

Oil & gas: Better safe than sorry

Safety: a risky business gets riskier

History has shown that it tends to take a major disaster to spring the industry into action on “extra-financial” issues like safety. The Gulf of Mexico spill has done just that, putting safety firmly on investors’, regulators’ and stakeholders’ agendas. While “Big Oil” is here to stay, the entire industry, from mature supermajors to NOCs, is looking again at how E&P is conducted – with stricter safety regulations and higher costs on the cards for producers and consumers for years to come.

Deepwater gearing up for new drilling cycle

Offshore and deepwater are key to production growth after 2015, but the industry is facing a major challenge in terms of ageing global fleets and technological obsolescence from tougher conditions and tighter global HSE standards. We believe that the move to stricter safety standards is catalysing an offshore rig, equipment, and drilling cycle. No company wants to face the backlash of a spill from a 30-year old rig, and premium assets should achieve premium dayrates.

New geologies, new geographies, new risks

Oil & gas companies are being pushed towards more difficult types of hydrocarbons and increasingly complex E&P to meet global demand. We anticipate a wide range of new safety challenges arising from shale oil, oil sands, pre-salt and the Arctic, in particular. We think regulators are likely to seek to strike a balance between producing economically and greater scrutiny on safety.

Hidden risks: infrastructure, employees, subcontracting

Boom and bust investment and the drive towards cost efficiencies have left the sector dealing with the safety risks of ageing physical and human assets and loss of control via subcontracting. Worrying examples are onshore pipelines, with 60% of US pipelines over 40 years old; and the “big crew change”: the industry’s ageing workforce, a wave of impending retirements and failure to attract talent.

Opportunities: our top safety plays

Beneficiaries should include oil service companies providing the latest offshore rigs and equipment; insurance companies, benefiting from the increase in pricing in energy; and TIC companies, which should gain from the regulatory push for independent certification. Our top picks: BV, KPELF, NOV, SDRLF and SMM.

A longer-term view

The long-term risks to oil and natural gas are hard to measure beyond our view that oil prices will hit \$100/bbl in 2011. However, the spill is framing the policy debate for the energy mix, with cleaner and safer forms of energy among the possible winners and “Big Oil” and consumers among the possible losers.

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Table 1: Winners & Losers

Winners	Losers
Deepwater drillers	“Big Oil”
Rig builders	Drillers with older rigs
Reinsurance	Consumers
TIC	

LT Winners

Cleantech, Coal, Nuclear, Shale gas

Source: BofA Merrill Lynch Global Research

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Oil & Gas: safety in brief

History has shown that it tends to take a major disaster to spring the industry into action on "extra-financial" issues like safety. The Gulf of Mexico spill has done just that, putting safety firmly on investors', regulators' and stakeholders' agendas. Regardless of the final findings of the Macondo investigations, the entire oil & gas industry, from mature supermajors to NOCs, is being forced to look again at how E&P is conducted. We expect stricter safety regulations and higher production and consumer costs to be on the cards for years to come.

A sea-change in occupational safety

We believe the oil & gas sector should be commended for the significant improvements in personal safety with a tenfold improvement in frequency, incidents and fatalities over the past two decades. Particular progress has been made on LTIF (lost time injury frequency), TRIR (total recordable incident rate) and FAR (fatal accidents rate), with the three indicators falling to record lows of 0.45, 1.75 and 2.76, respectively, for a panel of 43 oil & gas companies according to industry body estimates. Using our own analysis of publicly disclosed data on fatalities per 100,000 employees across the BofAML universe, oil & gas ranked third-highest and oil services sixth among different industry sectors. This data is consistent with International Labour Organization (ILO) fatality estimates for major industry sectors. It is a safer sector than, for example, mining and construction.

Running hard to keep up in many areas

Nonetheless, even with record-setting data, the oil & gas sector still experiences an average of 29 incidents every week of the year, as well as 260 person-years lost by companies and their contractors to injuries and at least 99 fatalities annually. Moreover, despite the best efforts of many companies to move towards a goal of zero accidents, actual figures remain worryingly high, particularly for offshore and drilling activity and contractors. Regionally, Europe and North America lag significantly behind global averages.

An already risky business getting riskier

Longer term, the Gulf of Mexico spill has raised the larger question of whether oil & gas companies' efforts are sufficient to manage the ever-growing process safety risks in the sector. After all, LTIF, TRIR and FAR indicators have shown themselves to have limited value for active monitoring of process safety risk(s), as precursors of systemic safety risks like ageing infrastructure, human resources challenges, investments in the race for increasingly difficult E&P and hydrocarbons, shareholder vs. stakeholder interests, or safety performance. Moreover, as we have seen, the effects of an offshore or deepwater incident are potentially devastating from health, safety and environmental perspectives.

O&G occupational safety indicators 2009*

Activity	LTIF	TRIR	FAR
Company	0.44	1.28	1.58
Contractor	0.46	1.89	3.11
Onshore	0.38	1.45	2.75
Offshore	0.70	2.79	2.75
Exploration	0.68	2.31	2.21
Drilling	1.22	3.81	3.12
Production	0.72	2.31	2.15
Construction	0.29	0.78	1.14
TOTAL	0.45	1.75	2.76
Region	LTIF	TRIR	FAR
Africa	0.42	1.65	2.21
Asia/Australasia	0.29	1.22	1.58
Europe	1.31	3.48	6.58
FSU	0.35	1.21	3.14
Middle East	0.26	0.92	2.16
North America	0.51	3.08	4.37
South America	0.69	3.17	2.37
TOTAL	0.45	1.75	2.76

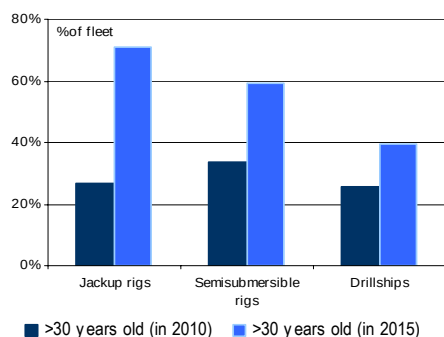
Source: OGP, BofA Merrill Lynch Global Research. * Based on 43 companies, 102 countries, 3,586mn work hours; LTIF = number of lost time injuries (fatalities + lost workday cases) per 1mn hours worked, TRIR = number of recordable injuries (fatalities + lost workday cases + restricted workday cases + medical treatment cases) per 1mn hours worked, FAR = the number of company/contractor fatalities per 100mn hours worked.

Table 2: Industry sector fatalities per 100,000 employees (2009)

Aerospace & Defense	0.32	Fixed Line Telecommunications	0.15	Industrial Engineering	1.40	Oil & Gas Producers	9.00
Alternative Energy	NA	Food & Drug Retailers	0.03	Industrial Metals & Mining	2.65	Oil Equipment & Services	4.30
Automobiles & Parts	0.30	Food Producers	1.45	Industrial Transportation	2.60	Personal Goods	0.27
Banks	0.05	Forestry & Paper	0.46	Leisure Goods	0.14	Pharmaceuticals & Biotech.	0.46
Beverages	1.84	Gas, Water & Multiutilities	3.31	Life Insurance	0.13	Software & Computer Services	0.00
Chemicals	2.32	General Industrials	0.98	Media	0.11	Support Services	1.76
Construction & Materials	10.25	General Retailers	0.02	Mining	19.75	Technology Hardware & Equip.	0.05
Electricity	6.36	Health Care Equipment & Services	NA	Mobile Telecommunications	4.91	Tobacco	1.13
Electronic & Electrical Equipment	0.20	Household Goods & Home Construction	0.21			Travel & Leisure	0.65
TOTAL AVERAGE	1.64						

Source: BofA Merrill Lynch Global Research, Bloomberg

Chart 1: Pressing need to start replacing ageing rigs



Source: Riglogix, BofA Merrill Lynch Global Research

Offshore and deepwater: safety turning the tide

Offshore production currently provides one-third of global supply, but this is projected to rise to about half in 2015, with deepwater oil fields among the only segment that can provide oil production growth after that period. Emerging markets in particular are keen to develop such resources and with NOCs already owning a big portion of offshore reserves, this trend is likely to become more pronounced in the coming years. The development of larger, deeper offshore oil will get increasingly complicated, from both an operational and safety perspective. However, the industry is facing major challenges in that older rigs cannot drill in deepwater, the inherent lifespan of an offshore rig is 30 years, and the proportion of ageing rigs 30 years or older is set to increase up to 2015. US efforts to play catch-up on safety regulations (such as via the introduction of the Drilling Safety Rule), other countries' efforts to ramp up their own safety standards, and post-Macondo efforts to reduce the chance of another oil spill have all shaken the core of global drilling activities. Operators' requirements have changed, kick-starting a wave of newbuild rigs.

Rig replacement and new drilling cycle

The rig replacement drivers include: 1) new regulations, increasing the specification of rigs and associated equipment (BOPs, risers), 2) growing differentiation between old and new generation rigs as operators look to high grade requirements and improve efficiencies, 3) shortening backlogs at the shipyards, leading to attractive rig pricing. With c.70% of the jackup and c.60% of the global semisub fleet built before 2000, we believe that this replacement cycle has a long way to go. This new rig era is not driven by dayrates, as was the case in 2004-08. That said, we believe that premium assets will achieve premium dayrates. We also believe that operators will express a preference for established service providers and contractors, especially those with newer equipment; that drilling contractors will show renewed preference for maintenance by OEMs; and that companies with older offshore rig fleets may be at a disadvantage.

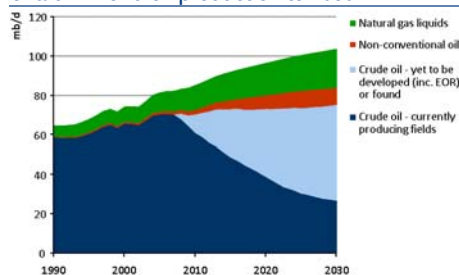
Unconventional O&G, unconventional risks

With two-thirds of the 100 countries currently producing O&G liquids and the majority of the world's giant oil fields past their production peak, the world needs the equivalent of four to six more Saudi Arabias if it is to maintain current levels of production by 2030. This is pushing oil & gas companies towards more difficult types of hydrocarbons and increasingly complex E&P to meet growing global energy demand.

New geographies and geologies = new risks

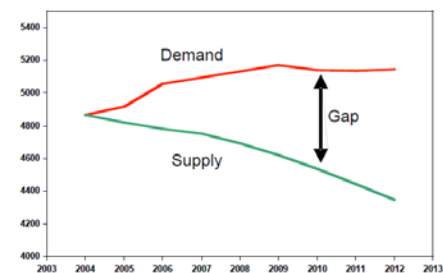
We see a wide range of new safety challenges emerging on 1) shale oil (hydraulic fracking, drilling fluids, water pollution, EPA investigation, moratoriums, regulations); 2) oil sands (market reaction to recent spills, growing case vs. "dirty oil", uncertain future of Keystone pipeline); 3) pre-salt (deepwater, salt layer, untested conditions, strengthening of HSE regulations); and 4) the Arctic (unique biodiversity, no proven technology to remove oil from ice, difficulties of a clean-up operation, regulations). Whereas some might have argued, only a year ago, that such issues are largely irrelevant to investors, GoM has heightened scrutiny of the potential risks. We anticipate that regulators will follow stakeholders in this direction and are likely to seek to strike a balance between producing unconventional oil economically and safety concerns. Either way, the result should be the same, with oil & gas companies facing the prospect of stricter safety regulations and higher production costs.

Chart 2: World oil production to 2030



Source: IEA WEO Reference Scenario, BofA Merrill Lynch Global Research

Chart 3: North American and European demand for mid-career O&G technical professionals (age 30-39): 2003-2013



Source: NPC, BofA Merrill Lynch Global Research

Biggest risks are hidden risks

Decades of boom and bust investment – on the back of volatile commodity prices – have left the industry with ageing physical and human resources, which are being pushed to the limit as companies seek to meet growing demand.

Ageing assets

A large proportion of O&G infrastructure is old, rusty and corroding and needs to be replaced, posing major safety risks. In addition to offshore drilling rigs, a worrying example is onshore pipelines, with 60% of US pipelines over 40 years old, despite having a typical design life of 20-25 years. It is no surprise that corrosion is at the heart of pipeline repair and replacement, accounting for up to 70% of all releases, which have caused \$4.4bn in property damage and spilled 2.5bn barrels in the past two decades. Global corrosion costs could be as high as \$80-100bn per year, and this year's Enbridge spill from a 41-year old pipe served as a reminder that markets are not averse to such events, with oil spiking at \$4/bbl and gasoline prices at 25 cents/gallon.

Ageing workforce

The safety risks around physical assets are being compounded by significant loss of human talent and highly specialised skills as the industry moves to "technical oil" such as unconventional, deepwater and new frontiers. The average age of petroleum engineers is 46-49 and one third are aged over 50. The industry is facing a "big crew change" with reduced talent and safety expertise via impending retirements and a failure to attract new talent, with only 30% of the workforce aged 20-40 (vs. 60% in other technical industries).

Subcontracting

These issues are being compounded by the long-standing trend toward outsourcing and subcontracting of assets and engineering work to oil services companies, which have the upper hand in terms of talent and experience in high-tech, high-growth areas like deepwater. The GOM spill is raising questions about whether such decentralisation and loss of control are appropriate in an industry with such high stakes from an HSE perspective. We believe that the relationship between third party contractors and Majors is changing and that we are likely to see a lot more hands-on involvement and control from the latter in operations (even if they are unlikely to go as far as owning and operating their own rigs).

While the downturn should come to an end at some point and energy demand is already rebounding, the lack of long-term sustained investments in assets and people, including a company's own employees, is another looming \$40bn problem. Bear in mind that human capital has the longest lead time in the exploration, production and drilling cycle (5-10Y to fully develop an engineer's operational competence).

"Under these new [Drilling Safety and Workplace Safety] rules, operators will need to comply with tougher requirements for everything from well design and cementing practices to blowout preventers and employee training. They will also need to develop comprehensive plans to manage risks and hazards at every step of the drilling process." US Secretary of the Interior Ken Salazar

The oil & gas industry has safely drilled 14,000 wells in depths of 300m or more. "But just a single spill, a single incident, a single injury or fatality is one too many... So working with regulators and other stakeholders, our collective aim should be to ensure that the right solutions are in place wherever the oil & gas industry operates – including deep water." - Joep Coppes of Shell and OGP's Global Industry Response Group (GIRG), September 2010

Regulation: history shows disasters can be game-changers

History has unfortunately shown that the industry tends to be reactive and it can take a major disaster to spring everyone into action on regulation. The 1988 Piper Alpha rig explosion and its impact on UK and Norwegian safety standards and the 1989 Exxon Valdez oil spill's hastening of double-hull tankers globally are two pertinent examples.

US playing catch-up on safety regulations

Offshore should be the initial focus for US regulators with the US GoM safety regulations having been in a different league in April 2010 from those in countries like Norway or the UK, which have been the benchmark for regulations ranging from rig and facilities, to drilling and well operations, and to oil spill preparedness. The U.S. Department of the Interior (DOI)'s September 2010 announcement of the Drilling Safety Rule and the Workplace Safety Rule, both aimed at improving drilling safety, are an important attempt to catch up to "best practice". A host of producing nations, including Brazil, Canada, Norway and Russia, are also waiting on the results and recommendations of the GoM investigation to propose stricter HSE regulations. We think offshore is only the start, with concerns over shale oil and the Arctic also pointing to greater regulation.

Trend towards unified regulatory systems

We are also seeing a trend towards unified regulatory systems and a move away from patchwork regulations, jurisdictions and enforcement, as well as the first signs of trans-national legislation. The European Commission is for the first time envisaging comprehensive EU legislation on oil platforms covering the criteria for granting permits and control of rigs and safety control mechanisms. We are also seeing the first calls for international safety standards for the sector, with the US Institute of Nuclear Power Operations (INPO) and the International Atomic Energy Agency (IAEA) both being held up by stakeholders as potential models. However, keep in mind the years of upheaval when the UK overhauled its regulatory system after the Piper Alpha disaster – stricter regulation or a move to global standards will not be an overnight event.

A strong industry response, but is it enough?

The Macondo accident showed that the industry as a whole – oil companies, contractors and regulators – was not prepared for such an event despite some serious precedents including Exxon Valdez, Piper Alpha and Montara. The impact of the spill was such that industry and regulators were quick to realise that the issues could engulf the sector unless swiftly dealt with. Indeed, the voluntary response of operators/drilling contractors in the GoM was such that at the time the new drilling regulations were introduced, the bulk of the deepwater units already complied with them. The financial and reputational impact of Macondo on BP pushed all operators to review their approach to drilling operations – even in countries where there have been no actual changes in regulations.

First indications are encouraging

The thorough reviews of deepwater drilling regulations by the industry are set to transform this part of the business with more limited opportunities and heavier scrutiny for smaller players in deepwater. By and large, the industry is taking the necessary steps both in prevention and response to avoid another disaster. There is still much to do, but we believe that the industry's proactive stance is encouraging, particularly on well control (prevention activities, technical standards, BOP testing, well designs) and cap & containment (oil spill response activities). We also note that the extremely competitive industry players are collaborating on containment such as the UK's Oil Spill Prevention and Response Advisory Group (OSPRAG) and the GoM Marine Well Containment JV set up by oil companies.

Companies themselves spearheading prevention, but watch this space

In contrast, prevention activities appear to have been driven by companies themselves. The key challenge remains to co-ordinate the way that the industry manages and prevents spills as standardisation remains difficult. The co-ordination could be easier in the response phase, but the diversity of geologies and types of well make the approach to prevention more difficult. Admittedly, it may be “too little, too late” from many stakeholders’ perspectives, but our experiences suggest that safety has risen to the top of the O&G sector’s agenda, whether it be a site visit in Angola or corporate results presentations. That said, stakeholders have good reason to keep the industry under close watch. The end of the downturn, a rise in oil prices and surging costs could all jeopardise the significant progress which has been made since April 2010.

Beneficiaries of O&G safety theme

We identify six key stocks

The spotlight on HSE issues – and safety and security in particular – will create new opportunities for companies working with the oil & gas sector. We have identified three industry segments, and within these six companies, which, on the basis of their current sales exposure and long-term growth prospects, offer exposure to the safety and security theme:

1. **Rig builders, rig technology, drillers, drilling rig equipment and oilfield consumables and products companies** providing new offshore rigs to replace ageing global fleets and tackle technological obsolescence from ever-deeper and tougher offshore drilling and production conditions;
2. **Insurance companies** benefiting from the up to 20-30% increase in pricing in energy post-Macondo; and
3. **TIC (testing, inspection, certification) companies**, which will benefit from the worldwide push for independent third-party certification for the sector.

Bureau Veritas (BV)

BV is the world's second-largest testing and inspection agency with strong positions in the provision of independent inspection services, especially in the marine, consumer and industrial sectors. BV offers strong exposure to the broad HSE theme via virtually all of its business lines. In terms of oil & gas, it should experience strong growth potential for offshore (20% CAGR 2010-14) via its combination of Marine and oil & gas businesses, strong technical experience (deepwater) and longstanding relationships in the sector. BV has had North Sea operations for 30+ years and is currently involved in compliance, verification, integrity management and maintenance support activities on over 120 platforms, which corresponds to 45% of all fixed assets in the region.

Offshore wins in H1 2010 include Goliat (third-party verification in the Barents Sea), integrity and inspection contracts for all North Sea assets of Total E&P UK, re-certification of complexes of ONGC in the West Coast of Mumbai, asset integrity management services for ADOC, and life extension, collision analysis, and stability studies (Xikomba FPSO, Nan Hai Fa Xian FPSO, N'Kossa II). BV also provides safety and risk services including behaviour and human factor management, rig containment surveys, management systems, permit applications for offshore and onshore legislation, advice on equipment specification and HSE training.

Table 3: Bureau Veritas' offshore oil & gas clients

Segment	Clients
Oil & gas companies	BP, BHP, CNOOC, CHEVRON, CONOCOPHILLIPS, ENI, EXXONMOBIL, GDFSUEZ, HESS, MURPHY, PERENCO, PETROBRAS, PETROCANADA, SANTOS, SHELL, STATOIL, TOTAL, WOODSIDE
EPCs	BLUEWATER, DSME, EXMAR, HHI, KBR, MAERSK, MISC, MODEC, PROSAFE, SAIPEM, SBM, TEEKAY, TECHNIP

Source: Bureau Veritas, BofA Merrill Lynch Global Research

BV is our Business Services analyst Toby Reeks' preferred stock within the TIC space. There are positive trading signals evident for Marine (the New Ships business is on an improving trend), Industry (the order book is strong in inspection and certification) and Consumer. In our view, BV's recent re-rating is justified by its accelerating organic growth (5.9% for Q310), scope for margin expansion, EM exposure (48% of revenue), and TIC 'best of breed' status.

Cross Reference

[BV, 04 November 2010](#)

[BV, 13 September 2010](#)

Cross Reference

[Offshore & Marine, 08 November 2010](#)

[Keppel Corporation, 25 October 2010](#)

Keppel Corporation (KEP)

Keppel Corp has three key businesses: offshore & marine, property, and infrastructure. KEP is a world leader in rigbuilding, and owns proprietary designs for various offshore units. We believe Keppel Corp's key Offshore and Marine business will benefit from the expected upswing in construction contracts for offshore rigs and units, using newer and more HSE-friendly designs which are well suited to new operating requirements such as deep waters and harsh environments.

The \$360mn LOI with Mermaid Marine to build two jack-up rigs for targeted delivery in 4Q12 and 1Q13 suggests there were grounds for our optimism. If this proposed deal proceeds, Mermaid will also be given the option to build another two jackup rigs. We believe the option value will be higher than US\$360mn, in line with the typical structure of such bundled deals.

Other known tenders that KEP is bidding for are: 1) Maersk Drilling's two harsh environment jackup rigs (worth >US\$900mn), 2) Vietsopetro's semisubmersible rig (worth ~US\$550mn), 3) Petrobras' P-58 FPSO. Our rating is Buy. Our analyst Wee Lee Chong is optimistic on Petrobras orders before end-2010 (for the challenging pre-salt operating environment), given that the company is facing increasing pressure from a tightening delivery schedule for its 28 rigs, with Greenfield yards yet to be built. We also expect the recent large newbuild orders placed by Seadrill, Atwood Oceanics, and Mermaid to add upward pressure on prices if the rig order momentum is sustained. Furthermore, KEP offers exposure to the larger SRI and sustainability theme as it is the lead private investor in Sino-Singapore Tianjin Eco-City, a 10-15 year model city development for sustainable residential housing in China; it provides eco-friendly proprietary waste treatment solutions globally; and the K-Green Trust should provide a ready financial platform for KEP to embark on eco-friendly infrastructure projects globally.

Lancashire Hldg (LRE)

Lancashire is from the class of 2005: (re)insurance start-ups positioned to take advantage of the improved underwriting environment following the devastating hurricane season in 2005. It specialises in the property (48% of its portfolio in 3Q10), energy (33%), marine (11%) and aviation lines (8%) and writes in the primary, reinsurance and retro markets.

We expect Lancashire to be one of the few insurers (possibly along with W.R. Berkley (WRB), which has a new energy team) to benefit from the increase in pricing in energy post GoM and the extent of demand for increased coverage should become more apparent from clients over the next 12-24 months. The company is seeing demand returning for the Gulf of Mexico with prices back to the all-time highs of 2009 and demand for global offshore significantly higher, with prices up 20-30% on average. In our view, barring legislative changes, there is currently sufficient capacity in the market to absorb increased demand following the Macondo well blowout. If this is indeed the case, we expect only those insurers that already have evident underwriting expertise and presence in energy, such as Lancashire, to benefit, before most of the profit gets competed away as all other insurers look for profitable niches in a softer market.

We consider Lancashire a high-risk, high-reward stock. Earnings forecasts are in part dependent on the broad theme of safety, i.e. major catastrophe activity (39% nat-cat exposed), but, in our view, not as much as perceived. The company continues to deliver on expectations: selectively underwriting during a softening

Cross Reference

[Lancashire Hldg, 08 November 2010](#)

market, while actively managing its capital base to continue to deliver a peer-leading RoE. The shares currently trade at less than forward fully diluted tangible book value, which offers a good entry point, in our view.

Table 4: Hardening energy insurance market post Deepwater-Horizon

Coverage	Buyer	Summary	Potential deepwater Horizon Impact
Physical Damage	Operator & Contractor	Cost of replacing physical assets in the event of an insured peril	1) Rate rises as a result of market forces
Control of Well	Operator	Cost of well control / cost of redrill / cost of clean up	1) Rate rises as a result of market forces and review of pricing adequacy 2) Increased demand as limits purchased increase? 3) Reduced supply as capacity providers review clash with drilling contractors?
Loss of Production Income (LOPI) / Loss of Hire (LOH)	Operator & Contractor	Loss of income following an insured peril trigger	1) Rate rises as a result of market forces
Third Party Liability – Primary & Excess	Operator & Contractor	Third party liability including liability resulting from a pollution incident	1) Rate rises as a result of market forces and review of pricing adequacy 2) Increased demand as limits purchased increase? 3) Review of coverage provided? 4) Reduced supply as capacity providers review clash with upstream energy portfolio
Third Party Liability – OPA specific	Operator & Contractor	Strict liability for pollution in US waters – “Polluter Pays” concept Certification required either through Insurance Certificate / Self Insurance (subject to satisfactory balance sheet) / Bond	1) Increased limits required – extent of which will be determined by US legislation currently US\$75m maximum for operators

Source: Lancashire Group, BofA Merrill Lynch Global Research

Cross Reference

[National Oilwell Varco, 29 November 2010](#)

[US Oil & gas, 15 November 2010](#)

[National Oilwell Varco, 27 October 2010](#)

National Oilwell Varco (NOV)

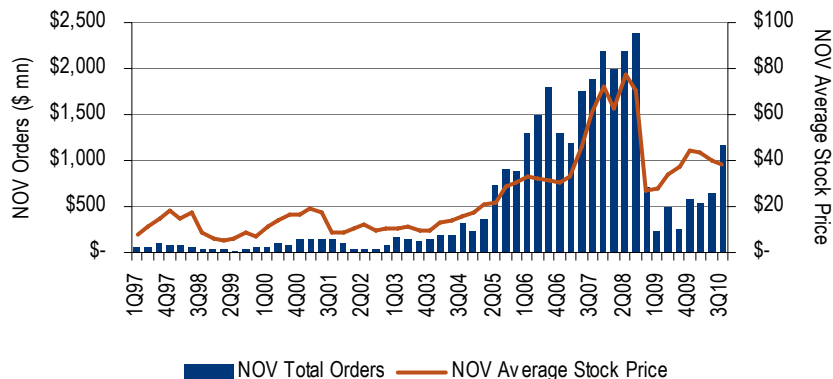
NOV is the dominant provider of equipment for drilling rigs and provides consumables such as bits and pipe, and also operates a distribution business (the equivalent of a convenience store for operators - which is exactly what they need in an increasingly safety-focused operating environment). We expect a combination of higher baseline orders, increasing interest in high specification jackups, and demand for new floaters from Petrobras and others to drive orders higher in 2011 vs. 2010.

The increasing interest in offshore newbuilds is a positive for NOV, given its roughly 60% market share in the rig equipment market (drilling packages). NOV can generate up to \$30-35m of revenue per jackup, \$150-\$200mn per semisubmersible and \$200-\$250mn per drillship. While pricing is down from peak levels, margins have been maintained through efficiencies. Demand for new and better equipment continues to rise, as can be seen from the six high-specification jackups and two drillships announced recently.

We expect NOV to get the Seadrill drillship rig equipment orders and initial bookings for Petrobras' 28 floaters (for the challenging pre-salt operating environment) should begin in 2Q11 after the company opened up commercial bids on 26 November 2010. Separately, Petrobras has reportedly launched a tender to contract at least two dynamically positioned (DP) deepwater rigs which is positive for the ultra-deepwater rigs market. Additionally, we expect pricing improvements to drive margins to 25% in 2011 for Petroleum Services & Supplies (PSS). We also see opportunities for its new low force shear ram, which could be a \$6bn opportunity for the industry related to the safety market for BOPs (blow-out preventers) over the next five years. Demand for aftermarket sales and repair services (25-30% of NOV's total revenue) has also increased in the aftermath of the Macondo blowout and the APL acquisition bolsters NOV's position as an integrated one-stop solution provider for all equipment needs, from drilling to production life cycle of deepwater development. Although NOV has been a recent outperformer, it is yet to catch up with its peers coming off a recent cycle trough. Furthermore, we believe that one should watch for acquisitions (FPSO, PSS) or a special dividend.

Risks include global economic weakness, slower oil and gas demand growth, oversaturation of the floating rig market and overcapacity in the jackup market. Company-specific risks are delivery delays or contracting difficulties for its ultra-deepwater newbuilds. While the “easy money” has been made as NOV’s shares have rallied in anticipation of such catalysts, the broad strength of industry newbuild orders has the potential to drive orders significantly higher. While still early, we see the potential for ~\$7.0bn of orders in 2011, driving 2012E EPS >\$5.00 (Street at \$4.17).

Chart 4: Orders and NOV stock price are strongly related



Source: Company reports; Bloomberg; BofA Merrill Lynch Global Research

Cross Reference

[SeaDrill, 01 December 2010](#)

[SeaDrill, 09 November 2010](#)

[SeaDrill, 28 October 2010](#)

Seadrill (SDRL)

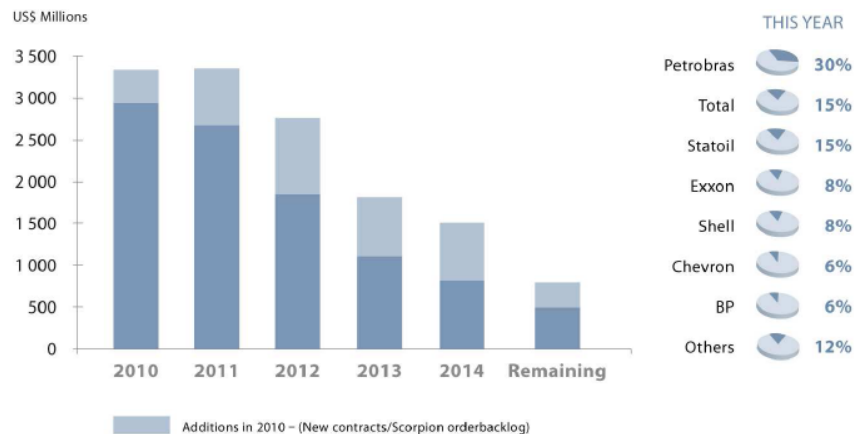
Seadrill is Europe’s largest offshore driller and has the world’s second-largest ultra-deepwater fleet. Based on an aggressive newbuild programme and an acquisitive strategy, Seadrill boasts one of the world’s youngest and most sophisticated fleets. Its fleet of 50 rigs (38 built after 2000) includes 14 floaters, 19 jack-ups and 17 tender rigs, and we believe positions Seadrill well to remain a leading contractor in the deepwater segment of the market.

Seadrill is looking to further strengthen what is already the most sophisticated and youngest fleet of ultra deepwater floater and ultra premium jackup rigs, with an ambition of increasing the fleet size from 50 currently to 60 in the medium term (harsh/ultra-premium jackups and drillships). Despite a strong backlog, which has tied in peak market dayrates over several years, Seadrill sees good opportunities to take advantage of low build costs and an improving macro environment in drilling to add a new class of high spec rigs (“seventh” generation), which will be compliant with new post-Deepwater Horizon safety regulations. Being the first mover (as it was in the last cycle) should help the company to secure sector-leading dayrates. Seadrill has been a market leader in securing high dayrates post Macondo, again showing that oil companies are willing to pay for quality assets and a sound operational track record.

