APPENDICES

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APPENDIX 1

TESTING PROCEDURE FOR PSH AND PSL

1. Close isolating valve on pressure sensing connection.

2. Apply pressure to sensor with hydraulic pump, high pressure gas or nitrogen, and record high sensor trip pressure.

3. If sensor is installed in series with the high sensor upstream from the low sensor, bleed pressure to reset the high sensor. Bleed pressure from sensors and record low sensor trip pressure.

4. Adjust sensor, if required, to provide proper set pressure.

5. Open sensor isolating valve.

APPENDIX 2

TESTING PROCEDURE FOR LSH AND LSL

INSTALLED INTERNALLY

1. Manually control vessel dump valve to raise liquid level to high level trip point while observing liquid level in gage glass.

2. Manually control vessel dump valve to lower liquid level to low level trip point while observing liquid level in gage glass.

INSTALLED IN OUTSIDE CAGES

1. Close isolating valve(s) on float cage(s).

2. Fill cage(s) with liquid to high level trip point.

3. Drain cage(s) to low level trip point.

4. Open isolating valve(s) on cage(s).

APPENDIX 3

TESTING PROCEDURE FOR TSH AND TSL

TEMPERATURE BATH METHOD

1. Remove temperature sensing probe.

2. Place a thermometer in the hot bath.

3. Insert temperature sensing probe in the bath and raise temperature of bath until the controller trips.

4. Verify that this temperature is no higher than the operator specified maximum temperature for the process.

5. Insert temperature sensing probe in the bath and lower temperature of bath until the controller trips.

6. Verify that this temperature is no lower than the operator specified minimum temperature for the process.

7. Reinstall temperature sensing probe.

OPERATION TEST METHOD

Test in accordance with the manufacturer's operating manual.

Note: **Because of the destructive tendencies, Eutectic type temperature devices are not to be tested.**

APPENDIX 4

TESTING PROCEDURE FOR PSV

1. Remove lock or seal and close inlet isolating block valve. (Not required for PSV's isolated by reverse buckling rupture disc or check valve or pilot operated PSV's.)

2. Apply pressure through test connection with nitrogen, high pressure gas or hydraulic pump, and record pressure at which the relief valve or pilot starts to relieve.

3. The safety valve or pilot should continue relieving down to reset pressure. Hold test connection intact until the pressure stops dropping to ensure that valve has reset.

4. Open inlet isolating block valve and lock or seal.

APPENDIX 5

TESTING PROCEDURE FOR FSV

1. Close upstream valve and associated header valves.

2. Open bleeder valve and bleed pressure from flowline between closed valves.

3. Close bleeder valves.

4. Open appropriate header valve.

5. Open bleeder valve.

6. Check bleed valve for backflow. If there is any continuous backflow, measure the leakage rate.

7. Close bleeder valve and open upstream valve.

MAXIMUM ALLOWABLE LEAKAGE

Gas - 5 cubic feet per minute
Liquid - 200 cubic centimeters per minute

APPENDIX 6

TESTING PROCEDURE FOR BSL

PILOT FLAME-OUT CONTROL

1. Light pilot
2. Block fuel supply to main burner.
3. Shut off fuel supply to pilot and check BSL for detection.

BURNER FLAME-OUT CONTROL

1. Light main burner.
2. Block fuel supply to pilot.
3. Shut off fuel supply to main burner and check BSL for detection.

APPENDIX 7

TESTING PROCEDURE FOR SDV

1. Bleed pressure off of the actuator and allow valve to reach the 3/4 closed position.

2. Return supply pressure to the actuator.

APPENDIX 8

TESTING PROCEDURE FOR SSV/USV

1. Close valve to be tested.

2. Position valve(s) as required to permit pressure to be bleed off downstream of the SSV/USV.

3. With pressure on upstream side of SSV/USV, open bleed valve downstream of test valve and check for flow.

4. Close bleed valve.

5. Return SSV/USV to service.

MAXIMUM ALLOWABLE LEAKAGE

No fluid flow allowed.

APPENDIX 9

TESTING PROCEDURE FOR SCSSV, TUBING PLUG, AND INJECTION VALVE

MAXIMUM ALLOWABLE LEAKAGE RATE

Gas - 5 cubic feet per minute
Liquid - 200 cubic centimeters per minute

Note:

1. The listed testing procedures are for wells that **do not produce H_2S**. For wells that produce H_2S, pressure must be bled into a closed system, such as pressure vessels or a flare system, using H_2S resistant material.
2. For SCSSV testing:
   A. Use either Method A or Method B for normal wells for gas.
   B. Use Method C for questionable wells or low pressure wells for gas.
   C. Use Method E for liquid.
3. For pump-through plug or injection valve testing:
   A. Use Method D for gas.
   B. Use Method E for liquid.

Method A:

1. Shut-in the well at the wellhead.
2. Wait for a minimum 5 minutes and record SITP.
3. Bleed SCSSV hydraulic control line pressure to zero to shut-in SCSSV.
4. Bleed surface pressure sufficiently to establish a differential pressure across SCSSV of approximately 20 percent of the SITP recorded in Step 2.
5. Wait a minimum of 30 minutes and record surface pressure.
6. Surface pressure recorded in Step 5 confirms SCSSV holding integrity or the need to determine leakage rate addressed in Step 7.
7. Determine gas leakage rate using the following formula:

$$\text{Leakage rate (SCF/min)} = \frac{Cd^2h(p_2-p_1)}{T_{TEST}}$$

Where: $C = 0.000363$
d = Inside diameter of tubing in inches
h = Distance between valve and tree in feet
p_1 = Initial pressure reading in psi
p_2 = Final pressure reading in psi
T_{TEST} = Time lapsed during test in minutes

Method B:

1. Shut-in the well at the wellhead.
2. Bleed SCSSV hydraulic control line pressure to zero to shut-in SCSSV.
3. Bleed surface pressure to ambient pressure.
4. Close bleed valve.
5. Attach Direct-Reading flowmeter.
6. Slowly open bleed valve and record gas leakage rate determined by flowmeter.
7. Close the bleed valve.
8. Remove the Direct-Reading flowmeter and return the SCSSV to service.

