Company

Global Markets Research

Deutsche Securities
A Member of Deutsche Bank Group

5 November 2010

Sasol Ltd

Reuters: **SOLJ.J** Bloomberg: **SOL SJ** Exchange: **JNB** Ticker: **SOLJ**

The GTL catalyst; Buy

Special Report

Catalysts aligning for further GTL expansion
Sasol has indicated significant interest in its gas-to-liquids (GTL) technology. Based on our analysis, we anticipate gas resource holders and stressed producers are seeking both monetisation and diversification options following improving performance from Oryx GTL. Sasol is one of two companies with commercial GTL technology. The increased interest is expected to solve Sasol's existing feedstock constraints, allowing the group to potentially double synthetic fuel production, given financial and technical constraints, within five years. Buy.

Buy

Price at 4 Nov 2010 (ZAR)	**325.48**
Price Target (ZAR)	**380.00**
52-week range (ZAR)	**326.90 - 268.00**

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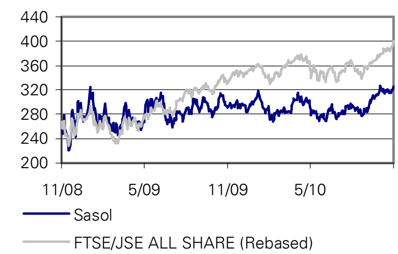
Price/price relative



Performance (%)	1m	3m	12m
Absolute	*2.7*	*11.1*	*11.9*
FTSE/JSE ALL SHARE	*6.9*	*9.8*	*20.8*

Stock data

Market cap (ZAR)(m)	**194,506.8**
Shares outstanding (m)	**616**
Free float (%)	**85**
FTSE/JSE ALL SHARE	**31,327.9**

Key indicators (FY1)

ROE (%)	**17.0**
ROA (%)	**10.5**
Net debt/equity (%)	**3.5**
Book value/share (ZAR)	**173.8**
Price/book (x)	**1.9**
Net interest cover (x)	**15.6**
EBIT margin (%)	**19.1**

Catalysts aligning for further GTL expansion

Sasol has indicated significant interest in its gas-to-liquids (GTL) technology. Based on our analysis, we anticipate gas resource holders and stressed producers are seeking both monetisation and diversification options following improving performance from Oryx GTL. Sasol is one of two companies with commercial GTL technology. The increased interest is expected to solve Sasol's existing feedstock constraints, allowing the group to potentially double synthetic fuel production, given financial and technical constraints, within five years. Buy.

GTL offers viable diversification to LNG, supported by improving Oryx GTL

Our analysis indicates two key variables in technological preference – the oil to spot gas ratio and LNG contract terms. Given greater global LNG competition and pressure on spot gas prices as a result of unconventional gas, we expect interest in GTL technology from resource holders' dependant on significant LNG sales in non oil indexed gas markets. The outlook for Oryx is bright; we expect a step change in FY11E EBIT margins to 60% on increased capacity utilisation (c.85%).

Uzbekistan GTL potentially first of several successful projects outside Qatar

Strong project economics support a positive investment decision up to a gas cost of US$2.6/mmBtu. We calculate a project IRR of c.21% (US$, unlevered), expecting the project to be cash breakeven within four years of commissioning, given the strong cash generation potential in an US$80/bbl oil environment.

GTL potentially yields favourable project IRRs across the US gas resource

Our analysis suggests a US GTL facility will yield a c.15% IRR (US$, unlevered) at US$80/bbl oil up to a purchased gas price of c.US$4.7/mmBtu, over c.30% above current spot prices. Based on post tax breakeven shale gas production costs, the economics are supported in oil environments ranging from c.US$64-87/bbl. We highlight Haynesville and Marcellus as key potential partnership regions, offering revenue diversification and an opportunity to reduce gas-weightings.

Valuation and risks

Our valuation is based on DCF for operating assets and approved projects, discounted at a WACC of 12.3% (we use a risk-free rate of 8.5%, equity risk premium of 4.5% and beta of 1.1). Downside risks include a weaker-than-forecast oil price, a stronger-than-forecast ZAR/USD exchange rate, delayed project delivery, cost overruns and suboptimal ramp-up. See p. 4.

Forecasts and ratios

Year End Jun 30	2010A	**2011E**	2012E	2013E
Revenue (ZARm)	122,256	**129,253**	145,872	172,811
DB EPS (ZAR)	26.54	**27.46**	35.77	49.54
P/E (DB EPS) (x)	10.9	**11.9**	9.1	6.6
EV/EBITDA (x)	5.5	**6.0**	4.9	3.5
DPS (ZAR)	10.50	**11.55**	12.70	13.98
Yield (%)	3.6	**3.5**	3.9	4.3

Source: Deutsche Bank estimates, company data

[1] DB EPS is fully diluted and excludes non-recurring items
[2] Multiples and yields calculations use average historical prices for past years and spot prices for current and future years, except P/B which uses the year end close

Model updated:03 November 2010

Running the numbers

Sub-Saharan Africa

South Africa

Oil & Gas Producers

Sasol

Reuters: SOLJ.J Bloomberg: SOL SJ

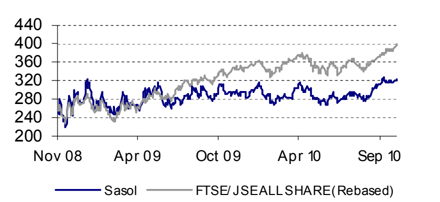
Buy

Price (4 Nov 10)	ZAR 325.48
Target price	ZAR 380.00
52-week Range	ZAR 268.00 - 326.90
Market Cap (m)	ZARm 194,507 USDm 28,556

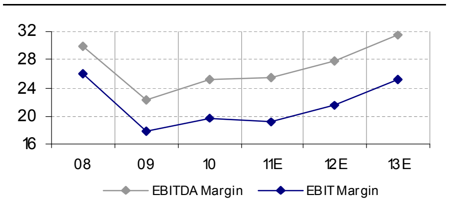
Company Profile

Sasol is an integrated oil and gas company with substantial chemical interests, and production facilities in SA, Europe, North America and Asia. The group operates commercial scale facilities to produce fuels and chemicals from coal in SA, and is developing ventures internationally to convert natural gas into clean diesel fuel.