While deep and ultra deepwater rates may take a little longer to recover post Macondo and supply entering the market, SDRL’s backlog keeps earnings well covered through 2012. SDRL appears set to sustain solid earnings over the next 2-3 years on the back of its ambitious newbuild programme which is coming to an end. Its fleet expansion provides Seadrill with unique exposure to the ultra deepwater drilling market, and the cash flow generation should allow for continued attractive dividend payments. Seadrill’s strategy continues to favour newbuild capex over corporate M&A, with management indicating they are becoming

frustrated with the lack of performance in their 9.5% Pride stake. We continue to expect the holding to be disposed off within the next 12 months. Risks include construction risk, unanticipated downtime and industry activity levels. SDRL remains our top pick in US Drilling and European Oil Services, Seadrill remains our favoured name in the offshore drillers, offering a combination of strong earnings visibility, attractive dividend yield (c.8%) and a high quality asset base.

Chart 5: Seadrill's US\$12.3 bn contract backlog



Cross Reference

[Offshore & Marine, 08 November 2010](#)

[Sembcorp Marine, 18 October 2010](#)

Sembcorp Marine (SMM)

Sembcorp Marine is one of the leading global rig builders, with principal activities in rig building, offshore engineering and production, ship repair, ship conversion, and ship building. It has a global network of 15 established yards, and yards under construction, in Singapore, Brazil, Indonesia, China, India, Saudi Arabia, and the US. We believe that SMM and the established shipyards in Asia are best positioned to benefit from the upcoming replacement cycle. Given their strong history of project execution, building at these yards reduces the risk of delivery delays, cost overruns and operational mishaps. The expected higher, but gradual, increase in construction costs for offshore units due to more stringent HSE standards is also likely to incentivise buyers to place orders for these expensive units in proven yards early in the replacement cycle. We have been surprised at the magnitude of (and short time taken to confirm) newbuild jackup contracts – but this supports our view that SMM should be one of the biggest beneficiaries of safety-related demand for deeper water offshore rigs. We expect SMM to achieve new record earnings in FY12, due to the lagged profit recognition from new rig building and offshore production contracts, and its strategic ship repair facilities expansion in Singapore.

Long-term, too early for long-dated oil

Despite the HSE implications of the Gulf of Mexico spill, the long-term risks to oil and natural gas are hard to measure. Assuming that the world continues to adopt stricter safety regulations and companies ramp up their regulations, many of which are already far more advanced than in the US, the long-term impact on hydrocarbon output could be substantial. World offshore proven oil reserves are about 300bn barrels out of a total of 1.3tn, with c.55bn barrels in deep offshore. However, energy policy may impact demand as well. Given stakeholder outrage over the spill, governments could opt to increase taxes on oil & gas to cover future health, safety or environmental calamities or even promote other sources of energy. HSE concerns also need to be balanced against “hearts and minds”

issues such as job creation and national energy security. The policy debate has just begun and the GOM oil spill is not an unequivocally bullish event for the oil market. In our view, this means that further rises in long-dated oil prices are not justified at this stage.

Table 5: BofAML Commodity Price Forecasts

	4Q10F	2010F	1Q11F	2Q11F	3Q11F	4Q11F	2011F
WTI Crude Oil (\$/bbl)	80.00	78.29	81.00	82.00	86.00	91.00	85.00
Brent Crude Oil (\$/bbl)	80.00	78.44	81.00	82.00	86.00	91.00	85.00
USGC No. 2 HO crack spread (\$/bbl)	10.09	9.51	10.55	7.30	8.60	12.75	9.80
USGC RBOB Gasoline crack spread (\$/bbl)	7.64	9.54	7.00	13.00	10.20	7.00	9.30
USGC 1% Residual crack spread (\$/bbl)	-8.30	-6.94	-6.90	-9.90	-10.00	-8.00	-8.70
NWE 0.2% Gasoil crack spread (\$/bbl)	10.41	9.82	11.40	7.60	8.80	13.40	10.30
NWE Prem. Gasoline crack spread (\$/bbl)	1.45	5.02	5.70	9.70	7.70	6.90	7.50
NWE 1% Residual crack spread (\$/bbl)	-4.90	-5.11	-6.00	-5.65	-5.60	-4.80	-5.50
US Natural Gas (\$/MMBtu)	4.80	4.59	4.90	4.60	5.00	5.50	5.00
Thermal coal, Pacific spot (\$/t)	105	91	105	110	110	110	107

Source: BofA Merrill Lynch Global Commodity Research

But the larger policy debate has just begun

The Gulf of Mexico spill has not provoked the response that some stakeholders might have hoped for in terms of pushing policy-makers in the direction of relatively cleaner, safer technologies. However, we do believe that the spill is helping to frame the long-term debate on energy mix issues on the basis of cost, CO2 emissions and prices, environmental impacts, geopolitics, health and safety, lobbying by different parties, regulations and reserves, among other factors:

- We view clean technology as a potential long-term beneficiary and believe that investors should be looking to wind companies like EDP Renovaveis and Iberdrola Renovables; solar companies like First Solar, as well as further afield to energy efficiency plays like Ener1 (a lithium-ion battery company expecting \$300 million of revenue in 2013 from grid storage; EnerNOC (the leader in demand response); and Cree (LEDs is a powerful secular trend with payback periods declining to 2-3 years).
- But we also think that the GOM spill has sparked what will be a long-standing debate among regulators, stakeholders and investors about other forms of “here and now” energy such as coal, nuclear and shale gas.

Table 6: Gulf of Mexico spill could help frame a long-term energy policy debate

	Long-term bull case	Long-term bear case	Some possible long-term beneficiaries
Coal	–Coal is integral to addressing climate change as coal provides c.40% of global electricity and is the biggest single source of carbon emissions –Coal is not going away as the world still has 120 years of coal reserves with Australia, China, Germany, India, Russia, and the US having major reserves –China is adding a new coal plant every two weeks to meet rising electricity demand –Subsidies for CCS	–Carbon capture technology is currently expensive and unproven –A commercial solution is unlikely to be available until 2015 at the earliest –CCS will only be viable with a long term carbon price of between 30-40/ton or a new entrant based power price of around 75/MWh –Carbon storage safety issues incl. MIMBY sentiments	–Cleaner coal & CCS equipment providers: Alstom, Air Liquide, Aker, Siemens –Cleaner utilities: Verbund, Fortum, Iberdrola
Nuclear	–GHG emissions are lower than wind, solar, gas or coal (incl. full life cycle emissions) –Policy makers are looking to build new nuclear capacity or extend the life of existing plants by 20-40 years –Global nuclear capacity is likely to increase from 367GW at present to 1,350GW by 2030, and in the same time frame, China's capacity is likely to rise to 200GW from 9GW. –New Generation IV reactors which attempt to make fission reactors cleaner, safer and lower risk –Post-Three Mile Island nuclear safety regime (INPO, IAEA)	–High initial investment of \$6-10bn to construct a new plant in deregulated markets –Cost overruns with 4th generation reactors –Need to sell smaller, cheaper reactors –Safety: spent nuclear fuel, reprocessing –Sourcing uranium (geo-political risk, government changes, human rights) –Emergence of shale gas, notably in the U.S. as a cheaper alternative	–Nuclear reactors: Alstom, Areva, BNFL, Mitsubishi Heavy Industries, Shaw Group, Toshiba –Nuclear operators Constellation Energy, EDF, Exelon, GDF-Suez –Uranium miners: Cameco, Palaidin, Uranium One, Uranium energy

Table 6: Gulf of Mexico spill could help frame a long-term energy policy debate

	Long-term bull case	Long-term bear case	Some possible long-term beneficiaries
Shale gas	–Shale gas could supply as much as 50% of US NG by 2020, and growing interest in Canada, EU, Asia and Australia –Could help to prevent the GCC and Russia from dictating higher prices for gas to the EU –US is looking to shale gas as central to its emissions reduction strategy –Long-dated gas prices remain relatively depressed, with the forward curve sitting below \$6/MMBtu until 2015	–US NG market is saturated and drilling needs to fall by 20-25% to significantly slow the pace of new supply and thus support prices. –Lack of regulation on safety concerns over fracking and drilling chemicals and their impact on drinking water could mean new restrictions and higher costs (see below) –Full life cycle CO2 concerns: if methane leak impacts are included, its footprint could be worse than coal or fuel oil	–Largest holders of shale gas reserves: ExxonMobil, Chesapeake, Anadarko, BP, Devon, EnCana, ConocoPhillips, EOG –Shale gas service companies: Halliburton, National Oilwell Varco, Schlumberger and Weatherford International

Source: BofA Merrill Lynch Global Research

Is industry response sufficient?

The Macondo accident has been a turning point for the global oil industry, forcing changes in the way that the sector operates. Whilst the response since April 2010 has been unprecedented in size, the accident showed that the industry as a whole – oil companies, contractors and regulators – was not prepared for such an event despite some serious precedents including the Exxon Valdez spill in Alaska, the Piper Alpha accident in the North Sea and the Montara blowout in Australia in 2009.

From a 'BP problem' to an industry-wide issue

Many of the arguments about Macondo in public forums have centred on three issues:

- well design and cementing procedure;
- well abandonment plan; and
- operators' decisions (and/or omissions) during drilling operations.

Financial/reputational impact spurred operators into action

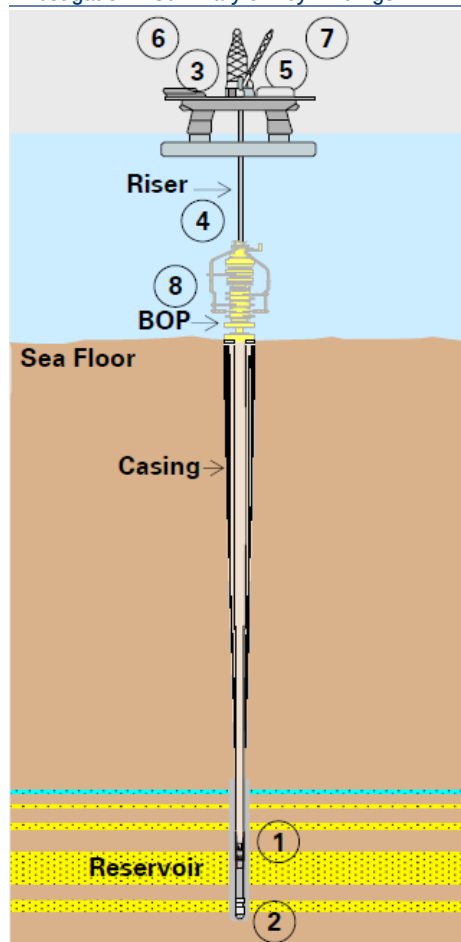
While these issues are specific to Macondo and BP, the impact of the spill was such that industry and regulators recognised that the issues ran the risk of engulfing the whole sector unless swiftly dealt with. Indeed, the voluntary response of operators/drilling contractors in the GoM was such that at the time the new drilling regulations were introduced, the bulk of the deepwater units already complied with them. The financial/reputational impact of Macondo on BP pushed all operators to review their approach to drilling operations – even in countries where there have been no actual changes in regulations.

Smaller players lose out

The main changes to the competitive landscape are:

- the more limited opportunities (and heavier scrutiny) that smaller players face in deepwater areas; and
- growing tensions in partnerships between large and smaller players.

Chart 6: Deepwater Horizon Accident Investigation – Summary of Key Findings



Source: BP

For instance, we believe that it will become increasingly difficult for a small player to operate a deepwater area when the non-operating partner is a Major. Given that BP has had to pay for the entire clean-up cost despite owning only 65% of Macondo, we believe that in some cases/jurisdictions majors will be better off from a risk management perspective operating at sole risk rather than partnering with smaller players.

Table 7: Deepwater Horizon Accident Investigation – Summary of Key Findings

Eight barriers were breached

Well integrity was not established or failed

- ❶ Annulus cement barrier did not isolate hydrocarbons
- ❷ Shoes track barriers did not isolate hydrocarbons

Hydrocarbons entered the well undetected and well control was lost

- ❸ Negative pressure test was accepted although well integrity has not been established
- ❹ Influx was not recognised until hydrocarbons were in riser
- ❺ Well control response actions failed to regain control of well

Hydrocarbons ignited on the Deepwater Horizon

- ❻ Diversion to mud gas separator resulted in gas venting onto rig
- ❼ Fire and gas system did not prevent hydrocarbon ignition

Blowout preventer did not seal the well

- ❽ Blowout preventer (BOP) emergency mode did not seal well

Source: BP; BofA Merrill Lynch Global Research

Drilling operations need co-ordinated responses

The thorough reviews of deepwater drilling operations by oil companies, regulators and contractors are set to transform this part of the business. By and large, we think the industry is taking the necessary steps in both prevention and response to avoid another disaster.

Proactive industry response is encouraging

There is still much more to do but we believe that the industry's proactive approach is encouraging. There are two areas of focus:

- **Well control:** focusing on prevention activities, including a review of technical standards, BOP testing and well designs; and
- **Cap & containment:** focusing on spill response activities.

Exhibit 1: Prevention & response

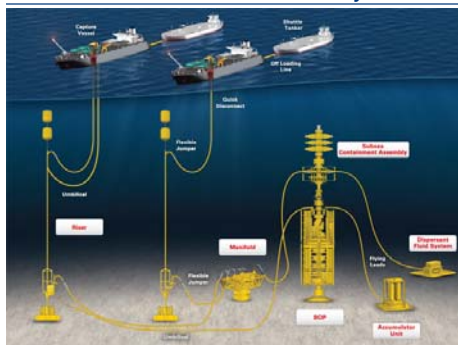


Source: Royal Dutch Shell

Collaborative industry initiatives

While we believe that more co-ordinated action by all stakeholders could help the industry reduce the inherent risks of drilling, we also note that there have been some industry initiatives. These include the Global Industry Response Group by the OGP (whose members produce more than half the world's oil and about a third of its gas) to identify, gather and co-ordinate the work being done by the Association's member companies and national regulators in response to GoM. It also includes technical cooperation, particularly around containment operations:

Exhibit 2: Marine Well Containment System



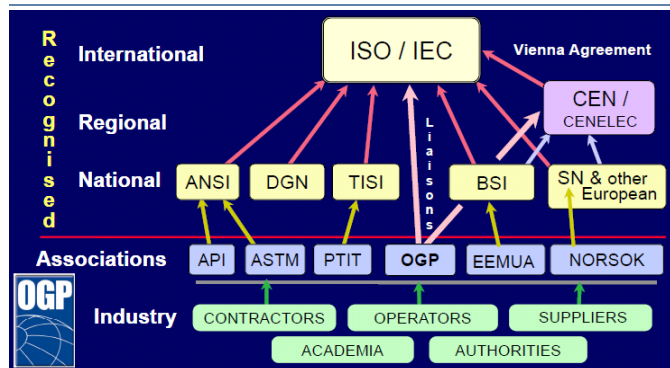
Source: XOM

- The UK's Oil Spill Prevention and Response Advisory Group (**OSPRAG**) – a combination of industry, regulators and trade unions operating in the North Sea attempting to deliver a modular device to close off a well in the event of a blowout by 2011.
- GoM **Marine Well Containment** JV – a company set up by Shell, XOM, CVX and COP (BP joined it more recently) to deliver a 100kbb/d containment system to operate in offshore US at an expected investment of US\$1bn.

Prevention still being driven by companies themselves

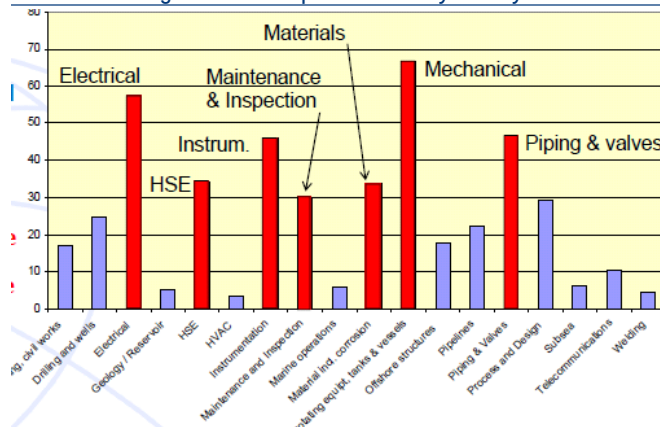
In contrast, prevention activities appear to have been driven by companies themselves – particularly in developing countries where regulations are less established. The key challenge remains to co-ordinate the way that the industry manages and prevents spills as standardisation remains difficult. The co-ordination could be easier in the response phase, but the diversity of geologies and types of well make the approach to prevention more difficult.

Exhibit 3: Standardisation bodies



Source: OGP

Exhibit 4: Average number of specifications by activity



Source: OGP

“Under these new [Drilling and Workplace Safety] rules, operators will need to comply with tougher requirements for everything from well design and cementing practices to blowout preventers and employee training. They will also need to develop comprehensive plans to manage risks and hazards at every step of the drilling process,” US Secretary of the Interior Ken Salazar.

Offshore and deepwater

Safety drives rig replacement & drilling cycle

Oil companies are looking to suppliers to tackle the inevitable trend towards more stringent HSE standards. This is acting as a catalyst for a new rig/equipment replacement cycle as offshore rigs need to be built to replace ageing global fleets and tackle technological obsolescence from ever-deeper and tougher offshore drilling and production conditions. Beneficiaries should include the rig builders, rig technology, drillers, drilling rig equipment and oilfield consumables and products companies.

Start of a new drilling age

The Macondo accident has shaken the core of global drilling activities, swiftly changing operators' requirements and kick-starting a wave of newbuild rigs. Specifically we see: 1) new HSE regulations increasing the specification of rigs and associated equipment (BOPs, risers), 2) growing differentiation between old and new generation rigs as operators look to high grade requirements and improve efficiencies and HSE standards, 3) shortening backlogs at the shipyards leading to attractive rig pricing. With c.70% of the jackup and c.60% of the global semisub fleet built before 2000, we believe that this replacement cycle has a long way to go. This new rig era is not driven by dayrates, as was the case in 2004-08. That said, we believe that premium assets will achieve premium dayrates.

2004 vs 2008 cycles

We see three differences between the upcoming cycle and that in 2004-08:

- There is likely to be a smaller net increase in the global fleet than in the previous upcycle, as newly delivered offshore rigs will increasingly be accompanied by removal/conversion of vintage rigs.
- The combined size of offshore rig orders will be less than in the previous upcycle, as the rig replacement cycle is likely to be a gradual event.
- This cycle is set to be driven by improving rig specifications as regulations change and oil companies look to secure higher-spec rigs than may necessarily be needed. Reservoir characteristics are also becoming more challenging, which will be reflected in more complex rigs.

Key stocks exposed to the replacement cycle

Key stocks exposed to this new wave of capex are equipment maker National Oilwell Varco (NOV), drilling operator Seadrill (SDRL) and the shipyard owners Keppel Corporation (KEP) and Sembcorp Marine (SMM) (see *Beneficiaries of O&G safety theme* section).

Mark Albers, ExxonMobil's senior vice president, summed it up best in an interview with Reuters, saying "It's important that in the next five years, deepwater will contribute 10 million barrels per day of oil (equivalent). That's equivalent to what Saudi Arabia is producing". In our view, the demand for the latest generation of offshore drilling rigs and equipment will rise, if global oil demand uptrend stays.

Table 8: Summary of global fleet

	Jackup	Semisub	Drillship
Fleet size	515	224	90
Average age	21	19	9
Mid water		109	8
Deepwater		47	14
Ultra deepwater		68	68

Source: ODS Petrodata, BofA Merrill Lynch Global Research

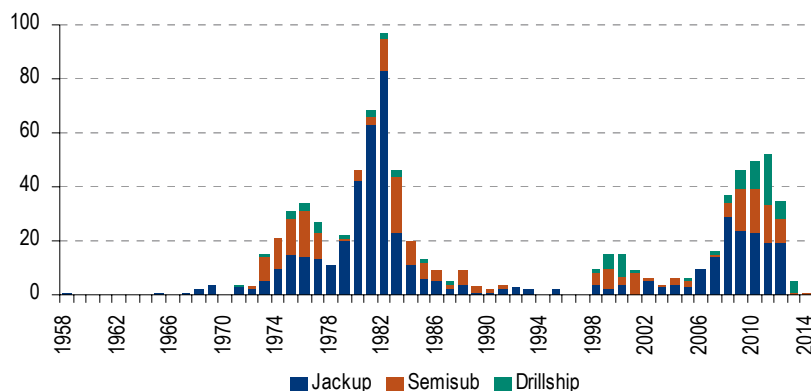
Ageing rigs struggle to meet deepwater needs

We expect deepwater oil fields to be one of the only segments that can deliver oil production growth after 2015, assuming that the world is still looking to build up oil reserves via offshore exploration and production. Emerging markets in particular are keen to develop such resources and with the national oil companies (NOCs) already owning a big portion of offshore oil reserves, this trend is likely to become even more pronounced in the years ahead to support their economic development (i.e. local content requirements). NOCs have both money and national interest to consider when adding new / best equipment on board their offshore rigs.

Older offshore rigs cannot drill in deeper-water oil fields

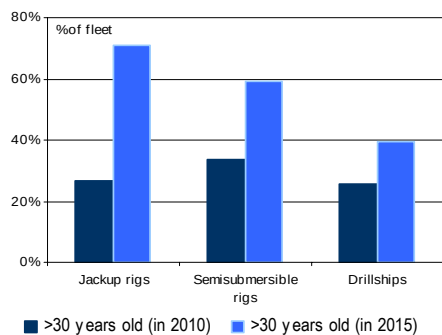
The secular trend towards deeper offshore oil fields applies to both shallow water oil fields and deepwater oil fields. The latest generation jackup rigs can drill in shallow water oil fields of more than 400ft water depth, which most of the older jackup rigs cannot replicate due to their shorter leg lengths. This is similar to semisubmersible rigs, where most of the older rigs drill in less than 7,500ft water depth oil fields, while the newer sixth generation semisubmersible rigs and drillships (built since 2005) can drill in water depths of 10,000ft.

Chart 7: Historical trend in additions to the global rig fleet



Source: ODS Petrodata

Chart 8: Newbuild wave 2 - Start replacing the ageing rigs, or face tighter yard slots in 5 years



Source: Riglogix, BofA Merrill Lynch Global Research

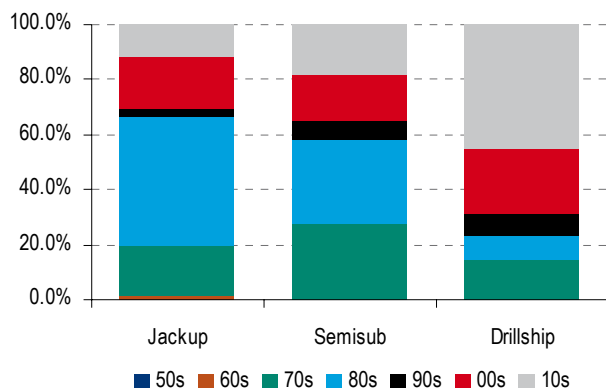
Percentage of vintage rigs has jumped since 2003

We estimate that more than 85% of global semisubmersible rigs are older than the sixth-generation designs (that can drill in 10,000ft water depth) used by both rig builders. Also, more than 78% of global jackup rigs are older than both rig builders' proprietary jackup rig designs that can drill in >300ft water depths.

The future is getting deeper and deeper

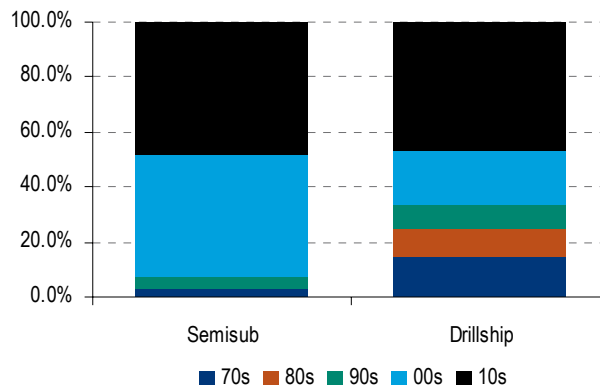
On the back of long-term demand, rig designers have started to market newer deepwater drilling rig designs, some of which are capable of operating in deeper water depths of up to 12,000ft. There are engineering constraints on the potential for upgrading vintage rigs for such depths – with older rigs simply unable to operate at such depths – and E&P companies are likely to look to rig designers to develop newer offshore rigs for harsh conditions and deeper and deeper water depths.

Chart 9: Percentage of current global fleet built each decade



Source: ODS Petrodata

Chart 10: Percentage of current ultra deepwater fleet built each decade



Source: ODS Petrodata

Table 9: Offshore drilling sites seen by stakeholders as being at high risk on HSE

Country	Area
Australia	Margaret River
Brazil	Santos Basin
Canada	Orrphan Basin
Nigeria	Delta region
Russia	Sea of Okhotsk
US	North Shore
	Arctic National Wildlife Reserve
	Gulf of Mexico
Shared	Arctic, North Sea

Source: BofA Merrill Lynch Global Research

"This industry is reactive... Improvements have only arisen as a result of major accidents." - Gordon Ballard, Chairman of OPITO and the UK chairman of Schlumberger

Higher HSE standards creating demand

We believe the combination of the trend for deeper water oil fields, the limited lifespan of offshore drilling rigs, and the catalysing factor of higher Health, Safety and Environment (HSE) standards following the Macondo oil spill will create a tipping point in the offshore rig/equipment cycle for ageing offshore rigs. US efforts to catch up with countries like Norway and the UK and ramp up safety standards (such as the Department of the Interior (DOI)'s 30 September 2010 announcement of the Drilling Safety Rule and the Workplace Safety Rule) are a positive step. Moreover, other countries, many of which have stricter safety standards than the US, are waiting on the results of the Deepwater investigation to further ramp up their own safety standards.

History shows disasters can be game-changers

History has unfortunately shown that it sometimes take a major disaster to galvanise an industry. The two most pertinent examples are the 1988 Piper Alpha rig explosion and its impact on UK and Norwegian safety standards, and the 1989 Exxon Valdez oil spill, which hastened the staggered expansion of double-hull tankers globally, via the Oil Pollution Act of 1990 in the US and the United Nations' decision to ban single-hull tankers worldwide by 2010. We see the Macondo oil spill as a similar game-changer for the entire offshore industry, including the gradual replacement of ageing offshore drilling rigs to meet more stringent HSE standards.

Consider the game-changing move to double-hull tankers

One interesting point on the mandatory shift to double-hull tankers is that it will not necessarily prevent oil spills from vessel collisions. There are still debates on the double-hull tankers' ability to prevent oil spills during high-speed collisions. More important is that these vessels are perceived to reduce the risk of an oil spill during high-speed collisions, and do reduce the chance of an oil spill in low-speed collisions. The key here is the "change" that they represented, and double-hull tankers quickly gained both popularity and traction.

US lags behind Norway/UK on offshore drilling rules

An examination of Norwegian, UK and US GoM offshore drilling regimes and regulations for drilling with Mobile Offshore Drilling Units (MODUs) revealed that there used to be fundamental differences between the countries' regulations. The US was operating in a different (lower) league in terms of safety regulations

relating to rigs and facilities, drilling and well operations, and oil spill preparedness. Moreover, the responsibility for risk was fundamentally different. Under the so-called "safety case" systems used in Norway and the UK, the onus is on oil & gas companies to perform - rather than complying with a raft of regulations and mandates issued by the government.

Table 10: Summary of differences between offshore drilling regulations in Norway and U.S. Gulf of Mexico (as at April 2010)

	Norway	U.S.
Regulatory regimes	Performance based with supplementary prescriptive requirements Mainly risk based Authority for resource management is separate from authorities for HSE management PSA has coordinating role in development and supervision of HSE regulations Overall responsibility of the operator to ensure safe and prudent operation of the entire petroleum activities in line with regulations	Primarily prescriptive Do not require participants in offshore drilling activities to systematically identify and manage risks Both were handled within the same authority (at April 2010) Responsibility is shared between different authorities Responsibility is shared between the operator and authorities through prescriptive requirements and regulatory approvals
Management systems	Cover requirements to establish and maintain documented HSE management system HSE regulations specifically state at whom (e.g. operator, licensee, contractor etc) the HSE requirements are directed Operator ensures that everyone carrying out work for it (contractor) complies with regulatory HSE requirements (i.e. duty "to see to it") Requirements for establishing technical, operational, organisational barriers are included General requirement that there shall be adequate competence in all phases of petroleum activities	Adoption of SEMP (safety and Environment management Program) is voluntary Responsibility for adherence to requirements within specific areas was defined in various parts of individual regulations No similar requirement No general requirements Competence requirements related to a few critical activities or operations; no overall requirements for competence in drilling operations
Drilling and well activities	Require 2 independent and tested well barriers to prevent unintentional flow from the formation into another formation or to the surface in the case of an unwanted event. If drilling with a riser margin is not possible due to deepwater and narrow pressure margin additional risk reducing measures shall be implemented (e.g. having both casing shear and shear seal ram) Well design, left to the operator to show compliance to their safety philosophy Pressure control equipment: require recertification of BOPs every fifth year	No similar requirements to well barriers in US. NORSOK D-010 defines how barrier requirements should be applied in all drilling and well operations Detailed requirements for the content of the Application for Permit to Drill which shall be approved by the MMS No recertification requirement (at April 2010)
Facilities and drilling systems	BOP: require an additional casing shear ram to the blind shear ram for dynamic positioned MODUs Require an alternative activation system of the BOP and a system that ensures release of the riser before a critical angle occurs due to loss of position of the drilling unit Latest edition of applicable regulations and referred standards shall be used as basis for compliance evaluations. Acknowledgement of Compliance (AoC) irrespective of a unit's age	No requirement No equivalent requirement No such requirement
Oil spill preparedness	Risk based approach to acute pollution: capacity and design of oil spill preparedness is specific for the offshore installation or exploration drilling location and is based on environmental risk assessments Effectiveness of oil recovery systems are calculated depending on the area-specific weather, operational light and oil weathering data Oil spill response strategy: mainly based on mechanical/physical recovery. Dispersion chemicals are only used in a limited extension and in-situ burning is only considered used in ice infested waters	"Worst case discharge" based Capacity is set by reducing the given manufacturers specification of collection capacity with 80% Spill/cleanup techniques fall into six categories including but not limited to: mechanical/physical recovery, in-situ burning, bioremediation, dispersant, natural remediation, additives (herding agents and polymers)

Source: DNV, BofA Merrill Lynch Global Research

US ramps up safety with new offshore drilling rules

The US Drilling Safety Rule, announced and rendered effective on 30 September 2010, makes mandatory several requirements for the drilling process that were laid out in US Secretary of the Interior Salazar's May 2010 Safety Report to President Obama. The regulation prescribes proper cementing and casing practices and the appropriate use of drilling fluids in order to maintain wellbore integrity. The regulation also strengthens the oversight of mechanisms designed to shut off the flow of oil & gas, primarily the BOP and its components. An

additional Workplace Safety Rule requires offshore operators to have clear programs in place to identify potential hazards when they drill, a clear protocol for addressing those hazards, and strong procedures and risk-reduction strategies for all phases of activity. Operators are also required to have a safety and environmental management system (SEMS). In addition, the rule makes mandatory API Recommended Practice 75, which was previously a voluntary program, to identify, address and manage safety hazards and environmental impacts in their operations.

