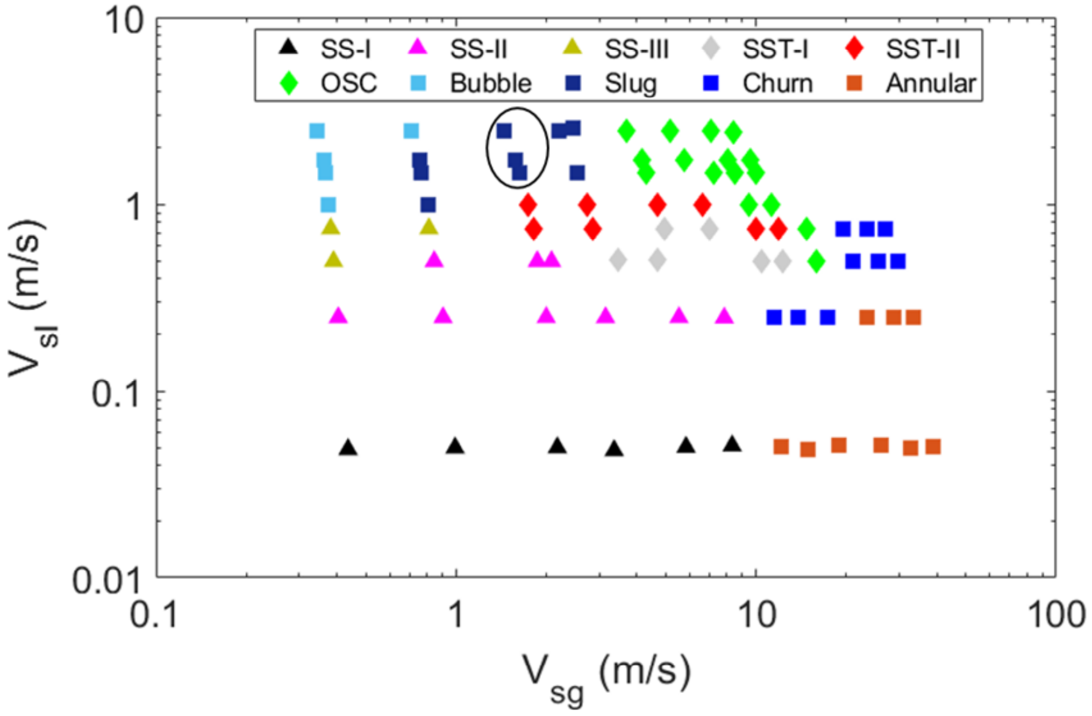

Figure 7-1 Flow regime map for the plain riser

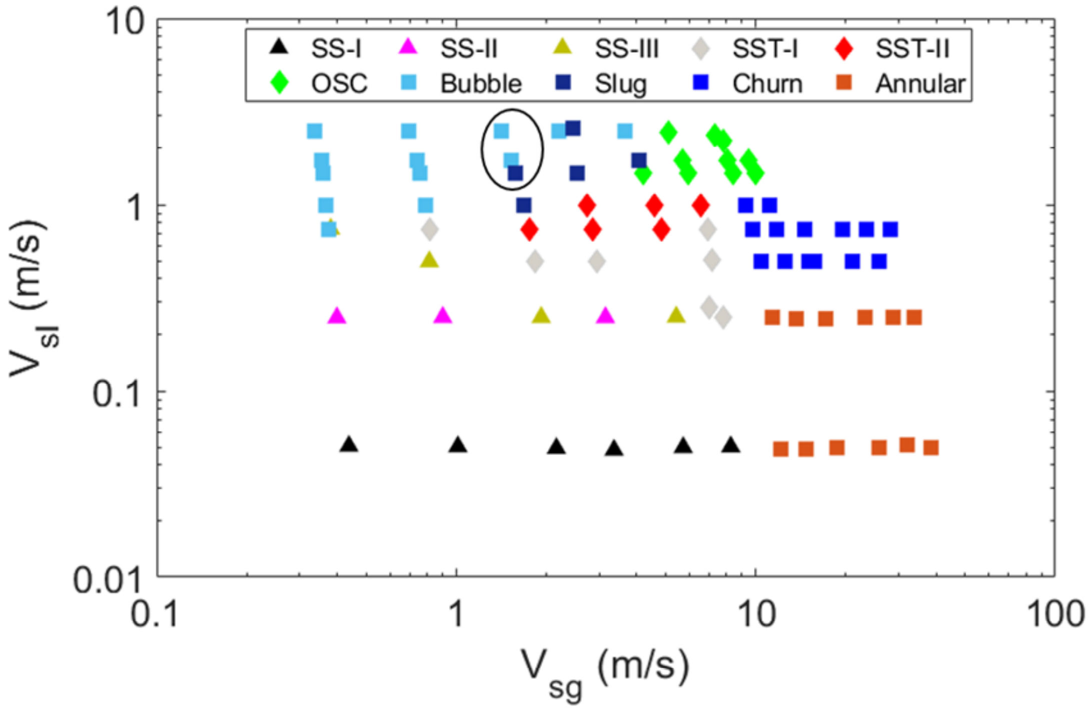

Figure 7-2 Flow regime map for the riser with injectable Venturi with no gas injection applied

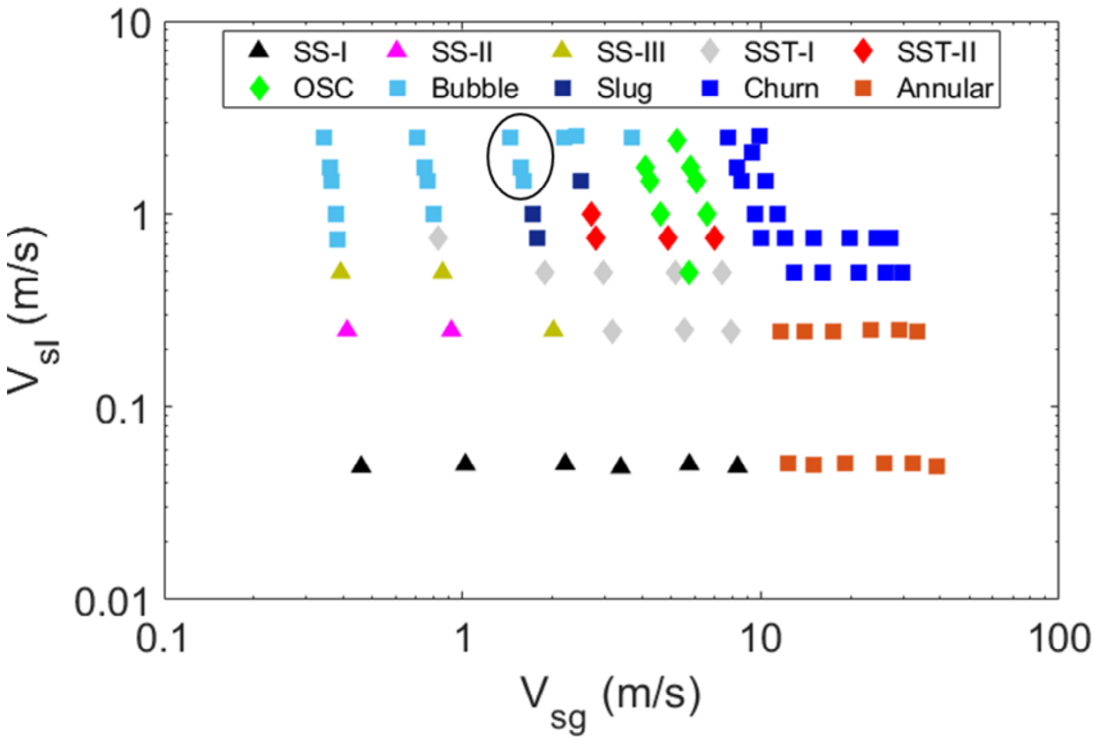

Figure 7-3 Flow pattern map for the riser with injectable Venturi with gas injection applied

Comparing Figures 7-1, 7-2 and 7-3 it can be seen that previously severe slugging and transitional severe slugging test points have been converted to stable ones. In addition, the severity of severe slugging and transitional severe slugging have been reduced as some test points have been converted from SS-I to SS-II, SS-II to SS-III, SST-I to SST-II and SST-II to OSC. Furthermore, some stable flow regimes have been converted to more stable ones. For example, the data points circled in Figure 7-1 are all slug flow regime data points. However, with the injectable Venturi with no gas injection applied to the riser two out of the three slug flow data points converted to bubble flow as shown in Figure 7-2. Also, with the injectable Venturi with gas injection applied to the riser all three slug flows were converted to bubble flows as can be seen in Figure 7-3.

Venturi produces less permanent pressure losses and high-pressure recovery; hence, it saves energy. The gradual flowing area expansion (diverging section) of the Venturi helps in accelerating the two-phase flow in the pipeline-riser. Thus, breaking down severe slugging, reducing its severity and in some instances converting them to stable flow. On the other hand, some stable flows were converted to more stable ones. These explain why the performance of the injectable Venturi with no gas injection is better than that of the plain riser.

However, the injectable Venturi with gas injection map (Figure 7-3) gave a better performance in terms of improving the stability in the pipeline-riser since it enhances the performance of the Venturi (injectable Venturi with no gas injection). Thus, the application of the injectable Venturi with and with no gas injection reduced the severity of severe slugging in some test points. It also eliminated severe slugging in some test points, as we can see that some of these test points were converted to stable flow. However, the injectable Venturi with gas injection had the best performance when compared to the injectable Venturi with no gas injection. This implies that severe slugging can be eliminated and the severity of severe slugging can be reduced by applying injectable Venturi to pipeline-riser systems. This practically translates to an improvement to the stability of the system, thus, enhancement of flow assurance.

7.3 Effects of Injectable Venturi on Severe Slug Flow Regime

The riser differential pressure is majorly induced by the hydrostatic pressure of the liquid column in the riser during severe slugging (Xing et al., 2013a). Pressure fluctuation in the riser has a chain reaction that could be felt upstream which would affect the bottom-hole pressure. Thus, this could lead to low production and poor recovery. The effectiveness of the injectable Venturi (with gas injection), when applied to the pipeline-riser, was investigated and compared with the plain pipeline-riser and the injectable Venturi without injection.

Figure 7-4 compares the riser differential pressure for the plain riser and the injectable Venturi with and with no injection at $V_{sl} = 0.25$ m/s and $V_{sg} = 0.41$ m/s. It can be seen that severe slugging (cyclic fluctuations) occurs with the plain riser and the injectable Venturi with no injection. The plain riser is the most unstable, followed by the injectable Venturi with no injection. However, the cyclic fluctuation was eliminated and the flow became stabilised (random fluctuations) when gas was injected into the injectable Venturi.

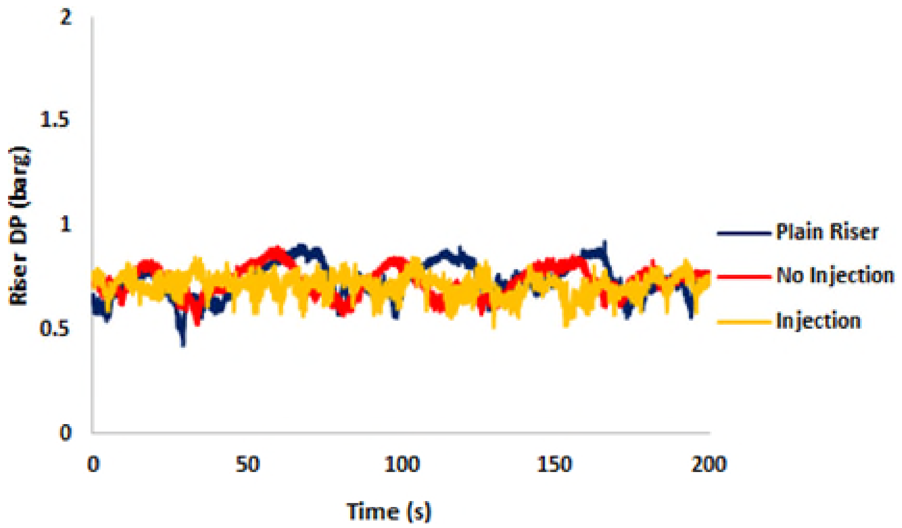

Figure 7-4 Differential pressure over the riser (time series) for the plain riser, injectable Venturi with and with no injection applied (V_{sl} = 0.25 m/s and V_{sg} = 0.41 m/s)

The standard deviations (SD) of the riser differential pressure associated with the plain riser, injectable Venturi with no injection and with injection were 0.083 barg, 0.067 barg and 0.049 barg respectively. The injectable Venturi with injection had the lowest SD. Thus, the SD of the riser differential pressure reduced by 41 % when the SD associated with the injectable Venturi with injection was compared to that of the plain riser. Also, the SD of the riser differential pressure reduced by 19 % when the SD associated with the injectable Venturi with no injection was compared to that of plain riser.

Similarly, the SD of the riser differential pressure reduced by 27 % when the SD associated with the injectable Venturi with injection was compared to that of injectable Venturi with no injection. This shows that the performance of the injectable Venturi is not entirely due to the Venturi itself, but due to the gas injection. The performance results are summarised in Tables 7-1, 7-2 and 7-3. Practically, these imply that the application of injectable Venturi with gas injection to the top side of a pipeline-riser system may be an excellent alternative for severe slug mitigation.

