Best Practices for Real Time Monitoring of Offshore Well Construction

DRAFT REPORT v3.0

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Statement of Purpose

In 2016, new well-control rules were established (CFR §250.724) whereby operators are required to provide real-time monitoring plans and capabilities for operations in the OCS detailing at least the following technical and operational capabilities:

- How the RTM data will be transmitted onshore, how the data will be labeled and monitored by qualified onshore personnel, and how the data will be stored onshore;
- A description of procedures for providing BSEE access, upon request, to the RTM data including, if applicable, the location of any onshore data monitoring or data storage facilities;
- Onshore monitoring personnel qualifications;
- Methods and procedures for communications between rig and onshore personnel;
- Actions that will be taken in case of loss of RTM capabilities or rig-to-shore communications; and
- A protocol for responding to significant or prolonged interruptions of RTM capabilities or communications, including procedures for notifying the District Manager of such interruptions.

As written the rule is open to interpretation. Therefore, to provide additional clarity regarding §250.724 OESI has provide a collection of recommendations that are likely to satisfy the spirit of the rule without imposing undue burdens on operators or prescribing specific technologies or practices.

The central purpose of this document is two-fold:

1. Provide a framework for operators to leverage real-time monitoring (RTM) capabilities and technologies to, within reason, prevent or mitigate potential or actual threats to life, health, property, or the environment.
2. Recommend practices that will allow a person or organization, sufficiently skilled in the art(s), to reasonably re-create, using the data and metadata specified herein, the observations, interpretations, and conclusions of an operator.

Additionally, this document contains several appendices which are included to spark discussion around several concepts which, in the opinion of the authors, present clear and present risks if left unaddressed, including:

- Discussion of common BOP testing practices
- Discussion of negative pressure testing practices

It is expected that these appendices will lead to better understanding of, and ultimately improvement in, the processes.

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1 Definitions

AAR	After Action Review
Accumulator	A device to store hydraulic and/or pneumatic pressure for operation of a BOP.
Annulus	(plural: annuli) the space between concentric tubulars (such as drillpipe and casing) or between tubulars and a wellbore
ANSI	American National Standards Institute (www.ansi.org)
APD	Application for Permit to Drill
API	American Petroleum Institute (www.api.org)
ASCE	American Society of Chemical Engineers
ASME	American Society of Mechanical Engineers (www.asme.org)
Azimuth	An angular measurement in a spherical coordinate system
Barite	A mineral (barium sulfate) commonly used as a weighting agent to increase the density of drilling fluid
BBLS	Oilfield Barrels (42 gallons, 159 liters)
BHA	Bottom Hole Assembly
BOE	Barrels of Oil Equivalent
Bourdon Tube	a thin-walled flattened tube of elastic metal bent into a circular arc whose application to certain pressure gauges and thermometers depends upon the fact that increase of pressure inside the tube tends to straighten it
BPM	Business Process Management
BSEE	Bureau of Safety and Environmental Enforcement (www.bsee.gov)
C_{10}+	Fraction of hydrocarbons or hydrocarbon mixtures containing the alkanes: with carbon counts >10 ($C_{>10}H_{>20+2n}$) and/or any of their isomers
C_1-C_5	Fraction of hydrocarbons or hydrocarbon mixtures containing the alkanes: methane (C_H4), ethane (C_2H_6), propane (C_3H_8), butane (C_4H_{10}) and pentane (C_5H_{12}) and/or any of their isomers
Calibration	The action or process of calibrating an instrument or experimental readings:
CBM	Condition Based Monitoring
CFR	Code of Federal Regulations
Data	Continuous analog or discretely sampled digital signals provided by machines, tools, or instruments. For example: stand-pipe pressure, top-drive torque, or pit volume(s)
Dead Reckoning	The process of calculating one's current position by using a previously determined position, or fix, and advancing that position based upon known or estimated speeds over elapsed time and course.
Deadwood	Objects in a tank or pit that are fixed and occupy space that could otherwise be occupied by fluid
DGPS	Differential GPS
DHS	Department of Homeland Security (www.dhs.gov)
DOI	Department of Interior (www.doi.gov)
Drilling Margin	Pressures between pore pressure and fracture pressure, at which a well can be safely drilled
FAA	Federal Aviation Administration (www.faa.gov)
FIT	Formation Integrity Test, a test to evaluate the competence of the rock at or below the casing shoe usually performed before after setting casing and before drilling.
FIP	Fracture Initiation Pressure
FMEA	Failure Mode Effects Analysis
FPP	Fracture Propagation Pressure

FPSO	Floating Production Storage and Offloading (vessel)
Fracture Pressure	The pressure required to fracture a rock
GPS	Global Positioning System
H_2S	Hydrogen Sulfide, a toxic and flammable gas commonly encountered in oil and gas wells
Hz	Hertz (cycles per second)
Inclination	The angle at which a straight line or plane is inclined to another. In drilling, the angle with respect to vertical where vertical is zero degrees.
ISCG	United States Coast Guard (www.uscg.mil)
ISCWSA	Industry Standards Committee Wellbore Survey Accuracy (www.iscwsa.net)
ISIP	Initial Shut-In Pressure
ISMS	Information Security Management System
ISO	International Standards Organization
ISPS	International Ship and Port-Facility Security
Kick	An uncontrolled influx of reservoir fluids into a wellbore
KM	Knowledge Management
Latitude	the angular distance of a place north or south of the earth's equator, or of a celestial object north or south of the celestial equator, usually expressed in degrees and minutes:
Longitude	the angular distance of a place east or west of the meridian at Greenwich, England, or west of the standard meridian of a celestial object, usually expressed in degrees and minutes:
LOP	Leak-Off Pressure
LOT	Leak Off Test. A test performed to determine the pressure at which fluid can be injected into a porous and permeable formation
LWD	Logging While Drilling
Measured Depth (MD)	The depth of a wellbore along the well-path.
Metadata	Information that describes or provides context about data provided from machines, tools, or instruments. Metadata includes: mnemonics, tags, comments, daily reports (i.e. mud), equipment, references, links, articles, configurations, calibrations, formulas or any other information that can be used to explain, transform, clarify, or otherwise modify data into more useful forms.
Mnemonic	A device such as a pattern of letters, ideas, or associations that assists in remembering something.
MODU	Mobile Offshore Drilling Unit
MSCF	Thousand Standard Cubic Feet (gas)
MTSA	Maritime Transportation Security Act
MVP	Minimum Viable Product
MWD	Measurement While Drilling
NAD	North American Datum
NASA	National Aeronautical and Space Administration (www.nasa.gov)
NIST	National Institute of Standards and Technology (www.nist.gov)
Nyquist Frequency	The slowest sample rate (frequency) at which a desired observation can be observed and differentiated from noise or other events. This is typically 2x the frequency of the desired observation.
OCS	Outer Continental Shelf
OEM	Original Equipment Manufacturer
OPC	OLE for Process Control (www.opcfoundation.org)

Operator	The company or organization that is primarily responsible for, and is the permit holder, for drilling a well. Wells may also have non-operating partners.
OSHA	Occupational Safety and Health Administration (www.osha.gov)
OSV	Offshore Supply Vessel
Permeability	The state or quality of a material that causes it to allow liquids or gases to pass through it
Pore Pressure	The pressure found in the pore space of a reservoir.
Porosity	The void fraction of a solid that is able to be occupied by a fluid (liquid or gas)
PSI	Pounds per Square Inch
R&R	Repeatability and Reliability
Reservoir	an underground porous and permeable formation containing hydrocarbons, water and/or other fluids.
Rheology	Describing the properties of deformation and flow, particularly of liquids and gasses
ROP	Rate of Penetration
RPM	Revolutions per Minute
RTM	Real Time Monitoring
Sampling	The process of discretely measuring an analog signal to transform it into digital information
SCFM	Standard Cubic Feet per Minute
SEC	Securities and Exchange Commission (www.sec.gov)
SEMS	Safety and Environmental Management Systems
Sigma	Symbol referring to one standard deviation in statistics
Skin Factor	A unitless description of near-wellbore effect that alter the ability for fluid to flow
SME	Subject Matter Expert
SOLAS	Safety of Life at Sea
SPE	Society of Petroleum Engineers (www.spe.org)
SQL	Structured Query Language
Surge	Hydrodynamic pressure change induced when advancing tools and/or tubulars into a wellbore
Swab	Hydrodynamic pressure change induced when removing tools and/or tubulars from a wellbore
TVD	True Vertical Depth. The depth of a wellbore with respect to the vertical axis.
UFP	Uncontrolled Fracture Pressure
USGS	United States Geologic Service (www.usgs.gov)
UTC	Coordinated Universal Time
UTM	Universal Transverse Mercator (projection)
WITSML	Wellsite Information Transfer Standard Markup Language (www.energistics.org)
WOB	Weight on Bit
WOC	Waiting on Cement

2 Background

2.1 RTM Background and Use Cases

There is nothing fundamentally new about real-time monitoring, which is a tool that has been around since the early 1960's. The U.S. Government has employed it extensively and agencies such as NASA, FAA, USGS, USCG and several others have, through its use, successfully increased efficiency, improved safety, and enhanced maintenance practices. In other industries, RTM grew from the need of separating personnel from direct physical contact with operating machinery and systems. RTM is a process through which operational personnel can observe, review, and evaluate data remotely, and has actually been utilized in the oil and gas industry since the early 1980's. Today's technology allows real-time data to be reported at - or very near - the time at which the specific process or event occurs, rather than being recorded and reported after an extended delay. Innovations in sensor technology, data transmission, and leaps in storage capability allow for enormous amounts of data collection, transfer and storage. Data is typically collected from multiple offshore sources and integrated at a central onshore hub that authorized users pull information from. Algorithms and software programs analyze and interpret the data with tremendous speed and accuracy to provide visual insights and deliver high-quality annotated data and trends to decision makers worldwide. RTM can also provide instant notifications and alerts concerning specific data-driven or administrator-specified events. Having the ability to see and monitor operational data from remote locations continues to prove worthwhile with increased efficiency, productivity and safety in oil and gas operations.

2.2 Origin of RTM Requirements

In April of 2016, Secretary of the Interior and Director of the Bureau of Safety and Environmental Enforcement announced publication of the final Well Control Rule. The new regulations are aimed at reducing the risk of offshore oil or gas blowouts that can result in the loss of life, serious injuries or substantial harm to the environment. Some key additions to the regulations include requirements for operators to use real-time monitoring (RTM) in their offshore operations. The RTM requirements are contained in 30 CFR §§ 250.724 and generally apply to higher risk drilling operations that take place in deep-water, when using subsea BOPs, surface BOPs on floating platforms, and well operations in high-pressure and high- temperature (>15,000 psi, 350°F) environments. The new RTM requirements reflect the reality of a changing offshore oil and gas environment and upholds national interests in safety, security, and environmental protection.

Beginning in 2019, operators are required to use RTM during drilling well operations. RTM is intended to be used as a tool to improve safety and environmental protection, not shift responsibility from the rig to onshore RTM personnel. Onshore staff can use RTM data to help rig personnel conduct their operations safely, reduce daily burdens, and assist in identifying and evaluating abnormalities and unusual conditions before they become critical issues. For example, RTM can be used to monitor and interpret data from areas such as BOP testing, cementing and zonal isolation, drilling margin management, station-keeping, borehole surveying, and eventually used for condition based maintenance and health monitoring of select equipment. There have been numerous cases were RTM data in conjunction with wellbore modeling and analysis has been used to successfully manage very narrow drilling margins, efficiently managing events such as kicks, lost circulation, wellbore breathing, and wellbore instability. In addition, operators can review stored RTM data after operations are complete in order to improve well barrier(s) and well integrity, well-control detection and efficiency, training, and incident investigation. Reviewing past data can help to improve operations (e.g., understanding well conditions in certain geological formations assists in the collection and use of well data to make drilling in similar formations more efficient) and establish well control best practices to advance safety and protection of the environment. It is important to note that review of past data may not be as effective as doing so in real time since not all considerations of the data recorded may be available for Peer Review / discussion and analysis after operations are complete.

2.3 RTM Philosophy

Generally, a performance-based approach to RTM expectations and requirements for operators is preferred. Performance-based requirements are written such that the requirements and the criteria for verifying compliance are not specifically stated; rather, they state the results that must be achieved. Prescriptive requirements, such as *30 CFR §§ 250.737 "What are the BOP system testing requirements?"*, describe exactly how the requirement must be met and provide preconceived solutions. Prescriptive requirements tend to lock-in solutions that, over time, may not be the best technical, or cost-effective solution. Having a performance based requirement for RTM allows for the flexibility of each operator to tailor their RTM plan to their individual operations, equipment, and environment. This approach creates opportunities for technology advancement and best-available solutions to be presented to meet the requirements. Performance-based RTM requirements also broaden the potential solutions, since the requirements are not built around specific parameters, equipment, and/or technologies that may only apply to a limited number of operations. This flexibility allows for new technology, more suppliers, reduced costs, better product availability and support, a stronger and more reliable industrial base, and fewer obsolescence issues. Further discussion of critical parameters and datasets can be found in subsequent sections of this document.

2.4 Objectives of This Document

The objective of this document is to provide guidance for a real-time monitoring (RTM) plan that can be utilized as an effective monitoring plan framework or methodology. The spirt of the framework is to leverage RTM capabilities and technologies to, within reason, aid in the prevention or serve to mitigate potential or actual threats to life, health, property, or the environment for ongoing critical operations. It is not intended to cover all possible scenarios nor is it intended to act as requirements or rules.

The primary objectives of implementing RTM rules and recommendations are as follows:

a. Promote the widespread use of high quality measurements and data for use during safety and environmentally critical operations and processes
b. Encourage rigorous and disciplined development and use of standard practices and structured workflows for safety or environmentally critical events
c. Independently validate and/or duplicate critical analyses and promote safety and environmental compliance
d. Independently evaluate well control readiness and well-control events using data provided to the agency.
e. Minimize negative impacts on, and promote the continuity and efficiency of, offshore operations.
f. Provide frameworks for compliance with existing and/or pending regulations regarding other critical factors such as cyber-security, station-keeping and others.

This document should not be considered a complete reference in that it does not address every possible monitoring scenario that an operator should or could reasonably perform. Each operator should address the risks associated with their particular operations. There are many instances when the recommendations contained herein may not be sufficient to ensure safety and protection of life, health, property, and the environment. Moreover, these may not be sufficient to ensure desired operational or economic outcomes. These serve as a set of minimums and a framework from which to build a more complete plan.

3 Recommended Minimum Real-Time Monitoring

3.1 Goals of this section

This section describes the events and systems that should be monitored, by operators, in a real-time context. Each event, including the recommended data and metadata which should be collected, transmitted, and stored, is described in detail. It is intended to provide guidance and a basic framework from which an operator may begin building a real-time monitoring plan.

3.2 Events and Systems Requiring RTM

Events that can reasonably be monitored, and are critical to safety and environmental regulation during the drilling and completion of a wellbore, are largely related to pressure management and uncontrolled or excessive release of fluids from a wellbore or annulus, or via migration of fluid through porous or fractured sub-surface formations, into/onto the land, water (ocean, sea, or other regulated waters), or atmosphere.

The following are the primary events and activities that should be monitored:

a. Wellbore Positioning
b. Blowout Preventer (BOP) Testing
c. Casing/Liner Pressure Testing
d. Formation Integrity Test (FIT)
e. Leak Off Test (LOT)
f. Positive and Negative Pressure Tests of Well Barriers
g. Cementing and Zonal Isolation
h. Drilling Margin Events
i. Station Keeping and Dynamic Positioning

Additionally, operators should use risk-based methods to include any additional critical activity which may be included in the following descriptions:

g. Operations that are performed to verify critical barrier systems or an element of a critical barrier system; e.g., pressure testing containment casing, formation integrity tests, BOP test, abandonment packers
h. The installation of critical barrier elements that are integral in a critical barrier system that are verified by means other than (or in addition to) pressure testing; e.g., cementing operations, hanger installation
i. Activities that require smaller operational windows than what is deemed normal practices or required operational controls and failure to maintain parameters within the operational limits could lead to the loss of a critical barrier.
j. Operations that critical to well integrity and are outside normal operations or require a specialty skills; e.g., exploration drilling with significant pore pressure uncertainty, riserless operations with

shallow flows, areas with offset well collision risk where the collision could result in the loss of primary well control

k. Operations that involve the reinstatement of a lost critical barrier; i.e., well control operations, lost circulation events

3.3 Reports and Analyses

Following sections refer to a variety of events that often have associated reports and analyses indicating pass/fail conditions, critical parameter values (i.e. maximum allowable pressure or volume), or other important information material to safety and well integrity. Examples will be provided; however, the exact composition and analytical methods should be determined by each operator after assessing all reasonable and applicable risks. All charts should clearly display all the data necessary to reach valid engineering conclusion(s). Additionally, each chart or analysis should contain a description of the method(s) used therein, and any assumptions made, such that anyone skilled in the art, could replicate the results.