Fundamental change in the US could still take years

However, it is still too early to say how far the US will go in overhauling its regulatory regime and whether it will move towards the performance-based systems used in other countries. We need to keep in mind the years of upheaval that resulted when the UK overhauled its regulatory system after the Piper Alpha disaster – we envisage something of a hybrid model that develops over time.

Table 11: US Drilling Safety Rule

- Makes mandatory API RP 65 – Part 2, Isolating Potential Flow Zones During Well Construction
- Requires certification that the casing and cementing program is appropriate;
- Requires two independent test barriers across each flow path during completions;
- Requires documentation and schematics for all control systems;
- Requires proper installation, sealing and locking of the casing or liner;
- Requires approval from BOEM district manager before replacing a heavier drilling fluid with a lighter fluid;
- Requires enhanced deepwater well control training for rig personnel;
- Requires third-party verification that the blind-shear rams are capable of cutting any drill pipe in the hole under the maximum anticipated surface pressure;
- Requires ROV intervention capability for subsea BOP stacks;
- Requires a trained ROV crew on each floating drilling rig on a continuous basis;
- Requires auto shear and deadman systems for dynamically positioned rigs;
- Establishes minimum requirements for personnel authorized to operate critical BOP equipment;
- Requires documentation of subsea BOP inspections and maintenance according to API RP 53, Recommended Practices for Blowout Prevention Equipment Systems for Drilling Wells;
- Requires testing of all ROV intervention functions on subsea BOP stack during stump test, and testing at least one set of rams in initial seafloor test;
- Requires function testing auto shear and deadman systems on the subsea BOP stack during the stump test, and testing the deadman system during the initial test on the seafloor; and
- Requires pressure testing if any shear rams are used in an emergency.

Source: US Department of the Interior, BOEM, BofA Merrill Lynch Global Research

Emerging market NOCs looking to HSE

National Oil Companies (NOCs) remain positive and determined to go ahead with deepwater drilling activities, but are keen to prevent another oil spill. A number of NOCs claim that they will use the Macondo oil spill as a real-life lesson to strengthen their offshore drilling safety guidelines, and enhance the efficiency and safety of future offshore exploration activities. This reinforces our view that the governments of emerging economies are likely to continue their efforts to build up offshore drilling technologies and capabilities, and HSE protocols.

Looking for a slice of the rig replacement pie

Emerging market companies such as CSSC's offshore rig building subsidiary, Shanghai Waigaoqiao Shipbuilding, are also looking to get a piece of the rig replacement pie. The company expects to deliver its first China-designed deepwater semisubmersible drilling rig by end 2010, with more orders to follow in China. China is interested in building up its own new fleet of offshore drilling rigs that have access to the latest safety and energy efficient technologies. We believe this also underlines the Chinese government's resolve to build up its rig building industry, as it sees long-term potential in developing offshore crude oil reserves to meet its own domestic demand.

Table 12: Offshore drilling sites seen by stakeholders as being at high risk on HSE

Country	Area
Australia	Margaret River
Brazil	Santos Basin
Canada	Orrphan Basin
Nigeria	Delta region
Russia	Sea of Okhotsk
US	North Shore
	Arctic National Wildlife Reserve
	Gulf of Mexico
Shared	Arctic
	North sea

Source: BofA Merrill Lynch Global Research

GoM rig standards to be applied globally

We expect the GoM standards to be slowly rolled out globally as: (1) operators apply common standards; (2) drilling contractors apply common standards; and (3) regulators increase requirements for operations and equipment. Application of the GoM standards worldwide and preference for floaters and jackup units with better capabilities lead us to believe existing floaters could be upgraded and newbuilds could have larger BOPs, dual activity and DP capability. Various governments and the European Commission are considering proposing this. We expect it to be a drawn-out affair, as some form of resistance is likely from countries with relatively less stringent operational procedures. However, if these global standards for offshore E&P activities are implemented, then it will be a boon to upgrading and rig replacement works for global yards.

Newer offshore rigs to gain gradual popularity

We expect a general trend for oil companies and rig owners to use newer offshore rigs, which are less environmentally damaging (all things being relative) and have newer safety features. These rigs cannot guarantee prevention of another oil spill, but they should make for a better offshore work environment and cater to growing public preference for HSE-friendly development of offshore oil (similar to the public preference for double-hull tankers). Recent signs also point to certain companies seizing the first-mover advantage and ordering the first seventh-generation rigs. Indeed, the *Deepwater Horizon* was a nine-year-old fifth-generation semisubmersible rig, but the public backlash would be far worse if faced with an incident involving a 30- or 40-year-old offshore rig.

Table 13: US Interior Secretary Ken Salazar and Director of the Bureau of Ocean Energy Management, Regulation, and Enforcement (BOEM) Michael R. Bromwich are raising the bar for US safety, oversight, and environmental protection at every stage of the review, permitting, drilling, and development process for offshore oil & gas operations.

1 - The Environmental Review Stage: Conducting Strong Environmental Reviews of Proposed Lease Sales and Drilling Projects Based on Sound Science

IN	OUT
BOEM, with the collaboration of federal agencies like the Fish and Wildlife Service (FWS) and the National Oceanic and Atmospheric Administration (NOAA), is conducting comprehensive new environmental analyses of the Gulf of Mexico and the Arctic to help inform future leasing and development decisions. Proposed lease sales and drilling projects must undergo thorough environmental reviews in accordance with NEPA.	Full review of the agency's use of 'categorical exclusions' under the National Environmental Policy Act (NEPA) and has limited their use in proposed deepwater drilling projects.

2 - The Permitting Stage: Raising the Bar for Safety and Environmental Protections in Proposed Drilling Projects

IN	OUT
Permit applications for drilling projects must meet new standards for well-design, casing, and cementing, which must be independently certified by a professional engineer. Proposed exploration plans must meet new requirements to show the operator is prepared to deal with a potential blowout and the potential worst-case discharge scenario and the operator's ability to respond to such a discharge.	Interior closed the loophole, established in 2003, that exempted operators in the Gulf of Mexico from submitting plans for worst-case discharge scenarios. The Administration has submitted legislation to remove the requirement that hamstrings BOEM by requiring review and approval of exploration plans within 30-days.

3 - Drilling and Production Stages: Strengthening Standards for Equipment, Safety Practices, Environmental Safeguards, and Oversight of Offshore Drilling and Production

IN	OUT
Operators must adhere to the new Drilling Safety Rule, implemented through emergency rulemaking, that raises the standards for blowout preventers, well design, casing, cementing, and safety equipment. Blowout preventers must also meet new standards for testing and must be independently certified. Under the new Workplace Safety Rule, operators will be required to develop a comprehensive management program for identifying, addressing and managing operational safety and environmental hazards and impacts, with the goal of reducing the risk of human error and improving workplace safety and environmental protection. The CEOs of drilling companies must – for the first time ever – put their signature on the line to certify that their rigs comply with all safety and environmental laws and regulations. BOEM is significantly expanding its team of inspectors, engineers, and other specialists to ensure that operators are following all laws and regulations.	Over the last three decades, safety equipment and regulatory requirements fell behind the technology that allowed companies to reach new oil & gas reserves in deeper waters.

02 December 2010

Table 13: US Interior Secretary Ken Salazar and Director of the Bureau of Ocean Energy Management, Regulation, and Enforcement (BOEM) Michael R. Bromwich are raising the bar for US safety, oversight, and environmental protection at every stage of the review, permitting, drilling, and development process for offshore oil & gas operations.

4 - Blowout Containment and Spill Response: Ensuring that Industry is prepared to respond to Deepwater Blowouts and Oil Spills	
IN	OUT
Eight public forums around the country to gather information about how to strengthen safety, blowout prevention, and spill response in deepwater. Director Bromwich will be developing recommendations for Secretary Salazar based on these meetings.	The <i>Deepwater Horizon</i> spill laid bare the gap between the oil & gas industry's drilling technology and the technology available to contain and control blowouts in deepwater.
Federal agencies, led by the Department of the Interior and the Department of Energy, are collaborating to institutionalize the experience, expertise, and leadership developed through the <i>Deepwater Horizon</i> source containment and spill response efforts.	Until the <i>Deepwater Horizon</i> disaster, oil spill response planning had not anticipated a spill of such a scale and duration.
5 - Enforcement and Oversight: Building a Strong, Independent Agency to Police Offshore Oil & gas Operations	
IN	OUT
Secretary Salazar appointed former DOJ Inspector General Michael R. Bromwich to lead the newly established BOEM and to oversee offshore oil & gas reforms.	Secretary Salazar has divided the former Minerals Management Service – which held conflicting missions of promoting energy development, regulating the industry, and collecting revenues - into three independent entities.
The Administration requested and Congress provided \$29 million in supplemental funds in FY 2010 to address immediate priorities. The Administration has also requested an additional \$100 million, as part of an FY 2011 budget amendment, for the Department to increase offshore oil & gas inspections, hire new inspectors, draft enforcement and safety regulations, and carry out environmental and other studies.	The Royalty in Kind (RIK) Program, which accepted oil & gas in lieu of cash as royalty payments on federal energy resources.
New internal investigations and review unit within BOEM that will root out problems within the regulatory agency and target companies that aim to game the system.	
New recusal policy for BOEM employees which will reduce the potential for real or perceived conflicts of interest.	
Implementing the recommendations of the OCS Safety Oversight Board, which Secretary Salazar established to evaluate how to strengthen oversight and management of energy development on the Outer Continental Shelf.	

Source: US Department of the Interior, BOEM, BofA Merrill Lynch Global Research

Favourable shipyard environment for drillers Orders to gravitate towards established yards

We believe that the Macondo oil spill will also drive a preference for using established yards to build offshore rigs and production units, so as to reduce the risk of operational mishaps. The expected higher, but gradual, increase in construction costs for offshore units due to more stringent HSE standards are also likely to incentivise buyers to place orders for these expensive units at proven yards early in the replacement cycle.

Table 14: Exposure of rig building since 1998

	Jackups	Semisubs	Drillships	
Built since 1998	163	88	69	
Region	Singapore	79	Singapore	31
	USA	28	South Korea	13
	China	27	China	11
Yard	Singapore:	Singapore:	Samsung	18
	Keppel FELS	43	Keppel FELS	14
	PPL	29	Jurong	14
	Jurong	7	South Korea:	
	USA:	Daewoo	10	
	Keppel AmFELS	12		
	LeTourneau	12		
	China:			
	Dalian	10		

Source: ODS Petrodata

Payment profile favourable to drillers

We expect the rig builders increasingly to use their balance sheets to shoulder part of the costs for offshore rig and production unit constructions, due to the possible change in payment structures. In the last cycle, the strong bargaining

power of rig builders due to tight yard slots resulted in the popularity of a progressive payment structure, with cash collection based on milestones achieved and the final 10-20% of payment made upon rig delivery. The balloon payment structure, with a large 70-90% quantum payment upon rig delivery, was more prevalent before 2004. We expect the payment scheme for new orders to tilt towards lumpier back-end loaded payments, with up to 90% of contract value as final payments upon vessel delivery.

We believe Seadrill is paying attractive terms for its recent rig orders: a deposit of 10-25% on signing the contract, followed by a 75-90% final payment on delivery.

Speculative buyers to play a minor role in new orders

In our view, the presence of speculative rig purchases that dominated the early part of the construction boom during 2004-08 could be diminished by a preference for oil companies to deal with proven rig operators following the Macondo oil spill. In our view, the more likely buyers of offshore rigs are national oil companies and international rig operators, which are also more willing to pay premium prices for proven rig designs built at established yards. The established yards have proven and longer track records for on-schedule on-budget delivery of rigs, which mitigate the opportunity cost of late deliveries.

More available yard slots at established rig builders

We believe that the availability of slots at established yards such as Daewoo, Keppel FELS, Samsung and Sembcorp Marine (Jurong, PPL) will reduce the incentive of buyers to place orders with newer yards. These yards already have strong relationships with national oil companies and international rig owners, the key buyers in this new cycle. The established yards will have emptier yard slots by 1H 2011, allowing them to take on new orders from rig buyers. This was not always the case during the 2004-08 boom, with rejected clients turning to newer yards in China if they wanted earlier delivery schedules.

Macro environment improving for drillers

Offshore rig demand picking up

In the jackup market, PEMEX currently has tenders and pre-tenders published for 21 jackups and one floater (1,000ft.). Around the world, there are currently seven tenders for 5-year terms in Thailand, two rigs for 3 years in Norway and three rig tenders for 5-year terms in Angola. Additionally, there is incremental demand forthcoming in Saudi Arabia.

Fuelled by increasing confidence in the economic outlook and higher oil prices, there has been a significant increase in offshore rig demand in the past three months. In Brazil, Transocean and other drilling contractors see potential incremental demand of 4-12 ultra-deepwater rigs from Petrobras, depending on dayrates. Additionally, West Africa looks to have demand for eight incremental ultra-deepwater rigs (two in Angola and six in Nigeria). The GoM has incremental demand, but permitting uncertainty remains. Notably, Pride now sees approximately 20 opportunities for the Deep Ocean Molokai, its uncontracted ultra-deepwater newbuild, with about 10 of these showing up in the last two months. These opportunities are spread across the globe.

Table 15: Demand highlights

		Rigs	Years
Jackups	Angola	3	5
	Mexico	21	
	Norway	2	3
	Saudi Arabia		
	Thailand	7	5
Floaters	Angola	2	
	Brazil	4-12	
	GoM		
	Mexico	1	
	Nigeria	6	

Source: BofA Merrill Lynch Global Research

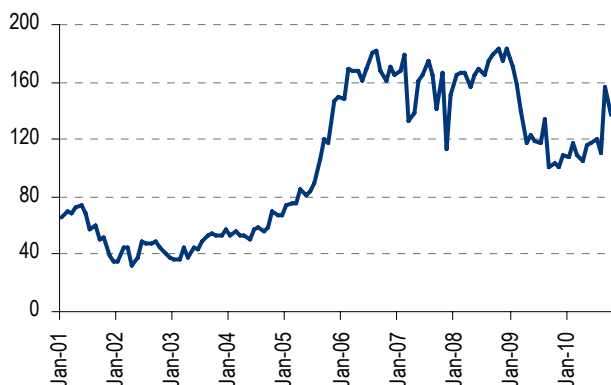
Upside potential for ultra-deepwater dayrates 2H11

The premium jackup market is picking up, as can be seen by recent awards. Additionally, we believe newbuild jackup orders (eight so far in the past couple of months) and Transocean buying a premium jackup unit from a shipyard underscore the offshore drillers' increasing optimism on the market outlook. We expect the standard jackup market to remain stable.

We see potential for ultra-deepwater dayrates to increase in 2H11 depending on incremental demand from Petrobras. While an anomalous sub-\$400k/d rate is likely, we forecast ultra-deepwater rates to remain between \$400-\$450k/d in 2011. However, given the recent increase in demand, we believe it is increasingly likely that ultra-deepwater rates could exceed \$500k/d in 2H11.

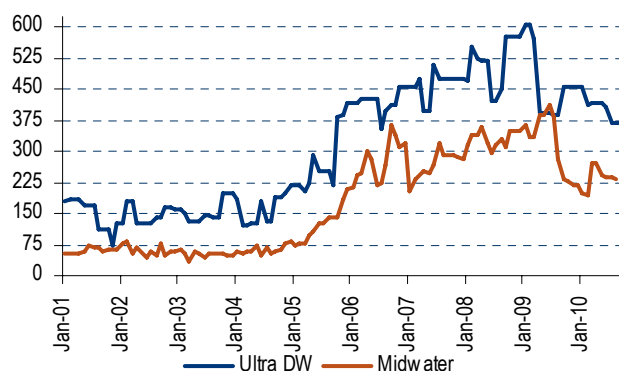
While the deepwater and mid-water markets are currently stable, we expect downward pressure as rigs move to less demanding jobs (ie, a decline in "capability utilization"). Operators are increasingly showing a preference for floaters with dynamic positioning (DP), dual activity and large blowout preventors (BOP), even if they do not necessarily need them. Pride estimates dayrates for moored rigs could run at \$100-150k/day less than a comparable DP unit. Additionally, mid-water rig migration from the GoM could put pressure on dayrates internationally.

Chart 11: Progression of jackup dayrates (US\$k)



Source: ODS Petrodata

Chart 12: Progression of ultra deepwater & midwater dayrates (US\$k)



Source: ODS Petrodata

The beginnings of a new replacement cycle New rig orders starting to trickle in

While near-term day rates continue to show restraint, note that it takes about three years to construct drillships/semisubmersible rigs, and two years for a jackup. With relatively more stable day rates for high spec floaters and jackup rigs, we expect the rig replacement secular trend to lead to a pick-up in newbuild orders (already evident), albeit at levels significantly lower than the average during 2004-08.

Table 16: Summary of rigs ordered YTD

Rig Name	Manager	Water Depth (ft)	Build Cost	Build Country	Build Yard	Order Date	Delivery Date
Jackup							
Saudi Aramco JU Tbn1	Saudi Aramco	300		Singapore	Keppel FELS	27-Jan	Sep-12
NDC JU Tbn1	National Drilling	200	159	UAE	Lamprell	28-Jul	May-12
NDC JU Tbn2	National Drilling	200	159	UAE	Lamprell	28-Jul	Sep-12
Atwood 12	Atwood	400	190	Singapore	PPL Shipyard	05-Oct	Sep-12
Atwood 13	Atwood	400	190	Singapore	PPL Shipyard	05-Oct	Dec-12
Eurasia Drilling JU Tbn1	Eurasia Drilling	350		UAE	Lamprell	18-Oct	Dec-12
Seadrill JU Tbn10	Seadrill	400	200	Singapore	Jurong Shipyard Pte Ltd	18-Oct	Dec-12
Seadrill JU Tbn11	Seadrill	400	200	Singapore	Jurong Shipyard Pte Ltd	18-Oct	Mar-13
Drilling & Offshore JU Tbn1	Drilling & Offshore	350	220	India	ABG Shipyard	02-Nov	Nov-12
Drilling & Offshore JU Tbn2	Drilling & Offshore	350	220	India	ABG Shipyard	02-Nov	Nov-12
Seadrill JU Tbn12	Seadrill	400	190	China	Dalian Shipbuilding Industry Co.	15-Nov	Dec-12
Seadrill JU Tbn13	Seadrill	400	190	China	Dalian Shipbuilding Industry Co.	15-Nov	Mar-13
Drillship							
Noble Globetrotter II	Noble	10000	550	China	STX Offshore & Shipbuilding	28-Jun	Jun-13
Queiroz Delba Drsh Tbn1	Queiroz Galvao/Delba	10000		South Korea	Samsung Heavy Industries	11-Nov	Jul-12
Queiroz Delba Drsh Tbn2	Queiroz Galvao/Delba	10000		South Korea	Samsung Heavy Industries	11-Nov	Sep-12
Seadrill Drsh Tbn5	Seadrill	12000	595	South Korea	Samsung Heavy Industries	11-Nov	Mar-13
Seadrill Drsh Tbn6	Seadrill	12000	595	South Korea	Samsung Heavy Industries	11-Nov	Jun-13
Semisubmersible							
Bolshaya Medveditsa	Rosneft	6562	700	Russia	Zvezda Shipyard	13-Jan	Jul-14
Delba IV	Delba	7874		UAE	Gulf Piping Company	01-Mar	May-13

Source: ODS Petrodata

The jackup orders were kicked off by NDC in Abu Dhabi, with momentum building strongly since October. For jackup rigs we have seen early signs of a trend for drillers to favour the returns attainable with a newbuild versus significant investment in refurbishing/upgrading the rig. For floaters the unit of choice at present is the ultra deepwater drillship, as evidenced by recent orders placed by Seadrill and Queiroz Galvao/Delba. The construction process of a drillship is less complex and shorter than that of a semisubmersible, as well as being more suitable for operations in ultra deepwater and remote locations.

More newbuilds likely to follow

Given the improving outlook for premium jackups and ultra-deepwater drill ships and limited opportunities to make acquisitions of distressed assets, we expect all established contractors with free cash flow to consider newbuilds. Notably, Transocean, Noble, Diamond and Ensco have all looked at various drillship designs. For Seadrill we see a strong probability of converting the two options at Samsung for drill ships, and a good probability of exercising the jackup options held at Jurong and Dalian. We believe that the majority, if not all, of Seadrill's contracts are at fixed prices, which may look more attractive nearer expiry if demand for newer assets continues to build.

Petrobras newbuild orders could be finalised by 2Q11

Petrobras opened up commercial bids on 26 November 2010 and could receive bids by year-end and finalise them in 2Q11. While there is significant uncertainty over the potential for Petrobras to order 28 incremental drill ships, the process is not dramatically different from in prior tenders. The units are due for delivery between 2013 and 2018. We continue to expect the initial rig equipment orders for the planned 28 newbuilds to be placed in 2Q11.

Possible bottlenecks

Stringent offshore HSE comes at a cost

The industry will have to adjust over time to the higher cost of operation for offshore E&P activities. This is a general consequence of the review of HSE standards for offshore drilling, post the Macondo oil spill. The established names in the offshore industry should benefit most from the higher costs resulting from more stringent HSE standards for offshore drilling. This is due to their established track records that mitigate the chances of breaching the higher HSE hurdle rates, their access to increasingly scarce experienced offshore personnel, and their exposure to newer and higher-technology equipment and rigs.

Human resources: fewer & older skilled staff

There are mounting concerns about the lack of trained personnel in the offshore drilling industry, especially in the relatively new area of deepwater drilling. The competencies of on-the-ground offshore personnel and management teams when it comes to understanding the viability and risks of offshore operations are also in urgent need of improvement, especially in light of calls for greater trust to be placed in offshore personnel for on-the-ground decisions on offshore drilling activities.

Worryingly, though, the industry faces a major greying workforce challenge and an ongoing shortage of skilled personnel, which has been an issue since the previous industry boom in 2004-08 exposed the pitfalls of a boom and bust approach to HR. Companies which adopted a long-term approach to pursuing the technical development of their personnel through in-house training programs will benefit as the rig replacement cycle comes to fruition. We believe that HR is a key risk for the sector and have explored it in detail *further below*).

Delay in E&P capex for global crude oil supply

There are concerns over the negative long-term crude oil supply impact of any sustained delay in offshore E&P capex, given the expected growth in global energy demand. The construction of offshore drilling rigs and production platforms generally takes three years, and a delay (in response to short-term market weakness) in E&P investment could result in severe supply shortages in the future. The longer the delay in newbuild offshore drilling rigs and production platforms, the greater the ultimate investment costs to oil companies and energy costs to global consumers.

Tight credit a constraint on newbuild contracts

Financial institutions are generally still less willing than they were in the 2004-08 upcycle to lend to potential rig buyers that need financial resources for building new rigs and upgrading plans. The tight credit situation has been an investment constraint for some industry names since 2H08. But there are signs that financial institutions may be turning more aggressive on lending to newbuild rig constructions, which would be a positive industry development. We also note that the shipyards are hungry for business, and the trade agencies in these countries, along with the shipyards, are providing increasingly attractive financing, making a newbuild seem more appealing. This is an important theme and critically suggests that newbuilds are about much more than simply rising oil prices, which should lend support.

Facility owners often underestimate the importance and value of corrosion control, which is neglected in favour of more tangible, short-term issues" – NACE International (National Association of Corrosion Engineers)

Corrosion is responsible for up to 70% of all pipeline oil and gas releases

Greater corrosion regulation only a matter of time

Onshore: out of sight, out of mind Pipeline corrosion a major hidden risk

Decades of boom and bust investment – on the back of volatile commodity prices – have left the industry facing age-related challenges. Both their physical and human resources are being pushed to the limit as companies seek to meet growing demand. A large proportion of O&G infrastructure is old, rusty and corroding and needs to be replaced, posing major safety risks. In addition to offshore drilling rigs, a worrying example is onshore pipelines, with 60% of US pipelines over 40 years old, despite having a typical design life of 20-25 years. These pipelines are not made to the same standard and lack the anti-corrosion coatings that new pipelines have.

Corrosion is at the heart of pipeline repair and replacement, accounting for up to 70% of all releases, which have caused \$4.4bn in property damage and spilled 2.5bn barrels in the last two decades in the US alone. The fact that pipelines often run underground means it can be a case of 'out of sight, out of mind' when it comes to safety. However, this could be about to change. Global corrosion costs could be as high as \$80-100bn per year, and this year's Enbridge spill from a 41-year old pipe served as a reminder that markets are not averse to such events, with oil spiking at \$4/bbl and gasoline prices at 25 cents/gallon. A Pacific Gas & Electric natural-gas pipeline explosion in San Bruno, California, which killed eight people also shows that although pipeline accidents are on the decline, the consequences can be catastrophic when they do occur.

We expect that onshore corrosion will only grow as a safety risk with ageing pipelines in the Middle East, Nigeria, Russia and the US, among other countries. Moreover, there are an estimated \$250bn of pipeline projects currently planned or under construction in 2010 – with drivers including global growth in energy demand of 1.2% p.a.; rising depletion rates (6.7-7.5% is the average production weighted worldwide decline rate for past-peak oil fields) and new technology to access new reserves in more challenging locations (deepwater, shale, frontier areas, LNG, oil sands/heavy oil, Arctic etc.).

Corrosion can be controlled and up to 33% of the total cost of corrosion can be saved using anti-corrosion technologies. We anticipate that it is only a matter of time before we see greater regulation on corrosion, which would mean raised operating costs for pipelines, higher pipeline tariffs, and potentially higher costs for consumers. While the downturn will eventually come to an end and energy demand is already rebounding, a lack of long-term, sustained investment in pipeline assets could be another looming safety catastrophe waiting to happen.

Table 17: Largest US Interstate Oil Pipeline and Natural Gas Companies

Oil Pipeline Companies			
Rank 2007	Company	Miles	Parent company / major shareholder
1	Magellan Pipeline Co. LLC	8,564	Magellan Midstream Partner
2	Plains All-American Pipeline LP	8,387	Plains All-American Pipeline LP
3	Mid-American Pipeline	7,833	MidAmerican Energy Holdings
4	ConocoPhillips Pipe Line Co.	6,693	ConocoPhillips
5	Colonial Pipeline Co.	5,591	ConocoPhillips, Shell Pipeline
6	Sunoco Pipeline Co.	5,432	Sunoco Logistics Partners LP
7	TE Products Pipeline Co. LP	4,676	Energias de Portugal
8	ExxonMobil Pipeline Company	4,559	Exxon Mobil Corporation
9	TEPPCO Crude Pipeline LP	3,967	Energias de Portugal
10	NuStar Logistics LP	3,746	Nustar Energy LP

Table 17: Largest US Interstate Oil Pipeline and Natural Gas Companies

Natural Gas Pipeline Companies

Rank 2007	Company	Miles	Parent company
1	Northern Natural Gas Co.	15,487	MidAmerican Energy Holdings
2	Tennessee Gas Pipeline Co.	14,463	El Paso Pipeline Partners, L.P.
3	Columbia Gas Transmission Corp.	10,339	NiSource Inc.
4	Transcontinental Gas Pipe Line Corp.	10,325	Williams Cos Inc
5	El Paso Natural Gas Co.	10,240	El Paso Pipeline Partners, L.P.
6	ANR Pipeline Co.	9,587	TransCanada Corporation
7	Texas Eastern Transmission Corp.	9,115	Spectra Energy Corp
8	Natural Gas Pipeline of America	9,045	Kinder Morgan Energy Partners LP
9	Southern Natural Gas Co.	7,636	El Paso Pipeline Partners, L.P.
10	Gulf South Pipeline Co. LP	6,499	Boardwalk Pipeline Partners LP

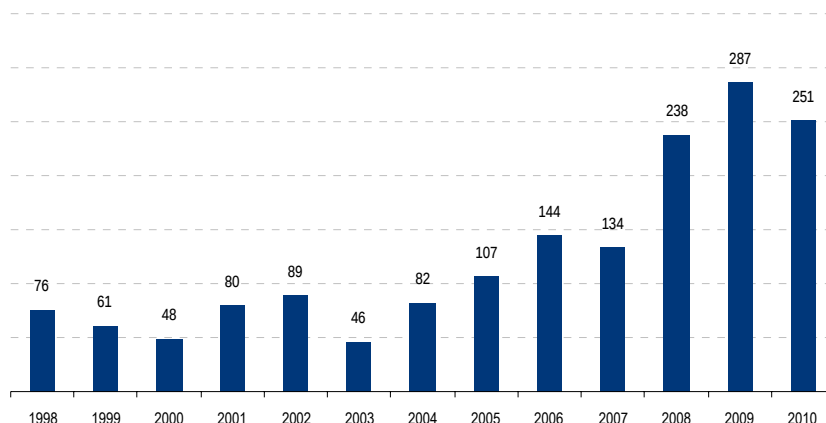
Source: PetroStrategies, Inc; BofA Merrill Lynch Global Research

Growing backlog of global pipelines

New energy sources from increasingly remote and challenging locations are required to replace depleting oil & gas resources. Three factors are driving the global investment in pipeline projects, with an estimated \$250bn of projects currently planned or under construction in 2010:

- **Demand** – Global growth in energy demand of 1.2% p.a.
- **Depletion** – Rising depletion: 6.7-7.5% is the average production-weighted worldwide decline rate for past-peak oil fields
- **Technology** – new reserves in more challenging locations (deepwater, shale, frontier areas, LNG, oil sands/heavy oil)

Chart 13: Global backlog of pipelines planned or under construction (US\$ bn)

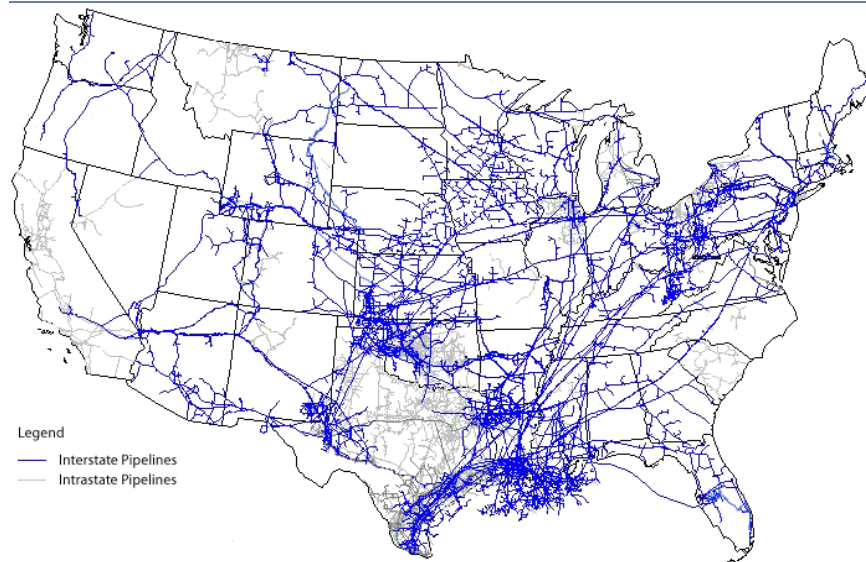


Source: ShawCor, OGJ, BofA Merrill Lynch Global Research

Corrosion is an inherent challenge

Crude oil and natural gas contain various impurities that are inherently corrosive, while refined products such as gasoline and diesel also corrode metal over time. Certain grades of crude, such as sour crude, contain hydrogen sulphide and are highly corrosive. Corrosive bacteria are also often found in either the crude or the water cut that begins to increase in volume as an oil field ages. The rising water cuts are highly saline – yet another source of corrosion. There are also serious and growing concerns about the ageing infrastructure for the O&G industry, from pipelines to tank farms, tankers and refineries.

