APPENDIX D

Offshore Drilling Well Control
Subsea and Surface Well Control – Major Differences

Vessel motion
Diverter system at the surface
Long (large ID) riser
Long (small ID) choke/kill lines
BOP is on the seafloor
Trapped gas in BOP stack
Potential for gas hydrates
Need to seal wellbore, disconnect LMRP
Generally lower formation integrity
Normally higher levels of equipment redundancy, reliability, and capability
Floating Drilling Well Control - Purpose of Subsea BOPE System

- Shut in the well
- Provide flexible and redundant methods for safely removing an influx
- Safely remove any trapped gas that could get into the riser
- Strip into/out of the hole
- Allow for rig motion & hang-off
- Disconnect the riser from BOPs
- Allow temporary abandonment of the location
- Shear the drill string and/or logging cable and seal the well
Moored vs. Dynamic Positioning (DP) BOP Requirements

- Rapid Disconnect Optional
- Shear Rams Required (EMDC)
- Riser Recoil System Optional
- Deadman System Optional

- Need Rapid Disconnect Capability
- Shear Rams a “Must”
- Riser Recoil System needed
- Deadman System Generally Used - 2 backup systems required (EMDC)
Floating Drilling Well Control

Topics:

• Shallow gas
• Reduced fracture gradient in deep water
• Kick prevention and detection
• Hydrates
• Drilling fluids considerations
• Riser margin considerations
• Kick containment - subsea BOP equipment, shut-in preparations and procedures
• Kick response - considerations when circulating a kick in deepwater
• BOP controls and backup systems
Shallow Gas

Shallow gas – gas bearing sands encountered before installation of the BOP stack on the wellhead. The sands are low pressure, but may flow if the formation pressure is greater than seawater gradient, lost returns occur, or if drilled too fast.

Prevention of shallow gas blowouts:

• Avoid shallow gas sands when possible
• Control drill to avoid excessive drill gas in mud
• Drill pilot hole to determine presence of shallow gas
• Keep hole full of heavy mud
### Shallow Gas

**Shallow gas blowout risk**

- Very dangerous for bottom founded rigs such as land rigs, jackups, submersibles, and floating rigs in shallow water when drilling with riser. The gas is brought to the rig by the conductor or riser.

- Moderate risk for floating rigs in shallow water when drilling without a riser. Gas levels may be high around the rig.

- Low risk for deepwater rigs drilling without a riser (riser never used by EM/IOL in deepwater). Gas levels low around the rig due to dispersion, currents. Rig can easily move away from gas boil.
Mitigation

- For bottom founded units and shallow water floating rigs with risers, a pilot hole should be drilled with heavy mud available to kill the pilot hole if the well flows.

- When drilling without a riser, shallow gas flows usually cause the well to collapse and stop the flow of gas naturally.

- If necessary, water or heavy mud can be pumped into the hole to kill the well.

- For floating units, if there is danger to the rig, it can be moved off location.
Formation fracture pressures are dependent primarily on:

1) Overburden pressure
2) Formation pore pressure

Formation fracture gradient on land is a direct function of the weight of the rock overburden above it.

Offshore, some of the rock is replaced by seawater.

The difference in densities between rock and water overburden reduces the fracture gradient.
Pore pressure and the fracture gradient may be very close to each other, especially in the shallower hole sections. These small kick tolerances result in:

- Increased probability of lost returns or a well “kick” unless higher mud weights are possible due to:
  - Additional strings of casing to increase the kick tolerance
  - Additional formation strength created by squeeze techniques

- Higher likelihood of ballooning formations

- Greater need for good pressure and kick detection to avoid kicks and/or keep kick volumes low
Ballooning is the term given to the loss/gain situation that occurs when the ECD friction pressure is enough to exceed the local fracture pressure and mud is injected into the fractures, to be followed by the expelling of the lost mud when the ECD is lost.
First sign that well may be ballooning is a loss of pit volume while circulating then a pit gain when circulation is suspended.

On first occurrence, the well is shut in to determine if flow is from ballooning or from a “kick”.

To identify ballooning, a step down test or continuous bleed down test should be performed; flowback should slow with each volume bled back.

Occurs in deeper sections of the hole.

