WellCAP®

IADC WELL CONTROL ACCREDITATION PROGRAM

DRILLING OPERATIONS
CORE CURRICULUM AND RELATED JOB SKILLS
FORM WCT-02DS

SUPERVISORY LEVEL

The purpose of the core curriculum is to identify a body of knowledge and a set of job skills that can be used to provide well control skills for drilling operations (including well testing and initial completion). The curriculum is divided into three course levels: Introductory, Fundamental, and Supervisor.

The suggested target students for each core curriculum level are as follows:

INTRODUCTION:	Floorman, Derrickman (may also be appropriate for non-technical personnel)
FUNDAMENTAL:	Derrickman, Assistant Driller, and Driller
SUPERVISORY:	Toolpusher, Superintendent, and Drilling Foreman

Upon completion of a well control training course based on these curriculum guidelines, the student should be able to perform the job skills associated with each learning objective listed.

Instructions:

- The curriculum contained in this form is designed for supervisory level of drilling operations personnel.
- Whenever you see the word “demonstrate” in the learning objective, consider utilizing simulation as a means of demonstrating or have the student demonstrate that objective.
- The current version of this curriculum contains revisions made since the last version was published.

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I. CAUSES OF KICKS

TRAINING TOPICS	LEARNING OBJECTIVE	KEY POINTS / COMMENTS
A. Unintentional Flow or "Kick" from a Formation	*1. Define unintentional kick* *2. Identify causes of unintentional kicks*	1. Unintended influx into the well 2. Causes of kicks include, but are not limited to: a. Failure to keep hole full b. Swab effect of pulling pipe c. Surge effect of running in hole d. Loss of circulation e. Insufficient density of drilling fluid, brines, cement, etc. f. Abnormally pressured formation g. Annular gas flow after cementing h. Stuck pipe mitigation
B. Intentional Flow or "Kick" from a Formation	*1. Define intentional flows and identify causes*	1. Causes of intentional flows include, but are not limited to: a. Drill stem test b. Completion c. Underbalanced drilling d. Differential sticking e. Negative testing

II. KICK DETECTION

TRAINING TOPICS	LEARNING OBJECTIVE	KEY POINTS / COMMENTS
A. Kick Indicators	*1. Identify positive kick indicators*	1. Kick indicators include: a. Gain in pit volume (rapid increases in fluid volume at the surface) b. Increase in return fluid flow rate (with no pump rate increase) c. Well flowing from formation with pump shut down d. Hole not taking proper amount of fluid during trips e. Well monitoring and alarm devices i. Pit volume totalizers (PVT) ii. Measured flow rate increase
B. Indications of Possible Changes in Formation Pressure associated with Well Control	*1. Identify formation changes that indicate increased kick potential*	1. Warning signals may include, but are not limited to: a. Change in otherwise constant Drilling parameters: i. Significant change in Rate of Penetration (ROP) (drilling break) ii. Torque, drag iii. Decrease in circulating pressure with increase in pump strokes b. Changes in gas trends i. Trip gas ii. Connection gas (Equivalent Circulating Density (ECD) loss during connection) iii. Background gas, bottoms up gas c. Change in mud properties i. Gas-cut mud ii. Water-cut mud iii. Chloride concentration change iv. Temperature v. Cuttings size and shape vi. Fill

TRAINING TOPICS	LEARNING OBJECTIVE	KEY POINTS / COMMENTS
		vii. Volume of cuttings viii. Appearance of sloughing shale d. Other pore pressure indicators based on technology (i.e., Logging While Drilling (LWD), Pressure While Drilling (PWD), Measurement While Drilling (MWD), etc.)
C. Distinguishing Kick Indicators and Warning Signals from Other Occurrences (False Kick Indicators)	*1. Identify the causes of increases in pit level*	1. Increases in pit level a. Surface additions, treatment b. Fluid transfers c. Flow due to compressibility and temperature effects d. Ballooning e. Bottoms up with Oil-based Mud (OBM)/Synthetic-based Mud (SBM) as gas breaking out of solution, close to surface
	2. Identify the causes of decreases in pit level	2. Decreases in pit level a. Solids control b. Dumping mud c. Loss of circulation
D. Importance of Responding to Kick Indicators in a Timely Manner	*1. Identify the importance of early detection*	1. Minimize a. Kick size b. Surface annular pressures c. Wellbore stress d. Loss of operations time
	2. Identify potential consequences of not responding to a kick in a timely manner	2. Potential consequences of not responding a. Kick becomes blowout b. Formation breakdown c. Release of poisonous gases d. Pollution e. Fire

III. PRESSURE CONCEPTS AND CALCULATIONS

TRAINING TOPICS	LEARNING OBJECTIVE	KEY POINTS / COMMENTS
A. Types of Pressure	*1. Explain u-tube concept and hydrostatic column* *2. Define and/or calculate various pressures*	1. U-tube concept and hydrostatic column 2. Pressures include: a. Pressure gradient b. Hydrostatic pressure c. Bottomhole pressure d. Differential pressure e. Surface pressure (gauge readings) f. Formation gradient g. ECD
B. Hydrostatic Pressure	*1. Calculate hydrostatic pressure changes due to loss of fluid levels and/or density (e.g., pills, slugs, washes, spacers, etc.)* *2. Calculate height of a given volume of fluid and how it translates to hydrostatic pressure*	1. Hydrostatic pressure change due to loss of fluid level and fluids with different mud densities 2. Calculated using given formulas
C. Bottomhole Pressure	*1. Calculate bottomhole pressure in both static and dynamic conditions*	1. Static and dynamic calculation of bottomhole pressure
D. Surface Pressure	*1. Describe surface pressure and its effect on downhole pressures*	1. Surface pressures: a. While shut-in (Drill Pipe and Casing) b. While circulating (Initial Circulating Pressure (ICP), Final Circulating Pressure, slow circulating pressures)

TRAINING TOPICS	LEARNING OBJECTIVE	KEY POINTS / COMMENTS
E. Equivalent Mud Weight	*1. Calculate fluid density increase required to balance formation pressure* *2. Calculate the effect of circulating friction pressure losses on surface and downhole pressures*	1. Required mud weight a. Fluid density increase required to balance formation pressure 2. Equivalent circulating density a. ECD loss during flow check while drilling b. No ECD loss during tripping flow check
F. System Pressure Losses	*1. Explain system pressure losses*	1. Identify system pressure losses: a. In drillstring and bit b. In Annulus c. Through choke d. Due to fluid and pump rate changes
G. Pump Pressure	*1. Describe why pump pressure drops as fluid density increases during a constant bottomhole pressure method*	1. Surface pressures drop to balance increase in hydrostatic pressure in constant BHP methods
H. Trapped Pressure	*1. Identify at least two causes of trapped pressure* *2. Describe the effect and consequences of trapped pressure* *3. Describe how to recognize and relieve trapped pressure without creating underbalance*	1. Causes and consequences: a. Causes: i. Shutting in with pumps on ii. Poor choke operation iii. Bumping float 2. Consequences: a. Too high initial shut-in pressure could lead to too high Kill Weight Mud (KWM). b. Formation breakdown c. Pipe light: Force up 3. Recognize and relieving trapped pressure a. Compare to initial shut-in pressures b. Observe surface pressures c. Bleed in increments through choke; awareness of

TRAINING TOPICS	LEARNING OBJECTIVE	KEY POINTS / COMMENTS
		overbalance, ensuring bleed off does not create underbalance
I. Surge and Swab Pressure	*1. Identify causes and effects of surge and swab pressures on wellbore* *2. Describe the piston effect* *3. Describe the effect of the items at right on surge and swab pressures*	1. Cause and effect a. Causes of swab and surge b. Effects of swab and surge 2. Restriction of free flow in the wellbore that can lead to either swab and surge, or rapid and excessive bottom hole pressure changes 3. Complexities leading to surge and swab can include, but are not limited to: a. Hole and pipe geometry b. Well depth c. Mud rheology d. Hole conditions and formation problems e. Pipe pulling and running speed f. Bottom Hole Assembly (BHA) configuration
J. Fracture Pressure	*1. Understand effects on casing shoe pressure and relation to fracture pressure (leak off pressure) as defined by American Petroleum Institute (API) Recommended Practice (RP) 59*	1. Casing shoe pressure. Fracture pressure (leak off pressure) as defined by API RP 59. Calculation and applicability of Maximum Allowable Annular Surface Pressure (MAASP). a. Recalculated with changing drilling fluids densities
K. Pressure Limitations	*1. Describe the consequences of exceeding maximum pressure limitations*	1. Consequences for non-formation related items: a. Wellhead b. Blow Out Preventer (BOP) c. Casing
L. Calculations	*1. Be able to perform the calculations listed and determine equipment efficiency*	1. Calculations include, but are not limited to: a. Volume of tanks and pits b. Pump output c. Displacement of open and closed pipe