Method C:

1. Close the SCSSV to be tested.
2. Position valve(s) as required to permit pressure to bleed downstream of the SCSSV, and bleed downstream pressure.
3. Close the bleed valve.
4. Attach the inlet of the Direct-Reading flowmeter to the bleed valve using hose barb and plastic tubing and keep flowmeter in the vertical position.
5. With pressure on the upstream side of the SCSSV, slowly open the bleed valve downstream of the SCSSV and record the leakage rate.
6. If leakage occurs, verify that the SCSSV is actually leaking, and not the FSV, wing valve, or gas trapped in the crown valve.
7. Close the bleed valve.
8. Disconnect hose barb and plastic tubing from the bleed valve and return the SCSSV to service.

Method D:

1. Record SITP.
2. Bleed surface pressure sufficiently to establish a pressure differential across pump-through plug or injection valve of approximately 20 percent of the SITP recorded in Step 1.
3. Wait a minimum of 30 minutes and record surface pressure.
4. Surface pressure recorded in Step 3 confirms pump-through or injection valve holding integrity, or the need to determine leakage rate addressed in Step 5.
5. Determine gas leakage with the following formula:

$$\text{Leakage rate (SCF/min)} = \frac{Cd^2h(p_2-p_1)}{T_{TEST}}$$

Where: $C = 0.000363$

d = Inside diameter of tubing in inches

h = Distance between valve and tree in feet

p_1 = Initial pressure reading in psi

p_2 = Final pressure reading in psi

T_{TEST} = Time lapsed during test in minutes

Method E:

For wells that contain no gas, determine leakage rate by capturing the leaking liquid in a measuring device.

APPENDIX 10

TESTING PROCEDURE FOR ESD AND FIRE LOOP SYSTEM

Testing Procedure for ESD System

1. Select well(s) or component(s) to be shut-in.
2. Bypass all SSVs and SCSSVs on wells not intended to be shut-in.
3. Bypass all component SSVs or pipeline SDVs not intended to be shut-in.
4. Activate ESD station
   - A. Mechanical Control
     1. Move valve handle to the shutdown position (full open).
     2. Observe for free valve movement and unobstructed gas bleed.
   - B. Electrical Control

     Push/trip electrical ESD control.
5. Verify that shut-in actuation of selected well(s) and component(s) has been achieved.
   - A. Within 45 seconds for SSVs on well(s) and other selected surface components.
   - B. Within 2 minutes thereafter for SCSSVs on selected well(s).
6. Return system to service.

Testing Procedure for Fire Loop System

> **Note:** If possible, consideration shall be given to avoid total platform shut-in, as well as those wells which have a history of problems returning to flow after extended periods of being shut-in.

1. Select well(s) or component(s) to be shut-in.
2. Bypass all SSVs and SCSSVs on wells not intended to be shut-in.
3. Bypass all component SSVs or pipeline SDVs not intended to be shut-in.
4. Randomly select an area that is protected by the fire loop system.

   Direct the Operator to conduct an actuation test of the fire loop system in accordance with the Operator’s test procedure.
5. Verify that shut-in actuation of selected well(s) and component(s) has been achieved.
   - A. Within 45 seconds for SSVs on well(s) and other selected surface components.
   - B. Within 2 minutes thereafter for SCSSVs on selected well(s).
6. Return system to service.

APPENDIX 14

TESTING PROCEDURE FOR FSL

1. Slowly close the valve on the media circulation pump discharge.

2. Watch a pressure drops with decrease inflow. The surge tank must be at significantly lower pump pressure than pump discharge pressure.

3. FSL should trip before the flow rate drops to 0 and before the discharge pressure drops below 50 percent of full discharge pressure.

APPENDIX 16

TESTING PROCEDURE FOR MOTOR STARTER INTERLOCK

1. Manually shut off motor starter to blower.

2. Verify interlock shuts down heater immediately.

3. Verify that PSL on blower trips after several seconds.

APPENDIX 17

TESTING PROCEDURE FOR FLAME ARRESTER

Visually inspect the flame arrester to verify that:

1. Flame arrester is clean and free of oil and paraffin residue.

2. Flame arrester is intact.

APPENDIX 19

TESTING PROCEDURE FOR WATER-FEEDING DEVICE

INSTALLED INTERNALLY

1. Adjust fuel gas controls so that the main burner of the steam generator shuts off. Assure continuous pilot light flame.

2. Shut off manual burner fuel valve.

3. Lower the water level of the vessel by opening the drain valve on the lowest portion of the steam generator and leaving it fully open.

4. Verify that the automatic water-feeding device initiates fill-up prior to exposing the fire tube.

5. Verify that the input rate exceeds the manual bleed rate by noting the rise in the water level.

6. Verify that the automatic water-feeding device ceases fill-up when the vessel is full.

INSTALLED EXTERNALLY

1. Adjust fuel gas controls so that the main burner of the steam generator shuts off. Assure continuous pilot light flame.

2. Shut off manual burner fuel valve.

3. Close isolating valves on float cage.

4. Drain cage to low level trip point.

5. Verify that the automatic water-feeding device initiates fill-up prior to exposing the fire tube.

6. Verify that the input rate exceeds the manual bleed rate by noting the rise in the water level.

7. Verify that the automatic water-feeding device ceases fill-up when the vessel is full.

APPENDIX 20

AREA CLASSIFICATION AND ELECTRICAL REQUIREMENTS

AREA CLASSIFICATION METHOD

Hazardous areas are locations where the potential for fire or explosion exist because of gases, dust, or easily ignitable fibers or filings in the local atmosphere. Areas are classified to identify their flammability and explosive hazard potential. On offshore facilities, two systems are used interchangeably to provide a short-hand identification of this hazard potential. One system is called the "Traditional Area Classification Method" and the other is called the "Zone Area Classification Method."

