WellCAP®
IADC WELL CONTROL ACCREDITATION PROGRAM

WELL SERVICING OPERATIONS – SNUBBING
CORE CURRICULUM AND RELATED JOB SKILLS
FORM WCT-2SS

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 well servicing operations. The curriculum is divided into three certification types: Coiled Tubing, Snubbing, and Wireline (Wireline is presented in document WCT – 2WSW) and within each certification, three levels: Introductory, Fundamental, and Supervisory. Students may complete an individual certification (e.g., Coiled Tubing) or combination certifications (e.g., Coiled Tubing and Snubbing). All knowledge and skills for each individual certification must be addressed when combining certifications.

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

INTRODUCTORY: New Hires (May also be appropriate for non-technical personnel)

FUNDAMENTAL: Helpers, Assistants, “Hands” involved with the operational aspects of the unit and who may act/operate the unit under direct supervision of a certified Unit Operator or Supervisor.

SUPERVISORY: Unit Operators, Supervisors, Superintendents, and Project Foreman

Upon completion of a well control training course based on curriculum guidelines, the student should be able to perform the job skills in italics identified by a "■" mark (e.g., ■ *Identify causes of kicks*).

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I. REASONS FOR WELL SNUBBING OPERATIONS

TRAINING TOPICS	*JOB SKILLS*
A. Definitions of well-servicing operations	■ *Describe well-servicing operations.*
B. Definition of snubbing operations	■ *Describe snubbing operations.*
C. Reasons for snubbing operations which may include:	■ *Identify reasons for performing snubbing activities or working over a well.*
1. Completing for production from a new reservoir.	■ *List potential well control problems that could occur during well servicing and workover operations.*
2. Completing a well in more than one reservoir.	
3. Stimulating a completion in a producing reservoir.	
4. Reworking a producing reservoir to control water and/or gas production.	
5. Rework to reduce or eliminate water coning.	
6. Repair mechanical failure.	
7. Cement repair.	
8. Perform logging or perforating operations	
9. Remove sand, scale or other solids impeding production.	
10. Perform well kill operations.	

II. DEFINITIONS AND CALCULATIONS

TRAINING TOPICS	*JOB SKILLS*
A. Pressure fundamentals 1. Definition of pressure a. Force b. Area 2. Types of pressure a. Pressure gradient 1) Liquid 2) Gas b. Hydrostatic pressure 1) General 2) Effect of fluid level change c. Total downhole pressure 1) Considering multiple fluid columns with varying densities 2) Considering shut-in surface pressures d. Bottomhole pressure e. Formation pressure 1) Balanced 2) Underbalanced 3) Overbalanced f. Differential pressure g. Trapped pressure h. Swab pressure i. Surge pressure j. Fracture pressure 3. Circulating frictional pressure losses	■ *Define the following items:* • Force • Pressure gradient • Hydrostatic pressure • Bottomhole pressure • Differential pressure • Total downhole pressure • Formation pressure ■ *Calculate the above pressures.* ■ *Calculate effect of surface pressure on downhole pressures.* ■ *Demonstrate understanding of U-tube concept.* ■ *Calculate hydrostatic changes due to fluid level changes.* ■ *Calculate fluid column height to generate a specific hydrostatic pressure.* ■ *Explain causes and effects of swab and surge pressures in the wellbore.* ■ *Explain circulating frictional pressure losses and calculate effects on pressure and equivalent circulating density for forward and reverse circulation.* ■ *Define and calculate equivalent fluid density.* ■ *Calculate overbalance or underbalance conditions.* ■ *Define the difference between a mechanical and fluid barrier.*

Definitions and Calculations continued on next page.

TRAINING TOPICS	*JOB SKILLS*
4. Equivalent static fluid density a. Definition b. Pressures expressed as an equivalent fluid weight 5. Equivalent circulating density a. Definition b. Frictional pressure loss effects on downhole pressure c. Surface pressure effects d. U-tube principles 6. Barrier concept	■ *Identify and describe the types of mechanical barriers.* ■ *Describe how to test barriers.* ■ *Calculate potential pressure below plug or bridge.* ■ *From a well diagram with a snubbing unit, identify primary, secondary and tertiary barrier systems.*
B. Live wells and kicking wells 1. Define live (producing or shut in) wells 2. Define kicking wells 3. Differences between live and kicking wells	■ *Define* • Live wells (both flowing and shut-in) • Kicking wells ■ *Describe the differences between a live and kicking well.*
C. Volumes/Capacities/Displacements 4. Definition of displacement a. Tubulars 5. Definition of capacity a. Tubing b. Annulus c. Hole d. Fluid pit	■ *Define* • Displacement • Capacity • Volume ■ *Calculate* • Capacity of tubulars, annulus, etc. • Displacement of tubulars, etc. • Volume inside string, annulus volume, string displacement, etc.

Definitions and Calculations continued on next page.

