REPORT

Provision of Blade Energy Study "Applied Advancements in Technologies That Continue Increasing Wells' Safety, Environmental Protection & Operations Across the Upstream Life Cycle"

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Purpose:

Provide an independent technical overview and analysis of Applied Technology Advancements that are Current and Emerging Across the Upstream Life Cycle that Continue the Increase in Safety, Environmental Protection and Operations of Wells.

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Table of Contents

Study: "Applied Advancements in Technologies Continue Increasing Wells' Safety, Environmental Protection & Operations Across the Upstream Life Cycle"

List of Figures

Study: "Applied Advancements in Technologies Continue Increasing Wells' Safety, Environmental Protection & Operations Across the Upstream Life Cycle"

I. Executive Summary

- The Upstream industry continues to develop & advance technologies – regardless of ups or downs in the industry cycles.

- Innovation and advancements in technologies simultaneously increase Safety & Environmental Soundness throughout the offshore well process – with commensurate efficiency & economic benefits to all Stakeholders.

- Upstream Stakeholders include the offshore lessee oil company operators & partner investors, U.S. Federal & State lessor royalty recipients, U.S. societal users of the gas & oil products and energy, and contractors and thousands of employees and communities in direct support, and indirect support of the Upstream industry.

- Advancements in technologies range from & through: intellectual property, software & large data analytics, well planning & design, heavy iron drilling rigs & tubulars, complex downhole completion equipment and tools, new methods & techniques, well intervention & workover, and wells plugging and abandonment.

- Numerous safety and training groups and entities work Upstream across Stakeholders to protect humans and natural resources.

- Applied Advanced Technologies across Upstream will apply safety and environmental soundness to any new U.S. offshore development areas, once allowed.

II. Introduction

The Upstream[1] segment of the United States and global gas, oil, and related wells industry continually improves safety, environmental protection, and operations practices for its own and society's benefit. Continual improvement is enabled through application of new technologies ("Applied Advanced Technology"), both equipment and methods, across the full life cycle of all wells. The 'life cycle of a well' starts during the pre-planning stage, goes through pre-drill

[1] Upstream herein is defined as gas, oil, geothermal, and potential other subsurface resource extractive phases, that include predictive planning & design, active drilling & completion, production, and plugging & abandonment. It is not defined here to include pipelines or facilities that transport or convert the production into products.

programming, drilling, completion, production, and ends when a well is plugged & abandoned with long-term integrity.

These advanced technologies provide higher assurance to all those directly or indirectly part of, or affected by Upstream activities, including resource licensees, operators, licensors & royalty owners, regulators, users of the resources, and the general public 'Stakeholders'.

This Report includes –

- Overview of Upstream offshore & deep water well development stages, including planning through production and training, with a discussion of each.

- Overview of the typical Upstream Applied Advanced Technology development processes, covering development steps: from basic ideas through operator use and industry acceptance, and why this Study will focus on the key technologies currently used or emerging.

- 'Applied Advanced Technologies' Upstream that now are currently being used, emerging, or may be expected to be applied in the future, that focus on continual improvements in safety, environmental protection, and operational efficiency, with rationale for those technologies' development and use per respective Upstream stage.

This study is not intended, and cannot be all-inclusive, since new technologies of every type and application are developed and brought out to or by the industry all the time on a continuous evolutionary basis. Furthermore, the application of any technology, standard or best practice must be based upon good engineering practices and must be fit-for-purpose for the specific operation.

This Report intends to overview, then cover key technologies commonly used or emerging which are most likely to have a strong impact and broad use across Upstream wells. The Applied Advanced Technologies covered in this Study are grouped within the general stage ranges in which they are used Upstream.

A. Overview Covering Where Oil & Gas Comes From -

Where does the oil and gas that we use today come from offshore? Millions of years ago microscopic organisms and algae died and settled to the bottom of the water column wherein they were suspended and trapped in shale (clay). Shale is rock that has little to no porosity or permeability, so these trapped organisms remained there, and with other rock layers on top of them, the rock layers sunk deeper to hotter depths in the earth 'source rock'. Some of the rock layers on top of the shale were porous[2], and the pores in that rock were filled with saltwater. As

[2] A substance that is 'porous' has 'porosity', which means imbedded within its structure are quite small holes or cracks. Different rock types have different levels of porosity – whether quite hard and seemingly impervious, or quite soft and granular. Oil and gas are comprised of hydrocarbon molecules, and when

the source rock got hotter, the algae and organisms converted into hydrocarbons[3]. As pressure increased on the source rock, the hydrocarbons were pushed into the pores of the nearby porous rock. The hydrocarbons then pushed out and displaced the saltwater in the porous rock, making it a hydrocarbon filled formation, hydrocarbon 'reservoir'.
Offshore the hydrocarbon reservoirs are thousands of feet below the seafloor, being compressed by the ocean and rock above it, and heated because the natural 'geothermal' gradient makes rocks hotter the deeper they are in the earth. These compressive forces and increasing temperatures play combined and integral roles in developing the high pressures observed in oil & gas reservoirs.

The original oil and gas fields were found arising from natural leakage of petroleum from subsurface reservoir rocks to the earth's surface. Native populations found that the petroleum from some seeps could be used as products – for waterproofing canoes, fuel, or paint. The Upstream industry today applies highly advanced technologies to explore for subsurface reservoirs – yet even today, new natural seeps onshore and offshore are found globally.

B. U.S.A. Offshore and Deepwater –

The 'offshore' waters of the United States are comprised of those waters off the coasts of the Atlantic Ocean, Gulf of Mexico, Pacific Ocean, and Arctic Ocean. (See Appendix D.) The offshore waters near shore are under the jurisdiction of the respective States they adjoin, with each State's waters going out 3 nautical miles from the coast line, with the exceptions being Texas and the west coast of Florida. Beyond each State's coastal waters, the U.S. Federal Government has jurisdiction over all offshore waters out until either a boundary with another country (i.e. U.S.-Mexico boundary in the Gulf of Mexico), or up to the U.S. Economic Zone. All U.S. Federal gas, oil and mineral activities offshore are governed by the U.S. Outer Shelf Lands Act 'OCSLA'[4]. The U.S. Department of Interior 'DOI' is the primary Executive department that administers and regulates activities in Federal waters. 'Deepwater' is defined by DOI as those Federal waters with water depth of 125 meters (410 ft.) or greater. Ultra-deepwater is defined as depths greater than 1,500 meters (4,922 ft.), or approximately one mile deep.

Qualified private companies 'operators' may bid on, be awarded, and operate certain delineated Leases in Federal waters to explore and produce gas and oil from rock formations far below the seafloor. These private companies typically do so in an agreed partnership manner, whereby the 'lead' partner company (often the partner with the largest percentage share) is the registered 'Operator' of the Lease, and the other company partners are 'non-operating' investors.

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discussing 'source rock' and formation 'reservoir' here, we mean that the porous rock has its porosity substantially filled with hydrocarbons.

[3] 'Hydrocarbons' are complex organic fluid molecules consisting of carbon and hydrogen atoms that chemically combine in numerous ways with various molecular weights. Physically, hydrocarbon mixtures are a continuum from heavy & viscous (i.e. asphalt and tar, through liquids (i.e. crude oil and fuel oil), to very light and gaseous (gasoline to natural gas). Petroleum is a broad term encompassing any mixture of hydrocarbons.
[4] 43USC29, Subchapter III, *et.seq*

Each company of the partnership on a Lease provides its percentage of costs and expenses, and each company shares its proportional share of risks and potential rewards. Investment risks may be high, yet so are potential rewards, if sufficient oil and gas is discovered in commercial production quantities, and the costs to produce and sell the oil and gas production are low enough to provide each partners' own requirement for expected minimum investment returns. The life of the wells, fields, and facilities are planned over 20+ years life, yet often last 30 years or more.

It is the Operator that decides, evaluates, explores, drills, completes, builds and installs flowlines and facilities, and produces the crude oil and natural gas for sale on behalf of all partnership companies. The Operator also retains the obligations of safe, environmentally sound, effective and efficient operations, and duty to plug and abandon the well and decommission the facilities years into the future. Assuming commercial wells are found, and the fields in the Lease are developed, the production from these Leases will flow up production risers to production facilities above the water surface, and then after some processing, be sold and pumped down pipelines along the sea bed back to facilities on shore. Some Applied Advanced Technology wells are 'subsea' wells with 'subsea systems'[5].

Today U.S. legislation and DOI regulations limit gas and oil operations to certain Federal Leases primarily in the central and western Gulf of Mexico.[6] The focus of this Study is U.S. Federal waters generally, and deep water in particular, located primarily in the central and western Gulf of Mexico - offshore Alabama, Mississippi, Louisiana and Texas – where continuous Upstream gas & oil operations have occurred since the 1960s. As discussed in the Introduction, this Report describes how the development and application of Advanced Technologies have, do, and will enable safer and more environmentally sound Upstream activities across current Federal operating Leases, and will further do so across any newly awarded Federal Leases.

- The reader of this Report should note that offshore operations are necessary to supply needed energy, and to supply raw material feedstock for a wide variety of end-use products derived from natural gas & crude oil hydrocarbons.[7]

- The reader of this Report will also get a glimpse of the complexity and high levels of science and technology routinely applied in offshore and deepwater, and that even through historical cyclic drastic swings in gas & oil prices, the industry continues its own

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[5] Please refer to Section "*VII. Production – Subsea Systems"* below for a description and discussion of subsea wells and subsea systems.

[6] Though today a few legacy Federal Leases operate offshore Alaska and California, no new Leases or drilling have been allowed off the coast of California for over 48 years, and quite limited new leasing, drilling or production has been allowed off the coast of Alaska. The eastern Gulf of Mexico was made unavailable for leasing through June 30, 2022 pursuant to the Gulf of Mexico Energy Security Act of 2006.

[7] For an interesting, yet incomplete list of example end-use products derived from natural gas & crude oil hydrocarbon feedstocks, please refer Appendix B herein.

investment in safety, environmental protections, and operating efficiencies. This Report highlights only a few Applied Advanced Technologies across the life-cycle of Upstream wells.

- *The Applied Advanced Technologies included herein can only be a snapshot, in that the time and space limitations of this Report preclude all the wide varieties of technologies and advancements in place, continually and newly applied, and always being researched, developed and tested prior to widespread use.*[8]

- The reader of this Report will also see the huge costs of investment, time, and planning it takes prior to drilling a well, and the 20-30+ years in the life of a well, and the cost that wells typically require modifications during their life. Considering all that is involved, spanning the mundane to cutting edge - people, support, planning, equipment, investment, science, information, security, manufacturing, transport, housing, finance, and generic use to bespoke one-of-a-kind need – technology options are always being reviewed, including how each technology affects all other aspects of operations.

- Looking at all the above bullets and more, the reader of this Report should also recognize that each offshore oil company Operator will make its independent decision when it is appropriate to apply an Advanced Technology, where and how. Analogous to any person making appropriate decisions, the Operator will wait until the need to apply a technology makes good engineering sense prior to the application – and it may take years before that need and the opportunity to apply a technology come together – and during that time, new technologies may eliminate or mitigate the original need, and/or simplify and replace older technologies with improved methods. The Operator must and does make these choices daily and continually - as the Operator garners all information available to it, analyzes the information, applies situational awareness, and makes responsible decisions for the personnel, wells, fields, and leases for which it has paid and is entrusted with safe and environmentally sound operation.

III. Applied Advanced Technologies

This section discusses certain Applied Advanced Technologies from different reference points, roughly following the continuum in the life of a well. It must be noted that each well will be planned and technology chosen for use based upon the best information available to the

[8] Please note that the specific "Applied Advanced Technologies" highlighted in this Report were picked by the authors only as examples of the panoply used today and upcoming in the future from published literature or provided reports. None were encouraged by the companies that develop and/or provide them, and none are endorsed by the authors or Blade or API. *The authors realize that there are and will be so many more technologies and innovations –evolutionary and revolutionary- which in good faith go from simple ideas to complex applications. And the authors apologize in advance to all the people and organizations involved with them that this Report's time and space cannot cover.*

Operator. The Operator may get its information by developing it within the Operator's range of expertise and/or by contracting it from others.

No technology is stand-alone, unique or complete - in that each must fit within the existing well, field, and operations architecture and methods. Therefore, prior to each technology being applied, it must be programmed or adapted for proper use in any separate scenario. Depending upon the situation, a single purpose or outcome may be achieved by using the technology, or multiple broader benefits of using the technology may be obtained.

The Upstream industry collaborated a few years ago to provide all offshore Operators a standardized process to achieve their goals and duties. The Safety and Environmental Management Systems 'SEMS', was developed to reduce the frequency and severity of accidents, thus increasing operational safety and environmental soundness. The SEMS rule, aka "The Workplace Safety Rule", became effective in November 2010. This rule is published in the U.S. Federal Register, 30 CFR part 250[9], and made a previously voluntary practice of the American Petroleum Institute 'API' Recommended Practice for the Development of a Safety and Environmental Management Program for Offshore Operations and Facilities (API RP 75) mandatory. API RP 75 consists of 13 sections, and establishes responsibilities for management, as well as the principles for SEMS.

The SEMS II rule became effective in June 2013, and it expanded upon the original SEMS rule. SEMS II adds additional requirements, such as employee training, stop work authority with field level personnel, and reporting of unsafe working conditions.[10]

The Center for Offshore Safety (COS) was created by the oil and gas industry in 2010 with a focus on achieving excellence in safety during operations on the OCS. The COS was designed "to promote the highest level of safety for offshore drilling, completions, and operations through leadership and effective management systems addressing communication, teamwork, and independent third-party auditing and certification." The COS continuously strives to improve the environmental and safety performance of the industry, as well as enlighten the public of its performance. The COS also accredits 3rd party auditors for the SEMS program, and developed good practice documents for the industry as a toolkit for SEMS audit.[11, 12]

Federal offshore Lease Operators were required to perform a comprehensive SEMS audit within two years of the initial implementation of the SEMS program, and are required to do so within a 3-year cycle afterwards (CFR 250.1920). COS offers an audit protocol checklist to assist in assessing one's readiness to meet the requirements of the SEMS program. Audits must be conducted by independent 3rd party auditors. Audit reports are to be submitted within 60 days after completion of the audit.

[9] 30 CFR part 250 - https://www.gpo.gov/fdsys/pkg/FR-2013-04-05/pdf/2013-07738.pdf

[10] B.S.E.E. - Safety and Environmental Management Systems (SEMS) Fact Sheet

[11] COS - Establishing a Culture of Safety http://www.centerforoffshoresafety.org/

[12] Offshore - SEMS, safety audits loom large after recent government mandates https://www.offshore-mag.com/articles/print/volume-75/issue-8/departments/regulatory-perspectives/sems-safety-audits-loom-large-after-recent-government-mandates.html

Safety and environmental soundness pushed into promulgation and publication by the Upstream industry compiling API Recommended Practice 96 – Deepwater Well Design and Construction (API RP 96) in March 2013. One key section of API RP 96 is section 5.3: Barrier Philosophy. API defines a 'barriers' as a "component or practice that contributes to the total system reliability by preventing formation fluid or gas flow"; and defines a 'barrier system' as "a combination of barriers acting together to prevent unintended fluid and/or gas flow". It also notes "The barrier system includes both physical and operational barriers."[13]

The number of barriers used may vary depending on the specific operation being performed, but it is generally accepted that the use of 2 physical barriers provides sufficient reliability. API RP 96 recognizes two types of barriers: physical and operational. Physical barriers include mechanical or hydrostatic barriers and are to be verified to ensure the barrier can perform as expected under the designed operating loads and conditions. Verification can be performed with pressure test or other physical test, or with inferences from observations. Pressure testing in the direction of flow is the most dependable way to verify physical barriers. Operational barriers rely on human recognition and response and include institutional controls- ex: policy manuals and casing design standards.

During the design and construction of a well, potential flow paths should be identified and a barrier plan created identifying the barriers that will prevent the flow of each potential path. In the course of drilling a well, the barriers constantly change according to the various drilling stages. For example, in one drilling stage you may be drilling through exposed formations, and the hydrostatic pressure exerted by drilling fluids is one barrier and the BOP stack the other barrier. After previously exposed formations are lined with casing and the casing string is cemented, the casing string becomes one of the barriers. After a well is completed and put on production, the two barriers in place will be the production tubing[14] string and casing string.

IV. Planning and Designing the Well

A. Overview Considerations in Planning and Designing the Well -

Depending upon the reason for drilling and type of well, project and well planning starts months to years ahead of actual well design and operations. Exploratory wells require years of geologic and geophysical study of rock basins formed over geologic time, and interpretation of seismic imaging coupled with data compiled across wells drilled in analogous basins, and in nearby fields. Oil companies invest large amounts of time and money gathering, interpreting and analyzing massive amounts of data to choose whether there is sufficient probability that hydrocarbon deposits exist which will be 'target zones' to reach with a wellbore. Then in conjunction with a company team of specialists in geology, mapping, reservoir, drilling, completions, logistics, and others, an asset team plans the drilling surface location, subsea sea

[13] API RP 96, sections 3.1.8 and 3.1.9.
[14] Please see Section *"VI. Completions"*, page 42 below, for a description of 'tubing'.

floor location, and subsurface wellbore targets of a well that may be drilled. Wells that are not exploratory, and either appraise further target zone(s), or will be one of multiple wells for production, may require less planning time, since more information is known that is closer in time and space to the previous well drilled in a field, with commensurate lessons learned.

Following the above well planning, then well path and well design issues will be considered (as briefly described below), and operational costs will be estimated. All the above will be done within jurisdictional lease, regulatory and permit requirements. Then an economic decision will be made whether to drill.

B. Well Path Software -

The well path from surface to and through all rock formations and target zones to the lowest target zone must be ascertained and decided in the well planning stage. This well path may range from going straight down, to extending out directionally or horizontally long distances, through various rock formations, and intersecting or going around other zones to get out the full distance to the target zone furthest away. A well's path consists of all the directions that drilling must follow, from the surface drilling rig start at the wellhead. In the shallow section of the well, the well path must travel far enough down from the wellhead, so the well path does not run into other wells close by at surface, then down through all rock formations to the target zone(s) that the operator oil company wants to reach and potentially from which it wants to produce.

A well path may be simple, in that it is a vertical straight hole down to the lowermost target. Most often, especially offshore, wells are drilled directionally down from surface, with curvy and sometimes with quite tortuous directional paths. 'Tortuosity' refers to how crooked the curvature of the well path is, and wells with high tortuosity may have tight curves – limiting the ability to drill, or making it impossible to drill further or run completions tools in the well.

The reasons for directional drilling are many, including: drilling away from other wells that may be directly side-by-side at and under the surface facility or subsea template; drilling around or through subsurface potential trouble formations of different lithologies, pressures, and fluids; needing to pass through multiple target zones to see if and how much gas & oil may be there; and potentially horizontal over very long distances to reach a far-away zone or expose the wellbore to a long distance within the same zone. All the above notwithstanding probabilistic geologic predictions.