In the "Traditional Area Classification Method," the three terms that are used to describe the level of hazard are "Class", "Group", and "Division." In the "Zone Area Classification Method," the three terms that are used to describe the level of hazard are "Class", "Group", and "Zone."

Traditional Area Classification Method:

The Traditional Area Classification Method classifies the level of hazard of an area from the most flammable and combustible to the least flammable and combustible. The primary descriptor in this system is **Class**. The term Class is used to classify the type of material in an area. Three levels of Class are used in this system, of which the following one is pertinent to offshore operations:

Class I - Flammable gases, vapors, and flammable or combustible liquids.

The secondary descriptor in this system is **Group**. The term Group is used to classify a material's flammability and explosive properties. Seven levels of Group are used in this system, of which the following four are pertinent to offshore operations:

Group A - Atmospheres containing acetylene. (Acetylene is a gas with extremely high explosive capability during combustion and is commonly used for welding and cutting.)

Group B - Atmospheres containing hydrogen, process gases containing more than 30% hydrogen, butadiene, ethylene oxide, or propylene oxide.

Group C - Atmospheres containing hydrogen sulfide (H_2S) or ethylene.

Group D - Atmospheres containing acetone, ammonia, benzene, methane, ethane, butane, propane, hexane, or natural gas.

The tertiary descriptor in this system is **Division**. The term Division is used to define the likelihood that a hazard will exist in the classified area relative to the material's flammability and explosive properties. The following two levels are used:

Division 1 - Locations in which the explosion hazard exists under normal operating conditions. The area may be hazardous all or most of the time or it may be hazardous some of the time. Division 1 also includes locations in which a breakdown or the faulty operation of electrical equipment or processes might release ignitable concentrations of flammable gases or vapors, and might also cause simultaneous failure of electrical equipment in such a way as to directly cause the electrical equipment to become a source of ignition. An example of such a location might be an area where a flammable liquid is stored under cryogenic conditions, and a leak of the extremely low temperature liquid directly onto electrical equipment could cause failure of the electrical equipment at the same time the vapors of the evaporating liquid are within the flammable range.

Division 2 - Locations in which ignitable concentrations of flammable gasses or vapors are not normally present, but could be present when a fault, such as a leak at a valve in a pipeline carrying flammable liquids, occurs. Division 2 locations often exist adjacent to Division 1 locations where there is no physical barrier or partition to separate a Division 1 location from a non-hazardous location, or where a ventilation failure (an abnormal condition) might extend the location in which flammables exceed normal conditions. Electrical equipment approved for Division 1 locations are also suitable for use in Division 2 locations; but electrical equipment approved for Division 2 locations are not suitable for Division 1 locations.

The descriptors in the Traditional Area Classification Method used for offshore operations are as follows:

Class	Group	Division
I	A	1
		2
	B	1
		2
	C	1
		2
	D	1
		2

Zone Area Classification Method:

The Zone Area Classification Method also classifies the level of hazard of an area from the most flammable and combustible to the least flammable and combustible. The primary descriptor in this system is **Class**. The term Class is used to classify the type of material in an area. The following three levels are used:

Class I - Flammable gases, vapors, and flammable or combustible liquids.

The secondary descriptor in this system is **Group**. The term Group is used to classify a material's flammability and explosive properties. Two levels of Group are used in this system, of which the following one is used in offshore operations:

Group II - Combustible gas or vapors typically found in above surface industrial operations, including offshore operations.

Group II is further divided into the following three subgroups of gas and vapor categories, based upon their explosive pressure and ignition temperature:

Subgroup IIA - Atmospheres containing acetone, ammonia, benzene, methane, ethane, butane, propane, hexane, or natural gas.

Subgroup IIB - Atmospheres containing hydrogen sulfide (H_2S), ethylene, butadiene, or ethylene oxide.

Subgroup IIC - Atmospheres containing acetylene, hydrogen, process gases containing more than 30% hydrogen, or propylene oxide. (Most flammable and explosive subgroup.)

The tertiary descriptor in this system is **Zone**. The term Zone is used to classify the likelihood that the flammability and explosive hazard will exist under normal conditions. The following three levels are used:

Zone 0 - Locations in which ignitable concentrations of flammable gases or vapors are present continuously or present for long periods of time. This classification is usually used inside tanks in which flammable or combustible liquids, gases, or vapors are stored. If venting is provided to allow gases or vapors to escape during the process of filling the tanks, then an 18-inch radius area around the opening of the vent must also be considered a Zone 0 location. Some other Zone 0 locations include the area:

- Between the inner and outer roof sections of a floating roof tank containing volatile flammable liquids;
- Inside open vessels, tanks, and pits containing volatile flammable liquids;
- Inside an exhaust duct that is used to vent ignitable concentrations of gas or vapors; and
- Inside adequately ventilated enclosures containing normally venting instruments utilizing or analyzing flammable fluids and venting to the inside of the enclosure.

Note: No amount of ventilation can change the classification of a Zone 0 area to a Zone 1 area.

Examples of electrical equipment that might be found in Zone 0 locations are equipment for functioning and monitoring of the system. The normal type of circuit that is installed to feed electricity to this equipment is a circuit considered to be intrinsically safe (**ia**) (i.e., a circuit with very low energy levels that, even in double fault conditions, will not ignite the gas or vapor in the area).

