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FOLLOWING THE CAPITAL TRAIL IN OIL & GAS

NAVIGATING THE NEW ENVIRONMENT

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A NEW PATH FORWARD

The reversal of oil prices in 2014 has been among the swiftest in history.

The fall of $50 per barrel and a bearish outlook have diminished the allure that O&G has held for investors over the past five years. They have all of a sudden changed the discussion in the sector from raising capital, to driving growth in the long term, to seeing capital as the biggest lever of adjustment in today's low-priced, cost-focused, and highly competitive market environment.

Navigating this new environment might be painful for many O&G companies, but they understand from past experience that adapting will only make them more efficient, dynamic, and innovative. The environment may question their traditional capital strategies and present several new capital choices, which will likely force many to explore and consider new forms of sourcing, deploying, and optimizing capital.

Such strategies include sourcing capital through new low-cost investment vehicles; deploying capital in assets and markets that offer greater portfolio and operational flexibility; and optimizing capital by adopting leaner designs and displaying higher commercial agility in supply chain and contracts.

Because this is just the beginning of the new environment, it is important to carefully study the dynamic nature of the shale business and its repercussions on the global O&G industry. Although each company will be developing a personalized action plan and addressing a unique set of questions across their decision-making cycle, the list of questions in figure 7 [on the next page] can get the ball rolling in the changing O&G world.

"The drop in oil prices has piqued investors' interest in oil and gas producers. But new research suggests that high-quality investments are scarce - for the moment."

(Fig. 7) The Capital decision-making cycle

Source: England, John, Gregory Bean, and Anshu Mittal. "Following the Capital Trail in Oil and Gas: Navigating the New Environment." Deloitte University Press. Deloitte University Press, 10 Apr. 2015. Web.

"…the market rout is cyclical rather than structural, and the low prices seen in early 2015 are unlikely to last."

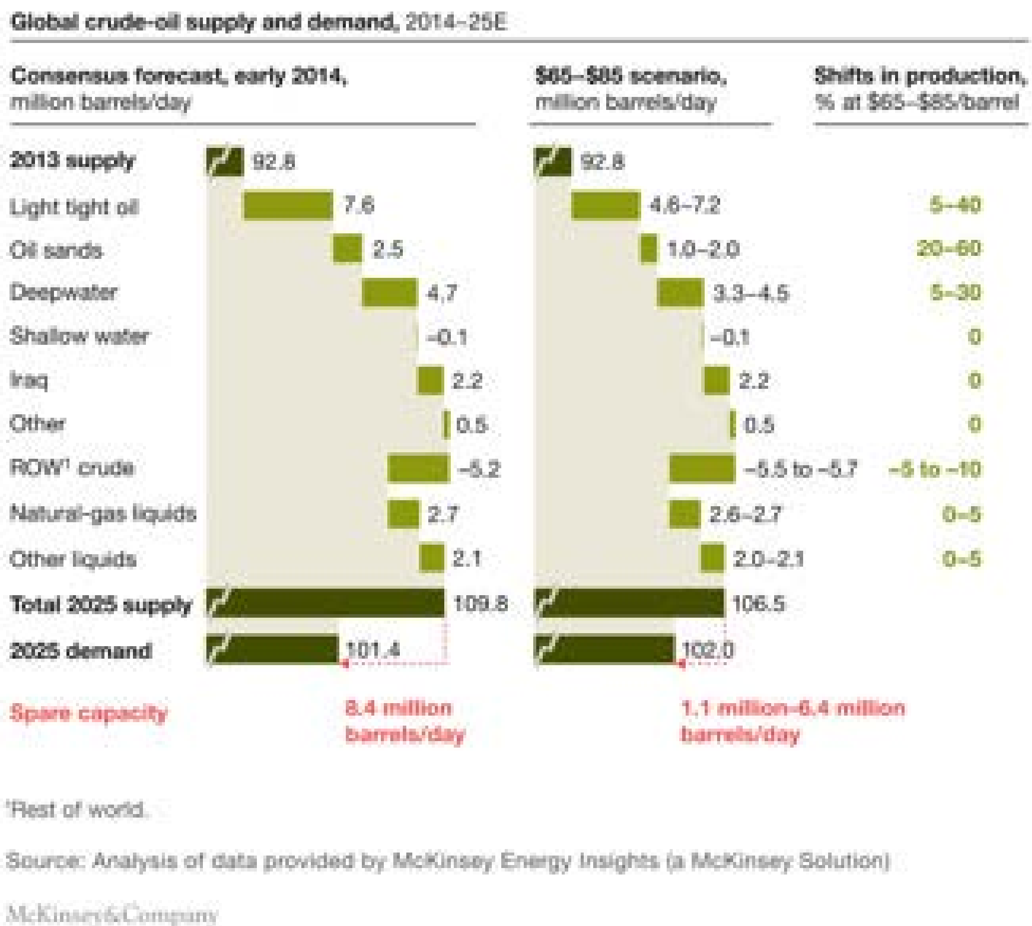
The oil and gas industry was shocked as oil prices fell by more than half, from $104.48 per barrel in July 2014 to $51.53 in March 2015. Valuations have also fallen, in some cases rather steeply. This sudden shift has escalated investors' interest in the sector, especially in North America, where private-equity firms and others have accumulated a war chest of more than $80 billion specifically intended for upstream assets. Investors are moving quickly to evaluate acquisitions across the value chain, with exploration and production (E&P) and oil-field services garnering the most interest.

