EARLY KICK DETECTION BAST ASSESSMENT

STEP 1.2 of the BAST DETERMINATION PROCESS

Office of Offshore Regulatory Programs

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Bureau of Safety and Environmental Enforcement

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EXECUTIVE SUMMARY

The Best Available and Safest Technology (BAST) Determination Process (BDP) provides BSEE with a structured methodology for assessing technology solutions wherever failure of equipment would have a significant effect on personnel safety, health, and/or the environment.

This BDP is being carried out to assess the feasibility of installing commercially available Early Kick Detection (EKD) systems (a technology that detects a downhole influx or loss early in time) on oil and gas drilling rigs[1] in the U. S. Outer Continental Shelf (OCS) to provide improved EKD which could result in a reduction in Loss of Well Control (LOWC) events. BSEE finds that improving kick detection should decrease the number of LOWC events by allowing operators more time to assess and initiate corrective actions and therefore the need to report LOWC incidents per BSEE's incident reporting requirement at 30 CFR 250.188[2].

This report presents the work and findings from Step 1.2 of the BSEE BDP during which the availability of proven technology was assessed, a budget and timeframe for the process established, and a preliminary feasibility analysis performed. The main conclusion is that use of EKD systems on OCS facilities is feasible (Step 1.3) and there is sufficient evidence to recommend continuing the process by establishing a Technology Improvement Objective (TIO) as stated in Step 1.4 of the BDP.

[1] For this Assessment, the terms "drilling rig" or "rigs" is understood to include Mobile Offshore Drilling Units (MODUs) and fixed facility platform drilling rigs that are used for the drilling of a new well, by-pass, side-track, or conducting completion, recompletion, abandonment or well workover operations.
[2] BSEE LOWC Information and Reporting Requirements can be found at https://www.ecfr.gov/cgi-bin/retrieveECFR?gp=&SID=d405001b836a488e17a0b513ffd187ae&mc=true&n=pt30.2.250&r=PART&ty=HTML#se30.2.250_1188

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BACKGROUND

On July 23, 2013 a well operated by Walter Oil and Gas in the Gulf of Mexico (GOM), ST Block 220, experienced a LOWC event during well completion operations which escalated to an explosion and fire causing damages originally estimated in BSEE's Panel Report 2015-02 at more than $10,000,000(M). More recent BSEE estimates place the real damage on the order of $50M, which includes the estimated cost of emergency well control services, rig repair, replacement, decommissioning and commissioning of the well and production facility, and lost production[3]. A ***BSEE Panel Investigation***[4]concluded that the main cause of this event was the failure of the crew to detect a kick triggered by unbalanced bottom-hole pressure while pulling (tripping) the drill string from the hole. While the signs of the kick were manifested by the rapid return flow of the drilling mud to the surface, the kick was not acted upon until the well began to flow from the top of the drill pipe.

The risk of a LOWC as the result of kicks, whether during tripping operations like the Walter Oil & Gas well or during other well operation (e.g., drilling, completion, temporary abandonment and workover), continues to be a major safety issue on the U.S. Outer Continental Shelf (OCS). LOWC presents a hazard to personnel, the environment, lost resources and offshore oil and gas infrastructure.

In a BSEE funded Technical Assessment Program (TAP) Study No. 765[5], data provided by *Exprosoft* indicated that LOWC incidents reported in the United States OCS GOM waters are significantly higher than those reported worldwide. As reported by *Exprosoft* on page 10, ***Table 1.1: Area-specific overview of the number of LOWC events that occurred during different operational phases (2000–2015);*** of the 156 LOWC events worldwide, 82 (or 53%) occurred in the US GOM. <u>BSEE recognizes that there are geologic, environmental and other factors that may explain the differences between GOM and global data, however, the data do suggest that safety improvements to OCS operations should be assessed.</u>

The improved ability to detect a kick earlier in time and avoid a LOWC is of strong importance to BSEE. EKD technology continues to evolve with advanced systems now being tested and used by multiple OCS operators. In consideration of these gains in EKD technology, the 2013 Walter Oil & Gas LOWC, the findings by *Exprosoft* in TAP Study 765, and findings made as part of the BAST Step 1.2 Assessment (as detailed in this document), the Office of Offshore Regulatory Programs (OORP) finds support for proceeding to the next step of the BDP.

JUSTIFICATION FOR BAST DETERMINATION

As provided in the supporting documentation below, based on BSEE's assessment, there are multiple commercially available technologies that can be used singularly or in combination to provide improved EKD and potential reduction in LOWC. Based on this Assessment, the Chief of OORP affirmed that there is sufficient safety justification to recommend that the Director initiate ***Step 1.3*** of the BDP. In Step 1.3, the Director reviews the findings from this document and decides whether to proceed with Step

[3] Relief Well $23.5 M (75 days at assumed $260 K/d rig spread rate plus $4 M in tangible costs), 900,000 MCF lost production at $1.75/MCF, rig repair $8 M including derrick, cantilever, BOP stack, and ancillary equipment and controls (choke manifold, hydraulic choke, …), emergency well control services $2 M, production structure decommissioning and replacement $15 M.

[4] Walter Oil and Gas, ST 220 BSEE panel investigation; https://www.bsee.gov/sites/bsee_prod.opengov.ibmcloud.com/files/southtimbalier-220-panel-report9-8-2015.pdf

[5] BSEE TAP Study 765

1.4 of the BDP or whether an alternative course of action outside the BDP should be pursued (e.g., safety alert, research, revision of inspection procedures, etc.).

DOCUMENTATION:

I. SAFETY ISSUE

The purpose of this BAST Step 1.2 Assessment is to analyze safety related incidents on the OCS and determine whether a BAST Determination can identify technology solutions to mitigate the safety issue. The safety issue related to this Assessment and incidents of concern for BSEE include:

- The July 23, 2013 Walter Oil and Gas, ST Block 220 LOWC incident which occurred during well completion operations causing damages initially estimated by BSEE at more than $10M and more recently on the order of $50M.
- Findings from OCS studies and investigations that show failure to detect kicks early, particularly in post-Macondo reports, are due in part, to the lack of effective detection instrumentation.[6, 7]
- Findings and conclusions provided by *Exprosoft in* TAP Study 765 [8] on the hazards of kicks (and/or lack of early detection of kicks) leading to LOWC events. Although BSEE recognizes that the *Exprosoft* report has many variations in the collection and reporting of data that may not be ideal for this EKD Assessment, the data still serves as a viable source of worldwide kick data and as an indicator for further assessing the need for earlier kick detection. Relevant excerpts from the *Exprosoft* TAP study include:

    - As illustrated on page 10, ***Table 1.1: Area-specific overview of the number of LOWC events that occurred during different operational phases (2000–2015)***, of the 156 LOWC events worldwide, 82 (or 53%) occurred in the US GOM.
    - As illustrated on page 172, ***Table 16.15: Annualized kick frequencies***, of the 1121 wells spudded in the GOM OCS for the period 2011-2015, 265 kicks resulted in a kick frequency per well of one (1) kick for ~ every 4th well (or 24%) drilled.
    - From the same table, ***Table 16.15: Annualized kick frequencies***, when considering only exploratory drilling, of the 300 wells spudded in the GOM from 2011-2015, 143 kicks occurred, for a kick frequency of one (1) kick for ~ every 2nd well drilled (or 48%).
    - The kick frequency for the 2011-2015 data set apparently includes "Shallow Zone" kicks, (i.e. no surface casing and no BOP stack; reference Page 8 of Glossary of Acronyms and Definitions and Section 16.5 and Table 16.16). This may be why GOM kick frequencies for 2011-2015 are higher than the other data on that table that excludes the "Shallow Zone" kicks.
    - In Section 16.5, Page 167 where a number of the search criteria and data sources used to identify kicks are mentioned along with uncertainties with the data reported in WARs. For example, Exprosoft states “There are probably several kicks that have not been identified, and some of the incidents identified as a kick may not be a kick”.
    - On Pages 172-173, Section 16.5, US GoM OCS Kick Statistics (For Wells Spudded 2011-2015) where *Exprosoft* states "Table 16.15 shows that the majority of the kick data

[6] "Deepwater, The Gulf Oil Disaster and the Future of Offshore Drilling", Report to the President", pgs 120-121

[7] Walter Oil and Gas, ST 220 BSEE panel investigation, pg 79

[8] BSEE TAP Study 765

stems from wells spudded in the period 2011 to 2013. This is mainly because less WAR reports exist for 2014 and 2015. The table is based on data in the WAR Database[9] that was downloaded 10th of March 2016. For the years 2011 to 2013 more than 90% of the wells spudded were included in the WAR database, for 2014 and 2015, 48% and 25% were included. In addition the drilling activity was lower in 2015 than the previous years (Table 2.1, Page 33.)."