Chart 14: US oil & gas pipeline network



Source: Energy Information Association, Office of Oil & gas, Natural Gas Division, Gas Transportation Information System, BofA Merrill Lynch Global Research

60% of US pipelines are over 40 years old

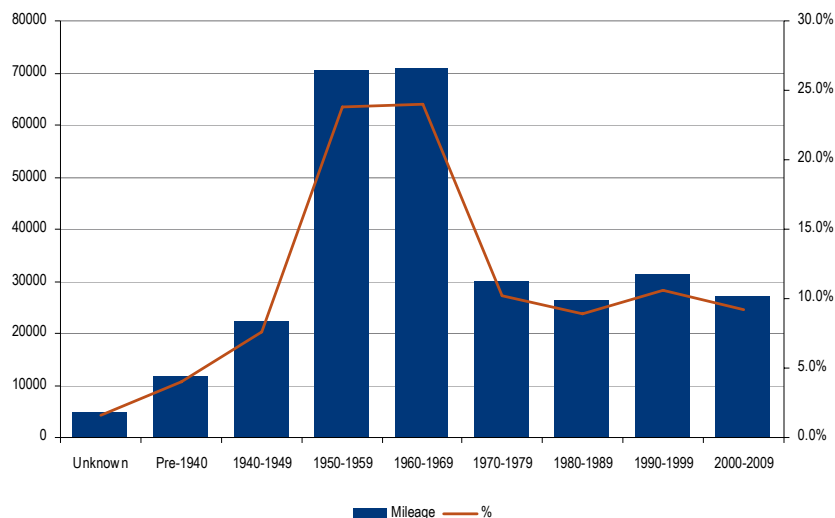
The typical design life for O&G pipelines was 20-25 years – but over 60% of US pipelines are now over 40 years old. Old pipelines are rarely retired and the length of active US pipelines has grown more than 20-fold since the 1920s, while oil refining has grown 10-fold over the same period.

Corrosion at the heart of pipeline repair and replacement

Wear-out (corrosion) is estimated to be responsible for up to 70% of all releases from pipelines (50%+ relating to internal corrosion). Other causes are third-party damage (5% of releases) and construction (8%). The US Department of Transport's Pipeline and Hazardous Materials Safety Administration (PHMSA) data shows that since 1985 over 60% of the biggest oil pipeline spills were on lines over 30 years old, and 81% were on lines over 20 years old. According to the US Pipeline Safety Trust, between 2002 and 2008, over 34,000 anomalies on pipelines were discovered and repaired due to internal company inspections.

Even tiny corrosion holes are risky - the discovery of corrosion and ensuing shutdowns on BP's aging Prudhoe Bay pipeline network started with a dime-sized hole which caused a 5,000 bbl spill in 2006

Chart 15: US Onshore Natural Gas Transmission Pipelines: Year installed



Source: US Department of Transport PHMSA, BofA Merrill Lynch Global Research

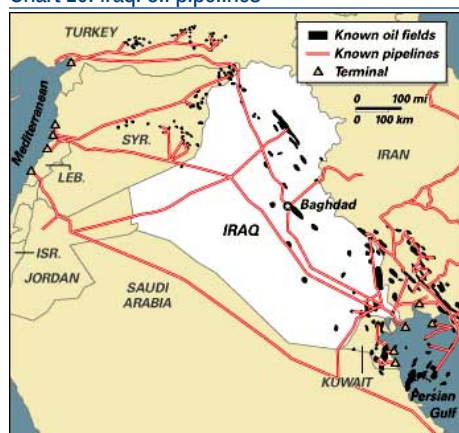
Transmission lines – which are placed 3-6 feet underground – are vulnerable to failure for a number of reasons. For example, corrosion can thin the pipe walls until they burst, a contractor can make a line-weakening gouge in the pipe (cover it over and leave), a control room operator can fail to identify a warning from a computer (allowing a spike in pressure), a poor pipe can rupture, or a valve can stick, among other reasons. If pipelines are operated and maintained properly, they can last for a long time, but operators have to inspect the lines frequently and well enough to find and fix any dangerous weaknesses. They must also constantly monitor the pressure in the pipeline system so that they can shut it down if trouble arises. Management of these issues is made more difficult by the highly decentralised pipeline business – with up to 3,000 operators in the US.

Pipeline safety a global issue

While there is growing attention on the US, increasing corrosion problems are posing a threat to production in the Middle East, Russia, Argentina, China, Indonesia, Nigeria and Venezuela, among other countries. A few examples are:

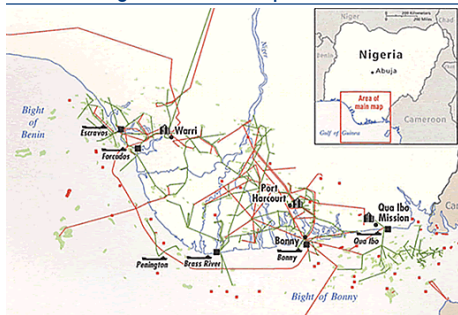
- **Iraq** - The pipelines that export most of Iraq's oil were built in the 1970s and were only supposed to last 20 years without any major inspections or upgrades. The pipelines were last inspected in 1991, when pipeline corrosion forced a 76% reduction in safe exporting capacity. According to a 2007 study commissioned by the US government, the country's 48 inch pipelines are at risk of failing at any time (assuming the average corrosion rate has continued). Shutting down the pipelines – the best option from an HSE perspective – would cause economic hardship and chaos for the country (Iraq relies on oil exports for 90%+ of state income). However, a severe pipeline rupture far from shore could be more damaging than in the GoM, with the entire Gulf potentially being impacted given the country's unpreparedness to deal with a spill.

Chart 16: Iraqi oil pipelines



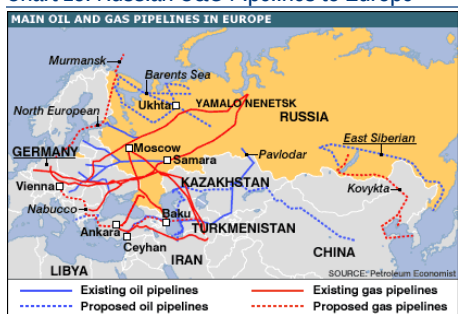
Source: Jerusalem Post, BofA Merrill Lynch Global Research

Chart 17: Niger delta O&G Pipelines



Source: Energy Information Administration, BofA Merrill Lynch Global Research

Chart 18: Russian O&G Pipelines to Europe



Source: BBC, BofA Merrill Lynch Global Research

- **Nigeria** - On some stakeholder estimates, the equivalent of the Exxon Valdez spill – 10.8m gallons – has been poured every year into the Niger Delta for the past 50 years. According to a study by the University of Lagos, oil spillage in Nigeria occurs mainly because of corrosion (50%), although sabotage (28%) and oil production operations (21%) are also factors. Nigerian pipelines are, on average, 40+ years old, and have been subject to far less regular inspection and maintenance than in other markets, with some western companies being accused of operating below accepted international standards such as API and ASME. The oil companies have long argued that they clean up much of what is lost (even when it is not their “fault”), but many stakeholders claim that the companies attribute too much to sabotage.
- **Russia** - Russia has one of the biggest pipeline networks in the world and also the longest oil pipeline – 4,000km – running from the eastern part of Russia to Ukraine, Belarus, Poland, Hungary, Slovakia, the Czech Republic, and Germany. The country has experienced a number of pipeline incidents (including Komi near the Arctic Circle in 1994), which the chief inspector for Russia's Natural Resources Ministry has in the past suggested are due to unusable pipelines. Stakeholders such as Greenpeace say there are more than 20,000 leaks or breaks in Russia every year and more than 50% of the pipelines are older than 20 years. The harsh climate and conditions make pipeline monitoring, repair and replacement all the more difficult.

New geographies and unconventional O&G mean new pipeline challenges and risks

The inevitable move to new geographies (Arctic) and unconventional forms of oil (oil sands, shale oil) will pose a raft of additional challenges in terms of pipelines and corrosion. Among the possible issues will be higher corrosion risk (sediment-laden oil sands), extreme environments, aggressive flow streams contributing to internal corrosion, material supply (high-strength steels; specialty coatings), special engineering challenges (strain-based design) and work in remote locations (see further below *Unconventional O&G*).

Table 18: New energy sources drive need for new pipeline technologies

New energy source	New pipeline technology needs	Value
Offshore	Anti-buoyancy, stability, mechanical protection for fixed and/or mobile plants	Significant logistics cost advantage
Deepwater	High compressive force, low thermal conductivity for ultra deepwater	Flow assurance in ultra deepwater
Challenging environments	Bendable mechanical protective coating for fixed and/or mobile plants	Significant cost advantage in pipeline construction
Oils and/heavy oil	Thermal insulation for high temperature bitumen, heavy oil and liquids lines	Significant cost advantage vs field-applied insulation

Source: ShawCor, BofA Merrill Lynch Global Research

\$4.4bn in pipeline damages & 2.5bn bbl spilled

While GoM has justifiably placed the focus on offshore O&G, onshore remains a major risk area. In the past six months alone, three serious oil spills have occurred on ageing US onshore pipelines and an explosion on a 54-year-old PG&E gas line killed eight people and destroyed 37 homes. From 2006 to 2009, US oil & gas pipelines killed 56 people, caused \$1.2bn in property damage and spilled 381,000 barrels of oil according to the US Department of Transport Data. And we have seen no significant signs of improvement over the past two decades.

Table 19: National (US) All Pipeline Systems: Significant* Incidents Summary Statistics: 1990-2009

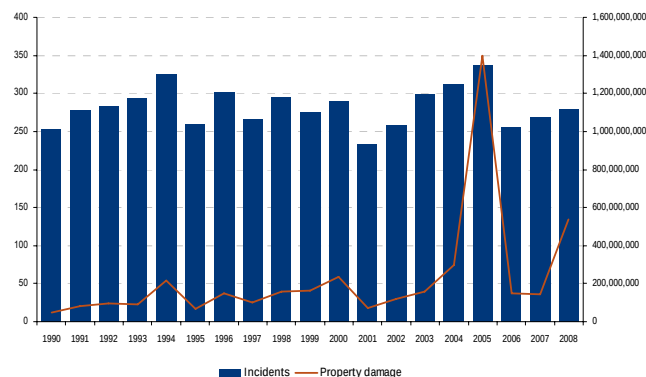
Year	Number	Fatalities	Injuries	Property Damage	Gross Barrels Spilled	Net Barrels Lost
3 Year Average (2007-2009)	271	12	59	\$278,737,810	82,228	56,515
5 Year Average (2005-2009)	282	14	51	\$476,364,373	104,047	53,758
10 Year Average (2000-2009)	280	16	58	\$326,301,777	99,080	59,931
20 Year Average (1990-2009)	282	18	170	\$221,854,577	125,682	68,554
TOTALS	5632	364	3406	\$4,437,091,536	2,513,630	1,371,082

Source: US Department of Transportation PHMSA, BofA Merrill Lynch Global Research. * Significant is defined by the PHMSA as those incidents reported by pipeline operators when any of the following specifically defined consequences occur: fatality or injury requiring in-patient hospitalization; \$50,000+ in total costs; highly volatile liquid releases of 50bbl+ more or other liquid releases of 50bbl+, liquid releases resulting in an unintentional fire or explosion

Things are not getting much better

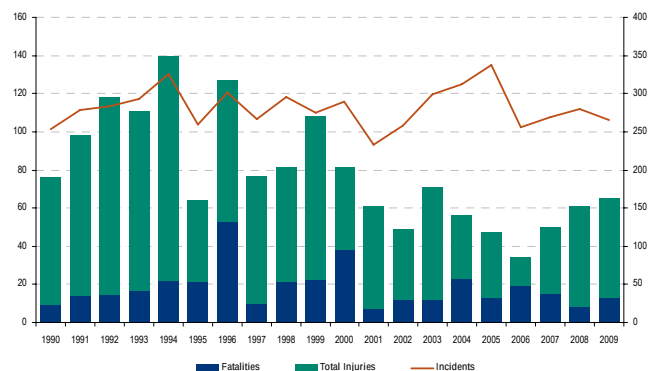
Between 1990 and 2009, there were 5,626 pipeline "significant [pipeline] incidents" nationwide in the US. Such incidents caused 365 fatalities, 1,553 injuries, \$4.4 billion in property damage, and 2.5mn barrels spilled into the environment. Despite improving safety records, we see a consistent yearly average of "significant incidents" (282) over that two-decade period.

Chart 19: US - All Pipeline Systems: Incidents and property damage 1990-2009 (\$bn/year)



Source: US Department of Transportation PHMSA, BofA Merrill Lynch Global Research

Chart 20: US - All Pipeline Systems: Significant Incidents Summary Statistics: 1990-2009



Source: US Department of Transportation PHMSA, BofA Merrill Lynch Global Research

Corrosion costs O&G \$80-100bn worldwide pa

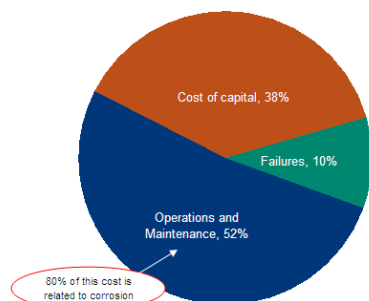
The most complete estimate of the cost of corrosion was the US Federal Highway Administration (FHWA)'s "Corrosion Cost and Preventive Strategies in the United States". The study showed that the total annual estimated direct cost of corrosion across all industries in the US is as high as \$276bn. Summing up for the O&G industry, it found corrosion impacts were as follows: Gas and Liquid Transmission Pipelines (US\$7.0 billion), Gas Distribution (US\$5.0 billion), Oil & Gas Exploration and Production (US\$1.4 billion), and Petroleum Refining (US\$3.7 billion) – making for a total estimate of \$17bn/year for the US back in 2000. Extrapolating these figures globally to 2010 gives a conservative worldwide estimate of the cost of corrosion to the oil & gas industry of c.US\$80-100bn.

Estimated costs of corrosion on the US O&G sector (\$mn/year)

Gas & liquid transmission pipelines*	\$USmn	Oil & gas E&P	\$USmn	Petroleum refining	\$USmn	Gas Distribution
Cost of Capital	2,670	Surface Piping & Facility Costs	589	Maintenance	1,800	
Operations & Maintenance (O&M)	3,630	Downhole Tubing Expenses	463	Vessel turnaround	1,400	
Cost of Failures (Non-Related O&M)	673	Capital Expenses	320	Fouling costs	500	
TOTAL	6,973	TOTAL	1,360	TOTAL	3,700	5,000

Source: NACE International, BofA Merrill Lynch Global Research. * Based on average estimates (low estimate = 5,391), high estimate = 8,555).

Chart 21: Cost of Transmission Pipelines



Source: Worley Parsons, BofA Merrill Lynch Global Research

Cost is the limiting factor in solutions

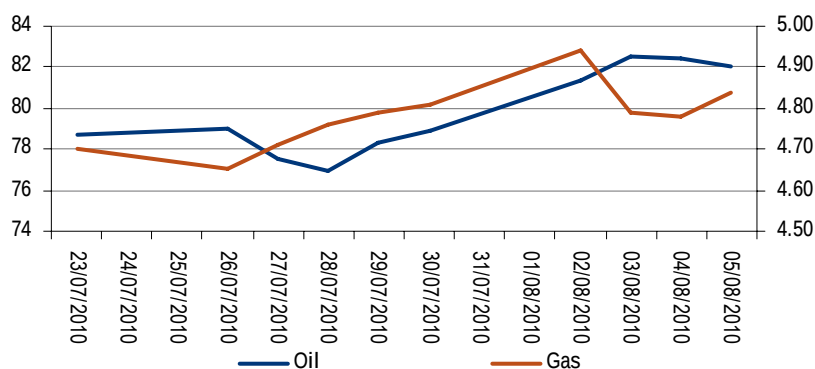
Major US operators of liquid pipelines spent \$2.7bn between 2004 and 2009 on pipeline integrity measures, including sending inspection machines through pipelines, according to the industry grouping, the Association of Oil Pipe Lines. However, given the age and risks involved, a strong argument can be made that cost is, yet again, the limiting factor in effective solutions – with owners pushing back on costs and corrosion problems and risks not being addressed or resolved at the design stage. Instead, the issue is shifted to operations – and higher opex costs owing to the need for more stringent maintenance practices, with increasingly costly results. It is something of a vicious cycle – with poor maintenance meaning high asset replacement implications. To put things in perspective, pipeline maintenance costs range from \$5,000 to \$10,000/mile, whereas asset replacement costs are estimated to be around \$1m/mile.

Leaks and market disruption on the increase

While total pipeline incidents have declined marginally in recent years, serious incidents involving death or injury reached a six-year high in 2009. 2010 has seen a series of high-profile pipeline incidents and outages. Given the ageing of the US pipeline network, the economic system is vulnerable and we believe incidents are set to rise with knock-on effects on the oil price:

- **BP and Prudhoe Bay** Following the BP Prudhoe Bay pipeline leak in March 2006, the price of crude oil on NYMEX jumped US\$2.22/bbl, closing at US\$76.98 per barrel. Due to delayed progress in stopping the oil spill, BP was forced to shut down its Prudhoe Bay oil facility, which at the time produced about 2.6% of the United States' demand for gasoline. The scenario was a contributing factor in again pushing the price of oil to US\$77 per barrel in August 2006.
- **Enbridge Illinois oil spill** Oil surged almost \$4/bbl in the days after Enbridge Inc.'s 670,000bpd 6A pipeline spilled 6,000 barrels in Illinois in September 2010. During the eight-day shutdown of the 41 year-old pipeline, Chicago gasoline prices rose 25 cents a gallon.

Enbridge 2010 spill's impact on oil & gasoline prices



Source: Bloomberg, BofA Merrill Lynch Global Research

BP had conducted 150,000 exterior pipeline inspections and 77,000 internal inspections on the Alaska North Slope (as of November 2010)

Only 7% of gas pipelines and 44% of liquids pipelines are currently being inspected under Federal law

Ongoing concerns over BP's Alaska North Slope pipelines

While the public focus has been on Enbridge and GoM, stakeholders such as ProPublica have been alleging that BP still faces significant corrosion risks in Alaska. They claim that leaked internal BP maintenance reports from October 2010 show that at least 148 pipelines received the most critical "F" rating, implying that the pipeline walls are 80% corroded. BP has responded by saying that the rating does not imply that the pipeline is unsafe or facing failure, but rather that it could refer to pipelines which have been prioritised for repairs or are located in sensitive areas. BP added that as of October 2010, 151 locations – rather than entire pipes – have the rating among more than 1,600 miles of North Slope pipelines. We believe the situation shows that BP's corrosion monitoring programs are working, with the company having conducted more than 150,000 exterior pipeline inspections and 77,000 internal inspections using a variety of tools, including "smart pigs" sent through pipelines to assess their condition – as well as allocating an estimated annual capital budget of \$850mn for North Slope maintenance and upgrades. However, it reiterates the ageing pipeline infrastructure risks that BP and other majors face.

US to adopt much stricter pipeline regulation

Pipeline safety legislation, which comes up for reauthorisation every four years, will likely include several regulatory additions as a result of the recent events and previously planned changes. The reauthorisation bill could be influenced by a US Dept. of Transportation measure introduced to Congress in September 2010, which is looking to strengthen pipeline oversight. The Department of Transport (DoT) is hoping to put together a bill that takes into account lessons from GoM, the natural gas pipeline explosion in San Bruno, California and the Michigan oil pipeline spill. The Department of Transportation's proposal would significantly step up scrutiny of oil & gas pipelines:

- **Increasing the maximum fine** on companies responsible for pipeline breaks that result in death, injury or environmental damage from \$1mn to \$2.5mn. This would go some way towards making up for the fact that fees for noncompliance have become too small, in our view, relative to the risk of pipeline shutdown or catastrophic failure.
- **Setting aside money for 40 additional pipeline inspectors**, to be hired over the next four years. This would go some way towards tackling concerns that the PHMSA does not have sufficient inspectors to oversee US pipelines and is being forced to rely on company records to ensure that pipelines are being inspected properly. At present, it is authorised to employ 137 inspectors, but has only 110 (ie, one inspector for every 18,500 miles of pipeline). For comparison, there is one federal railroad inspector per 350 miles of railroad.
- **PHMSA inspection overhaul** The PHMSA would be required to review and revise its current inspection policies. At present, Federal law requires only 7% of natural gas pipelines and 44% of liquid pipelines to be inspected. These pipelines fall within so-called "high consequence areas" (HCAs), near dense populations or vulnerable ecosystems. Pipelines that lie outside of these stretches are not required to be inspected. Under the proposed legislation, PHMSA would reassess and determine whether more or all pipelines should receive mandatory safety inspections. This could, in turn, see the PHMSA make use of its largely unused power to close down pipelines if it sees risk of a future accident.

- **Instructing the transportation secretary to review the exemptions**
some companies currently have from safety regulations – and telling the DoT to avoid giving exemptions, or special permits, to companies with poor safety records. The PHMSA has granted 16 special permits since January 2009, though it has granted only one since Cynthia Quarterman, Obama's choice to lead PHMSA, took charge in November 2009.

Call to action for a Corrosion Prevention Act

NACE International announced a "Call to Action" to support new US legislation introduced in 2009 – the "Corrosion Prevention Act of 2009", which will provide the energy industry with a tax credit for costs associated with preventing or mitigating corroding metals for amounts expended on corrosion prevention and central measures above and beyond federal, state, or local requirements.

Need better transparency

What is apparent, though, is the need for greater transparency on corrosion of the pipe material, corrosion monitoring, and repairs (were they related to corrosion, third-party damage, material of the pipe?).

Will the regulation go far enough?

While the proposals have been welcomed as a long-awaited starting point, lawmakers and stakeholders are already raising questions about their failure to address key concerns identified by pipeline safety experts, including: adequate funding for the PHMSA, mandating the improvement of leak protection systems; whether PHMSA should retain copies of O&G company integrity-management plans whereby they test the safety of their own lines (as it stands now, they do not); new requirements about how pipeline control centres respond to spills; what threshold PHMSA should have for requiring that damage to a pipeline be fixed; whether there should be new leak protection requirements; and whether PHMSA should do more pipeline safety R&D.

Will the regulation come quickly enough?

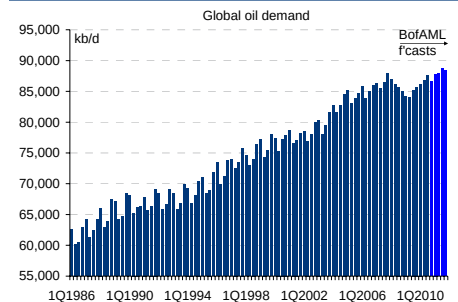
Seven hearings on pipeline safety have been held so far this year – five in the House and two in the Senate – an unprecedented number. However, passing the pipeline legislation this year has become impossible because of the legislative calendar – with no set schedule for beyond October 2010. Several Democratic representatives who were intimately involved in crafting pipeline safety legislation have now lost their seats, which could also delay legislation.

PHMSA public consultation underway

The PHMSA has begun a "public comment" period from October 2010 to January 2011 regarding possible changes to its regulations covering onshore liquid pipelines. In addition to those described above, areas for consultation include whether to order operators to use new anti-corrosion systems, install new safety valves and toughen leak detection requirements.

"Every day we delay strong pipeline safety reforms is one we put ourselves at risk" -
Pipeline Safety Trust

Chart 22: Global crude oil demand has been growing at among the fastest rates since 2005



Source: IEA, BofA Merrill Lynch Commodities Research

Oil shale is a fine-grain sedimentary rock containing kerogen (a waxy organic matter). By using a process called pyrolysis (thermal dissolution), the oil shale is subject to temperatures of 300–520°C which causes the kerogen to decompose and yield oil, gas and residual carbon. The pyrolysis is performed above ground or within the rock formation and the resulting oil is upgraded to meet refinery specs. by adding hydrogen and removing impurities (i.e. sulphur, nitrogen). NG and NG liquids account for 15-40% of the total recoverable energy (depending upon the specific shale rock and extraction process).

Unconventional O&G brings new risks New geographies and geologies

With two-thirds of the 100 countries currently producing O&G liquids and the majority of the world's giant oil fields past their production peak, the world needs the equivalent of four to six more Saudi Arabias if it is to maintain current levels of production by 2030. This, along with increasingly globalised competition for reserves, is pushing oil & gas companies towards more difficult types of hydrocarbons and increasingly complex E&P to meet growing global energy demand.

We see a wide range of new safety challenges emerging on 1) shale oil (hydraulic fracking, drilling fluids, water pollution, EPA investigation, moratoriums, regulations); 2) oil sands (market reaction to recent spills, growing case vs. “dirty oil”, uncertain future of Keystone pipeline); 3) pre-salt (deepwater, salt layer, untested conditions, strengthening of HSE regulations); and 4) the Arctic (unique biodiversity, no proven technology to remove oil from ice, difficulties of a clean-up operation, regulations).

Whereas some might have argued only a year ago that such issues are largely irrelevant to investors, GoM has heightened scrutiny of the potential safety risks of such E&P. We anticipate that regulators will follow stakeholders in this direction – with the former likely to seek to strike a balance between producing unconventional oil economically and safety concerns. Either way, the result should be the same, with oil & gas companies facing the prospect of stricter safety regulations and higher production costs.

1) Shale oil & gas playing catch-up for now

Despite the economic downturn, we have seen booming interest in new natural gas developments in the tight shale rock formations in the US. The stakes are very high with up to 500tn ft3 of reserves in the US alone – and shale oil becoming a major source of revenue and profit growth for Anadarko, Chesapeake and EnCana. Oil majors such as ExxonMobil (XTO Energy acquisition), Chevron (Atlas Energy acquisition) and Reliance Industries (JV with Atlas Energy) have also been making a big push on shale. And given the service intensity of horizontal oil shale drilling, so have oil services companies such as Halliburton, National Oilwell Varco, Schlumberger and Weatherford International.

However, the sector has largely moved one step ahead of regulations and oversight – with a patchy network of state by state requirements, restrictions and frequent lack thereof. Shale oil poses potential safety risks in terms of increased surface use and chances of spills and accidents. Most worrying for stakeholders is the potential for water pollution – a highly sensitive hearts and minds issue – via fracking and poor cementing and casing of wells. The US EPA is looking into the subject with a major study due out in 2012. A number of jurisdictions have passed moratoriums or more stringent restrictions on shale oil drilling. However, HSE challenges also need to be weighed up against natural gas's ability to create jobs (“American jobs”) and as a relatively clean form of energy.

While we do not anticipate draconian measures, we believe we are likely to move to more restrictive regulation of shale oil on a 1-5Y basis, covering everything from hydraulic fracking to treatment of drilling fluids to restrictions on water use and treatment. Stakeholder and regulator interest following the GoM is likely to mean that this happens sooner rather than later – and that regulators will seek to

strike a balance between producing shale oil economically and HSE concerns. This could add to costs – as much as \$0.15 to \$0.75 per BTU of production according to some estimates. This could be a margin make or break for high-cost shale plays and portfolios and players that entered the sphere after lease prices began to soar – all the more so in an environment where we expect NG prices to fall in the short- to-medium term with record production continuing to depress prices. However, with domestic players seemingly committed to reduced gas drilling in 2011, we suggest that a more rapid recovery in US natural gas prices could be the surprise of 2011.

Table 20: BofAML Natural Gas Price Forecasts

	4Q10F	2010F	1Q11F	2Q11F	3Q11F	4Q11F	2011F
US Natural Gas (\$/MMBtu)	4.80	4.59	4.90	4.60	5.00	5.50	5.00

Source: BofA Merrill Lynch Global Commodity Research

US and global shale plays

The US has been the main focus for shale with Antrim (Upper Michigan), Bakken (North Dakota, spans border into Canada), Barnett (near Fort Worth, East Texas), Fayetteville (Northern Arkansas), Haynesville (Northern Louisiana), and Woodford (Eastern Oklahoma) all under development. Another rapidly developing shale play in the US is the Marcellus (stretching into Western Pennsylvania, Western New York, and West Virginia).

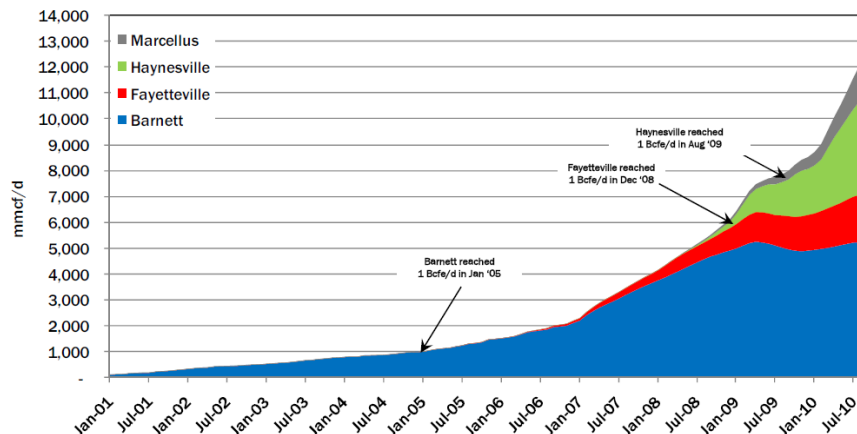
Table 21: Top 10 US Natural Gas Producers

Company	2Q10 daily production (mmcf/day)	2009 reported net US proved NG reserves	RP ratio	Proved US NG ranking	US gas rigs drilling on 24/9/10
ExxonMobil	3,810	24,189	17	1	66
Chesapeake	2,497	13,510	15	3	98
Andarko	2,324	7,764	9	6	22
BP	2,240	15,216	19	2	12
Devon	1,982	8,127	11	5	45
EnCana	1,850	5,713	8	8	48
ConocoPhillips	1,822	10,742	16	4	13
Chevron	1,317	2,698	6	14	3
Shell	1,145	2,258	5	18	15
Williams	1,110	4,255	11	9	19
Total for top 20	26,979	124,862	-	-	490

Source: Chesapeake, BofA Merrill Lynch Global Research

Marcellus has sparked significant stakeholder attention on HSE issues as it is the largest NG deposit in North America, spanning six states including New York, Pennsylvania, and West Virginia – and holding up to 500 trillion cubic feet of NG (i.e. 20x current US production and the most significant find outside Alaska). The growing importance of US shale gas is substantiated by the fact that of the 1.8 trillion cubic feet of total potential resources, shale gas accounts for 616tcf (33%).

