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I may be hard for those with no direct experience of the offshore industry to fully grasp the complexity and technical sophistication of what must take place to extract the world's much needed energy resources from deep within the earth's crust, under thousands of feet of water. As the drill rig operators place orders for additional deepwater units, it is worth reflecting on why these drillships carry a price tag of somewhere between one half and three quarters of a billion dollars each.

They must be able to maintain station with a high degree of accuracy in virtually any and all weather conditions in 10,000 feet or more of water. They must be able to drop a drill string through this nearly two miles of water in the exact spot as predetermined by extraordinarily sophisticated seismic surveys. They must then establish a well head on the sea floor, with the initial casing extending some 1,500 feet into the earth. From this base, they will continue to drill almost another seven miles into the earth's crust to finally intersect with the hoped for pocket of oil. And, most importantly, they must be able to do all of this safely.

That they do so on a daily basis should be a source of pride for all those involved in establishing and maintaining appropriate safety standards. But it also poses the constant challenge of reviewing and re-evaluating those standards to verify their adequacy as the physical and technical boundaries continue to expand.



## COVER:

Safety standards for the offshore industry have been subject to extensive review following the Macondo field incident in 2010. This issue reviews some of the more important actions taken, or under consideration by those who comprise the offshore safety regime, including class.

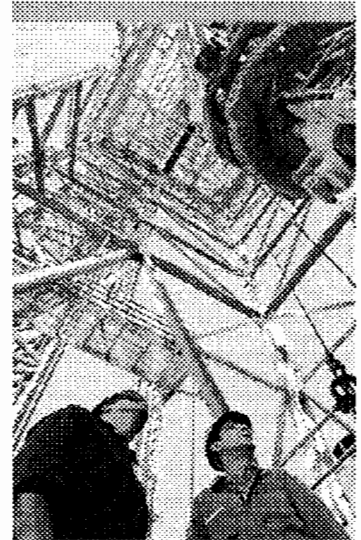
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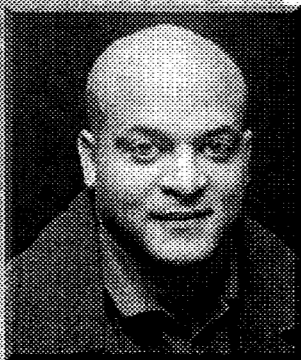
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# What is CDS and Can it Promote



Peter Williams  
Director of Offshore Energy  
Management, Regulation and  
Enforcement (BOEMRE)

*Classification of drilling systems may help offshore operators demonstrate a higher level of safety compliance.*

Following the April 2010 Macondo field incident in the Gulf of Mexico, the US Government imposed a moratorium on offshore drilling and began reexamining the country's offshore safety regime with the intention of identifying areas which could be strengthened. This scrutiny resulted in the replacement of the Minerals Management Service with a new regulatory agency, the Bureau of Offshore Energy Management, Regulation and Enforcement (BOEMRE). Before the moratorium was officially lifted in October, a joint Federal inquiry into the accident by BOEMRE and the US Coast Guard raised questions about the past approach to regulatory oversight of offshore energy projects and brought two new regulations into being: the Offshore Drilling Rule and the Workplace Safety Rule.

BOEMRE ordered that every rig in the Gulf of Mexico must subject a critical piece of drilling safety equipment – the blowout preventer (BOP) – to inspection and certification by a third party, before being allowed to re-commence drilling operations.

The move was seen by many as a first, and important, step towards a more comprehensive approach to offshore regulation. Although the specifics of that approach continue to emerge, there is widespread belief that BOEMRE will adopt some elements from a Safety Case regime – an approach to risk mitigation that is in use in the UK and other areas of the world. The question is if, and if so how, such future regulations will address the role of third-party verification, particularly with respect to the classification of drilling equipment.

A certified drilling system program normally relies on established international standards and industry guidelines that address the design, manufacture and testing of the covered systems and equipment. Such a program fits comfortably within the overall approach of classification, the purpose of which is to establish criteria and verify conformance with an internationally accepted set of standards. ABS, for example, has long offered an optional notation based on the standards contained in the *ABS Guide for the Certification of Drilling Systems*. However, since there has been no mandatory requirement for drilling operators to achieve and maintain certification, adoption of such standards throughout a drilling unit's life cycle has been limited. In spite of this, recently the ABS Guide was substantially updated and expanded and released as the *ABS Guide for the Classification of Drilling Systems* (CDS Guide).

The ABS CDS Guide criteria supplement the *ABS Rules for Building and Classing Mobile Offshore Drilling Units* (MODU Rules), which address the structure and principal machinery, equipment and systems of the rig itself. For the drilling equipment, the CDS Guide incorporates existing standards and practices – for example, in addressing the marine riser system, the CDS Guide specifies that the riser systems and equipment are to be designed and fabricated in accordance with applicable sections of American Petroleum Institute (API) Specification 16F, API Recommended Practice (RP) 16Q and API Specification 16R.





# Drilling Rig Safety?

"The CDS Guide covers the equipment and systems on the cantilever and on the drill floor and the equipment from the crown block to the wellhead: the top-drive, the draw-works, the mud pumps, the circulating system, shakers, agitators, de-gassers and the BOP. It takes a largely comprehensive approach to the drilling and well control system," says Luis Cruz, Principal Engineer with the ABS Offshore Technology department.

"Our requirements are based on the international industry standards – API, ISO, IEEE, IEC and others – and, as applicable, refer also to the ABS MODU Rules and IMO standards," he explains. "Issuance of the CDS notation says the individual pieces of the system have been evaluated and found in compliance with the standards, the system integration has been assessed for functionality and that the safety systems and the interlocks have been verified. Application of the system and its parts is up to the operator – in other words, responsibility for the actual drilling operation is outside the scope of the classification."

## Advantages of a CDS Program

Cruz was directly involved in drilling operations for 16 years before joining ABS. He started out as a roughneck and worked his way up the chain to project manager and, after graduation with a degree in Chemical Engineering, drilling engineer. As a drilling engineer on the North Slope of Alaska, he designed well plans, casing plans and managed operations.

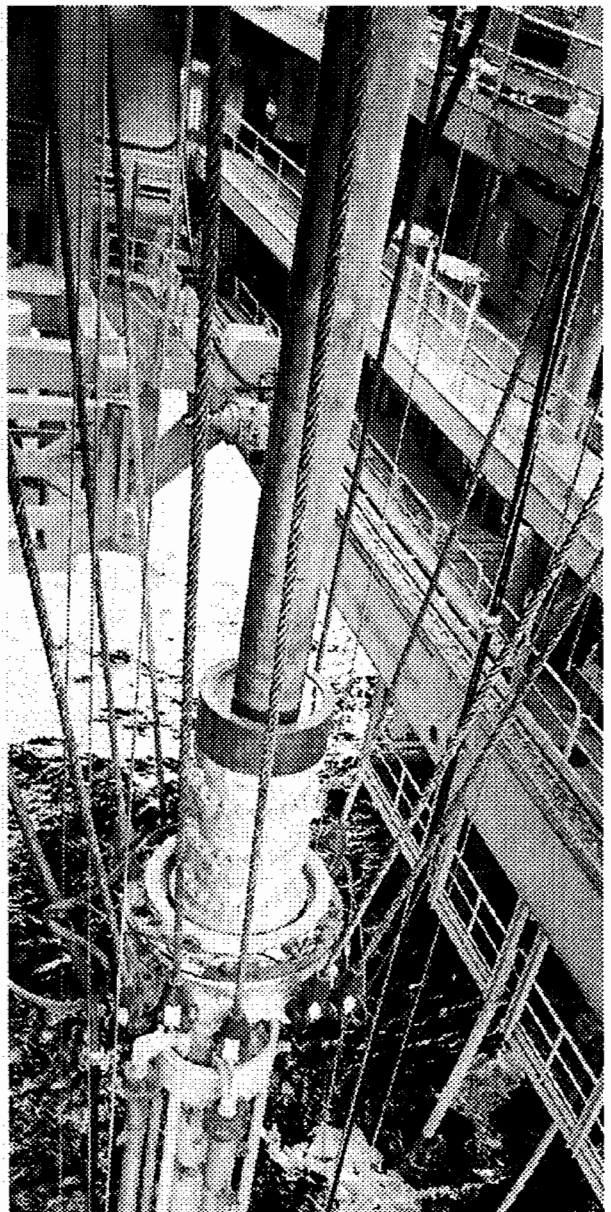
Offshore drilling contractors have come to recognize CDS as a standard to be applied during rig construction. One reason contractors order CDS for newbuildings is to present the builder with a clear standard and to use the services of ABS to verify that the drilling systems and equipment conform to the standard, in a similar manner to the classification of the unit itself. Recognizing this appeal is as a construction standard, a focus of the March 2011 update to the CDS Guide was to enhance the value added by CDS throughout the life of a drilling unit. Although regulatory schemes are still in flux, implementing and maintaining CDS

throughout a rig's life cycle can help to reduce additional regulatory burdens.

CDS would also fit within any future energy company developed quality standard to which their drilling contractors would be required to demonstrate adherence – a standard akin to the Tanker Management Self-Assessment (TMSA) scheme for tanker operators. Introduced by the majors in the energy sector in 2004, TMSA is recognized for having spurred further safety and quality improvements in the tanker sector.

"Oil companies have implemented specifications for rigs that they contract. In recent years, these rig specs have become tougher and contain very high criteria," says Cruz. "CDS fits well with the rig specs already in use by major oil companies and can be used as a means to demonstrate compliance with them."

There are some other very good reasons for a driller maintaining a rig's CDS notation on a strictly voluntary basis. "A rig with the latest class certificates is more marketable. It's an investment," Cruz believes. "Drilling can be a very demanding activity. Every single day the lives on board the rig depend on the safety of the equipment and the effectiveness of the operational standards and systems in use. For that reason there can be a very real incentive for a rig owner to voluntarily maintain a CDS," he says. "It is an effective risk mitigation tool that provides an additional level of protection for life and the environment." ♦



# BOEMRE's Drilling Safety Rule

**I**n October 2010, the US Bureau of Ocean Energy Management, Regulation and Enforcement (BOEMRE) issued new regulations on drilling safety and workplace safety.

The Drilling Safety Rule addresses numerous regulations related to well control including: subsea and surface blowout preventers (BOPs); well casing and cementing; secondary intervention; unplanned disconnects; record-keeping; well completion; and well plugging. The drilling safety rule calls for a number of prescriptive, near-term requirements meant to enhance the reliability of well equipment. Additional, longer-term safety measures and performance-based standards are being considered for future implementation.

Highlights of the new rule include:

- New casing installation requirements
- New cementing requirements (incorporating API, RP 65, Part 2, Isolating Potential Flow Zones During Well Construction)
- Required independent, third-party verification of blind-shear ram capability

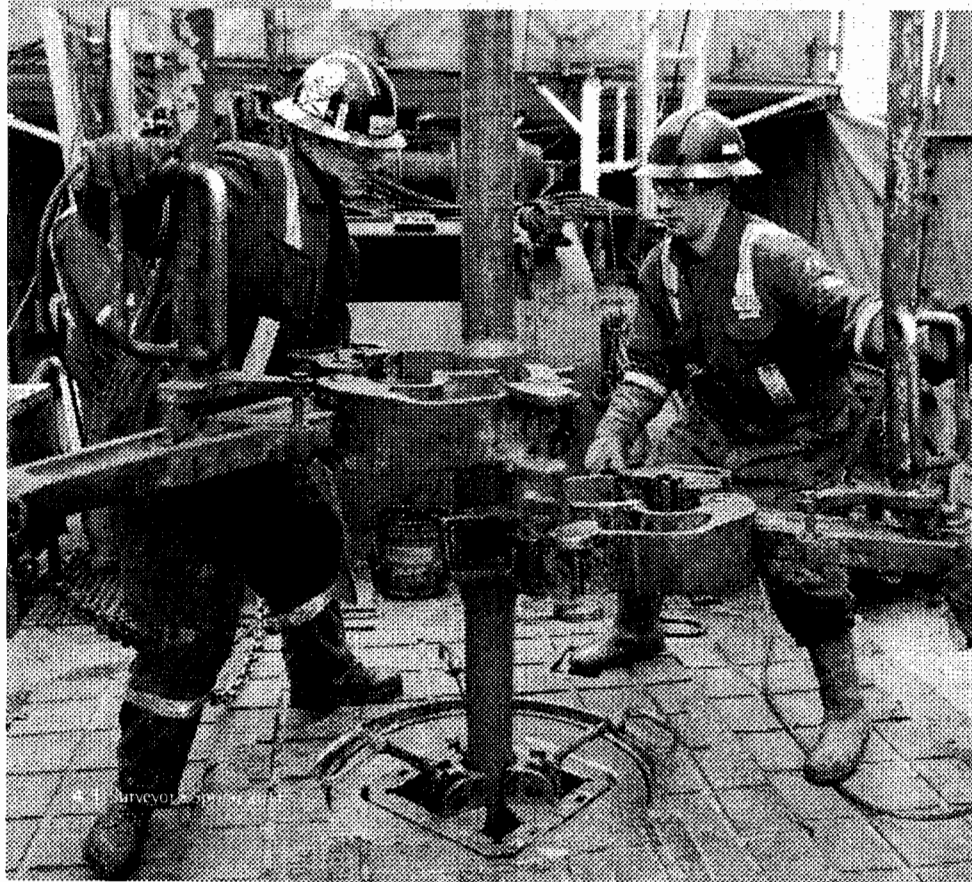
- Required independent, third-party verification of subsea BOP stack compatibility
- New casing and cementing integrity test requirements
- New requirements for subsea secondary BOP intervention
- Required functional testing for subsea secondary BOP Intervention
- Required documentation for BOP inspections and maintenance
- Registered Professional Engineer to certify casing and cementing requirements
- New requirements for specific well control training to include deepwater operations

At the heart of the new safety regulation is the need to better verify the reliability of the various systems employed in deepwater drilling. The rule requires independent, third-party verification that a subsea BOP stack is designed for the specific equipment used on the rig. The third-party must verify that the subsea BOP stack is compatible with the specific well location, well design and well execution plan. Information showing that the shear rams

are appropriate for the project must be included. The third-party must also verify that the subsea BOP stack has not been damaged or compromised from prior service.

The independent, third-party must be a technical classification society; an American Petroleum Institute (API) licensed manufacturing, inspection and/or certification firm; or a licensed professional engineering firm capable of providing the verifications required under this part of the rule. ABS provides classification of offshore drilling systems based on its *Guide for the Classification of Drilling Systems* which incorporates or references the latest industry and international standards. Compliance with the ABS requirements contained in the Guide may lead to the award of the classification notation **✱CDS**.

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# Classification of Drilling Systems: The ABS Guide

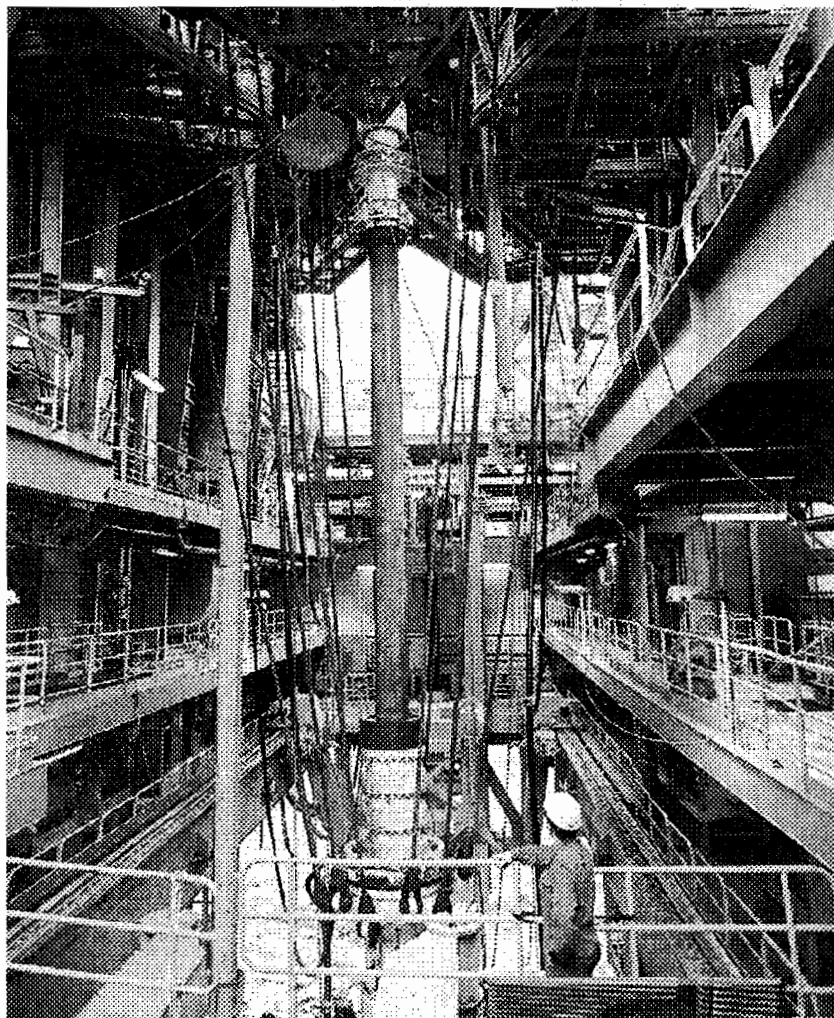
In the wake of the Macondo well incident in the Gulf of Mexico, many governments in whose waters offshore exploration for, and production of, undersea energy resources were taking place began reassessing the effectiveness of their regulatory oversight of such activity. Whether they concluded their existing safety regimes to be sufficiently robust, as in the United Kingdom, or began a series of reforms, as in Kazakhstan, there has been a renewed commitment to promoting the safety of offshore drilling and resource extraction.