Table 7-1 Comparison of plain riser and injectable Venturi with no injection performance (Riser Differential Pressure)

Set-up	SD (barg)	Percentage Change (%)
Plain Riser	0.083	19 % Reduction in SD of the riser differential pressure
Injectable Venturi (no injection)	0.067	

Table 7-2 Comparison of injectable Venturi with no injection and injectable Venturi with injection performance (Riser Differential Pressure)

Set-up	SD (barg)	Percentage Change (%)
Injectable Venturi with no injection	0.067	27 % Reduction in SD of the riser differential pressure
Injectable Venturi with injection	0.049	

Table 7-3 Comparison of plain riser and injectable Venturi with injection performance (Riser Differential Pressure)

Set-up	SD (barg)	Percentage Change (%)
Plain Riser	0.083	41 % Reduction in SD of the riser differential pressure
Injectable Venturi with injection	0.049	

7.4 Stability Analysis of Venturi Severe Slug Attenuation

Stability maps and stability curves were generated to determine the capability of the injectable Venturi in stabilising the system and further to demonstrate the severe slug attenuation benefits of the injectable Venturi coupled to the pipeline-riser system.

7.4.1 Stability Maps

Stability maps were generated by grouping severe slugging and transitional severe slugging from the flow regime map and re-categorising them as severe slugging. The stable flow remains as it was previously defined in Section 5.3.3 in Chapter 5. Thus, the stability maps are divided into two regions: unstable (severe slugging) and stable (stable flow). Figures 7-5, 7-6 and 7-7 show the stability maps for the plain pipeline-riser, with the injectable Venturi with no gas injection and with gas injection applied respectively.

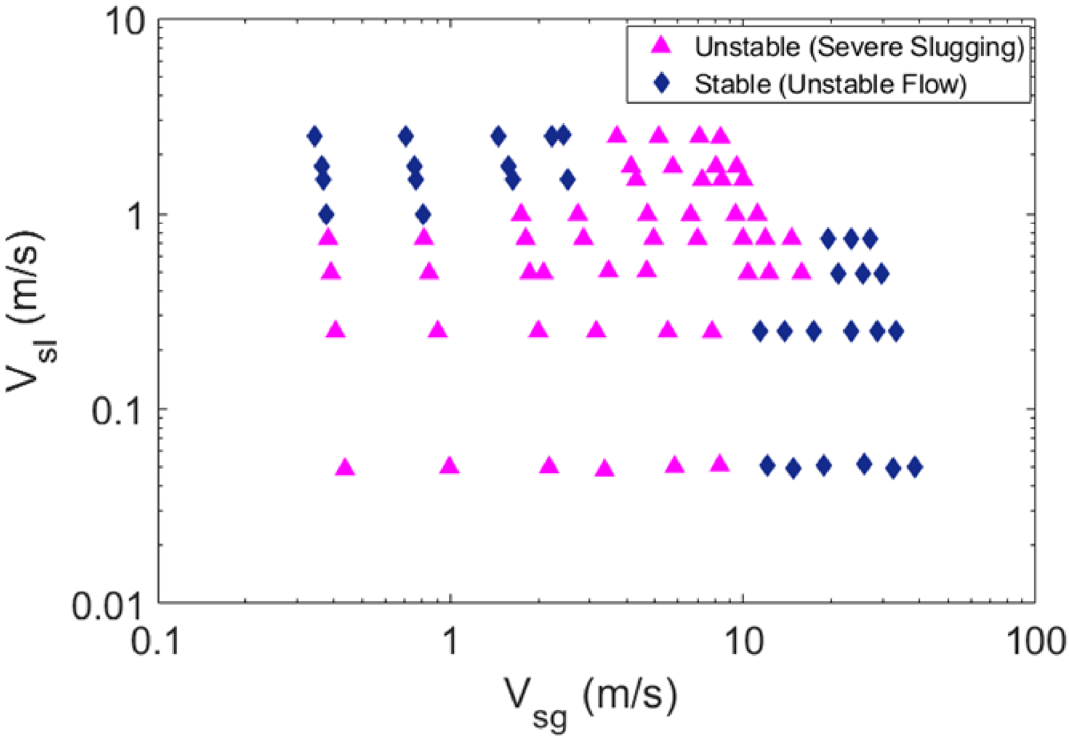

Figure 7-5 Stability map for the plain riser

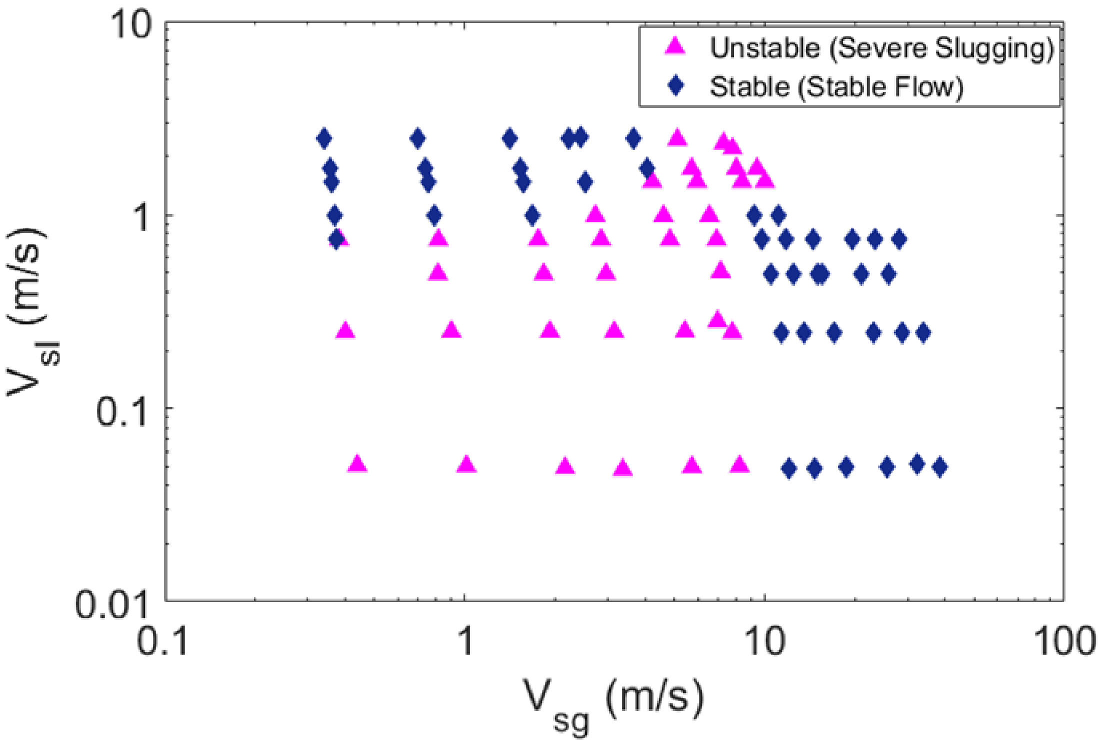

Figure 7-6 Stability map for the riser with injectable Venturi with no gas injection applied

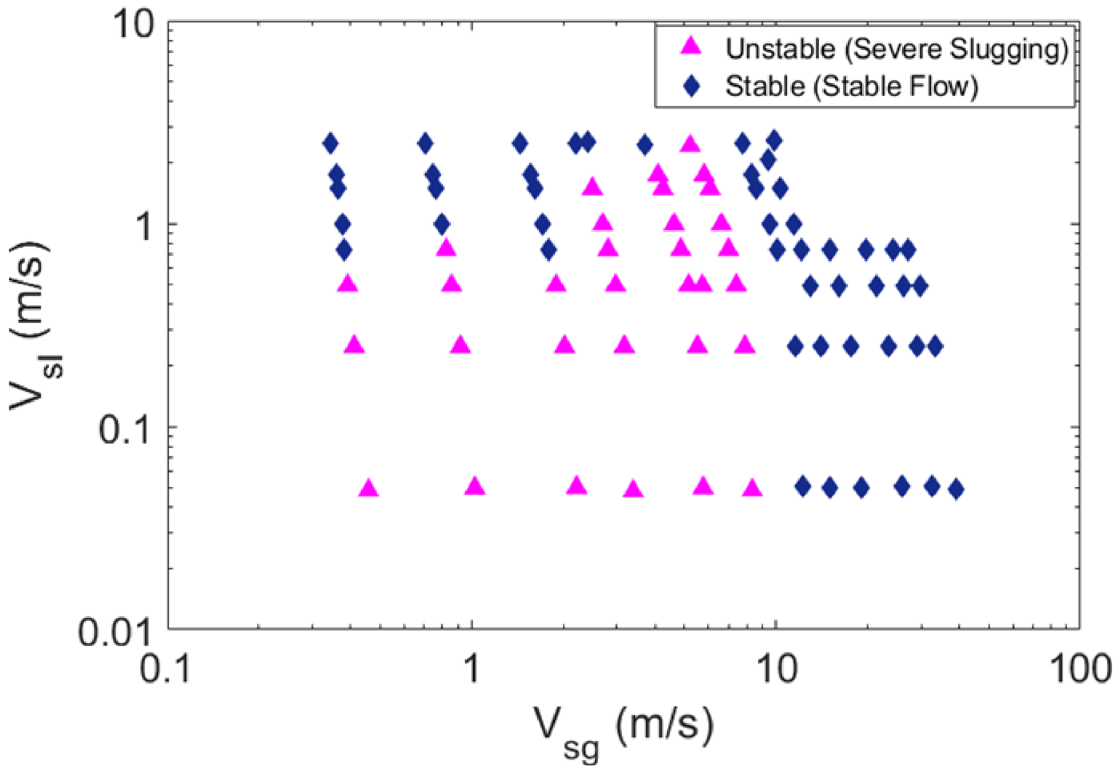

Figure 7-7 Flow pattern map for the riser with injectable Venturi with gas injection applied

Comparing Figures 7-5, 7-6 and 7-7, it can be seen that the plain riser and injectable Venturi without gas injection have 48 and 36 unstable data points respectively whereas with the injectable Venturi applied to the riser the number of unstable data points reduced to 32. Thus, the plain pipeline-riser has more unstable data points when compared to the pipeline-riser with injectable Venturi with no gas injection and the injectable Venturi with gas injection. However, the injectable Venturi with no gas injection has more unstable data points when compared to the injectable Venturi with gas injection. Hence, the injectable Venturi with gas injection has led to 33.33 % and 11.11 % reduction in the number of unstable data points when compared with the plain riser and the injectable venturi with gas injection respectively. Thus, injectable Venturi with gas injection increased the stable operating region. This practically implies an improvement to the stability of the system, thus, enhancement of flow assurance.

7.4.2 Stability Curves

Severe slugging causes intermittent delivery of oil and gas which usually manifests in significant fluctuation of pressure and flow. This instability is as a result of the change in geometry and compressibility of gas. Thus, an increment in gas flow rate could make a system gain or lose stability. Gas perturbation technique was used to develop a stability curve. The stability curve (Figure 7-8) displays the general relationship between the riser base pressure as a function of increasing gas flow rate, with a constant liquid flow rate.

Figure 7-9 shows a rapid decrease in riser base pressure until a nearly constant value at a low gas flow rate for the plain riser, injectable Venturi with and with no gas injection. Eventually, a minimum riser base pressure is attained, a further increase in gas flow rate resulted in an increase in the riser base pressure. The vertical lines are used to indicate where these minimum values occur for each case. The regions to the left and right of the minimum values represent the unstable flow regimes and stable flow regimes regions respectively. At low gas rates (below the minimum), any increase in the gas flow rate leads to an increase in frictional pressure loss that is less than the corresponding decrease in the hydrostatic pressure loss, and the riser base pressure decreases. On the other hand, at higher gas rates (above the minimum), any increase in the gas rate leads to an increase in frictional pressure loss that is greater than the corresponding decrease in the hydrostatic pressure loss, and the riser base pressure increases. Thus, the unstable region results from the fact that any decrease in gas flow rate will lead to an increase in back pressure which drives a further decrease in gas flow rate (Ehinmowo and Cao, 2016).

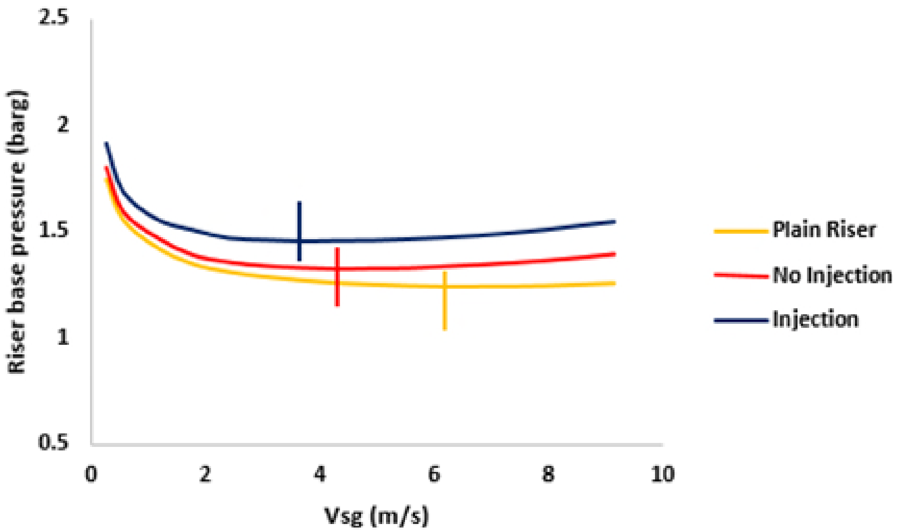

Figure 7-8 Stability curves for the plain riser, the injectable Venturi applied with and without gas injection

The performance of the plain riser, the injectable Venturi with and no gas injection was investigated for a constant water flow rate of 0.5 kg/s and increasing values of air flow rate. From Figure 7-8 it can be seen that with gas injected into the injectable Venturi the system arrived at the stable operating point (minimum riser base pressure) at a lower gas flow rate and time than without gas injection and with the plain riser. In addition, a lower amount of gas was required to achieve stability when compared to the plain riser and injectable Venturi with no gas injection.