- In the LOWC Risk Analysis section of the report, the 2011-2015 kick frequency is assumed applicable to the 2000-2015 period of wells (Page 184, Table 17.11).
- It appears unclear in the Risk Model section of the report how the 2011-2015 eWell - WAR underpopulated well data were addressed within the statistical data and analyses.[10]

II. BAST STEP 1.2: ASSESSMENT AND FINDINGS

The findings made under Step 1.1 of the BDP provided sufficient evidence that a safety issue exists and that initiating Step 1.2 of the BDP was necessary to further assess the safety issue and determine whether technology exists that can resolve, or at least lessen, the risks of this safety issue. Step 1.2 of the BDP involved an assessment of the following:

- **Technology Failures:** Were the incidents (technology failures or near-misses) caused by a failure or gap in the use of technology?
- **Potential for Safety Improvement:** Could the use of new technology have prevented or minimized the specific safety issue or increased safety across the OCS?
- **Availability of Proven Technology:** Is there sufficient information to establish the existence of technologies that are currently available?
- **BSEE Resources:** What are the expected costs and resources necessary from BSEE to perform this BD and the anticipated timeframe for completion?
- **Economic Feasibility:** Is it likely that the benefit of better performing technologies will justify the implementation cost?

Technology Failures and Potential for Safety Improvement

Future drilling activities in the GOM may be more challenging than those being conducted today as exploration and production continues to focus on the Lower Tertiary at water depths exceeding 5,000 – 10,000 feet into target zones at 12,000 - 35,000 feet below the mud line. At such depths the chance of kicks due to encountering unexpected high pore pressure zones increases. The consequences of failing to detect a kick early at these depths can result in lost lives and resources, environmental damage and associated clean-up (should the kick result in a LOWC to the surface), and financial losses in the form of greater Non-productive time (NPT). Should a kick result in a LOWC it may take from four (4) hours to four (4) days to address the situation and return to normal drilling operations resulting in NPT, costing OCS operators hundreds of millions of dollars and potentially lost hydrocarbon resources to the American consumer. The inability to detect kicks early is mostly due to the lack of and/or the improper

[9] WAR Database is a compilation of Weekly Activity Reports (WARs) submitted for drilling rig and well servicing activity to BSEE.

[10] BSEE recognizes the challenges faced by Exprosoft in preparing their report and the uncertainty in comparing OCS data with data from the rest of the world. The intent of this BD is not to prove the data, but rather to show 1) evidence of a safety issue related to delayed kick recognition in the OCS and 2) the potential net benefit from a reduction in LOWC by expanding the use of EKD practices and equipment.

use of available technology. Since the vast majority of kicks occur during drilling and completion operations and begin with an influx of reservoir fluids into the well, the use of EKD that allows for timely kick detection and mitigation is a critical tool for LOWC prevention.

As illustrated in this report, there are stand-alone EKD technologies designed for open annulus and closed annulus drilling, the latter of which is incorporated as part of Managed Pressure Drilling (MPD). For the purposes of this Assessment, the following distinction between EKD and MPD was made:

- An EKD system is understood to be a system of hardware, Intelligent Control Unit (ICU) and control software having the capability to **detect an influx** of formation fluids (oil, gas, water, or any combination thereof) into the borehole during well operations, commonly known as a **kick**. An EKD system may be:
  1) As simple as an ICU/software combination that utilizes the drilling rig's existing equipment (e.g., pit volume meters, radar and ultrasonic sensors, mud flow rates, mud pump stokes in, etc.) to provide simple display curves and audio/visual warning, or
  2) An advanced EKD system that utilizes high precision equipment (e.g., a density-compensated mass flow meter (e.g., Coriolis)) with ICU/software providing advanced models and algorithms for greater automation and comparison to controlled well conditions. As with simple EKD systems, audio and visual alarms are an integral part of any EKD system to provide real-time assessment.
- An MPD system is a more complex system of hardware and control software beyond EKD that not only **detects events** such as downhole influxes of formation fluids, but by closing the annulus (e.g., with a Rotating Control Device (RCD)) improves the ability to detect **and control** an influx through manual or automated responses. EKD is one of the main functionalities embedded in the MPD system. Typically an MPD system consists of an RCD, pressure sensors, choke manifolds, specialized pumps, flow meters, automated control valves, and sophisticated software. This system provides real time comparison to modeled controlled conditions and automated well control response and signals the driller for necessary actions when specified thresholds are exceeded. Not all equipment used in MPD is typical rig equipment and most existing rigs are not MPD-ready. Although the focus of this BAST Assessment was not to include a review of MPD systems, these systems are mentioned since the equipment used in many MPD systems includes EKD technologies. MPD systems in whole or in part may be appropriate for use as an EKD technology.

<u>Availability of Proven Technology</u>

Kick detection is identified by volumetric changes (gain or loss) in the circulated mud system. Once an influx occurs at depth, the influx typically has an immediate effect on the mud density and on the annular hydrostatic pressure which triggers some degree of a compressional wave that, without operator intervention, forces the mud to the surface at a rate above normal mud flow circulation. In order for an EKD system to be effective, it has to have the means to sense the presence of an influx in the mud returns, as well as the changes in the returning flow compared to flow into the well. More precise measurement of the volume of the mud flow-in and flow-out depends on measurement of the mud density in both flow directions. Some systems are equipped with at least one mass flow meter (typically a Coriolis meter) installed on the return mud flow line. While all OCS drilling rigs use equipment and tanks to measure changes in mud flow volume, in order to be considered having a true EKD system, most drilling rigs will require additional and/or more advanced precision mud flow measurement components.

Rigs continually add mud to the mud-circulation system to match/exceed reservoir pressure. Pit volume sensors measure the volume changes in the “pits” or “tanks” by sensing changes in mud tank levels; however these sensors do not account for mud density. Mud loggers determine mud density by periodically pulling tank samples to measure mud properties. To gain the added advantage of knowing the systems real-time mud density, specialized equipment must be added. *At the time of this Assessment, the Coriolis meter appears to be the most precise meter on the market for measuring density compensated mud flow volume as it is capable of measuring the mud density and factoring this into the flow volume calculation*. A density compensated flow meter can transmit data in real time, so that the software models update and provide the drilling crew with real-time mud properties. Knowing mud flow and density conditions allows the software to detect a kick when a certain preset threshold of mud volume gain is exceeded, at which time an audio-visual alert is triggered. It should be noted that in order to avoid false alarms, a mud volume gain that constitutes a kick should be defined at the well planning stage that reflects formation properties and a kick tolerance volume. EKD systems can detect a volume gain as small as one-half (1/2) gallon, although the gain may need to be larger to differentiate between a kick and other reservoir flow events such as ballooning or fracture closure. Because the pressure waves triggered by a kick travel approximately at the speed of sound, a kick occurring downhole at 10,000-20,000 feet true vertical depth theoretically should generate detectable surface volume gain within 10-17 seconds.

The EKD systems assessed by BSEE BAST have been grouped into two categories, **Open Annulus (OA)** and **Closed Annulus (CA**). Each type of system consists of equipment and software and can vary in configuration, level of equipment integration with existing systems, and sophistication as explained below.

Open Annulus (OA) EKD System

An OA EKD system utilizes conventional drilling methods, typically with equipment upgrades/additions, depending on the well-specific needs of the operator or driller. In OA EKD systems, the annulus is open to the atmosphere and the downhole pressure is controlled by conventional means (e.g., mud weight, circulation rate, etc.). The OA EKD system can be further divided into two subcategories:

a. Standard Precision (SP) EKD systems.
b. High Precision (HP) EKD systems.

Both systems calculate Flow Rate Differential as mud flow in vs. mud (and formation fluids, cuttings, etc.) flow out. Mud returning to the surface is stripped of most formation fluids and cuttings before being pumped back into the mud system.

