Well Control for Drilling Operations Personnel

Core Curriculum and
Related Learning Objectives

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Contents

1.0 Driller Course Overview 3
2.0 Curriculum 6
2.1 Drilling, Workover, & Completion Plan - Awareness 6
2.2 Well Control Concepts 6
2.3 Mud & Pit Management 13
2.4 Pre-Recorded Data 15
2.5 Causes of Kicks 17
2.6 Barriers 20
2.7 Shallow Gas, Water Flows, & Tophole Drilling 21
2.8 Abnormal Pressure Warning Signs 22
2.9 Well Control Drills 23
2.10 Kick Detection 25
2.11 Shut-In Procedures & Verification 27
2.12 Post Shut-In Monitoring & Activities 29
2.13 Well Control Methods 30
2.14 Casing & Cementing Considerations 32
2.15 Risk Management 33
2.16 Equipment 34
2.17 Extract of Subsea Elements 38

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1.0 Driller Course Overview

The purpose of the Driller course core curriculum is to define the well control body of knowledge and set of job skills needed by Drillers during drilling operations.

This curriculum incorporates both surface and subsea topics. Core Training Modules, Sub-Modules, Learning Topics, and Learning Objectives and Assessments Guidelines in this curriculum are relevant to both surface and subsea operations and are identified by **BLACK** font in this document. Subsea-specific information (for subsea operations only) is provided in **BLUE** font in this document.

This curriculum can be used to design and teach the following courses:

- SURFACE STACK ONLY DRILLER COURSE – A training provider who delivers a 'Surface Stack Only' course will teach surface well control concepts for those core Training Modules, Sub-Modules, Learning Topics, and Learning Objectives and Assessments Guidelines identified by **BLACK** font. All course content and exercises should have surface stack applications only (*for example, the BOP equipment module will only be taught on surface BOP equipment; subsea applications would not be taught)*. The Driller surface stack only knowledge and skill assessments will be administered. A 'Surface Stack Only' Certificate of Completion will be issued to the trainee upon successfully completing the assessments. Course length is the minimum course length indicated below. **Trainees seeking certification for combination stack may be combined in this course provided the following alternate delivery is followed.**

  Alternate Delivery: A training provider may deliver above surface stack only course and follow that delivery with an add-on subsea stack module. This permits the training provider to combine trainees who are seeking surface stack certification with trainees seeking the combination stack certification. The training provider would deliver surface stack course following all requirements as stated above for the surface stack course. All trainees would complete the surface stack knowledge and skills assessments. The Certificate of Completion for surface stack only would be issued to trainees not wanting to continue into the subsea module.

  The training provider would then teach subsea concepts as a separate stand-alone module to the remaining trainees. The module would contain only those curriculum items in **BLUE**. (To assist the training provider in designing the subsea stack only module, all subsea topics have been duplicated into Section 2.17.) A shorter subsea specific knowledge assessment would be performed. Skills assessments will be performed with focus on subsea topics. A 'Combination Surface Stack and Subsea Stack' Certificate of Completion will be issued upon successfully completing both surface stack only course and assessments and the add-on subsea training and assessments. Additional time must be added for the subsea module, as indicated below.

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- SUBSEA STACK ONLY DRILLER COURSE – A training provider who delivers a 'Subsea Stack Only' course will teach subsea well control concepts for all core Learning Topics, Learning Objectives, and Assessments and Learning Objectives identified by **BLACK** font and for all items identified by **BLUE** font. Course content and exercises should have subsea stack applications only (*for example, the BOP equipment module will only be taught on subsea BOP equipment; surface applications would not be taught*). The Driller subsea stack only knowledge and skill assessments will be administered. A 'Subsea Stack Only' Certificate of Completion will be issued to the trainee upon successfully completing the assessments. Additional time must be added to the minimum course length, as indicated below. **Trainees seeking certification for either a surface stack only or a combination stack will not be permitted in this course.**

- COMBINATION SURFACE & SUBSEA STACK DRILLER COURSE – A training provider who delivers a 'Combination Surface and Subsea Stack' course will teach both surface and subsea well control concepts for all curriculum identified by **BLACK** font and by **BLUE** font (*for example, the BOP equipment module will be taught on both surface and subsea BOP equipment*). Course content and exercises should have both surface stack and subsea stack applications. A single, comprehensive knowledge assessment covering content for both stacks will be administered. Skills assessment will focus on subsea stack-only skills. A 'Combination Surface Stack and Subsea Stack' Certificate of Completion will be issued to the trainee upon successfully completing the assessments. Additional training time is required. See below. **Trainees seeking certification for either a surface stack only or a subsea stack only will not be permitted in this course.**

Recommended Attendees: IADC recommends that persons in certain positions or job roles attend the Driller-level course. These positions or job roles are listed in the table below.

Company Type	Positions
Contractor	Assistant driller
	Driller (including intervention and workover drillers)
Service Company	Coiled tubing driller

Acceptable Delivery Methods: Instructor-led training for the initial and repeat delivery of this course is required. Simulator or live well exercises are required as are knowledge and skills assessments.

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Minimum Course Length: Twenty-four (24) classroom hours are required for teaching the core curriculum for either single stack type. An additional five (5) classroom hours must be added to the course length whenever subsea stack-specific topics are added to the core content delivery or delivered as a separate module. Course length includes simulator or live well assessment time, but excludes the knowledge assessment time.

Driller Course Curriculum Notes: The curriculum that follows includes five components: Training Module, Sub-Modules, Learning Topics, AIM, and Learning Objectives and Assessment Guidelines.

AIM: The AIM letters indicate the level of knowledge and skills required at the job level:

A = Awareness of Learning Topic

I = Implements Learning Topic at this job level; needs an increased level of knowledge because they may have to take action of some task related to the topic.

M = Mastery of Learning Topics at this job level; needs a full knowledge because they have to take action, perhaps unsupervised, of some task related to the topic.

Learning Topics**:** This section provides guidance for instructors on what the trainee should learn.

Learning Objectives and Assessment Guidelines**:** This section defines what trainees should be able to do at the conclusion of the training and provides some examples of how to meet the objectives.

Assessment Notes: Questions on the Knowledge Assessment will be graded as a cumulative score. To pass the course, the trainee must earn at least a 70% score. The Simulator or Live Well Skills Assessment will be graded at 70% passing score. Immediate repeating of the Skills Assessment will be permitted.

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2.0 Curriculum

2.1 Drilling, Workover, & Completion Plan - Awareness

Module Name: 2.1 Drilling, Workover, & Completion Plan - Awareness			
Sub-Modules	**AIM**	**Learning Topics**	**Learning Objectives and Assessment Guidelines**
		The instructor will impart knowledge on:	**The attendee will be able to:**
Well Work Objectives	A	Key elements of the drilling, workover, and completion program that are important to ensure control and containment of formation fluids at all times during rig operations.	List key elements of the well program that the Driller applies to help prevent kicks.
Fracture Gradients, Kick Tolerance, and Pore Pressures	A	Importance of knowing the fracture pressures, kick tolerance, and pore pressures in the well.	Explain why it is important to know fracture pressures, kick tolerance, and formation fluid pressures (pore pressures) when drilling and cementing.
Casing and Cementing Program	A	How casing and cementing are used in the drilling of a well and to contain formation fluids.	Describe how casing and cementing are used in a well.
Fluids Program	A	Why a well-designed drilling and fluids program is important to contain formation fluids.	Describe the key functions of a fluids program.
Barrier Management	A	Barrier management.	Define the term “barrier management.”

2.2 Well Control Concepts

Module Name: 2.2 Well Control Concepts			
Sub-Modules	**AIM**	**Learning Topics**	**Learning Objectives and Assessment Guidelines**
		The instructor will impart knowledge on:	**The attendee will be able to:**
Well Control Terminology and Formation Characteristics	I	Basic types and characteristics of sedimentary rock.	Identify common oilfield sedimentary rocks and describe potential flow characteristics (for example, sandstone, carbonates, shale/claystone, and salt; porosity, permeability, formation strength).
	I	Permeability	Explain how permeability can affect well control (for example, kick size; speed of influx; shut-in pressures).

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Module Name: 2.2 Well Control Concepts			
Sub-Modules	**AIM**	**Learning Topics** **The instructor will impart knowledge on:**	**Learning Objectives and Assessment Guidelines** **The attendee will be able to:**
	I	Formation fluid pressure" (pore pressure).	Explain formation fluid pressure (pore pressure).
	I	Types of formation fluids.	List the main formation (pore) fluids (for example, water, oil, hydrocarbon gas, and other gases).
			Explain the density difference between the main formation fluids.
	I	How formation fluids are contained in the formation during drilling operations, and primary well control.	Explain primary well control (hydrostatic pressure).
	I	The term "kick."	Define the term "kick."
			Explain secondary well control. (BOP equipment)
	I	The term "blowout."	Define the term "blowout."
			Explain why blowouts happen (for example, due to failure of secondary control such as the Blow Out Preventer [BOP]; failure of the drillstring BOP; burst casing; "broaching" around the casing).
	I	The terms "balance", "underbalance", and "overbalance" in relation to mud weight and formation fluid pressure.	Distinguish between balance, underbalance, and overbalance.
			Identify the balance condition from a well diagram showing mud weights and formation pressures.
Pressure, Force, Area	I	Relationship between pressure, force, and area.	Calculate the force on an area using given data. (For example, what is the force acting on an area of five square feet if pressure inside a vessel is 50 psi?) Explain the terms "buoyancy," "pipe light," and "pipe heavy."
Hydrostatic Pressure and Gradient	I	Hydrostatic pressure in relation to a well.	Explain the terms "hydrostatic pressure" and "pressure gradient."
			Explain why hydrostatic pressure is important in well control (for example, to maintain pressure to hold back formation fluids; to prevent wellbore collapse; to prevent formation fracture).
		Technique to calculate hydrostatic pressure and gradient.	Calculate hydrostatic pressure using given data (for example, the height and weight of a fluid; the height and pressure gradient of a fluid; given fluid level drop calculate the loss of hydrostatic pressure).