The performance results are summarised in Tables 7-4, 7-5 and 7-5. From Table 7-4 it can be observed that the injectable Venturi without gas injection has caused a 31 % reduction when the amount of gas required to stabilise flow in the case of the injectable Venturi with no gas injection was compared to that of the plain riser. Also, in Table 7-5 it can be seen that the injectable Venturi with gas injection has caused a 14 % reduction when the amount of gas required to stabilise flow in the case of the injectable Venturi with gas injection was compared to that of the injectable Venturi with no gas injection. Similarly, in Table 7-6 it can be observed that the injectable Venturi with gas injection has caused a 40 % reduction when the amount of gas required to stabilise flow in the case of the injectable Venturi with gas injection was compared to that of the plain riser. These practically imply an improvement to the stability of the system, thus, enhancement of flow assurance.

Table 7-4 Comparison of plain riser and injectable Venturi with injection performance (Stability Curve)

Set-up	V_{gs} (m/s)	Percentage Change (%)
Plain Riser	6.2	31 % Reduction in the Amount of Gas required for Stabilisation
Injectable Venturi (no injection)	4.3	

Table 7-5 Comparison of injectable Venturi with no injection and injectable Venturi with injection performance (Stability Curve)

Set-up	V_{gs} (m/s)	Percentage Change (%)
Injectable Venturi with no injection	4.3	14 % Reduction in the Amount of Gas required for Stabilisation
Injectable Venturi with injection	3.7	

Table 7-6 Comparison of plain riser and injectable Venturi with injection performance (Stability Curve)

Set-up	V_{gs} (m/s)	Percentage Change (%)
Plain Riser	6.2	40 % Reduction in the Amount of Gas required for Stabilisation
Injectable Venturi with injection	3.7	

7.5 Severe Slug Envelopes

The severe slugging envelopes were generated by combining the stability maps in Section 7.4.1. The envelopes were created by tracing the stability boundaries (outer severe slugging data points) for each case. These envelopes were used as a yardstick to measure, demonstrate and compare the severe slug elimination performance of the pipeline-riser with the injectable Venturi applied with and with no gas injection.

Figure 7-9 shows the severe slug envelopes for the plain riser, the riser with the injectable Venturi with and with no gas injection. It can be seen that the severe slug envelope of the injectable Venturi with gas injection is the smallest followed by that of the injectable Venturi with no gas injection when compared to that the plain riser. Thus, the coupling of the injectable Venturi with no gas injection to the pipeline-riser system has led to a reduction of the severe slugging operating region within the test matrix. However, the coupling of the injectable Venturi with gas has led to a further reduction of the severe slugging operating region within the test matrix. In addition, more severe slugging test points were eliminated and converted to stable ones. These test points would have required choking the topside choke valve to be converted to stable flow. This would require a reduction in the choke valve opening. However, with the injectable Venturi applied the choke valve will be fully (100 %) open at those test points. This practically implies that oil and gas production may be increased. Additionally, it implies an improvement to the stability of the system, thus, enhancement of flow assurance.

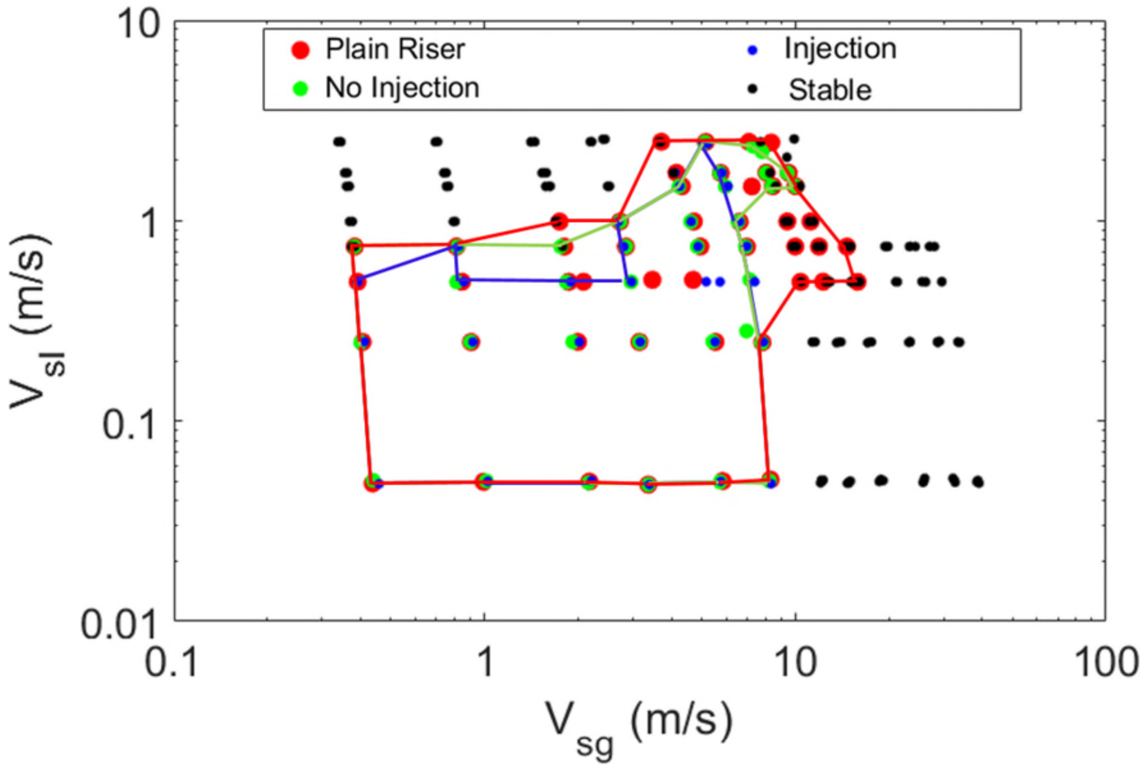

Figure 7-9 Severe slug envelopes for the plain riser, the riser with the injectable Venturi applied with and without gas injection

7.6 Production Benefit of the Injectable Venturi

The primary objective of any slug control technique is to mitigate slugging and stabilise the system. However, there is a need for a slug control technique to stabilise flow and increase production at the same time (Ogazi, 2011). As fields mature the reservoir pressure declines, the differential pressure between the topside pressure and the well decreases. Thus, the production flow rate reduces. This imposes instability on the riser system such that further action is required to stabilise the system. Having established the stabilising effects of the injectable Venturi on the pipeline-riser system in Sections 7.2 - 7.4, the next objective is to investigate its production increase capability. Hence, the traditional parameter variation (choking) technique and Hopf bifurcation technique were combined and used in this study to investigate the stability and production increase performance of the pipeline-riser with injectable Venturi applied. The study was conducted on a severe slugging condition of V_{sl} = 0.25 m/s and V_{sg} = 3.1 m/s for water and air respectively.

Figure 7-10 shows the riser base pressure bifurcation map for the severe slugging condition investigated for the plain riser. It was observed that as the pipeline-riser system is choked by reducing the valve opening the backpressure increases, the severity of slugging was reduced and the flow condition changed from severe slugging to stable flow. Bifurcation (critical valve opening) occurred at 21 % valve opening and average riser base pressure value of 2.7 barg.

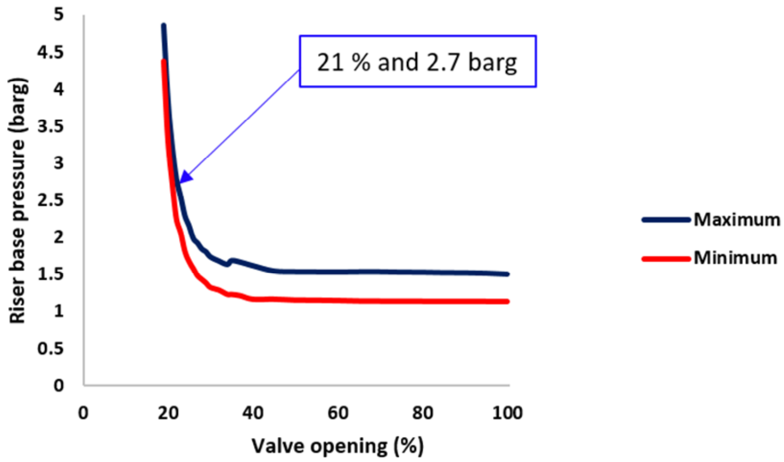

Figure 7-10 Riser base bifurcation map for the plain riser (V_{sl} = 0.25 m/s and V_{sg} = 3.1 m/s*)*

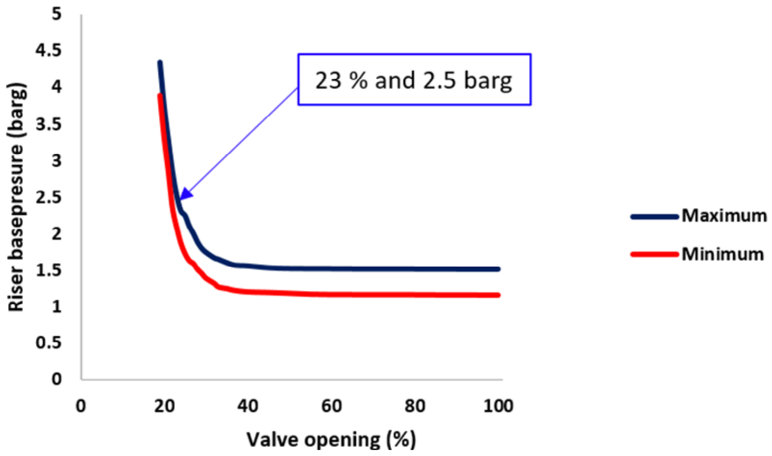

Figure 7-11 Riser base bifurcation map for the injectable Venturi with no injection (V_{sl} = 0.25 m/s and V_{sg} = 3.1 m/s)

Figure 7-11 shows the riser base pressure bifurcation map for the severe slugging condition investigated for the injectable Venturi with no injection. Similarly, it was observed that as the pipeline-riser system is choked by reducing the valve opening the backpressure increases, the severity of slugging was reduced and the flow condition changed from severe slugging to stable flow. However, bifurcation occurred at a larger valve opening of 23 % and a lower average riser base pressure value of 2.5 barg. The low loss of energy is due to the gradual change in geometry of the injectable Venturi. This may account for its ability to achieve stability at a lower riser base pressure.

Figure 7-12 shows the riser base pressure bifurcation map for the severe slugging condition investigated for the injectable Venturi with gas injection. Similarly, it was observed that as the pipeline-riser system was choked by reducing the valve opening the backpressure increased, the severity of slugging was reduced and the flow condition changed from severe slugging to stable flow. However, bifurcation occurred at a larger valve opening of 27 % and a lower average riser base pressure value of 2.3 barg. The injectable Venturi with gas injection stabilised the system at the largest valve opening and lowest pressure.

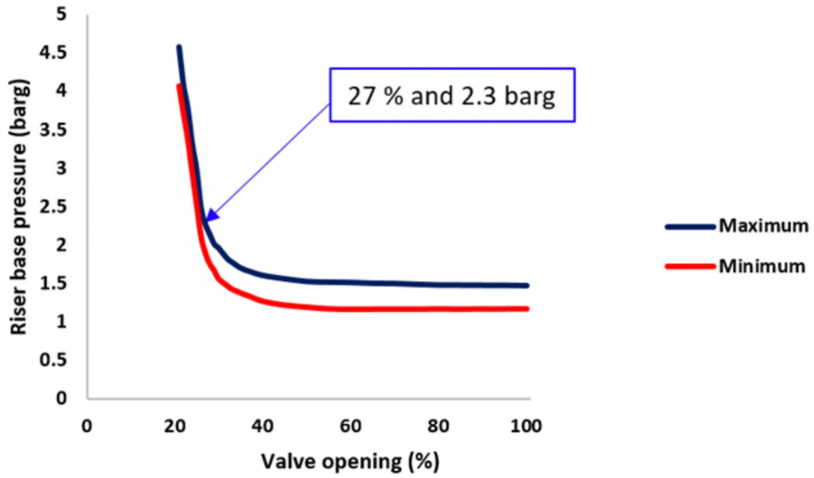

Figure 7-12 Riser base bifurcation map for the injectable Venturi with injection (V_{sl} = 0.25 m/s and V_{sg} = 3.1 m/s)

Comparing Figures 7-10 and 7-11, there was a 10 % increase in valve opening when the percentage of valve opening associated with the injectable Venturi with no injection was compared to that of the plain riser. In addition, there was a 7.4 % reduction in the riser base pressure when the riser base pressure associated with the injectable Venturi with no injection was compared to that of the plain riser. The performance results are summarised in Table 7-7, where it can be observed that the injectable Venturi with no injection stabilised the system at a larger valve opening and lower rise base pressure.

Table 7-7 Comparison of plain riser and injectable Venturi with no injection performance (Bifurcation Map)

Set-up	Valve Opening (%)	Percentage Change (%)	Riser Base Pressure (barg)	Percentage Change (%)
Plain Riser	21	10 % increase in valve opening	2.7	7.4 % reduction in riser base pressure
Injectable Venturi with no injection	23		2.5	

Also, comparing Figures 7-11 and 7-12, there was a 17.4 % increase in valve opening when the percentage of valve opening associated with the injectable Venturi with injection was compared to that of the injectable Venturi with no injection. In addition, there was an 8 % reduction in the riser base pressure when the riser base pressure associated with the injectable Venturi with injection was compared to that of the injectable Venturi with no injection. This proves that the performance of the injectable Venturi is not entirely due to the Venturi itself but due to the gas injected into the Venturi. The performance results are summarised in Table 7-8, where it can be seen that the injectable Venturi with injection stabilised the system at a larger valve opening and lower rise base pressure to those associated with the injectable Venturi with no injection.

