Title: Influx Volume Reduction System

Cross Reference Related Applications

[0001] This Application claims priority from, and claims the full benefits of UK patent application GB 1204310.5 (filed 12 March 2012) and US patent application 13/443,332 (filed 10 April 2012), the full contents of which are incorporated herein, for reference.

Field of the Invention

[0002] A system and methodology related to an Influx Volume Reduction – IVR–system consisting of a Quick Close Annular Preventer – QCA installed directly or indirectly atop a conventional annular blow out preventer and related hydraulic system componentry. The IVR controls have the ability to quickly shut-in or close off any annulus during drilling of a wellbore into a subterranean reservoir, preventing typically hydrocarbon fluids from such a reservoir from inflowing into the wellbore and/or uncontrollably releasing to the atmosphere at surface. The apparatus and method contains and/or diverts the drilling fluid and/or production of fluid (fluid, gas) from such a wellbore. As a result, it will produce a seal around the drillpipe or open hole, and provide pressure integrity and isolation of the wellbore from the external atmosphere.

[0003] The IVR apparatus and methodology are based on an operating philosophy of closing off the annulus rapidly, resulting in a significant reduction of influx volume from a reservoir into any drilling annulus. The invention is not limited, however, to only the drilling stages of a well, and is intended for use during all phases of the drilling operation until the well completion – tripping, drilling, circulating, cementing, casing installation, drill stem testing, connections, and logging.

Description of the Prior Art

[0004] Subterranean drilling typically involves rotating a drill bit from surface or on a downhole motor at the remote end of a tubular drill string. It involves pumping a fluid down the inside of the tubular drillstring, through the drill bit, and circulating this fluid continuously back to surface via the drilled space between the hole/tubular, referred to as the annulus. This pumping mechanism is provided by positive displacement pumps that are connected to a manifold which connects to the drillstring, and the rate of flow into the drillstring depends on

the speed of these pumps. The drillstring is comprised of sections of tubular joints connected end to end, and their respective outside diameter depends on the geometry of the hole being drilled and their effect on the fluid hydraulics in the wellbore.

[0005] Mud is pumped down the drill string utilizing the mud pumps which circulates through the drill bit, and returns to the surface via the annular space between the outer diameter of the drill string and the wellbore (generally referred to as the annulus). For a subsea well bore, a tubular, known as a riser extends from the rig to the top of the wellbore which exists at subsea level on the ocean floor. It provides a continuous pathway for the drill string and the fluids emanating from the well bore. In effect, the riser extends the wellbore from the sea bed to the rig, and the annulus also comprises the annular space between the outer diameter of the drill string and the riser.

[0006] The entire drillstring and bit may be rotated using a rotary table or using an above ground motor mounted on the top of the drill pipe known as a top drive. The bit can also be turned independently of the drillstring by a drilling fluid powered downhole motor, integrated into the drillstring just above the bit. Bit types vary and have different designs in their profile in regards to items such as cutter design and profile, and their selection is based on the formation type being drilled.

[0007] As drilling progresses, pipe has to be connected to the existing drillstring to drill deeper. Conventionally, this involves shutting down fluid circulation completely so the pipe can be connected into place as the top drive has to be disengaged.

[0008] Conventionally, the well bore is open to atmospheric pressure and there is no surface applied pressure or other pressure existing in the system. The drillpipe rotates freely without any sealing elements imposed or acting on the drill pipe at the surface, and flow is diverted at atmospheric pressure back to the fluid storage system at surface.

[0009] The bit penetrates its way through layers of underground formations until it reaches target prospects – rocks which contain hydrocarbons at a given temperature and pressure. These hydrocarbons are contained within the pore space of the rock (i.e. the void space) and can contain water, oil, and gas constituents – referred to as reservoirs. Due to overburden forces from layers of rock above, these reservoir fluids are contained and trapped within the pore space at a known or unknown pressure, referred to as pore pressure. An unplanned inflow of these reservoir fluids is well known in the art, and is referred to as a formation influx or kick and commonly called a well control incident or event.

[0010] Kick tolerance is simply defined as the maximum height (and hence, pressure) of an influx column that the open hole section (including the last casing shoe depth) can tolerate before the formation fractures or breaks down. Correctly calculating kick tolerance is essential

to safe well design and drilling. There are two values necessary to define the kick tolerance of a wellbore. Kick intensity is the amount of overpressure that is penetrated when the well flows – i.e. the summation of the existing higher formation pressure penetrated and the bottom hole pressure at this point, but expressed as a density in pounds per gallon (ppg). For example if the mud density is 10 ppg and the kick intensity is 0.5 ppg, then the equivalent formation pressure of the "kicking" formation is the addition of these two values - 10.5 ppg in this example.

[0011] The other value required is the influx volume - this is the quantity of gas/fluid which enters the well from the kicking formation. Therefore, increasing the rig's capability to reduce the influx volume which occurs into the wellbore reduces the risk of exceeding the kick tolerance for the well design.

