DP MTS SYMPOSIUM
September 28-30, 2004

Design and Control Systems

New Generation Deepwater Risers A Design Methodology

Steve W. Bernard,
P.E. Antares Offshore LLC, Houston

Robert H. Taylor
Pride International, Inc., Houston

Thomas A. Fraser, Jr. P.E.
Vetco-Gray International, Inc., Houston

Return to session directory

NEW GENERATION DEEPWATER RISERS
A DESIGN METHODOLOGY

Steve W. Bernard, P.E.
Antares Offshore LLC, Houston, Texas
Robert H. Taylor
Pride International, Inc., Houston, Texas
Thomas A. Fraser, Jr. P.E.
Vetco-Gray International, Inc., Houston, Texas

ABSTRACT

This paper presents an overview of the design methodology and manufacturing of a New Generation of Deepwater (Drilling) Risers, NGDR, that were developed for ultra-deepwater drilling with a new generation of DP drillships and semisubmersibles. Time constraints on delivery and dusting off the analysis tools created some special design and manufacturing challenges. Riser design and manufacturing industry standards had been idle for at least ten years. Bringing them forward without time for industry consensus was risky. Today, the riser systems described here, representing about one-half of the NGDR inventory, have worked without any significant failures and are responsible for most of the deepwater wells drilled beyond about 5,000 ft in the Gulf of Mexico, West Africa and Brazil.

INTRODUCTION

The definition of a deepwater drilling riser in 1995 was one that could operate safely in water depths between 3,000 and 5,000 ft. Risers were being extended beyond their initial design ratings by lowering the operating limits, combining risers of different strengths, or by simply taking higher risks. Between 1995 and 1997, the oil companies targeted drilling ultra deepwater wells in the Gulf of Mexico and West Africa at depths nearing 10,000 ft. At that time, a conscious decision was made by more than one operator to build DP drilling vessels big enough and risers strong enough to meet these objectives. This paper describes a design and manufacturing methodology used to achieve those goals.

DESIGN CHALLENGES

Design and manufacturing challenges for the NGDR's were:

- Manufacturing high strength connector bolts;
- Bolt and thread capacity design limits;
- Careful consideration of riser pressure end load effects, PEL;
- Loop current and VIV effects on the riser;
- Hurricane abandonment strategies require emergency disconnect systems, riser hang-off and centralizing;
- Larger mud flow rate requirements because of higher pressure drops across choke/kill auxiliary lines.
- Gas migration into the riser and deepwater well control issues require gas handling equipment;
- Riser mass limitations during running and out-of-phase heave acceleration of vessel causing riser buckling after disconnect;
- Lack of adequate riser buoyancy industry design standards;
- Strength limitations of shallow water connector designs.

ENABLING TECHNOLOGIES

Technologies that were sufficiently advanced that allowed for the development of NGDR's:

- Improvements in dynamic positioning of ultra deepwater drilling vessels;
- Improvements in thruster electro-mechanical drives;
- Availability of shipyards to design and build tanker hulls as drillships.
- Improvements in mooring winch systems for ultra-deepwater;
- Availability of high tolerance wall seamed pipe;
- More efficient riser design analysis programs and FEA tools;
- The construction of a new riser buoyancy plant in Houston;
- Improvements in buoyancy manufacturing quality control;
- Improvements in fabrication of high strength bolts for riser connectors;
- Direct acting riser tensioner technology;
- 60-inch rotary table development;
- Riser gas handling technology;
- Improvements in subsea control system designs.

EXTENDING RISER DESIGN TO 10,000 FEET

In the early 1990's drilling contractors responded to operator inquires for deepwater drilling equipment by providing rig upgrade solutions to older vessels. Increasing rig payloads was relatively easy with addition of hull and column sponsons. Increasing water depth capability required some changes to mooring equipment. Stretching existing drilling risers however was not feasible and became a major factor in limiting the vessel upgrades to about 5,000 feet. Some hull upgrades promoted themselves as being capable of reaching 8,000 feet on moorings, but without the riser, it was not possible to actually drill many of the wells.

Table 1 – Riser Design Comparison
(80 ksi Bolted Flange Type Connector)

WD = 5,000 ft 10-Yr GoM Storm

Mud Weight (ppg)	TSR (kips)	Indicated Tension (kips)/API Rating
12	800	1,450/Type D
16	1,200	1,800/Type E

WD = 10,000 ft 10-Yr GoM Storm

Mud Weight (ppg)	TSR (kips)	Indicated Tension (kips)/ API Rating
10	1,200	1,600/Type D
12	1,600	1,900/Type E
14	1,800	2,000/Type E
16	2,000	2,300/Type F

Alternatives looked at for extending riser designs included:

- Limiting the mud weight requirement;
- Running thicker-walled, higher strength (main tube) risers in the high stress regions;
- Investigations into lighter weight aluminum riser designs;
- Investigations into composite risers;
- Upgrading existing coupling designs and rebuilding risers.

RISER SYSTEM DESIGN DESCRIPTION

The typical new generation deepwater drilling riser systems consist of the following components from the wellhead up to the rig floor. Refer to Figure 6:

- Wellhead Connector
- Lower BOP (5 pipe/csg rams)
- Lower Marine Riser Package (LMRP) w/controls
- LMRP Connector
- Dual Annular's (integrated into LMRP)
- Riser Flexjoint
- Riser Booster Line Joint
- Standard Riser Joints
- Pup Joints (for proper telescopic joint space out)
- Intermediate Flexjoint (drillships only)
- Termination joint (required w/gas handler)
- Gas Handler (optional)
- Telescopic joint
- Tensioner Support Ring (around telescopic joint)
- Flexjoint (alternately included for riser hang-off)
- Riser Hang-off Joint (with flexjoint installed)
- Diverter
- Riser Centralizer (drillship only for hang-off survival)

The key critical components that make or break a deepwater design are the riser flange design, buoyancy selection, and riser-disconnect safety features. If you can't disconnect the riser before exposure to an unexpected storm or current condition, you may find yourself in a position of remaining connected to the customer's wellhead or losing the riser system altogether. Determining the maximum operating limits of the riser is critical to recovering it to the pipe rack prior to the maximum storm event.