Table 7-8 Comparison of injectable Venturi with no injection and injectable Venturi with injection performance (Bifurcation Map)

<table>
<tr><th>Set-up</th><th>Valve Opening (%)</th><th>Percentage Change (%)</th><th>Riser Base Pressure (barg)</th><th>Percentage Change (%)</th></tr>
<tr><td>Injectable Venturi with no injection</td><td>23</td><td rowspan="2">17.4 % increase in valve opening</td><td>2.5</td><td rowspan="2">8 % reduction in riser base pressure</td></tr>
<tr><td>Injectable Venturi with injection</td><td>27</td><td>2.3</td></tr>
</table>

Similarly, comparing Figures 7-10 and 7-12, there was a 29 % increase in valve opening when the percentage of valve opening associated with the injectable Venturi with injection was compared to that of the plain riser. Also, there was a 15 % reduction in the riser base pressure when the riser base pressure associated with the injectable Venturi with no injection was compared to that of the plain riser. The performance results are summarised in Table 7-9, where it can be observed that the injectable Venturi with injection stabilised the system at a larger valve opening and lower rise base pressure.

Table 7-9 Comparison of plain riser and injectable Venturi with injection performance (Bifurcation Map)

<table>
<tr><th>Set-up</th><th>Valve Opening (%)</th><th>Percentage Change (%)</th><th>Riser Base Pressure (barg)</th><th>Percentage Change (%)</th></tr>
<tr><td>Plain Riser</td><td>21</td><td rowspan="2">29 % increase in valve opening</td><td>2.7</td><td rowspan="2">15 % reduction in riser base pressure</td></tr>
<tr><td>Injectable Venturi with injection</td><td>27</td><td>2.3</td></tr>
</table>

The reduction in the riser base pressure achieved by coupling the injectable Venturi to the pipeline-riser system leads to an increase in production. Reservoirs are often considered to have reached the end of their useful life sometime before they are actually exhausted due to low pressures which give rise to severe slugging. This result suggests that the operational life of a reservoir might be extended by adopting this technique. Hence, oil recovery in brown fields would be enhanced. Also, the result shows that injecting gas at the throat of the injectable Venturi improves the performance of the conventional Venturi. Practically, these imply an improvement to the stability of the system and increase in oil and gas production.

7.7 Effects of Pressure on Production

The main aim of mitigating severe slugging is to achieve flow assurance; thus, a slug control system should be able to stabilise the system and increase production at the same time. Consequently, it is vital to analyse the effect of pressure loss associated with choking on oil production.

A large valve opening translates to higher flow capacity and lower pressure drop. Conversely, a small valve opening translates to higher pressure drop and lower flow capacity. In a typical oil and gas production system, the bottom-hole pressure is the sum of all the pressure drops downstream acting on the bottom-hole. Thus, any changes in the pressure of any section along the downstream have a chain reaction effect upstream which directly impacts the bottom-hole pressure. The pipeline-riser system is part of the downstream production system; hence, it may contribute significantly to the bottom-hole pressure. Consequently, for increased oil and gas production, it is desirable to have a large valve opening and lower pressure as shown in Section 7.6.

The pressure; and oil and gas production relationship from a linear well can be shown mathematically using Darcy's law as given by (Abou-Kassem et al., 2006; Ogazi, 2011):

$$q_w = B(P_{res} - P_{wbh}) \quad \textbf{(7-1)}$$

where q_w is the well production rate, B is the productivity index, P_{res} is the reservoir pressure and P_{wbh} is the well bottom-hole pressure. The expression $(P_{res} - P_{wbh})$ gives the pressure drop across the system. The relationship in Equation 7-1 shows that the well production rate (q_w) is directly proportional to the pressure drop across the system. Hence, an increase in the production rate can be achieved by reducing P_{wbh}. Thus, to have maximum production, the downstream pressure that contributes to the bottom-hole pressure must be kept low. This study focused on the riser base pressure of the pipeline-riser system which is part of the downstream pressure. The study in Section 7.6 showed that with injectable Venturi applied to the pipeline-riser system the riser base pressure was reduced. This reduction will trickle to the well bottom-hole pressure (P_{wbh}) and will make it reduce further than the reservoir pressure (P_{res}). Consequently, the production rate will increase and the operation life of a reservoir might be extended base on the relationship in Equation 7-1.

7.8 Chapter Summary

A new method for severe slugging stabilisation and mitigation has been developed. The severe slug attenuation potential of the injectable Venturi and its capability to increase the overall production in the pipeline-riser system were studied. The performance of the injectable Venturi was compared with that of the plain riser in terms of flow regime maps, severe slug envelopes and Hopf bifurcation maps.

The main findings in this chapter are summarised as follows:

1. The pipeline-riser system can be stabilised with the application of an injectable Venturi

2. An injectable Venturi is a viable and effective method for severe slugging mitigation

3. It has been established that the application of the injectable Venturi to the topside of a pipeline-riser system can attenuate severe slugging

4. The injectable Venturi arrives at the stable operating point (minimum riser base pressure) at a lower gas flow rate and time when compared to that associated the plain riser and injectable Venturi with no injection. Thus, the injectable Venturi reduces that amount of gas required to stabilise the pipeline riser system

5. The severity of severe slugging was reduced in some test points; thus, an injectable Venturi can be used to reduce the severity of slugging in a pipeline-riser system

6. Severe slugging was completely eliminated in some test point within the test matrix; thus, injectable Venturi can be used to eliminate severe slugging in a pipeline-riser system

7. Severe slug operating region can be reduced by applying an injectable Venturi to the pipeline-riser system

8. It has been established that gas injection at the throat of a Venturi can improve the performance of the Venturi. Thus, the effectiveness of the injectable Venturi is not entirely due to the Venturi itself, but due to gas injection at the throat of the Venturi

9. An injectable Venturi coupled to a pipeline-riser can stabilise flow at a larger valve opening and a lower pressure when compared to the plain pipeline-riser. This practically implies an increase in oil and gas production.

This is an economical severe slug mitigation method, its installation at the topside is an additional advantage when compared with other methods that require subsea deployment. The increase in brown fields due to diminishing reserves of oil from reservoirs have made oil recovery very vital. Reservoirs are often considered to have reached the end of their useful life sometime before they are actually exhausted due to low pressures. Thus, this technique potentially will help to extend the operational life of a reservoir, thus enhancing oil recovery and flow assurance.

The potential impact of the findings of this study would go a long way in helping the oil and gas industries in areas such as: production management, well testing, reservoir management and custody transfer.

8 STABILISATION OF SEVERE SLUGGING WITH ACTIVE CONTROL FOR MAXIMISED PRODUCTION

Chapter Highlights

1. Active control enhanced the performances of the Venturi and injectable Venturi
2. The severe slugging mitigation performance of the Venturi and injectable Venturi has been improved

8.1 Introduction

Severe slugging is problematic for oil production systems because it leads to unwanted flaring, deterioration in reservoir performance, separator flooding, production reduction, platform trips and plant shutdown. Thus, the need to handle severe slugs in a more efficient way has become very vital. This chapter is dedicated to improving the achievements gained in Chapters 6 and 7 and making the process more effective and efficient.

In Chapters 6 and 7 it has been established that the Venturi and the injectable Venturi can be used to mitigate severe slugging and stabilise the system beyond the open-loop stability point when compared to doing manual chocking without coupling them to the pipeline-riser system. However, their performance can be enhanced by implementing active control. Active control is a system that aims to stabilise the multiphase flow in the pipeline-riser at operating conditions that, without active control would lead to severe slugging. This has been shown to be an effective and efficient technique to eliminate severe slugging and stabilise the system at a larger valve opening (Stasiak et al., 2012; Havre et al., 2000, 2001; Henriot et al., 1999; Jansen et al., 1996; Godhavn et al., 2005; Storkaas and Skogestad, 2004; Ogazi et al., 2009, 2010; Siahaan et al., 2005; Storkaas and Skogestad, 2007; Ehinmowo and Cao, 2015). A larger valve opening corresponds to lower pressure inside the pipeline. As stated previously in Chapters 6 and 7 this leads to increase in production.

This chapter seeks to address the aim, the third objective of this study stated in Chapter 1 (Section 1.3). Also, it aims to address the third gap in research identified in Chapter 2 of this thesis. The chapter is organised as follows: Section 8.2 discusses the choice of controller; Section 8.3 presents the Inferential Slug Controller (ISC). Section 8.4 describes the controller design. Section 8.5 presents the implementation of the ISC, and Section 8.6 concludes the chapter.

8.2 Choice of Controller

The primary objective of active control is to stabilise the pipeline-riser system by suppressing severe slugging. Known solutions focus on active control of the flow by opening and closing the topside choke valve (control valve) located at the topside of the pipeline-riser. Most current active slug control strategies using choking depend on measurements from the bottom of the riser being available (Henriot et al., 1999; Jansen et al., 1996; Ogazi et al., 2009, 2010; Ehinmowo and Cao, 2015). This has its downside as it is expansive to install sensors upstream the riser base, especially in deep offshore where it will be difficult to install and maintain such sensing devices. Thus, such measurements may not be available in most cases. However, there have been a few approaches that rely on topside measurements (Sivertsen et al., 2009; Cao et al., 2013).

Cao et al., (2013) in their patent proposed novel method for severe slug mitigation using an Inferential Slug Controller (ISC). ISC uses topside measurements for slug control, which has helped to prevent the challenges common with using riser bottom measurements. ISC is used to implement active control in order to improve the performance of the Venturi and the injectable Venturi.

8.3 Inferential Slug Controller

The ISC proposed in Cao et al. (2013) uses multiple topside measurements as the input to attain a percentage choke valve opening that stabilises the flow. The function of the ISC is to control the movement of the topside choke valve to choke the fluid flowing through the pipeline-riser in such a manner that excessive slugging does not arise. Thus, minimise the impact of severe slugging on the overall production and avoid over choking. The choke valve position is determined by a control law given as:

$$U = U_o + K_c(W^T Y - R) \qquad \textbf{(8-1)}$$

where U is the choke valve position, U_o is the choke valve set point, K_c is the control gain which may be tuned using any available tuning technique that stabilises the flow fluctuation usually on a trial and error basis, W is the vector of measurement weights which is determined from samples of signals obtained over a long period of time usually more than two slug cycles when there is no controller in action, Y is the vector of measurements, $W^T Y$ is the control variable which may represent a principal component which is a linear combination of the weighted variables, and R is the set point of the control variable.

Cao et al. (2013) in their study set the value of K_c by trial and error to give optimal operation. However in this study the value of K_c was determined through open-loop tuning.

The ISC creates a single controlled variable by combining several measurements received from sensors at the topside to obtain a control variable which is relatively more sensitive to severe slugging. Each sensor produces a signal dependent on the fluctuation of the fluid flow properties at the topside area of the pipeline-riser. The ISC controls the valve openings by interpreting a combination of signals obtained from the topside of the pipeline-riser through Principal Component Analysis (PCA) techniques. This enables the flow to be controlled to prevent the development of severe slugging. Controlling the valve around a manually set valve point implies that the valve will generally be opened more than it would manually. Thus, the average flow rate over time will be increased.

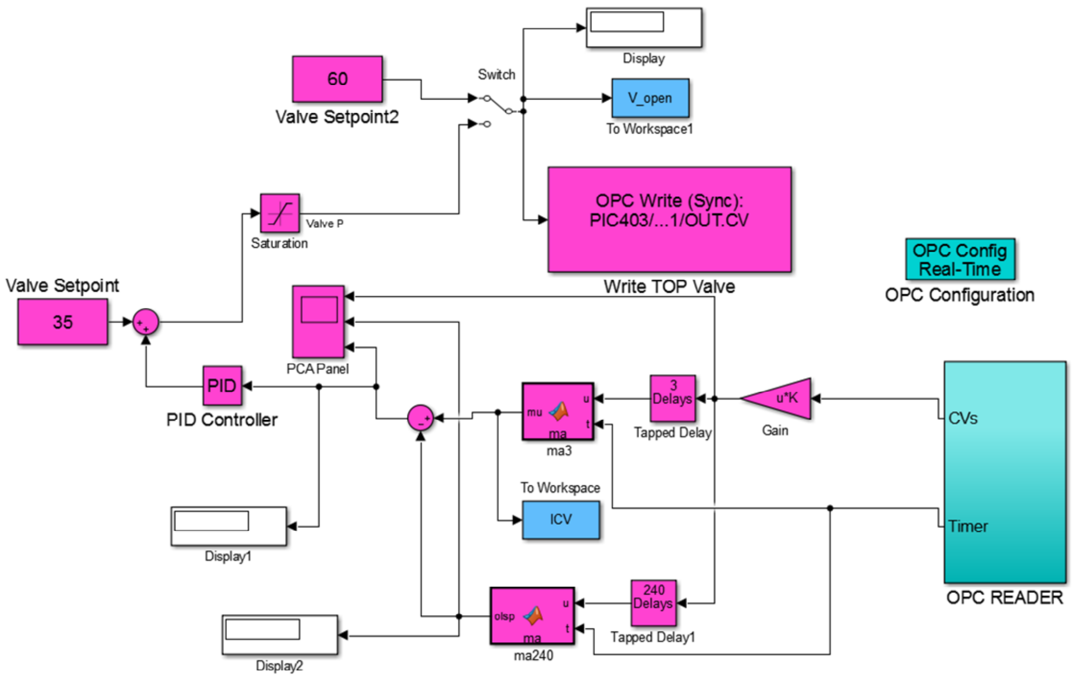

Figure 8-1 SIMULINK module of Inferential Slug Controller (Cao et al., 2013)

8.4 Controller Design

The controller was designed based on the critical values of the bifurcation map and subsequently tuned when the gain values were determined from the open-loop system through the process reaction curve. A controller that has the capacity to stabilise the system and increase production beyond open-loop bifurcation (critical valve opening) point is required.