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Module Name: 2.2 Well Control Concepts			
Sub-Modules	**AIM**	**Learning Topics**	**Learning Objectives and Assessment Guidelines**
		The instructor will impart knowledge on:	**The attendee will be able to:**
			Calculate the hydrostatic pressure gradient using given data (for example, the weight of a fluid or the pressure and height of a fluid column).
		Importance of using the correct 'constant' when calculating hydrostatic pressure.	Explain why the "constant" in a hydrostatic formula is important (for example, using different constants for different units of measurement).
Principle of U-Tube	I	Principle of a u-tube.	Explain the principle of a u-tube.
		How a u-tube works in a well.	Explain what happens if a certain weight of fluid is pumped into the well (u-tube) and how this can affect hydrostatic pressure and pump pressure (for example, the effect on the mud level in the two legs of the u-tube; the effect of surface pressures if the end of the u-tube is sealed by the BOP or a valve, and effect on bottomhole pressure [BHP]).
		Effect on the u-tube when a heavy weight slug is pumped before tripping.	Explain how pumping a heavy weight slug affects the mud level, mud returns, and BHP.
			Calculate the mud returns after a heavy weight slug is displaced into the drillstring before tripping (for example, how much mud should return back at surface using given weight and volume of slug data).
		How cement circulation affects pumping pressure.	Explain how the circulation and displacement of cement can affect pumping pressure. (For example, does the pumping pressure increase, decrease or stay the same during the various stages of cementing the casing?)
Pump Pressure	I	Friction and pump pressure.	Explain pump pressure.
		How friction in the different sections of the well contributes to the final pump pressure.	Explain how frictional losses around the circulating system contribute to pump pressure (for example, losses in the surface lines, drillstring, bit, and annulus).
		How mud weight, viscosity, flow rate, and hole geometry affect pump pressure.	Explain how mud properties, hole geometry, and flow rate affect the pump pressure, and the effect of pumping a different weight fluid around the well (the u-tube effect).
		Variations in pump pressure due to pump speed and mud weight changes.	Calculate the effect of mud weight and flow rate changes on pump pressure using industry-standard formulae.

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Module Name: 2.2 Well Control Concepts			
Sub-Modules	**AIM**	**Learning Topics**	**Learning Objectives and Assessment Guidelines**
		The instructor will impart knowledge on:	**The attendee will be able to:**
Pressure and Equivalent Mud Weights	I	Equivalent mud weight.	Explain "Equivalent Mud Weight." (For example, if the well is shut in on a kick, the Equivalent Mud Weight (EMW) is defined as total pressure at any point in the well converted to a pound per gallon value. In other words, EMW is what the mud weight inside the well "feels like" when a surface pressure is applied on top of it.).
		Standard formula and conversion factors used to convert a pressure to a pressure gradient and an equivalent mud weight, and back to a pressure.	Calculate the pressure gradient and equivalent mud weight using given well data.
Surge and Swab Pressures	I	The terms "surge and swab pressure."	Explain the terms "surge and swab pressures."
		Factors that affect surge and swab pressures.	Give examples of factors that affect surge and swab pressures (for example, trip speed; pipe/hole clearance; bit shape; Bottomhole Assembly [BHA] design; fluid characteristics; hole conditions).
		Potential problems associated with excessive surge and swab.	Explain the effects of excessive surge and swab pressures on the wellbore and the potential impact on well control/integrity (for example, swabbing formation fluid into the wellbore; surging wellbore fluid into the formation; BHP changes).
		Actions to take to minimize swab and surge as directed by the Supervisor.	Explain how to minimize surge and swab pressures (for example, by reducing the tripping speed according to swab-surge calculations; pumping out of the hole; maintaining good fluid properties; BHA design).
Equivalent Circulating Density and Bottomhole Pressure	I	Bottomhole Pressure (BHP).	Explain the term "bottomhole pressure."
		How BHP differs from hydrostatic pressure.	Distinguish between hydrostatic pressure and BHP (for example, static versus circulating BHP; cuttings loading; shut-in pressure; pipe movement).
		Importance of BHP.	Explain why BHP is so important to well control/integrity. (For example, if it is too low it can cause a kick; if too high it can cause losses.)
		The term "Equivalent Circulating Density" (ECD).	Explain the term "equivalent circulating density."

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Module Name: 2.2 Well Control Concepts			
Sub-Modules	**AIM**	**Learning Topics**	**Learning Objectives and Assessment Guidelines**
		The instructor will impart knowledge on:	**The attendee will be able to:**
		Where ECD comes from.	Explain where ECD comes from (formula not required) (for example, from calculated annular friction losses).
		Operations that affect ECD.	Give examples of how different operations can impact on ECD and the resulting effect on BHP (for example, a reduction when pumps are stopped at connections or flow checks; circulation across the flowline versus circulating through the choke or kill line; pumping out of the hole; circulating cement; pumping high viscosity pills; pumping lost circulation material).
Capacities, Displacements, and Strokes	I	How to calculate the capacities and volumes of fluid inside the drillstring and the annulus (using common formulae and kill sheets).	Calculate the capacities and volumes of fluid inside the drillstring and the annulus using given well data.
		Importance of calculating hole volumes.	Explain why the calculation of hole volume is important in preventing and detecting kicks and in well control (for example, bottoms-up time; connection and trip gas returns; spotting fluids around the well; displacing the hole with lighter or heavier fluid; trip monitoring).
		How to calculate the displacement of common tubulars.	Calculate the displacement of common tubulars using given well data.
		How to convert a volume into pump strokes and time.	Convert volumes into pump strokes and time.

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Module Name: 2.2 Well Control Concepts			
Sub-Modules	**AIM**	**Learning Topics**	**Learning Objectives and Assessment Guidelines**
		The instructor will impart knowledge on:	**The attendee will be able to:**
Formation Stresses and Strength	I	The term "formation strength."	Explain the term "formation strength."
		Why formation strength is important.	Explain why we need to know formation strength (for example, to determine the maximum pressure that can be safely applied to the open hole shoe formation).
		How formation strength can be determined on the rig.	Explain the differences between FIT and LOT; explain how to conduct FIT and LOT
		Key tasks to ensure an accurate FIT/LOT.	Explain the key tasks to carry out to to ensure accurate FIT/LOT measurements (for example, clean the hole, ensure consistent mud weight around the well, calibrate the pressure gauges, and test the surface equipment for leaks).
Maximum Anticipated Surface Pressure	A	Define the term "Maximum Anticipated Surface Pressure" (MASP).	Define the term "maximum anticipated surface pressure."
		How MASP is used in well design.	Explain why MASP is important for well control/integrity (for example, the consequences of exceeding maximum pressure limitations; BOP selection; casing burst selection; wellhead rating; surface manifolds pressure ratings).
Maximum Allowable Annular Surface Pressure and Maximum Allowable Mud Weight	I	The terms "Maximum Allowable Annular Surface Pressure" (MAASP) and "Maximum Allowable (leak- off) Mud Weight."	Explain the terms "MAASP" (Note: also known as Maximum Allowable Casing Pressure (MACP)) and "maximum allowable (leak-off) mud weight."
		Why MAASP and maximum allowable (leak-off) mud weight are important to the Driller.	State the consequences of exceeding MAASP or leak-off mud weight on well control/integrity (for example, lost circulation; a drop in mud level; potential kicks; downtime).
		Calculating MAASP.	Calculate MAASP using given data on formation strength.
		When MAASP must be re-calculated.	Give examples of when MAASP needs to be re-calculated.
Ballooning	I	The term "wellbore ballooning."	Explain the term "wellbore ballooning."
		How to recognize ballooning.	Recognize drilling trends that help the Driller to identify potential ballooning (for example, losses while circulating; gains when the pumps are off).

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Module Name: 2.2 Well Control Concepts			
Sub-Modules	**AIM**	**Learning Topics**	**Learning Objectives and Assessment Guidelines**
		The instructor will impart knowledge on:	**The attendee will be able to:**
		The first action to take if the well is ballooning.	Explain the first action to take if ballooning is suspected (for example, treat it as the first indication of a kick).
		The term "fingerprinting."	Explain the term "fingerprinting."
		Distinguishing ballooning from a kick.	Give examples of data that can be 'fingerprinted' (used to distinguish ballooning from a kick (for example, loss rates versus strokes per minute [SPM]; establishing a flow back profile [flow rate and flow back volumes and times] at the connection).
Gas Behavior	A	How gas affects the hydrostatic pressure.	List the effects of gas on wellbore mud hydrostatic and BHP (for example, it reduces pressure as gas expands; it can cause underbalance, the gas-cut mud at surface effect, and re-circulating gas-cut mud).
		Relationship between pressure and volume of a gas in the wellbore.	Describe the relationship between gas pressure and gas volume (for example, the Boyle's Law concept to explain the pressure/volume relationship with most expansion close to surface).
		Why gas must expand as it is circulated up the wellbore.	Describe why the pressure of gas in the mud must be reduced to allow expansion as it is circulated up-hole (for example, if it is not allowed to expand, the gas pressure will increase wellbore pressures; the danger of allowing it to expand uncontrolled (reduced hydrostatic, well kick, riser unloading]; circulating through the choke to maintain BHP).
		Gas migration.	Define the term "gas migration."
		Consequences of gas migration.	Describe the consequences of gas migration in the wellbore and on related pressure gauges (for example, in a shut-in well; in an open well [pit gain, reduced hydrostatic, well kick, riser unloading]; effect of migration rates on speed of pressure change; the effect of the hole angle changes on migration rate and pressure changes).
		Gas behavior in a water-based mud.	Describe how gas behaves in a water-based mud.
		Gas behavior in an oil-based mud (solubility).	Describe how gas behaves in an oil-based mud.

