

Global: Energy

280 projects to change the world

The winners keep on winning

The “Winners” of the last six editions of this report have outperformed their peers by 8% on an annualized basis (2% for the Top 230 winners since February 2009). The stocks we have identified as winners in this analysis are: BG, Shell, Petrobras, GALP, Tullow, and Woodside.

Non-OPEC production likely to disappoint

On our estimates, 2009 will be the last year of growth in non-OPEC production, as the industry suffers from the lack of new project sanctioning in 2007-09. Recent trends of poor delivery and increasing decline rates suggest that non-OPEC decline could be over 1 mnbls/d pa from 2011.

OPEC at full utilization by 2011-12

We estimate that OPEC capacity will only grow c.1%-2% pa in the coming years, mostly from Iraq. Our analysis points towards 100% OPEC capacity utilization by 2011/12, leading to the need for demand rationing pricing. Even if Iraqi redevelopments achieve their ambitious targets, OPEC would run close to full utilization.

Services key beneficiaries of new projects

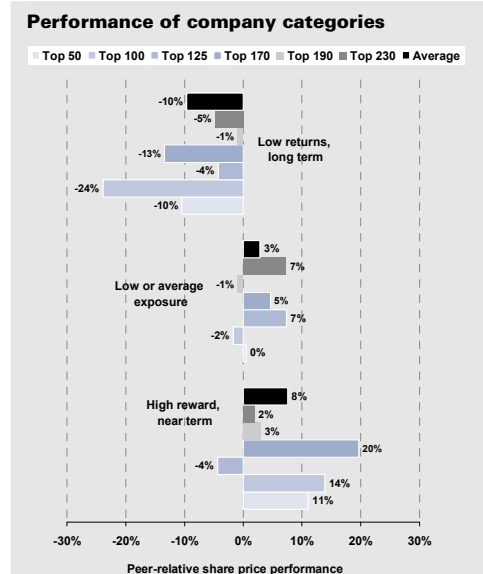
We believe that 2010 will see the largest number of new project sanctions since 2006, leading to increasing backlogs for oil services and new capacity bottlenecks in SURF, subsea equipment and LNG. A sharp increase in the technical risk of new developments is likely to prove positive for leaders in frontier developments.

Selecting Oil Services winners

We have screened our global Oil Services universe to identify winners with leading positions in high growth businesses (subsea, LNG) and attractive geographical areas (Brazil, ME, Asia-Pacific): Technip, Petrofac, FMC, Schlumberger, JGC and Foster Wheeler stand out.

Delivery will be key to value creation

Increasing technical risk requires strong delivery skills. We have back-tested the companies’ ability to bring fields into production, highlighting BG and Exxon. We have also tested the ability of companies to add value through exploration. BG is the only company to stand out on all metrics.



Source: Datastream, Goldman Sachs Research estimates.

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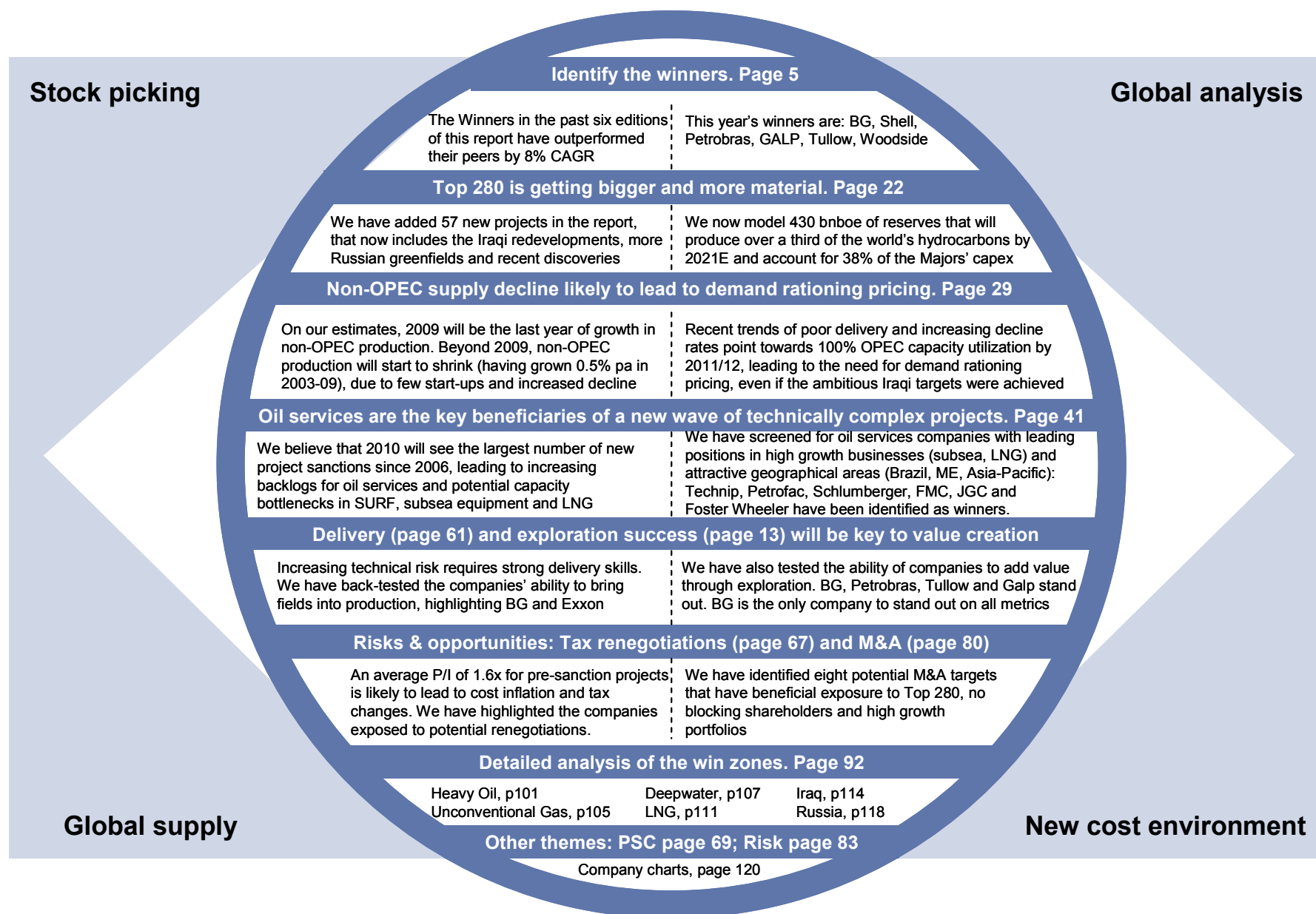
Table of contents

Key findings from the Top 280 Projects	3
The Top 280 Projects	21
Non-OPEC supply will be disappointing, with fewer big projects and higher decline rates	29
All regions show a disappointing delivery of oil projects	34
Cost deflation: 2009 input cost softening creates lower breakeven opportunities	39
Oil Services to benefit from increased sanctions and complexity – introducing the Winners	41
GS SUSTAIN winners continue to do well in Top 280	61
Top 280 assets likely to be a significant driver of M&A	80
Lower political risk comes at the cost of higher technical risk	83
Tracking the progress of the companies through our legacy asset analysis	89
Win zones in the Top 280	93
Company competitive positioning	120
Top 280 portfolio characteristics by company	121
A Top 280 NPV analysis shows the Russian oils as particularly attractive	122
Summary of key Top 280 Projects metrics by company	150
Disclosures	152

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The prices in the body of this report are based on the market close of January 13, 2010 unless otherwise stated.

Key findings from the Top 280 Projects



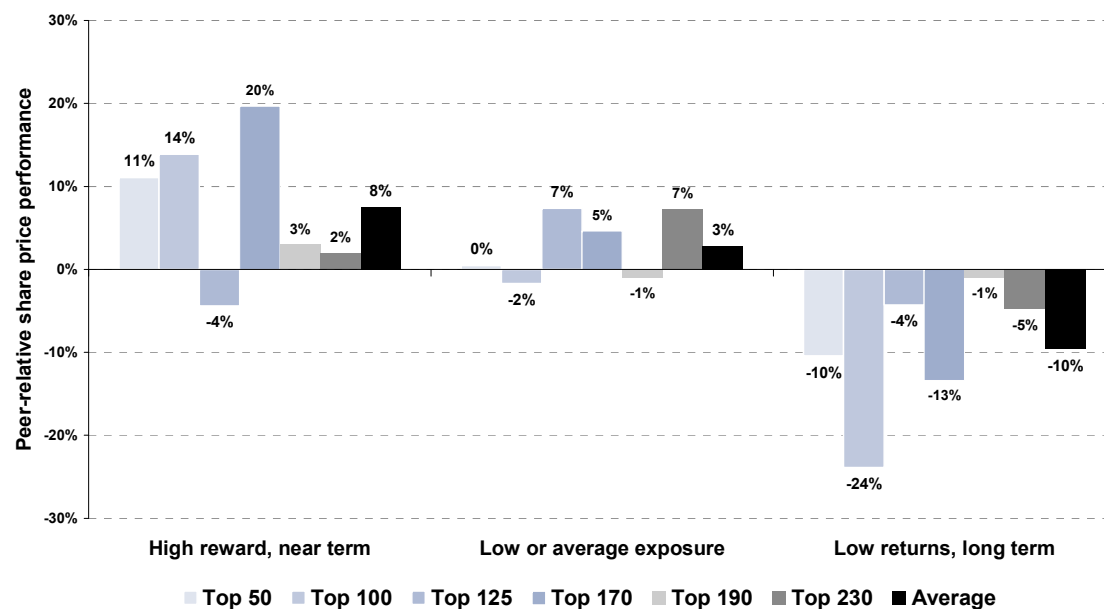
Source: Goldman Sachs Research estimates.

Picking winners: New legacy asset exposure drives share price performance

Outperformance trend of winners has continued despite oil price volatility

Since publication of the Top 230 in February 2009, the Top 230 winners have outperformed their peers by 2%, while those with low returns and long term exposure have underperformed by 5%. The outperformance of our “Winners” category now averages 8% pa across our six previous publications. This contrasts with an average 10% pa underperformance by stocks with exposure to the long-term, low-return assets which we consider to be less attractive. The performance calculation for each group of companies highlighted in the different editions of the report shows the relative performance of each company vs. its peer group in the period from the publication of that report to the publication of the one following. The peer groups used are “Europeans”, “US”, “EM”, “Canadians” and “E&P”.

Exhibit 1: Performance of core project categories between publications



The category “High reward, near term” includes “High risk/high reward” from Top 50, “High reward, near term” from Top 100, “Near term winners” from Top 125 and “Winners” from Top 170, Top 190 and Top 230. The category “Low or average exposure” includes “Muted exposure” and “Little or no exposure” from Top 50, “Manageable exposure” from Top 100, “Balanced exposure” and “Limited exposure” from Top 125, “Limited exposure” and “Near term exposure” from Top 170, “Limited exposure” from Top 190 and “Low or average exposure” from Top 230. The category “Low returns, long term” includes “High exposure but low returns” from Top 50, “Long term, lower return” from Top 100, “Long term winners” from Top 125, “Long term exposure” from Top 170 and Top 190 and “Low returns, long term” from the Top 230.

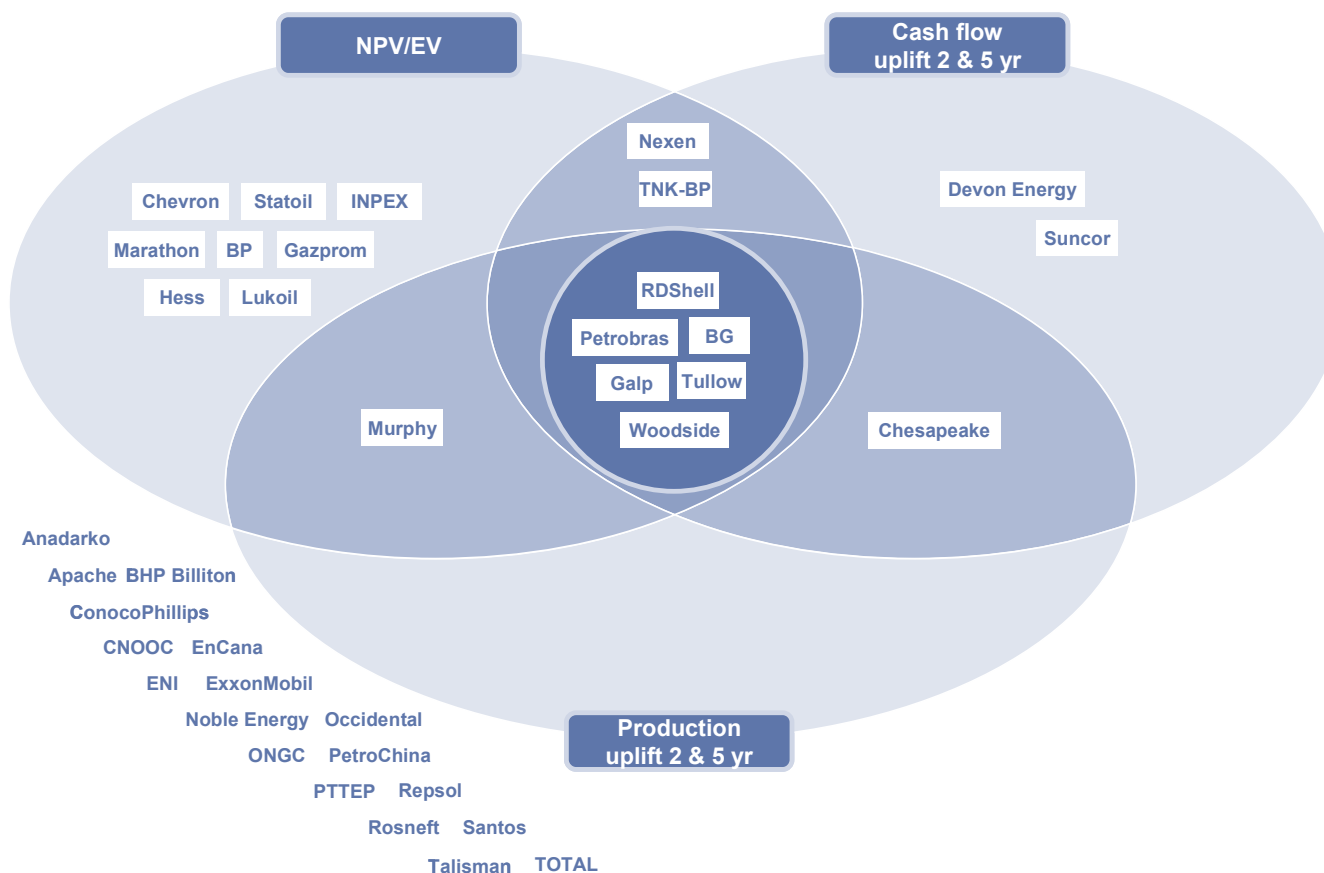
Previous publications: Top 50: June 2003; Top 100: January 2005; Top 125: February 2006; Top 170: February 2007; Top 190: April 2008; Top 230: February 2009. **Note:** Results presented should not and cannot be viewed as an indicator of future performance.

Source: Datastream, Goldman Sachs Research estimates.

Choosing the winners: High materiality combined with production and cash flow uplift

We have based our selection of winners on a combination of three factors (Exhibit 2). The first is materiality. We require that the NPV of a company's portfolio as a % of its EV is above 50%. The second is based on cash flow uplift, which measures how the Top 280 portfolio is likely to transform the company's cash generation: we select companies where the short-term uplift (two years) is above 20% and the medium-term (five years) is above 40%. Finally we screen for production uplift, and only select companies where the short-term uplift to production is above 10% and the medium-term is above 30%. The "Winners" therefore own material new projects, which represent a large component of their market value and which we estimate will materially lift their future cash flows and production in both the short and medium term. We no longer use profitability as a metric by which to judge the winners as we expect the portfolios of all the companies to achieve an impressive P/I (profit/investment) ratio of at least 1.4x at a discount rate of 8% – an indication of the overall attractiveness of the Top 280 universe.

Exhibit 2: The Top 280 winners have high profitability, high materiality and an attractive cash uplift



Source: Company data, Goldman Sachs Research estimates; Woodside and Santos are covered by GS JBWere.

280 projects to change the world: Modelling an industry striving to grow

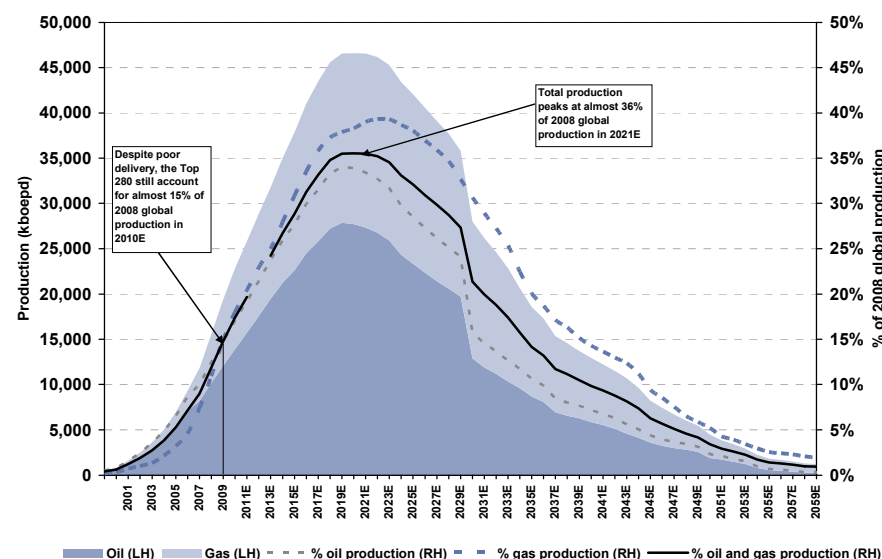
We have extended our analysis of the industry's new legacy assets to 280 projects (from 230). The Top 280 Projects now represent 430 bnboe of oil and gas reserves and almost half the planned E&P capex for the Majors over the next three years. In our view these projects will not only be the main driver of returns transformation for the companies under our coverage, but will also be a key driver for the global supply of oil and gas over the next 5-10 years, a key determinant of growth and margin transformation for the oil services industry, with implications for the refining sub-sector.

The Top 280 Projects sample set is more material for the Integrated oil companies than before

Our analysis of the industry's new legacy assets has grown from 91 bnboe in Top 50 Projects (June 2003) to 430 bnboe in Top 280 Projects. We estimate that these projects will deliver around 46.6 mnboe/d of production by 2021E (36% of current global oil and gas production). The sample set is material for the companies: the nearly US\$225 bn of expected Top 280 Projects capex by the Majors in the next four years represents 38% of overall capex, and 49% of total upstream capex for the Majors on our estimates.

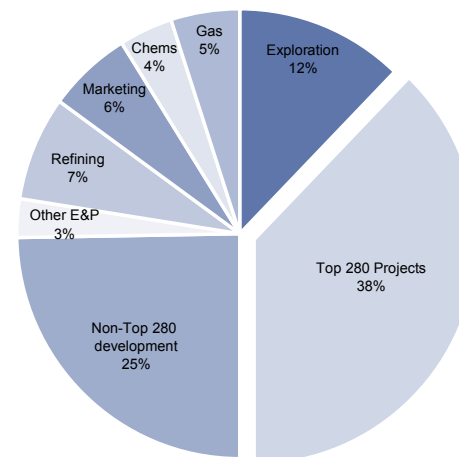
These projects represent the advantaged project slate for the industry as a whole, yet the average pre-sanctioned project requires almost US\$60/bl to meet the industry's hurdle rates and the marginal projects require more than US\$90/bl. This highlights the challenge faced by the industry in this environment.

Exhibit 3: Top 280 Projects oil and gas production profile



Source: Company data, Goldman Sachs Research estimates, BP Statistical Review 2009.

Exhibit 4: Top 280 capex as a percentage of Majors' total capex



Source: Company data, Goldman Sachs Research estimates.

Global oil supply: The slate of new projects keeps growing, but is maturing very slowly

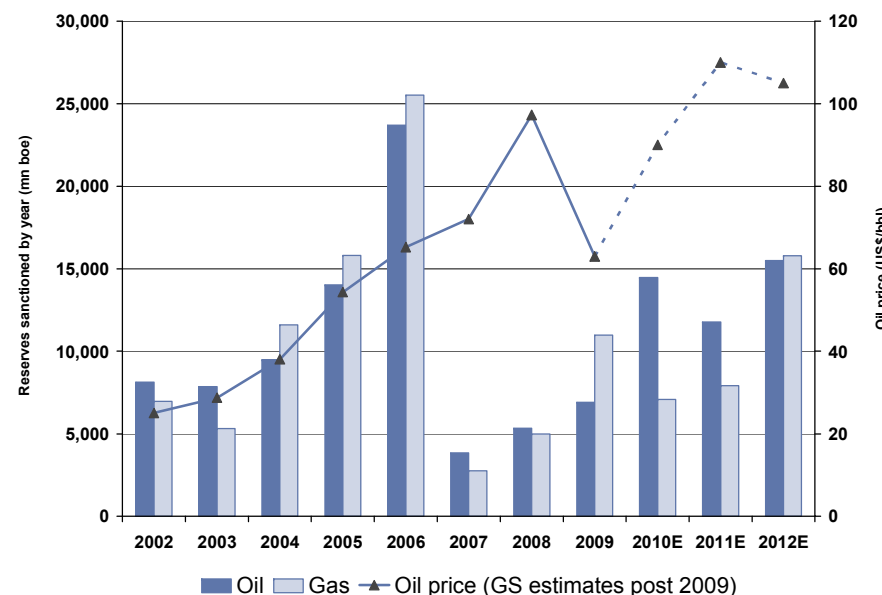
The Top 280 database of projects keeps growing thanks to new discoveries and developments (this year the largest additions are from exploration in Brazil and GoM and redevelopments in Iraq). However this should not lead to the conclusion that we will see strong supply growth in the coming years. These projects have been maturing very slowly, with only a handful getting FID over the past three years and delivery has also been problematic, with major delays.

FIDs have been delayed by uncertainty on costs and tax renegotiations and Exhibit 5 shows that the level of sanctions has been poor since 2007. The industry has effectively wasted around three years to progress a new wave of field developments. Given an average lead time of about four years to first production, this means that production growth in the 2011-13E period is likely to be disappointing. We assume a new wave of sanctions in 2010-12E, thanks to a more stable cost environment.

The problem of a relatively empty pipeline of projects for the next four years is likely to be compounded by poor delivery. Exhibit 6 shows the volumes that have been delivered from the forecasts in our previous six editions of this study. It should be noted that we are always too optimistic, as we are unable to forecast field-specific problems. On average, the industry has delivered 5% less than we expect 1 year forward, 10% less 2 years forward and 15% less three years forward.

Exhibit 5: Few new oil projects were sanctioned in the past three years ...

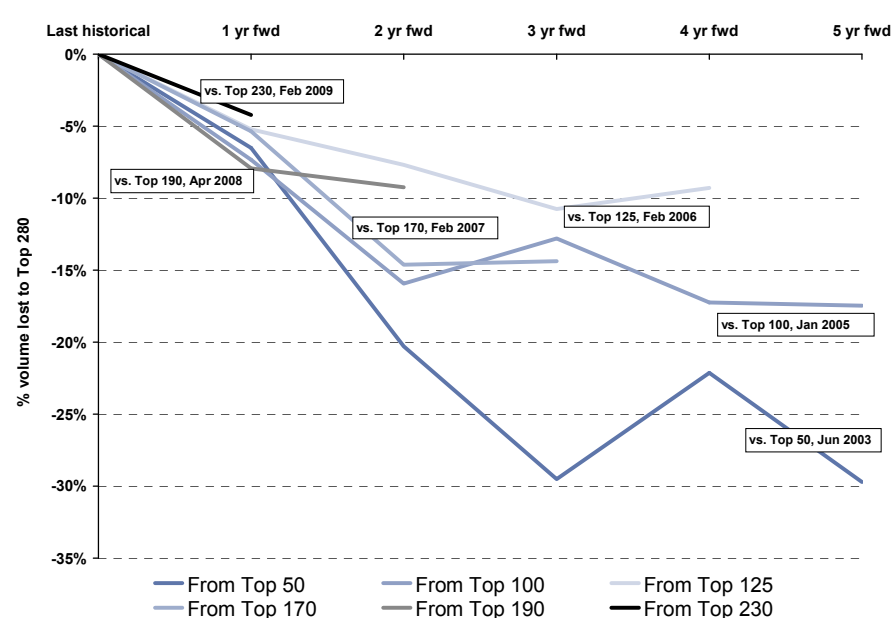
Top 280 oil & gas reserves sanctioned each year, excluding Iraq



Source: Company data, Goldman Sachs Research estimates.

Exhibit 6: ... and delivery has been poor

Oil volumes lost vs. our initial forecasts from the past six editions of this report



Source: Company data, Goldman Sachs Research estimates.

Supply remains structurally supportive of oil prices; demand rationing pricing a likely necessity

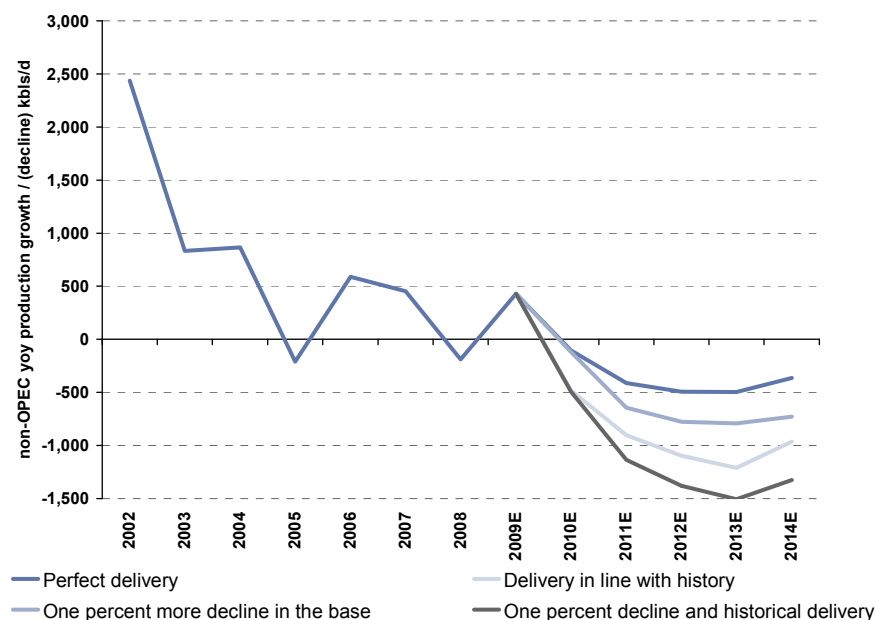
On our analysis, 2009 was the last year of growth in non-OPEC production, thanks to a slate of long-awaited new projects that came onstream (such as Thunder Horse, Agbami, Tahiti, Vankor). From 2010, the start-up of new projects will reflect the scarcity of FIDs in the 2007-09E period. We also assume an increase of decline in the mature basins, consistent with our observations since the start of the decade. On our estimates, non-OPEC production will shrink over the foreseeable future (having grown 0.5% pa in the 2003-09 period).

Our base case production forecast utilizes the Top 280 production forecast and a mild increase in decline rates. We can effectively define this as a best case or “perfect delivery” scenario, which would lead to almost 500 kbls/d of decline from 2011E. Exhibit 7 also shows three more realistic scenarios, where we factor in delivery in line with that observed over the past six editions of this report, a one percentage point increase in decline rates each year (also in line with our observations), and a combination of both. The result is a decline in non-OPEC production of up to 1.5 mnbls/d.

Exhibit 8 looks at OPEC capacity utilization, given these four scenarios and our forecast for global oil demand growth of 1.4% pa. This shows that we expect OPEC to achieve an unsustainable 100% utilization by 2011-12 according to the scenarios. This implies that demand rationing pricing is likely to be necessary over that timeframe.

Exhibit 7: Non-OPEC could decline by up to 1.5 mnbls/d from 2011E

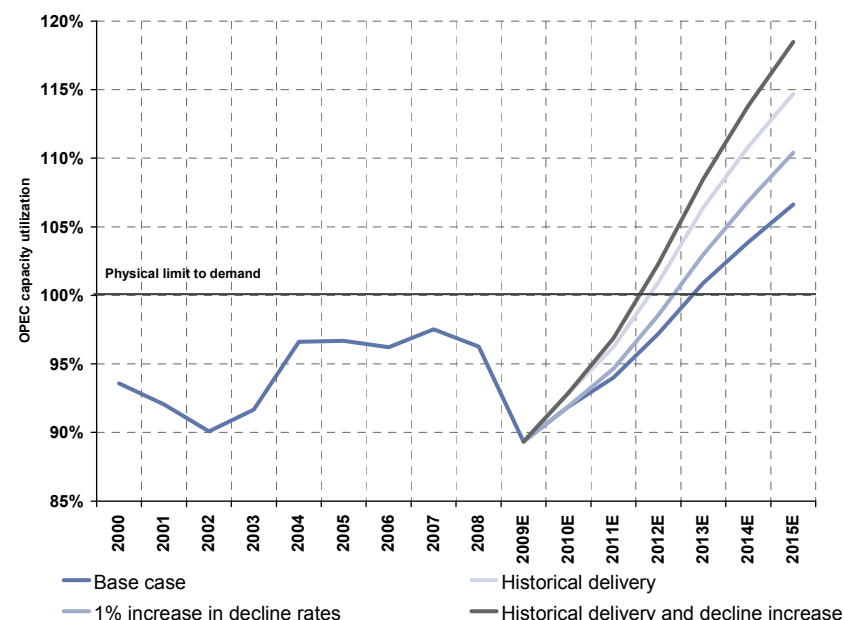
Scenarios of non-OPEC production growth/(decline) based on delivery and decline



Source: Company data, Goldman Sachs Research estimates.

Exhibit 8: OPEC likely to reach full capacity utilization in 2-3 years

OPEC capacity utilization on our estimates on different scenarios



Source: Company data, Goldman Sachs Research estimates.

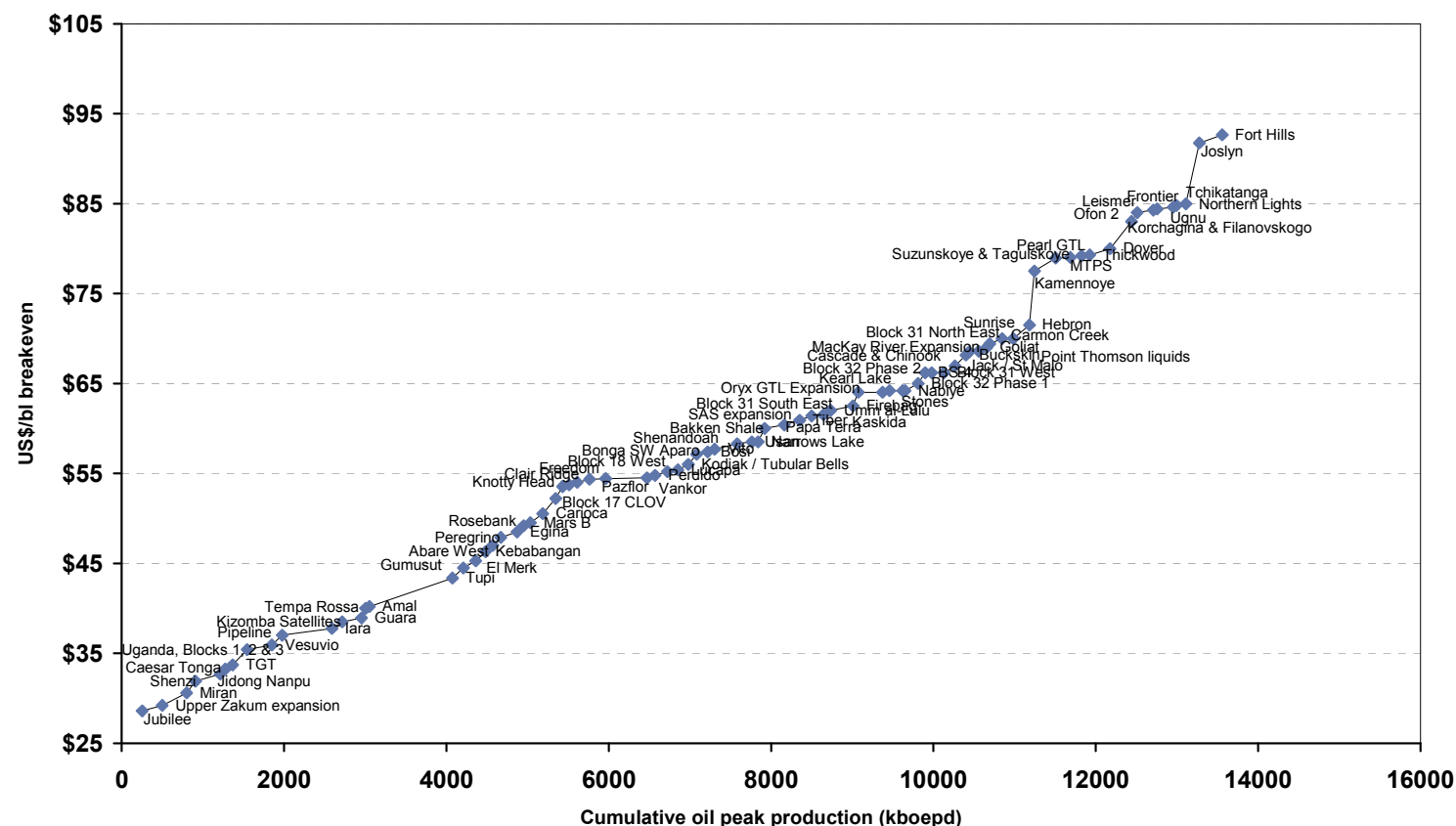
Marginal projects require US\$85-95/bl under current cost environment; 4 mnbls/d of 2018E production could remain unsanctioned at US\$60/bl

Our base case cost modelling in this report is based on the current cost environment and does not assume potential cost inflation in the future. In assessing the breakeven price required we use commercial hurdle rates (ranging from 11% in OECD to 15% in high risk countries; under our base case, the marginal cost of production (Canadian heavy oil) is in the US\$85-95/bl range). Beyond Canada, the next tranche of marginal projects (ultra-deepwater West Africa and lower tertiary GoM) requires a price of US\$65-75/bl while sub-salt Brazil requires c.US\$45/bl, thanks to economies of scale and exceptionally high flow rates.

Although the forward curve would justify the development of almost all projects in this study, we believe that the final investment decision of projects requiring more than US\$75/bl is unlikely to be taken until there is a further increase in the oil price.

Exhibit 9: Marginal Top 280 fields require US\$85-US\$95/bl oil price

Breakeven of non-producing oil assets



Source: Goldman Sachs Research estimates.

The risk profile is changing: Shying away from political risk, taking on technical challenges

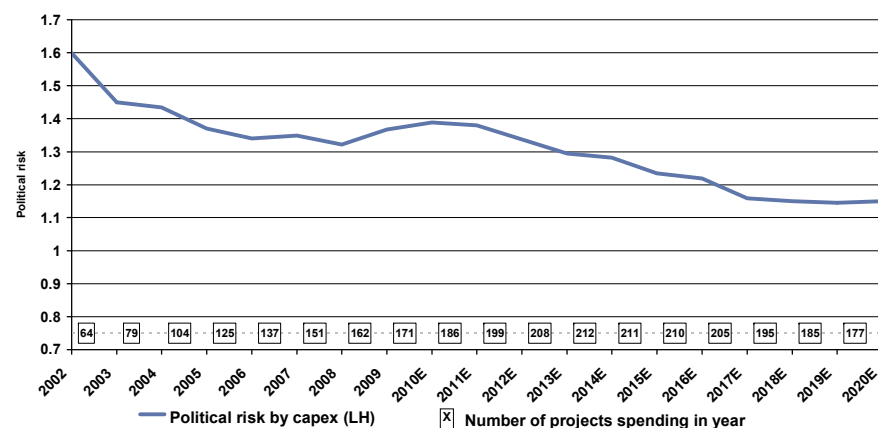
We believe that from 2010E, the Top 280 investment profile will increasingly focus on areas with lower political risk (Exhibit 10). On the gas side, this is primarily due to the large unconventional gas portfolio which adds significant US-based production, and the large weight of capital-intensive LNG projects in Australia. The picture is similar for oil with substantial investment expected to be made in ramping up the heavy oil sands projects in Canada, the Brazilian pre-salt plays and the Gulf of Mexico. These projects tend to be capital intensive, which further skews the investment towards these areas. We note that Iraq acts as a counterweight to this trend but has less of an impact due to the relatively low cost nature of the development that we assume.

While we see political risk declining, technical risk is likely to step up from 2011, as companies move into frontier areas to look for resources in politically safe countries that are more technically challenging to develop. This step-up in technological risk is likely to lead to an increase in development times, delays and cost overruns and is likely to benefit the oil services companies exposed to these frontier areas.

We believe that the increasing technical risk profile is caused by three main factors: 1) a change in production mix: more traditional and easily monetized oil and gas fields are replaced by fields with higher technological complexity and higher capital intensity (i.e. deepwater, LNG, GTL and heavy oil); 2) the increased depth of prospects and greater proportion of pre-salt or sub-salt fields in the deepwater win zone; and 3) the tackling of more geologically complex, HPHT and high sulfur reservoirs (i.e. Kashagan and Shah).

Exhibit 10: The industry is shying away from political risk...

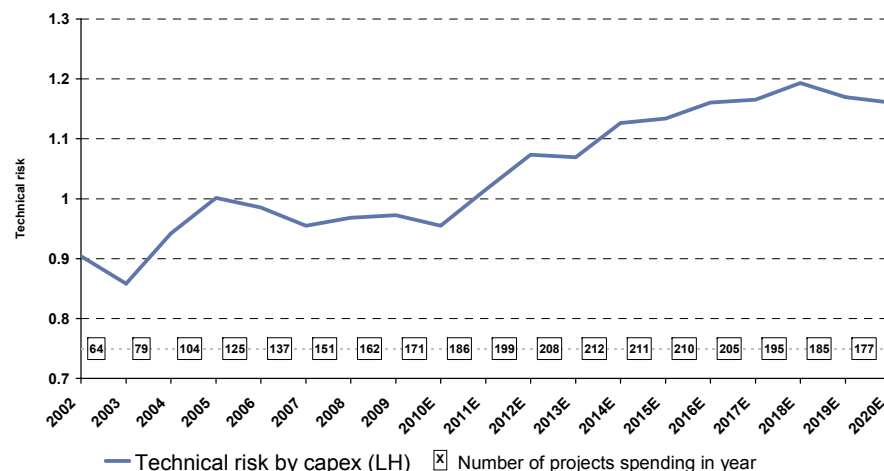
Political risk of the Top 280 projects weighted by capex spend



Source: Company data, Goldman Sachs Research estimates.

Exhibit 11: ...at the expense of ever increasing technical challenges

Technical risk of the Top 280 projects weighted by capex



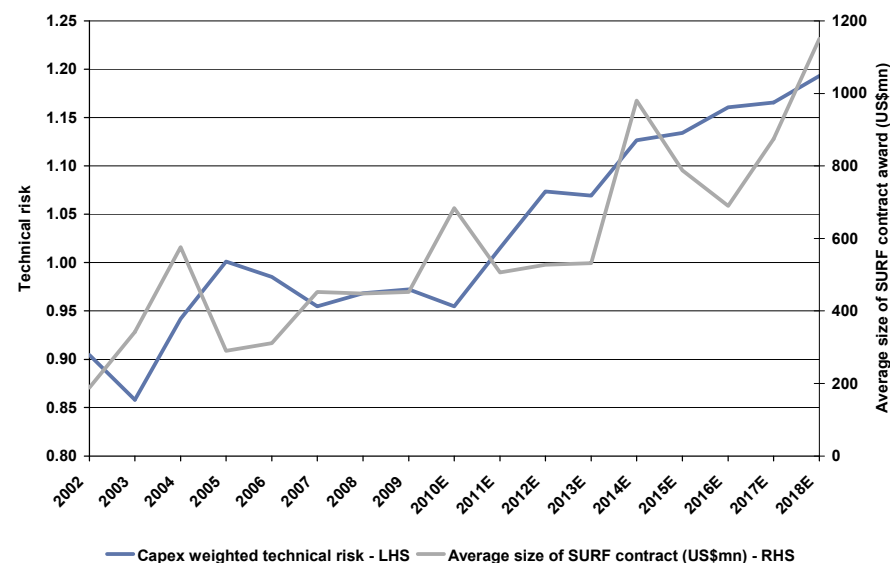
Source: Company data, Goldman Sachs Research estimates.

Oil Services companies are the main beneficiaries of the rising technical risk

We believe the global oil services companies offer some of the most compelling investment opportunities from the Top 280 analysis. We expect the service providers to continue to benefit from the new wave of infrastructure investment which began in 2H 2009 as further Top 280 investment is signed off by operators in 2010 as the oil industry looks to catch up on three years of low investment in large new projects. We believe this will be combined with a structural need for more sophisticated development solutions to meet the needs of producers targeting more challenging water depths and resource types. In our view, this will increase the capital outlay required for the projects, further increasing the size of the opportunity for oil service providers.

Exhibit 12: Top 280 contract awards are growing in size as investment shifts to more challenging areas

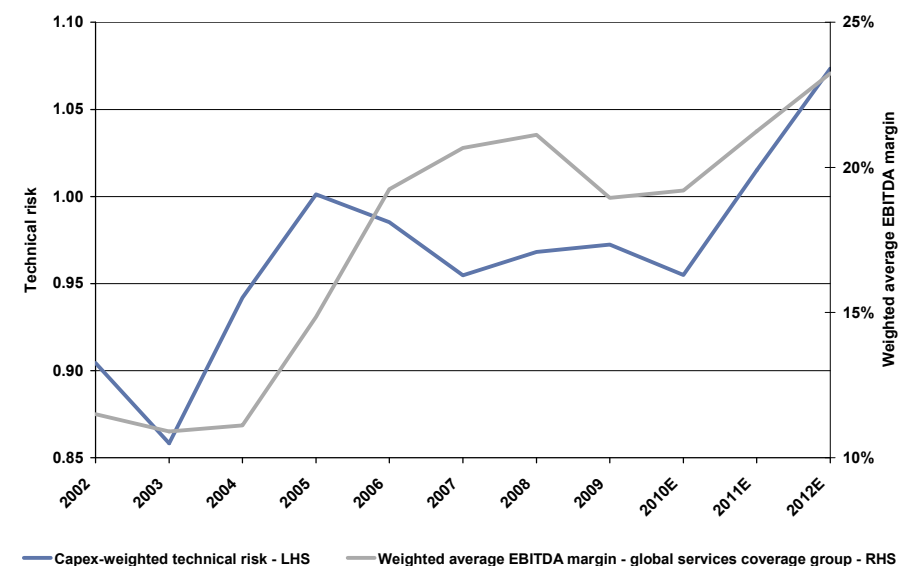
Technical risk of Top 280 project capex and average size of SURF contract (US\$ mn)



Source: Company data, Goldman Sachs Research estimates, Datastream.

Exhibit 13: We expect much of the new activity to yield higher margins for oil services companies

Technical risk of Top 280 capex and EBITDA margins of global oil services universe



Source: Company data, Goldman Sachs Research estimates.

Introducing the Top 280 Oil Services winners

We update our analysis to include a breakdown of which parts of the oil services chain we believe will benefit most from the increased project sanctions shown in Exhibit 5. Based on activity growth, we highlight subsea equipment, SURF, LNG and Iraq as positive areas of exposure for oil services companies. The FPSO construction industry screens well in terms of demand growth, however we believe it has poor leverage to the investment cycle and therefore exclude it from our winners screen. We identify heavy oil and Russia as areas where there is less potential for growth in the short term. We are also less positive on offshore drilling exposure, as we see a decline in the number of wells drilled to 2012 in all areas excluding ultra deepwater (>1,500m water depth).

Within our favoured areas of exposure, we screen across our global oil services coverage to highlight companies which we believe can become structural winners because of their exposure to the industry's new wave of growth projects. We filter out companies without exposure to the key growth areas of Brazil, the Middle East or Asia-Pacific, and select the companies with through-cycle returns of greater than their peer-group median (measured as CROCI).

The winners on this basis are: JGC, Foster Wheeler, Petrofac, Schlumberger, FMC Technologies and Technip. These companies are advantaged in either Australian LNG (JGC, Foster Wheeler), deepwater frontier developments (FMC Technologies, Technip, Schlumberger) or onshore Middle East and potentially Iraq (Petrofac, Schlumberger).

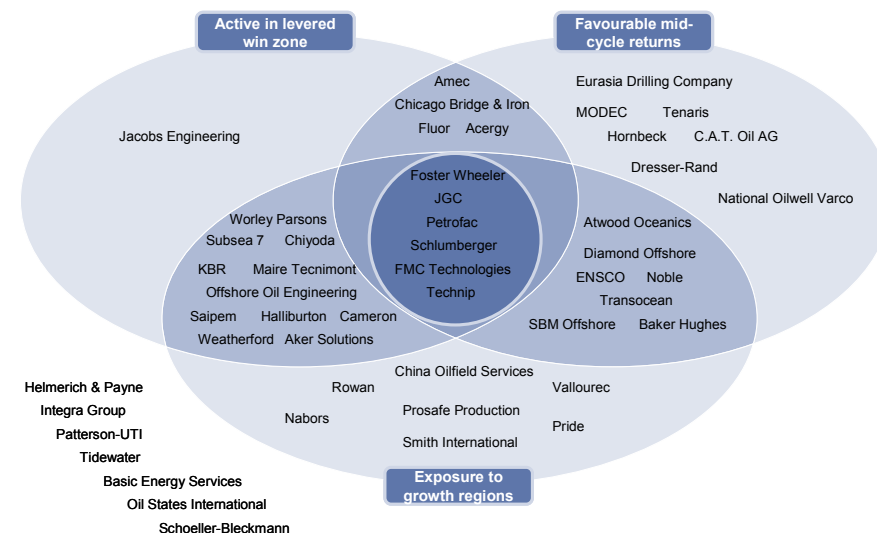
Exhibit 14: Deepwater-related services, LNG and Iraq screen well as areas of exposure, together with geographical exposure to LatAm and Asia-Pacific
Compound activity growth to 2012E by Oil Services win zone

Services win zone	Activity growth 2009 to 2012E		Activity growth 2009 to 2015	
FPSO	12%		10%	Based on expected capex
SURF	19%		22%	
Subsea	12%		10%	
LNG	14%		11%	
Heavy oil	6%		16%	
Russia	-4%		-6%	Based on expected wells drilled
Drilling: traditional (50 - 100m jack-up)	-22%		-13%	
Drilling: traditional (<750m)	-14%		1%	
Drilling: deepwater (<1500m)	-24%		-4%	
Drilling: ultra deepwater (>1500m)	21%		18%	
Iraq	7%		10%	Based on production

Growth region	Activity growth 2009 to 2012E		Activity growth 2009 to 2015E		
	Deepwater:	LNG:	Deepwater:	LNG:	Based on expected capex
Africa	-1%	-21%	6%	18%	
Asia-Pacific	33%	44%	-11%	27%	
Europe	-	-	-	-	
Latin America	16%	-	8%	-	
Middle East	-	-30%	-	0%	

Source: Company data, Goldman Sachs Research estimates.

Exhibit 15: We outline the companies best exposed to the Top 280 projects
Global Oil Services winners



Source: Company data, Goldman Sachs Research estimates.

The major oil companies have not created material value through exploration in the last 10 years

We have tested the industry's ability to create value through exploration by calculating the reserves discovered by each company since 2000 (excluding non-exploration led areas such as heavy oil, exploitation, unconventional gas, Russia and adjusting for asset transactions) and their value at the time of discovery (before their development). We remove Russian companies from this analysis as exploration has not been a key factor in their business models to date.

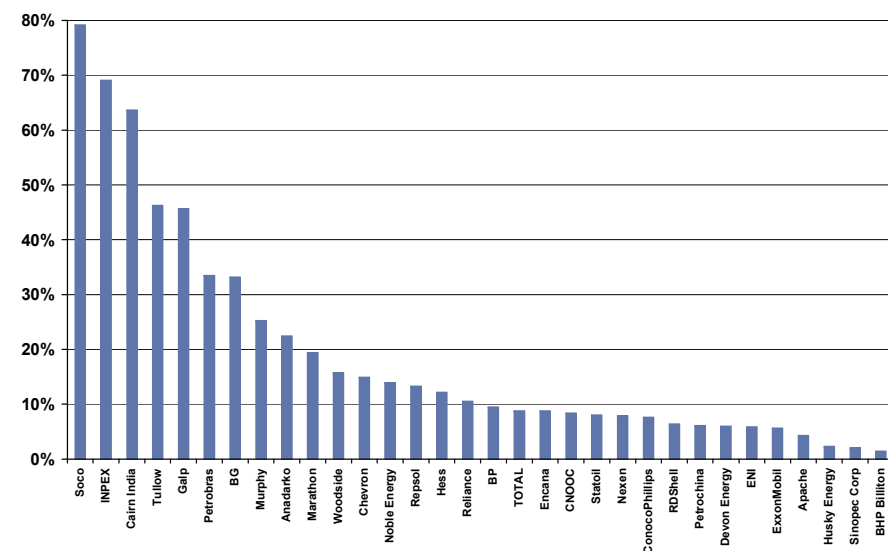
Exhibit 16 shows the value of these exploration successes as a % of EV. For only seven companies has the exploration success of the past decade created more than 30% of the current market cap. The rest of the value of the companies comes from the older legacy assets, from the capital invested to develop these reserves and from their time value.

If we exclude the smaller E&Ps with just one or two assets, the key winners are Petrobras, BG, Galp and Tullow, which have consistently created value through exploration in a variety of assets.

ENI and Exxon stand out as the Major oil companies that have created the least value from exploration.

Exhibit 16: Value added through exploration since 2000

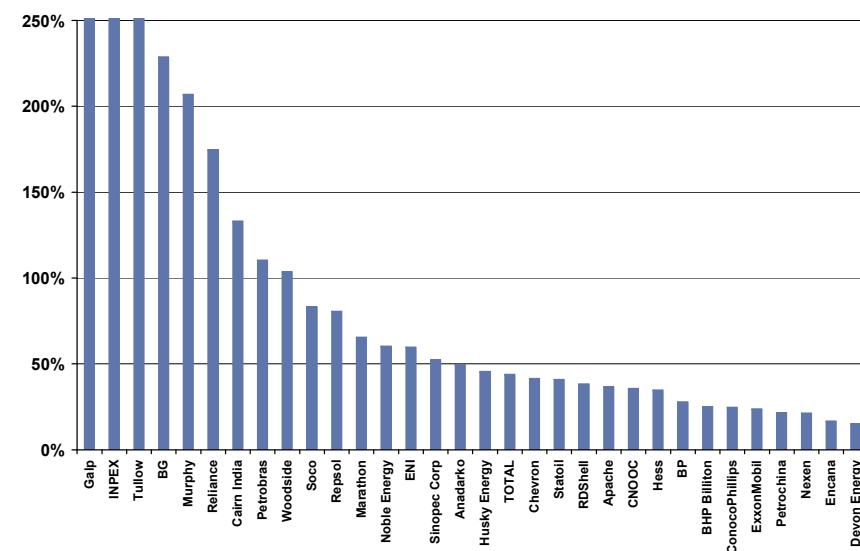
NPV of discovered hydrocarbon resources at the time of discovery as a % of EV



Source: Goldman Sachs Research estimates.

Exhibit 17: Reserves added through exploration since 2000

Discovered hydrocarbon resources as a % of corporate 2008 SEC reserves



y-axis limited to 250%. Galp = 8643%, INPEX + 316%, Tullow + 336%

Source: Goldman Sachs Research estimates.

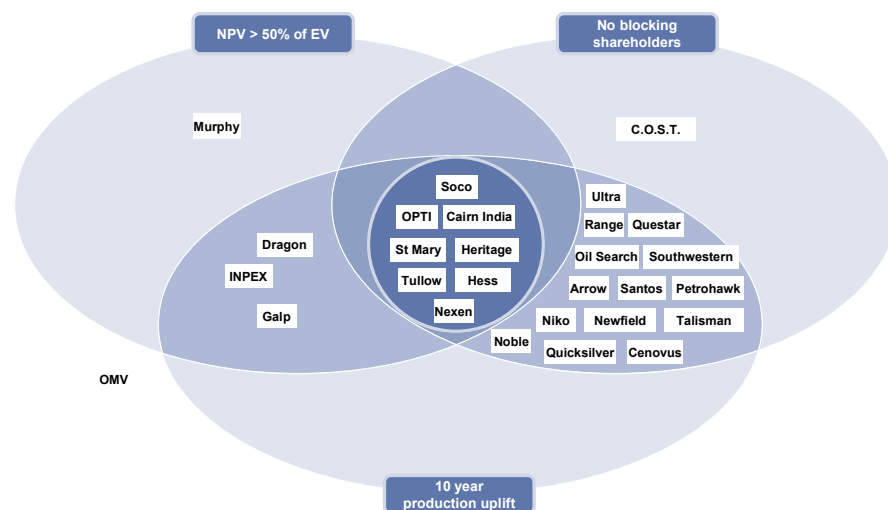
M&A around Top 280 assets is a likely outcome of poor exploration success

We believe that the Top 280 assets are strategically desirable and could provide an acquirer with strategic growth prospects. As such, we believe that smaller companies which have stakes in these assets could attract M&A attention in the future. We have screened the Top 280 to identify attractive targets using the following criteria:

- **Size:** We restrict our potential targets to those companies with an enterprise value below US\$25 bn.
- **Viability:** We exclude companies which are not publicly listed or have what we consider to be a blocking shareholder.
- **Materiality:** The Top 280 portfolio should account for at least 50% of the company's EV assuming an 8% discount rate.
- **Growth:** We exclude companies whose Top 280 net entitlement growth does not provide at least a 10% uplift to current production between 2010E and 2020E.

On this basis, Tullow, Soco, Cairn India, OPTI (not covered), Hess, Heritage, Nexen and St Mary Land & Exploration (not covered) screen attractively although we note that the Indian government could block NOC purchases of Cairn India. Of the companies whose EVs are over US\$25 bn, OGX and BG also screen attractively.

Exhibit 18: M&A screen of Top 280 companies



Source: Goldman Sachs Research estimates (when calculating production uplift for non-covered companies we use annual reports / SEC filings and use 2008 reported production figures).

Exhibit 19: M&A data for companies with EV under US\$25 bn

Company	NPV of Top 280 as % EV at 8% cost of capital	PI of Top 280	Net entitlement Top 280 reserves	Top 230 10 year production uplift as % of 2009 production	Blocking shareholder?
Heritage	219%	2.94x	124	915%	No
Soco	97%	3.50x	84	377%	No
OPTI Canada	199%	1.46x	871	525%	No
Dragon Oil	196%	2.30x	319	20%	Yes
St Mary Land & Exploration	78%	1.98x	542	79%	No
Arrow Energy	13%	1.58x	152	314%	No
Niko Resources	31%	2.00x	189	37%	No
Quicksilver Resources	7%	1.32x	150	33%	No
Oil Search	23%	1.59x	307	154%	No
Newfield	26%	1.98x	574	11%	No
Ultra Petroleum	27%	1.30x	1530	128%	No
Range Resources	36%	1.84x	764	213%	No
Petrohawk	42%	1.62x	846	177%	No
Questar	15%	1.30x	923	75%	No
Santos	34%	1.45x	1178	64%	No
Murphy	58%	2.04x	399	-2%	Yes
Cairn India	81%	3.37x	387	298%	No
Noble Energy	24%	2.33x	585	27%	No
Canadian Oil Sands Trust	30%	1.30x	419	1%	No
Tullow	63%	2.70x	593	222%	No
Nexen	110%	1.83x	2256	35%	No
OMV	8%	2.29x	86	4%	Yes
Southwestern Energy	27%	1.51x	1284	64%	No
Galp	50%	1.81x	2420	1808%	Yes
INPEX	93%	1.59x	3548	82%	Yes
Hess	59%	1.66x	1083	18%	No
Talisman	16%	1.69x	678	29%	No
Cenovus	29%	1.96x	1536	48%	No

Source: Goldman Sachs Research estimates, Bloomberg (when calculating production uplift for non-covered companies we use annual reports / SEC filings and use 2008 reported production figures).

Putting together exploration and delivery: BG is the clear winner

Exhibit 20 summarizes the positioning of each company which has at least five operated assets in this report on three key metrics of success:

- **Exploration** success measures the value added through exploration and is ordered in quartiles. BG and Petrobras are the key winners, followed by Chevron. Exxon and ENI look poor in comparison. (Exhibits 16 & 17)
- **Long-term delivery** measures how much of the expected volumes were delivered (or are expected to be delivered) five years after the publication of each of the past six editions of this report. This measure mainly captures the ability of companies to move projects forward from exploration into FID and then into production. Statoil, BG, BP and Exxon score consistently well. TOTAL and Conoco have been disappointing, while Shell, ENI and Petrobras have recovered from a disappointing performance.
- **Short-term delivery** measures how much of the expected volumes were delivered (or are expected to be delivered) two years after the publication of each of the past six editions of this report. This measure mainly captures the ability of companies to deliver the project from FID to production. BG and Exxon score consistently well. Petrobras and Conoco have been disappointing, while Statoil, BP and Chevron have recovered from a disappointing performance.

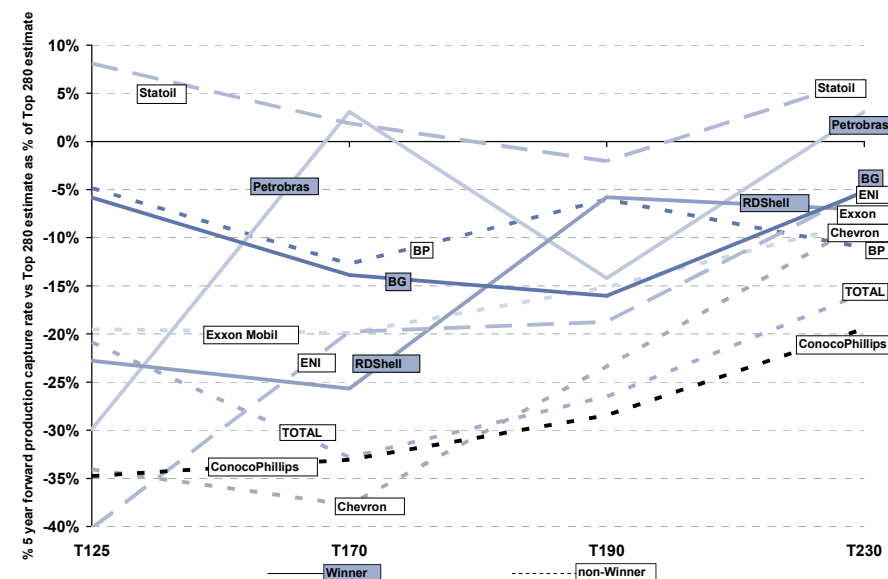
BG is the only company globally that scores well in all three metrics. Ranked behind BG are Chevron, Petrobras and Exxon. ENI, Conoco and TOTAL scores tend to be on the weaker side.

Exhibit 20: Summary of positioning on delivery and exploration success

Short-term delivery:	Poor	Improving from low base	Average	Strong
	Conoco Petrobras	Statoil BP Chevron	Shell TOTAL ENI	BG Exxon
Long-term delivery:	Poor	Improving from low base	Average	Strong
	TOTAL Conoco	Shell ENI Petrobras	Chevron	Statoil BG BP Exxon
Exploration quartile:	Q4	Q3	Q2	Q1
	Exxon ENI	TOTAL Conoco Statoil Shell BP	Chevron	BG Petrobras

Source: Goldman Sachs Research estimates.

Exhibit 21: Production capture rate of operators – five-year capture
100% of working interest operated production



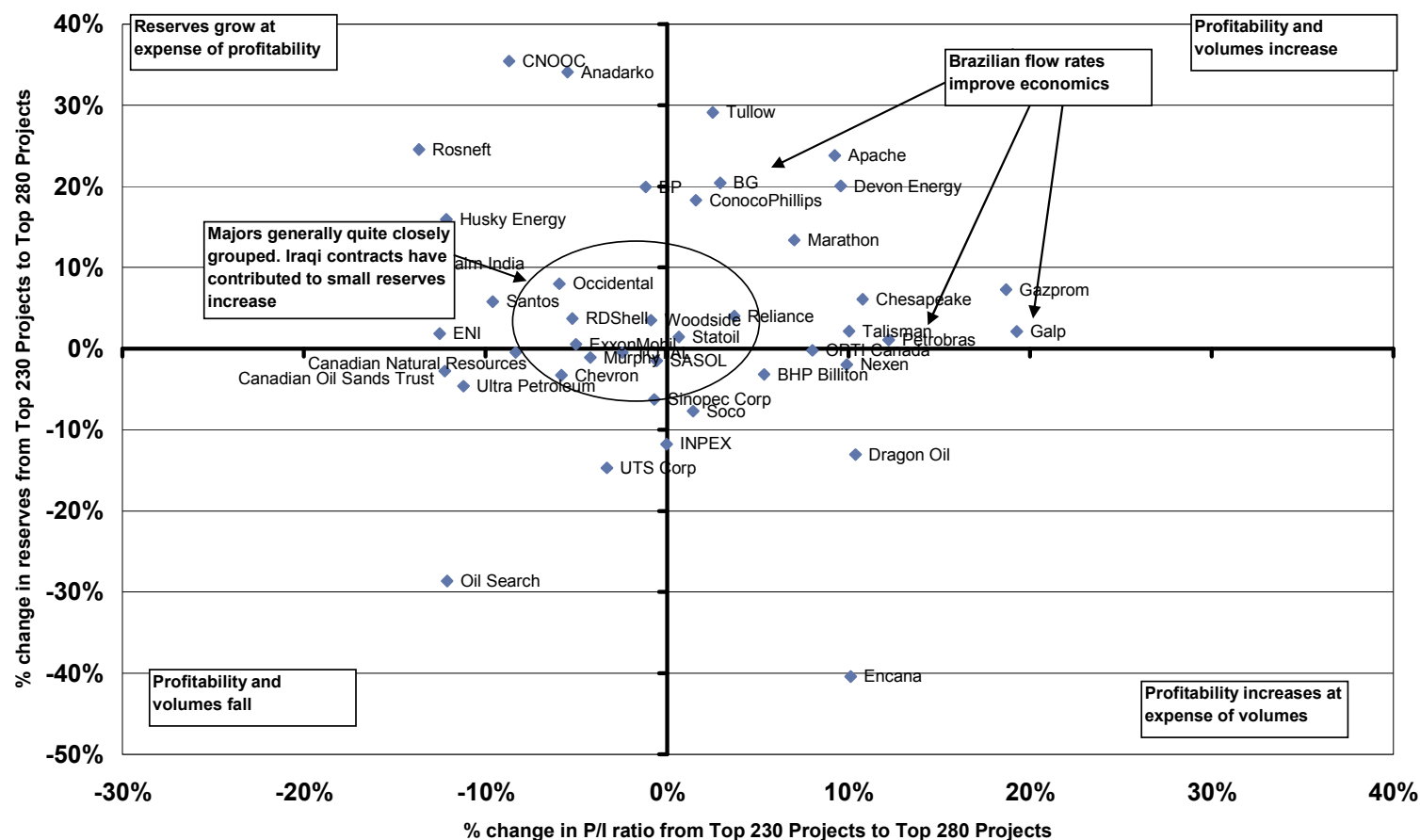
Source: Goldman Sachs Research estimates.

Brazil the major driver of valuable growth among the larger players

Among the larger players, those with exposure to Brazil have seen a strong increase in profitability growth between Top 230 and Top 280, thanks to the stronger-than-expected flow rates, with Galp, Petrobras and BG all performing well. Exploration success in West Africa is helping Anadarko and Tullow to increase reserve size, without sacrificing profitability.

The Majors are fairly closely grouped although BP has performed well in adding reserves mainly through GoM exploration and Russian greenfield projects, and Conoco has improved thanks to exploration success, e.g. the Poseidon discovery. ENI has seen a large deterioration in profitability without a consequent increase in reserve size.

Exhibit 22: The change in scale and profitability of company portfolios from Top 230 to Top 280 (excluding fields at plateau)



X-axis limited to 40%. Increases off scale are: Hess (reserves +49%, P/I +1%), PetroChina (+58%, -4%), Lukoil (+60%, -23%), Suncor (+108%, +29%), EOG (+110%, +10%), Repsol (+182%, +4%) and Noble (+388%, +61%)

Source: Company data, Goldman Sachs Research estimates.

Picking winners in the Top 280 Projects

We pick the winners in this report on three key metrics that reflect the materiality of their exposure, and the cash flow and production uplift from their Top 280 Projects in the short term (two years) and medium term (five years). In terms of materiality we require that the NPV of the Top 280 portfolio represents more than half of the company's enterprise value. The short-term cash flow uplift needs to be over 20% in the next two years and over 40% over the next five years while we require a production uplift of over 10% in two years and over 30% over the next five years.

Companies grouped according to their relative exposure

We have grouped the companies from our coverage universe, relative to their respective peers, into five categories on the quality of their new legacy asset portfolios:

- **Winners:** Our key picks of all companies with respect to new legacy asset exposure. We believe these companies have high return portfolios which will significantly impact corporate cash flows in the near term
- **Short-term exposure:** Companies that have portfolios which we believe will impact corporate cash flows in the near term
- **Long-term exposure:** Companies that have portfolios which we believe will impact corporate cash flows in the longer term
- **Limited exposure:** Companies whose Top 280 Projects NPV accounts for less than 30% of the current enterprise value
- **Single asset play:** Companies that own stakes in fewer than three fields, but the NPV of these stakes accounts for more than 50% of the company's EV

Exhibit 23: Top 280 Projects investable company rankings

	Winners	Long term exposure	Short term exposure	Limited exposure	Single asset play
Europeans	RDSHELL, BG, Galp	Total, ENI	BP, Statoil	Repsol	
US			Chevron, ConocoPhillips, Marathon, Hess	Exxon, Suncor, Anadarko, Occidental, Noble Energy, Apache	
Canadians				EnCana, Talisman	Canadian Natural Resources
Emerging Markets	Petrobras	PTTEP, Gazprom		PetroChina, CNOOC, ONGC, Rosneft	
E&Ps	Tullow, Woodside			Santos	Cairn India, Dragon Oil, Soco

Source: Company data, Goldman Sachs Research estimates.

Winners in more detail

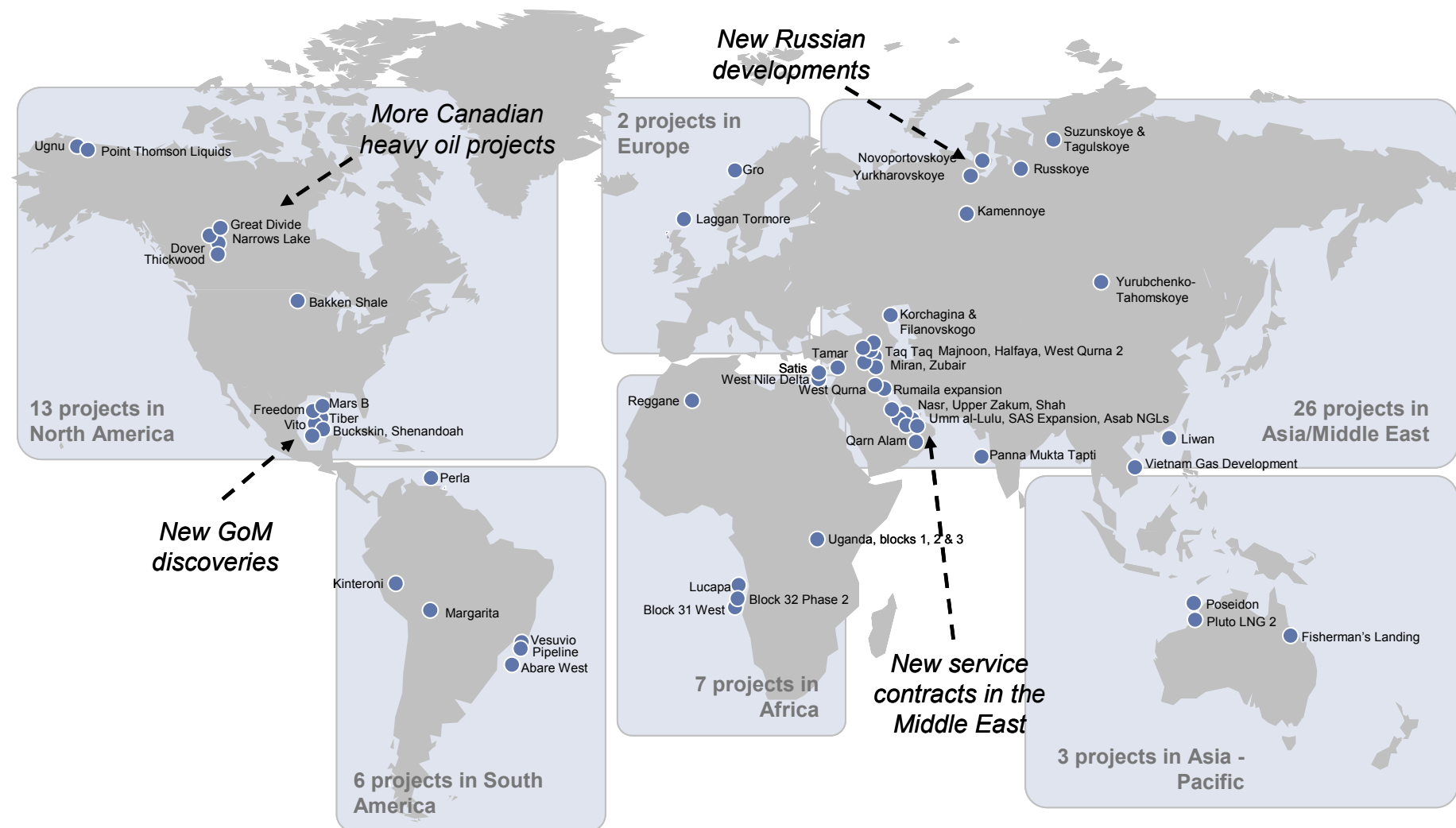
We have ranked BG, RDSH, Tullow, Petrobras, Galp and Woodside as “Winners” for the following reasons:

- **BG:** A high return, high impact portfolio that we believe will underpin sector-leading growth for the next decade. The transformational story is driven by LNG in Australia (Curtis) and by pre-salt Santos basin assets in Brazil. We believe that Brazil has scope for reserve additions and that the quality of the reservoirs in the area could make economics very attractive.
- **RDSH:** A potentially transformational story based on large stakes in giant and technologically challenging, but generally low decline, fields. These fields started to come onstream in 2009 and accelerate in the 2010-12E period, at a time when few other companies offer good volume growth. We believe fiscal regimes and realizations should mean that cash flows benefit disproportionately vs. volumes. RDSH's five largest new projects (Pearl GTL, Perdido, Sakhalin 2, Qatargas 4 and Kashagan) could add US\$8.5 bn post-tax cash flow to RDSH by 2013E on our normalized US\$85/bl oil price assumption.
- **Petrobras:** The deepwater leader with an advantaged licence position offshore Brazil, an enormous reserve base in the pre-salt Santos basin and very large exploration upside potential. In our view Petrobras has high profitability and materiality, high oil price exposure and a balanced portfolio of growth with visibility over the next 10-20 years; initial flow rate data from the pre-salt Santos basin bode well for project economics in the area.
- **Tullow:** Exceptional exploration success, particularly in Uganda and Ghana, have provided Tullow with a transformational growth portfolio. We also believe there is potential upside in the company's exploration portfolio in its Ugandan and West African acreage. Development of Jubilee has been quick by global standards, effectively translating exploration success into cash flow.
- **Galp:** On a similar theme to Petrobras, Galp offers highly levered exposure to the world-class pre-salt Santos play. We expect the near term cash flow uplift from Tupi to be transformational with Iara providing medium-term support and Jupiter a longer dated story in our view. Current production and a further cash flow uptick is provided by the company's Angolan portfolio.
- **Woodside:** A leveraged play on Australian LNG – an area which we believe could be as important for global hydrocarbon supply as Brazil will be for oil. The first train at Pluto is likely to provide transformational growth from 2011 on our estimates, with additional assets such as Greater Sunrise, Browse and a second train at Pluto providing longer dated potential.

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Introducing the projects – the additions

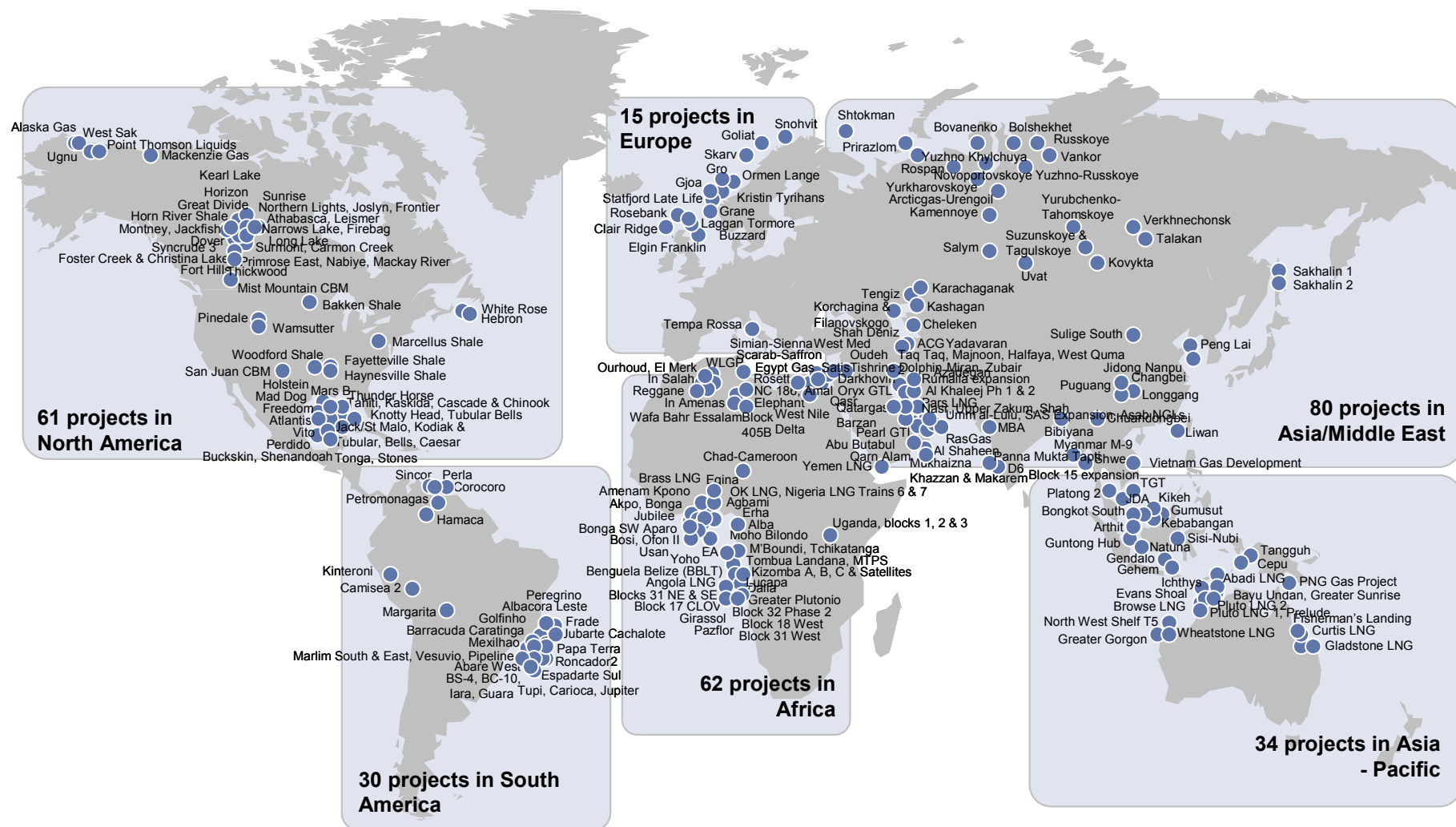
Exhibit 24: Map of the 57 new fields in the data set



Source: Company data, Goldman Sachs Research.

The Top 280 Projects

Exhibit 25: Map of the Top 280 Projects



Source: Goldman Sachs Research.

The Top 280 Projects are key to the development of the global oil & gas industry

We define legacy assets as those which represent a material profit centre for the industry with potential for expansion and provision of long-term reserve and production growth. We believe that the Top 280 Projects are true legacy assets for the oil and gas industry in terms of materiality, size of investment and profitability, and offer material opportunities for future growth.