As the leading classification society providing services to the offshore sector, ABS has been equally active in reviewing its existing standards and working with the applicable government administrations and industry in pursuit of the same safety and environmental goals. One consequence of this review was that, in March 2011, ABS released the latest edition of its *Guide for the Classification of Drilling Systems (CDS Guide)*.

Representing a significant revision of the society's previous Guide, its enhancements more clearly define the requirements and standards that must be followed for the award of the optional CDS class notation. The enhanced Guide adopts the latest industry best practices and the API recommended practices, and takes into account comments and feedback from industry members including operators, manufacturers and other stakeholders.

"The new Guide represents a step-change in design reviews and Rule requirements, from a component-based approach to a systems-based approach," says Bret Montaruli, ABS Vice President of Offshore Technology. "And we also strengthened the requirements for in-service surveys including verification of maintenance and testing records."

The new Guide takes a comprehensive approach to the drilling system and associated equipment and well control systems 'from the wellhead to the top of the derrick.' Where appropriate it gives clear references to other applicable ABS Rules and Guides, as well as international standards and industry codes. It expands on previous



editions with a section offering explanations, definitions and clarifications of, for example, specialist acronyms, references and industry terminology.

New sections also explain the drilling system classification process – what service ABS provides and what is required of the client during the design review and survey phases. It describes the process for attaining the independent review certificate (IRC) and the certificate of conformity (COC), the two main documents in the CDS program. There is also a walk-through of the classification society's role at the manufacturer, during survey and testing to the ultimate issuance of the ABS class certificate with the CDS notation (A1 MODU CDS). ♦



Bret Montaruli,  
Vice President,  
Offshore Technology,  
ABS



Surveyor talks to ABS Chief Surveyor, Offshore, Dave Forsyth

## On Surveyors and Classification of Drilling Systems



Dave Forsyth,  
Chief Surveyor  
for Offshore,  
ABS

*The classification of drilling systems is an issue that has attracted regulatory attention in recent months as the US offshore safety regime has come under scrutiny. While some classification societies, including ABS, have offered certification of drilling systems as an optional notation to drilling rig operators for many years, its adoption has not been widespread. Recently, the ABS Chief Surveyor for Offshore, Dave Forsyth, sat down with Surveyor to answer a few questions about this program.*

**Surveyor: What does CDS classification by ABS involve?**

**Dave Forsyth:** It follows standard classification procedure: we establish specific criteria in the same way we do with other ABS Rules and Guides. In this case the criteria are contained in either the ABS Rules for Building and Classing Mobile Offshore Drilling Units (MODU Rules) or the new ABS Guide for the Classification of Drilling Systems (CDS Guide), which has replaced the previous Guide for certification of these systems. ABS' criteria are established based on our own technical research, our in-service experience and, where appropriate, input from the relevant committee which would usually reflect the views of industry, academia and relevant regulatory authorities. The criteria also reflect established international standards and industry guidelines.

Our engineers review designs to verify that they satisfy those criteria; our surveyors attend the construction of the systems to verify that it is undertaken in compliance with the approved drawings. Once in service, the surveyors check the maintenance programs, perform annual function tests of the equipment and confirm that it is refurbished every five years.

The MODU Rules cover the vessel and the CDS Guide covers the drilling and well control system. The mud pumps, the choke and kill manifold, the cementing systems, the

draw-works, the lifting gear, the top drive, the diverter, the riser, the blowout preventer (BOP). In essence, CDS classification to class standards addresses the system from the wellhead to the crown block. It's a hazard identification and risk mitigation service that examines the safety-critical elements of the system and verifies its continued compliance with the relevant standards.

**S: In terms of risk mitigation on safety-critical elements, is the offshore industry seeing classification services in a different light?**

**DF:** We've always received good feedback from clients regarding class services at the shipyards and manufacturing facilities where surveyors verify that required standards are met during construction, equipment manufacturing and testing. Many rigs have been, and continue to be, built to ABS class with the CDS notation because it is recognized as a mark of quality.

**S: So the CDS notation addresses the design, construction and maintenance of the relevant equipment. But does it also apply, in any way, to the actual drilling operations?**

**DF:** No. The CDS notation requirements do not touch the drilling program. It takes a highly technical, specially-trained person to even comment on a drilling program, and that's not what the class society's role is. Our job is to certify that the system and individual components comply with appropriate industry standards and the ABS Rules.

**S: But do the operators maintain the CDS notation once the equipment is in service?**

**DF:** That has been a decision that rests solely with the operator as it is not mandatory to get or keep a class society's CDS notation. In our experience, less than 10 percent of the rigs maintain the notation after the first five-year period of currency has expired.

Right now in the Gulf of Mexico, the only mandate is that the BOP and control system are re-certified by a class society or an independent third-party that meets the requirements of the Bureau of Ocean Energy Management, Regulation and Enforcement (BOEMRE). Maintaining an ABS CDS notation provides more robust oversight with



surveyors witnessing and observing equipment in the field during operations.

**S: Do such surveys affect the rig's operation?**

**DF:** They can add extra time, if the driller doesn't plan for them. The BOP, for example, needs to stay on the wellhead when a driller is working. So, any time an operator has to run the BOP up for inspection or survey, is time spent not drilling. For the drillers, time really is money, which is why it is important to properly plan for any class surveys. If an operator has to get a class society surveyor out to the rig to witness a process, it can cost unnecessary time if not properly coordinated.

Maintaining the CDS notation does require regular surveys. It also requires that the equipment be refurbished every five years. Knowing these requirements well in advance should not cause interruptions with a drilling program. The scheduling has some flexibility. For example, a typical drilling program could run from, say, one to 12 months but there is a 15-month window in which the operator can complete the special survey and carry out the required refurbishment. This lets operators mesh their CDS requirements with their drilling schedules.

Operators also have the option of doing risk-based inspections within an approved preventive maintenance program and, in specific cases, they may be permitted to do a test themselves, record the results and then have the surveyor verify the documentation. So, in reality, a CDS notation should not be an operational inconvenience or burden. It is really just one more thing the driller has to plan for. We have clients managing a CDS program without any particular difficulty.

**S: Is this kind of inspection process unusual for this industry?**

**DF:** Not at all. For example, to operate in the North Sea under the UK Health and Safety Executive regime, drillers have to identify all the safety critical elements of their operation in their Safety Case. Because the drilling system is a safety critical element, the driller has to have a verification scheme in place to maintain the Safety Case. Australia, too, requires a Safety Case. Norway requires something similar. Offshore Brazil, you have to meet the Petrobras specification, which is a fairly strict industrial safety standard.

A Safety Case is not currently required for the Gulf of Mexico, but there's a chance the US could follow the example of other offshore

regimes and require one, or something like it. If they do, CDS could go a long way towards demonstrating to authorities that the safety-critical elements of the drilling system have been inspected and verified as conforming to accepted national or international standards.

**S: Are there other operational issues that have become a priority for drilling rig owners and if so, what role does class play?**

**DF:** Drilling rigs are much more sophisticated today than just a decade ago in terms of software and control systems. Class societies verify the systems, offering owners an increased level of confidence in software predictability thereby decreasing downtime.

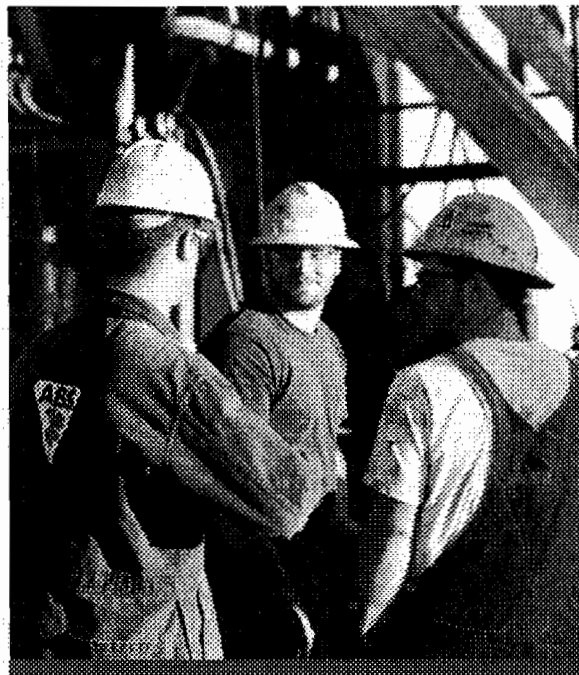
ABS offers two notations for software systems:

- The **SV** notation for system verification confirms that a control system does what it is intended to do and incorporates hardware-in-the-loop (HIL) testing.
- The **ISQM** notation for integrated software quality management provides a process to manage the software throughout the unit's life. The heart of the ISQM process is to identify functions that have the greatest impact on safety, environmental and business operations.

The use of large integrated control systems on offshore units has grown exponentially over the last decade. Many control and power systems are dependent on equipment interfaces run by software, independently verifying these functions has become increasingly important.

**S: What kind of preparation does a surveyor need to inspect drilling equipment?**

**DF:** Most of our surveyors have engineering degrees and valuable industry experience. Some of our surveyors have come to us from the drilling industry and they are very familiar with the equipment. However, prior to doing any surveys, ABS surveyors are required to attend mandatory training, on a continuing education basis, for mobile offshore drilling units and specialized courses on drilling equipment. ♦



# Encouraging a Culture of

Attitude is an important element of workplace safety.

**H**uman error is widely considered to be the proximate cause of most workplace accidents. For minor incidents to escalate to headline-grabbing disasters will usually require the convergence of a multitude of failures, with human error perhaps a contributing element within each. Therefore, it is understandable that government agencies charged with establishing and monitoring workplace safety place comparable importance on an organization's safety management system as on the technical design of fail-safe systems.



Steve Arendt,  
Vice President,  
North American Process  
Industries Sector,  
Organizational  
Performance Assurance,  
ABS Consulting

For example, one factor identified in the official investigations into the 2010 Macondo well failure in the Gulf of Mexico was unclear assignment of responsibilities; in the 1988 loss of the *Piper Alpha* rig, one contributing cause identified by the investigation was a lack of effective communication; in the 2005 explosion at BP's Texas City refinery, investigators found an atmosphere of parsimony, pressure, fear and fatigue had developed at the plant. Such findings inevitably raise the question of whether an effective safety culture was in place and being adhered to.

The term 'safety culture' is high-minded but rather nebulous. How should it be defined? The UK Health and Safety Executive (HSE) uses the following: "The product of the individual and group values, attitudes, competencies and patterns of behavior that determine the commitment to, and the style and proficiency of, an organization's health and safety programs."

Another definition comes from the International Atomic Energy Agency (IAEA): "That assembly of characteristics and attitudes in organizations and individuals which

establishes, as an overriding priority, that safety issues receive the attention warranted by their significance."

But such definitions then raise the question of how an organization should translate these lofty aspirations into easily understood and clearly followed instructions and practices in the workplace. How does 'safety' become part of an organization's DNA, whereby it becomes an inherent factor in every employee's thinking and actions?

Within the US offshore sector, these are questions that have been made tangible for operators of rigs and production units by the US Bureau of Ocean Energy Management, Regulation and Enforcement. The agency issued a new Workplace Safety Rule in late 2010 requiring offshore operators to develop and maintain a Safety and Environmental Management System (SEMS).

"Many facilities use management systems to help control operational risks; whether these systems focus on technological or human-factors issues, all are conducted by people – people whose inherent attitudes about safety can affect the choices they make in operating the management systems and, thus, the overall safety performance of the facility," says Steve Arendt, Vice President, North American Process Industries Sector, Organizational Performance Assurance, with ABS Consulting, an affiliate of ABS. "In terms of incident investigation, safety culture is the root cause of the decade," he says.

Management systems can be very effective tools but, underneath all the paper, all the instructions, all the procedures and all the programs, is a single pillar: commitment. From management the commitment should be to foster a corporate atmosphere in which safety is encouraged and right behavior is rewarded; from labor the commitment is to act in accordance with that atmosphere. And both should then commit wholeheartedly to do what they promise.

Over the last decade in particular, the application of risk-oriented management philosophies and accident investigation techniques have helped bring to light the all-important role of organizational attitudes



# Safety Offshore

in the performance of industrial facilities and the workers within them. The group mentality underlying industrial safety performance was described by Lord Cullen in his investigative report on the Piper Alpha explosion: "It is essential to create a corporate atmosphere or culture in which safety is understood to be, and is accepted as, the number one priority." In some industries, like nuclear power and chemical processing, this has been known for a long time. For the offshore energy sector, safety performance concepts are steadily being pushed from the voluntary into the mandatory requirements column.

"One very important and successful tool in managing risk offshore is the use of standards-based approaches and third-party inspection and verification, like classification services," says Arendt. "Internal to a company is the care and maintenance of facilities through good asset integrity management practices and, regarding personnel, programs geared to improving operating discipline – meaning that managers look for and encourage excellence in people's performance of their duties," says Arendt.

"In this regard, one approach that has proven successful is the use of leading indicators to trend performance and, thereby, help staff keep their eyes on the ball, on the right ball, and act in accordance with these practices," he adds.

A reduction in injury rates or accidents may be seen as a sign that safety programs are working but, for a company to sustain such gains, management must maintain a healthy corporate culture.

"Even if all these things are done, what is most important to sustainable improvement in safety is that the company maintains a sound corporate culture," Arendt stresses. "In the long haul, if you don't have a proper mentality, a proper safety culture, you will find it very difficult to make any of those approaches function and, with time, all your good works will evaporate."

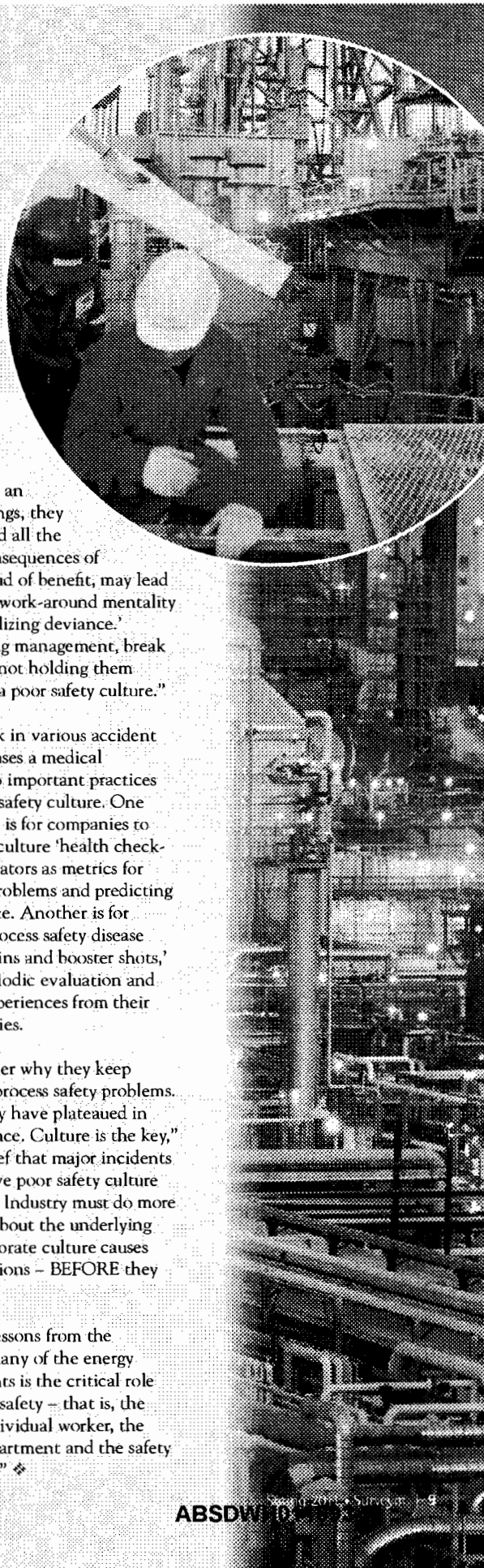
In one way, safety management comes down to a variation on the old adage about the road to perdition being paved with good intentions. "It is human nature to want good but what happens in facilities is that, rather

than following rules or procedures, people start to believe they know the way to generate the right outcome – the outcome their supervisor wants or that they think the company wants. Unfortunately, because they don't have an overarching view of things, they can't see all the risks and all the possible unintended consequences of their actions that, instead of benefit, may lead to disaster. Letting that work-around mentality flourish is called 'normalizing deviance.' Letting people, including management, break rules or procedures and not holding them accountable is a sign of a poor safety culture."