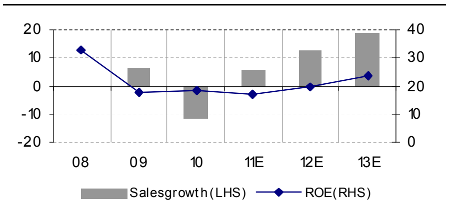
Price Performance



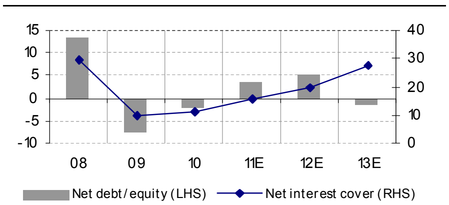
Margin Trends



Growth & Profitability



Solvency



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Fiscal year end 30-Jun	2008	2009	2010	2011E	2012E	2013E
Financial Summary						
DB EPS (ZAR)	37.56	25.25	26.54	27.46	35.77	49.54
Reported EPS (ZAR)	36.78	22.80	26.54	27.46	35.77	49.54
DPS (ZAR)	13.00	8.50	10.50	11.55	12.71	13.98
BVPS (ZAR)	127.2	140.6	158.5	173.8	198.0	235.1
Weighted average shares (m)	601	596	598	598	598	598
Average market cap (ZARm)	216,691	182,182	173,161	194,507	194,507	194,507
Enterprise value (ZARm)	222,377	173,626	168,011	195,159	197,703	189,251
Valuation Metrics						
P/E (DB) (x)	9.6	12.1	10.9	11.9	9.1	6.6
P/E (Reported) (x)	9.8	13.4	10.9	11.9	9.1	6.6
P/BV (x)	3.62	1.92	1.73	1.87	1.64	1.38
FCF Yield (%)	6.0	12.7	2.8	0.8	2.4	8.5
Dividend Yield (%)	3.6	2.8	3.6	3.5	3.9	4.3
EV/Sales (x)	1.7	1.3	1.4	1.5	1.4	1.1
EV/EBITDA (x)	5.7	5.6	5.5	6.0	4.9	3.5
EV/EBIT (x)	6.6	7.0	7.0	7.9	6.3	4.4
Income Statement (ZARm)						
Sales revenue	**129,943**	**137,836**	**122,256**	**129,253**	**145,872**	**172,811**
Gross profit	**55,309**	**49,328**	**43,073**	**43,598**	**51,387**	**64,692**
EBITDA	**39,016**	**30,896**	**30,637**	**32,758**	**40,622**	**54,437**
Depreciation	5,200	6,230	6,700	8,105	9,335	11,069
Amortisation	0	0	0	0	0	0
EBIT	**33,816**	**24,666**	**23,937**	**24,653**	**31,287**	**43,369**
Net interest income(expense)	-1,148	-2,531	-2,114	-1,585	-1,585	-1,585
Associates/affiliates	254	270	217	320	320	320
Exceptionals/extraordinaries	0	0	0	0	0	0
Other pre-tax income/(expense)	735	1,790	1,332	1,412	1,412	1,412
Profit before tax	**33,657**	**24,195**	**23,372**	**24,800**	**31,435**	**43,516**
Income tax expense	10,129	10,480	6,985	8,045	9,520	12,974
Minorities	1,111	67	446	246	297	442
Other post-tax income/(expense)	0	0	0	0	0	0
Net profit	**22,417**	**13,648**	**15,941**	**16,509**	**21,619**	**30,100**
DB adjustments (including dilution)	473	1,854	395	395	395	395
DB Net profit	**22,890**	**15,502**	**16,336**	**16,904**	**22,014**	**30,495**
Cash Flow (ZARm)						
Cash flow from operations	**23,720**	**38,031**	**20,889**	**22,461**	**27,393**	**36,208**
Net Capex	-10,671	-14,975	-16,056	-20,975	-22,782	-19,738
Free cash flow	**13,049**	**23,056**	**4,833**	**1,486**	**4,611**	**16,470**
Equity raised/(bought back)	-6,913	40	110	0	0	0
Dividends paid	-5,766	-7,193	-5,360	-7,362	-7,178	-7,896
Net inc/(dec) in borrowings	-1,132	-1,056	628	0	0	0
Other investing/financing cash flows	-219	1,410	-788	0	0	0
Net cash flow	**-981**	**16,257**	**-577**	**-5,876**	**-2,567**	**8,573**
Change in working capital	*-7,404*	*10,375*	*-3,424*	*-2,494*	*-3,587*	*-5,133*
Balance Sheet (ZARm)						
Cash and other liquid assets	5,249	20,672	16,711	10,835	8,267	16,841
Tangible fixed assets	77,966	84,866	93,541	106,463	119,932	128,623
Goodwill/intangible assets	1,838	1,873	1,931	1,931	1,931	1,931
Associates/investments	7,372	4,378	5,494	5,814	6,134	6,454
Other assets	47,687	34,049	38,807	40,498	45,099	52,017
Total assets	**140,112**	**145,838**	**156,484**	**165,540**	**181,363**	**205,865**
Interest bearing debt	15,786	14,112	14,543	14,543	14,543	14,543
Other liabilities	45,331	45,509	44,699	44,363	45,449	47,306
Total liabilities	**61,117**	**59,621**	**59,242**	**58,906**	**59,992**	**61,849**
Shareholders' equity	76,474	83,835	94,730	103,876	118,317	140,520
Minorities	2,521	2,382	2,512	2,758	3,054	3,496
Total shareholders' equity	**78,995**	**86,217**	**97,242**	**106,634**	**121,371**	**144,017**
Net debt	*10,537*	*-6,560*	*-2,168*	*3,708*	*6,276*	*-2,298*
Key Company Metrics						
Sales growth (%)	nm	6.1	-11.3	5.7	12.9	18.5
DB EPS growth (%)	na	-32.8	5.1	3.5	30.2	38.5
EBITDA Margin (%)	30.0	22.4	25.1	25.3	27.8	31.5
EBIT Margin (%)	26.0	17.9	19.6	19.1	21.4	25.1
Payout ratio (%)	34.9	37.1	39.4	41.8	35.1	27.7
ROE (%)	32.5	17.5	18.3	17.0	19.8	23.6
Capex/sales (%)	8.4	11.4	13.2	16.2	15.6	11.4
Capex/depreciation (x)	2.1	2.5	2.4	2.6	2.4	1.8
Net debt/equity (%)	13.3	-7.6	-2.2	3.5	5.2	-1.6
Net interest cover (x)	29.5	9.7	11.3	15.6	19.7	27.4

Source: Company data, Deutsche Bank estimates

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Investment thesis

Outlook

Sasol is an integrated liquid fuel and chemical company with upstream coal, gas and oil assets. Sasol leverages value from coal and gas feedstock through its proprietary coal-to-liquids (CTL) and gas-to-liquids (GTL) technologies in the production of liquid fuels and chemicals. Management is actively seeking expansion opportunities created by its technological positioning.

We forecast strong medium-term cash generation through high leverage to improving oil fundamentals. The expected margin expansion is supported by rationalisations predominantly in the Chemicals cluster and an expected curtailment of cost inflation through reduced dependence on Eskom-sourced power. We expect additional volume contributions from project ramp-ups, improved operational performance, and volume stability in existing assets from committed capex programmes into FY12.

The strong expected cash flows should allow the group further expansion opportunities while maintaining dividend yield levels (c.3.6- 4.0%). Buy.

Valuation

Our valuation includes only existing operations and committed capex. We see further potential upside to our valuation through volume growth, primarily from the China CTL and Uzbekistan GTL projects. We are cautious in including our assessment of the projects' value given the extended period until initial revenue generation and project-specific risks and uncertainties.

We use a discounted cash flow valuation (DCF) as the primary tool in arriving at our price target and investment view on Sasol. We believe this methodology allows us to take a much wider range of fundamental factors into account than would a comparable multiples valuation, which often fails to factor in differences related to capex plans, capital structure, and longer-term growth rates. Our discount rate is based on CAPM. Our one-year target price is derived by rolling our DCF forward at the cost of equity less expected dividend yield.

Our WACC of 12.3% incorporates a debt/equity ratio of 20:80, beta of 1.1x, risk-free rate of 8.5% and an equity risk premium of 4.5%. Our estimates of the cost of debt incorporate our estimates of the South African risk-free rate together with an appropriate corporate credit spread. Our 2.3% terminal growth rate represents a conservative outlook weighted according to Sasol's operational regions and products. Sasol's volume growth is dependent on the successful implementation of carbon sequestration technology and retaining its proven technological advantage.

Risks

Risks include a weaker-than-forecast oil price and a stronger-than-forecast ZAR/USD exchange rate. Delayed project delivery, cost overruns and suboptimal ramp-up are also risks. Sasol has an interest in, and may invest in, various higher-risk-rated countries, including Iran, China and Uzbekistan. Implementation of carbon costing, although remote, is an additional risk. We highlight the additional potential financial leverage risk added to an already highly operationally levered (c.2.2x oil, c.3x ZAR/USD) earnings base, should a rand-oil environment below R525/bbl continue or weaken during the proposed projects' (China CTL and Uzbekistan GTL) financing period. Rising gas prices are a significant downside risk for future GTL.

Executive overview

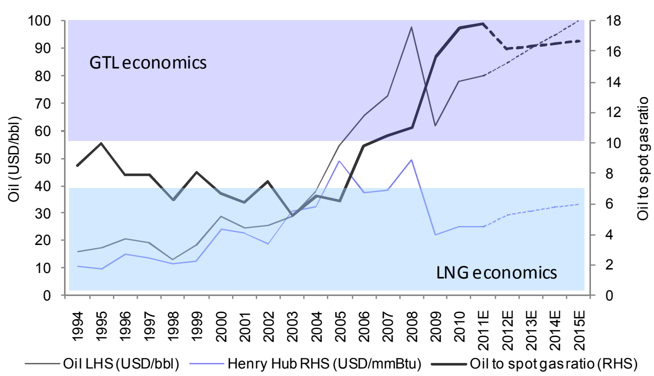
Gas market outlook supports GTL over LNG

Our analysis indicates two key variables in resource holder technological preference:

- The oil to spot gas ratio. As oil prices rise, so does the tendency to favour GTL.
- LNG sales contract terms. Higher levels of oil indexed contract sales support LNG given higher feedstock efficiency, specifically in low oil price environments.

Given the de-coupling of spot gas prices from oil prices in the US and Europe, GTL is expected to be a favoured technology for resource holders dependent on significant LNG volumes forced into either the spot US market or similar non oil indexed markets. LNG is only expected to be favoured where exclusive oil index sales above 14% are contracted, regardless of oil price environment. High levels of oil indexing are limited to the Pacific Basin.