3.4 Data Collection for Critical Operations

This section attempts to provide a brief description of operations which should require RTM, and brief justification for the recommended data and metadata. For the purposes of this document, data and metadata are defined as follows:

- *Data* is generally considered to be those parameters provided by instruments, sensors, machines, tools, or systems which perform or observe work. Data is typically the result of direct and/or indirect measurement. It is recommended that all data be sampled and stored with respect to time. Time intervals should be such that depth-based data sets can be reasonably reconstructed using time-based data.
- *Metadata* is contextual information. It may describe the properties of the instruments, sensors, machines, tools, or systems which perform the work. Metadata often includes date, personnel information, weather, cultural information, and other information. Necessary and sufficient metadata is required such that those skilled in the art can reasonably recreate the interpretations and conclusions reached by operators and their authorized representatives.

The following sub-sections represent each of the critical operations previously discussed in Section Error! Reference source not found.. Many tables are provided in subsequent sections which represent a logical structure for collection of data. These tables should not be considered complete; but, may serve as a starting point for risk-based analysis and discussion.

3.4.1 Wellbore Positioning

3.4.1.1 Background

Understanding the uncertainty associated with wellbore position is essential to ensure that safety and environmental objectives and requirements are met and that risks are properly identified. Well bore positional objectives that relate to safety and the environment are those related to relief well intersection, proximity that can result in over-pressured hydraulic communication, collision avoidance (when it compromises primary well control), proximity to shallow hazards, and or other potentially dangerous consequences. Generally, a poor understanding of errors associated to well placement can have financial impacts, such as reserves recovery and/or the failure to avoid events that may pose no immediate safety concern but have significant cost associated with recovery.

It is important to note that the following describes methods, concerns, and systems related to commonly used Measurement While Drilling (MWD) and currently available gyroscopic systems. Future technologies may have differences in sources of error, but the concepts presented here should be rigorously applied. Foremost among these should be a focus on risk-based definitions, clear estimation and communication of uncertainty, and dedication to quality, auditing, transparency, and traceability.

MWD wellbore surveying has numerous potential error sources including (but not limited to) those that are both mathematically estimated to a 1 sigma confidence and errors that are not predictable (i.e., gross error). Gross errors are most often associated with human factors and can be managed though good management systems that includes a “checks and balance” methodology.

Common systematic and random predictable and detectable errors are listed below. It should be noted that these errors may have significant impact on the spatial representation of the wellbore and can either co-vary or be mutually exclusive and additive.

Potentials for error include:

a. Magnetically induced errors from the local earth unconformities and the drill string components (Magnetic based tools)
b. Gravity induced errors from inaccurate geoid models, changes in the gravity gradients and movement. (Inclinometer based tools –both Gyro and Magnetic tools)
c. Inaccuracies in measured depth calculations from pipe torsion, friction, thermal effects, stretch and compression errors, buckling and surface tubular measurement errors.
d. Errors in extracting or correcting for drift and mass imbalance measurements (Gyro – May apply to both direction and inclination)
e. Instrumentation error that occur during drilling operations that result from excessive shock and vibration of electronics and other components.

Common Gross errors include:

f. Gross error in measured depth measurements; e.g., improper pipe tally, improper calibration systems, incorrect applied corrections, and practices that can result in stretch or compression beyond the calculated corrections
g. Flat corrections introduced when converting from True or magnetic north to true north due to mapping errors.
h. Improper surface location due to inconsistent mapping systems and/or datum references
i. Improper surface location surveying
j. Errors in vertical datum reference
k. Errors in Sighting headings, generally gyro related.
l. Tools run out of specification without proper quality assurance procedures.
m. Incorrect error estimation
n. Missing or incorrect databases.
o. Improper/incorrect tool calibrations

It should be noted that Gross errors are difficult to detect by inspecting a tools’ data alone as many of the gross errors listed above are ‘flat’ errors applied post-processing. Operators should employ reasonable methods to ensure that survey quality is in accordance with their plans.

Operators should use risk-based standards and practices for development of collision avoidance programs and definition of minimum separation criteria. Operators are encouraged to consider industry's proven practices such as those promoted by API (pending publication of API RP-78), technical guidance provided by the Industry Steering Committee for Wellbore Survey Accuracy (ISCWSA), or other recognized industry surveying authorities.

3.4.1.2 Fixed Station While Drilling (i.e. MWD)

3.4.1.2.1 Planning Data

Operators should develop an anti-collision plan, using risk-based methods, and identify all wells or wellbores which may be potentially intersected based on the expected (designed/planned) or actual uncertainty in wellbore position. Operators should provide all available surveys for all wells identified in the anti-collision plan.

3.4.1.2.2 Data of Interest

Data provided for wellbore positioning can be reasonably categorized in several manners

a. Raw Data
b. Header Data (on a per-survey basis)
c. Resultant Data (Wellbore Surveys and Basic QC Data)
    1. Data describing the position of the wellbore such as inclination, azimuth, and measured depth and parameters representing the accuracy and acceptability of the calculated values.
d. Processing Parameters and Metadata
    1. Data and metadata used to evaluate the quality of surveys and to make corrections to raw data provided by surveying tools.

Operators should provide, as soon as possible after performing necessary processing, quality control, and reviews, all wellbore surveys and header data. Operators should provide, upon request, all processing data and metadata such that one could reasonably re-create the survey(s) of interest using the information available to the operator at the time of the survey. All surveys and associated processing data and metadata should be retained and readily available for the life of the well or wellbore.

Minimum Resultant and QC Data for MWD Surveys	
Data	**Comment**
Inclination	
Azimuth	
Calculated Total Field	
Calculated Gravity	
Calculated Dip	
Reference Field	If unchanging from station to station
Reference Dip	If unchanging from station to station
Reference Gravity	If unchanging from station to station

The following are recommended for each survey, in addition to survey results:

Minimum Header Data for MWD Surveys

Data	Comment
Tie-in point	
Depth reference point (e.g., RKB)	
Permanent datum (e.g., MSL)	
Distance of reference point from Permanent	
Datum	
Surface location (Lat/Log)	
Surface Location (X/Y)	
Projection System (e.g. NAD 27 UTM Zone 15 usft)	
Tool number	
Tool Supplier	
Tool Operator	
BHA listing	
Bit to Survey distance	
Flat acceptance criteria	(if available)

The following data should be available for any survey. Operators should store said data for the lifetime of a well and should provide it upon request.

Recommended Processing Data and Metadata for MWD Surveys	
Data	**Comment**
Time	
Uncorrected Measured Depth	
Uncorrected Calculated Inclination	
Uncorrected Calculated Azimuth	
Uncorrected G_x,G_y,G_z,H_x,H_y,H_z	
Reference Data Source (e.g., BGGS, IFR, HDGM)	
Reference Gravity	
Reference Total Mag Field	
Reference Dip	
Sag correction Applied (If applicable)	
Magnetic Declination Applied	
Grid Convergence Applied	
Total Correction (Mag – Grid) Applied	
Uncorrected Calculated Gravity	
Uncorrected Calculated Total Mag Field	
Uncorrected Calculated Dip	
Delta Uncorrected Gravity	
Delta Uncorrected Total Mag Field	
Delta Uncorrected Dip	
Error Model Used	
Delta Tolerance Gravity	
Delta Tolerance Total Mag Field	
Delta Tolerance Dip	

Corrected Measured Depth (If applicable)	
Corrected Calculated Inclination (If applicable)	
Corrected Calculated Azimuth (If applicable)	
Corrected Calculated Gravity (If applicable)	
Corrected Calculated Total Mag Field (If applicable)	
Corrected Calculated Dip (If applicable)	
Depth Correction Method 1 (e.g., stretch)	
Depth Correction Method 2 (e.g., Temp)	
Inclination Correction Method 1 (e.g., MSA)	
Inclination Correction Method 2(e.g., Sag)	
Azimuth Correction Method 1(e.g., MSA)	
Azimuth Correction Method 2(e.g., Diurnal)	
Delta Corrected Gravity (If applicable)	
Delta Corrected Total Mag Field (If applicable)	
Delta Corrected Dip (If applicable)	
Final Inclination Presented	
Final Azimuth Presented	
Final MD used	
Final Error Model Applied	
Calculated Dogleg Severity or Wellbore Tortuosity	
Sigma used for uncertainty calculations	
Dimensions used for uncertainty calculations	
Major axis uncertainty radius	
Major axis orientation	
Minor axis uncertainty radius	
TVD uncertainty radius	
Depth Bias (if applied)	

If any corrections are made to a survey following initial submission, such information should be provided as soon as possible and the operator should provide updates to all previously submitted wellbore surveys.

While continuous MWD and other continuous measurements are often available, they are typically less accurate than other methods (such as gyro), and should not be used for surveys of record unless the quality thereof is equal to stationary surveys. If data from other survey methods are unavailable, MWD surveys may be accepted.

3.4.1.3 Survey Disparity

If performed, operators should provide any/all continuous or fixed station gyro, or other continuous wellbore surveys performed after a well, wellbore, or hole-section is drilled or completed (i.e. as-built). Operators should identify, in a table of values and using charts, any variance between or among surveys (whether continuous or fixed-station) in excess of the error tolerance of the least accurate surveying method used and should provide written explanation for those differences. Operators should provide, at the earliest opportunity, as-built surveys reflecting the most accurate and most recent survey method(s)

3.4.2 Blowout Preventer (BOP) Testing

3.4.2.1 Description

A BOP is a barrier element system designed to resist otherwise uncontrolled pressure that may be caused by influx from an underground reservoir. It generally consists of a series of devices to effectively block the flow path of a pipe or the annular space between two pipes. The BOP is considered a system of last resort (a secondary barrier) and should not be considered a primary barrier.

BOP testing is defined as the controlled pressurization and pressure monitoring of all or any part of a BOP system including valves, seals, sealing elements, sealing surfaces, or other devices used to resist pressure and to prevent uncontrolled release of wellbore fluids from the well and into the ocean of the atmosphere. It does not necessarily include evaluation of mechanical, hydraulic, electrical, software, or other functionality—it is an evaluation of the system's ability to resist pressure across an annular or another flow path.

3.4.2.2 Data of Interest

Data of Interest—BOP Pressure Testing						
Parameter	Accuracy		Sensitivity		Capability	Frequency
	Absolute	% full scale	Absolute	% full scale		
Pressure (Master Gauge)						
Pressure (Pressure Recorder)						
Flow Rate (test pump)						
Volume Displaced (test pump)						

3.4.2.3 Metadata of Interest

Metadata of Interest—BOP Pressure Testing	
Test Pump make/model/serial	The make, model, and serial number of the pump or pumps used to perform the test. If more than one pump was used, designate the make, model, and serial number used for each test or group of tests
Testing Company Name	The name of the company that performed the test
Testing Company Email	The primary email contact of the company that performed the test
Lead Technician Name	The name of the lead technician or person-in-charge (PIC) of the Testing Company testing crew
Lead Technician Email	The primary email contact for the lead technician or PIC of the testing crew
Operator Representative Name	The Operator's Representative on the rig who witnessed and/or approved the pressure test and has approval authority.
Operator Representative Email	The primary email contact of the Operator's representative
Operator	The name of the operating company as exists on the Permit

Permit Number	The permit number
Master Gauge Make/Model/Serial	The make, model, and serial number of the primary or master gauge for the pressured system. This should be in addition to the pressure recorder(s).
Pressure Recorder Make/Model/Serial	The make, model, and serial number of the pressure recorder(s) used during any/all tests.
Master Gauge Calibration Record	The most recent calibration results for the master gauge
Pressure Recorder Calibration Record	Date of and the most recent calibration results for the pressure recorder
Pressure system validation results	Any pre-test validation results
BOP Make/Model/Serial	The make, model, and serial number of the BOP and/or BOP component(s)
Test Start/End Time(s)	The start and end time of each test with respect to a reference and UTC offset
Temperature (at the tester)	The ambient temperature around the gauge(s) and/or recorder(s)
Temperature (of test fluid)	The average temperature of the fluid used for testing sampled continuously during the test or at the start and end of the test.
Test Fluid Used	Provide the chemical name and/or composition.

It is critical, during BOP testing, that operators have high accuracy, high sensitivity sensors which provide digital data and that all data from BOP tests be recorded and transmitted using a secure, traceable chain-of-custody.

3.4.2.4 Example Analysis

3.4.3 Performance Based Requirements for BOP Testing

3.4.3.1 Summary

BOP testing is a critical, time-consuming, and sometimes contentious part of drilling operations. Thus, many existing standards and practices have been written with a larger focus on operational continuity than on safety and environmental protection. It is recommended that future rules promote better testing methods that more effectively serve the goal of both performance and protection of life, health, property, and the environment.

3.4.3.2 Background

BOP testing has traditionally been done using hydro-mechanical (i.e. bourdon-tube) radial-chart recorders. Recently, many operators have made the transition to digital, transducer-based, pressure recorders. However, there are currently no standards specifying the quality (particularly resolution and fidelity) of data provided by these systems.

It is important to understand that the requirements for BOP testing sensors and instruments can and should be on or more orders of magnitude better than those used in an operational context. This is primarily because BOP testers can and should be used to validate, and even calibrate, other gauges on the rig. Given the relative frequency of BOP tester use, it is natural and convenient for them to be used so.

From a less practical, but significantly more important safety perspective, it must be assumed that there is a potential for properly assembled BOPs to leak. Given the large sealing surfaces, high pressures, and dynamic temperature, pressure, and rate conditions, it is not reasonable to require a BOP that has zero potential for fluid escape. However, it is imperative to quantify the rate and nature of leaks, should they exist, and that operators be able to determine if a leak will remain stable over time, improve, or get worse. This expectation is consistent with existing rules allowing pressure decline over time which could reasonably be attributed to leaks.

3.4.3.3 Purpose of BOP Testing

BOPs exist to prevent or minimize the release of wellbore fluids into or onto the ocean, earth, or atmosphere. Thus, testing of BOPs should ensure that this capability can be maintained during reasonably expected well-control activities.

BOPs should be tested in a manner which demonstrates that all seals, valves, and other actual or potential fluid flow restrictors/preventers demonstrate ability to resist pressure loads such that:

a. The BOP can resist pressure for the time required (in computed volume divided by slow pump rate) to complete a kill using the driller's method or to pump 2x hole volume minus the drillstring displacement, whichever is less.
b. The BOP can resist the maximum expected gauge pressure from the highest pressured zone which is or could be exposed considering fully evacuated (methane filled) casing.
c. The BOP should resist fluid flow or migration such that the maximum combined leak rate(s) do not present threats to life, health, or the environment, including:
    a. Potential for sustained combustion
    b. Exposure to H_2S or other toxic gases or liquids
    c. Exceeding statutory limits on discharge of wellbore fluids.[1]
d. Capability of testing should be within reasonable limits to prevent injuries due to inaccurate pressure measurements.

3.4.3.4 Recommended BOP Testing Requirements

a. Radial chart recorders are generally discouraged and should only be used when digital recorders are not available.
    a. Radial hydro-mechanical recorders should meet all accuracy and capability requirements for digital recorders (excluding digital sampling and digital security)
    b. All tests, using radial-chart recorders should use physical lockout-tag-out signed by company representative before beginning each test
b. Operators should provide a summary of applied torque(s) to all bolts including the final makeup torque (MUT) applied to each bolt/stud used to assemble any/all components the BOP stack which will be exposed to wellbore or annular pressure(s).[2]

3.4.3.5 Recommended Testing/Recording Equipment Specifications

BOP testing/recording apparatus(es) should meet or exceed the following minimum specifications:

[1] As defined in 30 CFR 254.46 in barrels of liquids (or barrels equivalent for hydrocarbon and/or toxic or otherwise regulated gasses)

[2] Proper assembly of BOPs is a leading indicator of successful pressure testing and is critical to effective operation and longevity of the BOP.

a. Accuracy=0.1% full range or 5 psi, whichever is less
b. Sensitivity=2psi or less
c. Process Capability=6σ (i.e. instruments should demonstrate the capability to reproduce the parameter of interest within the prescribed accuracy limits with +/- 6 standard deviations of the true value.)
    - This will ensure that, allowing for 1.5σ shifts and drifts, that 3.4 per 1 million measurements contain error in excess of the allowable error.
d. Thermal Stability or Corrected between -40F and 140F (or 25% greater than reasonably expected testing conditions)
e. NIST Traceable and calibrated within last 6 months
f. 3x redundancy for pressure measurement or ability to detect and correct bias and drift meeting all previous recommendations.