Stemming from his work in various accident investigations, Arendt uses a medical metaphor to suggest two important practices for tuning up corporate safety culture. One needed activity, he says, is for companies to perform periodic safety culture 'health check-ups,' using leading indicators as metrics for diagnosing past safety problems and predicting future safety performance. Another is for the company to take 'process safety disease prevention multi-vitamins and booster shots,' which would be the periodic evaluation and adoption of relevant experiences from their own and related industries.

"Some companies wonder why they keep experiencing the same process safety problems. Others wonder why they have plateaued in process safety performance. Culture is the key," he says. "There is a belief that major incidents in the future will all have poor safety culture as a contributing factor. Industry must do more to equip itself to learn about the underlying organizational and corporate culture causes of major accident situations – BEFORE they happen," Arendt says.

"One of the recurring lessons from the investigations into so many of the energy industry-related incidents is the critical role of culture in workplace safety – that is, the safety culture of the individual worker, the safety culture of his department and the safety culture of the company." ♦



# Guidelines for Improving Offshore Process Safety

**W**ith the issuance of the Workplace Safety Rule by the US Bureau of Ocean Energy Management, Regulation and Enforcement (BOEMRE) in late 2010, offshore operators working in US Federal waters must develop and maintain a Safety and Environmental Management System (SEMS). The rule makes mandatory what most operators have already followed on a voluntary, good business practice basis. Even so, the essence of any effective SEMS is the concept of continual improvement by which an organization should review, amend and update its SEMS to increase its effectiveness.

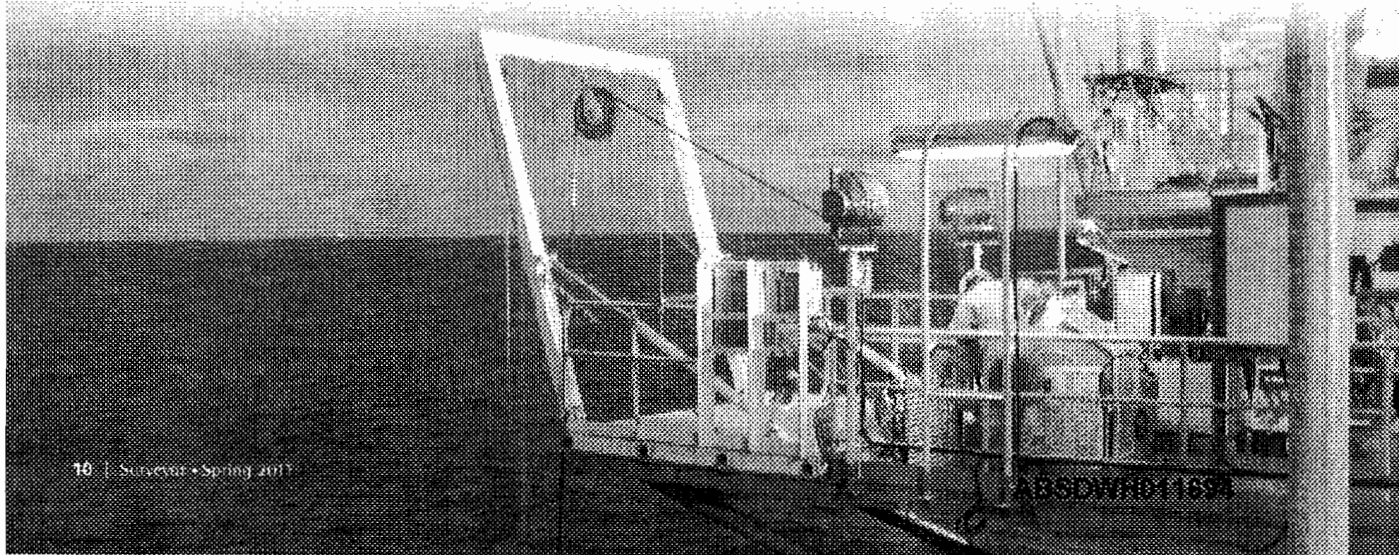
The BOEMRE initiative dovetails with actions taken by other government authorities. In the United Kingdom, the Safety Case has been the standard for many years. Elsewhere, quantitative risk analysis (QRA) is widely used during the design process so that fire and explosion risks are identified and either inherently safer measures are integrated into the design and/or appropriate 'life-cycle managed' safety critical elements are employed during operation to manage residual process safety risks.

Embedded within both the Safety Case and any underlying QRA is a presumption that appropriate management systems are employed to maintain the equipment throughout its operating lifetime. In light of the BOEMRE ruling, it can be assumed that operators working offshore in US waters will be undertaking a reevaluation of their SEMS. The

following guidelines are offered to assist operators in critically assessing the effectiveness of their existing system and to help identify areas that may be strengthened.

Start by asking the basic questions:

- Are process, health and environmental safety important to your organization? If it is viewed as a burden rather than as an effective management tool to improve performance, a fundamental re-evaluation of corporate priorities is needed.
- Has the commitment to safety and to the SEMS of the most senior management been effectively communicated to employees at every level within the organization?
- Each day every employee may make decisions that affect overall operations. Are they making the right decisions as determined by the SEMS procedures?
- Have individuals throughout the organization been empowered to successfully fulfill their safety responsibilities?
- Does the organization have a process in place that encourages the identification of management system weaknesses so that the errors of the past are not repeated?
- Is there a process and are there metrics in place to effectively, and continually monitor safety and environmentally-related performance?





An effective SEMS should recognize that all hazards and/or risks are not equal. Consequently, it should focus more resources on greater hazards and higher risks. The approach rests on the following:

- A commitment to process safety which includes the implementation of a process safety culture; the adoption of and adherence to appropriate standards, codes, regulations and laws; and encouraging process safety competency through work force training and involvement.
- An understanding of hazards and an evaluation of the risks to which the company or a specific facility may be exposed. This requires process knowledge management and an understanding of hazard identification and risk analysis. If this capability does not reside in-house, the company should seek outside assistance when establishing its SEMS or undertaking a critical evaluation of an existing system.
- Effective management of the identified risks by adopting easily understood operating procedures and safe work practices. These should include an effective asset integrity and reliability program. Procedures should also address issues such as training, consistency of performance, management of change, operational readiness, emergency management and contractor standards.
- A willingness to learn from experience by having in place procedures for responsive and critical incident investigations, establishing sensible measurement and metrics, conducting effective internal audits, and subjecting the results to periodic management reviews to determine if the management system is working as intended and if the actual work activities and asset integrity management practices are helping the facility to effectively manage identified risks.

It should be remembered that, despite the many unique characteristics of the offshore industry, there is also a great deal of commonality with shore-based process industries. An effective SEMS should therefore take into account lessons learned not only from incidents that occur at the operator's own facilities by identifying and addressing the root causes but also incidents at other operators' facilities and at facilities in comparable industries. ♦

## BOEMRE Rule Mandates Safety & Environmental Management Systems Offshore

**I**n October 2010, the US Bureau of Ocean Energy Management, Regulation and Enforcement (BOEMRE) issued a Workplace Safety Rule requiring offshore operators to develop and maintain a Safety and Environmental Management System (SEMS). The system is the basis for identifying, addressing and managing operational safety hazards and must promote onboard safety and environmental protection.

When issuing the new requirement, BOEMRE stated that, "although many large operators currently have a SEMS program, the voluntary nature of the programs limits their effectiveness." BOEMRE maintained that the Workplace Safety Rule would "provide a flexible approach to systematic safety that can keep up with evolving technologies."

Covering all offshore oil and gas operations in US Federal waters, the Rule makes mandatory 13 formerly voluntary practices under American Petroleum Institute (API) Recommended Practice 75 (RP 75):

1. Implementation, planning and management review/approval of the SEMS
2. Safety and environmental information, such as design data and diagrams on mechanical components and systems
3. A facility-level hazard analysis and risk assessment
4. A management of change program
5. Evaluation of operations and written procedures
6. Manuals, standards, rules of conduct, etc. regarding safe work practices
7. Safety and technical training for workers and contractors
8. Preventive maintenance programs and quality control
9. A pre-startup review of all systems
10. Emergency evacuation plans, oil spill contingency plans, etc., in place and validated by drills
11. Procedures for investigating incidents and taking corrective action
12. An initial audit within two years of implementation and subsequent audits every three years thereafter
13. Maintenance of records and documentation describing all elements of the SEMS program ♦

# Essential Safety Culture Features

**F**ocusing on the following features should assist a company to evaluate its existing safety culture practices and determine areas for possible improvement.

**Establishing safety as a core value:** The company should frequently reinforce the value it places on safety so that a deeply ingrained sense of that value exists at all levels of the organization. Each employee, regardless of position, should have an awareness of his or her responsibilities to self, co-workers, company and society with respect to their performance. Each person should feel not only accountable for their actions but for the actions of others such that there should be a strong individual and group intolerance for violations of performance norms.

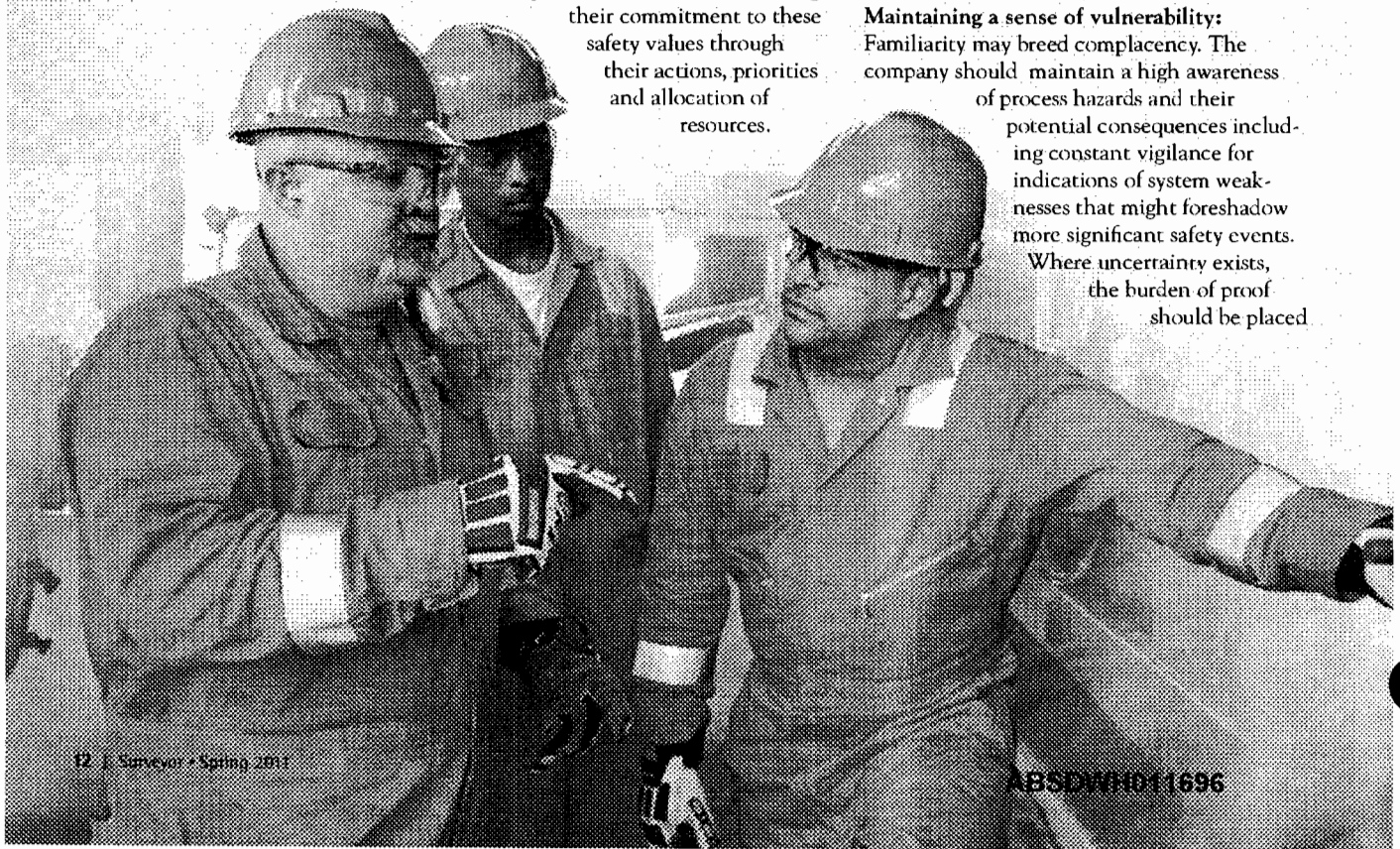
**Providing strong leadership:** Visible, active and consistent support for safety programs and objectives should exist at all levels of management within the organization. In particular, managers should be committed to making safe decisions in line with established procedures, and demonstrating their commitment to these safety values through their actions, priorities and allocation of resources.

Performance reviews of leaders and promotions into leadership positions should take account of the person's individual commitment towards safety performance improvement. The concept of 'safety as a line responsibility' cascades responsibilities through all levels of the organization.

**Enforcing high standards of performance:** High standards of safety performance should be established and consistently reinforced, for both groups and individuals. Where changing circumstances warrant, standards should be modified, but "normalization of deviance" (i.e., gradual erosion of standards due to increased tolerance of non-conformances) should not be accepted. There should be a corporate-wide zero tolerance for willful violations of safety standards, rules or procedures.

**Formalizing the safety culture:** The company should establish clear procedures for any significant or complex activity which could impact its safety or environmental performance.

**Maintaining a sense of vulnerability:** Familiarity may breed complacency. The company should maintain a high awareness of process hazards and their potential consequences including constant vigilance for indications of system weaknesses that might foreshadow more significant safety events. Where uncertainty exists, the burden of proof should be placed





on determining that an activity or condition is low risk (before it is allowed), rather than requiring that employees prove that it is high risk (in order to prevent it).

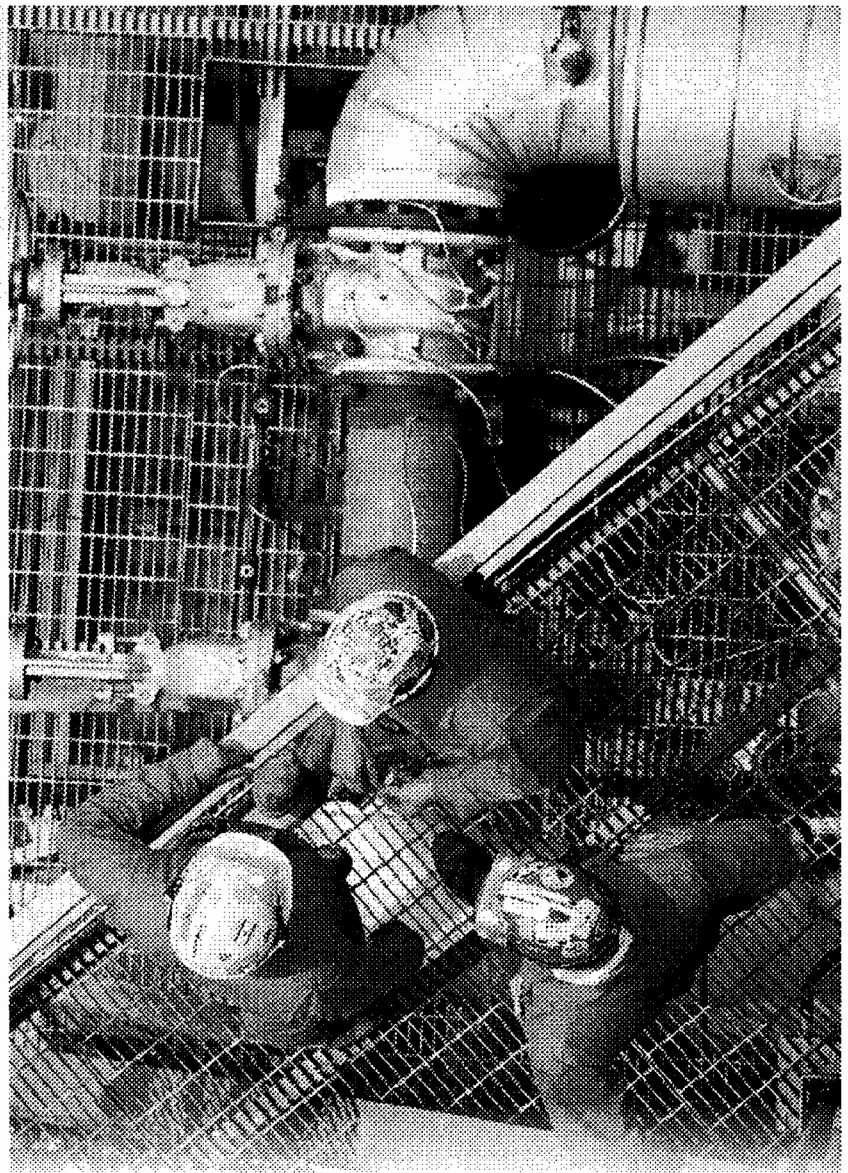
**Empowering individuals to successfully fulfill their safety responsibilities:** Employees should be provided with the authority and resources to allow them to take appropriate safety-related decisions in their assigned roles.