Well path software has been developed over time by a lot of companies of various sizes. Today all the large oilfield service companies (such as Schlumberger, Halliburton, Baker Hughes GE[15]), and most smaller companies that provide directional drilling services to operators have their own well path software to plan the well directions to allow drilling as easy as possible and achieve the operator's target objectives. The names of these software programs include:

[15] With due respect to all companies referenced in this Report, some will be first spelled out by full name, yet later identified by their stock symbols. The companies above will herein later respectively be identified as: Schlumberger 'SLB'; Halliburton 'HAL'; and Baker Hughes General Electric 'BHGE'.

COMPASS™[16], Petrel[17], and others. As the well path planning may require a lot of considerations, modeling of a number of 'what if' trial & error well paths will occur, then reviewed as achieving objectives the best way possible, and often re-figured. Often for a variety of reasons, the seemingly simplest well path is not the best pick. The well paths must be drillable, must be able to have casing run and cemented in them, completions must be installable inside them with current downhole technology and tools, and they must allow for future well remediation, workovers, and eventually plug & abandonment. Note again that today well paths can be quite long – to over 6 miles measured depth[18].

If an existing wellbore will be used, but from some point downhole a new well path will be drilled away from it, then a 'sidetrack' or 'bypass' well path will start from the existing well at some place downhole to the target(s).

As exponentially increasing amounts of geologic and geophysical data, drilling records, and producing histories are compiled, large operators have Applied Advanced Technology via coupled supercomputers with 3-D subsurface visualization and design engineering capabilities to provide immersive viewing of potential well paths through downhole strata. Whether via paper mapping and diagramming, or via supercomputer visualization, geologists and drilling engineers combine their expertise in specific basins and fields to plan the best well paths, and to design the optimal wells.

C. Well Design Software -

The Planning is the key to successful operations and projects of all types – and proper planning is essential for gas, oil and geothermal well designs. Well planning covers a lot of considerations offshore and in deepwater – at the water surface, at the seafloor, and along the wellbore down to the target formations in the earth that are the expected producing zones of energy and hydrocarbon products. Wells may be considered as planned top-to-bottom, because that's how the operator drills down to the targets. Yet, well design may best be considered as planned bottom-to-top, because assuming one or more potential target zones is successfully found to contain sufficient energy and hydrocarbons for economic production volumes, the well size at bottom must be large enough in diameter to produce the required production volumes over time. And depending upon the number of target zones, and each respective target zone's energy and product value and rates, as well as the multiple varied types of rock and other zones above and between the productive zones, and the capabilities of the downhole equipment to handle all, the downhole well design may be straightforward or extremely challenging and complex.

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[16] COMPASS™ is a Trademark of Halliburton's Landmark Graphics Corporation.
[17] Petrel is a Schlumberger product.
[18] Well 'depths' are measured in two ways: 1) 'Measured depth (MD)' is the total length of the well along its full curvatures, either from the wellhead to the lowest point the borehole was drilled 'total depth (TD)', or from the wellhead to the lowest point the well was plugged back to above TD (PBTD). 2) 'True vertical depth (TVD)' is the theoretical straight-line distance from the wellhead to any plumb point along the MD, and in all wells (except perfectly vertical straight holes), is always shorter than MD.

In general, ‘well design’ refers to just the well itself, which in deepwater will be from the bottom target zone up to and including the ‘wellhead and tree[19]’. The total ‘well’ therefore, is a structural pressure containing unit that accesses the producing zones, seals the zones off from each other and the wellhead, and allows one or more zones to produce up, or fluids be injected down, into and through the tree.

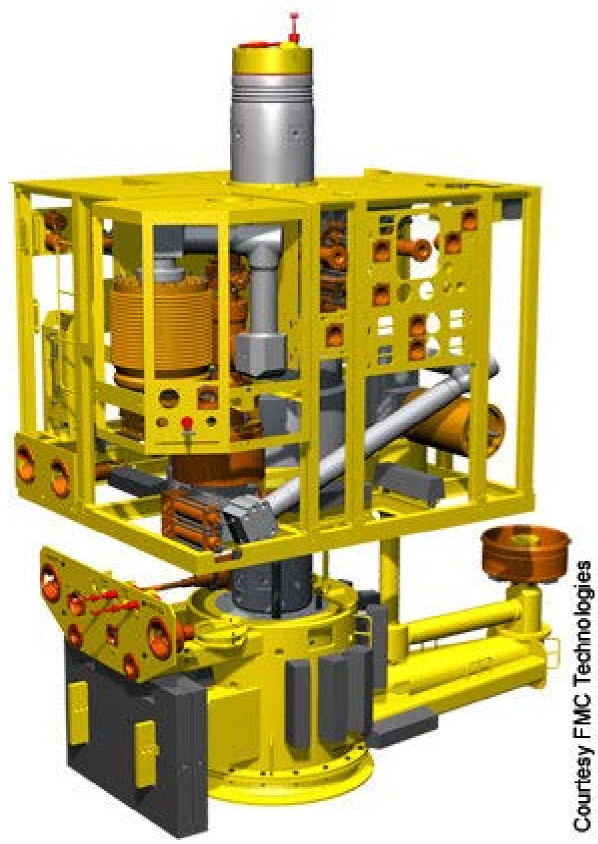

Figure 1: FMC Subsea Tree

http://www.spe.org/now/17dec2008-tm-fmc-evdt-web/

Some well mechanical design basics need to be discussed here. The top of the well ‘wellhead’ is limited in outside diameter ‘OD’ to the maximum size that can fit through a certain offshore drilling rig’s equipment configuration. A well is drilled from wellhead top to lowest target zone bottom ‘wellbore’ in a series of successively smaller telescoping hole sizes. After each hole size of a well is drilled, that hole size has run in it a tubular sheath ‘casing’. The casing both structurally supports the well like a skeleton, and the casing isolates the wellbore from the surrounding rock formations and pressurized zones. There are minimally 3 successively smaller diameter sizes of long length pipe casing ‘strings’ that must be installed. A casing string consists of hundreds or thousands of feet of tubular casing pipes, each approximately 60 ft.

[19] Figure 1 shows a drawing of a subsea tree that mounts on a subsea wellhead at the top of the well on the sea floor.

long, joined together by threaded pressure tight connections. As soon as the uppermost structural casing ‘conductor’ is installed, then all drilling, casing and tools below that top conductor string must pass through the inside diameter of that string. So in telescoping manner, all lower successive drilling, casing, completion and tool strings must pass through the inside diameter of the string above it, and still function in the smaller casing string or the non-cased wellbore below it. Very complex and deep wells may require 6 to 8 successively smaller diameter casing strings. Note that a well today may reach 36,000 feet (+6 miles) down into the earth from the wellhead; yet the inside diameter of the wellbore hole may be only 8-1/2 inches, and inside diameter of the production casing at lowest zone may be only 6 inches[20]. Accordingly, without proper well planning, design, and drilling operations, the wellbore at the lowest productive target zone may not be large enough to produce the required energy and/or hydrocarbons in sufficient economic volumes and rates – and if not, another well must be drilled.

Complex well casing design is performed by drilling engineers using software specifically fit for that purpose. Over the years, drilling engineers first wrote their own calculator well design programs; then more sophisticated computer software for well planning in 3-dimensions were developed and made commercially available for license by well designers. And now, (as with most digital technologies) the software continues to get easier to use with additional operator requested features on smaller yet more capable laptops and phones.

A first available Applied Advanced Technology industry casing design software was written by a company called Enertech, which was acquired years ago by Landmark (which became a Halliburton affiliate), and which was later improved and named *Wellcat*[21]. *Wellcat* is available for licensing by companies doing complicated well design, and for integration with large operators who used Halliburton’s Landmark data base system. The last few years a new well design software was written and available for industry licensing named *StrinGnosis*[22]. *StrinGnosis* provides complex and simple well designers a quick menu driven format integrated with drop-down features and graphics, providing fast training and easy use with any database.

These two examples of well design software are ‘Applied Advanced Technologies’ in their latest versions and features, so a single drilling and completion engineer can input the data needed, and perform accurate complex well designs for ‘what if’ optimal and alternative contingency scenarios - changing casing sizes, weights, grades, and connections to overcome design challenges. The casing and connection outside diameter size determines telescopic dimensional clearance. The casing weight determines the casing wall thickness for a given size. And the casing grade determines the casing metallurgy. The casing weight and grade combined provides respectively, both the rating ranges of casing physical properties for structural strength that the casing can support (such as burst, collapse, tension, compression)

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[20] For reference and to help visualize this, note that 6” is only this long between the two arrow points below:

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[21] *Wellcat™* is offered for licensing by Landmark Graphics Corporation.

[22] *StrinGnosis™* is offered for licensing by Blade Technologies Corporation.

against predicted downhole loads, and the corrosion resistance of the casing against wellbore exposure conditions.

Today's well design software output also allows the well design drilling engineer to easily exchange the files and results with others for cross-checking, verification, regulatory approvals, and procurement planning. Key technological benefits of today's well design software include: drilling engineer well design and casing design training, detailed in-depth and correct analyses regardless of well complexity, optimal use of time and resources, well safety with environmental soundness based upon proper design, and well integrity throughout the full range of changing conditions during well life. Planning a safe and environmentally sound well includes 'Drilling a Well on Paper' that such in-depth technically correct well design software efficiently allows.

D. Casing Variety -

Well casing strings are the set of steel tubular sheaths that separate the inside of the rock wellbore from the inside of the well. As previously noted, strings of well casing pipe with their connections are different outside diameter sizes, and they must be sized so a deeper string fits into and through the shallower string above. Certain U.S. and international steel pipe mills manufacture tubulars specifically for Upstream oilfield use, making drillpipe, casing, tubing, and related tubes, collectively called 'OCTG' – oil country tubular goods. Arising from the huge capital and operating costs of steel mills, and historical Operator application of standard available pipe sizes, casing was manufactured and sold in large batches (10s of 1000s of tons) in standard outside diameter sizes (such as: 20", 13-3/8", 9-5/8", 7-5/8", 7", 5-1/2"), and in a few grades (L-80, P-110, …, Q-125). OCTG steel mills fiercely compete against each other to provide global oilfield demand. So in the 2014 oil price and activity slump, OCTG product and service competition increased. This competition had a positive effect on well design of deepwater complex wells.

As wells continued to target deeper oil and gas zones, the well pressures and temperatures increased with depth. In the past, drilling engineers faced very tough, and in some cases insurmountable challenges designing deepwater wells with the historical standard casing sizes and grades. When the challenges were insurmountable, certain drilling projects could not be pursued. The 2014 industry slump resulted in pipe mills' overcapacity, which coupled with competition, then allowed smaller tonnage mill runs of new casing sizes and grades - offering more 'casing variety' at reduced prices. The new casing sizes and grades, which were previously unavailable or very expensive in small batches, included: 14", 10-1/4", and 8-5/8" in different grades. This new and broader casing variety is now available to satisfy a number of challenging well designs. These new Applied Advanced Technology sizes and grades now allow safe, environmentally sound access to previously unreachable resources, by assuring well design integrity under the wide range of deepwater downhole conditions.

Now that OCTG mills can handle a wider range of tubular sizes and grades, this steel mill flexibility we can expect to continue, even as the upstream and deepwater industry returns to robust growth, because of the market demand for diversity in casing sizes and grades.
of personnel it will house and feed (100+); and other ranges.

E. Expandable Casing -

A special downhole tubular used as casing is an expandable casing. An ‘expandable’ seems like a typical casing string of steel pipe with connections. What is extraordinary is the fact that the service companies that offer expandables provide perfect casing for the purpose, have it delivered to the rig with their special tools, have the rig run the steel pipe in the well, and then run their expansion tools inside the string. When positioned in the well, the expandable tools actually cold work[23] the steel tubular in situ, thereby expanding the inside and outside diameter of the tubular to a larger size. This downhole expansion may benefit operators by setting the expandable OD into the formation rock, into another string of casing, or into another expandable. In short or long strings, expandable casing within specification range can be used to fit where procured mill casing has a standard size gap, bigger inside diameter is required, and/or a casing patch is applicable.

This downhole expanding process is not new, in the sense that it was originally patented by Shell many years ago. In the year 1998 Shell Technology Ventures and Halliburton set up an independent company, Enventure Global Technologies ‘Enventure’, to make available to the industry Shell’s patented technology. Enventure has been in business 20 years, and has run more than 2,000 installations (with 1.6+ million feet pipe expanded). Other companies, including Weatherford and BHGE also developed their own expandable product lines. To date, expandables were and are only used in the rare situation where a short yet special size casing would provide coverage in a complex or unexpected well design situation as a ‘contingency’, or as a form of casing repair patch.

Emerging is an Applied Advanced Technology expandable casing concept that existed years ago - that of a ‘monobore’. The monobore concept is where one expandable casing string is run inside and close to the bottom of another, then internally expanded until it reaches the full inside diameter ‘ID’ of the string above, so another same size expandable can be run into it and expanded to the same ID of the previous string. During 2018 ‘monobore’ casing strings are being tried. With continual successes, longer monobore casing strings will be applied, and the monobore technology use may increase significantly - potentially to the point where well designs use it as a common casing method, instead of a special contingency when conventional casing does not work. The ultimate potential for monobores may be wells that can be drilled with larger wellbores, and casing strings that can be run to deeper depths, since concentrically smaller successive casing strings will not have to be used.

In the past, a limitation to expandable casing was lower physical properties (such as burst and collapse ratings) because of use of thinner wall casing and lower grade (50 or 80 ksi). But now this limitation has been mitigated by use of thicker wall and/or higher grade expandable pipe (up to 110 ksi). For some pipe sizes, the internal yield pressure ratings after expansion can be up

[23] ‘Cold working’ is a steel industry term that means changing the steel shape without applying heat. A plumber may use a simple radius tool to bend conduit tube running along a ceiling, which is cold working it. Cold working does change the steel strength slightly in the area affected. With expandable casing, typically the full length of ‘expandable’ casing string is radially outwardly made bigger, both its inside and outside diameter, arising from the cold working expansion; yet the casing strength reduction may low enough to satisfy the well design and expandable use in that application.

to 13,000 psi, and collapse ratings up to 9,000 psi. Also, certain expandable casing has been qualified for 'sour' hydrogen sulfide (H2S) applications per standard National Association of Corrosion Engineers (NACE) testing. Overall, a customized expandable solution can be developed for different and challenging environments.

V. Drilling

A. Overview of Drilling Planning & Preparation -

The basic drilling rig categories depend upon the choice of the location and/or type of surface facility on which the rig will locate and operate. There are three basic categories of offshore drilling rigs, and two basic type of wells.

Floater Rigs ('wet' wellheads & trees) -

'Floater' rigs operate while floating on the surface of the sea; and have two different configurations: drillships and semisubmersibles. Figures 2 and 3 below are pictures of the respective floater drilling rig configurations.

Figure 2: *Pacific Khamsin* Drillship[24] - This floater drillship drilling rig is capable of operating in water depths of up to 12,000 feet and drilling wells up to 40,000 feet deep. It can accommodate 200 persons.

https://www.offshoreenergytoday.com/pacific-drilling-three-out-of-seven-drillships-out-of-work/

[24] The *Pacific Khamsin* drillship is managed and operated by Pacific Drilling Corporation.

Figure 3: Ensco *8503* Semi-submersible[25] – This floater semi-submersible drilling rig is capable of operating in water depths up to 8,500 ft. and drilling wells up to 37,500 ft. depth. It can accommodate 150 persons.

https://www.enscoplc.com/GlobalOpertions/RigFleet/Ensco8503

A drillship has a ship shape, as shown in Figure 2 above. A drillship freely floats on the sea surface and ballasts with the bottom of its hull below the water line, as any ship may do. A semi-submersible ‘semi’ has a square or rectangular shape with its decks above the water line as much as 50 to 90 feet, and legs with pontoons that ballast below the sea surface as much as 50 to 75 feet below the water line. Both a drillship and semi-submersible have a drill rig derrick mounted on it standing above the top deck, and a cavity built through the hull underneath the derrick ‘moonpool’. The derrick hoists drillpipe and drilling tools and lowers them into the sea below the hull to the seafloor and well.

Floaters mobilize to a well location via a combination of being towed and using their own power of hull mounted thrusters. Floaters stay on location over the well by continuous computer monitored and controlled thruster direction and speed changes.

A floater arrives at the surface location and positions itself above the seafloor point that a well starts. The rig will then ‘jet’ a hole via circulating water, or drill a hole into the seabed, deep enough to install hundreds of feet of conductor pipe in the hole, with the wellhead mounted on top of the conductor, and the wellhead positioned within 10 ft. above the seafloor ‘subsea’ well.

Once the conductor with wellhead is set, then a floater will lower onto the wellhead and use a special connector to attach the rig’s series of valves and controls for safety called the subsea

[25] The *Ensco 8503* Semi-submersible is managed and operated by Ensco plc affiliates.

blow-out preventer 'BOP stack'[26]. Since the subsea wellhead with BOP stack mounted above is fixed on the seafloor, and a floater is always moving on the sea surface, dynamic forces act on the equipment that connects the well with the rig while operations are ongoing. Floater rigs are set up to handle these forces within a certain range of vessel motion. Yet when sea waves and/or currents result in floater movement beyond the operations range, well operations must stop; and in more extreme conditions, the floater rig must be disconnected from the well.

Wells with their wellheads located just above the seafloor are subsea wells with 'wet trees'. Wet trees and subsea BOP stacks are quite complex, requiring operation from the floating rig at surface through the water depth, using electromechanical bundles of hoses and cables 'umbilicals', plus acoustic and backup mechanical operation on the seafloor by remotely operated vehicles 'ROV's. All floater pressure control equipment (BOPs, marine riser packages, drilling risers[27], umbilicals) are highly engineered, extremely complex, heavy, and require specialized equipment to move, handle, and operate. Therefore, they are very expensive for drilling contractors to buy, operate, maintain, test and repair.

Platform Rigs ('dry' wellheads & trees) -

'Platform' rigs are mounted on top of the operator's offshore facilities, and those offshore facilities are fixed high off the surface of the sea. Platform rigs are brought to the facilities by boat in sections, then hoisted and assembled on top of the facilities by crane. A platform rig may stay on the same facility for years, even when the rig is not operating.

Offshore facilities that are fixed to the ocean floor are platforms. Wells are drilled and completed from the top of platform, and each wellhead with its tree bolted on top is located up in, and connected to, the platform deck high above the water surface. They are called 'dry trees'. Dry wellheads and trees are analogous to onshore wells; and therefore, quite a bit easier and less expensive to access, drill through, and work with than 'wet' trees.

On top of a facility, platform rigs are positioned over the facility's various wells by having the ability to slide on rails 'skid'. This allows the rig's BOP stack to be mounted on top of each separate well for safe well control.