The average project size is over 1.5 bnboe (split 55% oil and 45% gas), based on our estimates of proved plus probable (2P) reserves with an average expected reserve life (or duration) of 33 years. In total this represents a reserve life of over nine years at the current global rate of hydrocarbon production, meaning that we believe these projects will have lasting significance for the industry. There are 173 companies (including state-owned, public, private and National Oil Companies) included in the study with the average project stake being 32%, implying three partners on average per project. The average investment per company per project now stands at c.US\$3.3 bn – highlighting the importance of good execution and cost control on such major investments.

The average investment per project now stands at c.US\$10 bn. Despite this, unit upstream capital costs at c.US\$5.4/bl (US\$6.8/bl including infrastructure) remain very attractive relative to industry non-legacy assets – a reflection of the efficiencies that can be achieved through scale and a slight drop on a unit basis from the last edition of this report.

We have kept our long-term oil price assumptions flat since the publication of Top 230 in February 2009, but the NPV per barrel has dropped slightly on a reserves-weighted basis as we include a number of mega-projects (primarily in Iraq and UAE) with harsh fiscal terms that result in a lower value being accorded to the stakeholders. Nevertheless, returns are impressive with an average IRR of 21% from the Top 280 Projects as a whole, with a profit/investment (value creation) ratio of 1.8 at an 8% discount rate implying that the industry can create significant value over the long term from these investments. It is worth bearing in mind that relative to some smaller fields outside the scope of this report, the NPV is low – a function of long duration and significant upfront infrastructure investment which results in the average project at point of first investment being valued at only US\$2.7/boe at an 8% cost of capital.

Exhibit 26: Average Top 280 Projects statistics

Key Top 280 Projects average statistics per project					
Materiality		Investment		Profitability	
Field size	1524 mn boe	Total capex	US\$10,308 mn	IRR	20.7%
Duration	33 years	Infrastructure capex	US\$2,116 mn	P/I	1.81x
Company stake per project	32%	Upstream F&D cost	US\$5.4/bl	NPV _{life of field}	US\$2.7/bl
Peak Production	222 kboe/d	All-in capex per barrel	US\$6.8/bl	NPV ₂₀₁₀	US\$4.6/bl

Source: Goldman Sachs Research estimates.

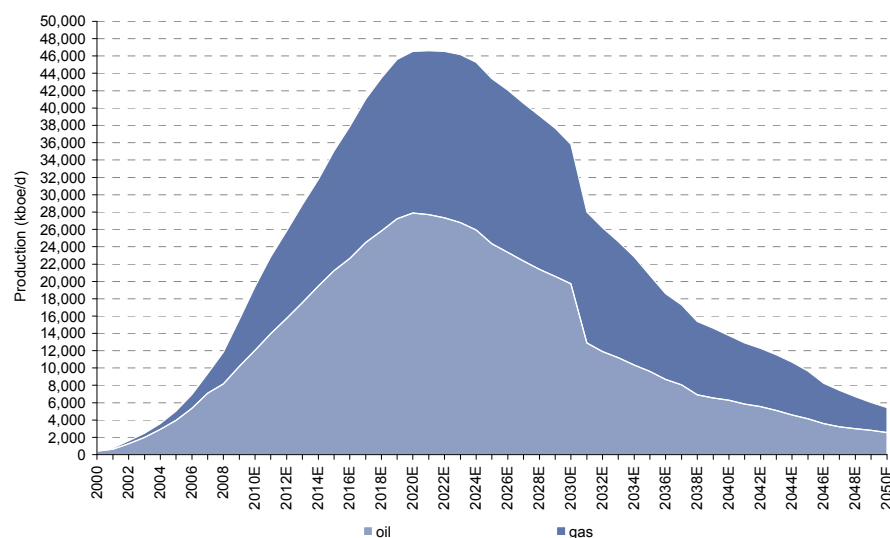
Top 280 projects at peak will account for c.36% of the global oil & gas supply

Over 46 mnboe/d modelled by 2020E – but peak moves back again

We expect the Top 280 Projects to deliver a peak production rate of c.46 mnboe/d of oil and gas by 2020E (up from 37 mnboe/d in 2019E in Top 230 Projects). Although there is clearly a significant quantity of oil and gas waiting to be developed (238 bnbls of oil and 192 bnboe of gas) we believe that the challenge for the industry in the near term will be translating these reserves into production.

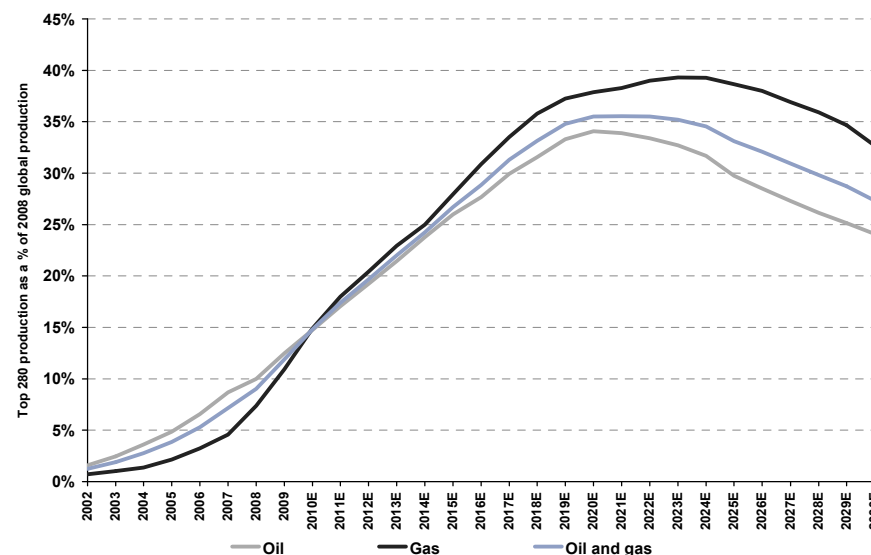
Peak oil production of 28 mnboe/d in 2020E would represent c.34% of current world oil production and peak gas production of 19 mnboe/d in 2023E would represent c.39% of current world gas production.

Exhibit 27: Top 280 Projects oil and gas production profile



Source: Goldman Sachs Research estimates.

Exhibit 28: Top 280 Projects production relative to 2008 global production



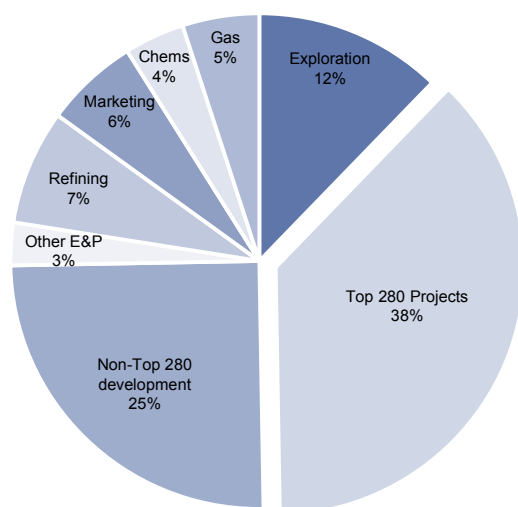
Source: Goldman Sachs Research estimates, BP Statistical Review 2009.

Top 280 is a key driver of growth: Represents almost 50% of the Majors' E&P capex

We believe that the Top 280 projects will represent a major element of the Majors' upcoming capital spend. We expect the Majors to invest almost US\$600 bn in the coming four years across all their businesses and believe that 77% of this will be on upstream. Exploration accounts for 12% of the total spend with the remainder of the upstream capex dedicated to developments. On our estimates, we believe that over these four years, US\$225 bn, almost half of the total upstream capex, will be dedicated to the Top 280 projects alone. Other upstream development accounts for US\$150 bn, and other E&P (infrastructure projects and any other E&P activities excluded from FAS 69 disclosure) for US\$15 bn. Spending on R&M, chemicals and gas and power accounts for the remainder.

When maintenance capex is stripped out, the incremental importance of the Top 280 Projects becomes still more apparent. We estimate that 44% of the group's total capex will be focused on 'growth' projects. We estimate the spending on the Top 280 assets that are not currently producing will account for 63% of this 'growth' spend over the next five years and 80% of the total E&P growth capex.

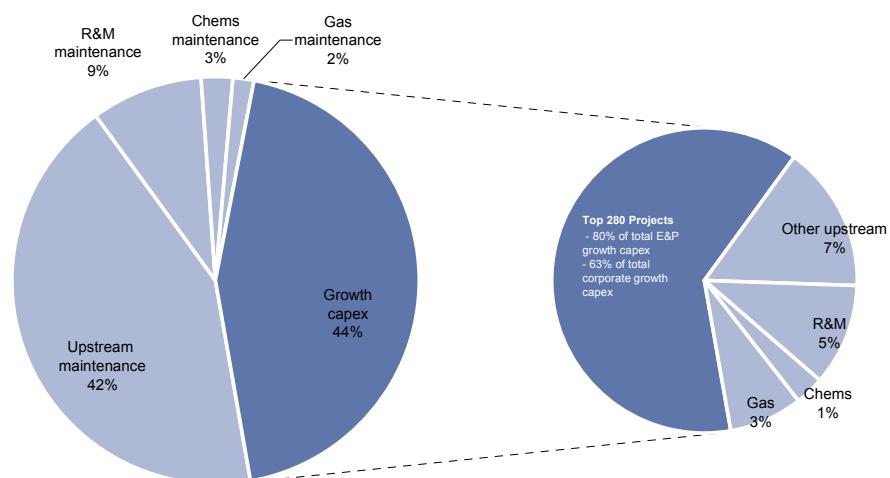
Exhibit 29: Top 280 capex as a percentage of Majors' total capex



The Majors include BP, Chevron, ConocoPhillips, ENI, Exxon, RDSHELL and TOTAL.

Source: Goldman Sachs Research estimates.

Exhibit 30: Top 280 spend as a percentage of growth capex



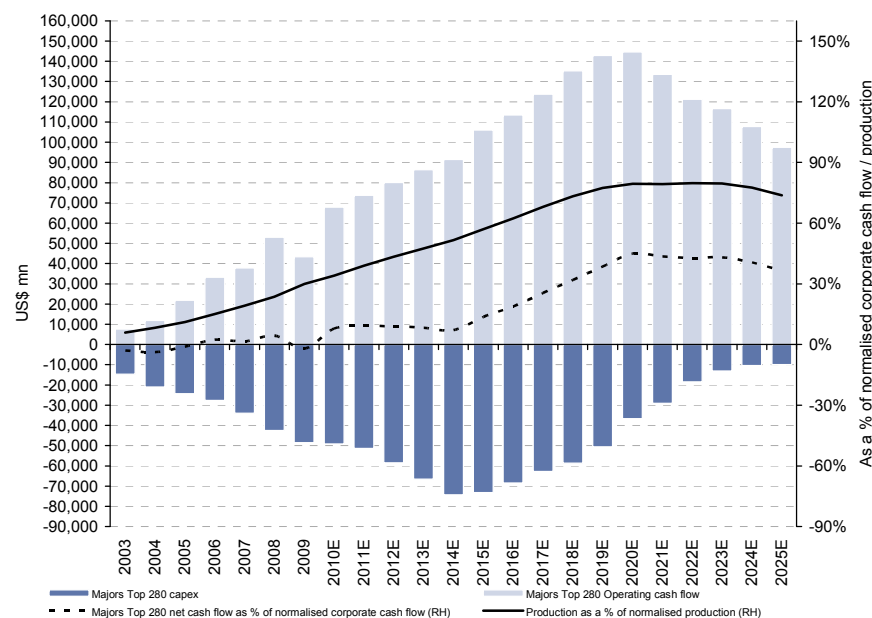
Source: Goldman Sachs Research estimates.

Top 280 projects are a very material element of the Majors' portfolios and are key in prolonging reserve lives

We estimate that the Top 280 projects will generate substantial cash inflows and outflows for the Majors. In total we believe that cash inflows will peak at nearly c.US\$145 bn in 2020E, with capex peaking at c.US\$75 bn by 2014E. At their 2023E peak, we expect these projects to contribute almost 80% of our 2013E production estimate for the Majors and 46% of the operational cash flow.

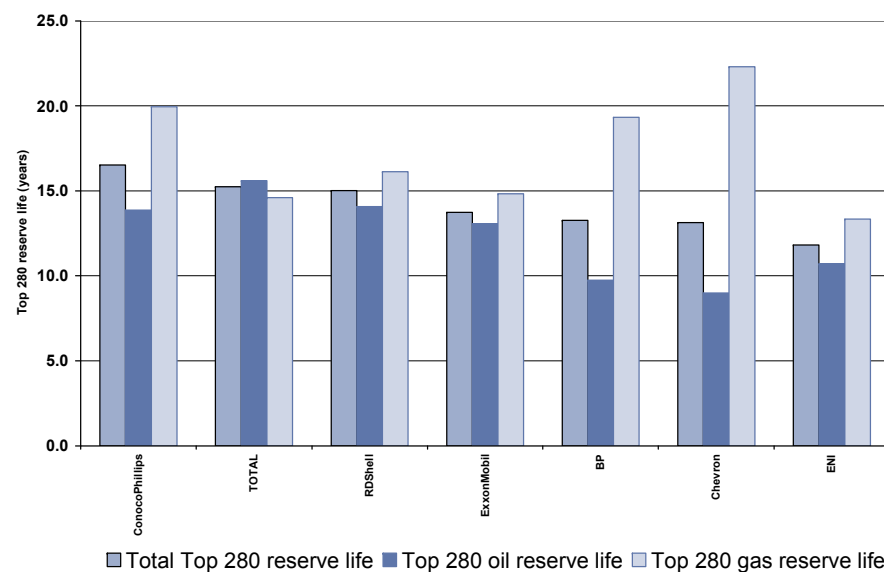
We believe that the Top 280 portfolios of the Majors have an average reserve life of just over 14 years (17 years in gas and 12 years in oil), and in all cases (except for Exxon) the total hydrocarbon reserves are in excess of the currently booked reserves (although we note that there is some overlap between them). Conoco has the greatest Top 280 reserve life; ENI has the shortest Top 280 reserve life at less than 12 years. Although the gas reserve lives of the Majors' Top 280 portfolios are generally longer than the oil reserve lives, in the cases of Shell, Conoco and Chevron in particular, we do not believe that this will result in a loss in oil price leverage as many of the gas reserves are LNG which we believe will ultimately be driven by the oil price.

Exhibit 31: Net cash flow for Majors from Top 280 Projects



Source: Goldman Sachs Research estimates.

Exhibit 32: Majors' Top 280 reserve life

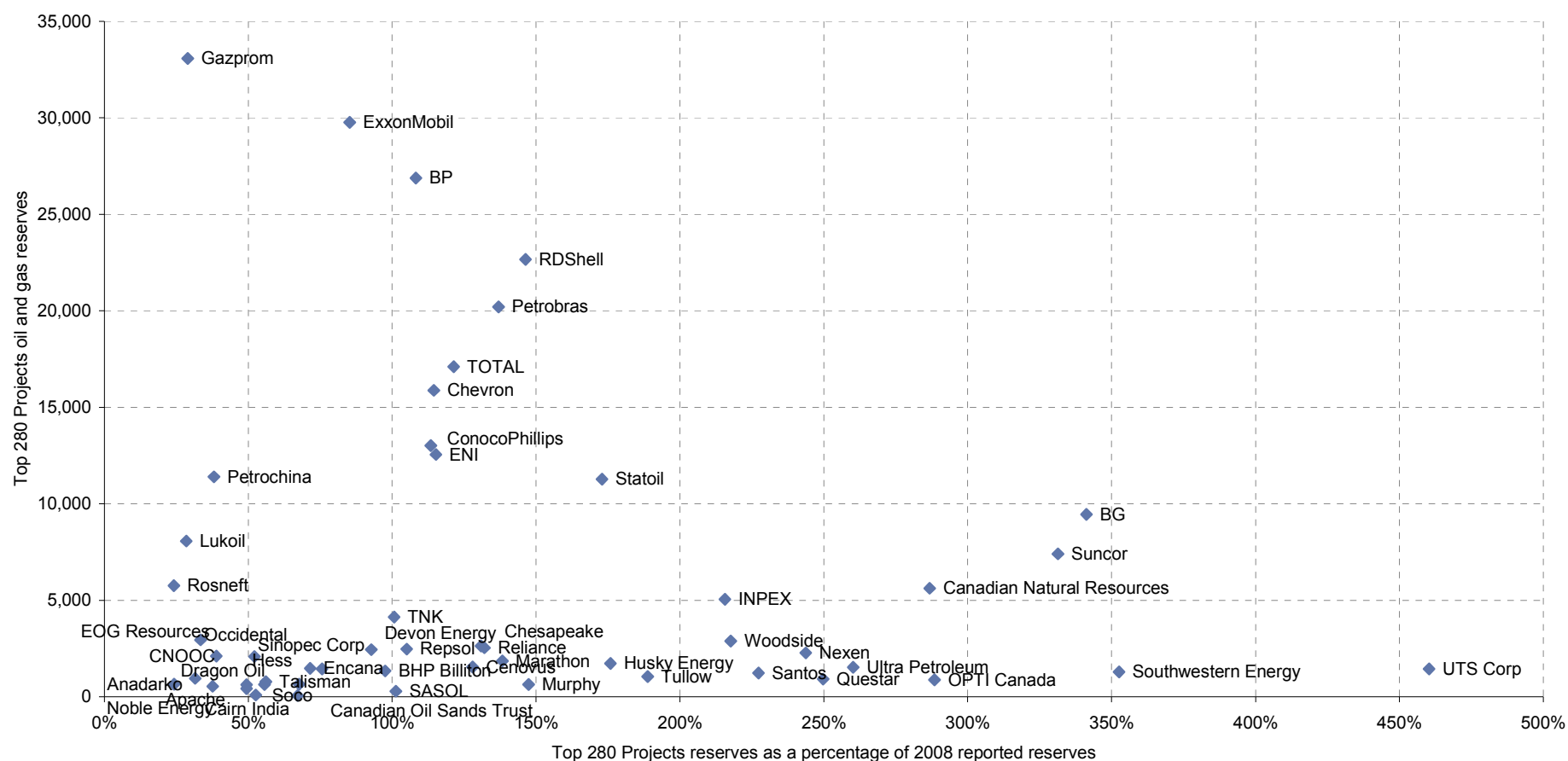


Source: Goldman Sachs Research estimates.

Companies and materiality: BG the most exposed of the larger players

Given the scope of the Top 280 projects' reserves and investment, it is unsurprising that Top 280 is likely to drive reserve replacement in the industry. We believe that these projects will ultimately be the base from which companies are able to generate growth in the medium to long term and that exposure to these assets is beneficial. Of the larger companies, BG's success in Brazil and Queensland Curtis LNG means that it leads the larger companies in terms of relative exposure, thereby giving confidence over the viability of the company's long-term growth; we expect this relative lead over the other majors to begin to diminish as more reserves from Brazil are booked. The Majors are closely grouped but Statoil is slightly advantaged. Repsol lagged last year but due to success in Brazil and the inclusion of a number of Latin American gas projects, it is close to the other Majors in terms of its Top 280 reserves as a percentage of most recently booked reserves.

Exhibit 33: Reserves exposure to the Top 280 Projects by company



Source: Company data, Goldman Sachs Research estimates.

Sanctioning to continue 2H09 pick-up after recent low activity; Iraq a potential step change

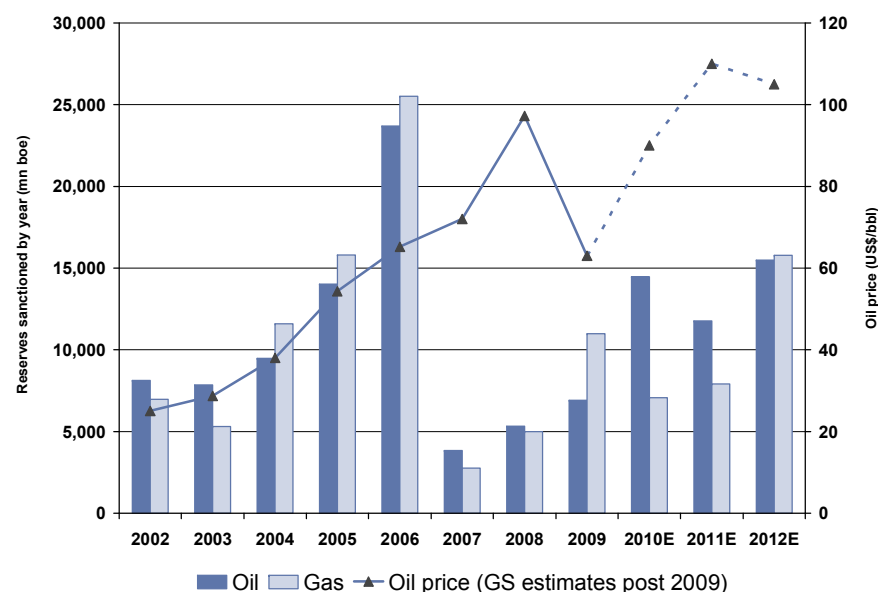
In 2007 and 2008 combined, only 20 project phases were sanctioned from the Top 280 – fewer than the projects sanctioned individually in 2006 (21) or 2005 (26). We believe that this sharp decline in activity was caused by a number of factors: 1) Rising costs and volatility in costs required changes in project scope and plans or resulted in re-tenders (Block 17 CLOV and Pazflor). 2) the increase in oil prices in regions with attractive PSCs has led to renegotiations of existing contracts, with governments delaying approval of new projects until the existing contracts had been changed (i.e. Kazakhstan, Libya, Nigeria). 3) Administrative difficulties in processing development plans under volatile oil prices, especially in countries with relatively small bureaucracies (i.e. Angola). In the first half of 2009 we believe that the low oil price and tight credit markets made sanctioning hard with activity picking up in the second half (from projects such as Gorgon, PNG, TGT) as oil prices stabilized somewhat.

Over the next few years we expect sanctioning activity to continue as: 1) the recent lack of sanctions means that companies have completed FEED on a number of projects which provide a portfolio of ready-to-go projects; 2) the will to sanction projects has increased as the lack of sanctions in the last three years increasingly puts pressure on production targets; 3) industry costs look to have bottomed; and 4) a large number of projects look to be economically viable at our assumed hurdle rates and at oil prices substantially lower than our long-term estimate of US\$85/bl and the current forward curve.

We believe that Iraqi service contracts could result in a step change in terms of sanctioning, meaning that execution of these projects becomes an important consideration in assessing medium to long term supply.

Exhibit 34: Oil and gas reserves sanctioned by year

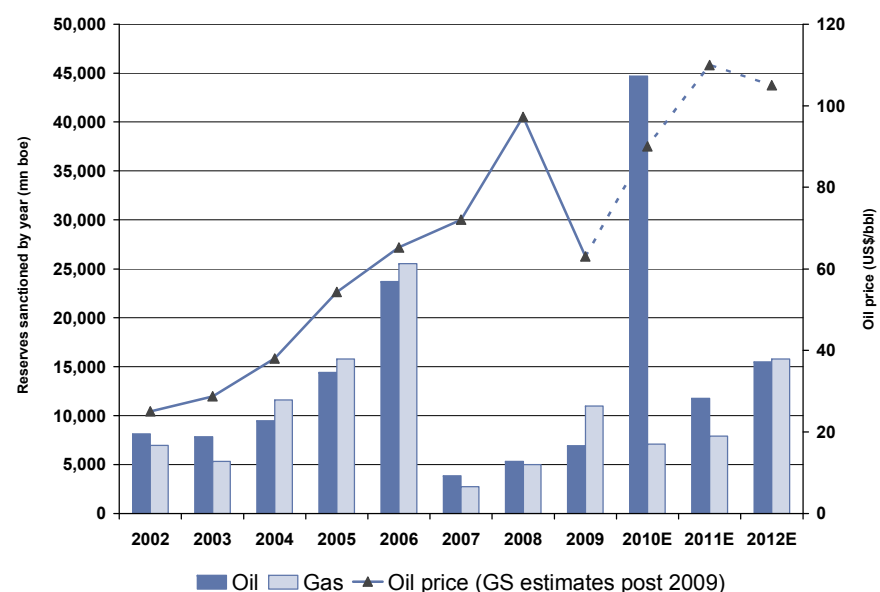
Excludes expected Iraqi sanctions



Source: Goldman Sachs Research estimates.

Exhibit 35: Iraqi contracts to lead to substantial level of sanctioned reserves

Includes expected Iraqi sanctions



Source: Goldman Sachs Research estimates.

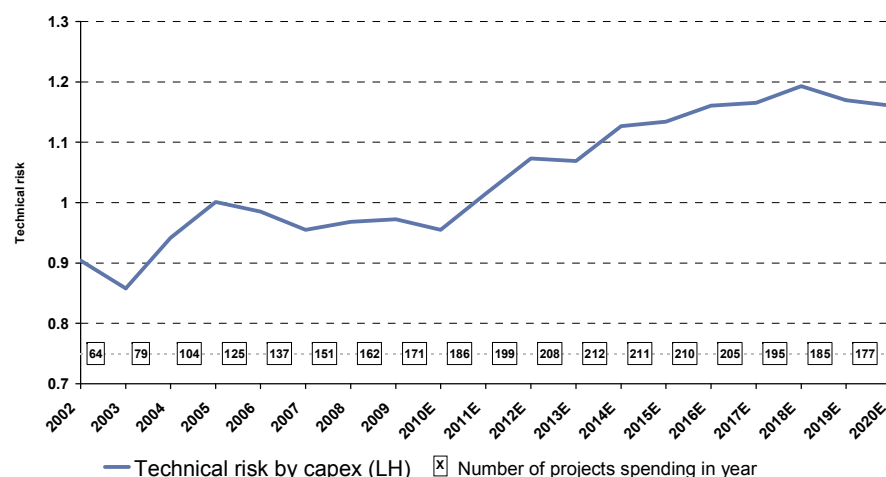
Technical complexity set to increase, risk to future supply

Although we believe the market perception is that of increasing technological complexity in the upstream sector, we do not believe that there has been a substantial increase in the level of technical risk to date. The capex on technically complex projects was relatively high in the early part of the decade as money was spent in the Caspian where large pipelines, HPHT reservoirs and high sulphur were issues. In deepwater, with a small number of exceptions, water depths have consistently been in the region of 1,500m. To date, only Perdido, Cascade/Chinook and Tupi from our Top 280 database, have been sanctioned in water depths of greater than 2,000m. We do not believe, therefore, that the increase in technical complexity was a significant reason for the project delays in the past five years.

Beyond 2010E, however, we expect a steep increase in technical risk. We expect the deepwater industry to move into a substantially more technically challenging environment as fields under salt layers and in water depths well in excess of 2,000m (such as the Lower Tertiary plays in GoM and in pre-salt Brazil) become major contributors. Individual fields with high complexity such as Shtokman, Kashagan and the Shah gas field, will also feature heavily while the increasing trend towards production from win zones such as LNG and unconventional assets – at the expense of traditional fields – will further increase the risk profile.

On our analysis, as technical risks increase, development time between sanction and first oil/gas also increases (Exhibit 37). As a result, we believe that increasing technical risk is likely to result in longer periods between sanction and first production. Given the lack of sanctions in the 2007 – 1H 2009 period, this is likely to be an additional downside risk to supply.

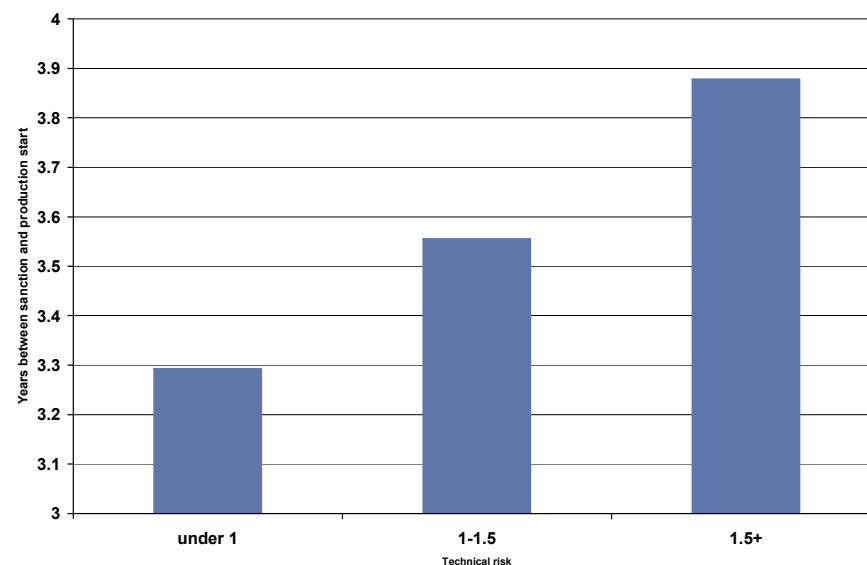
Exhibit 36: Technical risk of Top 280 projects weighted by capex



Source: Goldman Sachs Research estimates.

Exhibit 37: Technical risk influences development lead time

Excludes unconventional gas



Source: Goldman Sachs Research estimates.

Non-OPEC supply will be disappointing, with fewer big projects and higher decline rates

We forecast non-OPEC oil supply by modelling the decline rates of the production base by region and adding to this our forecasts of production from the Top 280 fields. Our analysis (Exhibit 38) leads us to conclude that non-OPEC production is likely to be declining again this year, after the 2009 uptick, and this decline is likely to get steeper in 2011-13. This increasing decline reflects a lack of major new project start-ups in 2010-13, and an increase in decline rates consistent with recent trends in the industry (and with 2009 capex cuts on the production base). The final outcome could be worse if the industry does not deliver its new projects in line with our expectations that have tended to prove optimistic in the past six editions of this report.

Exhibit 38: Non-OPEC production on our estimates will decline even with no delivery problems

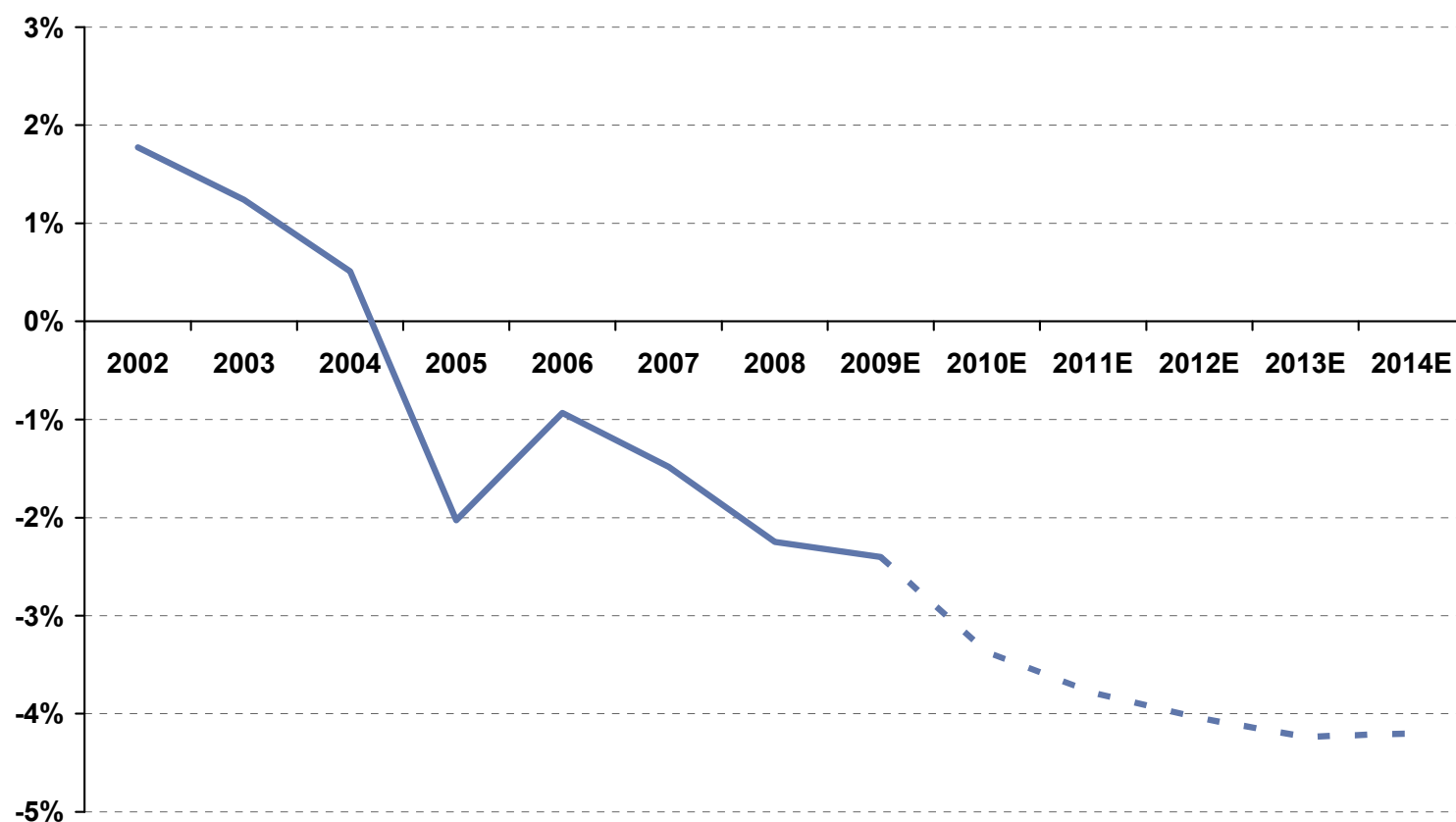
Production ex-Top280 growth/(decline)	2002	2003	2004	2005	2006	2007	2008	2009E	2010E	2011E	2012E	2013E	2014E
Russia	10%	11%	9%	2%	1%	0%	-1%	-1%	-2%	-3%	-4%	-5%	-5%
US	0%	-3%	-2%	-6%	0%	1%	-2%	2%	-2%	-3%	-3%	-3%	-3%
Canada	5%	2%	1%	-3%	1%	1%	-4%	-8%	-6%	-6%	-6%	-6%	-6%
Mexico	1%	6%	1%	-2%	-2%	-6%	-9%	-6%	-7%	-7%	-7%	-7%	-7%
Western Europe	-2%	-4%	-5%	-8%	-9%	-8%	-6%	-7%	-8%	-8%	-8%	-8%	-8%
Caspian	6%	10%	9%	6%	-5%	4%	-4%	3%	-2%	-2%	-2%	-2%	-2%
Australasia	1%	-2%	0%	0%	1%	0%	0%	-2%	-2%	-2%	-2%	-2%	-2%
Africa	1%	0%	5%	2%	2%	1%	-2%	-7%	-4%	-4%	-4%	-4%	-4%
Middle East ex-OPEC	-2%	0%	-5%	-4%	-4%	-5%	-2%	-2%	-4%	-4%	-4%	-4%	-4%
Latin America	2%	1%	-3%	-2%	0%	-2%	4%	-1%	-3%	-3%	-3%	-3%	-3%
Total	2%	1%	1%	-2%	-1%	-1%	-2%	-2%	-3%	-4%	-4%	-4%	-4%
Top280 production (kbls/d)													
Russia	30	61	107	161	238	497	555	885	1,184	1,295	1,460	1,697	1,959
US	2	8	26	131	155	200	351	757	1,010	1,167	1,278	1,312	1,355
Canada	10	83	160	200	309	403	433	538	700	937	1,087	1,208	1,479
Mexico	0	0	0	0	0	0	0	0	0	0	0	0	0
Western Europe	135	148	251	307	402	551	588	576	601	628	639	661	633
Caspian	504	512	564	644	962	1,203	1,355	1,597	1,713	1,759	1,790	1,966	2,086
Australasia	28	54	99	157	154	169	265	390	566	706	970	1,159	1,246
Africa	2	35	220	223	240	260	306	351	388	492	534	574	667
Middle East ex-OPEC	0	0	1	2	16	34	59	99	152	201	245	267	289
Latin America	105	137	189	455	577	716	773	980	1,200	1,490	1,793	2,076	2,382
Total	816	1,038	1,618	2,279	3,054	4,032	4,685	6,172	7,514	8,675	9,796	10,920	12,097
Total production (kbls/d)													
Russia	7,726	8,575	9,365	9,627	9,843	10,078	10,005	10,204	10,316	10,154	9,964	9,776	9,634
US	8,042	7,828	7,654	7,321	7,375	7,482	7,523	8,049	8,157	8,099	8,002	7,835	7,682
Canada	2,858	2,996	3,089	3,054	3,192	3,315	3,224	3,117	3,124	3,216	3,229	3,222	3,372
Mexico	3,585	3,789	3,825	3,760	3,682	3,477	3,164	2,966	2,758	2,565	2,386	2,219	2,063
Western Europe	6,971	6,690	6,447	5,984	5,591	5,312	5,066	4,741	4,434	4,154	3,882	3,645	3,379
Caspian	1,611	1,727	1,888	2,052	2,294	2,585	2,677	2,960	3,049	3,068	3,073	3,224	3,318
Australasia	7,969	7,839	7,896	7,949	8,014	8,024	8,097	8,064	8,117	8,106	8,192	8,208	8,126
Africa	2,098	2,132	2,420	2,456	2,522	2,574	2,563	2,459	2,412	2,434	2,399	2,365	2,386
Middle East ex-OPEC	2,638	2,647	2,515	2,420	2,329	2,227	2,210	2,213	2,182	2,149	2,115	2,063	2,013
Latin America	3,552	3,624	3,566	3,750	3,877	3,946	4,131	4,318	4,438	4,631	4,839	5,031	5,248
Total processing gains	1,303	1,339	1,386	1,467	1,709	1,861	2,032	2,032	2,032	2,032	2,032	2,032	2,032
	48,353	49,186	50,051	49,840	50,428	50,881	50,692	51,123	51,018	50,608	50,114	49,617	49,253
	2,437	833	865	-211	588	453	-189	431	-105	-410	-494	-497	-365
	5.3%	1.7%	1.8%	-0.4%	1.2%	0.9%	-0.4%	0.9%	-0.2%	-0.8%	-1.0%	-1.0%	-0.7%

Source: IEA, Company data, Goldman Sachs Research estimates.

Decline rates have increased and we estimate this trend will continue ...

Exhibit 39 shows how decline rates have changed in non-OPEC over the past seven years and our forecasts. These declines are calculated by subtracting major new start-ups (Top 280 projects) from historical production, to estimate the base decline including enhanced oil recovery, satellites and small field developments. This decline rate has been on an increasing trend since 2002, reflecting the ageing of the giant legacy fields and diminishing opportunities for new tie-ins in traditional areas. We assume the c.2.5% decline of 2008 will increase to c.4% in 2012 and stabilize at that level. The apparent improvement in decline rate trend in 2009 is due to the production recovery from a very damaging hurricane season in the US in 2008. Adjusted for that one-off, 2009 shows an increase in decline rates in line with the 2002-08 trend.

Exhibit 39: Non-OPEC decline rates have been consistently increased since the beginning of the decade



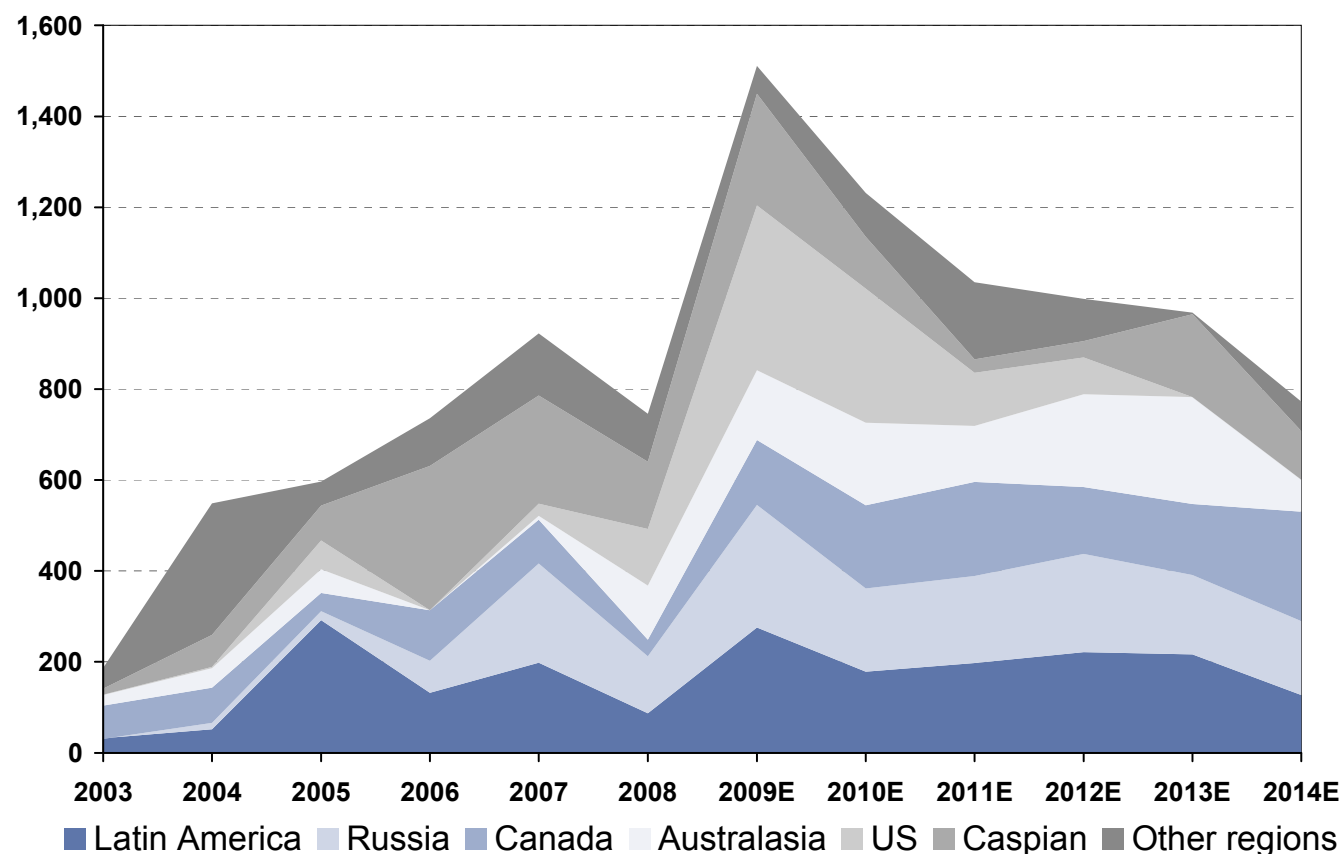
Source: Company data, Goldman Sachs Research estimates.

... while the 2009 start-ups are unlikely to be repeated

The lack of FIDs in 2007-09 (given a standard delivery period of approximately four years from FID to plateau production) suggests that 2011-13 will see few new start-ups (Exhibit 40). A record amount of new production in 2009 (and 2010E, due to the ramp-up of the projects) looks set to be followed by a dramatic fall. Growth in 2014 and beyond will depend on the industry maturing new projects to FID over the coming months, something which remains a key unknown.

Exhibit 40: 2009 was an exceptional year for start-ups and is unlikely to be repeated

Top 280 oil volume additions by year in each region



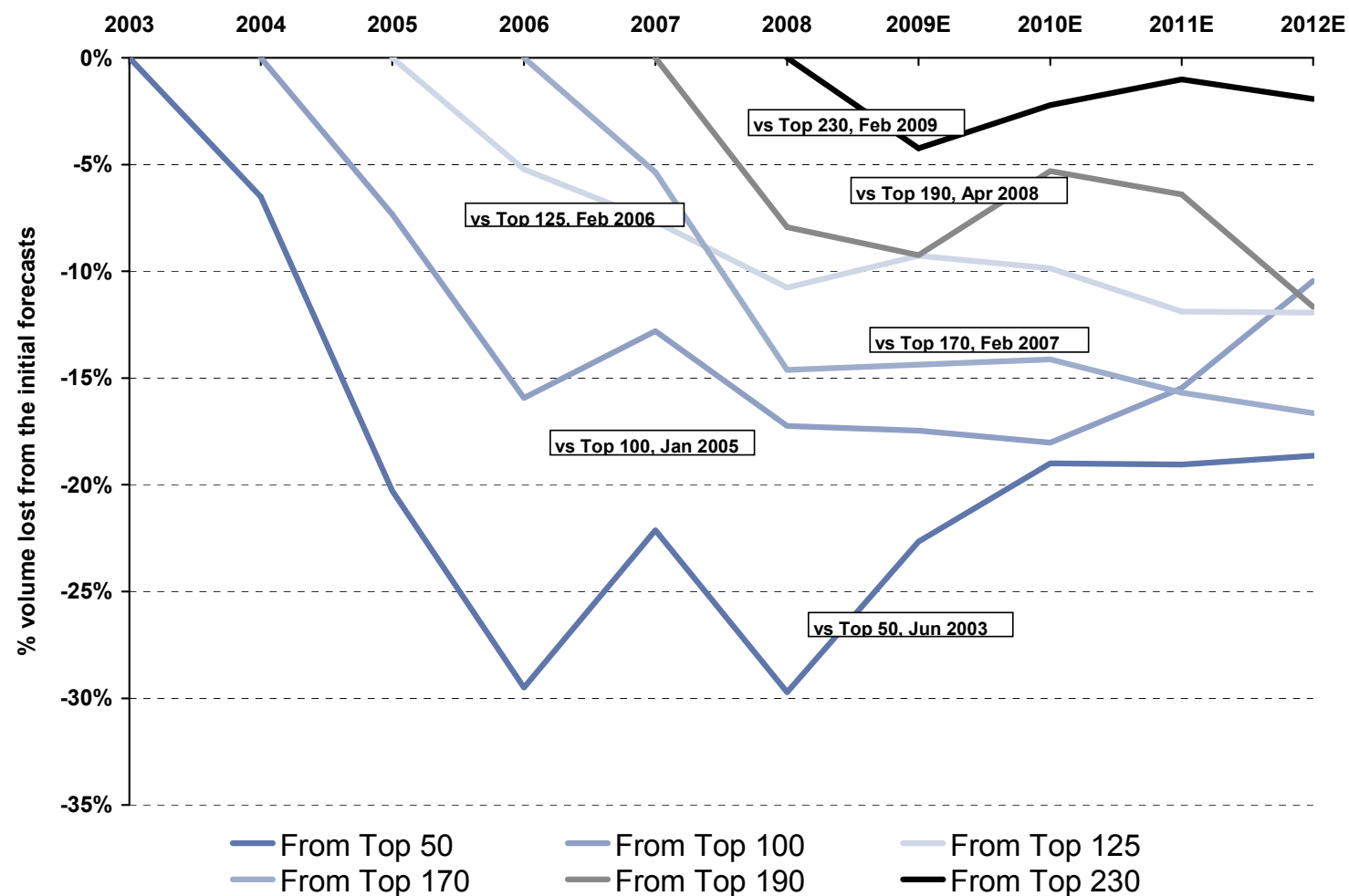
Source: Company data, Goldman Sachs Research estimates.

Delivery remains a key risk to non-OPEC supply growth...

The industry has not been successful through 2007-09 maturing projects to sanction. This will likely have a negative impact on future production. Poor project delivery could make the situation worse, and the industry's track record is not comforting, as shown by the oil volumes delivered by the industry vs. our expectations in each of the previous editions of this study (Exhibits 41 and 42).

Exhibit 41: Project execution: The industry has never delivered the volumes we expected

Percentage of oil volumes lost vs. our initial forecasts from the previous editions of our study

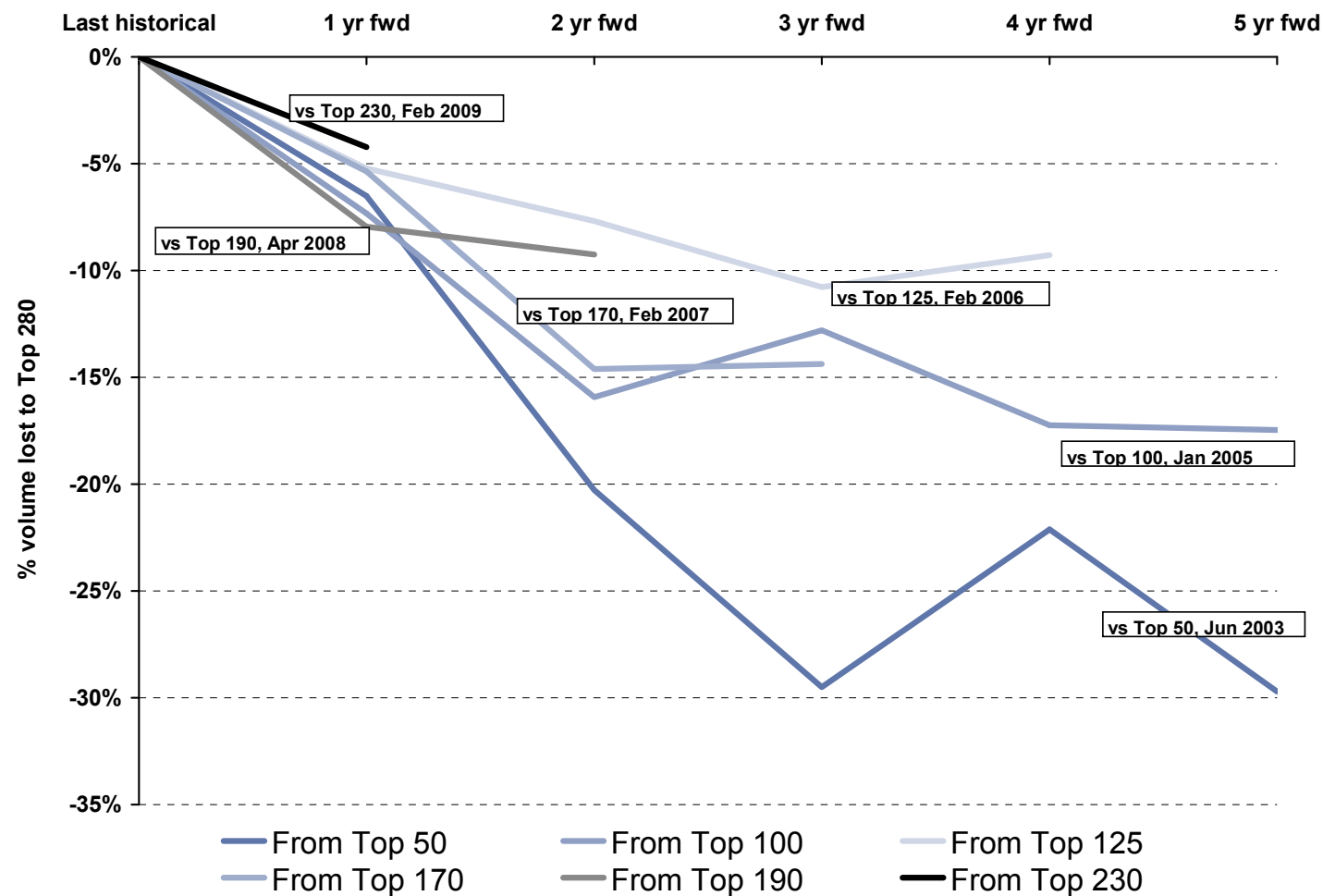


Source: Company data, Goldman Sachs Research estimates.

... with only 85% of the expected three-year forward oil production from new fields delivered

The industry has delivered on average 6% less oil volume than we expected one year forward in each of our previous reports; and 10%-15% less two years forward and 17% less three years forward. This was due to several issues: delays, longer time to reach plateau, lower plateau and an array of technical failures.

Exhibit 42: The industry's delivery vs. our expectations has been consistently disappointing



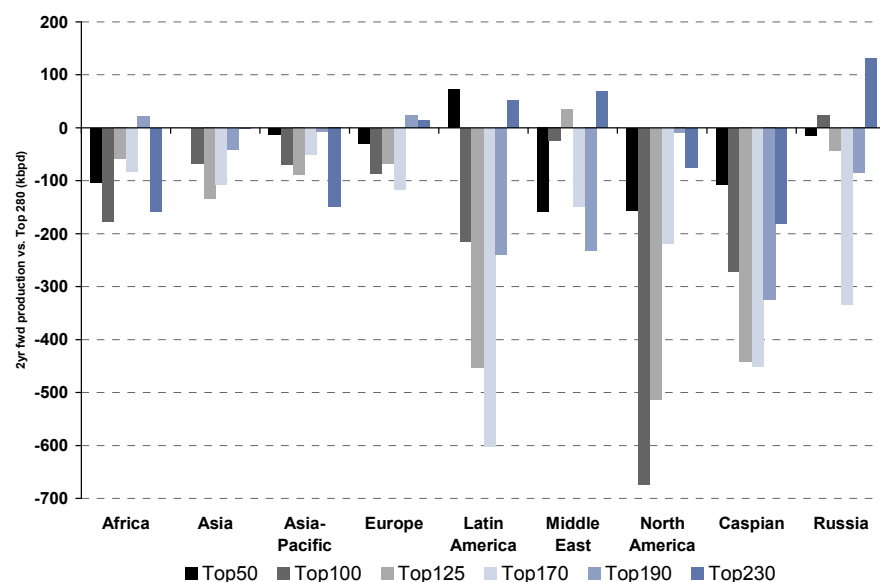
Source: Company data, Goldman Sachs Research estimates.

All regions show a disappointing delivery of oil projects

All major producing areas have been disappointing. But the causes of these delays have been different and specific to each region. The delays through disappointing delivery have emerged from North America as Canada's heavy oil production start-up was poor and from delays in the ramp-up of Gulf of Mexico projects such as Thunder Horse and a recent lack of major sanctions in the area. The Caspian disappointment has been driven largely by a slower ramp-up to ACG and Tengiz, and delay in production start for Kashagan. In contrast, the poor performance from Africa has stemmed from sanction delays in Nigeria and Angola, while the ramp-up of production once sanctioned (as highlighted in the two-year forward production exhibit) has in fact been near initial expectations. Developments in Europe, Asia and the Middle East have offered the best delivery globally as more stable fiscal policies and fewer service bottlenecks allowed projects to progress without significant delay.

Exhibit 43: North America and Caspian have disappointed in delivery ...

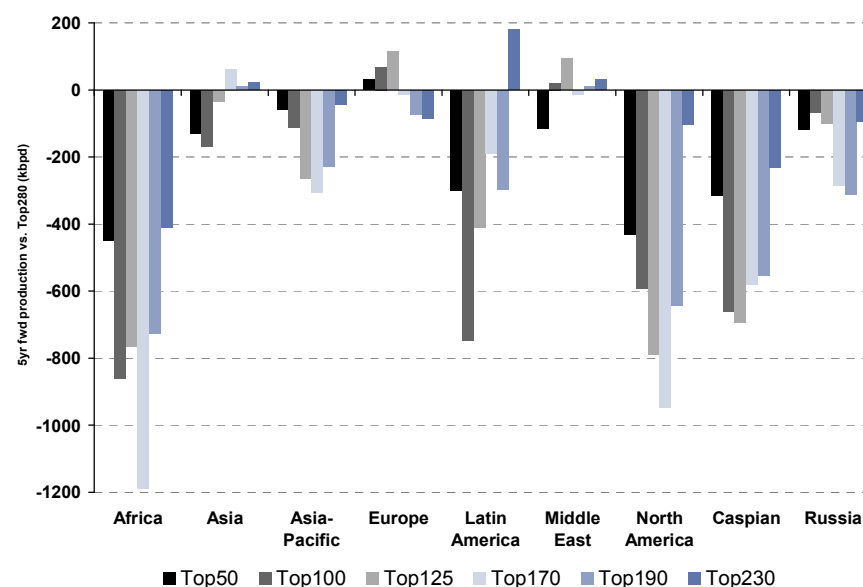
Two-year forward production vs. Top 280 two-year forward production



Source: Goldman Sachs Research estimates.

Exhibit 44: ... African disappointment stemmed from sanction delays

Five-year forward production vs. Top 280 five-year forward production



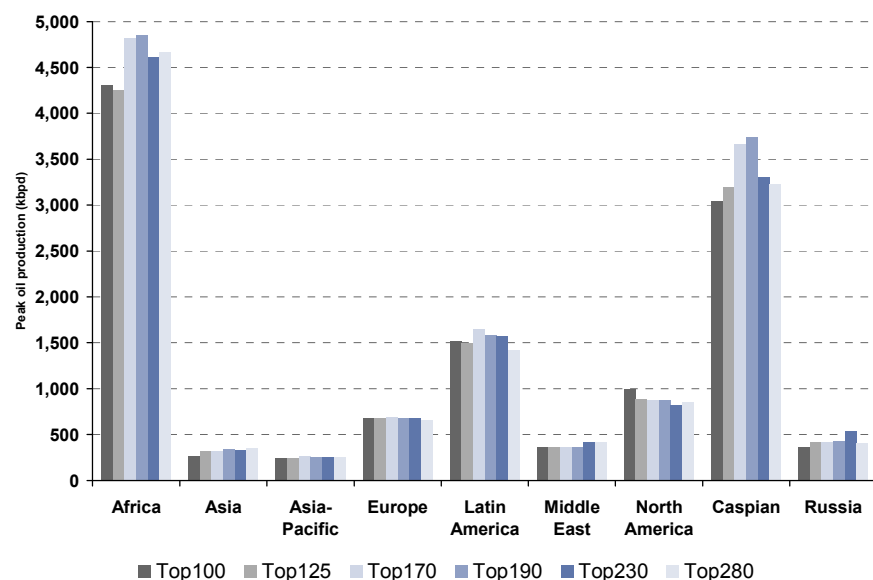
Source: Goldman Sachs Research estimates.

Production disappointment is not geological, but from sanction delays and poor execution

The industry's failure to deliver volumes has stemmed not primarily from geological disappointments, but from delays in sanctioning and poor execution. The maximum production and recoverable volume of oil fields we have analysed since Top 50 has not significantly changed, with the overall change better than we were expecting in Top 50 and Top 100 driven by reserve upgrades from Blocks 15/17/18 in Angola and increased capacity at Kashagan. The disappointments in overall volumes have stemmed from offshore Gulf of Mexico in Perdido, Holstein and Neptune and offshore Brazil at Golfinho. For the purpose of this analysis we have only analysed oil fields and have excluded all heavy oil fields, where peak production has been driven by the number of stages assumed in the modelling rather than a change in the accessible resources. We also exclude Venezuelan fields which have been nationalised.

Exhibit 45: Peak production by region has marginally increased ...

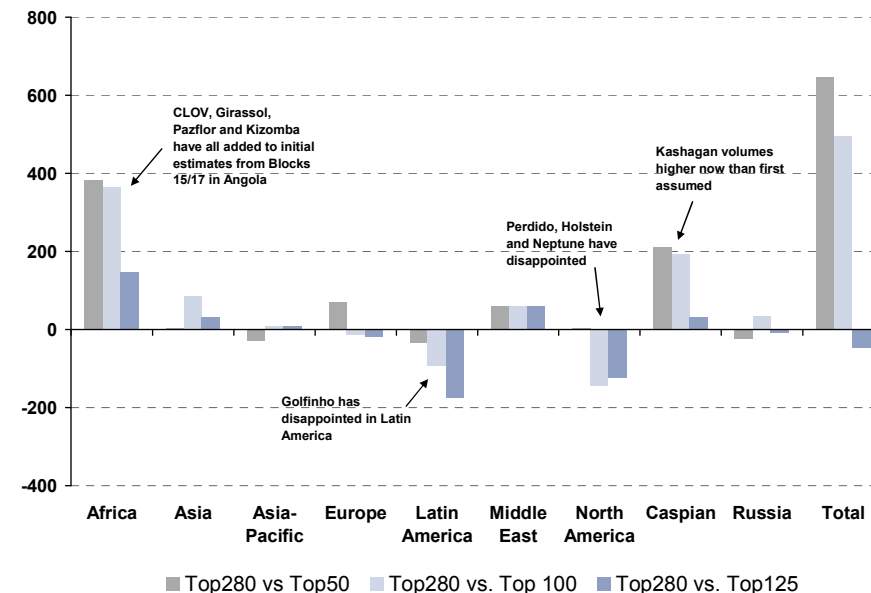
Peak oil production for the Top100 fields through time



Source: Goldman Sachs Research estimates.

Exhibit 46: ... with peak production increasing in Africa and Caspian

Top 280 maximum oil production vs. original maximum production assumption

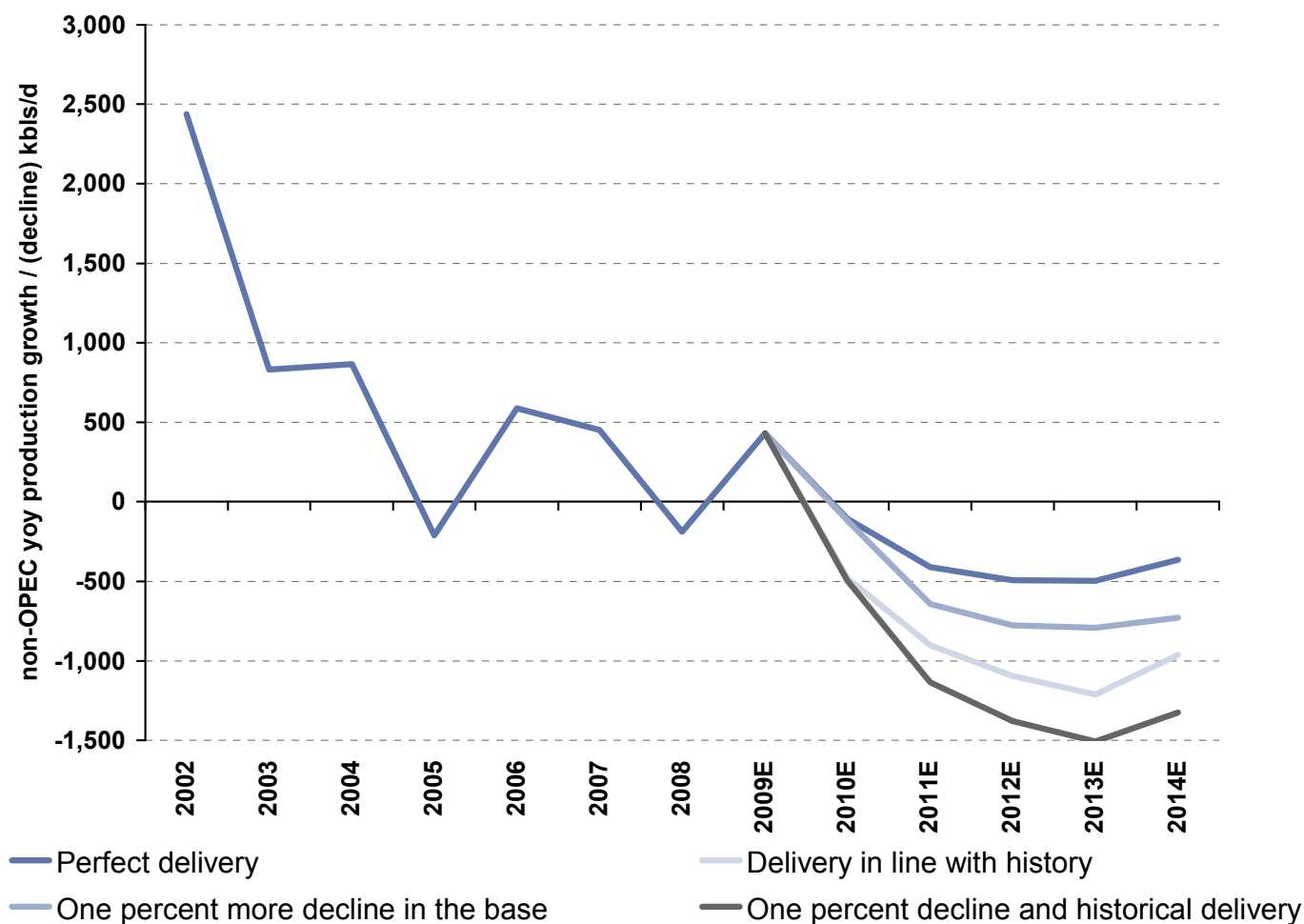


Source: Goldman Sachs Research estimates.

Non-OPEC decline could be much steeper than expected if recent trends continue

Exhibit 47 shows our estimate of future non-OPEC supply growth, assuming perfect delivery (see Exhibit 38 for detailed base case). It also shows projected output if delivery was in line with history (5% less than we forecast one year forward; 10% less two years forward and 15% less three years forward) and if decline rates increased by one percentage point each year (also in line with recent trends). These scenarios would imply an annual non-OPEC decline of around 1 mnbls/d from 2011E. A reasonable worst case scenario of both these trends continuing (poor delivery and increased decline) could lead to 1.5 mnbls/d of production decline.

Exhibit 47: Non-OPEC output could decline by up to 1.5 mnbls/d in a worst case scenario in 2011E-14E



Source: Company data, Goldman Sachs Research estimates.

OPEC capacity to increase 1%-2% in the coming years

Exhibit 48 shows our estimate of total OPEC production capacity (crude oil and NGLs), splitting out our assumptions for the underlying decline of the production base and production from the major new fields (Top 280 fields). We use the same methodology as for non-OPEC, with the only difference that here we focus on capacity, rather than production. For the purpose of this analysis we do not consider the Nigerian shut-ins as spare capacity and we assume no further disruptions in the coming years, but no major recovery in the production base either.

Unlike non-OPEC, 2010-11E show strong yoy production growth, as several important projects come onstream or ramp-up. This is followed by a more anaemic period, in line with history (c.400 kb/d growth in 2012-15E), characterized by few new start-ups, mainly concentrated in Iraq.

Exhibit 48: OPEC capacity will increase strongly in 2010-11, mainly thanks to Saudi, Qatar and Iraq

Total OPEC capacity (kbls/d)	2002	2003	2004	2005	2006	2007	2008	2009E	2010E	2011E	2012E	2013E	2014E	2015E
Algeria	1,680	1,852	1,946	2,105	2,141	2,192	2,059	1,998	1,939	1,901	1,891	1,890	1,908	1,918
Angola						1,708	1,965	2,058	1,951	1,916	1,905	1,862	1,914	1,823
Ecuador							497	482	468	454	440	427	414	402
Indonesia	1,289	1,183	1,129	1,113	1,062	1,013	1,028							
Iran	3,855	3,855	3,855	4,255	4,302	4,370	4,350	4,351	4,344	4,307	4,299	4,279	4,226	4,218
Iraq	2,838	2,500	2,250	2,000	2,000	2,113	2,408	2,356	2,363	2,608	2,844	3,204	3,641	4,118
Kuwait	2,232	2,329	2,475	2,548	2,625	2,625	2,650	2,575	2,502	2,457	2,413	2,497	2,472	2,530
Libya	1,480	1,485	1,624	1,728	1,837	1,853	1,873	1,852	1,821	1,802	1,773	1,756	1,699	1,637
Nigeria	2,316	2,316	2,316	2,598	2,751	2,858	2,659	2,948	3,069	2,995	3,007	3,035	3,040	3,194
Qatar	754	879	992	1,157	1,218	1,259	1,428	1,536	1,810	2,121	2,254	2,270	2,249	2,254
Saudi Arabia	11,281	11,386	11,744	11,460	11,439	11,429	11,413	11,730	12,330	12,719	12,867	12,752	12,796	12,847
United Arab Emirates	2,600	2,600	2,703	2,994	3,147	3,055	3,183	3,108	3,209	3,256	3,295	3,304	3,356	3,422
Venezuela	2,895	3,000	2,907	2,922	2,778	2,614	2,620	2,493	2,476	2,468	2,417	2,362	2,302	2,241
Total	33,219	33,385	33,941	34,880	35,301	37,333	38,133	37,487	38,282	39,004	39,405	39,639	40,018	40,604
Adj gr	-194	166	556	939	422	324	303	382	795	722	402	233	379	586
<i>ex-Iraq</i>	-194	504	806	1,189	422	211	8	434	788	477	165	-127	-58	109
as%	-0.6%	0.5%	1.7%	2.8%	1.2%	0.9%	0.8%	1.0%	2.1%	1.9%	1.0%	0.6%	1.0%	1.5%
<i>ex-Iraq</i>	-0.6%	1.5%	2.4%	3.5%	1.2%	0.6%	0.0%	1.1%	2.1%	1.2%	0.4%	-0.3%	-0.1%	0.3%

Top280 new OPEC capacity	2002	2003	2004	2005	2006	2007	2008	2009E	2010E	2011E	2012E	2013E	2014E	2015E	Decline rates
Algeria	15	180	230	230	260	286	257	229	203	196	216	245	291	330	-3%
Angola	246	280	359	622	821	1,176	1,510	1,644	1,574	1,571	1,589	1,573	1,649	1,580	-10%
Ecuador	0	0	0	0	0	0	0	0	0	0	0	0	0	0	-3%
Indonesia	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0%
Iran	0	2	7	7	7	167	205	324	432	507	607	692	741	832	-3%
Iraq	0	0	0	0	0	0	0	20	96	408	709	1,133	1,630	2,167	-3%
Kuwait	0	0	0	0	0	0	0	0	0	25	50	200	240	360	-3%
Libya	0	4	42	86	234	316	330	351	361	381	391	411	390	363	-3%
Nigeria	0	189	320	325	521	700	694	983	1,104	1,030	1,042	1,070	1,076	1,229	0%
Qatar	0	0	0	0	20	240	250	382	679	1,013	1,169	1,206	1,206	1,231	-3%
Saudi Arabia	0	0	0	0	0	0	290	905	1,795	2,465	2,885	3,035	3,335	3,635	-3%
United Arab Emirates	0	0	0	0	0	0	0	5	183	305	416	496	616	749	-3%
Venezuela	197	295	359	423	439	439	441	392	449	514	532	543	546	546	-4%
Total	458	950	1,317	1,692	2,302	3,324	3,977	5,235	6,876	8,415	9,607	10,604	11,720	13,020	
gr	306	492	367	376	610	-155	654	1,258	1,641	1,539	1,192	997	1,117	1,300	
<i>ex-Iraq</i>	306	492	367	376	610	-155	654	1,238	1,565	1,227	890	574	619	763	
as%	202%	107%	39%	29%	36%	-7%	20%	32%	31%	22%	14%	10%	11%	11%	
<i>ex-Iraq</i>	202%	107%	39%	29%	36%	-7%	20%	31%	30%	18%	11%	6%	6%	7%	

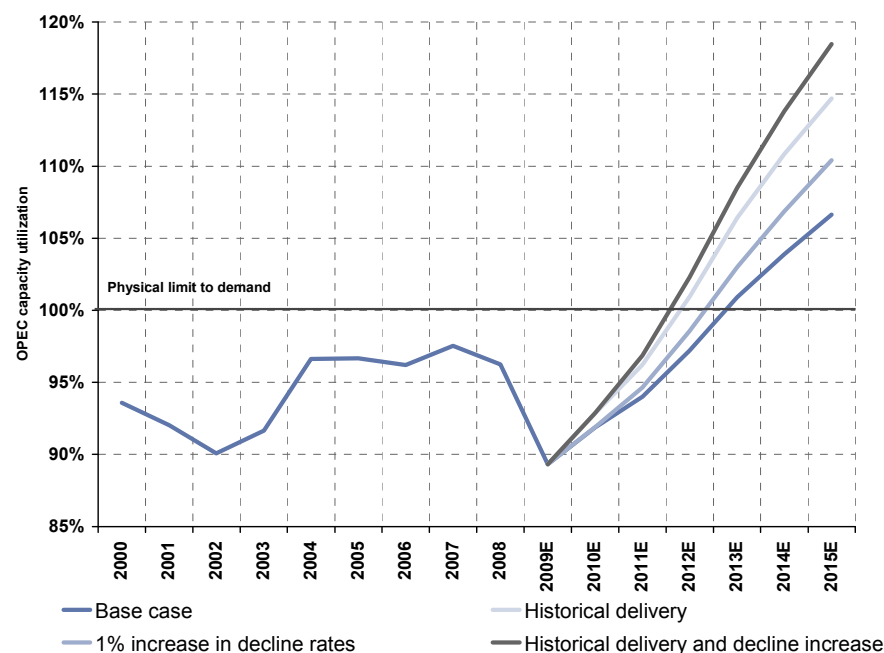
Source: Company data, Goldman Sachs Research estimates.

OPEC capacity to reach full utilization within two to three years

Exhibit 49 shows our estimates of OPEC capacity utilization, given our demand estimate (1.9% growth in 2010; 1.4% growth thereafter), our OPEC capacity estimate and our four scenarios of non-OPEC supply growth. This analysis implies that 100% capacity utilization will be reached in two to three years, according to the scenario utilized. This level of supply utilization will prompt demand rationing pricing, in our view.

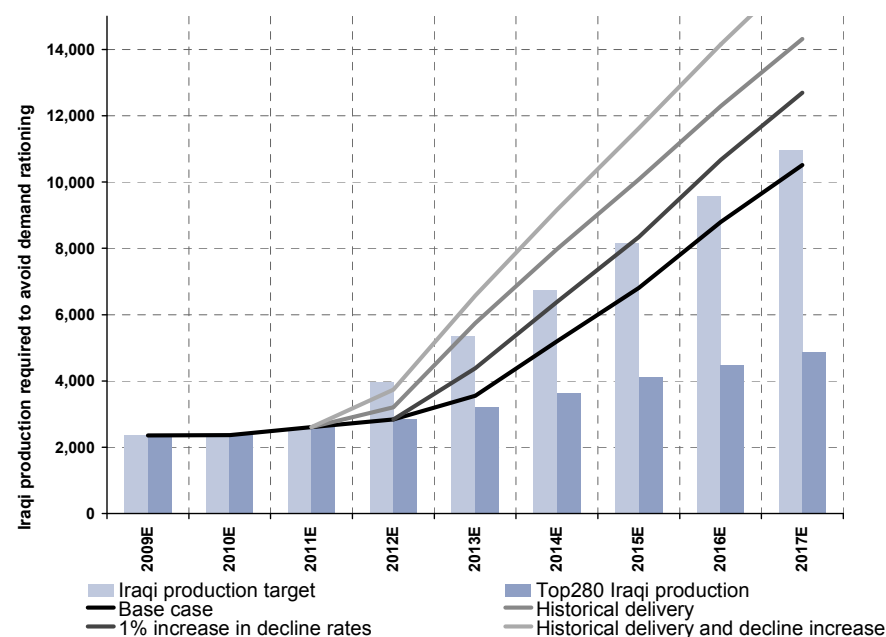
Exhibit 50 shows the Iraqi production needed to avoid OPEC capacity utilization going above 100% in our four scenarios, vs. what we think Iraq will be able to achieve (light blue bar) and what is implied by the promised plateau of the current field redevelopments. It is interesting to note that by 2015E the promised plateau would be needed to avoid demand rationing prices in most scenarios, except in the case of perfect delivery (base case). This supports our bullish view on the oil price.

Exhibit 49: Current production estimates vs. expectations two years forward



Source: Company data, Goldman Sachs Research estimates.

Exhibit 50: Current production estimates vs. expectations five years forward



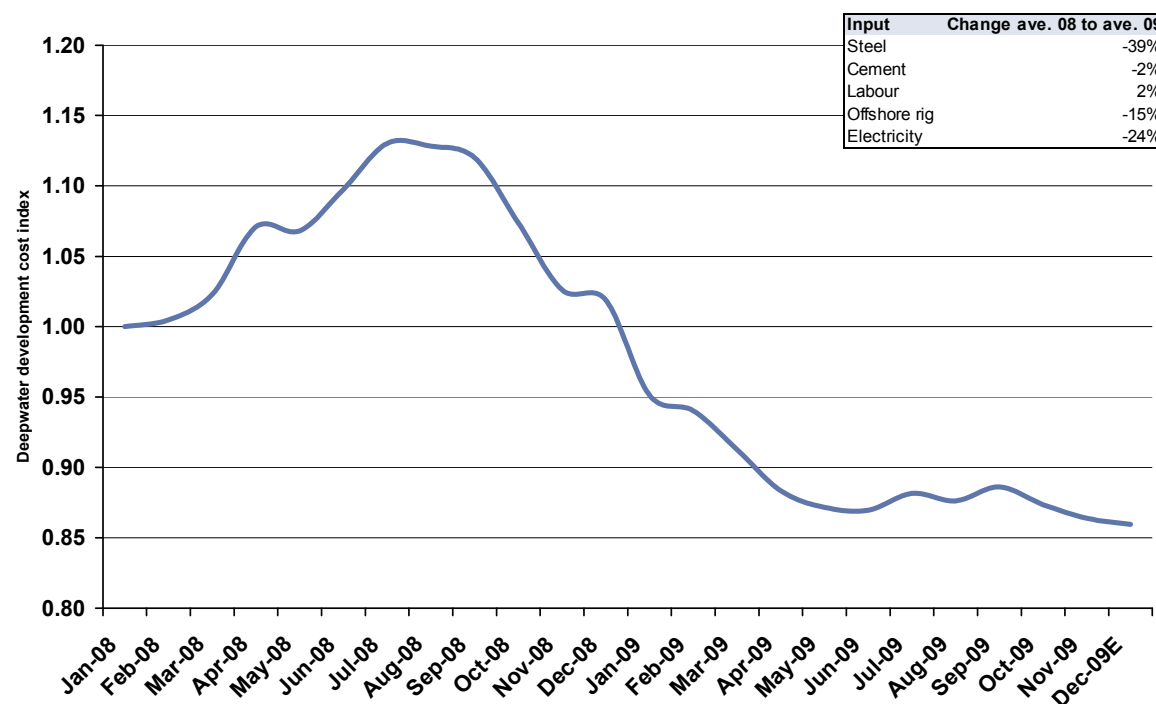
Source: Company data, Goldman Sachs Research estimates.