More likely to occur in NAF due to higher ECDs.

Makes kick detection difficult due to flowback from fracture.

To reduce or stop ballooning, reduce ECD (adjust pump rate, mud weight, mud rheology, hole size) or set casing.
Kick Prevention and Detection

Kick detection and abnormal pressure indicators are mostly the same for surface BOP and subsea BOP

- ROP, d-exponent
- Gas units in mud (drilling, circulating, connection)
- Mud properties
- Cuttings analysis
- Paleontology
- Real time MWD/LWD
  - Downhole temperature
  - GR, resistivity and conductivity
  - PWD, real time pressure samples (NAF only)
- Borehole instability
- Pit Volume Totalizer – more difficult to monitor due to vessel heave
- Flo-Sho – more difficult to monitor due to vessel heave
Use a conservative mud weight whenever possible to prevent kicks and maintain hole stability

- Use of a riser margin in shallow water depths when possible
- Watch for trends in parameters indicating increasing pressure and raise mud weight accordingly

Maintain tight control on the hydrostatic pressure exerted on the hole to prevent lost returns and kicks

- Control drill to limit cuttings, gas units, and ECD in critical formations
- Boost riser to lift cuttings, dilute gas
- Use of PWD tools to monitor ECD
Use all drilling practices available in transition zones and narrow margin zones to ensure pressure at wellbore face is sufficient to prevent kicks while drilling and tripping.

High ECDs can mask a pressure transition until the pumps are shut down for connection. Near pressure transitions, simulate connections to monitor pore pressure changes more frequently than once per stand. 10-10-10 Test (simulated connections)

Make frequent flow checks, understand ballooning formations

Limit trip speed and pipe movement in narrow margin formations

Pump out of hole in narrow margin situations

Keep hole full and maintain accurate trip book during all trips in and out of hole

Make a short trip, return to bottom, and circulate bottoms up before starting trip out of hole

Return to bottom if hole not taking correct fluid at start of a trip
Reduce Kick “catch” time to the minimum to ensure that the influx is caught below the BOP stack and to minimize surface pressures

• Train rig crews and mud loggers – pit drills, trip drill, tool box training, daily discussion on well condition, well control issues

• Maintain kick monitoring equipment in good condition with alarms set appropriately (Flo-line sensors, PVT, gas units)

• Ensure crews understand that vessel motion can effect PVT and flow line sensors. Set sensors to ensure that vessel motion is considered

• Keep trip tank on hole at all times when not circulating

• When pumps are turned off, the volumes draining from the flow lines need to be considered and understood
Gas Hydrates

Hydrate formation is dependent on the amount of free water in the mud, the composition of the gas, pressure, temperature, and time.
Gas Hydrates – External Wellhead Connector

Preventative Measures

ROV injection of:

- Glycol to prevent formation
- Methanol to dissipate

O-ring between high-pressure mandrel and low pressure housing

O-ring to seal at mud mat adapter

Use of mud mat

Hydrate seal on H-4 connector

Courtesy of GE Oil and Gas Drilling and Production Systems
Preventative measures – hydrates inside BOP

• Increase kick awareness to minimize kick volumes

• Use mud systems that have minimal free water available for gas molecules to attach to

• Do not give the hydrate time to develop

• URC can develop hydrate curves based on mud type and temperature/pressure combinations
Drilling Fluids Considerations - Deepwater Drilling

- Use of NAF muds in deeper water prevents hydrates in the BOP stack.
- Use of NAF muds usually allow for tighter filter cake, resulting in lower swab pressures, fewer hole problems, and less differential sticking.
- Kick detection may be more difficult in NAF muds than in WBM because the kick may be partially dissolved in the NAF; gas is 25 – 40 times more soluble in NAF than in WBM.
- Gas dissolved in NAF may only come out of solution high in the well, possibly in the riser above the BOP stack.
- NAF is compressible, so mud density on bottom may be different than on surface as a function of pressure and temperature; PWD tools are recommended to determine actual pressure and ECD on bottom.
The riser can be circulated (boosted) through a separate circulating line to:

- Help carry cuttings out of the large diameter riser in the deep, small diameter sections of the well where the flow rate through the bit may not be sufficient for riser cleaning
- Dilute the fluid coming from the bottom of the well in order to keep the mud density correct (dilute any cuttings and gas with clean fluid)

