Master's thesis

NTNU
Norwegian University of Science and Technology
Faculty of Engineering
Department of Geoscience and Petroleum

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Data analysis on numerical simulation results to determine the effectiveness of mitigation measures for hydrodynamic slugging in an oil and gas asset on the Norwegian Continental Shelf.

Master's thesis in Petroleum Engineering
Supervisor: Milan Stanko
Co-supervisor: Graham Rudrum
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Abstract

Multi-phase flow-related issues in subsea pipelines and risers may cause a lot of problems in oil and gas production. One of these issues is hydrodynamic slugging. This unwanted phenomenon which is an oscillatory flow may induce large flow and pressure fluctuations, which may lead to damage to the transportation and processing facilities and unstable production. In offshore pipeline-riser systems with flexible risers, this oscillatory multiphase flow can cause Slug-Induced Vibration (SIV) which can reduce the fatigue life of the risers.

The present thesis is focused on investigating hydrodynamic slugging in two flowline-riser systems in a field on the Norwegian Continental Shelf using numerical simulation. Measures to eliminate or mitigate hydrodynamic slugging are simulated and evaluated in the simulator and observations and conclusions are issued about their effectivity.

The case studies are two pipeline-riser offshore systems of 4.5 and 19.5 [km], respectively, that are currently producing in the Bøyla field and exhibit hydrodynamic slugging. The systems were simulated using the commercial transient multiphase flow simulator OLGA version (2020.2.0). Slug mitigation methods which were believed to be helpful and feasible to tackle the problem of hydrodynamic slug were investigated, namely external gas-lifting and topside choking. After applying these two methods in the simulator and evaluating them with the three analysis methods (Manual frequency calculations, Fast Fourier Transform, and Frequency Analysis), it turned out that, only the topside choking method can be helpful for dealing with the hydrodynamic slugging problem in these case studies. However, topside choking also has the side effect of decreasing production rates considerabley.

Acknowledgments

I would like to express my deep appreciation and thanks to my supervisor at NTNU, associate professor Milan Stanko for his support throughout the semester with my master's thesis. He has also supervised my specialization project and was the one who made me familiar with the topic of flow assurance in the first place.

My sincere gratitude goes to Graham Rudrum, Lead Flow Assurance Engineer at Aker BP ASA, for dedicating his time to helping me with the challenges throughout the process. His wonderful attitude created a friendly, yet professional atmosphere for me to learn and grow in this field.

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I would like to thank my dear friend Milad Khatibi, Principal Flow Assurance Engineer at Equinor, who helped me to extend my knowledge around the topic of slug flow.

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Nomenclature

Symbols

v_{SW}	The superficial velocity of the water [m/s]
v_{SO}	The superficial velocity of the oil [m/s]
v_{SG}	The superficial velocity of the gas [m/s]
v_m	The velocity of the mixture [m/s]
v_L	The velocity of the liquid phase [m/s]
v_G	The velocity of the gas phase [m/s]
Q_O	The volumetric flow rate of the oil [m^3/s]
Q_G	The volumetric flow rate of the gas [m^3/s]
A_W	The cross-sectional area of the pipe occupied by the water [m^2]
A_O	The cross-sectional area of the pipe occupied by the oil [m^2]
A_G	The cross-sectional area of the pipe occupied by the gas [m^2]
H_W	The holdup of the water [-]
H_O	The holdup of the oil [-]
H_L	The holdup of the liquid [-]
H_G	The holdup of the gas [-]
H_{LS}	The holdup of the liquid slug [-]

Abbreviations

OLGA	OiL & GAs (name of a multiphase simulator)
SIV	Slug-Induced Vibration
PST	Pseudo Spiral Tube
PID	Proportional Integral Derivative
PI	Proportional Integral
LPR	Lift Performance Relationship
PVPAT	Present Value Profit After Tax
MIMO	Multiple Input Multiple Output
MISO	Multiple Input Single Output
S^3	Slug Suppression System
MWA	Mid Water Arch
FFT	Fast Fourier Transform
FPSO	Floating, Production, Storage, and Offloading
NPD	Norwegian Petroleum Directorate
PDO	Plan for Development and Operation
ID	Inner Diameter
PSD	Power Spectral Density
OPEX	OPeration EXpenditure
CAPEX	CAPital Expenditure
MPPS	Multi Parallel Pipe Separator
CI	Corrosion Inhibitor

CHAPTER 1
Introduction

1.1 Problem Statement

A crucial component in terms of the design and operation of multiphase production facilities is flow assurance which refers to ensuring produced hydrocarbons flow from the reservoir to the topside processing facilities (Mokhatab et al., 2018). Handling multiphase flow-related issues such as slug, in offshore pipeline-riser systems is an important task, full of challenges for the flow assurance engineers.

The offshore multi-phase flow of hydrocarbon production and transportation through subsea pipeline-riser systems often face huge challenges due to unstable flow regimes, like hydrodynamic slugging. The upstream production process is subjected to many consequences because of the oscillating rate and pressure caused by slugging. Moreover, slug flow can cause production losses, damage to the equipment and facilities, and in the worst case, a shutdown of the production operation. Therefore, in the oil production industry, simulators have been developed for predicting the multi-phase flow behavior, and many research efforts are aimed at improving the reliability and accuracy of system design tools.

Besides, in a subsea pipeline-riser system, slugging can cause serious problems, especially in the risers. Risers which are long pipes with different shapes and configurations can connect a subsea pipeline to the surface facilities for hydrocarbon production. There are essentially two kinds of risers, flexible and rigid. The flexible riser which is the focus of this work can be affected by Slug-Induced Vibration (SIV) because the dynamic response of a flexible riser to the pressure fluctuation of slug flow can decrease the fatigue life of the riser.

The main purpose of this thesis is to study a flowline-riser system in an oil and gas field on the Norwegian Continental Shelf using a numerical simulator. The ultimate goal is to find a method to either eliminate the hydrodynamic slugging before entering the riser or reduce the intensity of the flexible riser movement by mitigating the slug frequency and scope of the pressure change caused by slugging.

This thesis was written based on the input provided by the flow assurance department at Aker BP which are the operators of the field which the study cases deal with and the communication with Graham Rudrum (lead flow assurance engineer at Aker BP).

The following sections will provide the objectives and structure of this thesis.

1.2 Objectives

The main objectives to accomplish in this thesis were:

1) Knowledge build-up to provide a thorough theoretical overview of multiphase flow, and specifically, of slug flow.
2) Perform a comprehensive literature review of the slugging phenomenon and mitigation techniques used for slug control.
3) Build computational models of two flowline-riser systems of an oil and gas field on the Norwegian Continental Shelf on a commercial multiphase transient simulator
4) Proposing slug mitigation methods considering the case study's capabilities and evaluating them using the computational model in OLGA.
5) Using three different analysis methods consisting of Manual frequency calculations, Fast Fourier Transform (FFT), and Frequency Analysis, to capture the effect of applying two of the slug mitigation approaches (external gas-lifting and topside choking) in two case studies.

1.3 Thesis Structure

- Chapter 1 (this chapter): Provides the problem statement and introduces the objectives of the thesis.
- Chapter 2: Focuses on the theory and literature surrounding the multi-phase flow which is essential for a better understanding of slug flow.

- Chapter 3: A comprehensive review of slug flow sources and mechanisms, slugging types, problems, and anti-slug control approaches, is presented. Moreover, slug characteristics such as length, frequency, holdup, and velocity are explained in this chapter.
- Chapter 4: Describes the case study purpose, the features of the investigated cases, and the methods that were used to examine slug mitigation approaches. Furthermore, analysis methods that were used in this work to evaluate the simulation results and the output of applying these analysis methods on two slug control approaches (external gas-lifting and topside choking) in the case studies are presented.
- Chapter 5: Presents the conclusions and recommendations for future works.

CHAPTER 2

Review of Multiphase Flow in Pipelines

2.1 Introduction

A definition of a phase in chemistry would be a homogeneous chemical composition, with no internal boundaries separating it into parts. The latter requirement means the phase must be in a single state of matter and no internal boundaries separate it into different states. According to this requirement, water is a substance that can be in one of the three different phases (gas, liquid and solid) concerning pressure and temperature. Also, the liquid brine consisting of water and a fixed fraction of sodium chloride in a reservoir would be a phase. In contrast to the definition used in chemistry, in petroleum engineering the requirement of "homogeneous chemical composition" is relaxed. Thus, in the definition used in petroleum engineering, a phase has no internal boundaries while the second requirement is relaxed to a vaguer similarity in the chemical composition, meaning that the brine even with variation in salt content is considered a single phase. And the solid matrix, although it might consist of different minerals, is considered a single solid phase (Berg & Slotte, 2021).

Considering this definition, the term multiphase flow refers to any fluid flow consisting of more than one phase. In a production flowline, different fractions of hydrocarbons (gas, oil, gas condensate), produced water (brine), and solid particles are the most encountered fluids. Therefore, a basic case containing gas, oil, and water is a typical example of a three-phase flow.

The purpose of this chapter is to provide an overview of some of the basic concepts important for understanding the multiphase flow behavior in a production flowline.

2.2 Multiphase Flow

Multiphase flow can be defined as two or more distinct phases that flow through a flowline. A common example of multiphase in the field of petroleum and flow assurance engineering is the production fluid which is a combination of liquid (oil and water), gas, and/or solids.

The topic of multiphase flow has great importance in the petroleum industry, where mixtures of gas, oil, and water are transported over a long distance in horizontal and vertical pipes. However, traditionally the different phases were separated before long transportation but recently it has been proven that it is more financially viable to transport the phases commingled in the same pipeline (Meland, 2011). Although there has been lots of research on multiphase flow recently, this topic is not yet fully understood, and the presented models have limited predictability. Therefore, to reach an accurate prediction of multiphase flow characteristics such as water holdup and pressure gradient, further investigation into the various concepts of multiphase flow is needed (Brauner, 2003).

2.3 Multiphase Flow Terminology

This section defines the commonly used variables for describing a multiphase flow. These variables are described based on *Figure 2-1*, which shows an ideal example of a three-phase flow in a production stream. It is assumed that the density of water is more than oil thus, the oil flows over the heavier phase, while gas which is lighter than oil flows in the top layer (Mokhatab et al., 2018).

Figure 2-1: *Three-phase flow pipe cross-section*

2.3.1 Superficial velocity

The term superficial velocity is used to refer to the velocity of one phase in a multiphase flow, assuming that the phase occupies the entire cross-sectional area of the pipe by itself. Thus, for each phase it is described as followed:

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

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

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

Where:

$$A = A_W + A_O + A_G$$

In the equations above A is the total cross-sectional area of the pipe, Q is the volumetric flow rate, v is the velocity, and the subscript W, O, and G denotes water, oil, and gas and S denotes superficial term.

2.3.2 Mixture velocity

The fluid mixture velocity is equal to the sum of the superficial velocities:

$$v_m = v_{sw} + v_{so} + v_{SG}$$

Where v_m is the multiphase mixture velocity.

2.3.3 Holdup

The occupied cross-sectional area by one of the phases of a multiphase flow, relative to the cross-sectional area of the pipe is defined as the Holdup of that phase. The equation for the liquid phase and the gas phase are shown below:

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

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

Parameter H is the phase holdup and the subscripts L and G denote the liquid and the gas phase respectively. Although the term "holdup" can be defined as the fraction of the pipe volume occupied by a given phase, it is usually used for indicating the in-situ liquid volume fraction, while for defining the in-situ gas volume fraction the term "void fraction" is used.

2.3.4 Phase velocity

In a multiphase flow, the velocity of one phase relative to the cross-sectional area of the pipe occupied by that phase is defined as the Phase velocity (in-situ velocity). For each phase it is defined as followed:

$$\mathrm{v_L} = \frac{\mathrm{v_{SL}}}{H_L} = \frac{\mathrm{v_{SW}} + \mathrm{v_{SO}}}{H_L}$$

$$\mathrm{v_G} = \frac{\mathrm{v_{SG}}}{H_G}$$

2.4 Flow Regimes

Unlike single-phase flow, multi-phase flow can take many different spatial configurations and that is one of the most challenging aspects of dealing with multi-phase flow. A multiphase flow can be characterized according to the interfaces between the phases and discontinuities of associated properties. These characteristics and flow structures are classified as "flow regimes". Flow regimes in a multiphase flow may vary depending on phase velocities, fluid properties, and pipeline geometries. The transition from one flow regime to another may be a gradual process. Since the nature of the forces ruling the flow regime transitions is highly nonlinear, it is challenging to predict these transitions. In the laboratory, the flow regime studies may take place by direct visual observation through a transparent pipe. However, nowadays visual observation is often complemented with signal analysis of sensors that are sensitive to average cross-sectional quantities, such as pressure drop or cross-sectional liquid holdup.

Although there are different types of flow regime classifications, they can be categorized into three basic flow patterns, separated, intermittent, and distributed flow. In separated flow patterns both phases (gas and liquid) are continuously flowing in the pipe while in the intermittent flow patterns at least one phase is discontinuous. When the liquid phase is continuous, and the gas phase is discontinuous the flow pattern is called distributed. (Hubbard & Dukler, 1966; Mokhatab et al., 2018; Taitel & Dukler, 1976)

In this work, only some of the flow regimes in the gas-liquid multiphase flow in the horizontal pipeline are explained which are essential for understanding the topic of slug flow. For a more detailed explanation of multiphase flow regimes in horizontal and vertical pipelines refer to (Bratland, 2010; Mokhatab et al., 2018; Rajan et al., 1993; Wu et al., 2017). *Figure 2-2* shows the two-phase, gas-liquid flow regimes for a horizontal flow. These flow regimes can be defined respectively as follows:

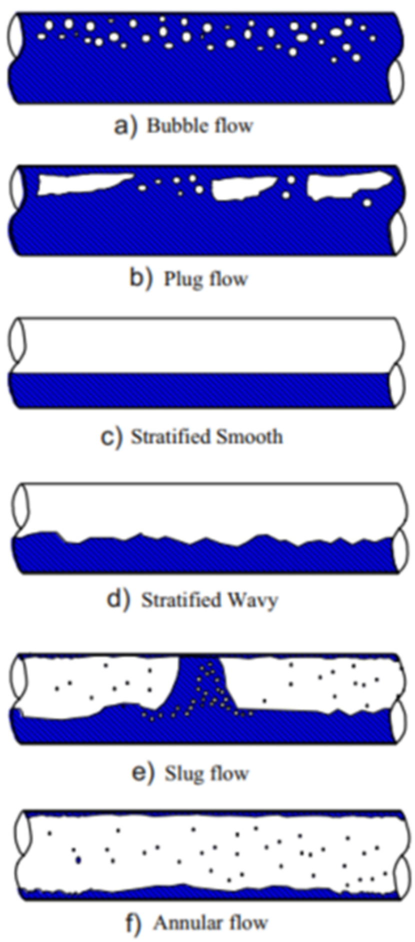

Figure 2-2: *Horizontal two-phase, gas - liquid flow regimes. (Mokhatab et al., 2018)*

2.4.1 Dispersed bubble flow

In gas-liquid two-phase, at high liquid flow rates, the gas may appear as small bubbles. These tiny amounts of gas bubbles are dispersed throughout the continuous liquid phase and due to the buoyancy effect, the bubbles can be observed in the upper part of the pipe. The schematic of this flow regime is illustrated in *Figure 2-2-a.*

2.4.2 Plug (elongated bubble) flow

Figure 2-2-b shows the plug flow, which is a flow regime that may appear as the liquid flow rate is decreased and the gas flow rate is relatively low. In this situation, the smaller dispersed bubbles start to accumulate to form larger bubbles that look like bullets. These bullet-shaped bubbles tend to move at the top of the pipe.

2.4.3 Stratified (smooth and wavy) flow

Due to gravitational effects, at low gas and liquid flow rates segregated layers of gas and liquid flow together with a smooth interface. *Figure 2-2-c* illustrates Stratified Smooth in which, the lighter phase (gas) floats over the heavier phase (liquid). Increasing the gas velocity intensifies the interfacial shear forces which results in the formation of a wavy interface. This flow regime is called Stratified Wavy flow, which is depicted in *Figure 2-2-d.*

2.4.4 Slug flow

The illustrated flow regime in *Figure 2-2-e* is called Slug flow which may appear as gas and liquid flow rates are increased from Stratified flow conditions. The increase in gas and liquid flow rates amplifies the formed waves along the two-phase interface. The wave's amplitude rises progressively until the wave crests get high enough to block the whole cross-sectional area of the pipe (H_L=1). Notice that there is a major difference between a Slug flow (*Figure 2-2-e*) and an Elongated Bubble flow (*Figure 2-2-b*). The difference is that in an Elongated Bubble flow there are no entrained gas bubbles in the liquid slugs.

2.4.5 Annular flow

When the gas velocity increases even further in Slug flow, sufficient turbulence is created in the gas phase to tear the liquid droplets. At this point, the transition occurs, and the gas phase turns to the continuous phase and the liquid phase flows partly in the shape of a thin film around the pipe wall and partly in the form of tiny droplets dispersed in the continuous gas phase in the core of the pipe. This type of flow regime which is also called annular mist flow is illustrated in *Figure 2-2-f* (Mokhatab et al., 2018).

2.5 Flow Pattern Maps

As has been explained in the previous part, flow mechanisms as well as the hydrodynamics of flow change drastically from one flow regime to another, thus it is vital to clearly understand two-phase gas-liquid flow regimes and the boundaries between them. For this aim, flow pattern maps are created to anticipate the occurrence of each flow regime and accordingly design the parameters and operating conditions such that the optimal results are obtained. An example of a flow pattern map in horizontal flow suggested by (Mandhane et al., 1974) is shown in *Figure 2-3.*

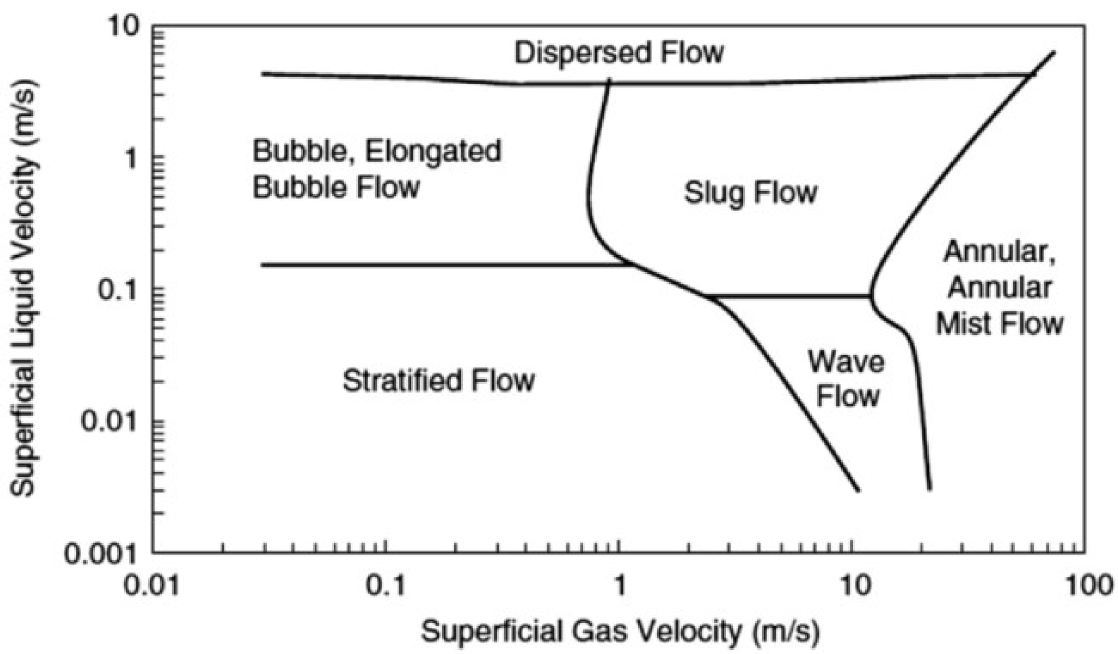

Figure 2-3: *flow regime map for a horizontal flow.(Mandhane et al., 1974)*

In the flow pattern map in *Figure 2-3*, superficial velocities of each phase are used to determine the flow regime and the transition boundaries.

It should be noted that although flow pattern maps are useful tools to gain an overview of the occurrence of expected flow regimes for a specific set of input data, each flow pattern map is valid for its own set of data (fluid properties, pipe characteristics, superficial velocities), and it cannot be generalized to cover all other input data sets. Thus, it is suggested that to achieve the optimal design of the parameters and operating conditions, the flow pattern map should be computed for the specific input parameters (Bratland, 2010).

CHAPTER 3

Slug Flow Characteristics

3.1 Introduction

For more than six decades the topic of multiphase flow in pipeline systems has been studied and experimental and mechanistic models were presented, however, these studies and models were not capable of providing a thorough understanding of the concept of multiphase flow, especially when it comes to slug flow (Ragab, 2008). With the advent and development of computers and numerical power, the subject of the multiphase flow phenomenon was investigated more in detail, and in terms of slug flow, trials have been presented to model some slug flow characteristics, such as slug length and frequency. However, the models may not be considered accurate enough for the design of the pipelines and downstream equipment. (Ragab, 2008)

Dynamic multiphase flow simulators, like OLGA, were developed which allow the user to model the pipeline and observe the flow characteristics and assess flow assurance issues such as slugging. However, for petroleum engineers who want to utilize these multiphase flow simulators in terms of slug flow, it is vital to building up knowledge around slug flow characteristics.

In this chapter, a review of slug flow in terms of slug flow sources and mechanisms, slugging types, and problems, and how to prevent and alleviate this problematic flow is presented. Furthermore, slug flow characteristics such as slug length, slug frequency, slug holdup, and slug velocity are explained to achieve a comprehensive understanding of the slug flow phenomenon in pipeline–riser production systems.

3.2 Slug Flow

One of the major challenges in terms of flow assurance is Slugging which is an unstable flow regime causing abrupt changes in the production parameters such as flow rates, pressure, and temperature. If not addressed, the issue of slugging may cause poor gas-oil separation, production reduction, extra fatigue loads to installations and facilities, and in the worst case, shut-off of the production system. Thus, analyzing slug characteristics and developing knowledge around its different types are necessary for an efficient and feasible design of operational parameters while dealing with a gas-liquid slug flow system. (Mokhatab et al., 2018; Pedersen et al., 2015)

3.3 Slug Flow Sources

Depending on the operating conditions in an oil field, liquid slugs may appear in the pipeline. To predict or detect the presence of slug flow it is vital to know the sources and mechanisms that result in the creation of slug flow. Of these sources, some are listed below:

3.3.1 Transient effects

Along the pipeline, transient effects such as changes in pressure or flow rate may cause slug production. For example, as it is shown in *Figure 3-1,* if a horizontal flowline operating in a Stratified flow region (point A) is opposed to an increase in gas flow rate and accordingly an increase in superficial gas velocity (v_{SG}), the flow regime would enter into Slug flow region (point B) and some slugs may appear in the pipe. (Ragab, 2008)

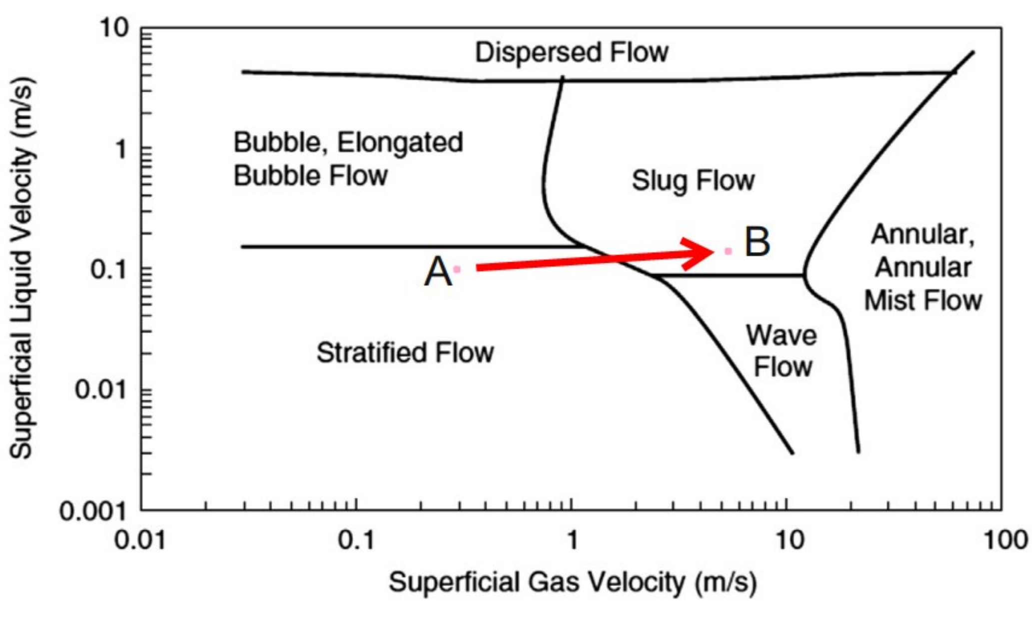

Figure 3-1: *An example of flow regime transition on the flow pattern map for a horizontal flow taken from (Mandhane et al., 1974)*

3.3.2 Start-up and blow-down operations

When a pipeline is shut down, the liquid which is the heavier phase in a gas-liquid multiphase flow has the tendency to accumulate at the low points in the pipeline as it is illustrated in *Figure 3-2*, and when the line is restarted again, the accumulated liquid will be pushed out. At the downstream of the pipeline, the liquid may exit in the form of slugs. During depressurization, there is also the possibility of slug production due to high gas velocities. (Mokhatab et al., 2018)

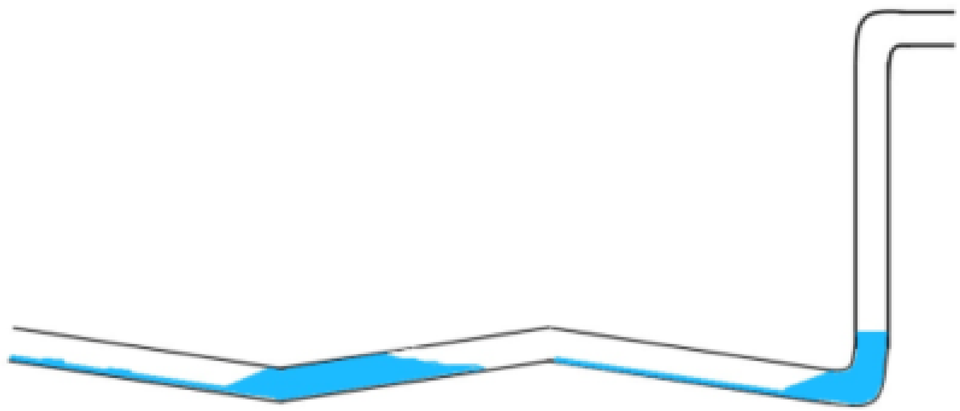

Figure 3-2: *Liquid build-up at the lowest points of the pipeline taken from (Sancho, 2015).*

3.3.3 Pigging operations

In a pigging operation, pigs are run through pipeline maintenance and data logging, or cleaning and de-waxing. This operation causes most of the liquid inventory to be pushed from the pipeline as a liquid slug ahead of the pig as it is shown in *Figure 3-3*.

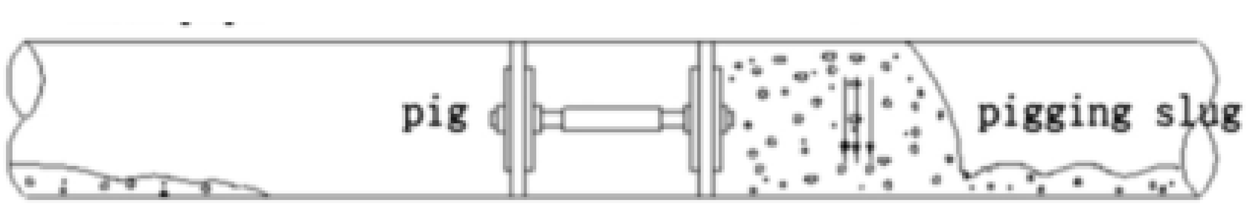

Figure 3-3: *Liquid build-up in front of the pig taken from (Ruixi et al., 2013)*

3.3.4 Topography of the pipeline

Significant elevation changes along the pipeline such as geographical features or vertical risers can cause slugs. The reason for that is the liquid has the potential to accumulate at the lowest points in the flowline as it is shown in *Figure 3-2*.