Cost deflation: 2009 input cost softening creates lower breakeven opportunities

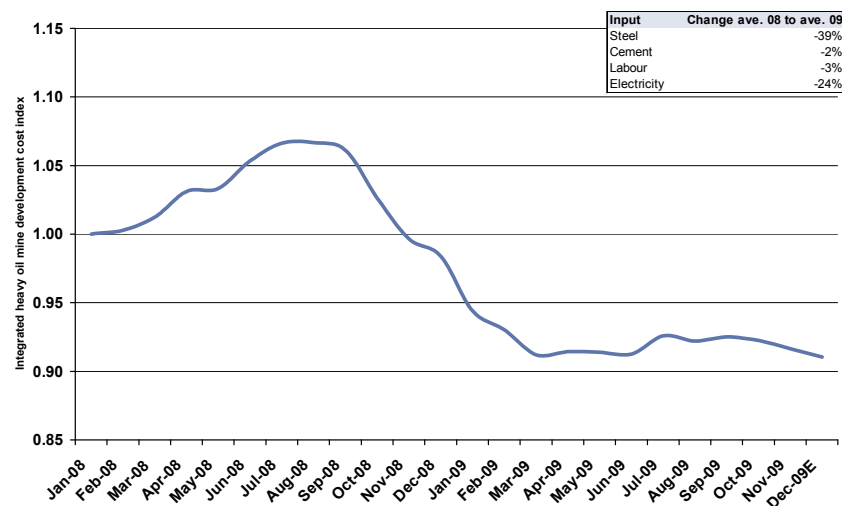
We update our analysis of the major cost components of the more marginal oil projects, namely deepwater and Canadian oil sands developments, based on the movement of the underlying inputs during 2009. The major materials and input costs for each of deepwater, integrated oil sands mines and thermal oil sands projects have generally softened in 2009, led by steel which we note has fallen c. 40% from the full-year average 2008 to 2009. Other notable areas of cost deflation have been rig rates, which we estimate to be down 25% in the onshore arena, and 15% in deepwater.

If the 2009 average cost environment could be locked in for the life of a new development, we believe projects would cost 16% less in deepwater, 10% less in integrated oil sands mining, and 14% less in thermal oil sands recovery, relative to the 2008 average cost environment which we used for the purposes of modelling the Top 230 projects. We note however that such a deflationary window is likely to be short as any increased investment in areas such as the oil sands will likely, in time, re-create the same bottlenecks which caused the cost inflation and delays of the 2006 to 2008 period. Exhibits 51 to 53 show how we believe the cost environment has changed over the course of the last two years in each of the three areas.

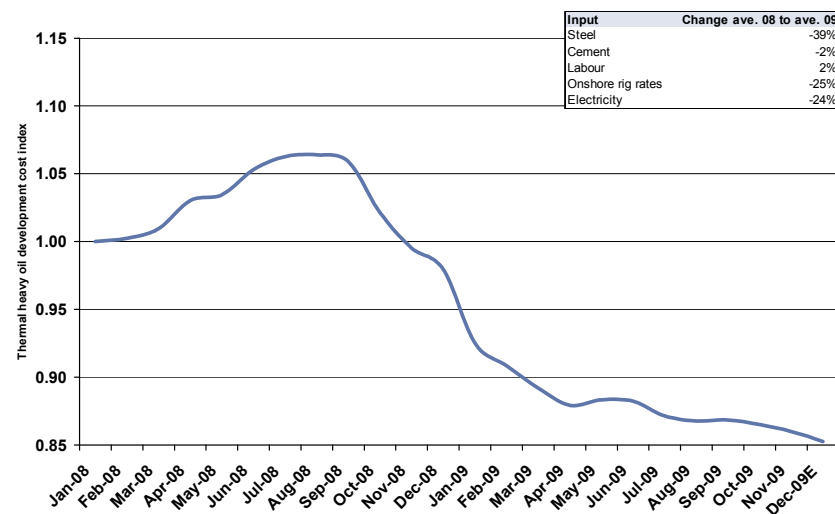
Exhibit 51: Based on our cost component analysis, we believe greenfield deepwater costs have fallen 16% yoy on average
Deepwater cost index Jan 08 – Dec 09



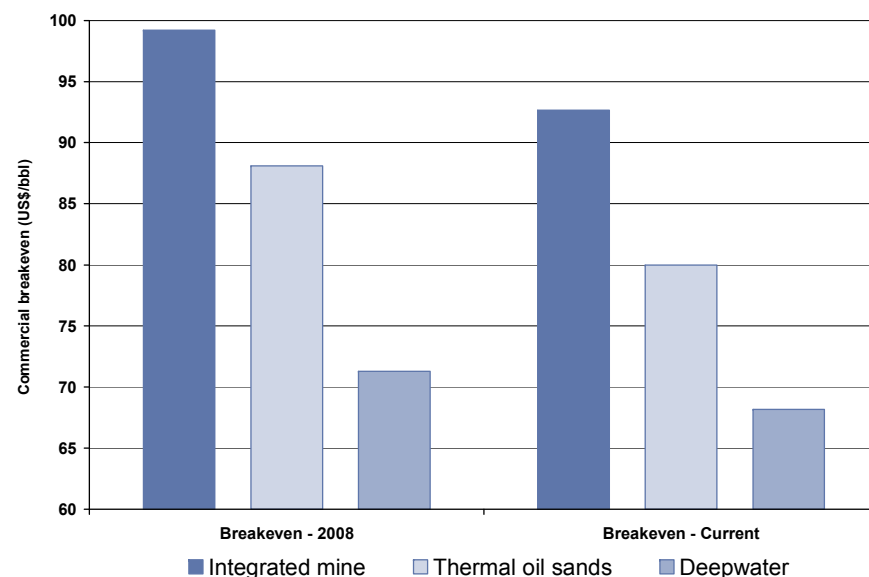
Source: Company data, Goldman Sachs Research estimates.

Exhibit 52: Integrated oil sands mine cost index Jan 08 – Dec 09

Source: Company data, Goldman Sachs Research estimates.

Exhibit 53: Thermal oil sands cost index Jan 08 – Dec 09

Source: Company data, Goldman Sachs Research estimates.

Exhibit 54: Commercial breakeven by development type – 2008 cost environment and current

Source: Company data, Goldman Sachs Research estimates.

We believe that costs for major developments have bottomed and that the risk to current capex figures is to the upside over the coming years. We note that large scale mining projects in the Canadian oil sands require over US\$90/bbl to achieve a commercial return, despite the deflation seen in 2009.

Oil Services to benefit from increased sanctions and complexity – introducing the Winners

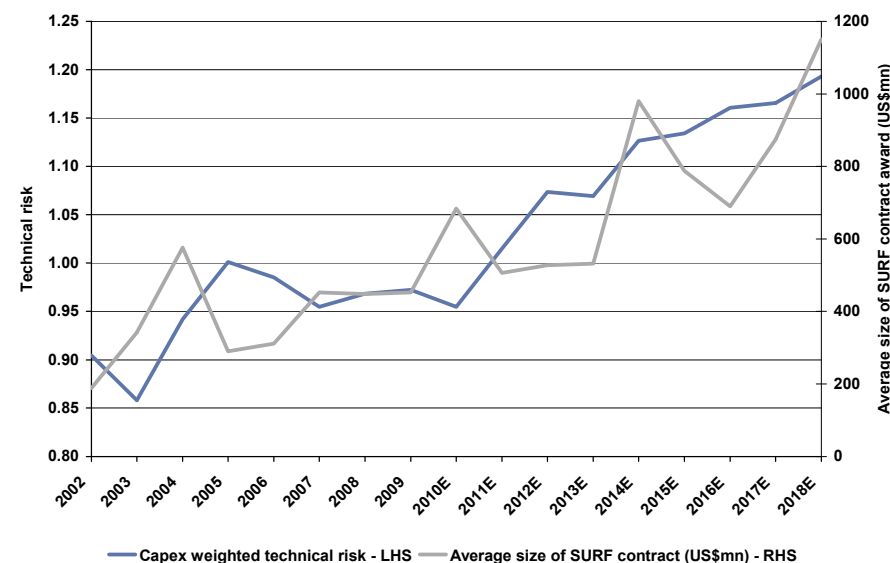
We continue to believe that the Oil Services sector globally will be the key beneficiary of the increased industry investment that we expect over the next few years. Following a period when few large projects were sanctioned (2007-2009), we see a significant pick-up in new project sanctions in 2010, driven in our view by the bottoming of industry costs, an oil price which leaves the majority of the large new projects economic at commercial hurdle rates, and oil companies looking to meet production targets and grow volumes again.

We note also that the opportunity set of greenfield projects around the globe continues to increase in complexity. We believe this will further benefit the leading services providers. An increasing focus on the ultra deepwater, pre-salt and unconventional resources will result in a greater absolute size of opportunity for oil services due to the higher cost of these development types. We note also that the EBITDA margins of our global Oil Services universe have increased over time, meaning the oil services companies are taking a relatively larger slice of a growing pie.

Using our analysis of the key growth areas from the Top 280 Projects, we identify the following global oil services winners for 2010: Petrofac, Foster Wheeler, JGC, Schlumberger, FMC Technologies and Technip.

Exhibit 55: Top 280 contract awards are growing in size as investment shifts to more challenging areas

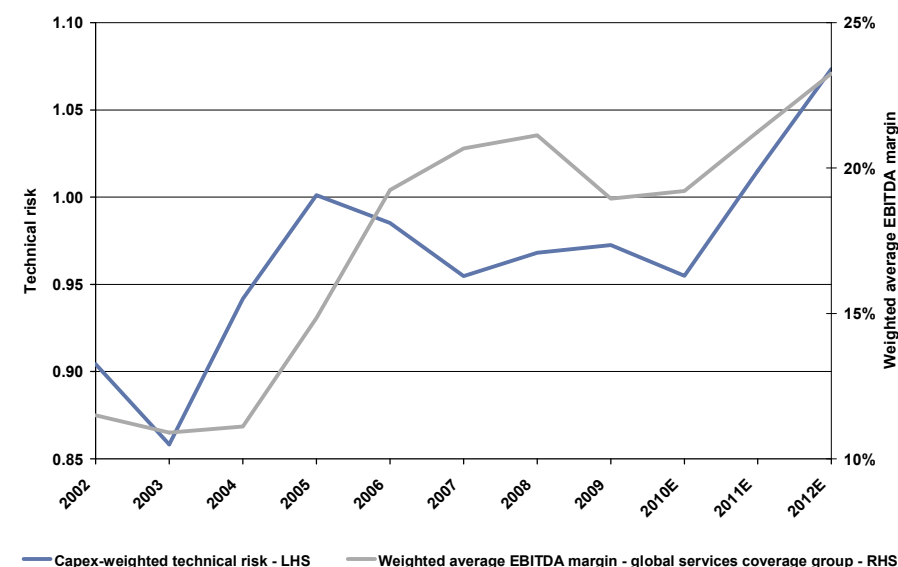
Technical risk of Top 280 projects capex and average size of SURF contract (US\$ mn)



Source: Company data, Goldman Sachs Research estimates.

Exhibit 56: While much of the new activity will yield higher margins for oil service companies

Technical risk of Top 280 capex and EBITDA margins of global Oil Services universe



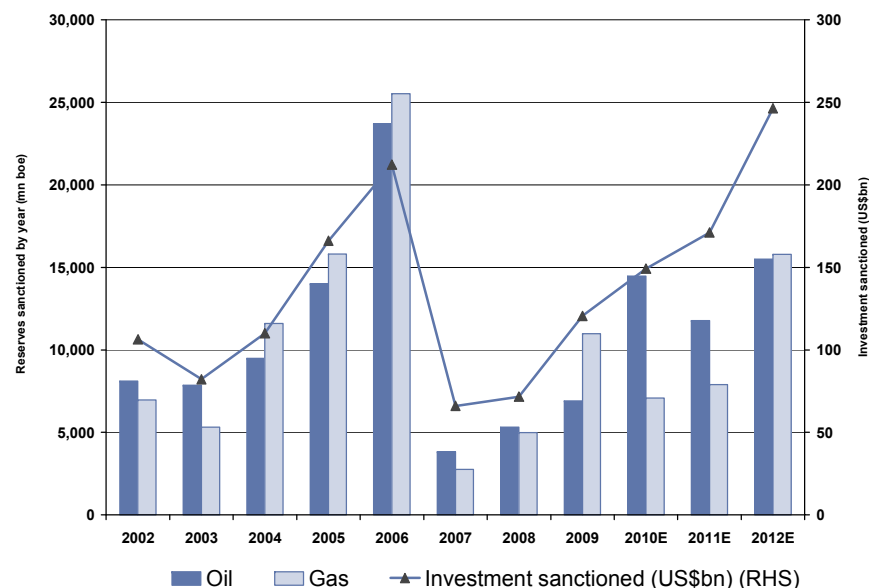
Source: Company data, Goldman Sachs Research estimates.

The oil price recovered significantly through 2009 and, although weak in historical terms, project sanctions and oil services contract awards in 2H 2009 were actually slightly ahead of expectations. We believe that 2010E will be the trough year of earnings for backlog-driven oil services companies (i.e., the majority of the European companies), and expect overall capex to be broadly flat across the Majors. While the major oil companies are likely to stress capital and cost discipline when they issue strategy updates for 2010, we do expect a shift of focus towards advancing large new projects, helping them to maintain existing portfolio production and to generate volume growth in greenfield areas. As we move through the budgeting period, and the oil price stays at or above the US\$70/bbl level, the oil companies are generating sufficient cash flow to meet their dividend and other cash requirements, and it should become easier for the oil companies to move ahead with large new developments which have been delayed or postponed until now. We believe that the engineering for many of these large projects can move ahead quickly when the oil companies decide to move to FID, potentially creating a significant uptick in activity levels for the oil services companies as the oil industry looks to catch up on three years of low investment in large new projects.

We expect a significant pick-up in project sanctions in 2010 (Exhibit 57), and we also expect sanctions and investment in 2011 to be significantly ahead of the 2007-2009 period. We believe that the increase in project sanctions will lead to significant growth in backlog for the European oil services companies, which should enable multiple expansion through 1H 2010 as the market gains greater visibility on revenue and earnings growth in 2011 and beyond. We then expect earnings upgrades from the middle of the year, driving the next leg of returns.

Exhibit 57: 2010 is set to be a strong year for sanctions in our view

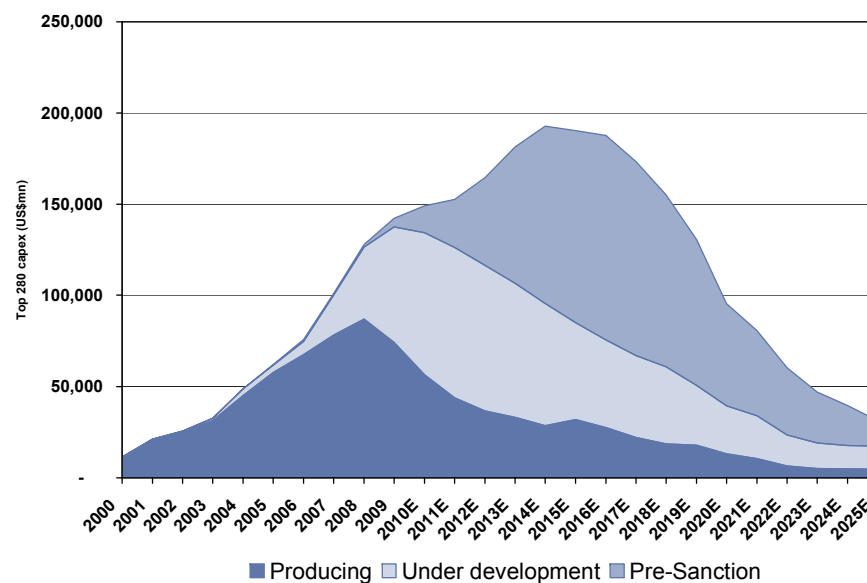
Top 280 oil and gas reserves and capex sanctioned by year, excluding Iraq



Source: Company data, Goldman Sachs Research estimates.

Exhibit 58: The projects will require significant investment in infrastructure

Top 280 capex by year (US\$ mn) split by development status



Source: Company data, Goldman Sachs Research estimates.

Deepwater frontier projects and LNG continue to look attractive from an oil services perspective

For this edition of the report, we have broken down capex by project and service type, in order to assess our expected growth rates across the major oil service areas.

As a result, we believe deepwater frontier is the most attractive development area for oil services companies seeking to benefit from the Top 280 growth projects. The SURF market screens as the most attractive service type from the analysis, with 19% pa potential growth out to 2012, driven by increased activity in Brazil, the Gulf of Mexico and West Africa. We are similarly positive on the subsea equipment market, which benefits from the same drivers; we expect 12% growth to 2012. We also expect an increasing trend of FPSO development solutions in basins offshore Brazil and in the Gulf of Mexico, and note the strong expected growth in this service type. In screening for services winners from the Top 280 report, however, we exclude the FPSO construction industry due to its poor historical leverage to the investment cycle.

In the onshore arena, we identify LNG as an attractive growth area (estimated 14% pa growth to 2012) together with Iraq. The former will be driven almost entirely by greenfield projects in Australia in our view as large, previously-stranded gas fields are developed and coal-seam methane fields are exploited. We also highlight Iraq in this report and identify winners based on their potential to do business in the country, following the emergence of the 2009 service contracts. Although this area looks less attractive in terms of absolute activity growth, it remains a key win zone as we note the new activity has the potential to open up an entirely new area of operation for some international service companies.

We are less positive on increased activity in heavy oil developments, Russia and shallower water drilling. We note the strong growth expected in the ultra deepwater drilling market but we do not choose this as a favoured area of exposure as we do not see an opportunity which is purely levered to the >1500m market and avoids the other weakening drilling markets. We exclude onshore drilling from our analysis due to the typically localised nature of these markets.

Exhibit 59: We view SURF, LNG, subsea equipment and Iraq as the most attractive areas of exposure, together with Latin America and Asia-Pacific in terms of geographical exposure

Compound activity growth to 2012E by Oil Services win zone

Services win zone	Activity growth 2009 to 2012E	Activity growth 2009 to 2015	
FPSO	12%	10%	Based on expected capex
SURF	19%	22%	
Subsea	12%	10%	
LNG	14%	11%	
Heavy oil	6%	16%	Based on expected wells drilled
Russia	-4%	-6%	
Drilling: traditional (50 - 100m jack-up)	-22%	-13%	
Drilling: traditional (<750m)	-14%	1%	
Drilling: deepwater (<1500m)	-24%	-4%	Based on production
Drilling: ultra deepwater (>1500m)	21%	18%	
Iraq	7%	10%	

Growth region	Activity growth 2009 to 2012E		Activity growth 2009 to 2015E		
	Deepwater:	LNG:	Deepwater:	LNG:	Based on expected capex
Africa	-1%	-21%	6%	18%	
Asia-Pacific	33%	44%	-11%	27%	
Europe	-	-	-	-	
Latin America	16%	-	8%	-	
Middle East	-	-30%	-	0%	

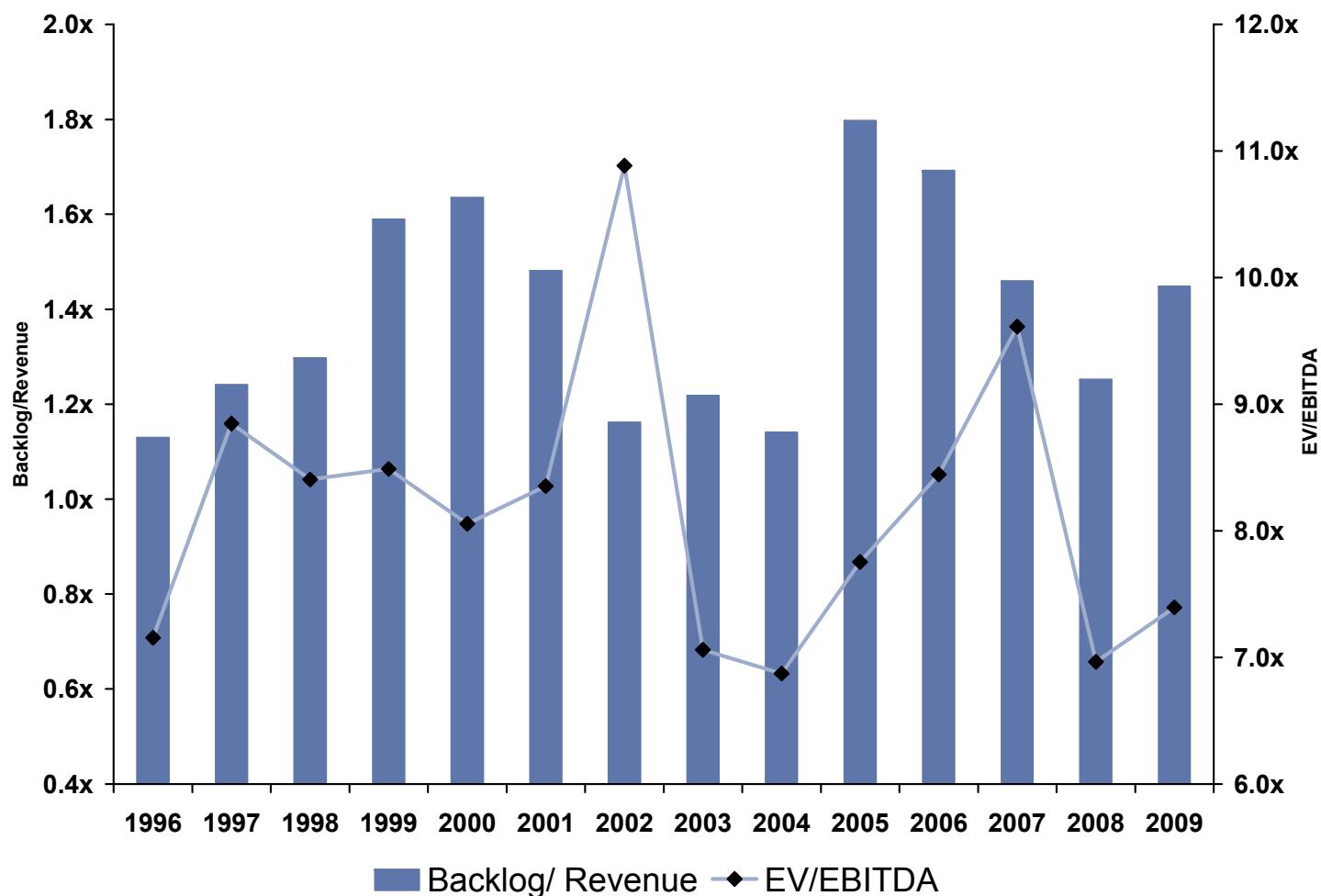
Source: Company data, Goldman Sachs Research estimates.

Oil services company multiples expand with growing opportunity pipeline

We expect oil services company multiples to continue to expand as contract awards from the Top 280 projects emerge in 2010, and we have already seen contract awards in the sector ahead of expectations in 2H 2009. These came first in the Middle East, but were followed by awards in Australia, West Africa and Brazil, and were coupled with the recovery and stabilization of the oil price from an average of US\$44/bbl in 1Q 2009 to US\$75/bbl in the fourth quarter. We believe the sector continues to be well placed for further improvements in activity levels and that multiples will continue to expand as backlog grows.

Exhibit 60: Increased order flow has driven multiple expansion in the past

Backlog/12-month revenue vs. EV/EBITDA multiple (RHS) - European E&C and SURF companies



Source: Company data, Goldman Sachs Research, Datastream.

We expect contract awards to pick up from 2010

Exhibit 61 shows the major contracts we expect to be awarded across the different activity types in 2010 from the Top 280 projects.

Exhibit 61: Expected contract awards 2010

Project	Region	Contract type	Expected award size (US\$m)
Tupi - Full system 1	Latin America	SURF	1560
Block 17 CLOV	Africa		1320
Jack / St Malo	North America		620
Guara - Phase 1	Latin America		580
Greater Gorgon - Phase 1	Asia-Pacific		510
Tupi - EPS	Latin America		510
Tamar	Middle East		420
Papa Terra	Latin America		350
Vesuvio	Latin America		290
Block 17 CLOV	Africa	Subsea equipment	1080
Tupi - Full system 1	Latin America		1020
Guara - Phase 1	Latin America		380
Jack / St Malo	North America		350
Tamar	Middle East		280
Papa Terra	Latin America		230
Vesuvio	Latin America		130
Laggan Tormore	Europe		110
Nasr	Middle East		100
Umm al-Lulu	Middle East		100
Block 17 CLOV	Africa	FPSO	1440
Guara - Phase 1	Latin America		1400
Iara - EPS / Iracema	Latin America		1400
Papa Terra	Latin America		720
Surmont - Phase 2	North America	Heavy oil	4020
Foster Creek & Christina Lake - 1F, 1D	North America		2740
MacKay River Expansion	North America		2180
Firebag - Stage 4	North America		1370

Source: Company data, Goldman Sachs Research estimates.

Introducing the global Oil Services winners

We have screened our global Oil Services and E&C coverage for companies which stand out as being well placed to benefit from the development of the oil industry that will be driven by the Top 280 projects. In order to identify the winners, we assessed our global Oil Services and E&C coverage against three criteria:

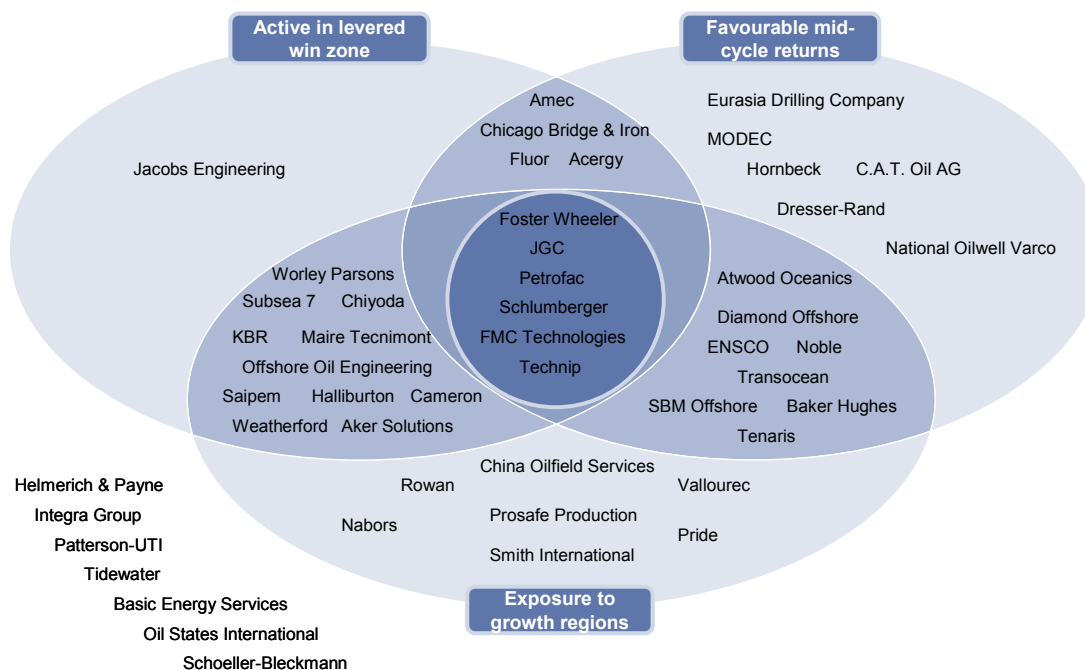
Active in win zone: companies active in the growth win zones identified by the Top 280 analysis, limited to win zones that we believe are positively levered to the investment cycle. The industrial winners are therefore those active in E&C (which will benefit from LNG and Middle Eastern activity growth), general major oil services providers (which we view as the best way to play the theme of increased investment in Iraq and frontier deepwater developments), and subsea (where growth will be driven by Brazil and GoM in the near term).

Exposure to growth regions: current sales exposure of at least 15% or imminent exposure to one of Brazil, ME or Asia.

Favourable mid-cycle returns: mid-cycle CROCI greater than peer group median.

The winners on this basis are: JGC, Foster Wheeler, Petrofac, Schlumberger, FMC Technologies and Technip. These companies are advantaged in either Australian LNG (JGC, Foster Wheeler), deep water frontier developments (FMC Technologies, Technip, Schlumberger) or onshore Middle East and potentially Iraq (Petrofac, Schlumberger).

Exhibit 62: Global Oil Services winners



Source: Company data, Goldman Sachs Research estimates.

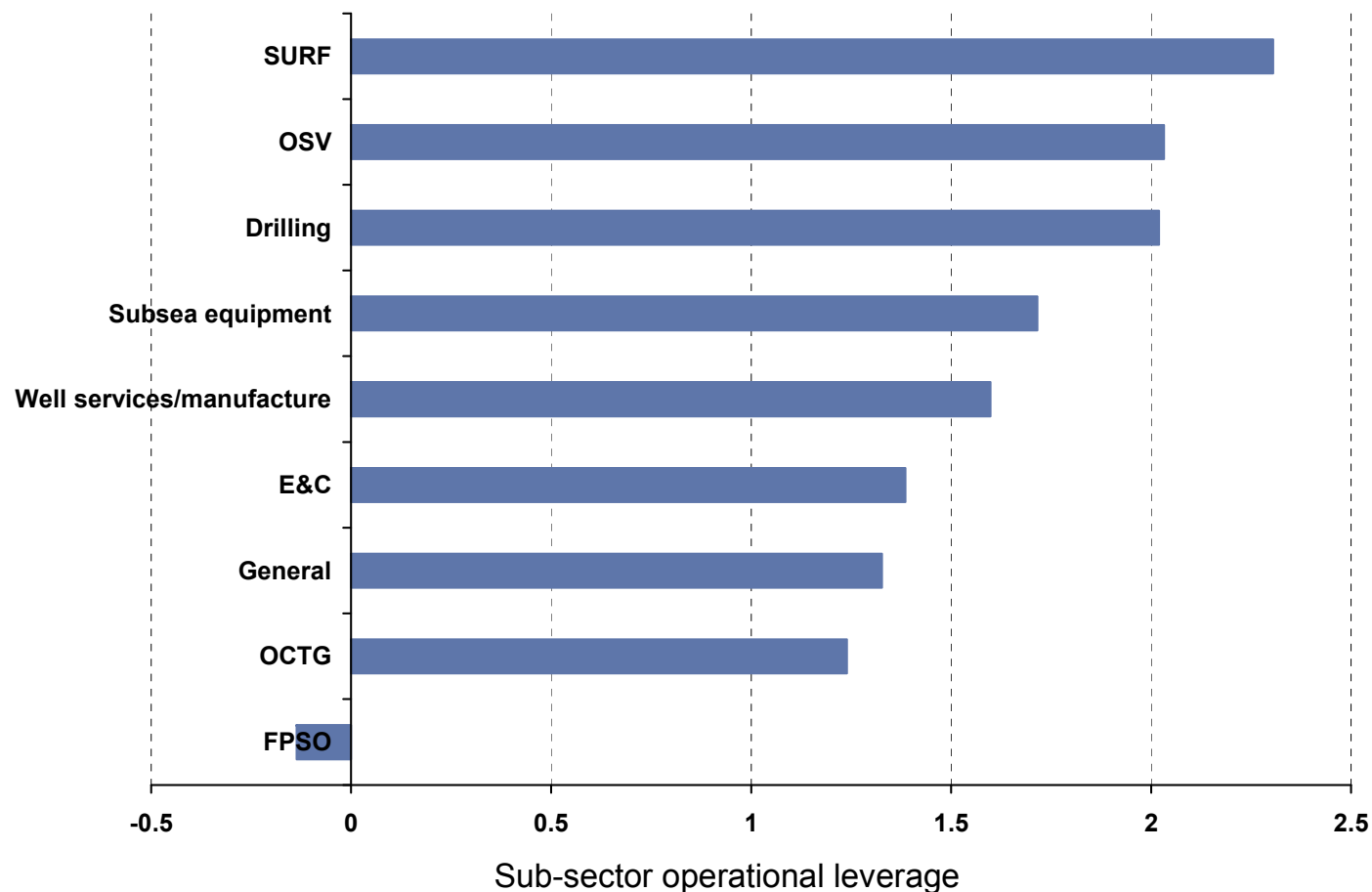
Exhibit 63: Global Oil Services Top 280 exposure round-up

Company	Exposure to growth region			Geographical winner	Service area	Top280 Growth area	Operational leverage	Industrial winner	Ave. CROCI 2009 - 2012E	Returns winner	Top 280 Services winner
	Brazil	Middle East	Asia								
Atwood Oceanics			✓	✓	Drilling		✓		18%	✓	
China Oilfield Services		✓	✓	✓					8%		
Diamond Offshore	✓		✓	✓					27%	✓	
ENSCO	✓		✓	✓					16%	✓	
Eurasia Drilling Company									30%	✓	
Helmerich & Payne									11%		
Integra Group									11%		
Nabors		✓		✓					12%		
Noble	✓			✓					23%	✓	
Patterson-UTI									8%		
Pride International	✓			✓					13%		
Rowan		✓		✓					9%		
Transocean			✓	✓					15%	✓	
Amec					E&C	✓	✓	✓	27%	✓	
Chicago Bridge & Iron								✓	25%	✓	
Chiyoda		✓	✓	✓				✓	24%		
Fluor								✓	50%	✓	
Foster Wheeler			✓	✓				✓	46%	✓	Foster Wheeler
Jacobs Engineering								✓	17%		
JGC		✓	✓	✓				✓	42%	✓	JGC
KBR		✓		✓				✓	24%		
Maire Tecnimont		✓		✓				✓	19%		
Offshore Oil Engineering			✓	✓				✓	22%		
Petrofac		✓		✓				✓	110%	✓	Petrofac
Saipem		✓		✓				✓	14%		
Worley Parsons		✓	✓	✓				✓	11%		
MODEC					FPSO	✓			13%	✓	
Prosafe Production	✓		✓	✓					7%		
SBM Offshore	✓	✓		✓	General	✓	✓		12%	✓	
Halliburton		✓	✓	✓				✓	18%		
Schlumberger		✓	✓	✓				✓	21%	✓	Schlumberger
Weatherford			✓	✓	OCTG		✓		11%		
Tenaris		✓		✓					15%	✓	
Vallourec	✓		✓	✓	OSV		✓		14%		
Hornbeck									12%	✓	
Tidewater					Subsea equipment	✓	✓		12%		
Aker Solutions			✓	✓				✓	12%		
Cameron	✓		✓	✓				✓	19%		
FMC Technologies	✓		✓	✓	SURF	✓	✓		35%	✓	FMC Technologies
Aceryg								✓	17%	✓	
Subsea 7	✓			✓				✓	16%		
Technip	✓	✓		✓	Well services / manufacture		✓	✓	17%	✓	Technip
Baker Hughes		✓	✓	✓					14%	✓	
Basic Energy Services									9%		
C.A.T oil AG									14%	✓	
Dresser-Rand									18%	✓	
John Wood Group									14%	✓	
National Oilwell Varco									14%	✓	
Oil States International									13%		
Schoeller-Bleckmann									13%		
Smith International			✓	✓					9%		

Source: Company data, Goldman Sachs Research estimates.

We overlay an operational leverage screen against our Top 280 growth win zone analysis in order to isolate those areas best exposed to a new investment cycle both in terms of volume growth and earnings growth. We note that all sub-sectors return positive leverage over the period 2000 to 2008, except for FPSO manufacturers and operators. We therefore exclude FPSO as a win zone when determining the Top 280 oil services winners. In our view this lack of leverage can be explained by the low economies of scale in the FPSO construction industry combined with oversupply in yard space. For the purposes of the screen, we calculate operating leverage as the percentage change in EBIT divided by the percentage change in sales for the period. We then take the median for each company and average this figure across the sub-sectors.

Exhibit 64: Sub-sector historical operational leverage (2000-2008)



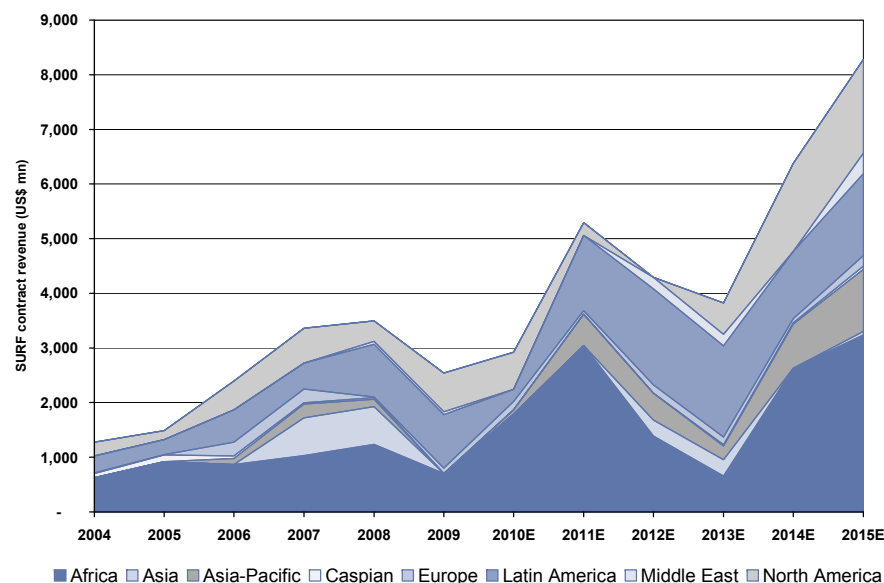
Source: Company data, Goldman Sachs Research estimates

SURF – strong growth ahead as investment shifts to the ultra-deepwater

We see strong growth in the SURF market over the coming three years, following a dip in 2008 and 2009, driven by strength in Brazil, Australia, and the Gulf of Mexico, along with a pick-up in West Africa. In Brazil we see contracts for Guara and Papa Terra in 2010 and Iara and BS-4 in 2011. Petrobras may not sign full EPC contracts for these fields, preferring instead to sign up assets on longer term contracts, but we still believe that the volume of work will require either more assets to be signed up over the coming months or separate EPC contracts on some of these projects. In the Gulf of Mexico, we expect the Jack/St Malo contract award in 2010, followed by Kodiak, Tubular Bells and Kaskida. In Asia there is strong growth from a lower base, driven mainly by the Australian LNG projects (Gorgon, Ichthys, Prelude, Pluto, Wheatstone). In West Africa we also see a pick-up after a period of few major contract awards, with CLOV to be awarded in 2010, and then potentially Block 32 in 2011, both in Angola, with Bonga SW and Egina potentially to be awarded in 2011 if projects in Nigeria begin to move forward again.

Exhibit 65: Investment in LatAm and GoM will drive strong growth

Top 280 SURF capex by year



Source: Company data, Goldman Sachs Research estimates.

Exhibit 66: LatAm followed by Asia and North America to grow the fastest

Regional heat-map of Top 280 SURF contract awards – relative to history

	2010E	2011E	2012E
Regional SURF contract award intensity relative to history			
Africa	Africa	Africa	Africa
Asia	Asia	Asia	Asia
Asia-Pacific	Asia-Pacific	Asia-Pacific	Asia-Pacific
Caspian	Caspian	Caspian	Caspian
Europe	Europe	Europe	Europe
Latin America	Latin America	Latin America	Latin America
Middle East	Middle East	Middle East	Middle East
North America	North America	North America	North America

Source: Company data, Goldman Sachs Research estimates.

Technip the best placed to benefit

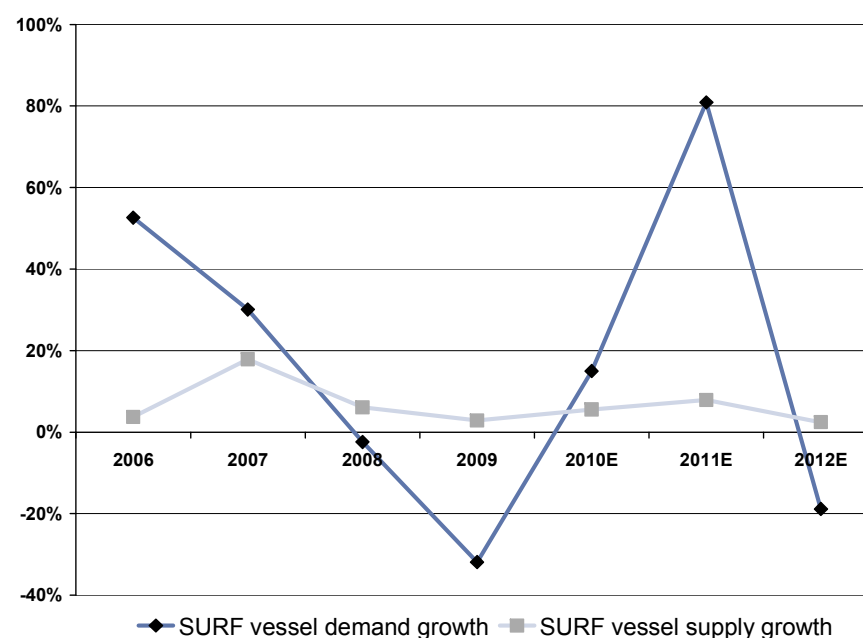
Exhibit 68 shows the major SURF vessel supply vs. demand, where the demand is implied from the Top 280 SURF awards, using an assumption for the movement of day rates through the period. While 2007 and 2008 saw supply grow in excess of demand, by 2010 we expect demand growth in terms of new projects to be significantly greater than the supply of large new vessels entering the market, which should mean a return to growth in the sector from 2H 2010. The company best positioned in our view is Technip, which derives more than half of its subsea revenues from the key growth areas of Brazil and Asia. Subsea 7 has a strong position in Brazil also, but does not have a manufacturing position to equal that of Technip, and is also generating less revenue in Asia, positioning it less well for an upturn in offshore work related to the Australian LNG projects. Technip also has a strong position in the Gulf of Mexico. While not a pure play on subsea, 74% of 2008 EBIT came from its subsea business. The pure play subsea companies (Subsea 7 and Acergy) have a greater reliance on the North Sea, which we believe will continue to be a difficult market in 2010. Although SURF assets are largely global, and can be transferred between regions meaning that the regional split of revenues can change dramatically, in practice local relationships and local infrastructure such as spoolbases or fabrication yards can have an important impact on winning contracts, so existing positioning is a key indicator for future growth in our view.

Exhibit 67: SURF companies' geographic exposure

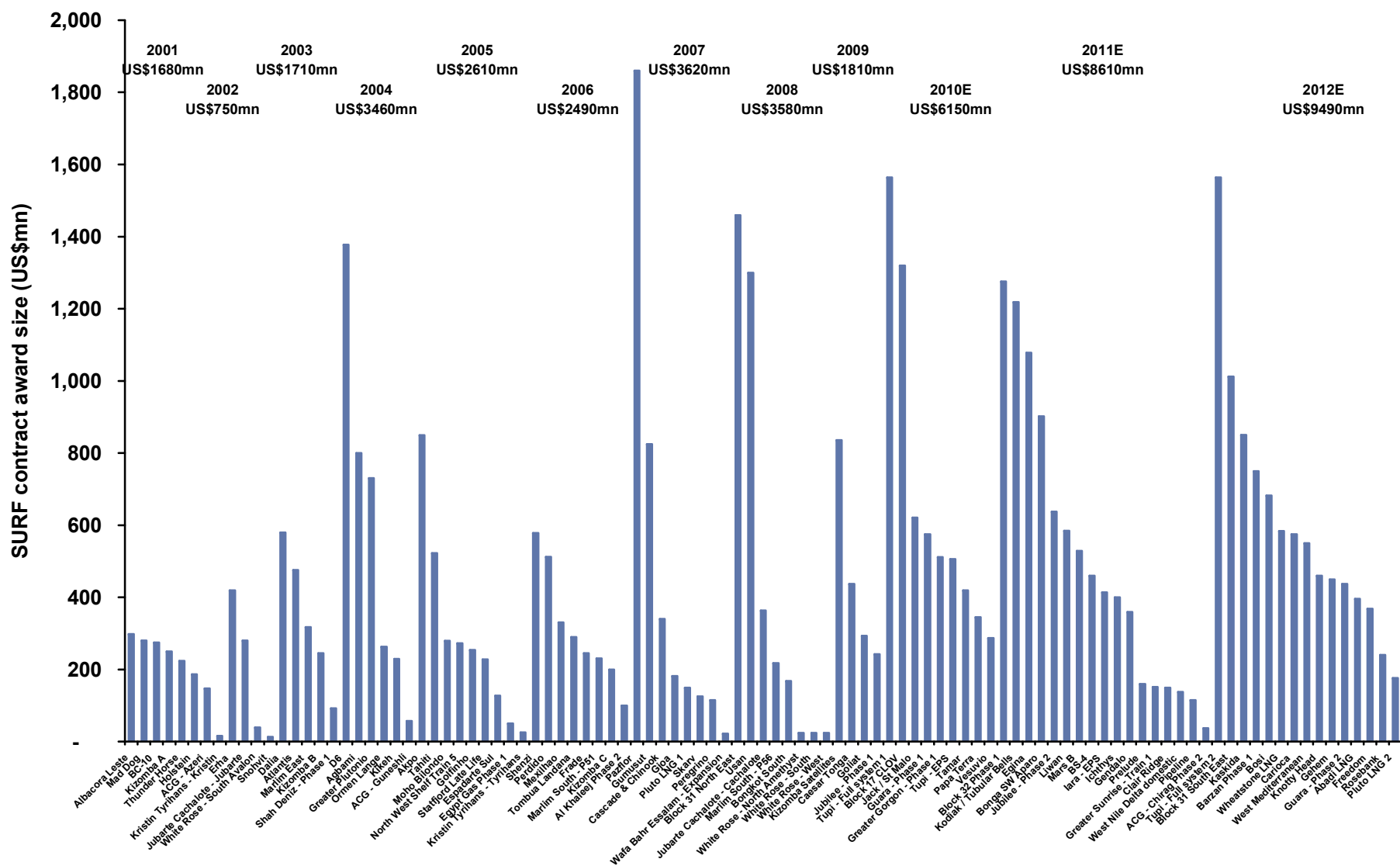
	% of SURF revenues from:		Total high growth
	Brazil	Asia	
Acergy	13%	7%	20%
Subsea 7	26%	3%	29%
Saipem	18%	14%	32%
Technip	42%	13%	55%

Source: Company data, Goldman Sachs Research estimates.

Exhibit 68: SURF vessel demand will outstrip supply in 2011E



Source: Company data, Goldman Sachs Research estimates.

Exhibit 69: Top 280 SURF contract awards by year 2001 to 2012E

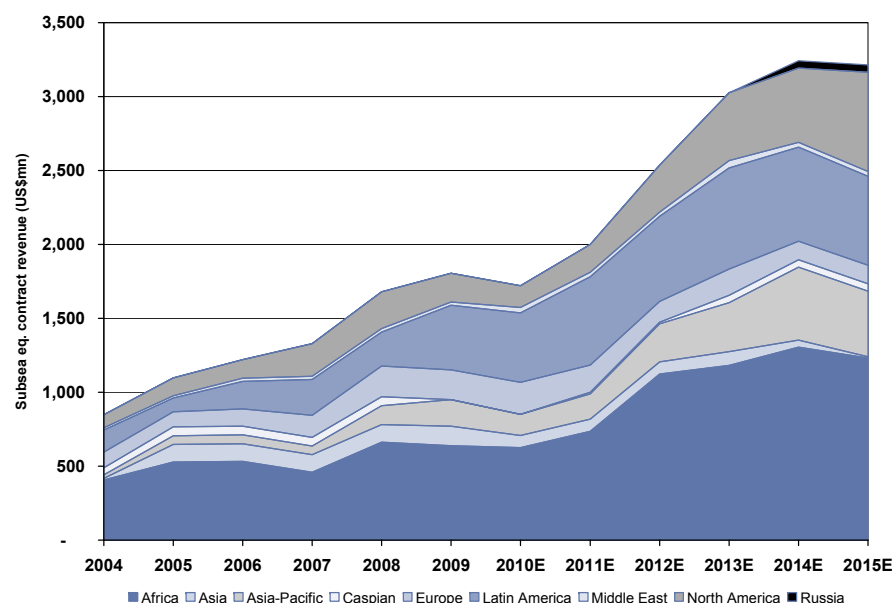
Source: Company data, Goldman Sachs Research estimates.

Subsea equipment – FMC Technologies well placed for growth

The subsea equipment market is driven by very similar dynamics, and the same projects, as the SURF market. We assume that West Africa is more important for the equipment market however due to a higher cost of subsea equipment per well in the region. The pick-up in 2011-2012E in Exhibit 70 reflects some of the West African projects (CLOV, Block 31 SE, Egina, Bonga SW) along with the ramp-up in Brazil of the Santos basin, and some of the Australian LNG projects.

We forecast subsector growth of 12% to 2012, and the companies with the greatest exposure to this growth are FMC Technologies, Cameron and Aker Solutions. While we consider all of these companies to be well placed to benefit from the growth in project awards, our preferred pick in the sector is FMC Technologies, which screens most attractively, having the highest proportion of profits from subsea equipment and related services, as well as having high through cycle returns. Roughly half of Aker Solutions' profits come from subsea equipment and related activities, although its remaining exposure does not screen as well in terms of growth potential. Cameron has a range of services around subsea systems, but also has valve manufacture, surface, measurement and process systems which do not fit the key growth profiles which we are highlighting. Cameron also has lower through cycle returns.

Exhibit 70: African fields under development the growth driver short term
Top 280 subsea equipment capex by year



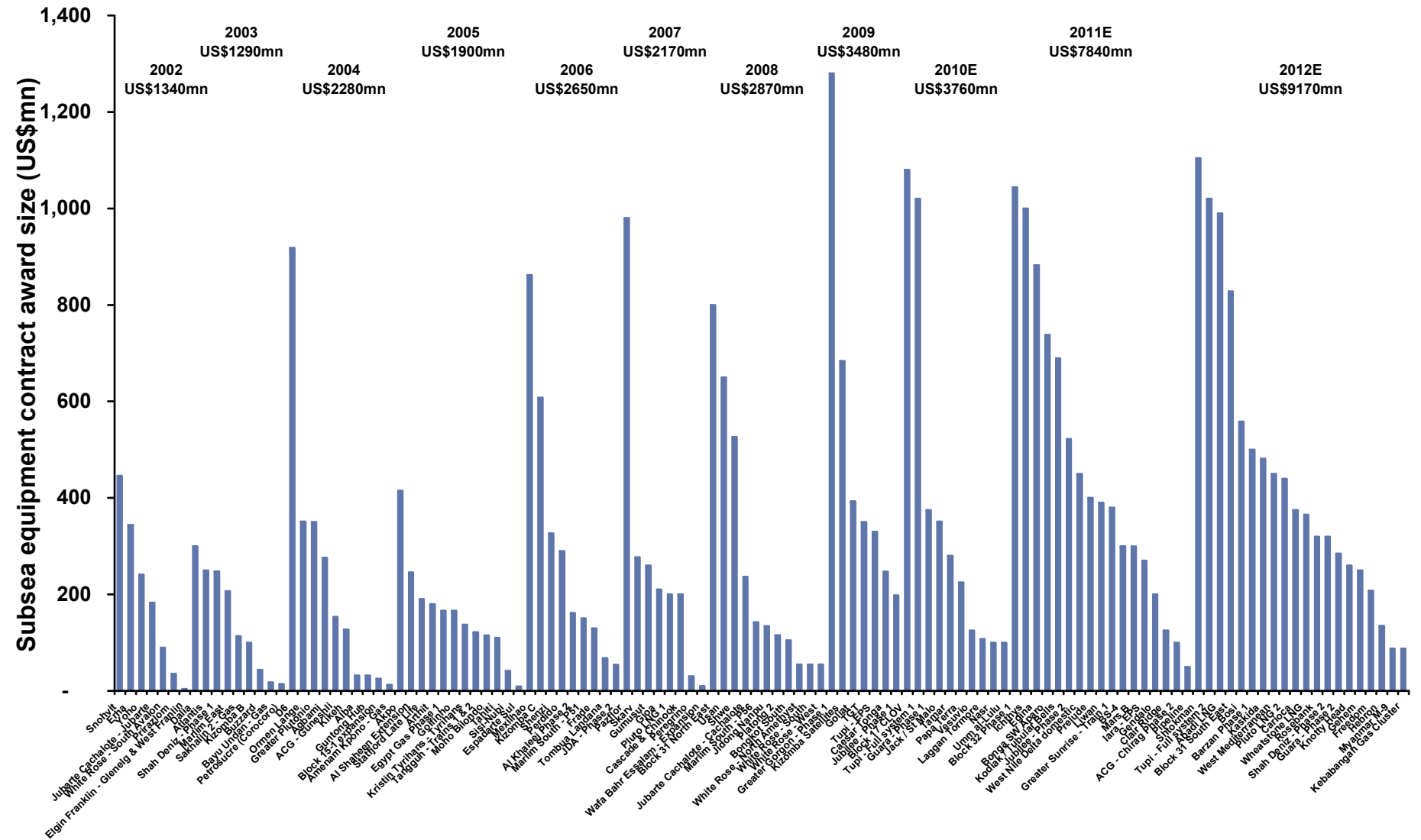
Source: Company data, Goldman Sachs Research estimates.

Exhibit 71: ... but Asia-Pacific will grow in importance
Regional heat-map of Top 280 subsea equipment contract awards

	2010E	2011E	2012E
Regional subsea contract award intensity relative to history	Africa	Africa	Africa
	Asia	Asia	Asia
	Asia-Pacific	Asia-Pacific	Asia-Pacific
	Caspian	Caspian	Caspian
	Europe	Europe	Europe
	Latin America	Latin America	Latin America
	Middle East	Middle East	Middle East
	North America	North America	North America

Source: Company data, Goldman Sachs Research estimates.

Exhibit 72: Top 280 subsea equipment contract awards by year 2002 to 2012E



Source: Company data, Goldman Sachs Research estimates.

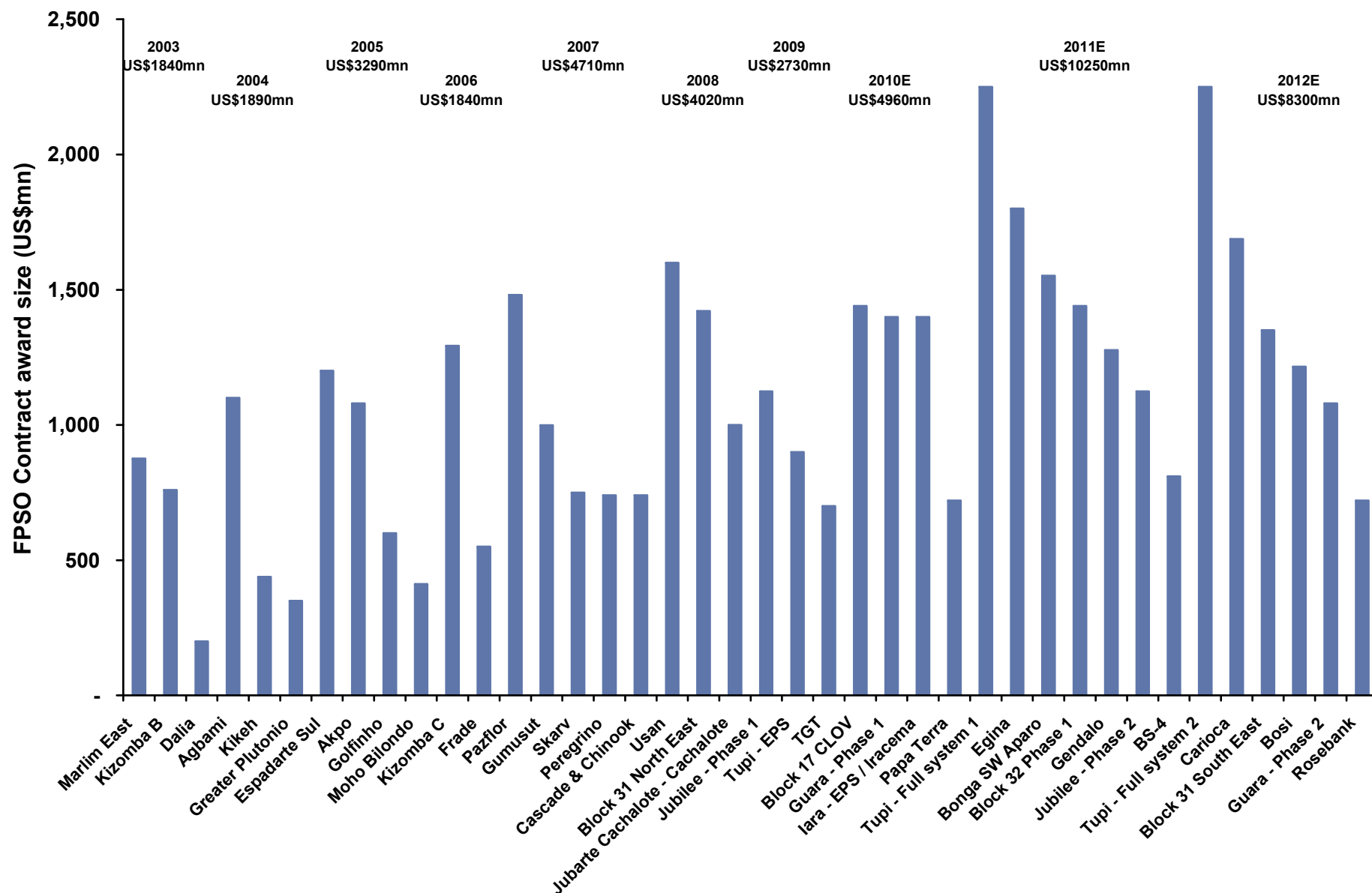
FPSO demand increasing, but industry positioning and leverage less attractive in our view

The FPSO market has been relatively weak over the last two years in terms of large new orders, and the subsector also suffered significantly from the cost increases in raw materials and components for FPSOs: the industry's major players (SBM Offshore, Modec, BW Offshore, Prosafe Production) all reported significant cost overruns in 2008-2009 on fixed price contracts. Cost inflation was very significant over 2005-2008, with costs virtually doubling. Most of the problematic units have now been delivered or renegotiated, and the companies have capacity to take on new contracts due to the low level of large new projects over the past two years.

Cost overruns have left balance sheets generally fairly stretched however, and cost inflation has meant that the upfront capital requirements for new units are higher, exacerbated by the credit crisis which has meant that credit spreads have increased, as has the amount of equity that the companies need to put into financing lease units.

We see demand for new FPSOs increasing significantly, with FPSO capex growing 12% compound until 2012, driven by developments in Brazil and West Africa. In Brazil, lease and operate contracts for Guara and Iracema are shortly to be awarded, and Petrobras has plans to build eight FPSOs for the Tupi full development, with the hulls being built in Brazil and the topside integration also in Brazil by a local/international JV. There will also be FPSO awards outside of the Santos basin in our view, on Papa Terra and BS-4. In West Africa, there are potential FPSO contracts on CLOV and Block 32 in Angola, Bonga SW, Egina and Bosi in Nigeria, and Jubilee phase two in Ghana.

The companies most exposed to this growth are SBM Offshore and MODEC, although while we expect demand to pick up meaningfully in the subsector over the coming two years, we do not see it as a win zone to which we would seek thematic exposure. We believe that the major FPSO companies have the engineering capacity to take on more work, and that competition will remain strong for contracts. Of the major FPSO companies it is only MODEC, SBM Offshore and potentially BW Offshore that we believe have the financial capability to win a US\$1 bn+ contract, but operators will usually want to own these larger FPSOs rather than lease the units. This may encourage the large engineering and shipbuilding companies to bid on the contracts, increasing competition, particularly given the financial constraints and size of the pure FPSO companies. The higher financing costs will also reduce returns in our view, leaving the industry less well placed to reap the reward of the increased demand for FPSOs that we expect.

Exhibit 73: Top 280 FPSO contract awards by year 2003 to 2012E

Source: Company data, Goldman Sachs Research estimates.

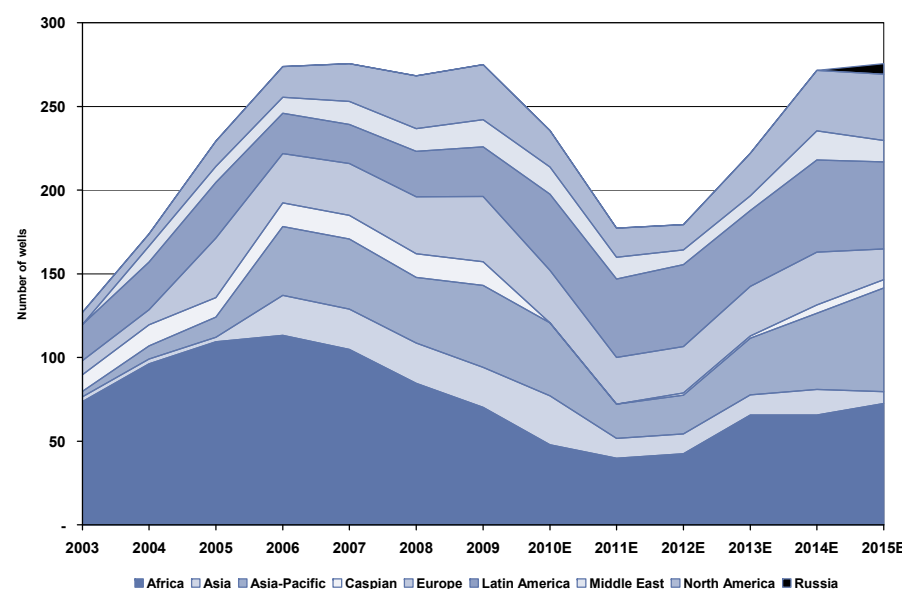
Offshore drilling – ultra deepwater the highest growth area

We have broken down the well requirements for the Top 280 projects through time, and looked at this by region and then by rig type. In absolute terms, we expect the number of wells drilled to fall in 2010 and 2011 from 2009 levels in these projects. This is being driven by fewer wells being drilled in West Africa primarily, but also in Europe, outweighing a higher number of wells being drilled in Latin America. In terms of water depth, from the Top 280 projects we see a lower level of wells being drilled in the deepwater (750-1,500m water depth) in 2010-2011 outweighing a pick-up in drilling in the traditional semi market up to 750m water depth, and in the ultra deepwater where we see significant growth from 2009.

Over 2009-2012, we see drilling in shallower water (50-100m) down 22% pa, in 100-750m water down 14% pa, and in deepwater (750-1,500m) we expect a 24% pa decline, driven by drilling on several large fields halting as they hit peak production or start producing, particularly in West Africa (Agbami, Akpo, Kizomba, Buzzard, Tombua Landana, Greater Plutonio and Tahiti). In ultra deepwater we see strong compound growth (21% pa) from a lower base, driven by Tupi primarily, and then Block 31 in Angola, and Jack/St Malo and Kaskida in the Gulf of Mexico.

Exhibit 74: Growth in Brazil offset by decline in Africa until 2012

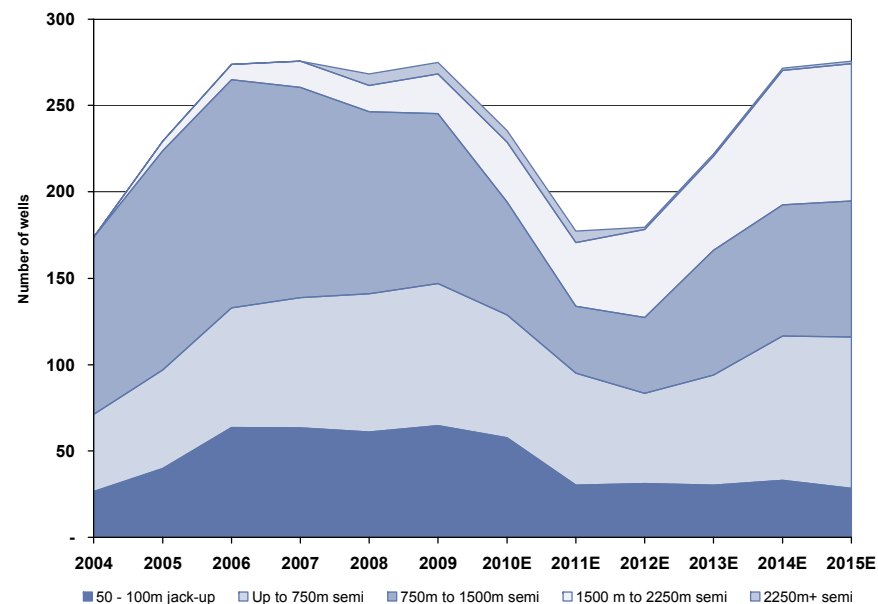
Top 280 offshore wells drilled by year, by region, excluding maintenance wells



Source: Company data, Goldman Sachs Research estimates.

Exhibit 75: Ultra deep water wells the clear area of growth

Top 280 offshore wells drilled by year, by rig type, excluding maintenance wells



Source: Company data, Goldman Sachs Research estimates.

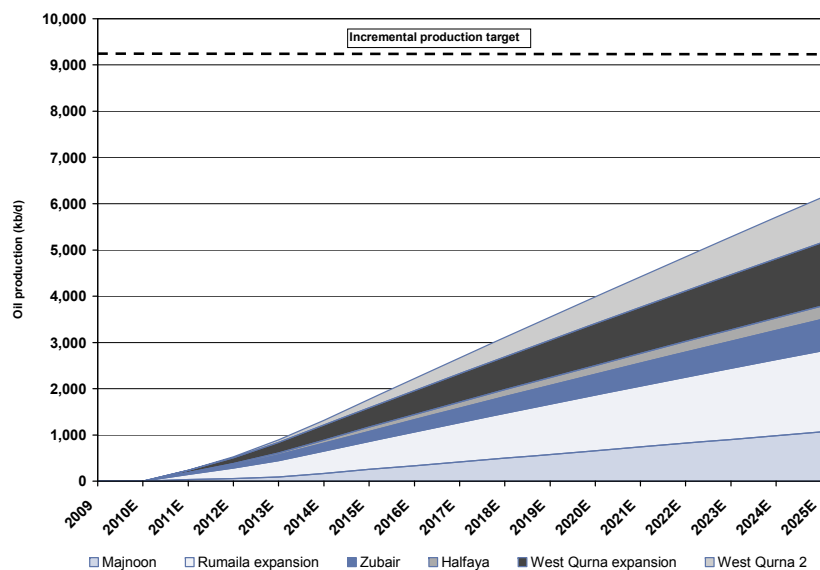
Iraq field development contracts potentially open an exciting growth opportunity

Following the recent signing of production contracts in Iraq, there is a good opportunity for the oil services industry to be a major beneficiary. Margins on the agreements for the oil companies were set at relatively low levels, but the scope of work planned is very significant: the ambitious production targets look for 12 mnbls/d from a base of c.2.5 mnbls/d currently. To achieve this, we believe the consortia will have to invest heavily in new onshore drilling, processing capacity, pipelines and other infrastructure.

All of the fields are onshore, with ramp-up likely to depend on more intensive onshore drilling programs and building out the infrastructure required to deal with the extra volumes. If all of the fields attempt to ramp up simultaneously, we believe that there could quickly be bottlenecks in onshore rigs and related services, potentially driving up prices in the region. Competition for the work is likely to be intense, however it remains to be seen how much of it will go to independent oil services contractors. At Rumaila for example, CNPC will supply the bulk of the pipes, rigs, valves and other equipment. Despite this, we believe that the US integrated oil services providers such as Schlumberger and Weatherford will benefit from some of the more technologically complex work. Weatherford is currently the leading service provider in the country and enjoys an early mover advantage. We also believe that some of the European E&C companies will benefit from the infrastructure build. Saipem and Petrofac are well placed to pick up work on pipelines and any processing facilities as Petrofac has a strong presence in the region (the main base of its engineers is Sharjah, UAE), and Saipem has an advantage with ENI which is one of the oil companies that signed a service contract on the Zubair field.

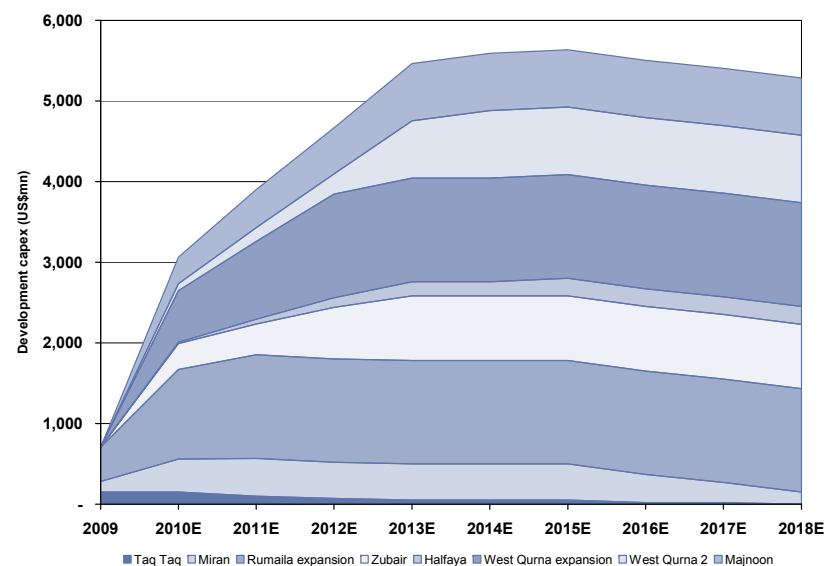
Our preferred way of gaining exposure to growth in Iraq would be through the higher return players, Schlumberger or Petrofac.

Exhibit 76: Iraq fields production profile



Source: Company data, Goldman Sachs Research estimates.

Exhibit 77: Iraq fields capex profile through time



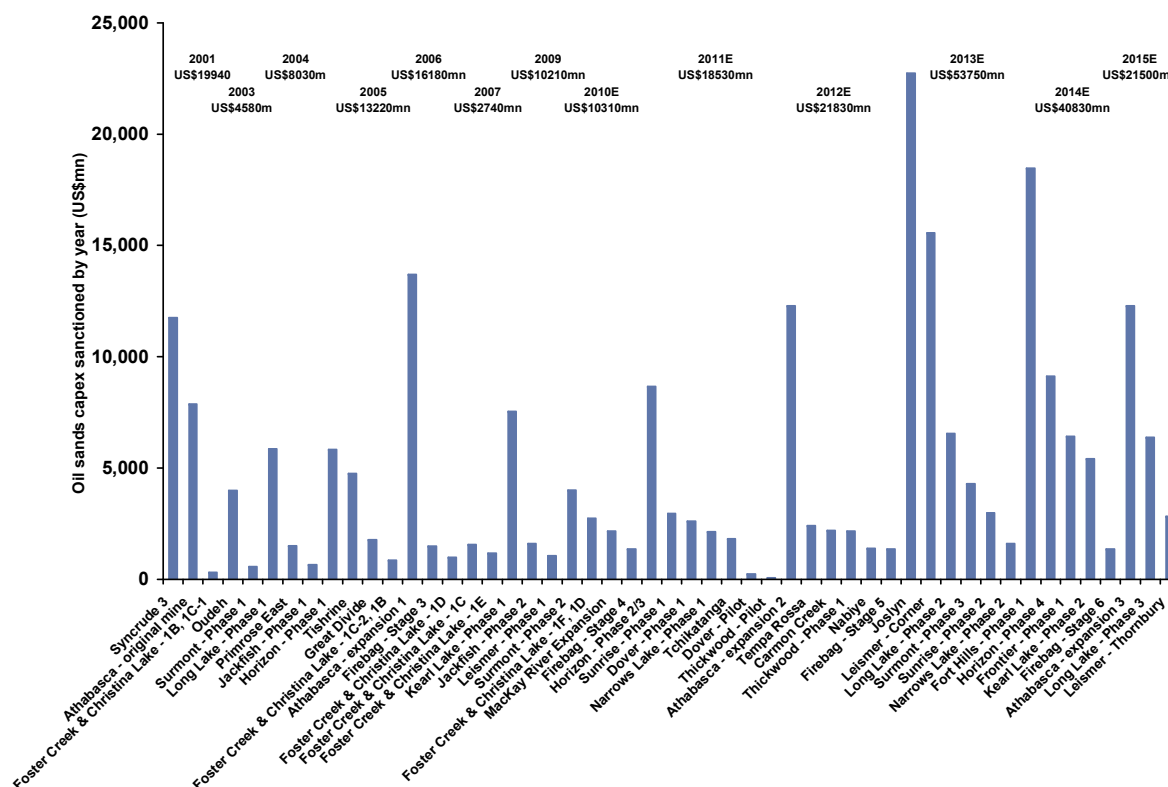
Source: Company data, Goldman Sachs Research estimates.

Heavy oil – some activity expected, but driven by expansions rather than greenfield

Large scale integrated mining projects in the oil sands remain the most marginal development type among the Top 280 and despite the softening of some input costs (such as steel), we expect only modest activity in 2010. In our view, expansions to existing projects are more likely to progress than greenfield projects, with a particular bias towards thermal projects (using parallel horizontal wells to recover bitumen) rather than the more labour-intensive mining projects.

Based on the Top 280 analysis, we view Canadian oil sands as one of the least attractive areas of exposure for oil services companies in 2010 as we expect companies to focus on developing resources in the deepwater and Australian LNG. The oil sands remain a compelling resource however and we expect large-scale activity to return to the oil sands in 2011, with the sanction of Horizon Phase 2, followed by Athabasca Expansion 2 and Joslyn. In the short term, thermal project expansions at Firebag, Foster Creek, and Christina Lake will continue to provide some support to demand for land rigs and construction workers, and we note in addition that activity will begin on ExxonMobil's Kearl mine, however large scale mine or upgrader construction activity is needed to make the area attractive for global oil services companies and, as such, we prefer exposure to other areas.

Exhibit 78: Top 280 oil sands sanctions by year 2001 – 2015E



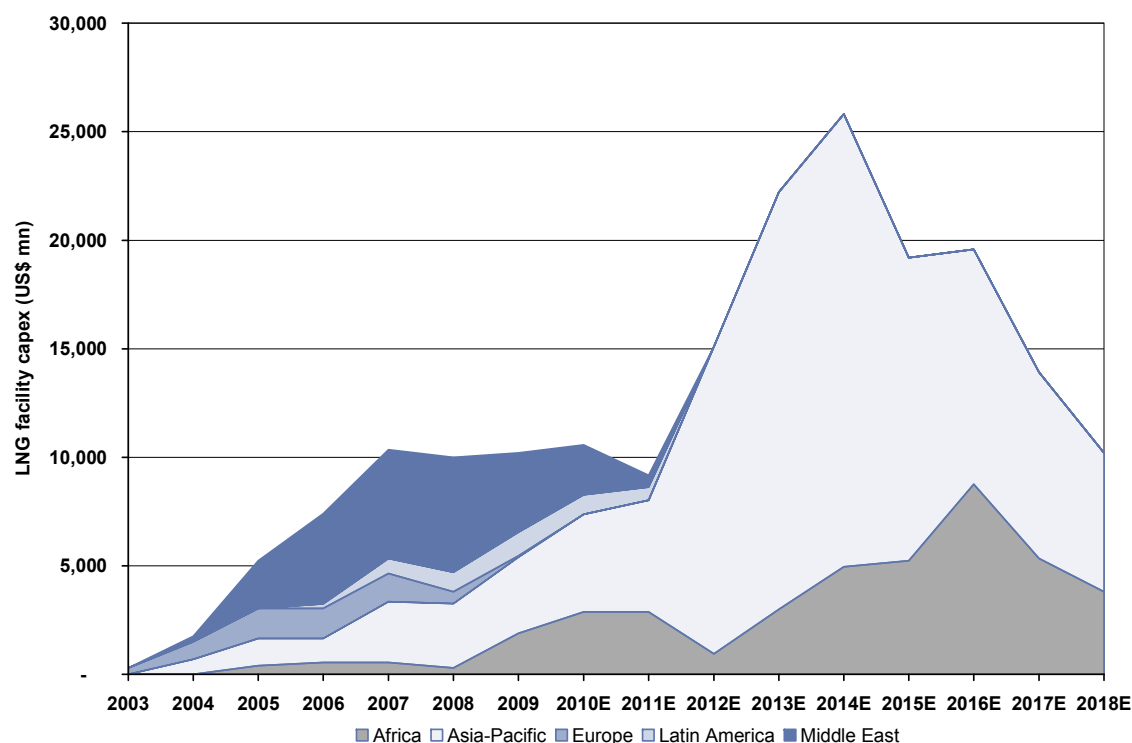
Source: Company data, Goldman Sachs Research estimates.

