SECTION SIX

<u>Appendices for Deep/High Pressure Oil Wells (EXTREME CAUTION)</u>

<u>FOUND IN SECTION: 6.</u>

Appendix: 12- API 54-Occupational Safety and Health for Oil and Gas Drilling and Servicing Operations (Good for Shallow and Deep Well Operations)

Appendix 13-Deep/High Pressure Oil Well Control Considerations

Appendix 14- Coverdale, MS High Pressure and Deep Well Plugging Methodology for Armstrong Union Number 3 in 1973. Plugs Failed.

Appendix 15- Re-plugging Plan for Armstrong Union Number 3 Well

Appendix 16- Callon Petroleum Re-plugging Report and Affidavit for Armstrong Union Number 3 Well Dated November 4, 2020

DEEP AND HIGH PRESSURE OIL WELL CONTROL AND PLUGGING CONSIDERATIONS

Charles K. Eger, Professional Geologist

Environmental Protection Agency-Region 4

Author Note

This section is intended to provide the basics of oil well control and includes a sample plugging workplan from a deep well in Natchez, Mississippi.

***** DO NOT EVER ATTEMPT TO PLUG A HIGH PRESSURE WELL WITHOUT FIRST HIRING A SEASONED PETROLEUM ENGINEER WHO IS HIGHLY QUALIFIED TO PRESCRIBE ALL MANDATORY BLOWOUT PREVENTERS, EQUIPMENT AND ASSOCIATED SAFETY PROTOCOLS WHEN REOPENING A WELL.**

UNITED STATES ENVIRONMENTAL PROTECTION AGENCY

REGION 4- ERRPPB

MEMORANDUM:

FROM: Charles K. Eger, Professional Geologist

TO: File

SUBJECT: Differences in Plugging and Safety Protocols for Oil Wells With and Without Reservoir Pressures

DATE: 29-January-2021

The reader who closely reviews this compendium in its entirety (i.e. Sections One through Six) will deduce immediately that the Author has provided minimal written protocol relating to the re-entering and plugging of deep (a.k.a. medium to high potential for oil reservoir pressure) wells. **This is no accident!** All of the associated well operations will ALWAYS require the full-time monitoring, supervision, and direction from a very seasoned petroleum engineer who has extensive knowledge of the specific oil field being remediated. Failure to adhere to this stipulation, will result in a catastrophic fire or explosion.

This cautionary recommendation is based on very extensive discussions involving two extremely seasoned petroleum engineers with over 70 years combined field experience and the Author who has amassed 37 years of knowledge relating to oil well plugging in four southeastern States. Section Six contains five (5) invaluable references and examples of issues, equipment, safety, and protocols relating to plugging deep and/or medium to high pressures wells. Appendices 12, 13, and 15 provide key references when a field responder is contemplating the plugging and/or re-plugging of the aforementioned wells.

If there is any possibility of oil and gas reservoir pressures associated with the well(s) in question, a highly experienced petroleum engineer must prescribe all equipment and safety procedures associated with all field operations and direct said actions. Potential required equipment shall include, but will be limited to:

- Workover Rig,
- Double Stack Blow-out preventers with pipe rams and blind rams installed,
- Rig-up Mat for ground support as workover rig support,

- Two Workover tanks (1 for drilling mud and 1 for fresh water),
- Approximately 250 bbls (i.e. 42 gallons per bbl) of drilling mud mixed at a minimum of 9.6 lbs/gallon,
- Triplex mud pump,
- 70 bbl Vacuum truck with pump,
- Roustabout crew labor for equipment setup and removal and site cleanup,
- Power Swivel- (approximately 85 tons of torque or more),
- Washout head and Replacement rubbers,
- Two pipe skids for rental tubing string,
- Truck and float for hauling tubing and plugging equipment,
- Bulldozer for building road to the well site,
- Rental string of 2 7/8", 8rd EUE J-55 tubing (equal to total depth of the well,
- Rental 3 ½ " drill collars and crossovers,
- Rental drill bits and scraper,
- Welder to cut off top of any bent casing and weld a bell nipple on it,
- Bell Nipple,
- Casing head with 2- 12" XS A/SA Grade B Carbon Steel seamless pipe nipples and 2- 2,000 pound ball valves,
- Swedge which tapers to a 2"-3" nipple that will screw into surface casing (for bullhead squeeze),
- Rhino UTV(s), and
- Command and Control trailer.

This list is not intended to be all-inclusive. It will aid the field responder, On-Scene Coordinator, and/or the Petroleum Engineer (PE) when scoping out deep well projects. One should NEVER blindly template off of this list without complete coordination with a PE.

Sections 3, 4, and 5 of this document provide a very detailed cookbook approach in sequential order for plugging a shallow-low pressure oil well. This is the simplest type of approach for permanently plugging a leaking oil well.

Plugging procedures for shallow and deep wells are nearly identical with the great exceptions associated the effective control of residual reservoir pressures **(as prescribed in Paragraph 3 of this document.** In more simple terms, both types of wells will require identical steps as it pertains to the following:

- well dismantling,
- tubing and pumping rod and removal,
- drilling and scraping the inside of the production casing from surface to total depth,

- geophysical evaluation of the well casing and quality of cement behind the production casing,
- setting of a cast-iron bridge plug to protect cement integrity during hardening,
- perforation of production casing where the cement in the annulus is insufficient to preclude the migration of fluids,
- circulating of cement from total depth to land surface, and
- squeezing of cement (via bullhead squeeze) on the back side of the production casing from total depth to land surface.

This sequential and comprehensive plugging approach has been consistently utilized on many hundreds of wells in the Southeastern U.S. When strictly used, the above methods assure unprecedented successes with respect to the effective plugging and abandonment of previously discharging oil wells. <u>The Author has never had an occasion to re-drill out a well plugged under his direction. These methods, in the opinion of the Author, are the only reliable standard to consistently use in the field.</u> Anyone who willfully chooses to deviate from these procedures will most likely encounter wells that will continue to leak long after the plugging methods are attempted. Should this happen, the well will require milling out the cement plugs back to the total depth of the well and re-plugged. This is a very expensive endeavor which can be avoided if the reader follows the protocol as prescribed in Sections 3 and 6.

Appendix: 12

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Occupational Safety and Health for Oil and Gas Well Drilling and Servicing Operations

API RECOMMENDED PRACTICE 54
FOURTH EDITION, FEBRUARY 2019

AMERICAN PETROLEUM INSTITUTE

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Suggested revisions are invited and should be submitted to the Standards Department, API, 200 Massachusetts Avenue, NW, Suite 1100, Washington, DC 20001, standards@api.org.

Contents

Contents

Occupational Safety and Health for Oil and Gas Well Drilling and Servicing Operations

1 Scope

1.1 Coverage

The purpose of this document is to recommend practices and procedures for promoting and maintaining safe and healthy working conditions for personnel in drilling and well servicing operations.

1.2 Applicability

These recommendations apply to rotary drilling rigs, well servicing rigs, and special services as they relate to operations on location. It is intended that the applicable requirements and recommendations of some sections of the document be applied, as appropriate, to other sections. The recommendations are not intended to cover seismic drilling or water well drilling operations. These recommendations do not apply to site preparation and site remediation operations.

1.3 Responsibility

Employers have the responsibility to identify, communicate, and mitigate hazards at the work site. A process of risk assessment may be an effective method to protect employees at the work site.

2 Normative References

The following referenced documents are indispensable for the application of this standard. For dated references, only the edition cited applies. For undated references, the latest edition of the referenced standard applies (including any addenda/errata).

API Recommended Practice 500, *Classification of Locations for Electrical Installations at Petroleum Facilities Classified as Class 1, Division 1 and Division 2*

API Recommended Practice 505, *Classification of Locations for Electrical Installations at Petroleum Facilities Classified as Class 1, Zone 0, Zone 1 and Zone 2*

ASSE Z359.1, *The Fall Protection Code*

ASTM F2413, *Standard Specification for Performance Requirements for Protective (Safety) Toe Cap Footwear*

ISEA Z87.1, *American National Standard for Occupational and Educational Eye and Face Protection Devices*

ISEA Z89.1, *American National Standard for Industrial Head Protection*

NACE MR0175/ISO 15156-1, *Requirements for Sulfide Stress Cracking Resistant Metallic Material for Oil Field Equipment*

NFPA 70, *National Electrical Code*

NFPA 2112, *Standard on Flame-Resistant Clothing for Protection of Industrial Personnel Against Short-Duration Thermal Exposures from Fire*

NFPA 2113, *Standard on Selection, Care, Use, and Maintenance of Flame-Resistant Garments for Protection of Industrial Personnel Against Short-Duration Thermal Exposures from Fire*

3 Terms, Definitions, and Abbreviations

3.1 Terms and Definitions

For the purpose of this document, the following terms and definitions apply.

3.1.1
acidizing
The act of pumping an acidic solution into a wellbore to remove materials from the perforations, pipe, and walls of the producing formation or pumping the solution into formations to improve permeability.

3.1.2
adequate ventilation
Air volume and velocity that is sufficient to dilute, render harmless, and carry away toxic, flammable, or explosive concentrations of gasses, dust, fumes or vapors.

3.1.3
approved
Officially agreed to or accepted as satisfactory.

3.1.4
authorized person
A person assigned by an employer to perform or supervise the performance of a specific type of duty or duties at the worksite.

3.1.5
blooey line
Return line for air drilling.

3.1.6
blowout
An uncontrolled flow of well fluids or formation fluids, or both, from the wellbore or into lower pressured subsurface zones (underground blowout).

3.1.7
blowout preventer
BOP
A device attached to the wellhead or tree that allows the well to be closed in with or without a string of pipe or wireline in the borehole.

3.1.8
casing
Pipe installed in the wellbore and cemented (or secured by some other means) in place to retain the borehole dimension and seal off hydrocarbon and water-bearing formations.

3.1.9
cathead spool
A concave, rotating, pulley-type device mounted on the end of the cat shaft of the drawworks.

3.1.10
catline
A line powered by the cathead used to lift or pull equipment around a rig.

3.1.11
catwalk
Elongated platform adjacent to the rig floor where pipe is laid out and lifted into the derrick.

NOTE The catwalk is connected to the rig floor by a pipe ramp on rigs with a sub-structure; some catwalks include moveable troughs and rams that can elevate and push pipe to the rig floor or lower pipe away from the rig floor without using a winch or cat line to move the pipe.

3.1.12
cellar
A stabilized excavation around the wellhead to provide space for equipment at the top of the wellbore.

3.1.13
cementing
Making cement into a slurry and pumping it into a wellbore.

3.1.14
circulate
Cycling fluid from the surface through the pipe and back to the surface through the annular space.

NOTE Annular space is the space surrounding the pipe in the wellbore.

3.1.15
combustible liquid
A liquid having a flashpoint at or above 100 °F (37.8 °C).

NOTE Check with local regulatory or other recognized authority for applicable requirements.

3.1.16
confined space
A tank, excavation, or space that meets the following:

— is large enough and configured so that personnel can bodily enter and perform assigned work;

— has limited or restricted means for entry or exit (e.g. tanks and vessels, storage bins, hoppers, vaults, cellars, excavations, and pits);

— is not designed for or meant to be continuously occupied by personnel.

3.1.17
critical equipment
Equipment and other systems determined to be essential in preventing the occurrence of or mitigating the consequences of an uncontrolled event.

NOTE Such equipment may include vessels, machinery, piping, blowout preventers, wellheads and related valving, flares, alarms, interlocks, fire protection equipment, and other monitoring, control, and response systems.

3.1.18
deadline (drilling operations)
The end of the drilling line that is not reeled onto the hoisting drum of the rig.

NOTE This end of the drilling line is anchored and does not move as the traveling block is hoisted.

3.1.19
deadline (well servicing operations)
The tension line between the crown and mast base used to secure the power swivel stiff-arm.

3.1.20
derrick
The fixed tower component of a drilling or well servicing unit.

3.1.21
derrick hand
Person whose work assignment is the drilling fluid system on the drilling rig and work station is up in the derrick while pipe or rods are being hoisted or lowered into the hole on a well service rig.

3.1.22
drilling line
The wire rope used in the rig's main hoisting system.

NOTE Also known as tubing line in well servicing applications.

3.1.23
drill pipe
The seamless tubing used to rotate the drill bit and circulate the drilling fluid.

NOTE The joints of drill pipe are coupled together with special threaded connections called tool joints.

3.1.24
drill stem

The drilling assembly from the swivel or top drive to the bit composed of the drill string (work string), subs, drill collars and other downhole tools such as stabilizers and reamers.

NOTE This assembly is used to rotate the bit and carry the drilling fluid to the bit.

3.1.25

drill stem test
DST
A test taken by means of special testing equipment run into the wellbore on the drill string (work string) to determine the producing characteristics of a formation.

3.1.26
drill string (work string)
Several sections or joints of drill pipe or tubing joined together for use in the wellbore.

3.1.27
driller
The person responsible for the operation of the drilling and hoisting equipment of the rig under normal conditions.

3.1.28
elevators
A device attached to the traveling block that latches around and supports the pipe or rods during hoisting or lowering operations.

3.1.29
energy isolation device
A mechanical device that physically prevents the transmission or release of energy.

3.1.30
energy source
A source of electrical, mechanical, hydraulic, pneumatic, chemical, thermal, or other energy.

3.1.31
flammable liquid
A liquid having a flashpoint below 100 °F (37.8 °C).

NOTE Check with local regulatory or other recognized authority for applicable requirements.

3.1.32
flowback operation
The process of allowing fluids to flow from the well following a treatment, either in preparation for a subsequent phase of treatment or in preparation for cleanup and returning the well to production.

3.1.33
freezing operation
Creation of a plug by freezing a liquid in a pipe or fitting to confine the pressure while removing defective or inadequate equipment downstream of the plug.

3.1.34
full body harness
Straps which may be secured about a person in a manner that will distribute the fall arrest forces over at least the thighs, pelvis, waist, chest, and shoulders, with means for attaching it to other components of a personal fall arrest system.

3.1.35
guard
To cover, shield, fence, enclose, or otherwise protect by means of suitable covers or casings, barrier rails, or screens to eliminate the possibility of accidental contact.

3.1.36
guyline
A wire rope for attaching an elevated structure, such as a derrick or mast, to a ground anchor for stability.

NOTE See API 4F or API 4G for additional information.

3.1.37
hazardous atmosphere
Atmosphere that has the potential to expose entrants to the risk of death, incapacitation, impaired ability to self-rescue (e.g. escape unaided from a permit required confined space), injury, or acute illness.

NOTE 1 The potential risks from exposure to a hazardous atmosphere could be caused from one or more of the following:

— atmospheric oxygen concentrations below 19.5 % and above 23.5 %;

— flammable gas, vapor, or mist in excess of 10 % lower explosive limit (LEL);

— airborne combustible dust at a concentration that meets or exceeds its LEL;

— atmospheric concentration of a substance for which a permissible exposure limit (PEL) is published in applicable government regulations, safety data sheets (SDS), standards, or other published or internal documents and could result in responder exposure in excess of its PEL;

— other immediately dangerous to life or health (IDLH) atmospheric conditions.

NOTE 2 In other regions, permissible exposure limit (PEL) may have other terms used, e.g. occupational exposure limits (OEL).

3.1.38
hazardous substance
A substance that, by reason of being explosive, flammable, toxic, corrosive, oxidizing, irritating, or otherwise harmful, has the potential to cause injury, illness, or death.

3.1.39
hot oil operations
The act of heating oil (or other fluids) and pumping it into the piping, tubing, casing, or formation to remove paraffin and asphaltines.

3.1.40
hot work
An operation that can produce enough energy from flame, spark or other source of ignition, with sufficient energy to ignite flammable vapors, gases, or dust.

NOTE 1 Hot work includes such things as, but not limited to, electric arc and gas welding, chipping, burning, heating, grinding, gas cutting, abrasive blasting, brazing, and soldering.

NOTE 2 See API 2009 for additional information.

3.1.41
hot tapping
The technique of attaching a mechanical or welded branch fitting to piping or equipment in service, or under pressure, and creating an opening in that piping or equipment by drilling or cutting a portion of the piping or equipment within the attached fitting.

NOTE A special saddle is used to attach a valve and lubricator to the pipe.

3.1.42

hydraulic fracturing
The propagation of fractures in a rock layer, as a result of the action utilizing one or more of the following: a pressurized fluid; chemical additives; physical proppants, in order to release petroleum, natural gas, or other substances to be extracted.

NOTE See API 100-1 and API 100-2 for information and guidance.

3.1.43
joint
A length of pipe that can be either drill pipe, casing, or tubing.

3.1.44
kelly
The square, hexagonal or other shaped steel pipe connecting the swivel to the drill pipe.

NOTE The kelly moves through the kelly bushings and rotary table and rotates the drill string.

3.1.45
lanyard
A flexible line of rope, wire rope, or strap which often has a connector at each end for connecting the full-body harness to a deceleration device, lifeline, or anchorage.

3.1.46
location (well site or worksite)
The place where well servicing or drilling is occurring.

3.1.47
lock-out/tag-out
A process to isolate and render inoperable hazardous energy sources.

3.1.48
lubricator
A fabricated length of tubular pipe equipped with a pack-off and bleed valve(s) that is installed to provide access while working on a well under pressure with wireline or other tools and equipment.

3.1.49
making a connection
Act of screwing a section of pipe or rods onto the string suspended in the wellbore.

3.1.50
mast
The mobile tower component of a drilling or well servicing unit.

3.1.51
mobile offshore drilling unit
MODU
A vessel capable of engaging in drilling or well workover operations for the exploration or exploitation of subsea resources.

3.1.52
monkey (tubing) board
The derrick hand's working platform in the mast/derrick.

3.1.53
mud bucket
Device used to enclose pipe connections to deflect fluid released when a joint or stand of pipe containing liquid (wet string) is unscrewed.

3.1.54
near miss (near hit, near loss)
An unplanned event that did not result in injury, illness or damage, but which had the potential to do so.

3.1.55
open hole
Uncased part of the wellbore.

3.1.56
operator
Lease owner or their designated agent who is responsible for the overall operation of the lease.

3.1.57
perforating
Making holes in pipe, cement, or formation at desired depths performed with an explosive device utilizing shaped charges.

3.1.58
personal fall arrest system
PFAS
A system designed and used to arrest an individual in a fall from a working level.

3.1.59
piping and instrumentation diagram
P&ID
A diagram that shows the details about the piping, vessels, and instrumentation.

3.1.60
pole mast
Structure consisting of one or more tubular sections, telescoping or not telescoping, that are the load-bearing members.

NOTE The structure, when erected to working position, often requires guylines; it may be attached to a carrier, skid base, or substructure.

3.1.61
pumping unit
Surface equipment used for the purpose of mechanically lifting fluids from a well.

3.1.62
qualified person/personnel
A person(s) who, by possession of a recognized degree, certificate, or professional standing, or who by knowledge, training, or experience, can successfully demonstrate the ability to solve or resolve problems relating to the subject matter or the work.

3.1.63
rabbit
An instrument or device that is dropped, pulled, or pushed through a section of pipe to ensure that it is free of obstruction.

3.1.64
racking
Act of placing stands of rods, tubulars, drill pipe, or drill collars in an orderly arrangement in the mast/derrick.

3.1.65
rated working pressure
The maximum internal pressure that equipment is designed to contain or control, or both.

NOTE Working pressure is not to be confused with test pressure.

3.1.66
rig up/rig down
The on-site erection and connection of equipment and components in preparation for drilling or well servicing operations and the taking apart of equipment for storage and portability prior to moving off the rig floor or location.

3.1.67
risk assessment
A systematic process to identify the potential causes of harm or hazards, and the precautions that can be taken to prevent or mitigate the hazards.

3.1.68
rod (sucker rod)
A length of steel, aluminum, fiberglass, or other suitable material, which are screwed together to make up the mechanical link (rod string) from the surface pumping unit to the pump in the well.

3.1.69
simultaneous operations
Two or more independent operations (such as drilling, workover, wireline, facilities construction, and so forth) conducted under common operational control in which the activities of an operation may impact the safety of personnel, equipment or the environment of the other(s), or a combination thereof.

NOTE Failure to coordinate can result in the potential clash of activities that can cause an undesired event or set of circumstances.

3.1.70
snubbing
Pulling or running pipe under pressure through a sealing element where special equipment is used to apply external force to push the pipe into the well, or to control the pipe movement out of the well.

3.1.71
special services
Those operations utilizing specialized equipment and personnel to perform work processes to support well drilling and servicing operations.

3.1.72
stabbing board
A platform in the mast/derrick on which personnel work while casing is being run to aid in guiding a tubular joint into another tubular joint for makeup.

3.1.73
strand
Several round or shaped wires helically laid about an axis.

3.1.74
stand of pipe
Multiple joints of pipe screwed together positioned within the derrick/mast or mousehole.

3.1.75
substructure
Depending on the design of the rig, the structure on which the derrick or mast may sit.

NOTE The substructure may provide space for wellhead and well control equipment.

3.1.76
supervisor
Person who has been given the control, direction, or supervision of work performed by one or more personnel.

NOTE Supervisors may be referred to as rig operators, operators, drillers, rig managers, company men, and others depending on job and area.

3.1.77
swabbing
Lifting of well fluids to the surface using a piston-like device installed on a wireline.

NOTE Swabbing can inadvertently occur due to piston action as pipe or assemblies are pulled from the well.

