# Paper #8-10

# ARCTIC WELL INTEGRITY AND SPILL PREVENTION METHODS AND TECHNOLOGY

Prepared for the

Technology & Operations Subgroup

On March 27, 2015, the National Petroleum Council (NPC) in approving its report, *Arctic Potential: Realizing the Promise of U.S. Arctic Oil and Gas Resources*, also approved the making available of certain materials used in the study process, including detailed, specific subject matter papers prepared or used by the study's Technology & Operations Subgroup. These Topic Papers were working documents that were part of the analyses that led to development of the summary results presented in the report's Executive Summary and Chapters.

**These Topic Papers represent the views and conclusions of the authors. The National Petroleum Council has not endorsed or approved the statements and conclusions contained in these documents, but approved the publication of these materials as part of the study process.**

The NPC believes that these papers will be of interest to the readers of the report and will help them better understand the results. These materials are being made available in the interest of transparency.

The attached paper is one of 46 such working documents used in the study analyses. Appendix D of the final NPC report provides a complete list of the 46 Topic Papers. The full papers can be viewed and downloaded from the report section of the NPC website (www.npc.org).

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| **Topic Paper**<br>(Prepared for the National Petroleum Council Study on Research to Facilitate Prudent Arctic Development) | | |
|---|---|---|
| **8-10** | **Arctic Well Integrity and Spill Prevention Methods and Technology** | |
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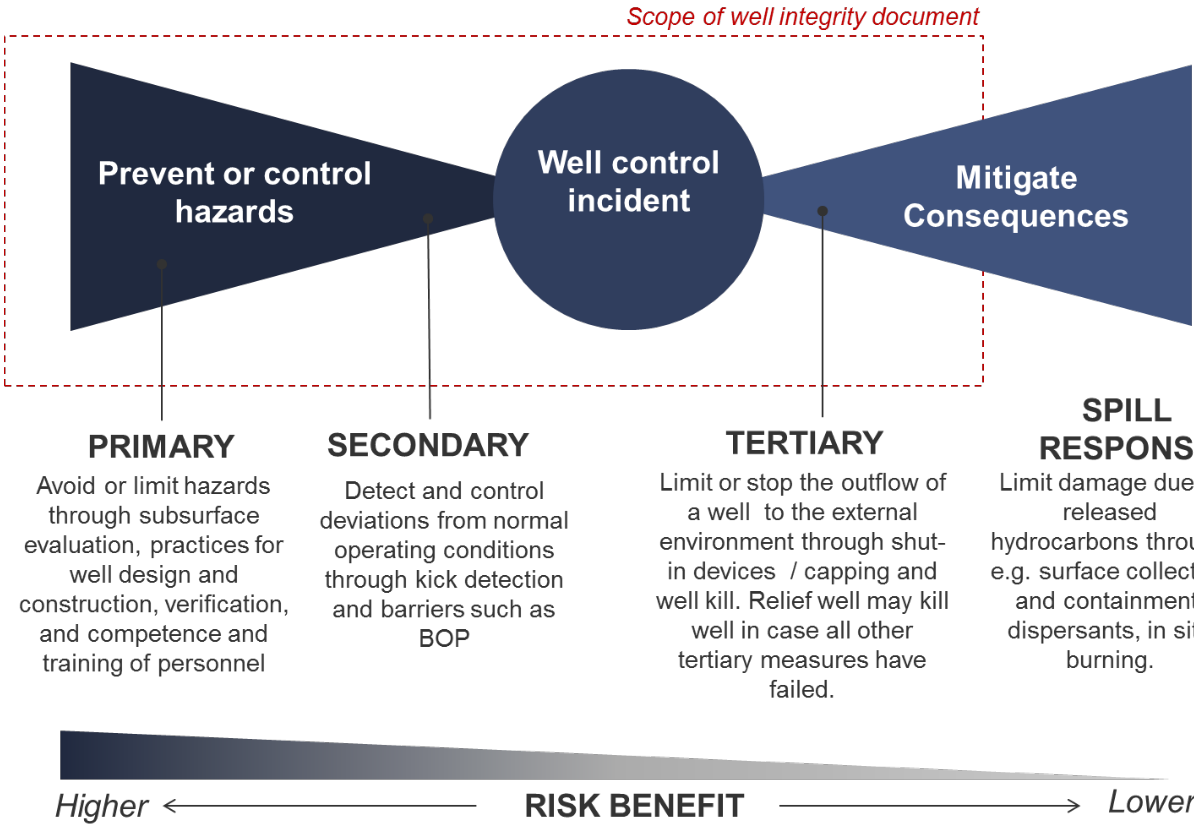
**SUMMARY**

This paper describes the practices and procedures associated with the design and construction of offshore arctic wells in such a manner as to prevent the release of hydrocarbons to the environment. US regulations and industry standards have been significantly upgraded since the Macondo incident of 2010. The primary approach to loss of well control is prevention and prudent well design as described in this paper. Operators must follow a strict set of controls that require extensive verification, testing, and certification of well control equipment, well designs, and barriers to the flow of hydrocarbons.


## I. KEY MESSAGES

Arctic well design and construction follows standard offshore well practices. Arctic specific hazards, including deep-keeled ice features and surface ice, require additional mitigations, but do not alter the basic well design and construction practice – and prevention of loss of well control. Permafrost and methane hydrates, if present, require special considerations including drilling fluid and tubular selection and control of heat, all within established and proven practices.

Industry's approach to loss of well control is prevention. This is shown schematically in the 'bow tie' figure below. The left hand side of the bow tie depicts controls, and barriers designed to prevent incidents that could escalate and lead to a loss of well control. A combination of barriers are employed in the well design. The right hand side of the bow tie depicts responses or preparedness in the unlikely event of a loss of well control.




US regulations, standards, and practices that have been upgraded post-Macondo make the likelihood of a major well control event extremely unlikely. This includes certification by a licensed professional engineer that there are two independently tested barriers across each flow path, and that the casing design and cementing design are appropriate, along with independent third party verification of the BOP. Furthermore, there are requirements for adherence to operations integrity management systems combined with a culture of safety and risk management.

Tertiary controls would be employed in the unlikely event of a loss of well control. Industry and BSEE have co-developed a screening tool to implement 2010-NTL 10, "Statement of Compliance with Applicable Regulations and Evaluation of Information Demonstrating Adequate Spill Response and Well Containment Resources" [Ref.6]. Wells meeting the Level 1 or 2 criteria can be contained via a capping stack in case of a worst-case discharge scenario, e.g., fully shut in without causing underground flow. Cap and flow and containment are considerations for wells not meeting the Level 1 or 2 criteria, but are not considered prudent for arctic development at this time.

US Government authored papers covering blowouts for period 1971-2006 indicate flow was stopped in all cases without need for a relief well [Ref. 29 and 30]. The reports states that "continued success will depend on sustained efforts by industry and government to improve safety management practices related to drilling and well control". The federal government and the offshore industry significantly adjusted the regulations and standards in the US after the Macondo incident in 2010.

Additional well control devices and techniques are available that are independent of the controls on the drilling rig, and combined with performance-based risk assessment, offer a better alternative to the same season relief well requirement and/or oil spill containment systems (based on a worst case discharge scenario). Examples of these devices are capping stacks that are deployed after an incident and subsea shut-in devices that are installed on the well during the drilling process [Ref.34].

## II. INTRODUCTION

Exploration drilling operations in the Arctic began at Norman Wells in the Canadian Northwest Territories in 1920 and production began in 1932 [Ref.1]. This field has been in continuous operation since then and has produced over 250 million barrels of oil. Most of the production is from artificial islands in the Mackenzie River. These wells have maintained a long record of integrity even with seasonal flooding, ice jams, and ice scouring and have been constructed through the permafrost.

The Prudhoe Bay field on the Alaskan North Slope has been on continuous production since 1977 and these wells have been successfully drilled and produced through the permafrost.

There have been numerous arctic shallow-water exploration wells in the US (United States) and Canadian Beaufort Sea drilled since 1970 [Ref.2]. These wells were drilled using gravel islands, ice islands, a Concrete Island Drilling System (CIDS), the *Molikpaq* (a steel caisson filled with granular material), ice-strengthened drillships (*Explorer 1, 2, 3, and 4*), an axisymmetric circular-shaped floater (*Kulluk*) that was moored, a converted tanker used as a submersible (SSDC and later renamed SDC), and two caisson retained island (CRI and Tarsuit) systems. There was an extensive network of infrastructure established for these activities including marine and air support. Some key vessels in Dome Petroleum's Canmar fleet were the *Canmar Kigoriak* and the *Robert Lemeur* and in the Gulf Canada's Beaudril fleet, two icebreakers (*Terry Fox* and *Kalvik*), two supply ice breakers (*Ikaluk* and *Miscaroo*), and multiple ice-strengthened supply boats. All of these wells were drilled without loss of containment from the reservoirs. In 1986 over 100,000 barrels of oil were produced from the Amauliqak field in the Canadian Beaufort Sea and shipped as return cargo to Japan in the tanker that delivered diesel to the drilling fleet. The first offshore Alaska Beaufort Sea production occurred in 1987 at the Endicott field using gravel production islands. No loss of containment has occurred from these wells with over 20 years of production. More details can be found in the Prudent Development Section 3 and E&P Technology Topical Paper TP2.

Over 350 wells have been drilled in offshore arctic (or arctic-like) [Ref.3] drilling programs in Canada, Norway, Greenland, and the USA. Almost 40 wells were drilled from floating ice platforms in water depths up to 550 meters (1800 ft). In addition, the industry has had successful and environmentally responsible arctic drilling campaigns in the Cook Inlet, the Gulf of Alaska, Norton Sound, the Navarin Basin, and elsewhere. Exploration wells have been drilled in the North American Arctic over the past five decades, and these wells have been drilled in all of the major arctic ice regimes.

There has also been more recent extensive offshore development in ice-prone regions offshore Sakhalin, Russia, although this region is clearly sub-Arctic. There are currently five offshore gravity base structures named Orlan, Berkut, Piltun Astokhskoye A & B, and Lunskoye A. These offshore structures support drilling rigs, and oil has been produced since 1998.

Finally, the Grand Banks offshore Newfoundland is probably the best example of iceberg management in the offshore oil industry. The operators employ a large gravity based structure with platform drilling rigs (Hibernia) to drill surface wells, and semisubmersibles to drill subsea wells that are tied back to floating production vessels (Terra Nova and White Rose). The subsea drilling has been conducted primarily using moored, floating semisubmersible rigs, but a jack-up rig has also been used.

These fields employ an extensive iceberg management program to minimize the risk of an iceberg reaching the surface structure or the subsea wells. Most of the subsea wells are located in excavated subsea drill centers (glory holes) where the christmas tree is located below the seafloor. The iceberg management program uses boats, aircraft, and a marine radar system to detect and track icebergs. Marine vessels use heavy cables with specially designed nets to tow and re-direct icebergs that pose a threat to the structures.

This topical paper discusses the state-of-the-art for well integrity and spill prevention. This state-of-the-art technology draws upon both the industry experience drilling in ice prone regions, cited above, and tens of thousands of wells drilled offshore worldwide. The industry employs extensive baseline monitoring and risk identification to ensure fit-for-purpose well design and operations to ensure that known operating conditions such as pressures, loads, and environmental factors are not only addressed, but are addressed with redundancy and with prudent safety factors. Industry and regulatory standards have both been made significantly more stringent since 2010 (post Macondo).

This paper will elaborate on how the industry has developed the technologies and methodologies to design and construct wells so that a hydrocarbon release from the reservoir is highly unlikely and continuously works to improve this practice. In the drilling and construction of a well, barriers to hydrocarbon flow are established; these will be discussed in detail in this paper. These barriers consist of drilling fluid of sufficient density, tubular goods (casing and tubing), cement, subsurface valves, the blowout preventer (BOP, which contains redundant components), christmas tree, and others. Loss of containment and the subsequent response can be more challenging in an arctic environment than a sub-arctic environment due to the potential presence of ice and the associated logistical issues. The prudent implementation of these barriers results in the prevention of a hydrocarbon release to the environment.

The industry's primary approach to loss of well control is prevention, which is achieved through adherence to operations integrity management systems combined with a culture of safety and risk management. Wells can be drilled safely and well control can be maintained when:

- Focus remains on safe operations and risk management,
- Wells are designed for the range of risks anticipated,
- Equipment has required redundancy and is properly inspected and maintained,
- Personnel are trained; tests and drills are conducted, and
- Established procedures are followed.

## III. SUBSURFACE KNOWLEDGE: PRESSURE, LITHOLOGY, GEOMECHANICS

The first step in the design and construction of a drill well begins with geoscience and typically starts with the analysis of seismic data. The geoscientists use the seismic (acoustic) data along with offset well logs (gamma ray, resistivity, sonic, etc.) and other available data sets to generate maps on key stratigraphic horizons and to predict pore, fracture, and overburden pressures. In addition, a shallow hazards analysis will be conducted to identify shallow hydrocarbon bearing zones, shallow overpressure, or other potential nonhazardous factors within the subsurface stratigraphic section above the first casing string that is connected to the blowout preventer (BOP). The well site is preferably selected to avoid the shallow hazards. This could result in a new well location or a directional well being drilled such that it avoids shallow hazards while still targeting the well objectives, even for exploration.

If the potential shallow hazard cannot be avoided, then a smaller diameter pilot hole can be drilled through this interval (riser-less) to determine if the hazard truly exists. If the hazard exists, then the zone can be managed by pumping drilling fluid down the drill string and up the annulus at a high enough rate to control the well through annular friction or equivalent circulating density (ECD). Furthermore, a technique may be employed where weighted water-base drilling fluid is pumped down the drill string and up the annulus to the seafloor. Again, if the assessment of the pilot hole determines that a shallow hydrocarbon hazard exists that cannot be mitigated in the planned hole size (needed for the casing string) by this method or some similar technique, the location of the well will be moved.

Pressure prediction is an important input to the drill well program. Geoscientists use seismic data, offset well logs and other available data to construct an integrated pressure prediction chart. Figure 1 shows an example of the expected pore, fracture, and overburden pressures versus well depth. The pressure prediction also contains information on depths, thicknesses, and potential fluid types for expected porous/permeable zones.

