Volumetric Capacity Determination for Accumulators

Thesis

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Department EPP-WE-OA

Submitted by

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Affidavit

I declare in lieu of oath, that I wrote this thesis and performed the associated research myself, using only literature cited in this volume.

(Stefan Bischof)

Acknowledgement

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ModuSpec

Also I thank my whole family for supporting me all the years.

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1 Abstract

The given diploma thesis was intended to provide OMV E&P GmbH with a clear understanding on how to address the issue of accumulator volumetric sizing within their new standard for Well Control. The first question that had to be answered was if the provisions made in API standards are sufficient. The thesis discusses the fundamental basics required to understand the calculations made in API and consequently looks at other international standards and their provisions. By defining standard cases for workover and drilling Blow Out Preventer (BOP) stacks it could be shown that API requirements leave room for improvement as they may lead to the inability of closing the BOPs in a worst case scenario. With this gap identified, the thesis describes a recommended practice on how to size accumulators in regard to their volumetric capacities.

Die vorliegende Diplomarbeit dient dem Zweck der OMV E & P GmbH Informationen über die volumetrische Dimensionierung von Accumulator Einheiten zu liefern. Zu Begin stellte sich die grundlegende Frage ob die API-Standards mit ausreichend Sicherheit definiert sind um im Ernstfall einen vollständigen Einschluss der Bohrung zu gewährleisten. Die Arbeit behandelt die wesentlichen Grundlagen um die in API vorgenommen Berechnungen nachverfolgen zu können. Weiters werden andere internationalen Normen und Bestimmungen für die in der Arbeit vorgenommen Berechnungen herangezogen. Durch die Definition von Standard Workover- und Drilling- Blow Out Preventer (BOP) Stacks hat sich gezeigt, dass die API Anforderungen Raum für Verbesserungen lassen, um eine sicher Schließung der BOPs in einem worst case scenario gewährleisten zu können. Nach Identifikation dieser Schwachstelle beschreibt die Arbeit eine empfohlene Vorgehensweise, wie Akkumulatoren im Bezug auf ihre volumetrischen Kapazitäten zu definieren sind.

2 Introduction

One of the worst occurrences during a drilling or work over operation is when liquid or gaseous media enters uncontrolled into the wellbore and creates what is referred to “a kick”. If there is no safety equipment installed on the rig the kick may grow up to become an uncontrolled flow of gas, oil or other media out of the wellbore. This uncontrolled flow is then referred to as a blowout. To prevent the drilling or work over rig from damage or possible destruction and the crew from serious injury and/or death a system to prevent such blowouts has to be installed.

The so called well control equipment principally composes of a blowout preventer (BOP) or a full BOP stack, an accumulator system, a remote control system and an arrangement of manifolds and special valves to allow a controlled release of medium from the wellbore.

The BOP is a hydraulic actuated device which can close the wellbore with and without a working string in it (depending on the type of BOP). The hydraulic energy to close this device is provided by the accumulator system. The accumulator stores the hydraulic energy produced by positive displacement pumps in bottles which are precharged by inert gas. The accumulator unit, for safety reasons, is to be located away from the workfloor and therefore a remote device, which allows for operation of the BOP´s from the working area, is required. The remote control is located on the workfloor and communicates with the accumulator unit through electric or pneumatic connections. When the blowout is trapped in the wellbore the evolving wellbore pressure has to be controlled. There are two more parts of well control equipment to regain control over the well. The choke line to release and regulate the pressure. For killing the well a kill line is installed, through which mud is circulated into the well to stop the flow out of the formation.

Due to the criticality of this equipment the EP industry has evolved several standards to ensure functionality for all kind of equipment and operations. The American Petroleum Institute (API) as a leader in regard to EP standards is dealing with well control processes within several of its papers. API SPEC 16D and API RP 53 are of major relevance when it comes to accumulator units.

The design criteria for accumulator units within API differ quite significantly from other standards (e.g. Norwegian Regulations).
Therefore this thesis is intended to determine what are the rational for the different approaches and to find a suitable solution for OMV.

3 Well control equipment

Every rig crew has to maintain well control at all times which means to maintain a minimum bottom hole pressure to prohibit formation fluid from entering the hole while drilling or workover operations are conducted. In the unwanted event of a blowout (when formation fluid or gas has entered the hole) the well control equipment shall have the ability to shut in the well and allow a controlled release of media. An overview of a standard well control arrangement is shown in Figure 1.

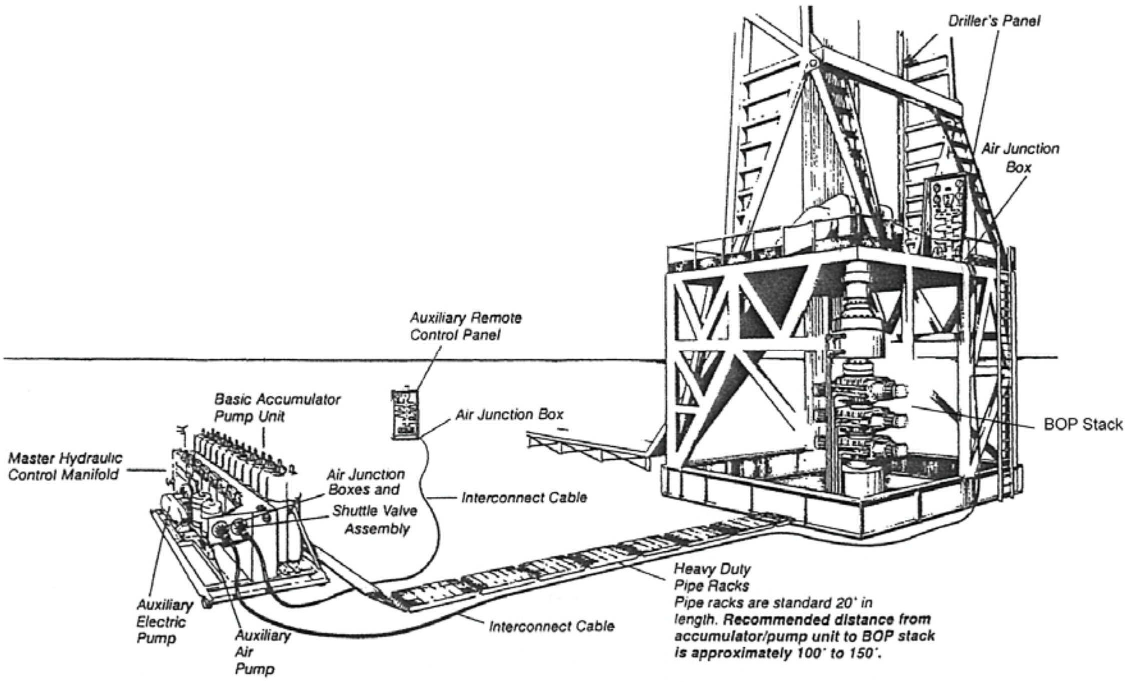


Figure 1 Well control equipment [1]

3.1 Blowout Preventer

The main part of the well control equipment is a hydraulic actuated device which allows to shut in the hole. This piece of equipment is referred to as BOP. The blowout preventer is mounted on the surface casing by a flanged joint. For most drilling operations more than one preventer is mounted on the surface casing, merged to a so called BOP stack. Figure 2 shows a typical surface mounted BOP stack without any hoses.

Figure 2 Surface mounted BOP stack [2]

The BOP stack shown in Figure 2 is found on rigs for onshore applications. For offshore applications the BOP stacks can be mounted above the sealevel or on the seabed.

This thesis only discusses well control systems for onshore drilling and work over rigs.

As shown in Figure 2 the BOP stack is structured in different types of BOP's and spools. The different types are listed below.

3.1.1 Annular Preventer

The annual blowout preventer is a universal tool to shut in a well. With this device it does not matter what size of work string (if at all) is inside the preventer when the BOP has to be closed.
A cutaway view of such an annular preventer is shown in Figure 3.

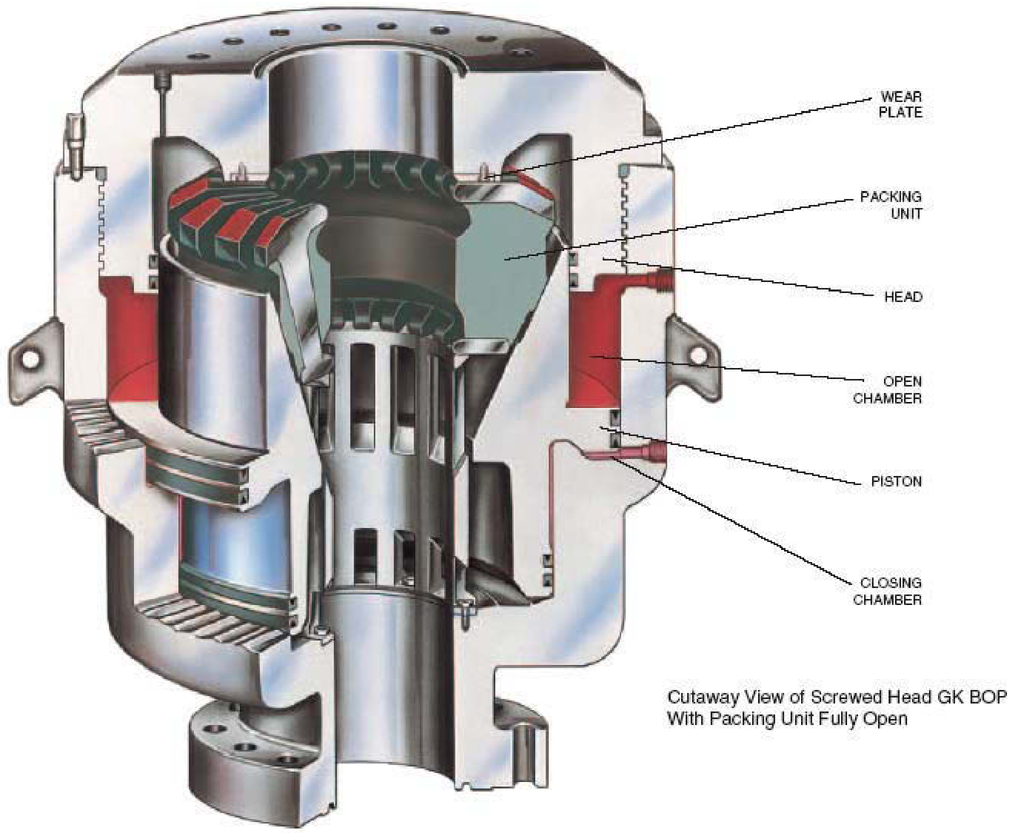


Figure 3 Annular preventer cutaway view [3]

The central functional element of this BOP type is the packing unit also called donut. The donut is composed of rubber and steel elements and is responsible for sealing of the well. Figure 4 shows a cut donut where the steel inlays can be observed, that support the rubber. Without these inlays the rubber would extrude uncontrolled and a correct function could not be ensured. The extrusion is enforced by the piston as illustrated in Figure 3. The tapered hole in the piston presses the donut inwards to the centre until it seals on the workstring or closes the empty hole. The seating stress of the rubber on the workstring is regulated by a separate pressure control device for this preventer.

Figure 3 illustrates an annular BOP in a wellbore assisted design; this means in case of a high pressure in the wellbore, the pressure adds to the closing force. The piston has a shoulder on the inner diameter where the pressure can act to support the closing operation and the sealing force.

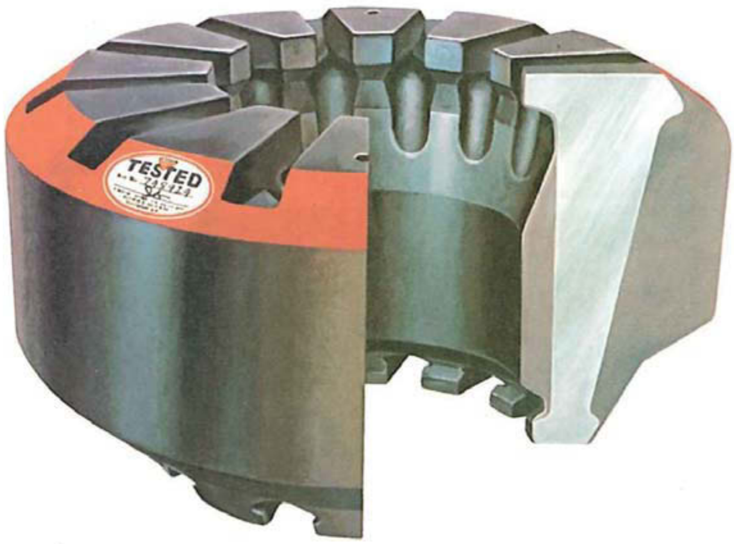


Figure 4 Annular BOP sealing element (donut) [1]

As this BOP can handle all possible diameters of the work string between zero and the nominal diameter, this type of preventer can also be used for snubbing and stripping operations. For these two operations the tooljoint on the workstring has to glide smoothly trough a closed annular BOP. In case of snubbing or stripping the workstring has to be moved through the closed preventer because the wellbore is under pressure. The main difference between stripping and snubbing is that by a stripping operation the workstring is forced down the wellbore only with help of gravity. By a snubbing operation there has to be a device installed on the rig which provides an additional down force for tripping in the workstring. This is of special importance on workover rigs, as theses are common operations on such units.

3.1.2 Ram Type Preventer

The ram type BOP, as the name indicates, has two rams which can close the wellbore at any time. The principal design of such a BOP type is shown in Figure 5.

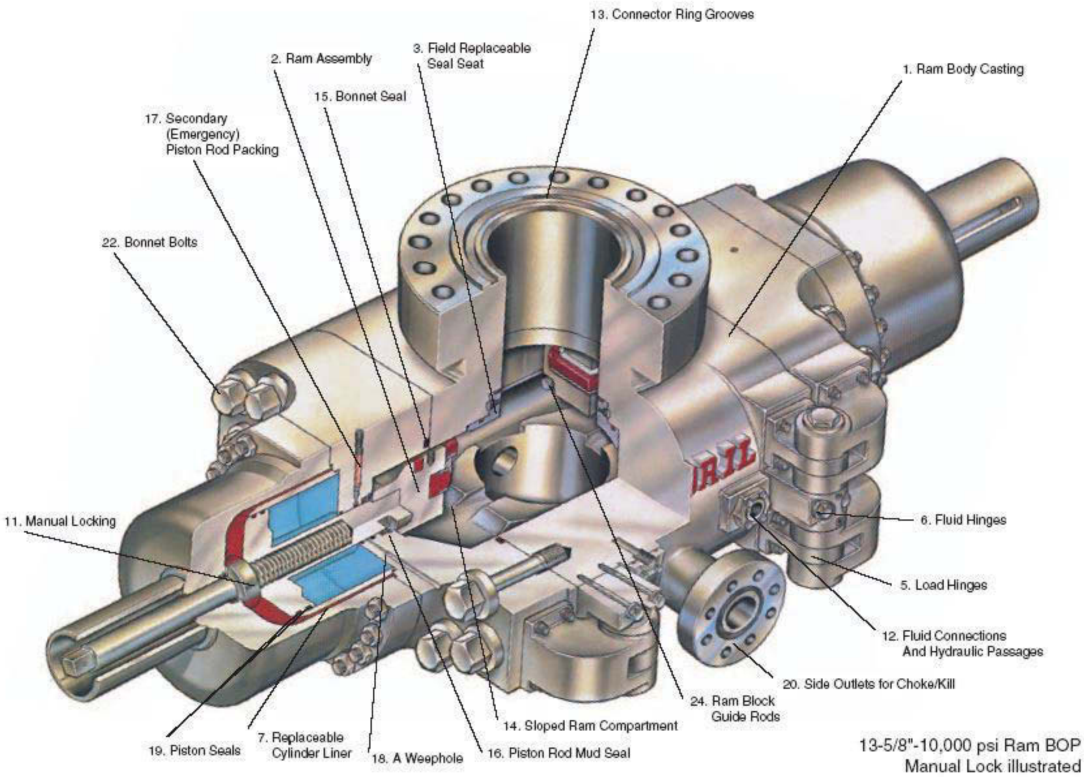


Figure 5 Ram type BOP [3]

The hydraulic energy produces a force on the piston to close the rams. This rams can be easily changed to optimize the device for the current situation on the rig. There are many different types of rams available. An overview of the most common used rams is shown in Figure 6. The standard rams, the so called pipe rams, are designed to shut in the well with a workstring in it. Blind rams are used for closing the BOP on an empty wellbore. A modification of the blind rams is the combined blind-shear-rams. This type can shear a workstring and seal the wellbore in one go. In most of the newer BOP stacks blind-shear-rams are installed. They are used in special cases where no preventer or other protection device is mounted to the workstring. When the workstring diameter is changed, normal, the pipe rams will have to be changed too. To avoid or minimize changing time variable pipe rams are on the market.