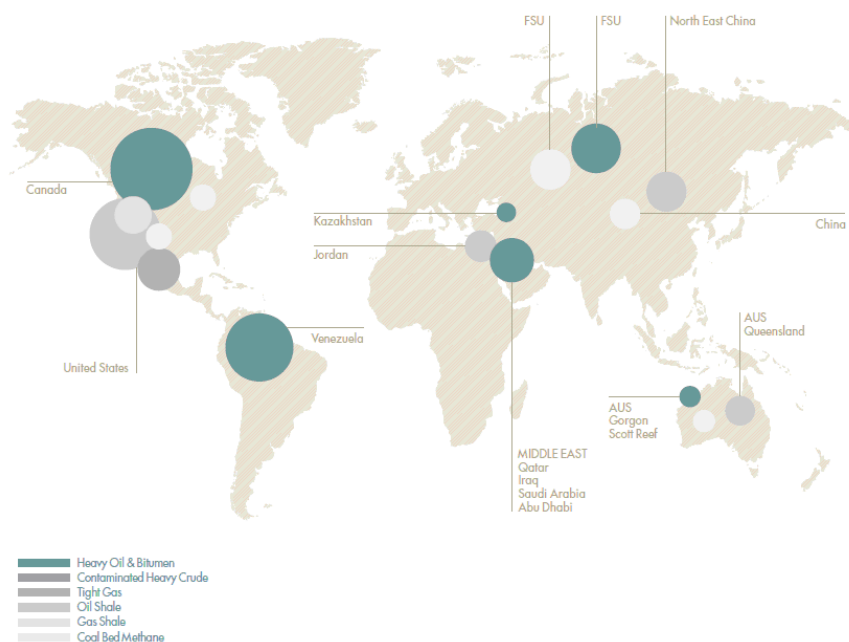
Exhibit 5: US Shale Gross Production Jan 2001 - Sept 2010



Source: Chesapeake, BofA Merrill Lynch Global Research

Worldwide production of shale oil is still small compared to conventional oil, with leading producers besides the US comprising Brazil, China and Estonia. Major reserves include the Green River deposits in the western United States, the Tertiary deposits in Queensland, Australia, deposits in Sweden and Estonia, the El-Lajjun deposit in Jordan, and deposits in France, Germany, Brazil, China, and Russia.

Exhibit 6: Global shale reserves



Source: Oil Shale Information centre, BofA Merrill Lynch Global Research

Shale gas is falling through the cracks on US HSE regulations, either via competing agendas or exemptions

Increasing focus on US HSE regulatory framework

Shale gas has become a key element of US national energy policy (with its low-carbon profile seen as a plus) and has grown from only 1% of US natural gas supply in 2001 to upwards of 20% in November 2010; we believe this could rise to as much as 50% by 2035. However, this rapid development has overtaken the regulators, with shale's development being criticised by stakeholders because of the lack of comprehensive, uniform or strict regulation – with shale oil also subject to a number of exemptions from relevant environmental legislation:

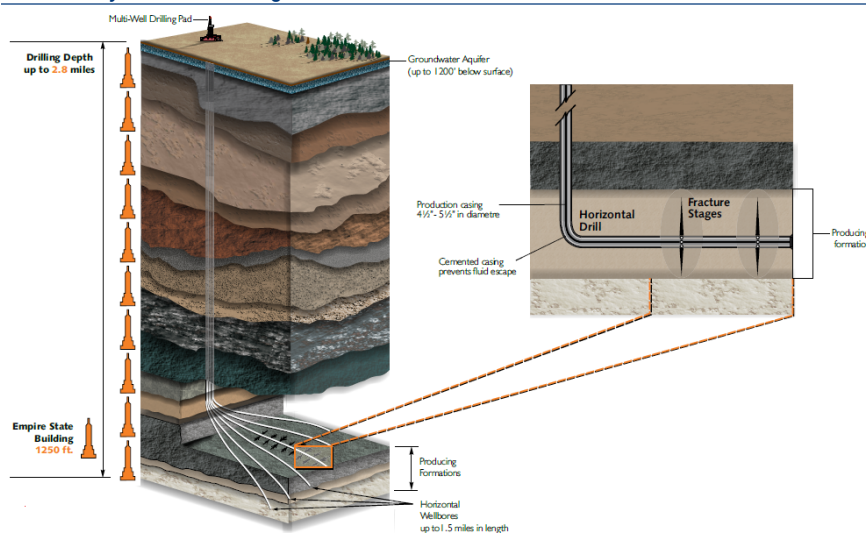
Hydraulic fracking and horizontal drilling have made the shale boom possible, but pose potential safety risks in terms of water contamination, fissures and clean-up

- **Natural gas E+P falls under a range of regulators with competing agendas**, resulting in a lack of comprehensive industry oversight. Regulations vary across US states and different parts of the drilling process are subject to different state and federal regulations, including treatment and disposal of potentially contaminating tracking fluid, which is subject to different federal regulations depending on whether it is above or below ground.
- **US Federal Energy Policy Act (2005) exempts fluids - water and chemicals - used in natural gas extraction fracking** from the protections contained in the Clean Air Act, Clean Water Act, and the Safe Drinking Water Act. This means that shale gas drillers do not have to disclose what chemicals they use. The decision was made after a 2004 EPA study which declared fracking safe, a move which was attacked by certain stakeholders, which alleged that the White House was pro-drilling (i.e. potentially influenced by then Vice President Dick Cheney (ex-CEO of Halliburton)) and that the scope of the EPA's review was too narrow. But as a result, shale gas drillers do not have to disclose what chemicals they use.

Fracking - a big safety risk?

The US NG boom has been largely based on innovations in drilling techniques, which have allowed oil services companies to pioneer accessing gas from deep, dense shale rock formations. The key technique raising HSE issues is known as hydraulic fracking or hydrofracking and involves injecting a mix of up to 8bn gallons of water, chemicals and solids (sand, ceramic pellets) at high pressure into wells up to 10,000ft below the water table. The fracking fluid breaks up underground shale rock and creates microscopic fractures. The fluid is then pumped back out and the fractures open, allowing the oil or gas to flow to the well. The process has become even more effective since the introduction of horizontal drilling in tandem with fracking in the early 2000s – which has allowed frac intensity per well to continue to increase, owing to longer horizontal laterals and increasing stages per well.

Exhibit 7: Hydraulic fracturing



Source: EnCana, BofA Merrill Lynch Global Research

While fracking is now used in about 90% of US gas and oil wells, it has been the subject of growing HSE controversy:

- **Potential for water contamination** Fracking wells can use as many as five million gallons of water per well. With companies drilling up to 16 wells per well pad, this amounts to 80 million gallons of water – and poses issues such as whether it is competing with other uses, like drinking water. The potential for water contamination comes after the fracking has occurred. Companies estimate that they receive back 20-40% of the fracking fluid when it is pumped back to the surface. As well as the risk this poses to groundwater, if improperly handled, this fluid could potentially harm surface water assets. While some efforts are being made to treat or contain the used fracking fluid, enforcement is currently not well developed.
- **Possibility of fissures or faults** Some academics and industry experts argue that hydrofracking involves wells being fracked many times over, increasing the risk of fissures. Longer-term, some have raised concerns about fracking potentially causing faults in rock formations.
- **Probable lack of capacity to clean up** the chemical- and sand-laden hydrofracking fluids in the event of a spill.
- **Additional HSE risks** include the full life-cycle CO2 emissions including emissions of the trucks bringing in the water and natural gas leaking from well heads or pipelines.

Again, the key issue is that the industry has grown faster than oversight and regulation of fracking and other HSE issues such as inefficient casings (which have been the cause of some incidents). The current patchwork of legislation probably needs to be standardised at the federal level, particularly in terms of clear sanctions, so that HSE issues do not slip through the cracks.

Fracking HSE incidents raising stakeholder scrutiny

In recent years, there have been several documented cases of HSE concerns including Cabot Oil & Gas being fined \$240,000 by the Pennsylvania Department of Environmental Protection for contaminating the groundwater of local homes with methane and Atlas Energy being fined \$150,000 by the state for violating its Oil & Gas Act, Clean Streams Law, and Waste Management Act for dumping fracking fluid. Moreover, despite many positive examples, we believe not enough companies are tackling the issue such as through reusing fracking fluid, reducing water use, disclosing chemicals used, and looking at how to make fracking water potable.

Table 22: Factors behind shale plays

Technology and efficiencies	Below-Ground Factors	Above-Ground Factors
Reservoir characterisation (selecting core drilling areas)	Organic content, maturity	Access to large mineral tracts
Advance horizontal drilling (deeper targets, longer laterals)	Rock quality (perm, porosity)	Royalty and tax rates
Completion optimization (increased stages, increased water and sand volumes)	Accessible gas in place	Regulatory environment
Cost optimization (gas factory, supply management)	Rock brittleness, frac-ability	Community access
	Frac geometry	Gathering & processing costs
	Depth, drill cost	Gas market access

Source: BofA Merrill Lynch Global Research

Some experts estimate that HSE regulation could add \$0.15 - \$0.75 per BTU to production costs

"Our research will be designed to answer questions about the potential impact of hydraulic fracturing on human health and the environment... The study will be conducted through a transparent, peer-reviewed process, with significant stakeholder input." - Paul Anastas, Assistant administrator for EPA's Office of Research and Development

Costly HSE regulation could be on the horizon

The imposition of a moratorium on shale oil by New York State and the Environmental Protection Agency (EPA)'s decision to undertake a review have sparked a debate about the potential HSE impacts of shale oil – and have raised the possibility of stricter regulation on a 3-5Y time horizon. Among the potential regulations we could see emerging are greater treatment of the fluids used to drill a well; tighter restrictions on where companies get water, stricter standards for the casing that lines a well hole; and giving the federal government a greater role in water monitoring. Some experts estimate that the regulations could potentially add \$0.15 to \$0.75 per BTU to production.

- **Legislation to regulate fracking has been passed in Ohio and West Virginia and introduced in Colorado and Pennsylvania.**
- **New York Senate fracking moratorium** The state Senate has had a moratorium on fracking in the Marcellus Shale for the last two years. It will not allow drilling to resume until a safety review is completed by the state's Department of Environmental Conservation, expected in May 2011. The Governor of New York announced in October 2010 that hydrofracking will not occur in the state's Marcellus shale region unless it can be proven that the procedure will not pollute water supplies. The state legislature also has a number of bills before it proposing new guidelines on where and when fracking can take place, stronger environmental impact statements before issuing fracking permits, and even calls for a permanent ban on fracking within certain distances of unfiltered sources of drinking water.
- **Quebec government is looking to tighten the rules on shale gas exploration** The Canadian province is holding public hearings on shale (Quebec currently has 10 wells being explored) and the provincial Environment Minister announced in October 2010 that any company that wants to carry out exploratory drilling and commercialisation from now on will have to get a new certificate – and pass a more rigorous inspection. The province's environmental protection agency, the Bureau d'audiences publiques sur l'environnement (BAPE), has also been asked to review shale practice and to report to government officials by February 2011.
- **Bills have been introduced to the US House and Senate** to give the EPA the right to regulate hydraulic fracturing and require disclosure of the chemicals used in the process. The House Energy and Commerce Committee is also conducting an investigation into the effects of fracking. The recent Republican victory in the House could play out in this regard.
- **US EPA study for 2012** Congress has also asked the US EPA to study the safety of the hydraulic fracturing technology and the potential dangers to groundwater. Its report is not expected before 2012 but is likely to go some way towards clarifying some of the HSE issues around shale oil for the US market. The EPA recently said that because hydrofracking occurs thousands of feet below the surface, there is a certain level of protection against contamination of groundwater. Nonetheless, the EPA addressed the volume of water used in fracking and said it would evaluate the integrity of some individual wells as part of a high-profile study. Industry had been urging the EPA to keep the study narrowly focused.
- **The US Interior Secretary is examining requiring producers** using federal land to disclose the chemicals used in hydraulic fracturing.

- **Stakeholders are calling for even more aggressive measures** such as 3D seismic imaging of drilling areas to detect cracks into which the gas could seep, and the plugging of older wells. While these do not appear to be on regulators' horizons, post-GoM scrutiny could change this.

Jobs vs HSE: the NG industry's battle for hearts and minds

The debate around regulation – and the current stakeholder consultation taking place across the Marcellus Shale states – is being influenced by natural gas companies, among others, arguing that it is a relatively clean form of energy (burning cleaner than coal), lessens the dependence on foreign oil, and creates significant numbers of domestic jobs (e.g. an estimated 100,000 to 200,000 in Pennsylvania and 180,000 in New York). All of these factors could temper the severity of any possible HSE regulation, especially if the downturn continues and employment numbers do not significantly improve.

2) Oil sands

NAm energy security vs rising HSE concerns and costs

Bitumen and extra-heavy oil have garnered significant stakeholder attention – notably Canada's oil sands, the largest crude oil source outside the Middle East – over a host of environmental concerns from impacts on biodiversity to full life cycle CO2 emissions. Recent spills have, however, placed a growing focus on pipeline safety and security issues with the oil price surging almost \$4/bbl in the days after Enbridge Inc.'s pipeline spilled millions of barrels in Illinois in 2010. During the shutdown of the 41 year-old pipeline, Chicago gasoline prices also rose 25 cents a gallon. Stakeholders and many US politicians have used the Enbridge spill to make a case against oil sands as a “dirty” and “unsafe” form of fuel.

We believe criticisms need to be balanced against the reality that the oil sands represent a key element of North American and US energy security. However, the upcoming review of the PHMSA regulations and the US Department of Transport's recent efforts to get tough(er) on pipeline safety have put oil sands safety in the spotlight following the Enbridge spill. Moreover, there is growing scrutiny of oil sands pipelines such as the Northern Gateway project to the West Coast and TransCanada Corp's planned 2,000-mile (3,200km) \$7bn pipeline linking Alberta oil sands with the US Gulf Coast refineries – with the latter attracting growing criticism from US lawmakers and stakeholders and scrutiny from the Environmental Protection Agency.

A pipeline leak this summer spiked oil prices by \$4/bbl and gasoline prices by \$0.25/gallon, and gave oil sands critics new ammunition

Exhibit 8: Enbridge pipeline expansion projects



Source: Enbridge, BofA Merrill Lynch Global Research

Exhibit 9: Location of Michigan incident



Source: Enbridge, BofA Merrill Lynch Global Research

Enbridge oil spill: the markets sat up and took note

Over the summer, there were leaks in two pipelines operated by a US affiliate of Enbridge Inc., the biggest shipper of Canadian oil, resulting in a reduction of the flow of oil sands crude into the US Midwest market during the quarter. The spill was the company's largest among a history of small spills and at least 30 federal citations for safety and inspection violations since 2002. As oil sands are more corrosive than standard crude (containing high levels of sulphur) and are loaded with higher levels of toxic heavy metals and chemical additives that keep the oil flowing, there were accusations that the company ignored warning signs of degradation on the 41-year-old pipe.

Market initially reacted very negatively to spill

Three days after initial reports of a crude oil spill near Marshall, Michigan, on Enbridge Energy Partners' (EEP) Lakehead System, the market apparently decided that this was a serious event, negatively impacting spreads on EEP's cash bonds (5.20% notes due 2020 wider by 25 bps) and credit default swaps (30 bps wider). In addition, EEP's equity unit price closed down \$3.77/unit, equating to a ~\$370 million loss of market capitalisation, significantly underperforming its peer group.

But Marshall spill was not Macondo

The spill in Michigan was a discrete event in which the oil flow was stopped early on and the clean-up got underway quickly. Unlike the Macondo well, where oil flowed for months, the oil flow on this spill was stopped in a matter of hours. According to EEP and parent, Enbridge, Inc., management, the oil spilled was estimated at 19,500 barrels with oil escaping into the Tallmadge Creek and from there into the Kalamazoo River. Separately, the EPA estimated the spill at over 1.0 million gallons, or ~24,000 barrels. While estimates of the amount spilled may vary, the key point is that the leak was stopped and EEP's and Enbridge's clean-up efforts are ongoing.

Q3 results: see no spill, hear no spill

However, when EEP reported 3Q10 DCF, it excluded non-cash expenses of \$475mn and foregone revenues of \$16mn related to the spills of lines 6A and 6B on its Lakehead system. In our view, the exclusion of these expenses is somewhat aggressive, especially with regard to lost revenues. Despite this, we can understand why EEP chose to exclude the expenses from its DCF calculation, namely the one-time nature of many of the spill costs, the overwhelming amount of the costs expected to be recovered by insurance and the desire to provide investors with a clear picture of its underlying performance.

Table 23: EEP line 6B and 6A cost estimates

	Line 6B	Line 6A	Total
Lost Revenues			
Date stopped	7/26/2010	9/9/2010	
Date restarted	9/28/2010	9/17/2010	
Days out of service	64	8	
Estimated throughput (bpd)	190,000	459,000	
Total Lakehead throughput in 2Q10 (bpd)	1,742,000	1,742,000	
3Q10E average tariff/bbl	\$1.58	\$1.58	
Total barrels lost	12,160,000	3,672,000	
Total operating revenues lost (\$mn)	(\$19.2)	(\$5.8)	(\$24.9)

Table 23: EEP line 6B and 6A cost estimates

	Line 6B	Line 6A	Total
Power cost			
Forecasted 3Q10 power cost per barrel	\$0.20	\$0.20	
Total barrels lost	12,160,000	3,672,000	
Power cost save from line shutdown (\$mn)	\$2.5	\$0.7	\$3.2
Incremental non-recoverable O&M (\$mn)			(\$35.0)
Total lost revenues (\$mn)			(\$56.7)

Source: Partnership reports, BofA Merrill Lynch Global Research estimates

Knock-on impact on other companies

Beyond Enbridge, the relatively minor spill impacted other Canadian producers that were hit by wide discounts on their heavy crude due to the shutdowns of two US pipelines in Enbridge Inc's US system:

- **Cevus Energy Q3 results** saw the company stating that lower realised heavy oil prices due to pipeline outages led to lower than expected results and reduced the midpoint of its 2010 cash flow per share guidance by about 12%.
- **Imperial Oil's Q3 results** were below consensus and BofAML as the company estimates that third-party pipeline reliability issues (i.e. outages on the Enbridge system) negatively impacted third quarter earnings by about \$60 million; an effect that will carry over into fourth quarter results.

Cross Reference

[Imperial Oil Limited, 02 November 2010](#)

Pipeline spills of this nature are not uncommon

Unfortunately, with the well-developed but ageing energy infrastructure that exists throughout the United States and Canada, incidents such as this are not uncommon. EEP has experienced several large spills in recent years, including a ~3,000 barrel spill in North Dakota on line 2B of the Lakehead System in January 2010. Away from EEP/Enbridge, one high-profile spill of note was the 2006 Prudhoe Bay spill, where BP ultimately pleaded guilty to negligent discharge of oil and paid a \$20 million fine or an average of ~\$4,000/barrel leaked. In addition, other pipeline operators, such as Kinder Morgan Energy Partners, Enterprise Products Partners, El Paso Corp. and Colonial Pipeline Co., have experienced spills or other types of accidents in their respective systems.

Table 24: A sample of major US pipeline spills 2000-2010

Date	Location	Leak / spill	Companies involved
June 2010	Tributary of Kalamazoo River, Michigan	Rupture of est. 1m gallons	Enbridge
June 2010	Salt Lake City	Leak of 33,600 gallons	Chevron
April 2010	Delta National Wildlife Refuge south of New Orleans.	Leak of 18,000 gallons	Chevron
April 2010	Rupture near Green River, Wyo	Spills 84,000 gallons	Bridger Lake LLC
January 2010	North Dakota	Leak of 126,000 gallons	Enbridge
January 2009	Utah	Leak of 58,800 gallons	NA
March 2006	Alaska's North Slope near Prudhoe Bay	Corroded pipe leaks 267,000 gallons	BP
December 2003	Grande Isla, La, Gulf of Mexico	Leak of 15,400 gallons	ExxonMobil

Table 24: A sample of major US pipeline spills 2000-2010

Date	Location	Leak / spill	Companies involved
January 2003	Douglas County, Wis	Release of >100,000 gallons	Enbridge
July 2002	Near Cohasset, Minn	Release of 252,000 gallons	Enbridge
April 2002	SE coast of Louisiana	Leak of 90,000 gallons	BP
January 2000	Winchester, Ky	Release of 489,000 gallons	Marathon Ashland LLC

Source: BofA Merrill Lynch Global Research

An average of 282 "significant [pipeline] incidents" over the last 20 years

\$4.4bn in pipeline damages & 2.5bn bbl spilled in 20Y

According to the US Department of Transportation's Pipeline and Hazardous Materials Safety Administration (PHMSA), between 1990 and 2009, there were 5,626 pipeline "significant incidents" nationwide (which are defined as those incidents reported by pipeline operators when any of the following specifically defined consequences occur: fatality or injury requiring in-patient hospitalization; \$50,000+ in total costs; highly volatile liquid releases of 5bbl+ more or other liquid releases of 50bbl+, liquid releases resulting in an unintentional fire or explosion). Such incidents caused 365 fatalities, 1,553 injuries, \$4.4 billion in property damage, and 2.5 million barrels spilled into the environment. Moreover, despite improving safety records, we have seen a yearly average of 282 "significant incidents" over the last two decades.

National (US) All Pipeline Systems: Significant Incidents Summary Statistics: 1990-2009

Year	Number	Fatalities	Injuries	Property damage	Gross bbl spilled	Net bbl lost
3Y average (2007-2009)	271	12	59	\$278,737,810	82,228	56,515
5Y average (2005-2009)	282	14	51	\$476,364,373	104,047	53,758
10Y average (2000-2009)	280	16	58	\$326,301,777	99,080	59,931
20Y average (1990-2009)	282	18	170	\$221,854,577	125,682	68,554
Totals (1990-2009)	5,632	364	3,406	\$4,437,091,536	2,513,630	1,371,082

Source: US Department of Transportation PHMSA, BofA Merrill Lynch Global Research

Exhibit 10: Keystone XL pipeline project



Source: Transcanada Corp, BofA Merrill Lynch Global Research

Is Keystone XL at risk because of HSE?

TransCanada Corp plans to build a 2,000-mile (3,200km) \$7bn pipeline linking Alberta oil sands with the US Gulf Coast refineries - which US proponents argue could help to lessen dependence on foreign oil. The first stretch of the 36-inch Keystone pipeline went operational in June 2010 when high energy prices and reducing dependence on foreign oil were on government and public minds. If it were to receive full planning permission, it would roughly double the system's capacity to 1.1 million bbl/d. TransCanada has long-term shipping deals for most of the line's capacity with large oil sands producers such as ConocoPhillips, Suncor Energy and Royal Dutch Shell. However, the pipeline is coming under growing criticism from US lawmakers and stakeholders and questioning by the Environmental Protection Agency.

State Department months away from a decision

The US State Department said it would delay any decision on the pipeline until all necessary steps in the environmental review and consultation among agencies had been taken. Despite Secretary of State Hillary Clinton saying that her department was "inclined" to give preliminary approval to TransCanada Corp.'s Keystone XL pipeline, approval is not a foregone conclusion, according to State Department officials. Clinton is also on record as saying that "We're going to be dependent on dirty oil from the Gulf or dirty oil from Canada".

The Secretary of State has “authority to act” on cross-border energy infrastructure on behalf of the US government by virtue of a 2004 executive order signed by President Bush. The process includes a State Dept-led EIA, public comment and consultation with other executive branch offices and key legislators.

EPA expresses HSE concerns over the draft EIA

The primary reason for the delay is growing HSE concerns over the pipeline. Concerns were raised by the EPA's comments on the State Department's Draft Environmental Impact Statement (DEIS) for the project, which received a low ranking due to concerns over significant environmental degradation caused by the extraction of oil from the tar sands, GHG emissions from extraction, and the risks associated with transporting the oil into and across the US. The EPA asked the Department to provide additional analysis including on safety and spill response capabilities. The Department is now working on a final version of the DEIS - and drafting a new version of the statement, which may stand as the final version or may itself be subject to additional comment and review. Once a final statement is released, federal agencies will have a further 90 days to contribute to a "national interest determination" on the project before the permit is either granted or rejected.

Elected officials join the fray

Eleven United States senators – 10 Democrats and one independent (none from states on the pipeline's route) – wrote to Secretary of State Clinton on 29 October 2010 expressing their concerns over the significant environmental degradation caused by the extraction of oil from Canadian tar sands, the emissions of greenhouse gases from this extraction, and the risk associated with transporting this oil into and across the United States. This comes after a similar letter from 50 members of the House of Representatives was sent to Clinton in June.

Table 25: US Senators' safety concerns over Keystone pipeline

Stakeholder concern	Overview
Local communities and first responders	Lack of opportunity to access the emergency response plans submitted by TransCanada (Emergency Response Plan, Facility Response Plans, and Spill Prevention Control and Countermeasure Plans for Keystone XL)
Athabasca watershed, Ogallala Aquifer water-related impacts	Risk of contamination to the watershed (downstream from extraction) and the Aquifer (through which the pipeline would extend) by tar sands oil production and transportation. The water reservoir spans eight states and yields nearly a third of water for US irrigation (and the Governor of Nebraska has also asked for it to be re-routed out of his State). Possible need for design as the Keystone pipeline has already had two leaks - at the Roswell and Carpenter pump stations.
Environmental assessment of pipeline safety issues	TransCanada has withdrawn its application for a special permit from the Pipeline and Hazardous Materials Safety Administration, and DOT is therefore no longer conducting a separate Environmental Assessment of pipeline safety issues.
Quality	Further details on pipeline thickness, quality, construction, operating procedures, and potential environmental risks.
Communities around refineries	Impact on communities already experiencing high levels of air and water pollution surrounding the refineries that would refine tar sands oil from the Keystone XL pipeline.

Source: US Senate, BofA Merrill Lynch Global Research

Transcanada arguing environmental & social benefits of pipeline

Despite the delay and growing controversy over the project, TransCanada believes that it will make its target of a start-up in 1Q 2013. It reiterates its arguments that pipelines are the safest mode of transporting oil, that the DEIS said “Keystone will have limited impact on the environment” and that TransCanada will continue to work with DOS through an extended comment period. It is also arguing the social benefits, notably that it would bring a \$20 billion boost to the US economy, \$500 million in state tax revenues, \$99 million to local governments during construction, \$5 billion in property taxes over the life of the project, and 119,000 person years of employment.

Possible scenarios for the resolution of the Keystone pipeline's HSE issues

	State Department finalises EIS, EPA OK	State Department finalises EIS, EPA asks for stakeholder consultation	EPA asks White House's Council on Environmental Quality to decide	State Department gives "national interest" OK, EPA/DOE disagree	EPA/other agency ask President to decide	Pipeline fails, Canada uses NAFTA
Overview	No stakeholder consultation	Stakeholder consultation could open up pipeline to changes (diversion from environmentally sensitive areas, increased safety measures, reduce daily throughput)	EPA disagrees with changes to EIS (post-stakeholder consultation). The CEQ's head supports a mix of clean energy, emissions reductions and reducing foreign oil dependence	EPA and/or Department of Energy contest "national interest" determination" with energy security and/or emissions arguments	President Obama has made pledges both on reducing dependence on foreign oil and on cutting emissions	Efforts to stop the pipeline could be deemed illegal under the agreement
Pipeline success probability	Very high	High	Med	Low to med	Low to med	?

Source: BofA Merrill Lynch Global Research

"Is it possible to drill in such challenging conditions with the confidence that everything is going to work fine? That's a very important question that we had to ask ourselves after the accident in the Gulf of Mexico." - Haroldo Lima, Director of Brazil's ANP (National Petroleum Agency)

3) Pre-salt

Most complex HSE offshore operating environment to date

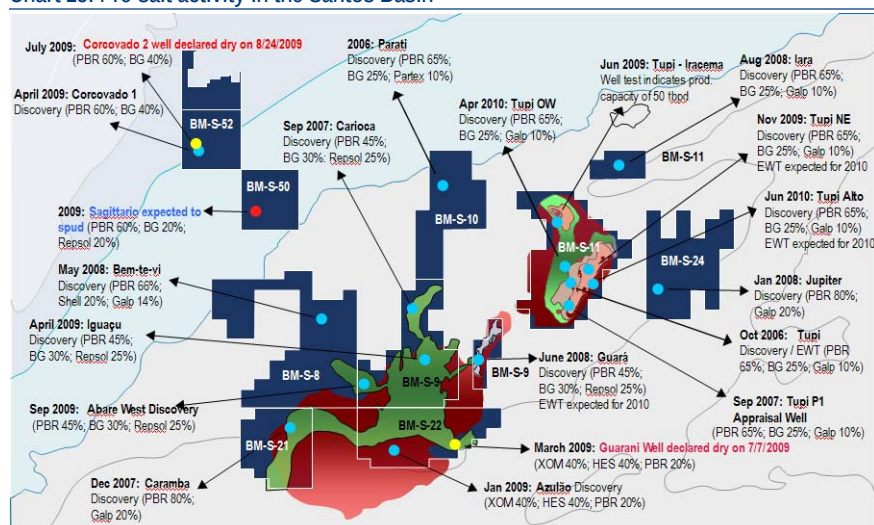
Drilling in the hugely rich pre-salt fields will pose HSE challenges greater than Petrobras – or indeed any other oil company – has possibly ever faced before. Despite stringent safety regulations in Brazil, pre-salt poses difficulties in terms of deepwater (i.e. constructing an 18-inch pipeline under 10,000 ft of water, 300km from the coast); the layer of salt (huge pressure, high temperatures, stability); and the fact that the E+P area is a complex and aggressive environment posing difficulties in terms of access, corrosion, extreme pressure, extreme weather and waves of 10m (33 feet) – which mean that no engineering solution can be 100% safe and secure. Compounding these difficulties are a host of technological challenges and a lack of skilled personnel.

In light of GoM, there are legitimate concerns about the potential risks of operating at such depths (7,000m) and in such largely untested conditions. HSE concerns are also bound to rise as the Brazilian government seeks to use the findings post-GoM to further strengthen existing regulations.

Petrobras and the Santos basin, the key focus

Petrobras is a key player in the offshore oil bed in the Santos and Espirito Basins, a region off the South-east coast of Brazil known as the pre-salt cluster. The region is called pre-salt because the oil is beneath deep and ultradeep waters, under 3,000m of sand and rock, and an additional layer of salt that can reach further depths of over 2,000m, making extraction challenging. In 2010-12, key projects will be the Pilot Production Project in the Tupi field and extended-well tests (two tests in Tupi NE and Guar have been identified for 2010 and a further four EWTs are expected for both 2011 and 2012). The start-up of the Baleia Azul field is expected in 2012. The potential for 5-8bn barrels of reserves in Tupi, another 3-4bn barrels in Lara, 1-2bn in Guar, plus un-quantified amounts in other areas is expected to dramatically alter growth in both reserves and production in coming years. We expect that the potential of pre-salt oil & gas production should enable Petrobras' total output growth to remain among the fastest globally through 2012 and that its production trends will lead global producers for the 2009-2020 period.