SP EKD

SP EKD systems employ standard flow volume meters and sensors with simple computerized displays of the volume data on the driller’s panel/monitor. The mud pit volumes are estimated or calculated from positions of floats installed in the pits or calculated from sensors that sample the level in the active pits often without compensation for heave or other platform motions. Typically, the mud return flow rates are established from return line flow paddles and at least one sensor installed on the mud return flowline. An ultrasonic or other sensor may be used for the returns, none of which accounts for the mud density. Since sensory data (mud density, percent return flow, and active mud system volume) is often checked manually/visually and entered into various reports, kick detection can be delayed, inaccurate and/or misinterpreted. The data is not sampled continuously but in intervals ranging from 5 to 30 minutes by a crew member who has to physically examine the sensors. With this type system, mud losses to the reservoir and ballooning during pipe connections may often be mistaken for a kick that can trigger a false alarm.

Examples of SP EKD systems:

Several examples of SP EKD systems were reviewed for this Assessment. Typically such systems are embedded in the driller's panel and the mud logger's station to monitor and display readings in real time. The system is preloaded into the instrumentation that is delivered to the rig at customer's request.

SP EKD systems are typically wired to flow meters, pit volume and other sensors on the rig. Wired systems allow the driller and the mud logger to see at any one time which pits are active. Flow-out data (e.g., from paddles) however has to be checked manually. These systems typically depend on changes in active system volume or an estimation of percent of return flow to detect a kick.

Manual systems (non-hard wired) rely on visual checks of trip tank volumes, meter readings, and flow out during connections, tripping, or other interruptions of the drilling process. This approach typically results in detecting a kick 5 - 15 minutes latter then a wired system and offers less reliability due to the effects of manual checks, facility heave, ballooning, etc.

HP EKD

HP EKD system measurement components are fully wired (or wireless) and consists of: at least one density compensated mass flow meter (typically installed on the mud return line), multiple pit volume sensors, an ICU, and an integrated software system with complex logic involving hydraulic and other computer models able to receive real time measurements allowing for comparison and recalibration of the models in real time. Such models are preloaded with formation pre-drill data, mud properties, casing sizes, pressure margins, and well geometries and have the ability to compensate for system anomalies (e.g., facility heave, wellbore friction, pipe deviations, and fluid compressibility). Often in such systems the flow meter and other electronic sensors can be directly hooked into the ICU and the data can be automatically interpreted by the resident software in real-time, or even sent remotely to other neighboring or land based real-time monitoring control centers for in-depth interpretation.

One common denominator for most if not all HP EKD systems is that the method for calculating volumetric differential flow (flow-in minus flow-out). Flow-in is generally measured by the number of mud pump strokes and the expected volume produced by each stroke. Flow-out is measured by any one or combination of a mass flow meter, flow paddles, or redundant pit level sensors installed on the mud return line.

Examples of HP EKD Systems and Components:

The HP EKD systems evaluated for this Assessment are software based and integrated with sensors (wired or wireless) if special data transmitters and electronic buses are set up. Each system has different degrees of automation, but none are fully automated. Perhaps the most important component of these systems is the density compensated flow-out meter, traditionally a Coriolis meter. The Coriolis meter requires mud flow in order to provide a mass flow measurement. Other designs appear to be coming to market, for example a wedge design meter recently developed by MezurX called the X-Omega. The X-Omega wedge-design meter is commercially available; however, although proposed for use on the OCS, BSEE was told that it has not been used in commercial application in the US oil and gas offshore industry at the time of this writing.

The following description of each HP EKD system evaluated for this Assessment is, for the most part, based on OEM descriptions of their system. Not all statements have been fully verified by BSEE.

Surface Logging Services (SLS). The SLS systems are offered by Baker Hughes, Halliburton, Schlumberger, and Weatherford. In addition to the data recording systems that drilling rigs are equipped with, these SLS can deploy a variety of sensors for qualitative or quantitative return flow measurements with audiovisual alarms built into the software platforms. Alarm screens are customized to suit client needs. The alarm screens are continually monitored in the surface logging cabin, but can also be shown on remote monitors. Monitoring can also be carried out in each company's remote data center or sent to other service companies to load into their monitoring display and alarm systems. During connections and other pump-off events, flowback monitoring software determines whether mud volumes returning to the pits are normal or not. The software also helps differentiate between kicks and formation ballooning and enables personnel to monitor hole fill-up volumes and trends.

Coriolis Mass Flow Meter. This meter can be used with the surface logging services and other systems discussed in this section. In order to detect a kick using the Coriolis meter, the mud circulation through the Coriolis meter must be continuous (pumps on). Therefore when making connections, tripping, or any other situation when circulation is stopped, this system is not effective. Other methods are typically used for identification of kicks or losses during connections or other pumps-off periods.

Connection Flow Monitoring (CFM). This is a software based system that monitors and interprets the return flow rates and volumes of drilling mud to identify kicks or ballooning, especially at the time of connections. It performs a trend analysis of pressure, flow rate, pit volume and pit volume rate of change. It compares trends of parameters from the same start point with the pumps shut-off and can activate audible alarms when a kick is suspected. This software helps distinguish between a kick and ballooning by the return flow trend of the volume. In ballooning when the pumps are shut off the flow rate usually tapers off at some time during the monitoring, while an increase in flow rate may be indicative of a kick. CFM helps avoid misdiagnoses. The software establishes baselines and monitors return flow during each connection from when the pumps are shut down. Using multi-measurement trend analysis, CFM fingerprints a normal connection profile, and any deviation from it will signal an alarm (kick, ballooning, or mud loss). CFM software can be connected with data management software and can receive data straight from the sensors. So, it can be run and displayed at both the rig and remotely. Baker Hughes, Halliburton, Schlumberger, and Weatherford offer CFM software and service.

National OilWell Varco's Kick Monitoring Display S2. The KMD or KMS-S2 is a Kick Monitoring Display system and offers a dedicated display triggered by flow increases while drilling. The KMD-S2 has several features and built-in-logic that alerts the driller either through alarms or specially designed graphical pop ups that will trigger certain operational criteria. KMD-S2 uses a "fingerprinting" technique to detect deviations from the normalized values. This means that the system continuously calculates an expected flow and compares it against actual flow. Flow-in, active pit volume and flow-out are continuously measured and compared with the expected flow. The KMD-S2 also plots the standpipe pressure and calculates compensated active pit volume (using pit volume sensors in each corner of the tanks). Coriolis meters have been used for flow-out monitoring.

Safe Kick's SafeVision TM System. This system can be used as stand-alone software or in conjunction with a rig's existing sensors and components. The SafeVision system includes a control panel combined with its proprietary software that utilizes a driller's existing equipment (flow meters, pumps strokes, mud pit volumes, chokes, pressure sensors, etc.) Space requirements are minimal. The simplicity of the system makes it attractive for any type of drill rig, as the SafeVision system does not require piping reconfigurations or a density-compensated mass flow meter to function. This system includes various automated EKD functions and is designed to provide practical well control-related benefits far beyond SP EKD. If more sophisticated features of the system are needed then additional data sources may be used (e.g., rig equipment upgrades may be recommended to make existing equipment "readable and controllable" by the SafeVision system). The software takes advantage of real-time hydraulics modeling.

Pegasus Vertex, Inc. Drilling Software. This is a second tier kick detection tool and the single software-only system assessed. Pegasus Vertex provides sophisticated models for drilling hydraulics. It provides program modules for various aspects of the drilling and completion processes. EKD can be done within this software by comparing the model values with the measured values of downhole parameters. HydPro is the module that builds hydraulic models suitable for vertical as well as horizontal wells. SurgeMod is the pressure prediction module that provides surge and swab hydraulics for drilling and completion operations. The suite has modules for Mud Properties Reporting (MUDPRO); a module for Underbalanced drilling hydraulics (UBDPRO); a module for Casing Wear, and others. Many in the industry have acquired the software as a tool for cross checking results from other modeling software.

Based on BSEE's assessment, the following is our summary of the benefits and shortcomings of OA EKD Systems as a whole:

<u>OA EKD System Benefits</u>:

- Simple design, installation, and decommissioning, ranging in complexity and benefits from low- to high-precision systems.
- Established and proven for use in many offshore projects.
- Affordable and available for widespread use on the OCS.
- Versatile and suitable for most rigs configurations, has a relatively small footprint, and can function with a variety of flow and volume sensors, with or without Coriolis meter.

