Risk Profile of Dual Gradient Drilling

Bureau of Ocean Energy Management, Regulation, and Enforcement
Technology Assessment and Research Program
Operational Safety and Engineering Research
Contract M09PC00016
2-May-2011
Final Report

STRESS ENGINEERING SERVICES INC.
MOHR ENGINEERING DIVISION

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Forward

A safe workplace is a vital concern to all. We are charged with providing a safe working environment for all on the rig, its environs, and to the public at large. It is the intent of the author to provide information that will be helpful in well designing, well planning, and well construction for the experienced and the inexperienced drilling engineer; with the chief intent to make drilling a safer operation. If in the process, the combination of equipment and techniques makes drilling more economical compared to some benchmark or take less time than some benchmark, then so much the better.

The data contained in this report is the best available information on this date. Use of this report is not intended to replace a legal standard of conduct or duty toward the public on the part of a well designing, well planning, or well construction organization. The intent of this document is to provide a fair and balanced engineering approach to resolving chronic drilling engineering problems while maintaining or improving the current safety mandate already in place. It is the hope of the author that current regulatory requirements be tempered to reflect the vast improvement in technology, making drilling operations more productive and safer simultaneously. Until such time that regulatory requirements are modified to reflect acceptance of a higher degree of well control and safety, the standard and duty of care is intended to remain that standard that has been established by statutory law and judicial determinations within the industry.

The information contained in this document is intended solely for the purpose of informing and guiding the staff and management of organizations charged with well design, well planning, and well construction. As with any guideline, the techniques presented in this manual should be applied carefully and should be modified to fit the particular situation. In each instance, where it is determined that the standard of care in the industry is greater than that appearing to be indicated in this document, it must, of course, be the policy of the organization to proceed with that the standard of care in the industry be practiced.

Every effort has been made to restrict the frequency of words like ***always, will, should, shall, must, and never***. These words and their synonyms are too absolute. Experience has shown me that on occasion, although rare, the textbook can have the wrong answer or describe the wrong technique for a specific situation. Often times the circumstances in the field are not exactly the same as what the author envisioned at the moment the thought was transcribed to paper. A prudent engineer is mindful of those absolutes and incorporates them into his pool of professional judgment.

With respect to professional judgment and absolutes, Dual Gradient Drilling operations are application dependent. A successful Dual Gradient Drilling operation requires a certain minimum amount of equipment, technology, and know-how. Dual Gradient Drilling is not unlike a lot of other projects. Not only do you have to have tools, you have to have the correct tools and use them in an appropriate manner.

For progress to be made the experienced drilling engineer needs to "push the envelope" and seek the prudent limits for equipment and techniques within established safety margins without being handcuffed with absolutes. The inexperienced engineer when wanting to deviate from the norm would do well to do the homework necessary to fully justify the departure and be prepared to defend the rationale for the departure based on risk and reward. In either case, where confidence is lacking, the engineer would do well to consult knowledgeable resources in the industry to help guide his path forward.

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Respectfully submitted,

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Executive Summary

Dual Gradient Drilling (DGD) is a variation and a subset of Managed Pressure Drilling (MPD). Managed Pressure Drilling is a drilling tool that is intended to resolve chronic drilling problems contributing to non-productive time. These problems include:

- Well Stability
- Stuck Pipe
- Lost Circulation
- Well Control Incidents

Numerous papers describe how Managed Pressure Drilling, when properly applied, is as safe or safer than current conventional drilling techniques.

The Underbalanced Operations and Managed Pressure Drilling Committee of the International Association of Drilling Contractors have defined Managed Pressure Drilling.

> **Managed Pressure Drilling is an adaptive drilling process used to <u>precisely</u> <u>control</u> the annular pressure profile throughout the wellbore. The objectives are to ascertain the downhole pressure environment limits and to manage the annular hydraulic pressure profile accordingly. The <u>intention</u> of MPD is to avoid continuous influx of formation fluids to the surface. Any influx incidental to the operation will be safely contained using an appropriate process.**
>
> - **MPD process employs a collection of tools and techniques which may mitigate the risks and costs associated with drilling wells that have narrow downhole environmental limits, by proactively managing the annular hydraulic pressure profile.**

- **MPD may include control of back pressure, fluid density, fluid rheology, annular fluid level, circulating friction, and hole geometry, or combinations thereof.**
- **MPD may allow faster corrective action to deal with observed pressure variations. The ability to dynamically control annular pressures facilitates drilling of what might otherwise be economically unattainable prospects.**

The centerpieces of the definition are rooted around the words “intent” and “precisely control”. The various technologies available today allow us to control maintenance of the bottomhole pressure from the surface within a range of 30 – 50 psi. One MPD method does not address all problems. Managed Pressure Drilling is application specific. The drilling engineer will have his choice of many options that will best address the drilling problems he confronts.

Dual Gradient Drilling is a variation and a subset of Managed Pressure Drilling, mainly used in deepwater applications, that the drilling engineer has in his tool bag to avoid or mitigate drilling problems.

The Underbalanced Operations and Managed Pressure Drilling Committee of the International Association of Drilling Contractors have defined Dual Gradient Drilling as:

The intentional use of two pressure gradients within the wellbore and/or conduit(s).

This definition could also be used to describe Mud Cap Drilling. For our purposes and vernacular, Dual Gradient Drilling is a Managed Pressure Drilling technique that would most typically be practiced in deepwater drilling applications.

Not all DGD approaches are the same hydraulically. For example, dilution based approaches do not offer full riser margin, as the fluid above the wellbore is still more dense than seawater. A mid-riser withdrawal approach, perhaps with pump transfer system, does not necessarily offer full riser margin either. Numerous adaptations of Dual Gradient Drilling have been attempted, researched, failed, or abandoned.

Dual Gradient Drilling Adaptations

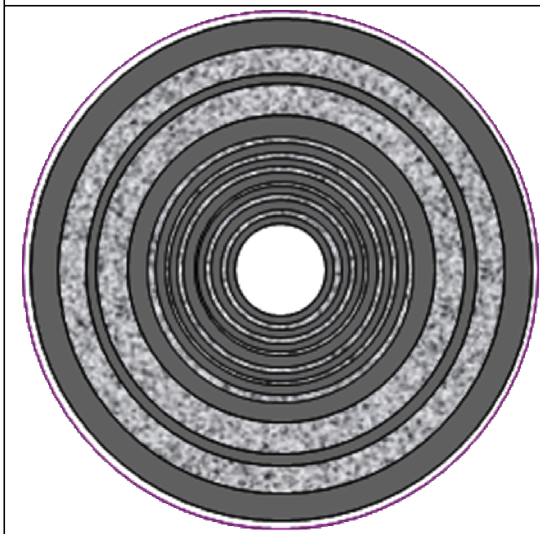
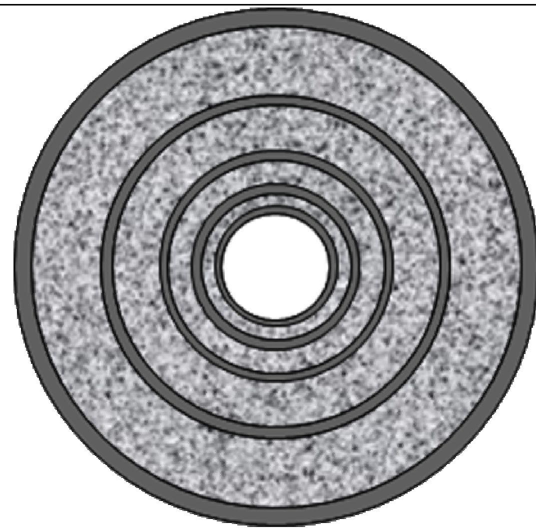
Currently Ongoing	Researched-Attempted-Failed-Abandoned
Positive Displacement Seabed Pump	Seabed Centrifugal Pump
Seabed Disk Pump	Seabed Separation and Electric Submersible Pump
Liquid Dilution	Gas Dilution
	Glass Beads

The adaptation that is the subject of this report was first successfully attempted in the Gulf of Mexico in September, 2001. At that time, it was known as the **SubSea MudLift Drilling Joint Industry Project (SML JIP)**. The technique has laid dormant for a number of years because of the enormous cost associated with the demonstration prototype model. Dual Gradient Drilling has been revived because we are in a different place now.

Prior to April 20, 2010, the question of a catastrophic event was not a matter of “if”, but “when”. Drilling operations in a deepwater environment is an expensive endeavor. It is expensive for a number of reasons, but the chief reasons are to protect human life, equipment, and the wellbore in a very inhospitable environment. In a single pressure gradient environment (conventional drilling), it is easy to depart from the drilling window because of the narrow drilling window between the pore pressure and the formation fracture pressure. The Dual Gradient Drilling System re-establishes a margin of safety not obtainable in a single gradient system. Even the popular variant of Managed Pressure Drilling called Constant Bottomhole Pressure falls short of providing all of the well control benefits associated with DGD.

The most impressive aspect of Dual Gradient Drilling is that it is as safe or safer than current conventional drilling techniques AND provides for full riser margin, where the well is fully controlled in the event of riser disconnect AND problem wells can be drilled and completed instead of abandoned either with cement plugs or in a file labeled “TOO RISKY TO DRILL – TECHNOLOGY NOT AVAILABLE”.

Narrowing of the pore pressure – fracture gradient window along with the annular friction component from borehole geometry and drilling fluid circulation often leads to many tight tolerance casings in the deepwater well. Dual Gradient Drilling takes the industry back to a more conventional casing program.

Where We Are Now….	Where We Want To Be….
	
Current Deepwater Casing Program	Conventional Casing Program Dual Gradient Drilling Casing Program

With Dual Gradient Drilling the cement sheath hydraulic seal is a more effective barrier against the undesirable intrusion of produced fluids, particularly hydrocarbons. Dual Gradient Drilling is a sophisticated form of deepwater well control and deserves a balanced quality appraisal of risks – positive and negative.

While there are risks associated with any drilling operation, deepwater well control is enhanced with DGD. Environmental episodes are also minimized. In the event of an emergency disconnect from the wellhead, seawater or a similarly compatible fluid dissipates into the surrounding water AND the well is under control because the hole is full of properly weighted drilling mud. DGD is like having a rig on the seabed floor. The riser margin is intact. It does not matter if the water depth is 5,000 feet or 15,000 feet, should the riser become disconnected, the well will be dead.

Generally, trouble time on any project is inversely proportional to the quality of the risk assessment, whether it is called a HAZID+HAZOP or a What-if+Checklist, performed in the planning stages prior to drilling the well. This report "Risk Profile of Dual Gradient Drilling" summarizes the first iteration of a risk assessment developed for a major operator entailing over 2,500 Subject Matter Expert man-hours of formal meeting time alone. This is a conservative estimate and does not account for other discussions, preparations, and resolution of issues. A risk assessment is more intense than drilling the well on paper (DWOP). The first iteration of this risk assessment exposed some issues that had not been previously considered and spawned a number of sidebar discussions to resolve conflicts and issues. The data mined to populate the example in this study is summarized in a Microsoft Excel spreadsheet.

Because this report summarizes the first iteration, the original documents are currently unavailable at this time because they are under construction and are in a constant state of being updated. They are being utilized as a basis for the second and future iterations so that the risks associated with Dual gradient Drilling Operations is "As Low As Reasonably Possible" (ALARP).

As with many risk assessments, it becomes obvious where the weaknesses and strengths are in the overall application. To no surprise, training of personnel often shows up as a repetitive safeguard and recommendation.

Glossary

Dual Gradient Drilling

Ann Friction	AF	Annular friction
Ann Hydro		Annular hydrostatic pressure
Annular Capacity	V_{Ann}	The unit volume of fluid contained between the inside diameter, ID, of the hole or casing and the outside diameter, OD, of the drillstring, measured in bbl/ft.
Annular Friction Pressure	AFP	The increase in circulating system pressure resulting from the drag force imposed upon the drilling fluid by the wall of the wellbore annulus and the drill pipe, analogous to the equivalent circulating density (ECD).
Below Mudline	BML	Depth below the mudline (MD or TVD).
Blowout Preventer	BOP	The equipment installed at the wellhead at surface level on land , platform, and jackup rigs, and on the seafloor on floating rigs to prevent the escape of pressure either in the annular space between the casing and the drillpipe or in an open hole during drilling or completion operations. The BOP stack consists of all annular and ram preventers, as well as drilling spools.
Boost Line Choke		Subsea low pressure choke incorporated in the boost line to be used while tripping to fill the wellbore. This choke isolates the wellbore from the full column of mud in the boost line.
Bottomhole Assembly	BHA	The drilling assembly located at the end of the drillstring, usually consisting of the bit, bit sub, drill collars, MWD tools, LWD tools, stabilizers, drilling jars, etc. The BHA is essentially everything below the drill pipe.
Bottomhole Pressure	BHP	The total pressure in the wellbore at the bottom of the hole. This pressure is due to the hydrostatic pressure of all the fluids in the wellbore plus any other imposed pressure (e.g. surface pressure, annular friction pressure, or formation pressure).
Bottoms Up	BU	The volume of fluid required to circulate in order to bring what is at the bottom of the hole to the

		surface (equal to the annular capacity of the wellbore from TD to surface).
Cast Iron Bridge Plug	CIBP	
Check for Underbalance	CUB	Procedure used to determine that the wellbore pressures are balanced and the well will not flow under static conditions.
Choke and Kill	C & K	
Circulate and Condition	C & C	
Circulating Drill Pipe Pressure	DPP_{circ}	Drill pipe pressure recorded on the standpipe gauge during circulation.
Consequence		The result of an action, event or condition. The effect of a cause. The outcome or range of possible outcomes of an event described qualitatively (text) or quantitatively (numerical) as an injury, loss, damage, advantage, or disadvantage. Although not predominantly thought of in this manner, consequences do not always have negative connotations; they can be positive.
Continuous Loop Circulation System		Fluid path circuit where fluid is recycled; beginning and end point are in the same proximate location.
Delta Hydrostatic Pressure	∆HSP	The change in hydrostatic pressure for one bbl of mud added to the top of the casing.
Delta Mud/SeaWater Hydrostatic to Mudline	∆M/W	The difference in the hydrostatic pressure exerted by the mud in the drillstring and the hydrostatic pressure exerted by the seawater in the riser annulus at a depth equal to water depth.
Deviation		Departure from agreed upon process, procedure, or normal expected function.
Diluent		Liquid added to dilute a solution or slurry.
Displacement	Disp	The unit volume of fluid that a length of tubular displaces, usually measured in bbl/ft or ft^3/ft.
Drill Pipe Capacity	V_{dp}	The unit volume of fluid contained inside the drillstring, measured in bbl/ft or ft^3/ft.
Drill pipe Hydrostatic	DP Hydro	Drill pipe hydrostatic pressure
Drill Pipe Pressure	DPP	The surface pressure recorded on the standpipe gauge (on the drill pipe side). Same as standpipe pressure (SPP).
Drillstring Valve	DSV	A spring loaded valve located in the drillstring used to prevent the mud in the drillstring from u-tubing into the wellbore annulus due to the

		pressure imbalance between the drillstring and the wellbore annulus. This pressure imbalance is caused by settting the MLP inlet pressure equal to seawater hydrostatic pressure. The DSV automatically closes when circulation with the rig pump ceases, isolating the wellbore from the pressure effects of the column of mud in the drill pipe. It requires a positive opening pressure in excess of the hydrostatic pressure of the mud column in the drillstring.
Dynamic Check for Underbalance	Dynamic CUB	Maintain the flow rate such that the drill pipe remains full. Hold the surface pump rate constant and check return flow rate to ensure that volume in equals volume out. Reduce surface pump rate by a predetermined amount and check return flow rate. As long as flow in / flow out remain equal, the last known circulating BHP is sufficient to prevent an influx.
Dynamic Shut-in		After kick detection, slowing the MLP to pre-kick rate to stop well flow. Also allows operator to obtain SIDPP and SICP while circulating. A calculated or measured AFP value is required for this operation.
Dynamic Underbalance		Increase in DPP at dynamic shut-in, equivalent to (SIDP – Ann Friction). See Dynamic CUB and Static CUB
Equivalent Circulating Density	ECD	The density of the drilling fluid that would be required to provide the hydrostatic pressure under static (non-circulating) conditions at a given depth equal to the actual pressure exerted while circulating. The ECD is equal to the mud density in the wellbore plus the annular friction pressure expressed in ppg equivalent.
Equivalent Mud Weight	EMW	The total pressure exerted in the wellbore, at a given depth, expressed in ppg equivalent.
Event		An occurrence caused by humans, automatically operating equipment, components, external events or the result of a natural phenomenon.
Failure		The inability of a system or system component to perform a required function to its rated capacity at the time that the function is

		required.
Final Circulating Pressure	FCP	The drill pipe pressure (DPP) maintained during a kill operation after the kill weight mud (KWM) has reached the bit.
Formation Integrity Test	FIT	Test to determine pressure above which injection of fluids will cause the rock formation to fracture hydraulically.
Fracture Gradient	FG	The pressure required to induce fractures in rock at a given depth.
Frequency		A measure of the rate of occurrence of an event described as the number of occurrences per unit time.
Full Shut-in		A pressure test conducted on the casing seat to determine, experimentally, if the formation can withstand the hydrostatic pressure that would be exerted by a predetermined mud density. This test is conducted when it is not necessary to know the maximum pressure a formation can withstand, only that it can withstand the maximum anticipated mud weight plus a safety factor.
Full Underbalance		Stopping all pumps, allowing u-tube to stabilize if active, then closing well in.
Hazard		A HAZARD is defined as, the potential to cause harm, ill health or injury, damage to property, products, or the environment, induce production losses, or increase liabilities. The result of a hazardous event may adversely impact the health or safety of employees, or adversely impact the environment.
Hazard Safety and Operability Review	HAZOP	Designed to review process systems and operating procedures to confirm whether they will operate and be operable as intended, without having introduced any avoidable hazards. Applies to the technique of quantitative assessment of particular risks, the likelihood or frequency of the event and the severity of the consequence using key words. This is often combined with the analysis of proposed risk reduction (or protection) measures to provide a risk assessment report.
Hydrostatic Pressure	P_{hyd}	The pressure exerted by a column of fluid. It is

		a function of the density of the fluid and the vertical height of the fluid column.
Hydrostatic Pressure Increase	HPI	
Influx Gradient	G_i	Dynamic Underbalance + Ann Friction (excess of kick zone pressure over pre-kick hydrostatic at kick zone); equivalent of traditional stabilized SIDPP. The pressure gradient of the influx (kick) fluid, expressed in psi/ft.
Initial Circulating Pressure	ICP	The DPP maintained while circulating a kick from the wellbore until the drillstring is full of kill weight mud (KWM).
Initial Circulating Rate	ICR	The pump rate maintained while circulating a kick from the wellbore until the drillstring is full of kill weight mud (KWM).
Inside Diameter	ID	The inside diameter of the hole, casing, drillpipe, drill collars, etc.
Kick Circulating Pressure	KCP	The pre-kick DPP measured at a constant kick circulating rate (KCR).
Kick Circulating Rate	KCR	The pre-determined circulation rate maintained while circulating a kick from the wellbore. This rate can be the normal drilling rate which could be used in a dynamic kill, or a rate other than normal drilling rate, usually 1/2 to 1/3 of the normal drilling rate.
Kick Intensity		The measurement of the size or severity of a kick. Can be expressed in psi underbalanced (SIDPP), pit gain, or ppg kick.
Kick Tolerance		The maximum pressure that the wellbore can withstand without fracturing, usually equal to the fracture pressure of the formation immediately below the last casing shoe, generally quantified by results of a leak off test (LOT). Can be expressed as maximum casing pressure, maximum influx volume, or maximum ppg kick.
Kill Weight Mud	KWM	The mud density required to provide the hydrostatic pressure to exactly equal formation pressure under static (or non-circulating) conditions. For conventional drilling operations KWM is calculated based upon a full column of KWM from the surface datum to the bottom of the hole. For SMD the datum to calculate KWM is the seafloor to the bottom of the hole

