STUDY OF THE EFFECT OF PRODUCTION CHOKE SIZES ON WELL HEAD PRESSURE IN SELECTED FIELD IN NIGER DELTA

BY
SELE MICHAEL IYERE
ENG2002635

DEPARTMENT OF PETROLEUM ENGINEERING
FACULTY OF ENGINEERING
UNIVERSITY OF BENIN
BENIN CITY

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SELE MICHAEL IYERE
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CERTIFICATION

This is to certify that this project was carried out by SELE MICHAEL IYERE of the Department of Petroleum Engineering with matriculation number ENG2002635 in partial fulfillment of the requirements for the Award of the Degree, Bachelor of Engineering (B.ENG)

DR. SUNNY A. IGBINERE (PROJECT SUPERVISOR)	**DATE**
DR. OLUWASEUN TAIWO (PROJECT COORDINATOR)	**DATE**
DR. IKPONMWOSA OHEHEN (HEAD OF DEPARTMENT)	**DATE**
PROF. KELVIN CHINWUBA IGWILO (EXTERNAL SUPERVISOR)	**DATE**

DEDICATION

This thesis is dedicated to God Almighty, who made it possible for me to complete the study successfully. This work is dedicated to my father, mother, siblings, alongside my professors and lecturers who have taught me that the best kind of knowledge to have is that which is learned for its own sake and have been a major source of motivation in this academic journey.

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ABSTRACT

The production of oil and gas globally can only be made possible with the aid of drilling technology. However, after well completion, that is making a well ready for production, the surface equipment such as wellhead and Christmas tree is required to flow in the well. The production Choke is precisely regulating the flow of oil or gas to achieve a carefully calculated rate of recovery. By maintaining the correct backpressure, chokes can increase the ultimate recovery of hydrocarbons from a formation pressure decline, reduce sand production and the migration of fines, possibly control water coning and gas fingering, and minimize tree damage from erosion caused by turbulence and cavitations. Two wells were discussed, Well No (SELE 01) and (SELE 02), the effect of increase in the choke sizes were seen to affect the reservoir characteristics, i.e. Pressure decline, API, Flow rates, Sand Control, Water cut, etc. The results and analysis has shown that as the choke size increased, the flow rate increased, the rate of decline of the FTP increased, the API increased and the Water cut also increased. The choke size was later adjusted to a value of 16/64'' for well NO (SELE 01) and 30/64'' for well NO (SELE 02) in order for the well to flow at an optimum rate. At this rate, the pressure decline was also maintained, little or no water cut, and traces of sand. Conclusively, to maintain optimum flow rate, the choke size was carefully chosen so that the pressure in the reservoir is maintained for a considerable length of time, also there was no traces of sand and water production.

CHAPTER ONE

1.0 INTRODUCTION

1.1 Background of Study

An oil well is a general term for any boring through the earth surface that is designed to find and acquire petroleum hydrocarbons. Usually some natural gas is produced along with the oil. A well that is designed to produce mainly or only gas may be termed a “gas well”.

The earliest known oil wells were drilled in China in 347 CE. They had depths of about 800 feet (240m) and were drilled using bits attached to bamboo poles. The oil was burnt to evaporate brine and produce salt. By the 10th Century, extensive bamboo pipelines connected oil wells with salt springs. The ancient records of China and Japan are said to contain many allusions to the use of natural gas for lighting and heating. Petroleum was known as burning water in Japan in the 7th century.

The Middle East’s petroleum industry was established by the 8th century, when streets of the newly constructed Baghdad were paved with tar, derived from petroleum that became accessible from natural fields in the region. Petroleum was distilled by Persian alchemist Muhammad ibn Zakariya Razi (Rhazes) in the 9th century, producing chemicals such as kerosene in the alembic (al-ambiq), and which was mainly used for kerosene lamps. Arab and Persian chemists also distilled crude oil in order to produce flammable products for military purposes. Through Islamic Spain, distillation became available in Western Europe by the 12th century.

Some sources claim that from the 9h century, oil fields were exploited in the area around modern Baku, Azerbaijan, to produce Naptha for the petroleum industry. These fields were described by Marco Polo in the 13th century, who described the output of those oil wells as hundreds of shiploads. When Marco Polo in 1264 visited the Azerbaijan city of Baku, on the shores of the Caspian Sea, he saw oil been collected from the seeps. He wrote that "on the confines toward Geirgine there is a fountain from which oil springs in great abundance, in as much as hundred shiploads might be taken from it at one time".

Shallow pits were dug at the Baku seeps in ancient times to facilitate collecting oil, and hand-dug holes up to 35 meters (115ft) deep were in use by 1594. These holes were essentially oil wells. Apparently 116 of these wells in 1830 produced 3840 metric tons (about 28000 barrels) of oil. Also, offshore drilling started up at Baku (the Russian Empire) at Bibi-Eibat field in 1846. In the New World, the first offshore oil well was drilled in 1896 at the summerland oil field on the California Coast.

The earliest oil wells in modern times were drilled percussively, by hammering a cable tool into the earth. Soon after, cable tools were replaced with rotary drilling, which could drill bore holes to much greater depths and in less time. The record depth Kola Borehole used non rotary mud motor drilling to achieve a depth of over 12,000 meters (39,000ft). Until the 1970s, most oil wells were vertical, although lithological and mechanical imperfections cause most wells to deviate at least slightly from true vertical. However, modern directional drilling technologies allow for strongly deviated wells which can, given sufficient depth and with proper tools, actually become horizontal. This is of great value as the reservoir rocks which contain hydrocarbons are usually horizontal, or sub-horizontal; a horizontal wellbore placed in a production zone has more surface area in the production zone than a vertical well, resulting in a higher production rate. The use of deviated and horizontal drilling has also made it possible to reach reservoirs several kilometers or miles away from the drilling location (extended reach drilling), allowing for the production of hydrocarbons located below locations that are either difficult to place a drilling rig on, environmentally sensitive, or populated.

Choke valves are severe service valves which are specially designed specifically for oil and gas wellhead applications, both in surface and subsurface context. They are used for controlling the flow on production, reinjection, and subsurface wellheads. Choke valves are subjected to typical wellhead extreme conditions which can cause erosion, corrosion and other damage. Typically this can include high fluid velocity, slugging, sand production and multiphase of oil, gases and water. Also a choke valve has to have a high turndown capability as it has to cover a wide range of flowrates. Thus, the design of Choke valves is required to be very robust with careful selection of valve configuration, flow path profiles, materials and ease of maintenance.

In subsea applications the Choke valve has to cope with severe marine environmental conditions and be designed for subsea robot maintenance. If choke valves are selected poorly, maintenance becomes a real issue with valves having to be removed regularly which is a real cost import. Chokes can be operated manually or automatically. Sometimes a “choke bean” size is detailed, this is a device placed in choke line that regulates the flow through choke. Flow depends on the size of the opening in the bean; the larger the opening, the greater the flow.

Actuator selection is also important; actuators may be a “stepping type” or linear depending on the valve design. Control systems can be complex on large facilities where multiple wells are controlled to production and reinjection manifolds. A basic surface tree consists of two or three manual valves (usually gate valves because of strength).

A typical sophisticated surface tree will have at least four or five valves, normally arranged in a crucifix type pattern (hence the endurance of the term “Christmas tree”). The two lower valves are called master valves (upper and lower respectively) because they lie in the flow path, which well fluids must take to get to the surface. The lower master valves will normally be manually operated, while the upper master valves are often hydraulically actuated, allowing it to be a means of well control while an actuated wing valve is normally the primary well remotely (from control room or control panel) controlled valve. Hydraulic tree wing valves are usually built to be safe closed, meaning they require active hydraulic pressure to stay open. The right hand valve is often called the flow wing valve; because it is in the flow path the hydrocarbons take to production facilities (or the path water or gas will take from production to the well in the case of injection wells). The left hand valve is often called the kill wing valve. It is primarily used for the injection of fluids such as corrosion inhibitors or methanol to prevent hydrate formation. In the North Sea, it is called the non-active side arm (NASA). It is typically manually operated. The valve at the top is called a swab valve and lies in the path used for well interventions like wireline and coiled tubing. For such operations, a lubricator is rigged up into the top of the tree and wire or coil is lowered through the lubricator, past the swab valve and into the well. This valve is typically manually operated.

Some trees have second swab valve, the two arranged one on top of the other. The intention is to allow rigging down equipment from the top of the tree with the well flowing while still preserving the Two barrier rule. With only a single swab valve, the upper master valve is usually closed to act as the second barrier, forcing the well to be shut in for a day during the rig down operations. However, avoiding delaying production for a day is usually too small a gain to be worth the extra expense of having a Christmas tree with a second swab valve.

Subsea trees are available in either vertical or horizontal configurations with further specialty available such as dual bore, monobore, concentric, drill-through, mudline, guideline less or guideline. Subsea trees may range in size and weight from a few tons to approximately 70 tons for high pressure, deepwater (>3000 feet) guideline less applications. Subsea tree contains many additional valves and accessories compared to surface trees. Typically, a subsea tree would have a choke (permits control of flow), a flowline connection interface (hub, flange or other connection), subsea control interface (direct hydraulic, electro hydraulic, or electric) and sensors for gathering data such as pressure, temperature, sand flow, erosion, multiphase flow, single phase flow such as water or gas.

1.1.1 Life of a Well

The creation and life of a well can be divided into five segments:

- Planning
- Drilling
- Completion
- Production
- Abandonment

1.1.1.1 Drilling

The well is created by drilling a hole 5 to 50 inches (127.0mm to 914.4mm) in diameter into the earth with s drilling rig that rotates a drill string with a bit attached. After the hole is drilled, section of steel pipe(casing), slightly smaller in diameter than the borehole, are placed in the hole. Cement may be placed between the outside of the casing and borehole. The casing provided structural integrity to the newly drilled borehole, in addition to isolating potentially dangerous high pressure zones from each other and from the surface.

With these zones safely isolated and the formation protected by the casing, the wells can be drilled deeper (into potentially more unstable and violent formations) with a smaller bit, and also cased with a smaller size casing. Modern wells often have two to five sets of subsequently small hole sizes drilled inside one another, each cemented with casing.

To drill a well;

- The drill bit, aided by the weight of thick walled pipes called “drill collars” above it, cuts into the rock. There are different types of drill bit; some cause the rock to disintegrate by compressive failure, while others shear slices off the rock as the bit turns.
- Drilling fluid, a.k.a “mud”, is pumped down the inside of the drill pipe and exists at the drill bit. Drilling mud is a complex mixture of fluids, solids and chemicals that must be carefully tailored to provide the correct physical and chemical characteristics required to safely drill the well. Particular functions of the drilling mud include cooling the bit, lifting rock cuttings to the surface, preventing destabilization of the rock in the wellbore walls and overcoming the pressure of the fluids inside the rock so that these fluids do not enter the wellbore.
- The generated rock “cuttings” are swept up by the drilling fluid as it circulates back to surface outside the drill pipe. The fluid then goes through “shakers” which strain the cuttings from the good fluid which is returned to the pit. Watching for abnormalities in the returning cuttings and monitoring pit volume or rate of returning fluid are imperative to catch “kicks” early. A “kick” is when the formation pressure at the depth of the bit is more than the hydrostatic head of the mud above, which if not controlled temporarily by closing the blowout preventers and ultimately by increasing the density of the drilling fluid would allow formation fluids and mud to come up through the drill pipe uncontrollably.
- Pipe or drill string to which the bit is attached is gradually lengthened as the well gets deeper by screwing in additional 30-foot (9m) sections or “joints” of pipe under the Kelly or top-drive at the surface. This process is called making connection. Usually, joints are

combined into three joints equaling one stand. Some smaller rigs only use two joints and some rigs can handle stands of four joints.

This process is all facilitated by a drilling rig which contains all necessary equipment to circulate the drilling fluid, hoist and turn the pipe, control downhole, remove cuttings from the drilling, and generate on-site power for these operations.

1.1.1.2 Completion

After drilling and casing the well, it must be ‘completed’. Completion is the process in which the well is enabled to produce oil and gas.

In a cased-hole completion, small holes called perforations are made in the portion of the casing which passed through the production zone, to provide a path for the oil to flow from the surrounding rock into the production tubing. In open hole completion, often ‘sand screens’ or a ‘gravel pack’ is installed in the last drilled, uncased reservoir section. These maintain structural integrity of the wellbore in the absence casing, while still allowing flow from the reservoir into the wellbore. Screens also control the migration of formation sands into the production tubular and surface equipment, which can cause washouts and other problems particularly from unconsolidated sand formation of offshore fields.

After a flow path is made, acids and fracturing fluids are pumped into the well to fracture, clean or otherwise prepare or stimulate the reservoir rock to optimally produce hydrocarbons into the wellbore. Finally, the area above the reservoir section of the well is packed off inside the casing, and connected to the surface via a smaller diameter pipe called tubing. This arrangement provides a redundant barrier to leaks of hydrocarbons as well as allowing damaged sections to be replaced. Also, the cross-sectional area of the tubing produces reservoir fluids at an increased velocity in order to minimize liquid fallback that would create additional backpressure , and shields the casing from corrosive well fluids

In many wells, the natural pressure of the subsurface reservoir is high enough for the oil or gas to flow to the surface. However, this is not always the case, especially in depleted fields where the pressures have been lowered by the other producing wells, or in low permeability oil reservoirs, installing smaller diameter tubing may be enough to help the production, but artificial lift methods may also be needed. Common solutions include downhole pumps, gas lift or surface pump jacks. Many new systems in the last ten years have been introduced for well completion. Multiple packer systems with frac ports or port collars in an all in one system have cut completion costs and improved production, especially in the case of horizontal wells. These new systems allow casings to run into the lateral zone with proper packer/frac port placement for optimal hydrocarbon recovery.

1.1.1.3 Production

The production stage is the most important stage of a well's life, when the oil and gas are produced. By this time, the oil rigs and work over rigs used to drill and complete the well have moved of the wellbore, and the top is usually outfitted with a collection of valves called Christmas Trees or Production Trees. These valves regulate pressure, control flows, and allow access to the wellbore in case further completion work is needed. From the outlet valve of the production tree, the flow can be connected to a distribution network of pipelines and tanks to supply the product to refineries, natural gas compressor stations or oil export terminals.

As long as the pressure in the reservoir remains high, the production tree is all that is needed to produce the well. If the pressure depletes and is considered economically viable, an artificial lift method mentioned in the completion section can be employed. Workovers are often necessary in older wells, which may need smaller diameter tubing, scale or paraffin removal, acid matrix jobs, or completing new zones of interest in a shallower reservoir. Such remedial work can be performed using workover rigs- also known as *pulling units* or *completion rigs* – to pull and replace tubing, or by the use of well intervention techniques utilizing coiled tubing. Depending on the type of lift system and wellhead rod rig or flush by can be used to change a pump without pulling the tubing.

Enhanced recovery methods such as water-flooding, steam flooding or CO_2 flooding may be used to increase reservoir pressure and provide a "sweep effect" to push hydrocarbons out of the reservoir. Such methods require the use of injection wells (often chosen from old production wells in a carefully determined pattern), and are used when facing problems with reservoir pressure depletion, high oil viscosity, or can even be employed early in the well's life. In certain cases – depending on the geo-mechanics of the reservoir – reservoir engineers may determine that ultimate recovery oil may be increased by applying a water-flooding strategy early in the field's development rather than later. Such enhanced recovery techniques are called "tertiary recovery".

1.1.1.4 Christmas Tree

In petroleum and natural gas extraction, a Christmas tree is an assembly of valves, spools, and fittings, used for an oil well, gas well, water injection well, water disposal well, gas injection well, condensate well and other types of well. It was named for a crude resemblance to a decorated tree.

They are subsequently manufactured from blocks of steel containing multiple valves rather than made from multiple flanged valves. This is especially true in subsea applications where the resemblance to Christmas trees no longer exists given the frame and system supports into which the main valve block is integrated.

It is common to identify the type of tree as either “subsea” or “surface tree”. Each of these classifications has a number of varieties within them. Examples of subsea include conventional, dual bore, mono bore, TFL (through flow line), horizontal, mudline, mudline horizontal, side valve and TBT (through bore tree) trees

The primary function of a tree is to control flow into or out of the well, usually oil or gas. A tree often provides numerous additional functions including chemical injection points, well intervention means, pressure relief means (such as annulus tree) and well monitoring points (such as pressure, temperature, corrosion, erosion, sand detection, flow rate, flow composition, valve and choke position feedback, connection points for devices such as down-hole pressure and temperature transducer (DHPT)).

When the operator, well and facilities are ready to produce and receive oil or gas, valves are opened and the release of formation fluids is allowed to flow into and through a pipeline. The pipeline then leads to a processing facility, storage depot and/or other pipelines eventually leading to a refinery or distribution center (for gas). Subsea wells and thus trees usually flow through flowlines to a fixed or floating production platform or to a storage vessel (known as floating storage offloading vessel (FSO), or floating processing unit (FPU), or floating production and offloading vessel or FPSO or other combination of structures).

