PRESSURE MAINTENANCE IN OIL PRODUCTION PIPELINES:
EQUIPMENT AND SIMULATION

A Thesis

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Abstract

The oil production in every well will ultimately decline after some production period and "intense" treatment of the reservoir, the well and/or the surface flowlines will be necessary to maintain the production at an economically viable rate. The oil recovery methods are distinguished in three major categories: primary, secondary and enhanced oil recovery. From the aforementioned categories, only the second involves intervention to the midstream facilities. Pressure maintenance of the multiphase production fluids in the flowlines is a technique, which can be easily implemented in existing installations.

It may be implemented either by reducing the pressure with surface chokes and orifice plates or by boosting the pressure with new equipment (pumps and compressors).

Two primary factors of the pressure maintenance have to be studied in detail and closely monitored: the flow assurance in the pipeline and the proper sizing and selection of the pressure boosting equipment (pumps and compressors).

In this study, a research is conducted on multiphase flow assurance issues and particularly the ones associated with the pressure boosting techniques. Several means of pressure control exist, for example changing the opening frequency and duration of flow valves and surface chokes and installation of orifice plates, but this study focuses on the application of multiphase pumps in line with the production flowlines both onshore and offshore (not inside the well). All major types of production multiphase pumps are presented in detail, together with their operational characteristics.

At the last part of the thesis, the performance of a multiphase pump in an oilfield is simulated in order to demonstrate the utility of such novel systems in the oil midstream sector.

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1. Pressure maintenance in Oil and Gas Midstream Facilities

1.1. Midstream operations

The midstream operations include the transportation, distribution and storage of crude oil and natural gas products.

Transportation and distribution are referred to the systems and means that are used to enable the transport of the effluents from the surface production sites to processing facilities and gathering stations. For the transportation are used pipelines, in order to transfer crude oil and natural gas.

Gathering stations are facilities where separation processes take place and large oil storage tanks are installed. The effluents from different wells are gathered in the tanks through pipelines, often referred as flowlines. In gathering stations are installed the pumping or compressor stations, in order to boost the flow to the main flowlines.

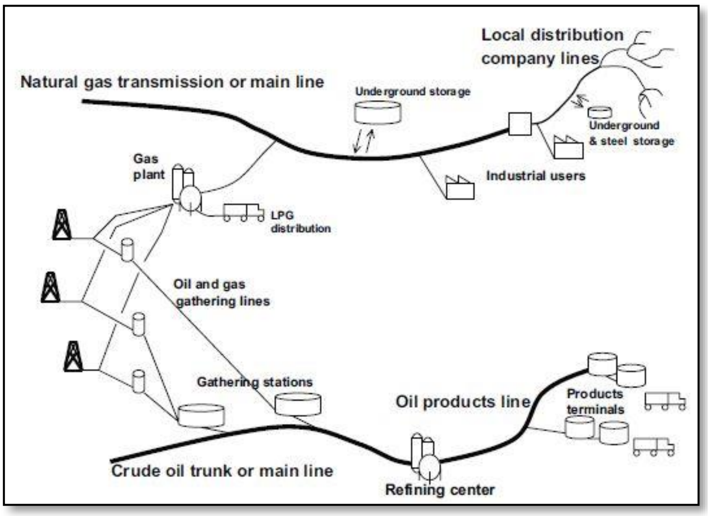


Figure 1: *Oil and natural gas value chain* [1].

The pipelines are distinguished in the following categories:

- Crude oil and natural gas gathering lines (flowlines)

They are used to transport the effluents from the wellheads and manifolds to the gathering stations. They can transfer either single or multiphase mixture. The use of multiphase flow gathering lines is not used often in the oil and gas industry.

The complexity of the multiphase flow dictates very careful design and sizing of the pipelines. But since the pipeline system is appropriately designed, the field operations are minimised and the project's cost eventually.

- Crude main lines
- Natural gas transmission lines
- Local distribution lines

1.2. Trends and facts in Oil and Gas (O&G) industry

According to experts the future challenges referred to the production facilities in the oil and gas industry, are the following:

- *Minimum expectations for the discovery of big new fields.*

According to the exploratory data for the possible oil and gas reserves that have been conducted so far, only a few large oil and gas fields are expected to be discovered.

- *The number of offshore production facilities will increase by far.*

It is claimed that more than 25% of the oil fields and 15% of the gas fields around the world will be subsea and many of them located in deep water [2].

- *Multiphase flow transport techniques will develop.*

The use of multiphase pipelines and multiphase boosting systems provides the advantage of full exploitation of the existing fields.

- *1% recovery factor increase needed for an additional 2-year oil and gas supply* [3]
- *More than 70% of the current world oil production is from matured fields. Almost 50% of the oil reserves are from 30 big mature fields* [4].

The definition of “mature field” is not clearly declared and many times there is confusion about it. For some professionals as a mature field is considered the one that has reached its peak production and its production has started to decline [3].

1.3. Pressure maintenance

The oil production enhancement may be achieved in many different ways. The primary, the secondary and the enhanced oil recovery mechanisms are the three major categories of this kind of techniques. Pressure maintenance is referred to the change of the pressure drive downstream of the wellhead in order to maintain the production flow rates. This can be achieved by controlling the opening and closing times of the surface chokes or by interfering with the midstream facilities by boosting the pressure downstream of the wellhead with surface/seabed pumps. The application of artificial oil recovery techniques is imposed by the necessity to increase the oil production and to increase the recovery rate from already producing fields.

Pump-lifted production is commonly used because it serves some of the above-mentioned trends while the integration cost is low. The pumps that are usually used are divided in single phase and multiphase pumps, depending on the number of phases they are able to handle. The application of multiphase pumps remains a challenging and perspective technique in order to achieve pressure maintenance in midstream facilities.

2. Multiphase flow

In the Oil and Gas (O&G) industry multiphase flow exists inside the wellbores and the pipelines (vertical, horizontal and nearly horizontal multiphase flow).

Single phase flow description is implemented through the characterization of the flow regime as laminar or turbulent, concerning the pressure and velocity distribution of the fluid along space and as steady, semi-steady or unsteady state, concerning the pressure and velocity distribution of the fluid along time.

Multiphase flow is described through the flow patterns that categorize the flow according to the distribution of the phases. The types of multiphase flow that may appear in the pipelines of the O&G industry are:

- **Two-phase flow**, between gas and liquid.

Two-phase flow type is observed as gas bubbles developed in the liquid flow or as liquid droplets developed in the gas flow. It is described through the flow regime maps.

- **Two-phase flow**, between liquid and liquid.

It is referred to the multiphase flow between oil and water which is met in crude oil pipelines very often. Water exists in the flow after some years of oil production. Up to this point, the water cut is an important factor that will influence the decision for the design of surface facilities as well as the decision about continuing the production. Water is also used in pipelines in order to transport high viscosity oil. In this case, water is creating an annular film in the walls of the pipelines acting like a lubricant for the oil flow [5].

- **Three-phase flow,** between gas and two different liquids or between two fluids and solid particles.

Usually, it is referred to Gas, Oil and Water flow (gas-liquid-liquid) or to a flow in which one of the G-O-W phases are replaced by solids. The solid particles that may exist in the flow usually are not considered as a different phase, because they enter the flow with a low mass rate and with a high velocity so that they leave from the examined control volume quickly. The existence of sand is taken into consideration only for the establishment of flow assurance (confrontation of erosion problems and sand build-up). Instead of using flow maps for the visualization of the three-phase flow, a three phase diagram is used (Figure 2). This illustrates the different flow regimes that may occur in a three-phase flow as combinations of the interactions between two phases.

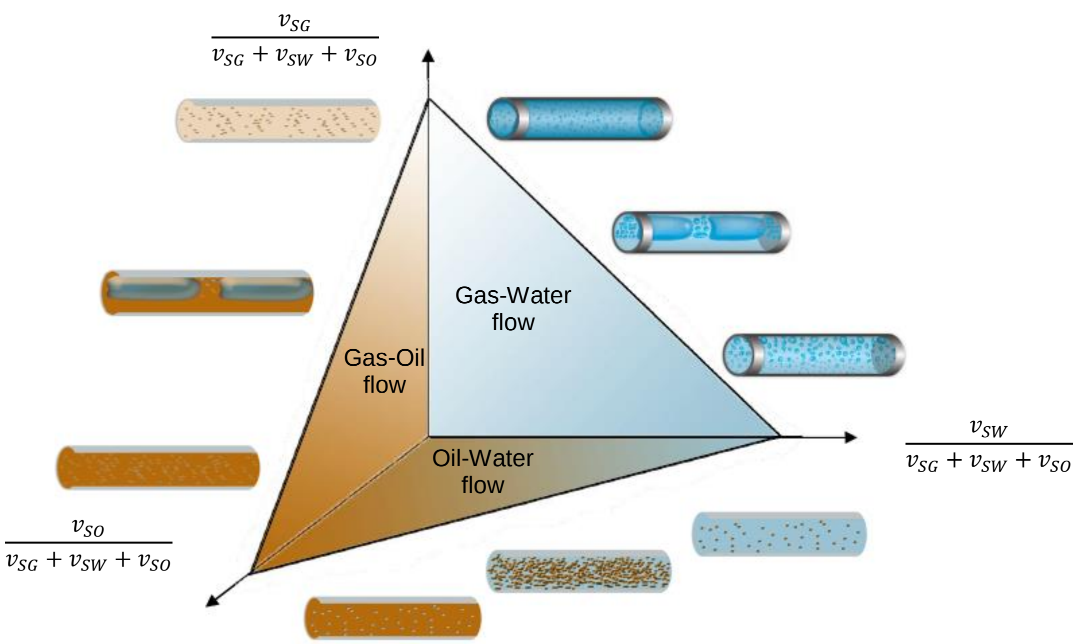


Figure 2: *Three phase diagram for multiphase flow in horizontal pipes.* [5]

The three phase diagram axes correspond to the normalized superficial velocity of each phase (X≡water normalized superficial velocity, Y≡oil normalized superficial velocity, Z≡gas normalized superficial velocity). The normalization is over the summation of the superficial velocities of all phases contributing to the flow.

2.1. Horizontal Multiphase Flow patterns

Main categories of multiphase flow in horizontal pipes

The horizontal multiphase flow is distinguished in the three main categories [6]:

- Segregated flow (smooth stratified and wavy stratified flow), where the different phases flow separately in layers,
- Intermittent flow (elongated bubble and slug flow), where the flow of each phase is interrupted from the other phases,
- Distributive flow (annular and dispersed bubble flow), where the different phases appear in the flow without following any order.

The distinction between the different flow patterns can be done semi-quantitatively by using the flow pattern maps and quantitatively by using complex mechanistic models. In the flow pattern maps, the distinction between the different patterns is done according to the superficial velocity of the phases.

Flow maps

The flow maps present the different flow regimes according to the fluctuations of gas and liquid superficial velocities. The superficial velocities are expressed in terms of gas and liquid influx respectively. The influx represents the volume of each phase that passes through a specific pipeline segment for a specific period of time. The flow map in Figure 3 shows the different flow patterns and the typical superficial velocities where each pattern is developed.

Gas and Liquid influxes respectively: $\boxed{G_G = \frac{Q_G}{A_p}}$ $\boxed{G_L = \frac{Q_L}{A_p}}$

Gas and Liquid superficial velocities respectively: $\boxed{v_{SG} = G_G \cdot \psi}$ $\boxed{v_{SL} = \frac{G_L}{\lambda}}$

Fluid coefficients: $\boxed{\psi = \frac{1{,}147 \cdot \mu_L^{1/3}}{\sigma \cdot \rho_L^{2/3}}}$ $\boxed{\lambda = 0.463 \cdot \sqrt{\rho_L \cdot \rho_G}}$

Where:
σ: surface tension [dyn/cm]
μ: viscosity [cp]

Flow maps interpretation

In flow maps, the y-axis represents the superficial velocity of the lighter phase (Gas for Gas-Liquid flow and Oil for Liquid-Liquid flow) and the x-axis the superficial velocity of the denser phase (Oil for Gas-Liquid flow and Water for Liquid-Liquid flow).
Because of the complex phenomena that occur in multiphase flow, the determination of the boundaries between the different flow regimes is not always accurate. In order to visualize the different flow regimes in the same map, the interpretation of the flow map can be done considering that the pipe diameter is stable and the only parameter that changes is the volumetric flow rate and consequently the superficial velocity of one of the multiple phases.
More specifically the flow maps can be interpreted following the direction of increasing or decreasing the superficial velocity of only one phase. So the interpretation of the transition between the different flow regimes can occur by moving either from right to left, considering almost stable the superficial velocity of the lighter phase that is represented in the y-axis or from bottom to top, considering almost stable the superficial velocity of the denser phase that is represented in the x-axis.

2.1.1. Two phase flow: Gas-Liquid

As previously mentioned the multiphase flow maps are a theoretical estimation of the occurring flow regimes in a pipeline. Every flow map corresponds to specific fluids flowing in a pipeline with specific diameter and inclination. Unfortunately, they cannot be generalized for all types of flow regimes, so they are not accurate for the estimation of the flow regime for all the possible flow situations. All the scientific efforts have concluded that the existence of a general flow map is possible for the distinction between the three basic flow categories: segregated, intermittent and distributed [6]. The axes are dimensionless parameters that are affected by flow properties. However, these maps are not accurate for the discrimination of flow regimes between the stratified and annular flow, which is essential for multiphase flow modelling. The Baker modified flow map is suggested from operating companies as the most accurate for the distinction and prediction of slug and annular flow [7].

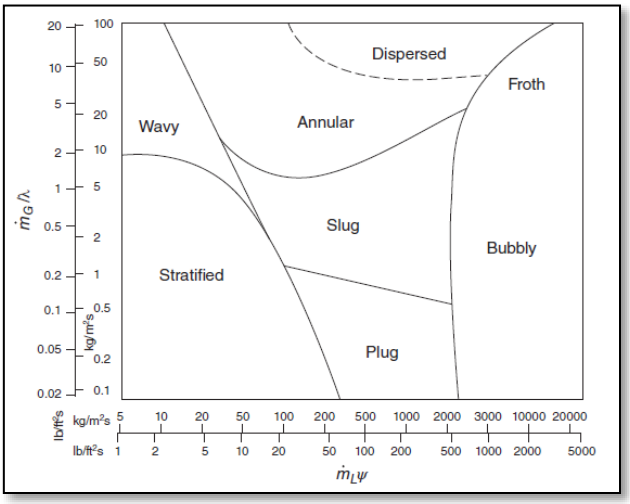


Figure 3: *Baker modified plot - Flow pattern map for horizontal pipes.* [8]

Stratified/Smooth flow

The flow of the different phases is fully developed, meaning that the phases are completely separated. It is characterized by relatively small flow rates of all the fluids. Is the type of flow that is mostly met in the entrance of pipes. The order of the observed flowing phases in the pipeline follows the gravitational properties of the flow. The denser phases flow along the bottom of the pipe and the lighter phases along the top of the pipe. As a result on the top of the pipe is observed the gas phase, the oil phase in the middle and the water phase is met at the bottom, where the solids are also concentrated. Stratified flow is observed when both gas and liquid phases have small velocities and the flow is thoroughly segregated.

Stratified Wavy flow

While the fluids are flowing under the conditions of stratified flow, if the velocity of the gas phase increases, the result will be the transition of the smooth stratified flow to the wavy stratified flow. In this type of flow, waves are created in the liquid surface, as a result of the flow transition, indicating the increasing gas kinetic energy. Due to adhesion and shear stress induced to the liquid surface by the gas, the liquid that exists in the gas-liquid interface drifts away provoking the increase of the liquid velocity. If the gas velocity increases more, the flow will become annular. Together with the development of waves, the liquid that exists in the gas-liquid interface is drifted away; forming liquid droplets that bounce to the gas stream. Wavy flow is observed usually in gas condensate effluents because the volume fraction of gas is bigger than the liquids.

Dispersed Bubble flow

This flow is inherent with high turbulence at high gas and liquid flow rates. The gas is dispersed among the liquid flow, in the form of small bubbles. The size of the bubbles is very small and depends on the gas flow rate. Due to gravity, the bubbles tend to concentrate on the top of the flow.

Annular/Mist flow

When the gas flow rate is high while the liquid flow rate is moderate, the flow presents initially waves, as when the flow is characterized stratified wavy. As the gas velocity increases more, the height of the waves increases. Then and since the liquid flow rate has not changed, the area that is occupied by the liquid will be decreased. Finally, the liquid phase may concentrate around the pipeline's walls, creating an internal annular ring. This is created because the fluids' velocity is decreasing in the vertical axis while going towards the walls. At the level where the gas velocity is no longer higher than the liquid velocity, starts the annular liquid layer. More liquid is concentrated on the bottom of the pipeline due to gravity. Annular flow is mostly observed in gas condensate effluents because the volume fraction of gas is bigger than the liquids.

Slug flow

Is the type of flow that indicates the transition from stratified to intermittent flow. It is occurring when moderate liquid and gas flow rates are observed. According to some scientific suggestions [6] in case that under stratified wavy flow the gas velocity increases so that the waves' height to overcome the pipe centreline, an intermittent flow will develop. The liquid will be entrapped in big continuous areas flowing in-between of the gas phase. The liquid areas are flowing like liquid plugs along the pipe. Their size may be similar to the pipe diameter and usually, they are called "Taylor bubbles".

The different types of slugs that may appear are the following:

- **Hydrodynamic slugs**: When the gas flow rate is large and the gas phase flows with a much greater velocity than the liquid phase, waves are showing up to the surface of the flow. The two different phases have different velocities and this appears as a flow disturbance in the boundary of liquid and gas interface. This phenomenon is also described as Kelvin-Helmoltz instability. This wavy flow is reinforced by the increasing gas velocity and may lead to the creation of areas occupied with liquid, which look like liquid slugs.

Hydrodynamic slugging is not included to the flow assurance problems, but it acts as an indicator of the transition to a different flow pattern. The slugs appear with high frequency.

- **Riser-based/Severe slugging**: When the multiphase flow in horizontal or slightly inclined pipelines meets the risers, its direction changes and it is moving upwards. At the points of the pipeline, where it changes direction, slugs may be created.
- **Terrain generated slugs**: Many pipelines change direction along their path and the flowing fluids have to face different elevation levels. Then arise the same issues as when the pipeline change direction so that to meet the risers. This type of slugs appears with the same way of the riser/severe slugs. Its duration is long.
- **Pigging/ramp-up slugs**: The pigging procedure involves the cleaning of the pipeline from solid depositions on the walls (waxes, etc.). During the procedure, the pig is forcing the liquid remaining in the pipe to move and to form slugs.

Elongated Bubble/Plug flow

At low gas and moderate liquid flow rates, the gas phase creates a layer interrupted by liquid droplets. Because of the much higher liquid velocities than the gas velocities, the gas tends to get mixed with the liquid. This type of flow is usually met when the reservoir fluid has low Gas-Oil-Ratio (GOR) or high GOR and it is operated at high pressures.

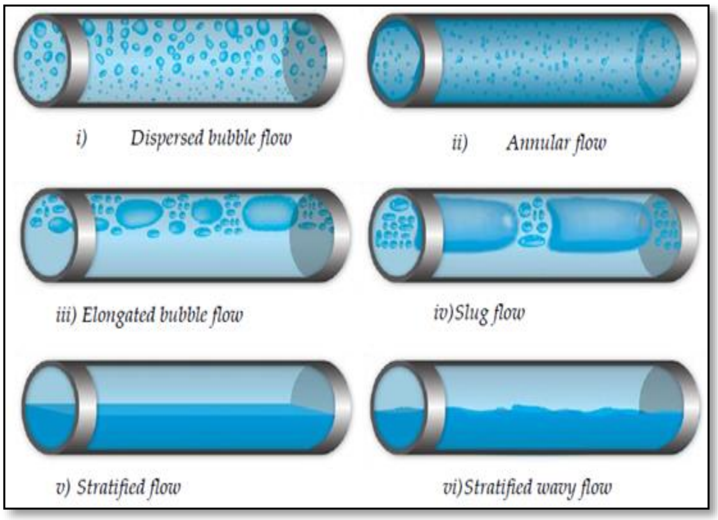


Figure 4: *Typical flow patterns for multiphase flow in horizontal pipes.* [5]

The transition from one pattern to another is gradually done. Generally the bubbles of smaller size coalescent and they form slugs. The size of the bubbles is always suspended by the pressure. The transition velocity is controlled by the frequency of bubble coalescence, liquid loading and flooding phenomena.
In Figure 5 is presented the generalized flow map that Taitel & Dukler suggest.

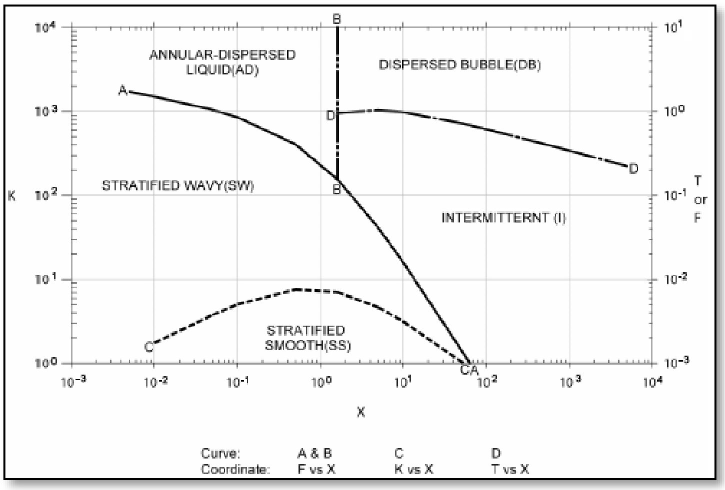


Figure 5: *Taitel & Dukler plot – Generalized flow pattern map for horizontal pipes.* [6]

<u>Transition criterion SS -> SW flow:</u> The transition between the smooth stratified (SS) and the wavy stratified (SW) flow occurs when the gas phase velocity overcomes the wave's propagation velocity. (Curve CCA)

<u>Transition criterion Segregated -> Intermittent flow:</u> According to some scientific notifications [6] the hold-up threshold for flow transition between segregated and intermittent is $\boxed{\frac{h_L}{D} = \frac{1}{2}}$ (Curve ABCA)

<u>Transition criterion Intermittent -> Distributed flow:</u> The transition between intermittent and distributed flows occurs when the forces that are induced due to the turbulent fluctuations overcome the hydrostatic pressure forces and displace the gas from the top level of the pipeline [6] (Curve DD)

2.1.2. Two phase flow: Oil-Water

In this type of flow the densities, volume fractions and the viscosities of the liquids, the temperature and the existence of impurities in the flow are the major parameters that affect the flow patterns that may appear.

The modelling of this type of flow is difficult and so far is based on many empirical considerations. Phase inversion and emulsification are the major phenomena that make this multiphase flow complex. In order to describe this type of flow, the parameters that are needed are the determination of the continuous and the non-continuous (or dispersed) phase, the variation of mixture viscosity μm with the holdup and the extent of emulsification [9].

As dispersed or non-continuous or internal phase is defined the one that is formed in droplets and dispersed in the other phase, while the continuous or external phase is defined as the one in which the droplets are suspended [10].

Phase inversion

Each flow pattern may have different appearances as indicated in Figure 6 below. This is caused by the phase inversion phenomenon. This phenomenon is describing the alternation of the continuous and the dispersed phase between oil and water phases. The conditions under which phase inversion occurs are not accurately defined [5]. However, when the volume fraction of the non-continuous phase starts to increase, this phase will start to disperse in the continuous flow of the other phase. The non-continuous phase may form droplets in the interface and as its volume fraction keeps increasing the droplets may coalescent and form a continuous layer. This is how the continuous phase is inverted to the dispersed phase and the opposite.

In the left side of Figure 6 is visualized the creation of a water-in-oil dispersion. The continuous phase of pure oil is disturbed by water droplets, which gradually increase in size as the volume fraction of water increase. At the inversion point, the continuous phase of oil has become the non-continuous phase. In the right side of Figure 6 is visualized the creation of an oil-in-water dispersion with the same way.

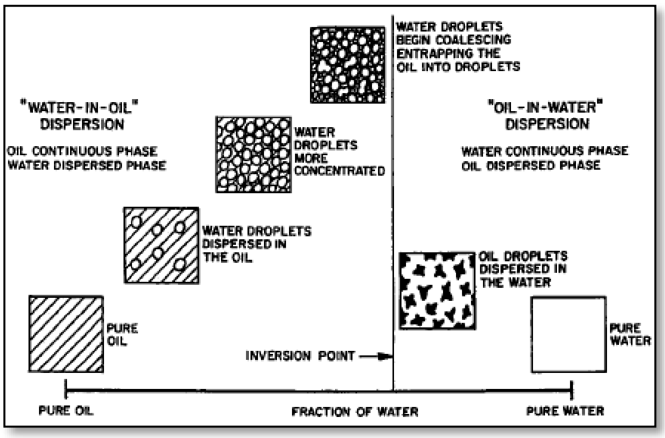


***Figure 6:** Phase inversion for oil-water dispersion flow.* [11]

In order for this flow alteration to occur the average flow velocity v_m has to be high, in order to provide the appropriate mixing of the fluids before and after the phenomenon [5]. Also, the distinction between the continuous and the dispersed or non-continuous phase is easier to be done when at least one of the liquids has high superficial velocity because In this case the phase inversion will occur and the flow regime will have become definite.

Another parameter that affects the phase inversion phenomenon is the oil viscosity. The higher is the viscosity of oil the more it tends to form the non-continuous phase. For this reason, when the flow contains high viscous oil, the phase inversion occurs even for low water cut [9].

The inversion point refers to the combination of volume fractions of each phase, above which phase inversion will occur resulting to the alternation of the dispersed phase to continuous phase [9]. As phase inversion criterion is considered a critical water fraction (water cut), which is calculated according to different correlations that have been proposed. When the water cut exceeds this critical value, phase inversion will occur. In general, emulsions exhibit Newtonian behaviour when the water cut is less than 40% approximately, meaning that when the mixture's viscosity increases, the shearing stress also increases and that the mixture's viscosity is constant for a given temperature. When the water cut increases more than 40%, the mixture starts to behave as a Non-Newtonian fluid, meaning that its viscosity is not constant for a given temperature, because it depends on the shearing rate. In this case, the viscosity increases when the shear stress decreases [10].

Phase inversion consequences

When the inversion is referring to the establishment of the more viscous phase as the continuous phase, this results in the **increase of mixture viscosity**, because the mixture viscosity is considered equal to the viscosity of the continuous phase. Since the viscosity is highly affecting the frictional pressure losses in the flow, it will also result in the **increase of pressure drop in the pipeline**.

Emulsions

In the Liquid-Liquid flow, the fluids can be assumed to create emulsions when the droplets of the non-continuous phase are very small. As emulsion is considered the flow that consists of two immiscible fluids and one of them is dispersed in the other. In this case, the flow can be considered as homogeneous. In the oil industry water-in-oil emulsions are more common; therefore the oil-in-water emulsions are sometimes referred to as "reverse" emulsions [10].

The problem in the modelling of the emulsions arises when the emulsions become unstable and they separate into the original phases after a time period of flowing. Instability may occur when the mixing procedure becomes less sufficient due to the reduction in the superficial velocities of the fluids. In order to overcome this, surfactants are added to the flow. These are substances that have the ability to prevent the separation and demulsification of the flow.

If the concentration and the superficial velocity of the water phase become very high, emulsions behave as non-Newtonian pseudoplastic fluids and as a result, their viscosity decreases with the increase of shear rate.

General flow map

The different flow regimes that appear in the Liquid-Liquid flow depend on the viscosities and the densities of the phases that constitute the flow as well as on which is the continuous and the non-continuous phase. The distinction between continuous and non-continuous phase is based on the phase fractions and the coalescence of its molecules. The continuous phase will be the one that occupies more space without any or with the fewer discontinuities in the flow. The transition between the flow regimes is based on the occurrence of phase inversion phenomena.

In Figure 7 is presented the general flow map for Liquid-Liquid flow. The axes are scaled logarithmically for better illustration and they represent the superficial oil velocity in the y-axis and the superficial water velocity in the x-axis. The oil's kinematic viscosity is considered to be μo=0.065Pas. The dotted line distinguishes the two different flow occasions according to the nature of the continuous and the non-continuous phase. The interpretation of the flow map is the following:

Water-In-Oil flow: The continuous phase is oil and the non-continuous phase is water. The different flow patterns that may appear are the three on the left side of the map. The water phase is intermingled in the oil phase and the extent of its dispersion depends on the superficial velocity of the oil. For a specific superficial velocity (specific volumetric flow rate and pipeline diameter) of the water phase (non-continuous phase), as the oil volumetric flow rate decreases, the water phase spreads more in the oil phase by creating water slugs, tending to become the continuous phase.

Oil-In-Water flow: The continuous phase is water. The possible flow patterns that appear are the four on the right side of the flow map. Considering a specific superficial velocity of water (continuous phase), as the oil volumetric flow rate increases for a given pipeline diameter, meaning that the superficial velocity of the water phase will increase, the oil will coalescent gradually and create slugs, tending to become the continuous phase.

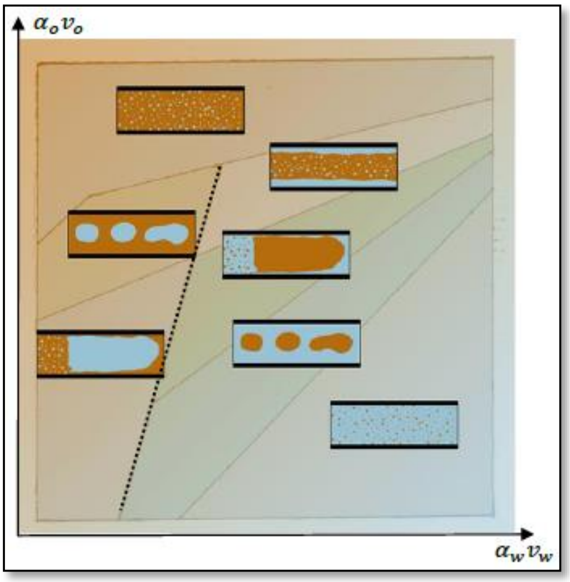


Figure 7: *Generalized flow map for Oil-Water flow in horizontal pipelines.* [5]

<u>*Stratified Smooth/with Globules/with Mixing Layer flow*</u>

Stratified Smooth flow is observed for low mixture velocities. The liquid with the greater density will flow on the bottom of the pipeline due to gravity and the different phases are totally segregated. When the densities are very different the flow can be assumed to be similar to the multiphase Gas-Liquid flow [5].

The effects of phase inversion phenomenon in stratified flow are presented in Figure 8. The transition to the continuous phase to the dispersed phase and the inverse is gradually occurring. Specifically, in this figure the continuous phase is oil and the discontinuous phase is water. Initially, as indicated in Figure 8a, both phases; oil and water, coexist in continuous layers when their velocities are both low. If the volumetric and mass flow rate of the discontinuous phase (water) starts increasing, the result will be the creation of water droplets that gradually will disperse in the continuous oil phase. Depending on the velocity and the concentration of the water phase the flow pattern may become similar to one of the patterns that are presented in Figure 8b to 8h.

When the oil-water interface is no more smooth because the increase in the oil or water volumetric flow rate has caused the abruption of flow with the formation of water or oil droplets respectively, the flow is characterized Stratified with Globules, because of the droplets formation (Figures 8c and 8d).

As the volumetric flow rates keep increasing, the dispersion extends to the whole flow and the flow is characterized as Stratified with Mixing Layer (Figures 8e and 8f).

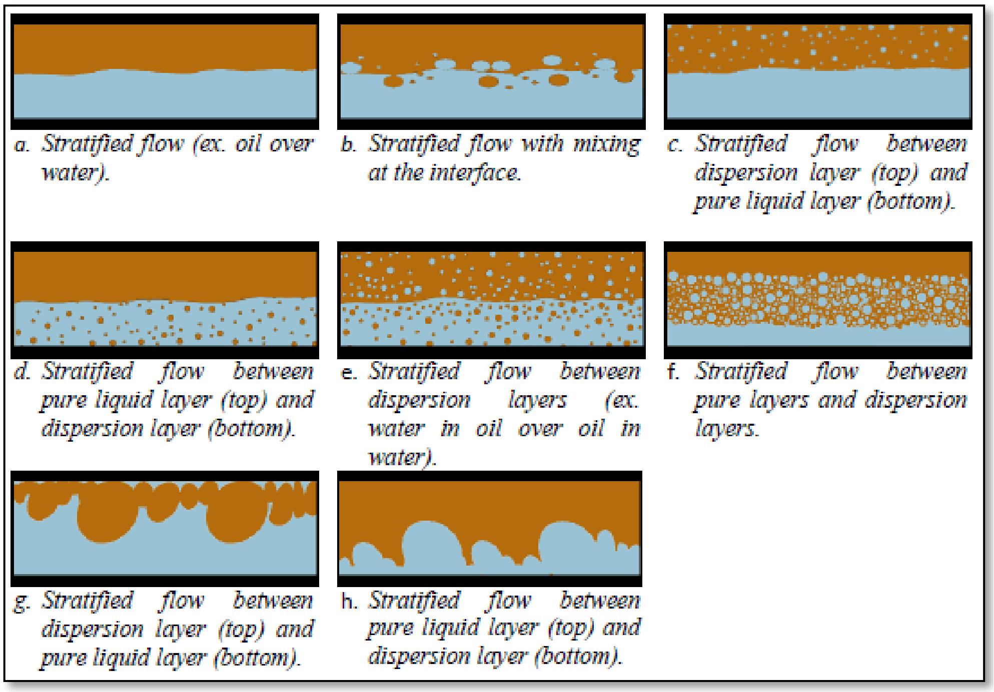


Figure 8: *Different patterns of stratified Oil-Water flow in horizontal pipelines.* [5]

The appearance of stratified Oil-Water flow can be estimated by the calculation of Eötvös number. It is a dimensionless measure that indicates how much different are the densities of the liquids that appear in the flow. Very small values of the Eötvös number (E_o<<1) indicate that the liquids have very similar densities and the possibility of stratified flow is negligible.

Eötvös number: $$\boxed{E_o = \frac{|\rho_w - \rho_o| \cdot g \cdot D^2}{8 \cdot \sigma_{ow}}}$$

Where:

σ_{ow} : the interfacial shear stress in the interface of oil-water

When the densities are quite similar the flow regimes become independent of inclination angle and stratified flow cannot exist [5].

Annular/Mist flow

Annular flow is connected with a high superficial velocity of one of the phases and moderate superficial velocity for the other one. In Figure 9 are presented the different annular flow regimes that may appear depending on which phase is the continuous and which one is the non-continuous. The phase with the greater superficial velocity will flow in the core of the pipeline, while the other one will create an annular film (Figures 9a and 9b). In case that the volumetric flow rate of the slow liquid increases it will start being dispersed in the continuous core flow of the fast liquid (Figures 9c to

9e). There is no restriction in which fluid will be the dispersed one, but this depends on the volumetric flow rate and the volume fraction.