TRAINING TOPICS	*JOB SKILLS*
D. Force 1. Definition of Force 2. Stripping (considering buoyed tubing weight) 3. Buckling 4. Packer, plug, etc. (considering differential pressure across packer, plug, etc.)	■ *Define force and buoyancy.* ■ *Calculate net force effects due to pressure against a surface and due to differential pressure.* ■ *Calculate buoyancy effects and stripping force.* ■ *Define snub force and describe forces that must be overcome to push/pull pipe into/out of a pressured well.* ■ *Recognize situations that may lead to buckling.*

III. KICK FUNDAMENTALS

TRAINING TOPICS	*JOB SKILLS*
A. Definition of a kick	■ *Define a kick.*
B. Causes of kicks	■ *Identify causes of a kick.*
1. Insufficient fluid density	■ *Explain how the following can result in a kick:*
2. Failure to keep hole full	• Insufficient fluid density • Failure to keep hole full
3. Swabbing the well	• Swabbing the well
4. Loss of circulation	• Lost circulation
C. Kick detection	■ *Identify indicators and warning signs of a kick*
1. Kick indicators and warning signs including, but not limited to: a. Increase in return fluid flow rate b. Gain in pit volume c. Well flowing with pump shut down d. Decrease in pump pressure/increase in pump rate e. Hole not taking proper amount of fluid when pulling pipe f. Volume displacement change during trip in g. Change in Surface pressures h. Change in string weight i. Oil or gas shows during circulation j. Trip, connection or background gas changes k. Changes in fluid properties	■ *Rank indicators from most to least reliable.*

Kick Fundamentals continued on next page.

TRAINING TOPICS	*JOB SKILLS*
D. Importance of responding to kick indicators in a timely manner 1. Minimize kick volume 2. Consequences of not responding a. Kick becomes blowout b. Possible release of poisonous gases c. Pollution d. Potential for fire e. Loss of life, equipment resources f. Larger kick and higher shut-in surface pressure	■ *Identify the benefit of timely response to kick indicators.* ■ *Identify or describe potential consequences of improper or untimely response to kick indicators.*

IV. GAS CHARACTERISTICS AND BEHAVIOR

TRAINING TOPICS	*JOB SKILLS*
A. Pressure, volume, relationship (Boyles Law)	■ *Describe pressure and volume relationships for gas.* ■ *Calculate simple pressure-volume gas relationships.*
B. Gas expansion and migration relationships 1. In the wellbore a. Gas density based on pressure b. Effect on bottomhole pressure c. Effect on surface pressure d. Effect on uncontrolled pressure	■ *Describe the effects of gas migration (both expanded and unexpanded) on surface equipment and downhole pressures.*
C. Solubility of gases 1. Water based fluid 2. Oil based fluid 3. Effect on kick detection 4. Gas migration	■ *Describe the effects of gas solubility on the following:* • Kick detection • Gas migration • Gas flashing near surface

V. DRILLING, COMPLETION AND WORKOVER FLUIDS

TRAINING TOPICS	*JOB SKILLS*
D. Primary function is pressure control	■ *State the primary function of completion and workover fluids.*
E. Characteristics of circulated fluids 1. Control fluid loss 2. Minimize formation damage 3. Minimize corrosion 4. Control pressure 5. Deliver hydraulic energy 6. Environmental concerns 7. Convey materials into or out of well	■ *Describe desirable properties of drilling, workover and completion fluids.* ■ *Describe undesirable properties and how it may effect running/pulling activities*
F. Fluid types 1. Oil and oil based fluids 2. Water and water based fluids a. Muds b. Brines (selection based on density requirements) c. Gels d. Stimulation Fluids - Acids 3. Gases 4. Completion fluids 5. Packer fluids 6. Other types	■ *Identify various fluid types and their relative densities.* ■ *Describe why various fluid types would be used.*

Drilling, Completion and Workover Fluids continued on next page.

TRAINING TOPICS	*JOB SKILLS*
G. Pressure losses and causes 1. Density 2. Viscosity 3. Flow rate 4. Well geometry 5. Downhole tool restrictions	■ *Describe frictional pressure loss changes due to the following:* • Density • Viscosity • Flow rate • Well geometry • Downhole tools
H. Fluid density concerns and measuring techniques 1. Mud balance 2. Marsh funnel 3. Pressurized mud balance 4. Effect of temperature 5. Settling of solids 6. Crystallization 7. Hydrates	■ *Using a mud balance, demonstrate or explain the procedure to measure the density of a fluid.* ■ *Using a Marsh funnel, demonstrate or explain how to take a funnel viscosity measurement.* ■ *Describe other techniques for measuring fluid density and viscosity.* ■ *Describe fluid density changes due to temperature effects.* ■ *Describe conditions that would lead to settling of solids in the fluid.* ■ *Define crystallization and hydrates and describe conditions that would lead to crystallization and to formation of hydrates.*

VI. EQUIPMENT
VIa. GENERAL SURFACE EQUIPMENT

TRAINING TOPICS	*JOB SKILLS*
A. Production (Christmas or Xmas) tree 1. Equipment a. Pressure gauges b. Gauge flange or cap c. Swab valve d. Flow or cross tee e. Wing valves f. Master valves g. Surface safety valves 2. Configuration	■ *Identify and describe function and configuration of the key Xmas tree components.* • Master, swab and flow line valves • Hanger nipple sealing mechanisms • Surface safety valve (SSV) • Control line pressure versus tubing pressure • Cutting ability ■ *From a given configuration, identify and describe how to rig up BOPs and prepare for well entry.*
B. Rig blowout preventer stacks 1. Equipment a. Annular preventers and strippers b. Rams 1) Blind 2) Pipe/Multiple string 3) Shear 4) Blind/Shear 5) Variable bore and slip c. Ram locking mechanisms d. Sealing elements e. Valves 2. Configuration	■ *Identify function and configuration of key rig BOP stack components.* ■ *Describe major components and operating principles of BOP closing and locking mechanisms.* ■ *Identify flow path(s) used in well control operations.* ■ *Identify locations for choke and kill line valves.* ■ *Given a rig BOP configuration and snubbing BOP configuration, be able to identify the proper crossovers/adapters that must be utilized.* ■ *Given a rig BOP configuration, describe or demonstrate procedures to rig up snubbing BOPs.*

General Surface Equipment continued on next page.