TRAINING TOPICS	LEARNING OBJECTIVE	KEY POINTS / COMMENTS
		d. Annular capacity e. Annular volume f. Hydrostatic pressure g. Fracture pressure (defined by API RP 59) h. Formation pressure i. Conversion from pressure to equivalent fluid density j. Kill mud weight k. Circulation time l. Bottoms up time for normal drilling m. Circulating time, including surface lines n. Surface-to-bit time o. Bit-to-shoe time p. Bottoms up strokes q. Surface-to-bit strokes r. Bit-to-shoe strokes s. Total circulating strokes, including surface equipment based on annular pressure drop data t. Pump output (look up chart values) u. Relationship between pump pressure and pump speed v. Relationship between pump pressure and mud density w. Maximum allowable annular surface pressure x. Gas laws y. Weighting material required to increase density per volume z. Volume increase due to increase in density (e.g., barite + water) aa. Volume to be bled off, corresponding to pressure increase (volumetric method) bb. Initial circulating pressure cc. Final circulating pressure dd. Pressure drop per step ee. Choke and kill line volumes ff. Choke and kill line strokes

TRAINING TOPICS	LEARNING OBJECTIVE	KEY POINTS / COMMENTS
		gg. Choke and kill line circulation time hh. Riser volume and fluid required to displace ii. Effect of water depth on formation strength calculation

IV. PROCEDURES

TRAINING TOPICS	LEARNING OBJECTIVE	KEY POINTS / COMMENTS
A. Alarm Limits	*1. Demonstrate the procedures for setting well control monitoring indicators, including, where applicable, the items at right*	1. Items include, but are not limited to: a. High and low pit level b. Return flow sensor c. Trip tank level
B. Pre-Recorded Well Control Information	*1. Identify appropriate pre-recorded information*	1. Pre-recorded information includes: a. Pressure at slow pump rates, read at choke panel b. Well configuration c. Fracture gradient d. Maximum safe casing pressures i. Wellhead rating ii. Casing burst rating iii. Pipe/tubing collapse iv. Subsurface weak zone (optional)
	2. Recognize an error in gauge readings based on discrepancies between readings	2. Focus on gauge where well control operation is being completed: a. Awareness of discrepancies with other gauges b. Drill pipe and casing pressure gauges should preferably be at the same location
C. Flow Checks	*1. Describe the procedure to perform a flow check in the situations listed, and recognize and measure normal versus abnormal flow back*	1. Flow check procedure: a. While drilling (normal versus abnormal flow back) b. Pumps off - Loss of ECD c. While tripping i. Establish well is static before starting trip ii. Use a trip sheet rather than flow check
	2. Explain why an absence of	2. Absence of flow during flow check is not an absolute factor. There is

TRAINING TOPICS	LEARNING OBJECTIVE	KEY POINTS / COMMENTS
	flow (during flow check) is not an absolute indicator that there is no influx and provide examples of when this could occur	no influx due to: a. Small swab volume but still overbalanced (could go underbalanced at some point as gas rises and expands) b. Gas in solution (OBM/SBM) c. Horizontal wells
NOTE: THE FOLLOWING LISTS ARE NOT INTENDED TO PRESCRIBE THE EXACT SEQUENCE OF EVENTS		
D. Shut-In	*1. Upon observing positive flow indicators, shut in the well in a timely and efficient manner to minimize influx. Proceed according to a specific procedure to address the operations listed*	1. Procedures for the following operations: a. While drilling i. Individual responsibilities ii. Pick up (with pump on) iii. Space-out iv. Shut pump off v. Flow check vi. Close-in BOP, open High Closing Ratio valve (HCR) vii. Close choke as applicable viii. Notify supervisor b. While tripping i. Individual responsibilities ii. Isolate flow through drill string (i.e. Full Opening Safety Valve (FOSV), top drive) iii. Close BOP, open HCR iv. Close choke as applicable v. Notify supervisor c. While out of hole i. Individual Responsibilities ii. Close BOP, open HCR iii. Close choke as applicable iv. Notify Supervisor d. While running casing i. Individual responsibilities ii. Isolate flow through casing (i.e. casing running tool assembly valve and top drive valves)

TRAINING TOPICS	LEARNING OBJECTIVE	KEY POINTS / COMMENTS
		iii. Close appropriate BOP, open HCR or divert as appropriate iv. Close choke as applicable v. Notify supervisor e. While cementing i. Individual responsibilities ii. Space out, including consequences of irregular tubular lengths iii. Shut pump off iv. Close BOP, open HCR v. Close choke as applicable vi. Notify supervisor f. During wireline operations i. Individual responsibilities ii. Close BOP with consideration for cutting/closure around wire g. During other rig activities i. Individual responsibilities ii. Use of surface equipment to shut in well iii. Close choke as applicable iv. Notify supervisor
	2. List differences between the Soft versus Hard Shut-in Procedures	*2.* Hard shut-in versus soft shut-in
	3. *For any shut in, verify well closure by demonstrating that the flow paths listed at right are closed*	3. Verification of shut in a. Annulus i. Through BOP ii. At the flow line b. Drillstring i. Pump pressure relief valves/ washpipe ii. Standpipe manifold c. Wellhead/BOP i. Casing valve

TRAINING TOPICS	LEARNING OBJECTIVE	KEY POINTS / COMMENTS
		ii. Broaching to surface (outside of wellbore) d. Choke manifold i. Choke ii. Overboard lines
E. Well Monitoring During Shut-In	*1. Explain or demonstrate recommended procedures to use for well monitoring during shut in*	1. Recordkeeping a. Time of shut in b. Drillpipe and casing pressures i. At initial shut in ii. At regular intervals c. Estimated pit gain
	2. Identify principles of bleeding a volume of fluid from a shut-in well	2. Principles of bleeding volume from a shut in well a. Trapped pressure (See types of pressure: Trapped) i. Pressure increase at surface and downhole from: gas migration ii. Gas expansion
	3. If a float valve is in use (ported, non-ported or plugged), demonstrate the procedure to open the float to obtain shut in drillpipe pressure	3. Determining shut in drillpipe pressure when using a drillpipe float
	4. List two consequences on surface pressure resulting from shutting in on a gas versus a liquid kick of equivalent volume	4. Effects of density differences from gas, oil, or salt water kick on surface pressures
	5. List two situations in which shut-in drillpipe pressures would exceed shut in casing pressures	5. Situations in which shut-in drillpipe pressure exceeds shut-in casing pressures a. Cuttings loading b. Inaccurate gauge readings c. Density of influx fluid greater than drilling fluid

TRAINING TOPICS	LEARNING OBJECTIVE	KEY POINTS / COMMENTS
		d. Flow through drill string e. Blockage Downhole
	6. *Perform choke manipulation to achieve specific pressure or volume objectives*	6. Choke manipulation during simulator training
	7. *List hazards if closed-in annulus pressure exceeds maximum safe pressure and option that can be applied*	7. Maximum safe annulus pressure
	8. *Describe at least one method for controlling bottomhole pressure (BHP) while gas is migrating*	8. Volumetric Method
	9. *Identify two causes of pressure between casing strings*	9. Pressure between casing strings a. Poor Cement job allowing communication b. Casing integrity
	10. *Describe potential hazard(s) of pressure trapped between casing strings and actions required*	10. Potential hazards and action required a. Flow to shallow or lower pressured zones b. Action may include: monitoring, repair
F. Response to Excessive or Total Loss of Circulation	1. *Identify responses to excessive or total loss of circulation.*	1. Actions for loss circulation include: a. During drilling, shut the well in and determine if the well will flow b. Fill annulus with fluid in use (but do not want to pump all fluid away) c. Notify supervisor immediately d. Use of bridging materials (e.g., cement, barite plugs, gunk plugs, loss of circulation materials, etc.) e. Elimination of overbalance