Figure 1: GTL providing diversification options



Source: Deutsche Bank, DataStream

We note that above a 10x oil to spot gas price ratio, a resource holder will prefer GTL over LNG given our assumptions and equal spot and oil indexed sales. We estimate the ratio expands to 12x given 70% oil indexed sales. Deutsche Bank anticipates the oil to spot gas ratio remaining above 16x in the medium term, favouring GTL.

We expect sentiment towards GTL technology to improve greatly given improved operational performances from Oryx and an on-schedule commissioning process at Pearl GTL. The increasing resource holder confidence in GTL technology reliability offers a welcomed diversification of end-market price risk in our view of long LNG markets in the medium term.

Key milestones for GTL to gain significant traction

- Oryx GTL capacity utilisation over 80% reported in CFO letter, expected by end-November.
- Positive investment decision (expected 2011) on Uzbekistan GTL, demonstrating significant end product value uplift is possible outside of Qatar.
- On-schedule commissioning processes (beginning 2011) in Shell’s Pearl GTL facility, suggesting teething problems originally associated with GTL are resolved.
- Sasol announcement of a significant gas acquisition. In our opinion, Sasol would acquire gas for a GTL facility, signalling GTL economics are supported at market priced reserves, effectively removing Sasol’s feedstock constraint.

Oryx and Uzbekistan, positive signals to market

The outlook for Oryx GTL (c.70%of currently operating global capacity) is bright; we expect a step change in FY11E EBIT margins to 60% on increased capacity utilisation (c.85%).

Revisiting Uzbekistan, strong project economics support a positive investment decision up to a gas cost of US$2.6/mmBtu. Sasol has indicated an unlevered target IRR above 18% for the project. Given our assumptions, we calculate a project IRR of c.21% (US$, unlevered) and expected the project to be cash breakeven within four years of commissioning, illustrating the strong cash generation potential in an US$80/bbl oil environment.

The GTL heat map: Options supplemented by unconventional gas

Sasol's GTL expansion will need to either be based on a partnership with a significant gas resource holder or producer, a significant exploration find or a potential resource acquisition.

Identified regions which could be receptive to GTL technology, given their vast gas resources, a need to diversify end product revenues, or infrastructure constraints, include Russia, Central Asia, the Middle East (unlikely in medium term), North Africa and South East Asia, based on conventional reserves. Unconventional gas (tight gas, shale gas and coal bed methane) has transformed the supply/demand landscape. Accordingly, we also see the US, Canada, Indonesia, Australia and Brazil as locations for future GTL projects.

The potential for a gas acquisition or feedstock partnership, focused on the North American market, results from the recent shale gas influence on gas prices and an active M&A market. Recent benchmark transactions have been priced between US$0.2/mmBtu and US$0.9/mmBtu on a total resource basis at an average cost of c.US$0.6/mmBtu, within the range of Sasol's funding capabilities, effectively removing the existing feedstock constraint.

Sasol's un-geared balance sheet, coupled with strong expected cash flow generation, allows various combinations of securing significant feedstock (3tcf) and funding additional attributable (c.50,000bbl/b) capacity, without compromising currently proposed growth projects (China CTL and Uzbekistan GTL).

Potential US GTL, biting at the bit

A potential partnership with North American shale gas producers is increasing in probability considering a depressed gas price outlook, with gas-weighted independents looking increasingly distressed. Our analysis indicates GTL technology is capable of yielding favourable project IRRs across the majority of the US gas resource.

A partnership securing gas feedstocks and price visibility for Sasol would allow the resource holder to benefit from the recent expansion in the US oil to gas ratio, diversify revenue streams and reduce exposure to our view of suppressed US gas prices medium term.

Our analysis suggests a North American GTL facility will return a c.15% IRR (US$, unlevered) in an US$80/bbl oil environment at a purchased real gas price of up to c.US$4.7/mmBtu, over c.30% above current spot prices. Based on post tax breakeven shale gas production costs, GTL economics are supported in oil environments ranging from c.US$64/bbl for the Eagle Ford shales to c.US$87/bbl for Antrim. We do not expect short-term GTL activity in these two regions as Eagle Ford and Antrim both offer limited current production and commercial reserve holdings.

We highlight Haynesville and Marcellus as key potential partnership regions as:

- supportive GTL economics, returning Sasol's hurdle rate of c.US$75-80/bbl oil on current post tax gas production costs,
- vast potential recoverable reserves and with gas breakeven costs above spot price levels.

Key players in the region with 2P reserves above 3tcf include Chesapeake, Encana, Shell, PetroHawk and Range. CONSOL and Statoil hold significant acreages in the region. The extent to which GTL technology delivers robust returns is clearly dependent on the oil price environment; we expect significant interest in GTL technology given an above c.US$80/bbl consensus, long-term oil outlook.

Gas market outlook supports GTL over LNG

In this section, we analyse resource holder optionality between LNG and GTL technology. With global LNG markets in oversupply over the last 12-18 months due to weak economic conditions, spot indexation of LNG pricing has grown in prominence. While North American LNG is generally sold at posted prices into key hubs, most gas in Europe and Asia has traditionally been sold under long-term contracts indexed to oil. The availability of spot gas, coupled with questions as to whether oil is the most relevant substitution benchmark for gas, has led to speculation that Europe is heading away from oil indexed pricing.

Our analysis indicates two key variables in technological preference;

- The oil to spot gas ratio. As oil prices rise, so does the tendency to favour GTL.
- The LNG contract terms. Higher levels of oil indexed contract sales supports LNG given higher feedstock efficiency, specifically in low oil price environments.

We expect GTL to be favoured where significant LNG volumes are forced into spot markets.

The GTL concept

Conceptually, the GTL process is simple. It involves taking the most basic natural gas hydrocarbon molecule (methane or CH4) and polymerising it to make longer chain hydrocarbons, the length of which is determined by the process conditions and the catalyst used. From here, the long chain molecules can be further altered to produce a slate of high value, colourless, odourless, liquid hydrocarbons (diesel, naphtha, base oils, etc) with exceptionally low levels of impurity (sulphur, nitrogen, benzene, etc). The result is a differentiated, high performance fuel and substantial value uplift on the natural gas feedstock. In effect, the process results in the production of several of the highest value end-products of a refinery but without the need to actually build a refinery itself. Further details of the GTL process are provided in Appendix A.

The GLT process is very energy intensive with around 40% of feedstock gas utilised as fuel (compared with nearer 15% in LNG). Access to an inexpensive and substantial source of natural gas is, consequently, a pre-requisite. Only Shell and Sasol have proven commercial GTL technology which competes directly for feedstock with LNG and direct gas sales into both spot and oil indexed markets.

Basic economics and GTL's place in the global gas market

The output slate from the GTL process, combined with strong financial results (EBIT margin c.44% in FY10) from Sasol's Oryx GTL JV despite poor capacity utilisation (refer to pg 17 for Oryx economics), illustrates that at crude oil prices above c.US$60/bbl, GTL production can be very profitable. In large part this reflects the financial benefits that come from realising oil-related pricing from a natural gas feedstock that has, historically, traded at a significant discount to oil on an energy-equivalence basis.

Value uplift on a per day basis from producing 1bbl/d GTL from 10mmBtu
The broad value uplift on a per day basis from producing 1bbl/d of high value fuel products from natural gas, assuming an opportunity cost equivalent to the net revenue that would currently be achieved from the sale of that gas as LNG in the North American market at a 4.5US$/mmBtu landed price, is illustrated by Figure 2. This is then compared with the uplift

that would be achieved from refining the equivalent volume of oil at US$80/bbl, assuming an US$8/bbl refining margin. Not surprisingly, because of the higher value output slate and lower relative cost of the input stream, end product values and value uplift are higher in GTL.

Having said this, equally apparent is that to the extent oil linkage can be obtained from the straight sale of natural gas as LNG at an oil parity price (as was the case through much of 2008), production of LNG could derive better economics for the low cost resource holder. In large part this reflects the fact that, even though the end product value of 'oil-parity' LNG may not be as great as that of the GTL product stream, considerably less energy is required in the liquefaction process (i.e. only around 15% of the feed gas in LNG production is required as energy, compared to nearer 40% in the GTL process).