Riser bolted flange designs were considered to be the only viable type design for the 10,000 ft water depth application. It was determined that two primary vendors had existing designs in place with a reasonable confidence that their prior connector product lines could be extended beyond the perceived limit of about 5,000 ft water depth. One development was actually being completed in 1997 for the ultra deepwater application and the other need further design enhancements. The current designs went up to the Type E design which was capable of an API-defined maximum static tension capacity of 2,000,000 lbs. Initial estimates of the 10,000 ft riser system indicated that a 2,400 kips minimum was required. At that point an API Type F connector was included in the request for proposals.

The analysis of a flanged, drilling riser joint should include all the possible loads that could be applied to the riser simultaneously. Those loads are simply:

- Actual Tension at the Support Ring, TSR
- Equivalent tensions from bending
- Equivalent tension from the contents riser
- Pressure end load effects
- Buoyancy effects

By summing the effect of these loads at each joint along the length of the riser a maximum tension capacity of the connector is determined. Leaving out any one of these loads could be catastrophic in the design of ultra-deepwater risers.

Figure 1, is a chart of those loads for a riser with specific buoyancy and specific mud weight, 14 ppg, in 10,000 ft water depth. It can be seen that that the maximum tension occurs at about 6,000 feet below MSL. The connector and its bolting preload needs to be able to accommodate the stresses from this maximum load condition. The flange itself may need to only meet a lower load condition, say 2,400 kips, but the bolts need to accommodate the 3,100 kip equivalent tension. Figure 13 illustrates these effects in 7,500 ft water depth for a higher mud weight.

Von Mises stresses for the pipe body are shown in Figure 2. They are required to be below 2/3 x yield stress of the pipe strength (80 ksi). This design approach may seem simplistic, but the manufacturing of the high strength bolts is difficult and subject to extreme metallurgical scrutiny in the effects from chloride stress corrosion and hydrogen embrittlement at areas of concentrated stress (bolts and thread inserts). These effects are non-trivial in the design of a flanged riser connector.

The primary factor governing riser stability and operability is the angle at the flexjoint above the BOP and wellhead. High angles cause wear, called keyseating inside the flexjoint or riser joints. By keeping the angle at a minimum during normal operations, keyseating can be minimized. Table 2 represents some maximum acceptable mean angles and the maximum stresses along the riser for the 10,000 foot case discussed herein.

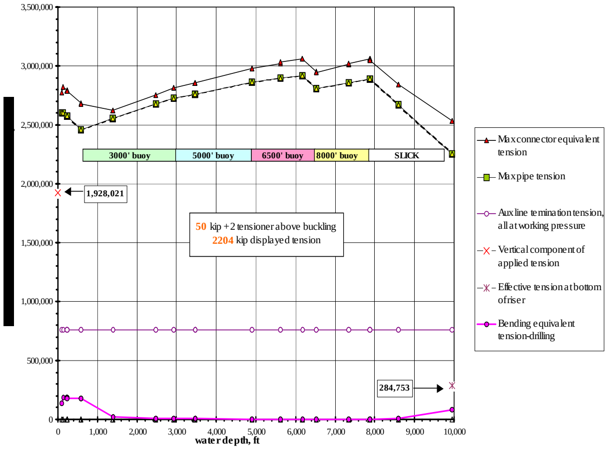


FIGURE 1. Coupling Design Tension Required in 10,000 ft Water Depth-21” Riser

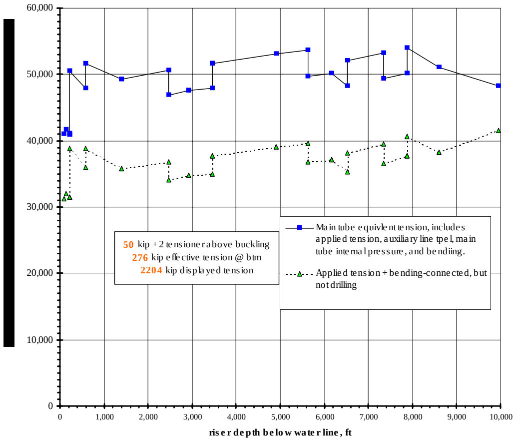


FIGURE 2. Riser Stress Profile in 10,000 ft

Table 2 – Flexjoint Angle and Max. Stress

Storm Condition	Vessel Offset of 2%	
	FJ Angle (deg)	Von Mises Stress (psi)
1-yr	1.5	30,000
10-yr	2.0	50,000

RISER BUOYANCY

Riser buoyancy standards were not given serious consideration by API until the early 1990's. Recurring problems associated with loss of buoyancy due to water ingress and limited outer shell strength resulted in the need for a continuous buoyancy module repair and replacement programs. Standards began to creep into the API Committee 16 drilling riser and design standards, but materially there were no significant changes put forward by the manufacturers until it was apparent that a significant market for buoyancy was about to take off with the deepwater impetus.

Up to this time, buoyancy module lengths were limited by the size of the manufacturers' ovens. Depth ratings for standard syntactic glass foam composite materials were not fully developed for drilling riser buoyancy beyond about 5,000 ft.

About 15 feet was the maximum length module that could be produced by industry. In one design effort, it was determined that the additional weight of the buoyancy clamping and other accessories was too much of a weight penalty on the already overloaded, 90 foot long riser joints. Additional weight would adversely impact the capacity of the API Type F (2.5 Million Lb) rated riser connector and it was too late to qualify a new design to a type G or H rating without increasing project schedule and missing the drilling contract date.

A buoyancy vendor put forward a proposal to build a new plant in the US that could produce 21 foot long modules at a production rate that would meet the current schedule for the first rig and two subsequent rigs. Both parties were taking a risk, but proceeded with a contract nonetheless. The vendor leased a site and ordered equipment to construct a higher capacity facility similar to their main plant in Europe. They implemented improvements in macrosphere dimensional tolerances, syntactic material batching processes and quality control.