TRAINING TOPICS	LEARNING OBJECTIVE	KEY POINTS / COMMENTS
G. Tripping	*1. Demonstrate, explain, or perform the following actions listed with regard to tripping both in and out of the hole* *2. Identify the use and purpose of a trip sheet* *3. Procedures for keeping the hole full* *4. Means of measurement/recording* *5. Calculations* *6. Measure hole fill-up*	1. Tripping - the well is hydrostatically balanced (no ECD loss considerations) 2. Purpose of trip sheet: it is the primary indicator of influx (hole fill-up) rather than flow check 3. Procedures and line up for keeping hole filled a. Using rig pump b. Using trip tank c. Using re-circulating trip tank (continuous fill) 4. Means of measuring and recording hole fill/displacement volumes a. With check valve in drillstring b. Without check valve in drillstring c. Using Trip Sheet 5. Calculate correct fill volumes a. Wet trip calculations i. Return to mud system ii. No return to mud system b. Dry trip calculations 6. Measure hole fill - up a. Recognize discrepancy from calculated fill-up b. Take appropriate action i. At flow, go to shut-in ii. At no flow and short fill-up, go back to bottom
H. Well Control Drills (Types and Frequency)	*1. Describe the steps involved in conducting the types of drills listed*	1. Drills Include: a. Pit drills b. Trip drills c. Choke drills

TRAINING TOPICS	LEARNING OBJECTIVE	KEY POINTS / COMMENTS
		d. Diverter drills as they relate to shallow gas hazards e. Personnel evacuation
I. Formation Competency	*1. Describe or perform proper hook-up, preparation and procedures for conducting a leak-off test or pressure integrity test for a given configuration* *2. Identify from a plot the point at which leak-off begins* 3. *Describe how formation competency test results may be affected by fluid density change (as well as differential of height of pump to rotary table)*	1. Formation competency tests can be either: a. Pressure integrity test (testing to a specific limit) b. Leak-off test (testing to formation injectivity) 2. Interpret data from formation tests a. Calculate equivalent mud weight based on formation test 3. Calculate the effect of fluid density changes on MAASP based on either a. Leak-off test (at least one method) b. Formation pressure integrity test
J. Stripping Operations	*1. Define stripping and identify the following aspects of stripping:* • *purpose* • *suitability* • *method* *2. Describe stripping procedures listed to the right*	1. Stripping is moving pipe under its own weight <u>Purpose</u>: to get back to bottom (True Vertical Depth (TVD)) to control BHP <u>Suitability and Method</u>: Must take into account equipment, pressures and crew training 2. Stripping procedures including, but are not limited to: a. Line up for bleeding volume to stripping tank b. Stripping procedure through BOP c. Measurement of volume bled from well d. Calculations relating to volumes and pressures to be bled for a given number of drillstring stands run in the hole e. Stripping with/without volumetric control

TRAINING TOPICS	LEARNING OBJECTIVE	KEY POINTS / COMMENTS
	3. *List hazards of pipe light with different diameter pipe at BOP. Perform pipe light calculations for drill pipe and casing*	3. Cross section change between tube and tool joint and corresponding changes in lift force
K. Pipe Movement	1. *Understand reasons for and against pipe movement during well kill operations*	1. Considerations: a. Stuck pipe, maintaining circulation b. Reciprocating versus rotating c. Annular preventer closing pressure d. Equipment design and readiness
L. Shallow Hazards	1. *Define shallow hazards* 2. *Explain why it is relatively easy to become underbalanced at shallow depths* 3. *Explain the well control procedural options available (i.e. divert)* 4. *Explain shallow gas situations*	1. Any formation that has potential to flow that is encountered before a competent shoe is set (no BOP installed). 2. Mechanisms and timing of events, such as: a. Limited reaction time for kick detection b. Hole sweeps c. Gas cutting d. Swabbing – pump out of hole e. Loss of circulation f. Abnormal pressure g. Charged formations h. Artesian Flow i. Abnormally pressured lenses 3. Well Control Procedures a. Use of diverters i. With drillpipe ii. Running casing b. Use of pilot holes 4. Shallow gas situations

TRAINING TOPICS	LEARNING OBJECTIVE	KEY POINTS / COMMENTS
	after cementing while setting conductor and surface casing	a. After cementing b. Risk of annular gas flow while BOPs are removed to set casing slips
	5. Describe the considerations for the ability to dynamically killing a well	5. Mud volume, pump rates, hole size, equipment limitation
	6. Describe the difference between diverting and conventional well kills	6. Diverting versus shutting in the well
	7. List conditions under which the use of a diverter may be applicable	7. Conditions for using diverter a. Shallow hazards: gas or water
	8. List at least two potential hazards when using a diverter	8. Hazards when using diverter a. Wash out b. Equipment failure (i.e. diverter packer failure)

V. GAS CHARACTERISTICS AND BEHAVIOR

TRAINING TOPICS	LEARNING OBJECTIVE	KEY POINTS / COMMENTS
A. Gas Types	*1. Identify type of gas, related hazards and its effects on people, environment and equipment in well control operation*	1. Type, hazard and required well control equipment for: a. Hydrocarbon b. Hydrogen Sulfide (H_2S) c. Carbon Dioxide (CO_2) d. Sulfur Dioxide (SO_2)
B. Density	*1. Recognize and explain the various effects of gas in mud*	1. Gas effects include: a. Low density of gas affects hydrostatic column b. Gas effects on wellbore pressure c. Gas cutting on bottomhole pressure and the use of pit level monitoring to recognize hydrostatic loss d. Conditions where gas cutting may have little affect on hydrostatic head and bottom hole pressure
C. Migration	*1. Explain the consequences of gas migration*	1. Consequences: a. If the well is left shut-in while gas is migrating b. If the well is allowed to remain open with no control c. If bottomhole pressure is controlled
D. Expansion	*1. Explain the relationship between pressure and volume of gas in the wellbore using Boyle's Law (General Gas Law)*	1. Boyle's Law concepts include, but are not limited to: a. Why a gas kick must expand as it is circulated out in order to keep BHP constant b. Consequences of gas moving through the choke from a high pressure area to a low pressure area c. Calculation of gas expansion in wellbore using Boyle's Law, such as pressure and volume
E. Compressibility and Phase Behavior	*1. Identify the effect of pressure and temperature on the gas entering the well* *2. Describe the consequences*	1. Hydrocarbon gas can enter the well in either liquid or gaseous form, depending on its pressure and temperature 2. Consequences based on gas phase include: a. Hydrocarbon gas entering as a liquid may not migrate or expand until it is circulated up the wellbore

TRAINING TOPICS	LEARNING OBJECTIVE	KEY POINTS / COMMENTS
		b. Liquids can move down the annulus and come up the drill string if no or failed float present
F. Solubility in Mud	*1. Identify combinations of gas and liquid that may result in solubility issues*	1. Combinations of gas and liquid in which solubility issues may apply: a. H_2S and water b. CO_2 and water c. H_2S and Oil-based Mud (OBM) d. Methane and OBM e. CO_2 and OBM
	2. Describe the difficulty of detecting kicks with soluble gases while drilling and/or tripping	2. Gases dissolved in mud behave like liquids
	3. Describe how dissolved gas affects wellbore pressures as it approaches surface	3. Rapid pressure and volume changes when gas approaches surface a. Underbalanced considerations b. Uncontrolled expansion of gas leads to accelerated level of underbalance

VI. TYPES OF FLUIDS

TRAINING TOPICS	LEARNING OBJECTIVE	KEY POINTS / COMMENTS
A. Types of Drilling Fluids	*1. Identify types of drilling and completion fluids* *2. Identify factors affecting fluid gradient and therefore bottom hole pressure*	1. Fluid types include, but are not limited to: a. Water-based mud b. Oil-based mud c. Synthetic-based mud (SOBM) d. Compressible fluids (e.g., air, foams, mist) e. Completion brines 2. Fluid gradient affected by: a. Temperature b. Compressibility
B. Fluid Property Effects on Pressure Losses	*1. Explain how fluid properties affect pressure losses*	1. Explain how the following properties affect pressure loss: a. Density b. Viscosity c. Changes in mud properties due to contamination by formation fluids
C. Fluid Density Measuring Techniques	*1. Measure fluid density*	1. Measure fluid density using: a. Mud balance b. Pressurized mud balance
D. Mud Properties Following Weight-up and Dilution	*1. Explain the effects of weighting-up and diluting fluid on gel strength, Plastic Viscosity (PV) and Yield Point (YP)* *2. Describe how fluid density can be unintentionally reduced*	1. Effects on: a. Gel strengths b. PV and YP 2. Reasons include, but are not limited to: a. Barite ejected by centrifuge b. Dilution c. Cement setting up d. Temperature effects on fluids e. Settling of mud weighting materials