The logic behind this surge seems robust. While most investors are rightly cautious about a recovery of prices to former levels, they believe that the market rout is cyclical rather than structural, and the low prices seen in early 2015 are unlikely to last.

Oil demand is expected to grow for the next decade in most scenarios.

In a scenario where oil prices return to equilibrium between $65 and $85 a barrel, both onshore and offshore unconventional assets (including deepwater) will contribute more to the global oil-supply "stack" (Exhibit 1). Investors that believe in this scenario find today's market to be a buying opportunity for good-quality assets.

(Exhibit 1) If oil returns to ~$75/barrel, spare capacity will be reduced, and an equilibrium could be reached.



This argument has certainly been behind some prominent deals recently. In January 2015, Blackstone's $70 billion credit arm, GSO Capital Partners, committed up to $500 million to help cash-strapped LINN Energy develop its production assets. Two months later, Kohlberg Kravis Roberts & Co. bought $135 million of discounted loans that were used to finance the 2014 buyout of Scottish oil-field-services firm Proserv, a provider of subsea equipment and services.

These deals notwithstanding, the wave of M&A and consolidation that some industry watchers predicted has not yet happened. In the first quarter of 2015, just 49 deals worth $10 million or more were announced. That's down from 2014, when at least 104 deals (and as many as 149) got done every quarter. The total value of M&A in the first quarter of 2015 is also down from 2014, at $9 billion relative to quarterly totals of $50 billion to $88 billion in 2014. We see three primary explanations for this:

North American operators have quickly adjusted to the new reality by rapidly cutting their activity (the rig count has halved, to fewer than 900 rigs), shifting development to the most prospective and predictable parts of their acreage (driving up initial production rates by more than 25 percent in some cases), and driving down development costs (by between 30 and 40 percent at many big unconventional operators).

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Firms are financially stronger than expected. Many operators enjoyed cheap and covenant-light credit before the crash and had large revolvers of debt that they could draw on. While these lines begin to mature next year, they are sustaining operators through the down cycle. Also, production at many operators is hedged.In a sample of 25 US E&P companies we studied, around 54 percent of oil production in 2014 was hedged through a combination of fixed-price swaps and three-way collars. Hedged production drops to around 30 percent in 2015 and around 15 percent in 2016.

Several pure-play E&P companies seem to be valued by the market at substantially higher levels than can be justified by current prices. For example, the economic value of one operator in the Permian Basin is down by just 17 percent since 2014, in spite of a much larger drop in oil prices. To believe this valuation, the market would also have to believe that oil will return to $80 a barrel, that the company can reduce capital expenditures by around 30 to 40 percent on future wells (even though it has increased 15 percent annually for the past several years), and that the company's acreage in a new play can be "down spaced" to close to 40 acres per well, similar to what is only now being achieved in the most advanced sections of the Eagle Ford and Bakken Formations.

"Investment opportunities can be found by patient investors with a fundamental approach."

Does this mean that the E&P subsector is an unattractive one for investment? Hardly.