8.4.1 Control Objectives

A suitable approach for the design of a controller for the system is to define the control objectives to reflect and address the core operation targets of an unstable pipeline-riser system. In this study, the slug control objectives are:

1. Stabilising operation
2. Increasing the overall production

Given these objectives, the ability to stabilise the system at a valve opening that is large enough to ensure increased production is paramount. The analysis of production dependency on the flow line pressure is discussed in Chapters 6 and 7, where it was shown that a reduction in the riser base pressure leads to an increase in the production rate. It was established that any changes in the pressure of any section downstream of the bottom-hole have a chain reaction effect upstream which directly impacts the bottom-hole pressure. The topside choke valve is part of the downstream production system; hence, it may contribute significantly to the bottom-hole pressure.

Assuming linear valve characteristics, we can approximately define the relationship between the pressure loss across the choke valve (DP_U) and the valve opening (U) as given by (Ogazi, 2011):

$$DP_u \ \alpha \ \frac{1}{U^2} \tag{8-2}$$

The relationship in Equation (8-2) shows that the valve opening is indirectly proportional to the pressure drop across the valve. Hence, a small valve opening will result in high DP_U and consequently, high riser base pressure. On the other hand, a large valve opening will result in low DP_U and consequently, low riser base pressure. Thus, it is vital to achieve system stability at a relatively large valve opening in order to reduce the riser base pressure.

8.4.2 Stability Analysis

In controller design after setting your control objectives, the first step in the design procedure is to establish the system bifurcation point, which is the maximum valve opening for which the flow remains stable in an open-loop condition. This valve opening is set as the reference point for the controller to stabilise flow in an open-loop unstable region. Hopf bifurcation was used for the stability analysis.

8.4.2.1 Hopf Bifurcation Map

Hopf bifurcation occurs in a system when there is a loss of stability due to changes in an independent variable of the system (Thompson and Stewart, 1986). For a nonlinear system like the pipeline-riser system, Hopf bifurcation can occur if a change in an independent variable such as the valve opening causes the system to become unstable at an operating point. The Hopf bifurcation map was generated through manual choking of the topside choke valve (open-loop control) in order to transform the unstable flow condition in the system into the stable flow.

Figure 8-2 shows the bifurcation map obtained from the open-loop control of the 2″ pipeline-riser system with the Venturi applied at a severe slugging condition of V_{sl} = 0.25 m/s and V_{sg} = 0.37 m/s for water and air respectively. It can be seen that as the topside choke valve is manually choked from a fully open position by reducing the valve opening; the back pressure increased, the severity of slugging is reduced and the flow condition changed from severe slugging to stable flow. The bifurcation map shows that the riser base pressure is stabilised at a valve opening $U \leq 18$ %. However, for $U > 18$ % the system becomes unstable and oscillates between a maximum and minimum pressure values. Thus, bifurcation (critical valve opening) occurred at $U = 18$ % and a corresponding average riser base pressure value of 2.8 barg.

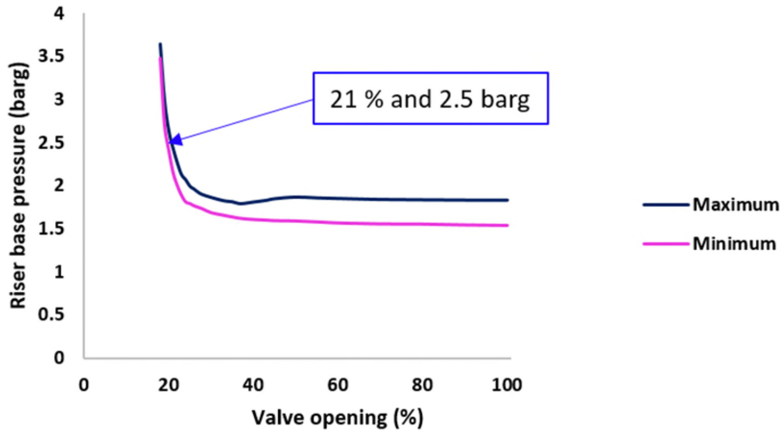

Figure 8-2 Riser base bifurcation map for Venturi with no controller (V_{sl} = 0.25 m/s and V_{sg} = 0.37 m/s)

Figure 8-3 shows the bifurcation map obtained from the open-loop control of the 2″ pipeline-riser system with the injectable Venturi applied at a severe slugging condition of V_{sl} = 0.25 m/s and V_{sg} = 3.1 m/s for water and air respectively. Similarly, it can be seen that as the topside choke valve is manually choked from a fully open position by reducing the valve opening; the back pressure increased, the severity of slugging is reduced and the flow condition changed from severe slugging to stable flow. The bifurcation map shows that the riser base pressure is stabilised at a valve opening $U \leq 27\ \%$. However, for $U >$ $27\ \%$ the system becomes unstable and oscillates between a maximum and minimum pressure values. Thus, bifurcation (critical valve opening) occurred at $U = 27\ \%$ and a corresponding average riser base pressure value of 2.3 barg.

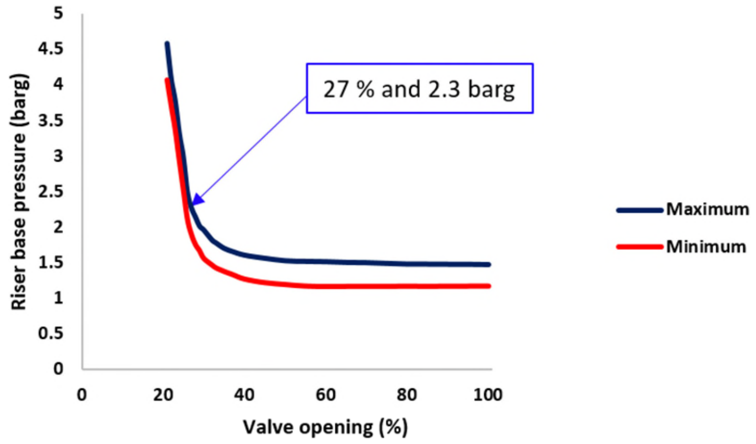

Figure 8-3 Riser base bifurcation map for injectable Venturi with no controller (V_{sl} = 0.25 m/s and V_{sg} = 3.1 m/s)

At and below these critical valve openings, severe slugging does not exist; the system can be operated at these open-loop stable operating points without cyclic oscillation and without the application of active control. The interest is to stabilise the system at unstable operating points, where the valve openings are larger than these critical valves openings, such that the total pressure drop across the riser and the valve are reduced, and consequently, increasing the overall production.

8.4.3 Determination of the System Model

The second step in the design procedure is to determine the model of the pipeline riser system with the Venturi and the injectable Venturi applied. Thus, we need to determine the process model parameters (process gain, time constant and time delay). The process gain values, time constants and time delays for the pipeline-riser system with Venturi and injectable Venturi applied were determined using their respective process reaction curves. The process reaction curve is an approximation model of the process, it is the plot of the output response of the process to a step-change in the input. The process reaction curve is generated at stable operating point by doing an open-loop step test of the system and then identifying the process model parameters. The following steps were applied:

1. Set the system in open-loop (manual) mode
2. Allow the system to stabilise
3. Apply a step change to input
4. Record the response from the output of the sensor
5. Collect data and plot the process reaction curve

The general first-order-plus-time-delay (FOPTD) transfer function $G(s)$ is given as:

$$G(s) = \frac{K_p e^{-\tau_d s}}{\tau s + 1} \tag{8-3}$$

where K_p is the process gain (steady-state gain), τ_d is the time delay and τ is the time constant. The process reaction curve for the pipeline-riser system with the Venturi and the injectable Venturi installed are in Appendix C.

The process gain is estimated as

$$K_p = \frac{Change\ in\ output}{Change\ in\ input} \tag{8-4}$$

where the output is the riser base pressure and the input valve opening.

The time delay (τ_d) and time constant (τ) are determined from a tangent line drawn in the point of inflection of the reaction curves for the Venturi and the injectable Venturi. The process parameters for the pipeline-riser system with Venturi and with injectable Venturi applied are shown in Table 8-1.

Table 8-1 Process model parameters for the pipeline-riser system with Venturi and injectable Venturi applied

Set-up	Step Change in Input	Step Change in Output	Process Model Parameters		
	(%)	(barg)	K_p	τ_d(s)	τ (s)
Venturi	2.0	2.3	1.15	50	340
Injectable Venturi	2.0	1.4	0.7	25	215

Using these process parameters, the FOPDT model of the pipeline-riser system with Venturi and with injectable applied are given in Equations (8-7) and (8-8) respectively.

$$G_v(s) = \frac{1.15e^{-50s}}{340s + 1} \tag{8-5}$$

$$G_I(s) = \frac{0.70e^{-25s}}{215s + 1} \tag{8-6}$$

8.4.4 Determination of Controller Parameters (Open-Loop Tuning)

The process model parameters were used to calculate the controller parameter (control gain for the ISC) using Ziegler-Nichols open-loop tuning table. Ziegler-Nichols table for open-loop tuning and the control gain for the ISC controller are shown in Tables 8-2 and 8-3 respectively. The ISC control gain was tuned using the control gain of the proportional controller (P) in Table 8-2.

Table 8-2 Ziegler Nichols open-loop tuning table (Mikleš and Fikar, 2007)

Controller	K_c	τ_I	τ_D
P	$\frac{\tau}{\tau_d K_p}$		
PI	$\frac{0.9\tau}{\tau_d K_p}$	$3.33\tau_d$	
PID	$\frac{1.2\tau}{\tau_d K_p}$	$2\tau_d$	$0.5\tau_d$

Table 8-3 Control Gain for the ISC controllers for the pipeline-riser system with Venturi and injectable Venturi applied

Set-up	Controller Parameter (K_c)
Venturi	5.91
Injectable Venturi	12.29

8.5 Implementation of the ISC Controller

The ISC was implemented in MATLAB (SIMULINK), and it communicated to the Delta V program through OPC server. The control gains in Table 8-3 were used to implement the ISC controllers for the pipeline-riser system with the Venturi and the injectable Venturi applied. The ISC controllers were used to generate Hopf bifurcation maps at the same conditions reported in Section 8.4.2.1. The application of the active controller transformed the system to closed-loop system and the system was stabilised in previously open-loop unstable region. The results of the experiments for the pipeline-riser system with Venturi and injectable Venturi applied are shown in Figures 8-6 and 8-7.

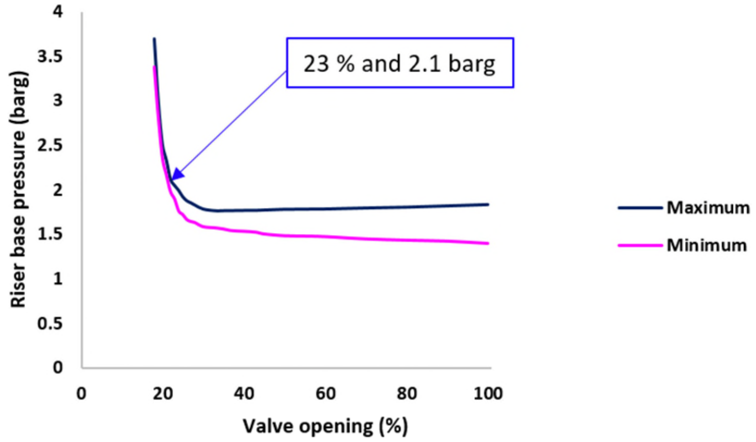

Figure 8-4 Riser base bifurcation map for Venturi with controller (V_{sl} = 0.25 m/s and V_{sg} = 0.37 m/s)

Figure 8-4 shows the bifurcation map obtained from the closed-loop control of the 2″ pipeline-riser system with Venturi applied at a severe slugging condition of V_{sl} = 0.25 m/s and V_{sg} = 0.37 m/s for water and air respectively. It can be seen that as the topside choke valve is automatically choked from a fully open position by reducing the valve opening the backpressure increased, the severity of slugging is reduced and the flow condition changed from severe slugging to stable flow. However, bifurcation occurred at a larger valve opening of 23 % and a lower average riser base pressure value of 2.1 barg when compared to those of manual choking reported in Section 8.4.2.1.

Comparing Figures 8-2 and 8-4, there was a 10 % increase in valve opening when the percentage of valve opening associated with the Venturi with controller was compared to that of the Venturi with no Controller. In addition, there was a 16 % reduction in the riser base pressure when the riser base pressure associated with the Venturi with controller was compared to that of the Venturi with no Controller. The performance results are summarised in Table 8-

4, where it can be observed that the active control (automatic control) of the pipeline-riser-Venturi system stabilised the system at a larger valve opening and lower rise base pressure when compared with manual control.

Table 8-4 Comparison of injectable Venturi with no controller and injectable Venturi with controller performance (Bifurcation Map)

Set-up	Valve Opening (%)	Percentage Change (%)	Riser Base Pressure (barg)	Percentage Change (%)
Venturi with no Controller	21	10 % increase in valve opening	2.5	16 % reduction in riser base pressure
Venturi with Controller	23		2.1	

Figure 8-5 shows the bifurcation map obtained from the closed-loop control of the 2″ pipeline-riser system with the injectable Venturi applied at a severe slugging condition of V_{sl} = 0.25 m/s and V_{sg} = 3.1 m/s for water and air respectively. It was observed that as the topside choke valve is automatically choked from a fully open position by reducing the valve opening the back pressure increased, the severity of slugging is reduced and the flow condition changed from severe slugging to stable flow. However, bifurcation occurred at a larger valve opening of 29 % and a lower average riser base pressure value of 2.0 barg when compared to those of manual choking reported in Section 8.4.2.1.