A tree may also be used to control the injection of gas or water injection application on a producing or non-producing well in order to sustain economic “production” volumes of oil from other well(s) in the area (field).

On producing wells, injection of chemicals or alcohols or oil distillates to prevent and or solve production problems (such as blockages) may be used. Functionality may be extended further by using the control system on a subsea tree to monitor, measure, and react to sensor outputs on the tree or even down the wellbore.

The control system attached to the tree controls the downhole safety valve (scssv, dhsv, sssv) while the tree reacts as an attachment and conduit means of the control system to the downhole safety valve.

Christmas trees are used on both surface and subsea wells (current technical limits are up to around 3000 meters and working temperatures of -50 ^{0}F to 350 ^{0}F with pressure of up to 15, 000 psi). The deepest installed subsea tree is in the Gulf of Mexico at approximately 9000 feet.

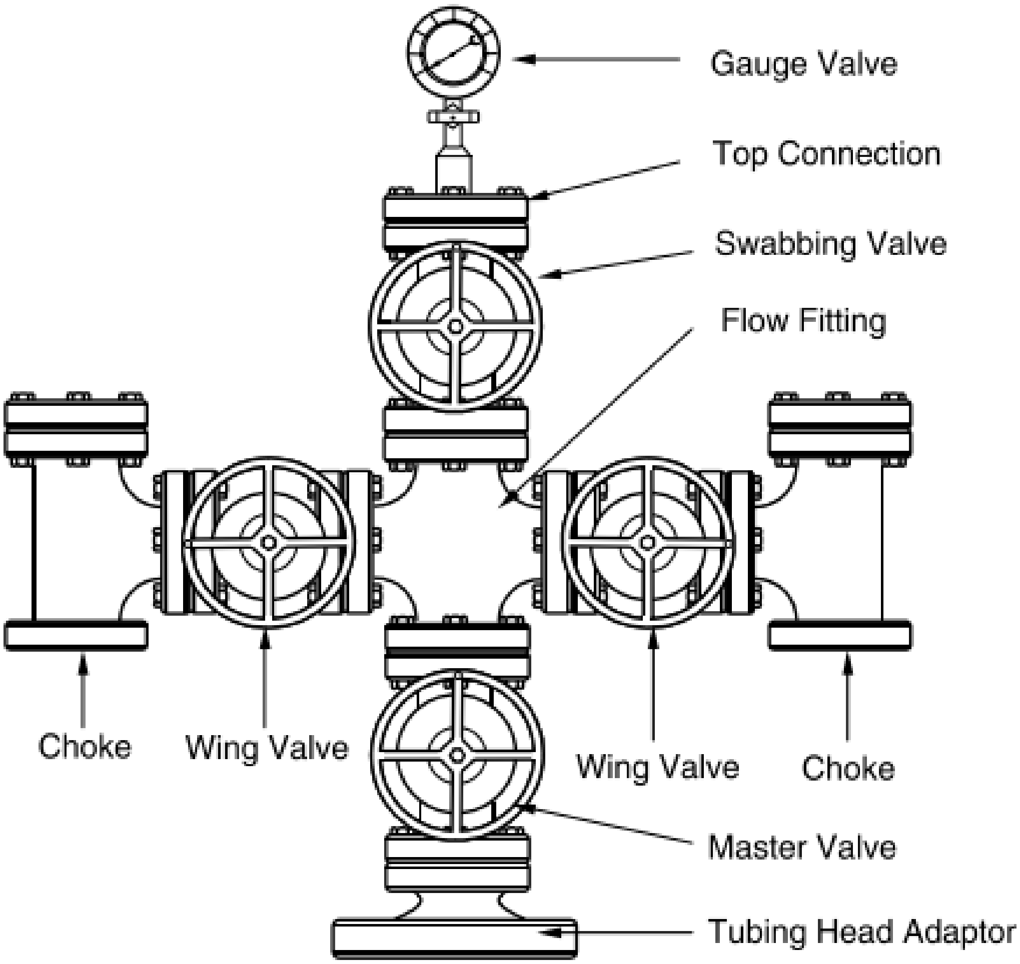


Figure 1.0: A Sketch of a Christmas tree

Tubing hanger (also called donut) is used to position the tubing correctly in the well. Sealing allows Christmas tree removal with pressure in the casing.

Master valve: Includes the lower and upper master valves. The upper master valve is hydraulically actuated, while the lower master valve is manually driven. They are both used for opening and shutting in well.

The pressure gauge: The minimum interpretation is a pressure gauge placed above the master gate valve before the wing valve. In addition, other instruments such as temperature will normally be fitted.

The wing valve: It is primarily used for injection of fluids such as corrosion inhibitors or methanol to prevent hydrate formation. It is also used to shut in the well in case of emergency.

The swab valve: The valve is located at the upper part of the Christmas tree. It is the path taken, when carrying out work – over.

The variable flow choke valve: This valve is typically a large needle valve. Its calibrated opening is adjustable in 1/64 inch increments (called beans). High quality steel is used in order to withstand the high-speed flow of abrasive materials that pass through the choke, usually for many years, with little damage except to the dart or seat if a variable choke is normally installed on smaller wells.

The Christmas tree shown above is a **vertical tree**. Christmas trees can also be **horizontal**, where the master, wing and choke is on the horizontal axis. This reduces the height and may allow easier intervention. Horizontal trees are especially used on subsea wells.

1.2 Statement of the Problem

Good production engineering requires regular design and setting checks for production chokes.
In practice, all flowing wells make use of some surface restrictions in order to regulate the flowing rate. Only very few wells are produced with absolutely no restrictions for getting maximum production rate. The overall performance of a production well is a function of several variables. Examples of these variables are tubing size, choke size, flow line size, and perforation density. Hence, the need to evaluate the effects of choke sizes as it affects production.

1.3 Aims and Objectives

The aim of this work is to study the effect of production choke sizes on wellhead pressure in some Niger Delta fields.

The specific objectives are as follows;

1. To review the oil and gas production choke, the types, and the components in general.
2. To discuss the major parts/components of an oil and gas Christmas tree including the production chokes.
3. To relate the flow rate of a producing well using various production choke sizes as it affects the reservoir characteristics.
4. To explain the major functions of production choke in the oil and gas industry.
5. To see how the production choke will affect the wellhead pressures.

1.4 Scope of Study

The scope of this project is to review the Christmas tree production choke as it affects pressure maintenance and also give possible recommendations for pressure maintenance in the reservoir using production choke.

1.5 Limitation of Study

This report/study limits to the use of data from two wells in Egbema field only. Another limitation to the study was my inability to gather enough statistical data and records on the flow rate data for a particular well.

CHAPTER TWO

2.0 LITERATURE REVIEW

Production chokes are Christmas tree components that precisely regulate the flow of oil and gas to achieve a carefully calculated rate of recovery. By maintaining the correct backpressure, chokes can increase the ultimate recovery of hydrocarbons from a formation, control the rate of formation pressure decline, reduce sand production and the migration of fines, possibly control water coning and gas fingering, and minimize tree damage from erosion caused by turbulence and cavitations.

Chokes come in two basic types: adjustable and positive. Adjustable chokes are often used during completion operations to allow the operator to clean and flow test the well. Once the optimum flow rate is determined, the adjustable choke is usually replaced with a positive choke for production. Both styles are available in a variety of sizes, connections, and pressure ranges to meet various requirements. They are almost located just downstream of a wing valve on the Christmas tree to facilitate isolation for service or orifice changes.

Adjustable chokes consist of a choke body, adjustable choke bonnet and stem, and stem seat. Counter clockwise rotation of the choke handle moves the stem tip out of the stem seat, thereby increasing the effective flow area.

The stem tip consists of some type of hardened steel to resist abrasion. Located on the bonnet assembly is a position indicator sleeve, which is commonly calibrated in the 64th s of an inch, from zero to full bore opening. The adjustable choke is not designed to stop to stop the flow completely, although it may do so at low pressures. As with gate valves, the stem packing acts to isolate choke body pressure from the atmosphere. Almost all chokes, and especially those with higher pressure ratings, have an injection port from stem packing.

A positive choke consists of a choke body with constant orifice size. Choke nipples were once used with a carefully calibrated bore. While their initial cost was low, their use has been virtually abandoned because changing them is difficult and time consuming. Modern Chokes have internal threads and a seating shoulder in the bore to accommodate choke beans with specific size orifice. The bean can be inserted and removed quickly with a special wrench. Many low-pressure adjustable chokes can be converted to positive chokes by replacing the stem seat with s choke bean and the bonnet/stem assembly with a seal cap.

2.1 Choke Valve Design Specification

A typical Choke Valve Design Specification should include but is not limited to;

- Process Data – Gas and Liquid Flow Rates (including initial start-up, maximum flow for the life of the well), Production Profile over the life the well, Wellstream Composition, Fluid Type (e.g. oil), Compressibilty. Design Pressure, Pressure Inlet and Outlet, Pressure Drop, Liquid Density, Design Temperature, S.G., Vapour Pressure, Critical Pressure, Molecular Weight, Specific Heat Ratio, H_2S content, Sand Content, snd Actuator Sizing Differential Pressure. When selected, the vendor should be requested to advise the calculated Cv of the valvem, percentage opening for the Cv selected for the Flow Rates specified and predicted noise of the valve.
- Mechanical Requirements – Body - Inlet and Outlet Size Ratings, body type (e.g., angle), Rated Pressure and Temperature, Standard (e.g. API 6A), Materials, NACE Requirements, Bonnet Requirements.
  - Trim – Size, Design, Flow Direction, and Material for trim, stem, plug and seals, Leakage class, Maximum, allowable noise.

    - Actuator – Type, Air/hydraulic, operating medium pressures, Failure Mode, Actuator torque, Orientation, Stroke and Stroking Time and Limit stops.
    - Positioner – Positioner type (e.g. Pneumatic, Hydraulic, Electric) - Input signal, Output Pressure, Tube Fittings, Material and Cable Entry.
    - Accessories – Handwheel, Limit Switches, Pressure Trip valve, Position Indicator, Filter Regulator, Volume Tank.
- Special Notes – In Marine locations, selection of materials should take the local environmental conditions into account as considerable corrosion can result from poor choices. This is particularly relevant for instrument fittings, tubing, positioners (feedback arms, etc.), actuator materials (especially in the case of pneumatic which "breathe", in which case "closed loop systems should be considered). Also for Hydraulic Systems the cleanliness of the hydraulic oil and system must be addressed at the design and maintenance stages.

2.2 Choke Valve Problems and Solutions

1. Corrosion

Corrosion is generally associated with the choice of wrong materials. A common mistake is to use a choke valve specification based on history. It must be remembered that an oil/gas well has a process component make up that is associated with a particular well. One well may produce Carbon Dioxide, while the other doesn't. A standard specification may cause the wrong material to be selected for an application. Corrosion is relatively easily solved, as a choice of suitable materials is widely available. However, a comprehensive knowledge of materials is required as combinations of certain materials may lead to galling.

2. Erosion

It is important to understand the difference between single and two phase scenarios. Velocity can cause body erosion, trim erosion and piping erosion. There are different philosophies with respect to what velocities are and not acceptable. However, generally selected velocities are too high. For liquid application, a rule of thumb is that the velocity has to be controlled below 5-7 m/s measured in outlet of the flange, for two phases, this is 10-15 m/s and for gas 25 – 40 m/s. It should be noted that these figures do not include for sand production and also do not take the gas/liquid ratio into account for two phase situations. It should also be noted that often choke valves are reduced in size, for example a 4 inch nominal bad with 6 inch inlet and/or outlet flanges. If the velocity at the outlet flange is still within the above mentioned rule of thumb it does not automatically indicate that everything will be expected to work out, as the velocity in the so called nominal body goes up and may well exceed what is considered to be acceptable. The choke velocity should be calculated first of all with the same body and flange size before reducing the normal body size. If the velocity is lower than mentioned in the above rule of the thumb, one can calculate a smaller nominal body with smaller flanges can be used with reduced risk of erosion.

Thus velocity is the most important design criteria; correct design limitation of this in combination with a well-designed trim will limit any erosion.

Calculating velocities has to be based on general calculations for gas, liquids and a combination of the two phases. A calculation is required to determine the required Cv and this can be achieved by fitting different trims in nominal body sizes. However, different pipe diameter selection produces different velocities. Relatively low velocities are not advised, as the result is likely to result in the selection of a too large size choke size. High velocities are likely to result in erosion of the body with an associated high maintenance cost.

Trim selection is also very important. As an example, Mokveld chokes are equipped with a cage provided with holes uniformly distributed over the full circumference. This design ensures that fluid is symmetrically distributed. The many flow jets are diametrically opposed. Consequently, the energy is dissipated in the centre of the valve. This occurs in the fluid itself and not near the surface of any choke component. Also, preferential flow, the major cause of body erosion, is fully avoided.

3. Cavitation

Cavitation should not be taken lightly as it can not only lead to erosion but it can also cause vibration. The vibration may shatter brittle materials as Tungsten Carbide often used for the trim.

4. Leaking

Leaks on Choke valves are sometimes caused by the selection of incorrect materials, but may also be attributed to general design of the Choke valve. Some chokes have a split body design; these vary from a forged block (main body) with weld on or fitted flange connections (adapters) to main body bolted bonnet type. A one piece body casting is one answer to these problems. Also the Choke Valve seals have to fail before leaks occur. Seals utilized on almost all designs are of the ‘O’Ring’ type. As a choke is used under high pressure and pressure drop, these O’Rings may be subjected to explosive decompression. This can cause them to split or deform. Should this happen, the sealing property is lost. Explosive decompression often occurs when Viton is used. This happens to be one of the most suitable resilient materials for hydrocarbon service. Hence, careful consideration of seal materials is required if Viton is selected as it is subject to explosive decompression. Furthermore, the service of the O'Rings has to be considered as this can differ from static to dynamic applications. Most problems with O'Rings occur in dynamic applications.

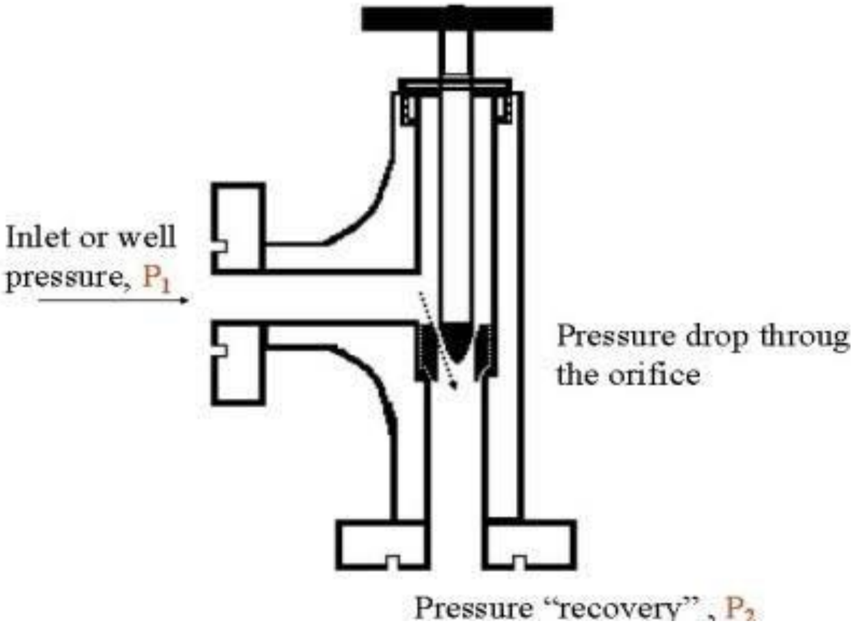


Figure 2.1 Rough Schematic of an adjustable choke.