- Multiple systems are commercially available, generally by service companies as part of their service contracts.
- Does not require the presence of excessive contractor personnel on the rig.
- The analysis of the sensor data is automated on HP systems making kick detection an objective decision process, thus diminishing the chance for human delay and/or error.
- Many of the software products supporting the HP systems have sophisticated algorithms, which can process many parameters and trends at the same time. Some claim to differentiate between a kick and ballooning.
- HP systems allow for remote real time monitoring.
- HP systems generally consist of at least one density compensated mud flow meter (flow-out), mud pump stroke counter (flow-in), motion-compensated pit volume sensors, ICU to capture inputs and provide display output, and computer software to provide use of algorithms and trend analysis

<u>OA EKD System Shortcomings:</u>

- Both SP and HP EKD systems are open to subjectivity in setting the threshold for kick alarm or differentiating between ballooning and a kick.
- Despite the overall benefit of HP EKD systems over SP EKD systems, HP EKD systems still incur shortcomings, including:
    - To precisely detect a kick with density compensated Coriolis meter systems, mud circulation must actively pass through the Coriolis flow meter. When pumps are off with no flow, as is most often the case during connections or tripping, the system cannot detect a kick. Some EKD software products still continue to receive pit volume data during connections/tripping, although mud density is not measured.
    - To ensure "full" volumetric flow (no slugging) of mud returns through a Coriolis flow meter, a hydrostatic head must be maintained prior to the mass flow meter via a long run of pipe. This limits use on some rigs and facilities used in the OCS, although in many, if not most cases, a deck extension is an option to provide the additional space required.
        - Note: The MeasurX wedge-type mass flow meter, which has been proposed for use on the OCS, does not require as long of a pipe-run as a Coriolis to achieve the needed hydrostatic head.
    - Due to pressure limitations, Coriolis type meters are typically not installed on the high pressure side of the Mud pumps (between the pump output and the drill pipe). If installed on the suction side of the pumps, one meter for each mud pump or one for a manifold type suction system may be required.
    - Flow meters, such as Coriolis, with components that are subjected to the mud flow are highly susceptible to wear and damage due to solids and chemicals in the drilling mud.
    - Due to the design of Coriolis meters, accurate readings are susceptible to external vibration therefore the meters are restricted to location without vibration or require vibration dampening additions.

<u>Closed Annulus (CA) EKD System</u>

Like the OA EKD system, the CA EKD systems utilize conventional drilling methods with the difference being the addition of a means to "close the loop" from atmosphere, i.e. adding a Rotating Control Device (RCD). While each of the vendors offering this type of service has a proprietary configuration, they all share the same purpose which is to close the annulus while allowing rotation of the drill pipe. The RCD can be placed on the rig immediately below the rig floor above the tension ring (dry configuration) of the riser, or below the tension ring (wet configuration).

A CA system allows for better control of the bottom-hole pressure and easier detection of an influx from the formation into the well. With a CA system a longer pipe run is not required prior to the mass flow meter due to the presence of back-pressure on the system as a result of the "closed loop". With a CA system, options for additional sensory equipment can add to the capability of the system. For example, sensors near the drill bit used during Pressure While Drilling (PWD) to compliment the CA EKD system provide an earlier indicator of a kick. The strength of CA systems lies in the fact that uninterrupted mud circulation is possible during pipe connections and tripping, which minimizes conditions most susceptible to kicks.

Although the scope of this BAST Assessment was not intended to include MPD systems, BSEE chose to capture MPD to a limited extent since many of the components and technologies used in MPD systems are also used in EKD.

<u>Examples of CA EKD Systems (all considered HP):</u>

Weatherford's Microflux Control System. This system has three primary components: an RCD, a density compensated mass flowmeter (Coriolis) and an ICU. This hardware, combined with the proprietary software programmed into the ICU, monitors for irregularities in the system (e.g., heave, finger printing, etc.) in order to detect and identify influxes and provides for alarm and/or automated control of the well. An added key feature of this system is the uninterrupted mud circulation during connections and tripping, which allows for extended kick detection and control over OA EKD systems. Weatherford's Microflux Control system manifold is as integral part of their Secure Drilling MPD system and has been used on numerous offshore projects around the world. It has a proprietary configuration and has been used with both surface and subsea BOPs. It uses the dry or wet RCD, riser gas handler, specialized (automated) choke manifolds, and redundant gas diverting lines and chokes.

Halliburton GeoBalance System. This system employs a Coriolis meter and software (*DetectEV* and *ActEV*) that has a number of predefined pressure and mud flow rate signatures, as well as predefined alarm and/or automated control thresholds. *DetectEV* and *ActEV* monitor for mud loss and kick detection. The MPD system uses an above-riser tension ring RCD with a subsea BOP. A number of subsea projects have used the GeoBalance MPD EKD system around the world, however no use of this system has been identified in the GOM.

Schlumberger's @Balance System. This system also offers EKD and kick prevention capabilities within the MPD system. At this time, most of the applications have been for a surface BOP with a dry RCD (above riser tension ring), although they are testing new designs for subsea BOP configurations. The EKD is based mainly on hydraulics and pressure analyses. The Coriolis meter is not integrated with this system, but can be used in conjunction with it.

Based on BSEE's Assessment, the following is a summary of the benefits and shortcomings of the CA EKD Systems as a whole:

Benefits of the CA EKD system:

- Improved early indication of influx at depth of drilling.
- Greater detection, control and prevention of kicks with a closed system.
- Minimal (or no) losses of mud into the formation, thus less (or no) ballooning.
- Improved ability to differentiate between ballooning and a kick.
- Shorter pipe runs needed to generate a hydrostatic head prior to the Coriolis meter (as on OA EKD systems) due to the back-pressure being continually applied to system.
- Allows for uninterrupted mud circulation during tripping or connections, thus reducing kick occurrence.
- Automation of EKD using software with an adaptive model.
- CA EKD is designed to provide earlier and faster kick response, thereby reducing the probability of a LOWC event.

Shortcomings of the CA EKD System:

- Requires additional and often costly equipment.
- Typically requires specialized personnel on the rig.
- Requires longer and more specialized staff training than for OA systems.
- Has higher dependency on complex equipment and therefore subject to higher equipment failure rates.
- May not be applicable/feasible on all rigs.

BSEE Resources

As part of this Step 1.2 Assessment, BSEE made an assessment of the time, effort and resources needed by the agency to complete all three stages of this BAST Determination. BSEE concluded that all necessary resources in terms of budget and expertise are present internally, to allow the continuation of this process through completion.

Feasibility Analysis

As part of this Step 1.2 Assessment, BSEE made an assessment of the anticipated cost to industry to adopt technologies necessary to address the safety issue. The Feasibility Analysis (FA) determines the range of costs needed to purchase/lease, install, and maintain various proven technologies, as well as any training needed for industry personnel to operate such technologies. Additionally, this FA looks into benefits (cost savings) that will result due to the avoidance of accidents/incidents. The FA is located in Appendix A.

Based on the FA, BSEE has determined that the cost of adopting today's more advance EKD technology will not only increase the safety of operations through the reduction in the size of kicks and the risk of

LOWC, but also reduce NPT by decreasing; 1) the time required to circulate out kicks since these kicks should be smaller in size as a result of earlier detection, 2) the number of stuck pipe events and often resulting bypasses, and 3) other precautionary actions taken when kicks happen or are suspected to have happened, including but not limited to:

- Reduced NPT from detecting a kick early and reduced mitigation time,
- Improved differentiation between kicks and ballooning and reduction of such NPT,
- Earlier and better informed responses to reservoir and other wellbore control events,
- Preventing pollution to the environment from mud diverted overboard,
- Preventing oil spills as a result of LOWC,
- Preventing loss of human life from LOWC and explosions, and
- Creating standardized and more uniform performance across all drilling activities.

III. RECOMMENDATION

Based on the information provided above, BSEE finds that use of more advanced EKD systems on OCS facilities is feasible (Step 1.3) and that sufficient justification is available to continue to Step 1.4 (establish the Technology Improvement Objective) of the BDP (see Appendix B. BSEE BAST Determination Process Flowchart).