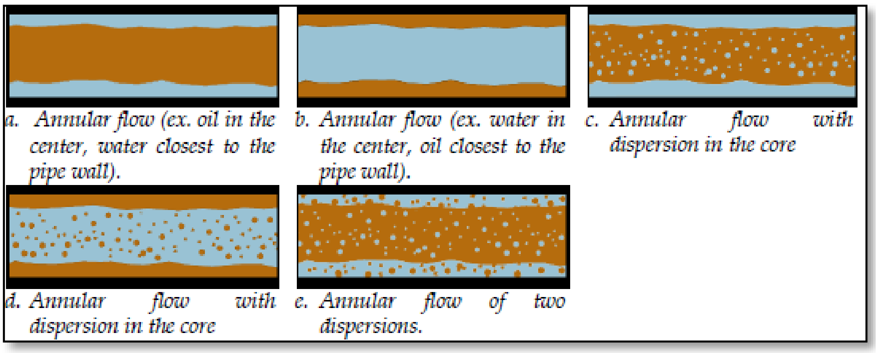


Figure 9: *Different patterns of annular Oil-Water flow.* [5]

<u>Elongated Bubble/Plug flow</u>

The occurrence of plugs in the flow is connected with moderate volumetric flow rates of one phase while the other has a high volumetric flow rate. In Figure 10a the oil plugs are created due to the oil droplets coalescence that happens as a result of the increased oil volumetric flow rate. The opposite phenomena happen for the water slugs in Figure 10b.

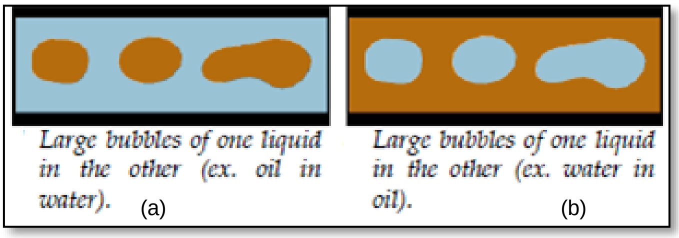


Figure 10: *Different patterns of plug Oil-Water flow.* [5]

<u>Slug flow</u>

The occurrence of slugs in the flow is connected with moderate volumetric flow rates of both phases. In Figure 11a the oil slug is created due to the oil droplets coalescence that happens as a result of the increased oil volumetric flow rate. The opposite phenomena happen for the water slugs in Figure 11b.

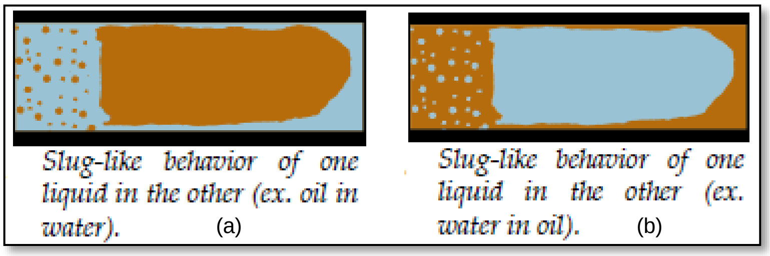


Figure 11: *Different patterns of slug Oil-Water flow.* [5]

Dispersed flow

In dispersed flow the phase with higher superficial velocity will be the continuous phase while the "slower" fluid will be dispersed in forms of bubbles. There are water-in-oil (w/o) and oil-in-water (o/w) dispersions.

2.1.3. Two phase flow: Liquid-Solids

In oil & gas industry solids appear very often in the pipelines and they create slurries; mixtures with oil or water that flow in the pipeline. The solids may be:

- Sand that is mixed with the reservoir effluents,
- Proppants, which usually contain sand, that was inserted in the wells for fracturing purposes,
- Solids that originate from hydrocarbon blockages such as hydrates, waxes, asphaltenes and scales,
- Corrosion particles that have been detached from the interior of the pipelines' walls

The sand particles that are observed in oil & gas industry are usually coarse-grained up to a few millimetres. Due to their magnitude, they are characterized as settling slurries. Their characteristic is that the solid particles tend to accumulate at the bottom of the pipe [12]. The flow patterns that are observed in Liquid-Solids flow are dictated by the gravity rules, while the surface tension is negligible. Depending on how sufficient is the mixing, the flow may be characterized as homogeneous or heterogeneous.

Two different models have been developed in order to describe the Liquid-Solid flow: the Two Layer model and the Three Layer model. The Two Layer model cannot describe the movement of the upper layer of a stationary solids' bed when low mixture velocities occur, which is observed in real applications [13]. So, the theory of three layers existence is more realistic and the flow patterns of this type of flow will be described according to this in the following paragraphs.

Stationary bed flow

This type of flow is characterized by low liquid volumetric flow rates. The solid particles concentrate to the bottom of the pipe because they are much heavier than the liquids, thus creating a solid bed (Figure 12a). If the liquid volumetric flow rate is low, the solids will remain stable without moving at all, creating a stationary deposition. If the liquid volumetric flow rate increases, the solid particles at the upper layer of the solid bed will start moving downstream. The solids' bed height will be stabilized when the solid inflow rate becomes equal to the downstream transportation rate of the solids that are moving on the bed's upper layer [7].

Moving dunes flow

If the liquid volumetric flow rate increases further, the solid particles will create dunes, which move downstream (Figure 12b). This phenomenon is also known as "saltation".

Scouring/Moving bed flow

The liquid volumetric flow rate is increased even more than in the case of moving dunes flow and the decomposition of dunes starts. More specifically the particles on the upper parts of the dunes are drifted away by the liquid flow but new upstream particles replace them (Figure 12c). Finally, the solid deposits on the bottom of the pipe create a moving bed.

Heterogeneous Dispersed flow

When the liquid flow rates become high enough, the solid particles disperse in the flow. The bottom of the pipeline is free of concentrated particles because they are all drifted by the inflow and disperse in the liquid stream (Figure 12d). This flow pattern may be distinguished in two types, depending on the homogeneity of the flow:

- *Pseudo homogeneous dispersed flow*, where the solid particles distribution in the liquid flow can be assumed to be almost uniform and
- *Heterogeneous dispersed flow*, where the concentration of the solid particles is increased as moving downwards the pipeline's cross section.

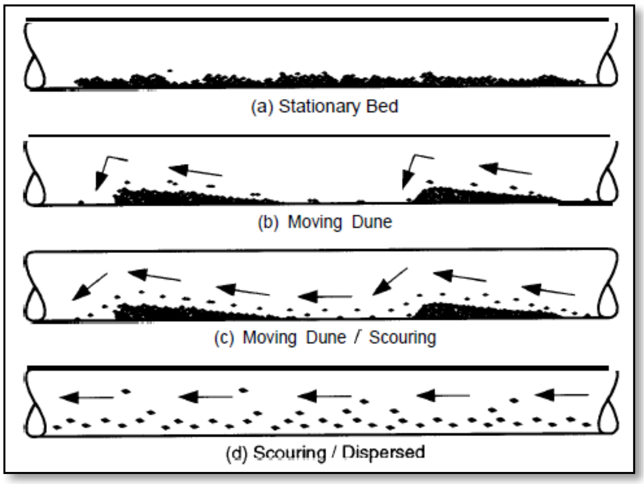


Figure 12: *Flow patterns for Liquid-Solids flow.* [7]

2.1.4. Three phase flow: Gas-Oil-Water

When more than two phases exist in the flow, the final flow pattern is a result of the impacts of gravity, velocity and shear stresses that connect the different phases of the flow. The final flow regime will be a mishmash of the regimes that appear in two-phase flows and the flow will have many similarities with the patterns that appear in two-phase flows between gas-liquid and liquid-liquid.

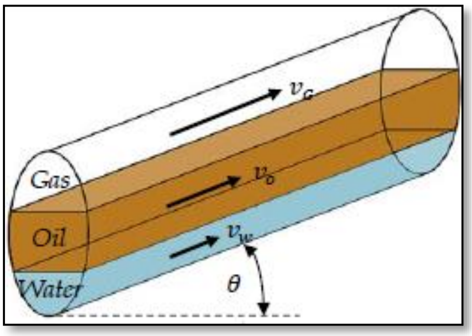


Figure 13: *Stratified Gas-Oil-water flow.* [5]

The stratification order of phases will follow the gravity rules; the water will flow at the bottom of the pipeline because it is the denser, the gas will flow at the top because it is the lighter and the oil which is intermittent in terms of density, will flow in-between the other two fluids (Figure 13).

An important characteristic of this three-phase flow is the definition of the pressure. In gas-oil-water multiphase flow, the pressure that characterizes the flow is the one that is imposed on the surface of the gas and the uppermost liquid layer, which is the oil [5].

Stratified/Smooth flow

As in other types of multiphase flow, the stratified flow of Gas-Oil-Water is observed when all the phases flow with low velocities. The flow is thoroughly segregated according to the gravity's rules (Figure 15a).

Plug flow

It is characterized by low gas superficial velocity and moderate liquid superficial velocities. The gas concentrates in big areas (plugs) on the top of the flow. The plugs are created as a result of the liquid wavy movement. No gas bubbles have been dispersed in the liquid flow yet (Figure 15b).

Slug flow

It is characterized by moderate liquid superficial velocities and moderate gas superficial velocities, which are higher than the ones observed for plug flow. Due to the contribution of many liquids, the slug flow of Gas-Oil-Water is more complex and so is the computational interpretation of it. Two different flow regimes may appear depending on the grade of the mix between the phases.

- In case of complete mix of oil and water, they can be considered as a single liquid with properties that correspond to their mixture.
- In case of completely separated phases, without any mixture appearance, the flow pattern will show discontinuities and waves. The gas will disperse in the liquids forming bubbles and Taylor bubbles may appear. The liquids may be considered as two stratified layers with bubbles in the liquid slug for calculation purposes [14] (Figures 14 and 15c).

In Figure 14 a liquid slug with length ℓ_S and a Taylor bubble with length ℓ_T are illustrated.

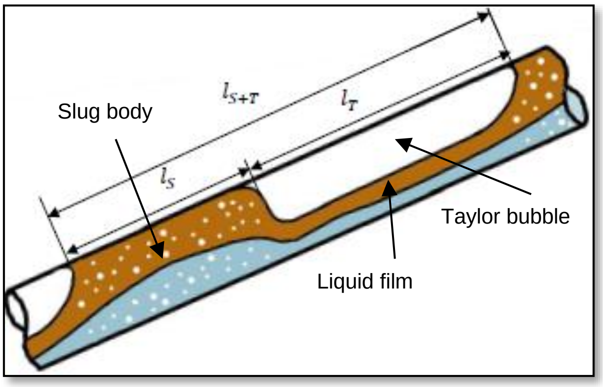


Figure 14: *Slug Gas-Oil-Water flow with stratified liquid layers.* [5]

Annular/Mist flow

In case of high gas volumetric flow rate and high gas content (as in gas condensate fluids) but with moderate liquids superficial velocities, the gas will concentrate in the middle of the pipeline while the liquids will concentrate at the walls of the pipeline, creating a liquid annulus (Figure 15e). The liquids (Oil and Water) may be assumed to be well mixed and to behave as an emulsion or dispersion [5].

Dispersed flow

In case of high volumetric flow rate of one of the liquid phases and of the gas phase, the gas will be formed in bubbles and flow dispersed in the liquid phases. The liquids flow can be evaluated as a two phase Liquid-Liquid flow, with gas bubbles. The liquid of high velocity will occupy the central part of the pipeline cross section.

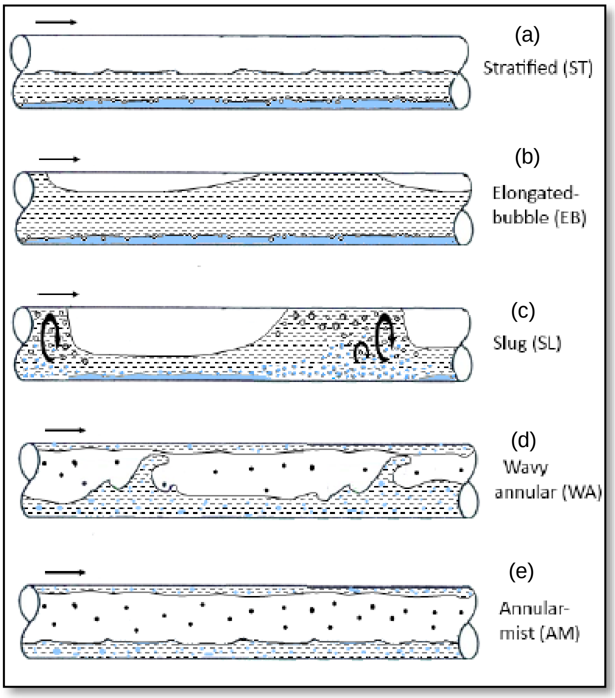


Figure 15: *Flow patterns for horizontal Gas-Oil-Water flow.* [15]

2.1.5. Three phase flow: Gas-Liquid-Solids

The flow patterns that are observed in Gas-Liquid-Solids flow are dictated by the gravity rules. The flow regimes that appear are similar to those that appear in two phase Liquid-Solids flow because in both types of flow the solids are the heaviest phase and they remain at the bottom of the pipeline and they are in contact with the liquid phase.

Plug flow

In case of plug flow the gas volumetric flow rate is low and the liquid volumetric flow rate is moderate. The gas does not affect the solid particles which are deposited in the bottom of the pipeline due to gravity. If the gas velocity increases more, the gas bubbles may extend and affect a greater part of the pipeline's cross section, so that the solid particles may start to move downstream [7] (Figure 16a).

Slug flow

In case that the gas and the liquid volumetric flow rate are moderate, slugs will be created according to the mechanisms that were explained in the two phase Gas-Liquid flow. The solid particles may be transferred in the slugs if the velocity of the liquid slug is high enough to drift away particles that have deposited in the bottom of the pipeline (Figure 16b).

Low hold up wavy flow

In case of wet gas pipelines, where low liquid hold up is observed, the bigger part of the pipeline is occupied by gas. The liquid is forming a thin film on the bottom part of the pipeline, where solid particles are also concentrated.

The solids may be dispersed in the liquid film or may be accumulated on the lower layers creating a wet solid bed [7] (Figure 16c).

Annular flow

In case of annular flow high gas and liquid volumetric flow rates are observed. As a result of the high superficial velocities in the mixture, the solid particles may disperse in both liquid and gas phases [7] (Figure 16d).

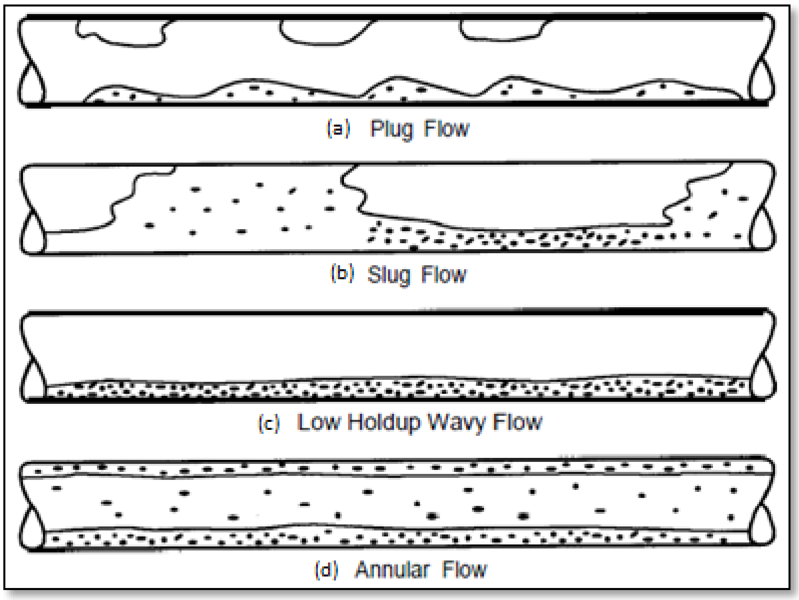


Figure 16: *Flow patterns for horizontal Gas-Liquid-Solids flow.* [7]

2.2. Multiphase horizontal flow considerations

As mentioned above the modelling and prediction of multiphase flow in horizontal pipelines is complex, which makes the flow assurance issues also complex.

The Multiphase compositional triangle is commonly used for the prediction of the flow regime (Figure 17). Each one of the three sides indicates the volume fraction of each phase and corresponds to a two-phase flow, while each one of the three vertices corresponds to a single phase flow of water, oil or gas. The area of the triangle corresponds to a three-phase flow and each point presents a unique mixture with a specific concentration of each phase. The transition region indicates the phase inversion region. The triangle as all the flow maps is generated and referred to a specific mixture flowing to a pipeline of specific diameter and inclination, under specific temperature and pressure conditions.

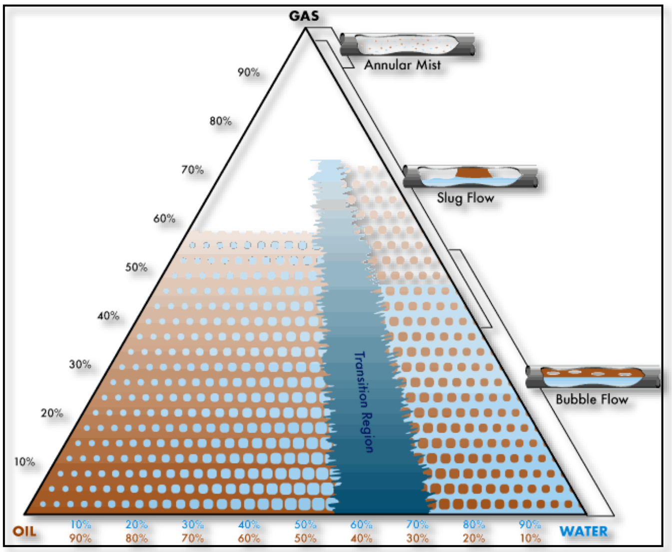


Figure 17: *Gas-Oil-Water flow compositional triangle* [16].

Since the Gas-Oil-Water flow is commonly met in manifolds and wellheads the three phase triangle is a useful generalization of this type of multiphase flow. In brief it shows the following:

- Mixtures with high gas volume fraction exhibit a flow where the oil and water phases are dispersed in the gas phase.
- Slugs of liquid may be created in mixtures with moderate or low gas fraction. The slugs will contain oil or water, depending on their fractions. In case of high water fraction, water will be the continuous phase; while oil will be dispersed or will create slugs and the gas will form bubbles.

Difficulties in multiphase flow modeling

- Generalization of flow maps for multiphase flow
- Discrimination of the boundaries of the different flow regimes for Liquid-Liquid flow.
- Conditions under which phase inversion occurs in Liquid-Liquid flow.
- Prediction and modeling of emulsions behavior as non-Newtonian fluids.

Problems that may arise in horizontal multiphase flow and affect flow assurance

- Increase of mixture's viscosity and frictional pressure losses, due to phase inversion between oil and water,

- Instabilities in flow, due to transformation of the mixture to Non Newtonian, when water cut exceeds around 40%,
- Instabilities in flow, due to large pressure fluctuations that may be caused by liquid slugs,
- Internal corrosion of the pipelines' walls, due to slugs formation,
- Flow blockages that may be created by stationary bed solid depositions on the bottom of the pipeline,
- Non uniform heat transfer in the pipes' walls due to the formation of solid bed layer,

2.3. Effect of design parameters

The flow regimes of multiphase flow that appear in flowlines are of major importance for their design. The engineers prefer to design themso that to encourage the development of wavy stratified flow in the pipelines because in this type of flow the slippage is reduced and the liquid hold up phenomena are eliminated [17]. In the case of intermittent flow, the pressure fluctuations that are created due to slug formation must be avoided. On the other hand annulus and bubble flow is developed under special occasions of high velocity of gas and liquid phase respectively, so they are rarely met. So the transition from stratified to intermittent flow is the major aspect when designing facilities with a multiphase flow.

The flow patterns that appear in the pipeline depending on the following characteristics of the flow:

- **Velocities** (in terms of flow rates) of the different fluids that constitute the multiphase flow. Fluids with higher volumetric flow rates tend to occupy a bigger part of the pipe's cross section area. Depending on the magnitude of their superficial velocity, they may create slugs or core flows where the other phases are dispersed in them. In the case of vertical flow, liquid loading phenomena may occur.
- **Viscosity** affects mostly the liquid-liquid flows. For gas-liquid flows, the difference in the viscosities of the fluids is very big. In the case of water-oil flows the oil is the lighter component and will be dispersed in form of droplets along the water continuous flow. If the oil volumetric flow rate increases, the flow pattern will be inversed (phase inversion phenomenon).
- **Surface tension,** because it is correlated with viscosity,
- **Density** of the liquid and gas phase,
- **Pressure.** If the pressure in the pipeline is high, the expected velocities of the fluids will be less than the ones that would be expected in case of regimes with lower

pressure. This results to expedite the transition between the different flow regimes and the transition boundaries are shifted to lower velocities.

- **Orientation and Inclination** of the pipeline.

In pipelines that have a downward inclination the gravity accelerates the flow resulting in greater velocities. So in downward inclined pipelines the transition boundaries occur for higher velocities than in horizontal pipelines. Also the intermittent flow region is shrinked for downward inclined pipelines, because the transition boundary between the dispersed and intermittent flow is not influenced by the pipeline's inclination.

- **Pipe diameter**

The pipe diameter affects the superficial velocity of each phase. The volumetric flow rate is directly dependent on the velocity of the fluid and on the cross sectional area of the flow. Consequently any change in the pipeline diameter, while the volumetric flow rate remains the same, results in the change of the fluid velocities and the shift of the transition boundaries in the flow maps. More specifically when the pipe diameter increases, the fluid velocities will move to bigger values. The differences are more intense for more than 30cm increase in pipe diameters [6].

The transition boundaries between SS - SW flow (Smooth Stratified and Stratified Wavy) and the boundaries between I – AD flow (intermittent and Annular Dispersed) are not affected by any change in the pipeline diameter.

- **Content of the liquid phases**.

The percentage of the liquid phases in the flow determines the density of the flow. In case that it is high, liquid loading phenomena may occur.

REGIME	LIQUID VEL(ft/sec)	VAPOR VEL.(ft/sec)
Dispersed	Close to vapor	> 200
Annular	<0.5	> 20
Stratified	<0.5	0.5-10
Slug	15 (But less than vapor vel.)	3-50
Plug	2	< 4
Bubble	5-15	0.5-2

Table 1: *Typical velocities of two phase flow.*

3. Modeling of multiphase flow in pipelines

3.1. Multiphase flow modeling approaches

Multiphase flow can be described by the three main fluid mechanics and thermodynamics theorems: conservation of mass, momentum and energy.

The modelling of multiphase flow is an issue under investigation since 1950's when the first observations and efforts were implemented in order to predict the multiphase flow behaviour.

One of the first approaches was the non-slip approach according to which multiphase flow is considered homogeneous and no slippage occurs between the different phases. This approach contains high uncertainty and the results are inaccurate, so later were used correlations for the liquid hold-up in order to describe more precisely the slippage phenomena between the different phases [18]. For more realistic results are used a combination of two fluids model and empirical correlations for the liquid hold up, namely mechanistic models.

Homogeneous Flow Model - Non slip approach

The flow is considered to be a homogenous mixture of gas and liquid, where no interaction between the two phases is taken into consideration. The equations of single phase flow are used for the configuration of the flow.

The multiphase flow can be considered homogeneous for annular and bubbly flow since the velocity of the fluid entering the pipeline is almost the same with the velocity of the flow.

But in cases that the gas velocity is low, as it occurs in stratified and plug flow regimes when the velocity starts increasing, the void fraction will also start increasing, so it cannot be considered as a homogeneous flow.

The main disadvantage of this method is that the pressure drop that is calculated is lower than the real because the liquid volume is considered lower than the real [18].

Empirical correlations

The empirical correlations that are related with multiphase flow can be distinguished to three categories according to the physical approach for modeling:

A. Non slippage correlations

The main consideration for these correlations is that the flow consists of more than one phases but there is no interaction and slippage between them, so the flow is considered homogeneous. Both gas and liquid velocities are the same and the mixture's density is calculated based on the input gas over liquid ratio (GLR).

The most well-known correlations of this category are the following: Poettmann & Carpenter, Baxendell &Thomas and Fancher & Brown.

B. Slippage correlations without flow pattern consideration

These correlations take into account the slippage occurrence between the different phases, but the flow is considered to be homogeneous. So they do not differentiate between the different flow patterns that appear in a multiphase flow, but they are used for all of them. The most well-known correlations of this category are the following: Hagedorn & Brown, Gray and Asheim.

C. Slippage correlations with flow pattern consideration

These correlations take into account the slippage occurrence between the different phases and the type of flow pattern that is established. The most well-known correlations of this category are the following: Duns & Ros, Orkiszewski, Aziz et all., Beggs & Brill and Mukherjee & Brill.

The correlations of Beggs & Brill and Mukherjee & Brill can be used for many different flow inclination angles, but all the other correlations are used only for vertical flows.

One –Dimensional Two-Fluids Model – Mechanistic model

It is a combination of empirical correlations and two fluids modelling. According to this approach, the flow of each phase is examined separately as well as the influence of the flow of each phase to the others. The two phases have different velocities but they are interfering with the interfacial forces. With the mechanistic models are predicted the flow patterns that appear in the multiphase flow and then is calculated the pressure gradient according to the corresponding correlation for the suitable flow pattern.

The most well-known mechanistic models are the following: Ansari et al and Hasan & Kabir for upward vertical flow.

3.2. Multiphase flow design parameters

Some basic design parameters for the description, simulation and prediction of multiphase flow are the following:

- *Two phase mass flow rate*

The total mass flow rate of the multiphase flow is considered to be the summation of the mass flow rates of the liquid and the gas phase:

$$\boxed{\dot{m} = \dot{m}_L + \dot{m}_G}$$

$\dot{m}_L$: mass flow rate of the liquid phase,

$\dot{m}_G$: mass flow rate of the gas phase

- *Two phase volumetric flow rate*

The total volumetric flow rate of the multiphase flow is considered to be the summation of the volumetric flow rates of the liquid and the gas phase:

$$\boxed{Q_G = \frac{\dot{m}_G}{\rho_G}} \quad \boxed{Q_L = \frac{\dot{m}_L}{\rho_L}} \quad \boxed{Q = Q_L + Q_G}$$

Where:

Q_L: the volumetric flow rate of the liquid phase,

Q_G: the volumetric flow rate of the gas phase,

ρ_L: density of the liquid phase,

ρ_G: density of the gas phase,

- *Total mass flux of the multiphase flow*

When the flow properties of a multiphase flow in a pipeline are examined it is of great importance to take into consideration the mass influx. It represents the mass flow rate of the flow that passes through a specific cross sectional area of the pipeline. The mass influx is usually used in computational fluid simulation of the multiphase phase:

$$\boxed{G = \frac{\dot{m}}{A}}$$

- *Quality/Dryness fraction*

The dryness factor is the percentage of the mass flow rate of the gas phase over the total mass flow rate:

$$\boxed{x = \frac{\dot{m}_G}{\dot{m}} = \frac{\dot{m}_G}{\dot{m}_G + \dot{m}_L}}$$

- *Volumetric quality*

The volumetric quality is the percentage of the volumetric flow rate of the gas phase over the total volumetric flow rate:

$$\boxed{\beta = \frac{Q_G}{Q} = \frac{Q_G}{Q_L + Q_G}} \quad \boxed{\beta = \frac{x \cdot v_G}{x \cdot v_G + (1-x) \cdot v_L} = \frac{1}{1 + \left(\frac{1-x}{x}\right) \cdot \left(\frac{\rho_G}{\rho_L}\right)}}$$

- *Superficial liquid and gas velocity*

Superficial velocity is the velocity which each phase would have if the flow was single phase, so that each specific phase would occupy entirely the cross sectional area (reduced velocities over the cross sectional area of the pipe).

$$v_{SL} = \frac{Q_{LA}}{A_p} \quad v_{SG} = \frac{Q_{GA}}{A_p}$$

Where:

Q_{LA}: actual flow rate of the liquid phase at pipeline conditions [ft^3/s]

Q_{GA}: actual flow rate of the gas phase at pipeline conditions [ft^3/s]

A_p: cross sectional area of the pipe [ft^2]

- ***Average liquid and gas velocity***

The average velocity of each phase represents the volumetric flow rate of each phase that occupies a specific part of the cross sectional area of the pipeline.

$$v_G = \frac{Q_G}{A_G} = \frac{Q_G}{H_G \cdot A_p} = \frac{v_{SG}}{H_G} \quad v_L = \frac{Q_L}{A_L} = \frac{Q_L}{(1-H_G) \cdot A_p} = \frac{v_{SL}}{(1-H_G)}$$

- ***Two phase flow velocity***

The velocity of the flow consisting of two or more phases depends on the volumetric flow rate of each phase as it is indicated from the following equations:

$$v_m = \frac{Q_m}{A_p}$$

$$v_m = \sum_{k=1}^{N} v_{Sk} \quad Q_m = \sum_{k=1}^{N} Q_{kA}$$

Where:

Q_m: actual total fluid multiphase flow rate [ft^3/s]

k: refers to the different phases that consist the flow

- ***Void/Area/Volume fraction and Liquid Hold up***

The volume fraction represents the part of a cross sectional area of the pipeline that is occupied by each phase. It can be also expressed as the percentage of the volumetric flow rate of the each phase over the total volumetric flow rate. In literature usually the liquid volume fraction is referred as liquid hold up. However the proportion of liquid phase's volume in a specific cross sectional area of the pipeline, is indicative of the volumetric flow rate of the liquid phase and hence it's velocity.

$$v_{SL} = v_L \cdot H_L \quad v_{SG} = v_G \cdot H_G \quad H_L + H_G = 100\% \quad VF = \frac{A_G}{A_G + A_L}$$

Where:

VF: void fraction

v_L: the actual velocity of the liquid phase [ft/s]

v_G : the actual velocity of the gas phase [ft/s]

H_L : the hold-up fraction of the liquid phase [%]

H_G : the hold-up fraction of the gas phase [%]

v_{SL} : superficial velocity of the liquid phase [ft/s]

v_{SG} : superficial velocity of the gas phase [ft/s]

Consequently the hold-up is a major parameter on the design of the multiphase flow in pipelines. More specifically the hold-up is connected with the following:

a) The dominating flow pattern,
b) Pressure drop through the pipeline,
c) Slugcatcher design

- *Slippage and hold-up*

Slippage describes the phenomenon of the slipping of the two phases between each other. This happens because the gas phase travels with higher velocity in the flow than the liquid phase.

The slippage and hold up for each phase are correlated through the actual and the superficial velocities of each phase and they affect the design of the pipelines.

In case that the gas and liquid phase are flowing with the same velocity, then no slippage occurs between the phases.

Non slip liquid hold-up is called the fraction of the liquid phase that occupies the cross sectional area of the pipe when no slippage conditions occur.

$$\boxed{\lambda_L = \frac{v_{SL}}{v_m}}$$

Where:

λ_L : the non slip liquid hold-up fraction [%]

v_m : two phase flow (mixture) velocity [ft/s]

Slip ratio is another factor that is used to characterize the multiphase phase flow regime. It represents the ratio of the average velocity of the gas phase over the corresponding of the liquid phase.

$$\boxed{s = \frac{v_G}{v_L}}$$

$$\boxed{v_G >> v_L \Rightarrow SLIPPAGE - LIQUID\,AND\,GAS\,HOLD\,UP \Rightarrow H_L >> \lambda_L}$$

$$\boxed{v_G = v_L \Rightarrow SLIPPAGE - LIQUID\,AND\,GAS\,HOLD\,UP \Rightarrow H_L = \lambda_L}$$

When no slippage conditions (homogeneous flow), s=1.

3.3. Pressure drop in pipelines

Along the pipeline the pressure declines due to restrictions, geometry and the non ideal flow. The total pressure drop along the pipeline is a contribution of the friction pressure losses, the hydrostatic pressure drop when elevation changes occur and the change in the kinetic energy of the fluids. All these factors are presented with the following equation:

$$\boxed{\Delta p_t = \Delta p_f + \Delta p_h + \Delta p_a}$$

Δp_t: total pressure drop/losses,

Δp_a: pressure drop/losses due to the fluids' acceleration,

Δp_h: hydrostatic pressure drop/losses due to elevation changes,

Δp_f : frictional pressure drop/losses due to the viscosity of the fluids.

The total pressure losses can be estimated using correlations that have been developed, like the one that is proposed by Lockhart and Martinelli (1949). They consider the total pressure drop as a proportion of the contribution of the liquid over gas phase and assuming a correction factor depending on the type of flow regime.

$$\boxed{\Delta p_t = \phi^2 \cdot \Delta p_G} \quad \boxed{\phi = \alpha \cdot X^b} \quad \boxed{X = \frac{\Delta p_L}{\Delta p_G}}$$

Where α and b are coefficients and their values depend on the occurring flow regime. The factor X is considered as the two phase flow frictional multiplier.

	a	*b*
Bubble	14.2	0.75
Slug	1190	0.82
Stratified (horizontal)	15400	1
Plug	27.3	0.86
Annular	4.8 -0.3125 D(in)	0.343-0.021 D(in)

Table 2: *Values for the coefficients of the Lockart and Martinelli correlation.*

3.3.1. Frictional pressure losses

No slippage

When the no slippage conditions are met, meaning that the mixture is considered homogeneous and the gaseous and liquid phases are moving with the same velocity, the pressure drop due to friction is expressed by the following equation:

$$\boxed{\Delta p_{f,ns} = f_{ns} \cdot \frac{L}{D} \cdot \frac{\rho_{ns} \cdot v_m^{\;2}}{2}} \quad \boxed{\rho_{ns} = \frac{\rho_L \cdot v_{SL} + \rho_G \cdot v_{SG}}{v_m}}$$

Where:

f_{ns}: the friction factor for non-slip multiphase flow

L: length of the pipeline

D: diameter of the pipeline

ρ_{ns}: fluid density for non-slip multiphase flow

The friction factor f_{ns} when no slippage occurs between the different phases derives graphically from the Darcy-Weisbach diagrams, using the Reynolds number that is calculated within the following equation:

$$\boxed{\mathrm{Re} = \frac{v_m \cdot \rho_{ns} \cdot D}{\mu_{ns}}}$$

Where:

μ_{ns}: the viscosity of the flow under no slip conditions

Slippage

When the flow cannot be considered as homogeneous and as a result slippage occurs between the different phases, the friction pressure losses are higher than in case of no slippage. The additional pressure losses are induced by the development of shear stresses on the phases' interface and by the energy consumption by flow mechanisms. In this case the pressure drop due to friction is expressed by the following equation:

$$\boxed{\Delta p_{f,s} = f_s \cdot \frac{L}{D} \cdot \frac{\rho_{ns} \cdot v_m^{\;2}}{2}} \quad \boxed{f_s = m_s \cdot f_{ns}}$$

Where:

f_s: the friction factor for multiphase flow when slippage occurs,

m_s: coefficient empirically derived

3.3.2. Frictional pressure losses for the flow through equipment

As the flow passes through the pipelines it meets equipment and geometry changes that influence the pressure distribution, because they induce pressure losses. The pressure drop is calculated according to the following equation:

$$\boxed{\Delta p_{f,eq} = K \cdot \frac{\rho_m \cdot v_m^2}{2}} \quad \boxed{K = \frac{f \cdot L_e}{D}} \text{ (in terms of pressure drop)}$$

$$\boxed{\Delta h = K \cdot \frac{v_m^2}{2 \cdot g}} \text{ (in terms of head loss)}$$

Where:

K: the friction loss coefficient, which is obtained from experimental data or calculated, taking into consideration the equivalent pipe length L_e

f: the friction (Darcy-Weisbach) factor

g: acceleration of gravity

Δh: the head loss [m]

Pressure losses in fittings		
Type of fitting	Loss coefficient K	L_e/D
45-degree elbow.	0.35	17
90-degree bend.	0.75	35
Diaphram valve, open	2.30	115
Diaphram valve, half open	4.30	215
Diaphram valve, 1/2 open	21.00	1050
Gate valve, open	0.17	9
Gate valve, half open	4.50	225
Globe valve, wide open	6.40	320
Globe valve, half open	9.50	475
Tee junction	1.00	50
Union and coupling	0.04	2
Water meter	7.00	350

Table 3: *Typical values of the pressure loss coefficient for different types of fittings.*

3.3.3. Pressure losses due to elevational changes

The pipelines may be designed to change direction either in order to follow the terrain's elevation or in order to reach the facilities on an offshore platform or FPSO, in case of risers. In any case of inclined pipelines the hydrostatic pressure downstream will be less than upstream, due to hydrostatic pressure losses. The hydrostatic pressure losses are calculated within the following equation:

$$\boxed{\Delta p_h = \rho_s \cdot g \cdot L \cdot \sin\theta} \quad \boxed{\rho_s = \rho_L \cdot H_L + \rho_G \cdot H_G}$$

Where θ: inclination angle and ρ_s: density of multiphase mixture under slippage conditions

4. Multiphase Flow Assurance

The most important parameters related to the flow in the pipelines are the following:

- *Noise suppression*

Noise is generated from vibrations induced to the pipelines from the disturbances in the flow that are propagating as pressure waves. It's the result of the interaction between the fluid and the pipeline walls.