2.3 Most Common Chokes

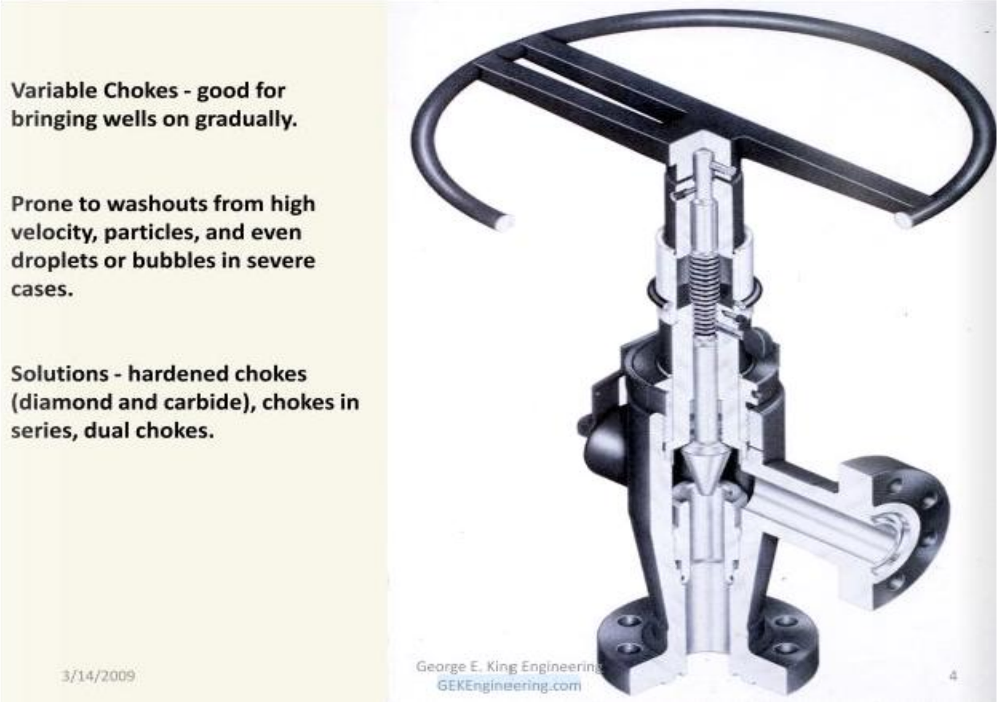
- **POSITIVE:**

❖ Fixed Orifice

❖ Shut in well (or divert flow) and disassemble choke housing to change the restriction of "flow bean"

- **ADJUSTABLE:**

❖ Provides variable orifice size through external adjustment without choke disassembly.



Variable Chokes - good for bringing wells on gradually.

Prone to washouts from high velocity, particles, and even droplets or bubbles in severe cases.

Solutions - hardened chokes (diamond and carbide), chokes in series, dual chokes.

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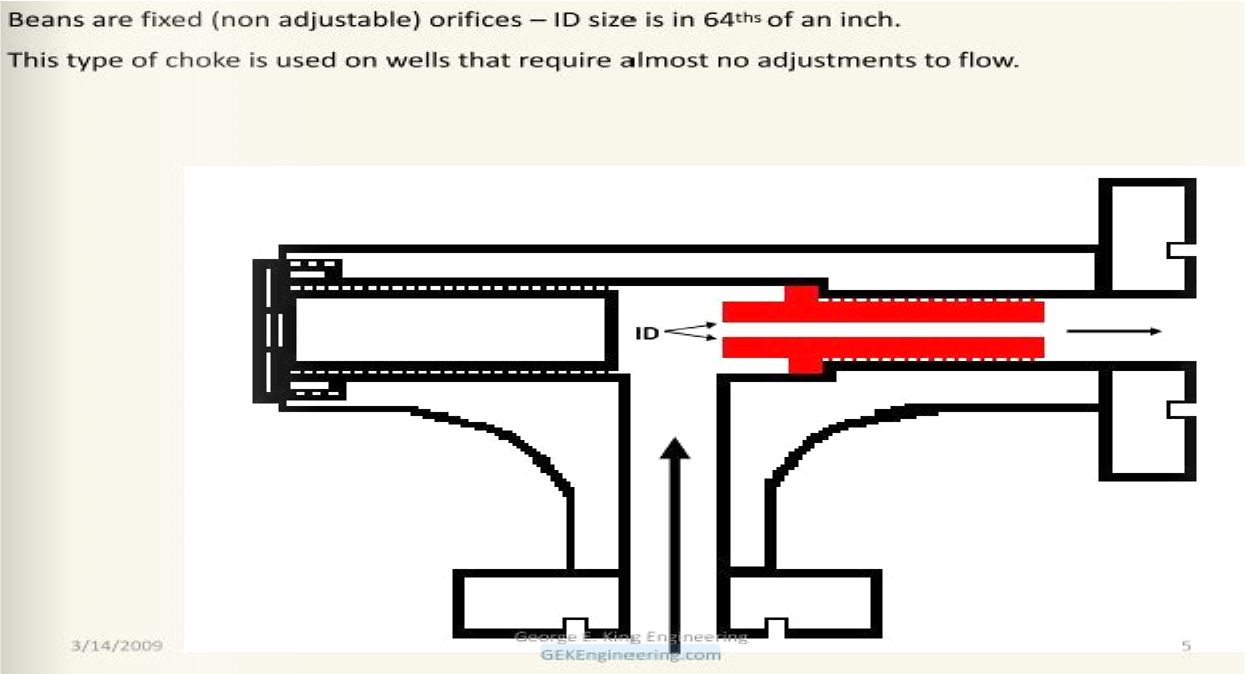
Figure 2.2: Variable Orifice Size (External Adjustment)



Beans are fixed (non adjustable) orifices – ID size is in 64^{ths} of an inch.

This type of choke is used on wells that require almost no adjustments to flow.

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Figure 2.3: Fixed Beans (non-adjustable orifices)

2.4 Choke Uses

- Control flow – achieve liquid lift
- Maximize use – best use of gas lift
- Protect equipment – abrasion and erosion
- Clean up – best use of backflow energy
- Control circulation – holds a back pressure
- Control pressures at surface (during flow)
- Control injection – on injection time

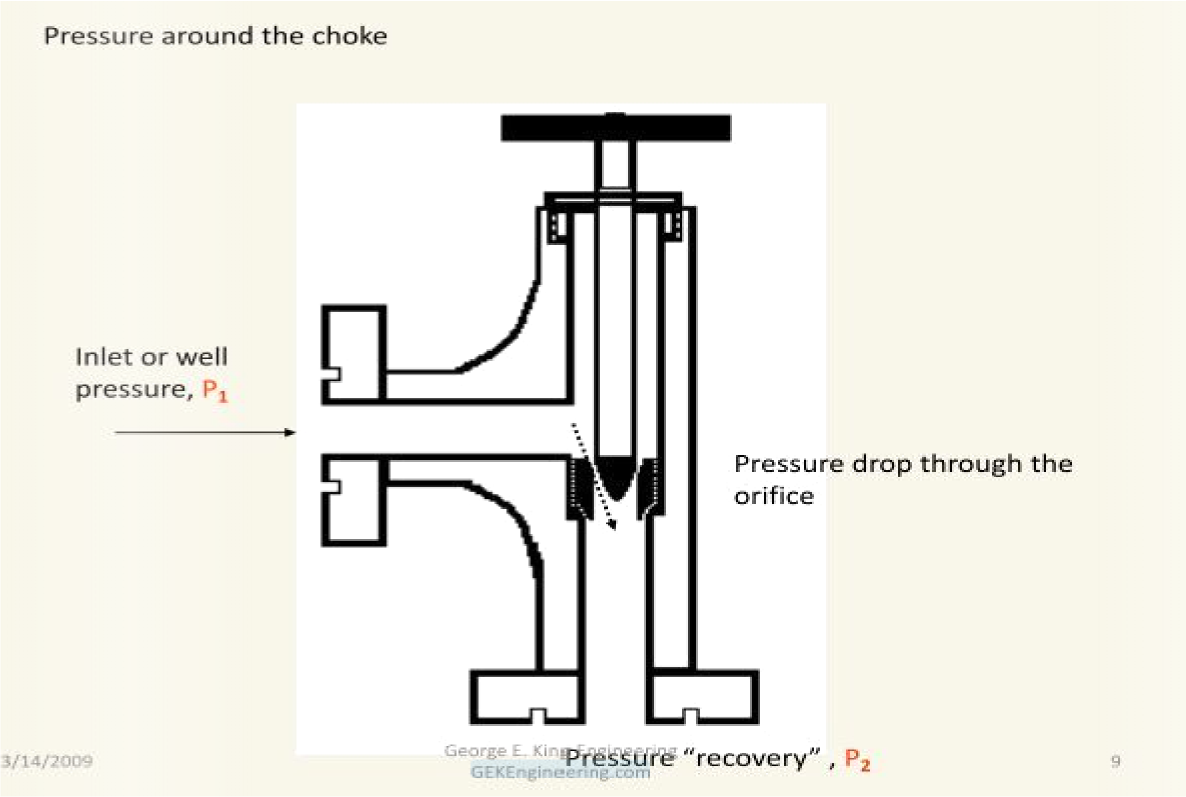
2.5 What Happens as Choke Provides a Pressure Drop and What Happens to the Pressure?

Energy from pressure drop is lost in;

- Increased velocity (from gas expansion)
- Vaporization (flashing) of light (short carbon chain) hydrocarbon liquids to gas
- Vaporization of water
- Cavitation
- Heat production (usually liquid friction)

2.5.1 Detriments

- Flashing – hydrocarbon light ends lost (value lost)
- Cavitation – erosion of surfaces in and around choke
- Erosion – solids, droplets and bubbles in high velocity flow
- Freezing – expansion of gases cools the area – refrigeration principle



Pressure around the choke

Inlet or well pressure, P_1

Pressure drop through the orifice

Pressure "recovery" , P_2

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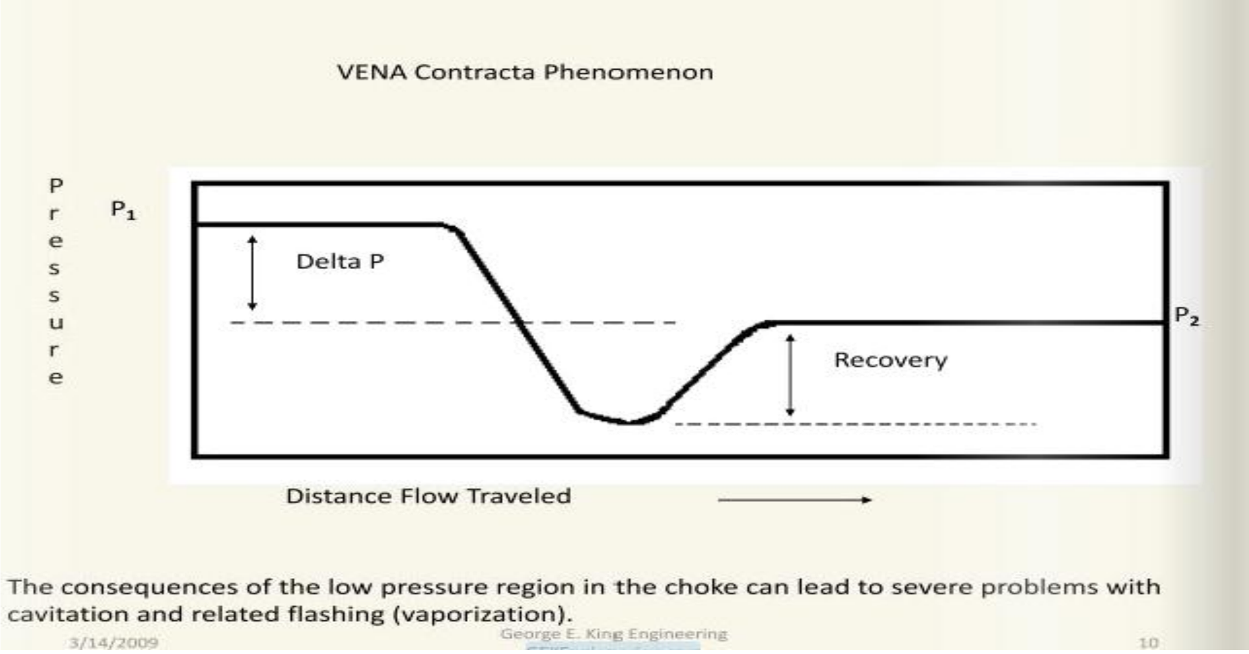
Figure 2.4: Pressure around the choke



VENA Contracta Phenomenon

The consequences of the low pressure region in the choke can lead to severe problems with cavitation and related flashing (vaporization).

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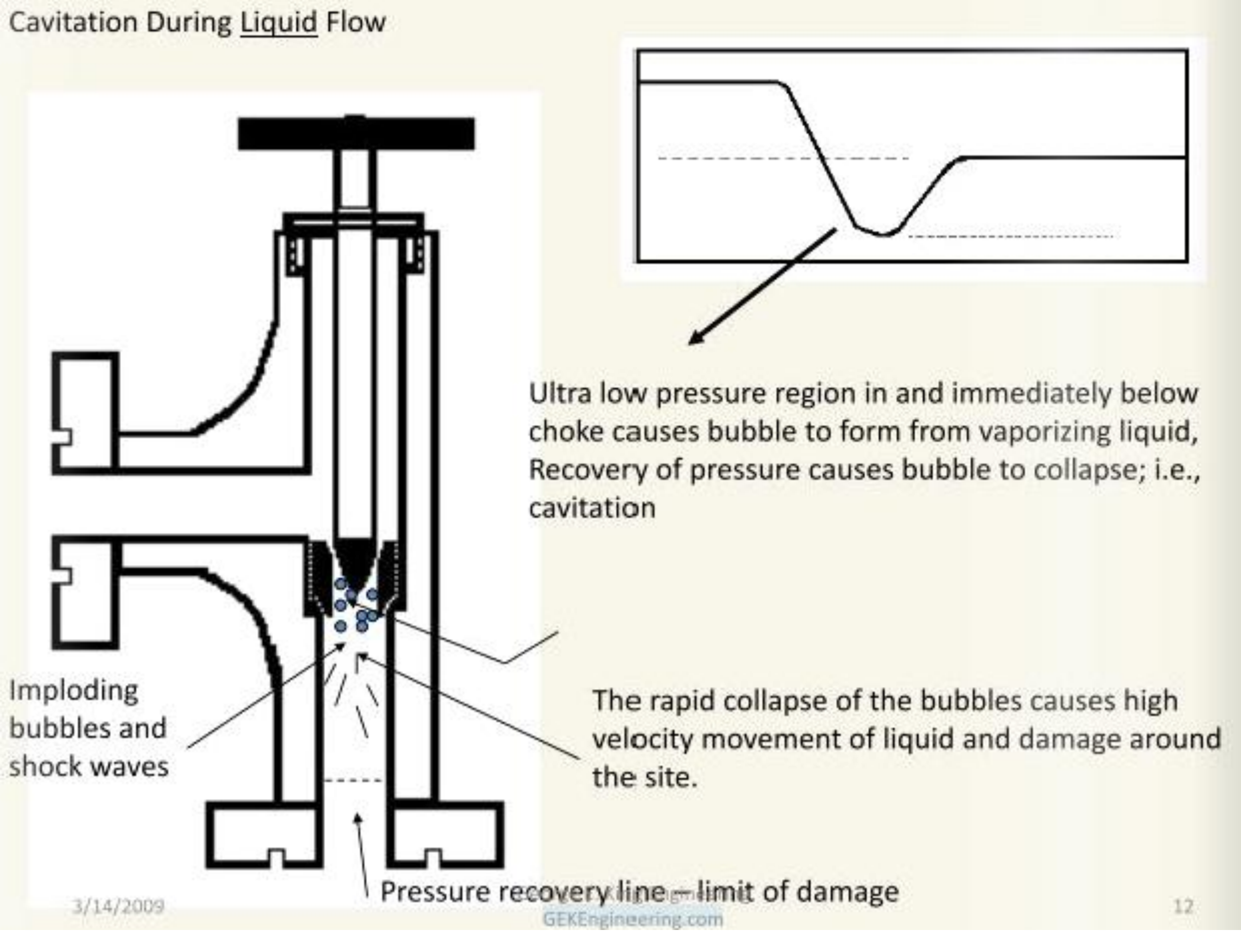
Figure 2.5: VENA Contracta Phenomenon

2.5.2 Problems with VENA Contracta Phenomenon

- The larger the difference between the inlet and outlet pressures, the higher the potential for damage to the internals of the choke
- When delta P ratio (i.e., $(P_1 - P_2)/P_1$) rises above 0.6, damage is likely. Changes in choke type, materials of construction, or choke management may be needed (multiple chokes in series for high pressure drops?)



Cavitation During <u>Liquid</u> Flow

Ultra low pressure region in and immediately below choke causes bubble to form from vaporizing liquid, Recovery of pressure causes bubble to collapse; i.e., cavitation

Imploding bubbles and shock waves

The rapid collapse of the bubbles causes high velocity movement of liquid and damage around the site.