BSEE does not feel an alternative course of action outside the BDP (e.g. safety alert, research, revision of inspection procedures, etc.) is appropriate to address this safety issue at this time.

APPENDIX A. FEASIBILITY ANALYSIS

The purpose of this feasibility analysis (FA) is to;

1) Evaluate whether commercially available technologies analyzed by BSEE are functional for use on the OCS, and

2) Estimate the potential benefits and impacts (costs) to industry and the environment by requiring the use of such technologies.

This FA takes into consideration technological, operational, economic and other factors to determine the possible positive/negative outcomes of requiring operators to use EKD technologies during drilling rig operations and includes both a Technological/Operational Analysis and an Economic Analysis.

TECHNOLOGICAL AND OPERATIONAL ANALYSIS:

As previously mentioned, BSEE analyzed technologies marketed as being able to detect and warn of an early influx to the wellbore. From these analyses, BSEE identified multiple commercially available technologies available on the open market with applicability to OCS operations and with the capability to provide improved early warning of an influx.

ECONOMIC ANALYSIS:

BSEE analyzed the application and cost of technologies through a structured Economic Analysis. This analysis was based on data for the 5-yr period prior to initiating BSEE's Step 1.2 Assessment. The data from this 5-yr period was used to forecast economics for a future 10-year period (beginning in 2019) in the event an EKD BAST Determination implementation order is issued by BSEE. BSEE considered the **benefits** and **costs** (e.g., EKD equipment, installation, personnel, training, etc.) of incorporating EKD technology where:

- Benefits include measurable cost savings (e.g., reduced incidents/fatalities/damage, reduced loss of resources, reduced NPT, etc.) as well as immeasurable improvements (e.g., reduced false-positives). NPT is expected to drop as a result of smaller kick volumes that are required to be circulated out of a well, and fewer incidents of stuck pipe/bypasses, LOWC, and spills.
- Costs include the price of the EKD equipment, installation, demobilization, maintenance, on-site or remote contract personnel, operator training, etc.

Recognizing the range of equipment costs and the presence of some pre-existing "high-precision" equipment already in use on some OCS rigs (which would not require upgrade/replacement) BSEE simplified this FA by assuming an "average" cost to upgrade each rig since the type of equipment, software, installation, training, etc. varies by rig.

Based on BSEE's findings, this FA indicated that the use of more advanced EKD technologies is economically feasible and that requirements for EKD technology implementation will have an overall positive impact on the safety of personnel, facilities, and the environment.

METHODOLOGY

Rather than assess conditions in each of the four OCS regions (Alaska, Pacific, GOM, and Atlantic) under BSEE jurisdiction, this FA is based solely on data for GOM Region operations. BSEE based its assessment on the five years (2011 through 2015) immediately preceding this BAST Determination Assessment and applied our findings as both a probability and a cost to future operations under a future BAST EKD implementation requirement beginning in 2019.

The equipment and operations cost data used for this FA was gathered from BSEE's Technical Information Management System (TIMS) and publicly provided sources made available by IHS, Baker Hughes, and other companies. Based on the 2011 – 2015 data and assuming that a slower pace of drilling will occur in the future, BSEE estimates that approximately 1,200 wells will be drilled during the future 10-year period (120 wells/year) from MODUs and fixed facilities in the GOM.

BSEE completed the FA by offsetting the estimated COST to the operators needed to add EKD systems to OCS rigs/drilling facilities against the estimated BENEFITS that adoption of such technology may provide.

Assumptions made with respect to wells and rigs over the future 10-year period:

- Full occupancy of the rigs each year,
- 78 Shallow Water wells drilled per year, 60 days/well drilling time or 6 wells/year/rig, 13 rigs/year,
- 42 Deepwater wells drilled per year, 120 days/well drilling time or 3 wells/year/rig, 14 rigs/year
- This equates to an average of 27 rigs/year or 270 rig-years over 10-years.

Where: Net Benefit = [Financial Cost Benefits of EKD] – [Financial Cost of EKD]

COST OF ADOPTING EKD TECHNOLOGIES ON THE OCS

Of the OA EKD technologies assessed by BSEE that appear fit-for-service BSEE categorized them as SP EKD and HP EKD. For this Assessment, BSEE is proceeding with the assumption that a HP EKD system is required where possible for all OCS drilling, completion, temporary abandonment and workover operations.

SP EKD: All rigs are assumed to have this capability. SP EKD is typically included in mudlogging services and will not result in any additional costs. As a result, there is no incremental cost increase foreseen for use of SP EKD technology.

HP EKD: The capital and installation cost to equip a rig with a density compensated mass flow meter (Coriolis or equivalent) ranges from $150,000 - $500,000. Additional cost for implementing the HP EKD may come from having to add other high-precision equipment and/or either rent or pay service fees to install equipment and software and to monitor the well in real time. The following costs are assumed to retrofit a rig to accommodate an HP EKD system and are reflected in Table A below:

- The capital cost for upgrading to a HP EKD (with the mass flow meter being the largest cost) is estimated to average $350K/rig.
- 95% of all rigs will require upgrade to EKD capability (estimate that 5% are now EKD ready).

- 25.65 rigs (95% x 27 rigs/year) require mass flow meter installation in the first year. BSEE estimates that 80% of these 25.65 rigs will maintain their existing EKD system between wells and that the remaining 20% of the rigs will demobilize their EKD equipment.
- EKD service and rental fees of up to $5000/day for up to 365 days. BSEE estimated an annual utilization rate of 2/3 to account for downtime during activities such as mob/demob, spudding, etc.
  - Cost for maintenance is included in the EKD service/rental cost.
- The FA estimated benefits for the 10 year period at a 3% discount rate.

Table A, below, displays the cost for EKD implementation and operation over the first 10 years assuming an “average cost” to upgrade a drilling rig to a HP EKD system. As illustrated by the following equations, the 3% discounted NPV amounts to a 10-yr cost to industry of approximately **$297,200,000**.

To explain how BSEE arrived at the aforementioned figure, we use the data in Table A, Column Year 1, as follows:

Step 1. Rig Upgrade Cost/yr. for Year 1= [Equipment Cost] x [Rigs/yr.] = ($350K) x (25.65) = **$8,977,500**

Step 2. S/R/M[11] Cost for Year 1 = [S/R/M Cost] x [Days/yr.] x [Rigs/yr.] = ($5K) x (243) x (25.65) = **$31,207,500**

Step 3. Total Projected Costs for Year 1 = ($8,977,500) + ($31,207,500) = **$40,185,000**

Step 4. Gross Total Cost = Step 3, repeated for Years 2 – 9, to yield 10-year total = **$337,300,000** (rounded up to the 6th integer)

Step 5. NPV Total Cost for All Years @ 3% discount = **$297,200,000** (rounded up to the 6th integer)

Thus, the cost to use EKD on all of the estimated 27 rigs operating on the OCS during a future 10-year period equals **$297,200,000**.

Table A: OCS EKD 10-yr HP EKD Implementation and Operation Cost Data

Description	Year 1	Year 2	Year 3	Year 4	Year 5	Year 6	Year 7	Year 8	Year 9	Year 10
	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
Equipment Cost (includes shipping & installation)	$350,000	$350,000	$350,000	$350,000	$350,000	$350,000	$350,000	$350,000	$350,000	$350,000
Gross Rigs/Year	27	27	27	27	27	27	27	27	27	27
Rigs/Yr, 95% that Require Mass Flow Meter Upgrade	25.65	25.65	25.65	25.65	25.65	25.65	25.65	25.65	25.65	25.65
Rigs/Yr, 80% Re-Used	0.00	20.52	20.52	20.52	20.52	20.52	20.52	20.52	20.52	20.52
Rigs/Yr to be Upgraded	25.65	5.13	5.13	5.13	5.13	5.13	5.13	5.13	5.13	5.13
Rig Upgrade Costs/Yr	$8,977,500	$1,795,500	$1,795,500	$1,795,500	$1,795,500	$1,795,500	$1,795,500	$1,795,500	$1,795,500	$1,795,500
Service/Rental & Maintenance Daily Costs	$5,000	$5,000	$5,000	$5,000	$5,000	$5,000	$5,000	$5,000	$5,000	$5,000
Days/Year*2/3 Utilization Rate	243	243	243	243	243	243	243	243	243	243
Service/Rental & Maintenance Costs	$31,207,500	$31,207,500	$31,207,500	$31,207,500	$31,207,500	$31,207,500	$31,207,500	$31,207,500	$31,207,500	$31,207,500
Total Projected Costs, not NPV	$40,185,000	$33,003,000	$33,003,000	$33,003,000	$33,003,000	$33,003,000	$33,003,000	$33,003,000	$33,003,000	$33,003,000

Gross Total Cost, All Years	$337,300,000
NPV Total Cost, All Years (3 % discount rate)	$297,200,000

[11] The Acronym "S/R/M" refers to Service/Rental and Maintenance.