		assuming the pressure at the seafloor is equal to seawater hydrostatic pressure.
Leak Off Test	LOT	An experimental determination of the fracture pressure of the casing seat. During this test the surface pressure is slowly increased and plotted vs. volume of mud pumped until a decrease in the slope is noted. The decrease in slope is an indication that mud is being pumped into the formation, indicating leak-off.
Length of Free Fall	L_{ff}	Length of fluid free fall inside the drill pipe or casing due to the u-tube effect in the wellbore (see TOM below).
Likelihood		The potential of an occurrence. See Frequency.
Logging while Drilling	LWD	The operation in which open-hole logs are run during the drilling operation. Log data is usually transmitted to the surface via pressure pulses in the mud column in the drillstring.
Maximum Allowable Casing Pressure	MACP	Maximum pressure that the formation can withstand prior to fracture
Maximum Allowable Annular Surface Pressure	MAASP	The most limiting (minimum pressure) of the four different ways that an annulus may be overpressured: burst of the outside casing, collapse of the inside casing, fracturing of the formation at the shoe, overpressure of the surface equipment. Each of these produces its own limiting pressure at the shoe.
Mean Sea Level	MSL	
Measured Depth	MD	The distance from the rotary kelly bushing (RKB) to the bottom of the hole, measured along the wellbore.
MLP Discharge Pressure		The discharge pressure recorded at the subsea MLP.
MLP Inlet Pressure		Inlet pressure recorded at the subsea MLP.
Mud Density, ppg	MW	Density of the drilling fluid expressed in ppg. Mud density is converted to pressure (psi) for use on the Depth vs Pressure plot.
Mud Gradient	G_m	The pressure gradient of the drilling fluid, expressed in psi/ft.
Mud Trip Tank		Circulating mud trip tank for filling hole below the SRD via the boost line.
Mud Weight Dual Density	MW_{dd}	Mud weight required to balance wellbore from seafloor to TD with SW density from seafloor to surface.
Mud Weight Injected	MW_{inj}	Mud weight injected at the seafloor into the drilling riser during conversion from dual density

		to single density system.
Mud Weight Single Density	MW_{sd}	Mud weight required to balance wellbore from surface to TD (per conventional operations).
Mud-Gas Separator	MGS	
Mudlift Pump	MLP	A diaphragm mud pump located on the seafloor which takes fluid from the wellbore annulus and pumps the mud and cuttings from the seafloor back to the surface mud tanks via a return line. The MLP can be set to operate on a constant inlet pressure, constant rate, or manually operated.
Mudline	ML	Seafloor (water depth).
Non-continuous Circulating System		Circulation path interrupted. Start and end points not in same location. Example: Pump and Dump
Oil-Based Mud	OBM	
Operating Company	OPCO	Individual, partnership, firm or corporation having control or management of operations on the leased area or a portion thereof. The operator may be a lessee, designated agent of the lessee(s), or holder of operating rights under an approved operating agreement. Party which assumes ultimate responsibility for the operation and maintenance of the drilling or production operations.
Original Mud Gradient	G_{mo}	The pressure gradient of the original density drilling fluid, expressed in psi/ft.
Original Weight Mud	OWM	The original density of the drilling fluid that was in the wellbore at the time a kick was taken.
Outside Diameter	OD	The outside diameter of the casing, drillpipe, drill collars, etc.
Pit Gain		A measurement of kick intensity. The pit gain is the increase in surface mud volume due to an influx of formation fluid into the wellbore during a kick. Gives an indication of how long the well was allowed to flow prior to stopping the influx.
Pit Volume Totalizer	PVT	The system of devices that continuously monitors the level of drilling mud in the pits. The system usually consists of a series of floats placed in the mud pits that senses the level of mud in the pits and transmits data to a recording and alarm device mounted near the driller's position on the rig floor. An

		unexplained increase in fluid level in the pits often indicates a kick has occurred.
Pore Pressure	PP	The pressure of fluids within the pores of geologic formation (reservoir).
Pounds per Gallon	ppg	Fluid density
PPG Kick		A measurement of kick intensity in ppg. The ppg kick is the increase in density of the mud required to provide enough hydrostatic pressure at the bottom of the hole to exactly balance formation pressure under static (non-circulating) conditions.
Pressure Margin		Pressure applied at the MLP inlet as required by conditions to counteract swab pressure or pressure underbalance in the well. This pressure is achieved by adjusting the MLP inlet pressure.
Pressure While Drilling	PWD	An LWD tool which uses mud-pulsed telemetry to convey downhole pressure information to the surface and allows continuous measurement of BHP during drilling operations.
Pull Out of Hole	POOH	The operation of removing the bit, bottomhole assembly, and drillstring from the wellbore (also TOH).
Riser Fluid Trip Tank		Circulating seawater trip tank for maintaining and monitoring the seawater level in the riser. The seawater trip tank is operational whenever the marine riser is connected to the BOPs.
Riser Margin		Mud weight sufficient from seabed to TD such that the well will not flow in the event of a disconnect. Hydrostatic head does not depend on any mud volume in the riser. This is the mud weight needed for all SMD operations.
Riser Return Line	RRL	
Risk		Risk is usually defined mathematically as the combination of the severity and probability of an event. In other words, how often can it happen and how bad is it when it does happen? Risk can be evaluated qualitatively or quantitatively. **Risk = Frequency x Consequence of Hazard**
Rotary Kelly Bushing	RKB	Fixed height reference taken as the top of the rotary table.
Rotating Control Device	RCD	An element above the BOP stack which allows

		rotation of the drillstring while still containing any surface pressure that may be present up to the rated working pressure of the RCD.
Safeguard		There are three basic techniques available to an organization designed to minimize risk exposure as low as reasonably possible at a reasonable cost. They are: • Prevention • Detection • Mitigation
Seawater Gradient	G_{sw}	The pressure gradient of seawater, expressed in psi/ft.
Shut-in Casing Pressure	SICP	The stabilized surface pressure recorded on the annulus side of the well when the well is shut in, and circulation has ceased. Or the stabilized MLP inlet pressure when the well is shut in and circulation has ceased.
Shut-in Drillpipe Pressure	SIDPP	A measurement of kick intensity. It is the stabilized surface pressure recorded on the drillstring side when the well is shut in, and circulation has ceased. It is a measurement of the degree of underbalance while in a kick situation.
SRD Bypass		Manifold bypass line consisting of a flowline and subsea valve that allows mud to flow from the wellbore annulus into the base of the riser.
SRD Bypass Valve		Subsea low pressure valve installed on the SRD bypass line. The opening of this valve allows mud to flow from under the SRD to the riser during certain conditions such as a failure of the MLP. By stacking mud in the riser, the pressure in the well can be managed while the surface mud pumps are shut down.
Standpipe Pressure	SPP	See DPP
Static Check for Underbalance	Static CUB	Stop the surface pump and bleed trapped AFP, if any, to zero. Ensure there is no return flow under static conditions.
Strategic Business Unit	SBU	
Subsea Mudlift Drilling	SMD	A drilling process in which mudlift pumps (MLPs) located on the seafloor take suction from the wellbore annulus and lifts the mud and

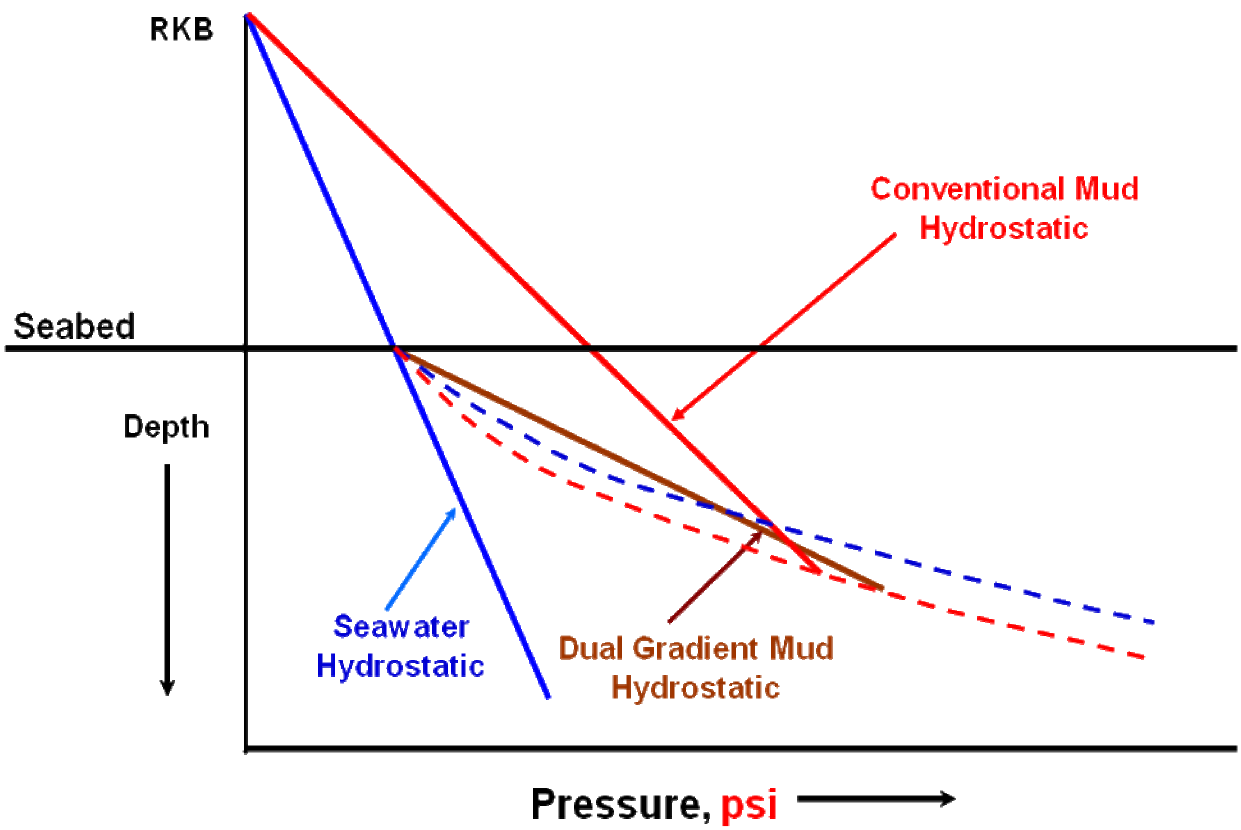
		cuttings from the seafloor to the surface via a return line (or lines). The MLPs isolate the wellbore from the hydrostatic pressure (P_{hyd}) of the mud in the return line(s) from the seafloor to the surface. The resulting wellbore pressure profile simulates drilling with a dual density mud system of seawater from the surface to the seafloor, and a higher density mud from the seafloor to the bottom of the hole.
Subsea Rotating Device	SRD	A retrievable elastomer diverter element located above the annular preventers which seals around the drillstring, isolating the seawater from the wellbore and allowing rotation of the drillstring, while maintaining a pressure seal around the drillstring. The SRD remains closed while drilling and tripping; it is pulled with the BHA on TOH. The SRD is an integral part of the SMD operation. This device allows AFP to be trapped during connections, such that circulating bottomhole pressure is held constant at all times
SW Hydro		The hydrostatic pressure exerted by the column of seawater at the seafloor.
SW Seawater Density		Density of the seawater expressed in ppg (usually 8.6 ppg).
SW/MW Mud Column Height		Height of mud column required to balance seawater at the mudline, expressed percent of total water depth (0 – 1, with a typical range of 0.45 - 0.60). This number is then multiplied times the WD to determine the height of a column of mud from the seafloor which will balance the seawater hydrostatic pressure at the mudline. SW / MW = total water depth – TOM
Synthetic-Based Mud	SBM	
Top of Cement	TOC	Depth at which cement is first encountered in the open hole or annular section of interest.
Top of Mud	TOM	When DSV is not in use, the distance from RKB to the top of the mud column when the system is static. This is an air-filled or a void interval (if the drillpipe has not been opened) interval inside the drill pipe. The height of the mud column from the seafloor plus TOM is equal to

		total water depth. See SW/MW above.
Trapped Pressure	TP	
Trip in Hole	TIH	The operation of running the bit, bottomhole assembly, and drillstring into the wellbore.
Trip Margin		A slight increase in mud weight to maintain circulating BHP under static conditions (usually 0.1 – 0.2 ppg).
Trip Out of Hole	TOH	See POOH. The operation of removing the bit, bottomhole assembly and drillstring from the wellbore.
True Pump Output	Q_{tpo}	The volumetric output of the rig pumps, usually measured in bbl/stk. In this case a stroke, stk., represents one complete cycle of the mud pumps.
True Vertical Depth	TVD	The vertical distance from the RKB (or some other datum) to the bottom of the hole. Only on a straight hole will the TVD and MD be equal.
Underbalance	UB	The condition in which the pressure in the wellbore is less than the pressure contained within the formation adjacent to the wellbore at the depth of interest.
Water Depth	WD	The vertical depth from the mean sea level to the mudline. WD = ML – MSL; WD = ML
Water-Based Mud	WBM	

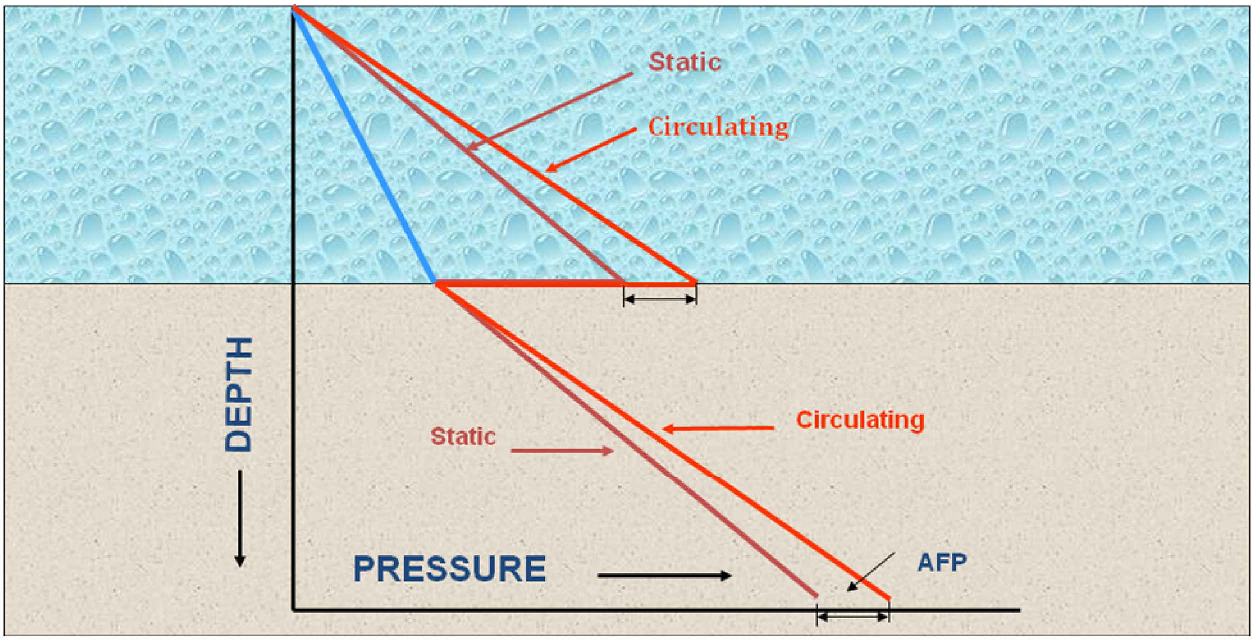
Dual Gradient Drilling System

Overview

Currently the deepwater drilling industry uses the conventional single gradient drilling technique, a single mud weight from the surface to total depth (TD) to control the thin margins between fracture gradient and pore pressure gradient. In this conventional system, a single mud column extends from the rig floor to TD, resulting in a hydrostatic bottomhole pressure. Pore, fracture and mud pressure gradients are referenced to the rig floor.



Dual Gradient Drilling (DGD) provides the same bottomhole pressure with a combination of two fluids back up to the rig floor. All gradients are referenced to the mudline rather than the rig floor.



Dual Gradient Drilling is one of the very few methods available to the drilling industry to drill in deepwater, where the drilling window between the pore pressure and frac gradient is so very narrow. With DGD, the margins between fracture gradient and pore pressure are significantly greater while drilling the well. This technology overcomes a significant deepwater drilling challenge: eliminating some of the casing strings necessitated by the relatively high pore pressures and low formation strengths found in areas like the deepwater Gulf of Mexico.

The objective of Dual Gradient Drilling is to mimic drilling operations as if the drilling rig were on the seabed floor. The next best thing to having the rig on the ocean floor is to have the riser full of seawater or seawater equivalent to mimic the same hydrostatic pressure profile at the seabed floor and beyond (deeper). To control the well below the seabed floor heavy drilling mud will be utilized.

Historical Perspective

In 1996, a “riserless drilling” concept was developed. The SubSea MudLift Drilling Joint Industry Project (SMD JIP) developed a DGD system together with associated drilling and well control techniques and procedures. The world’s first dual gradient well was drilled in Green Canyon Gulf of Mexico in 910 feet of water in 2001 where the pore pressure was well documented.

Green Canyon 136 #8

Diamond Offshore
Ocean New Era

2nd Generation,
Built in 1975

Texaco Well
Shasta Prospect
910 feet Water

September, 2001

The industry's first dual gradient drilling project was a success. The initial enormity of cost had for some time dampened the enthusiasm for continuation of the project. The table below describes the current status of Dual Gradient Drilling Research and Development. Some companies are developing systems that are spin-off versions of the first study based on lessons learned. Some companies have merged with others. Some companies have ceased to exist in their original form. This technology, if allowed to lapse, will have to be redeveloped in its entirety because it is one of the very few methods available to the drilling industry to drill in deepwater, where the drilling window between the pore pressure and frac gradient is so very narrow.

Dual Gradient Drilling Adaptations

The table below summarizes the current state-of-the-art and adaptations that have been researched, and/or attempted, and/or failed, and/or abandoned.

Currently Ongoing	Researched-Attempted-Failed-Abandoned
Positive Displacement Seabed Pump	Seabed Centrifugal Pump
Seabed Disk Pump	Seabed Separation and Electric Submersible Pump
Liquid Dilution	Gas Dilution
	Glass Beads

Pump and Dump

System	Features	Benefits	Drawbacks
Pump and Dump	Non-continuous Circulating System Pump mud to drill and keep top hole open	Increased local hydrostatic pressure keeps top hole open	No returns to surface Mud and drill solids deposited on seabed floor.

Seabed Centrifugal Pumps

System	Features	Benefits	Drawbacks
Seabed Centrifugal Pumps	Pack-off at the mudline to divert annulus drilling mud into multi-stage frequency-controlled centrifugal pumps located at the seabed which deliver the mud back to surface via a separate return line. Solids were handled within this system by making the first pump stage act as a grinder.	The grinder reduced solid particle size small enough to pass through the rest of the pumping system without plugging.	Each pump required an individual electrical cable as large as three inches in diameter. Whatever cable remained wound on the running spool, would generate considerable heat. Possible riser margin.

Mid-Riser Centrifugal Pumps

System	Features	Benefits	Drawbacks
Mid-Riser Centrifugal Pumps	A single centrifugal pump placed in a specially built riser joint at a constant setting depth at about 2500 feet. Uses a single mud gradient, via a pack-off at 2500', to divert annulus drilling mud into centrifugal pumps which add energy and deliver the boosted mud into the riser and back to surface.	Single Density Mud. Can manage Equivalent Circulating Density. Could control lost circulation. Set slightly deeper casing strings. Possibly eliminate 1-3 casing strings from the well design. Relatively inexpensive.	Does not achieve full dual gradient capability. Unlikely riser margin.