Pressure recovery line – limit of damage

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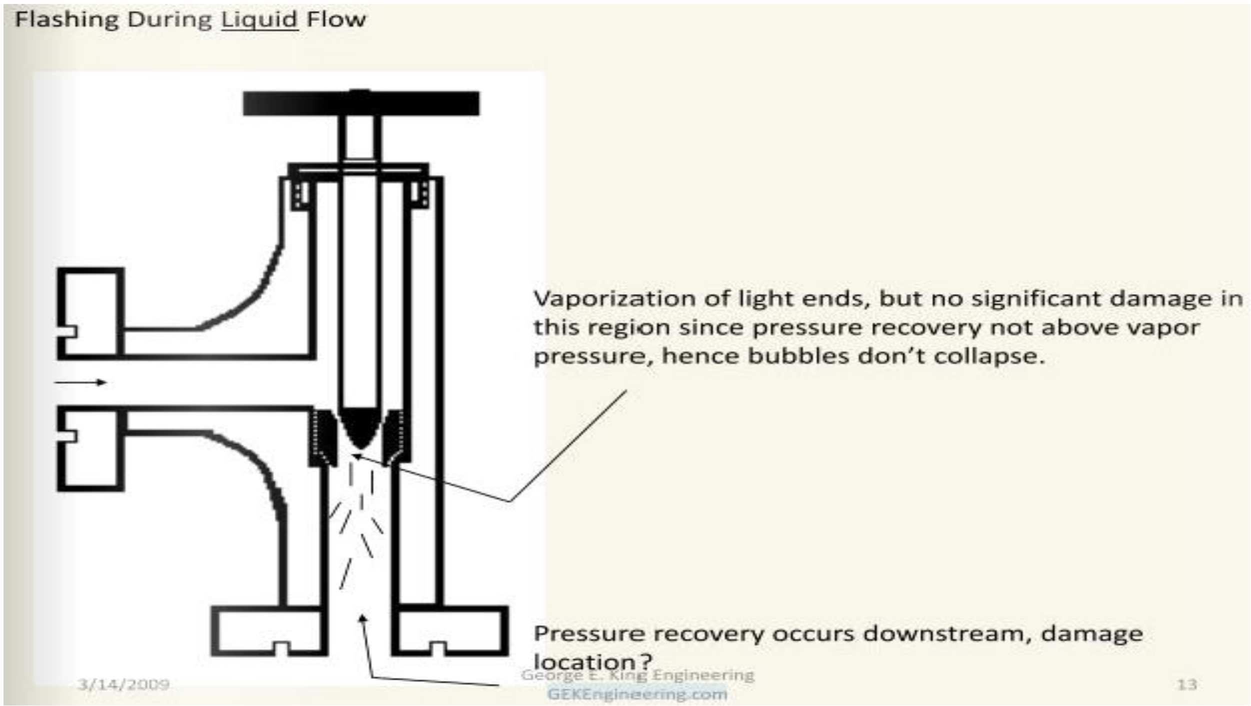
Figure 2.6: Cavitation during Liquid Flow



Flashing During Liquid Flow

Vaporization of light ends, but no significant damage in this region since pressure recovery not above vapor pressure, hence bubbles don't collapse.

Pressure recovery occurs downstream, damage location?

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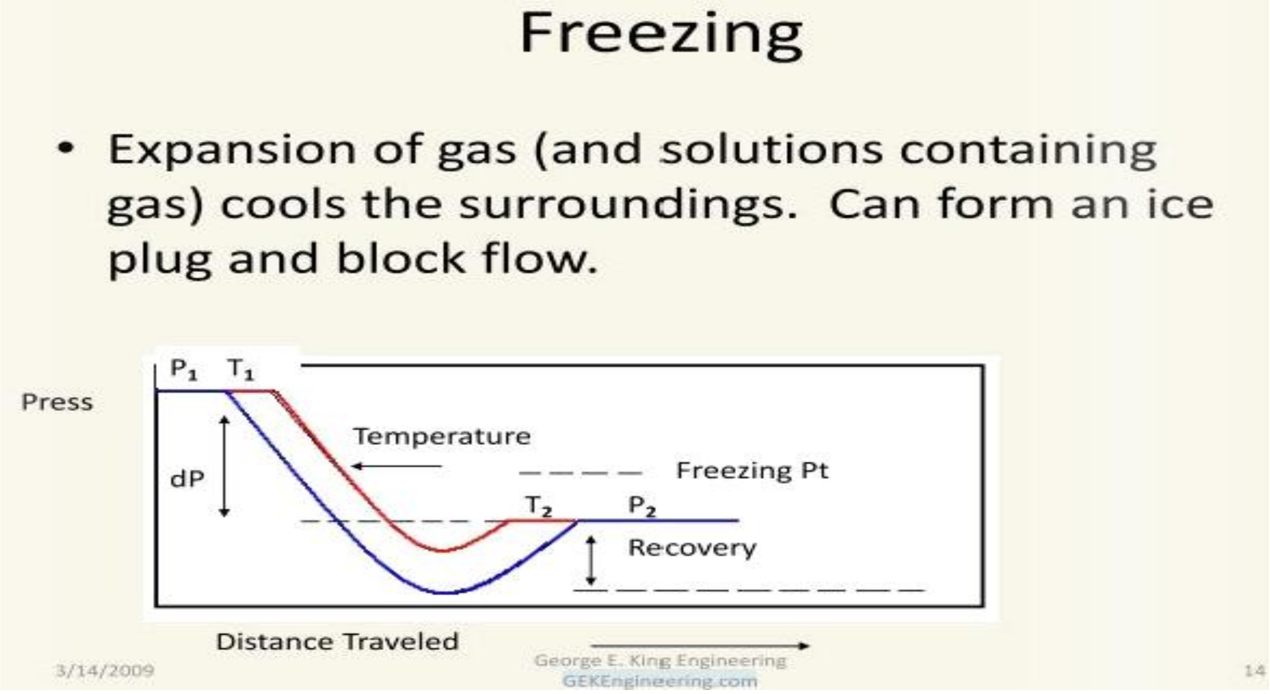
Figure 2.7: Flashing during Liquid Flow



Freezing

- Expansion of gas (and solutions containing gas) cools the surroundings. Can form an ice plug and block flow.

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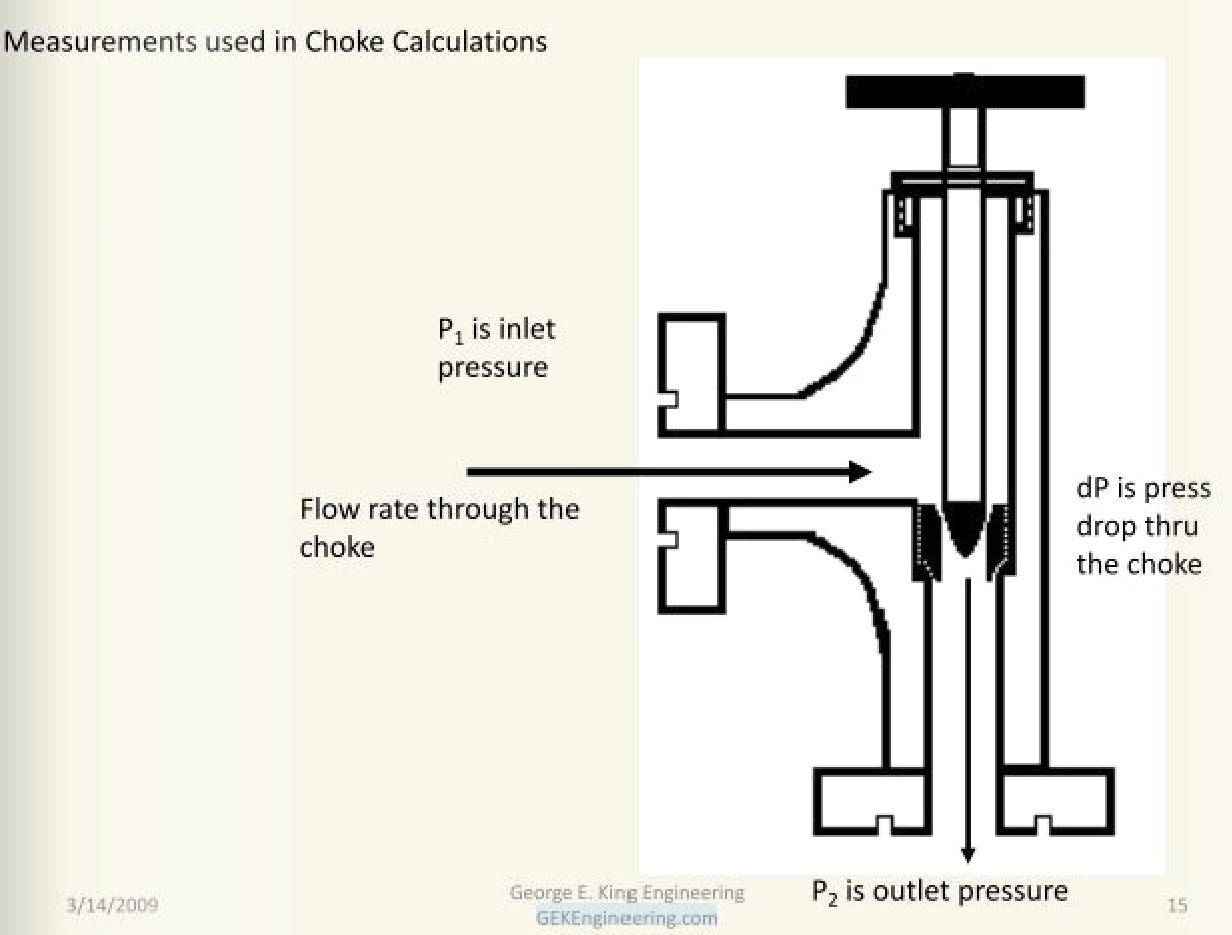
Figure 2.8: Freezing during Liquid Flow



Measurements used in Choke Calculations

P_1 is inlet pressure

Flow rate through the choke

dP is press drop thru the choke

P_2 is outlet pressure

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Figure 2.9: Measurements used in choke calculations

Calculations

- Delta P = $P_1 - P_2$
- Delta P ratio = delta P_2/P_1
- These values are used to measure the capacity and recovery of the choke

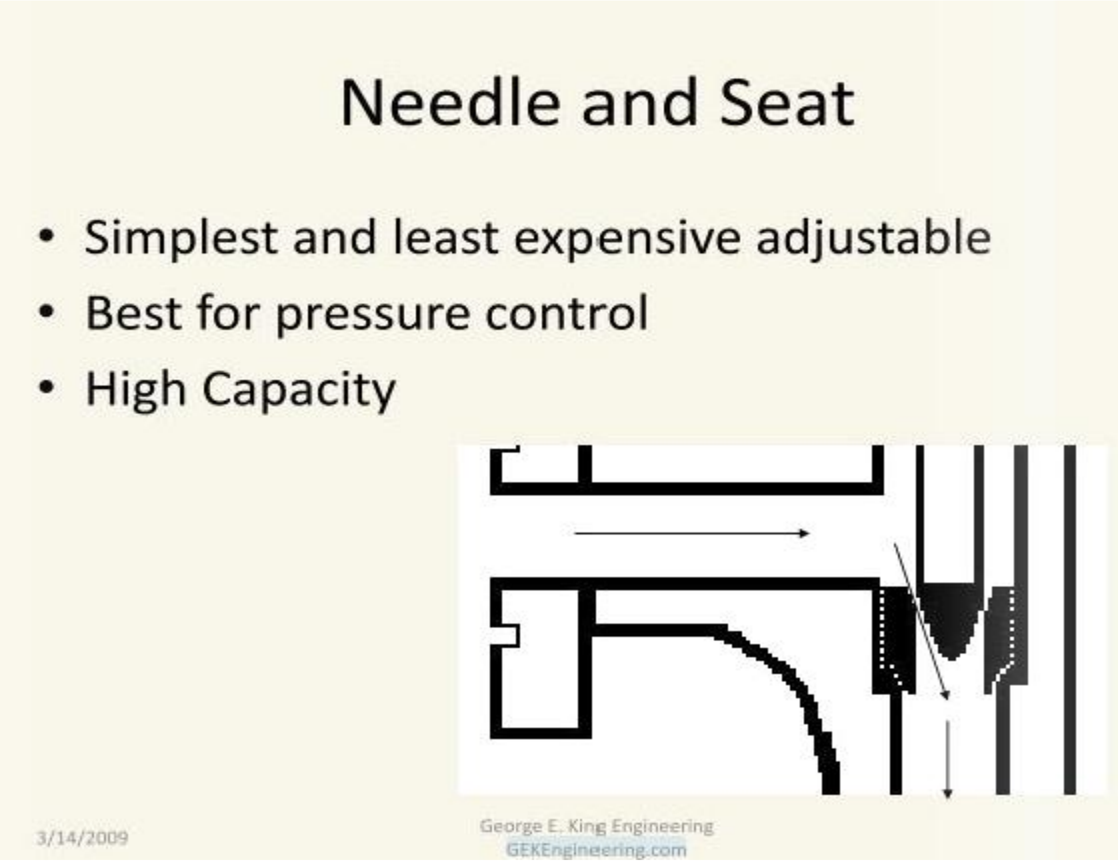
2.6 THROTTLING METHODS

- Needle and seat

- Multiple orifice
- Fixed Bean
- Plug and Cage
- External Sleeve

2.6.1 Needle and Seat

- Simplest and least expensive adjustable
- Best for pressure control
- High Capacity



Needle and Seat

- Simplest and least expensive adjustable
- Best for pressure control
- High Capacity

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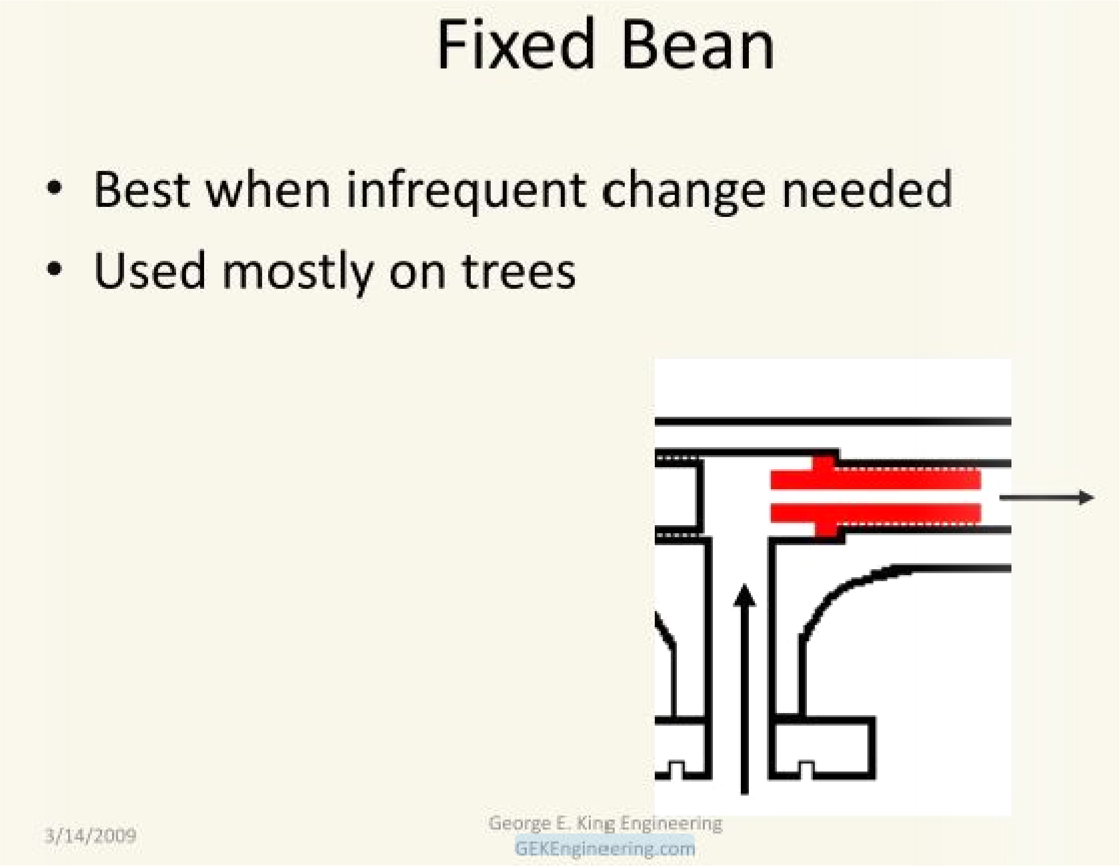
Figure 2.10: Needle and seat

Multiple Orifices

- ❖ Quick open and close
- ❖ Good rate and pressure control
- ❖ An in-line instrument – not usually used on the wellhead