3.4.3.6 Recommended Testing Data Collection and Transmission Requirements

Tests should be recorded with at least the following process specifications

a. >=1 Hz data capture (i.e. sampled once per second or faster)
b. WITSML or other standard digital output, simultaneously to local and remote storage
c. Local (on-board) encrypted binary files, or equivalent security.
d. Lockout/Tagout (physical and/or virtual) or other method to prevent manipulation by user(s)

3.4.3.7 Recommended BOP Testing Procedure Requirements

a. Testers should use constant pressure methods if possible.
    1. Constant pressure methods enable testers to identify flow regimes and to more accurately assess the potential long-term performance of the system. Constant volume methods do not provide sufficient information to infer system performance. By definition, constant volume methods (i.e. those specified in API Standard 53) have two changing parameters (pressure and volume) and one measurement (pressure); and, thus, cannot be solved analytically.
    2. Constant-pressure systems should be able to measure incremental volumes pumped or injected of 0.0002bbl (~30ml) or 0.1% of the initial testing volume, whichever is less[3].
b. Test duration should extend for however long is necessary to demonstrate that the BOP can resist maximum allowable pressure loss and/or fluid flow for the time required (in computed volume divided by slow pump rate) to complete a kill using the driller's method or to pump 2x hole volume minus the drillstring displacement, whichever is less.
c. All reports and/or data should list the metadata of interest for all gauges and sensors used during any and all tests—even those that do not pass.
d. Before performing any tests, preferably within 24 hours of the test, and with the equipment in the same environment and orientation expected during testing, the BOP testing technician should perform one or more on-site closed-system validations of high-pressure and low-pressure instruments such that:

[3] Leaks of other flow measured through tests performed with sea water or other similar liquids do not accurately reflect the flow potential of natural gasses or other reservoir fluid; thus, volumetric accuracy is critical (see Figure 6).

1. All gauges and/or sensors are exposed to the closed, pressurized system
2. Tests are performed at 50%, 100%, and 125% of the maximum and minimum test pressure(s) for subsequent tests.
    i. This will help ensure that the test(s) performed fall within the recommended pressure window of 20%-80% of the known good range of the gauge as stated in ASME B40.100
3. Pressure for each gauge and/or sensor should be noted at the beginning of each test
4. Validation pressure should be held for at least 5 minutes
5. Pressure for each gauge and/or sensor should be recorded during and verified at the end of each test.
6. Pressure gauge/sensor validation data should be recorded using the same method used during BOP testing should be provided in addition to BOP test data.
    i. Pressure should not decline, on any gauge or sensor, by more than 1% of the applied test pressure or 100 psi, whichever is less during or at the conclusion of the 5-minute validation test.

e. BOP testing apparatus validation results should be provided to the Operator's on-site authoritative representative before any testing is performed.
f. Any differences among the instruments composing the testing apparatus, greater than the error of the least-accurate component thereof, should be explicitly and conspicuously noted as part of any report and/or data.
g. Any test performed using equipment that does not meet the preceding requirements should require supervisory approval before proceeding.

3.4.3.8 Recommended Minimum Analysis of BOP Test Data

Analysis of BOP test data should include at least the following:

a. Description of analytical method(s) used[4]
b. Corrections for:
    1. Temperature and temperature gradients
    2. Fluid storage and compressibility effects
c. Actual or expected time to bleed off 100, and 500 psig (if using constant volume tests)
d. Actual (if measured) or expected (if modeled) flow rates at 1, 5, and 60 minutes and for every whole hour interval for the actual or projected duration recommended in section 3.2.3.3a.
e. Actual or expected time at which system reaches steady-state and/or pseudo-steady state flow
    1. It is not reasonable to assume that all BOPs must prevent all fluid flow. Rather a BOP should be able to resist flow and prevent excessive discharge. Thus, a small leak may be tolerated if the flow is steady, predictable, sufficiently small, and will not impair proper operation of the BOP or cause damage or faults to the system.
    2. Systems that do not display steady-state or pseudo-steady-state behavior should not be relied upon as a barrier.
f. Indication of pass/fail for each test

Additional metadata should include

g. Make/Model/Serial number of BOP tester(s) (as a unit or as subcomponents thereof)

[4] All methods should be based on material balance. Statistical, empirical, or other methods should include justification including results of laboratory experiments, simulations, and/or other methods.

h. Make/Model/Serial number of all gauge(s) and sensor(s) comprising the testing apparatus and an indicator of the primary sensor used to record data for each test.
i. Firmware/Software version of BOP tester(s)
j. Make/Model/Serial number of BOPs and all critical elements comprising the BOP stack including:
    1. Separable BOP Sections (i.e. rams, shears, annulars, etc.)
    2. Accumulator Units
    3. Control Pods
    4. Any other device or component of the BOP system that is/are tested by the BOP testing apparatus(es).

3.4.3.9 Recommendations for BOP Testing Personnel Certifications and Qualifications

Lead testing technicians, at least one of which should be present during any and all tests, should hold a certification provided or approved by the API, IADC, or other recognized body.

3.4.4 Casing/Liner Pressure Testing

3.4.4.1 Description

Casing and liner pressure testing are performed to ensure that as-built or as-assembled casing and/or liner strings meet minimum required pressure loading limits for expected worst case scenarios. Hydrostatic testing is performed on a closed wellbore section and barrier envelope until testing criteria are satisfied; typically a maximum pressure change per unit time. Testing criteria should be reasonably defined to ensure well barrier envelope integrity during reasonably expected operations and well-control scenarios.

3.4.4.2 Data of Interest

Data of Interest—Casing/Liner Pressure Testing, FIT, LOT						
Parameter	Accuracy		Sensitivity		Capability	Frequency
	Absolute	% full scale	Absolute	% full scale		
Pressure (Stand Pipe)						
Pressure (Bottom Hole-Measured)						
Pressure (Bottom-Hole Calculated)						
Flow Rate (Flow In)						
Temperature (bottom hole measured)						
Temperature (surface, measured)						
Volume Displaced (Stroke Count)						
Volume Displaced (calculated volume)						
Volume Displaced (measured volume)						
Fluid Density In						
Fluid Density (Bottom-Hole Calculated)						

3.4.4.3 Metadata of Interest

Metadata of Interest—Casing/Liner Pressure Testing, FIT, LOT	
Testing Company Name	The name of the company that performed the test
Testing Company Email	The primary email contact of the company that performed the test
Operator Representative Name	The Operator's Representative on the rig who has witnessed and/or approved the pressure test and has approval authority.
Operator Representative Email	The primary email contact of the operator's representative
Operator	The name of the operating company as exists on the permit
Permit Number	The permit number
Test Start/End Time(s)	The start and end time of each test with respect to a reference and UTC offset
Temperature (at the tester)	The ambient temperature around the master pressure gauge
Temperature (of test fluid)	The average temperature of the fluid used for testing sampled continuously during the test or at the start and end of the test.
Test Fluid Used	Provide the chemical name and/or composition.

3.4.4.4 Example Analysis

3.4.5 Formation Integrity Test (FIT)

3.4.5.1 Description

A FIT is performed to a maximum allowable pressure at the casing shoe true vertical depth (TVD) as pre-determined by engineering constraints or material (i.e. formation PPFG) mechanical limits. It is performed to confirm the ability of the well to contain a kick of a reasonable volume and density (gas gradient). It typically does not include intentional inelastic yield of the exposed formation(s) (fracture initiation or FIP on Figure 1) although there may be some deformation and/or mud filtrate loss as observed on a volume-vs-pressure trend.

It should be noted that FIT is part of a class of tests used to determine allowable applied pressure loads. Others in this class include, but are not limited to: Leakoff Tests, Extended Leakoff Test (ELOT, XLOT), Repeat Leakoff Tests, and others. Test of this class should provide similar data and have similar analysis to that shown in this section. For convenience, a section regarding LOT has been provided as well.

3.4.5.2 Data of Interest

Data and metadata of are the same as for Casing/Liner Pressure Testing.

3.4.5.3 Metadata of Interest

Data and metadata of are the same as for Casing/Liner Pressure Testing.

3.4.5.4 Example Analysis

An example analysis is provided as a reference from SPE 105193 (van Oort & Vargo, 2007). At minimum, analyses should include plot(s) or pressure vs. time with annotations identifying the transition from elastic to inelastic deformation and should identify the following pressures:

- Leak-off Pressure (LOP) or Fracture Initiation Pressure (FIP)
- Formation Breakdown Pressure (FBP) or Uncontrolled Fracture Pressure (UFP)
- Fracture Propagation Pressure (FBP)
- Instantaneous Shut-In Pressure (ISIP)
- Fracture Closure Pressure (FCP)

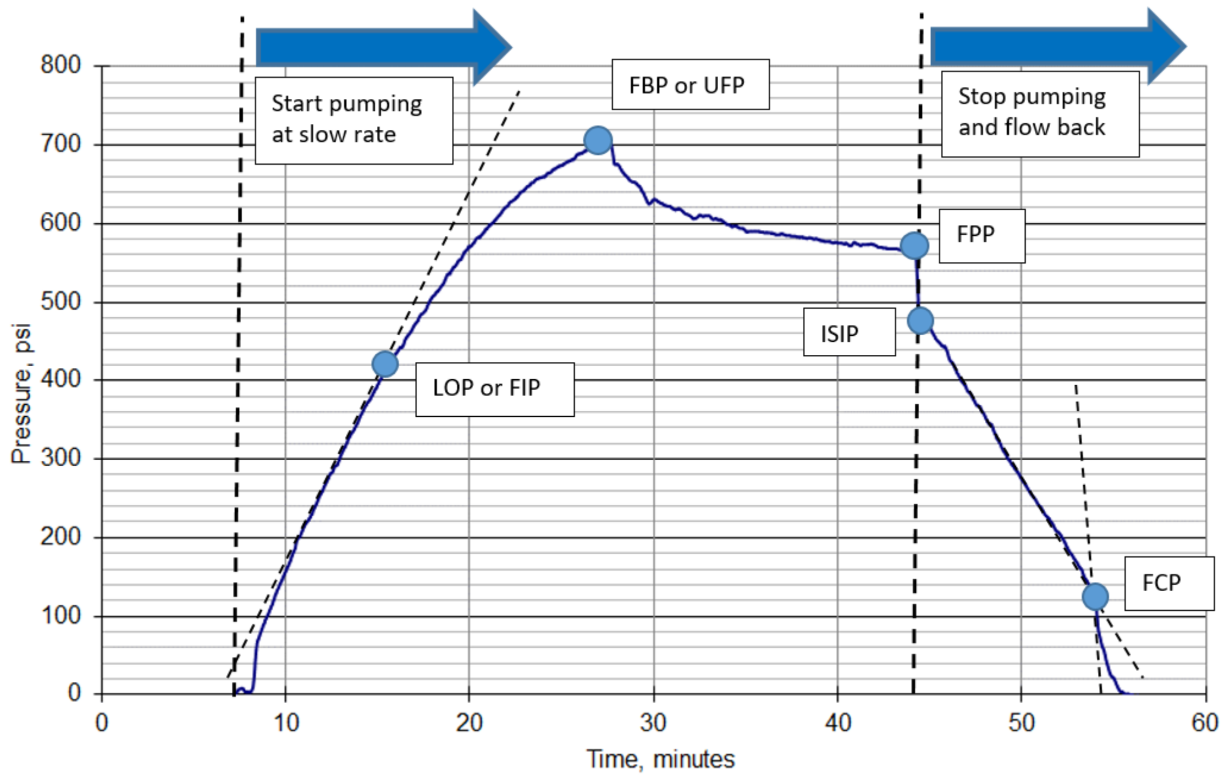

Figure 1—Example FIT Test and Annotated Analysis

3.4.6 Leak Off Test (LOT)

3.4.6.1 Description

A LOT is similar to a FIT but it is performed to determine the maximum allowable pressure that may be applied to the casing shoe true vertical depth (TVD) above which fracture initiation and whole mud loss is expected. As the name implies, applied pressure is increased until inelastic yield (ideally fracture initiation or FIP on Figure 1) is observed as evidenced by significant reduction in volume-vs-pressure trend which indicates loss of whole mud to the formation (FIP to UFP on Figure 1) as opposed to mud filtrate loss.

3.4.6.2 Data of Interest

Data and metadata of are the same as for Casing/Liner Pressure Testing.

3.4.6.3 Metadata of Interest

Data and metadata of are the same as for Casing/Liner Pressure Testing.

3.4.6.4 Example Analysis

See Figure 1.

3.4.7 Positive and Negative Pressure Tests of Well Barriers

3.4.7.1 Description

Positive and negative pressure tests are performed to ensure that mechanical or other barriers can withstand reasonable pressure(s) in one or more directions. This includes pressure from the reservoir or other sub-surface formation(s) (i.e. negative pressure) or from hydrostatic pressure from a fluid column plus other pressure applied from the surface (i.e. positive pressure).

Positive pressure tests are applied above the particular barrier being tested and is usually applied surface pressure which tests the entire barrier envelope (i.e. casing plug, casing, wellhead, and BOPs). Negative pressure tests and their proper interpretation are critical to ensure that the pressure from a porous and permeable sub-surface formation below the barrier being tested is isolated by that barrier.

Like BOP tests, positive and negative pressure tests have two input parameters: pressure and volume, and only one measurement: pressure. When practical, tests should report either: the volume of fluid pumped per unit time to maintain a constant test pressure or the initial and final height of the fluid column. It should be noted that flow-out is not considered a measured parameter for this and other sections because it is generally only a qualitative measure and operations devices to quantitatively measure flow out are not common at the time of this writing.

3.4.7.2 Performance-Based Recommendations for Negative Pressure Testing

Data should be provided for any and all negative pressure tests performed, regardless of success or failure and should be made available no less than 12 hour in advance of any negative pressure test(s) and digital data should be made available before the start of any test(s).

Operators should provide a maximum expected pressure at the barrier being tested. This is the difference between sub-surface formation (or reservoir) pressure(s) (calculated or measured) and the hydrostatic gradient(s) of the test fluid column. If the expected negative pressure at the barrier exceeds 500psi, or if the barrier is installed so that the rig can be mobilized, operators are encouraged to perform tests of sufficient duration and capability as approved in the Application for Permit to Drill such that pressure data can be interpreted to identify potential flow regimes such as:

- Wellbore storage
- Fracture or Channel flow
- Infinite-acting flow
- Flow barriers

3.4.7.3 Data of Interest

Data of Interest—Positive/Negative Pressure Test						
Parameter	Accuracy		Sensitivity		Capability	Frequency
	Absolute	% full scale	Absolute	% full scale		
Pressure (Stand Pipe)						

Pressure (choke/kill)						
Pressure (annular, all)						
Pressure (Bottom Hole-Measured)						
Pressure (Bottom-Hole Calculated)						
Flow Rate (Flow In)						
Temperature (bottom hole measured)						
Temperature (surface, measured)						
Volume Displaced (Stroke Count)						
Volume Displaced (calculated volume)						
Volume Displaced (measured volume)						
Fluid Density In						
Fluid Density (Bottom-Hole Calculated)						
Flow Out[5]						
Fluid Column Height						

3.4.7.4 Metadata of Interest

Metadata of Interest— Positive/Negative Pressure Test	
Operator Representative Name	The person on the rig, representing the operator, who has witnessed and/or approved the pressure test and has sign-off authority.
Operator Representative Email	The primary email contact of the operator's representative
Operator	The name of the operating company as exists on the permit
Permit Number	The permit number
Test Start/End Time(s)	The start and end time of each test with respect to a reference and UTC offset
Temperature (at the tester)	The ambient temperature around the master pressure gauge
Top of Cement	TVD and MD for any annuli potentially exposed to test pressure(s)
Hole Depth	TVD and MD
Top of Barrier	TVD and MD of top of packer, plug, or other seal
As-Built Wellbore Schematic	Showing all casing, liners, cement, packers, seals etc..

[5] Measurements of flow out, for any purpose, should be expressed in volume/time or mass/time and not as a fraction of pipe cross-sectional area or as a binary flow/no-flow condition.

Wellbore (Displaced) Fluid	Provide the chemical name and/or composition.
Displacing Fluid(s)	Provide the chemical name and/or composition.
Spacing/Buffer Fluids(s)	Provide the chemical name and/or composition.

3.4.8 Cementing and Zonal Isolation

3.4.8.1 Description

Cementing is the pumping of cement, cementitious mixtures, foams, gels, resins, epoxies, or other high compressive strength materials or mixtures to isolate or block the differential-pressure flow-path (some or all of one or more annuli, typically between open-hole and casing/liner and within them but sometimes between tubulars) between one or more sub-surface formations, and ocean and/or atmosphere. Cement is considered a primary barrier and structural component of a well-barrier envelope.

Poorly designed and/or implemented cementing has been one of, if not the root cause of many well-control incidents. Operators are encouraged to take special care to ensure the capability of the tools and machines used during cementing to ensure that the instruments and sensors used to evaluate the success of cement jobs are sufficient. This is to ensure the reliability of engineering analysis and interpretations of cementing operations.