**Deferring to expertise:** An effective safety and environmental management system (SEMS) should address the question of appropriate training for all employees at all levels. It then follows that properly trained and empowered employees will make the appropriate, safety-based decisions that fall under their responsibilities. The authority for key safety decisions should then naturally migrate to the proper people based upon their knowledge and expertise, rather than their rank or position.

**Maintaining effective communications:** Open communication channels should exist both vertically and horizontally within the organization. Vertical communications go both ways; managers should listen as well as speak. Horizontal communications are the key to disseminating the information needed for safe operations. The effectiveness of these communication channels should be monitored. The presence of ad-hoc and informal communication channels should be considered as an indication of a need to reevaluate and repair the approved processes.

**Encouraging critical thought and learning:** There is an organizational imperative for enhancing risk awareness and understanding as a means to continual improvement in safety performance. This requires all employees at all levels within the company to be encouraged to critically assess their activities. In particular, catastrophic events are typically complex in their causation; consequently, overly simple solutions should be avoided and the assessments of all employees as to possible contributing factors should be taken into account when addressing appropriate procedural changes.

**Fostering mutual trust:** Employees should have confidence that a just system exists where honest errors can be reported without fear of reprisals and suggestions for improvements will be given due process regardless of the position of the originator. Mutual trust should also mean that



employees should be willing to challenge and be challenged regarding their activities, particularly as they relate to controlling safety risks.

**Responding to safety issues and concerns:** The company should emphasize the need for timely reporting and resolution of employee concerns relating to safety and environmental performance. Failure to do so can encourage the normalization of deviance from appropriate processes and procedures.

**Continuous monitoring of performance:** The company should constantly ask itself the question, "How are we doing?" Relevant, clear metrics should be established to address both leading and lagging indicators. Metrics should be tracked, trended and responded to. There should be a high level of corporate sensitivity to all operations which could have a bearing on safety performance. ❖

# MAINTAINING SAFETY BY MANAGING CHANGE



Henrique Paula,  
Senior Vice President,  
Global Process Sector,  
ABS Consulting

**S**pecific usage aside, a ship or offshore rig is fundamentally a floating industrial plant. Over its working life it will be subject to repair, replacement of structural components and equipment, possibly even major modification such as upgrading or conversion as occurs with a tanker being adapted to an FPSO role.

Unconsidered or undocumented change of any component of the ship or unit may result in future operational or maintenance problems which could adversely impact the safety of the vessel or unit and create the potential for an environmental incident. These consequences may be simple, such as a pump failing because an improper gasket was once installed for reasons of expediency. Since the installation was undocumented, the gasket was not subsequently replaced when the correct fitting became available. However, on rare occasions an apparently innocuous but ill-considered change could be a contributing element to the causation of a major incident.

As a consequence, an effective management of change (MOC) program should be considered as, not only an essential element of a facilities asset integrity management (AIM) program but also an equally essential element in every safety and environmental management system adopted by an offshore operator.

"Say, for example, you have a sound corrosion management program,

but one day a repair crew comes along and replaces a fitting, a section of tubing or some other part with one made of a material that is not already in the system," says Henrique Paula, Senior Vice President of the Global Process Sector for ABS Consulting. "If they don't document the change, they defeat the purpose of the corrosion management program, because the program is based on the original materials. Knowing the materials and their

corrosion behavior, the program designer may have determined that no inspection of this part of the process would be needed for a specified period. However, if the wrong material is introduced, the new component may corrode at a much faster rate and cause the system to fail within the previously specified timeframe," he says. "In such a situation, if the company does not control change, it may compromise the corrosion management program and, as a consequence, the entire operation."

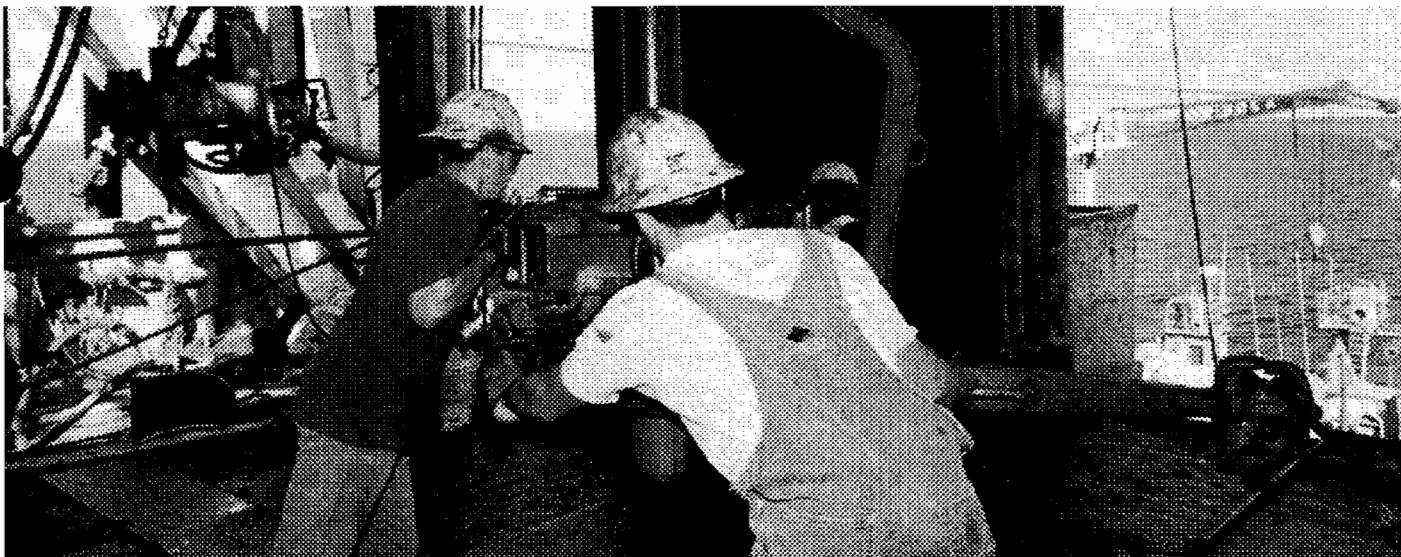
An effective MOC program should encourage a comprehensive evaluation of broader operational changes that could influence the behavior of the structure or equipment of a rig. As an example, Paula says that the selection of a larger helicopter to service a rig may be thought to fall outside a management of change program. "What should happen is that the company should check the new helicopter weight against the design of the installed helideck. If the structure is not designed for the additional weight, it could eventually fail," he warns.

The MOC program should also monitor outside factors. Again Paula provides an example. "The company's technical team may identify a new anti-corrosion chemical or application that could be used for a production unit's piping. A straight comparison of the new and existing treatments' properties may indicate the new product should be more effective. But a robust management of change program would not permit its introduction until the product had been analyzed for any unintended, collateral effects – maybe there's a seal on a pump somewhere in the system that will be damaged by leaching from the new application. An MOC process should look at the possible implications of that change, including any impact on other elements that have no direct relation with its intended function."

Paula also warns against a company thinking that its asset integrity and change management programs should only focus on hardware – the structure and its equipment. "Another item that should always be considered is changes in staffing and staffing







levels," he points out. "Say, for example, a facility has three operators at night with two auxiliaries, for a total staff of five. Management may install a new control system that allows a reduction in the number of duty staff. The new system may function effectively with the reduced staff but, before making that change, management should initiate an MOC process. There may be unforeseen or longer term implications that should be taken into account such as chronic operator fatigue. The importance of checking for these types of new hazards introduced by change cannot be overemphasized."

The US Occupational Health and Safety Administration (OSHA) offers a useful model that can be applied broadly to managing change. OSHA Regulation 29 CFR 1910.119, Process Safety Management, outlines some best practices under the MOC model:

- ❖ Establishing written procedures and documentation for all changes
- ❖ Documenting the purpose of each change
- ❖ Reviewing each change for impact on safety, health and the environment
- ❖ Authorizing the implementation of the change
- ❖ Reviewing additional risks introduced into the process
- ❖ Setting a timetable for when temporary changes are to be removed or reevaluated
- ❖ Updating process safety information
- ❖ Revising or developing new operator and maintenance procedures as necessary
- ❖ Training all employees and contractors who are affected by the change
- ❖ Maintaining the configuration of the plant

"An effective MOC program is really just a methodical breakdown of one element in an overall management plan," says Paula. "It can

be considered as a separate element but is more effective when it is integrated with an operator's asset integrity and safety and environmental management plans as the synergies with both are very strong."

For an offshore facility, AIM should begin at the design stage and end with decommissioning. It should be the base program used for tracking the condition, maintenance and replacement of the unit's equipment, systems and structures. "After the initial data input relating to the design, installation and commissioning of the unit, it is very difficult to maintain an effective AIM program unless it is fully coordinated with a comparable MOC program," Paula counsels.

"Even if a unit and its equipment are set up well and operating smoothly, sometime during the life of the facility, there will be changes – perhaps the installation of a valve where formerly there was no valve, or piping connected where there was no connection. Usually these changes are intended to bring some operational benefit. But even a beneficial improvement has the potential to create a new hazard as it may, for example, disable an existing protection, or cause a conflict with another system somewhere down the line," Paula says.

"It's very important that proposed changes be closely scrutinized for potential hazards," Paula emphasizes. "It's also very important that, before a change is made, the MOC program requires an evaluation of what is intended and of the hazards associated with the change – hazards that might be created and existing hazards that the proposed action may exacerbate. The key is that the operator should always be aware of the state of the unit's defenses so that a state of adequate safety and protection can be maintained." ❖

# DEVELOPING AN OIL SPILL RESPONSE SYSTEM IN THE CASPIAN

No industry is more global in its reach and impact than the energy industry. And few industries are ultimately more environmentally sensitive. So a safety breach in one area of the world inevitably draws the attention of the relevant government authorities in other regions involved with energy-related exploration and production.

That was certainly the case following last year's incident in the Gulf of Mexico when the Macondo well failed. From the North Sea to the South China Sea governments instituted reviews of applicable safety standards and response capabilities.

The incident sparked special interest in the Caspian Sea region in which five littoral states, Azerbaijan, Iran, Kazakhstan, Russia and Turkmenistan, have an interest in the energy

resources known to lie beneath its waters.

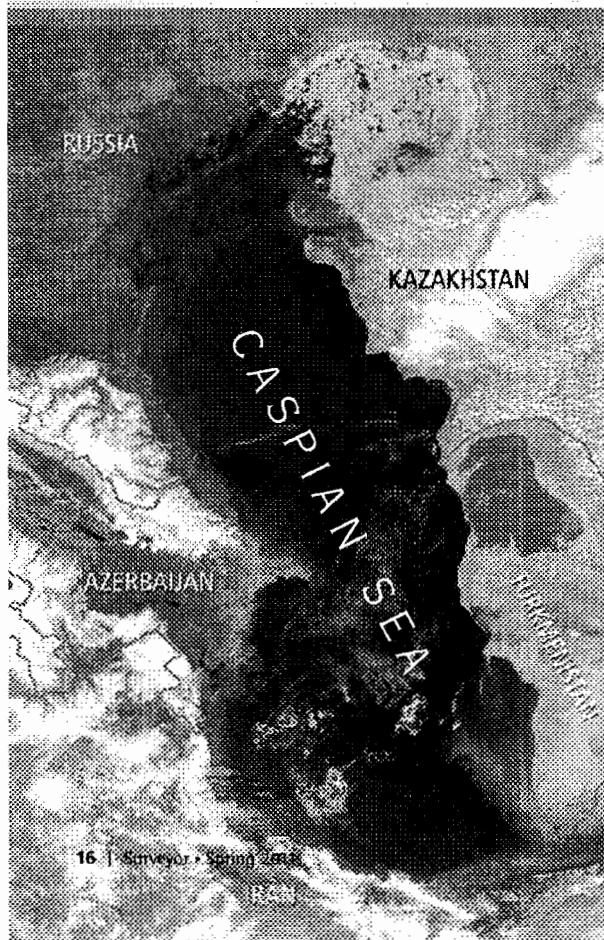
All five States have ratified the 2003 Framework Convention for the Protection of the Marine Environment of the Caspian Sea (the Tehran Convention), which gives them a basis for jointly resolving emergencies and environmental problems in and around the sea. Even so, there are now new initiatives aimed at evaluating existing readiness programs and identifying regulatory improvements that could enhance the region's ability to handle offshore incidents.

The thinking behind the heightened environmental attentiveness in the region was expressed by Kazakhstan's Emergency Situations Minister Vladimir Bojko on the day in October that Kazakhstan and Azerbaijan signed an agreement to coordinate regional oil spill response: "I am suggesting the establishment of a joint fund to eliminate the duplication of equipment and coordinate a common action plan," Bojko told the press. "The issue is urgent in light of recent events in the Gulf of Mexico and the complex biological conditions of the Caspian Sea."

At 386,000 km<sup>2</sup> in area, the Caspian is the world's largest inland sea. It has a unique marine environment produced by millennia of isolation from the world's great waters. The evidence of past environmental neglect when recovering oil is well catalogued. While there are varying estimates of the extent of the Caspian region's remaining energy wealth, it is generally agreed that it is at least equal to that of the North Sea (17 billion barrels of oil) and may range up to ten times that amount – representing about a quarter of all proven reserves in the Middle East. With exploration activity on the increase in the region, concern of the consequences of a significant oil spill is also on the rise.

Once again, history provides the reality check. While the area was under Soviet rule, a well at Kazakhstan's Tengiz oil field blew out in 1985 and burned for more than a year before it was brought under control.

Last year, Russian Prime Minister Vladimir Putin told an energy conference in the Caspian port of Astrakhan that all work related to the development of oilfields in the Russian sector of the Caspian is being conducted "in strict compliance with international environmental standards," applying zero discharge technology. Soon after, Russian oil company LUKoil began production from the Yury Korchagin field in the Russian sector of the North Caspian Sea. Plans for the development include 30 wells (26 production wells, one gas-injection well and three water-injection wells), with these to be brought on stream in a phased manner.