In many deepwater locations, loss of riser and associated mud hydrostatic could create an under balanced situation to the formation - use of a riser margin may be considered
Riser Margin

Used to maintain hydrostatic balance of the well in the event of unplanned disconnect, or loss of the riser

Additional mud weight is added to the mud system to maintain hydrostatic balance with a combination of the hydrostatic pressure of the seawater and the mud in the hole from the mud line to TVD

Used in shallower water depths when formation strength is strong enough to support additional mud weight

Often cannot be used in deep water due to low formation strengths; if the riser is lost on a deepwater system, the well is automatically shut in using the BOP’s “deadman system,” with the acoustic and ROV systems as backup
Prior to drilling each hole section, preparation for a kick must be completed

- BOP and riser diagram on rig floor with hang off spacing
- Shut-in procedures posted on rig floor
- Trip drills and pit drills practiced until crew competent
- Slow pump rates and choke line friction pressures (CLFP) established, power choke drills completed before drilling out shoe
- Choke and kill lines flushed and filled with current mud weight
- Well control worksheet updated with volumes, depths, slow pump rates, and CLFP and posted on rig floor
- BOPs and all auxiliary well control equipment functioned and pressure tested
- All BOP valves labeled and set to normal drilling position
Kick Containment – Planning and Preparation

Choke Line Friction Pressure (CLFP)

- Long choke and kill lines create high friction pressures during circulation of a kick out of the wellbore
- Choke line friction is a function of line ID, line length, circulating rate, and the fluid properties
- Drilling fluids can become very viscous in cold subsea environment, particularly NAF
- During a well kill operation, the choke line friction pressure must be taken into account in order to maintain constant bottomhole pressure using the choke
- CLFP is determined by pumping though the lines at slow circulating rates before drilling out each casing, and whenever mud properties are significantly changed
Kick Containment – Planning and Preparation

Rig specific shut in procedures should take these questions into account:

• Is the rig moored or dynamically positioned?
• Is there an outlet directly under the upper annular?
• Will the influx be circulated out using the annular or hung-off on a pipe ram?
• Which ram will be used for hang-off?
• Is there clearance for tool joints between the blind shear ram(s) and the hang-off ram?
• Is there a choke or kill line outlet under the preventer to be used for the kill operation?
• How will stack arrangement affect ability to flush any trapped gas out of the stack?
Kick Containment Equipment – Wellhead Connector

SHD H-4 Connector

VX Seal

Hydraulic VX/VT Retainer Pins (4) Places

Cam Ring

Lock Dogs

Hydraulic Piston

Hydrate Seal

Flush Ports (4) Places

Adapter Kit for standard 27” wellhead Rig Installed

LOOOG

UNLOCK

SMS-700 30” OD Wellhead

MS-700 27” OD Wellhead

Courtesy of GE Oil and Gas Drilling and Production Systems
Kick Containment Equipment – LMRP Connectors

Vetco High Angle Release (HAR) Connector

Cameron HC Connector

Ensure manufacturer’s recommended maintenance is being performed on a regular basis
Kick Containment Equipment – Typical Subsea Ram Preventer

Cameron “TL” Ram Preventer with “ST” Locks

Hydraulically Actuated Ram Locks

Large Bore High Bending Capacity Flanges

Side Outlet Used for Choke/Kill Valves

Courtesy of Cameron
Kick Containment Equipment – Ram BOPs for Floaters

- Large bore - typically 18-3/4” with pressure ratings of 10 or 15k psi
- Utilization of side outlets for choke & kill lines to minimize connections and reduce overall height of stack
- Hydraulically actuated locking mechanism
- Capabilities to hang-off the drillpipe
- Use of shear blind rams
- High bending loads at flanged connections
- Operated with 1500 psi hydraulic pressure
- Typically need to close on a variety of pipe sizes; hence VBRs used routinely
A required component

Designed to shear drillpipe, wireline, and some ranges of casing and/or seal off the open hole

Force required to shear affected by:

- Pipe material and thickness
- Riser hydrostatic pressure
- Blade design

Available force increased by oversized and tandem pistons (booster), high operating pressures (up to 5000 psi)