BENEFITS OF ADOPTING EKD TECHNOLOGIES ON THE OCS

While not expected to include all benefits, BSEE identified four (4) significant cost saving benefits attributable to the use of EKD as detailed below. The savings include reduction of Kick Non-Productive Time, Prevention of Stuck Pipe Events, Prevention of LOWC Events, and Prevention of Oil Spill Events. In order to determine the monetary value of the first two (2) benefits, BSEE had to establish average costs of operating deepwater and shallow water rigs in the GoM OCS. Rig types include deep water and shallow water MODUs and those used on fixed and floating facilities.

A dynamically-positioned semisubmersible is the most common type of rig used in deep water while Jackups are the most common in shallow water. As illustrated in Table B below, rates can vary significantly from year to year. For the 5 year period, 2011-2015 daily rates for a dynamically positioned semisubmersible rig ranged from $350 K/d - $650 K/d and for a Jackup rig from $100 K/d - $120 K/d.

Table B: 2016 Diamond Offshore GOM Rig Status Data

Drill Rig Day Rate ($K/d)	YEAR				
	2011	2012	2013	2014	2015
Deepwater	550	650	650	500	350
Shallow Water	100	120	120	100	100
Fixed Facility	NA	NA	NA	NA	NA
Estimated Number of Active Rigs (Deepwater & Shallow Water)	41	50	59	55	47

Applying the rig cost data in Table B to a future 10-year period BSEE estimated rig rates as $450K/day for a dynamically positioned semisubmersible rig and $110 K/day for a Jack-up rig.

In addition to rig rates, onboard rig contract services and operational support costs must be considered. Onboard contract services include, but are not limited to, directional drilling, Logging-While-Drilling, cementing, mudlogging, maintenance, meals, cleaning, and multiple other services. All of these services have associated personnel, equipment, and transportation costs associated with them and are generally charged directly to each well. The total of these contracted services and operational support costs are typically 50% of a deepwater rig's rate and 150% or more for a shallow water rig's rate for the GOM, this considering some may be HPHT wells or sidetracking out of casing which usually requires more rental and daily services.

Combining the rig rate and other costs (contract services rate, allocated costs, etc.), we assume average daily rates for GOM rigs for the 10-year period to be:

- **Dynamically positioned semi =** $450K/day/rig + $250K/day/other costs = **$700K/day/rig**
- **Jackup =** $110K/day/rig + $150K/day/other costs = **$260K/day/rig**

Next, BSEE estimated the cost savings (benefit) expected by reducing the NPT associated with earlier kick detection, stuck pipe and associated bypasses, and lowering LOWC events, based on their probability of occurrence. From data provided by *Exprosoft* from TAP Study 765, BSEE assumed that the frequency of kicks for exploration and development drilling is approximately 1 (one) kick per 4th

well (24%)[12] in the OCS. For a 10-year period following EKD implementation, if 1,200 wells are drilled, this kick occurrence rate equates to 288 kicks (i.e., 1,200 wells x 0.24) or 101 in deep water (420 deep water wells x 0.24 and 187 in shallow water wells (780 shallow water wells x 0.24). These numbers of kicks in deep water and shallow water wells will be used in the cost benefit analyses that follows.

Benefit 1: Reduction of Kick Non-Productive Time (NPT)

"In killed wells, all LOWC events start with a well kick."[13] NPT results in the stopping (or slowing) of drilling operations while continuing to pay daily rates for the rig, rental equipment, rig crew, and logistical support. Time spent controlling and resolving a kick equates to NPT. Kicks detected late are by nature usually more troublesome to address, requiring more time to resolve due to larger influxes of gas into the wellbore.

As stated earlier, there are 288 kicks estimated for the 10-year period under evaluation; 101 occurring in deepwater (420 deepwater wells x 0.24) or **10.1/yr**, and 187 (780 shallow water wells x 0.24) in shallow water or **18.7/yr**. For the sake of this analysis, we assume that half of the kicks (50%) take less than 2 days and half (50%) take 4 days to resolve and that a reduction of 70% in kick event duration can be achieved through the implementation of EKD. By using these numbers of kicks per year and assuming half (as explained above) take 2 days (or less) to resolve and half take 4 days (or more) to resolve, and using the corresponding daily total rig spread rates explained above, BSEE calculated the benefit due to reduction in NPT to equal ~ $25 million, as illustrated below and tabulated in Table C below.

For example, a 70% reduction in Deepwater (DW) kick events can be calculated as follows:

For a 2-day event, [2 days/event x $700,000/day x 70% = $980,000 reduction per 2-day DW event
Then 50% of 10.1 kicks/year = 50% x 10.1 x $980,000 = **$4,949,000** reduction for 2-day DW events

For 4-day events = [4 days/event x $700,000/day x 70%] = $1,960,000 reduction per 4-day event
Then 50% of 10.1 kicks/year = 50% x 10.1 x $1,960,000 = **$9,898,000** reduction for 4-day DW events

Thus the NPT Savings/yr in Deepwater = $4,949,000 + $9,898,000 = **$14,847,000**.

Using the same set of equations and steps, from the deepwater example above, for shallow water, yields:
The NPT Savings/yr in Shallow water = $3,403,000 + $6,806,000 = **$10,210,000**.

Combining the deep and shallow water = $14,847,000 + $10,210,000 = **$25,057,200**, as illustrated in Table C below.

[12] BSEE TAP Study 765, page 172, Table 16.15: Annualized kick frequencies.
[13] BSEE TAP study 765 page 16.

Table C: Benefit due to reduction of Kick NPT Days (per year)

Benefit due to reduction in Kick NPT Days (per year)	
Deep water Kicks (101 kicks in 10 years): 10.1/year	10.1
Savings per kick, 70% reduction of a 2-day events at $700 K/day	$980,000
50% of 10.1 kicks/year for 2-day events	5.05
Sub-total Deep water 2-day event reduction	**$4,949,000**
Savings per kick, 70% reduction of a 4-day events at $700 K/day	$1,960,000
50% of 10.1 kicks/year for 4-day events	5.05
Sub-total Deep water 4-day event reduction	**$9,898,000**
Savings per year in deepwater (50% each 2-day and 4-day events)	**$14,847,000**
Shallow water Kicks (187 kicks in 10 years): 18.7/year	18.7
Savings per kick, 70% reduction of a 2-day events at $260 K/day	$364,000
50% of 18.7 kicks/year for 2-day events	9.35
Sub-total Shallow water 2-day event reduction	**$3,403,400**
Savings per kick, 70% reduction of a 4-day events at $260 K/day	$728,000
50% of 18.7 kicks/year for 4-day events	9.35
Sub-total Shallow water 4-day event reduction	**$6,806,800**
Savings per year in shallow water (50% each 2-day and 4-day events)	**$10,210,200**
Total Gross Kick NPT Savings per year	**$25,057,200**

Populating the $25,057,200/yr savings from Table C above into Table D below yields a 10-yr Cost Benefit of $250,572,000. Using a 3% discount rate for this 10-yr cost benefit period rounding to the 6th integer yields a NPV Total Cost benefit of $220 M.