*3.4.8.2 Data of Interest**

Data of Interest—Cementing						
Parameter	Accuracy		Sensitivity		Capability	Frequency
	Absolute	% full scale	Absolute	% full scale		
Pressure (Stand Pipe)						
Pressure (cement pump)						
Pressure (Bottom Hole-Measured)						
Pressure (Bottom-Hole Calculated)						
Flow Rate (Flow In)						
Volume Displaced (Stroke Count)						
Volume Displaced (calculated volume)						
Volume Displaced (measured volume)						
Slurry Density (real-time measured)						
Slurry Density (real-time calculated)						
Slurry Density (spot-check)						
Flow Rate Out						
Density Out						
RPM (if rotating)						

Block Height (if reciprocating)						

3.4.8.3 Metadata of Interest

Metadata of Interest—Cementing	
Lead Technician Name	The name of the lead technician or person-in-charge (PIC) of the cementing crew
Lead Technician Email	The primary email contact for the lead technician or PIC of the cementing crew
Operator Representative Name	The person on the rig, representing the operator, who has witnessed and/or approved the cement job and has sign-off authority.
Operator Representative Email	The primary email contact of the operator's representative
Operator	The name of the operating company as exists on the permit
Permit Number	The permit number
Test Start/End Time(s)	The start and end time of the job with respect to a reference and UTC offset
Densitometer Information	Make/Model/Serial of any device(s) used to measure density, whether continuously sampled or spot-checks
Densitometer Calibration	Results of the most recent calibration of any/all densitometers use during the job
Densitometer Validation	Results of field-validation of any/all densitometers used during the job.
Laboratory Test Results	Laboratory results demonstrating compressive strength vs. time, rheological/thixotropic properties, and other chemical/additive properties.
Cement Pumping Plan	Demonstrating: Planned rate/pressure/density (surface and downhole) schedules, and compressive strength vs time.
As Build Casing/Liner Detail	Details for existing open hole diameter, casing/liner size(s), weight(s), grade(s), inner diameter(s), outer diameter(s), and setting depth(s)
Top of Cement (measured)	Top of cement as measure by CBL, temperature, or other log, or by observations of cement returns to surface.
Top of Cement (calculated)	Cement top calculated from pressure measurements. NOTE: this cannot be used in place of top of cement measurements
As Performed Pumping Schedule	Demonstrating: Planned vs. actual rate/pressure/density (surface and down-hole) schedules and explanation of significant variances
Shoe and Shoe-Track detail	Description of all tubulars and devices that constitute the shoe and shoe track
Diverter(s) or Other Devices	Description of any diverters or other down-hole devices used during the job

Centralizer	Location (MD), size, and type of all centralizers used during the job.
Calculated / Predicted Pore Pressure Gradient	The estimate of pore pressure calculated from seismic, down-hole tools, laboratory studies, or other methods.
Calculated / Predicted Fracture Pressure Gradient	The estimate of pore pressure calculated from seismic, down-hole tools, laboratory studies, or other methods.
Measured (in situ) Pore Pressure Gradient (if available)	The measured pore pressure from down-hole measuring devices
Measured (in situ) Fracture Pressure Gradient (if available)	The measured fracture pressure from down-hole measuring devices
TVD/MD of Exposed Interval(s)	The True Vertical and Measured depth(s) of interval(s) exposed to test pressure(s)

*NOTE: Temperatures cannot be reasonably measured downhole without fiber optic or other dedicated tools because cement reactions are exothermic. Some form of modeling is needed to estimate down-hole or other temperatures.

3.4.8.4 Example Analysis

Operators should provide real-time data for cementing for any/all periods during which the cement column is held static whether mechanically (i.e. floats), by applied pressure, or any combination thereof. This should encompass what is currently understood to be waiting-on-cement (WOC) intervals.

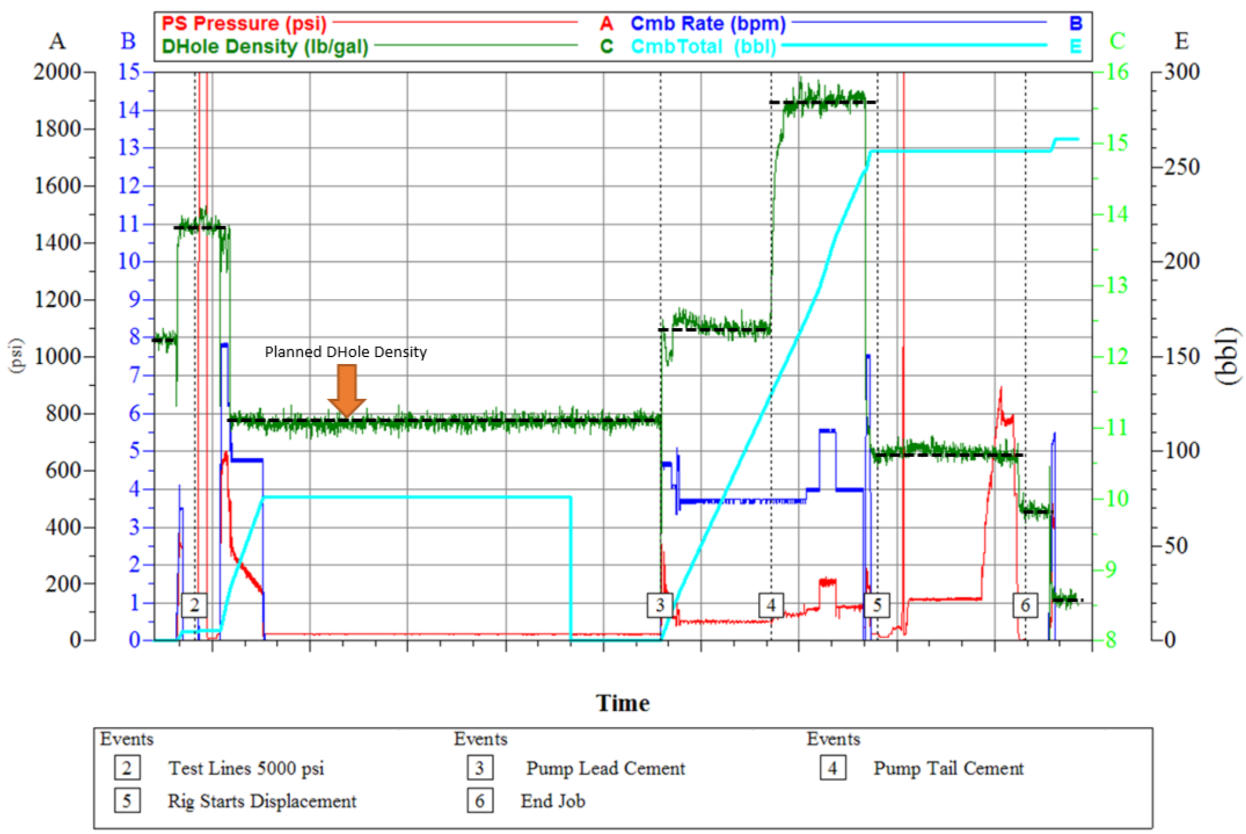

Figure 2--example of annotated cement pumping data showing at least one planned vs. acutal parameter

Cement and other zonal isolation methods, such as packers, plugs, or other tubular or annular barriers, are critical to prevent unwanted migration of sub-surface fluids to the surface—in particular, kicks and leaks. While a kick is the most visible form of fluid migration, it is possible that slow leaks discharge significantly more fluids into the ocean and atmosphere.

Cementing should be carefully designed and monitored to reasonably ensure that fluid migration is effectively prevented in casing, liners, wellbores, and any annuli between or among them. Operators should employ cementing best practices to ensure successful placement of cement to act as a primary barrier and structural component of a well-barrier envelope.

Operators should be able to provide graphical analys(es) of cement jobs, using real-time data, which show both planned and actual values for each parameter (an example of which is shown in Figure 2). Operators should annotate figures, charts, and graphs to clearly identify significant deviations from plan and provide detailed analysis of each deviation including whether the it could reasonably lead to a compromise of the barrier.

Zonal isolation cannot be explicitly confirmed solely by interpretation of a cement bond log or other qualitative measurement of cement integrity. The only method to determine isolation is by negative and or positive pressure testing.

3.4.9 Drilling Margin Events

3.4.9.1 Description

The drilling margin is the available window for mud weight between the pore pressure gradient and the lesser of estimated fracture gradients or casing shoe pressure integrity test. Current regulations state that offshore well operators in the OCS must maintain a safe drilling margin identified in an approved Application for Permit to Drill (APD) (30 CFR §250.427(b) and §250. 414.c). This safe drilling margin is required to ensure that mud weights can control the pore pressure while not fracturing the formations. If an operator cannot maintain the safe drilling margin, it must "suspend drilling operations and remedy the situation." Thus, operators with RTM capabilities should be able to demonstrate the ability to measure or calculate both values at any point along an actual or proposed wellbore and to readily identify and communicate any deviation.

Operators should record and/or report any drilling margin events that are directly or indirectly causal to well-control incidents.

3.4.9.2 Data of Interest

Data of Interest—Drilling Margin Events, Lost Circulation, Fracturing						
Parameter	Accuracy		Sensitivity		Capability	Frequency
	Absolute	% full scale	Absolute	% full scale		
Pressure (Stand Pipe)						
Pressure (Bottom Hole-Measured)						
Pressure (Bottom-Hole Calculated)						
Flow Rate In (stroke count calculated)						
Flow Rate In						

(measured)						
Volume Displaced (Stroke Count)						
Volume Displaced (calculated volume)						
Volume Displaced (measured volume)						
Fluid Density In (continuously measured)						
Fluid Density In (spot check)						
Fluid Density Out (continuously measured)						
Fluid Density Out (spot check)						
Gas Concentration (C_1-C_5)						
Gas Concentration (C_1-C_{10})						
Gas Concentration (C_{10+})						
Pit Level(s) (measured)						
Pit Volume(s) (calculated)						
Plastic Viscosity						
Yield Point						
Fluid Temperature IN						
Fluid Temperature OUT						

3.4.9.3 Metadata of Interest

Metadata of Interest—Drilling Margin Events, Lost Circulation, Fracturing	
Mud Pump Liner Volume(s)	The volume (or diameter and stroke length) of each mud pump in use, if positive displacement pumps are used.
Calculated Pore Pressure Gradient	The estimate of pore pressure calculated from seismic, down-hole tools, laboratory studies, or other methods.
Calculated Fracture Pressure Gradient	The estimate of pore pressure calculated from seismic, down-hole tools, laboratory studies, or other methods.
Measured (in situ) Pore Pressure Gradient (if available)	The measure pore pressure from down-hole measuring devices
As Build Casing/Liner Detail	Details for existing casing/liner size(s), weight(s), grade(s), inner diameter(s), outer diameter(s), and setting depth(s)
Driller Name	Name of driller on duty when drilling margin was compromised
Assistant Driller Name	Name of assistant driller on duty when drilling margin was compromised

Toolpusher Name	Name of tool pusher on duty when drilling margin was compromised
Operator Representative Name	The person on the rig, representing the operator, who was on duty when the drilling margin was compromised
Drilling Fluid Rheological, Physical, and Chemical Properties	More recent sampled rheological measurements recorded on the daily mud report(s). This data should be provided in real-time if available.
Operator	The name of the operating company as exists on the permit
Permit Number	The permit number

3.4.9.4 Lost Circulation / Fracturing
Loss of circulation is the loss of whole mud/drilling fluid, typically to downhole formations and sometimes to the ocean, both being unplanned events. Lost circulation is generally distinguished from seepage losses. Seepage losses occur at lower volumes/rates and are due to the natural seepage/filtration of the drilling fluids liquid component across the solids portion of the drilling fluid that builds up (filter cake) on the porous and permeable subsurface formations. Lost circulation is the loss of whole mud into a formation void of some sort, frequently induced or natural fractures, rubble/brecciated zones, zones with large vugs, etc. Lost circulation can only be positively affirmed through mass balance.

3.4.9.5 Wellbore Breathing / Ballooning
Ballooning is the result of loss and gain of drilling fluid due to fluid migration in fracture networks through the open wellbore. The amount of breathing is typically restricted to a return of fluids equal or proportional to the amount of fluid originally lost to the formation but may bring with it into the wellbore some component(s) of formation fluids. It is important for an operator to be able to differentiate between wellbore storage, fluid compressibility, transient flow thorough porous media, and uncontrolled flow (influx). The process of differentiation is typically referred to as 'fingerprinting'. Fingerprinting should not be relied on in place of physics-based models or interpretations of physical models.

3.4.9.6 Wellbore Stability
Wellbore stability is the ability of the wellbore to accommodate elastic and inelastic deformation without failure. It is influenced by in-situ and induced stresses, temperature and chemical changes, i.e. drilling operations. Unstable wellbores pose a risk of unplanned events which are much more likely to experience safety or environmental hazards. Operators should have the ability to measure or calculate wellbore stability criteria and to identify and communicate actual or potentially unstable wellbores.

3.4.9.7 Surge and Swab
Surge and Swab are induced wellbore stresses caused by the piston-effect of a moving drill or work string or casing/liner when run in/out of the wellhead/casing. Surge/Swab effect is more severe in portions of a well that present less annular clearance between the hole/casing and the drill or work string or tubing. When fluid is unable to freely flow around a bit, BHA or other wellbore restriction, there is insufficient ability for pressure to equalize on either side and the pressures on either side can be significantly higher or lower than the static condition. This phenomenon is well known to be the root cause of many kicks by (temporarily) reducing hydrostatic pressure resisting influx (swab), or by fracturing the formation (surge) which results in loss of mud and corresponding hydrostatic pressure below the formation pressure.

Operators should have the ability to predict/calculate surge and swab, and to identify and immediately communicate adverse surge and swab conditions and take precautionary measures to minimize both.

3.4.9.8 Well Control Events

3.4.9.8.1 Description

A kick is an influx of reservoir fluids (oil, gas, brine, or any combination thereof). It is vital, during well-control operations, that all parties, particularly those on the rig have access to data with properties that are necessary and sufficient to safely execute a well-control plan.

By definition, managed pressure systems which may intentionally operate with potential or actual flow from a subsurface formation. Any operator using managed pressure systems should collect the same data as would be recorded for a well-control incident; however, it is not reasonable to continuously transmit the associated metadata. Rather, the metadata should be updated daily or whenever a change to any metadata occurs.

3.4.9.9 Data of Interest

Data of Interest—Well Control						
Parameter	Accuracy		Sensitivity		Capability	Frequency
	Absolute	% full scale	Absolute	% full scale		
Pressure (Stand Pipe)						
Pressure (Bottom Hole-Measured)						
Pressure (Bottom-Hole Calculated)						
Pressure (surface annuli, all)						
Flow Rate/Volume In (lubricator, if used)						
Flow Rate In (stroke count calculated)						
Flow Rate In (measured)						
Volume Displaced (Stroke Count)						
Volume Displaced (calculated volume)						
Volume Displaced (measured volume)						
Fluid Density In (continuously measured)						
Fluid Density In (spot check)						
Fluid Density Out (continuously measured)						
Fluid Density Out (spot check)						
Gas Concentration (C_1-C_5)						
Gas Concentration						

(C_1-C_{10})						
Gas Concentration (C_{10+})						
Pit Level(s) (measured)						
Pit Volume(s) (calculated)						
Pressure (Accumulator(s))						
Pressure (Annular Ram Operating)						
Pressure (Blind Ram Operating))						
Pressure (Shear Ram Operating)						
BOP Health/Condition (if available)						

3.4.9.10 Metadata of Interest

Metadata of Interest—Well Control	
Mud Pump Liner Volume(s)	The volume (or diameter and stroke length) of each mud pump in use, if positive displacement pumps are used.
Driller Name	Name of driller on duty when kick was detected
Assistant Driller Name	Name of assistant driller on duty when kick was detected
Toolpusher Name	Name of tool pusher on duty when kick was detected
Operator Representative Name	The person on the rig, representing the operator, who was on duty when the kick was detected
Drilling Fluid Rheological, Physical, and Chemical Properties	More recent sampled rheological measurements recorded on the daily mud report(s). This data should be provided in real-time if available.
Operator	The name of the operating company as exists on the permit
Last Measured Slow Pump Pressure	The last calculated slow-pump pressure (the frictional pressure created by fluid flow at rates typical of well control) as reported on the driller's well control sheet.
Pressure data for last 24 hours	All stand-pipe and annular pressures for the 24 hours immediately preceding the detection of a kick, if not already provided
BHA details and Pipe Tally	List of inner diameter (ID), outer diameter (OD), Size, Weight, Grade, Length, and connection type of every tool and tubular that comprises the bottom hole assembly (BHA) and the drillstring currently in the well or wellbore.
Open Hole Details	The diameter of open hole. Please note if there are any reamers or hole-openers that make the open-hole of varying diameter. Exposed formation(s) fracture gradient,

	pore pressure gradient, and estimated porosity and permeability (if available)
Casing/Liner Details	The Inner diameter (nominal and measured), of all casing and/or liners through which the drill string, in its current position has passed into or through.
Pressure Test Details	The results of all previous LOT and FITs performed for the well or wellbore.
Measured Depth of Drillstring	The current measured depth of the deepest portion of the drill string.
Calculated Kick Size (bbls)	The volume of the kick as determined by rig personnel and approved by the PIC.
Calculated Kick Density (sg)	The density of the kick as determined by rig personnel and approved by the PIC
Results of last BOP Pressure Test	The results of the last BOP pressure test if not already provide
Results of last BOP Function Test	The results of the last BOP function check if not already provided
Pressure Gauge Calibration/Validation	The results of the most recent calibration and/or validation of all pressure gauges used during well control.
Results of last Shear Capability test	The results of the last test of the shear rams that show the ability of the BOP to effectively shear the pipe currently in the shear rams.
Mass of Barite	The available mass (weight) of barite, or other weighting materials, available for well control.
Permit Number	The permit number