- *Drag reduction*

Drag forces may be reduced by reducing the pipe diameter, smoothing the walls of the pipes, using surfactants.

- *Water-oil flow*
- *Slug control*
- *Multiphase flow simulation*
- *Flow assurance*

Flow assurance in the O&G industry is related to the issues arising from the establishment of the beneficial flow of effluents in pipelines, in terms of financial profit and flow preservation. Concerning the flow of oil and gas effluents arriving at the wellhead through the flow lines that will guide them to the separation installations, the engineering science has to deal with the optimum way of fluid transport.

Things are more complicated when the flow refers to the more than one phases. In this case, the physical interaction between the phases may create blockages in the flow. Also the physical conditions (pressure and temperature) of the environment surrounding the pipelines strongly affect the effluents properties. The adverse effects in the flow lead to severe production losses with financially catastrophic consequences.

Flow assurance is of major importance for the downstream and midstream facilities in the following cases:

- Subsea deep water reservoirs where the temperature is very low and the pressure is very high,
- Onshore reservoirs with very low ambient temperatures (northern countries),
- Flowlines exposed in extreme temperature fluctuations

4.1. Multiphase Flow assurance challenges

When the exploitation project reaches the stage of midstream facilities design and it has been decided that the effluents will be transported under multiphase flow, many design parameters have to be specified so that to accomplish the establishment of flow assurance. The flow assurance challenges that arise during the multiphase flow refer to the prevention of blockages in the flow, corrosion, erosion problems, avoidance of extended pressure surges, managing of slugs and the appearance of cavitation in the pipeline wall, while ensuring sufficient capacity.

4.2. Blockages

4.2.1. Waxes

Deposits formation

Paraffins are groups of hydrocarbons with high carbon numbers in their chemical structure, which are soluted in oil. Waxes belong to the paraffins' group and they are linear hydrocarbons with more than 16 carbon atoms [19]. They are solid deposits coming from the solidification of the paraffinic hydrocarbons' molecules.

The solid deposits are distinguished in macrocrystalline (or paraffinic) and microcrystalline waxes. Macrocrystalline waxes are long-chain saturated hydrocarbons formed by paraffinic molecules (C18 to C36). Microcrystalline waxes are formed by naphthenic molecules (C30 to C60).

Microcrystalline waxes have higher melting points than the macrocrystalline waxes because the heavier carbon molecules that they contain are connected with strong chemical bonds and more heat is needed in order to break the intermolecular bonds.

The formation of waxes is strongly connected to:

- Low temperatures: Wax deposits are formed when the temperature of the pipe's wall is lower than the Wax Appearance Temperature (WAT), which is different for each hydrocarbon mixture. For temperatures lower than the WAT, paraffins start to crystallize on the wall. The temperature difference between the effluent's WAT and the pipe's surface is more important than that between the flow temperature and the pipe's surface. The magnitude of this difference and the rate of cooling affect the deposits structure. When the cooling is rapid the wax crystals have small sizes. Also, when the temperature difference is large, the crystals are not formed uniformly because of the different melting points and the final structure may contain cavities full of oil [20].
- Low flow rate: When the volumetric flow rate is high, the turbulence drifts away from the wax crystals and they do not agglomerate or deposit. Under these conditions the possibility of waxes deposition is low. In order the particles to deposit, they have to be cohesive enough to attach on the pipe's surface. The opposite happens when the flow rate is low and the flow is considered laminar [20].

- Pipe's internal surface properties: the wax deposition on the internal surface of the pipes is hindered when the surface is wetted by oil, because of lack of free surface in order to develop. Also surfaces with high roughness are friendly environments for waxes deposition [20].
- Fluid composition: waxes formation is determined by the existence of heavy compounds in the oil. Light and volatile oils will not face wax problems.

Wax formation may occur under the following flow and field operations:

- Restrictions: the effluents expand when passing through restrictions, resulting to the temperature's reduction [19]. \
- Artificial gas lift: artificial lift is applied in wells with low flow rate. In this case the oil needs more time to reach the wellhead and in the meanwhile its temperature is getting lower.
- Dissolved gas liberation and evaporation of the lighter components: as the light components of the oil evaporate the heavy components become less soluble. The oil becomes heavy which means that it has higher concentration in molecules that in the appropriate conditions may form waxes.

Effects of wax deposition

The formation of waxes is altering the flow behavior of the crude oil, which starts to demonstrate non Newtonian characteristics.

The problems that are created are the following [20]:

- **Increase of oil viscosity**: more viscous oils exhibit higher pressure drops due to increased friction pressure losses. This will decrease the pipe's capacity, resulting to higher pumping demands.
- **Increase of yield stresses that are applied when restarting the flow after a shut down**: after a shut down the oil has rested and cooled down, so becomes more viscous. If waxes have been developed, its viscosity will be increased and the initial pressure that has to be imposed in order to restart the production has to be bigger.
- **Depositions of wax crystallites at the internal walls of flowlines, tubings, wellheads, tank bottoms and process equipment**: Macrocrystalline waxes increase the paraffin content of the oil that is guided to production facilities and transport operations [19]. Microcrystalline waxes create problems in storage facilities, because they accumulate in tanks, where they form sludges that remain in the bottom.

Prevention/Reduction techniques

Paraffin waxes can either be prevented or removed [19]. The methods that are used in order to prevent and to remove the wax deposits are the following:

- **Pigging**: When they have been formed in the flow, they can be removed by implementing techniques as pigging. With pigging the pipelines are cleaned by the waxes that are formed in the walls, by "scratching" them.
- **Injection of solvents**: they increase the solubility of deposits and re-dilute them. As solvents are commonly used xylene and mixtures of xylene, toluene and naphthalene [20].
- **Injection of chemical inhibitors**: there are surfactants that either inhibit the wax deposition on the surfaces or inhibit the wax crystal growth (chemicals and biochemicals) [20].
- **Control the temperature** at values greater than the WAT. Insulation of the associated equipment is a common prevention action.

4.2.2. Asphaltenes

Deposits formation

Asphaltenes are one of the four compound groups that constitute oil (Saturates, Aromatics, Resins, Asphaltenes). They are defined as the oil compounds that are insoluble in n-pentane or n-hexane (light alkanes), but soluble in toluene or benzene [5].They have the biggest molecular weight than the other oil compounds. They are large, highly polar components made up of condensed aromatic and naphthenic rings, which also contain heteroatoms such as nitrogen (N), sulfur (S) and oxygen (O). Pure asphaltenes are black, nonvolatile powders. [21]

The asphaltene molecules suspended the solution due to the co-existence of resins (oil compounds with low molecular weight and heteroatoms N, S, O) in the fluid. In case that the resins fraction reduces below the limit, the asphaltenes molecules form groups of long molecular chains, which are called micelles. The micelles appear in the fluid as solid depositions i.e. asphaltenes' precipitation [22].

The precipitation depends on the oil's composition, temperature and pressure regime. For pressures up to the bubble point, the precipitation increases and becomes maximum at the bubble point, for pressures greater than the bubble point pressure, precipitation is decreasing. This occurs because for pressures above the bubble point the flow is single phase (only liquid), no gas is released and no changes in composition are happening, so the asphaltenes remain soluted in the fluid and do not create deposits [23].

Asphaltenes deposition may appear in production wells, flow lines and storage facilities. The possibility of asphaltenes deposition is higher under the following conditions:

- **Acidization of the wells**: it results in coagulation of the asphaltenes and impediment of production, due to chemical reactions that affect the micelles [24].
- **CO_2 flooding of the well**: the CO_2 reacts with the fluid's molecules and as a result asphaltenes start to create agglomerates.
- **Turbulence in the flow**: the occurrence of turbulence induces the development of big shear stresses. This affects the oil's composition because it may provoke the breakage of the chemical bonds of some of its molecules. In this case the asphaltenes are affected and destabilized, which results to the increase of their deposition.
- **Hydraulic equipment**: the existence of hydraulic equipment such as valves and chokes reinforces the deposition of asphaltenes because they induce more turbulence in the flow.
- **Well tubing**: in case of metal corrosion in the tubing, the oxidized metal reacts with the fluid's molecules resulting to the destabilization of the asphaltenes and they start to create depositions.
- **Formation rock**: in the reservoir it is possible to occur asphaltenes deposition. During depletion the pressure is reduced and this may cause precipitation.

Effects of asphaltenes deposition

Problems arise when the depositions cause the reduction of the cross sectional area of the pipelines. Therefore the effective flowing area is reduced and the oil production is either reduced or completely jammed.

Prevention/Reduction techniques

The prevention of the asphaltenes deposition is a complex problem for which no specific remediation method has been found yet, due to the difficulty in determining the chemical structure of the deposits. Some of the commonly employed methods to prevent and to reduce the asphaltenes deposition are the following [24]:

- Xylene mixtures are applied as **solvents** and wash the affected equipment,
- **Injection of chemicals additives** as aromatic fatty sulfates and aromatic amines.
- **Control the pressure and temperature** of the flow so that to avoid the formation of asphaltenes depositions. If it is possible the pressure should be retained at values below the bubble point, only in case that this doesn't affect the production.

- Cleaning the pipelines and the wells where asphaltenes deposits appear by applying **pigging**.

4.2.2.1. Scales

Scales are crystalline deposits consisting mostly by inorganic salts like barium sulphate ($BaSO_4$), strontium sulphate ($SrSO_4$), calcium carbonate ($CaCO_3$) while they may also contain organic molecules like naftenates [5]. Their crystalline structure derives from chemical reactions in the production water.

There are two categories of scales: sulphate and carbonate scales:

- **Sulphate scales** are formed due to chemical reactions between reservoir effluents and brines (sea water or formation water).
- **Carbonate scales** are formed when the pressure reduces enough or when the pH of the effluents mixture increases [5].

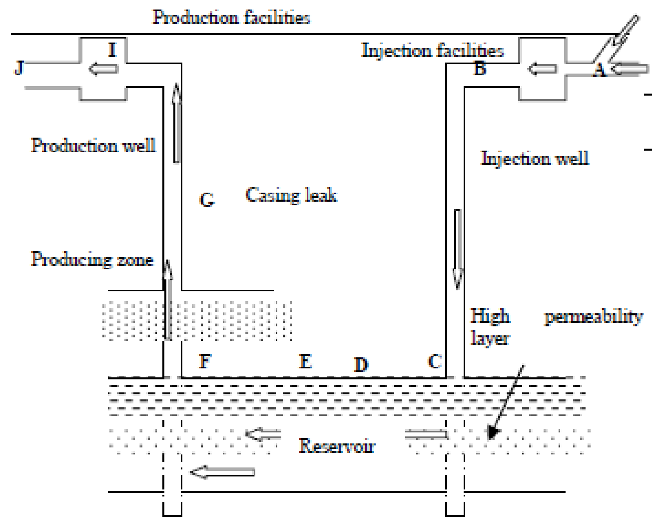
Generally the reason for scales formation is the supersaturation of fluids in minerals, which may happen due to mixing of incompatible brines or change of flow pressure and temperature. The majority of the minerals become less soluble, when temperature or pressure decrease and this results to the deposition of the insoluble salts. Exeption is the calcium carbonate for which solubility in water decreases when temperature increases.

Also when pressure decreases, the CO_2 that is contained in the water starts to evaporate, causing pH increase (i.e. decrease of acidity), which also leads to the formation of carbonate scales [25].

In Figure 18 are presented the possible locations in an oilfield, where scales may occur. More specifically the possibility of scale deposition is higher under the following conditions:

- **Gathering flow lines**: surface horizontal or near horizontal pipelines transfer effluents that arrive from different wells. Each effluent has different brine composition and their mixing may result into scale formation due to chemical reactions between the minerals of the different brines [5]. Also the flow temperature decreases because of the heat transfer from the fluids to the environment.
- **Water flooded wells**: in case of injecting sea water, the minerals of the sea water may react with the minerals of formation water and form sulphate scales [5]. Also as the sea water is flowing towards the reservoir, its pressure and temperature increase and the deposition of calcium carbonates is possible.

- **Depleted wells**: after some years of exploitation the water cut will start to increase. If water injection will be selected as an artificial production lift, the formation water will reacts with the injected water, as previously described for the water flooded wells.
- **Wells under normal production**: during oil production the pressure and temperature decline. This results to the evaporation of CO_2 that is contained in the formation water, which decreases flow acidity and may result to the deposition of carbonate scales.



Location	Change which could produce scale formation
A to B	Mixing of brines for injection
B to C	Pressure and temperature increase
C to D	Pressure decline and continued temperature increase
C to F	Solution composition may be adjusted by cation exchange, mineral dissolution or other reactions with the rock
D to F	Mixing of brines in the reservoir
E to J	Pressure and temperature decline. Release of carbon dioxide and evaporation of water due to the pressure decline if a gas phase is present or forms between these locations.
F	Mixing of formation water and injection water which has "broken through" at the base of the production well
G	Mixing of brines produced from different zones.
H	Mixing of produced brine with brine from casing leak

Figure 18: *Scale formation occurrence during different oil field's operations* [26]

Effects of scales deposition

The major problems that scale deposits create are the following:

- Formation damage (near the wellbore): in this case scales result in the decrease of permeability and increase of the skin factor.
- Blockages in:
  - perforations or gravel packs
  - restrict/block flow lines: in these cases scales create a film that surrounds the pipe walls peripherally.
  - safety valve & choke failure
- Corrosion underneath the deposits
- Some scales are significantly radioactive (NORM)

Suspended scale particles can create the following problems:

- Plug of the formation & filtration equipment
- Reduce oil/water separator efficiency

Reduction techniques

Scales prevention is not an easy task, although it is a pressing issue, because of the increasing use of water flooding as a secondary oil recovery method in many oilfields [26]. Most scale reduction techniques are referred to their detection and elimination. Their removal can be achieved by applying mechanical techniques as pigging or by injecting chemical and acid inhibitors. Also periodical chemical tests of the produced water should be conducted in order to detect any scales formation tendency. More specifically:

- **Inhibitors injection**: Their removal can be achieved by injecting either polyphosphate crystals or liquid phosphonate inhibitors in the formation when hydraulic fracturing operations are conducted.
- **Sonic tools**: they create high-frequency pressure pulses that remove the deposits [25].
- **Pigging**: deposits removal with mechanical methods can be achieved by using positive displacement motors and mill, hydraulic impact hammers, blasting techniques for injecting water or chemical washes in the damaged equipment [25].

4.2.2.2. Gas hydrates

Formation conditions

Hydrates are solidified gas molecules, entrapped in water cells that are formed under ambient temperatures close to the freezing water point and high pressures [5]. This results to the formation of structures of rigid and solid water molecules with entrapped gas molecules.

The possibility of hydrates formation is most likely to occur in the operation facilities during:

- **Shut down operations**: after shutting down the production, the temperature in the pipelines drops because of the heat transfer to the environment. If the temperature reaches the water hydrate equilibrium value, formation is possible.
- **Subsea operations**: in subsea environments the ambient temperature decreases from the water surface towards the seabed. Under so low temperatures that are close to the freezing water point, the formation of hydrates is very possible.

Once gas hydrates are formatted they can create blockages in the flow and reduction of the effective cross sectional area of the pipeline and thus to the reduction of production and in case of severe blockage to the destruction of the pipeline.

Prevention techniques

In order to avoid hydrates formation, the flow must be characterized by high temperatures (>20°C for a natural gas mixture). In Figure 19 are presented the conditions of hydrates formation for a natural gas mixture.

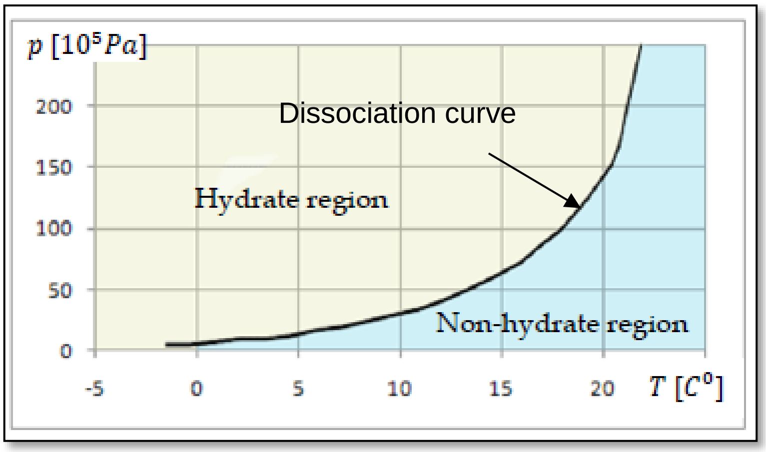


***Figure 19:** Typical mixture hydrate curve for a natural gas mixture* [5].

Many prevention methods have been developed:

- **Temperature control**: Thermal insulation is usually applied to the external walls of the pipelines in order to keep the temperature in the interior of the pipeline, above the hydrate formation limit. This requires extensive thermal analysis of the system taking into consideration the ambient temperatures and management of the cold spots. The insulation materials and points of placement must be chosen carefully so that the cost threshold not to be exceeded. Another way to control the temperature and to keep it high is by conducting heat from an external source in the flow.
- **Injection of chemical inhibitors in the flow**: As inhibitors for the prevention of gas hydrates is commonly used Methanol or MEG (MonoEthyleneGlycol), salts, alcohols, glycols or ammonia.
- **Cold Flow Technology (CFT)**: The main concept is the controlled formation of hydrates and the prevention of destructive blockages. The Cold Flow Technology is based on the conclusion of scientific studies and observations [27] that the hydrates do not accumulate when the temperature is kept constant. When the flow is entering the pipeline, which is not insulated, hydrates start to form, because the ambient temperature is low. Before the hydrates start to create agglomerates and depositions, the flow is separated in gas and liquid phase. The liquid phase is cooled down in a heat exchanger reaching a final temperature similar to the ambient and then it is boosted to the reactor, where it is mixed again with the gas phase. By this way the already formed hydrates do not accumulate to create blockages in the flow and they

remain in suspension since there is no heat convection between the ambient environment and the flow in the pipeline.

<u>Reduction techniques of already formatted hydrates in the pipelines</u>

- **Heating up the flow**: If heat is provided to the flow, the temperature will increase, which will cause the hydrogen bonds that are responsible for the formation of the hydrates to loosen up and to break eventually.
- **Depressurization**: by reducing the pressure the gas and the solid water molecules tend to liquefy. The pressure reduction must be done simultaneously and uniformly from both sides of the hydrate plug otherwise the pressure difference between the sides of the hydrate plug might cause the hydrate to move and result in a sudden expansion with catastrophic results for the pipeline.

4.2.3. Operational

4.2.3.1. Liquid slugging

Gas-Liquid slugs are not considered as a flow assurance problem, as long as they do not dominate the flow and create blockages. The pipeline network and the equipment can be designed so to take into consideration the formation of slugs and that it can be avoided, however prevention techniques can be applied to eliminate its formation.
Riser and terrain oriented slugging are the two types of slug flow that may cause problems to the flow assurance.
At a riser plug liquids reach the bottom of the riser (the point of elevation change at Figure 20a) and move upwards having as driving force the pressure of the flow, which is induced mostly by the gas phase. As the flow moves upwards, the pressure increases, because of the addition of the hydrostatic head from the liquid phase. Under these conditions the liquid accumulates upstream and create slugs preventing the gas from passing through the pipeline (Figures 20b). The pressure of the accumulated gas downstream of the liquid slug increases. When the gas pressure overcomes the pressure drop in the upstream pipeline, the liquid will blow out (Figure 20c). After the blow out the pressure downstream will decrease and as the production continues liquid loading may occur and liquid may start again to accumulate downstream (Figure 20d) [28].

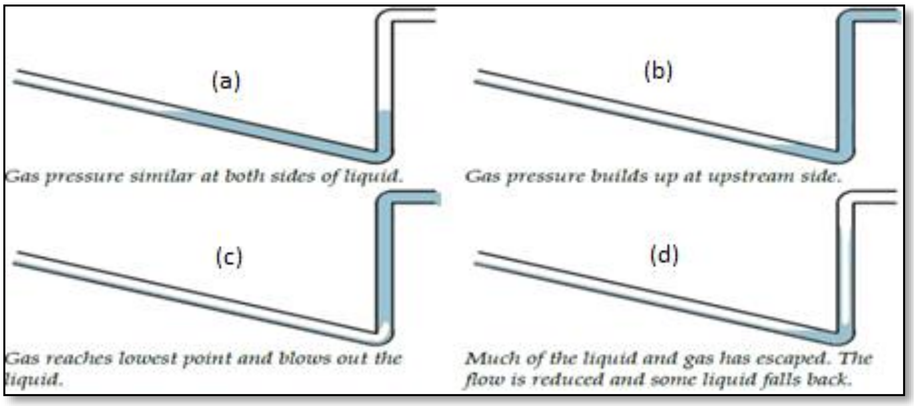


***Figure 20**: Production phases of riser slugs.* [5]

Slugs create density discontinuities in the flow as well as pressure fluctuations. This affects the gas flow as well as the separation procedure.

- **Hydrates formation**: The discontinuities of the density are created due to the extended occupation of flow with gas areas, the low density is fluid and the lower heat capacity of the fluid. As a result, in case of extreme low ambient temperatures, the areas occupied with gas may solidify, forming hydrates and even more solid plugs that act as "bullets" for the pipe, guiding to its destruction.
- **Bad separation**: The separation procedures are strongly affected by the homogeneity of the layers that constitute the different phases. As a result of the presence of slugs in the flow, the fluids can't separate properly because of the multiple layers of the same phase in a specific cross section.
- **Corrosion**: High gas rates that are met in slug flow regimes, increases the erosion rate.

Slug reduction techniques

- **Slug catchers**: they operate as physical low-pass filters that filter the flow with high wave propagation frequency (like slug flow) and transform it to smooth flow [29].
- **Subsea separation**: Subsea separation is the conventional method for treating the effluents in the midstream facilities. In this case slugging possibilities are eliminated because the flow is separated in different streams per phase right after the wellhead.
- **Riser base gas injection** [30]: In case of gas injection at the lower parts of the risers, the fluid becomes lighter and the liquid flowing back is reduced. The creation of severe slugging is prevented because the liquid flow is reinforced by inserting gas. The backpressure increases and the liquid is forced to flow, preventing the accumulation and slugging.
- **Self induced gas lift** [28]: The idea behind self gas lifting is the usage of the gas that exists at the top of the smooth flow, in order to inject it at the base of the riser. The

result is expected to be the same by injecting gas from a new well, as mentioned above.

- **Topside choking** [29]: By installing a choke at the outlet of the riser the flow rate is controlled in such a way that disables the slug formation. When the choke closes, the flow, that is able to pass through it, is reduced and consequently the velocity of the fluid is reduced. However, the gas on the bottom of the riser keeps forcing the liquid to blow out and the liquid slugging is avoided because the liquid is imposed in greatest pressure differences, which is the driving force for the flow.
- **Optimize well production**: By changing the production with chokes, the slug phenomena may be prevented. The chokes control the flow rate so that the pressure that is imposed to the liquid phase from the gas phase, is low enough to prevent slugging.
- **Increase gas injection rate**: By increasing the rate of the injected gas, the backpressure is increased and liquid slugging is avoided. In this case should be paid attention to the Joule-Thomson effect. More specifically, as the gas expands and taking into consideration that the pipelines are well insulated, so that no heat exchange with the environment to occur, the temperature of the gas will drop. This may cause the unpleasant consequences of hydrates formation. In addition the increased gas flow rate will add frictional losses, which must be overcome and this reduces the injection system's efficiency.
- **Active choking**: Reduces the slug length by opening the hock valve when the slugs start to develop.

4.2.3.2. Pressure maintenance

The pressure drop in the flowlines and the risers must be as lower as possible, in order to achieve maximum production efficiency. This is interpreted as retaining the flow regime in the pipelines constant, avoiding the pressure and temperature fluctuations and reducing the backpressure of the wells.

Keeping the flow properties and the flow regime constant is achieved by inspecting and regulating the PVT (Pressure-Volume (in terms of volumetric flow rate)-Temperature) properties of the multiphase flow constant during the transport of the effluents. Appropriate mechanical and hydraulic equipment as chokes, valves, flow meters is used in order to regulate the flow rates and measure the fluid properties.

Reduction of the wells backpressure can be achieved by using multiphase pumps just after the rise of the effluents to the manifolds. The types of the multiphase pumps and the pumping system configuration will be presented analytically in the subsequent chapters.

Factors affecting pressure drop in multiphase flow in pipelines

a. Flow rate

The flow rate is expressing the velocity of each phase that enters the flow. Any change in the flow rate of one phase is enough to change the flow pattern in the pipeline. In case that the gas phase velocity increases, the pressure drop also increases.

b. Friction losses

Between the fluid and the walls of the pipeline friction is developed and it is expressed as pressure losses $\Delta P_{friction}$. Friction is developed by the shear stresses on the surface of the fluid flow. The more viscous the fluid the higher the shear stresses and the friction losses.

c. Liquid percentage in flow

The liquid phase increases the density of the flow, because liquids are denser than gases. This increase in the flow’s density leads to an increase of the frictional pressure losses along the flow. So, the larger the densities of the liquids constituting multiphase flow, the larger the pressure drop in the flow. For this reason when the wells start producing more water than oil and gas, the pressure drop increases because the water has greater density.

d. Length of the pipeline

The flow in the pipeline is not ideal, but viscous. Due to the viscosity of the fluid, the velocity and pressure distribution in the direction vertical to the flow is characterized by the boundary layers that are created on the walls of the pipeline. Along a cross sectional area of the pipeline the thickness of the boundary layers increases and this result in the formation of a bottleneck area in the pipeline, this restricts the flow and increases the pressure drop.

e. Temperature

Any change in the temperature of the gas phase is enough to change the flow pattern in the pipeline, because gas is very compressible. In case that the gas phase temperature increases, the pressure drop also increases.

f. Restrictions in the flow due to pipeline geometry

Changes in the pipeline’s geometry and flow’s direction, as curvatures, inclinations and elevation changes, create local pressure losses.

g. Restrictions in the flow due to mechanical equipment

The mechanical equipment that is installed along the pipeline for the surveillance, control and measurement of flow properties, like chokes, valves and flow meters enforces the flow to pass through smaller diameters. As a result their presence in the pipeline adds pressure imposes additional pressure.

4.3. Integrity

4.3.1. Corrosion

Corrosion is referred to the abruption of particles from the surfaces that are in contact with the flow, due to chemical or electrochemical reactions. The main causes of corrosion are the reaction of the steel surfaces of the equipment with carbon dioxide (CO_2), hydrogen sulfide (H_2S) and water (H_2O).

The corrosion that may appears on the oil and gas facilities can be categorized to external and internal corrosion, according to the parts of the equipment where it may be developed.

External corrosion is caused by the oxidation of the steel when it is exposed to air. As a result of this the metal surface loses its strength and becomes more brittle. If the phenomenon continues for a long time, the corrosion can extend to the interior of the pipeline and may cause the collapse of the pipeline.

Internal corrosion is caused by the chemical reaction of some of the transported fluid ingredients and the steel material of the pipelines' walls or equipment.

According to the nature of the corrosive agents, the following corrosion types may appear:

- **CO_2 in the flow (sweet corrosion)**: CO_2 may appear in the flow as one of the non hydrocarbon compounds of oil or because of direct injection for enhanced oil recovery purposes. When it comes in contact with water it reacts, causing the formation of carbonic acid (H_2CO_3). The corrosion due to CO_2 is caused by the electrochemical reaction between the carbonic acid and the iron of the metallic surface of the pipeline [31].
- **H_2S in the flow (sour corrosion)**: H_2S may appear in the flow as one of the non hydrocarbon compounds of oil. As the CO_2 corrosion, the prerequisite for sour corrosion is the presence of water in the flow. Corrosion due to H_2S is caused by the chemical reaction between the hydrogen sulphide, water and the iron of the metallic surface of the pipeline [31]. The result of this reaction is the creation of iron sulphide (FeS), which is observed as a film on the surface of the pipe.
- **O_2 in the flow (oxygen corrosion)**: O_2 may intrude the flow through leakages in pumps' seals, open hatches and process vents [32]. It reacts with the metallic surfaces causing its oxidization.

- **Galvanic corrosion**: galvanization is referred to the phenomenon of the electrochemical reactions between the molecules of two metallic surfaces with different electrochemical potentials, when they are in contact. The result of those reactions is the charging of the surfaces with opposite electric loads thus altering their chemical structure. The material properties change due to the change of the intergrannular chemical bonds, resulting into corrosion damage.
- **Crevice corrosion**: is a type of corrosion that appears on the surface of the metallic equipment due to the concentration of different corrosive agents in these spots. It appears in crevices and gaps of the equipment where fluid may get stagnant [32].
- **Microbiological corrosion**: microorganisms such as bacteria are accumulating and create colonies in reservoirs and in spots of equipment where stagnant water is concentrated. Common products of the digestion procedures are CO_2, H_2S and organic acids which cause corrosion on the metallic surfaces [32].
- **Stress Corrosion Cracking (SCC)**: is a combination of corrosion and tensile stress failure. It occurs when the material is reaching its fatigue thresholds and cracks start to propagate to the rest of the material meanwhile the corrosive environment contributes to the expansion of the cracking [32].

Factors that affect (internal) corrosion

- **Flow temperature**: in flows with high pH, high temperatures enhance the formation of iron carbide on the surface of steel equipment, which is responsible for the creation of the corrosion protective layer [32]
- **High pressure**: under high pressures the solubility of CO_2 and H_2S in water increases, so the environment becomes more corrosive.
- **pH of the environment**: The pH of a flow is indicative of the number of cations (positively electrically charged molecules) of hydrogen (H^+) in the flow, which contribute to the neutralization of the electrochemical potential. High pH is connected to the low solubility of iron carbonate ($FeCO_3$). Hence, iron carbonate doesn't dissolve fast and can accumulate on the metallic surfaces, as a protective layer, lowering by this way the corrosion rate [31].

Problems that are created due to corrosion

Corrosion is not causing problems directly in the flow, but it affects the properties of the pipe's material.

As the corrosion keeps spreading in the surface of the metallic equipment, the properties of the material change. More specifically the steel loses its elasticity and becomes more brittle. The impacts of corrosion accumulate with time and they may lead even to the complete failure of the material and its breakage.

Prevention/Reduction techniques

- **Inhibitors**: chemical (organic and inorganic) inhibitors are imported in the flow and protect the metallic surface from corrosion. They can create a protective surface layer which prevents the contact of the metallic surface with the corrosive agents or they can react with them and inactivate their corrosive effect [32].
- **Cathodic and Anodic protection**: by this technique is prevented any electrochemical reaction between the metallic surfaces and the possible corrosive agents by neutralizing the electric potential [32].
- **Usage of corrosion resistant materials**: oil and gas equipment is usually made of steel alloys with high corrosion resistance.
- **Internal and external surface resistant coating**: in order to avoid the corrosion, the metallic surfaces of the equipment, are covered with protective coatings, usually a primer rich in zinc [33]. Covering steel with zinc coatings is commonly referred as galvanization. Galvanized metals are "corroded" metals, where zinc has reacted with iron. The properties of the metallic equipment are altered but the steel has not reach the brittleness' thresholds. The zinc creates a layer on the steel, disabling corrosion from environmental parameters to intrude the equipment. In the same way other commonly used coatings are fiber glass, glass flake, epoxy, rubber, nickel and cadmium [32].
- **Modifying the environment's chemistry**
- **Modifying operational parameters (decrease temperature)**

4.3.2. Erosion

Erosion failure

Erosion is a common problem that is met when fluids, that contain solid particles, flow over metallic surfaces. Erosion damage is caused by the solid particles that are transported with the effluents flow or from the liquid droplets that are detected in the flow. Solids in flow may come from sand, proppants and deposits of hydrates, asphaltenes, waxes and scales, as mentioned in two phase flow between Liquid-Solids chapter.

It is referred to the abruption of particles from the surfaces that are in contact with fluid flow that contains solids. The erosive damage affects the protective oxide film of the metallic surfaces and the result is observed as the creation of grooves, pits and other types of deformation of the metallic surfaces [34].

The main erosion mechanisms are the following [35]:

- **Liquid droplets impingement**: In case of multiphase flow or wet gas flow, liquid droplets may appear in the flow in case of high gas velocities and volumetric flow rates. The extension of erosion in this case depends on the droplet size, impact velocity, impact frequency and liquid and gas density and viscosity [34]. The constant collision of the liquid droplets on the walls of the pipeline may cause material fatigue and abrasion [35].
- **Cavitation**: in case of liquid droplets that are accumulating on the walls of the pipeline and they break suddenly, metallic particles from the walls may abrupt.
- **Solid particles impingement**: in case of multiphase flows that contain solids, the flow regimes will exhibit the patterns and the characteristics of two or three phase flow as described in previous chapters. So the solid particles may be deposited on the bottom of the pipe or they may transport as dispersed flow in other fluids. When they collide with the pipeline walls they gradually cause material fatigue and abrasion [35].