3.1.78
swing rope
A vertically suspended rope that is hung above the boat landing on an offshore platform and is used to facilitate personnel transfer between boat and platform, and vice versa.

3.1.79
swivel
Device at top of the drill stem that permits simultaneous circulation and rotation.

3.1.80
tree
The valves and fittings assembled at the top of a completed well to control the flow of hydrocarbons and other fluids.

3.1.81
tour
Designates the work period of a rig crew.

NOTE Often pronounced as if it were spelled "t-o-w-e-r."

3.1.82
tripping
The process of removing and/or replacing tubulars from the well.

3.1.83
tubing
Pipe installed in the wellbore inside casing strings and extending from the wellhead to a depth below, at, or above a producing, disposal, or injection formation through which the produced or injected fluids flow.

3.1.84
welder (certified)
A person who can provide documentation attesting to that person's capability to create welds of acceptable quality following a defined welding procedure.

3.1.85
welder (qualified)
A person who has demonstrated the capability to create welds of acceptable quality following a defined welding procedure.

3.1.86
winch (tugger) line
A wire rope powered by a winch and used for the controlled moving of loads around a rig.

3.1.87
V-door
The opening at the rig floor that leads to the catwalk and pipe rack area.

3.1.88
V-door ramp
A ramp that extends from the catwalk to the rig floor V-door opening to allow for transfer of pipe and equipment.

3.1.89
well servicing rig
Equipment and machinery assembled primarily for the purpose of well work involving pulling or running tubulars or sucker rods, to include but not be limited to redrilling, completing, recompleting, workover, and abandoning operations.

3.1.90
wire rope
Several wire strands helically laid along an axis.

3.1.91
wireline
A special wire or wire rope used to convey a tool(s) into and out of a wellbore.

3.2 Abbreviations

BOP	blowout preventer
DST	drill stem test
IDLH	immediately dangerous to life or health
LEL	lower explosive limit
LNG	liquefied natural gas
LPG	liquefied petroleum gas
MODU	mobile offshore drilling unit
P&ID	piping and instrumentation diagram
PEL	permissible exposure limit
PFAS	personal fall arrest system
PPE	personal protective equipment
SDS	safety data sheets

4 Safety and Health Management System

4.1 General (Safety and Health Management)

4.1.1 One of the most effective ways to reduce workplace hazards and injuries is through a comprehensive, proactive safety and health management system. The safety and health management system are a systematic approach to minimize the risk of injury and illness that involves identifying, assessing, and controlling risks to workers in all workplace operations.

4.1.2 A safety and health management system may include the following, but not limited to:

— instruction on job safety analysis and risk assessment;

— instruction and monitoring of new personnel;

— instruction of personnel on work procedures, job responsibilities, and managing changes;

— regularly scheduled safety meetings in which the job tasks, probable hazards, and related safe practices are emphasized and discussed;

— a plan to facilitate and organize employer and employee actions during workplace emergencies;

— safety education through safety meetings, company publications, training, and other media;

— a shift or personnel changeover process to communicate ongoing operations and potential hazards,

— good housekeeping practices.

4.2 Risk Assessment

4.2.1 Each company should evaluate the workplace hazards and risks and develop and implement measures to manage identified risks.

4.2.2 Job tasks, including potential simultaneous operations, shall be risk assessed before operations commence. The risk assessment shall be communicated during a pre-job meeting with the crew and other involved personnel.

4.2.3 Each company should determine the best method to conduct a risk assessment appropriate for the task which may include, but are not limited to:

— a documented process,

— a visual or verbal process,

— the Job Safety Analysis, or

— other company specific process to recognize risk.

4.3 Hazard Communication

4.3.1 A hazard communication program that evaluates the presence and potential hazards of chemicals found in the workplace shall be established. Workers shall be provided with information concerning the hazard of chemicals and appropriate measures to protect themselves while working with hazardous chemicals. The program shall be written and include information about hazard evaluation, labeling, safety data sheets, employee training and methods to review and update changes in the program based on chemical usage.

4.3.2 Elements of a program may include:

a) Hazard Evaluation—An inventory of all the hazardous chemicals in the work area shall be completed. An evaluation of the potential hazard of a chemical should be conducted before the hazardous chemical is handled. This evaluation may include potential wellbore fluids, drilling fluids, additives/chemicals, and so forth. Generally applicable measures including engineering controls, safe work practices and PPE should be considered for safe handling and use of a hazardous chemical. This information shall be communicated to the worker.

b) Labeling—A labeling system shall be developed that warns of the potential hazards of working with a hazardous chemical. Hazardous chemical labels shall identify (at a minimum) the material or substance and the physical and health hazards.

c) Safety Data Sheet (SDS)—An SDS shall be available and readily accessible for each hazardous chemical used in the workplace. A system to collect and maintain information and inform workers about the chemical hazard information found on an SDS shall be part of the program.

d) Training (required) Personnel shall be provided hazard communication training upon:

1) initial assignment to a work area;

2) when a new chemical has been introduced.

e) Training (recommended) Personnel should also be provided with training, as appropriate, that includes:

1) information regarding the method and observations that can be used to detect the presence of a release of a hazardous chemical in the work area;

2) physical and health hazard information;

3) measures to protect the worker from harmful exposure, including engineering, safe work practices, emergency procedures, PPE use, and so forth;

4) specific details on how to recognize and understand labels in the work area, SDS interpretation, and safe procedures when working with hazardous chemicals.

4.4 Personal Protective Equipment (PPE)

4.4.1 General

Personnel shall use personal protective equipment (PPE) at the worksite as determined by a risk assessment. Efforts should be made to eliminate identified hazards through engineering or administrative controls. The following items may be considered as part of a PPE hazard assessment:

a) The safety hard hat should meet the requirements of ISEA Z89.1, or equivalent standards;

b) Eye protection equipment should meet the requirements of ISEA Z87.1, or equivalent standards;

c) Safety shoes, safety boots, or toe guards should meet the requirements of ASTM F2413, or equivalent standards;

d) Fire retardant or flame-resistant clothing (FRC) should meet the requirements of NFPA 2112 and NFPA 2113, or equivalent standards. See API 99 for more information on flash fire risk assessment;

e) Gloves, boots, apron, or other protective equipment, as appropriate, shall be worn by personnel handling chemicals that can irritate or be absorbed through the skin;

f) Hearing protection should be worn, as applicable;

g) Fit-for-purpose gloves should be worn, as applicable.

4.4.2 Wearing of Apparel, Jewelry, and Hair

4.4.2.1 Apparel should be appropriately sized and worn in a way to avoid entanglement hazards.

Personnel should change clothing as soon as practicable when saturated with flammable, hazardous, or irritating substance(s).

Personnel shall not wear jewelry or other adornments subject to snagging or hanging and causing injury while in the worksite.

4.4.2.2 Personnel with hair of such length as determined to be an entanglement hazard in worksites should keep it contained in a suitable manner while performing their duties.

4.4.2.3 Hair (head and facial hair) shall not interfere with the effective functioning of PPE, if such equipment is required at the worksite.

4.4.3 Hearing Protection

4.4.3.1 A risk assessment shall identify and evaluate the noise exposure(s) in the worksite. Protection against the effects of noise exposure shall be provided when identified by the risk assessment. For guidance on measuring sound levels, see ASA S1.4/IEC 61672-3 and ASA S1.13. For guidance on hearing protection equipment, see ASA S12.6.

4.4.3.2 Personnel should be trained in the use and operation of hearing protection available at the worksite. Personnel shall be advised of the potential dangers of noise exposure.

4.4.3.3 Noise surveys should be conducted, and signage posted to alert employees of any high noise areas as a result.

4.4.4 Respiratory Protection

4.4.4.1 A risk assessment shall identify and evaluate the respiratory hazard(s) in the worksite; this assessment shall include potential exposures to respiratory hazard(s) and an identification of the contaminant's chemical state and physical form.

4.4.4.2 Based on the risk assessment, the appropriate PPE shall be used. For respiratory protection practices, including equipment selection, use, medical history review, fit testing, storage, inspection, maintenance, and training, see ASSE Z88.2 or equivalent for reference.

4.4.4.3 Approved self-contained or supplied-air breathing equipment shall be used for those atmospheres where tests indicate toxic or hazardous gases are present in quantities immediately dangerous to life or health (IDLH) or oxygen content is less than necessary to sustain life.

4.4.4.4 Air from the rig utility system shall not be used as the source for breathing air supply.

4.4.4.5 Personnel shall be advised of the potential dangers of flammable, hazardous, oxygen deficient atmosphere, and toxic or hazardous gases (e.g. hydrogen sulfide, sulfur dioxide, and so forth) environments. See API 49, API 55, and API 68 for additional information.

4.4.5 Fall Protection

4.4.5.1 A risk assessment shall identify and evaluate the fall hazard(s) in the worksite. Personnel, when engaged in work equal to or greater than 4 ft (1.2 m) above the working surface (e.g. rig floor, ground, decking) or when immediate fall hazards are present (e.g. mud pits, cellars), should be protected from falling by guardrail systems, safety net systems, fall restraints, or personal fall arrest systems (PFAS) that comply with ASSE Z359.1, or equivalent. See 6.13 for information regarding hoisting personnel.

4.4.5.2 Personnel shall be trained in the selection, use, and inspection of fall protection provided.

4.4.5.3 Where there is an identified risk of entanglement with rotating equipment, lanyards and other fall protection equipment should be restrained.

4.5 Incident Management

4.5.1 Incident Reporting

4.5.1.1 Occupational fatalities, injuries, illnesses, and near miss incidents shall be reported in accordance with company policy. Additional reports to regulatory agencies and others may be required.

4.5.1.2 The cause of injury, illness, or a near miss event should be investigated and steps taken to prevent a recurrence. When possible, consideration should be given to share lessons learned with company employees and the industry following an incident.

4.5.2 Medical Response

4.5.2.1 Provisions should be made for prompt medical attention in case of serious injury to include, but not limited to, transportation of the injured person to a medical treatment facility.

4.5.2.2 Relevant information such as telephone numbers and location, pertaining to availability of medical personnel, transportation, and medical facilities should be available at drilling and well servicing sites.

4.5.2.3 Suitable facilities for quick drenching or flushing of the eyes or body, or both, shall be readily accessible for emergency use where personnel can be exposed to injurious corrosive materials. For information on emergency eyewash and shower equipment, see ISEA Z358.1.

4.5.3 First Aid

4.5.3.1 An individual trained in first aid and cardiopulmonary resuscitation (CPR) techniques should be available at the worksite to render aid. The individual(s) should be trained using approved courses (e.g. American Red Cross, American Heart Association, or equivalent training).

4.5.3.2 A first aid kit shall be maintained and available at the worksite. The kit should contain appropriate materials and should be inspected at frequent intervals and replenished as necessary.

5 Safe Work Practices

5.1 Housekeeping

5.1.1 Worksites should be kept orderly to minimize hazards.

5.1.2 Care should be taken to leave egress routes open, especially around the rig floor.

5.1.3 Tools, equipment, and materials should be placed and stored in a secure position or manner to prevent them from falling.

5.1.4 Fire extinguishing equipment shall be accessible and free of obstructions during operations.

5.1.5 A way to convey fluids away from the rig floor while pulling wet strings of pipe should be provided.

5.1.6 Efforts should be taken to keep accumulations of water, oil or drilling fluid out of the cellar on a routine basis. Care should be taken to keep loose equipment or materials not being used out of the cellar.

NOTE There will almost always be some small amounts of fluids in the cellar.

5.2 Fire Safety

5.2.1 Fire Prevention

5.2.1.1 A fire risk assessment shall be conducted in accordance with company procedures. The risk assessment shall be reviewed if the fire risk changes. The fire risk assessment may include potential fuel, sources of combustible fluids or vapors, and ignition sources. Results of the risk assessment shall be communicated to the employees and implemented as applicable.

a) Examples of potential ignition sources include the following, but are not limited to:

— open flames,

— internal combustion engines,

— lightning,

— hot surfaces,

— radiant heat,

— smoking,

— portable electronic devices,

— cutting and welding,

— spontaneous ignition sources (e.g. iron sulfide, discarded oily rags),

— frictional heat or sparks,

— static electricity,

— electrical sparks,

— stray currents, and

— ovens, furnaces, and heating equipment.

b) Examples of potential sources of combustible fluids or vapors include the following, but are not limited to:

— wellbore, shakers, flow lines, flare lines,

— tanks (e.g. frac, production, flowback), and

— chemical storage.

5.2.1.2 Combustible and flammable materials shall be stored in accordance with company procedures. See NFPA 30 for information on the proper storage of combustible and flammable materials.

5.2.1.3 Discarded oily rags and combustible waste should be stored in metal containers with the covers kept in place.

5.2.1.4 A fire risk assessment should be conducted when using material for cleaning with a flash point less than 100 °F (38 °C); refer to the material SDS.

5.2.1.5 Metal or other conductive material containers should be used in handling, storing, or transporting flammable liquids. Metal parts on plastic containers used in such service should be bonded to the fill connection. See NFPA 77 and API 2003 for additional information.

5.2.1.6 Smoking shall be permitted only in designated areas.

5.2.1.7 Only explosion proof and intrinsically safe heaters shall be permitted on or near the rig floor, substructure, pits, or cellar (see API 500 or API 505 for guidance on electrical area classification). The safety features of these heaters shall not be altered.

5.2.1.8 Stoves and heaters using combustible fuels should only be used in accordance with the manufacturer's recommendations to prevent buildup of carbon monoxide.

5.2.1.9 The handling, maintenance, storage, transportation, usage, and disposal of batteries should follow manufacturer recommendations.

5.2.2 Fire Protection/Control

5.2.2.1 Fire extinguishing equipment shall be available, suitably located, readily accessible, and plainly labeled as to their type and method of operation. See 6.2.3 for fire protection provisions during hot work operations.

5.2.2.2 Drilling rigs and well servicing units shall have readily accessible fire extinguishers in operating condition with an appropriate class rating for the potential application. See NFPA 10 for additional guidance.

5.2.2.3 Crew members shall be familiar with the location of fire extinguishing equipment and shall be trained in the use of such equipment, application, and associated hazards, in accordance with company policy.

5.2.2.4 Fire extinguishing equipment shall not be tampered with and shall only be used for fire protection, firefighting purposes, and servicing. Where a fire protection water system is available, it may be used for wash down and other utility purposes only if its firefighting capability is not compromised.

5.2.2.5 Fire extinguishing equipment shall be periodically inspected and maintained in operating condition. A record of the most recent equipment inspection shall be maintained.

5.3 Flammable Liquids and Gases

5.3.1 Containers

5.3.1.1 Hand portable containers for storing flammable liquids or gases should be underwriters' laboratories (UL) or factory mutual (FM) approved, or equivalent.

5.3.1.2 Tanks, drums, and other containers containing flammable liquids or gases should be properly labeled to denote their contents.

5.3.2 Fuel and Oil Transfers and Refueling

5.3.2.1 A risk assessment should be performed prior to refueling and transfer operations. The risk assessment may include, but is not limited to:

— engines running during refueling,

— grounding and bonding procedures,

— simultaneous operations,

— environmental conditions and concerns, and

— potential ignition sources.

5.3.2.2 Fuel and oil transfer procedures should be established and followed.

5.3.2.3 One person should be designated to gauge or monitor tanks (e.g. fuel, mud, etc.) while they are being filled to prevent overfill and spillage.

5.3.2.4 Above ground storage tanks and equipment being refueled shall be grounded. Portable containers should be bonded back to the fuel tank during transfer operations. See API 2003 for additional information.

5.3.3 Portable Cylinders Containing Compressed Flammable Gas

5.3.3.1 Portable cylinders that are in use or in storage shall:

a) be secured to prevent them from falling or being knocked over,

b) be transported, stored and used in an appropriate position,

c) use valve protective caps (if designed for) except when being filled or connected for use,

d) comply with the regulations, rules, or code under which the container was fabricated for repairs or alterations,

e) not be exposed to temperatures exceeding manufacturer's specifications,

f) not be subjected to heating methods that conflict with manufacturer's specifications,

g) be removed from service in accordance with the pressure vessel code under which they were manufactured for denting, bulging, gouging, corrosion, or exposure to fire, and

h) be marked or labeled in accordance with the requirements of the appropriate authority having jurisdiction or by agreement where no such authority exists.

NOTE See the Compressed Gas Association (CGA) documents for additional guidance.

5.3.3.2 Only qualified personnel should be allowed to fill portable cylinders. Protective gloves should be worn when refilling or replacing portable cylinders.

Warning—There is a possibility of freeze burns if compressed gases come in contact with skin.

5.3.4 Flammable/Combustible Liquids Storage

5.3.4.1 A risk assessment should be performed to determine the appropriate safe location and distance from the wellbore, and appropriate safety measures for storing flammable and combustible liquids.

5.3.4.2 Enclosed flammable or combustible liquids storage areas shall:

a) maintain adequate ventilation to the outside air or engineer design to control vapors,

b) have unobstructed exit(s),

c) be maintained with due regard to fire potential with respect to housekeeping and materials storage,

d) be identified as a hazard, and appropriate warning signs posted,

e) have an appropriate fire extinguisher (see NFPA 10 for information) readily available or fixed extinguishing system installed for the hazard(s) being stored, and

f) be properly classified for electrical installations in accordance with API 500 or API 505; if dispensing is done within the area, it shall be classified as Class 1, Division 1 or appropriately zoned area.

5.3.4.3 Containers that are labeled *flammable* or *combustible* should be properly stored when not in use.

5.3.5 Liquefied Petroleum Gases

5.3.5.1 A risk assessment should be performed to determine the appropriate safe location and distance from the wellbore, and appropriate safety measures for storing liquefied petroleum gases.

5.3.5.2 On land locations, liquefied petroleum gas (LPG) tanks larger than or totaling more than 250 gal (0.95 m^3) and liquefied natural gas (LNG) tanks should be placed at least 100 ft (30.5 m) from, and parallel to the closest side of the rig (as terrain and location configuration allow) or the appropriate distance as determined by the risk assessment.

6 Operations and Procedures

6.1 General (Operations and Procedures)

6.1.1 Well control shall be maintained as needed for the type of operation.

NOTE See API 16ST, API 53, API 59, API 75, and API 92U for more information on well control operations, procedures, and training.

6.1.2 A risk assessment should be performed to determine the appropriate safe location and distance from the wellbore for land operations, to include safe distance for vehicles, housing, or areas where personnel gather that are not involved with the current operation being performed, or a combination thereof.

For land operations, a risk assessment should be performed to determine the appropriate safe location and distance from the center of a derrick or mast for vehicles, housing, and/or areas where personnel gather that are not involved with the current operation to minimize the potential of the derrick or mast striking personnel or equipment in the fall zone.

NOTE The fall zone hazards may be dependent on, but not limited to:

— environmental conditions,

— type of rig (carrier mounted rigs warrant special consideration),

— rig orientation, or

— current operation(s) (e.g. raising and lowering the derrick/mast).

6.1.3 The rig substructure, derrick, mast, and other equipment as appropriate, shall be grounded while in operation.

6.2 Hot Work, Welding, and Flame Cutting Operations

6.2.1 General (Hot Work, Welding, Flame Cutting)

6.2.1.1 A risk assessment should be performed and communicated to the affected crew and other personnel (as appropriate) that determines the appropriate safe location and distance from the wellbore and other potential flammable and combustible sources, appropriate safety measures for hot work, welding, and flame cutting operations, and the requirement for a written procedure. See API 2009 for additional information.

6.2.1.2 Depending on the risk assessment, a written procedure covering hot work, welding and flame cutting operations shall be utilized. The written procedure should consist of the following if applicable:

a) Pre-work stage:

   1) Designation of person in charge

   2) Meetings with the crew and other persons involved regarding:

      — Scope of work,

      — Simultaneous operations,

      — Atmospheric testing,

      — Equipment isolation,

      — Equipment preparation,

      — Hazard identification and control,

      — Emergency procedures and response,

      — Personal protective equipment requirements, and

      — Fire watch and extinguishing equipment.

   3) Authorization to perform work

b) Work-in-progress stage:

1) Atmospheric monitoring

2) Management of changes, including shift changes

3) Special procedures/precautions

c) Return to service stage:

1) Verification of completion of hot work

2) Authorization for return to work

6.2.1.3 A hot work permit normally is not required for work done in designated hot work areas which are separate from areas where hydrocarbons, flammable, or combustible materials may be present.

6.2.1.4 Qualified welders (certified welders where required) shall perform welding or flame cutting operations on surface facilities, piping, and equipment for which the primary function is to contain hydrocarbons or is designated critical equipment.

6.2.2 Personal Protective Equipment (PPE)

6.2.2.1 Personnel performing hot work operations shall wear appropriate PPE as required in 4.4.

NOTE For additional information on PPE, see appropriate AWS, ISEA, or ASTM documents for additional information (e.g. AWS F2.2, ISEA Z49.1, ISEA Z87.1, ASTM F2412, ASTM F2413).

6.2.2.2 Fit-for-purpose helmets and face shields, with shade selection, shall be used during all arc welding or arc cutting operations. Proper clear eye protection may be worn for submerged arc welding operations.

6.2.2.3 Fit-for-purpose goggles or other suitable eye protection shall be used during gas welding, oxygen cutting, or brazing operations.