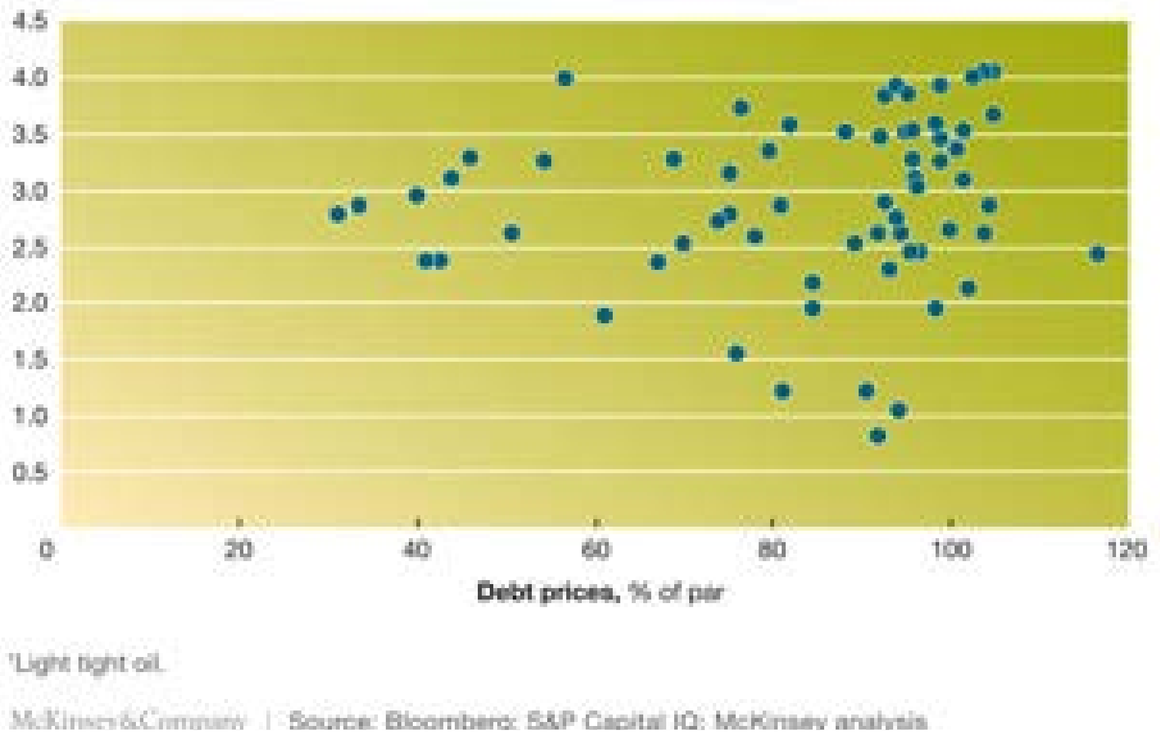
We believe that investment opportunities can be found by patient investors with a fundamental approach. We recently examined nearly 1,000 E&P companies operating in North America and benchmarked their operations "outside-in" to understand how they performed on essential sources of value such as asset quality; drilling performance; selling, general, and administrative performance; and other metrics. We adjusted for geological differences and weighted the attributes for their relative impact on value creation. The result is an intrinsic-valuation index, which we then compared with the capital markets' perspective. A snapshot of the resulting analysis (large light-tight-oil producers) is shown in Exhibit 2. Across all the 1,000 or so E&P firms we studied, less than 5 percent can truly be called undervalued.

Exhibit 2

Few unconventional producers are currently distressed.

Intrinsic value and traded prices of debr largest North American LTO[1] producers, 2015

Intrinsic-valuation index



Source: Kalavar, Sanjay, Hyder Kazimi, and Mihir Mysore. "North American Oil and Gas: Caveat Emptor." North American Oil and Gas: Caveat Emptor. McKinsey & Company, June 2015. Web.

That picture may change over time; if prices stay low, more producers will become distressed. Investors can also take heart that distress is only one of several possible investment themes. Opportunities for recompletions of older wells, high-quality management teams, and other themes offer ways to drive value.

Finally, a word on North American oil-field-services companies. Many investors struggle with the subsector, perceiving it to have low entry barriers, high cyclical exposure, and a mixed history of “real” value creation. While these concerns are valid, we believe that there are certain niches that offer a promising upside at current valuation levels. A rapid drop in demand has driven some small mom-and-pop firms out of business, granting more pricing power and other benefits to the survivors. In some niches, companies are more exposed to operating expenses, rather than capital expenditures, and their earnings have not suffered the way that companies in other segments have. The market has not completely recognized this difference, which might represent a buying opportunity.