Factors that affect erosion

- **The velocity of the solid particles**: the bigger the velocity of the solid particles, the rougher will become the surface and thus the more extended will be the erosion. Many scientific researches have correlated the relationship between the impact velocity and the erosion rate by the general equation [31]:

$$\boxed{E = E_o \cdot V^p}$$

Where:

E is the erosion rate, E_o is a constant, V is the impact velocity and p is the velocity exponent p. the values of E_o and p vary according to the different experimental approaches.

- **The shape and size of the solid particles**: the size of the solids particles affects the erosion rate up to a certain size (50 to 1000μm) while the particles with spherical shape contribute less to the erosion damage than the ones with angular shapes [31].
- **Angle of attack**: it has been observed that solid particles that collide on the metallic surface with non orthogonal angle of incidence have a great contribution to the deformation of the surface [31].
- **Flow rate**: when the volumetric flow rate increases, more liquid and solid particles will collide on the walls of the pipe, which results to increased erosion damage [35].

- **Restrictions in the flow**: the existence of restrictions along the pipeline indicates that downstream of them the flow will exhibit high velocities. In case of sand or liquid droplets in the flow, they will collide on the walls of the pipeline with greater velocity, thus increasing the erosion damage.
- **Sudden changes of flow direction**: when the pipeline network has sharp elevation changes, the sand particles and/or liquid droplets in the flow may collide at the points of elevation change on pipeline's walls, resulting in their abrasion.

Problems that are created due to erosion

Related studies and experiments have concluded that the eroded metals become more brittle [31]. When it is combined with extended corrosion the impacts are more severe and may become destructive for the pipeline. The corroded particles that have created a layer on the metallic surface are removed by the transported solid particles thus destroying the corrosion layer. This layer was acting as a surface protection, disabling the corrosion to intrude further below the surface [32].

Components of the pipeline network that are more vulnerable to erosion are the following [34]:

- Chokes
- Sudden constrictions
- Partially closed valves, check valves and valves that are not full bore
- Standard radius elbows
- Weld intrusions and pipe bore mismatches at flanges
- Reducers
- Long radius elbows, mitre elbows
- Blind tees
- Straight pipes

Prevention/Mediation techniques

- **Modeling the solids flow**: there are several correlations about the dependence of the erosion rate and the solids flow that can be used in combination with flow modeling [36]. This measure implies the control over the production flow rate. In the same direction the international standard API RP14E limits the maximum flow velocity according to the density of the fluid by the following equation [35]:

$$\boxed{V_e = \frac{C}{\sqrt{\rho}}}$$

Where:

V_e is the maximum allowable erosional velocity [ft/sec], ρ is the density of the fluid [lb/cft], C is a constant value that ranges between 100 to 125.

- **Use of improved pipe materials**: the pipelines are made of alloys with improved resistance on erosion. The alloys UNS N06625 and UNS S32750 are some of the materials used for subsea applications [36].
- **Sand removal**: downhole sand screens and gravel packs or sand separation devices are used to remove sand from the flow [34].

4.3.3. Cavitation

When the pressure falls below the bubble point of the mixture, gas bubbles start to appear in the flow. The gas bubbles are drifted away to areas with lower velocity and higher pressure, where they collapse and the gas condensates. The problem is caused when the bubbles are in contact with the pipe's walls, because when they collapse they cause locally high pressure, they may cause the abruption of some solid particles from the pipe's walls.

Cavitation may occur on pump impellers because of the low suction pressure regime. In the suction side of the pump low pressure appears due to [37]:

- High flow velocity in case that the volumetric flow rate is high or
- High elevation difference between the point of flow inlet in the pump (suction side) and the effluent level (reservoir), with the pump operating at a much higher elevation level or
- Pumping of highly volatile effluent or
- Pressure drop in the fittings

4.3.4. Water hammer/Hydraulic Shock

Hydraulic shock (or water hammer) is a common problem that is met in hydraulic installations of single or multiple phase flow pipelines. Usually flow under these conditions is called "surge flow".

It is referred to a sudden pressure drop or increment in the flow. Usually sudden pressure fluctuations are met when sudden closing of non return valves (valves that allow the flow through them only by one direction) and chokes occur upstream of the flow or when a pump starts or stops suddenly. Under these violent pressure fluctuations, the fluid stops moving abruptly sudden. The change of its kinetic energy creates a great pressure difference that is induced to the fluid as wave that propagates in the inverse direction of the flow. This phenomenon is met in flows that have at least one liquid phase, because the liquids are highly incompressible, so the surge pressure deviations are more intense [38].

Problems that are created due to hydraulic shock

- **Pipeline rupture**: The pressure waves produce vibrations which are transformed to sound waves. The vibrations affect the strength of the pipeline. Th forcesapplied on the walls of the pipelines are big enough to lead to the pipeline's burst [38].
- **Well completion damage, unset packers** due to the great pressure surge.
- **Leakage at pipeline's joints** due to the high forces that are imposed on the joints.
- **Damage to pumps downstream of the flow**

Operations and facilities during which hydraulic shock may occur

- **Downward inclination of the pipeline**: The damage and burst of the pipeline may be greater if it is inclined downwards. In this case the pressure difference that will be created will be higher due to the additional hydraulic pressure drop [38].
- **Well Shut in and Start up**: during these operations both bottomhole and wellhead pressure increase and reduce respectively. The pressure fluctuations may lead to hydraulic shock occurrence if they are not controlled [38].
- **Cavitation**: when a valve close or a pump stops, the pressure difference downstream creates an inverse flow backwards, towards the pump or valve. In case that the pressure downstream the valve or pump decreases more than the bubble point of the mixture, gas bubbles will appear in the flow. When the gas bubbles meet the surface of the closed valve/pump, they will break resulting to an extended and violent pressure surge [39].

Prevention/Reduction techniques

The noise that is created as an effect of the sharp pressure fluctuations in the flow, by unexpected opening of pressure relief valves and when the flow shows pulse periodicity, are indications of the hydraulic shock occurrence [39].
When one of these indications in the flow occur the following reduction techniques may be applied:

- **Reduction of flow velocity**: by using pipelines of larger diameter or by lower the volumetric flow rate, the sudden pressure drop that may occur won't be harmful for the pipeline.
- **Surge tanks**: they are used to absorb liquid in order to reduce the pressure surge.
- **Surge alleviators**
- **Pressure relief valves**
- **Air inlet valves**
- **Injection of nitrogen or air into the fluid**

5. Conventional midstream production boosting system

5.1. Conventional production system description

In conventional production systems, the effluents are guided to separators, where the multiphase flow is separated into two or more different phases. From the separators, one single phase pipeline is leaving. A gas pipeline is connecting the separator with the dry gas compressor and an oil pipeline is connecting the separator with the liquid (single phase) pump. Single phase flow lines are guiding each phase to the gathering stations.

In multiphase production systems the effluents are guided to a multiphase pump and then multiphase pipelines are responsible for their transportation to the gathering stations.

In Figures 21 are presented the different configurations between a subsea production system in which a multiphase pump is installed downstream of the wellhead and a conventional production system in which a satellite platform hosts the separation, single phase pumping and compression facilities.

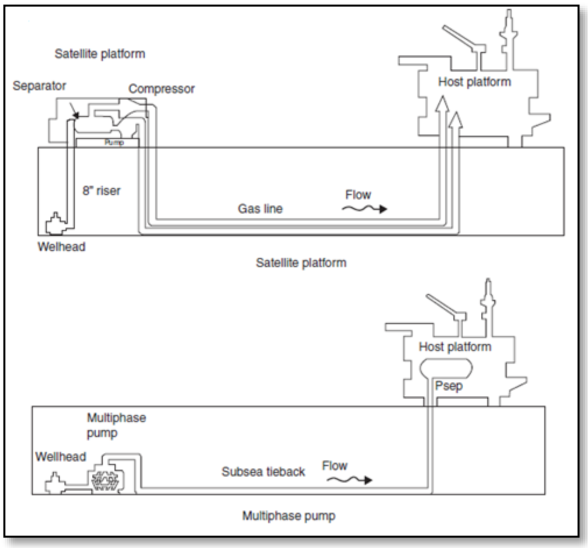


Figure 21: *Differences in offshore production system configuration with and without using MPPs* [8].

<u>*Seabed equipment*</u>

- <u>Umbilicals:</u> They are cables which consist of different type of wires grouped in a steel tube matrix. The wires are used to transfer power and heat from the surface to the seabed or control signals. They provide electric and fiber-optic signals, electrical power and hydraulic and chemical injection fluids to the subsea unit. They can also power subsea boosting and compression, as well as provide flow-line heating to prevent the formation of wax and hydrates that could slow oil production.

- <u>Tie-in Systems:</u> The pipelines that lie on the seabed cannot get connected manually by divers because the human factor increases the risk of the project and mostly is only possible for shallow depths. Tie-in-systems operate in favour of divers so that to connect the pipelines on the seabed remotely. All the subsea operations all implemented by ROVs (Remote Operated underwater Vehicles).
- Different patented schemes have been developed from companies with great experience in the subsea piping sector.

Different patented schemes have been developed from companies with great experience in the subsea piping sector.

  - **Horizontal Connection Systems (HCS)**: They are used for the connection of horizontal rigid jumpers and spools, flexible flow lines and umbilicals.
  - **Remote Tie-In System (RTS):**The system can be installed by a ROV which is operated from the surface
  - **Vertical Connection Systems (VCS):** They are used for tying in vertical rigid jumpers, spools and flexible flow lines, usually in deep waters without fishing activity that would require extra protection for subsea structures.
- <u>Power System</u>
- <u>Control System</u>
- <u>Electrical and hydraulic jumpers</u>
- <u>Chokes</u>

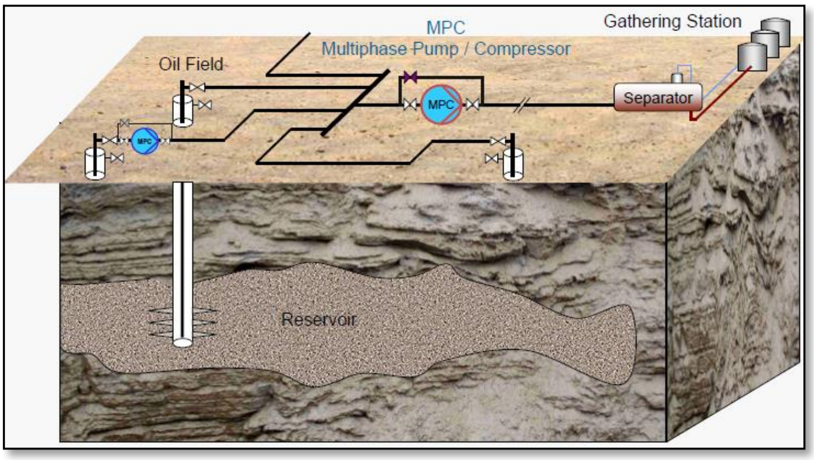


Figure 22: *Configuration of an onshore production system using multiphase boosting* [40].

5.2. Other midstream production boosting systems

5.2.1. Subsea dry gas compression

Subsea compression is necessary for gas fields that exist in extreme ambient conditions, like low arctic temperatures, because the ice formations in surface disable the development of floating production facilities [41].

Dry gas compressors can handle fluids with less than 0.5% liquid volumetric fraction, which means that they are referred to gases without water or liquid condensate when the gas is imposed to very low temperatures. Subsea compression is complex and needs high power drive (from 10 to 50MW) [41].

The first subsea dry gas compressor was installed in September 2015 in the Åsgard gas field. The project was a contribution of AkerSolutions which designed and installed the system and Statoil which operate the field.

For the design of the system, the selection of the suitable equipment and the establishment of the flow assurance must be taken into consideration the following parameters:

- Prevention of gas hydrates formation in the dead legs and the gas line,
- Elimination or absorption of the flow induced vibrations,
- Control of the fluid's temperature

The gas compression systems do not withstand alone on the seabed, but they are connected with the appropriate hydraulic equipment, which enables the control, regulation and measurement of the flow properties, in order to establish flow assurance and the desired flow result.

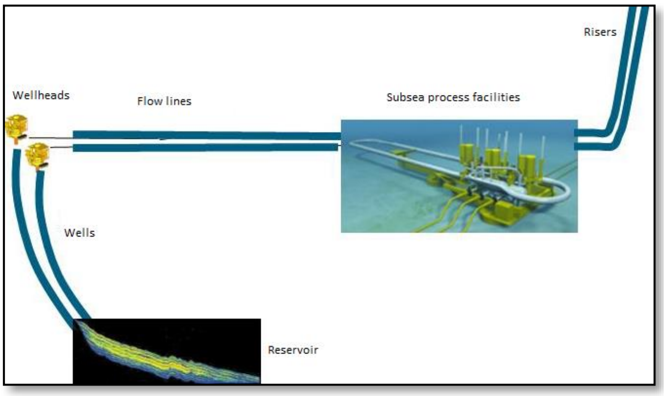


Figure 23: *Subsea production system.*

The major hydraulic components that are met in gas compression systems are:

- *Compressor:* The compressors that are used in the oil and gas industry do not differ from the ones that are used in other industries. Their main operation is the increase of the pressure of the gas phase.
- *Anti-surge, Control, By-pass valves*

➢ *Venturi pump*

➢ *Inlet cooler:* Inlet coolers are heat exchangers that reduce the temperature of the effluent inserting the scrubber. By this the efficiency of the compressor is increased, because it needs to spend less energy in order to increase the pressure of the gas phase. They don't have rotary parts, because they use the laws of natural heat convection between the cold sea water and the effluents. The cooler consists of tubes, open from both sides, through which pass the effluents. The system is open and in contact with the ambient environment of sea water (Figure 8).

➢ *Outlet/Discharge cooler:* They have similar operational with the inlet coolers. They are heat exchangers that reduce the temperature of the gas that is exerting the compressor. They don't have rotary parts, because they use the laws of natural heat convection between the cold gas and the even colder sea water.

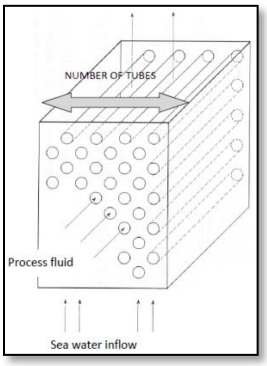


Figure 24: *Cooler configuration.*

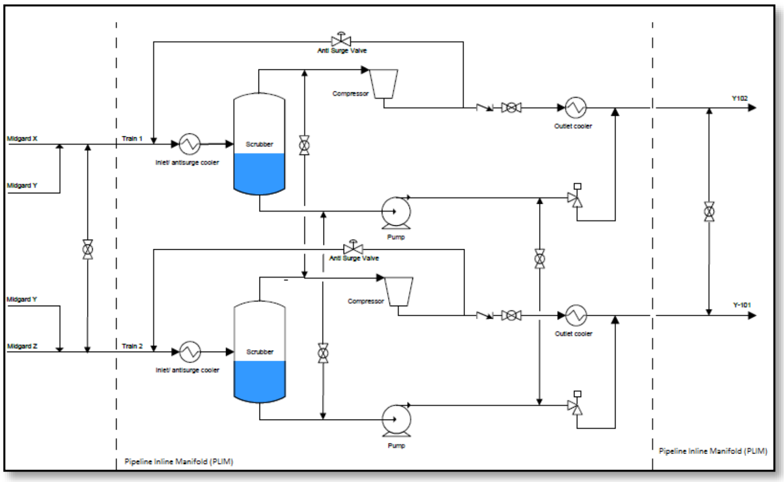


Figure 25: *Schematic of subsea gas compression station with two compressor trains.*

<u>Advantages</u>

- Reduce the operational costs (OPEX) because the need for an offshore platform or onshore compression facility is eliminated.
- The compressor is closer to the well and this contributes to a bigger recovery.
- The CO_2 emissions are reduced because less energy is consumed.

- No emissions or disposals to the sea.
- The operation doesn't need any human operation, which is safer.

5.2.2. Multiphase Flow Turbines

Their operation is the inverse of the pumps and compressors. They are obtaining energy from the fluid and they transform it in another form.

Their major applications in the oil and gas industry are the following [41]:

- Recovery of energy and boosting production of low pressure wells. In this case the turbines are used to drive multiphase pumps. Actually they are using a part of the flow from high pressure wells that need throttling in order to operate. By this way the energy that would be wasted is obtained from the flow and is used for the boosting of wells that couldn't be produced.
- Replacement of a choke or let-down valve in two-phase flow,
- Production of electricity in remote areas [42].

5.2.3. Multiphase Pumping Systems

From all the types of multiphase pumps, finally two types are used for offshore (subsea and topside) applications; the Twin Screw Pump (TSP) and Helico Axial Pump (HAP).

6. Surface Jet pumps/Ejectors/Eductors (SJP)

Operating Principle

Their purpose is the increase of the effluents production and the flow boosting downstream of the wellhead.

The operating principle of jet pumps is based on the fluid mechanics theory for nozzles and diffusers. So the pressure increment is a result of energy conservation and can be expressed by the Bernoulli equation.

The interior of jet pumps doesn't have any moving part. It consists of a High Pressure (HP) nozzle, which is connected to the diffuser with a mixing tube.

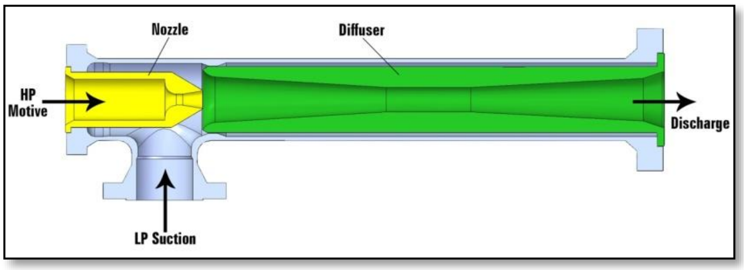


Figure 26: *Surface Jet Pump configuration.*

In Figure 27 are presented the fluctuations of flow pressure and velocity through the different components of a jet pump. A high-pressure power fluid is guided to a convergent nozzle. The flow is imposed to pass through a cross section of smaller diameter and thus its velocity will increase and its pressure will decrease. Just before the throttling section, a low or intermediate pressure fluid (LP and IP respectively) enters the pump. Its velocity also increases and its pressure decreases as it is approaching the nozzle's tip. As the two fluids pass the outlet of the nozzle, the cross-sectional area increases, so their pressure starts to increase. At the tip of the nozzle, the pressure of the HP fluid has decreased enough, so that to create an appropriate pressure drive and the LP fluid to be guided to the mixing chamber. After the nozzle exit the two fluids start to mix, so the HP fluid transfers energy in terms of momentum to the LP or IP flow, so the velocity of the HP flow decreases but the velocity of the LP or IP flow increases slightly above its initial velocity [43]. Their final mixing is achieved in the mixing tube. At the end of the mixing tube exists is a divergent diffuser where they expand, so the mixture's velocity decreases further and their pressure increases. Finally, the discharge pressure has an intermediate value between the high pressure of the power fluid and the lower pressure of the produced fluid.

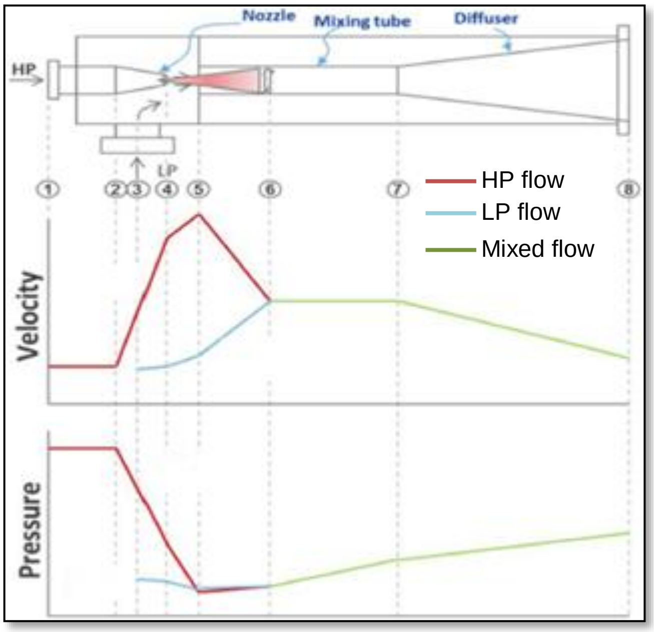


Figure 27: *Jet Pump flow dynamics* [43].

As power (high pressure) fluid (HP) may be used the flow from a high-pressure stream that has an extra energy potential that would be wasted or that its energy abstraction is more beneficial for the general energy content of the production operation. Some of the different types of HP fluids that may be used are the following:

- HP oil from associated wells
- HP water from injection water lines
- Produced water
- Pumped liquid
- Downhole ESP liquid
- HP gas from process systems
- Lift gas
- Compressor recycled gas

The phase of the power fluids that are used depend on the phase of the low pressure fluid that is produced and will be boosted.

- **Low Pressure Gas production:** In case of gas production, both HP and LP fluids should be gases [44]. Then there is no need for separation of the production stream (Low-pressure fluid).

If the LP flow contains a liquid with a volumetric flow rate greater than 1~2% of the gas volumetric flow rate at the operating pressure and temperature, there is a need for separation of the LP liquid upstream (before the entrance). In case of slightly wet gas, the liquid phase increases the incompressibility of the flow, so the discharge pressure that can be achieved will be lower [44].

On the other hand, the percentage of liquid in the HP flow is limited. In case of liquid content in the HP flow higher than a threshold, the energy losses are increased and the nozzle performance is affected. Also, the flow loses its homogeneity and this induces pressure fluctuations in the flow and further reduction of the pump's efficiency. Generally, the usage of liquid power fluid in order to boost low-pressure gas flow is less efficient and not suggested. Liquid flow is considered incompressible, so the liquid volumetric flow rate that is needed in order to boost gas flow is much higher than the gas volumetric flow rate that is boosted.

- **Low Pressure Multiphase (liquid and gas) production:** In case of multiphase LP flow, the HP fluid is liquid. The HP liquid is inserting the SJP, while the HP gas is bypassing the SJP and is connected with the outlet flow of the SJP. Using of HP liquid for boosting the LP flow is mandatory in order to achieve the desired pressure, as the use of HP gas would result in less pressure boosting because the liquid is denser than the gas, so the boosting would be insufficient.

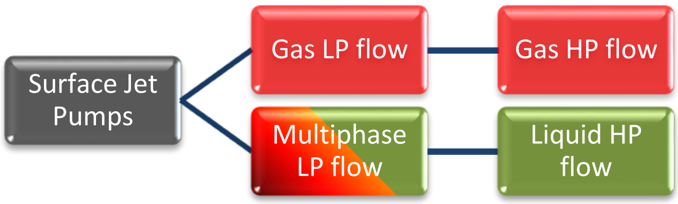


Figure 28: *Combination of types of phases for the LP and HP fluids that a SJP can handle.*

Operating characteristics

Its main design specifications are summarized in Table 4:

Jet Pumps	
Viscosity	Any viscosity
Solids tolerance	No
Gas Volume Fraction (GVF)	70~95%
Design total flow rates (at suction conditions) [bbl/day]	Small capacity <15,000bbl/day
Applications	Onshore
	Offshore
	Subsea

Table 4: *General specifications of commercial surface jet pumps.*

Location of the SJP along a project's facilities

The placement of the SJP depends on the location of the sources of the HP and LP fluids. At onshore installations is usually installed at the gathering stations, while at offshore installation sis usually placed close to the HP source. In details for cost minimizing reasons, it is usually placed at:

- Downstream and as close as possible to the wellhead, manifold and transportation line,
- Upstream of the compressor's suction line,
- Upstream and downstream of the inlet or outlet of a separator
- Near the recycle line of the compressor in order to debottleneck them, downstream of the compressor or between the compressor stages

Surface equipment

- **Silencers (for gas production):** Inlet Silencers (Low Pressure) are placed in the entrance of the jet pump. Outlet Silencers (High Pressure) are placed after the medium pressure flow part (after the mix of the power and the production flow). They are necessary because the gas velocity is so high that transmits noise in the environment.
- **Commingler (αναμίκτης)**
- **Separator:** A separator is needed when the HP is multiphase.
- **Pressure Relief (PRV):** In most cases the SJPs and silencers are designed to meet the highest operating pressure, plus an allowance for safety. Normally no pressure relief is needed. It is, however, possible to incorporate a Pressure Relief Valve (PRV) if the LP side piping system is of a lower pressure rating than the HP side piping, or to meet site specific requirements such as the site fire case.

Operational advantages

- When they are installed downstream of the wellhead they **decrease the wellhead flowing pressure** [44], so they boost the production. When the power fluid enters the nozzle, its pressure decreases due to the Venturi effect and obtains values lower than the wellhead pressure. By this way the flow of the production fluid to the pump is enabled and enhanced. So the actual pressure that exists downstream of the wellhead is lower than upstream of the wellhead.
- They have no moving parts and this means that they have **low maintenance** needs and cost.
- There are many different configurations for their implementation and installation in existing facilities.

- They **don’t consume extra energy for their operation**. The high pressure power fluid that is used would be otherwise wasted.

<u>Design</u>

For the design and the performance analysis of the jet pumps as **pump’s head H_p** is considered the dimensionless ratio of the pressure increase of the formation fluid over the pressure loss of the power fluid [45]:

$$\boxed{H_p = \frac{P_d - P_f}{P_p - P_d}}$$

Where:

P_d is the pressure at the discharge side of the pump,

P_f is the inlet pressure of the formation fluid (LP fluid),

P_p is the inlet pressure of the power fluid (HP fluid)

A **dimensionless area ratio** is used and indicates the ratio of the nozzle’s tip area (A_n) over the throat area of the mixing tube (A_m) [45]:

$$\boxed{R = \frac{A_n}{A_m}}$$

A **dimensionless density ratio** is used and indicates the ratio of the LP fluid density (ρ_{LP}) over the HP fluid density (ρ_{HP}):

$$\boxed{D = \frac{\rho_{LP}}{\rho_{HP}}}$$

A **dimensionless flow rate** is also used for the description of the pump’s performance [45]:

$$\boxed{M = \frac{Q_f}{Q_p}}$$

Where Q_f is the volumetric flow rate of the formation fluid (LP fluid) and Q_p is the volumetric flow rate of the power fluid (HP fluid).

The **pump’s efficiency** is:

$$\boxed{\eta_p = \frac{Q_f}{Q_p} \cdot \frac{P_d - P_f}{P_p - P_d} = M \cdot H_p}$$

<u>Performance</u>

The performance curve of a surface jet pump is similar to that of a centrifugal pump, but the curves of H_p – Q depend on the area ratio instead of the rotational speed.

The considerations for the performance curve of a jet pump are presented graphically in Figure 29. Each parabolic curved line is the locus of the possible operating conditions of head and volumetric flow rates and the different efficiencies that the pump may have when the pump is designed for a specific area ratio, thus diameter of nozzle and mixing tube. So the pump's performance under different operating conditions may be resulted.

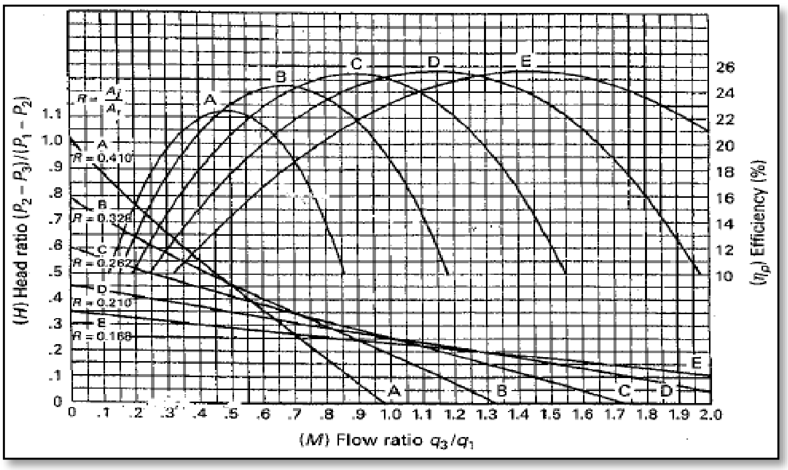


Figure 29: *Example of jet pumps characteristics H_p – Q –η_o for different area ratios* [45].

Factors that affect the performance of the surface jet pumps:

- **HP and LP pressure ratio:** *High pressure ratio results in high efficiency*

The higher is this ratio, the higher is the pressure of the power fluid than the pressure of the formation fluid, as it is presented in Figure 30. So more energy will be provided to the formation fluid for a specific flow rate ratio and this will cause the increase over the discharge pressure.

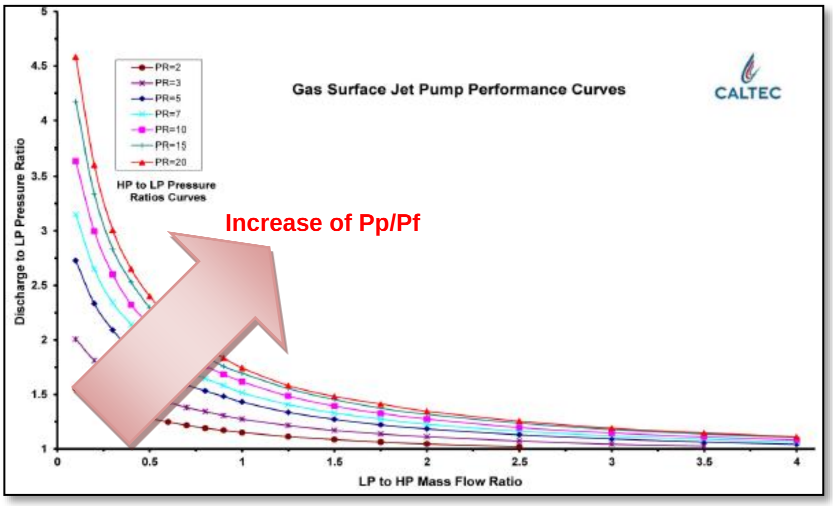


Figure 30: *Performance curve of a jet pump H_p-M for gas LP and HP flows for different ratios of HP flow pressure over LP flow* [46].

- **HP and LP flow ratio:** *The adaptivity of the pump at changes in flow ratio can be achieved by the diameters of the nozzle and the mixing tube.*

In case of reduction of the flow ratio the nozzle or mixing tube has to be changed in order to keep the pressure ratio constant and to avoid any change at the pump's efficiency. Less flow ratio means that the pump has to provide less energy to the flow, either due to reduction of the formation flow rate or increase of the power flow rate. The adaptivity of the pump can be achieved by increasing the area, thus by increasing the nozzle's tip diameter or decreasing the mixing tube's diameter.

In real applications the change of the area diameter is a way to adapt the pump's operation when the production flow rate decreases in time since the initial operating flow rates due to depletion. On the other hand an increase of the production flow rate may occur when the surface jet pump gets connected with a manifold, where production flow from more wells are arriving, while it initial was operating in order to handle less flow rate coming from less wells.

- **Area ratio:** *High values of the area ratio lead to the decrease of the head ratio and the efficiency for constant flow ratio for handling constant mass flow ratio*

Low values of the area ratio indicate that the nozzle tip and the mixing tube diameters are of similar magnitude. On the other hand high values of the area ratio indicate that the difference between these two diameters is large. This means that the nozzle tip diameter is much bigger and that the mixing tube diameter is much smaller. Consequently for operation under constant flow rates, high values of the area ratio indicate higher fluid velocity and lower pressure at the mixing tube inlet. This means that less energy will be provided to the mixture, so the head ratio and the pump's efficiency will both decrease.

In real applications the increase of the head ratio and thus the necessary energy that has to be provided to the flow may occur for example because of increment of the MW of the fluids. In general the nozzles may be replaced during production with nozzles of smaller tip diameter, in order to gain head.

- **MW of the HP and LP:** *High density ratios indicates low efficiency pump*

The molecular weight of a hydrocarbon mixture indicates its specific gravity and is directly connected with its compressibility. So fluids with high molecular weight have high density and small compressibility.

When the LP fluid has high molecular weight and density, it won't be easily compressed. This means that the energy transformation inside the pump will not be very efficient and more energy would be needed in order to achieve a specific discharge pressure. For this reason the pumps that are handling flows (LP fluids) with high molecular weight will have less efficiency than the ones that handle flows with low molecular weight.

On the other hand HP fluids with high density are preferred, because they are less compressible so they will provide the estimated energy to the LP fluid.

So in general the MW of the fluids that are getting into the pump are represented by the density ratio and according to the previous high density ratios increase the pump's efficiency.

Operational restrictions and limitations - Design and flow assurance issues

- **Hydrate Formation:** Hydrates do not normally form within the SJP because of high velocity of flow and the combination of HP and LP flow. If the predicted outlet temperature is within the hydrate formation band, then injection of hydrate inhibitor and / or use of heat tracing are recommended. It is usually recommended not to run the HP flow alone (for over a few minutes) without flowing the LP gas in advance.
- **Noise:** when the SJPs are handling low pressure gas production streams, the produced noise level may often exceed 85dBA [43]. Silencers can be installed on the LP inlet and the discharge line of the SJP to prevent noise travelling through the interconnecting pipe work. In cases where noise emitted directly through the body of the SJP exceeds the acceptable limit, the entire SJP can be lagged with acoustic insulation materials [44]. The normal acceptable limit is generally 85dBA at 1.0m from the SJP. There are, however, exceptional cases where lower noise level is required.
- **Vibration:** If vibration from the SJP is predicted to be a problem, then the SJP and Silencer supports can be fitted with custom designed anti-vibration mounts.
- **Temperature Drop Effect:** This is an issue dependent on factors such as HP and LP pressure, temperature and flow rate and the presence of liquids in the LP flow. In general, the theoretical Joule Thomson temperature drop across the SJP does not fully materialize, mainly as a result of the LP flow mixing rapidly with HP gas and the pressure increasing along the mixing tube and diffuser. Low temperature may be experienced if only HP gas passes through the SJP with no LP gas.

In general, the outlet temperature is often lower than the LP or HP temperature by approximately 20% to 30%, whichever has the lower value.

- **Cavitation:** At the tip of the nozzle the pressure is the lowest that can be met in the pump. If its value decreases more than the bubble point pressure of the flow, gas bubbles will start to appear and cavitation phenomena may occur.
- **Erosion:** Not a major issue unless sand is produced. In this case, the internals can be coated with materials resistant to erosion or lined with ceramic materials.

- **Liquid content in the LP flow in case of gas production:** The low pressure gas flow that is boosted from the pump may contain up to 2% liquid [44]. Otherwise the discharge pressure may become very low and the efficiency of the pump will be reduced.