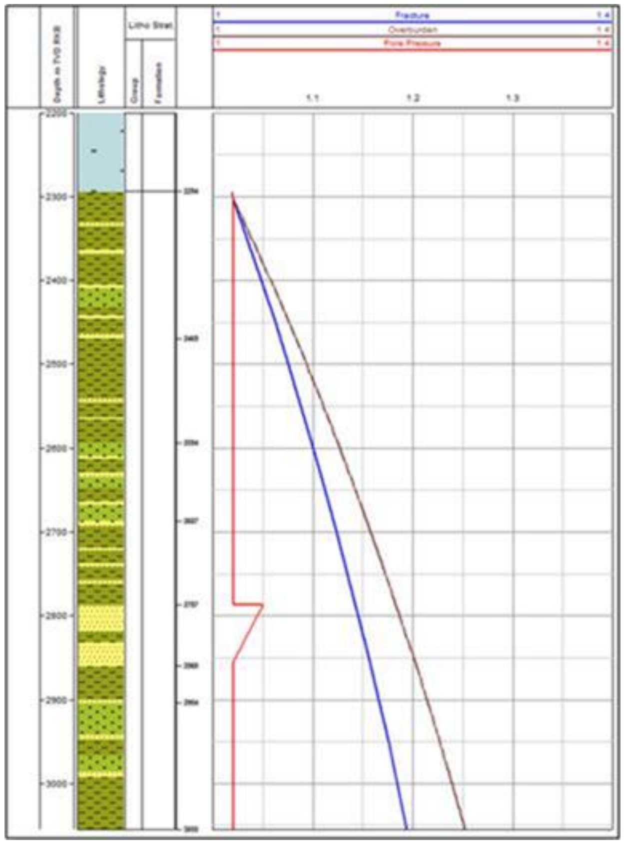


Figure 1. Example of a Pore Pressure, Fracture Gradient Chart

The drilling engineer then uses the pressure prediction to develop the drilling program. The engineer selects drilling fluid (mud) densities that are greater than the predicted pore pressure, but less than the fracture pressure. Furthermore, the engineer selects the depths of the casing strings that allow a margin for mud density plus ECD versus the fracture strength of the rock (kick tolerance), and applies a suitable safety margin to prevent lost returns during the drilling and cementing processes.

Recently developed Logging While Drilling (LWD) technologies like Seismic Guided Drilling and Deep Directional Resistivity allows geoscientists to look ahead of the drill bit and continually update existing models for hazards and pore pressure further reducing operational uncertainty. This technology has been applied offshore Norway.

## IV. BASIC WELL ARCHITECTURE (SURFACE AND SUBSEA)

Well Construction

The basic well architectures for the drilling phase and completion phase are illustrated in Figures 2 through 5.

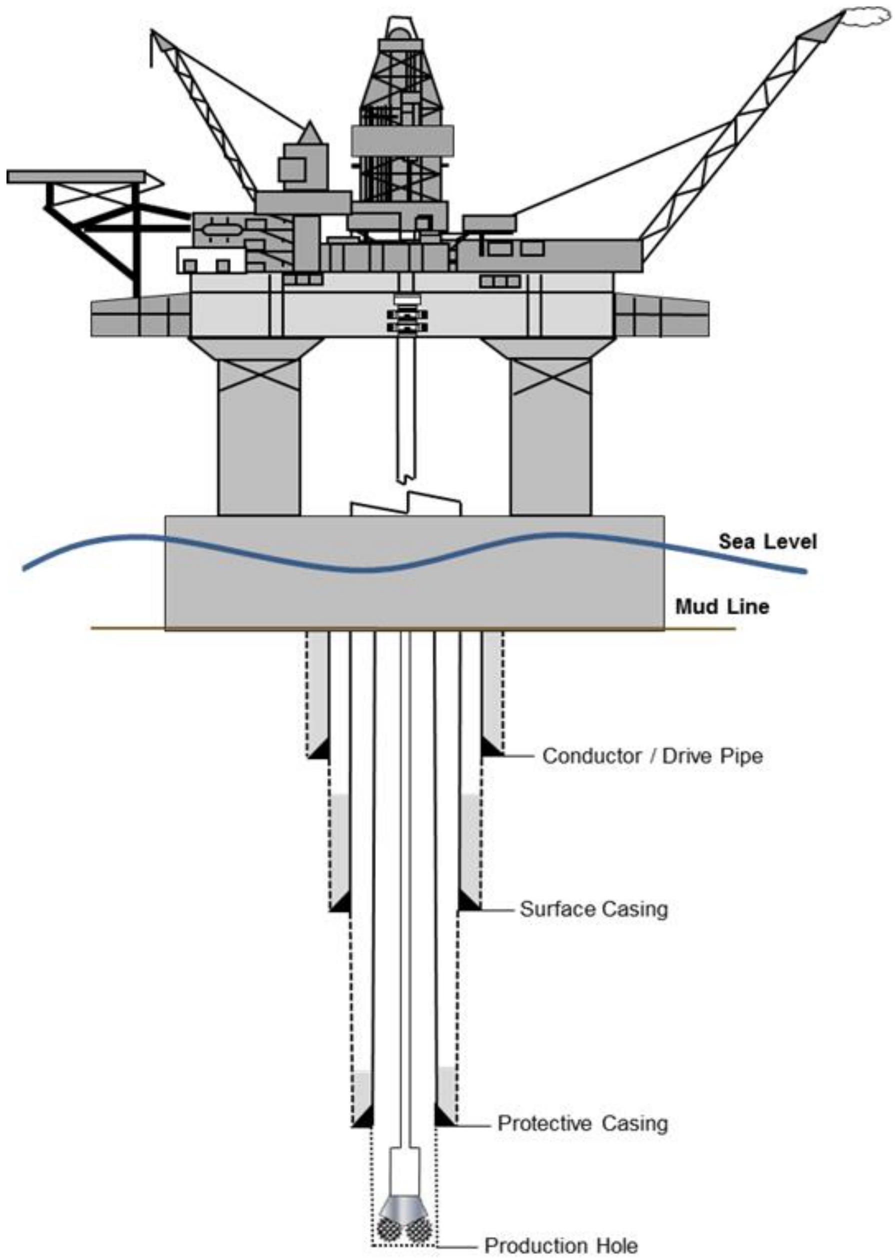



Figure 2. Schematic of a Surface Drill Well – Drilling Phase

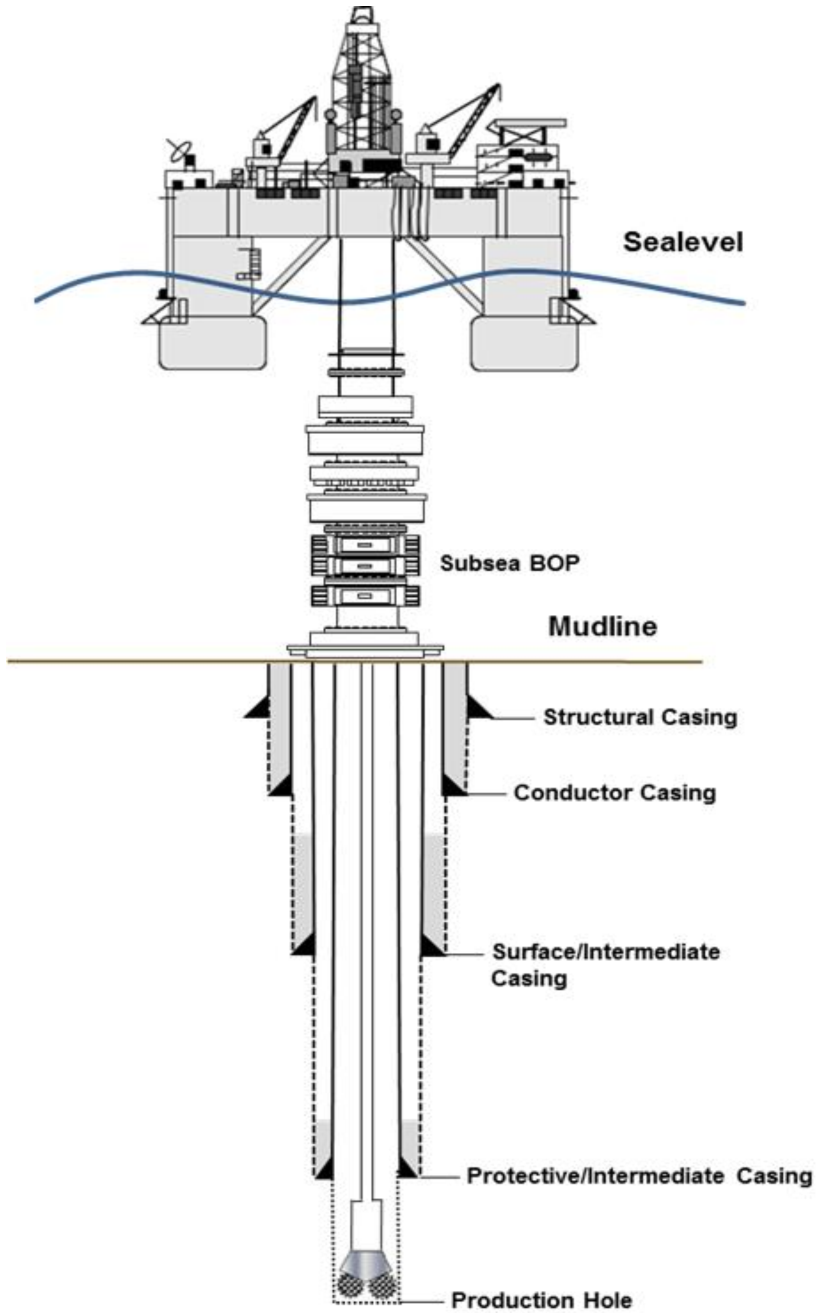



Figure 3. Schematic of a Subsea Drill Well – Drilling Phase

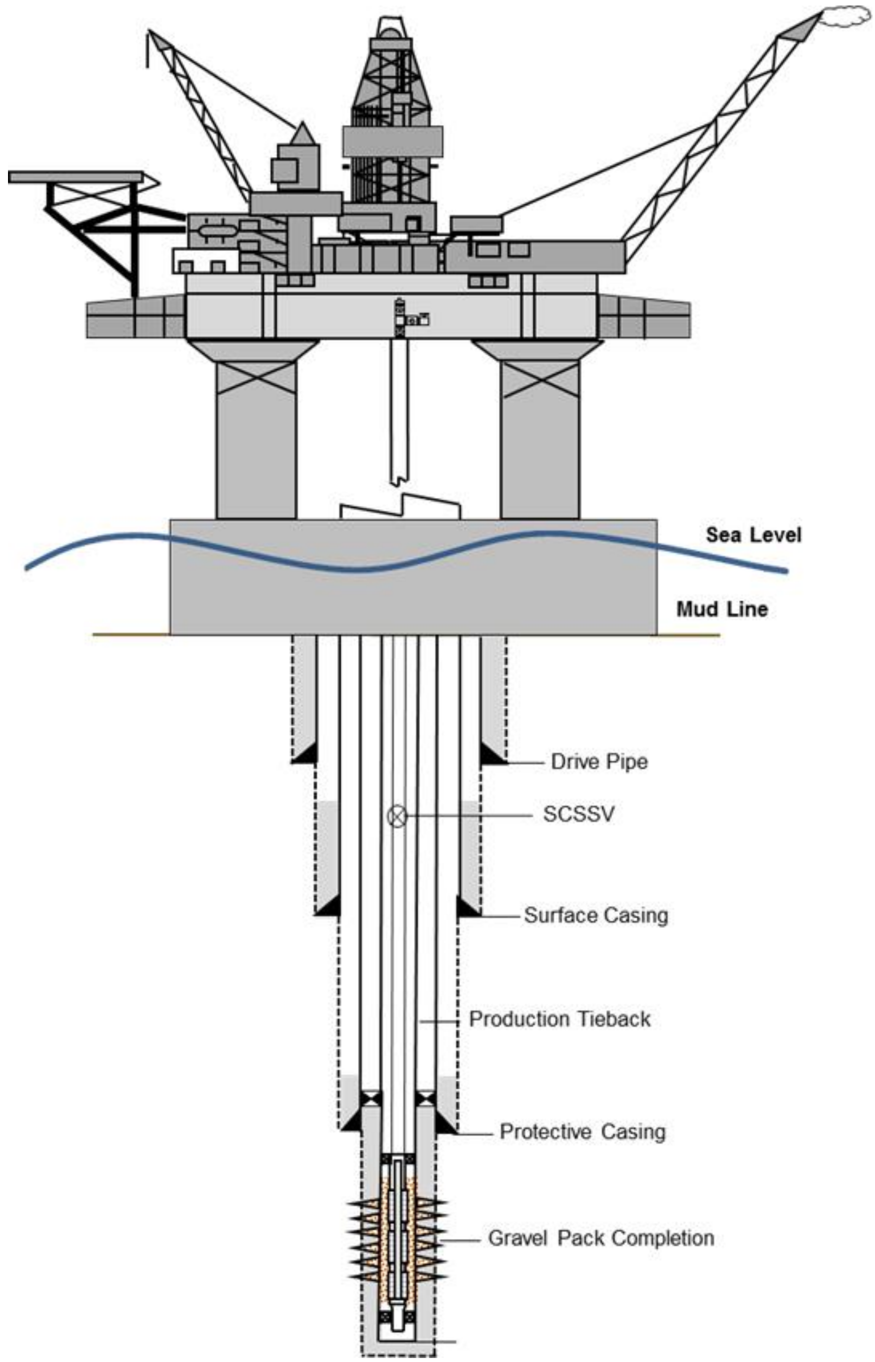



Figure 4. Schematic of a Surface Drill Well – Completion/Production Phase

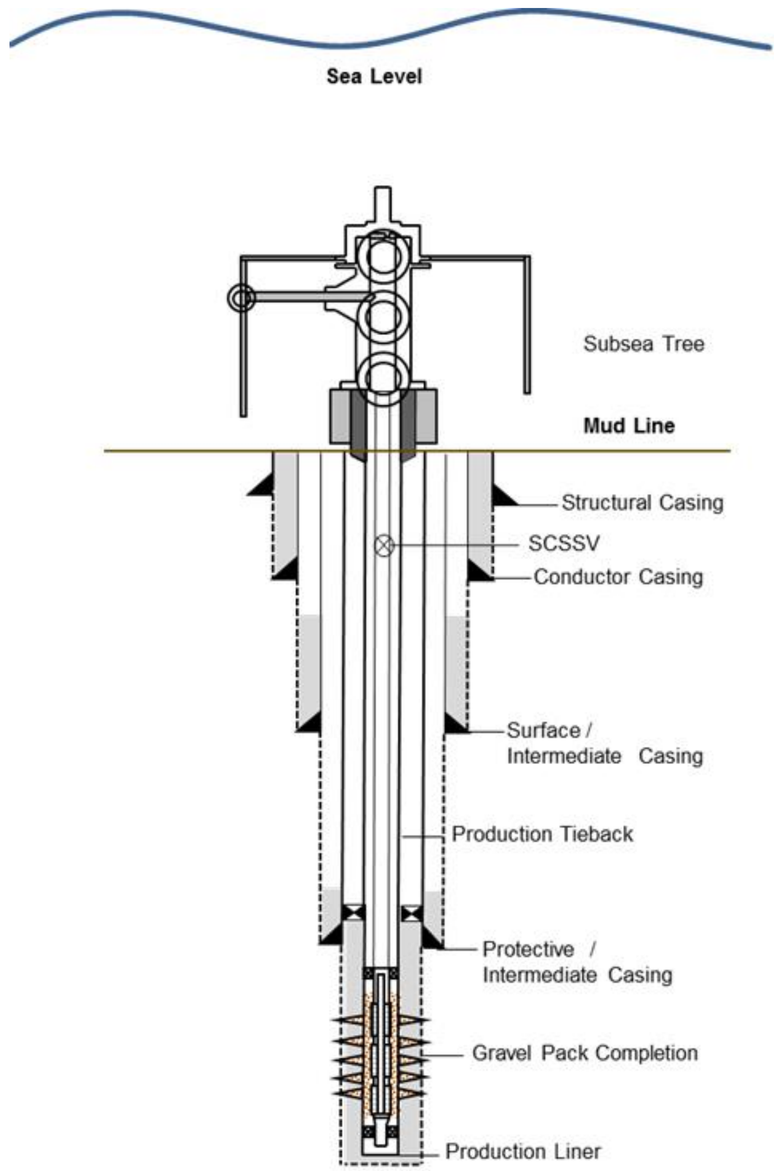



Figure 5. Schematic of a Subsea Drill Well – Completion/Production Phase

For a well with a surface wellhead, a conductor (or drive) pipe is driven or hammered into place at a prescribed depth, but if the seafloor soils are too stiff for this, a hole can be drilled, the conductor pipe is run, and then cement is pumped into the annulus to secure the pipe. A low pressure wellhead is attached to the conductor pipe and then the next hole section is drilled to the prescribed depth. This is called the surface hole and the surface casing is run and cemented in place and partially supported by the conductor pipe and low pressure wellhead. The surface casing must isolate any fresh water zones and must be set before drilling into any hydrocarbon zones. It is also set at a depth that prevents hydrocarbons from broaching to the surface in a well control scenario. Then the high pressure wellhead is attached and a BOP is connected to it. At this point, the drilling process is conducted with a closed loop fluid system. Subsequent hole sections and casing strings are run in accordance with the prescribed program written by the drilling engineer.