The low flexibility is the main negative aspect of this BOP type. To compensate this there are normally more than one ram-type-BOP with different ram types installed in the stack.

After shearing a workstring, the next tooljoint has to rest on the lower pipe ram otherwise the whole string would fall down into the wellbore. The whole weight of the workstring rests on the pipe rams. Concerning these weights there is a difference between the variable and the fix diameter pipe rams

The variable pipe rams have a dedicated load rating from the manufacture which they can carry. This load is considerably lower than the load of the very robust designed single pipe rams. These specifications of the pipe rams are very important when a shear ram is placed in the stack.

The evolving forces and the short response time are the great benefits of this type.

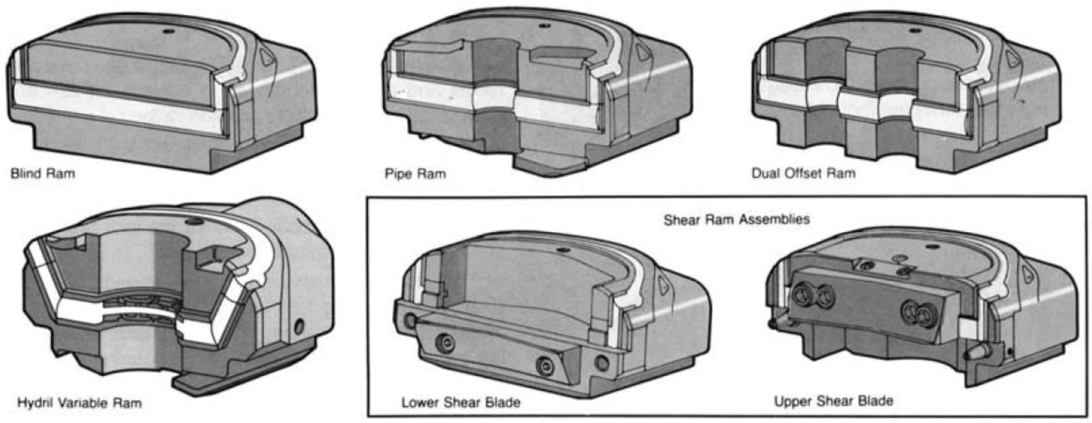


Figure 6 Ram styles [3]

3.2 Accumulator

Every BOP is powered by a hydraulic system which provides a sufficient amount of hydraulic energy. For closing a BOP the hydraulic power system has to provide a high volume of fluid with high pressure in a short period of time. Pumps which can deliver such high volumes and pressures at the same time would be inefficient in terms of size and costs. Therefore the accumulator is much more than just a pump system. It is an energy storage device for quick pressure release.

For the purpose of storing energy accumulator bottles are mounted on several manifolds. A pump system with two different pump types supplies the pressure to charge these bottles. The manifolds merge the bottles hydraulically together and control valves manage the flow of the hydraulic fluid to the different BOPs on the stack. For the hydraulic flow return from the BOP a reservoir is located on the accumulator. It has to be mentioned that the accumulator bottles serve an additional important purpose: to provide hydraulic energy in case all power is lost on location.

In most cases an accumulator is placed about 100’ (33m) to 150’ (50m) away from the BOP stack. On small high mobility workover rigs the accumulator is sometimes directly mounted on the truck or the mobile platform. On offshore rigs there exist different concepts for the mounting of the accumulator units. Dependent on the water depth the accumulator can either be mounted on the BOP stack above the seabed or on the offshore platform. The remainder of this thesis will only cover onshore units. Figure 7 shows the general layout of an accumulator for onshore use. This picture, showing an older type of accumulator, is only indented to show the principal layout of such a unit. As in Figure 7 shown only two manifolds are installed on which the accumulator bottles are mounted. For this reason this design is not in accordance with the API provisions.

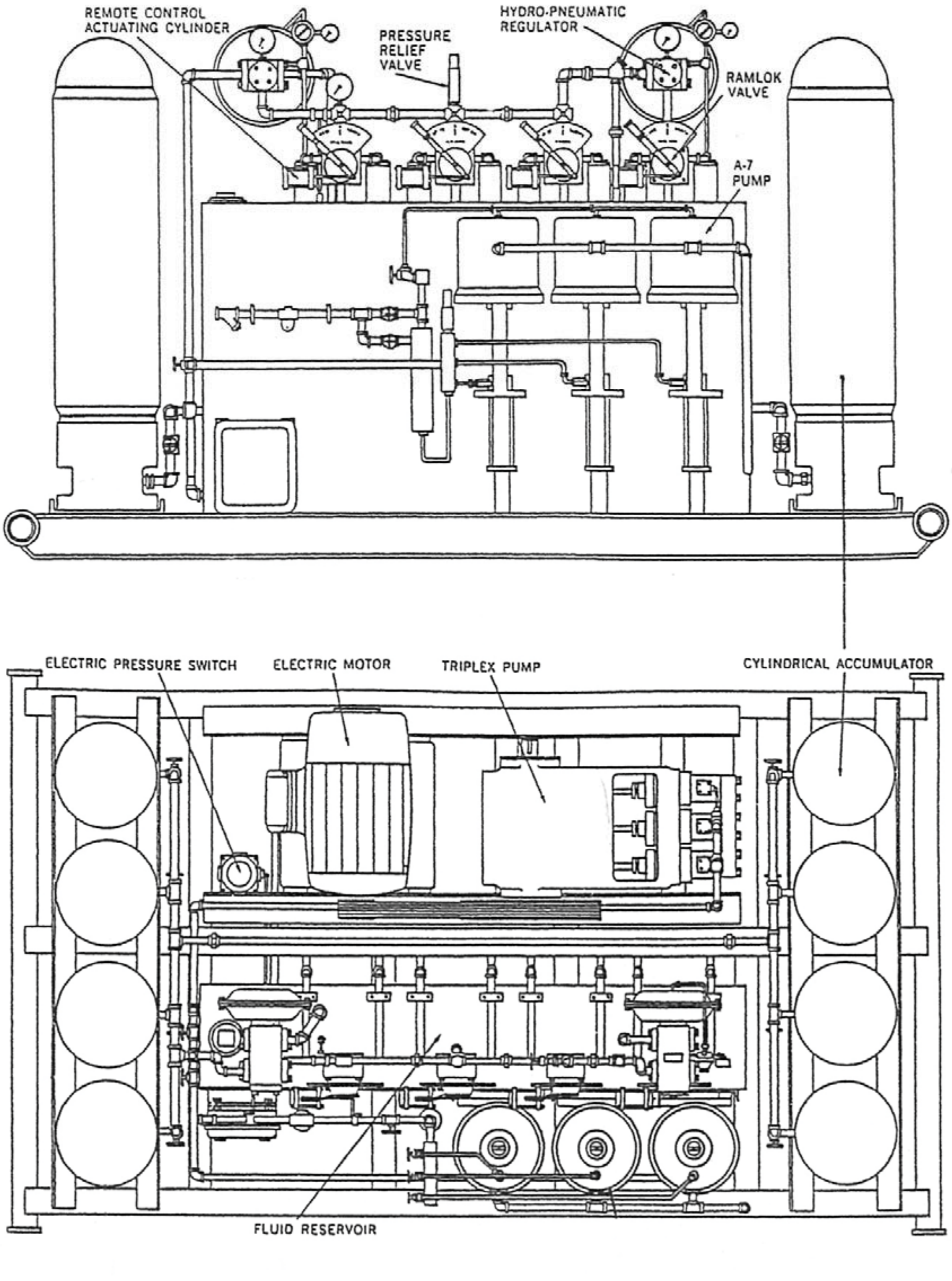


Figure 7 Accumulator unit layout [1]

3.2.1 Accumulator Bottles

The accumulator bottles are one of the main components in the accumulator unit. These steel-made containers are precharged with an inert gas. Nitrogen is used in most cases for that purpose. The precharged nitrogen gas is compressed by the hydraulic fluid further giving the gas an equal function to a simple spring for storing energy. By regulating the precharge pressure the “spring stiffness” can be easily changed in positive or negative way. There is also no material fatigue within the nitrogen gas, as it may occur for a mechanical spring. Another benefit of nitrogen charged bottles is that nitrogen is an inert, non flammable gas yielding a low safety risk for a rig. For maintenance of the bottles the stored energy has to be released; where nitrogen can easily be drained out a spring would require careful expansion with a special device. When the spring is not expanded in a controlled way it could produce a spark, or injure personnel. The body of the bottles is produced out of seamless steel and has a mechanical safety factor of 4 against burst. [1]

To prohibit a mixture of the nitrogen gas and the hydraulic fluid there has to be a separator installed in the accumulator bottle. This can be achieved by two different concepts. The most commonly used type of accumulator separates the gas and liquid by a bladder is filled with the nitrogen gas. In addition there are also accumulators with a piston achieving the separation.

3.2.1.1 Bladder Accumulator

This type of accumulator has a gas filled non-pleated rubber bladder which has the function to separate the nitrogen gas and the hydraulic fluid. The bladder is mounted with a gas-inlet valve on the top of the steel shell, through this valve the bladder will be precharged with gas. On the bottom of the steel shell the fluid port is located, this port is connected to the manifold. This fluid port assembly also supports a poppet valve. Figure 8 shows a section drawing of this valve. The poppet valve is pre-stressed by a conventional spring, the purpose of this valve is to regulate the flow rate and to protect the bladder from damage. An excessive flow will cause the poppet to close (e.p. in case a manifold leak).

If for example the manifold would leak the high flow would effect a large pressure difference between the two sides of the valve so the valve is closed until sufficient pressure is restored in the manifold. The poppet also closes in case the fluid side of the accumulator is not filled with sufficient fluid to compress the bladder to prevent damage of the bladder. To realize this, the bladder pushes the poppet down and a flat surface on the bottom of the bottle is generated. A section drawing of a typical bladder accumulator bottle is shown in Figure 9.

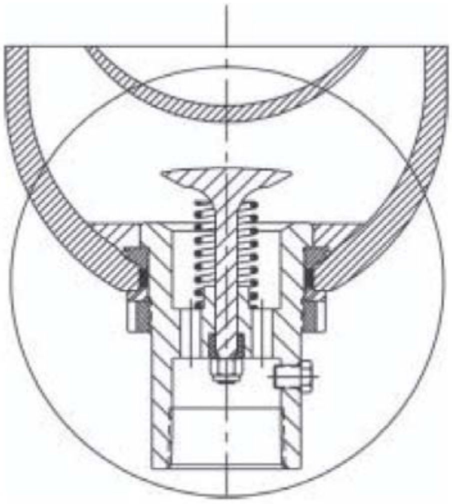
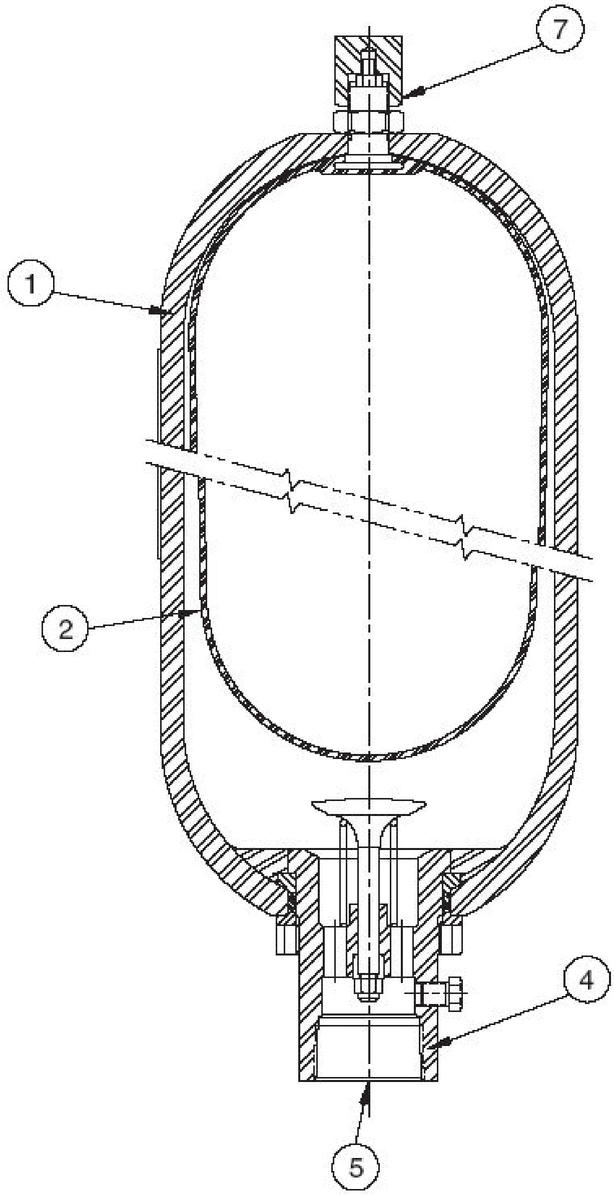


Figure 8 Section drawing of poppet valve [4]



1 Steel bottle
2 Bladder
4 Bottom vlave ass.
5 Fluid outlet
7 Gas valve

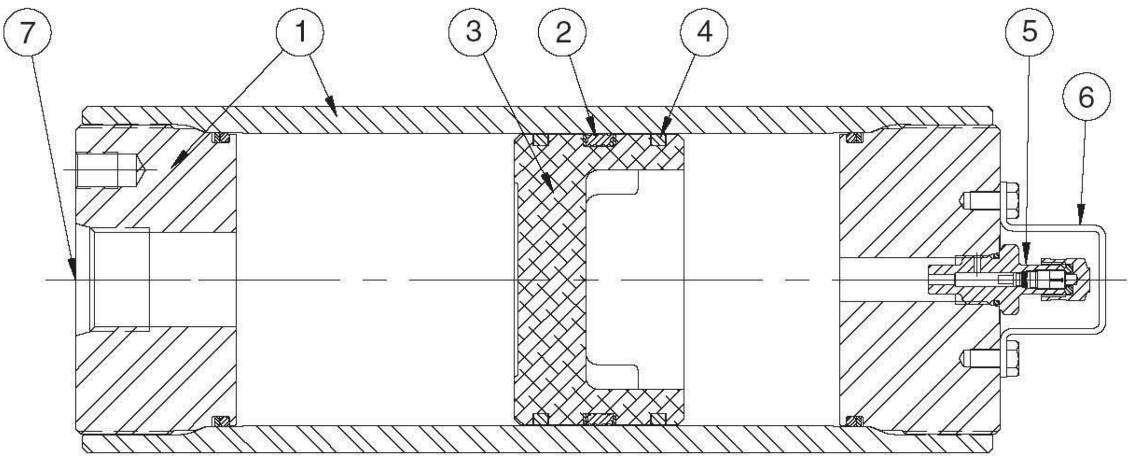
Figure 9 Bladder accumulator [4]

The rugged design and the high degree of pollution of the hydraulic fluid that can be handled by this accumulator are reasons why this accumulator type is commonly used in the EP industry. Another benefit for this accumulator design is the short response time, because there is no extra inertia such as a piston which has to be accelerated when fluid is flowing out.