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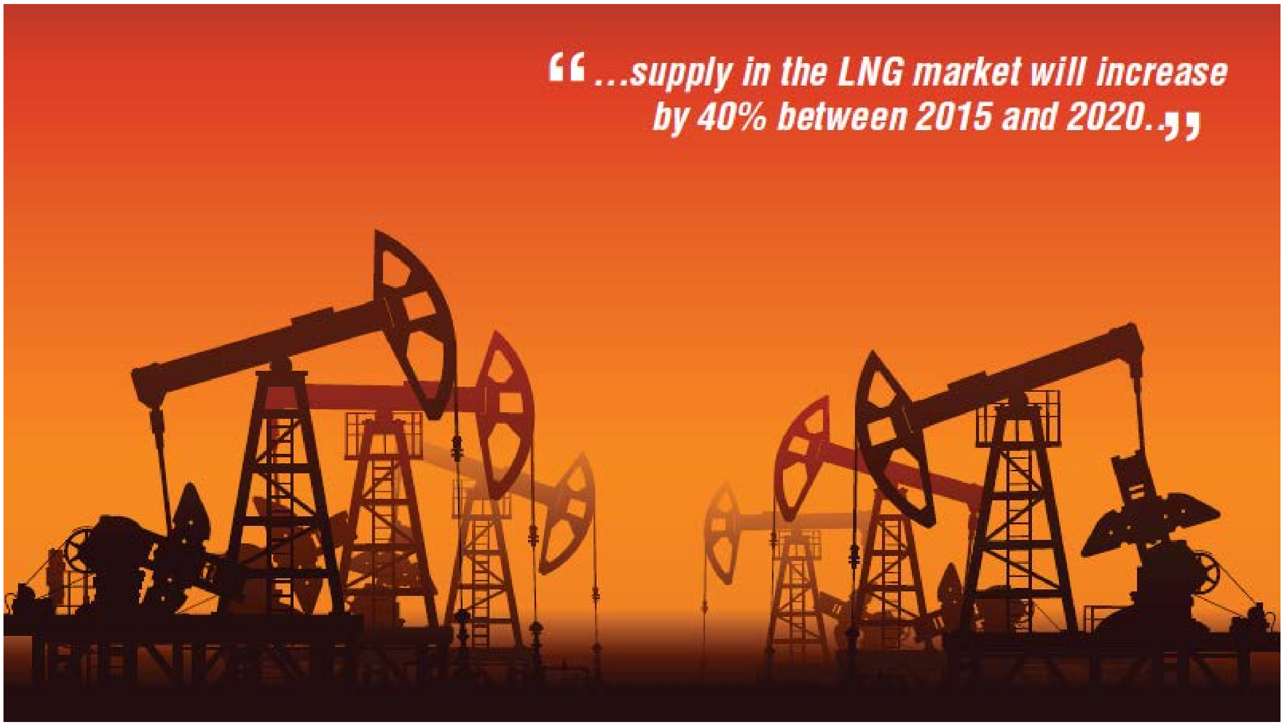
"Despite low oil prices and a weak medium-term outlook, LNG has a bright future."

There is the need for ~15 new LNG trains by 2025 and over double that by 2030. Players should look past the structural loose market in the medium term and push ahead with FIDs for this growing market.

A new wave of LNG export capacity is on its way to the global market by 2020: 115mtpa of capacity already post- FID or under construction will start to bring volumes to market in the next five years (and a further 15mtpa by 2022). On balance, supply in the LNG market will increase by 40% between 2015 and 2020 – the largest volume increase in supply the market has seen in any 5-year period.