In deep water, these facilities are designed with buoyancy, and are tethered by cables 'tendons' anchored into the sea floor. They may be a 'spar' or 'tension-leg platform'; and the slight movements of these facilities do not affect drilling or production operations. In shallow water, these facilities are true platforms that have steel truss members 'jackets' cemented below the seafloor; and these platforms do not move.

Jackup Rigs ('dry' wellheads & trees) -

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[26] For a description and explanation of 'BOP' and 'BOP stack', please refer to page 24., section: *V.E. Well Control Equipment – Secondary Mechanical Barrier.*

[27] For a description and explanation of 'marine riser packages' and 'drilling risers', please refer to page 28 section: *V.E. Well Control Equipment – Secondary Mechanical Barrier.*

‘Jackup’ rigs are like small self-contained platforms with 3 or 4 integral legs, and the legs can be upwards of 450 ft. high. With the legs up, jackups float on the water, and are towed to the well location. The well location may be only for a single new well with no facility nearby, or the location may be an existing well that’s one of many drilled as part of a shallow water platform facility. Once the jackup rig arrives on location, it lowers its legs down to the seafloor ‘jacks down’, and the bottom of the legs sink a few feet until they set into the sea bottom. Once the legs are firmly set, then the rig jacking system keeps going, until it lifts the whole platform over the sea, and above the surface waves. Jackups also have a skid rail system extending over one side ‘cantilever’, so the drilling rig tower ‘derrick’ and BOP stack can be positioned as needed over each separate well. Jackups generally operate in less than 20 ft. to ~400 ft. water depth. The operating water depth will depend upon multiple factors, such as: how long the jackup’s legs are, how deep the legs sink into the sea bed, and how high above a well the cantilever can be positioned.

Since platform and jackup rigs operate over wells that are supported by or mounted on facilities, and the wellheads are above the water and located in the facility decks, these wells are called ‘dry trees’. BOP stacks for dry trees have the same basic components of those for wet trees; however, they are much simpler, and do not require long drilling risers or special disconnection systems. Therefore, they are less expensive for drilling contractors to buy, operate, maintain, test and repair than floaters.

All Rigs -

Different drilling rigs of each configuration have different capacities covering: the maximum water depth and ‘sea states’[28] within which its equipment is designed to safely operate; how much casing it will lift (100,000 lbs. to 2,500,000 lbs.); whether it has dual-derrick activity capabilities; how much capacity it will store (barrels of drilling mud, completion fluid, water, fuel, etc.) and handle (feet of various sized tubulars, including riser, drill pipe, casing, tubing, and other equipment), and pump (number of pumps, barrels per hour & pressure); ability to keep the well safe under pressure (ratings of BOPs and related pressure control equipment); number of personnel it will house and feed (100+); and other ranges.

B. Latest Ultra-Deepwater Drillships -

The most modern and expensive drilling rigs are drillships that have the highest capabilities, highest capacities, and widest range of capabilities in all aspects. Previously, drillships were generally classified by ‘*Nth* Generation, with *7th Generation* considered the latest designs that drilling contractors started ordering 2015-18, that were delivered then, or that are still under construction. The newest 7th Generation drillships are designed to operate in water depths up to 12,000 ft. (2.3 miles deep), which is the maximum water depth in the Gulf of Mexico.

[28] The term ‘sea state’ is a marine term that includes all sea surface conditions arising from the singular and combined effects of winds, currents, and waves acting on a vessel. Each vessel is designed to operate throughout a range of sea states. If a sea state exceeds the operating range, a vessel must stop operating and/or move off location, depending upon the vessel’s capability and how it is operated.

There is generally no standardization between how different drilling contractors classify their rigs. Seadrill, for example classifies their newest drill ships as "6th generation" and Transocean classifies their newest rigs as "Ultra-deepwater". Transocean's "Ultradeep" classification refers to drillships and semi-submersibles capable of operating in water depths greater than 7,500 ft.[29]

Seadrill's "6th generation" classification is a dynamically positioned 'DP3' ship capable of operating in 12,000 ft. water depth with dual activity capability[30]. The term 'dual activity' means that the drilling mast 'derrick' has two separate systems. These separate drilling systems allow drilling with the large system, while in parallel the other system complementarily handles pre-drill or post-drill downhole equipment – thus increasing operations efficiency. New dual activity drillships have combined derrick hookload capacities upwards of 5 million pounds, where they can pick up: 2.8 million pounds with the main derrick, and 2.2 million pounds with the auxiliary derrick. These new drillships are huge: over 775 ft. long and 135 ft. wide, and capable of sleeping 200 people onboard. Not only are they designed with the ability to drill in water depths up to 12,000 feet, they can drill wells down to a total depth of 40,000 ft.

C. Overview of Well Pressures and Control -

Focusing on safety & environmental effectiveness, the most important drilling rig function is well control. 'Well control' is the general term for keeping the well contents contained within the wellbore at all times while the drilling rig is hooked up to the well.

Drilling engineers must always consider that pressure in the well is paramount from the standpoint of safety in well pressure management and well control. Well pressures include natural pressures arising from the column of seawater above the wellhead, the natural downhole pressures from formation zonal compaction and temperature, reduced formation pressures from production depleted zones, and the resultant downhole pressures due to the column weight of static or circulated drilling mud or pumped injection fluids into the well from surface. Accordingly, the drilling engineer needs to understand and answer multiple questions simultaneously: Where does any wellbore pressure come from? What causes an influx of fluids into the wellbore? What is the rock formation's pore pressure & fracture gradient at each depth in the wellbore? How is pressure control of a well maintained? How to maintain downhole wellbore pressure overbalance? What frictional effects do circulating fluids have on wellbore pressure management at each depth in the wellbore?

When it comes to preventing the flow of formation fluids into and up the wellbore, two barriers are to be considered: primary and secondary barriers. These barriers can then be broken down into one of two types: a mechanical barrier or a hydrostatic barrier.

[29] The U.S. Energy Information Agency 'EIA' refers to 'Ultra-deepwater' as water depths greater than 1,500 meters (~4,920 ft.).

[30] OCS Study BOEM 2013-0112: Offshore Drilling Industry and Rig Construction Market in the Gulf of Mexico.

D. Drilling Fluids – Primary Hydrostatic Barrier -

Drilling fluid[31] is a hydrostatic barrier, and the primary barrier during drilling to prevent well fluids from entering the wellbore. This primary barrier is designed to prevent fluids from entering the wellbore if, in a managed or controlled manner, the wellbore's fluid hydrostatic pressure is greater than the formations' pore pressures. Drilling fluids are used to exert a hydrostatic overbalance in the wellbore, thereby keeping the formation fluids from flowing out the open rock formations and into the wellbore.

Geologists predict the formation pressures prior to drilling using advanced seismic technologies and data from applicable offset wells. When drilling for oil and gas, engineers need to design a drilling fluid program to keep the weight of the drilling fluid column within a narrow range 'window' – so the designed program manages the pore pressures of the rock formations into and through which they are drilling. Engineers create these 'windows' by first determining the resultant drilling fluid pressure that will push against the formation pressures required to keep the formation fluids in the rock. They then determine the drilling fluid composition and density, with respective drilling fluid column weight, that ensures the wellbore will have higher pressure than formation pressure at each formation depth. The drilling fluid column 'window' has two factors that need to be kept in mind at each depth in the wellbore: the rock formation pore pressure and the rock formation fracture pressure. The pore pressure is the natural pressure of the fluids in a formation that can push formation fluids into the wellbore. And the fracture pressure is the amount of wellbore pressure that is high enough to fracture or break down a formation, which can push the wellbore fluids into the formation.

Drilling fluid engineers use chemistry to design 'fluids' capable of operating in the drilling 'window' - creating hydrostatic pressures downhole higher than the pore pressure of the formation, thus preventing the formation fluids from entering into the wellbore 'influx' - while at the same time, these drilling fluids have a fluid hydrostatic pressure lower than the formation fracture pressure, thus preventing the wellbore fluids from flowing into and being lost from the wellbore into the formation 'fluid loss'. Pumping drilling fluids from surface and circulating the fluid in the wellbore past formation zones increases wellbore pressure, due to the frictional effects of circulation. Drilling engineers must calculate these frictional effects of drilling fluid circulation at every point in the wellbore, then add these frictional effects to the drilling fluid hydrostatic pressure. To prevent against drilling fluid losses, lighter drilling fluids are used than pore pressure would naturally indicate. Drilling fluids are pumped by the rig from surface downhole through the inside of the drill pipe, out through the nozzles in the drill bit at the bottom of the wellbore, and then up the annular space between the outside of the drill pipe and inside the wellbore, and back to the rig. The driller can reduce the circulated fluid flow returning back up to the rig by closing a valve 'choke' on the rig floor 'increasing backpressure', which then

[31] 'Drilling fluid', aka 'drilling mud' or 'mud', is a generic term for the 'fluid' the drilling rig pumps down the well (typically down the center of the drill pipe or work string), through the bottom of the work string, and that mixes and brings up 'circulates' solid particles and formation fluids back to the drilling rig at surface. Drilling fluid may range in density from heavy salt water to aerated foam. The drilling rig personnel have control over the pumped down drilling fluid composition and pump rate, and (when applying MPD), the circulated fluid mixture return pressure. For more details, please see this Section "*V.D. Drilling Fluids – Primary Hydrostatic Barrier*" above and the next page; and see Section "*V.H. Managed Pressure Drilling 'MPD' & Early Influx Detection 'EID'",* pages 28 & 29.

increases the pressure in fluid system circulating downhole. Well influxes are managed through a downhole combination of frictional effects arising from drilling fluid circulation and backpressure arising from smaller choke sizing the circulated fluid system.

Drilling fluids are constantly being formulated for various scenarios and conditions. For years drilling fluids were made from a base fluid of water or oil. Then mineral and chemical compounds were added to the base fluid to make each specific fluid density and weight with certain characteristics favorable to drilling through certain rock formation properties. Deepwater drilling required a special fluid system that would retain its characteristics throughout the process (1) when pumped by the rig from surface at ambient temperature, (2) through the drilling riser and subsea BOP at 34ºF[32], (3) to bottomhole temperatures that could be as high as 400ºF, (4) back up to the seafloor 34ºF, and (5) back up to the drilling rig at ambient surface temperature. The Upstream industry Applied Advanced Technology 'synthetic' drilling fluid was then formulated that maintains its purposeful characteristics through these temperature changes and along this circulation pathway. The synthetic drilling fluid also performs its necessary job of carrying drill cuttings[33] up from the downhole bit to the surface rig, as all drilling fluids must do.

E. Well Control Equipment – Secondary Mechanical Barrier -

Well control equipment on a drilling rig makes up a mechanical barrier, and the secondary barrier during drilling to prevent well fluids from escaping the wellbore. The blowout preventers 'BOPs', rig choke manifold, and choke and kill lines are all part of this secondary, mechanical barrier - to prevent flow from the formation if the primary barrier fails.[34] Well control equipment will have the same basic configuration on all rigs. Yet, floater rigs have the most complex and sophisticated well control equipment, because floater well control equipment operates subsea with wet wellheads and trees. Simpler well control equipment is applicable on platform and jackup rigs with dry wellheads and trees.

All drilling rigs have a safety blowout preventer 'BOP stack' attached to the top of the well 'wellhead'. On any specific well, the contracted drilling rig must be equipped with its BOP stack which is designed, qualified and tested to withstand the maximum allowable surface pressure 'MASP' expected to be encountered during that well's rig operations. If well pressure exceeds the primary hydraulic barrier of drilling fluid, then the BOP is closed 'shut in', sealing the well underneath. Once the well is sealed, the well fluids will stop entering the wellbore, with a hydrostatic equilibrium between the wellbore and formation pressures.

The 'BOP stack' combination of safety valves consists of sets of high pressure hydraulic operated valves bolted together to each other bottom-to-top. Each BOP valve has inside it a

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[32] Seas get colder with increasing water depth, until the lowest temperature of 34ºF is reached. Because seas do not freeze on the bottom, globally the minimum temperature at sea floor depth will be 34ºF.
[33] Drill cuttings are the small pieces of sheared or broken rock that are formed when the drill bit cuts them off from the forward rock remaining at the bottom of the wellbore ahead of the drill bit. Once drill cuttings are formed, they must be removed from in front of the drill bit, or these rock pieces will build up under the drill bit and prevent the bit cutters from working. The drill bits are designed with holes by their cutters in the leading edge 'jets', whereby the drilling fluid pumped through the jets cleans the bit cutters, and circulates the drill cuttings to surface.
[34] IWCF.

pair of opposite facing sealing inserts ‘rams’. Each BOP valve sealing ram pair will seal in a different way. Yet if needed to shut in and contain a well in an emergency, each valve will separately seal the well below it.

The lower portion of a BOP stack will have 2-4 different valves, and within each valve will be a different sized pair of rams ‘pipe rams’. Each valve will close and seal around a different specific outside diameter pipe size[35], sealing the well below. Each will have a ram pair that is sized in a ½-round shape with resilient seal on their leading edges, so that they will close around a specific outside diameter of a pipe in the valve center. Because each single valve in a BOP stack is very large and heavy, and changing pairs of rams takes hours or days, drilling rig management plans in advance which types of valves will be bolted up into a BOP stack, and what sized pipe rams will be used within the upcoming well drilling stages.

The upper BOP stack will include a special valve that internally has is a pair of rams which both shear pipe and sealing the valve ‘shear rams’.[36] The shear ram pair in this BOP valve shears and cuts though pipe as these shear rams close, and then the leading edges of this shear ram pair resiliently seal against themselves - thus sealing the well below the shear rams.

On top of the BOP stack will be a special valve that [though typically lower pressure than the higher pressure ‘ram’ valves below] has an internal large elastomer that seals like a bag around any shape within it, known as the ‘annular’ preventer. The annular offers the most versatile capability range of dimensional sealing. The annular is also the most accessible and easiest valve for seal replacement and maintenance.

Each of the BOP stack valves is hydraulically actuated from surface within a safety sequence. The hydraulic control systems that sequence and operate the BOP stack valves are quite sophisticated and complex. And they have redundant systems, in case of one portion of a system doesn’t work properly.

Example (normal operations): Typically during normal operations when tubular pipes are in the well and through the BOP stack, only the annular on top of the BOP stack may be used occasionally. The other valves bolted below the annular with shear rams and pipe rams are not used. The control system therefore only actuates the annular when requested.

Example (emergency operations): If a potential emergency well control incident occurs when tubular pipes are in the well and through the BOP stack, and closing the annular will not provide sufficient safety, then the hydraulic control system will close the valve with correct sized pipe

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[35] The size of different tubulars in the wellbore, and size of each pair of BOP valve pipe rams, will depend upon the drilling rig’s stage in drilling or completion. In quite deep wells, the rig may use a drill pipe string that’s the same outside diameter the whole length, or it may use a ‘split string’, where the upper drill pipe section is heavier with bigger outside diameter than the lower drill pipe section. During completion operations, the BOP valves will be sized with pipe rams for combinations of casing or tubing outside diameters and drill pipe ‘work string’ outside diameters. During completions, the drill pipe work string latches to the top of the casing or tubing string below it, lowers that string in the well, sets that string in place, and then releases from the casing or tubing, before the work string is pulled up out of the wellbore.

[36] Shear rams do not seal around any pipe. Shear rams cut through pipe that may be inside this BOP valve. Shear rams do seal against themselves, so that this BOP valve seals against well pressure and flow below it.

rams, without closing the other valves. However, if an emergency rises to a point where closing a BOP valve with pipe rams will not provide sufficient safety, then as a last resort, the upper BOP valve with shear rams will be actuated to cut the pipe within that valve and seal the well below that BOP upper valve's closed shear rams.

Operators ask drilling contractors to tender drilling rigs that meet the conditions expected for each well an operator plans to drill.

A drilling rig's BOP stacks and BOP controls are designed and supplied to operate up to the maximum working water depth of that drilling rig. On floater rigs, the umbilicals are coiled in reels on deck, and the umbilicals will be uncoiled as the BOP stack is lowered to the seafloor onto the wellhead. Wellheads, BOP stacks and BOP control systems are designed and provided by original equipment manufacturers 'OEM's in 5,000, 10,000, 15,000, and now, 20,000 psi working pressure ranges to drilling contractors.

The BOP stack also has attached nearby hydraulic accumulator bottles that are 'charged' with stored nitrogen to pressures often exceeding 6,000 psi. These accumulator bottles supply the BOP with boosted energy to close and seal the rams and annular preventer quickly against pressure in the well. Upon activation of the BOP, the hydraulic accumulator bottles supply the energy to close and seal the rams or annular preventer, and resultingly stop the influx of fluids from going any further up the wellbore and into the drilling riser.

Attached to flanged connections on the sides of the BOP stack are choke and kill lines - high pressure hoses used to circulate drilling fluids inside the BOP stack. Depending upon the situation at hand, the well control process will vary.

In one critical well control scenario, the drilling rig may pump 'kill weight' drilling fluid down the center of the drillpipe string, with pipe rams sealed closed around the outside of that drillpipe, and circulate well fluids up from the underneath the closed pipe rams back to the rig on surface. Kill weight fluid has high density that is heavier in weight than the well fluids, so a well full of kill weight mud will push the well fluids back into the formation rock If the drill rig cannot pump down the drillpipe, then kill weight fluid can be pumped down the kill line underneath a sealed BOP valve at high pressure to overcome the formation pressure and keep control of the well fluids.

After the well pressure underneath the sealed BOP is overcome, and after confirming the well is stable and under control, the BOP stack can be opened to resume normal drilling operations.

A schematic diagram of a floater BOP stack is shown in Figure 4 below (next page).