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Module Name: 2.2 Well Control Concepts			
Sub-Modules	**AIM**	**Learning Topics**	**Learning Objectives and Assessment Guidelines**
		The instructor will impart knowledge on:	**The attendee will be able to:**
		Detecting kicks while drilling and/or tripping when gas is in solution.	Tell why it can be difficult to detect kicks when gas is in solution in the mud (for example, smaller volume increase seen on the surface; flow rate and pit volume totalizer (PVT) equipment are not accurate enough to detect small influxes; little or no expansion takes place until bubble point is reached).
Well Control in High Angle Wells	I	Shut-in pressures.	Interpret shut-in pressures for high angle wells and explain how they impact well kill operations.
		Gas expansion and migration.	Explain the effect of hole angle on gas expansion and migration (for example, a minimal effect in the horizontal section but a significant change as it enters the build section).
		Well-kill calculations.	Explain the effect on BHP if vertical well-kill calculations are used on a high angle well.
Tapered Drillstring	I	Trip monitoring.	Explain how a tapered string will affect fluid displacement.
		Kill procedures.	Give examples of how a tapered string will affect well control calculations (for example, Initial Circulating Pressure (ICP) to Final Circulating Pressure [FCP]).

2.3 Mud & Pit Management

Module Name: 2.3 Mud & Pit Management			
Sub-Modules	**AIM**	**Learning Topics**	**Learning Objectives and Assessment Guidelines**
		The instructor will impart knowledge on:	**The attendee will be able to:**
Functions and Types of Wellbore Fluid	A	Main types of wellbore fluids and additives used for drilling and completing wells.	List the main types of fluids and additives related to well control (for example, water-based and non-aqueous mud, completion fluids, compressible fluids [air, foams, and mist], weighting material, and viscosifiers).
		Key functions of these fluids.	List key mud functions related to well control (for example, regulate hydrostatic pressure, carrying cuttings, and holding Barite in suspension).

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Module Name: 2.3 Mud & Pit Management			
Sub-Modules	**AIM**	**Learning Topics**	**Learning Objectives and Assessment Guidelines**
		The instructor will impart knowledge on:	**The attendee will be able to:**
Fluid Density Measuring Techniques	M	Two different methods to measure fluid density and reason why they are different.	Compare and contrast the use of atmospheric or pressurized mud-balances to measure mud density and the importance of calibration. Recommend a method based on various scenarios.
		Importance of regular mud property measurements in kick prevention.	Explain why key mud properties are checked at the suction pit and shakers at regular time intervals (for example, to recognize mud weight problems early; to maintain appropriate time intervals between measurements; to know who to tell).
Potential Contaminants and their Effects (including Temperature)	A	Main mud contaminants and how they affect hydrostatic pressure.	List the fluid and solids contaminants that can affect well control (for example, formation fluids, cuttings, and surface water/base oil additions).
		How mud temperature can affect mud properties.	Describe the effect of temperature on mud weight and hydrostatic pressure (for example, reduced hydrostatic pressure; gas solubility; the effect of the subsea environment on density and solubility).
		Action(s) to take if contaminated mud is present in the circulating system	List appropriate action(s) to take if mud is contaminated (for example, inform the Supervisor and Mud Engineer, stop drilling and condition the mud; know the effect of volume change when mixing).
Pit Management	M	How to calculate the mud volume per unit of depth of fluid in the mud pit.	Calculate mud pit volume using given data (for example, calculate bbl/ft or the volume in the pit based on the level).
		Situations that can affect accurate measurement of pit levels.	Give examples of rig operations and environmental conditions that can affect the accuracy of pit volume measurements, and verify accuracy of pit volume measurements (for example, crane operations; ballasting; movement; seawater suction).
		Acceptable pit level alarm limits.	Demonstrate how to set up acceptable high and low pit level alarm values.
		How to line up pits and pumps.	Demonstrate how to line-up pits and pumps ready for normal circulation.
		Dangers of adding/transferring fluids to a pit system during active drilling/circulating operations.	Analyze possible well-control problems when adding/transferring mud (for example, being unable to measure gains or losses).
		Action(s) to take in the event of a pit volume discrepancy.	Evaluate possible action(s) to take if there is a pit level discrepancy (for example, stop drilling, flow check, and analyze the pit level records).

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Module Name: 2.3 Mud & Pit Management			
Sub-Modules	**AIM**	**Learning Topics**	**Learning Objectives and Assessment Guidelines**
		The instructor will impart knowledge on:	**The attendee will be able to:**
		Why muds and brines are "agitated."	Explain why drilling and completion fluids are "agitated" in the pits (for example, to prevent settling and/or crystallization).
		Role and responsibilities of drill crew personnel who are working with the pit system.	Explain the roles and responsibilities of the crew monitoring the pits when drilling and during a well kill (for example, on pit measuring devices; communication with the rig floor).
		Role and responsibilities of drill crew personnel during well kill operations.	Explain the crew's roles and responsibilities during a well kill (for example, weighting up mud; monitoring pit levels; switching suction when required; monitoring shakers).

2.4 Pre-Recorded Data

Module Name: 2.4 Pre-Recorded Data			
Sub-Modules	**AIM**	**Learning Topics**	**Learning Objectives and Assessment Guidelines**
		The instructor will impart knowledge on:	**The attendee will be able to:**
Slow Circulating Rates	M	Why Slow Circulating Rates (SCRs) are taken.	Explain why an SCR is taken (for example, to calculate the Initial Circulating Pressure [ICP] or Final Circulating Pressure [FCP]; to detect potential leaks in the system).
		Recommended times to take SCR reading.	Explain when an SCR can be taken (for example, at a selected depth interval; when mud property changes; when hole geometry changes; during every shift).
			Give examples of when taking an SCR can give an inaccurate result (for example, immediately after a trip, extended non-circulating time or when there are different mud weights in the hole).
		Typical flow rate/SPM for an SCR.	Identify the typical flow rates for an SCR (for example, the common rates of 1-4 barrels/minute converted to SPM; how it varies dependent on hole size).

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Module Name: 2.4 Pre-Recorded Data			
Sub-Modules	**AIM**	**Learning Topics**	**Learning Objectives and Assessment Guidelines**
		The instructor will impart knowledge on:	**The attendee will be able to:**
		How to take an SCR.	Explain how to take an SCR (for example, when there are a minimum two pumps and pre-selected rates).
		Gauges commonly used to read SCR.	Identify which gauges are used to record an SCR (the same gauge that is used to kill the well).
Choke and Kill Line Friction	M	Why Choke Line Frictions (CLFs) are taken.	Explain why a CLF is taken (for example, to assist the startup process, or as an indication of expected pressure increase towards the end of the kill operation).
		Reading CLF.	Explain when a CLF can be taken (for example, when the mud property changes).
			Assess when a CLF can give an inaccurate result (for example, immediately after extended non-circulating time; when there is cold mud or gelled mud).
		Typical flow rate/SPM for a CLF.	Explain the typical flow rates for a CLF (for example, the same as the SCRs).
		Two common ways to take a CLF.	Explain how to take a CLF (for example, circulating down the choke or kill line, circulating through the bit and up the choke line).
		Gauges commonly used to read CLF.	Explain which gauges are used to record a CLF (the same gauge that is used to kill the well).
		Effect of taking the CLF on BHP.	Analyze the effect on BHP when using different methods of taking CLF (for example, how a different technique can impose CLF pressure on the wellbore).
Volumes and Strokes	M	How to calculate the volume and stroke data on a kill sheet.	Calculate volume and stroke data on a kill sheet.
Choke and Kill Line Fluid Densities	I	Reason why choke and kill lines may be circulated to a different fluid than in the well.	State why choke and kill lines may be displaced to a different fluid than used in the well (for example, to prevent plugging or blockages due to mud solids).
Kill Sheet	I	How to calculate and update relevant pre-kick data on the kill sheet.	Calculate and update pre-kick data on a kill sheet (for example, volumes, strokes, SCR/CLF, MAASP/MAMW, depths, diameters, and daily recorded values; data to add following shut-in [SIDPP, SICP, and pit gain]).

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2.5 Causes of Kicks

Module Name: 2.5 Causes of Kicks			
Sub-Modules	**AIM**	**Learning Topics**	**Learning Objectives and Assessment Guidelines**
		The instructor will impart knowledge on:	**The attendee will be able to:**
Abnormal Formation Fluid Pressure	I	Abnormal pressure and how it affects primary well control.	Explain the term "abnormal pressure." Explain the effect of abnormally pressured formations on primary well control (for example, a reduction in overbalance/safety margin; a reduced trip margin).
Mud Weight and Contamination by Formation Fluids	M	How hydrostatic pressure can be reduced due to contamination by formation fluids or circulation of cuttings from the well.	Explain how formation fluids (gas, oil, and water) affect mud hydrostatic pressure. Explain how removing cuttings from the hole can affect hydrostatic pressure.
		How to recognize mud weight changes resulting from contamination.	Explain how to recognize mud contamination (for example, through mud weight, viscosity, returns at shakers, and gas levels).
		Role and responsibility of rig crew members in monitoring for contamination.	Differentiate how key rig crew members monitor for mud contamination (for example, the Shakerhand, Derrickhand, and Mud Engineer monitor for return weight, viscosity, pit volume, and mud condition).
		Effects of displacing mud in the hole to a lightweight fluid.	Explain potential well control problems that can occur when displacing wellbore fluids with a lighter fluid downhole (for example, reduced hydrostatic pressure; mud contamination/Barite settling; reduced safety margin/trip margin; reduced hydrostatic pressure when pumping lightweight pills to release differentially stuck pipe).
Improper Mud Weight Control at Surface	M	How hydrostatic pressure can be reduced due to improper mud weight control at the surface.	Explain mud weight reduction due to incorrect actions at the surface (for example, dilution, Barite settling, and excessive use of solids control equipment).
		How to recognize reduced mud weight on surface.	Explain how reduced mud weight can be recognized (for example, regular weight and viscosity checks at the active pit and shakers; the effect on pump pressure when pumping a lighter mud).
		Role and responsibility of rig floor crew members in monitoring for reduced mud weight.	Explain how key rig floor crew members monitor for mud weight reduction (for example, the importance of regular weight and viscosity checks at the active pit and shakers and informing the Driller).