Fixed Bean

- ❖ Best when infrequent change needed
- ❖ Used mostly on trees



Fixed Bean

- Best when infrequent change needed
- Used mostly on trees

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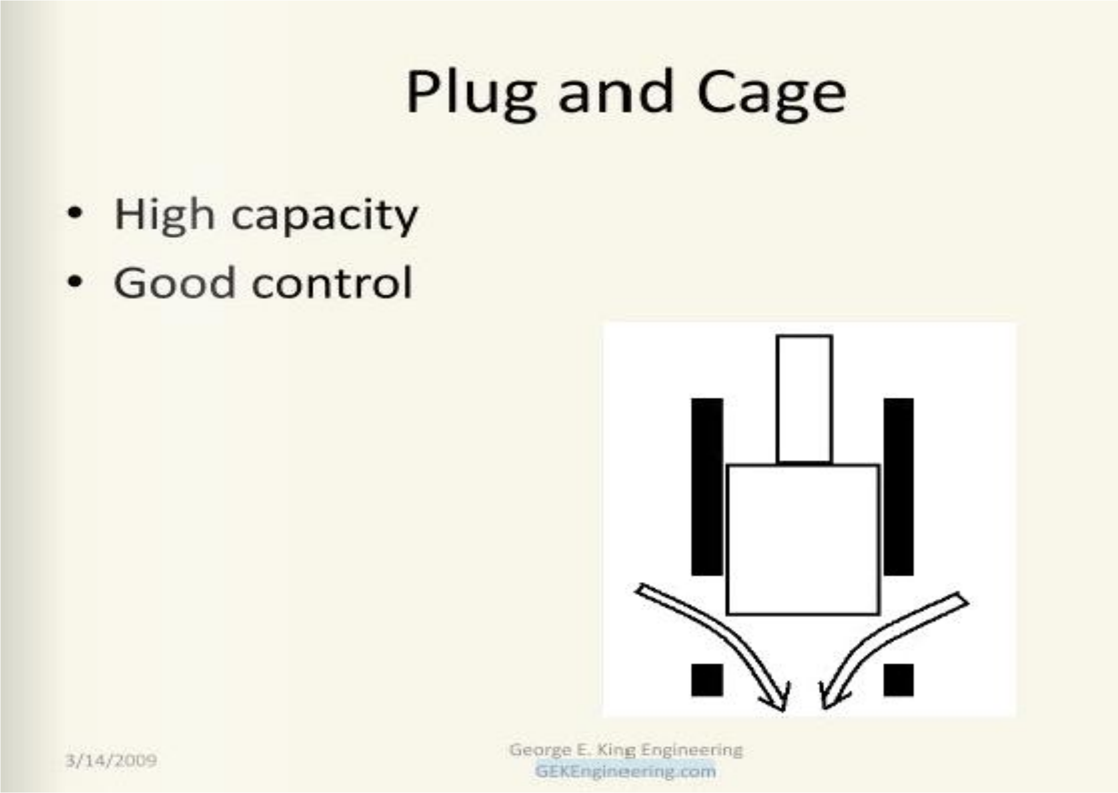
Figure 2.11: Fixed Bean

Plug and Cage

- ❖ High capacity
- ❖ Good control



Plug and Cage

- High capacity
- Good control

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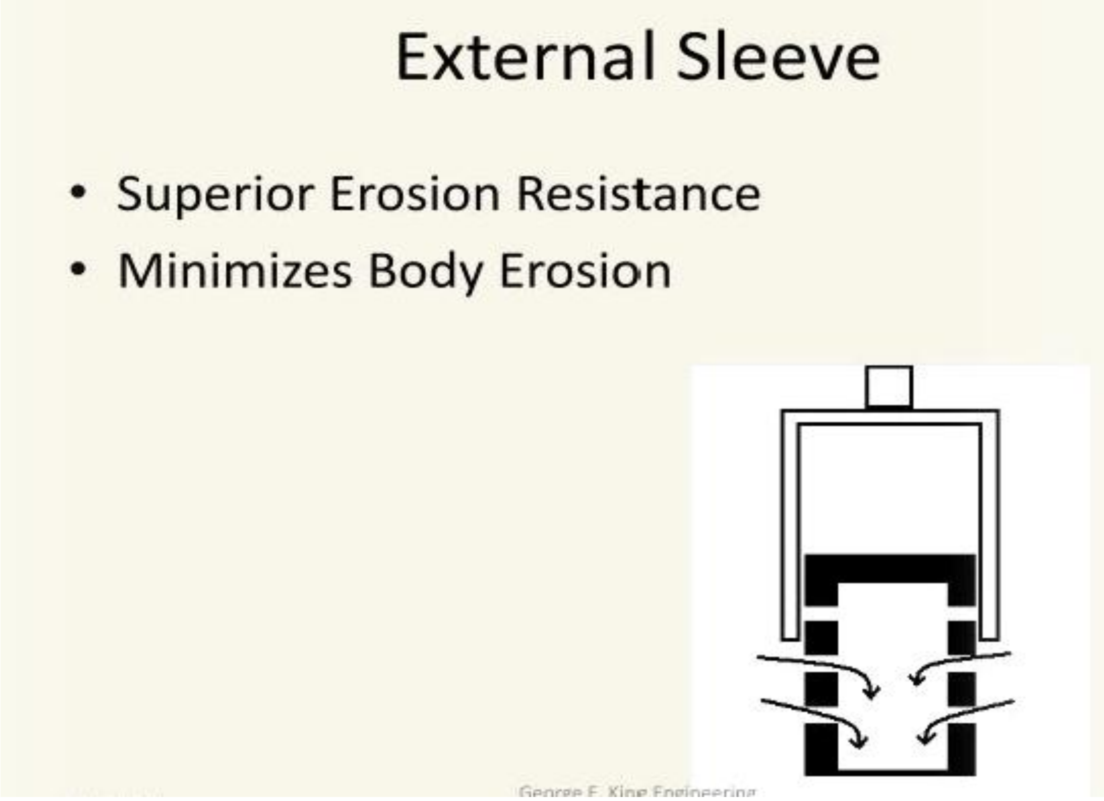
Figure 2.12: Plugs and Cage

External Sleeve

- ❖ Superior Erosion Resistance
- ❖ Minimizes body Erosion



External Sleeve

- Superior Erosion Resistance
- Minimizes Body Erosion

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Figure 2.13: External Sleeve

Choke Sizing

- Control the flow – maximize production
- Minimized vibration damage
- Minimize erosion damage

Choke Selection

- Based On:
- Application (lift, deliquifying the well, erosion control, solids production prevention, etc)
- Rate or flow and range of flow rate
- Presence of solids
- Maximum velocity
- Total pressure drop
- Fluid – liquid, gas, or GOR of mix.
- Pressure – both pressure drop and total pressure

- Temperature – range of acceptable temperatures during service
- Occurrence and timing of solids in flow
- Droplets, bubbles
- Scale and organic deposit potential

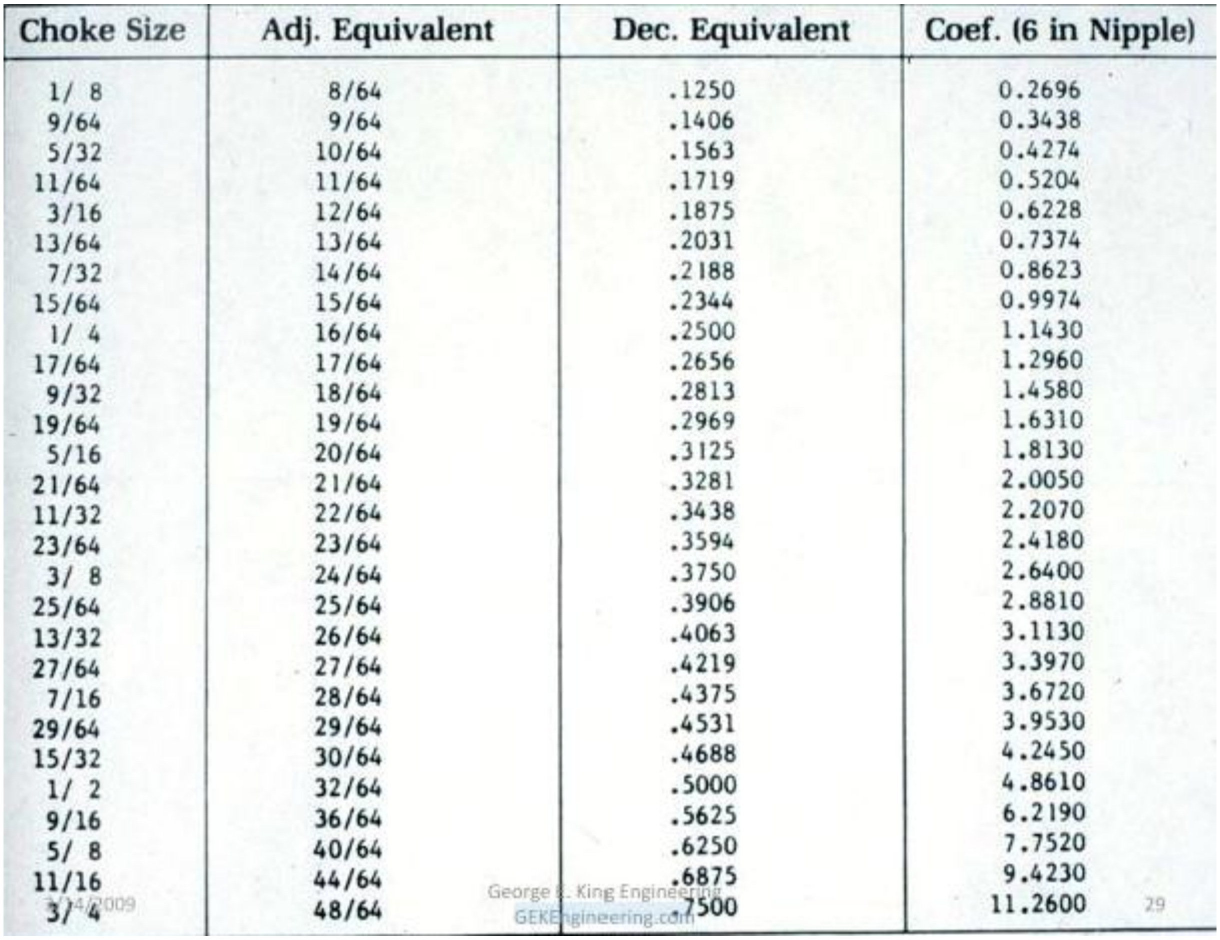
2.7 How would you set a choke with minimum monitoring equipment?

- One way is by measuring the temperature at surface……….

- Producing a well at maximum rates means lifting more liquids. Using the high heat capacity of liquids (3 to >10x most gas heat capacities), the max lift in a well would be achieved very near the maximum wellhead pressure.

Choke Sizing

- C_v = coefficient value
- Number of gallons of water per minute that will pass through a restriction with a pressure drop of 1 psi at 60 ^{0}F
- Used as the "flow capacity index"
- Does not correspond to a specific throttling method



Choke Size	Adj. Equivalent	Dec. Equivalent	Coef. (6 in Nipple)
1/ 8	8/64	.1250	0.2696
9/64	9/64	.1406	0.3438
5/32	10/64	.1563	0.4274
11/64	11/64	.1719	0.5204
3/16	12/64	.1875	0.6228
13/64	13/64	.2031	0.7374
7/32	14/64	.2188	0.8623
15/64	15/64	.2344	0.9974
1/ 4	16/64	.2500	1.1430
17/64	17/64	.2656	1.2960
9/32	18/64	.2813	1.4580
19/64	19/64	.2969	1.6310
5/16	20/64	.3125	1.8130
21/64	21/64	.3281	2.0050
11/32	22/64	.3438	2.2070
23/64	23/64	.3594	2.4180
3/ 8	24/64	.3750	2.6400
25/64	25/64	.3906	2.8810
13/32	26/64	.4063	3.1130
27/64	27/64	.4219	3.3970
7/16	28/64	.4375	3.6720
29/64	29/64	.4531	3.9530
15/32	30/64	.4688	4.2450
1/ 2	32/64	.5000	4.8610
9/16	36/64	.5625	6.2190
5/ 8	40/64	.6250	7.7520
11/16	44/64	.6875	9.4230
3/ 4	48/64	.7500	11.2600

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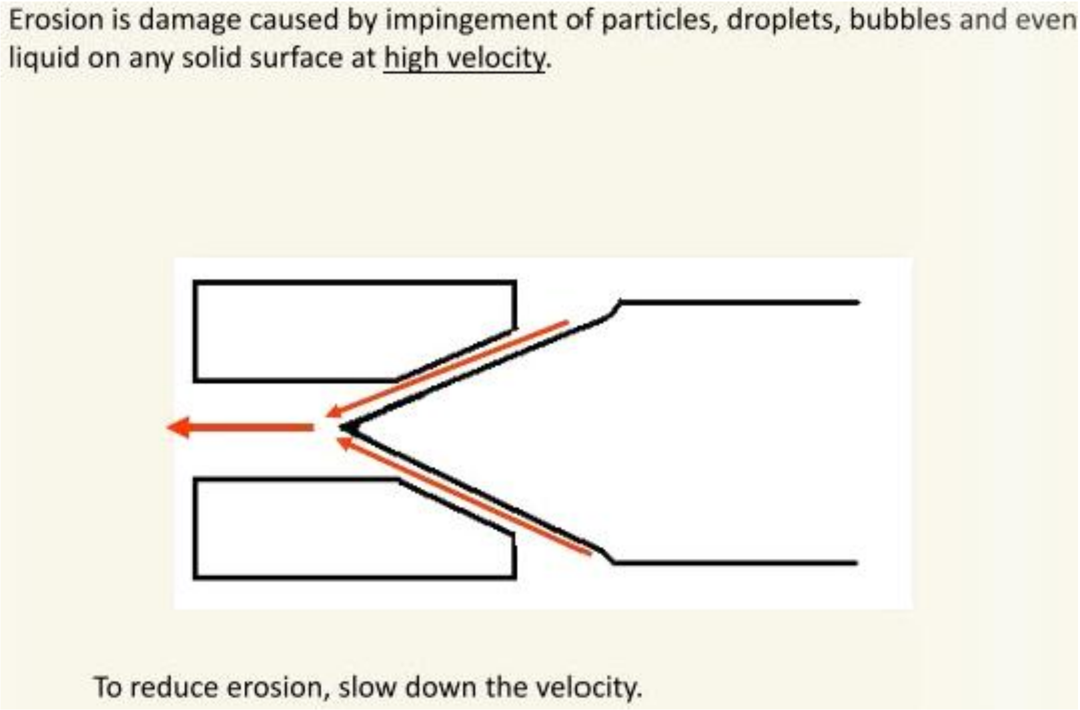
Table 2.1: Choke Sizes

2.8 Choke Operations

- Problems with Erosion
- Solutions

Erosion is damage caused by infringement of particles, droplets, bubbles and even liquid on any solid surface at high velocity.



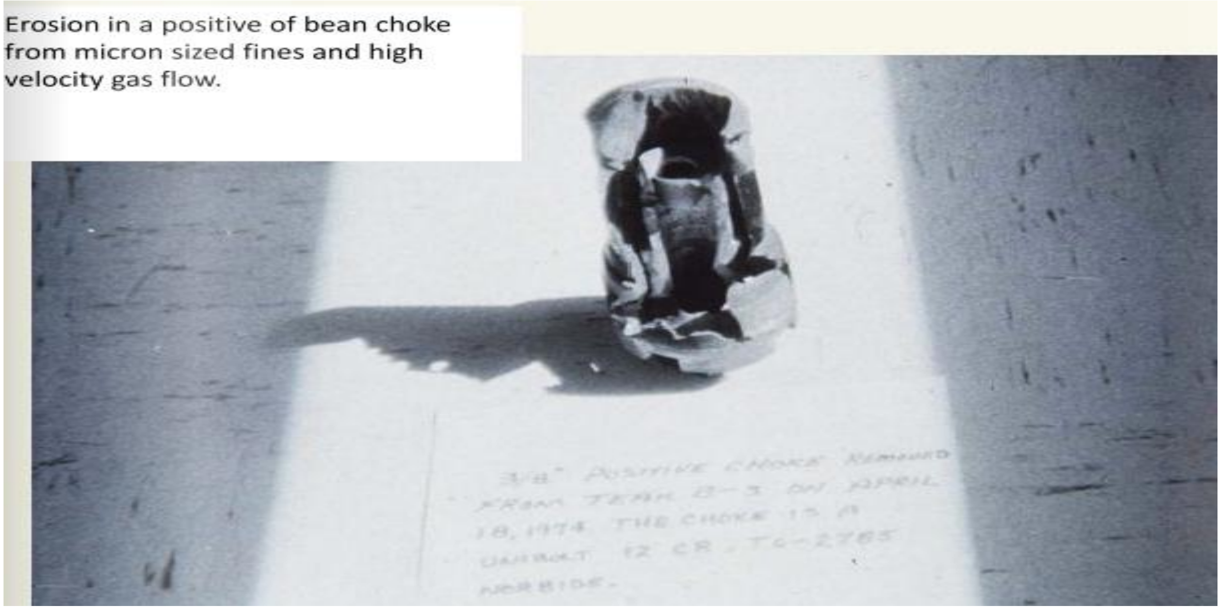
Erosion is damage caused by impingement of particles, droplets, bubbles and even liquid on any solid surface at high velocity.

To reduce erosion, slow down the velocity.