3.4 Slugging Types

Depending on different operational conditions and installation structures, slugging may appear in different types. These types, which are usually categorized concerning the origins of slugs, will be explained in this section:

3.4.1 Hydrodynamic slugging

In a two-phase gas-liquid flow, at low flow rates, the liquid layer flows as a stratified phase with the gas passing above. Increasing the superficial velocity of the gas results in the growth of waves on the gas-liquid interface and the liquid layer decelerates while moving along the pipe. The wave amplitude may progressively increase under specific flow conditions until it occupies the whole cross-sectional area of the pipe. Under these circumstances, the wave height would be sufficient to bridge the pipe and momentarily block the gas flow. (See *Figure 3-4*, parts A, B, and C). Once the bridging phenomenon takes place, the liquid in the bridge (*Figure 3-4*, part C) is accelerated to the gas velocity. It appears that the liquid is accelerated uniformly across its cross-section, thereby like a scoop, sweeping up all the slow-moving liquid in the film ahead of it. Eventually, the fast-moving liquid builds its volume and turns into a slug. (See *Figure 3-4*, part D). (Dukler & Hubbard, 1975)

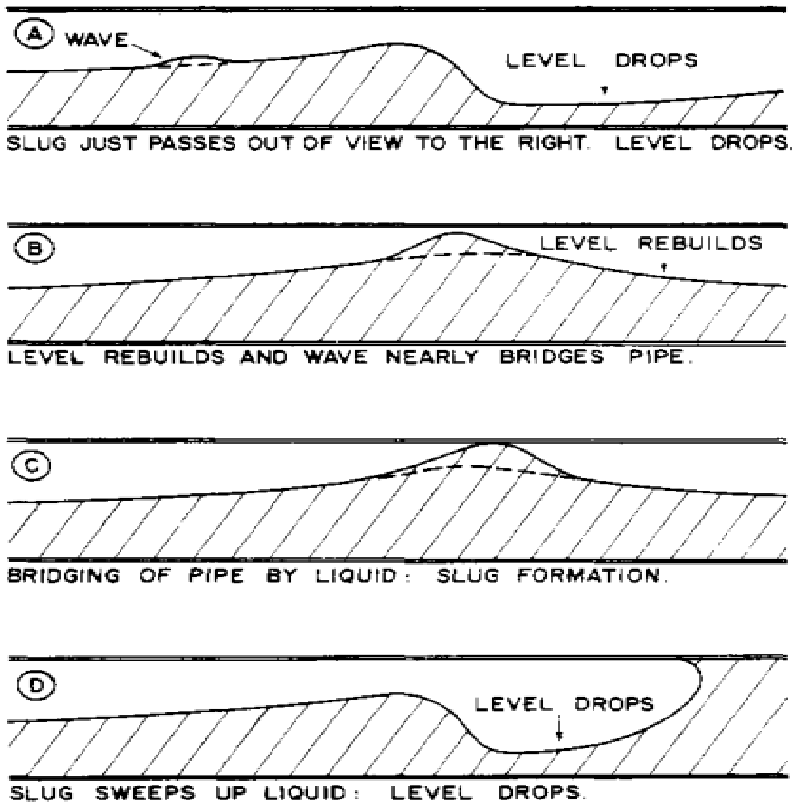

Figure 3-4: *The process of Hydrodynamic slug formation, adopted from (Dukler & Hubbard, 1975)*

This type of slug is called hydrodynamic or normal slug and when there is a large amount of hydrodynamic slug it is said that the flowline is operating in the slug flow regime. A fully formed slug of this type is demonstrated in *Figure 3-5.*

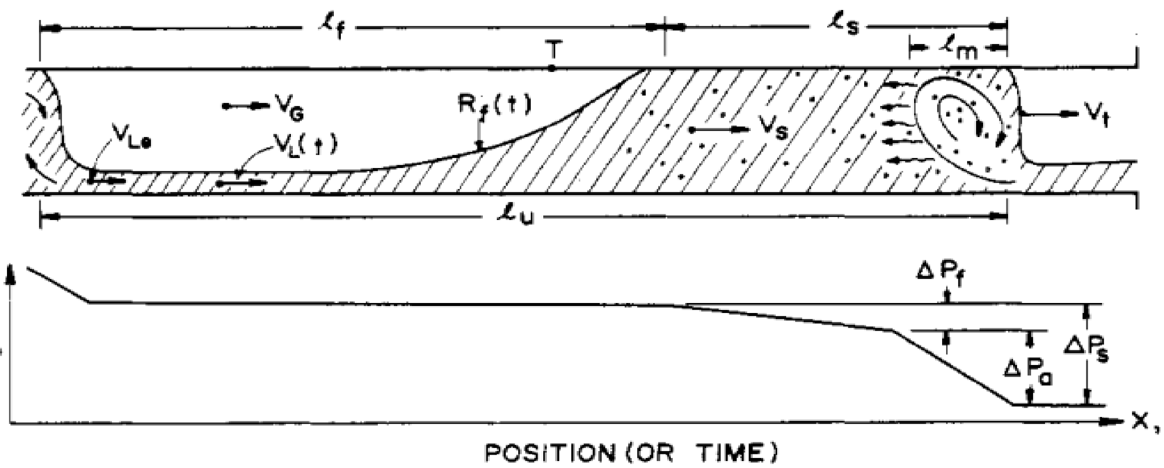

Figure 3-5: *The physical model for a fully formed slug. adopted from (Dukler & Hubbard, 1975)*

3.4.2 Operationally induced slugging

Operations, such as pigging, depressurization, ramp up and production shutdown can cause abrupt changes in flow rate and initiate slugging. Thus, these types of slugging are categorized as operationally induced slugging. When designing the production flowline, it is important to estimate the volume of these slugs to ensure that the downstream facilities' capacity is sufficient to function preferably and prevent any possible damage to the production system. (Mokhatab et al., 2018; Murashov, 2015; Sivertsen et al., 2010)

3.4.3 Terrain-induced slugging

The topography of the field is the major cause of this type of slugging, therefore in a flowline across undulating terrain, there is a strong potential for terrain-induced slug formation. Terrain slugging is most likely to occur at low flow rates, with a low pipeline pressure, because under these circumstances, the liquid phase, which is the heavier phase, tends to accumulate at the lowest parts of the pipeline until it blocks the cross-sectional area of the pipe and forms the slug. The slug size may grow to a noticeable length until it is pushed by the pressure of the gas captured behind. Terrain-induced slugging will only form in an upwardly inclined section of the flowline, and they are unlikely to persist throughout the whole length of the pipe. Instead, they will steadily decay and then collapse in horizontal or downwardly inclined sections where liquid cannot build up. As an example, a sketch illustrating typical terrain-induced slugging, with the denser phase accumulating in elbows and uphill sections of the pipe is shown in *Figure 3-6*. In this example, the flow is from left to right. (Bendiksen et al., 1986; McGuinness & McKibbin, 2002; Mokhatab et al., 2018)

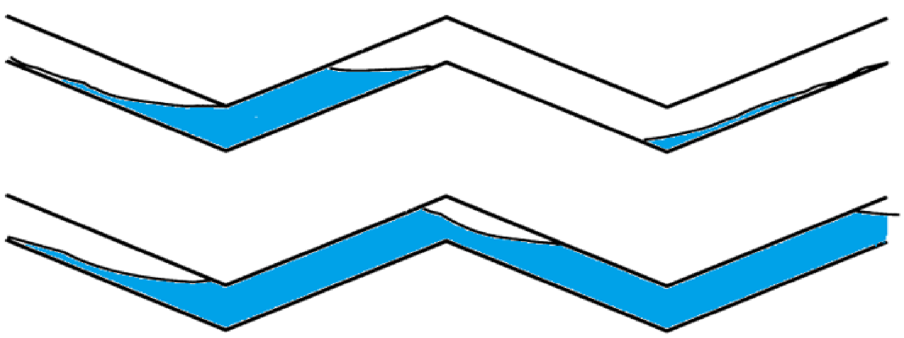

Figure 3-6: *Typical terrain-induced slugging formation in elbows and uphill sections, taken from (McGuinness & McKibbin, 2002)*

3.4.4 Riser-induced (severe) slugging

Severe slugging and terrain-induced slugging have the same mechanism; however, these two types of slugging differ in the location of the origin. In another word, an extreme case of terrain-induced slugging which occurs in a pipeline-riser system is denoted as severe slugging. Since in severe slugging the liquid accumulates at the riser base, this phenomenon is known by various names in the industry, including “riser-base slugging” and “riser-induced slugging.” In the early 80s, the severe slugging phenomenon received much attention as part of the Tulsa University Fluid Flow Projects run by Zelimir Schmidt and his team. (Schmidt, 1977; Schmidt et al., 1981; Schmidt et al., 1980; Schmidt et al., 1985). The reason behind this attention was probably linked to the increase in the number of subsea production platforms and the depth of offshore developments, thereby growth in demand for utilizing more risers which are longer and consecutively causing severer riser induced slugging conditions. (Murashov, 2015). The phenomenon of severe slugging is very undesirable due to the fluctuations in pressure and flow rate that result in unwanted flaring and reduce the operating capacity of the separation and compression units. These fluctuations and the undulating behavior of flow rates and pressure during severe slugging have been studied in several papers (Gong et al., 2014; Malekzadeh et al., 2012; Mokhatab, 2007). *Figure 3-7, Figure 3-8*, and *Figure 3-9* show examples of time trace for the riser outlet gas and liquid flow rates and pressure changes during severe slugging, respectively.

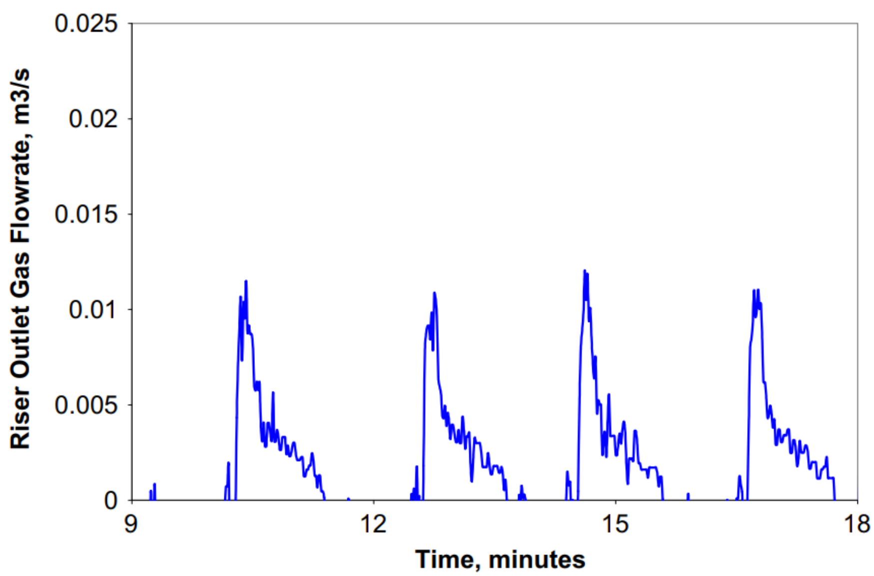

Figure 3-7: *Example time trace of the riser outlet gas flow rate during severe slugging, taken from (Mokhatab, 2007)*

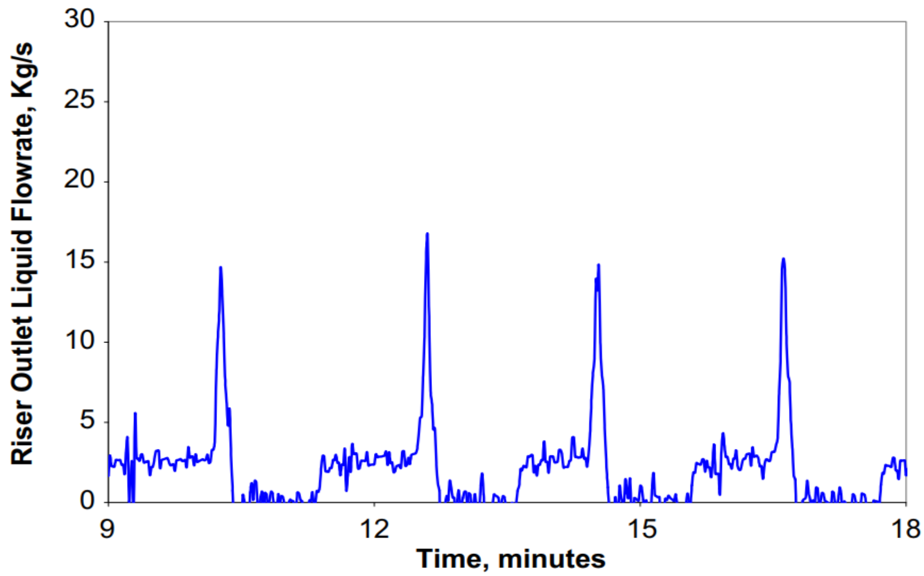

Figure 3-8: *Example time trace of the riser outlet liquid flow rate during severe slugging. taken from (Mokhatab, 2007)*

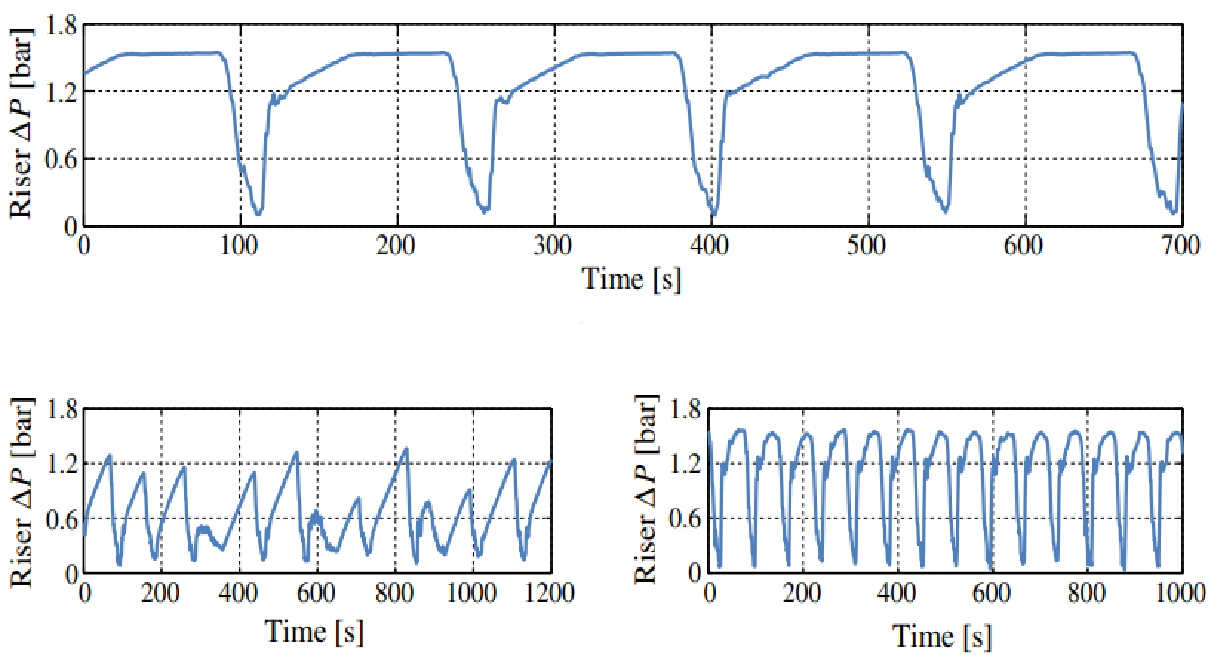

Figure 3-9: *Examples of the riser pressure changes during severe slugging, taken from (Malekzadeh et al., 2012)*

Clearly, such large transient variations in flow rates and abrupt pressure changes could oppose some difficulties for topside facilities unless they are designed to accommodate them.

Figure 3-10 shows the cycle of the severe slugging process in a pipeline-riser system which consists of four stages: (1) slug generation, (2) slug production, (3) bubble penetration, and (4) gas blowdown.

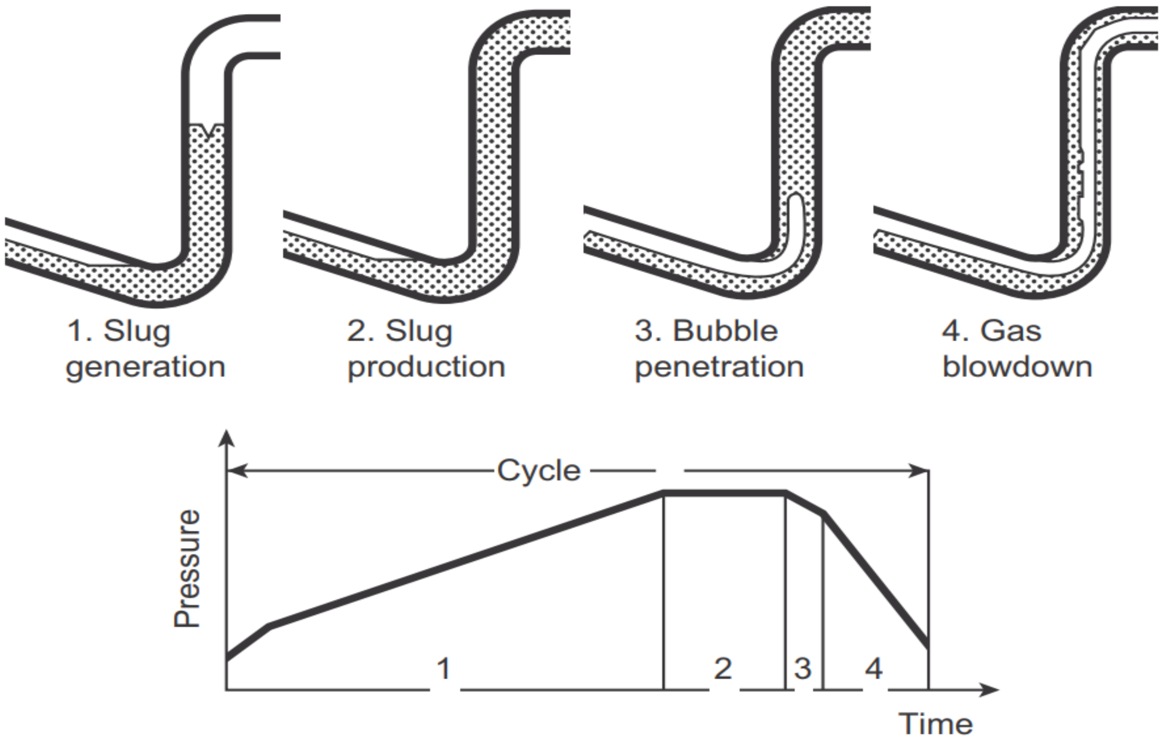

Figure 3-10: *process of severe slugging in pipeline/riser systems with the corresponding pressure changes, taken from (Fabre et al., 1990).*

3.4.4.1 Slug generation

The first stage is slug formation, which corresponds to an increase in the pressure at the riser base. During this period, since the liquid is not supported by the gas behind, the liquid does not reach the top of the riser and begins to accumulate at the riser base. The accumulated liquid will block the riser entrance, and as a result, pressure in the pipeline will increase until the liquid level in the riser reaches the top.

3.4.4.2 Slug production

During the second stage, once the liquid level reaches the riser outlet, the liquid slug is produced continuously until the gas reaches the bottom of the riser. At this stage, the liquid slug may occupy the whole riser length.

3.4.4.3 Bubble penetration

In this stage, when the gas-liquid interface reaches the arch at the riser base, the gas penetrates the liquid column forming a bubble front. Due to the reduced hydrostatic pressure, the gas flow rate increases, and the bubble expands continuously.

3.4.4.4 Gas blowdown

The fourth stage corresponds to the gas blowdown, in which, the produced gas at the riser base reaches the top, and the pipeline pressure drops to its minimum. The liquid is no longer lifted by the gas; thus the liquid level starts to fall and repeatedly a new cycle begins. (Fabre et al., 1990)

3.5 Slug Flow Characteristics

Slug flow is a complicated phenomenon to characterize since it has various mechanisms and origins. *Figure 3-11* illustrates a schematic of an ideal horizontal slug flow. In detail, a fully formed slug unit consists of four parts: (1) mixing or front zone, (2) slug body, (3) film zone, and (4) bubble zone. A complex balance of gas and liquid transfer from one zone to the other defines the size of each part.

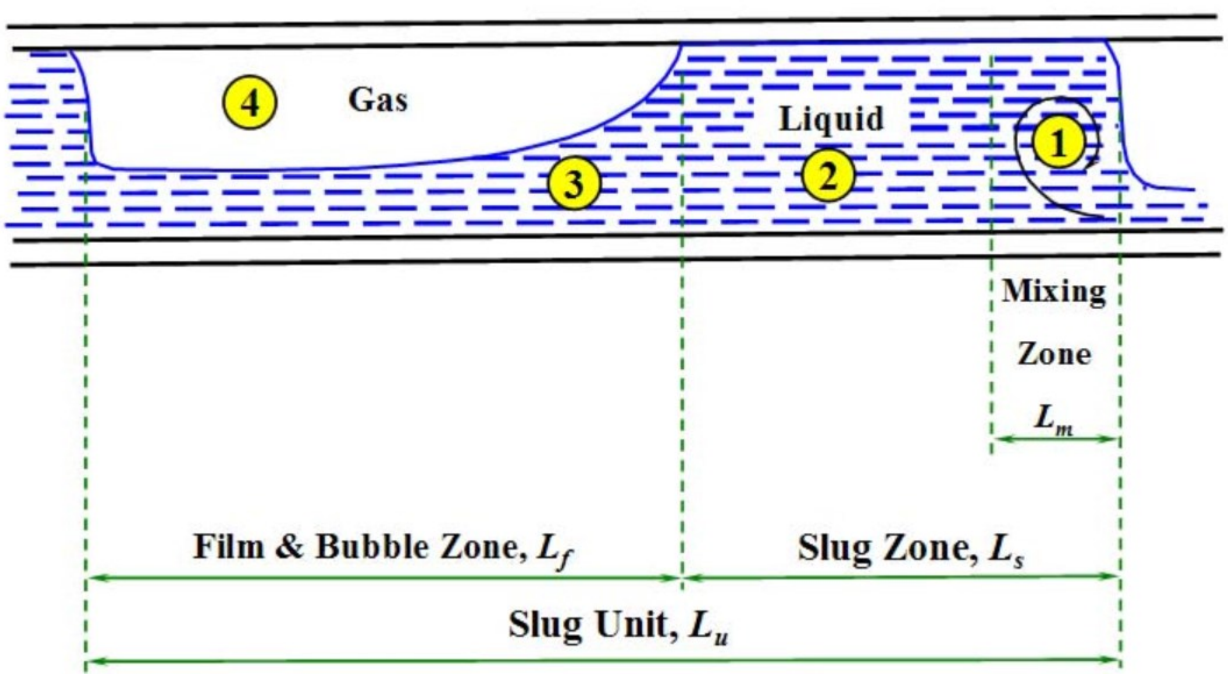

Figure 3-11: *Schematic of a fully formed slug unit adopted from (Campbell, 1992)*

Each slug unit can be characterized based on several parameters. Some of these parameters are slug body length, slug frequency, slug holdup, and slug transitional velocity. These parameters play an important role while designing production facilities.

The next sub-sections will explain these characteristic parameters of slugging flow.

3.5.1 Slug length

The slug length is the length of the liquid slug body (see *Figure 3-11*) for a slug unit. In terms of designing the pipelines and separation facilities calculation of the slug length and its distribution is crucial. Previously some models were developed based on steady slug flow with constant lengths and shapes of liquid slugs and elongated bubbles. However, subject to some conditions such as a subsea pipeline with a downwards inclination connected to a platform with a vertical riser, or a pipeline over hilly terrain, a steady-state operation may not be possible (Taitel, 1986). Therefore, practical solutions are needed for finding the volume of the large slugs and designing a separator or slug catcher accordingly (Ragab, 2008).

3.5.2 Slug frequency

This parameter is defined by the number of slug units at a point in a pipeline over a time interval. The slug frequency can change based on the nature of the flow and the pipe inclination. Since it has a major impact on the design of downstream facilities, slug frequency has been investigated by several researchers, and several correlations were suggested based on experimental and field data. See (Gregory & Scott, 1969; Hill & Wood, 1990, 1994; Taitel & Dukler, 1977).

3.5.3 Slug liquid holdup

The slug liquid holdup (H_{LS}) is the amount of liquid in the slug body (Ibarra et al., 2019). Several correlations and models have been developed for estimating the slug liquid holdup in full pipe systems, covering a wide range of flow conditions. For example, (Barnea & Brauner, 1985; Gregory et al., 1978; Zhang et al., 2003).

3.5.4 Slug velocity

Slug velocity can be defined as the velocity of the interfaces between the liquid slug and gas region which is considered the highest velocity in a slug unit in a horizontal flow. It consists of two components, the liquid velocity in the slug body, and the liquid accumulation at the velocity front because of the scooping process. This parameter can be determined by dividing the distance between two surfaces over the required time for a slug unit to travel between these surfaces (Ragab et al., 2008). Slug velocity is an important parameter for calculating slug load, therefore several studies such as (Gregory, 1974; Nicklin, 1962), presented equations and correlations for slug velocity calculation.

3.6 Slug Flow Problems

This section will examine the problems that arise when slug flow is present in the well-pipeline-riser production process. A typical well-pipeline-riser section of a typical offshore oil & gas field is illustrated in *Figure 3-12*. In this example, the system consists of three connected subsections: (Pedersen et al., 2017)

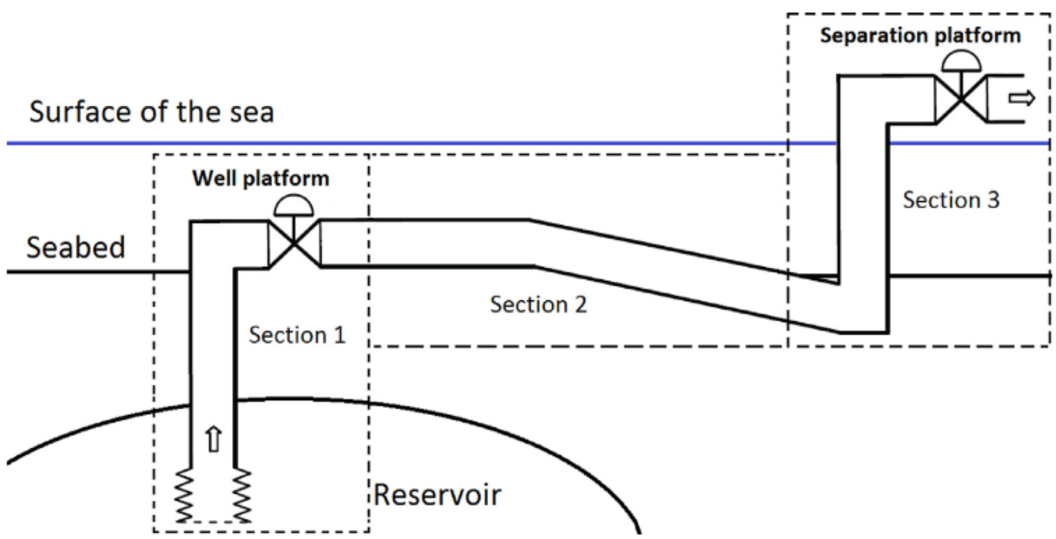

Figure 3-12: *Schematic of a typical well-pipeline-riser system taken from (Pedersen et al., 2017).*

The production well section

This section is depicted as section 1 in *Figure 3-12*. Reservoir fluid which may contain gases, liquids, and solid compounds flow from the reservoir through a vertical well. To keep a reasonable production rate from the reservoir, some production wells use artificial lifting techniques. In some constructions, the wellhead can be above sea level to connect to a manifold platform. In a manifold platform flows from several wells can join into one stream and then commingle into a single pipeline. Topside choke valves are used in most cases. These chokes which are located at the top of each well can be utilized to regulate the flow through the tubing of the production well.