VII. CONSTANT BOTTOMHOLE PRESSURE WELL CONTROL METHODS

TRAINING TOPICS	LEARNING OBJECTIVE	KEY POINTS / COMMENTS
A. Constant Bottomhole Pressure Well Control Methods	*1. Identify the constant bottomhole pressure methods*	1. Constant bottomhole pressure methods: a. Circulating i. Driller's Method ii. Wait & Weight Method b. Non-circulating methods i. Volumetric ii. Lube & Bleed Method
	2. Identify primary objectives of well control methods	2. Primary objectives of well control methods: a. Remove kick safely out of the well b. Re-establish primary well control by restoring hydrostatic balance c. Manage surface and downhole pressure to prevent inducing additional influx or underground blow out
B. Principles of Circulating Constant Bottomhole Pressure Methods	*1. Explain how pump and choke manipulation relates to maintaining constant bottomhole pressure*	1. Circulating out a kick by maintaining enough choke back pressure to keep bottomhole pressure equal to or slightly greater than formation pressure
	2. Understand the importance of monitoring drill pipe and annular pressures throughout circulation	2. Reasons include, but are not limited to: a. Maintain pressure trends during well kill b. Identify trends that may lead to complications
	3. *Explain the importance of having the bit on bottom*	3. Bottom of the drillstring must be at the kicking formation (or bottom of the well) to effectively remove the kick and kill the well to resume normal operations
C. Steps for Maintaining Constant Bottomhole Pressure while using the	*1. Demonstrate understanding of the Wait &Weight and Driller's Methods*	1. Details / sequence specific to: a. Driller's Method b. Wait & Weight Method

TRAINING TOPICS	LEARNING OBJECTIVE	KEY POINTS / COMMENTS
Driller's or Wait and Weight Method of Well Control	*2. For at least one constant bottom hole pressure well control method:* • *Demonstrate proficiency on a simulator* • *Read, record and report drill pipe, annulus pressure and prepare kill sheet* • *List the steps of the method* • *Explain how these steps relate to maintaining bottomhole pressure equal to or greater than formation pressure* • *Demonstrate or describe the process of organizing the specific responsibilities of the rig crew during the execution of a well kill operation*	2. Key points to be considered: a. Complete kill sheet & organize the specific responsibilities of the rig crew during a well control/kill operation b. Bring pump up to slow kill rate while opening choke c. Maintain BHP while circulating according to appropriate method d. Increase mud weight in pits to kill weight e. Line up pump to kill mud f. Line up choke manifold and auxiliary well control equipment g. Pump kill weight mud until kill mud completely fills the wellbore h. Circulate until all kicks are removed from well i. Shut off pumps j. Close choke and observe pressure gauges (SIDPP + SICP = 0 psi) k. If hydrostatic balance is restored, open BOPs and check for flow l. Resume operations
D. Well Control Kill Sheets	*1. Correctly fill out a kill sheet for one well control method, determine weight up material required and corresponding volume increase* *2. Describe the consequences of exceeding maximum wellbore pressure at surface and subsurface*	1. Well control calculations a. Drill string and annular volumes b. Fluid density increase required to balance increased formation pressure c. Initial and final circulating pressure as appropriate for method(s) taught 2. Maximum wellbore pressure limitations a. Surface b. Subsurface

TRAINING TOPICS	LEARNING OBJECTIVE	KEY POINTS / COMMENTS
	3. Identify factors affecting selection of kill rate for pump	3. Selection of a kill rate for pump a. Allowing for friction losses b. Barite delivery rate c. Choke operator reaction time d. Pump limitations e. Mud Gas Separator capacity
	4. Describe relationship of gas expansion with respect to volume increase (pit volume)	4. Expansion explained using Boyle's law. Maximum gas volume when gas reaches choke
E. Well Control Procedures for Driller's Method and Wait & Weight Method	*1. Demonstrate bringing pump on and off line and changing pump speed while holding bottomhole pressure constant by using choke*	1. Procedure to bring pump on and off line and change pump speed while holding bottomhole pressure constant using choke a. Use of casing pressure gauge b. Lag time response on drill pipe pressure gauge
	2. Determine correct initial circulating pressures	2. Initial circulation pressure a. Using recorded shut-in drillpipe pressure and reduced circulating pressure b. Without a pre-recorded value for reduced circulating pressure c. Adjustment for difference in observed versus calculated circulating pressure
	3. Operate choke to achieve specific pressure objectives relative to Driller's Method and Wait & Weight Method, and describe why pump pressure must drop as heavier fluid is pumped into a well during a constant bottomhole pressure as heavier fluid is pumped to the bit	3. Choke adjustment during well kill procedure a. Changes in surface pressure as a result of changes in hydrostatic head or circulating rates i. Drop in pump pressure as fluid density increases in drillstring during well control operations ii. Increase in pump pressure with increased pump rate and vice versa b. Pressure response time i. Casing pressure gauge

TRAINING TOPICS	LEARNING OBJECTIVE	KEY POINTS / COMMENTS
		ii. Drillpipe pressure gauge
	4. Given any well control scenario, identify the problem, demonstrate and describe an appropriate response	4. Handling of problems during well control operations a. Surface pressure exceeds MAASP i. Continue to circulate per plan (constant BHP) unless surface pressure limitations (wellhead ratings, casing burst or equip ratings) are being approached b. Pump failure c. Changing pumps d. Plugged or washed out nozzles e. Washout or parting of drillstring f. BOP failure i. Flange failure ii. Weephole leakage iii. Failure to close iv. Failure to seal g. Plugged or washed out choke h. Fluid losses i. Flow problems downstream of choke j. Hydrates k. Malfunction of remote choke system l. Mud/Gas Separator not exceeding pressure limitation m. Problems with surface pressure gauges n. Annulus pack-off

TRAINING TOPICS	LEARNING OBJECTIVE	KEY POINTS / COMMENTS
F. Other Well Control Methods	*1. Demonstrate understanding of other well control/kill methods including volumetric with lubrication and bleeding, bullheading, etc.*	1. Other well control/kill methods include: a. Volumetric i. During drilling ii. During well testing/completion b. Lubrication/bleed c. Bullheading i. During drilling ii. During well testing/completion d. Reverse circulation during well testing/completion
	2. Identify reasons for selecting the specific well control methods	2. Reasons to use each method listed above
	3. List assumptions and limitations of well control methods	3. Assumptions and limitations of methods listed above
	4. Identify reasons for and limitations of off-bottom kills	4. Reasons and limitations include, but are not limited to: a. Unable to get to bottom b. Complexity of using several different mud weights if staging pipe to bottom (versus stripping)

VIII. EQUIPMENT

TRAINING TOPICS	LEARNING OBJECTIVE	KEY POINTS / COMMENTS
A. Well Control Related Instrumentation		
1. Fluid Pit Level Indicator	*1. Identify the purpose of a pit level indicator* *2. Identify types of indicators* *3. Identify issues or limitations of indicators*	1. Purpose: monitor pit levels 2. Indicator types may include: U-Tube type, Float type, Sonic type, etc. 3. Limitations can include: a. Floats can hang up b. Sonic misreadings due to foam c. Lack of line of sight
2. Fluid Return Indicator	*1. Identify the location and purpose of the fluid return indicator (flow rate sensor, flow show)* *2. Identify types, issues or problems of indicator* *3. Understand fluid flow paths in relationship to the sensors location* 4. *Describe the relationship among mud pit volume and flow sensors, and drill floor kick indications*	1. Purpose is to detect variations in flow coming from the well; it is located on the return flow line 2. Indicator types may include Flapper type, Gamma-ray type, Sonar type, etc. 3. Flapper and Sonar types measure flow directly in flow line; Coriolis type diverts some flow away to measure 4. Time delay between sensor reading and indication on rig floor. Affected by pit size and shape, surface pipe volume, flow lines, shakers, solids control equipment
3. Pressure Measuring Equipment and Locations	*1. Identify gauge locations*	1. Locations: a. Standpipe pressure gauge b. Drillpipe pressure gauge c. Pump pressure gauge d. Casing pressure gauge (also referred to as choke

TRAINING TOPICS	LEARNING OBJECTIVE	KEY POINTS / COMMENTS
	2. *List reasons for possible gauge inaccuracies* 3. *Discuss the importance of gauge range and accuracy*	manifold or annular pressure gauge) 2. Possible gauge inaccuracies and error sources for: a. Hydraulic gauges i. Not enough oil ii. Ruptured bladder iii. Not calibrated iv. Location (height) variances b. Electronic gauges 3. Additional pressure gauges suitable for anticipated operating pressures to ensure pressures are accurately monitored and observed
4. Mud Pump/Stroke Counter	1. *Describe the purpose and use of the mud pump/stroke counter*	1. Include stroke rate, flow rate, and displaced volume
5. Mud Balance and Pressurized Mud Balance	1. *Describe the difference between mud balance and pressurized mud balance, potential effects on downhole conditions, and procedure to measure the density of a fluid with the two types*	1. Mud balance and pressurized mud balance
6. Gas Detection Equipment	1. *Describe the following for gas detectors* *a. Purpose* *b. Capabilities* *c. Location of gas detectors*	1. Gas detectors: a. Purpose i. Measures gas levels entrained in mud that could potentially lead to a kick b. Capabilities i. H_2S ii. Flammable/explosive gases c. Location typically: i. Flowline