3.4.10 Station Keeping and Dynamic Positioning

Station keeping of an offshore oil rig, or other vessel, is critical to ensure the structural integrity of the well and riser, and proper operation of the BOP and BOP systems. Minimum design and performance requirements are generally specified and audited by the Coast Guard and additional specificity should be provide by that organization at their discretion. However, operators should be able to provide the following as part of their real-time plan:

3.4.10.1 Data of Interest

Data of Interest—Station Keeping						
Parameter	Accuracy		Sensitivity		Capability	Frequency
	Absolute	% full scale	Absolute	% full scale		
Station Calculation Method						
Position Error (instantaneous)						
Position Error (cumulative)						
Latitude (riser center at water surface)						
Longitude (riser center at water surface)						

Calculated Current Vector						
Wind Direction						
Position Vector from Subsea Well Center						
Riser Angle						
Flex Joint Angle (if applicable)						
Riser Tension						
BOP Tension (if measured)						

3.4.10.2 Metadata of Interest

Metadata of Interest—Station Keeping	
Differential GPS Reference Station Description(s) and Coordinates.	
Reference Datum	
Flex Joint Angle (if applicable)	
Riser Angle	

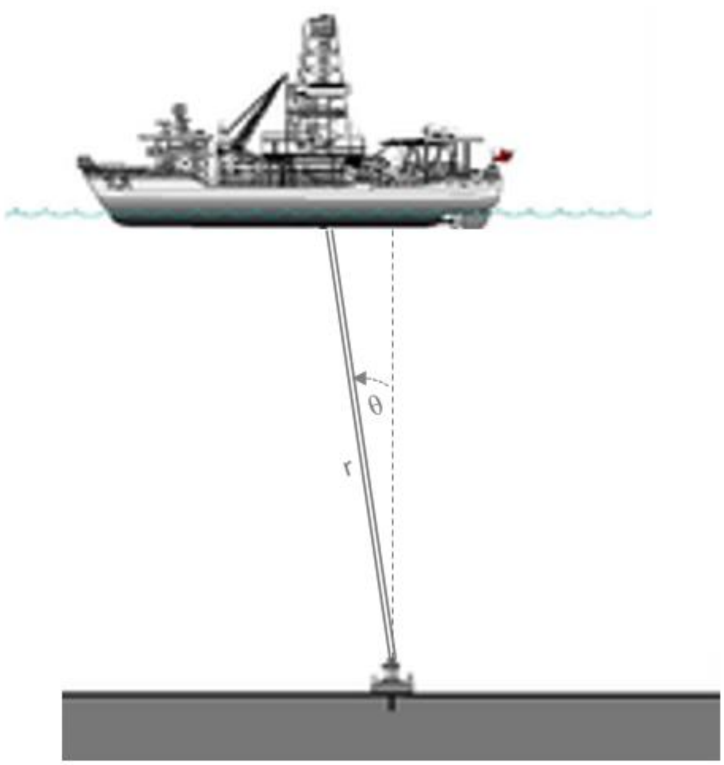

Figure 3—Example of Riser Angle (ϑ)

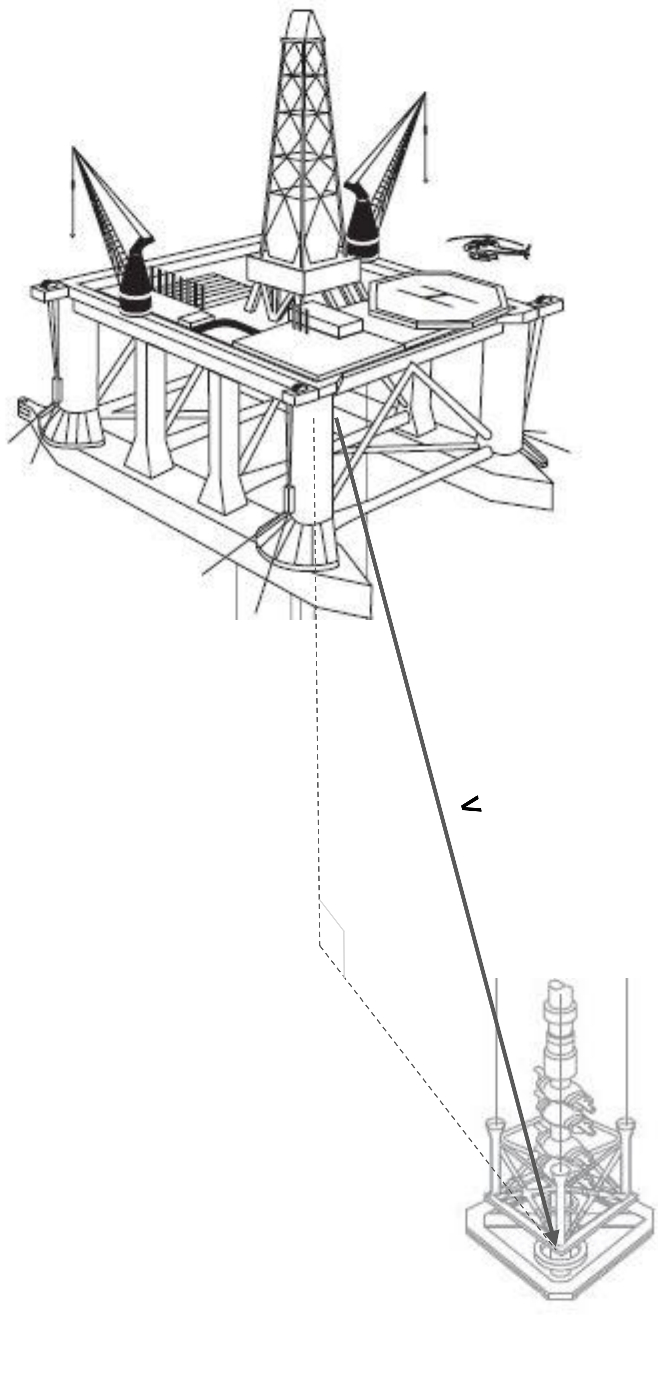

Figure 4--Example of Displacement Vector (V) with Respect to Subsea Well Center

Desired Future Capabilities

3.4.11 BOP Health Monitoring and Condition Based Monitoring (CBM)

BOP health monitoring and condition-based monitoring are evaluations of the systems and sub-systems required to restrict flow and to ensure proper operation of all critical BOP components. These may include information related to the status of subsea BOP elements, surface systems, emergency systems, accumulators, solenoids, pneumatic or hydraulic actuators, hydraulic pumps and pressure lines, electrical systems, software(s), and any other system or sub-system that is necessary and/or critical to the proper and contingent operation of the BOP.

In the context of RTM, the primary purpose of BOP Health Monitoring is to ensure that the critical systems meet or exceed the minimum performance criteria in the event of a kick, emergency disconnect, deadman actuation or other critical event. Health monitoring is generally binary in that it is designed to provide a go/no-go indicator.

The main goal for a real-time BOP Health monitoring system would be to simplify and broaden the reach of BOP diagnostics to assist in the operational decision making process. Whereas BOP Health Monitoring represents a pass/caution/fail condition, condition-based monitoring describes the remaining useful life, or projects future performance capabilities of BOP systems. It is understood that these systems are currently relatively immature and that there is considerable effort by the industry to improve these capabilities.

4 Recommended Minimum Quality and Capability Standards for Real-Time Monitoring

4.1 Goals of This Section

While not explicitly stated in RTM requirements, it is implicitly expected that the data provided by operators should accurately represent the truth to best of operators abilities.

This section outlines the basic quality and capability standards that operators should consider when constructing their RTM plan. Additionally, it provides a robust framework for dialogue with service providers, partners, and other third parties to ensure the veracity of data collected, transmitted and stored.

Operators should develop Data Quality and Capability plan to ensure that the data is necessary and sufficient such that anyone skilled in the art could reasonably recreate their interpretations and conclusions using the same data and metadata. Each plan should contain a risk-based assessment of minimum sensor specifications, such as a failure modes effect analysis (FMEA), SEMS or other structured approach. Such plans should address potential errors in measurements or failure to measure, potential negative outcomes, and tolerance for such errors and failures. Each plan should also provide operator-specific standards and practices describing the following:

4.2 Traceability and Supply Chain Management

Operators should demonstrate the ability to trace, through commonly accepted manufacturing and supply chain methods such as those documented in ISO 9000, API 18LCM, and API Q1/Q2 standards, the origin and history of machines, tools, and instruments for which data is recorded. Traceability should include, at least, records from materials origin to machining, assembly, calibration, use, handling, maintenance, repair, and decommissioning. Operators are also encouraged to require and actively participate in gauge repeatability and reliability (R&R) and other quality programs with their suppliers and vendors.

4.3 Time-Based Data Gathering and Monitoring

It is assumed that all parameters will be sampled with respect to time. Times should be reported with respect to a reference such as network time, NIST time, or other standard reference. All time should be represented with respect to an offset such as UTC offset. Both time reference and offset should be explicitly stated as part of any data set. Time synchronization should be performed regularly. If applicable, time stamps for down-hole measurements should be synchronized before and after passing through the rotary table and, if possible, during operations in the wellbore.

Depth data may also be provided, though not to the exclusion of time-base data. It is recommended that depth be reported in at least 0.5ft (6 inch) increments.

4.4 Minimum Recommended Data Sampling Frequency

All data should be gathered at a frequency no less than 2x the frequency which represents the smallest time interval in which a significant change in the intended observation or event to be monitored can occur, also known as the Nyquist Frequency. For instance: If, during a BOP test, the system pressure can reasonably change by more than 1% of the full range of the test during a 10 second interval, the test may require sampling every 5 seconds, or 0.2 Hz. However, if such a change may reasonably occur in 1 second, pressure should be sampled every 0.5 seconds, or 2 Hz. Sampling rates should be determined using risk-based methods and may be unique to each process or operator. Rationale for sampling rates should be detailed as part of an RTM plan.

4.5 Recommended Minimum Real-Time Parameter Set

During normal drilling operations, the following minimum data are recommended, in real-time and in archival form.

a. Pressure (stand-pipe, annular, and downhole)
b. Fluid Flow Rates (for dynamic conditions and hydrostatic testing)
c. Fluid Temperature (surface, wellhead/mudline, and downhole)
d. Fluid Rheology (for hydraulic models)
e. Fluid density
f. Block position (to determine drill string velocity and acceleration)
g. Fluid system and sub-system (i.e. pit) volume(s)
h. BOP system and sub-system status(es)
i. Station keeping positions(s) and status(es)
j. Critical safety and power system status(es)
k. Bit Depth
l. Measured Depth (i.e. Hole Depth)
m. True Vertical Depth (TVD)
n. Bit Position (Projected Latitude/Longitude)
o. Hydrocarbon and Toxic Gas Concentrations
    1. If possible, gas detecting sensors should also report lower explosive limits and fractions thereof

In addition, to aid in determining rig states and activities, operators are encouraged to make available:

p. Drill String Rotary RPM
q. Drill String Surface Torque
r. Hookload
s. Surface Calculated Weight on Bit

4.6 Downhole Dynamic Measurements

If used, down-hole dynamics parameters (such as WOB, pressure(s), flow rates, or others) should be provided as well. Down-hole measurements should be specified and managed in similar manner to surface measurements. Additionally, downhole dynamics instruments should receive out-bound validation to ensure that there was not significant bias and/or drift in the parameter(s) during use. Particularly, time should be recorded both inbound and outbound for tools that provide data only after retrieval from in-memory downloads. It is not uncommon to see significant deltas in time after outbound evaluation of down-hole tools.

4.7 Quality and Capability

Operators should use quality and capability standards, practices, measures, metrics, descriptions, and definitions that meet or exceed those provided by the National Institutes of Standards and Technology in the Handbook of Statistical Methods (HSM) found at http://www.itl.nist.gov/div898/handbook/

Additionally, when applicable, operators should consult American National Standards Institute (ANSI) bodies such as API, ASCE, ASME or others for references to recommended and/or minimum quality standards.

Operators should provide a plan to achieve and maintain minimum standards for the follow data attributes:

a. Range—The difference between the minimum and maximum values a sensor can detect
b. Accuracy—The maximum error tolerated in the measurement, preferably determined using risk-based assessment.
c. Precision—The ability of a sensor to reproduce a value within a given accuracy.
d. Sensitivity—The smallest change that can be observed, stored, and transmitted. For digital sensors, this is often related to resolution.
e. Resolution—The smallest change in value that can be resolved. For analog instruments, this is a function of the smallest readable interval or graduate. For digital instruments, this is determined by the number of data bits used.
f. Process Sigma (Capability)—The fraction of observations which fall within the accuracy tolerance of a calibrated and properly working instrument.
g. Traceability—How calibration and validation of data will be traced—preferably to NIST or equivalent laboratories standards.
h. Reliability—Minimum up-time requirements and redundancy or contingency plans for all required measurements.
i. Fidelity—The methods in place to ensure that data faithfully represents the true observation throughout its existence.

4.8 Minimum Specifications for Critical Measurements

Generally, it is not recommended to prescriptively define specifications and operations expectations for measurements. Two measurements, however, are considered fundamental to protection of life and the environment, such that minimum requirements could reasonably be justified: pit volumes, and pressure.

4.8.1 Pit Level and Volume Measurements

Accurate measurements of the volume(s) of pits/tanks (particularly trip-tanks), and active/inactive fluid systems on drilling rigs are both fundamental, and critical to well-control. Pit gain is often a key parameter in calculating mud density to kill or control a well. Thus, special care should be taken to ensure the accuracy and reliability of these measurements.

4.8.1.1 Determination of Pit Volumes and Schedules

a. Pit levels are not generally linearly related to pit volume. It is common for significant deadwood (i.e. permanent or semi-permanent installations or obstructions in a tank/pit that occupy space and change the volume available for fluid to occupy) to be present and for pits and tanks to be non-prismatic in their geometry.
b. Each pit and sub-section thereof should be uniquely identified and conspicuously marked with easily readable identifiers, including the Trip Tank(s).
c. Engineering drawings and as-built diagrams should not be used to estimate depth vs. volume correlations. Rather, pits should be strapped per an API standard or better with a minimum accuracy of 1% for any separable section or sub-section and 1% for the total system.
    a. Reference API Standard 2555: Liquid Calibration of Tanks and API Standard 2554: Measurement and Calibration of Tank Cars.
d. Pits and separable pit sections should contain fixed, easily readable gauges which clearly identify the volume at various depth with major interval markings of no greater than 10% of the total volume or 10bbls, whichever is less.

4.8.1.2 Pit Measurement Guidelines

Pit level sensors should be installed in a manner that prevents or minimizes the influence of:

a. Solids Buildup
b. Deadwood, Mixers, Structural, and Mechanical Components Which Can Impede Measurements or Induce Errors.
c. Vapors and Off-Gassing
d. Foam or Other Floating Impediments to Measurement
e. Background and ambient effects of the atmosphere, magnetic effects, and radiation
f. Vessel Motion

4.8.1.3 Pit Level Measurement Specifications

Pit levels and corresponding volumes should meet the following minimum criteria:

a. Resolution of pit level sensors should be better than 0.1” or 0.1bbls per separable section, whichever is less.
b. Pits/tanks should be re-calibrated and/or re-strapped after the installation of any dead space, after any damage or after 3 years, whichever occurs first.
c. Pit/tank sensors should be sufficiently reliable or have sufficient redundancy to ensure that pit volumes can be reported with 99.99% up time during safety or environmentally critical operations.

d. Each pit/tank, or separable section thereof, should have sufficient number, placement, and orientation of sensors to ensure minimum accuracy during reasonably expected vessel motion.
e. Operators should provide a gauge repeatability and reproducibility (R&R) program for all pit level sensors with traceability to NIST or equivalent with a minimum frequency of once per year.
f. Pits/tanks, and all separable sections volumes thereof, should be reconciled to visual observations once per crew shift to ensure that reported volumes match readings taken from fixed gauges within the pit.

4.8.1.4 Conditional Use of Pit Level Measurements

Pit levels are a lagging indicator in most scenarios. Moreover, they are not, by themselves, a sure indicator of potential well control events. Accurate analysis requires at least: flow rate in, flow rate out, fluid density in, and fluid density out. With these data, users can more readily identify the size and nature of gains or losses and operators are encouraged to use mass-flow meters on all inflow and outflow measurements of the drilling fluid system. Even then, these measurements may not indicate underground blowouts where influx from one zone or zones is equal to losses into another zone(s).