Zone 1 - Locations in which an ignition hazard is considered to be present under normal conditions, including repair and maintenance activities, or in which there are operations or processes which could result in the release of a flammable mixture of gases or vapors, including leakage, and there may be a simultaneous failure of electrical equipment. An area that is adjacent to a Zone 0 location from which ignitable concentrations of flammable gases or vapors could migrate would be a Zone 1 location, unless positive pressure ventilation has been provided and there are safeguards in place to ensure against ventilation failures.

The normal operating conditions referenced here for a Zone 1 location does not take into consideration catastrophic leaks; however, small leaks from valves, pump packing glands, and other similar leaks considered common for that type of equipment handling hazardous gases or vapors, are considered normal operating conditions.

Zone 2 - Locations in which gases or vapors are not likely to occur during normal operations; but, if a leak does occur, it would only continue for a very short duration of time. An area would be classified as a Zone 2 location if liquids, gases, or vapors are normally confined within closed piping or containers that can only leak as a result of a rupture or some other abnormal condition. An area that is adjacent to a Zone 1 location, from which ignitable concentrations of flammable gases or vapors could migrate, would be a Zone 2 location, unless positive ventilation has been provided and there are safeguards to ensure against ventilation failure.

The descriptors in the Zone Area Classification Method used for offshore operations are as follows:

Class	Group	Subgroup	Zone
I	II	A	0
			1
			2
		B	0
			1
			2
		C	0
			1
			2

<u>Comparison of the Two Classification Methods</u>:

The fundamental difference between the two classification methods is that the Traditional Area Classification Method recognizes 4 gas groups and the Zone Area Classification Method recognizes 3 gas groups. Both methods recognize the same representative gases; but the Zone Area Classification Method combines acetylene and hydrogen in the same gas group. Another difference between the methods is the order in which the sensitivities of the gases to flammability or combustion are listed, with acetylene being the most sensitive gas.

Representative Gas	**Traditional Area Classification Method (API RP 500)**			**Zone Area Classification Method (API RP 505)**			
	Class	**Group**	**Division**	**Clas s**	**Group**	**Sub-group**	**Zone**
Acetylene	I	A	1 or 2	I	II	C	0,1, or 2
Hydrogen	I	B	1 or 2	I	II	C	0,1, or 2
Hydrogen Sulfide	I	C	1 or 2	I	II	B	0,1, or 2
Methane	I	D	1 or 2	I	II	A	0,1, or 2

The Zone Area Classification Method also recognizes more differences in the potential for combustion.

Area Classification	**Continuous Hazard**	**Intermittent Hazard under Normal Conditions**	**Hazard under Abnormal Conditions**
Zone Area Classification Method (API RP 505)	Zone 0	Zone 1	Zone 2
Traditional Area Classification Method (API RP 500)	Division 1		Division 2

Locations on offshore facilities not classified as Zone 0, 1, or 2 in the Zone Area Classification Method, or Division 1 or 2 in the Traditional Area Classification Method are to be considered “Unclassified” locations.

Note: Care should be taken where both Division and Zone classified areas exist on the same offshore facility. There may be some instances where Zone classified areas are located adjacent to existing Division classified areas. This dual classification of an offshore facility is acceptable; however, certain precautions must be observed. Class I, Zone 0 and Zone 1 areas must not abut or overlap any Class I, Division 1 or Division 2 areas. However, it is permissible to have Class I, Division 2 areas, and Class I, Zone 2 areas adjacent to each other.

Dual classification permits these two different area classification methods, with their different wiring requirements, to exist on a single offshore facility; but it does not provide a clear line of demarcation between the two classification methods' areas. A lessee or operator could reclassify a Class I, Division 1 or Division 2 area as a Class I, Zone 0, Zone 1, or Zone 2 area, provided all of the reclassified space is classified using flammable gas or vapor source.

ELECTRICAL EQUIPMENT MARKING

Electrical equipment must be marked to show the area classification and temperature class that it is designed to operate in. It must also be marked to show the country whose standards it complies with (United States of America is coded **A**) and the protection techniques that are incorporated in the equipment. An example of the marking on a piece of electrical equipment in an area classified using the Traditional Area Classification Method is as follows:

Class I Division 1 Group D T4

Which means:

Class I - Flammable gas or vapor

Division 1 - Explosive atmosphere exists under normal operating conditions

Group D - Atmosphere containing acetone, ammonia, benzene, methane, ethane, butane, propane, hexane, or natural gas

T4 - Maximum surface temperature of 135^{o}C

An example of the marking on a piece of electrical equipment in an area classified using the Zone Area Classification Method is as follows:

Class I, Zone 0, AEX ia IIA T4

Which means:

Class I - Flammable gas or vapor

Zone 0 - Ignitable concentrations of flammable gas or vapor are present continuously or present for long periods of time

A - Conforms to United States of America standards

EX - Explosionproof enclosure

ia - Intrinsic Safety – Two Fault

IIA - Atmosphere containing acetone, ammonia, benzene, methane, ethane, butane, propane, hexane, or natural gas

T4 - Maximum surface temperature of 135^{o}C

TEMPERATURE IDENTIFICATION

Temperature Identification Numbers (**T-ratings**) are short-hand notations which correlate to the temperature at which a gaseous atmosphere will ignite without requiring a spark or flame to initiate the combustion. An example of this type of combustion initiation would be the spontaneous combustion caused by the heat produced by a high temperature device (e.g., an operating light or motor) in a Division 1 location on an offshore platform.

High temperature devices are defined as those devices whose maximum operating temperature exceed 80% of the ignition temperature (expressed in ^{o}C) of the gas or vapor atmosphere the device is operating in. For example, any device (e.g., lights, transformers, motors, etc) with an operating temperature above 726^{o}F (386^{o}C) should not be installed and operated in a classified area with a natural gas atmosphere. Since the ignition temperature (autoignition temperature) of natural gas is usually considered to be 900^{o}F (482^{o}C):

$$\mathbf{0.80 \times 482^{o}C = 386^{o}C\ (726^{o}F)}$$

In a hydrogen sulfide (H_2S) atmosphere, which is usually considered to have an ignition temperature (autoignition temperature) of 500°F (260°C), any device with an operating temperature above 406°F (208°C) should not be installed and operated:

0.80 x 260°C = 208°C (406°F)

Note: This calculation is always done using the temperature in **°C**. The temperature may later be converted to **°F**.