Electric Submersible Pump (ESP) with Seabed Solids Separation

System	Features	Benefits	Drawbacks
Electric Submersible Pump (ESP) with Seabed Solids Separation	Lifts clean drilling mud from seabed to surface. A separate compartment would hold the solids.		ESP does not handle easily handle solids greater than ¼ inch in diameter. Maintenance of mud compartment. The solids would be discharged onto the seabed floor. Requires significant electrical power on sea floor.

Gas Dilution

System	Features	Benefits	Drawbacks
Gas Dilution	Use nitrogen gas to "gas-lift" and lower the hydrostatic pressure in the riser.	Similar to gas lifting used in the oil industry for many years so it is somewhat understood.	If air is injected, then corrosion and flammability are issues. Difficult to control hydrostatic pressure for riser margin. Deeper water depths require hugh amounts of gas (due to compression of bubble) for it to be effective. Large gas expansion when gas traverses from deep to shallow depth. Stored energy from gas component in the slurry inside large surface area riser creates an enormous safety issue. Possible density segregation of materials and slurry if flow is interrupted

			Expense of nitrogen. Expense and difficulty of large volume nitrogen separation at the surface.

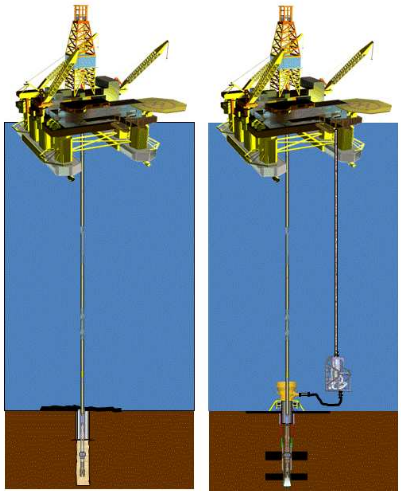
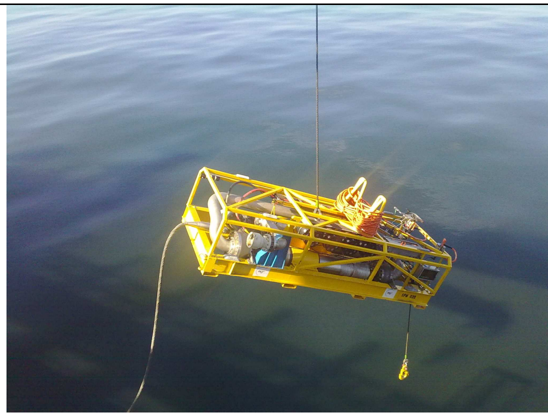
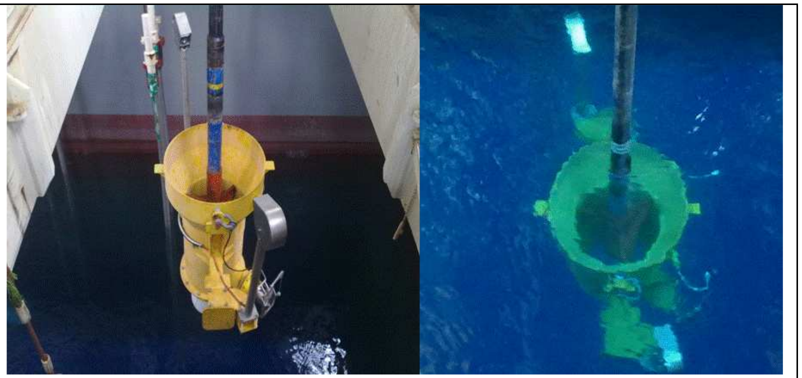
Solids Dilution with Glass Beads

System	Features	Benefits	Drawbacks
Solids Dilution with Glass Beads	Mixing drilled solids with low-gravity glass beads into the riser mud at the seabed to the surface.	Some degree of dual gradient drilling	Surface bead recovery Bead concentration Bead survival rate Bead injection system unproven Possible density segregation of materials and slurry if flow is interrupted. Riser margin doubtful.

Seabed Disk Pump

System	Features	Benefits	Drawbacks
Seabed Disk Pump	Continuous Loop Circulating System	Drill top hole before installation of BOP. Pump is very abrasion resistant and handles cuttings of various sizes up to 2 in. diameter very well.	Qualified for top hole use before installation of BOP. Pump has limited head and multiple pumps are necessary to achieve higher head for system.
Riserless Mud Return (RMR®) System with Dual Gradient Dynamic Kill Drilling	Employs the dual gradient drilling concept, consisting of the seawater hydrostatic above the mud line with the ability to vary the hydrostatic below the mud line by drilling fluid weight variations Compact equipment	Returns brought back to surface where mud is reconditioned and reused Recycle drilling fluid Improve safety while drilling zones with shallow gas or potential water flows through volume monitoring such that an influx can be detected early and mud weight adjusted to maintain overbalance on the formations	A severe gumbo attack can overwhelm suction module. If severe enough, may have to flush gumbo with rig mud pumps onto the seabed floor.

		Solids segregation and separation at the surface. Minimize environmental impact of mud and cuttings on seabed floor. Can be deployed over the side of the vessel, offline of moon pool operations. Controls weak formations producing better more stable well bore through volume monitoring by detecting losses early such that mud weight can be adjusted to minimize losses	

		
Conventional vs Riserless Mud Recovery	Subsea Pump Module	Suction Module on Running Tool

Liquid Dilution

System	Features	Benefits	Drawbacks
Liquid Dilution Continuous Annulus Pressure Management (CAPM)	Continuous Loop Circulating System Liquid dilution through boost line at base of the riser. Drilled solids, drilling mud, and diluent to the surface. Utilizes retrievable Rotating Control Device Utilizes Drill String Valve or Flow Stop Valve to arrest drill pipe U-tube hydraulics when circulation is interrupted.	Returns to surface Recycle drilling fluid Solids segregation and separation at the surface Plug and play with current conventional drilling equipment Enhanced kick detection by way of continuous Flow in / Flow-out comparison (closed circulation system with RCD if return flow meters are used – no heave effect) leading to a smaller influx Wider MW range between pore pressure and frac gradient limits. Lower shoe pressures compared with SG WC techniques. Permits killing the well without raising the riser mud weight, resulting in smaller	Dilution rates may exceed pressure/flowrate limitations on booster lines. An inner concentric riser may provide sufficient dilution rates but may restrict return flow in the riser and may restrict drill string movement inside the riser, possibly leading to inner string riser wear. Overbalanced drillstring precludes its use as hydraulic conduit to formation pressure. Pore pressure calculations are indirect. Although subsea BOP pressure may be used to calculate BHP once the kick is circulated above the BOP. Heavy reliance on properly operating Flow Stop Valve. Use pump-open test on FSV to

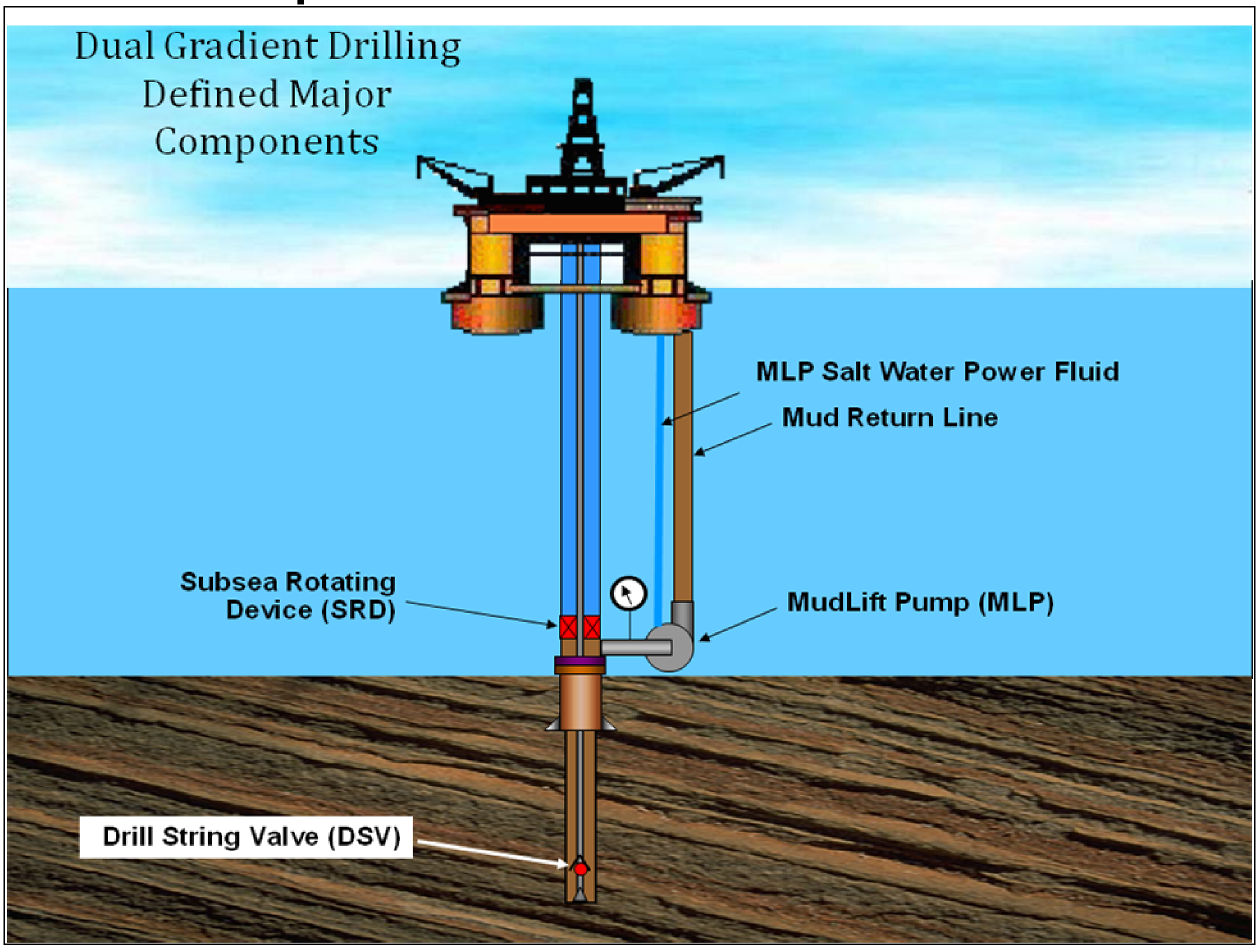
		volumes to weight up. This also helps to preserve the flexibility in managing the pressure profile afforded by dual gradient drilling. Option to increase Downhole mud weight, Riser mud weight, or both, as appropriate for the subject wellbore pressure profile. Allows use of the SECURE Drilling Manifold choke to apply necessary additional back pressure to maintain adequate BHP while circulating the kick out of the hole through an open BOP. Have capability to kill well by adjusting Riser mud weight, either by varying the dilution ratio or – less likely - by weighting up the Dilution mud.	determine change in BHP relative to baseline from pump-open tests done on each connection. Extended circulating time due to need to dilute at injection point. This effect can be reduced if the SECURE system is used to circulate the kick at least partially up the hole with the subsea BOP open Requires use of both choke and kill lines (one to inject dilution mud below closed BOP and one to take well returns) when circulating out through the choke. Unlikely to have full riser margin

Positive Displacement Seabed Pump

System	Features	Benefits	Drawbacks
Positive Displacement Seabed Pump	Continuous Loop Circulating System Utilizes retrievable Rotating Control Device Utilizes Drill String Valve or Flow Stop Valve to arrest drill pipe U-tube hydraulics when circulation is interrupted. Solids Processing Unit reduces large solids into pumpable size. Mud lift pump operates in constant rate mode or constant pressure mode.	Returns to surface Recycle drilling fluid Closed system measuring volume in and volume out so kick detection is extremely quick Solids segregation and separation at the surface. System designed to fingerprint flows so small differences can be discerned hence U-tube flow fingerprint will be different from kick flow fingerprint System is designed to control AFP (annular friction pressure) so that BHP (or any other spot in the well) can be held constant at all times Full riser margin when riser full of seawater or equivalent density fluid.	Mechanically more complex and expensive (valves, pistons, controls).

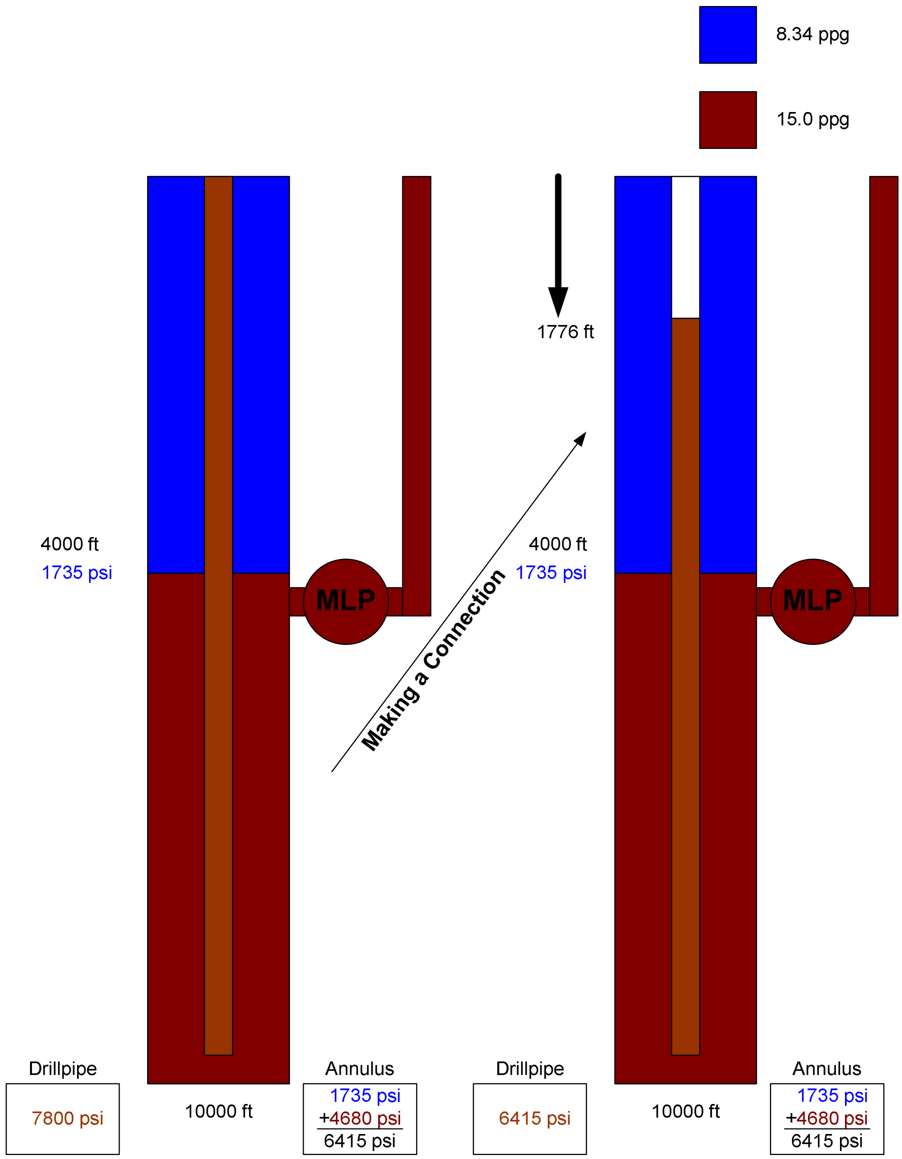
		Mud pushed into the mud lift pump. Mud lift pump has no suction capabilities and cannot induce a kick.	

Subsea Components

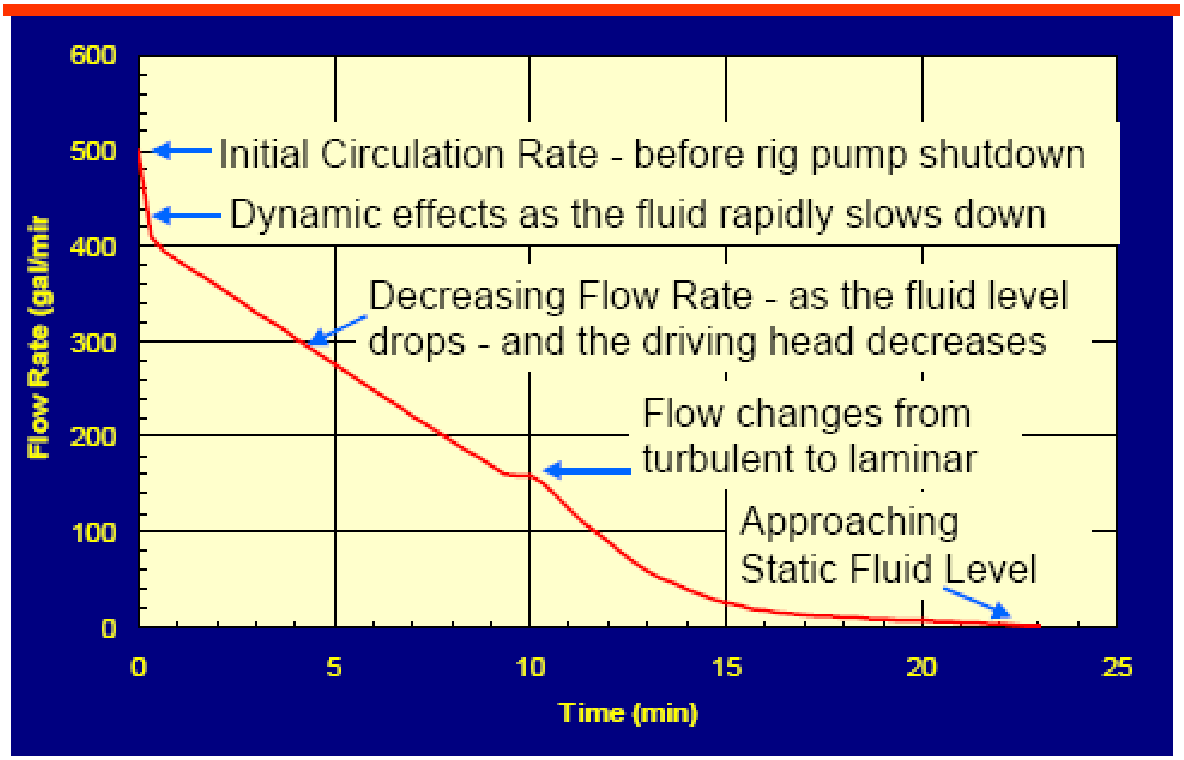


Drillstring Valve (DSV)

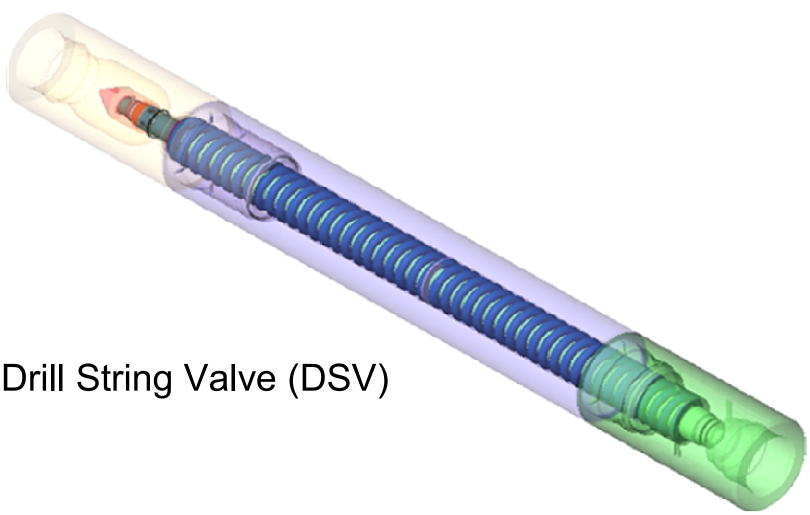
Unfortunately, the laws of nature supersede our operational desires. Once the mud pumps slow to some low threshold flow rate prior to making a connection, for instance, a U-tube phenomenon occurs to hydrostatically balance the column of drilling mud in the drilling string and annulus of the hole (variable volume) and the column of seawater in the riser above the subsea rotating control device (fixed volume).