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Module Name: 2.5 Causes of Kicks			
Sub-Modules	**AIM**	**Learning Topics**	**Learning Objectives and Assessment Guidelines**
		The instructor will impart knowledge on:	**The attendee will be able to:**
Loss of Circulation	M	Common causes of lost circulation.	Give examples of the common causes of lost circulation (for example, seepage losses through to total losses during tripping and drilling).
		How loss of circulation can affect the mud volume and hydrostatic pressure in the wellbore.	Explain the effect of losses on the mud pit volume, flow rate, and downhole pressure.
		Driller's actions to a loss of circulation	Explain the action(s) for the Driller to take when lost circulation happens (for example, keep the hole full and monitor volume over time, inform the Supervisor, choose the type of fluid to use to fill the hole, and possible shut-in).
		Role and responsibility of rig crew members in monitoring for losses.	Explain how key rig crew members monitor for mud losses (for example, electronic monitoring and manual monitoring; fluid returns at the shakers; awareness and communication of potential loss zones in the well; slower tripping speeds; ECD effects on losses; awareness of possible ballooning).
Tripping and Improper Hole Fill	M	Change in mud level when tripping.	Explain the effect of tripping in and out of the hole on the mud level in the hole (for example, the level reduces when tripping out; the well overflows on the way in).
			Explain how mud level impacts BHP (for example, the mud level drop reduces the hydrostatic pressure).
		Swabbing.	Explain the term “swabbing.”
		Surging.	Explain the term ““surging.”
		Action(s) to take to minimize swabbing and surging.	Explain action(s) the Driller can take to minimize swabbing and surging (for example, modify trip speed; maintain selected mud weight and viscosity; minimize bit balling; improved BHA design; monitor the trip; communicate between Drillers of tight zones or where cuttings can build up).
		Why trip monitoring is used when tripping in and out of the hole.	Explain why trips are monitored in and out of the hole (for example, to detect swabbing or surging).
			Explain how to monitor a trip (for example, using a trip sheet and trip tank; alternative methods without a trip tank).

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Module Name: 2.5 Causes of Kicks			
Sub-Modules	**AIM**	**Learning Topics**	**Learning Objectives and Assessment Guidelines**
		The instructor will impart knowledge on:	**The attendee will be able to:**
			Explain how pipe displacements in and out of the hole help detect swabbing or surging (for example, mud to replace pipe removed on the trip out; dry trip and wet trip calculations).
		How to analyze if the hole-fill on a trip sheet is normal or abnormal.	Analyze a trip sheet to identify if the hole-fill is normal or abnormal for the operation (for example, look at swabbing or surging and the effect of swabbing on the trip margin).
		Action(s) to take if the hole-fill readings are abnormal.	Explain action(s) to take if the hole-fill is abnormal (for example, flow check, run back to bottom, and circulate bottoms-up).
		How to monitor the trip when pumping out of the hole.	Compare and contrast pulling and pumping out of the hole in trip monitoring (for example, how to monitor for swabbing when pumping out of the hole).
Running/Pulling Liners and Casing	M	Effects of running/pulling casing on BHP.	Explain how running/pulling casing affects BHP (for example, swabbing and surging).
		Why casing should be regularly filled when running in the hole.	Explain why casing should be kept full when running in the hole (for example, to maintain the hydrostatic balance on the u-tube; to prevent casing collapse).
		Precautions to take when running self-fill/automatic casing shoe floats.	Explain the precautions that must be taken when running casing with a self-fill float assembly (for example, check that it is filling; ensure it is 'converted' if applicable).
		How a kick can happen when running/pulling casing due to running/pulling speed (swab/surge) and failure to fill the casing.	Explain why kicks can happen when running casing (for example, surging causes losses which reduces hydrostatic pressure; not keeping casing full that leads to float failure and failure of auto -fill float to keep casing full).
Barrier Failure	M	How barrier failure can cause a kick.	Give examples of how a kick can be caused by the failure of a mechanical barrier (for example, a barrier that is retaining pressure can fail and allow formation fluids to flow up the hole; when displacing the well to a lighter weight fluid, a barrier can fail).

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Module Name: 2.5 Causes of Kicks			
Sub-Modules	**AIM**	**Learning Topics**	**Learning Objectives and Assessment Guidelines**
		The instructor will impart knowledge on:	**The attendee will be able to:**
Riser Disconnect and Riser Gas	M	How riser-disconnect and riser gas can reduce BHP.	Explain how riser-disconnect and riser gas can affect BHP (for example, a reduction due to loss of mud column at disconnect; the principle of riser margin; gas expansion in the riser from drilling operation; gas coming out of solution in non-aqueous muds; the risk to people and equipment; the action to take).

2.6 Barriers

Module Name: 2.6 Barriers			
Sub-Modules	**AIM**	**Learning Topics**	**Learning Objectives and Assessment Guidelines**
		The instructor will impart knowledge on:	**The attendee will be able to:**
Philosophy and Operation of Barrier Systems	I	Barriers and barrier systems.	Explain the term “barrier” and identify types of barriers.
			Define the term “barrier system.”
		Purpose of barriers in drilling and casing operations.	Explain how barriers maintain well integrity in typical drilling operations (for example, the role of mud, cement, casing, BOP, string valves, and packers).
			Explain how barriers maintain well integrity for typical casing and cementing operations (for example, the role of mud; the importance of cement placement; previous casing; and BOP).
		Effect of the subsea BOP on barrier location.	Explain the location of barriers at the sea floor and the effects if breached (for example, gas in the riser; the effect of formation breakdown around the wellhead; the impact of a blowout at the seabed; the option to unlatch or use the Emergency Disconnect System [EDS]).
Number of Barriers for Safe Operation	I	Minimum number of barriers required for safe operations and why.	State the recommended number of barriers for normal operations.
Testing Barriers	I	How common mechanical barriers are tested to verify integrity of the barrier.	Explain the term “positive pressure test.”
			Explain the term “negative pressure test.”

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Module Name: 2.6 Barriers			
Sub-Modules	**AIM**	**Learning Topics**	**Learning Objectives and Assessment Guidelines**
		The instructor will impart knowledge on:	**The attendee will be able to:**
		Recognizing a failed barrier.	Give examples of how a failed barrier can be detected (for example, the flow from the well; BOP leaks using the trip tank; losses to the well; an increase in surface pressure when shut-in; pressure between casing strings; a failed BOP pressure test).

2.7 Shallow Gas, Water Flows, & Tophole Drilling

Module Name: 2.7 Shallow Gas, Water Flows, & Tophole Drilling			
Sub-Modules	**AIM**	**Learning Topics**	**Learning Objectives and Assessment Guidelines**
		The instructor will impart knowledge on:	**The attendee will be able to:**
Definitions and Causes of Pressure in Tophole Formations	I	The term “tophole drilling.”	Define the term “tophole drilling.”
		The terms “shallow gas flow” and “shallow water flow.”	Define the term “shallow gas flow.”
			Define the term “shallow water flow.”
		Causes of abnormal pressure in tophole formations.	List the causes of abnormal pressure in tophole sediments (for example, trapped fluids, weight of overburden, and charged formation).
		How shallow gas and water flows are detected and why there is limited reaction time.	Describe how shallow flows can be detected and related problems with detection (for example, the normal flow route if connected to the rig floor; the use of a Remotely Operated Vehicle [ROV] if riser-less; visual indication at surface near a rig or vessel; pump pressure decrease with increased strokes).
			Explain why reaction time is important with shallow flow (for example, the reduced time due to being close to the surface).
Causes of Underbalance in Tophole	I	Causes of underbalance in tophole drilling.	Explain why underbalance happens in tophole drilling (for example, the mud weight is too low; gas cutting; swabbing; an overloaded annulus; lost circulation; abnormal pressure; artesian flow; reduced hydrostatic pressure while waiting for cement to set).
		Why it is easy to become underbalanced at shallow depths.	Explain why a margin for error can be much smaller in top hole (for example, the small difference between formation fluid pressure and fracture pressure; the margin for error is less).

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Module Name: 2.7 Shallow Gas, Water Flows, & Tophole Drilling			
Sub-Modules	**AIM**	**Learning Topics**	**Learning Objectives and Assessment Guidelines**
		The instructor will impart knowledge on:	**The attendee will be able to:**
Diverting Procedure	M	Diverting procedure.	Evaluate examples of diverting procedures (diverter connected).
		Relevant checks on the diverter control panel.	Demonstrate checks to ensure the control panel will function (for example, confirm the correct valve line-up and sequence; ensure valves returned to normal if the over-ride function is used).
Tophole Drilling/Tripping Practices	M	Tophole drilling/tripping practices that can reduce the risk of a well flow.	Assess whether good drilling and tripping practice is taking place in top hole to prevent kicks (for example, control of mud weight; regular hole sweeps; drill a pilot hole; controlled Rate of Penetration [ROP]; pump out of hole; controlling the risk of swabbing when 'hole opening' small diameter pilot holes).