The subsea transport pipeline section

This section consists of a transportation pipeline that follows the seabed and thereby is influenced by the topography of the seabed. This section which involves most of the complete pipeline length is shown in *Figure 3-12*, section 2.

The vertical riser section

In this section, there is a riser that raises the well fluids from the subsea transport pipeline (section 2) up to the topside facilities such as the separator, above sea level. Sometimes artificial lifting is used at the riser base to improve the production rate (Hu, 2004). To regulate the flow fed into the separator, a topside choke valve is often placed before the separator as it is shown in *Figure 3-12,* section 3.

Subject to specific operating conditions and system configurations, the slug flow may occur at many different geometric locations in an offshore production system. Starting from section 1 in *Figure 3-12,* due to a casing-heading mechanism, slugging can take place in the gas-lifting production wells (Eikrem, 2006). The subsea transport pipeline section (section 2 in *Figure 3-12*) is exposed to hydrodynamic slugging. Hydrodynamic slugs may continue to increase in size as they flow into the pipeline. (Guzmán & Zenit, 2012; Guzmán Vázquez & Fairuzov, 2009). Moreover, the occurrence of terrain slugging in transportation pipelines (section 2) is possible due to the seafloor elevations. (Jansen, 1990; Ogazi, 2011). Severe slugging could appear at the riser part which is shown in *Figure 3-12,* section 3. The reason for severe slugging formation in this part is significant gravity influence (Di Meglio et al., 2012; Jahanshahi et al., 2013b).

Slug flow is an intermittent flow, meaning that the flow may vary from about 100% liquid to near 100% gas flow. This behavior of the slugging flow can cause serious design and operating problems in a subsea production system such as the one shown in *Figure 3-12*. Some of the main negative impacts of the slug are listed below: (Pedersen et al., 2017)

3.6.1 Liquid overflow and high pressure in the separators

Varying flow inputs to the separator may occur because of the liquid blowout. (Yang et al., 2010) observed that the varying input flow can affect a controller's ability to decrease the output flow of the separator and thereby reduces the separation efficiency. Furthermore, poor separation in the separator will affect the next stages of the separation process. (Husveg et al., 2007)

3.6.2 Overload on gas compressors

The handling capacity of production facilities such as gas compressors is limited. In presence of slugging, gas compressors are subject to a much larger pressure and flow rate than the equipment is designed for. Thus, the compressors are needed to be designed in a way to handle the probable high pressure and flow rates.

3.6.3 Fatigue caused by repeating impact

Pressure oscillations cause extra fatigue load which shortens the pipeline's lifetime. (Hill & Wood, 1994). The fatigue caused by slug flow-induced vibrations (SIV) is an important design factor when designing a piece of subsea transportation equipment (Van Der Heijden et al., 2014). The curvature plane of the flexible riser is the point where the SIV mainly occurs. The fluctuation frequencies of the pressure of slug flow take part in the dynamic response of a flexible riser (Zhu et al., 2019).

3.6.4 Increased corrosion

In a pipeline, an oscillating flow rate can increase friction, which ultimately increases the corrosion rate. Corrosion acceleration caused by slugging is discussed in several articles such as (Kang et al., 1996; Zhou & Jepson, 1994).

3.6.5 Low production

Slugging may lead to a significant reduction in the average daily production rate. This production decrease is due to the increase in friction at the liquid blowout stage and at the liquid fallback stage where the production rate is transitory negative. Moreover, emergent shut-off of production can cause production loss.

3.6.6 Production slop

When slug flow occurs, the produced natural gas might be flared as waste by a gas combustion device to secure a safe pressure. Flaring of the gas is a method to handle the large amounts of gas in the separator.

3.7 Slug Mitigation and Prevention Methods

Because of its negative influences, the slug flow must be addressed to ensure safety and economic interests. Slug mitigation and elimination methods are also known as "slug control" methods. From the control engineering point of view, these methods or approaches can be classified into two categories: (1) Passive approaches, and (2) Active approaches.

To avoid confusion in this classification, those cases in which a feedback control strategy is applied along with some dedicated change in the system/process, are put into the active approach category. (Pedersen et al., 2015)

3.7.1 Passive slug control methods

In passive slug control methods, instead of using a feedback control strategy, a proper and dedicated system/process design is utilized. Over several decades, slug control by creating a change in the process has been investigated. Several different solutions for process changes to handle the slug are identified in early studies such as (Yocum, 1973). These solutions which still are being applied today can be categorized into three groups: (1) Reducing the incoming line diameter near the riser, (2) Using dual multiple risers, and (3) Using a fluid remix device. These three main groups of solutions form the fundamental basis for all passive slug control methods which are explained as followed.

3.7.1.1 Flow conditioners

A special device installed in the pipeline to affect the original flow regime is called a flow conditioner. (Yocum, 1973) suggested that the slug flow alleviation can be done by remixing the multiphase flow right before the riser inlet. The purpose of remixing the flow is to break up the stratified flow in a pipeline, which is one of the preconditions for severe slugging formation. In a series of studies conducted by (Brasjen et al., 2013; Brasjen et al., 2014) several passive devices, such as mixers, were investigated and it was concluded that the optimal placement of such a device is near to flowline undulation dip. Moreover, it was observed that slugging frequency can be reduced up to 16% in large-scale test facilities, however, at the price of significant pressure drop over the system.

Although the undulating shape of the pipeline may be one of the main reasons for severe slugging formation (Jansen et al., 1996; Malekzadeh & Mudde, 2012), Some researchers suggested that altering the pipeline shape can be a suitable passive method for severe slugging alleviation. For example, (Shen & Yeung, 2010) suggested an undulating pipeline design to serve the purpose of stratified flow mixing. A schematic of this undulating pipe design is shown in *Figure 3-13.*

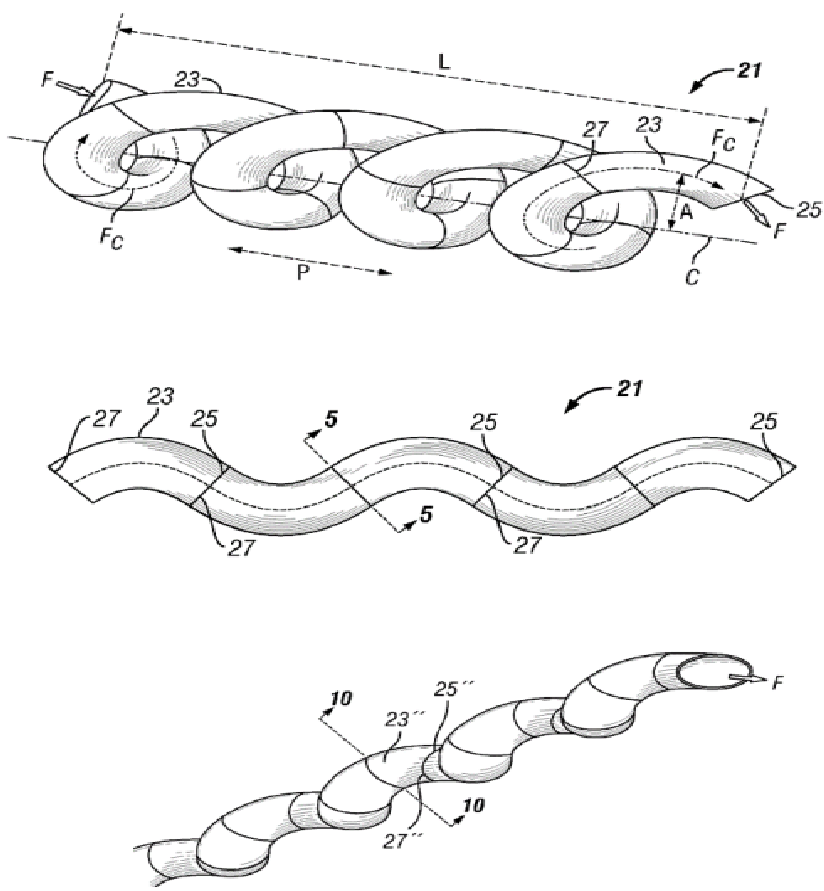

Figure 3-13: *Undulating pipes design proposed by (Shen & Yeung, 2010).*

Another example of undulating pipes is a “Wavy Pipe" developed by (Xing et al., 2013b) at Cranfield University (UK). The basic idea behind this method is to artificially introduce some small slugs through the wavy pipe section so that a severe riser slug can be avoided since the gas movement in the pipeline to the riser base is accelerated compared to the liquid accumulation. The effectiveness of this proposed method for slugging alleviation is investigated both numerically and experimentally by (Xing et al., 2013a, 2013c). The experimental study by (Xing et al., 2013a) proved that this concept can be quite efficient in the small-scale model. According to the authors, the presence of the wavy pipe section before the riser base can reduce the slug length and the severe slugging occurrence region on the flow regime map which will eventually reduce the severity of slugging. A photograph of the wavy pipe suggested by (Xing et al., 2013a) is illustrated in *Figure 3-14.*

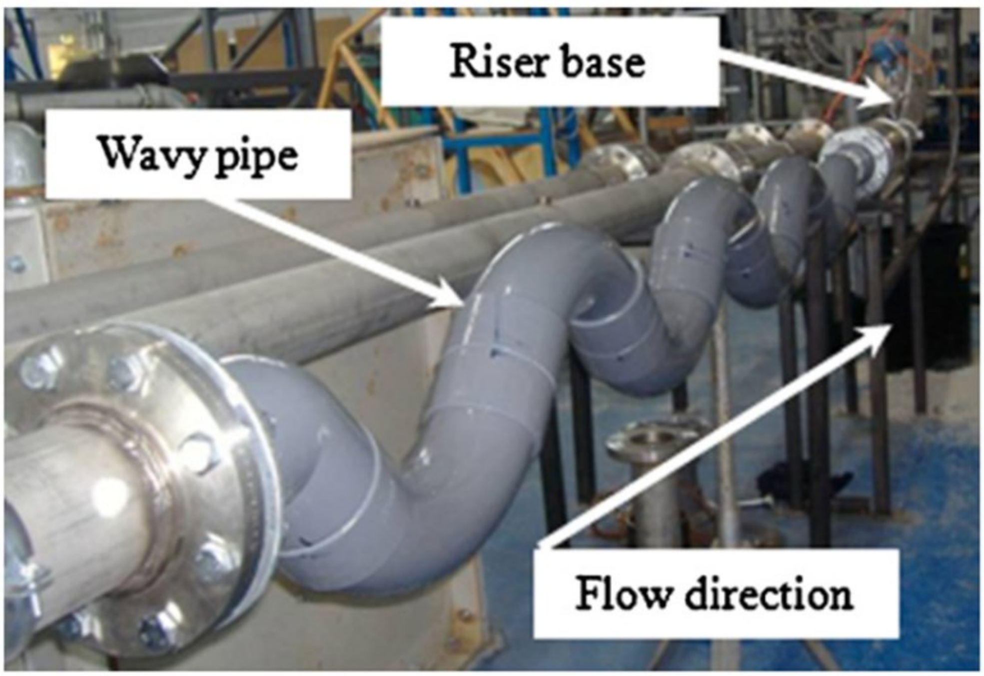

Figure 3-14: *A photograph of the wavy pipe of 7 bends in the pipeline taken from (Xing et al., 2013a)*

(Adedigba, 2007) investigated another type of flow conditioner using a helix-shaped pipeline and the results reported in his work proved that the helical pipe can be successful in reducing the menace of severe slugging. *Figure 3-15* is taken from (Adedigba, 2007) and it illustrates a helical type flow conditioner.

Figure 3-15: *A photograph of the helical pipe suggested by (Adedigba, 2007).*

A recent study is done by (Ogunbiyi et al., 2018) to examine a technique for mitigating the threat posed by slugs to production systems. In this study, a passive slug control device is experimentally investigated. This device, which is a type of flow conditioner, is called Pseudo Spiral Tube (PST). *Figure 3-16* shows a photograph and a schematic design of the Pseudo Spiral Tube or (PST). The published results show a promising potential of the capability of PTS to partially attenuate slug flow. For the case studied, the slug severity was reduced by 24%. However, since the slug was redeveloped a few meters downstream of the device, to achieve the maximum slug attenuation, the device should be installed immediately upstream of the topside separator. Besides, to overcome the challenge of occasionally stuck of the pig during the pigging operation, it is suggested to utilize a flexible pig (Ogunbiyi et al., 2018).

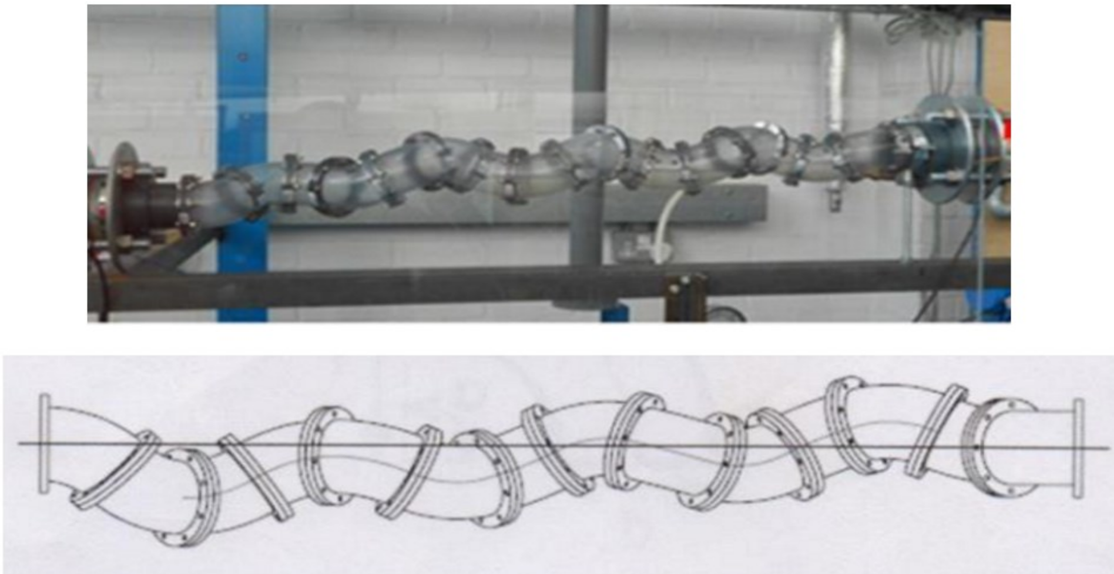

Figure 3-16: *A photograph and a simple schematic diagram of the PST taken from (Ogunbiyi et al., 2018)*

An interesting approach for severe slugging elimination is patented by (Almeida & Goncalves, 1999). The patent is a venturi-shaped tube which is illustrated in *Figure 3-17*. This device is a type of flow conditioner and consists of a convergent nozzle section followed by a divergent diffuser section. The venturi-shaped device is a part of the horizontal pipeline, and its assumed location is near the riser base. The pressure drop induced by this flow conditioner can cause a mixing effect and it would further contribute to converting the stratified flow to a non-stratified flow regime temporarily.

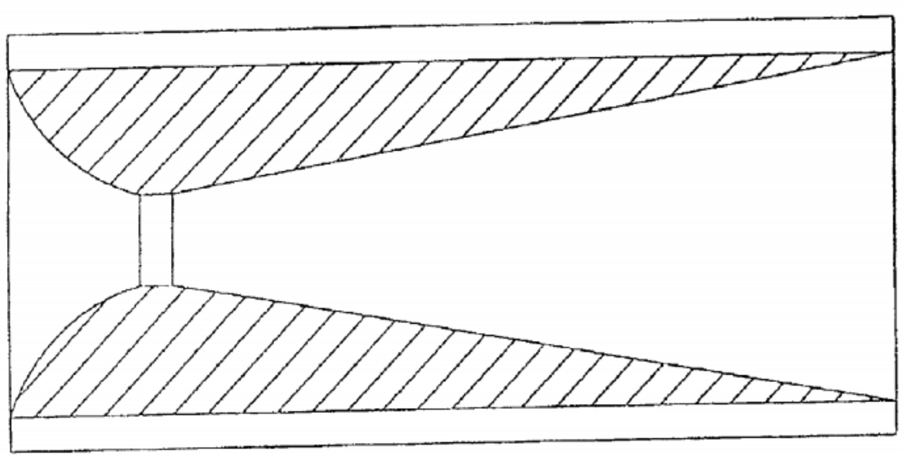

Figure 3-17: *Schematic of Venturi-shaped tube taken from (Almeida & Gonçalves, 2000)*

A similar functional flow conditioner is proposed by (Makogon & Brook, 2009). The patent is made of at least one section of pipeline configuration, consisting of a positively inclined part followed by a horizontal and declining section. Depending on the design and operational condition this undulating section can be changed as it is illustrated in *Figure 3-18*. Like a junction, this flow conditioner connects the pipeline outlet to the riser inlet. In case of appropriate configuration and placement, this device not only breaks up severe slugging flow into smaller slugs but also allows the pigging operation to be run with no restriction due to its appropriate bending radiuses. (Makogon et al., 2011) tested the patent using the dynamic multiphase flow simulator OLGA, on a scaled-down model at the University of Tulsa. Published results prove that the method is viable in terms of severe slugging alleviation, and reduction of pressure fluctuations over the riser because of small slugs' generation.

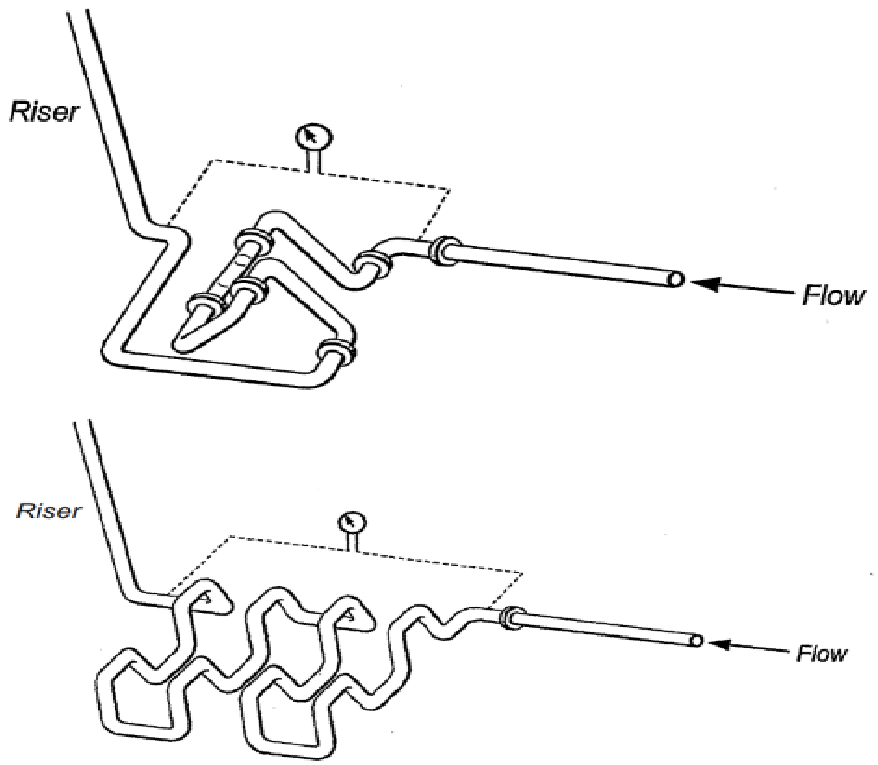

Figure 3-18: *Examples of flow conditioning by (Makogon & Brook, 2009)*

It should be noticed that the flow conditioner approach and the permanent choking method proposed by (Jansen et al., 1996) are similar, thus they both may have the disadvantage of a decrease in production rate. (Ogazi et al., 2010; Pedersen et al., 2014)

3.7.1.2 Slug catchers

Slug catchers are tools that can be utilized to eliminate slugging. Although a slug catcher has extra liquid capacity and a special design, it functions like a separator. The slug catcher mainly includes two different compartments: the first is the gas-liquid separator under steady flow conditions and the second consists of the storage of the liquid that is accumulated under operating conditions. The gas will be sent to the downstream facilities while the stored liquid will displace the existing gas in a quite continuous pattern. From the designing point of view, it should be noted that the size of the slug catcher is determined by the size of the largest possible slug that can be formed in the pipeline (Karam, 2012). The approach of using a slug catcher which is located after the riser or topside of the well is one of the most common passive slug elimination methods. This method can be very simple and robust but expensive due to the vessel's cost (McGuinness & Cooke, 1993). Several types and model designs for slug catchers are investigated by (Bos & Du Chatinier, 1987; Burke & Kashou, 1995; Genceli et al., 1988; Kovalev et al., 2003; Miyoshi et al., 1988). The slug catchers can be divided into three main types: (1) the vessel type, (2) the multi-pipe type, and (3) the parking loop type.

The vessel type

The vessel type is a simple two-phase separation vessel and in terms of geometry, this type of slug catcher can range from simple knockout vessels to more sophisticated layouts (Kalat Jari et al., 2015). *Figure 3-19*, shows an example of the vessel-type slug catchers.

Figure 3-19: *An example of a vessel-type slug catcher taken from (Kimmitt et al., 2001)*

Due to their limited size, vessel-type slug catchers can only be utilized if the incoming liquid volume is small. Compared to other types, since a vessel slug catcher does not require a large space in the processing plant is more size effective, but it is more expensive due to its thick wall.

The multi-pipe type

For large volumes of liquid (approximately more than 100 m^3), the multi-pipe type slug catcher should be used (Mokhatab et al., 2018). This type of slug catcher is made up of a series of pipes known as fingers. Therefore, the multi-pipe slug catcher is also known as the finger-type slug catcher. As it is depicted in *Figure 3-20,* the upper end of these parallel pipes or fingers discharges the gas while the bottom end is designed for discharging the liquid.

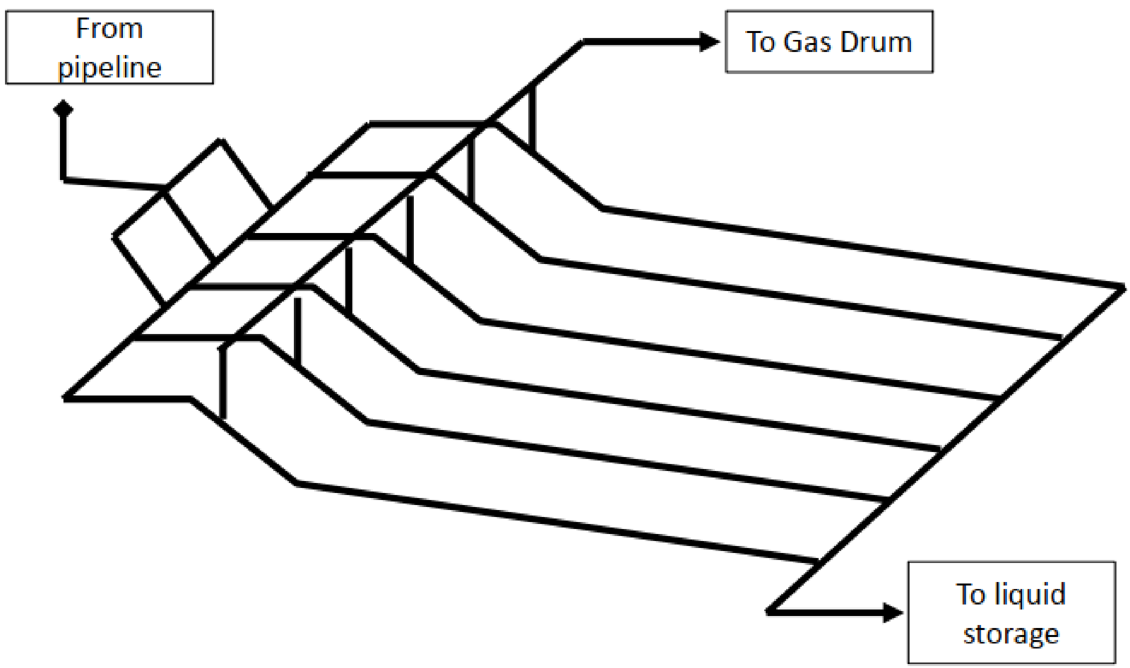

Figure 3-20: *Layout of a finger-type slug catcher taken from (Faluomi et al., 2013)*

Each one of the pipes in a multi-pipe slug catcher has three sections which are shown in *Figure 3-21.* Once the fluid passes the inlet section, two phases of gas and liquid are separated due to the inclination in the separation section. The separated liquid phase accumulates in the storage section while the gas flows toward the gas outlet.

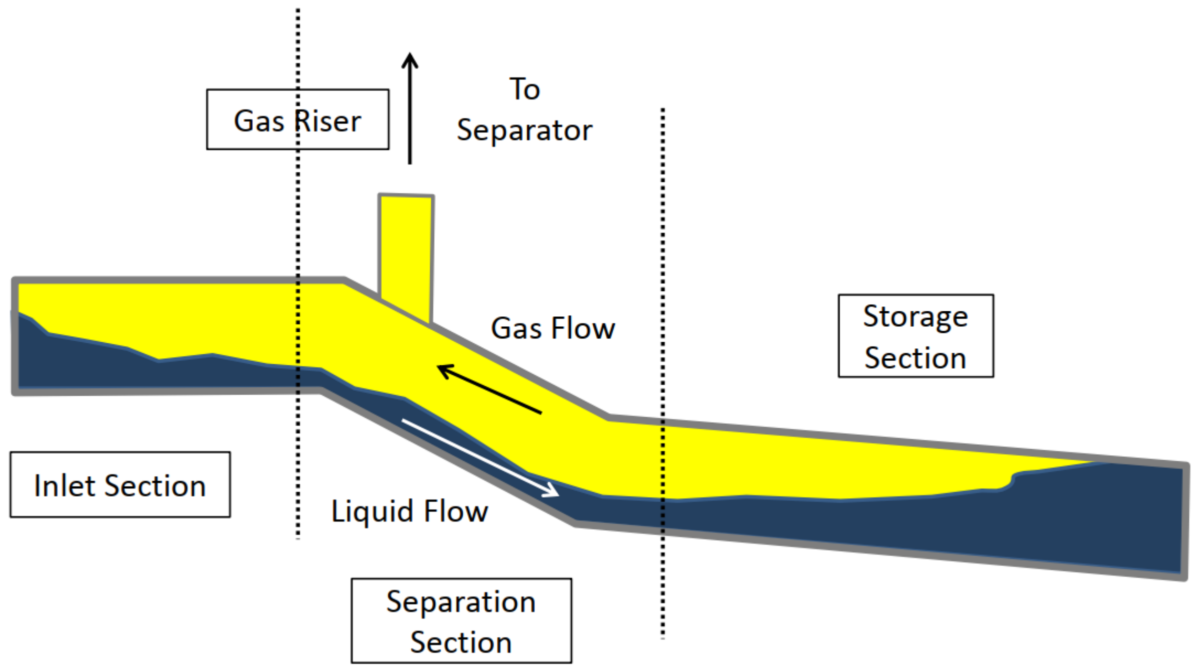

Figure 3-21: *Schematic of one finger of finger-type slug catcher adopted from (Faluomi et al., 2013)*

Compared to vessel-type slug catchers, the multi-pipe type has lighter weight and smaller pieces which makes it easy to be transported and assembled in a field. Moreover, since each finger is made of a thin wall the multi-pipe slug catcher is cheaper than the vessel type. However, it is not size effective because of its large volume (Karam, 2012).