For a well with a subsea wellhead, a structural casing string is jetted (use of high pressure nozzles at the drill bit) at the seafloor to a depth that will be competent enough to support the weight of subsequent casing strings and the BOP. This pipe contains a low pressure wellhead that can support the next casing string. Sometimes, if the seafloor is stiff or highly competent, this hole section will be drilled and the structural casing will be run and cemented in place. The next hole section will be the conductor hole and will contain the conductor pipe. If the high pressure wellhead is attached to this casing, it is commonly referred to as surface casing. This casing is set deep enough to prevent broaching in a well control event and cemented in place with cement returns typically to the seafloor. Both of these sections are typically drilled riser-less with water base mud or seawater with drilling fluid returns to the seafloor. However, for shallow water locations, a temporary casing string can be run from the seafloor to the rig and the fluid and cuttings can be routed to the surface once the first string is installed. After the casing and high pressure wellhead are set, the BOP stack and marine riser are connected to it and routed back to the rig above sea level. It should be noted that the casing string that is directly connected to the BOP stack is normally referred to as surface casing. At this point, the drilling process is conducted with a closed loop fluid system. For low temperature applications or regions where hydrates could form in a water base fluid system under pressure, the drilling fluid could be a low toxicity synthetic oil base mud, more commonly referred to as a non-aqueous fluid (NAF).

After all the casing strings have been run and cemented, the completion phase will commence for development and production wells. This may also be conducted if a well test of an exploration well is desired.

In the completion phase, the drilling fluid is displaced to a weighted brine (usually a salt solution), and the inner-most casing string or liner is perforated at the reservoir zone. Production tubing and a packer are typically run to isolate the hydrocarbons from the casing which provides a barrier. The production tubing can be run either before or after the perforation phase. An alternative to the cased and perforated completion, can be an open hole completion below the last casing string. Screens and/or gravel packs can be employed if the reservoir formation contains mobile sands (unconsolidated). A christmas tree is installed at the wellhead and above the production tubing to control the flow of hydrocarbons from the reservoir to the surface facilities. The christmas tree is located at the seafloor for subsea wells and above sea level on a surface structure/platform for surface wells. Almost all offshore wells have a surface-controlled subsurface safety valve (SCSSV) as an additional isolation device below the seafloor in case the christmas tree is damaged.

The production tubing and the production casing are both designed to withstand full reservoir pressure with a safety factor. The christmas tree is also designed to withstand full reservoir pressure with an appropriate safety factor, and the tree normally has at least two valves that can shut in the well in addition to the subsurface valve. Therefore, there are multiple barriers to contain hydrocarbons.

For offshore arctic wells, the basic well construction below the seafloor is similar to offshore wells in non-arctic locales. Special provisions may be needed for arctic specific hazards like permafrost, surface ice, and deep-keeled ice features, but these hazards are well understood and mitigations are well established as will be discussed later in this paper.

Surveying

To ensure wellbores do not collide (intersect each other) while drilling, the operator and directional survey company use well path planning software that includes modeling capabilities to determine the distance and direction of all offset wells to the well being drilled. In addition, the software calculates the ellipse of uncertainty (EOU, statistical error range of the survey tools' accuracy) and separation factor (ratio between the center-to-center distance divided by the sum of the EOU's) of the offset wells and the well being drilled, and relates their relative positions to each other to ensure the wells do not collide.

In order to know the positional location of a wellbore while it is being drilled, the operator will run surveying tools that measure the wellbore's inclination (angle from vertical) and azimuth (bearing direction) at given depth intervals. When drilling directional wells (>5° inclination), surveys are typically obtained at ~100 feet intervals to obtain an accurate survey.

The most common survey tools used today are the measurement-while-drilling (MWD) tool and the north-seeking gyro or rate gyro. MWD tools are high accuracy survey tools that are placed in non-magnetic drill collar components run in the drill string. They have accelerometer sensors for measuring the Earth's gravity field and magnetometer sensors for measuring the Earth's magnetic field. The accelerometers can determine the wellbore's inclination and the magnetometers can determine the wellbore's azimuth.

North-seeking-gyro devices (rate gyros) are higher accuracy survey tools (that also have accelerometers to determine the inclination of the wellbore) with high speed spinning mass "gyroscopes". The gyroscope's position remains fixed due to the inertia created by the spinning of the Earth. Its torque sensors measure the force applied to the gyroscopes as the wellbore changes direction and coverts this to an azimuth. Gyro's are conveyed in and out of the wellbore via wireline line, the drill string, coiled tubing, and/or dropped down the drill string and retrieved when the BHA is pulled out of the hole. They can be run inside the drill string or, most commonly, inside the casing just prior to drilling out. The north-seeking gyro can survey in continuous mode such that they can report out in a higher depth interval such as every 10 ft.

Since MWD tools use magnetometers, they are susceptible to two main sources of error: variations in the local magnetic field and interference from magnetized elements in the drill string. New techniques developed for identifying and compensating for these errors involve a better understanding of the natural variations in the earth's main field and new methods of mapping local variations to improve crustal field modeling. Magnetic north must be converted to true north by applying the declination angle.

Due to the proximity to the earth's North Pole, arctic wells require more accurate sensors and reference than sub-arctic wells for directional magnetic measurements due to the smaller horizontal component of the magnetic field and the greater dip of the earth's magnetic field at higher latitudes.

The declination values are a function of the well's location and time, as the Earth's magnetic field changes slightly but continuously. The directional survey companies obtain the correction values from published global magnetic models: British Global Magnetic Model (BGGM) or more accurate models like the High Definition Geomagnetic Model (HDGM). MWD survey accuracy can be enhanced by these methods, especially with respect to azimuth bearing, using techniques such as Interpolated In-Field Referencing (IIFR) or Geomagnetic Referencing (GRS) which corrects for the crustal field, localized magnetic effects, and the real time disturbance field. Furthermore, for the US Arctic, there are geomagnetic survey stations located in the towns of Barrow and Deadhorse, Alaska to help provide real-time data to convert magnetic MWD survey data to true north and this "has been successfully used for accurate wellbore positioning" [Ref.33].

The north-seeking gyro is not affected by the Earth's magnetic field; hence, they do not require magnetic corrections, however its accuracy diminishes at high latitude due to the earth's lower spinning rate at high latitudes. However, a true north reference can be resolved at latitudes less than 80 degrees north or south.

The improvements in surveying accuracy described above improve the survey accuracy for the well and would hence help reduce the time it takes to drill a relief well as the operator knows more accurately both where they are and where they are going.

Anti-collision issues are not a factor for exploration wells since they are distant from existing wells. For closely spaced production wells where the proposed well path is close to an existing well, operators take special precautions to avoid collisions (more frequent surveys) and typically shut-in subsurface valves or set plugs in the production tubing below the potential collision point. In the unlikely event there is a wellbore collision, this further reduces the possibility of a hydrocarbon release.

## V. DRILLING FLUIDS AND ITS IMPACT ON WELL CONTROL

The drilling fluid (often called mud) is the primary barrier to prevent the influx of subsurface fluids such as reservoir hydrocarbons or formation brines. The drilling fluid is designed to have a density greater than the pore pressure of the fluid in the subsurface strata (rock). If the drilling fluid exerts more pressure than the formation pore pressure, an influx will not occur and hydrocarbons will remain in the subsurface rock, except for a very small amount that is released by the rock formation that has been drilled. The drilling fluid will create additional downhole pressure on the rock when the pumps are circulating the fluid during the drilling process. This additional pressure caused by the fluid friction in the annulus between the borehole wall and the drill string is referred to as equivalent circulating density, or ECD. The depth of a hole section, and thus the setting point of the next casing string, is limited by the fact that the mud density plus ECD must be less than the weakest exposed formation (kick tolerance), typically the shoe (bottom) of the previous casing string. The formation fracture strength is determined after drilling out of the casing shoe and a few feet of new formation, and then pressure testing the rock until fluid begins to leak off (fluid enters the formation). This is referred to as the pressure integrity test (PIT) or formation integrity test (FIT) and is an important factor in well control. The drilling engineer uses pore pressure, mud density, ECD, and formation fracture strength to determine the setting depth of the casing strings. In US (United States) federal waters, regulations also exist that specify the depth the next string of casing must be set to maintain an appropriate margin between mud weight and rock fracture strength as measured by the PIT/FIT.

In colder climates and in deep water environments, the combination of low temperature and high pressure can create hydrates in a water base drilling fluid if gas becomes entrained. A hydrate is a solid crystalline structure of water and gas molecules that can block the flow of fluids. Therefore, non-aqueous fluid (NAF) is frequently used when the hydrate phase could occur in the drilling operation because the continuous phase is oil instead of water. Sometimes, glycol or methanol (or other chemicals) are added to the drilling or completion fluid to suppress the formation of hydrates as well and can be added to water-base drilling fluids to prevent freezing.

Probably the most important aspects of well control and in keeping a well secure during drilling, completion, and workover/ intervention operations are keeping the hole full of fluid and monitoring for kick (influx) detection. Kick detection is normally done using equipment located at the surface of the drilling rig. If formation fluid flows into the wellbore, a net increase in the closed volume drilling fluid system can be detected. A trained drilling crew will detect this and take the necessary action, which normally involves closing the BOP. The equipment used for kick detection will be discussed later in this paper.

## VI. CASING AND WELLHEAD DESIGN

The casing and wellhead are the pressure vessels that contain pressures from the downhole formations. The design and performance of these are covered by API specifications. For casing and tubing, the American Petroleum Institute (API) Specification 5CT, “Specification for Casing and Tubing”, and other API standards and references define dimensions, performance specifications, material properties, testing requirements, quality measures, and other aspects. It should be noted that for low temperature applications such as the Arctic, API Spec 5CT allows the purchaser to specify low temperature tests for the impact testing (Charpy V-notch) to ensure the casing and tubing will be suitable for the environment [Ref.16].

Wellhead equipment is manufactured to proprietary specifications but tested to API standards such as a pressure test to 1.5 times the rated working pressure of the equipment. API Spec 6A, "Specification for Wellheads and Christmas Tree Equipment" governs the manufacture and quality of these well components in the US and many other parts of the world [Ref.20]. To date, most wellhead equipment is manufactured to a range of 3000 to 15,000 psi which is suitable for arctic reservoir pressures.

Safety and design factors are an important part of the integrity of the well. The engineer will calculate all loads that the casing and tubing could experience such as tension, compression, bending, internal pressure, external pressure, temperature, torsion, and others. Then a safety factor is applied to the calculated load and this load is compared to the performance rating of the tubular (or working load of the equipment). The rated performance should exceed the expected load plus the safety factor. For example, a safety factor of 1.25 would be multiplied by the net burst pressure calculated for a casing string, and the engineer would select a tubular with a pressure rating equal to or greater than this operational load. The API rating for internal pressure of casing and tubing assumes minimal wall thickness and minimal yield strength which is conservative.

The quality of the casing and tubing strings is ensured by the pipe manufacturers, and verified by manufacturers' qualifications, agreed quality requirements, audits, and sometimes third party checks by the customer. API Specification 5CT requires nondestructive testing, material property testing, tensile strength measurement, yield strength measurement, ductility tests, Charpy impact toughness, and others as well as hydrostatic pressure testing of the pipe. Supplemental inspection requirements allow the purchaser to include additional inspections to flaw sizes as small as 5% of the nominal wall thickness. In addition, torque-position or torque-turn quality assembly methods can be specified for the threaded connections for casing and tubing. These quality assembly techniques help ensure that the pipe connections are tight and leak free at the assembled connection.

The nondestructive testing techniques can scan virtually 100% of the area of every joint of pipe manufactured to measure wall thickness and pipe geometry and to identify and reject any flaws that were created during the manufacturing process. Many customers (operators) use third party inspectors stationed in the steel mills to ensure the quality program is implemented and documented.

After the casing is run and cemented in the well, a pressure test is conducted to ensure integrity. The pressure and duration is specified by 30 CFR Part 250 [Ref. 4] for the US Federal waters.

## VII. CEMENTING

The cement is a critical part of the integrity of the well and is placed in the annulus between the casing and the bore hole. The API Spec 10A, "Specification for Cements and Materials for Well Cementing," governs the design, formulation, testing, and quality of oilfield cement [Ref.35]. The amount of cement that is pumped is based on a volumetric calculation of the bore hole (logs, calipers, or flow measurements) and the casing diameter. The casing string that is connected to the BOP stack (conductor casing for subsea wells and surface casing for surface wells) is normally cemented to the surface at the wellhead (seafloor for subsea wells). For the other casing strings, the height of cement in the annulus is based on the desired degree of isolation. For hydrocarbon intervals in US federal waters, the Bureau of Safety and Environmental Management (BSEE) requires the top of cement to be at least 500 feet (measured length) above the shallowest hydrocarbon zone.

There exist several techniques and types of equipment that can improve the quality of the cement seal. Wiper plugs and fluid spacers are used to keep the cement from being contaminated by other fluids during the pumping operation. Float shoes and float collars are basically one-way check valves that allow the cement to pass from inside the casing to the annulus and prevent backflow into the casing. Centralizers are mechanical devices attached to the outside of the casing to help ensure a more uniform layer of cement between the casing and the rock formations.

Prior to pumping cement, the cement company calculates the formulation of the cement slurry and tests it in a laboratory to the downhole conditions (temperatures and pressures). The lab report confirms the compressive strength of the cement versus time. In addition, during the pumping operation, samples are collected at the surface and put into an oven to simulate the downhole environment. Drilling normally does not commence until the samples have properly hardened and the times specified in the lab report are met.