Table D: Cost Benefit resulting from a Reduction of Kick Non-Productive Time (NPT)

Significant Benefits	Year 1	Year 2	Year 3	Year 4	Year 5	Year 6	Year 7	Year 8	Year 9	Year 10
	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
Savings, Deepwater Kicks	$14,847,000	$14,847,000	$14,847,000	$14,847,000	$14,847,000	$14,847,000	$14,847,000	$14,847,000	$14,847,000	$14,847,000
Savings, Shallow water Kicks	$10,210,200	$10,210,200	$10,210,200	$10,210,200	$10,210,200	$10,210,200	$10,210,200	$10,210,200	$10,210,200	$10,210,200
Total Projected Benefits, not NPV	**$25,057,200**	**$25,057,200**	**$25,057,200**	**$25,057,200**	**$25,057,200**	**$25,057,200**	**$25,057,200**	**$25,057,200**	**$25,057,200**	**$25,057,200**

Gross Total Benefit, All Years	**$250,572,000**
NPV Total Cost, All Years (3 % discount rate)	**$220,000,000**

Benefit 2: Prevention of Stuck Pipe Events

Kicks cause stuck pipe and, although much less frequent, stuck pipe can result in kicks. Kicks detected late lead to a higher probability of stuck pipe. To determine the cost savings for avoiding stuck pipe incidents and resulting **bypass** (when an operator drills around a mechanical problem in the original hole to the original target from the existing wellbore) operations, the following assumptions and Table E are used.

Per the Exprosoft report[14], 47 of the 265 (or 17.7%) development and exploratory well kicks recorded from the 2011-2015 WARs were identified as having a kick and stuck pipe in the same week. Of these 47 WARs, 25 recorded a kick before the pipe became stuck and 12 recorded a kick after the pipe became stuck. For the remaining 10 WARs, the stuck pipe and kick were not found to be related. This equates to approximately 14% (or (17.7% x (25+12)/47) of the kicks were associated with stuck pipe.

To determine the benefit of avoiding kick related stuck pipe over the 10-year forecast period we estimate that 288 kicks will occur (780 shallow water wells x 0.24 = 187 kicks, and 420 deepwater wells x 0.24 = 101 kicks). Applying the 14% stuck-pipe value and assuming a stuck pipe duration of 3 days (from the time the pipe becomes stuck until the pipe comes free or until plugback above the lost pipe) yields an estimated coast savings of $5MM/year as calculated immediately below (rounding to the 6th integer) and illustrated in Table E.

Shallow Water: 187 kicks x 14% kick stuck pipe frequency x 3 days/stuck pipe = 78.5 days x $260,000/day = $20,000,000

Deep Water: 101 kicks x 14% kick stuck pipe frequency x 3 days/stuck pipe = 42.2 days x $700,000/day = $30,000,000

Total 10 Year Gross Stuck Pipe benefit = $50,000,000 or $5,000,000/yr

To determine the benefit of avoiding kick related bypasses over the 10-year forecast period, BSEE recognizes the following; 1) a large percentage of stuck pipe instances results in having to bypass around the stuck pipe and 2) the probability of freeing stuck pipe

[14] BSEE Tap study 765, page 177.

diminishes rapidly with time. Accordingly to the Exprosoft report[15], approximately 50% of kicks are detected late. Assuming that 50% of the stuck pipe events lead to the need to bypass, of the 288 kicks estimated to occur over the 10-year forecast period, equates to 20 bypasses of which **13 are in shallow water** (187 kicks x 14% kick stuck pipe frequency x 50%) and **7 are in deep water** (101 kicks x 14% kick stuck pipe frequency x 50%). Assuming a total rig spread rate averaging **7 (seven) days** to plug-back the original hole and bypass the well to the original total depth, plus a minor amount of consumables used to do so ($15,000/bypass), yields a gross 10 year cost savings benefit of ~ $5.8MM/year as calculated immediately below (rounded to the 6th integer) and illustrated in Table E:

Shallow Water: 7 days/bypass x $260,000/day + $15,000 = $1,835,000 /bypass x 13 bypasses/10Years = $23,855,000

Deep Water: 7 days/bypass x $700,000/day + $15,000 = $4,915,000 /bypass x 7 bypasses/10Years = $34,405,000

Total 10 Year Gross Bypass benefit = $58,260,000 or $5,826,000/yr

Using the previously established daily rig spread rates, **the cost for stuck pipe and bypasses can reach $108 MM over the 10-year period or about $95 MM NPV using a 3% discount rate**. Note, to be conservative, it has also been assumed that each plugback and bypass are successful.

Table E: Cost Benefit resulting from Prevention of Stuck Pipe and Bypass Events

Description	Water Depth		Totals
	Shallow	Deep	
Number of Wells in 10 Years	780	420	**1200**
Kick Frequency	24%	24%	
Number of Kicks	187	101	**288**
% of Kicks resulting in Stuck Pipe	14%	14%	
Number of Kicks with Stuck Pipe	26.18	14.14	**40.32**
Days per Each Stuck Pipe	3	3	
Total Stuck Pipe days	78.54	42.42	**120.96**
$/d for Stuck Pipe	$260,000	$700,000	
$ for Stuck Pipe, 10 Years	**$20,000,000**	**$30,000,000**	**$50,000,000**
Days for Each Bypass	7	7	
Consumables to Bypass	$15,000	$15,000	
$ for Each Bypass	$1,835,000	$4,915,000	
% of Stuck Pipe for Bypass	50%	50%	
Number of Bypasses	13	7	**20**
$ for Bypasses, 10 Years	**$23,855,000**	**$34,405,000**	**$58,260,000**
Total Gross Cost of Stuck Pipe and Bypass, 10 Years	**$43,855,000**	**$64,405,000**	**$108,260,000**
10 Yr NPV Cost of Stuck Pipe and Bypass (3% Discount Rate)			**$95,000,000**

[15] BSEE TAP study 765 page 15 and 158.

Benefit 3: Prevention of LOWC Events

For the reference period 2011-2015 and as explained on pages 167 and 168 of the *Exprosoft* report, out of 266 total kicks (including 1 relief well) in the US OCS, 9 (nine) [16] resulted in LOWC of which 2 (two) or 0.75% happened after the BOPs were installed (i.e. "Deep Zone" as described in the Exprosoft report) while another 2 had no description of activities in the WAR.

Using the same 288 kicks calculated in Benefit 2 and the 0.75% for LOWC-per-kick calculated immediately above, the future 10-year period will experience **two (2) LOWC events**. This number is consistent with the ~ 4 surface LOWC events/yr (from all causes; including kicks) identified in the BSEE Annual Report 2016 (for the 10-year period from 2007 – 2016), page 35, Figure 3.9[17]. The cost associated with LOWC ranges from minimal NPT when well control is reacquired within several hours, to fully losing the well, the rig, human lives, emergency response, and cleanup. The damage caused by LOWC, with no oil spill and no personnel injuries, could range from several hours of NPT and relatively low cost to beyond $50 M when the well is lost along with damage to other structures, as in the case of Walter Oil and Gas well in ST 220. For this benefit estimate, BSEE assumed that **one (1) of the two (2) projected LOWC events (with no oil spill response/cleanup) results in a high cost value of $50 M (including litigation).** Applying the 3% discount rate results in a **NPV of $45 M** (see Table F below).

Note: The Walter Oil and Gas LOWC was a gas well with minimal associated condensate or oil, therefore the cost of the LOWC is considered conservative as compared to an oil well where LOWC requiring a major oil spill clean-up can result in significant additional costs. The worst possible LOWC is likely to be on the scale of the Macondo[18] well. As of July 14, 2016, the pre-tax cost of the Macondo event to the operator was over $61 billion[19] and the cost to the offshore industry compounded this due to a subsequent drilling moratorium[20]. While the extent and cost of Macondo is unprecedented in the GOM, there is probability of such an event recurring. Such an event is addressed in Benefit 4, Prevention of Oil Spill Events.

[16] Per BSEE TAP Study 765 page 168. Two (2) events no description on the WARs, five (5) shallow water flow before BOPs installed, two (2) LOWC events after BOP installed. Also, there were also seven (7) other LOWC events in the 2011-2015 data but the wells were spudded before 2011 and were WORKOVER related incidents.

[17] BSEE Annual Report 2016; https://www.bsee.gov/sites/bsee.gov/files/bsee_2016_annual_report_v5_final_january2017.pdf

[18] Macondo was a catastrophic oil spill that occurred approximately 41 miles south of Louisiana in Federal waters on April 20, 2010, killing 11 workers, injuring 17 others and discharging nearly 5 million barrels of oil into the Gulf of Mexico.