Critical design issues included bending strength of the longer modules during handling of the 90 foot long joints. Joints were positioned on the riser joint in an arrangement that would minimize the bending stresses on any individual module. The vendor performed an FEA analysis confirming the strength along the principal axis was sufficient, with utilization factors of only about 50% based a 2 ft deflection at the riser midpoint. The out-of-plane axis is somewhat weaker. Handling the joints was specified by a field procedure with specific orientation during pickup. Overstressing modules was solved by adding a 12" flat section to the normally round buoyancy module and riser lifting pins designed for insertion in the flange bolt holes. A secondary advantage was that the flat allowed more compact stacking of riser joints and improved safety during handling by preventing the joint from rolling during pickup.

Another critical issue was stress concentrations at "cutouts" to accommodate clamping mechanisms. There were some fracture mechanics type failures on shorter modules at these high stress concentration areas. These type failures are best prevented in the design by strengthening these areas and keeping them out of the clamping load path.

With regard to quality control and manufacturing standards, end users were at the mercy of the buoyancy vendors. Reliance on their integrity, design practices and experience were paramount in the success of the project. Some assurances, like testing, were not met by some of the vendors because of schedule and availability of suitably sized hyperbaric chambers. Customers relied on batch sample test blocks to assure material qualifications, but these were considered only grossly representative of the overall module behavior and lift capacity. The proof of the overall buoyancy design would not be known exactly until the riser was on the hook and in the water, at depth.

A larger weather window of for running and retrieving operations can be achieved where the buoyancy requirements are better understood early in the design. Using smaller diameter modules that provide smaller incremental changes in total lift distributed along the total length of the riser may be desirable.

DEEPWATER RISER PERFORMANCE PREDICTION VS. FIELD EXPERIENCE

A key aspect in the NGDR's development was to develop a workable design within the given limitations of the current technology and manufacturing infrastructure that remained after such a long downturn.

The state-of-the-art in numerical performance prediction of risers had not significantly matured over the previous decade, and non-linear coupled time domain analysis methods and VIV prediction tools were still too immature to handle the coupled dynamic responses. The designers relied on static modeling and field experience to prepare a functional riser geometry followed by frequency domain analysis to obtain an outline specification. The riser manufacturer prepared a time-domain analysis to verify that the specified design was indeed feasible.

DYNAMIC POSITIONING AND RISER DESIGN

DP drilling vessels have special design considerations such as allowable time to disconnect the riser in an emergency caused by excessive vessel excursions or loss of stationkeeping commonly referred to as "drift-off." To prevent a catastrophic failure of the riser system an Emergency Disconnect System, EDS, is required. The EDS needs to be capable of performing a fixed sequence of control functions at the LMRP on the seafloor prior to releasing the riser from the wellhead.

DP time domain analysis of a drillship was performed to evaluate the time that is considered reasonable to react to a drift-off or drive-off event. The environments considered are shown in Table 4. The critical angles for both lower flexjoint and telescopic joint were analyzed for a range of offset conditions. The time to drift-off within the allowable riser angle watch circle was then related to those maximum allowable angles.

Risers deployed in shallower water have less time to disconnect than deepwater well drilling because offset limits and riser angle have a one to one correspondence as a percentage of water depth. The time allowed for a controlled riser disconnect is also driven by the nature of the DP event. For a drift-off, more time margin is allowed than in a drive-off condition where the control system thinks the vessel location is somewhere other than over the well. Drive-off events are not typically included in any DP risk scenarios because they fall outside the risk probabilities with DP II or DP III classifications being required for deepwater drilling rigs. A computer analysis and simulation of the time allowed for a drive-off however as a worst case event is reasonable and is used for checking maximum EDS timed sequence limits.

An EDS sequence of events prior to disconnect would be as follows:

a) Close all side outlet valves, shutdown mud pumps;
b) Pick pipe up off bottom for preparation to hang off;
c) Close pipe rams;
d) Hang off pipe, balance pipe load for neutral weight shear to avoid main block recoil;
e) Lock pipe rams;
f) Close shearing rams (may also be sealing shear/blind rams);
g) Pick up pipe;
h) Close blind rams, if different from shear rams;
i) Lock blind rams;
j) Vent all pod to stack pressure connections;
k) Vent LMRP annular preventer(s);
l) Unlatch LMRP connections, main connector, mini connectors, if fitted;
m) Activate riser recoil system.

All of the above must be completed prior to reaching the offset limits of the riser. Offset limits can be governed by impact of the slipjoint with the moonpool structure, or angular limits of the flexjoint at the wellhead. EDS's have been designed for deepwater risers with the foregoing functions taking place in between 30 sec to 150 sec depending upon the drilling condition at that moment and sequence selected by the driller. Table 3 summaries the computer simulated times for a shallow water drift-off event and a deepwater drift-off event. The driller may have up to three EDS scenarios that he may select from and he should know at all times during his tour which scenario is in effect and have it pre-selected on his EDS control panel. Figures 14, 15 and 16 illustrate the relationship between maximum offset limits, riser angles and time to reach those limits.

Other factors that should be considered in designing and EDS control system interface include:

a) Shearing and sealing the well bore may be accomplished by a lower stack mounted auto shear accumulator circuit, allowing earlier release of the LMRP from the stack.

b) Different tubulars and well operations may require multiple disconnect options, and potentially different timing requirements.

c) Rapidly developing emergency situations may require shortening or deleting some steps. For example, first choice may be to have the main control system shear pipe and seal the well bore. However, if a rapidly developing stationkeeping emergency requires riser disconnect this step is bypassed and an auto shear circuit completes the pipe shear and well bore sealing.

		Wave	*Wind*	*Current*
Environment Direction(s)	*Hs*	*Tmean*	*1 hour*	*Velocity*
	m	*sec*	*kts*	*kts*
10 year Winter Storm	5.8	8.2	42.7	1.2
1-year Typical Storm	4.6	7.1	35.5	0.7
1-year Winter Storm+10 Yr Loop Current	5.0	7.2	29.0	2.7

TABLE 3 DP EDS TIME LIMITS

		Wave	*Wind*	*Current*
Environment Direction(s)	*Hs*	*Tmean*	*1 hour*	*Velocity*
	m	*sec*	*kts*	*kts*
10 year Winter Storm	5.8	8.2	42.7	1.2
1-year Typical Storm	4.6	7.1	35.5	0.7
1-year Winter Storm+10 Yr Loop Current	5.0	7.2	29.0	2.7

TABLE 4 DP STUDY ENVIRONMENTS

PRESSURE END LOAD, PEL

There is a significant tensile load in a working riser system that has largely been ignored in most riser analysis. This tensile load is the pressure end load from the auxiliary lines, the auxiliary line connection seal diameter area times the pressure in the auxiliary line. Note that the axial tension is generated by the seal diameter area, not the ID area of the pipe, as in most conventional piping applications. This result in both a tension and a moment added to the top of the riser below the tension support ring of the telescopic joint. Also, there is an equal but opposite balancing reaction at the flexjoint terminations above the flex element body.