2.8 Abnormal Pressure Warning Signs

Module Name: 2.8 Abnormal Pressure Warning Signs			
Sub-Modules	**AIM**	**Learning Topics**	**Learning Objectives and Assessment Guidelines**
		The instructor will impart knowledge on:	**The attendee will be able to:**
Abnormal Pressure	I	Warning signs of increasing formation fluid pressure (or a reduction in overbalance).	Interpret the abnormal pressure warning signs (for example, changes in shaker returns; changes to mud data; changes in drilling data trends).
		Possible corrective action(s) the Driller should consider when warning signs are recognized.	Compare and contrast possible corrective action(s) the Driller and crew should consider if warning signs are seen (for example, inform the Supervisor, stop drilling, and consider flow check).
		Role and responsibilities of various rig crew members in monitoring for warning signs.	Explain which crew members can monitor the various warning signs (for example, the Derrickhand, Shakerhand, and Mud Logger).
Shaker Evidence	I	Returns at the shale shaker as potential indicators of a kick.	Interpret trends at the shakers that can help crew members recognize abnormal pressure (for example, volume of mud returns, the visual condition of the mud; cuttings load; cuttings shape; sloughing shale [cavings]; gas-cut mud; mud weight; viscosity).
Changes to Mud Properties	M	Mud properties as potential indicators of changes in pore pressure.	Evaluate trends in mud data that may indicate abnormal pressure (for example, weight; viscosity; gas cutting; background gas increases; trip gas; connection gas; mud chlorides; mud temperature).

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Module Name: 2.8 Abnormal Pressure Warning Signs			
Sub-Modules	**AIM**	**Learning Topics**	**Learning Objectives and Assessment Guidelines**
		The instructor will impart knowledge on:	**The attendee will be able to:**
Changes in Drilling Data/Parameters Trends	M	Drilling parameters as potential indicators of a kick.	Evaluate trends in drilling parameters that can help identify abnormal pressure (for example, ROP changes [drilling break]; torque; drag and pump pressure decrease with or without simultaneous SPM increase).
		Drilling breaks.	Recognize and explain the importance of positive and reverse drilling breaks.

2.9 Well Control Drills

Module Name: 2.9 Well Control Drills			
Sub-Modules	**AIM**	**Learning Topics**	**Learning Objectives and Assessment Guidelines**
		The instructor will impart knowledge on:	**The attendee will be able to:**
Pit Drills	M	Purpose of pit drills.	Explain why pit drills are used.
		Roles and responsibilities of rig crew personnel for a pit drill.	Explain the normal crew roles for a pit drill (for example, what crewmembers normally do during this drill).
		Drill procedures.	Explain the standard procedure for a pit drill.
Trip Drills	M	Purpose of trip drills.	Explain why trip drills are used.
		Roles and responsibilities of rig crew personnel for a trip drill.	Explain the normal crew roles for a trip drill (for example, what crewmembers normally do during this drill).
		Drill procedures.	Explain the standard procedure for a trip drill.
Stripping Drills	M	Purpose of stripping drills.	Explain why stripping drills are used.
		Roles and responsibilities of rig crew personnel for a stripping drill.	Explain the normal crew roles for a stripping drill (for example, what crewmembers normally do during this drill).
		Drill procedures.	Explain the standard procedure for a stripping drill.
Choke Drills	M	Purpose of choke drills.	Explain why choke drills are used.
Diverter Drill	M	Purpose of diverter drills.	Explain why diverter drills are used.
		Roles and responsibilities of rig crew personnel for a diverter drill.	Explain the normal crew roles for a diverter drill (for example, what crewmembers normally do during this drill).
		Drill procedures.	Explain the standard procedure for a diverter drill.

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Module Name: 2.9 Well Control Drills			
Sub-Modules	**AIM**	**Learning Topics** **The instructor will impart knowledge on:**	**Learning Objectives and Assessment Guidelines** **The attendee will be able to:**
Hang-Off Drill	M	Purpose of a hang-off drill.	Explain why a hang-off drill is used.
Early Response and Empowerment to Act	M	Importance of early detection and the consequences of not shutting in on a kick without delay.	Explain why early detection of a kick is important (for example, to minimize kick size, surface annular pressure, and the chance of formation fracture or blowout; for personnel safety; to minimize the potential for broaching around casing, gas releases, fire, pollution, and loss). **The Driller has the authority to shut in without waiting for permission.**
		Why each crew member has the authority to stop work and communicate any possible early indications of well control problems.	Explain why all crewmembers must inform their Supervisor if they see any potential well control issues (for example, this minimizes the chance of a kick and related consequences; increased communication means the more eyes on the problem the better; the consequence of stopping work is insignificant compared to a kick or blowout).

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2.10 Kick Detection

Module Name: 2.10 Kick Detection			
Sub-Modules	**AIM**	**Learning Topics**	**Learning Objectives and Assessment Guidelines**
		The instructor will impart knowledge on:	**The attendee will be able to:**
Well Flow with Pumps Off	M	Flow checks.	Explain the term "flow check."
		Conducting a flow check.	Evaluate when to carry out a flow check and the steps to take (for example, the difference between a tripping and a drilling flow check; the use of the trip tank or not).
		Action(s) to take if a flow check is positive.	Perform follow-up action if the flow check is positive (for example, shut in the well and inform Supervisor).
		Using trip tank as a flow check.	Demonstrate how to carry out a flow check using the trip tank (for example, line-up on the trip tank and monitor flow).
		Conditions on surface that can make it difficult to decide if the well is flowing.	Analyze surface conditions that can make it difficult to identify if the well is flowing (for example, an inoperable flow meter; rig movement; a dumping trip tank).
		Conditions that can make it difficult to detect a kick.	Assess sub-surface conditions that can make it difficult to identify if the well is flowing (for example, low permeability formation; small underbalance; ECD effects; gas solubility; a small volume of swabbed fluid; temperature effects [heating and cooling]).
		Reacting to flow if ballooning is suspected.	Assess the situation to decide on the action(s) to take if ballooning is suspected (for example, at first assume an influx and shut in; make an assessment for ballooning criteria).
Pit Gain	M	Why and when to monitor pit levels are closely monitored at all times.	Explain why it is important to monitor pit levels at all times when the rig is connected to the well (for example, open hole always has a potential to flow; tested barriers may fail).
		How to monitor the well to detect pit level increases.	Demonstrate the set-up of the Pit Volume Totalizer (PVT) monitoring system (for example, the correct line-up and active pits monitored on PVT).
		Acceptable alarm limits for pit levels.	Demonstrate the set-up of the PVT alarm system (for example, the acceptable values for high and low level alarms).
		Operations that can give false increase to pit level indications.	Analyze surface operations that can give false pit level indications of a kick or losses (for example, surface additions of fluid; fluid transfers; ballooning; gas solubility; losses through solids control equipment; leaks).

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Module Name: 2.10 Kick Detection			
Sub-Modules	**AIM**	**Learning Topics** **The instructor will impart knowledge on:**	**Learning Objectives and Assessment Guidelines** **The attendee will be able to:**
		Conditions on surface that can make it difficult to get accurate pit level readings.	Analyze surface conditions that can make it difficult to accurately measure pit level (for example, inoperable pit level sensors; rig movement; incorrect line-up of the circulation system; mixing mud; dumping or transferring fluid/by-pass shakers; tides; the riser not being connected; use of the riser boost line).
		Action(s) to take in the event of an abnormal pit level.	Explain and demonstrate action(s) to take if there is a pit level increase/decrease (for example, flow check, shut-in, and investigate other options such as the pit line-up [only after shut-in]).
		Abnormal trip tank returns when tripping pipe or during wireline operations.	Identify abnormal trip tank readings from a trip sheet.
Flow Return Rate Increase	M	Why flow rates are closely monitored at all times.	Explain why it is important to monitor flow rates at all times when the rig is connected to the well (for example, open hole always has a potential to flow; tested barriers may fail).
		How to monitor the well to detect flow rate increases.	Demonstrate the set-up of the flow rate monitoring system (for example, the correct line-up).
		Acceptable alarm limits for flow rates.	Demonstrate the set-up of the flow rate alarm system (for example, the acceptable values for high and low level alarms set on the flow rate indicator).
		What operations can increase or decrease flow rate that are not related to increased flow or losses in the well.	Assess surface operations for false flow rate indications of a kick or losses (for example, increased SPM; a dumping trip tank; leaks in the surface system).
		Accurate flow rate readings.	Analyze surface conditions that can make it difficult to accurately measure flow rate (for example, an inoperable flow sensor; rig movement; tides; a leaking slip joint; the use of the riser boost line).
		Action(s) to take if there is an abnormal flow reading.	Explain and demonstrate action(s) to take if there is a flow rate increase/decrease (for example, flow check, shut-in, and investigate other options [only after shut-in]).