6.2.2.4 Helpers or attendants shall be provided with and use proper eye protection.

6.2.2.5 Filter lenses and plates used in helmets and goggles shall meet the test for transmission of radiant energy prescribed in ISEA Z87.1 or applicable regulatory requirement.

6.2.3 Fire Protection

6.2.3.1 Objects to be cut or welded shall be in an area free from combustible or flammable materials. If the object to be cut or welded cannot be moved, then:

a) movable fire hazards in the vicinity should be removed from the area, or

b) guards should be used to confine the heat, sparks, and slag to protect the immovable fire hazards.

6.2.3.2 Properly maintained fire extinguishing equipment shall be available for use during hot work, unless a variance is granted under the risk assessment. This equipment is in addition to the fire protection equipment already in place.

6.2.3.3 Fire watches with extinguishing equipment shall be required whenever welding or cutting is performed in locations outside of the safe welding area whenever combustibles are located within 35 ft (10.7 m) of the welding or cutting operation.

6.2.3.4 Fire watches shall have no other job duties during the period of their watch and shall be maintained at the job site for at least one-half hour after completion of welding or cutting operations.

6.2.3.5 Cutting or welding shall not be permitted in the following situations:

a) In areas not authorized by the person in charge.

b) In a hazardous atmosphere or where such atmospheres may develop. This does not preclude the use of hot tapping when proper precautions are taken. See API 2201 for additional information on hot tapping.

c) In areas that are close to the storage of large quantities of exposed readily-ignitable materials.

d) Where ignition can be caused by heat conduction, such as on metal walls or pipes in contact with combustibles on the other side.

e) On used containers, such as drums, storage tanks, or cargo tanks without prior atmospheric testing.

f) Lack of proper ventilation.

6.2.4 Equipment (Hot Work, Welding, Flame Cutting)

6.2.4.1 Apparatuses such as torches, regulators, hoses, and arc welding machines shall be in good operating condition and repair. Only approved and certified oxygen and acetylene cylinders shall be used.

6.2.4.2 Oxygen and acetylene torches should be equipped with flash-back arrestors and approved strikers.

6.2.4.3 Valve caps shall be in place except when cylinders are connected for use.

6.2.4.4 Cylinders shall be stored in assigned places away from personnel elevators, stairs, or walkways and shall be secured to prevent overturning.

6.2.4.5 Cylinders shall not be kept in unventilated enclosures, such as lockers and cupboards.

6.2.4.6 Oxygen cylinders in storage shall be separated from fuel gas cylinders or combustible materials a minimum distance of 20 ft (6.1 m) or by a noncombustible barrier at least 5 ft (1.5 m) high having a fire-resistance rating of at least one-half hour.

6.2.4.7 Acetylene and oxygen cylinders shall be stored valve end up with protective caps affixed and properly secured. When a job using acetylene and oxygen devices is completed or prior to transporting cylinders, the valve on the cylinders shall be closed and pressure on the hoses bled to zero.

6.2.4.8 When transporting cylinders by a crane or derrick: a cradle, bin or other suitable platform shall be used; slings shall not be used; cylinders shall not be dropped, struck or permitted to strike each other.

6.2.4.9 Input power terminals, top charge devices, and electrically energized metal parts shall be completely enclosed and accessible by means of tools.

6.2.4.10 Terminals from welding leads shall be protected from accidental contact by personnel or metal objects. Damaged leads should not be repaired but should be immediately discarded.

6.2.4.11 Cables with splices within 10 ft (3.1 m) of the holder shall not be used.

6.2.4.12 The welder should not coil or loop welding electrode cables around parts of the person.

6.2.5 Welding Fumes and Ventilation

6.2.5.1 Toxic fumes can be generated from welding on metals. Persons involved in welding operations should understand the hazards of the materials they are working with.

6.2.5.2 Adequate mechanical ventilation shall be provided when welding is performed under the following circumstances:

a) In confined spaces or where the welding space contains partitions, balconies, or other structural barriers to the extent that they obstruct cross ventilation;

b) When the release of toxic fumes or gases is possible due to the nature of the welding, cutting, or brazing work or the materials being welded;

c) Respiratory protection may be required if work practices and ventilation do not reduce exposures to safe levels.

6.2.5.3 When torches are not being used (e.g. meal breaks, end of tour, etc.) the oxygen and acetylene valves shall be turned off at the bottle, the hoses bled down, and torches and hoses removed from an area in which fumes may accumulate.

6.3 Machinery and Tools

6.3.1 Machinery shall be operated by qualified personnel.

6.3.2 Belts, drive chains, gears, and drives (excluding rotary table, catheads, and kelly) shall have guards installed to prevent personnel from coming in contact with moving parts. See ASME B15.1 and ASSE B11.19 for additional information on construction specifications and clearances for such equipment guards.

6.3.3 Machinery shall not be operated unless the guards are secured in position and are maintained in a functional condition. During maintenance or repair work limited testing may be performed by qualified personnel without guards in place.

6.3.4 There should be a process in place for the management of maintenance activities on location.

6.3.5 Personnel shall not clean, lubricate, or repair machinery where there is a hazard of contact with moving parts until such machinery has been stopped, energy isolated and verified, or such parts have been properly guarded.

6.3.6 Hand tools, power tools, and similar equipment, shall be maintained in a safe condition and inspected prior to use.

6.3.7 Electrical hand tools shall be double-insulated or grounded in accordance with NFPA 70. Ground fault circuit interruption protection is recommended.

6.3.8 Manufacturer's safety features for electric, battery-powered, or pneumatic hand tools shall not be modified or made inoperable.

6.3.9 When personnel are climbing or working at heights, tools shall be secured, or the relevant risk be mitigated (barrier or buffer zone).

6.3.10 Temporary lifting and rigging devices in use shall be designed to handle expected load capacity. A risk assessment shall be performed before using these devices.

6.4 Confined Spaces, Excavations, and Hazardous Environments

6.4.1 Prior to commencing work activities, a risk assessment shall be performed to determine if any confined spaces exist or will be created as a result of work at the site. Cellars, excavations, and other confined areas often meet the definition of a confined space (see 3.1.17).

6.4.2 Spaces that are determined to be confined spaces shall be assessed to determine if any of the following hazards exist or have the potential to exist:

a) hazardous atmosphere,

b) potential for engulfing an entrant,

c) internal configuration such that an entrant could be trapped or asphyxiated by inwardly converging walls or by a floor which slopes downward and tapers to a smaller cross-section, or

d) other recognized safety or health hazard(s).

When any of these hazards exist or have the potential to exist, the employer shall implement measures necessary to isolate the space(s) and prevent unauthorized entry.

NOTE See ASSE Z117, API 2015 and API 2016 for additional safety guidelines for working in confined spaces and refer to jurisdictional regulations for additional requirements.

6.4.3 There are two different kinds of confined space: permit required confined space and non-permit required confined space.

Permit required confined space means a confined space that has one or more of the following characteristics:

— contains or has a potential to contain a hazardous atmosphere,

— contains a material that has the potential for engulfing an entrant,

— has an internal configuration such that an entrant could be trapped or asphyxiated by inwardly converging walls or by a floor which slopes downward and tapers to a smaller cross-section, or

— contains any other recognized serious safety or health hazard.

Non-permit required confined space means a confined space that does not contain a hazardous or potentially hazardous atmosphere, and where all other hazards identified above have been eliminated.

6.4.4 Where permit required confined space conditions exist or have the potential to exist, a confined space entry or other permit system should be activated. The system should include the following:

a) posting procedures,

b) evaluation of permit space conditions (e.g. internal atmospheric testing, internal configuration, etc.),

c) procedures for safe entry,

d) equipment required (e.g. respiratory protection),

e) assignment of entrants, attendants and entry supervisors,

f) emergency/rescue procedures,

g) multi-employer coordination,

h) permit cancellation procedures,

i) review practices.

6.4.5 Prior to entry of a permit required space, completion of internal atmospheric testing by a qualified person should be done to determine:

a) oxygen content,

b) airborne combustible dust,

c) acceptable level of flammable gases/vapors,

d) potential toxic air contaminants.

Entry to conduct tests shall comply with atmospheric testing procedures for confined space testing requirements.

6.4.6 To maintain occupation of confined spaces, the atmosphere within the space shall be monitored continuously accordance with company operating practices.

6.4.7 Mitigation, elimination, or protection from the following characteristics should be considered and implemented as appropriate:

a) hazardous atmosphere,

b) a material that has the potential for engulfing an entrant,

c) an internal configuration such that an entrant could be trapped or asphyxiated by inwardly converging walls or by a floor which slopes downward and tapers to a smaller cross-section, or

d) other recognized safety or health hazard.

6.5 Lock-out/Tag-out (Energy Isolation)

6.5.1 A documented lock-out/tag-out program shall be established and implemented. Personnel shall be trained in the program.

6.5.2 Where locks and tags are utilized:

a) Locks and/or tags should be placed on energy isolation devices to plainly identify the equipment or circuits being worked on. Tags on equipment should include the name of the person(s) installing the lock or tag;

b) The lock or tag should be removed by the person who installed it or by that person's authorized replacement. In the event neither individual is available, the lock or tag may be removed by the supervisor after ensuring that no hazard will be created by energizing the locked or tagged equipment or circuit(s);

c) When multiple locks are used, the process being utilized shall be communicated, understood and agreed upon by the users.

6.5.3 Examples of energy isolating devices may include, but not limited to:

- manually operated electrical circuit breakers,
- disconnect switches,
- double block and bleed valve systems,
- blanks and blinds,
- threaded caps and plugs, conduit seals, and so forth,
- blocks for mechanical linkages, or
- roof drain valves on external floating roof tanks.

6.5.4 Prior to performing work on equipment where energy isolation has been applied, the equipment shall be tested to verify (try out) that energy isolation is successful and stored energy has been released.

6.6 Work in Proximity to Exposed Energized Power Sources

6.6.1 General (Energized Source Proximity)

6.6.2 A risk assessment should be performed prior to working near, or to moving or placing equipment when there are energized utility line hazards.

6.6.2.1 Equipment or machines should not be operated closer to power lines than the clearances shown in Table 1, except when such lines have been de-energized and visibly grounded or when barriers are present to prevent physical contact with the lines.

6.6.2.2 When moving equipment under power lines and an individual is designated to observe equipment clearance as defined in Table 1, that individual should communicate to the operator when clearance is not maintained.

6.6.2.3 When cage-type boom guards, insulating guylines, insulating links, or proximity warning devices on rigs or guylines are used, the clearances provided in Table 1 shall be followed.

6.6.2.4 Overhead wires should be considered energized (live) unless either the electrical system owner reports them to be non-energized, or a qualified electrical person tests and finds them to be non-energized.

Table 1—Minimum Clearances between Power Lines and Derricks, Masts, or Guylines

Equipment Status	Line Voltage	Minimum Clearance, ft
Operating Rigs	All	10 ft (3 m) plus 4 in. for each additional 10 kV over 50 kV
In Transit (lowered mast)	Less than or equal to 50 kV	4 ft (1.2 m)
	Greater than 50 kV	4 ft (1.2 m) plus 4 in. (10 cm) for each additional 10 kV

6.6.3 Rig Electrical Systems Equipment

Electrical equipment used in hazardous locations should be designed for such locations, and approved by a nationally recognized testing laboratory, or country equivalent (see API 500 or 505 for guidance for classification of areas as hazardous locations for electrical equipment). Wiring components and electrical equipment should be maintained in accordance with the manufacturer's recommendation.

6.6.3.1 Rig wiring should be protected from abrasion, vehicular and foot traffic, burns, cuts, and damage from other sources.

6.6.3.2 Wiring, including insulation, should be replaced, properly repaired, or sealed as necessary, when damage is detected.

6.6.3.3 Extension cords shall be fit for purpose, properly insulated, and in good condition.

6.6.3.4 Wiring on drilling and workover rigs used on platforms in offshore waters should be in accordance with applicable regulations or standards (e.g. API 14F and API 14FZ).

6.6.4 Classification of Areas

Area classifications determine the type of and maintenance requirements for electrical equipment on drilling and well servicing rigs under normal operating conditions. When special service operations are being performed, the recommendations for electrical installations under the conditions of service should be followed. See API 500 and API 505 for details of various area classifications.

6.7 Hydrogen Sulfide (H_2S) Environment and Hazardous Atmospheres

6.7.1 Safety guidelines and recommendations for use in drilling and well servicing operations where hydrogen sulfide or sulfur dioxide gas may be encountered are contained in API 49. Also see API 55 and API 68 for additional information. These recommended procedures should be utilized, as appropriate, in applicable operations to enhance safety of personnel and the public.

6.7.2 Where hazardous atmospheres are known or suspected to exist, or may be created as a result of operations, the operator shall ensure that personnel are trained and advised of the potential hazards

6.7.3 When work is to be conducted in areas where hazardous atmospheres are suspected or known based on the risk assessment, atmospheric conditions should be monitored and/or mitigated.

6.8 Simultaneous Operations (SIMOPS)

6.8.1 Each company involved should evaluate the workplace hazards and risks and develop and implement specific components to mitigate identified risks.

6.8.2 Prior to commencing simultaneous operations, the responsible personnel shall meet with the involved parties to verify the aspects of the operation, confirm emergency procedures, and identify any constraints, limitations, or conflicting activities.

6.8.3 During simultaneous operations, responsible personnel should stop work and reevaluate the operations if conditions vary from the original scope of work.

6.9 Hot Tapping and Freezing Operations

6.9.1 General

A risk assessment should be performed to determine the appropriate safe location and distance from the wellbore, and appropriate safety measures should be taken for hot tapping and freezing operations.

6.9.2 Hot Tapping Operations

Hot tapping operation should be conducted in accordance with API 2201.

6.9.3 Freezing Operations

Freezing operations should be performed by and supervised under the direct supervision of a qualified person.

6.10 Rig Up Operations

6.10.1 Prior to commencing rig up operations, a risk assessment should be performed to determine the planned arrangement of equipment to be placed on the location and should also be reviewed to identify and mitigate potentially hazardous conditions.

6.10.2 Drilling and well servicing equipment shall be set up and checked for proper installation prior to commencing work in accordance with company guidelines.

NOTE Inspection checklists may be available from equipment manufacturer, service provider, third-party, company provided, and so forth.

6.10.3 Prior to initiating well servicing operations, the well shall be checked for pressure. If pressure is indicated, the operator's authorized person should be notified; then proper steps should be taken to remove pressure or to operate safely under pressure before commencing operations.

6.11 Rig Down Operations

6.11.1 Prior to commencing rig down operations, a risk assessment should be performed to identify and mitigate potentially hazardous conditions.

6.11.2 Prior to initiating rig down operations, the lines and equipment shall be checked for pressure. If pressure is indicated, then proper steps should be taken to remove pressure or to operate safely under pressure before commencing rig down operations.

6.12 Auxiliary Escape

6.12.1 The derrick or mast shall have an auxiliary means of escape installed prior to personnel working on elevated fixed platforms in and on the derrick or mast. The auxiliary escape route should use a specially rigged and securely anchored escape line attached to the derrick or mast to provide a readily available and convenient means of escape from the elevated fixed platform. The escape line route shall be kept clear of obstructions.

6.12.2 Escape equipment shall not be used except during an emergency, maintenance or training purposes. Personnel shall be trained in the proper procedure(s) for escaping the derrick or mast.

6.12.3 Auxiliary escape lines and equipment shall be installed in accordance with manufacturer recommendations.

6.13 Personnel Hoisting Systems

6.13.1 Equipment used for the lifting of personnel shall be fit-for-purpose, comply with local regulations, and operated in accordance with the manufacturer's instructions by trained and authorized personnel. See 4.4.5 for information regarding fall protection.

6.13.2 Before hoisting personnel, an assessment shall be done to determine if other non-hoisting methods are available.

6.13.3 Personnel shall not ride the elevators.

Exceptions for extreme emergency conditions, when other alternatives have been exhausted, may be permitted when in the judgment of the supervisor; riding the elevators with appropriate personal fall protection equipment is necessary. In this instance, the elevators shall be empty of pipe and other equipment when personnel are riding.

6.13.4 Prior to utilizing equipment for personnel hoisting:

a) an appropriate level of risk assessment for the lifting operations and surrounding conditions shall be conducted;

b) operations that may interfere with personnel hoisting operations shall be suspended;

c) hand signals, when used, should be reviewed and agreed upon.

6.13.5 When using winches for hoisting personnel:

a) the controls shall be attended at all times while lifting, lowering, or stabilizing personnel;

b) visual contact and communication shall be maintained between the winch operator and the rider; if the winch operator cannot maintain visual contact, a spotter shall be utilized;

c) the manual brake, if applicable, should be set whenever the rider is not being hoisted;

d) there shall not be a clutch mechanism or other means for the winch to freewheel;

e) a load limiting mechanism, line speed limiter, automatic secondary brakes along with normal braking system, or controlled descent feature, or a combination thereof, shall be used (if applicable);

f) a self-centering control lever, which when released, should return to the neutral position;

g) an automatic brake should be installed that will engage when returning the control lever to the neutral position or upon loss of power;

h) the winch should be equipped with an emergency shut-off valve within immediate reach of the winch operator;

i) the winch should be equipped with a drum guard and a mechanism that ensures proper spooling.

6.14 Tubular Handling

6.14.1 Loading and Unloading Tubulars

6.14.1.1 Pipe should be handled at the pipe ends during manual pipe loading and unloading operations, and transfers between pipe racks or pipe tubs.

6.14.1.2 Personnel shall not pass between joints of pipe during loading and unloading operations.

6.14.1.3 Personnel should not stand on, walk on, or roll pipe with their feet.

6.14.1.4 Equipment such as stops, pins, wedges, or chocks should be used to prevent tubulars from accidentally rolling off pipe racks or pipe trucks. Pipe should be loaded and unloaded layer-by-layer, with each completed layer pinned or blocked securely on the four corners of the pipe rack.

6.14.1.5 On pipe racks, layers of tubulars should be separated with boards or equivalent.

6.14.2 Tripping and Racking

6.14.2.1 In well servicing operations, personnel shall be out of the derrick/mast, or cellar, or both, and stand clear when a downhole assembly is being unseated or when initial pull on the tubing or rods is made.

6.14.2.2 Rods, tubulars, drill pipe, and drill collars racked or hung in the derrick or mast should be secured to prevent them from falling across the derrick or mast.

6.14.2.3 Safety clamps (e.g. wedding band, dog collar) shall be removed from drill collars, flush joint pipe, or similar equipment before they become an overhead hazard.

6.14.2.4 When there is a possibility of an ice plug forming in the bottom of racked tubular stands, provisions should be made to allow good drainage from the racked tubulars.

Warning—When going in the hole, an unsuspected ice plug in the tubulars can be blown upward and endanger crew members.

6.14.2.5 A rabbit or drift should be used to verify that tubular stands are free of plugs before pipe is run in the hole when appropriate.

6.15 Offshore and Inland Waters Operations

6.15.1 A risk assessment should be performed prior to offshore and inland waters operations.

Users of this standard should also refer to other applicable requirements and guidance, such as local regulations for onshore, inland waters, and offshore waters.

NOTE See API 2D, API 16ST, API 53, API 59, API 65, API 65-2, API 75, API 96, API 97, and API 92U for more information on offshore and inland waters operations, procedures, and training.

6.15.2 When work is to be performed on a barge, work boat, mobile offshore drilling unit (MODU), crew boat, or platform, personnel should be instructed on station bill, abandonment procedures, emergency signals, abandonment stations, water entry procedures, and muster list as appropriate.

6.15.3 A minimum of two emergency escape means should be provided from the platform to the water.

6.15.4 Personnel working over water or where the potential to fall into the water exists, shall be provided with approved personal flotation devices in serviceable condition.

6.15.5 An overboard emergency rescue plan shall be established, and the required equipment be readily available.

6.15.6 Each continuously manned platform shall be provided with appropriate means of evacuation with the sufficient capacity to accommodate each person present in accordance with regulatory requirements.

6.15.7 In accordance with appropriate regulatory and company requirements, approved survival suits should be provided, and crew members should be instructed in the proper use of this equipment when operations are conducted in cold water areas.

6.15.8 When a crane is being used to transfer personnel over water, personnel shall wear approved personal flotation devices and should not ride on anything other than a device designed for that purpose. The crane operator should avoid lifting or lowering personnel directly over a vessel, except to clear or land personnel. The load being lifted shall not exceed basket manufacturer's specifications. Personnel baskets shall be inspected prior to use and periodically in accordance with the manufacturer's recommendations. Personnel baskets should be used only for the transfer of personnel.

6.15.9 When personnel use a swing rope for transferring from boat to landing platform and vice versa, they shall wear approved personal flotation devices during such transfer operations.

7 Drilling and Well Servicing Equipment

7.1 Derricks and Masts

7.1.1 Derricks, masts, and their auxiliary parts shall be constructed to conform to good engineering practices and maintained in a safe condition. See API 4F and API 4G for additional information.

7.1.2 Derricks and masts should have a permanent name plate attached to the structure indicating the following:

a) name of manufacturer,

b) model number and serial number,

c) rating including static hook load capacity with number of lines, and

d) whether guying is applicable and, if so, the recommended guying pattern; if the manufacturer's guying requirements are not denoted on the name plate, the derrick or mast should be guyed in conformance with recommendations of API 4G.

7.1.3 Carrier-mounted masts should not be moved while in a raised position. This does not apply to skidding of a drilling rig or pole mast well-servicing rig.