3.2.1.2 Piston Accumulators

In this accumulator bottles the separation between gas and fluid is achieved by a lightweight piston. The accumulator itself has a cylindrical body where the piston is gliding. Both ends of the cylinder are closed with two screwable caps. On the gas side the cap involves a gas charging valve where the nitrogen gas, for precharging the system, is filled in. The other cap is on the fluid side where a treat is located to mount the bottle on a manifold or a pipe.

The separator, in this case the piston, is moving into the cylinder, and if a lot of volume is needed the piston has to be accelerated. To optimize the responding behavior the piston weight and its seals have a critical influence to this parameter. The friction between the piston and the cylinder is optimized by Polytetrafluorethylen (PTFE) glide rings on the piston. For that reason this design concept of this type of accumulator is very sensitive against a particle contaminated operating fluid. The main components of a piston accumulator are shown in Figure 10 in a section drawing.



1 Steel body 2 Piston sealing 3 Piston
4 PTFE glide ring 5 Gas valve 6 Valve protection
7 Fluid port

Figure 10 Piston accumulator [4]

The great benefit of this design is the modular construction, a seamless bottle is not required. A seamless pipe is sufficient, granting for a large variety of sizes.
Cameron, a manufacture in the petroleum industry, introduced another type of piston accumulator. This type of accumulator utilizes a float instead of a piston. This float separates the gas from the oil and is additionally used to precharge the accumulator. For filling the nitrogen gas a pipe is mounted right trough the float as can be seen in Figure 11.

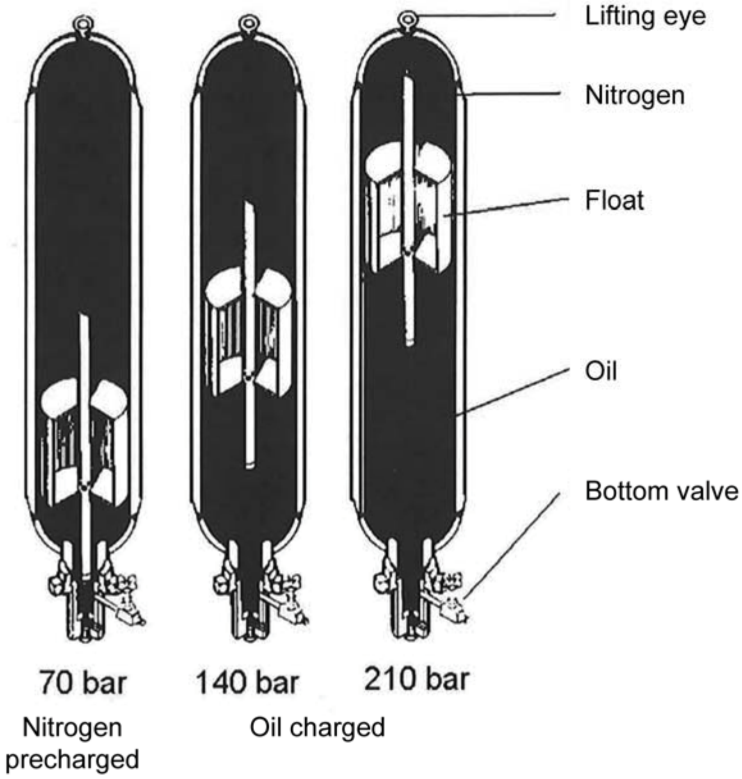


Figure 11 Accumulator bottle with floating lever [1]

In Figure 11 a cylindrical float is shown, in the industry there are also spherical float in use. When a spherical float is in use the accumulator bottle possesses a gas charging valve on his top to precharge it.
For bigger equipment the accumulator bottle has no typical bottle style, the bottle has a spherical shape with a cylindrical support for the float in it. Such a spherical accumulator is shown in the Figure 12 below. Figure 13 gives an impression on such a bottle assembly.

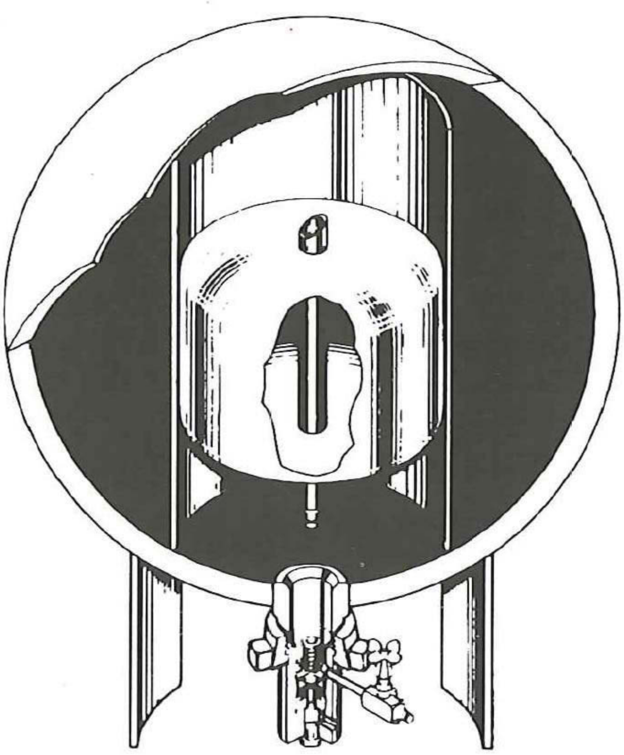


Figure 12 Spherical accumulator bottle [1]

Figure 13 Accumulator unit with spherical bottles (not in accordance with API)

3.2.2 Manifold

The manifold is a subassembly from the accumulator and in each accumulator there are three different manifolds types in use.

3.2.2.1 High Pressure Manifold

On the high pressure manifold the accumulator bottles are mounted. This manifold is also connected to the pumping system. This manifold sees the highest pressure in the whole system (3000 psig for a standard unit). As API requires a 75% redundancy in case of a fault of this equipment, there have to be at least four independent manifolds with equal number of accumulator bottles mounted on them. This type of manifold is labeled at number 1 in the schematic drawing in Figure 14 which is not in accordance with the API requirements.

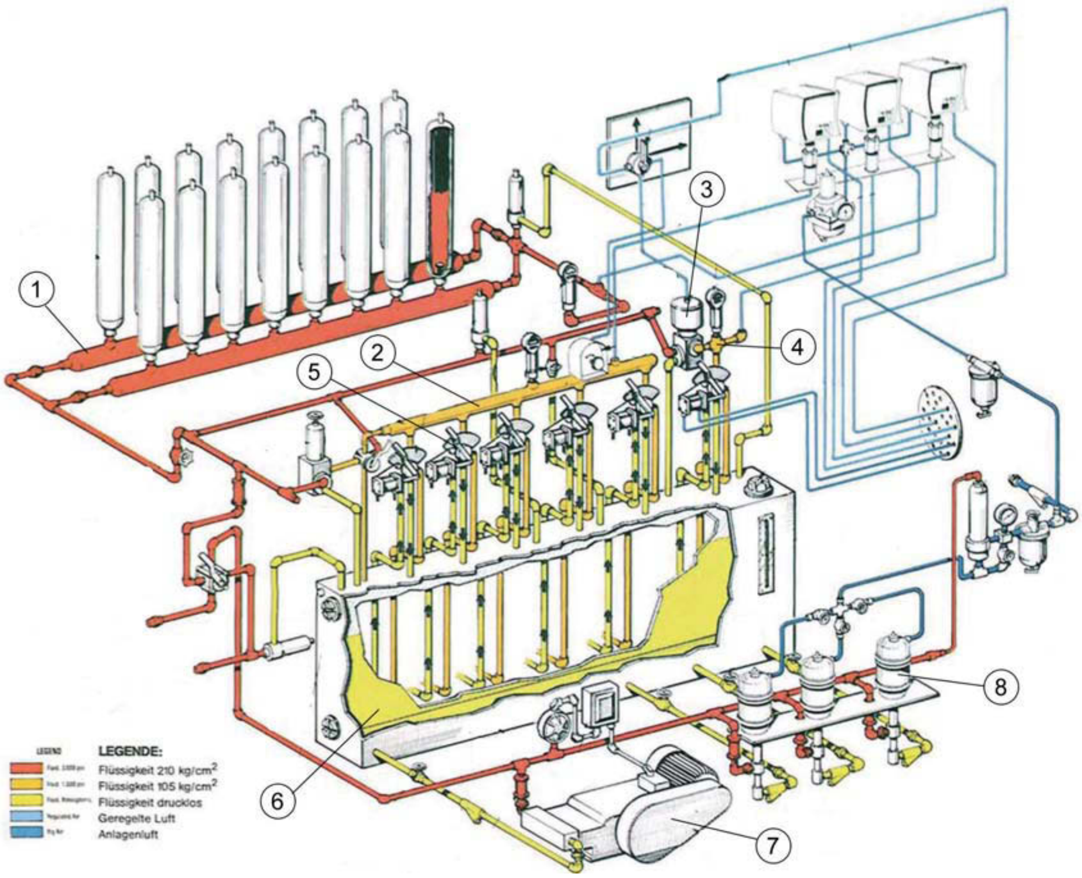


Figure 14 Manifold overview [1]

3.2.2.2 Hydraulic Control Manifold

The valves for controlling the ram BOPs and the valves for the kill- and choke line are mounted on this manifold. The connection between the control manifold and the high pressure manifold is realized with a manual adjustable pressure regulating valve. The pressure for the standard case (3000 psig operating pressure) in this manifold will be about 1500 psig. When a ram BOP with shear rams is installed on the stack, the regulated pressure could be in certain cases to low so there is some device needed to higher this pressure. All manufactures of such accumulators realized this problem with a pneumatic actuated bypass valve. This valve connects the high pressure manifold with the control manifold and consequently to the BOP. Number 2 in Figure 14 shows the control manifold.

3.2.2.3 Annular BOP Control Manifold

The annular BOP is actuated with a lower pressure level that the ram BOP; therefore this BOP possesses a separate manifold. For a stripping operation the pressure has to be regulated online in order to optimize the life time of the annular rubber packer. For the regulation operation the annular BOP manifold is connected via a pneumatically controlled pressure regulating valve with the high pressure manifold. These components are shown in Figure 14; labeled with 3 is the pneumatic controlled valve and with 4 the manifold assembly. This control valve has to be designed in a way that in case of an air supply failure the pressure remains constant. Figure 14 is schematic and does not conform to the actual API requirements.

3.2.3 Control Valves

For activating the BOPs and the hydraulic controlled valves in the kill and choke line control valves are needed. The valves for the ram BOPs and for the kill and choke line valves are mounted on the hydraulic control manifold, for the annular BOP the control valve is mounted on the annular BOP control manifold. This valves come in form of a 3 position, 4 way valve. Such a 3 position, 4 way valve is shown in Figure 15 and are labeled in the overview in Figure 14 with 5.

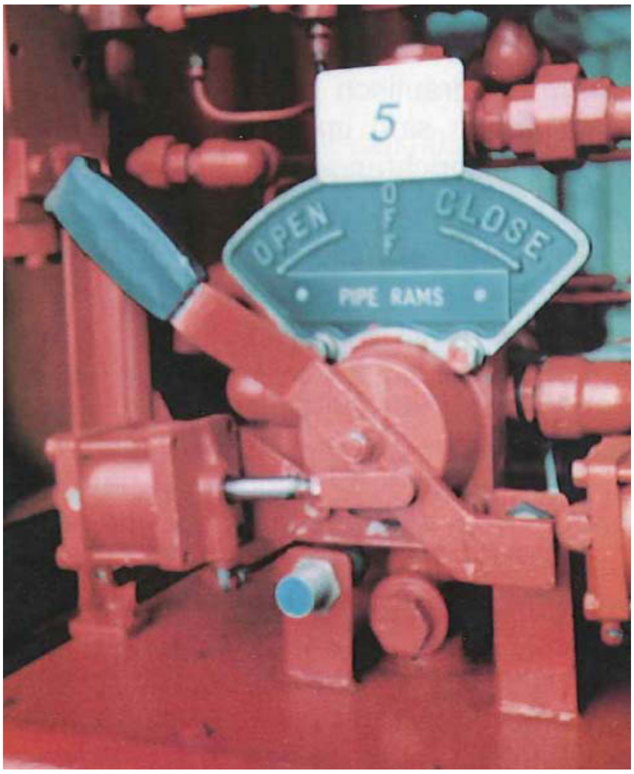


Figure 15 BOP control valve [1]

The valve has 3 switch positions: open position, close position and a neutral position (labeled “off” in Figure 15).

In the open position the valve connects the manifold with the opening hydraulic chamber on the BOP. In the close position the manifold is connected to the closing chamber. In the neutral position, the lines to the BOPs respectively to the kill or choke line valves a connected to the reservoir. Therefore these lines are referred of pressure and the hydraulic devices can not defined hold open or close. This position is only for maintenance or other work on the BOP or hoses in case of damage. The three positions of the valve are shown in the sketch in Figure 16.

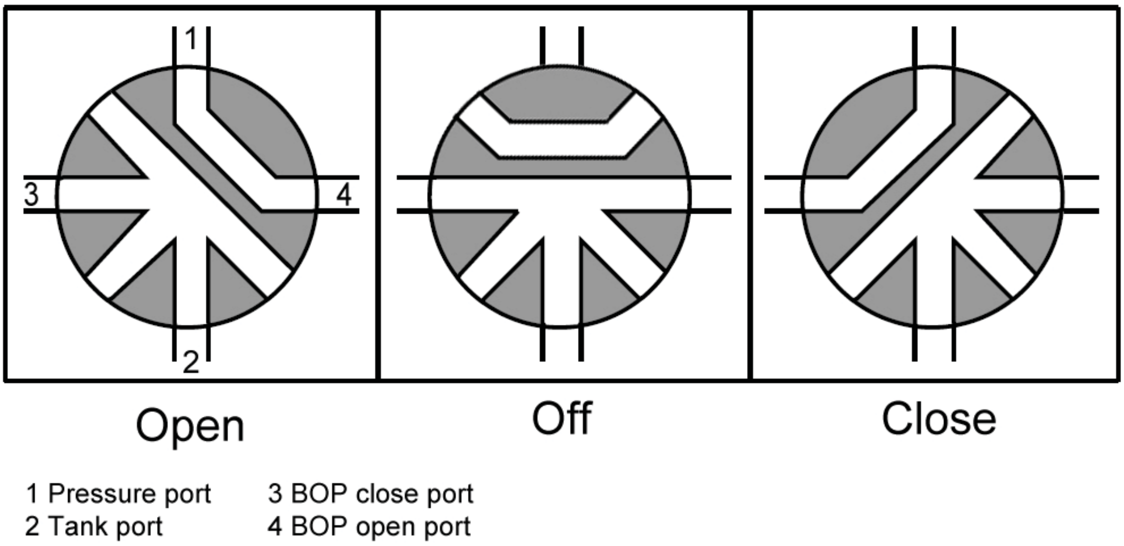


Figure 16 Schematic 3/4 way valve [5]

The valves are normally actuated manual by a handle as shown in Figure 15. For remote control of the well control equipment there needs to be a remote actuator installed for each valve. This device is realized with small pneumatic or hydraulic cylinders as shown in Figure 15.

3.2.4 Reservoir

The backflow from the BOPs /HCR valves has to be collected. This is done with a tank or reservoir that also supplies pressure less fluid to the pumps. The reservoir inhabits indicators for low fluid level and fluid filters for sustaining a clear system.

3.2.5 Pump Systems

Supplying the pressure for charging the accumulator bottles is the main job of the pump systems on the accumulator. The most commonly used pumps are plunger pumps which are of the positive displacement type. A schematic drawing of such a system is shown in Figure 17.
The principal function of this system is that the plunger also referred to as a piston, that is displacing the fluid in the chamber to the high pressure outlet. This is possible through the outlet valve in the system.