LNG – strong activity growth ahead, driven by a wave of new projects in Asia Pacific

We view services providers in the LNG arena positively and forecast 14% compound activity growth (based on capex) between 2009 and 2012E in this win zone, driven almost entirely by Asia-Pacific. The region is set to become a major area of liquefaction facility construction, as ground is broken at projects such as Greater Gorgon (off Australia's North West Shelf) and at the PNG Gas Project. This will be followed in 2010 and 2011 in our view by a gradual ramp-up of activity in Queensland as coal-bed methane liquefaction projects such as Queensland Curtis LNG and Gladstone LNG get under way.

With an expected US\$113 bn to be spent over the next decade on liquefaction facilities alone (i.e. excluding upstream costs) the Asia-Pacific LNG prize is substantial and we expect a range of services companies to benefit. The downstream aspects of the development will require large-scale E&C contractors for the design, fabrication, installation and commissioning of the facilities, and the upstream portions will require complicated subsea tie-back infrastructure (in the case of Greater Gorgon) or the drilling of many unconventional gas wells (e.g. Queensland Curtis LNG, Gladstone LNG). We analyse the SURF and subsea equipment awards associated with these projects in the relevant sections above, while in Exhibit 79 we outline the expected spend on the downstream aspect of the projects by region.

Exhibit 79: Top 280 liquefaction capex by region 2003 – 2018E



Source: Company data, Goldman Sachs Research estimates.

In the case of the Australian North West Shelf and Queensland coal-bed methane projects, we expect a significant amount of work to be awarded to domestic contractors, however we also see scope for international involvement as experienced LNG contractors will help to avoid the bottlenecks and inefficiencies that have beset other regions of intense investment, such as the Canadian oil sands and the Qatari gas projects. Projects such as Gorgon, for which we forecast US\$56 bn of investment over the life of the development, will be broken down and awarded in discrete packages ranging in size (e.g. the US\$400 mn award to GE to provide compression trains and CO₂ sequestration equipment) and we expect many of these to go to international bidders with specific expertise. We provide a summary of our expectations in Exhibit 80.

We highlight Foster Wheeler and JGC as being well exposed to the growing LNG theme in Asia-Pacific.

Exhibit 80: Status on key LNG projects

Project	Participants	Cost US\$ bn	Current status	FEED Contractor	FEED Award date	Likely FID
Gorgon LNG	Chevron; Exxon; Shell	56	KBR led JV was awarded EPCM for \$2.3bn on 9/14/09.	Downstream: KBR, JGC, Hatch & Clough JV	Sep-08	4Q09
PNG LNG	ExxonMobil; Oil Search; Santos; Nippon Oil ; AGL; MRDC	16	Early works on the project have commenced. It has reached commercial terms for its initial production capacity with four Asian buyers.	Downstream: Bechtel & Chiyoda Upstream: Eos JV (KBR+Worley Parsons)	May-08	4Q09
Fisherman's Landing LNG	Liquefied Natural Gas	6	FEED for the second train commenced recently and the first train FEED is nearing completion. CBI was also recently appointed as the Project Management Consultant.	SK Engineering & Construction; Laing O'Rourke Australia Construction	Aug-09	2010
Gladstone LNG (GLNG)	Santos; Petronas	14	GLNG Environmental Impact Statement (EIS) has been submitted to the Queensland Government and released for public comment.	Downstream: Bechtel Upstream: FWLT & FLR	Dec-08	2010
Queensland Curtis LNG (QCLNG)	BG Group	23	Environmental Impact Statement (EIS) has been submitted to the Queensland Government and released for public comment.	Bechtel	Jul-08	2010
Ichthys LNG	Inpex; Total	27	An Environmental Impact Statement (EIS) was to be released by Christmas 2009 although this has now been delayed and is expected in the first half of 2010.	Downstream: JKC JV (JGC, Chiyoda & KBR)	Jan-09	2011
Greater Sunrise LNG	Woodside	16	Woodside is currently evaluating the commercial and technical aspects of the Greater Sunrise LNG project.	Probable winners: KBR/FWLT/Worley Parsons		2011
Australia Pacific LNG (APLNG)	Origin Energy; Conoco Phillips	20	Owners recently acquired a site on Curtis island. Draft terms of reference was also released outlining the background of the project and EIS is expected to be lodged in early 2010.	Probable winners: KBR/FWLT/Worley Parsons	1Q10	2011
Prelude FLNG	Shell	7	Environmental Impact Statement (EIS) was recently released for public comment. The project has entered the FEED phase.	Technip & Samsung Heavy Industries	\$39,995	2011
Pluto Train 2	Woodside	8	Woodside has commenced early FEED work on Pluto train 2 . Woodside is in talks with several companies to supply additional gas for the project.	Probable winners: KBR/FWLT/Worley Parsons	4Q09	2012
Wheatstone LNG	Chevron	20	Chevron recently awarded the FEED contract and expects to ship first gas from the plant in 2016.	Bechtel	Jul-09	2012

Source: Company data, Goldman Sachs Research estimates.

GS SUSTAIN winners continue to do well in Top 280

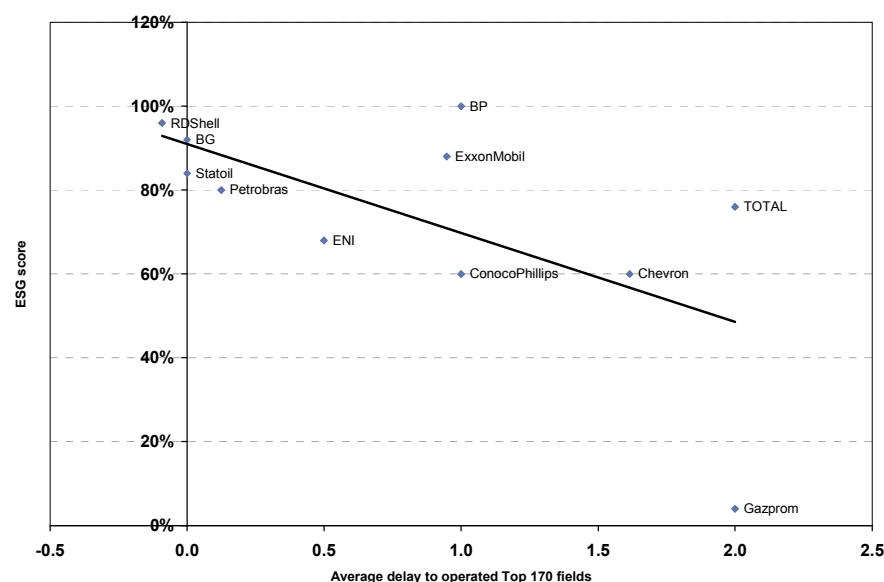
The value of the Top 280 assets can be severely impaired by poor project execution, both as a result of cost overruns and delays. This is particularly true at a time when projects are becoming bigger and more complex. We have therefore attempted to assess the track record of different companies as operators.

We find that the ESG (Environmental, Social and Governance) score compiled by the GS SUSTAIN team has a correlation with each company's ability to deliver projects on time (Exhibit 81). This score reflects the effectiveness with which each company is addressing a range of ESG issues including overall corporate governance.

More broadly, we find a strong correlation between the Top 280 and the GS SUSTAIN winners. GS SUSTAIN identifies long-term industrial winners that have a strong industry positioning, high ESG scores and high return on capital. Three of the six winners in Top 280 are GS SUSTAIN winners. RDSH scores well on management quality with respect to ESG issues and its industry positioning but its below sector-average returns mean it is not highlighted as an overall GS SUSTAIN leader, although we note that exposure to a profitable Top 280 portfolio could change this in the longer term. Tullow and GALP are currently not assessed under the SUSTAIN methodology.

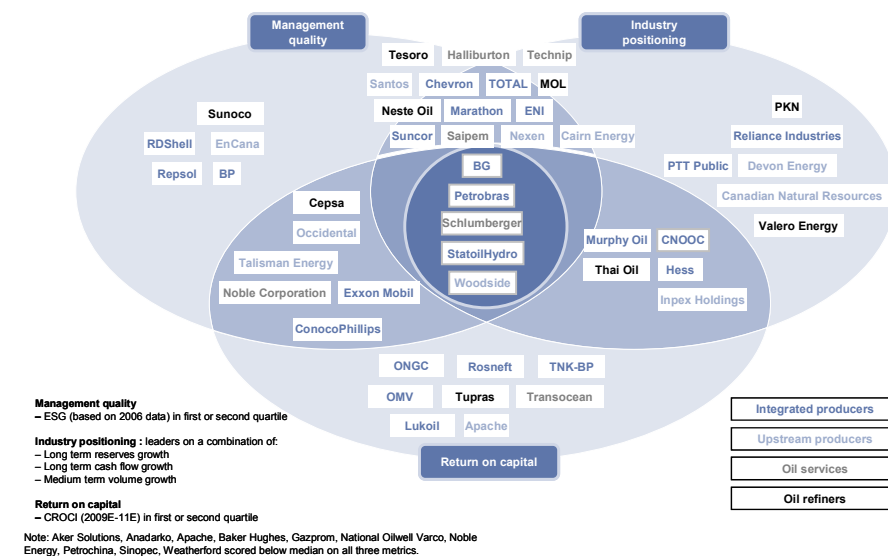
Exhibit 81: ESG scores vs. delays

Some correlation between ESG scores and delays experienced on operated Top 170 projects since February 2007



Source: Company data, Goldman Sachs Research estimates.

Exhibit 82: Global Energy GS SUSTAIN winners



Source: Company data, Goldman Sachs Research estimates; Santos and Woodside are covered by GS JBWere.

Top 280 winners have delivered on potential

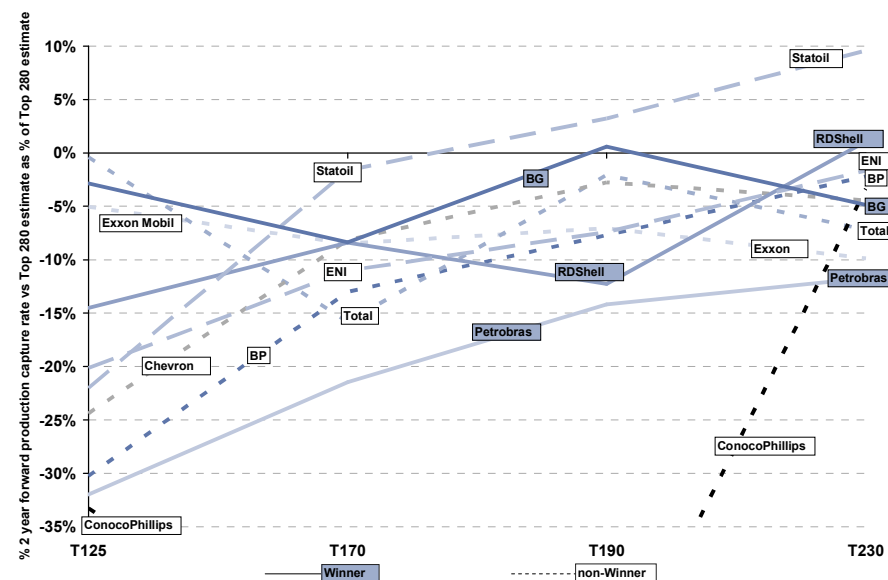
We believe that an assessment of operator effectiveness should consider both the execution of sanctioned projects and also the ability to get projects sanctioned. Although poor project delivery tends to be well flagged, the negative impact of failing to sanction a portfolio can have a more material effect. As a result we look at capture rates for both two (operational delivery) and five years (ability to move projects from discovery to production).

We have analysed those companies with more than five operated projects to assess how effective each company has been in bringing production online over the past five years and two years. To do this, we have looked back to each of the six previous iterations of the Top 280 report (starting with Top 50 in 2003). We have taken the volumes that we predicted that the fields operated by each company would produce in five years and two years from the date of publication and we compare it with the production that we currently expect from those fields, thereby giving an idea of the capture rate for each company. We believe that low levels of lost production are an indication of effective operatorship, both in terms of effective development and prompt sanctioning. We note that these data points are based on our estimates and do not necessarily reflect companies' guidance at the time of writing and that companies with a large proportion of assets already in production tend to be favoured by this analysis.

The three Top 280 winners included in this analysis ranked in the top five operators assessed on this metric in the Top 190 and in the Top 230 (on a five-year basis), which we believe indicates a good combination of delivery and ability to sanction. On a two-year view, BG has been a consistently strong performer, with Shell also a reasonable performer. Petrobras has been weaker on a two-year capture rate, but this is offset by its ability to sanction projects effectively in the Brazilian offshore

Exhibit 83: Production capture rate of operators – two-year capture

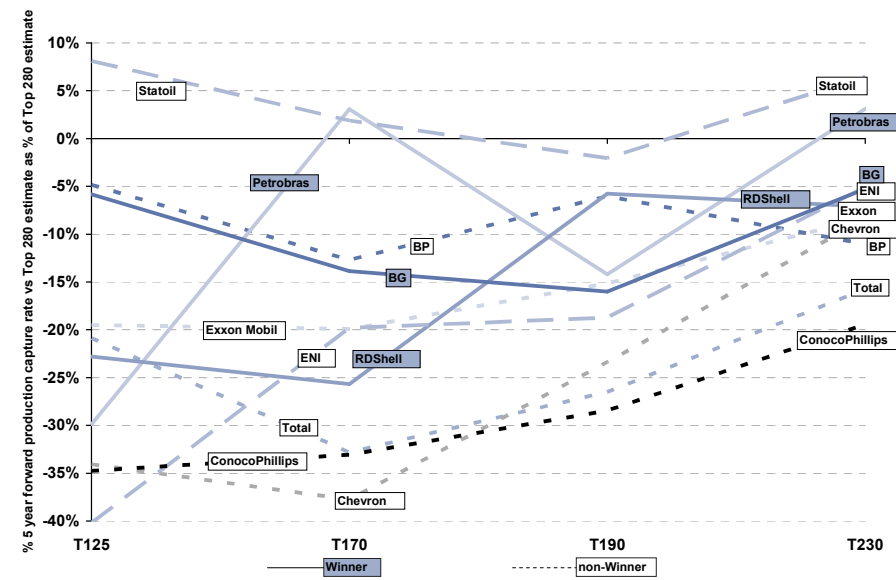
100% of working interest operated production



Source: Goldman Sachs Research estimates.

Exhibit 84: Production capture rate of operators – five-year capture

100% of working interest operated production



Source: Goldman Sachs Research estimates.

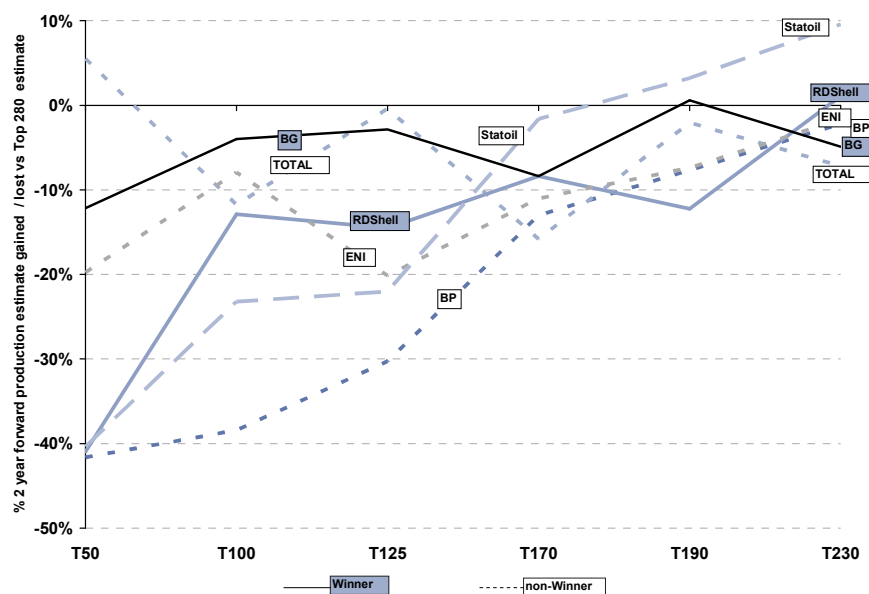
Operatorship in more detail: BG consistently performs well

Among the Europeans, Statoil performs well on both the two-year and five-year view – largely a result of the Norsk Hydro legacy, with successful delivery of Ormen Lange and Grane, with Peregrino and Gjoa remaining on track. BP has also executed its projects well in the past four years, after a disappointing performance in the earlier years on a two-year horizon (largely driven by delays at Thunder Horse). RDSH's performance has improved over time, in both time horizons, with its key projects in Qatar and the US progressing relatively well vs. expectations after initial disappointments from Athabasca and Bonga SW. BG has been a consistently good performer on both metrics, albeit this only involves the production in Egypt and Karachaganak, which were delivered early in the dataset, although continuing progress at Curtis LNG has meant that performance between Top 230 and Top 280 has been reasonable. TOTAL has been adversely impacted by the decision to delay Joslyn and by the slower than expected sanctioning in deepwater West Africa. On the longer dated assessment, ENI has suffered from delays at Kashagan vs. our assumptions in the first years of publication but much of its portfolio is now producing or about to begin producing, thereby minimizing the risks of delays and giving the company a good performance from the Top 230.

Overall, we note that on a two-year view there has been a trend of improving performance as more projects from the dataset are brought online, thereby reducing the risks of production loss.

Exhibit 85: Production capture rate of European operators – two-year capture

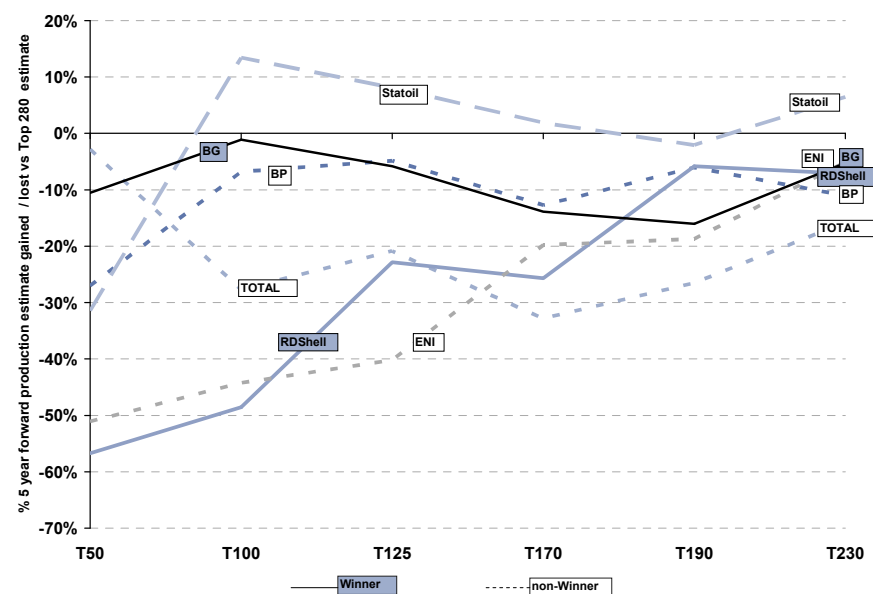
100% of working interest operated production



Source: Company data, Goldman Sachs Research estimates.

Exhibit 86: Production capture rate of European operators – five-year capture

100% of working interest operated production

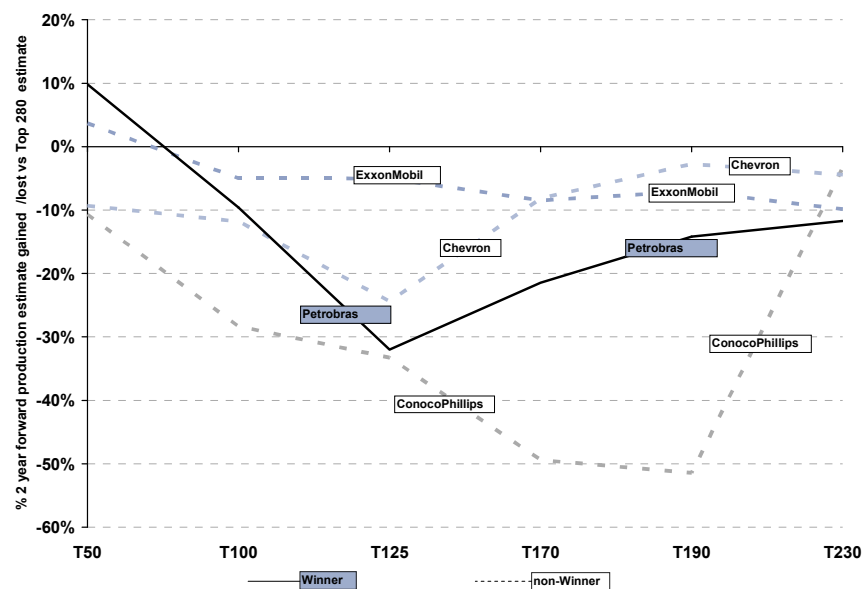


Source: Company data, Goldman Sachs Research estimates.

Operatorship in more detail: ExxonMobil scores consistently well

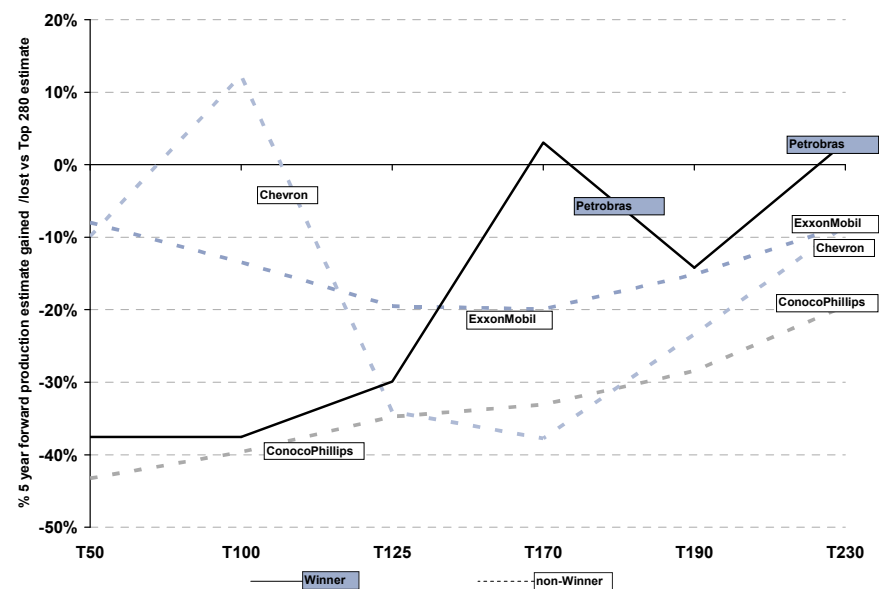
Petrobras has been a good performer on a five-year view, showing the company's ability to sanction new projects and keep the development hopper full; on a two-year view, however, it has been less impressive, highlighting some of the delays and lower-than-expected plateau rates that the company has had to contend with (from fields such as Golfinho). Although it is early days in the development of the pre-salt Santos plays, sanctions of major phases look imminent in this area. Exxon has been a good operator on both a two-year and five-year view relative to its peers. Chevron's five-year performance dipped since Top 100 as a result of delays in sanctioning Greater Gorgon, Ranggas Geheem and Gendalo which slipped back vs. our original estimates. The sanctioning of projects such as Greater Gorgon in 2009 and the imminent sanctioning at Jack/St Malo have helped the company recover since publication of the Top 230, however, and shows the importance of effective sanctioning in securing production growth. Disappointing production at projects such as Surmont and Block 15-1 relative to our original estimates weighs on Conoco's performance.

Exhibit 87: Production capture rate of American operators – 2 year capture
100% of working interest operated production



Source: Company data, Goldman Sachs Research estimates.

Exhibit 88: Production capture rate of Americas operators – 5 year capture
100% of working interest operated production



Source: Company data, Goldman Sachs Research estimates.

Self-operatorship allows greater control of Top 280 portfolio; Petrobras leads the large players

The oil & gas industry is characterized by split ownership of fields, with one company as the operator; thus companies rarely operate 100% of their new legacy assets, especially when they have a large portfolio.

Of the companies which have a large portfolio of projects, Petrobras stands out for the very high percentage of assets it operates itself (95% of net entitlement reserves worth 93% of the company's Top 280 NPV). This means that its future is in its own hands – an attractive position in which to be given the good five-year production capture rate that the company has achieved in recent editions of this report. We note, however that heavy demands will be placed on the company's own human resources and believe that assistance in the Santos basin will be increasingly offered by partners (such as BG operating the Abare West asset).

Most of the Majors operate around half of their portfolio's value, highlighting the importance that they place on being in control of their major developments. It also illustrates the relevance of assessing each company's ability to deliver the fields according to plan.

It is notable that both BG and Repsol have relatively low exposure to self-operated fields – a result of them both being heavily exposed to Brazil, and therefore levered to the quality of Petrobras' operatorship. Statoil's proportion of self-operated value is also low, indicating a reliance on partners for the development of some of its legacy assets, especially in areas outside Norway.

Exhibit 89: Company exposure to self-operated projects by reserves and value

Company	# projects operated	Reserves operated	NPV of operated projects	Total reserves	Total NP	% of reserves	% of NPV
Cairn India	1	387	\$10,383	387	10383	100%	100%
Canadian Natural Resources	2	5620	\$23,645	5620	23645	100%	100%
Dragon Oil	1	319	\$5,204	319	5204	100%	100%
Heritage	1	124	\$3,065	124	3065	100%	100%
Husky Energy	3	1576	\$7,277	1576	7277	100%	100%
Woodside	5	2891	\$19,809	2891	19809	100%	100%
Cenovus	1	1536	\$6,575	1536	6575	100%	100%
PetroChina	5	7565	\$31,958	8148	33419	93%	96%
Maersk	1	457	\$12,120	558	12892	82%	94%
Tullow	2	572	\$9,574	593	10197	96%	94%
Petrobras	17	19097	\$149,544	20092	161482	95%	93%
Reliance	1	1702	\$14,714	1837	16607	93%	89%
Nexen	3	1931	\$15,773	2256	18028	86%	87%
Lukoil	4	4831	\$25,726	5508	30524	88%	84%
Murphy	1	234	\$5,589	399	6792	59%	82%
Rosneft	2	5147	\$21,396	5396	27335	95%	78%
Gazprom	6	28539	\$121,049	32754	155057	87%	78%
PTTEP	3	703	\$5,419	833	7004	84%	77%
SASOL	1	137	\$3,416	291	4464	47%	77%
BP	27	9649	\$91,655	19365	124681	50%	74%
Apache	1	159	\$2,451	718	3351	22%	73%

Company	# projects operated	Reserves operated	NPV of operated projects	Total reserves	Total NPV	% of reserves	% of NPV
Devon Energy	1	580	\$10,608	2252	14608	26%	73%
RDSShell	19	7798	\$83,457	16908	121039	46%	69%
Chevron	19	8040	\$58,616	12823	94811	63%	62%
Suncor	4	6733	\$12,896	7297	20961	92%	62%
Santos	2	970	\$2,517	1178	4100	82%	61%
ExxonMobil	22	10107	\$60,241	19593	112900	52%	53%
ConocoPhillips	9	5202	\$21,337	11312	40214	46%	53%
Sinopec Group	2	266	\$3,801	924	7217	29%	53%
INPEX	2	2403	\$8,101	3548	18614	68%	44%
TOTAL	20	4497	\$30,953	12216	72032	37%	43%
Statoil	7	4307	\$25,211	9057	60806	48%	41%
ENI	10	2864	\$22,629	7441	55849	38%	41%
Occidental	1	171	\$2,562	996	6596	17%	39%
Marathon	1	151	\$5,053	1652	13084	9%	39%
Noble Energy	1	408	\$1,315	585	3588	70%	37%
Hess	1	165	\$3,904	1083	12020	15%	32%
BHP Billiton	1	243	\$6,325	1341	20214	18%	31%
Anadarko	3	191	\$2,318	546	7514	35%	31%
BG	6	3028	\$13,143	8391	49067	36%	27%
Repsol	4	761	\$2,770	2233	15028	34%	18%

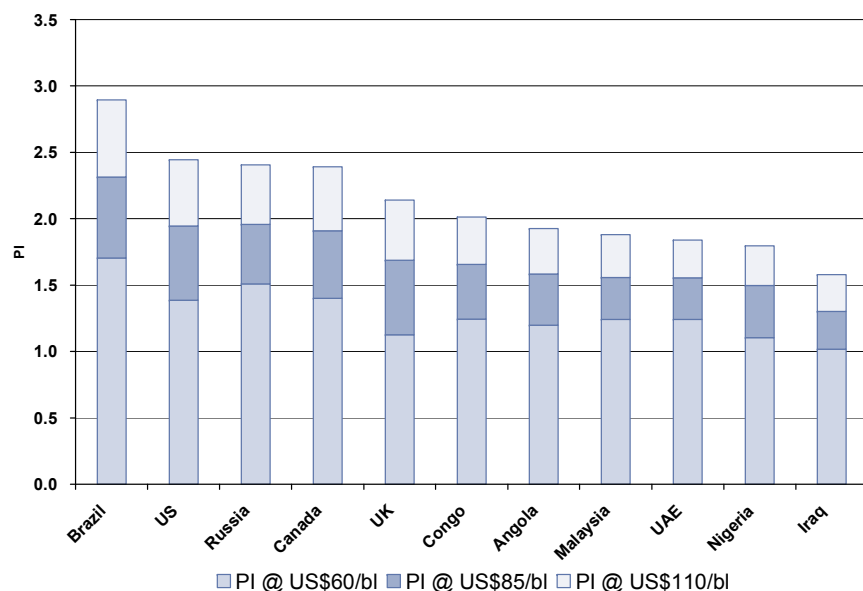
Source: Goldman Sachs Research estimates.

Profitability, the oil price and the Top 280; costs and fiscal regimes erode oil price returns

The fiscal regime under which a project operates is a significant element in determining the project's sensitivity to the oil price and profitability. Typically the areas of most sensitivity are in license regimes (Brazil, UK and US), production based PSCs (Nigeria) and fixed take PSCs (Congo). Despite an element of the tax take in Alberta in Canada being levered to the oil price, this is a relatively small part of the overall tax take and, in any case, a large number of the projects generate relatively low returns at our US\$85/bl oil price assumption meaning that the operational leverage from the country remains high. The lower sensitivity projects are those which have either windfall taxes at higher oil prices (Malaysia), service based contracts governed by a fixed remuneration fee (Iraq and UAE) or a profitability based PSC regime (Angola). Oil price sensitivity in Iraq is a result of the Miran field which is governed by a PSC while oil price leverage in UAE is a result of liquids production in gas fields operated under PSCs. We see no material leverage from fixed remuneration services contracts in these countries aside from the impact on the pace of cost recovery.

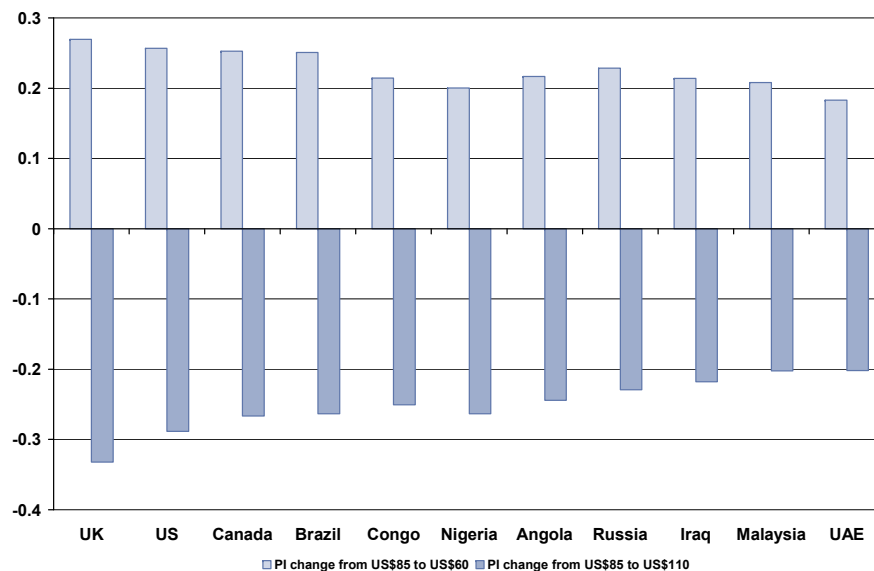
We note that US\$110/bl – our oil price assumption for 2011E – results in a number of jurisdictions seeing P/I ratios in excess of 2, indicating very high returns. We believe that the risk of fiscal renegotiation tends to increase as returns go up. Although most of the countries where returns are particularly high at high oil prices are in relatively stable political areas, we are dubious as to the level of protection this provides given the tax changes in Canada and the UK in the last decade.

Exhibit 90: P/Is of oil projects under different oil price scenarios by country
Excludes gas based and producing projects



Source: Goldman Sachs Research estimates.

Exhibit 91: Sensitivity of PI under different oil price scenarios
Excludes gas based and producing projects



Source: Goldman Sachs Research estimates.

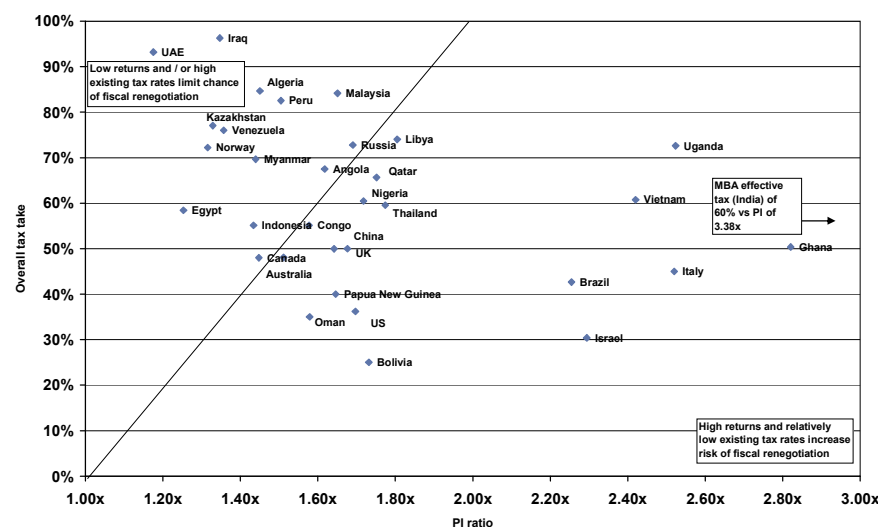
High returns and low taxation rates in production increase the risk of fiscal renegotiations

In recent years as commodity prices have increased, we have seen a number of countries adjust their fiscal regime in order to effectively tax away outsized returns gained through access to a country's hydrocarbons (i.e. Kazakhstan, Nigeria, Canada, UK, Venezuela). We believe that three factors are worthy of consideration in assessing whether a country is at risk of adjusting its fiscal terms:

- High returns for producers in the country. Countries need to ensure that companies continue activities and therefore low returns are likely to dissuade any fiscal changes
- A low existing tax rate. If a government's fiscal take is already high, a relatively large proportion of profits will go to the government in any case and the possible delta by which to move the tax take is more limited
- If a country's major oil assets are already producing, we believe there is less incentive to avoid changing the fiscal terms as oil companies in the country will have already sunk substantial costs and will be less able to simply halt development

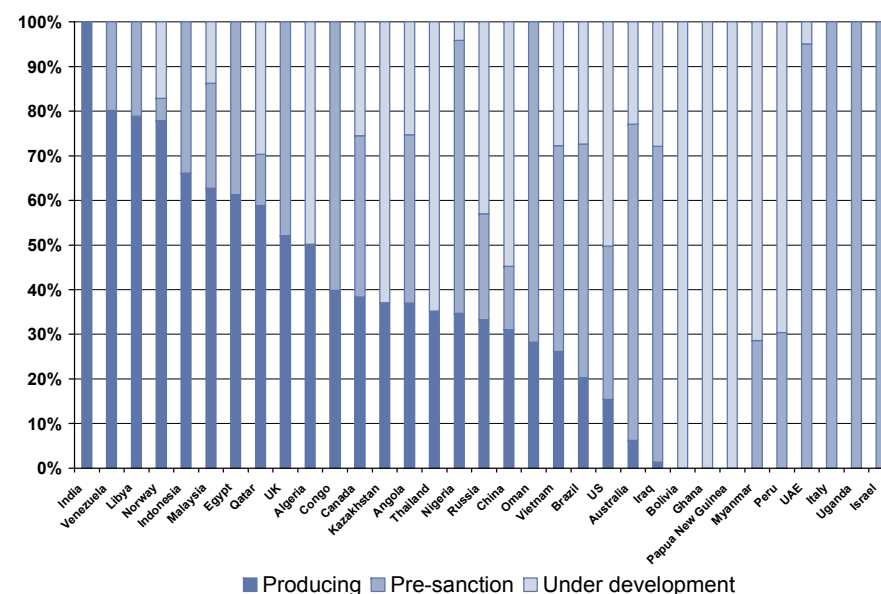
We note that if a country is regarded as a "frontier" location fiscal terms will need to be better in order to encourage drilling activity. We believe that a number of those countries at the bottom right of Exhibit 92 meet this criterion. Although we believe that in the short term the desire to encourage further exploration may prevent short-term fiscal changes, we expect future activity to be more highly taxed. We believe some risk could remain to initial discoveries in the medium term due to the outsized returns generated.

Exhibit 92: High P/Is and low tax rates put outsized returns at risk
Country tax rates vs. PIs for pre-sanction and under development projects



Source: Goldman Sachs Research estimates.

Exhibit 93: Countries with many legacy assets in production are at risk
% of Top 280 reserves in production by country



Source: Goldman Sachs Research estimates.

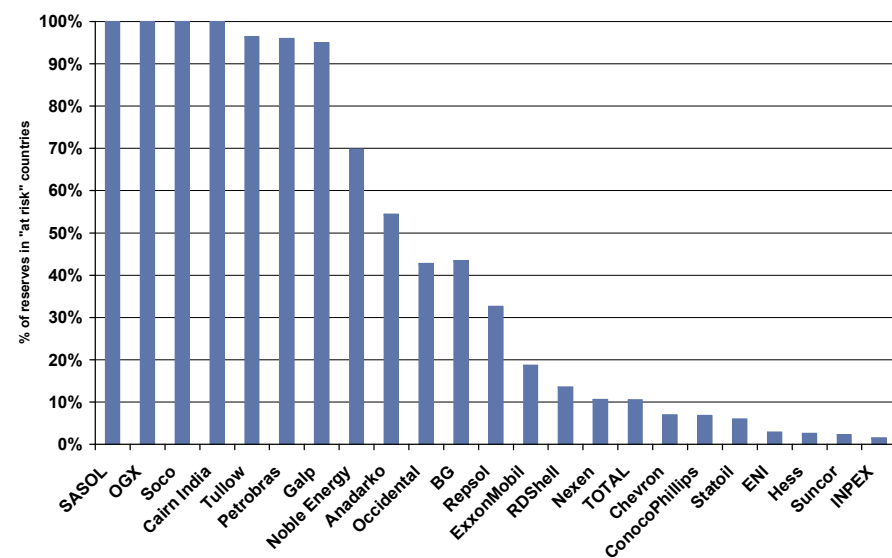
Companies and oil price sensitivity: BP low sensitivity; ConocoPhillips and RDSHELL higher

Unsurprisingly, the geographical focus of a company's Top 280 portfolio has a significant effect on the portfolio's sensitivity to the oil price. As expected, we find that the pure play Canadian oil sands producers typically have the highest levels of sensitivity to the oil price.

When analyzing oil price sensitivity on a company level, however, location is not the only factor. Exposure to fixed price gas or gas prices which have only a weak relationship to the commodity price (i.e. Henry Hub) will limit sensitivities regardless of the fiscal regimes under which a company operates. Therefore, we see less sensitivity in BP's portfolio relative to other Majors, despite its relatively high exposure to license regimes, as we assume that the company's large US gas portfolio is insensitive to changes in crude prices. BG's portfolio is also limited in its oil price sensitivity by its exposure to Egyptian and Omani fixed price gas contracts and the low operational leverage of its Brazilian portfolio. Statoil is also limited.

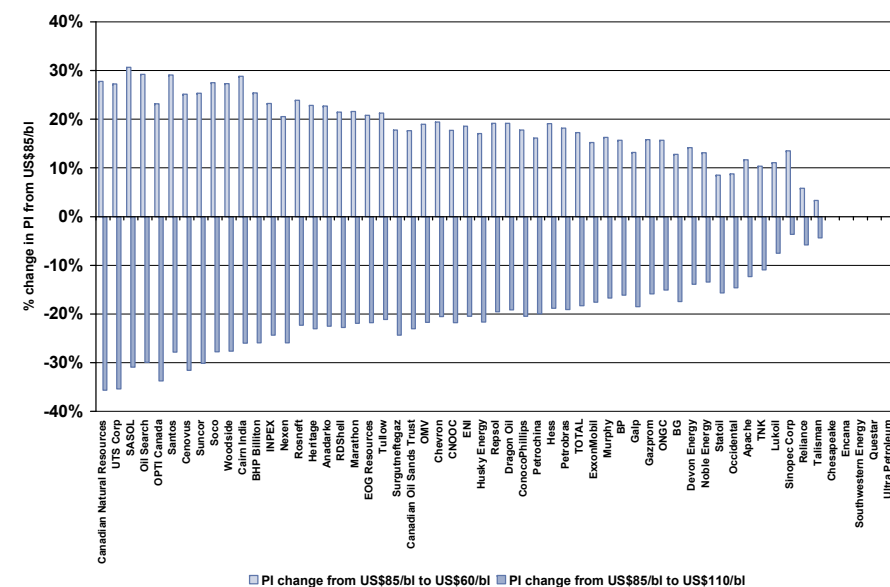
We have assessed which companies have the most exposure to those countries we believe are at risk of a fiscal renegotiation (defined as those countries on the far right of Exhibit 92 – namely, Israel, Italy, India, Ghana, Uganda, Vietnam and Brazil, or countries with over 50% of their Top 280 reserves in production and are on the right of the line in Exhibit 92). We note that, especially in the context of frontier locations where discoveries have only recently been made, renegotiation may take some time and is initially likely to occur to PSCs/licences signed subsequent to the first discoveries. We continue to believe, however, that at some point the initial discoveries in an area are exposed to some risk of fiscal renegotiation.

Exhibit 94: % of Top 280 reserves exposed to at-risk countries



Source: Goldman Sachs Research estimates.

Exhibit 95: Company sensitivity dependent on asset type and location



Source: Goldman Sachs Research estimates.

Tax and oil price linked through PSC taxation

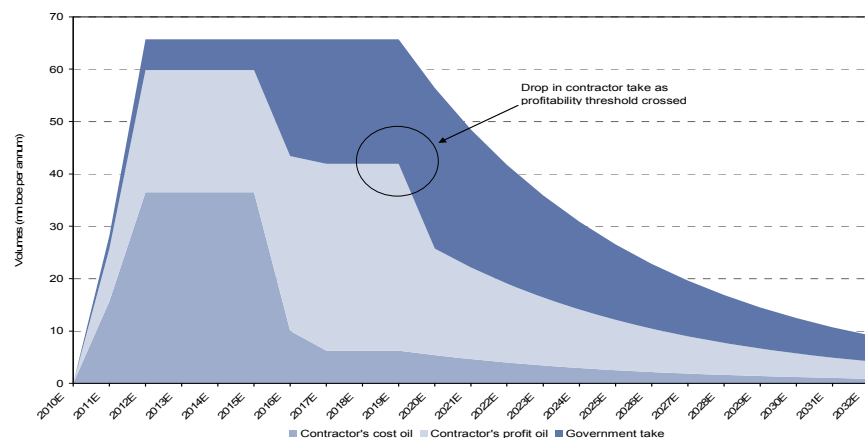
In 2010E, production from PSCs accounts for 50% of total production, making the fiscal structure an important consideration in the universe. PSCs vary greatly from country to country, but the basic mechanism is usually similar. Typically the IOC is allowed to recover all of its costs (in the form of barrels) from a share of the project's production, and the remaining production is shared with the NOC. This share, called profit share, typically decreases as the investment goes through certain profitability or production thresholds.

This is generally calculated using an IRR factor, an R-factor which determines the historical ratio of operational cash flow to capex (Angola), production (Nigeria), or a mix of the three (Kazakhstan) and triggers a higher government take at higher levels.

In a high oil price the PSC effect is more pronounced as costs are recovered and projects become more profitable earlier. Once profitability thresholds have been breached, an extremely low oil price or very large subsequent investment is required to bring the IRR or R-factor down to a lower profitability band. As many governments/NOCs often take their royalties and profit oil in barrels rather than cash, this is likely to affect production growth and make it even harder for companies to achieve production targets.

Exhibit 96: Low oil prices result in higher cost oil and delayed breaching of profitability thresholds

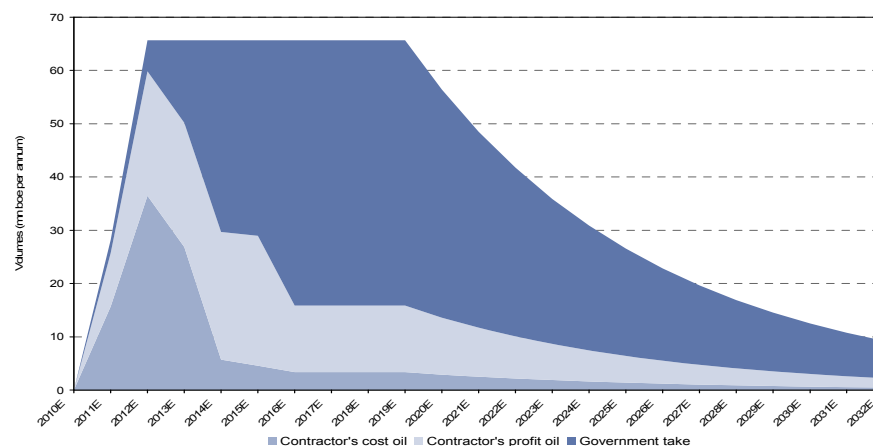
Based on a generic PSC regime with 15% royalty, 50% cost recovery limit and profit oil share to government based on IRR; modelled at US\$60/bl



Source: Goldman Sachs Research estimates.

Exhibit 97: Higher oil prices shorten the "cost recovery" period and see profitability thresholds breached earlier

Based on a generic PSC regime with 15% royalty, 50% cost recovery limit and profit oil share to government based on IRR; modelled at US\$100/bl



Source: Goldman Sachs Research estimates.

Service contracts provide even less leverage than PSCs, but do not reward efficient field management

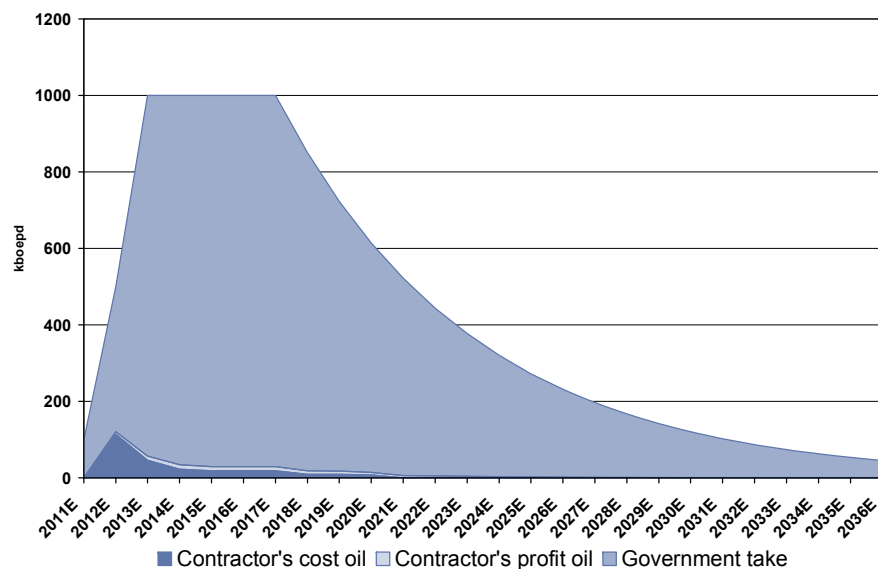
Since publication of the Top 230 in February 2009, we have added a number of contracts with significant reserves from the UAE and Iraq which are governed by “technical service contracts”. The exact form of these will change from contract to contract, but we would typically expect:

- Cost recovery of capex spent, up to a maximum % of revenue
- A fixed remuneration fee per barrel, possibly with corporation tax and/or an R-factor reducing the value of this to the company
- A threshold that must be reached in order to begin recovering costs

The mechanics of this contract type mean that the projects are very insensitive to the oil price, with only the first few years being influenced due to the speed of cost recovery being impacted by the commodity price. The other corollary of this fiscal mechanism is that it is relatively inefficient inasmuch as we believe there is little additional incentive for companies to ramp up production significantly once costs have been recovered, or to control costs once the field is in the cost recovery period.

Exhibit 98: 1000 kb/d plateau and US\$7 bn capex results in net entitlement volumes of 138 mnboe from c.4 bnboe produced

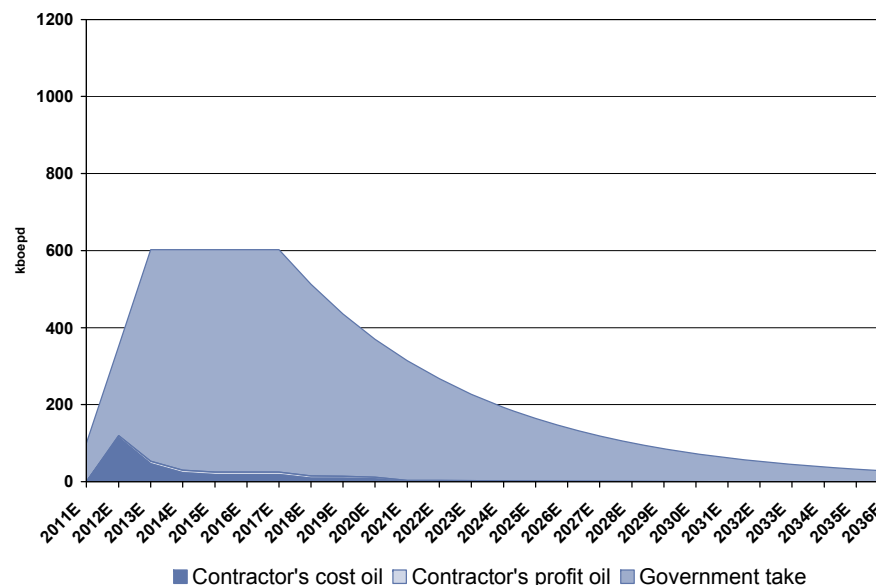
Excluding opex recovery



Source: Goldman Sachs Research estimates.

Exhibit 99: 600 kb/d plateau and US\$7 bn capex results in net entitlement volumes of 122 mnboe from c.2.5 bnboe produced

Excluding opex recovery



Source: Goldman Sachs Research estimates.

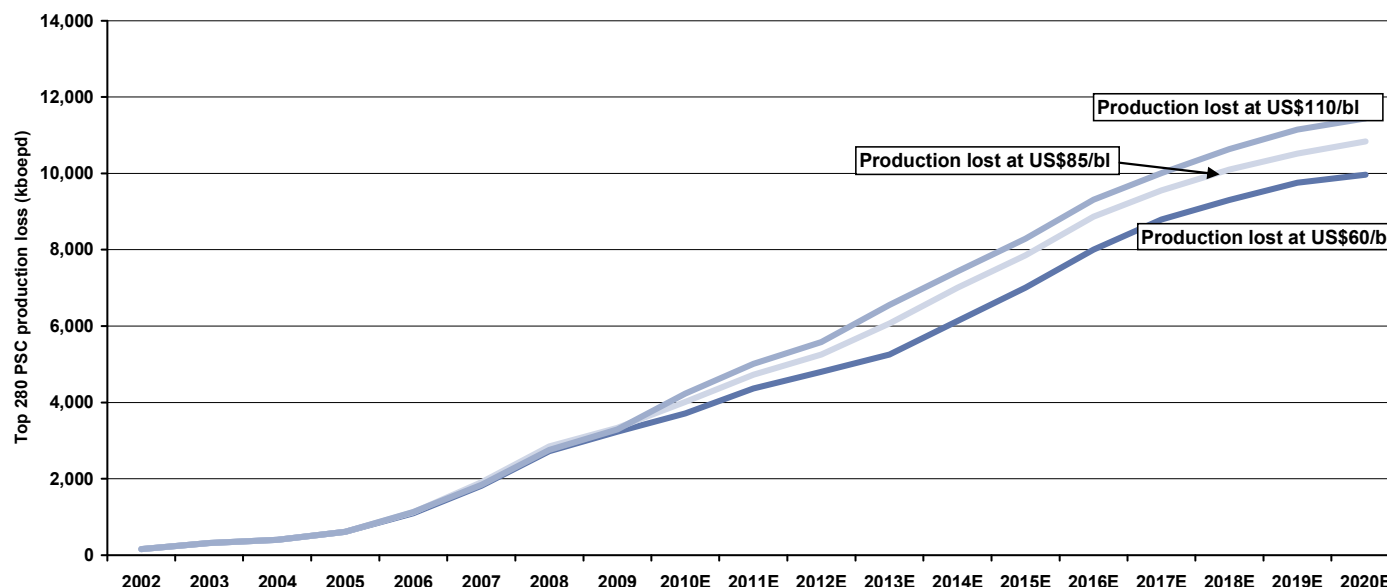
PSC effects still relevant; technical service contracts increase the magnitude of the PSC effect

Our company analysis of the Top 280 projects is mainly based on profitability and as such it does not make much difference whether taxes are paid in kind (barrels) or cash. However it makes a big difference for oil companies with production growth targets. The PSC effect will continue to be driven by the oil price and the geographical location of a company's portfolio and will continue to be relevant when analyzing company production figures. Despite a substantial increase in the PSC effect in recent years, a drop to US\$60 would see a slowing of this trend rather than a reversal as PSC effects are likely to persist as: 1) initial capex is recovered on some assets, leaving only opex and ongoing capex to be recovered through additional barrels on our estimates thereby increasing the PSC effect (i.e. Elephant), 2) overall production increases from other assets (such as ACG and Al Shaheen extension) and 3) fields (such as Dalia) continuing to breach profitability thresholds.

As a result of these factors, we expect the impact of PSCs on overall production of the Top 280 to increase gradually until 2012E (at US\$85/bl and above) or 2013E (at US\$60/bl), when we expect a more rapid increase in its impact. Again, to a degree this reflects the increase in production from PSC contracts, the breaching of profitability thresholds and the ending of substantial initial cost recovery in some assets (such as at Cepu and Dolphin). However, the other factor that increases the PSC impact from this period onwards is our expectation of a substantial ramp-up in assets governed by technical service contracts in Iraq and the UAE. We assume that companies receive cost oil and the remuneration fee in the form of entitlement barrels, but due to the harsh fiscal terms we expect increasing amounts of working interest production being lost as a result of these fields ramping up.

It is important to note that PSCs do not affect the volumes produced, just the share of production to which the IOCs are entitled.

Exhibit 100: Impact of different oil price scenarios on the PSC effect of the Top 280 projects



Source: Goldman Sachs Research estimates.

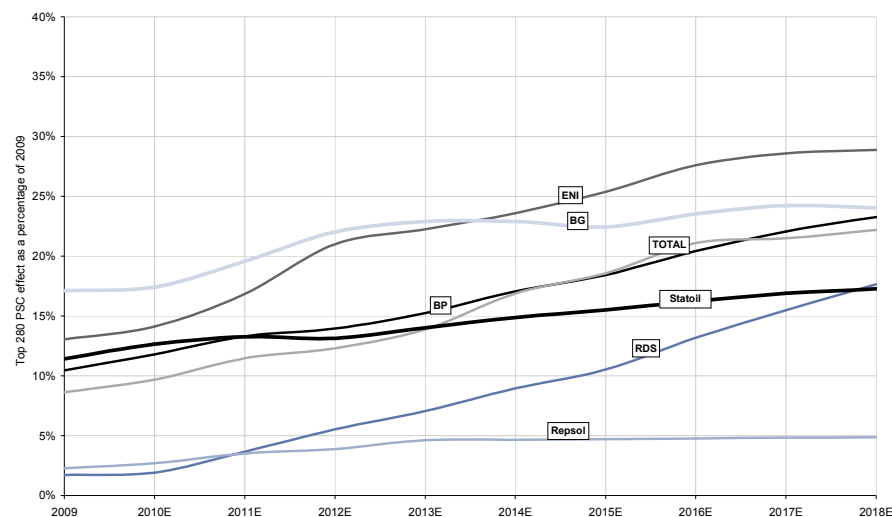
Estimating PSC effects in Europe: BG most exposed in short term, Statoil in long term; service contract impact will be substantial

BG stands out as having high Top 280 PSC exposure relative to current production in the short term – a result of its Egyptian gas projects and Panna Mukta Tapti in the short term and the Abu Butabul field in the longer term with the sensitivity between different oil prices due mainly to the effect of the Karachaganak PSC. Due to the fixed price gas in the company's Egyptian assets, even at low oil prices the impact is high relative to peers. As Brazil kicks in, however, this impact is reduced substantially leaving BG with a high ratio of net entitlement reserves vs. working interest reserves.

Those fields with exposure to Iraq will see an increase in PSC impact from the service contracts as they begin ramping up; Statoil (West Qurna 2), BP (Rumaila), Shell (Majnoon and West Qurna 1), ENI (Zubair) and TOTAL (Halfaya) are all likely to see upticks in the second half of the next decade. The sensitivity of the PSC effect of these contracts to higher oil prices is, however, muted as a result of our assumption of net entitlement being based on the cost recovery and a fixed price per barrel, meaning that the spreading of the costs over fewer barrels is the only impact of a higher oil price. Shell experiences a fairly steep increase in the PSC effect from its Iraqi projects and from Pearl GTL.

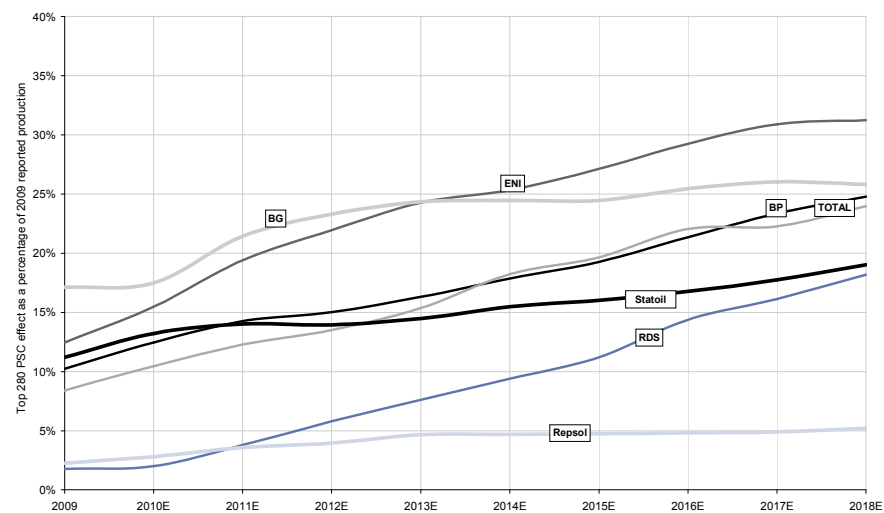
Repsol has the lowest impact, a result of its higher proportional exposure to licence regimes in the US and Brazil.

Exhibit 101: Service contracts are the main drivers of PSC effects on European IOCs at US\$85/bl



Source: Goldman Sachs Research estimates.

Exhibit 102: PSC effects become more pronounced at US\$110/bl



Source: Goldman Sachs Research estimates.

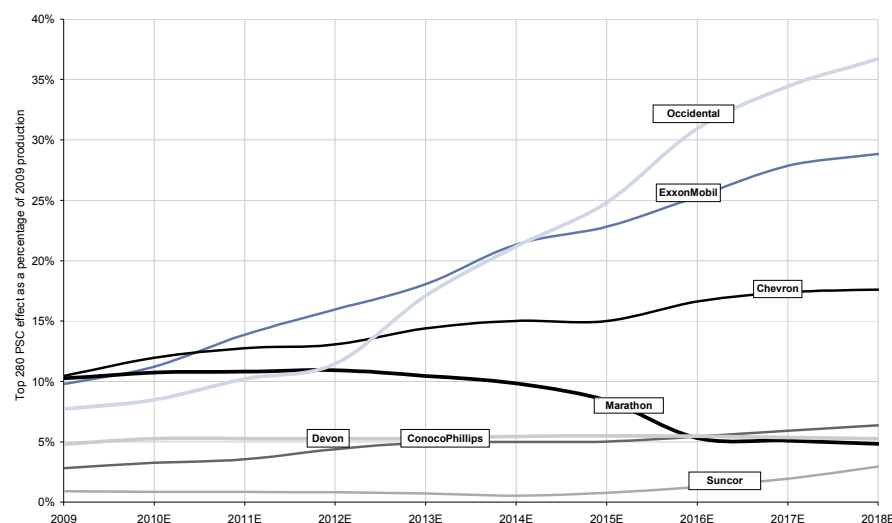
Iraq the big differentiator among the larger US companies

There is a clear divergence in the PSC impact between the larger North American names as the companies that have chosen to expand the most geographically see the most impact. Of those companies, the two with exposure to the Iraqi service contracts (Exxon and Occidental) see the biggest impact when the fields start ramping up faster beyond 2012E. Exxon is also impacted by its portfolios in West Africa and other areas in the Middle East, while Occidental's participation in Dolphin is also a factor.

After these two companies, Chevron has the most exposure, due to its deepwater West African and Caspian portfolio.

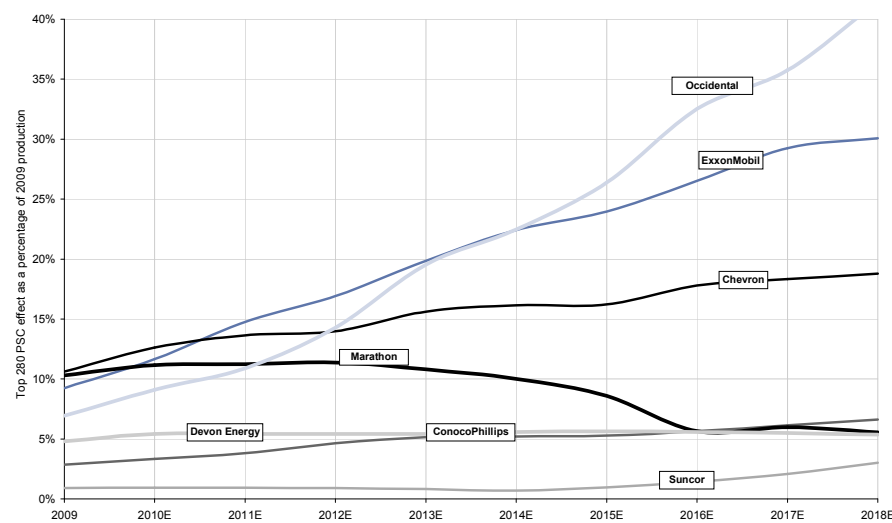
The effect on ConocoPhillips' production is more muted than for its US Major peers given that its Top 280 portfolio is more heavily weighted towards Canadian heavy oil and North American gas, and as fewer of its assets operate under PSCs. Marathon's near-term impact is also muted as we believe it will be some time before its Angolan portfolio breaches profitability thresholds, especially at lower oil prices, meaning that Alba is the main driver of its medium-term PSC impact. Suncor and Devon's US bias mean that both companies are less levered to PSC effects than other large US companies.

Exhibit 103: US companies exposed to Iraq see the greatest impact from PSC effects by far (at US\$85/bl)



Source: Goldman Sachs Research estimates.

Exhibit 104: PSC effect on Top 280 portfolios at US\$110/bl is more pronounced

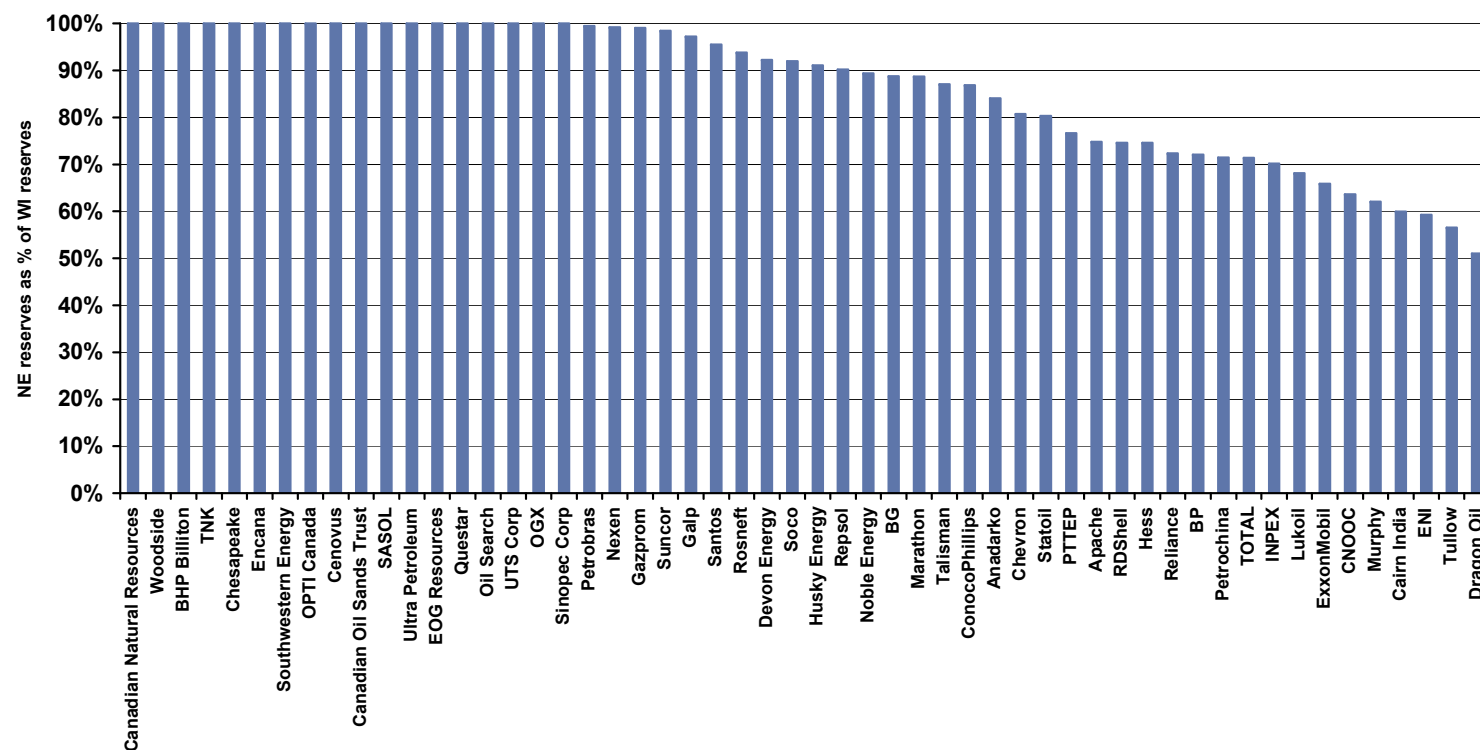


Source: Goldman Sachs Research estimates.

PSC effects result in substantial loss of working interest to host governments

The impact of the government take from PSCs and service contracts can be significant, with the Majors typically losing between 10% (BG) and 40% (ENI) of their total working interest volumes to the government as a result of this offtake. Companies which lose little in the way of production tend to be those focused on North American and Australian unconventional production and Russian firms which operate under licence regimes. Of the Majors, ENI loses the most of its working interest reserves to the government, with 40% of its remaining reserves being lost, primarily as a result of its exposure to contracts such as Wafa Bahr Essalam, Elephant and Kashagan, the first two of which are especially levered as they have already recovered a large proportion of the cost barrels to date.

Exhibit 105: PSC reserves exposure of the Top 280 companies



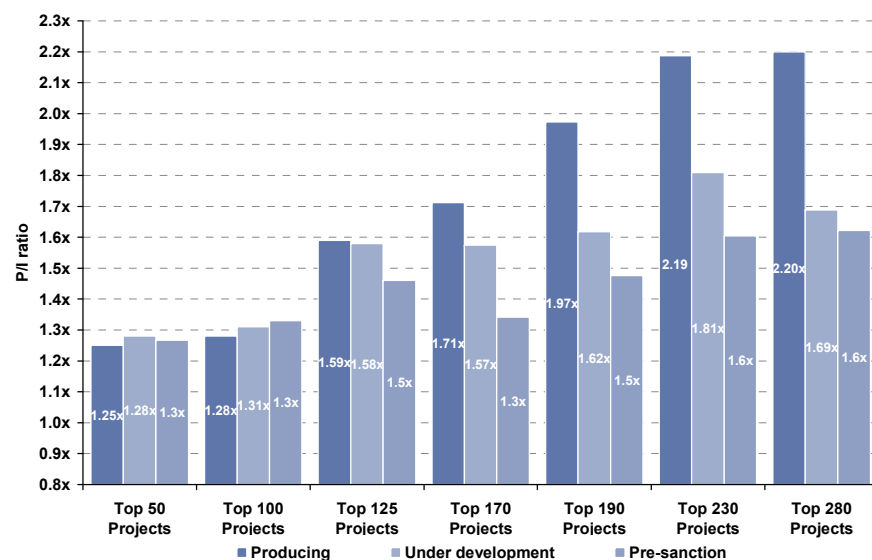
Source: Goldman Sachs Research estimates; Woodside and Santos are covered by GS JBWere.

Profitability has improved but the overall impact of the oil price since Top 50 is limited

Since the publication of the Top 50 Projects in 2003, we have increased our oil price assumptions from US\$17/bl to US\$85/bl. As a result, the profitability of the projects in this study has increased, putting an even greater premium on exposure to the assets and good execution.

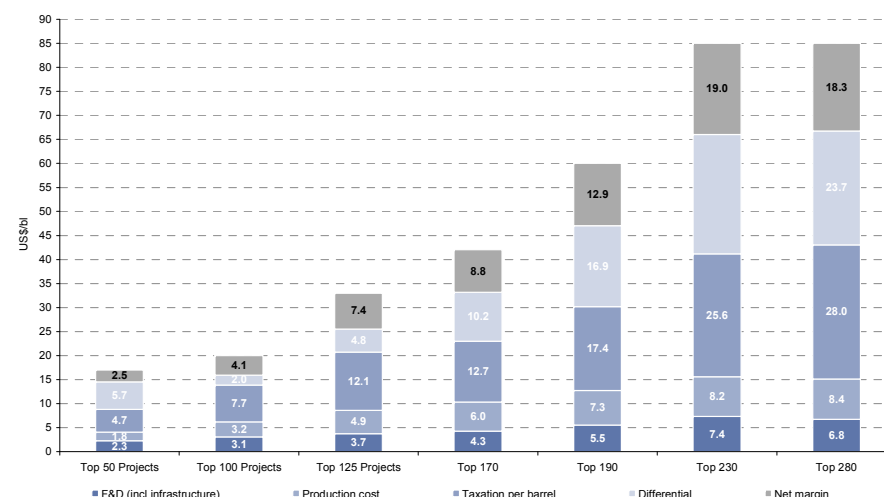
Despite this oil price increase, however, the profitability of pre-sanction projects has increased a relatively small amount (from 1.3x to 1.6x). While projects currently in production have seen a significant increase in profitability as sunk capex protects against inflation, leaving them more able to benefit from higher revenues driven by our increased oil price assumption, growth in profitability of projects still to be sanctioned has been more muted as higher costs and tax takes have eroded returns. Other factors which have put pressure on profitability for pre-sanction projects are the increase in the differential and increased tax takes at higher oil prices (whether through renegotiations of fiscal regimes or dynamic, profitability or oil price based PSCs such as those in Angola or Malaysia). Between the Top 230 and the Top 280 we have not adjusted our oil price assumptions. As a result, there has not been a substantial change in forecast profitability. Although we assume a slightly lower operational cost base in 2009 as a result of raw material costs coming down, this is largely offset by higher taxation rates in some of the larger fields that we have added since Top 230 (such as that implied in the technical services contracts) and concerns over bottlenecking re-emerging (mainly in Australian LNG and oil sands). We note that if oil prices remain at current levels, taxation and costs could rise, bringing down the P/I of pre-sanction projects to the levels prevailing in earlier editions of this study.

Exhibit 106: The pre-sanctioned projects are not much more attractive than in 2003, despite the underlying oil price assumption going up significantly



Source: Goldman Sachs Research estimates.

Exhibit 107: Cost breakdown of pre-sanction projects



Source: Goldman Sachs Research estimates.

Cost deflation has increased profitability marginally but risk is for erosion of returns from here

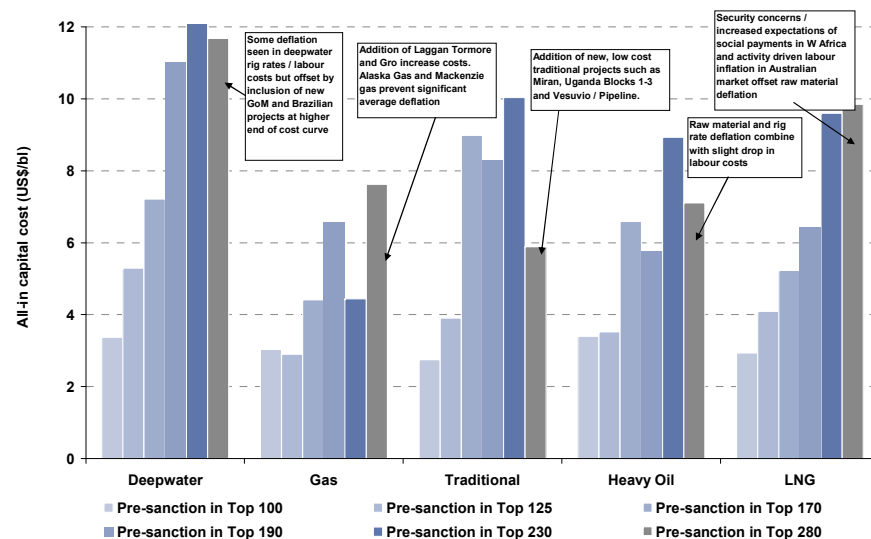
We have seen a small increase in the profitability of most win zones between this edition and the Top 230, driven by: 1) cost deflation in most win zones, 2) a change in realizations for some products (i.e. a narrowing in our assumed bitumen and Asian LNG differentials), and 3) improved leading operational indicators from some areas (such as flow rates in Brazil and the Lower Tertiary).

We note, however, that despite a significant increase in our oil price forecast since the publication of Top 100, there has generally been only a small increase in the profitability of pre-sanction projects. In this edition, however, as a result of the factors mentioned above, returns are above average in each of the win zones. While we appreciate that part of the benefit of higher oil prices should feed down to stakeholders, we believe that there is a risk of some mean reversion in projects that have yet to be sanctioned:

- We believe that labour bottlenecks (such as those seen in Canada over the last 3-4 years) and higher demand for services as sanctioning activity begins to increase, could result in cost inflation returning.
- We believe that at higher levels of profitability, government takes will rise through profitability mechanisms in the fiscal regime (i.e. Angola, Malaysia) or renegotiation of contracts as governments claw back excess returns (i.e. Libya, Kazakhstan)

We therefore believe that the current levels of returns could be unsustainable in those win zones where returns are substantially ahead of the average since 2005 (i.e. deepwater, LNG and heavy oil). We believe that the traditional win zone is harder to analyse in this way, as the projects are more independent and less linked to one another by generic trends.

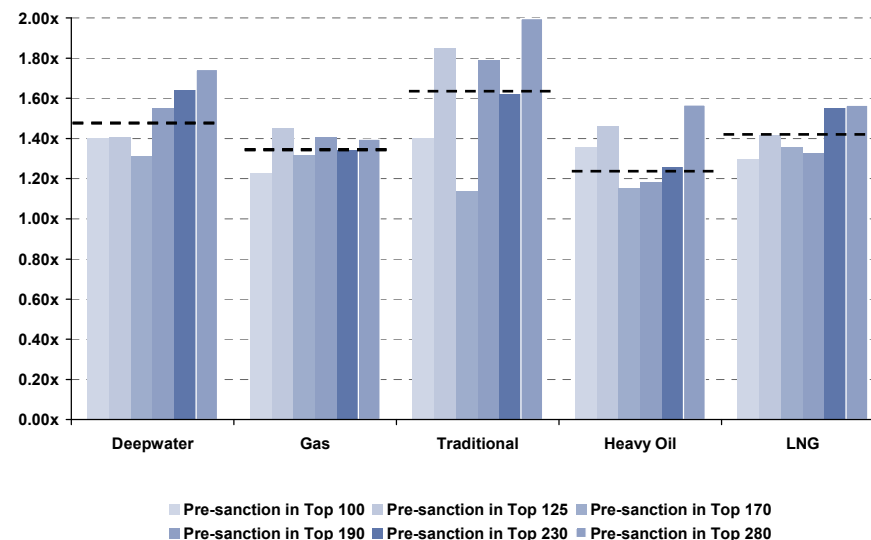
Exhibit 108: Cost increases for pre-sanction projects by win zone



Source: Goldman Sachs Research estimates.