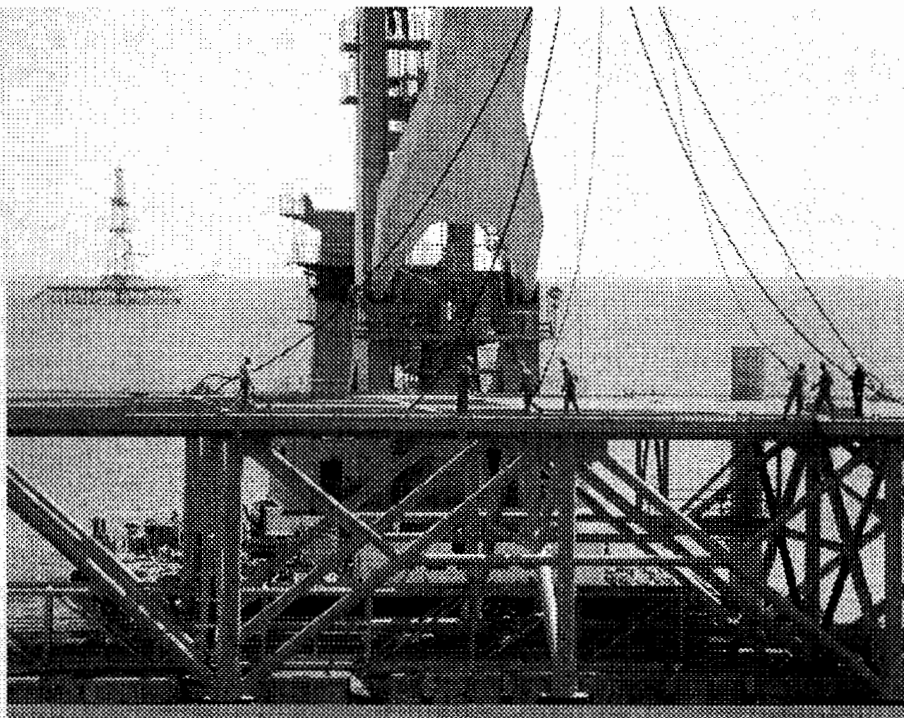


In June of last year, Russian authorities conducted an exercise in offshore oil spill response and containment capabilities, placing particular emphasis on rapid spill response at the field's floating storage unit. The exercise also tested the effectiveness of joint government-industry operations under the regional plan for oil and petroleum product spill prevention and containment. Indicating the regional sensitivities, the exercise was also attended by authorities from Kazakhstan.

The Republic of Kazakhstan has been the most active of the Caspian States in pushing environmental protection reforms. Since achieving independence in 1991, the country's economy has been led by its energy sector. Oil and gas development, and mining, have attracted most of the \$40-plus billion in foreign investment that has come to Kazakhstan since independence, and account for some 57 percent of the nation's industrial output (about 13 percent of gross domestic product).

Exploration activity to date has indicated that recoverable reserves of some 3.5 billion tons of oil and 2.5 trillion cubic meters of gas could lie in the country's Caspian areas. Overall, the estimate of Kazakhstan's oil deposits is 6.1 billion tons. Expansion of oil production and development of new fields are expected to yield up to 3 million barrels of oil per day by 2015. This is part of the State's overall target to double annual oil production to 160 million tonnes by 2020, placing it among the world's top five oil producers.

Last July, reflecting the heightened awareness of governments to the consequences of an oil-related incident, Kazakhstan's Prime Minister Karim Massimov urged a further strengthening of safety standards relating to Caspian Sea oil exploration and production. He called for the creation of a governmental entity charged with inspecting production facilities in the Caspian Sea and, soon after, the government established an inter-departmental commission on safety operations in oil production. The commission includes representatives from various Kazakhstan ministries (oil and gas, environmental protection, emergency situations, industry and trade), local governments and the oil companies active in the country.



In October, the Kazakhstan Government, again working with the international oil companies active in the country, released an oil spill prevention and response plan that includes, among other provisions: ongoing inspection of oil and gas facilities; annual spill response exercises involving government agencies and international oil companies; and agreements with its neighbors on coordinating response efforts.

At the end of December, Massimov approved new national requirements for oil spill cleanup in the Caspian Sea. Developed under Kazakhstan's new Law on Subsoil and Subsoil Use, enacted in June 2010, the move aims to encourage the creation of rapid response systems by the companies directly involved in developing offshore energy resources.

The law establishes a three-tier approach to incidents offshore. Under the rules, every offshore structure and every vessel is required to carry sufficient equipment and materials to handle spills of up to 10 tonnes. The second, or 'moderate', level covers spills of between 10 and 250 tonnes; to handle these, materials and equipment resources must be available on maritime structures, worksites and at coastal facilities. The third level addresses major spills exceeding 250 tonnes, and such emergencies as the long-term loss of well control or incidents aboard fuel barges, in storage facilities or at distribution systems. As stipulated in the law, spills from such facilities require rapid response, immediate containment and mobilization of materials and equipment from domestic and international sources. ♦

# Deepwater Well Capper Unit at the

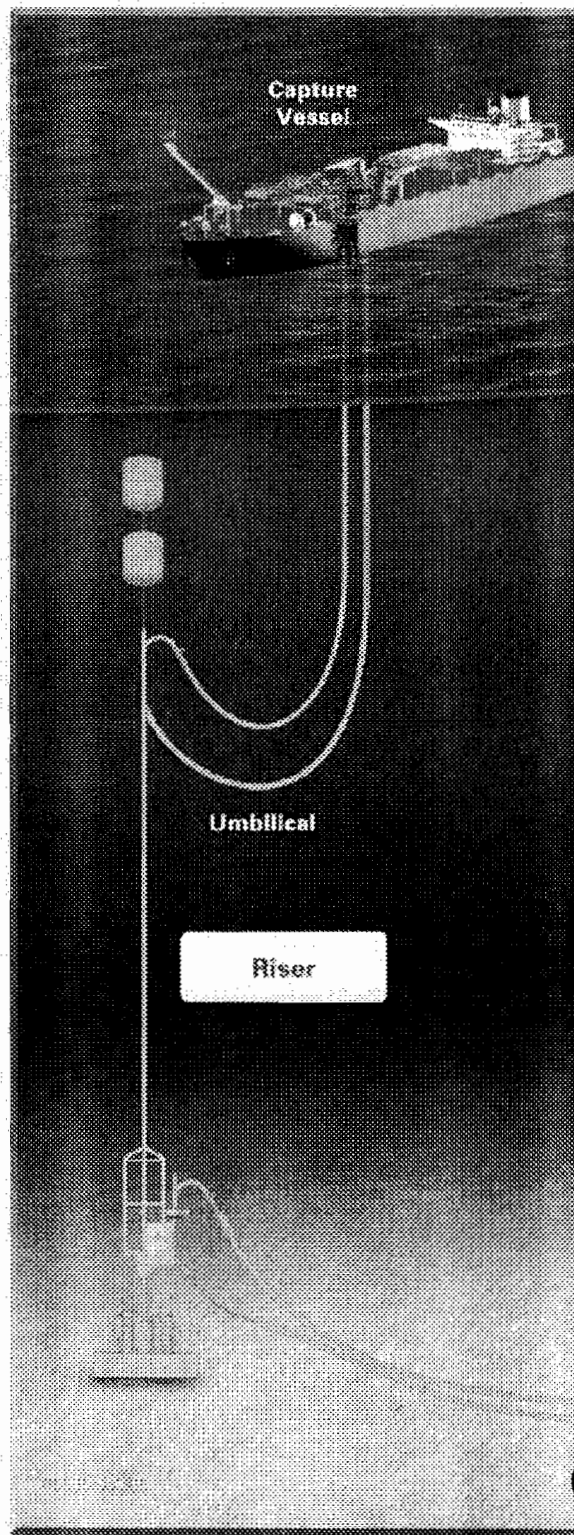
Cooperation and innovation help an industry get back to work.

**“T**he most critical missing piece in the process of approving applications for permits to drill in deep water is the demonstration of well control and subsea containment capability.” That was the key phrase in a letter to energy industry CEOs sent in early February 2011 by the Director of the US Bureau of Ocean Energy Management, Regulation and Enforcement (BOEMRE), Michael Bromwich.

Later that same month, at a conference on offshore oil exploration risks, Bromwich reiterated the message that the energy industry should not expect new drilling permits to be issued until it could demonstrate preparedness to respond to another Macondo field type of incident. “It would be irresponsible to approve new drilling before we have answered the simple, yet compelling, question, ‘How do you deal with [a spill],’” he said. Less than a week later, industry answered.

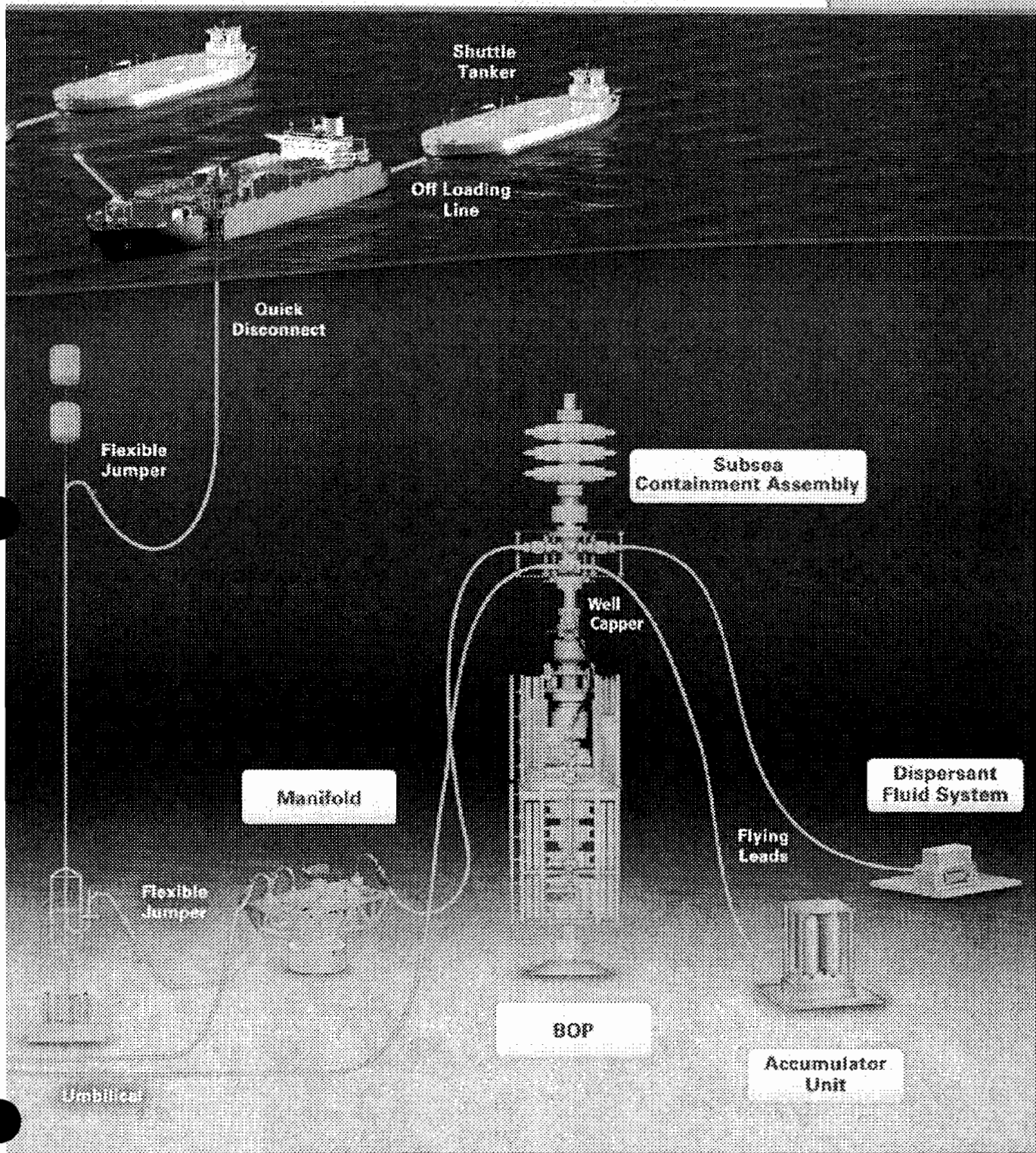
On 17 February a group of energy companies, led by ExxonMobil, announced it had developed a collaborative disaster response system for the deepwater Gulf of Mexico. The centerpiece of the approach is the not-for-profit organization that was established in 2010 after the Macondo incident, named the Marine Well Containment Company (MWCC). The member companies’ combined equipment, support vessels and personnel will be brought together through the organization to provide rapid containment response for a future well-control disaster. Membership in the MWCC is open to all operators in the US Gulf of Mexico. At press time, current members are ExxonMobil, Chevron, ConocoPhillips, Royal Dutch Shell, BP, Apache, BHP Billiton and Statoil.

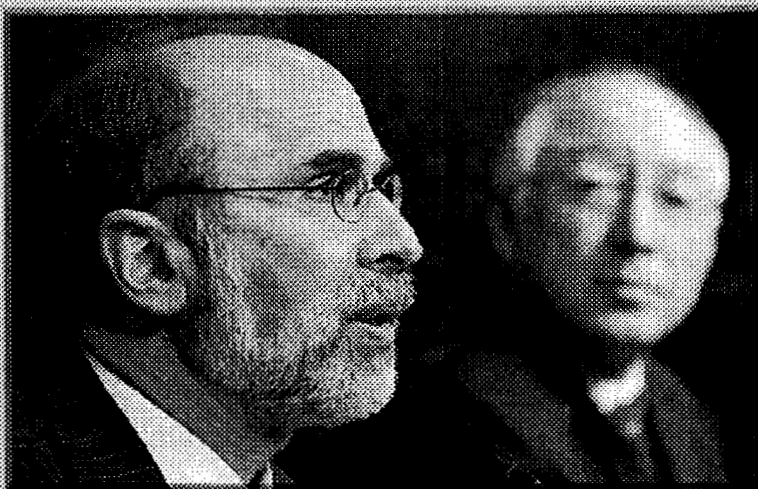
Members make a capital commitment to the organization, each paying a proportional share of the system’s development and operating costs and receiving in turn an equal share of the company. Members have free access to the initial response system and, when completed, the expanded system. Other companies can pay a fee to





# Heart of Future Spill Response





Michael Bromwich has reiterated that operators seeking US deepwater drilling permits must demonstrate well control and subsea containment capability.

use the system and include it in their drilling permit applications. Costs for deployment of the system for any member or non-member company are solely the responsibility of the company that has the well control event.

The centerpiece of the response system is a massive, multifunction well control device called the Capping Stack. Wholly owned by the MWCC, the 100-ton capping stack has been designed to shut off an out-of-control well with pressures of up to 15,000 psi. Capable of working at water depths to 8,000 ft (2,438 m), the capping stack is designed to divert 60,000 barrels of liquid and 120 million cubic feet of gas per day through flowlines and risers from the well to surface collection vessels.

To put the well capper's capabilities in perspective, consider that the Macondo well, which took 85 days to close, is in 5,000 ft of water and released an average of 52,400 barrels per day and a maximum rate of 61,900 barrels per day. The well was finally shut down by a system of valves and controls assembled during the response. The capping stack is similar to that construction, but incorporates more functionality and a refined design.

Though impressive, the unit is just the first well capper, part of the 'interim response system.' A larger version of the well capper, scheduled to be released next year as part of the 'expanded' response system, will be able to operate in up to 10,000 ft of water and handle up to 100,000 barrels of oil per day.

"It's called a capping stack, but it does a lot more than that," says Mario Lugo, whose Houston-based company Trendsetter Engineering built the well capper. "The MWCC asked us to design and build a capping stack with double barriers that could cap the well, kill the well, divert oil and gas flows subsea and allow you to attach a riser and capture production while the relief well is

being drilled – and do it all in a controlled manner. The capping stack we built is a real innovation," he adds with satisfaction. "It's made from existing technology but it's a tool that did not exist before."

The MWCC also specified the well capper should have hot stabs (fittings for connection with remotely-operated vehicles (ROVs)) that allow subsea injection of dispersants and chemicals to prevent the formation of hydrates. Injecting dispersant into the well stream under pressure should cause any escaping oil to break up and disperse more effectively, says Lugo.

"We elected to build the well capper with a full 18 3/4-inch, 15,000-psi system with four 5-inch, 15,000-psi outlets," Lugo says. "The reason is that it's common, conventional technology; every drilling vessel in the world will have an interface for an 18 3/4-inch connection. Plus, it allows you to connect other equipment to do things we haven't thought of yet."

Although it is the key piece of equipment in the response system, the capping stack is still just one component among many. The disaster response system also involves equipment and services ranging from ROVs, manifolds and subsea devices to the various vessels that will capture, process and store the oil. All of the equipment is provided through a mutual aid agreement among the member companies of the MWCC.

At a press briefing discussing the well capper and the MWCC, Clay Vaughn, an ExxonMobil Vice President supervising the response network, told reporters that crews have been training on deploying the equipment such that, within hours of an incident, the stack and the crews can be en route to a disaster site. He further noted the system has three main parts: containment at the wellhead; managing the well flow; and capturing the produced fluids via surface vessels.

The first capping stack is located at a staging area near Houston while much of the support equipment is being stored at Port Fourchon in Louisiana. Both locations have access to rail lines, major airports and channels into the Gulf of Mexico. By 2012, Vaughn said, the MWCC will be developing fixed bases along the Texas and Louisiana Gulf Coast where the equipment will be stored and ready for use. The surface support vessels are, at present, to be provided by BP and Chevron.