7.1.4 A person qualified in procedures for raising and lowering the mast shall be in charge of raising or lowering operations.

7.1.5 A visual inspection of the raising and lowering mechanism shall be made by the qualified person prior to raising or lowering the mast.

7.1.6 Prior to raising or lowering a mast, tools and materials not secured shall be removed from the mast.

7.1.7 The mast base should be level and properly positioned before raising, lowering, or telescoping the mast structure, and before tightening guylines.

7.1.8 Properly designed sub structures and base beams should be designed and installed according to manufacturer's recommendations. See API 4G and 4F for additional information.

7.1.9 During raising, lowering, or telescoping operations, observations should be made to mitigate the chance of wire ropes snagging on the braces or other portion of the mast.

7.1.10 No personnel shall be allowed in or under the mast unless it is in the fully raised or lowered position. An exception may be: only essential personnel may be allowed on the carrier platform, in or under the mast while being raised or lowered.

7.1.11 Prior to imposing a load on a derrick or mast, required guylines shall be tensioned in accordance with manufacturer's guidelines.

7.1.12 Derrick and mast platforms above the rig floor shall be constructed, maintained, and secured to the structure to withstand the weight of personnel and other forces which may be applied. See API 4F and API 4G for additional information.

7.1.13 To prevent dropped object hazards:

a) tools, parts, and other materials:

   1) should be secured/tethered when working in the mast or derrick,

   2) shall not be kept in the derrick or mast above the rig floor unless they are in use and measures are taken to prevent them from falling,

   3) should be inventoried to ensure that they are not left in the derrick or mast, or both, at the completion of the work.

b) a periodic inspection program should be in-place to ensure that there are no unsecured items in the derrick or mast,

c) personnel should not be under suspended loads, and

d) personnel should not be under work being performed overhead without additional safeguards in place.

7.1.14 Crown mounted bumper blocks should be adequately secured and protections in place to prevent a dropped object event.

7.1.15 Counterweights above the rig floor, if not fully encased or running in permanent guides, should have a safety chain or wire rope safety line anchored to the derrick or mast.

7.1.16 Load-bearing, hydraulic-leveling jacks shall have a safety lock device, double valves, or equivalent.

7.2 Ladders, Stairways, and Platforms

7.2.1 Each derrick/mast shall be equipped with a fixed ladder(s) providing access from the rig floor to the crown block platform and access to each intermediate platform.

7.2.2 Permanent ladders fastened to a derrick or mast should remain securely held in place in accordance with manufacturer's specifications.

7.2.3 The distance from the centerline of fixed ladder rungs, cleats, or steps to the closest object behind the ladder should not be less than 7 in. (17.8 cm). The distance between ladder rungs should be uniform throughout the length of the ladder including the landing(s) and no more than 12 in. (30.5 cm). The minimum rung clear length should be 16 in. (40.6 cm). When unavoidable obstructions are encountered, minimum clearances for the two rungs on either side of the obstruction should be measured vertically from the obstruction no less than 1.5 in. (3.8 cm) to the upper rung, and 4.5 in. (11.4 cm) to the lower rung.

7.2.4 Side rails of fixed ladders should extend a minimum of 42 in. (106.7 cm) above the platform or landing.

7.2.5 Cages and landing platforms are not necessary where a personal fall arrest system is used.

7.2.6 Platforms shall be provided wherever fixed ladders are offset laterally, unless a personal fall arrest system is utilized.

7.2.7 Open stairways of four or more risers should be securely fastened and equipped with handrails and mid rails extending the entire length of the stairway.

7.2.8 The width of tread and height of rise should be uniform throughout the length of a stairway and the treads should be level.

7.2.9 A minimum of two unobstructed stairways shall be installed on drilling rigs to provide alternate exits from the rig floor during operations. During rig-up and rig-down operations, one unobstructed stairway may be installed.

7.2.10 Stairways, ladders, ramps, runways, and platforms (including rig floor, etc.) should be kept free of objects and substances that may create a slipping or tripping hazard and hinder or prevent emergency egress of personnel.

7.2.11 Derrick, mast, or other platforms shall be adequately secured, inset, or otherwise appropriately protected against accidental dislodging during operations.

7.2.12 When personnel cannot perform necessary duties from ground level, well servicing rigs should use a working platform around the wellhead. The platform should be of sufficient size and construction to support the maximum working load and the number of personnel.

7.2.13 When a wellhead level working platform is in the folded (storage) position, the platform shall be secured with no less than two fasteners of a positive locking or double locking device.

7.2.14 The stabbing board and each finger shall either be bolted, welded, hinged-and-pinned, or attached by other equivalent means to its support beam. A secondary retention means should be utilized to secure each of the fingers and the stabbing board.

7.2.15 Guardrails, consisting of 42 in. (106.7 cm) high (nominal) top rail, mid rail, toe boards and posts, should be installed at the outer edge of a floor, platform, or walkway, that is 4 ft (1.2 m) or more above ground level or another floor or working level. A runway of 4 ft (1.2 m) or more above ground level should be equipped with a guardrail. Exceptions are as follows:

— personnel egress (exit and entrance) openings,

— catwalk, false floor, and V-door opening when being used,

— work station being used to rack tubulars, and

— alternate arrangements providing equivalent safety are acceptable.

The V-door opening should be secured when not being used to avoid personnel falling down the V-door ramp.

See ASSE A1264.1 for additional information on wall opening, stairs, and railing systems.

7.2.16 Standard toe boards should be a minimum of 4 in. (10.2 cm) in vertical height from the top edge to the level of the floor, platform, walkway, or runway. Toe boards should be securely fastened in place and have not more than $^{1}/_{4}$ in. (0.64 cm) vertical clearance between the bottom of the toe board and the floor level. They may be constructed of a substantial material, either solid or with openings not to exceed 1 in. (2.54 cm) in greatest dimension.

7.2.17 Floor openings should be protected by a cover, a physical barrier, or constantly attended to avoid accidently walking into them and falling.

7.3 Drawworks

7.3.1 A visual inspection of the drawworks and its visible moving parts should be made at least once each day.

7.3.2 Drawworks guards should remain in place and in good condition when in operation.

7.3.3 The equipment operator shall not leave the drawworks brake unattended on a lever activated brake system without tying down the brake or securing it with a catch lock, unless the drawworks is equipped with an automated control system.

7.3.4 Shut-down switches for drawworks or devices that power the drawworks should be installed at the operator's control console.

7.3.5 Brake systems on the drawworks should be inspected and maintained according to the manufacturer's recommendations.

7.3.6 An auxiliary braking system should be installed on the drawworks of lever activated brake system drilling rigs.

7.3.7 Drilling rig drawworks should be equipped with a safety device which is designed to prevent the traveling block from striking the crown block. The device should be function tested at least once per tour/shift or when moved or altered. Results of the function test shall be documented.

7.4 Cathead Spools and Lines Powered by Cathead Spools

7.4.1 Catlines shall not be used for hoisting personnel.

7.4.2 Alternative methods of hoisting or moving equipment should be used if possible.

7.4.3 Only qualified personnel shall be permitted to operate the cathead spool or lines powered by the cathead spool.

7.4.4 If a cathead spool is used:

a) If mounted on the end of a shaft that projects beyond the guard for other moving parts of machinery, the shaft end, key, or other device for securing the cathead to the shaft shall be covered with a smooth thimble. The thimble cover shall be of such design to prevent accidental entanglement;

b) When a rope is manually operated, it shall have a rope guide to hold the on-running rope in alignment with its normal running position against the inner flange. Clearance of the rope guide from the cathead spool should be based on size of the rope in use. Consult the equipment manufacturer for recommended rope guide clearance for the specific rope size being used;

c) It shall be checked for grooves and rebuilt and turned when necessary to prevent fouling. Cathead spool groove depth should not exceed 1/4 in. (0.64 cm);

d) Precautions shall be taken to prevent entanglement of other lines with a line in use on the cathead spool;

e) When unattended, rope or line shall not remain wrapped on or in contact with the cathead spool;

f) The drawworks control shall be attended while a manually operated cathead spool is in use;

g) Rope splicing shall not be allowed to contact the cathead spool friction surface, with the exception of endless rope properly spliced;

h) A headache post or guard shall be provided for protection of the personnel at the drawworks control when the line is close to the operator during operation of lines powered by the cathead spool;

i) Lines powered by the cathead spool should be of proper length and maintained in safe working condition.

7.5 Hoisting Lines and Other Wire Rope

7.5.1 Hoisting lines should be visually inspected at least once each day when in use. Hoisting lines should be thoroughly inspected once each month and a record made of the monthly inspection, designating noted defects. See API 9B for additional guidance on application, care, and use of wire rope.

7.5.2 Wire rope used as running ropes (hoisting or hauling) should be removed from service when any of the following conditions exist:

a) Three broken wires are found within one lay length of 6×7 wire rope;

b) In other six and eight strand constructions:

   1) six randomly distributed broken wires are found within one lay length, or

   2) three broken wires are found in one strand within one lay length;

c) In rotation-resistant constructions:

   1) four randomly distributed broken wires are found within one lay length, or

   2) two broken wires are found in one strand within one lay length.

7.5.3 Wire rope used as standing ropes, such as guylines, escape lines, and pendant lines should be removed from service when either of the following conditions exist:

a) three broken wires are found within one lay length, or

b) one broken wire is found at the end connection in the strand valley.

7.5.4 Other conditions you can consider for removal of wire rope from service are, for example but not limited to:

— marked corrosion appears,

— corroded wires are observed at end connections,

— end connections are corroded, cracked, bent, worn, deformed, or improperly applied, or

— evidence of kinking, crushing, cutting, cold working (peening), or bird-caging is observed.

7.5.5 When the hoisting line is wrapped on the hoisting drum, the end shall be securely fastened and there should be a sufficient number of line wraps remaining on the drum to eliminate strain on the fastening devices.

7.5.6 Deadline anchors for hoisting lines should be so constructed, installed and maintained that their strength equals or exceeds the working strength of the hoisting line.

7.5.7 When calculations indicate ton-mile limits have been reached, or visual inspection shows breaks, crushing, or damage, the wire rope should be slipped, cut, or replaced. See API 9B, or the manufacturer's cutoff system for computation procedures.

7.5.8 A moving hoisting line (drilling line/tubing line) under load should not be allowed to come in contact with the derrick or mast or other stationary equipment except at the crown block sheaves and traveling block sheaves.

7.5.9 The hoisting line should not be removed from the hoisting drum until the traveling block is rested on the rig floor or held suspended by a separate purpose-built, support device.

7.6 Hoisting Tools, Hooks, Elevator Links (Bails), Elevators, and Related Equipment

7.6.1 Hoisting tools and their component parts shall be constructed to conform with good engineering practice and maintained in safe condition. Equipment specifications are contained in API 8A and API 8C. Suggested inspection and maintenance procedures for hoisting tools are contained in API 8B. Equipment manufacturers' specifications and recommended maintenance procedures should be consulted.

7.6.2 No element in the hoisting tool system should be subjected to a load in excess of its design limitations.

7.6.3 The block hook assembly shall be equipped with a safety latch or other equivalent device to prevent accidental release of the load being hoisted or lowered.

7.6.4 Traveling blocks should have line guides and should not be operated unless guides are in place to keep lines from jumping sheaves in accordance with the manufacturer's recommendations.

7.6.5 Traveling blocks shall not be moved while the crown block is being lubricated. Drawworks should be locked out/tagged out while lubricating the crown block.

7.6.6 The pump end of the rotary hose should be securely fastened to the derrick or mast by a cable or by a chain clamped to the hose and to the derrick or mast leg. The swivel end of the hose should be secured by a similar cable or chain, with the other end of the cable or chain affixed to the swivel. Clamps and cables or chains should be used in accordance with the manufacturer's recommendations.

7.6.7 Elevators, latches, latch locks, pins, and springs should be carefully inspected by rig crews. Worn or damaged parts should be replaced. See API 8B for recommendations on inspection and maintenance of hoisting tools.

7.6.8 Field welding shall not be permitted on elevators, elevator links (bails), or other heat-treated hoisting equipment.

7.6.9 Slings should have permanently affixed durable, legible identification stating size, grade, rated capacity, and reach.

7.6.10 Tag lines or other hands-off devices should be used to guide, and steady loads being lifted or lowered.

7.7 Rotary Table

7.7.1 The operator shall not engage the power to begin rotation until the rotary table is clear of personnel and materials.

7.7.2 Rotary table power shall not be used to accomplish initial breakout of tool joints. The rotary table can be used for spinning out joints once initial breakout is affected.

7.7.3 The kelly bushing shall be of smooth design to prevent catching or snagging of personnel, clothing, fall arrest lanyards, or other material.

7.7.4 Openings in the rotary table, rathole, and mousehole should be kept covered or an appropriate barrier in-place when not in use.

7.8 Drill String Handling Equipment

7.8.1 Appropriately sized elevators (inserts), wire rope line(s) or sling(s) should be used when lifting tubulars.

7.8.2 Manual drill pipe slip handles and drill collar slip handles should be the original manufacturer's handles or equivalent engineered equipment.

7.8.3 The tapered side of drill pipe slips should be maintained in accordance with the manufacturer's recommendations. Slip dies should be clean and sharp with retainers installed.

7.8.4 Slips should not be kicked into place.

7.8.5 Fittings snub line/stiff arm and anchor points shall have a minimum working load limit greater than the load to be applied.

7.8.6 Tong safety lines should be of sufficient length to obtain full benefit of the pull from the break-out/make-up device, but short enough to prevent complete rotation of the tongs. Tong snub lines should be of such length that when securing pipe in the rotary table, a 90-degree angle is formed between the tong body and the snub line.

7.8.7 Tongs should be properly maintained. Tongs and tong heads (including dies) should be inspected for size and condition before use according to manufacturer's recommendation.

7.8.8 Tongs and tong heads should be greased prior to each trip or according to conditions and amount of use. Tong dies should be clean and sharp with retainers installed.

7.8.9 Power tongs shall have safety devices in proper working order in accordance with the manufacturer's recommendations.

7.8.10 Power tong pressure systems (hydraulic or air) should be operated according to and equipped with a safety relief valve in accordance with the manufacturer's specifications.

7.8.11 Tong jaw handles should be fitted with bumper guards and with colored handles (dumb bells) to properly identify hand placement to minimize instances of hand and finger injuries.

7.9 Weight Indicators

7.9.1 A weight indicator should be installed and used on operating drilling rigs and well servicing rigs intended to manipulate tubulars. The indicator should be constructed, installed, and maintained to register a close indication of the hook load suspended (within 5 % of the maximum hook loading).

If the weight indicator becomes inoperable and for rigs where a weight indicator is not installed, an alternative method to limit maximum load shall be utilized.

7.9.2 The weight indicator system should be checked periodically for calibration by comparing its reading with the calculated drill string or tubing string weight, with adjustments made as necessary.

7.9.3 The weight indicator should be mounted so that the gauge is easily visible to the operator standing at the brake position.

7.9.4 When the weight indicator is installed above the rig floor, it should be securely fastened to prevent it from falling. The load cell should be secured to the drill line by a secondary safety device.

7.10 Drilling Fluid Tanks

7.10.1 A risk assessment on land locations should be performed to determine the appropriate safe location and distance from the wellbore for pits and tanks, used to circulate flammable materials. Safety measures should be considered where terrain, location, rig configuration, or other conditions do not permit this spacing.

7.10.2 Mud guns used for jetting should be secured when not in use or unattended.

7.10.3 When necessary for personnel to enter a drilling fluid tank that may contain hazardous or toxic substances, applicable provisions for entering confined space shall be followed.

7.10.4 Electric motor driven blowers used for ventilation should be of an appropriate electrical classification for the area in which they are located (see 7.14.8, API 500 and API 505).

7.10.5 Appropriate precautions should be taken to prevent personnel from falling through open holes on walking surfaces of drilling fluid tanks (see 7.3.17).

7.11 Pressure Equipment

7.11.1 Air receivers should have the ASME pressure vessel marking and be installed by authorized personnel (for additional information see ASME BPVC Section VIII).

7.11.2 Pressure relief valve discharges should be located and secured to prevent a hazardous condition due to sudden discharge or piping movement.

7.11.3 Based on a risk assessment, lines and hoses should be appropriately secured to restrict unsafe movement that could cause serious injury or death. Other suspended hydraulic and, air lines should be appropriately secured. A buffer zone based on the risk assessment is recommended to limit injury exposure.

7.11.4 Pumps, piping, hoses, valves, and other fittings shall not be operated at pressures greater than their rated working pressure and shall be maintained in good operating condition. Test pressures shall not exceed the design test pressure. Pumps, piping, hoses, and pressure relief devices shall be designed to meet the requirements of the operating conditions to be encountered and should be adequately identified.

7.11.5 Hammer unions shall be made up of like halves with the same pressure ratings and thread type. Many connecting threads look alike but will fail under working conditions. "Go/No Go" rings should be used whenever there is a potential for connecting mismatched 2-in. (602/1502) style hammer unions.

Caution—Check clearance for the hammer's swing path when making/breaking hammer unions and inspect piping if accidentally hit.

7.11.6 Pressure relief devices shall be set to discharge at a pressure equal to or less than the rated working pressure of the pump, piping, hose, or fitting that the devices protect.

7.11.7 The inside diameter of piping on the pressure and discharge side of pressure relief devices shall at least equal the ID of the pressure relief devices. The piping shall be such as to prevent obstructions and minimize restrictions to flow.

7.11.8 Positive displacement pumps should be equipped with pressure relief devices that discharge to the circulation system or other acceptable location.

7.11.9 Shear pin pressure relief valves shall have the valve stem and shear pin enclosed to prevent any accidental contact and contain the shear pin from flying when sheared. The enclosure shall be designed and attached to prevent it from dislodging. Only the correct shear pin shall be used when replacement is necessary.

7.12 Generators, Motors, and Lighting

7.12.1 Electrical conductors and switch gear shall be sized and installed in accordance with NFPA 70 or equivalent regulatory requirements.

7.12.2 A risk assessment on land locations should be performed to determine the appropriate safe location and distance from the wellbore for rig generators. Safety measures should be considered where terrain, location, rig configuration, or other conditions do not permit this spacing (see API 500 or API 505).

7.12.3 Generators should have an overload safety device that will provide protection from shorting and burnout.

7.12.4 Light fixtures should be placed and maintained to provide illumination for worksites.

7.12.5 Rig lighting and fixtures shall be of appropriate electrical classification for the area in which they are located (for additional information see API 500 or API 505).

7.12.6 Rig lighting equipment in the derrick or mast, tanks, and on the rig floor, not specifically addressed in API 500 or API 505, should be enclosed and gasketed.

7.12.7 Electrical repairs to equipment shall not be performed unless the power source has been isolated, the isolation device has been locked out/tagged out (see 6.5) and verified, and the person making the repairs is qualified and authorized to do so.

7.12.8 Electric motors, and generators, shall be bonded or grounded when in use.

7.13 Internal Combustion Engines

7.13.1 Emergency shut-down devices that will close off the combustion air should be installed on rig and skid-mounted diesel engines.

7.13.2 Rig power emergency shutdown devices on each engine should, as operations allow, be function tested without load in accordance with company procedure to determine that they are in proper working condition. The testing frequency may be prescribed by manufacturer or regulatory requirements.

7.13.3 Spark arrestors or equivalent equipment should be provided on internal combustion engine exhausts.

7.14 Inspection of Critical Equipment

Critical equipment (see 3.1.20) should be periodically inspected as recommended by the manufacturer or in accordance with recognized engineering practices.

8 Well Pumping Units in Well Service Operations

8.1 A risk assessment, including a review of manufacturer's guidelines, should be conducted prior to commencing work on well pumping units.

8.2 Electric power to the pumping unit should be de-energized a sufficient distance from the wellhead to eliminate potential electrical hazards during service rig operations as determined by the risk assessment. In confined locations, overhead electric power to the pumping unit control panel should be deenergized. Where necessary, electric power service should be de-energized while moving the rig in or out and during rig up and rig down operations.

8.3 Brake systems on pumping units in service should be maintained in safe working order.

8.4 When well servicing operations require the pumping unit to be offline (i.e. wireline, service rigs, coiled tubing, etc.), the pumping unit should be turned off, the brake set, and where applicable, the power source locked out/tagged out.

8.5 If the pumping unit is stopped with counterweights not in the down position, additional securing of the beam to a fixed member of the pumping unit should be used to prevent unintended movement of the counterweights or beam.

8.6 An appropriately rated lifting chain or wire rope sling should be used to handle the horsehead if removal or installation operations are necessary. On installation, the horsehead should be bolted or latched in accordance with the manufacturer's specifications.

8.7 Upon completion of well servicing operations and before energizing the power source, clear personnel and equipment of the weight and beam movement.

8.8 After well servicing operations are completed, guards need not be in place until final adjustments (pump, spacing, etc.) are made, without compromising the safety of personnel. Pumping unit guards and enclosure guards (belt and motor sheaves), or other appropriate barriers, shall be in place prior to placing the unit in full operation.

9 Special Service Operations

9.1 General (Special Service)

9.1.1 Each tubing string of multiple completion wellheads shall be identified by marking.

Caution—For multiple-completion wellheads, use special care and attention to avoid errors in opening and closing valves.

9.1.2 Wherever possible, the service unit(s) should be located on the upwind side of the wellhead and spotted where the crew has optimum visibility and can work unobstructed.