The U-tube phenomenon complicates the identification of taking a kick. Additionally, the decay of flow from the U-tube can extend for many minutes. Drilling operations cannot afford those minutes because time is money AND if the U-tube is actually masking a kick, the kick could get larger with each second.



The DSV arrests U-tube that would occur in DGD operations due to light density fluid in riser. Without a flow restriction in the drillstring, the U-tube can last ±20 minutes, with an initial high flow rate and decay over time. The drillstring can be maintained full without a DSV if a continuous high pump rate is sustained (e.g., 500 GPM required to show SPP). In some cases, the ability to read standpipe pressure (SPP) is necessary, so the DSV is designed to close at low flow rates if it is installed below equilibrium point for mud if it were in free fall (top of mud = TOM).



Drill String Valve (DSV)

DSV spring pushes back against the change in mud weight until target flow rate is achieved and cracking pressure is achieved. If the spring is set for 12.0 ppg and the mud weight is 12.0 ppg, then minimal cracking pressure is required to open the DSV. If it is set for higher mud weight than the fluid in use, an increased cracking pressure is required. When flow ceases, the DSV closes. Increasing differential pressure between the piston vents result in full open point. Achieving a repeatable cracking pressure is important is obtaining a fingerprint to compare against a possible kick scenario.

Subsea Rotating Device (SRD)

SRD can be compared to subsea rotating control device. Returns coming up the annulus will be stopped from flowing up the marine riser by the SRD. The SRD seals the annulus inside the marine drilling riser while allowing the drillpipe to pass through and rotate. This will cause the returns to seek a different flowpath out of the lower riser segment below the SRD. A chief benefit of the SRD is the allowance of very rapid detection and reaction to changes in wellbore conditions, such as lost circulation or a kick.

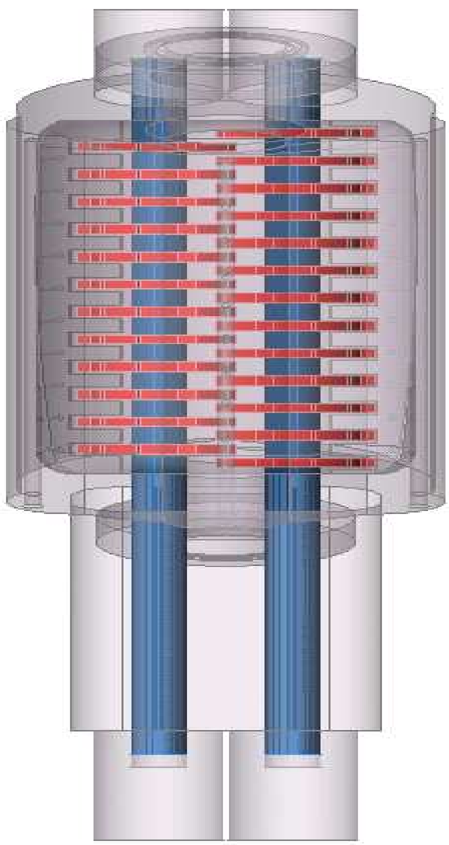
The SRD is NOT a well control device. The retrievable SRD provides a barrier / separation between the wellbore fluid and riser fluid. The riser fluid will be less dense than the wellbore fluid, close to seawater gradient.

The SRD helps minimize contamination between fluids and serves as supplemental to block gas intrusion into riser. SRD bypass line has a setpoint monitored by pressure sensor to relieve the pressure on the well should the MudLift Pump fail. Excessive high pressure will trigger the bypass to open and allow mud into the riser during certain emergency conditions. Normally, all annular flow is diverted to the Solids Processing Unit (SPU).

Solids Processing Unit (SPU)

The purpose of the SBU is to provide size reduction of the wellbore solids or cuttings from the wellbore annulus to assure that neither the suction line to the Mud Lift Pump (MLP) nor the discharge flow entering the Mud return Line (MRL) from the MLP will plug.

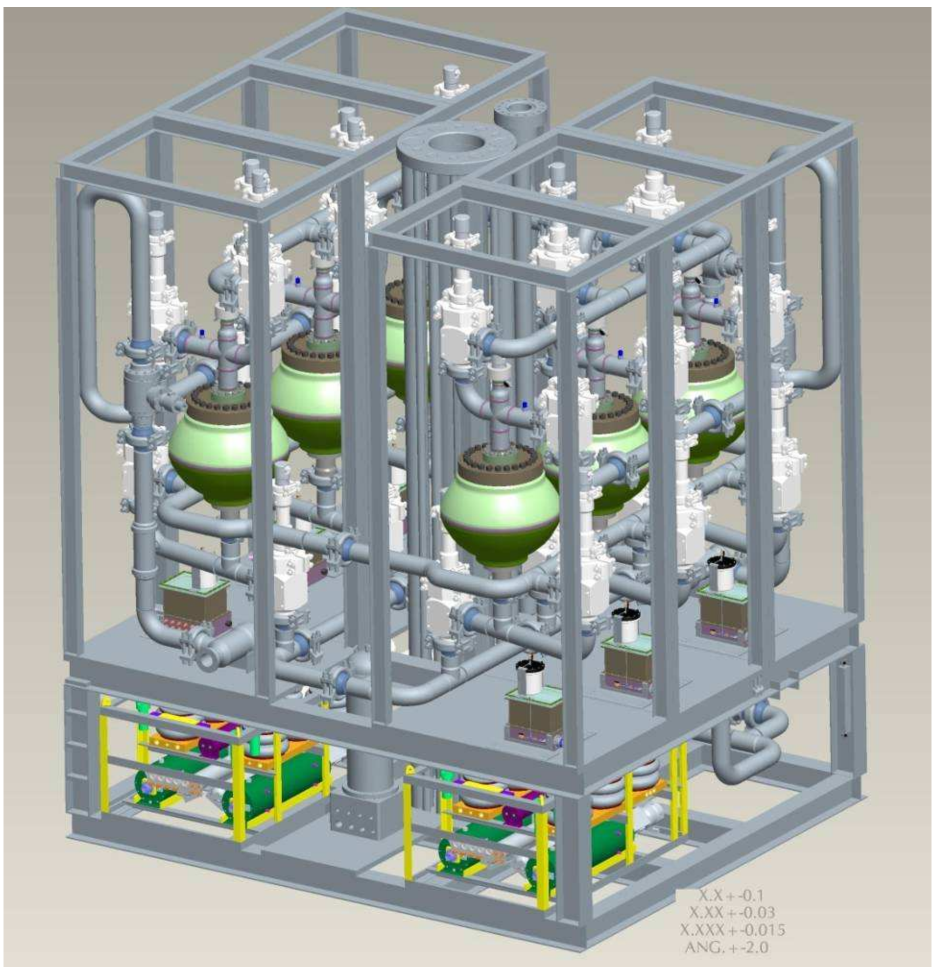
Within the flowpath is an SPU that processes all of the cuttings to easily pass through the Mud Lift Pump. There will be redundant SPUs operating. Each side of the SPU can take 100% of the annular flow.



Windows are cut inside riser joint to direct flow from annulus through cutters (higher position) and into SPU outlet lines (lower position) utilizing gravity. Using the SBM will enhance inhibition and cuttings (chunk) integrity downstream of cutters. Cutter configuration is field proven in other industries as well as in subsea operations on SMD JIP field trial, even with severe gumbo. Hydraulic motors installed above cutters auto-reverse if plugging or resistance occurs.

MudLift Pump (MLP)

The MLP has six independent chambers. Flow feeds all six chambers for a total flow rate capacity of up to 1800 GPM. The MLP inlet pressure is maintained at the hydrostatic of the fluid in the riser (e.g., seawater) plus a predetermined feed pressure (typically stated as 50 psi). Inlet pressure is not "suction" pressure – instead it is the "push" required to operate chambers. Inlet pressure can increase but it cannot fall below the hydrostatic of the riser fluid or MLPs will not operate. Multiple sensors monitor inlet pressure. MLPs can pump in user-defined constant rate or constant pressure modes.



The MLP is not a well control device. In the event that wellbore pressures become excessive (over the MLP pressure rating) the pump assembly can be isolated from the wellbore. The MLPs are powered by seawater being circulated at a pressure/rate somewhat higher than MLP operating pressure/rate. Seawater is the power fluid that operates the MLPs. Auxiliary subsea DGD equipment is powered by electricity via two umbilicals.

MLPs and return lines have been sized for certain cutting size. Materials have been chosen taking into account erosion issues at expected drilling circulation rates. The MLP should process cuttings to a size about 1/3 of line IDs, assuming 5” ID. In addition to normal drilling operations, MLPs can be utilized in utility operations like testing, measuring pressures, etc. MLPs pump mud returns to surface via a 6” return line rated to 7500 psi.

Hazards and Risk

INTRODUCTION

The purpose of this section is to offer some rationale and guidance of the Hazard Identification and Hazard Operation (HAZID / HAZOP) process for Dual Gradient Drilling (DGD) operations.

HAZARD IDENTIFICATION STUDIES (HAZID)

Designed to identify all potential hazards, which could result from operation of a facility or from carrying out an activity.

HAZARD SAFETY AND OPERABILITY REVIEW (HAZOP)

Designed to review process systems and operating procedures to confirm whether they will operate and be operable as intended, without having introduced any avoidable hazards. Applies to the technique of quantitative assessment of particular risks, the likelihood or frequency of the event and the severity of the consequence using key words. This is often combined with the analysis of proposed risk reduction (or protection) measures to provide a risk assessment report.

This analysis will aid in the development of procedures to avoid or mitigate potential risks of certain drilling operations or resolving incidents that may occur from human error or equipment malfunction.

While use of this guide does not guarantee a trouble-free operation, it is hoped that the reader will find that significant parts of these general planning guidelines will at least lessen the economic and environmental consequences of trouble if not diminish the frequency of their occurrence.

Risk does not come in convenient units like volts or kilograms. There is no universal scale of risk. Scales for one industry may not suit those in another industry. Fortunately, the method of calculation is generally consistent and it is possible to arrive at a reasonable scale of values for a given industry.

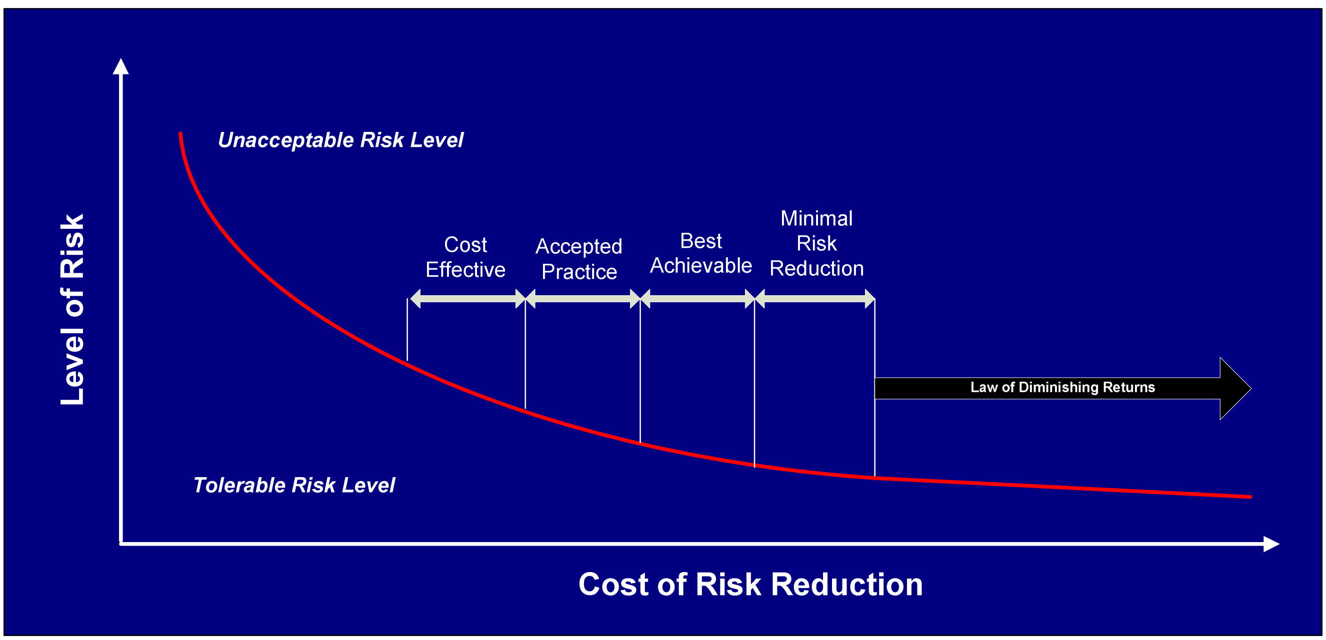
Risk assessment needs to be thorough, is often detailed almost to the extreme, and can get as complicated as one would like. We should also be mindful that we live in an imperfect world. It is not possible to eliminate all incidents because human error accounts for vast majority of all incidents. Our mistakes are our guide to improvement.

Generally, the most desirable approach is to break down the process into simple steps. Risk reduction can be achieved by reducing either the frequency of a hazardous event or its consequences or by reducing both of them. The first step is to minimize the frequency since all events are likely to have cost implications, even without dire consequences. Safety systems are all about risk reduction. If we can't take away the hazard we shall have to reduce the risk. Altering the risk profile is part of risk management.

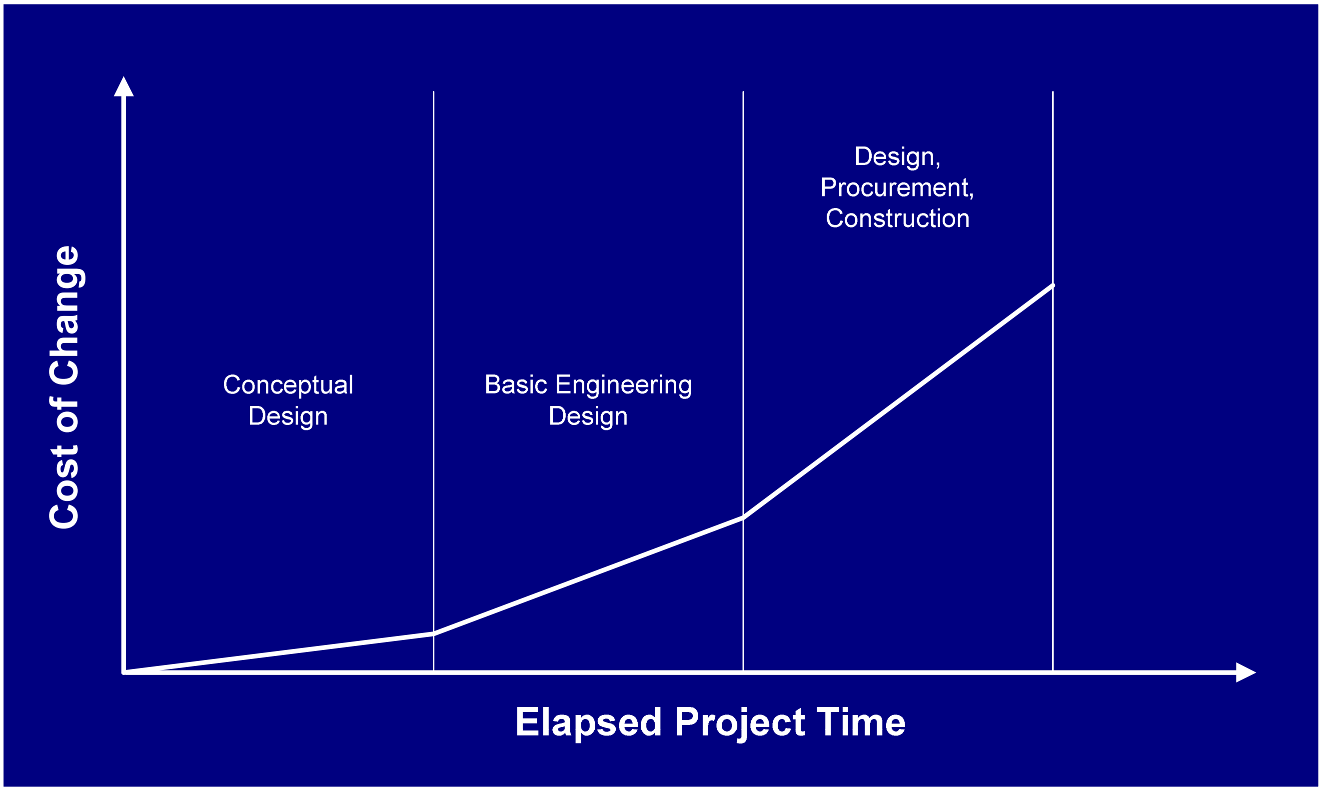
Managing risk:

- Requires rigorous thinking. It is a logical process, which can be used when making decisions to improve the effectiveness and efficiency of performance.
- Encourages an organization to manage proactively rather than reactively.
- Requires balanced thinking ... Recognizing that a risk-free environment is uneconomic (if not impossible) to achieve, a decision is needed to decide what level of risk is acceptable.
- Requires hazard studies that are part of the disciplined approach to managing risks and they should be conducted in accordance with the principles described in this report.

Typically, the cost of reducing risk levels will increase with the amount of reduction achieved and it will follow the “law of diminishing returns”. Risk is usually impossible to eliminate so there has to be a cut off point for the risk reduction we are prepared to pay for. We have to decide on a balance between cost and acceptable risk. This is the principle of ALARP, As Low As Reasonably Practical.



The second factor that will influence the hazard study work is the relationship between design changes and their impact on project costs.



Typically, there are heavy cost penalties involved in late design changes. It is economically prudent to design the hazard study program to identify critical safety and operability problems at an early stage. This is where preliminary hazard study methods are valuable. Preliminary studies can often identify major problems at the early stage of design, where risk reduction measures or design changes can be introduced with minimum costs.

There is a common saying in the control systems world, “If you want to control something, first make sure you can measure it.” To control the risks of harm or losses in the workplace due to hazards of all forms we need to measure RISK. We need to spend some time defining the terms associated with Hazards and Risk.

HAZARD CONCEPTS

ACCIDENT

An incident with unexpected or undesirable consequences. The consequences may be related to personnel injury or fatality, property loss, environmental impact, business loss, etc. or a combination of these.

CAUSE

A person, event, or condition that is responsible for an effect, result, or consequence.

CONSEQUENCE

The result of an action, event or condition. The effect of a cause. The outcome or range of possible outcomes of an event described qualitatively (text) or quantitatively (numerical) as an injury, loss, damage, advantage, or disadvantage. Although not predominantly thought of in this manner, consequences do not always have negative connotations; they can be positive.

DEVIATION OR UPSET

Departure from agreed upon process, procedure, or normal expected function.

EVENT

An occurrence caused by humans, automatically operating equipment, components, external events or the result of a natural phenomenon.

FAILURE

The inability of a system or system component to perform a required function to its rated capacity at the time that the function is required.

HAZARD

The potential to cause harm, ill health or injury, damage to property, products, or the environment, induce production losses, or increase liabilities. The result of a hazardous event may adversely impact the health or safety of employees, or adversely impact the environment.