Figure 2.14: Erosion

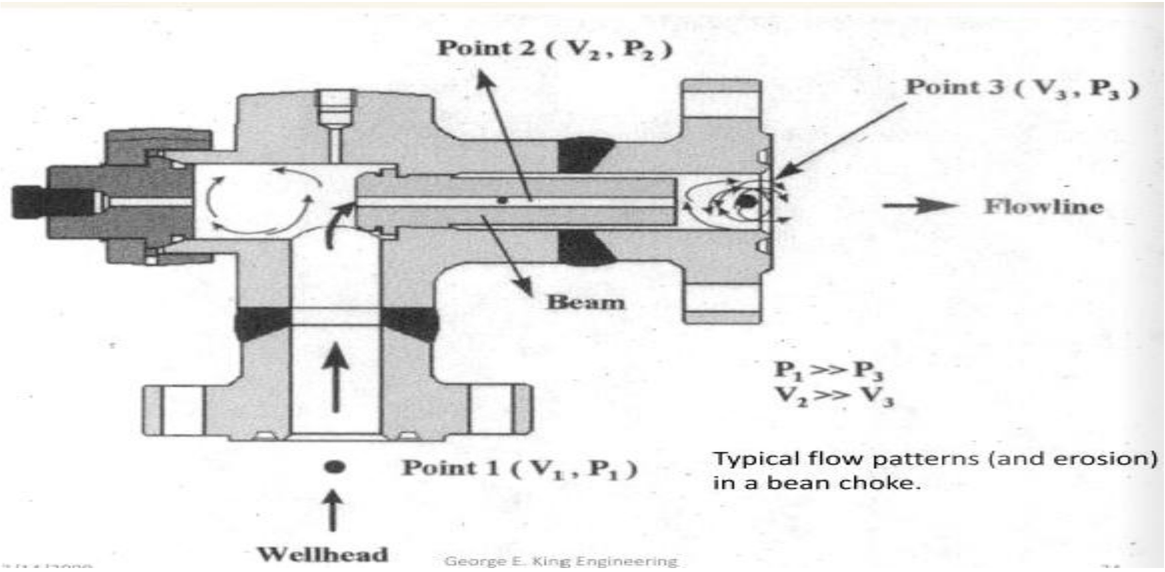
From figure above, it could be seen that to reduce erosion, slow down the velocity.

Erosion in a positive bean choke from micron sized fines and high velocity gas flow.



Erosion in a positive of bean choke from micron sized fines and high velocity gas flow.

Figure 2.15: Erosion in a positive choke bean



Typical flow patterns (and erosion) in a bean choke.

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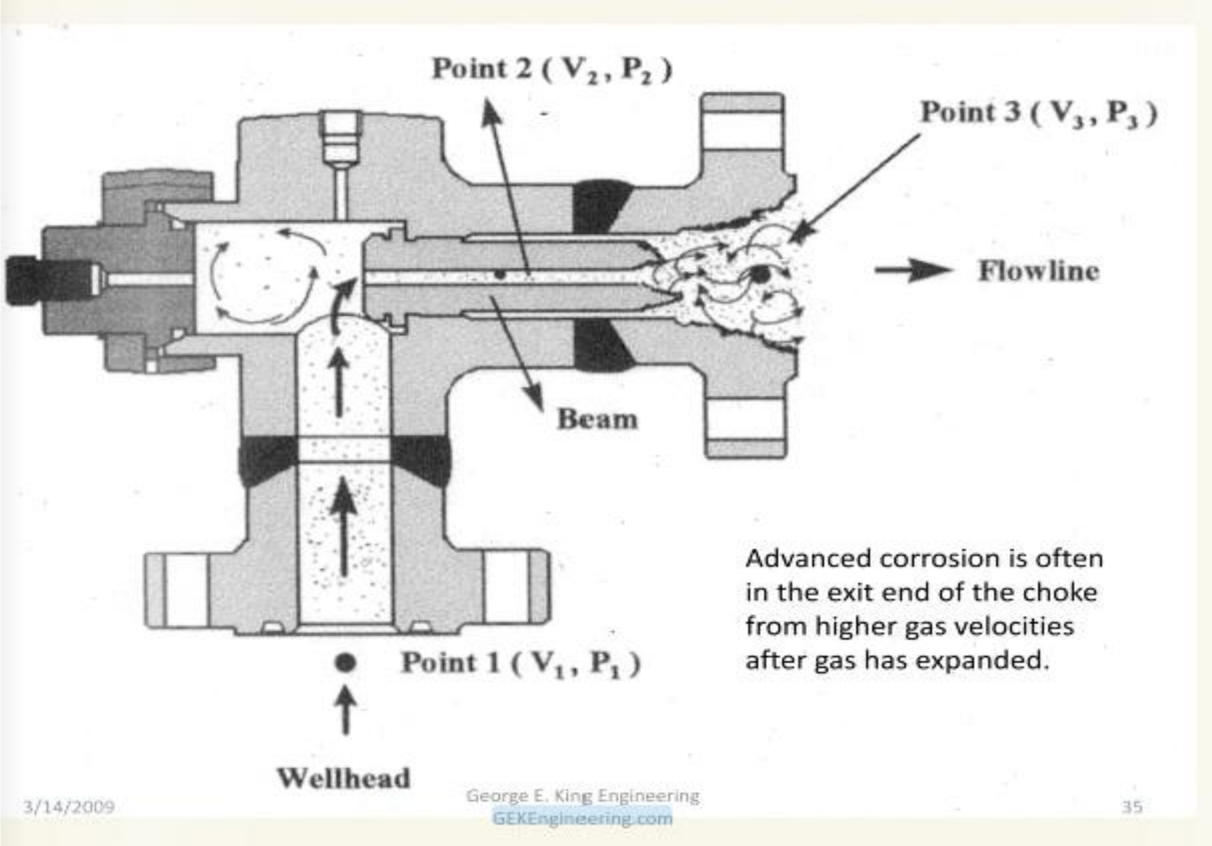
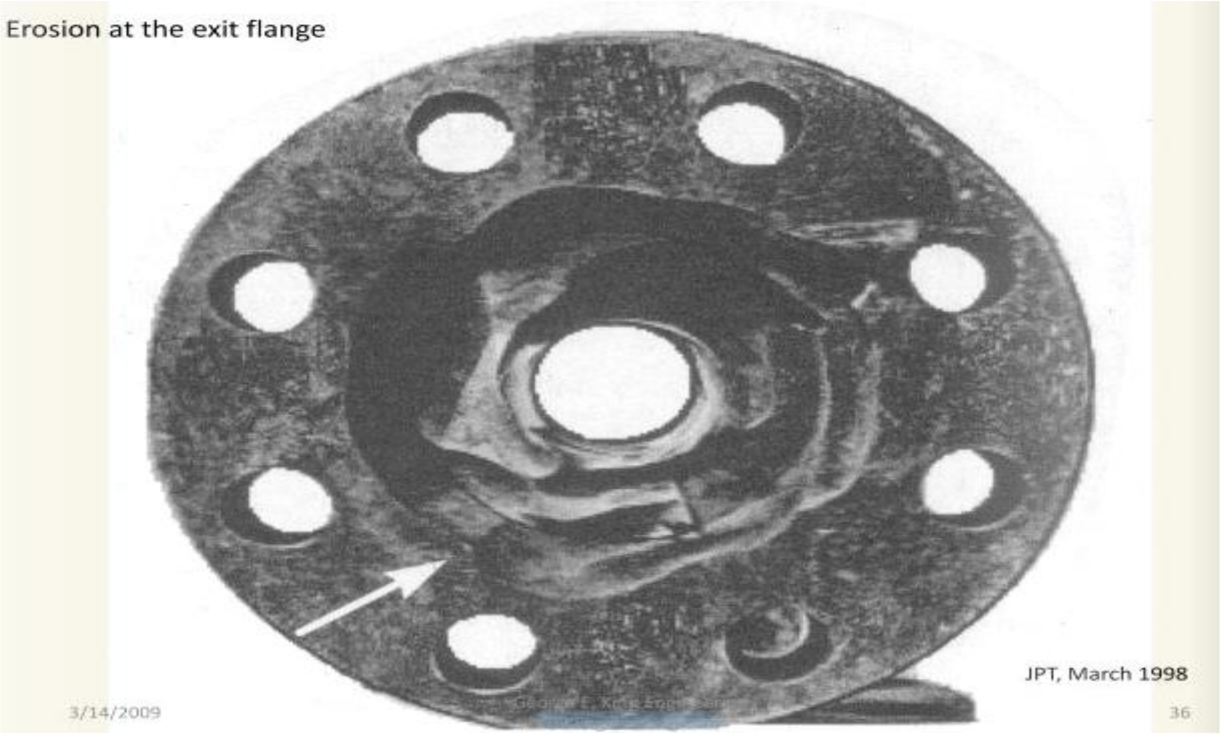
Figure 2.16: Erosion in bean choke



Advanced corrosion is often in the exit end of the choke from higher gas velocities after gas has expanded.

Figure 2.17: Erosion choke bean from higher gas velocities



Erosion at the exit flange

JPT, March 1998

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Figure 2.18: Erosion at the exit flange

The velocity profile and pressure drop across a choke with a large pressure drop

-Opportunity for erosion is very high.

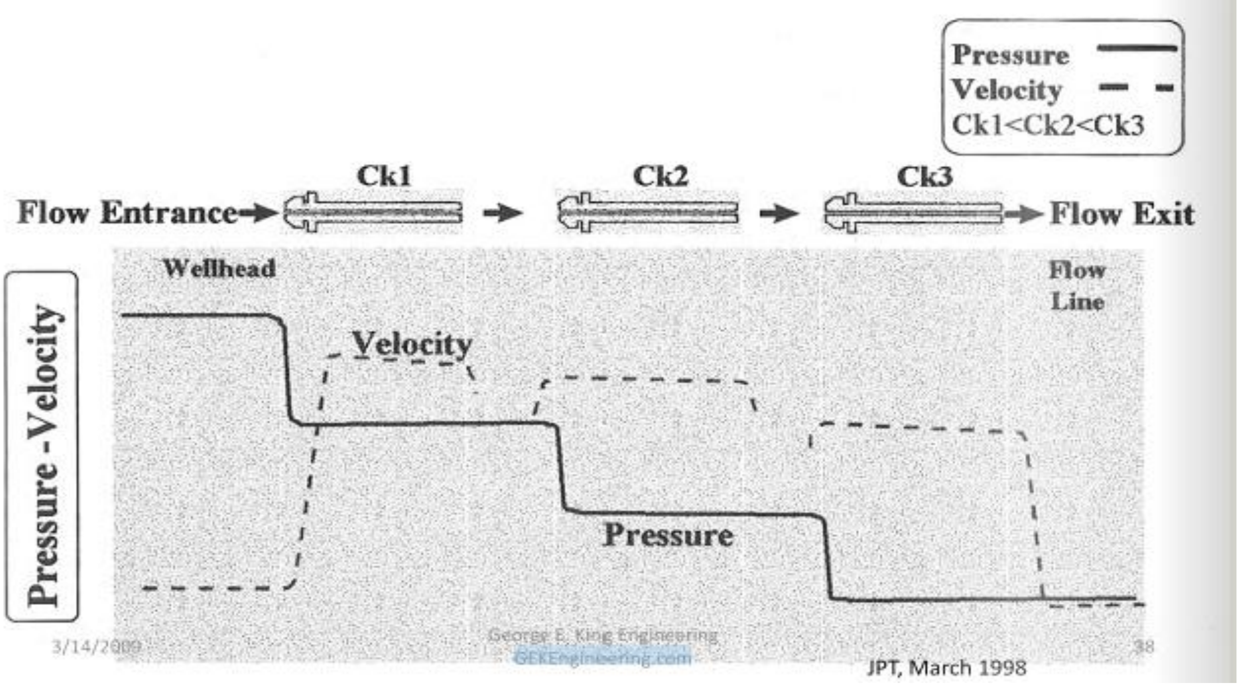

Figure 2.19: Pressure - Velocity graph

One solution to the problem is to take the pressure drop in series and hold a slight backpressure. For example, a 1000 to 0 psi pressure drop produces a 68 fold expansion in gas volume, while a 1500 to 500 psi pressure drop produces a 3 fold gas volume expansion.

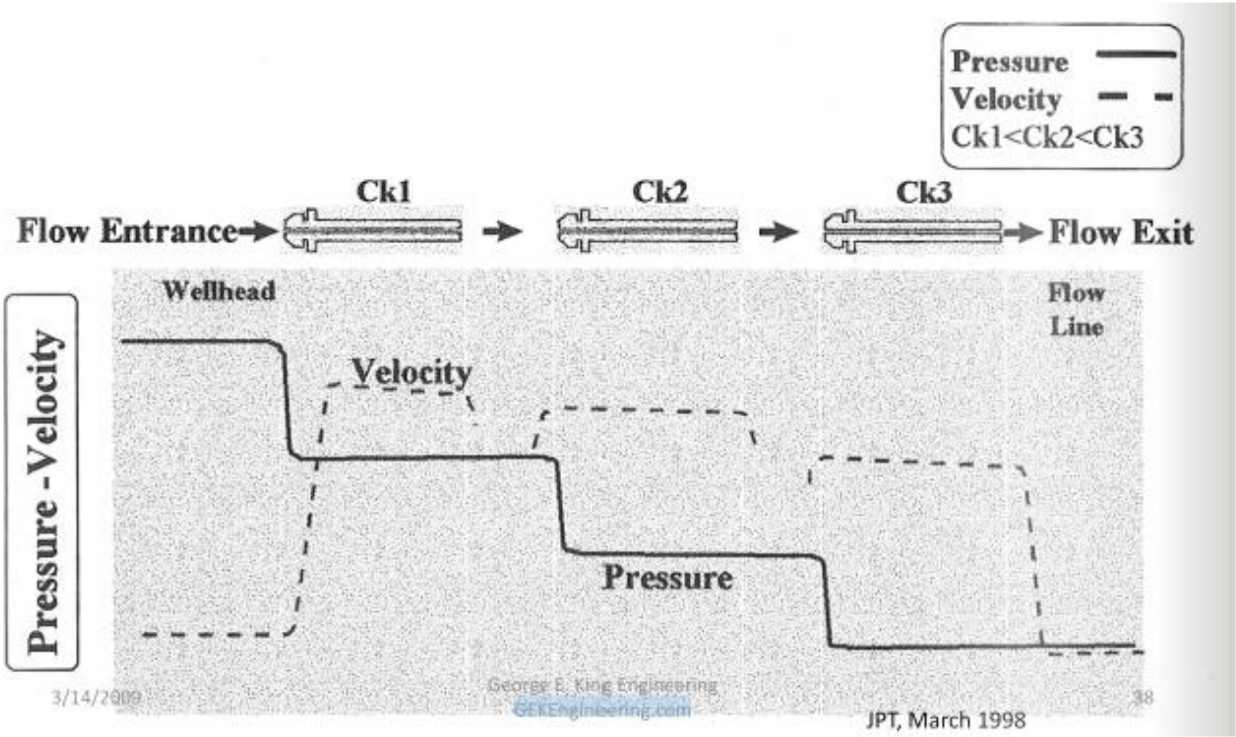

Figure 2.20: Pressure – Velocity graph with 3 chokes

CHAPTER THREE

3.0 METHODOLOGY

This section deals with the geographical location of the field and the various flow equations, which were used for the analysis of the data required for achieving the set objectives.

3.1 Sele's Field

Sele's field has a mini flowstation housing only two separators, the medium pressure and test separators, a degasser and five storage tanks A- E (A-1,000bbls, B-10,000bbls, C-10,000bbls, D-20,000bbls, E-20,000bbls) to increase the settling time which will result in better de-sanding (removal of sand) and draining of produced water.

At the Sele's field, there are eleven producing strings, which are dual completed (i.e. long and short string). The wells are as follows 2L,2S,4L,4S,5S,5L,7L,7S,8L,8S,9L,9S,10S,10L,11S,11L. some of the wells are oil wells while others are gas/condensate well (A gas condensate well is one in which the fluid is a gas under reservoir condition but on getting to the surface, due to changes in pressure and temperature condenses to liquid). Due to the dual completion, the Sele 2S, 4S, 5S and 7S started producing gas. All Sele wells are produced by natural reservoir pressure and are also monitored constantly.

Sele's flow station is primarily owned and supervised by the NPDC under the Petroleum Mining Lease 100 (PML 100), Its operated by two other companies in joint agreement, with each playing an important role in the production of oil and gas namely; Old Early Production Facility(EPF)-(NPDC) this is a 5,000bbls per day production facility, New Early Production Facility(EPF)-(OBAX) it's a 10,000bbls per day production capacity and the Integrated Gas Handling Facility-(IGHF) where produced gases from the Old and New EPF are been conditioned and sent to NIPP.

3.2 Flow Measurement

Flow measurement is critical to determine the amount of material purchased and sold, and in these applications, very accurate flow measurement is required. In addition, flows throughout the process should be regulated near their desired values with small variability; in these applications, good reproducibility is usually sufficient. Flowing systems require energy, typically provided by pumps and compressors, to produce a pressure difference as driving force, and flow sensors should introduce a small flow resistance, increasing the process energy consumption as little as possible. Most flow sensors require straight sections, of piping before and after the sensor, this requirement places restrictions on acceptable process designs, which can be partially compensated by straightening vanes placed in the piping. The sensors discussed in this subsection are for clean fluids flowing in the pipe; special considerations are required for concentrated slurries, flow in an open conduit, and other process situations.