The parking loop type

The features of both the vessel and finger types are combined into a parking loop slug catcher. Therefore, this type is also named a hybrid slug catcher. In a conduit, the counter-current flow of gas and liquid is possible due to gravity, which drives the fluid of higher density downward, while the lighter fluid flows upward. During the counter-current flow regime, a part of the downward-flowing liquid is carried over by the gas and entrained in the opposite direction. The parking loop type slug catcher can be designed in a way that it copes with the liquid carry-over formed in case of counter-current gas/liquid flow. The vessel used in this slug catcher is the place where the separation of the gas and liquid phase takes place, while the parking loop-shaped fingers provide the buffer volume and work as the storage medium for the liquid. An example of a parking loop-type slug catcher is shown in *Figure 3-22.*

Figure 3-22: *Parking loop type slug catcher taken from (Kalat Jari et al., 2015)*

Although parking loop type slug catcher can be utilized onshore to reduce the required space for slug catcher installation, this type is mainly used in offshore production systems where the separator is based on the platform while the loop is mounted on the seabed.

3.7.1.3 Homogenizing the multiphase flow

Another passive method to avoid slug formation is homogenizing the mixture such that the two separate phases of gas and liquid are forced into a single-phase homogeneous fluid. Thus, the intermittent flow regime such as slug flow which is associated with the non-homogeneous multiphase flow will be eliminated.

Based on this method, (Hassanein & Fairhurst, 1998) proposed that injecting a surfactant into the flowline could reduce the surface tension and change the fluid into foam until a homogeneous fluid is achieved. However, their original work lacks further details regarding this technique. The first experimental investigation of severe slugging mitigation using surfactant is published by (Sarica et al., 2014). The results of their study showed that adding a surfactant to an air/water system may lead to a considerable reduction of severe slugging. Once the surfactant is injected, the foam will be generated by the self-agitation of the phases. Hence, no further energy is required or added to the system, and mitigation of severe slugging takes place due to the change in the flow pattern occurring in the system. Furthermore, as an extension of the work of (Sarica et al., 2014), an experimental study of severe-slugging suppression by use of a combination of surfactants and gas lift was conducted by (Sarica et al., 2015).

A major disadvantage regarding using the surfactant is that this approach makes the downstream separation process inconvenient, thereby eventually affecting the product quality and often constraining the processing capacity.

3.7.1.4 Self-gas lifting

This passive slug control method is an artificial way of making the slug cycle, and consequently the amplitude of the pressure oscillations smaller. The principle of the method is to create a shortcut pipeline gas to the riser at a point above the riser base. This idea was first proposed by (de Almeida Barbuto, 1995), and later developed independently by (Sarica & Tengesdal, 2000). In the paper published by (Sarica & Tengesdal, 2000) it is suggested that by creating a smaller pipeline feeding from the main pipeline to the riser, where a one-way rectifier is linked to the riser to ensure one-directional flow, the static head (or liquid column weight) can be reduced. This way, not only the gas will accumulate for a shorter period because of being linked to the riser, but also no external gas lift supply would be required. They also proved that this method could provide a smoother start-up transient where flow blow-outs usually exist.

Furthermore, an investigation of the possibility of avoiding gas compressing in the pipeline by separating the gas upstream of the riser base and re-injecting it into the riser is published in the thesis of (Tengesdal, 2002).

A layout of the self-gas lifting system is depicted in *Figure 3-23.* As the re-injected gas through bypass (see *Figure 3-23*) enters the riser it can reduce the hydrostatic pressure created by the liquid in the riser, and therefore inhibit the slug formation. In case of slug occurrence, it also decreases the pressure amplitude. The major drawbacks of the self-gas lifting method are the difficulties of pigging operation and the extra cost of the additional pipeline.

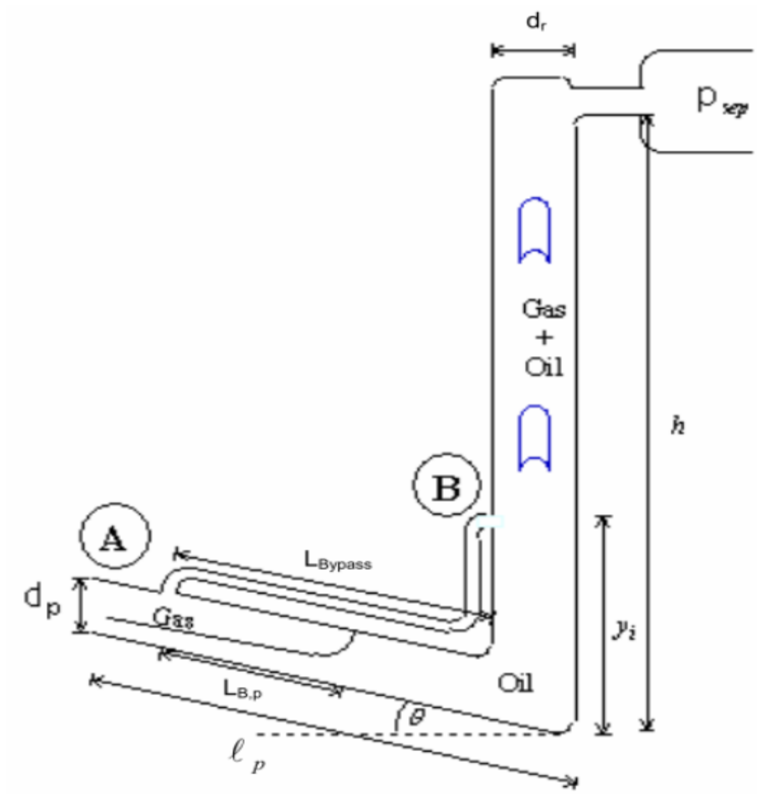

Figure 3-23: *Schematic depiction of the self-gas lifting system taken from (Tengesdal et al., 2002)*

3.7.2 Active slug control methods

Slug elimination approaches in this category involve some actuators which are installed in the processing system and subject to some sensor feedback signals. These actuators are manipulated in a feedback loop mainly with pressure, temperature, and flow transmitters signals. The sensors are often located topside on the platforms; however, their placement may change depending on which specific platform is studied. Some fundamental system property analyses such as input-output controllability analysis can be done to guide the selection of the actuators and sensors (Jahanshahi et al., 2012; Skogestad & Postlethwaite, 2005).

3.7.2.1 Active valve choking

Since valve choking is a cheap, easy, and flexible implementation solution, this method has been investigated the most. But a negative aspect of this method is a reduction in production rate. For many years, the slug elimination method of using the (riser) topside choke valve has been studied by several researchers, see (Di Meglio et al., 2012; Havre & Dalsmo, 2001; Jahanshahi et al., 2012; Storkaas & Skogestad, 2007). (Ogazi, 2011) investigated a different location for the control valve.

In his thesis, he suggested a valve located at the separator gas outlet as an alternative anti-slug control actuator. (Eikrem et al., 2004; Jahanshahi et al., 2013a; Scibilia et al., 2008) considered the seabed/downhole pressure estimation by a topside pressure transmitter to regulate the topside choke valve. To overcome the problem of production rate reduction while slug elimination, (Ogazi et al., 2009) suggested an active control system operating at a large valve position. A self-learning controller consisting of a supervisor and two baselines proportional–integral–derivative controller (PID controller or three-term controller) is developed by (Pedersen et al., 2014). The purpose of implementing such a control system is to automatically find out the optimum choke valve's operating position with the maximum production rate and no slug.

3.7.2.2 External gas-lifting

This active slug control method serves two purposes:

(1) Re-pressurizing a reservoir that is depleted or producing at a low production rate by injecting gas at the bottom of the well. *Figure 3-24* shows an oil production well subject to external gas-lifting.

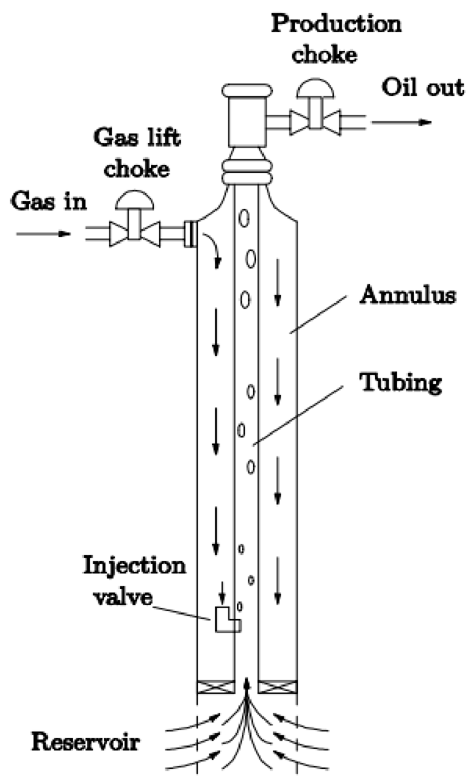

Figure 3-24: *A schematic of gas lifted oil well taken from (Eikrem et al., 2004)*

(2) Preventing severe or riser-induced slugging by injecting gas at the bottom of the riser. A schematic of such a method is depicted in *Figure 3-25*.

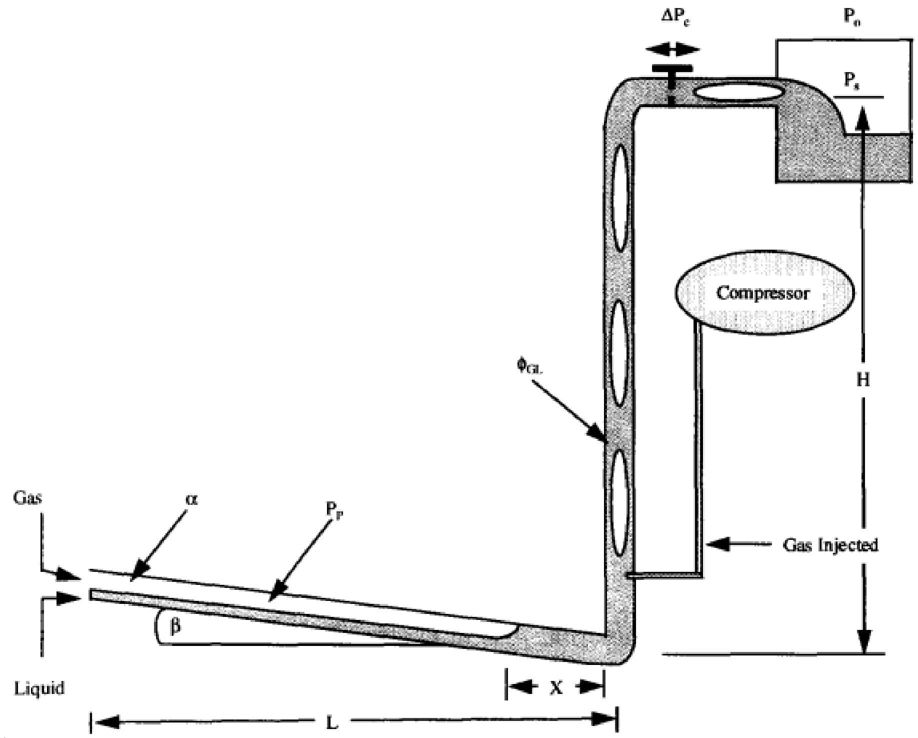

Figure 3-25: *Pipeline-riser configuration with riser base gas-lift taken from (Jansen et al., 1996)*

(Asheim, 1988; Plucenio et al., 2012) proved that applying artificial gas-lifting can be an effective approach to eliminate severe slugging. the study published by (Jansen et al., 1996) is an experimental and theoretical investigation that concludes that gas lifting can eliminate severe slugging by increasing the velocity and reducing the liquid holdup in the riser. It was also found that gas injection reduces the slug length and cycle time which results in more continuous production and lower system pressure. Hence utilizing the gas-lifting method causes a reduction in the vertical pipeline's hydrostatic pressure and stabilizes the flow in the direction of the superficial velocity of the gas. However, a relatively large amount of gas is demanded to fully stabilize the flow through the riser (Jansen et al., 1996). (Krima et al., 2012) developed several PI controllers for external gas-lifting. The study aimed to mitigate hydrodynamic slugging in OLGA simulations. The results show that applying a topside hold-up transmitter as the controlled variable is the best control solution.

An illustration of a typical gas-lift performance relationship (LPR) of a hypothetical gas-lift well can be seen in *Figure 3-26*.

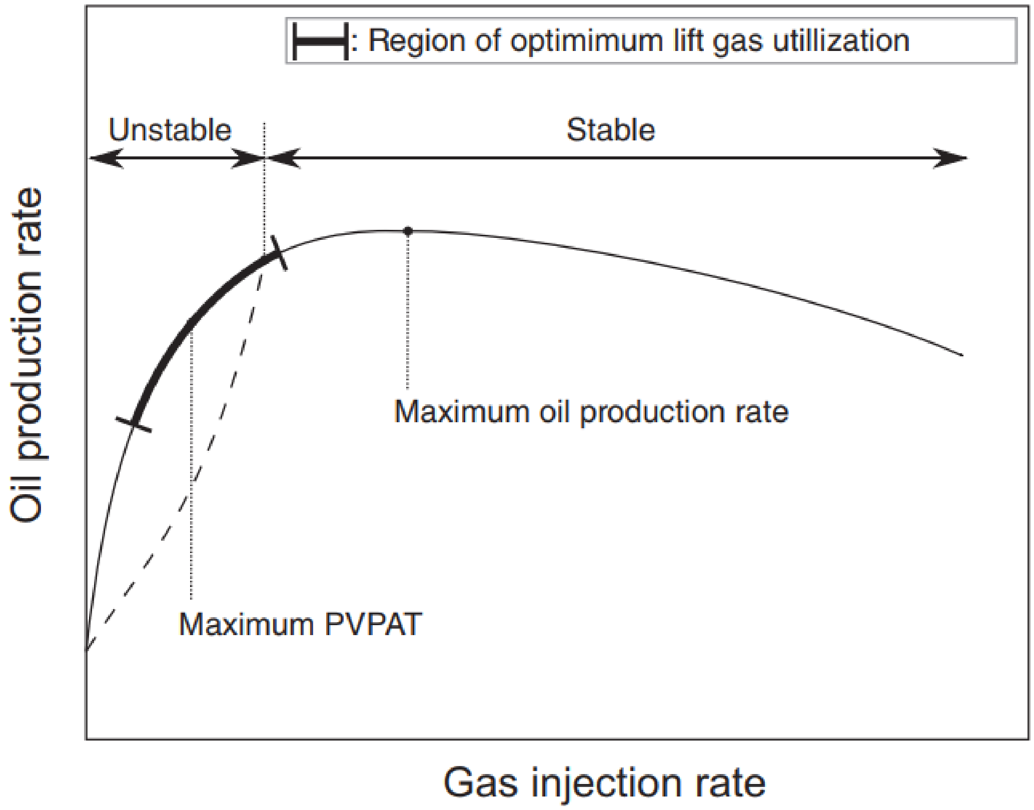

Figure 3-26: *A performance graph of a hypothetical gas-lift well taken from (Pedersen et al., 2017).*

The solid line in *Figure 3-26* represents the operators' estimated production rate resulting from steady-state simulations. At first, as the gas injection rate increases, a rapid rise in the oil production rate takes place and then the curve tends to level off before reaching a peak. After the peak is reached, the escalation of gas-induced friction cannot be compensated by the reduced hydrostatic pressure in the well, thus further increase in the gas injection rate will cause the production rate to decrease gradually. Two points are marked on the graph. The first one is the operation points for maximum "Present Value Profit After Tax" or (PVPAT) and the second one is the maximum oil production rate. Although PVPAT can be in the slugging region, this point is often the value aimed for in daily production. Where the physical and economic uncertainties are being considered, is the region of optimum gas lift utilization. This region is also shown in *Figure*

3-26. The dashed line indicates the actual producing rate during slug flow. The plot shows that slugging may decrease the production rate drastically. It should be noted that the estimated LPR can misinform the operators to aim for an unstable operating point such that slug flow and consequently production decrease occur. Moreover, since the external gas-lifting operation is usually limited by the gas compressors' capacity, the optimal gas-lift inflow is not always feasible (Pedersen et al., 2017).

3.7.2.3 MIMO slug control

MIMO stands for Multiple-Input Multiple-Output. This wireless technology consists of multiple transmitters and receivers to transfer more data at the same time (Krumbein, 2016). In oil and gas production the topside choke valve and the external gas lifting are the two most available actuators that can be combined in a MIMO or MISO (Multiple-Input Single-Output) control system. (Pagano et al., 2008) developed a model-free PI controller for the well case. In the suggested system the injection valve of the gas-lifting can be controlled in a way that it stabilizes the gas flow injected into the production tube, while the topside choke valve is utilized for stabilizing the topside pressure. In her thesis (Esmaeilpour Abardeh, 2013) proposed a robust anti-slug control solution using the topside choke valve and artificial gas lift. (Jahanshahi et al., 2013b) designed a nonlinear model-based control for a pipeline-riser system using both the riser base and the topside pressure. To design this control system feedback linearization is used.

3.7.2.4 Slug compression system (S^3)

(Kovalev et al., 2003) reported a Slug Suppression System (S^3) which is designed by Shell (see *Figure 3-27*). This solution includes a combination of process change and active feedback control of choke valves. A topside gas-liquid mini-separator separates the liquid from the gas upstream of the first stage oil-water-gas separator. For the gas pipeline and the liquid pipeline, two choke valves are installed between the two separators such that the liquid injection into the first stage separator is controlled to stabilize the liquid height, while the gas injection compensates for the potential slugging formation. The advantage of implementing this slug suppression system is that it can successfully eliminate all types of slugs and enhance oil and gas production. However, the additional expense of extra equipment as well as the corresponding extra maintenance should be considered while estimating the costs for running production. (Henkes et al., 2001; Hollenberg et al., 1995) can be referred to for more details about the slug suppression system.

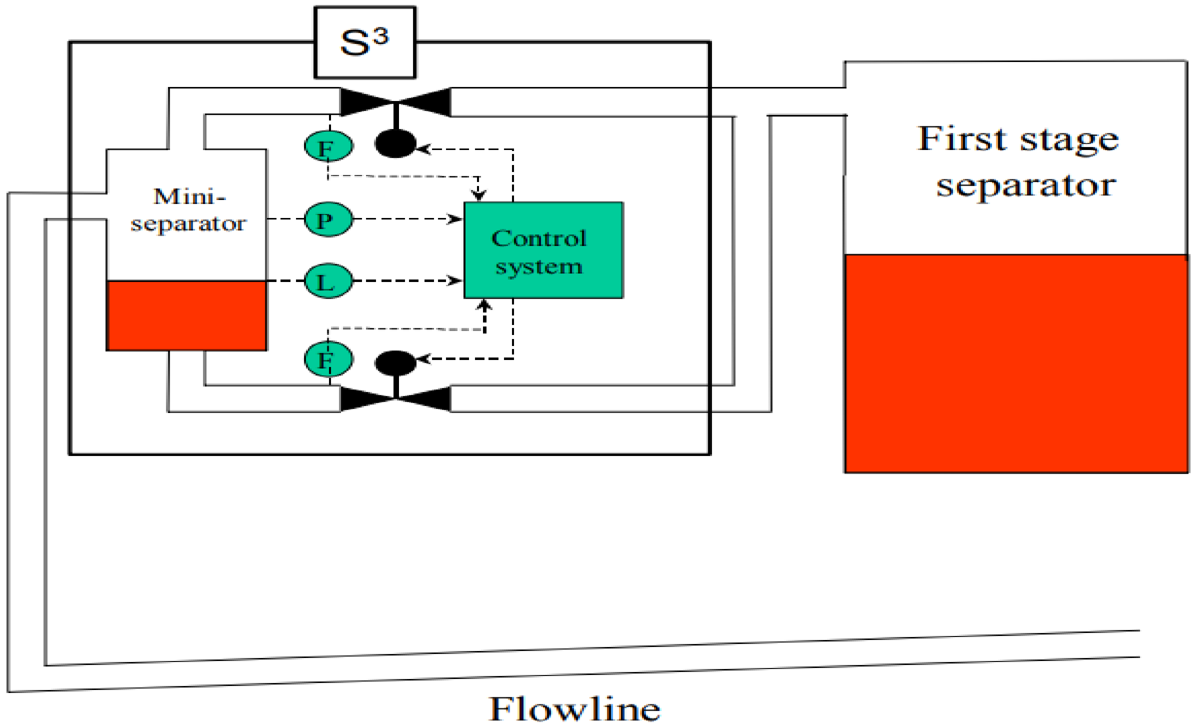

Figure 3-27: *Schematic of the S^3 implemented between the pipeline outlet and a first stage separator taken from (Kovalev et al., 2003)*

CHAPTER 4

Analyzing the Applied Slug Control Methods in the Case Studies

4.1 Introduction

This chapter describes the purpose of the case study, the features of the investigated cases, and the main principles that were used to examine slug mitigation methods. Furthermore, analysis methods that were used to assess the simulation results will be explained. At the end of this chapter, five approaches were suggested for handling the hydrodynamic slugging namely, (1) Subsea finger-type slug catcher, (2) Flow conditioners and diameter reduction, (3) Surfactant injection, (4) External gas-lifting, and (5) Topside choking. Among them, the last two approaches (External gas-lifting, and Topside choking) were considered applicable in the field based on the literature review and communication with Graham Rudrum from Aker BP. Thus, all three analysis methods were performed on these two slug mitigation approaches and results were presented.

4.2 Purpose of the Case Study

The purpose of this work is to investigate a pipeline-riser system that is producing under Aker BP's flow assurance team monitoring. This pipeline-riser system exhibits the problem of hydrodynamic Slug-Induced Vibration (SIV) in the riser. The dynamic response of a flexible riser (see *Figure 4-1*) to the fluctuation frequencies of the pressure of slug flow can decrease the fatigue life of the riser (Gundersen et al., 2012; Zhu et al., 2019). Thus, to prevent this issue slug control methods need to be applied to either eliminate slugging or manipulate the slug frequency such that the vibrations are alleviated.

Based on observations in different pipeline-riser production systems in Aker BP company the point that is most affected in terms of decreasing fatigue life of a flexible riser is the Mid Water Arch (MWA) or Hog bend as shown in *Figure 4-1.* Therefore, the focus of the analysis is on MWA or Hog bend.

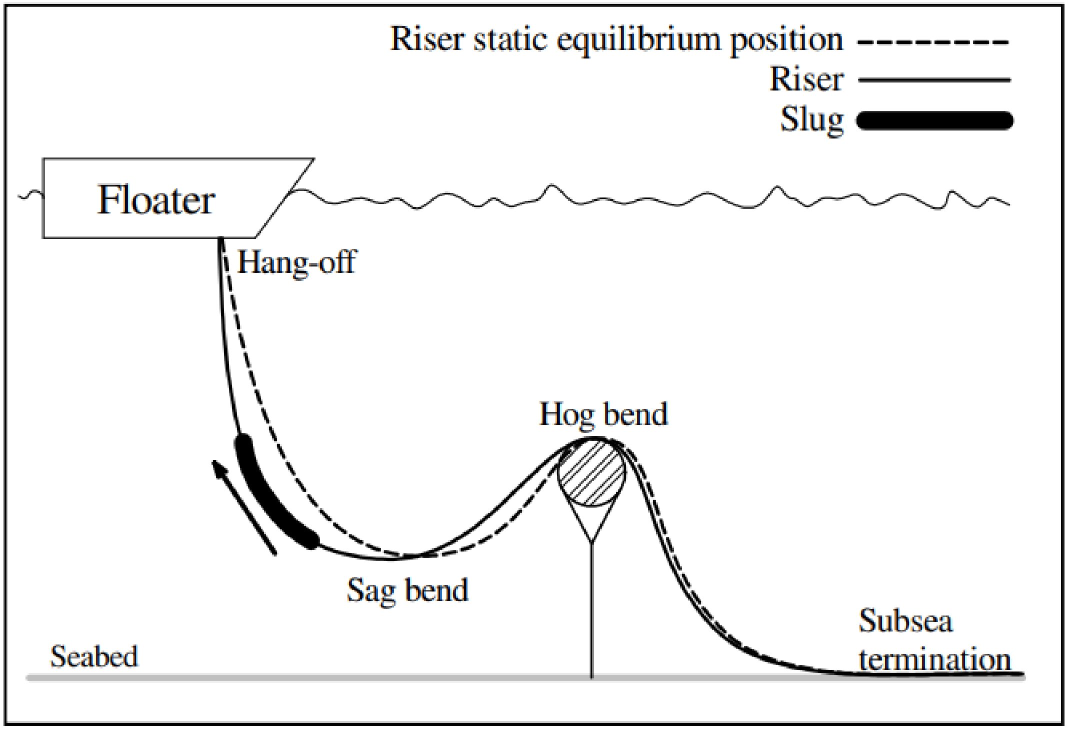

Figure 4-1: *Sketch of a lazy-S flexible riser dynamic response to slug flow taken from (Gundersen et al., 2012).*

The system was simulated using the transient multiphase flow simulator OLGA to quantify pressure fluctuation and assess the effectiveness of slug control methods. As the data generated by the simulator is large (for example time series slug flow pressure fluctuations), a robust analysis method called Fast Fourier Transform (FFT) was employed often, instead of other manual methods or using Excel sheets.

4.3 Case Study Description

The system investigated is a pipeline-riser system that transfers the produced fluid from the Bøyla field to the Alvheim floating production, storage, and offloading (FPSO) vessel. The horizontal length is about 4.5 [km]. To apply slug mitigation methods like choking and gas lifting, a model of this pipeline-riser system generated in OLGA was used. For further evaluation such as frequency analysis, results from OLGA simulations were imported into Excel sheets and for FFT analysis on the pressure fluctuations caused by slug, Python programming language was utilized.

Moreover, another flowline in the Bøyla field (a pipeline-riser system with a length of 19.5 [km]) was also simulated in OLGA. This was performed for additional investigation of the slug mitigation methods and to compare the results against the case study on the 4.5 [km] flowline.

To avoid confusion, the case study on the 4.5 [km] flowline is called Case Study (I) and the other case study on the 19.5 [km] flowline is called Case Study (II).

4.3.1 Bøyla field

According to the Norwegian Petroleum Directorate (NPD, 2022), Bøyla is a field in the central part of the North Sea, about 200 kilometers west of Haugesund and 28 kilometers south of the Alvheim field, see *Figure 4-2*.