INCIDENT

An unplanned sequence of events and/or conditions that results in, or could have reasonably resulted in a loss event. Incidents are a series of events and/or conditions that contain a number of structural/machinery/equipment/outfitting problems, human errors, external factors, as well as positive actions and conditions. This definition includes both accidents and near misses.

LOSS EVENT

Undesirable consequences resulting from events or conditions, or both.

MANAGEMENT SYSTEM

A system put in place by management to encourage desirable behaviors and discourage undesirable behaviors. Examples of management system elements include policies, procedures, training, communications protocols, acceptance testing requirements, incident investigation processes, design methods and codes and standards. Management systems, also known as corporate culture, strongly influence the behavior of personnel in an organization.

NEAR MISS

An incident with no consequences, but that could have reasonably resulted in consequences under different conditions.

An incident that had some consequences that could have reasonably resulted in much more severe consequences under different conditions.

SAFEGUARD OR CONTROL

There are three basic techniques available to an organization designed to minimize risk exposure as low as reasonably possible at a reasonable cost. They are:

- Prevention
- Detection
- Mitigation

With some overlap, there are three areas that tend to originate and maintain safeguards.

- Administration
  - Training
  - Emergency Plans
  - Directives

  - Supervision
  - Planned Inspections
  - Communications
  - Security
  - First Aid
  - Legal/Regulatory Requirements
  - Management of Change
- Engineering
  - Equipment Design
  - Energy Barriers
  - Identification of Critical Equipment
  - Warning Signs
  - Emergency Equipment
- Operations
  - Procedures
  - Job Safety Analysis
  - Permit to Work
  - Emergency Drills
  - Pre-use checklist
  - Planned Maintenance
  - Incident Management

SYSTEM

An entity composed of personnel, procedures, materials, tools, equipment, facilities, software, etc. used together to perform a specific task or objective.

METHODS OF IDENTIFYING HAZARDS

CHECKLIST

Technique that applies previously developed or published checklists for known failure and deviations, consequences, safeguards and actions. Technique can be used at any stage of a project or process provided the checklist has been made available by experienced staff.

FAILURE MODE EFFECTS ANALYSIS (FMEA)

Technique starts with components of system or process and presumes failures. All possible modes of failure are listed followed by an evaluation of whether the failure produces a hazard. Some of the failure effects (consequences) will be harmless and some may be dangerous.

Results are then deduced to see if they cause a hazard. Good for final design stages or for evaluation of reliability. Good for electronic systems, mechanical equipment, and complex. Not well suited to processes because deviations and hazards may not be due to any failure of components.

FAULT TREE ANALYSIS (FTA)

The technique begins with a top event that would normally be a hazardous event. Then all combinations of individual failures or actions that can lead to the event are mapped out in a fault tree. This provides a valuable method of showing all possibilities in one diagram and allows the probabilities of the event to be estimated. This also allows us to evaluate the beneficial effects of a protection measure.

HAZARD IDENTIFICATION STUDIES (HAZID)

Designed to identify all potential hazards, which could result from operation of a facility or from carrying out an activity.

HAZARD SAFETY AND OPERABILITY REVIEW (HAZOP)

See What If Analysis and Checklist. Designed to review process systems and operating procedures to confirm whether they will operate and be operable as intended, without having introduced any avoidable hazards. Applies to the technique of quantitative assessment of particular risks, the likelihood or frequency of the event and the severity of the consequence using key words. This is often combined with the analysis of proposed risk reduction (or protection) measures to provide a risk assessment report.

PROCESS HAZARD ANALYSIS (PHA)

Identification of hazards and the evaluation of risks in the process industries. Within the range of PHA activities there are two main stages:

- Hazard Identification
- Hazard Assessment sometimes also called Risk Analysis.

ROOT CAUSE ANALYSIS (RCA)

The study is typically reactive and is usually a part of the investigation of the hazardous event after it takes place. The technique begins with the final hazardous event. Then working backwards all combinations of individual failures or actions that can lead to the event are mapped out (sometimes in a fault tree arrangement).

WHAT-IF ANALYSIS

Team of experienced persons to test for hazards by asking relevant 'What-If' questions. Technique can be used at any stage of a project for new or existing processes.

WHAT-IF + CHECKLIST

Combination of What If Analysis and Checklist. Forerunner to HAZOP method. Designed to review process systems and operating procedures to confirm whether they will operate and be operable as intended, without having introduced any avoidable hazards. Applies to the technique of quantitative assessment of particular risks, the likelihood or frequency of the event and the severity of the consequence. This is often combined with the analysis of proposed risk reduction (or protection) measures to provide a risk assessment report.

RELIABILITY CONCEPTS

AVAILABILITY

Not the same as reliability. The percent of time the system is alive and ready for use if called upon.

FAILURE

Usually expressed mathematically as the Probability of Failure (POF) as decimal or percentage. The opposite of Reliability.

RELIABILITY

The probability that a component, system, or process will function without failure for a specific length of time when operated correctly under specific conditions.

Reliability = 1 – Probability of Failure

Reliability = 1 – POF

RISK CONCEPTS

CONSEQUENCE

The result of an action, event or condition. The effect of a cause. The outcome or range of possible outcomes of an event described qualitatively (text) or quantitatively (numerical) as an injury, loss, damage, advantage, or disadvantage. Although not predominantly thought of in this manner, consequences do not always have negative connotations; they can be positive.

CONTROLS AND SAFEGUARDS

Safeguards in place by company management utilized to prevent a potentially negative impact as a result of an incident. A physical, procedural or administrative safeguard that prevents or mitigates consequences associated with an incident.

FREQUENCY

A measure of the rate of occurrence of an event described as the number of occurrences per unit time.

LIKELIHOOD

The potential of an occurrence. See Frequency.

UNMITIGATED LIKELIHOOD (UL)

Likelihood of event without intervention by administration, engineering, and/or operations.

MITIGATED LIKELIHOOD (ML)

Likelihood of event with intervention by administration, engineering, and/or operations to prevent the event or lessen the impact of the event.

PROBABILITY

Prediction of uncertainty. The likelihood of a specific outcome determined by the ratio of specific events to the total number of possible events. The probability must be a number between 0 and 1. The sum of the probabilities for all possible conditions of uncertainties must be 1.

[PURE] RISK (PR)

The possibility of a hazard becoming an incident that may have a negative or positive impact on overall objectives. It is measured in terms of likelihood and magnitude of severity.

Risk is usually defined mathematically as the combination of the severity and probability of an event. In other words, how often can it happen and how bad is it when it does happen? Risk can be evaluated qualitatively or quantitatively.

Risk = Frequency x Consequence of Hazard

Risk = Probability of Occurrence x Impact

SEVERITY (S)

The degree of an outcome or range of possible outcomes of an event described qualitatively (text) or quantitatively (numerical) as a loss, injury, damage, advantage, or disadvantage. The degree or magnitude of a consequence.

RISK ANALYSIS

The analysis of available information to determine how specific events may occur and the magnitude of their consequences.

RISK ASSESSMENT

Prioritizing risk ranking utilizing risk analysis and risk evaluation.

RISK EVALUATION

A process to compare levels of risk against pre-determined standards, target risk, or other criteria.

RISK MANAGEMENT

The culture comprised of structure and process that proactively optimizes management of risk events and their adverse effects.

TYPES OF RISK

PURE RISK (PR)

The possibility of a hazard becoming an incident that may have a negative or positive impact on overall objectives. It is measured in terms of likelihood and magnitude of severity.

Risk is usually defined mathematically as the combination of the severity and probability of an event. In other words, how often can it happen and how bad is it when it does happen? Risk can be evaluated qualitatively or quantitatively.

Pure Risk = Frequency x Consequence of Hazard

Pure Risk = Probability of Occurrence x Impact

RESIDUAL RISK (RR)

The risk that remains after taking into account the effects of controls applied to mitigate the associated pure risk. No matter how much the causes are mitigated, the consequences are the same; only the frequency of incidence or occurrence can be altered.

Residual Risk = Mitigated Frequency x Consequence of Hazard

Residual Risk = Mitigated Probability of Occurrence x Impact

SIGNIFICANT RISK

Level of risk that will not or cannot be tolerated by management, regulatory bodies, work force, or public and needs to be controlled.

TOLERABLE RISK

Level of risk that will be tolerated by management, regulatory bodies, work force, or public.

TYPES OF RISK ASSESSMENT

BASELINE RISK ASSESSMENT

Used to determine the current risk profile and identify the main focus areas for improvement. Areas of interest include:

- Processes
    - Tasks
    - Equipment
- Operations
    - Activities
- Environment
- Social Impact or Impact on Reputation
- Legal/Regulatory Requirements
- Security

ISSUE-BASED RISK ASSESSMENT

Detailed assessment of issues identified during the baseline risk assessment as posing significant risk. Various techniques utilized to conduct issue based risk assessments include:

- Root Cause Analysis
- Fault Tree Analysis
- What-if + Checklist
- HAZOP
- Process Hazard Analysis

Instances where an issue based risk assessment would be appropriate are:

- Changes in the baseline risk profile
- Changes to equipment or processes
- Near-misses
- Accidents
- Change in tolerable risk perception
- Finding from a Continuous Risk Assessment

CONTINUOUS RISK ASSESSMENT

Proactive identification of occupational health, safety, and environmental hazards to actively mitigate significant risks. It is best performed as structured activities at specific and pre-determined time intervals. Such activities would include:

- Pre-use equipment checklist
- Permit to Work
- Planned inspections
- Preventive maintenance
- Planned task observations
- Job Safety Analysis (JSA)
- Health, Safety, and Environment Audits

BASELINE RISK ASSESSMENT PROCESS

There are ten facets to organizing a successful baseline risk assessment.

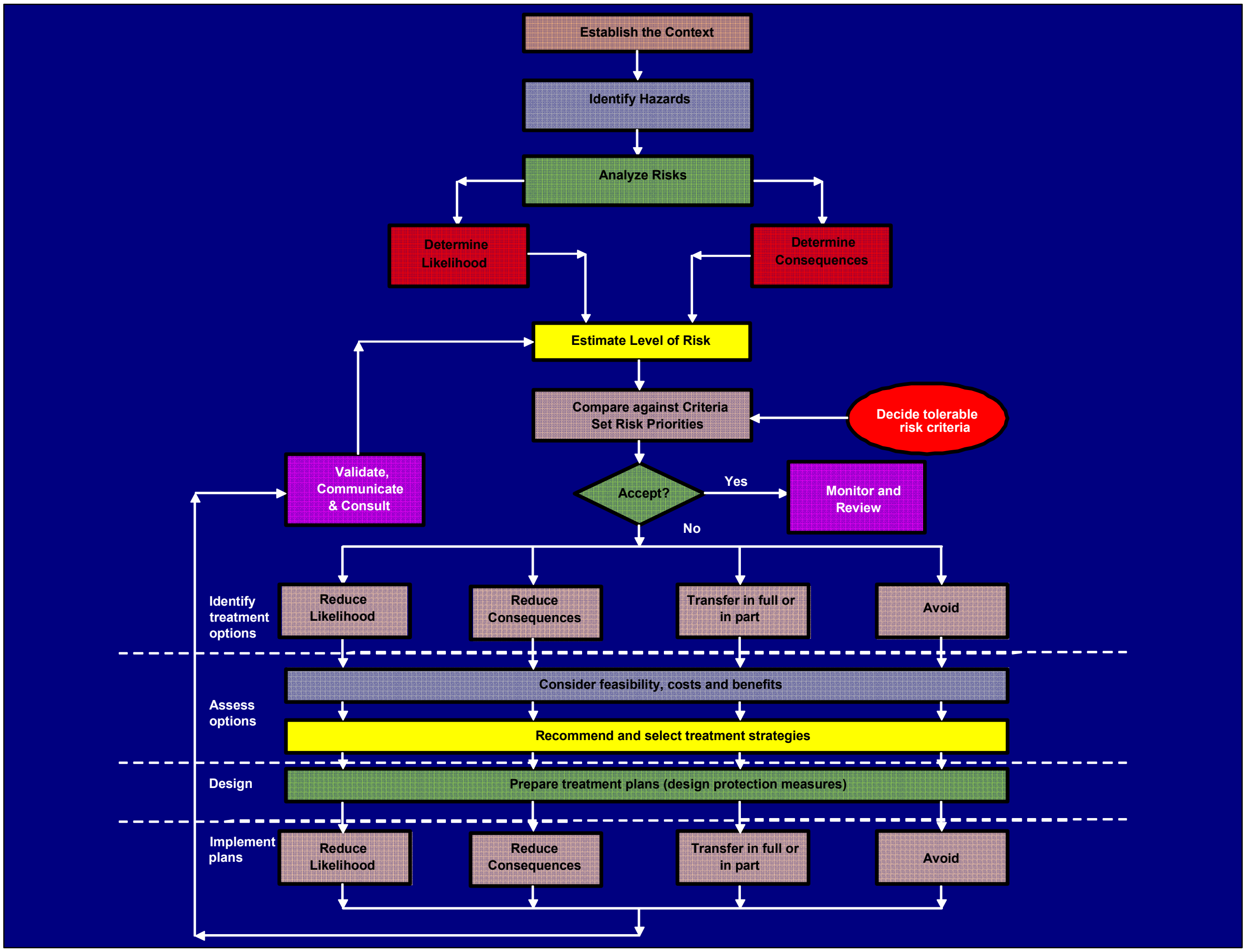
1. Preparation
2. Hazard Identification
3. Converting Hazards to Risks
4. Ranking the Risks
5. Evaluating Effectiveness of Existing Controls
6. Expressing Consequences in Monetary Terms
7. Cost/Benefit Analysis
8. Implementation of Controls
9. Audits
10. Follow-up

PREPARATION

MANDATE FROM MANAGEMENT

First and foremost, no risk assessment will have any validity unless there is a clear and unequivocal mandate from senior management. Corporate buy-in is not only essential to the success of the risk assessment it is a pre-requisite. It demonstrates the commitment and participation of management. The mandate includes funding and support for the Risk Assessment Team.

This model is a general overview of what management would expect from a risk assessment study.



Management presents important issues to the organization with policy statements. Policies define specific areas of concern and indicate the desired outcome. Policies increase decisiveness by removing uncertainty about action required to meet the objective. Policy statements communicate information to the staff in general terms for detailed implementation by procedures in a consistent fashion through individual acceptance and individual commitment. Good policies reduce the potential for bad events such as inefficiency, counter productivity, inappropriate risk taking, and conflicts over requirements so that nothing is implemented because of the void.

Modern organizations have safety policies and quality policies. Before safety and quality policies, both areas originally operated with "Everyone knows what to do, we don't need a policy." Prior to policies injury rates were high and quality was poor. After policies it was clear the safety goal was zero injuries and the quality goal was full conformance to *the requirements.* Risk *issues need a clear and concise policy statement to avoid fuzzy interpretations.*

Management has the responsibility to approve, distribute, educate, and train the organization in the requirements for risk *as a display of leadership.* (Adapted from Barringer, 2001).

GUIDANCE FROM MANAGEMENT

- Summary of the strategic, corporate and risk management context
- Reason for the review
- Objectives of the review clearly stated
- Description of the system being assessed
- Boundaries clearly and unambiguously defined
- Is the facilitator identified together with related experience?
- Is the facilitator appropriate?

NOMINATION OF A TEAM LEADER (FACILITATOR)

The Team Leader is a competent, impartial, honest, and ethical facilitator; independent of the area being analyzed, and having some working knowledge of the area being analyzed. His primary responsibilities are:

- Direct, Manage, and Focus the Team and its Activities
  - Establishes schedules
  - Leads team meetings.
  - Obtains clear objectives for the analysis
  - Ensures that objectives of the analysis are accomplished
  - Ensures that the analysis is completed on schedule
- Management of Resources
  - Obtains resources necessary for analysis
    - Arrange for funding consistent with the objectives, scope, and schedule
  - Initiates formal requests for or assigns a team member to this task
    - Information, interviews, test results, technical or administrative support
  - Establish administrative protocols for the analysis.

        - Gathering data activities
        - Preserving data

- Spokesperson
    - Serve as point of contact for the team.
- Training
    - Determine level of training required for team members to adequately function on the team
- Reporting
    - Keep management informed through verbal contact and periodic interim reports.
    - May make periodic verbal reports to management and staff, as required
    - Prepares interim written reports, as required
- Analysis Activities
    - Organizes team work for analysis activities
    - Assigns individuals to tasks and coordinates work with non-team members
- Impartiality and Integrity
    - Ensure team members maintain objectivity and commitment to the analysis
- Confidentiality
    - Protect proprietary and other sensitive information
- Final Report
    - Ensures that the final report is properly reviewed:
    - Factual accuracy of report for internal and external reports
    - Review by legal department, as necessary
    - Proprietary information protected.

GUIDANCE FOR THE TEAM LEADER

For the study to proceed efficiently and quickly (and so at lower cost) the best possible information should be assembled before the formal meeting and made available to the team members.

Some suggested items are:

- Draft project definition
- Process or equipment description with outline diagrams or flow sheets

- A listing of known HSE issues and incidents with similar projects (if any)
- Chemical or material hazard data sheets
- A hazards checklist for the type of activities in the process
- List the applicable legislation for compliance
- Draft occupational health statement
- Draft environmental statement

The following issues should be considered:

- Is the reason for the review defined?
- Are the objectives of the review stated?
- Is there a description of the system being assessed?
- Are the boundaries clearly and unambiguously defined?
- Is the documentation provided sufficient to understand the scope and function of the system?
- Is there a summary of the strategic, corporate and risk management context?
- Are the participants identified together with their organizational roles and experience related to the matter under consideration?
- Is the range of experience/expertise of the team appropriate?
- Is the method of identifying the risks clearly identified?
- Is the reason for the choice of methodology explained?
- Is the method of assessing likelihood and consequence of the risks identified?
- Is the reason for the choice of methodology explained?
- Is there a hazard inventory table?
- Is there a listing of external threats?
- Are all the core assumptions identified?
- How was the acceptability of the risks determined?
- Is the determination of the acceptability of the risks justifiable?
- Are all the risks prioritized by risk magnitude and consequence magnitude?
- Was the hazard identification process comprehensive and systematic?
- Has the approach to each part of the study been consistent?

- Have all the existing controls and performance indicators been identified and their function determined accurately?
- Have all potential new controls been identified, adequately assessed and assigned performance indicators if adopted?
- Is there a recommended action list giving actions, responsibilities and timelines for completion?
- Is there a review process to ensure the assessment is consistent with others completed at the same facility/business?

ASSEMBLY OF THE TEAM

- Composition
    - Vertical slice of the organization being analyzed.
    - Wide range of people and knowledge
    - Able to work in a "team" environment
    - Understand methods to gather and assess information
    - Able to identify workplace hazards and assign risk
    - Able to distinguish hazards between…
        - Physical
        - Behavioral
        - Procedural
    - Understand the hazards of energy sources located within the analysis area
    - Include experts on an as needed basis for specific knowledge

IDENTIFY HAZARDS

Perceptions of risk can vary significantly between members of the vertical slice of the organization. Although the perceptions differ, the initial questions are the same.

- What can happen?
- How can it happen?

The result is a list of hazards with the possible causes. Hazards can be found in processes, tasks, and activities; and most typically involve the presence of an energy source, a component of an energy source, or the abrupt change of energy that has the potential to cause a loss event. To identify all the hazards in a system can be a daunting task. A "Divide and Conquer" approach may prove beneficial.