Exhibit 109: P/I of pre-sanction projects by win zone is above trend

Dotted line indicates average over publication



Source: Goldman Sachs Research estimates.

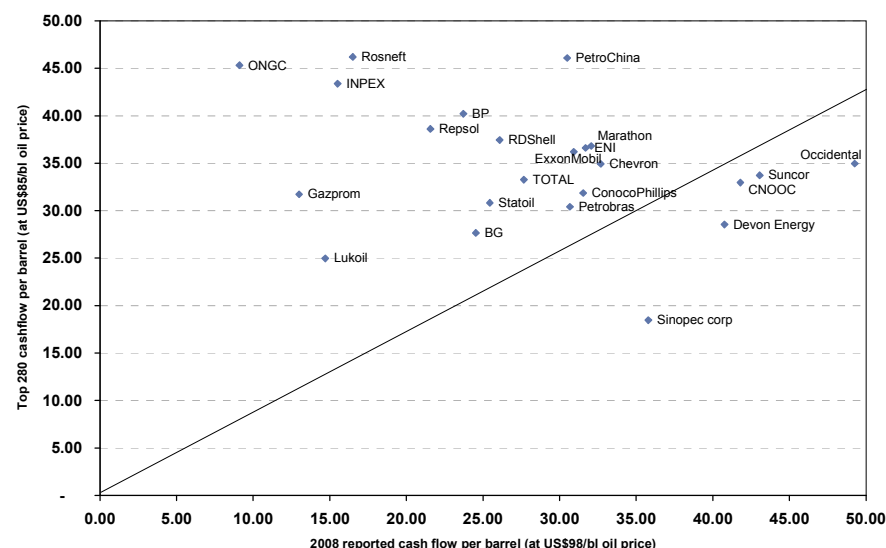
Companies and profitability: Scale advantages Top 280 projects

Despite the challenges caused by higher and more volatile oil prices, we believe that the advantages of scale that the Top 280 Projects have over other, smaller assets still make them valuable drivers of profitability, and believe that on a net entitlement basis, most companies will see an increase in cash flow/bl as a result of their Top 280 exposure. At our assumption of US\$85/bl oil, we believe that all the included projects return at least 8%.

In 2012E we believe that Rosneft and ONGC will see the biggest advantage in their Top 280 cash flow relative to 2008 cash generation per barrel. For Rosneft, we see this dropping back substantially once the three-year export tax relief on Vankor ends. ONGC is advantaged because of the cash generation of Top 280 projects such as MBA, relative to a low current base. By 2015E, we see the Majors relatively closely grouped with the exception of ConocoPhillips and Statoil which, while improving vs. their current portfolio, are relatively less advantaged as Statoil's West Qurna 2 project and unconventional gas production increases and Conoco's relatively high cost oil sands projects ramp up. INPEX also looks advantaged by 2015E. Occidental's Top 280 portfolio is generally worse than its current, relatively high value portfolio, mainly as a result of its Iraqi service contracts which generate very low realizations. Sinopec's Top 280 Puguang asset is more disadvantaged vs. its current, more oily portfolio, while we assume Devon Energy's unconventional gas assets realize US\$6.50/mcf, putting them at a discount to the company's 2008 cash flow per barrel.

Exhibit 110: Top 280 projects provide advantaged cash flow vs. current portfolios

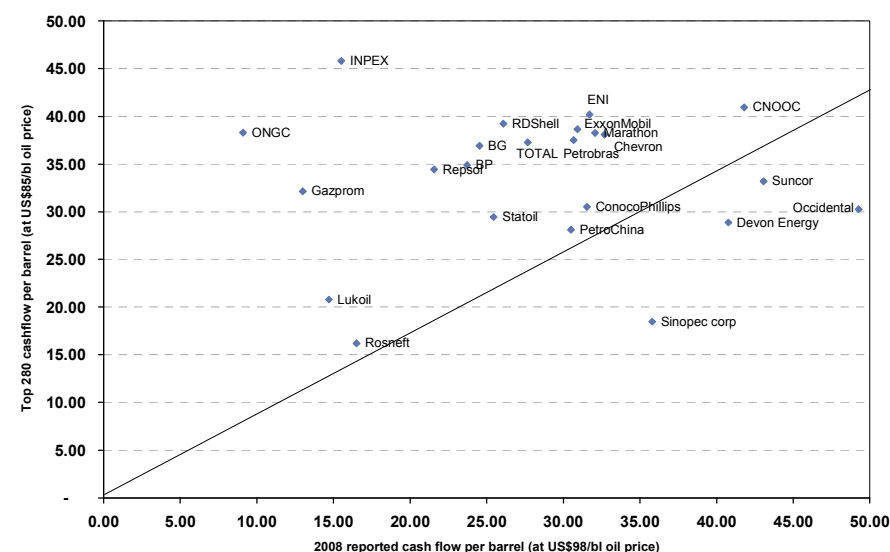
2012E Top 280 cash flow/bl vs. 2008 cash flow/bl



Source: Goldman Sachs Research estimates.

Exhibit 111: In 2015E, INPEX and ONGC see biggest improvements

2015 Top 280 cash flow/bl vs. 2008 cash flow/bl



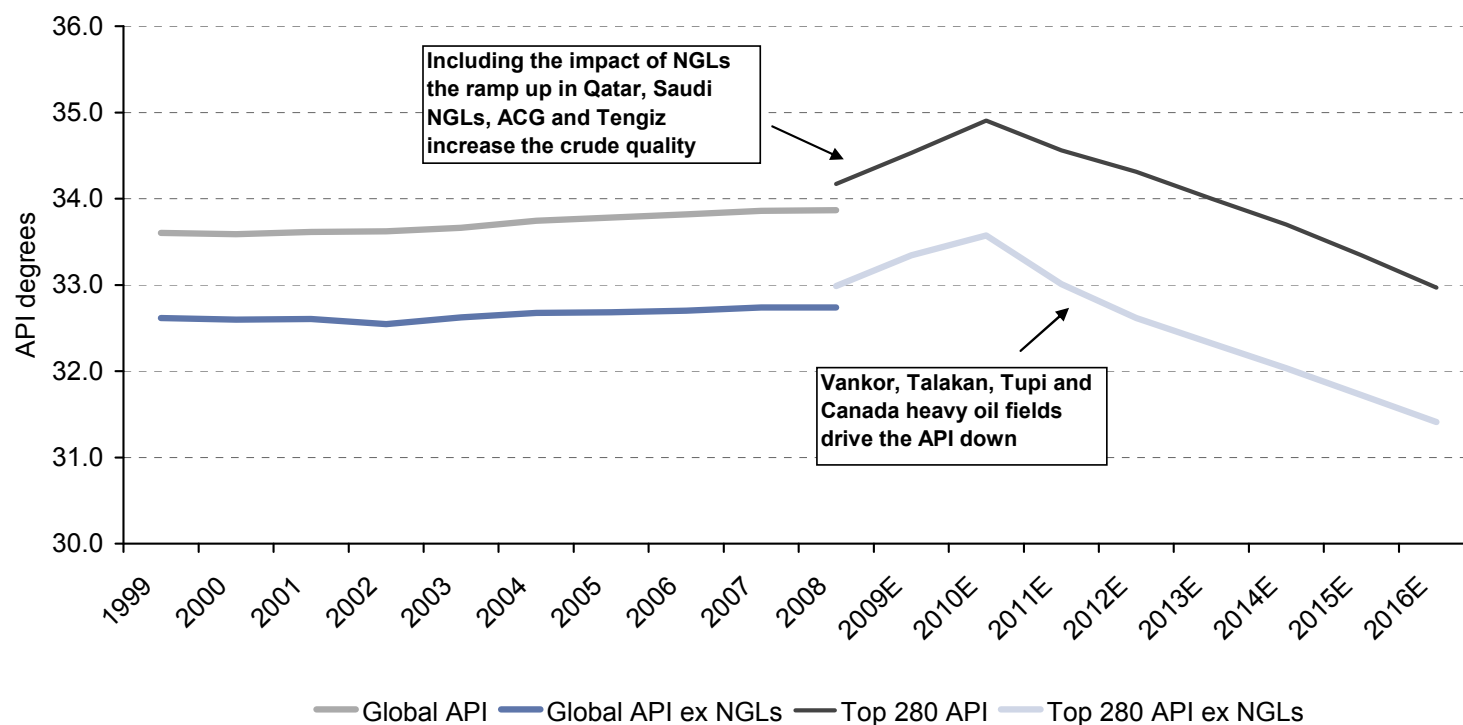
Source: Goldman Sachs Research estimates.

Top 280 crude oil supply excluding NGLs heavier than current global production

Top 280 API gravity lifted by NGL production but heavy oil dominates in longer term

Our analysis of the API gravity of the crude and condensates coming on-stream from the Top 280 projects suggests that new production will be on average 1.25° lighter than the gravity of current global crude and condensate production as the ramp-up of NGLs from Qatar, ACG and Tengiz lift the overall API quality. As the decade progresses however we expect the increasing production of heavy oil from Canada, as well as major fields such as Vankor, Talakan, Tupi and the Iraqi fields of West Qurna and Rumaila to lower the API gravity below the current global average. The Top 280 crude API gravity excluding NGLs is marginally lighter than the current global average and gradually turns heavier into the end of the decade to reach an average of 30.5° in 2018E. We note that this analysis assumes no spare OPEC capacity; we believe that any cuts from OPEC would have the effect of making the supply lighter as heavier crudes are lost first.

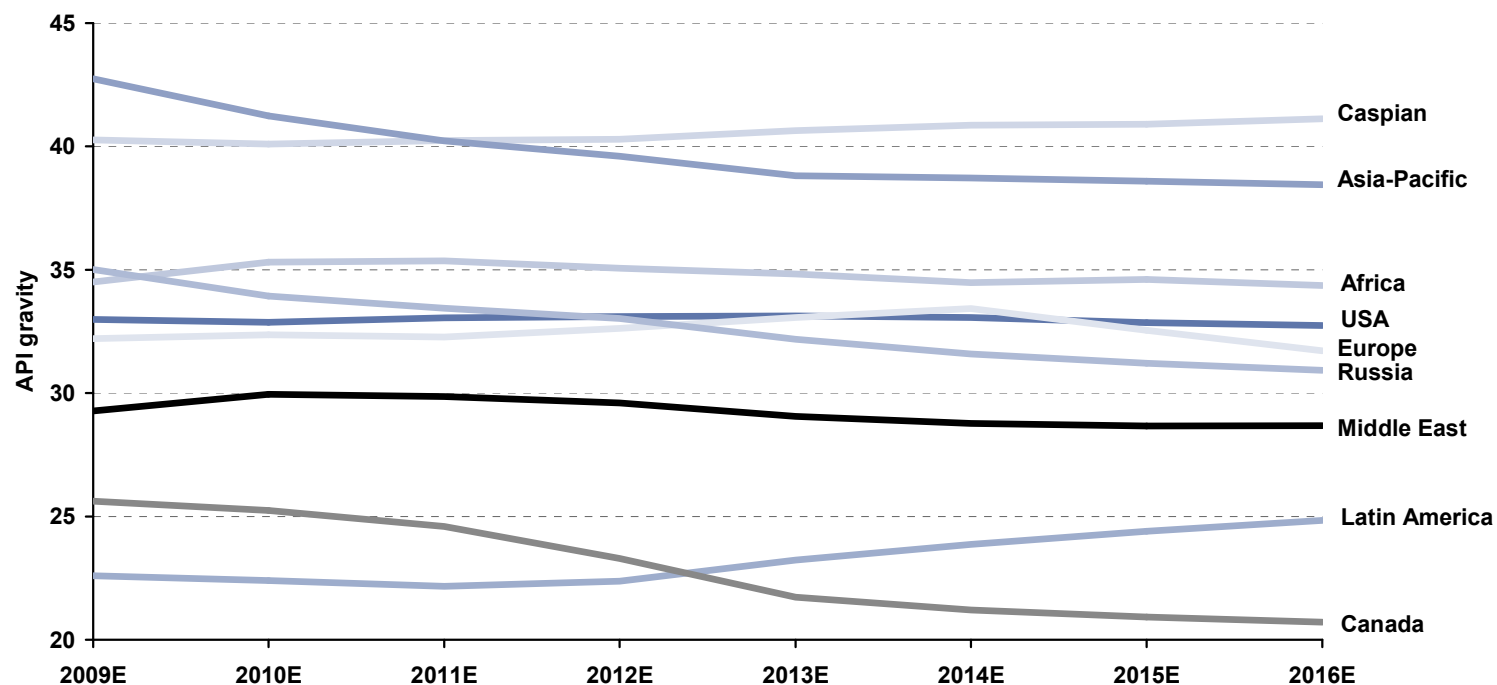
Exhibit 112: Qatargas condensates lead the API rise before Canadian heavy oil takes hold



Source: Goldman Sachs Research estimates.

The significant ramp-up of light condensates from the Qatargas and RasGas projects in the Middle East as well as ACG and Tengiz in the Caspian offsets the near-term ramp-up of Talakan and Vankor to raise the overall API of the Top 280 projects including condensates. This increase in gravity will be relatively short-lived however as the significant investment in Canadian heavy oil, deepwater Brazil and Iraq drives the average API down from 2010E. Excluding the impact of NGLs the Top 280 crude projects will become gradually heavier than the global average, in particular driven by the larger share of Canadian heavy oil production. Excluding Canada from our analysis of Top 280 crude oil production, the average API still falls versus history as the share of relatively heavier Iraqi production increases.

Exhibit 113: Evolution of API quality by region; Caspian and Asia-Pacific lightest regions, Latin America and Canada the heaviest



Source: Goldman Sachs Research estimates.

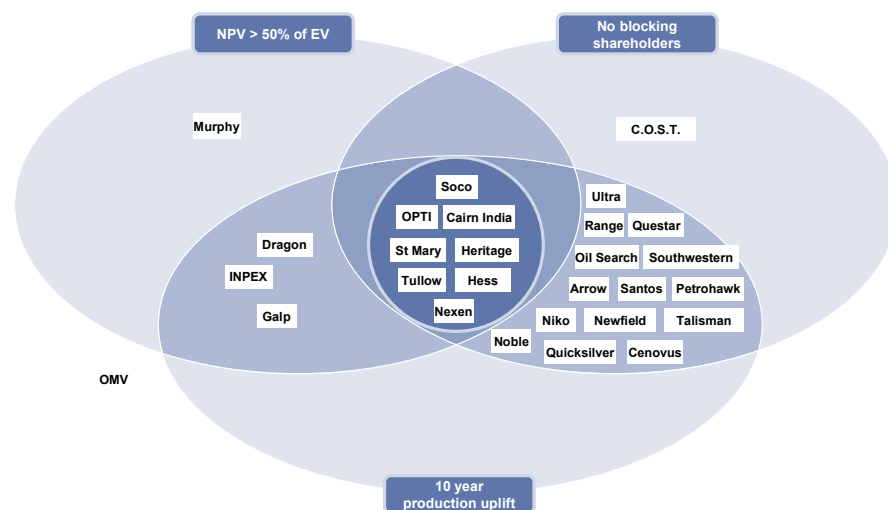
Top 280 assets likely to be a significant driver of M&A

We believe that the Top 280 assets are strategically desirable and could provide an acquirer with strategic growth prospects. As such, we believe that smaller companies which have stakes in these assets could attract M&A attention in the future. We have screened the Top 280 to identify attractive targets using the following criteria:

- **Size:** We restrict our potential targets to those companies with an enterprise value below US\$25 bn as we believe a corporate deal can be reasonably financed at such a level and a Top 280 asset sale would likely have a material impact.
- **Viability:** We exclude companies which are not publicly listed or have what we consider to be a blocking shareholder.
- **Materiality:** The Top 280 portfolio should account for at least 50% of the company's EV assuming an 8% discount rate
- **Growth:** We exclude companies whose Top 280 net entitlement growth does not provide at least a 10% uplift to current production between 2010E and 2020E.

On this basis, Tullow, Soco, Cairn India, OPTI (not covered), Hess, Heritage, Nexen and St Mary Land & Exploration (not covered) screen attractively. Of the companies whose EVs are over US\$25 bn, OGX and BG also screen attractively.

Exhibit 114: M&A screen of Top 280 companies



Source: Goldman Sachs Research estimates (when calculating production uplift for non-covered companies we use annual reports/SEC filings and use 2008 reported production figures).

Exhibit 115: Data for companies with EV under US\$25 bn

Company	NPV of Top 280 as % EV at 8% cost of capital	PI of Top 280	Net entitlement Top 280 reserves	Top 230 10 year production uplift as % of 2009 production	Blocking shareholder?
Heritage	219%	2.94x	124	915%	No
Soco	97%	3.50x	84	377%	No
OPTI Canada	199%	1.46x	871	525%	No
Dragon Oil	196%	2.30x	319	20%	Yes
St Mary Land & Exploration	78%	1.98x	542	79%	No
Arrow Energy	13%	1.58x	152	314%	No
Niko Resources	31%	2.00x	189	37%	No
Quicksilver Resources	7%	1.32x	150	33%	No
Oil Search	23%	1.59x	307	154%	No
Newfield	26%	1.98x	574	11%	No
Ultra Petroleum	27%	1.30x	1530	128%	No
Range Resources	36%	1.84x	764	213%	No
Petrohawk	42%	1.62x	846	177%	No
Questar	15%	1.30x	923	75%	No
Santos	34%	1.45x	1178	64%	No
Murphy	58%	2.04x	399	-2%	Yes
Cairn India	81%	3.37x	387	298%	No
Noble Energy	24%	2.33x	585	27%	No
Canadian Oil Sands Trust	30%	1.30x	419	1%	No
Tullow	63%	2.70x	593	222%	No
Nexen	110%	1.83x	2256	35%	No
OMV	8%	2.29x	86	4%	Yes
Southwestern Energy	27%	1.51x	1284	64%	No
Galp	50%	1.81x	2420	1808%	Yes
INPEX	93%	1.59x	3548	82%	Yes
Hess	59%	1.66x	1083	18%	No
Talisman	16%	1.69x	678	29%	No
Cenovus	29%	1.96x	1536	48%	No

Source: Goldman Sachs Research estimates, Bloomberg (when calculating production uplift for non-covered companies we use annual reports/SEC filings and use 2008 reported production figures).

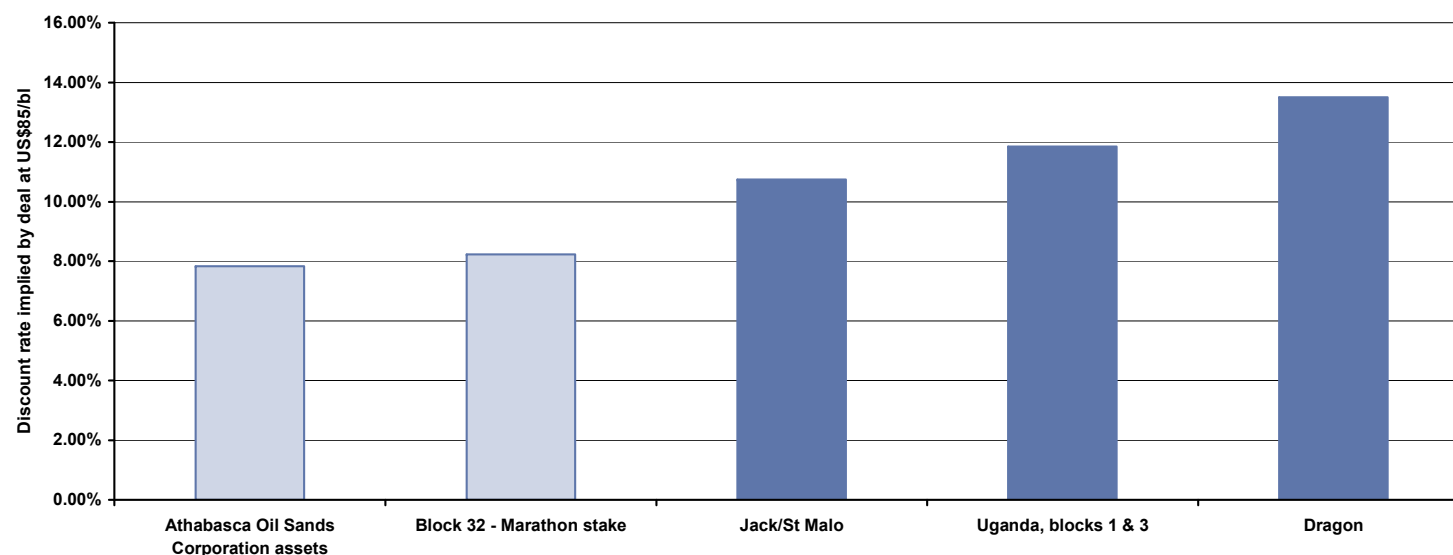
NOC purchasers may be more price insensitive and better able to offer more upside than IOCs

We believe that the rationale for asset purchases is likely to vary by acquirer. We assume that the decisions of IOCs are made primarily on a commercial basis rather than according to a strategic rationale, and therefore expect most deals in which the IOC is the acquirer to be done at a WACC similar to the commercial hurdle rate for a particular asset. In our view, national oil companies are driven less by value and more by a strategic desire to secure future reserves and supply. As a result, we believe that acquisitions involving NOCs are likely to be more price insensitive – which would likely be manifested in lower implied discount rates for pricing acquisitions.

We have analysed deals performed on Top 280 assets in 2009 in order to assess the implied discount rates at a US\$85/bl oil price assumption (close to the back end of the forward curve at the time of each deal). Exhibit 116 shows that those deals with Chinese NOCs as the buyer (the Athabasca Oil Sands Corporation deal and the proposed acquisition of Marathon's stake in Block 32 in Angola) imply a discount rate of c.8% based on our Top 280 analysis. Of the others, Maersk's acquisition of Devon's stake in Jack/St Malo and Cascade implies an 11% discount rate on our analysis (consistent with our assumption of an 11% hurdle rate for GoM assets), and ENI's attempted purchase of Heritage's Ugandan stake implies a 12% discount rate. ENOC's bid for Dragon implied a c.13.5% discount rate – which we believe reflects ENOC's majority holding and possible capital constraints.

Exhibit 116: Discount rates implied by 2009 deals based on analysis of Top 280 Projects

Deals involving NOCs have implied a lower discount rate at US\$85/bl. Tengiz excluded as deal included pipeline company



Source: Goldman Sachs Research estimates.

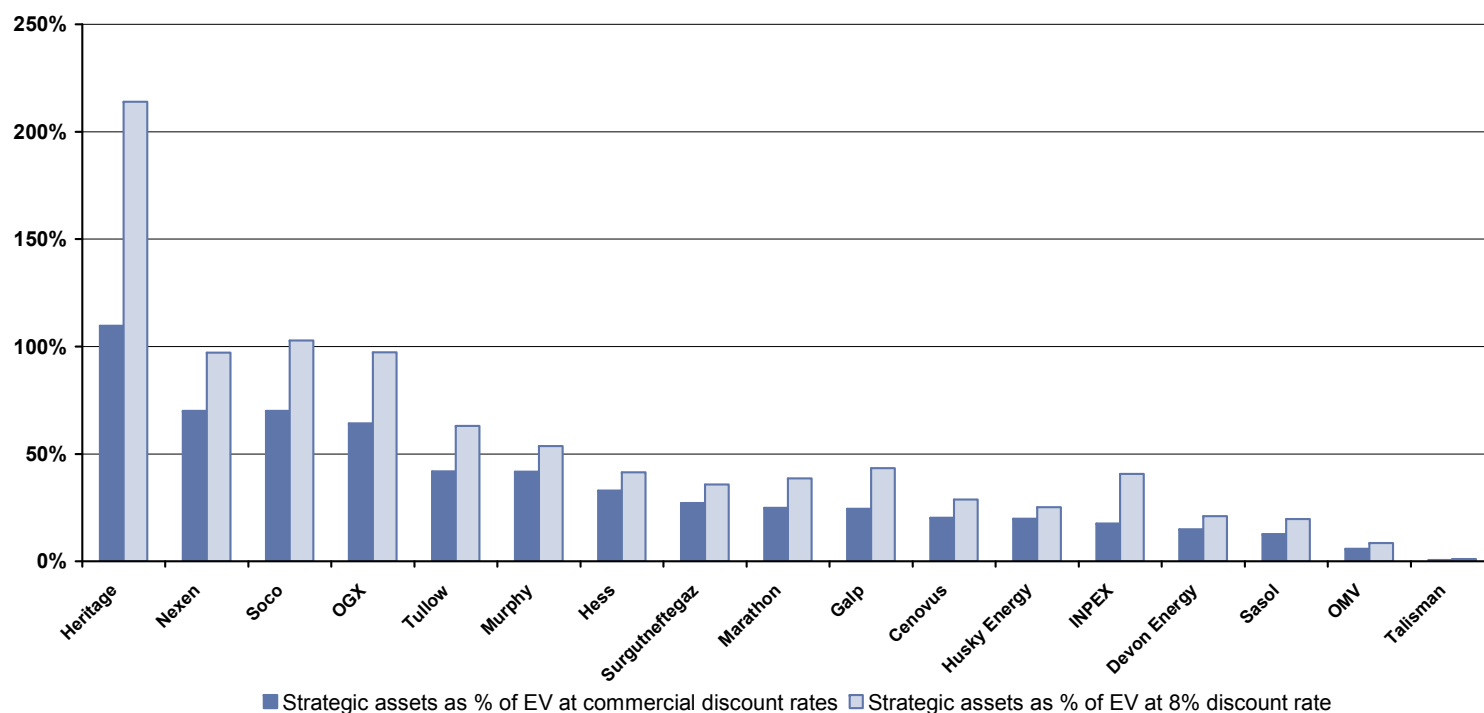
Higher risk exposure maximizes the potential discount rate arbitrage

If we assume that purchases by NOCs are more price insensitive and that the average 8% discount rate implied by the deals done in 2009 can be replicated in other deals, but that listed oil companies will likely attempt to perform transactions at more commercial discount rates, a more significant valuation uplift could result from acquisitions by NOCs of those assets which are of strategic value, and in riskier areas of the world where the potential discount rate arbitrage between a listed company's hurdle rate and a NOC's strategic cost of capital is higher. Exhibit 117 shows the potential difference between smaller companies' assets valued at what we would regard as a commercial cost of capital and an 8% cost of capital. We believe that the type of assets likely to appeal most to NOCs are predominantly oil based and therefore do not include gas-based assets in this analysis.

We note that we do not believe that Cairn India would be an obvious target for Chinese NOCs given the potential for opposition from the Indian government to an acquisition by a Chinese state-owned company. We similarly rule out Dragon as a result of its blocking majority shareholder. We note that a purchase of Heritage's assets would carry high political risk even for a NOC given the possibility of being barred from Iraq in the event of a purchase of an asset in the Kurdistan Region of Iraq.

Exhibit 117: Transactions at an 8% cost of capital could generate significant additional value for a target

Based on "strategic" oil-based assets



Source: Goldman Sachs Research estimates.

Lower political risk comes at the cost of higher technical risk

As mature basins such as the North Sea and the US onshore continue to decline and offer little potential for incremental growth, IOCs are being required to take on additional risk in order to replace reserves and keep returns attractive. We split risks into two types – technical (i.e. those related to the complexity of extracting hydrocarbons from the ground) and political (the risk of doing business in a particular location). Although the opening up of Iraq to IOCs allows companies to produce from simple oil fields in a politically challenging location, we believe that this bucks the trend and expect political risk to fall in future as companies both look for reserves in more stable regimes and are prevented by NOCs and governments from developing simple assets in politically riskier countries more prone to resource nationalism. As a result, we believe that the geographical opportunity set will be more limited for IOCs which will need increasingly to rely on their technical competence to gain access to reserves in non-OECD countries and to enable monetization of resources in OECD countries. This can be seen in companies increasingly focusing on unconventional resources in politically stable plays (such as heavy oil in Canada, or LNG in Australia).

Technical risk analysis

We have identified six main areas of technical risk and ranked the projects accordingly.

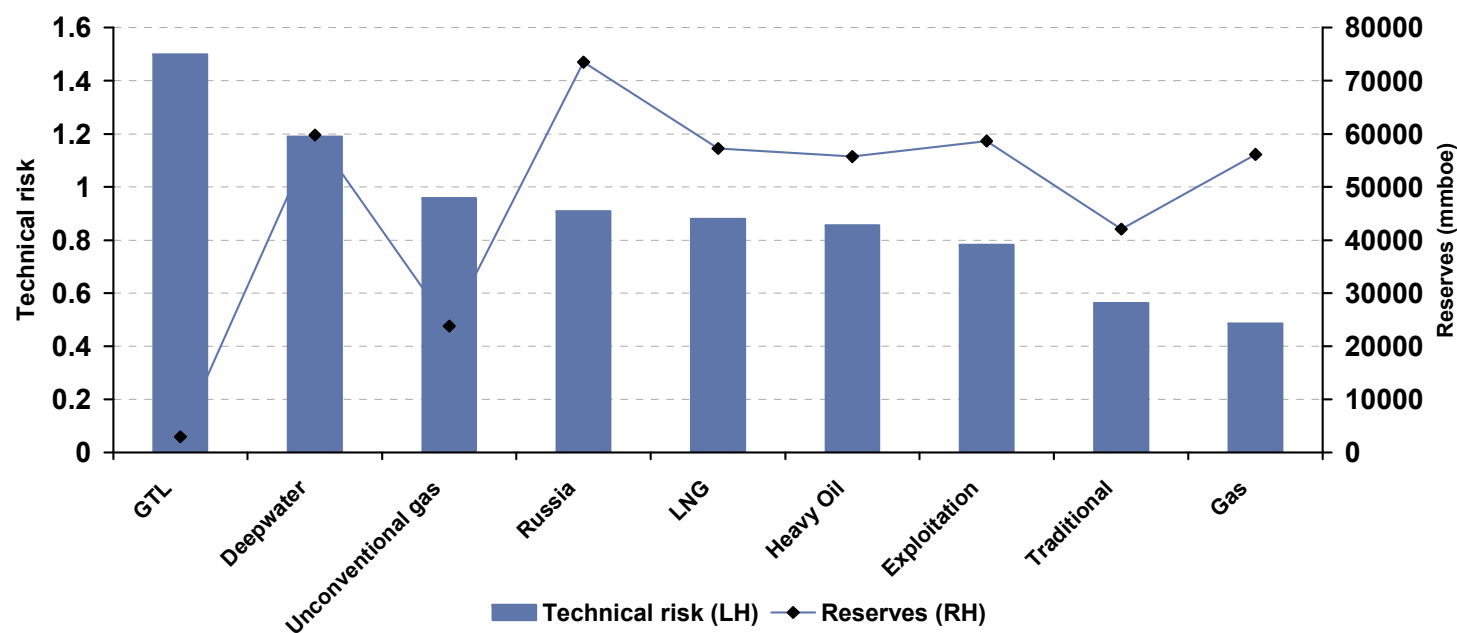
Exhibit 118: Summary of key technical risk criteria

	Category	Description	Example fields	% of Top 280 technical risk score
Technical risk score	Water depth	Fields in greater water depths are assumed to have higher risk profiles	Jack, Stones, Tupi	15%
	Environment, geography & climate	Fields subject to hostile operating conditions, e.g. Arctic operations, environmentally sensitive areas or other complex geographies, e.g. sub-salt or hostile weather patterns	Shtokman, US GoM, Greater Gorgon	19%
	Technology dependence	Greater than average dependency on new or complex production technologies, e.g. subsea systems, early generation deepwater developments, LNG, GTL, heavy oil	Kashagan, GTL, Shtokman	28%
	Geological issues	Risks regarding complex reservoirs, heavy oil, HPHT, sour gas or sour liquids	Kristin Tyrihans, Kashagan, Shah	17%
	OPEC quota compliance	Fields that we believe are at a higher risk of cutting production to comply with OPEC quotas	Venezuelan Orinoco projects, Algeria, Libya, Nigeria	4%
	Infrastructure dependence	Technologically and politically complex issues surrounding the development and exporting of hydrocarbons	African LNG, Karachaganak, ACG	17%

Source: Goldman Sachs Research estimates.

We believe that the riskiest projects on a purely technical basis are GTL, deepwater projects, high pressure, high sulphur projects such as Kashagan, or large developments in new environmentally-sensitive areas such as Shtokman. GTL risking is mainly a product of the high complexity technology which is relatively untested on a large commercial basis. For the deepwater zone, the risks are more varied. Water depth is the most obvious, but also the complexity of subsea technology and the presence of many fields in hurricane zones or underneath substantial salt layers (especially if these layers are active) raises the technical risk. LNG and heavy oil present average risk, largely linked to the technological and infrastructure issues. We see the gas, exploitation and traditional win zones as relatively low risk on a purely technical basis, with fields such as Kashagan and Shtokman as notable exceptions.

Exhibit 119: Technical risks and reserves by win zone



Source: Goldman Sachs Research estimates.

Political risk analysis

Exhibit 120: Summary of political risk analysis

	Country	Top 280 political risk score	Top 280 reserves (mnboe)
Low risk	Norway	0.3	7323
	Italy	0.5	400
	Canada	0.5	52487
	Australia	0.6	25555
	UK	0.6	2650
	US	0.8	39228
	United Arab Emirates	0.9	6100
	Qatar	0.9	30075
	Malaysia	1.2	3213
Medium risk	Oman	1.3	4467
	Algeria	1.5	3825
	Brazil	1.6	29833
	China	1.6	10103
	Thailand	1.6	1425
	Libya	1.6	4511
	Peru	1.7	1237
	Kazakhstan	1.7	26440
	Russia	1.7	73495
	Vietnam	1.7	1100
	Azerbaijan	1.8	8355
	Ghana	1.8	1267
	India	1.9	4586
	Indonesia	2.0	6724
	Egypt	2.0	4762
High risk	Turkmenistan	2.1	700
	Equatorial Guinea	2.1	580
	Syria	2.1	824
	Papua New Guinea	2.1	1250
	Syria	2.1	824
	Bangladesh	2.2	515
Very high risk	Nigeria	2.3	14975
	Angola	2.3	14335
	Chad	2.5	900
	Congo	2.5	2055
	Uganda	2.6	1000
	Yemen	2.6	1533
	Iran	2.8	35
	Venezuela	3.0	7415
	Bolivia	3.0	1318
	Myanmar	3.0	1400
	Iraq	3.0	30638

In our political risk analysis we attempt to reflect index components from external political risk indices (the World Bank, Governance Matters Index and the UNDP Human Development Index). As previously published in Top 125, Top 170, Top 190 and Top 230 we select five indicators from these indices that we believe reflect the risks of the operational environment the companies face in each country.

The components are:

- **Corruption** (World Bank Index) - the extent of corruption which can distort international competitive conditions

- **Political stability** (World Bank Index) - the likelihood that the government in power will not be destabilised or overthrown by possibly unconstitutional and/or violent means, including domestic violence and terrorism

- **Rule of law** (World Bank Index) - the extent to which individuals and businesses have confidence in and abide by the rules of society

- **Regulatory quality** (World Bank Index) - the level of market-friendly policies such as price controls

- **Human development Index** (UNDP Index) - characteristics of the population such as life expectancy

We have combined the scores from these individual components into an overall political risk index for the Top 280 Projects and made adjustments where necessary to reflect oil and gas specific risks. Our index has higher scores for more politically risky countries and has a weighting which brings overall political risk scores in line with the overall technical risk scores for the Top 280 Projects as a whole

We also make specific adjustments based on our perception of the security and stability of IOCs operating in each country. We therefore increase risks on countries such as Bolivia and Venezuela which have previous examples of changing fiscal regimes / nationalising energy assets, or have no prior record of oil production (e.g. Uganda). We do not adjust Russia as most of the companies operating the Top 280 fields are of Russian origin - a factor which we believe reduces the risk profile for the country.

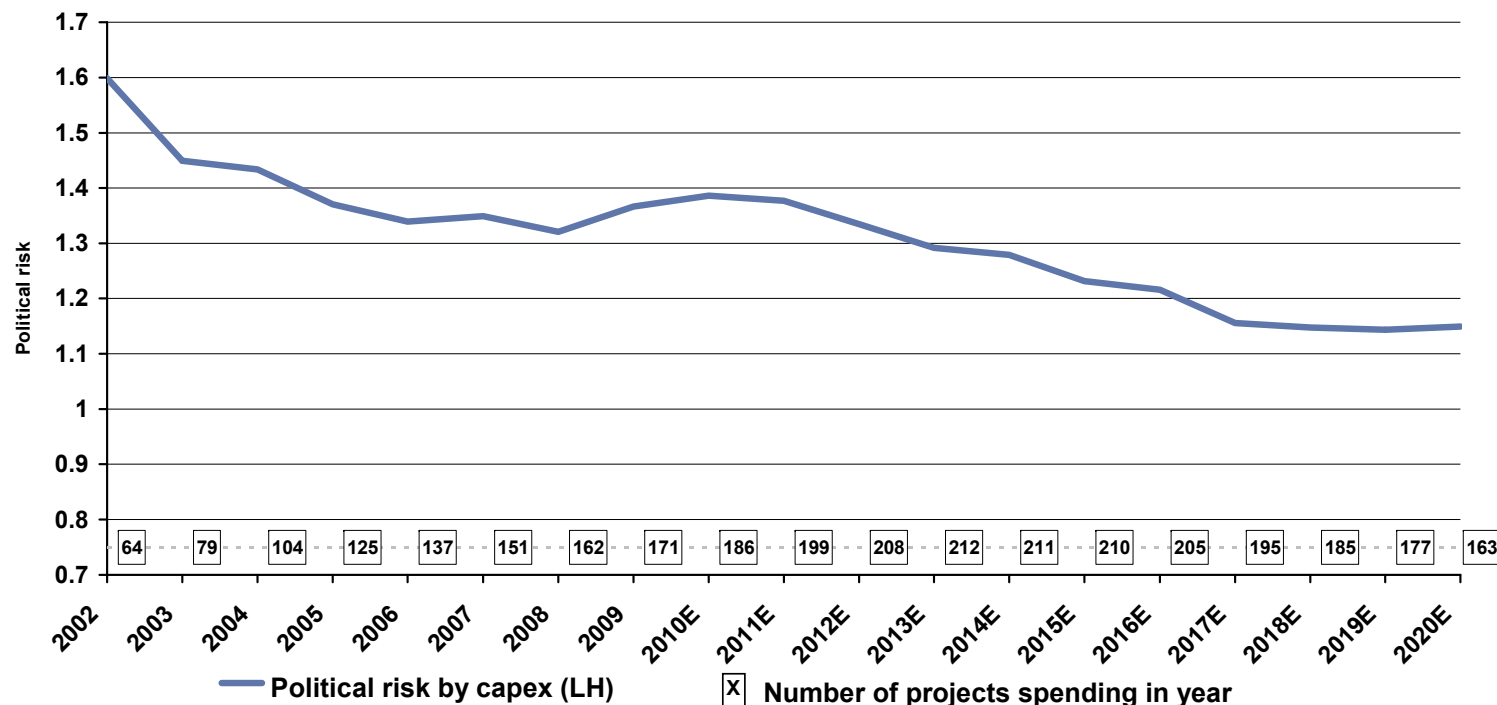
Source: Goldman Sachs Research estimates, World Bank Index, UNDP Index.

The risk profile: Political risk falling as IOCs look for more politically stable reserves and are pushed away from non-OECD reserves

We believe that from 2010E, Top 280 investment will increasingly focus on areas with lower political risk. On the gas side, this is primarily due to the large unconventional gas portfolio which adds significant US based production and the large weight of capital intensive LNG projects in Australia. The picture is similar for oil: we expect substantial investment in ramping up the heavy oil sands projects in Canada, the Brazilian pre-salt and the Gulf of Mexico. These projects tend to be capital intensive which further skews the investment towards these areas. We note that oil company activity in Iraq acts as a counterweight to this trend but has less of an impact due to the relatively cheap nature of the development that we assume.

We believe that this profile shows partly a conscious decision on the part of the IOCs to avoid risking capital in countries where high political risk could result in substantial value destruction (such as Venezuela) and also their marginalization in other areas such as parts of the Middle East.

Exhibit 121: Political risk of the Top 280 projects weighted by capex



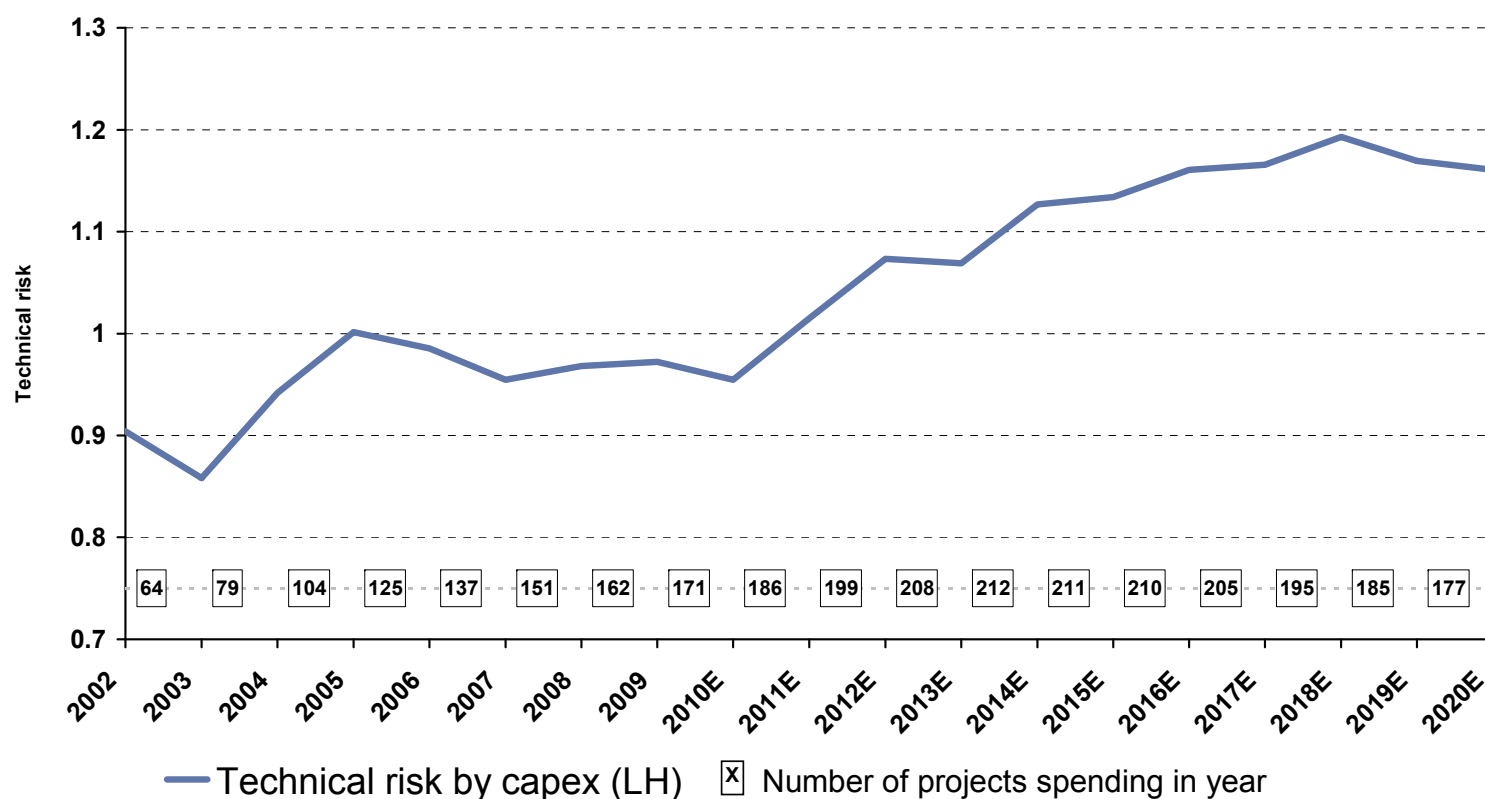
Source: Company data, Goldman Sachs Research estimates, World Bank Index.

As political risk declines, technical risk looks set to increase

As a whole, however, we do not believe that the risk profile of the Top 280 portfolio will change substantially as a result of this political de-risking, as we believe that technical risk is likely to increase, as companies lever balance sheets and technological capabilities to continue replacing production, effectively replacing political risk with technical risk.

We believe that the technical risk profile is increased by three main factors: 1) a change in production mix where more traditional and easily monetized oil and gas fields are replaced by fields with higher technological complexity and higher capital intensity (i.e. deepwater, LNG, GTL and heavy oil); 2) the increased depth and greater proportion of pre-salt or sub-salt fields in the deepwater win zone; and 3) the tackling of increasingly more geologically complex, HPHT and high sulfur reservoirs (i.e. Kashagan and Shah).

Exhibit 122: Technical risk of the Top 280 projects weighted by capex



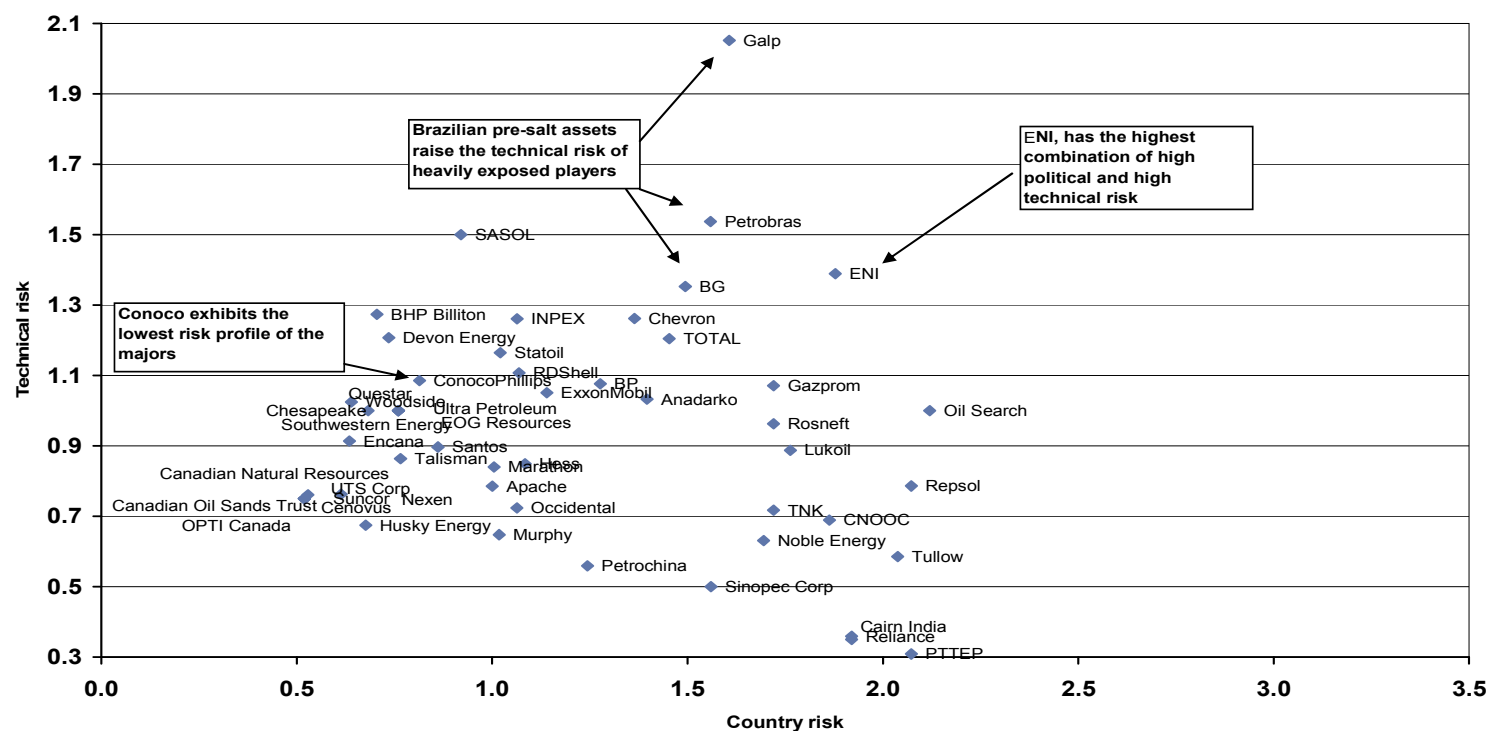
Source: Company data, Goldman Sachs Research estimates, World Bank Index.

Companies and risk: ENI has the highest risk profile among the Majors, Conoco the lowest

Of the Majors, ConocoPhillips has the lowest level of country risk which reflects a partial trade-off for the relatively low profitability of its portfolio and its significant positions in Canada, the US and Australia. Exxon, BP, Statoil and Shell have a similar combination of technical and country risk with Chevron and TOTAL having slightly higher risk profiles. Companies with a high concentration of their assets in the Brazilian pre-salt play have high technical risk. This is particularly the case for BG, Galp and Petrobras for whom these assets form a particularly significant part of their portfolios. Repsol's risk is more muted as a result of its significant exposure to the relatively simple Block N186 and Shenzi although its political risk remains high. ENI stands out as having the highest combined political/technical risk – primarily a result of its large exposure to Kashagan, West Africa and Perla in Venezuela.

The lower risk assets are, in our view, the heavy oil and LNG assets based in Canada and Australia. As we would expect from an efficient market, companies with this low risk profiling also tend to have relatively low returns.

Exhibit 123: Technical versus political risk by company



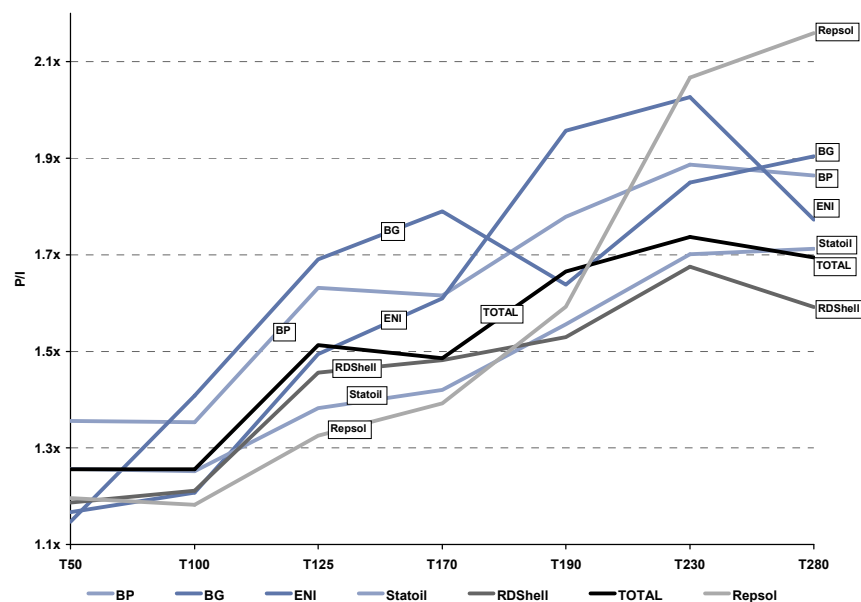
Source: Goldman Sachs Research estimates; World Bank Index.

Tracking the progress of the companies through our legacy asset analysis

We now have seven separate data series, over a period of seven years which allows us to track the change in value creation of each of the companies with respect to their new legacy asset portfolios. The overall profitability levels for the companies are mixed although the trend is upwards as a result of the increase in our oil price assumption. Among the European companies Repsol, BG and Statoil are the only ones to have improved profitability since Top 230. BG and Repsol benefit mainly from the improved economics in Brazil generated by the improved flow rates in the area while Statoil's uptick is fairly marginal. RDSH has the least profitable exposure, partly due to its presence in three Middle Eastern service contracts (West Qurna expansion, Majnoon and Asaba NGLs) and its high exposure to unconventional projects. Our estimate of ENI's profitability has seen a sharp dip partly as a result of the addition of new projects with a lower P/I than its Top 230 portfolio.

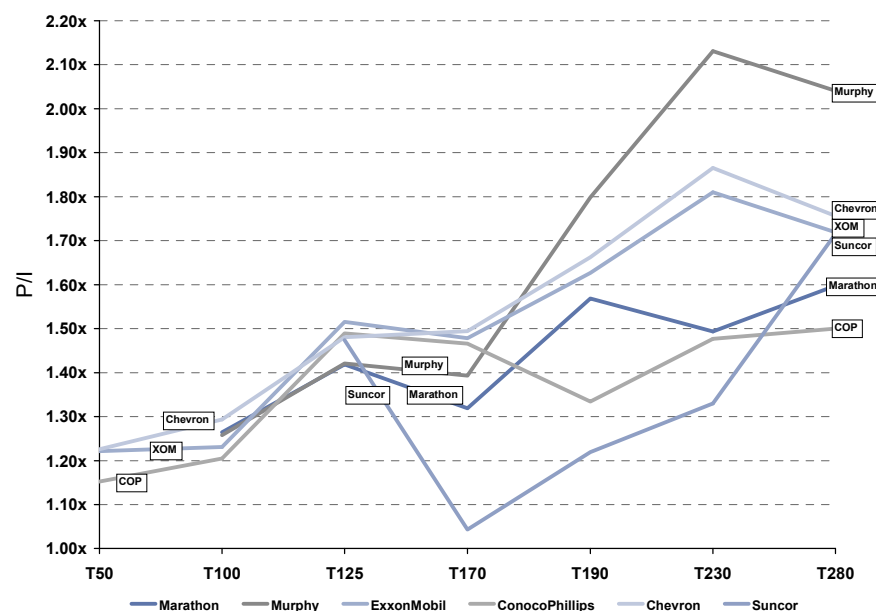
Among the North Americans, Suncor has seen the greatest uplift in P/I, thanks to the merger with PetroCanada which has seen higher profitability assets brought into the portfolio. ConocoPhillips is the negative outlier, due to its longer duration, low political risk unconventional exposure which tends to generate lower returns than more risky, shorter life ventures. Despite seeing an increase in profitability over the past two years Chevron, ExxonMobil and Murphy have dropped, partly due to the addition of new projects with a lower P/I than the Top 230 portfolio. Murphy's profitability has also declined, as a result of the addition of the lower profitability Point Thomson Liquids project and small revisions in our estimates of profitability for Gumusut and Syncrude 3.

Exhibit 124: Europeans: P/I development since Top 50 Projects



Source: Goldman Sachs Research estimates.

Exhibit 125: Larger North Americans: P/I development since Top 50 Projects

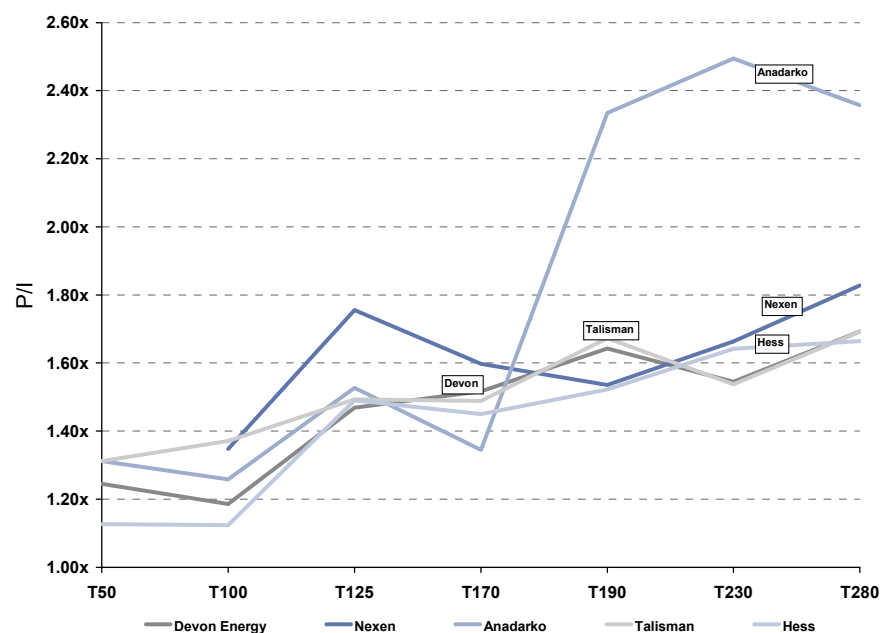


Source: Goldman Sachs Research estimates.

Similar to the Europeans, the overall profitability of the Americas E&P companies is mixed. Despite a decline in P/I on last year's levels, Anadarko remains the most profitable E&P company, with its deepwater focus and presence in highly profitable fields such as Caesar Tonga and Jubilee. The other Americas E&Ps are fairly closely grouped, with Nexen marginally more profitable than its peers, largely due to its stake in the producing Buzzard field.

Of the global companies, Petrobras now has the most profitable portfolio, and has improved largely as a result of the excellent flow rate data we have seen coming out of Brazil in 2009. Lukoil remains profitable but drops from the Top 230 level as a result of our revised assumptions surrounding the Karachaganak PSC and the addition of some new fields with lower P/Is than the majority of its Top 230 portfolio. CNOOC's profitability has also dropped since Top 230 as a result of the addition of the lower profitability Liwan field into a relatively small population set. Sinopec has the least profitable Top 280 portfolio of the emerging market players, with exposure to only one asset – Puguang – in China.

Exhibit 126: Smaller North Americans: P/I development since Top 50 Projects



Source: Goldman Sachs Research estimates

Exhibit 127: EM: P/I development since Top 50 Projects



Source: Goldman Sachs Research estimates

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Criteria and methodology for the Top 280 Projects

We have included fields in our Top 280 Projects analysis that meet the following criteria:

- Estimated recoverable reserves of at least 300mnboe, as for Top 230, Top 190, Top 170 and Top 125 (vs. 500mnboe in Top 50 and 350mnboe in Top 100)
- At least one equity participant that is an investable entity
- For which we could find good quality data in the public domain or directly from the companies involved and have confidence (from development plans and results of exploration/appraisal) that the reserves cross the required threshold.

We acknowledge that some projects will have been excluded due to lack of information, but we stress that we have endeavoured to include all the fields that meet our criteria. As part of the analytical process, we have requested feedback from all companies with material exposure and have attempted to include their commentary although we note that all the estimates in this analysis are our own and do not necessarily reflect any specific company guidance.

Methodology unchanged from previous analysis; Brent oil price assumption stays at US\$85/bl

We continue to use the same modelling methodology for the analysis although we note the following:

- **Oil price assumption:** US\$85/bl Brent oil price remains constant from the Top 230 (published February 2009). Regional gas prices have been adjusted for local pricing dynamics and regulation, with actual historical data used.
- **Discount rate:** For headline NPV and P/I calculations, we have used an 8% nominal cost of capital assumption.
- **Breakeven oil price:** The oil price required for a project to generate what we consider to be a commercial rate of nominal IRR (i.e. cost of capital). We assume geography determines this rate of return with projects in the OECD requiring 11% up to a maximum of 15%.

Win zones in the Top 280

Exhibit 128: Success criteria for each of the win zones

	Criteria for success	Well positioned	Trends
Deepwater	High exploration risk minimised through technological advances, especially in seismic, subsea and production technologies. First movers gain exploration advantage in new basins. Balance sheet strength to take high risk approach and potential for expensive dry holes and cost inflation. Advantaged access to deepwater drilling rigs increasingly important at current inflated dayrates	Petrobras, BP, ExxonMobil, TOTAL, Chevron, Statoil, BG, Repsol, Tullow	Parts of West Africa and GoM now moving to more of an exploitation phase but new deepwater basins still exist (e.g. Gulf of Guinea, Arctic and Mexico). Brazil the greatest exploration excitement in the industry since the beginning of the decade although Ghana and the offshore to its West is also receiving attention. Exploration moving into increasingly deeper water and encountering more complex assets, resulting in increasing capital intensity for the winzone
Exploitation	Little or no exploration risk. Skills in production enhancement, project management, political negotiation and cost control. Technical execution in terms of commercialising reserves is key with cost control in the early phases necessary to enhance returns. Balance sheet backing also required. Political risk often high.	Chevron, BP, Exxon, BG, ENI, Occidental, Statoil, RDSHELL	Middle East the most attractive area where industry can get access to huge reserves at low cost. Iraq has revitalised this winzone with its 2009 contract awards. Returns on new projects being depressed with increasing competition, poor fiscal terms and delays
Traditional	A varied win zone with varying exploration risk in typically smaller, more satellite-like plays. Higher exploration risk generally gives higher rewards due to the use of attractive fiscal terms to attract players to frontier locations. Access to existing infrastructure ensures commerciality with generally little technology edge. Balance sheet backing less important. Kashagan stands out within this Win Zone for its size.	ENI, TOTAL, Exxon, Shell and smaller E&Ps	Redirection of capital from the Majors in search of scale leaves room for the emergence of scaled regional players in both mature and frontier areas
Heavy Oil	Little or no exploration risk. Significant resources that require solid process technologies and efficient operations that could make or break generally weak project economics. Project management skills to minimise risk of cost overruns and process skills to ensure smooth 'factory style' operations. Pace has slowed vs previous expectations due to the drop in the oil price in 2H 2008 and capacity bottlenecking especially in labour prior to this.	CNR, Exxon, Suncor, Conoco, RDSHELL, TOTAL, Statoil	Intense activity levels in Canada with strong interest in new developments. Increasing focus on GHG emissions and high capital costs impact economics leaving projects at the marginal end of the cost curve. 2008 adjustments to Albertan oil royalties highlight that the area is not 100% free of fiscal risk. New activity sensitive to the oil price with delays to sanctions likely in falling oil price environments
Gas: traditional	A nearby domestic market able to support sufficient gas prices to justify development is a key consideration. In the absence of this, sufficient reserves required to justify and LNG scheme. Technological risks and upfront capital requirements relatively low in most cases although if pipelines are required, costs can escalate substantially	ExxonMobil, PetroChina, BP, Conocophillips	Economic development in emerging markets leading to increasing realisations has enabled development of previously fallow fields. Technological advances has also meant that previously unviable fields can increasingly be unlocked (i.e. Shah)
Gas: unconventional	Exploration risk varies depending on the location of the acreage in the licence so prime acreage position is a substantial advantage. Track record and experience with tight shallow gas reservoirs is a bonus, as is the ability to access rig capacity to enhance returns. First mover advantage has proved significant in capturing prime acreage spots	Chesapeake, RDSHELL, BP, Questar, Encana, Ultra, XTO, statoil,	Advances and cost reductions in horizontal drilling and fracking has led to a rapid increase in activity by making these marginal plays commercial. Activity relatively dependent on gas price due to high capital and operation costs
Gas: LNG	Little exploration risk but large upfront capex combined with high commodity input costs (i.e. steel and concrete) raises development risks. Significant single project capital commitment requires balance sheet backing. Ability to enhance returns through trading process is also key. Technology well tested but trains larger than c. 5 mtpa still carry some technological risk in our view	Chevron, RDSHELL, ExxonMobil, INPEX, ConocoPhillips, Woodside, TOTAL, BG	Middle East and Australia the most attractive areas where industry can get access to huge reserves. Few sanctions have been seen in recent years but planned sanctioning levels in Australia in the near term are high. Multi train projects at a significant cost advantage, meaning that resource bases in excess of 10 mtpa are advantaged
Russia	Significant resource base now largely out of reach to non-Russian companies. In depth political negotiations required to gain initial development, export and sales contracts and thereafter to retain licences. Licence ownership a more important factor than technology	Gazprom, Rosneft, Lukoil, TNK-BP, ENI	A new wave of significant project sanctions is needed to balance the decline of the existing fields. Political interference increasingly slows development timelines and raises project risk. High production potential in medium term.

Source: Goldman Sachs Research estimates.

Key characteristics of each of the win zones

Exhibit 129: Key characteristics of the win zones

Deepwater: largest number of projects with best combination of returns, growth and value. Highest unit F&D costs reflect technical component. Production and cash flows are fast growth but short duration. Brazil pre-salt fields are extending average life			Exploitation: limited number of large fields with low costs, decent returns and long duration cash flows. Awards of Iraqi service contracts have increased field numbers and reserves substantially, but the tough fiscal terms lower average profitability to be in line with other winzones			Traditional gas: Large number of relatively small fields. Low F&D costs and are offset by some projects having regulated gas prices which limit exposure to increases in oil price assumptions therefore causing the win zone to lag as we have increased our oil price assumption			LNG: A relatively low number of large reserves projects with average returns. Low F&D costs offset by highest infrastructure capex requirements allowing the monetisation of gas at international prices, although little visibility is available on large scale LNG plant costs		
Deepwater		As % of T280	Exploitation		As % of T280	Gas		As % of T280	LNG		As % of T280
Number of fields	68	24%	Number of fields	18	6%	Number of fields	52	19%	Number of fields	33	12%
Reserves (mnboe)	59,766	14%	Reserves (mnboe)	59,636	14%	Reserves (mnboe)	56,104	13%	Reserves (mnboe)	57,247	13%
2010E production (kboe/d)	4,754	25%	2010E production (kboe/d)	2,831	15%	2010E production (kboe/d)	3,290	17%	2010E production (kboe/d)	1,683	9%
Duration (years)	24	78%	Duration (years)	24	77%	Duration (years)	28	89%	Duration (years)	33	105%
F&D capex (US\$m)	549,699	24%	F&D capex (US\$m)	216,315	9%	F&D capex (US\$m)	270,986	12%	F&D capex (US\$m)	250,154	11%
Infr capex (as a %)	1%	7%	Infr capex (as a %)	14%	70%	Infr capex (as a %)	21%	108%	Infr capex (as a %)	46%	229%
Upstream F&D (US\$/boe)	9.2	171%	Upstream F&D (US\$/boe)	3.6	67%	Upstream F&D (US\$/boe)	4.8	90%	Upstream F&D (US\$/boe)	4.4	81%
IRR	26.4%	121%	IRR	21.2%	97%	IRR	18.2%	83%	IRR	18.2%	83%
P/I ratio	2.35x	123%	P/I ratio	1.81x	95%	P/I ratio	1.59x	83%	P/I ratio	1.80x	95%
NPV (US\$/boe) <small>life of field</small>	6.5	203%	NPV (US\$/boe) <small>life of field</small>	2.1	67%	NPV (US\$/boe) <small>life of field</small>	1.7	54%	NPV (US\$/boe) <small>life of field</small>	3.6	111%
Unconventional gas: High capex but long duration assets. Returns helped by the timing of cashflows where drilling is undertaken throughout field life. Highly sensitive to gas price assumptions and low prices can lead to falling activity			Heavy Oil: Increasing proportion of fields with potential for very long duration production and cash flows. High infrastructure component and slow production build-up limit returns and value but long durations are attractive in a balanced portfolio			Traditional: least homogeneous Win Zone (heavily skewed by Kashagan) but offset by low tax rate OECD projects with high returns and value creation. Costs and duration are only slightly above average.			Russia: Predominantly gas. Characterised by long duration, low cost projects relative to other Win Zones. Taxation and regulated prices for gas fields for domestic sale reduce profitability. High political risk for non-Russian based companies		
Unconventional Gas		As % of T280	Heavy Oil		As % of T280	Traditional		As % of T280	Russia		As % of T280
Number of fields	12	4%	Number of fields	32	11%	Number of fields	41	15%	Number of fields	23	8%
Reserves (mnboe)	23,801	6%	Reserves (mnboe)	55,718	13%	Reserves (mnboe)	41,074	10%	Reserves (mnboe)	73,495	17%
2010E production (kboe/d)	1,035	5%	2010E production (kboe/d)	1,040	5%	2010E production (kboe/d)	2,307	12%	2010E production (kboe/d)	2,420	13%
Duration (years)	36	115%	Duration (years)	37	120%	Duration (years)	27	86%	Duration (years)	42	134%
F&D capex (US\$m)	217,000	9%	F&D capex (US\$m)	287,377	12%	F&D capex (US\$m)	252,511	11%	F&D capex (US\$m)	256,360	11%
Infr capex (as a %)	1%	7%	Infr capex (as a %)	29%	145%	Infr capex (as a %)	8%	41%	Infr capex (as a %)	29%	144%
Upstream F&D (US\$/boe)	9.1	169%	Upstream F&D (US\$/boe)	5.2	96%	Upstream F&D (US\$/boe)	6.1	114%	Upstream F&D (US\$/boe)	3.5	65%
IRR	26.3%	120%	IRR	16.7%	76%	IRR	28.4%	130%	IRR	19.8%	90%
P/I ratio	1.84x	97%	P/I ratio	1.58x	83%	P/I ratio	2.20x	116%	P/I ratio	2.07x	109%
NPV (US\$/boe) <small>life of field</small>	1.6	50%	NPV (US\$/boe) <small>life of field</small>	1.9	59%	NPV (US\$/boe) <small>life of field</small>	5.7	178%	NPV (US\$/boe) <small>life of field</small>	2.5	78%

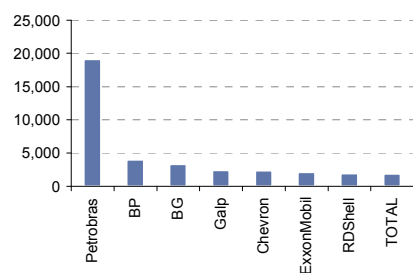
Source: Goldman Sachs Research estimates.

Company exposure to the win zones

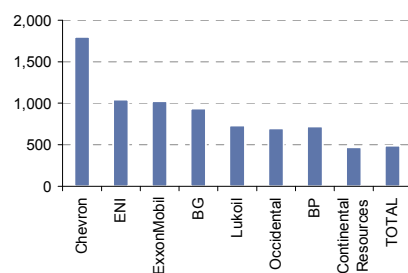
Exhibit 130: Company reserves exposure by win zone (mnboe)

Assessed on a net entitlement basis. GTL not included due to limited number of participants and projects

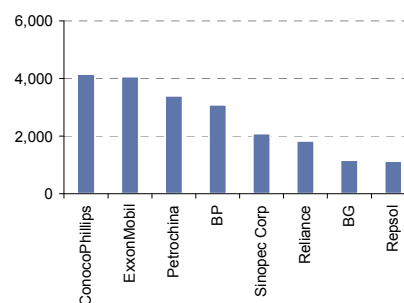
Deepwater: Petrobras dominates via Brazil. BP's exploration success (i.e. Tiber) improves its position. BG and Galp stay strong due to Brazilian exposure. Chevron strong from US and West Africa. Exxon is strong due to West Africa, but PSC effects erode net entitlement volumes



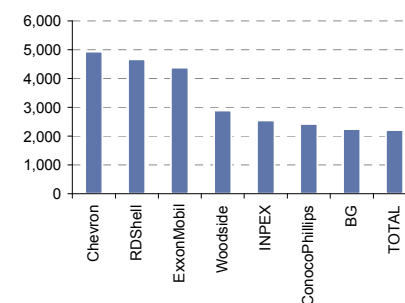
Exploitation: Iraq strengthens the positions of ExxonMobil, BP and RDSHELL although the fiscal contract limits the impact on net entitlement volumes. Chevron continues to lead due to the Tengiz and Karachaganak assets. Karachaganak boosts ENI.



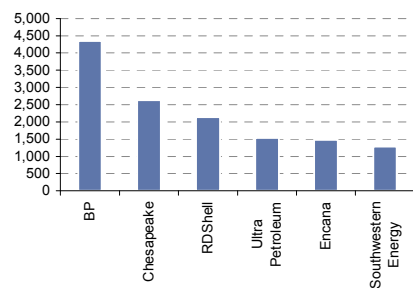
Gas: Conoco's Poseidon discovery in a licence regime brings it to the top. ExxonMobil is also a strong performer with Alaska Gas, Barzan and MacKenzie Gas. BP's assets in Egypt and Alaska result in a strong position. Repsol's South American assets lead it to feature.



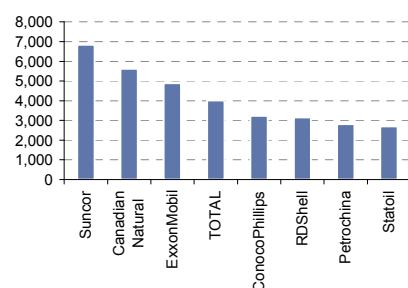
LNG: Chevron, ExxonMobil and RDSHELL with a lead over the other Majors due to Qatar, West African and Australian exposure. ConocoPhillips and BG are exposed through Australia with TOTAL exposed through a portfolio including Qatar, Australia, Europe and West Africa.



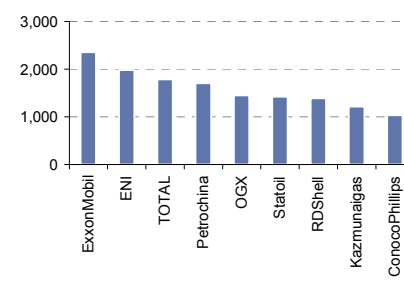
Unconventional gas: BP and RDSHELL the obvious winners from the majors. Aside from these majors the remaining large players are generally gas-focused US E&P companies. The US majors are notably absent.



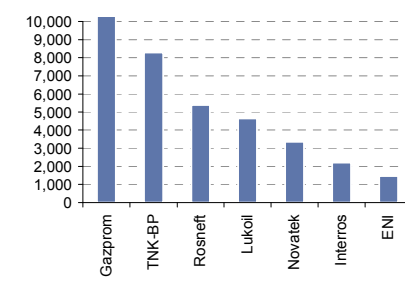
Heavy Oil: Exxon has the biggest exposure of the Majors. A number of smaller companies have significant reserves exposure. PetroChina moves up the list with its approach to buy into AOSC's Canadian assets. TOTAL also well levered.



Traditional: Kashagan exposure dominates this Win Zone. Otherwise, exposure is diverse and limited, relative to other Win Zones



Russia: Exposure is largely skewed to Russian firms, with Gazprom dominant. BP leads the Majors through its TNK-BP venture although ENI's inclusion in the Artigas & Urengoi projects gives it greater exposure in this win zone



* Gazprom's reserves in the Russian win zone amount to 33 bnboe.

Source: Goldman Sachs Research estimates.

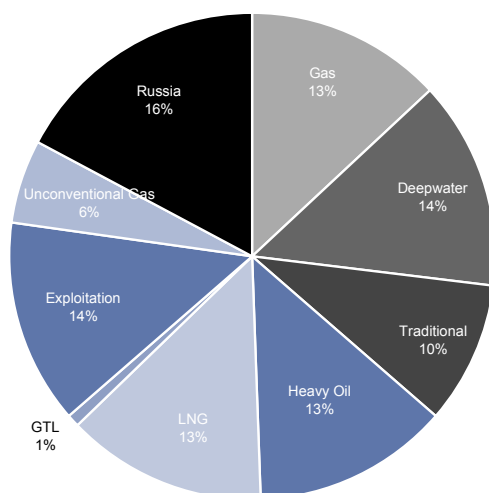
Production by win zone: Exploitation gains; technology not exploration the big driver

The most notable change in the make-up of the Top 280 Projects win zones relative to last year has been the addition of a large number of working interest reserves from the exploitation win zone in Iraq and the UAE as both countries attempt to substantially ramp up their existing production. The incremental exploitation reserves added from these two countries alone amount to 46 bnbls and exploitation now accounts for 14% of Top 280 assets (vs. 8% in Top 230). We take a conservative view of the possible ramp-up of these fields, especially in Iraq, relative to the targeted production, but still see these fields as being major contributors to global supply over the next 10 years.

The addition of a number of new Russian fields means that this win zone maintains its importance, while additions of recent gas discoveries such as Perla and Poseidon have meant that the gas win zone has also remained relatively constant. Despite a number of new discoveries (Tiber, Vesuvio etc.) the deepwater win zone has shrunk to represent only 14% of the total (vs. 15% last year). LNG has also shrunk.