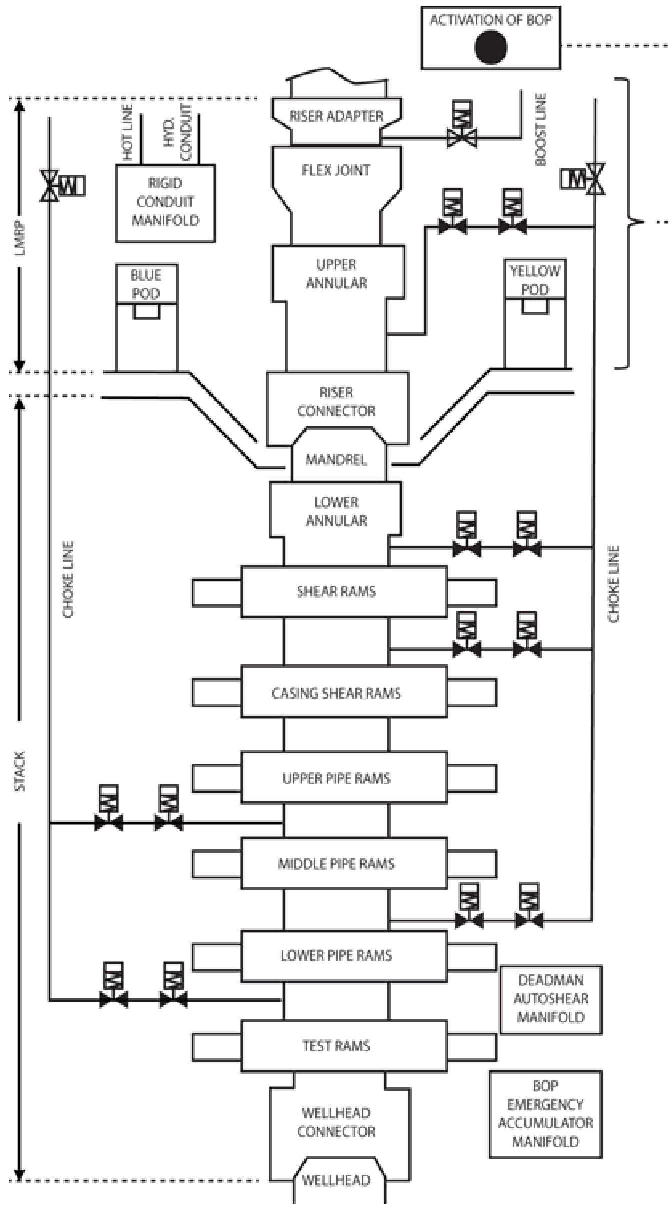

Figure 4: Floater Subsea BOP Stack Configuration
(http://www.drillingcontractor.org/anadarko-nasa-complete-first-phase-of-probabilistic-risk-assessment-of-generic-20k-bop-44123)

'Subsea' wells are so named, because the wellhead is mounted on the seafloor (ocean bottom). Floating rigs set the subsea wellhead, and then a subsea BOP stack is installed onto the wellhead. Above the BOP stack is a series of bolt-together large diameter tubulars to just below the rig floor 'drilling riser', which provides a flow path for pumped return well fluid back to the rig. The floater rig drilling riser must be and is designed to be flexible, so drilling operations will safely continue within the range of the drilling rig vessel movements on the sea surface. This is absolutely critical, because the rig is floating on the ocean surface, with pitch, heave and roll based upon sea surface currents, waves and wind 'sea states'.

Significant effects on the drilling riser occur throughout its full height while operating in the seawater column. The drilling riser is fixed via the marine riser package 'MRP' and BOP stack to the top of the well. The drilling riser weight is held up in the water by the combination of some buoyancy modules strapped to the riser circumference, and a tensioning system attached around the riser top that's then attached to the drilling rig below the rig floor. The tensioning system holds up the drilling riser and adjusts upward tension within a range, while surface sea states move the floating drilling rig due to weather and/or currents, and while various subsurface currents affect the drilling riser. Effects on the drilling riser will also change based upon changing drilling fluid density inside the drilling riser.

If the floater drilling rig finds that severe sea states or currents take it outside the drilling riser tensioner operating range, or an emergency well control event scenario occurs that requires the rig to move away from the well, a floater rig's riser subsea equipment includes a disconnect mechanism. This disconnect system protects against damage to both the well and the rig due to excessive rig motions at surface and riser motions in the seawater column. The MRP allows the drilling riser to disconnect from the well above the BOP stack. Before any drilling riser disconnect, the subsea BOP stack is closed to seal the subsea well, and the BOP stack remains closed over the sealed well. Then as soon as the riser disconnects at the MRP, the floater rig can immediately move off location safely.

AFGlobal, National Oilwell Varco, SLB's Cameron division, and BHGE are among the well control OEMs that design and make floater BOP stacks and systems, drilling risers, and drilling riser equipment. It must be noted that well control and drilling rig equipment are sold to or rented to the drilling contractor that uses it to drill the well for the operator. The safety and environmental effectiveness of the new well control equipment is that it provides additional and faster actuation of well barriers – even in the deepest water depths. This enables drilling operations in new offshore areas and conditions that previously were limited. The new technologies developed improved revised practices that both are safer and more efficient, thus reducing risk, and more effectively protecting the environment.

Two key technological advancements are emerging that may reduce the time it takes to shut in a well – each related to the BOP stack valve with rams made to hydraulically shear and cut the drillpipe, and seal the well in an applicable emergency. A drillpipe connection 'tool joint' is quite thick wall steel, and very hard to shear.

An Applied Advanced Technology development is robust BOP valve shear rams capable of shearing thick tool joints and other tubulars that are not centered between the valve shear rams. This development allows thick and off-center tubulars to be positively sheared by the valve's shear rams and the well sealed below the valve's shear rams within this BOP valve body.[37] This provides valuable time in an emergency well control scenario.

Another Applied Advanced Technology development detects if a non-shearable tool joint is near a BOP valve's rams. The technology provides real-time position information of that tool joint location to the driller. BHGE developed a measuring system for their BOP that indicates when

[37] Cameron BroadShear Rams Case Study.

the very thick 'tool joints' are across the BOP valve shear rams.[38] If it is indicated that the non-shearable tool joint is in the closing path of the shear rams, the drilling rig can move the drillpipe a couple of feet up or down 'space out', so the tool joint will not be across the shear rams, and the shear rams will positively cut the drillpipe body. This also provides safety combined with valuable time in a well control scenario.

F. Capping Stacks -

In 2010, the Upstream industry assembled multiple separate consortia, each which consisted of integrated teams to design and build a totally new Applied Advanced Technology concept called a 'capping stack', with the common goal of being ready to respond to deepwater well control events. The capping stack concept was based upon previous ideas, yet development was prompted by new well control regulations promulgated by the U.S. Department of Interior 'DOI'. The purpose of a 'capping stack' is to stop any well flow through and out a BOP stack that did not seal, and/or redirect the flow of hydrocarbons to vessels that can capture and store the well flow.

Capping stacks provide a dual barrier consisting of a BOP valve and a containment cap, which meets the recommended practice of maintaining two barriers between the hydrocarbons and the environment. They include a set of valves that would be installed over a subsea BOP stack. Capping stacks have connection points to allow pumping down the capping stack, BOP stack, and wellhead, to kill the well, and/or flow the well up temporary lines to a collection vessel floating on the water surface. Capping stacks also contain chemical injection ports, as well as sensors to monitor temperature and pressure during all shut-in operations.[39] A capping stack is part of a well containment system that includes various sizes and types of connections, tools, material handling, and accessory equipment mounted on offshore lifting frames or in offshore toolboxes for ready deployment.

Offshore Operators quickly joined forces in forming different private consortia. Each consortium designed, developed, manufactured and tested their own capping stack systems for rapid deployment in the Gulf of Mexico and worldwide. These companies provide capping stack systems with operating personnel and logistics support set up for 'on call' mobilization. Their capping stack systems are strategically staged at offshore logistics ports. Test capping stack deployment scenarios are run from the logistic support base to a specific offshore rig location of a designated Operator in conjunction with DOI's B.S.E.E., the U.S. Coast Guard, and other stakeholders. Test capping stack and well containment drills typically also include coordinated mobilization of command center communications, notifications, surveillance, work boats, and vessels that deploy oil booms and pumps that entrain and suck up oil at surface. Figure 5 below (next page) shows a capping stack in the rig moonpool for deployment at Macondo.

The Marine Well Containment Corporation 'MWCC' and HWCG are two such U.S. groups with capping stack systems capable of use in water depths up to 10,000 ft. and pressures up to 15,000 psi, and capable of capturing over 100,000 barrels of liquid per day.[40] Each group

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[38] Baker Hughes-GE TJ Locator.
[39] SPE-0114-025-TWA.
[40] MWCC - marinewellcontainment.com; HWCG - hwcg.org

keeps its capping stack system maintained in ready operating condition; and an affiliate of each handles deployment operations.

Figure 5: Macondo capping stack onboard *Discovery Inspiration* 11 July 2010. (SPE-0114-025-TWA)

G. Pressurized Drilling Risers, Rotating Control Devices 'RCD' & Riser Gas Handling 'RGH' Equipment -

The drilling riser provides an annular pathway for circulating fluid returns back up to the rig during conventional drilling operations. Since hydrostatic pressure increases with water depth, then the external hydrostatic pressure of sea water acting against the outside of the drilling riser increases to the maximum pressure at the bottom of the drilling riser. Historically, subsea drilling risers were designed primarily to withstand collapse pressure when the external seawater pressure acting on them was higher than the fluid pressure inside them. Subsea drilling risers were not traditionally designed or intended to withstand internal pressures arising from high pressure wellbore fluids inside.

However today, Applied Advanced Technology pressurized drilling risers are designed and available to handle pressure within them, up to 2,000 psi,[41] underneath a closed rotating control device 'RCD' during managed pressure drilling 'MPD' operations.[42] Pressurized drilling risers have pressure relief safety valves that provide an alternate flow path to ensure that the drilling riser will not become over pressured, thus increasing the safety of MPD systems.[43]

Today additional floater rig well control equipment with Applied Advanced Technology includes combining more devices integrated into the top of the drilling riser to efficiently and safely perform multiple functions. Combined riser equipment devices may include a rotating control device 'RCD' and possibly a riser gas handling 'RGH' device. The RCD is the basic essential piece of equipment for the technique of managed pressure drilling 'MPD' [see MPD below]. The rotating control device is a lower pressure[44] device that is bolted integral to and near the top of the drilling riser string. Through hydraulic hoses to the RCD operations panel on the rig floor, the RCD hydraulically seals around drillpipe inside the drilling riser. This internal drilling riser seal allows some internal pressure to be applied within the drilling riser underneath the RCD seal - to the space between the outside of the drillpipe and inside of the drilling riser 'annulus' below that seal. A riser gas handling system 'RGH' allows managing any gas in the drilling riser annulus by harmless gas removal out of the drilling riser. An RGH assists if formation gas that may enter the wellbore downhole rises, expands, and enters the drilling riser, increasing the drilling riser internal pressure.

Another Applied Advanced Technology development to increase the safety of drilling risers is a device capable of providing real-time data on the integrity of the drilling riser. Stress Engineering's device is an enhanced fatigue monitoring system 'FMS' which provides stress and fatigue measurements on risers, wellheads, and other subsea systems. With operations moving into deeper waters, drilling risers are exposed to harsher environmental loads, such as ocean currents and surface weather. The real-time FMS provides the driller real-time information every 15 minutes by having several sensors located along the drilling riser length.[45]

H. Managed Pressure Drilling 'MPD' & Early Influx Detection 'EID' -

Managed Pressure Drilling and Early Influx Detection are discussed in the same section below, because the continuing development of each Applied Advanced Technology enhances advanced analytics in the other technique - and as each is used more, additional new benefits are found. EID is a key advantage of the closed loop system created by MPD. On floater rigs, as the MPD closed loop system isolates the well from the floating rig's heaving motion due to

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[41] OTC-27242-MS.

[42] For descriptions of RCD and MPD, please see the next section: *H. Managed Pressure Drilling 'MPD' & Early Influx Detection 'EID'.*

[43] Drilling Contractor - Mechanical pressure relief system.

[44] The term 'lower pressure' is used here, because the working pressure of a rotating control device is much lower than the BOP stack. Yet Weatherford's deepwater RCD for floaters is rated 3,500 psi working pressure dynamic. https://www.weatherford.com/en/documents/brochures/products-and-services/drilling/rotating-control-devices-subsea-rotating-control-devices-(marine-series)/.

[45] OTC-27808-MS & OTC-24216.

sea states, the EID advantage provides increased sensitivity to influxes or losses of fluids into or out of the wellbore.

Managed Pressure Drilling 'MPD' -

As the oil and gas industry ventures into deeper waters and to deeper total well depths searching for new reservoirs, new drilling challenges are arising. New challenging environments include freshly drilling into and through rock formations that have narrow differences 'margins' between the natural rock formation zones' pore pressure and fracture pressure 'drilling windows'. If the wellbore bottom hole pressure 'BHP' is less than the formation pressure, formation fluids may flow into the wellbore 'influx'. And if the wellbore BHP is greater than the fracture pressure of the formation, drilling fluids may be forced into the formation 'loss'.

A key Applied Advanced Technology to overcome narrow drilling windows is to use a managed pressure drilling 'MPD' system. "Managed pressure drilling is an adaptive drilling process used to precisely control the annular pressure profile throughout the wellbore …."[46] MPD allows the driller on the rig to change the wellbore BHP without the conventional, time-consuming and costly practice of increasing or decreasing the mud weight to stay in the drilling window.

An MPD system comprises a specialty section in the drilling riser 'flow spool' below the rotating control device 'RCD', and an MPD backpressure choke manifold located on the rig floor. On floater rigs, the RCD is installed near the top of the drilling riser, directly beneath the riser telescopic slip joint. On some new floater rigs, the MPD specialty riser section may have both an RCD and riser gas handling 'RGH' system[47].

The key to MPD is the rotating control device 'RCD'. Inside the RCD is a sealing element mounted on a bearing, that when activated, the RCD creates a wellbore seal around the outside of the drill pipe and inside the drilling riser – while allowing the drill pipe to rotate and continually drill deeper. While drilling with the RCD element sealing, circulated return mud flows up the drilling riser annulus, through a flow spool below the RCD, and through a high pressure hose back to the rig. The RCD element seal around the drillpipe allows application and adjustment of riser annulus pressure 'back pressure' to the return circulated mud flow by opening or closing a variable valve 'choke' that's mounted in the surface MPD manifold. Since MPD is a closed loop system, this applied backpressure effectively increases and adjusts the BHP to stay within the drilling window along the length of the wellbore.

The MPD manifold consists of drilling chokes, pressure and temperature measurements, and one or more wellbore fluid flowmeters. Circulated wellbore fluid from under the RCD returns up a hose to the rig floor, passes through the MPD choke manifold and a Coriolis flow meter[48], and then into the conventional drilling rig fluid circulating system. The MPD drilling choke allows managing the mud pressure in drilling riser annulus and down throughout the wellbore The flowmeters provide measured wellbore fluid return flow data right as it returns at surface. The

[46] Phillip Frink-Drilling Contractor article March/April 2006.
[47] Please refer to Section "*V.G. Pressurized Drilling Risers, RCD & RGH Equipment"*, page 27 above.
[48] Coriolis meters are mass flow meters.

flowmeters and other measurements capture data and send it to an intelligent control unit 'ICU'. The ICU is capable of detecting formation influxes or losses in gallons (versus in barrels like conventional drilling methods), and it provides that data with analytics electronically to the driller on the rig floor, toolpusher and company representative in the rig control room, and to others remotely.

The measurements and choke control allow drillers faster, better decisions and actions, based on data rather than predictions. If a formation influx into the wellbore is detected, the choke can be closed, which increases the drilling riser annular backpressure and corresponding wellbore BHP, and stops the flow of formation fluids into the wellbore. If losses are occurring, the chokes can be opened, which decreases the riser annular backpressure and the BHP, and mitigates the flow of drilling mud into the formation. MPD operations have helped overcome tough drilling challenges and developed new deepwater resources by navigating through narrow drilling windows with fewer casing strings than conventionally drilled wells, and commensurate less drilling rig time on the well, resulting in more safety, and higher efficiency.[49]

MPD is not the same as the initiation of well control operations, since if a true well control event is detected, then conventional well control equipment (i.e. the BOP system) and methods are still present and immediately can be implemented. Yet MPD is complementary to conventional methods, and MPD provides several advantages by enhancing conventional well control methods. As a closed loop drilling mud system, MPD detects smaller formation influxes, leading to better discrimination between manageable influxes and kicks that require well control – which results in smaller formation influxes or kicks, quicker actions and safer return to normal drilling operations. Managing pressures downhole also reduces the risk of drillpipe getting stuck downhole – allowing drillpipe movement for more effective circulation of the influx or kick out of the well.

The quicker response actions of MPD saves valuable time, which is safer, and allows a wider range of corrective actions compared to conventional well control. To effect conventional well control (whether unnecessarily with a manageable influx, or absolutely required with a kick), drilling must stop, the drillpipe must be moved up, and mud pumps turned off, which decreases the BHP, and makes the influx or kick worse before closing the BOP. The well pressure must build up and stabilize underneath the closed BOP before any further actions are taken to circulate out the pressure. It may take many hours or even days before pressure stabilizes under a sealed subsea BOP and further actions are complete. Furthermore, it is not uncommon that well control operations become associated with secondary complications, such as ballooning/losses, or stuck pipe, which statistically adds 4.39 days to the well control event; and which 45% of the influxes result in drilling a sidetrack, and additional 9 days extra rig exposure per well.[50] Absolutely, well control actions are necessary if there was a kick; yet statistics show that most wellbore influxes are not kicks, they are small influxes. Utilizing MPD and EID[51]

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[49] JPT retrofitting article, AFG MPD specialty joint, OTC-25256.
[50] ES201252, Reliability of Deepwater Subsea BOP Systems and Well Kicks.
[51] For a description of 'EID' – Early influx Detection, please see page 37, below.

provides early, correct identification and proper handling of influxes - thus reducing rig exposure on the well.

Figure 6 below is a schematic diagram of a floater MPD system at the top of the drilling riser and at surface on the rig. It shows the RCD and high pressure lines (choke and kill hoses) going to/from the rig, and the MPD choke and flow meter. What it doesn't show is the multiple pressure measurement points, pressure safety valves, computer programs and readout for well MPD and EID management.

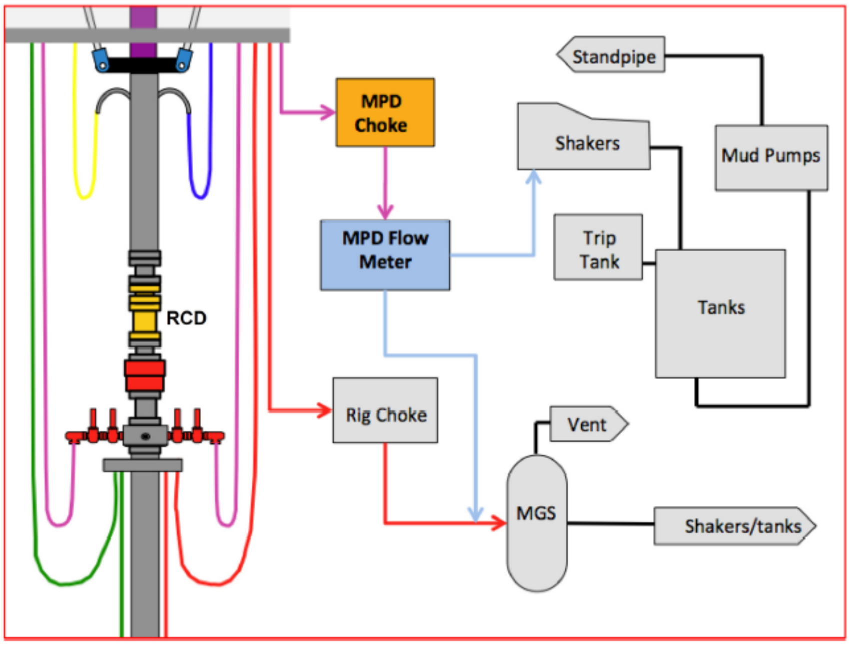

Figure 6: MPD Process Flow Diagram for Offshore Operations (OTC-25256-MS)

Figure 7 below shows an MPD Operations Matrix that establishes limits distinguishing between well formation influxes and kicks - and assists in making the decision between MPD actions and well control. This MPD Operations Matrix was developed and used by Operators, drilling contractors, MPD consultants, associations, and service companies prior to becoming a regulatory requirement. In 2007, the U.S. DOI Bureau of Safety and Environmental Enforcement 'B.S.E.E.'[52] established it as a regulatory requirement.