TRAINING TOPICS	LEARNING OBJECTIVE	KEY POINTS / COMMENTS
		ii. mud pits
7. Drilling instrumentation	*1. Demonstrate the use of drilling instrumentation in relationship to kick indication during the simulation time*	1. Instrumentation to measure: a. Pit volume (number of barrels of fluid in the pit) b. Flow rate c. Rate of penetration (ROP) d. Pressure e. Strokes per minute (SPM) f. Mud weight g. Depth recorder
B. BOP Stack and Wellhead Components		
1. **Diverter Systems**	*1. Identify the purpose and limitations of a Diverter in well control operations* *2. Identify changes in valve positions resulting from opening or closing the diverter*	Reference API, Government Regulations and Company Policy
2. **BOP Components**	*1. Demonstrate basic understanding of the functions and limitations of ram and annular preventers* *2. Given a BOP stack, identify parameters listed*	1. Understanding of: a. Annular preventer b. Ram preventers/elements i. Blind ii. Blind/shear iii. Pipe iv. Variable bore pipe v. Ram elements c. Drilling spool 2. Given a BOP stack, identify: a. Working pressure rating, type and size for the rams and annular

TRAINING TOPICS	LEARNING OBJECTIVE	KEY POINTS / COMMENTS
	     3. *Describe the purpose of drilling spool versus ram bodies key ports*	b. Flow path for normal drilling operations and compare with flow path for well control operations c. Areas exposed to high and low pressure during shut-in and pumping operations 3. Drilling spool provides space between the BOPs for facilitating stripping, hang off, and/or shear operations, allows attachment of choke and kill lines, and lessens the chance of erosion issues Ram bodies: reduces the number of stack connections and stack height
3. Wellhead	1. *Demonstrate basic understanding of functions* 2. *Understand the limitations of wellhead components*	1. Components include: a. Casing hangers b. Casing isolation seals c. Connections and fittings 2. Pressure ratings of wellhead and seals in relation to: a. Bullheading pressures b. Shut-in pressures c. Test pressures
C. Manifolds, Piping and Valves		
1. Standpipe Manifold	1. *Discuss purpose, pressure rating, and test requirements of the standpipe manifold* 2. *Describe flow path option between standpipe and other manifolds*	1. Allows fluid to be directed from the pumps to the kelly or top drive and provides isolation to the drillstring; valves should be pressure tested in the direction from which they will be required to hold pressure. 2. Allows fluid to be pumped directly into the annulus through the kill line and to fill the well during trips through a dedicated fill up line.
2. Drillstring Valves	1. *Describe the purpose, location, operation and limitations of the drill string valves*	1. Valves include: a. FOSVs are full opening and can be used to run wireline tools through. Kelly valves on top drive are also FOSV.

TRAINING TOPICS	LEARNING OBJECTIVE	KEY POINTS / COMMENTS
		Note – kelly cocks do not necessarily have the same inside diameter as the drill string (important to note the operations when balls or darts have to be dropped through the valve). b. Check valves include IBOP and dart sub with dart engaged; do not allow tools to be run through them c. Float valves – ported, non-ported
	2. Describe the difference in use between a full-opening safety valve and an inside blowout preventer (IBOP)	2. FOSV is run open and must be actuated either manually or remotely (key or hydraulic air), while IBOP is always activated. FOSV allows tools to be run through it; the IBOP does not.
	3. Describe the purpose, advantages and disadvantages of ported versus non-ported float valves	3. Ported float allows SIDPP to be read immediately, but can allow flow of gas into drill string; non-ported floats prevent gas entering drill string, but must bump float to obtain SIDPP
	4. Identify compatibility of thread types between the workstring and the valve (e.g. taper string, different connection type of top drive)	4. Valve with correct connection (or required crossover) on rig floor for string currently being handled
3. Choke Line and Kill Lines	*1. Identify the purpose and general requirements for choke and kill lines*	1. Include size, pressure rating, minimum bends, secured, connection type, etc.
4. Choke and Kill Line Valves **a. Manual Gate Valves** **b. Remote Hydraulically Controlled Valve (HCV)** **c. Kill Line Check Valve**	*1. Identify purpose, characteristics and limitations of each valve on both the choke and kill line* *2. Given a BOP stack configuration, identify locations for each valve (operator specific) and*	1. Include the manual gate valves, HCV, spring-assisted closure valves and the kill line check valve 2. Valve location, advantages, disadvantages: a. HCV inside location - prevents build up of cuttings and prevents plugging of choke line

TRAINING TOPICS	LEARNING OBJECTIVE	KEY POINTS / COMMENTS
	advantage/disadvantages location 3. *Demonstrate on simulator the correct alignment of standpipe, choke manifold valves, including downstream valves for: drilling operations, shut-in, well control operations*	b. HCV outside location - If valve needs to be replaced or repaired, the manual valve can be closed c. Check valve - If a check valve is installed on kill line: Can present problems when trying to pump Loss Circulation Material (LCM) or monitoring wellbore pressures through the kill line 3. Part of simulator testing; valve alignment consistent with type of shut-in (hard versus soft)
5. Choke Manifold	1. *Describe the purpose of a straight through/emergency line off the choke manifold* 2. *Describe the purpose of choke manifold*	1. In event of equipment failure or inability to control flow, it directs flow away from the rig 2. Allows for the re-routing of flow (in event of eroded, plugged or malfunctioning parts) without interrupting flow
6. Choke	1. *Define the function of a choke and components of a typical choke system* 2. *Distinguish the function of the choke from that of other valve types* 3. *Describe the differences between manual and hydraulic chokes*	1. Function: either a fixed or variable aperture used to control bottom hole pressure by applying backpressure through controlling the rate of flow from the well 2. Choke can be opened fractionally to allow bleeding fluids at high pressure; it is not designed to hold pressure 3. Includes: a. Hydraulic (remote operated) b. Manual
7. Mud Pressure Relief Valve (Pop-off Valve)	1. *Understand the purpose of pop-off valves*	1. Purpose is to protect the pump and discharge line against extreme pressure; pressure is set according to pump manufacturer's rating for a given liner size

TRAINING TOPICS	LEARNING OBJECTIVE	KEY POINTS / COMMENTS
D. Auxiliary Well Control Equipment		
1. Mud/Gas Separator (MGS)	1. *Identify the two most common types of MGS* 2. *Describe the function, operating principles, flowpaths, and components of mud-gas separators* 3. *Explain and calculate the pressure limitations of MGS* 4. *List possible consequences of overloading the mud gas separator and explain the appropriate corrective actions* 5. *Describe the procedures for handling of gas in return fluids*	1. Includes: Atmospheric and Pressurized (<100 psi) 2. Separates the gas from the mud and vents it a safe distance from the rig; components include, but are not limited to, vent line, liquid leg, impingement plate 3. Calculated mudleg; understand how input variables affect the pressure limitations of the MGS (including vent line friction) 4. Gas cut mud back at the shakers, gas blow through, vessel rupture a. Reduce pump rate 5. Options including a mud gas separator, the degasser and a bypass line to a flare stack
2. Mud Pits	1. *Describe pit alignment during well control operations* 2. *Distinguish the pit capacity from the usable volume*	1. Include : a. Suction pit b. Return pit c. Mixing equipment *2.* Usable volume is less than pit capacity due to pit geometry, internal piping, height of suction line and fill/solids in tank
3. Degasser	1. *Describe different types, the function and operating principles of degasser*	1. Degasser removes entrained gas bubbles in the drilling fluid that are too small to be removed by the MGS, using some degree of vacuum to assist with entrained gas. Two