Several sensors rely on the pressure drop or head occurring as a fluid flows by a resistance; an example is given in Figure 3.1. The relationship between the flow rate and pressure difference is determined by Bernoulli equation, assuming that changes in elevation, work and heat transfer are negligible.

When the process is operating, the meter parameters are fixed, and the pressure difference is measured. Then, the flow can be calculated from the meter equation, using the appropriate values for C meter and Y. In the usual situation in which only reproducibility is required, the fluid density is not measured and is assumed constant; the simplified calculation is where the density is assumed to be its design value of ρ_0. This is a good assumption for liquid and can provide acceptable accuracy for gases in some situations. Again, all constants can be combined (including ro) into C1 to give the following relationship.

Relationship for installed head meter with constant density

$$F = C_0\sqrt{P_1 - P_3} \ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots (1)$$

If the density of a gas varies significantly because of variation in temperature and pressure (but not average molecular weight), correction is usually based on the ideal gas law using low cost sensors to measure T and P according to relationship for installed head meter, gas with constant MW, changing T and P.

$$F = C_0\sqrt{\frac{(P_1 - P_3)}{\rho_0}}\sqrt{\frac{P_0 T}{P T_0}} \ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots (2)$$

Where, the density (assumed constant at ro), temperature (To) and pressure (Po) were the base case values used in determining Co. If the density varies significantly due to composition changes and high accuracy is required, the real-time value of fluid density (r) can be measured by an on-stream analyzer for use as ro in equation (4) (Clevett, 1985).

The flow is determined from equation (5) by taking the square root of the measured pressure difference, which can be measured by many methods. A U-tube manometer provides an excellent visual display for laboratory experiments but is not typically used industrially. For industrial practice a diaphragm is used for measuring the pressure drop; a diaphragm with one pressure on each side will deform according to the pressure difference.

The pressure in the pipe increases after the vena contracta where the flow cross section returns to its original value, but because of the meter resistance, the pressure downstream of the meter (P_3) is lower than upstream pressure (P_1). This is the “non-recoverable” pressure drop of the meter that requires energy, e.g., compressor work, to overcome and increases the cost of plant operation.

The non-recoverable pressure losses for three important head meters are given in Figure 3.4.

The low pressure at the point of highest velocity creates the possibility for the liquid to partially vaporize; it might remain partially vaporized after the sensor (called flashing) or it might return to a liquid as the pressure increases after the lowest pressure point (called cavitation). We want to avoid any vaporization to ensure proper sensor operation and to retain the relationship between pressure difference and flow. Vaporization can be prevented by maintaining the inlet pressure sufficiently high and the inlet temperature sufficiently low.

3.3 Some Typical Head Meters are Described in the Following

Orifice: An orifice plate is a restriction with an opening smaller than the pipe diameter which is inserted in the pipe; the typical orifice plate has a concentric, sharp edged opening, as shown in Figure 1. Because of the smaller area the fluid velocity increases, causing a corresponding decrease in pressure. The flow rate can be calculated from the measured pressure drop across the orifice plate, $P_1 - P_3$. The orifice plate is the most commonly used flow sensor, but it creates a rather large non-recoverable pressure due to the turbulence around the plate, leading to high energy consumption (Foust, 1981).

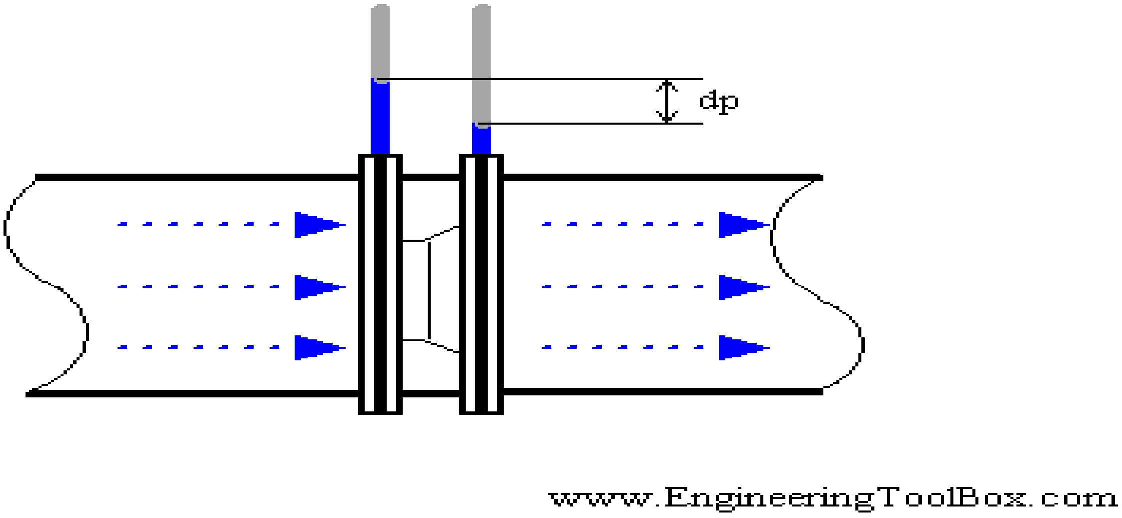

Figure 3.1: Orifice flow meter

Venturi Tube: The venturi tube shown in Figure 3.2 is similar to an orifice meter, but it is designed to nearly eliminate boundary layer separation, and thus form drag. The change in cross-sectional area in the venture tube causes a pressure change between the convergent section and the throat, and the flow rate can be determined from this pressure drop. Although more expensive than an orifice plate; the venture tube introduces substantially lower non-recoverable pressure drops (Foust, 1981).

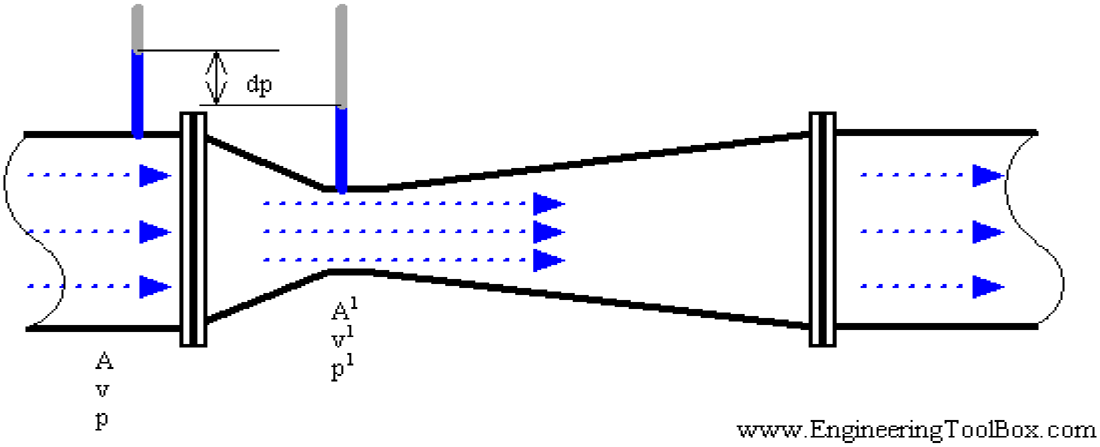

Figure 3.2: Venturi flow meter

Flow Nozzle: A flow nozzle consists of a restriction with an elliptical contour approach section that terminates in a cylindrical throat section. Pressure drop between the locations one pipe diameter upstream and one-half pipe diameter downstream is measured. Flow nozzles provide an intermediate pressure drop between orifice plates and venturi tubes; also, they are applicable to some slurry systems.

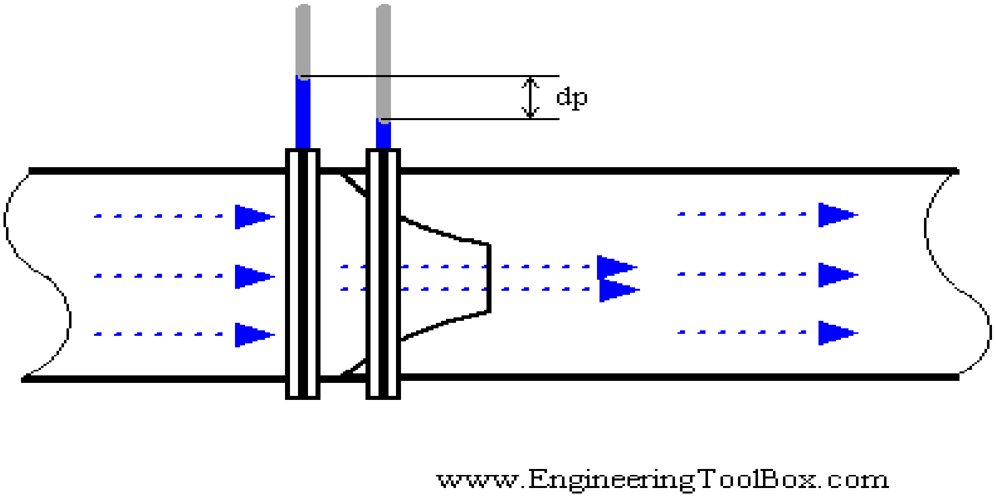

Figure 3.3: Flow Nozzle

Elbow Meter: A differential pressure exists when a flowing fluid changes direction due to a pipe turn or elbow, as shown in Figure 3 below. The pressure difference results from the centrifugal force. Since pipe elbows exist in plants, the cost for these meters is very low. However, the accuracy is very poor; there are only applied when reproducibility is sufficient and other flow measurements would be very costly.

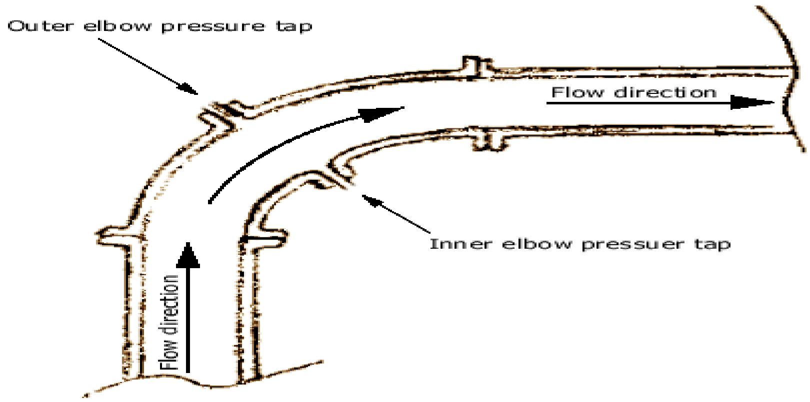

Figure 3.4: Elbow flow meter

Pitot tube and annubar: The Pitot tube, shown in Figure 3.4 below, measures the static and dynamic pressures of the fluid at one point in the pipe. The flow rate can be determined from the difference between the static and dynamic pressures which is the velocity head of the fluid flow. An annubar consists of several pitot tubes placed across a pipe to provide an approximation to the velocity profile, and the total flow can be determined based on the multiple measurements. Both the pitot tube and annubar contribute very small pressure drops, but they are not physically strong and should be used only with clean fluids.

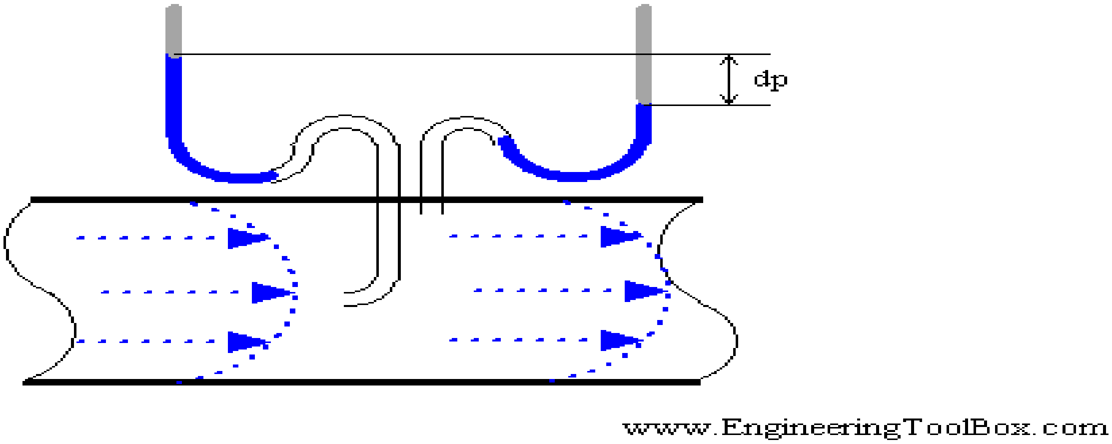

Figure 3.5: Pitot flow meter

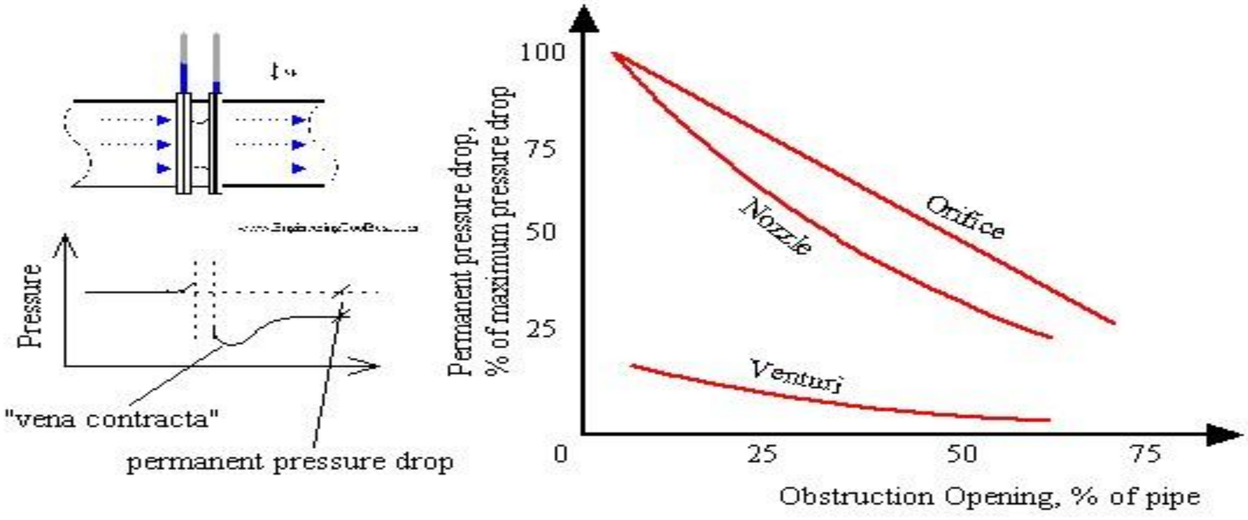

Figure 3.6: Flow meter non-recoverable pressure losses (Andrews and Williams, Vol 1, 1979)

The following flow sensors are based on physical principles other than head;

Turbine: As fluid flows through the turbine, it causes the turbine to rotate with an angular velocity that is proportional to the fluid flow rate. The frequency of rotation can be measured and used to determine flow. This sensor should not be used for slurries or systems experiencing large, rapid flow or pressure variation.

Vortex shedding: Fluid vortices are formed against the body introduced in the pipe. These vortices are produced from the downstream face in an oscillatory manner. The shedding is sensed using a thermistor and the frequency of shedding is proportional to volumetric flow rate.

Positive displacement: In these sensors, the fluid is separated into individual volumetric elements and the numbers of elements per unit time are measured. These sensors provide high accuracy over a large range. An example is a wet test meter.

Assuming a horizontal flow (neglecting minor elevation differences between measuring points) the Bernoulli Equation can be modified to:

$$p_1 + {}^{1}/_{2}\,\rho v_1^2 = p_2 + {}^{1}/_{2}\,\rho v_2^2 \dots\dots\dots\dots\dots\dots\dots\dots\dots\dots\dots\dots\dots\dots\dots\dots\dots\dots\dots\dots (3)$$

Where,

p = pressure

ρ= density

v = flow velocity

The equation can be adapted to vertical flow by adding elevation heights h_1 and h_2.

Assuming uniform velocity profiles in the upstream flow – the Continuity Equation can be expressed as

$$q = v_1 A_1 = v_2 A_2 \dots\dots\dots\dots\dots\dots\dots\dots\dots\dots\dots\dots\dots\dots\dots\dots\dots\dots\dots\dots\dots\dots. (4)$$

Where,

q = flow rate

A = flow area

Combining (1) and (2), assuming $A_2 < A_1$, gives the “ideal” equation:

$$q = A_2[2(p_1 - p_2)/\rho(1 - (A_2/A_1)^2)]^{1/2} \dots\dots\dots\dots\dots\dots\dots\dots\dots\dots\dots\dots (5)$$

For a given geometry (A), the flow rate can be determined by measuring the pressure difference $p_1 - p_2$.

The theoretical flow rate q will in practice be smaller (2 – 40%) due to geometrical conditions.