After the cement has hardened, the isolation of the new hole from the upper zones can be verified by the PIT test described earlier.

Bond logs are electronic wireline tools used to measure the integrity of the cement seal between the casing and the bore hole (rock). This measurement can be done along the full length of the casing.

API Recommended Practice 65 Part II has several best practices identified to help ensure a good cement job (seal). The BSEE has now incorporated this recommended practice in the Code of the Federal Register (CFR).

## VIII. PERMAFROST CONSIDERATIONS

In many cases, arctic wells must be designed to penetrate through permafrost formations. Onshore on the Alaskan North Slope, there have been numerous wells successfully producing in permafrost regions for decades (while maintaining operational integrity), and the industry has clearly demonstrated appropriate design and construction methods for these wells.

Permafrost can be found below the seabed on the Arctic shelf down to where the water level was during the last ice age (in the Canadian Beaufort Sea this is roughly at 130 meters of current water depth). Methane hydrate can be found in and below permafrost on the Arctic shelf and as marine hydrate deposits like the deposits in the GOM, but arctic marine hydrates can be found at shallower water depths because the water and sub-seabed temperatures are lower. A large number of offshore wells have safely been drilled through both by controlling bottom-hole pressure and temperature during the drilling and completions process.

A casing string is normally run from surface through the permafrost and into competent rock below the permafrost. This casing string (usually the surface casing for surface wells and the conductor casing for subsea wells) is cemented from the shoe to the wellhead. Since permafrost thawing can create some subsidence in the permafrost zone, the casing material selected needs to have good ductility and strain capacity. API grades such as L-80 have proven to be successful.

Some effective drilling and completion practices used for onshore arctic wells that could also be applied to offshore arctic wells are:

a. Use of an insulated conductor set deep enough to resist subsidence

b. Using a mud cooler for drilling the permafrost hole section to reduce washout due to thawing

c. Specially formulated cement for low temperature; permafrost (low heat of hydration) cement has been used in the Canadian Beaufort Sea wells in which it was planned to intersect permafrost. Both the conductor and surface casings have been fully cemented with permafrost cement.

d. Thermo-siphons placed around the conductor to reduce/eliminate permafrost melting due to production

e. Vacuum insulated tubing to prevent heat transfer from the reservoir to the permafrost zone

f. Insulating packer fluid: an oil-based system that has lower conductivity and less convection, thus reducing heat transfer from the reservoir

g. Methanol injection for hydrate prevention on cold startup

h. Increased brine (completion fluid) true crystallization temperature (TCT) to account for the low temperature environment

i. Casing drilling to reduce the exposure time and minimize thawing of the open hole when drilling through deep permafrost has been successfully used in the Mackenzie Delta, Canada

## IX. BOP STACK – SURFACE AND SUBSEA

The surface and subsea BOP stacks are similar and should be considered as secondary barriers to the drilling fluid. Both use annular and ram preventers where the annular preventer can seal around nearly any geometry and the ram preventer is designed to seal around a specific pipe diameter. Variable bore rams can seal around a specified range of pipe diameters, for example 5 to 7 inch diameter pipe. Two other types of preventers are blind shear rams that can cut pipe and seal the bore and casing shear rams that typically cut larger diameter pipe (casing) or heavier wall thickness pipe. Both BOP types are attached to the wellhead, with the surface BOP located just under the rig floor and above sea level and the subsea BOP stack located near the seafloor.

A typical BOP stack would have at least one annular preventer and two or more ram preventers. A subsea BOP stack (Figures 6a and 6b) has a lower marine riser package (LMRP) attached by a hydraulic connector to the rest of the BOP stack (normally all of the ram preventers) that is connected to the wellhead. The LMRP connector allows the drilling rig to disconnect from the well, but still leave the main part of the BOP stack attached to the wellhead to keep the well secure.

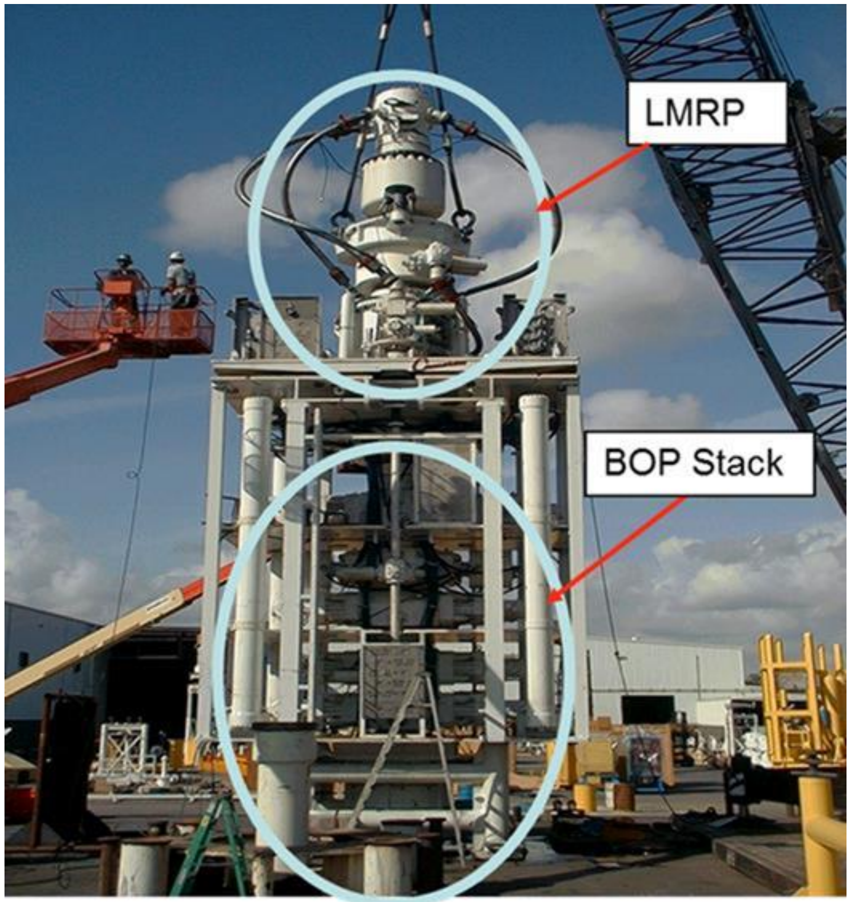



Figure 6a. Photo of a Typical Subsea BOP Stack

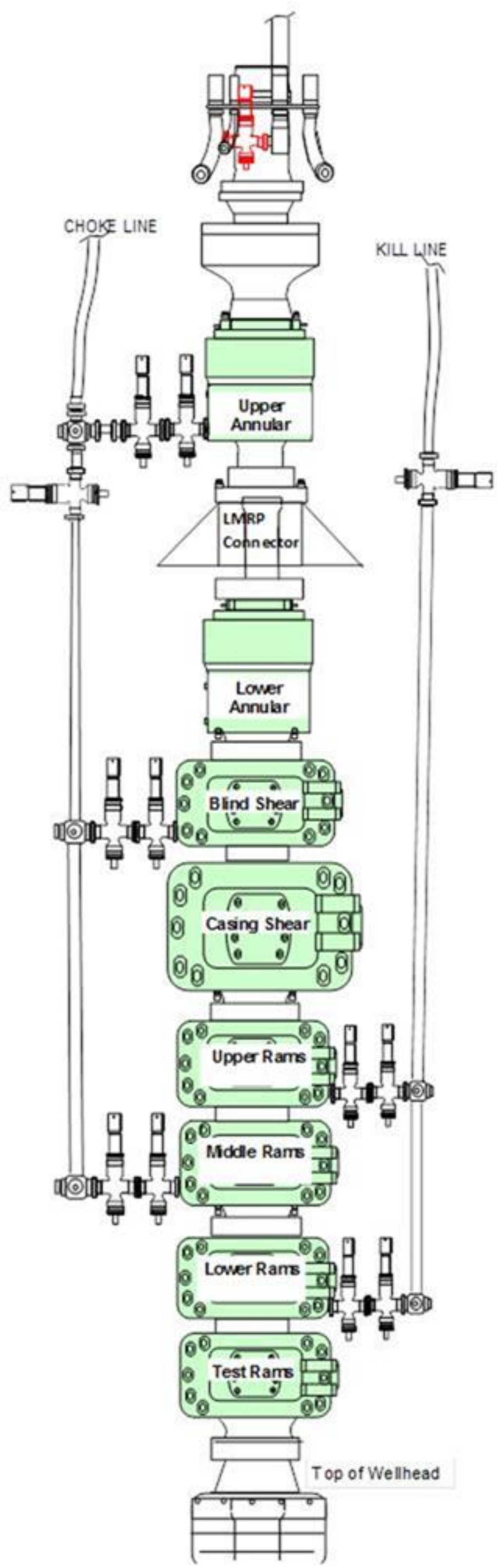



Figure 6b. Typical Subsea Blowout Preventer Stack (multiple redundancy)

The BOP stack operates on hydraulic pressure supplied by a bank of accumulator bottles located at the surface and also subsea (specific for subsea stacks). Regulations specify two independently powered pumping methods for charging the accumulators and these can be hydraulic, pneumatic, or electric. The volume and capacity of the accumulator bank and control system is tested to ensure that all critical BOP functions can be operated without recharging. The Industry has BOP equipment designed to working pressures as high as 15,000 psi. It is expected that this should be sufficient for the arctic reservoirs based on what is known today.

If a hydrocarbon influx or kick does occur, the drilling crew needs to respond promptly, and they are trained to do so. Since there are multiple preventers in the stack, redundancy exists. Once the BOP is closed, the size and energy of the influx is constrained. The normal practice if a kick occurs is to close one of the BOP components, and then circulate out the influx using one of two methods. The driller's method involves pumping the same density mud as currently in the well with back pressure from the surface choke, followed by a heavier weight mud (kill weight) pumped on a second circulation. The other method is called the wait-and-weight method where the kill weight mud density is calculated from the shut-in drill string measurement, and this higher density mud is circulated through the drill string on the first circulation. The hydrocarbon influx is circulated around the BOP stack via the choke line to the choke manifold. The bottom hole pressure is maintained above the formation pressure to prevent further hydrocarbon influx by manipulating the choke. The choke valve is connected to a mud gas separator, and gas is vented out a flare line safely away from the rig crew.

The rig supervisors, tool pushers, drillers and assistant drillers are trained on these well control techniques via computer simulators in well control schools similar to training methods used by other industries. The crews can also practice their well control and choke expertise at casing points with a technique called a power choke drill. This is done before any exposed formations are drilled in the subsequent hole section.

BOP stacks have redundancy to prevent the flow of hydrocarbons since there are several independently sealing components. For a typical surface BOP, there would be three or more preventers (5000 psi or greater service), and for a typical subsea BOP stack there would be five or more preventers depending on the expected working pressure as stated in API Standard 53 [Ref.19].

## X. REGULATIONS FOR DRILLING AND WELL CONSTRUCTION

Post Macondo (April 2010), the US Bureau of Safety and Environmental Enforcement (BSEE) was formed. Prior to this, the Minerals Management Service (MMS) had jurisdiction over US offshore drilling plans and operations. Numerous new safety rules were implemented into the Department of the Interior's Code of Federal Register, namely 30 CFR Part 250 which governs offshore drilling in federal waters. Some of the key new provisions that have been adopted to improve the safety and secureness of the drill wells include the following:

- Independent third party verification that the blind shear rams are capable of shearing any drill pipe body (excluding the bottom hole assembly, BHA) in the hole under maximum anticipated wellhead pressure.
- Independent third party verification that the subsea BOP is designed for the intended service and for the specific rig.
- Certification by a licensed professional engineer that there are two independently tested barriers across each flow path and that the casing design and cementing design are appropriate; also a negative pressure test is required to ensure proper installation of casing and cement for the intermediate and production casing strings. Where it is not practical to establish two independently verified barriers, a documented risk assessment should be conducted to demonstrate that process safety risks are managed to as low as reasonably practical.
- Remote Operated Vehicle (ROV) must be capable of closing one set of pipe rams, closing one set of blind shear rams, and unlatching the lower marine riser package.
- Autoshear and deadman systems must be available for dynamically positioned drilling rigs.
- Test all ROV intervention functions on the subsea BOP stack during the surface stump test and test at least one set of rams during the initial test at the seafloor with the ROV.
- Function test the autoshear and deadman systems during the surface stump test. Test the deadman system during the initial test on the seafloor.
- Certification by a licensed professional engineer of the well abandonment design and procedures and that there will be at least two independently tested barriers (preferably at least one mechanical) across each potential flow path.
- Well control training is required for selected rig personnel.
- The cementing program must comply with API RP 65 Part II, "Isolating Potential Flow Zones During Well Construction."
- The BOP stack must be designed and maintained in accordance with certain provisions of API Standard 53, "Blowout Prevention Equipment Systems for Drilling Wells."

The BSEE has numerous requirements for BOP tests. The BOP stack has to be fully pressure tested every 14 days for subsea BOPs and every 21 days for surface BOPs and a function test has to be conducted every week. Also, the BOP stack has to be pressure tested upon initial hook-up to the wellhead and after each casing string is set. The BOP stack must be tested to a low pressure (250 psi) and then the maximum anticipated wellhead pressure.

Another BSEE regulation added after Macondo was to make parts of API Standard 53 mandatory. Also, the API upgraded this document from a recommended practice to a standard. Some key provisions of this standard are as follows:

- All BOP stacks and components have to be certified by the original equipment manufacturer (OEM) every five years.
- Surface BOP stacks must have a blind or blind shear ram when ram preventers are required.
- Surface BOP stacks must have at least 3 BOPs for 5000 psi service, 4 BOPs for 10,000 psi service, 5 BOPs for 15,000 psi service.
- All sealing ram preventers must be equipped with locking devices.
- Surface BOPs must have two valves on the choke side outlet and one of the valves must be remotely controlled
- Surface BOPs must have a least two manual valves on the kill line side outlet.
- Surface and subsurface well control systems must have two remotely operated chokes on the choke manifold for 10,000 psi service or greater.
- For surface BOPs, the closing system must close ram preventers and annular preventers (less than 18.75 in bore) in 30 seconds or less.
- There must be two control stations, one located near the rig floor and the other distant from the rig floor.
- All subsea BOP stacks must have at least 5 preventers with a minimum of one annular, two pipe rams, and two shear rams of which one must be a sealing type.
- Control systems for subsea BOP stacks must comply with API Specification 16D.
- For subsea BOPs, the closing system must close ram preventers in 45 seconds or less, close annulars in 60 seconds or less, and unlatch the lower marine riser package (LMRP) in 45 seconds or less. Disconnecting the LMRP allows the rig to move away from the well site.
- Subsea BOP stacks must have two (fully redundant) control pods. There must also be at least two surface to subsea power fluid supply lines.
- An emergency disconnect sequence (EDS) is required for all dynamically positioned rigs, and is optional for a moored rig and must be operable from two separate locations on the rig. The EDS is a programmed sequence of events that operates the functions of the BOP stack to leave it in a desired state and then disconnects the LMRP from the lower part of the BOP stack.
- An autoshear system must be installed on all subsea BOP stacks. The autoshear system closes the blind shear ram if the LMRP is disconnected.
- A deadman system is required on all subsea BOP stacks. The deadman system automatically closes the blind shear ram if electrical and hydraulic power are lost subsea.
- Subsea BOP stacks must be equipped with remote operated vehicle (ROV) intervention panels that allows for the function of the blind shear ram, one pipe ram, the corresponding ram locks, and the LMRP connector.