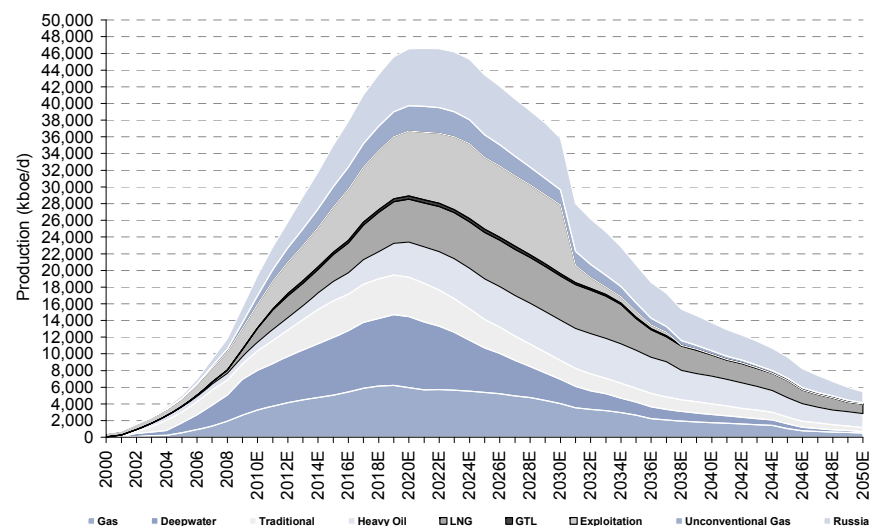
We believe that reserves are increasingly being added as a result of technological or political developments rather than as a result of exploration. We regard the exploitation, LNG, heavy oil, unconventional gas and Russian win zones as having relatively low exploration risk and believe that additions in these win zones are driven by technology and commodity prices making previously discovered reserves commercial or (as in the case of Iraq) changes in geo-political conditions allowing development of known reserves rather than success with the drillbit. Of the reserves added between Top 230 and Top 280, only 37% were from the more exploration-led win zones. Overall 64% of reserves are from what we regard as non-exploration based win zones.

Exhibit 131: Reserves split by win zone



Source: Goldman Sachs Research estimates.

Exhibit 132: Production split by win zone



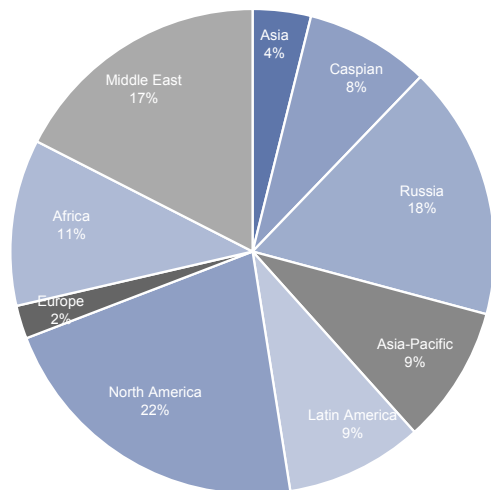
Source: Goldman Sachs Research estimates.

Production by area: Middle East becoming the key focus for producers in the medium term

In the short term, the largest volumes from the Top 280 look set to come from African projects but we expect the importance of this region to fall for producers, with only 12% of total production coming from this area by 2020E (vs. 24% in 2010E). We expect the big relative increases to come from the Middle East as a result of the ramping up of Iraqi, UAE and Qatari production (to 21% of the total production in 2020E vs. 12% in 2010E) and Asia Pacific – mainly due to the large number of LNG projects looking to be sanctioned in Australia over the next few years. The US should also increase its relative share of production over this period as a result of exploration success in the Gulf of Mexico and its large unconventional gas reserves. We expect Europe to decline to contribute only 3% of total production by 2020E, reflecting its status as a mature basin.

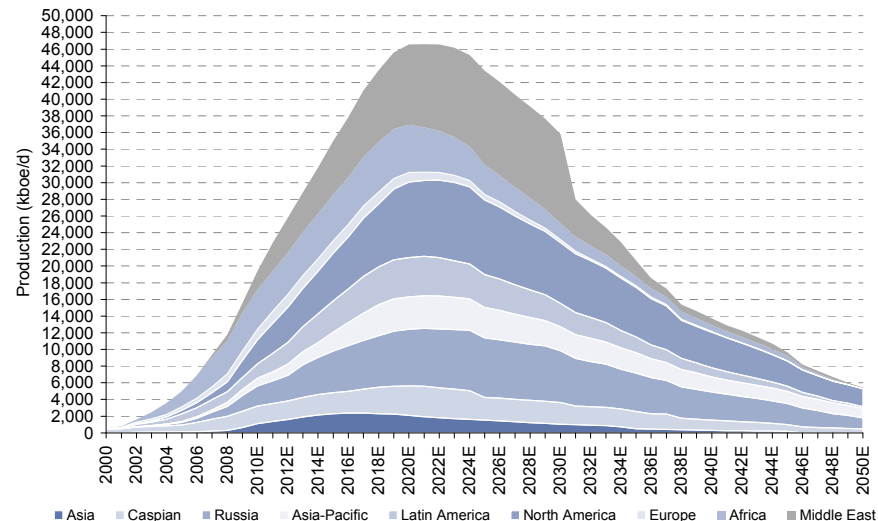
In the longer term, we expect the key producers to be North America, Asia-Pacific and Russia, reflecting more than anything, the long-duration, low-decline nature of the assets that are found in these areas. In North America heavy oil and unconventional gas provides a strong, low-decline base, whereas in Asia-Pacific, the Australian LNG schemes should also provide long asset lives. Africa becomes less relevant in the longer term, and contributes less than 10% of the total by 2022E – a reflection of the region's shorter duration, deepwater bias. The Middle East retains its importance until c.2030E when we expect the service contracts on Iraqi fields to end. However, we note that if the IOCs are successful in ramping up production in Iraq, further deals may be signed beyond this timeframe and that, from a supply point of view, these projects will continue to produce beyond the end of the contract.

Exhibit 133: Reserves split by region



Source: Goldman Sachs Research estimates.

Exhibit 134: Production split by region



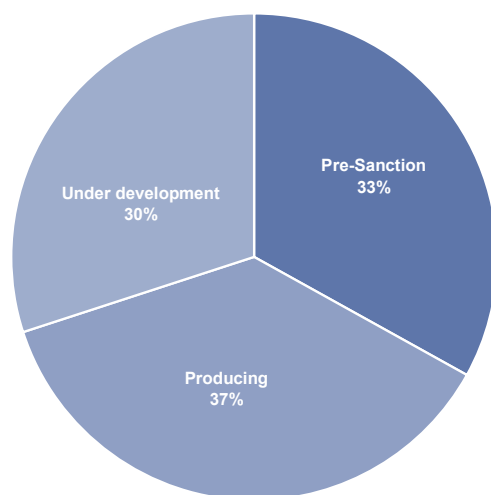
Source: Goldman Sachs Research estimates.

Weak production from new developments in the short term, healthier picture in mid term

The lack of sanctions between 2007 and 2009 has resulted in a low expected level of new production coming online in the near term; we believe only 8% of 2010E production is likely to come from projects that are currently under development. We are more bullish on the potential for projects to be sanctioned over the next few years, however, and believe that projects currently in the pre-sanction phase will contribute almost 15% of production by 2015E. There were more sanctions in 2009 than we anticipated in the Top 230 (projects such as Kearl Lake, PNG and Greater Gorgon added substantial reserves to the “Under development” group) meaning that the reserves under development increased from 28% in the previous edition of this study to 30% now. We regard this as an important development as a lack of sanctions can be as damaging for global supply as project delays and overruns.

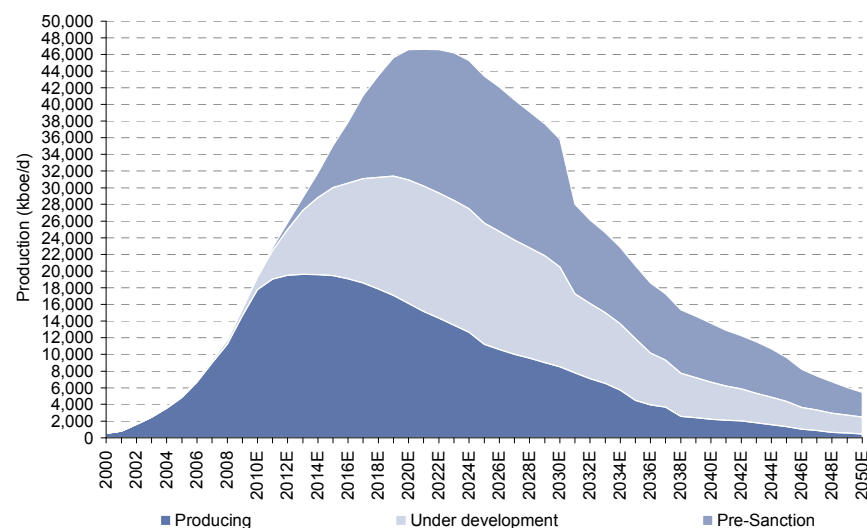
Note that for the purposes of Exhibits 135 and 136 we aggregate reserves on a project-by-project basis, meaning that additional reserves to be sanctioned in assets where production is already online will show under the producing category. This split therefore overestimates the reserves in production, meaning that the back end of the development pipeline should be healthier still.

Exhibit 135: Reserves split by development type



Source: Goldman Sachs Research estimates.

Exhibit 136: Production split by development status



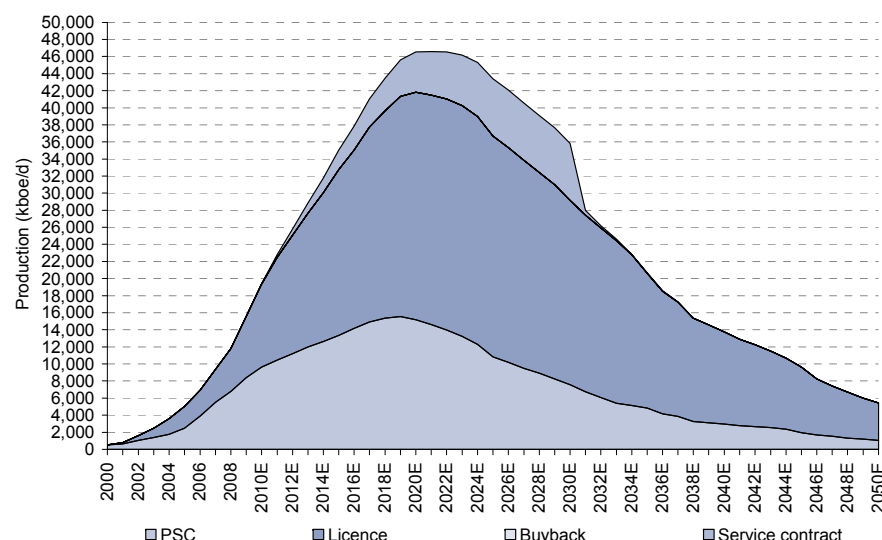
Source: Goldman Sachs Research estimates.

PSCs and service contracts important in short term; oil sees a medium-term spike from Iraq

The long duration of typical projects in licenced areas such as Canada, Australia and Russia means that in the long term we expect licences to dominate the Top 280 production. As a large number of the shorter duration deepwater and traditional projects are located in countries operating a PSC regime however, the relative importance of these contracts remains high in the near term: 50% of production will come from PSC-based contracts in 2010E, and over one third by 2020E. We believe that the technical service contracts that are being awarded in the UAE and Iraq will also have a substantial medium-term impact on oil production, although we note that these contracts typically have a limited duration and are likely to be largely finished by the mid-2030s.

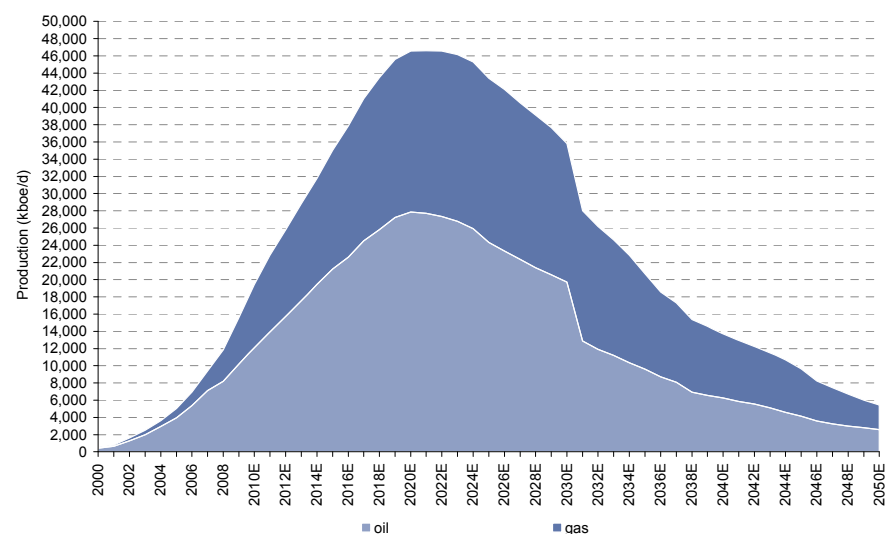
The Middle Eastern service contracts have also resulted in the proportion of oil vs. gas going up substantially: oil reserves now account for 55% of the Top 280 reserves (vs. 50% in the Top 230). Gas retains its importance in the long term, accounting for over 50% of the volumes when the Iraqi service contracts end (although we note that from a hydrocarbon supply perspective, the Iraqi fields will continue producing beyond the end of the contract date). Prior to this, gas accounts for less than 45% of the hydrocarbons produced by oil companies from their Top 280 portfolios.

Exhibit 137: Production split by contract type



Source: Goldman Sachs Research estimates.

Exhibit 138: Production split by oil/gas



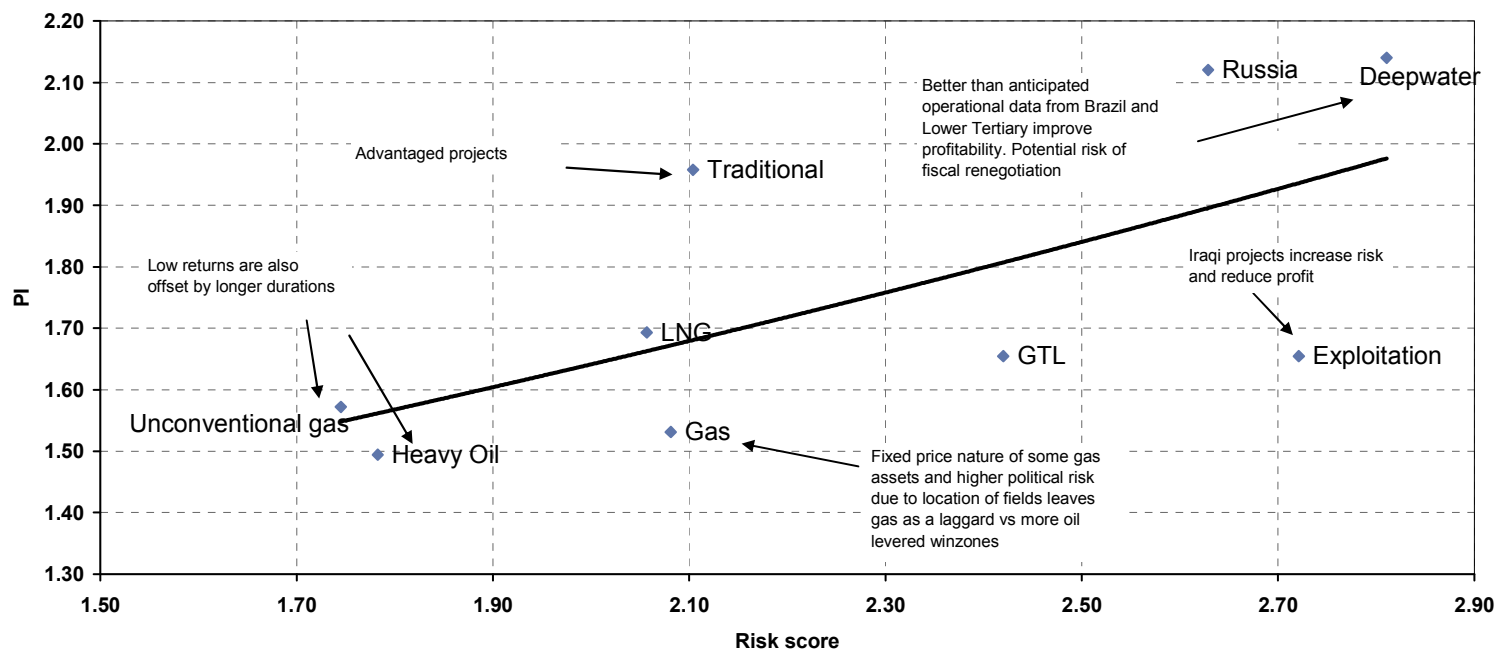
Source: Goldman Sachs Research estimates.

Win zones: Market should normalize risk-adjusted returns

The different win zones into which we divide the Top 280 projects are diverse and have differentiated drivers and risks associated with them. Exhibit 139 shows that there is generally a trade-off between profitability and risk in the different win zones. Win zones in more secure political environments with longer durations, such as unconventional gas and heavy oil, tend to have returns eroded by the market as either an oversupply of capacity (as in US unconventional gas) or higher cost (as in Canadian heavy oil) bring returns back in line with a risk-adjusted trend. Gas and exploitation are two notable laggards. In the case of gas, market forces have less ability to impact returns as many projects are reliant on fixed price contracts which do not therefore profit in the event of rising commodity prices as do some of the other win zones. Iraq skews the risk/profit profile of the exploitation win zone with low returns relative to political risk – in our view a partial result of the fact that service contracts are often seen by oil companies as a low value contract to be entered into in order to gain future access to Iraqi resources. The traditional win zone is, as ever, advantaged, mainly due to its exploration-led bias, where risk is taken early in the project and rewarded with higher returns thereafter. The deepwater win zone has improved vs. other win zones since the last edition as cost deflation combines with excellent flow rate data from Brazil and the Lower Tertiary to support a higher returns profile. We believe that if this persists, fiscal renegotiations could bring future deepwater projects back in line with other win zones.

Exhibit 139: Profitability vs. risk for the Top 280 win zones

Includes technical and political risks



Source: Goldman Sachs Research estimates.

Heavy oil – a year of little progress, however consolidation may ease some bottlenecks

As expected, 2009 was a year of few developments in the Canadian oil sands as operators followed through on their announcements of late-2008 that they would delay any further investment until a more stable cost environment emerged. This has led us to trim further our production forecast from the oil sands basin, which makes up 86% of our global heavy oil win zone in terms of reserves. When viewed next to the equivalent forecast from Top 190 (2008) it becomes clear just how radically the unstable cost environment in Alberta has impacted expectations. Our 2008 oil sands production forecast was for 2.5mnbl/d by 2015E; we now expect only 1.6mnbl/d by that year, despite adding nine new developments to the data set since then (equivalent to 8.7 bnbls of resource).

ExxonMobil took FID on its Kearl oil sands mining project in early 2009 following a lengthy environmental assessment and regulatory process. This may prove opportunistic given the retrenchment of other major oil sands players, which we believe has eased demand on the labour pool and the materials supply chain in the region, although how much of this is ultimately realized in the cost to start-up of Kearl is yet to be seen. The project will be a standalone mining project, with no bitumen upgrader attached.

Exhibit 140 gives our expectations for oil sands project sanctions out to 2015E. In our view, the next major mine sanctions following Kearl are unlikely to emerge until Horizon Phase 2, in 2011E, and Athabasca Expansion 2, in 2012E.

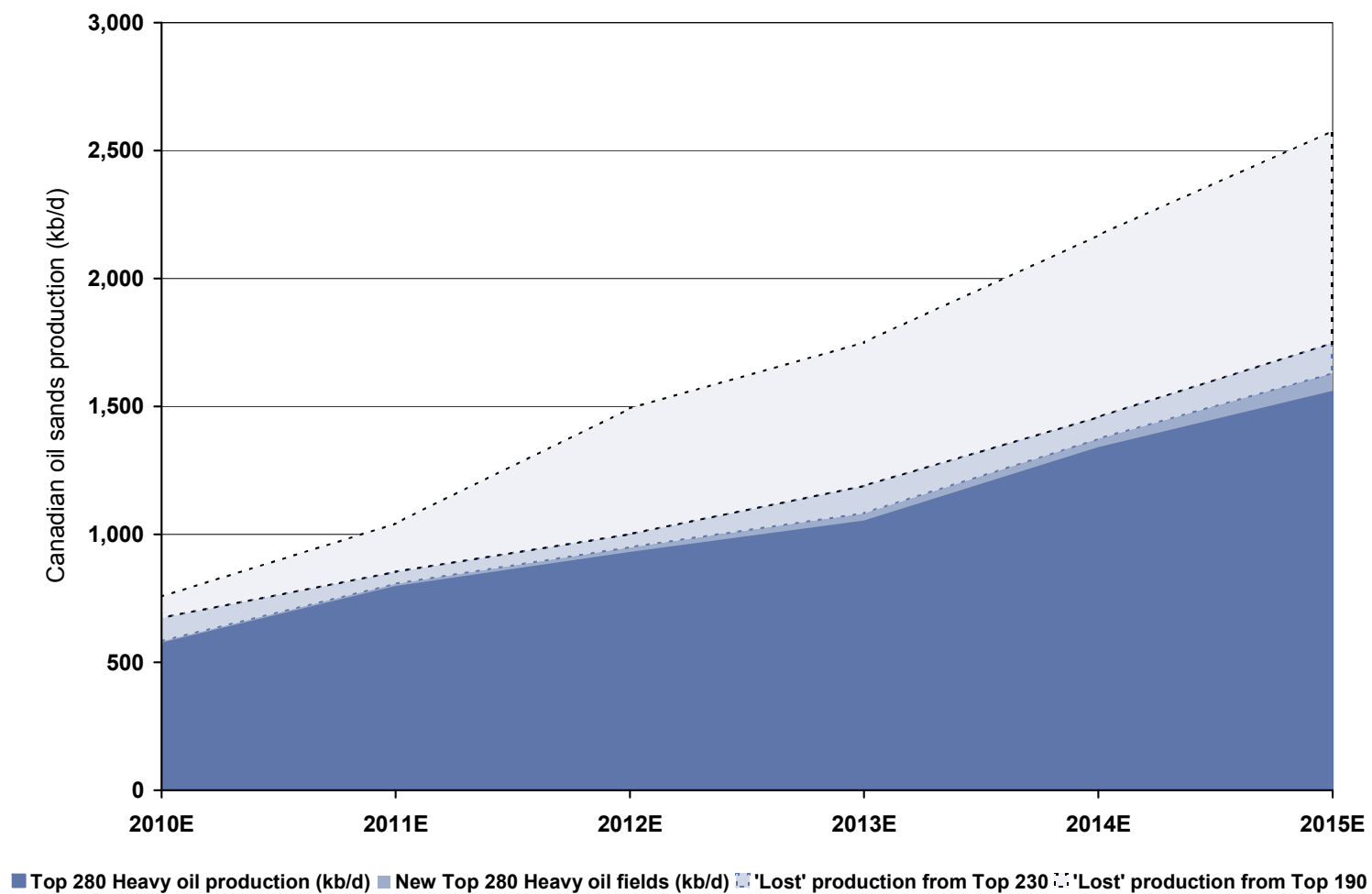
Suncor increased its reach in the oil sands by merging with Petro-Canada during the year, supplementing its existing Millennium, Steepbank and Firebag projects with further proposed projects at Mackay River and Fort Hills, as well as a stake in the existing Syncrude project. Although we have delayed our expected start-up for the Fort Hills development (from 2014E to 2018E), we believe that the merger may improve the prospects for the oil sands' ramp-up in general, as it may allow a more rational approach to large-scale projects, potentially avoiding the dangers of having several large-scale projects under construction at the same time (e.g. Voyageur Upgrader, Firebag 4 and Fort Hills).

Large-scale integrated mining projects in the oil sands remain the marginal cost area of supply in the Top 280 database. We have analysed the movement of the underlying cost components of heavy oil developments and believe that if projects could be executed at current cost levels, this would represent a 10% fall compared to 2008 levels for integrated mines, and 14% for thermal recovery projects. We therefore believe that this, combined with a lower normalized gas price assumption (US\$6.50/mcf down from US\$7.00/mcf), will drive investment towards small-scale thermal projects, rather than large-scale mines in the near term. Specifically, we believe additional phases will be sanctioned at Surmont, Firebag, Mackay River and Foster Creek & Christina Lake in 2010E.

We note that the most favourable oil sands portfolios are held by those companies with exposure only to thermal production (Devon Energy, ConocoPhillips, Cenovus) or to legacy assets (RDSHELL, Marathon, Chevron). The least favourable positioning lies with the greenfield operators, particularly those with pure mining exposure: INPEX, Occidental, UTS, Teck Cominco.

Exhibit 140: Our estimated Canadian oil sands ramp-up has changed dramatically since 2008

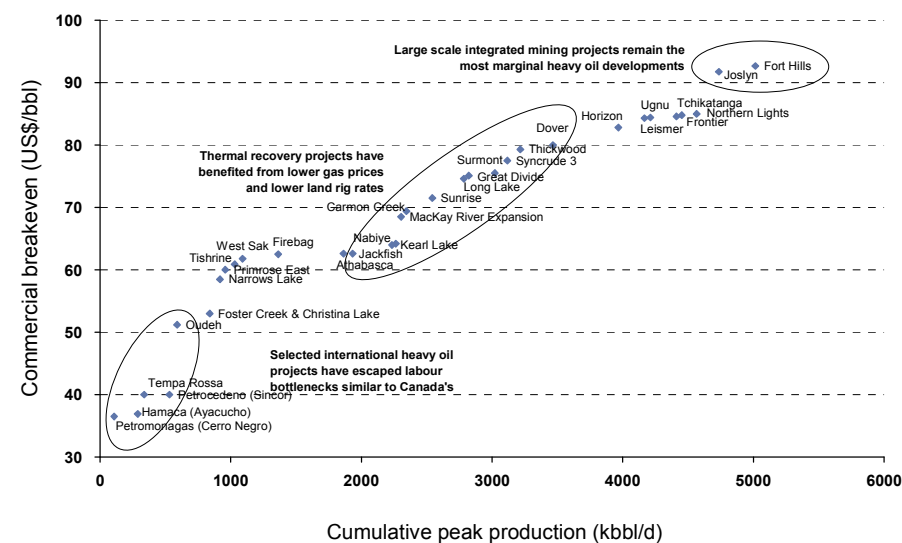
Top Projects Canadian heavy oil production (kb/d) – Top 190, Top 230, Top 280



Source: Goldman Sachs Research estimates.

Exhibit 141: Integrated mine development remains the marginal cost area

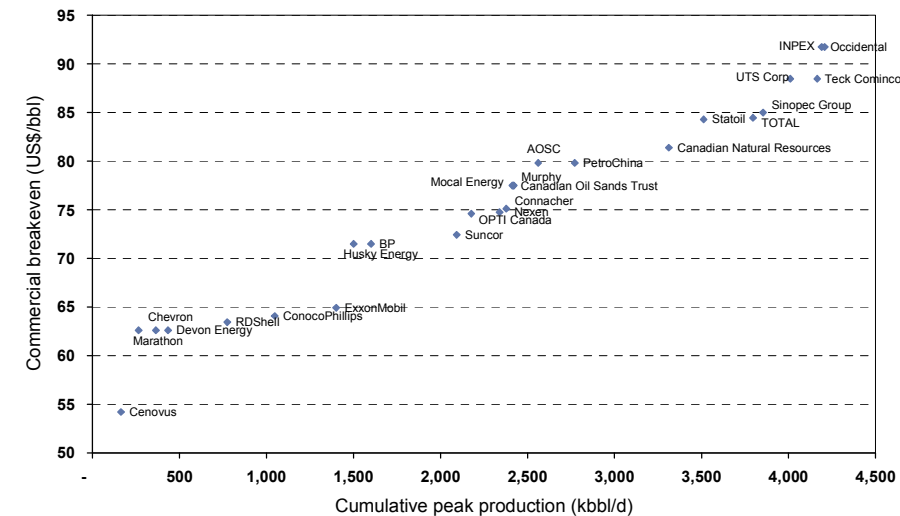
Top 280 Canadian oil sands breakeven and production



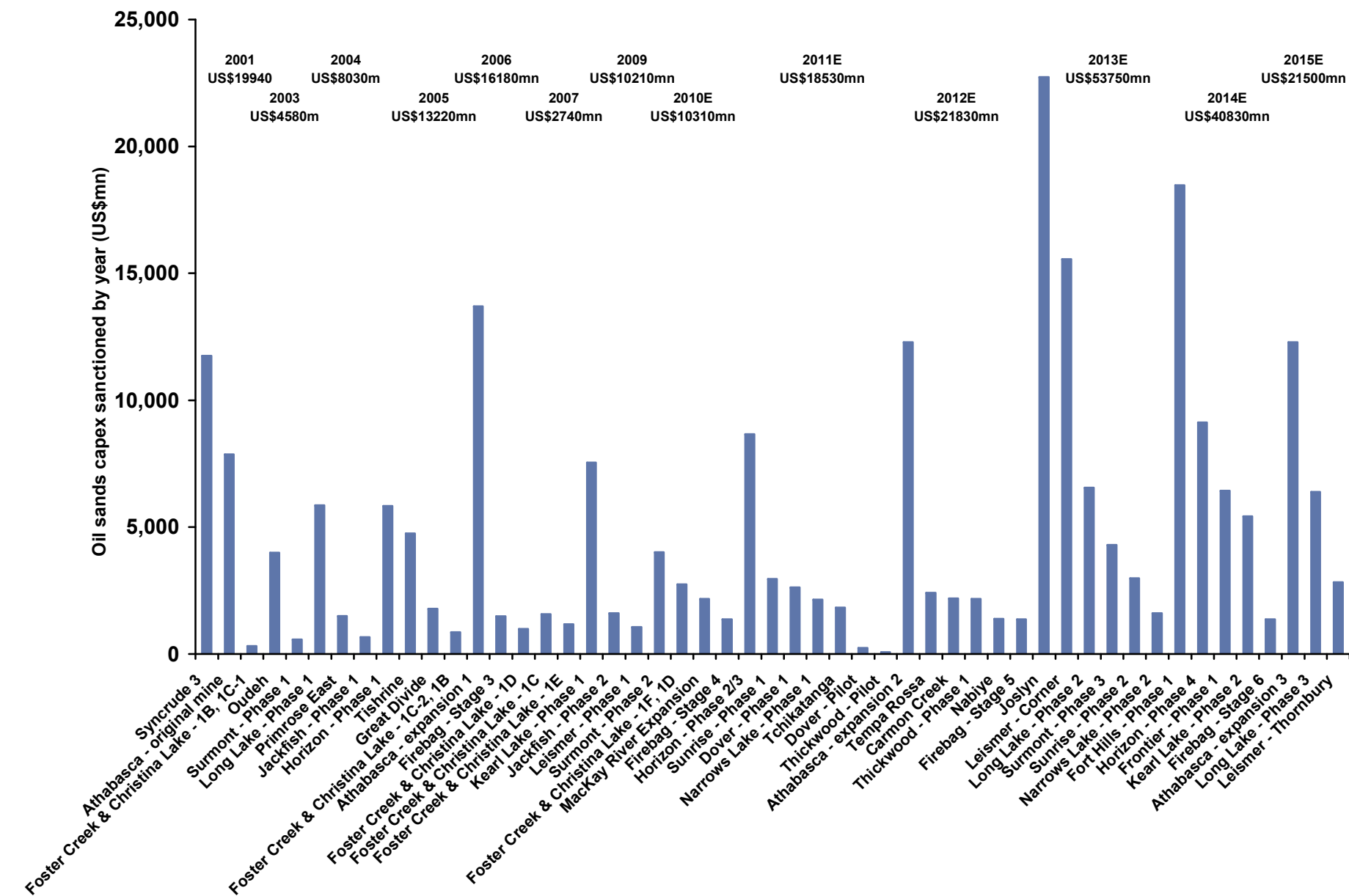
Source: Company data, Goldman Sachs Research estimates.

Exhibit 142: Therefore thermal exposure makes for the cheapest portfolio

Top 280 company portfolio breakeven and production



Source: Company data, Goldman Sachs Research estimates.

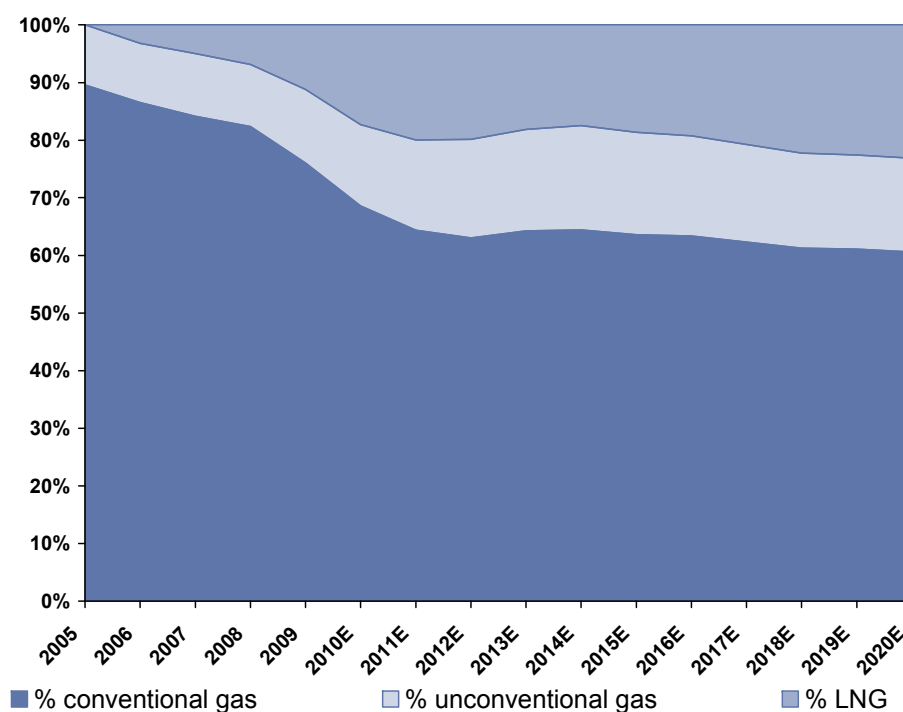
Exhibit 143: Top 280 oil sands capex sanctions by year

Source: Company data, Goldman Sachs Research estimates.

Unconventional gas: A growing slice of the global gas balance, at competitively low cost

We believe gas from unconventional reservoirs will make up an increasing proportion of the global gas balance in the coming decade, forming 16% of total Top 280 gas production by 2020E, driven primarily by low-risk shale, coal-bed methane and tight gas reservoirs in North America.

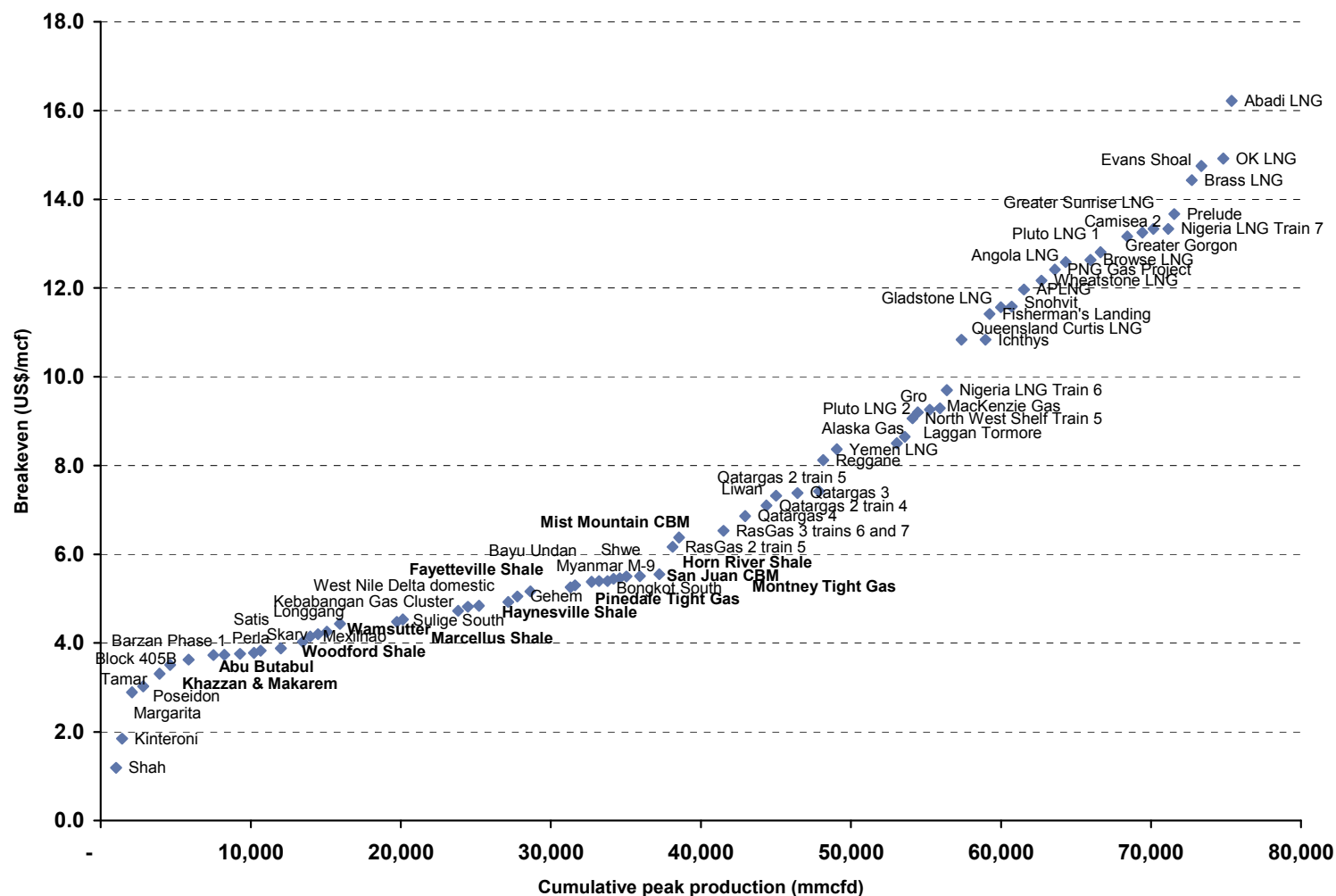
Exhibit 144: Change in mix of Top 280 gas production 2005 to 2020E



Source: Company data, Goldman Sachs Research estimates.

The unconventional gas developments themselves typically consist of several thousands wells tied back to simple gas processing infrastructure, linked to market hubs. The processing facilities are often owned by third parties, meaning the only significant capital outlay is on drilling, completing, and fracturing the wells. We believe the major plays have benefitted from a fall in land rig-rates across North America in 2009, which we estimate to be down 25% yoy. Based on the current cost environment, we calculate a reserves-weighted breakeven for our North American unconventional gas coverage to be US\$4.82/mcf, versus US\$5.76/mcf in February 2008, and versus US\$5.38/mcf for the pre-sanction gas developments in aggregate.

Exhibit 145: Unconventional gas projects vary in competitiveness vs. conventional, but are virtually all economic under US\$6/mcf
 Gas project commercial breakeven and cumulative production – Unconventional fields in bold



Source: Company data, Goldman Sachs Research estimates.

Deepwater: More confidence in Brazil and Lower Tertiary flow rate assumptions

Flow-rates a key element in determining costs

Since publication of the Top 230, data has become available on the pre-salt Santos Basin and, to a lesser degree, on the Lower Tertiary in the Gulf of Mexico, suggesting higher flow rates than we had previously assumed. We assume a relationship between the flow rates that can be achieved from a well and the ultimate reserves to be recovered from a well meaning that higher flow rates result in lower numbers of wells that need to be drilled both to reach plateau and over the life of the field which therefore lowers capital cost assumptions. Given the large proportion of costs spent on drilling in deepwater assets, we believe that a significant change in flow rates can have a major impact on the capital cost assumptions surrounding a field, with a movement from 20 kb/d (the same as the impressive rates achieved at Jubilee) to 60 kb/d reducing capital costs per barrel by US\$6.12/bbl assuming a 90 day drilling period.

Context is important in judging flow rates and we view flow rate estimates of 50 kb/d from pre-salt Santos plays as exceptional when set against other regions (Exhibit 147). We believe that flow rates of c.12 kb/d will make the Lower Tertiary economic even assuming a drill time of c.6 months due to the depth of the reservoirs and the difficulty in drilling into sub-salt reservoirs.

Exhibit 146: Flow rates and drilling times drive value per barrel

F&D costs based on a generic Santos pre-salt asset with 1.5 bnbls reserves and US\$1.5 bn gas infrastructure cost, together with implied NPV/boe at 8% WACC

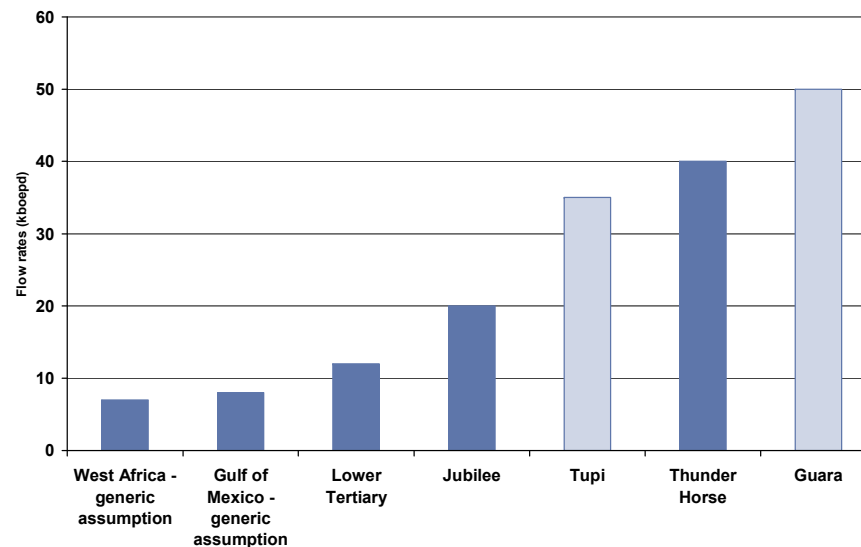
F&D/boe				
Flow rate (kb/d)	Drill time (days)			
	30	60	90	120
10	14.27	18.2	22.14	26.08
20	9.01	10.98	12.95	14.92
30	7.26	8.58	9.89	11.2
40	6.39	7.37	8.36	9.34
50	5.86	6.65	7.44	8.23
60	5.51	6.17	6.83	7.48

NPV/boe				
Flow rate (kb/d)	Drill time (days)			
	30	60	90	120
10	7.71	6.27	4.64	2.86
20	9.33	8.69	8.19	7.57
30	9.66	9.46	9.18	8.74
40	9.91	9.69	9.52	9.25
50	10.05	9.85	9.68	9.55
60	10.15	9.97	9.78	9.68

Source: Goldman Sachs Research estimates.

Exhibit 147: Santos flow rates are world class

Tupi and Guara flow rates could be higher



Source: Goldman Sachs Research estimates.

Flow rates confirm the Santos Basin's status as a world-class play

Petrobras started up an extended well test on the Tupi field in May and subsequently revealed in September that the Guara reservoir had responded extremely well to flow testing and that initial well rates of 50,000 b/d could be expected from the development. Little data was available up until this point on how the reservoirs would perform and the Guara data, combined with similar indications of high potential flow rates at the Iracema section of Tupi, confirms the play as an attractive resource both in terms of size and cost of extraction. The impact of these flow rates on our assumed capital costs has therefore led us to improve economics in the basin dramatically.

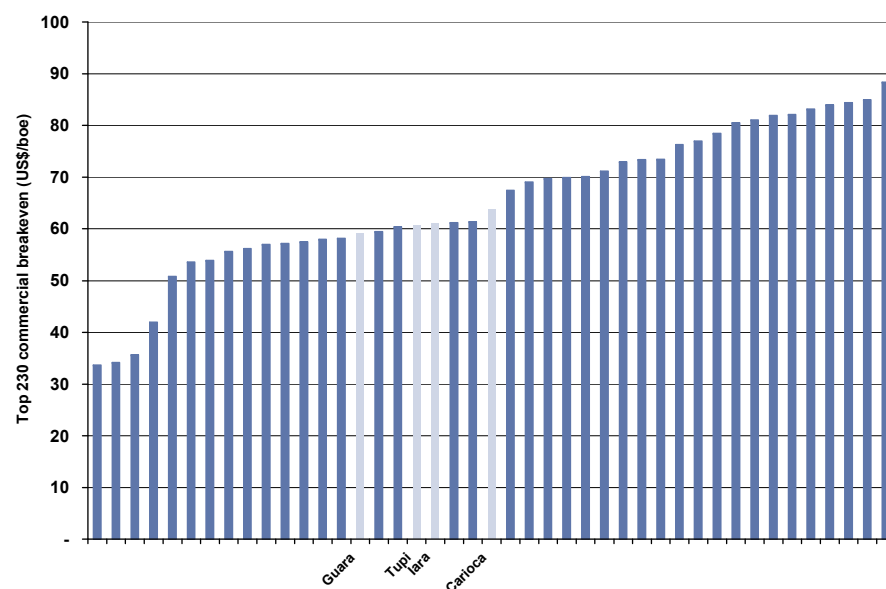
Exhibit 148: Key metrics – Santos Basin Brazil developments

Field	Reserves (mnboe)	Start-up	Flow rate (kboe/d)	F&D		NPV/boe	
				New (US\$/boe)	Old (US\$/boe)	New (US\$/boe)	Old (US\$/boe)
Tupi	6500	2009	35	8.68	13.14	6.83	5.15
Iara	3500	2013	35	8.36	14.15	6.76	5.80
Guara	1500	2012	50	7.46	14.50	9.68	7.95
Carioca	765	2016	25	11.31	15.85	7.32	5.96
Abare West	500	2019	25	10.91	NA	6.31	NA
Reserves-weighted average NPV/boe:						7.15	5.73

Source: Company data, Goldman Sachs Research estimates.

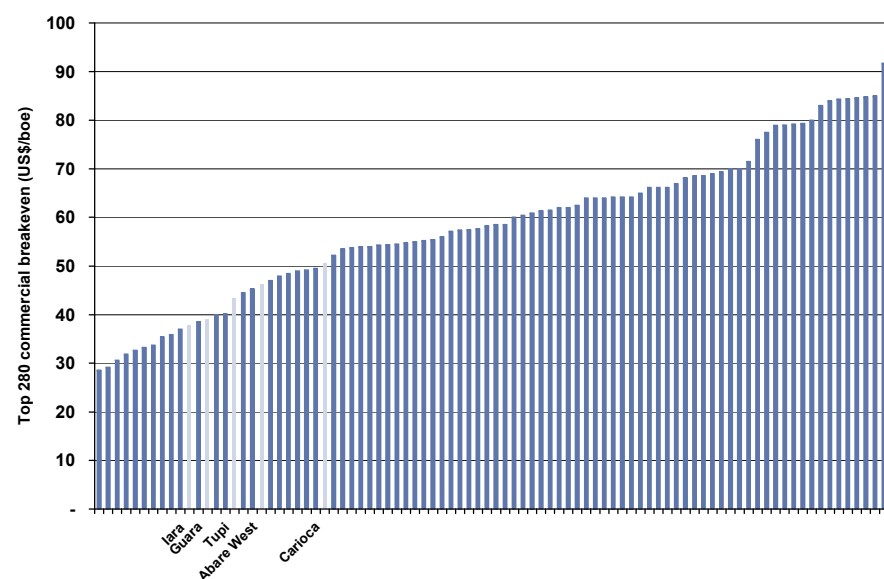
These changes have the result of moving the fields down the marginal cost curve, to the extent that they approach the upper quartile of our pre-sanction dataset in terms of the oil price required for a commercial return (in the case of Brazil, we assume a commercial hurdle rate of 13%). In our view, the flow rate data provides clarity on the attractive economics of these enormous developments, which, when combined with an almost unblemished exploration record in the basin, confirms its position as a world-class play.

Exhibit 149: In February 2009 we estimated Santos breakeven at c.US\$60/bl
 Top 230 pre-sanction commercial breakeven (US\$/boe)



Source: Company data, Goldman Sachs Research estimates.

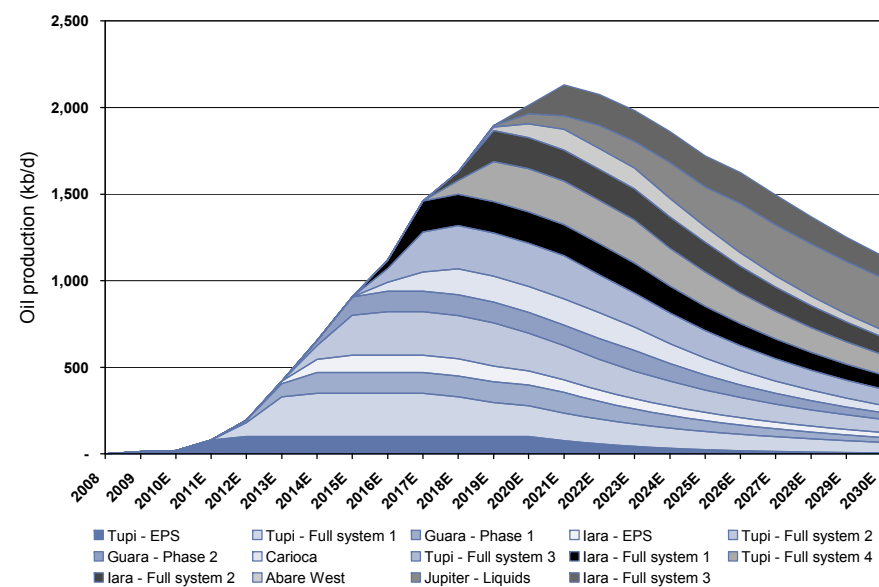
Exhibit 150: Recent flow rate data lowers this to US\$43/bl av in our view
 Top 280 pre-sanction commercial breakeven (US\$/boe)



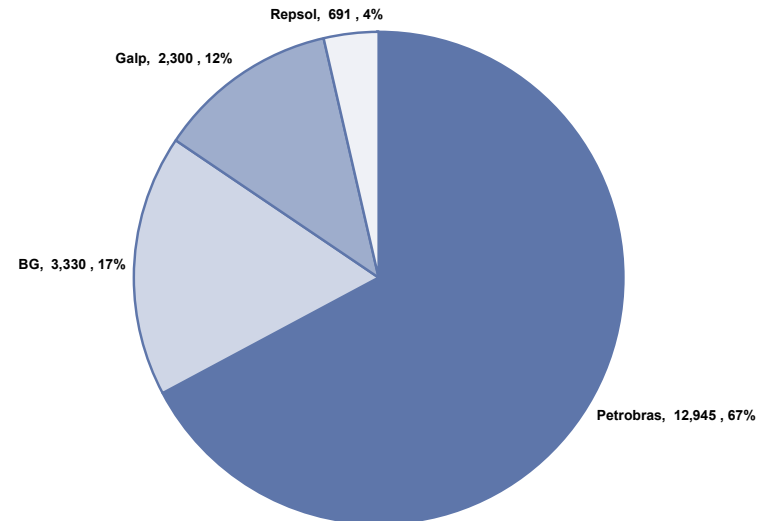
Source: Company data, Goldman Sachs Research estimates.

Over 2 mnb/d expected from Santos by 2020E

We split out by phase our oil production profile from the Santos Basin in Exhibit 151. We estimate the basin will produce over 1 mnb/d by 2016E, rising to over 2 mnb/d by 2020E following the addition of the final vessels at Iara, Abare West and Jupiter (liquids). Although resource development on this scale has typically disappointed in terms of actual delivery of new barrels (e.g. Kashagan and the Canadian oil sands), the operator has made notable progress on Tupi to date, bringing the field into commercial production within three years of discovery with the extended well test. Petrobras is aiming to bulk-order equipment for the projects and to use a 'design one, build many' approach for the production units in order to control costs. However the Santos Basin remains a frontier development for the industry, due to extreme water and reservoir depths. Following the discussions that took place in 2009 on the topic of how to tax the newly-discovered resource, there appears to be relatively low risk around already licensed acreage, and we would highlight that the most significant risk to the value of Santos barrels remains actual execution of the development.

Exhibit 151: Top 280 Santos Basin oil production by phase 2008 to 2030E

Source: Company data, Goldman Sachs Research estimates.

Exhibit 152: Top 280 Santos Basin reserves by company (mnboe)

Source: Company data, Goldman Sachs Research estimates.

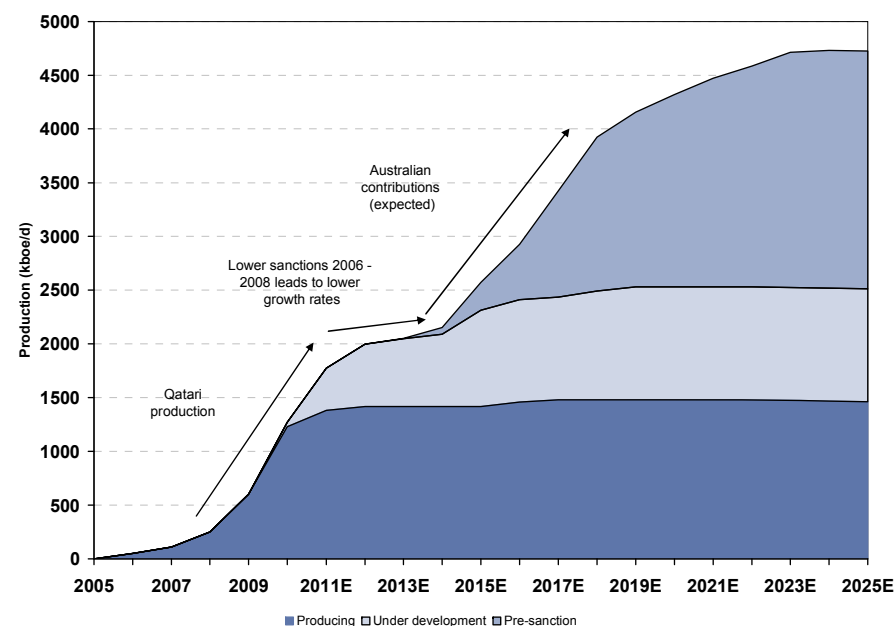
Liquefied Natural Gas (LNG) – Medium-term supply tightness

The impact of few sanctions between 2006 and 2008 will be felt between 2011E and 2015E

Our combined LNG models indicate that we are in a period of steep ramp-up that is primarily coming out of the Qatargas and RasGas projects in Qatar and Sakhalin 2 in Russia; beyond this however, we expect Camisea (Peru) and Pluto (Australia) to start production in 2010E and 2011E respectively, but very little else, leading to a relatively flat period of LNG growth. We expect to see a surge in production post-2014E, by which time the Eastern Australian LNG projects, which will use Queensland's coal-bed methane as feedstock, should be underway, along with a number of Australian north west shelf projects.

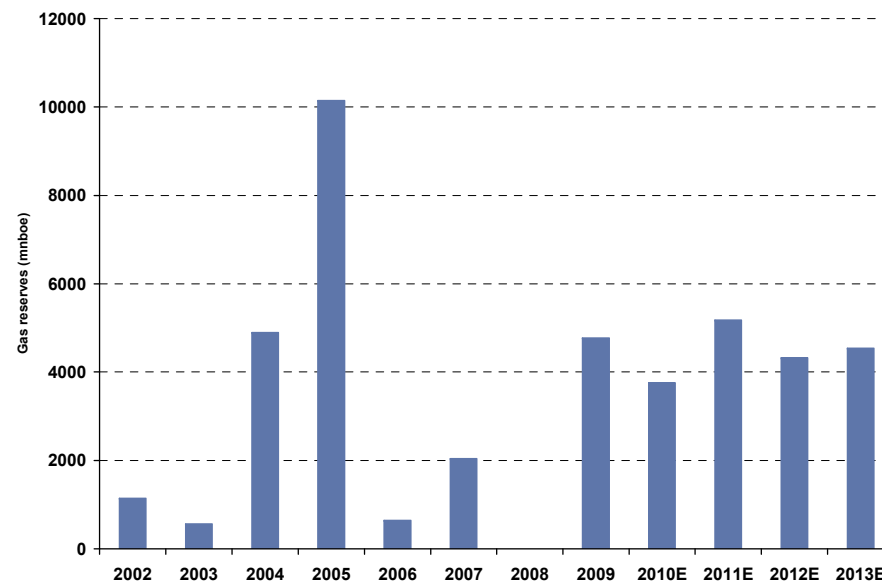
2009 surpassed our expectations in terms of sanctioning – both PNG and Gorgon were sanctioned. In 2010E we expect Queensland Curtis, Gladstone and Fisherman's Landing (all in Queensland) to be sanctioned, and another three in 2011E.

Exhibit 153: Top 280 LNG production profile



Source: Goldman Sachs Research estimates.

Exhibit 154: LNG gas reserves sanctioned by year



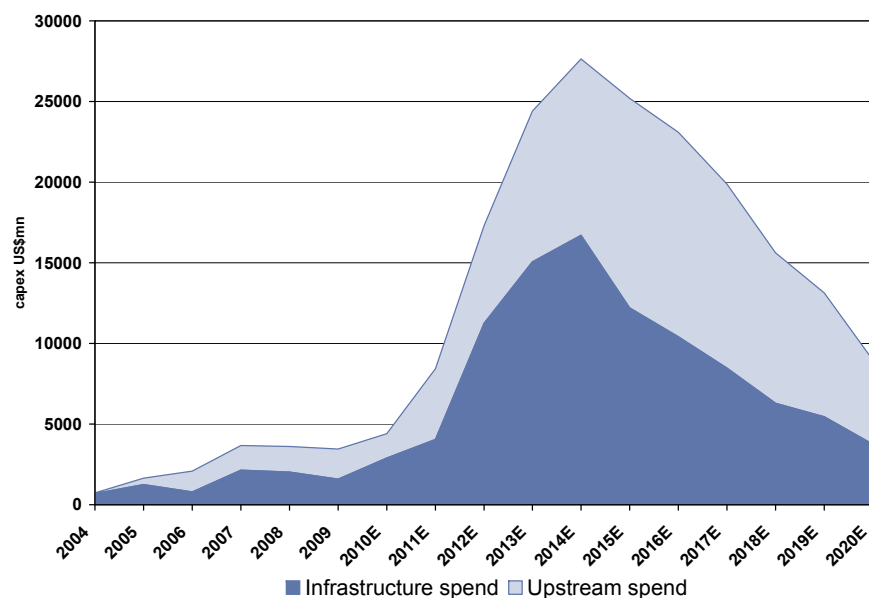
Source: Goldman Sachs Research estimates.

Global LNG supply highly levered to rapid ramp-up in Australia

The significant ramp up in our production forecasts is mainly as a result of activity in Australia. Between 2014E and 2020E we expect the Top 280 LNG supply to grow from 2.2 mnboe/d to 4.3 mnboe/d. Of this 2.1 mnboe/d increase, we expect almost two thirds from Australian LNG projects and the majority of the remainder from Nigeria from 2017E onwards. Between 2012E and 2016E the picture is even starker: 75% of the expected 929 kboe/d increase is from Australia.

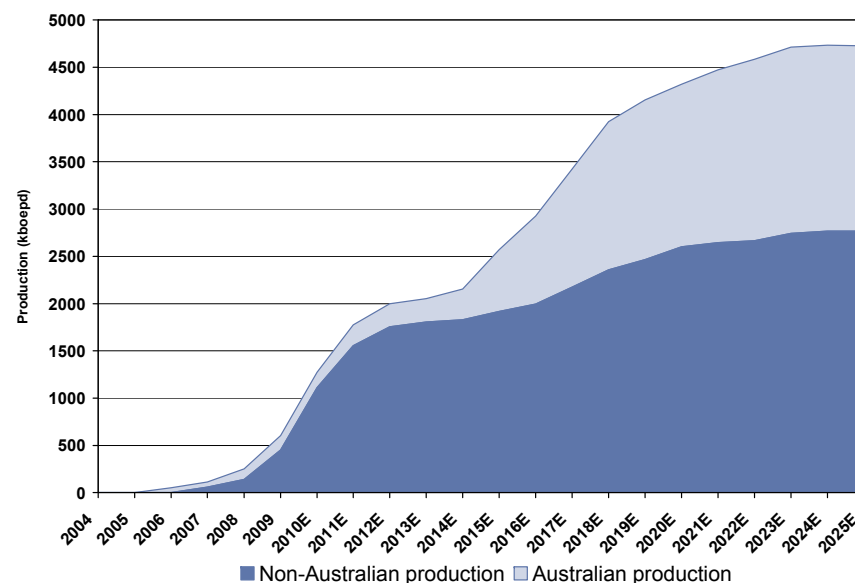
We believe that in total, capex spent on Australian LNG projects will increase by 700% from the 2009 base to the peak of activity in 2014E, with infrastructure spend increasing by 950%. We note that not all of this spend will be in the country as many units will be built abroad and shipped to Australia for assembly. Nevertheless, we believe that this level of increase is likely to result in cost inflation especially regarding labour and believe that some bottlenecks may occur. As a result, we take a cautious view on sanctioning relative to corporate guidance, and assume that no more than three projects can be sanctioned a year – an assumption which still leaves 14 projects being developed concurrently.

Exhibit 155: Step change in Australian activity on the horizon



Source: Goldman Sachs Research estimates.

Exhibit 156: Australia accounts for 64% of the increase in global LNG production from 2014E to 2020E



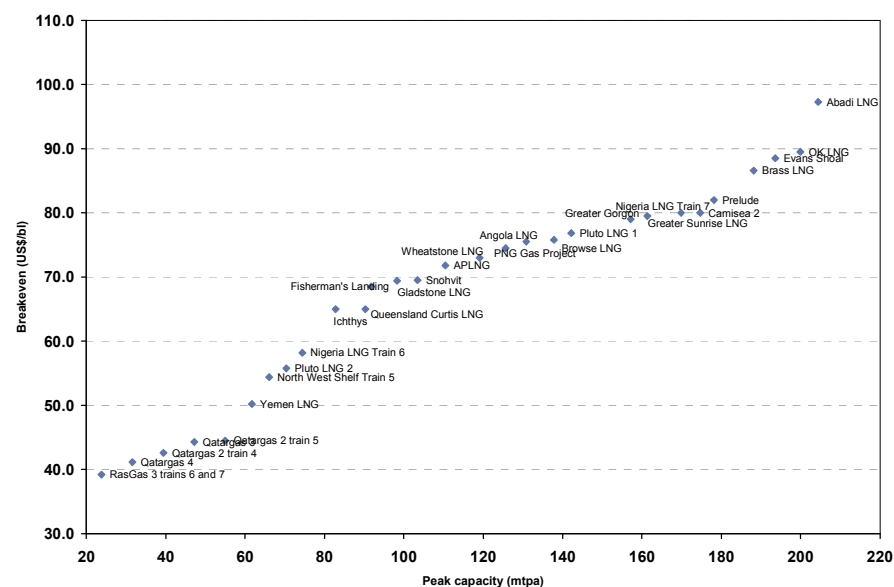
Source: Goldman Sachs Research estimates.

Security and labour costs offset raw material deflation; most new projects require over US\$70/bl

Although we believe that LNG projects have benefitted from the drop in raw material prices (primarily steel), we believe that to a large extent, this has been offset by the likely increase in labour costs as a result of the high levels of activity that are being planned in the next few years. We now estimate that an LNG plant in Australia will require US\$1-1.1bn/mtpa, with plants in West Africa costing more due to the likely increased costs of security and social payments.

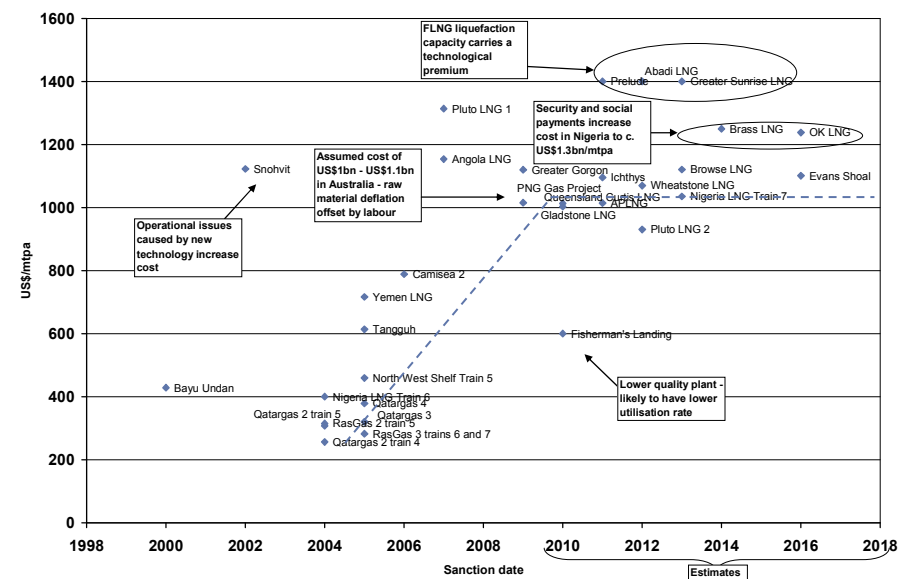
We analyse breakevens for LNG projects using the oil price to take into account the sometimes substantial liquids volumes and the link between many LNG contracts and crude. In addition, we believe that going forward, contract pricing is likely to reference the crude price. We believe that the majority of new Australian projects require an oil price of between US\$70/bl and US\$80/bl in order to break even at an 11% cost of capital. In Africa we look for a higher return and, as a result, believe that a minimum of US\$80/bl is required for most of these projects to achieve hurdle rate returns. Floating LNG projects are also towards the top of the cost curve in our view, as a result of the cost per mtpa and the lack of synergies available for additional liquefaction capacity. Nevertheless, we believe these projects have additional option value in allowing the stakeholders the opportunity to pursue a cookie cutter approach to additional vessels which may bring down costs and allow monetization of other stranded gas assets.

Exhibit 157: LNG breakeven vs. liquefaction capacity



Source: Company data, Goldman Sachs Research estimates.

Exhibit 158: Liquefaction cost assumptions



Source: Goldman Sachs Research estimates.

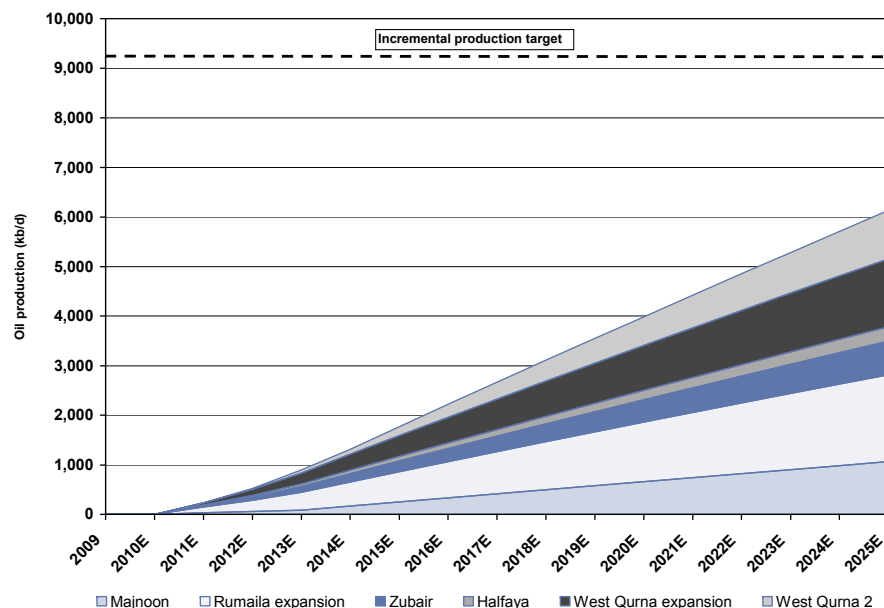
Iraqi contracts: Gigantic resource, but hitting targets will be challenging

We add eight new projects to the database with this publication to account for the new development contracts signed with IOCs in Iraq during the year, and to capture the start-up of two fields in Kurdistan. The Iraqi fields increase the resource captured by the database by 30 bnbls although we believe that with perfect execution this figure could increase.

We believe it is unlikely that the contractors will hit the production targets implied in their contracts. Although the scale of the resource is enormous, and could allow a ramp-up to the 9+ mnb/d level of incremental production implied by the production targets of the contracts, we believe that a number of problems exist that will likely limit ultimate production including, security, water supply, political risks and the structure of the contract which we believe encourages firms to bid to high production targets without substantial economic penalty in the event of failure. We note, however, that the scale of the proposals is significant. A ramp-up of the proportions targeted, even assuming some shortfalls in delivery, will require thousands of wells to be drilled together with significant investment in new gathering, processing and power generation infrastructure.

Exhibit 159: Rumaila, Majnoon & West Qurna will underpin the new wave of developments

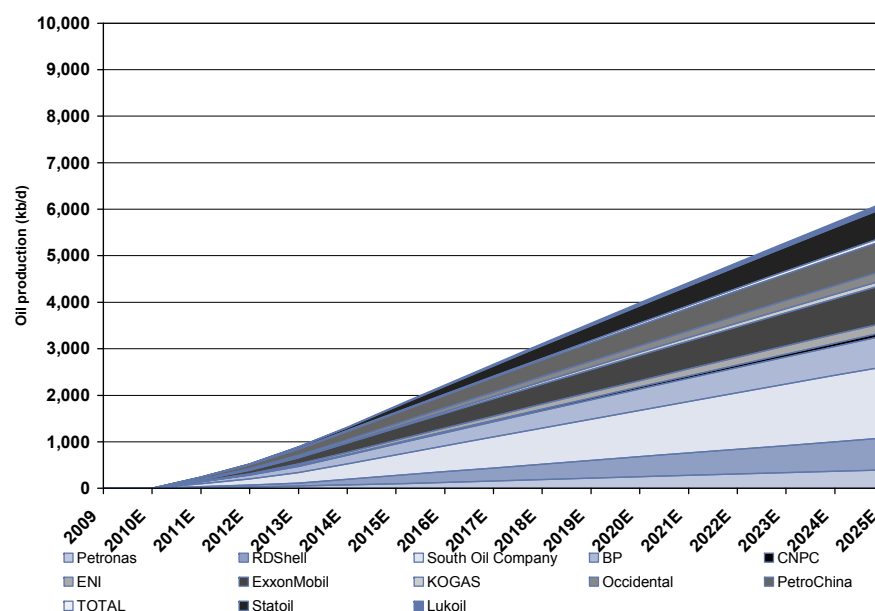
Top 280 Iraqi oil production by field 2009 to 2025E (kb/d)



Source: Company data, Goldman Sachs Research estimates.

Exhibit 160: ExxonMobil, Statoil & RDSHELL will be the largest IOC producers

Top 280 Iraqi oil production by company 2009 to 2025E (kb/d)



Source: Company data, Goldman Sachs Research estimates.

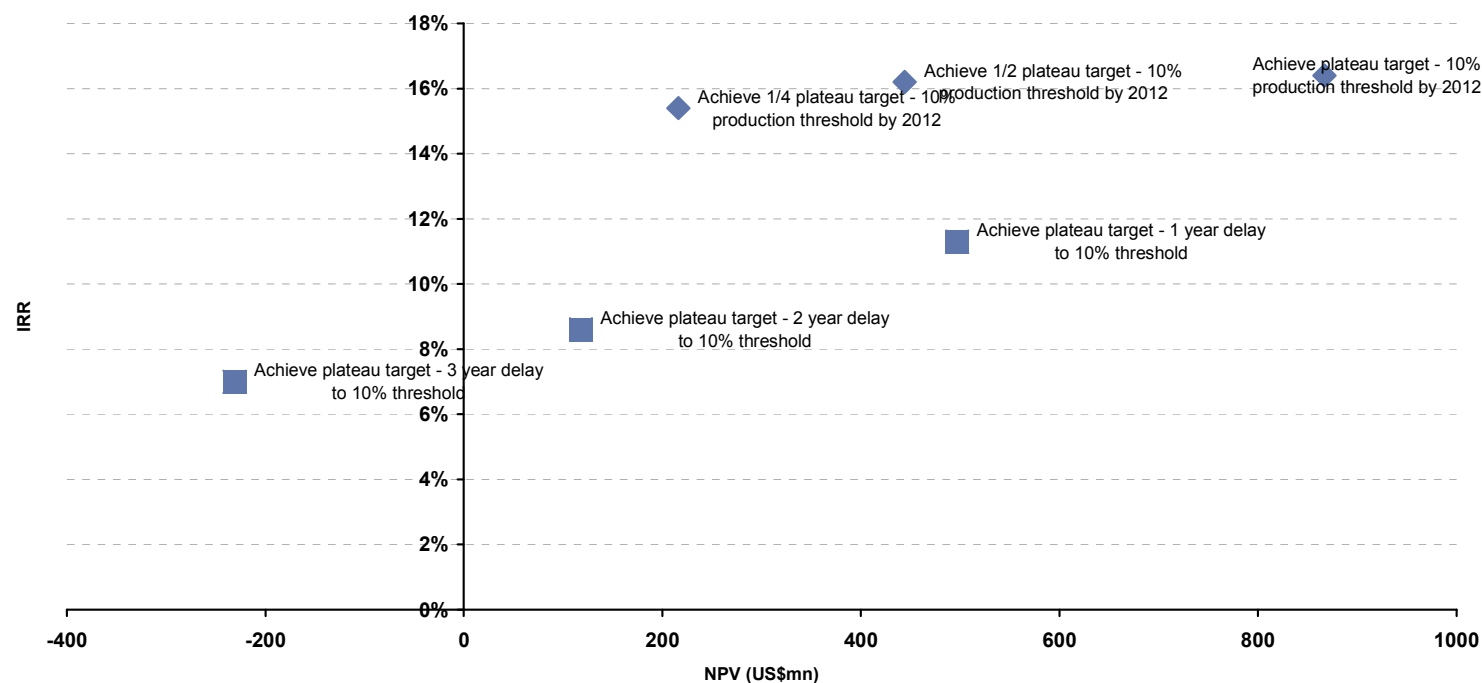
Contracts offer incentive for initial uptick, but little subsequent reason to ramp up

We believe that each contract will be asset-specific, but we would typically expect:

- Cost recovery of capex spent, up to a maximum % of revenue
- A fixed remuneration fee per barrel, possibly with corporation tax and/or an R-factor reducing the value of this to the company
- A production uplift threshold that must be reached in order to begin recovering costs

We believe that this arrangement, results in a format which provides reasonable returns (typically in excess of 15%) if the production uplift threshold is achieved within two years, but that offers little additional profitability beyond this. We have modelled a generic field under different production scenarios (Exhibit 161) to indicate where the sensitivities lie. Due to the small remuneration fee for barrels, we believe that the material differences in returns and NPV/bl are a result of how quickly a company is able to breach the production threshold required to recover costs, not the production profile once the contractor has recovered initial costs. As a result, the major advantage in bringing additional barrels into production is to generate a higher NPV through volume, despite the relatively low value of the individual barrels.

Exhibit 161: Returns do not increase substantially with greater production; achieving production threshold is more important



Source: Goldman Sachs Research estimates.

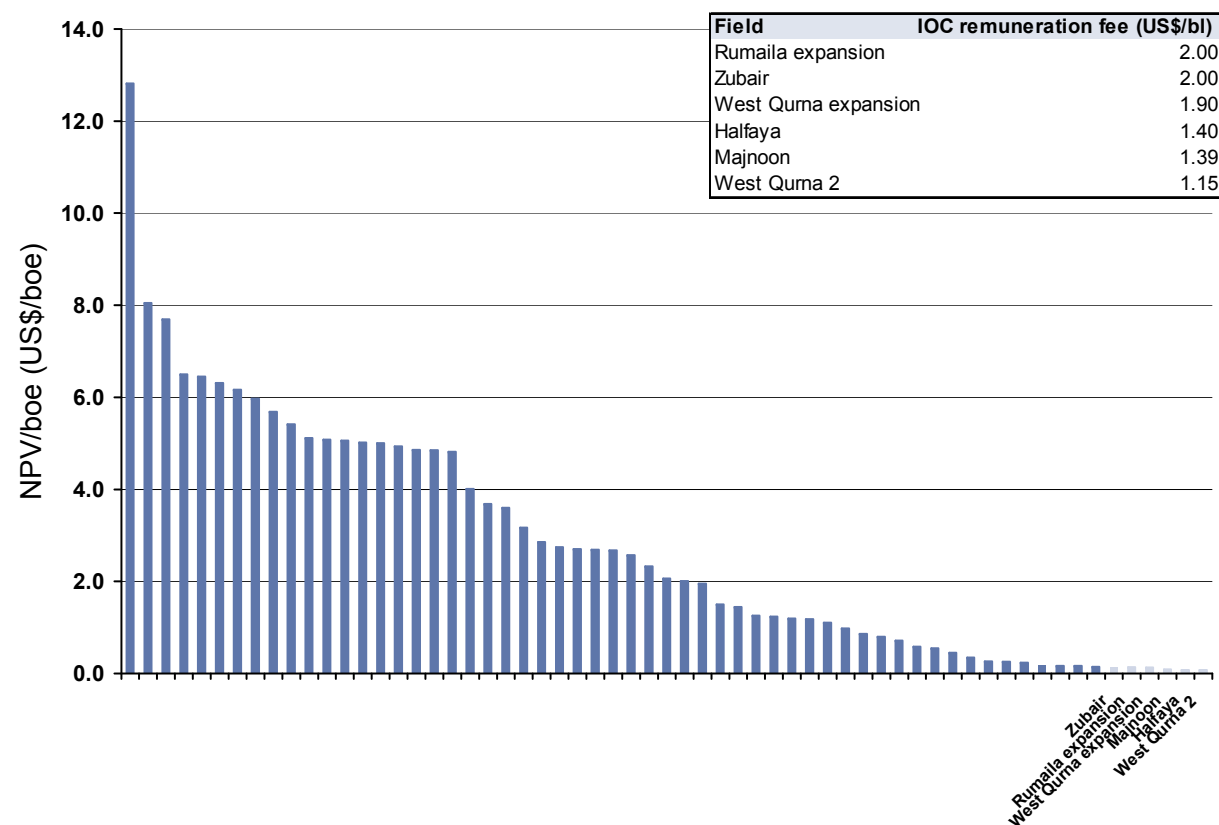
Economics suggest that capital is better employed elsewhere

Although the returns are reasonable, if the threshold can be crossed within two years, we do not believe they are outsized given the political risks we assume in operating in Iraq. We understand that there is a penalty in the event that production targets are not reached but do not believe that this alone is punitive enough to encourage a materially larger application of capital to the fields than we have modelled.