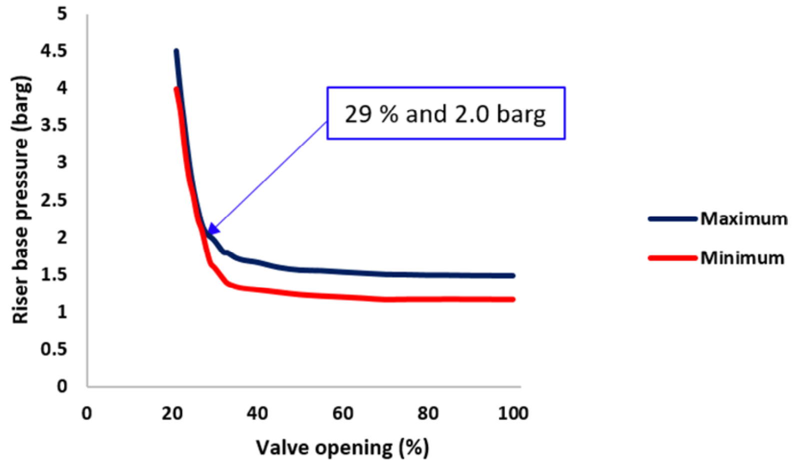

Figure 8-5 Riser base bifurcation map for injectable Venturi with controller (V_{sl} = 0.25 m/s and V_{sg} = 3.1 m/s)

Comparing Figures 8-3 and 8-5, there was a 7.4 % increase in valve opening when the percentage of valve opening associated with the injectable Venturi with controller was compared to that of the injectable Venturi with no Controller. In addition, there was a 13 % reduction in the riser base pressure when the riser base pressure associated with the injectable Venturi with controller was compared to that of the injectable Venturi with no Controller. The performance results are summarised in Table 8-5, where it can be observed that the active control (automatic control) of the pipeline-riser-injectable Venturi system stabilised the system at a larger valve opening and lower rise base pressure when compared with manual control.

Table 8-5 Comparison of injectable Venturi with no controller and injectable Venturi with controller performance (Bifurcation Map)

<table>
<tr><th>Set-up</th><th>Valve Opening (%)</th><th>Percentage Change (%)</th><th>Riser Base Pressure (barg)</th><th>Percentage Change (%)</th></tr>
<tr><td>Injectable Venturi with no Controller</td><td>27</td><td rowspan="2">7.4 % increase in valve opening</td><td>2.3</td><td rowspan="2">13 % reduction in riser base pressure</td></tr>
<tr><td>Injectable Venturi with Controller</td><td>29</td><td>2.0</td></tr>
</table>

The active controllers stabilised the system at a larger valve opening and lower pressure. The controllers extended the stable operating region of the system, thus, the system can operate beyond the open-loop stable regions reported in Section 8.4.2.1. This further reduction in backpressure achieved by the application of active control leads to an increase in production. These results suggest that the operational life of a reservoir might be extended further. Also, it practically implies an increase in oil and gas production.

8.6 Chapter Summary

In this chapter, the design, implementation and the performance analysis of active controllers (ISC) for increased oil production have been presented. The severe slug controllers design were focused on achieving two important objectives: mitigating severe slugging (stabilising the operation) and increasing liquid production in operating regions that were not achievable by just applying the Venturi and the injectable Venturi to the pipeline riser system.

The main findings in this chapter are summarised as follows:

1. Active control is effective in mitigating severe slugging in a pipeline-riser-Venturi and pipeline-riser-injectable Venturi system

2. Active control improves the performance of the injectable Venturi
3. Active control improves the performance of the Venturi
4. The application of controller stabilises the pipeline-riser-Venturi and pipeline-riser-injectable Venturi systems beyond their open-loop stability point achieved during manual operation. Thus, stability in some operating regions that were not previously achievable is now achievable, and the system can now operate in some conditions that, without active control would lead to severe slugging
5. Active control increases the valve opening and lowers the riser base pressure of the pipeline-riser-Venturi and pipeline-riser-injectable Venturi systems beyond those obtainable during manual operation
6. It has been established that these severe slugging mitigation methods are compatible with active control

As stated in Chapters 6 and 7, and in Section 8.4.1 increased valve opening results in reduction in riser base pressure. Active control has further increased the valve opening and reduced the riser base pressure. This additional reduction in riser base pressure will trickle to the well bottom-hole pressure and the bottom-hole pressure will be further reduce than the reservoir pressure. Consequently, the production rate will increase. This potentially will help to further extend the operational life of a reservoir, thus enhancing oil recovery, continuous production of low-pressure wells and flow assurance.

9 CONCLUSIONS AND FURTHER WORK

9.1 Introduction

In this chapter, a summary of the main conclusions and contributions from this study are presented. Also, the recommendations for further research are identified. This thesis has discussed a comprehensive approach to severe slugging control using both passive and active techniques, with focus on achieving stable operation and maximising the overall production. It presents the study of the capabilities of the Venturi and the injectable Venturi in mitigating severe slugging and increasing production. The study involved both experimental and numerical investigations.

Several active and passive severe slug mitigation techniques such as design modification of downstream facilities, permanent choking, use of multiple risers, use of flow conditioners, use of intrusive devices, use of intermittent absorber, self-gas lifting, smart choking, external gas lifting, combination of external gas lifting and topside choking, combination self-gas lift and external gas lift, homogenising the multiphase flow, combination of surfactants and external gas lift, and slug suppression system were reviewed. However, these methods have their peculiar disadvantages; slug catcher and flow conditioning require very expensive design changes. Pipeline choking is one of the effective approaches to eliminate severe slugging in oil and gas production systems. Nevertheless, due to the restriction caused by choking, oil production could be significantly reduced by fixed choking

Despite the advances made in severe slug mitigation, the mixed results on the performance of these severe slug mitigation methods exposes the need for a better and viable solution. Thus, a robust and effective severe slug mitigation approach that would stabilise the system and increase the overall production is needed. This work explored two novel methods for stabilising severe slugging while maximising the overall production at the same time. Also, these two techniques are cheaper options when compared to other methods that require expensive installation and maintenance which will significantly increase CAPEX and OPEX. Besides, their installations at the topside is an additional advantage when compared with other methods that require subsea installation.

This chapter is organised as follows: Section 9.2 presents the conclusions drawn from the study, Section 9.3 presents the research contribution to knowledge, Section 9.4 discusses the potential impact of this research and Section 9.5 recommends the future work to be undertaken in this area of study.

9.2 Conclusions

9.2.1 Simplified Model of the Injectable Venturi

A simplified model of the injectable Venturi was developed using physical first-principles such as Bernoulli and continuity equations. The developed model was validated using the experimental results. One of the major highlights in Chapter 4 was the development of some correlations for the calculations for K_{vt} . The predicted K_{vt} curve showed good agreement with the measured K_{vt}. Thus, the percentage of the average discrepancy between the predicted and the experimental result was 3.3 % for the cases studied. K_{vt} was used in the development of the injectable Venturi model.

The injectable Venturi model was implemented in MATLAB. Certain tuning parameters were used, in addition to fine-tuning using MATLAB's optimisation tools. The goal of the model was to simulate the pressures at the throat and outlet of the injectable Venturi, and the differential pressure across the injectable Venturi given the values of the input pressure from the experiment.

The simulations results obtained from the model were compared to the experimental data. NMSE fitness metric was used to measure the goodness of fit of the MATLAB models results against the experimental data. Thus, the tuned MATLAB model was validated against the experimental data by achieving 78 % goodness of fit in one of the test point considered. Thus, the model closely matched the experimental results. Consequently, the experiment was validated by the simplified MATLAB model.

The development of the injectable Venturi model has addressed some part of the fifth gap in research stated in Chapter 2 during critical literature review. Thus, the understanding provided by this study will enhance the understanding and proper design of the injectable Venturi and how it could be deployed for field operations.

9.2.2 Characterisation of Flow in S-shape Pipeline-Riser System

The flow regimes in the s-shape pipeline-riser system were objectively characterised. The differential pressure across the entire length of the riser was used in this study. Previous studies of flow regime characterisation have not examined the entire length of the S-shape riser. Most studies have been focused on using either riser base pressure or using part of the differential measurements across different sections of the riser (lower limb, downcomer and upper limb). Hence, it will not give an accurate representation for characterisation of flow within the riser. This was the first gap in research identified in the critical literature review discussed in Chapter 2. However, this study has addressed this research gap by using pressure measurements across the entire riser to characterise flow regimes.

The flow regimes were classified into ten categories viz.: severe slug type I (SS-I), severe slug type II (SS-II), severe slug type III (SS-III), transitional severe slug type I (SST-I), transitional severe slug type II (SST-II), oscillation flow (OSC), bubble flow, slug flow, churn flow and annular flow. They were further broadly categories as severe slugging, transitional severe slugging and stable flow. Flow pattern maps were produced based on experimental results, and PDF and PSD were used to objectively classify the flow regimes.

9.2.3 Severe Slugging Mitigation in an S-Shape Pipeline-Riser System with a Venturi for Maximised Production and Recovery

A novel passive approach to severe slugging mitigation has been presented. Critical evaluation of the severe slug attenuation potential of the Venturi and its ability to increase the overall production was studied. The experimental evidence showed that the application of the Venturi to the pipeline-riser system breaks down severe slugging and stabilises the system. It drove the system to a stable operating point quicker than when only the plain pipeline-riser was used. These practically imply an improvement to the stability of the system, thus, enhancement of flow assurance. Also, the Venturi was effective in mitigating severe slugging. Furthermore, it was shown that Venturi can eliminate severe slugging and can also reduce the severe slug operating region in the pipeline-riser system.

The Venturi stabilise flow at a larger valve opening and a lower pressure when compared to the plain riser. For the case studied, the Venturi increased the valve opening by 17 % and reduced the riser base pressure by 11 % when the percentage of valve opening and riser base pressure associated with the Venturi was compared to that of the plain riser. Thus, the Venturi reduces the degree of valve choking required to achieve stability. The reduction in backpressure achieved by applying Venturi to the pipeline-riser system leads to an increase in production. This result suggests that the operational life of a reservoir might be extended by adopting this technique. Thus, oil recovery in brownfields would be enhanced.

This study has adequately addressed the aim, first and second objectives of this research. Also, addressed are the second and fourth gaps in research identified in Chapter 2 of this thesis.

9.2.4 Severe Slugging Mitigation in an S-Shape Pipeline-Riser System with Injectable Venturi for Stabilised, Increased Production and Recovery

A novel active approach to severe slug flow mitigation has been presented. Critical evaluation of the severe slug attenuation potential of the injectable Venturi and its ability to maximise the overall production in the pipeline-riser system was studied. The experimental evidence showed that coupling the injectable Venturi to the pipeline-riser system breaks down severe slugging and stabilises the system. Also, it drove the system to a stable operating point quicker than when only the plain pipeline-riser was used. These practically imply an improvement to the stability of the system, thus, enhancement of flow assurance.

Furthermore, it has been shown that the injectable Venturi can eliminate severe slugging and can also reduce the severe slug operating region in the pipeline riser system. The combination of the injectable Venturi and manual choking was shown to stabilise the system at a larger valve opening when compared to using manual choking alone. It imposed lower backpressure on the pipeline-riser system at the open-loop unstable operating point, lower than the high backpressure imposed by manual choking method alone. For the case studied, there was a 29 % increase in valve opening and a 15 % reduction in the riser base pressure when the percentage of valve opening and riser base pressure associated with the injectable Venturi was compared to that of the plain riser.

This result suggests that the operational life of a reservoir might be extended by adopting this technique. Hence, oil recovery in brown fields would be enhanced. Also, the result shows that injecting gas at the throat of the Venturi improves the performance of the conventional Venturi. Practically, these imply an improvement to the stability of the system and increase in oil and gas production. In addition, this method method would allow smooth operation of the system and also ensure safe and continuous production of low-pressure wells.

This study has adequately addressed the aim, first and second objectives of this research. Also, addressed are the second and fifth gaps in research identified in Chapter 2 of this thesis.

9.2.5 Stabilisation of Severe Slugging With Active Control for Maximised Production

The design, implementation and the performance analysis of the Venturi and injectable Venturi with the application of active controllers (ISC) for improved stability and maximised production have been presented. The experimental evidence showed that active control improves the performance of the injectable Venturi and the Venturi. Also, it stabilised that the pipeline-riser-Venturi and pipeline-riser-injectable Venturi systems can operate beyond some operating regions that were previously not achievable without active control. These operating regions would ordinary have experienced severe slugging. In addition, active control increases the valve opening and lowers the riser base pressure of the pipeline-riser-Venturi and pipeline-riser-injectable Venturi systems beyond those obtainable during manual operation.

For the case studied, there was a 10 % increase in valve opening and a 16 % reduction in the riser base pressure when the percentage of valve opening associated with the Venturi with the controller applied was compared to that of the Venturi with no controller. In another case studied, there was a 7 % increase in valve opening and a 13 % reduction in the riser base pressure when the percentage of valve opening associated with the injectable Venturi with the controller applied was compared to that of the injectable Venturi with no controller. These further increase in valve openings and additional reduction in backpressure achieved by implementing active control leads to an increase in production. This potentially will help to further extend the operational life of a reservoir, thus enhancing oil recovery and flow assurance. Hence, the implementation of active control improved the performance of the two devices investigated in this study. Practically, these results imply that oil and gas production can proceed more smoothly. In addition, it suggest a safe and continuous production of low-pressure wells.

This study has adequately addressed the aim and third objective of this research. Also, addressed is the third gap in research identified in the critical literature review discussed in Chapter 2 of this thesis.