[0012] Blow out preventers, referred to as BOP's, are used to seal and control the formation influxes described herein in the wellbore. These are well known in the art, and are compulsory pressure safety equipment used on both land and off-shore rigs. Land rigs have their BOP's generally secured to a well head at the top of the wellbore below the rig floor/deck on the surface. However, deep water offshore rigs have their BOPs secured subsea to the well head at the top of a wellbore which is subsequently located on the ocean floor. The primary market for the present invention will be shallow offshore rigs (jack-ups, platforms, etc.) which pose a challenge for the installation of the invention due to the limited space capacity in their riser system configurations. With these rig types, the wellhead is located at the ocean floor and a riser system connects this to a surface BOP situated directly below the rig floor deck – thus minimal vertical height exists within the riser to install and connect the invention.

[0013] The annular BOP elements seal around the drill string, thus closing the annulus and stopping flow of fluid from the wellbore. They typically include a large flexible rubber or elastomer packing unit configured to seal around a variety of drillstring sizes when activated, and are not designed to be actuated during drillstring rotation as this would rapidly wear out the sealing element. A pressurized hydraulic fluid and piston assembly are used to provide the necessary closing pressure of the sealing element to allow for the capability if necessary to close or shut in the annulus during the course of drilling a well. Each BOP may consist of but not limited to a blind &/or shear ram, pipe rams, and annular preventer. Certification standards for Annular BOP's specify closure times of 45 seconds for Ram BOP's and 60 seconds for Annular BOP's. References to these standards can be found in API 1st Edition 16D, API 3rd Edition RP-53, Norwegian NPD YA-001A & IADC Chapter K2.

[0014] The primary function of a BOP is to prevent a Blow Out. The extended time duration from the time of activation to the time that a closed position is achieved as a result of the large volume of hydraulic fluid that must be displaced into the closing line and chamber of the BOP

system, and pressurized to the required closing pressure of the BOP system. These are well known in the art.

[0015] A standard BOP annular consists of the following main componentry - a sealing element, referred to as a packer, and actuator enclosed in a housing. The packer is composed of an elastomeric compound (typically Nitrile Rubber) bonded with metallic reinforcement. The actuator divides the housing into two cavities or chambers ("open" and "close" chambers). Fluid pressure is then used and injected on either side of the actuator to close and open the packer when required. An early design of annular BOP is disclosed in US 2,609,836.

[0016] In the event of an undesired well kick it is necessary for the drilling rig to activate the BOP as quickly as possible. It is most common to activate the annular preventer as it has the greater capability of sealing on varying dimensions and geometries of the drill string as well as full closure on open hole.

[0017] Once a kick has been determined and a subsequent decision has been made to activate the BOP and shut in the well there may be a considerable amount of reservoir fluid volume invading the annulus as a result of the 45 second annular closure on the drill string. In addition to the existing annular fluid volume there may be hydrocarbons invading the annulus which in turn may cause a pressure increase below the annular BOP when closed. In reality, once the kick is detected at surface the well control procedure followed to shut in the rig's BOP may take up to 2 minutes. This poses a major problem, because over this extended time duration the formation will continue to free flow into the annulus, resulting in larger volumes of influx to manage and control at surface. This will result in higher pressures throughout the well control procedure, potentially exceeding the wellbore kick tolerance and breaching the safety limits of well control and surface equipment.

[0018] There is a need for a system and method to effectively close in the annulus as quickly as possible once a kick/influx has been detected, such that the total volume of reservoir fluid and hydrocarbons ingress to the well bore is minimized and prevention of subsequent potential for a blow out is achieved. There is the need for a system to be in place to allow rapid shut in of the wellbore annulus to minimize and prevent further influx into the well while the rig completes its well control procedures to close the BOP. Furthermore, there is a requirement to enhance safety in land and offshore environments through a system and method which will result in a large reduction in influx volume, such that the influx can be safely managed and controlled at surface with the existing safety equipment without breaching wellbore and equipment safe operating limits.

Summary of the Invention

[0019] Apparatus and method is disclosed for having an annular packer element that is enclosed in, but not limited to, a housing having an alternative configuration of apparatus, providing the capabilities of closing in and sealing off the annulus in 5 seconds or less. The apparatus's main components include a quick closing annular, a flow spool, a hydraulic system and accumulator, and an integrated pressure relief system.

[0020] An embodiment of the invention comprises a hydraulic system consisting of high volume pressure pumps and an accumulator bank, having the capabilities of injecting closing fluid at high volumes and pressure via 1" or larger conduits on, but not limited to, both close and open chambers. The Accumulator bank is used to store pressurized fluid provided by the high volume pressure pumps, and includes a quick release actuating valve in line to the close chamber allowing for quick release of the fluid to quickly close the packer. Simultaneously, a quick release dump valve will be situated on the open line which will release all opposing pressure on the piston assembly from the opening chamber to eliminate all resistance for the closing function. The system further has a means of controlling the valve and activating the packer remotely from a desired location ideally being the driller's cabin. The valves may be controlled electrically, pneumatically or hydraulically.