Some newer rigs have casing shear rams (non sealing) in addition to blind shear rams (sealing)

Always check to ensure pipe in use can be sheared by system
Kick Containment Equipment – Casing Shear Rams

Designed to shear heavy pipe and casing, some with three millions pounds force

Do not seal

After pipe is sheared, blind shear rams closed to seal open wellbore

May operate on “High-Pressure Shear Circuit” with 3000 to 5000 psi closing pressure
Most common annular preventers in use:

- Shaffer Spherical
- Cameron ‘D’
- Hydril ‘GX’

The only option to shut in the well with drill collars or casing in the stack

Majority of stacks have two annulars to provide for redundancy

Annular working pressure is usually 5 or 10k psi

The two annulars are sometimes separated by the LMRP connector
Kick Containment Equipment - Choke & Kill Lines

Two lines provide redundancy - there is a backup line in case one fails

Inactive line can be used to compensate for CLFP

Allows circulation (or flushing) across the BOP

Allows circulation of the well if the pipe is hung-off and sheared

When circulating up both lines, back pressure on the formation is reduced
Balanced valve has tailrod below gate to null out effect of seawater hydrostatic pressure

Also serves as a position indicator

Metal to metal dynamic seals

Spring may not be sufficient to close valve with wellbore at rated working pressure

For true “fail-safe,” a “pressure assist circuit” is often used

Double block design is a space saver

Courtesy of Cameron
Kick Containment Equipment - Flexible Choke & Kill Lines

High-pressure hoses connect choke and kill lines to choke manifold at surface

Hoses are typically 60 to 90 feet long and allow for rig heave, vessel offset, and slip joint stroke

High-pressure hoses or a steel flex loop are used on the LMRP to connect C&K outlets on BOP stack to riser

Mini-hydraulic connectors (such as the Cameron HC connector) are used at the LMRP to BOP stack interface
BOP equipment set-up

- All BOPs in open position
- All subsea choke & kill line valves closed
- Remote hydraulic choke closed
- Downstream valve of remote hydraulic choke closed
Shut-in procedure

- Spaceout and shut down pumps
- Close upper annular preventer
- Open upper subsea choke line valves (limits trapped gas volume)
- Record shut-in DP, CSG and SSWH (if available) pressures every minute until stabilized; record pit gain
- Monitor riser for flow
- Hang off pipe if required
Kick Containment (Shut-In Procedure - Subsea Stack)

If the riser is flowing:

• Close diverter & divert riser flow to the system de-gasser or overboard
• Monitor slip joint for leakage & adjust pressure as required
• Monitor overboard lines
• Fill riser as needed
• Continue monitoring well shut-in pressures below BOP
Kick Containment (Shut in - Hang-off Criteria)

Close pipe rams and hang-off drillpipe when:

• DP vessels during well control events
• Annular leak or pressure above 1500 psi
• Drillpipe is trying to stick while working the pipe
• Bad or deteriorating weather or ice conditions, such that the LMRP might need to be disconnected (excessive heave, high riser angle, mooring line tension or thruster force)
• Possible underground flow
• No circulating line under the annular preventer to clear trapped gas leaving large volume of trapped gas, possibility of hydrates
• While sweeping gas from stack
Hang-off the drillpipe

- Locate tool joint with upper annular
- Open motion compensator
- Slack off to +/- 5’ from hang-off ram
- Close hang-off ram & set tool joint down on ram
- Check C/K line valve alignment to ensure well can be circulated from below the selected hang off ram
Kick Response - Well Kill Methods

Original mud weight (Drillers Method)

- Circulate the influx from the well with original mud weight
- Method of choice in deeper water
- Less time spent without circulating, minimizes gas migration if shoe tolerance is low
- Less time for hydrates to form
- Higher maximum surface pressures than other methods
- Time consuming if second circulation required

Balanced mud weight (Wait & Weight Method)

- Lowest surface pressures
- A second circulation will be required to add additional hydrostatic to drill ahead
Overbalance mud weight (Wait and Weight)

- One circulation required
- Added hydrostatic could break down formation

Bullheading

- Used if influx cannot be circulated to surface due to the nature of the influx (sour gas)
- Used if fracture gradient and pore pressure are close and circulating the well would cause well to breakdown anyway
- Used when large volumes of gas could exceed surface equipment limitations, if circulated to surface
Whichever method is chosen:

*The shut-in period should be minimized as much as possible to reduce the possibility of bubble migration and hydrate formation*
Kick Response - Well Kill Considerations – BOP Pressure

Kill line gauge can be used to monitor the “inactive line” and simplifies removing the CLFP from the circulating system when starting the well kill.