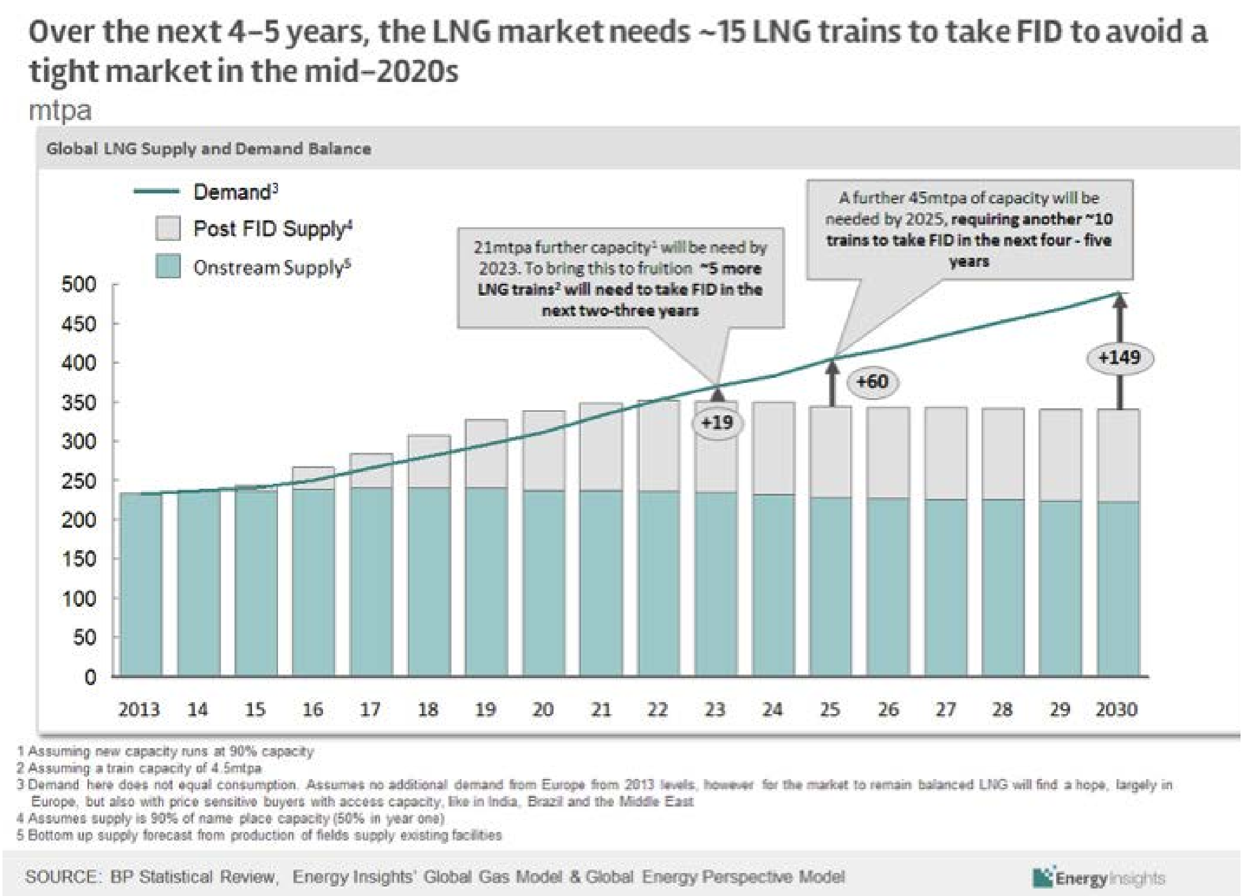


Given the current demand outlook however, in the next 5 years, Asian demand growth is unlikely to be strong enough to absorb all of this new capacity.

The market looks likely to be structurally long until 2022 (however weather effects could eliminate some of this in the next two years). For the market to stay balanced, volumes which have been diverted out of Europe to Asia will instead flow back to Europe, re-exports will slow, and price-sensitive consumers will step in to take advantage of LNG below its full cycle costs. The result of the change in trade flows suggests that LNG spot markets will trade much closer to European price levels, instead of close to oil price parity prices seen during tight market conditions.

Longer term however, LNG markets have a much more positive outlook. Demand is expected to grow on average between 4-6% p.a. until 2030, with our base case expectation at 4.5% p.a. between 2015 and 2020. Given this long-term demand outlook, the market needs to take FIDs on a further ~20mtpa of capacity in the next ~2.5 years to bring it to market by 2023, and a further 45mtpa by the end of the decade so it's ready for 2025. Otherwise from 2023, we quietly enter a very tight global LNG market.

The race is on for which global projects will fulfill this increasing demand. Our article Brownfield expansion projects in pole position in US LNG market highlights that US brownfield projects have a competitive edge compared to other purposed projects globally. However, there are portfolio diversification, security of supply, and political considerations that might help keep global projects in Australia, East Africa, and elsewhere viable. Some consumers will want to diversify both their pricing exposure (Henry Hub vs Oil indexed) and their dependence on any single country for a high proportion of their energy needs. For example, for the US to fill half of the needed non-FID capacity, this would mean all major LNG consuming countries would need to rely on the US for upwards of 30% of their supply. In 2013, Qatar, the largest LNG supplier, met only 25% of demand of the three largest consumers (in total, Japan, Korea, & China) and only Korea allowed itself to take more than 30% of its supply from Qatar (Korea took 34% of its supply from Qatar though ~6% was on a spot basis).



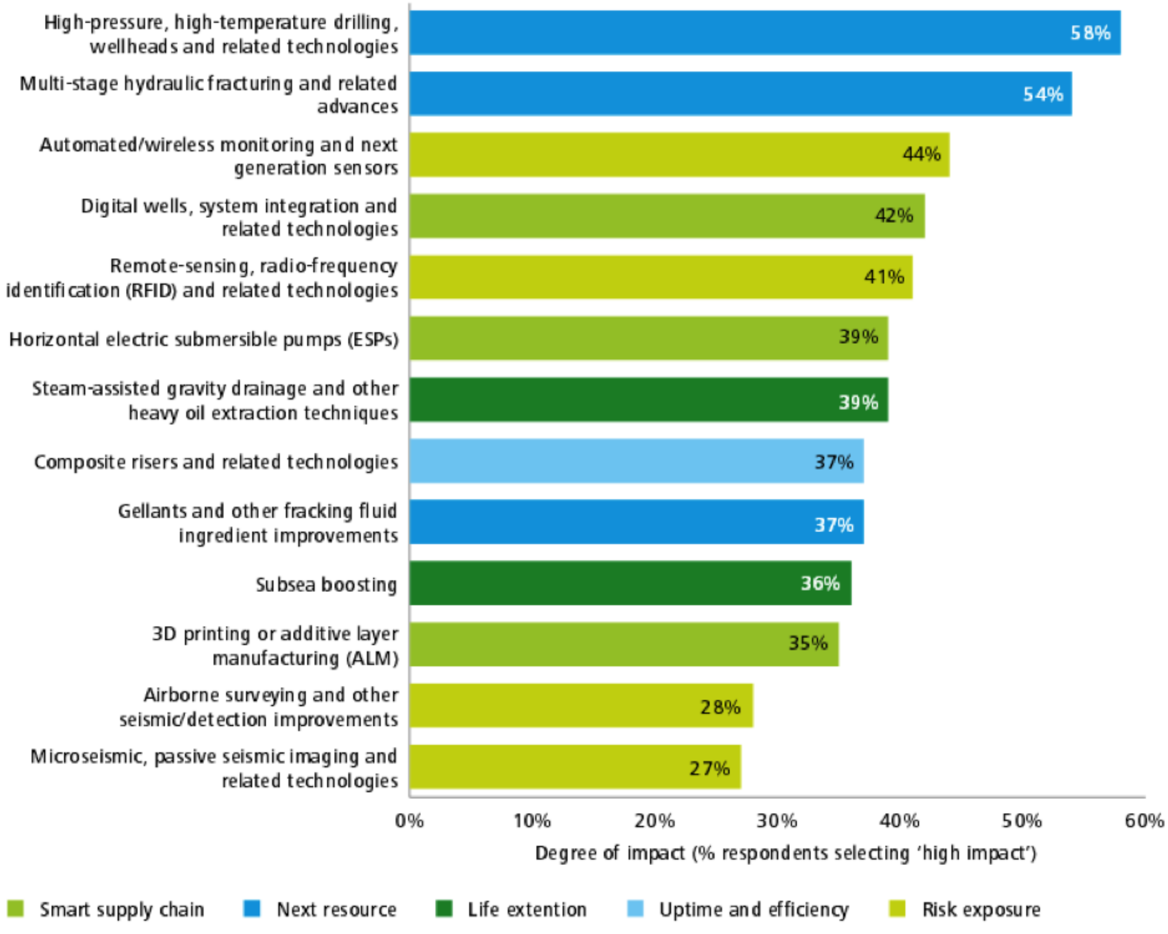
Source: Maddock, Kerri, and Peter Lambert. "Positive Outlook for LNG." Positive Outlook for LNG. McKinsey Solutions, June 2015. Web.