The backward movement of the plunger produces a reduced pressure in the main pump chamber; fluid can flow from the reservoir through the inlet valve into the chamber.

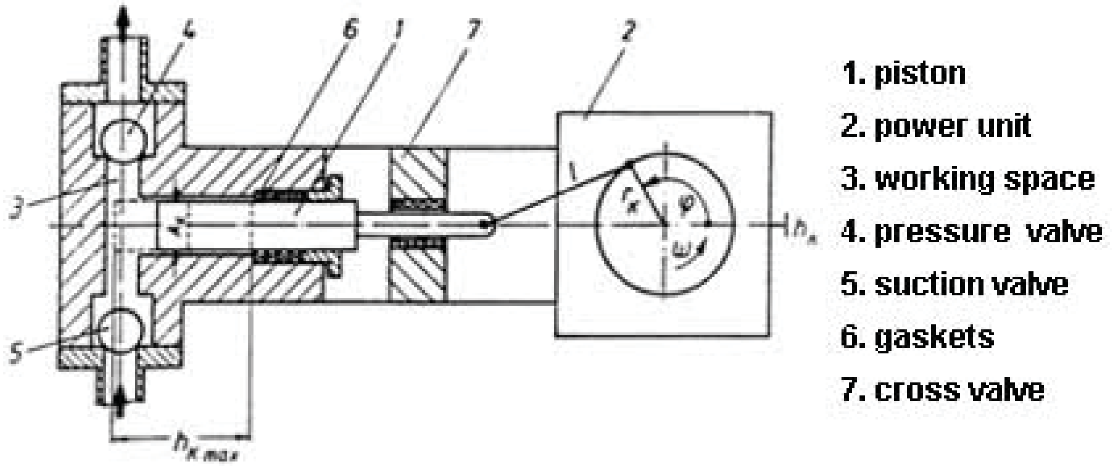


Figure 17 Schematic drawing of the plunger pump system [6]

The reason why the EP industry uses the plunger pump system for charging the accumulator is the ability to handle high pressure fluids. The fundamental difference between the plunger pump and the positive displacement piston pump is in the sealing concept of the moving components. The sealing between moving parts for the piston pump is direct placed on the piston. The plunger pump possesses no moving seals; they be changed easily for maintenance and also be adjusted to minimize the leakage. The common used sealing system in such plunger pumps is a stuffing box or packing gland. There are also new innovations with no sealing of all. Such a new "packer-free" pump is shown in Figure 18.

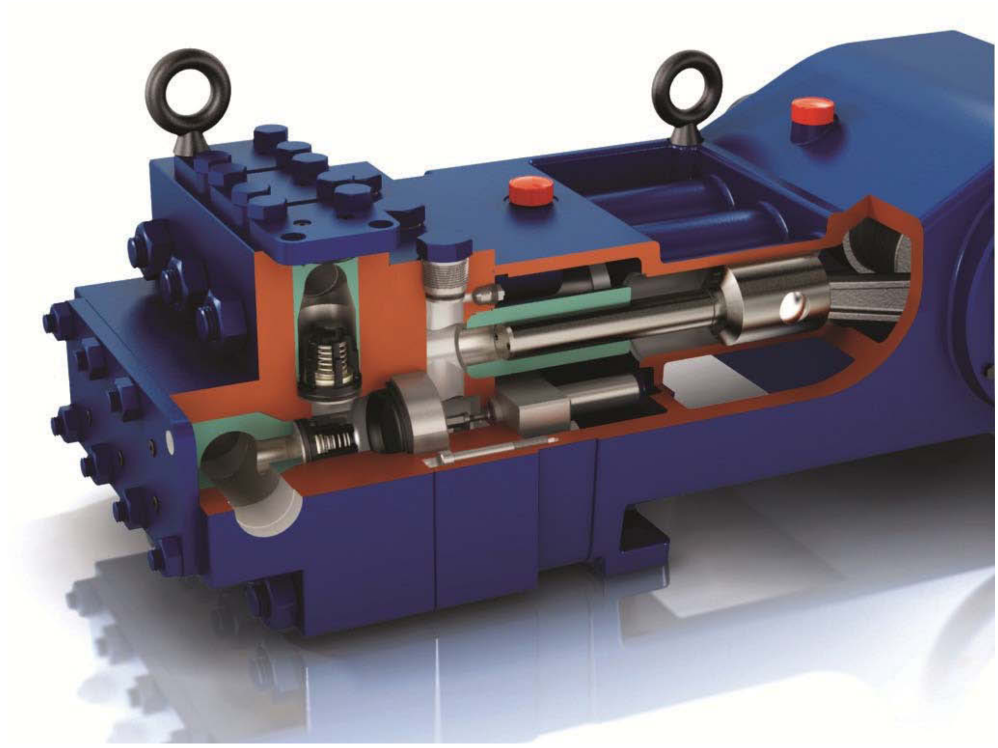


Figure 18 "Packer-free" plunger pump [7]

The pump shown in Figure 18 has 3 pumping assembly's; this pump type is therefore called a triplex plumper pump. In the EP industry the triplex system is the most commonly used because of the weight- and economic optimized concept. The crankshaft of this triplex pump is powered by an electric motor.

For accumulator units the API specifies the requirement for a redundant pumping system with a minimum of two independent systems powered by two independent power supplies. The main device is in most of the used accumulators an electrical driven triplex pump. The backup system can also be electrical driven but the electricity must be supplied from an independent source. This option is in many cases too expensive and therefore pneumatic energy is commonly used for the backup system. For this normally the rig high pressure air system is used. Such an air pump has the same fundamental function as a plunger pump. In Figure 19 a section drawing of an air plunger pump is shown.

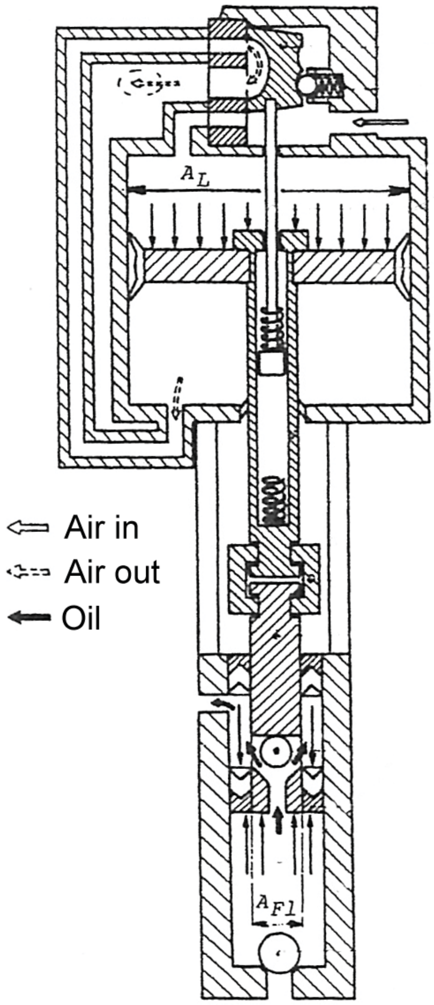


Figure 19 Air plunger pump [1]

The volumetric dimensioning of those pumps systems for both the air and the electric pumps are specified in API:

“a. With the accumulators isolated from service and with one pump system or one power system out of service, the remaining pump system(s) shall have the capacity to, within two (2) minutes:

1. Close one (1) annular BOP (excluding the diverter) on open hole.
2. Open the hydraulically operated choke valve(s).
3. Provide final pressure at least equal to the greater of the minimum operating pressure recommended by the manufacturer(s) of both the annular BOP and choke valve(s).

b. The cumulative output capacity of the pump systems shall be sufficient to charge the entire accumulator system from precharge pressure to the system rated working pressure within 15 minutes.” [8]

3.3 Control Hoses

Control Hoses in this context refers to the hoses which provide the BOP with hydraulic energy. They have the distinct job to connect the accumulator to the BOP stack. The hoses are often combined with remote wires or air lines and build up in a compound of these different hoses in a protective frame.

3.4 Remote Control

For safety reasons the position of the accumulator is intended to be at least 100' away from the working floor. Once a kick is recognized the driller will have to act immediate. To prevent him from running to the accumulator unit the workfloor possesses a remote control for the accumulator. There are two main control concepts for such a device: the air controlled system and an electrical powered remote control. The older air supported system requires for any function on the accumulator a small air hose from the remote control to the accumulator. The remote control unit on the workfloor is powered by the central high pressure air system. When a function, for example closing the rams, is required, the driller has to activate an air valve on the remote control, the air activates through a pneumatic piston the BOP control valve placed on the accumulator unit. On newer rigs the remote control is powered by electrical energy. So the air tube bundle is no longer needed eliminating several sources for faults. A bus cable connects the accumulator with the remote control unit. Figure 20 shows an air powered remote control.

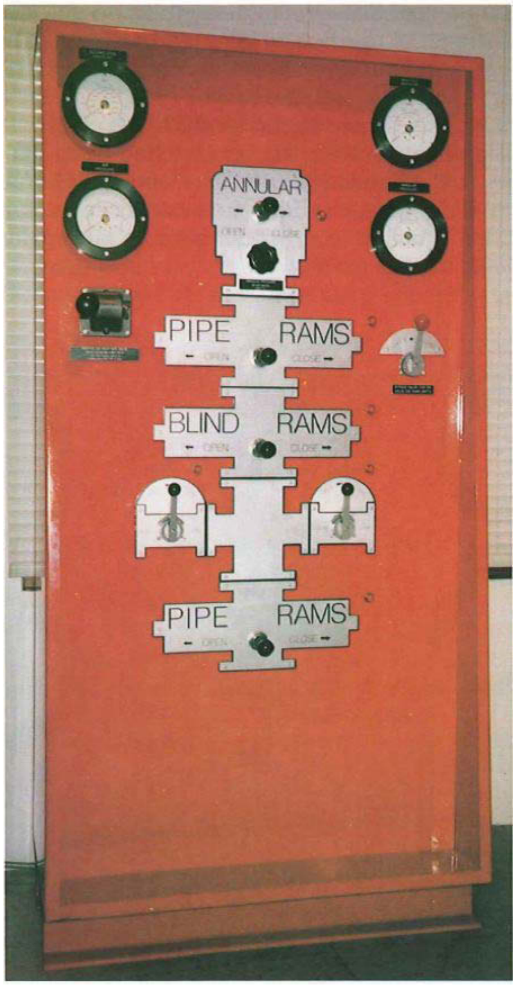


Figure 20 Air powered remote control [1]

3.5 Kill Line

To kill the well in case of a closed BOP there has to be a connection from the mud pump system to the annular below the stack. This line is flanged to the so called drilling spool or a side outlet on a ram BOP. The spool is kind of a T-piece shown in Figure 2 between the ram type BOPs. The kill line itself is of simple design; there are valves to shut in the line and pressure gauges which allow monitoring the pressure situation in the system.

3.6 Choke Line

To circulate out the mud during a killing operation in a manner condition the choke line is a part of the well control equipment. This choke line is also flanged to the drilling spool or an optional BOP side outlet.

The main parts of this equipment, the chokes are located on the choke manifold illustrated on Figure 21. With this equipment the pressure during a killing operation can be controlled online from the workfloor by a remote control system and manually on the choke manifold. For the different procedures to kill a well a combination of diverse drilling equipment together with the choke and kill line is required.

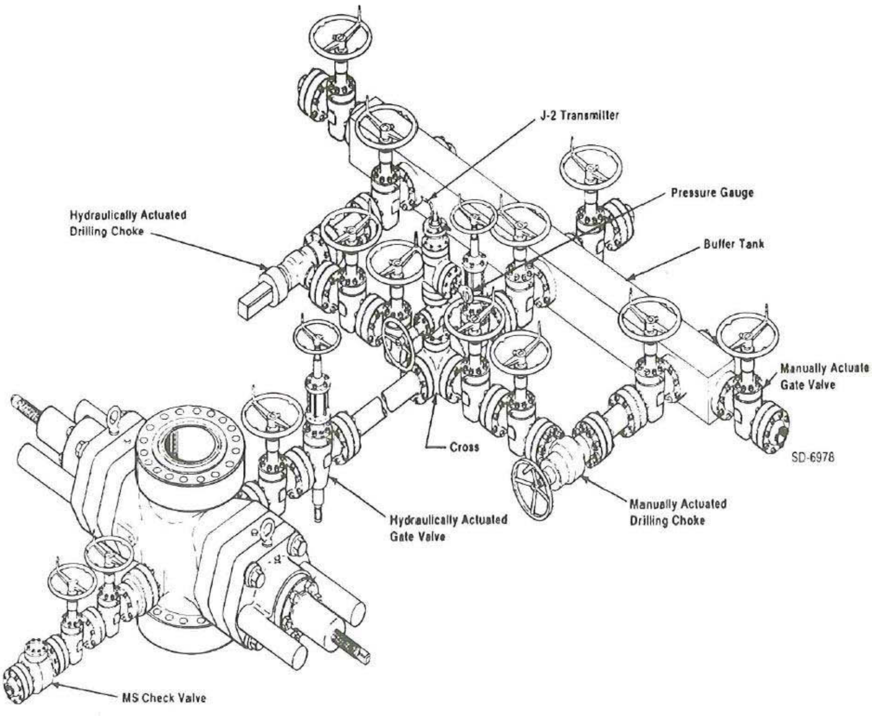


Figure 21 Choke line overview [1]

The chokes are exposed to erosion by the mud which has in many cases a high flow velocity. For this reason a choke manifold possesses at least 2 chokes to keep the redundancy. After reducing the pressure the fluid or gas is transferred via pipe to the degasser to extract gas from the kick.

4 Physical Fundamentals

4.1 Ideal Gas Law

The accumulator bottles are precharged with nitrogen. The maximal operation pressure of an accumulator is in the most cases 3000 psig in certain cases there is a 5000 psig well control equipment in use. The ideal gas law can be used to describe the interactions in this gas charged system. The prerequisites for using this gas law are an isothermal discharging and charging process. Also the maximal gas pressure should stay below 5000 psig for calculating the volumes with the ideal gas law.
Only in special rapid discharge systems the gas has no time to balance the temperature. For this case the ideal gas law can not be used for the calculations. These rapid discharge systems are used in special subsea applications which are not discussed in this thesis.

The ideal gas law says:

$$p \cdot V = m \cdot R \cdot T \quad \text{..........} \quad (1)$$

Under the assumption that the temperature remains constant and the gas is in a closed system, the right side of Eq. 1 is constant. The resulting equation is called the Law of Boyle and Mariotte.

$$p \cdot V = const \quad \text{..........} \quad (2)$$

A diagram showing the relation between temperature, volume and pressure is shown in Figure 22. This diagram is called PVT diagram and shows the conditions of the nitrogen gas in two states.

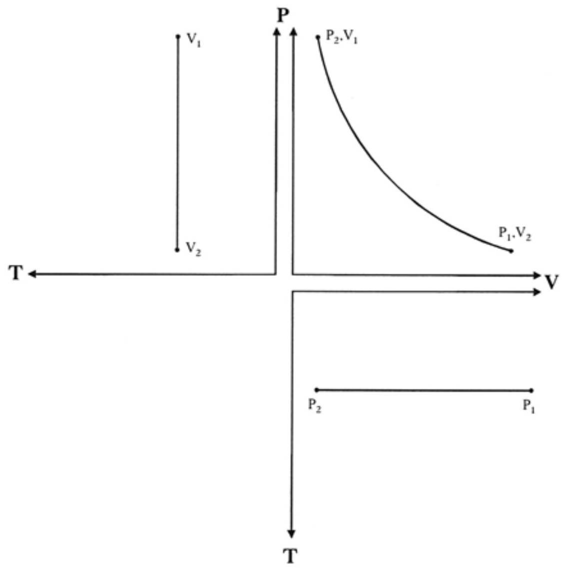


Figure 22 PVT diagram of the isotherm change of state [9]

4.2 Fluid Laws

For discussing the pressure loss in the BOP control hoses witch length are up to 150' the basics of the fluid dynamic is listed in this chapter.