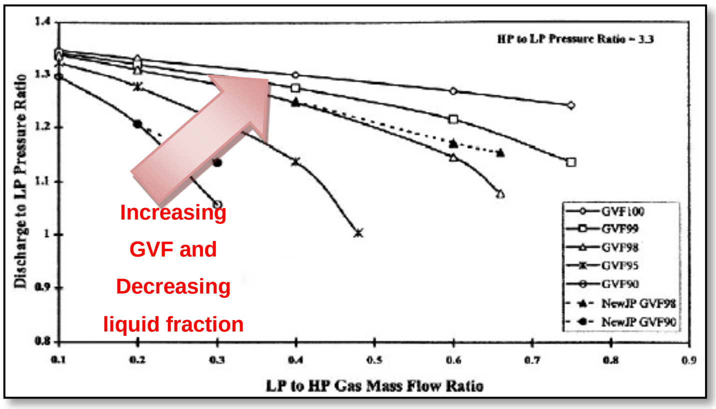


Figure 31: *Effect of liquid presence in LP gas production* [47].

- **Liquid content in the HP flow in case of gas production:** when the produced low pressure fluid is single phase gas, the liquid content of the power fluid is limited. The existence of liquid on the high pressure flow enables friction pressure losses in the inlet pipe upstream of the nozzle, so the inlet pressure in the nozzle will be less and thus the kinetic velocity at the outlet of the nozzle. So the nozzle becomes less efficient and this decreases the overall pump's efficiency [44].
- **They don't have flexible operation.** If the HP flow pressure or flow rate change, the nozzle has to be changed. In case of both HP and LP volumetric flow rates changes beyond 20%, the mixing tube has to be changed [48].

Case studies

The SJPs may be used for the following applications [46]:

- Boosting the pressure and the production of a low pressure flow by reducing the well back pressure.
- Prevention of flaring of very low pressure gas
- Replacing intermediate compressors
- De-bottlenecking compressors
- Revival of liquid-loaded wells
- Lower separator pressure to increase oil/gas production
- Prevent HP wells imposing back pressure on LP wells
- Assisting artificially lifted wells

Example Case study - Multiphase Boosting System: Depleted wells with very high back pressure facing liquid loading problems. No compressor or pump is available to boost production.

In this case HP wells from one field were used to increase production of LP wells of another field. The multiphase flow from the LP wells is guided to the pump, where it meets with the liquid phase of the HP wells.

It is more efficient if the HP power fluid is liquid, so in case that the HP flow is multiphase it is suggested to be separated. In this case the high pressure liquid will be used as power fluid and the high pressure gas will be mixed with the flow at the discharge side.

Objective: Reduce the back pressure (wellhead pressure) of LP wells.

Vendors

Caltec, Transvac, Tech-Flo, Weatherford

7. Multiphase pumping systems

The production of the subsurface hydrocarbons and the reservoir effluents which may contain solids is achieved due to the reservoir drive mechanisms. Every reservoir may have three drive mechanisms:

1. Segregation drive mechanism: Pressure difference between the reservoir and the well bottomhole and between the well bottomhole and the wellhead,
2. Gas drive mechanism,
3. Water drive mechanism.

When the reservoir is not able to produce the flow rate of the plateau hydrocarbons either due to low reservoir pressure due to depletion or due to high pressure drops within the production path, enhanced recovery production methods are implemented.
According to recent researches almost 67% of the oil and gas production worldwide comes from mature fields. Field maturity is defined by several ways: when production has reached 50&% or f the plateau rate or when the field's age is greater than 10 years old, etc [46].
The multiphase flow boosting is applied downstream of the wellhead and the main target is to increase the recovery factor of the reservoir.

Natural flow drive mechanisms	•Pressure •Gas cap •Water drive-Aquifer
Primary enhancement	•Water injection •Electrical Submersible Pumps (ESP)
Secondary enhancement	•Gas injection •Steam injection •Multiphase surface/seabed boosting systems •Single phase surface/seabed boosting systems

Table 5: *Different types of field development techniques.*

The installation of surface pumps is considered as a common measure method for boosting the production. The surface pumps are separated according to the type of flow they can handle, at the following categories:

- Single phase pumps, which are used for handling of flows with up to 10% gas content.
- Hybrid pumps, which are used for handling of flows with up to 40% gas content.

• Multiphase pumps, which are used for handling of flows with up to 100% gas content.

The multiphase pump technology is considered to be a "Young Technology" [49].

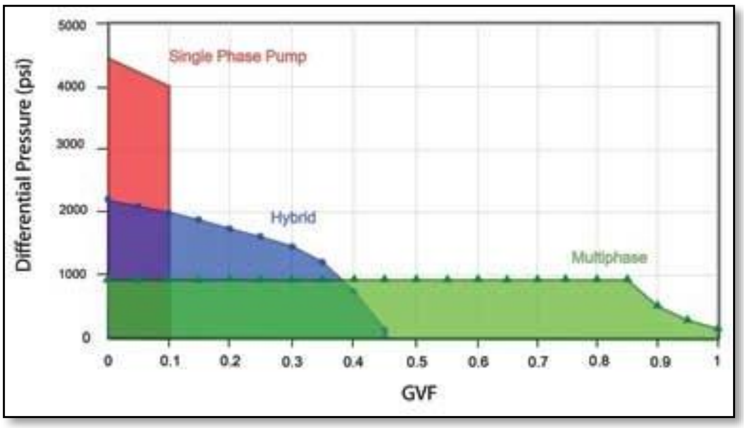


Figure 32: *Pump's performance chart* [50]

7.1.1. Selection criteria for the enhanced recovery method

When the decision of production lift is met, all the primary and secondary enhancements methods are probable to be implemented. The different artificial lift methods provide solutions for different production obstacles and have the same result: increase of the recovery factor. The sources of the production problems should be first defined because they offer the guidance needed to select the most suitable method. The production midstream and downstream facilities are also taken into account but as constraints for the boosting system deployment.

Before selecting the appropriate method for each occasion the following data should be analyzed:

• **The reservoir conditions**

The well bottomhole pressure and the reservoir pressure should be estimated in order to evaluate the pressure drop in the reservoir

• **The production system**

The design of the pipelines network, the mechanical and hydraulic equipment that is used at the midstream facilities till their transport to the process facilities and the arrangement of the separation facilities affect the decision for the most suitable boosting technique and more specifically the cost and the practical feasibility of their application. Production enhancement methods that are commonly used as first boosting techniques are [7]: Well/Riser gas lift, Water Flooding, Electrical Submersible Pumps (ESPs), Subsea Separation with single phase pressure boosting, Surface Multiphase Pumps with multiphase pressure boosting.

- **The surface/seabed facilities**

The selection procedure of the optimum technical and financially enhanced recovery method is based on a combined analysis of the above information.

7.1.2. Multiphase pumping industrial status

The application of multiphase pumps in different field occasions provides with many advantages, but the installation of multiphase pumps is not widely selected as a boosting technique. Some thoughts about this fact are the following [51]:

- The multiphase pumping technology started to develop at the 1980s.
- The first subsea separation facility in shallow water (22m) was installed in 1969 in the Zakum field in Abu Dhabi, which was operated by BP and Total.
- The first subsea helico-axial multiphase pump was installed in 1993, at (280m)920ft depth on the Draugen field that was operated by Shell [52]

Consequently, it is obvious that multiphase boosting technology has been developed the last 20 years and it remains a new technology, so there is little operating experience on multiphase pumps. They are low reliability systems because their operation has not been tested for appropriate time.

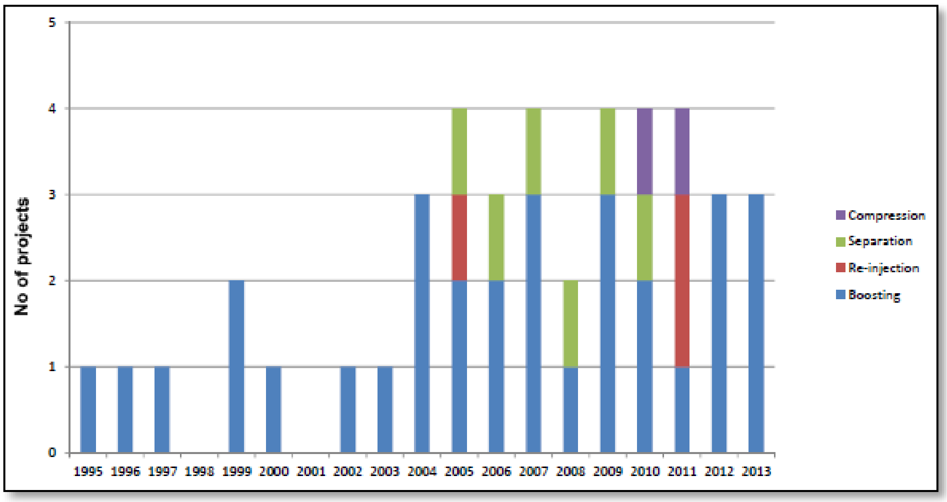


Figure 33: *Boosting systems per type implemented projects from 1995 until 2013* [53].

- There are many uncertainties on the flow regimes of multiphase flow as well as on the performance of some multiphase pumps under special flow conditions that has to be investigated. But because of the low oil prices, the funding for further research is not an option.
- The personnel in the oil and gas industry are not very specialized on the multiphase pumps technology and this prevents the companies to invest on this technology.

7.1.3. Types of multiphase pumps

Multiphase pumps can be categorized according to their hydraulic operation principle to the following categories:

- Centrifugal/Rotodynamics/Dynamic pumps/Turbomachines
    - Helico-axial pumps
    - Multi stage centrifugal pumps
- Positive displacement/Volumetric pumps:
    - Progressive cavity pumps (Single screw) (PCP)
    - Twin Screw Pumps (TSP)
    - Triple and Multiple Screw Pumps
    - Reciprocating
- Dynamic pumps
    - Hydraulic/Jet pumps/Ejectors/ Eductors/Velocity spools

From all the different types of multiphase pumps in the Oil & Gas industry are most commonly used three of them; helico-axial, single and twin screw pumps. These three types of pumps represent the largest number of Multiphase Pumping applications [41].

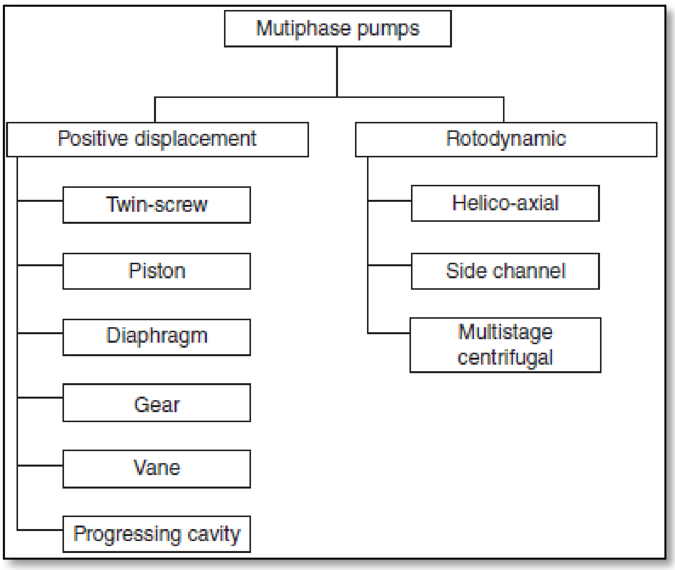


Figure 34: *Categories of multiphase pumps* [8].

7.1.4. Application of multiphase boosting systems

Purpose

Multiphase flow pumping systems are usually used to enable the flow of the fluid from the production site (wellheads and manifolds) to the gathering stations where separation and process facilities take place. These are the only flow paths in-between the midstream and downstream facilities that the transported flow in the pipelines is multiphase (liquid and gas). After reaching the separation facilities, the flow is separated into liquid and gas and then each different stream is guided through a different pipeline system to the appropriate processing facilities. Usually, they are installed as close to the wellhead or the manifolds as possible, in order to gain in pressure [52].

Multiphase Pumps are used as an artificial lift method and in many applications, they are used in combination with other recovery methods (ESPs, gas lift, etc.). Generally, the target of the deployment of multiphase pumping systems is the overlapping of the pressure drop that may occur along many components of the midstream production facilities, so that to boost the pressure downstream of the wellhead.

Application in different field's lifetime

They can be deployed in different time steps during the field's life, depending on the pressure boosting requirements. The typical phases of field life at which multiphase boosting can be applied are the following [54]:

- **Natural flow-Marginal fields/remote wells where unmanned facilities are preferred**

The P_{fwh} (wellhead flowing pressure) is larger than the required at the inlet of the flowline and flow can occur due to the pressure difference. If the wellhead or manifold are placed in a hostile environment where human intervention is not easy and the flowlines have to transport the effluents to a large distance in order to reach separation and process facilities, multiphase pumps are installed close to the wellheads even if there is no need for pressure boosting, in order to enable the transport of effluents through a long distance.

- **Wells with increasing water cuts**

As the field's production continues with the years, the P_{fwh} (wellhead flowing pressure) is decreasing while the water cut increases. This result is lower oil production with a possibility of abandonment of the well. In this case, must be added energy to the effluent by one of the known artificial lift methods or by the deployment of multiphase pumping systems.

- **Mature wells with low wellhead or bottomhole flowing pressure**

This case is referred to the oil fields that are difficult to establish flow even from the beginning of production. The utility of multiphase pumps offers the advantage of decreasing the well back pressure and eliminating the flow obstacles. Usually, for this type of applications, they are used in combination with gas lift of submersible pumps.

<u>Application for different types of flow</u>

The multiphase pumps can be used for single phase flow, but the inverse cannot happen. The cost of multiphase pumps is almost negligible for the project's cost control, so they are used only in case that boosting of multiphase flow is needed.

<u>Application in different types of production fields</u>

- They can be applied for **onshore and offshore fields**. Offshore they can be installed at the seabed or on surface platforms or FPSO (Floating Production, Storage and Offloading) vessels. Onshore they can be installed close to the wellhead. In case of subsea wellheads or manifolds the backpressure is further increased by the hydrostatic pressure of the sea water, so the application of multiphase boosting is usually mandatory [52].
- They are applied for reservoirs with production of approximately **250,000 oil bbl/day** and with a **GOR ranging between 100 and 1,000 scf/bbl** [54].

In fields of **medium or long tie-back distances**. When the effluents have to be carried for long distances to the process facilities, the application of multiphase pumps compensates with the friction and static pressure losses [52].

7.1.5. Benefits of multiphase pumping

Production systems using conventional separation facilities before pumping have generally more than 30% less capital cost than multiphase pumping systems. Although the high cost, multiphase pumps have more technical advantages that lead to increased production and financial profits. Some of the advantages of their usage are the following:

1. Reduce the need for subsea separation and process to achieve similar recovery. In offshore production systems conventionally the separation facilities are implemented in satellite platforms and then the gases and liquids are guided towards the host platform through separate flow lines. By using multiphase pumps, the need for satellite platforms is eliminated. The effluent is pumped after the exit of the wellhead and transported directly to the host platform through a single flow line.

- **Boost the production from mature wells with low wellhead flowing pressure.**

The reservoirs lose their productivity ability as they keep producing with the years, because the bottom hole reservoir pressure is decreasing due to depletion. As a result the flowing wellhead pressure is reduced, reaching a point that it is not able to create the appropriate pressure difference in the pipeline to create flow. These guide either to the abandonment of the LP well or to choke back the HP well. Using a MPP will increase the flowing pressure after the wellhead, enabling the flow.

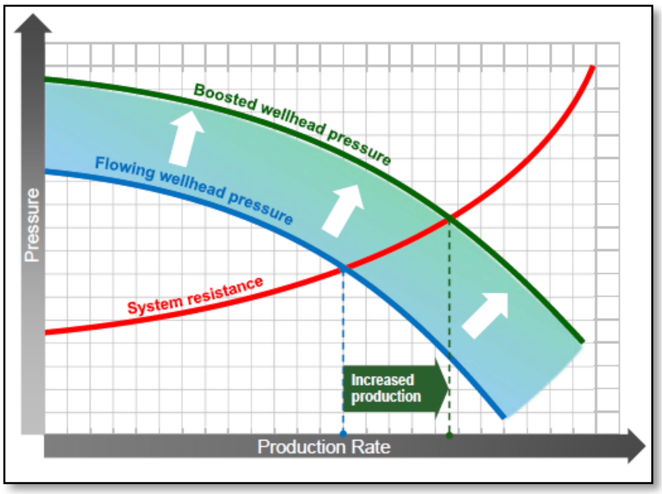


Figure 35: *Effect of production boosting on well's performance.* [53]

2. Reduce the field life but increases the field recovery. Both result in economic benefits coming from the reduced operational cost due to minimization of consumables, maintenance needs and expenses for the personnel.

3. Reduce liquid slugging in the risers. This results in economic benefits coming from the reduced operational costs due to the elimination of the need for slug catchers.

4. The multiphase pumping systems can be integrated with the onshore and offshore (subsea) production systems, which means **reduced operational complexity.** On the other hand the installation of multiphase pumps in already working fields is easy. Their installation doesn't require any modification in the existed installations as tie-in systems are used for their installation.

5. Reduction of environmental impact due to the reduction of gas flaring. The multiphase pump eliminates the need for separation of the produced fluids. As a result less or negligible amount of associated gas is produced. In most cases the associated gas is flared because it is not used. So the MPP deployment is an ideal if the minimization of flared gas is need for environmental and financial reasons.

6. Increase of production rate by **lowering the well's backpressure**. Well's backpressure is the pressure imposed in the flow from the components and fittings of the wellhead. It indicates the resistance that the effluent will meet when it reaches the wellhead. By applying multiphase boosting downstream of the wellhead, the backpressure that the effluent will have to overcome in the wellhead is lower, because it is compensated by the additional boost.

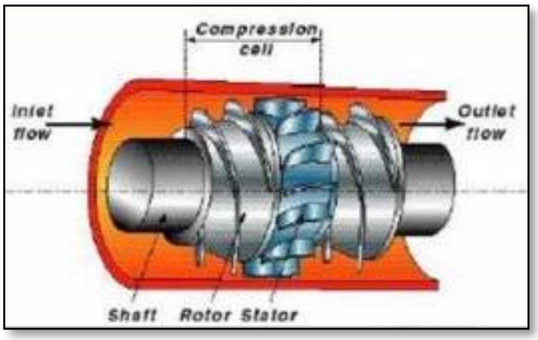
7. Production of gas that would be flared in conventional production facilities.

7.2. Helico-axial pumps (Rotodynamic Centrifugal type)

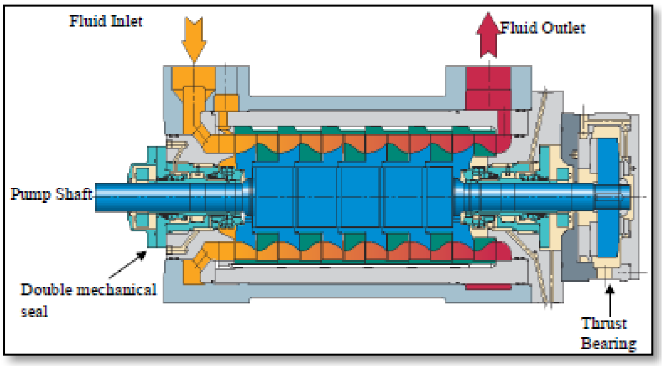
They belong to the greater category of rotodynamic pumps, together with the Multistage Centrifugal Pumps which are used as downhole electric submersible pumps. The name "helico-axial" derives from the combination of the helical shape of the blades and the global axial flow direction, ***i.e.*** parallel to the shaft [41].

Operating Principle

Its configuration combines construction elements from centrifugal pumps and axial compressors [42]. The operating principle is that the kinetic energy of the accelerated fluid that enters the pump is converted into dynamic energy (through pressure change) by decelerating when it passes through the different stages of impellers-diffusers. The liquid-gas mixture enters the pump in the axial direction and passes through an impeller, where its direction changes to radial and is subjected to centrifugal forces. The centrifugal forces that are applied to the fluid cause the development of angular momentum. Then the fluid is guided through a stationary diffuser, where its angular momentum is converted into pressure change (the velocity of the fluid is decreasing). When the flow passes through the diffusers it becomes more homogeneous and the separation is prevented.



(a) Side view



(b) Cross section

Figure 36: *Helico-axial pump configuration* [55].

Mechanical design

The mechanical design is based on the international standard API 610 and the rotordynamic design is based on the international standard API 917 which is referred to compressors [54].

Their design varies depending on the number of stages between one or multiple stages. Each stage (or compression cell) consist of an impeller (rotor) and a diffuser (stator) as they are presented in Figure 36. The number of stages depends on the required differential pressure (head) that is required to be developed between the suction and the discharge sides [41].

Operating characteristics

Its main design specifications are summarized in Table 6:

Helicoaxial Pump	
Viscosity	Low
Type of fluids	Fluids with sands, abrasives
Solids tolerance	Low
Gas Volume Fraction	50~100%
Suction Pressure	Any (70~600psia)
Diferential Pressure [psi]	≤3,000 psi
Design total flow rates (at suction conditions) [bbl/day]	Large capacity 15,000~560,000bbl/day of gas, oil and water
Applications	Onshore
	Offshore
	Subsea
Speed [rpm]	3,500~6,800rpm
Priming	Not self-priming

Table 6: *General specifications of commercial multiphase helico-axial pumps.*

Operational advantages

- They can get connected directly with electric motors, without intervention of any kind of switch gear box. This indicates **less energy losses** and greater efficiency.
- They can be driven either by an **electric motor or by a gas turbine**.
- They don't need a lot of space for their **installation**.
- **Simple construction with low maintenance cost**.
- While the flow progress to the different stages, it mixes better and thus this interstage mixing prevents the separation of the oil-gas mixture and retains the **homogeneity of the flow**. In centrifugal pumps the phase may separates under specific conditions which are connected with the high gas velocity and a dynamic stress combination that are imposed to the fluid. In the helico-axial pumps the shape of the helical impeller vanes reduces the effect of the centrifugal and coriolis forces and diminishes the phase distribution [56].
- It offers the advantage of **easier control of the well head pressure**. The helicoaxial multiphase pump can operate in variable speed, so it can be adjusted in variable pressure differences that arise due to changes of the wellhead pressure.
- The construction of the helicoaxial pumps offers the advantages of **hydraulic flexibility** that the turbomachinery has: the number of stages for the impeller-diffuser can change during the time of their operation according to the demanded pressure boosting at each stage of the field's life. This can be implemented by using a cartridge with inactive, dummy stages that are being activated when it is necessary [54].

- They can be designed for operation in **unmanned and hostile environments or unattended fields**, because they get easily adapted to different operating conditions. This is achieved by being driven by a variable speed motor.
- They can handle **liquid slugs and gas pockets.** They are able to handle high GVFs even when the flow consists only by gas phase, (100% GVF).
- They are **self-adapted to flow changes**. By changing their rotational speed they change the energy that is provided to the fluid. This gives them the advantage to handle pressure and density variations in the flow.

Surface Equipment

- Motorised suction and discharge **valves** and non-return valve
- Speed increasing **gearbox**
- **Seal** system
- Lube **oil system** for pump, motor and gearbox
- **Electric installation** (switchboards, transformers, etc)
- Common **air blast cooler** for seal and lube oil system
- **Variable speed motor.** Due to the high differences between the flow regimes that may appear when the multiphase flow passes through a pump, the selection of a variable speed motor is preferable. It gives the advantage of speed adjustment so that the pump to be able to maintain the volumetric flow rate that is handling. For example if the GVF increases or the liquid volume fraction decreases, the rotational speed will also increase in order to achieve the required pressure difference [56].
- **Buffer tank.** It is needed to be placed upstream of the pump, so that to prevent liquid slug and gas pockets that may harm the pump. The buffer tank is installed at the suction side of the pump. The flow is entering the tank before entering the pump. Its actual operation is the smoothening of the pressure fluctuations in the flow [56].

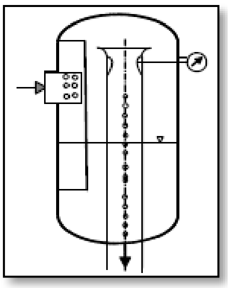


Figure 37: *Buffer tank* [56].

Vendors

The helico-axial design is based on a patent proposed from Sulzer and Framo which worked on the “Poseidon” project in behalf of Statoil, IFP and Total. So Sulzer and

Framo are the companies that construct and produce the helico-axial multiphase pumps.

Case study

(2001) Priobskoye oilfield in Siberia - SC Nefteyugansk, part of Yukos [54]

Field description: The Priobskoye field is in western Siberia, it was discovered in 1982 and has an area of 5,446km^2. An area of 3,000 km^2 at its northern part is operated from the company JSC Yuganskneftegas. This area is of high environmental interest and before the implementation of any engineering operation must be given priority to the environmental impacts.

The oil reserves are estimated at 4.5 MMMbbl (4.5 billion bbl).

The surface facilities are located on the left bank of the river Ob. The oil production is enhanced by the use of submersible pumps. The oil transportation from the production site to the treatment facilities is implemented with a pipeline of 426mm diameter and 33km long. The maximum capacity of the pipeline is 36,000bbl of oil/day.

The area is not easily approachable during spring and summer due to the flood from the river. Meanwhile the ambient temperature fluctuations during the year are significant: during winter the medium ambient temperature is -55^{o}C and in summer it rises to +35^{o}C. This means that the flow assurance has to compensate with 90^{o}C temperature difference during the year.

Solution: 4 helicoaxial multiphase pumps with power > 6MW (8,000HP) were used in this project.

The engineers came across with the solution of installing separation facilities close to the production site as well as with the solution of installing additional pipelines across the river but were neglected due to the above mentioned advantages of the helicoaxial pumps.

Pump characteristics:

Two pumps will start operate initially, following the constraint of the transferring capacity of the pipeline. Later a new pipeline will be installed and the other two pumps will contribute to production too.

Total Volumetric Inlet Capacity	GOR	Discharge Pressure		Speed	Driver Rating
bbl/d	scft/bbl	psi	bar	rpm	kW
500,000	392	800	55	5,800	6,000

Table 7: O*perating characteristics of the installed multiphase helico-axial pumps in Priobskoye field.*

Result: After the operation of the first two pumps, the oil production increased to 93,000bbl/day (158% increase of daily oil production). When the four pumps were installed, the oil production reached 200,000bbl/day, corresponding to a total increase of production by 456%).

Figure 38: *Installation of 4 helicoaxial MPPs of Sulzer Company, in Priobskoye oilfield in Siberia* [57].

7.3. Positive Displacement Pumps (PDP type)

These types of multiphase pumps are the most commonly used in the Oil &Gas industry. They appear in many different configurations but the operation principles remain the same. The fluid is displaced from the suction side where it exists under low pressure, to the discharge side where its pressure is increased. The volume of the displaced fluid depends on the geometrical configuration of the interior of the pump and it can be assumed constant over each circle of suction and discharge.

Positive Displacement Pumps contribute to the production boosting not by increasing the flow pressure as the rotordynamic pumps do, but by enhancing the displacement of fluid and thus by increasing the total production volume.

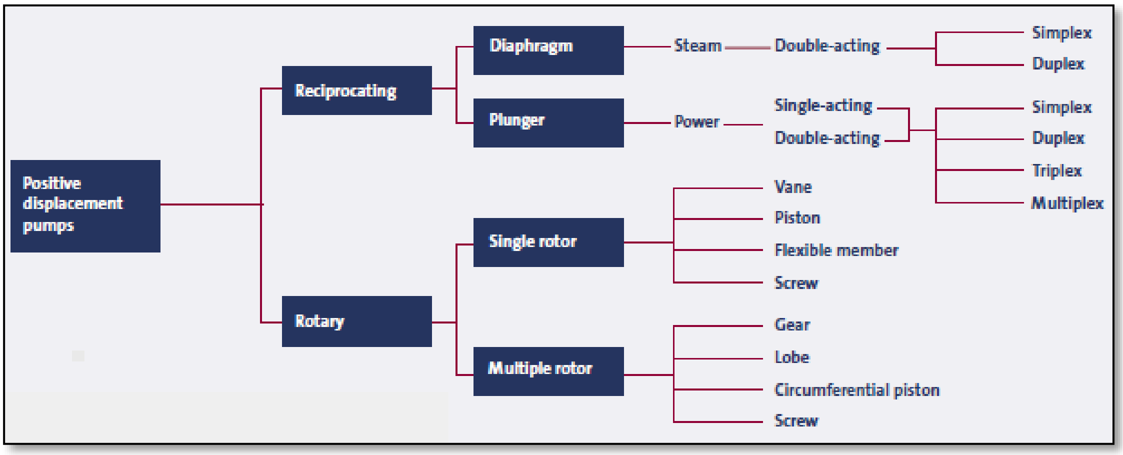


Figure 39: *Classification of positive displacement pumps* [58].

7.3.1. Twin Screw Pumps (TSP)

<u>Operating Principle</u>

The twin screw pumps are based on the positive displacement principle. The screws intermesh while mounted on two parallel shafts and they counter-rotate, resulting in the creation of C-shaped sealed chambers between them. One of the screws is mounted on a rotating shaft, which is powered electrically or mechanically by a gas engine. The drive force is transferred to the other screw by timing gears [59].

The structure is enclosed inside a casing with tight clearances. The screws are controlled by time gear mechanisms so that not to make contact.

The Low Pressure (LP) fluid enters the pump from the suction side and it gets trapped in the clearances that are created between the stationary and the moving elements. Then it is guided to the chamber with the moving elements (screws), where it is displaced as a result of the rotary movement of the rotating elements.

As the screws rotate they apply centrifugal forces to the fluid, which cause the separation of the gas phase from the multiphase mixture. Due to centrifugal forces the heavier liquid will concentrate at the perimeter of the screws' tips and the lighter gas will stay in the clearances between the screws' hubs. By this way the liquid is creating a sealing on the gas flow. As the flow moves in further channels towards the discharge side of the pump, its pressure increases. Some of the liquid flow will travel; reversely from the discharge to the suction side, as a result of the differential pressure drive [60]. This backflow is responsible for the compression of the gas that is trapped in the clearances. In Figure 40 are presented the directions of the flow on the suction and the discharge side as previously described.

The pressure traverse between the channels of the pump is illustrated in Figure 40 (blue is referred to the gas phase and green to the liquid phase and the arrows indicate the liquid backflow).

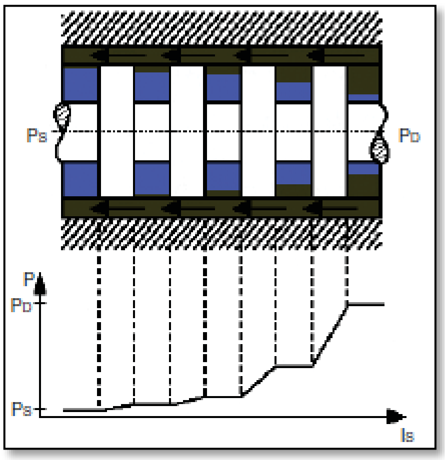
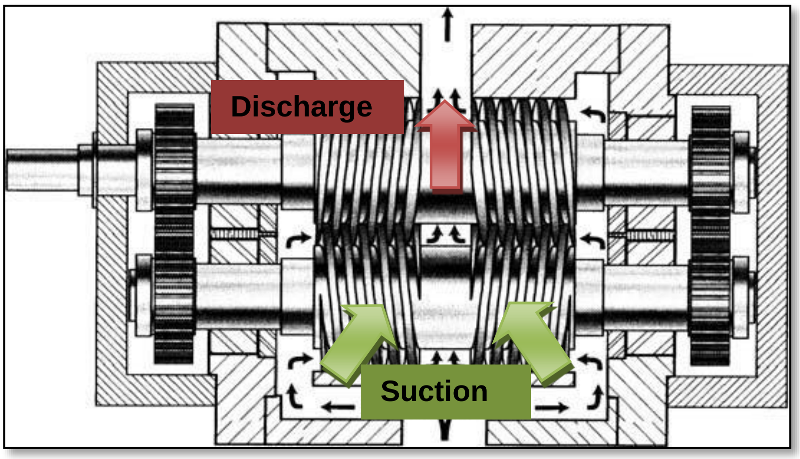
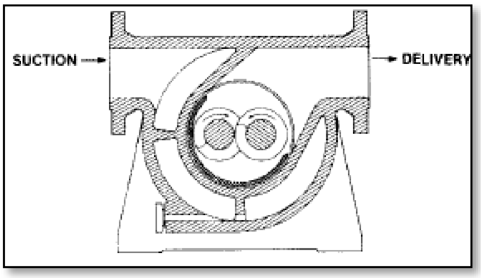


Figure 40: *Pressure traverse between the screw chambers, from the suction up to the discharge side* [60]

The volume of the trapped and displaced fluid is constantly the same and specific for each pump and the flow rate is independent of the pressure or temperature of the fluid. The displacement of the fluid has direction from the suction to the discharge side.





(a) Top view (b) Side view

Figure 41: *Top view of a twin screw back-to-back pump configuration* [41, 61].

<u>Internal Configuration characteristics</u>

Their design follows the rules and calculations described in the standard API 676.

- **Screw arrangement:** the screws are not in contact between each other or with their housing. There are two different arrangements: Standard Screw and Degressive Screw: It has decreasing pitch.
- **Rotor:** the rotors used in these pumps may be timed by external gears or untimed. In case of using untimed rotors, the internal is designed so that to avoid contact between the screws.

<u>Operating characteristics</u>

Twin screw multiphase pumps are used especially for the pumping of heavy crude oil. Their main operating characteristics are summarized in Table 8:

Twin Screw Pump (TSP)	
Viscosity	High
Type of fluids	Heavy crude oil
Solids tolerance	Limited
Gas Volume Fraction	50~100%
Suction Pressure	Low
Diferential Pressure [psi]	≤1,000 psi
Design total flow rates (at suction conditions) [bbl/day]	Medium capacity 10,000~440,000bbl/day of gas, oil and water
Applications	Onshore
	Offshore
	Subsea
Priming	Self-priming

Table 8: *Main operating characteristics of multiphase twin screw pumps.*

Operational advantages

The main advantages of the twin screw multiphase pumps are the following [41]:

- The ability to handle **highly viscous fluids**.
- The ability to operate at **low suction pressure**.
- They operate at **low rotational speeds** and they don't need expensive and hard to find accessories as bearings and drivers [41].
- They have **low sensitivity to variations in flow conditions** (suction pressure, GVF).
- They have **high tolerance in liquid slugging flows.** In case of liquid slugs in the flow, they will hit both sides of screws at the suction side simultaneously, applying forces of same magnitude but of opposite direction on the screws [8]. Consequently the applied forces will counteract each other and the net resulting force on the screws will be zero.

Surface Equipment

- **Pressure relief valve**: they are installed downstream of the twin screw pumps if they are not embedded on the pump's main structure. They are used for operational safety reasons. In case that the pressure after the outlet of the pump increases (as it may happens when it meets a closed valve) the pipe may failure due to burst. By installing the pressure relief valves, the fluid may re-circulate through the valve and thus preventing the damage in the pipe [41].