[52] 'B.S.E.E.' was formed by under the Department of Interior 'DOI', after DOI split the single former Federal offshore regulatory body, the Minerals Management Service 'MMS', into two separate Bureaus. B.S.E.E. - the Bureau of Safety and Environmental Enforcement is directly responsible for the safe and environmentally sound planning, operations, and subsequent abandonment of wells, operations, facilities, and pipelines in U.S. Federal waters. (DOI's separate Bureau of Offshore Energy Management 'BOEM' is directly responsible for U.S. Federal waters rights, leasing, and royalties.)

		Wellhead / Surface / Choke Pressure			
		At Planned Drilling Pressure	At Planned Connection Pressure	> Planned Back Pressure < Back Pressure Limit	> Back Pressure Limit
Influx Indicator	No Influx	Optimum	Optimum	Increase pump rate, mud weight, or both AND reduce applied surface pressure to planned levels.	Pick up, shut in well with rig's BOPs, and evaluate next action.
	Planned Limit	Increase back pressure, pump rate, mud weight, or a combination of all.	Increase back pressure, pump rate, mud weight, or a combination of all.	Increase pump rate, mud weight, or both AND reduce applied surface pressure to planned levels.	Pick up, shut in well with rig's BOPs, and evaluate next action.
	> Planned Limit	Pick up, shut in well with rig's BOPs, and evaluate next action.	Pick up, shut in well with rig's BOPs, and evaluate next action.	Pick up, shut in well with rig's BOPs, and evaluate next action.	Pick up, shut in well with rig's BOPs, and evaluate next action.

Figure 7: MPD Operations Matrix (SPE/IADC-179191-MS)

Figure 8 below shows an Influx Management Envelope 'IME' recently developed by industry. The IME built upon the MPD Operations Matrix. The IME uses the measured influx size and observed surface pressures, but also considers the effects of hole size, depth and wellbore geometry. The IME provides direction in determining whether an influx can be safely circulated out of the well using the MPD system. If it appears the influx is too large or pressures too great, then immediate conventional well control methods using the BOP system commences.

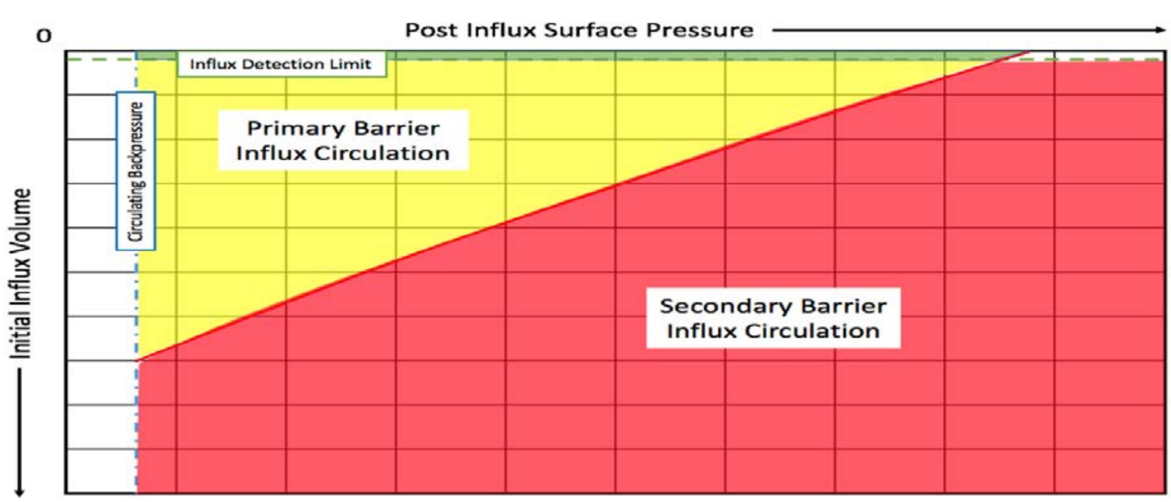

Figure 8: Influx Management Envelope Incorporating Elements of the MPD Operations Matrix (SPE/IADC-179191-MS)

The IME adopted the same 'traffic light' system as the MPD Operations Matrix above: Green- continue drilling; Yellow- pressures and influx volume are within capabilities of circulating using the MPD system; Red- pressures and influx volume would exceed the limits and cannot be circulated to surface safely using the MPD system, apply well control procedures. The moment an influx is detected, the MPD applied surface backpressure will increase to control the influx and the influx size can be determined. The applied surface backpressure and volume of the influx are then plotted on the IME to indicate how to safely manage the influx.

Early Influx Detection 'EID' -

Early influx detection 'EID' is an important Applied Advanced Technology where the industry is focusing its attention because of operations encountering downhole environments with increasingly narrow formation pressure drilling margins. The earlier that one can detect the occurrence of an influx from the formation into the wellbore, and the earlier that one can distinguish whether an influx is benign or a potential well control event 'kick', the lower the risk of well control actions, regardless whether those well control actions were unnecessary or proper under the circumstances.

API RP 92M defines a 'well control event' as "[a]n event during well activity that requires activation of the blow out preventer equipment when the operational envelope of the primary barrier is exceeded."[53] Early influx detection and recognition coupled with proper rig procedures can and will reduce the size of influxes, thereby leading to quicker and safer identification of the type of influx, and the management of that influx.

On all rigs, there are three key influx measurements that are constantly monitored: (1) a change in flow rate of circulated wellbore fluid 'mud' returning back to the rig; (2) a gain in mud tank 'pit' volume; and (3) whether the well is flowing after the mud pumps are turned off to stop mud circulation. Any of these three can indicate that an influx from the formation may be occurring. On floater rigs, pit volumes are monitored by pit volume totalizer systems. In all drilling operations, if a gain in mud volume in the pits is suspected, a 'flow check' is required. To perform a flow check, mud pumps are turned off, which ceases mud circulation in the wellbore and drilling riser. If a flow check shows that a formation influx is occurring, then proper actions start to manage that formation influx, or commence well control procedures. Since EID both lessens influx detection time and allows discrimination between smaller flows of manageable influx versus critical well control event, EID mitigates unneeded flow checks, and saves critical time that an otherwise required flow check takes prior to further actions. Saving critical time is important for safety and environmental soundness, because when drilling mud is not circulating during a formation influx, that extra time results in a larger influx, which is tougher to manage or control.[54]

Managed Pressure Drilling 'MPD' is an Applied Advanced Technology closed loop fluid system on the drilling rig that provides the ability to detect small formation fluid influxes by enabling EID. This ability to detect small influxes helps measure the rate of mud flow back to the rig, and therefore distinguish between mud flow that has either a (1) short and/or low-rate, or (2) long and/or high-rate. This direct measurement, coupled with digitally stored pre-drill models and comparisons to other wells drilled in the same area, allows fast understanding and correct

[53] API RP 92M. First Ed. Sep. 2017, Errata 1 Oct. 2017.; Sec. 2.1.21.
[54] SPE-170756-MS.

decisions for any next steps. Accurate and fast information enhances correct decisions and efficient actions, with reduced operational risks. The combination of reducing operational risk and reducing the operations time that a drilling rig is on a well, provides enhanced safety and environmental soundness to all Upstream operations – whether deep or shallow water or onshore in any Federal or State jurisdiction.

Another Applied Advanced Technology development is BHGE's subsea annular flowmeter for EID applications located near the BOP. This technology uses an acoustic "delta" flow meter that can measure the flow influx while gas is in solution.[55]

Applied Advanced Technology was recently presented by a small company named KnowFlow, which has developed a drilling riser mounted metering that directly and simply shows whether there is wellbore fluid flow up the top of the drilling riser. The KnowFlow system measures, collects and displays the real-time data, and provides immediate indication. On floaters, since KnowFlow's monitor is mounted on the drilling riser below the riser telescopic joint, drilling rig heave caused by sea states does not affect it. This is important because flow up the drilling riser at the wrong time or an unexpected fast increase in flow can indicate potential or actual need of well control.[56]

I. Downhole Drilling Equipment & Services Selection -

As previously noted, anything going down in the well has special design, primarily due to dimensional limitations and downhole rigors. Downhole equipment may be: any short time work string to drill or work on the well; installed permanently as part of the casing string; installed in the completion for medium to long term use, yet changeable as part of the completion; or during intervention to perform a mechanical or measurement function as a tool. All these downhole equipment devices must be quite small in outside diameter to fit in the wellbore or casing or tubing (i.e. under 19" to fit inside 20" nominal size surface casing; under 3" to fit inside 3.5" nominal size production tubing), yet function within the downhole environment of very high pressures, high temperatures, and possibly corrosive fluids. Downhole equipment is run and retrieved by being mounted on a well tubular 'pipe string' or via wire run inside the well 'wireline'.

Downhole equipment run by the drilling rig at the bottom working end of the drill pipe 'drill string' starts at the bottom with the drill bit. The drill string includes tools threaded together and stacked up above the drill bit combined into the 'bottomhole assembly' – 'BHA'. The sophistication and high technology of BHAs is quite impressive. Oilfield service companies (such as SLB, HAL, BHGE, and WFT) develop and manufacture the BHA tools' development and provide the services that operate and interpret the measurements from them - though it is individual inventors and small companies that often come up with the ideas and develop those ideas into new, innovative tools, products and services.

[55] IADC Advanced Rig Technology 2017 and DEC Technology Forum 7 Sept. 2016.
[56] KnowFlow System Presentation IADC Spark Tank Dec 12, 2017.

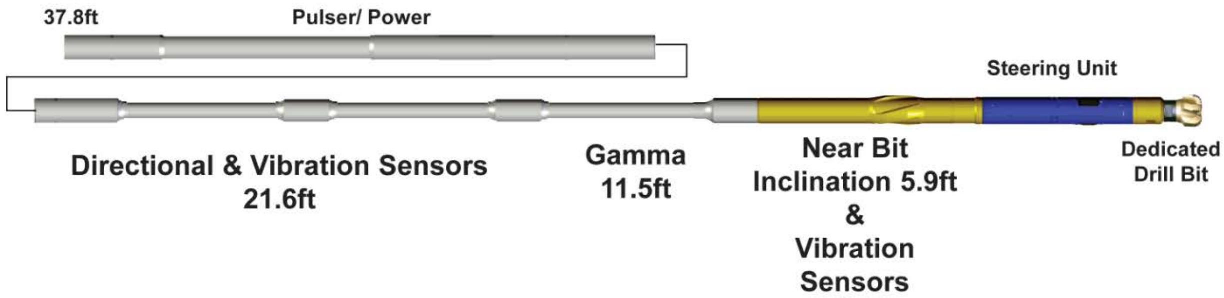

Figure 9: Schematic Diagram of a Generic Bottomhole Assembly 'BHA'[57]

For directional and horizontal well drilling, the BHA often includes (bottom-to-top): a drill bit with type and size for the specific hole section to be drilled; a downhole mud motor that turns the drill bit and is powered by drilling mud circulated from surface down the drillpipe through the drill bit nozzles; multiple sensors located in the BHA that are powered by a downhole generator above the mud motor; and a 'mud pulser' mounted at the top of the mud motor that generates and sends small pressure pulses in the drilling mud back to the surface for decoding into useful data. Figure 9 above shows a generic example of a BHA

The sensors may measure the speed the mud motor is turning the drill bit, the downhole weight the drill string above is exerting onto the drill bit, the downhole vibration that the combined drill bit and drill string weight causes in the whole BHA, the angle and direction of the drill bit, the downhole pressure & temperature of the wellbore fluid outside the drill string, and the formation rock properties the drill bit has just cut through. These sensor measurements may be considered electronic 'eyes downhole'.

The small pressure pulses generated by the BHA are a form of code that is telemetry of measurements from downhole to the rig drilling monitors at surface. The pressure pulse telemetry transmits all this information up the mud column to surface simultaneously while the drilling mud is being circulated down the drill pipe, through the drill bit, and up the annular space between the outside of the drillstring and inside the wellbore. On the rig at surface are sensors that detect these mud pulses, convert them into electronic signals, and then decode the signals into their separate component measurements.

Importantly, BHAs today not only provide information via mud pulse telemetry up to the surface on the drilling mechanical and formation attributes, the mud pulse telemetry may also send signals with instructions down to the BHA. The signal instructions sent down to the BHAs primarily are to activate small motors within the BHAs that cause the bit to move at slight constant angles while rotating and drilling. These 'rotary steerable' BHAs are therefore both

[57] A. Jones, D. Livingston, A. Serdy, S. Janwadkar, T. Rice, and D. Rice, "High-build RSS drills consistent, in-zone wells in Marcellus," *Drilling Contractor*, 11-Jul-2013. [Online]. Available: http://www.drillingcontractor.org/. [Accessed: 15-Aug-2018]. Note that Figure 9 shows an example BHA for drilling Marcellus shale onshore, the configuration is similar onshore and offshore.

‘navigated’ by the operations geologist to direct that the wellbore be drilled around or through geologic zones, and ‘driven’ by the driller according to the geologist’s directions towards target zones. This ‘geosteering’ greatly advances how wells get drilled to the right place and get downhole formations accurately measured, thereby safely reaching targets, while reducing the time drilling the well.

The BHA component measurements are inputs to computer algorithms on the rig that simultaneously provide the sensor measurements and interpretation of those measurements to multiple key persons on the rig, and oftentimes via secure communications to remote offices onshore granted electronic access. This information tells those electronically tied in what is going on downhole and on surface. The multiple key persons receiving this information include the drilling contractor’s ‘driller’ in his cabin on the rig floor and his boss, the ‘toolpusher’ in the rig office, the oil Operator’s head man in the rig office ‘company man’, operations geologist and drilling engineer, and certain service company specialists on the rig. Depending upon the drilling operation, well, rig, and other factors, electronic access also may be given to others.

The oilfield service companies that provide BHA drilling, measurement, downhole telemetry, surface recording, and interpretation have each developed their private proprietary systems, developed over tens of years - from quite rudimentary to extremely sophisticated, as well as multi-sensor, and bi-directional. They fiercely compete to provide Applied Advanced Technologies to Operators. The oilfield service companies employ scientists, engineers, specialists, and decades of experience developing new tools and methods ‘techniques’. New drilling techniques include but are not limited to: additional closer-to-the-bit measurements downhole, more advanced telemetry to surface, faster as-measured data interpretation, and predictive analytics software.

The information collected on the rig is the Operator’s trade secret information. The Operator oil company uses stored information from previous wells to plan new well drilling programs, and to design and make the next well safer and more efficient. While drilling a well, the previous well’s information, and current well design may be called up and compared quickly to the new updated drilling information that is continually arriving. New information with analytics allows quick changes and adjustments, if needed, as the drill bit cuts and exposes new wellbore drilled within different natural formations and drilling conditions. Being able to pre-plan drilling the current well, and then having ‘eyes downhole’ while drilling it, and making fast corrections and adjustments during drilling, reduces risks, reduces time to drill, and commensurately reduces exposure time of persons and the environment to potential drilling issues. This information gives the operator oil company the downhole target zone(s) and fluids information that allows it to make more accurate and faster decisions for safety and environmental soundness, while also providing the economic basis for sound large investment decisions, such as whether and where to complete the well, and for early or later production.

***J. High Volume Data Acquisition & Analyses* -**

‘Applied Advanced Technology’ includes but is not limited to new equipment and procedures. Exponential advances in storing and processing and analyzing massive well and field data is, has and continues to be the newest high impact ‘Applied Advanced Technology’, with the largest oil company operators employing supercomputers to do it. Examples include BP recently announcing the world's 3rd fastest computer in their Houston complex; and various companies deploying IBM's Watson service in drilling operations. Fast computing allows the massive amount of geologic and geophysical 'G&G' data and subsurface imaging to be updated constantly with new formation data while drilling, and it allows changing well path trajectories consistent with geosteering to and through formations and targets as the drill bit cuts into new rock.

Oil companies keep their information confidential because all the information is both highly competitive and very expensive to obtain, store and analyze. Supercomputer technology allows companies to 'visualize' the subsurface formations in 3-dimensions on their computer screens and determine the chosen target zones, then model and plan the best well path to get to those targets. The geologic and geophysical technological advances have and continue to propel the Upstream industry into high percentages of successful gas & oil discoveries per each exploration well drilled – as well as better placement of each well, resulting in more production from fewer number of drilled wells, and associated safety advantages.

In the Gulf of Mexico (GOM), the biggest leap in geologic interpretation and in the finding of new producible oil & gas has been the ability to visualize underneath massive subsurface salt structures. After the U.S. Upstream industry predicted, drilled, and confirmed that large 'subsalt' zones of oil & gas existed and were producible, the deepwater GOM industry took off. These G&G advancements will continue advancing deepwater resource exploration and development. Drilling downhole and surface data acquisition and analyses are quite important to well safety and environmental soundness. However, even though those advantages are huge, we don't expound on the G&G data acquisition advances here, because the G&G aspect of the industry is a topic of itself, sequentially prior to the deepwater drilling focus of this Report.

K. Drill Bits -

Overview of Drilling Systems & Drill Bits -

Many drilling system tools are available that enable the well drilling process to penetrate a set of geological formations. The deepest working end of a drillpipe string has a type of mechanical drill 'bit', which is used to apply either cutting or breaking forces, or more frequently a combination of both, over a small contact surface on the rock formations. The cutting or breaking forces generally generate mechanical stresses that exceed either the rock tensile strength or the rock shear strength. As a result, the rock will break into newly cut small rock fragments 'cuttings', due to brittle failure or plastic yielding. Combinations of the formation rock natural stress state, the drill bit design, the borehole geometry, and the drill-string dynamics play critical parts in the rock failure mechanism. A drill bit not only cuts the desired borehole diameter, the drill bit itself is designed to have a direct impact on the characteristics of the cuttings that are circulated up from the bottom of the borehole being drilled, through the wellbore annulus to surface, and then on the rig to be recovered. Drill bit design is also critical when trying to drill a directional borehole, or when trying to maintain or drill a vertical borehole. The borehole trajectory is essentially controlled by the drill bit tilt and the side forces acting on the bit - both which are functions of the drill bit type, time rate of penetration 'ROP' the drill bit cuts new borehole, bottom hole assembly, rock characteristics, and G&G data. Cumulatively, these variables define the direction of the drill bit force, and hence the borehole trajectory.