We have assessed the NPV/bbl that of the Iraqi projects relative to the other fields in the Top 280 and believe that on a unit basis, they are in the bottom quartile when assessed on this metric. Although we appreciate that there are other considerations to be taken into account when investing in fields (i.e. time until payback, optionality of initial development), we believe that greater NPV on a unit basis can be gained from investment in other fields rather than ramping up Iraqi fields governed by a service contract.

Exhibit 162: Iraqi fields are among the least attractive in the database when assessed on NPV per entitlement barrel

NPV2010/ barrel – pre-sanction and under development PSC and Service Contract fields



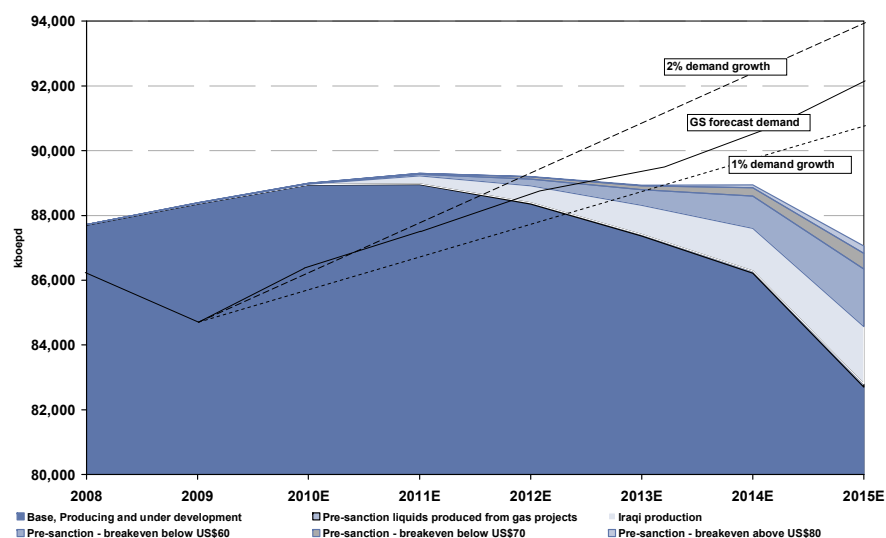
Source: Company data, Goldman Sachs Research estimates.

Supply/demand still tight by 2012E if targets are achieved

As a result of our concerns over the political, security and infrastructure issues likely to be faced in ramping up the fields to their targeted production in the official timeline, combined with our belief that the service contracts do not provide sufficient economic motivation to achieve this, we model a conservative production plateau which only sees the fields achieve c.20% of their targeted volumes by 2015E. As a result, we believe that supply is likely to remain tight and that OPEC spare capacity will be totally utilized by 2013E.

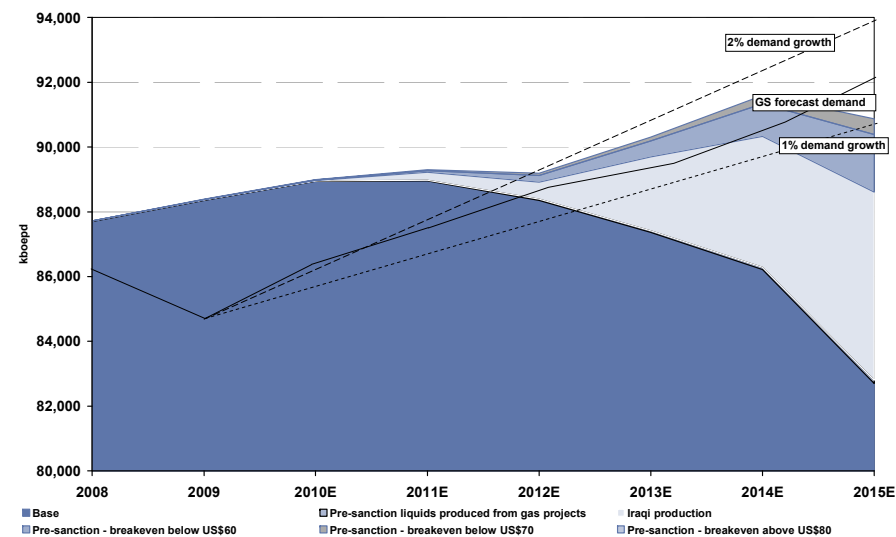
Although we believe it is unlikely, we have also constructed a “blue sky” scenario in which we assume that ramp-up begins in earnest in 2013E that allows companies to achieve their target production levels by 2017E. Under this scenario, and using our demand forecasts, we believe that this still results in a tight supply/demand balance from 2012E onwards, leaving c.1 mnb/d of spare OPEC capacity. Given we believe that a portion of mothballed OPEC capacity is unlikely to be reused in the future, we continue to regard this as a positive for the oil price. Even under this scenario, we see excess demand by 2015E – probably too early for new discoveries to impact this significantly. If we assume 2% demand growth from 2009 onwards, excess demand returns by 2013E even under the more bullish Iraqi production scenario. In the event of the most bullish production scenario, we still believe that even fields with a breakeven oil price in excess of US\$80/bl could be sanctioned with a view to first oil in 2015.

Exhibit 163: Supply shortage by 2013E under our assumptions



Source: Goldman Sachs Research estimates.

Exhibit 164: Excess demand by 2015E if fields stay on track to reach targets



Source: Goldman Sachs Research estimates.

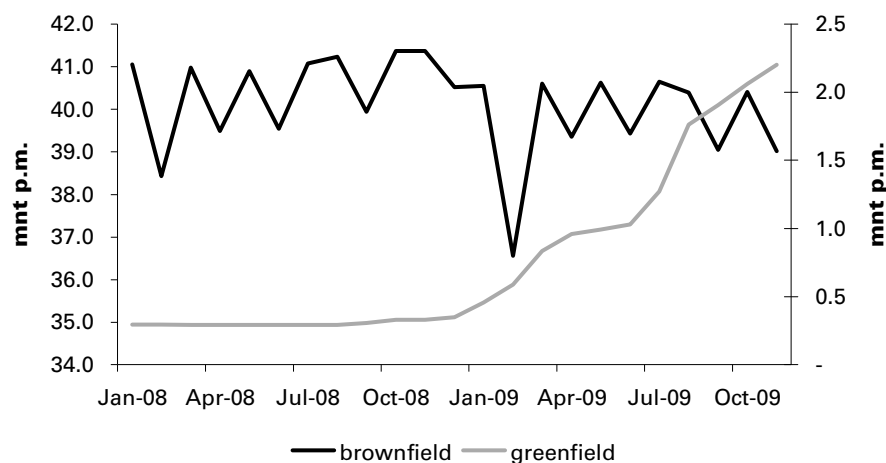
Russia – greenfield boom has started but foreign participation is limited

The greenfield boom has started after three years of investments

2009 marked a visible shift in Russia crude output structure. After the gradual boost of investments in greenfield upstream projects over the past three years, several large fields finally came onstream helping overall Russian crude production to grow yoy despite weakness in oil prices. The Yuzhno Khylochuyu field that started production in 2H2008 and the 3.1 bnboe Vankor project, whose start-up was delayed from autumn 2008, were the key contributors to the crude output growth in 2009. The first stage of the Eastern Siberia-Pacific Ocean pipeline became fully operational late in 2009 making development of East Siberian fields materially more attractive due to lower crude transportation costs (vs. railroad that was used before). This is good news for the owners of the more than 8 bnboe of Top 280 projects reserves located in the region including Verkhnechonsk and Talakan projects that started to ramp up deliveries of crude in 2009.

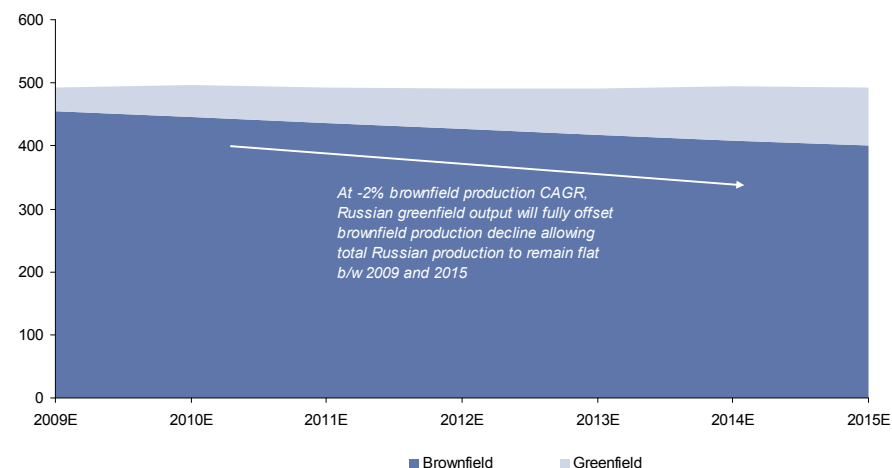
We expect that greenfield projects will continue to make a material contribution to Russian crude output in the mid term. In 2010E continued growth of output at Rosneft's Vankor field alone may add up to 200 kb/d. Beyond that several smaller start-ups in the Caspian region, West Siberia and Yamal peninsula fields should help Russia to offset brownfield production decline. We estimate that aggregate crude output from the Top 280 projects could allow total Russian crude output to remain flat assuming a 12% base output decline between 2009 and 2015.

Exhibit 165: Greenfield projects' contribution became material in 2009
2009 monthly Russian crude output, mtpa: greenfield right axis, brownfield left



Source: Interfax, Goldman Sachs Research estimates.

Exhibit 166: If we assume -2% CAGR in brownfield production, greenfield output would allow total Russian output to remain flat 2009-2015E
Russian crude output, in mnt



Source: Goldman Sachs Research estimates.

Key Russian themes – limited foreign participation, lack of systemic fiscal support, higher gas profitability

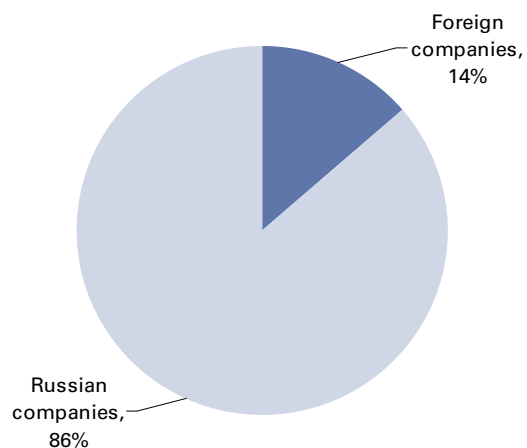
We believe that the key trends observed in Russian greenfield projects remain unchanged.

The ability of global oils to gain exposure to Russian oil and gas projects, in particular large-scale, remains limited. TOTAL's JV with Novatek for development of a mid-size Termokarst gas field was the only meaningful example of foreign participation in a greenfield project during the year.

Developments in Russian oil tax legislation in 2009 have highlighted the state's selective and non-systemic approach towards support of upstream investments. The Russian oil tax burden is among the highest in the world with a 90% upstream marginal tax rate, and certain amendments to the tax code became effective from 2009 introducing mineral extraction tax (MET) breaks for the important greenfield regions to provide support to investors. At year-end the government also introduced a crude export duty break for a limited list of oilfields in Eastern Siberia that has significantly improved the economics of the fields relative to other upstream investments. To illustrate, the break that is expected to last three years allows c.US\$34/bbl higher cash flows per barrel for qualifying projects vs. the standard tax regime under US\$85/bbl oil price assumptions. The state-owned Rosneft, operator of the Vankor field in the region, is set to gain most of the related benefits. Gas projects continue to be more profitable relative to development of oil fields, driven by a lower tax burden for the gas sector and the gradual increase in regulated domestic gas prices. It is important however to differentiate between development of gas fields in the conventional gas production regions of Russia (such as Nadym-Pur-Taz) and Gazprom's large-scale projects such as Bovanenko (in Yamal region) and Shtokman (Barents sea) whose profitability is materially depressed by the need for significant upfront investments in infrastructure that will be utilized not only by these but also by future projects in the regions.

Exhibit 167: Share of foreign ownership in Russian Top 280 remains low

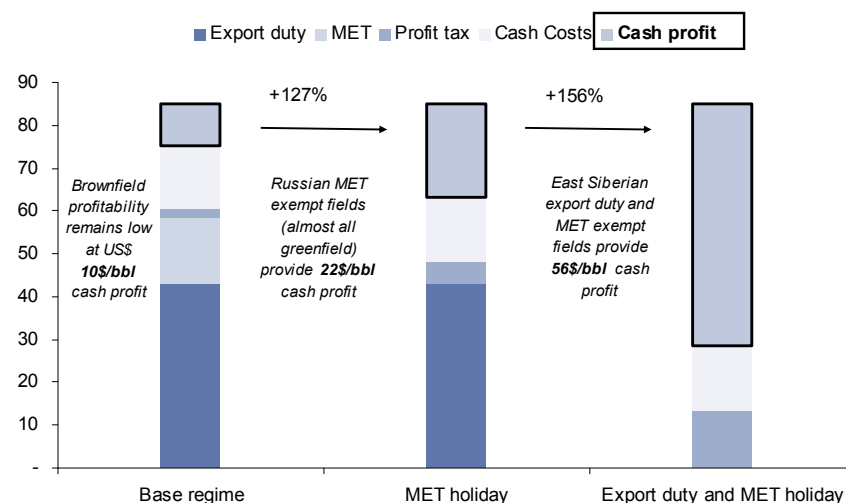
Share of Russian and foreign companies in Russian Top 280 reserves



Source: Goldman Sachs Research estimates.

Exhibit 168: Per barrel cash flow may vary significantly depending on the tax regime approved by the government

Upstream economics under normalised oil price assumption of US\$85/bbl



Source: Goldman Sachs Research estimates.

Company competitive positioning

We have ranked the companies on six key metrics to reflect the exposure, reward and risk undertaken in their Top 280 Projects portfolios:

- **Exposure** measured as Top 280 net entitlement oil and gas reserves as a percentage of corporate proved 2009 oil and gas reserves and additional metrics to reflect the balance of that portfolio
- **Profitability** primarily measured as the profit/investment ratio (the ratio between the present value of the post tax operating cash flow from Top 280 and the present value of the investment) and the IRR of the Top 280 portfolios on a life of field basis
- **Cash flow** measured as the timing and size of uplift from the Top 280 Projects operational cash flow as a percentage of corporate normalised cash flow and the capex as a percentage of the corporate normalized capex
- **Risk** measured as the combination of technical risk and political risk (as measured by our proprietary risk indices) and the level of this risk relative to project profitability
- **Quality of delivery** measured as a combination of project delays, cost increases and production delivery relative to our previous estimates
- **Oil price sensitivity** measured as the upside and downside to profitability and asset value between our base case US\$85/bl Brent oil price assumption and our other price scenarios of US\$110/bl and US\$60/bl and impacts of price changes on production

Exhibit 169: Top 280 Projects company rankings for our covered companies

	Winners	Long term exposure	Short term exposure	Limited exposure	Single asset play
Europeans	RDSHELL, BG, Galp	Total, ENI	BP, Statoil	Repsol	
US			Chevron, ConocoPhillips, Marathon, Hess	Exxon, Suncor, Anadarko, Occidental, Noble Energy, Apache	
Canadians				EnCana, Talisman	Canadian Natural Resources
Emerging Markets	Petrobras	PTTEP, Gazprom		PetroChina, CNOOC, ONGC, Rosneft	
E&Ps	Tullow, Woodside			Santos	Cairn India, Dragon Oil, Soco

Source: Company data, Goldman Sachs Research estimates.

Exhibit 170: In search of the winners: Portfolio screening



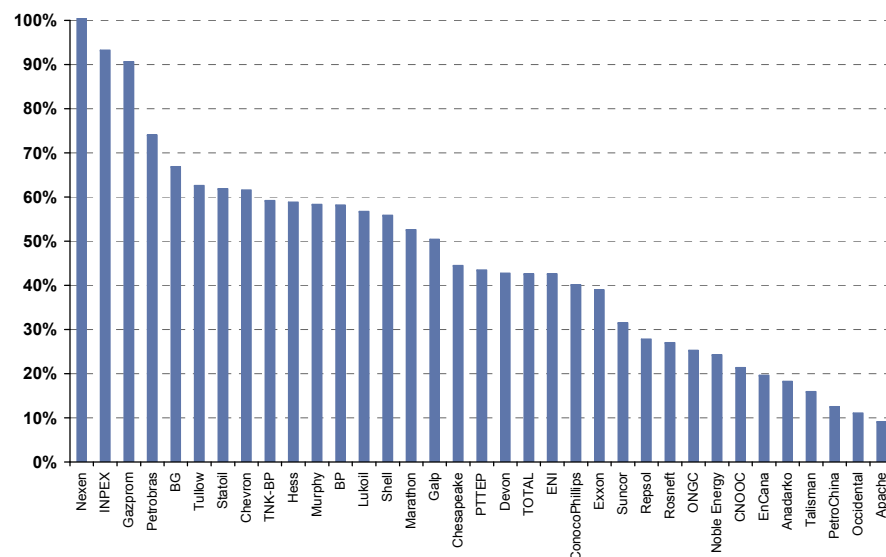
A Top 280 NPV analysis shows the Russian oils as particularly attractive

Our modelling of the Top 280 fields allows us to calculate the Net Present Value (NPV) of each company's portfolio. We do this at an 8% cost of capital, discounting the free cash flow of the portfolio to the year 2010.

Exhibit 171 shows the NPV of each company's portfolio as a % of the EV. We have included in this analysis only companies with at least three Top 280 assets, as we believe that the greatest value of this report is in analyzing portfolios of assets, rather than single asset plays. Nexen, INPEX, Gazprom, Petrobras, BG and Tullow stand out for having the largest part of their EV in the Top 280 portfolio.

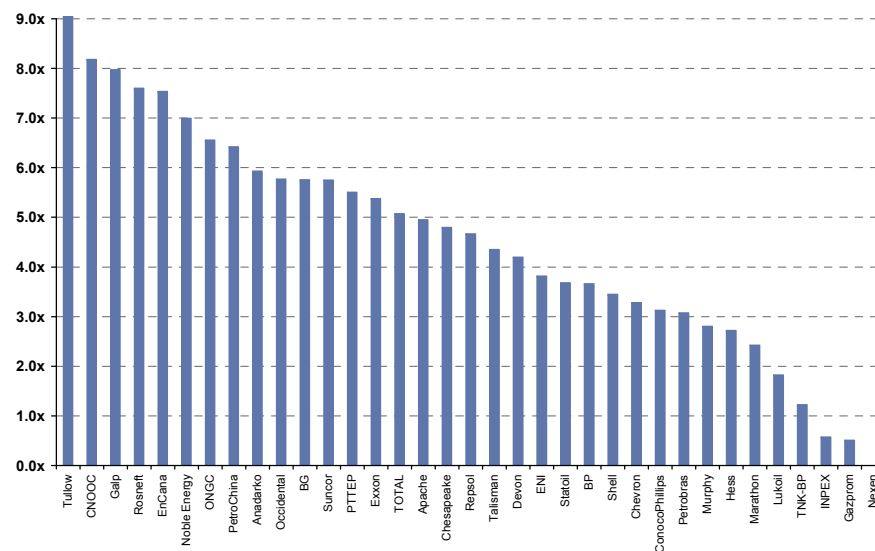
Exhibit 172 takes this analysis one step further, showing the cash flow multiple of the rump business. This is calculated by subtracting the Top 280 NPV from the company's EV and subtracting the Top 280 cash flow from the company's EV/DACF. This effectively shows how much the market is paying for the rest of the assets. Nexen, Gazprom, INPEX, TNK-BP and LUKOIL stand out as being particularly attractive on this metric.

Exhibit 171: Top 280 accounts for a large % of the oil companies' value...
NPV of Top 280 portfolio as a % of EV at 8% cost of capital



Source: Company data, Goldman Sachs Research estimates.

Exhibit 172: ... and the valuation is dramatically different
Implied 2010E EV/DACF of the non-Top 280 business



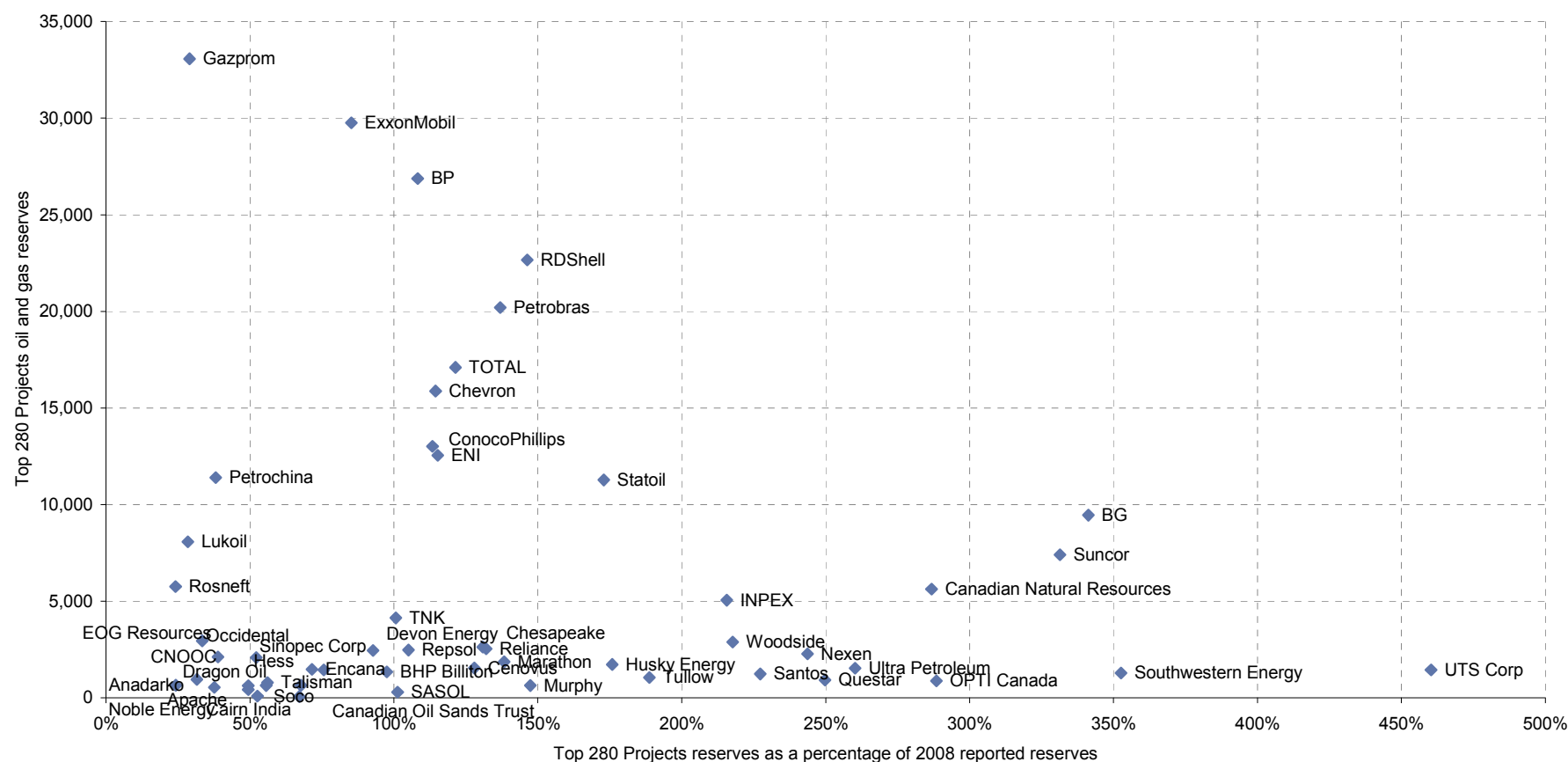
Source: Company data, Goldman Sachs Research estimates.

We believe exposure to new legacy assets provides visibility on future growth and is a positive

On our estimates, ExxonMobil leads the Majors in the absolute level of new legacy asset reserves (although Gazprom lies ahead in absolute size) but relative to existing reserves, the winner among the Integrations is BG. Aside from BG, Statoil is the winner in a relatively compact ranking. ExxonMobil is a slight laggard in terms of relative exposure.

BG stands out from other integrated companies by a wide margin, thanks to its giant discoveries in the pre-salt Santos play in Brazil. This lead is likely to consolidate in coming years in our view, as further appraisal and exploration is done in the area although booking of these reserves could erode the lead relative to existing reserves. Most of the other companies with such high exposure tend to be single asset plays which have not booked what we consider to be all recoverable reserves in the relevant asset. We believe that these companies will experience transformational production growth in the medium term if delivery is effective.

Exhibit 173: Reserves exposure to the Top 280 Projects by company (for all companies with Top 230 reserves greater than 40% of reported 2007 reserves)



Throughout the company analysis, in order to avoid double counting of BP's Russian assets, we analyse TNK as a separate entity rather than the TNK-BP JV that it shares with BP, assuming it holds 50% of TNK-BP's assets

Source: Goldman Sachs Research estimates.

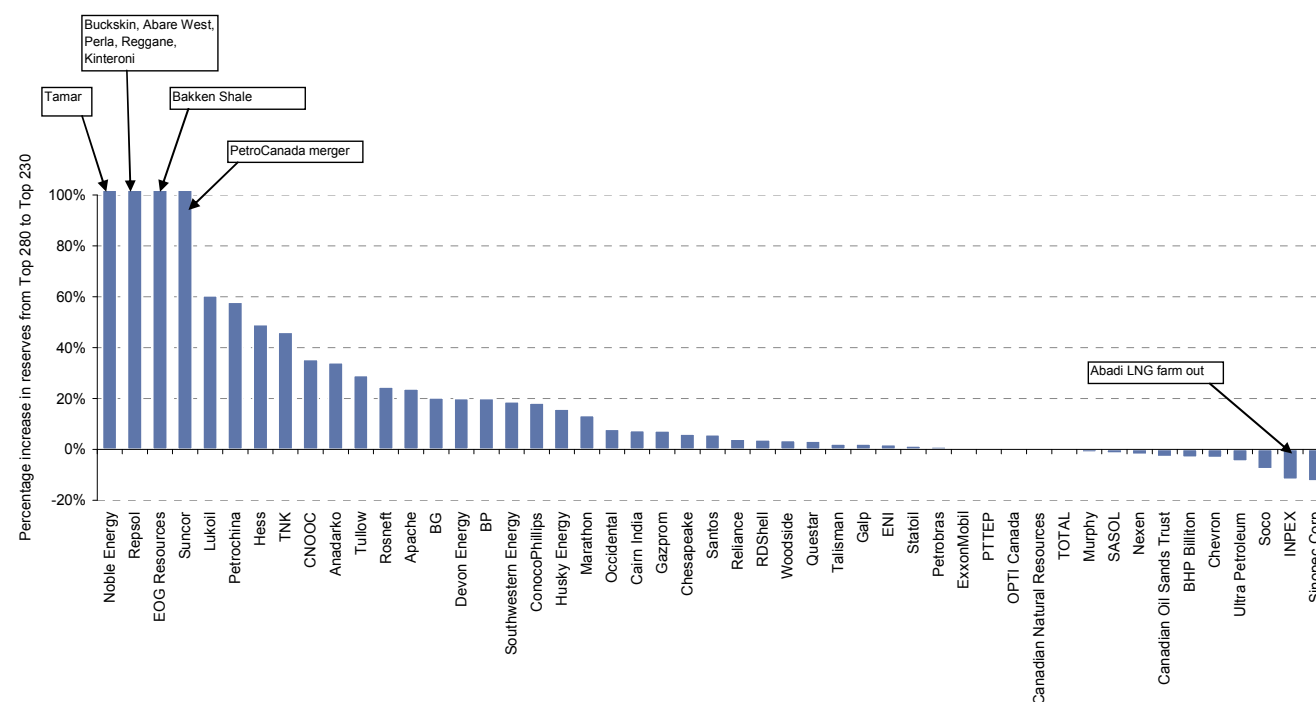
Exposure: Increase of scope and exploration success have been the key drivers

The net addition of a further 50 fields in this edition has led to a net increase in reserves in the companies that we analyse. The addition of further fields in Russia has been a boost while exploration has also driven reserve additions with major discoveries coming from the US (Tiber, Shenandoah), Australia (Poseidon) and Venezuela (Perla). Brazil has continued its impressive run of exploration success with additional discoveries being made at the Pipeline, Vesuvio and Abare West assets.

Substantial working interest reserves have been added in the UAE and Iraq as the countries offer companies technical service contracts based on remuneration fees in order to boost existing production. As we look at reserves on a net entitlement basis, however, the effect of this increase on the companies is muted, due to the relatively tough fiscal terms on offer.

The addition of some of Repsol's Latin American assets, combined with impressive exploration success in the Gulf of Mexico, Brazil and Latin America has meant Repsol has improved most of the integrated firms. Aside from Repsol, BG and BP have added the most reserves of the Integrates since Top 230. For BG, exploration and appraisal within Brazil has been a positive contributor as has the addition of the Panna Mukta Tapti asset. BP has benefited from further exploration success in the Gulf of Mexico (with Tiber) and from the inclusion of some relatively material Russian fields (such as Russkoye, Suzunskoye and Tagulskoye). Conoco's exploration success at Poseidon and Shenandoah has helped improve its position.

Exhibit 174: Percentage increase in Top 280 Projects net entitlement reserves relative to Top 230 Projects



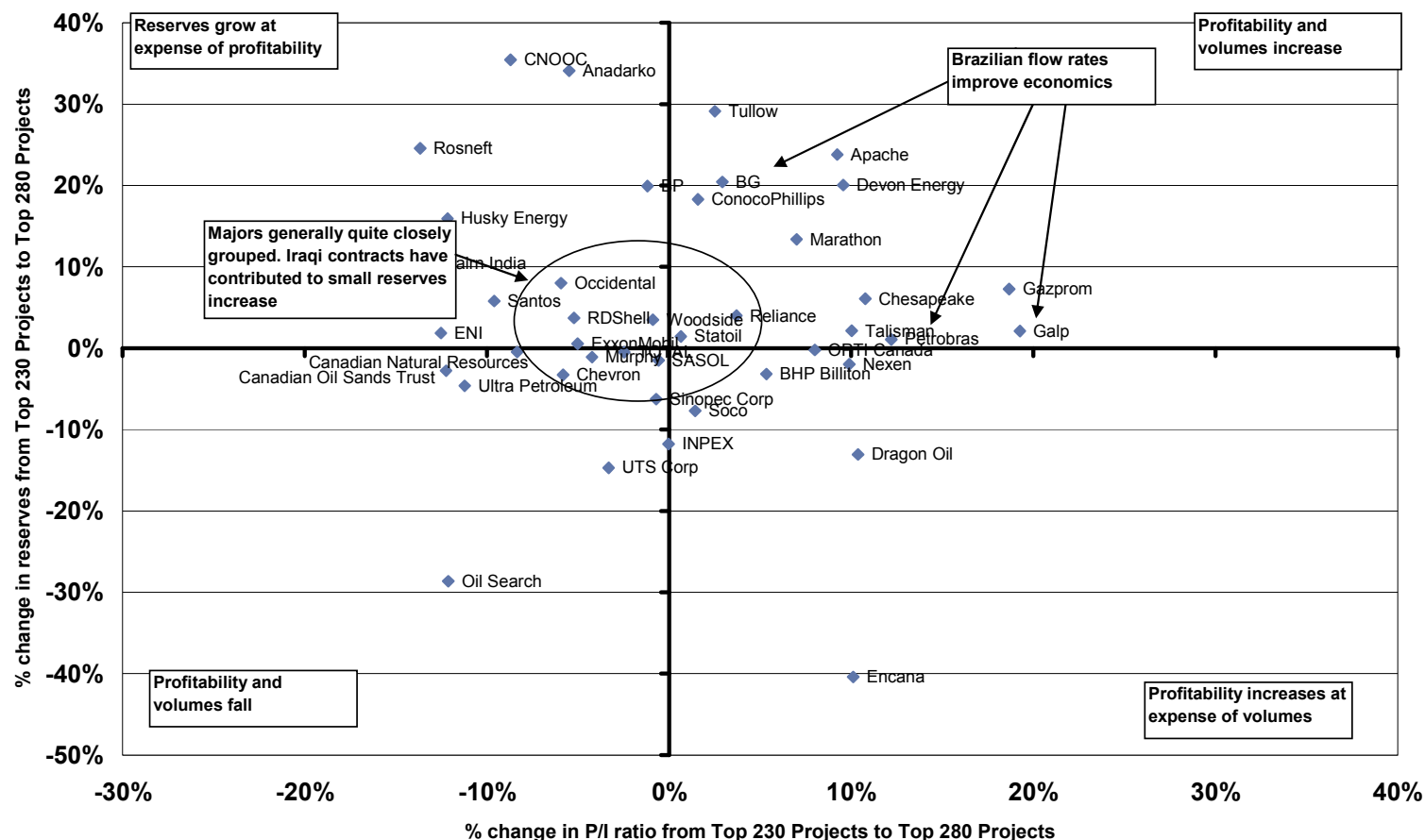
Scale limited to 100%. Noble is actually 388%, Repsol 182%, EOG 110% and Suncor 108%.

Source: Company data, Goldman Sachs Research estimates.

Brazilian flow rates improve economics. Iraq provides reserves but lowers average profitability

Among the larger players, those with exposure to Brazil have seen the greatest profitability growth between Top 230 and Top 280 as the recent flow rate data (up to 50 kb/d for Guara) have lowered our capex estimates on the pre-salt Santos play substantially, resulting in increases in the P/I ratio of Galp, Petrobras and BG. BP, Shell, Exxon, ENI and Statoil have all seen an increase in reserves, but with the exception of Statoil, have also seen a drop in profitability. Although a number of factors are at work here, one theme is the inclusion of the Iraqi service contracts which we believe will generate sizable reserves (even at a net entitlement level) but relatively low P/I. As we have not changed our oil price assumption since the last publication, the impact of changes in commodity prices on companies' portfolios should be minimal.

Exhibit 175: The change in scale and profitability of company portfolios from Top 230 to Top 280



X-axis limited to 40%. Increases off scale are: Hess (reserves +49%, P/I +1%), PetroChina (+58%, -4%), Lukoil (+60%, -23%), Suncor (+108%, +29%), EOG (+110%, +10%), Repsol (182%, +4%) and Noble (+388%, +61%)

Source: Goldman Sachs Research estimates.

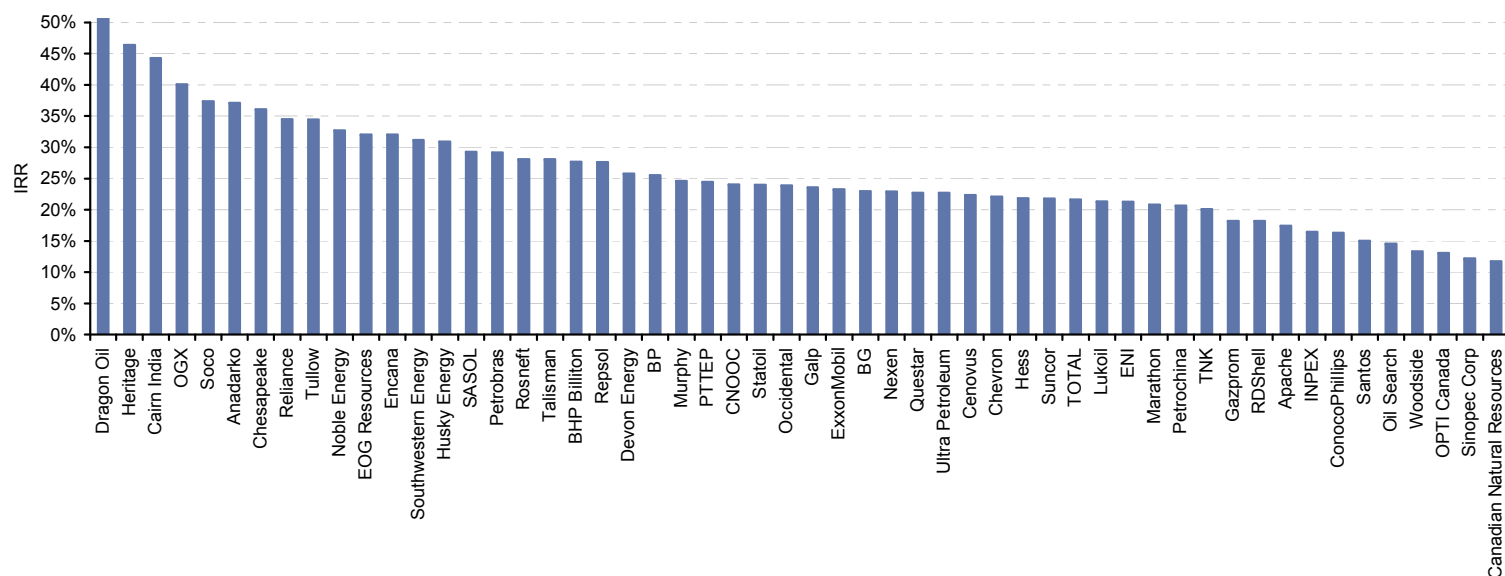
Profitability: Exploration risk paying off

On our analysis the smaller E&Ps lead the industry on pure portfolio profitability. In large part, this is driven by these companies taking greater exploration risks by drilling in countries with little or no historical exploration success – a strategy that is typically encouraged by the more favourable fiscal terms available in frontier regions, designed to attract such activity and resulting in better returns in the event of success. The companies are also generally helped by the fact that they have only a small number of assets in the Top 280 universe, meaning that they are more likely to be at the extremes.

BP performs well partly due to its high exposure to unconventional gas (which has a high IRR but a low P/I due to the timing of the cash flows) and higher risk, higher return deepwater projects (which also tend to carry higher exploration risk). Repsol is well positioned vs. the integrated companies due to its profitable fields in deepwater Brazil and GoM. BG is well placed due in part to the level of producing assets in its portfolio and its high-return pre-salt Brazilian portfolio, while Statoil also screens well. ConocoPhillips lags the other Majors, reflecting the company's higher reliance on oil sands and Alaskan/North Canadian gas projects (Alaska Gas and Mackenzie Gas).

The heavy oil and LNG-orientated companies suffer lower rates of return at our assumption of US\$85/bl oil. We note, however, that to a degree the low profitability of these portfolios is partly offset by low political and exploration risk and long duration.

Exhibit 176: Top 280 Projects IRR by company (excluding fields at plateau)



Source: Goldman Sachs Research estimates.

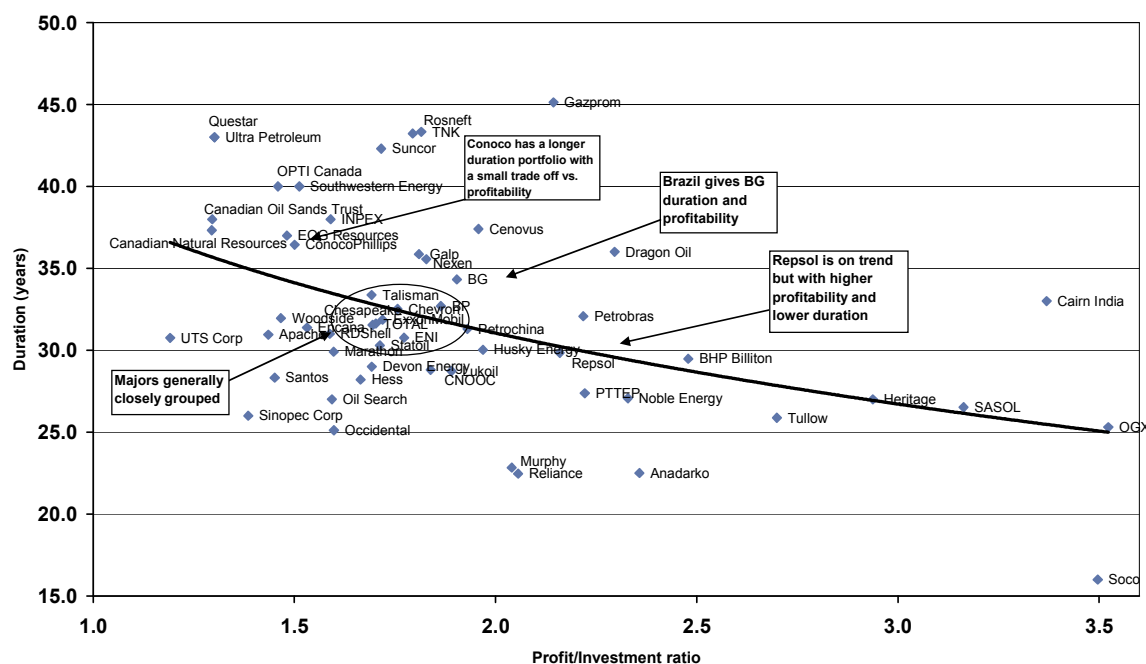
Profitability: Majors closely grouped on duration vs. profitability, but BG and Conoco stand out

We view high value creation over a long duration asset base as being the optimal mix. However, investment decisions usually offer a trade-off between these two qualities, with longer duration projects typically sacrificing some profitability.

On this metric of profitability vs. duration, the Majors are closely grouped with three exceptions. Repsol remains on the same (logarithmic) trend line as the rest of the population but sacrifices some duration for a higher profitability. BG and Conoco, however, are distinct from the rest of the majors and attractive inasmuch as their portfolios are above the trend. For BG, the Brazilian portfolio's excellent flow rates mean that the large reserves and durations continue to have good profitability (with BG's Brazilian assets generating an average P/I of 2.3x). ConocoPhillips also screens well, with its longer duration oil sands and LNG assets not sacrificing substantial levels of profitability.

Companies with a lower P/I ratio are generally heavily involved either in oil sands projects or LNG projects – both types of projects in which the longer duration provides compensation for a lower return. The other obvious outliers on the other side of the chart, Cairn, Soco, Heritage and SASOL, are single asset players in India, Vietnam, the Kurdistan Region of Iraq and Qatar and benefit on this metric due to the risk taken on at some point in the life of the project. For Soco and Cairn India, the favourable showing on this metric is a reward for the higher level of risk taken in the exploration phase in drilling a wildcat exploration programme. SASOL was exposed to substantial technical risk in the early stages of its GTL project; for Heritage the risk is political, with little visibility on how PSCs signed with the Kurdistan Regional Government will be treated by the central Iraqi administration.

Exhibit 177: Top 280 Projects value creation vs. duration (excluding fields at plateau)



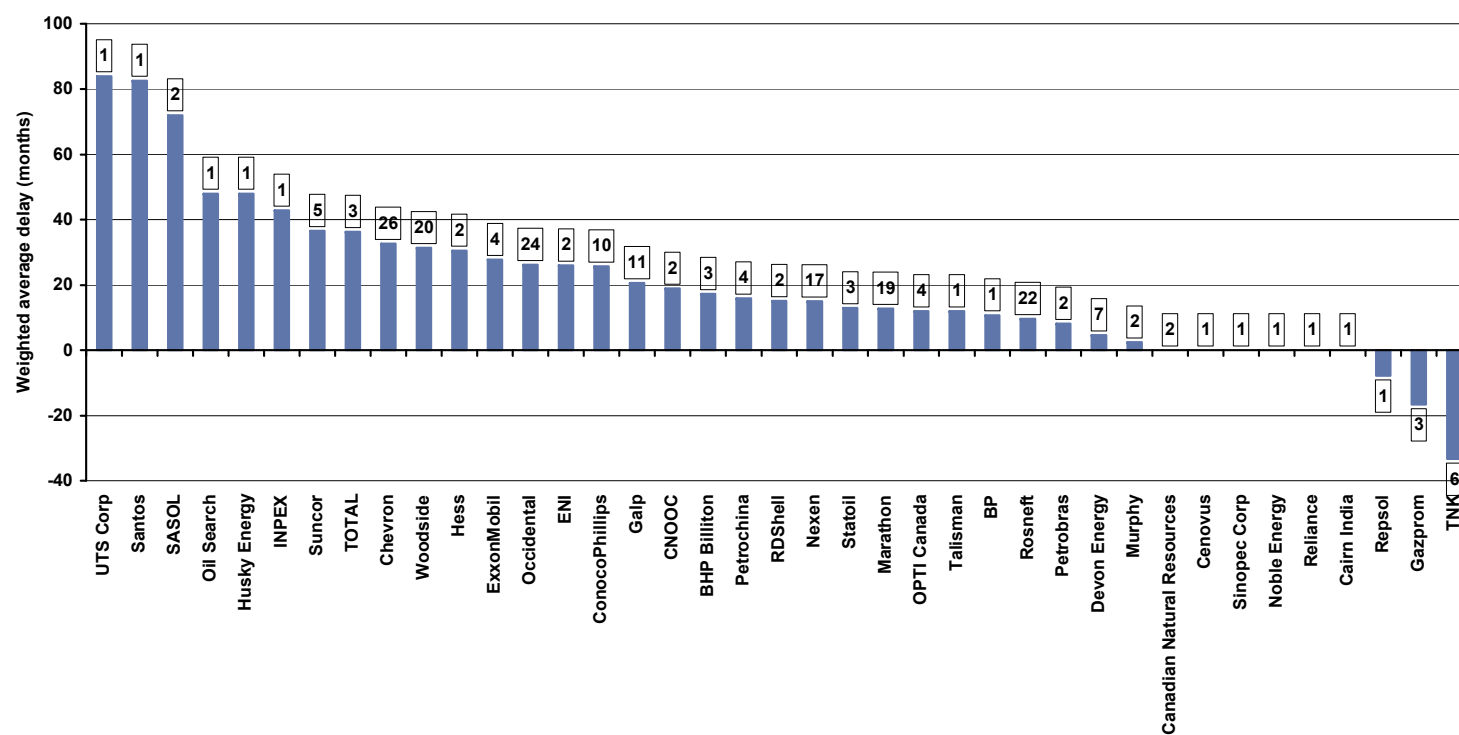
Source: Goldman Sachs Research estimates.

Quality of delivery: Failure to sanction can damage companies' production targets

We have attempted to measure each company's success in delivering its own new legacy asset portfolio, by reviewing the cost changes, timing changes and production delivery of those projects that we included in Top 170 Projects (February 2007) that were not already under production. We have performed the analysis on the basis of equity ownership in order to display the companies' total exposure to these effects. We note that this analysis reflects the success or failure of each company in delivery of its new legacy assets, relative to our own expectations of the projects in our previous Top 170 Projects report (and may potentially differ from company guidance).

TOTAL performs worst of the Majors on this metric, a result primarily of its large West African portfolio, which has been slower to sanction than we originally anticipated. Chevron is the next worst performer, again driven to a large degree by sanctioning projects later than we anticipated (primarily Gehem, Gendalo, Hebron and Gorgon), although we note that the recent sanctioning of Gorgon and the apparently imminent sanction of Jack/St Malo should help mitigate the risk of delays going forward. These case studies highlight the importance of sanctioning projects in a timely fashion. BP fares well among the Majors on this metric, partly a result of its Top 170 portfolio having been well advanced in the development process.

Exhibit 178: Average change in expected project start-up for the original Top 170 projects (from February 2007 to January 2010))
Fields producing in February 2009 excluded



Boxed number indicates number of operated, non producing projects in the Top 170 database

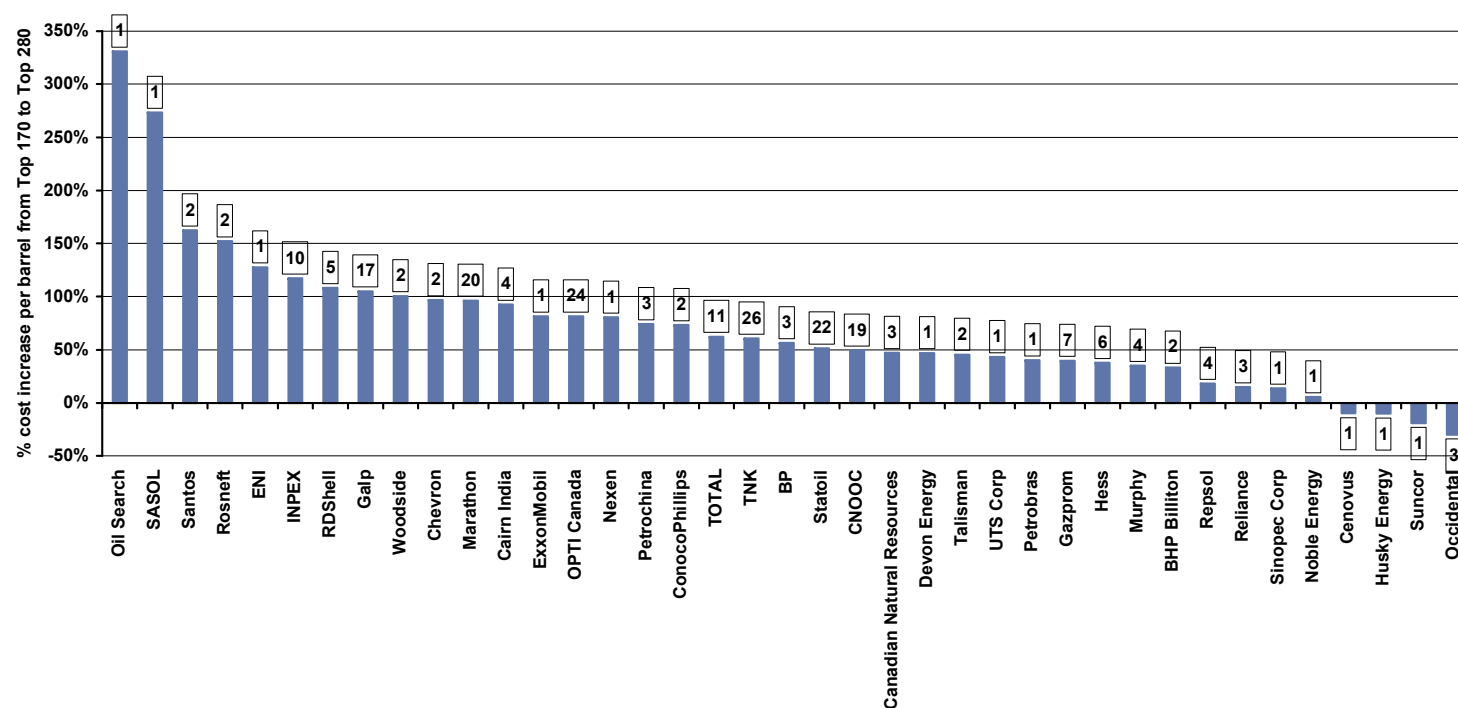
Source: Goldman Sachs Research estimates.

Quality of delivery: Costs still elevated vs. Top 170

We have also analysed cost inflation on the same project sample set. At first glance, quality of execution with regard to cost control is poor. It should be remembered, however, that cost inflation has been a fact of life in the upstream industry in recent years and that despite the recent deflationary environment, we believe current costs are still higher than those prevalent in 2007, when Top 170 was published.

ENI performs the worst of the Majors on this basis, primarily a result of the increase in costs experienced at its Kashagan project. Shell has also experienced relatively high cost inflation – largely a function of our previous underestimation of costs at Pearl, Kashagan and Perdido. Repsol benefits from having had the majority of its Top 170 portfolio well under construction by the time the Top 170 was published (primarily Camisea and Shenzi) meaning that costs were locked in to a greater extent than for companies with a higher proportion of assets in the pre-sanction phase.

Exhibit 179: Average change in our expected unit capital costs for the original Top 170 Projects (from February 2007 to January 2009)



Boxed number indicates number of operated, non producing projects in the Top 170 database

Source: Goldman Sachs Research estimates.

Oil price sensitivity: Shell has the most levered Top 280 portfolio of the majors

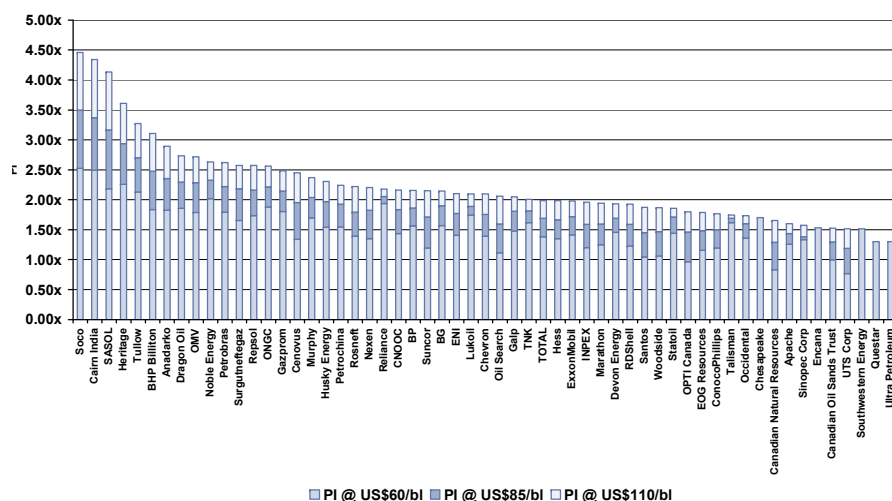
Companies with the most leverage to the oil price tend to be those in relatively marginal, oil based assets with exposure to a license regime. As a result, it is no surprise that many of the more sensitive company portfolios tend to be those with exposure to the Canadian oil sands, such as CNRL, UTS, Suncor and Cenovus. As we assume a direct link between GTL and LNG production and oil price, SASOL, Oil Search, Woodside and Santos also display high leverage. Finally, single asset plays with oil based assets in generous PSCs, or those that reach the threshold of profitability very quickly are also well levered (Cairn India/Soco).

Of the Majors, RDSH is the most levered due to the high levels of liquids/LNG in its portfolio and its relatively low exposure to fiscal regimes in which the tax rate is determined by the oil price. At the lower end of the sensitivity chart are BG (due to its portfolio of fixed price gas in Oman and Egypt), BP (due to the high proportion of its assets being gas, linked to Henry Hub where we do not assume a relationship with crude) and Exxon Mobil (due mainly to its participation in both Mackenzie Gas and Alaska gas and its Middle Eastern gas portfolio (e.g. Al Khaleej and Barzan) where we assume a fixed price and its presence in a number of oil-levered PSCs).

At high oil prices, Soco shows the highest profitability, followed by Cairn India and SASOL – a result of projects with favourable fiscal regimes. We note, however, that exceptionally high returns under high oil prices are likely to be eroded by windfall taxes or changes to fiscal structure – putting these portfolios at greater risk of such governmental interference.

Exhibit 180: Company P/Is under different oil price sensitivities

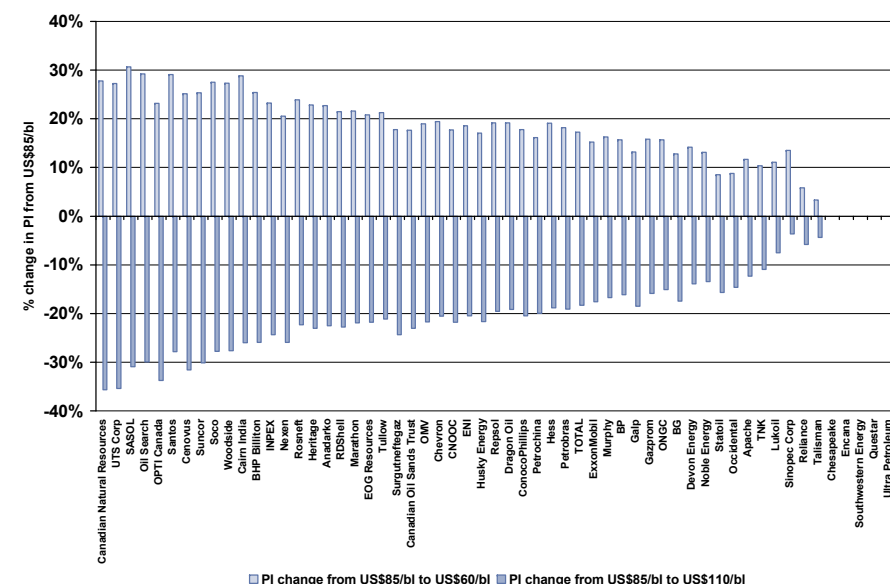
All projects included



Source: Goldman Sachs Research estimates.

Exhibit 181: Sensitivity of companies' portfolios to oil price

All projects included



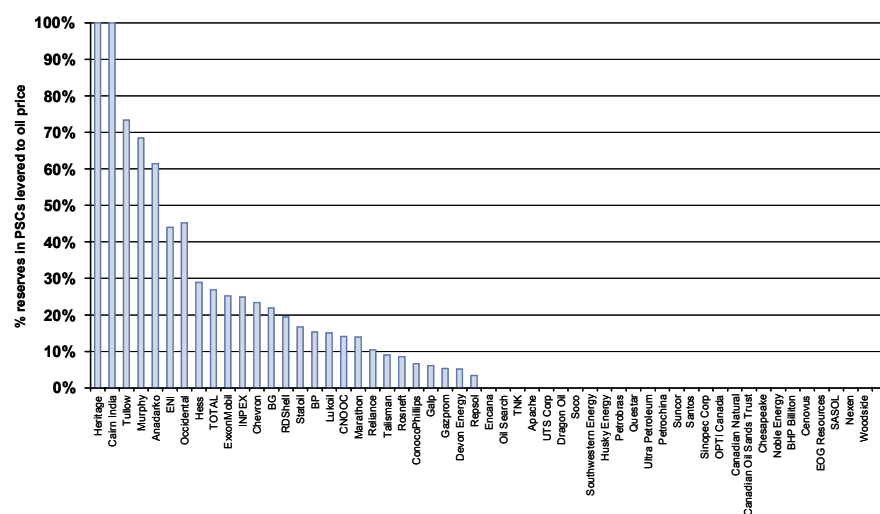
Source: Goldman Sachs Research estimates.

Oil price sensitivity: Exposure to licences and oil based assets provides greater leverage

We have assessed the fiscal terms of each of the fields in our analysis and classified them depending on whether the tax rate is influenced by the impact of the oil price on the project's profitability. This typically happens in Production Sharing Contracts, but not in all of them. An obvious comparison is between Nigeria and Angola. Nigerian PSCs are driven by volume, not profitability, and therefore offer good leverage to the oil price for the companies involved in the projects. Angolan PSCs are instead profitability based and offer limited exposure to commodity price increases. Of the Majors, ENI stands out for having a substantial proportion of its reserves in contracts levered to the oil price, while the next nearest Majors are ExxonMobil and TOTAL. BP screens as having little exposure to oil price based tax regimes – primarily a result of its exposure to the Gulf of Mexico and large US gas projects, although this is offset by the fact that a large proportion of its assets are linked to Henry Hub, which limits its oil price leverage. RDSshell is not far behind in its limited PSC exposure, and is also helped by the fact that almost 80% of its net entitlement reserves are levered to the oil price. ConocoPhillips has the lowest profitability based fiscal exposure (as a result of its heavy oil and Australian LNG projects).

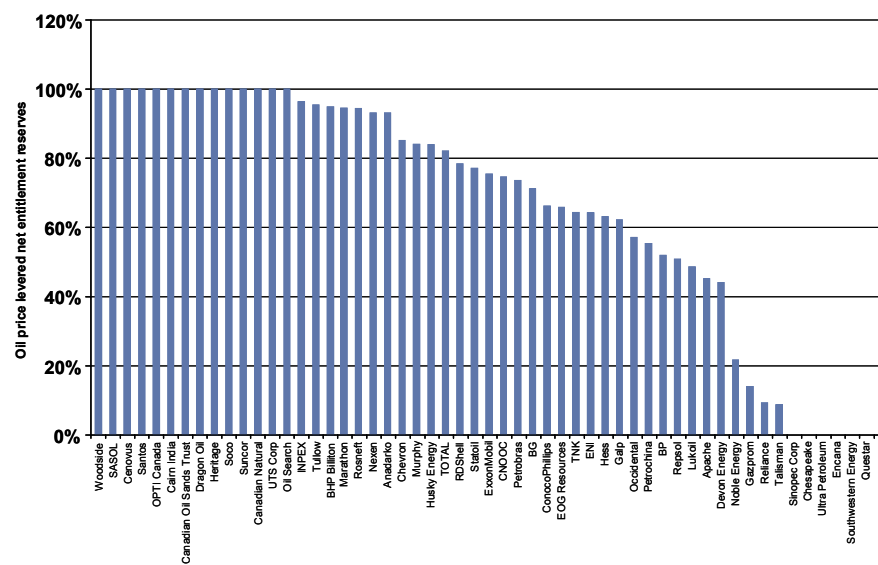
Exhibit 182: Proportion of reserves governed by oil-based PSCs

Net entitlement reserves



Source: Goldman Sachs Research estimates.

Exhibit 183: Proportion of reserves levered to crude price



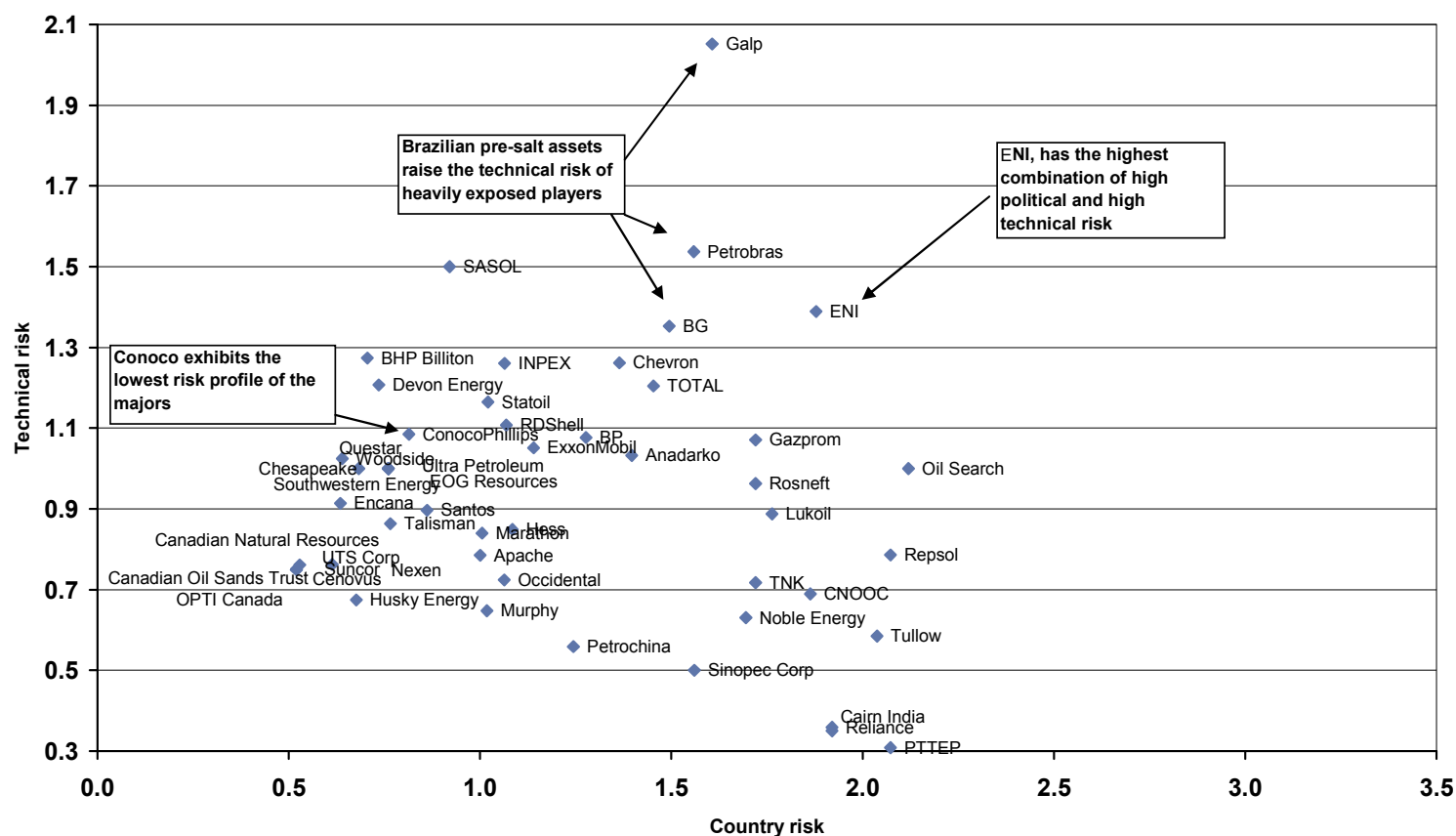
Source: Goldman Sachs Research estimates.

Risk: ENI has the highest risk profile among the Majors, Conoco is the least risky

Of the Majors, ConocoPhillips has the lowest level of country risk which reflects a partial trade-off for the relatively low profitability of its portfolio as a result of its significant positions in Canada, the US and Australia. Exxon, BP, Statoil and Shell have a similar combination of technical and country risk with Chevron and TOTAL experiencing a slightly higher risk profile. Companies with a high concentration of their assets in the Brazilian pre-salt play have a high technical risk. This is particularly the case for BG, Galp and Petrobras for whom these assets form a particularly significant part of their portfolio. Repsol's risk is more muted as a result of its significant exposure to the relatively simple Block N186 and Shenzi, although it is highly levered to country risk. ENI has the highest combined political/technical risk – primarily a result of its large exposure to Kashagan, West Africa and Perla in Venezuela.

The lower risk assets are, in our view, the heavy oil and LNG assets based in Canada and Australia. As we would expect from an efficient market, companies with this low risk profiling also tend to have relatively low returns.

Exhibit 184: Technical versus political risk by company (excluding fields at plateau)



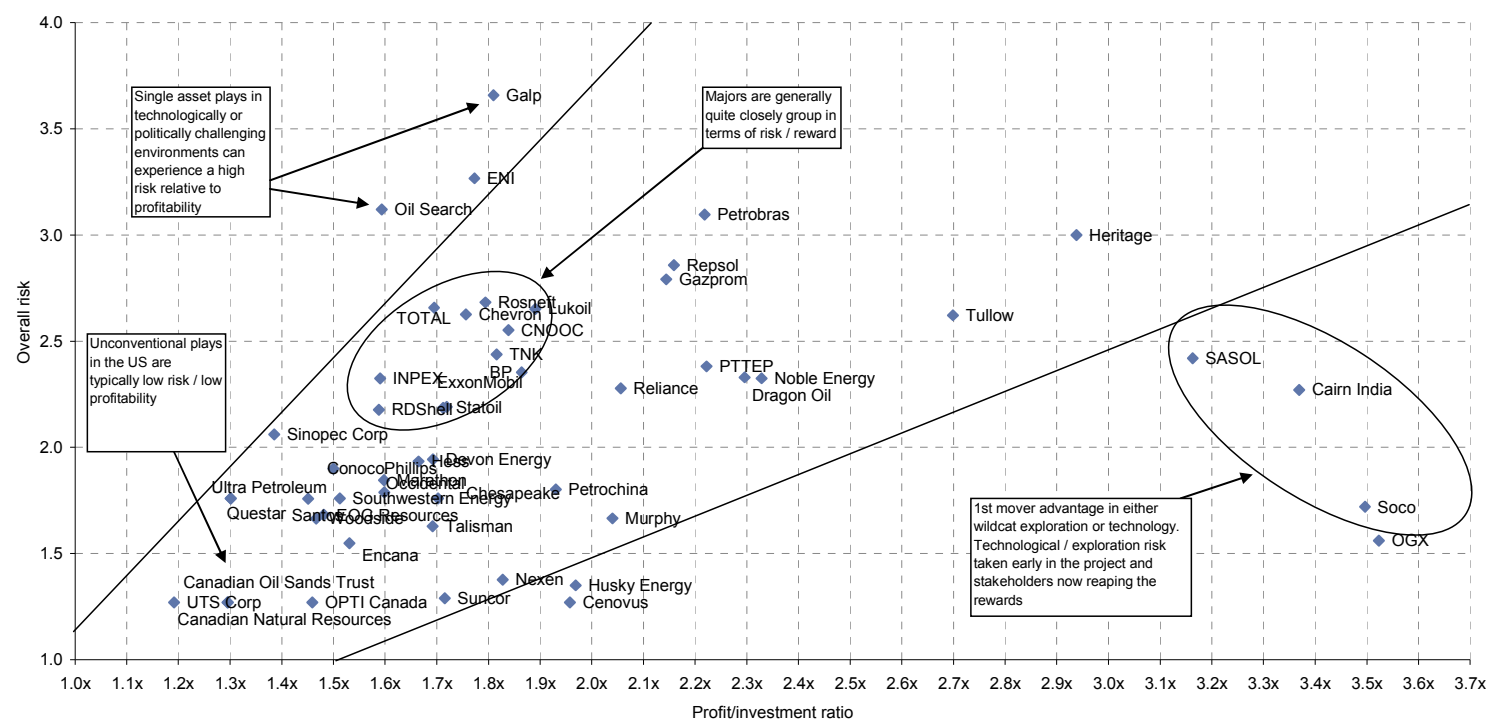
Source: Goldman Sachs Research estimates, World Bank Index.

Risk: Exploration and technological first movers rewarded with outsized risk-adjusted returns

As a rule we believe that companies are rewarded for the extra risk that they may take on through higher profitability. Although the relationship is muddled by the timing of project starts (with projects near to production generally being more profitable) and duration, there is a correlation between risk and returns.

Canadian oil sands producers and OECD-based LNG producers take on much lower political and exploration risks and, as may be expected, generate lower returns. Outliers on the right of Exhibit 185 are generally single asset plays that have taken on significant exploration or technological risk at the start of the project and are now being compensated for this with a combination of relatively low risks and high profitability. The Majors are generally grouped together, with the exception of ENI (skewed by Kashagan and its heavy West African exposure which leaves it with lower risk-adjusted profitability) and ConocoPhillips which is lower down the risk scale due to the relatively higher weighting of its assets in the US and Australia.

Exhibit 185: Overall risk versus profit/investment ratio by company (excluding fields at plateau)



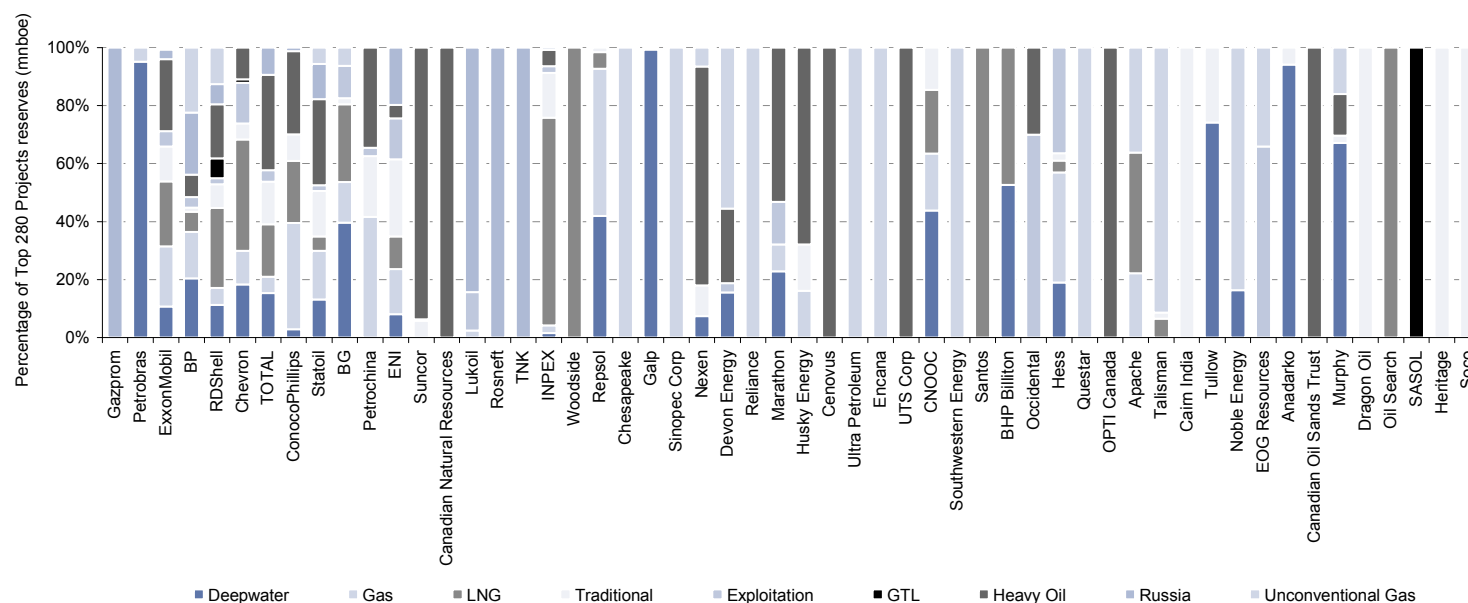
Source: Goldman Sachs Research estimates.

Exposure: Differentiation of strategies for the Majors in win zone choice

ExxonMobil has a well balanced exposure, having material exposure to all win zones except GTL (following its withdrawal from its planned Qatari project). RDSH is also well balanced, with exposure to all eight win zones, but exhibits a clear skew towards less conventional reserves; two thirds of its Top 280 reserves are in GTL, heavy oil, unconventional gas and LNG – more than any other Major and a composition that partly explains the high capital intensity of the company's portfolio in the near term. ENI, meanwhile, is least exposed to the unconventional win zones among the Majors with most of its assets in the traditional win zone (a result skewed somewhat by the presence of Kashagan in its portfolio). BP has a balanced portfolio but is weighted to deepwater and gas (both conventional and unconventional). BG and Repsol are more concentrated deepwater plays among the Integrations, however, primarily as a result of their exposure to Brazil and (in the case of Repsol) the Gulf of Mexico). Chevron is relatively strong in deepwater but has its most significant position in LNG while Conoco is the least exposed to deepwater among the Majors, focusing instead on heavy oil, gas and LNG. TOTAL is skewed towards heavy oil with Statoil also having a lot of exposure to this win zone through Leismer. ENI, BP and Statoil all have relatively high exposure to Russia – a region which carries significant levels of political risk for foreign investors.

As the portfolio sizes decline, so does diversification, meaning that a significant number of players are highly levered to only one win zone – making them a clear play on either short-term returns or longer duration. The exceptions to this rule are Gazprom which is focused on Russia and Petrobras which is the most levered way to play deepwater among the largest, global companies.