[0021] A further embodiment of the invention comprises a packer enclosed in a housing which is ported to allow for the high fluid volume and pressure to be injected into the close chamber.

[0022] The hydraulic system will be equipped with, but not limited to, one quick pressure relief dumping valve on the "opening" line of the hydraulic system. This will relieve pressure in the opening chamber immediately such that there is no opposing force, allowing rapid closing of the annular preventer of the Quick Close Annular.

[0023] The system will have an integrated safety system, comprised of but not limited to, a safety relief spool and valves, preventing over pressuring of the packer which may result in leak-by. Additionally, the relief system will be pre-set to the lowest pressure rated component of the system which will protect the formations in the wellbore and any adjoined equipment below the QCA from over pressuring. The relief of fluid and pressure may be diverted through a 4" line but not limited to, and further diverted to a choke and mud gas separator (MGS), or directly to an overboard diversion point.

[0024] The system will be adaptable to any land based drilling rig or offshore drilling installation including jack-ups, platforms, and barges having a blow out preventer (BOP) at the surface. The system will be positioned at, but not limited to, a position on top of any BOP and/or at any point in any riser configuration (e.g. for semi submersibles & drill ships

referenced in UK patent application GB 1204310.5 (filed 12 March 2012) and US patent application 13/443,332 (filed 10 April 2012).

[0025] The system will be compatible with, but not limited to, any pressure containment device currently used. These will include, but are not limited to, RCD, RDD, RBOP, and PCWD technologies.

[0026] The system will be comprised of compact geometrical dimensions which will allow it to be drifted through standard 49 ½" inch rotary tables used in drilling for easy and safe installation. Ideally, the outside diameter (OD) of the IVR will not exceed a 46.5" OD.

[0027] Alternatively, the IVR system may include the RDD technology, a dual sealing pressure containment device used in drilling, installed above the flow spool component (without the QCA) as a secondary configuration of the IVR in any given riser and/or BOP configuration. With this configuration, the RDD sealing assembly will provide the necessary pressure sealing functions during drilling, and when the seal assembly is not installed the RDD system will revert back to functioning with quick closing capabilities with its internal housing packer arrangements. The QCA is not designed to withstand the forces created during drillpipe rotation, and thus utilizing the RDD assembly for the IVR system provides an upper and lower pressure seal while rotating the drillpipe during drilling operations, and provides the contingent rapid closing pressure seal with its lower packer assembly when the seal sleeve is removed.

[0028] The apparatus and method will provide an immediate response to rapidly close the annulus to minimize influx volumes and prevent additional influx while the rig's well control procedure is implemented to close the rig BOP – a procedure which can take up to 2 minutes. Thus, the apparatus and method provide a safety factor for existing well control equipment present in any drilling operation.

[0029] The apparatus and method will result in a significant reduction of influx volume through sealing the annulus rapidly via enhanced closing times which are, but not limited to, a factor of 10 times faster than conventional BOP systems. This is achievable by allowing the bottom hole pressure to reach a balanced pressure with the formation quicker by sealing off the annulus in less than 5 seconds. Once the seal is achieved, the formation flow will cease more rapidly as pressures balance, resulting in minimal volumes of influx when compared to a 45 to 60 second closing time of conventional BOP's. In conventional scenarios the well will continue to free flow into the wellbore until the annulus is sealed – it is only at this point the pressures will have the ability to balance, thus ceasing formation flow into the annulus. Thus, there will be a substantially higher volume of influx incurred into the wellbore with conventional systems when compared to the IVR system.

[0030] Aspects of the invention provide a method and apparatus that is unique in operation and principle, based on rapid closing of the annulus (5 seconds or less) with drillpipe present in the wellbore such that formation influx volume into the wellbore will be stopped immediately. By closing the annulus rapidly, the formation pressure will balance quickly in the wellbore such that inflow will cease, resulting in a significant reduction in the influx volume into the system.

[0031] Aspects of the invention also provide a method and apparatus that is unique in operation and principle, based on rapid closing of the open wellbore when there is an absence of drillpipe in the well (less than 5 seconds) such that formation influx volume into the wellbore will be stopped immediately. By closing the annulus rapidly, the formation pressure will balance quickly in the wellbore such that inflow will cease, resulting in a significant reduction in the influx volume into the system.

[0032] Aspects of the invention also provide a method and apparatus which may allow reduction in the kick tolerance in well design/engineering because of the ability of the system to close in the annulus rapidly, thus reducing influx volumes and higher surface and well pressures normally associated with larger influx volumes. This will result in considerable cost savings on a well to well basis for the operator.