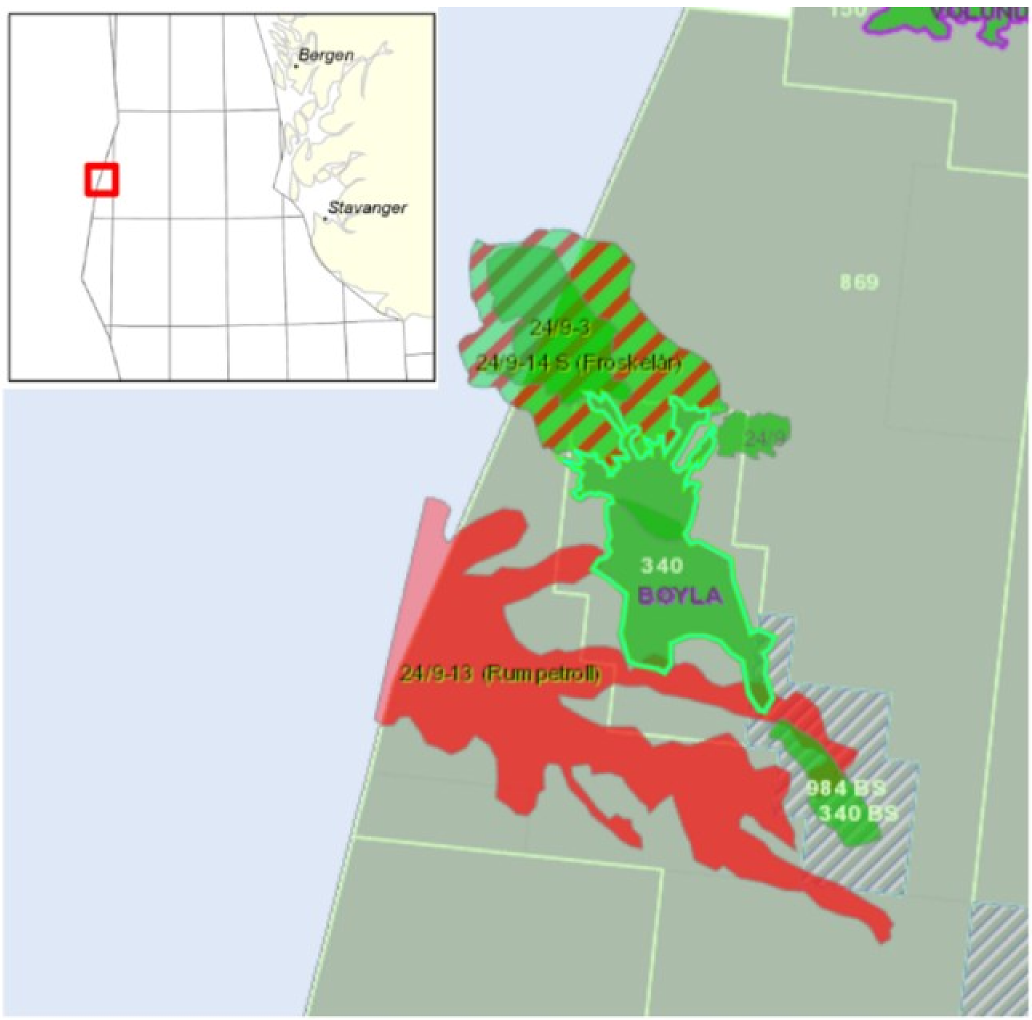

Figure 4-2: *Location of Bøyla field*

Bøyla was discovered in 2009, and in 2012 the plan for development and operation (PDO) was approved. The estimated total recoverable reserves in this discovery are approximately 23 million barrels of oil equivalents with total investments of nearly 4.9 billion NOK. The water depth is 120 [m] and development of the field is done using a subsea installation including two horizontal production wells and one water injection well. The field is tied-back to the Alvheim floating, production, storage, and offloading (FPSO) vessel and the production started in 2015. Bøyla produces oil from sandstone of the late Paleocene to early Eocene age in the Hermod Formation. The reservoir has good quality and lies in a channelized submarine fan system at depth of 2,100 [m]. The current licensees in Bøyla are Aker BP ASA (65 %), Vår Energi ASA (20 %), and ABP Norway AS (15 %). (NPD, 2022)

4.3.2 OLGA

OLGA® (OiL and GAs simulator) is a commercial multiphase flow simulator owned and distributed by Schlumberger and is used for dynamic simulation in multiphase transportation. The idea for the tool was conceived in 1979 by two researchers named Dag Malnes and Kjell Bendiksen in Norway. The software was developed by IFE in collaboration with SINTEF and initially was financed by Statoil and later bought by Schlumberger. The basis for the OLGA model is the experiments based on realistic conditions, i.e., high pressure and large diameters performed at the SINTEF multiphase flow laboratory in Trondheim, Norway. *Figure 4-3* shows the SINTEF multiphase flow laboratory.

Since the basis for the OLGA model can be considered close to the real conditions this dynamic multiphase flow simulator is widely used in the oil and gas industry. Considering the system's dynamics, OLGA solves many numerical equations to simulate the flow and offers heat and mass transfer models. This is the reason why OLGA can be used to deal with flow assurance issues such as slug flow and hydrates.

In this work, the models for both cases were constructed in OLGA. OLGA version [2020.2.0] was used for the simulations. To simulate the slug flow behavior in more detail, the slug tracking module was used. The unique capability of this module is to track each slug from formation to either exit from the pipeline or extinction. The model considers slug formation, merging of slugs, growth, and decay of slugs mechanisms (SLB, 2022). The simulation period for each case is 3 [hr].

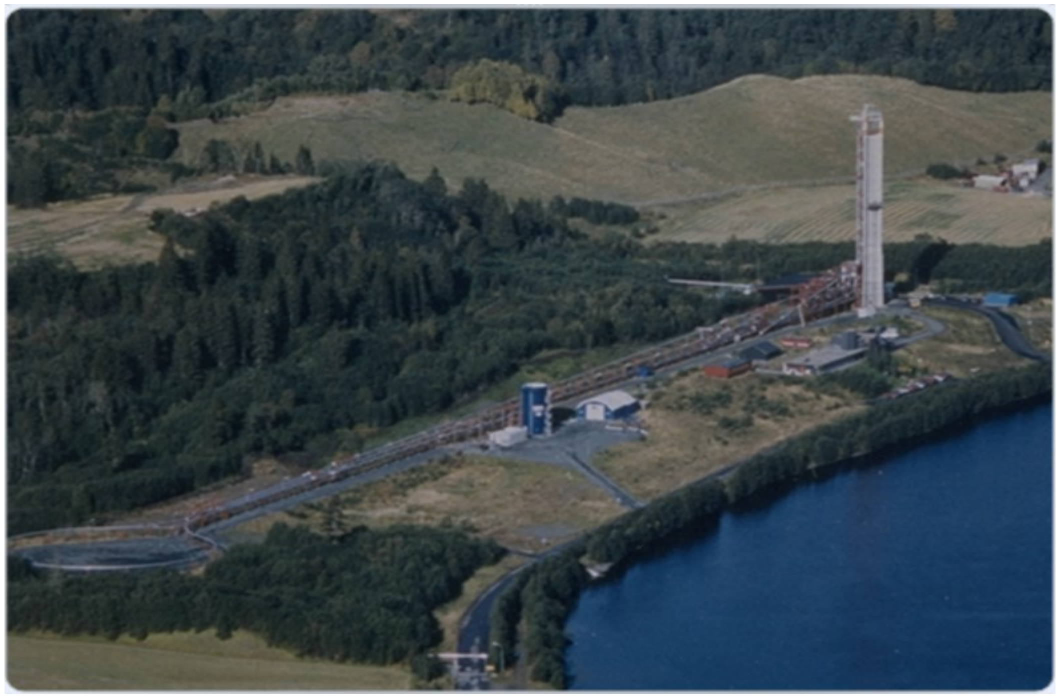

Figure 4-3: *SINTEF multiphase flow test laboratory in Trondheim, Norway*

4.3.3 The pipeline-riser systems

Figure 4-4 shows the overall pipeline geometry of the Case Study (I). This flowline consists of a 4.5 [km] pipeline section with an inner diameter (ID) of 10.8 [in] followed by a 150 [m] high flexible S-shaped riser.

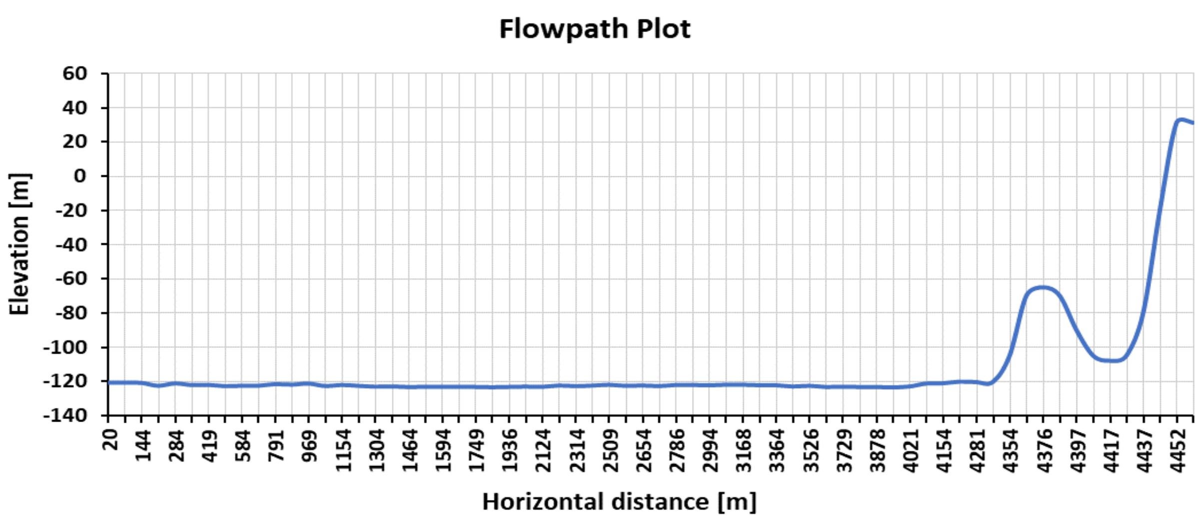

Figure 4-4: *Pipeline geometry of the Case Study (I)*

The model for the Case Study (II) is shown in *Figure 4-5*. The flowline for the Case Study (II) includes a 19.5 [km] pipeline with an inner diameter (ID) of 11.26 [in] that is connected to the topside facilities through a 150 [m] high flexible S-shaped riser.

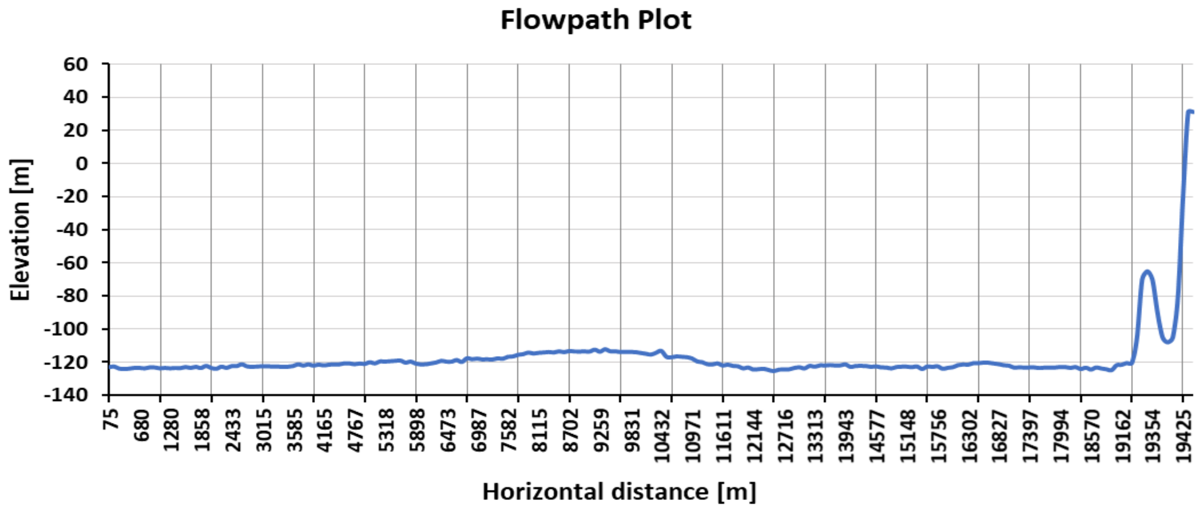

Figure 4-5: *Pipeline geometry of the Case Study (II)*

Since these two systems are currently producing, to respect the privacy policies of the Aker BP company, more details about these pipelines cannot be shared.

4.4 Data Analysis Methods

The goal of analyzing the pressure fluctuations data generated by OLGA simulations is to investigate the different slug control methods and observe their effects on the frequency of the oscillations induced by slug flow. If a slug control method decreases the frequency of pressure fluctuations, it can be considered a useful method to apply to the production system.

4.4.1 Manual frequency calculation

The definition of frequency is the number of regular waves that pass a fixed place in a time interval. For example, if a wave passes a fixed place in 1/2 second, the frequency is 2 per second. The unit for the frequency is hertz [Hz], which is named in honor of the 19th-century German physicist Heinrich Rudolf Hertz. [Hz] unit, is the number of waves that pass per second. The simplest method for slug frequency calculation is to count the number of peaks from the pressure data and divide them by the time interval. As an example, see *Figure 4-6* which shows pressure versus time data of an arbitrary producing flowline.

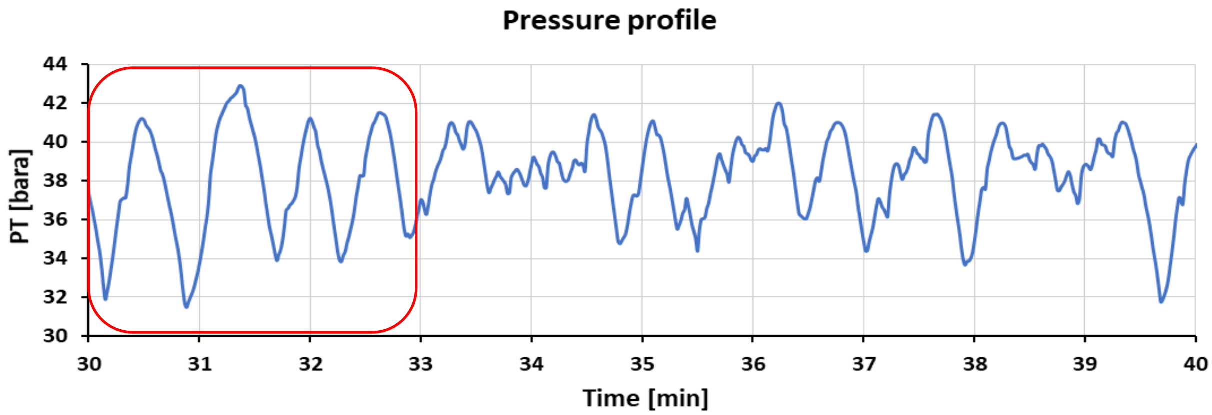

Figure 4-6: *Example of manual frequency analysis*

In the first three minutes, four peaks (in the red square in *Figure 4-6*) can be observed. Thus, the frequency calculations will be as followed:

$$Frequency = \frac{Nr.\ peaks}{Time\ interval\ [s]} = \frac{4}{3 \times 60} = 0.022\ [Hz]$$

This method for analyzing the pressure data might be quite troublesome and time-consuming especially when it comes to analyzing a huge amount of data points. For example, in this work, visual observation and counting peaks of pressure fluctuation versus time in 3 hours of OLGA simulation results (shown in *Figure 4-7*) is practically unfeasible.

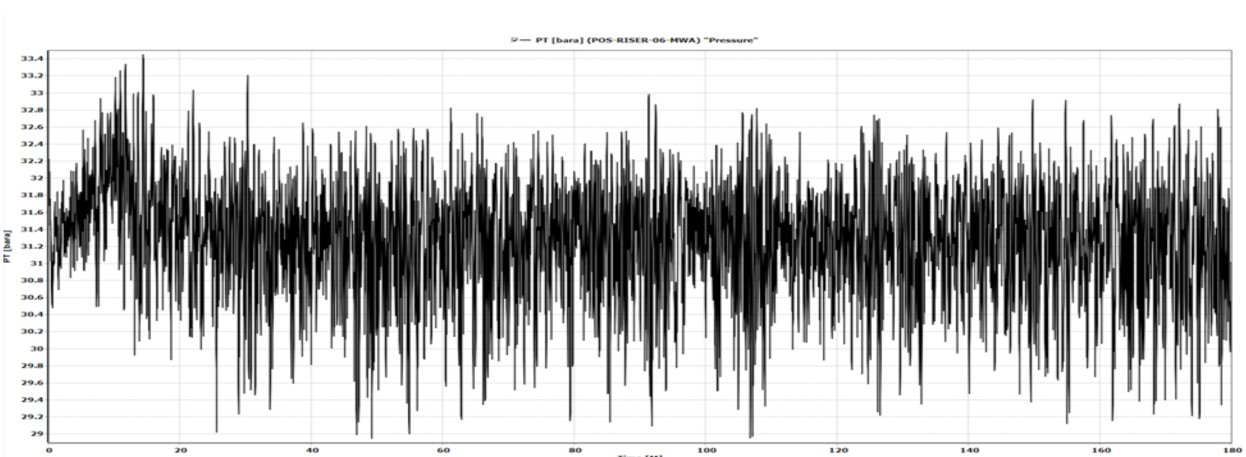

Figure 4-7: *Pressure vs Time of Case Study (I) of a 3-hour period simulation in OLGA*

Hence for calculating the slug frequency from the pressure profile, the 3 hours should be divided into smaller intervals. Although in OLGA there is an option that the user can zoom in on the pressure profile and observe the pressure changes in different time intervals, in this thesis the data points generated in OLGA were imported to an Excel sheet since in Excel more options are provided for faster calculation and easier data analysis. After importing the pressure data in the Excel sheet pressure change in small time intervals was plotted like the one shown in *Figure 4-8*.

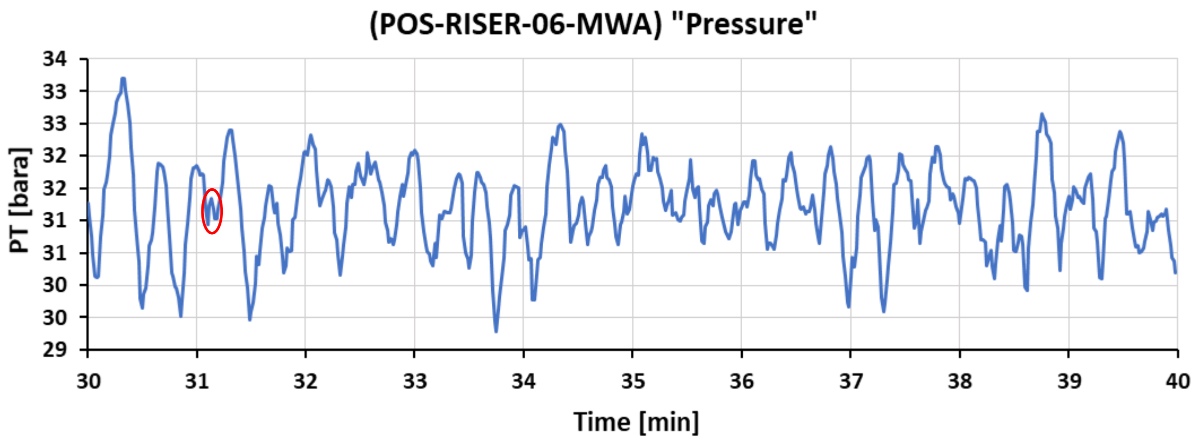

Figure 4-8: *Pressure vs Time of Case Study (I) in a ten-minute interval*

Figure 4-8 shows an example plot in a ten-minute interval from minute 30 to 40 at the position of the MWA point in the Case Study (I). By dividing the 3 hours, the peaks become recognizable, and calculation of the frequency will be possible. Moreover, for calculating the frequency only those peaks that had a change of equal or more than 1 [bara] were considered, and small peaks like the one depicted with the red circle in *Figure 4-8,* were neglected.

To make sure that the calculated frequency is representative of the whole 3-hour period, different intervals were examined, and results were presented in *Table 4-1*. Based on the calculated frequencies presented in *Table 4-1*, it can be concluded that one interval can be representative of the whole 3-hour period since the frequency remains almost unchanged in different time intervals and therefore, one arbitrary time interval from 3 hours of simulation results can be chosen for the frequency calculations. In this study, the interval of minutes 30 to 40 was chosen because, after approximately 20 minutes of simulation, the flow is stabilized.

Table 4-1: Frequency calculation results in different periods.

Case Study (I)				
Interval [min]	**Peaks**	**Δt [min]**	**Δt [s]**	**Frequency [Hz]**
[30 - 33]	8	3	180	0.044
[30 - 40]	26	10	600	0.043
[90 - 93]	8	3	180	0.044
[90 - 100]	26	10	600	0.043
[140 - 143]	8	3	180	0.044
[140 - 150]	26	10	600	0.043

4.4.2 FFT analysis

In 1965, James W. Cooley (IBM) and John W. Tukey (Princeton) developed the revolutionary fast Fourier transform (FFT) algorithm (Cooley & Tukey, 1965). FFT which is a coordinate transform had a significant and profound role in shaping the modern world. This algorithm has become the cornerstone of computational mathematics, enabling real-time image and audio compression, global communication networks, modern devices and hardware, numerical physics and engineering at scale, and advanced data analysis (Brunton & Kutz, 2022).

Simply put, using Fourier transform, an arbitrary function or a signal (see *Figure 4-9* the plot on the right) can be approximated by a sum of sines and cosines of increasingly high frequency as it is shown in *Figure 4-9*.

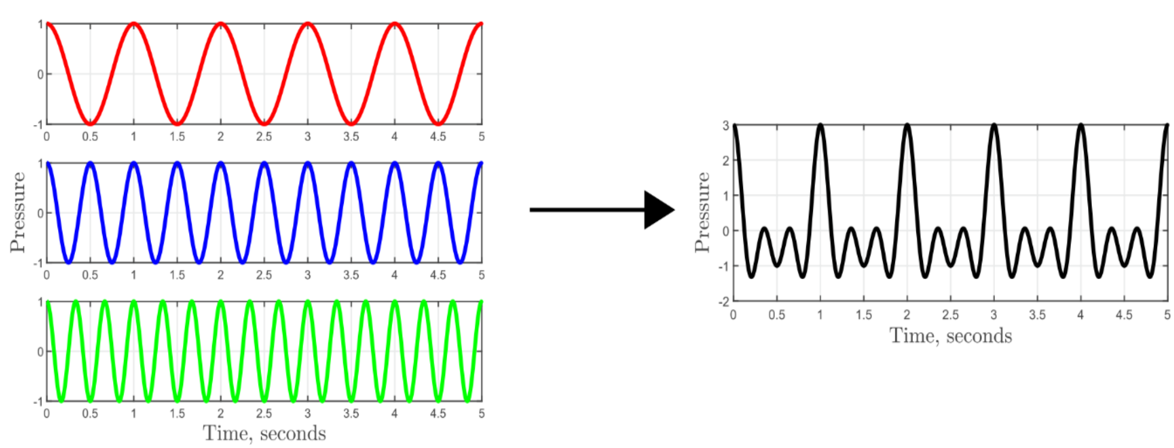

Figure 4-9: *Example of approximation of an arbitrary function taken from (White, 2020)*

To deal with the variability of a signal versus time, the Fast Fourier transform (FFT) can be applied to determine the dominant frequencies. In other words, the result of applying FFT on data points of a signal would be a plot such as the one shown in *Figure 4-10*. PSD or Power Spectral Density (on the y-axis in *Figure 4-10*) indicates how much power the signal contains in each frequency. Thus, the frequency with the highest PSD can be considered the dominant frequency.

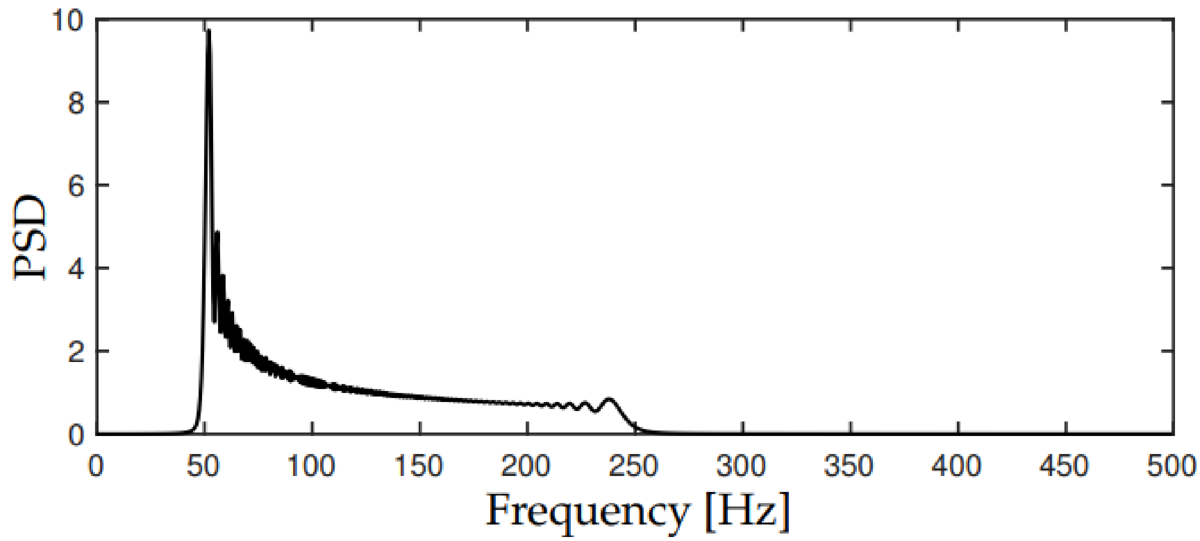

Figure 4-10: *Power spectral density of an arbitrary signal taken from (Brunton & Kutz, 2022)*

If a signal is a simple sine wave with a constant frequency the PSD plot would be a single vertical line since the signal has only one dominant frequency, and if there are no oscillations in the signal the PSD plot would be a horizontal line since spectral power of each frequency is zero. To understand comprehensively how the FFT algorithm functions see (Brunton & Kutz, 2022).

In this work, pressure data points versus time extracted from OLGA were imported in a text file and the FFT function in Python programming language was applied to these data points to determine slug frequency. An example of the Python code used in this work is attached in the appendix.

4.4.3 Frequency analysis

Oscillating pressure versus time will be displayed as a wave in OLGA. Each wave is governed by amplitude and frequency. The amplitude indicates the strength of the wave, and the frequency presents the number of full oscillations completed per second. FFT can give the dominant frequency of the wave, but it does not provide any information about the wave amplitude or in general under what dominant pressure the system is producing. Thus, Frequency Analysis can be applied to pressure data to attain an overall view of the dominant amplitude range which is the dominant pressure range of the production system. Frequency Analysis is an important area of statistics that is used to estimate how often certain values of a variable phenomenon may occur. This analyzing method deals with the number of occurrences (frequency) and analyzes measures of central tendency, dispersion, percentiles, etc. As a simple example consider the imaginary data in *Table 4-2*. This table shows the price of one liter of gasoline in several countries in Europe.

Table 4-2: *Gasoline prices in different countries in Europe*

Price per liter [$]																			
10	7	2	6	1	8	1	7	3	9	1	4	8	2	9	3	10	5	6	9

For applying the Frequency Analysis on the data in Excel, three parameters are required, namely maximum, minimum, and the number of bins. By these three components length of the intervals (delta) can be indicated, and then data will be categorized accordingly. The formula for calculating the delta is shown as followed:

$$\Delta = \frac{Max - Min}{Nr.\ Bins - 1}$$

After calculating the delta all the requirements for Frequency Analysis are acquired, which are listed in *Table 4-3*:

Table 4-3: *Required parameters for frequency analysis*

Max	Min	Nr. Bins	Delta
10	1	5	2.25

The number of bins in this example is an arbitrary number that can change regarding the scope of the search, the number of bins is considered 5 in this example. Next, in an Excel sheet, we can allocate a column for bins such that the first bin is the minimum, after that the min plus the delta, and next the previous bin plus delta, and so on until the maximum is reached. The bins are shown in *Table 4-4*. In the next step by applying the frequency function in Excel, the number of counts in each bin is calculated. (See *Table 4-4*.)

Table 4-4: *The bins and their respective number of counts*

Bins	Nr. Counts
1	3
3.25	4
5.5	2
7.75	4
10	7

From the results shown in *Table 4-4*, it can be concluded that most of the countries in Europe sell gasoline at a price of more than 7.75 $. It should be noted that by changing the number of bins, the length of each interval will change accordingly, and thereby the frequency analysis can categorize data in bigger or smaller intervals regarding the purpose of the analysis. *Figure 4-11* illustrates the plot of the bins and their respective number of counts.