4.2.1 Flow States

For evaluating the pressure loss the flow state has a big influence in the calculations.

There are two main flow states in fluid dynamics, the laminar flow and the turbulent flow state. The Reynolds number (Re) defines the flow state of the fluid in a fix geometric profile. The border between these two states is defined by a critical Reynolds number. After passing the critical value of 2320 for pipe flow, the flow becomes instable and changes to the turbulent flow state. For calculating the Reynolds numbers following dates are needed. The dimension of the pipe, the inner diameter d, is defined by the designer. The fluid manufacture defines the kinematic viscosity ν at the defined temperature. The average velocity v_m is determined by the required flow.

$$\mathrm{Re} = \frac{\mathrm{v}_m \cdot d}{\nu} \quad (3)$$

The average flow velocity v_m is defined by the continuity equation:

$$\mathrm{v}_m = \frac{\dot{V}}{A} \quad (4)$$

The flow state influences the pressure loss in that way that for a laminar flow the pressure loss is independent of the pipe wall roughness. So the manufacture has more tolerance in the production process.

4.2.2 Bernoulli Equation

The Bernoulli equation is a special form of the law of conservation of energy. This equation considered two points in a defined system; between these two points the energy has to be equal. Without any friction or other losses the Bernoulli equation is shown below:

$$\frac{\mathrm{v}^2}{2} + \frac{\mathrm{p}}{\rho} + g \cdot z = const \quad (5)$$

In reality any flow of a fluid through a pipe will cause friction loss. To show this loss in the Bernoulli equation a term has to be added. This term is called the overall pressure loss. The extended Bernoulli equation between a point 1 and 2 in a hydraulic system becomes as follows:

$$\frac{\mathrm{v}_1{}^2}{2} + \frac{\mathrm{p}_1}{\rho} + g \cdot z_1 = \frac{\mathrm{v}_2{}^2}{2} + \frac{\mathrm{p}_2}{\rho} + g \cdot z_2 + \frac{\Delta \mathrm{p}_\mathrm{v}}{\rho} \quad (6)$$

A hydraulic system composes of different parts. There are straight parts of cylindrical pipes which are connected by different fittings. Valves, bending and other hydraulic equipment are found in such a system. The pressure lost is composed of two different parts. One for the straight pipe sectors and another part for all the joints, fittings and valves in the system.

4.2.3 Pressure Loss in Pipes

The pressure loss in pipes and hoses which are bended in a not too small radius is defined by the following equation.

$$\frac{\Delta p_v}{\rho} = \lambda \cdot \frac{l}{d} \cdot \frac{v_m^{\ 2}}{2} \quad \text{...} (7)$$

The main parameter in Eq. 7 is the friction factor λ. This parameter is influenced from the flow state. For a laminar flow state λ is independent of the wall roughness in the pipe, it is only dependent of the Reynolds number which is proportional to the flow conditions. On the other site in turbulent flow state, the friction factor is dependent on the wall roughness and the Reynolds number.

4.2.3.1 Laminar Flow State

For the laminar flow state the friction factor is defined by following equation.

$$\lambda = \frac{64}{\mathrm{Re}} \quad \text{...} (8)$$

The Reynolds number is defined in Eq. 3. In the most cases in high pressure hydraulics there is no laminar flow in the pipe system so the wall roughness has an influence on the pressure losing.

4.2.3.2 Turbulent Flow State

In turbulent flow there are more ways to derive the friction factor λ. Extract the friction factor from a diagram like the one shown in Figure 23 or calculate it with an approximation. The turbulent state over a Reynolds number of 2320 is structured in three areas: a so called smooth pipe area, a transition area and a rough pipe area. These three areas are illustrated in Figure 23.

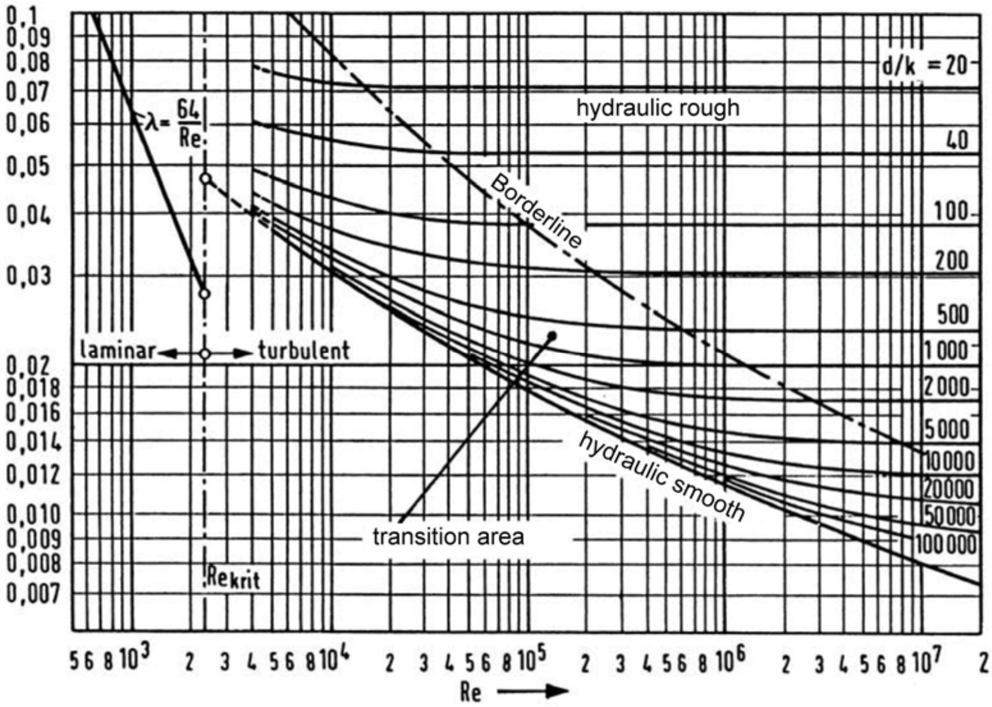


Figure 23 Moody diagram [10]

The smooth pipe area is valid between following limits:

$$2320 < \mathrm{Re} < \frac{d}{k} \cdot \left(0{,}1 \cdot \frac{d}{k} \right) \qquad (9)$$

In this area a laminar layer covers the rough pipe wall so the pipe roughness k has no influence at the friction factor. The approximation in the literature to calculate the friction factor for this area is shown in Eq. 10.

$$\lambda = \frac{0{,}309}{\left(\log \frac{\mathrm{Re}}{7} \right)^2} \qquad (10)$$

In the transition area the friction factor is a function of the Reynolds number and the wall roughness. This approximation is valid for the following area of the Reynolds number:

$$\frac{d}{k}\cdot\log\left(0{,}1\cdot\frac{d}{k}\right) < \mathrm{Re} < 400\cdot\frac{d}{k}\cdot\log\left(3{,}715\cdot\frac{d}{k}\right) \qquad (11)$$

The friction factor λ for the transition area is defined by:

$$\lambda = \frac{0{,}25}{\left[\log\left(\frac{15}{\mathrm{Re}}+\frac{k}{3{,}715\cdot d}\right)\right]^2} \qquad (12)$$

In the third area the laminar layer on the wall is too thin so the wall roughness has a great influence at the friction factor. This area begins with a Reynolds number greater than the in Eq. 13 defined value

$$\mathrm{Re} > 400\cdot\frac{d}{k}\cdot\log\left(3{,}715\cdot\frac{d}{k}\right) \qquad (13)$$

So there is only an influence on the friction factor from the wall roughness k.

$$\lambda = \frac{0{,}25}{\left(\log 3{,}715\frac{d}{k}\right)^2} \qquad (14)$$

The wall roughness k is the technical (natural) roughness of the surface which is in contact with the floating fluid. This value is an empirical found approximated value. Figure 24 gives an impression on the influence of k in the different areas.

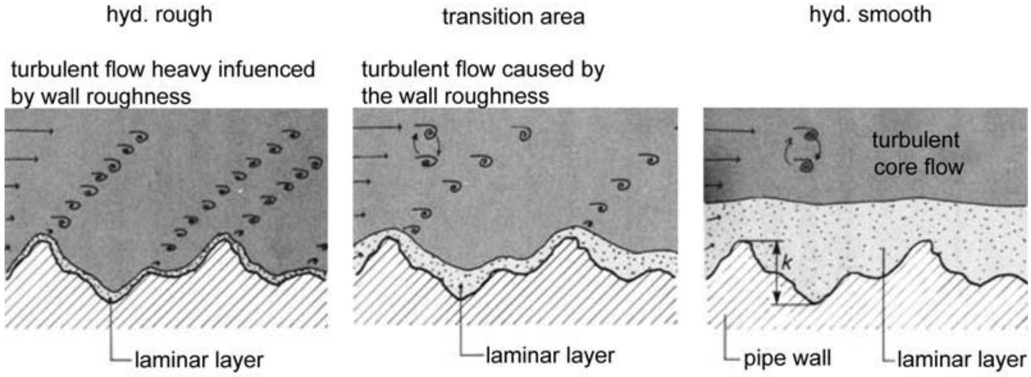


Figure 24 Flow states [10]

Some known values for the factor k are listed in Table 1.

Material type	k [mm]
Glass, copper, brass	0,001-0,005
New rubber hose	0,0016
Steel pipe new	0,02-0,1
Steel pipe rusty	0,15-1,5

Table 1 Wall roughness

4.2.4 Pressure Loss in Fittings

In fittings, valves and all other components which cause a disruption in the flow there evolves an additional pressure loss. This loss is calculated by the following equation:

$$\frac{\Delta p_v}{\rho} = \zeta \cdot \frac{v_m^2}{2} \qquad (15)$$

For each component in the system there is a special friction factor. These factors are all empirical determined and there is lots of literature with this factor for every component. For this reason it is hard to find a value for a common used accumulator. The influence of this type of pressure loss is not so significant for the overall loss when the fittings and valves have an optimal designed nominal bore.

4.3 Hydraulic Power

In order to calculate the power which is used to close the BOPs the following chapter explains the background for such a calculation.
The basic definition of power is in shown Eq. 16.

$$P = F \cdot v \quad \text{(16)}$$

For hydraulics the Eq. 16 has to be modified to use the hydraulic data. The average flow velocity defined in Eq. 4 can bee used in the equation for the power to displace the velocity. The force F has also to be displaced with an in hydraulic equivalent data.

$$F = p \cdot A \quad \text{(17)}$$

After joining the Eq. 4, 16, 17 the hydraulic power is defined:

$$P = p \cdot \dot{V} \quad \text{(18)}$$

5 Detailed Discussion on Accumulator

5.1 Bottles

The common used accumulator bottle type in the industry is of the bladder type. The main benefits, the easy handling and the low maintenance costs, are the reason for commonly using this type. In the following chapter the bladder accumulator is discussed in detail.

5.1.1 Useable Fluid Calculation

The useable fluid of an accumulator bottle is defines as fluid with a minimal pressure which can be used for actuating the different BOPs and valves.
For calculating the useable fluid in an accumulator bottle it is required to define the different pressure conditions for the system:

Condition 0: Precharged

In this status the accumulator is filled with nitrogen gas at precharge pressure. Commonly used in the EP industry the precharged pressure in onshore drilling or workover accumulators is 1000 psig. This pressure should be specified at a standard temperature, in most cases at 20°Centigrade. In certain cases this pressure can be set up to 1400 psig for a standard 3000 psig system. This increase of the precharge pressure decreases the useable fluid and decreases the amount of necessary bottles, when a high minimum operating pressure is required.

Condition 1: Charged

In the charged condition the nitrogen gas is further compressed by the fluid forced into the bottles. The pump system on the accumulator unit supplies this pressure in the hydraulic system, so the final charge pressure is equal to the pump stopping pressure. The pressure switch on the high pressure manifold has a certain range to trigger. In most cases the range of this pressure switch is adjusted from 2700 psig until 3000 psig in a standard 3000 psig accumulator unit. For the calculations the pump stopping pressure is used by API.

Condition 2: Minimum operating pressure

See chapter 5.1.1.1

The worst case in an emergency well control situation is a complete blackout in the infrastructure. So the accumulator has to provide the energy for shutting in the well without any supply from a pump system. In this worst case at the time of the blackout the pressure level in the hydraulic system is only at 2701 psig. In this case the pump has not started before the blackout.
API SPEC16D contains concrete definition: the charged pressure is equal with the pump stopping pressure set by the electrical pressure switch which controls the triplex pump. The motivation of the API to take this pressure for the calculations might be that in normal case the pumps produce the pressure until the switch is activated. In that standard case there are no leaks and so the pressure stays all the time at the maximum level. In chapter 7.3.5 there is a calculation with this special well control case. In this calculation the high pressure manifold pressure (P_2) is set to 2700 psig.

5.1.1.1 Minimum Operating Pressure

API defines this pressure in three different requirements. At the design stadium the minimum operating pressure shall be complied with all this three definitions.
The three definitions are:

1. The minimum operating pressure should be 200 psi above the precharge pressure (1200 psig in a common used 3000 psig system)
2. The minimum operating pressure should be higher than an effective closing pressure. This pressure is calculated by dividing the maximum wellbore pressure by the closing ratio. The closing ratio is a constructive factor defined by the manufacture.
3. The minimum operating pressure is recommended by the manufacture for each component on the stack that means the annular BOP, the ram type BOP and the hydraulic actuated valves

5.1.1.2 API Method

API describes within Spec 16D three different methods to calculate the useable volume. There is a differentiation between surface and subsea mounted accumulators and the maximum working pressure. Also rapid discharge systems are discussed in the standard. For a detailed view on the calculation method in this thesis only the so called API Method A is used. The gas pressure will stay under 5015 psia, no rapid discharge system is used and the accumulator is onshore. Therefore all criteria are fulfilled for Method A which is based on the ideal gas law

This calculation is based on a factor called Volume Efficiency (VE) multiplied by the whole bottle volume. There are two different VE factors and the smaller one has to be used for the calculation:

- The VE for the volume limited case (VE_V)
- The VE for the pressure limited case (VE_P)

The two factors are influenced by the minimum operating pressure and the system pressure in condition 1.

API defines the equitation for the Volume Efficiency factors in following way:

$$VE_V = \frac{\left(1{,}0 - \frac{P_0}{P_1}\right)}{1{,}5} \qquad (19)$$

$$VE_P = \frac{\left(\frac{P_0}{P_2} - \frac{P_0}{P_1}\right)}{1{,}0} \qquad (20)$$

The constant factors in the two equations (19, 20) are design factors defined by API special for every calculation method described in API Spec 16D.

The useable fluid in the API called Functional Volume Required (FVR) is calculated with the minimum of the two Volume Efficiency factors.

$$\mathrm{FVR} = \mathrm{BV} \cdot \text{minimum of } (\mathrm{VE_v} \text{ and } \mathrm{VE_p}) \qquad (21)$$

BV (the Bottle Volume) is the total useable volume of the accumulator bottles. For example a nominal 11 gallon bottle has a useable volume of 10 gallon as the bladder has a volume requirement of about 1 gallon.

5.1.1.3 Calc. with Boyles Law

Based on Eq. 2 the calculation of the useable fluid is calculated as follows:
Eq. 2 states that the product of pressure and volume is constant. This is valid for every condition of the system. In the preacharged condition 0 the pressure and the volume is known, the gas volume for condition 1 can now be calculated.

$$V_1 = \frac{p_0 \cdot V_{tot}}{p_1} \quad (22)$$

After calculating that, the gas volume at condition 2 can be calculated with the same equation.

$$V_2 = \frac{p_1 \cdot V_1}{p_2} \quad (23)$$

With this gas volume the non useable liquid volume V_{2L}can be calculated with an easy subtraction.

$$V_{2L} = V_{tot} - V_2 \quad (24)$$

The total useable liquid volume V_{us} in the bottle between the full charged and minimum pressure is calculated by:

$$V_{us} = V_{tot} - V_1 - V_{2L} \quad (25)$$

5.2 Pressure Loss in Control Hoses

The accumulator unit is located in a safe distance from the BOP stack. For this reason the hydraulic control hoses have a length of up to 150’ (50m). The inner diameter in this control hoses is in most cases 1’’ (25,4mm). For this reasons of the piping length and the finite inner diameter there have to be discussed if there is a critical pressure loss in the hydraulic control system.