The following table extracted from Table 2-1 in the National Fire Protection Recommended Practice NFPA 497 provides a list of the ignition temperatures (autoignition temperatures) for the various gas and vapor atmospheres found on offshore platforms:

Atmosphere	**Traditional Area Classification Method**	**Zone Area Classification Method**	**Autoignition Temperature**	
	(Group)	**(Subgroup)**	**(°C)**	**(°F)**
Acetone	D	IIA	465	869
Acetylene	A	IIC	305	581
Ammonia	D	IIA	498	928
Benzene	D	IIA	498	928
Butadiene	B	IIB	420	788
Butane	D	IIA	288	550
Ethane	D	IIA	472	882
Ethylene	C	IIB	450	842
Ethylene Oxide	B	IIB	429	804
Hexane	D	IIA	225	437
Hydrogen	B	IIC	520	968
Hydrogen Sulfide (H_2S)	C	IIB	260	500
Methane	D	IIA	630	1166
Natural Gas	D	IIA	482	900
Propane	D	IIA	450	842
Propylene Oxide	B	IIC	449	840

The following formula is used to convert a temperature from °C to °F:

((XXX**°C** × 9) ÷ 5) + 32 = XXX**°F**

The following formula is used to convert a temperature from °F to °C:

((XXX**°F** – 32) × 5) ÷ 9 = XXX**°C**

The following table provides a list of the T-ratings from Table 500.8(B) in the National Electrical Code (NEC 2002):

T-ratings		**Maximum Surface Temperature**	
Traditional Area Classification Method (Divisions)	**Zone Area Classification Method (Zones)**	**°C**	**°F**
T1	T1	450	842
T2	T2	300	572
	T2A	280	536
	T2B	260	500
	T2C	230	446
	T2D	215	419
T3	T3	200	392
	T3A	180	356
	T3B	165	329
	T3C	160	320
T4	T4	135	275
	T4A	120	248
T5	T5	100	212
T6	T6	85	185

PROTECTION TECHNIQUES

Electrical equipment intended for use in a Class I, Division 1 area must be explosion proof, intrinsically safe, or purged and pressurized equipment. Electrical equipment intended for use in a Class I, Division 2 area must be nonincendive, purged and pressurized, or hermetically sealed equipment. Electrical equipment intended for use in a Class I, Zone 0 area must be intrinsically safe equipment. Electrical equipment intended for use in a Class I, Zone 1 area must be flameproof, purged and pressurized, oil immersed, increased safety, encapsulated, or powder filled equipment. Electrical equipment intended for use in a Class I, Zone 2 area must be non-sparking, restricted breathing, or sparking equipment. The following information is provided to define these requirements.

Protection Techniques	Type Code	Traditional Area Classification Method		Zone Area Classification Method		
		Division 1	Division 2	Zone 0	Zone 1	Zone 2
Encapsulation	m	no	yes	no	yes	yes
Explosionproof Enclosure	EX	yes	yes	no	yes	yes
Flameproof	d	no	yes	no	yes	yes
Hermetically Sealed Device	nC	no	yes	no	no	yes
Increased Safety	e	no	yes	no	yes	yes
Intrinsic Safety *	IS	yes	yes	---	---	---
Intrinsic Safety – Two Fault	ia	---	---	yes	yes	yes
Intrinsic Safety – One Fault	ib	---	---	no	yes	yes
Nonincendive Equipment	NI	no	yes	no	no	yes
Non-sparking	nA	no	yes	no	no	yes
Oil Immersion	o	no	yes	no	yes	yes
Powder Filling	q	no	yes	no	yes	yes
Purged and Pressurized – Type X	pX	yes	yes	no	yes	yes
Purged and Pressurized – Type Y	pY	yes	yes	no	yes	yes
Purged and Pressurized – Type Z	pZ	no	yes	no	no	yes
Restricted Breathing	nR	no	yes	no	no	yes
Sparking Equipment **	nC	maybe	maybe	maybe	maybe	maybe

Note: * - Must be a Two Fault Intrinsic Safety system, which is the USA standard.
** - Must be used in conjunction with another protection technique other than Restricted Breathing.

Encapsulation (m) - This method of protection is used to prevent flammable or combustible gas or vapor from migrating, in large enough quantities to form an ignitable atmosphere, into contact with an electrical arc or excessive temperatures. Electrical equipment components are enclosed in a compound in such a way as to prevent or limit migration of gas or vapor through the compound.

Encapsulation is only permitted in Class I, Division 2, and Class I, Zone 1 and 2 areas.

Explosionproof Enclosure (EX) - An enclosure that is capable of withstanding an explosion of a gas or vapor within the enclosure and of preventing the ignition of an explosive gas or vapor atmosphere that may surround it, and that operates at an external temperature such that a surrounding gas or vapor atmosphere will not be ignited. This enclosure is suitable for Class I, Division 1 or 2 and Zone 1 or 2 locations; but is not acceptable for Class I, Zone 0 locations.

Flameproof (d) - This method of protection is used to ensure that an explosion of gas internal to an enclosure will not transmit the explosion to an explosive gas or vapor atmosphere surrounding the enclosure. The enclosure will withstand an internal explosion of the flammable gas or vapor mixture, for which it was specifically designed, that has penetrated into the interior without suffering damage; however, the enclosure will not allow an external explosion to occur by preventing a source of ignition from exiting the enclosure through any joints or structural openings in the enclosure.