- A trip tank is required for all wells and is a low volume (~50-100 barrels) calibrated vessel that can accurately monitor the amount of fluid going into or out of the well; this enables the drilling crew to rapidly respond to a formation influx (kick).

In addition to API Standard 53, API Specification 16A specifies requirements for performance, design, materials, testing and inspection, welding, marking, handling, storing and shipping of drill-through equipment used for drilling for oil and gas. It also defines service conditions in terms of pressure, temperature, and wellbore fluids for which the equipment will be designed. This specification is applicable to and establishes requirements for the following specific equipment:

a. ram blowout preventers

b. ram blocks, packers and top seals

c. annular blowout preventers

d. annular packing units

e. hydraulic connectors

f. drilling spools

g. adapters

Another important document for the integrity of well control equipment is API Specification 16D, "Specification for Control Systems for Drilling Well Control Equipment and Control Systems for Diverter Equipment." This specification establishes design standards for systems that are used to control blowout preventers (BOPs) and associated valves that control well pressure during drilling operations.

Another important regulation introduced by BSEE is the Notice to Lessees, 2010-NTL 10, dated November 8, 2010 to give lessees operating on the US Outer Continental Shelf (OCS) additional requirements that must be fulfilled before granting a Permit to Drill/Revised Permit to Drill/Permit to Modify (APD/RPD/APM). The title of NTL 10 is "Statement of Compliance with Applicable Regulations and Evaluation of Information Demonstrating Adequate Spill Response and Well Containment Resources." Although not explicitly stated in the NTL 10 notice, the BSEE requires the operator to demonstrate in the APD that the well design is adequate to contain an uncontrolled flow.

A Joint Industry Task Force (JITF) was established to develop evaluation tools to demonstrate to the BSEE that the well design and equipment [e.g., blowout preventer (BOP) and capping stack] is adequate for well containment. The BSEE elected to start with a Level 1 screening that uses a very conservative approach. The Level 1 Well Containment Screening Tool was developed for this first pass, and is designed to expedite approval for wells that can be fully shut in without causing underground flow, using very conservative assumptions and simple calculations (i.e., do not require computer simulations). However, not all wells can pass a Level 1 screening successfully due to application of the broad simplifying assumptions.

The Level 2 tool uses field/offset data and more advanced calculations to demonstrate equipment and well integrity for an unrestricted flow from the well and subsequent full shut-in. The Level 2 analysis also identifies failure points and possible loss zones that must be addressed in a consequence analysis.

The Level 3 tool is used to evaluate whether a well design allows "cap and flow," in which the flow from the well is choked back (but not shut in) to reduce the pressures on the well components or exposed formations.

Level 1 Well Containment Screening Tool:

This section provides instructions for completing the Level 1 Well Containment Screening Tool (WCST). The tool is a Microsoft Excel® spreadsheet that provides a simple check to determine whether a well can be contained via a capping stack in case of a worst-case discharge scenario. Wells that do not pass a Level 1 screening require a Level 2 engineering analysis to confirm that the wellbore is suitable for containment.

Level 2 Well Containment Screening Tool:

The Level 2 analysis builds on the Level 1 WCST. Much of the design methodology is the same for Level 1 and Level 2; for example, both use the same models to calculate external pressures.

If a well does not pass the Level 1 WCST, a Level 2 analysis could still demonstrate that the well design is adequate for containment. The Level 2 WCST is used to evaluate whether a well can survive an uncontrolled flow and subsequently be shut in.

A well may not pass the Level 1 screening because it did not meet some base criteria for using the screening tool. In particular, the Level 1 WCST does not allow the following:

- Presence of trapped annulus.
- Formation breakdown.

These design challenges must be addressed in a Level 2 analysis.

In addition, some of the standard assumptions for the Level 1 WCST may be too conservative. Using more advanced modeling and field/offset data may allow the well to pass the Level 2 analysis. In particular, the Level 1 WCST uses the following assumptions:

- Formation fluid gradient (0.1 to 0.15 for gas, and 0.23 psi/ft for oil/water/gas combination).

The operator may also elect to use strength ratings above the ratings allowed for Level 1 (i.e., survival ratings). Other options may include ratings based on triaxial, ductile rupture, or other methodologies.

The Level 2 WCST is based on the Level 1 WCST, with modified/additional calculations. The Level 2 tool provides the following additional calculations:

- Annulus pressure buildup for trapped annuli
- Secondary string collapse and burst verification
- Formation strength verification for failed strings

Level 3 Well Containment Screening Tool:

The Level 3 WCST analysis is similar to the Level 2 WCST, except that Level 3 is designed to assess a well design capability to permit cap and flow.

An operator may want to permit a well as a Level 3 cap and flow for several reasons, including the following:

- Shut-in pressures exceed burst capacities of the well design (mechanical integrity)
- Shut in results in an unacceptable underground flow (e.g., flow broaches to seafloor)

The cap-and-flow analysis can be used to evaluate whether the well design still survives choked flow loads, and whether unacceptable underground flow is prevented.

Note that for a cap-and-flow permit, the operator must provide an analysis of the subsea and surface capturing system to demonstrate that it is adequate for the required fluid rates. This analysis will be part of the well containment package submitted with the permit.

## XI. MARINE RISER, DIVERTER, AND OTHER WELL CONTROL EQUIPMENT

The marine riser connects the subsea BOP stack to the drilling rig (Figure 7). The marine riser provides a conduit for the drilling fluid to return from the well bore to the rig. It is not designed to contain the reservoir pressure. Choke and kill lines are routed along the side of the riser that are designed for the same pressure as the BOP stack and can contain the reservoir pressure. For well control, the drilling crew is trained to detect a kick and secure the well via the BOP stack before hydrocarbons can enter the riser. However, if some hydrocarbons do flow into the riser, there is a diverter located just below the rig floor that contains an elastomer element that can be hydraulically closed around the drill string. Then the hydrocarbons are routed overboard through the large diameter diverter lines (pipes), thus protecting the rig and crews.

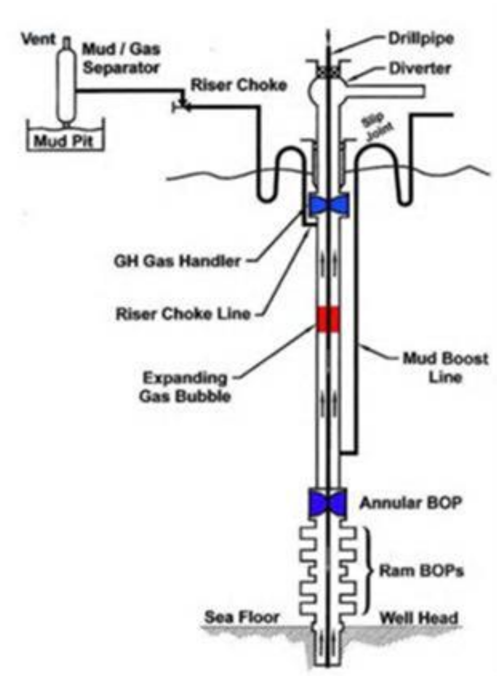



Figure 7.  Well Control Equipment for a Subsea Well (note gas handler is optional)

## XII. SURFACE AND SUBSURFACE KICK DETECTION

Surface kick detection has been in wide use by the industry for many years and is specified in the API standards and the regulations.

The pit volume totalizer (PVT) is a required sensor that measures the active volume of the drilling fluid system (pits).  If a kick occurs, the sensor notes an increase in the fluid level and at a prescribed level, an alarm is sounded and a visual indication (red light) occurs at the driller's console.

The flow rate sensor (Flo-Show) measures the rate of fluid in the flow line between the annulus of the well and the mud cleaning equipment (shale shakers, pits, etc).  If the sensor indicates an increased rate of flow from the well, then audible and visual alarms are activated indicating that a kick may have occurred.   The Flo-Show is also required on all drilling rigs.

Mud logging is conducted on all wells to monitor the types of formations being drilled via analysis of the cuttings and also uses a gas analysis meter to measure the amount and types of gases being released from the formations.  The mud logger can also alert the drilling crew to potential high pressure zones by analysis of the cuttings and gas units.

Logging while drilling (LWD) tools are used in nearly all offshore wells to instantaneously measure rock and fluid properties downhole while drilling proceeds. The subsurface information is relayed to surface computers, real time, via mud pulse telemetry. Gamma ray and resistivity sensors provide information on rock type and formation fluids. The LWD engineer located at the rig site can help determine if a higher pressure (abnormal pressure) zone is imminent. Another LWD sensor that assists with well control is the annular pressure while drilling tool. If a kick occurs, this subsurface sensor will note the density change in real time and the LWD engineer will alert the drill crew. In recent years, the LWD tools have included a formation evaluation tool that can measure the formation pressure and send this data to the surface. This gives a direct measurement of the pore pressure and the mud density can then be adjusted accordingly. These well control techniques are discussed in greater detail in SPE Paper # 154928, "Challenges Associated with Drilling a Deepwater, Subsalt Exploration Well in the Gulf of Mexico: Hadrian Prospect," June 2012 [Ref.36].

A relatively new technology that is available on some drilling rigs is a Coriolis flow meter(s). This device provides a more accurate measure of flow rate into and out of the well and could replace or augment the Flo-Show sensor. By monitoring the trends of flowrates while drilling, vessel motion can be tuned out of the system, and a more accurate measure of kick detection could be possible. This technology may be justified for exploration wells or wells with potential abnormal pressure zones that are not well understood.

## XIII. TRAINING AND COMPETENCE

Human factors are recognized by the industry as an important aspect of maintaining the integrity of the well. A variety of well control drills are required by the US regulations such as:

- Weekly pit drills to test the crews on their ability to detect a simulated influx of formation fluid (kick) while drilling. The crew must recognize the kick has occurred, space out the drill string in the proper location in the BOP stack, shut off the pumps, and secure the well using the BOP controls.
- Weekly trip drills to test the crews on their ability to detect a simulated kick while tripping the drill string into or out of the well. The crew must space out the drill string in the proper location in the BOP stack, secure the well using the BOP controls, and stab the rig floor safety valves into the top of the drill string.
- Various other drills are conducted with the rig crews such as fire drills, abandon rig drills, muster point drills, man overboard drills, etc.

Many operators' rig supervisors are required to take a certified well control course every two years and the key members of the rig crew are also required to be certified in this same training for US federal waters as well as some other countries.

Many operators conduct safety seminars and Drill Well on Paper (DWOP) exercises with the drilling crews and service company personnel prior to the start of a drilling program. This builds a thorough understanding of the program, potential hazards, and mitigation steps prior to the drilling process. It is not uncommon for the operator to conduct a thorough risk assessment of the drilling program before commencement and involve the drilling contractor and key service companies. And finally, a written and approved drilling program is required prior to commencing the drilling operations. Any significant changes to a signed drilling program should be approved at the same level of management that approved the original program.

One of the most important human factors at the rig site is the accepted practice that anyone has the right to stop the work if he/she feels that it is unsafe. This is broadly accepted in the drilling industry today. Also, many drilling rigs use an observational safety program that encourages workers to watch out for one another and intervene as needed. This promotes a culture of "Nobody Gets Hurt". Workers are encouraged to submit observation cards or $\text{STOP}_{\text{TM}}$ cards that show that the entire crew is engaged in safety.

Once drilling commences, there are several safety processes widely in use today. A job safety analysis (JSA) is a written description of the possible hazards and mitigation steps associated with a particular task. All workers involved in the task are required to participate in the JSA. Some companies refer to this as a job risk assessment (JRA). Tool box talks are also held at the work site, just prior to commencing the task. This is a final opportunity to assess risks and apply mitigations.

And the comfort and protection of the drilling crew from the environment are also important factors. Harsh weather rigs have wind walls and other barriers in place as well as heaters and steam pipes strategically located. Heavy duty overalls, thermal gloves, head and ear protection, and other forms of clothing are provided to the workers to protect them from the environment.

## XIV. SAFETY PROCESSES AND RISK MANAGEMENT

Post Macondo, the BSEE instituted a requirement for a Safety and Environmental Management System (SEMS) that was codified under API RP 75, "Recommended Practice for Development of a Safety and Environmental Management Program for Offshore Operations and Facilities." This document requires the operator and owner (rig contractor) to develop a management system designed to promote safety and environmental protection during the performance of offshore oil and gas operations. This recommended practice addresses the identification and management of safety hazards and environmental impacts in design, construction, start-up, operation, inspection, and maintenance, of new, existing, or modified drilling and production facilities. The objective of this recommended practice is to form the basis for a Safety and Environmental Management Program (SEMP). By developing a SEMP based on this document, owners and operators will formulate policy and objectives concerning significant safety hazards and environmental impacts over which they can control and can be expected to have an influence. Some operators refer to this as their operations integrity management system (OIMS) or operations management system.

The SEMP [Ref.27] is based on the following hierarchy of program development:

1. Safety and environment
2. Planning
3. Implementation and operation
4. Verification and corrective action
5. Management review
6. Continual improvement

It is recommended that each operator have a safety and environmental management system for their operations. The owner(s) should support the operator's SEMP.

The SEMP requires the following elements:

1. Safety and environmental plan
2. Hazards analysis
3. Management of change
4. Operating procedures
5. Safe work practices
6. Training
7. Assurance of quality and mechanical integrity of critical equipment
8. Pre-startup review
9. Emergency response and control
10. Investigation of incidents
11. Audit of safety and environmental management program elements

Most operators conduct thorough risk assessments of their drilling programs prior to commencement [Ref.32]. The risk assessment process includes the key participants in the drilling program such as the operator's engineers and operations personnel, rig owner personnel, service company personnel, and sometimes other experts. Hazards are identified and prevention techniques and mitigation measures/procedures are discussed and documented. The consequence and probability of each key hazard/event are analyzed, and the risks are managed through documented operational practices and procedures. An example of the process is shown in Figure 8.

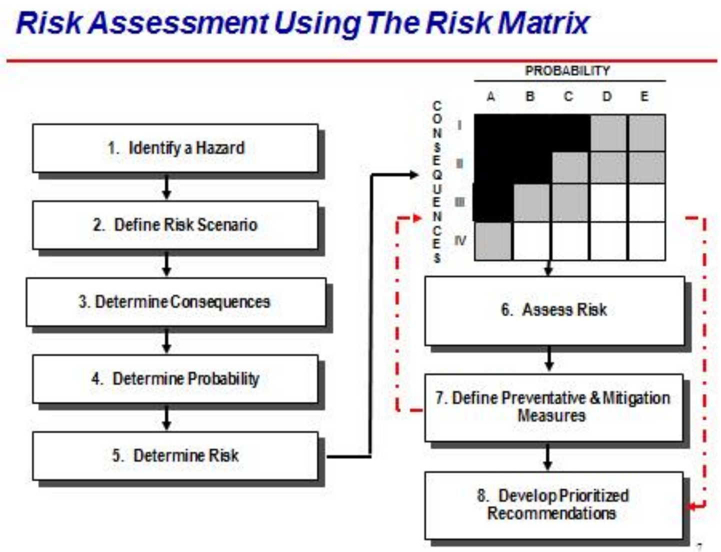



Figure 8. Risk Assessment and Management Process

The risk assessment process is then operationalized. Engineers, operations personnel, service companies, rig personnel, and others implement the findings and mitigations, close out items, and loop back lessons learned for future operations.