Chart 23: Pre-salt activity in the Santos Basin



Source: BofA Merrill Lynch Global Research, company reports

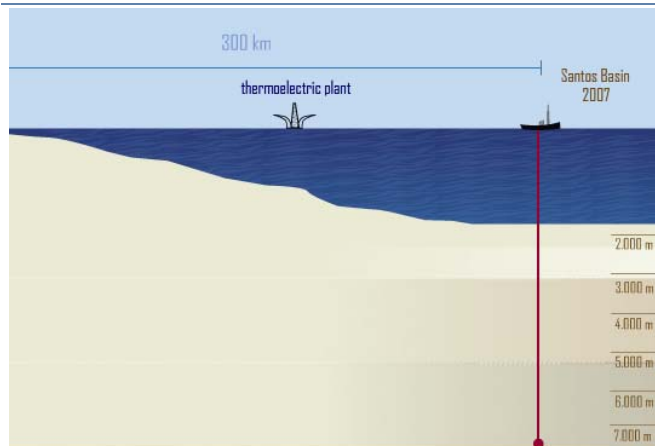
Safety challenges include operating under 10,000ft of water, 300km from the coast; and the salt layer itself

Some of the biggest safety and security challenges to date

Despite stringent regulations and Petrobras' strong track record with deepwater, pre-salt poses some of the greatest challenges that it or any other O&G company have faced to date. Besides the difficulties – which are posed by the deep water (i.e. constructing an 18 inch pipeline under 10,000 ft of water, 300km from the coast), the layer of salt (see below) and the difficulties formulating a contingency plan for HSE emergencies when you are far from the coast – the area is a complex and aggressive environment presenting difficulties in terms of access, corrosion, extreme pressure, extreme weather and waves of 10m (33 feet). Consequently, no engineering solution can be 100% safe and secure:

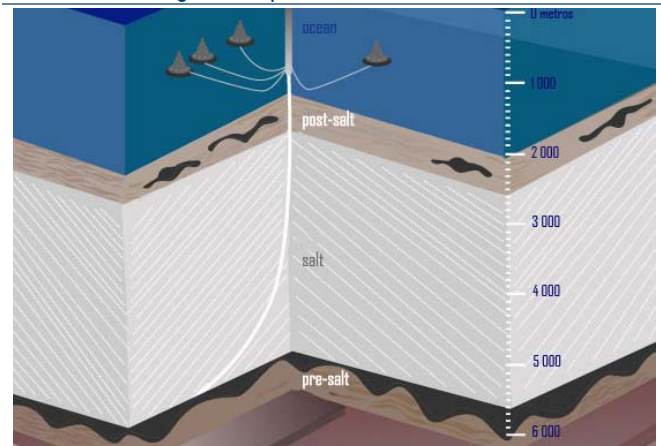
- **Oil is located 5km below the water surface** including 2km to the sea floor, a further 1km on the post-salt rock (the geological layer currently explored, which due to the pasty salt layer requires special care with exploration equipment), and 2km on the pre-salt layer (where the oil is stored in the pores of the reservoir rock lakes)
- **Distance between Tupi and the Santos coast**, which makes it more difficult to transport the liquids extracted from the wells. Some of the proposed solutions to tackle access include a thermoelectric plant at high sea (to be transported to the coast via cables) and compressing or liquefying the gas so that it can be transported to the coast in vessels.

Exhibit 11: 300 km distance to Santos basin



Source: Petrobras, BofA Merrill Lynch Global Research

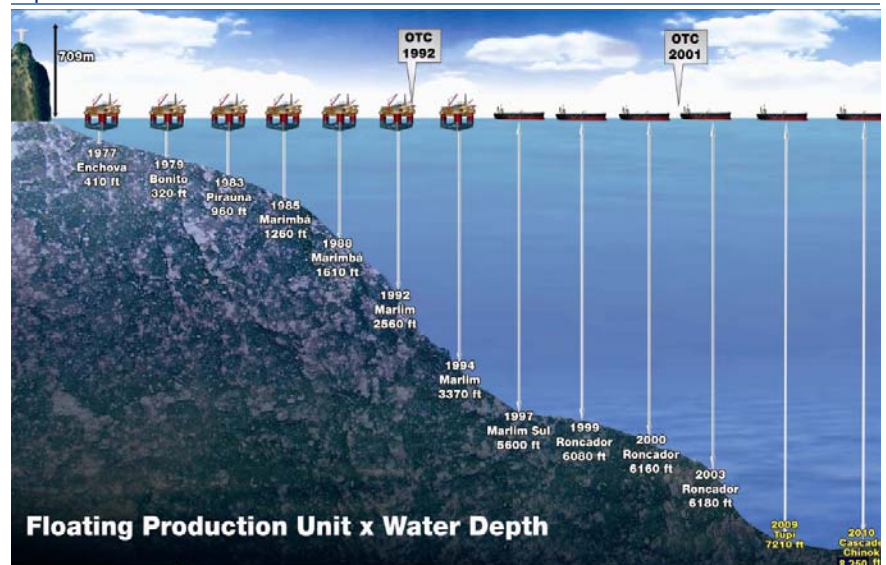
Exhibit 12: 5km to get to the pre-salt oil



Source: Petrobras, BofA Merrill Lynch Global Research

- **Ensuring stable drilling in the salt layer** The layer of salt is a huge challenge, as it is under great pressure and at high temperatures, which make it behave like a plastic. Consequently, it is hard to ensure the stability of the rock in the thick layer of salt - which can flow and prevent drilling in the wells (and does not allow for the use of current techniques of using water-based fluids to fill the gaps and avoid the walls). The main technical issue for drilling is ensuring the stability of the thick layer of rock salt (>2,000m), which can flow and keep the well from being drilled and increase well-drilling time. The salt layer also contains several kinds of salts, some of which are soluble, and thus require chemical analysis to define the drilling fluid.
- **Availability of high-spec. equipment** capable of 30,000ft drilling on 10,000ft water depths (rigs with mud mixing pumps and liquid storage capacity, hoisting systems, active heave compensation, hook load and derrick capacity, fluids handling systems, dealing with increased deck load).
- **CO2 challenges** Large concentrations of CO2 can potentially damage drilling equipment. Moreover, there is the question of what to do with the large quantities of CO2 that will be stripped out. Reinjection is a possibility and carbon storage is a long-term option.
- **Human resources** The predominance of Petrobras could become an issue, with the company, like the sector as a whole, stretched to the limit in terms of technical PTP professionals and people with the necessary deepwater skills to match its ambitious investment targets (see *HR section of report*)
- **Rising insurance costs** (See *Insurance section*).

Exhibit 13: Offshore output has been aided by increased technical capacity at greater depths



Source: BofA Merrill Lynch Global Research, company reports

Could Brazilian “Dutch Disease” become a safety risk?

A possible risk is “Dutch Disease” – with Brazil’s dependence on oil & gas posing the risk that other sectors, particularly industry, are left behind (as with the Netherlands’ discovery of natural gas in the 1960s). This risk could be compounded by Petro-Sal’s dominant role (a state-owned company with a seat and veto power in all blocks’ operating committees), the strict local content requirements for the Brazilian O+G sector (which could challenge costs and HSE capabilities) and the high specification technical equipment needed for E&P. The government is conscious of this risk – and of the historical problem of inconsistent, boom and bust investment in the sector – and is looking to create a more predictable environment. It intends to allow the oil industry only to develop at the same pace as the industries that provide it with ships, rigs, equipment and services.

Petrobras - massive capex investments to counter the risk

Of the total US\$108bn in E&P capex for 2010-14, included in Petrobras’ Strategic Plan, US\$33bn (30.5%) is directed to pre-salt areas and US\$75bn (69.5%) for post-salt projects. Drilling costs are expected to be the largest single component of pre-salt capex at an estimated 36%. These investments are paying dividends. The company has also made strides in reducing times and costs associated with pre-salt: the first well drilled in the section took over 1Y and cost more than \$240m, whereas more recent wells have taken 60 days and cost \$66m. Petrobras has made significant progress in well drilling (in the salt), well lining specifications, improving drilling fluid quality, well geometry design, drill bit specs and chemical analysis.

Brazil looking carefully at the GoM

Brazilian officials have been monitoring developments in the GoM closely, as over 85% of the country’s crude is offshore, and the overwhelming bulk of its long-term production prospects are offshore and deepwater pre-salt. In light of GoM, concerns have been raised about the dangers of operating at such depths and in such largely untested conditions. Positively, Brazil, along with Norway, is regarded as being well placed to address these challenges, having some of the:

- **Most experience with offshore and deepwater drilling and production** Petrobras is the largest deepwater producer in the world with four decades of experience in Brazil and internationally. It has the capability to drill at 2,000m and has several wells at this depth (including the former world record of 1,886m in the Campos basin).
- **Most stringent platform safety and regulatory systems** (with a number of stringent rules being introduced in 2001 after an explosion sank a P36 rig and killed 11 workers in a deepwater field in the Campos basin).

Chart 24: Petrobras' crude oil production growth from 1992 has been a result of the development of many offshore fields

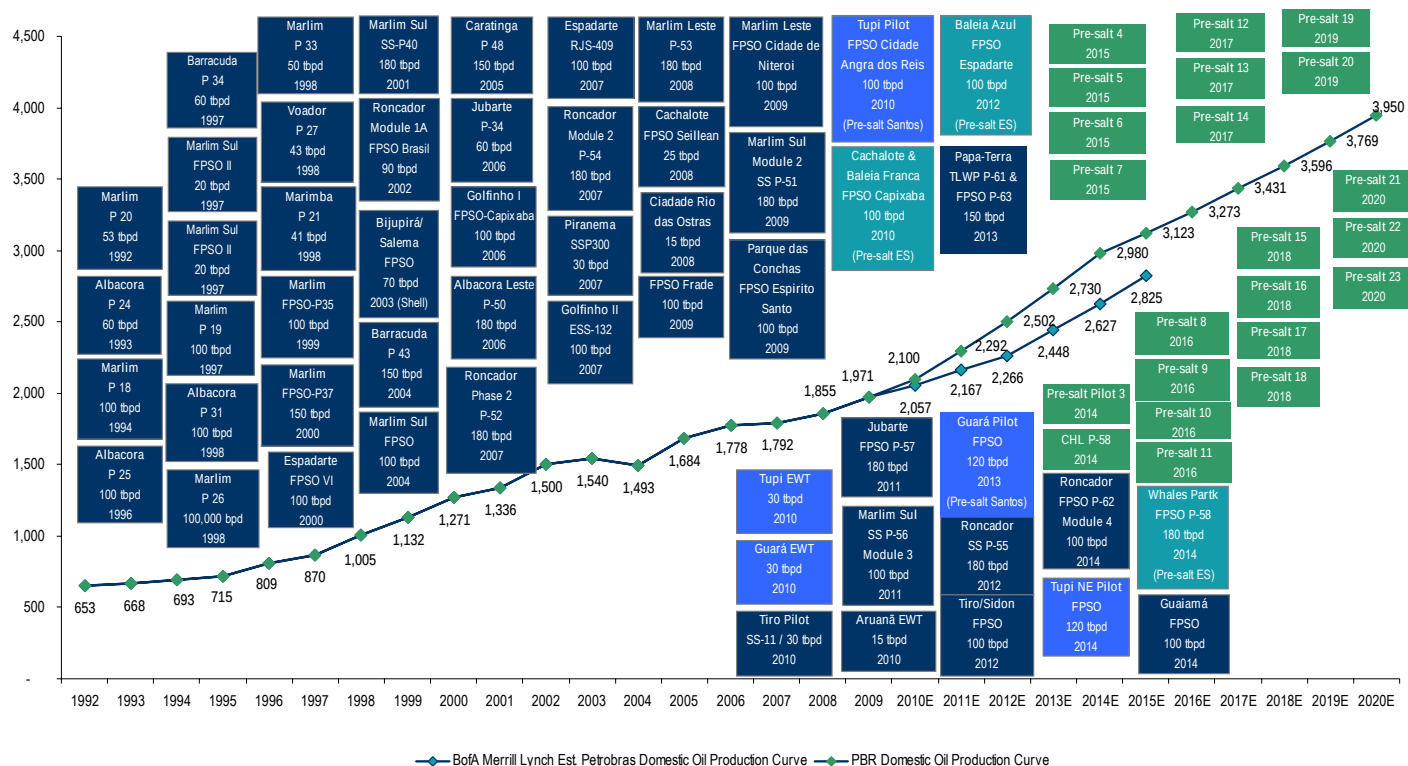
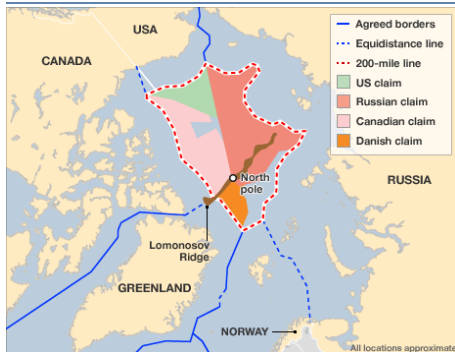


Chart 25: Race for Arctic O&G centres on the Lomonosov ridge which extends under the North Pole



Source: BBC, BofA Merrill Lynch Global Research

4) The Arctic

Last major frontier vs unknown dangers of oil and ice

The Arctic has been recognised as a source of resources dating back to its first onshore oil wells in Canada in the 1920s and offshore wells in Alaska in 1963 – and Arctic operations have produced 40bn barrels of oil and 1,100 trillion cubic feet of gas to date. However, majors are now looking to exploit the estimated 13% of the world's undiscovered oil and 30% of its undiscovered gas which the Arctic contains, according to the 2008 US Geological Survey. This is the equivalent of c.400 billion barrels of oil, 80% of which lies offshore. Before GoM, it had appeared that we were moving towards an opening up of the Arctic for exploration and development, with President Obama proposing to end the drilling moratorium in territorial waters and open up the Chukchi and Beaufort Seas.

GoM has, however, been a game-changer with the EU, US, Canada, Norway and Russia, among others, either putting a hold on Arctic drilling or looking to significantly strengthen regulations for the region because of the irreparable damage that an Arctic spill or disaster could have on the Arctic's unique environment. It is not that an oil spill is more likely, simply that the Arctic environment could be another game-changer in terms of the risks associated with a clean-up in ice-infested darkness. Also unclear is the speed with which industry could mobilise response equipment and staff in the event of an oil spill in the difficult operating environment. While we do not expect the BP-related hiatus to last forever – as recent Norway-Russia maritime boundary negotiations demonstrate – in the near future we expect regulators to err on the side of caution. We believe companies looking to drill face the prospect of stricter HSE regulation, heavier drilling costs and opposition and legal challenges from stakeholders.

Table 26: Sample of exploration, production and drilling activity in the Arctic and sub-Arctic

Company	Region	Location	Status
			2-4 well drilling programme for 2011 - 2bi bbl target
Cairn Energy	Greenland	Baffin Bay	Company is exiting Asia to focus on the Arctic exploration
Chevron	Canada	Beaufort Sea	Greenland 2010 program to cost \$400m
ConocoPhillips	Alaska		Won the right to explore a parcel in 2009 with a commitment to spend \$103mn
Eni	Norway		50 leases (Statoil 25%)
ExxonMobil	Alaska	North Slope	Company with the highest level of activity in the Barents Sea, with 3 projects
	Canada	Labrador Shelf	Invested about \$1.5 billion in 2 wells completed in Nov/2010
	Russia	Okha	JV with Aker for O&G development in the Hebron Field, 350 kilometres offshore from St. John's
Gazprom	Norway		Started producing in 2010, plans to produce 30,000 bpd at the Odoptu field
			Shtokman project postponed until 2016
	Russia	Siberia	In 2008, the company constructed a 684-mile-long pipeline under the Kara sea.
	Russia	Pechora Sea	Postponed opening the Bovanenkovo field on Yamal peninsula until 2012
Great Bear	Alaska		Just completed the oil rig to be used on Russia's first Arctic offshore oil field - Pirazlomnoje.
			\$8 million in Oct/2010 to acquire exploration rights
Imperial Oil	Canada	Beaufort Sea	Seeking an extension on its 2007 \$585mn, nine-year exploration licence (if it fails to meet that spending target by 2016, it forfeits a \$146mn deposit)
Novatek	Russia	Laptev Sea	Just delivered 70,000 ton of hydrocarbons to China on first journey along the northern passage route.
			Invested \$3.5 billion in the project (hopes Chukchi could produce up to 400,000bbl/d, Beaufort Sea 100,000bbl/d)
			Regulatory delays and lawsuits for four years have caused it to scaled back its initial drilling plans to just one or two wells in the Beaufort Sea and postpone drilling in the more remote Chukchi Sea
		Beaufort and Chukchi seas	Unprecedented oil spill response plan
Shell	Alaska		-Has support of the Alaska government
	Alaska	North Slope	multi-year agreement with North Slope Borough to explore and develop in outer continental shelf
Statoil	Alaska		16 leases - 2 at 100%, 14 with partner ENI (Statoil 60%, ENI 40%)
	Norway	Barents Sea	Said in Oct that completed oil spill preparedness plans and drilling of 2 wells will start imminently.
37 companies	Norway	Norwegian Sea	37 companies applied for production licence - individually or in groups - on the 21st licensing round at Norwegian shelf

Source: Company, BofA Merrill Lynch Global Research

Renewed interested in Arctic oil

The Arctic has long been seen as the last major fossil fuel frontier to satiate the long-term rise in energy demand and the increasing focus on energy security. A number of Arctic and sub-Arctic E&P locations are currently being investigated for E&P potential including the Azov Sea, Baltic Sea (including the Gulfs of Finland and Bothnia), Barents Sea, Beaufort Sea, Bering Sea, Bohai Sea, Caspian Sea, Chukchi Sea, Cook Inlet in Alaska, Gulf of St Lawrence, Laptev Sea, Kara Sea, offshore Eastern Newfoundland, Pechora Sea, Northern Sea of Japan, and the Sea of Okhotsk.

Chart 26: Arctic oil & gas provinces and basins



Source: The Pew Center, BofA Merrill Lynch Global Research

Among the factors at play are:

- **Improved technology**, which has made remote locations more viable;
- **Revaluation of potential resources** The US Geological Survey issued a revaluation of the Arctic's potential resources in 2008, estimating that "90 billion barrels of oil, 1,669 trillion cubic feet of natural gas, and 44 billion barrels of natural gas liquids may remain to be found in the Arctic, of which approximately 84% is expected to occur in offshore areas. In October 2010, the USGS downgraded estimates for the National Petroleum Reserve from 10.6bn (2002 est.) to 896mn bbl – showing that the data can evolve as and when exploration drilling takes place.

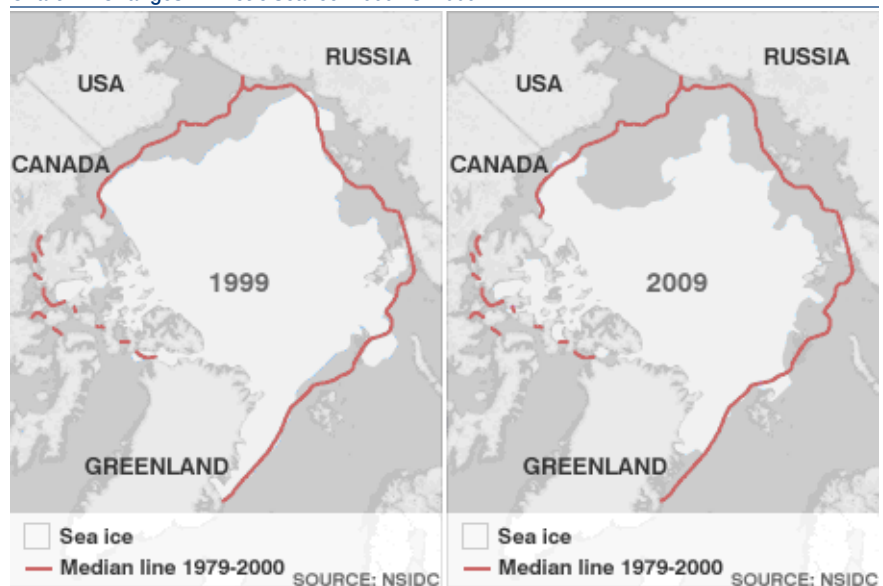
Table 27: Circum-Arctic resource potential

Province	Oil (MMBO)	Total Gas (BCFG)	NGL (MMBNGL)	BOE (MMBOE)
West Siberian Basin	3,659.88	651,498.56	20,328.69	132,571.66
Arctic Alaska	29,260.94	221,397.60	5,904.97	72,765.52
East Barents Basin	7,406.49	317,557.97	1,422.28	61,755.10
East Greenland Rift Basins	8,902.13	86,180.06	8,121.57	31,387.04
Yenisey-Khatanga Basin	5,583.74	99,964.26	2,675.15	24,919.61
Amerasia Basin	9,723.58	56,891.21	541.69	19,747.14
West Greenland-East Canada	7,274.40	51,818.16	1,152.59	17,063.35
Laptev Sea Shelf	3,115.57	32,562.84	867.16	9,409.87
Norwegian Margin	1,437.29	32,281.01	504.73	7,322.19
Barents Platform	2,055.51	26,218.67	278.71	6,704.00
Eurasia Basin	1,342.15	19,475.43	520.26	5,108.31
North Kara Basins and Platforms	1,807.26	14,973.58	390.22	4,693.07
Timan-Pechora Basin	1,667.21	9,062.59	202.80	3,380.44
North Greenland Sheared Margin	1,349.80	10,207.24	273.09	3,324.09
Lomonosov-Makarov	1,106.78	7,156.25	191.55	2,491.04
Sverdrup Basin	851.11	8,596.36	191.20	2,475.04
Lena-Anabar Basin	1,912.89	2,106.75	56.41	2,320.43
N. Chukchi-Wrangel Foreland Basin	85.99	6,065.76	106.57	1,203.52
Vilkitskii Basin	98.03	5,741.87	101.63	1,156.63
Northwest Laptev Sea Shelf	172.24	4,488.12	119.63	1,039.90
Lena-Vilyui Basin	376.86	1,335.20	35.66	635.06
Zyryanka Basin	47.82	1,505.99	40.14	338.95
East Siberian Sea Basin	19.73	618.83	10.91	133.78
Hope Basin	2.47	648.17	11.37	121.87
Northwest Canada Interior Basins	23.34	305.34	15.24	89.47
Mezen' Basin	NQA	NQA	NQA	NQA
Novaya Zemlya, Admiralty Arch	NQA	NQA	NQA	NQA
Tunguska Basin	NQA	NQA	NQA	NQA
Chukhi Borderland	NQA	NQA	NQA	NQA
Yukon Flats (Central Alaska Prov.)	NQA	NQA	NQA	NQA
Long Strait	NQA	NQA	NQA	NQA
Jan Mayen Microcontinent	NQA	NQA	NQA	NQA
Franklinian Shelf	NQA	NQA	NQA	NQA
TOTAL	89,283.21	1,668,657.82	44,064.22	412,157.08

Source: US Geological Service, BofA Merrill Lynch Global Research. NQA = not quantitatively assessed.

- **Shrinking of the ice cap** Arctic weather conditions have kept energy companies at bay, but climate change could see receding or even significant melting of ice caps, opening up the region to energy exploration and development. Smaller ice caps create longer open water seasons, increased open water areas and diminished risk of ice collisions. As temperatures in the Arctic increase, the extent of overall ice cover and the length of time that ice blocks the sea decreases. Long-term estimates are that the Arctic is warming faster than other regions and could become ice-free during the summer months ("open water") between 2030 and 2100.

Chart 27: Changes in Arctic sea ice: 1999 vs. 2009



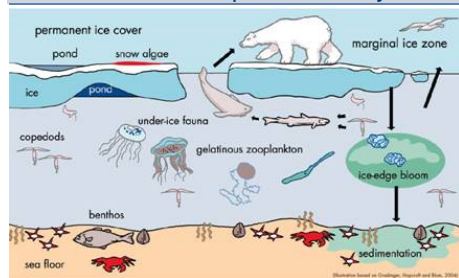
Source: NSIDC, BofA Merrill Lynch Global Research

Chilling safety risks

The difficulties in cleaning up a spill in calm waters and good weather in the Gulf of Mexico – relative to the Arctic – raise serious questions about the clean-up and effects of a potential spill or disaster in the region. The Arctic poses some of the most unique and untested challenges for oil spill response of any region globally. A major spill or blowout in certain areas (e.g. Chukchi Sea) would be difficult to access, let alone tackle, and once winter sets in access would be impossible. Even well-equipped institutions like the US Coast Guard have admitted they are ill-prepared to deal with a response in the Arctic, with a lack of ice-class vehicles capable of responding to a spill, distances of up to 1,600km between operations base and leasing sites and the lack of permanent infrastructure. Among the major challenges:

- **Difficult operating environment** – broken sea ice, freezing temperatures and darkness throughout much of the year. For instance, for the Sakhalin II project: temperatures fall to -45 in winter; production platform concrete legs are 20m wide and 56m tall; where the sea is less than 30m deep, pipelines are buried under the seabed; to provide protection against ploughing from ice ridges, the pipeline is reinforced by extra steel.
- **Changing ice conditions** Ice conditions vary widely between regions, and depending on water depths and distance to shore, ice changes through the seasons (i.e. freezes in autumn, reaches its thickest point during winter, melts in spring and creates open water in summer). During periods when ice develops, wind and water currents cause it to move and form ice ridges. The design of platforms and equipment needs to take into account the type, movement, thickness and strength of changes in ice conditions, as well as the pressure ice can exert on oil & gas structures.

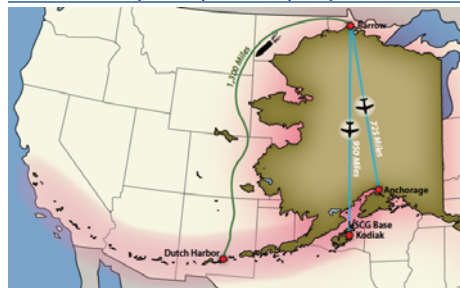
Exhibit 14: Arctic's complex biodiversity chain



Source: Shell, BofA Merrill Lynch Global Research

Drilling a relief well in ice-infested Arctic waters of the Beaufort Sea could take up to three years according to Canada's National Energy Board briefing notes

Chart 28: Putting the challenge of distance for an Arctic oil spill response in perspective



Source: Pew, BofA Merrill Lynch Global Research

- **Unique biodiversity** The Arctic ecosystem comprises a unique variety of plant and animal life with sea ice shaping a complex chain of marine and plant life from microscopic plant and animal life to larger marine animals, polar bears and seals and bird species. In addition, some 400,000 indigenous people live in the Arctic, largely maintaining a traditional subsistence lifestyle and relying on the ecosystem for shelter, food and cultural and social identity. Companies are still at the stage of trying to understand how their operations might impact everything from whale migration routes to caribou migrations and the impact of sound on marine creatures, among other areas – never mind dealing with the impact of any potential spill.

- **Diplomatic challenges** - northern sovereignty has been a particularly delicate issue since the polar ice began to melt, making the Northwest Passage a potential conduit for international shipping, and raising issues about the clean-up implications if oil were to spill into foreign waters, either directly or via melting ice.

No 100% proven technologies to recover oil from ice

While incidents in the Arctic have been limited, stakeholders make reference to two specific incidents. Four decades ago, a crew looking for gas on Canada's Melville Island, more than 400km west of Lancaster Sound, sparked a blowout that lasted 485 days – 5x what it took to contain the gulf spill. A year later, perhaps the largest blowout Canada has seen took place north of Melville on tiny King Christian Island. The gas ignited, fried the drilling rig and created an 85m high column of flame that burned for three months and could be seen from the air hundreds of kilometres away. Concerns over a potential Arctic clean-up include:

- **Adverse weather and response gap** Response rate times would be severely limited because of the weather with Shell's own [Arctic response] C-Plan noting that temperature alone could prevent response 50% of the time in January and 64% of the time in March. Further response complications include: the presence or absence of ice; cold temperatures' impact on the consistency of oil and the speed at which it degrades; high energy from wind and waves, which could break thick slicks into multiple slicks; seasonally short days; and the prevalence of fog and storms.
- **Locating the oil** Oil spilled into broken ice tends to move with the ice, and becomes more difficult to locate if it moves beneath or becomes encapsulated by ice. Existing methods of locating oil under ice are expensive, dangerous and often not feasible because of adverse weather - with new and largely untested technologies such as GPR (ground penetrating radar) being needed to tackle trapped oil.
- **Mechanical recovery technology** Ice acts as a physical barrier to mechanical containment and response and even low concentrations can limit the effectiveness of booms and skimmers, obliging response teams to deal with the oil when the ice melts. Such a "leave in place" strategy is, however, largely untested and other questions remain as to the behaviour of oil on ice. As for a relief well, it would require companies to summon a new drillship to remote waters, with many in the region limited to water depths of 400ft (120m) with harsh weather and ice conditions delaying potential progress.
- **In situ burning** Burning gathered oil (via fireproof booms to between natural ice berms) would probably be the major response technique in the Arctic because of the limited risk of the fire burning out of control. However, it also

Shell says that it is undertaking an “unprecedented spill response approach” including a subsea containment system, an upgrade of the drilling rig’s blowout preventer and an enhanced response plan that include teams and equipment at the ready 24 hours a day

requires accessibility for vessels (no commercially produced herders are available for the Arctic), the technique works best with a rapid response and efficiency rates in studies/tests have varied between 3.4-6.4% and company estimates of 85-95%.

- **Chemical countermeasures** The use of dispersants is limited by uncertainty over their effectiveness (studies vary between 10-99%) and toxicity in the unique Arctic environment, about which very little is known.
- **Bioremediation and natural processes** Adding bioremediation materials to accelerate the natural biodegradation process is an experimental possibility which is complicated by the lack of a regulatory framework.

Shell says it can manage the risk

Shell, which has invested \$3.5bn in developing projects in the Beaufort and Chukchi seas, insists that drilling in Arctic waters is safe. It states that it would be drilling in 100 to 150 feet of water in the Beaufort Sea, compared with depths of 5,000 feet and more in the Gulf, which means that the equipment would be subject to far less pressure. It has also been trying to tackle some of the issues surrounding the HSE challenges and launched a major campaign in October 2010 on its “unprecedented spill response approach” to the Arctic. Its strategy includes a sub-sea containment system, an upgrade of the drilling rig’s blowout preventer (BOP) and an enhanced response plan that include teams and equipment at the ready 24 hours a day. The containment system would include a dome that could be placed over any leak, and a funnel to take any escaping oil to surface ships. A rig would be at the ready to drill a relief well if needed. Shell says that its assets can be onsite and deployed within one hour. The company has the support of Alaska’s state government.

Chart 29: Matrix of Arctic oil spill response limits

LIMITING FACTOR	ICE COVERAGE					WIND			WAVE HEIGHT			VISIBILITY		
Conditions	<10%	11% to 30%	31% to 70%	>70%	Solid Ice	0-20 mph	21-35 mph	>35 mph	<3 ft	3-6 ft	>6ft	High	Moderate*	Low*
Mechanical recovery with no ice management														
Mechanical recovery with ice management					n/a									
In-situ burning														

Source: Pew, BofA Merrill Lynch Global Research. * moderate visibility = light fog or <1 mile visibility, low visibility = heavy fog, <1/4 mile visibility, darkness

Arctic HSE regulation is on the cards in Canada, the EU, Norway, Russia and US

New regulations likely to emerge

We are seeing increasing signs of stricter regulations for Arctic and sub-Arctic drilling, with regulators taking a very cautious position post GoM. This could ultimately add to the cost of producing a barrel of oil in the region:

- **US Arctic drilling on hold at the time of this report** – The Department of Interior announced in September 2010 that exploratory drilling for O&G in the outer continental shelf would remain on hold until the DoI have completed a review of issues relating to Arctic offshore drilling. It is not said to be an official moratorium, but rather a period of additional review of proposed drilling plans, which is scheduled to last until at least 2011. The DoI is on

record as planning to take a cautious approach and is requiring additional information about spill risks and spill response capabilities. The state of Alaska has taken issue with the DoI, contending that the review imposed an improper de facto moratorium on drilling and did not give the state a chance to comment or to appeal.