Flameproof is only permitted in Class I, Division 2, and Class 1, Zone 1 and 2 areas.

Hermetically Sealed Device (nC) - An enclosure designed to prevent a hazardous or corrosive gas from coming into physical contact with an arcing or high temperature component. Hermetically sealed enclosures must be sealed through glass-to-metal or metal-to-metal fusion at all joints and terminals. A common type of hermetically sealed equipment is a contact block or reed switch.

These enclosures are suitable for use in Class I, Division 2 areas and in Unclassified areas. However, enclosures whose seals are accomplished by O-rings, epoxy, molded elastomer, potting or silicone compounds cannot be considered hermetically sealed unless such equipment has been determined to be suitable for the specific Class I, Division 2 area by a nationally recognized testing laboratory.

Increased Safety (e) - This method of protection is only applicable to electrical equipment that does not arc or spark, or generate temperatures high enough to cause ignition in normal operation, such as fluorescent light fixtures. It is intended for products in which arcs and sparks do not occur in normal service or under fault conditions, and in which surface temperatures are controlled to remain under incendive values. Increased Safety is achieved by enhancing insulation values, and creepage and clearance distances, above those required for normal service. This method of protection is different from the Intrinsically Safe method of protection, which prevents any spark or thermal effect from igniting a gas or vapor atmosphere by limiting voltage and currents with electrical circuit components, such as Zener Diode Barriers.

Increased Safety is only permitted in Class I, Division 2, and Class I, Zones 1 and 2 areas.

Intrinsic Safety (IS) - Low-energy systems that are designed to ensure safety by eliminating the ignition source leg of the combustion triangle. The energy in the system is maintained below that needed to ignite a flammable atmosphere, even under fault conditions. Opening, grounding, or short-circuiting of field-installed wiring is considered a condition of normal operation in this protection technique, rather than a fault condition. The common protective device used in intrinsically safe circuits is a Zener Diode Barrier. While this type of device controls the energy going to a circuit, it does not prevent incorrectly installed products, such as capacitors, which store energy, from increasing the maximum current in the system. It is important to understand that intrinsic safety is a "system approach" and that no single device provides total protection.

This type of protection technique uses an energy-limiting interface in the wiring between safe and hazardous areas, and limits the maximum level of current and voltage measured as energy (usually in millijoules) under normal and fault conditions. The interface passes signals in either direction as required, but limits the voltage and current that can reach the hazardous area under fault conditions. (Intrinsic safety IS is acceptable for Class I, Division 1 and 2 areas as a two fault system, which is the USA standard.)

- **Two Fault (ia)** is allowed in Zone 0 and less dangerous locations. In the event of a failure of two zener diodes, a third zener diodes must perform its functions (i.e., one excessive zener diode). Intrinsic safety ia is acceptable for Class I, Zone 0 areas.

- **One Fault (ib)** is allowed for Class I, Zone 1 and 2 areas only. In the event of a failure of one zener diode, a second zener diode must perform its functions. Intrinsic safety ib is acceptable for Class I, Zone 1 and 2 areas, but is not acceptable for Class I, Zone 0 areas.

Nonincendive Equipment (NI) - This method of protection is used for contacts, systems, circuits, and equipment that is incapable of releasing sufficient electrical or thermal energy to ignite flammable gases or vapors under normal operation and environmental conditions. The housing of a nonincendive component is not intended to exclude the flammable atmosphere or contain an explosion. Nonincendive devices need no special enclosure or other physical safeguard.

Nonincendive equipment must be certified and can be installed in a Class I, Division 2 area. To be allowed in a Class I, Division 1 area, nonincendive equipment must be installed in an explosionproof enclosure.

Non-sparking (nA) - This method of protection is used to ensure that electrical equipment does not have energy to ignite the gas or vapor atmosphere around it during normal operation and is not likely to have a fault that could cause ignition. The electrical equipment has no normally arcing parts or thermal effects capable of ignition. Examples of electrical equipment that do not comply with this protection method are relays, circuit breakers, servo-potentiometers, junction boxes, adjustable resistors, switches, non-latching type connectors, and motor brushes.

The Non-sparking method of protection is normally used together with another method of protection and the area in which it is permitted is dependent upon the other method of protection it is used in conjunction with. This method of protection is normally intended for Class I, Division 2, or Class I, Zone 2 areas.

Oil Immersion (o) - This method of protection is used to ensure that the gas or vapor located above arcing or sparking equipment within an enclosure or the gas or vapor located exterior to the enclosure cannot be ignited by the arcing and sparking. In this method, the electrical equipment is immersed in a protective fluid of nonconductive liquid or oil. The fluid level is such that the arcing and sparking parts of the electrical equipment are always covered by the protective fluid.

A major use for this protection technique is for electrical contacts, particularly high-voltage contacts in high-current circuits. Oil immersion is only permitted in Class I, Division 2, and Class I, Zones 1 and 2 areas.

Powder Filling (q) - This method of protection is used to ensure that gas and vapor atmospheres are insulated from the heat produced by electrical equipment components. Electrical equipment components, such as fuses and fluorescent fixture ballasts, are fixed in position and completely surrounded by a filling, insulating material (usually glass or quartz powder) to prevent the exterior temperature from reaching incendive values.

Powder Filling is only permitted in Class I, Division 2, and Class I, Zones 1 and 2 areas.

Purged and Pressurized (p) - This protection technique reduces the concentration flammable gas or vapor inside an enclosure to an acceptable safe level. An inert gas or instrument quality air is used as a protective gas to first purge the atmosphere inside of an enclosure from any hazardous quantity of flammable gases or vapors. It normally takes between 5 to 10 volume changes to ensure that the enclosure is purged. The enclosure is then kept pressurized by the protective gas at a pressure high enough above the atmosphere outside of the enclosure to prevent the flammable gas or vapor from reentering the enclosure. The enclosure pressure must be monitored for all of the following three types of purging:

- **Type X** purging changes a Class I, Division 1 area to an Unclassified area; therefore, no protection or special equipment is required inside the protective enclosure.