Overall the US is not going to fill the entire market supply need in the longer term – so don't count out Australia, East Africa, and other players from this race. The market could absorb US export capacity at 60% higher than what has already taken a FID and still need well over 100 mtpa of capacity to meet demand.

INVESTING IN INNOVATION: THE COST OF COMPLEXITY

While E&P spending is slowing amid ongoing commodity price volatility, as of March 2014, the world's four biggest super-major oil and gas companies were spending roughly 40% of their capital budgets on megaprojects (those with capital investments of $1 billion or more). Notably, a full 50% of that 40% allocation was going to technically complex projects, such as the Gorgon LNG project in Australia, the Pearl GTL project in Qatar, the Kashagan project in the Caspian Sea and the Sakhalin project in Russia.Thanks to significant investments in technology and innovation, the industry is accessing previously inaccessible deposits by engaging in deepwater and ultra deepwater exploration, building floating LNG (FLNG) and storage facilities, and exploring new frontiers in the Arctic. Innovations include the automation of remote and subsea operations; high pressure, high temperature (HPHT) drilling; multi stage fracking; and even subsea robotics (see Figure 12).

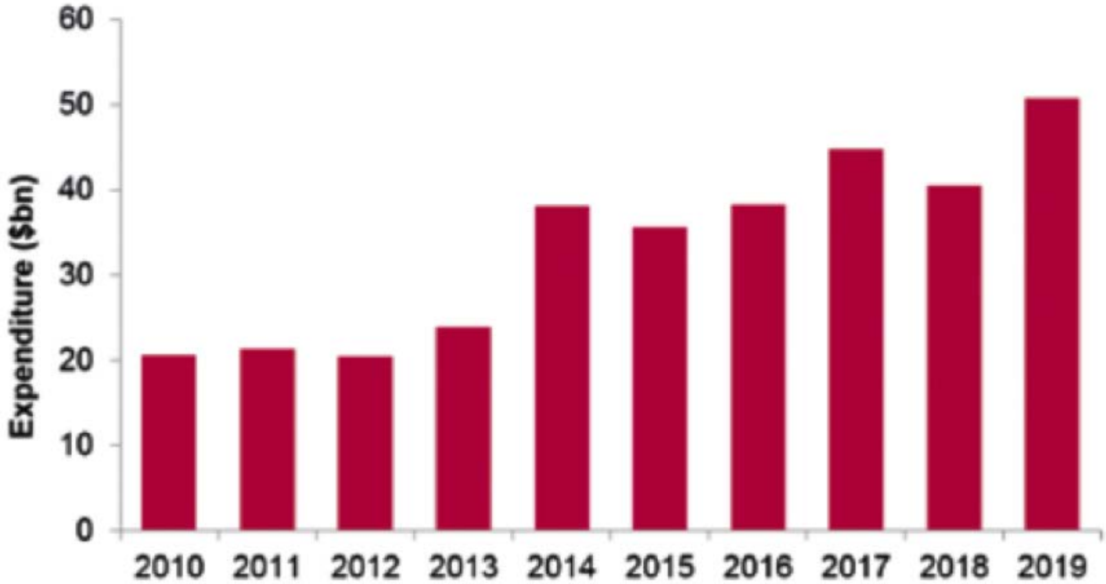
(Figure 12) High-impact technologies going mainstream in the medium-term (around 2020)