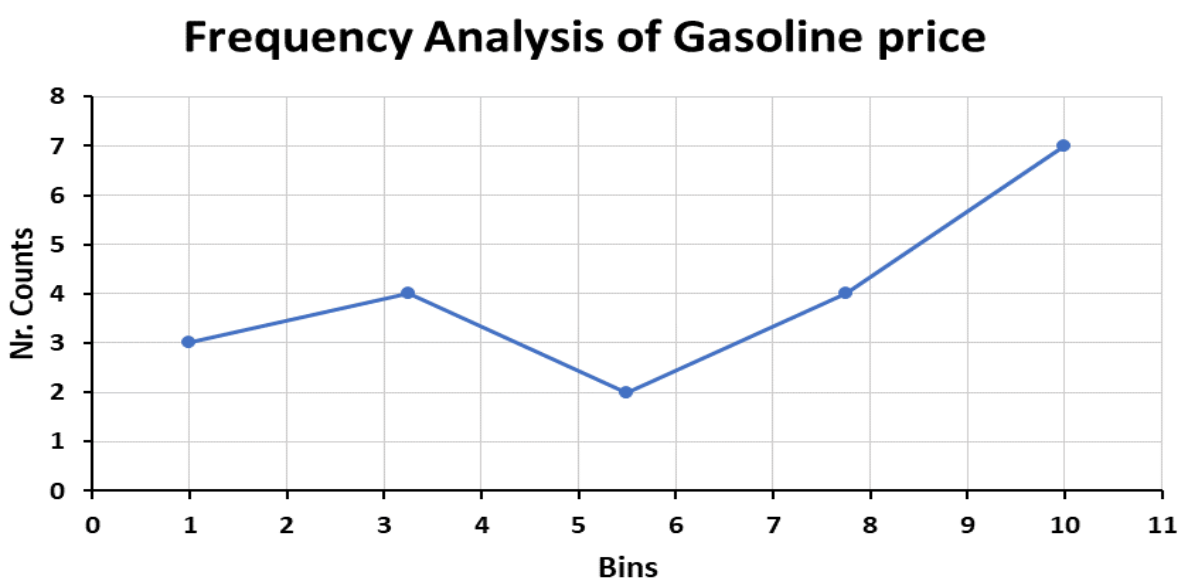

Figure 4-11: *Frequency analysis of gasoline price results*

Figure 4-11 shows that the maximum number of counts takes place in the last bin. When the number of data points is high both table and plot can be used for analysis.

The method of Frequency Analysis can be applied with the same process explained in the above example on the data points of pressure change in time to reach some overall information about the dominant pressure as different slug control methods are employed. It should be noticed that in the example, the number of bins was chosen arbitrarily but in pressure fluctuations frequency analysis, the number of the bins was picked in a way that the delta is approximately 1 [bara]. Moreover, when there is no pressure fluctuation which is an ideal situation, we see the plot as one single vertical line since in that case there is no maximum and minimum and the bins are all the same. For example, *Figure 4-12* shows an imaginary pipeline producing with no pressure fluctuation at a constant pressure of 110 [bara]. The vertical line shows that there is no diversity in the data points which means there is no oscillation.

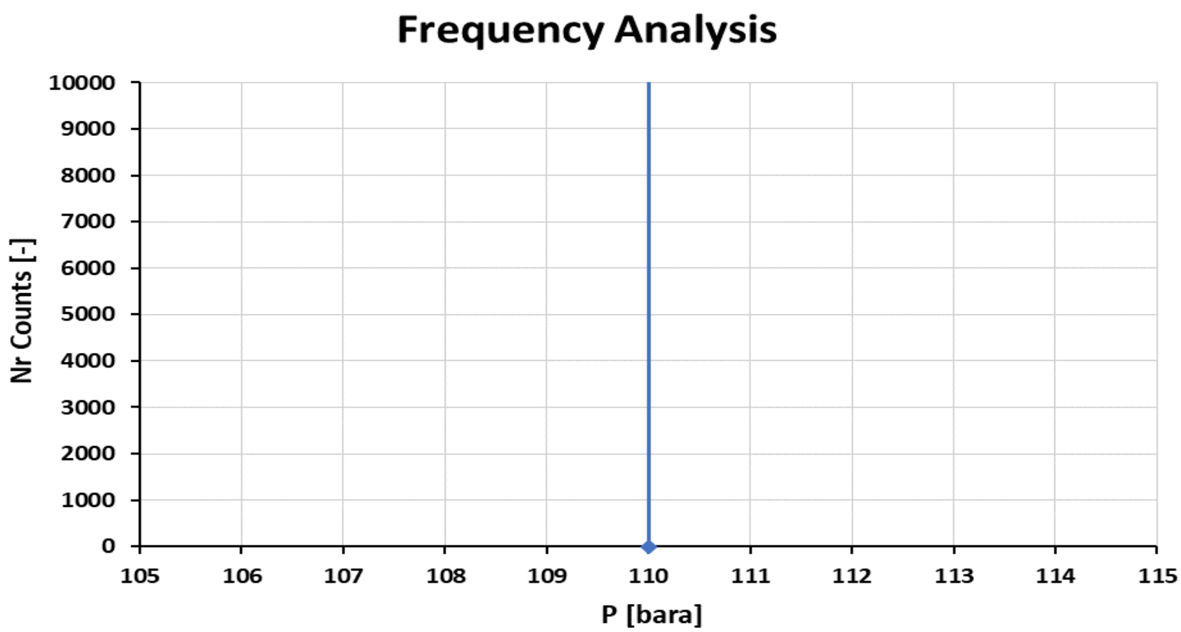

Figure 4-12: *Example of Frequency Analysis on a pipeline producing at a constant pressure of 110 [bara]*

Thus, in Frequency Analysis the plot that is closer to a vertical line shows that the fluctuation in that case, is low, and as the area under the plot expands it indicates that the variety of the data points is increasing, and thereby the fluctuations.

4.5 Slug Control Methods and the Case Study

The purpose of flow assurance is to ensure the flow of produced hydrocarbons from the reservoir to the downstream processing facilities by prediction, prevention, and remediation of flow problems such as hydrate, wax, and slugging. Flow assurance is a critical component in the design and operation of multiphase production facilities (Mokhatab et al., 2018).

The major challenge is that during the early stages of field development there is great flexibility in the design of the production system based on the little information from a reservoir. However, once the production begins more details about the reservoir and production process will be revealed and in case of an issue, there is less flexibility in terms of installing new equipment or changing the current production facilities especially when it comes to offshore production systems' operation expenditure (OPEX) and capital expenditure (CAPEX). Thus, a flow assurance engineer should provide a feasible solution for securing production operations, minimizing downtime, and reducing the costs of production and transportation, considering the capabilities and requirements for all parts of the production system.

In the next sub-sections, some slug control methods that can be effective at hydrodynamic slug mitigation are suggested and the possibility of utilizing each method depending on the capabilities of the current production system and the process facilities is checked. Moreover, of the suggested methods those that are applicable (external gas lifting and topside choking) are simulated on the case studies I and II in OLGA, and the results of the simulations were analyzed using data analysis methods explained in section 4.4.

4.5.1 Subsea finger-type slug catcher

Using slug catchers can be considered an efficient method for slug elimination. Slug catchers of all types are categorized as topside facilities, often installed at the receiving terminal of a multiphase flow processing plant. However, regarding the purpose of this work, a method should be applied to either prevent slugging or mitigate the frequency of the slug to alleviate the vibration of the flexible riser that is installed in the production system. Thus, the installation of a finger-type slug catcher which is installed on the sea floor where the pipeline ends and connects to the riser was suggested. The idea is like the Multi Parallel Pipe Separator (MPPS) presented in (Skjefstad & Stanko, 2018; Skjefstad & Stanko, 2019). An illustration of the MPPS is shown in *Figure 4-13*.

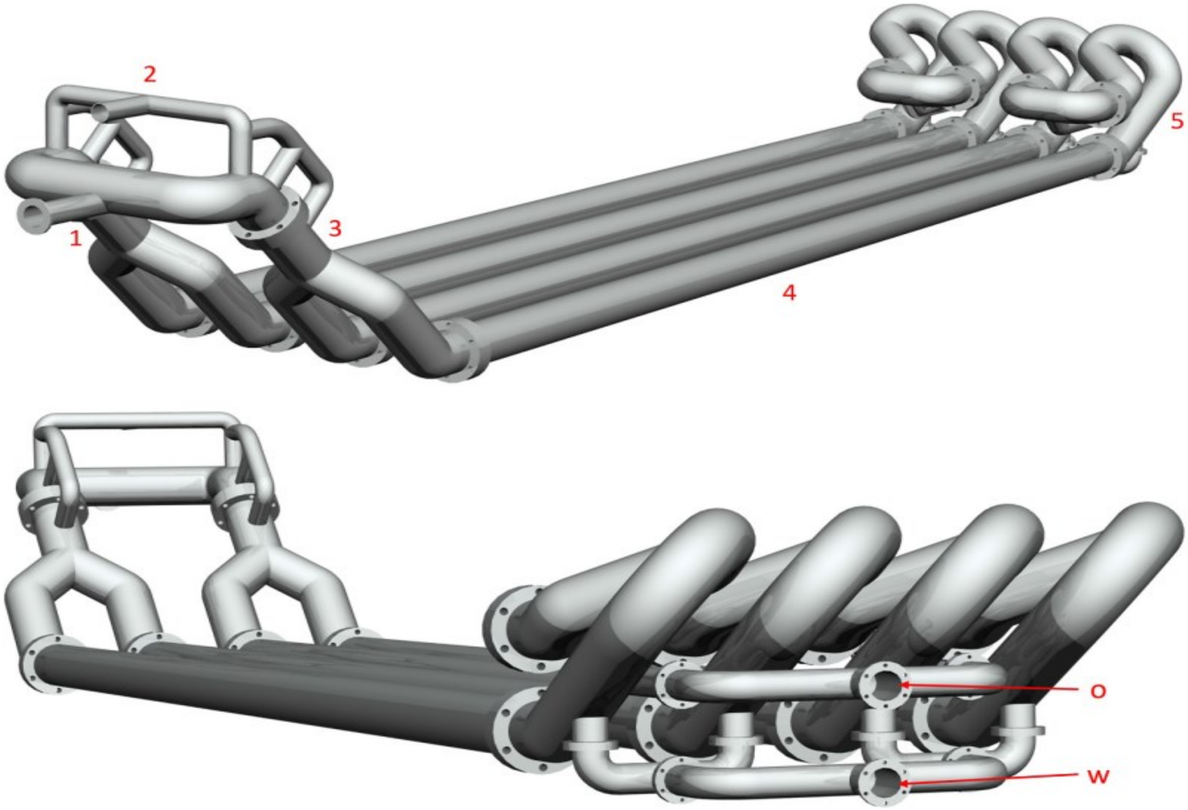

Figure 4-13: *Illustration of the MPPS design adapted from (Skjefstad & Stanko, 2019)*

In *Figure 4-13* the inlet (1) is a T-section header that splits the incoming produced fluid evenly to each branch. The gas-liquid separation section is also depicted (2). The descending pipes (3) following the gas-liquid separation section, split the production stream further into horizontal pipes (4), where most of the separation takes place. Next is section (w) where water extraction occurs in an inclined group of pipes (5). The inclination causes water to slow down which leads to a large holdup of water for controlled extraction. The remaining oil-rich stream will flow up through the inclined pipes to the separated oil outlet (o).

To optimize the design of this prototype and observe the separation performance efficiency, Skjefstad conducted several experiments and numerical analyses. However, the performance data collected are based on experiments with model oil and water (Skjefstad & Stanko, 2019). The performance with real crude and brine could be significantly different.

The fact that this field has been already producing for several years and considering the extra expenses of installation of subsea finger-type slug catcher and production shut down made this idea not financially justified for the case investigated in this work. Yet installation of a subsea finger-type slug catcher or separator can be considered an efficient method for slug prevention for the production systems which are at the early stages of development.

4.5.2 Flow conditioners and Diameter reduction

Installation of a flow conditioner for slug mitigation was considered for Case Study (I). However, all the investigated literature about flow conditioner methods emphasized that utilizing a flow conditioner is a suitable method for severe slugging mitigation by mixing the stratified flow regime that takes place before the riser inlet but there was no information about the mitigation of hydrodynamic slugging.

To investigate the effect of a flow conditioner on the system's behavior, in the model for Case Study (I), the inner diameter (ID) of the pipe that connects the pipeline to the riser inlet was reduced using the parametric study tab in OLGA to simulate the flow conditioner's pressure drop. The placement of the reduced-diameter pipe is chosen based on the common location of flow conditioners. The inner diameter of the pipe was altered such that it was equal to the 0.9, 0.8, and 0.7 of the base case ID as it is shown in *Table 4-5.*

Table 4-5: *Effect of diameter reduction of the riser inlet*

	ID ratio to the base case	Inner diameter ID, [m]	Max liquid volume flow, [m3/d]	Max pressure at the MWA, [bara]	Min pressure at the MWA, [bara]
Base case	1	0.269	3.20E+04	33.45	28.95
Case 1	0.9	0.242	3.22E+04	33.70	28.74
Case 2	0.8	0.215	3.19E+04	33.63	28.45
Case 3	0.7	0.188	3.28E+04	33.89	28.37

According to the results shown in, the diameter reduction of the riser inlet had almost no effect on the system behavior, and maximum liquid volume flow, maximum, and minimum production pressure remained at approximately the same level.

To investigate the influence of riser inlet ID reduction on pressure fluctuation and slug frequency, a Fast Fourier transform (FFT) was applied to the pressure versus time data points. *Figure 4-14* shows the results of the FFT analysis on the Base case, Case 1, Case 2, and Case 3. The dominant frequency area in the base case in *Figure 4-14* is between 0.03 and 0.05 [Hz] with the peak at approximately 0.038 [Hz]. As the diameter is reduced the dominant area and peak move slightly to the right. This displacement shows that reducing the riser inlet ID has a negative effect on slug frequency meaning that the smaller the ID the bigger the slug frequency.

A noticeable phenomenon is the secondary dominant area roughly between 0.01 and 0.02 [Hz] that also moves to the right as the diameter is reduced. This area might be representative of a secondary wave with a dominant frequency of nearly 0.01 [Hz].

Power Spectral Density (PSD) does not show an ascending or descending behavior as in the Base case the PSD of the dominant frequency is about 0.13 and then a drastic rise to 0.17 occurs in Case 1 and then it decreases until it reaches almost 0.125 in Case 3.

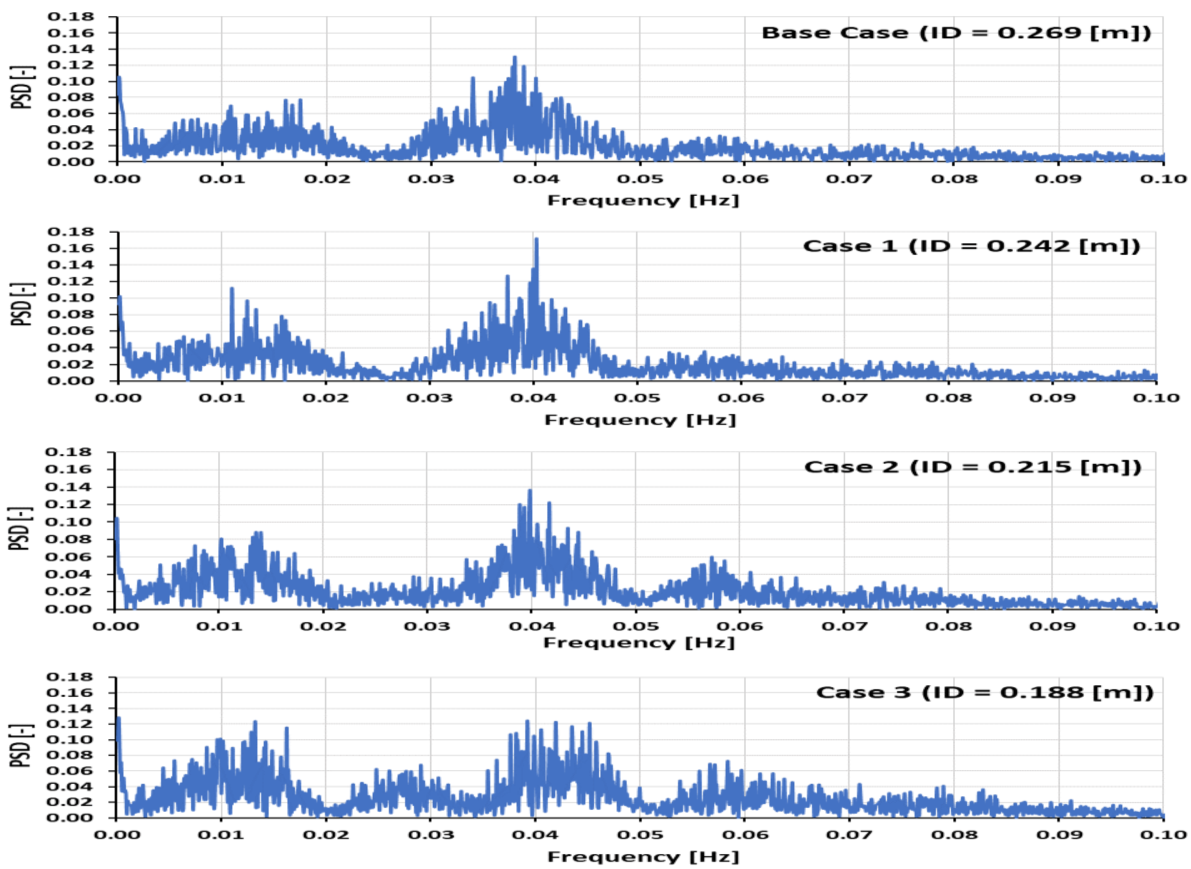

Figure 4-14: *The results of FFT analysis on ID reduction of riser inlet of Case Study (I)*

Furthermore, reducing the entire riser diameter was considered for the case study since smaller risers generally have less severe slugging potential, but results published by (Meng & Zhang, 2001) show that reducing the riser diameter is not effective in mitigating slugging. They investigated the concept of using a smaller riser size while keeping the same pipeline diameter and it was concluded that even reducing the riser diameter to 4 inches does not change the slug characteristics.

In addition to the results presented in (Meng & Zhang, 2001), reducing the riser diameter might cause problems in pigging operation, and also the extra cost of installation in the pipeline-riser system that is studied in this thesis. Thus, this option was not taken into consideration for further evaluations.

4.5.3 Surfactant injection

Surfactant injection into the flowline will reduce the surface tension and mitigate severe slugging by changing the flow regime in the pipeline from stratified to mixed. In this work, after reviewing some of the papers about the effectiveness of surfactant injection it was assumed that surfactant can deal with the problem of hydrodynamic slugging by decreasing surface tension. However, the results published by (Tzotzi et al., 2011) show the opposite. (Tzotzi et al., 2011) evaluates the effect of surface tension, using aqueous solutions of normal butanol, and compares it with the base case of an air-water fluid mixture. Experiments were conducted at atmospheric conditions in a 12.75-meter-long pipe with a diameter of 0.024 [m] and downwardly pipe inclinations of 0°, 0.25°, and 1°. In their experiment surface tension was decreased from 72 to 35 millinewton meter [mN/m] and the effect of decreasing surface tension on the flow pattern was published as it is shown in *Figure 4-15*.

Figure 4-15 shows that by reducing the surface tension, the transition boundaries of pseudo-slug, annular flow, and other flow regimes will be shifted to lower gas velocities. But the transition to slug flow is not affected by changing this physical property.

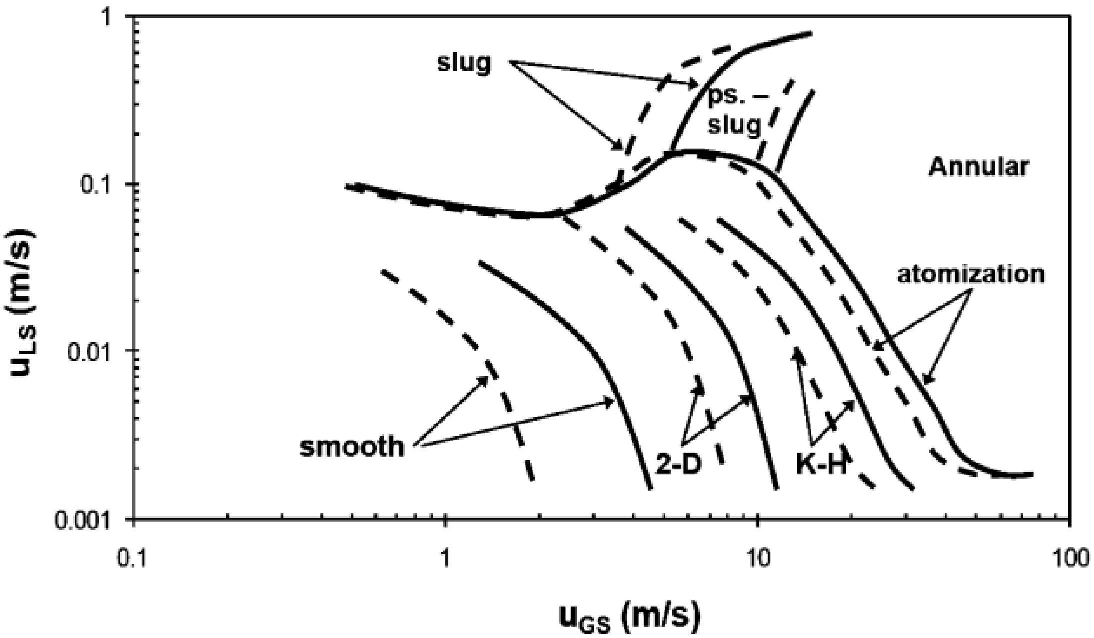

Figure 4-15: *Comparison between air-water (continuous lines) and air-aqueous butanol solution flow pattern map (dashed lines) adapted from (Tzotzi et al., 2011)*

The figure uses nomenclature different from the rest of the thesis. 2-D waves, K-H waves, and atomization are flow regimes (or sub-regimes) observed and explained in (Tzotzi et al., 2011)

Furthermore, some operating information observed at Aker BP support some of the conclusions in (Tzotzi et al., 2011) paper. Graham Rudrum from Aker BP who is the co-supervisor of this thesis provided the observed information as followed:

Injection of drag reducer on the Valhall Flank flowlines

The Valhall Flank South and Flank North flowlines both exhibit hydrodynamic slugging and various slug suppression control schemes have been unsuccessfully implemented over the years. However, at some point, a surfactant was introduced to reduce the pressure drop by either eliminating or significantly reducing the slugging over the Flank South flowline. This would suggest that the surface tension between the oil and gas phases, affects the transition from stratified wavy to slug flow. Certainly, a reduction in interfacial surface tension would reduce the ability of the gas to grip the liquid and therefore reduce the waviness. But in practice, the desired result was not achieved and due to the high cost of the drag-reducing chemical used in this operation, a decision was taken to continue with the slugging problem and stop the surfactant injection.

Alvheim - Vilje 19.5 km 12" flowline pressure drop increase

This is another observation made during an operational upset when the injection of Corrosion Inhibitor (CI) failed at the Vilje production manifold for several hours. During this period of non-injection, the pressure at the Vilje manifold increased by 4-5 [bar] and remained at that level until the CI injection was resumed. The increase in pressure was first noticed and while investigating the possible reason for the pressure increase, it was unexpectedly discovered that the CI injection had failed. It is reasonable the CI would act like a surfactant and/or drag-reducing agent in the water phase, and therefore influence the liquid hold-up and the pressure drop in the flowline. A noticeable phenomenon that remained unexplained in this operation was that the effect of CI was immediate and did not take time to establish itself.

In addition to the results published by (Tzotzi et al., 2011), and operational observations injection of surfactant may lead to some issues in the downstream separation process, and eventually affect the product quality and capability. Thus, using surfactant for hydrodynamic slug mitigation or elimination was not considered a helpful method in this case and further evaluation of this slug control method was stopped.

4.5.4 External gas-lifting

Injecting gas at the riser base can eliminate severe slugging by reducing the liquid holdup and the vertical pipeline's hydrostatic pressure in the riser. To examine this method's effectiveness the Case Study (I) model was altered by adding a constant mass flowrate source at the riser base. The gas source was set to have a constant injection temperature of 32°C. GASFRACTION is equal to 1, and TOTALWATERFRACTION is considered 0, thereby allowing only gas injection with a specified flow rate. The average gas mass flow in Case Study (I) was estimated at approximately 6.2 [kg/s]. The gas injection rates of 1.5, 2, 5, 10, 15, and 20 [kg/s] were applied using the parametric study tab in OLGA to cover a large range of injection rates. These rates of injection were investigated and compared to the base Case Study (I). The changes in pressure concerning each flow rate are summarized in *Table 4-6*. The results show that the scope of pressure change in a certain interval which is equal to p_{max} - p_{min}, expands as the mass flow rate increases.

Table 4-6: *Changes in pressure at MWA (or Hog bend) with applying different injection rates*

Case Study (I) & Gas-Lifting			
Gas injection mass flow rates [kg/s]	**Maximum pressure at MWA [bara]**	**Minimum pressure at MWA [bara]**	**Scope of pressure change [bara]**
0	33.45	28.95	5.07
1.5	34.82	29.48	5.34
2	34.97	29.89	5.08
5	38.05	31.37	6.67
10	43.50	35.13	8.37
15	49.28	39.62	9.65
20	53.92	44.59	9.33

To investigate the effect of external gas-lifting in the other flowline in the Bøyla field and to compare it with the Case Study (I), different injection rates were also examined in Case Study (II). For this purpose, a mass flow source with the same properties was added to the model of Case Study (II) in OLGA. The average gas mass flow rate in Case Study (II) was approximately 7.6 [kg/s]. Gas injection rates of 1.5, 2, 5, 10, 15, and 20 [kg/s] were investigated and compared to the base case. *Table 4-7* shows the effect of external gas lift with different injection rates.

Table 4-7: *Changes in pressure at MWA (or Hog bend) with applying different injection rates*

Case Study (II) & Gas-Lifting			
Gas injection mass flow rates [kg/s]	**Maximum pressure at MWA [bara]**	**Minimum pressure at MWA [bara]**	**Scope of pressure change [bara]**
0	31.03	21.08	9.94
1.5	31.54	21.48	10.05
2	31.94	21.57	10.37
5	33.62	22.33	11.30
10	36.97	24.66	12.31
15	40.48	26.21	14.27
20	43.48	29.03	14.45

By applying the gas-lifting method in Case Study (II) we can see that by increasing the injection rate, the scope of the pressure change expands as it is shown in *Table 4-7*.

The following sub-sections present the data analysis on the effects of the gas-lifting parametric study on Case Study (I) and (II), using the three data analysis methods explained in section 4.4:

4.5.4.1 Manual frequency calculations of external gas-lifting in the Case Study (I)

The results of applying manual frequency calculation on pressure data points regarding each injection rate in the Case Study (I) are presented in *Table 4-8.*

Table 4-8: *Frequency calculations of each injection rate in external gas-lifting*

Case Study (I) & Gas-Lifting								
Injection rate [kg/s]	**Interval [min]**	**Nr. Peaks [-]**	**Δt [min]**	**Δt [s]**	**Frequency [Hz]**	**Crest [bara]**	**Trough [bara]**	**Scope of change [bara]**
0	[30 - 40]	26	10	600	0.043	33.21	29.29	3.92
1.5	[30 - 40]	30	10	600	0.050	34.23	29.96	4.27
2	[30 - 40]	30	10	600	0.050	34.27	30.36	3.91
5	[30 - 40]	32	10	600	0.053	36.97	32.46	4.51
10	[30 - 40]	30	10	600	0.050	42.66	35.66	7.00
15	[30 - 40]	30	10	600	0.050	46.86	41.18	5.68
20	[30 - 40]	30	10	600	0.050	52.53	45.71	6.82

According to the calculated frequencies shown in *Table 4-8,* once the gas injection begins in Case Study (I) the frequency increases from 0.043 to 0.050 [Hz], and after that, it remains almost unchanged regardless of what injection rate is applied. The scope of the pressure change, on the other hand, shows an oscillating behavior, however in general the scope of change is seemed to be increasing.

4.5.4.2 Manual frequency calculations of external gas-lifting in the Case Study (II)

Manual frequency calculation is applied on pressure data points from the Case Study (II) and results were summarized in *Table 4-9.* Results show that the frequency remains almost the same despite increasing injection rate. And the scope of the change (p_{max}-p_{min}) in each interval increases with the injection rate, although there are some fluctuations.