Exhibit 186: Top 280 Projects reserves split by win zone (in order of reserve size)



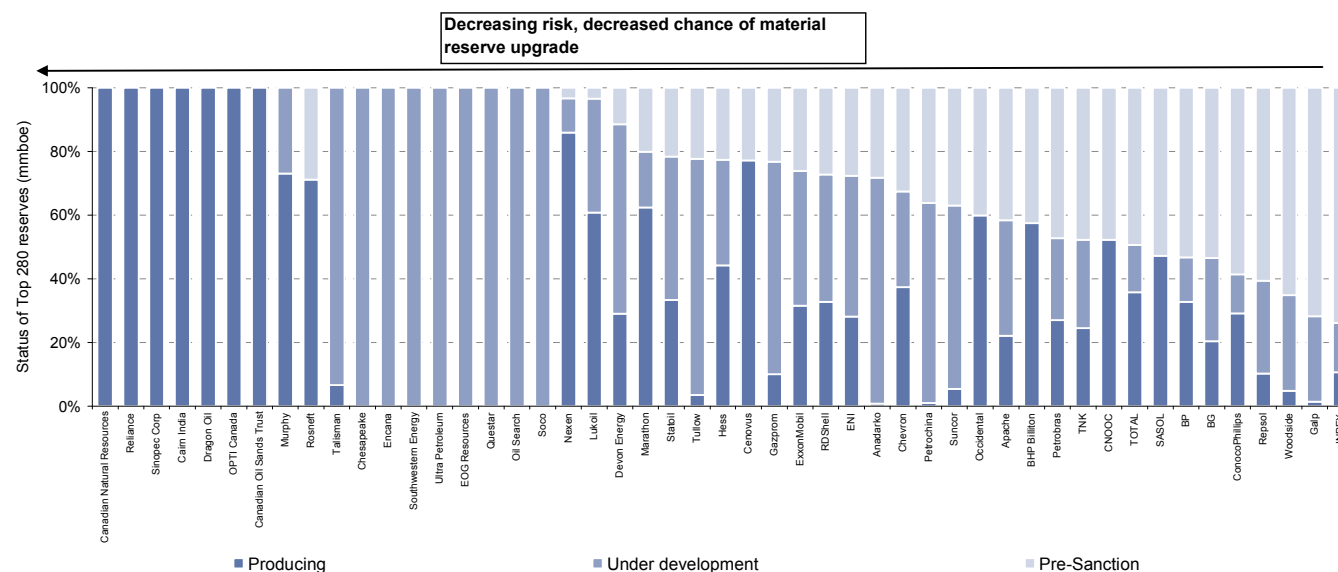
Source: Goldman Sachs Research estimates.

Exposure: Producing assets vs. new developments – balancing risk and growth

We see most risk to reserves and economics at the pre-sanction stage of a project when less is known about the reserves size, development plan and final costs. We therefore view a portfolio that is weighted towards assets under development and production as more secure and less susceptible to development issues or reserves downgrades. We also see difficulties in sanctioning projects as one of the key reasons for project delays, and as such believe that a high proportion of pre-sanction assets can mean lower visibility on medium-term growth prospects. As sanctioning tends to lock in at least a portion of costs, sanctioned projects will benefit under a rising oil price relative to pre-sanction projects, which are likely to experience more cost inflation as prices rise although pre-sanction assets, have greater flexibility—sanction can be delayed to take advantage of cost deflation in falling oil prices or to conserve capital when liquidity is stretched.

Of the Majors, Chevron and TOTAL have experienced the biggest change since the publication of the Top 230. For Chevron a significant proportion of its pre-sanction assets have now moved into the development phase (primarily as a result of the sanctioning of Greater Gorgon and Caesar Tonga), meaning that 30% of its reserves are now under development (vs. c.4% in Top 230). We believe that the visibility of Chevron's Top 280 portfolio could be further enhanced as we expect Jack/St Malo to be sanctioned in 2010E. TOTAL's portfolio has become much more weighted to the “producing” category since the start-up of assets such as Tombua Landana, Tahiti, Qataragas 2 train 5, Yemen LNG and Akpo, leaving the company with little in the “under development” hopper. BP, BG and ConocoPhillips have the highest proportion of pre-sanctioned assets, although we note that the majority of BG's assets in this class relate to projects for which we believe there is a good degree of visibility such as QCLNG and the development of pre-salt Brazilian assets which reduces the risk of the portfolio in our view. Statoil, Exxon, Shell and ENI have the fewest assets in the pre-sanction phase.

Exhibit 187: Top 280 Projects reserves split by development status

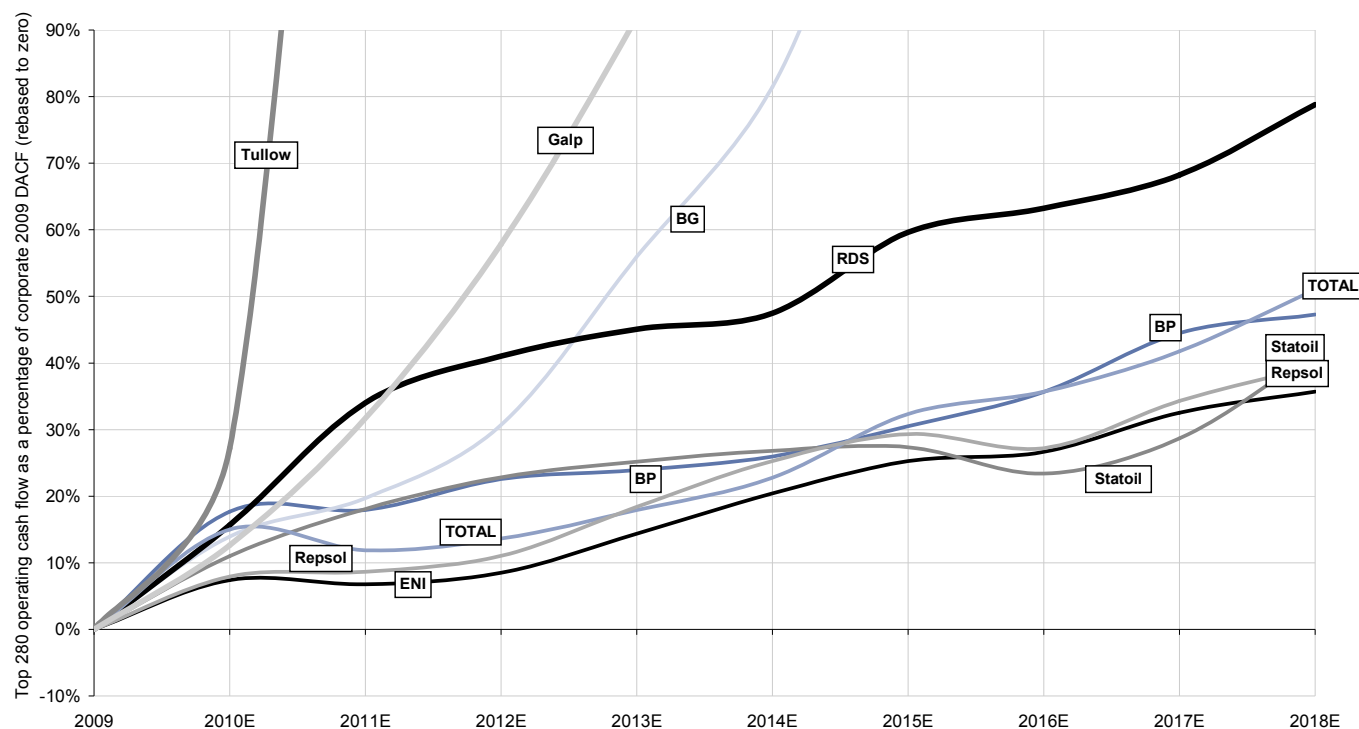


Source: Goldman Sachs Research estimates.

Timing of operating cash flows: BG and Shell the long-term Major winners; BP strong in near term

BG and Shell are the medium- to long-term winners of the Integrations, with BG's expected outperformance being driven by contributions from Curtis and Brazil, and Shell benefiting primarily from its Qatari and Australian assets. BP performs well in the near term, helped by the leverage of its Gulf of Mexico and ACG assets to the increase in oil price from a relatively low 2009 base. In the medium term, we see BP's incremental cash flow growth slowing, despite cost oil at Rumaila and it is not until 2015E that we see a new period of growth, driven primarily by its GoM exposure. TOTAL sees an initially strong uptick in value over 2009-2010E, due to the oil price and the ramp-up of assets such as Akpo, Qatargas 2, Tahiti, Pazflor and Yemen LNG. Although we expect Top 280 growth to return in 2013E, however, we expect the company's cash flow growth from Top 280 projects to be more muted between 2010E and 2012E. Statoil has consistent, if not sector-leading growth to 2014E, from projects such as Peregrino, and Pazflor but as we have delayed Leismer's expected ramp-up vs. the Top 230, growth beyond this point is less impressive than some of its peers. ENI's profile is more muted than its peers in most parts of the cycle, although the company does enter a period of growth between 2012E and 2016E as Kashagan, Goliat, Artigas and Urengoil and its Latin American gas assets ramp up. Repsol's growth is muted but fairly consistent, driven by Shenzi in the short term and Latin America further out (Guara, Margarita etc.). Tullow and Galp's Top 280 portfolios are transformational in the short term.

Exhibit 188: Operating cash flow from Top 280 projects as a percentage of 2009E corporate cash flow (rebased to zero)



Scale limited to 90%. BG reaches 150% by 2018E

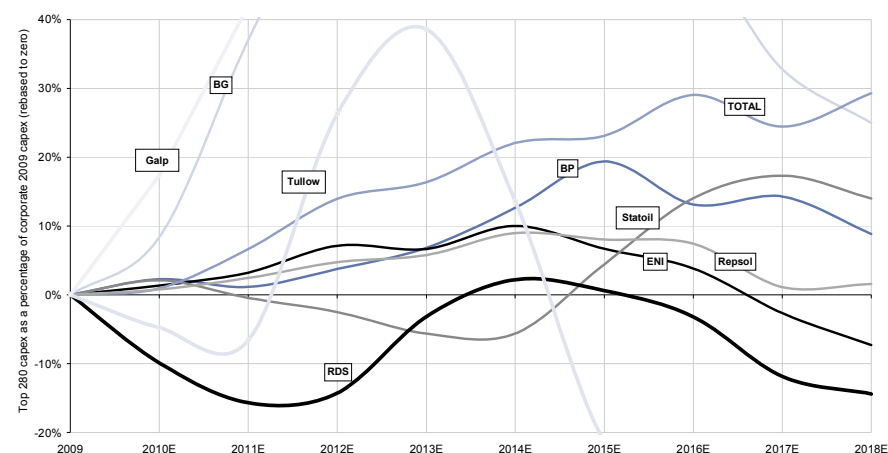
Source: Goldman Sachs Research estimates.

Capex timing: Shell drops from current high base; BG investing for outsized growth

We believe that Shell's capex spend from the Top 280 projects is likely to drop off as the company's current spend on mega-projects such as Pearl ends. We believe that Shell's investment is likely to pick up for a time from 2012E, as the company spends on projects such as Prelude, its share of Gorgon and its Iraqi portfolio. BG's capex spend on the Top 280 will increase by a far greater extent than its peers, as the company funds its outsized growth prospects in Brazil and Australia. Total's spend increases progressively to support its post-2012E growth with Kashagan and Ichthys being the biggest single sources of expenditure, and spend in West Africa also remaining consistently high. BP's spend is fairly muted at first vs. 2009, but begins to increase from 2013E as expected spending on its GoM and West African portfolios begins in earnest. ENI's Top 280 spend increases mainly due to Kashagan and Zubair but does not increase markedly from its relatively low base (25% of total 2009 capex) which tallies with the company's relatively muted Top 280 production growth relative to peers. Statoil's spend remains relatively constant until the middle of the decade when we expect expansions at Leismer to be sanctioned and spending on Block 31 West and Vito to begin. Galp and Tullow are both investing for outsized growth, although Tullow's spend drops once the assumed Ugandan pipeline and second phase of Jubilee are completed.

Exhibit 189: BG spending for transformational growth

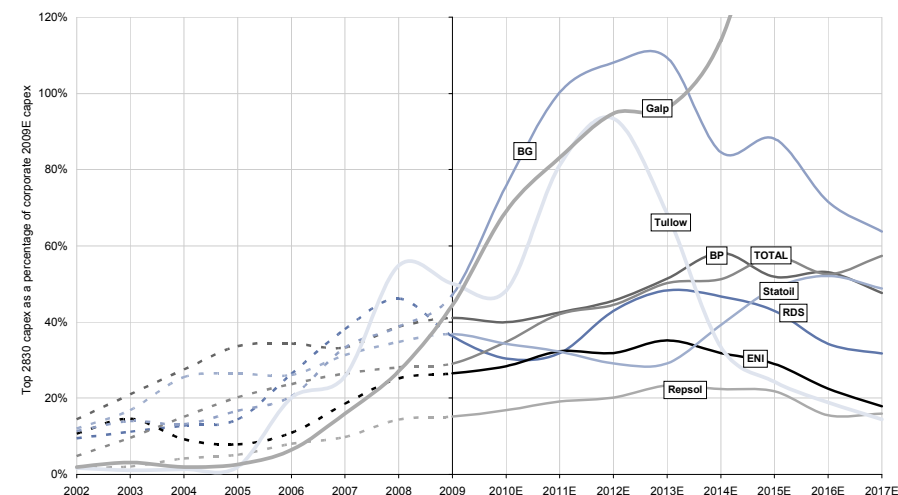
Top 280 capex as a percentage of corporate 2009E capex (rebased to zero)



Source: Goldman Sachs Research estimates.

Exhibit 190: ENI and Repsol are the lowest Top 280 spenders

Top 280 capex as a percentage of 2009E capex (absolute)



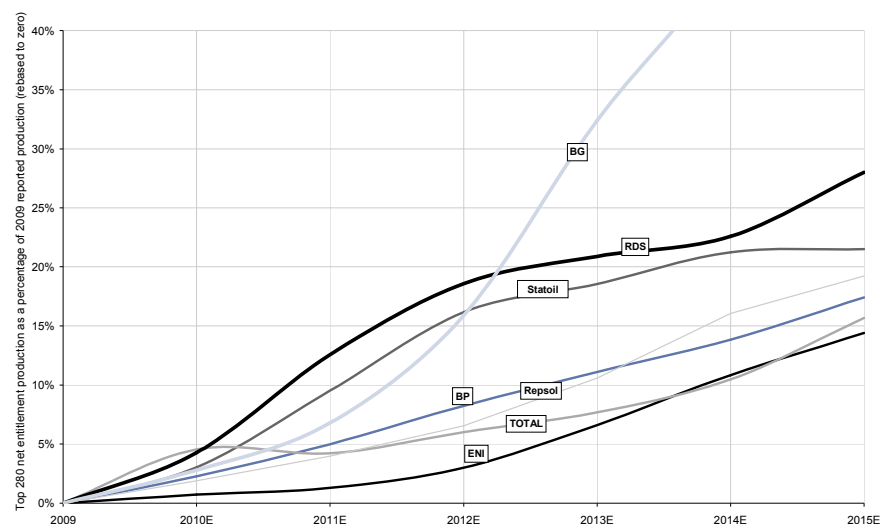
Source: Goldman Sachs Research estimates.

Production: BG the clear winner from Brazil and Australia

Although we prefer cash flow as a metric to judge a company's potential, we note that production is still an important metric to the market and therefore look at the likely net entitlement production growth from each company's Top 280 portfolio. Of the Europeans, we believe that, unsurprisingly given its investment, BG is the company set to generate the most transformational production growth in the medium term. Shell is also advantaged due to its Qatari portfolio and other projects such as Athabasca and Perdido. Statoil is also set for strong production growth in the medium term from relatively low cash flow projects such as Marcellus Shale and Peregrino. The other companies tend to close the gap between themselves and Statoil by c.2015E, although Shell continues to grow thanks to further assumed expansions of Athabasca and other diverse projects such as Mars B and Prelude.

We also assess the proportion of production that comes from low decline fields in each company's Top 280 portfolio – an indication of longevity. We define a "low decline" project as one in which the plateau lasts for 10 years or more. A clear bifurcation exists between the European Majors on this metric with BG (Curtis LNG), Shell (Pearl, Kashagan, Gorgon etc.), TOTAL (Kashagan, Ichthys) and ENI (Kashagan and African LNG) all developing projects which provide substantial levels of low decline production which should support production growth in the future. Repsol, BP and Statoil's focus on deepwater projects mean that these low decline projects represent a smaller proportion of their respective portfolios, although we note that beyond this timeframe, Statoil's Leismer project has the potential to provide substantial low decline growth.

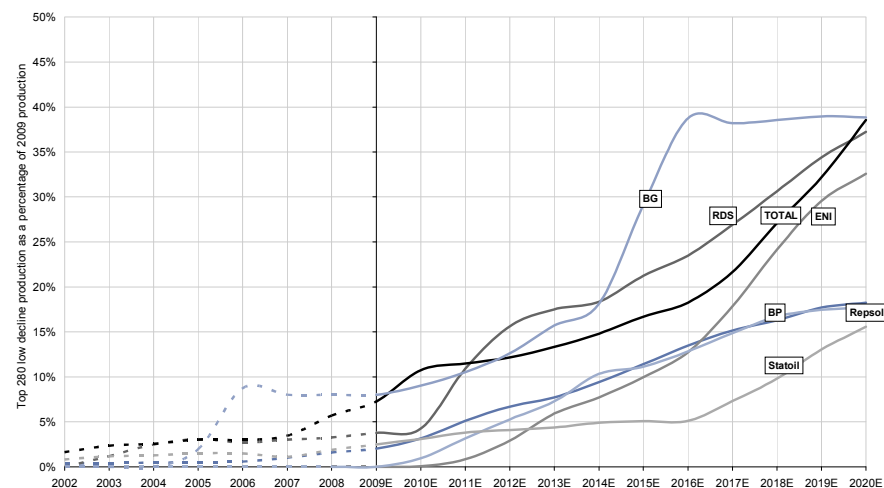
Exhibit 191: BG a winner; Statoil and Shell see medium-term growth



Source: Goldman Sachs Research estimates.

Exhibit 192: BG, Shell, TOTAL and ENI see low decline portfolios

% of production coming from low decline Top 280 projects



Source: Goldman Sachs Research estimates.

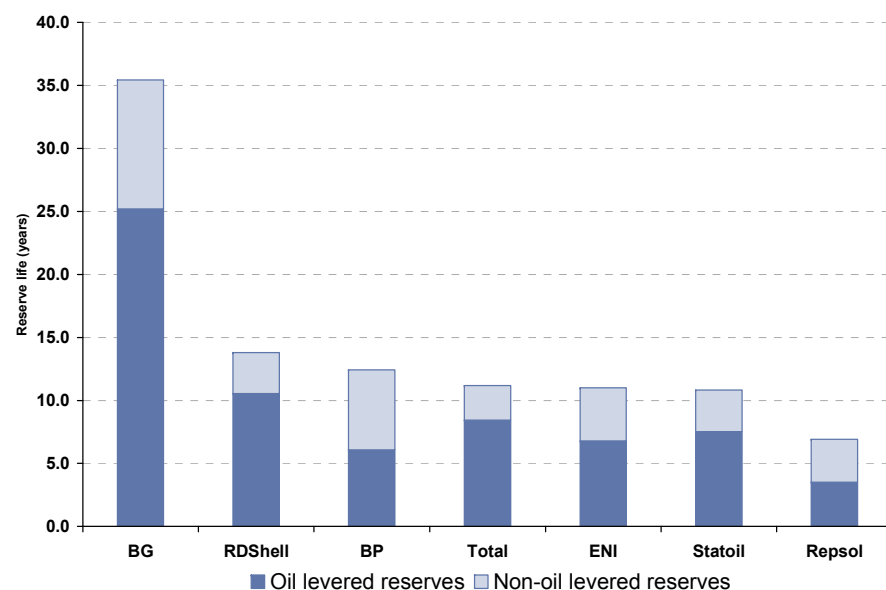
BG, Statoil, Total and Shell getting oilier

We believe that the Top 280 portfolio is material enough for many companies that it will substantially alter the outlook for future production. We believe that one of the major impacts will be on the oil/gas mix of reserves and production.

We have assessed the net entitlement reserve life vs. the overall 2009 production to determine how this mix could change in the future (Exhibit 193). In doing this, we have split reserves not according to hydrocarbon type, but according to what we believe is the driver of the price. We assume that liquids, LNG and European gas is ultimately driven by the oil price, with locally priced gas (including Henry Hub) trading on a more independent basis. We also assume that service contracts with a fixed remuneration fee are not oil-levered. Finally we strip out pre-sanction oil sands projects on the back of concerns that sanctioning may be delayed, meaning that the reserves have little immediate impact on a company's cash flows. On our estimates, most of the European Integrations have a greater weighting of oil levered reserves in their Top 280 portfolio, suggesting that the oil price will have an increasing impact on future earnings; BG, TOTAL, Shell and Statoil have oil-based reserve lives that are more than twice their gas levered reserve lives. For ENI, BP and Repsol, the impact of oil-levered reserves is less, with Repsol's Latin American gas exposure, BP's North American gas exposure and ENI's exposure to Latin American and Egyptian gas muting the impact of the companies' oil assets on a relative basis.

Exhibit 193: Reserve life of oil levered and gas levered reserves

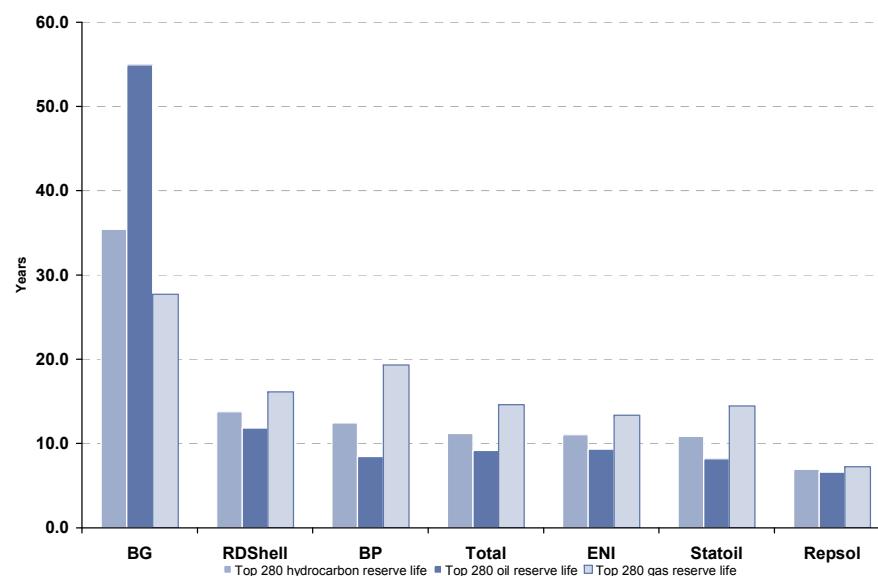
Based on remaining net entitlement volumes vs. overall 2009 production; excludes pre-sanction oil sands phases



Source: Goldman Sachs Research estimates.

Exhibit 194: European Top 280 oil and gas reserve lives

Based on net entitlement volumes and 2009 production; excludes pre-sanction oil sands phases

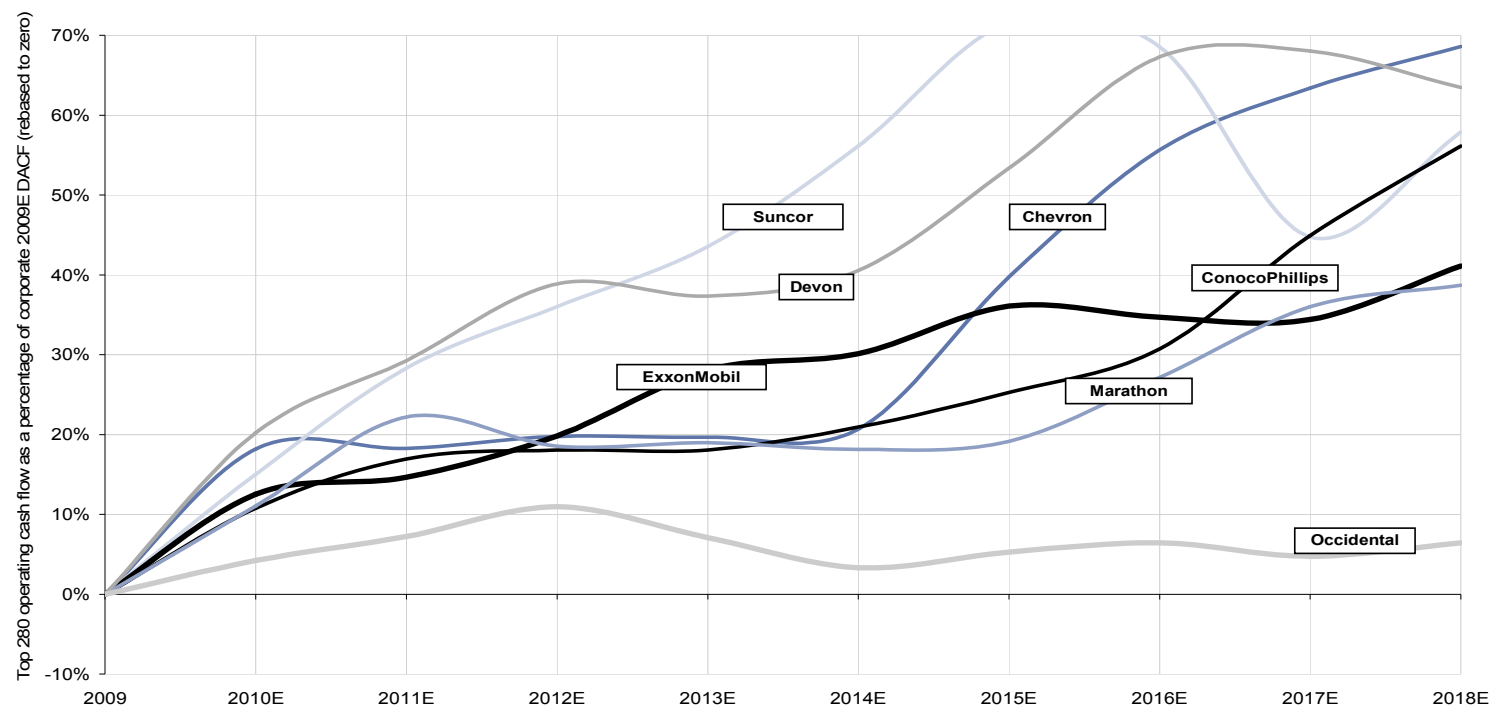


Source: Goldman Sachs Research estimates.

Timing of operating cash flows: Chevron long-term winner; Devon and Suncor in medium term

Chevron is a reasonable performer in the short term (due to projects such as Perdido, Shenzhi and Tombua Landana) but ramps up impressively beyond 2015E, primarily due to contributions from its LNG portfolio (Gorgon, Wheatstone) and its Gulf of Mexico portfolio (such as Jack and Buckskin). Exxon has a consistent incremental cash flow growth profile with its Middle Eastern portfolio (Qatargas, Rasgas, Al Khaleej etc.) contributing strong growth in the short term, and diverse projects such as Gorgon, Kashagan and West Qurna (especially through the cost recovery phase) contributing in the medium term. ConocoPhillips sees a significant increase in its cash flow growth rate from 2015E, largely as a result of cash flows from APLNG and Shah, although Kashagan provides the company with some nearer term growth. We expect Devon's Top 280 cash flows also to grow over time, mainly as a result of its unconventional gas position in the US, although we note that the continuing ramp up of Cascade and Chinook will also benefit the company. We expect to see a steady expansion in Suncor's Canadian heavy oil assets (such as Firebag and Mackay River) which should provide continued growth, although we expect a downturn in cash flows from Firebag in 2017E as the tax shield from initial costs ends. Fort Hills is too late to provide a substantial uptick in the time frame we look at (with production beginning during 2018E). Occidental benefits from its stake in Zubair and our assumed second stage at Dolphin, that helps maintain cash flow after the cost recovery period from Dolphin phase 1 ends. Marathon's growth from 2015E onwards is a result of its deepwater GoM and Angolan portfolios.

Exhibit 195: Operating cash flow from Top 230 projects as a percentage of normalised corporate cash flow (rebased to zero)



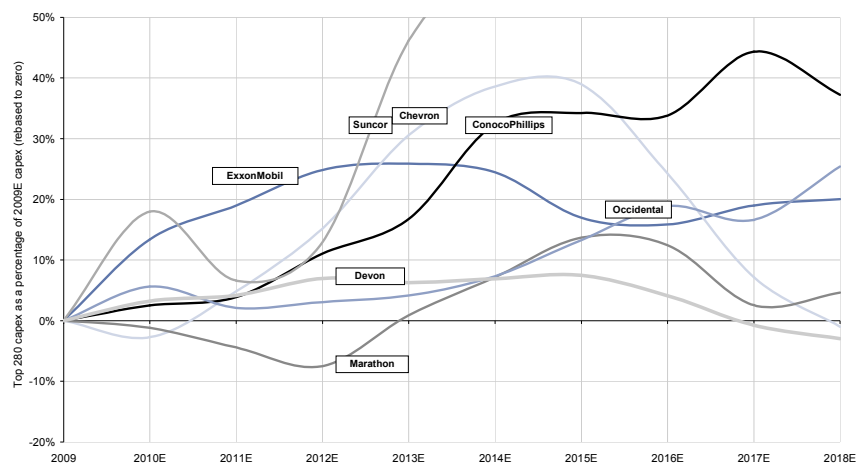
Source: Company data, Goldman Sachs Research estimates.

Capex timing: The Integrations and Suncor are the big spenders in the US

As expected, those companies benefiting most from high operational cash flows are also those which look set to invest the most in the short to medium term. Exxon is the big near-term spender with Kashagan, Kearl Lake and West Qurna the sources of particularly significant spend. Even by 2018E, spend remains high on the long dated West Qurna, Kearl Lake and Kashagan projects. Chevron's spend is muted in the short term but ramps up significantly in the medium term as the company spends on its LNG portfolio before dropping off after 2015E as Wheatstone starts production. Conoco's incremental spend in the short term is muted as we expect spending to slow at the Foster Creek/Christina Lake and Peng Lai assets. From 2013E onwards, however, Conoco's Top 280 capex grows significantly, primarily due to its spend at APLNG, Shah and Greater Sunrise – highlighting further the company's strong gas/LNG portfolio. Suncor's Fort Hills and Firebag assets should see significant expenditure, despite Fort Hills not beginning production on our estimates until 2018E, but this is reflected in the duration of the portfolio (42 years vs. average of 33 years for the Top 230 overall). Occidental's capex spend grows from 2013E as a result of its investment in long-dated assets such as Zubair and Joslyn while we expect Devon's spend on its unconventional gas acreage and GoM to remain fairly constant until Kaskida is fully ramped up at which point we see the company's visible deepwater spend begin to drop.

Exhibit 196: Exxon top 280 capex to grow most rapidly in the short term

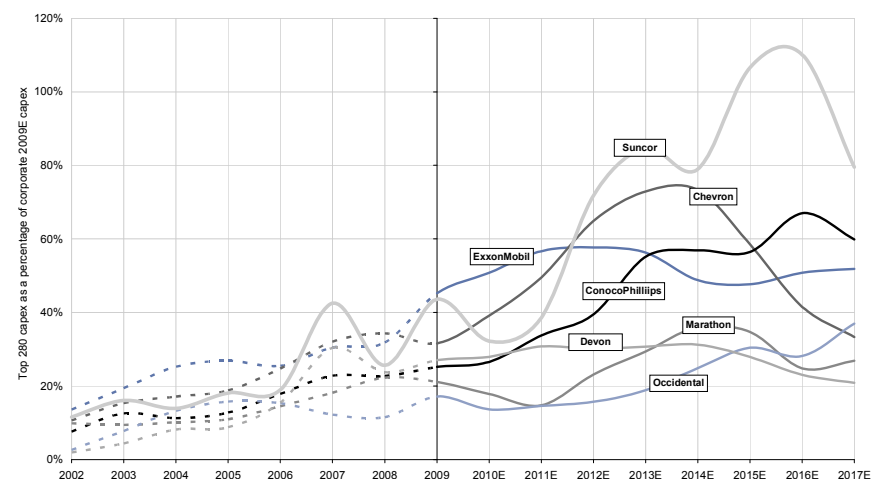
Top 280 capex as a percentage of 2009E capex (rebased to zero)



Source: Goldman Sachs Research estimates.

Exhibit 197: US Integrations have largest proportion of spend on legacy projects

Top 280 capex as a percentage of 2009E capex (absolute)



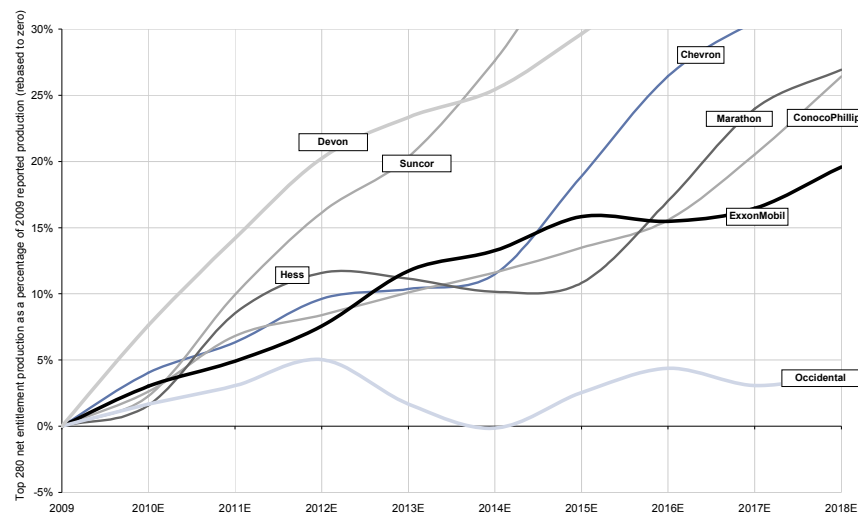
Source: Goldman Sachs Research estimates.

Production: Chevron the long-term winner of the majors, Occidental lags on net entitlement

We see Occidental lagging the group in incremental growth as a result of its relatively limited portfolio (consisting of only four projects) combined with the fact that it gets hit relatively hard by the PSC effect on projects such as Dolphin and Zubair, especially once costs have been recovered. Chevron, on the other hand, is the best performer of the Majors, with projects such as Bonga SW, Jack/St Malo and Gorgon providing significant growth from 2014E. Suncor and Devon grow substantially from a relatively smaller base.

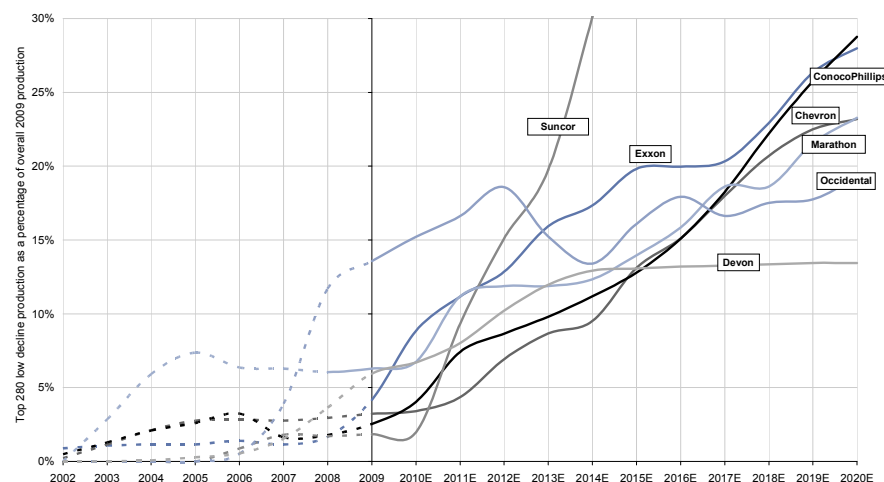
After Suncor Conoco and Exxon end the next decade with the largest proportion of low decline production from their Top 280 portfolios on our estimates. Conoco's is primarily a result of its Canadian portfolio and Kashagan, while Exxon benefits from its Middle Eastern portfolio, Kashagan and Gorgon. It is worth noting, however, that with the exception of Hess, which lags, the companies are relatively closely grouped in terms of how great a proportion low decline Top 280 assets are as a percentage of production. Suncor benefits from its heavy exposure to the heavy oil win zone.

Exhibit 198: Suncor and Devon see transformational growth; Chevron is the longer term integrated winner



Source: Goldman Sachs Research estimates.

Exhibit 199: Suncor shows the lowest decline
% of production coming from low decline Top 280 projects



Source: Goldman Sachs Research estimates.

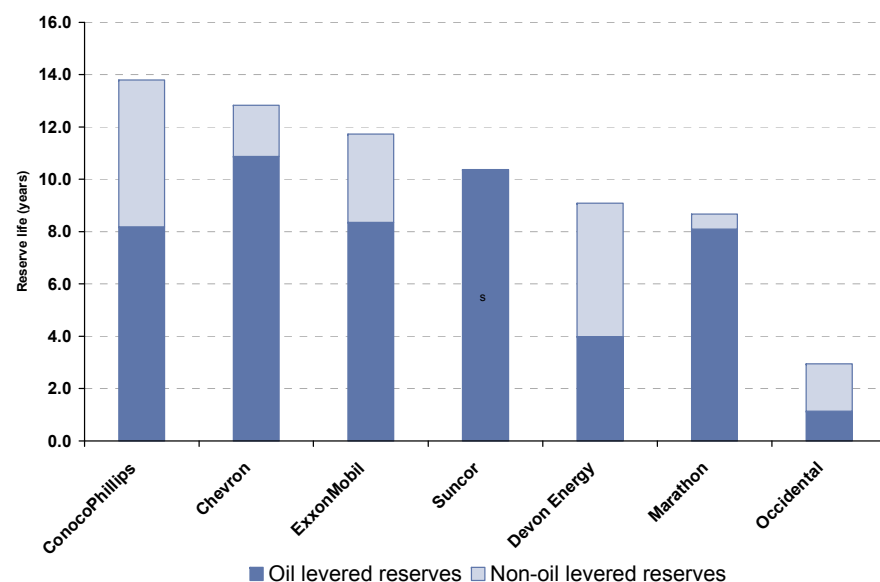
US Integrateds gaining oil leverage through LNG

All three US Integrateds have reserves that are relatively geared to the oil price, despite both ConocoPhillips and Chevron having a greater proportion of gas and a lower proportion of oil in their portfolios relative to their currently booked reserves. To a large degree, this is a result of the US integrated firms typically being more levered to the LNG market than their European counterparts with all three seeing over 20% of their reserves in the LNG win zone (vs. the Europeans where only Shell crosses this threshold). The relative lack of exposure to US unconventional gas relative to European peers is also highlighted in the lower reserve lives of gas levered reserves.

Of the smaller companies, Suncor's heavy oil assets make it very heavily exposed to oil. Its exposure would be greater, but we strip out much of its heavy oil reserve on the basis that it has yet to be sanctioned. Occidental's position in the oil-rich Mukhaizna and Joslyn assets is offset by the gas from Dolphin and the service contract exposure in Iraq (which we do not count as being oil levered due to the fixed remuneration fee), while Marathon's exposure to the Bakken Shale and Athabasca makes the company more oil-levered.

Exhibit 200: Reserve life of oil levered and gas levered reserves

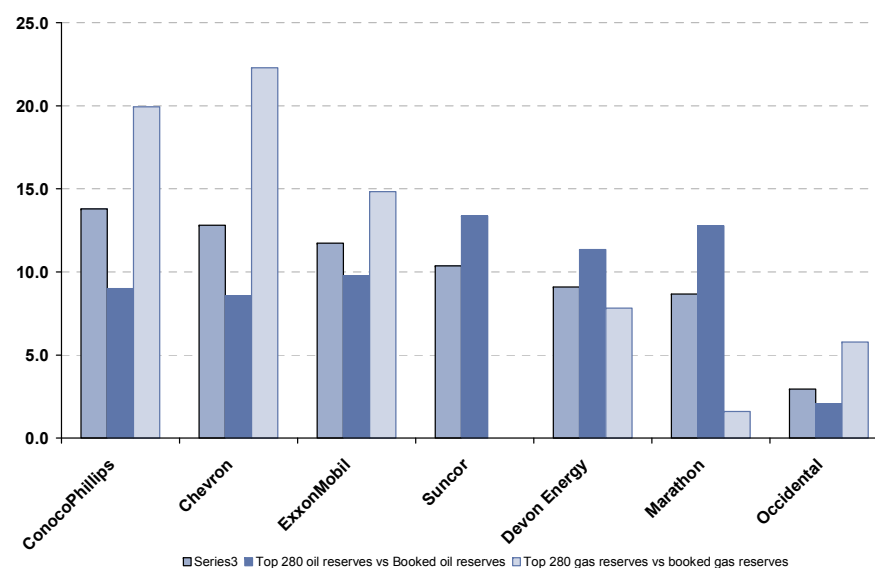
Based on remaining net entitlement volumes vs. overall 2009 production; excludes pre-sanction oil sands phases



Source: Goldman Sachs Research estimates.

Exhibit 201: US Top 280 oil and gas reserve lives

Based on net entitlement volumes and 2009 production; excludes pre-sanction oil sands phases

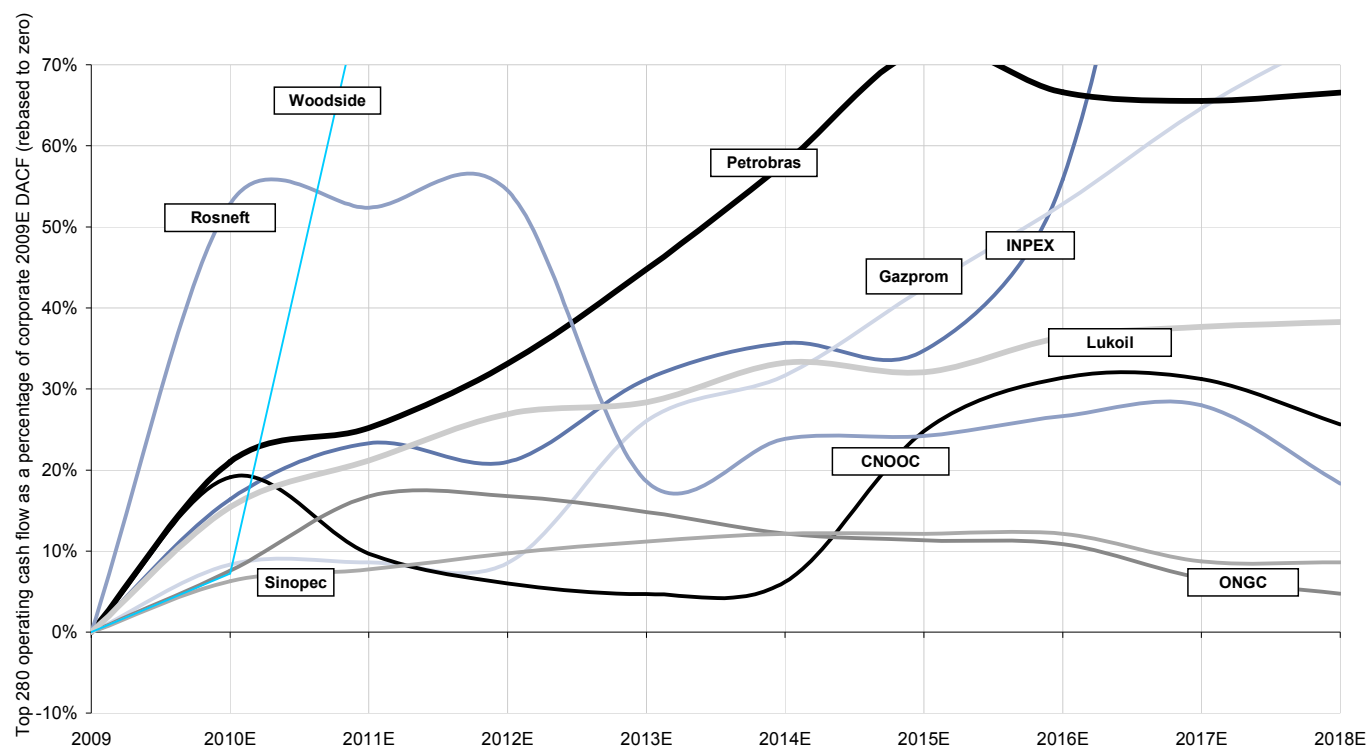


Source: Goldman Sachs Research estimates.

Timing of operating cash flow: Rosneft short term, Petrobras medium term and INPEX/Gazprom long term; Sinopec starts from a low base

The material expected ramp-up of Vankor, combined with first oil from Verkhnechonsk means that Rosneft is the clear near-term winner in terms of incremental Top 280 cash flow growth. In the medium term Petrobras' growth is substantial, coming mainly from the company's pre-salt Santos assets. Although we expect Petrobras' production to grow until 2020E, we expect the pace of growth to steady from 2015E as production growth is offset by cost recovery ending and fields breaching thresholds for Special Participation Tax in Brazil. We expect a substantial uptick in Top 280 production from INPEX from 2016E onwards as Ichthys begins producing, with Frade and Kashagan providing near-term growth. Gazprom's cash flow growth is also very strong in the back end, with Kovykta and Bovanenka the main contributors (Bovanenka accounts for almost two thirds of 2018E incremental Top 280 cash flow. ONGC sees a short-term uplift in 2011E as a result of the ramp-up of MBA, although this comes off over time as costs are recovered, profitability thresholds breached and as the corporate tax rate increases from the minimum applicable level. while Lukoil is a consistent grower as a result of its Russian portfolio (primarily Korchagina and Filanovskogo). Sinopec Corp is more muted with the only contribution coming from Puguang, with the other assets being held by the parent. Woodside's transformational growth comes from its Pluto LNG asset.

Exhibit 202: Operating cash flow from Top 280 Projects as a percentage of normalised operating cash flow (excl fields at plateau)

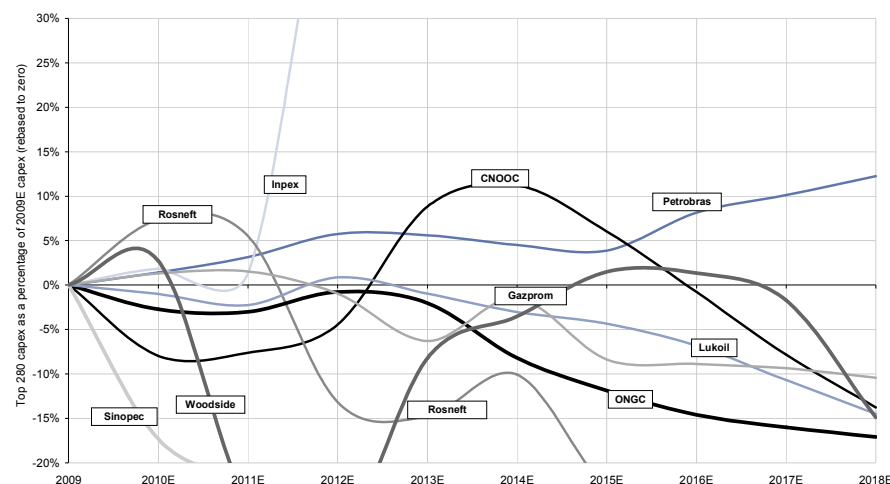


Source: Goldman Sachs Research estimates.

Capex timing: We expect a big relative uptick in Top 280 spend from Petrobras and INPEX

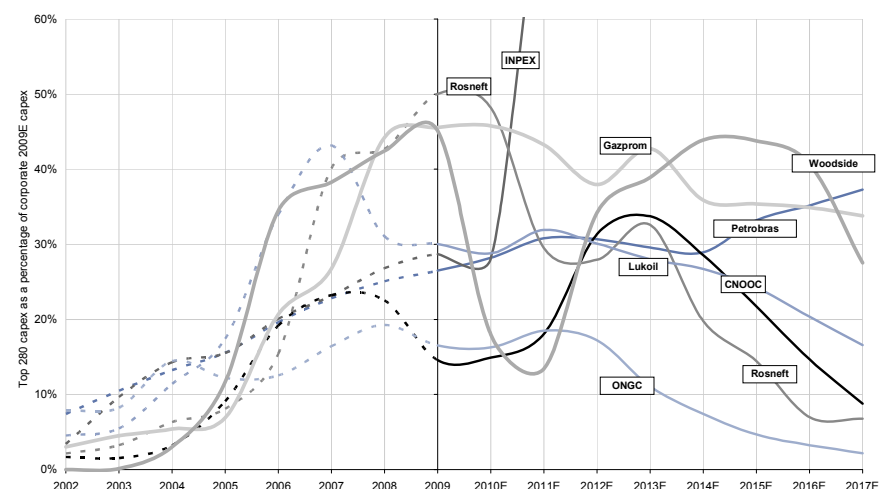
We expect Petrobras Top 280 spend to increase steadily as activity ramps up in the pre-salt Santos basin discoveries, making Petrobras one of the largest proportional Top 280 spenders vs. its EM peers in the long term. INPEX sees the most significant uptick in Top 280 capex, however, with substantial expenditure coming from its participation in Ichthys, Joslyn, Kashagan and Abadi. In line with its production profile, Rosneft's spend is very high over the next few years as it ramps up Vankor and Verkhnechonsk, before dropping to relatively low levels vs. its peers. Gazprom's incremental Top 280 spend actually reduces in the long term, but given the high base that it is starting from, with substantial amounts currently being spent at Bovanenka and Yuzhno-Russkoye, it remains a high spender in Top 280 legacy projects relative to its overall corporate spend. We expect CNOOC's medium-term spend to increase due to its Egina and Liwan assets. ONGC and Lukoil both have relatively muted Top 280 spends vs. the rest of their portfolios compared to the rest of the EM group. Woodside's capex drops sharply in 2011E as Pluto comes online but then ramps up once again to its relatively high base as other projects are developed (such as Pluto 2 and Greater Sunrise).

Exhibit 203: INPEX and Petrobras the big incremental long-term spenders
Top 280 capex as a percentage of 2009E capex (rebased to zero)



Source: Goldman Sachs Research estimates.

Exhibit 204: Gazprom still a significant investor from a relatively high base
Top 280 capex as a percentage of 2009E capex (absolute)



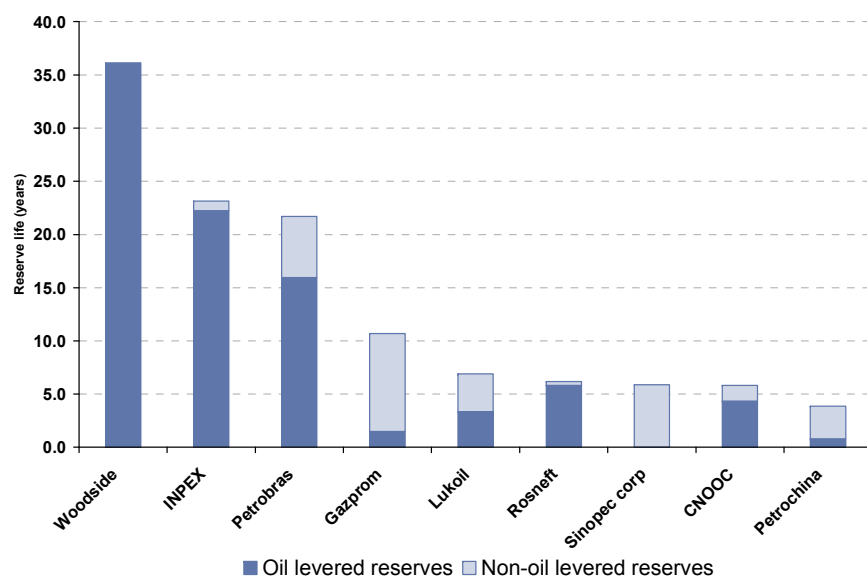
Source: Goldman Sachs Research estimates.

Santos basin gives Petrobras long dated oil reserve life; LNG projects result in oil leverage for Woodside

There is significant divergence among the other global players in terms of how levered their future Top 280 portfolio is to either oil or gas. Petrobras is, understandably, much more levered to oil due to the deepwater nature of its operations, although it is worth noting that associated gas in these prospects along with more gas-levered plays such as Mexilhao and Jupiter also provide a reasonable gas reserve life vs. current production. Woodside's LNG projects give it a substantial gas reserve life but, as we believe that LNG will continue to trade in relation to the crude price, we believe that the company's Top 280 portfolio remains highly levered to oil. Similarly INPEX's exposure to LNG via Abadi and Ichthys along with its stakes in the Kashagan and Joslyn projects give the company a substantial level of reserves levered to the oil price. In Russia it is no surprise that Gazprom is more weighted to gas and Rosneft more levered to oil (although Gazprom's relatively low current oil production still results in a relatively high oil reserve life for the company). Lukoil and PetroChina are relatively balanced while Sinopec Corp's Puguang asset means its Top 280 portfolio is exclusively gas, with many of the oilier assets sitting in the parent company.

Exhibit 205: Reserve life of oil levered and gas levered reserves

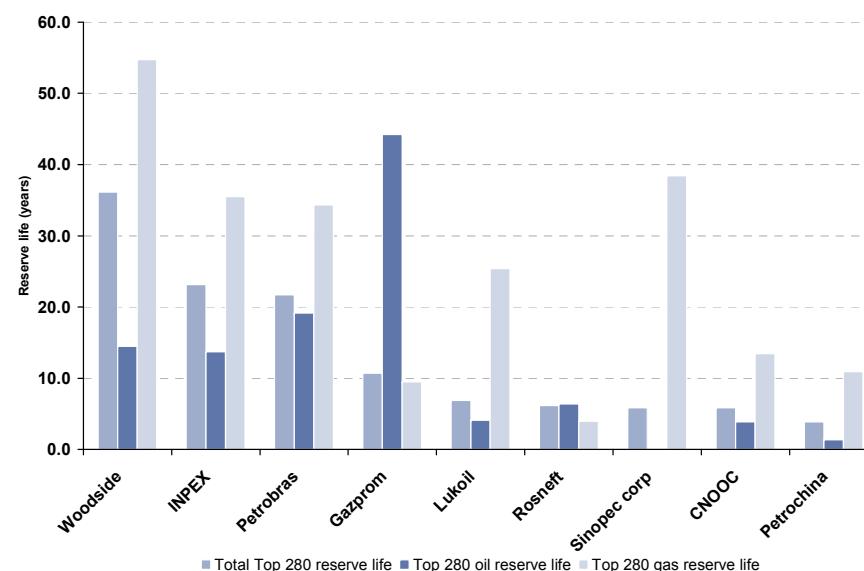
Based on remaining net entitlement volumes vs. overall 2009 production; excludes pre-sanction oil sands phases



Source: Goldman Sachs Research estimates

Exhibit 206: Global Top 280 oil and gas reserve lives

Based on net entitlement volumes and 2009 production; excludes pre-sanction oil sands phases

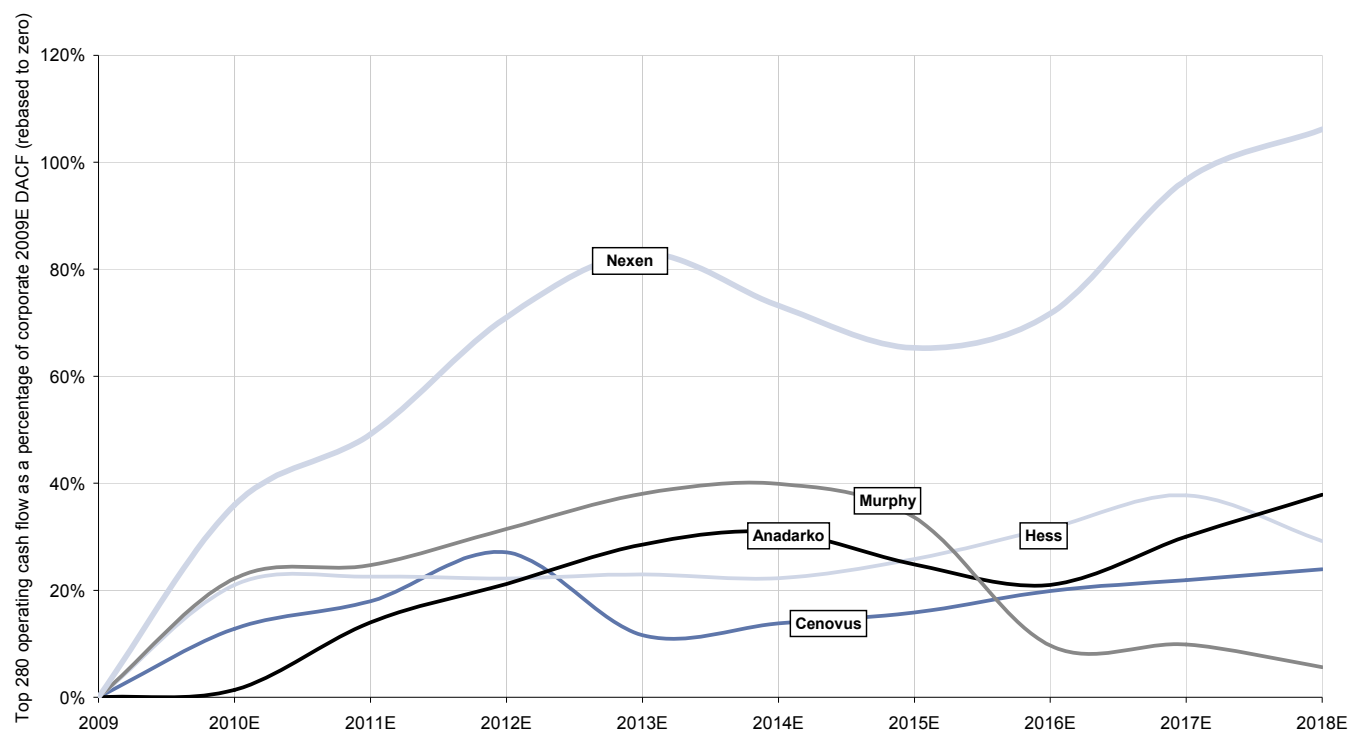


Source: Goldman Sachs Research estimates.

Timing of operating cash flows: Nexen the winner from the smaller Americas companies

Despite our expectation that Nexen's cash flows from Buzzard will begin to drop from 2010E, we believe that increasing contributions from Long Lake and Usan will more than offset this effect, and result in a growing Top 280 base for the company. Murphy experiences an initial uptick as a result of the continuing ramp-up of Kikeh which we believe should generate a full year's capacity production in 2010E but believe that the start-up of Gumusut and a ramp-up of production from the company's Montney Tight Gas asset will be insufficient to offset the decline in cash flows from Kikeh that we expect from 2015E. Cenovus sees more muted cash flow growth than its peers with Foster Creek/Christina Lake providing fairly stable cash flows. Hess benefits from Shenzi and Bakken Shale in the near term, and, with the Shenzi plateau now longer than we had previously modelled, these cash flows remain relatively strong in the medium term. Anadarko's growth is muted until 2011E, after which it sees growth from Jubilee and Caesar Tonga and, later, Shenandoah and Vito.

Exhibit 207: Operating cash flow from Top 280 projects as a percentage of normalised corporate cash flow (excl fields at plateau)



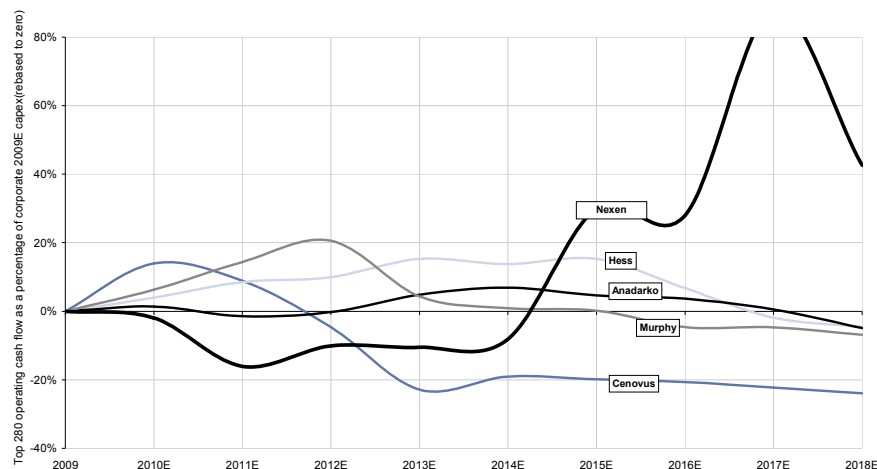
Source: Goldman Sachs Research estimates.

Capex timing: Nexen's heavy oil portfolio to create high expenditure in return for long duration

We expect Suncor and Nexen to be the big spenders of the smaller Americas companies, reflecting the size and capital intensity of their heavy oil assets. Nexen's Long Lake asset takes up the majority of the company's spend. While capital intensive at the beginning, we believe that this expenditure in heavy oil should allow for a greater duration of portfolio Nexen seeing a Top 280 duration of reserve life of 36 years– vs. 33 years for the average Top 280 portfolio of the 58 companies analysed in this report. In contrast, Anadarko's capex spend is largely focused on high return, but shorter dated deepwater assets such as Jubilee, Shenandoah and Caesar Tonga. We expect Talisman to spend primarily on its unconventional gas assets in the US, with Marathon spending on its Angolan and GoM deepwater portfolios, and its share of Athabasca. The peaking of Kikeh's production should see Murphy's Top 280 capex begin to drop.

Exhibit 208: Nexen and Suncor heavy oil expenditure leads them to be biggest spenders

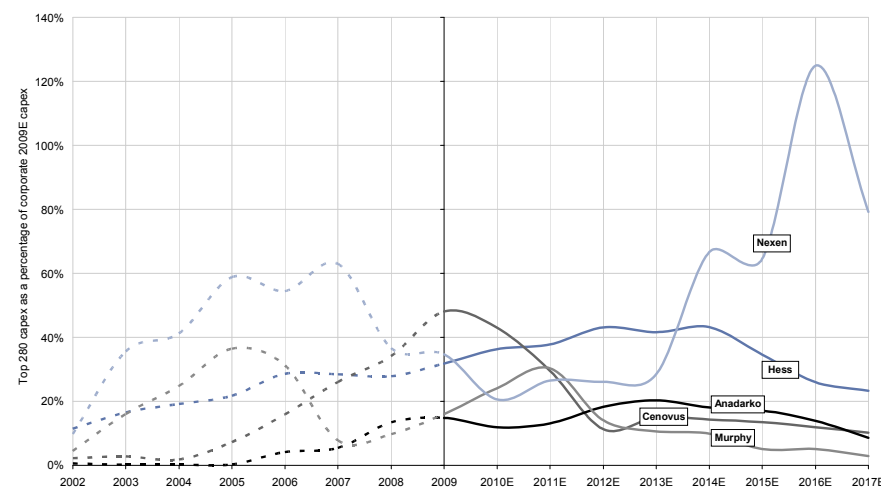
Top 280 capex as a percentage of 2009E capex (rebased to zero)



Source: Goldman Sachs Research estimates.

Exhibit 209: Committed capex from Top 280 projects as a % of 2009E capex

Top 280 capex as a percentage of 2009E capex (absolute)



Source: Goldman Sachs Research estimates.

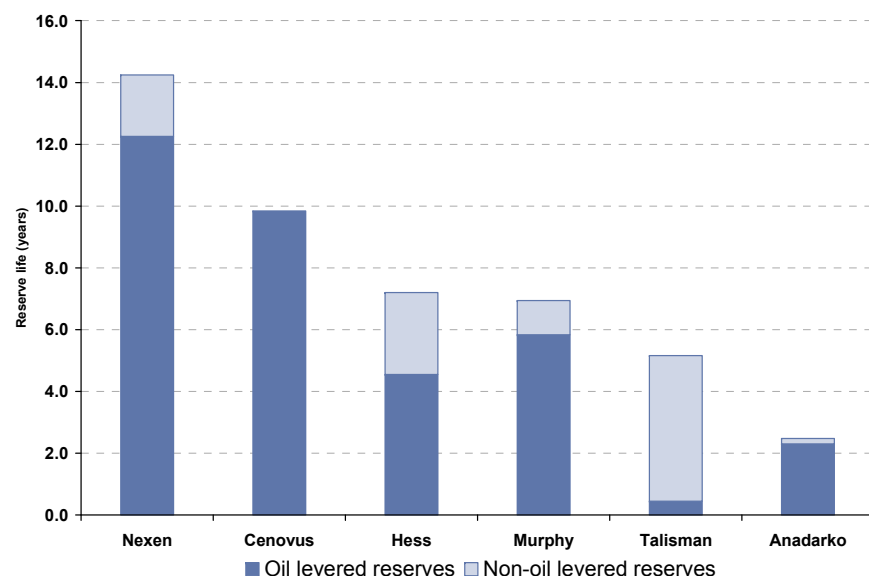
Oil leverage more apparent in smaller Americas firms

The smaller Americas companies are generally more levered to oil. Cenovus' exposure is the result of its participation in Foster Creek & Christina Lake and Narrows Lake while Nexen's reserves are skewed by its exposure to Long Lake, although the oily Buzzard field also makes a large contribution. Murphy's portfolio is also biased towards oil and is mainly the result of its Kikeh asset.

Hess, Anadarko and Talisman show much lower reserve lives than Cenovus and Nexen and all have lower Top 280 reserves than they have booked in both oil and gas. This is simply an indication of the fact that their portfolio is more diverse than that simply captured in our Top 280 universe. Anadarko's deepwater exploration success leaves its Top 280 portfolio far more levered to oil than gas, while Talisman's acreage positions in Marcellus and Montney result in a far higher gas-levered exposure. Hess is reasonably well balanced. Hess is the most balanced of this group, holding both oil assets (such as Bakken Shale acreage and GoM assets) and more gassy assets such as JDA and Snohvit.

Exhibit 210: Reserve life of oil levered and gas levered reserves

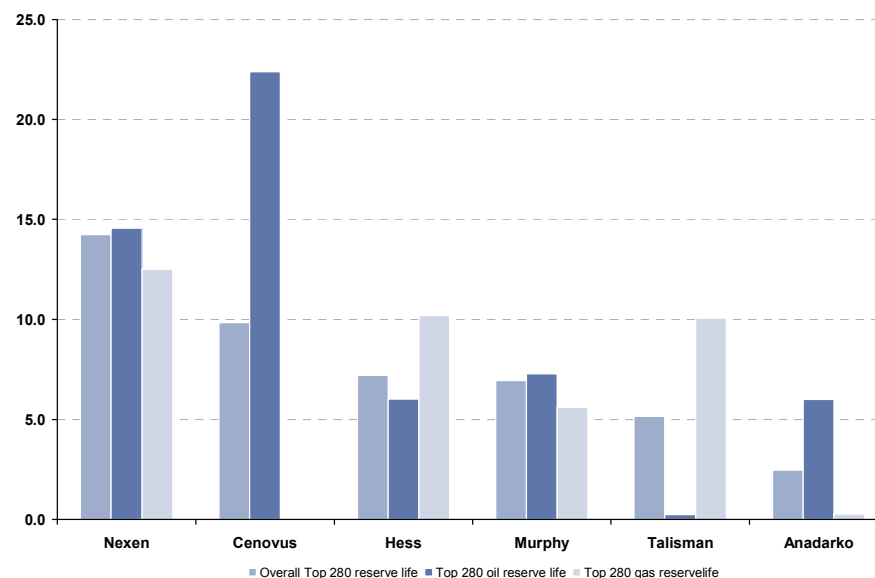
Based on remaining net entitlement volumes vs. overall 2009 production; excludes pre-sanction oil sands phases



Source: Goldman Sachs Research estimates.

Exhibit 211: Smaller Americas Top 280 oil and gas reserve lives

Based on net entitlement volumes and 2009 production; excludes pre-sanction oil sands phases



Source: Goldman Sachs Research estimates.

Summary of key Top 280 Projects metrics by company

Exhibit 212: Summary of key Top 280 Projects metrics by company

	Top 280 Projects reserves *					Capex (US\$m) **			Profitability					Risk		
	Oil (mnbbls)	Gas (mnbbls)	Total (mnbbls)	As % of 2008 proved reserves	Duration (yrs)	Total capex (incl infr)	Total capex (US\$/bl)	Upstream F&D (US\$/bl)	IRR	P/I ratio	NPV 2010 / bl (US\$/bl)	NPV as % of current EV	% change in P/I vs Top 230	Technical	Political	Overall
Major																
ExxonMobil	11,406	8,187	19,593	85%	32	156,333	5.3	4.1	23%	1.72	3.8	39%	-5%	1.1	1.1	2.2
BP	9,024	10,342	19,365	108%	33	144,606	5.4	4.5	26%	1.86	4.6	58%	-1%	1.1	1.3	2.4
RDSHELL	8,623	8,284	16,908	146%	31	152,027	6.7	4.1	18%	1.59	5.3	56%	-5%	1.1	1.1	2.2
Chevron	6,056	6,768	12,823	115%	33	111,387	7.0	4.8	22%	1.76	6.0	62%	-6%	1.3	1.4	2.6
TOTAL	7,898	4,318	12,216	121%	32	101,322	5.9	4.5	22%	1.69	4.2	43%	-3%	1.2	1.5	2.7
ConocoPhillips	5,337	5,975	11,312	113%	36	90,134	6.9	4.8	16%	1.50	3.1	40%	2%	1.1	0.8	1.9
ENI	3,917	3,525	7,441	115%	31	60,230	4.8	3.7	21%	1.77	4.5	43%	-12%	1.4	1.9	3.3
EUR Regional / E&P																
Statoil	5,457	3,600	9,057	173%	30	70,136	6.2	4.5	24%	1.71	5.4	62%	1%	1.2	1.0	2.2
BG	3,683	4,708	8,391	341%	34	65,358	6.9	5.6	23%	1.90	5.2	67%	3%	1.4	1.5	0.2
GALP	1,505	915	2,420	8641%	36	21,794	8.8	8.4	24%	1.81	3.9	50%	19%	2.1	1.6	3.7
Repsol	1,038	1,195	2,233	105%	30	12,634	5.1	4.5	28%	2.16	6.1	28%	4%	0.8	2.1	2.9
Tullow	566	27	593	189%	26	5,279	5.0	3.9	34%	2.70	9.7	63%	3%	0.6	2.0	2.6
Dragon Oil	319	0	319	49%	36	4,720	7.6	7.6	61%	2.30	8.3	196%	10%	0.3	2.1	2.3
Heritage	124	0	124	536%	27	2,098	2.3	2.2	46%	2.94	3.3	547%	na	0.0	3.0	3.0
OMV	86	0	86	8%	27	945	4.2	4.2	29%	2.29	6.4	8%	7%	0.7	1.0	1.8
Soco	84	0	84	53%	16	412	4.5	4.5	37%	3.50	16.9	97%	1%	0.0	1.7	1.7
US Regional																
Chesapeake	0	2,630	2,630	131%	32	23,901	9.1	9.1	36%	1.70	4.8	44%	7%	1.0	0.8	1.8
Devon Energy	990	1,262	2,252	93%	29	18,767	7.7	7.6	26%	1.69	6.0	43%	10%	1.2	0.7	1.9
Marathon	1,560	92	1,652	138%	30	18,858	10.1	7.3	21%	1.60	7.0	53%	7%	0.8	1.0	1.8
Hess	648	435	1,083	76%	28	13,512	9.3	7.7	22%	1.66	8.3	59%	2%	0.8	1.1	1.9
Occidental	668	328	996	33%	25	10,550	3.6	2.7	24%	1.60	2.2	11%	-6%	0.7	1.1	1.8
Apache	26	692	718	32%	31	6,792	7.1	4.6	17%	1.44	3.5	9%	10%	0.8	1.0	1.8
Noble Energy	127	458	585	68%	27	3,002	4.6	4.6	33%	2.33	5.5	24%	61%	0.6	1.7	2.3
Newfield	0	574	574	102%	42	3,462	6.0	6.0	44%	1.98	4.1	28%	27%	1.0	0.7	1.7
Anadarko	508	38	546	24%	23	5,707	8.8	8.7	37%	2.36	11.6	18%	-2%	1.0	1.4	2.4
EOG Resources	359	186	545	38%	37	10,424	19.1	16.4	32%	1.48	7.3	15%	11%	1.0	0.7	1.7
Murphy	335	64	399	147%	23	2,621	4.1	3.6	25%	2.04	10.6	58%	-4%	0.6	1.0	1.7

* reserves displayed on a net entitlement basis

** per barrel figures displayed on a working interest basis

Source: Company data, Goldman Sachs Research estimates.

Exhibit 212 cont'd: Summary of key Top 280 Projects metrics by company

	Top 280 Projects reserves *					Capex (US\$mn) **			Profitability					Risk		
	Oil (mmbbls)	Gas (mnbob)	Total (mnbob)	As % of 2008 proved reserves	Duration (yrs)	Total capex (incl infr)	Total capex (US\$/bl)	Upstream F&D (US\$/bl)	IRR	P/I ratio	NPV 2010 / bl (US\$/bl)	NPV as % of current EV	% change in P/I vs Top 230	Technical	Political	Overall
Canada Regional																
Suncor	7,297	0	7,297	331%	42	39,817	5.4	3.9	22%	1.72	2.8	31%	29%	0.8	0.5	1.3
Canadian Natural Resources	5,620	0	5,620	287%	37	49,999	8.9	2.9	12%	1.29	4.2	52%	-7%	0.8	0.5	1.3
Nexen	2,101	155	2,256	244%	36	19,223	8.5	4.3	23%	1.83	7.9	110%	10%	0.8	0.6	1.4
Husky Energy	1,322	254	1,576	176%	30	10,391	6.0	5.9	31%	1.97	4.2	na	-12%	0.7	0.7	1.4
Cenovus	1,536	0	1,536	128%	37	5,782	3.8	3.8	22%	1.96	4.3	29%	na	0.8	0.5	1.3
Encana	0	1,478	1,478	72%	31	13,865	9.4	9.4	32%	1.53	4.1	20%	10%	0.9	0.6	1.5
Talisman	16	662	678	56%	33	6,113	7.9	7.6	28%	1.69	4.3	16%	0%	0.9	0.8	1.6
EM Regional																
Petrobras	14,770	5,322	20,092	137%	32	135,188	6.7	6.5	29%	2.22	8.0	74%	12%	1.5	1.6	3.1
Petrochina	4,756	3,392	8,148	38%	31	38,520	3.4	3.4	21%	1.93	2.9	12%	-4%	0.6	1.2	1.8
INPEX	1,328	2,220	3,548	216%	38	38,991	7.7	5.1	16%	1.59	3.7	93%	0%	1.3	1.1	2.3
Sinopec Corp	0	2,088	2,088	52%	26	3,245	1.6	0.8	12%	1.39	5.4	10%	-4%	0.5	1.6	2.1
Reliance	169	1,667	1,837	132%	22	8,643	3.4	3.4	35%	2.06	6.5	20%	4%	0.4	1.9	2.3
CNOOC	710	635	1,345	39%	29	12,489	5.9	5.2	24%	1.84	7.2	21%	-9%	0.7	1.9	2.6
ONGC	415	512	927	17%	39	5,308	3.4	3.2	29%	2.21	7.8	25%	-26%	0.5	1.9	2.4
PTTEP	149	685	833	88%	27	3,957	3.6	3.4	24%	2.22	6.4	43%	5%	0.3	2.1	2.4
Russian																
Gazprom	4,566	28,188	32,754	29%	45	133,693	4.0	2.0	18%	2.14	4.7	82%	18%	1.1	1.7	2.8
Lukoil	2,861	2,647	5,508	28%	29	23,551	2.9	2.6	21%	1.89	3.8	57%	-23%	0.9	1.8	2.7
Rosneft	5,092	304	5,396	24%	43	25,235	4.4	3.0	28%	1.79	4.8	27%	-14%	1.0	1.7	2.7
TNK	2,659	1,481	4,140	101%	43	15,930	3.8	3.3	20%	1.82	3.5	118%	-3%	0.7	1.7	2.4
Surgutneftegaz	569	0	569	7%	29	1,428	2.5	0.4	30%	2.19	11.9	27%	0%	1.0	1.7	2.7
Other																
Woodside	536	2,355	2,891	218%	32	27,029	9.3	3.6	13%	1.47	6.9	53%	-1%	1.0	0.6	1.7
UTS Corp	1,450	0	1,450	460%	31	13,456	9.3	7.1	10%	1.19	0.8	na	-3%	0.8	0.5	1.3
BHP Billiton	705	636	1,341	98%	29	8,543	6.4	4.1	28%	2.48	15.1	10%	5%	1.3	0.7	0.2
Santos	48	1,129	1,178	227%	28	15,813	12.8	6.5	15%	1.45	3.3	39%	-10%	0.9	0.9	1.8
Origin Energy	0	1,042	1,042	141%	45	10,052	9.6	6.4	14%	1.52	2.3	14%	-9%	1.1	0.6	1.7
OPTI Canada	871	0	871	288%	40	7,707	8.8	3.8	13%	1.46	5.5	na	8%	0.8	0.5	1.3
Maersk	554	4	558	na	30	4,004	2.1	2.1	23%	1.86	6.6	23%	-4%	0.5	0.9	1.3
Cairn India	387	0	387	56%	33	2,022	3.1	2.2	44%	3.37	16.1	81%	-13%	0.4	1.9	2.3
Oil Search	43	264	307	620%	27	3,832	12.5	5.6	15%	1.59	5.8	26%	-12%	1.0	2.1	3.1
SASOL	291	0	291	101%	27	1,715	8.1	0.0	29%	3.16	15.4	17%	-1%	1.5	0.9	2.4
Daewoo	0	273	273	na	25	2,708	5.3	5.1	11%	1.22	1.5	na	-14%	0.3	3.0	3.3
Nippon	11	217	228	na	41	1,981	4.5	1.9	16%	1.71	5.7	na	-9%	0.6	2.0	2.5

* reserves displayed on a net entitlement basis

** per barrel figures displayed on a working interest basis

Source: Company data, Goldman Sachs Research estimates.

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