9.1.3 A risk assessment on land locations should be performed to determine the appropriate safe location and distance from the wellbore for discharges of oil or gas to the atmosphere. Safety measures should be considered where terrain, location, rig configuration, or other conditions do not permit this spacing.

9.1.4 A frozen, plugged, or pressurized flow line should not be flexed or hit.

9.1.5 When tubing is being hydrostatically tested above the rig floor, slips should be set and personnel should stand clear while pressure is applied.

9.2 Equipment (Special Service)

9.2.1 Service unit engines should be equipped with an emergency shutdown device that is conspicuously labeled and easily accessible.

9.2.2 Unit operators should be trained on the proper use of emergency shutdown devices.

9.3 Communications

9.3.1 Equipment should be located so that equipment operators can see the personnel involved in the operation; or alternate specific arrangements should be made to assure adequate communication.

9.3.2 Signals between supervisors, personnel, and other involved persons should be agreed upon and fully understood prior to initiation of operations.

9.3.3 Communications equipment should be in good working order before commencing operations.

9.3.4 Ensure that communication equipment is appropriate for the respective area(s) in which they are being used (see 6.6.3). In perforating operations, refer to API 67 for additional communication equipment recommendations.

9.4 Discharge Line (Temporary Treating or Cementing Lines)

9.4.1 Discharge lines should not be placed under mobile equipment.

9.4.2 Discharge lines (pressure lines) should include sufficient flexible joints to avoid line rigidity and minimize vibration at the wellhead.

9.4.3 When using an open-ended flow line to flow or bleed-off a well, the line should be secured at the wellhead, at the end of the flow line, and at intermediate intervals along the line. The flow line should be secured prior to opening the wellhead control valve.

9.4.4 Pressure shall be bled from line(s) prior to breaking out or rigging down the line(s).

9.4.5 After hazardous substances have been pumped and prior to rigging down, lines should be flushed.

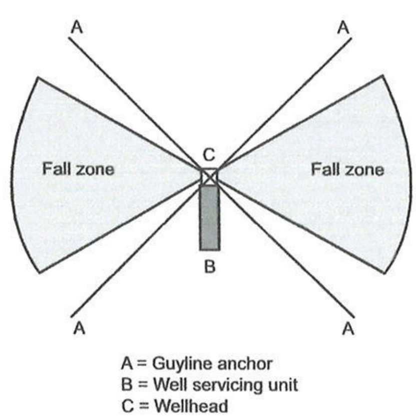
10 Wireline Service Operations

10.1 General (Wireline Service)

Job tasks, including potential simultaneous operations, shall be risk assessed before operations commence. The risk assessment shall be communicated during a pre-job meeting with the crew and other involved personnel.

10.2 Placement and Handling of Wireline Service Units

10.2.1 If fracturing or hot oil units are on the location, wireline units should be spotted as far away from them as practicable. The wireline unit should be spotted so a path of emergency exit from the operating compartment faces away from the fracturing or hot oil units. During land operations, wireline units, other vehicles, or portable houses should be placed outside the guywires of the well service unit and outside the fall lane of the derrick represented by 2:00 o'clock to 4:00 o'clock, and 8:00 o'clock to 10:00 o'clock on each side of the rig (see Figure 1).



NOTE Not to scale.

Figure 1—Guyline Anchor Locations Outside the Fall Zones

10.2.2 Mobile, portable, or skid-mounted wireline service units should be secured to prevent unwanted movement of the unit when a load is taken on the lines.

10.2.3 A wireline service unit should be spotted in such manner that it will not interfere with the entrance or exit of personnel from that unit or other service units.

10.3 Wellheads, Wellhead Connections, and Adapters

10.3.1 Wireline equipment should not be rigged up on the wellhead if the surface pressure exceeds or is expected to exceed the maximum rated working pressure of the wellhead and wellhead equipment.

10.3.2 In wireline operations where the weight and pull of the tools are to be supported by the lubricator, the adapter from the wellhead to the lubricator equipment should be constructed for the intended service.

10.4 Lubricators and Wireline Blowout Preventer Equipment

10.4.1 Lubricator equipment should be manufactured and fabricated in accordance with the test/ working pressure of the equipment to which it is attached, using the safety factor indicated by the manufacturer's specifications (see API 6A).

10.4.2 Lubricator and wireline blowout preventer equipment should be pressure tested in accordance with manufacturer's guidelines.

10.4.3 The rated working pressure of the sections of the lubricator, including stuffing box, wireline valve connections, and adapters should not be exceeded.

10.4.4 A lubricator of sufficient pressure rating should be used whenever pressure at the wellhead may be anticipated. The lubricator shall allow removal of the wireline downhole equipment when the master valve or blowout preventer is closed.

10.4.5 Materials to be used in a service that could cause sulfide stress cracking shall meet the requirements of NACE MR0175/ISO15156-1.

10.4.6 Lubricators, swages, and unions shall be visually inspected for defects prior to use. Defects that could affect safe operations (i.e. cuts, corrosion, thread damage) shall be corrected prior to installation.

10.4.7 Check lubricator assembly for pressure, isolate the equipment from the wellbore, and bleed pressure before working on or breaking a connection.

10.4.8 When a lubricator is installed on a wellhead, a wellbore connection (kill line) below the lubricator should be provided for well control operations.

10.4.9 Hammering, or otherwise striking, a lubricator or connection should not be permitted while they are subjected to pressure.

10.4.10 Threaded connections or unions on lubricators should not be loosened or tightened while they are subjected to pressure.

10.4.11 Due to the nature of wireline operations and where the lubricator is needed to support the wireline load, relatively high loads can be placed on an unsupported (free-standing) lubricator assembly. The stress resulting from side loading is normally highest at the point where the lubricator assembly is connected to the well. The lubricator assembly should be adequately supported and/or properly guyed to reduce the side loading effect of wireline operations.

10.5 Wireline Operations

10.5.1 When handling a wireline that will recoil when released, the loose end should not be left unsecured.

10.5.2 If slack line occurs while tools are in the hole, the wireline should be clamped off at the wellhead prior to working with the slack line. Wire rope or chain should be used to tie off the wireline clamp. The clamp should be held with a device capable of withstanding the loads to which it may be subjected.

10.5.3 Hands, loose clothing, and other objects should be kept clear of sheaves while the line is in motion.

10.5.4 Mast and cranes used in wireline operations should be moved from one location to another and driven with the mast stored and properly secured.

10.5.5 Use, storage, and transportation of radioactive materials shall comply with applicable standards and regulations. During wireline operations, non-essential personnel should stay clear from radioactive materials.

10.5.6 Welding operations should not be performed in the immediate wellhead area during wireline operations.

10.5.7 Precaution(s) shall be taken to prevent personnel or vehicles from crossing under or over wirelines or pressurized lines.

10.5.8 Personnel should observe a safe buffer zone on either side of the wireline between the wireline unit and the wellhead when the wireline is in tension or moving.

10.5.9 Wireline wipers should be adequately secured.

10.5.10 Oil savers should be adjusted only by remote control while the wireline is in motion.

10.6 Perforating

The wireline supervisor should hold a pre-job meeting with personnel on location to review responsibilities for the operation(s) to be performed. See API 67 for additional information.

10.7 Swabbing

10.7.1 While swabbing operations are being conducted, engines, motors, and other possible sources of ignition not essential to the operation should be shut down.

10.7.2 When swabbing, the swabbing line should be packed off at the surface and have sufficient lubricator length so that fluids are routed through a closed flow system to the maximum extent possible.

10.7.3 If slack line occurs while tools are in the hole, the wireline should be clamped off at the wellhead prior to working with the slack line. Wire rope or chain should be used to tie off the wireline clamp. The clamp should be held with a device capable of withstanding the loads to which it may be subjected.

10.7.4 Swabbing operations should be conducted during daylight hours, or if adequate lighting is provided.

10.7.5 The swabbing unit should be positioned upwind of the swab tanks or pit.

10.7.6 Swab return lines should not be placed under mobile equipment.

10.7.7 When using an open-ended flow line to flow the swabbed well to a pit, the lines should be adequately secured.

10.7.8 Pressure shall be bled from line(s) prior to breaking out or rigging down the line(s).

10.7.9 After hazardous substances have been swabbed and prior to rigging down, lines should be cleared and, if possible, flushed.

10.8 Bailing

10.8.1 Hydrostatic bailers should be secured prior to dumping. Sudden release of high pressure can cause the bailer to whip.

10.8.2 Hydrostatic bailers should not be opened until personnel are clear of the discharge orifice.

10.8.3 Use a hose and flush nozzle to attempt to clear a blocked bailer.

Warning—Do not use your fingers when clearing a blocked bailer.

10.8.4 Use of PPE, including slicker and face shield, is recommended to protect against pressurized fluids and solids when clearing a bailer.

11 Stripping and Snubbing Operations

11.1 The stripping and snubbing supervisor should hold a pre-job meeting with the stripping and snubbing crew and other involved persons to review responsibilities for the operation(s) to be performed. Personnel involved in the job task(s) should be made aware of the established maximum pressure limit under which safe stripping procedures are permissible.

11.2 The snubbing operator and rig operator shall calculate the pipe-heavy or pipe-light point before beginning snubbing operations (into or out of the wellbore).

11.3 An individual emergency escape line shall be available for each person when working atop hydraulic snubbing equipment.

11.4 A risk assessment should be performed to determine the appropriate safe location and distance from the wellbore, and appropriate safety measures for the operation and for the location of personnel, engines and other possible sources of ignition.

11.5 Prior to commencing snubbing operations, the snubbing work platform shall be guyed if not otherwise supported.

11.6 Pumps, power packs, tool boxes, doghouses, and so forth, should be located away from flow lines or bleed-off lines (in the event one of these lines should burst).

11.7 Pump units should be located where the pump operator can be seen by the snubbing operator. When this is not possible, two-way voice communications with equipment rated for the hazardous location should be established.

11.8 Well pressure should be continuously monitored.

11.9 Pipe snubbed into the wellbore should have at least one back pressure valve or blanking plug installed in the pipe string. A back pressure valve or blanking plug installed in a landing nipple, preferably located closest to the lower end of the pipe string, is one way of meeting this practice.

11.10 Snubbing operations should not be performed while welding is being done in the immediate vicinity of the wellhead.

11.11 The volume(s) of fluids pumped into or bled from the well during snubbing or stripping operations should be measured.

11.12 Tool joints or other connections should be lubricated as they go into the hole.

12 Drill Stem Testing

12.1 Preliminary to the Drill Stem Test

12.1.1 The operator's representative in charge should hold a pre-job meeting with the crew and other involved personnel to review responsibilities for the operations to be performed.

12.1.2 A risk assessment should be performed to determine the appropriate safe location and distance from the wellbore, and appropriate safety measures for engines during the drill stem testing operations.

12.1.3 Measures should be taken to exclude unauthorized personnel from the area during drill stem testing operations.

12.1.4 Drilling fluid density and viscosity should be checked and maintained within specified limits to minimize blowout possibilities.

12.1.5 A fill-up line should be installed to keep the casing full of drilling fluid and should be used only for this purpose. Provisions for the kill line should be made separately.

12.1.6 Test line connections to the control head should be secured.

12.1.7 Each test head used above the rig floor should be attached to the elevator links by safety cable or chain.

12.1.8 One or more reversing valve(s) should be incorporated in the test tool assembly.

12.1.9 The swivel/top drive and kelly hose should not be used as part of the test line.

12.1.10 A safety valve of proper size and thread configuration to fit the test string and a properly sized wrench should be readily available on the rig floor for emergency use. A safety valve should not be used in the test string as a pressure control device.

12.1.11 A test line should be laid to a reserve pit or test tank and anchored. If the drill stem test recovery is to be flared as produced, more than one pilot light may be needed to assure that ignition is achieved under both high velocity and low velocity discharge conditions.

12.1.12 If hydrogen sulfide is suspected or known to be present in the area, the applicable recommendations of API 49 and API 68 should be considered.

12.1.13 For offshore operations and applicable onshore operations, the complete gas detection system and safety equipment including emergency shutdown systems, firefighting systems, alarms and communication systems, shall be verified as fully operational prior to the commencement of DST operations.

12.1.14 The service provider should develop a diagram of the lines in the well test system, including the flow paths from the drill stem through the well test equipment, bleed off points, and emergency shutdown system.

12.1.15 Connections on pressurized lines shall be secured to prevent them from swinging or kicking in case of sudden release of pressure or rupture of the line and shall be rated for the pressure intended.

12.1.16 Adequate volumes of kill weight fluid shall be on location prior to flowing the well.

12.1.17 Surface well tests and completion equipment shall be pressure tested with water to a set point above the maximum anticipated surface pressure prior to being exposed to the wellbore pressure. A full function test of the valves and automatic systems shall be conducted, and the well test/DST emergency shutdown system operation verified, as applicable.

12.1.18 Air lines to burners shall be fitted with non-return valves. The air supply shall be independent of the rig's air supply system.

12.2 Performing the Drill Stem Test

12.2.1 Fluid volume in the casing should be monitored while going in and coming out of the hole to assure that the well remains under hydrostatic control.

12.2.2 The mud bucket should be hooked up and ready for use before the drill stem test tool is pulled out of the hole.

12.2.3 The rig floor should not be left unattended during the drill stem test.

12.2.4 Test tools should be initially opened only in daylight hours or where adequate lighting is provided.

12.2.5 For offshore operations, support vessels and helicopters within a designated area shall be informed of the time of commencement of testing.

12.2.6 The maximum anticipated temperature during the well test shall not exceed the continuous temperature rating of the BOP elastomers.

12.2.7 The well test tree control station shall be continuously manned.

12.2.8 For offshore operations, prior to installation and subsequent use of the burner/flare boom system, a risk assessment shall be performed to assess hazards. A permit-to-work system may be used to manage its operation thereafter.

13 Acidizing, Fracturing, and Hot Oil Operations

13.1 General (Acid, Frac, Hot Oil Pumping)

13.1.1 The operator's representative in charge should hold a pre-job meeting with the crew and other involved personnel to review the operations to be performed.

13.1.2 A risk assessment should be performed to determine the appropriate safe location and distance from the wellbore, and appropriate safety measures for trucks and tanks on location.

NOTE The risk assessment may include reassessing the location when there are changes in environmental conditions or potential exposure to airborne contaminants (e.g. silica, diesel particulates, caustic and hydrocarbon volatile organic compounds).

13.1.3 Lines connected from the pumping equipment to the tree or wellhead should have a check valve installed as close to the well as practicable. In addition, when a multi-pump manifold is used, a check valve should be placed in each discharge line as close to the manifold as possible.

13.1.4 All flowlines and relief lines should be restrained to prevent potential *whipping* of these lines or a designated buffer zone established.

13.1.5 When pumping flammable fluids, the blending equipment used shall be grounded.

13.1.6 Equipment unloading sand into the hopper should be bonded or grounded.

13.1.7 Lines containing flammable fluids shall not be laid under vehicles.

13.1.8 A pre-treatment pressure test on the pump and discharge lines should be made at a pressure no less than the maximum expected treating pressure specified by the operator, but not to exceed the rated working pressure of the equipment with the lowest rated working pressure.

13.1.9 Personnel not directly involved in the operations should remain beyond a designated minimum distance during pressure testing and pumping operations.

13.1.10 The pumping supervisor, or the person designated, should check to see that valves in discharge lines are open prior to pumping.

13.1.11 Unguarded openings in the top of covered frac tanks or other covered service tanks should be too small to allow personnel entry. An opening large enough to permit personnel entry should be covered by a hatch or bars mechanically secured to prevent unwanted entry. If securing the opening is not feasible, appropriate warning signs shall be prominently posted near to the tank opening.

13.1.12 Engineering controls and PPE shall be used to protect personnel from silica exposure.

13.2 Pumping Operations (Acid, Frac, Hot Oil Pumping)

13.2.1 The equipment operator should remain at the controlling station while the equipment is in operation, unless relieved as directed by the pumping supervisor. Equipment operators should remain alert for communications from the pumping supervisor.

13.2.2 While pumping flammable fluids, electrical equipment and internal combustion equipment not used in the job should be shut down or shut off and any fires should be extinguished. At locations where this recommendation may be impractical, appropriate safety measures should be implemented.

13.2.3 Flammable fluids should not be bled back into open measuring tanks on equipment designed for pumping.

13.2.4 Control measures should be in place to prevent spills or accidental releases on location.

13.2.5 For additional information to consider in the planning of hydraulic fracturing operations, as well as safety guidelines and recommendations, see API 100-1 and API 100-2.

14 Cementing Operations

14.1 General (Cementing)

14.1.1 A risk assessment should be performed to determine the appropriate safe location and distance from the wellbore, and appropriate safety measures for trucks and tanks on location.

14.1.2 The cementing supervisor should hold a pre-job meeting with the cementing crew and other involved persons to review responsibilities for the operation(s) to be performed.

14.1.3 Personnel not directly involved in the operations should remain beyond a designated minimum distance during pressure testing and pumping operations.

14.1.4 Prior to commencing operations, the pump and discharge lines should be tested to a pressure no less than the maximum cementing pressure specified by the operator, but not exceeding the rated working pressure of the equipment.

14.1.5 The cementing supervisor or the person designated should check to see that the valves in the pump discharge lines are open prior to pumping.

14.1.6 The lead-off connection to the cementing head should be secured prior to pumping operations.

14.1.7 The valves and sections of cementing lines left after completion of cementing operations should be secured to prevent *whipping* when pressure is bled off.

14.1.8 All flowlines and relief lines should be restrained to prevent potential *whipping* of these lines or a designated buffer zone established.

14.1.9 Consideration should be given to personnel safety when releasing cement wiper plugs under pressure.

14.1.10 When cementing at shallow depths, the tubulars should be secured to prevent pumping the tubulars from the hole.

14.1.11 Engineering controls and PPE shall be used to protect personnel from silica exposure.

14.2 Pumping Operations (Cementing)

Pump operators should remain at the controls while the pump is in operation, unless relieved as directed by the cementing supervisor.

15 Gas, Air, or Mist Drilling Operations

15.1 General (Gas, Air, Mist Drilling)

A risk assessment should be performed to determine the appropriate safe location and distance from the wellbore, and appropriate safety measures for compressors.

15.2 Training

15.2.1 Personnel directly involved in gas, air, or mist drilling operations should be trained in the use of emergency shutoff, blowout preventer, and fire-fighting equipment.

15.2.2 Personnel should be familiarized with the air or gas supply and circulating system.

15.3 Equipment (Air, Gas, Mist Drilling)

15.3.1 If practicable, compressors should be visible from the driller's position.

15.3.2 Compressors should have such safety features as pressure relief valves, discharge temperature and pressure gauges, engine governors, and engine shut-off valves.

15.3.3 Kill switches should be provided for the drilling engines and should be mounted near to the driller's console for immediate emergency use.

15.3.4 All surface lines should be rated for the maximum anticipated pressure.

15.3.5 The discharge line from each compressor should be equipped with both a check valve and a block valve.

15.3.6 To minimize the possibility of explosion that could result from accumulation of air cylinder lubricants in the air supply line, it is important that proper lubricants be used. For this reason, scrubbers should be used after each stage of compression to remove entrained oil.

15.3.7 Compressors should be equipped with after-coolers designed to maintain temperatures within the limitations of the downstream piping system.

15.3.8 A rotating head may be used on the blowout preventer assembly with appropriate working pressure.

15.3.9 The blooey and bleed-off lines should be a minimum of 150 ft (45.8 m) in length or equivalent safety measures shall be taken. The blooey and bleed-off line should be located downwind of the rig for the prevailing wind direction at the location. Equivalent safety measures should be taken for other wind conditions. These lines should be laid from the wellbore as straight and free of sags as practicable and be securely anchored.

15.3.10 The blooey line should be as large as or larger than the rotating head outlet into the blooey line.

15.3.11 The blooey and bleed-off lines should be securely anchored to prevent movement when pressure surges occur.

NOTE This is particularly applicable in mist drilling.

15.3.12 A full-opening, quick-closing valve (stopcock) should be installed at the top of the kelly to contain formation pressures in the drill string.

15.3.13 There should be two valves installed in the standpipe, one accessible on the rig floor and one at ground level below the rig floor, to control the air or gas supply to the borehole.

15.3.14 In gas drilling operations, a shut-off valve should be installed on the main feeder line a minimum of 150 ft (45.8 m) from the wellhead. In air drilling operations, the shut-off valve should be installed in the main feeder line closest to the compressors.

15.3.15 Geological sample catchers attached to the blooey line should be of design to protect personnel from deflected solids in the air or gas flow (see Figure 2).

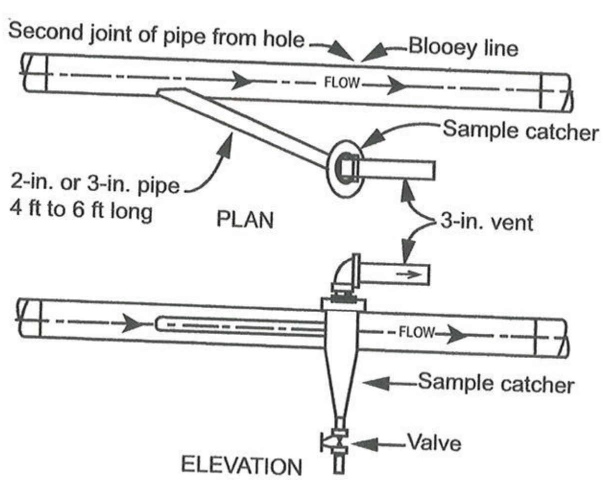


Figure 2—Example of Sample Catcher Recommended to Protect Personnel from Deflected Solids

15.4 Procedures

15.4.1 Sample catching by manual means at the end of the blooey line should not be permitted.

15.4.2 When drilling with natural gas, a spinning chain should not be used to make up drill pipe (tool joint) connections to minimize the danger of ignition caused by mechanical sparks.