- **Alaska is conducting an analysis of the state's regulations** concerning offshore drilling. The Alaska Oil & Gas Conservation Commission has put together a commission to review offshore drilling practices and ultra-extended reach wells. The Department of Natural resources' Division of Oil & Gas is also evaluating its rules and requirements to determine whether existing regulating authorities are sufficient.
- **Canada has called a moratorium on Arctic offshore drilling until the National Energy Board of Canada has launched a full public review** of Arctic offshore drilling and safety requirements. The NEB states that its review will be guided by analysis of the cause of the Deepwater Horizon oil rig explosion and that it will use this information to enhance safety and environmental oversight for all future applications for work in the Arctic offshore. The review will look at topics such as whether relief wells are needed, protecting the environment, responding effectively when things go wrong and raising the liability cap for operators. The NEB has placed a moratorium on all Arctic offshore drilling until its review is completed and the NEB is not expected to approve drilling in the Beaufort Sea for at least a few years. Ottawa has also asked Greenland to provide it with more information on the offshore licenses it has issued for drilling in the Davis Strait, part of the North Atlantic Ocean that separates it from Canada (Canada is a designated oil responder for Greenland, which does not have significant oil spill equipment capacity).
- **The EU said in October 2010 that the Arctic merits special attention** due to its particularly sensitive natural environment, harsh climate and significant unexplored hydrocarbon reserves. It said that binding international rules or benchmarks should be introduced, building inter alia on the guidelines of the Arctic Council²⁷.
- **Norway will not issue new deepwater licences** until the Norwegian Petroleum Safety Authority has investigated what GoM means for its own regulations including a review of procedures for handling blowouts, or unexpected pressure surge.
- **Russia's administration has drafted a new bill on oil spill removal** that, if passed by the state Duma, would overhaul Russia's safety and environmental regulations. Oil companies say Russia already has some of the tightest regulations in the world – although it is sometimes claimed that they are inconsistently applied, with openness to corruption cited as a factor (Russia was ranked 154th out of 178 countries in Transparency International's 2010 Corruption Perceptions Index). Under the proposed regulations, Moscow wants all oil and oil transport, marketing and storage companies to create an oil-spill response plan (OSR) for each deposit and installation they operate. The Duma's Natural Resources Committee is also drafting a new law on the protection of seas from oil pollution, which has been welcomed by stakeholders.

The sector's talent shortage costs the industry over \$5bn/year in terms of direct employee costs, lost profits from labour shortages and strategic opportunity costs (ex-extreme risks) - University of Houston ("Workforce Crisis in the Upstream Oil & gas Sector")

More hidden risks, employees Employees dwindling and ageing

Decades of boom and bust investment - on the back of volatile commodity prices - have left the industry facing major human resources challenges. The O&G industry has lost close to 1 million jobs over the last 20 years as a result of a wave of M&A, mega-mergers, increased outsourcing and boom and bust hiring patterns – with significant losses of talent and highly specialised skills. As a result, almost 90% of senior human resources executives at top international O&G companies think the industry faces a major talent shortage and that the workforce issue is one of the most critical challenges going forward for the sector.

The average age of petroleum engineers is 46-49 and one third are aged over 50, with only 30% of the workforce aged 20-40 (vs 60% in other technical industries). The sector is facing a "big crew change" phenomenon with an ageing workforce, significant retirements of experienced staff, growing need for new blood in developed markets and experienced staff in emerging markets, and a need for more specialised skills to tackle the challenges of unconventional resources and new geological and geographical frontiers. But in light of these challenges, the sector has continued to demonstrate a boom and bust, hire and fire and outsourcing of control mentality as regards HR issues. The downturn moved HR issues even further down the risk agenda, rather than companies adopting the type of long-term approach needed to meet escalating energy demand while ensuring strong HSE.

There is significant downside to missing the opportunity to adopt a more sustainable approach to HR. Those that manage their employee bases well should enjoy a significant advantage in terms of reduced margin for safety risk and a higher probability of delivering on the potential of their resource portfolios. We believe that the GOM spill will help shift the emphasis in this direction, notably by majors changing the nature of their relationships with third party contractors and demonstrating more hands-on involvement in operations. While the downturn will come to an end at some point and energy demand is already rebounding, the lack of long-term, sustained investments in assets and people will pose risks of project delays or cancellation, lower productivity, and higher opex costs. In our view, it is potentially another looming \$40bn problem waiting to happen, especially when one considers that human capital has the longest lead time in the exploration, production and drilling cycle.

Industry facing a major talent crunch

According to a recent survey by the Society of Petroleum Engineers, almost 90% of senior HR executives at top international O&G companies think the industry faces a major talent shortage and the workforce issue is one of the most critical challenges. Some have drawn parallels with the US semiconductor industry in the 1980s. The O&G industry needs more geoscientists, drillers and engineers and is facing growing competition for talent with NOCs and other emerging players in the hunt for talent. The experience gap is being further compounded by a 'greying' workforce.

Table 28: Overview of key HR roles in the O&G sector

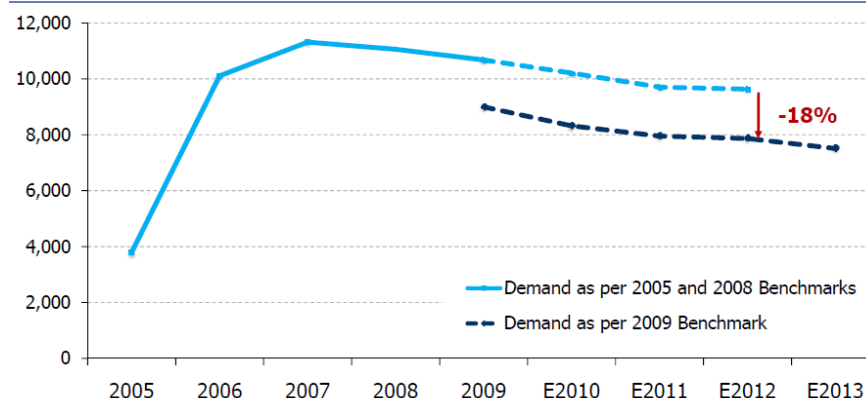
Exploration	Production	Transportation	Refining	Distribution	Marketing
Geoscientists	Petroleum Engineers	Mechanical Engineers	Chemical Engineers	Industrial Engineers	Analysts and Traders
Oil Drillers and Seismic Crews	Oilfield Workers	Pipeline Workers	Plant Operators	Terminal Operators and Truckers	Service Station Attendants
Landmen	Petroleum Attorneys	Petroleum Accountants	Human Resources	Information Technology	Administrative Assistants

Source: BofA Merrill Lynch Global Research

6% PTP talent shortfall to 2013

These views were confirmed in the 2009 SBC HR Benchmark Survey – the leading Petrotechnical Professionals (Geologists, Geophysicists & Petroleum Engineers) human resources survey in the sector (based on responses from companies representing more than 40% of global oil & gas production). According to the Survey, for the O&G sector to meet IEA production forecasts, the required global workforce of PTPs (i.e. skilled exploration and production geoscientific specialists) would need to rise to approximately 141,000 by 2013. However SBC analysis based on downturn-impacted recruitment targets and forecast retirements shows that the current PTP workforce is only likely to be 132,000. This shortfall of 9,000 workers, or nearly 6%, is based on IEA estimates and expected retirement and attrition rates within the industry.

Chart 30: Current recruitment forecasts mean reduced global demand forecast for petrotechnical professionals to 2013

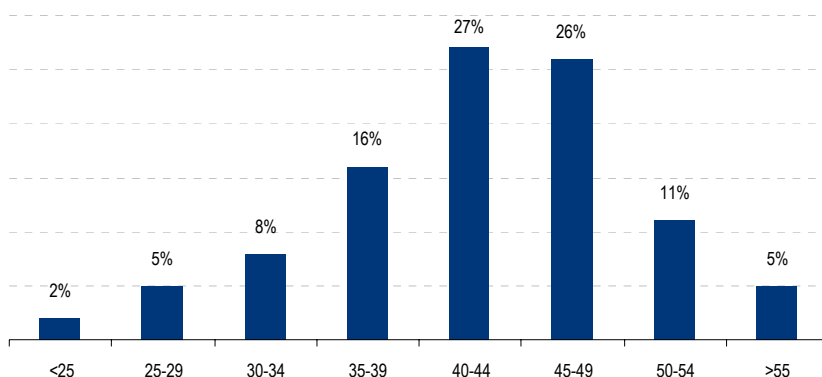


Source: SBC O&G HR Benchmark 2009, SBC Analysis, BofA Merrill Lynch Global Research

The “big crew change”

The industry is facing a major age pyramid risk with the average age of Society of Petroleum Engineers members at 46-49, one third of the technical workforce who entered the workforce in the 1970s now estimated to be over the age of 50, and the average retirement age for the industry at 55. The combination of these factors means that the industry is facing an ever-reduced pool of talent via impending retirements. A new generation must be found to fill their experienced and highly skilled jobs and ensure that the work adheres to the most stringent safety standards.

Chart 31: Age Range of Professional E&P Staff

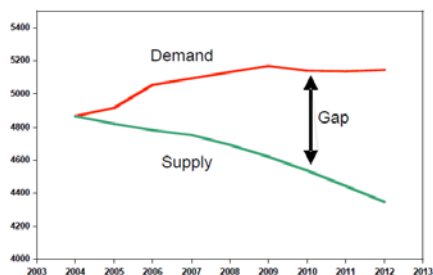


Source: Booz Allen, BofA Merrill Lynch Global Research

Failure to attract new talent

Despite O&G being technical, which typically attracts a young demographic, less than 30% of the oil & gas workforce is aged 20-40 (vs. close to 60% in other technical industries such as software and IT). This partly reflects the impact of boom and bust hiring on supply and demand, but also falling enrolment on geosciences and petroleum engineering courses at universities in the 1980s and 1990s. Attrition rates for young hires are also thought to be as high as 20-30%.

Chart 32: Exhibit 3: North American and European demand for mid-career technical professionals (age 30-39)

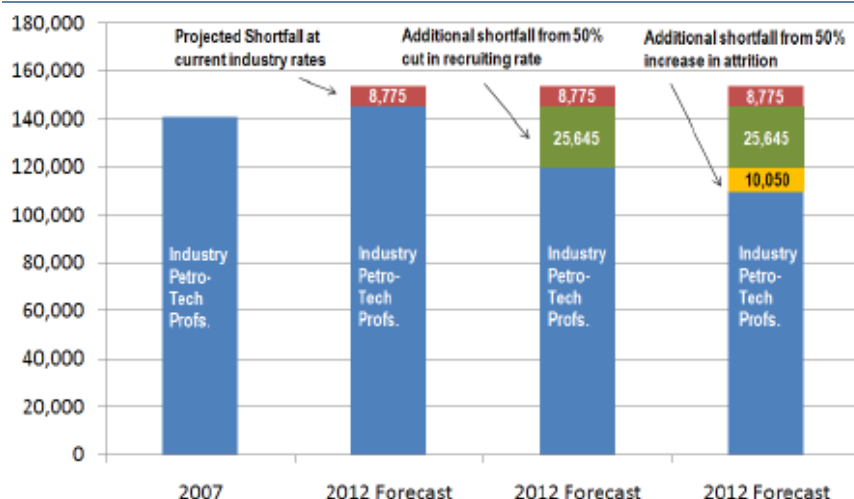


Source: NPC, BofA Merrill Lynch Global Research

Technical oil needs technical staff

We are seeing a broad move towards more “technical oil” – unconventional, offshore, deepwater and new frontiers exploration. The nature of the industry is also changing, with greater use of customised technology and project management expertise. Geology is also a new challenge – as new reservoirs are more complex and require new technologies to develop. This has intensified the need for highly skilled, technical staff with strong technological and project management skills – in a context where the industry is also faced with increased competition for technical skills from other sectors and higher turnover. It is this skills gap that poses some of the biggest challenges for companies in terms of HSE and security.

Chart 33: Projected talent shortfalls



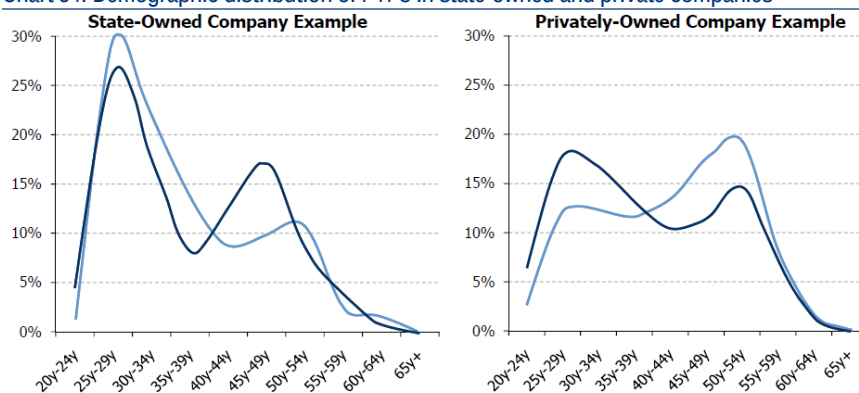
Source: Schlumberger, BofA Merrill Lynch Global Research

NOCs are gaining an upper hand in terms of their demographic profile

IOCs stands to lose out to NOCs on young talent

2008-10 has seen the first major sign of a divergence between IOCs and NOCs in their strategies for recruiting and training senior technical staff. In contrast to IOCs, state-owned companies have reduced recruitment targets by only 8% - and many are maintaining or increasing their recruitment budgets. There are also large differences in their age pyramids. The profile of IOCs is one of dramatic peaks in older employees, low presence of young engineers and severe gaps in mid-careers. In contrast, African, Asian and GCC NOCs are seeing a peak in juniors and a dramatic absence of mid-careers and older employees. We believe both need to change their skewed demographic profiles.

Chart 34: Demographic distribution of PTPs in state-owned and private companies



Source: SBC O&G HR Benchmark 2009, SBC Analysis, BofA Merrill Lynch Global Research

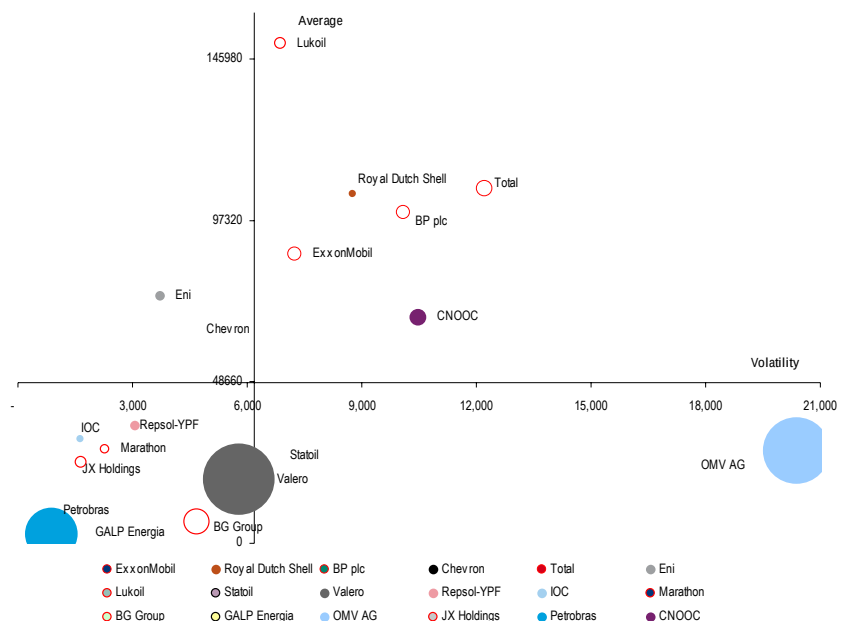
Boom and bust HR practices

Capex and investments in people are inextricably linked to the price of oil & gas, meaning decades of HR booms (higher prices and new, riskier E&P and extensive hiring) and busts (low prices, supply outstrips demand and layoffs and firing). The downturn has led many experienced employees to postpone retirement, resulting in companies putting new recruitments on hold. Whereas 90% of petroleum engineering graduates were offered jobs two years ago, only 70% of available graduates were hired in 2008-9, with numbers expected to fall further in 2010.

Highly volatile hiring and firing

An examination of publicly disclosed total staffing numbers in the sector from 2000-09 shows relatively high volatility in total employee numbers for western majors. More broadly, trends in staffing over the same period have shown a significant decline or only a marginal increase in employee numbers for a number of such companies. However, we note that it is complicated to draw any more specific company-by-company conclusions given the general lack of disclosure for total E&P employees or on an activity-by-activity basis (i.e. making distinctions on the basis of the risk profiles associated with offshore drilling vs. retailing).

Chart 35: Total Employees 2000-2009



Source: BofA Merrill Lynch Global Research, Bloomberg, Datastream. Horizontal axis = volatility 2000-2009, vertical axis = Average 2000-2009, Size of bubble = evolution 2000-2009 (red circle with blank interior = negative evolution).

Table 29: Top 10 risks for O&G 2010

Rank Business risk (2009, 2008 rank)

- 1 Uncertain energy policy (2, 6)
- 2 Access to reserves: political constraints and competition for proven reserves (1, 4/6)
- 3 Cost containment (4, 3)
- 4 Worsening fiscal terms (5, 2)
- 5 Climate and environmental concerns (7, 8)
- 6 Price volatility (3)
- 7 Human capital deficit (6, 1)
- 8 Supply shocks (9, 9)
- 9 Overlapping service offerings for IOCs and oilfield service companies (8, NA)
- 10 New operational challenges, including unfamiliar environment (new).

Source: E&Y, BofA Merrill Lynch Global Research

Downturn means a return to stop and go HR

While 2004-08 saw some optimism in the form of an upturn in both the number of graduates in petroleum engineering (the largest pool of young graduates in 20 years) and in hiring, 2008-10 have seen a reversal and a return to old patterns of boom and bust hiring and reduced focus on human capital issues. The downturn has seen IOCs continuing to hire but at a much reduced rate and often with a freeze on recruiting new graduates. It is anticipated that we will see a 30% cut in the recruitment of geoscientists and petrotechnical experts by majors and IOCs from 2008 to 2013. The HR-safety threat tandem could thus, yet again, pose an increasing risk when demand for hydrocarbons picks up again.

Near 30% cut in IOC recruitments

Between 2008 and 2010, IOCs reduced their recruitment targets by 27% and their recruitment budgets by 70% according to the SBC. In 2010, 40% of students in geosciences will not receive an offer on graduation and global demand for graduates is expected to decline by almost 20% in the next five years, putting pressure on universities to reduce or cut their O&G activities. While it may be a short-term result of the downturn, the flight of talent to NOCs could pose a further HR safety threat to IOCs.

The Gulf of Mexico spill has sparked a debate as to whether operators should be looking to retain and develop skills, talent and expertise “in-house”

Human capital slipping down the list of priorities

It would appear, broadly speaking, that human capital issues are seen as a necessity during good times and a luxury during down times. This appears to be borne out in Ernst & Young's annual “Business Risk Report” for the oil & gas sector. After structured consultation with industry leaders and professionals, it identifies the top 10 strategic risks for oil & gas companies. In the 2010 report, human capital fell to seventh place, down from sixth in 2009 and first place in 2008.

Subcontracting being called into question

The capital-intensive nature of the oil & gas sector and ever-growing pressure on margins have led to a trend towards outsourcing, particularly for less capital-intensive functions like IT and BPO (business process outsourcing), but also outsourcing assets and engineering work to third party oil services companies and other subcontractors. While a generation ago we might have seen a production site or a rig filled entirely with “company men” – the industry vernacular for oil & gas companies' own employees – today we can see production sites or rigs being “manned” with as few as one or two “company men”. The Gulf of Mexico spill has, however, led to increased questioning of the sector's push to maximise the balance sheet impact via outsourcing and whether such decentralisation and outsourcing of control are appropriate in an industry with such high stakes from an HSE perspective.

Is subcontracting the right model for this industry?

While subcontracting has worked in most cases, the Gulf of Mexico spill has raised a number of concerns as to whether the Majors need to exercise greater control of their operations:

- Roles and responsibilities in subcontracting contracts are not always spelled out precisely and things can be complicated by a subcontractor hiring third-party staff to work on a Major's rig, blurring the boundaries of responsibilities and the decision-making lines.
- The HSE impacts of a major incident, particularly offshore or deepwater, are potentially huge and the lack of delineated responsibilities and potential finger-pointing by subcontractor and Major can detract focus from the clean-up effort.
- There are in, some cases, not enough “company men” on rigs, for instance, to ensure that the HSE standards given by the Major are followed precisely by subcontractors or their subcontractors, and to make and act on any final decisions in that regard.
- Despite the subcontractor being a rig operator, it is the Major which ultimately bears the greatest financial and stakeholder responsibility for any safety incidents.

Operators unlikely to own and operate their own rigs

There has been some debate as to whether we will see operators move to bring PTP functions in-house. In the immediate aftermath of the GoM spill, some went as far as to suggest that O&G companies would move to own or operate their own rigs. This has quickly faded from view. The rationales are two-fold: any such move would require them to develop the technical expertise of a service player, entailing significant time and investment from management (rather than chasing ever more difficult growth opportunities); and the majors are dependent on the contractors, as they have the upper hand in terms of talent and experience in high-tech, high-growth areas like deepwater drilling.

Chart 36: Expected Talent Gaps on a 5Y Time Horizon*



Source: Schlumberger Business Consulting, BofA Merrill Lynch Global Research. * % of survey respondents expecting shortage in position.

But are moving towards “in-housing” and greater control

That said, we believe that the relationship between third party contractors and Majors is changing and that we are likely to see more hands-on involvement from the latter in operations. BP’s move to split the company’s upstream division into three divisions – exploration, development and production – which was said to be a move to better manage risk, could also be interpreted as an implicit move away from sub-contracting. The industry needs to make significant investments in developing talent and we could see competition heating up between the Majors and oil services companies for high-end PTP talent. However, given the realities of hiring during a recession and the long lead times needed to develop E&P talent (discussed below), we think the move to exert greater control over operations may be too little too late from a safety perspective.

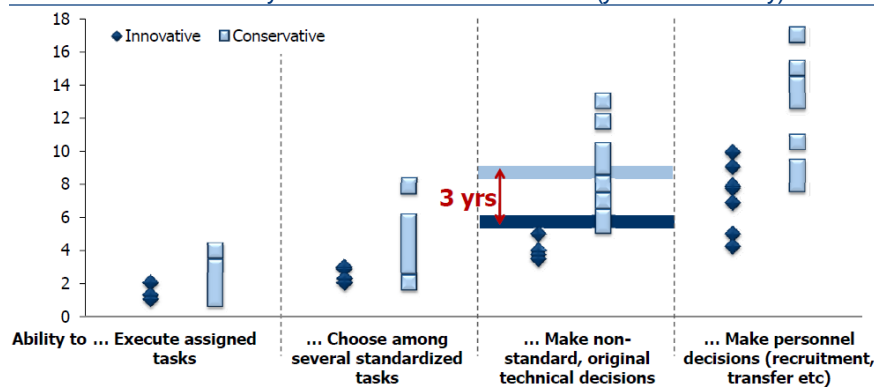
Human capital has E&P’s longest lead time

Human capital is a long-term story – as are the challenges implicit in attracting, recruiting, and retaining talent, accelerating time to autonomy, and capturing and transferring the skills and experience of older employees. Human capital issues need to be viewed on a 5-10 year time horizon, making human capital the longest lead-time component of E&P delivery, rather than based on the 5-10 day, weekly or monthly trajectory of the oil price.

‘Time to autonomy’ is the challenge

The challenge is to make young professionals operational faster – including leveraging senior employees’ wealth of skills and experience. Time to autonomy – commonly defined as “time needed for an engineer to be fully operational, and in doing so, to maximise his/her value – is the key metric for companies to be able to deliver on projects.

Chart 37: Time To Autonomy For Petrotechnical Professionals (years to autonomy)

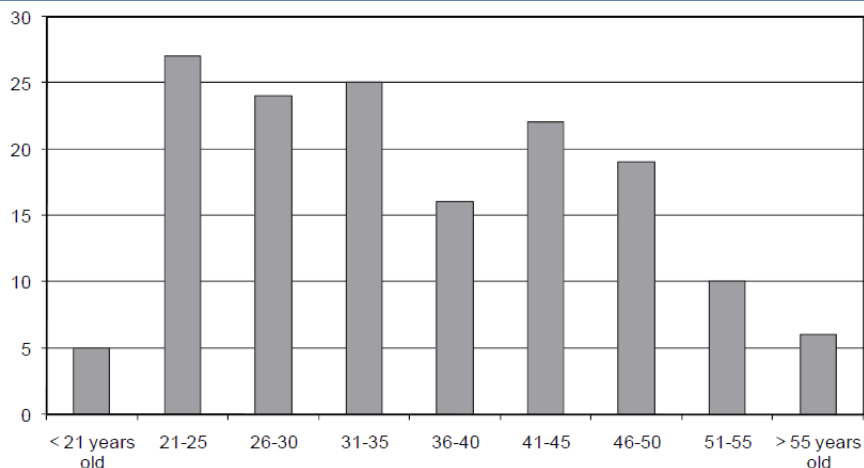


Source: SBC O&G HR Benchmark 2009, SBC Analysis, BofA Merrill Lynch Global Research

Even the most innovative companies take 5-7 years to develop talent

It takes up to three years to develop staff up to basic industry operating competence - and even the most innovative companies take 5-7 years on average to develop new entrants into professionals who can work autonomously because of the complex decision-making and ability to exploit advanced technology needed by today’s professionals. In contrast, more conservative companies are looking at 10 years on average. The differences are not thought to be a question of size, maturity or geography, but of the ability of companies to develop technical competency and accelerate employee development and promotions. From an HSE perspective, this is also worrying given that E&P’s highest proportion of fatalities tends to be in the younger 21-35 age bracket.

Chart 38: E&P Fatalities in Age Group, 2004-2006

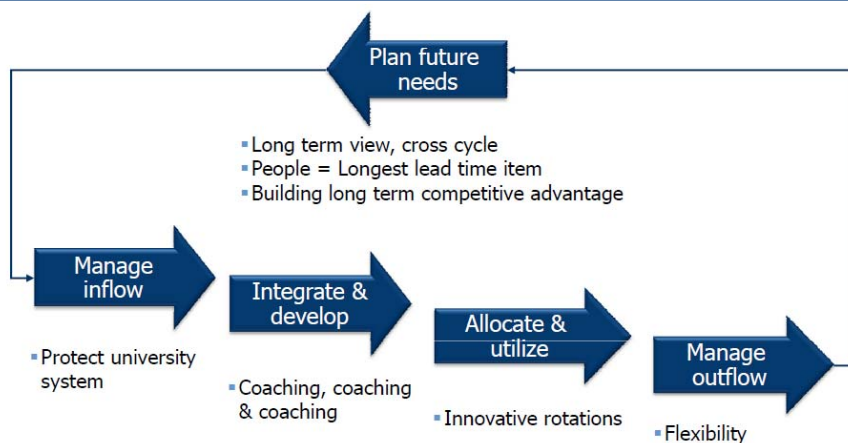


Source: OGP, BofA Merrill Lynch Global Research

Industry needs to tackle its bad reputation

The industry's boom and bust reputation has reduced interest from graduates, with enrolment rates on the decline for the past 20 years. Rising consciousness of environmental, social and governance (ESG) issues and stakeholder perceptions of the industry as environmentally and socially "irresponsible" – combined with a perception of poor working conditions, dangerous working environments and the "grey ceiling" facing new engineers entering the industry – have seen qualified prospective talent turning to other technical industries. If the sector is to find sustainable solutions to its HR problem, it will have to present a more positive image on HSE issues, including collaboration with academia and governments to try to rebuild its attractiveness as a sector for young graduates.

Chart 39: Need to take a long-term approach to using the supply chain of human talent



Source: SBC O&G HR Benchmark 2009, SBC Analysis, BofA Merrill Lynch Global Research

Growing pressure for 3rd party cert. TIC to benefit

The upstream, midstream and downstream parts of the Oil & Gas industry already work extensively with the TIC (testing, inspection certification) sector on a range of safety and security issues including operational verification, inspection, product conformity assessment, asset integrity management and HSE services. Deepwater Horizon is set to boost the role of TIC – as there will be a more acute focus on traditional safety and reliability issues – and regulators are looking to extend the range of products and services requiring certification by independent third-party bodies. Indeed, the new certification provisions in the US recently passed Drilling Safety and Workplace safety rules and the host of countries waiting for the final recommendations of the Deepwater Horizon investigation to ramp up such provisions are a sign of things to come in this regard.

Beyond their traditional HSE expertise, we anticipate that post-GoM safety concerns will benefit TIC in terms of strong growth potential for offshore oil & gas (fixed platforms, floating units, rigid/flexible risers and flowlines, pipelines and subsea systems, gravity base structures, LNG and even wind) as well as deepwater (floating units, offloading facilities, mooring systems, pipelines and subsea systems). Bureau Veritas believes that Offshore is set to experience a 20% CAGR from 2010 to 2014 on the back of a more stringent focus on HSE and increases of 15% for large offshore and deepwater opex and capex in Latin America, Asia, Africa and traditional offshore areas. By 2014, offshore should represent an estimated €1.7bn+ market for TIC. Bureau Veritas is our top play on the theme.

TIC plays an important role for O+G

Even prior to Deepwater Horizon, the TIC sector had a long and established track record of providing upstream (onshore, offshore, deepwater), downstream and general HSE/security services for both oil & gas and EPCI (engineering, procurement, construction and installation) companies:

- **Operational verification** Examining the facilities equipment that has been deemed safety-critical and the associated operator programmes of inspection and maintenance, and ensuring that performance standards are achieved and maintained.
- **Inspection** to determine if a product, service, process, piece of equipment or installation complies with applicable regulations or other requirements. It can cover transport and logistics services, product conformity assessment and specific requirements of the local O+G industry.
- **Product conformity assessment** on products falling within the scope of the relevant directives and regulations. International certification is also provided, which considers all aspects of design and verifies conformance to specific standards such as ASME, API and many others.
- **Asset integrity management** Offering comprehensive risk-based inspection services across all aspects of the onshore refining and petrochemical industry and offshore oil & gas industry including hulls, jackets, topside structures and topside process facilities.
- **Safety & Risk** Providing a complete HSE service profile ranging from identification and assessment of hazards, through the identification of remedial controls, to the development of effective management controls.

Table 30: HSE-related TIC services for the oil & gas sector

Service name	Description	Business Scope*
Asset Integrity Management	Staying fit for purpose over the whole lifecycle	EHS
Design Review of Industrial Facilities	Design achieves best practice standards	EHS
HSE Management	Meet HSE regulations	EHS, CSR
Hazard & Operability Study (HAZOP)	Identifying the causes of undesirable plant conditions	EHS
Hazard Identification Study (HAZID)	Identifying occupational, facility, and external hazards	EHS
Independent Verification	Assessment of conformity with Safety Case	EHS, Quality
Offshore Platform Re-certification & Life Extension	Keeping existing offshore structures in good repair	EHS, Quality
Offshore Safety Case Management and Review	Best-practice approach to major hazards management	EHS, CSR
Pipeline Integrity Management	"License to Operate", pipeline safety and reliability	EHS, Quality
Process Safety Management	Major accident hazard management	EHS, CSR
Quantified Risk Assessment	Risk Management	EHS
Risk-Based Inspection (RBI)	Preventing shutdowns and protecting the environment	EHS, Q
Emergency Planning	Prepared to respond to a major accident situation	EHS, CSR
HSE Management	Assessing and implementing HSE best practices	EHS
HSE Training Services	Developing HSE policy	EHS, CSR
In-Service Verification of Electrical Installations	Checking electrical safety	HS
In-Service Verification of Fire Safety Equipment	Checking fire safety equipment	HS
In-Service Verification of Lifting Equipment	Checking lifting equipment	HS
In-Service Verification of Lifts	Safe operation of lifts	HS
In-Service Verification of Machinery	Checking machinery	HS
In-Service Verification of Pressure Vessels	Pressurized equipment	HS
Inspection during Periodic Shutdowns	Inspection activities	EHS, Q, Security, CSR
Inspections and Audits for Boilers and Pressure Vessels	ASME, PED, IBR compliance	HS, Q
Inspections and Audits of Safety Instrumented Systems	Safety, availability and reliability of SIS	HS, Q
Machinery Diagnostics & Troubleshooting	Rotating equipment	HS, Q
Machinery Inspections and Audits	Compliance with regulations	HS, Q
OHSAS 18001 Certification	Demonstrate your ability to manage hazards...	HS
Occupational Hygiene	Recognizing and controlling workplace health hazards	EHS, CSR
Process System Integrity- Piping Vibration Management	Vibration-induced fatigue	EHS, Q
Safe Behaviour Management	Reducing injuries and lower costs	HS, CSR
Seveso II and COMAH compliance	Best-practice approach to major hazards management	EHS, CSR
Structural and Machinery Vibration Services	Structural failure due to excessive vibration	HS

Source: Bureau Veritas, BofA Merrill Lynch Global Research. * E = environment, H = health, S = safety, Q = quality, CSR = social responsibility

Rising focus on offshore safety drives growth

The Gulf of Mexico oil spill has increased safety and security awareness and is set to increase the role for third party certification bodies vis-à-vis services for oil & gas and EPCI (engineering, procurement, construction and installation) companies. The TIC companies are the best positioned on independent certification, as has been demonstrated by their role in the investigation of the DH blowout preventer.