The MWCC also addressed procedures, developing a checklist that details the responsibilities of the company and the well operator. Among the issues that arose during hearings into the Macondo incident was that, during the incident, there appeared to be some confusion regarding the lines of command. "This spells out exactly what we will do and what the operator is responsible for," Vaughn said. "There is no confusion about who is in charge or what they should be doing."

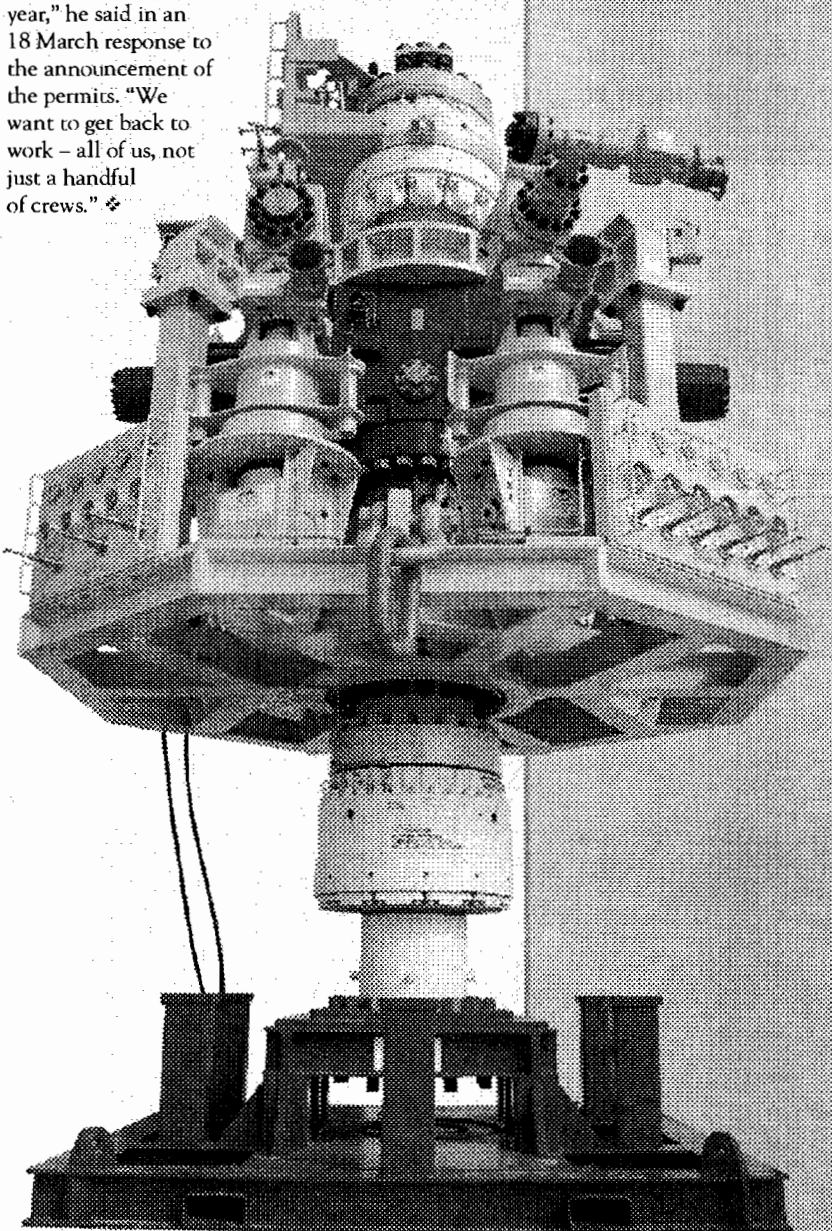
Soon after the well capper's unveiling, President and CEO of the American Petroleum Institute Jack Gerard told the press, "The oil and natural gas industry's more than 60-year history of safely drilling more than 42,000 offshore wells, our unprecedented response to last year's Gulf accident, our ongoing efforts to raise the bar on safety standards, and our record of workplace safety, all speak to our commitment to safety. The readiness of the Marine Well Containment Company and the systems necessary to respond to a deepwater drilling incident, show this industry has met every requirement for resuming operations in the Gulf and is ready to get back to work providing the energy this country needs."

A week later, 50 US Congressmen signed a letter to President Obama that read, in part: "The MWCC's work on improving underwater well control capabilities in the US Gulf of Mexico is demonstrative of the industry's commitment to abide by the Administration's instructions to return to safely and responsibly utilizing our domestic energy resources... Considering these facts, we respectfully request that you...return to approving the full slate of permit applicants that have been submitted and allow this industry to return to work." Within two weeks they had an answer.

In late March, BOEMRE had issued four deepwater drilling permits and approved the first new deepwater exploration plan for the Gulf of Mexico post-Macondo. One of the four permits issued was for the first project to designate the MWCC containment system as its containment response. Director Bromwich said on 22 March the Administration has "growing confidence" in the industry, noting that more approvals are pending. "As we have seen, the rate of deepwater permit applications is increasing, which reflects growing confidence in the industry that it understands and can comply with the applicable requirements, including the containment requirement,"

he said in a statement: "We expect additional permit approvals in the near future."

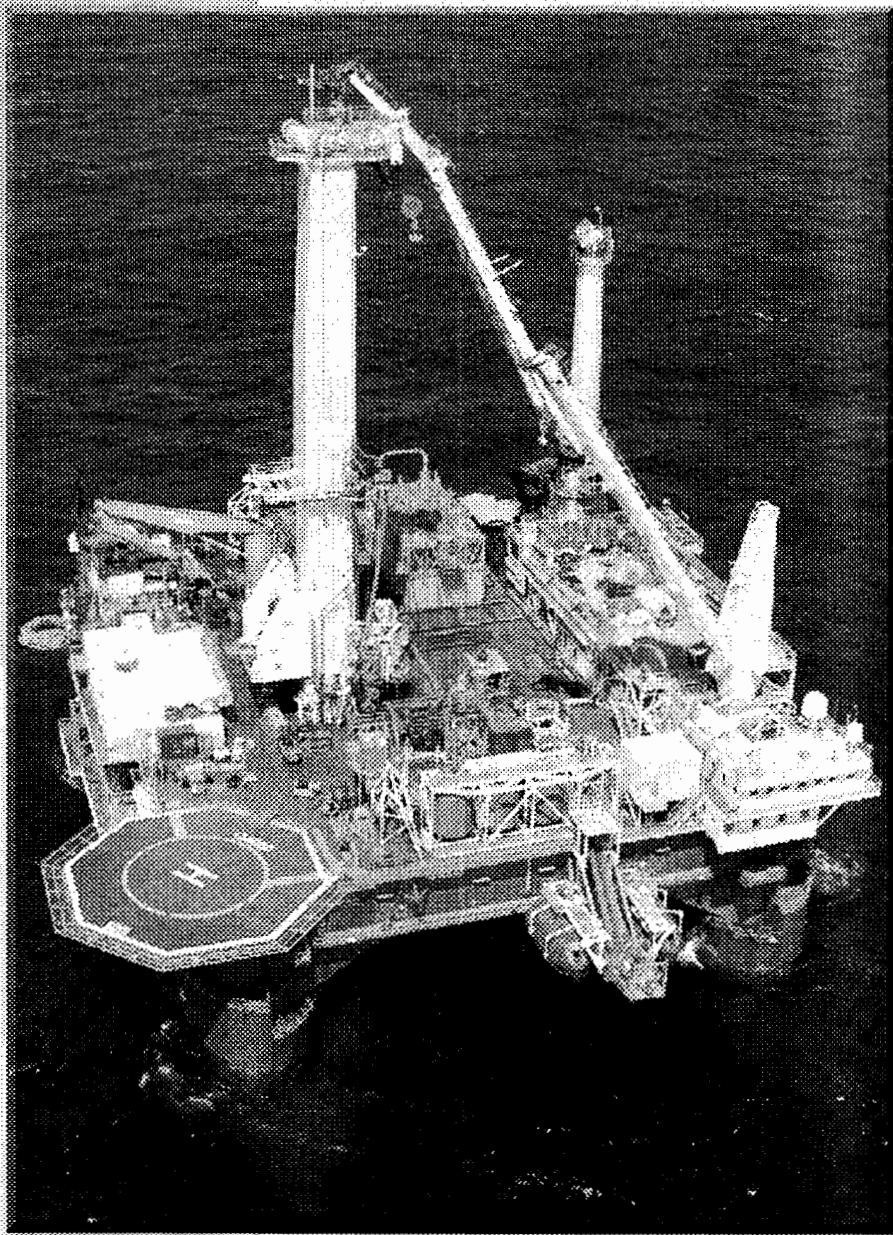
The permits issued were actually permission for companies to resume projects that had started before the moratorium, leading Jim Adams, President and CEO of the Offshore Marine Service Association (OMSA), to call for faster action on new proposals. OMSA reports that there are over 100 deepwater development plans yet to be cleared to even become eligible for a permit. "There were 32 deepwater drilling operations already permitted when the president imposed his moratorium last year," he said in an 18 March response to the announcement of the permits. "We want to get back to work – all of us, not just a handful of crews." ❖



# Helix and CGA Develop a Spill Response System

**D**rilling in the US Gulf of Mexico was suspended last year when the Obama Administration imposed an extended moratorium following the Macondo well incident. Although the ban was lifted in October, as this issue went to press, deepwater drilling had not yet resumed – but permitting had.

By late March, BOEMRE had granted four deepwater drilling permits and approved a deepwater oil and gas exploration plan (following a site-specific environmental assessment) that includes three exploratory wells drilled in about 2,950 feet of standing water.



Three of the drilling companies receiving the first permits had signed on to a spill response system offered by Helix Energy Solutions, the Helix Fast Response System (HFRS). This system incorporates the use of two vessels: Helix's Q4000 multipurpose semisubmersible platform which acts as the well intervention vessel and the *Helix Producer I* is a floating production unit.

Each vessel played a prominent role in the Macondo response. The system also includes the company's own subsea equipment, containment system, risers, umbilicals and tanker loading system. At full capacity, the Helix HFRS has been designed to handle daily rates of up to 55,000 barrels of oil and 95 million cubic feet of gas.

Helix promoted its system through an alignment with the nonprofit cleanup group Clean Gulf Associates (CGA), making the HFRS available for a two-year term to CGA members in exchange for a retainer fee.

Based in New Orleans, CGA is a cooperative enterprise formed in 1972 by 33 oil and gas exploration and production operators to be an owner of equipment dedicated to responding rapidly to spill incidents in the Gulf of Mexico. Its three basic goals are: to provide oil spill containment and cleanup capability for use by member companies; to





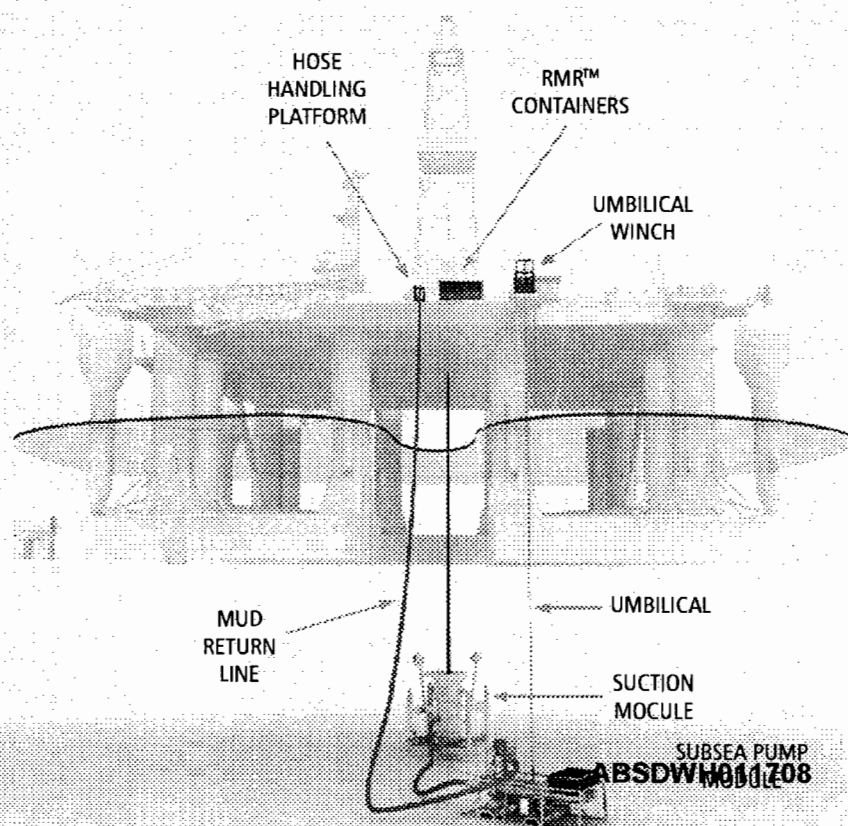
# Riserless Recovery of Top-hole Mud Addresses Key Environmental Issues

An innovative way to recover top-hole mud has helped one company make its mark on the offshore industry.

Innovation has been the key to unlocking the undersea energy treasure chest. Sometimes an innovation advances slowly, spending years percolating up through the sea of interesting concepts before conditions are right for a field application; sometimes a good idea comes along at just the right moment to make a dramatic impact on the way things are done. In the case of riserless mud recovery, the path to prominence has involved a little of both.

Riserless mud recovery (RMR™), conceived and developed by Norway's AGR Group, began as a response to specific problems in shallow-water drilling. It has progressed into deeper waters and has evolved into a

widely-applicable solution that is still pushing boundaries today. Patented by AGR in 1999, RMR found its first field application in the shallow waters of the Caspian Sea in 2003. It did not appear in the Gulf of Mexico until 2009. In the intervening six years, RMR built a reputation for resolving longstanding shallow-well problems and reducing project costs, while also providing the kind of 'zero-discharge' drilling that authorities around the world were beginning to demand for environmentally-sensitive areas. This latter attribute has become increasingly important as the number of areas designated as 'sensitive' increases and some national authorities attempt to restrict the 'pump and dump' method traditionally used at the start of drilling operations.



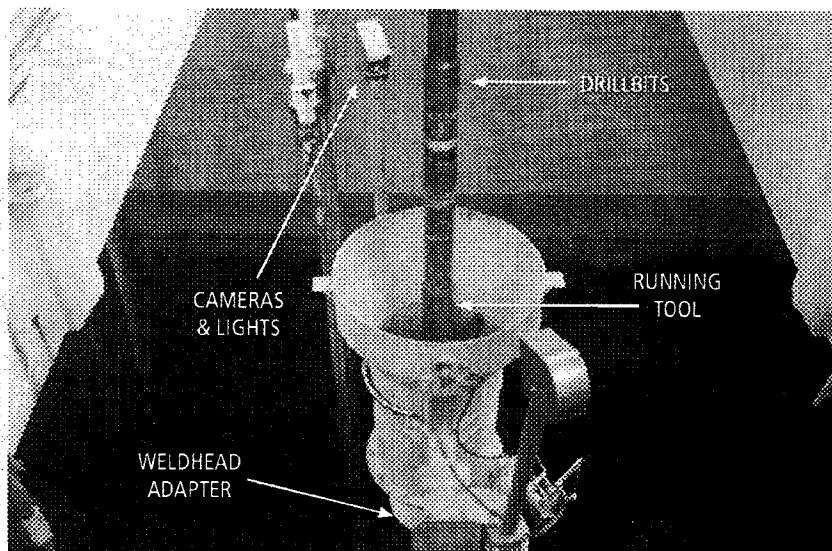


Pump-and-dump, used in the first section of a well (the top-hole), has been standard practice since the earliest days of offshore drilling. Top-hole drilling bores a large-diameter hole (typically 36 inches) into which is set the first section of casing (the steel tube that lines the well), called the conductor casing. Conductor casing is a critical well component because it is the base for the wellhead. For the life of the development it will support both the full weight of the wellhead above it and contribute to the stability of all the casing down to the reservoir. In essence, the top-hole section becomes the stable foothold for the rest of the drilling operation and the importance of its proper completion cannot be overstated.

Because pressurized oil and gas are not typically encountered in top-hole drilling, it is the only stage of a well that is drilled without a blowout preventer. It is also the only stage in which drilling mud is allowed to be released onto the sea floor. Drilling mud is an engineered fluid made of water or oil, combined with a mineral mixture. It is pumped through the drill string (the run of pipe on which the drill bit is mounted) to cool and lubricate the drill bit, clean the hole of fragments and, by its presence, maintain safe working pressures in the wellbore. It is only allowed to be released during top-hole drilling, the section that consists of about the first 1,500 ft underground, because the conventional method of mud recovery doesn't work at that stage.