Based on FY11E gas (US$4.5/mmBtu) and oil (US$80/bbl) price forecasts

Figure 2: GTL produces a premium product stream from a discount input source

Input	Process	Output	Value uplift
Natural gas (LNG) to US market	GTL	Diesel/naphtha***	
10mmBtu/d	→	1bbl/d	
Daily revenue US$25.5*		US$96	+275%
Natural gas (LNG) oil index of 15% (US$80/bbl)	GTL	Diesel/naphtha	
10mmBtu/d	→	1bbl/d	
Daily revenue US$89.5		US$96m	+8%
Crude oil	Refining	Refinery slate**	
1b/d	→	1bbl/d	
Daily revenue US$80		US$88	+10%

* Assuming a US$3mmbtu netback from Hub (i.e. post shipping & re-gas of c.US$1.50) and 15% gas used in LNG process
** assuming a US$8/bbl refining margin (simple)
*** 20% premium assumed for GTL products over oil.
Source: Deutsche Bank

GTL presents the resource holder diversification of end-market price risk

The latter point suggests that in the event oil-parity pricing can be achieved on long-term LNG contracts, GTL would have limited appeal for the lowest cost resource holder. As the significant weakening in contract LNG pricing has illustrated over the past 24 months, this is not something that should, however, be taken for granted. Indeed, if anything, with LNG markets now looking likely to remain in over-supply for at least the next three to four years, for the gas-market dependent Qataris, having exposure to oil product markets through GTL rather than gas markets has almost certainly represented a much welcome diversification of their end-market price risk.

Reserve holder optionality: GTL adding value to the bottom line

GTL expected to be favoured where resource holders are dependent on LNG sales into non oil indexed markets

To further illustrate the point in the previous section, we have assessed the theoretical net revenue per 10mmBtu gas feedstock. In doing so, we have accounted for the differences in technology costs (assumptions summarised in Figure 5), excluding gas feedstock costs, which allows the resource holder equal optionality on GTL or LNG.

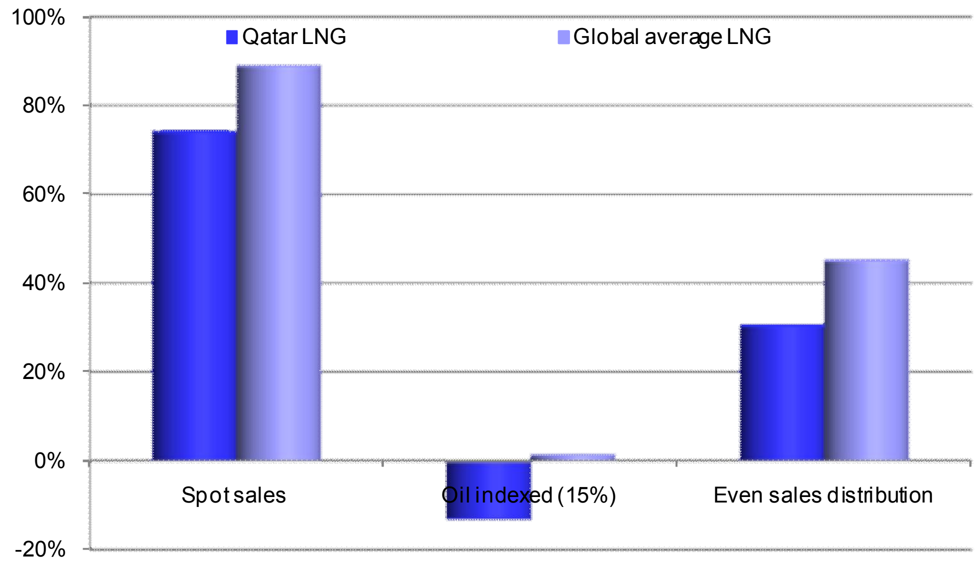
The LNG advantage in oil indexed pricing for low cost producers, such as the Qataris, is again evident. This, however, becomes increasingly marginal as we approach the global average LNG producer, suggesting that individual project economics and LNG contract terms are critical. The current appeal of GTL is largely attributed to the recent de-linkage between spot gas and oil prices, with our analysis suggesting GTL is a favoured technology where resource holders are dependent on significant LNG sales mix to the US or other non oil index markets (Figures 3 and 4).

Figure 3: GTL products relative to LNG, given zero well head gas cost, hence resource holder optionality at US$80/bbl oil

	Net revenue US$/bbl			GTL product value premium %		
	Qatar LNG	Global average LNG	GTL	Qatar LNG	Global average LNG	GTL
US market sales (spot)	19	8	73	74	89	0
Oil indexed (15%) sales	**83**	**72**	**73**	**-13**	**1**	**0**
50:50 sales mix	51	40	73	31	45	0

Source: Deutsche Bank

Figure 4: GTL products net profit premium relative to various LNG sales markets



Source: Deutsche Bank

Assumptions

The key assumptions used to determine GTL products' net profit premium to LNG are summarised in Figure 5 and supported in Appendix C.

Figure 5: Key assumptions used

Assumption	Value	Unit	Assumption	Value	Assumption	Value	Unit
Transportation and regas costs	1.5	US$/mmBtu	GTL gas efficiency	60%	Oil price, FY11E	80	US$/bbl
Henry Hub spot, FY11E	4.5	US$/mmBtu	LNG gas efficiency	85%	GTL opex	14	US$/bbl
Global avg LNG opex	1.5	US$/mmBtu	Oil price indexing	15%	Global avg LNG/GTL capex	9	US$/bbl
Qatar LNG opex	0.25	US$/mmBtu	GTL product premium	20%	Qatar LNG capex	5.3	US$/bbl

Source: Deutsche Bank

The swing factor: Spot sales and oil indexed contracts

Our analysis indicates two key variables in technological preference;

- The oil to spot gas ratio. As oil prices rise, so does the tendency to favour GTL.
- The LNG contract terms. Higher levels of oil indexed contract sales supports LNG given higher feedstock efficiency, specifically in low oil price environments.

Given the de-coupling of spot gas prices from oil prices in the US and Europe, GTL is expected to be a preferred technology for resource holders dependent on significant LNG volume sales to a spot US market or similar non oil indexed markets, based on our oil to gas ratio forecasts.

Europe is heading away from oil indexed pricing

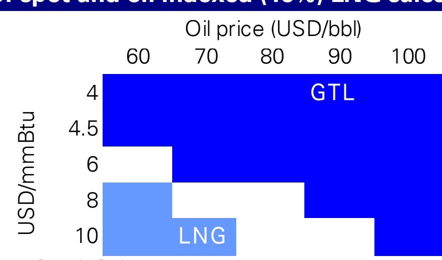
With global LNG markets in oversupply over the last 12-18 months due to weak economic conditions, spot indexation of LNG pricing has grown in prominence. While North American LNG is generally sold at posted prices into key hubs, most gas in Europe and Asia has traditionally been sold under long-term contracts indexed to oil. The availability of spot gas, coupled with questions as to whether oil is the most relevant substitution benchmark for gas, has led to speculation that Europe is heading away from oil indexed pricing. Figure 6 illustrates the relative technology preferences assuming equal LNG sales into both 15% oil indexed and spot markets.

High levels of oil indexing is not the rule

Wood Mackenzie does not see LNG pricing moving away from oil indexation in the Pacific Basin in the foreseeable future, which looks set to remain a long-term contract market with pricing linked to oil. Wood Mackenzie believes recent deals have been signed towards the upper end of a 14-15% JCC (Japan Customs-cleared Crude) range. The exception has been two MOUs between Qatar and China believed to be 16% JCC + 0.575, highlighting a continued Qatari strategy for high–priced, long-term contracts into the Pacific Basin. Under these contract terms LNG is the favoured technology regardless of oil price environment (Figure 7). Again, high levels of oil indexing is not the rule (refer to Figures 8 and 9).

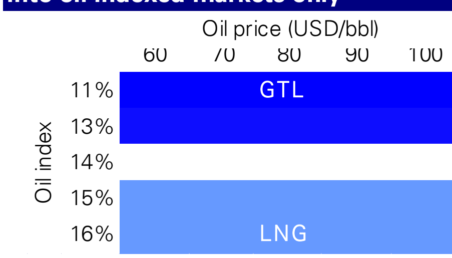
We highlight a preference for a given technology where the net revenue premium is 10% higher than the relative.