## XV. REMOTE MONITORING CENTERS

Many operators have set up remote monitoring centers onshore to help assist the rig supervisors and drilling crews on the drilling operations. A wide variety of rig mounted surface and downhole sensor data are relayed to the onshore center. The center can monitor drilling rate, mud density, flowrates, drillstring weight on bit, RPM, measurement-while-drilling (MWD), logging-while-drilling (LWD), and many other parameters.

It is important that on-site rig supervisors and rig crews manage the operations and make the critical real-time decisions such as the well control response. However, the monitoring center can be used by the onshore technical team in the support of the rig personnel and the rig operations.

## XVI. CAPPING STACKS

Subsea

Subsea well capping operations were widely publicized during the Macondo subsea blowout in 2010, however the well capping technique has been used by industry for surface well blowouts for many decades. The basic steps of capping a subsea well are:

(1) assess the well and well site conditions;

(2) mobilize the required dispersants, debris removal and capping equipment and personnel;

(3) clear any debris and prepare the BOP or high pressure wellhead for capping stack installation;

(4) deploy the capping stack (Figure 9) subsea and connect it to the flowing well;

(5) stop or divert the well flow by closing the capping stack sealing elements

Figure 9. Capping Stack, Shell Arctic Capping Stack

The well casings and equipment below the capping stack must have adequate pressure and structural integrity for the well capping to be successful for a full shut-in scenario. BSEE requires this scenario to be documented through the worst case discharge analysis which assumes a full hydrocarbon column from the reservoir to the wellhead. Current technology is capable of containing pressures as high as 15,000 psi (at the wellhead), which should be sufficient for arctic reservoirs.

Capping stacks are typically designed to be deployed via drill pipe or wire lines from a drilling rig or a support vessel (boat). Installation of capping stacks in deeper water depths have been proven. Some shallow water installation techniques have been developed that include strategically-positioned suction piles with wire rope connected to offset winches/vessels to help guide the capping stack into place and purpose-built equipment such as the Offset Installation

Equipment concept being studied by the Subsea Well Response Project (SWRP), refer to Figure 10. An animation of this can be found on the OSRL website: *http://subseawellresponse.com/2014/06/24/video-oie-how-it-works/*

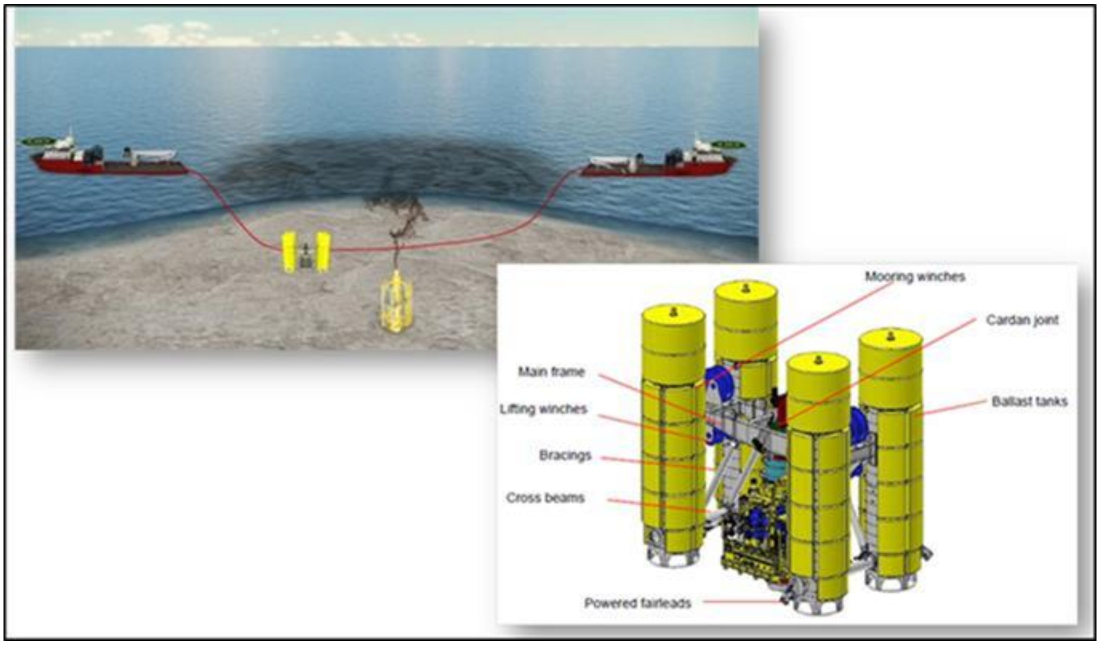



Figure 10. SWRP Offset Installation Equipment Concept

The capping stack is designed to be attached to the mandrel or hub of the high pressure wellhead or BOP via a wellhead connector. The heart of a capping stack (Figure 11) is the wellbore sealing elements which are typically either a single or dual blind rams that are controlled by a subsea accumulator package and operated by an ROV.

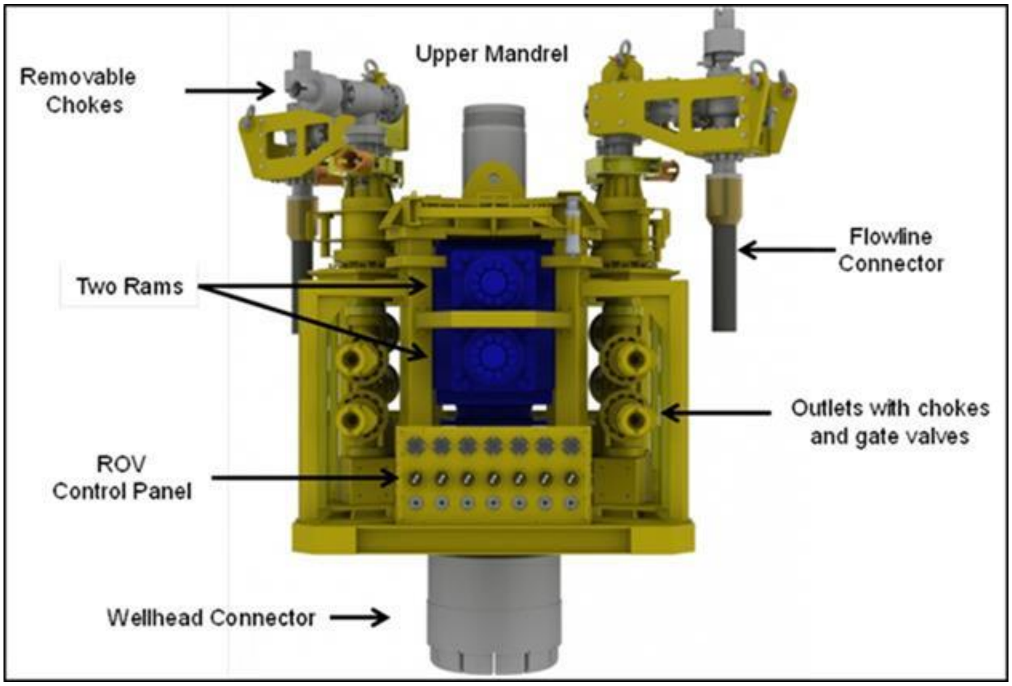



Figure 11. Example of a Dual Ram Capping Stack

Capping stack BOP rams and valves are operated hydraulically using an external fluid source via an ROV hot stab, and/or manually by an ROV torque tool. Capping stack designs also provide pressure and temperature sensors to monitor well conditions and the capability to inject hydrate inhibitors or other chemicals into the capping stack during, or after, well capping operations.

Since Macondo, capping stacks have become a standard part of the subsea drilling emergency response planning. Several cooperative industry consortiums, individual companies and operators have designed and built capping stacks to ensure that industry has a significantly enhanced capability to respond to a subsea well blowout. These entities include Marine Well Containment Company (MWCC, only for the Gulf of Mexico), Oil Spill Response Limited (OSRL), which is responsible for managing and maintaining the four Subsea Well Response Project (SWRP) capping stacks, Oil Spill Response and Prevention Advisory Group (OSPRAG), Helix Well Containment Group (HWCG), Wild Well Control (WWC), and some operators. There are approximately 20 capping stacks currently available in industry at this time. These capping stacks are strategically located proximal to many offshore operating areas such as Alaska, the Gulf of Mexico, Brazil, the United Kingdom, Norway, Angola, South Africa, and Singapore. Shell's Alaska Exploration Plan includes a pre-staged capping stack.

In addition to the capping stacks, industry has amassed a sizeable stock pile of dispersants available (OSRL has approximately 5,000 $m^3$) to allow for an effective response to a spill or well blowout. The industry has also enhanced the availability of associated support equipment that is required of a response, such as dispersant delivery systems, containment domes (i.e., "top hats"), riser insertion tubes, subsea accumulator modules, shipping containers, hydraulic flying leads, flexible flowlines, debris removal tools, etc.

To ensure that the industry not only has subsea well capping equipment available but can effectively respond to an incident, full scale deployment drills have been performed. These drills, performed in the Gulf of Mexico in approximately 5,000 feet and 7,000 feet water depths, showed that it was possible to mobilize and install a capping stack to a given well in approximately seven days. In addition to drills, the various groups have completed a significant number of table top exercises and training sessions to familiarize responders with the equipment, their roles and responsibilities, and the installation and operating procedures that will be utilized in a response.

Surface

The industry has also developed procedures and processes for capping wells with surface wellheads. Surface capping stacks normally include blind or blind shear rams, and these can be used to seal on an open wellbore and/or shear and seal drill pipe. The procedures and processes are similar to subsea capping stacks, but the installation process is much different and must be designed for the specific offshore facility.

Shallow Water

Although there are solutions for shallow water, most are based on very specific conditions, well flow rate, and limited ice. Shallow water with ice present poses unique challenges. The Offset Installation System being developed by Subsea Well Response Project and OSRL is designed for 70 meters or greater depth and relies on substantial vessel support. It may have limited application to the Arctic when there is significant ice present. An alternate to well capping in shallow water is discussed in Section XVIII.

## XVII. WELL KILL OPTIONS

If the drill string is intact and near the bottom of the well, the normal practice to kill the well is to circulate a drilling fluid with a greater density than the pore pressure of the formation. By a combination of a closed BOP stack and manipulation of the choke at the surface manifold, a constant bottom hole pressure greater than the formation pressure is maintained and the influx is circulated out of the well; this is a standard operation.

However, if the drill string is not in the well, an option is bull-heading kill weight fluid from the surface down the kill line below the closed blind shear ram (or blind ram). This is also the method to kill the well if the BOP stack is compromised and a capping stack is installed after a blowout. As long as the casing has sufficient integrity, this method is also acceptable and was used to kill the Macondo well in the Gulf of Mexico in 2010.

## XVIII. SUBSEA SHUT-IN DEVICES

Subsea shut-in devices, sometimes referred to as seabed isolation devices, mudline containment devices, or alternative well kill systems, are pre-installed on the high pressure wellhead housing below the rig's BOP stack. The advantage of this "drill-through" arrangement is that the pre-installed shut-in device dramatically reduces the response time to seal the wellbore. This quick response characteristic could be advantageous in remote locations and ensure the well is secure if the rig needs to leave, or is forced off, location without the proper time available to secure the wellbore by more traditional methods. An example of this situation in the arctic environment could be encroaching ice that causes a rig to leave location and prevents its return for some extended period of time. Thus, some operators have proposed a subsea shut-in device as an equivalent alternative to a single season relief well for a well blow-out in the arctic region.

The subsea shut-in devices (Figures 12 and 13) are generally similar to capping stacks with a few notable features and enhancements. Because they are installed between the high pressure wellhead and the BOP, and are "drilled-through" they have a rated working pressure and bore consistent with the rig BOP and the sealing elements are single or dual BOP blind shear rams capable of shearing drill pipe and certain well casings. Due to the additional weight and height, the shut-in device adds to the BOP "stack-up" on the wellhead, the well design must be capable of resisting the additional axial, bending and shear loads caused by the equipment weight, drilling riser loads, and rig offset.