After completion of the top-hole stage of a well, mud used for the remainder of the well is typically returned to the offshore rig via a riser, a steel tube that links the rig with the sea floor through which the drill string passes. The mud flows up the annulus of the riser (the open space between the riser wall and the drill string) and is received onboard for cleaning and processing.

Were a riser to be used in top-hole drilling, the weight of the mud within it would put unnaturally high pressure on the geological structures just beneath the sea floor through which the drill has to cut. The added pressure would exacerbate hazards already present in that zone, creating potentially dangerous complications for the drilling operation. Top-hole drilling using a riser is considered so risky, particularly if shallow gas flows are present, that it is banned in many locations. For example, the Norwegian authorities



banned its use on the country's continental shelf following a 1985 blowout on the rig *West Vanguard*, caused by shallow gas.

SMO deployment

## Pump-and-Dump No More

For the first half-century of offshore drilling the only practical solution had been to drill the top-hole without a riser. The only way to do that was to pump the mud into the hole and let it flow onto the seabed leading to the moniker 'pump-and-dump' taking its place in the offshore lexicon.

The approach left much to be desired: money was lost in unrecoverable drilling mud; and the mud that was in fact used, was not the preferred choice of the driller. Muds engineered for specific behavior at specific geologic points underground contain oils and chemicals and cannot be released onto the ocean floor. For this reason, top-hole drilling calls for seawater-based mud mixtures that are environmentally benign, except for the physical impact on the ocean floor. However, these seawater-based solutions are not as operationally effective as other mud types. Consequently, in order to maintain well integrity, the driller must stop several times to install casing strings while still in the well's initial depths.

Riserless mud recovery provided a new approach to these longstanding top-hole wellbore structural and operational difficulties. A key advantage has been the manner in which it addresses the previous environmental concerns, so much so that RMR technology is now used to drill near Australia's coral reefs and will soon be used to drill in Brazil near the pristine beaches so prized by tourists.

In a riserless mud recovery system, a suction module, mounted at the wellhead, directs the returning mud and cuttings to a subsea pump



RMR control screen

which sends them up to the drilling rig via a flexible hose (in shallow water) or a rigid pipe. Because RMR circulates the mud in a closed loop it allows the use of highly-engineered fluids that control pressures in the borehole, such that they closely resemble those of the geological formations in their undisturbed, natural state, and maintain those conditions for the full depth of the hole.

This, in turn, provides benefits to both the drilling and production operations. For example, the ability to reuse drilling mud leads to higher success rates for top-hole drilling in difficult conditions because operators can use better engineered fluids. There is also a reduction in the amount of fluids consumed, with some operators reporting using 75 percent less mud in the top-hole phase than they

normally would. In addition, by reducing the number of different diameter casings needed to stabilize the borehole, riserless mud recovery can lead to significant savings in steel consumption and overall project time.

The first commercial application of the riserless mud recovery approach was in 2003 in the West Azeri oilfield of the Caspian Sea, a relatively shallow-water region known for unique challenges to top-hole drilling. Drilling through a template 120 meters deep, BP encountered problems with shallow formations that ultimately caused it to abandon eight wells. Applying RMR provided the operators with sufficient control of borehole conditions that all eight wells were subsequently revived as active projects. Since then, the technique has been applied on 42 wells in the Caspian, 40 of them for BP.

2004 saw a North Sea field trial for RMR technology funded by the Norwegian Government's Demo 2000 research effort which qualified the technique for the North Sea/Norwegian Continental Shelf environment in water depths to 1,500 feet. Two years later, AGR gained a commercial foothold in the North Sea market on a well in 113 m of water off the Scottish Isle of Jura, deployed from the ABS-classed semisubmersible *Sedco 714*.

Work in other difficult environments soon followed, with notable applications including two exploration wells in the Shrokmán field of the Barents Sea and a pair of wells offshore Sakhalin Island. The operator on the Sakhalin job reported that using riserless mud recovery technology saved nine days of work per well (compared with earlier wells) while satisfying Russian environmental protection regulations forbidding cuttings discharge after the conductor casing is set. Soon after this, the technology was applied to a dozen wells in the Western Australia Drilling Project.

While the riserless mud recovery concept can be described simply, to develop it into a commercial product took seven years of development work. It grew out of a technology development program that occupied AGR for much of the 1990s.

AGR was founded in 1987 as AGR Services AS, a specialist in cleaning and inspection of North Sea oil rigs. From its home on the western Norwegian island of Sotra, the company achieved prominence as a North Sea services company. Now headquartered





in Straume, Norway, the company has grown through acquisition and expansion into three divisions – Petroleum Services, Drilling Services and Field Operations – whose international offices provide a variety of services to the global oil and gas industry.

In the early 1990s, AGR began manufacturing subsea pump systems and launched an active research and development program into top-hole drilling support. The company installed its first subsea mud pump in 1998 and, the next year, released its Cutting Transport System (CTS), a variation of pump-and-dump in which a long flexible hose attached to a suction pump moves the mud/cuttings refuse away from the drill site, but still onto the sea floor. The riserless mud recovery concept emerged during the development of the CTS and the two technologies evolved together. In 1999 AGR patented RMR technology, which extended the idea of the CTS by taking the mud hose up to the surface.

In 2008 AGR Subsea (the Group's US division), together with Joint Industry Project partners Shell, BP Americas and the DEMO 2000 Program, undertook a successful field trial of deepwater riserless mud recovery technology at 1,500 m water depth. Deployed from the ABS-classed semisubmersible *Atwood Falcon* in Sabah, Malaysia, the deepwater RMR was subsequently used during drilling operations for a Petronas-Shell project. It was not until 2009, that the concept made its debut in the Gulf of Mexico when it was deployed on Statoil's *Krakatoa* prospect in 2,060 ft of water. To date, riserless mud recovery has been successfully applied on over 130 wells, confirming AGR's position as an offshore innovator. ♦

## Further Innovations in the Pipeline

**A**GR's riserless mud recovery (RMR™) system is proving to be a platform for a range of future innovations, among them controlled mud pressure drilling, an extension of the riserless mud recovery technique into the post top-hole sections of the well, and EC Drill, a version of RMR that works with an adjustable column of mud in the riser.

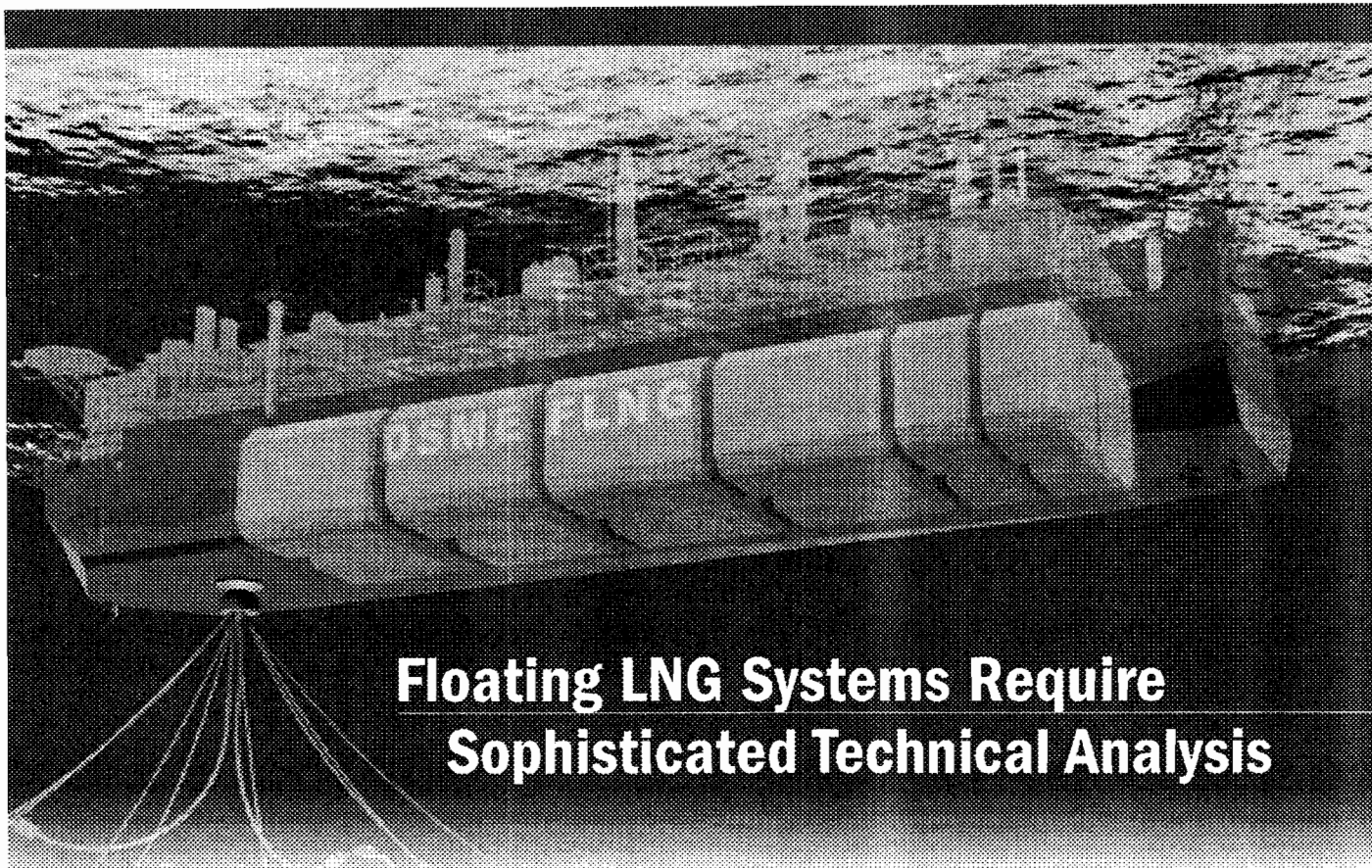
In 2009, AGR contracted with Chevron for integrated project management and engineering for the build, deployment and prove-up of the world's first full-scale application of deepwater dual gradient drilling, a revolutionary new technology that holds the promise, among other benefits, of greatly extended well depths in ultra-deep-water energy exploration and production. Similarities between riserless mud recovery and the larger, more complex dual gradient systems were a factor in AGR's selection for the role. In the two years since, AGR technical staff have been working on an integrated team with Chevron and other companies on the design and development of the dual gradient system.

RMR's progress into deep waters has also attracted the interest of the scientific community, which has had a major unattained deep drilling objective on the books for many decades. Two years ago, RMR technology came to the attention of the Integrated Ocean Drilling Project (IODP), a joint research effort between some two dozen countries with the goal of advancing earth sciences through deep drilling at globally located sites to collect geological samples for analysis. In 2009, the IODP reported that RMR could be used by its existing research ship, the ABS-classed *JOIDES Resolution*, to drill in 9,000 ft of water with minor modification, and that 12,000 ft depths could be achieved with additional pump stages.

Since the earth's crust is thinnest under the deep ocean floor, the ability to drill at such depths might allow the IODP to reach the goal of Project Mohole, the 1950s-era effort to drill into the Mohorovičić discontinuity (or Moho) – the boundary layer between the earth's crust and mantle. The IODP has not announced any plan to revive the mission to the Moho, but has stated that deepwater riserless mud recovery holds promise for the day it does.

Not all of AGR's innovations have grown out of RMR-related technologies. Among its other inventions are the Neptune Subsea Inspection system, which uses an ultrasound scanner on a remotely operated vehicle (ROV) to produce high-definition images for mapping and inspection of pipeline systems to depths of more than 18,000 feet; the Dynamic Desander for removing sand, scale, and other solids from the fluid stream when cleaning out wells, usually with coiled tubing; and the recently introduced Managed Pressurized Cementing to promote casing cement integrity. ♦





## Floating LNG Systems Require Sophisticated Technical Analysis

**A**s recently as five years ago, floating solutions for the import and export of LNG were still considered new and novel concepts. Today, emerging proprietary technologies and designs have meant industry is poised to inaugurate the first projects. More than one-third of global gas reserves stranded by their location or field size, without commercially viable access to world markets. The 'marinizing' of production, liquefaction and export facilities on floating units offers the potential to bring a significant volume of these stranded reserves to market.

Major projects already in progress include Shell's Prelude field in the Browse Basin off Western Australia, which gained environmental approval in late 2010 and has a target production start date of 2016. Also being closely followed are several projects offshore Papua New Guinea and Inpex's Abadi Field gas project offshore Indonesia.

Floating liquefied gas terminals (FLGT) offer a number of advantages over land-based terminals. Floating LNG installations offer lower overall project costs and a reduced environmental footprint as they eliminate the need for facilities such as offshore compression platforms, long pipelines to shore and extensive onshore development.

However, the design of the floating units themselves has also raised many technical challenges. FLGT concepts have broached the possibility of hull structures up to 450 meters in length and 70 meters in breadth, which would make them the largest ship-shaped units of any type to be built.

Evaluating such large structures can be a challenge. Certain engineering analyses should be carried out including buckling, yielding, ultimate strength and fatigue strength. It is also important to keep in mind that a floating terminal structure behaves differently than a trading LNG carrier. A terminal experiences cyclic and more frequent loading and discharge, therefore low cycle fatigue should also be factored into the analyses.

With a hull structure so large, designs with two cargo tanks abreast are being proposed to minimize the internal load effects, particularly from sloshing within the often partially-filled tanks during loading and discharge operations. Such designs also require careful analysis as existing criteria is based upon single tank configurations.

The onsite environment for the vessel may be close to shore. In such instances shallow water effects, which can place more severe environmental loads on the hull structure



than when it is in deeper water, need to be considered. Another important consideration in the structural analysis is the effect of offloading operations, either side-by-side or in tandem. This can have an impact on a floating terminal's response motions as the coupling effects and relative motions between the terminal's hull and offloading vessel must be taken into consideration. Appropriate analysis of the hull and topside interface is also important as the size and weight of the topsides modules can be significant.

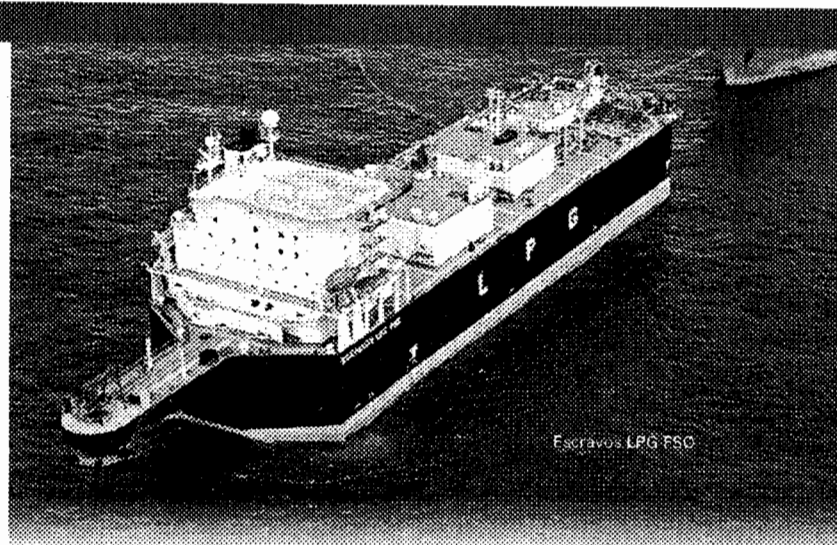
The production facilities themselves pose a different set of challenges. Gas technology has been developed for land-based facilities. To operate such systems aboard a floating installation, which is subject to ship motions and harsher environments at sea, will require much of the key equipment to be redesigned or otherwise adapted to marine applications.

Industry experience to date has been limited to the operation of the ABS-classed LPG floating storage and offloading (FSO) unit *Escravos* and the ABS-classed LPG floating production storage and offloading (FPSO) vessel *Sanha*, both in service off West Africa.

Operator interest has emerged in both conversion and new construction projects for FLNG projects, with conversions offering a shorter time-to-operation profile. Since LNG carriers are some of the best maintained vessels, conversions do present an attractive option depending upon the size demands of a particular project.

Recent newbuilds have been designed with an effective 40-year fatigue life and the strict maintenance regimes that characterize the operation of LNG carriers mean that even older ships may have many years of serviceable life ahead of them following conversion. A life extension assessment of the vessel's structure can help an operator clarify his options when considering an existing vessel for conversion, identifying the remaining fatigue life of the structure when subject to the expected operational and environmental conditions.