Figure 6: Relative economics, equal ratio of spot and oil indexed (15%) LNG sales



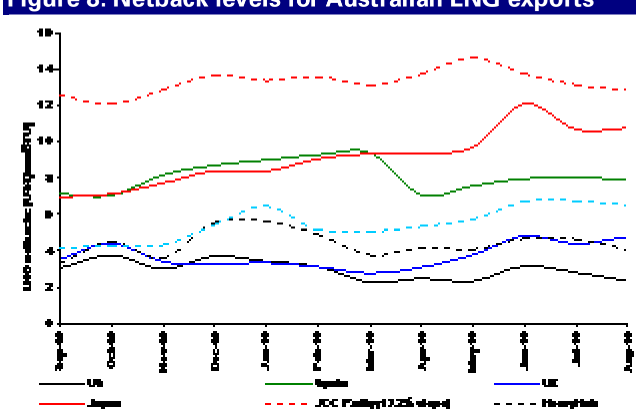
Source: Deutsche Bank

Figure 7: Relative economics, LNG sold into oil indexed markets only



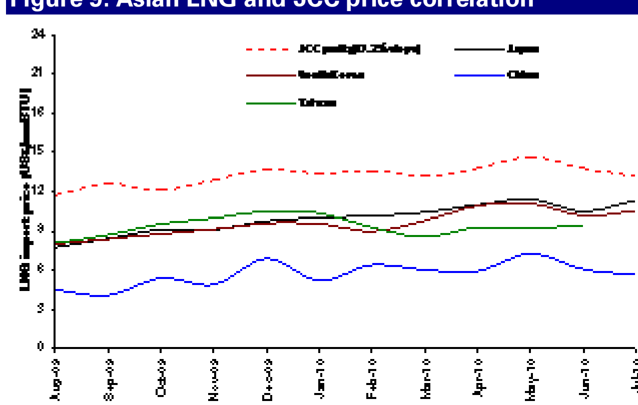
Source: Deutsche Bank

Figure 8: Netback levels for Australian LNG exports



Source: Deutsche Bank, Bloomberg Finance LP, World Gas Intelligence

Figure 9: Asian LNG and JCC price correlation



Source: Deutsche Bank, Bloomberg Finance LP, World Gas Intelligence

Expanding Figure 6, we can assess the relevant oil to associated spot gas ratio which would lead to a resource holder favouring a particular technology. The values in the table below represent the theoretical net profit of GTL products relative to LNG (a value of 1 represents equivalent net profit), considering differences in capex and operating costs. We have based our calculations on the economics of a low-cost LNG producer, proxied by Qatar LNG in the summarised assumptions. Again, we have not considered gas costs to demonstrate the relative preference of the resource holder. The net back revenue allows for an even mix of sales into both a spot (referenced to Henry Hub) and oil indexed oil price market (15%). We have allowed for a 10% middle ground for flexibility in assumptions.

Figure 10: Relative economics, low cost LNG sold equally into spot and oil indexed market

Henry Hub gas prices (USD/mmBtu) \ Oil price (USD/bbl)	45	50	55	60	65	70	75	80	85	90	95	100
4	1.18	1.26	1.32	1.37	1.41	1.45	1.48	1.50	1.53	1.55	1.57	1.58
4.5	1.09	1.17	1.24	1.29	1.34	1.38	1.41	1.44	1.47	1.49	1.51	1.53
5	1.02	1.10	1.17	1.22	1.27	1.31	1.35	1.38	1.41	1.44	1.46	1.48
5.5	0.95	1.03	1.10	1.16	1.21	1.26	1.29	1.33	1.36	GTL	1.41	1.43
6	0.89	0.98	1.05	1.11	1.16	1.20	1.24	1.28	1.31	1.34	1.37	1.39
6.5	0.84	0.92	0.99	1.05	1.11	1.15	1.20	1.23	1.27	1.30	1.32	1.35
7	0.79	0.88	0.95	1.01	1.06	1.11	1.15	1.19	1.22	1.26	1.28	1.31
7.5	0.75	0.83	0.91	0.97	1.02	1.07	1.11	1.15	1.19	1.22	1.25	1.27
8	0.72	0.80	0.87	0.93	0.98	1.03	1.07	1.11	1.15	1.18	1.21	1.24
8.5	0.68	0.76	0.83	0.89	0.95	0.99	1.04	1.08	1.11	1.15	1.18	1.21
9	0.65	0.73	0.80	0.86	0.91	0.96	1.01	1.05	1.08	1.12	1.15	1.17
9.5	0.62	LNG	0.77	0.83	0.88	0.93	0.97	1.01	1.05	1.09	1.12	1.15
10	0.60	0.67	0.74	0.80	0.85	0.90	0.95	0.99	1.02	1.06	1.09	1.12
10.5	0.58	0.65	0.71	0.77	0.83	0.87	0.90	0.96	1.00	1.03	1.06	1.09

Source: Deutsche Bank

As the oil price increases, so does the relative attractiveness of GTL over LNG. The oil to spot gas ratio is consistent along the frontier for a referenced technology, varying according to the ratio of spot to oil indexed sales (summarised in Figure 11).

Figure 11: Technology preference determined by oil to spot gas ratio

Oil indexed sales %	Oil indexing %	Spot sales %	Spot proxy	LNG economics supportive	GTL economics supportive
40	15%	60%	Henry Hub	7	9
50	15%	50%	Henry Hub	7	10
60	15%	40%	Henry Hub	7	11
70	15%	30%	Henry Hub	7	12

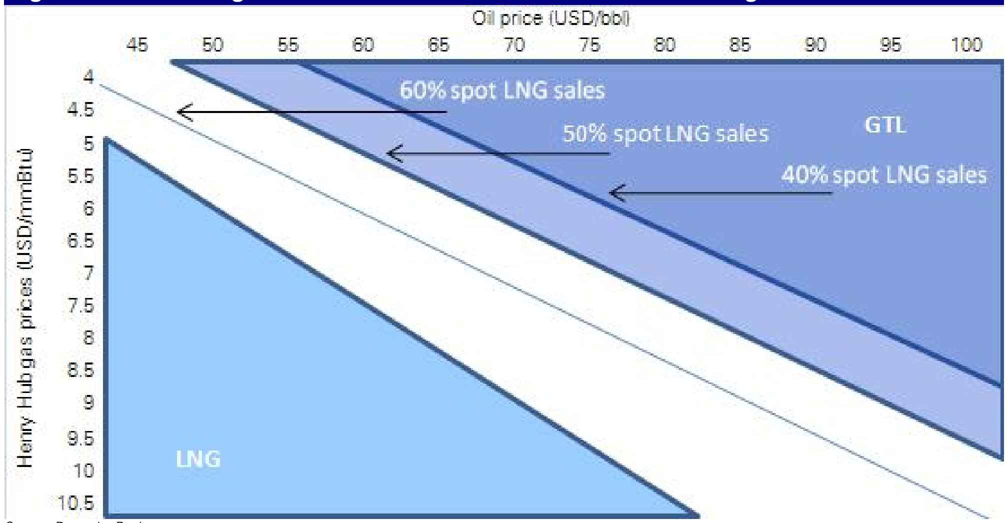
Source: Deutsche Bank

We note that above a 10x oil to spot gas ratio, a resource holder will prefer GTL given our assumptions and equal spot and oil indexed sales. Increasing sales volumes into an oil indexed market logically increases the oil to gas ratio that would tend to favour LNG. We note the LNG favoured ratio change is muted, suggesting individual project economics become increasingly relevant in monetising gas reserves as the marginal economic region expands. This is broadly illustrated in Figure 12.

Only Shell and Sasol have proved GTL technology

Currently only Shell and Sasol have GTL technology proved on an economic scale and are positioned to benefit from the currently elevated oil to spot gas ratio. Deutsche Bank forecasts the oil to spot gas ratio to remain above 16x through 2015E.