- **Type Y** purging reduces the inside of the enclosure from Class I, Division 1 to Class I, Division 2. This enables Class I, Division 2 rated equipment to be operated inside an enclosure located in a Class I, Division 1 area.

- **Type Z** purging reduces the inside of an enclosure from Class I, Division 2 to Unclassified. This enables general-purpose equipment to be operated inside an enclosure located in a Class I, Division 2 area.

The enclosure pressure must be monitored for all three types of purging. For Type X purging, the electrical power to the equipment in the enclosure must be disconnected if the enclosure pressure is lost and a re-purging is required before the power supply is restored. For Type Y and Z purging, an audible or visual alarm must automatically initiate if the enclosure pressure is lost.

Restricted Breathing (nR) - This method of protection is used to control the movement of gas and vapor into an enclosure. It relies on tight seals and gaskets in an enclosure to prevent diffusion of an explosive gas or vapor atmosphere into the enclosure. Provision is provided for checking that the restricted breathing properties of an enclosure are maintained. This method of protection is used where internal components in an enclosure run hotter than the required T-rating of the surrounding gas or vapor atmosphere. The T-rating is achieved by very tightly enclosing the offending components in the enclosure to prevent the explosive atmosphere from entering.

This method of protection is normally intended for Class I, Division 2, or Class I, Zone 2 areas.

Sparking Equipment (nC) - This method of protection is used for electrical equipment that contains normally sparking or arcing parts in which the contacts are protected by a method <u>other than</u> Restricted Breathing and may include contacts protected by other means suitable for a Class I, Division 1, or Class I, Zone 1 area. It may also include nonincendive components suitable for a Class I, Division 2, or Class I, Zone 2 area.

APPENDIX 21

AREA CLASSIFICATION

PRODUCTION EQUIPMENT

Any area containing any of the following production equipment:

1. Flowing well
   A. Surface safety valve
   B. Sample valve, bleed valve, or similar device
   C. Wireline lubricator

2. Artificially lifted wells
   A. Beam pumping well
   B. Electric submersible pumping well
   C. Hydraulic subsurface pumping well
   D. Gas lift well

3. Injection wells
   A. Flammable gas or liquid
   B. Nonflammable gas or liquid

4. Multi-well installations

5. Oil and gas processing and storage equipment
   A. Flammable liquid storage tank
   B. Combustible liquid storage tank
   C. Hydrocarbon pressure vessel
   D. Header or manifold
   E. Fired equipment
   F. Vents
   G. Relief valve
   H. Launcher or receiver
   I. Ball or pig launcher or receiver
   J. TFL tool launcher or receiver
   K. Dehydrator, stabilizer, and hydrocarbon recovery unit

6. ACT unit

7. Flammable gas-blanketed and produced water-handling equipment

8. Gas compressor or pump handling volatile, flammable fluids

9. Hydrocarbon-fueled prime movers

10. Instruments
    A. Not operated by flammable gas
    B. Operated by flammable gas

11. Sumps

12. Drains

13. Valves and Valve Operators
    A. Block valves and check valves
    B. Process control valves
    C. Valve operators
    D. Sample, bleed and drain valves, and similar devices.

DRILLING EQUIPMENT

Any area containing any of the following drilling equipment:

1. Rig floor and substructure areas

2. Mud tank

3. Mud pump

4. Shale shaker

5. Desander or desilter

6. Degreaser

7. Diverter line vent

8. BOP

APPENDIX 22

WELL-CONTROL DRILL REQUIREMENTS

ON-BOTTOM DRILLING

A drill conducted while on bottom shall include the following as practicable:

1. Detect kick and sound alarm.

2. Position kelly and tool joints so connections are accessible from floor, but tool joints are clear of sealing elements in BOP systems, stop pumps, check for flow, close in the well.

3. Record time.

4. Record drill-pipe pressure and casing pressure.

5. Measure pit gain and mark new level.

6. Estimate volume of additional mud in pits.

7. Weight sample of mud from suction pit.

8. Check all valves on choke manifold and BOP system for correct position (open or closed).

9. Check BOP system components and choke manifold for leaks.

10. Check flow line and choke exhaust lines for flow.

11. Check accumulator pressure.

12. Prepare to extinguish sources of ignition.

13. Alert standby boat or prepare safety capsule for launching.

14. Place crane operator on duty for possible personnel evacuation.

15. Prepare to lower escape ladders and prepare other abandonment devices for possible use.

16. Determine materials needed to circulate out kick.

17. Time drill and enter drill report on driller's report.

TRIPPING PIPE

A drill conducted during a trip shall include the following as practicable:

1. Detect kick and sound alarm.
2. Install safety valve, close safety valve.
3. Position pipe, prepare to close annular preventer.
4. Install inside preventer, open safety valve.
5. Record time.
6. Record casing pressure.
7. Check all valves on choke manifold and BOP system for correct position (open or closed).
8. Check for leaks on BOP system component and choke manifold.
9. Check flow line and choke exhaust lines for flow.
10. Check accumulator pressure.
11. Prepare to extinguish sources of ignition.
12. Alert standby boat or prepare safety capsule for launching.
13. Place crane operator on duty for possible personnel evacuation.
14. Prepare to lower escape ladders and prepare other abandonment devices for possible use.
15. Prepare to strip back to bottom.
16. Time drill and enter drill report on driller's report.

APPENDIX 23

BOP SYSTEM AND AUXILIARY EQUIPMENT

BOP systems and auxiliary equipment may include but not limited to:
1. Annular and ram-type preventers.
2. Choke and kill lines with various valve assemblies.
3. Remote control stations.
4. Diverter lines.
5. Choke manifolds and valve assemblies.
6. Upper and lower kelly cocks, inside BOP valves, and drill string safety valves.