TRAINING TOPICS	LEARNING OBJECTIVE	KEY POINTS / COMMENTS
		common types are: a. Horizontal vacuum degasser b. Centrifugal
4. Trip Tank	*1. Describe the characteristics of a trip tank* *2. Distinguish between a gravity feed and re-circulation type*	1. Low volume, small cross-section, accurate fluid volume measurements and ability to isolate from main system 2. Include the following: a. Gravity feed b. Re-circulation type
5. Top Drive Systems	*1. Describe well control considerations when using top drive systems, including kelly valves (lower), spacing out, shutting in and stripping*	1. Crossover may be required to install an inside BOP on top of the manual valve; may limit ability to strip into the well
E. BOP Closing Unit – Function and Performance		
1. Components and Functions of the BOP Control/Accumulator System	*1. Using a diagram of a surface control unit, identify major components and their functions*	1. Major components include, but are not limited to: a. Fluid storage b. Regulator c. Unit/remote switch d. By-pass valve e. Accumulator isolator valve f. Remote panel
2. Accumulator Pressure	*1. Given a 3000 psi system, state the standard operating pressures*	1. Standard operating pressure includes, but is not limited to: a. Pre-charge pressure b. Minimum system pressure c. Operating pressure d. Maximum system pressure e. Regulated annular and manifold pressures
3. Adjustment of Operating Pressure	*1. Identify the purpose of opening the high pressure bypass valve*	1. Include effects on: a. Manifold pressure

TRAINING TOPICS	LEARNING OBJECTIVE	KEY POINTS / COMMENTS
		b. Annular pressure
	2. *Identify reasons for adjusting regulated annular operating pressure*	2. Reasons: a. Stripping operation b. Improve annular seal (leak) c. Rotating d. Reciprocation
4. Usable Fluid Volume	1. *Given a stack design, calculate usable fluid requirements* 2. *Identify the consequences on usable fluid due to a reduction in pre-charge pressure*	1. Reference API, Government Regulations and Company Policy 2. Usable fluid volume is increased and closing pressure will decrease
5. Accumulator	1. *Identify the purpose of an accumulator volume test* 2. *Identify components and uses of an accumulator unit*	1. Reference API, Government Regulations and Company Policy; mention importance of using same sequence each test so you can see discrepancies 2. Include how it works, charges, 4-way valves, subsea
F. Function Tests		
1. Procedures for Function Testing all Well Control Equipment	1. *Identify components that require function testing* 2. *Identify the purpose of a function test (verification that the component is working as intended)*	1. Well control equipment a. BOP stack b. Accumulator control system c. Diverter d. Auxiliary high and low pressure well control equipment (as per Section VIII: C and D) 2. Testing practices include: a. Frequency of tests b. Alternate functions at remote/main stations c. Actuation times recorded

TRAINING TOPICS	LEARNING OBJECTIVE	KEY POINTS / COMMENTS
	3. *Identify documentation required (e.g. IADC Daily Drilling Report)*	3. Reference API, Government Regulations and Company Policy
G. Pressure Tests		
1. Procedures for Pressure Testing Well Control Equipment	1. *Identify reasons for testing equipment* 2. *Identify all components that need to be tested* 3. *Describe pressure testing procedures for well control equipment components* 4. *Identify documentation required* 5. *Demonstrate awareness of the maximum safe working pressure (not necessarily test pressure) for a given set of well control equipment upstream and downstream of the choke*	1. Include, but not limited to, ensuring integrity & functionality 2. Well control equipment: a. BOP stack b. Standpipe manifolds c. Upper/lower kelly valves, Full Opening Safety Valve (FOSV), IBOP, and kelly. d. Diverter systems e. Choke manifolds f. Choke/Kill (C/K) lines 3. Testing procedure should include: a. Visual inspection b. High/low test pressures c. Holding time d. Period between tests e. Direction of pressure f. Test fluid type 4. Reference API, Government Regulations and Company Policy 5. Well control equipment including: a. BOP stack b. Standpipe manifolds c. Upper/lower kelly valves, FOSV, IBOP, and kelly. d. Diverter systems e. Choke manifolds

TRAINING TOPICS	LEARNING OBJECTIVE	KEY POINTS / COMMENTS
		f. Choke/kill lines g. Company specific guidelines
H. Well Control Equipment Alignment and Stack Configuration		
1. General Equipment Arrangements	*1. Identify the flow path for well control operations*	1. Could be either down the drill pipe or into the annulus through the kill line
	2. Identify areas exposed to high and low pressure during shut-in and pumping operations	2. Include wellbore, BOPs, choke line, etc.
	3. Demonstrate ability to shut in the well in the event of primary equipment failure	3. Primary equipment may include, but is not limited to: a. BOPs b. Choke c. Drillstring d. High pressure pumping system
	4. Demonstrate the correct alignment of standpipe and choke manifold valves, including downstream valves	4. BOP, manifold and valve line-up, and auxiliary equipment a. For drilling operations b. For shut-in c. For well control operations d. For pressure testing
	5. Given a BOP stack configuration, identify shut-in, monitoring, and circulation operations that are possible and those that are not	5. Use simulator to demonstrate

IX. ORGANIZING A WELL CONTROL OPERATION

TRAINING TOPICS	LEARNING OBJECTIVE	KEY POINTS / COMMENTS
A. Government, Industry and Company Rules, Orders and Policies	*1. Identify the key sources of information governing well control*	1. Key sources of information include, but are not limited to the following: a. API and International Standards Organization (ISO) Recommended Practices b. Standards and bulletins pertaining to well control c. Regional and/or local regulations where required d. Company policies e. Manufacturers' bulletins f. IADC WellCAP Program
B. Bridging Documents	*1. Describe how bridging documents can resolve differences between operator and contractor well control policies*	1. Documents should address: a. Kill methods b. Shut-in procedures c. Shallow gas d. Diverter operations e. HTHP f. BOP stack configuration g. Evacuation h. Emergency Response Plans
C. Personnel Assignments	*1. Identify personnel assignments/job responsibilities of those required to participate in well control operations*	1. For any individual who may be involved in the operations including the rig crew and service companies as required
D. Communications Responsibilities	*1. Describe the lines of communication and the roles of personnel, including the importance of pre-job, on-site planning meetings and tour safety meetings*	1. Communicate job duties associated with routine well control operations

X. SUBSEA WELL CONTROL (REQUIRED FOR SUBSEA ENDORSEMENT)

TRAINING TOPICS	LEARNING OBJECTIVE	KEY POINTS / COMMENTS
A. Subsea Equipment	1. *Identify and describe the function of systems and equipment*	1. Systems and equipment include, but are not limited to: a. Marine Riser Systems b. BOP Control systems i. Block position ii. Pilot system iii. Subsea control pods iv. Accumulator unit c. BOP Stack i. Lower marine riser package (LMRP) ii. Configuration iii. Ram Locks d. Ball Joint e. Flex Joint f. Slip Joint g. Riser Dump Valve
	2. *Describe how ram locks operate*	2. Automatic lock versus manually activated
	3. *Describe operating principles of subsea BOP stack control system*	3. Hydraulic versus Multiplex System for controlling subsea accumulator system (MUX)
	4. *Describe methods to ensure the equipment is functioning properly*	4. Volume counter, pressure gauges, Remote Operated Vehicle (ROV)
	5. *Describe how to operate in case of emergency, loss of communication from the surface*	5. Dead man, acoustic systems
	6. *Describe the hydraulic flow to control and operate the*	6. Through pods; pilot versus power fluid

TRAINING TOPICS	LEARNING OBJECTIVE	KEY POINTS / COMMENTS
	equipment	
B. Diverter System	1. *Describe principles of operation of the diverter system on a floating unit* 2. *Describe the diverter system on a floating unit and when it should be used*	1. Principles include: a. Configuration and components b. Diverter line size and location 2. Line-up for diversion a. Valve arrangement and function b. Valve operational sequence c. Limitations of the diverter system
C. Kick Detection Issues	1. *Describe how the items listed at the right affect kick detection* 2. *Describe how to set up the kick detection system and alarm due to vessel motion*	1. Items affecting kick detection include, but are not limited to: a. Vessel motion b. With and without riser c. Water depth (BOP placement) d. Use of a boost line (allows trending of gas units, but also increases dilution) 2. Adjust sensitivity to include heave, roll and pitch; might be harder to detect a kick
D. Procedures	1. *Define or describe the effects of fluids of different densities in the choke and kill lines* 2. *Explain consequences of trapped gas in subsea BOP system* 3. *Describe procedure for removing trapped gas from the BOP stack*	1. Choke and /or kill line friction a. Measurement of choke and/or kill line friction b. Compensating for choke and/or kill line friction i. Static kill line ii. Casing pressure adjustment 2. Removing trapped gas from BOPs a. Use of bleed lines b. U-Tubing of trapped gas 3. Clearing riser a. Gas in riser