- Define the boundaries of the risk assessment; where it starts and where it ends.
    - Geographical
    - Process
    - Activities
    - Prior Documentation
- Determine any deviations from prior documentation.
- Identify the energy sources (hazards) present during the subject process. This is only to identify a hazard. Assigning risk will come later. An aid to hazard identification
    - Areas of Impact
        - People
            - Work Conditions
                - Ergonomics
                - Unauthorized work
                - Inclines, Height
                - Alcohol and Drugs
                - Smoking
                - Behavior
                - Wet surfaces
                - Lighting
                - Ventilation
                - Noise
                - Radiation
                - Vibration
                - Monotony
                - Fatigue
                - Work – Rest Cycle
                - Stress levels

        - Shift work
        - Personal relationships
        - Hygiene and Housekeeping
    - Natural Phenomena
        - Extreme heat
        - Extreme cold
        - Rain
        - Snow
        - Wind
        - Hurricane
        - Earthquake
        - Tsunami
        - High Seas
    - Third Party Impact
        - Labor unrest
        - Fire
        - Explosion
        - Spill
        - Gas release
        - Vehicular accidents
        - Electrical supply
        - Terrorism
        - Transportation
        - Local population
        - Local commerce
        - Commercial fishing
- Environment
    - Air
    - Land

        - Sea
    - Production
        - Process Specific
            - Drilling
                - Engineering
                - Planning
                - Maintenance
            - Production
                - Engineering
                - Planning
                - Maintenance
        - Hazardous Chemicals
            - Storage
            - Transportation
            - Gas
            - Liquid
            - Dust
            - Explosive
            - Toxic
            - Flammable
            - Vapors
            - Fumes
    - Asset Damage
        - Facility Specific
            - Housekeeping
            - Offices
            - Workshop
            - Kitchen
            - Living Quarters

- Equipment Specific
  - Age
  - Component Failure
  - Corrosion
  - High pressure
  - High flow
  - Vibration
  - Spills/Leaks
  - Lubrication
- Reputation
  - Impact on Third Party
    - Labor unrest
    - Fire
    - Explosion
    - Spill
    - Gas release
    - Vehicular accidents
    - Electrical supply
    - Terrorism
    - Transportation
    - Local population
    - Local commerce
    - Commercial fishing
- Regulatory

Force/Energy	Consequences					
	People	Environment	Asset	Production	Reputation	Regulatory
Chemical	Burns Lung Damage Poisoning Irritation	Water Pollution Air Pollution Soil Pollution	Fire Explosion Corrosion Melting	Not Available Too Much Too Little Wrong Material	Social Impacts	Single Action Multiple Action Class Action
Electrical	Burns Shock Eye Damage	Resource Use Pollution	Fire Fault Flashover Back Feed Induction	Not Available Too Many Amps Too Few Amps Wrong Voltage		Single Action Multiple Action
Mechanical	Contusions Crushes Impact Injuries		Impact Damage Structural Failure	Not Available Too Much Too Little Wrong Machine		Single Action Multiple Action
Pressure Flow	Contusions Crushes Cuts	Erosion	Burst Collapse Structural Failure	Not Available Too Much Too Little		Single Action Multiple Action
Noise	Hearing Damage	Noise Pollution			Social Impacts	Single Action Multiple Action Class Action
Gravity	Impact Injuries		Impact Damage			Single Action Multiple Action
Radiation Thermal	Burns Cancer Freezing	Water Pollution Air Pollution Soil Pollution Ecological Impacts	Fire Melting Heat Damage Cold Damage	Not Available Too Much Too Little	Social Impacts	Single Action Multiple Action Class Action
Bio-Mechanical	Sprains Strains Slips Trips		Drop Damage			Single Action Multiple Action
Microbiological	Illness	Contamination	Contamination	Contamination Delays	Social Impacts	Single Action Multiple Action Class Action
Meteorological	Impact Injuries Evacuation	Water Pollution Air Pollution Soil Pollution Contamination Ecological Impacts	Water Damage Impact Damage Structural Failure	Not Available	Social Impacts	Evacuation

CONVERTING HAZARDS TO RISK

Hazards are not assessed, risks are assessed. Converting hazards to risk requires reason and judgment in how the magnitude of a hazard affects health, safety, and environment. The question of reasonableness usually resolves itself. Example: an airplane striking a drilling rig.

It is most advantageous to narrow the scope as much as possible to hazards of a particular interest, or specific process, or impact area. In terms of a particular scope of work, let's define the risk of an energy source that can get out of control. First, we must assume that as a baseline the energy sources described are normally and initially under control. To maintain organization during the assessment, every hazard should be considered for each step in the process under normal, abnormal (upset), and emergency conditions.

HAZARD OUT OF CONTROL

- Management System Failure or Non-conformance
  - Quality Assurance Program
  - ISO 9000 Program
  - ISO 14000 Program
  - API Recommended Practice
  - API Specifications
- Training or Skill Deficiency
- Latent Design Defects
  - Equipment
  - Equipment layout
  - Substandard Physical Conditions
- Inappropriate or Inadequate Maintenance
  - Substandard Physical Conditions
- Faulty Procedures
- Communication Systems
  - Inadequate Supervision
- Barrier or Containment Failure
  - Physical
  - Natural

        - Time
        - Distance
    - Human Action
    - Administrative

OUTCOME

The outcome of this portion of the risk assessment process is to note:

1. The step in the process that the hazard exists
    a. Startup
    b. Normal Operations
    c. Shutdown
    d. Maintenance
2. The energy source that can go out of control
3. The cause for the uncontrolled energy
4. The consequence that may result

From the outcome we can judge if the consequence of interest is of sufficient reasonableness to warrant further scrutiny. Another issue of concern is the consequence of the deviation.

CONSEQUENCES

We can measure consequences in terms of injury to persons, damage to the environment, damage to property, damage to work productivity, social impact and reputation damage, and legal costs and impact. Below is a sample quantitative scale:

RISK MATRIX

MEASURING RISK

Risk is something we can measure approximately by creating a scale based on the product of frequency and consequence.

RISK = Frequency x Consequence of Hazard

RISK = Probability of Occurrence x Impact

Occurrence Index			
Occurrence	Description	Frequency (1 in X)	Ranking
Frequent	Very high number of failures likely	100	5
Probable	Frequent number of failures likely	1,000	4
Occasional	Occasional number of failures likely	10,000	3
Remote	Very few failures likely	100,000	2
Rare	Failure unlikely. History shows no failures.	1,000,000	1

Severity Index								
Severity	People	Assets	Production	Environment	Regulatory	Reputation	Value	Ranking
Severe	Multiple fatalities	Extensive damage	Total loss	Regional scale Long term impact	Cease and Desist	Major international impact	$10,000,000,000	5
Major	Single fatality	Major damage with delays	Extensive loss	Medium scale Medium term impact	Formal Investigation	Major national impact	$1,000,000,000	4
Significant	Multiple injuries	Local damage	5-7 Days lost	Medium scale Short term impact	Incident of non-compliance	National Bad mention	$100,000,000	3
Minor	Minor injuries	Performance reduction	2-4 Days lost	Localized Temporary impact	Possible incident of non-compliance	Short term Local concern	$10,000,000	2
Low	No recordable injuries	Very minor repairable damage	1 Day lost	Localized Temporary impact	No citation	Local mention	$1,000,000	1

THE RISK MATRIX

From the above, it is clear that a scale of risk can be created from the resulting products of frequency and consequence. One popular way to represent this scale is by means of a simple chart that is widely known as a risk matrix.

When the product of frequency and consequence is high, the risk is obviously very high and is unacceptable. The unacceptable region extends downwards towards the acceptable region of risk as frequencies and/or consequences are reduced. The transitional region, as shown in the diagram, is where difficult decisions have to be made between further reduction of risk and the expenditure or complexity needed to achieve it. Our diagram shows some attempt at quantifying the frequency scale by showing a range of frequencies per year for each descriptive term. This is usually necessary to ensure some consistency in the understanding of terms used by the hazard analysts.

Some companies go a step further and assign scores or values to the descriptions of frequency and consequence. This has the advantage of delivering risk ranking on a numbered scale, allowing some degree of comparison between risk options in a design.

The scoring system adopted is an arbitrary scheme devised to suit the tolerability bands as best as possible. Each company and each industry sector may have its own scoring system that has been developed by experience to provide the best possible guidelines for the hazard study teams working in their industry. There does not appear to be any consensus on a universally applicable scoring system but the ground rules are clear. The scales must be proportioned to yield consistently acceptable results for a number of typical cases. Once the calibration of a given system is accepted, it will serve for the remainder of a project.

Consistency of grading is more important than absolute accuracy. However, without the ranking, decisions based on risk identification along may be ineffectual. Economic prudence would dictate that more resources be put on high frequency/high impact risks rather than the low hanging fruit of low frequency/low impact risk.

FREQUENCY						
	Frequent 5	5	10	15	20	25
	Probable 4	4	8	12	16	20
	Occasional 3	3	6	9	12	15
	Remote 2	2	4	6	8	10
	Rare 1	1	2	3	4	5
		Low - 1	Minor - 2	Significant - 3	Major - 4	Severe - 5
		CONSEQUENCES ($ MM)				

EVALUATE RISKS

The next step is to compare the risk level with certain reference points to decide if the risk level is acceptable or not. If the risks are unacceptable the choice is to treat the risks or decide to avoid the risks altogether by doing something else. The diagram below introduces the concept of tolerable risk or acceptable risk. In practice, the reference point for acceptable risks may depend on the company, regional practice, or legal or regulatory requirements.

The format of the risk matrix allows companies to set down their interpretations of consequences in terms of losses to the business as well as harm to the environment and harm to persons. However, there seem to be some problems here that need to be sorted out:

- Where are the boundaries for the tolerable risk zone?
- Who defines the risk graph?
- Who defines the tolerable risk band?
- How far down the risk scale is good enough for my application?

These problems bring us to issues of tolerable risk and deciding how much risk reduction is justified.

RISK CONTROL AND RESIDUAL RISK

IDENTIFYING CONTROL MEASURES

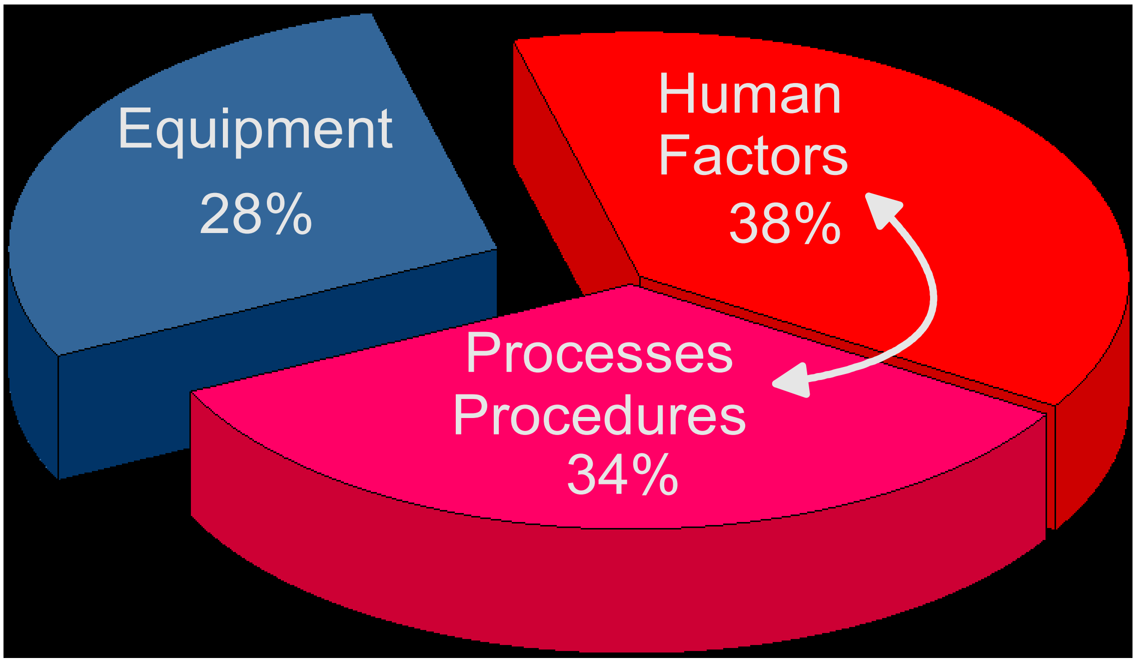
Reliability Issues

No control measure is 100% effective. It is naïve to think that we can achieve perfection. Nature's Law of Entropy expresses that the lowest energy state is chaos and disorder. Everything fails over time. Reliability requires ongoing diligence.

Reliability is defined as the probability that a component, system, or process will function without failure for a specific length of time when operated correctly under specific conditions. While we speak of reliability we actually measure unreliability, simply because we expect things to work when they are expected to work. Failure is supposed to be the exception, not the rule. Since failure is expected to be a low or small number, it should be less difficult to track.

Human Factors

To err is human. The American Institute of Chemical Engineers (AIChE, 1999) studied the root causes of failures and performed a Pareto Distribution of those failures. The illustration below demonstrates the human factors account for 38% of the failures, 34% were attributed to processes and procedures, and 28% were attributed to equipment. In reality, there is a strong inter-relationship between processes, procedures, and human factors; where the percentage actually ranges between 40 – 70%.



Human error can be expressed as follows:

$$\text{Human Error Probability} = \frac{\text{Number of Errors}}{\text{Number of Opportunities for Error}}$$

$$\text{Human Error Rates} = \frac{\text{Number of Errors}}{\text{Total Task Duration}}$$

The table below describes the time available for diagnosis of an abnormal event after a control room annunciation (AIChE, 1999).

Time (minutes)	Probability of Failure (%)
1	~100
10	50
20	10
30	1
60	0.1
1500	0.01

Open-minded managers realize that most mistakes are committed by skilled, productive, and well-meaning personnel. The concept that humans are reliable and equipment is unreliable underemphasizes human faults. Human unreliability is often a dominant factor in unreliability issues.

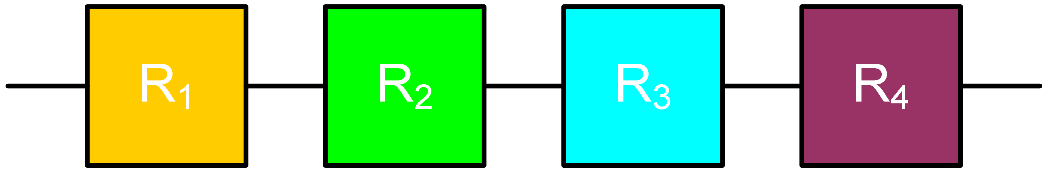
Equipment Reliability

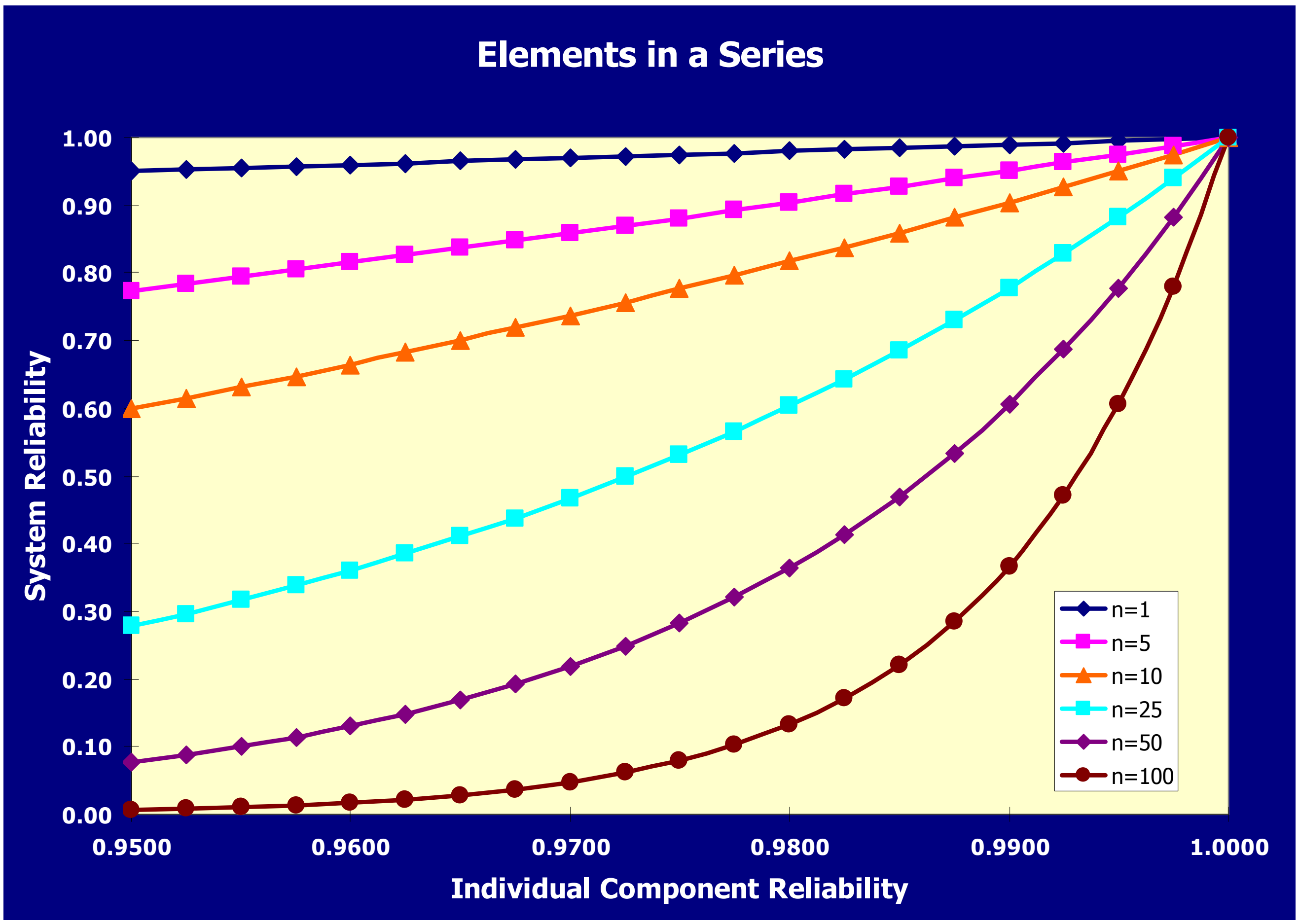
Aside from human frailties, equipment is subject to reliability issues. As an example, a piece of equipment is designed for 10,000 operating hours and will work 99.999% of the time. If operating on a 24/7 basis, that piece of equipment may not function for 10 hours within a 13 month period. How critical is that equipment to the operation? What happens when that equipment is out of service? What are the safety implications of that equipment in operation and not in operation?