TRAINING TOPICS	*JOB SKILLS*
C. Auxiliary well control equipment 1. Kelly valves (kelly cock) 2. Full open safety valve a. Top drive valves b. Floor stabbing valves 3. Inside BOP 4. Floats/back pressure valves	■ *Describe function and use of the following rig/unit equipment:* • Full open safety valve • Inside blowout preventer • Floats/back pressure valves ■ *Describe location of the above when not in use.* ■ *Basic understanding of the following equipment and its functions* • *Kelly/top drive system valve*
D. Accumulators 1. Operating functions of main and remote BOP control panels	■ *Basic understanding of the type of the following equipment and its functions* • *Main and remote BOP control panels*
E. Chokes and choke manifolds 1. Fixed chokes 2. Manual adjustable chokes 3. Remote adjustable chokes and back-up systems 4. Choke manifolds	■ *Describe function and components of choke system.* ■ *Explain how back-up system(s) to remotely operated chokes work.*

General Surface Equipment continued on next page.

TRAINING TOPICS	*JOB SKILLS*
F. Fluid measuring devices 1. Volume pumped a. Pump stroke counter b. Rate vs. time 2. Fluid flow indicators 3. Pit volume totalizer 4. Pit level indicator 5. Trip tank a. Gravity fed type b. Recirculating or continuous fill type	■ *Describe various fluid measuring devices and their uses:* • Stroke counter • Fluid flow • Pit volume totalizer • Pit level indicator • Trip tank • Coriollis meter • Propeller meters
G. Gas detection and handling systems 1. Gas detectors 2. Fluid-Gas separators 3. Degasser	■ *Describe functions of fluid-gas separators.* ■ *Describe function of degasser.*
H. Lubricator/Stripper assemblies 1. Wireline 2. Snubbing	■ *Describe general functions of lubricators and strippers and their use.* ■ *Identify potential risks when using lubricators or strippers.* ■ *Calculate net forces associated with the use of lubricators and strippers.*

TRAINING TOPICS	*JOB SKILLS*
I. Accumulators 1. Operating functions of the remote BOP control panel	■ *Demonstrate the ability to operate the BOP from the unit's and the remote control panels.*

VIb. SNUBBING EQUIPMENT

TRAINING TOPICS	*JOB SKILLS*
A. Snubbing equipment 1. Types of snubbing units a. Hydraulic units b. Mechanical units 2. Components of snubbing units a. Hydraulic jacks b. Controls c. Power unit d. Pumps and circulating system e. Slips f. Guide tube g. Work window h. Hoisting system i. Escape system j. Rotating system	■ *Identify and describe the types of snubbing units:* • Hydraulic workover unit (HWO) • Jack based snubbing unit a. Short stroke b. Long stroke c. Space saver • Mechanical (rig assist) ■ *Identify and describe general snubbing unit components.* • Tubing • Hydraulic jacks • Control head/cables/pulley system • Controls • Power unit • Pumps and circulating system • Slips (traveling and stationeries) • Guide tube • Work window • Hoisting system • Escape system • Rotating system ■ *Describe general equipment layout.* ■ *Describe general types of tubing utilized by snubbing units and its limitations.* ■ *Describe and identify physical and mechanical causes of damage to tubing.* ■ *Define buckling and describe when and where it occurs.* ■ *Describe limitations of equipment.* *Snubbing Unit Equipment continued on next page.*

TRAINING TOPICS	*JOB SKILLS*
B. Lubricator/Stripper assemblies	■ *Identify the main components and sealing elements.* ■ *Describe or demonstrate how to install sealing elements.* ■ *Identify and describe the components subject to wear or failure and describe or demonstrate how these may be repaired at the jobsite.* ■ *Describe the operating principles and limitations.* ■ *Describe effects of well pressure on obtaining pressure seal.*
C. Blowout preventer stack 1. Annular BOPs 2. Stripping rams 3. Safety ram (s) 4. Shear or cutter rams 5. Blind/Shear rams 6. Slip rams 7. Stripping BOP stacks 8. Snubbing BOP stacks 9. Circulating port (cross or flow tee) and valves	■ *Identify function, uses and configuration of key BOP stack components.* ■ *Given well information, identify pressure rating of equipment for specific operations.* ■ *Describe operating principles and limitations.* ■ *Describe components that may be well pressure assisted to affect a seal on closure.* ■ *Describe major components and operating principles of BOP closing and locking mechanisms.* ■ *Identify and describe the components subject to wear or failure and describe or demonstrate how these may be repaired at the jobsite.* ■ *Describe or demonstrate proper installation procedures of sealing elements* ■ *Describe and identify the different types of sealing elements from a schematic drawing.* ■ *Describe equipment limitations.* ■ *Identify flow path(s) used in well control operations.* ■ *Identify locations for choke and kill line valves.*