TRAINING TOPICS	LEARNING OBJECTIVE	KEY POINTS / COMMENTS
	following a kill operation	b. Displacing riser with kill weight mud
	4. *Describe killing a subsea riser with kill mud and the consequence of failure to fill riser with kill mud after circulating out a kick*	4. Use booster lines to displace original mud with kill weight mud; failure to do so will lead to underbalanced condition
	5. *Describe possible consequences on bottomhole pressure during riser disconnect and reconnect*	5. Riser margin
	6. *Describe steps necessary to space out drill pipe and hang-off using motion compensator, ram locks, etc.*	6. Spacing and hang-off
E. Choke Line Friction	1. *Define choke line friction and describe its effect*	1. Friction pressure created when circulating through choke line; increase in friction pressure could increase BHP
	2. *Demonstrate ability to adjust circulating pressure to compensate for choke friction*	2. Let casing pressure decrease by CLF while bringing pumps up to speed
	3. *Demonstrate ability to determine and identify the choke line friction pressure*	3. Discuss methods to take and compensate for CLF, watching kill line gauge or BOP sensor versus casing gauge
	4. *Demonstrate ability to adjust choke appropriately to compensate for rapid change in hydrostatic pressure due to gas in long choke lines*	4. Test competency in simulator exercises

TRAINING TOPICS	LEARNING OBJECTIVE	KEY POINTS / COMMENTS
F. Hydrates	*1. Identify possible complications caused by hydrates*	1. Discuss locations of hydrates, not limited to: a. BOP stack b. Choke and kill lines c. Wellhead connectors
	2. Describe how to prevent and mitigate the presence of hydrates	2. Including: a. Methanol b. Glycol c. Injection systems d. Temperature e. Drilling fluid type f. Reduced static time g. Pressure drop

XI. SHUT-IN FOR SUBSEA WELLS

TRAINING TOPICS	LEARNING OBJECTIVE	KEY POINTS / COMMENTS
A. Shut-In for Subsea Wells	*1. Demonstrate the ability to shut in the well in a timely manner to minimize influx after observing positive flow indicators*	1. Pre-kick preparation a. Hard shut-in versus soft shut-in b. Annular shut-in versus ram shut-in c. Immediate shut-in versus flow checking before shut-in
	2. For any operation, verify shut-in sequence and flow paths	2. Shutting in: a. While drilling b. While tripping c. While making a connection d. With bit above BOP e. While running casing/liner
	3. *Describe how choke pressure readings are affected in subsea by the high gels of the mud in the choke and kill lines*	3. Masking of choke pressure by high gel strength in C/K lines

XII. SUBSEA WELL KILL CONSIDERATIONS

TRAINING TOPICS	LEARNING OBJECTIVE	KEY POINTS / COMMENTS
A. Constant Bottom Hole Pressure Methods	*1. Demonstrate understanding of the Wait & Weight (WW) and the Driller's Method in a subsea environment* *2. Identify the advantages and disadvantages of these methods in subsea environment (include managing the effect of choke line friction on BHP)*	1. Differences include, but are not limited to: a. Pump start-up procedure b. Gas in choke and/or kill line c. Understanding how max casing pressure is going to be affected when using Driller's or WW 2. Mitigation options such as: a. Compensate for C/K line friction during pump start-up b. Use kill line monitor and/or stack pressure sensors c. Use both kill and choke line d. Reduce pump rate e. When kill mud reaches the stack, shut down pumps and close rams below choke and kill lines; displace kill and choke line fluid with kill mud
B. Choke and Kill Lines	*1. Explain how choke and kill lines can affect circulating well kill methods*	1. Discussion topics include, but are not limited to: a. ID effects on CLF b. Taking returns through a single line versus both lines c. Pressure monitoring at well head level d. Kill start up procedure i. static kill line pressure ii. choke line pressure e. Fluid in C/K lines before, during and after kill operation

XIII. SUBSEA WELL CONTROL – SHALLOW FLOW(S) PRIOR TO BOP INSTALLATION

TRAINING TOPICS	LEARNING OBJECTIVE	KEY POINTS / COMMENTS
A. Shallow Flow(s)	*1. Describe mechanisms that can result in shallow flow* *2. Describe types of shallow flow*	1. Types of mechanisms: a. Artesian flow b. Abnormally pressured lenses 2. Types of shallow flow: a. Shallow water flow b. Shallow gas
B. Shallow Flow Detection	*1. Explain how shallow flows can be detected*	1. Shallow flow detection methods and equipment during the following operations a. While drilling i. Decrease pump pressure ii. Increase in strokes iii. ROV b. During tripping c. While running casing d. During/after cementing
C. Shallow Flow Prevention	*1. Describe ways to prevent shallow water and shallow gas flows* *2. Describe methods to mitigate or avoid the shallow flows*	1. Prevention methods include: a. Move location b. Drill overbalanced 2. Methods of mitigation and/or avoidance include but are not limited to: a. Seismic data (bright spots, surface location evaluation) b. Offset well information

TRAINING TOPICS	LEARNING OBJECTIVE	KEY POINTS / COMMENTS
		c. Pilot hole d. Use of logging tool while drilling (MWD/ LWD) e. Well design in relation to shallow flow f. Drilling with weighted mud system g. Considerations around barite supply, tank space, etc.
D. Shallow Flow Well Control Methods	*1. Explain how to implement shallow water kill procedures, shallow gas kill procedures and implementation in different scenarios*	1. Considerations include, but are not limited to: a. ECD – dynamic kill b. Pump kill mud c. Different scenarios include i. During drilling ii. While running casing iii. During/after cementing iv. During tripping d. Describe the contingency plan when shallow flow is out of control (evacuation drills, use of diverters versus riserless)

XIV. SUBSEA WELL CONTROL – KICK PREVENTION AND DETECTION

TRAINING TOPICS	LEARNING OBJECTIVE	KEY POINTS / COMMENTS
A. Kick Prevention & Detection	*1. Explain why subsea kick detection is more difficult*	1. Rig motion related a. Heave, tide and weather effects b. Rig activities
	2. Explain why early kick detection is necessary in subsea operating environments	2. Early kick detection a. Avoid kick in riser b. Minimize kick size in relation to shoe strength with increase in water depth
	3. Describe how various devices/tools are beneficial in detecting kicks or loss of circulation	3. Early kick detection a. Drilling data analysis b. Downhole pressure detection c. Drilling fluid analysis d. Trip, connection, background gas changes e. Mud gas levels
	4. Describe practices to manage operations within the limits of pore and fracture pressures in subsea drilling environments	4. Minimize swab and surge pressure a. Tripping practices, running casing, breaking circulation, managing choke line friction
	5. Describe practices used to identify and manage ballooning versus well kicks	5. Ballooning a. treat first indication as a kick b. establish flowback profile (finger printing) c. any deviation would indicate kick
	6. Understand riser margin in relation to well control	6. Examples of effect on BHP with riser on or off: a. Accidental disconnect b. Planned disconnect (e.g., due to weather)
B. Riser Gas Considerations	*1. Describe the causes of gas in the*	1. Causes of gas in the riser

TRAINING TOPICS	LEARNING OBJECTIVE	KEY POINTS / COMMENTS
	riser	a. Kick gas b. Drill gas c. Trapped BOP gas d. Gas coming out of solution
	2. *Explain the risks and hazards of gas in the riser*	2. Riser unload and collapse, gas at surface
	3. *Describe procedures to minimize gas in riser as result of stack gas*	3. Flush stack gas; options available: a. Use of bleed line b. U-tube c. Circulate under a closed ram preventer
	4. *Explain procedures for handling riser gas*	4. Procedures available: a. Divert overboard b. Divert inboard – discuss safety issues, regulations, volumes, decision points, MGS or flowline degasser capacity, etc. c. Riser circulation timing (¼, ½, ¾ riser bottoms up (BU) time, etc.) d. Use of boost line

XV. SUBSEA WELL CONTROL – BOP ARRANGEMENTS

TRAINING TOPICS	LEARNING OBJECTIVE	KEY POINTS / COMMENTS
A. Subsea BOP Stack and Riser	*1. Describe the purpose/function of BOP arrangements and elements in a subsea stack*	1. BOP Arrangements a. LMRP b. Annular c. Blinds/Shears d. Fixed rams versus Variable Bore Ram (VBR) e. Casing Rams f. Test Rams g. Connectors
	2. Describe placement of outlets in a subsea stack	2. Placement of outlets a. C/K lines b. Boost line c. Bleed line
	3. Describe essential hang-off and shearing requirements and limitations for BOP rams	3. Hang-off and shearing a. Reasons i. Well control ii. Weather iii. Drive off/drift off iv. Mooring failure b. Hang off limitations i. Fixed versus VBR c. Shearing capability i. Pipe size versus shearing pressure and capability ii. Positioning of tubulars iii. Non-shearables
	4. *Describe BOP instrumentation for subsea*	4. BOP instrumentation arrangements a. Temperature and pressure readouts b. Purpose