[0033] Aspects of the invention also provide a method and apparatus which results in a significant reduction of influx volume into the wellbore because of its ability to rapidly seal the annulus. When compared to shutting in the annulus with conventional BOP equipment, this may take a minimum of 45 to 60 seconds to achieve. The apparatus and method will result in wellbore closing times which are, but not limited to, a factor of 10 times faster than conventional BOP systems. Thus, the apparatus and method provide a safety factor to the existing well control equipment present in any drilling operation, and greatly reduces the risk of exceeding the kick tolerance of the well.

[0034] It will be the only method and apparatus that will protect the rig and personnel during all phases of the drilling operation until well completion – tripping, drilling, circulating, cementing, casing installation, connections, drill stem testing, and logging. The method and apparatus will have the capability to rapidly seal off the wellbore during any of these operations, which is not possible with conventional BOP equipment and their extensive closing times. During cementing, logging, and casing operations in particular, the rig equipment and personnel are more vulnerable to influx occurrence and will likely result in an even more extensive time period to shut in the annulus with conventional BOP equipment.

[0035] Aspects of the invention also provide a rapid riser sealing solution which may incorporate the fast closing annular BOP concept of UK patent application GB 1204310.5 (filed 12 March 2012) and US patent application 13/443,332 (filed 10 April 2012) into its total

system. The IVR's main target market will be for shallow water and/or fixed rig installations (land, jack-ups, barges, fixed platform). These rigs have a surface BOP installed at the top of a short section of riser which is connected to the wellhead on the seabed floor (shallow water < 400 ft) or on land where there is BOP directly on surface connected to the wellhead with limit vertical height above the BOP to just below the rig floor (no riser, well directly beneath). Thus, the IVR will be installed directly or indirectly above and connected to this surface BOP to enhance the capabilities of shutting in the riser/wellbore immediately (<5 seconds).

[0036] The IVR will provide an inventive method which will provide a large safety factor to these rigs for rapidly closing in the well and sealing off the riser to prevent large volumes of influx from entering the well. Once a kick is detected at surface the IVR has the capability to shut in the well with a closing time of less than 5 seconds – this allows the formation pressure and bottom hole pressure to balance immediately where it will cease flowing into the well - significantly reducing the influx volume. This will be activated first when the kick is detected, such that the well is shut in immediately and the rig crew can then implement well control procedures to shut in their BOP – actual closing times of an annular BOP are 60 seconds, with a ram BOP 45 seconds, and with this procedure taking up to 2 minutes in reality. It is clearly observed that during these 45 second – 60 seconds (depending on which ram is activated) that the formation will free flow into the annulus, with the differences in influx volume when compared to having the IVR system in place being exponentially larger.

[0037] Thus, with the IVR system and method in place above the BOP, the risk of taking on large volume influxes which will produce large pressure and volumes at surface during its removal which may be hard to safely control and manage is greatly reduced. Further, the method significantly reduces the risk of exceeding the kick tolerance of the wellbore – i.e. the maximum influx/pressure that can be incurred before formation breakdown or fracture occurs in the well. It does so by minimizing the ability of the formation to influx large volumes into the annulus due to the high speed shut in time of the IVR located above the BOP. The implications for this may allow an Operator (oil company) to alter well their well designs with respect to its casing setting depths given the kick tolerance because this system and method provides a heightened safety factor when in place with enhanced speed of the riser/wellbore shut in capability.

Brief Description of the Figures

[0038] Specific and non-limiting embodiments of the invention will now be described, strictly by way of example only, and by way of reference to the following drawings of which:

[0039] FIG **1** An embodiment showing block diagram for the apparatus configuration with a conventional BOP.

[0040] FIG **2** An embodiment showing the process flow diagram of the apparatus, illustrating its operating methodology.

[0041] FIG **3** An embodiment comparing two systems and their respective well shut in times and resultant influx volume behavior. The 2 systems include the apparatus (i.e. the IVR) configured with a conventional BOP, and a conventional BOP in absence of the apparatus.

[0042] FIG **4** An embodiment of the proposed invention detailing the componentry comprising the device with the quick closing capabilities.

[0043] FIG **5** An embodiment of the proposed invention detailing, but not limited to, a typical means of connecting the invention atop of the BOP as well as providing a connection means to the rigs diverter and / or riser bell nipple.

[0044] FIG **6** An embodiment of the proposed invention detailing, but not limited to, a typical means of connecting the invention atop the BOP as well as providing a connection means to the rigs diverter and / or riser bell nipple. In addition having a means of diverting the flow from the annulus while drilling & / or circulating the well to conventional rig fluid and solids control equipment. The invention is further detailed as having dual function capability inclusive of the quick closing annular and riser drilling device with the addition of a secondary packer element and latching mechanism.

[0045] FIG **7a** An embodiment of the invention detailing the functionality of the Riser Drilling Device with Seal Sleeve Assembly installed.