The materials that are used to build drill bit systems are critical for their performance, durability and application to cut specific rock formations. The materials are usually hardened and tempered carbon steel, cobalt steel and tungsten carbide. For some drill bit designs, man-made artificial polycrystalline diamonds are embedded into the tips of the cutting tools, and coatings such as black oxide, titanium carbon nitride or zirconium nitride are applied on the diamonds to increase bit wear resistance.

Drill bits come in various forms and sizes using different cutting surfaces, and the drill bit body can be composed of different materials. Drill bit original equipment manufacturers 'OEM's offer a very large catalogue of drill bits that they respectively design and manufacture, and that are made available to operators to reach optimum performance when drilling different geological layers. OEMs compete vigorously to provide the best bit for efficient performance in various formations, with economic offerings to operators.

Drill Bit Technology Types -

Depending upon the type of geological layer and the rock formation's geotechnical and petrophysical characteristics (e.g. hardness, abrasively, strength, etc.), the Operator will select a certain drill bit type and design. The drill bits types include (1)"soft rock drill bits" that are specifically designed to drill through soft formations, (2) "very hard formation rock bits" to enable drilling through hard formations such as hard shale or carbonates which are often encountered by the oil and gas industry, (3) bits designed for hard igneous and abrasive chert rocks. Some common types of drill bit systems that can be used in drilling well boreholes are discussed below.

Roller Cone Tricone and Tungsten Carbide Insert Bits -

The roller tricone cutter drill bit is the most common bit type currently used with the rotary drilling[58] process. By definition, tricone bits have three cones that hold the cutters. The cones turn or roll around the drill bit axis at the bottom of the hole while the rig rotates the drill string above the bit, newly cutting the rock wellbore. The drill string weight applied to the cutters results in pressure beneath the cutters increasing, so the bit teeth apply a high point pressure onto the rock that exceeds the rock formation's crush strength. The rock fails in compression.

[58] 'Rotary drilling' is a term that refers to rotating the drill bit at the bottom of the drillpipe string by the drilling rig rotating the drillpipe from top. Rotary drilling is historically the most common drilling method, and it remains so globally. Yet the advantages of long directional and horizontal wells were not achievable until modern Applied Advanced Technology of BHAs, which included downhole drilling motors (please refer to "*Section V.I. Downhole Drilling Equipment & Services Selections"* above). Downhole drilling motors have replaced conventional rotary drilling in many applications and wells.

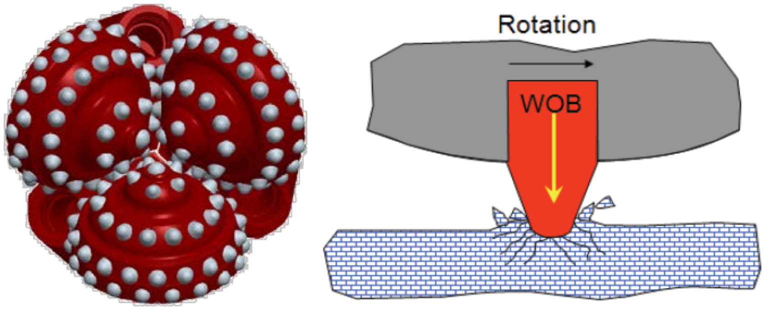

Figure 10. Roller Cone Cutter Formation Failure Mechanism: Compression

Tungsten carbide inserts may be manufactured into the drill bit. The tungsten insets will apply pressure to the formation until the pressure exceeds the crushing strength of the rock, and a wedge of finely powdered rock forms beneath the cutters. As the force on the cutters increases, the material in the wedge compresses and exerts high lateral forces on the rock surrounding the wedge. Finally, the shear stress will exceed the shear strength of the rock, and the rock will fracture and fail, breaking into cuttings. Roller cone bits are available with numerous cutter designs and roller bearing types to be used to drill a wide range of geological formations. The capability to efficiently drill through soft or hard rock will vary by length and spacing of the cutters on the cones.

Polycrystalline Diamond Compact 'PDC' Bits -

PDC bits today allow their use in a lot of drilling applications. Polycrystalline diamond compact 'PDC' bits consist of polycrystalline diamond compact inserts that have high abrasion resistance in the diamond layer mounted with tungsten carbide cylinders. They break the rock with a shearing action. The tungsten carbide layer is used to provide mechanical support and high resistance to impact loading. Since PDC bits are built in a mold with the compacts positioned prior to pouring the metallic compound, the design of PDC bits can be almost unlimited, allowing the variety of special designs for specific rock formation applications.

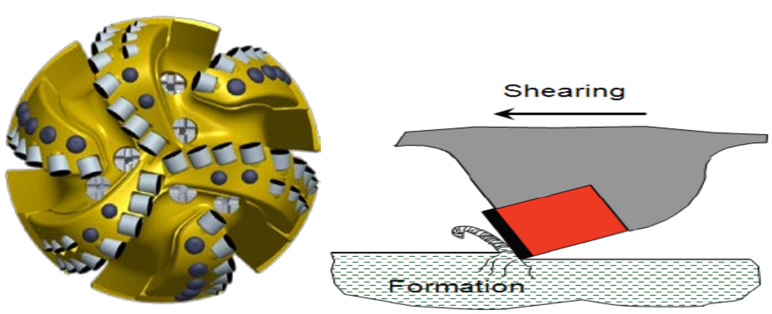

Figure 11. PDC Formation Failure Mechanism: Shear.

Insert and Impregnated Diamond Drill Bits -

Insert bits are also called surface set diamond bits. These bit systems consist of several single diamonds which have been set in the metallic body matrix. They are utilized to drill through very hard formations. Impregnated diamond drill bit systems are specifically designed for ultra-hard, abrasive rock formations, such as relatively high silica, quartz or iron content. This bit design consists of a diamond grit which is mixed with tungsten carbide in its liquid form. Then the mixed compound is molded into the bit design shape. The wear resistance of impregnated bits is necessary to drill through abrasive formations.

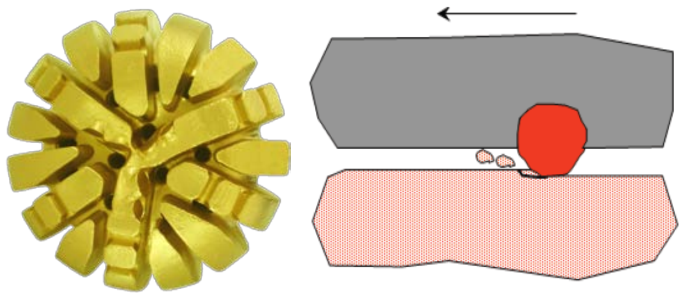

Figure 12. Diamond Impregnated Formation Failure Mechanism: Grind and Shear.

Drill Bit Designs and Types -

Applied Advanced Technologies in the drill bit world constantly emerge, enabled by 3D imaging and drilling simulator trials. These new technology drill bits derive from redesigned cutting structures and crossbreeds that integrate between two different drill bit types.

PDC bits are now incorporating conical diamond cutting elements (CDE) along with conventional PDC cutters. These CDEs are designed to provide a higher level of impact strength and wear resistance compared to conventional PDC cutting elements.[59]

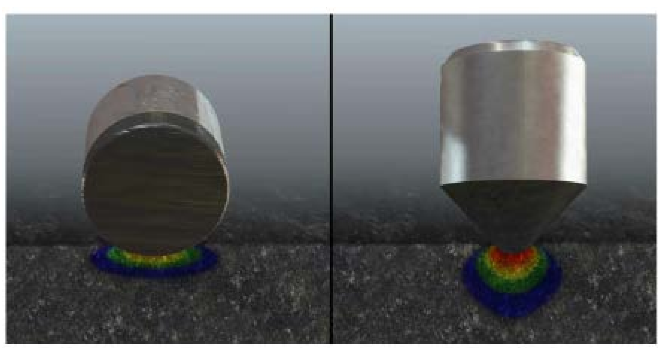

Figure 13: Conventional PDC cutter vs. CDE-PDC cutter. (SPE-177085-MS)

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[59] SPE-177085-MS.

Another new development is the crossbreed of PDC bits and rollercone bits into 'hybrid' drill bits. These hybrid bits combine the abilities of two previously separate bit types into one drill bit, with the shearing abilities of PDC bits and the crushing abilities of roller cone bits. The roller cone provides two important benefits: it provides a depth of cut control and it pre-fractures the formation. The pre-fracturing that is done by the roller cone portion of the bit enables easier shearing of the rock by the fixed PDC cutters.[60]

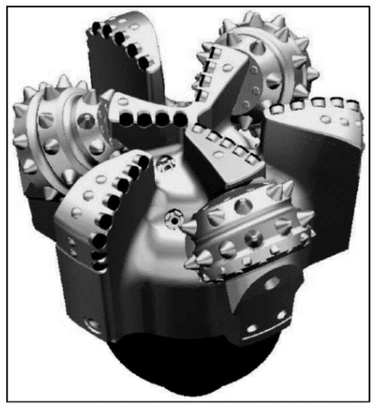

Figure 14: Hybrid bit used in Gulf of Mexico. (SPE-180342-MS)

One of the newest Applied Advanced Technologies being introduced is the "smart" drill bit with self-adapting depth of cut control (DOC) elements, which will extend or retract based on the loads observed by the bit. The smart drill bit can increase the cutting aggressiveness when it is under a constant load by retracting the DOC control elements. If the observed load decreases, the depth of DOC control elements will extend to reduce the aggressiveness of the bit.[61]

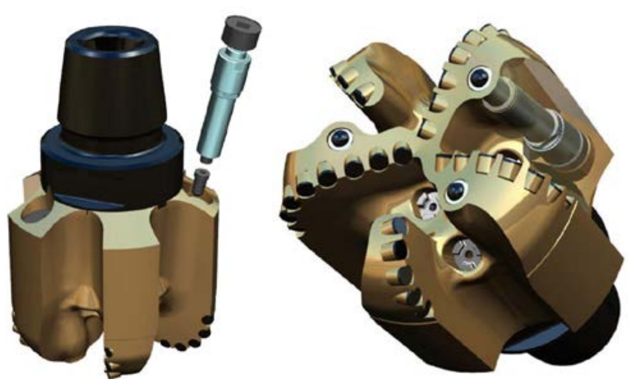

Figure 15: Self-adjusting element and self-adjusting PDC bit. (SPE-187370-MS)

[60] SPE-180342-MS.

[61] SPE-187370-MS.

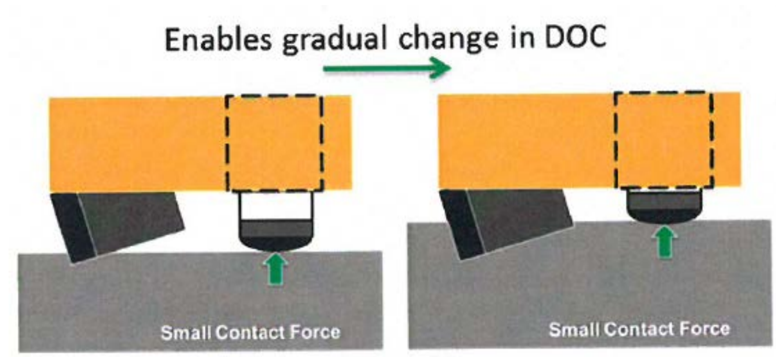

Figure 16: An illustration of the self-adjusting DOC control element. (SPE-178815-MS)

Continuing with the new drill bit designs above are the Applied Advanced Technologies in manufacturing. BHGE revealed recently that 'additive manufacturing', commonly known as '3D printing', is being used to make new drill bits. Some of these new drill bits are in field trials with operators. Field trial results will help ascertain if this will be a future trend.[62]

L. Well Integrity Techniques -

Applied Advanced Technologies bring increasing well integrity assurances. A lot of this assurance comes from higher levels of research in thermal and materials sciences in downhole applications, and the downhole measurements that indicate technological effectiveness. Two examples are discussed in this section.

Attached to the wellhead and hanging from below it are the concentrically smaller strings of steel tubular pipes called 'casing'. The outside of the steel casing strings must be sealed from the formation at certain points, so that wellbore fluids cannot flow up between the annular space between the outside of the casing and the inside of the wellbore, or inside the wellbore between separate formation zones. Sealing is also required to seal off the annular space between the inside of a larger casing and the outside of a smaller concentric casing that's run inside it. Oilfield cement historically is used to seal this annular space; and the process of doing so is called 'cementing'. Cementing is performed by pumping cement from surface down the drillstring[63], and around the bottom of a casing string, until the pre-calculated sufficient amount of cement fills a section of the cylindrical annulus, and then sets up as a solid cement seal.

Well cementing practices have advanced, and problems with poor cementing practices have been greatly reduced. Previously accepted cementing practices are now eclipsed by advanced methods, reducing potential well issues. Applied Advanced Technologies in sensors and

[62] LinkedIn article by Mathias Schlecht, VP Enterprise Technology, covering a range of new technologies by BHGE, with a paragraph dedicated to Additive Manufacturing and discussing 3D-printed Drill Bit: https://www.linkedin.com/pulse/adapt-adopt-successfully-navigate-through-new-normal-mathias-schlecht.

[63] Note that during cementing, drill pipe is used as a 'workstring'; and is often called that because of its function. Nevertheless, the drillpipe in the cementing and other workstring tasks is normally the same drill pipe used for drilling, since it is most efficient to not have to change out drill strings for different functions, if possible. Therefore, it's normal to use and call it a 'drillstring', even when it's being used for other tasks than drilling.

measurement analyses confirm that the cement sheath has sealed without channels or voids in the cement. This improvement in sensor and measurement analysis gives an improved cement bond log 'CBL'. A CBL is the output of the series of measurements from a tool run in the well on wireline after cementing, that via acoustic and/or electronic methods 'sees' through the steel casing and the cement, allowing a view whether the cement sheath has a hole or leak path though it or not.

On high temperature wells, the specter of well fluids trapped in annular spaces when cement sealed the bottom of two casing strings together was a real risk. This risk, called annular pressure build-up 'APB', is especially critical for subsea wells. To address this risk, the Upstream industry applied heat transfer science to high temperature well design. It can now be calculated how a rise in well internal temperature will result in a rise in pressure within each sealed annulus of a well. Steel material science is then used to determine the ultimate mechanical properties of each casing string. This 'APB analysis' provides needed results for complex subsea well design, since mitigation of APB effects may require any combination of (1) stronger tubulars, (2) a type of thermal insulating that keeps heat from transmitting to the outer annuli, or (3) special types of annulus pressure relieving methods.. Deepwater Operators performed APB analyses years ago. Yet the DOI B.S.E.E. now oversees the proper management of APB. APB analysis provides wells that are environmentally sound with well integrity.

VI. Completions -

Well completions and completion tools are a specialty – yet critically, this specialty is the final stage between when the well is drilled and when the well is put into use for its intended purpose of producing oil and natural gas. Completion engineers focus on the complexity of this final well stage.

A. Overview of General Downhole Well Test & Completion Equipment and Tools -

Generally, downhole well test and completion equipment and tools have two functions, either: (1) to flow well fluids from target zone(s) to the wellhead at surface 'production', or (2) to pump fluid from the surface wellhead down into target zone(s) 'injection'[64]. Completion equipment and their configuration, and completion types and complexities vary, depending upon the well function, the number of zones, and the expected term of zonal useful life.

Well completion for testing and/or production begins after well drilling, casing and cementing operations. The 'completion equipment', is highly specialized in design, consisting of many separate functional devices 'tools', and operating within the small internal diameters downhole. These completion tools normally have moving internal parts, sliding assemblies, and seals that

[64] Wells have intended purposes, which usually are either to produce oil & gas, or to inject produced water or gas for disposal and/or reservoir pressure maintenance. During some wells' lives, they may have both functions, being producing wells first, and later injection wells.

allow the tools to perform their specialized function, within the downhole high temperature, pressure, and sometimes corrosive environment, yet restricting the production from each zone as little as possible.

A well test / production engineer is often the 'completion engineer' who is responsible for designing and running the completion equipment. The completion engineer's specialty includes: (1) running a test string or production string of pipe 'tubing' inside the cased wellbore to near and above a potential producing zone, (2) sealing the annulus between the inside of the casing and outside of the test/production string, then (3) perforating holes through the casing and casing cement sheath into the formation 'perforations' that allows formation fluid flow into the wellbore. The well test / production engineer will regulate the well flow up the tubing string by operating valves and chokes.

When well testing, the engineer will plan and execute flowing the well at different flow rates and monitor the well pressures at those rates, and also look at the rate of change of well pressure each time. The changing rates and pressures 'transients' are analyzed, and the ability of that well to produce through its completion is then calculated. The well test time must be long enough to flow the well at stabilized rates to evaluate and predict how much of what formation fluid types will be producible in the future. Predictions include target zone(s)[65] reservoir characteristics of extended productivity and a minimum size of that tested hydrocarbon reservoir. This information will be essential in later understanding the life of the well, and (cumulatively with other field wells) the field's life.

Well test strings typically are only installed for a temporary period. The well test time may be days or weeks, as determined by the well test engineer. If safe for a short duration test, the test string may be composed of drill pipe with special test tools.

The production string of pipe with special connections attached underneath the wellhead inside the production casing is the production or injection 'tubing'. The tubing string is designed to handle a specific range of fluids at full well pressure and temperature and corrosion resistance top to bottom. Because tubing will be exposed to the toughest well conditions during the life of each well completion, the steel pipe and pipe connections size, wall thickness, grade, and integrated completion tools made up as part of the tubing string are specified with utmost precision. The completion tools and tubing string must be able to operate for extended periods of time under expected downhole conditions.

Production tubing string completions are designed for semi-permanent installation in the well when the well will be used for production from, or injection into, target zone(s)[66] over extended periods of years. They are 'semi-permanent', because at some point in the future a rig may

[65] Note that a well completion may be for a single target zone, or multiple target zones. The completion engineer in conjunction with the reservoir engineer must decide promptly between when the well is drilled, logged, cased and cemented, and when it is time to run the completion, which formation zone(s) will be perforated, and where and what completion tools will be set. The decisions are made so each well production stage is efficiently operated, and so each can be remediated in the future. In this Report, the term target 'zone' will mean one or more target zones produced or injected, per well completion.

have to move onto the wellhead, and each tubing completion will have to be pulled for a variety of reasons. This is referred to as intervention. Intervention reasons include: well maintenance ‘remediation’; formation depletion (the perforated zones no longer produce economic rates of gas or oil); equipment change (one or more new completion tools must be added, or the previous tools no longer function properly); or final removal before well plug & abandonment (P&A). If a tubing string is pulled from the well and another tubing string completion is run back in, this is typically referred to as a ‘workover’.

Certain completion tools are designed so that interventions can be performed inside the tubing ‘thru-tubing’ without removal of the wellhead by using wireline or small diameter coiled tubing.