TRAINING TOPICS	LEARNING OBJECTIVE	KEY POINTS / COMMENTS
	5. *Identify riser components and limitations*	i. Pump start up ii. Leak off testing iii. Monitoring pressures during well control operation iv. Monitoring hydrostatic in riser 5. Riser components/limitations include, but are not limited to: a. Slip joint b. Collapse c. Riser angle d. Fill-up/dump valves
B. Choke Manifold System	1. *Explain and demonstrate the alignment of choke/kill manifold in preparation of well control procedures*	1. Line up for: a. Hard versus soft shut-in b. Use of C/K lines in kill operations i. Choke ii. Choke and kill c. Determining CLF pressure d. Trip tank/MGS tie-in (lube and bleed, volumetric)
C. Subsea Control Systems	1. *Explain basic principles, functions and differences of direct hydraulic control system and multiplex control system*	1. Basic principles, functions and differences include, but are not limited to: a. Hydraulic circuit i. Hose (Hydraulic) versus hardline (MUX) ii. Hose reel iii. Accumulator • Surface and subsea bottles • Useable fluid iv. Remote panel v. Pods (yellow, blue) and pod selector vi. SPM valves vii. Solenoids valves (hydraulic versus MUX)

TRAINING TOPICS	LEARNING OBJECTIVE	KEY POINTS / COMMENTS
		viii. Power fluid ix. Pilot fluid (hydraulic versus MUX) x. Shuttle valves b. Functionality i. What happens when you put it in open, closed and block position • Readback pressures • Flowmeter volumes • Closing/opening rimes • Indicator lights

XVI. SUBSEA WELL CONTROL – DRILLING FLUIDS

TRAINING TOPICS	LEARNING OBJECTIVE	KEY POINTS / COMMENTS
A. Subsea Drilling Fluid Considerations	*1. Identify how the drilling fluid properties are affected in a subsea environment*	1. Subsea specific issues include, but are not limited to: a. Temperature effects (density, rheology) i. Effect on pressure losses in the choke and kill lines b. Gas solubility (Water-based mud (WBM), OBM, SBM)

XVII. SUBSEA WELL EMERGENCY DISCONNECT

TRAINING TOPICS	LEARNING OBJECTIVE	KEY POINTS / COMMENTS
A. Emergency Disconnect Systems	*1. Reasons for an emergency disconnect on a dynamically positioned rig* *2. Describe emergency systems and functionality*	1. Reasons include but not are limited to: a. Drift/drive off b. Uncontrolled blowout c. Vessel position alarms d. Riser evacuation or rig fire 2. General options to close-in well and disconnect a. Emergency disconnect sequence functions b. Autoshear c. Deadman d. Acoustic back-up e. ROV hot stab

XVIII. SPECIAL SITUATIONS (OPTIONAL)

TRAINING TOPICS	LEARNING OBJECTIVE	KEY POINTS / COMMENTS
A. Hydrogen Sulfide (H_2S)	1. *Identify risks associated with H_2S* 2. *Specify crew responsibilities* 3. *Identify well control options, including bullheading and circulation with flaring* 4. *Understand basic knowledge of H_2S effects on equipment*	1. Risks encountered in well control operations involving H_2S a. Toxicity b. Potential for explosion c. Corrosivity d. Solubility 2. Well Limitations: a. Alarm settings b. Equipment settings c. Exposure Limits 3. Well control handling options a. Bullheading b. Circulation with flaring c. Consider H_2S scavengers in mud 4. Verify if equipment is qualified for H_2S service
B. Directional (including Horizontal) Well Control Considerations	1. *Explain the following considerations related to directional (horizontal) well control:* *a. Kill sheet modifications* *b. Kick detection* *c. Procedure for off bottom kill* *d. Gas in horizontal section* *e. Pump start up procedure* *f. Stripping*	1. Directional and horizontal well control considerations include: a. Killsheet pressure modifications: b. Kick off points c. Horizontal sections and S, J-shaped wells d. Drill pipe schedule for pumped KWM e. Impact on shut-in pressures f. Adjusted volumes and final circulating pressures for off bottom kills g. Awareness of residual gas in wellbore h. Awareness of gas entering vertical section during pump start up, causing improper ICP

TRAINING TOPICS	LEARNING OBJECTIVE	KEY POINTS / COMMENTS
		i. Stripping could be used to place the bit at end of build prior to start of kill operation of the vertical leg
C. Underground Blowouts	*1. Demonstrate how to recognize loss of formation integrity* *2. Explain problems and procedural responses for combination thief and kick zone*	1. Indications of underground blowouts a. At shut-in b. During kill 2. Communication between two more zones a. Thief zone on top, kick zone on bottom b. Kick zone on top, thief zone on bottom
D. Slim-Hole Well Control Considerations	1. *Explain well control concerns due to a narrow annulus* 2. *Identify other operations that involves slim hole considerations*	1. Concerns include but are not limited to: a. Ability to detect kick quickly b. High ECD – kicks more likely during connections c. Once shut-in, annular pressure higher than normal hole; similar volume of gas creates higher column of gas, less hydrostatic & higher surface and shoe pressures d. Pack off 2. Casing drilling, High Temperature High Pressure (HTHP)
E. High Pressure High Temperature Considerations (Deep Wells with High Pressure and High Temperature)	*1. Explain the effects on drilling and completion fluids in relation to formation pressure and temperature* *2. Explain the effects on equipment in relation to formation pressure and temperature*	1. Effects a. High temperature reduces hydrostatic of drilling fluids and brines b. Thermal expansion while shut-in 2. Effects a. Failure of elastomers due to excessive pressure for long durations, including in BOPs, valves and hoses b. Rheology and mobility of control fluid
F. Tapered String/Tapered Hole	*1. Explain the change in casing pressure readings caused by the different annular capacities in a*	1. Casing pressure may not follow traditional increasing trends during circulation of gas

TRAINING TOPICS	LEARNING OBJECTIVE	KEY POINTS / COMMENTS
	tapered well 2. *Explain effects of changing internal drill string geometries during Wait and Weight method*	 2. Drill pipe pressure schedule (pressure drop per stroke) will vary for each change in drill string inside diameter
G. Shut-In and Circulating Kick Tolerance (KT)	1. *Explain the limitation of maximum pressure and volume of a kick to safely shut-in and circulate kick to surface*	1. Components of KT: a. Kick intensity b. Kick volume *c.* Shoe pressure/MAASP

XIX. Acronyms used in This WellCAP Curriculum

A		**G**		**M**	
API	American Petroleum Institute			**MAASP**	Maximum Allowable Annular Surface Pressure
				MGS	Mud Gas Separator
				MUX	Multiplex “System (for controlling subsea accumulator system)
				MWD	Measurement While Drilling
B		**H**		**N**	
bbl	Barrel	**H_2S**	Hydrogen Sulfide		
BHA	Bottom Hole Assembly	**HCR**	High Closing Ratio Valve		
BHP	Bottom Hole Pressure	**HCV**	Hydraulically Controlled Valve		
BOP	Blow Out Preventer	**HTHP**	High Temperature High Pressure		
BU	Bottoms Up				
C		**I**		**O**	
C/K	Choke/Kill	**IBOP**	Inside Blow Out Preventer	**OBM**	Oil-based Mud
CLF	Choke Line Friction	**ICP**	Initial Circulating Pressure		
CO_2	Carbon Dioxide	**ISO**	International Standards Organization		
D		**J**		**P**	
DP	Drill Pipe			**P**	Pressure
				psi	Pounds per Square Inch
				PWD	Pressure While Drilling
				PV	Plastic Viscosity
				PVT	Pit Volume Totalizer
E		**K**		**Q**	
ECD	Equivalent Circulating Density	**KT**	Kick Tolerance		
		KWM	Kill Weight Mud		
F		**L**		**R**	
FCP	Final Circulating Pressure	**LCM**	Loss Circulation Material	**ROP**	Rate of Penetration
FOSV	Full Opening Safety Valve	**LMRP**	Lower Marine Riser Package	**ROV**	Remote Operated Vehicle
		LWD	Logging While Drilling	**RP**	Recommended Practice

S		**V**		**Y**	
SBM **SICP** **SIDPP** **SO_2** **SPM**	Synthetic-based Mud Shut-In Casing Pressure Shut-in Drill Pipe Pressure Sulfur Dioxide Strokes per Minute	**V** **VBR**	Volume Variable Bore RAM	**YP**	Yield Point
T		**W**		**Z**	
TVD	True Vertical Depth	**WBM** **WW**	Water Based Mud Wait & Weight		
U		**X**			