Source: Lloyd's Register Energy – Oil and gas Technology Radar 2014 www.lr.org/technologyradar

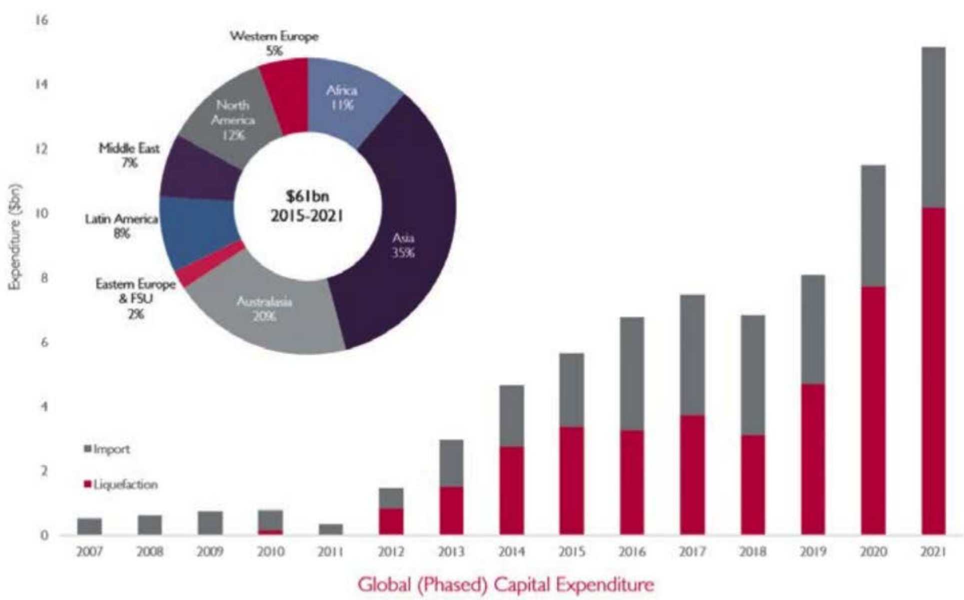
In E&P companies' quest to innovate, global exploration and production spending in 2014 reached an estimated $723.3 billion, 79 despite lower energy prices. While overall spending is expected to fall for 2015, projects past FID are unlikely to be cancelled. As of December 2014, Douglas Westwood was still predicting offshore development wells to grow by 17% by 2018. Of the $1.4 trillion that is projected to be spent on offshore E&P during that time period, 39% is expected to go to life of field services, 31% to drilling and 15% each to EPC and subsea development. In fact, deepwater capital expenditures are set to rise by 130%, as an additional 1,500 subsea wells are drilled and completed around the world. The spend on floating production is also anticipated to grow, reaching $164 billion by 2020, with FLNG accounting for roughly $81 billion of that capital expenditure.

(Figure 13) Deepwater capital expenditure 2009-2019



Source: Douglas-Westwood – Deepwater market forecast 2015 edition

(Figure 14) FLNG global capex and regional split



Source: Douglas-Westwood – World FLNG market forecast 2014 edition

OVER TIME, OVER BUDGET

The challenge, however, which has been brought into particularly sharp relief in recent months, is the significantly high spending associated with so many complex projects. A full 65% of capital projects around the world exceed budgets by at least 25% and/or exceed scheduled timelines by up to 50%.

As the technical risk of projects rises, capital expenditures rise apace. In Australia, for instance, the Pluto LNG project came online a full 14 months after its target start, at a cost of U.S.$14.9B – 33% above original estimates, the Gorgon LNG project went 40% over cost and saw delays of over one year and the Wheatstone project's price went up 13% between 2011 and 2013.

Elsewhere, the Pearl GTL project in Qatar rose nearly 300% from its 2003 budget of $5 billion, while Norway's offshore oil and gas projects are running roughly 20% above original cost estimates. Cost and time delays have also plagued the only two offshore fields currently producing in the Arctic: the Snøhvit field in Norway which is the region's first LNG development, and the Prirazlomnoye project in Russia which is the Arctic's first oil development. Meanwhile, in October 2014, the cost of Kashagan – already the world's most expensive oil project – was set to rise by nearly $4 billion as developers were forced to replace roughly 150 miles of leaking pipelines.

There are myriad reasons for these overruns, ranging from regulatory mandates that require additional investment, rising labor and material costs, and mounting technical and geopolitical risks. Less benign factors exist as well, including a tendency to over invest in bleeding edge technologies and an insistence on customizing each project rather than looking for ways to standardize.