	■ *Given a BOP arrangement, be able to state what operations can be can or cannot be performed.* ■ *Given a scenario, be able to describe what equipment is necessary, and select a suitable BOP arrangement (e.g., use and placement of Shear or Blind/shear rams)* ■ *Describe or demonstrate correct closing and operating sequences to strip and/or snub pipe into the well.* ■ *Describe or demonstrate the correct sequence required to shear pipe.*
D. Auxiliary well control equipment 1. Check (back-pressure) valves a. In string valves b. Pump down valves 2. Stab in valves a. Full open safety valve b. Inside blowout preventer valve	■ *Define Check (back pressure) valves.* ■ *Identify components and describe uses and installation.*
E. Accumulators 1. Usable fluid volume test 2. Closing time test 3. Accumulator pressure a. Pre-charge pressure b. Minimum system pressure c. Operating pressure d. Maximum system pressure 4. Adjustment of operating pressure a. Manifold pressure regulator b. Annular pressure regulator 5. Operating functions of the remote BOP control panel	■ *Demonstrate analogous understanding of the accumulator system functions, including an explanation of the consequences of losing nitrogen pre-charge pressure.* ■ *Describe the reasons and procedure for a usable fluid volume test.* ■ *State, for a 3000-psig system (or 5000-psig system, if applicable), the following:* • Pre-charge pressure • Minimum system pressure • Normal regulated operating pressure • Maximum system pressure ■ *List two reasons for adjusting regulated stripper/annular operating pressure.* ■ *Demonstrate the ability to operate the BOP from the unit's and the remote control panels.*

VII. SUBSURFACE EQUIPMENT

TRAINING TOPICS	*JOB SKILLS*
A. Workstring and production tubing 1. Ratings a. Burst b. Collapse 2. Washouts	■ *Identify tubing ratings (burst and collapse).* ■ *Identify or troubleshoot possible tubing failure (washouts, etc.).*
B. Completion equipment 1. Tubing hanger 2. Surface controlled subsurface safety valves 3. Packers and bridge plugs 4. Landing nipples and bridge plugs 5. Sliding sleeve 6. Multiple completions	■ *Identify potential well control complications and solutions when running completion equipment.* ■ *Describe the function and positioning of packers.* ■ *Describe the function and positioning of landing nipples* ■ *Describe the function of tubing hangers:* • Seal off annulus • Support tubing weight • Provide locking or threaded profile for Tubing Hanger Profile (TBH) ■ *Describe the primary function of the circulation and communication devices (sliding sleeves and ported nipples).* ■ *Describe the primary function of side pocket mandrels, either with a working valve (gas lift, circulation, and chemical injection) or with a dummy valve installed.* ■ *Describe the manipulation of all circulation and communication devices with respect to pressure control.* ■ *Describe the primary function, restrictions, applications and positioning of surface and sub-surface controlled safety valves.* ■ *Recognize and describe the advantages/disadvantages*

	of: • Maximum tool size versus DHSV ID, requirements and possibilities of pulling DHSV's before intervention and use of wear sleeves or lock out devices. • Sub-surface controlled sub-surface safety valves (differential pressure design or ambient pressure design). • Surface controlled sub-surface safety valves (wireline retrievable and tubing retrievable). ■ *Calculate potential pressure differentials across packers, plugs, etc.* ■ *Identify proper ram selection for multiple completions.*

VIII. PROCEDURES

TRAINING TOPICS	*JOB SKILLS*
A. Set/Check alarm limits 1. High and low pit level 2. Return flow sensor 3. Trip tank level 4. Others (H_2S and flammable/explosive gas sensors)	■ *Identify the need for and reasons for setting high and low pit volume levels.* ■ *Describe relationship of relative flow sensor to a possible kick situation.* ■ *Describe the purpose for and locations for H_2S and explosive mixture gas sensors.* ■ *Describe the use of a trip tank and how it can be used to identify possible kicks.*
B. Pre-recorded well information 1. Well configuration a. Top and bottom of perforations b. Packer/Tool locations c. Tubing dimensions, lengths and strengths 2. Maximum safe casing pressures a. Wellhead rating b. Casing burst rating c. Tubing collapse and burst ratings d. Production zone/perforations 3. Fluid density (ies) in well 4. Reservoir data a. Pore pressure b. Fracture pressure 5. Selecting kill/circulating pump rates	■ *Demonstrate ability to document pre-recorded data significant to well control situations (perforation interval, packer locations, tubing strengths, safe working pressures, etc.).* ■ *Given a well and equipment scenario determine pump rates to circulate, pump or kill well.* ■ *Demonstrate ability to document snubbing tubing lengths, strengths, capacities, safe working pressures.*

Procedures continued on next page.