[19] See BP press release July 14, 2016; http://www.bp.com/en/global/corporate/media/press-releases/bp-estimates-all-remaining-material-deepwater-horizon-liabilitie.html

[20] DOI Drilling Moratorium; https://www.doi.gov/news/pressreleases/Interior-Issues-Directive-to-Guide-Safe-Six-Month-Moratorium-on-Deepwater-Drilling

Table F: Cost Benefit resulting from Prevention of LOWC Events

Significant Benefits	Year 1	Year 2	Year 3	Year 4	Year 5	Year 6	Year 7	Year 8	Year 9	Year 10
	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
Savings, Prevention of LOWC	$0	$0	$0	$0	$50,000,000	$0	$0	$0	$0	$0
Total Projected Benefits, not NPV	**$0**	**$0**	**$0**	**$0**	**$50,000,000**	**$0**	**$0**	**$0**	**$0**	**$0**

Gross Total Benefit, All Years	**$50,000,000**
NPV Total Cost, All Years (3 % discount rate)	**$45,000,000**

Benefit 4: Prevention of Oil Spill Events

If an EKD system is capable of preventing a LOWC and subsequent oil spill, the benefit can be in the millions of dollars. Oil spills of less than 50 bbl. are not uncommon for the GOM, oil spills between 50 and 1,000 bbls are less common than 50 bbl. spills, and spills over 10,000 bbls even less. The Bureau of Ocean and Energy Management (BOEM), refers to spills of less than 1,000 bbl. as "small" spills and spills greater than or equal to 1,000 bbl. or more as "large" spills. According to BOEM's July 13, 2016, Oil Spill Report[21], page 16, Table 5, for the most recent 10-year period (2006 through 2015) a total of 334 small spills have occurred from platforms and one (1) large spill (Macondo). This data is generally consistent with the data provided by *Exprosoft* for the US OCS GOM 2000-2015 period during which one large spill (Macondo) was reported.[22]

Using data from Tables 17.1 and 17.2[23] of the *Exprosoft* report, of the 10259 wells drilled between 2000 and 2015, nine (9) development wells and fourteen (14) exploratory wells experience surface blowouts, a factor of 0.224% of wells drilled. Applying this 0.224% factor to our future 10-year period wherein 1,200 wells are estimated to be drilled, **equates to an estimate of nearly three (3) wells resulting in a surface blowout with oil spill**. The cost of an oil spill, depending on size, may include any or all of the following; spill response, clean-up, incident reporting, investigations, civil/criminal penalties and litigation, damage to the environment and sea-life, etc. In addition to oil spills, a LOWC may produce pollution from mud discharged overboard during a kick event.

Estimating the cost of these three projected LOWC oil spill events is not easily quantifiable since the average cost of small spills is not readily available and the cost of large spills like the 1989 Exxon Valdez and the 2010 BP Macondo events may not be applicable due to their size and public scrutiny. Even the estimates of the total cost of these large spills vary, depending on the costs (e.g., clean-up, litigation/compensation, fines, etc.) reported. For purposes of this report BSEE used the Exxon Valdez and BP Macondo spill cost

[21] 2016 Update of Occurrence Rates for Offshore Oil Spills, July 13, 2016, https://www.boem.gov/occurrence-rates-for-offshore-oil-spills/.
[22] See BSEE TAP study 765, page 12
[23] See BSEE TAP study, page 179-180, Tables 17.1 and 17.2; a total 14 LOWCs resulting in Blowout (surface flow) or Well Release in 10,262 wells.

figures to estimate of OCS oil spills. BSEE used $3.8BN for the Exxon Valdez as reported by CBS[24] and $61.6BN for the BP Macondo as reported by BP[25]. Combining the cost estimates for these two major spills yields an estimated average cost of $14,905/bbl. as calculated below:

- Exxon Valdez, March 24, 1989 where 257K bbls spilled and cost an estimated $3.8BN ($3.8BN/257Mbbl) = **$14,786/bbl.**, and

- Macondo LOWC, April 10, 2010 where 4.1MMbbl spilled and cost an estimated $61.6BN ($61.6BN/4.1MMbbl) = **$15,024/bbl**.

Averaging the Valdez and Macondo events yields a total cost of $14,905/bbl (14760/bbl Valdez and 15,024/bbl Macondo). Applying this $14,905/bbl cost to the three anticipated 500 bbl each oil spills over the 10 year forecast period totals ~ $22.3MM over the ten (10) year period equating to ~ $2.2 MM/yr as calculated below and detailed in Table G.

Oil Spill Prevention Benefit = 500 bbl/spill, * 3 spills * $14,892.bbl = **$22,357,500** over 10 years = $2,235,750/yr.

Table G: Cost Benefit resulting from Prevention of Oil Spill Events (without including a Macondo-like event)

Table B: Estimated Benefits										
Significant Benefits	Year 1	Year 2	Year 3	Year 4	Year 5	Year 6	Year 7	Year 8	Year 9	Year 10
	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
Savings, Prevention of Oil Spills	$2,235,750	$2,235,750	$2,235,750	$2,235,750	$2,235,750	$2,235,750	$2,235,750	$2,235,750	$2,235,750	$2,235,750
Total Projected Benefits, not NPV	**$2,235,750**	**$2,235,750**	**$2,235,750**	**$2,235,750**	**$2,235,750**	**$2,235,750**	**$2,235,750**	**$2,235,750**	**$2,235,750**	**$2,235,750**

Gross Total Benefit, All Years	**$22,357,500**
NPV Total Cost, All Years (3 % discount rate)	**$20,000,000**

NET BENEFIT SUMMARY OF ESTIMATES

BSEE finds that EKD implementation across the OCS will result in a cumulative overall net benefit. For the forecasted 10-year period, adding all the NPV estimates, without including a Macondo-like event or loss of life, yields a total potential savings of $375 MM as illustrated in Table H below.

[24] CBS Evening News Article; http://www.cbsnews.com/news/exxon-valdez-oil-spill-20-years-later/
[25] BP Press Release; http://www.bp.com/en/global/corporate/media/press-releases/bp-estimates-all-remaining-material-deepwater-horizon-liabilitie.html

Table H: Combined (Total) Net Benefit of Incorporating EKD in the OCS (without including a Macondo-like event)

Table B: Estimated Benefits										
Significant Benefits	Year 1	Year 2	Year 3	Year 4	Year 5	Year 6	Year 7	Year 8	Year 9	Year 10
	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
Table D: Deepwater Kicks	$14,847,000	$14,847,000	$14,847,000	$14,847,000	$14,847,000	$14,847,000	$14,847,000	$14,847,000	$14,847,000	$14,847,000
Table D: Shallow water Kicks	$10,210,200	$10,210,200	$10,210,200	$10,210,200	$10,210,200	$10,210,200	$10,210,200	$10,210,200	$10,210,200	$10,210,200
Table E: Prevention Stuck Pipe & Bypasses	$10,826,000	$10,826,000	$10,826,000	$10,826,000	$10,826,000	$10,826,000	$10,826,000	$10,826,000	$10,826,000	$10,826,000
Table F: Prevention of LOWC	$0	$0	$0	$0	$50,000,000	$0	$0	$0	$0	$0
Table G: Prevention of Oil Spills	$2,235,750	$2,235,750	$2,235,750	$2,235,750	$2,235,750	$2,235,750	$2,235,750	$2,235,750	$2,235,750	$2,235,750
Total Projected Benefits, not NPV	**$38,118,950**	**$38,118,950**	**$38,118,950**	**$38,118,950**	**$88,118,950**	**$38,118,950**	**$38,118,950**	**$38,118,950**	**$38,118,950**	**$38,118,950**

Gross Total Benefit, All Years	**$431,189,500**
NPV Total Cost, All Years (3 % discount rate)	**$379,000,000**

RESULTS:

NET BENEFIT (NB) = System Benefit(s) – System Cost(s)

NET BENEFIT = $379 MM - $297 MM = <u>$82 MM Benefit over 10-year period</u>.

Based on the findings of this FA, BSEE finds that implementation of EKD in the OCS has a positive benefit on the safety of personnel and the environment. If EKD is found later to not be economically feasible across the entire OCS, BSEE may end this BAST Determination or instead, reserve the EKD requirement to target higher risk wells and/or specific drilling, completion, temporary abandonment and workover operations.

APPENDIX B: BSEE BAST Determination Process Flowchart