[0046] FIG **7b** A component, referred to as a seal sleeve or seal sleeve assembly, used in the functionality of the RDD during conventional or managed pressure drilling operations and illustrating the capability of being installed or removed when required.

[0047] FIG **8** A typical Drill Ship used for offshore drilling operations for up to 10,000 feet of water depth, whereby a subsea BOP is connected to a subsea wellhead on the ocean floor, further having a riser to surface connection providing a means of circulating drill fluid to surface.

[0048] FIG **9** A typical Jack-Up drilling rig used for offshore drilling operations for up to 400 feet of water depth, whereby a subsea well head on the ocean floor is further connected to conventional BOP at surface via a riser conductor and a proposed point of installation of the invention within this configuration.

[0049] FIG **10** A typical conventional drilling rig used for drilling operations on land, and a proposed point of installation of the invention within this configuration.

Detailed Description of the Preferred Embodiments

[0050] FIG. **1** An embodiment that illustrates a simplified block diagram for the configuration of the Influx Volume Reduction system with a conventional BOP. A conventional BOP (**1**) is connected to any given well, and drillpipe (**4**) extends from surface, through the internal diameters of the quick closing annular (QCA, 3), the flow spool (**2**), the BOP (**1**), and into the well below. The flow spool (**2**) is connected to any point above the BOP (**1**), either directly on top or at some point above the BOP (**1**). The quick close annular (**3**) is connected directly on top of the flow spool (**2**) or at some point above the flow spool (**2**). Crossovers to the correct connection types may or may not be needed to integrate this system into any existing drilling rig system &/or BOP configuration whether land based or offshore. A minimum of one pressure relief line (**5**) is connected to a minimum of at least one side outlet located on the flow spool (**2**). The relief line (**5**) is connected to a pressure relief valve (**6**), which is set at a predetermined value that will activate when the pressure below the QCA (**3**) approaches the lowest pressure limits of any of the well formations and casing, and/or the surface equipment, including the QCA (**3**), the riser, the BOP (**1**), the flow spool (**2**), and/or any other equipment connected to the system. Downstream of the pressure relief valve (**6**), the relief line (**5**) further connects to a mud gas separator (**7**) or to an overboard flow diversion point offshore which vents to a safe point away from the operation (**8**). This allows the pressurized fluid which may or may not contain gas to be directed safely away from the operation to be depressurized safely and in a controlled manner. The mud gas separator (**7**) will vent all gas to a vent line located at a safe distance away from the rig (**8**) and return the fluid volume fraction of the relief flow stream to the rig's fluid storage system.

[0051] FIG **2**. An embodiment that illustrates the process flow diagram for an Influx Volume Reduction System installed offshore but not limited to land, atop a conventional BOP once an influx occurs into the wellbore. During drilling, fluid flow from the wellbore circulates up the annulus, through the rig BOP (**B**), through the flow spool (**C**) and QCA (**D**) and up into the rig's diverter bell nipple / bell nipple or diverter assembly (**E**). The flow is redirected to the rig shakers and mud tank system (**J**) via a flow line equipped with a flow indicator sensor, where cuttings are removed and the drilling fluid is processed to remove formation cuttings before being pumped back down into the well through the drillpipe.

[0052] A formation influx occurs into the wellbore (**A**), and as soon as the influx is detected at surface the pumps are immediately shut down. The rig BOP (**A**) or the QCA (**D**) are activated – the QCA (D) shuts in the annulus immediately (less than 5 seconds), minimizing the influx volume.

[0053] Conventionally, the rig BOP (**B**) would be closed, and the influx would be managed/controlled through the rig well control system – circulated through the rig choke

manifold (**H**), with all returns sent to the rig mud gas separator or Poor Boy (**I**), where fluid is degassed. The separated gas is vented to the vent line which extends up the height of the derrick (**K**), and the fluid is redirected to the rig shaker and mud tank system (**J**). There is the option to send all returns overboard (**M**) if flooding of the rig mud gas separator (**I**) occurs such that carry over through the derrick vent line (**K**) is prevented. Normally, the shut in procedure with the rig BOP (**B**) will take a minimum of 45 (ram) to 60 (annular) seconds, over which time the formation will continuously inflow into the wellbore annulus.

[0054] With the Influx Volume Reduction system, the QCA (**D**) is actuated to seal off the annulus and riser top in less than 5 seconds with drillpipe present in the wellbore. The rapid closing action prevents large volumes of formation influx from entering the well, because as the annulus seals the bottom hole pressure will balance with the formation pressure quickly and thus inflow volumes are minimized. The QCA (**D**) can also be actuated to quickly seal off the riser top when gas has been circulated undetected to surface. Additionally, the QCA (**D**) closes much quicker – 5 seconds versus 30-45 seconds for a surface rig diverter (**F**), and therefore the IVR system will have an enhanced response time for sealing off the annulus immediately after kick detection, further reducing the risk of uncontrolled gas and fluid release at surface. The QCA (**D**) adjustable closing pressure will also allow for the stripping of the drill string to occur if necessary. The QCA (**D**) is actuated immediately upon influx detection (**A**), followed by the rig's well control procedures implemented to close the rig BOP (**B**).