4.8.2 Pressure and Volume Gauges and Sensors

Operators should take special care to ensure reliable measurements from pressure recorders, sensors, and gauges. Any instrument or device that reports pressure should be:

a. Calibrated before beginning initial work on a well
b. Calibrated or replaced at least every 6 months after work begins or as per OEM recommendations, whichever is less
c. Regularly validated against a trusted (i.e. calibrated, NIST traceable) master gauge and/or BOP testers' equipment at a frequency not to exceed every 30 days.

Additionally, pressure gauges and sensors should be monitored closely and:

a. Any gauge/sensor that reports a value with a difference in magnitude, with respect to a master or reference device, exceeding the devices allowable error tolerance should be immediately repaired or replaced.
b. Any device that is relocated, damaged, or otherwise experiences a significant change in environmental conditions (such as ambient pressure, temperature, vibration, background radiation, or others) should be validated before being used for operations.
c. Any device exposed to pressure exceeding its working limit should be removed from service, recalibrated, and examined for hysteresis.

Operators should specify a single operational gauge or sensor as a reference (preferably the stand-pipe gauge) and should immediately correct or replace any critical gauge or sensor that disagrees with the reference by more than its specified error, or validate the reference gauge. Rigs should have mechanical backups (i.e. gauges that do not require a power source) for all critical pressure measurements and should monitor for any shifts or drifts between or among digital and mechanical instruments. Any shift/drift should be rectified and annotations to the data made that reflect any actual or attempted correction(s). It is recommended that adjusted parameters (i.e. those that have been corrected) be stored and transmitted separately and that all original data be preserved.

Operators should consult ASME B40.100 for best-practices regarding gauge specification and should provide gauges with the following minimum specifications:

a. 10psi maximum error (regardless of full range)
b. 1psi sensitivity/resolution (regardless of full range)
c. Range should be such that expected operating pressures are within 25%-75% of the range of the device. If significant pulsation is present or expected, maximum pressure should not exceed 50% of the full-scale range.

4.9 Calibration and Validation

Calibration is the measurement of and correction for errors of an instrument with respect to a trusted, traceable standard of known accuracy. Calibration should be performed in a laboratory or shop setting to minimize environmental effects. Validation is a check, under operational conditions, to ensure that an instrument has remained calibrated and/or within allowable tolerances.

To ensure the quality of data provided, operators should provide specifics regarding standards and practices for the following:

a. Method(s) by which all measurements can be calibrated and/or validated.
b. Frequency and/or other conditions under which sensors should be calibrated or validated.
c. Method(s) of tracing, recording, storing, and auditing the results of calibration and validation of any and all necessary measurements.

4.10 Outliers and Drift

Operators should have a documented plan to identify, alert on, and, if possible correct, outliers and drift in data submitted where:

a. Outliers are data which are spurious or likely to be spurious using physical, statistical, or other definitions or attributes.
b. Drift is a slow change in the response of a measurement ultimately leading to unacceptable error in the measurement or data.

Any correction made to outlying or drifted data should be considered a manipulation and should conform to the section contained herein (*Data Manipulation*) and recorded in the RTM with a time stamp.

4.11 Data Manipulation and Derived Measurements

Data manipulation and derived measurements, if not well defined and communicated, can significantly impair the ability of anyone, even those highly skilled in the art(s), to reach valid analytical conclusions. Moreover, combinations of manipulations and inclusion of non-mutually-exclusive derived measurements (i.e. those derived measurements which depend on each other or on the same third derived measurement) can often lead to compounding errors which are very difficult to extricate from data.

It is recommended that the following be defined and disclosed as part of an RTM plan:

a. Any method(s), notwithstanding intellectual property or trade secret concerns, employed by the operator, including sampling, filtering, smoothing, averaging, decimation, up-sampling, down-sampling, interpolation, or any other manipulation. Many measurements and derived values such as weight on bit (WOB), torque, rate of penetration (ROP), measured depth, as well as many others, are commonly sampled at rates higher than reported and are averaged, or otherwise transformed to the down-sampled (i.e. less frequent) resultant display value.

b. Any method(s) employed by contractors, vendors, suppliers, or other data providers, notwithstanding intellectual property or trade secret concerns, by which data are modified before receipt by the operator including sampling, filtering, smoothing, averaging, decimation, or any other manipulation.
c. Any methods employed by the operator or any vendor, contractor, or supplier, whether physical, mechanical, analog, digital, or other used to correct for environmental factors such as vessel motion, changes in temperature or pressure, changes in chemical composition, background or other radiation, gravitational effects, or any other phenomena that could reasonably affect the quality of the data provided.
d. Any formula(s), algorithm(s), or other methods, notwithstanding intellectual property or trade secret concerns, used to manipulate or generate any calculated or derived parameters, or other data provided. In addition, operator should provide any scalars, constants, coefficients, or other parameters by which derived parameters are calculated so that one can reproduce the derived value using available datasets.
e. Operators should record (with a reference time stamp) and make available, in conjunction with data provided, any changes to scalars, constants, coefficients or other parameters which modify the value of any data, or parameter provided.

Operators should document management of change procedure(s) describing if, how, when, and by whom software, and firmware can be changed on any system which creates, aggregates, transfers, or stores data or derived parameters, or any system which is critical for safety.

Operators are encouraged to use standard collections and definitions of derived measurements such as (ROP), Measured Depth and others that are commonly used. Operators are also encouraged to use publicly available and/or industry standard derived measurements when practical.

4.12 Sampling and Aggregation

It is recommended that the following be defined and disclosed as part of an RTM plan

a. Method(s) by which all measurements are provided, whether they are analog or digital, and whether they are directly from machines, tools, or instruments, or from a customer-facing digital interface.
b. Method(s) by which analog data are transformed into digital data
    a. This should include a risk-based analysis of the proper bit depth of the sampled interval such that the parameter can be resolved into sufficiently small intervals to support appropriate analysis for the event(s) of interest.
c. Type(s) of network(s) used to collect data, and whether or not they are deterministic in nature, and whether or not unique time-stamps are provided for each individual measurement (i.e. when up-scaling, do values between samples represent the previously sampled value or are other methods of interpolation or modeling used).
d. Data model(s) or standard(s) used to store data, in any data store, for any purpose material to real-time monitoring (i.e. WITSML, OPC, SQL, etc.).

   a. Data storage and transfer models should remain constant during the entire job and/or well. For instance, it is common for WITS and WITML systems to change the content of extra channels based on the operation. This is generally discouraged as it introduces opportunities for channels to be overwritten or interpreted incorrectly.
   b. Ideally, data storage and transfer models should be modular such that any channel contains only one parameter, and each channel also contain metadata required to identify it uniquely.

4.13 Transmission and Storage

It is recommended that the following be defined and disclosed as part of an RTM plan:

a. Type(s) of compression used, if any, whether or not compression is without data loss (loss-less), and, if applicable, what lossy behavior or artifacts are induced by means of compression.
b. Audit plan to demonstrate loss-less database behavior throughout the required life of data
c. Archival planning to demonstrate for how long data will be kept active and for how long data will be archived for use by the operator and for audit.
d. Data storage plan which defines where/how data will be stored and methods whereby the data may be accessed.
   a. It is recommended that operators keep operational data in a fast-access database for at least 12 months after first production of the well. Thereafter data can be stored in most cost-effective media for future access.
   b. It is recommended that operators keep all operational data for 7 years after first production of a well

4.14 Mnemonics and Metadata

Operators should provide, as part of or in advance of any data set, a list of mnemonics and descriptions of all parameter channels including:

a. Mnemonic (tag/parameter name)
b. Measurement Description
c. Unit of Measure
d. Absolute Minimum Value
e. Absolute Maximum Value
f. Null Value

It is recommended that operators use an industry standard or equivalent mnemonics. For mnemonics not covered under a standard, it is recommended that operators follow an internally defined nomenclature which provides a structured description of each data channel to avoid duplication or using multiple tags for the same channel. If possible, mnemonics should include information related to the parameter name, instrument location, instrument type, and measurement system.

Null values and mnemonics for each parameter should remain constant for the duration of a well.

5 Cyber-Security for Critical Infrastructure

5.1 Goals of This Section

This section outlines the need for, and basic components of cyber security for oilfield operations in the outer-continental shelf (OCS). It cannot possibly address every potential threat or solution and operators are encouraged to evaluate cybersecurity from a risk-based perspective.

5.2 Background

On December 12, 2014, the DHS and the USCG issued a Notice of Guidance on Maritime Cybersecurity Standards, 79 Fed. Reg. 73896-01. This Notice addressed concerns about cyber risks and vulnerabilities among vessels and facilities that are subject to the Maritime Transportation Security Act of 2002 (MTSA). Based upon the scope of the MTSA, the new Guidance on Maritime Cybersecurity Standards would extend to:

a. Facilities and vessels located on or adjacent to navigable waters under U.S. jurisdiction.
b. U.S. cargo vessels greater than 100 gross register tons subject to 46 C.F.R. Subchapter I (except commercial fishing vessels).
c. Tankships subject to 46 C.F.R. Chapter I, Subchapters D or O.
d. Certain towing vessels that are engaged in towing barges subject to 46 C.F.R., Subchapters D or O
e. Passenger vessels subject to 46 C.F.R. Chapter I, Subchapter H.
f. Foreign flag vessels possessing a valid International Ship Security Certificate required by the International Ship and Port Facility Security (ISPS) Code, which is incorporated in part by 33 C.F.R. §§101-104.
g. Facilities and vessels handling packaged and bulk-solid dangerous cargo under 33 C.F.R. §126.
h. Mobile Offshore Drilling Units (MODUs), cargo or passenger vessels subject to the International Convention for Safety of Life at Sea (SOLAS).
i. U.S. flag offshore supply vessels (OSVs).
j. Fixed or floating facilities operating on the Outer Continental Shelf (OCS) engaged in the exploration, development or production of oil, natural gas or mineral resources regulated by 33 C.F.R. Subchapter N, that:
    1. Hosts more than 150 passengers for 12 hours or more for each 24-hour period for more than 30 days or more;
    2. Produce greater than 100,00 barrels of oil per day; or Produces greater than 200 million cubic feet of natural gas per day.
k. Floating Production, Storage and Offloading (FPSO) units under 33 C.F.R. §106.

Thus, drilling, completions, production, workover and other servicing, and abandonment of offshore oil and gas wells are clearly covered under these rules. In addition to clear and present safety and environmental concerns, priorities are placed in the following:

a. Partnership coordination
b. Implementation and communication
c. Identification of sector needs/gaps and/or best practices
d. Information sharing
e. Business continuity

5.3 Information Security Management Requirements

While each organization must determine the most appropriate security model for their organization, operators should provide an Information Security Management System (ISMS) plan that details at least the following:

a. Information Security Policies—general standards and practices an operator will employ in developing an ISMS.
b. Risk Based Assessment—assessment of cyber-security threats including a Failure Mode Effects Analysis (FMEA) for any system that is reasonably associated with safety or environmental critical operations.
c. Organization of Information Security
d. Human Resource Security—prevention or mitigation of social engineering, inadvertent, or other human-centric exploits or failures.
e. Physical and Environmental Security including:
    1. Prevention of unauthorized or inadvertent access to hardware, software and firmware.
    2. Protection from environmental effects or hazards that prevent or inhibit the ability to physically protect any part of a system.
f. Asset Management—define and administer inventories, ownership, acceptable use, and return of uniquely identifiable assets.
g. Access Control—define and administer permission(s) of users and systems respecting networks, systems, services, and data.
h. Cryptography—rules for the use of cryptographic controls, as well as the rules for the use of cryptographic keys, to protect the confidentiality, integrity, authenticity and non-repudiation of information.
i. Operational Security including:
    1. Definition of redundancy to maintain safety and environmental compliance.
    2. Managed failover to manual operations in case of cyber breach or system failure(s).
    3. Protection from software/firmware threat vectors (e.g. malware)
    4. Backup, Logging and Monitoring
    5. Control of Operational Software
    6. Technical Vulnerability Management
j. Communication security – methods to secure networks and data in transit.
k. Data Security—methods to protect data at rest and to ensure the fidelity of archived data.
l. Supply Chain – securing hardware, firmware, and software during development, manufacture, testing, storage, transit, installation, commissioning, and repair and preventing malicious actors from otherwise compromising the supply chain.
m. Information Security Incident Management including:
    1. How to detect an incident or breach
    2. Escalation and Communication Plans, including reporting.
    3. Forensic Evidence Preservation
    4. Restoration of Services and Business Continuity
n. Information and Controls Systems Auditing—methods to regularly evaluate ability to detect, prevent, resist, communicate, and report cybersecurity threats
o. Compliance – Demonstration of compliance with legal, regulatory, and contractual requirements

The informed reader may notice significant similarity between these requirements and those detailed in ISO 27001:2013. While ISO certification is not currently required, operators and drilling contractors are encouraged to review ISO 27001, and its associated standards, ISO 27002-27006. Moreover, the industry at large is encouraged to develop an oilfield-specific cybersecurity standard under an appropriate ANSI body.

5.4 Cybersecurity Recommendations for Real-Time Monitoring

While one cannot possibly envision all potential safety and environmental concerns, there are several that currently present the most severe cybersecurity threats. These include:

a. Station Keeping
b. Fire Detection and Suppression
c. Ballast Systems
d. Drilling Fluid Pressure and Rate Controls
e. BOP Controls
f. Hoisting Controls
g. Operational Data Aggregation, Transmission, and Storage Systems.

Each ISMS submitted should especially address these systems specifically.

6 Additional Fundamental Recommendations for Real-Time Monitoring

6.1 Goals of This Section

This section outlines additional capabilities that are considered fundamental to successful real-time monitoring. It attempts to address aspects that were not outlined in previous sections; however, it is not a comprehensive list of all potential features that might help ensure effective real-time monitoring

6.2 Skills

Operators should define all necessary and recommended work positions/roles required to provide 24/7 real-time monitoring and should define minimum and recommended education, training, competency, and experience requirements for each role. Operators should, upon request, provide competency and continuing education details for any or all persons assigned to any or all roles materially related to RTM.

It is recommended that all training and/or competency programs include exposure at regular intervals to the physical processes which they will be monitoring.

6.3 Basic analytical capabilities

Operators should demonstrate reasonable ability to perform at least the following analyses (if direct measurements are not available) which could be considered a minimum required capability to operate safely:

a. Pore-pressure and fracture-gradient estimation
b. Hydraulic modeling to determine
    1. Pressure(s) at critical point(s) in the wellbore during drilling, tripping, and cementing.
    2. Surge and swab effects
    3. Cement displacement
c. Kick (influx) detection

    a. Mechanical specific energy analysis may be an effective early indicator of kicks.
d. Drilling margin window (mud weight window)
e. Violations of anti-collision procedures or minimum separation requirements

These capabilities may be done by: direct measurement, simulation, laboratory or other empirical observations, or using other reasonable practices. Operators should document the justifications, assumptions, workflows, calculations, results, and other information which are part of each analytical method.

6.4 Data Visualizations

Operators are encouraged to use visualizations which support their operational objectives and meet minimum safety and environmental protection (if applicable) requirements. It is possible that no visualizations may be required to meet minimum monitoring requirements.

6.5 Workflow Management

Operator should provide documentation demonstrating the following:

a. Plans to support RTM for all offshore operations, physically or virtually
b. Methods of manual or automated Alerts and Alarms including:
    1. Communication protocols
    2. Maximum allowable response time(s)
    3. Escalation protocols
    4. Stop work authority
c. In advance for each critical process, methods to define the maximum allowable deviation from plan (in absolute or percentage terms, or as a function of variables that are statutorily defined)
d. Methods to identify and communicate if/when critical processes deviate from plan more than predefined allowable tolerances.
e. Methods to alert required third parties of any deviation(s) from plan which exceed prescribed limits or which represent a clear and present danger to life, health, or the environment.
f. Methods to alert required third parties of any dysfunction, defect, or other fault in the BOP and BOP systems and sub-systems
g. A plan to regularly simulate or induce fault(s) for all critical BOP operational elements; and, to simulate alert(s) to required third parties) within allowable or prescribed time frame(s)
h. Definitions of roles and responsibilities for all parties involved in RTM (e.g. 24/7 monitoring staff, subject matter experts (SMEs), decision makers), referencing minimum training, qualifications, certifications, experience, and/or licensure requirements for each role
i. Escalation and operational decision assurance workflows demonstrating standard operating procedures for at least the following events:
    1. Failure, incapacity, malfunction, or other deficiency of any barrier
    2. Loss of well control
    3. Discharge or any oil, natural gas, brine, diesel, or any other potentially harmful fluid(s) in excess of statutory allowable maximum-cumulative or instantaneous rates.
j. Decision making hierarchies or matrices showing responsible roles and specific personnel assigned to each role at any point in time.
k. Fail-over and contingency plans in case of loss of network connectivity, natural or man-made disaster, or other catastrophic events that could interrupt service.

While it is understood that any, or all, of these requirements can be managed with strict discipline and attention to detail using non-digital means, operators are encouraged to use widely available digital technologies to expedite, simplify, and lower the cost of these requirements. Additionally, the operators are wise to consider the very real possibility of power or network failures that can limit or disable real-time monitoring systems and should ensure that their operations can be performed safely in the absence of real-time monitoring.