Note: All test pressures and test schedules may be altered by approval of District Supervisor.

Sample Calculation of the Maximum Pressure to Protect the Formation at the Casing Shoe:

$$MP = (Emw - Pmw) \times 0.052 \times D$$

Where:
MP = Maximum pressure to be contained under the BOP in psi.
Emw = Equivalent mud weight from formation pressure integrity test (PIT) at the shoe of the last casing string in lbs/gal.
Pmw = Present mud weight in use in lbs/gal.
0.052 = Conversion factor (weight to pressure)
D = Present drilling depth in feet.

REMOTE BOP CONTROL STATION

Unit must have capability of functioning all components of the stack and diverter system.

ACCUMULATOR SYSTEM

1. Identify the primary and secondary independent power sources.
2. Each component must have an individual control valve.
3. Unit must be properly sized and pressurized.
4. Air regulators must have overrides or secondary air source.
5. Blind/blind shear ram control valves may be caged but never locked in neutral position.

Test Procedure:

1. Identify and turn off the primary power source.
2. Open the manifold bleed valve to the accumulator fluid reservoir.
3. Allow the pressure to drop enough for the secondary power source to begin building pressure automatically (no more than 1/3 of the initial pressure).
4. Turn on the primary power source to observe both systems building pressure and turn off automatically.

Surface Stack Accumulator Size Calculations:

BOP Equipment	Gallons to Close
Typical Annular BOP (13 5/8 inches, 5k)	23.6
Three Typical Ram BOP's (13 5/8 inches, 10k) [11.6 gal. x 3]	34.8
Two Typical Hydraulic Valves (4 inches HCR, 5k) [0.52 gal x 2]	1.1
Total Gallons for Closure [round to 60]	59.5
MMS Regulations [Total Gallons x 1.5]	90
Manufacturer Recommendation [Total Gallons + 50% SF x 2]	180

Typical 3000 psi System
1. Precharge Condition - 1000 psig
1. Full Charge Condition - 3000 psig
2. Discharged or Used Condition - 1200 psig*
   (* MMS Requirement - 200 psi above precharge)

Usable fluid in 11 gallon cylinder type	5
Usable fluid in 80 gallon spherical type	54

Typical 3000 psi System (as noted above):
1. MMS - 18 cylinder or 2 spherical
2. Manufacturer - 36 cylinder or 4 spherical

DIVERTER SYSTEM

1. Check for sizing, installation, and remote capability.
2. Drive Pipe - Actuated and flow tested.
3. Conductor - 200 psi minimum test and flow tested.
4. Actuated every 24 hours.
5. Retest every 7 days if used for that length of time.
6. No manual or butterfly valves allowed.
7. Diverter lines > 8 ft. in length from the outlet valve flange will require support. (Memo 8-28-98)

BOP STACK

Check for:

1. Installation with proper number of ram-type and annular preventers, choke and kill lines, valves, control lines, and remote operation capability. Only the kill line can be installed below the ram type preventers.
2. Properly sized inside BOP and drill string safety valves in open position on rig floor.
3. Upper and lower kelly cocks with wrenches or top drive valves when applicable.
4. Dual pod system on subsea installations.

TESTING

1. Surface BOP, subsea BOP stump test, and auxiliary equipment must be tested with water. (Completion stacks may be tested with filtered completion fluid if approved.)
2. All BOP tests must have an associated test chart and a reference document if necessary.
3. All tests must be properly recorded.
4. Low Pressure Test - (Conducted prior to the high test) Between 200 and 300 psi.
   - Initial pressure above 300 psi but less than 500 psi may be bled back to the required pressure.
   - Initial pressure above 500 psi must be bled to zero and re-pressured.
5. High Pressure Test - Test pressure for the high pressure test must not exceed the working pressure of the BOP or the wellhead assembly rating, whichever is lesser, by more than 10% during initial build up.

APPENDIX 24

CRANE USE CATEGORIES AND INSPECTIONS

Infrequent Usage

Used 10 hours or less per month, based on the average use over a quarter. These cranes will be subject to a pre-use and an annual inspection.

Moderate Usage

Used more than 10 hours but less than 50 hours per month, based on quarter average. These cranes will be subject to a pre-use, quarterly, and an annual inspection.

Heavy Usage

Used 50 or more hours per month. These cranes will be subject to a pre-use, monthly, quarterly, and an annual inspection.

INSPECTIONS

Monthly - Anytime during the calendar month.
Quarterly - Every three months (January, February, & March = 1st quarter; April, May, & June = 2nd quarter, etc.)
Annual - Every 12 months

FREQUENTLY ASKED QUESTIONS

Q: Crane was inspected for monthly on 3/5/2000, when is my next monthly due?
A: No later than 4/30/2000, O.K. to the last day of the month.

Q: Crane was inspected for quarterly on 1/20/2000, when is my next quarterly due?
A: No later than 4/30/2000, O.K. to the last day of the month.

Q: Crane was inspected for annual on 4/1/1999, when is my next annual due?
A: No later than 4/30/2000, O.K. to the last day of the month.

Q: When a crane shifts from infrequent to moderate use, when is the quarterly due?
A: By the end of the first month of the quarter following the shift.

Q: When a crane shifts from moderate to heavy use, when is the monthly due?
A: By the end of the month following the shift, followed by a monthly or quarterly, as needed to set up the required inspection schedule.

APPENDIX 25

PIT VOLUME TOTALIZER TEST PROCEDURE

Recommended procedure for Alarm Setting:

To determine loss/gain setting and calibration of the recorder, lift and lower the indicator float in the mud pit to activate the alarm and verify the calibration of the recorder. The recommended maximum and minimum tolerance for the mud volume measuring device is ± 10 bbls.