__Table 4-9:__ Frequency calculations of each injection rate in external gas-lifting

Case Study (II) & Gas-Lifting								
Injection rates [kg/s]	**Interval [min]**	**Peaks [-]**	**Δt [min]**	**Δt [s]**	**Frequency [Hz]**	**Crest [bara]**	**Trough [bara]**	**Scope of Change [bara]**
0	[30 - 40]	13	10	600	0.022	30.42	22.28	8.14
1.5	[30 - 40]	13	10	600	0.022	31.39	22.97	8.42
2	[30 - 40]	14	10	600	0.023	30.70	23.80	6.90
5	[30 - 40]	13	10	600	0.022	33.28	23.32	9.95
10	[30 - 40]	14	10	600	0.023	36.46	25.23	11.23
15	[30 - 40]	16	10	600	0.027	38.89	28.63	10.27
20	[30 - 40]	13	10	600	0.022	42.92	31.47	11.45

4.5.4.3 FFT analysis of external gas-lifting in the Case Study (I)

Applying Fast Fourier Transform (FFT) on pressure versus time data in the Case Study (I) leaded to plots shown in *Figure 4-16.* Based on these plots, the dominant frequency area in the base case (injection rate = 0 [kg/s]) is approximately between 0.03 and 0.05 [Hz] with the peak at approximately 0.038 [Hz]. Once the gas injection starts, the dominant area and peak move to the right until the dominant area takes place in the interval between 0.05 and 0.07 [Hz] peaking at around 0.057 [Hz] at an injection rate of 20 [kg/s]. This displacement indicates that injecting more gas in the external gas-lifting method leads to an increase in the slug frequency in this case study.

It should be noticed that injecting gas may induce another dominant area roughly between 0.01 and 0.02 [Hz] that also moves to the right and expands as the injection rate is increased. We can see the dominant area at an injection rate of 20 is between 0.01 and 0.04 [Hz].

The Power Spectral Density (PSD) of the dominant area between 0.03 and 0.05 [Hz] is approximately 0.13 in the base case and it starts to rise as the injection rate elevates and then decreases until it reaches back to the amount of around 0.14. However, PSD of the secondary dominant area between 0.01 and 0.02 [Hz] shows an ascending behavior with an increasing injection rate.

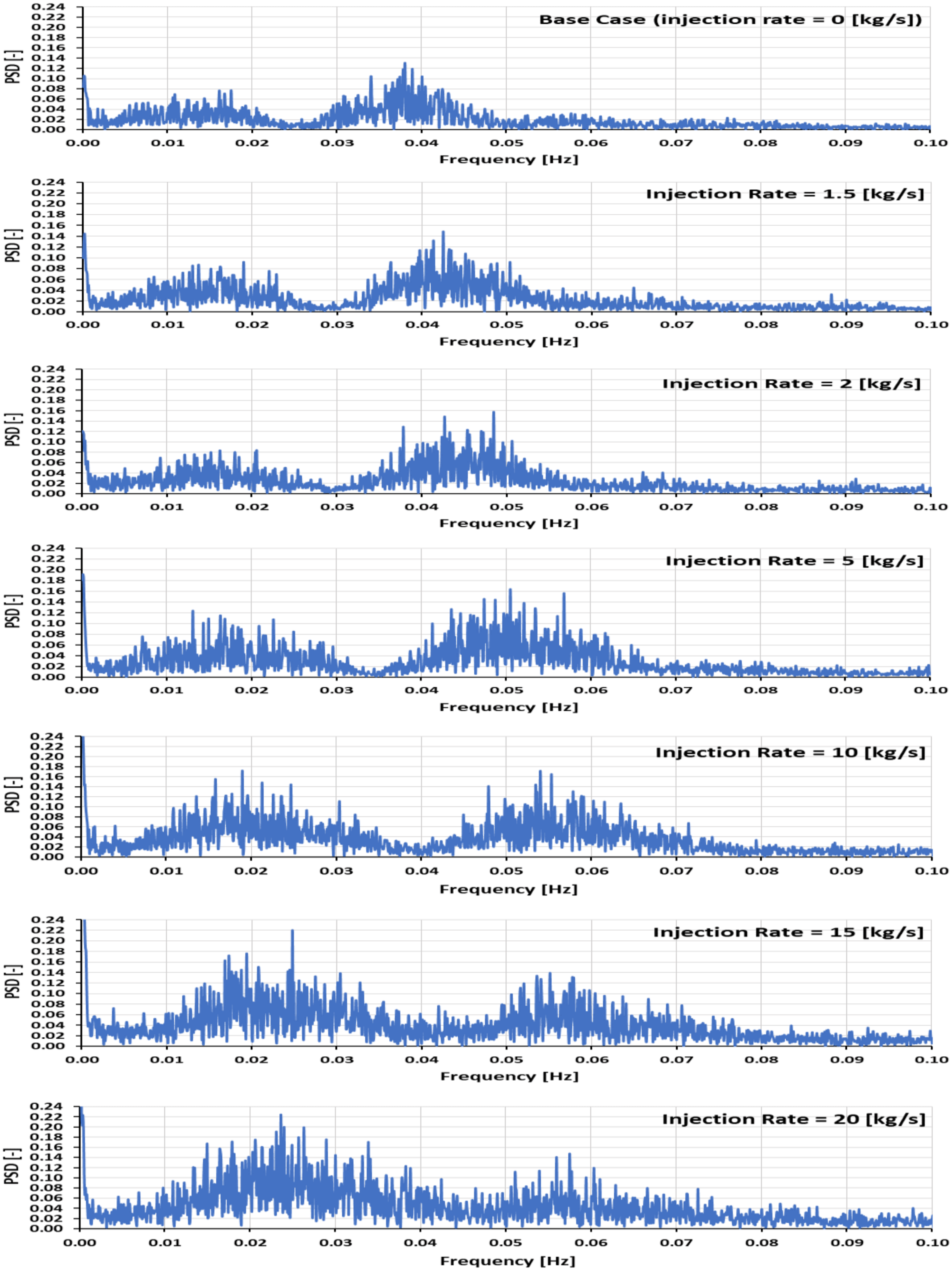

Figure 4-16: *The results of FFT analysis on external gas-lifting in the Case Study (I).*

4.5.4.4 FFT analysis of external gas-lifting in the Case Study (II)

Figure 4-17 shows Fast Fourier Transform (FFT) analysis on pressure versus time data in the Case Study (II). The FFT analysis plot of each injection rate is presented in *Figure 4-17*, which shows that the dominant frequency area in the base case (injection rate = 0 [kg/s]) is approximately between 0.00 and 0.02 [Hz] with the peak at approximately 0.008 [Hz]. Applying external gas-lifting in the Case Study (II) leads to a slight displacement of the dominant area and peak to the right until the dominant area reaches the interval between 0.005 and 0.025 [Hz] with peaking at around 0.012 [Hz] at an injection rate of 20 [kg/s]. This displacement in this case study shows that the external gas-lifting method and injecting more gas may increase the slug frequency.

The Power Spectral Density (PSD) of the dominant area is approximately 0.5 in the base case and with increasing the injection rate it remains almost the same until it elevates at the injection rate of 10 [kg/s].

Unlike the Case Study (I), in the Case Study (II) no secondary dominant area was induced by gas injection and PSD was high which means that the pressure changes with one dominant frequency. That might be one reason for not having severe slug-induced vibration (SIV) in the Case Study (II).

Moreover, by comparing the results of FFT analysis with the manual calculation of frequency, we can notice that manual frequency calculation failed at capturing the effect of gas-lifting on slug frequency since the frequency almost remained unchanged in both cases regardless of the increasing injection rate but with FFT it was possible to observe even small changes in the frequency. In terms of analyzing process time, FFT was way faster than the other method.

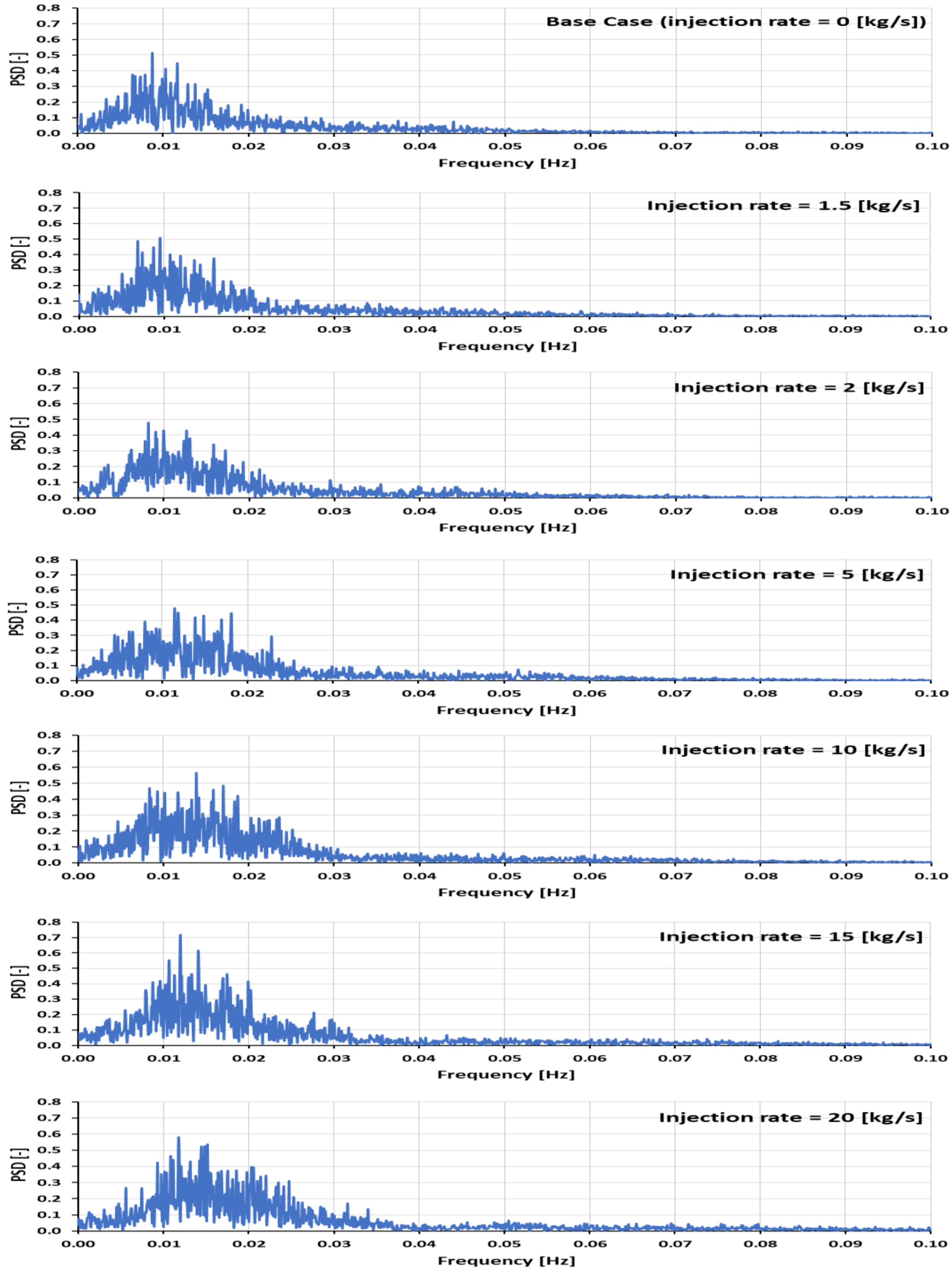

Figure 4-17: *The results of FFT analysis on external gas-lifting in the Case Study (II).*

4.5.4.5 Frequency analysis of external gas-lifting in the Case Study (I)

Applying Frequency Analysis in the Case Study (I) led to the results summarized in *Figure 4-18*. To track the changes in each injection rate, color scaling was used such that green designates the minimum number of counts, and red indicates the maximum number of counts.

Base Case (injection rate = 0 [kg/s])	
Bins	**Nr Counts**
28.95	1
30.07	563
31.20	3908
32.32	5792
33.45	537

Injection Rate = 1.5 [kg/s]	
Bins	**Nr Counts**
29.48	1
30.82	591
32.15	4245
33.49	5417
34.82	547

Injection Rate = 2 [kg/s]	
Bins	**Nr Counts**
29.89	1
31.16	605
32.43	4110
33.70	5230
34.97	855

Injection Rate = 5 [kg/s]	
Bins	**Nr Counts**
31.37	1
32.71	108
34.04	1907
35.38	4714
36.71	3742
38.05	329

Injection Rate = 10 [kg/s]	
Bins	**Nr Counts**
35.13	1
36.53	55
37.92	615
39.32	3070
40.71	4369
42.11	2486
43.50	204

Injection Rate = 15 [kg/s]	
Bins	**Nr Counts**
39.62	1
41.00	44
42.38	604
43.76	2303
45.14	4055
46.52	3122
47.90	623
49.28	49

Injection Rate = 20 [kg/s]	
Bins	**Nr Counts**
44.59	1
45.92	118
47.26	572
48.59	1536
49.92	2957
51.26	3845
52.59	1630
53.92	141

Figure 4-18: *The results of Frequency Analysis on external gas-lifting in the Case Study (I).*

Furthermore, to see the overall effect of external gas-lifting in the Case Study (I), the number of counts versus bins (or pressure intervals) were plotted and shown in *Figure 4-19*.

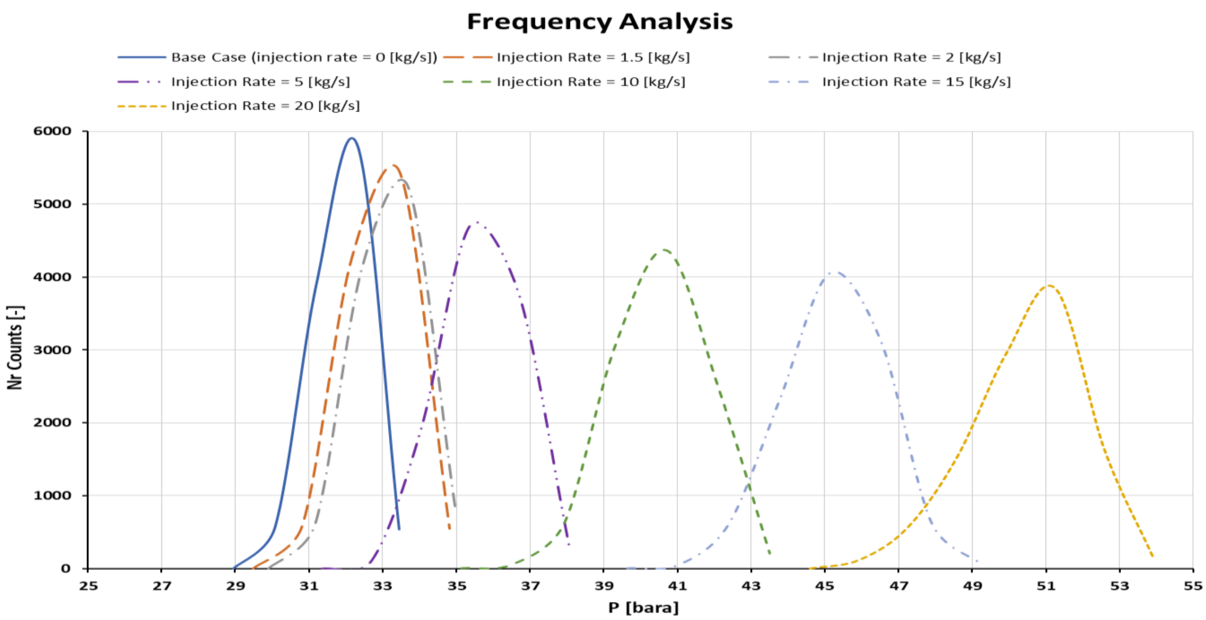

Figure 4-19: *The plot of Frequency Analysis results on external gas-lifting in the Case Study (I).*

The presented results indicate that applying external gas-lifting in the Case Study (I) not only increases the pressure at the MWA or Hog bend point in the riser, but also can intensify the oscillations since the maximum number of counts decreases as shown in *Figure 4-18,* and the area under each plot is expanding in comparison with the base case in *Figure 4-19,* as the injection rate increases.

4.5.4.6 Frequency analysis of external gas-lifting in the Case Study (II)

The results of applying external gas-lifting in the Case Study (II) were analyzed by the Frequency Analysis method and the results are presented in *Figure 4-20*. Color scaling is used in the figure to indicate the maximum and minimum of number of counts. Red stands for the maximum and green designates the minimum.

Base Case (Injection rate = 0 [kg/s])	
Bins	**Nr Counts**
21.08	1
22.19	126
23.29	394
24.40	572
25.50	868
26.61	1370
27.71	2546
28.82	2779
29.92	1668
31.03	476

Inection Rate = 1.5 [kg/s]	
Bins	**Nr Counts**
21.48	1
22.60	146
23.72	486
24.83	728
25.95	826
27.07	1229
28.19	2273
29.30	2775
30.42	1652
31.54	685

Inection Rate = 2 [kg/s]	
Bins	**Nr Counts**
21.57	1
22.72	180
23.87	516
25.03	667
26.18	848
27.33	1346
28.48	2388
29.64	2750
30.79	1636
31.94	468

Inection Rate = 5 [kg/s]	
Bins	**Nr Counts**
22.33	1
23.58	126
24.84	458
26.09	721
27.35	934
28.60	1228
29.86	2370
31.11	2582
32.37	1924
33.62	456

Inection Rate = 10 [kg/s]	
Bins	**Nr Counts**
24.66	1
26.02	211
27.39	534
28.76	776
30.13	1102
31.49	1580
32.86	2295
34.23	2397
35.60	1635
36.97	270

Inection Rate = 15 [kg/s]	
Bins	**Nr Counts**
26.21	1
27.64	80
29.07	260
30.49	548
31.92	934
33.35	1334
34.77	1876
36.20	2246
37.63	2007
39.05	1231
40.48	284

Inection Rate = 20 [kg/s]	
Bins	**Nr Counts**
29.03	1
30.34	33
31.65	170
32.97	399
34.28	600
35.60	836
36.91	1232
38.22	1882
39.54	2212
40.85	2042
42.16	1232
43.48	162

Figure 4-20: *The results of Frequency Analysis on external gas-lifting in the Case Study (II).*

For investigating the overall effect of external gas-lifting in the Case Study (II), plots of each injection rate are presented in *Figure 4-21*.

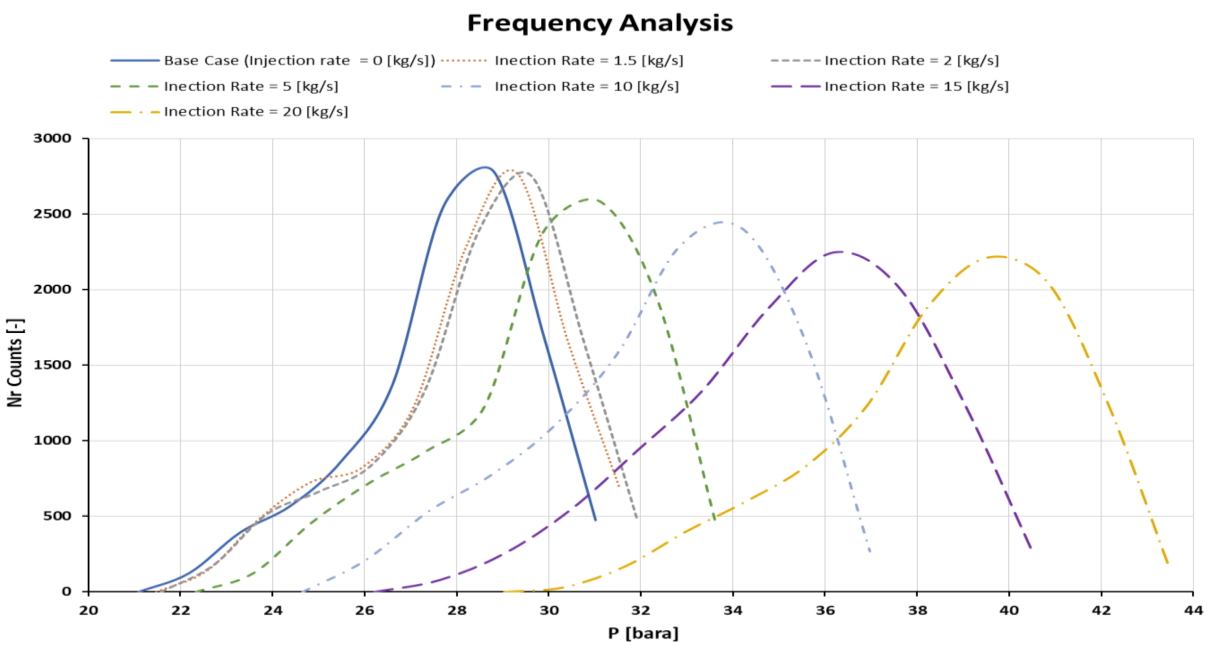

Figure 4-21: *The plot of Frequency Analysis results on external gas-lifting in the Case Study (II).*

Based on the results shown in *Figure 4-20* by increasing the injection rate in the Case Study (II) the pressure at the MWA or Hog bend point in the riser increases and the maximum number of counts decreases which means that the pressure oscillates more. Besides, the expanding area under each plot as the injection rate increase (see *Figure 4-21*), proves that the gas-lifting method intensifies the fluctuation in this case as well.

According to the outputs of three analyzing methods on applying gas-lifting in the Case Studies (I) and (II) for hydrodynamic slug mitigation, we can conclude that this method is not suitable for this field.

It should be noted that the results from this work disagree with the results published by (Meng & Zhang, 2001). Their results show that by increasing the gas injection rate at the riser base, the pressure would decrease, and thereby the pressure difference along the entire well declines. This might be due to the fact the case study in their work had the problem of severe slugging in which the major pressure drop takes place due to static head. However, in the case study in the current work, the major pressure drop may occur because of friction, and thus injecting more gas leads to an increase at the riser base. Simply put, in *Figure 4-22* which is taken from (Kargarpour & Dandekar, 2016), we can see a typical pressure drop through the entire well string.

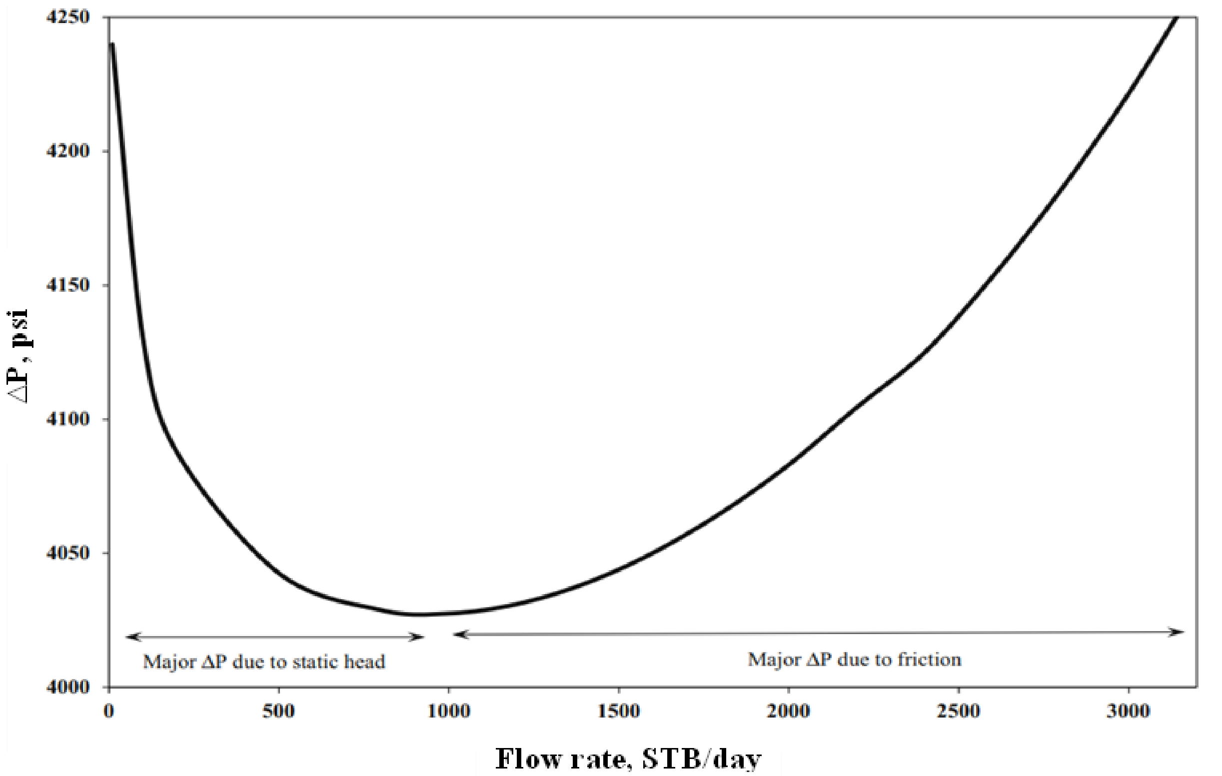

Figure 4-22: *Typical ΔP along the entire well string taken from (Kargarpour & Dandekar, 2016)*

If the reservoir is producing in the area where the pressure drop is caused by a static head, increasing the flow rate (for example by injecting gas) can decrease the pressure drop. On the other hand, if the reservoir is producing in the friction pressure drop area, increasing the flow rate by gas injection will increase the pressure drop. In conclusion, the external gas lifting at the riser base is not an effective solution for dealing with the issue of hydrodynamic slugging in the case study.

4.5.5 Topside choking

Using a topside choke valve can be a promising solution for slug elimination. To evaluate this method and examine its functionality in the case study subjected to this thesis, the chock was added to the Case Study (I) at the end of the horizontal section that connects the riser outlet to the topside facilities. For the choke valve the following setting was used: MODEL = HYDROVALVE (this model uses OLGA choke model to determine flowrate or pressure drop over the choke). EQUILIBRIUMMODEL = FROZEN (this equilibrium model represents no mass transfer). THERMALPHASEEQ = NO (This option means the gas expands isentropical while the liquid is isothermal). SLIPMODEL = NOSLIP (this option indicates that there is no slip in the choke throat).

Using the parametric study tab in OLGA, the stepwise closing of the choke valve from fully opened (choke opening = 1) in the base case to 0.7, 0.5, 0.3, and 0.2 opening ratio was performed. The pressure changes with applying each choke opening are presented in *Table 4-10*. Once the choke is closed from 1 to 0.7, the scope of pressure change (p_{max} - p_{min}) increases from 4.5 to 5.63 [bara] and in the next steps, it decreases and remains almost unchanged at approximately 5 [bara]. A noticeable fact is that the maximum and minimum pressure at the MWA point in the riser increases drastically.

Table 4-10: *Changes in pressure at MWA (or Hog bend) with applying different choke opening ratio*

Case Study (I) & Topside choking			
Choke opening ratio [-]	**Maximum pressure at MWA [bara]**	**Minimum pressure at MWA [bara]**	**Scope of pressure change [bara]**
1	33.45	28.95	4.50
0.7	39.37	33.74	5.63
0.5	49.21	44.02	5.19
0.3	77.40	72.39	5.01
0.2	113.47	108.20	5.27

To compare the results of applying topside choking in the Case Study (I) with the other case study, the same process of stepwise closing of the choke valve was performed in the model of the Case Study (II) in OLGA and the results were presented in *Table 4-11*. By applying topside choking in the Case Study (II) we can see that the scope of pressure change expands in the beginning when the choke is closed from fully opened to a ratio of 0.7 and thereafter it decreases from 10.59 to 6.37 [bara]. Moreover, the maximum and minimum pressure at the MWA point in the riser increase sharply like the results of the Case Study (I).

Table 4-11: *Changes in pressure at MWA (or Hog bend) with applying different choke opening ratio*

Case Study (II) & Topside choking			
Choke opening ratio [-]	**Maximum pressure at MWA [bara]**	**Minimum pressure at MWA [bara]**	**Scope of pressure change [bara]**
1	31.03	21.08	9.94
0.7	33.62	23.03	10.59
0.5	39.33	29.67	9.66
0.3	58.27	50.74	7.53
0.2	84.09	77.72	6.37

Using the three data analysis methods explained in section 4.4, the results of applying topside choking parametric study on the Case Study (I) and (II) have been evaluated and the outputs are summarized in the upcoming sub-sections.