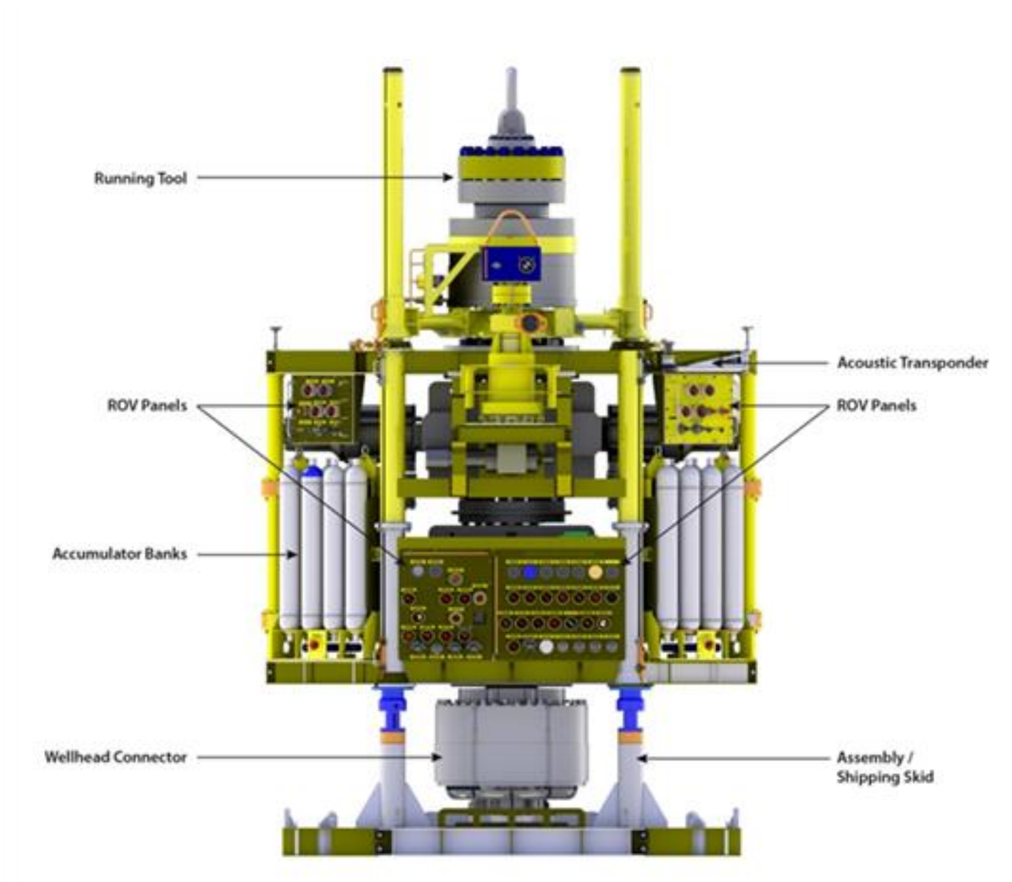



Figure 12. External View of a Subsea Shut-in Device

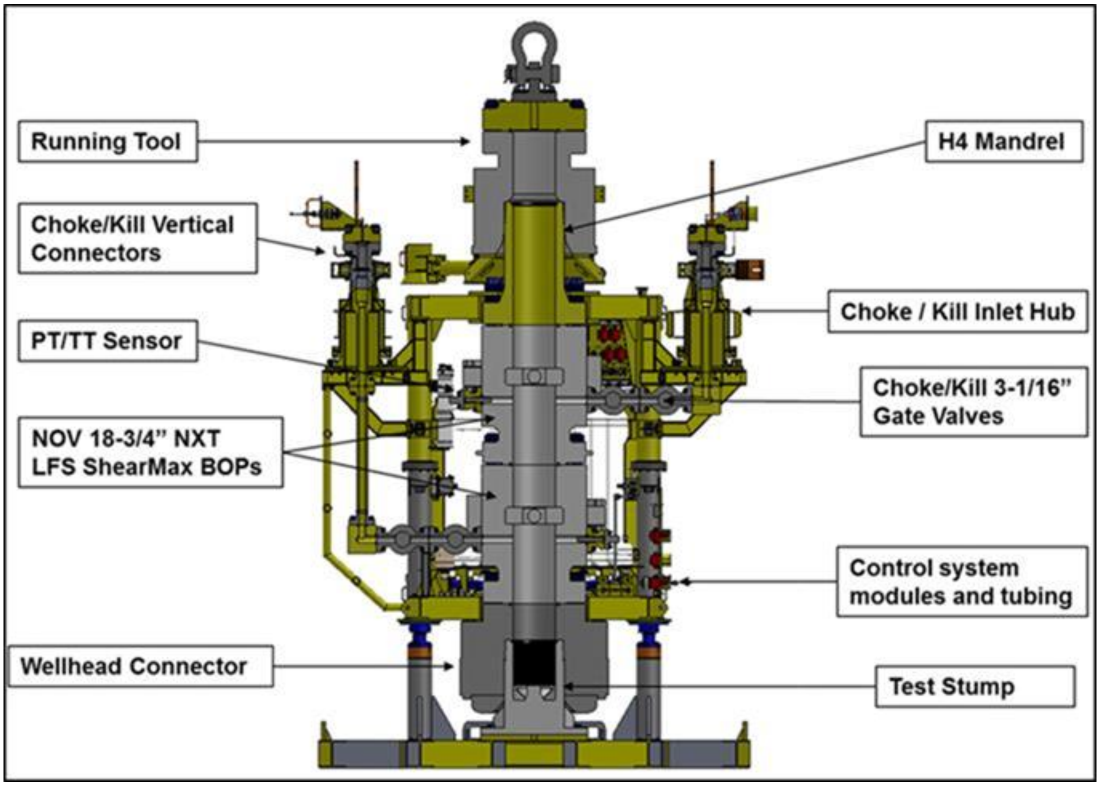



Figure 13. Internal View of a Subsea Shut-in Device

The subsea shut-in device has its own independent control system and hydraulic fluid supply and thus does not rely on, and is operated independently from, the rig's BOP control system. The shut-in device control system design includes enhanced levels of redundancy from the rig's control system as it is equipped with an independent acoustic control system and subsea accumulator bottles that allow select critical functions such as the closing of a ram and valves to isolate well flow with or without ROV intervention. Similar to capping stacks, the shut-in device functions can also be performed with fluid provided from an external source (i.e., subsea accumulator module) via an ROV hot stab, or manually by a ROV torque tool. The acoustic control system can also be programed to monitor and store pressure and temperature data for long shut-in periods (depending on sampling rate) for future download and review.

The subsea shut-in device has similar capabilities as a capping stack in regards to installation methods (although the largest shut-in devices are heavier and larger than capping stacks), well flow capabilities (including chokes), pressure and temperature sensors, hydrate and chemical injection, and the ability to install additional valves or pressure containing caps on the flow outlets.

The subsea shut-in device is capable of being configured for installation in an excavated drill center (i.e., "glory hole"), therefore it could also be utilized in arctic jack-up drilling operations with surface BOP stacks and a high pressure riser.

Examples of subsea shut-in devices are Cameron's single BOP Environmental Safe Guard system, Chevron's dual ram Alternative Well Kill System (AWKS) [Ref.34], and Trendsetter Engineering's Enhanced Subsea Shut-in Device (ESSD) which has been deployed in the Kara Sea in relatively shallow water (80m). These devices can be integrated into the existing BOP stack or positioned between the wellhead and the BOP stack.

There are other nomenclatures for this type of device. ConocoPhillips calls their system a Pre-positioned Capping Device or Auxiliary Safety Isolation Device. These names imply that the device can be used on any type of installation and avoids the assumption that the device would have to be subsea. The Industry also uses the term Shutoff Isolation Device (SID) which implies the device could be positioned above or below sea level. For a gravity based structure the device could be placed on a lower deck in an area that was protected from fire/explosions on the upper deck.

The decision to use a capping stack or pre-positioned device for shut-in is based on an analysis of the well and environmental conditions. If ice conditions, water depth, and/or anticipated well conditions or combinations of these would complicate well capping, then a prepositioned device may be the most efficient option.

## XIX. CONTAINMENT SYSTEMS (SWRP, MWCC, SHELL'S ARCTIC CONTAINMENT SYSTEM, OTHER)

Several industry groups have been developing well containment systems, including, Marine Well Containment Company (MWCC), Subsea Well Response Project (SWRP, in collaboration with Oil Spill Response Limited), Helix Well containment Group (HWCG), and Shell (Arctic Containment System). The MWCC and HWCG systems are for GOM response and the SWRP containment system is intended for international response in sub-arctic environments.

The current industry containment systems are sized to handle well flow rates as high as approximately 100,000 BOPD (barrels of oil per day) and 200 MCFD (million standard cubic feet per day) depending on the system and its design. A containment system is assembled on site using existing hardware and can be sized to accommodate the well flow rate by installing additional equipment. The limitation on the well containment flow rate is dependent on the system design and surface processing and storage capabilities. Figure 14 is an illustration of a well containment system that utilizes drillships as capture vessels.

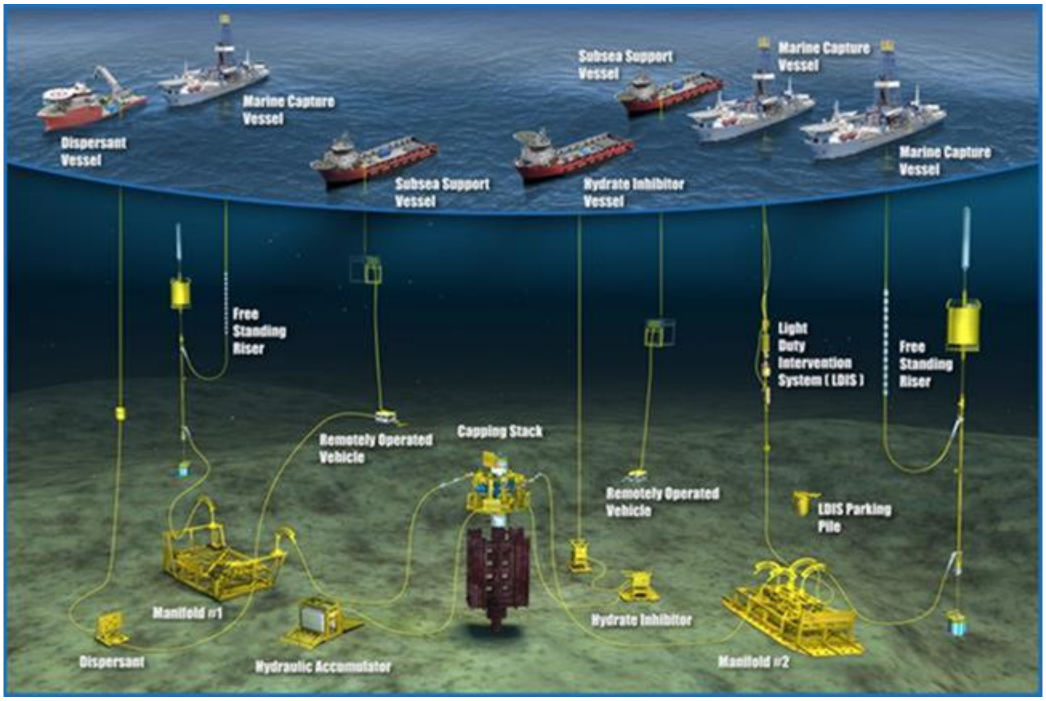



Figure 14. Illustration of a Well Containment System Utilizing Multiple Surface Processing Vessels

The typical containment system used in sub-arctic environments includes flowlines from the capping stack to subsea manifolds located on the seafloor and flowlines from the manifold to a riser system that brings the well flow to surface. Industry has multiple concepts for the riser system including the free standing riser systems shown in the figure to casing or drill pipe risers with crossovers to the manifold flowline. It is apparent that these types of containment systems that allow the well to continue to flow are not practical for arctic locations because of the presence of ice for much of the year. Therefore, for the operators, the focus needs to be on prevention and establishing multiple barriers to the flow of hydrocarbons as discussed previously.

BSEE has specified three levels of well designs as discussed in Section X. Both Levels 1 and 2 allow for shut-in at the wellhead with a full column of hydrocarbons from the reservoir (worst-case scenario) and it should be noted, that if the well is designed to a worst case scenario as defined by BSEE, then the well can be capped and shut-in without the need for the extensive containment system shown in Figure 14. Once the well is secured by the BOP or capping stack, there is no hydrocarbon flow and a relief well can be drilled at any time afterwards (even the next ice season) if deemed necessary. Only wells designed as Level 3 would require a cap and flow response system as shown in Figure 14. Therefore, at the present time, only Level 1 and 2 well designs are practical for arctic environments. It is not envisioned that this will be a significant limitation for arctic resource development because well designs and well control equipment are available to contain pressures as high as 15,000 psi at the wellhead.

## XX. COMPLETIONS

The completion of the well (Figure 15) can have many components, but the essential components are a method to allow the flow of reservoir fluids (perforations or open hole), a downhole packer, and production tubing.

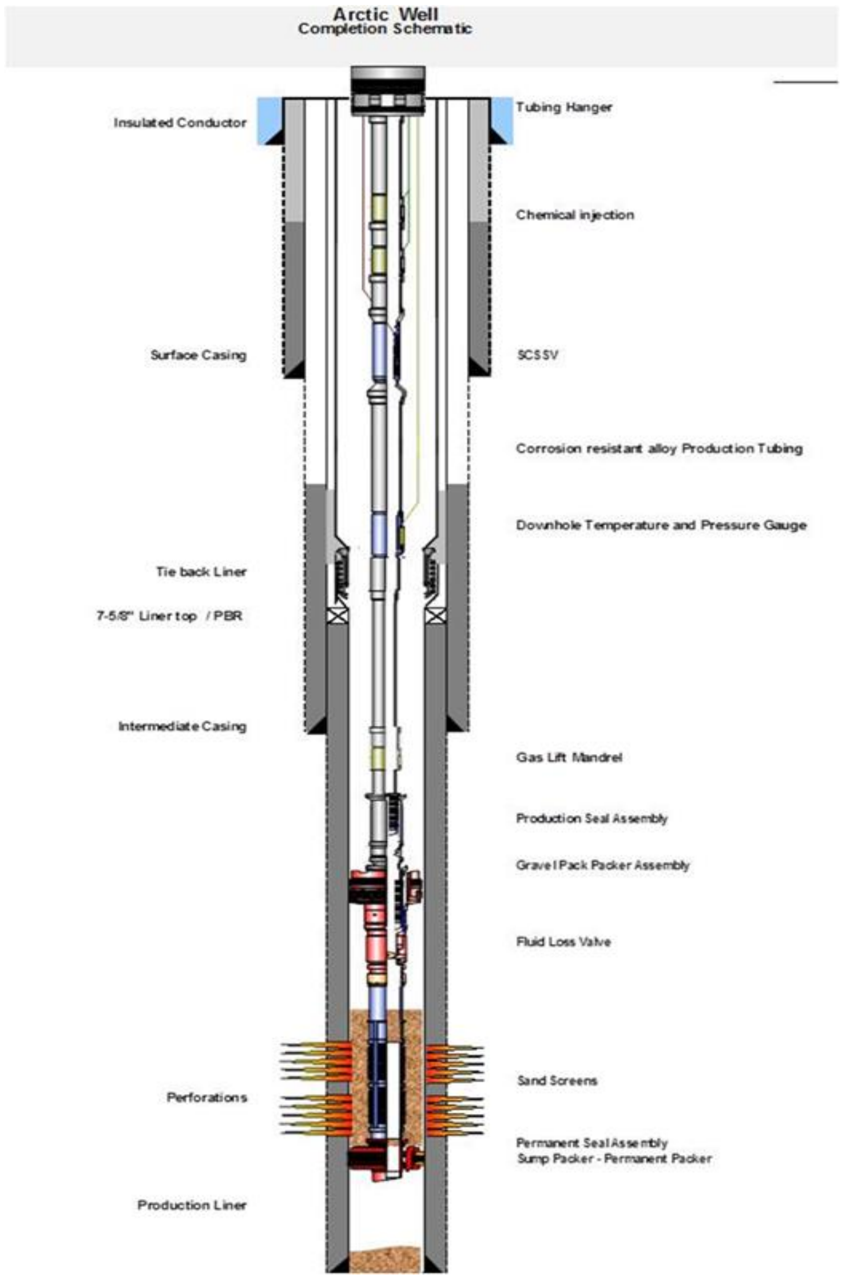



Figure 15. Example of an arctic well completion

Some safety and integrity features are also employed. All US offshore wells are required to have a subsurface safety valve below the sea floor that is held open with hydraulic pressure from the surface (SCSSV). If the christmas tree is damaged to the extent that the control line is ruptured, the SCSSV is designed to be fail-safe closed (mechanical spring shifts a closing mechanism). These SCSSV's are tested periodically while in service to ensure they can contain the reservoir fluids.

The christmas tree is positioned above the production tubing. It has multiple barriers to contain flow such as the upper and lower master valves, the crown/swab valve, and the wing valve.

Since the production tubing and christmas tree are exposed to the full stream of reservoir fluids, they are constructed of materials that are resistant to corrosion. Also, the annulus between the production tubing and production casing is monitored, and if a leak occurs, production is normally halted. The design of the threaded connections on the production tubing are typically qualified through an extensive testing program that represents downhole conditions. These connections are assembled in the field using quality control techniques such as Torque-Turn or Torque-Position which helps ensure a leak tight connection.