TRAINING TOPICS	*JOB SKILLS*
C. Preparing for well entry 1. Well shut-in will stop influx when BHP equals formation pressure 2. Mechanical and fluid barriers 3. Use of back pressure valves 4. Use of valve removal plug (VR plug) 5. Surface and subsurface safety systems 6. Removal of tree and tubing hanger 7. Installation and testing of BOP and wellhead prior to removal of back pressure valves and tubing plugs	■ *Describe procedure for preparing for well entry.* ■ *List two safety concerns and well control considerations when removing a VR plug.* ■ *List three safety concerns and well control considerations when removing a tree and tubing hanger.* ■ *Describe reasons for and use of back pressure valves and surface and subsurface safety systems.* ■ *Describe procedure for installing and testing of BOP and wellhead prior to removal of back pressure valves and tubing plugs.* ■ *Calculate maximum potential force below back pressure valves and tubing plugs.*
D. Shut-in 1. Procedure (steps not necessarily in order) a. While on bottom 1) Individual responsibilities 2) Space out, including consequences of irregular tubular lengths 3) Shut pump off 4) Shut-in well 5) Notify supervisor b. While tripping 1) Individual responsibilities 2) Space out 3) Close off workstring given variety of tubulars in use	■ *Describe or demonstrate shut-in techniques (and sequence of execution).* ■ *List the precautions to be taken when opening a valve under pressure.* ■ *Describe or demonstrate the necessary procedures when shutting in with tools, pipe, tubing or wireline in the hole.* ■ *Understand the necessary procedures when shutting in the well at the Xmas tree (e.g., number of turns to close, which master valve to use, etc.).*

4) Shut-in well 5) Notify supervisor c. Other operations 2. Shut-in techniques a. Hard b. Soft	
E. Verification of shut-in 1. Annulus a. Through BOP b. At the flow line 2. Workstring a. Pump pressure relief valves b. Standpipe manifold c. Full opening safety valve 3. Wellhead/BOP/Xmas tree a. Casing valve b. Crown, wing, master valves, etc. 4. Manifold a. Manifold valves b. Choke(s) (manual and remote)	■ *Identify appropriate valves/BOP equipment that will be closed to effect a proper shut-in.* ■ *Describe procedure to ensure that the well is properly shut in.*

TRAINING TOPICS	*JOB SKILLS*
F. Well monitoring during shut-in 1. Record keeping a. Time of shut-in b. Tubing and casing pressures 1) At initial shut-in 2) At regular intervals c. Estimate pit gain d. Pressure increase at surface and downhole due to: 1) Gas migration 2) Gas expansion e. Pressure between casing strings	■ *Explain or demonstrate recommended procedures to use for well monitoring during well shut-in.* ■ *Read, record and report well shut-in record keeping parameters.* ■ *Describe the effects of trapped pressure on wellbore pressure.* ■ *List two surface pressure distinctions or differences that may result from shutting-in on a gas vs. liquid kick of equivalent volume.* ■ *Demonstrate procedure for relieving trapped pressure without creating underbalanced conditions.* ■ *Perform choke manipulation to achieve specific pressure or volume objectives.* ■ *Identify two causes for pressure between strings.*
G. Tripping 1. Procedure for keeping hole full a. Using rig pump b. Using trip tank (gravity fill) c. Using recirculating trip tank (continuous fill) 2. Methods of measuring and recording hole fill volumes (trip sheet) 3. Wet trip calculations (non open-ended) a. Return to fluid system b. No return to fluid system c. Hole fill-up volumes 4. Dry trip calculations (open-ended) a. Hole fill-up volumes	■ *Describe methods for filling hole during trips.* ■ *Calculate hole filling requirements when pulling pipe and displacement when running pipe.* ■ *Describe the use of a trip tank.*

TRAINING TOPICS	*JOB SKILLS*
H. Stripping operations 1. Line up for bleeding volume to stripping tank 2. Stripping procedure for BOP 3. Measurement of volumes bled from the well 4. Calculations relating volumes and pressure to be bled for a given tubing length or workstring stands run in the hole 5. Stripping with or without volumetric control	■ *Describe purpose and procedure for stripping operations (with and without volumetric control).* ■ *Perform calculations for bleed volumes or pressures, as method requires.* ■ *Demonstrate ability to line up to stripping tank.* ■ *Demonstrate sequence of BOP/rams when stripping.*
I. Well control drills 1. Pit drill 2. Trip drill	■ *Describe the purpose for pit and trip drills, etc.* ■ *Describe procedure for pit and trip drills and proper response to each.*
J. Flow checking after cementing 1. Normal flow back 2. Not normal flow back	■ *Identify signs of a kick via flow checks.* ■ *Recognize U-tube effect.*

IX. WELL CONTROL TECHNIQUES

TRAINING TOPICS	*JOB SKILLS*
A. Objectives of well control techniques 1. Killing a shut in, producing or flowing well: a. Circulate formation fluid out of well or back into formation b. Re-establish primary well control by restoring hydrostatic balance c. Avoid additional kicks d. Avoid excessive surface and downhole pressures so as not to induce an underground blowout 2. Live well intervention: a. Pressure control without killing the well b. Allowing well to flow or avoiding additional flow/kicks c. Circulate formation fluid out of well or back into formation	■ *Explain and list objectives of well control techniques.* • Circulate formation fluid out of well • Displace formation fluid back into formation • Re-establish hydrostatic control • Minimize formation damage • Avoid excessive surface and downhole pressures • Avoid additional kicks ■ *Explain and list advantages and disadvantages of live well intervention* • For operations where well is allowed to flow • For operations where well is not allowed to flow
B. Techniques for controlling or killing a producing well 1. Well types 2. Bullheading 3. Volumetric techniques a. Principles b. Gas migration c. Stripping/tripping/snubbing considerations 4. Lubricate and bleed 5. Constant bottomhole pressure (BHP) techniques	■ *Given a set of wellbore conditions, select the most appropriate control/kill technique (s).* • Gas wells • Oil wells • Gas/oil wells • Liquid filled wells with and without kick (e.g., completion or workover fluids, muds, etc.) ■ *Describe and demonstrate on simulator or test well one or more technique (s) for controlling or killing a producing well.* ■ *Describe the effects of different kill pump rates on well*

a. Wait and weight b. Driller's method 6. Reverse circulate	*bore pressures and on well-bore conditions. Consistent with the formation strength, annulus friction loss, well-bore conditions and fluid-handling capacity of the surface disposal system.*