9.3 Contribution to Knowledge

The contributions recorded by these techniques are significant. This work has contributed the following among others to the body of knowledge:

1. A new correlation is proposed and developed for the calculation of K_{vt} (Effective area ratio) from flow conditions

2. A simplified injectable Venturi two-phase homogeneous flow model is developed in MATLAB from physical first-principles
3. Objective (using both PDF and PSD) characterisation of ten flow regimes in a 2" S-shaped pipeline-riser system using differential pressure across the entire length of the riser
4. Identification of ten flow regimes in an S-shaped pipeline-riser-Venturi and S-shaped pipeline-riser-injectable Venturi setups objectively (using both PDF and PSD) using differential pressure across the entire length of the riser
5. A novel passive severe slugging mitigation technique, the application of a Venturi at the topside is proposed and developed for severe slug mitigation, increase production and enhancement recovery
6. A new flow regulation device, the injectable Venturi is proposed and developed. The injectable Venturi extents the operation regime of conventional Venturi to make its flow characteristics adjustable during real-time operation
7. A novel active severe slugging mitigation technique, the injectable Venturi is proposed and developed for severe slug mitigation, increase production, enhanced recovery and improvement of flow assurance

9.4 Impact of Research

The potential impact of the findings of this research would go a long way in helping the oil and gas industries in areas such as:

1. ***Flow assurance:*** Severe slug attenuation would help in enhancing flow assurance and ensuring uninterrupted extraction and transportation of hydrocarbons from reservoirs to the processing facilities

2. ***Production management:*** This arises when different wells and fields owned by different operators are commingled in the same pipeline for export to a common processing facility. For this process to be successful, intermittent or irregular flow needs to be avoided. This research would help in enhancing smooth product management

3. ***Well testing:*** The process of well testing could be very rigorous. Elimination or drastic reduction in severe slugging will allow the operator to test more wells, more frequently, with more consistent accuracy without experiencing intermittent flow that could lead to unwanted shutdown of plants. The overall well test time and cost will also be significantly reduced

4. ***Reservoir management****:* The depletion of conventional oil wells has made reservoir management very vital. Elimination or prevention of severe slugging will help in enhancing the developments in reservoir management and production techniques geared towards maximising the production capabilities of these wells

5. ***Custody transfer:*** This is a very important process for operators in the oil and gas industries. Precise and continuous custody transfer measurement for hydrocarbon products sales and distribution are critical for the industry. Severe slug elimination would enhance smooth and continuous flow of hydrocarbon which is desirable for custody transfer

9.5 Recommendations for Further Work

This work has developed novel methods for severe slugging mitigation and established the capability of the Venturi and the injectable Venturi to stabilise the system and increase the overall production. However, there are still a number of issues which are necessary for further work, in order to achieve further improvement on the application of these devices for severe slugging mitigation.

The following investigations are recommended:

1. A simplified S-shape pipeline-riser system model from physical principles; coupled to the Venturi, and the injectable Venturi model could be developed and used to further investigate the severe slug attenuation potential of the Venturi and the injectable Venturi

2. The gas injection into the throat of the injectable Venturi could be regulated with a controller. Thus, multivariable control could be used for severe slugging detection and when to increase or reduce the gas injection into the throat of the injectable Venturi

3. Other advance active control methods such as: cascade control, adaptive control, non-linear control, multi-loop and multivariable control and model predictive control can be investigated to see if they could further improve the performance of the Venturi and the injectable Venturi.

4. The combination of the Venturi and the injectable Venturi techniques with other severe slugging mitigation techniques (self-gas lift, external gas lift etc.) for severe slug mitigation should be investigated

5. The capability of the Venturi and the injectable Venturi methods in mitigating hydrodynamic slugging can be investigated. In addition, their ability to stabilise the system and increase the overall production should also be considered

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APPENDICES

Appendix A
Cranfield University Multiphase Flow Test Facility

The test facility can be divided into five sections: the fluid supply section, the flow metering section, the valve manifold section, the test section and the phase separation section. Figure A-1 shows these sections in the Delta V SCADA system.

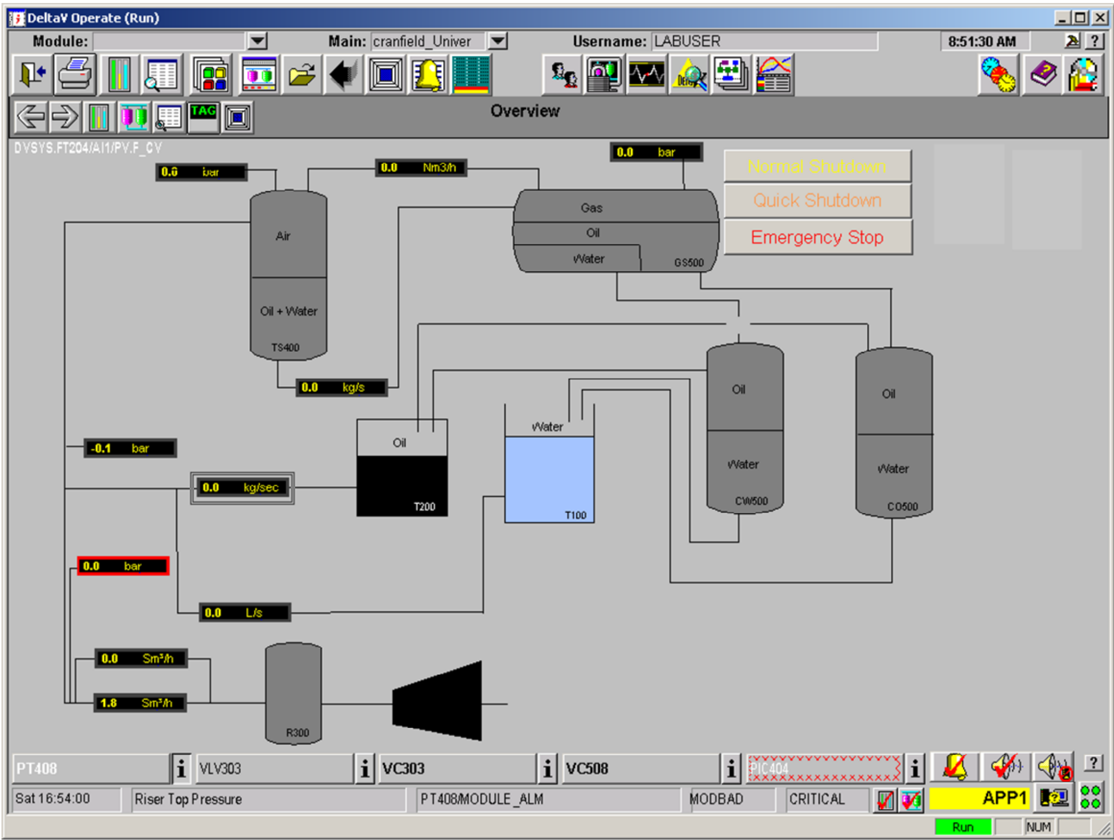

Figure A.1-1 Overview screen of the Delta V control system

A.1 Fluid Supply Section

The fluid supply section is where the individual single phase is supplied. The facility has three supplies: air supply, water supply and oil supply. However, for this project, only the air and water supply were used.

A.1.1 Air Supply

Air is supplied from a bank of two compressors connected in parallel. When both compressors are run in parallel, a maximum air flow rate of 1410 m^3/hr FAD at 7 barg can be supplied. The air from the two compressors is accumulated in an 8 m^3 capacity receiver to reduce the pressure fluctuation from the compressor. One of the air compressors is shown in Figure A-2. Air from the receiver passes through a bank of three filters (coarse, medium and fine) where the debris is removed and then through a cooler where condensates present in the air are removed before it goes into the flow meters. The receiver, filters and cooler are shown in Figures A-3, A-4 and A-5 respectively.

The pneumatic valve service compressor (PVSC) is used to power all the pneumatic control valve in the multiphase facility. This compressor is shown in Figure A-6.

Figure A.1-1 Air Compressor

Figure A.1-2 Air receiver (the long grey cylinder)

Figure A.1-3 Air filters

Figure A.1-4 Air Cooler

Figure A.1-5 Pneumatic valve service compressor (PVSC)

A.1.2 Water Supply

Water is supplied from a 12.5 m^3 capacity water tank. The water is supplied into the flow loop by a multistage Grundfos CR90-5 pump with a duty of 100 m^3/hr at 10 barg. Speed control is achieved using variable frequency inverters. The pump is operated remotely using the DeltaV SCADA system. The pump is shown in Figure A-7.

Figure A.1-6 Water pump

A.2 Flow Metering Section

The flow rates of the air and water are regulated by their respective control valves. The water flow rate is metered by a 1" Rosemount 8742 Magnetic flow meter (up to 1 kg/s) and 3" Foxboro CFT50 Coriolis meter (up to 30 kg/s). The air is metered by a bank of two Rosemount Mass Probar flow meters of ½" and 1" diameter respectively. Lower air flow rate (up to 150 Sm^3/h) are measured by the smaller air flow meter while the larger one meters the higher air flow rate up to 4250 Sm^3/h (subject to compressor capacity). The Foxboro CFT50 Coriolis flow meter, pneumatic control valve and the Delta V control system flow metering section are shown in Figures A-8, A-9 and A-10 respectively.

Figure A.2-1 Flow meter

Figure A.2-2 Pneumatic safety valve

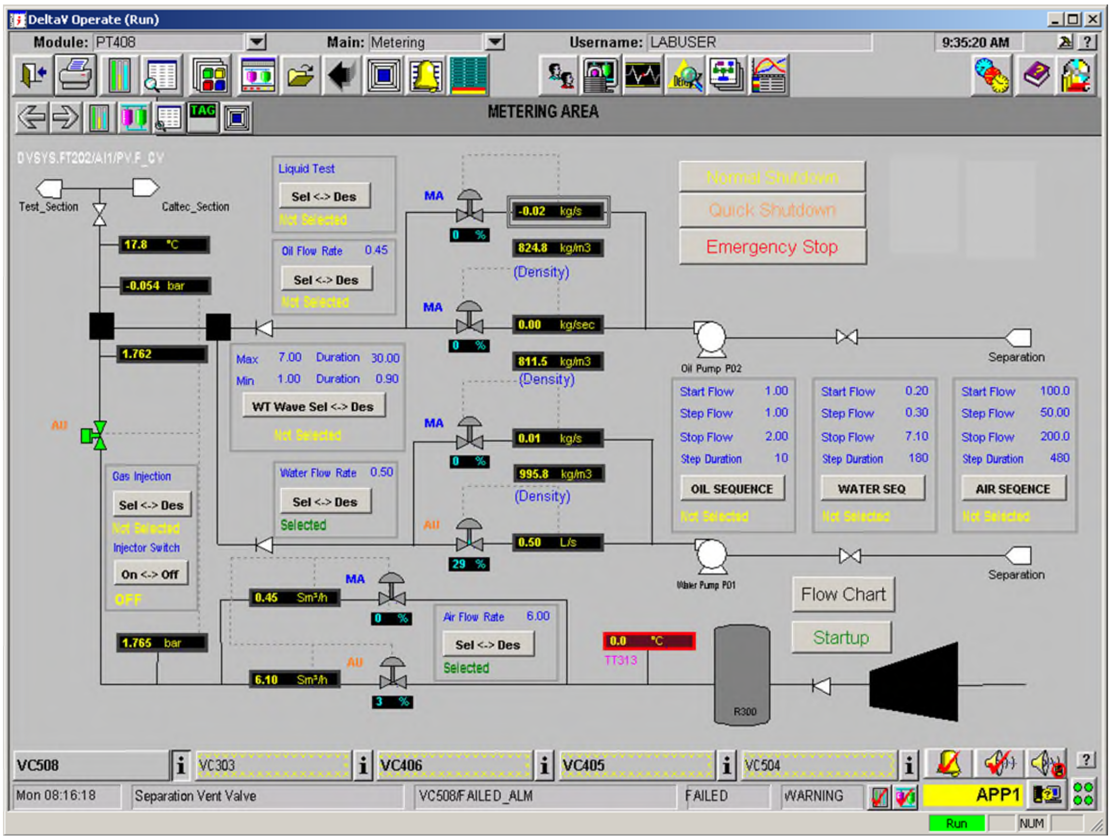

Figure A.2-3 Flow metering section of the Delta V program

A.3 Valve Manifold Section

This section is between the fluid supplies and test rigs. It is designed to distribute fluids to experiment rigs in addition to 4" and 2" flow loops. The mixing of the various single phase (air, water and oil) is implemented here. The relevant valves need to be positioned appropriately to run each rig and test conditions. Some section of the valve manifold section is shown in Figure A-11.

Figure A.3-1 Some valves in valve manifold section

A.4 Phase Separation Section

The separation process starts with the two phase separator. The main separation occurs in the horizontal three-phase separator (Figure 3-20) where air, water and oil are gravity separated. The pressure, oil-water interface level and gas-liquid interface level are controlled by the use of pressure controller and two level-displacer type level controllers, maintained by the DeltaV control system. The two-phase and 3-phase separator are shown in Figures A-12 and A-13 respectively.

Figure A.4-1 Topside two-phase separator

Figure A.4-2 Three-phase separator

After separation and cleaning in the horizontal three-phase separator, air is exhausted into the atmosphere. However, water and oil are transported to their respective coalescers, where the liquids are further cleaned before returning to their respective storage tanks. The water and oil return lines have two flow control valves off sizes 1" and 3" respectively. These are employed in a split range flow control scheme to keep the oil-water and the gas-liquid interfaces stable in the three-phase separator. For example, the smaller valve will operate when a small amount of water or oil exits the separator and vice versa. The separation section of the Delta V control system and the coalescers are shown in Figure A-14 and A-15.