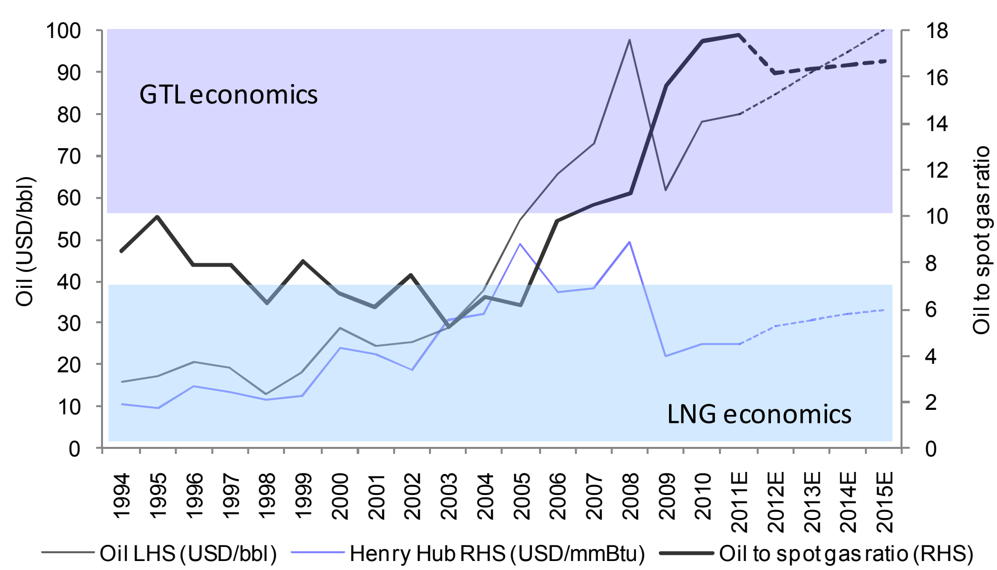
Figure 12: Increasing the oil indexed sales mix increases the marginal economic zone



Source: Deutsche Bank

The de-coupling of gas from oil prices in spot markets is a recent (post-2008) event. We expect sentiment towards GTL technology to improve greatly given improved operational performances from Oryx and an on-schedule commissioning process at Pearl GTL. The increasing resource holder confidence in GTL technology reliability offers a welcome diversification of end-market price risk in our view of long LNG markets into 2020 (refer to the following section).

Figure 13: Expansion in oil to spot gas ratio expected to continue, favouring GTL



Source: Deutsche Bank, DataStream

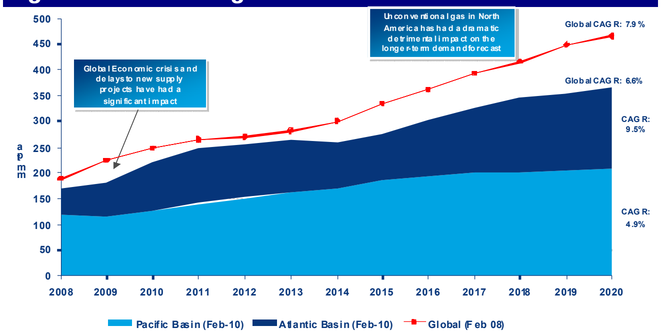
As spot gas is proxied by the US market, the most important downside risk to future GTL expansion is potential spot gas price growth (outside US). This would have a similar effect to raising the proportion oil indexed sales levels. Although not our base case, in the event that global-ex US spot gas prices reach a 15% oil indexed level, the oil to spot gas ratio as defined would need to be above 12x assuming 30% non oil indexed sales to support GTL economics over LNG.

Global outlook for LNG: oversupplied

LNG extracts: Global Gas: Battlefield Analysis, published 13 September 2010

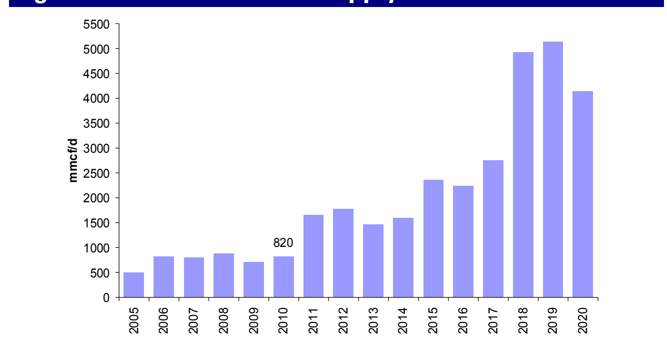
Using a bottom-up view of LNG demand shows that forecasts have been cut on the global economic slowdown and development of unconventional gas in the US. The global LNG demand outlook has weakened considerably over the last two years, but LNG will force itself into the market regardless. When project growth in supply is added to the more muted demand outlook, a major growing surplus in supply is evident.

Figure 14: Forecast global LNG demand



Source: Deutsche Bank

Figure 15: Global LNG oversupply



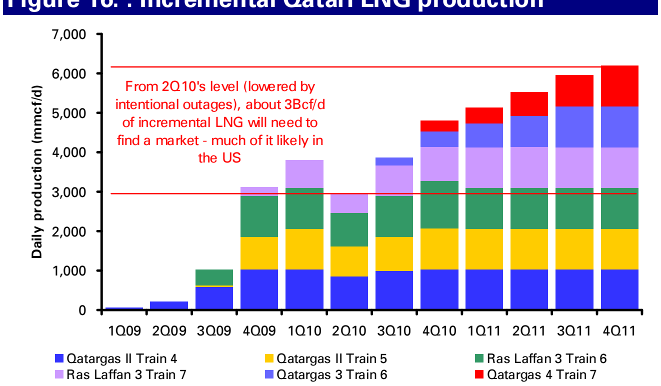
Note: Excludes speculative supply and demand. Includes existing, proposed imports and imports under development
Source: Wood Mackenzie, Deutsche Bank

LNG oversupply allows for diversification into GTL

From a global perspective, the LNG market appears to be long to 2020. Capacity from operating projects plus projects currently under construction appear to exceed forecast demand. This is expected to keep global spot gas prices at current low levels, and maintain the pressure of flows of LNG into the liquid North American and European markets. These markets do not physically need the LNG, but will use it to cut more expensive gas. Some currently operating projects may elect to reduce production, especially in Indonesia where reserves and domestic requirements are uncertain.

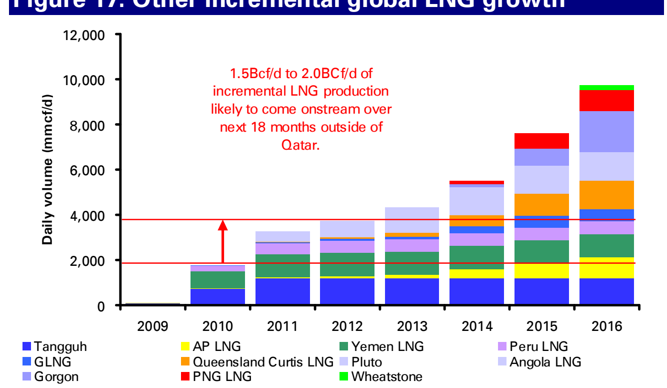
The threat here is the LNG at the margin, particularly from Qatar, which is about to ramp up on a major scale, with around 3-4Bcf/d of growth from Qatar alone over the period from 2Q10 to 4Q11. Other global LNG projects will likely contribute another 1-2Bcf/d of incremental production over the next 18 months, thus bringing total new LNG supply over this upcoming six quarter period to about 5Bcf/d.

Figure 16: : Incremental Qatari LNG production



Source: Wood Mackenzie, Company data, Dow Jones, Deutsche Bank estimates

Figure 17: Other incremental global LNG growth



Source: Wood Mackenzie, Company data, Dow Jones, Deutsche Bank estimates

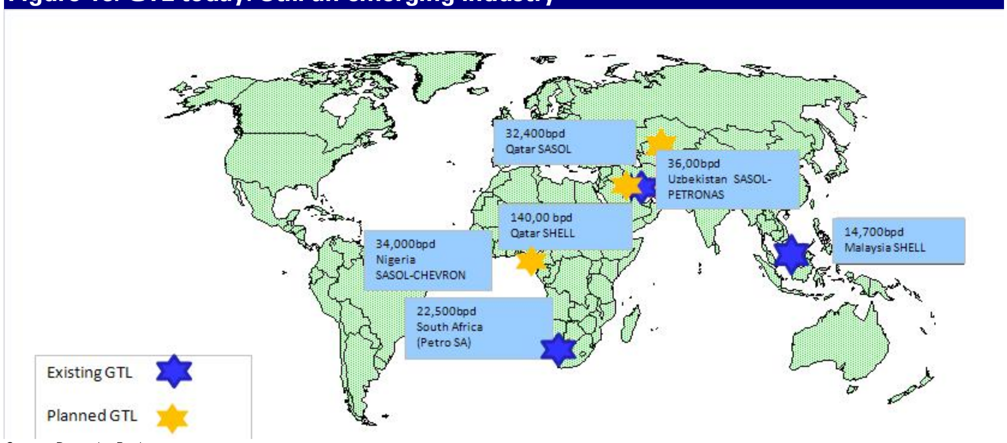
Sentiment on GTL technology improving, Oryx and Pearl key

GTL's rapid expansion dependent on Oryx and Pearl

GTL's future role in energy markets is likely to depend heavily on the direction of future oil prices and the extent to which technology can bring down the associated capital costs. In the near term, however, its role in energy markets is likely to be determined more than anything by the success or otherwise of both Sasol's and Shell's development projects. If technologies are proven here and costs contained at budgeted levels, considerable enthusiasm could follow. Oryx's initial teething problems are broadly expected to have been left behind and we anticipate c.85% capacity utilisation for FY11E.