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2.11 Shut-In Procedures & Verification

Module Name: 2.11 Shut-In Procedures & Verification			
Sub-Modules	**AIM**	**Learning Topics**	**Learning Objectives and Assessment Guidelines**
		The instructor will impart knowledge on:	**The attendee will be able to:**
Drilling	M	How to shut-in the well while drilling.	Demonstrate how to shut-in the well (for example, surface or subsea [including hang-off] the correct line-up for drilling; the hang-off capability of rams).
		Why an immediate shut-in is essential.	Explain why an immediate shut-in is essential (for example, to minimize influx size, minimize SICP, and lower pressures on the wellbore).
		Action(s) to take to verify the well is secure.	Explain and demonstrate the checks following shut-in to ensure the well is secure (for example, ensure there are no leaks at the BOP, string, pumps or manifolds).
Tripping	M	How to shut-in the well while tripping.	Explain or demonstrate how to shut-in the well while tripping (for example, surface or subsea [including hang-off]).
		Why an immediate shut-in is essential.	Explain why immediate shut-in is essential (for example, to minimize influx size, minimize SICP, and lower pressures on the wellbore, pipe light/heavy and stripping).
		Action(s) to take to verify the well is secure.	Explain and demonstrate the checks following shut-in to ensure the well is secure (for example, no leaks at the BOP, string, pumps or manifolds).
Out of Hole	M	How to shut-in with all tubulars out of the hole.	Explain or demonstrate how to shut-in the well.
		Why an immediate shut-in is essential.	Explain why immediate shut-in is essential (for example, to minimize influx size, minimize SICP, and lower pressures on the wellbore, increases remedial options).
		Action(s) to take to verify the well is secure.	List and/or demonstrate the checks following shut-in to ensure the well is secure (for example, no leaks at the BOP, string, pumps or manifolds).
Running Casing and Cementing	M	Procedure for shut-in while running casing.	Explain the shut-in procedure, including isolating flow through casing and BOP closing pressure.
		Procedure for shut-in while cementing casing.	Explain the shut-in procedure, including isolating flow through casing and BOP closing pressure.
		Action to take if non-shearables are across the BOPs.	Explain the action(s) to take if the well kicks with non-shearable tubulars across the BOP.

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Module Name: 2.11 Shut-In Procedures & Verification			
Sub-Modules	**AIM**	**Learning Topics**	**Learning Objectives and Assessment Guidelines**
		The instructor will impart knowledge on:	**The attendee will be able to:**
		Why an immediate shut-in is essential.	Explain why immediate shut is essential (for example, to minimize influx size, minimize SICP, lower pressures on wellbore, and prevent casing collapse).
		Action(s) to take to verify the well is secure.	Demonstrate checks following shut-in to verify the well is secure (for example, ensure there are no leaks at the BOP, the casing BOP/cement head, pumps or manifolds).
Wireline	I	Procedure for shut-in with wireline in the hole.	Explain the shut-in procedure, including consideration for cutting/closure around wire.
		Why an immediate shut-in is essential.	Explain why immediate shut is essential (for example, to minimize influx size, minimize SICP, and lower pressures on the wellbore).
		Action(s) to take to verify the well is secure.	Explain how to verify shut-in.
Shut-in Methods	M	Soft vs. hard shut-in.	Distinguish between the two methods.
Blind & Blind Shear Rams	M	Reasons for using blind/shear rams.	Explain why blind and blind/shear rams are used.
	M	Action to take if non-shearable tubular is across the BOP.	Explain the action to take if the well kicks with non-shearable tubulars across the BOP.
	I	Shear ram capabilities.	Explain why knowledge of shear ram capability versus tubular shear strengths is critical to the development of shut-in procedures and the management of risk.
Diverting	M	Diverting procedure.	Explain the procedure for diverting, including the correct line-up for diverting.
		Relevant checks on the diverter control panel.	Demonstrate the checks to ensure the control panel will function.

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2.12 Post Shut-In Monitoring & Activities

Module Name: 2.12 Post Shut-In Monitoring & Activities			
Sub-Modules	**AIM**	**Learning Topics**	**Learning Objectives and Assessment Guidelines**
		The instructor will impart knowledge on:	**The attendee will be able to:**
Kick Log	I	Reason for recording data following a kick.	Explain why shut-in data is recorded (for example, to show the buildup of pressures over time; to calculate kill data).
		Main data to record following a kick.	Identify main data to record following shut-in (for example, pressures, volumes, and time).
		Gauges used when recording drillpipe and casing pressures.	Record data from chosen gauges (for example, the choke panel gauges; compare with other gauges for variation/calibration). Evaluate the action to take if gauge readings show a discrepancy.
Gas Migration	I	Identify gas migration based on shut-in pressures.	Analyze shut-in data to determine if gas migration is taking place, and communicate with supervisor (for example, shut in drillpipe pressure, shut-in casing pressure).
		Action(s) the Driller must take if gas is migrating.	Explain the action(s) to take if gas is migrating (for example, inform the Supervisor, monitor the pressure buildup and time).
Trapped Pressure	I	Cause(s) of trapped pressure.	Give examples of the possible causes of trapped pressure (for example, improper pump shutdown or startup).
		Effects of trapped pressure on wellbore pressures.	Explain the effect that trapped pressure has on wellbore pressures (for example, an increased pressure in all parts of the wellbore).
		Procedure to reduce trapped pressure.	Explain the procedure to reduce trapped pressure.
Handling Ballooning	I	Bleeding fluid back from the well.	List the potential dangers when bleeding back drilling fluid from a ballooning formation.
Opening (Bumping) the Float Valve	I	Procedure to open the float to obtain Shut-In Drillpipe Pressure (SIDPP).	Demonstrate the procedure to open the float to read the SIDPP.
Line-Up	I	Line-up in preparation for a kill.	Demonstrate the line-up of pits, pumps, and manifolds in preparation for a kill.
		Line-up to monitor riser and potential annular/ram leaks.	Demonstrate the line-up of the trip tank, valves, and manifolds to allow detection of a leaking BOP.

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2.13 Well Control Methods

Module Name: 2.13 Well Control Methods			
Sub-Modules	**AIM**	**Learning Topics**	**Learning Objectives and Assessment Guidelines**
		The instructor will impart knowledge on:	**The attendee will be able to:**
Principles of Constant Bottomhole Pressure Methods	I	Importance of constant Bottomhole Pressure (BHP) in kill operations.	Explain why constant BHP is important in kill operations (for example, it prevents well flows, prevents losses, removes kick, and allows controlled replacement of old mud with kill mud).
Pre-kill Planning Meeting	I	Key roles and responsibilities of the Driller and crew in kill planning and during kill operation.	Explain the key roles and responsibilities of the Driller and crew during well control operations (for example, pit management, pit monitoring, mixing Barite, expected pit gain, handling formation fluids, hydrates, pump control, looking for leaks, correct line-ups, communication with rig floor, operator representative and mud engineer, and reviewing kill sheet data and calculations).
Pump Startup Procedure	I	Importance of pump startup (and shutdown).	Explain why the startup procedure is so important (for example, avoid trapping pressure during startup, prevent going over or under balanced).
		Startup procedure for surface stacks.	Demonstrate the Driller's role in startup (for example, operating pumps, monitoring and recording pressures, communicating with choke operator and determining the ICP).
		Startup procedure for subsea stacks.	Demonstrate the Driller's role in startup (for example, operating pumps, monitoring and recording pressures, communicating with choke operator and determining the ICP).
The Driller's Method	I	Basic principles of the Driller's Method.	Explain the basic principles of the method (for example, bit at bottom, two circulations, remove influx then kill, surface pressure changes, pit level changes; the importance of maintaining the correct SPM, mud weight, and good communication).
The Wait and Weight Method	I	Basic principles of the Wait and Weight Method.	Explain the basic principles of the method (for example, bit at bottom, one circulation, remove influx and kill, surface pressure changes, pit level changes; the importance of following a drillpipe reduction schedule and maintaining the SPM, mud weight, and good communication).

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Module Name: 2.13 Well Control Methods			
Sub-Modules	**AIM**	**Learning Topics** **The instructor will impart knowledge on:**	**Learning Objectives and Assessment Guidelines** **The attendee will be able to:**
Kill Problems	I	Problems during a kill operation.	Identify kill operation problems, inform the Supervisor immediately and act on instructions (for example: pump problems, abnormal increase or decrease in pump pressure, drillstring failure, BOP equipment failures/leaks, mud-gas separator overload, and mud mixing problems or pit management).
Stripping	I	Reasons for stripping.	Explain why stripping is used (for example, as the technique to get back to bottom before killing the well).
		Steps in stripping.	List steps to take in stripping (for example, check pressures and displacements, bleed-off fluid, monitor and adjust BOP operating pressures, monitor trip tank/strip tank volumes, and fill pipe).
		Ensuring well integrity during stripping operations.	Explain considerations to ensure well integrity during stripping (for example, pressure limitations on equipment and wellbore, drillstring integrity, stripping BOP integrity).
Volumetric Method	A	A non-circulating procedure for controlling the BHP.	Identify when to use the Volumetric Method: When unable to circulate, the method to control bottomhole pressure and allow gas influx to migrate without causing any damage to the well.
Lube and Bleed	A	A non-circulating procedure to remove gas from the surface.	Identify when to use the Lube and Bleed method: When unable to circulate, the method to control and remove gas at the surface.
Stack Gas clearing procedure	I	Trapped stack gas.	Explain the term “trapped gas.”
		Problem of stack gas at the subsea BOP.	Explain why having trapped gas below the BOP is a problem (for example, the potential for rapid expansion when the BOP is opened: in deeper water, the severity increases greatly).
		Procedure for safely removing trapped stack gas.	Explain the procedure for removing trapped gas safely (for example, flushing stack and choke/kill lines, u-tubing from the riser up the choke line, and monitoring for riser gas expansion).
Displacing Riser Post Kill	I	Reason for displacing the riser mud to kill mud following a kill.	Explain why old mud is displaced to kill mud in the riser before opening the BOP (for example, to match the kill mud in hole and to prevent a drop in BHP when BOP is opened).
		Procedure for displacing the riser and associated lines.	Describe the procedure to use for displacement.