6.6 Auditing and Transparency Requirements

All data, and associated metadata should be stored in active databases (those databases that can be accessed in real-time) for a period of no less than 2 years after a well has been completed and for extended periods of time upon request. Afterwards, all data should be archived, in its original format, for a period of no less than 7 years, or for extended periods upon request.

6.7 Reporting

Operators should perform formal after-action reviews and create reports after any of the following:

a. Uncontrolled Influx (kick)
b. Violation of the Drilling Margin
c. Release of Fluid(s) into the atmosphere or environment
    1. For gasses, in excess of 50 MSCF[6] cumulative or 500 MSCF/day instantaneous
    2. For liquids in excess of 1 barrel cumulative or 10 bbls/day instantaneous
d. Any failed BOP Function Test or Static Pressure Test
e. Loss of Station (exceeding pre-defined or approved station deviation or riser angle tolerance)
f. Excess Riser Tension (if measured)
g. Any Fire or Explosion

[6] Consistent with 30 CFR § 250.1160

APPENDIX

7 Appendix 1: Additional Recommended RTM Capabilities

7.1 Goals of this Section

This section provides basic guidance for those developing their own real-time capabilities. The intent is to provide basic guidance that will help develop systems and practices that will most likely lead to success.

7.2 Training Plan

Staff which physically or virtually monitor offshore oil and gas operations should receive training in the following:

a. Fundamentals of Measurements
b. Basics of Statistical Process Control
c. Risk-Based Approaches to Standards and Practices
d. References to Industry Accepted Standards and Practices
e. Collaboration with Industry—FAA examples, Industry Consortia
f. Well Control
g. Safety Training (as required for field visits)

It is also recommended that all staff associated with RTM undergo regular continuous educations including trips to the field at least yearly.

7.3 RTM Monitoring Guidelines

There is much to be learned from the past successes and failures in real-time monitoring—from the oil and gas industry as well as many others including nuclear, aerospace, and manufacturing. Several primary lessons stand out:

a. Culture is the most important aspect of any operational process.
b. Openness and transparency should be encouraged.
    1. Industry should strongly consider a model similar to the FAA's Voluntary Disclosure Reporting Program (VDRP, see below).
c. Ability to execute (i.e. good process control, discipline, robustness, and scalability) is often more important than high-levels of subject matter expertise.
    1. Subject matter experts can be consulted as-needed and should be used sparingly in a 24/7 context.
d. Management by exception is more efficient. Normal behavior should be well understood and any deviation should be thoroughly documented, reviewed, and, if necessary, acted upon.
e. Real-time monitoring cannot replace field-level operational audits and must always be subordinate to actual field observations; however, it can be a powerful addition that may help reduce the frequency of audits in the field.
f. Data quality is fundamental and cannot be overlooked.

When considering the core capabilities of a RTM solution, there are several primary functions that must be delivered as part of a minimum viable product (MVP). These may be expressed as the 5R's:

Recognize—detect when certain situations have occurred or will likely occur. These may include planned events such as BOP testing or cementing, or unplanned events such as a kick or lost circulation.

Route—get data to the right people/systems at the right time. In most analyses, data identification and collection takes between 40% and 60% of the time it takes to reach a conclusion. RTM solutions must be able to do this very quickly.

React—deliver results of analysis to persons or systems to enable a change in the operation based on data available in real-time. This may be permission to proceed, stop-work authority, or suggestions for changes in procedure.

Report—tell all relevant stakeholders involved in RTM what happened. This should be structured, timely, and easy for a novice (or the public) to understand.

Review—follow up after events with after-action reviews (AARs), Job Safety Analysis (JSA) reviews, informal tool-box talks, meetings, questionnaires, or other post-process information sharing/gathering. Have regular conversations about lessons learned. Create a knowledge sharing database if possible/practical.

To serve these ends, there is a small, but important set of basic technologies (most of which are Commercial Off the Shelf—COTS and can be used with little or no modification) that should be evaluated including:

a. Data Acquisition and Storage
    1. There are a wide variety of reliable, industrial data acquisition and storage options available. Current industry standards for data transmission are largely based on the well information transfer markup language (WITSML[7]) v1.3x-1.4x. Though widely used, these standards do not necessarily offer sufficient capabilities for future monitoring and interaction needs. A more mature standard that is used by other industries is open platform communications (OPC[8]). There are current efforts to make WITSML more like OPC in version 2.0. These standards are useful for communicating between and among machines and databases but may not necessarily be ideal for analysis. It is important to consider how data will be used for later tasks when building a data store.

b. Data Visualization
    1. Visualization, while important, is not required to do most basic monitoring. Visualization solutions should focus on simplicity, ease of use, and reliability. While it is tempting to incorporate many data streams, complex analyses, alarming, and other capabilities into visualization, additional features often make it difficult for humans to identify the most important data or trends. Additionally, visualizations should enable, to the extent possible, the ability for untrained, or uninformed users to identify anomalies. Design paradigms should consider the following:
        i. Only data required for the process of interest should be visible by default. Additional data often leads to confusion and non-unique interpretations.
        ii. Visualizations should follow ISO colors and symbols when possible

[7] http://www.energistics.org/drilling-completions-interventions/witsml-standards/current-standards
[8] https://opcfoundation.org/about/opc-technologies/opc-ua/

iii. Visualizations should consider color blindness, low-light conditions, and human eye fatigue in their design.
iv. Visualizations should be easily exportable and/or shareable
v. Visualizations should enable analysis that is not explicit in other alarms or automated systems.

2. It is recommended that additional forms of communication and notification (such as audible, tactile, olfactory, and others) be evaluated in the real-time context to prevent fatigue of the visual senses and to allow faster responses to a variety of potential information.

c. Data Analysis

1. Preference for data analysis tools are highly subjective. Within organizations or teams there may be strong individual preferences for different tools and methods. Moreover, each problem may lend itself to a different approach. Users are encouraged to use tools with which they are most comfortable and productive, so long as cost and support are not issues. Users may find that most analyses can reasonably be accomplished with widely available tools like Microsoft Excel. Others analyses may require special engineering or modeling software that is bespoke for the industry. Yet others may only be effectively completed with more sophisticated numerical simulations and 'big data' tools, or even require cutting edge tools like deep learning or artificial intelligence. Regardless of the analyses required, users are encouraged to use the tool that most effectively and efficiently meets the needs of the organization. Additionally, analyses should place priority on physics-driven solutions rather than stochastic or artificial-intelligence systems which are known to suffer from non-uniqueness and non-repeatability.

b. Ticketing (Case Management) and Workflow

1. Visualization and data analysis tools are effective if, and only if, they can affect current or future outcomes. This requires a system to instantiate, communicate, escalate, track, and report against shared information and/or requests for work. There are many existing solutions in the market that perform these and many more tasks very well. Commonly referred to as business process management (BPM), these tools serve consumer call-centers, emergency response centers and a wide variety of real-time operations and processes. Most available BPM solutions will likely meet the needs of RTM for oil and gas with little or no modifications. Thus, organizations should consider solutions that best integrate with their current systems, are easy to use and manage, and are cost effective.

c. Knowledge Management

1. It is important, when attempting to influence a process, to ensure that the information provided will most likely lead to positive (or at least non-negative) outcomes. If possible, RTM operations should have real-time access to summaries of similar situations and best or standard practices. Fortunately, there are numerous commercially available knowledge management (KM) solutions and most will meet or exceed oilfield technical requirements. Thus, organizations should focus on usability and sustainability. The most difficult part of knowledge management is organizational discipline to maintain the system. Organizations should plan and budget for sufficient human resources to ensure the system is curated properly.

7.4 Proposed Data Access Methods

Operators should provide as part of the RTM plan, and in a reasonable time, data or access to data, in real-time or in archival formats.

The preferred embodiment for this relationship is shown in Figure 5. In this arrangement, operators would provide credentials, per pre-defined agreement(s), and allow others to access the WITSML store(s) containing relevant datasets. A cloud-hosted application (poller) would then poll the data stores during periods of interest such as during pressure testing or well-control incidents. This proposed solution allows operators to grant access to data with minimal cost and administrative burden while using industry accepted tools and security models.

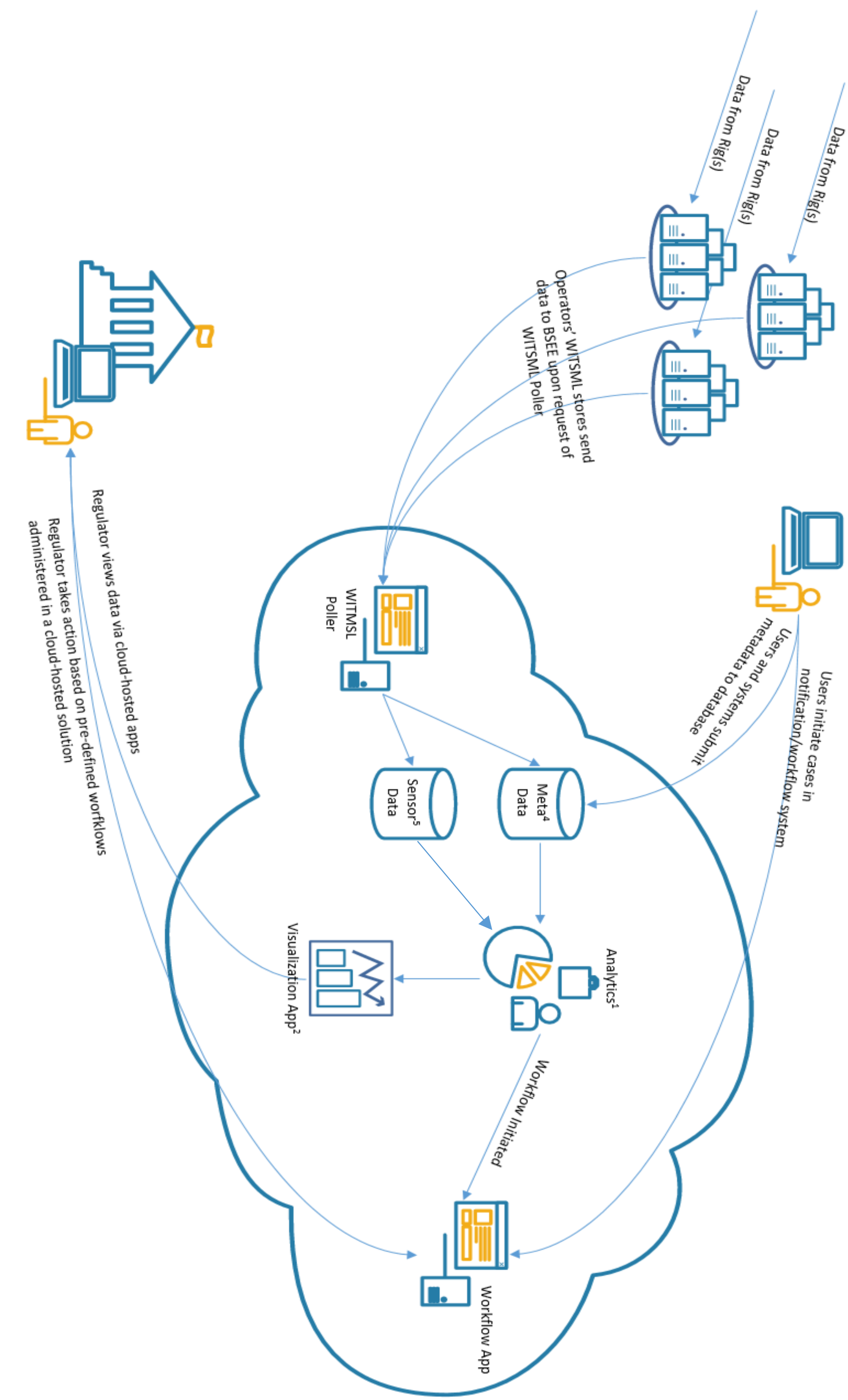

Figure 5--Idealized RTM Solution for Data Access

7.5 Additional Considerations

7.5.1 Industry Cooperation

Industry is encouraged to collaborate on common problems which are related to safety and well integrity. Several approaches should be considered including:

7.5.2 Industry Steering Committees

There are several successful and well regarded industry steering committees that have effectively solved problems that are common to all operators, such as the Industry Steering Committee for Wellbore Survey Accuracy (ISCWSA). Since the 1990's this committee has significantly improved wellbore surveying and has published extensively on data standards and other best practices. They have established common formulae, tool design and testing standards, data and data interpretation standards, and measurement and quality standards. They have also developed training materials and basic documentation for operators to use as the foundation for wellbore positioning policies. In doing so, they have developed a framework which, if implemented, will ensure the quality of wellbore position data.

The industry is encouraged to form similar industry consortia to address well know measurements and data quality deficiencies, RTM standards and practices, and other cooperative groups as necessary.

7.5.3 Other Industry Collaboration and Open Source Initiatives

Certain derived measurements and analytical methods are recommended or required in nearly all offshore operations. The industry is encouraged to develop common standards which can be made freely available to all. The most common and effective approach is to disseminate software, algorithms, documents and other information, that is not the domain of an ANSI body, through open source foundations and under open source licenses. This allows for rapid collaboration and transparency. For example, the industry may consider open-sourcing:

a. Basic FIT and LOT interpretation
b. Basic BOP test interpretation
c. Rig Activity and State Determination
d. Basic Wellbore Positioning Calculations

7.5.4 Rig Activity and State Determination

Rig Activity and State Determination should be considered a fundamental unit of analysis and a basic analytical capability for RTM. It is the basis for all alerting and alarming and is critical to visualizations, reporting, and analysis of real-time data. Most operators, however, use custom rig-state determination logic and it is unlikely that operators would evaluate them consistently within, between, or among themselves. Thus, the industry is encouraged to promote a standard body of rig-state logic or code to promote sharing and a more rigorous understanding of operational processes. Moreover, it is encouraged that these be made open-source and freely available to all.

7.5.5 External Analyses, Reports, and Interpretations

Third parties, when practical, should attempt to perform independent and unbiased analyses of data and events. If this is impractical due to time or other constraints, interpretations and analyses should meet the following minimum requirements:

a. All external analyses, reports, and interpretations should include the actual data or references thereto.
b. Third parties should require submitter(s) to provide a description of the method(s), approach(es), software(s), assumption(s), physical model(s), data quality, or any other input or processes that could reasonably influence the results of the analysis.
c. When practical, third parties should attempt to, validate, simulate, or reproduce (s capabilities) the results or conclusions of critical reports or analyses

8 Appendix 2: Practical Limitations of Common BOP Testing Methods and Comments on API Standard 53

8.1 Goals of this Section

This section intends to highlight areas where existing regulations and recommended practices could reasonably fail to ensure that BOPs can perform as expected during reasonably expected well-control situations.

API Standard 53 **Requires only that 'visible leaks' are not present for it to be considered a passing test**. There is no definition of visible leaks and, equally troubling, leaks are significantly more difficult to detect in a subsea environment. As show in Figure 6, a small leak—one that is likely to not be visible to human operators during a hydrostatic test, could lead to dangerous outcomes under a dynamic gas situation. A leak of just one teaspoon could reasonably lead to a sustained methane leak of 5 standard cubic feet per minute (SCFM) if methane is the migrating fluid.

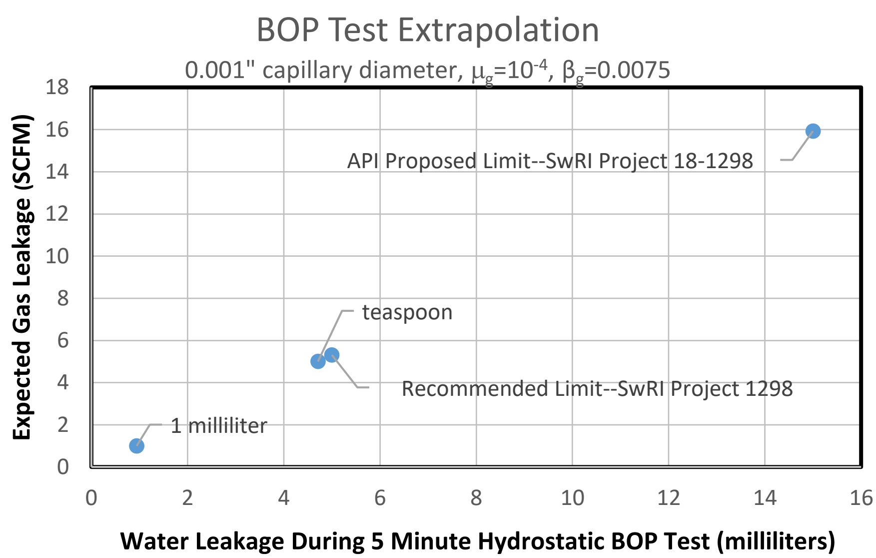

Figure 6—Evaluation of various 'visible' leaks

Additionally, even a very small flow path on the order one one-thousandth of an inch (a typical machining tolerance) could lead to dangerous, sustained methane leak (see Figure 7). While subsea installations are less susceptible to combustion due to methane diffusion and transport in sea water, there is significant potential for flow that can sustain combustion if gas were to collect in structural traps around the rig. Such small leaks and flow paths are suspect to cause erosion over time and thus a more severe leak.