Although it is now almost 90 years since the discovery of the Fischer-Tropsch (FT) process, the commercialisation of GTL remains very much in its infancy. To date, only three plants are operating commercially, Petro SA's 22.5kb/d in South Africa, Shell's 14.7kb/d Bintulu plant in Malaysia and Sasol's recently built 32kb/d Oryx facility in Qatar.

Figure 18: GTL today: Still an emerging industry



Source: Deutsche Bank

Only Sasol and Shell have commercial scale technology

With the exception of Shell, Sasol and Chevron (through access to Sasol's technology via the Sasol-Chevron JV in the construction of Escravos GTL), none of the major oil and gas companies has technology that has been proven on a commercial scale. Although Exxon, BP and Conoco all claim to have GTL technology, it is unclear at this time whether their technology is sufficiently advanced to be applied in a large scale, commercial facility. This has been emphasised following decisions by Conoco and Marathon in recent years to abandon planned Qatari GTL projects and Exxon's more recent 2007 decision not to proceed with a planned 154kb/d GTL facility, again in Qatar.

Figure 19: GTL plants globally, little competition for Sasol and Shell

Name	Company	Location	Start-up	Capacity (bbl/d)	Comment
Mossgas	Petro SA	South Africa	1993	22,500	Producing
Sasolburg	Sasol	South Africa	1993	2,500	Producing
Bintulu	Shell	Malaysia	1993	14,700	Producing
Alaska	BP	USA	2002	300	Pilot
Oklahoma	Conoco	USA	2002	400	Pilot
Oryx	Sasol	Qatar	2007	32,400	Catalyst disappoints
Planned					
Pearl GTL	Shell	Qatar	2012	140,000	Costs triple
Escravos	Sasol-Chevron	Nigeria	2012+	34,000	Delayed
Uzbekistan	Sasol-Uzbekneftegaz-Petronas	Uzbekistan	2015+	36,000	Investment decision expected 2011
On hold/cancelled					
Tinrhert GTL	Under bid	Algeria	n/a	36,000	Postponed (cost)
Palm	Exxon	Qatar	2012+	154,000	Cancelled (costs)
n/a	Conoco Phillips	Qatar	2010	80,000	Cancelled
n/a	Marathon	Qatar	2010	120,000	Cancelled

Source: Deutsche Bank, Wood Mackenzie

It is difficult to pin-point or quantify the technical risks surrounding Pearl. What must be recognised, however, is the sheer scale of the project as well as the complexity of the engineering. Not only does the start-up of Pearl require the smooth introduction of around 20 FT reactors, but it also involves the successful commissioning of a multitude of offshore facilities, gas processing plants, combined heat and power facilities and air separation units, to name but a few. Nevertheless, Shell will rightly argue that in contrast to Sasol, it has been running a commercial 14.7kb/d GTL facility at Bintulu in Malaysia for close to two decades and that its catalyst is proprietary, uses a different technology to that of Sasol (cobalt tubular trickle bed versus Sasol's larger cobalt slurry bed) and is tried and tested.

We believe Oryx's improved performance is attracting significant interest globally

We believe that Oryx's improving operational performance (excluding an unplanned shutdown in FY10 unrelated to the GTL technology) is attracting significant interest in the technology globally as, for the resource holder, GTL also offers the potential to reduce its dependence on international gas prices and gain greater exposure to the higher value oil products, not least diesel and lubricants, thereby diversifying its risk. Refer to pg17 for details of Oryx's performance.

Equally, for the integrated oil company, the high quality of the output slate offers the opportunity to market a high performance, differentiated fuel that because of its purity (no sulphur, no metals) burns more cleanly and with limited particulate emissions.

GTL fuel represents a cleaner, unconventional fuel

The GTL product slate, although variable according to catalyst technology, is primarily diesel and naphtha. Diesel is far more energy efficient than petrol and contributes to the drive to reduce carbon dioxide emissions in the transportation sector.

Figure 20: Difference between product slate of a refinery and Qatari GTL projects – with no low value fuel oil produced the GTL slate is of far greater value

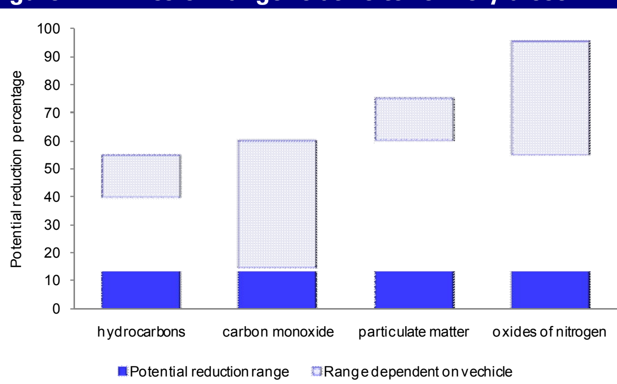
	Traditional crude slate	Shell GTL slate	Sasol GTL slate
Raw material	Crude oil	Natural Gas	Natural Gas
Process	Refinery		
	Product slate	Product slate	Product slate
LPG	3%	3%	3%
Naphtha	7%	28%	26%
Gasoline	27%	0%	0%
Middle distillate (diesel)	40%	54%	71%
Fuel oil	21%	0%	0%
Lubricants/waxes	2%	15%	0%

Source: Deutsche Bank

GTL diesel is of significantly higher quality, proving environmentally superior to conventional diesel

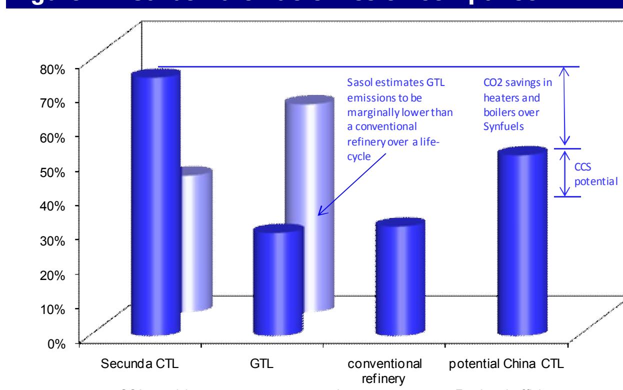
GTL diesel is of significantly higher quality than diesel derived from crude oil. GTL diesel has a high cetane number (at least 70 compared with a 45-55 rating of most diesels), low sulphur (less than five parts/million), low aromatics (less than 1%), and good cold flow characteristics, which can be optimised to suit specific applications. GTL diesel is positioned as a clean, premium product or as a blend stock to enhance the quality of conventional diesels. Emission benefits vary depending on vehicle type and its technological level. The reductions in emissions are illustrated in Figures 21and 22.

Figure 21: Emission range relative to refinery diesel



Source: Deutsche Bank, company data

Figure 22: Carbon dioxide emission comparison



Source: Deutsche Bank, company data

Sasol's GTL performance looking bright

In this section we assess the existing and proposed GTL projects (Oryx and Uzbekistan GTL). The outlook for Oryx is bright; we expect a step change in EBIT margins on increased volumes, a positive technological signal to the market.

Revisiting Uzbekistan, strong project economics support a positive investment decision, reinforcing the merits of GTL.

Outlook for Oryx

Oryx GTL, a 51% Qatar Petroleum and 49% Sasol Joint Venture, purchases gas from Al Khaleej (a joint venture between ExxonMobil Middle East Gas Marketing Limited and Qatar Petroleum) under a minimum take or pay agreement. The gas supply contract expires in 2031, but is extendable for a further seven years.

We expect the gas agreement was signed at US$0.5/mmBtu, which increases equally proportioned to US inflation and oil price movements, as is common in the region. Adjusting for US inflation and the oil price differential, we estimate a current gas price of c.US$1.2/mmBtu. The low cost feedstock advantage Oryx enjoys is reflected in strong operating results (44% EBIT margin) despite only c.60% capacity utilisation.

We anticipate a robust operational performance from Oryx GTL into the future following the resolution of initial teething problems delaying volume ramp-up (in short, unexpected levels of impurities or 'fines' in the feed-gas entering the Oryx FT reactors corrupted the catalyst and, despite certain process improvements, have resulted in two years of sub-optimal production levels).