Well Control Techniques continued on next page.

TRAINING TOPICS	*JOB SKILLS*
C. No returns pumping technique (e.g., bullheading) 1. Determine status of shut-in tubing pressure (SITP), shut-in casing pressure (SICP) 2. Pump rates and pressure limitations a. Maximum pump pressure b. Friction of fluids vs. rate c. Gain in hydrostatic pressure vs. volume pumped d. Burst pressure of tubulars e. Collapse pressure of tubulars f. Formation fracture pressure 3. Determine volume to be pumped a. Theoretical volume to formation b. Overdisplacement (if any) c. Volume to pump to load surface lines 4. Pump rate vs. volume pumped 5. Gas migration vs. pumped fluid viscosity 6. Determine if well has been successfully killed	■ *Describe and/or demonstrate knowledge and proficiency in the bullhead method:* • Given shut-in well conditions together with well and equipment data, explain if the bullheading method should be applied or not. • Prepare a pumping schedule for bullheading a given well scenario. • Calculate the necessary pumping rate for bullheading a gas well for a given well configuration with respect to formation damage. • Calculate the maximum allowable surface pressure with given well data. ■ *Describe gas migration affects into fluids pumped while bullheading.* ■ *Explain how to minimize gas migration while bullheading:* • Pump rates • Use of viscous pill • Pumpdown device ■ *Describe advantages and disadvantages of overdisplacing tubing.* ■ *Given a scenario, or simulation/test well exercise, determine if well has been successfully killed.*
D. Volumetric techniques and lubricate and bleed 1. Fluid pressure/volume relationship 2. Pressure to maintain vs. fluid lost or added 3. Safety margin, working margin and minimum pressures 4. Stripping/tripping/snubbing considerations	■ *Describe and demonstrate on a simulator or test well, a volumetric well control technique.* • Calculate pressure/volume relationship. • Describe the difference between safety and working margins. • Accurately measure volumes bled or added and maintain correct surface pressure (s).

	• Correctly manipulate choke and/or pump to maintain correct surface pressure (s). ■ *Define and determine if pipe "light" or "heavy" based on given well scenario.* ■ *Describe differences in running pipe in/out and choke and/or pump manipulation procedures given well type (i.e., gas, oil, gas/oil, liquid filled with kick, liquid filled without kick, etc.).*
E. Constant bottomhole pressure (BHP) methods (forward or reverse circulation) 5. Well shut-in will stop influx when BHP equals formation pressure 6. Circulating out a kick with choke back pressure to maintain desired BHP d. Bottom of the workstring must be at the kicking formation (or bottom of the well) to effectively circulate the control or kill fluid, displace produced fluids from the well and be able to resume normal operations effectively.	■ *Describe and demonstrate on a simulator or test well, a constant bottomhole pressure (BHP) technique.* ■ *From a schematic, identify proper pump and manifold alignment for forward and reverse circulation.* ■ *Explain how pump/choke manipulation relates to maintaining BHP.*
F. Preparation of well control kill worksheet 1. Well control calculations a. Tubing and annular volumes, strokes/volume and times b. Fluid density increase required to balance formation pressure c. Initial and final circulating pressure as appropriate for methods taught 2. Maximum wellbore pressure limitations a. Surface	■ *Prepare a well control worksheet for killing a well:* • calculate tubing and annulus volumes • determine fluid density increase (if required) • calculate total strokes/volume to circulate the well and time required (as appropriate) ■ *Identify wellbore pressure limitations and list consequences of exceeding pressure limitations identified.* ■ *Select pump rate, considering frictional losses, choke operator reaction time, pump limitations, etc.*