Vendors

The main vendors for surface multiphase twin screw pumps are: Bornemann Pumps Inc., Flowserve Corp., and Leistritz Corp. Other suppliers are: Colfax Pump Group (Houttuin, Imo, Allweiler, and Warren), GE Oil & Gas, Nuovo Pignone Corp., CAN-K Artificial Lift Systems Inc. and OAO Livgidromash [62]

Case study

Huwaila oilfield in southern Abu Dhabi

Field description: The Huwaila field is in southern Abu Dhabi, it was discovered in 1965. The surface facilities are located in a gathering station (RDS-3) 27km northern of the Bu Hasa field. The area has sand hills and it is approachable only by off-road vehicles. The oil production started from one well (Hu-44) using the natural flow drive mechanisms. The oil transportation from the production site to the treatment facilities was implemented with a pipeline of 8in diameter and 27km long.

In 1996 an ESP was used to enhance the recovery but it also increased the water cut. The well (Hu-44) was sidetracked as a 1,800ft horizontal well.
The area around the field is a dessert with high temperatures (during summer the medium ambient temperature is +50°C).
Effluent description: The effluent was crude oil of low viscos.ity, 0.55cp. The content in H_2S and the content in CO_2 were very high, 0,7% and 7,0%.respectively. Also the formation water contained chlorides.
Pump characteristics:

Name	Type of pump	Type of installation	Vendor	Case study of deployment	Screw pitch		Driver Rating	Discharge Pressure		Suction pressure	Nominal liquid flow rate	Nominal gas flow rate	GVF at suction conditions
					1st pump	2nd pump	kW	psi	bar	psi	bbl/d	MMscf/day	%
MPC208	Twin screw	Onshore	Bornemann	Huwaila's field, Abu Dhabi	45mm	38mm	400	1,480		550	5,000	1.74	67.2

Table 9: O*perating characteristics of the installed multiphase twin screw multiphase pumps in Huwaila field.*

7.3.2. Single Screw/Progressive Cavity Pumps (PCP)

Operating Principle

Progressive cavity pumps used to be called as eccentric screw pumps, eccentric gear pumps and helical gear pumps. The principle of operation was first established in the 1930s by Rene Moineau [63].
They belong to the rotary positive displacement pumps category of multiphase pumps. Their operating principle is similar to the operating principle of twin screw pumps: the fluid is transferred from the suction to the discharge side of the pump through the clearances between the screws and the casing. The backflow is responsible for both pump types for the gas compression and the progressive movement of the flow.
They consist of a rotating metallic shaft with screw configuration, which is driven electrically or hydraulically. The rotor is mounted in a stationary casing which is made of flexible elastomeric material. The internal part of the stator has cavities in the shape of a multiple helix (number of rotor screws plus one) [41]. The design of the stator and the rotor is made so that the pitch of the screws and the stator's cavities to be in contact and to create closed clearances.
The Low Pressure fluid enters the pump and is guided to the chamber with the screw. There the fluid is trapped between the cavities of the screw (rotor) and the sealing (stator). As the rotor rotates centrifugal forces are imposed to the flow and result to phase separation. The liquid is forced to occupy the screw's outer diameter and seals

the clearances, so the gas is trapped in the hub of the screws. The clearances are moving progressively from the suction to the discharge side, so the motion of the rotor causes the displacement of the gas. As the liquid moves towards the discharge side, a liquid backflow is created due to the differential pressure drive mechanism. The backflow is responsible for the compression of the gas and so the flow can be continuously displaced.

The volume of the displaced fluid is constantly the same, specific for each pump and the flow rate is independent of the pressure or temperature of the fluid.

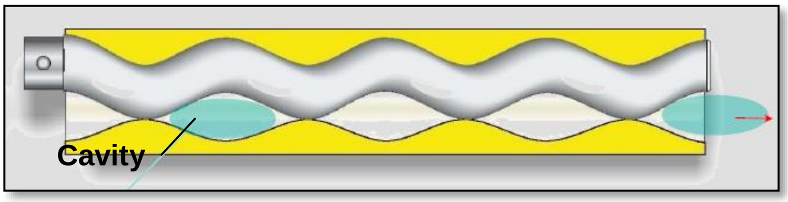


Figure 42: *Configuration of cavities in progressive cavity pumps* [64].

Internal Configuration characteristics

The design of the progressive cavity pumps is based on the API 676 international standard. The main components of a single screw multiphase pump as presented in Figure 43, are the following:

1) **Rotor**
2) **Stator:** the stator is made of flexible materials and the internal surface has a shape of a multiple helix (number of rotor screws plus one).
3) **Drive Chain:** Couples the rod with two gimbal joints and transmits the necessary electrical energy to the rotor.
4) **Shaft Seals**
5) **Suction and Discharge Housing**
6) **Block Construction**

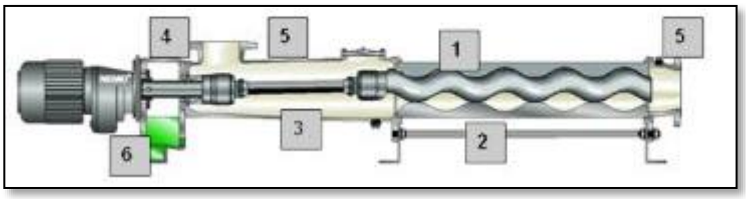


Figure 43: *Single screw pump configuration.*

Surface Equipment

- Systems for controlling the conveying pressure
    - Pressure gauges
    - Gate valves

    - Safety valves
    - Pressure relief valve
- Dry running protection systems
- Electrical Control System
- Bypass lines
- Application-specific baseplates
- A great variety of drive systems

Operating characteristics

Their main operating characteristics are summarized in the Table 10:

Single Screw Pump (PCP)	
Viscosity	Any viscosity
Type of fluids	Fluids with sands, coarse of fine particles, abrasives
Solids tolerance	High
Gas Volume Fraction	50~95%
Suction Pressure	Low
Diferential Pressure [psi]	≤600 psi
Design total flow rates (at suction conditions) [bbl/day]	Small capacity <91,000 bbl/day of gas, oil and water
Applications	Onshore
Speed [rpm]	Low
Priming	Self-priming

Table 10: *Main operating characteristics of multiphase single screw pumps.*

Operational advantages

The main advantages of the twin screw multiphase pumps are the following [41, 45]:

- They **can handle flows with more than 8% of solids** because the elastomeric stator is not damaged by them.
- The ability to handle **highly viscous fluids**.
- They **don't need liquid recirculation** when handling flows with high GVF (>90%).

Vendors

Colfax Pump Group (Houttuin, Imo, Allweiler, and Warren), Seepex, NETZSCH Pumpen & Systeme GmbH, Weatherford.

8. Multiphase pumps performance and selection

8.1. Performance characteristics

Modeling of the MPPs performance is quite complex due to the different geometries and the complexity of the multiphase flow. For this reason there isn't a general model for their performance.

For design purposes the multiphase pumps can be considered as wet gas compressors [7], because the gas volume fraction is higher than the liquid volume fraction, thus it influences the behavior of the liquid phase. The flow regime is considered as steady state for calculations simplification.

In multiphase pumping design the most important parameters that must be calculated are the following [7, 41]:

- Pump's capacity (gas and liquid flow rates),
- The Gas Volume Fraction (GVF) and the water fraction (or water cut),
- The fluid densities (gas and liquid),
- The required pressure rise,
- The suction pressure and fluid temperature,
- The oil viscosity,
- The pressure and temperature gradients along the pipeline,
- Fluid characteristics and gas composition (presence and concentrations of corrosive components, possible wax deposition),
- Possible presence of solid particles (sand, scale formation).

All the different types of pumps have the same fundamental working principle: increasing the pressure of the transferred fluid by different ways and means. The pressure that is provided to the fluid is better expressed in terms of equivalent height of a column that contains the transferred fluid [65]. More specifically the term **pump's (manometric) head (H_p)** is usually used to express the specific work (mechanically induced energy per unit of mass flow) ΔW that is transferred to the fluid, but it is expressed in terms of liquid column's height and it has dimensions of length. The energy that is transferred to the fluid is dictated by the energy conservation law (Bernoulli equation) and it expresses the kinetic energy of the fluid, its potential energy and its dynamic energy.

Hence the pump's head is an indication of the differential pressure between the suction and the discharge side of the pump, which is affected by the fluid's properties (density). The head depends on the pump's geometry, its rotational speed, the velocity slip between the phases and the volumetric flow rate, but is independent of the fluid density [41].

In terms of head: $\boxed{H_p = H_{pr} + H_{st} + H_u + H_f}$

In terms of extended Bernoulli's equation:

$$\boxed{H_p = \frac{\Delta W}{g} = \frac{(P_d - P_s)}{\rho_m \cdot g} + (z_d - z_s) + \frac{(u_d^2 - u_s^2)}{2 \cdot g} + \frac{\Delta P_f}{\rho_m \cdot g}}$$

Where d is an indicator for the discharge side and s is an indicator for the suction side, g is the acceleration of gravity [g=9.81m/s^2], ΔW is the specific work [J/kg], P is the flow pressure [kg/ms^2], ρ_m is the mixture's density [kg/m^3], u is the flow velocity [m/s] and z is the vertical distance from the datum level [m]. As datum level can be used the axis level that comes through the suction side of the pump or any other level in the pumping system.

The different types of static heads are presented schematically in Figure 44 and are explained further as follows:

Total static head (H_{st} **)** is the vertical distance between the suction and discharge sides of the pumpu. It is calculated as the difference between the static delivery head and the static suction heads.

$$\boxed{H_{st} = H_{sd} - H_{ss}}$$

Static suction head (H_{ss}) is the vertical distance between the flow level at the suction reservoir or flowline up to the pump's axis on its suction side when no flow rate occurs.

Static delivery head (H_{sd}) is the vertical distance between the flow level at the discharge side of the pump up to the tank or separation facilities when no flow rate occurs.

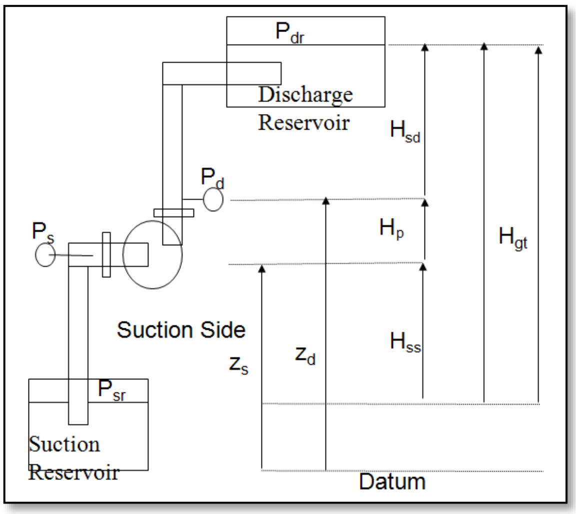


Figure 44: *Different static head types.*

Pressure head (H_{pr}) represents the potential energy that is converted the fluid's elastic energy that comes from its hydrostatic pressure $\boxed{H_{pr} = \frac{P}{\rho_m \cdot g}}$

Velocity head (H_u) represents the potential energy that is converted to fluid's kinetic energy $\boxed{H_u = \frac{u^2}{2 \cdot g}}$

Friction head (H_f) represents the potential energy that is lost during the flow through the pipeline. They include the losses at the entrance of the pipeline from the suction side, the losses at the exit of the pipeline from the discharge side, the friction losses as the flow is moving through the pipeline and the friction losses due to restrictions in the flow from hydraulic components as valves, heat exchangers, etc. The friction head is calculated by the following formula: $H_f = k \cdot Q^2$ where k is the loss coefficient of the hydraulic components [66].

Dynamic Total Suction Head (TSH) represents the total energy of the flow when it is on the suction side. From the Bernoulli equation is the summation of the pressure head, the velocity head and the static head at the suction side subtracted by the friction head on the suction side (friction head is reducing the pressure at the suction side of the pump and hence its energy regime). $\boxed{TSH = \frac{P_s}{\rho_m \cdot g} + H_{ss} + \frac{u_s^2}{2 \cdot g} - H_{fs}}$

Dynamic Total Discharge Head (TDH) represents the total energy of the flow when it is on the discharge side. From the Bernoulli equation is the summation of the pressure head, the velocity head, the static head at the discharge side and the friction head on the discharge side (friction head is increasing the pressure at the discharge side of the pump and hence its energy regime). $\boxed{TDH = \frac{P_d}{\rho_m \cdot g} + H_{sd} + \frac{u_d^2}{2 \cdot g} + H_{fd}}$

Total Pump's Head (H_p) represents the energy that is provided to the fluid by the pump. It is the overall pump's head and it is equal to the difference:

$$\boxed{H_p = TDH - TSH = \frac{(P_d - P_s)}{\rho_m \cdot g} + H_{st} + \frac{(u_d^2 - u_s^2)}{2 \cdot g} + (H_{fd} + H_{fs})}$$

P_d: the pressure at the discharge side

P_s: the pressure at the suction side

Total Suction Lift (TSL) is the total suction head (TSH) when the flow level at the suction reservoir or flowline is lower than the datum level. In this case TSH has negative value and instead of using a negative value, it is expressed as total suction lift but with positive sign.

Net Positive Suction Head (NPSH) is the total head on the suction side of the pump, over the bubble point pressure.

Net Positive Suction Head Available (NPSHA) is the energy that the pump must overcomes on the suction side in order to avoid cavitation. It is a characteristic of the hydraulic system, not only the pump.

$$\boxed{NPSHA = TSH - \frac{P_b}{\rho_m \cdot g}}$$

P_b: is the pressure at the bubble point of the flow

Net Positive Suction Head Required (NPSHR) is the energy that is required to move and accelerate the liquid from the suction side to the inlet of the pump. It is a characteristic of the pump provided by the manufacturer.

The **pump's capacity (Q)** is the total actual volumetric flow rate that is delivered by the pump in the discharge side [m^3/s].

$$\boxed{Q = u_d \cdot A_d}$$

u_d: flow velocity at the discharge side [m/s]

A_d: pipe's diameter at the discharge side [m^2]

The **normal volumetric flow rate of the pump** (**Q_N)**, corresponds to the total actual volumetric flow rate in the discharge side when the pump operates at its maximum efficiency, at the nominal total head, at the nominal rotational speed and for the specific fluid.

The **nominal volumetric flow rate of the pump** (**Q_N)**, corresponds to the total actual volumetric flow rate in the discharge side when the pump operates at its nominal total head, at the nominal rotational speed and for the specific fluid, but not at the maximum efficiency. The pumps are designed according to this value.

The **minimum volumetric flow rate of the pump** or surge limit (**Q_{min})**, corresponds to the minimum possible volumetric flow rate that the pump can handle.

The **maximum volumetric flow rate of the pump (Q_{max})**, corresponds to the maximum possible volumetric flow rate that the pump can handle.

The **Gas Volume Fraction (GVF)** is the ratio of the actual gas volumetric flow rate to the total oil and gas rate at suction conditions. Often instead of GVF the **Gas Liquid Ratio (GLR)** in suction conditions is used [41]. They derive from the following equation:

$$\boxed{GVF = \frac{Q_g}{Q_g + Q_l + Q_{rec}} = \frac{GLR}{1+GLR}}$$

Where Q_{rec} is the flow rate that is used for recirculation

GVF must not be confused with GOR (Gas Oil Ratio) which represents the ratio of the gas volumetric flow rate at standard conditions to total liquid flow rate at standard conditions. In Figure 45 is presented a plot of gas and liquid flow for different inlet gauge pressures. GOR corresponds to the ratio between the values of gas volume and liquid volume at the vertical axis, while GVF corresponds to the ratio between the values of gas volume of over gas and oil volume at the all the other points of the surface, except the ones on the vertical axis.

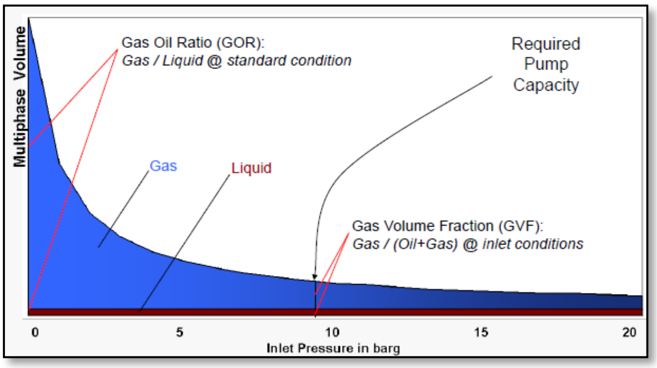


Figure 45: *GOR and GVF difference* [40].

Pump's delivery/hydraulic power ($W_{h,out}$) is the power that the pump delivers to the fluid. The hydraulic efficiency of the pump is highly affected by the temperature and the GVF.

In case that the flow is considered adiabatic, no heat exchange with the environment is taken into consideration. This is a theoretical approach for the estimation of the hydraulic power and then the following equation is used for its calculation:

$$\boxed{W_{h,out} = \rho_m \cdot g \cdot H_p \cdot Q_t}$$

More realistic approaches consider that the thermodynamic processes that take part in the passageways of a pump are:

When the flow enters a multiphase pump it is subjected to an isochoric heating and an isothermal compression. The mechanical energy of the rotating element is transferred to the fluid, which results to an increase in its pressure, while its volume remains constant (isochoric heating). The fluid progressively is further compressed when it is passing through the pump's stages, while its temperature remains constant (isothermal compression). The thermodynamic processes to which the fluid is subjected are not ideal, but some of the energy that is transferred to the fluid is lost due to the resistance that must the flow overcome in suction and discharge sides (backflows).

In case of low GVF the flow is liquid dominated and because liquids have greater heat capacities than gases, the flow will be more influenced by the temperature changes. In this case the compression of the flow is not any more considered as adiabatic but as isothermal. The hydraulic power that is provided to the fluid is calculated by the following equation [59]:

$$\boxed{W_{h,out} = \rho_m \cdot g \cdot H_p \cdot Q_l + Q_g \cdot p_s \cdot \ln\left(\frac{p_d}{p_s}\right)}$$

For higher GVF values the liquid content is low and the flow has less thermal capacity. The compression of the flow is considered as polytropic and the hydraulic power that is provided to the fluid is calculated by the following equation [59]:

$$\boxed{W_{h,out} = \rho_m \cdot g \cdot H_p \cdot Q_l + \frac{n}{n-1} + Q_g \cdot p_s \cdot \left[\left(\frac{p_d}{p_s}\right)^{\frac{n}{n-1}} - 1\right]}$$

Shaft's power (W_s) is the power output from the motor that is provided to the shaft

$$\boxed{W_s = \frac{\rho_m \cdot g \cdot H_p \cdot Q}{\eta_o}}$$

Motor power (W_m) the power that the motor needs in order to operate

$$\boxed{W_m = \frac{W_s}{\eta_m \cdot \eta_e} = \frac{2 \cdot \pi}{60} \cdot n_p \cdot M_p}$$

Where η_e is the transmission efficiency and η_m is the efficiency of the motor.

The motor power is given by the manufacturer. In case of an electrically driven motor, it depends on the rotational speed n_p and the rotating torque M_p.

Theoretical Pump's drive power ($W_{th,in}$) is the theoretical power that the pump needs in order to operate.

$$\boxed{W_{th,in} = Q_{th} \cdot \Delta p}$$

Where Δp is the differential pressure that the pump creates

The **volumetric efficiency of a pump (η_{vol})** represents the percentage of the actual volumetric flow rate of the displaced fluid Q_t over the theoretical volumetric flow rate of the fluid that would be displaced if no flow obstacles and restrictions existed Q_{th}. It is calculated by the following equation:

$$\boxed{\eta_{vol} = \frac{Q_t}{Q_{th}}}$$

The **hydraulic efficiency of a pump (η_h)** represents the ratio of the pump's hydraulic power ($W_{h,out}$) over the shaft's power that is provided to the fluid when it enters the pump (W_s). It is calculated by the following equation:

$$\boxed{\eta_h = \frac{W_{h,out}}{W_s}}$$

The **mechanical efficiency of a pump (η_m)** represents the ratio of the shaft's power (W_s) over the motor power (W_m). The power requirements can also be expressed in terms of torque. The pump needs more power than the theoretical calculated in order to deliver the appropriate pressure boost, due to the power losses that occur as a result of the friction between the fluid and the moving parts of the pump (bearings, gears, etc.). It is calculated by the following equation:

$$\boxed{\eta_m = \frac{W_s}{W_m}}$$

The **overall efficiency (η_o)** is the ratio of the hydraulic power output of the pump ($W_{h,out}$) over the motor power input (W_s) and can also be expressed as the product of the mechanical, the hydraulic and the volumetric efficiency of the pump. Due to the friction pressure losses and the backflows, the overall efficiency is less than 100%. It is calculated by the following equation:

$$\boxed{\eta_o = \eta_m \cdot \eta_{vol} \cdot \eta_h}$$

The performance of a multiphase pump is better described by the **pump effectiveness**. It represents the ability of the pump to compress liquid as the gas content in the flow increases [59], in other words it shows the performance of the pump when handling a multiphase flow in comparison of the performance of the pump for single phase flow (so $\eta_{effective}$ =100% for GVF=0%) and is calculated as following:

$$\boxed{\eta_{effective} = \frac{W_{h,out\ isothermal\ or\ polytropic}}{W_{h,out\ adiabatic}}}$$

8.2. Multiphase Pump selection

The selection of a multiphase pump is an optimization problem that can be solved by the field's architect and the pump engineer [54]. They will decide about the time that the operation of a multiphase pump is needed, the operating characteristics and the type of the pump. The selection for each application is based on the desired delivery flow rate Q and the head that the pump needs to overcome H.

The following steps are followed for the selection of an MPP [41, 65]:

1) Selection and calculation of the **overall pumping system's characteristics**. The pumping system is consisting of the pumps, the pipelines and other hydraulic components (valves, etc.). The design and the arrangement of all the components are implemented according to technical regulations and space restrictions. The result of the first step will be the construction of the characteristic curve of the pumping system between different flow rates and the total pumping head.

2) Selection of the **type of the pump** (single or twin screw, helico-axial multiphase pump). The selection is done according to the total volumetric flow rate that each pump type can handle and some additional parameters suction pressure, pressure rise, liquid viscosity and the characteristic curve of each pump.

3) Selection of a specific **pump model**. After having decide about the type of pump, it must be verified the feasibility of its application. The model that will be selected must be able to give the required pressure rise. Also in this step the driver power is calculated as well as the pump's efficiency.

4) Design optimization. In the third step are conducted design optimization calculations, about the number of pump's stages and the selection of the nominal rotational speed. In this step it is decided the speed variation according to the production fluctuations.

For the first step the procedure is the following [65]:

1A) Design of the overall pumping system and calculation of the overall system's head: At the first step are designed the pipelines and the appropriate hydraulic components with the characteristics (length, material, diameter, configuration in the area) that will have after construction. Finally the overall system's head will be calculated.

1B) Calculation of the design volumetric flow rate: it is the flow rate that the pump will have to handle. The calculation is referred to the production flow rates of the well (IPR and VLP) as they have been estimated from the production engineers.

1C) Specify the properties of the transferred fluid: in order to accomplish flow assurance through the pipelines and the pumps, the following fluid characteristics must be known: type of fluids, chemical composition, pressure and temperature at bubble point and pumping conditions, density, viscosity, acidity, solids concentration.

1D) Calculation of the Total Pump's Head (H_p): the calculations must be implemented for the most extreme suction temperatures that may occur. For safety reasons the calculated total pump's head may be increased by 10%.

For the second step the procedure is the following [65]:

2A) Examine the influence of the rheological characteristics of the fluid to the different types of pumps:

For viscosity values higher than 110cSt the friction pressure losses in centrifugal pumps are getting very high, because of the creation of turbulence in the flow. This may result also to the decrease of NPSHA and to increase the possibility of cavitation. The positive displacement pumps are not affected so much because their operating principle is not affected by the flow characteristics. So in this case of flows, positive displacement pumps are preferred.

For flows with high solids content and highly erosive characteristics the positive displacement pumps may get damaged easier.

2B) Examine the margins of possible handling flow rates for each type of pump: it is an initial estimation of the type of pump that can be used according to the flow rate that each type can handle and the required flow rate.

For the third step the procedure is the following [65]:

3A) Calculation of the net positive suction head available (NPSHA)

3B) Calculation of the required motor power

For the fourth step the procedure is the following [67]:

4A) Estimation of the operation/duty point: the characteristic curves of the overall pumping system (Q-H) and the pump (Q-H_p) are plotted in the same diagram. The operation point of the pump is the intersection point of the two curves (Figure 46a for rotodynamic pumps and 46b for positive displacement pumps).

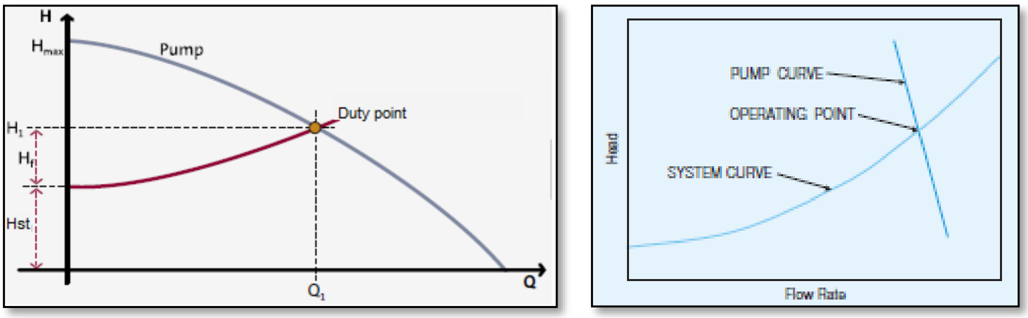
4B) Estimation of the best efficiency point: the characteristic curves of the pump (Q-H_p) and the pump's efficiency curve (η-H_p) are plotted in the same diagram. The best efficiency point is the point of maximum pump's efficiency for a specific flow rate.

System's characteristic curve

The characteristic curve of the pumping system provides information about all the possible pressure losses that occur at the flow path between reservoir and separation facilities in the flowlines upstream and downstream and the well [41]. It is the summation of the total static head (H_{st}) and the friction head (H_f).

With increasing flow rate the friction pressure losses increase, because they are directly connected with the flow velocity and thus with the flow rate. Consequently the system's head increase when the flow rate increases (Figure 46).

The system's characteristic is a parabola with positive slope, because the friction head is directly proportional to the square of flow rate (considering no liquid hold up phenomena occurrence).



(a) (b)

Figure 46: *System curve, positive displacement (b) and helico-axial (a) pump's characteristic curve and duty/operating point* [58, 68].

Pump's performance and characteristic curves

Pumps performance can be predicted by their characteristic curves. For multiphase pumps, the performance can be predicted for each pump under specific operating conditions of Gas Volume Fraction, suction pressure, liquid density and viscosity, because of the high complexity of the multiphase flow patterns and the different internal configuration of the pumps [8]. The operation of the multiphase pumps and thus their characteristic curves are influenced by the Gas Volume Fraction (GVF) and the gas and liquid properties [56].

The pumps' performance can be presented with four different types of characteristic curves: pump's overall efficiency η_o over capacity Q (Q-η_o), pump's overall head H_p over capacity Q (Q-H_p), shaft's power W_s over capacity Q (Q-W_s) and NPSHR over capacity Q (Q- NPSHR) [65]. Usually, they are all presented in one plot. The abscissa of the characteristic curves of multiphase pumps is referred to total (liquid and gas) or liquid volumetric flow rates.

- **Characteristic curve (Q- NPSHR)**

The NPSHR is increasing with increase of the flowrate, as it is presented in Figure 49, because friction pressure losses are induced and operate as an obstacle to the flow.

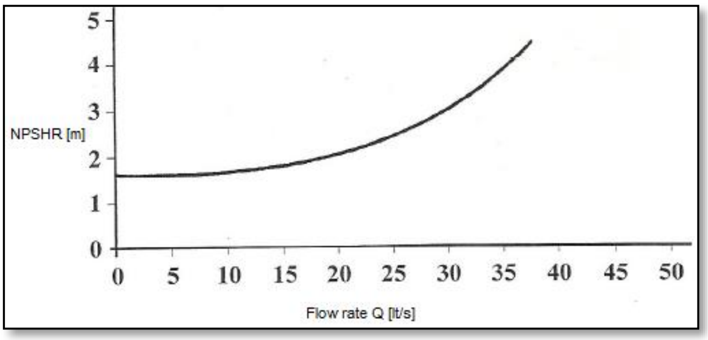


Figure 47: *Multiphase pump's general characteristic curve Q-NPSHR* [65].

- **Characteristic curve (Q-H_p)**

It represents the locus of the possible operational points for a given rotational speed. When the pump operates at a certain rotational speed the flow rate that can handle is reduced as the energy that has to provide to the fluid and hence the head, increases.

- **Characteristic curve (Q-W_S)**

The shaft power is increasing with the increase of pump's head because the pump needs to provide more energy to the fluid in order to overcome the higher head and the necessary power will be transferred through the shaft. In the case of closing a valve at the discharge side of the pump, while it is operating, the pump will provide zero flowrates at its outlet. However, the shaft will receive energy from the motor drive, which will be transformed into thermal energy and will increase the flow temperature. For this reason, the characteristic curve of (Q-W_S) indicates a non-zero shaft power for zero flow rate (Figure 48).

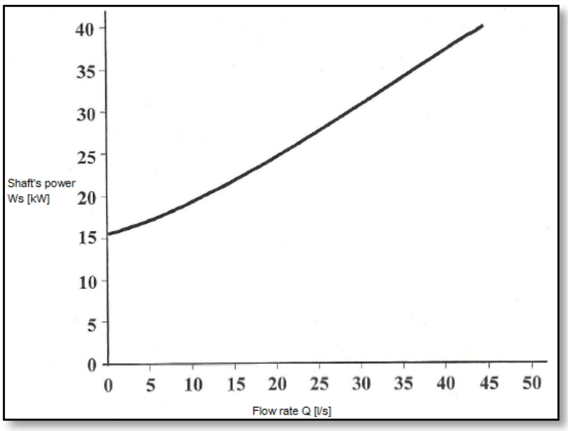


Figure 48: *Multiphase pump's general characteristic curve Q-W_S* [65].

- **Characteristic curve (Q -η_o)**

Each characteristic curve is the locus of the pump's overall efficiency that can be achieved for different combinations of volumetric flow rate and differential pressure or head when the pump is operating at a specific rotational speed. The pump's efficiency is close to its maximum value for a specific range of flow rates but it decreases sharply as the flowrate approaches zero or its maximum as it is presented in Figure 47 [65].

The combination of the (Q-H_p-η_o) curves includes information about the Best Efficiency Point (BEP) of the pump, which indicates the optimum operating conditions in order to achieve the maximum or optimum efficiency for a specific deliverable total flow rate [56].

The operating range of the pump is between the Shut-Off and the Run-Out Point [69]. The head for zero flow rate is called "Shut-Off Head". The shut-off head is an indicator of the feasibility of the pump to start. The static head needs to be less than this. This is important in particular cases of boosting systems where the pump is at a lower level than the discharge tank (for example in the case of seabed pumps and risers as discharge flowlines). The maximum flow rate that the pump can handle corresponds to a minimum head and this point is called "Run-Out Point". Beyond this point, the pump cannot operate.

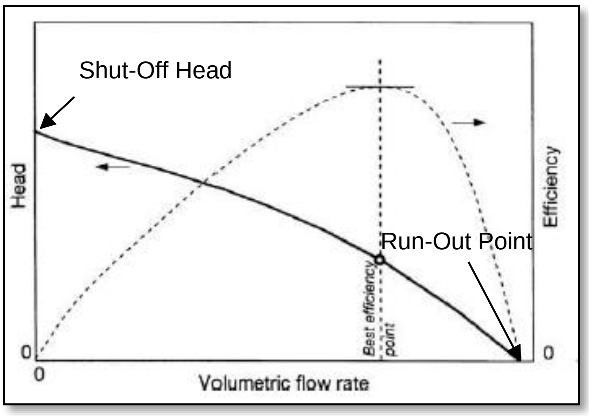


Figure 49: *Multiphase helico-axial pump's general characteristic curve Q-η_o* [41].

The pump must operate as closest as possible to the best efficiency point and the ideal margins of operation are ±10% of the BEP flow rate [70].

If the pump operates at flow rates lower than the one that corresponds to the BEP, so at the left side of the BEP, the main problems that may arise are thermal build up, cavitation, recirculation and components damage. The low flow rate indicates high-pressure flow which means may that possible recirculation may occur. Due to the recirculation unbalanced forces are implied to the internal components of the pump, which can cause shaft deflection, vibrations, bearings and mechanical seals fatigue and vanes damage. Also, the high pressures are connected with the occurrence of high temperatures. This increases the risk of thermal build up of the pump.

Runout is the operating condition with flow rates higher than the flow rate that corresponds to the BEP, so it corresponds to the right side of the BEP [71]. The main problems that may arise are cavitation and components failure. In this case, the increased flow rate will cause the decrease of the pressure at the inlet of the pump, which means that the head that can be provided by the pump (NPSHA) may be less than the bubble point pressure. As a result, bubbles will start to develop in the flow (cavitation) that may break when the flow reaches the discharge area where high pressures occur. The collapse of the bubbles may cause uneven axial and radial loading on the impeller which can cause shaft deflection, vibrations, bearings and mechanical seals fatigue and vanes damage.

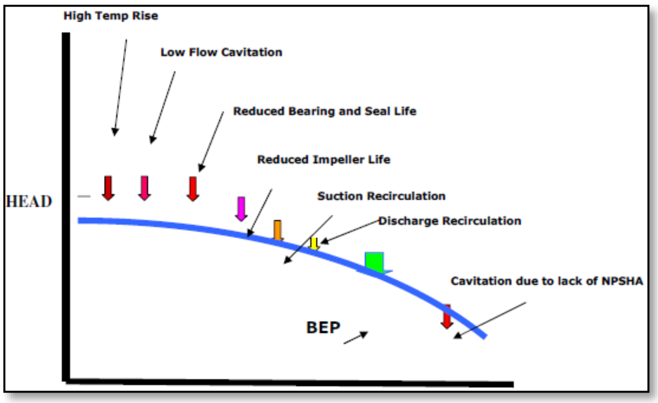


Figure 50: *Possible problems for operation of a helico-axial pump away from the BEP* [72].