15.4.3 A float valve should be installed in the drill string directly above the bit-either a heavy-duty dart or flapper-type float valve is acceptable.

15.4.4 Float valves installed in drill strings should be inspected each time the bit is pulled and, if damaged, should be replaced.

15.4.5 Fuel and oil storage used in compressor operations for gas, air, and mist drilling operations should be located at least 50 ft (15.2 m) from the compressor location and follow Section 5.

15.4.6 Liquid or LPG fuel supply lines should be equipped with shut-off valves at storage tanks and at engines and follow 5.3.5.

15.4.7 Natural gas fuel should have a master valve located on the main fuel line at least 50 ft (15.2 m) upstream from a compressor and follow Section 5.

15.4.8 One fire extinguisher of at least 150 lb (68kg) Class BC rating dry chemical capacity, or equivalent, should be stationed on the job in addition to the normal minimum of four 20-lb capacity fire extinguishers with a Class BC rating (see NFPA 10).

15.4.9 The stripper rubber in the circulating head should be visually inspected according to company procedure. If leaks are found, remedial action should be taken.

15.4.10 Equipment and materials for killing the well with drilling fluid should be readily available and operational before drilling commences. Precautions should be taken to ensure the drilling fluid system will not become inoperable.

15.4.11 A dedicated hydrocarbon ignition source shall be kept operational at the end of the flow line, except when the stripper rubber is being removed.

15.4.12 For air drilling operations, an air compressor should be kept operating during trips with a discharge of air through the blooey line.

15.4.13 When making a connection, the standpipe valve should be closed, and the bleed-off line should be opened prior to breaking out the tool joint.

15.4.14 Upon returning to the bottom of the hole at the conclusion of a trip in gas drilling operations, gas should be circulated to assure that air is out of the circulating system prior to lighting the flare.

15.5 Minimizing Sources of Ignition

15.5.1 To prevent or minimize objectionable quantities of dust permeating areas surrounding the blooey line discharge, an appropriate amount of water should be introduced into the blooey line to wet cuttings.

15.5.2 The rig substructure should have appropriate measures to prevent or mitigate the accumulation of hydrocarbon gases.

16 Flowback Operations

16.1 A risk assessment should be performed to determine the appropriate safe location and distance from the wellbore, and appropriate safety measures for trucks, tanks, and other flowback equipment on location. The assessment should include the piping and instrumentation diagram.

16.2 A meeting with involved personnel should be conducted to review the operations to be performed before starting work, anytime equipment is reconfigured or when there are significant operational changes, or both.

16.3 Personnel involved in the operations shall perform routine equipment checks throughout the shift. These checks will involve audio, visual and olfactory observations.

16.4 Engineering controls and PPE shall be used to protect personnel from hydrocarbon or H_2S vapor exposure, or both.

16.5 All enclosed gas busters/separators should relieve to applicable venting or flaring options, or both, depending on local or other regulatory requirements.

16.6 All flare lines, when in use, should have flame arrestors placed as close to the flare as possible.

16.7 All wells equipped with remote shut-off devices (hydraulic or pneumatic operating) should have the emergency shutdown system located along the path of egress and be tested prior to commencing flowback operations.

16.8 All flowlines and relief lines should be restrained to prevent potential *whipping* of these lines or a designated buffer zone established.

16.9 All equipment should be pressure tested before use.

16.10 All flowback iron shall be certified/recertified annually using nondestructive testing. Banding is required to show the test date for all flowback iron to ensure compliance. Any flowback iron with missing or illegible bands will be taken out of service immediately and sent in for certification. The bands shall be visible after rig-up.

NOTE See manufacturer's information or recommendations on banding.

16.11 All equipment shall be bonded and grounded when in use.

16.12 All tanks should have internal grounding using a static drain line for static dissipation for the incoming fluids.

16.13 Non-metallic containers should not be used to drain or sample hydrocarbon fluids.

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Oil well control

Oil well control is the management of the dangerous effects caused by the unexpected release of formation fluid, such as natural gas and/or crude oil, upon surface equipment of oil or gas drilling rigs and escaping into the atmosphere. Technically, oil well control involves preventing the formation gas or fluid (hydrocarbons), usually referred to as kick, from entering into the wellbore during drilling or well interventions.

Formation fluid can enter the wellbore if the pressure exerted by the column of drilling fluid is not great enough to overcome the pressure exerted by the fluids in the formation being drilled (pore pressure).[1][2] Oil well control also includes monitoring a well for signs of impending influx of formation fluid into the wellbore during drilling and procedures, to stop the well from flowing when it happens by taking proper remedial actions.[3]

Failure to manage and control these pressure effects can cause serious equipment damage and injury, or loss of life. Improperly managed well control situations can cause blowouts, which are uncontrolled and explosive expulsions of formation hydrocarbons from the well, potentially resulting in a fire.[4]

Contents

Importance of oil well control

Oil well control is one of the most important aspects of drilling operations. Improper handling of kicks in oil well control can result in blowouts with very grave consequences, including the loss of valuable resources and also lives of field personnel. Even though the cost of a blowout (as a result of improper/no oil well control) can easily reach several millions of US dollars, the monetary loss is not as serious as the other damages that can occur: irreparable damage to the environment, waste of valuable resources, ruined equipment, and most importantly, the safety and lives of personnel on the drilling rig.[5][6]

Modern driller Argentina.

In order to avert the consequences of blowout, the utmost attention must be given to oil well control. That is why oil well control procedures should be in place prior to the start of an abnormal situation noticed within the wellbore, and ideally when a new rig position is sited. In other words, this includes the time the new location is picked, all drilling, completion, workover, snubbing and any other drilling-related operations that should be executed with proper oil well control in mind.[6] This type of preparation involves widespread training of personnel, the development of strict operational guidelines and the design of drilling programs – maximizing the probability of successfully regaining hydrostatic control of a well after a significant influx of formation fluid has taken place.[6][7]

Fundamental concepts and terminology

Pressure is a very important concept in the oil and gas industry. Pressure can be defined as: the force exerted per unit area. Its SI unit is newtons per square metre or pascals. Another unit, bar, is also widely used as a measure of pressure, with 1 bar equal to 100 kilopascals. Normally pressure is measured in the U.S. petroleum industry in units of pounds force per square inch of area, or psi. 1000 psi equals 6894.76 kilo-pascals.

Hydrostatic pressure

Hydrostatic pressure (HSP), as stated, is defined as pressure due to a column of fluid that is not moving. That is, a column of fluid that is static, or at rest, exerts pressure due to local force of gravity on the column of the fluid.[8]

The formula for calculating hydrostatic pressure in SI units (N/m^2) is:

> Hydrostatic pressure = Height (m) × Density (kg/m^3) × Gravity (m/s^2).[9]

All fluids in a wellbore exert hydrostatic pressure, which is a function of density and vertical height of the fluid column. In US oil field units, hydrostatic pressure can be expressed as:

> $HSP = 0.052 \times MW \times TVD'$, where **MW** (**M**ud **W**eight or density) is the drilling-fluid density in pounds per gallon (ppg), **TVD** is the true vertical depth in feet and **HSP** is the hydrostatic pressure in psi.

The 0.052 is needed as the conversion factor to psi unit of HSP.[10][11]

To convert these units to SI units, one can use:

- 1 ppg = ≈ 119.826 4273 kg/m^3
- 1 ft = 0.3048 metres
- 1 psi = 0.0689475729 bar
- 1 bar = 10^5 pascals
- 1bar= 15 psi

Pressure gradient

The pressure gradient is described as the pressure per unit length. Often in oil well control, pressure exerted by fluid is expressed in terms of its pressure gradient. The SI unit is pascals/metre. The hydrostatic pressure gradient can be written as:

> Pressure gradient (psi/ft) = HSP/TVD = 0.052 × MW (ppg).[12]

Formation pressure

Formation pressure is the pressure exerted by the formation fluids, which are the liquids and gases contained in the geologic formations encountered while drilling for oil or gas. It can also be said to be the pressure contained within the pores of the formation or reservoir being drilled. Formation pressure is a result of the hydrostatic pressure of the formation fluids, above the depth of interest, together with pressure trapped in the formation. Under formation pressure, there are 3 levels: normally pressured formation, abnormal formation pressure, or subnormal formation pressure.

Normally pressured formation

Normally pressured formation has a formation pressure that is the same with the hydrostatic pressure of the fluids above it. As the fluids above the formation are usually some form of water, this pressure can be defined as the pressure exerted by a column of water from the formation's depth to sea level.

The normal hydrostatic pressure gradient for freshwater is 0.433 pounds per square inch per foot (psi/ft), or 9.792 kilopascals per meter (kPa/m), and 0.465 psi/ft for water with dissolved solids like in Gulf Coast waters, or 10.516 kPa/m. The density of formation water in saline or marine environments, such as along the Gulf Coast, is about 9.0 ppg or 1078.43 kg/m³. Since this is the highest for both Gulf Coast water and fresh water, a normally pressured formation can be controlled with a 9.0 ppg mud.

Sometimes the weight of the overburden, which refers to the rocks and fluids above the formation, will tend to compact the formation, resulting in pressure built-up within the formation if the fluids are trapped in place. The formation in this case will retain its normal pressure only if there is a communication with the surface. Otherwise, an *abnormal formation pressure* will result.

Abnormal formation pressure

As discussed above, once the fluids are trapped within the formation and not allow to escape there is a pressure build-up leading to abnormally high formation pressures. This will generally require a mud weight of greater than 9.0 ppg to control. Excess pressure, called "overpressure" or "geopressure", can cause a well to blow out or become uncontrollable during drilling.

Subnormal formation pressure

Subnormal formation pressure is a formation pressure that is less than the normal pressure for the given depth. It is common in formations that had undergone production of original hydrocarbon or formation fluid in them.[12][13][14][15]

Overburden pressure

Overburden pressure is the pressure exerted by the weight of the rocks and contained fluids above the zone of interest. Overburden pressure varies in different regions and formations. It is the force that tends to compact a formation vertically. The density of these usual ranges of rocks is about 18 to 22 ppg (2,157 to 2,636 kg/m^3). This range of densities will generate an overburden pressure gradient of about 1 psi/ft (22.7 kPa/m). Usually, the 1 psi/ft is not applicable for shallow marine sediments or massive salt. In offshore however, there is a lighter column of sea water, and the column of underwater rock does not go all the way to the surface. Therefore, a lower overburden pressure is usually generated at an offshore depth, than would be found at the same depth on land.

Mathematically, overburden pressure can be derived as:

$$S = \rho_b \times D \times g$$

where

g = acceleration due to gravity

S = overburden pressure

ρ_b = average formation bulk density

D = vertical thickness of the overlying sediments

The bulk density of the sediment is a function of rock matrix density, porosity within the confines of the pore spaces, and porefluid density. This can be expressed as

$$\rho_b = \varphi\rho_f + (1 - \varphi)\rho_m$$

where

φ = rock porosity

ρ_f = formation fluid density

ρ_m = rock matrix density[16][17]

Fracture pressure

Fracture pressure can be defined as pressure required to cause a formation to fail or split. As the name implies, it is the pressure that causes the formation to fracture and the circulating fluid to be lost. Fracture pressure is usually expressed as a gradient, with the common units being psi/ft (kPa/m) or ppg (kg/m^3).

To fracture a formation, three things are generally needed, which are:

1. Pump into the formation. This will require a pressure in the wellbore greater than formation pressure.
2. The pressure in the wellbore must also exceed the rock matrix strength.
3. And finally the wellbore pressure must be greater than one of the three principal stresses in the formation.[18][19]

Pump pressure (system pressure losses)

Pump pressure, which is also referred to as *system pressure loss*, is the sum total of all the pressure losses from the oil well surface equipment, the drill pipe, the drill collar, the drill bit, and annular friction losses around the drill collar and drill pipe. It measures the system pressure loss at the start of the circulating system and measures the total friction pressure.[20]

Slow pump pressure (SPP)

Slow pump pressure is the circulating pressure (pressure used to pump fluid through the whole active fluid system, including the borehole and all the surface tanks that constitute the primary system during drilling) at a reduced rate. SPP is very important during a well kill operation in which circulation (a process in which drilling fluid is circulated out of the suction pit, down the drill pipe and drill collars, out the bit, up the annulus, and back to the pits while drilling proceeds) is done at a reduced rate to allow better control of circulating pressures and to enable the mud properties (density and viscosity) to be kept at desired values. The slow pump pressure can also be referred to as "kill rate pressure" or "slow circulating pressure" or "kill speed pressure" and so on.[21][22][23]

Shut-in drill pipe pressure

Shut-in drill pipe pressure (SIDPP), which is recorded when a well is shut in on a kick, is a measure of the difference between the pressure at the bottom of the hole and the hydrostatic pressure (HSP) in the drillpipe. During a well shut-in, the pressure of the wellbore stabilizes, and the formation pressure equals the pressure at the bottom of the hole. The drillpipe at this time should be full of known-density fluid. Therefore, the formation pressure can be easily calculated using the SIDPP. This means that the SIDPP gives a direct of formation pressure during a kick.

Shut-in casing pressure (SICP)

The *shut-in casing pressure* (SICP) is a measure of the difference between the formation pressure and the HSP in the annulus when a kick occurs.

The pressures encountered in the annulus can be estimated using the following mathematical equation:

$$FP = HSP_{mud} + HSP_{influx} + SICP$$

where

FP = formation pressure (psi)

HSP_{mud} = Hydrostatic pressure of the mud in the annulus (psi)

HSP_{influx} = Hydrostatic pressure of the influx (psi)

$SICP$ = shut-in casing pressure (psi)

Bottom-hole pressure (BHP)

Bottom-hole pressure (BHP) is the pressure at the bottom of a well. The pressure is usually measured at the bottom of the hole. This pressure may be calculated in a static, fluid-filled wellbore with the equation:

$$BHP = D \times \rho \times C,$$

where

BHP = bottom-hole pressure
D = the vertical depth of the well
ρ = density
C = units conversion factor
(or, in the English system, $BHP = D \times MWD \times 0.052$).

In Canada the formula is depth in meters x density in kgs x the constant gravity factor (0.00981), which will give the hydrostatic pressure of the well bore or (hp) hp=bhp with pumps off. The bottom-hole pressure is dependent on the following:

- Hydrostatic pressure (HSP)
- Shut-in surface pressure (SIP)
- Friction pressure
- Surge pressure (occurs when transient pressure increases the bottom-hole pressure)
- Swab pressure (occurs when transient pressure reduces the bottom-hole pressure)

Therefore, BHP can be said to be the sum of all pressures at the bottom of the wellhole, which equals:

BHP = HSP + SIP + friction + Surge - swab[24][25]

Basic calculations in oil well control

There are some basic calculations that need to be carried during oil well control. A few of these essential calculations will be discussed below. Most of the units here are in US oil field units, but these units can be converted to their SI units equivalent by using this Conversion of units link.

Capacity

The capacity of drill string is an essential issue in oil well control. The capacity of drillpipe, drill collars or hole is the volume of fluid that can be contained within them.

The capacity formula is as shown below:

$$\textit{Capacity} = ID^2/1029.4$$

where

Capacity = Volume in barrels per foot(bbl/ft)
ID = Inside diameter in inches
1029.4 = Units conversion factor

Also the total pipe or hole volume is given by :

$$\textit{Volume in barrels}\ (\text{bbls}) = \textit{Capacity}\ (\text{bbl/ft}) \times \text{length (ft)}$$

Feet of pipe occupied by a given volume is given by:

$$\textit{Feet of pipe}\ (\text{ft}) = \textit{Volume of mud}\ (\text{bbls}) / \textit{Capacity}\ (\text{bbls/ft})$$

Capacity calculation is important in oil well control due to the following:

- Volume of the drillpipe and the drill collars must be pumped to get kill weight mud to the bit during kill operation.
- It is used to spot pills and plugs at various depths in the wellbore.[26]

Annular capacity

This is the volume contained between the inside diameter of the hole and the outside diameter of the pipe. Annular capacity is given by :

$$\textit{Annular capacity}\ (\text{bbl/ft}) = (ID_{hole}^2 - OD_{pipe}^2) / 1029.4$$

where

ID_{hole}^2 = Inside diameter of the casing or open hole in inches

OD_{pipe}^2 = Outside diameter of the pipe in inches

Similarly

Annular volume (bbls) = *Annular capacity* (bbl/ft) × length (ft)

and

Feet occupied by volume of mud in annulus = *Volume of mud* (bbls) / *Annular Capacity* (bbls/ft).[27]

Fluid level drop

Fluid level drop is the distance the mud level will drop when a dry string(a bit that is not plugged) is being pulled from the wellbore and it is given by:

Fluid level drop = Bbl disp / (CSG cap + Pipe disp)

or

Fluid level drop = Bbl disp / (Ann cap + Pipe cap)

and the resulting loss of HSP is given by:

Lost HSP = 0.052 × MW × *Fluid drop*

where

Fluid drop = distance the fluid falls (ft)

Bbl disp = displacement of the pulled pipe (bbl)

CSG cap = casing capacity (bbl/ft)

Pipe disp = pipe displacement (bbl/ft)

Ann cap = Annular capacity between casing and pipe (bbl/ft)

Pipe cap = pipe capacity

Lost HSP = Lost hydrostatic pressure (psi)

MW = mud weight (ppg)

When pulling a wet string (the bit is plugged) and the fluid from the drillpipe is not returned to the hole. The fluid drop is then changed to the following:

Fluid level drop = Bbl disp / Ann cap

Kill Mud weight (KMW)

Kill Mud weight is the density of the mud required to balance formation pressure during kill operation. The Kill Weight Mud can be calculated by:

KWM = SIDPP/(0.052 × TVD) + OWM

where

KWM = kill weight mud (ppg)

$SIDPP$ = shut-in drillpipe pressure (psi)

TVD = true vertical depth (ft)

OWM = original weight mud (ppg)

But when the formation pressure can be determined from data sources such as bottom hole pressure, then *KWM* can be calculated as follows:

$$KWM = FP / 0.052 \times TVD$$

where *FP* = Formation pressure.[28]

Kicks

Kick is the entry of formation fluid into the wellbore during drilling operations. It occurs because the pressure exerted by the column of drilling fluid is not great enough to overcome the pressure exerted by the fluids in the formation drilled. The whole essence of oil well control is to prevent kick from occurring and if it happens to prevent it from developing into blowout. An uncontrolled kick usually results from not deploying the proper equipment, using poor practices, or a lack of training of the rig crews. Loss of oil well control may lead into blowout, which represents one of the most severe threats associated with the exploration of petroleum resources involving the risk of lives and environmental and economic consequences.[29][30]

Ixtoc I oil well blowout

Causes of kicks

A kick will occur when the bottom hole pressure(BHP) of a well falls below the formation pressure and the formation fluid flows into the wellbore. There are usually causes for kicks some of which are:

- Failure to keep the hole full during a trip
- Swabbing while tripping
- Lost circulation
- Insufficient density of fluid
- Abnormal pressure
- Drilling into an adjacent well
- Lost control during drill stem test
- Improper fill on trips

Failure to keep the hole full during a trip

Tripping is the complete operation of removing the drillstring from the wellbore and running it back in the hole. This operation is typically undertaken when the bit (which is the tool used to crush or cut rock during drilling) becomes dull or broken, and no longer drills the rock efficiently. A typical drilling operation of deep oil or gas wells may require up to 8 or more trips of the drill string to replace a dull rotary bit for one well.

Tripping out of the hole means that the entire volume of steel (of drillstring) is being removed, or has been removed, from the well. This displacement of the drill string (the steel) will leave out a volume of space that must be replaced with an equal volume of mud. If the replacement is not done, the fluid level in the wellbore will drop, resulting in a loss of hydrostatic pressure (HSP) and bottom hole pressure (BHP). If this bottom hole pressure reduction goes below the formation pressure, a kick will definitely occur.

Swabbing while tripping

Swabbing occurs when bottom hole pressure is reduced due to the effects of pulling the drill string upward in the bored hole. During the tripping out of the hole, the space formed by the drillpipe, drill collar, or tubing (which are being removed) must be replaced by something, usually mud. If the rate of tripping out is greater than the rate the mud is being pumped into the void space (created by the removal of the drill string), then swab will occur. If the reduction in bottom hole pressure caused by swabbing is below formation pressure, then a kick will occur.

Lost circulation

Lost circulation usually occurs when the hydrostatic pressure fractures an open formation. When this occurs, there is loss in circulation, and the height of the fluid column decreases, leading to lower HSP in the wellbore. A kick can occur if steps are not taken to keep the hole full. Lost circulation can be caused by:

- excessive mud weights
- excessive annular friction loss
- excessive surge pressure during trips, or "spudding" the bit
- excessive shut-in pressures.

Insufficient density of fluid

If the density of the drilling fluid or mud in the well bore is not sufficient to keep the formation pressure in check, then a kick can occur. Insufficient density of the drilling fluid can be as a result of the following :

- attempting to drill by using an underbalanced weight solution
- excessive dilution of the mud
- heavy rains in the pits
- barite settling in the pits
- spotting low density pills in the well.