Why is this pressure end load tension commonly overlooked in the design of deepwater drilling risers?

The tensile loading of the riser joint is not carried above the gooseneck attachments on the telescopic joint outer barrel, nor below the kick-out subs in the flexjoint auxiliary line termination. It does not affect the loads on the drilling rig or the BOP stack below the flexjoint auxiliary line termination. PEL is strictly internal to the riser system and does not impact the minimum tension required for riser stability because the riser is required to remain stable even if the auxiliary lines are not pressurized.

Early riser systems had smaller lines and lower pressures. The resulting loads were smaller and the loads were a smaller percentage of the total riser tension capacity.

When examining a joint of riser in the middle of a riser string, it appears that the tension at the top connection is equal to the tension at the bottom connection plus the wet weight of the riser joint. If the joint is neutrally buoyant, the tension is the same at the top and bottom connection.

GAS HANDLER SYSTEM IMPACT ON DEEPWATER VESSEL AND RISER [REF 2]

The application of pressurized riser system including limited surface containment devices is worthy of consideration in ultra deepwater designs and has been incorporated into at least one ultra deepwater rig design. Refer to the Figure 5 schematic. The potential benefits in safety mitigating the risk associated with gas in the riser are compared against the design impacts on both the riser and overall vessel design.

The basic functional premise for a gas handler riser system is to provide an alternate to the conventional floating rig diverter system for handling gas past the BOP stack, by reducing the volume of mud displaced (lost) from the riser. This is accomplished by keeping the gas pressure significantly higher than atmospheric pressure. This system is sized to operate at a maximum pressure of 1,500 psi. The flow sizing is nominally sized for 1,400 psi to allow some pressure fluctuations while controlling the flow with the dedicated gas handler choke. The nominal volume difference is almost 100 to one for the gas between one atmosphere and 1,400 psi.

Comparison table for diverter riser system upgraded to gas handler riser system		**Diverter**		**Gas handler**	**added for Gas handler**
riser data:					
rated coupling separating load, lbf		3,000,000		3,500,000	
equivalent tension required for connector, by analysis		2,910,507		3,475,468	564,961
main tube, wall (in), jt qty (no.)	0.875	16	1.000	31	
	0.688	81	0.813	66	
equivalent tension for pipe		2,562,586		3,063,114	500,528
actual tension in pipe, no bending		2,378,650		2,878,201	499,550
pressure in main tube at surface, psi		500		1,500	1,000
lbm steel		3,035,108		3,359,775	324,668
lbm buoyancy		1,874,643		2,066,868	192,225
lbm riser joints		4,909,751		5,426,643	516,893
total subsea equipment variable deck load, including riser, lbm		5,619,431		6,200,323	580,893
mud in riser					
bbl	4,228		4,154		
ppg	15		15		
lbm		2,595,091		2,540,860	-54,231
Tension, displayed, lbf		2,192,201		2,311,131	118,930
effective tension @ btm, lbf		381,265		400,096	18,831
riser weight in water, lbf		543,208		657,312	114,103
mud weight in water, lbf		1,158,118		1,138,167	-19,950
BUCKLING TENS: wet riser wt + mud (no added main tube pressure)		1,701,326		1,795,479	94,153
rig gravity acceleration allowed		0.098		0.098	0
vertical tension above buckling (eff. Tens @ btm)		381,265		400,096	18,831
displayed tension to avoid buckling, with loss of tensioners		2,149,043		2,267,973	118,930
tensioner efficiency, %	95%		95%		
max allowable hook load		1,404,000		1,404,000	0
RISER TENS.(LMRP liftoff +50kip)		808,429		922,532	114,103
LMRP TO BOP LANDING WT		758,429		872,532	114,103
BOP TO WHD LANDING WT		1,026,650		1,140,753	114,103
MAX HANGING WT		1,026,650		1,140,753	114,103
MIN HANGING WT		215,221		215,221	0

Table 4 Riser Gas Handler Riser Data

Table 4 represents the tension impact of the gas handler versus using the diverter for handling gas in the riser. For the design case analyzed here, a 9,000 ft. deep riser full of 15 ppg mud has a "bottom hole pressure" of about 7030 psia. The riser cannot withstand the full brunt of this pressure rise, so the pressure is bled of through a choke line exiting the riser just below the gas handler annular element, located just below the slip joint. The riser design for this system is 1500 psi above mud to sea water gradient. The intent is to keep the pressure rise near 1400 psi without exceeding 1400 psi. A choke operator monitors the riser pressure continuously while the riser is closed in, and adjusts the choke accordingly.

To keep from having the gas handler from having to add the hydraulic conduit plus two choke/kill lines including a mud boost line, a special auxiliary line termination joint was constructed; refer to Figures 5, 6 and 8. The added lines on the gas handler would have been greater than 60" and would not pass through the rotary table.

RIG AND RISER ABANDONMENT STRATEGIES

An on-going dilemma is what condition should the riser be in when a hurricane approaches and can the DP vessel transit with the riser in a hang-off position? A plan of action is needed for riser hang-off in rough seas or high-current condition. It was decided that a means for centralizing the riser in the drillship moonpool was necessary. The designers' solution was to develop a hydraulic capturing device below main deck in the moonpool. Refer to Figure 10, a Bardex customized centralizer. Ideally, the device should be above the water level for maintenance reasons, but the drillship hull/moonpool structural configuration had been decided much earlier in the project and did not allow for a centralizer. In the end, the centralizer was mounted just below the operating draft level of the vessel.