b. Subsurface 3. Selection of pump rate a. Allowing for friction losses b. Choke operator reaction time c. Pump limitations	
G. Well control procedures 4. Procedure to bring pump on and off line and change pump speed while holding BHP constant using the choke a. Use of casing pressure gauge b. Lag time response on standpipe pressure gauge 5. Procedure for determining initial circulating pressure a. Using recorded shut-in tubing pressure and reduced circulating pressure b. Without a pre-recorded value for reduced circulating pressure c. Adjustment for difference in observed vs. calculated circulating pressures 6. Choke adjustment during well kill operations a. Changes in circulating pressure as a result of changes in hydrostatic head or circulating rates 1) Drop in pump pressure as fluid density increases in tubing during well control operations 2) Increase in pump pressure with increased pump rate and vice versa b. Changes in casing pressure during well control operations 1) Adjustments due to fluid velocity changes across the choke 2) Adjustments due to fluid type changes across the choke 3) Adjustments due to fluid density change c. Pressure response time 4) Casing pressure gauge (immediate)	■ *Describe and demonstrate on simulator or test well (procedures for "Wait and Weight", "Driller's" or "Concurrent" method):* • The ability to bring pump on and off line using the casing or annulus gauge. • The ability to establish correct initial circulating pressure. • Obtaining an initial circulating pressure without a pre-recorded reduced circulating pressure. • The ability to relate changes in choke position to changes seen on the circulating pump pressure (aka "Drill Pipe Pressure") • The ability to control pressures using a choke while maintaining a constant pump speed given gas expansion and changes in fluid velocity, type and density. • The ability to follow the constant bottomhole pressure well control plan using the pump and choke. ■ *Describe and/or demonstrate procedures to shut well back in after kill attempt and determine if successful.* ■ *Describe or demonstrate a procedure to ensure pressures are not trapped after well has been circulated.* *Well Control Techniques continued on next page.*

5) Drill pipe pressure gauge (lag time) 7. Procedure for shutting down, shutting in and determining if kill attempt was successful a. Shutting down pump while maintaining correct pressure on choke b. Observing pressures c. Determining change in pressures versus time d. Bleeding/venting trapped pressure e. Checking for flow	

X. COMPLICATIONS AND SOLUTIONS

TRAINING TOPICS	*JOB SKILLS*
A. Blockages in string and trapped pressure 1. Wireline plugs 2. Subsurface safety valves (storm chokes) 3. Surface controlled subsurface safety valve 4. Bridge plugs 5. Sand bridges 6. Paraffin 7. Hydrates 8. Beneath packer	■ *Given specific well data, identify a possible blockage in the well and determine the most appropriate procedure to control the well.* ■ *Identify sources of potential trapped pressure.* ■ *Determine potential pressures beneath various downhole plugs, valves, etc.* ■ *Describe procedure for resolving sources identified at left.*
B. Pressure on casing 1. Hole in tubing 2. Hole in casing 3. Seal or packer leak. 4. Pressure or temperature pulled seals out of seal bore 5. Failed squeeze job or patch	■ *Identify sources of pressure on casing and explain the well control implications.*
C. Underground flow	■ *Describe conditions that may lead to flow from one zone into another.* ■ *Based on surface parameters, identify underground flow and possible solutions.*
D. Cannot circulate well (i.e., plugged workstring, etc.)	■ *List three reasons why a well cannot be circulated and a solution for each.*

Complications and Solutions continued on next page.

TRAINING TOPICS	*JOB SKILLS*
E. Hydrates	■ *Describe the possible effects of hydrates on well control.* ■ *Describe how hydrate formation may be prevented.* ■ *Describe actions to be taken in event of hydrate forming.*
F. Lost circulation	■ *Identify signs of lost circulation.* ■ *List at least two possible remedies to lost circulation.*
G. Collapsed tubing	■ *Identify signs of collapsed tubing* ■ *Describe potential complications and solutions as a result thereof.*
H. Junk in hole	■ *Identify signs of junk in hole* ■ *Describe potential complications and solutions as a result thereof.*
I. Hole in tubing/parted tubing	■ *Know how to detect a pinhole r washout and the steps that must be taken to isolate it and to get out of the hole.* ■ *Know how to detect a broken string, coiled tubing or lost BHA and the steps that must be taken to get out of the hole again.* ■ *Describe complications that may arise from a hole in the tubing.*
J. Stuck tool string	■ *Identify signs of collapsed tubing* ■ *Describe potential complications and solutions as a result thereof.*

Complications and Solutions continued on next page.

TRAINING TOPICS	*JOB SKILLS*
K. Fishing under pressure	■ *Describe tools, equipment and precautions that must be used while fishing with wireline under pressure.* ■ *Identify potential complications and list possible solutions.*
L. Hole angle	■ *Describe how hole angle affects deployment of wireline tools* ■ *Identify factors allowing or preventing continuation of wireline as hole angle increases*

XI. ORGANIZING A WELL KILL OPERATION

TRAINING TOPICS	*JOB SKILLS*
A. Personnel assignments	■ *Describe personnel assignments and indicate those personnel (if any) not required during a well control operation.* ■ *List required information that is available prior to a well control event.* ■ *Given certain well information, define most likely well control scenarios.* ■ *Identify personnel who must coordinate effectively to effect a well kill and name their main responsibilities.*
B. Pre-recorded information	■ *Describe locations of pre-recorded information, collection process, and where supervisor will keep well documentation.*
C. Plan responses to anticipated well control scenarios	■ *Describe procedures for implementing responses to well control scenarios.*
D. Communications responsibilities 1. Planning and outlining routine well control responsibilities 2. Organizing abnormal operations	■ *Describe the lines of communication and the roles of personnel, including the importance of pre-job on site planning meetings and tourly safety meetings.* ■ *Describe how equipment and personnel would be organized to recover a situation, once the well is safely shut in.* ■ *Analyze the communication modifications that may be necessary because of an abnormal operation and describe how communications could be handled if differing from standard personnel assignments.*