A BOP pressure sensor can also be used to initiate well kill operations and remove the CLFP.

The choke operator simply holds the SubSea Wellhead pressure gauge constant while the pump is brought up to speed, then switches to DP gauge.

SSWH pressure gauge simplifies removing CLFP when using both choke and kill lines to circulate.
MUX type systems typically have a subsea wellbore pressure sensor mounted in a ram outlet or in the choke line.

This sensor relays the pressure reading electronically to a surface mounted digital pressure gauge.
Use of a single choke line is normal practice due to:

- One line use is consistent with industry well control training and experience
- Uncertainty of CLFP during circulation start-up, inactive line provides the required information
- BOP stack arrangement may not permit the use of choke and kill lines when hung-off

When should two lines be used?

- When the choke line friction pressure is greater than the shut-in casing pressure
- When the choke line friction pressure would cause the casing shoe pressure to exceed the leak-off value
Effect of gas entering the choke line

• A high volume, non-dispersed gas bubble entering the choke line will cause a sudden loss of mud hydrostatic, making choke adjustments more difficult

• Slower pump rates will give choke operator more time to make choke adjustments as the gas enters the smaller ID choke line and at surface

• The “inactive” line and/or SSWH gauge should be closely monitored to detect when gas is entering the line
• Trapped gas is residual gas trapped in a BOP stack after the kick has been circulated from the wellbore.

• Failure to remove the trapped gas can be dangerous.

• Problem is more severe in deep water.

• Each rig must develop rig-specific removal procedures.

• Procedures must be posted on the drill floor.

• Most 5th & 6th generation rigs have a sweep line installed between the annular preventers to simplify gas removal from the BOP stack.

• If no sweep line is installed in the BOP stack special procedures must be used to remove trapped gas safely from below the BOP stack.
Diverter System

- Primary function is to handle gas in the riser
- System interlocked to prevent inadvertent shut in of well
- Routinely function tested rarely pressure tested
- Must accommodate:
  - Overboard downwind
  - Route gas to separator
  - Use of flowline
  - Use of trip tank

Typical Diverter System Layout
Kick Response - Well Kill Considerations – Gas in Riser

Diverter lockdown dogs

Annular style element with full capabilities

Diverter housing connected to substructure

Closing Chamber

Flowline, diverter line, trip tank line connections

Courtesy of GE Oil and Gas Drilling and Production Systems
Gas in riser can be a dangerous situation - possibility of riser flow, riser collapse, and/or fire on the rig

Gas in the riser can occur from:

• Circulation of drill gas
• Gas influx above BOPs before detection
• Poor handling of trapped gas in BOPs after well control operation

Boosting the riser will dilute drill gas

Be prepared to divert flow overboard in an emergency, or to the riser degasser if flow is manageable with the system on the rig

Risk of getting gas above the BOP stack increase with percentage of wellbore above the BOP stack, in areas with massive lost return potential (carbonates), and with the use of NAF
Gas expansion from 10,000 feet, 13 ppg mud, 1 bbl kick

Note: Figure Does Not Include Dynamic Effects of a Rapidly Expanding Gas Bubble

Assumptions:
1. 13.0 PPG Mud
2. 1.0 BBL Gas Volume at 10,000 Feet
3. Gas Allowed to Freely Expand
4. Temperature Affects Not Considered
BOP Controls and Backup Systems

Purpose is to deliver hydraulic fluid to the desired side of a BOP function, at the desired time, while venting the pressure from the opposite side of the function.