The primary design environment for the disconnected riser and thereby the centralizer was a Loop Current event. Two primary design questions arise. With a 10-Year loop current, can the centralizer hold the riser and telescopic joint in place after an emergency disconnect? Secondly, a related design issue is to determine what speed the ship can transit at with the riser in a hang-off condition.

In an emergency disconnect there is no time to pull the slip joint, therefore the centralizer must capture the slip joint and restrain the riser to prevent catastrophic impact with the moonpool. The slipjoint is designed with a protective can around the auxiliary lines for protection from the centralizer arms after full closure. Refer to Figures 8 and 10 for a sketch and photos of the equipment.

In a controlled disconnect with time allowed for pulling the slipjoint and intermediate flexjoint the riser can be pulled until a point is reached when the sea conditions no longer permit handling the riser joints. At that point a hang-off joint with a flexjoint is attached to the last joint and lowered into the moonpool. At that point the centralizer is actuated and closed around the hang-off joint that has a 48” OD that is compatible with the closure formed by the centralizer fingers.

LESSONS LEARNED AND DEEPWATER RISER DESIGN GUIDEANCE NOTES

The following lessons learned were reached from the New Generation Deepwater Riser design development and a few years of deepwater riser operations for the risers addressed in this paper:

- The requirement for a new generation of deepwater drilling risers pushed the limits of the available technology that was stagnant for more than a decade.

- Accurate prediction of riser performance and tension requirements is necessary to prevent over stressing or under tensioning the riser.

- Deepwater buoyancy design, testing and fabrication methods need industry standardization.

- Mud density, mud volume, wet weight of the riser, and pressure end loads are primary drivers for riser connector design ratings

- Riser design and manufacturing standards need to be more prescriptive.

- Riser design methods used on shallower risers can be applied to the new generation of deepwater risers, but more stringent standards for fatigue and welding procedures need to be developed.

- Handling high-pressures from gas intrusion in the riser is feasible, but the impact on the riser design, rig payloads, increased cost and operations is significant.

- For 10,000 ft water depth ratings, API 16Q, Type 'F' connectors (2,500 kip rating) are limited about a 15 ppg mud density. Type 'G" (3,500 kips) connectors have a higher mud density capability.

- For adding riser tension in deepwater, it's cheaper, pound-for-pound to add buoyancy than additional hydro-pneumatic tensioning equipment.

- Length limitation of buoyancy modules is controlled by allowable bending stress, not manufacturer's oven length. Additional module length can reduce overall weight of long riser joints.

- Syntactic foam is actually fairly brittle stuff, and controlling stress concentration factors around clamp access holes and riser auxiliary line cutouts is paramount

- Longer riser strings are typically less buoyant than shorter strings, because the concentrated weight at the bottom (LMRP or LMRP+BOP stack) is a smaller percentage of the wet weight to effective mass ratio. This ratio, expressed in terms of 'g' force, is a primary consideration for disconnecting the riser in severe weather and compressive heave buckling avoidance.

- Removing buoyancy at the bottom to enhance the 'g' force acceleration ratio has a threshold which is limited by hookload capacity of the rig. The more 'g' force safety factor, the more weight added to the bottom of the riser. As a result, deepwater risers require significantly more hookload capacity to be disconnected safely.

Figure 5 Riser Gas Handler Schematic

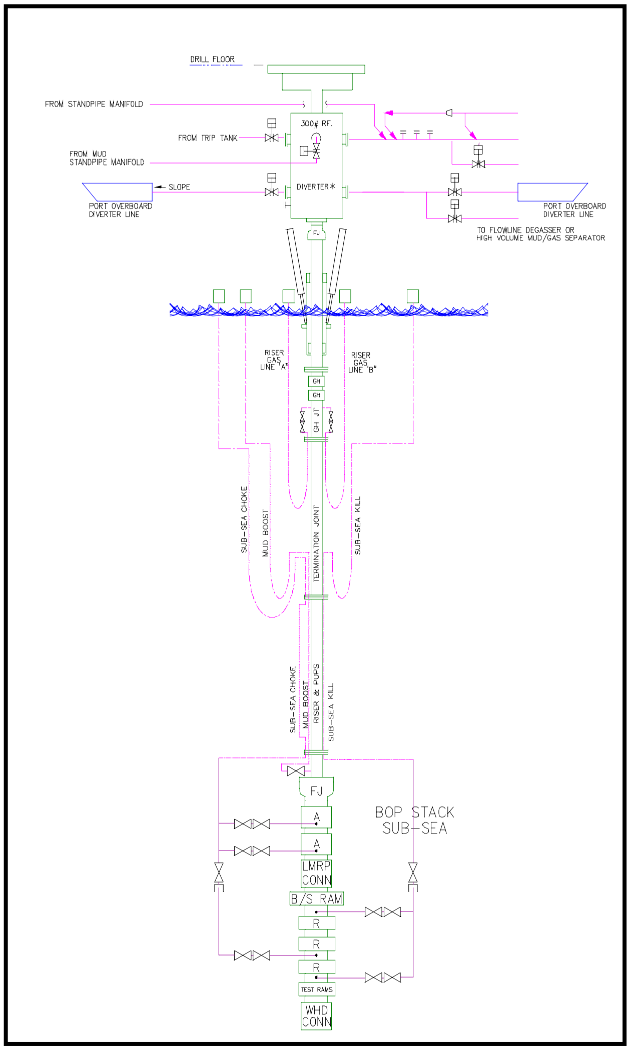
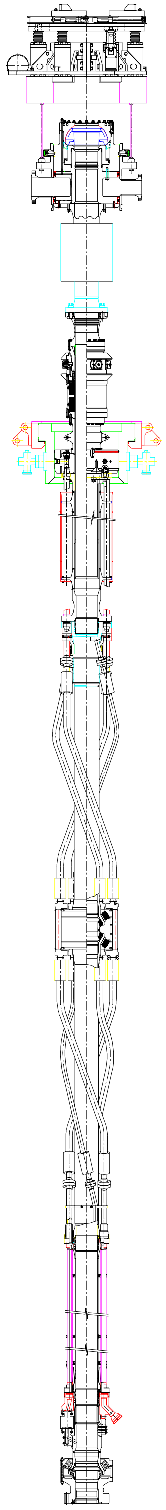


Figure 6 Riser System Drawing



21" HMF RISER SYSTEM – DRILLING MODE
CLASS 'F' – 2.50 MILLION LB CAPACITY

About the authors …

Steve W. Bernard is a Principal Engineer at Antares Offshore LLC, in Houston, Texas. His areas of expertise are in project engineering and management of production and drilling risers, subsea and marine construction planning, drilling operations engineering, and mooring system design. He has over 25 years offshore experience. He has a BS in ocean engineering from Florida Atlantic University, and an MS in Environmental Management from the University of Houston. Mr. Bernard is a Registered Professional Engineer in Texas. He has worked in the drilling industry for Sedco, Inc. and Zapata-Arethusa Offshore Company. At the time of the development of these deepwater riser systems, Mr. Bernard was President of Wescott Enterprises, Inc., Houston, Texas.