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2.14 Casing & Cementing Considerations

Module Name: 2.14 Casing & Cementing Considerations			
Sub-Modules	**AIM**	**Learning Topics**	**Learning Objectives and Assessment Guidelines**
		The instructor will impart knowledge on:	**The attendee will be able to:**
Procedures when Running or Pulling Casing	M	Why the running speed is controlled.	Explain why casing-running speed is controlled (for example, keep from surging and swabbing the well).
		Filling casing when running in the hole.	Explain why casing is filled when running in the hole (for example, to maintain the integrity of the float valve due to differential pressure; to minimize the risk of casing collapse; to quickly recognize a kick inside the casing; to prevent underbalance if the float fails).
		Precautions when using a self-filling float.	Explain problems of a self-filling float (for example, it allows formation fluids to flow directly up inside the casing; it allows cement to backflow up inside the casing).
Cement Waiting Time	A	Effect of cement hardening on cement hydrostatic pressure and resulting BHP.	Describe the effect of cement hardening on cement hydrostatic pressure and how that affects well control (for example, it reduces hydrostatic pressure; there is potential for a kick).
Monitor the Well During and After Cementing Operations	I	Importance of maintaining pump-rate and monitoring pit levels during cementing and displacement.	Identify reasons for monitoring flow changes during cementing and displacement operations (for example, to monitor for well flow or lost circulation).
		How a well is monitored during cement waiting time.	Describe the procedure for monitoring the well during the cement waiting time (for example, monitoring flow returns in the trip tank).
Cement Testing Procedure - Positive and Negative	I	Importance of testing after the cement job.	Explain the importance of testing after a cement job (for example, to measure the integrity of the cement in place; the difference between testing cement behind casing strings and testing cement plugs).
		Purpose of a positive test.	Explain the purpose of a positive pressure test (for example, to ensure cement integrity from the above).
		Purpose of a negative test.	Explain the purpose of a negative pressure test (for example, to test the integrity of the barrier in the direction of the formation pressure).

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2.15 Risk Management

Module Name: 2.15 Risk Management			
Sub-Modules	**AIM**	**Learning Topics**	**Learning Objectives and Assessment Guidelines**
		The instructor will impart knowledge on:	**The attendee will be able to:**
Managing Change during a Well Kill	I	How to respond to common problems that can happen during the well kill.	Explain how to react to common problems and, if necessary, mobilize the crew (for example, shut down, realign the manifold line-up, change the choke, change the pump, and correct any mud pit/weight management issues or dynamic positioning problems).
		Handover/ changes to personnel during a well kill operation.	Explain importance of and key components of handover procedures during a well kill operation (for example, there must be clear communications between Drillers, other crew members to ascertain the good and the bad; how handovers between crewmembers must be managed during meal breaks and shift changes; written instructions, and questions).
		Kill log as a tool for troubleshooting unplanned events.	Identify and communicate trends on a kill log (for example, pressures; volumes; mud weights; the choke position; shutdowns/startups).

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2.16 Equipment

Module Name: 2.16 Equipment			
Sub-Modules	**AIM**	**Learning Topics**	**Learning Objectives and Assessment Guidelines**
		The instructor will impart knowledge on:	**The attendee will be able to:**
Diverters	I	Purpose of the diverter.	Explain the purpose of the diverter in well control operations both for surface and subsea.
		How it works.	Explain how the diverter functions (for example, the valve/s open when the diverter is closed).
		General operating parameters.	Explain the general operating parameters (for example, system pressure required to operate the diverter; the equipment pressure rating).
		Potential Diverter failure.	Give examples of where failure can happen during a well control operation (for example, in the packer element and the flowline seals).
Well Control Equipment Alignment and Stack Configuration	M	How to line-up equipment for the chosen operation.	Demonstrate the line-up of the BOP stack and manifolds for operations such as drilling ahead for a chosen shut-in procedure and well kill operations.
BOP Stack, Stack Valves, and Wellhead Components	M	Purpose of key equipment.	Explain the purpose of the key components of equipment on the BOP Stack (for example, the annular, pipe rams, Variable Bore Rams (VBR), blind/shear rams, casing rams, test rams, rubber goods, locking devices, Failsafe or HCR valves, drilling spool, choke and kill line connections, and wellhead connector/casing head).
		Riser equipment.	Explain the purpose of the key items of equipment (for example, the Lower Marine Riser Package [LMRP], riser connector, slip joint, ball joint, flex joint, choke and kill lines, riser dump valve, booster line, and bleed line).
		How the equipment works.	Explain how each of the key components of equipment works.
		General operating parameters.	Explain general operating parameters (for example, pressures to operate at; temperature rating; maximum equipment rating; flow measurement devices; lights; H_2S trim).
		Importance of redundancy in BOP design.	Give examples of where failure can happen in a well control operation and how to recognize failure (for example, stuck in open position; leaking primary packers and seals; leaking flange seal rings).

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Module Name: 2.16 Equipment			
Sub-Modules	**AIM**	**Learning Topics**	**Learning Objectives and Assessment Guidelines**
		The instructor will impart knowledge on:	**The attendee will be able to:**
Manifolds, Piping, and Valves	I	Function of this equipment	Explain the function of this equipment in the well control process.
		Typical operating pressure.	Explain how pressure rating can affect line-ups during the well kill process (for example, standpipe manifold; choke manifold; cement manifold; various pressure ratings; temperature rating; valves upstream and downstream of chokes; flexible hoses; mud pump valves and pressure-relief valve; targeted 'tees'; H_2S trim).
Drillstring Valves	M	Purpose of key equipment.	Explain the purpose of key items of this equipment (for example, Inside BOPs, full opening safety valves [including top-drive/Kelly valves], non-return valves, 'dart' valves, float valves in drillstring, casing, and crossovers).
		How each component works.	Explain how each of the key components of equipment works.
		General operating parameters.	Explain the general operating parameters (for example, the maximum wellbore pressures; temperature rating; H_2S trim).
		Potential failure and remedial actions during shut-in and on-going kill operation.	Give examples of where failures can happen in a well control operation and how to recognize them (for example, stuck in the open position, seals and sealing faces, operator seals, and leak paths to surface).
Instrumentation and Auxiliary Well Control Equipment	M	Purpose of key equipment.	Explain the purpose and location of key well control instrumentation equipment (for example, pit level indicators, flowline indicators, pressure measuring devices, mud pump stroke counter, pressure gauges, Rate of Penetration (ROP) indicator/recorder, correct calibration, daily maintenance, and pressure gauge validity).
Gas Detection Equipment	I	Purpose of this equipment.	Explain the purpose of gas detection equipment in the circulating system (for example, to measure gas levels in mud and air, flowline, pits, cellar, and shakers).
BOP Closing Unit and Control Panels	M	Purpose of this equipment.	Explain the purpose of this equipment in the well control process (for example, to operate the BOP, give feedback on whether the BOP is closed, feedback on operating pressure on the BOP, secondary stations to operate the BOP; control valves must be in the correct position and the accumulator charging pumps set correctly).

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Module Name: 2.16 Equipment			
Sub-Modules	**AIM**	**Learning Topics**	**Learning Objectives and Assessment Guidelines**
		The instructor will impart knowledge on:	**The attendee will be able to:**
		How the unit and control panel work.	Explain how key equipment in this system works (for example; fluid storage and accumulators; the importance of pre-charged, pressure systems, valves and piping to the BOP; regulators; feedback instrumentation such as gauges, flow meters, lights, block position, and bypass valve).
		General operating parameters.	Explain general operating parameters (for example, pressures to operate; how wellbore pressure can affect operating pressures).
		Potential failure and remedial actions during shut-in and on-going kill operation.	Monitor the operation of gauges, flow meter, and lights to check the status of the BOP during and after closing and opening operations (for example, demonstrate an understanding of panel lights and gauges to decide if the BOP has functioned correctly).
Function Tests and Pressure Tests	I	Difference between function and pressure tests.	Describe a function test and a pressure test; explain the differences between the two tests.
		Difference between high- and low-pressure tests.	Describe a high-pressure test and a low-pressure test, and explain the differences between the two tests (for example, typical test values; holding time; test fluid type; test sequence).
		How often tests must be carried out.	Explain how often these tests are to be carried out, what equipment must be tested.
Monitoring Equipment Failures/Erroneous Readings	M	Common failures.	Detect errors in gauge readings based on the discrepancy between gauges (for example, the drillpipe and casing gauges on the standpipe manifold, the choke manifold, and the choke panel; analog versus digital).
Deadman, Autoshear, and Emergency Disconnect System	I	Purpose of this equipment.	Explain the purpose of this equipment in the well control process and its basic working (for example, the basic difference between the systems, reasons for the differences, and the basic sequence of events).
		Action to take in case of an emergency-disconnect.	Explain the action the Driller must take if an emergency-disconnect is required.
Mud-Gas Separator	I	Purpose of this equipment.	Explain the purpose and location of the mud-gas separator in the circulating system.

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Module Name: 2.16 Equipment			
Sub-Modules	**AIM**	**Learning Topics**	**Learning Objectives and Assessment Guidelines**
		The instructor will impart knowledge on:	**The attendee will be able to:**
		General operating parameters.	Explain the general operating parameters (for example, the maximum operating pressure; vent line diameter, u-tube height; potential dangers if overloaded).
Control Chokes (Manual and/or Hydraulic)	I	Purpose of this equipment.	Explain the purpose and location of the control choke/s in the well control system (for example, manual, hydraulic, and fixed).
		General operating parameters.	Explain the general operating parameters (for example, how they operate; the maximum operating pressure; positive seal or leak potential; control of choke operating speed; H_2S trim).
ROV Hot Stab Capability	A	Purpose of this equipment.	State the purpose of this equipment in the well control process.
Riser Gas Handling Equipment	I	Purpose of this equipment.	Explain the purpose of this equipment in the well control process and potential dangers with its use.
Stripping and Tripping Tanks	I	Purpose of this equipment.	Explain the purpose of this equipment in the well control process (for example, to monitor for leaks or for tripping and stripping).
Rules and Regulations	A	Common industry regulation bodies for well control.	Explain the main regulating bodies for the trainee's area of operation.