Elements in a Series

The graph below describes how many elements (i) in series can have a potentially deleterious affect on the reliability of a system (R_s).

$$R_S = \prod_{i=1}^{n} R_i = R_1 \times R_2 \times R_3 \times R_4 \ldots.$$

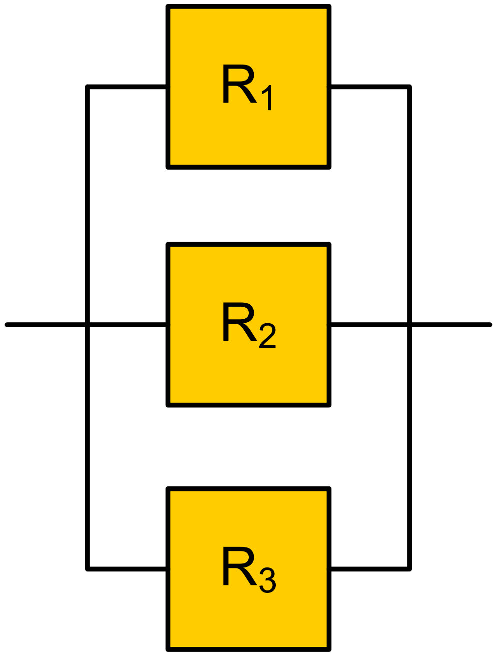




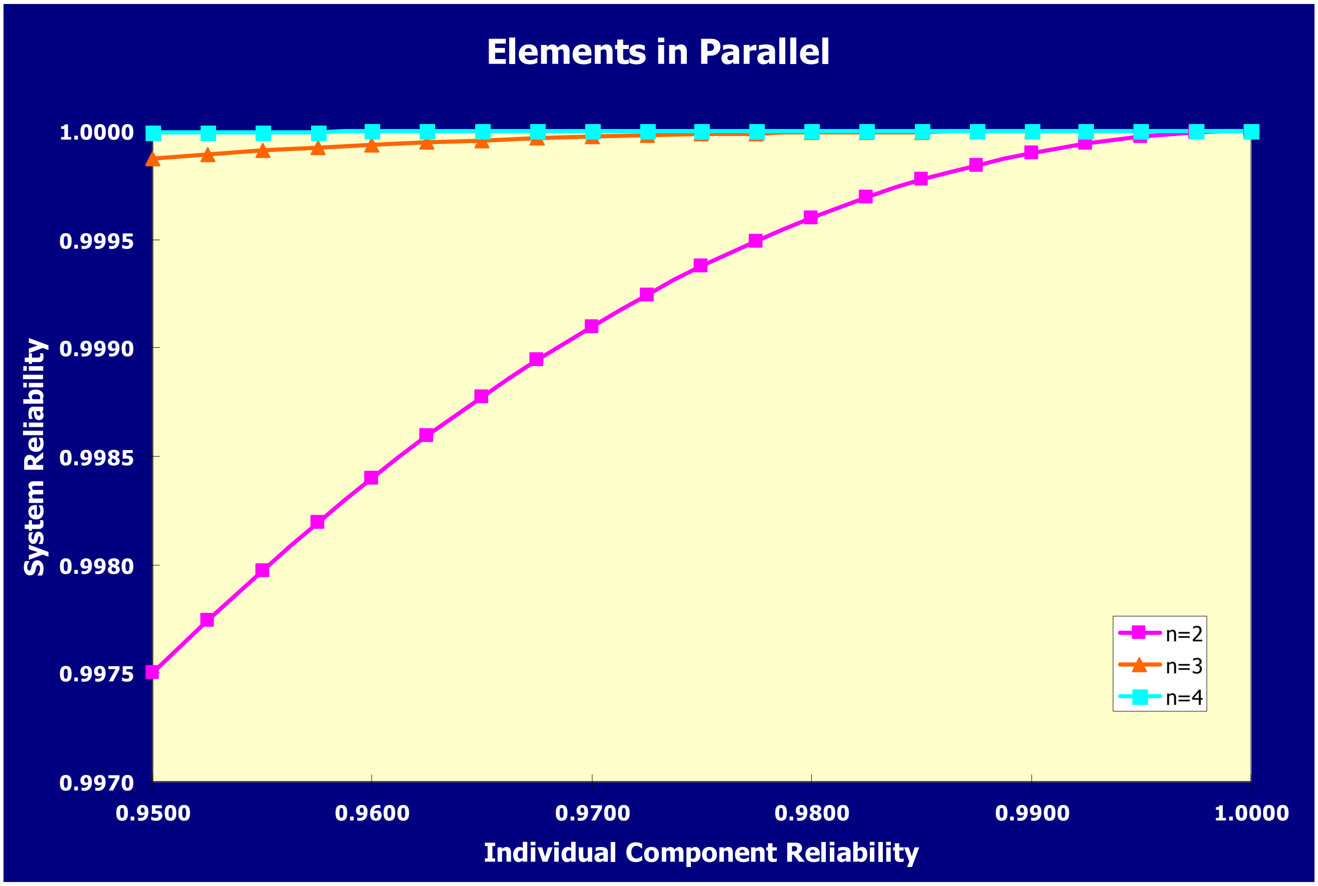
Elements in Parallel

On the other hand, high reliability elements need only a few items in parallel to achieve a high reliability system.

$$R_s = 1 - (1 - R_1) \times (1 - R_2) \times (1 - R_3) \times (\ldots)$$



Each element in parallel must be able to carry the load.



Control Measures

While there is a hierarchy of control measures that range from the most effective to the least effective, no control is 100% effective. The more dependent controls are on human action, the less effective they are when required. At least two effective controls (barriers) should be in place for any critical task.

A recommended hierarchy of control has been devised by the International Labor Organization Convention 176: Safety and Health in Mines, Article 6, 1995.

In taking preventive and protective measures under this Part of the Convention the employer shall assess the risk and deal with it in the following order of priority:

- Eliminate the risk;
- Control the risk at source;
- Minimize the risk and;

- If the risk remains,
  - Provide for the use of personal protective equipment and
  - Institute a program to monitor the risks employees may be exposed to; having regard to what is reasonable, practicable and feasible, and to good practice and the exercise of due diligence.

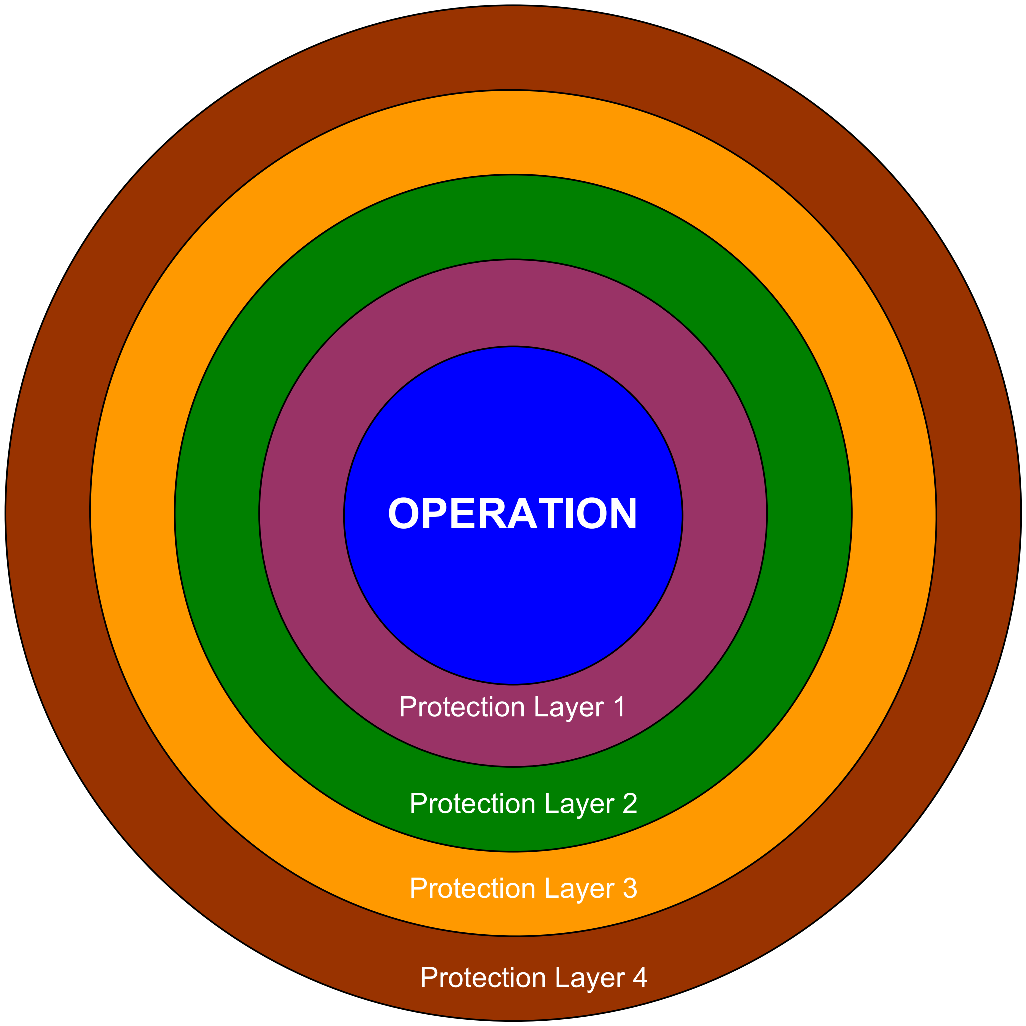
The identification of measures to reduce risk takes place during the hazard study. It is useful for the study team to have a set of prompts of typical measures available. The best measures are those that prevent the causes of hazards. We are often able to reduce the risk by reducing the likelihood or frequency of an event.

Measures to reduce consequences are used when the causes of a hazard cannot be further reduced. These measures accept that the hazardous event may occur but provide means of mitigating the scale of events to reduce the consequences.

Protection layers are divided into two main types:

- Prevention
- Mitigation

Each layer must be independent of the other, so that if one layer fails, the next layer can be expected to provide back-up protection.

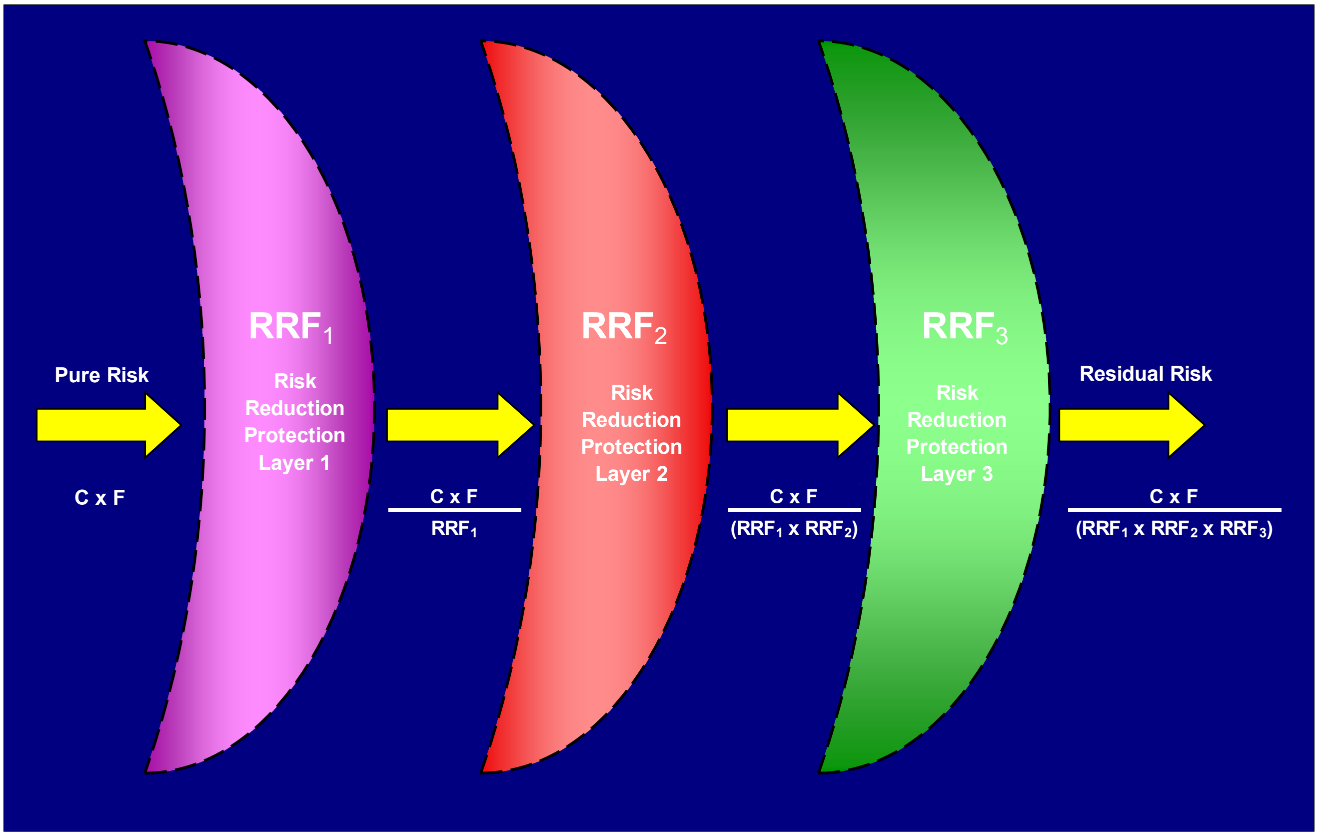


Protection Layers

A protection layer consists of a grouping of equipment and/or administrative controls that function in concert with other protection layers to control or mitigate process risk. The pure risk is reduced by each layer of protection.

Mitigation Layers

Mitigation layers reduce the consequences after the hazardous event has taken place. Mitigation layers include fire extinguishing systems, containments, and evacuation procedures. Anything that contributes to reducing the severity of harm, after the hazardous event has taken place, can be considered a mitigation layer.



Where C= Consequences, F= Frequency, and RRF_x = Risk Reduction Factor

Establishing Tolerable Risk Criteria

The risk assessment team is charged with the task of determining the effectiveness of controls to prevent or mitigate particular risks. The effectiveness of the control measures will point toward a modification of pure risk exposure and assist in identifying additional control measures that may be instituted as appropriate, where …

Pure Risk – Effective Controls = Residual Risk

Residual Risk is an estimate taking into account the effectiveness of prevention and mitigation methods to control a pure risk situation.

Control Measures – What Are They?

There are three basic techniques available to an organization designed to minimize risk exposure as low as reasonably possible at a reasonable cost. They are:

- Prevention
- Detection
- Mitigation

Listed below are some examples that are measureable. While this list is not exhaustive it acts as a checklist to consider risks and their potential controls systematically and could help to determine if additional controls are necessary. With some overlap, there are three areas that tend to originate and maintain safeguards.

- Administration
    - Training
    - Emergency Plans
    - Directives
    - Supervision
    - Planned Inspections
    - Communications
    - Security
    - First Aid
    - Legal/Regulatory Requirements
    - Management of Change
- Engineering
    - Equipment Design
    - Energy Barriers
    - Identification of Critical Equipment
    - Warning Signs
    - Emergency Equipment
- Operations
    - Procedures
    - Job Safety Analysis

- Permit to Work
- Emergency Drills
- Pre-use checklist
- Planned Maintenance
- Incident Management

Residual Risk Ranking

One method to estimate the effectiveness of certain controls against a specific risk, as described in this particular exemplar table, would be to:

FREQUENCY						
	Frequent 5	5	10	15	20	25
	Probable 4	4	8	12	16	20
	Occasional 3	3	6	9	12	15
	Remote 2	2	4	6	8	10
	Rare 1	1	2	3	4	5
		Low - 1	Minor - 2	Significant - 3	Major - 4	Severe - 5
		CONSEQUENCES ($ MM)				

1. Count the number of controls measures that act as safeguards for a specific risk.
2. Determine the percentage effectiveness of the collection of controls against a specific risk.
    a. As an example, say the collective effectiveness of the controls is 85%. If Pure Risk equals 100%, then the Residual Risk will equal 15% (100% - 85%).
3. Multiply the Pure Risk by the Residual Risk percentage.
    a. 25 x 0.15 = 3.75
    b. 4 falls in the green, tolerable range in the example risk matrix.

Had the effectiveness of the control been 60%, the residual risk would have been 10 (25 x 0.40). That may have been defined as still a Significant Risk. If so, the risk assessment team would be encouraged to find additional or stronger methods of control to get the Residual Risk to a more tolerable number.

The Residual Risks are then ranked with attention given to the higher numbers from highest priority to lowest priority.

QUANTIFYING RISK

The language of business is money. The civilized world holds that a human life is priceless, but society does allow for certain risks. For communication purposes certain values need to be assigned to convert humanitarian and violation issues into time and cost – the language of commerce, decision-making and action; so that business trade-off decisions can be made. Any values described herein are not intended to be guidance values for attorneys, nor do they represent callous and cynical views on the value of human life.

Measures to control risk always cost money. There is always the potential for conflict between management, employees, and the public over the extent and magnitude of expenditures necessary to promote safety, health, and environment issue that are considered reasonable and practical.

By analyzing the costs of risks through an activity-based cost approach, the relationship between cost drivers and activities can be better understood.

The list below describes some typical cost drivers that reflect the comprehensive cost of incidents.

- Wages and compensation paid to the injured or ill while not working
- Recovery, rescue, and cleanup cost
- Loss of production
- Training of replacement worker(s)
- Re-training cost of injured/ill worker(s)
- Investigation costs
- Medical and hospitalization costs
- Worker rehabilitation and therapy
- Equipment damage
- Incident site repair and renovation
- Statutory fines and penalties\
- Administrative costs

- Loss of market share, reputation, and integrity
- Litigation

Using the list such as one described above will aid in the development of an effective cost/benefit analysis.

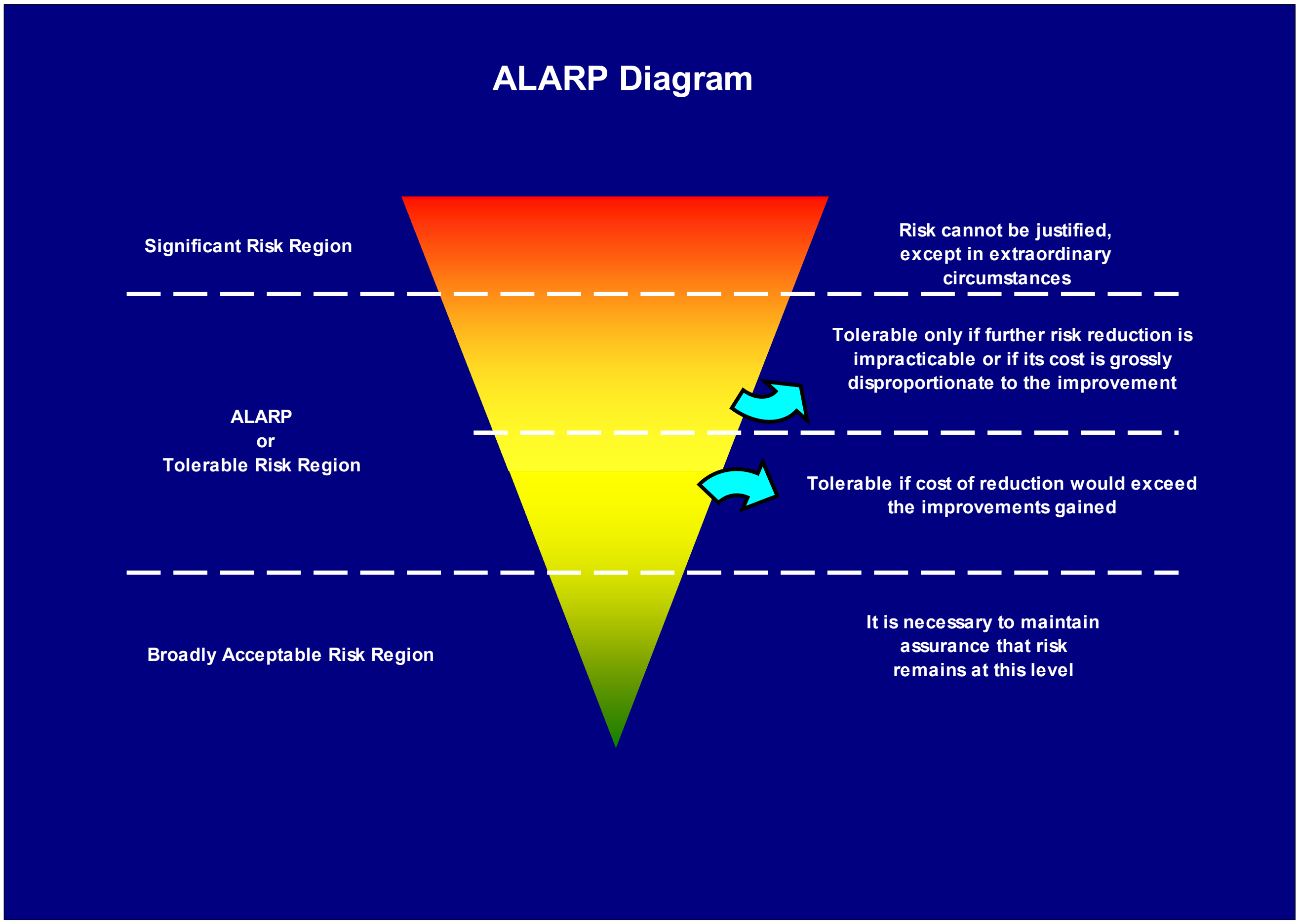
COST BENEFIT ANALYSIS

While the identification of measures to reduce risk takes place during the hazard study by the risk assessment team, the final decision to implement a specified control rests with management after quantifying the risk and performing a cost/benefit analysis. Conducting a formal cost/benefit analysis to determine tolerable risk is a joint responsibility effort between management and employees.