On every rig there is the situation always different relating to the position and the detailed design of the piping. Especially the different types of fittings and valves which are used in the control system can not be standardized for an overview of the pressure loss. Without knowledge of this fittings and valves only the pressure loss in the hydraulic control hose from the accumulator unit to the BOP stack can be calculated.

Following assumptions where made for a rough calculation:

- The length of the control hose is 50 m.
- The inner diameter of the hose is 1’’.
- The fluid in use is a mixture of soluble oil and water.
- The time for closing the all BOPs is 30 sec.
- The volume for closing the stack is 35 gal (0,16m³) (see chapter 7.2)

The described control fluid is commonly used in the EP industry nowadays; in former times simple hydraulic oil was used. This mixture of different chemicals protects from corrosion, foam formation and bacterial contamination. The concentration of the soluble oil in the control fluid is only 1 to 5%; therefor it has a negligible influence on the kinematic viscosity.

To derive the Reynolds Number using Eq.3 the average flow velocity is required. This value can be calculated by the given time and volume for closing of all the BOPs in the stack

$$v_m = \frac{\dot{V}}{A} = \frac{\frac{0,16}{30}}{\frac{0,0254^2 \cdot \pi}{4}} = 10,53\left[m/s\right] \quad (26)$$

$$\mathrm{Re} = \frac{v_m \cdot d}{\nu} = \frac{10{,}53 \cdot 0{,}0254}{1 \cdot 10^{-6}} = 2{,}67 \cdot 10^5 \quad (27)$$

In this calculation the kinematic viscosity is set to $1 \cdot 10^{-6}$ m²/s, this is the value of the viscosity of water at 20°C.

The control hoses are in most cases flameproof covered rubber hoses with a steel armor. To calculate the friction factor for the pressure loss a wall roughness is required. In Table 1 are different factors listed and for a new rubber hose the wall roughness is 0,0016 mm.

Eq. 11 defines the borders in which Eq. 12 is valid for calculating the friction factor.

$$\frac{25{,}4}{0{,}0016} \cdot \log\left(0{,}1 \cdot \frac{25{,}4}{0{,}0016}\right) < \mathrm{Re} < 400 \cdot \frac{25{,}4}{0{,}0016} \cdot \log\left(3{,}715 \cdot \frac{25{,}4}{0{,}0016}\right) \quad (28)$$

$$5{,}08 \cdot 10^4 < \mathrm{Re} < 3{,}03 \cdot 10^7 \quad (29)$$

By Eq.29 the actual Reynolds Number is between the limits of the transition area, so the friction factor can be calculated with Eq. 12.

$$\lambda = \frac{0{,}25}{\left[\log\left(\frac{15}{\mathrm{Re}} + \frac{k}{3{,}715 \cdot d}\right)\right]^2} = \frac{0{,}25}{\left[\log\left(\frac{15}{2{,}67 \cdot 10^5} + \frac{0{,}0016}{3{,}715 \cdot 25{,}4}\right)\right]^2} = 0{,}0146 \quad (30)$$

The pressure loss as per Eq. 7 can now be calculated.

$$\Delta p_v = \lambda \cdot \frac{l}{d} \cdot \frac{v_m^2}{2} \cdot \rho = 0{,}0146 \cdot \frac{50}{0{,}0254} \cdot \frac{10{,}53^2}{2} \cdot 1000 = 231 psi \quad (31)$$

If there is a continuous flow in the hydraulic control hoses with this high flow rate which is chosen in this example the pressure loss would have a significant influence.

To shut in the well without any external power, is the worst case in a typical well control situation. In such a situation the target is to close the BOPs as quickly as possible. The lever of one valve on the control manifold is set to close. The gas in the bottles expands and a flow with the defined pressure loss is starting. After filling up the closing chamber in the BOP the flow decreases to zero. By a flow rate of zero also the flow velocity is zero. That causes a zero pressure loss in the system. The calculated pressure which is needed to hold for example the rams closed against the wellbore pressure is available without any friction loss. Of course there is an energy lost during a closing cycles for example, caused by the friction in the pipes in inside the fluid. This energy changes the state from hydraulic into thermal energy. This energy is feed into the system also by thermal energy which heats up the nitrogen gas that has cooled down due the expansion. In reality the expansion process is not an isothermal process; there is a temperature change during one work cycle. However this temperature changes are too small to have any influence in the working process of the accumulator. Furthermore the increase in temperature of the control fluid is too small to decrease the quality or the lifetime of the fluid.

6 Standards used in the Industry

The volumetric requirements for a accumulator unit are defined in a similar way in most of the international standards concerning such units. Adequate accumulator volumetric sizing is achieved by determining the volume requirements for a series of operations with the BOPs incorporated in the used BOP stack. Most of the operators in the EP industry are in possession of their own standards for well control equipment that are normally addressing the issue of accumulator sizing as well. Of all international standardization organizations API is one of the most recognized in the E&P industry. The API provisions for accumulator sizing are therefore widely accepted as the absolute minimum. Operators like OMV have to decide for their own well control standards if these provisions are sufficient or have to be made more stringent for their operations. This chapter is therefore taking a close look at API requirements in regard to accumulator sizing and is determined to identify if there are sufficed and if not to inform on an acceptable minimum requirement incorporating the ALARP principle.

6.1 API

The minimum requirements for designing the volumetric capacity of an accumulator unit are well defined in API standards. API Specification 16D defines exactly the calculation methods as shown in chapter 5.1.1.2 and design details for the well control system. API Recommended Practice 53 is more practical structured than SPEC 16D. In RP 53 there is also a volumetric capacity requirement for the accumulator unit but there is no calculation method or detailed design specification. This standard is more useful for installing and testing a well control system in the field.

This two standards from API yield generally the same volumetric capacity requirements for the accumulator unit. In API SPEC 16D the volumetric capacity requirements are defined as follows:

“The BOP accumulators shall have a minimum usable power fluid volume, with pumps inoperative, to satisfy the two following requirements:

a. A FVR (Functional Volume Requirement) of one hundred percent (100%) of the BOP manufacturer’s specified volume to close from a full open position at zero (0) wellbore pressure, one annular BOP and all of the ram BOPs in the BOP stack and to open the valve(s) of one side outlet on the BOP stack. The volume design factor for volume-limited accumulator discharge shall be determined by the sizing calculation method selected per 4.2.3.1. If more than one annular BOP is present, the larger closing volume requirement shall be used for sizing purposes.

b. The calculated pressure of the remaining accumulator fluid after discharge of the required volume including the volume design factor for pressure-limited discharge shall exceed the minimum calculated operating pressure required to close one annular, any ram BOP (using the ram-type BOP closing ratio, excluding the shear rams) and to open and hold open required side outlet valve(s) at the maximum rated wellbore pressure of the stack. The volume design factor for pressure limited accumulator discharge shall be determined by the sizing calculation method selected per 4.2.3.1.” [11]

Chapter 4.2.3.1 is described in a simplified way in chapter 5.1.1.2 of this thesis.

6.2 NORSOK

The Norwegian government regulates the procedures and equipment in the EP industry with a standardization system called NORSOK. These standards are much more conservative in regard to well control system. Therefore NORSOK can be regarded to be the high class end in the spectrum of standards dealing with well control. A big difference between API and NORSOK is the separation between offshore and onshore drilling operations. NORSOK only deals with offshore drilling and workover operations. The reason for this comes from the fact that Norway does not possess any onshore oilfields.

The following passage describes the NORSOK volume requirements:

“The accumulator capacity for operating a BOP stack with associated systems shall as a minimum have sufficient volumetric capacity to close, open and close all the installed BOP functions plus 25 % of the volume for one closing operation for each one of the said BOP rams.” [12]

NORSOK standard D-002 defines the volume requirements three times higher then API 16D. API by itself defines the volume requirements for offshore operations to be larger than for onshore operations.

6.3 EUB

The Alberta Energy and Utility Board (EUB) defines in their regulations the volume requirements for the accumulator unit as follows. The regulation called “Directive 036 Drilling Blowout Prevention Requirements and Procedures” defines all requirements regarding to the well control equipment. A project which would be developed in the Province of Alberta has to be complied with this standard. The EUB classifies a well in six classes depended on the true vertical depth of the well and a special kind of class for critical sour wells. In general the volume requirements are the same as the API requirements. To close all BOPs installed on the stack and open the HCR valve on the choke line. The minimum pressure after actuating the BOP operation without recharging should be not less than 8400 kPa (1200psi) in the accumulators.
Except the so called critical sour wells in which sour gas is expect or known, has special requirements. These requirements are similar to the standard requirements of the NORSOK standard. The requirements of the EUB in this case are, to open the HCR valve, close the annular BOP and close-open-close on of the installed ram preventer. In order to close all other ram BOPs on the stack too and in the special case that are shear rams in place the minimum operating pressure may have to be higher than 8400 kPa in order to shear the workstring.

7 BOP Stack Model

For calculating an example and show the differences in the standards a commonly used BOP stack is defined. For every well which is developed a special well control design is set up because of always changing requirements. In the following chapter there are two different types of BOP stacks discussed. A stack which is used in an onshore drilling operation and a stack used on a workover rig.

7.1 Workover Model

The chosen one is an arrangement of three BOPs with a nominal diameter of 11” (279mm). The maximum wellbore pressure of the stack is 5000 psig.
A layout of the BOP stack is shown in Figure 25.

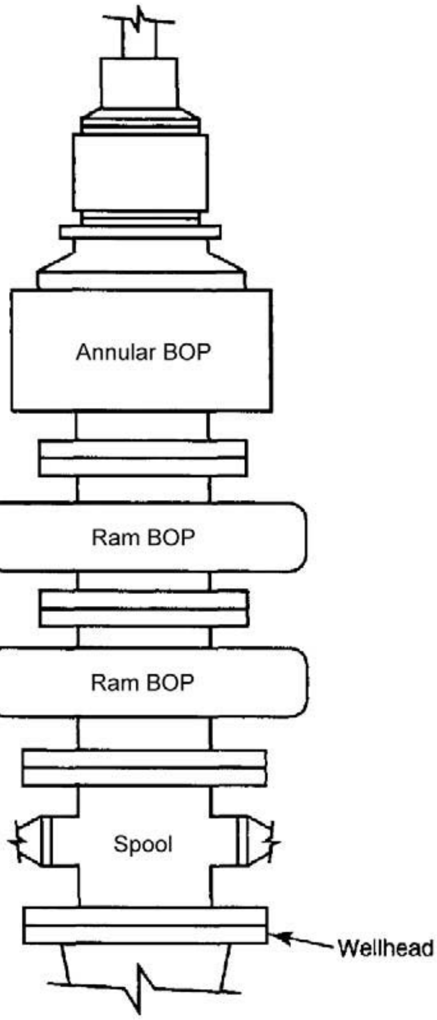


Figure 25 BOP stack workover[13]

The two ram BOPs in this stack can be designed as a double-ram type BOP or a design with two single standard ram BOPs. The double ram BOP is most commonly used in such a situation because the construction height is smaller than the height of two single BOPs. Therefore high of the whole stack decreases and the work floor can be constructed close to the ground. In most cases on workover rigs the space between the cellar bottom and the work floor is limited. The overall high of the BOP stack is limited by the design of the rig. The rams which are installed in the ram BOPs are commonly pipe rams in the top BOP and blind rams in the lower BOP.

The data of the BOPs are:

The double ram BOP CAMERON Type U:

Closing Volume: 7 gal (3,5 gal for each BOP)

Opening Volume: 6,8 gal (3,4 gal for each BOP)

Closing ratio: 7,3

The annular BOP CAMERON Type D:

Closing Volume: 5,65 gal

Opening Volume: 4,69 gal

The total closing volume of the stack: 12,65 gal

The total opening volume of the stack: 11,49 gal

7.2 Drilling Model

During a drilling operation the uncertainty in regard to the expected wellbore pressure is higher than on a workover operation. In this case the BOP stack is more conservative dimensioned than an ordinary workover stack. The expected wellbore pressure is in most onshore drilling operations and for this example 10 000 psig. Also the work floor is mounted higher so the BOP stack can be optimized for the requirements. A general used BOP stack in drilling operations is shown in Figure 2 and a drawing in Figure 26.

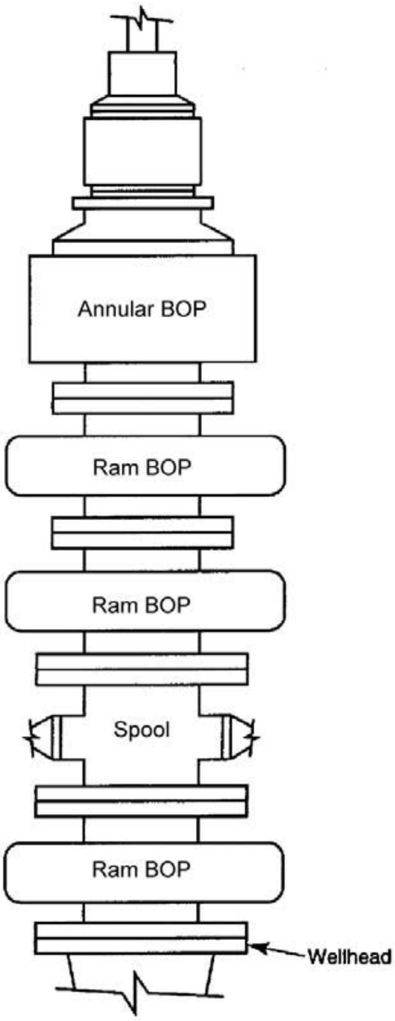


Figure 26 BOP stack drilling [13]

The total construction height is also limited on a drilling rig, many manufactures and contractors also choose the design variant with the double ram BOP as shown in Figure 2. The chosen stack arrangement has a nominal bore diameter of 13 5/8'' (346 mm). In the first ram BOP on top of the stack variable pipe rams are commonly mounted. In the second BOP blind or blind-shear rams are installed and the last BOP has commonly inhabits fixed pipe rams. For this example stack blind rams are chosen. There is only a difference in the closing volume between the blind and blind-shear rams. CAMERON, one of the biggest manufactures of BOPs, describes in their manuals for this BOP type, the different modules which are needed for shearing. For a shearing operation there has to be a larger piston installed and in certain cases an additional device (booster) has to be mounded on the BOP.

The booster is just a second piston which increases the pressure acting area. So there is no change of the working pressure required and only the useable fluid requirements increases.

For this stack model the BOP data are:

The double ram BOP CAMERON Type U:

Closing Volume: 11,6 gal (5,8 gal for each BOP)

Opening Volume: 11 gal (5,5 gal for each BOP)

Closing ratio: 7,0

The single ram BOP CAMERON Type U:

Closing Volume: 5,8 gal

Opening Volume: 5,5 gal

Closing ratio: 7,0

The annular BOP CAMERON Type D:

Closing Volume: 18,10 gal

Opening Volume: 16,15 gal

The total closing volume of the stack: 35,5 gal

The total opening volume of the stack: 32,65 gal

7.3 Accumulator Calculations

The number of bottles and the hydraulic system pressure are the two main characteristics of an accumulator unit. In the following chapter the required bottles for both stacks would be calculated. Once with the minimal requirements as defined in API Spec 16D and the other calculation with the more conservative Norwegian standard NORSOK D-002.

For these example calculations the following assumptions apply:

The nominal working pressure in the hydraulic system is 3000 psig.

The precharge pressure of the Bottles is set to 1000 psig.