Abnormal pressure

Another cause of kicks is drilling accidentally into abnormally-pressured permeable zones. The increased formation pressure may be greater than the bottom hole pressure, resulting in a kick.

Drilling into an adjacent well

Drilling into an adjacent well is a potential problem, particularly in offshore drilling where a large number of directional wells are drilled from the same platform. If the drilling well penetrates the production string of a previously completed well, the formation fluid from the completed well will enter the wellbore of the drilling well, causing a kick. If this occurs at a shallow depth, it is an extremely dangerous situation and could easily result in an uncontrolled blowout with little to no warning of the event.

Lost control during drill stem test

A drill-stem test is performed by setting a packer above the formation to be tested, and allowing the formation to flow. During the course of the test, the bore hole or casing below the packer, and at least a portion of the drill pipe or tubing, is filled with formation fluid. At the conclusion of the test, this fluid must be removed by proper well control techniques to return the well to a safe condition. Failure to follow the correct procedures to kill the well could lead to a blowout.[31][32][33]

Improper fill on trips

Improper fill on trip occurs when the volume of drilling fluid to keep the hole full on a Trip (complete operation of removing the drillstring from the wellbore and running it back in the hole) is less than that calculated or less than Trip Book Record. This condition is usually caused by formation fluid entering the wellbore due to the swabbing action of the drill string, and, if action is not taken soon, the well will enter a kick state.[34][35][36]

Kick warning signs

Deepwater Horizon drilling rig blowout, 21 April 2010

In oil well control, a kick should be able to be detected promptly, and if a kick is detected, proper kick prevention operations must be taken immediately to avoid a blowout. There are various tell-tale signs that signal an alert crew that a kick is about to start. Knowing these signs will keep a kicking oil well under control, and avoid a blowout:

Sudden increase in drilling rate

A sudden increase in penetration rate (drilling break) is usually caused by a change in the type of formation being drilled. However, it may also signal an increase in formation pore pressure, which may indicate a possible kick.

Increase in annulus flow rate

If the rate at which the pumps are running is held constant, then the flow from the annulus should be constant. If the annulus flow increases without a corresponding change in pumping rate, the additional flow is caused by formation fluid(s) feeding into the well bore or gas expansion. This will indicate an impending kick.

Gain in pit volume

If there is an unexplained increase in the volume of surface mud in the pit (a large tank that holds drilling fluid on the rig), it could signify an impending kick. This is because as the formation fluid feeds into the wellbore, it causes more drilling fluid to flow from the annulus than is pumped down the drill string, thus the volume of fluid in the pit(s) increases.

Change in pump speed/pressure

A decrease in pump pressure or increase in pump speed can happen as a result of a decrease in hydrostatic pressure of the annulus as the formation fluids enters the wellbore. As the lighter formation fluid flows into the wellbore, the hydrostatic pressure exerted by the annular column of fluid decreases, and the drilling fluid in the drill pipe tends to U-tube into the annulus. When this occurs, the pump pressure will drop, and the pump speed will increase. The lower pump pressure and increase in pump speed symptoms can also be indicative of a hole in the drill string, commonly referred to as a washout. Until a confirmation can be made whether a washout or a well kick has occurred, a kick should be assumed.

Categories of oil well control

There are basically three types of oil well control which are: primary oil well control, secondary oil well control, and tertiary oil well control. Those types are explained below.

Primary Oil Well Control

Primary oil well control is the process which maintains a hydrostatic pressure in the wellbore greater than the pressure of the fluids in the formation being drilled, but less than formation fracture pressure. It uses the mud weight to provide sufficient pressure to prevent an influx of formation fluid into the wellbore. If hydrostatic pressure is less than formation pressure, then formation fluids will enter the wellbore. If the hydrostatic pressure of the fluid in the wellbore exceeds the fracture pressure of the formation, then the fluid in the well could be lost into the formation. In an extreme case of lost circulation, the formation pressure may exceed hydrostatic pressure, allowing formation fluids to enter into the well.

Secondary Oil Well Control

Secondary oil well control is done after the Primary oil well control has failed to prevent formation fluids from entering the wellbore. This process uses "blow out preventer", a BOP, to prevent the escape of wellbore fluids from the well. As the rams and choke of the BOP remain closed, a pressure built up test is carried out and a kill mud weight calculated and pumped inside the well to kill the kick and circulate it out.

Tertiary (or shearing) Oil Well Control

Tertiary oil well control describes the third line of defense, where the formation cannot be controlled by primary or secondary well control (hydrostatic and equipment). This happens in underground blowout situations. The following are examples of tertiary well control:

- Drill a relief well to hit an adjacent well that is flowing and kill the well with heavy mud
- Rapid pumping of heavy mud to control the well with equivalent circulating density
- Pump barite or heavy weighting agents to plug the wellbore in order to stop flowing
- Pump cement to plug the wellbore[37][38][39][40]

Shut-in procedures

Using shut-in procedures is one of the oil-well-control measures to curtail kicks and prevent a blowout from occurring. Shut-in procedures are specific procedures for closing a well in case of a kick. When any positive indication of a kick is observed, such as a sudden increase in flow, or an increase in pit level, then the well should be shut-in immediately. If a well shut-in is not done promptly, a blowout is likely to happen.

Shut-in procedures are usually developed and practiced for every rig activity, such as drilling, tripping, logging, running tubular, performing a drill stem test, and so on. The primary purpose of a specific shut-in procedure is to minimize kick volume entering into a wellbore when a kick occurs, regardless of what phase of rig activity is occurring. However, a shut-in procedure is a company-specific procedure, and the policy of a company will dictate how a well should be shut-in.

They are generally two type of Shut-in procedures which are soft shut-in or hard shut-in. Of these two methods, the hard shut-in is the fastest method to shut in the well; therefore, it will minimize the volume of kick allowed into the wellbore.[41]

Well kill procedures

Source:[42] A well kill procedure is an oil well control method. Once the well has been shut-in on a kick, proper kill procedures must be done immediately. The general idea in well kill procedure is to circulate out any formation fluid already in the wellbore during kick, and then circulate a satisfactory weight of kill mud called Kill Weight Mud (KWM) into the well without allowing further fluid into the hole. If this can be done, then once the kill mud has been fully circulated around the well, it is possible to open up the well and restart normal operations. Generally, a kill weight mud (KWM) mix, which provides just hydrostatic balance for formation pressure, is circulated. This allows approximately constant bottom hole pressure, which is slightly greater than formation pressure to be maintained, as the kill circulation proceeds because of the additional small circulating friction pressure loss. After circulation, the well is opened up again.

The major well kill procedures used in oil well control are listed below:

- Wait and Weight
- Driller method
- Circulate and Weight
- Concurrent Method
- Reverse Circulation
- Dynamic Kill procedure
- Bullheading
- Volumetric Method
- Lubricate and Bleed[43][44]

Oil well control incidents - root causes

There will always be potential oil well control problems, as long as there are drilling operations anywhere in the world. Most of these well control problems are as a result of some errors and can be eliminated, even though some are actually unavoidable. Since we know the consequences of failed well control are severe, efforts should be made to prevent some human errors which are the root causes of these incidents. These causes include:

- Lack of knowledge and skills of rig personnel
- Improper work practices
- Lack of understanding of oil well control training
- Lack of application of policies, procedures, and standards
- Inadequate risk management[45]

Organizations for building well-control culture

An effective oil-well-control culture can be established within a company by requiring well control training of all rig workers, by assessing well control competence at the rigsite, and by supporting qualified personnel in carrying out safe well control practices during the drilling process. Such a culture also requires personnel involved in oil well control to commit to following the right procedures at the right time. Clearly communicated policies and procedures, credible training, competence assurance, and management support can minimize and mitigate well control incidents. An effective well control culture is built upon technically competent personnel who are also trained and skilled in crew resource management (a discipline within human factors), which comprises situation awareness, decision-making (problem-solving), communication, teamwork, and leadership. Training programs are developed and accredited by organizations such as the International Association of Drilling Contractors (IADC) and International Well Control Forum (IWCF).

A FOUNTAIN AT BIBI-EIBAT IN FLAMES, BAKU

1904 oil well fire at Bibi-Eibat (near Baku, Azerbaijan).

IADC (http://www.iadc.org), headquartered in Houston, TX, is a nonprofit industry association that accredits well control training through a program called WellSharp, which is aimed at providing the necessary knowledge and practical skills critical to successful well control. This training comprises drilling and well servicing activities, as well as course levels applicable to everyone involved in supporting or conducting drilling operations—from the office support staff to the floorhands and drillers and up to the most-experienced supervisory personnel. Training such as those included in the WellSharp program and the courses offered by IWCF contribute to the competence of personnel, but true competence can be assessed only at the jobsite during operations. Therefore, IADC also accredits industry competence assurance programs to help ensure quality and consistency of the competence assurance process for drilling operations. IADC has regional offices all over the world and accredits companies worldwide. IWCF (http://www.iwcf.org/) is an NGO, headquartered in Europe, whose main aim is to develop and administer well-control certification programs for personnel employed in oil-well drilling and for workover and well-intervention operations.[46][47][48]

See also

- Blowout (well drilling)
- Oil well fire
- Formation fluid
- Oil well

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Appendix: 14

Blank Cover Page

Callon Petroleum Company
CALLON BUILDING
P. O. BOX 1287
Natchez, Mississippi 39120
AREA CODE 601
TELEPHONE 442-1601

July 15, 1971

Mississippi State Oil & Gas Board
P. O. Box 1332
Jackson, Mississippi

Attention: Mr. J. F. Borthwick, Jr.
Supervisor-Secretary

Re: Callon Petroleum Company
Armstrong Union #1 Well 3
Carthage Point Field
Adams Co., Mississippi

Gentlemen:

Attached is the Recompletion Report (Form 3) for the above well.

Very truly yours,

Jack C. Norman

JACK C. NORMAN
Petroleum Engineer

JCN:jc
Enclosure
cc: Harry Hurt, Inc.
1510 First City National Bank Bldg.
Houston, Texas 77002

Meyers-Lasher, Inc.
2030 Bank of the Southwest Bldg.
Houston, Texas 77002

RECEIVED
JUL 19 1971
STATE OIL & GAS BOARD

RECEIVED
JUL 21 1971
STATE OIL & GAS BOARD

23-001-20277

APPLICATION FOR PERMIT TO DRILL, WORKOVER OR CHANGE OPERATOR

APPLICATION TO DRILL [ ] WORKOVER [X] CHANGE OPERATOR [ ]

NAME OF COMPANY OR OPERATOR: Callon Petroleum Company

DATE: 5-19-71

Address: P. O. Box 1287, Natchez, Mississippi 39120

City

State

DESCRIPTION OF WELL AND LEASE

Name of lease: Armstrong Union

Well number: 1

Elevation (ground): 47

Well location (give footage from section lines): From NW corner of Sec. 21, go S alg section line for 915' th E/ly @ RA 4004' to location.

Section—township—range or block & survey: 21-6N-3W

Field & reservoir (If wildcat, so state): Carthage Point

County

Check the type of proposed well Oil X Gas Other (Name)

Nearest distance from proposed location to drilling unit line: 330 feet

Distance from proposed location to nearest drilling, completed or applied—for well: feet

Proposed depth: 6380 feet

Proposed length of surface casing: 461 feet

Approx date work will start: Immediately

Number of acres in drilling unit: 40

Name of drilling contractor

Address City State

STATE OIL AND GAS BOARD OFFICES:	P. O. Box 181 NATCHEZ, MISS. Tel. 445-5041	P. O. Box 2782 CS LAUREL, MISS. Tel. 428-4044	P. O. Box 1332 JACKSON, MISS. Tel. 355-9361; Ext. 301 or 303

NOTE: Notify nearest field office or Jackson office on dates of soudding and reaching total depth.

Remarks: (If this is an application to workover, briefly describe work to be done, giving present producing zone and expected new producing zone)

Well is now producing from the Wilson Sand with perforations from 6050'-52'.

Will recomplete in Baker Sand.
Set Bridge Plug @ 6046'
Perforate Baker Sand from 6038' to 6042' for production.

RECEIVED
MAY 21 1971
STATE OIL & GAS BOARD

Executed this the 19 day of May 19 71
State of Mississippi
County of Adams

Jack C. Norman
Signature of Affiant

Before me, the undersigned authority, on this day personally appeared Jack C. Norman known to me to be the person whose name is subscribed to the above instrument, who being by me duly sworn on oath states, that he is duly authorized to make the above report and that he has knowledge of the facts stated therein, and that said report is true and correct.

Subscribed and sworn to before me this 19 day of May, 19 71

SEAL

My commission expires 8-30-72

Eloise S. Dixon
Notary Public in and for Mississippi
County, Adams

Permit Number: WO#229
Approval Date: 5-21-71
Approved By: J. E. BORTHWICK JR / By
Notice: Before sending in this form be sure that you have given all information requested.
See Instructions on Reverse Side of Form

MISSISSIPPI STATE OIL AND GAS BOARD
Form No. 2
A P I Well Number

State	County	Well
23	001	20277

WELL COMPLETION OR RECOMPLETION REPORT AND WELL LOG

DESIGNATE TYPE OF COMPLETION:

New Well ☐ Work-Over ☐ Deepen ☐ Plug Back ☒ Same Reservoir ☐ Different Reservoir ☐ Oil ☐ Gas ☐ Dry ☐

DESCRIPTION OF WELL AND LEASE

Operator: Callon Petroleum Company
Address: P. O. Box 1287, Natchez, Mississippi

Lease Name: Armstrong Union
Well Number: 1 3
Field & Reservoir: Carthage Point-Baker Sd.

Location: Fr NW corner of Sec. 21 go S alg section line for 915'; th E @ RA 4004' to location
Sec.—TWP-Range or Block & Survey: 121-6N-3W

County	Permit number	Date issued	Previous permit number	Date issued
Adams	W. O. 229	5-21-71	114	8-19-68

Date spudded	Date total depth reached	Date completed, ready to produce	Elevation (DF. RKB. RT or Gr.) feet	Elevation of casing hd. flange feet
8-29-68	9-4-68	5-26-71	54	47

Total depth	P.B.T.D.	Single, dual or triple completion?	If this is a dual or triple completion, furnish separate report for each completion.
6380	6046	Single	

Producing interval (s) for this completion	Rotary tools used (interval)	Cable tools used (interval)
6038 to 6042	0-6380	None

Was this well directionally drilled?	Was directional survey made?	Was copy of directional survey filed?	Date filed
No			

Type of electrical or other logs run (check logs filed with the commission)	Date filed
IES* - Cement Bond and Gamma Ray Logs	9-6-68

CASING RECORD

Casing (report all strings set in well—conductor, surface, intermediate, producing, etc.)

Purpose	Size hole drilled	Size casing set	Weight (lb./ft.)	Depth set	Sacks cement	Amt. pulled
Surface	12 1/4	8 5/8	24	461	195	None
Producing	7 7/8	5 1/2	15.5	6135	150	None

TUBING RECORD / LINER RECORD

Size	Depth set	Packer set at	Size	Top	Bottom	Sacks cement	Screen (ft.)
2 1/2 in.	5839 ft.	- ft.	- in.	ft.			

PERFORATION RECORD

Number per ft.	Size & type	Depth interval
4	1 11/16 jets	6038 to 6042

ACID, SHOT, FRACTURE, CEMENT SQUEEZE RECORD

Am't. & kind of material used	Depth interval

INITIAL PRODUCTION

Date of first production: 5-27-71
Producing method (indicate if flowing, gas lift or pumping—if pumping, show size & type of pump:): Pumping 2 1/2 x 2 1/8 x 16' Insert

Date of test	Hrs. tested	Choke size	Oil prod. during test	Gas prod. during test	Water prod. during test	Oil gravity
7-8-71	24	16/64	22 bbls.	TSTM MCF	18 bbls	43 °API (Corr)

Tubing pressure	Casing pressure	Cal'ted rate of Production per 24 hrs.	Oil	Gas	Water	Gas—oil ratio
100	100		22 bbls.	TSTM MCF	18 bbls.	TSTM

Disposition of gas (state whether vented, used for fuel or sold):

Executed this the 15th day of July, 19 71

State of Mississippi
County of Adams

Jack C. Norman
Signature of Affiant

Before me, the undersigned authority, on this day personally appeared Jack C. Norman known to me to be the person whose name is subscribed to the above instrument, who being by me dully sworn on oath states, that he is duly authorized to make the above report and that he has knowledge of the facts stated therein, and that said report is true and correct.

Subscribed and sworn to before me this 15th day of July, 19 71

SEAL

My commission expires 7-18-75

Doris E. Jones
Notary Public in and for Adams
County Mississippi

Casing tests as required by Statewide Rules 11 and 12 must be made.

RECEIVED JUL 21 1971 STATE OIL & GAS BOARD

MISSISSIPPI STATE OIL AND GAS BOARD
Well Completion or Recompletion Report and Well Log
FORM 3 - IOCC P-7
Adopted by Order No. 118-58 Effective November 1, 1958

23-001-20277

Form No 6

MISSISSIPPI STATE OIL AND GAS BOARD

NOTICE OF INTENTION TO PLUG AND ABANDON

Operator Callon Petroleum Co. Address Natchez, Miss.

Lease Name Armstrong Union Well No. 3

Location of Well

FIELD NAME Carthage Point

Sec. 21 Twp. 6N Rge. 3W Or Block & Survey County Adams

Date Plugging to Commence as soon as possible

Firm Engaged to Plug Well Address Permit No.

Natchez Pipe & Equipment Co., Vidalia, La.

Operators of Offset Leases Notified

Operator	Lease	Direction from this Well
Same Operator		

E L Larry

Signature of Operator's Agent.

Approved 10-5-72

By Quincy R. Hodges / By AAD
Supervisor ~~Secretary~~

RECEIVED
OCT 05 1972
STATE OIL & GAS BOARD

STATE OF Mississippi

COUNTY OF Adams

Before me, the undersigned Notary Public on this day personally appeared E. L. Larry known to me to be the person whose name is subscribed to the above instrument, who being by me duly sworn on oath, states that he is authorized to make the above instrument and that he has knowledge of the facts stated therein and that said instrument is true and correct.

Subscribed and sworn to before me this 2nd day of October, 19 72

My Commission expires 5/6/74

Roberta B. La Mark
Notary Public

23-001-20277

PLUGGING RECORD

Operator	Address
Callon Petroleum Co.	Natchez, Miss.

Name of Lease	Well No.	Field & Reservoir
Armstrong Union	3	Carthage Point

Location of Well	Sec-Twp-Rge or Block & Survey	County
	21 6N 3W	

Application to drill this well was filed in name of	Has this well ever produced oil or gas	Character of well at completion (initial production): Oil (bbls/day)	Gas (MCF/day)	Dry?
Callon Petroleum Co.	yes	68	200/1	

Date plugged:	Total depth	Amount well producing when plugged: Oil (bbls/day)	Gas (MCF/day)	Water (bbls./day)
October 7, 1972	6360			

Name of each formation containing oil or gas. Indicate which formation open to well-bore at time of plugging	Fluid content of each formation	Depth interval of each formation	Size, kind & depth of plugs used Indicate zones squeeze cemented, giving amount cement.
Placed 50 ft. cement plug from 6045 -		5995	
Filled hole with mud			
Placed 50 ft. cement plug from 460 to		450	
Placed 5 sx. cement plug top of surface below plow depth			

CASING RECORD

Size pipe	Put in well (ft.)	Pulled out (ft.)	Left in well (ft.)	Give depth and method of parting casing (shot, ripped etc)	Packers and shoes
8 5/8	461	0	461		
5 1/2	6135	456	5679	shot	

Was well filled with mud-laden fluid, according to regulations? yes

Indicate deepest formation containing fresh water. 1100 ft.

NAMES AND ADDRESSES OF ADJACENT LEASE OPERATORS OR OWNERS OF THE SURFACE

Name	Address	Direction from this well:
All the same operator		

In addition to other information required on this form, if this well was plugged back for use as a fresh water well, give all pertinent details of plugging operations to base of fresh water sand, perforated interval to fresh water sand, name and address of surface owner, and attach letter from surface owner authorizing completion of this well as a water well and agreeing to assume full liability for any subsequent plugging which might be required.

Use reverse side for additional detail
File this form in duplicate with

Executed this the 8th day of October 19 72

State of Mississippi
County of Adams

E L Larry
Signature of Affiant

Before me, the undersigned authority, on this day personally appeared E. L. Larry known to me to be the person whose name is subscribed to the above instrument, who being by me duly sworn on oath states, that he is duly authorized to make the above report and that he has knowledge of the facts stated therein, and that said report is true and correct.

Subscribed and sworn to before me this 8th day of October

SEAL

My commission expires 5/6/74

Roberta B. La Mark
Notary Public in and for Adams
County Miss.