Robert H. Taylor is a Senior Subsea Engineer for Pride International, Inc., in Houston Texas. He is responsible for the analysis and engineering support of Pride’s fleet of subsea and drilling equipment. Mr. Taylor has over 28 years offshore experience. His experience includes positions with Zapata Offshore Company, Cameron Oil Tools and Wescott Enterprises, Inc.

Thomas A. Fraser is Director of Research and Development for Vetco Gray, Inc., in Houston, Texas. Mr. Fraser has worked for Vetco dating back to the time when the company was located in Ventura, California in 1980. He has been involved solely in the design and manufacturing of drilling risers systems since those early days with Vetco.

FIGURE 7. Riser Gas Handler

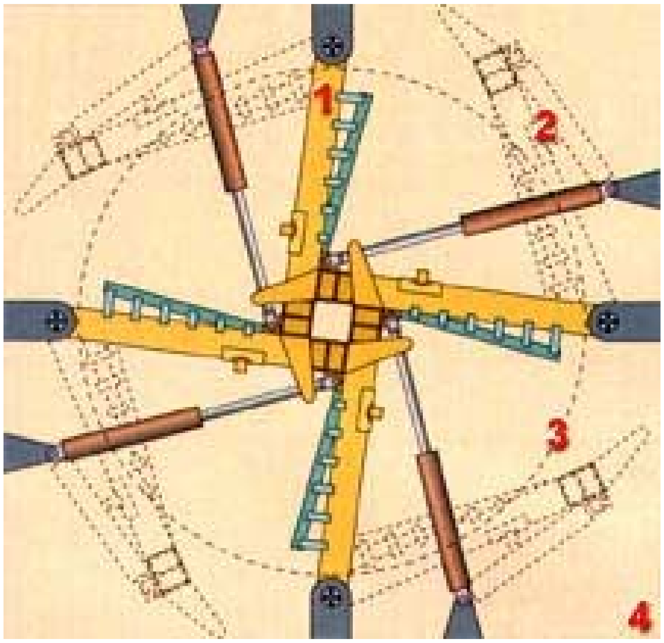


FIGURE 8. Riser Centralizer (Courtesy of Bardex)