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2.17 Extract of Subsea Elements

Module Name: 2.17 Extract of Subsea Elements			
Sub-Modules	AIM	Learning Topics	Learning Objectives and Assessment Guidelines
		The instructor will impart knowledge on:	The attendee will be able to:
Well Control Concepts			
Equivalent Circulating Density and Bottomhole Pressure	I	Operations that affect ECD.	Give examples of how different operations can impact on ECD and the resulting effect on BHP (for example, a reduction when pumps are stopped at connections or flow checks; circulation across the flowline versus circulating through the choke or kill line; pumping out of the hole; circulating cement; pumping high viscosity pills; pumping lost circulation material).
Gas Behavior	A	Why a gas kick must expand as it is circulated up the wellbore.	Explain why the pressure of gas in the mud must be reduced to allow expansion as it is circulated up-hole (for example, if it is not allowed to expand the gas pressure will increase wellbore pressures; the danger of allowing it to expand uncontrolled [reduced hydrostatic, well kick, riser unloading]; circulating through the choke to maintain BHP).
	A	Consequences of gas migration.	Explain the consequences of gas migration in the wellbore and on related pressure gauges (for example, in a shut-in well; in an open well [pit gain, reduced hydrostatic, well kick, riser unloading]; effect of migration rates on speed of pressure change; the effect of the hole angle changes on migration rate and pressure changes).

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Module Name: 2.17 Extract of Subsea Elements			
Sub-Modules	**AIM**	**Learning Topics**	**Learning Objectives and Assessment Guidelines**
		The instructor will impart knowledge on:	**The attendee will be able to:**
Barriers			
Philosophy and Operation of Barrier Systems	I	Effect of the subsea BOP on barrier location.	Explain the location of barriers at the sea floor and the effects if breached (for example, gas in the riser; the effect of formation breakdown around the wellhead; the impact of a blowout at the seabed; the option to unlatch or use the Emergency Disconnect System [EDS]).
Mud & Pit Management			
Potential Contaminants and their Effects (including Temperature)	A	How mud temperature can affect mud properties.	Describe the effect of temperature on mud weight and hydrostatic pressure (for example, reduced hydrostatic pressure; gas solubility; the effect of the subsea environment on density and solubility).
Pit Management	M	Situations that can affect accurate measurement of pit levels.	Give examples of rig operations and environmental conditions that can affect the accuracy of pit volume measurements: for example, crane operations; ballasting; movement; seawater suction.
Pre-Recorded Data			
Choke and Kill Line Friction	M	Why Choke Line Frictions (CLFs) are taken.	Explain why a CLF is taken (for example, to assist the startup process, or as an indication of expected pressure increase towards the end of the kill operation).
		Reading CLF.	Explain when a CLF can be taken (for example, when the mud property changes).
			Assess when a CLF can give an inaccurate result (for example, immediately after extended non-circulating time; when there is cold mud or gelled mud).
		Typical flow rate/SPM for a CLF.	Explain the typical flow rates for a CLF (for example, the same as the SCRs).
		Two common ways to take a CLF.	Explain how to take a CLF (for example, circulating down the choke or kill line, circulating through the bit and up the choke line).
		Gauges commonly used to read CLF.	Explain which gauges are used to record a CLF (the same gauge that is used to kill the well).

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Module Name: 2.17 Extract of Subsea Elements			
Sub-Modules	AIM	Learning Topics	Learning Objectives and Assessment Guidelines
		The instructor will impart knowledge on:	The attendee will be able to:
		Effect of taking the CLF on BHP.	Analyze the effect on BHP when using different methods of taking CLF (for example, how a different technique can impose CLF pressure on the wellbore).
Choke and Kill Line Fluid Densities	I	Reason why choke and kill lines may be circulated to a different fluid than in the well.	State why choke and kill lines may be displaced to a different fluid than used in the well (for example, to prevent plugging or blockages due to mud solids).
Kill Sheet	I	How to calculate and update relevant pre-kick data on the kill sheet.	Calculate and update pre-kick data on a kill sheet (for example, volumes, strokes, SCR/CLF, MAASP/MAMW, depths, diameters, and daily recorded values; data to add following shut-in [SIDPP, SICP, and pit gain]).
Causes of Kicks			
Riser Disconnect and Riser Gas	M	How riser-disconnect and riser gas can reduce BHP.	Explain how riser-disconnect and riser gas can affect BHP (for example, a reduction due to loss of mud column at disconnect; the principle of riser margin; gas expansion in the riser from drilling operation; gas coming out of solution in non-aqueous muds; the risk to people and equipment; the action to take).
Shallow Gas, Water Flows, and Tophole Drilling			
Definitions and Causes of Pressure in Tophole Formations	I	How shallow gas and water flows are detected and why there is limited reaction time.	Describe how shallow flows can be detected and related problems with detection (for example, the normal flow route if connected to the rig floor; the use of a Remotely Operated Vehicle [ROV] if riser-less; visual indication at surface near a rig or vessel; pump pressure decrease with increased strokes).
Well Control Drills			
Hang-Off Drill	M	Purpose of a hang-off drill.	Explain why hang-off drills are used.

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Module Name: 2.17 Extract of Subsea Elements			
Sub-Modules	**AIM**	**Learning Topics**	**Learning Objectives and Assessment Guidelines**
		The instructor will impart knowledge on:	**The attendee will be able to:**
Kick Detection			
Pit Gain	M	Conditions on surface that can make it difficult to get accurate pit level readings.	Identify surface conditions that can make it difficult to accurately measure pit level (for example, inoperable pit level sensors; rig movement; incorrect line-up of the circulation system; mixing mud; dumping or transferring fluid/by-pass shakers; tides; the riser not being connected; use of the riser boost line).
Flow Return Rate Increase	M	Conditions on surface that can make it difficult to get accurate flow rate readings.	Give examples of surface conditions that can make it difficult to accurately measure flow rate (for example, an inoperable flow sensor; rig movement; tides; a leaking slip joint; the use of the riser boost line).
Shut-In Procedures & Verification			
Drilling	M	How to shut-in the well while drilling.	Demonstrate how to shut-in the well (for example, surface or subsea [including hang-off] the correct line-up for drilling; the hang-off capability of rams).
Tripping	M	How to shut-in the well while tripping.	Explain or demonstrate how to shut-in the well while tripping (for example, surface or subsea [including hang-off]).
Diverting	M	Diverting procedure.	Explain the procedure for diverting, including the correct line-up for diverting.
Well Control Methods			
Pump Startup Procedure	I	Startup procedure for subsea stacks.	Demonstrate the Driller's role in startup (for example, operating pumps, monitoring and recording pressures, communicating with choke operator and determining the ICP).
Stack Gas Clearing Procedure	I	Trapped stack gas.	Explain the term “trapped gas.”
		Problem of stack gas at the subsea BOP.	Explain why having trapped gas below the BOP is a problem (for example, the potential for rapid expansion when the BOP is opened: in deeper water, the severity increases greatly).
		Procedure for safely removing trapped stack gas.	Explain the procedure for removing trapped gas safely (for example, flushing stack and choke/kill lines, u-tubing from the riser up the choke line, and monitoring for riser gas expansion).

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Sub-Modules	**AIM**	**Learning Topics**	**Learning Objectives and Assessment Guidelines**
		The instructor will impart knowledge on:	**The attendee will be able to:**
Displacing Riser Post Kill	I	Reason for displacing the riser mud to kill mud following a kill.	Explain why old mud is displaced to kill mud in the riser before opening the BOP (for example, to match the kill mud in hole and to prevent a drop in BHP when BOP is opened).
		Procedure for displacing the riser and associated lines.	Describe the procedure to use for displacement.
Risk Management			
Managing Change During a Well Kill	I	How to respond to common problems that can happen during the well kill.	Explain how to react to common problems and, if necessary, mobilize the crew (for example, shut down, realign the manifold line-up, change the choke, change the pump, and correct any mud pit/weight management issues or dynamic positioning problems).
Equipment			
Diverter	I	Purpose of the diverter.	Explain the purpose of the diverter in well control operations both for surface and subsea.
BOP Stack, Stack Valves, and Wellhead Components	M	Purpose of key equipment.	Explain the purpose of the key items of equipment on the BOP Stack (for example, the annular, pipe rams, Variable Bore Rams [VBRs], blind/shear rams, casing rams, test rams, rubber goods, locking devices, Failsafe or HCR valves, drilling spool, choke and kill line connections, and wellhead connector/casing head).
		Riser equipment.	Explain the purpose of the key items of equipment (for example, the Lower Marine Riser Package [LMRP], riser connector, slip joint, ball joint, flex joint, choke and kill lines, riser dump valve, booster line, and bleed line).
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		Action to take in case of an emergency-disconnect.	Explain the action the Driller must take if an emergency-disconnect is required.
ROV Hot Stab Capability	A	Purpose of this equipment.	State the purpose of this equipment in the well control process.

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Module Name: 2.17 Extract of Subsea Elements			
Sub-Modules	**AIM**	**Learning Topics**	**Learning Objectives and Assessment Guidelines**
		The instructor will impart knowledge on:	**The attendee will be able to:**
Riser Gas Handling Equipment	I	Purpose of this equipment.	Explain the purpose of this equipment in the well control process and potential dangers with its use.

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