[0055] Once the QCA (**D**) is closed, there may be potential for the system to overpressure from either increasing surface pressure from the influx in the annulus, or failure to stop the pumps before the QCA (**D**) closes. The QCA (**D**) pressure rating will be lower than that of the flow spool (**C**) and the BOP (**B**) and riser sections below it, and therefore there is a pressure break (**L**) between the flow spool (**C**) and the BOP (**B**) components below the IVR system. To mitigate this condition, a pressure relief system (**N**) will be connected to the flow spool (**C**) assembly. The pressure relief system (**N**) will consist of one or more relief valves and lines, with each relief line being independent of the other. The relief valves (**N**) will be set at the lowest pressure rating in the drilling system which exists below the sealing point of the QCA (**D**).

[0056] When the pressure below the sealing point of the QCA (**D**) approaches the set points of the pressure relief valves (**N**), the valves will actuate and relieve the riser pressure immediately, directing the flow to either a mud gas separator (**G**) where fluid will depressurize in a safe and controlled manner, or directly to the overboard flow diversion point on the rig (**M**). In this example, the pressure relief valve (**N**) connected to the mud gas separator (**G**) may be set slightly lower than the pressure relief valve (**N**) connected to the overboard diversion point (**M**). This will allow more controlled pressure relief to the mud gas separator (**G**) initially, with the overboard diversion relief valve (**N**) activating if pressure continues to climb in the system.

Fluid will be returned to the rig shaker and mud tank system (**J**) and gas will vent to the vent line extending up the derrick (**K**). There will be an option to divert the flow overboard (**M**) downstream of the mud gas separator (**G**) if the vessel begins to flood with fluid – this will prevent liquid carry over through to the derrick vent line (**K**). Thus over-pressuring of the system will be mitigated with the pressure relief valves (**N**). Alternatively, the discharge of the pressure relief valves (**N**) could be routed to the rig's existing mud gas separator/Poor Boy (**I**).

[0057] FIG. **3a** and **3b** An embodiment that illustrates two systems and their respective well shut in times and resultant influx volume behavior. The 2 systems include the IVR configured with a conventional BOP, and a conventional BOP in absence of the IVR in any given offshore or land drilling system (FIG. **3b**). In both systems, an identical formation begins to influx into the annulus. FIG. **3a** graphically illustrates the initial plotting point on the associated graph, assuming that the influx/kick has already been detected on surface, the rig pumps have been turned off, and the rig is ready to initiate well control procedures and shut in the well.

[0058] The first system, in absence of the IVR components, is a conventional BOP system and will take approximately 45 seconds (**3**) (best case scenario) to 60 seconds (**4**) to shut in the well and seal around the drillpipe. For this example, a 1 barrel per minute influx was assumed (0.017 barrels per second). Referring to the graph, the "BOP – Linear Flow" trend line clearly illustrates the theoretical linear relationship of influx volume versus time which may occur for the total influx volume entering the well over this duration of 45 (**3**) to 60 (**4**) seconds. The formation will continue to free flow into the annulus until the annulus is sealed by the conventional BOP at 0.017 barrels per second.

[0059] However, the more likely behavior will not be a linear relationship, but a non-linear relationship for increasing influx volume in the annulus. As the formation continues to free flow into the annulus, its lighter density will infiltrate the existing higher density drilling fluid system and begin to lighten the fluid column at the bottom of the well. This will decrease the bottom hole pressure further which will result in the formation influx rate to increase as the pressure differential increases between the formation pressure and the bottom hole pressure. This relationship between the increases in inflow rate with increasing pressure differential is defined in Darcy's Law for fluid flow through a porous medium, and is well known in the art.

[0060] Therefore, the plotted trend "BOP – Non-Linear Flow" is the more realistic behavior which will result while the conventional BOP is closed to shut in the well. The longer it takes to achieve sealing off the annulus the larger the influx volume will be from a continuously increasing inflow rate. The result is that there will be a much higher influx volume than anticipated by the linear relationship, and hence greater risk to manage and control the influx when it reaches surface. This could potentially exceed the kick tolerance for the wellbore design and/or exceed equipment limits at surface while removing the influx from the annulus.

[0061] The second system includes the IVR components and will take approximately 3 seconds (**1**) (drillpipe in the well) to 5 seconds (**2**) (no drillpipe in the wellbore) to shut in the well and seal off the annulus. Assuming the same influx rate of 1 barrel per minute (0.017 barrels per second), the plotted trend line "IVR" clearly illustrates the significant reduction in influx volume through rapidly sealing off the annulus within this time interval. By sealing off the annulus rapidly, the formation and bottom hole pressures balance immediately which reduces the volume of the influx by a large factor when compared to that of a conventional BOP system. Due to the much smaller volume of the influx it will be much safer to manage and control the influx during its removal from the well.