Two basic classifications of control systems:

1. Hydraulic system (primarily older moored rigs)
2. Multiplexed control system (deepwater and DP rigs)
BOP Controls and Backup Systems - Hydraulic Controls System

- Hydraulic power unit (HPU)
- Accumulator bank(s)
- Control panels
  - Primary on HPU
  - Driller’s
  - Auxiliary remote
- Hydraulic hose reels (2)
- Hose “bundles” (2)
  - Power fluid line
  - Pilot lines
- Two subsea control pods
- Stack mounted accumulators (if needed)
HPU produces and stores power fluid

Two independent pump systems:
- Primary system - electric triplex pumps
- Secondary system - air-operated pumps

Fluid is mixture of potable water and BOP fluid (~1 to 3%)

Fluid is filtered as it flows to a pod select valve (not shown)

Electric control box receives signals from the remote panels

Solenoid valves send rig air to cylinders on the primary panel

Cylinders shift valves and direct pilot fluid via hoses to subsea control pods

Figure courtesy of Hydril Pressure Control, a GE Oil and Gas Business
Generally composed of a 1” power fluid hose surrounded by many 3/16” pilot and readback lines

Low volumetric expansion hose material is desired to shorten response time on pilot signal

Dedicated hose bundle to each pod

Pressure drop in the 1” supply line substantial

To compensate for pressure drop and assure faster actuation times, subsea accumulator bottles, charged by the power fluid supply lines, are often used
BOP Controls and Backup Systems - Hose Reel

Stores the hose bundle
Motor drive and brake
Manifold and junction box

When the BOP is run, the jumper hose is disconnected
Select functions are run live

Manifold pressure is supplied by swivel assembly on the hose reel

Hose is either clamped to riser or run on wireline with pods

Some pods are run with stack and not independent
An alternate method of delivering hydraulic control fluid to the pods

Consists of a 2 or 3” ID line attached to the riser

Can be used independently or in conjunction with the hose bundle supply

Rigid conduit line terminates at a conduit valve manifold located on the LMRP

Manifold consists of three valves - supply power fluid to active pod, isolate power fluid from inactive pod, and dump valve
Hydraulic Subsea Pod

Subsea distribution hub for fluid to BOPs
Two control pods for basic redundancy
Historically designated yellow and blue
Power fluid is delivered to pods at 3000 psi
Each pod contains annular and manifold regulators
Regulators reduce pressure to the operating pressure
Pod valves (SPM) downstream of regulators
SPM valves are operated by pilot pressure
SPM valves direct fluid to desired BOP function
Retractable stack and LMRP stingers
Stingers allow pods to be retrieved
- Individually, or
- With LMRP
Multiplex (MUX) simply means that the communications system (i.e., modems) from the surface to seafloor carries multiple “commands” and/or data back and forth via a single channel (electric or fiber optic).

A MUX system decreases the amount of time required to function a BOP component.

Response times in ultra deepwater are critical for an emergency disconnect on a DP vessel.

Triple-redundant computers and multiple parallel communications paths support the system.

Typically work at 5000 psi instead of 3000 psi.

Incorporate multiple backup systems.
BOP Controls and Backup Systems - Multiplex (MUX) Systems

Driller’s panel
Toolpusher’s panel
UPS/CCU
HPU
Lubricant mixing system
Surface accumulators
Rigid conduit lines
Rigid conduit manifold
MUX reels / cables
Redundant subsea pods
Subsea accumulators (optional)

Figure courtesy of Hydril Pressure Control, a GE Oil and Gas Business
Driller’s Panel

- Sends signal to CPU to be processed and sent subsea
- Include push to activate buttons
- Critical functions protected by cover
- Right half of panel shows “read backs”
- Regulators are adjusted on right half
- Warning lamps for abnormal pressures and fluid levels
- 6th generation rigs have Drillers Panel incorporated into driller’s touchscreen
BOP Controls and Backup Systems - Multiplex (MUX) Systems

HPU

- No air-driven charging pumps
- No surface mounted panel valves
- Three or four electric powered triplex charging pumps are typical with one pump connected to emergency generator
- 3000 to 5000 psi working pressure systems
- Pressurized hydraulic fluid is stored in surface accumulator bottles
- Includes surface flow meter
- Diverter controls are also located at HPU
MUX Cables

- Two MUX cable systems (blue and yellow) are stored on storage reels and have a slip ring to allow circuitry to be maintained while the reel rotates