The high closing ratio (HCR) valve on the site outlet requires 0,5 gal to open the choke line

7.3.1 Workover arrangement applied to API

The functional volume required (FVR) for in this case is:

Close all ram and the annular BOP is 12,65 gal

Open the HCR valve 0,5 gal

The total needed volume for the operations is 13,15 gal.

The different pressure in the conditions:

P_0=1000 psig

P_1=3000 psig

P_2=1200 psig

The pressure in condition 2, the minimum operation pressure is set to 200 psi above precharge pressure, in accordance with API RP53. The reason for this acceptance is that the minimal operating pressure for the ram BOPs is lower than the precharge pressure. The Eq. 32 shows the calculation of the minimum operating pressure by dividing the wellbore pressure by the closing ratio.

$$\frac{5000}{7,3} = 685\,psig \qquad (32)$$

As shown in Eq. 19 and 20 the volume efficiency factors for the given conditions are:

$$VE_V = \frac{\left(1,0 - \frac{P_0}{P_1}\right)}{1,5} = \frac{\left(1,0 - \frac{1000}{3000}\right)}{1,5} = 0,444 \qquad (33)$$

$$VE_P = \frac{\left(\frac{P_0}{P_2} - \frac{P_0}{P_1}\right)}{1{,}0} = \frac{\left(\frac{1000}{1200} - \frac{1000}{3000}\right)}{1{,}0} = 0{,}5 \quad (34)$$

In Eq. 21 the bottle volume (BV) is a part of this equation; converting this equation, the required bottle volume can be derived:

$$BV = \frac{\text{FVR}}{\text{minimum of VE}_\text{V}\text{ and VE}_\text{p}} = \frac{13{,}15}{0{,}444} = 29{,}6gal \quad (35)$$

The output of Eq. 35 is 29,6 gal; utilizing standard bottles with a useable capacity of 10 gal per bottle 3 bottles are required. API Spec 16D requires for 75% redundancy in case of a manifold and/or bottle failure. By that reason on the accumulator unit there has to be at least 4 bottles on separate banks.

7.3.2 Workover arrangement applied to NORSOK D-002

As described in chapter 5.2 the NORSOK standard requires 3 operations of the stack plus 25% safety volume.
The required volume for this workover stack is:

Close all BOPs on the stack	12,65 gal
Open all BOPs on the stack	11,49 gal
Close all BOPs on the stack	12,65 gal
25% of the all ram BOPs closing	1,75 gal
Total required volume	38,54 gal

In the NORSOK standard no definition is given about the calculation method. The following calculations for this example model will be referenced to the chapter 5.1.1.3.

The pressures for the three different conditions are defined as follows:

P_0=1000 psig

P_1=3000 psig

P_2=1200 psig

The minimum operating pressure P_2 is set to 200 psi above the precharge pressure for the same reason as is discussed in 7.3.1 and Eq. 32.

To calculate the number of the required bottles Eq. 22 to 25 has to be converted in one combined equation which gives the bottle number.

An additional definition for the transformation is required:

The total volume V_{tot} is defined by the useable bottle volume per bottle (V_B) multiplied by the quantity of the bottles x.

The transformed equation becomes:

$$x = \frac{V_{us}}{V_B \cdot \left(\frac{P_0}{P_2} - \frac{P_0}{P_1} \right)} \quad \text{......} \quad (36)$$

By filling in the data and using the total required volume V_{us}, the number of bottles required becomes:

$$x = \frac{38{,}54}{10 \cdot \left(\frac{1000}{1200} - \frac{1000}{3000} \right)} = 7{,}708 \quad \text{......} \quad (37)$$

The required quantity of bottles is 8 pieces of the 10 gal bottle type. In the Norsok standard there is also a part similar to the API Spec 16D which requires a 25 % redundancy in case of a manifold and/or bottle broke. The 8 bottles have to be mounted on 4 single manifolds.

7.3.3 Drilling arrangement applied to API

The functional volume required FVR is in this case are:

Close all ram and the annular BOP is 35,5 gal

Open the HCR valve 0,5 gal

The total needed volume for the operations is 36,0 gal.

The different pressure in the conditions:

P_0=1000 psig

P_1=3000 psig

P_2=1429 psig

The pressure in condition 2, the minimum operation pressure is set to 1429 psig. Eq. 38 shows the calculation of the minimum operating pressure by dividing the maximal anticipated wellbore pressure by the closing ratio.

$$\frac{10000}{7} = 1429\,psig \quad (38)$$

As shown in Eq. 19 and 20 the volume efficiency factors for the given conditions are:

$$VE_V = \frac{\left(1{,}0 - \frac{P_0}{P_1}\right)}{1{,}5} = \frac{\left(1{,}0 - \frac{1000}{3000}\right)}{1{,}5} = 0{,}444 \quad (39)$$

$$VE_P = \frac{\left(\frac{P_0}{P_2} - \frac{P_0}{P_1}\right)}{1{,}0} = \frac{\left(\frac{1000}{1429} - \frac{1000}{3000}\right)}{1{,}0} = 0{,}366 \quad (40)$$

In Eq. 21 the bottle volume BV is a part of this equation by converting this, the required bottle volume will be:

$$BV = \frac{\text{FVR}}{\text{minimum of VE}_\text{V}\text{ and VE}_\text{p}} = \frac{36,0}{0,366} = 98,3gal \quad (41)$$

The output of Eq. 41 is 98,3 gal and when utilizing the standard bottles with a useable capacity of 10 gal per bottle 10 bottles are required. API Spec 16D also requires for 75% redundancy in case of a manifold and/or bottle failiure. By that reason on the accumulator unit there has to be at least 12 bottles on 4 separate manifolds.

7.3.4 Drilling arrangement applied to NORSOK D-002

As described in chapter 5.2 the NORSOK standard requires 3 operations of the stack plus 25% safety volume.
The required volume for this workover stack is:

Close all BOPs on the stack	35,5 gal
Open all BOPs on the stack	32,65 gal
Close all BOPs on the stack	35,5 gal
25% of the all ram BOPs closing	4,4 gal
Total required volume	108,1 gal

In the NORSOK standard no definition is found about the calculation method. The following calculations for this example model will be referenced to the chapter 5.1.1.3.
The pressures for the three different conditions are following defined:
P_0=1000 psig
P_1=3000 psig
P_2=1429 psig

The minimum operating pressure P_2 is set to 1429 pisg. In Eq. 38 the calculation of the minimum operating pressure is shown. To calculate the number of the required bottles the equations 22 to 25 has to be converted in one combined equation which results the bottle number.

A small definition for the transformation is also needed:

The total volume V_{tot} is defined by the useable bottle volume V_B multiplies by the quantity of the bottles x.

The transformed equation is:

$$x = \frac{V_{us}}{V_B \cdot \left(\frac{P_0}{P_2} - \frac{P_0}{P_1} \right)} \qquad (42)$$

By filling in the dates and using the total required volume as V_{us} the number of needed bottles is:

$$x = \frac{108{,}1}{10 \cdot \left(\frac{1000}{1429} - \frac{1000}{3000} \right)} = 29{,}5 \qquad (43)$$

The required quantity of bottles is 30 pieces of a 10 gal bottle type. In the Norsok standard there is also a part like in the API Spec 16D which requires a 25 % redundancy in case of a manifold and/or bottle broke. In this case 32 bottles mounted on 4 separate manifolds are required.

7.3.5 Drilling arrangement applied to API with different pressure

This sample calculation is in basic the same as in chapter 7.3.3, only the pressure in condition 1 is set to 2700 psig. The motivation for this changes is in the chapter 5.1.1 discussed.

The functional volume required FVR is in this case are:

Close all ram and the annular BOP is 35,5 gal

Open the HCR valve 0,5 gal

The total needed volume for the operations is 36,0 gal.

The different pressure in the conditions:

P_0=1000 psig

P_1=2700 psig

P_2=1429 psig

The pressure in condition 2, the minimum operation pressure is set to 1429 psig. Eq. 38 shows the calculation of the minimum operating pressure by dividing the max anticipated wellbore pressure by the closing ratio.

As shown in Eq. 19 and 20 the volume efficiency factors for the given conditions are:

$$VE_V = \frac{\left(1{,}0 - \frac{P_0}{P_1}\right)}{1{,}5} = \frac{\left(1{,}0 - \frac{1000}{2700}\right)}{1{,}5} = 0{,}419 \quad \text{.......................................} (44)$$

$$VE_P = \frac{\left(\frac{P_0}{P_2} - \frac{P_0}{P_1}\right)}{1{,}0} = \frac{\left(\frac{1000}{1429} - \frac{1000}{2700}\right)}{1{,}0} = 0{,}329 \quad \text{....................................} (45)$$

In Eq. 21 the bottle volume BV is a part of this equation by converting this, the required bottle volume will be:

$$BV = \frac{\text{FVR}}{\text{minimum of } \text{VE}_\text{V} \text{ and } \text{VE}_\text{p}} = \frac{36{,}0}{0{,}329} = 109{,}4\,gal \quad \text{.........................} (46)$$

The output of Eq. 46 is 109,4 gal and when utilizing standard bottles with a useable capacity of 10 gal per bottle 11 bottles are required. The API Spec 16D also requires for 75% redundancy in case of a manifold and/or bottle failure. By that reason on the accumulator unit there has to be at least 12 bottles on 4 separate manifolds.

In this case there is no change in the main layout of the accumulator unit because of the API requirements.
Is there an other stack to calculate the fact to need one additional bottle will make different in the whole design layout.

7.4 Comparison of the Calculations

An overview about the results from the volume calculations is given in Table 2.

	Workover	Drilling
API Spec 16D /API Rp 53	4 Bottles	12 Bottles
NORSOK D-002	8 Bottles	32 Bottles

Table 2 Required bottles

This shows there is a significant difference between the two standards. The big problem on onshore rigs is the mobility. Onshore drilling and workover rigs have to be very mobile. In most cases the workover rigs are directly mounted on a truck. Drilling rigs are commonly constructed in a building-block design. So in both cases all parts of the equipment should be transportable in a simple way like in standard containers or mounted on special racks for truck transportation. An accumulator unit with four bottles can be simply mounted on the main structure, the mainframe of the truck, on a workover rig. With increasing the bottle quantity the whole unit requires more space. By increasing the bottle number the reservoir, which job is to provide pressure less fluid to the pumps and collects the backflow from the BOPs, increases too. Also the two redundant pump systems need to be designed larger. API requires that the pump system has to be able to charge all the accumulator bottles in a defined time. For this reason an accumulator system with more useable volume requires pumps with a greater flow rate. This causes, as shown in chapter 4.3 for higher power, so in the whole system the changes become quick considerable.

8 Risk Analysis

To compare the both standards (API and NORSOK) in not only a technical and economical way a risk analysis has to be prepared. To define the failure cases is the first step in this analysis.

This thesis focuses mainly on the accumulator bottles and their quantity. For this reason an assumption in regard to the pump system is made.

In all following considerations the primary and secondary pump system is inoperative. Therefore the accumulator bottles have to provide the hydraulic energy without being continuously charged by the pump during a well control operation. This is regarded to be a worst case scenario during a well control situation.

8.1 Operation Cases

To concretize the risks involved there are different operation cases defined at this point. Such a case can be a failure case or a normal operating case. A failure case means the operation, in this example shutting in the well, has to be conducted with defined failures in the system.

8.1.1 Baseline Case

The normal operating status of the accumulator unit is to provide 3000 psig of pressure and the full volume as calculated. The pumps are inoperative.

8.1.2 Failure Cases

In case of any failure different scenarios can occur. In these cases the accumulator unit doesn't have the design characteristics for volume and pressure.

8.1.2.1 Failure Case I

One bottle and/or one manifold is down.

If one bottle or manifold leaks the accumulator unit has to be designed in a way that only 25% of the volume is lost when the leaking bottle ore manifold is separated from the system.

API and NORSOK standards require these design criteria of the hydraulic system. In this case only 75% of the calculated fluid with a pressure of 3000 psig is available.

8.1.2.2 Failure Case II

The system pressure in the accumulator unit is in the area between 2700 and 2800 psig.

Every pressure switch has an adjustable control range between the on-off signal is send to a controller. API SPEC 16D requires that the minimum pump starting pressure is 90% of the nominal operating pressure. In the standard 3000 psi system the Pump staring pressure with therefore be no less then 2700 psig. The second standard which is discussed in this analysis has no requirements regarding to the range of the pressure switch of the primary pump system. To compare the two standards in both systems a pressure level of 2700 psi is chosen.

For consideration on the feasibility of how often this case occurring a range of this lowest system pressure is chosen between 2700 and 2800 psig.

8.1.2.3 Failure Case III

Both failure cases are combined in this one; the system pressure is at the lowest level (2700 psig) and one accumulator manifold is separated from the system. In this case only 75% of the calculated volume with a pressure of 2700 up to 2800 psig is available.

8.2 Feasibility Calculation

To interpret the risks, a defined feasibility for the discrete failure cases has to be calculated. The baseline case has 100% feasibility for the following considerations.

8.2.1 Feasibility of Case I

To calculate the feasibility there a failure plausibility has to be known. It is very hard to get such information from the industry. For that reason there are several assumptions made. One failure of a manifold and/or bottle per 10 years is supposed.

The range of 10 years is evident from API. API 510 (chapter 6.5.1.1), a standard regarding to the test procedures and test intervals of different pressure vessels, the inspection interval is no more than 10 years. So in a worst case it is assumed that once in 10 years there is a failure in the high pressure system. Such a failure causes a breakdown for the broken manifold for up to 7 days until it is fixed. This time strongly depends on the place where the rig is located and how fast the spare parts are available. 7 days is again believed to be the worst case.

The likeliness of a failure is therefore 7 days in 10 years. In Eq. 47 the percental value is calculated.

$$P_1 = \frac{100\%}{(365 days \cdot 10 years)} \cdot 7 days = 0{,}192\% \quad \text{...(47)}$$

8.2.2 Feasibility of Case II

The main reason for the lower pressure level in the high pressure system is minimal leakage at the components. That can be a leakage in the piston sealing of the ram BOP or a minimal leakage in the valves or similar. This leakage causes a constant pressure reduction. For the calculation it is assumed that the pump starts once a day. That means once a day the pressure level decreases to a value where the low pressure switch activates the pump. In the worst case scenario the hydraulic pressure is needed when the pressure level is at a low value (between 2700 and 2800 psig). This characteristic of the pressure level is shown in the diagram in Figure 27.

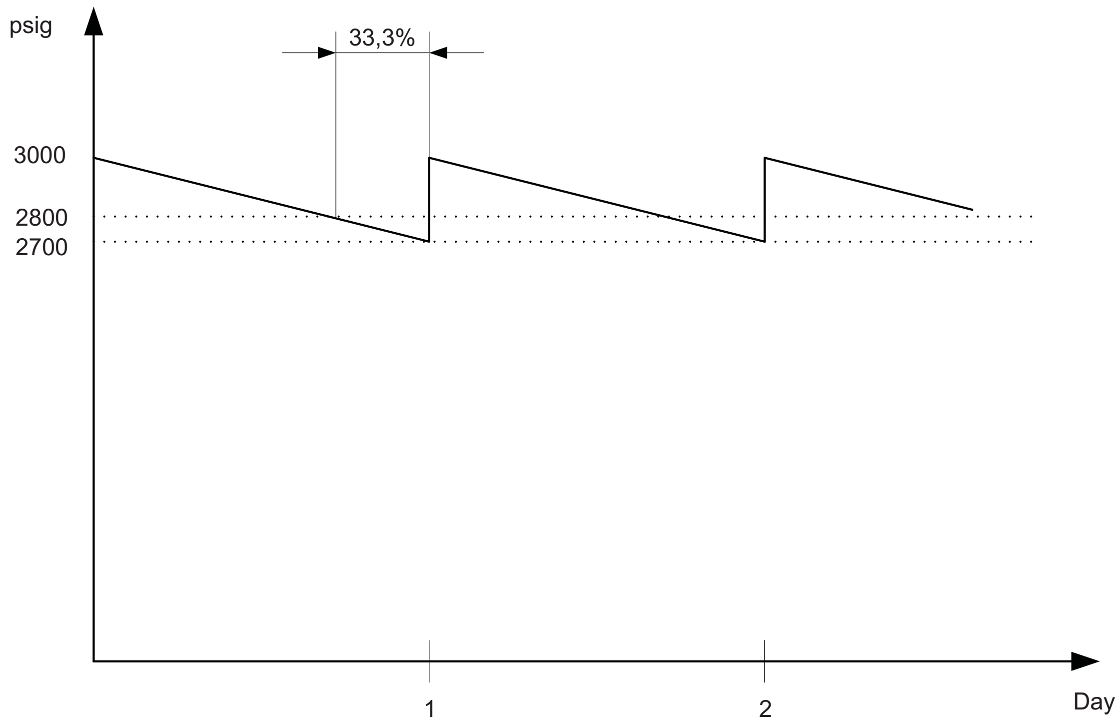


Figure 27 Feasibility Case II

With the linear equation the feasibility can easily be calculated. The gradient of the line is 300 psi divide by one day which presents 100%. With a conversation of the linear equation (y=k*x+d), the feasibility where the pressure is in the discussed area can be calculated.

$$x = -\frac{y-d}{k} = -\frac{2800-3000}{3} = 66,\dot{6}\% \quad (48)$$

The conclusion of Eq. 48 is the feasibility that the pressure is above the 2800 psig limit. So with a feasibility of P_2=33.33% the case II is occurring.