Figure 9. Riser Joints and Termination Joint

Figure 10. Telescopic Joint

Figure 11. Riser in Moonpool

Figure 12. 5,500 HP Thruster

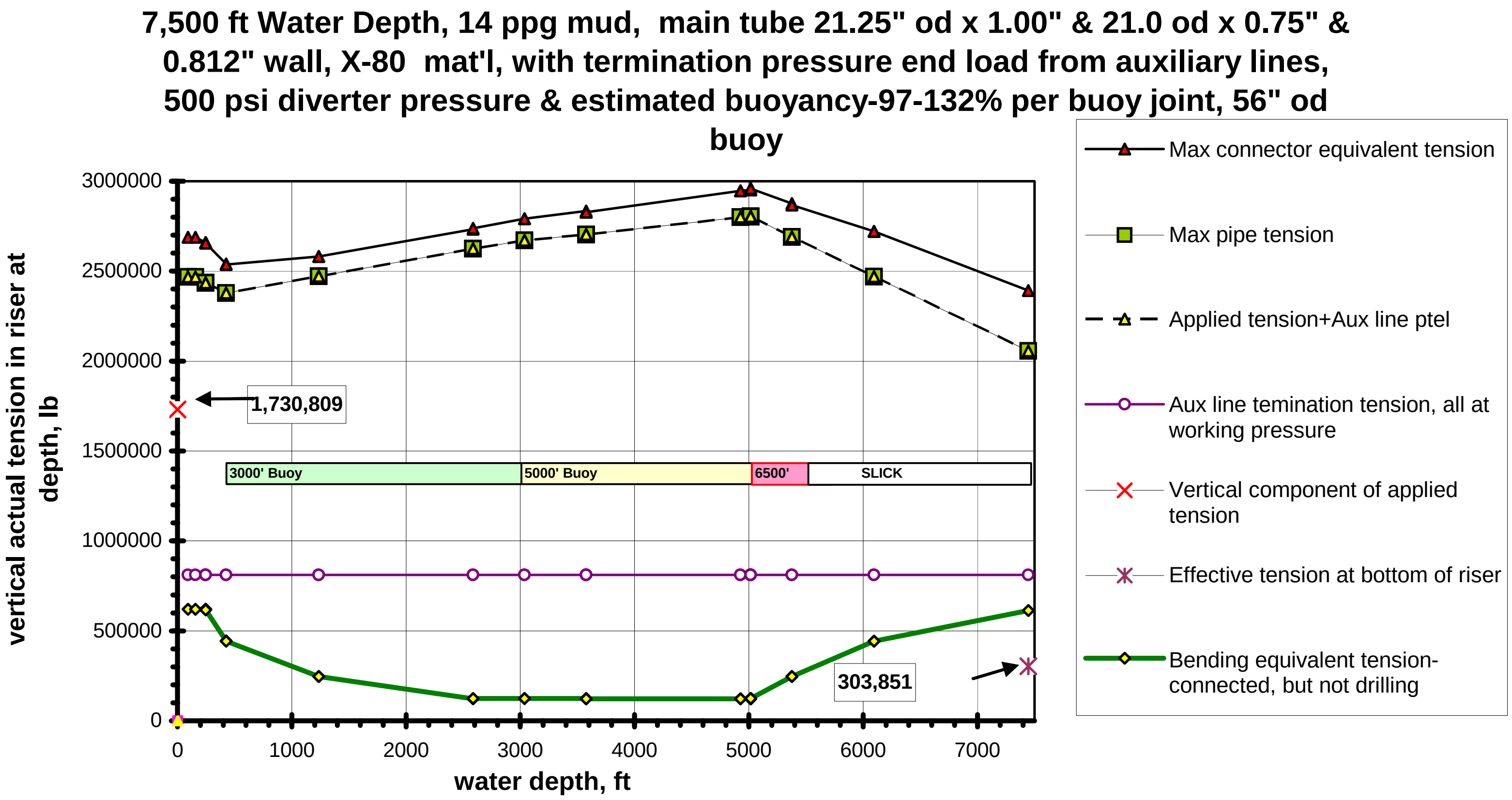


FIGURE 13. Riser Combined Tension vs. Depth along Riser

FIGURE 14.

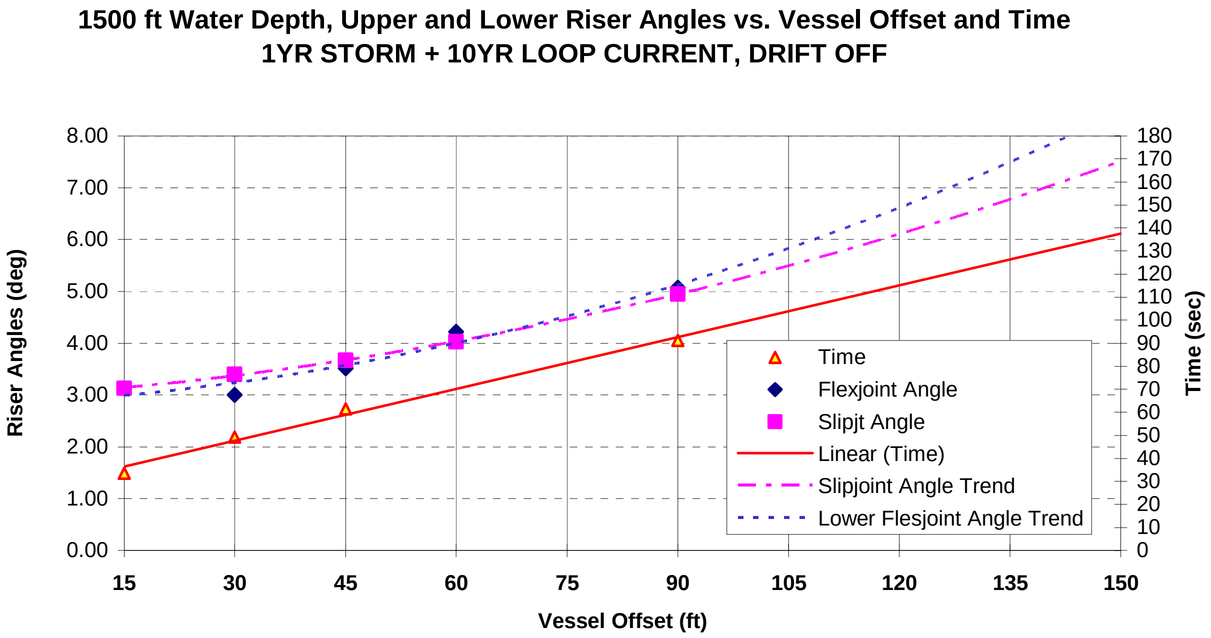

1500 ft Water Depth, Upper and Lower Riser Angles vs. Vessel Offset and Time
1YR STORM + 10YR LOOP CURRENT, DRIFT OFF
Riser Angles (deg)
8.00
7.00
6.00
5.00
4.00
3.00
2.00
1.00
0.00
Time (sec)
180
170
160
150
140
130
120
110
100
90
80
70
60
50
40
30
20
10
0
15
30
45
60
75
90
105
120
135
150
Vessel Offset (ft)
Time
Flexjoint Angle
Slipjt Angle
Linear (Time)
Slipjoint Angle Trend
Lower Flesjoint Angle Trend

FIGURE 15.