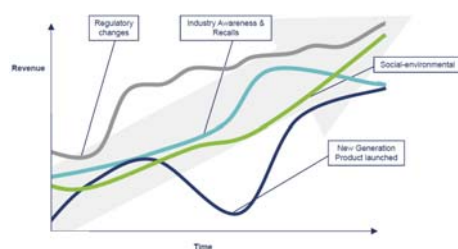
New regulations will be a catalyst

We expect global oil companies and rig owners to be gradually incentivised by the more stringent health, safety, and environment (HSE) standards to replace their vintage offshore drilling rigs and other older offshore equipment. While changes are already underway, the finalisation of new HSE guidelines could be a 2-3-year event.

US offshore drilling rules a sign of things to come

The US Drilling Safety Rule, announced and rendered effective on 30 September 2010, makes mandatory several requirements for the drilling process that were laid out in US Secretary of the Interior Salazar's May 2010 Safety Report to President Obama. The regulation prescribes proper cementing and casing practices and the appropriate use of drilling fluids in order to maintain wellbore integrity. The regulation also strengthens oversight of mechanisms designed to shut off the flow of oil & gas, primarily the BOP and its components. An additional

Exhibit 15: Role of regulation in driving long-term TIC growth



Source: Intertek, BofA Merrill Lynch Global Research

Workplace Safety Rule requires offshore operators to have clear programs in place to identify potential hazards when they drill, clear protocol for addressing those hazards, and strong procedures and risk-reduction strategies for all phases of activity. Operators are also required to have a safety and environmental management system (SEMS). Furthermore, the rule makes mandatory API Recommended Practice 75, which was previously a voluntary program, to identify, address and manage safety hazards and environmental impacts in their operations.

Table 31: US Drilling Safety Rule

- Makes mandatory API RP 65 – Part 2, Isolating Potential Flow Zones During Well Construction
- Requires certification that the casing and cementing program is appropriate;
- Requires two independent test barriers across each flow path during completions;
- Requires documentation and schematics for all control systems;
- Requires proper installation, sealing and locking of the casing or liner;
- Requires approval from BOEM district manager before replacing a heavier drilling fluid with a lighter fluid;
- Requires enhanced deepwater well control training for rig personnel;
- Requires third-party verification that the blind-shear rams are capable of cutting any drill pipe in the hole under the maximum anticipated surface pressure;
- Requires ROV intervention capability for subsea BOP stacks;
- Requires a trained ROV crew on each floating drilling rig on a continuous basis;
- Requires auto shear and deadman systems for dynamically positioned rigs;
- Establishes minimum requirements for personnel authorized to operate critical BOP equipment;
- Requires documentation of subsea BOP inspections and maintenance according to API RP 53, Recommended Practices for Blowout Prevention Equipment Systems for Drilling Wells;
- Requires testing of all ROV intervention functions on subsea BOP stack during stump test, and testing at least one set of rams in initial seafloor test;
- Requires function testing auto shear and deadman systems on the subsea BOP stack during the stump test, and testing the deadman system during the initial test on the seafloor; and
- Requires pressure testing if any shear rams are used in an emergency.

Source: US Department of the Interior, BOEM, BofA Merrill Lynch Global Research

Emerging offshore and deepwater TIC needs

- **Offshore growth of 20% CAGR** We are seeing large offshore capex in Western Africa, South America and Asia-Pacific, in addition to traditional areas such as the Gulf of Mexico and North Sea, and we anticipate strong growth for offshore TIC services with the market set to show at a 20% CAGR from 2010 to 2014. Offshore O+G production systems operate with a combination of equipment and conditions not seen in other industries and relevant TIC services include operation risk analysis, hazard identification, fire and explosion, origin and cause investigations, material and corrosion control, and asset integrity management of infrastructure and equipment. Bureau Veritas, which is well positioned on offshore via the combination of its Marine and oil & gas businesses, expects +15% pa growth in its opex and capex services and that offshore will become a €1.7bn market by 2014.
- **Acceleration of deepwater** Parallel to offshore, we anticipate that accelerating offshore deepwater capex will present the TIC sector with new opportunities as the deepwater offshore environment has new potential hazards, which must be identified and controlled. Relevant deepwater services will encompass technical, research and manpower and are outlined in the table below.
- **New and emerging opportunities** including new standards for Arctic, shale oil and pre-salt oil & gas E+P and green shipping services (ship dismantling, ballast water management, greenhouse gas reduction, maritime labour inspections).

Overview of TIC services for onshore, offshore and deepwater oil & gas

	Facilities	Technical services and expertise	General O+G services
DEEPWATER	> Floating units (FPSO, Semi-Sub...) and TLP/SPAR > Offloading Facilities incl export lines & buoys > Mooring Systems > Rigid or Flexible Flow lines, Risers and Towers > Pipelines and Subsea Equipment	Conformity Assessment -Design review or certification of systems -Project certification (engineering, procurement, construction, commissioning + start-up of project) -Independent Analysis of offshore structures -Pushover Analysis/Life Extension offshore -Type Approval and Project Certification of Bonded or -Non-Bonded Flexible Pipes. -Verification + certification of risers + flowlines. -Fitness-For-Service studies vs applicable standards of new, damaged or repaired systems. Asset Integrity Management -Risk Based Inspection studies on topsides -Safety & Risk Management studies (HAZID, HAZOP, Quantitative Risk Assessment). -Safety Integrity Level assessment studies for Safety Instrumented Systems. -Process System Integrity studies to address vibration induced fatigue in process piping. -Maintenance management optimization using condition based monitoring approach.	Third Party Inspection -In-service statutory/voluntary Inspection of any type of system/equipment; shop & site Inspection Product Conformity Assessment -Conformity assessment of equipment or system vs. EU Directives, ASME (independent design review combined, inspection) System Certification -Management System Certifications such (ISO). -Personnel Certification Training -Technical Training in Safety and risks. - Training in Integrated HSE Management Outsourcing -Inspection Management, Quality Management, Expediting and Vendors Evaluation Services. Tests and Measurements -Non Destructive -Testing services Consulting QHSE -Development of Standards; supplier independent audit.; safety management system benchmarking
OFFSHORE	> Fixed Offshore Platforms and Floating Units > Rigid or Flexible Risers and Flowlines > Pipelines and Subsea Systems > Concrete Gravity Base Structures > Offshore LNG, Export or Receiving Terminals	See above (deepwater)	See above
ONSHORE	> Onshore production plants including storage > Gas Treatment Plants > LNG Export or Receiving Facilities > Refineries > Onshore Oil & Gas Pipelines Systems > Petrochemical Complexes > Distribution Infrastructures	Conformity Assessment ■ Independent review of process safety, mechanical equipment, pressurized equipment, lifting appliances, safety systems ■ Project certification (engineering, procurement, construction, commissioning start-up) ■ Corrosion + materials expertise and review. ■ Fitness-for-service studies Training ■ Technical training in safety + specific risks ■ Training in integrated HSE management Outsourcing -Inspection management, quality management, Asset Integrity Management ■ Risk based inspection for refineries + petrochemical Complexes. ■ Safety & Risk Management studies covering services (HAZID, HAZOP, QRA) ■ Safety Integrity Level (SIL) assessment studies for Safety Instrumented Systems. ■ Process System Integrity studies to address vibration induced fatigue in process piping. ■ Maintenance management optimization based on reliability studies.	See above

Source: Bureau Veritas, BofA Merrill Lynch Global Research

The potential amendment of current provisions limiting the liability of operators for private economic and environmental payouts for offshore pollution under the US Oil Pollution Act (OPA) of 1990 to \$75mn is the potential game changer the insurance industry is hoping for

Insurance: offshore pricing +10-30%

The Deepwater Horizon catastrophe – the worst oil spill in US history, which is expected to generate tens of billions of dollars in third-party liability claims from affected businesses – is a low-frequency, high-severity event which by its nature is the kind of risk for which insurance is most attractive. However, the gravity of the insured losses involved in DH, which could be as high as \$3.5 to \$6bn, may lead to fundamental changes for insurance in the O+G sector. Tough new proposed safety regulations will place E&P companies, offshore and even shallow water, under greater financial pressure as insurers demand a higher risk premium for such activity and increases in limits and coverage purchased.

Putting this in the context of the softening pricing cycle, barring legislative changes, we expect rate increases in offshore energy insurance to stay at about 10-30%. The full impact should be felt around April 2011 when the bulk of reinsurance is bought, with some 80% of energy insurance placed in the first six months of the year (before the start of the US hurricane season). For the moment, though, we would expect only a few insurers to materially benefit before pricing increases start to run dry. Of the stocks under our coverage, we expect that only Lancashire will be able to significantly benefit due to its expertise and exposure to the energy sector.

Table 32: Hardening energy insurance market post Deepwater-Horizon

Coverage	Buyer	Summary	Potential deepwater Horizon impact
Physical Damage	Operator & Contractor	Cost of replacing physical assets in the event of an insured peril	1) Rate rises as a result of market forces
Control of Well	Operator	Cost of well control / cost of redrill / cost of clean up	1) Rate rises as a result of market forces and review of pricing adequacy 2) Increased demand as limits purchased increase? 3) Reduced supply as capacity providers review clash with drilling contractors?
Loss of Production Income (LOPI) / Loss of Hire (LOH)	Operator & Contractor	Loss of income following an insured peril trigger	1) Rate rises as a result of market forces
Third Party Liability – Primary & Excess	Operator & Contractor	Third party liability including liability resulting from a pollution incident	1) Rate rises as a result of market forces and review of pricing adequacy 2) Increased demand as limits purchased increase? 3) Review of coverage provided? 4) Reduced supply as capacity providers review clash with upstream energy portfolio
Third Party Liability – OPA specific	Operator & Contractor	Strict liability for pollution in US waters – “Polluter Pays” concept Certification required either through Insurance Certificate / Self Insurance (subject to satisfactory balance sheet) / Bond	1) Increased limits required – extent of which will be determined by US legislation currently US\$75m maximum for operators

Source: Lancashire Group, BofA Merrill Lynch Global Research

Insurance in the offshore energy sector

Normal operations of O&G producers face a broad range of risks including blowouts, reservoir damage, loss of production, loss of well control, punch-through, craterings, and fires and natural disasters such as hurricanes and tropical storms. Offshore O+G drilling is subject to a cascade of additional risks peculiar to marine operations, including capsizing, grounding, collision and loss or damage from severe weather and damage to the environment (particularly oil spills or extensive fires). These risks have the potential to generate significant first-and third-party losses and subsequent claims for cleanup costs and related liabilities. Accordingly, offshore oil rigs and platforms are among the world's most complex and expensive assets to insure, with coverage for property damage, general liability, environmental damage, injury, death and other risks, as well as specific industry risks, like third-party property claims, cleanup and containment operations, oil well blowouts, and re-drilling.

Table 33: Offshore insurance overview

Type of coverage	Overview
Business Interruption/Loss of Production Income	Provides coverage for energy businesses against loss due to temporary interruption in oil/gas supply from an offshore facility as a result of physical loss or damage to an offshore facility.
Comprehensive General Liability	Provides coverage for claims an energy business is legally obligated to pay as a result of bodily injury or property damage to a third party.
Environmental/Pollution Liability	Provides coverage for bodily injury, property damage, and clean up costs as a result of a pollution incident from a designated site.
Operators' Extra Expense (Control of Well)	Provides coverage for costs incurred by energy businesses when regaining control of a well after a "blowout". Coverage may include redrilling expenses incurred in the restoration of a well after a 'blowout' as well as the legal expenses emanating from an incident such as the sinking of a rig, or oil spill.
Physical Damage	Provides coverage for physical damage or loss to a company's offshore property and equipment, including offshore fixed platforms, pipelines and production and accommodation facilities.
Workers compensation/employers liability	Covers energy businesses for claims arising out of injury or death of employees incurred while in the line of duty.

Source: Insurance Information institute, BofA Merrill Lynch Global Research

Risk management the key driver since Exxon Valdez

Offshore energy insurance has been premised on the concept of risk management since the 1989 Exxon Valdez oil spill, when the US Congress passed the Oil Pollution Act of 1990 (OPA) in order to make companies accountable for the costs of any oil pollution they generate:

- **Polluter Pays:** Under OPA the owner or operator of a facility from which oil is discharged ("responsible party" (RP)) is liable for damages resulting from the spill and costs associated with the containment or cleanup of the spill.
- **Limits of Liability:** OPA established new and higher limits for oil spills. Responsible parties (holders of leases or permits) for offshore facilities are liable for up to \$75 million per spill, plus removal costs.
- **Liability Exception:** The limit of liability **does not** apply if the incident was caused by gross negligence or wilful misconduct or violation of a Federal safety, construction or operating regulation.

Additionally, the OPA created the national Oil Spill Liability Trust Fund (OSLTF) as the mechanism for compensating oil spill victims (up to \$1 billion for any one oil pollution incident, for costs not directly paid by the polluter); b) offshore facilities are required to maintain evidence of financial responsibility of \$150 million; and the OPA increased fines for regulatory non-compliance to \$500,000 for an organisation with civil penalties of \$25,000 for each day of violation or \$1,000 per barrel of oil discharge.

These measures were set in place in order to improve risk management activities, which would make companies take effective measures to reduce the probability of accidents and reduce consequent damages to a minimum point where the marginal cost is equal to the expected marginal recovery paid to victims. Following the imposition, there was a strong increase in the demand for offshore energy facility liability insurance protection.

The offshore insurance market

Large supermajors such as BP usually self-insure via captive insurers or purchase pollution liability coverage and excess liability limits in the surplus market or in the international markets (typically on a subscription basis through specialised brokers who negotiate with underwriters in the energy field). Once the

insurance limits cross the \$1bn barrier, the market becomes very much specialised with no single insurer covering one entire risk exposure. The market is thus extremely syndicated, with insured losses placed in the London and Bermuda insurance markets and spread across a wide range of global insurers and reinsurers.

Table 34: Major offshore, onshore and power losses in 2009

Major offshore energy losses (in excess of \$10mn ground up)				Onshore energy losses exceeding \$10mn			
Date	Cause	Location	Est. loss (\$mn)	Date	Cause	Location	Est. loss (\$mn)
Jan	Blowout	Nigerian well	20mn	Jan	Mechanical breakdown	Portuguese refinery	45mn
Jan	Blowout	Vietnamese offshore oil well	12.5mn	May	Fire & explosion	Delaware refinery	30mn
Jan	Construction	Chinese offshore single buoy mooring sys.	38mn	May	Fire & explosion	Ohio chemical plant	50mn
Jan	Corrosion	Gulf of Mexico drillship	35mn	Jun	Fire & explosion	Belgian chemical plant	97mn
Jan	Anchor/jacking/rawl	Angolan subsea drillship	90mn	Jul	Fire & explosion	Texas refinery	
Feb	Construction	Indian platform	17mn	Jul	Fire & explosion	Texas gas plant	25mn
Feb	Blowout	Nigerian offshore oil well	45mn	Jul	Fire & explosion	Indian petrochemical plant	20mn
Feb	Blowout	Gulf of Mexico offshore gas well	13mn	Aug	Fire & explosion	Detroit chemical plant	62mn
Mar	Mechanical	Australian breakdown offshore platform rig	25mn	Sep	Fire & explosion	California refinery	>10mn
Mar	Mechanical	Brazilian breakdown FPSO	18.3mn	Oct	Fire & explosion	Puerto Rico oil storage facility	36mn
Apr	Fire & explosion	Singapore jack-rig under construction	15mn	Oct	Fire & explosion	Indian oil storage facility	160mn
Apr	Blowout	Louisiana onshore gas well	11.2mn	Nov	Fire & explosion	Utah refinery	>50mn
Apr	Fire	Singapore FPSO in yard	17.5mn			Total aggregate all claims >\$1mn	\$648,486,000
May	Punch through	Qatar jack-up rig offshore	25mn				
May	Blowout	Louisiana onshore gas well	14mn				
Jun	Collision	North sea platform/supply vessel	1,000mn				
Jun	Faulty design	Philippines FPSO riser	11.5mn				
Jul	Damage	Gulf of Mexico offshore pipeline	13.3mn				
Jul	Collision	Brunei offshore platform	15mn				
Aug	Fire	Gulf of Mexico compression platform	60mn				
Aug	Blowout	Indian offshore gas well	>10mn				
Aug	Windstorm	Taiwan underwater LNG pipeline	>10mn				
Aug	Blowout	Timor Sea (Australia) offshore oil well	250mn				
Aug	Blowout	Timor Sea (Australia) jack-up	250mn				
Aug	Blowout	Timor Sea (Australia) well head platform	>10mn				
Sept	Windstorm	South China Seas FPSO	100mn				
Sept	Windstorm	Macau semi-sub drilling rig offshore	22mn				
Oct	Leg damage	Malaysia jack-up offshore	50mn				
To Oct	Total under \$10mn (minimum of \$1mn)		\$192,408,025				
	Total (known) for year (excess of \$1mn)		\$2,2360,672,760				
				Major power losses (in excess of \$10mn ground-up)			
				Date	Cause	Location	Est. loss (\$mn)
				Jan	Fire & explosion	Indian power plant	11mn
				Jan	Mechanical breakdown	Israeli power plant	37.5mn
				Jan	Mechanical breakdown	Italian power plant	19.4mn
				May	Mechanical breakdown	Malaysian power plant	27.1mn
				May	Windstorm	Oklahoma T&D lines	43mn
				July	Mechanical breakdown	Thai power plant	21.5mn
				Aug	Explosion	Russian hydro-electric plant	200mn
				Nov	Fire & explosion	French chemical plant	>10mn
				To Nov	Total under \$10mn (Minimum of \$1mn)		\$75,039,072
					Total (known) for year (>\$1mn)		\$434,539,539

Source: Lloyd & Partners, Insurance Insider, BofA Merrill Lynch Global Research

Deepwater Horizon could be a game-changer

The total insured losses from deepwater horizon (DH) could run as high as \$3.5bn (Swiss Re's June 2010 est.) to \$6bn (Fitch's October 2010 est.) – which is more than the \$2.2-2.5bn in annual insurance premiums worldwide for the oil & gas sector. While institutions such as Lloyds will take a short-term hit (an estimated \$300 to \$600 million hit to its members' claim bill), the long-term impact of DH is likely to be increases in limits and coverage purchased. We believe this presents a potential opportunity for insurers and reinsurers.

Table 35: Largest offshore energy events in US history

Date	Event type	Location	Fatalities and/or oil spilled
2010	Explosion/fire, sinking of Deepwater Horizon	Gulf of Mexico	11 dead and estimated 4.9mn bbl oil spilled
1964	Blowout, gas explosion	Gulf of Mexico	22 dead
1967	Pipeline leakage, die to damage caused by anchor	Gulf of Mexico	19,155 m3 oil spilled
1968	Blowout, gas explosion	Gulf of Mexico	11 dead, 20 injured

Table 35: Largest offshore energy events in US history

Date	Event type	Location	Fatalities and/or oil spilled
1969	Oil & gas blowout	Pacific	Significant oil pollution on beaches, 9,539 m3 oil spilled
1970-1971	Blowout, gas explosion	Gulf of Mexico	4 dead, 36 injured, 6,439 m3 oil spilled

Source: Munich re, MMS, IS Dept of Interior, BofA Merrill Lynch Global Research

New regulations could fuel demand for insurance

DH has fuelled demand for insurance, as regulators move to a significantly tougher stance on how much cover is needed by oil & gas companies:

- **US amendments set to transform sector** The key proposals are for mandatory insurance and the amendment of current provisions limiting the liability of operators for private economic and environmental payouts for offshore pollution under the US Oil Pollution Act (OPA) of 1990 to \$75 million. The changes – which could have a major impact on smaller and independent O+G players – are expected to come into force next year.
- **EU looking to insurance capability** The European Commission wants to ensure that the firms drilling in Europe have the cash or insurance to cover potential clean-up costs, and is willing to go as far as a potential ban if governments have any doubts about their safety. EU Energy Commissioner Guenther Oettinger's revamp of offshore drilling safety in Europe includes much stricter inspections of oil & gas platforms, as well as provisions on the "Financial capability to handle the consequences of unforeseen events, including possible *participation in suitable insurance schemes or risk-coverage instruments.*"

Insurance premiums for offshore +30%

The insurance sector is seeing premiums in many classes falling to their lowest levels in a decade, which had been mirrored in the energy sector with eroding margins (-10-15%) and reduced offshore energy volumes. The DH loss has, however, been a game-changer for offshore (even if a large portion of BP's losses were absorbed by its captive insurer, Jupiter Insurance), with some oil & gas clients looking to purchase double the amount of insurance that they previously did. This is upping the stakes in the offshore insurance market with increased rate adequacy and new opportunities. Global energy premium rates are increasing between 10% and 30% and premiums for insuring deepwater drilling by 100%, according to large insurers of energy risks. Companies may also see a tightening of the terms and conditions on their policies. Furthermore, DH has had a knock-on impact on marine liability premiums because of concerns over potential pollution from spills.

Impact on drilling operators

Once drilling reverts to normal activity levels, we believe the drilling process will involve more time-consuming operations, and lengthen the time required to drill a well. Along with this, the insurance premiums paid by the drilling operators will increase and deductibles are set to rise. However, we believe some operators will have insurance escalation clauses written into contracts that span multi-year programmes, so at least some of the additional cost will be passed on to the oil company. We also expect to see more drilling operators following the Seadrill model of insurance, where they pay a premium to cover the cost of the rig as well as any backlog associated with the asset. While insurance may rise 30-40%, these costs account for only 5% of daily operating costs.

For Seadrill around half of their contracts have a mechanism where it gets compensated for increases in insurance costs. For the other contracts they have under the general clause and general provisions, so that when operating costs go up, there is escalation according to various indices and the insurance increase would fall into that.

Companies facing worst-case discharge requirements

Despite the lifting of the post-DH deepwater drilling moratorium in October 2010, energy companies are facing more stringent safety standards such as insurers' demands for them to disclose the "worst-case discharge" of oil & gas from their proposed offshore wells. That calculation factors in a host of other requirements – including how much insurance companies must carry and the amount of response equipment they must reserve to clean up such a spill. The financial impact is significant – with an increase from a \$35 million financial responsibility category (by law companies must be able to pay \$35 million for up to 35,000 barrels of oil spilled each day) to the next level of \$50 million – resulting in an extra \$1.5 million in payments to the insurer that issues a financial responsibility certificate guaranteeing the money.

Big oil could benefit at expense of independents

Interestingly, there is a chance that the big oil companies could emerge as beneficiaries of the structural changes in the industry in the long run, as increased insurance costs could effectively exclude smaller, independent players. Assuming the argument that there is not sufficient capacity to provide protection for new limits is borne out, larger companies with strong balance sheets and an ability to raise new capital could rely on captive insurance to keep costs down, giving them a potential competitive advantage over smaller players.

Even shallow water drillers are finding it difficult. By law, they must be able to pay \$35 million for up to 35,000 barrels of oil spilled each day, and another \$35 million for each 35,000-barrel-a-day increment, all the way up to \$150 million for anything over 105,000 barrels a day. A worst-case spill of 100,000 barrels a day would require a company to be able to pay \$105 million, which exceeds the annual total investment of some shallow water players. To self-insure for such an amount would require a prohibitively high net worth of \$1.1 billion (i.e. a \$105 million spill insurance policy, which carries an annual premium of about \$625,000, based on recent industry analysis).

Full impact to be felt in 2011

The full impact of rising premiums is not expected to be felt until around April 2011 when the bulk of reinsurance is bought – with some 80% of energy insurance placed in the first six months of the year (before the start of the US hurricane season).

Safety driving offshore drilling liability cover

In the wake of DH, some insurance companies have expressed concerns that there is not enough insurance capacity and that the insurance sector might limit coverage or reduce limits, potentially requiring financial responsibility to be met through self-insurance, bonds or letters of credit,

While we do not yet believe this is an issue, the insurance industry has put forward a potential long-term solution, with Munich Re proposing direct cover for drilling operations via a critical mass of insurance companies and oil companies – something that had not previously been available on a standalone basis. We

believe the tightening of safety standards is behind this development, with companies buying coverage on fears that an inability to pay high compensation claims could lead to insolvency, with even speculation about such eventualities potentially affecting share prices.

Munich Re looking to increase standard cover up to \$20bn

Munich Re is the first major company to make the move – saying that it could increase potential cover for offshore drilling liability from the current standard of \$1 to 1.5 billion to up to \$10 to 20 billion. Other reinsurers, such as Hannover Re and Swiss Re, expressed their support for Munich Re's proposal at September and October 2010 industry gatherings on the condition that the coverage was properly structured. Scor has said that it would take part if there were US Senate support for a re/insurance solution:

- **Requires primary insurers, reinsurers and brokers** to work together – with Munich Re willing to contribute around \$2 billion of its own capital and other insurers committing the remaining capital to the policies in return for a portion of the premiums paid. A number of other initiatives are in the offing, including Torus Insurance Holdings Ltd announcing that it plans to offer \$1 billion in limits for drilling projects and Oil Insurance Ltd. and Oil Casualty Insurance Ltd. already providing some of the coverage above deductibles for their members.
- **Offer capacity for drilling liability** via three possible structures: 1) a consortium of insurers and reinsurers, each providing uniform prices and conditions of fixed capacity; 2) traditional insurance or reinsurance on a subscription basis, with flexible pricing, conditions and limits; or 3) a pool, with contributions reflecting market share.
- **Market participation** could come through voluntary commitments by oil companies to purchase liability insurance or by the possible introduction of compulsory insurance in the licensing procedure. Coverage would attach a \$1 to \$1.5 billion retention.
- **Would be applied to operations in the US**, where drilling start-ups average about 300 a year in the Gulf of Mexico, and could eventually be extended to other regions.
- **Coverage would be provided for risks based on the US Oil Pollution Act**, mainly including costs relating to cleanup and removal of oil, impairment of natural resources and property damage, along with loss of earnings in areas such as fishing and tourism.

Exhibit 16: Proposed insurance industry solutions

Insurance consortium	Traditional (re)insurance	Pool
- Fixed group of (re)insurers - Each participant agrees fixed capacities - Uniform prices and conditions	Each drilling operation is placed on a co-insurance basis at current market conditions	- Consortium comprising all oil companies that carry out drilling operations - Oil companies pay into the pool according to market share - Losses are paid proportionally from the pool - Pool is reinsured on the free market
- Guaranteed capacity available  - Simple administration	- Free competition  - Flexible pricing, conditions and limits	Relatively secure capacity 
Antitrust issues need to be clarified 	Capacity not secured 	Acceptance among oil companies may prove difficult 

Source: Munich Re

Many unanswered questions

While the idea has garnered support among reinsurers, it would probably require:

- A long-term commitment from a number of insurance industry and oil industry players. A lack of purchasers would not generate enough premiums to pay claims. We are probably looking at 100+ oil rig projects to purchase coverage to achieve sustainability.
- Convergence among the different schemes currently on offer.
- Greater clarity on what liability cap the US Senate might set for incidents (the HOR has approved legislation to raise the cap from \$75 million to \$10billion).

Finally, it is possible that even a new pan-industry coverage product would be insufficient to cover an accident of the magnitude of DH – meaning that improved risk management by oil majors is essential. The industry may well have to think about more fundamental and far-reaching changes.

New models could develop for smaller E&P companies

Depending on how things pan out, the post-oil spill changes could force smaller E&P companies to take out unaffordable or unattainable insurance cover. Some US oil explorers – which do not have BP's massive resources – are talking about forming a new insurance fund that would cover the costs of any future oil spill, to avoid a scenario whereby smaller companies are unable to drill offshore. It could follow the example of a \$1bn fund formed after Exxon Valdez by companies to pay for future oil spills.

Investors to step up pressure

Investors are also set to step up pressure on energy and insurance companies. A group of 58 investors with \$2.5 trillion in AUM sent disclosure request letters to 27 energy companies asking them to provide, information regarding their risk oversight measures for their own offshore oil operations around the world, including spill prevention and response plans. They also sent letters to 26 insurance companies that provide insurance to offshore drilling activity, enquiring about adjustments to their overall exposure to offshore oil & gas operations

including possible changes in policy volume, considering changes in their underwriting criteria. A sample analysis of the five companies most affected by the DH spill shows that only Transocean presents comprehensive public disclosure regarding insurance within its operations.

Table 36: Sample insurance disclosure of companies involved in DH

	Structure	Period	Aggregate covered amount	Captive program (2009)
Transocean	Commercial market and captive insurance policies Only Captive (except when it is required for legal or contractual obligations)	12-month policy periods beginning May 1, 2009.	\$39 billion	\$201m
BP		ND	ND	ND
Anadarko	Commercial market	ND	ND	ND
Cameron	N/A	ND	ND	ND
Halliburton	N/A	ND	ND	ND

Source: Company, BofA Merrill Lynch Global Research. ND = not disclosed

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Coverage Universe	Count	Percent	Inv. Banking Relationships*	Count	Percent
Buy	12	60.00%	Buy	6	54.55%
Neutral	7	35.00%	Neutral	5	71.43%
Sell	1	5.00%	Sell	1	100.00%

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Buy	168	60.87%	Buy	96	63.16%
Neutral	55	19.93%	Neutral	26	57.78%
Sell	53	19.20%	Sell	19	40.43%

Investment Rating Distribution: Engineering & Construction Group (as of 01 Oct 2010)

Coverage Universe	Count	Percent	Inv. Banking Relationships*	Count	Percent
Buy	34	65.38%	Buy	12	40.00%
Neutral	7	13.46%	Neutral	2	28.57%
Sell	11	21.15%	Sell	6	54.55%

Investment Rating Distribution: Financial Services Group (as of 01 Oct 2010)

Coverage Universe	Count	Percent	Inv. Banking Relationships*	Count	Percent
Buy	163	52.58%	Buy	72	46.15%
Neutral	104	33.55%	Neutral	42	42.00%
Sell	43	13.87%	Sell	14	33.33%

Investment Rating Distribution: Utilities Group (as of 01 Oct 2010)

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Buy	75	40.98%	Buy	29	43.28%
Neutral	58	31.69%	Neutral	27	51.92%
Sell	50	27.32%	Sell	15	33.33%

Investment Rating Distribution: Global Group (as of 01 Oct 2010)

Coverage Universe	Count	Percent	Inv. Banking Relationships*	Count	Percent
Buy	1948	54.31%	Buy	821	46.73%
Neutral	891	24.84%	Neutral	397	49.07%
Sell	748	20.85%	Sell	259	37.16%

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