[0062] Additionally, by having the IVR system installed into the riser configuration, the kick tolerance in the well design could be reduced due to the capability to shut in the well rapidly. There will be a high level of control over influx volume, with the capability of the IVR to significantly reduce the volume of influx which could enter the annulus. This will keep wellbore pressures and volumes to a minimum during the removal of the influx volume from the wellbore, and thus a large safety factor is introduced into the well design. Otherwise formation and/or casing shoe fracturing may result from larger influx volumes associated with a slower closing conventional BOP system.

[0063] FIG. **4** An embodiment of the invention allowing for quick closure and sealing off of the annulus. The QCA (BOP) is divided in a first housing (**13**) and a second housing (**14**) with movement of housing (**13**) and housing (**14**) being prevented by fasteners (**18**), each fastener including a shaft which extends through a fastener receiving orifice (not detailed) in the second housing (**14**) into a thread orifice in the first housing (**13**).

[0064] Located within housing (**13**) and (**14**) is a spherical packing element (**8**) made of an elastomeric material such as, but not limited to, elastomer/rubber with metallic inserts (**9**), and a fluid pressure/hydraulically operated actuator or piston (**10**). The piston (**10**) divides the interior of the housing (**13**) into two chambers, an open chamber (**12**) and a closed chamber (**11**).

[0065] The configuration of BOP is described in more detail in our co-pending UK patent application, GB 1104885.7 and further referenced in UK patent application GB 1204310.5 (filed 12 March 2012) and US patent application 13/443,332 (filed 10 April 2012) the contents of which are incorporated herein by reference. It should be appreciated that the invention is not restricted to use in conjunction with this type of BOP. The invention may be used with any type of hydraulically operated BOP.

[0066] The piston (**10**) is moveable by means of the supply of pressurized hydraulic fluid via an injection port (**15**) to the close chamber (**11**) to push the packing element (**8**) against a curved

portion (**21**) of the second housing (**14**) which causes the packing element (**8**) to be compressed and its diameter to reduce. With a tubular extending through the QCA the packing element (**8**) closes until engaging the drill pipe and creating a fluid, gas and/or pressure tight seal. Where no tubular is present (i.e. an open wellbore), if sufficient pressure is applied to the close chamber (**11**) the packing element (**8**) may be compressed so much that its central aperture (**18**) disappears and in turn acts as a plug preventing flow of fluid through the BOP (this may be referred to as full closure). In either case the QCA (BOP) is in its closed position. The packing element (**8**) is released from sealing engagement with the tubular or full closure by supply of pressurized hydraulic fluid via the open injection port (**16**) to the open chamber (**12**) until the packing element (**8**) is returned to its original relaxed position.

[0067] The fluid injection ports / orifices (**15**) and (**16**) are typically, but not limited to, 1 inch in diameter. In the example they are referenced as being a single injection orifice for (**15**) and (**16**) however there may be in fact more than one, each for the separate close and open functions, to allow for greater fluid volume to be injected over a short period of time. This will assist in achieving the rapid closing time of 5 seconds or less. It is understood that when injecting pressurized fluid via (**15**) or (**16**) into either chamber (**11**) or (**12**) that there must be a quick release of fluid in the opposing chamber (**11**) or (**12**).

[0068] Referenced as (**22**) is the lower flange connection which is detailed as being a studded flange 18.75 inch 5000 psi, and is an integral part of the first housing (**13**). Referenced as (**23**) is the upper flange connection which is detailed as being a studded flange 18.75 inch 5000 psi, and is an integral part of the second housing (**14**). While the present invention incorporates this studded flange sizing and design, it is not limited to this and may incorporate other standard flanges of varying sizes and pressure ratings for compatibility to any system it is configured with and resulting in simplified installation.

[0069] FIG. **5** Illustrates the invention coupled with cross overs / spool adapters and flow spool / flow cross for ease of installation atop a conventional BOP as well as the ability to interface with any other connectors or devices normally connected atop the BOP. These devices may be referred to in the industry as Diverter Bell Nipples or simply Bell Nipples.

[0070] Component (**2**) may be referred to as a flow spool enabling the invention to be connected atop a conventional BOP having flanged connections on its top and bottom. While the top flange will be adjoined to the lower studded connection of the QCA (**22**), the bottom connection would be manufactured for compatibility with any connection type atop the BOP and thus will vary among drilling rig installations. Outlet flanges (**26**) oriented on a horizontal plane of the flow spool (**2**) allow for the connection of the pressure relief line (**5**) and pressure relief valve (**6**) as detailed in FIG. **1**.