4.5.5.1 Manual frequency calculations of topside choking in the Case Study (I)

Table 4-12, shows the manual frequency calculation of pressure data points generated in OLGA after applying the topside choking method.

Table 4-12: *Frequency calculations of each injection rate in topside choking*

Case Study (I) & Topside choking								
Choke opening ratio [-]	**Interval [min]**	**Peaks [-]**	**Δt [min]**	**Δt [s]**	**Frequency [Hz]**	**Crest [bara]**	**Trough [bara]**	**Scope of change [bara]**
1	[30 - 40]	26	10	600	0.043	33.21	29.29	3.92
0.7	[30 - 40]	23	10	600	0.038	38.33	34.26	4.08
0.5	[30 - 40]	20	10	600	0.033	48.91	45.59	3.32
0.3	[30 - 40]	20	10	600	0.033	76.66	73.30	3.36
0.2	[30 - 40]	17	10	600	0.028	112.39	109.33	3.07

Based on the calculated frequencies presented in *Table 4-12,* as the choke is closing from fully opened to 0.2 of the cross-sectional area of the choke in the Case Study (I), the slug frequency decreases from 0.043 to 0.028 [Hz]. The same descending behavior is observed in the scope of the pressure change, although at first when the choke opening is decreased from 1 to 0.7 a slight rise from 3.92 to 4.08 [bara] was experienced.

4.5.5.2 Manual frequency calculations of topside choking in the Case Study (II)

The frequency of each choke opening ratio in the Case Study (II) is calculated and presented in *Table 4-13.*

Table 4-13: *Frequency calculations of each injection rate in topside choking*

Case Study (II) & Topside choking								
Choke opening ratio [-]	**Interval [min]**	**Peaks [-]**	**Δt [min]**	**Δt [s]**	**Frequency [Hz]**	**Crest [bara]**	**Trough [bara]**	**Scope of change [bara]**
1	[30 - 40]	13	10	600	0.022	30.42	22.28	8.14
0.7	[30 - 40]	15	10	600	0.025	33.28	26.55	6.73
0.5	[30 - 40]	13	10	600	0.022	38.31	33.21	5.10
0.3	[30 - 40]	15	10	600	0.025	57.50	52.72	4.78
0.2	[30 - 40]	13	10	600	0.022	83.95	80.74	3.20

Based on the data in *Table 4-13,* the frequency remains almost unchanged despite closing the choke. On the other hand, the scope of the change (p_{max}-p_{min}) in each interval decreases as the choke is closing.

4.5.5.3 FFT analysis of topside choking in the Case Study (I)

Figure 4-23, shows the plots of applying Fast Fourier Transform (FFT) on pressure versus time data in the Case Study (I) regarding each choke opening ratio. The plots show that the dominant frequency area in the base case (choke opening = 1) is approximately between 0.03 and 0.05 [Hz] with the peak at approximately 0.038 [Hz]. As the choke is closed by different ratios, the dominant area and peak move to the left until the dominant area reaches the interval between 0.01 and 0.02 [Hz] peaking at around 0.015 [Hz] at an opening ratio of 0.2. This displacement specifies that the topside choking method is an effective method for slug frequency mitigation in this case study.

Unlike riser base gas injection, topside choking not only does not induce another dominant area but also eliminates the secondary dominant area placed roughly between 0.01 and 0.02 [Hz] in the base case.

The Power Spectral Density (PSD) of the dominant area that is placed between 0.03 and 0.05 [Hz] is approximately 0.13 in the base case. Once the choke is closed from a fully opened state to 0.7 of its cross-sectional area, the PSD increases to around 0.18 and thereafter it decreases until it reaches approximately 0.065 at the opening ratio of 0.2.

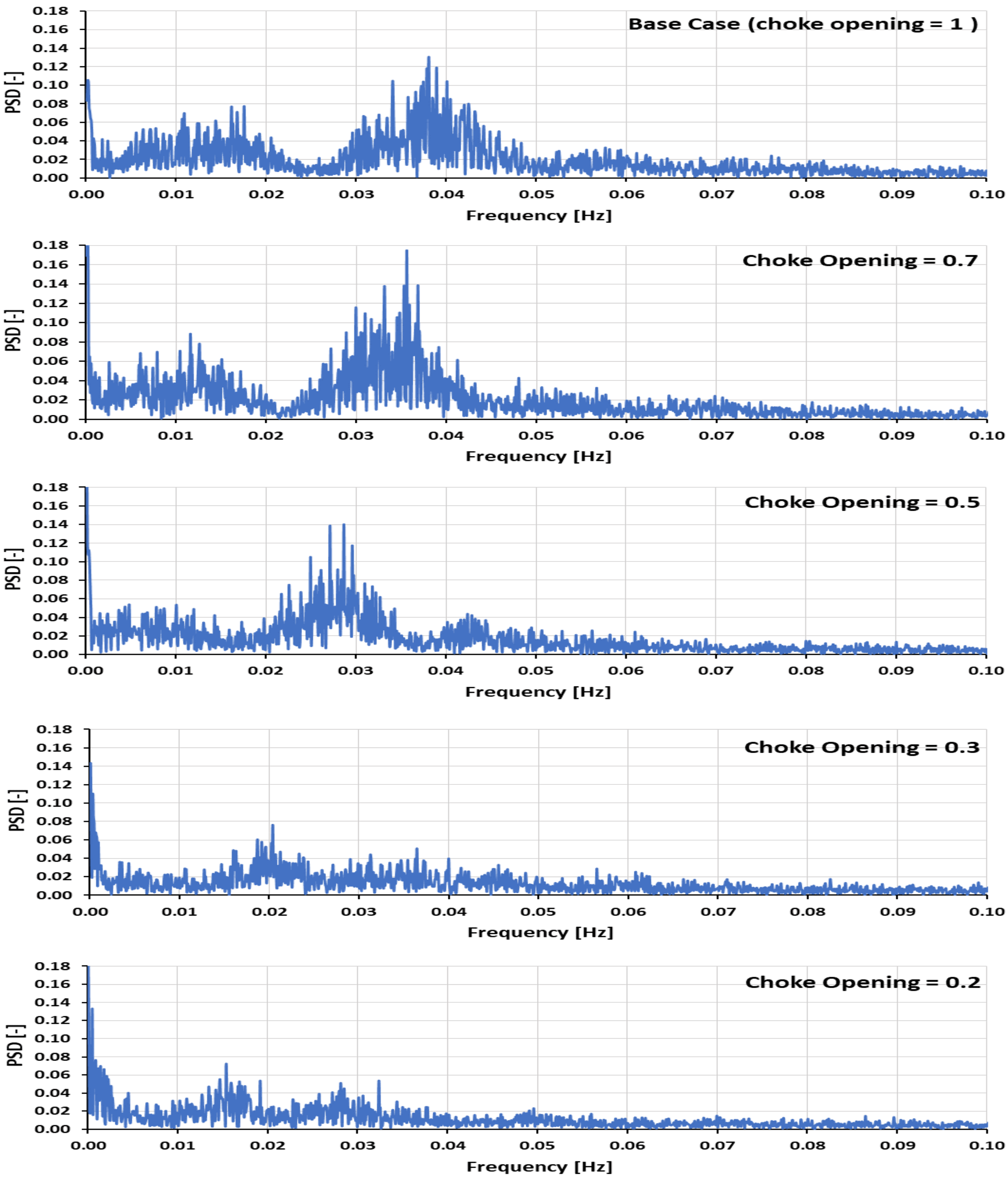

Figure 4-23: *The results of FFT analysis on topside choking in the Case Study (I).*

4.5.5.4 FFT analysis of topside choking in the Case Study (II)

Fast Fourier Transform (FFT) analysis on pressure versus time data in the Case Study (II) was performed and the output plots are shown in *Figure 4-24*. The dominant frequency area in the base case (injection rate = 0 [kg/s]) is approximately between 0.00 and 0.02 [Hz] with the peak at approximately 0.008 [Hz].

In the Case Study (II) topside choking moves the dominant frequency area which is approximately between 0.00 and 0.02 [Hz] with the peak at approximately 0.008 [Hz] in the base case (choke opening = 1) to the left until the dominant area reaches the interval between 0.000 and 0.008 [Hz] with a peak at around 0.002 [Hz] at an opening ratio of 0.2. This displacement indicates that the topside choking method can be considered an effective solution for slug frequency alleviation in this case study.

The Power Spectral Density (PSD) of the dominant area is approximately 0.50 in the base case and when the topside choking is applied it decreases until it reaches the minimum of 0.20 at a choke opening ratio of 0.3 and then it increases slightly to 0.25 in the last case with an opening ratio of 0.2.

Unlike the Case Study (I), in the Case Study (II) applying topside choking causes a secondary dominant area that reaches its maximum PSD at the opening ratio of 0.3 and it almost disappears at the opening ratio of 0.2. However, since the PSD of this second area is not a considerable amount to induce severe vibration

Furthermore, comparing the results of FFT analysis with the manual calculation of frequency, shows that the manual frequency calculation could capture the effect of topside choking on slug frequency in the Case Study (I) but in the Case Study (II) the calculated frequency remained almost unchanged meaning that calculation of frequency manually is not a reliable method in general.

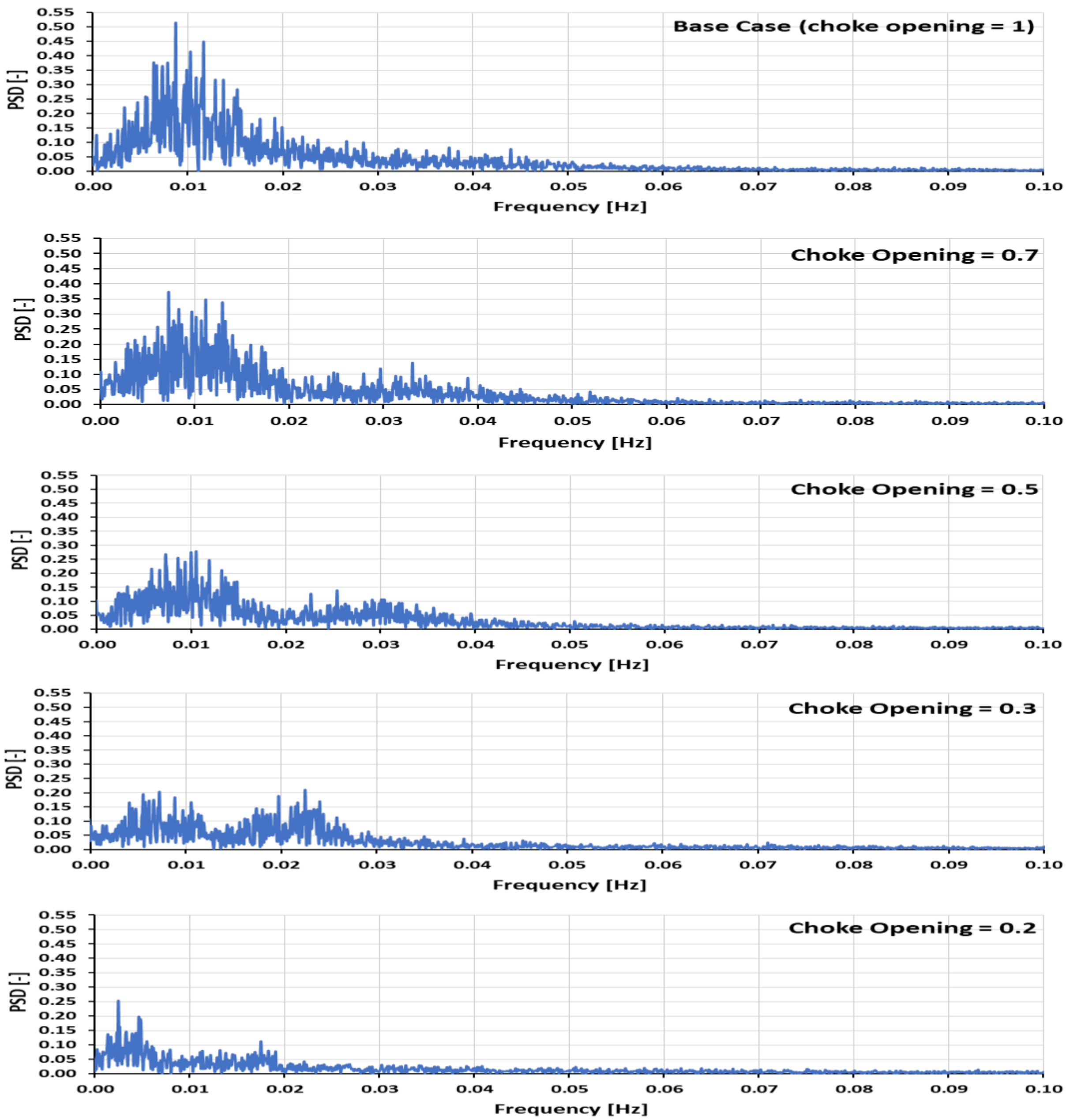

Figure 4-24: *The results of FFT analysis on topside choking in Case Study (II).*

4.5.5.5 Frequency analysis of topside choking in the Case Study (I)

Frequency Analysis for topside choking in the Case Study (I) was performed and the results were presented in *Figure 4-25*. For recognizing the minimum and the maximum number of counts, color scaling was used between green (minimum) and red (maximum).

Base Case (choke opening = 1 [-])	
Bins	**Nr Counts**
28.95	1
30.07	563
31.20	3908
32.32	5792
33.45	537

Choke Opening = 0.7 [-]		Choke Opening = 0.5 [-]		Choke Opening = 0.3 [-]		Choke Opening = 0.2 [-]	
Bins	**Nr Counts**	**Bins**	**Nr Counts**	**Bins**	**Nr Counts**	**Bins**	**Nr Counts**
33.74	1	44.02	1	72.39	1	108.20	1
35.14	369	45.32	81	73.64	54	109.52	63
36.55	3270	46.62	1145	74.89	384	110.83	631
37.96	6702	47.91	7755	76.14	8890	112.15	9530
39.37	459	49.21	1818	77.40	1472	113.47	576

Figure 4-25: *The results of Frequency Analysis on topside choking in the Case Study (I).*

For observing the overall effect of topside choking in the Case Study (I), the number of counts versus bins (or pressure intervals) was plotted in *Figure 4-26*.

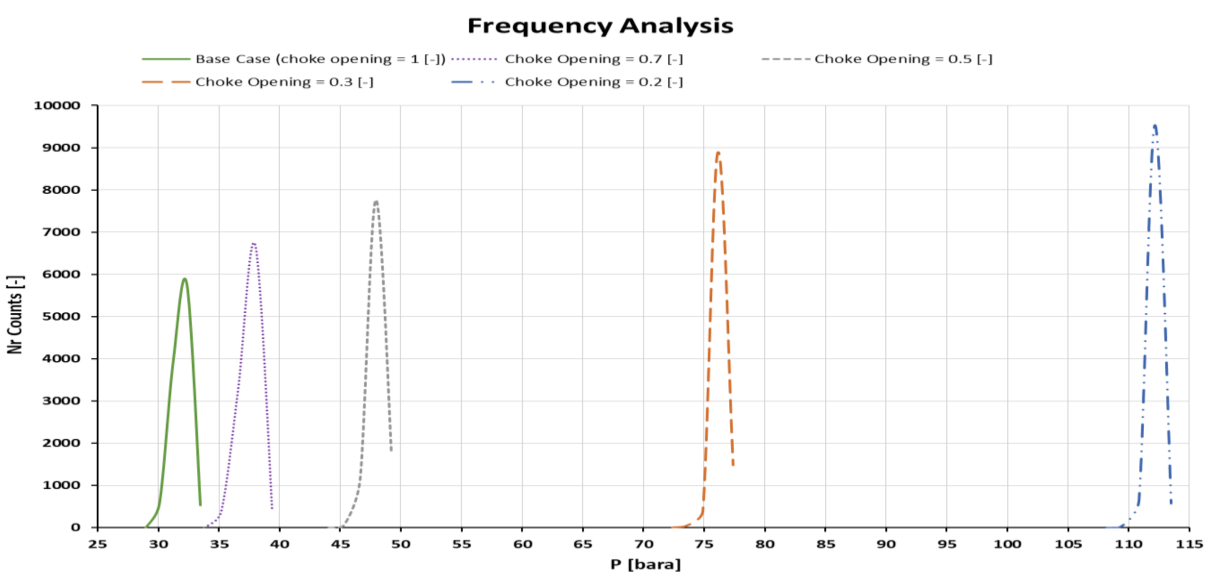

Figure 4-26: *The plot of Frequency Analysis results on external gas-lifting in the Case Study (I).*

Although applying external topside choking in the Case Study (I) increases the pressure at the MWA or Hog bend point in the riser, it can decrease the oscillations since the maximum number of counts increases as shown in *Figure 4-25* and the area under each plot gets narrower in comparison with the base case in *Figure 4-26,* as the choke is closing in each step.

4.5.5.6 Frequency analysis of topside choking in the Case Study (II)

Figure 4-27 shows the Frequency Analysis of the results of topside choking in the Case Study (II). Conditional formatting of color scaling is used in the figure to indicate the maximum (red) and the minimum (green) of number of counts.

Base Case (choke opening = 1 [-])	
Bins	Nr Counts
21.08	1
22.19	126
23.29	394
24.40	572
25.50	868
26.61	1370
27.71	2546
28.82	2779
29.92	1668
31.03	476

Choke Opening = 0.7 [-]	
Bins	Nr Counts
23.03	1
24.09	21
25.15	120
26.21	230
27.27	408
28.33	704
29.39	1450
30.44	2555
31.50	3169
32.56	1739
33.62	403

Choke Opening = 0.5 [-]	
Bins	Nr Counts
29.67	1
30.75	44
31.82	155
32.89	244
33.97	637
35.04	1533
36.11	2833
37.19	3397
38.26	1715
39.33	242

Choke Opening = 0.3 [-]	
Bins	Nr Counts
50.74	1
51.81	74
52.89	356
53.96	1127
55.04	2483
56.12	3593
57.19	2551
58.27	616

Choke Opening = 0.2 [-]	
Bins	Nr Counts
77.72	1
78.78	9
79.85	127
80.91	924
81.97	2860
83.03	5500
84.09	1380

Figure 4-27: *The results of Frequency Analysis on topside choking in the Case Study (II).*

The overall effect of topside choking in the Case Study (II) can be observed in plots of each choke opening ratio presented in *Figure 4-28.*

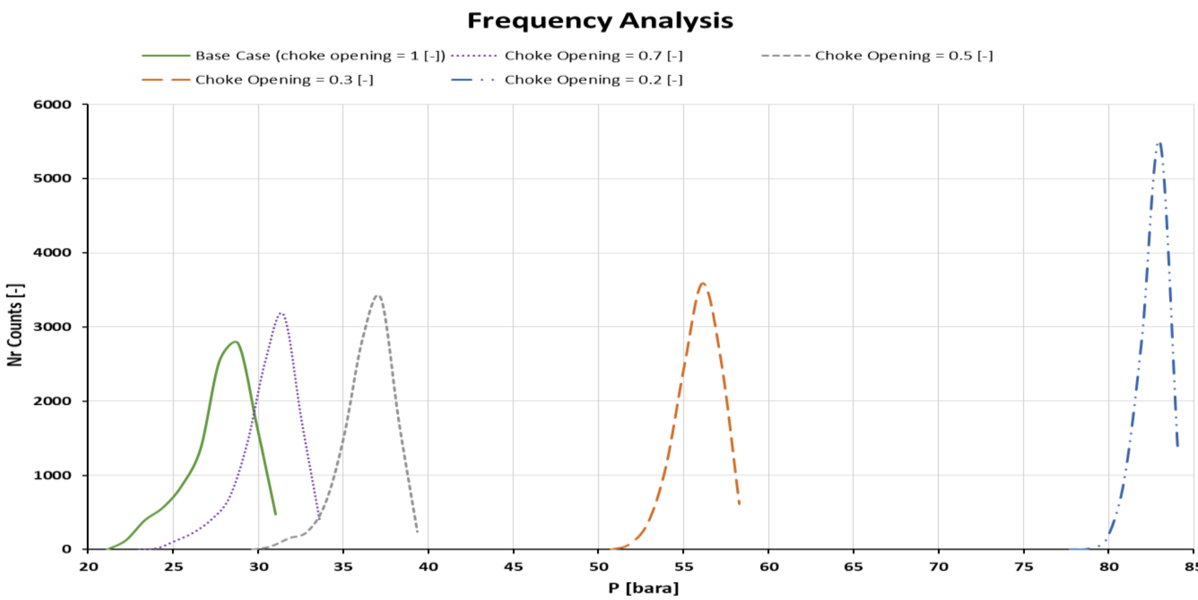

Figure 4-28: *The plot of Frequency Analysis results on choke opening in the Case Study (II).*

The results in *Figure 4-27* show that by closing the choke valve in the Case Study (II) the pressure at the MWA or Hog bend point in the riser and the maximum number of counts increase. Moreover, in *Figure 4-28* the area under each plot gets narrower as the choke is closed more in each step, which proves that the topside choking method mitigates the fluctuation in this case as well.

Based on the outputs of three analyzing methods of applying topside choking in the Case Studies (I) and (II) for hydrodynamic slug mitigation, we can conclude that this method is beneficial for this field to deal with hydrodynamic slugging.

CHAPTER 5

Conclusions and Recommendations

This chapter presents the conclusions and recommendations for future works.

5.1 Conclusions

The following conclusions were derived from this work:

- Two systems of flowline-riser, part of an offshore field in the Norwegian Continental Shelf, were successfully simulated numerically using a commercial transient multiphase pipe simulator to study the mitigation of hydrodynamic slugging.
- A thorough literature review was performed to screen out feasible methods to mitigate hydrodynamic slugging pressure fluctuations. After input from the field's operator, two methods were evaluated using the numerical simulator: gas lifting at the riser base and topside choking. To investigate the proposed slug control methods and observe their effects on the frequency of the oscillations induced by slug flow three different analysis methods were used on the simulator results: (1) Manual frequency calculation (2) FFT analysis (3) Frequency analysis.
- Due to the large amount of data computed with the simulator, the data analysis method using manual frequency calculation requires dividing the results into small intervals which makes this method time-consuming. Often, hydrodynamic slug pressure changes are not recognizable with ease. Thus, this method cannot be considered accurate, and it should be used in combination with other methods to reach better results.
- The data analysis using the Fast Fourier Transform (FFT) was applied using Python programming language. Although this method is way faster in comparison with the manual calculation of the frequency and it does not require splitting into sub-intervals, it cannot provide thorough information about the dominant pressure of the production system because FFT only indicates the dominant frequency and its PSD. Therefore, it should be complemented with other methods.

- The data analysis using Frequency Analysis was performed successfully to determine the dominant pressures under which the system produces.

After reviewing different slug control methods, several methods were suggested for hydrodynamic slug elimination or mitigation to alleviate slug-induced vibration in the flexible riser: 1) subsea finger-type slug catcher, 2) flow conditioners and diameter reduction, 3) surfactant injection, 4) gas-lifting at the riser base, and 5) topside choking. The first three methods were discarded after input from the operator, as there were deemed too expensive (methods 1 and 2) or ineffective and counterproductive for the separation (method 3):

- According to simulation results, external gas lifting in the riser base failed at alleviating hydrodynamic slugging and, in some cases, contributed to an increase in the slug frequency in this field. The results from this work disagree with the results published by (Meng & Zhang, 2001). This could be partly due to the fact that they were dealing with severe slugging, which is density and gravity dominated while in this work the focus is hydrodynamic slug which is friction-dominated.
- In this work, topside choking is the most efficient technique to mitigate the hydrodynamic slug frequency but at the cost of pressure increase at the riser base. By closing the choke from fully opened to 0.2 of the cross-sectional area of the choke the dominant frequency decreases from 0.038 to 0.015 [Hz], and the maximum pressure at the MWA point in the riser increases from 33.45 to 113.47 [bara]. The operator has indicated they will test this measure in the future on the asset to find the optimum choke opening.

5.2 Recommendations for Future Works

The following are recommended for further investigations:

- It is recommended to evaluate the effect of active controlled topside choking (also called dynamic topside choking) on the hydrodynamic slugging using the commercial simulator.
- It is recommended to test the measure of topside choking for hydrodynamic slug mitigation on the field and compare the measured values with the simulation results to verify the accuracy of the simulator.

- In this thesis, a constant mass flow rate source was used for the riser-base injection method in OLGA. It is recommended to model it with a gas-lift mandrel instead, and include the gas-lift distribution system, to consider transient effects on the gas-lift system.
- This study has shown that topside choking can be helpful for hydrodynamic slug frequency alleviation in a production system without the presence of severe slugging. Yet more experimental investigations and real-time data from the field are required to assess this method's efficiency since in almost all the cases reviewed by the author, were investigating a case study with the severe slugging problem.
- The analysis methods used in this thesis can be used for evaluating other production parameters such as flow rate and superficial velocities of each phase and their effects on the flow regime.
- This study was on a case with the simulation model starting from the wellhead, for more in-depth investigation (for example bottom-hole gas injection), It is recommended to use a model including the well.
- The idea of a subsea finger-type slug catcher that functions like a subsea separator is still new and there is a need for a better understanding of this method through further simulations and experiments. It may be possible to implement the method and evaluate its functionality.

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Appendix

Screenshot of the Python code for applying FFT on the pressure versus time data points generated in OLGA. The code is written in Google Colab.

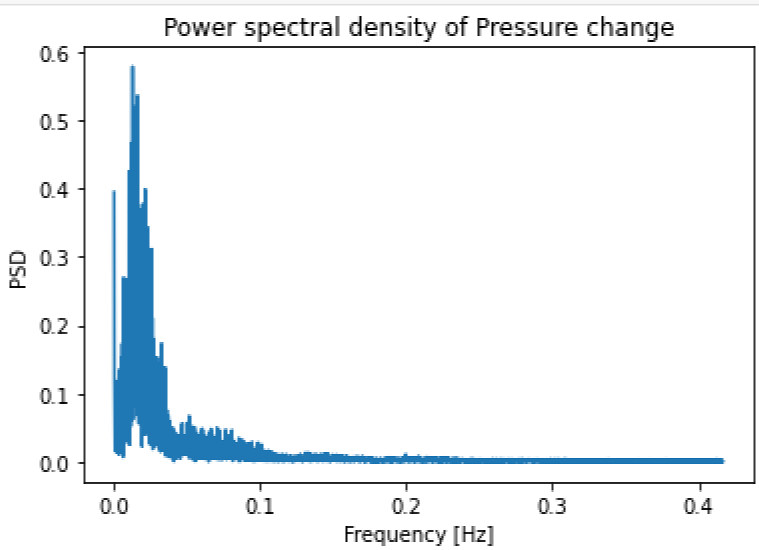
```
#Importing needed libraries
import numpy as np
import matplotlib.pyplot as plt
import pandas as pd
```

```
#Reading Pressure (P) data vs Time (T) from the txx file

Data=np.loadtxt('PTC2GL20.txt') #The data is in two column taken from OLGA
P=Data[:,1] #The second column (which is index 1 in Python) indicates the Pressure
T=Data[:,0] #The first column (which is index 0 in Python) indicates the Time
```

```
#Performing FFT on the Data
T=Data[:,0]*60 #Multiplied by 60 to get the Frequency in [Hz]
NumPoints=T.size
FftMag= np.abs(np.fft.fft(P))*2/NumPoints
DeltaT= T[1]-T[0]
FftFrequency= np.fft.fftfreq(NumPoints,DeltaT)

NPoints= int(np.ceil(NumPoints/2))
FftFrequency=FftFrequency[1:NPoints]
FftMag = FftMag[1:NPoints]
#Plotting FFT results
plt.plot(FftFrequency,FftMag)
plt.title('Power spectral density of Pressure change')
plt.xlabel('Frequency [Hz]')
plt.ylabel('PSD')
```



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