8.2.3 Feasibility of Case III

Case III is a combination of case I and II so the feasibility of this case is also a combination of the two cases. By multiplication of the two percentage values the total feasibility of the two combined cases can be derived.

$$P_3 = P_1 \cdot P_2 = 0{,}192\% \cdot 33{,}33\% = 0{,}064\% \quad (49)$$

8.3 Effect of the Failure Cases

The main effect of a failure in any case is that less fluid for the BOP operation is available. This effect can be calculated so that a statement about the risks regarding to the different cases can be given.

The following calculations for the effective useable fluid in each case will be made only once a time for showing the work procedure. All calculation results are shown in Table 3.

8.3.1 Calculation According to API

This following calculation is very similar to the calculation in chapter 7.3. At first there has to be two volume efficiency factors calculated and afterwards the useable fluid.

For this calculation case I is used with the workover BOP stack model:

The pressure level in this calculation is the same as in the design calculation and that reason both volumetric efficiency factors are the same as in chapter 7.3.1. The Eq. 35 has to be modified to derive the FRV

$$\mathrm{FVR} = \mathrm{BV} \cdot \text{minimum of } \mathrm{VE_V} \text{ and } \mathrm{VE_p} \quad (50)$$

After shutting down one manifold the bottle volume (BV) decreases from 40gal to 30gal. The remaining useable fluid becomes:

$$\mathrm{FRV} = 30 \cdot 0{,}44 = 13{,}32\mathrm{gal} \quad (51)$$

8.3.2 Calculation According to NORSOK

As the calculation according to API this calculations are also very similar to the calculations in chapter 7.3.

For this calculation case I is used with the workover BOP stack model:

The Eq. 36 has to be converted in a way that the output of the equation is the in Eq. 36 called V_{us} useable fluid. An other definition has to be made regarding to the bottle volume. The total bottle volume (BV) is the useable volume of one bottle (V_B) multiply by the number of bottles (x).

$$V_{us} = BV \cdot \left(\frac{P_0}{P_2} - \frac{P_0}{P_1} \right) \qquad (52)$$

The useable fluid with only 75% of the bottle volume for case I according to the NORSOK standard for the workover BOP stack:

$$V_{us} = 60 \cdot \left(\frac{1000}{1200} - \frac{1000}{3000} \right) = 30 gal \qquad (53)$$

8.3.3 Comparison of the Calculations

The calculations for the different cases and standards for the drilling and the workover BOP stack are summarized in the following table. The values are given in gallons of useable fluid.

	API		NORSOK	
	Drilling	Workover	Drilling	Workover
Baseline Case	43,9	17,7	117,1	40,0
Case I	32,9	13,3	87,8	30,0
Case II	39,5	16,7	105,4	37,0
Case III	29,6	12,5	79,0	27,7
Close all + HCR open	36	13,15	36	13,15

Table 3 Fatigue summary

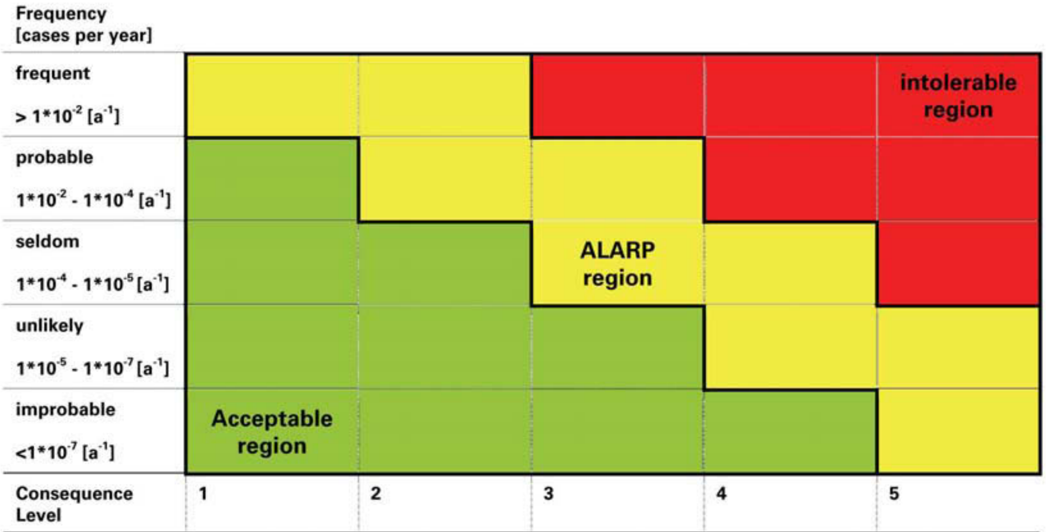
The values shown in Table 3 display the big differences between the single failure cases. In the last row the gallons, which are required to close the stack and open the HCR valve, are shown. After a comparison of the issues the conclusion is that in two cases the API requirements are not sufficient to close the stack in a worst case situation. The NORSOK requirements are more conservative; therefore in any case of failure the BOP stack at least can fully be closed.

8.4 Risk Assessment

The following risk assessment is based on the OMV E&P HSEQ Guideline for Risk Assessment Criteria, Doc.Nr.HSEQ-HQ-04-02-01 and the provisions of the OMV E&P standard for Deviation from the Requirements of Technical Standards, Doc.Nr. EP-HQ-010.

Theses standard guideline defines the basics for a risk assessment process and include also a matrix for estimation of the risks. The input which is needed to use this matrix is a defined feasibility of the single cases.

The feasibilities of the two critical cases are calculated in chapter 8.2.1 and 8.2.3. There they are given as a percentage value. For using the risk assessment matrix the feasibility has to be defined as cases per year. The percentage values are to be derived by 100 in order to fit them into the matrix shown in Figure 28. For case I the feasibility is 1,91 10^{-3} cases per year and for case II the feasibility is 6,39 10^{-4} cases per year.



Description of the Consequence Levels	1	2	3	4	5
Human	▶ single person of workforce injured but able to continue work, first aid needed ▶ single person of workforce with minor reversible short term health effect	▶ single person of workforce 1 or 2 days off work ▶ single person of workforce with moderate reversible mid term health effect ▶ single person of public with minor reversible short term health effect	▶ single person of workforce at least 3 work days lost ▶ single person of workforce with onset / signs of moderate irreversible health effect ▶ single person of public with moderate reversible mid term health effect	▶ 1 fatality of workforce ▶ more than 3 people on-site hospitalized ▶ single person of public hospitalized ▶ single person of workforce with onset / signs of severe irreversible health effect ▶ multiple persons of public with reversible health effect	▶ multiple fatalities (>1) of workforce ▶ 1 fatality of public ▶ more than 6 people of workforce and/or public hospitalized
Environment	▶ slight reversible environmental damage within the boundaries ▶ actions for restoration may be required	▶ slight reversible environmental damage outside the boundaries ▶ actions for restoration may be required	▶ short-term environmental damage within a limited area outside the boundaries ▶ actions for restoration may be required	▶ mid-term, major environmental damage ▶ actions are required for restoration	▶ massive long-term environmental damage on a large area ▶ major actions are required to restore environment
Reputation	▶ awareness, no external concern	▶ local concern, limited impact and/or single complaints	▶ regional concern and/or many complaints	▶ national concern	▶ international attention
Finance	▶ < EUR 10.000	▶ ≥ EUR 10.00 up to < 100.000	▶ ≥ EUR 100.000 up to < EUR 2 Mio	▶ ≥ EUR 2Mio up to < 10 Mio	▶ ≥ EUR 10 Mio

Figure 28 Risk assessment matrix [14]

In Figure 28 the two failure cases are in the probable frequency area. The second input to use the matrix is the consequences which could occur when the failure case is happen. For this input a consequence level is defined in the guideline. Of course when in worst case the available fluid is too less for actuating the well control equipment in the right way a blowout will better with the possible outcome of a major incident. Therefore the consequence level is set to 5, the worst level.

The conclusion of this risk assessment is that in this discussed worst scenarios the risk is in an intolerable area. By this reason the API volume requirements are too small in case of a failure and as the OMV E&P standards defines the risk is not manageable. For an OMV standard regarding the well control equipment the volume requirements have to be adjusting to a higher level. To adapt the whole NORSOK standard is not the best way in this case. Such a modification will not the best way in regarding an economical design especially in the onshore sector. On an offshore rig the mobility is not such a big influence on the design of this kind of equipment.

9 Recommendation for the OMV Well Control Standard

At the time when this thesis was put together OMV E&P was currently setting up its Well Control Standard. This chapter is therefore indented to give recuperation on the minimum accumulator volumetric capacity determination that will be part of that standard.

9.1 Definition

As lined out in chapter 6 API requirements are consider to be the absolute minimum and shall not be compromised. As shown in chapter 8 this requirements may not be sufficient in all cases to reduce the risk to ALARP level. It is therefore recommended that OMV incorporates additional requirements in its Well Control Standard. A structure approach similar to what is described in chapter 8 led to the following result:

Accumulator systems shall have sufficient useable hydraulic fluid volume (with pumps inoperative) to close one annular type preventer, all ram type preventers from a full open position, open one annular type preventer, open one ram type preventer and open one HCR vale against zero wellbore pressure. After performing all of this operations the remaining pressure shall be no less than the minimum required operating pressure for the shear/blind/pipe ram (as applicable; whichever yields the higher pressure requirement).

The rational for this recommendation is shown below.

9.2 Calculations applied to the OMV

To evaluate if there is a risk with the new designed volume requirements a calculations as to be done. The calculations for the different BOP stack models are identical with the API calculations in chapter 7.3. Also the pressure level in the different conditions is the same.

9.2.1 Workover arrangement applied to OMV

The volume requirements for the workover stack as described in chapter 9.1 have the following values:

Close annular	5,65 gal
Close all ram (2)	7 gal
Open annular	4,69 gal
Open 1 ram	3,4 gal
Open HCR	0,5 gal
Sum	21,24 gal

The pressure in the three conditions is the same as in the calculation in chapter 7.3.1 by this reason the volume efficiency factors are the same.

VE_V=0,444 taken from Eq. 33

$$BV = \frac{\text{FVR}}{\text{minimum of } \text{VE}_\text{V} \text{ and } \text{VE}_\text{p}} = \frac{21{,}24}{0{,}444} = 47{,}84\,gal \quad \text{..........................(54)}$$

A bottle volume of 50 gal or 5, 10 gal bottles is needed. Also in an OMV standard the design requirements are valid. For a complied design of the accumulator unit there have to be a 75% redundancy, so 8 bottles on 4 manifolds are needed.

9.2.2 Drilling arrangement applied to OMV

The in chapter 9.1 described volume requirements for the drilling stack model has following values:

Close annular	18,10 gal
Close ram (3)	17,4 gal
Open annular	16,15 gal
Open ram	5,5 gal
Open HCR	0,5 gal
Sum	57,65 gal

The pressure in the three conditions is the same as in the calculation in chapter 7.3.1 by this reason the volume efficiency factors are the same.

VE_p=0,366 taken from Eq. 40

$$BV = \frac{\mathrm{FVR}}{\text{minimum of } \mathrm{VE_V} \text{ and } \mathrm{VE_p}} = \frac{57{,}65}{0{,}366} = 157{,}51 gal \quad \text{.........................} (55)$$

An arrangement with 16 bottles is complied with the design requirements from the API standard if the bottles are mounted on 4 manifolds.

9.3 Effect of the Failure Cases with OMV Requirements

The results from the calculations conducted in chapter 8.3 are shown once more in Table 4 now including also the results for the calculation on the designated OMV case. The values in this table clearly show that in case of any failure as described in chapter 8.1 the BOP stack can fully be closed and one HCR valve can be opened. Therefore the accumulator volumetric sizing recommendation made in chapter 9.1 is considered to be sufficient.

	API		NORSOK		OMV	
	Drilling	Workover	Drilling	Workover	Drilling	Workover
Baseline Case	43,9	17,7	117,1	40,0	58,56	35,52
Case I	32,9	13,3	87,8	30,0	43,92	26,64
Case II	39,5	16,7	105,4	37,0	52,64	33,52
Case III	29,6	12,5	79,0	27,7	39,48	25,14
Close all + HCR open	36	13,15	36	13,15	36	13,15

Table 4 Extended Fatigue Summary

10 Conclusion

The given diploma thesis was intended to provide OMV E&P GmbH with a clear understanding on how to address the issue of accumulator volumetric sizing within their new standard for Well Control. The first question that had to be answered was if the provisions made in API standards are sufficient. The thesis discusses the fundamental basics required to understand the calculations made in API and consequently looks at other international standards and their provisions. By defining standard cases for workover and drilling BOP stacks it could be shown that API requirements leave room for improvement as they may lead to the inability of closing the BOPs in a worst case scenario.

Identifying this gap the thesis describes a recommended practice on how to size accumulators in regard to their volumetric capacities. Further calculations have proven this recommendation to be adequate in order to lower the residual risk to ALARP level.

It can be concluded that the thesis achieved the goals set up by OMV and the accumulator volumetric sizing recommendation given in the thesis is meanwhile incorporated in the OMV Well Engineering Well Control Standard (Doc No EP-EPP-WE-09-00) for worldwide application.

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12 Figure Index

13 List of Abbreviations

A Pipe flow profile [m²]

ALARP As Low As Reasonably Practicable

API American Petroleum Institute

BOP Blow Out Preventer

BV Bottle Volume

d Inner pipe diameter [m]

E&P Exploration & Production

EUB Alberta Energy and Utility Board

FVR Functional Volume Required

g Acceleration of gravity [m/s²]

k Wall roughness [mm]

λ Friction factor (pipe)[-]

l Pipe length [m]

m Mass [kg]

NORSOK Norsk Sokkels

ν Kinematic viscosity [m²/s]

p Pressure [psi]

P_0 System pressure at condition 0

P_1 System pressure at condition 1

P_2 System pressure at condition 2

psi psig (gauge) psia (absolute)

PTFE Polytetrafluorethylen

p_v Pressure loss [Pa]

ρ Fluid density [kg/m³]

R Gas constant

Re Reynolds number [-]

T Temperature [K]

V Volume [gal]

$\dot{V}$ Volumetric flow rate [m³/s]

V_B Useable bottle volume

VE_P Volume Efficiency pressure limited case

VE_V Volume Efficiency volume limited case

v_m Average flow velocity [m/s]

x Number of accumulator bottles

ζ Friction factor (fitting)

z Height measured from a central staring point [m]