XII. TESTING

TRAINING TOPICS	*JOB SKILLS*
A. Testing of completion pressure control equipment 1. Packers 2. Lubricators 3. Production (Xmas or Christmas) trees 4. Test trees	■ *Demonstrate the ability to line up piping and valving to perform test.*
B. Pressure and function tests 1. Maximum safe working pressures of well control equipment 2. Reasons for de-rating 3. Areas exposed to both high and low pressures during shut-in and pumping operations	■ *Identify the maximum safe working pressure for a give set of well control equipment.* ■ *List two reasons for de-rating the maximum safe working pressure of well control equipment.*
C. BOP Testing 1. Requirements for pressure testing 2. Performing pressure tests	■ *Given details of specific equipment and operation, describe pressure testing procedures.* ■ *Describe/identify proper routing or demonstrate correct procedures to pressure test a valve or BOP function.* ■ *Describe or demonstrate how a preventer or valve can be tested with tubulars or wireline in place.*
D. Installation of rings, flanges and connections	■ *Describe or demonstrate proper installation of rings, flanges and connections.* ■ *Given a scenario, be able to describe or demonstrate which adapters and connectors are necessary to complete a hook-up using proper pressure ratings, dimensions, ring types, etc.*

XIII. GOVERNMENT, INDUSTRY AND COMPANY RULES, ORDERS AND POLICIES

TRAINING TOPICS	*JOB SKILLS*
A. Incorporate by reference 1. API and ISO recommended practices, standards and bulletins pertaining to well control 2. Regional and/or local regulations where required	■ *Describe or identify appropriate regional government regulations pertaining to job being completed.*

XIV. SPECIAL SITUATIONS (OPTIONAL)

TRAINING TOPICS	*JOB SKILLS*
A. H_2S considerations	■ *Describe additional procedures, precautions and supplemental safety equipment necessary while operating in an H_2S environment.* ■ *Describe equipment addition, limitations, modification or replacement necessary to work in an H2S environment.* ■ *Provide documentation of successful completion of a H2S training course.*
B. Subsea considerations	■ *Identify components of a subsea wellhead/production tree.* ■ *Describe how the subsea wellhead/production tree and/or BOP stack is functioned and the similarities/disparities between surface snubbing BOP/valve applications.* ■ *Identify components and describe running procedure of snubbing equipment and installation onto subsea wellhead/production tree.* ■ *Describe entry procedures into a subsea wellhead.* ■ *Describe tool deployment methods.* ■ *Describe safety controls and limitations while snubbing activities are taking place.* ■ *Describe the complications and consequences of snubbing operations in subsea environments*

Special Situations continued on next page.

TRAINING TOPICS	*JOB SKILLS*
C. Nitrogen operations	■ *Identify and describe types of and components of nitrogen units.* • Direct fired • Ambient air • Co-generative • Direct air/gas membrane ■ *Describe or demonstrate an understanding of the cryogenic portion, supply loop and pumps on a nitrogen unit.* ■ *List and describe a minimum of three activities using nitrogen.* ■ *Describe the transportation, care and handling of liquid nitrogen.* ■ *Describe hazards associated with liquid nitrogen.*
D. Drilling operations	■ *Identify and describe basic drilling rig components and functions.* ■ *Demonstrate or describe procedures to rig up snubbing pressure control equipment while a drilling rig is rigged up on location.* ■ *Describe open hole logging well control considerations.* ■ *Demonstrate or describe general rig up procedures of snubbing pressure control equipment on the rig's BOP stack.* ■ *Describe the complications and consequences of snubbing operations rigged up on a drilling rig's pressure control equipment.*

Special Situations continued on next page

TRAINING TOPICS	*JOB SKILLS*
E. Workover operations	■ *Identify and describe basic workover rig components and functions.* ■ *Demonstrate or describe procedures to rig up snubbing pressure control equipment while a workover unit is rigged up on location.* ■ *Describe logging well control considerations.* ■ *Demonstrate or describe general rig up procedures of snubbing pressure control equipment on the rig's BOP stack.* ■ *Describe the complications and consequences of snubbing operations rigged up on a workover rig's pressure control equipment.*
F. Wireline operations	■ *Identify and describe basic wireline unit components, pressure control equipment and functions.* ■ *Demonstrate or describe procedures to rig up snubbing pressure control equipment while a wireline unit is rigged up on location.* ■ *Describe the complications and consequences of wireline operations rigged up on snubbing equipment.*

Special Situations continued on next page.

TRAINING TOPICS	*JOB SKILLS*
G. Small tubing unit	■ *Identify and describe basic small tubing unit components and functions.* ■ *Demonstrate or describe procedures to rig up snubbing pressure control equipment while a small tubing unit is rigged up on location.* ■ *Describe the complications and consequences of snubbing operations rigged up on a small tubing unit's pressure control equipment.*
H. Safety systems and Emergency Shutdown Devices (ESDs)	■ *Identify areas on rig or platform where ESDs may be found.* ■ *Describe the sequence of events once and ESD is activated.* ■ *Describe why and when an ESD should be activated.* ■ *Describe the potential consequences to production and wells if the ESD is inadvertently activated.*
I. Operations with specific well control concerns 1. Perforating 2. Acidizing 3. Stimulation (fracturing, energized fluids, etc.) 4. Gravel packing	■ *List and describe hazards and extra safety precautions for:* • High pressure pumping operations • Handling corrosive materials ■ *Describe and identify procedures and location for hazardous material spills and cleanup and equipment.*