B. HPHT Completion Tools -

Significant Applied Advanced Technology effort has gone into development of high pressure – high temperature ‘HPHT’ completion equipment over the last 10 years. The Upstream industry ability to drill and cement casing to deeper depths and higher temperatures and pressures has enabled production of vast new sources of oil and natural gas. In order to produce in these conditions, completion equipment qualified and rated for operation in these extreme environments had to be developed. The development process for HPHT equipment must follow B.S.E.E.’s processes.

As with all oilfield equipment, completion tools continue to improve and arise to meet new challenges. Some Applied Advanced Technologies are mentioned here.

High Pressure 20,000 psi Rated Tools -

The offshore industry continues to move forward with qualifying completion equipment for 20,000 psi working pressure wells. These working pressures are defined by expected shut in tubing pressure at the mud line. These 20,000 psi Applied Advanced Technology tools include the usual upper completion equipment for initial development and primary depletion: production packers, nipples and plugs, chemical injection valves and mandrels, and subsurface safety valves.

High Temperature Tools -

Geothermal temperature is a function of water depth, depth below mud line, and formation properties (such as sand, shale, salt). Wellbore true vertical depth ‘TVD’ generally increases the bottomhole temperature ‘BHT’, although the geothermal gradient may vary depending upon formation thickness above a salt zone, and the salt thickness. Offshore, high pressure is often accompanied by high temperature, which means that 15,000 psi and 20,000 psi Applied Advanced Technology completion equipment is simultaneously designed to temperatures to 350^{o}F. This practice is common for deepwater wells.

There are some offshore wells that are located in shallow waters (not deepwater) and yet are quite deep in total depth ‘deep shelf wells’. These deep shelf wells have high geothermal gradients, so that at depths of over +25,000 ft. they have very hot BHT. These deep shelf wells may have BHTs up to 450^{o}F, which greatly affects the selection of elastomers and thermoplastic seals in Applied Advanced Technology completion equipment.

VII. Production – Subsea Systems

Oil and gas Operators are moving into the deepest U.S. GOM waters searching for additional new hydrocarbon reserves. Nevertheless, Operators must expend a large amount of capital investment to find, and eventually produce new reserves. Exploration G&G and well drilling costs are generally higher in deepwater. These higher costs and associated capital expenditures extend to the facilities required for deepwater production, with new facility costs in the billions of dollars range. Production facilities are quite large, and support, handle, and process production from multiple wells. When wellheads are supported by a facility's structure, a platform rig may be used to drill, complete, and perform workovers on these wells. Yet some wellheads must be mounted on the sea floor, and these subsea wells may be located far from the offshore process facility. Subsea production systems include a set of Applied Advanced Technologies for production and processing that are located on the sea floor. These advancements allow the operators to drill wells miles away from current production facilities and 'tie-back' to the surface process facility from the seafloor.

Typical subsea production involves produced hydrocarbons flowing up the wellbore, through the wellhead and subsea tree, through a subsea flowline 'jumper' to and through a subsea manifold and flowline, into a vertical production riser, and up into the surface production facility. The surface facility will then treat and process the produced hydrocarbons, before pumping them through export pipelines to onshore storage facilities.

The importance of the subsea wellhead cannot be discounted. The wellhead provides the foundational support for the structure of the well, providing the primary landing to support the casing loads. The wellhead is a pressure containing vessel which contains receptacles for casing hangers and provides metal-to-metal sealing. Also, the wellhead provides the 'male fitting' for latching of the BOP and subsea trees.[67] Figure 16 below shows a cut-away drawing of a subsea wellhead with various casing strings and seals in different colors.

[67] Petrowiki - Introduction to Wellhead Systems.

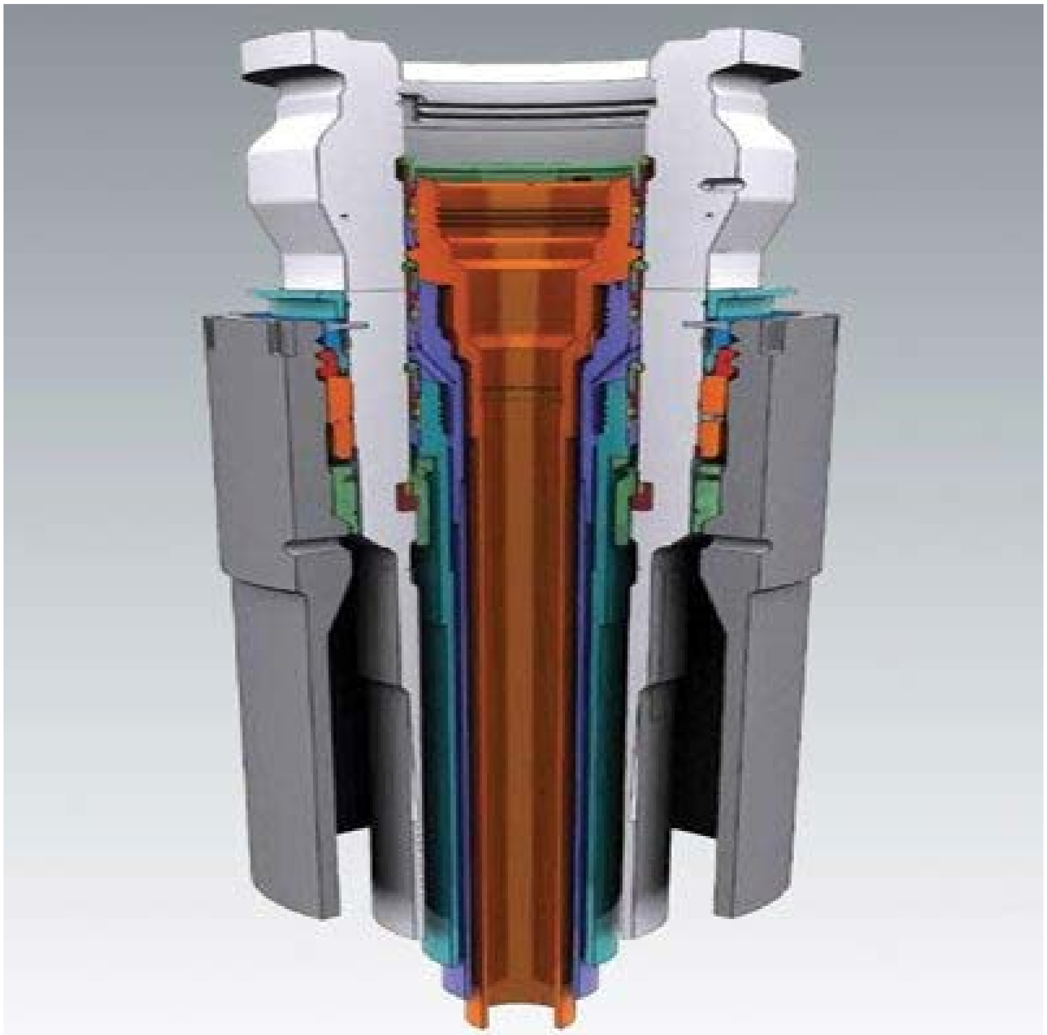

Figure 17: SLB Cameron STM-15 DW5 Deepwater High Capacity Subsea Wellhead System

https://aemstatic-ww1.azureedge.net/content/os/en/articles/2012/03/sstb-2012--cameron-features/_jcr_content/leftcolumn/article/footerimage.scale.large.jpg/1331144005000.jpg

Subsea trees are designed based on expected operating conditions. The purpose of a subsea tree is to monitor and control the flow of production, as well as to manage the injection of fluids into the well.[68] Subsea trees can be horizontal or vertical designs, with each design having its own set of advantages. Horizontal trees are shorter in height and are better in areas in which workovers are often done. This is due to the fact the tree doesn't need to be removed for

[68] https://www.geoilandgas.com/sites/geog/files/345_GE_SS_Subsea_Trees_Pages_280113.pdf.

workovers, like a vertical tree does. Vertical trees, however, are easier and cheaper to swap out.[69]

Every subsea well has a jumper flowline from it, and the jumper flowline has the full, unseparated stream of produced well formation hydrocarbons running through it, often at high wellhead pressure. A well jumper flowline goes to the subsea manifold.

Subsea manifolds may have an inlet choke for each well jumper flowline that attaches to it; with the choke reducing each well's flow rate and pressure to the working pressure of the subsea system. Collectively, a subsea manifold collects produced hydrocarbons from multiple wells, and after managing the flow rates and pressures, then directs those produced hydrocarbons to the production facilities via larger subsea flowlines and production risers. By combining production from multiple wells, subsea manifolds allow fewer yet larger diameter flowlines and risers to be tied back into the surface facilities.

Subsea trees and manifolds transmit and receive information to and from facilities with the use of an umbilical. Umbilicals also deliver the power, communications, and fluids to subsea equipment to function the seafloor sensors and valves. The subsea equipment is designed, so that if the umbilical happens to fail, a remotely operated vehicle 'ROV' or autonomous underwater vehicle 'AUV' will perform such tasks.

Applied Advanced Technology subsea boosting capabilities allow hydrocarbon production up to the surface facility via the production riser. Especially in the deepwater GOM, natural well pressure is not sufficient to pump the hydrocarbons up through the seawater column to surface. Special pumps that operate on the seafloor provide the energy to do so 'subsea boost'. Subsea manifolds tie into the subsea booster and subsea flowlines before the production is pumped up the production riser to surface. Key is that subsea boosting technology uses multiphase pumps, and these multiphase pumps will handle a range of full wellbore formation fluid components – hydrocarbons (gas & oil) and water 'wellstream' - without the previous requirement that each of the wellstream components be separated prior to pumping each separately. This Applied Advanced Technology continues to develop, so that the pumpable wellstream compositional range gets wider. Full wellstream subsea boosting has allowed operators to have subsea wells that are long distances away from their production facilities (referred to as a 'stepout'); yet have flowlines and production risers connect to the facilities 'tieback'. The longest subsea tieback in the Gulf of Mexico will soon be tied back a distance of 22 miles to its surface production facility.

Another advantage of subsea boosting is that by pumping at the seafloor, the wellhead producing pressure 'backpressure' is reduced, which commensurately reduces the downhole wellbore pressure. This reduction in backpressure can increase the production rate of resource recovery, and it has led to potential increases in reservoir resource recovery factors by as much as 10-30%.[70]

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[69] (http://www.drillingformulas.com/vertical-subsea-tree-vs-horizontal-subsea-tree/.

[70] One Subsea Boosting Systems Contribute to Jack/St. Malo's Success.

Applied Advanced Technology also includes subsea separation of wellstream produced fluids. Subsea separation has multiple advantages, such as decreasing the required subsea boosting power required to pump fluids to surface facilities, and reducing the equipment needed on the surface facilities. Subsea separation also gives the operator the ability, at the seafloor, to immediately re-inject the formation produced water for bottomhole pressure maintenance, enhanced recovery, and/or disposal. Currently the longest tiebacks in the world are 15.6 miles for subsea separation, and 19.3 miles for subsea injection. Both are offshore Norway.

Subsea compression is the latest Applied Advanced Technology development in subsea processing. It is similar to subsea boosting, but subsea compression is used in fields producing mostly gas. The longest subsea compression tieback in the world is 25 miles in offshore Norway.[71]

Subsea processing offers a way to reduce the cost of bringing wells and fields online by: reducing surface equipment and energy requirements on the production facility, increasing production and recovery of resources, and reducing surface facility risk to personnel and environment.[72]

VIII. Training -

Training of personnel - individuals, crews, teams, Operators, contractors, and all Stakeholders – is critical for safety and environmental soundness of all operations. The Upstream industry offers, provides, and mandates general and specific and specialized training for offshore and deepwater operations. All personnel are required to take safety training and confirm certification of the training, prior to boarding a helicopter or boat to head offshore.

Applied Advanced Technology in specialized training is offered in a comprehensive form for personnel who are new to the Upstream industry. The International Association of Drilling Contractor 'IADC' Gateway® program is intended to "attract, hire, train and promote onshore and offshore O&G workers worldwide".[73] Gateway starts with an Introduction to Oil & Gas, and includes IADC's RigPass® program with SafeGulf Endorsement.[74] For those involved in drilling operations on the rig, IADC has offered for a long time its WellCap® well control training, which has been expanded by its WellCap Plus, and Advanced Technology WellSharp® programs.[75] IADC audits training provided by drilling contractors and others that adhere to IADC's training

[71] 2017 Subsea Processing Poster.

[72] Decommisioning Methodology and Cost Evaluation, OTC 27661; The Defining Series- Subsea Infrastructure www.slb.com/defining; DNV Subsea technology developments Report No. 18IM1UH-4_2014, OCS study on Effects of Subsea Processing on Deepwater Environments in GoM.

[73] http://www.iadc.org/gateway.

[74] http://www.iadc.org/iadc-rig-pass. / In addition to the SafeGulf Endorsement, RigPass also offers a SafeLandUSA Endorsement.

[75] http://www.iadc.org/wellcap-plus; http://www.iadc.org/wellsharp.

programs requirements; then gives accreditation to these trainer entities and the personnel that pass the accredited courses.

Helicopter Underwater Egress Training 'HUET' is required for Upstream personnel before they embark to head offshore. Only select training company locations offer HUET safety tests, with certificates issued to those persons that pass it. The training companies have mock-up helicopter cabins that candidates would normally belt themselves into. The mock-up cabin is dunked into a pool, and it is inverted under water. The candidates then have to unstrap themselves, find the mock-up helicopter exit door, and swim to surface, thus passing the safety test.

The Offshore Petroleum Industry Training Organization 'OPTIO' is an independent international organization that offers safety and other training through locations in five regions worldwide. OPTIO training includes Basic Offshore Safety Induction and Emergency Training 'BOSIET', and Further Offshore Emergency Training 'FOET', as well as 'Tropical' versions of both for those who may work in a tropical region.[76]

Applied Advanced Technology in training is highlighted by that offered by Maersk Training[77]. Originally starting with vessel and crane simulators, and now expanded into a number of offshore drilling safety and operations simulations, Maersk Training provides classroom and 'hands-on' scenario training via simulators at their large, dedicated Houston facility. Drilling simulators, with rig floor drillers chair control and rig control room monitoring and communication, replicate the look and feel of routine and emergency scenarios and responses. Working with actual rig controls, and offshore rig protocols, all participants in the scenario training understand the causes and effects of various issues, and the proper handling of those issues, before any may be seen in a real drilling rig situation. The scenarios go beyond specific tasks - to lighting blackouts, engine power outages, and emergency well BOP shut-in with riser disconnect and rig location drive-off. Maersk Training also can set up a rig or other vessel mapping, alarms, and communications, to replicate situations where specific hazards or threats may suddenly occur (such as fire, collision, electronic or data glitch or hack), and how they may be mitigated, worked around, eliminated, and/or resolved safely with environmental soundness.

In 2013 Noble Corporation created Noble Advances, a state-of-the-art training facility and simulation program, which is fully integrated into the offshore DP drilling exercises.[78] A key feature of Noble Advances' program is the interconnectivity of the simulators. Noble is able to bring in full rig crews (drilling, marine, engineering, and even shore-based managers from both Operators and drilling contractors) and immerse them in their "native environment." Noble replicates the controls for each vessel so that its users are seeing the same equipment they are used to. The simulation allows crews to practice real well scenarios. Operators are able to incorporate into the simulation their well planning and data, from which Noble may then create "events" in the environment. Events may consist of faults, well-control scenarios, equipment failure, and even weather related occurrences. The shore-based managers and operators are

[76] https://www.optio.com.
[77] https://maersktraining.com.
[78] https://nobleadvances.com

able to participate in the exercises via a telephone. These simulations are all recorded in order to hold simulator based “after action” reviews to identify lessons learned and other opportunities upon which to improve behaviors.

When all personnel involved in, and collateral to an event participate together, the individual and position roles and responsibilities and lines of communication are clear, direct, and continue improving. Non-participant Stakeholders may also be invited to witness and/or join in the training, for their edification and confirmation that earnest effort is covering scenarios that cannot be tested in actual trials. (An example is that a regulator may watch or participate in a simulated well control event with emergency safety and operational actions, with direct reporting to authorities, and comprehensive environmental protective responses.)

Oilfield service companies and their operating departments provide the most specialized training for their personnel. Because each service company provides one or more discrete tasks on a location that’s integrated into a rig or facility’s whole purpose, the service company will train on their specific equipment and methodology, how it fits in a subset of their and other’s work, and how it achieves the intended positive results safely, efficiently, and in an environmentally sound manner.

IX. Conclusions -

The ingenuity, innovation and hard work of the U.S. Upstream sector contributes to the continual advancement of technologies that drive safety forward and spur efficient production of oil and natural gas for the nation. Those within the Upstream industry recognize that safety and environmental soundness are resultant outcomes when technology is matched with efficient quality operations, and commensurate reduced rig time over wells. This Report only mentions and highlights a small portion of technology advancements focused on wells offshore and in deepwater. Of course, there are untold many more. And as long as there is a need to provide these resources economically in the future, knowledge, experience and engineering will drive advancement of equipment and methods, resulting in safety and environmentally responsible operations, as they have since the Upstream industry began 150 years ago.[79]

X. Acknowledgements -

The authors of this report want to thank the American Petroleum Institute for engaging Blade Energy Partners to do this project. Additionally, the authors are deeply appreciative to the many individuals and companies that shared their time, resources, and information that went into compiling this Report. This work only captured and relayed a very small amount of the current and new technologies that are ongoing throughout the Upstream industry. These technologies

[79] www.oil150.com; *The Prize,* by Daniel Yergin.

are compounding the industry's increasing successful efforts to find, develop, produce, and provide the valuable subsurface offshore resources in safer and more environmentally sound ways.

Based on the history of Upstream developments, the Upstream industry will continue successfully driving innovation going forward. All - from idea generators through researchers, design engineers, machinists, service specialists, and the those who invest, support, encourage, and sweat with them, as well as the Operators who are their Applied Advanced Technology first adopters - we congratulate. They and all in their efforts and good work must be appreciated at all times. Any omissions of companies and technologies is respectfully inadvertent, as the Report is intended to provide only a snapshot into the innovations and advancements within the offshore industry.

New technologies can only be applied when the confluence of circumstances is ripe for a technology's application that integrates it into any operation. Therefore, it is tough to capture and document any one point in time (like now), since technologies constantly develop for the needs of today and those of the future. Nevertheless, it is important, through reports like this, for the Upstream industry to present to the public and all Stakeholders (and itself), the high levels of compounding applied science, engineering, analytics, know-how, and trials to success that actively advances Upstream operations.