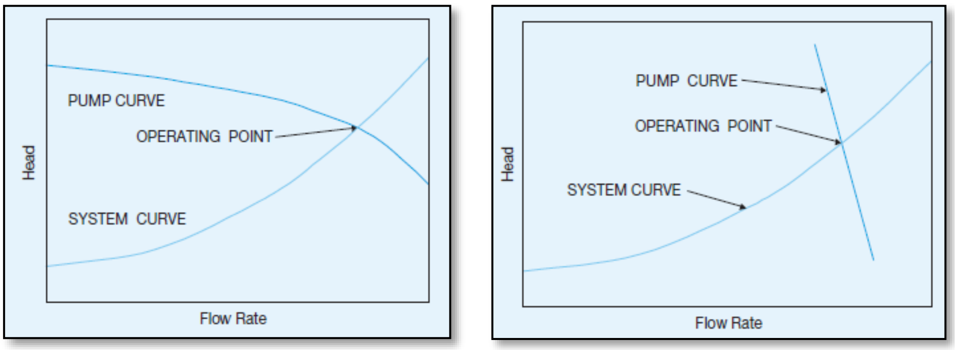
- **Operating Point**

The conditions of head and flow rate under which the pump will operate are the ones that correspond to the best efficiency point. The operating point corresponds to the flow and head required for the pump to operate. Graphically is the intersection of the system's curve with the pump's performance curve of Q-H_p-η_o. The performance curve in Figure 51 corresponds to a helico-axial pump and in Figure 51b corresponds to a positive displacement pump.

There are two possible operating conditions when a centrifugal pump starts [69]:

- *When the discharge valve is closed*. In this case, after starting the pump the head is equal to that of shut-off point because no flow rate is passing through the pump. As the discharge valve opens gradually, the operation of the pump reaches the operating point by following the pump's curve. So, the operation of the pump follows a path on the performance curve, starting from the shut-off point up to the operating point.
- *When the discharge valve is open*. In this case the pump gradually increases its speed, so initially, it can handle low flow rate and creates a small head. Gradually the

operation of the pump reaches higher values for flow rate and head because its performance curve shifts to higher speeds. This method is not preferred because it may cause water hammer effects in case of high initial speed.



(a) (b)

Figure 51: *Operating point of a helico-axial (a) and a positive displacement pump (b)* [68].

In Figure 52 is presented a typical characteristic curve for a multiphase pump. The areas that can be distinguished are the following:

- The **dotted lines** indicate the possible operational points of the pump when it is operating at constant Gas Liquid Ratio (GLR) and suction pressure, but the rotational speed varies. Each one of them corresponds to a different rotational speed.
- The **continuous black lines** indicate the possible operational points of the pump when it is operating at constant rotational speed and suction pressure, but the GVF varies. Each one of them corresponds to a different GVF percentage.
- The **red line** indicates the locus of all the possible operational points that can handle the maximum total volumetric flow rate.
- The **green line** is the locus of all the possible operational points that can handle the minimum total volumetric flow rate, which is the surge limit. All the multiphase pumps need to handle a minimum flow rate. The fluctuations of pressure that are created under low flow rate result in low-frequency fluctuations of power and thus vibrations and dynamic stresses imposed to the pump elements, that may hurt their strength.

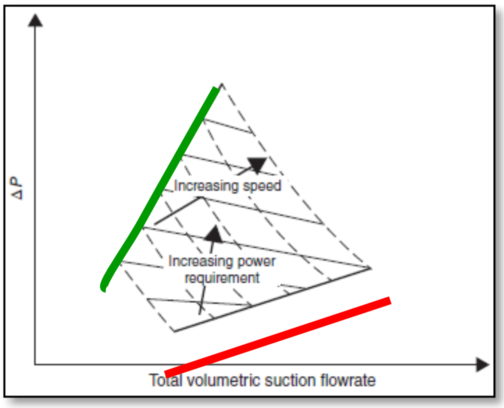


Figure 52: *Multiphase pump's general performance curve* [8].

8.3. Helico-axial Pumps (Rotodynamic)

Multiphase flow in helico-axial pump

The flow regimes that may appear inside a helico-axial pump in case of multiphase flow are dictated by the same physical mechanisms that create the flow regime that may appear inside a pipe [56].

The important differences are related to the pressure distribution and the pressure losses in the pump. The flow is imposed by centrifugal forces which are generated by the rotational motion of the impeller. This affects the phase distribution in the flow and creates pressure fluctuations.

Performance

Factors that affect the performance of the multiphase helico-axial pumps:

- **Increase of Pump's stages:** *Discharge pressure increases (P_d), GVF decreases, mixture's density (ρ_m) increase, total volumetric flow rate decrease* [41]

When the fluid passes through the diffuser it is compressed. Its pressure increases because of the tighter flow passages that are created from the stator. Since the flow pressure increases, its velocity and its volumetric flow rate decreases, as it is prescribed by the energy conservation law. The gas phase will condensate due to compression, so the GVF will decrease and the average mixture's density will increase. The profiles of the affected flow parameters are presented in Figure 53.

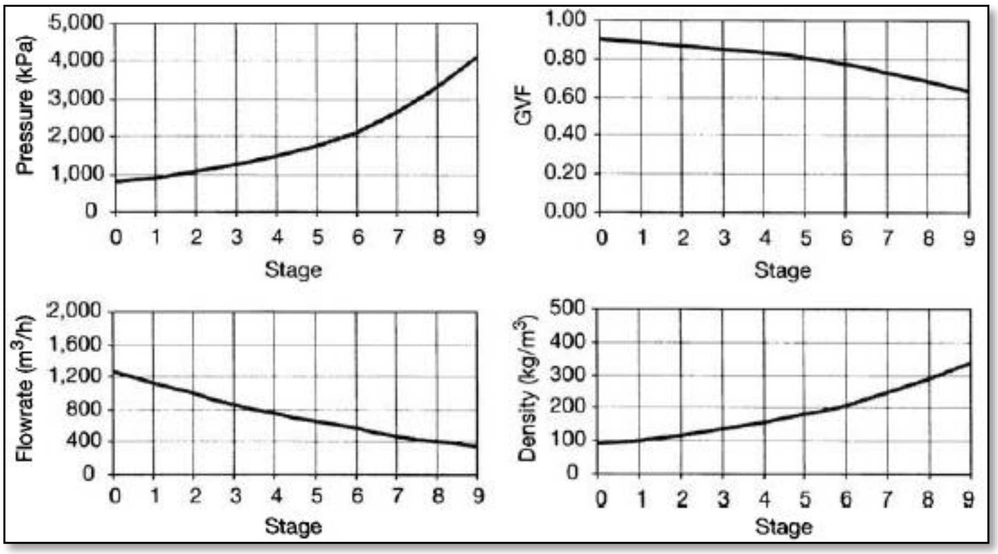


Figure 53: *Multiphase helico-axial pump's discharge pressure, total volumetric flow rate, average mixture density and GVF profile* [41].

- **Increase in Gas Volume Fraction (GVF) and Gas Liquid Ratio (GLR):**

Compression ratio decreases

In centrifugal and helico-axial pumps in case of high gas flow rate the gas bubbles coalescent in the areas of low pressure (near to the impeller's eye) resulting in gas accumulations. The flow regime becomes similar to slug or plug flow in pipes and gas pockets are created. In the case of continuous gas accumulation, the flow may be blocked and the pump may become gas-locked, which means that the pressure at the discharge side may be disrupted [56]. However, the helico-axial pumps have the advantage of being able to handle up to 100% GVF. This occurs due to the shape of the vanes because the helical-shaped vanes enable the homogeneity of the flow.

In Figure 54 are presented the characteristic curves for a multistage helico-axial two-phase pump for its operation at GLR between 2 and 15, when the same constant inlet pressure and rotational speed occur for all the different operation cases. The upper boundary indicates the surge limit and the lower boundary indicates the maximum liquid flow rate that can be handled. As the GLR increases the GVF increases too, so the curves of increasing GLR correspond to increasing values of the gas fraction. The fluid is imposed in compression as it passes through the pump, so as the compression ratio increases through the pump stages, the gas volume fraction GVF will decrease [51]. So the curve is shifted to the right, at higher flow rates as the GVF decreases.

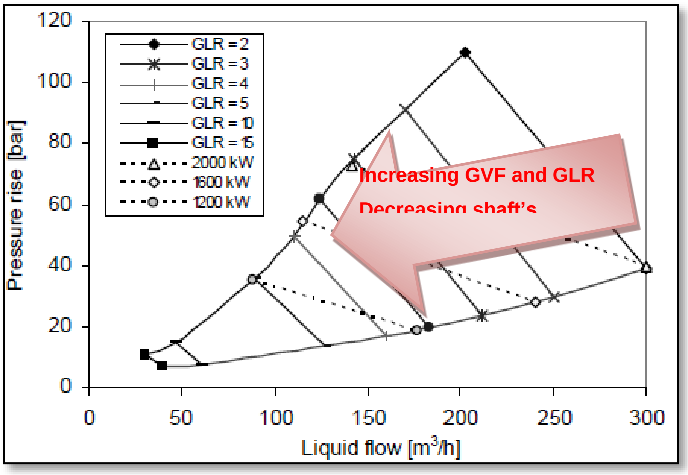


Figure 54: *Helico-axial pumps' characteristic curve for constant speed and inlet pressure* [56].

- **Decrease in rotational speed (n):** *Compression ratio decreases* [56]

In Figure 55 are presented the characteristic curves for a multistage helico-axial two-phase pump for its operation at speeds between 4,000rpm and 6,000rpm, when the same constant inlet pressure and GVF occur for all the different operation cases. As the rotational speed decreases, without any change in GVF and suction pressure, the shaft's power decreases, consequently less energy is transferred to the fluid and less pressure boosting is given to the flow (in terms of head) and thus less flow rate can be handled. So the curve is shifted to the right, at higher flow rates as the rotational speed increases. Also, the curves for constant speeds become sharper for higher rotational speeds, because with increasing speed the compression increases and the void fraction and density ratio decreases [56].The upper boundary indicates the surge limit and the lower boundary indicates the maximum liquid flow rate that can be handled.

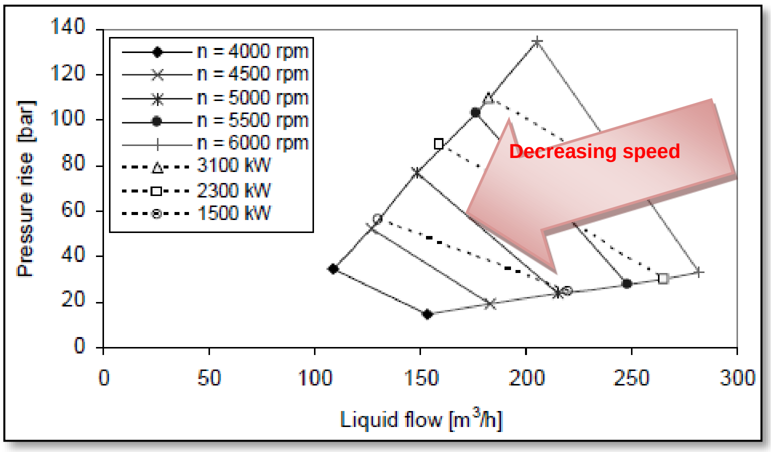


Figure 55: *Helico-axial pumps' characteristic curve for constant GVF and inlet pressure* [56].

<u>*Operational restrictions and limitations*</u>

- They can handle flows with dissolved **solid particles**, but they must have small size in order to prevent their accumulation in the pump casing or gaps [41]. The flow regime will be homogeneous in case that the particles have small size so that they settle down fast. Else their concentration will vary on the three axes and the flow regime will be heterogeneous.
- The **number of stages** is restricted by the mechanical strength of the shaft on the dynamic stress.
- The operational target of a pump is the pressure increase in its outlet. This means that while the fluid is guided to the discharge side, it is imposed to flow to the opposite direction, as a result of the force that is applied to the flow due to the pressure difference. This force is the **axial thrust** and it acts as an obstacle to the flow. In order to overcome it, balance pistons (or thrust bearings) are placed next to the discharge side of the pump [56]. The piston is pushed by the flow that is escaping from the exit of the pump, so the discharge pressure decreases and the axial thrust too. When the suitable pressure decrease is achieved, the fluid is provided again to the suction side. Another solution is the rearrangement of the impellers like in the double suction pumps, where the axial thrusts that are created from the two suction sides are neutralized.

- As for all the different types of pumps there is a **surge capacity limit** for the flow rate that they can handle, below which they become unstable, due to the stress fatigue that is imposed to the pump's elements [56].
- **Impeller Slip of the flow.** The fluid is exerting the pump (at the discharge side) with a different velocity than the one it is inserting (at the suction side). This phenomenon is called "impeller slip of the flow". It is occurring independently of the viscosity of the fluid. In case that the flow is considered non-ideal (viscous) the slip of the velocity is more intense due to the consideration of the boundary layers.

When the fluid is inserting the pump, it meets the impeller with its initial velocity v_u. The impeller is rotating with a constant angular velocity ω. While the fluid is getting trapped between the gaps of the blades, its flow is affected by the dynamic field that is created from the movement of the impeller and the flow becomes similar to a vortex. The flow direction towards the tips of the vanes follows the direction of the centrifugal forces that are imposed by the rotating shaft. Meanwhile, corriolis forces are applied to the flow because of the movement of the flow relatively to the impeller, which causes the redirection of the flow from the direction that would have in case of stationary impeller vanes. As a result, the fluid is exerting the pump with a velocity of a different direction and of less magnitude than the velocity that it is inserting (due to energy losses from the vortex flow) [66]. The difference between the inlet and outlet velocity indicate the energy loss due to non-ideal processes (the actual outlet velocity is less than the ideal outlet velocity, which indicates that the fluid lost energy).

The different types of velocities that are met in impellers can be described with the velocity triangles. In Figure 56 is presented a typical velocity triangle for a centrifugal pump, where u is the flow velocity, Vu is the actual flow velocity in the tip of the vanes when it is exerting the impeller and Vu' is the ideal flow velocity when it is exiting the tips of the vanes without any energy loss to occur. The difference between the actual and the theoretical flow velocity, which indicates the energy losses, is presented as the horizontal dotted line.

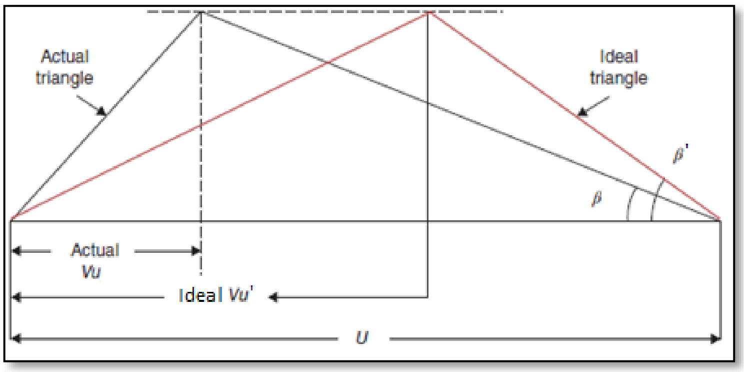


Figure 56: *Slip effect on velocity triangles for centrifugal pumps* [8].

Design

The flow is considered to be well mixed and its properties vary between the properties of a single phase liquid and a dry gas flow. In other words, the flow density and compressibility are calculated using the mixtures' equations.

The operating pressures are expressed in terms of head because it is more important to know how much a pump can raise the liquid it is pumping, rather than the amount of pressure the pump is adding to the liquid.

- **Pump's head:** The calculation of the head of a helico-axial multiphase pump is simplified by assuming that the flow is homogeneous, the phases are in thermal equilibrium and the thermodynamic processes in the pump are considered isothermal and the GVF is not too high. In case of very high values of GVF, the flow behavior is more similar to the dry gas. Then the thermodynamic processes are considered as polytropic and the temperature change of the flow in the pump must be taken into consideration for the pump's head calculation [41].

$$\boxed{H = \frac{(1-GVF)\cdot(P_d - P_s) + GVF \cdot P_1 \cdot ln\left(\frac{P_d}{P_s}\right)}{\rho_m}}$$

Where:

P_d : is the absolute discharge pressure

P_s : is the absolute suction pressure

ρ_m: is the mixture's density

$$\boxed{\rho_m = (1-GVF)\cdot \rho_L + GVF \cdot \rho_G}$$

ρ_L : is the liquid phase density

ρ_G: is the gas phase density

8.4. Single and Twin Screw Pumps

Performance

Factors that affect the slip and the flow rate and thus the performance of the multiphase screw pumps:

- **Increase of the number of internal clearances:** *Increase of differential pressure*

By increasing the number of the internal clearances, the pressure rise that can be achieved is increased. But the clearances are preferred to be as less as possible, so that to avoid backflow and to have greater efficiency.

- **Increase of the flow viscosity:** *Decrease of backflow and increase of volumetric efficiency*

Liquid mixtures with high viscosity create less backflow, because the shear stresses increase and it will be more difficult for flow to move backwards. This results to the increase of the volumetric efficiency.

- **Increase of the suction pressure:** *Increase of hydraulic efficiency and effectiveness*

When the pump is operating at high suction pressure, the high pressure may cause the condensation of the gas phase, so the flow is behaving as incompressible. Hence the pump's ability to compress the gas content of the multiphase flow increases, so its hydraulic efficiency and effectiveness increase [59].

- **Increase of the Gas Volume Fraction (GVF):** *Increase of volumetric efficiency up to a threshold for low pressure rise, decrease of volumetric efficiency for high pressure rise*

The volumetric efficiency of screw multiphase pumps is highly affected by the gas volume fraction (GVF). The gas appears in the suction side of the pump either as entrained or dissolved gas and when it enters the pump it will expand/released and will occupy the clearances [63].

When the pump operates at a specific speed and delivers low-pressure rise, the pump's volumetric efficiency increase as the gas volume fraction increases up to a specific value (around 85%), as indicated in Figure 57 [7]. With increasing gas fractions the flow becomes more compressible. So the pump is compressing the flow "easier" and consumes less energy, so the hydraulic, the volumetric and overall efficiency of the pump increase.

For values of GVF exceeding this threshold, the flow regime may become more turbulent which means that flow instabilities may occur. The flow regime is characterized by gas pockets, which lead to pressure pulsations that consequently lead to vibrations and strength failure of the pump's components.

On the other hand for such high values of GVF, the flow can be considered that consists almost totally of gas phase, so the pump clearances will be filled mostly by the gas phase. Consequently, the liquid film sealing in the perimeter of the screws tips cannot be created due to low liquid content in the flow and thus the gas that is trapped in the clearances cannot be compressed and may remain trapped. So the flow will be blocked and the liquid flow rate that the pump can actually handle as well as its volumetric efficiency will be reduced.

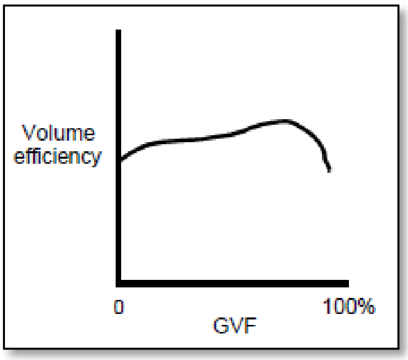


Figure 57: *Volumetric efficiency curve of a multiphase screw pump for different GVF values when it is operating at constant pressure rise and speed* [7].

<u>When the pump operates at a specific speed and delivers high-pressure rise</u>, the pump's volumetric efficiency shows fluctuations that depend on the amount of pressure rise. As it is indicated in Figure 58, the efficiency decreases up to a threshold for high gas volume fractions (>50% GVF), then it increases, meets a maximum efficiency and decreases again. The pump will operate smoothly under these conditions, but the flow temperature will rise since there will be almost no liquid recirculation to cool down the pump [51].

The flow which is characterized by 50% GVF seems to behave as a 100% of liquid flow, meaning that the volumetric efficiency of the pump decreases for constant GVF as the pressure rise demand increases.

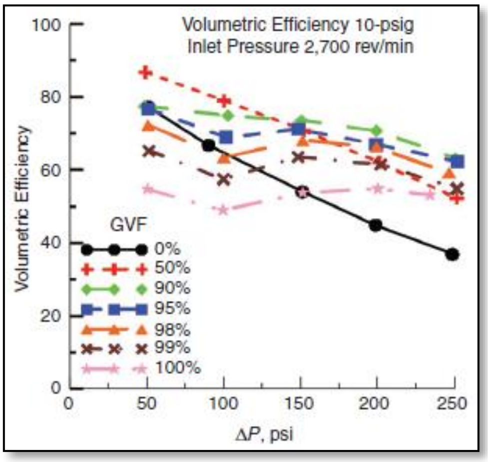


Figure 58: *Volumetric efficiency curve of a multiphase screw pump for different GVF values when it operates at constant inlet pressure and speed* [59].

- **Screw geometry (size and pitch of screws):** *<u>Decrease of pitch results in decrease of slip and increase of volumetric flow rate</u>* [51]

As the pitch decreases, more clearances between the screw locks are created, so there is more space where gas may be trapped. Consequently the slip will be reduced and the volumetric efficiency of the pump will be increased. For this reason in case of high GVF as preferred pumps with small pitch.

- **Liquid recirculation (slip):** *<u>Excessive values reduce pump's volumetric efficiency</u>*

Some amount of the liquid effluent is recirculated because of the backflow leakages. One of the benefits that it can provides is that it enables cooling of the pump's components, lubrication of the rotating elements and sealing of the spaces between the screws and the liners. But this amount is considered as a leakage (slip) from the inlet effluent. So the less is the need for recirculation, the less is the slip and the more efficient the pump.

- **Decrease in rotational speed (n):** *<u>Decrease in volumetric flow rate</u>*

In Figure 59 are presented the characteristic curves for a multiphase screw pump for its operation at speeds between 400rpm and 1,800rpm, when the same constant inlet pressure and GVF occur for all the different operation cases. As the rotational speed decreases, the frequency in which the screws are rotating will decrease and thus the frequency in which is fluid displaced by the clearances movement. Consequently, the flow rate that the pump can handle is decreasing as its speed decreases. Also, the shaft's power will decrease, due to its direct connection with the rotational speed.

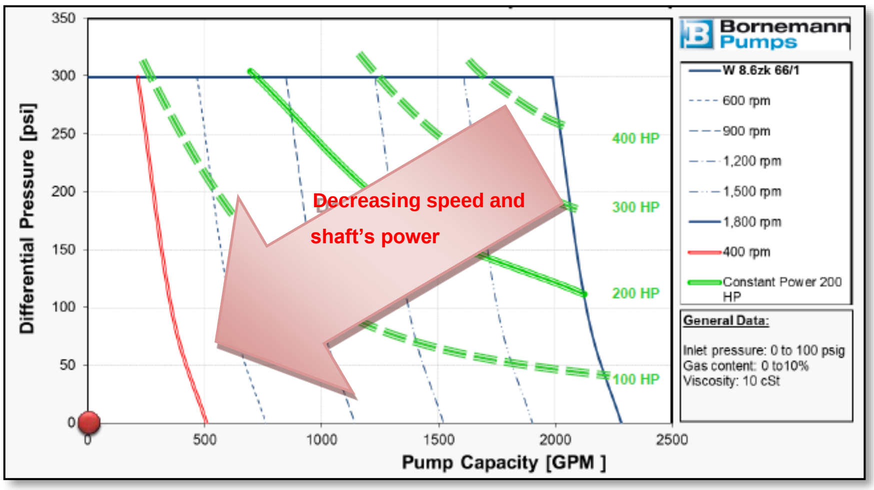


Figure 59: *Multiphase screw pumps' characteristic curve for constant GVF and inlet pressure* [40].

- **Characteristic curve (Q-H$_p$):** *<u>Constant volumetric flow rate per working cycle and decrease in volumetric flow rate when the differential pressure increases</u>*

The performance characteristics of the screw pumps are presented as the curve in which are plotted the flow rate Q that the pump can handle and the differential pressure that can create. The differential pressure that is created by the pump is independent of the flow rate that the pump can handle, because the pressure rise is not based on the transformation of the fluid kinetic energy, as it is on rotodynamic pumps. However, the volumetric flow rate that the pump can handle, when it is operating under specific speed, is reduced when the pressure rise increases. When this happen the backflow increases and the theoretical volumetric flow rate that the pump is able to handle is decreased by this amount. As indicated in Figure 60, the actual volumetric flow rate is relatively constant per working cycle but it reduces due to the backflow losses.

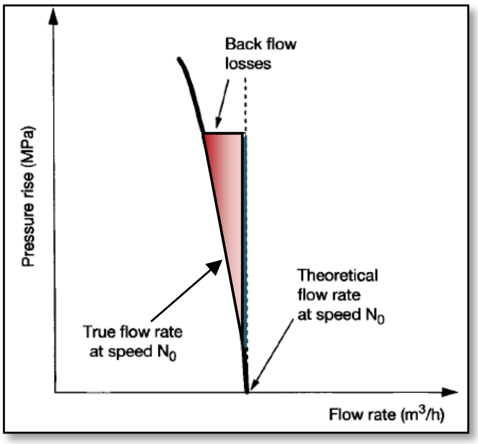


Figure 60: *Positive displacement pumps' characteristic curve* [41].

Operational restrictions and limitations of twin screw multiphase pumps

- The twin screw multiphase pumps **cannot handle liquids with high solids content.** The fluid is displaced due to the differential hydrostatic pressure that is created from the alternation of clearances. As a result, the clearances must be as higher as possible in order to achieve higher pressure difference and flow boosting. In case that the fluid contains solids, the clearances will be less, resulting in less efficiency.
- **The volumetric capacity** that a twin screw pump can handle depends on the volume of the clearances that are created by the screws in the core of the pump and thus by the size, the rotational speed and the number of pitches on the screws. Generally tight clearances reduce backflows and improve pump capacity and efficiency [41].
- **Backflow (or slip)** between the suction side and the clearances may occur and reduce the volumetric efficiency and the differential pressure between the suction and the discharge side of the pump [41, 7]. As the flow moves from the suction to the discharge side, its pressure increases, creating a pressure drive mechanism that forces the flow to the different direction. This drive mechanism is known as axial thrust and the result is the creation of backflow, which acts as an internal fluid leakage. In order to overcome it, the two screws are installed back-to-back. With this arrangement, the high-pressure channel is placed in the middle of the shaft and the low-pressure part, from which the flow enters the pump, is placed on the sides [41].

- **The differential pressure** between the suction and the discharge side of the pump is restricted by the strength of the pipe in pressure induced forces [7].
- A **minimum magnitude of the clearances** must be satisfied in order to accomplish safe operation. The clearances must big wide enough so that to allow thermal expansion of the flow and to provide the appropriate mechanical tolerance that the shafts need in order to withstand the pressure loads. For this reason the back-to-back arrangements are preferred since they provide larger clearances.
- A **maximum number of chambers** can be applied. The internal configuration of twin screw multiphase pumps may vary between the different manufacturers, but they can't overcome a specific number of chambers. The restriction arises from the fact that more chambers require longer shafts and in this case is possible the occurrence of internal leakages (backflow).

Operational restrictions and limitations of single screw multiphase pumps

- The can operate up to a **maximum temperature** which is dictated by the strength of the elastomeric material of the stator [41].
- The **rotational speed of the pump** is restricted by the strength of the shaft [41]. As the rotor rotates it is imposed to dynamic stresses coming from the rotational motion and the fluid that hits on the shaft. In case of increase of the rotational speed of the rotor's shaft, its fatigue increases and limits its mechanical strength.

The **volumetric capacity** is affected by the number of clearances that are created between the screw and the stator's sealing, the rotational speed and the pitch of the screws [41].

Design of twin screw multiphase pump

The twin screw pumps are characterized by two flow rates: the theoretical and the actual. The **actual flow rate Q_a** is measured with multiphase flow meters. It is influenced by the slip, the backflow of the effluent to the clearances and for this reason it is different from the theoretical flow rate that the pump can handle. From the flow rate that enters the pump from the suction side, there is an amount that is not handled because it is leaked from the internal clearances that exist between the screws and between the screws and the seal (slip). So, the **theoretical flow rate Q_{th}** is the maximum that the pump can handle.

The theoretical flow rate depends on the pump speed and the dimensions of the pump and is calculated by the following equation [73]:

$$\boxed{Q_{th} = A \cdot h \cdot n = Q_a + Q_{slip}}$$

Where:

h: pitch of the screws,

n: rotational speed of the pump,

A: net flow cross sectional area of the screws

Design of single screw multiphase pump

The **fluid displacement** is the fluid volume that is handled in one operating circle [45]. It depends on the geometrical characteristics of the screw and the clearances and it is calculated by the formula:

$$\boxed{V_o = 4 \cdot E \cdot D \cdot L_s}$$

Where:

D is the rotor's diameter

L_s is the pitch length of the stator

E is the eccentricity

As for the twin screw pumps, the theoretical flow rate that can be handled by the pump is decreased due to the backflow losses.

The **actual flow rate Q_a** is calculated by the formula [45]:

$$\boxed{Q_a = Q_{th} - Q_{slip}}$$

And the **theoretical flow rate Q_{th}** is calculated by the formula [45]:

$$\boxed{Q_{th} = 4 \cdot E \cdot D \cdot L_s \cdot n}$$

Where n is the rotational speed of the screw.

8.5. Performance issues in multiphase pumps

8.5.1. Cavitation

Cavitation is a phenomenon that occurs when the pressure of a liquid falls below its critical pressure and gas bubbles start to appear. In multiphase pumps cavitation is most likely to occur in the suction side, where low pressures occur or in case of handling fluids of high volatility. The pressure may decreases because of pressure losses or because of increase of the velocity of the fluid and thus it is more possible to occur in dynamic pumps (their operating principle is the increase of the kinetic energy of the flow) [65].

Initially the phenomenon starts with the formation of small bubbles (incipient cavitation) which gradually gather and create a slug gas flow, as the pressure continues decreasing. This may happen at any point of the flow. The existence of dissolved air in the liquid and solids are responsible for the initiation of cavitation.

The phenomenon may become destructive for the structure of the machine and for its operation. In case that the gas bubbles break, the pressure expansion is big enough that may harm the blades (the points where the bubbles break are destroyed, not the points where the bubbles appear).

Cavitation phenomena are more intense in helico-axial pumps as their operation is similar to centrifugal pumps. The flow pressure start to decrease due to friction when it enters the suction pipe, as it is indicated in Figure 61. The lowest pressure is met near the impeller's eye due to turbulence pressure losses. If the pressure decreases more than the bubble point pressure, gas bubbles will be created. As the flow goes near the tip of the blades, the pressure increase and the bubbles collapse, resulting to cavitation damage (noise, vibration and material loss from the blades).

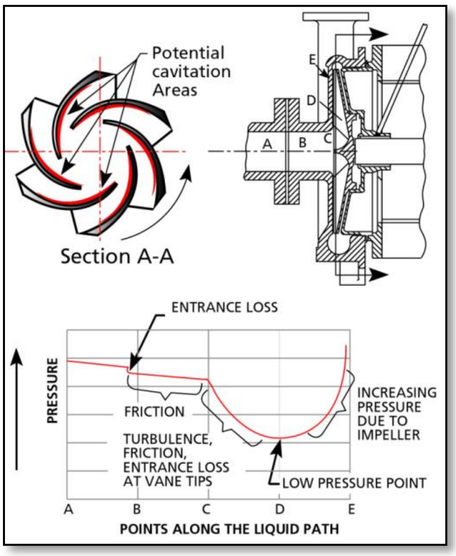


Figure 61: *Pressure variation through the inlet and the impeller of centrifugal pumps* [69].

The NPSHA is directly connected with cavitation. As long as the NPSHA has negative values (NPSHA≤0), the flow pressure decreases below bubble point and gas formation starts.

In order to avoid cavitation, the pumping system must be designed in a way that:

NPSHA>NPSHR + 0.5m and
NPSHA>0

This means that the pressure at upstream of the pump must be high. The additional 0.5m are proposed as a safety annotation [65]. For this reason the upstream vessels and flow lines are usually installed at higher elevation levels than the pump. In this way the upstream flow pressure increases by the hydrostatic pressure component. Another way to keep the suction pressure high enough in order to avoid cavitation is the use of pipelines with big diameter on the suction side, so that to decrease the friction pressure drop at this point. In case of centrifugal pumps the suction pressure may be decreased by decreasing the flow rate.

8.5.2. Priming

Priming is a significant issue that influences pump's ignition and is related to the ability of the pump to create the necessary pressure drive mechanism on the suction side when it is put into operation so that to start pumping the effluents. The pumps are distinguished in self-priming and non-self-priming pumps. Self-priming pumps have the ability to pump when they ignite, the air that is initially placed in the suction pipeline and the effluents. Non-self-priming pumps need to be filled with liquid in order to start pumping the effluents.
In case that the pump is non-self-priming the pressure at the suction side must be controlled in order to avoid losing of prime.

Centrifugal and Helico-axial pumps (non-self-priming)

Helico-axial pumps' operation is similar to centrifugals' and they are non-self-priming.
From their ignition centrifugal pumps operate according to the principle of increasing the kinetic energy of the flow and then transforming it into pressure increase. The increase of the kinetic energy of the fluid is accomplished by the movement of the impeller's blades. When the shaft starts to rotate the impeller also rotates counterclockwise and the air that is initially occupying the suction pipeline is getting into the pump's passageways [74]. This amount of air must be removed in order to start the fluid pumping.
Each pump is constructed to operate at a specific speed, so the lighter is the effluent, the less will be the kinetic energy that will be induced to the fluid. Since air is about 1/600 times less dense than oil, the impeller needs to rotate at a high speed, but it is constructed to operate at lower speed in order to pump the oil [74]. So the pump may not be able to remove the air and it will get stuck inside the pump and the pump won't be able to operate (loss of "prime"). The problem is enhanced when the static suction head is high, in case of installation of the pump at a higher elevation level than the reservoir.
In order to overcome this, before the ignition of the pump, the liquid must be inserted to the pump, so that to create the pressure difference that is needed when the pump will start operation. This may be achieved by the following ways [74]:

- Installation of **foot (non-return) valve** in the suction line: it's a valve installed at the bottom of the suction line and it closes when the pump stops, so liquid remains in the suction line.
- Installation of **priming tanks**: they are tanks installed between the suction side of the pump and the reservoir. They store liquid, so that when the pump ignites the liquid is directly guided through them to the pump's inlet.
- Installation of **priming inductor**: through them liquid is entering to the suction line.
- Installation of **vacuum providing devices** such as dry and wet vacuum pumps and ejectors.

Centrifugal and Helico-axial pumps (self-priming)

In order for the centrifugal pumps to be self-primed, an amount of liquid is always retained in the casing or in an accessory-priming chamber. When the pump starts, the impeller starts rotating and creates a vacuum which is filled with air from the suction side. This amount of air is mixed with the liquid that enters the pump. The air-liquid mixture is guided to the air separation chamber within the casing, where the air is separated and expelled to the discharge side. Since the air is lighter than the liquid, they will separate, so the liquid will return to the priming chamber and the air is guided to the atmosphere through the air release line. By this procedure is implemented the self-priming of the pumps, until all of the air from the suction side has been expelled and prime has been established [75].

Priming assurance can be achieved through the following [75]:

- In the priming chamber should exist adequate liquid.
- For outdoor and remote installations a heating element may be required to prevent freezing.
- In case of solids in the fluid, a strainer may be required so that to prevent the solids entrance to the priming chamber. If the eye of the impeller is plugged with solids the capability of the impeller to create a low-pressure area will be reduced.
- All the piping connections at the suction side should be sealed, in order to prevent the entrance of air (no air leak in the suction line).
- The time needed for priming should be minimized so that to avoid vaporization of the liquid in the priming chamber.
- Installation of a bypass priming line may be needed so that to prevent the creation of a backpressure in the discharge side during priming.
- The design of the suction side of the pump should not allow air entrapment.