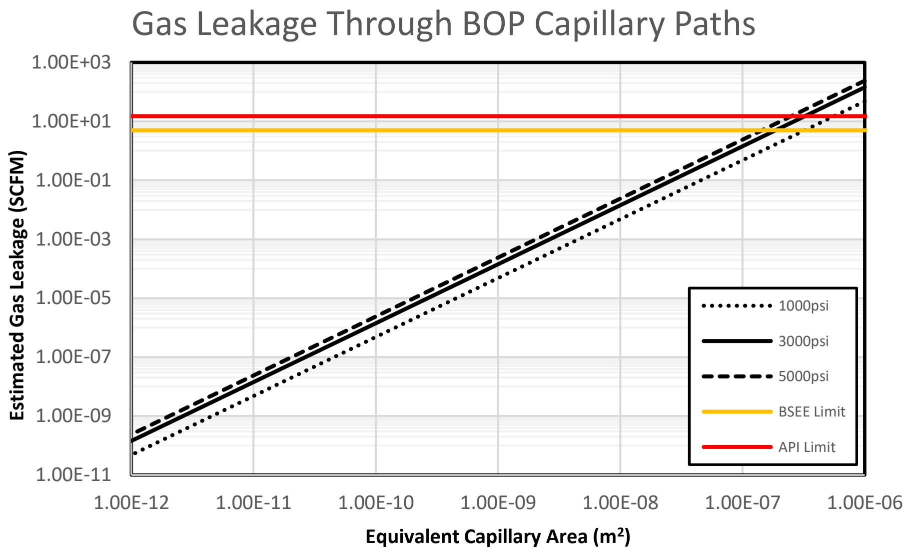

Figure 7—Methane flow rates through capillary paths of various sizes at real-world testing and operational pressures

API Standard 53 has several limitations including:

a. Does not specify allowable pressure loss. API 6D recommends 500psi/hr. for pipeline testing which suggests <42psi for a 5-minute test; however, specifying pressure loss is meaningless unless accuracy and sensitivity of pressure recorders is specified.
b. Does not specify maximum fluid loss rate
c. Does not require isothermal testing or temperature correction(s)
d. Does not require incompressible fluids or compressibility correction(s)
e. Does not require demonstrable lockout/tagout (LOTO) of instruments to prevent manipulation
f. Does not require or specify minimum capabilities of technicians, tools, or instruments.
g. Requires only a 5-minute test.
    1. This is often insufficient when considering the multiple pressure, compressibility, and temperature transients present during a BOP test. The example shown in Figure 8, and Figure 9 shows the danger of such a vague rule. The chart provided by the BOP tester appears to show no 'visible leaks' over 5 minutes. However, a more detailed inspection shows that the test would have failed if carried out for a few more minutes.

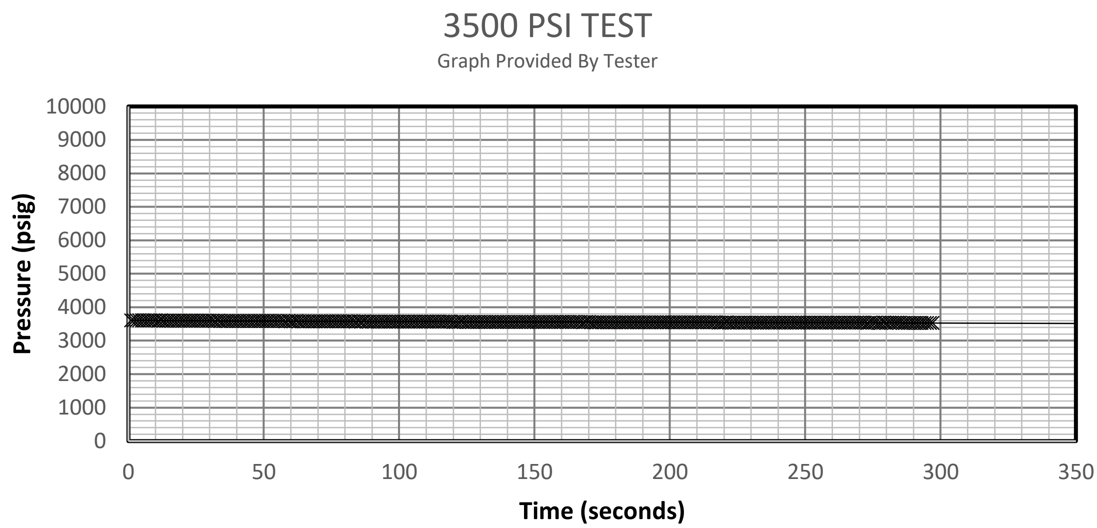

Figure 8—Typical 5-minute test required by API Standard 53 that would pass using conventional inspection and analysis methods.

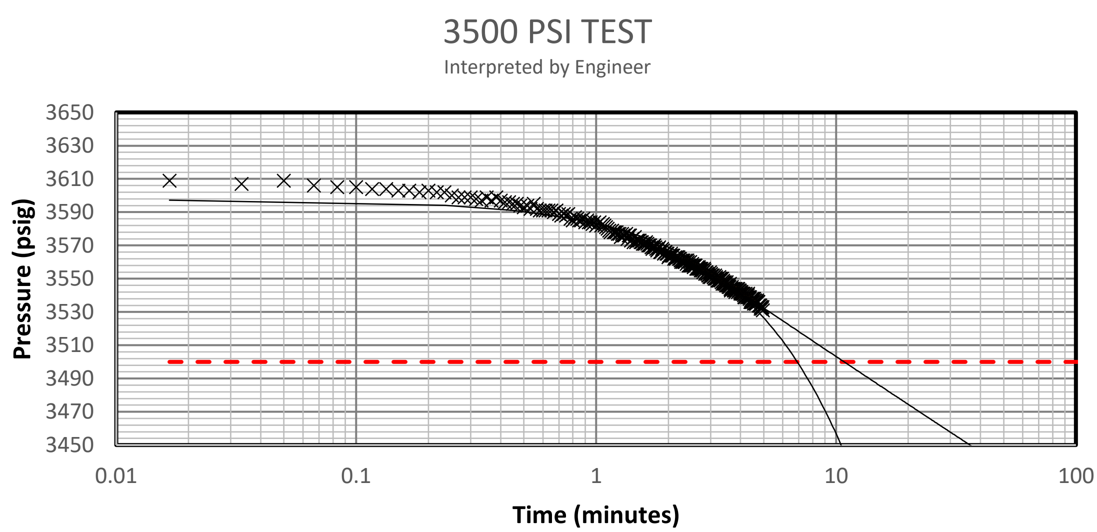

Figure 9—Example analysis enabled by high frequency, high quality data

When considering that well control situations can last for days, not minutes or hours, it is clear that a five-minute test, as currently performed, is insufficient to qualitatively asses the expected performance of a BOP.

The logical conclusion of these findings is that the data quality required of BOP testing systems should be very high and is suitable for some level of prescriptive definition.

8.2 Comments on Bourdon-Tube (Barton-Style) BOP Test Recorders

a. Testers can be easily manipulated before, during and after tests

1. Field ‘calibration’ or manipulation can be performed by any user with a screwdriver. Most users are not trained to do this and improper adjustment can lead to significant errors.
2. Pens can be artificially held in place by hands, rubber bands or other cheat devices.
3. The paper chart can be easily rotated by hand to simulate a longer duration test than was performed. This is commonly referred to as a ‘thumb chart’.

b. Testers are susceptible to many types of non-mutually-exclusive error modes
   1. Helical bourdon tubes can be deformed by rough handling or shock pressure leading to hysteresis and non-linear pressure response
   2. Mechanical linkages can come out of spec or be deformed by rough handling
   3. Testing is not isothermal and test fluids expand and contract with temperature
   4. The friction between pen and paper leads to a realized sensitivity (resolution) of ~500psi
   5. The thickness of the pen mark is often >= 100psi.
   6. Friction between pen and paper is not constant and is a function of cleanliness, humidity, pen wear and other factors
   7. The holes in the center of paper charts have been found to be non-centered or eccentric from the printer leading to non-linear errors

c. Calibration is not done consistently or correctly

d. Counterfeit is common among Barton-style Recorders

8.3 Comments on Pressure Gauges

a. Traceable and High-Spec Gauges are not required
   1. Piezo-Electric gauges are often more accurate and reliable than hydromechanical gauges, yet they are often not required
   2. BOP testing companies are not required to use serialized gauges
   3. BOP testing companies are not required to use factory calibrated gauges
   4. Non-calibrated gauges have an observed out-of-spec rate of ~10%

b. Gauges are transported or handled in such a way as to minimize error

c. Gauge sensitivity is often 1%-2% of full range
   1. A 20ksi gauge has 200-400psi minimum error

d. Gauges are often exposed to pressure shocks and experience hysteresis.

e. Many gauges in use do not return to zero at atmospheric pressure or have a post to prevent them from going negative which hides potential errors

9 Appendix 3: Comments on Negative Pressure Testing

9.1 Goals of this section

This section intents to highlight areas where existing regulations and recommended practices could reasonably fail to ensure that negative pressure tests are properly interpreted and that a wellbore is under control for removal of one or more temporary barriers.

9.2 Background

Negative pressure tests are performed to evaluate one or more flow barriers in a wellbore or annulus and to determine whether a blowout preventer may be removed or work (such as further drilling) may proceed. Failure or incorrect interpretation of a negative pressure test can lead to loss of well-control and was a root cause of the tragedy on the Deep Water Horizon in 2010.

9.3 Description

A negative pressure test is performed by lowering the hydrostatic pressure from the mud or other fluid column to less than that of the formation pressure on the other side of a barrier, typically a mechanical packer, retainer, cement plug, or liner lap prior to setting a liner top packer. This is usually done by circulating out heavier (i.e. high density or specific-gravity) fluids that can, without assistance from additional barrier(s), resist the flow or migration of reservoir fluids. The resulting pressure differential or flow potential is resisted by the barrier. The term negative pressure is correct only in the context of the relative total hydrostatic pressure of the fluids versus the in-situ reservoir pressure—it does not represent negative absolute or gauge pressure.

9.4 Purpose

A successful negative pressure test should demonstrate that it is safe to remove the blowout preventer and to temporarily or permanently cap the well or to resume work. The test should demonstrate that with the BOP removed there will be no flow from the well and that the barrier can resist reservoir pressure(s).

9.5 Testing Considerations

The procedures used to monitor and evaluate pressure(s) before, during, and after negative pressure test(s) are not sufficient to ensure the safety of crews and the environment. For example, CFR §250. 721.f,g, suggest only three conditions to pass a negative pressure test:

1. No Pressure Buildup
2. No Flow

As such, there is significant potential for negative outcomes for the following reasons:

1. Testers are not required to demonstrate capabilities of testing apparatus(es) (such as pressure recorders or other pressure testing systems) or measuring devices (gauges and transduces).
    a. All pressure gauges and transduces that could read pressure during a negative pressure test should be calibrated per OEM, or better, standards and practices and should be validated and signed off on before testing begins
        i. All instruments should read zero PSI when exposed to atmosphere.
        ii. All instruments should be exposed to stand-pipe pressure at three pressures between 25% and 125% of the expected surface pressure from absolute open flow (AOF) of the unstimulated reservoir or 1000 psi, whichever is less
            1. During each test, all instruments should read within 1% of the reference (preferably the drillpipe pressure), corrected for hydrostatic differences.
            2. Any devices that fail to meet calibration and validation criteria should be replaced, repaired, and/or recalibrated before proceeding
    b. Requirement for testing does not specify an allowable pressure increase in terms of absolute or proportional scales, only that test have defined success criteria.

c. Any pressure that could lead to potential flow or spill(s) in excess of statutorily defined rules (30 CFR §254.46) should be reported and remedied. This will likely lead to <=1 psi of allowable residual pressure.
d. Allowable pressure increase should consider:
    i. Tubular volume(s) or capacities being tested
    ii. Annular capacities
    iii. Expected reservoir pressure
    iv. Worst-case cement permeability or flow potential
    v. Physical, thermodynamic, or rheological properties of the fluids used.
e. Identification of the source of pressure is not required and pressure immediately following circulation and shut-in (i.e. residual pressure) can come in several forms:
    i. Residual inertia from dynamically induced (i.e. frictional) pressures.
    ii. Pressurized tank behavior, commonly referred to as well-bore storage in well test analysis
    iii. System compressibility from other sources such as wellbore materials elasticity, subsurface formation plasticity and elasticity, heat transfer and thermal stabilization, and other effects that are do not represent flow potential.
    iv. Reservoir communication—pressure resulting from reservoir influx
f. Recommended test duration, as defined in 30 CFR §250.423, 250.721, is defined at 30 minutes, without respect to test parameters or pressure behavior

2. Tests do not require evaluation of material balance (i.e. well-test methods)
    a. Current method only requires evaluation of a threshold value for pressure and do not examine derivatives of other valuable transformations of available data.
    b. Well-test analysis is a mature field of study that used time-based analysis of shut-in pressure data to determine the nature of the flow potential of a reservoir. It is a universally used an accepted approach to identify:
        i. Reservoir extent
            1. If pressure communication in a reservoir is consistent with estimated volumes
        ii. Reservoir properties
            1. Porosity, permeability, and transmissibility can be evaluated
            2. Skin factor (near wellbore damage or stimulation)
        iii. Flow regimes
            1. IF flow is from fractures, channels, or other sources
        iv. Flow barriers
            1. IF flow is restricted or prevented by faults, fractures, seals or other barriers

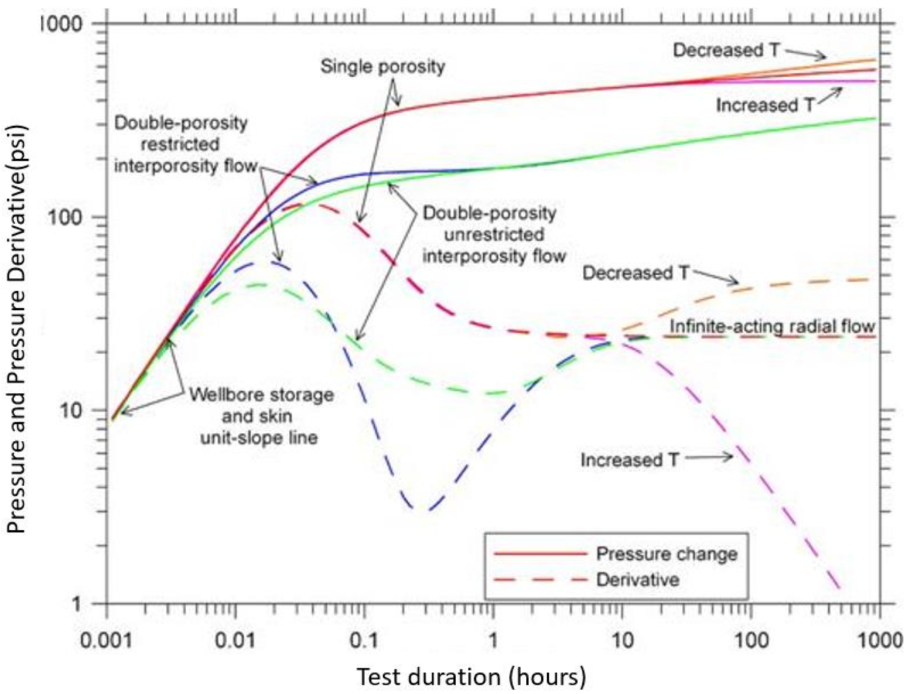

Figure 10—Example pressure build-up test, courtesy DOE Waste Isolation Pilot Plant Study-HYDRO 2009

   c. Well-test analysis is used universally by offshore operators to design completions, determine future drilling locations, and to design/manage secondary and tertiary recovery schemes.
   d. Well-test analysis is an SEC approved methodology to determine the size and potential productivity of a formation for reporting to government(s) and investors.
3. Existing rules allow for subjective interpretation in place of objective, physics-based analysis, to determine the pass/fail conditions of a test.

9.6 Recommendations

1. Test parameters (duration, and allowable pressure response(s)) should be based on the physical descriptions of the testing environment and constraints.
2. All negative pressure test interpretation should be done using generally accepted principles based on material balance, empirical testing, or other physics-driven methods
3. If gauges are calibrated and validated, all negative pressure tests should read 0 +/- 1 psi or the derivative thereof should trend to zero in a reasonable amount of time with a magnitude that meets the potential statutorily defined flow limits
4. Any pressure in excess of statutorily defined tolerances should be evaluated by the Operator, and one or more unbiased, objective third parties (such as a University or third-party expert with no potential for conflict) before resuming work.

This section does not intend to specify or promote any method of testing. Rather, it is intended to raise important questions about the spirit of existing regulations and whether commonly used procedures conform to that spirit.