XI. Appendices -

Appendix A - Blade Background

Blade Energy Partners, Ltd. is an independent technical consulting firm providing upstream expertise to operators, industry consortia, government agencies, and scientific organizations globally, especially in the focus areas of well design, drilling systems, advanced techniques, complex & critical applications, and related technologies. Blade's clients and those clients' applications are worldwide - spanning the super-major integrated operators, through large independents, national oil companies, and certain industry or governmental organizations. Within Blade's staff of ~80 employees (most with advanced engineering or scientific degrees) and ~20 select consultants, Blade's expertise range includes deep water, high-pressure & high-temperature 'HPHT', complex, and challenging wells in the U.S. Gulf of Mexico and worldwide, primarily from our Texas offices in Houston and Frisco.

Blade provides consulting advisory and offers specialized training and software to the industry, as well as U.S. B.S.E.E.-required Professional Engineer Certification services for offshore wells. Independently Blade provides non-compensated return to the industry through our technical contributions to, and personnel volunteer work for industry organizations and committees, and active participation (and often work group leadership) in: SPE, IADC, API, AADE, RPSEA, DeepStar, PRCI, and others.

Appendix B - List of Example End-Use Products Derived From Oil & Gas Hydrocarbon Feedstocks

The International Association of Drilling Contractors 'IADC' compiled a partial list of the 6,000 products that it found are derived from crude oil and natural gas. Please see a copy of their document here[80]:

> A partial list of products made from Petroleum (6000 items).
>
> One 42-gallon barrel of oil creates 19.4 gallons of gasoline. The rest (over half) is used to make things like [those products listed below]. Although [today] the major use of petroleum is as a fuel, (gasoline, jet fuel, heating oil), and petroleum and natural gas are often used to generate electricity, there are many other uses.
>
> Here are some of the ways petroleum is used in our every-day lives. All plastic is made from petroleum, and plastic is used almost everywhere: in cars, houses, toys, computers and clothing. Asphalt used in road construction is a petroleum product, as is the synthetic rubber in the tires. Paraffin wax comes from petroleum, as do fertilizer, pesticides, herbicides, detergents, phonograph records, photographic film, furniture, packaging materials, surfboards, paints, and artificial fibers used in clothing, upholstery, and carpet backing.

Solvents	Diesel	Motor Oil	Bearing Grease
Ink	Floor Wax	Ballpoint Pens	Football Cleats

[80] www.IADC.org.

Upholstery
Bicycle Tires
Dresses
Cassettes
Motorcycle Helmet
CD Player
Curtains
Vitamin Capsules
Dashboards
Putty
Percolators
Skis
Tool Racks
Mops
Umbrellas
Roofing
Denture Adhesive
Speakers
Tennis Rackets
Nylon Rope
Water Pipes
Shampoo
Guitar Strings
Antifreeze
Clothes
Combs
Vaporizers
Heart Valves
Enamel
Anesthetics
Dentures
Cold Cream
Fan Belts
Refrigerators
Ink
Toys
Dolls
Tires
Tents
Shoes
Glue
Skis
Dyes
Cameras
Combs
Checkers
Mops
Purses
Sneakers
Pajamas
Pillows

Sweaters
Sports Car Bodies
Tires
Dishwasher
Caulking
Faucet Washers
Food Preservatives
Antihistamines
Cortisone
Dyes
Life Jackets
TV Cabinets
Car Battery Cases
Slacks
Yarn
Toilet Seats
Linoleum
Plastic Wood
Rubber Cement
Candles
Hand Lotion
Wheels
Luggage
Football Helmets
Toothbrushes
CD's
Balloons
Crayons
Pillows
Artificial Turf
Model Cars
Movie Film
Car Enamel
Golf Balls
Dishwashing Liquids
Unbreakable Dishes
Car Sound Insulation
Motorcycle Helmets
Refrigerator Linings
Electrician's Tape
Roller-skate Wheels
Permanent Press
LP Records
Food Preservatives
Transparent Tape
Disposable Diapers
Dashboards
Electric Blankets
Car Battery Cases
Synthetic Rubber
Vitamin Capsules

Boats
Nail Polish
Golf Bags
Tool Boxes
Petroleum Jelly
Antiseptics
Basketballs
Purses
Deodorant
Panty Hose
Rubbing Alcohol
Shag Rugs
Epoxy
Insect Repellent
Fertilizers
Fishing Rods
Ice Cube Trays
Electric Blankets
Fishing Boots
Trash Bags
Roller Skates
Paint Rollers
Aspirin
Awnings
Ice Chests
Paint Brushes
Sun Glasses
Parachutes
Dishes
Artificial Limbs
Folding Doors
Soft Contact lenses
Shaving Cream
Toothpaste
Paint Brushes
Insecticides
Fishing Line
Linoleum
Paint Rollers
Plastic Wood
Trash Bags
Hand Lotion
Shampoo
Fishing Rods
Anesthetics
TV Cabinets
Salad Bowls
Awnings
Safety Glass
VCR Tapes

Insecticides
Fishing Lures
Perfumes
Shoe Polish
Transparent
Clothesline
Soap
Shoes
Footballs
Refrigerant
Linings
Electric Boxes
Pigments
Oil Filters
Hair Coloring
Lipstick
Synthetic
Glycerin
Dice
House Paint
Surf Boards
Shower Shields
Safety Glasses
Eyeglasses
Footballs
Detergents
Tents
Telephones
Cameras
Bandages
Hair Curlers
Drinking Cups
Ammonia
Gasoline
Telephones
Antiseptics
Deodorant
Sweaters
Floor Wax
Model Cars
Soap Dishes
Clothesline
Panty Hose
Oil Filters
Upholstery
Plaques
Hoses
Ammonia
Hair Curlers
Eyeglasses

Candles	Rubbing Alcohol	Loudspeakers	Ice Buckets
Boats	Wading Pools	Credit Cards	Fertilizers
Signs	Insect Repellent	Water Pipes	Parachutes
Caulking	Roofing Shingles	Fishing Boots	Carpeting
Balloons	Shower Rods	Garden Hose	Vaporizers
Curtains	Plywood Adhesive	Umbrellas	Detergents
Milk Jugs	Beach Umbrellas	Rubber Cement	Sun Glasses
Putty	Tubes	Hearing Aids	Bandages
Tool Racks	Antihistamines	Hair Coloring	Nail Polish
Slacks	Drinking Cups	Lipstick	False Teeth
Yarn	Petroleum Jelly	Toothpaste	Golf Shoes
Roof Vents	Tennis Rackets	Toothbrushes	Perfume
Luggage	Wire Insulation	Folding Doors	Handles
Fan Belts	Ballpoint Pens	Shower Doors	Cortisone

Americans consume petroleum products at a rate of three-and-a-half gallons of oil and more than 250 cubic feet of natural gas per day each. But, as shown here petroleum is not just used for fuel.

The U.S. Gulf of Mexico has been responsible for the production more than 1 million barrels of oil per day for the past 20 years, at times amounting to nearly 30 percent of domestic production. This production has thus been critical, and will continue to be critical, for meeting our fuel and consumer needs.

Appendix C – Partial List of Upstream Safety & Environmentally Focused Organizations

American Petroleum Institute 'API' –

The American Petroleum Institute (API) is the only national trade association representing all facets of the oil and natural gas industry. API's mission is to promote safety across the industry globally and to influence public policy in support of a strong, viable U.S. oil and natural gas industry.

API conducts or sponsors research ranging from economic analyses to toxicological testing. And we collect, maintain and publish statistics and data on all aspects of U.S. industry operations, including supply and demand for various products, imports and exports, drilling activities and costs, and well completions. This data provides timely indicators of industry trends. API's Weekly Statistical Bulletin is the most recognized publication, widely reported by the media.

For more than 90 years, API has led the development of petroleum, natural gas and petrochemical equipment and operating standards. These represent the industry's collective wisdom on everything from drill bits to environmental protection and embrace proven, sound engineering and operating practices and safe, interchangeable equipment and materials. API maintains nearly 700 standards and recommended practices. Many have been incorporated into state and federal regulations and they are also the most widely cited standards by the international regulatory community.

Each day, the oil and natural gas industry depends on equipment to produce, refine and distribute its products. The equipment used is some of the most technologically advanced available in the search for oil and gas and allows the industry to operate in an environmentally safe manner. Designed for manufacturers of production, drilling, and refinery equipment, the API Monogram Program verifies that manufacturers are operating in compliance with industry standards. API also provides quality, environmental, and occupational health and safety management systems certification through APIQR. This service is accredited by the ANAB (ANSI-ASQ National Accreditation Board) for ISO 9001 and ISO 14001. Let APIQR's industry expertise certify your organization to API Spec Q1, OHS 18001.

API also certifies inspectors of industry equipment through our Individual Certification Programs, designed to recognize working professionals who are knowledgeable of industry inspection codes and are performing their jobs in accordance with those codes. Through our Witnessing Programs, API provides knowledgeable and experienced witnesses to observe critical material and equipment testing and verification. API's Training Provider Certification Program provides third-party certification for a variety of oil and gas industry training courses, further ensuring that any training provided meets industry needs.

Offshore Energy Safety Institute 'OESI'[81] -

The primary mission of the OESI is to provide a forum for dialogue, shared learning, and cooperative research among academia, government, industry, and other non-governmental organizations, in offshore energy-related technologies and activities that ensure safe and environmentally responsible offshore operations. The OESI will coordinate and focus an effort to identify scientific and technological gaps and to recommend improvement of drilling and production equipment, practices, and regulation. OESI will gather, consider, and harmonize the proposals promoted by other research and development centers and other groups to inform BSEE on technological and other developments within the offshore industry. Additionally, the OESI would provide a forum for the continuous education and training of BSEE and BOEM employees to ensure that the federal workforce maintains the same level of technological expertise as the engineers, scientists and technical experts in the oil and gas industry.

The Center for Offshore Safety 'COS'[82] -

The Center for Offshore Safety 'COS' is an industry sponsored group focused exclusively on offshore safety on the U.S. Outer Continental Shelf (OCS). The Center serves the US offshore oil & gas industry with the purpose of adopting standards of excellence to ensure continuous

[81] oesi.tamu.edu.
[82] www.centerforoffshoresafety.org.

improvement in safety and offshore operational integrity. The Center is a program of the American Petroleum Institute and operates out of Houston with its own governing board.

The Center is responsible for:

- Development of good practice documents for the offshore industry in the areas of Safety and Environmental Management Systems (SEMS)
- Assuring that third party certification program auditors meet the program's goals and objectives
- Compiling and analyzing key industry safety performance metrics
- Coordinating Center sponsored functions designed to facilitate the sharing and learning process
- Identifying and promoting opportunities for the industry to continuously improve
- Development of outreach programs to facilitate communicating with government and external stakeholders.

Offshore - SEMS, safety audits loom large after recent government mandates: https://www.offshore-mag.com/articles/print/volume-75/issue-8/departments/regulatory-perspectives/sems-safety-audits-loom-large-after-recent-government-mandates.html

COS SEMS Audit Protocol-Checklist : http://asq.org/ee/2014/08/center-for-offshore-safety-protocol-checklist.%202.0%20cos%20sems%20ii%20rp%2075%20audit%20protocol%20-%203%20december%202013.pdf

Safety and Environmental-Management Requirements for Offshore Operations: http://www.ehstoday.com/print/12827

Safety and Environmental Management Systems (SEMS) Fact Sheet: https://www.bsee.gov/site-page/fact-sheet

Safety and Environmental Management Systems – SEMS: https://www.bsee.gov/resources-and-tools/compliance/safety-and-environmental-management-systems-sems

DEPARTMENT OF THE INTERIOR- Bureau of Safety and Environmental Enforcement- 30 CFR Part 250: https://www.gpo.gov/fdsys/pkg/FR-2013-04-05/pdf/2013-07738.pdf

SEMS Program Summary—First Audit Cycle (2011-2013): https://www.bsee.gov/sites/bsee.gov/files/memos/safety/sems-program-summary-8132014.pdf

International Association of Drilling Contractors – Health, Safety & Environment 'IADC HSE'[83]

[83] www.iadc.org/hse.

Improving industry health, safety, environmental protection and training is a cornerstone of IADC's mission. To communicate potential problem areas, IADC regularly issues safety alerts contributed by its members describing rig accidents, their causes and corrective actions.

IADC has tracked through its Incident Statistics Program (ISP) drilling industry accident statistics since 1962, compiling the definitive database on drilling incidents worldwide. Similarly, IADC makes available at no cost safety posters to visually reinforce safety messages on the rig itself.

The IADC HSE RIG PASS program is the definitive accreditation system for basic rig floor safety. The IADC HSE Committee provides a forum to exchange and disseminate best practices; to structure industry performance measures and assist IADC in their promotion and publication; and to serve as a channel for members, government agencies, manufacturers and customers to interact to improve the performance of the industry in matters relating to occupational safety and health, and environmental affairs.

IADC issued HSE Case Guidelines for both Mobile Offshore Drilling Units and for Land Drilling Units. The Guidelines provide a framework for developing an integrated health, safety and environmental management system for use in reducing the risks associated with offshore and onshore drilling activities. These Guidelines are gaining worldwide exposure and acceptance.

The IADC Training Committee was organized to promote awareness of training and to facilitate the exchange of information regarding suitable training methods and materials benefitting the global drilling and drilling services industries.

Offshore Operators Committee 'OOC'[84] -

The Offshore Operators Committee is comprised of volunteer members who are oil & gas operators offshore the U.S. The OOC provides training HAZID training, as well as a video on marine trash.

Houston Advanced Research Center 'HARC' – Environmentally Friendly Drilling Systems 'EFD'[85] –

[84] www.theooc.org/training.
[85] harcresearch.org.; efdsystems.org.

The Houston Advanced Research Center set up its EFD Systems program to “provide unbiased science to address environmental issues” in conjunction with industry and environmental sponsors, advisors and collaborators. It has done projects on natural gas fueled operations, dope free pipe, and produced water re-use. It also set up an EFD Virtual Site for animated visualization of drilling facilities.

National Ocean Industries Association ‘NOIA’[86] -

Founded in 1972 with 33 members, represents all facets of the domestic offshore energy and related industries. Today, nearly 300 member companies are dedicated to the safe development of offshore energy for the continued growth and security of the United States. Our membership also includes companies involved in or branching out to pursue offshore renewable and alternative energy opportunities. NOIA members are engaged in many business activities, in addition to those listed below, including environmental safeguards, equipment supply, gas transmission, navigation, research and technology, shipping and shipyards.

International Association of Oil and Gas Producers ‘IOGP’[87] -

Vision

- To work on behalf of the world’s oil & gas exploration and production (E&P) companies to promote safe, responsible, and sustainable operations.

Mission

- To facilitate continuous improvement in HSE, security, social responsibility, engineering and operations.
- To undertake special projects and develop industry positions on critical issues affecting the industry.
- To create alignment between oil & gas E&P companies and with relevant national and international industry associations.
- To advance the views and positions of oil & gas E&P companies to international regulators, legislative bodies and other relevant stakeholders.
- To provide a forum for sharing experiences, debating emerging issues and establishing common ground to promote co-operation, consistency and effectiveness.

Objectives

- To improve understanding of our industry by being a visible, accessible, reliable and credible source of information.
- To represent and advocate industry views by developing effective proposals based on professionally established technical arguments in a societal context.

[86] www.noia.org/offshore-energy/safety.
[87] http:/www.iogp.org/oil-and-gas-safety.

- To improve the collection, analysis and dissemination of data on HSE and security performance.
- To develop and disseminate best practice in HSE, security, engineering and operations continually improved by feedback from members, regulators and other stakeholders.
- To promote awareness and best practice in social responsibility and sustainability.
- To ensure that the membership is highly representative of our industry.

IPIECA[88] -

IPIECA develops, shares and promotes good practice and knowledge to help the industry and improve its environmental and social performance. We do this with the understanding that the issues that dominate the sustainable development agenda – climate and energy, environmental and social issues – are too big for individual companies to tackle alone. The industry must work together to achieve improvements that have real impact. IPIECA helps to achieve this goal.

IPIECA is a not for profit association that provides a forum for encouraging continuous improvement in industry performance. IPIECA is the only global association involving both the upstream and downstream oil and gas industry. It is also the industry's principal channel of communication with the United Nations.

On joining IPIECA, organizations become part of a respected industry group with shared values and a commitment to:

- Contribute to sustainable development by providing safe and reliable energy in an environmentally and socially responsible manner.
- Conduct their operations and activities in accordance with applicable law related to environmental and social issues and ethical business practices.
- Improve their performance in addressing environmental and social issues.
- Develop, share and promote implementation of sound practices and solutions with others in the industry, and engage with stakeholders in order to take into account their expectations, concerns, ideas and views, and work with government and non-government organizations.

Appendix D – Government Jurisdictional References

1: The **Submerged Lands Act (SLA) of 1953** grants individual States rights to the natural resources of submerged lands from the coastline to no more than 3 nautical miles (5.6 km) into the Atlantic, Pacific, the Arctic Oceans, and the Gulf of Mexico. The only exceptions

[88] www.ipieca.org. Formerly named the International Petroleum Industry Environmental Conservation Association.

are Texas and the west coast of Florida, where State jurisdiction extends from the coastline to no more than 3 marine leagues (16.2 km) into the Gulf of Mexico.
https://www.boem.gov/Federal-Offshore-Lands/

2: Global offshore oil production (including lease condensate and hydrocarbon gas liquids) from deepwater projects reached 9.3 million barrels per day (b/d) in 2015. Deepwater production, or production in water of depths greater than 125 meters, has increased 25% from nearly 7 million b/d a decade ago. Shallow water has been relatively less expensive and less technically challenging for operators to explore and drill, yet changing economics and the exhaustion of some shallow offshore resources has helped to push producers to deepwater or, in some areas, ultra-deepwater (at depths of 1,500 meters or more) resources. The share of offshore production from shallow water in 2015 was 64%, the lowest on record.
https://www.eia.gov/todayinenergy/detail.php?id=28552

A ‘deepwater play’ covers exploration activity located in offshore areas where water depths exceed approximately 600 feet [200 m], the approximate water depth at the edge of the continental shelf. While deepwater targets are geologically similar to reservoirs drilled both in shallower present-day water depths as well as onshore, the logistics of producing hydrocarbotn from reservoirs located below such water depth presents a considerable technical challenge.
http://www.glossary.oilfield.slb.com/Terms/d/deep-water_play.aspx

3: Oil and Gas Leases

California's most valuable oil and gas resources are primarily located in and adjacent to some of the state’s most spectacular beaches and coastline. The controversy over the development of oil and gas resources has been going on since 1921 when the first development was permitted. Since 1969, the concern about potential environmental damage resulting from a spill and the desire to avoid marring the coast with unsightly development has outweighed the desire to generate revenue from new offshore development. While the Commission put a moratorium on new oil and gas leases after the 1969 spill in Santa Barbara, the leases issued before 1969 continue to generate significant revenue to the state, as they have for almost 80 years. To ensure that the public fully benefits from existing production, the Commission operates a rigorous financial auditing program to ensure that California receives all the money it is owed.

http://www.slc.ca.gov/Info/Oil_Gas.html

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