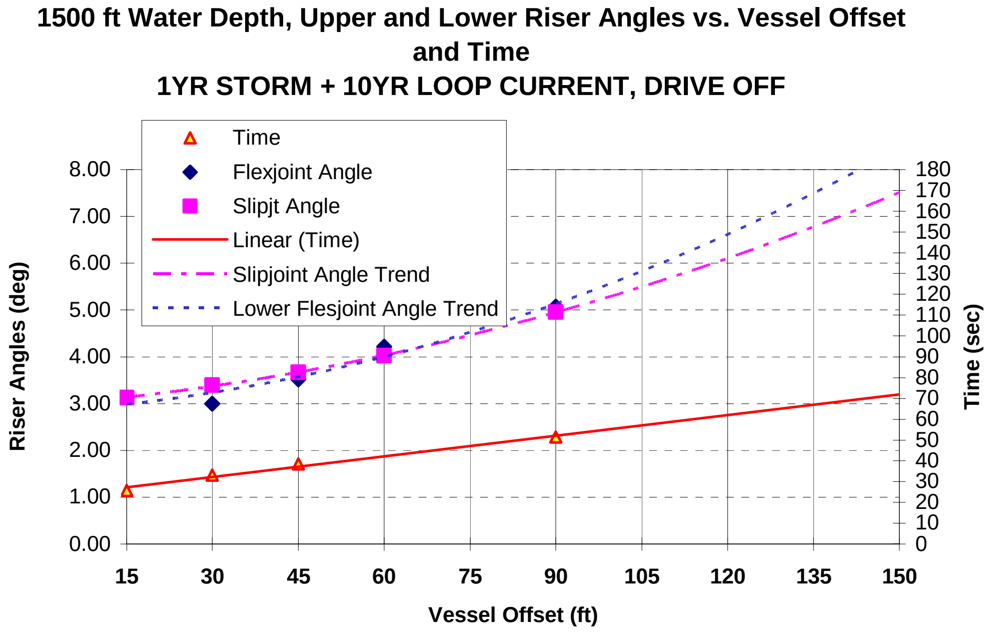
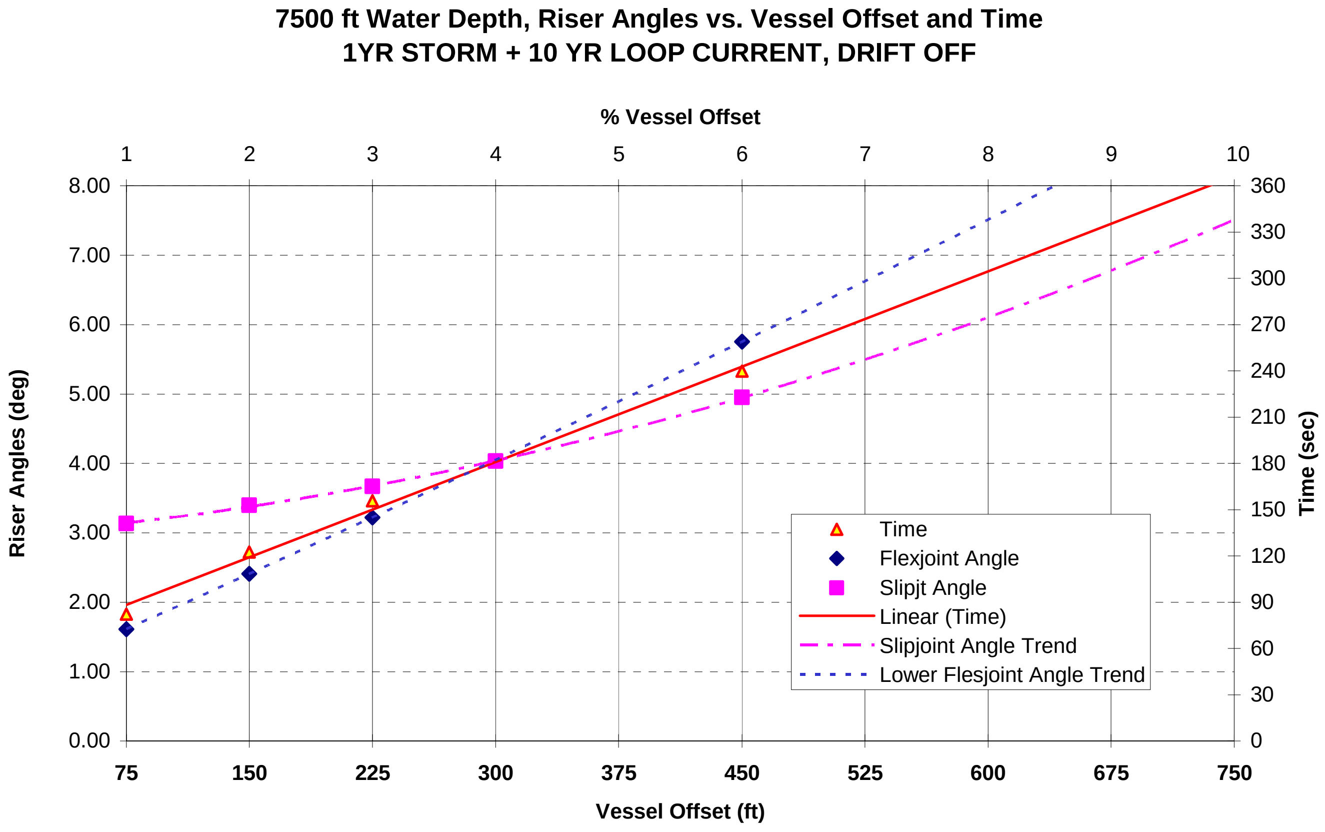

1500 ft Water Depth, Upper and Lower Riser Angles vs. Vessel Offset and Time
1YR STORM + 10YR LOOP CURRENT, DRIVE OFF
Time
Flexjoint Angle
Slipjt Angle
Linear (Time)
Slipjoint Angle Trend
Lower Flesjoint Angle Trend
Riser Angles (deg)
8.00
7.00
6.00
5.00
4.00
3.00
2.00
1.00
0.00
Time (sec)
180
170
160
150
140
130
120
110
100
90
80
70
60
50
40
30
20
10
0
15
30
45
60
75
90
105
120
135
150
Vessel Offset (ft)

FIGURE 16.


7500 ft Water Depth, Riser Angles vs. Vessel Offset and Time
1YR STORM + 10 YR LOOP CURRENT, DRIFT OFF
% Vessel Offset
1
2
3
4
5
6
7
8
9
10
Riser Angles (deg)
8.00
7.00
6.00
5.00
4.00
3.00
2.00
1.00
0.00
Time (sec)
360
330
300
270
240
210
180
150
120
90
60
30
0
Time
Flexjoint Angle
Slipjt Angle
Linear (Time)
Slipjoint Angle Trend
Lower Flesjoint Angle Trend
75
150
225
300
375
450
525
600
675
750
Vessel Offset (ft)

GLOSSARY OF TERMS

Slipjoint	The telescoping riser joint that compensates for vessel motion
TSR	**T**ension at the telescopic joint **S**upport **R**ing attached to Slipjoint
Flexjoint	An articulating rubber/steel composite technology spherical ball joint
Indicated Tension	The tension readings at the riser control panel
LMRP	Lower Marine Riser Package
Drift-off	Loss of stationkeeping following a total loss of power to DP system.
Drive-off	Loss of stationkeeping following a spurious DP system command to drive the vessel off the well location
Keyseating	Excessive wear of the drillpipe while rotating inside the riser

REFERENCES

Reference 1: R. H. Taylor, Deepwater Riser System Management Forum, League City, Texas, 14 June 2000

These referenced papers were valuable in understanding the development of the riser gas handling system:
Reference 2: Hall, Eugene, et. al., “Means for Handling Gas Influx in a Marine Riser”, IADC/SPE 14739, 1986
Reference 3: Johnson, et. al., “Gas Migration: Fast, Slow, or Stopped”, IADC/SPE 29342, 1995