Significant Risk is not tolerated by management, regulatory bodies, work force, or public and needs to be controlled. Tolerable Risk is tolerated by management, regulatory bodies, work force, or public. Tolerable does not necessarily mean acceptable. Tolerable refers to the willingness to accept a risk to secure certain benefits in the confidence that the risk is being properly controlled.

CONCEPTS OF ALARP

Control measures are designed to reduce risk. In some cases, this will be an alternative way of doing things or it can be a protection system. When we set out to design a protection system, we have to decide how good it must be. We need to decide how much risk reduction is needed. The target is to reduce the risk from the unacceptable to at least the tolerable. The concept of tolerable risk is part of the widely accepted principle of ALARP (As Low As Reasonably Practical).



RISK REDUCTION DESIGN PRINCIPLES

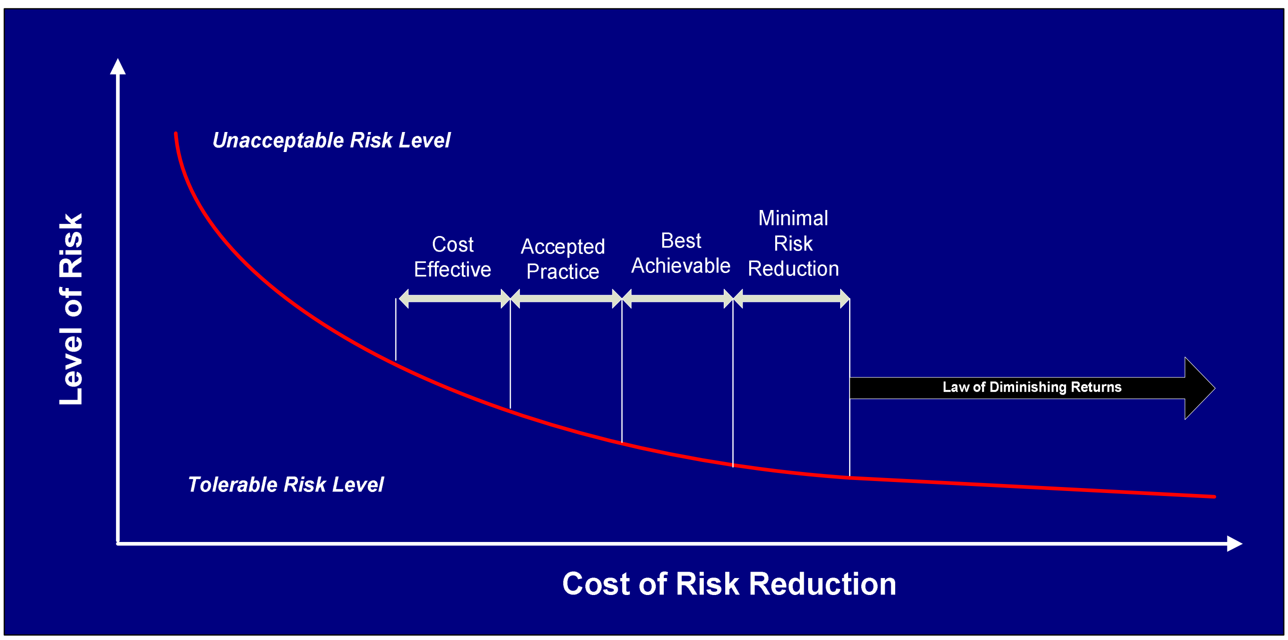
The ALARP principle recognizes that there are three broad categories of risks:

- Significant risk: The risk level is so high that we are not prepared to tolerate it. The losses far outweigh any possible benefits in the situation.

- Tolerable risk: We would rather not have the risk but it is tolerable in view of the benefits obtained by accepting it. The cost in inconvenience or in money is balanced against the scale of risk, and a compromise is accepted.
- Negligible risk: Broadly accepted by most people as they go about their everyday lives, these would include the risk of being struck by lightning or of having brake failure in a car.

The width of the triangle represents risk, and as the width reduces, the risk zones change from unacceptable through to negligible. The hazard study and the design teams for a hazardous process or machine have to find a level of risk that is as low as reasonably practicable in the circumstances or context of the application. The problem here is: How do we find the ALARP level in any application?

- The pure level of risk must first be reduced to below the maximum level of the ALARP region at all costs. This assumes that the maximum acceptable risk line has been set as the maximum tolerable risk for the society or industry concerned.
- Further reduction of risk in the ALARP region requires cost benefit analysis to see if the additional expenditure is justified.



- Risk control measures should be undertaken within the broad corporate scope of risk aversion, reputation, and financial objectives considering health, safety, environment, and social benefits measured against further risk reduction to the broadly acceptable risk region.
- The principle is simple: If the cost of the unwanted scenario is more than the cost of improvement the risk reduction measure is justified.

IMPLEMENTATION OF CONTROLS

Upon receipt of approval to enact controls, an implementation schedule should be drafted. The action plan should include personnel, resources, and completion dates; and where possible integrated into normal day-to-day operations.

AUDITS

As part of the ongoing evaluation process, a risk management audit is a detailed and systematic review to determine if the objectives of the risk management program are appropriate to the needs of the organization, whether the steps taken to achieve the stated objectives were appropriate and suitable, and if those controls were properly implemented. Whether the review is conducted internally or by an external auditor, the process typically involves the following:

- Evaluate risk management policy
  - Are objectives being met consistent with policy
- Identify exposure to loss
- Evaluate decisions related to exposure to loss
- Evaluate implementation of risk control methods and techniques
- Recommend changes for improvement

FOLLOW-UP

Upon conclusion of the Audit Phase, management should periodically begin the risk assessment process again for re-validation, ensure controls are working properly and in place, develop additional controls as necessary, and possibly de-activate non-essential controls if the modified risk profile has made them unnecessary.

Probabilistic Risk Model Summary

ASSUMPTIONS

For Dual gradient Drilling with positive displacement mud pumps on the seabed floor certain assumptions are made largely based on lessons learned in 2001. These assumptions do not necessarily apply to other Dual Gradient Drilling methods, nor do the well control procedures translate from one method to another. Each approach must develop suitable well control procedures based on equipment selection, fluid properties, and the hydraulic profiles generated. Because choke and kill lines are downstream of the MLP, friction losses are not applicable. Other systems may have to contend with choke and kill line frictional losses.

- All DGD operations are performed above LMRP and BOP stack to prevent interference with well control operations.
- The DGD system is designed to be part of the emergency disconnect package.
- Redundancy protects against an accumulation of failures, but there is no compromise on WC systems.
- Pressure sensors detect flow impairment in valves, and the MLP response will indicate impairment too.
- Electric power for DGD components travels down two umbilicals (green and red).
- Tripping operations concern two vessels: riser and wellbore.
- Two trip tanks are required: one for riser fluid and one for mud.
- Riser fluid trip tank circulates at steady volume as long as riser volume is stable; when collars enter the riser, this trip tank will show a gain. This is not an “alarm” volume change, just a pipe displacement effect.
- Mud trip tank is isolated from seawater system and a centrifugal surface pump fills the hole.
- If the DSV is closed, it will be a wet string requiring a high flow rate to fill the wellbore during the trip out.
- MLPs continue to pump off excess mud, as triggered by preset inlet pressure. The u-tube rate for mud fill is probably too slow for tripping, so the centrifugal pump augments rate.
- The wellbore fill-up needs to maintain a full line at all times by catching up with natural drop or pinched choke, with back pressure on the centrifugal.
- The result is a closed system. We can evaluate having a bypass line in the subsea line up to increase the fill rate if other valves are restricted.
- While the SRD is in place between riser and wellbore, tripping out requires continuous circulation across the top of the wellbore while filling the hole.
- After the SRD is unseated, the mud level will rise into riser because the MLP circulation initiation pressure will be lost.
- While drilling ahead, the MLPs operate in constant pressure mode as opposed to constant rate.

Risk Matrix

MEASURING RISK

Risk is something we can measure approximately by creating a scale based on the product of frequency and consequence.

RISK = Frequency x Consequence of Hazard

RISK = Probability of Occurrence x Impact

EXAMPLE HYPOTHETICAL OCCURRENCE INDEX

Occurrence Index			
Occurrence	Description	Frequency (1 in X)	Ranking
Frequent	Very high number of failures likely	100	5
Probable	Frequent number of failures likely	1,000	4
Occasional	Occasional number of failures likely	10,000	3
Remote	Very few failures likely	100,000	2
Rare	Failure unlikely. History shows no failures.	1,000,000	1

EXAMPLE HYPOTHETICAL SEVERITY INDEX

Severity Index								
Severity	People	Assets	Production	Environment	Regulatory	Reputation	Value	Ranking
Severe	Multiple fatalities	Extensive damage	Total loss	Regional scale Long term impact	Cease and Desist	Major international impact	$10,000,000,000	5
Major	Single fatality	Major damage with delays	Extensive loss	Medium scale Medium term impact	Formal Investigation	Major national impact	$1,000,000,000	4
Significant	Multiple injuries	Local damage	5-7 Days lost	Medium scale Short term impact	Incident of non-compliance	National Bad mention	$100,000,000	3
Minor	Minor injuries	Performance reduction	2-4 Days lost	Localized Temporary impact	Possible incident of non-compliance	Short term Local concern	$10,000,000	2
Low	No recordable injuries	Very minor repairable damage	1 Day lost	Localized Temporary impact	No citation	Local mention	$1,000,000	1

HYPOTHETICAL RISK MATRIX

Risks were evaluated under two general categories:

1. Health-Safety-Environment-Regulatory (HSER)
2. Reliability, Production, and Operational Efficiency (RP&OE)

FREQUENCY						
	Frequent 5	5	10	15	20	25
	Probable 4	4	8	12	16	20
	Occasional 3	3	6	9	12	15
	Remote 2	2	4	6	8	10
	Rare 1	1	2	3	4	5
		Low - 1	Minor - 2	Significant - 3	Major - 4	Severe - 5
		CONSEQUENCES ($ MM)				

HYPOTHETICAL RISK EVALUATION TEMPLATE

Item	Deviation	Causes	Consequences	Category	S	UL	PR	ML	RR	Safeguards	Action Items

Risk Assessment Table Legend

Deviation	Departure from agreed upon process, procedure, or normal expected function.
Cause	A person, event, or condition that is responsible for an effect, result, or consequence.
Consequence	The result of an action, event or condition. The effect of a cause. The outcome or range of possible outcomes of an event described qualitatively (text) or quantitatively (numerical) as an injury, loss, damage, advantage, or disadvantage. Although not predominantly thought of in this manner, consequences do not always have negative connotations; they can be positive.
Category	With respect to consequence, specific area of impact. Examples: • People • Environment • Asset • Production • Reputation • Regulatory
Severity **(S)**	The degree of an outcome or range of possible outcomes of an event described qualitatively (text) or quantitatively (numerical) as a loss, injury, damage, advantage, or disadvantage. The degree or magnitude of a consequence.
Unmitigated Likelihood **(UL)**	Likelihood of event without intervention by administration, engineering, and/or operations.
Pure Risk **(PR)**	The possibility of a hazard becoming an incident that may have a negative or positive impact on overall objectives. It is measured in terms of likelihood and magnitude of severity. Risk is usually defined mathematically as the combination of the severity and probability of an event. In other words, how often can it happen and how bad is it when it does happen? Risk can be evaluated qualitatively or quantitatively. **Pure Risk = Frequency x Consequence of Hazard** **Pure Risk = Probability of Occurrence x Impact**
Mitigated Likelihood **(ML)**	Likelihood of event with intervention by administration, engineering, and/or operations to prevent the event or lessen the impact of the event.
Residual Risk **(RR)**	The risk that remains after taking into account the effects of controls applied to mitigate the associated pure risk. No matter how much the

	causes are mitigated, the consequences are the same; only the frequency of incidence or occurrence can be altered. **Residual Risk = Mitigated Frequency x Consequence of Hazard** **Residual Risk = Mitigated Probability of Occurrence x Impact**
Safeguards	There are three basic techniques available to an organization designed to minimize risk exposure as low as reasonably possible at a reasonable cost. They are: • Prevention • Detection • Mitigation With some overlap, there are three areas that tend to originate and maintain safeguards. • Administration • Engineering • Operations

RISK EVALUATION SUMMARY

				Risk Ranking		
Operation	Driiling Circuit ± Equipment Description	Risk Matrix	Deviations	Acceptable Manageable	Tolerable	Avoid
Drill Ahead	DGD Subsea Manifold	RP&OE	26	25	1	0
Drill Ahead	DGD Subsea Manifold	HSER	9	7	2	0
Tripping	DGD Subsea Manifold	RP&OE	40	32	7	1
Tripping	DGD Subsea Manifold	HSER	8	8	0	0
Kill Line	DGD Subsea Manifold	RP&OE	45	45	0	0
Kill Line	DGD Subsea Manifold	HSER	11	10	1	0
Circulation of Choke and Kill Lines	Specialty Riser Joint	RP&OE	4	4	0	0
Circulation of Choke and Kill Lines	Mid Riser joint	RP&OE	2	2	0	0
Circulation of Down Choke Line Against Choke Test Valve	Last Riser Joint	RP&OE	4	4	0	0
Circulation of Down Choke Line Against Choke Test Valve	Top Slip Joint	RP&OE	3	3	0	0
Circulation of Down Choke Line Against Choke Test Valve	Latching LMRP	RP&OE	1	1	0	0
Circulation of Down Kill Line Against Kill Test Valve	DGD Subsea Manifold Valves	RP&OE	8	8	0	0
After SRD Element Set	SRD, LMRP, MLP Flange	RP&OE	5	4	1	0
After SRD Element Set	SRD, LMRP, MLP Flange	RP&OE	1	1	0	0
Drilling	Drilling Circuit	RP&OE	9	7	2	0
Circulation While Tripping	Drilling Circuit	RP&OE	11	9	2	0
Dual Gradient to Single Gradient	w/ Mud Lift Pump	RP&OE	2	2	0	0
Dual Gradient to Single Gradient	w/o Mud Lift Pump	RP&OE	2	2	0	0
Single Gradient to Dual Gradient	w/ Mud Lift Pump	RP&OE	2	2	0	0
Drilling Ahead	Drilling Circuit	RP&OE	12	10	2	0
Drilling Ahead	Drilling Circuit	HSER	1	0	0	1
Drilling Ahead - Check for Underbalance	w/o Drill String Valve	RP&OE	5	5	0	0
Start/Stop Circulation	w/o Drill String Valve	RP&OE	2	2	0	0
Drilling Break - Dynamic CUB	w/ Drill String Valve	RP&OE	1	1	0	0
Drilling Break - Dynamic CUB	w/o Drill String Valve	RP&OE	1	1	0	0
Annular Friction Pressure Management - Dynamic CUB	w/ Drill String Valve	RP&OE	5	3	1	1
Annular Friction Pressure Management - Dynamic CUB	w/o Drill String Valve	RP&OE	5	3	1	1
Annular Friction Pressure Management - Start/Stop Circulation	w/ Drill String Valve	RP&OE	3	2	0	1
MPD - Static CUB	w/ Drill String Valve	RP&OE	3	2	0	1
MPD - Static CUB	w/o Drill String Valve	RP&OE	3	2	0	1
Unplanned Shutdown - Normal Drilling Mode	MLP Inlet Pressure Increasing	RP&OE	2	2	0	0
Unplanned Shutdown - Annular Friction Pressure Mode	MLP Inlet Pressure Increasing	RP&OE	2	0	0	2
Unplanned Shutdown - Normal Drilling Mode	MLP Inlet Pressure Decreasing	RP&OE	1	0	1	0
Unplanned Shutdown - Annular Friction Pressure Mode	MLP Inlet Pressure Decreasing	RP&OE	2	0	0	2
Unplanned Shutdown - Tripping	Drilling Circuit	RP&OE	2	2	0	0
Tripping Out of Hole	Drilling Circuit	RP&OE	7	6	1	0
Tripping Out of Hole	Drilling Circuit	HSER	1	1	0	0
Tripping In Hole	Drilling Circuit	RP&OE	8	8	0	0
Tripping In Hole	Drilling Circuit	HSER	1	1	0	0
Wireline Operations	Drilling Circuit	RP&OE	6	6	0	0
Drilling Packer	Drilling Circuit	RP&OE	1	1	0	0
Lost Circulation	Drilling Circuit	RP&OE	6	4	2	0
Setting Balanced Plug	Drilling Circuit	RP&OE	2	1	1	0
Running Casing In Normal Tripping Mode	Through the riser with BOP Shut-in with Pin Plug no Allamon Tool	RP&OE	2	2	0	0
Running Casing In Normal Tripping Mode	Below Mud Line with Pin Plug no Allamon Tool	RP&OE	6	4	2	0
Running Casing In Normal Tripping Mode	Below Mud Line with Pin Plug no Allamon Tool	HSER	2	0	2	0
Cementing Casing	Drilling Circuit	RP&OE	3	2	1	0
Running Liner	Above MLP with BOP Shut-in, No SRD and No DSV, with Allamon Tool	RP&OE	1	1	0	0
Running Liner	Below MLP with BOP Shut-in, No SRD and No DSV, with Allamon Tool	RP&OE	3	1	1	1
Running Liner	Below MLP with BOP Shut-in, No SRD and No DSV, with Allamon Tool	RP&OE	1	0	0	1
Cementing Liner	Drilling Circuit	RP&OE	4	3	1	0
FIT/LOT through Kill Line	With or Without DSV	RP&OE	9	8	1	0
Casing Pressure Test	Drilling Circuit	RP&OE	6	3	2	1
Kick Detection	Drilling Circuit	RP&OE	6	5	1	0
Kick Detection	Drilling Circuit	HSER	1	0	1	0
Basic Well Control	w/ DSV	RP&OE	10	9	1	0
Basic Well Control	w/ DSV	HSER	1	0	1	0
Kick Detection while Tripping	Drilling Circuit	RP&OE	9	7	2	0
Kick Detection while Tripping	Drilling Circuit	HSER	1	1	0	0
Well Control	w/o DSV not Shut-in	RP&OE	7	4	3	0
Well Control	w/o DSV not Shut-in	HSER	1	1	0	0
Driller's Method - First Circulation	Drilling Circuit	RP&OE	10	7	3	0
Driller's Method - First Circulation	Drilling Circuit	HSER	1	1	0	0
Trapped Pressure	Drilling Circuit	RP&OE	1	1	0	0
Stripping	Drilling Circuit	RP&OE	3	3	0	0
Bullheading	Drilling Circuit	RP&OE	3	3	0	0
		Total	366	305	47	14
		RP&OE	328	275	40	13
		HSER	38	30	7	1

This HAZOP review of this Dual Gradient Drilling process is only in its first iteration. It incorporates not only the lessons learned in 2001 but also the far-reaching consequences (overwhelmingly good) of utilizing this technology in the future. The HAZOP review has been quite thorough and represents the work of Subject Matter Experts conservatively estimated at 2,500 man-hours. It will take quite a few more man-hours to address the risks that have been brought to the attention of drilling operations. Many issues are still being addressed to improve the overall safety, reliability, and efficiency of the Dual Gradient Drilling process as described in this report.

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