- MUX cable typically has four power supply wires and 6 to 10 communication conductors

- Cable is typically about 1-1/2” OD

- Cable is clamped to riser or tugger lines while stack is being run

Typical MUX Cable

Power Lines (4)

Communication Lines (8)

Courtesy of West Engineering
MUX pods comprised of two sections:

• Electronics module
• Hydraulic section

Electronics module receives mux signal from CPU and sends pilot pressure to Hydraulic section

Hydraulic section basically same as on an “all hydraulic” system

Only one pod has power fluid supplied to it, but both are electrically active and solenoids allow inactive pod to mimic the active pod; thus, when the other pod is selected, the BOP function status will be consistent

Courtesy of Cameron
Emergency Disconnect System (EDS)

- Required on DP rigs to ensure wellbore can be sealed and LMRP disconnected before the rig excursion reaches the limit of the riser
- Computers activate BOP and rig functions in a programmed sequence when EDS is activated
- Most EDS systems have different sequences depending on the rig operating mode – drilling, running casing, testing
- Typical time to complete sequence is 45 to 90 seconds
BOP Controls and Backup Systems - EDS

BOP functions typically activated with the EDS are:

• POD stabs extend
• Choke and kill valves close
• Choke and kill connectors open
• Casing shear rams close
• Blind shear rams close
• Ram locks engage
• All stabs retract
• Riser connector unlock

Rig functions typically activated with the EDS are:

• Riser recoil
• Drawworks pickup string after casing shears fire
BOP Controls and Backup Systems - Acoustic Backup System

Used to actuate pre-selected functions if primary control system is lost

Designed to operate in 10,000’ water depth

Acoustic signals sent from surface to hydrophones and a subsea battery powered electronic package on the BOP stack

Acoustic signals are converted to electrical signals which actuate solenoid valves in the acoustic mini-pod
Acoustic Backup, Continued

Fluid from a stack mounted acoustic accumulator supply is then directed to the BOP function.

Acoustic system is plumbed into BOP hydraulic control lines with a second shuttle valve mounted at the function.

Select functions may include:

- Hang-off pipe rams close
- Blind shear rams close
- Ram locks engage
- LMRP connector unlatch

Acoustic bottle supply is usually 1.5 times the volume required at 3000 psi operating pressure.
Systems can be “armed” or “disarmed” depending on operator preference

When “armed,” deadman system will automatically actuate if both hydraulic and electric power is lost to both pods

System was designed to provide a means to secure the well if the riser parted and the pod control systems were lost

Power fluid for the backup systems is stored in dedicated accumulator banks on the BOP
Autoshear system will automatically actuate if the LMRP is disconnected accidentally.

Deadman and autoshear systems are triggered by different events, but actuate the same functions using a dedicated pod and accumulator bank of the BOP stack.

Typical functions for the deadman or autoshear system include:

- Close blind shear and/or casing shear rams
- Close ram locks
- Close choke and kill line valves
Consists of a stab-type device inserted into a pressure receiving coupling by an ROV.

Couplings are mounted on ROV Intervention Panels located on the LMRP and the BOP.

Power fluid is provided by ROV hydraulic pump using seawater or by a hydraulic fluid supply attached to the ROV.

Hot stabs can be designed to do two functions at once (i.e., close a ram and close ram lock).

Stacks are run with dummy hot stabs in panel receptacles to keep out debris.
ROV Hot Stabs, Continued

LMRP hot stab function may include:

• LMRP connector primary and secondary unlock
• LMRP connector glycol injection
• LMRP connector gasket release

BOP hot stab functions may include:

• Wellhead connector primary and secondary unlock
• Wellhead connector glycol injection
• Blind / shear rams close
• Casing shear rams close
• Wellhead gasket release

Hard piping is recommended from hot stab to wellhead connector unlock function
Deepwater well control has some additional issues when compared to surface or shallow water well control

- Equipment and procedures must all be planned before well spud
- Generic well control training and well specific crew training must occur before well spud
- Drills, toolbox training, and daily well control discussions continue for the duration of the well

With extensive training, clear procedures, dedicated maintenance personnel, and highly redundant equipment, deepwater well control operations are often safer and more reliable than surface well control operations.