[0071] Component (**25**) may be referred to as a cross over or spool adapter enabling the invention to be connected to devices normally connected atop the conventional BOP. While the bottom flange will be adjoined to the upper studded connection of the QCA (**23**), and the upper connection will be manufactured to allow for the connection to the specific interface type of the device normally connected atop the BOP.

[0072] It is further envisioned that (**2**) and (**13**) may be an integral component rather than two separate components. For example the first housing (**13**) may be manufactured to incorporate (26) and with a lower flange allowing for connection atop the BOP.

[0073] FIG. **6** Illustrates the invention as it may be configured having both quick closing annular and RDD functionality within one combined system. The flow spools and cross over detailed in FIG. **5** may remain as part of the system requirements however not limited to the possibility of having these components integral to the first (**13**) and second (**14**) housings.

[0074] Further detailed is the first or lower housing (**13**) and second or upper housing (**14**) with the addition of third or middle housing (**27**) allowing the interconnectivity of (**13**) and (**14**) now with the addition of a second packer element (**8**). Further explained is that in this configuration during a well control event the lower packer (**8**) within the lower housing (**13**) would be closed with, but not limited to, the upper packer (**8**) within the upper housing (**14**) of the RDD.

[0075] The lower flow spool (**2**) in this configuration has a 4 1/16" 5K outlet (**26**) with the addition of a 7 1/16" 5K outlet (**28**) allowing for fluid diversion to the rigs fluids & solids control equipment or diversion to managed pressure drilling surface control equipment.

[0076] FIG. **7a** Illustrates the invention as its configuration related to operating in MPD-managed pressure drilling operations. FIG. (**7a**) details the invention having the seal sleeve assembly (**29**) secured within the bore of the invention, enabling the dual pressure sealing capabilities of the device during rotation of the drill string and or while stripping under pressure.

[0077] FIG. **7b** Details particular reference to the seal sleeve assembly (**29**) positioned and secured within the RDD housing, with a further aspect showing that it as a removable and replaceable component of the RDD.

[0078] FIG. **8** Illustrates the QCA (**3**) as it is installed on a deep-water drill ship in a preferred position forming an integral part of the riser (**33**) between the subsea BOP and surface (**30**). This specific configuration is detailed and referenced in Patents GB 12043105 and GB 12064051. Persons trained in the art will fully understand the distinct differences with regards to deep water drilling operations in comparison to shallow water or land based drilling. For the purpose of this application, the significant difference will be that the BOP's are installed on the

ocean floor for deep water drilling operations versus at surface as per shallow water and land based drilling. It is further realized that subsea BOP's are not considered conventional drilling equipment compared to their predecessors, which do not have to function below the water line in submersed environments. Common components found in all drilling operations, however possibly having varying capabilities, complexities or positioning, can be referenced as being a wellhead (**31**), casing (**32**), derrick (**34**), rotary table (**35**) and surface area (**30**) along with a BOP. Additional reference worth detailing is the presence of a water line (**36**) on both a deep-water drilling installation FIG. **8** and a fixed installation shallow water drilling rig FIG. **9** - however this is not present in land based drilling FIG **10**. It is demonstrated here the large degree of vertical space available in the riser for the installation of the IVR system above the subsea BOP (**1**).

[0079] FIG. **9** Illustrates a shallow water jack-up drilling rig with the QCA (**3**) installed directly or indirectly atop a conventional BOP (**1**) at surface (**30**) above the water line (**36**). Reference is given to same or similar operational required components, being that of the wellhead (**31**), casing (**32**), derrick (**34**), rotary table (**35**), and surface area (**30**). Further referenced is the diverter bell nipple/bell nipple (**E**) in this configuration. This figure demonstrates the potential of there being limited vertical space available in the riser above the BOP (**1**) that may result for the installation of the IVR system in shallow water fixed drilling platforms.

[0080] FIG. **10** Illustrates a conventional drilling rig on land having similar operational components, being that of the wellhead (**31**), casing (**32**), derrick (**34**), rotary table (**35**), and surface area (**30**). The BOP (**1**) is located at the surface, and the QCA (**3**) is installed in directly or indirectly atop the conventional BOP (**1**) at surface (**30**). This figure demonstrates the limited degree of vertical space available above the BOP (**1**) to position the IVR in land based operations, which may impose some restrictions on the options for its installation.

CLAIMS

1. Apparatus for drilling comprising a substantially annular packer element disposed within a housing, which is capable of closing in and/or sealing off a drill string closure in 5 seconds or less.

2. Apparatus according to claim 1 further comprising one or more of: a quick closing annular, a flow spool, a hydraulic system and accumulator, and a pressure relief system (which may be integrated).

3. Apparatus according to claim 1 or claim 2 further comprising any feature or combination of features disclosed herein.

4. A method for drilling comprising the use of a substantially annular packer element disposed within a housing, and closing in and/or sealing off a drill string closure in 5 seconds or less.

5. A method according to claim 4 further comprising any feature or combination of features disclosed herein.