RECEIVED
OCT 12 1972
STATE OIL & GAS BOARD

MISSISSIPPI STATE OIL AND GAS BOARD

Plugging Record

FORM 7 - IOCC P-15

23-001-20277

Authorized by Order No. 118-58

Effective November 1, 1958

150 BOPD

OPERATOR'S CERTIFICATE OF COMPLIANCE AND AUTHORIZATION TO TRANSPORT OIL OR GAS FROM DRILLING UNIT

Lease - Well No.	Field	Pool
Armstrong Union No. 3	Carthage Point	Wilson
Survey or Sec-Twp-Rge	**County**	**State**
21-6N-3W	Adams	Mississippi

Operator

Callon Petroleum Company

ADDRESS ALL CORRESPONDENCE CONCERNING THIS FORM TO:

Street	City	State
P. O. Box 1287	Natchez	Mississippi

Above named operator authorizes (name of transporter)

Ashland Pipe Line Company

Transporter's street address	City	State
	Ashland	Kentucky

Field address

Ferriday, Louisiana

Oil, condensate, gas well gas, casinghead gas

To transport 100 % of the oil from said drilling unit

OTHER GATHERERS TRANSPORTING FROM THIS DRILLING UNIT ARE AS FOLLOWS:

Name of gatherer	% transported	Product transported

RECEIVED SEP 23 1968 STATE OIL & GAS BOARD

Indicate whether or not this certificate is for a new drilling unit. If not a new drilling unit, indicate whether or not it is a change of operator, change of drilling unit name, change of gatherer, and give effective date of change.

New Drilling Unit: 9/15/68 Flowed-24 hours-8/64 ck-68 bbls. of oil. No water.

The undersigned certifies that the rules and regulations of the Mississippi State Oil and Gas Board have been complied with in drilling and producing operations on this drilling unit, except as noted above, and that the above transporter is authorized to transport the above specified percentage of the allowable oil or gas produced from the above described drilling unit, and that this authorization will be valid until further notice or until cancelled by the State Oil and Gas Board.

Executed this the 18 day of September, 19 68

State of Mississippi

County of Adams

Jack C. Norman

Signature of Affiant

Before me, the undersigned authority, on this day personally appeared Jack C. Norman known to me to be the person whose name is subscribed to the above instrument, who being by me duly sworn on oath states, that he is duly authorized to make the above report and that he has knowledge of the facts stated therein, and that said report is true and correct.

Subscribed and sworn to before me this 18th day of September, 19 68

SEAL

My commission expires My Commission Expires Aug. 30, 1972

Catherine G. Willard

Notary Public in and for Mississippi

County, Adams

Approved September 23 '68

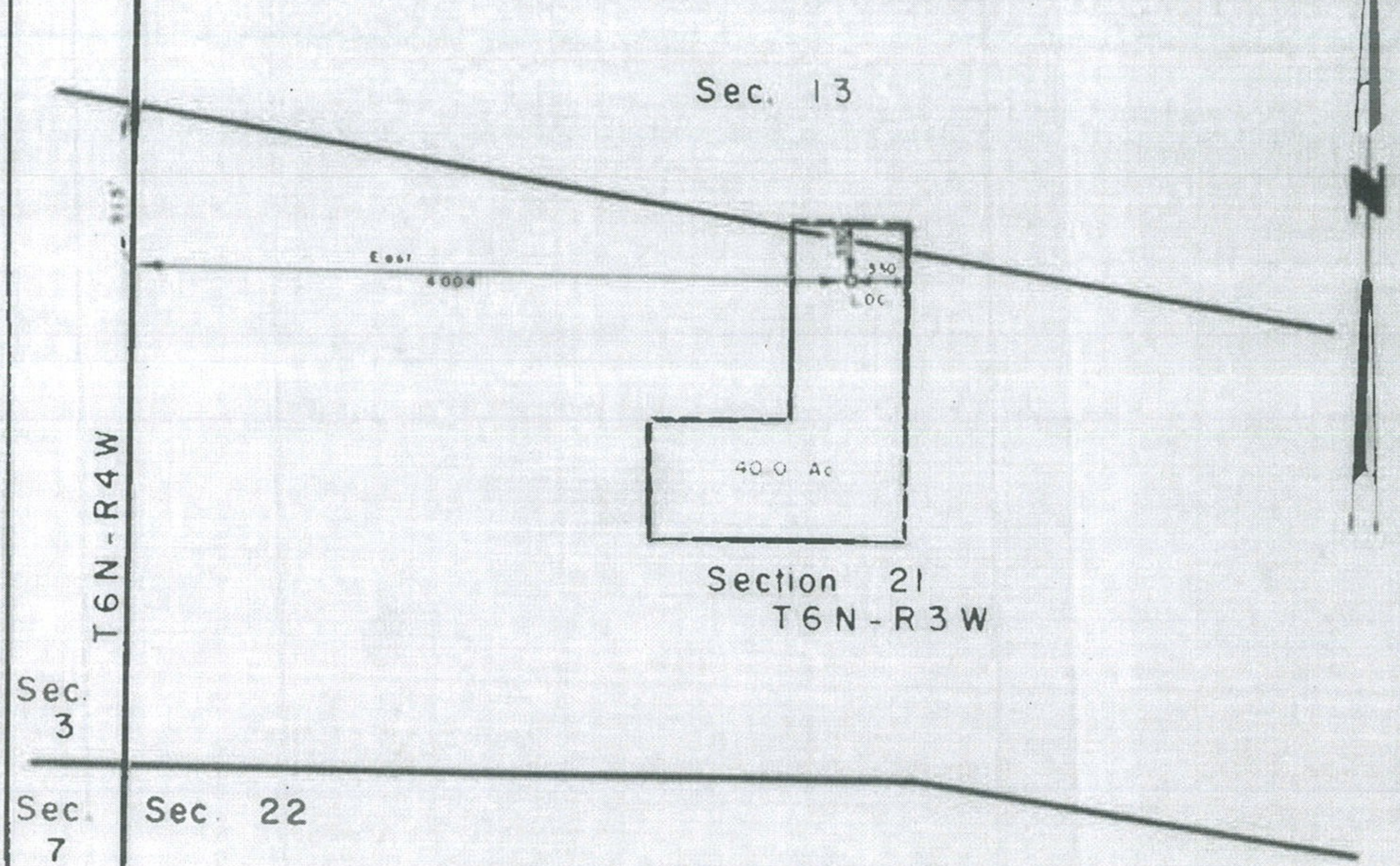
STATE OIL AND GAS BOARD

By J. F. BORTHWICK, JR.

MISSISSIPPI STATE OIL AND GAS BOARD
Operator's Certificate of Compliance & Authorization to Transport Oil or Gas from Drilling Unit
FORM 8 - IOCC P-17
Authorized by Order No. 118-58 — Effective November 1, 1958

23-001-20022

NOTE: The drilling unit shown hereon lies totally within the confines of a rectangle 1810.0 feet by 1445.0 feet.



DESCRIPTION OF LOCATION: From the northwest corner of Section 21, T6N-R3W, Adams County, Mississippi, go South along the west boundary of said Section 21 for 915 feet; thence East for 4004 feet to location in Section 21.

B. C. Jordan, Jr.

B. C. Jordan, Jr., Reg. C. E. No. 574

B. C. JORDAN
REGISTERED PROFESSIONAL
ENGINEER
574
STATE of MISSISSIPPI

RECEIVED
AUG 19 1968
STATE OIL & GAS BOARD

Well Location For

CALLON PETROLEUM CO.

Armstrong - Union Oil No. 3

in

Section 21, T6N-R3W
Adams County, Mississippi

JORDAN, KAISER & SESSIONS
Civil Engineers - Natchez, Miss

Scale 1" = 1000'

August 1968

23-001-20277

C-19-68

Appendix 15

Re-Plugging Plan for Armstrong Union # 3

Cloverdale Plug & Abandonment Project

Estimated Equipment Needed

Workover Rig – National C4 Self Propelled Mobile Rig

Double stack blowout preventers with pipe rams and blind rams installed

Two workover tanks (1 for drilling mud and 1 for freshwater)

(250 bbls of drilling mud)

Triplex Mud Pump

70 bbl. Vacuum Truck with pump

Roustabout crew labor for equipment setup and removal and site cleanup

Power Swivel – Bowan S85 (85 ton)

Washout Head and Replacement rubbers

2 - Pipe Skids for rental tubing string

Truck & Float for hauling tubing and plugging equipment

Bulldozer for building road to the well site

(250 bbls. of drilling mud)

Rental string of 2 7/8" , 8rd EUE J-55 tubing (6,200')

Rental 3 ½" drill collars and crossovers

Rental 4 ¾" drill bits & scraper

Welder to cut off top of bent casing and weld a bell nipple on it

8 5/8" , 8rd Bell Nipple

8 5/8" x 2 7/8" Casing Head with 2 – 12" XS A/SA Grade B Carbon Steel seamless pipe nipples and 2 – 2,000 # ball valves

8 5/8" X 2" swedge

Rhino UTV & 2 – 4 wheelers

Command & Control Trailer

Landfill Disposal costs for leftover drilling mud and drillout debris

Proposed Action Plan for Plugging Operations on Armstrong Union # 3 Well

A meeting prior to the start of operations should include representatives of the following organizations:

EPA Region IV On-Scene Coordinator

Callon Petroleum Representative

Mississippi Oil & Gas Board Representative

WT Drilling Company, Inc. Representative

St Catherine Creek Wildlife Refuse Representative

Determine best route for access road from the current gravel road closest to the site.

Dozer work needs to be performed to build access road.

Mobilize equipment for plugging operations to the site.

Estimated Equipment Needed

Workover Rig – National C4 Self Propelled Mobile Rig

Double stack blowout preventers with pipe rams and blind rams installed

Rig up mat for ground support as the workover rig foundation.

Two workover tanks (1 for drilling mud and 1 for freshwater)

(250 bbls of drilling mud mixed at 9.6 lbs/gal)

Triplex Mud Pump

70 bbl. Vacuum Truck with pump

Roustabout crew labor for equipment setup and removal and site cleanup

Power Swivel – Bowan S85 (85 ton)

Washout Head and Replacement rubbers

2 - Pipe Skids for rental tubing string

Truck & Float for hauling tubing and plugging equipment

Bulldozer for building road to the well site

(250 bbls. of drilling mud mixed at 9.6 lbs./gal.)

Rental string of 2 7/8" , 8rd EUE J-55 tubing (6,200')

Rental 3 ½" drill collars and crossovers

Rental 7 7/8" & 4 ¾" drill bits & scraper

Welder to cut off top of bent casing and weld a bell nipple on it

8 5/8", 8rd Bell Nipple

8 5/8" x 2 7/8" Casing Head with 2 – 12" XS A/SA Grade B Carbon Steel seamless pipe nipples and 2 – 2,000 # ball valves

8 5/8" X 2" swedge

Rhino UTV & 2 – 4 wheelers

Command & Control Trailer

Spot up all equipment required for the plugging and abandonment operations at the site.

Fill one workover tank with 9.6 lb/gal drilling mud for the re-entry and plugging.

Fill the other workover tank with freshwater for the cementing operations.

Dig a bell hole around the casing for a welder to weld a 8 5/8" casing head on.

Backfill the hole for the rig up mat to set on.

Set the rig up mat at the well head.

Rig up the workover rig with all guy lines out and anchored.

Install the well head flange and the double stack blow out preventers.

Hook up the power swivel. Pick up a drill collar and a 7 7/8" bit and scraper.

Start drilling out the top cement plug.

Continue drilling out cement to the second cement plug located at 425' to 475'.

Drill out the secondary plug to the top of the cut off 5 ½" casing.

Pull out of the hole and pick up a 4 3/4" bit and attempt to get inside the 5 ½" casing.

If successful in getting inside casing proceed to the next step. If we can not reenter the 5 ½" casing proceed to PLAN B below.

Continue drilling out the second plug and wash and ream as needed to the top of the bottom plug at 6,010' .

DO NOT DRILL OUT BOTTOM PLUG

Circulate the well clean with 9.6 lbs/gal. drilling mud.

Pull out of the hole with tubing , bit and scraper.

Rig up wireline truck.

Run cement bond log with a collar locator. Set a cast iron bridge plug fifty (50') feet above the old bottom production perforations at the top of the original bottom cement plug from the August 1, 1972 plugging operation. The top of the original plug is at 6,010' therefore the cast iron bridge plug will be set at 5,960'. If the original plug is in fact properly placed.

The results of the cement bond log will determine if the casing should be then perforated for any cement squeeze operations for protecting the base of the freshwater @ approximately 1,300'. If it is decided to squeeze operations are required the wireline truck will then perforate the casing at the locations determined at that time. Any additional perforations deemed necessary will be determined at the time by input from representative petroleum engineer , logging engineer , and the EPA OSC's Courtney Swanson and Chuck Eger. Any new perforations added to the well casing shall be located at a minimum of 150' above the cast iron bridge plug to be set on bottom. This will prevent the perforating charge from affecting the mechanical bond of the CIBP to the casing wall.

Rig up cementers and pump 15.6 lbs/gal. cement to plug and abandon the well. We would recommend going above and required cement and fill the casing string up completely with cement as the casing string has been in the ground for fifty (50) years. This option is in place of pumping separate 100' plugs on bottom and at the base of the freshwater and the base of the surface casing and the top 100' plug.

Rig the workover rig down.

Dig the bell hole back out and have a welder cut the casing off three foot below ground level and weld a metal cap on top with the pertinent well id information.

Backfill the bell hole.

De-mobilize the rig and workover equipment utilized in the plugging operations.

Have the bulldozer restore the location and road back to the satisfaction of the St Catherine Creek Wildlife Refuse agents.

Submit post job report and file a new Mississippi Oil & Gas Board Form 7 (Plugging Record)

END OF JOB

PLAN B

Attempt to pump out of the shoe into the open hole. If we can pump out , set a cement retainer or a squeeze packer inside the 8 5/8" casing at approximately 425'. Mix and pump 16.2 lbs/gal cement into the borehole until squeeze pressure is obtained for isolation. If a cement retainer is utilized , then sting out of the retainer to prevent cement flowback. If a squeeze packer is utilized close the tool in with pressure on it and leave the well closed in for 48 hours until the cement hardens .

If we can not pump into the wellbore. Rig up a wireline truck and perforate the well at 450' to 454' for squeeze perforations. Squeeze cement the new perforations for isolation with a squeeze packer. Hold pressure with the well closed in for 48 hours until the cement sets up.

Then mix and circulate sufficient cement to get cement back to the surface. Pull the tubing out and top off the pipe displacement volume with cement on the surface.

Rig the workover rig down.

Dig the bell hole back out and have a welder cut the casing off three foot below ground level and weld a metal cap on top with the pertinent well id information.

Backfill the bell hole.

De-mobilize the rig and workover equipment utilized in the plugging operations.

Have the bulldozer restore the location and road back to the satisfaction of the St Catherine Creek Wildlife Refuse agents.

Submit post job report and file a new Mississippi Oil & Gas Board Form 7 (Plugging Record)

END OF JOB

Appendix 16 :

CALLON Petroleum

Re-Plugging Report

Armstrong - Union # 3

November 4, 2020

CALLON
PETROLEUM

Mississippi State Oil & Gas Board
500 Greymont Avenue, Suite E
Jackson, MS 39202

November 4th, 2020

Re: Plugging Report – Armstrong Union #3

Dear Sir/Madam

Callon Petroleum recently finished plugging the Armstrong Union #3 well, API #23-001-20301.

Enclosed is a notarized plugging report, filed in duplicate. I have also enclosed a document providing a more detailed summary of the P&A.

Please let me know if you have any questions. The easiest way to get in touch is by email.

Sincerely,

Ryan Emery
Regulatory Compliance Specialist
Office: 281-589-5262
remery@callon.com

Armstrong Union #3

P&A Work Summary

Armstrong Union #3 was re-entered in September 2020 to evaluate integrity of the original P&A work performed back in 1972.

- Existing 8-5/8" casing stub was damaged at some time after the original plugging work in 1972 (the top was bent and partially collapsed, preventing the installation of a casing head). Initial excavation work on 9/9/20 found good pipe roughly 7' below ground level.

- A hot tap on the 8-5/8" casing to check for any pressure was performed. Some condensate was bled off, requiring additional containment procedures to be implemented as a contingency. Ultimately, the flow turned to water from a second hot tap at 13.5' below ground level. The damaged top part of the casing was cut off and a wellhead installed on 9/18/20.

- Final location preparation to bring in the workover rig was completed by 9/20/20. Workover rig and associated equipment mobilized to location. An 11" 3M BOP system was rigged up and tested.

- **<u>9/23-9/24/20:</u>** TIH with 7-7/8" bit and cleaned out to the top of the 5-1/2" casing stub at 479' MD (18' below the 8-5/8" shoe at 461' MD). Circulated hole cleaned with 9.5 ppg mud. TOH and LD bit.

- **<u>9/25/20:</u>** TIH with 4-3/4" bit – unable to get inside 5-1/2" casing stub (worked down to 825' – circulated up sand which indicated the bit was outside the casing.

- **<u>9/26-9/27/20:</u>** PU 2-7/8" muleshoe on 2-7/8" workstring and TIH. Worked into 5-1/2" casing top. TIH to 5698' MD (circulated hole every 600' with 9.0 ppg mud). Washed down to 6065' MD (through old perforations).

- **<u>9/28/20:</u>** Due to difficulty in entering 5-1/2" casing stub, decision was made to re-plug well through 2-7/8" workstring (consulted with EPA representative onsite). Initial plugs were set as follows:
    - Plug #1 – 250' balanced plug f/6047'-5797' MD (33 sx Premium cement @ 16.3 ppg)
    - Plug #2 – 250' balanced plug f/ 5415'-5165' MD (33 sx Premium cement @ 16.3 ppg)

  TOH to 1293' MD.

- **<u>9/29/20:</u>** Ran wireline through 2-7/8" workstring. Perforated 5-1/2" casing f/ 1370'-1372' MD to set up for plug to isolate usable water interval.
    - Plug #3 – 250' balanced plug f/ 1357'-1107' MD (33 sx Class A cement @ 15.6 ppg)

  Squeezed 4 bbls into formation. TOH to 570' MD (set up to plug top of 5-1/2" casing stub and isolate 8-5/8" casing shoe).
    - Plug #4 – 370' balanced plug f/ 570'-200' MD (94 sx Class A cement @ 15.6 ppg).

- **<u>9/30/20:</u>** ND BOP. Set 40' surface plug (15 sx Class A cement). Cut off wellhead / installed cap plate on 8-5/8" casing. RD workover rig and begin demobilizing equipment.

MISSISSIPPI STATE OIL & GAS BOARD
PLUGGING RECORD

Operator Callon Petroleum Co.	Address 2000 W. Sam Houston Pkwy, Suite 2000, Houston, TX, 77042
Name of Well Armstrong Union	Well No. 3 — Field & Reservoir Carthage Point - Wilcox Sand
Location of Well Latitude 31.48867, Longitude -91.45656	Section - Township - Range Section 13, Township 6N, RNG 3W
API No. 23-001-20301	County Adams

Application to drill this well was filed in name of:	Has this well ever produced oil or gas	Character of well at completion (initial production): Oil (bbls/day)	Gas (MCF/day)	Dry
Callon Petroleum Company	Yes	109	TSTM	

Date Plugged	Total Depth	Amount well producing when plugged: Oil (bbls/day	Gas (MCF/day)	Water (bbls/day)
10/01/2020	6215	0	0	0

Name of each formation containing oil or gas. Indicate which formation open to wellbore at time of plugging.	Fluid content of each formation	Depth interval of each formation	Size, kind & depth of plugs used. Indicate zones squeeze cemented, giving amount cement.
Plug #1 (above existing perfs)			250' Plug f/ 6047'-5797' (33 sx Premium)
Plug #2 (2nd plug above perfs)			250' Plug f/ 5415'-5165' (33 sx Premium)
Plug #3 (isolate FW interval / squeezed)			250' Plug f/ 1357'-1107' (33 sx Class A)
Plug #4 (across 8-5/8" shoe / top 5-1/2" stub)			370' Plug f/ 570'-200' (94 sx Class A)
Surface Plug			40' Plug to surface (15 sx Class A)

CASING RECORD

Size pipe	Put in well (feet)	Pulled out (feet)	Left in well (feet)	Give depth & method of parting casing (shot,ripped, etc.)	Packers and shoes
8 5/8	461	0	461		
5 1/2	6138	452	5686	Shot	

Was well filled with mud-laden fluid, according to regulations? Yes

Indicate deepest formation containing fresh water: 1150'

NAME AND ADDRESSES OF ADJACENT LEASE OPERATORS OR OWNERS OF THE SURFACE

Name	Address	Direction from this well

In addition to other information required on this form, if this well was plugged back for use as a fresh water well, give all pertinent details of plugging operations to base of fresh water sand, perforated interval to fresh water sand, name and address of surface owner, and attach letter from surface owner authorizing completion of this well as a water well and agreeing to assume full liability for any subsequent plugging which might be required.

Use reverse side for additional details
File this form in duplicate with:

Executed this the 9th day of November, 20 20.

State of Texas
County of Harris

Signature of Affiant

Before me, the undersigned authority, on this day personally appeared Ryan Emery known to me to be the person whose name is subscribed to the above instrument, who being by me duly sworn on oath, states that he is duly authorized to make the above report and that he has knowledge of the facts stated herein, and that said report is true and correct.

Subscribed and sworn to before me this 9th day of November, 20 20.

SARAH DANIELLE ROBERTSON
NOTARY PUBLIC
STATE OF TEXAS
ID 13050584-4
EXP. 01-21-2024

My commission expires 01-21-2024

Signature
Notary Public in and for Callon Petroleum
County Harris

MISSISSIPPI STATE OIL & GAS BOARD
PLUGGING RECORD
FORM 7
REVISED MAY, 2001