Positive displacement pumps (self-priming)

Positive displacement pumps do not need help to be primed because the working principle is not based on energy transfer from the shaft to the fluid but on the mechanical displacement of the fluid. The characteristic of self-priming gives them the ability of dry running operation when they start to operate, meaning to run without liquid presence in the flow.

Self-priming is achieved due to the backflow internal leakage. Because of the backflows, the pump's chambers maintain always an amount of liquid and they don't lose prime.

8.5.3. Gas locking

Gas locking is referred to the flow blockage or stop that may occur due to high gas content in the suction side of the pump. In case of high gas content in the flow and high flow rates, the gas may accumulate and create gas pockets. The gas pockets that may appear in multiphase pumps are not always bad. In the twin screw pumps, gas pockets are developed between the screws clearances and in the helico-axial pumps as a result of the phase separation due to the centrifugal forces that are imposed to the flow. They are not creating problems in the flow as long as the liquid flow is not blocked, which occurs when the GVF becomes very high.

High gas content at the suction side of the pump may appear under the following possible conditions:

- When the suction pressure is low enough (less than the bubble point pressure) due to high friction losses or high flow velocities in the upstream pipeline and consequently dissolved gas is released.
- When the pressure in the upstream pipe is lower than the atmospheric pressure (vacuum piping pressure), in case of gaps at the sealing of the pump, ambient air will entrain through them.
- When the minimum static head at zero flow rate is large [41].

Gas starts to accumulate at the suction side of the pump, where low pressures are met and finally they may coalescent (gas pockets). Consequently, the flow obstacles are increased (head) as well as the NPSHR increases and this may result to complete blockage of the liquid flow and.

Multiphase submersible pumps are considered as the best option in case of extremely high differential pressure in the well.

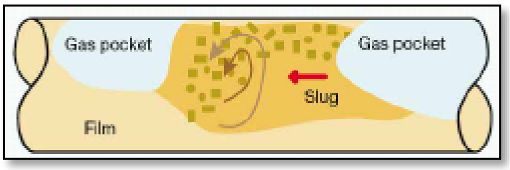


Figure 62: *Gas pockets configuration in slug flow* [40].

8.6. Multiphase pumps operation in series and in parallel

The efficiency of the pumping system that results from the combination of two or more pumps in series or in parallel is the same with the efficiency of one pump. The pumps can be driven by one motor all together all each one separately. The arrangement of the hydraulic connection of the pumps may combine more than one groups of pumps connected in series with more than one groups of pumps connected in parallel.

In series operation

In series installation of the pumps corresponds to the hydraulic connection of the pumps so that the same flow rate to pass through them and the result will be the increase of the dynamic head that they can handle. The overall operating point is shifted to greater differential pressures, while each pump is operating within her performance envelope.

The rotational speed of the pumps in series must be controlled in order to avoid instabilities [41]. As the flow passes through the first pump, the volumetric flow rate decreases and if it falls below the surge limit, the pressure in the suction side of the next pump may increase more than the value that it can handles. So by controlling the rotational speed of the intermediate pump, are prevented excessive pressure fluctuations.

In parallel operation

In parallel installation of the pumps corresponds to the hydraulic connection of the pumps so that the flow rate that can pass through will be the summation of the flow rate each one can handle, while the dynamic head will remain the same.

8.7. Comparison of multiphase pumps

The main differences between the two different categories of multiphase pumps (helico-axial and positive displacement with screws) are the following [54]:

- *Positive displacement pumps provide constant flow rate for a given rotational speed at one working cycle, regardless the discharge pressure*

When a PDP operates under constant rotational speed, the screw clearances keep creating the gap cells with the same frequency. So the clearances are “trapping” and displacing a specific amount of flow, which is gathered in the gap cells. If the speed changes the volumetric flow rate will also change because the speed of displacement will also change. So the flow rate that all the positive displacement pumps handle doesn’t depend on the discharge pressure, but only on the volume of the screw clearances and its rotational speed.

On the other hand the flow rate that all the helico-axial pumps can handle depends on the impeller’s size, the rotational speed and the total head that the pump needs to overcome.

- *Positive displacement pumps tend to have lower capacity than the rotodynamic* [7]

Positive displacement pumps are used when the flow rate that the pumps must handle is low or moderate and the discharge pressure must be high.

Progressive cavity pumps can handle only very low flow rates because they are restricted by the small size of the clearances between the screw and the sealing of the pump.

Helico-axial pumps are used for the handling of large flow rates under low or moderate differential pressure but they are not suitable for handling low flow rates under high pressure [8]. This limitation is connected with the energy conservation principle in helico-axial pumps. The pressure they can deliver is connected with the head losses. Operation under high pressure means that the flow velocity and the flow rate will be low, the impeller diameter will be high and consequently, a pump of bigger size will be needed and the mechanical losses will be increased.

On the other hand operation of helico-axial pumps at low flow rates induces vibrations due to internal flow re-circulations (backflows), high-temperature rises and possible surge behavior, that may damage the pump [41].

In Figure 63 are presented the different operational envelopes for the four main categories of multiphase pumps. The envelopes indicate the ranges of the possible pressure boost that each pump may give to the flow and the range of the total flow rates that each pump can handle. The data for the pressure boost and the handling flow rates are based on published information from pump manufacturers [62].

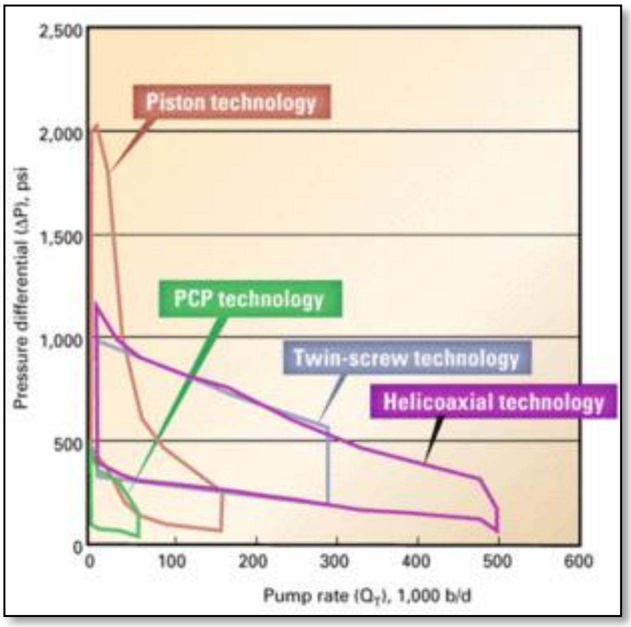


Figure 63: *Multiphase pump's operational envelope* [62]

- *Corrosion tolerance*

Positive displacement pumps are more prone to corrosion than the rotodynamic [7].

- *Solids tolerance*

Positive displacement pumps tend to have higher tolerance in the existence of solids in the flow than the rotodynamic [7]

- *Gas Volume Fraction*

Positive displacement pumps are less affected by changes in GVF, Suction Pressure and Differential Pressure than the rotodynamic [7]. However both twin screw and helico-axial multiphase pumps can handle flows with high GVF.

- *Fluid viscosity*

High viscosity fluids are better handled by positive-displacement pumps. In helico-axial pumps the increase of flow viscosity leads to the increase of the friction pressure losses, so the friction head is increased and the total pump's head is decreased [8].

- *Differential pressure*

The differential pressure is the pressure that is created between the discharge and the suction side of a pump.

In helico-axial pumps the differential pressure depends on the mixture's density [42]. This means that the pump adjusts its operating characteristics (rotational speed) and changes the discharge pressure, according to the variations of mixture's density in the inlet of the pump that cause pressure variations.

	Twin Screw Pump (TSP)	Single Screw Pump (PCP)	Helicoaxial Pump
Viscosity	High	Any viscosity	Low
Type of fluids	Heavy crude oil	Fluids with sands, coarse of fine particles, abrasives	Fluids with sands, abrasives
Solids tolerance	Limited	High	Low
Gas Volume Fraction (GVF)	50~95%	50~95%	0~100%
Suction Pressure	Low	Low	Any (70~600psia)
Diferential Pressure [psi]	≤1,000 psi	≤600 psi	≤3,000 psi
Design total flow rates (at suction conditions) [bbl/day]	Medium capacity 10,000~300,000bbl/day of gas, oil and water	Small capacity <91,000 bbl/day of gas, oil and water	Large capacity 15,000~220,000bbl/day of gas, oil and water
Applications	Onshore	Onshore	Onshore
	Offshore		Offshore
	Subsea		Subsea
Priming	Self-priming	Self-priming	Not self-priming

Table 11: *Operational characteristics for different types of multiphase flow boosting systems (the jet pumps are operating only in single phase flow but they appear in the table for comparison reasons.).*

9. Simulation and Results

9.1. Simulation

Description of the case

In the present work the replacement of a conventional separation system with a surface multiphase pump is evaluated. The simulation is based on the data presented in the Example 2a of GAP software from the IPM suite [76].

An offshore oilfield at the Loggie Mill area is considered. It has two reservoirs (A and B). Each reservoir is drained by three wells which end up to a manifold. Both manifolds (A and B) are installed on the seabed, around 600ft under the sea level. A flowline of 7.5 km is connecting the manifolds between each other and another one is connecting Manifold B with the separation facilities. In the conventional production configuration the effluents from all the six wells are transferred through a 12km pipeline to the onshore separation facilities.

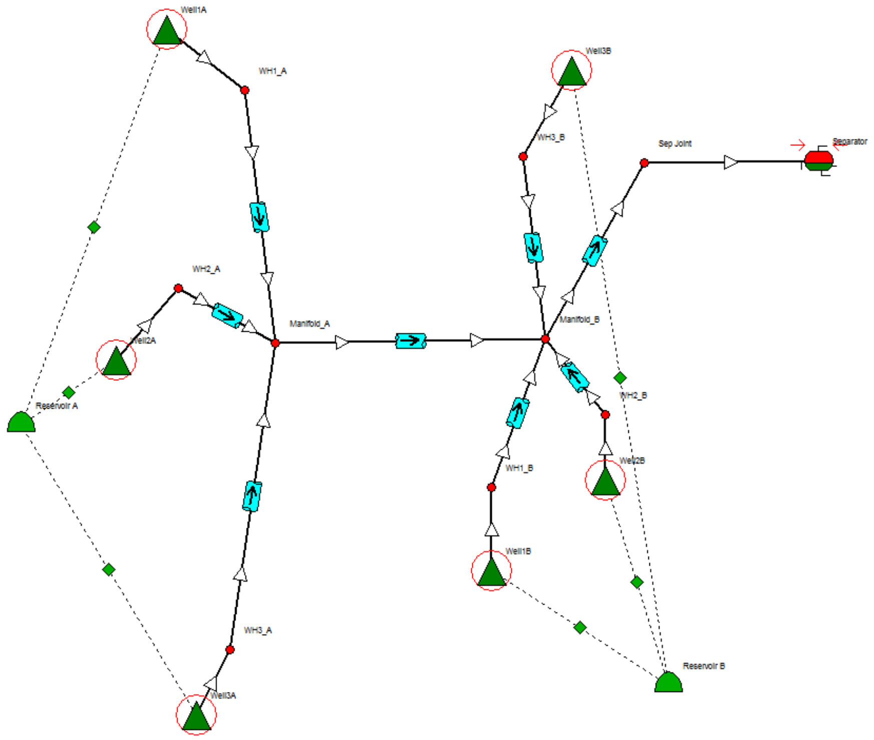


Figure 64: *Field configuration before the multiphase pump installation.*

The multiphase pump is installed on the seabed, it boosts the flow and a multiphase flowline transfers the effluents to the separation facilities onshore.

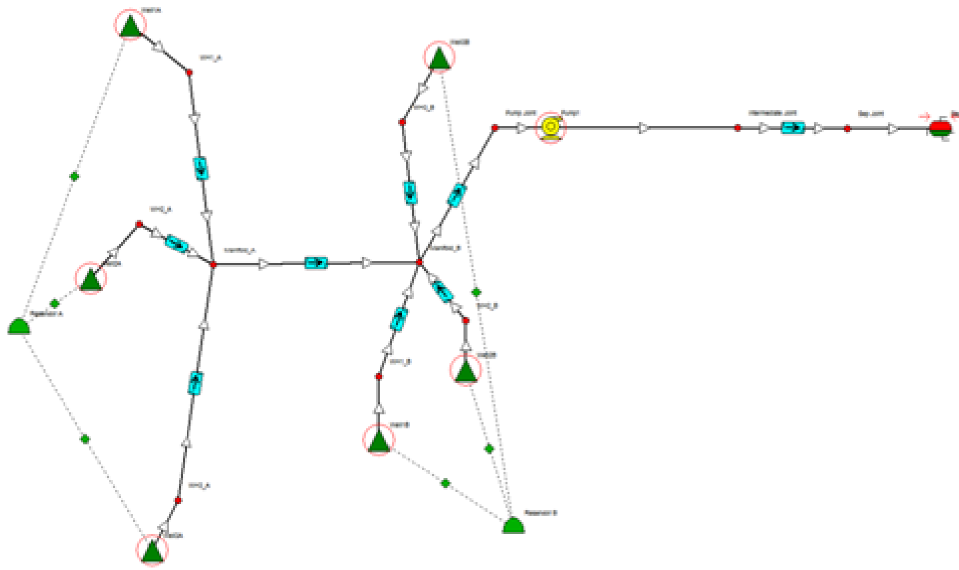


Figure 65: *Field configuration after the multiphase pump installation.*

<u>Constraints and assumptions</u>

- The pressure of the separator is selected to be 200psig, which is a realistic value, since the pressure at the separator usually doesn't exceed 500psia.
- The liquid capacity of the separator is selected to be limited to 20,000sbbl/day.
- The simulation is taking in consideration the ability to control the pressure in the midstream pipelines, by opening and closing the wellhead chokes at the surface. So it is assumed that the chokes will not be fully open during all the years of production. This is achieved by enabling the dP calculation option for each well. Also by this selection, the simulation can be implemented with main target the optimization of the production, which can be achieved by changing the status of the chokes with respect to the constraint of the liquid flow rate that the separation facilities can handle.

<u>Reservoirs and wells data</u>

Since no accurate data about the production effluents composition existed, the black oil model method was used for the estimation of the fluid properties. For this reason, the flow assurance issues of wax accumulation and hydrates formation were not calculated.

Information for the reservoirs is obtained by applying history matching of production data, according to the material balance method. Production data for the reservoir A were collected for the period 01/01/2003 up to 22/12/2010 and the volume of the oil initial in place was estimated 376.952MMsbbl in standard conditions (STOIIP). Similarly, production data for Reservoir B are available for the period 01/01/2008-01/12/2010 and the corresponding STOIIP was estimated 238.93MMsbbl. The history

matching was implemented with the software package MBAL of the IPM suite and the output files were used as input for the reservoirs at the GAP software.
Information for the wells is obtained by the output files of the software PROSPER (from IPM suite), with which the IPR and VLP curves were built.

PVT data

Both reservoirs are oil reservoirs. The main characteristics of the reservoirs as the oil specific gravity, average reservoir pressure, Gas-Oil-Ratio (GOR) are presented in Table 12:

Properties	Reservoir A	Reservoir B
API [º]	37	39
GOR [scf/ sbbl]	800	500
Average reservoir pressure [psig]	3,750.42	3,542.19

Table 12: *Main characteristics of the reservoirs.*

Reservoir B becomes undersaturated at 01/08/2010 when the reservoir pressure declines below the bubble point pressure which is P_b=3,500psia. On the other hand Reservoir A becomes undersaturated earlier at 01/05/2010. The pressure keeps declining after production starts, due to depletion.

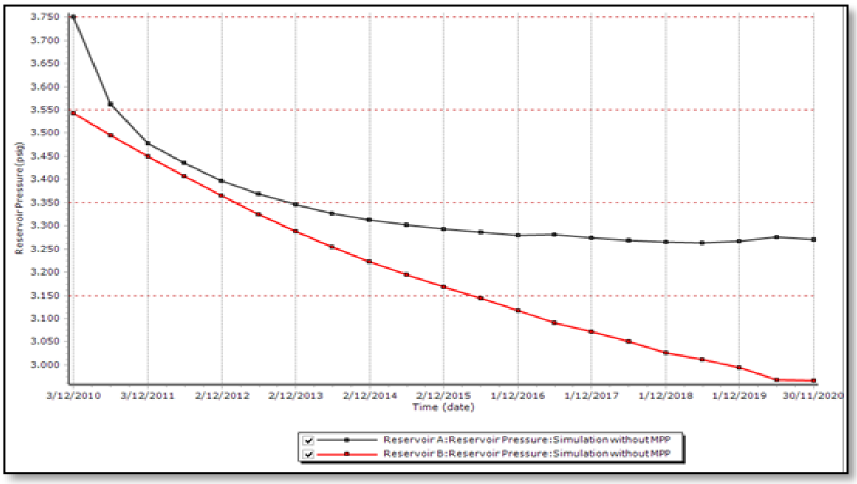


Figure 66: *Reservoir pressure declination during production for both reservoirs.*

Flowline data

In GAP simulation package the distance between the reservoirs and the wells are not taken into account, because they are governed by the VLP curves which are estimated by the PROPSER simulation package they have been inserted in GAP for the wells' description.

The flowlines that are taken into consideration are the ones that connect each well with the corresponding manifold, the flowline that interconnects the two manifolds as well as the flowline that connects manifold B with the midstream facilities.

All the flowlines have 0.0006in roughness. The rest of their dimensions are given to the Table 13 for the conventional system without the MPP and for the system with the MPP.

		Pipe Segment Length [km]	Pipe ID [in]	Upstream TVD [ft]	Downstream TVD [ft]
	WH1A to ManifoldA	1	6	600	600
	ManifoldA to ManifoldB	7.5	8	600	525
Before the MPP installation	**ManifoldB to Sep Joint**	3	12	525	0
	ManifoldB to Sep Joint	4	12	515	525
	ManifoldB to Sep Joint	3	12	480	515
	ManifoldB to Sep Joint	2	12	525	480
After the MPP installation	**ManifoldB to Pump Joint**	0.050	12	600	525
	Intermediate Joint to Sep Joint	3	12	525	0
	Intermediate Joint to Sep Joint	4	12	515	525
	Intermediate Joint to Sep Joint	3	12	480	515
	Intermediate Joint to Sep Joint	2	12	525	480

Table 13: *Flowline dimensions before the MPP installation.*

The flow in the pipelines is considered to be multiphase. The pressure drop is calculated using the "*Petroleum Experts 5*" correlations, as it is recommended by the GAP software.

Pump data

The pump that was selected is a multiphase helicoaxial type pump manufactured from the company OneSubsea. The pump has 12 stages and its name is H300/105. The minimum flow rate that can handle is 9,056.6bbl/d and the maximum capacity is 72,452.8bbl/d, while the maximum differential pressure that can be ontained is 1,522.9psi. The discharge pressure of the pump is calculated 345psia and its optimum power 753HP.

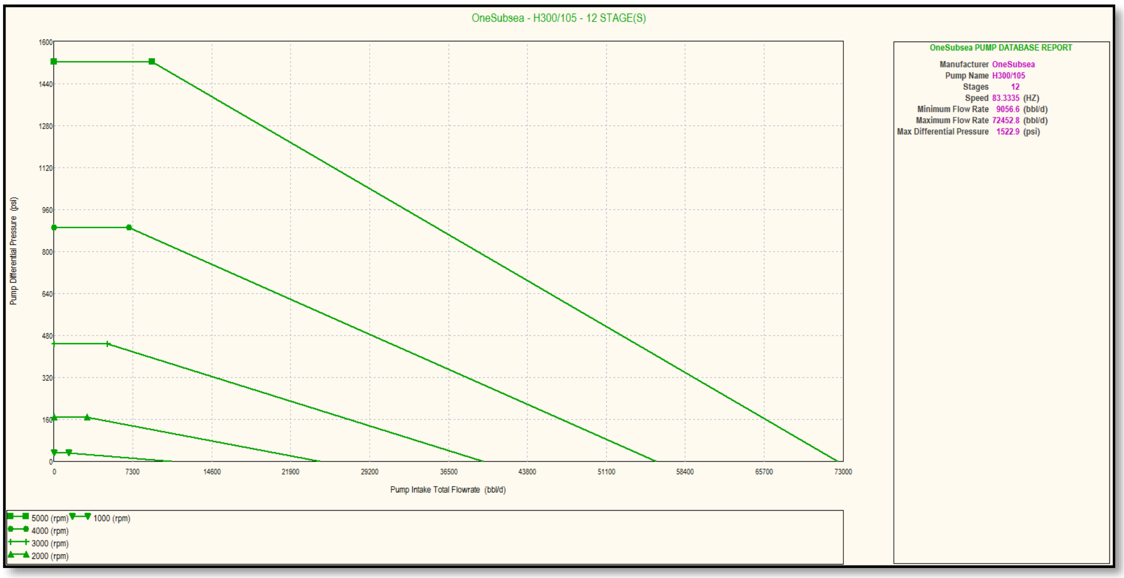


Figure 67: *Pump's data and characteristic curves for different speeds.*

<u>Prediction results for the conventional system</u>

A prediction simulation was run for the period from 01/12/2010 up to 10 years later until 01/12/2020 (3,653 days in total) with a time step of 6 months. The prediction was ran with the target of optimization of the oil production taking into consideration the constraint of the maximum daily liquid rate that the separator can handle. The simulation is taking into consideration the ability of optimizing the production by alternating the opening and closing of the surface chokes.

The results of the simulation are the following:

A. <u>Increase of the oil recovery</u>

The oil recover from Reservoir A is increased by 0.5% and from Reservoir B by 1%

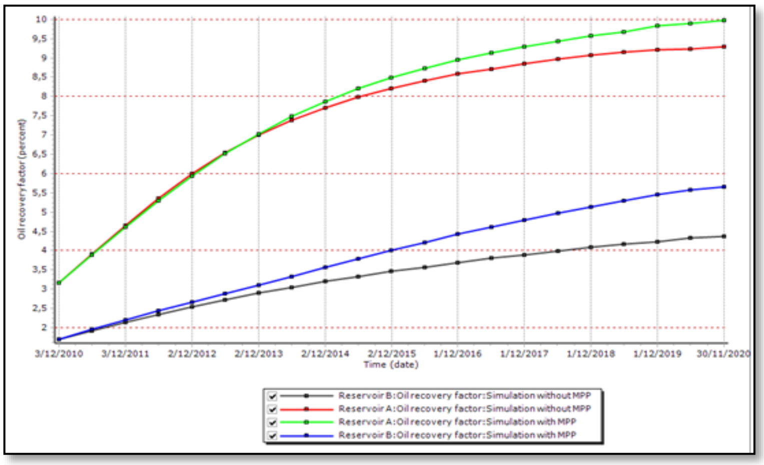


Figure 68: *Oil recovery from both reservoirs before and after installation of the MPP.*

B. Cumulative production before and after the integration of the MPP

By installing a multiphase pump the cumulative oil production in the period of 10 years between 1/12/2010 until 1/12/2020, increases by 20%. Specifically the cumulative oil production for the conventional system is approximately 29.5MMsbbl/day and after installing the multiphase pump, it increases to 35.4MMsbbl/day.

	Cumulative Oil flow rate [sbbl/day]	Cumulative Gas flow rate [MMscf/day]	Cumulative Water flow rate [sbbl/day]	GOR [scf/sbbl]
Before MPP installation	29.484	20,973.40	17.159	660
After MPP installation	35.402	25,257.76	26.958	1,433
Difference	+20.07%	+20.43%	+57.11%	+117%

Table 14: *Cumulative production flow rates and GOR at the separator at 01/12/2020 before and after installation of the MPP.*

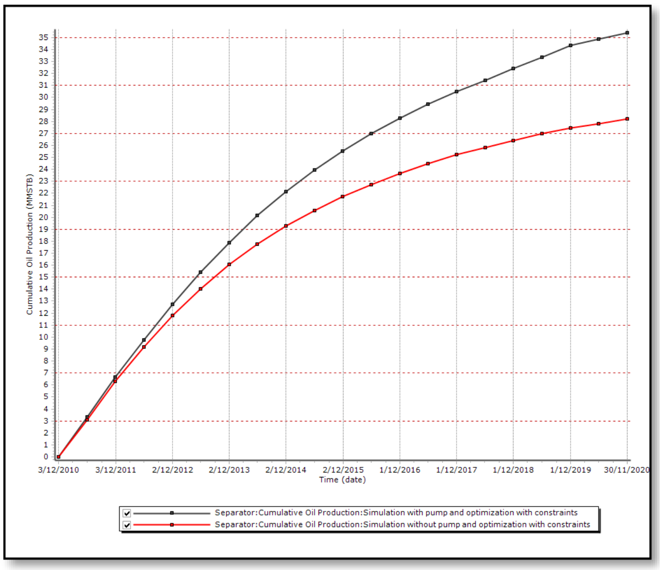


Figure 69: *Cumulative oil production on the separation facilities before and after installation of the MPP.*

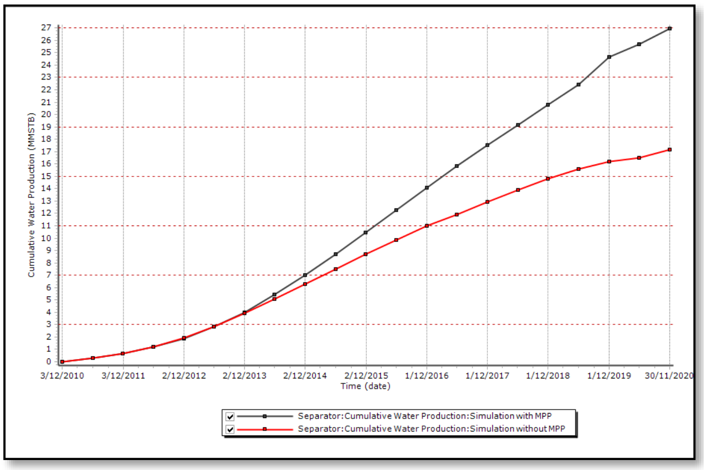


Figure 70: *Cumulative water production on the separation facilities before and after installation of the MPP.*

C. Oil-Gas-Water-Liquid production rates when the MPP is integrated

The multiphase pump boosts the production from each well. The prediction calculations start at 01/12/2010. The oil production flow rates from each well up to this time are summarized in Table 15:

	Separator	Well1A	Well1B	Wel2A	Well2B	Well3A	Well3B
Oil flow rate [sbbl/day]	18,358.2	4,758.4	1,059.3	5,443.8	1,085.3	4,789.3	1,222

Table 15: *Oil production flow rates at 01/12/2010.*

The wells that are connected to the Reservoir B are more influenced by the installation of the MPP. Their oil production is increased more than 70% for Well 1B, 55% for Well 2B and 30% for Well 3B. Well 1A is depleted on 1/12/2019 when the oil flow rate that is produced is becoming zero as it is shown in Figure 72. With the installation of the MPP the production curves over time are shifted upwards. As it is observed from the Figures 71 and 72 the oil rates increase and the life of the wells 3A, 2B and 3B are elongated.

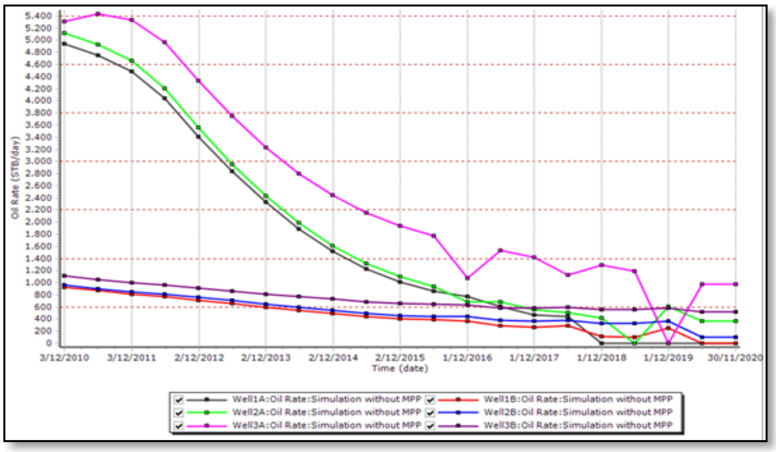


Figure 71: *Oil production rates from each well before the installation of the MPP.*

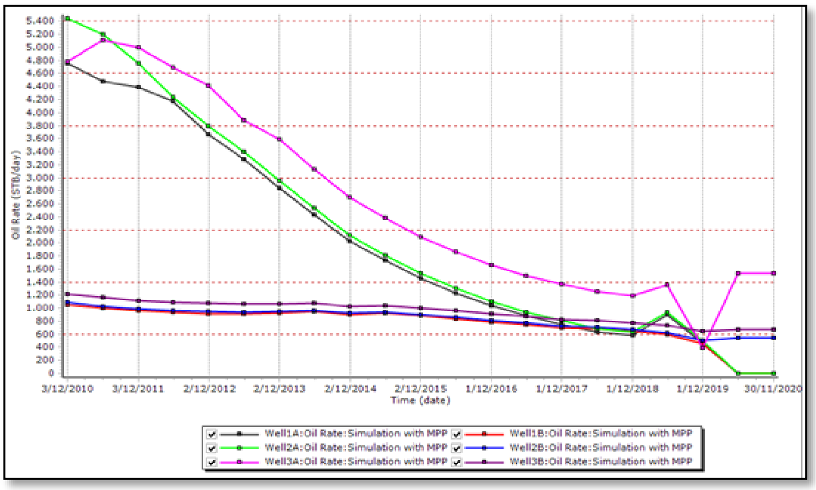


Figure 72: Oil production rates from each well after the installation of the MPP.

As the production continues the reservoirs get depleted so the production flow rates, as they are measured at the separation facilities, decrease. However the water production increases, which indicates the depletion. Also the GOR increase, which means that more gas will be produced for every barrel of oil that is produced. Since the API has not changed significantly, the increase of GOR also indicates the depletion, meaning that the reservoir gets drained of oil. The production flow rates and the effluents characteristics for the scenario of MPP placement are presented in Table 16.

Production dates	Oil flow rate [sbbl/day]	Gas flow rate [MMscf/day]	Water flow rate [sbbl/day]	Liquid flow rate [sbbl/day]	API	GOR [scf/sbbl]	Water cut [%]
01/12/2010	18,358.2	13.677	1,646.6	20,004.8	37.36	744.98	8.23
01/12/2020	2,897	4.152	6,844	9,941	37.93	1,433.22	70.26

***Table 16:** Production flow rates at the separator at the beginning and the end of prediction dates, for the case of MPP installation. (The Liquid flow rate exceeds the constraint of 20,000sbbl/day, but this is not an actual increase but it is correlated to the software simulation calculations).*

9.2. Conclusions

Remarks on the results

The integration of the multiphase pump (MPP) in the midstream facilities right after the wellhead, is beneficial and delivers the purposes for the production enhancement.

This simulation used a pump that actually was much oversized for the needs of the field. On 01/12/2010, when the pump’s operation started the oil production was approximately 18,358.2sbbl/day. The minimum flow rate that the pump can handle is 9,000bbl/day, which is reached almost 4.5 years after its operation (approximately on May 2014). This means that after this date the pump is not actually boosting the production. So it is an oversized pump, which was intentionally selected from the database of the software and used only for academic purposes, in order to emphasize to the benefits of MPPs use. The simulation results show an average pump’s efficiency of about 30%, which is very low.

However, the simulation shows that even in case of using an oversized multiphase pump which doesn’t operate at the optimum operation or maximum efficiency point, it comes up with an increase of 20% of the oil production.

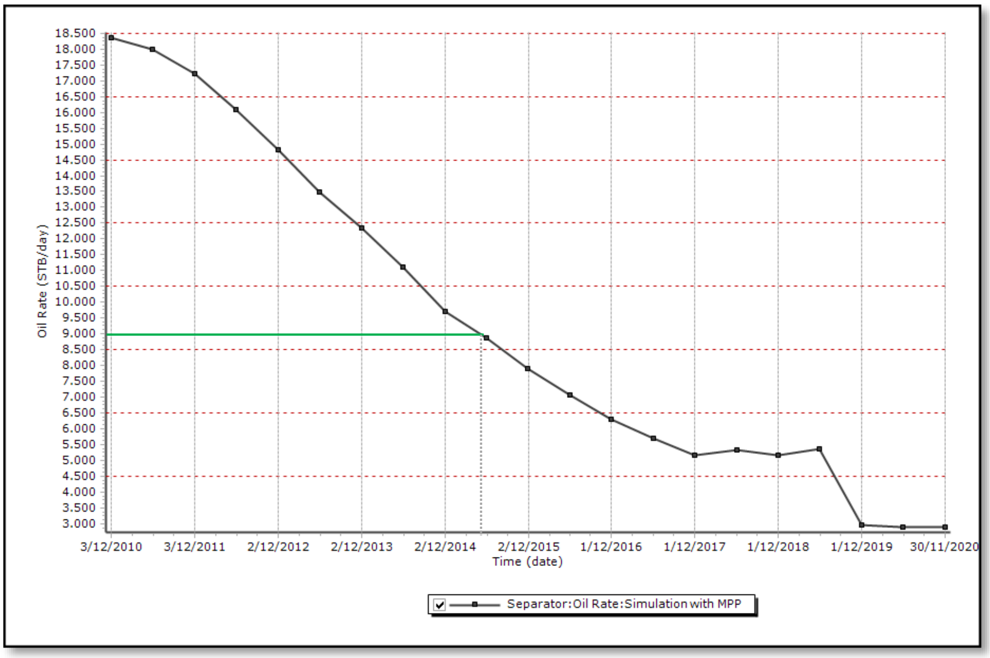


Figure 73: *Oil production rate after the installation of the MPP.*

<u>*General*</u>

✓ The installation of a multiphase pump enhances the oil recovery. The gas and oil production increase, as well as the water cut, because the reservoirs reach to their depletion.

✓ The selection of the appropriate pump follows some technical rules relevant to the characteristic curves of each pump. Normally the optimum operating range is between ± 10% of their maximum efficiency point. Pumps are usually oversized in order to cover possible changes in the future production, which means that are imposed to operate outside of their optimum efficiency range. According to the simulation that was implemented in this thesis, it seems that even in case of a “bad design, they are quite beneficial.

✓ The minimum 20% increase of the cumulative oil production in the 10 years of operation of the MPPs are interpreted in big financial profits. Assuming 40$/bbl, the gross benefit will be approximately 288million $. The total financial benefits from the elimination of single phase flowlines and their equipment are additional cost minimizer parameters.

✓ The installation cost, the limited installations, hands-on experience and knowledge about multiphase pumps operation are the biggest obstacles for the wider implementation of these applications.

10. References

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