As these concepts for floating LNG processing and terminal projects advance, their realization depends on comparable advances in the technology of design. Given the industry's history of advances in computing applications, there is every reason to believe a wide range of new software tools will become available to efficiently create and analyze advanced FLNG designs. In particular,



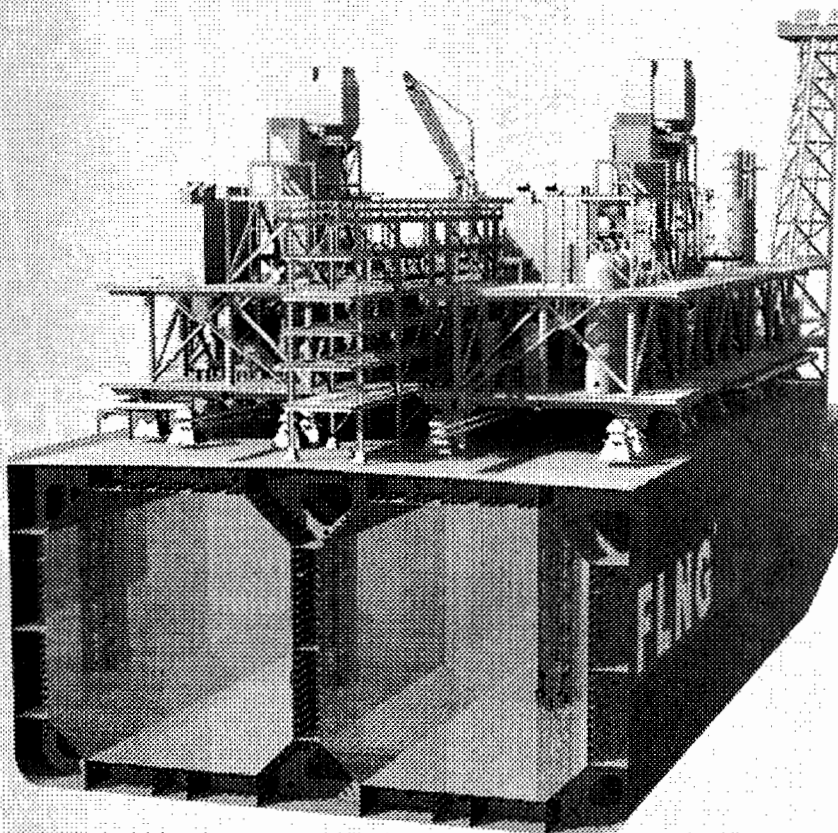
Escravos LPG FSO

software tools in the field of computer simulation are on the threshold of a new era. Advances in mathematical modeling, computational algorithms, the speed of computers, and the science and technology of data-intensive computing have prepared the way for improvements in modeling, simulation, and computing.

One area that is attracting particular attention that has relevance to the proposed very large FLNG newbuild concepts is physics-based simulation within computational fluid dynamics. This technique enables users to produce virtual prototypes, realistically simulating and analyzing the behavior of complex systems and multiple design variations until an optimal design is achieved. Another evolution is helping close the gap between computer-aided design (CAD) and finite element analysis.

Designers generate CAD files that must be translated into analysis-suitable geometries, meshed and input to large scale finite element





analysis (FEA) codes. Computer simulation using the finite element method involves many man-hours spent in remodeling the object into a suitable finite element mesh. With the development of Isogeometric Analysis, differences between the CAD and finite element model are reduced such that the CAD model more realistically reflects the real geometry.

That said, these advances must be economically viable. Commercial viability is the watchword in the energy sector where advances may have to wait for market conditions to make their application viable. As the offshore industry looks for economically attractive solutions for offshore LNG, developers continue to address such issues as the integration of subsea architecture with FLNG; offloading systems, in particular for harsher environments with tandem configurations based on cryogenic hoses or flexible pipes; and the qualification and testing of components with regard to LNG transfer systems. ♦

## New Class Criteria Support FLNG Development



William J. Sember  
Vice President  
of Global Gas,  
ABS

Supporting advances in floating LNG concepts is the ABS *Guide for Floating Offshore Liquefied Gas Terminals*, which reflects the latest structural design and analysis developments in gas handling, storage and transportation. ABS has been involved with several groundbreaking FLNG and floating storage and re-gasification unit (FSRU) concepts, either directly as the class society for the project or in the design review stage.

The Guide provides criteria that can be applied to the classification of the hull structure of floating offshore liquefied gas terminals (FLGTs) with membrane tanks or independent prismatic tanks. It addresses liquefied gas terminals with ship-shaped or barge-shaped hull forms, having single center cargo tanks or two cargo tanks abreast arranged along the centerline of the terminal's hull. ABS has also developed proprietary software for the application of the new criteria to the evaluation of a proposed design.

Structural design challenges are being driven by the increase in the size of terminal hulls, shallow water load effects, frequent partial filling, offloading operations and critical interfaces between the hull and topside structure and between the hull and position mooring system.

"From a class society perspective there are no technology showstoppers for FLNG," says ABS Vice President of Global Gas, William J. Sember. "Liquefaction plants have been suitably optimized in order to efficiently use deck space while taking into account the safe and efficient operation of process equipment," he notes. "The advances and level of sophistication in all these subjects are evident. The time for commercialization and the first project is now." ♦



INNOVATION SNAPSHOT:

## 'LNG Blanket' Addresses Sloshing Impact in Membrane-type Ships

Industry concern relating to possible deformation of sections of some membrane LNG containment systems under very specific partial filling and vessel motion conditions has sparked development of a novel piece of equipment. Named the ABAS (Anti-Boil-off gas/Anti-Slosh) blanket, its objective is to reduce both cargo sloshing and cargo boil-off in the holds of ships with membrane-type tanks.

Developed by Samsung Heavy Industries, the ABAS is made of cubes of cryogenic foam that have a hollow aluminum ball at the center. The cubes are stitched into covers made of a cryogenic textile, then linked together with U-bolt-type connectors to form a flexible mat. The ball provides the buoyancy that lets the mat float on the surface of the LNG cargo.

Samsung reports that testing showed a reduction in sloshing pressures of 60 percent and that, after the design is optimized, a reduction of 80 to 90 percent may be achieved. The shipyard also reports a 0.15 to 0.1 percent reduction in the rate of cargo boil-off.

Samsung conducted the tests using a prototype and plans to run full-scale tests towards the end of the year. Initial results have been sufficiently positive to have attracted the interest of several shipowners, according to the shipyard. Some have already volunteered ships for the further development trials.

According to Samsung, when the blanket is used, no structural reinforcement is needed for the upper part of the cargo tank. This would help contain construction costs as well as reduce the possibility of in-service repairs.

Yard experiments have also indicated that the ABAS blanket may allow a simpler design of the cargo tank itself. A paper presented recently by Samsung Principal Research Engineer Sangeon Chun indicated that the sloshing relief provided by the ABAS system could let designs move away from the traditional octagonal shape of membrane-type tanks. This has been the standard design approach to minimize the impact of cargo sloshing. The blanket could allow a more squared-off upper tank arrangement.

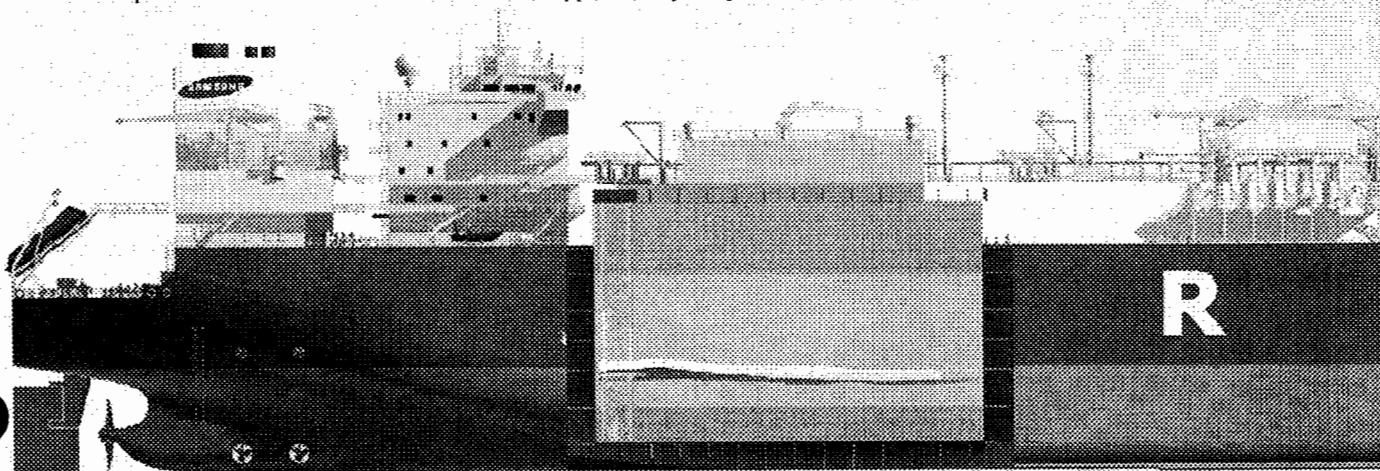
Further, according to Samsung, use of the blanket might even allow designs of much larger cargo tanks. If the number of tanks could be reduced as a consequence, further reductions in the initial cost of the ship would be possible.

The blanket also is of interest for use on proposed floating liquefied gas terminal units. These units will, by the nature of their production and offloading operations, often operate with partially-filled tanks. As a consequence the impact of sloshing within these tanks is of particular concern for designers.

The ABAS blanket design has received approval-in-principle from ABS. ♦



Sangeon Chun,  
Principal Research Engineer,  
Samsung Heavy Industries



# Should the Shipping Industry be Further Regulated as a Result of an Offshore Accident?

Joe Angelo, Managing Director, Intertanko

The tragedy that occurred last year in the Gulf of Mexico when the Macondo well blew out, destroying the *Deepwater Horizon* drilling rig, resulted in the terrible loss of 11 lives and the largest pollution incident to have occurred in US waters. Since then, there have been numerous government and industry investigations into the cause of the accident. Some new regulations have been issued but the final full consequences that will result from this tragic event remain to be seen. Perhaps more could have been done more quickly if the proposed remedies had remained focused on offshore drilling.

The US Congress held numerous hearings. Legislation was drafted in both the House of Representatives and the Senate aimed at preventing another such incident and improving the nation's response capabilities. Although some legislation was enacted, the 111th Congress adjourned in December 2010 without passing much of what had been the proposed. Why was that? The main reason could be that the 111th Congress failed to recognize that offshore oil exploration entails exposure and risks which are very different from those associated with maritime transportation and the shipping industry.

Unfortunately, a considerable portion of the legislation drafted in Congress to remedy perceived failings in the offshore safety regime also included changes to statutes affecting the shipping industry which had been in place for years and, in one case, more than a century. These were existing laws governing the liabilities of vessel owners and operators which have proven, over time, to work effectively while, at the same time, preserving the commercial viability and insurability of maritime transport operations.

The result was that a large and broad industry coalition, representing cargo, container, oil carriers, barge and towing, and passenger shipping companies operating in US domestic and international commerce, expended considerable time, energy and resources in successfully convincing key members of Congress that such changes were not only unnecessary but could have a devastating effect on the shipping industry.

The shipping coalition's main concerns centered on the limits of liability in damage claims, punitive damages and damage awards in the event of a death on the high seas. The following is a quick overview of each.

**Limits of liability in damage claims:** The House passed HR.5503 which would have repealed the bulk of the Limitations of Liability Act of 1851 thereby exposing shipowners to unlimited liability in damage claims not related to oil pollution. To repeal the key provisions of this statute would have resulted in a liability exposure with unknown insurance effects and unnecessarily increased the cost of commerce to and from the United States.

**Punitive damages:** Senate bill S.3600 would have allowed unlimited punitive damage awards without regard to compensatory damages assessed in any maritime tort action. This change would have superseded the US Supreme Court decision of *Baker v. Exxon* which set a 1:1 ratio of punitive to compensatory damages in certain maritime cases. This provision for unlimited punitive damages raises constitutional problems and violates a defendant's due process rights under the Fourteenth Amendment.

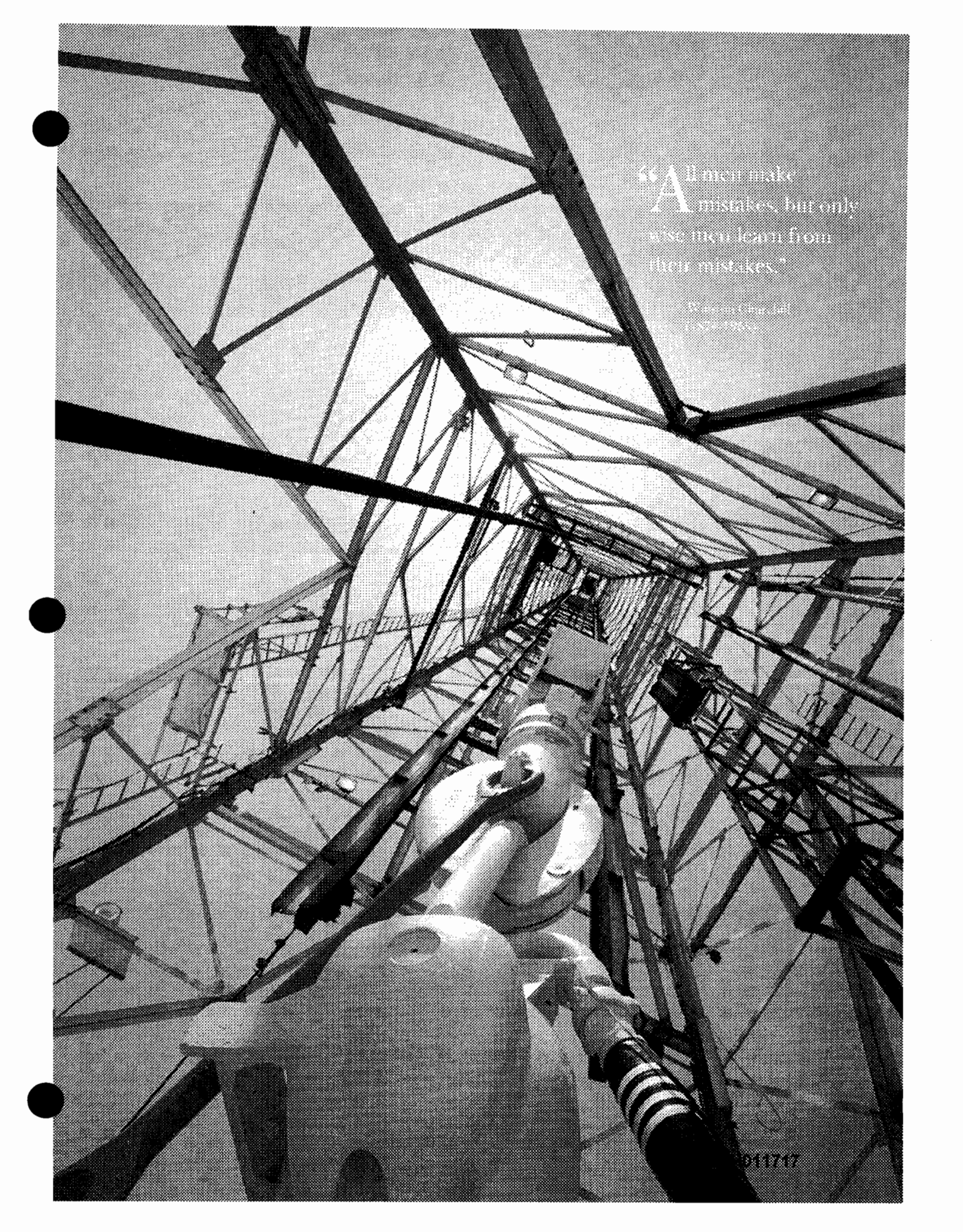
**Death on the high seas:** The House passed HR.5503 which would amend the Death on the High Seas Act (DOHSA) by including damage awards for non-pecuniary losses, such as pain and suffering and loss of companionship. Together with unlimited punitive damages, the effects of these changes on the insurability of maritime commerce would have been unknown but potentially severe. The maritime coalition recognized and supported the need and desire of Congress to provide recovery for the families of the *Deepwater Horizon* victims, but any change to DOHSA beyond that were not considered necessary or justified.

Vessels operating to and from the US have an excellent safety record. The number of incidents and amounts of oil spilled in US waters by vessels has dramatically declined over the past 20 years. The combination of effective liability limits for vessel owners and the oil industry funded Oil Spill Liability Trust Fund has meant that the cost of vessel accidents and spills is not borne by the general taxpayer. This effective national system has served the United States well.

The 112th Congress, now in session, should focus its attention on addressing the risks posed by deepwater oil exploration and production and avoid harmful consequences that would adversely and needlessly affect maritime transportation and the shipping industry. ♦







“All men make  
mistakes, but only  
wise men learn from  
their mistakes.”

William Churchill  
1874-1965

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