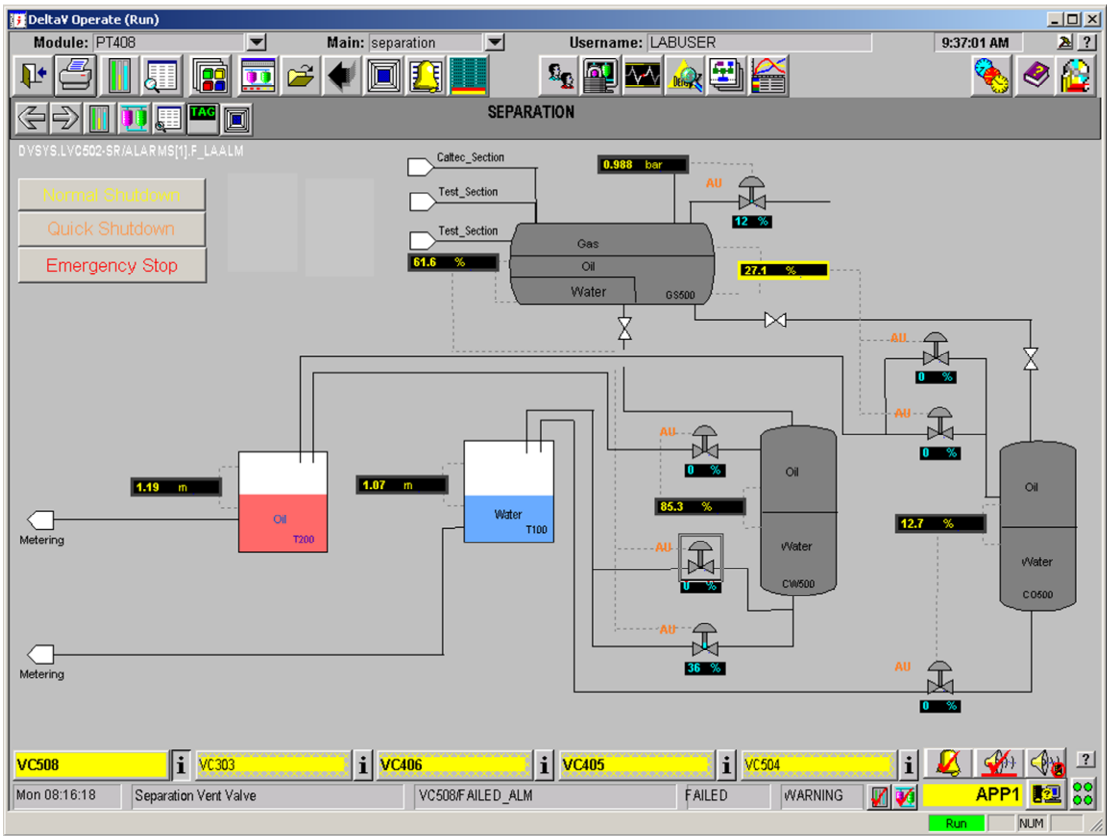

Figure A.4-3 Separation section of the Delta V SCADA system

Figure A.4-4 Water and oil coalescers

A.5 Valve Setup for 2" Pipeline-Riser Experiment

Table A-1 shows the general valve set up for experiments on the 2” S-shape pipeline-riser system.

Table A-1 Valve setup for experiments on the 2" S-shape pipeline-riser

Valve Number	Notation	Position
Valve 1	V1	CLOSED
Valve 2	V2	CLOSED
Valve 3	V3	CLOSED
Valve 4	V4	OPEN
Valve 5	V5	OPEN
Valve 6	V6	CLOSED
Valve 7	V7	CLOSED
Valve 8	V8	CLOSED
Valve 9	V9	CLOSED
Valve 10	V10	CLOSED
Valve 11	V11	OPEN
Valve 12	V12	CLOSED
Valve 13	V13	OPEN
Valve 22	V22	OPEN - serpent
Valve 23	V23	CLOSED - serpent
Valve 24	V24	CLOSED - serpent
U -shape Valve 31	U31	CLOSED
U -shape Valve 32	U32	OPEN
U -shape Valve 33	U33	OPEN
U -shape Valve 34	U34	CLOSED
U -shape Valve 35	U35	CLOSED
U -shape Valve 36	U36	CLOSED
U -shape Valve 37	U37	CLOSED
U -shape Valve 38	U38	OPEN
U -shape Valve 39	U39	CLOSED
U -shape Valve 40	U40	CLOSED
U -shape Valve 41	U41	CLOSED

Appendix B
Some Simplified Injectable Venturi Model Simulation Results

B.1 Comparison Plot

The simulation and experimental results were also compared using comparison plots in Figures B-1 and B-2 for two different test points. Here, comparison plots are scattered plots of the differential pressure across the Injectable Venturi, $P_1 - P_3$, as obtained from the model versus that from the experiment in the y- and x-axes, respectively. A good fit is achieved if the scatter points coincide with the line, $y = x$, which is the solid 45-degree line in the middle of the plot.

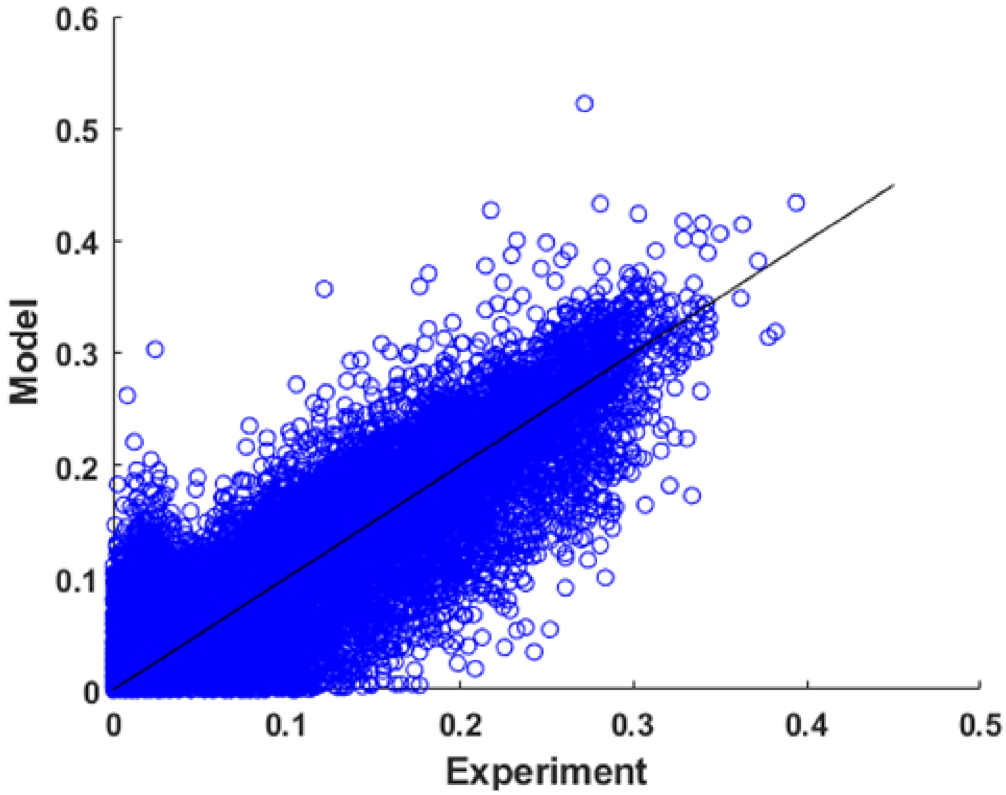

Figure B-1 Comparison plot (V_{sl} = 0.25 m/s, V_{sg} = 2.0 m/s, Q_g = 50 Sm^3/hr and K_{vt} = 0.44)

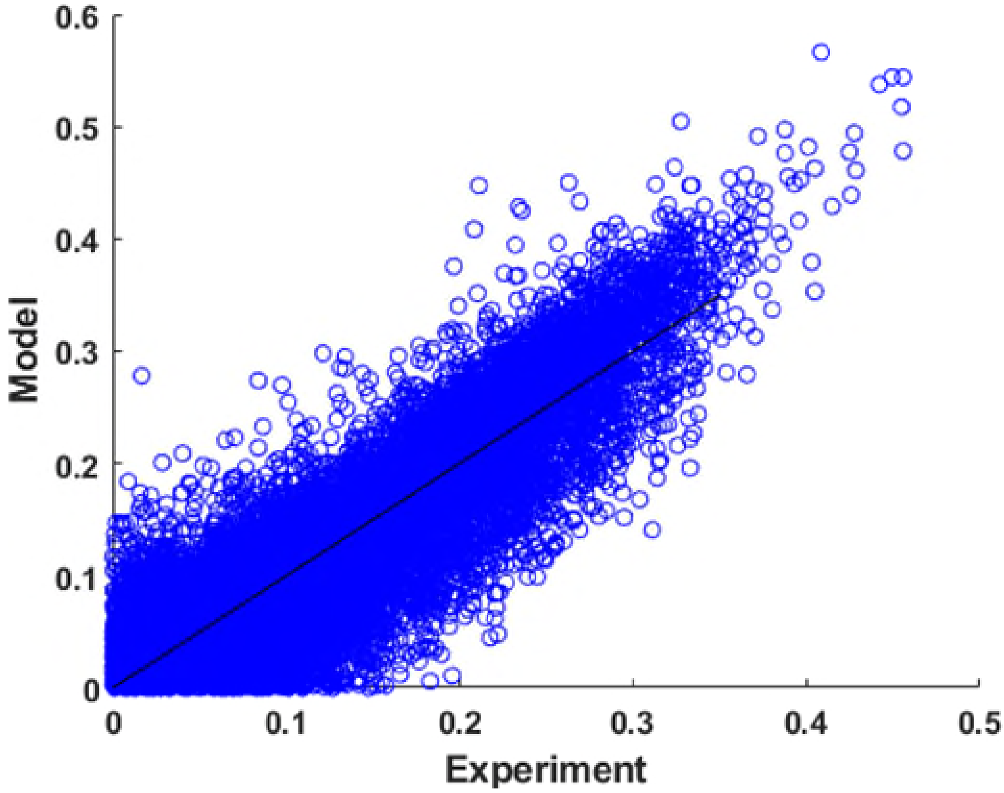

Figure B-2 Comparison plot (V_{sl} = 0.25 m/s, V_{sg} = 5.5 m/s, Q_g = 50 Sm^3/hr and K_{vt} = 0.49)

Appendix C
Process Reaction Curve

The process reaction curve for the pipeline-riser system with the Venturi and the injectable Venturi installed are given Figure C-1 and C-2.

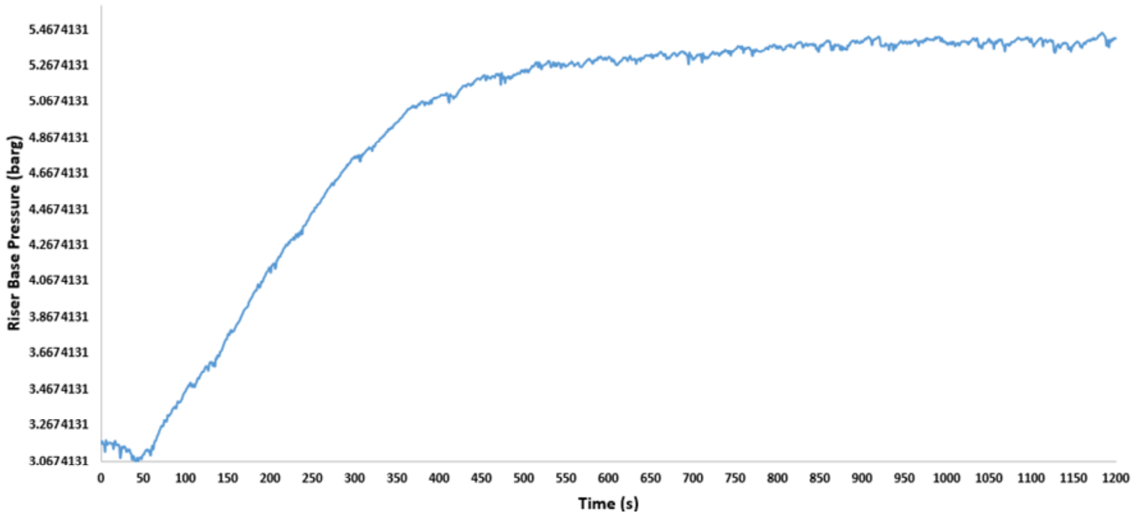

Figure C-1 Reaction curve for the pipeline-riser system with Venturi applied

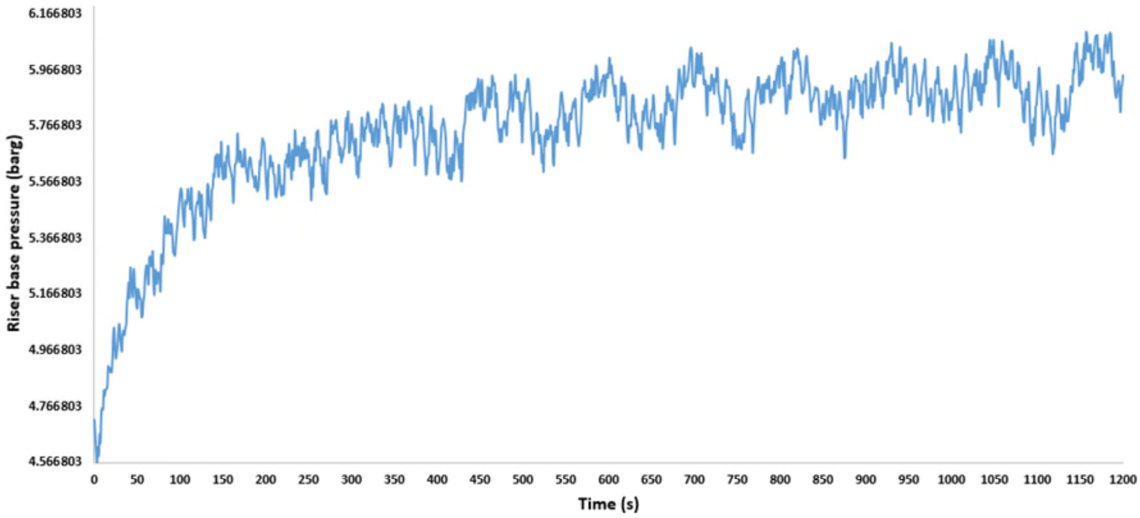

Figure C-2 Reaction curve for the pipeline-riser system with injectable Venturi applied