The ideal equation (3) can be modified with a discharge coefficient:

$$q = c_d A_2[2(p_1 - p_2)/\rho(1 - (A_2/A_1)^2)]^{1/2} \dots\dots\dots\dots\dots\dots\dots\dots\dots\dots\dots\dots\dots (6)$$

Where,

c_d = discharge coefficient

The discharge coefficient c_d is a function of the jet size – or orifice opening – the area ratio = A_{vc}/A_2

Where

A_{vc} = *area in "vena contracta"*

"Vena contracta" is the minimum jet area that appears just downstream of the restriction. The viscous effect is usually expressed in terms of the non-dimensional parameter Reynolds Number – *Re*.

Due to the Bernoulli and Continuity Equation, the velocity of the fluid will be at its highest and the pressure at the lowest in *"Vena Contracta"*. After the metering device, the velocity will decrease to the same level as before the obstruction. The pressure before the obstruction and adds a head loss to the flow.

Equation (3) can be modified with diameters to:

$$q = c_d \pi/4 D_2^2\ \rho[2(p_1 - p_2)/\rho(1 - d^4)]^{1/2} \dots\dots\dots\dots\dots\dots\dots\dots\dots\dots\dots\dots\dots.... (7)$$

Where,

D_2 = orifice, venture or nozzle inside diameter

D_1 = upstream and downstream pipe diameter

$d = D_2 / D_1$ diameter ratio

$\pi = 3.14$

Equation (4) can be modified to mass flow for fluids by simply multiplying with the density:

$$m = c_d \pi / 4 D_2^2 \; \rho [2(p_1 - p_2)/\rho(1 - d^4)]^{1/2} \ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots \ldots. (8)$$

When measuring the mass flow in gases, it’s necessary to considerate the pressure reduction and change in density of the fluid. The formula above can be used with limitations for applications with relatively small changes in pressure and density.

CHAPTER FOUR

4.0 RESULTS AND DISCUSSION

4.1 Results

The values of the pressures choke diameter, water cut, oil produced, and GOR were gotten from an oil and gas production well test, SELE 01 and 02 respectively. The data are given in the table below:

Table 4.1: Well No (SELE-01)

TEST DATE mm/dd/yr	**CHOKE** (1/64")	**FTP** (Psig)	**OIL** (Bopd)	**GOR** (Scf/Stb)	**WATER CUT** (%)	**API** degree	**SAND** Ib/Mstb
3/16/2003	12	2,750	438	1,801	0.000	39.20	
3/25/2003	12	3,200	336	2,958	3.500	37.20	
3/26/2003	12	3,200	344	2,890	3.500	37.20	
3/30/2003	16	3,350	718	4,343	7.000	39.30	
3/30/2003	16	3,350	725	4,301	7.000	39.30	
4/11/2003	16	3,400	731	4,312	7.000	39.30	
4/11/2003	16	3,400	740	4,259	7.000	39.30	
4/12/2003	16	3,400	740	4,259	7.000	39.30	
5/09/2003	16	3,350	752	4,252	7.000	39.20	
9/04/2003	18	3,350	643	3,395	15.00	36.40	
5/19/2005	20	3,200	590	2,707	20.00	36.40	
6/2/2008	20	2,900	627	3,053	30.00	34.10	
5/5/2009	22	2,800	611	3,586	45.00	34.00	

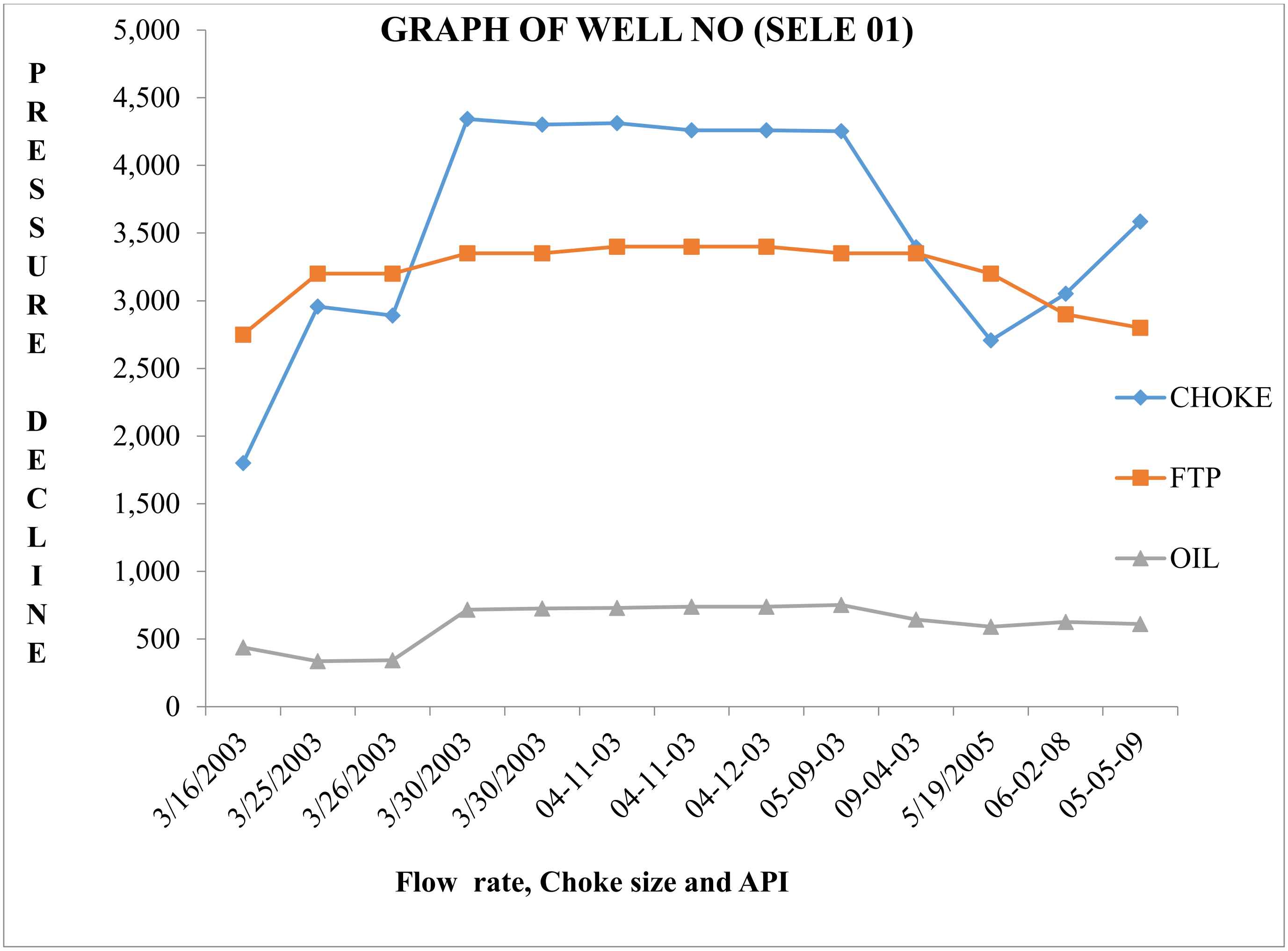

Fig 4.0: Graph of Pressure vs Time for well No (SELE 01)

Table 4.1: Well No (SELE-02)

TEST DATE mm/dd/yr	**CHOKE** 1/64"	**FTP** Psig	**OIL** Bopd	**GOR** Scf/Stb	**WATER CUT** (%)	**API** degree	**SAND** Ib/Mstb
3/15/2003	12	1,050	282	248	2.00	41.50	
3/17/2003	16	1,140	630	594	0.00	41.10	
3/26/2003	20	1,150	925	474	0.50	41.90	
3/27/2003	20	1,150	919	504	0.50	41.90	
4/3/2003	24	1,180	1,323	504	0.50	42.00	
4/3/2003	28	1,250	2,020	811	0.00	42.00	
4/5/2003	32	1,200	2,728	738	0.00	41.30	
4/6/2003	32	1,200	2,736	736	0.00	41.30	
4/9/2003	36	1,350	3,036	724	0.00	42.30	
4/9/2003	36	1,350	3.032	725	0.00	42.30	
4/13/2003	30	1,400	2,300	678	0.00	42.50	
4/14/2003	30	1,400	2,300	697	0.00	42.50	
9/9/2003	30	1,450	2,304	691	0.00	42.50	
9/18/2003	32	1,400	2,712	569	0.00	41.70	
4/15/2004	32	1,260	2,156	901	15.00	39.80	
11/25/2004	34	1,000	1,711	794	40.00	34.30	
3/15/2005	34	900	1,793	649	40.00	28.70	
5/19/2005	34	900	1,724	441	40.00	28.70	
11/1/2005	34	900	1,752	841	45.00	28.70	
4/30/2008	34	740	1,850	418	58.00	41.20	
5/1/2008	34	740	1,855	390	58.00	41.50	
7/9/2008	34	620	2,477	380	14.00	37.90	Traces
7/9/2008	34	620	2,456	380	14.00	37.90	
2/6/2009	34	418	934	757	70.00	37.90	

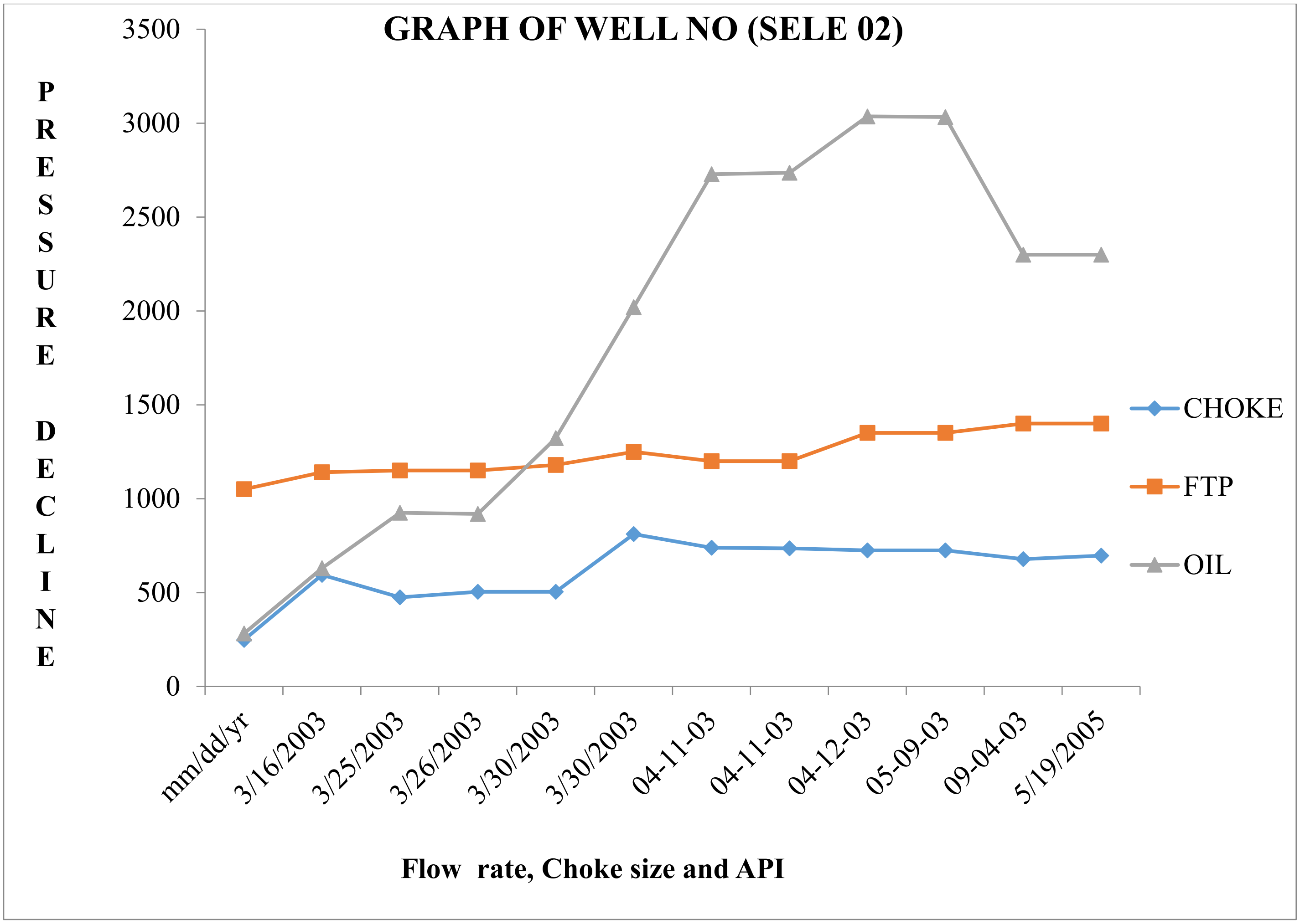

Fig 4.1: Graph of Pressure vs Time for Well No (SELE 02)

4.2 Discussion of Result

From the well SELE 01 in Table 4.0 above, it will be observed that at Choke size 16/64" there was consistency in the FTP, OIL produced, GOR, Water Cut and finally API. Here the oil API is 39.30º which is the highest in the table. Hence the oil is of good quality at this point.

At Choke size of 18/64", 20/64", and 22/64" it will be observed that the water cut beginning to increase as the choke size is increase as such water will be produced alongside with the oil. While at choke size 12/64" and 16/64" the water cut is minimal i.e 3.50% and 7.00% respectively.

Also from the well SELE 02 in Table 4.1 above, it will be observed that at choke size 30/64" there was consistency in the FTP also, the OIL produced, GOR, Water Cut and finally API. Here the API is 42.50º which is the highest in the table. Hence the oil is of good quality at this point.

For choke size 12/64" – 32/64" it will be observed that the Water Cut is minimal compared to that of choke size 34/64" where the Water Cut increased drastically from 0.00% to 70%. At flow rate 34/64" for the date 7/9/2008 with Water Cut of 14%, some traces of sand was observed. Here the well was allowed to flow for months at the same choke size before testing. On the 2/6/2009 at this point, the Water Cut increased to 70% which signifies higher water production from the reservoir.

It can be seen from the data available and results obtained, that the choke size of an oil and gas Christmas tree is the major factor contributing to the pressure decline, flow rate, and water cut which also need proper attention in the oil and gas production. Therefore, the choke size should be reduced in such a way that the pressure decline will be minimal, also the flow rate and lastly to avoid production of water from the formation. Such flow rate is called optimal flow rate, where the well is producing at a rate not above the Federal Government specification and not too large for fast pressure decline.

CHAPTER FIVE

5.0 CONCLUSION AND RECOMMENDATIONS

5.1 Conclusion

1. Production chokes help unload and produce the well through pressure management.
2. At choke size 16/64” of Well No (SELE 01) on TABLE 4.0, the Flowing Tubing Pressure (FTP) was consistent as well as the oil production rate and also the Gas Oil Ratio (GOR) was consistent, the water cut was 7.000% at this choke size. It was also observed that at this particular choke size, we have the best oil of API 39.30º i.e the higher the API the better the quality of oil produced.
3. Therefore for SELE 01, the optimum flow rate was observed at choke size 16/64” for which the well flow characteristics were optimum.
4. At choke size 30/64” SELE 02 on TABLE 4.1, the Flowing Tubing Pressure (FTP) was consistent as well as the oil production rate and also the Gas Oil Ratio (GOR) was consistent, the water cut was 0.000% (zero). It was also observed that at this particular choke size, we have the best oil of API 42.50º i.e the higher the API the better the quality of oil produced.
5. Therefore for SELE 02 the optimum flow rate was observed at choke size 30/64”for which the well flow characteristics are optimum.
6. Choke setting requirements change as pressure drops, rate changes and fluid composition varies
7. Good production engineering requires regular design and setting checks for production chokes.

5.2 Recommendations

This project recommends the following;

1. The choke size should be carefully chosen to ensure optimum flow rate, minimal pressure decline, water production and sand production.

2. Regular well testing should be carried out to check for water production and sand production for the case of well flow abnormalities.

3. There should be a schedule choke inspection program to check for erosion and cavitation, flashing and freezing.

5.3 Contribution to Knowledge

This study contributes significantly to the field of production engineering, reservoir management, and flow assurance, particularly within the Niger Delta region.

1. Demonstrating the efficacy of precise choke sizing as a primary, cost-effective mechanism for mitigating water coning and controlling sand production in unconsolidated reservoir systems.
2. Providing new empirical data on the direct correlation between choke size variations and crude oil quality (API gravity), establishing that optimum flow rates are critical not just for quantity, but for maximizing the commercial value of the produced hydrocarbon stream.
3. Promoting sustainable reservoir management by quantifying the specific pressure drawdown thresholds ("tipping points") where reservoir equilibrium is compromised, thus offering a blueprint for extending the economic life of mature wells without immediate recourse to artificial lift.

4. Adding to the growing body of knowledge on production optimization in the Niger Delta by bridging the gap between theoretical nodal analysis and practical, field-based pressure maintenance strategies.

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