## XXI. ICE PROTECTION AND ICE MANAGEMENT

The ice management plan needs to include the operating limits for the drilling rig and the fleet of support vessels combined with a monitoring program to ensure that the vessels are not exposed to conditions outside their operating range. For arctic operations, there are normally more support vessels deployed than non-arctic regions due to remoteness and to assist with ice management. Anchor handling boats can be used to help deflect icebergs such as is done offshore Newfoundland. High speed crew boats can be used to survey a broader area and deploy environmental instruments. And icebreaker vessels can be used to clear a path for the rig and other support vessels.

Operators will normally collect metocean data and seasonal ice data for the region to be drilled over as long a period as the data exists. Exploration drilling with mobile offshore drilling units (MODUs) will typically be conducted during the ice-free season.

An ice monitoring system needs to be in place. This could include any or all of the following:

- Weather forecasts
- Visual data from all available ships in the operations spread
- Marine radar data including ice radar
- Sea water temperature (can be a good predictor of impending sea ice)
- Sonar data
- Satellite data
- Metocean data from observations, instruments, and from data buoys, in open water and ice
- Reconnaissance by air, fixed wing, helicopter, or UAV (underwater autonomous vehicles)

The operator will routinely calculate the T-time for the ongoing operations. The T-time is the amount of time to suspend the current operation, secure the well, and move the drilling rig out of harm's way. If a threat is detected, operations can be suspended if the time for the hazard to approach is converging on the T-time. Also, drilling into a hydrocarbon zone can be timed when ice hazards are well beyond the T-time. For arctic conditions, the drilling rig's mooring lines can contain quick disconnect links that are remotely operated which can greatly reduce the T-time.

The response for ice hazards approaching a drilling rig is very similar to those developed by the Industry for tropical regions in response to hurricanes, cyclones, or typhoons. If a hazard is detected via the monitoring program or the weather forecast, and it is determined that the drilling rig needs to leave the location, several well-practiced steps can commence. The open hole interval will be secured by cement plugs, and/or a mechanical retainer (e.g. bridge plug) will be set near the bottom of the last casing string (i.e. shoe). Next drill pipe is run near the bottom of the last casing string. The drill pipe is secured to the well by either a storm packer placed in the casing string below the seafloor or by hanging off at a tool joint in the middle pipe ram of the BOP stack. The upper part of the drill string is pulled out of the well and the blind shear rams are closed above the remaining drill string in the well. The LMRP connector is remotely disconnected from the lower part of the BOP stack (contains the ram preventers), the riser is pulled to the surface, and the drilling rig can sail away. It should be noted that the ram preventers contain mechanical locks that keep the well secure even if the hydraulic control pressure is lost.

## XXII. RELIEF WELL DRILLING

A relief well is a directional well drilled to communicate with a nearby uncontrolled (blowout) wellbore and control or stop the flow of reservoir fluids. If it is assumed that the original rig is disabled, a second rig would need to be mobilized and brought into proximity of the flowing well. The second rig will need to be equipped with casing, cement, drilling fluids, and wellhead equipment to construct the relief well. The distance between the blowout well and the relief well typically ranges between 500 feet and 3500 feet.

There are two types of relief wells – direct intercept and geometric. The direct intercept relief well is usually an 'S' shaped directional well which actually intercepts the blowout well bore and is the preferred technique. The direct intercept relief well requires a "target" in the blowout well. A "target" is ferrous casing or drill pipe in the blowout well bore in the intercept interval. The incidence angle between the relief well and the blowout well is preferred to be at a low angle (10 - 20 degrees) as the relief well approaches the blowout well bore. The blowout is usually intercepted immediately above the blowout zone. Highly specialized magnetic ranging is used to identify, track, and intercept the blowout. The well may be drawn down and the simple U-tube from the relief well into the blowout may be sufficient to kill the blowout. In other instances, modeling the fluid dynamics will further define the requirements.

As a contingency in case the well cannot be intercepted, the "geometric" relief well is one that is drilled when there is not a "target" in the blowout well. In this instance, the relief well is a directional well drilled into the blowout zone as close as possible to the best determination of the location of the blowout well bore. When a geometric relief well is drilled, the incidence angle in the blowout zone is generally higher – 30 plus degrees – in order to improve injection into the blowout zone. After the blowout zone is penetrated, the blowout zone is basically water flooded at pressures below fracture pressure until communication is established. Once communication is established, it is enhanced by alternately pumping water and/or acid until the communication is sufficient to permit a kill. Designing the kill requirements is much less precise for the geometric relief well operation since the kill fluid lost into the formation is not known. It is not uncommon for the blowout to have to be killed more than once.

There are two methods of determining the distance and direction from the relief well to the blowout well – active and passive magnetics. Passive magnetics simply utilizes the presence of a ferrous target (drill string, casing, etc). Active magnetics involves inducing an alternating current into the formation. The induced electricity passes radially into the formation. If a ferrous object is found, the current passes up and down the ferrous object creating a magnetic field. Sensitive magnetometers are then used to determine the magnitude and direction of the magnetic field from the relief well. Modeling and calculations are used to determine the direction and estimate the distance.

The Minerals Management Services published two papers [Ref. 29, 30] on statistical data for blowout wells in the outer continental shelf of the US. These studies covered the 35 years from 1971 to 2006. These reports state, "Although relief wells were initiated during several of the blowouts, all of the flowing wells were controlled by other means prior to completion of the relief wells". Also, "significant volumes of liquid hydrocarbons were not associated with any of the drilling blowouts". The reports state that "continued success will depend on sustained efforts by industry and government to improve safety management practices related to drilling and well control". The federal government and the offshore industry significantly adjusted the regulations and standards in the US after the Macondo incident in 2010.

In arctic environments, it may be more prudent from an environmental standpoint to focus on prevention and alternate methods than on a relief well plan. Prevention through prudent well design and operations should be the primary method for containment. Alternate methods such as capping stacks or subsea shut-off devices are a secondary method of spill mitigation and containment. A relief well under good weather conditions may take 30 to 90 days plus rig mobilization, whereas a capping stack could be installed significantly sooner, and a subsea shut-in device could be activated in minutes.

Some regions of the world (e.g. Canada) specify a same season relief well (SSRW) capability for arctic drilling. In the Arctic, a similar, and in some cases higher, level of protection to a SSRW may be achieved with appropriate well designs which are executed with the right equipment, best available technology, and utilizing proven drilling practices by personnel who are trained and competent. Both Chevron Canada and Imperial Oil Resources have requested an equivalent approach to the SSRW for the Canadian Beaufort Sea that includes incident prevention as well as securing the well and response plans.

## XXIII. PRUDENT DEVELOPMENT POLICY and REGULATORY CHALLENGES

There are several policy and regulatory challenges that inhibit prudent development of the offshore arctic.

Lease terms – Due to the limited open water season, only 2-3 months of a given year are available for exploration drilling with bottom-founded or floating drilling rigs. This effectively limits the number of available drilling months in a 10-year lease to 20-30 months versus nearly 120 months for the US Gulf of Mexico. Furthermore, exploration equipment must be typically contracted for 12 months to be ready for the short open water season creating economic challenges given the remoteness relative to other opportunities.

Offshore drilling season is not based on drilling system capability – The prescriptive provision for a same season relief well with drilling limited to the "open water" season currently defines the latest date that the hydrocarbon bearing zone can be entered, which further challenges the lease terms.

Regulatory flexibility – Prescriptive (current) versus performance based (i.e. risk based) regulations do not necessarily account for the strengthened standards following the Macondo incident (2010) nor the commitment made for capping solutions. Prescriptive regulations may drive non-cost effective technologies and requirements that do not necessarily reduce risk or offer a significant contribution to environmental protection and could be detrimental to prudent development.

Complexity of the regulatory regime – The Exploration Plan approval is required from a multitude of government agencies creating the potential for delay that puts pressure on lease terms and risks the future production start date. Streamlining government approval processes and/or increasing the transparency of the various government requirements for approval can reduce government and industry costs associated with approvals and reduce approval delays. Measures which reduce regulatory and permitting timelines and give greater regulatory predictability to operators can contribute to maintaining sustained investment in an operating environment which already faces the challenge of longer development timelines

## XXIV. RECOMMENDATIONS FOR FURTHER STUDY

Two areas that the industry has identified as impediments to prudent development of the offshore arctic are the requirements for a same season relief well (SSRW) and the need to have oil spill response capability equal to a worst case discharge scenario. A possible resolution to this would be a joint industry and US government study to develop a methodology to quantify the risks and benefits of the multiple barrier technologies, using appropriately detailed reliability data and assessments. The study should consider overall acceptability of risk levels, contribution of different risk mitigation practices, and other mitigations to risks that could be incorporated into arctic operations. Risk levels of different approaches to environmental protection, current technology, and practices/methods compared to a same season relief well can be part of the study. Practices in assessment techniques from the nuclear, aviation, and petrochemical industries such as accident sequence precursor (ASP) analysis could be applied [Ref. 31]. This paper states, "Precursor analysis targets outcomes that are encompassed by broad regulatory oversight" and envisions "an effective purpose-built tool directed at spill prevention would improve oversight capability".

Therefore, the industry and US government could initiate a study to develop methodology to quantify the risks and benefits of multiple current barrier technologies, using appropriately detailed reliability data and assessments. The results should consider overall acceptability of risk levels, contribution of different risk mitigation practices, and how current practices are justified on an as-low-as-reasonably-practicable basis compared to other industries. Practices in assessment techniques from the nuclear, aviation, and petrochemical industries such as accident sequence precursor analysis could be applied. With a focus on spill prevention and barriers, this study could be used as a basis to eliminate the need for a same season relief well.

This risk-based methodology could then be used on a well by well basis to determine the suitable barrier requirement to prevent loss of well control, and thus serve as a performance based requirement as opposed to the prescriptive requirements. If this methodology shows that environmental risks are less (or not significantly different) than a SSRW; then SSRW and other spill response requirements could be relaxed for appropriate wells. This would extend the drilling season and facilitate exploration and development.

Industry is leading efforts to enhance well capping and shut-off technology. Identification and development of technologies that can lead to material advancements (e.g. reliability, speed, and practicality) are potential areas for industry and government collaboration.

Offshore arctic drilling could benefit from more data or studies supported by the US government on metocean, climate, and seafloor bathymetry. This would enable operators to design systems, structures, rigs, and support vessels specifically for their intended locations. More research on ice management technologies could be used to extend the drilling season. Also, additional scientific/engineering studies for ice scour protection of permanent subsea wells would benefit the industry.

## XXV. SUMMARY

The primary method to prevent a hydrocarbon spill is prevention and prudent well design as discussed in this paper. After the Macondo incident in 2010, the operators, BSEE, and the API significantly upgraded the regulations and standards with respect to well integrity and well control. Operators must follow a strict set of controls that require extensive verification, testing, and certification of well control equipment, well designs, and barriers to the flow of hydrocarbons. In US federal waters, there is ample regulation to ensure operators and rig owners follow prudent practices. And BSEE regularly sends inspectors to the drilling rigs to verify compliance. Furthermore the API has numerous documents that specify the equipment and procedures for well integrity and for rigorous drilling practices. In the highly unlikely event that all of the normal barriers fail during a drilling operation, the Industry has developed subsea shut-in devices and capping stacks designed to be capable of securing the well from the flow of hydrocarbons.

Industry's primary approach to loss of well control is prevention – achieved through adherence to established codes/standards and operations integrity management systems combined with a culture of safety and risk management. Wells can be safely drilled when designed for the range of risks anticipated, equipment has the required redundancy, personnel are trained, drills/tests are conducted, and established procedures are followed.

Multiple spill prevention measures and barriers are currently designed into the wells, and these barriers are defined and specified in API/ISO standards and US offshore regulations. Drilling fluid, casing design, cement, and other well components are the primary barriers and the blowout preventers (multiple redundancies) are the secondary barrier to prevent a release to the external environment.

Industry is seeking an alternative to a same season relief well for the US Arctic:

- to stop the flow and secure the well in the fastest possible time thus minimizing the associated environmental impact and
- to safely extend the drilling season to support economic drilling operations.

The decision to use a capping stack or pre-positioned device for capping is based on an analysis of the well and environmental conditions. If ice conditions, water depth, and/or anticipated well conditions or combinations of these would complicate well capping, then a pre-positioned device may be the most efficient option. Industry continues to develop/deploy technology in this area such as the Shell Arctic Capping Stack, Chevron Alternative Well Kill System (AWKS), and the Kara Sea Enhanced Subsea Shut-in Device.

In June 2014, the Chief Executive Officer of ExxonMobil, Rex Tillerson spoke at the World Petroleum Congress in Moscow. Some of his comments are:

"The oil industry is capable of developing new resources in areas such as the Arctic in a safe, environmentally sound manner, but needs governments to provide regulatory stability..."

"Contrary to some claims, [the Arctic] is not unfamiliar territory for our industry".

The industry "has proven time and time again that we can develop [Arctic] reservoirs safely and responsibly, managing the region's unique challenges," pointing to past experience in Alaska and at the "sub-Arctic" Sakhalin-1 project offshore Russia, Tillerson said.

"By applying extensive scientific research and making operational accommodations, our industry has shown we can expand supplies of energy from the Arctic and sub-Arctic as well as protect wildlife and biodiversity".

"Government is uniquely suited to promote the rule of law, provide a clear regulatory pathway and hold companies accountable. Government is critical to establishing the level playing field that allows companies to compete and consumers to win."

In summary, the Industry's primary approach to loss of well control is prevention, which is achieved through adherence to operations integrity management systems combined with a culture of safety and risk management. Wells can be drilled safely and well control can be maintained when:

- Focus remains on safe operations and risk management,
- Wells are designed for the range of risk anticipated,
- Equipment has required redundancy and is properly inspected and maintained,
- Personnel are trained; tests and drills are conducted, and
- Established procedures are followed.

## XXVI. ABBREVIATIONS

ALARP – as low as reasonably practicable

API – American Petroleum Institute

ASP – accident sequence precursor

AWKS – alternative well kill system

BHA – bottom hole assembly

BOP – Blowout preventer(s)

BOPD – barrels of oil per day

CFR – Code of the Federal Register

DWOP – drill well on paper

ECD – equivalent circulating density

EDS – emergency disconnect sequence

ESSD – enhanced subsea shut-in device

EOU – ellipse of uncertainty

FIT – formation integrity test

ISCWSA – Industry Steering Committee for Wellbore Survey Accuracy

JSA – job safety analysis

LMRP – lower marine riser package

LWD – logging while drilling

MCFD – million cubic feet per day

MODU – marine offshore drilling unit

MWCC – Marine Well Containment Company

MWD – measurement while drilling

NAF – non-aqueous fluid

OIMS – operations integrity management system

OSRL – Oil Spill Response Ltd

PIT – pressure integrity test

PVT – pit volume totalizer

ROV – remote operated vehicle

RPM – revolutions per minute

SCSSV – surface controlled subsurface safety valve

SEMS – safety and environmental management system

SSRW – same season relief well

SWRP – Subsea Well Response Project

TCT – true crystallization temperature

US – UNITED STATES

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