THE CASE FOR COST CONSCIOUSNESS

With energy prices declining, companies are already postponing FIDs and putting low margin projects on hold. Now that companies have lost the cushion of buoyant prices that could have bailed them out of a cost overrun, the imperative to wrestle costs under control is becoming even more critical. According to Goldman Sachs, companies will need to cut costs by up to 30% to make a range of high cost projects profitable should oil prices average roughly $70 per barrel.

This is mandating new approaches to project design, development, financing and approval. Traditional stage gate processes still have their place for highly technical projects. The complex projects that increasingly dominate the oil and gas industry, however, have a high degree of variability, reducing the utility of stage gate processes. The challenging geologies, engineering and regulatory environments associated with these projects make outcomes unpredictable and mandate more dynamic responses.

To address poor project performance, companies are adopting a range of strategies. These include:

Integrated project delivery (IPD) – by improving collaboration across the supply chain, the intent of IPD is to align the commercial objectives of all project participants (owners, engineers, contractors, subcontractors, major suppliers). This serves to focus team efforts on improving project delivery from inception through final turnover and closeout.

Advanced analytics – as industry reliance on so called ‘big data’ rises, companies can increasingly benefit from the use of advanced analytics to identify early indicators of potential issues that could affect project performance. For instance, by leveraging vast sets of in field employee performance data, companies can make more informed workforce planning decisions. Similarly, by integrating external data (i.e. weather patterns, political unrest, multi tier supply chain issues), they can model scenarios in which projects typically go off the rails and put mitigation strategies into place in advance.

Lean project management – this involves the dynamic adjustment of project delivery needs to contemporaneous project mandates, enabling organizations to adjust workflow and resource allocation in real time, in response to shifting requirements.

Talent management – during industry downturns, companies have a tendency to lay off professionals and reduce their hiring of entry level workers. In the past, this created a generation gap that still defines today’s oil and gas workforce. To avoid fueling a shortage of skilled workers into the future, companies need to pursue talent processes that better manage the attraction and retention of engineering and technical talent. At the same time, training programs should also focus on fostering a higher level of cost consciousness among existing workforces, who will likely be asked to operate in more fiscally constrained manners going forward.

A shift towards the digital oilfield, which relies on technologies such as 4D seismic imaging to business intelligence initiatives. Investments in the digital oilfield are changing project economics. For instance, Shell's Amberjack project reported a 20% reduction of operating costs, a 5 10% increase in recovery and a 75% reduction in work flow cycle times – results that enable this so called 'smart field' to produce an additional 600 barrels of oil per day.

Modular approaches – as an engineering dominated industry, modular standardization is sometimes regarded as suspect in the oil and gas sector. Applied effectively, however, modular approaches can reduce project costs by up to 15% and accelerate project delivery by up to 20%. Modularization spans the gamut and could include using common design specifications for similar projects, reusing already developed plant designs for new projects and relying on rapidly evolving modular technologies (i.e. skid mounted process systems, pre assembled infrastructure components) to streamline work efforts.

SERVICE SECTOR STRUGGLES

In the short term, oilfield services (OFS) costs are also likely to come down due to market overcapacity. Given the frequency with which both IOCs and NOCs outsource substantial portions of their development and production operations to the OFS sector, declining costs in this area can help strengthen margins. While this may come as good news to large E&P companies, it's already taking a serious toll on the OFS sector. Schlumberger intends to lay off a full 20,000 employees through 2015,while Baker Hughes, which recently merged with Halliburton, announced headcount cuts of 7,000 people.

OFS mergers and acquisitions also fell 40% for the second half of 2014 compared to the year previous. This reduced activity most acutely affected drilling (deals down 67%) and support services (deals down 56%), although these numbers were offset by two U.S. deals that comprised roughly 70% of total OFS deal value: the merger between Halliburton and Baker Hughes, and Siemens' acquisition of Dresser Rand.

Just as in the E&P sector, recovery in the OFS sector will require more rigorous cost discipline, particularly given the huge debt burdens under which many of these companies operate.

CONCLUDING THOUGHTS

Although capital spending is likely to fall off in the near term, megaprojects will still be required to meet long term global energy demand. To avoid the cost and time overruns that have typically characterized these projects, companies may want to explore a range of strategies, including pre-project planning, integrated project delivery, lean project management, modularization and talent management. They may also want to invest in advanced analytics to enable agile project monitoring and evaluation.

At the same time, it bears recalling that weak price signals often spur innovation. It is more than reasonable to expect that lagging oil prices will spur greater innovation as well.

JOIN US

VPs of Construction, Directors of Modularization, Design Engineers, and other industry professionals will go in-depth on the modular design strategies which apply to working in a compromised market at the 5th Modular Construction & Prefabrication Summit, taking place March 21 – 23 at the Westin, Calgary.

If you would like to learn more about the event, don't hesitate to:

Download the agenda or the 2015 Post Show Report