Capacity utilisation at c.85% in FY11E, we expect a step change in operating margin to c.60%

With production capacity anticipated at c.85% in FY11E, we expect a step change in operating margin to c.60%, a direct result of operating cost on an absolute basis showing muted increases. Operating costs consist of the fixed volume take or pay gas agreement and essentially fixed labour and catalyst costs.

Figure 23: Step change in EBIT margin through improved capacity utilisation

	2007	2008	2009	2010	2011E	2012E	2013E	2014E	2015E
Production capacity (kbd)	32.4	32.4	32.4	32.4	32.4	32.4	32.4	32.4	32.4
Nameplate production %	5	30	67	57	85	85	85	85	85
Production (kbd)	1.6	9.7	21.7	18.3	27.5	27.5	27.5	27.5	27.5
Ktons sold	221	221	508	426	642	642	642	642	642
Sasol revenue (Rm)	142	1,571	2,885	2,350	3,184	3,714	4,443	5,123	5,504
Sasol EBIT (Rm)	(307)	366	1,305	1,045	1,895	2,265	2,741	3,210	3,497
Operating margin %	-216	23	45	44	60	61	62	63	64

Source: Deutsche Bank, company data

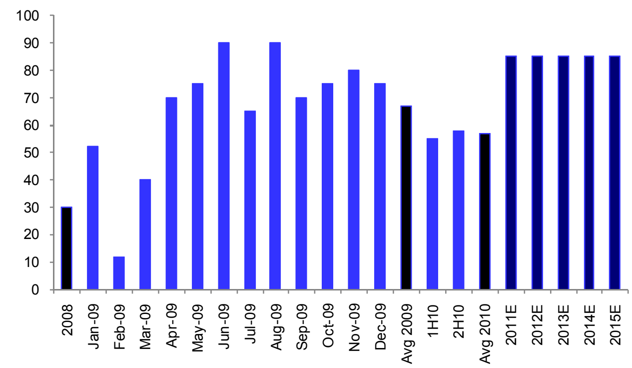
Oryx's improved operational performance will attract significant interest in the technology globally, in our view. Plant performance in FY10 was affected by technical issues unrelated to the GTL technology (a result of a failure in a vendor-supplied air compressor unit) combined with one month of planned statutory maintenance work.

Original gas contract allows for c.10% volume expansion

Sasol's gas contract allows for the original 34kbbl/d nameplate production capacity to be utilised. As such, Sasol could increase production from the current capacity of 32,4kbbl/d. The expansion project is expected to be completed in 2013, but we have been cautious in not giving Oryx the additional volume benefit until the guided c.80-90% capacity utilisation level is consistently achieved (Figure 24).

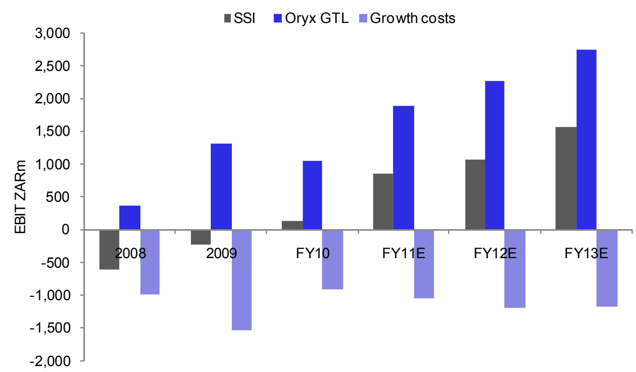
The operational performance of Oryx is incorporated in the Sasol Synfuels division, part of the International Energy cluster. As such, the expected improvement in margins is largely diluted by growth-funding activities within the synthetic fuels expansion programmes combined with existing catalyst plant expenditure. The main growth programmes relate to China CTL and the Uzbekistan GTL project. We anticipate stable c.R1bn growth and catalyst plant expenditure in the medium term (Figure 25).

Figure 24: Plant utilisation expected to stabilise at c.85%



Source: Deutsche Bank, company data

Figure 25: Oryx profits funding potential fuel growth



Source: Deutsche Bank, company data

Proposed Uzbekistan GTL

In April 2009, Sasol, Uzbekneftegaz and Petronas signed agreements to evaluate the feasibility of GTL and up-stream co-operation in Uzbekistan. The project feasibility study commenced on 15 July 2009 and an investment decision is expected in 2011.

Impact on Sasol is far less substantial than the positive market signal

The project has the ability to increase Sasol's attributable synthetic fuel capacity by c.10% and overall group volumes by c.2%. The muted overall impact is a result of Sasol's 33% effective interest in the proposed project. The volume impact on the group is far less substantial than the positive market signal following an investment decision which could serve as a catalyst for accelerated global GTL volume growth, in our opinion.

Given our assumptions, summarised in Figure 26, we anticipate a positive investment decision based on our calculated project IRR of c.21% (US$, unlevered). Sasol has indicated an unlevered target IRR above 18% for the project.

Figure 26: Key assumptions for Uzbekistan GTL

Assumption	Value	Unit
Capex	2,500	US$m
Ownership %	33	
Operating capacity	36,000	bbl/d
Capacity utilisation %	85	
First products	Year 5	Years
Stable operation	Year 6	Years
Gas feedstock cost	1.5	US$/mmBtu
Production cost	12.5	US$/bbl
Cash production costs	**28**	**US$/bbl**
Depreciation	9	US$/bbl
Total costs	**37**	**US$/bbl**
Carbon capture cost	0	US$/bbl
Corporate tax rate %	20	pa
Gas Inflation %	3.0	pa
General Inflation %	6.0	pa
Oil forecast FY11E	80	US$/bbl real
Premium diesel refining margin	16	US$/bbl
Naphtha margin	2	US$/bbl
Project NPV10	2,556	
Project IRR	**21.2**	**%**
NPV10	1.4	US$/Sasol share
NPV10	11.0	R/Sasol share
Oil price for 15% IRR	**60**	**US$/bbl real**

Source: Deutsche Bank

We estimate the project to meet the minimum hurdle rate (18%) in a c.US$70/bbl oil environment and return WACC at c.US$45/bbl. Our gas price assumption of US$1.5/mmBtu escalates in equal proportions to US inflation and oil price movements. Although our assumed gas price is at a significant discount to a potential European net back price, Uzbekistan has limited export potential given infrastructure restraints and competition from Turkmenistan and Russia. Refer to Central Asia Focus, pg 37 for regional details.

Gas cost of c.US$2.6/mmBtu returns the hurdle rate (18%)

Given Uzbekistan's significant equity participation in the project we believe the reduced gas feedstock cost is reasonable in light of attracting foreign investment combined with increased tax revenue supplementing the expected c.21% IRR on the equity participation. We note a gas feedstock cost of c.US$2.6/mmBtu returns the hurdle rate (18%) at US$80/bbl oil and our assumed cost is above our expected production costs. Refer to Figure 27 for oil and gas feedstock sensitivities on NPV and IRR.

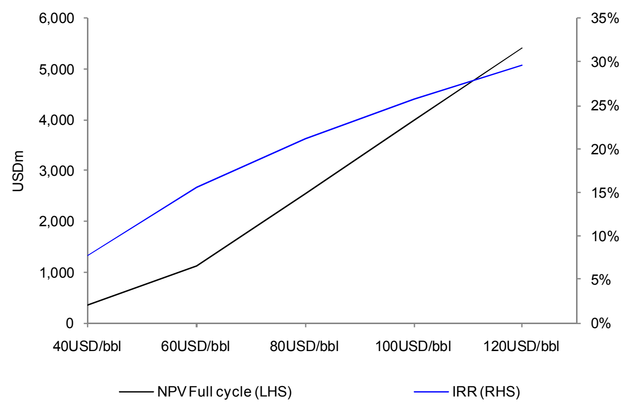
Figure 27: Oil and gas sensitivity to NVP and IRR

	Oil price US$/bbl					US$10/bbl	Gas cost (US$/mmBtu) in US$80/bbl oil			
	40	**60**	**80**	**100**	**120**	**delta**	**1.5**	**2.6**	**3.6**	**4.85**
NPV full cycle US$m	345	1,117	**2,556**	3,989	5,418	716.5	**2,556**	1,721	959	0
IRR %	7.7	15.6	**21.2**	25.7	29.6	2.3	**21.2**	18.0	15.0	10.0

Source: Deutsche Bank

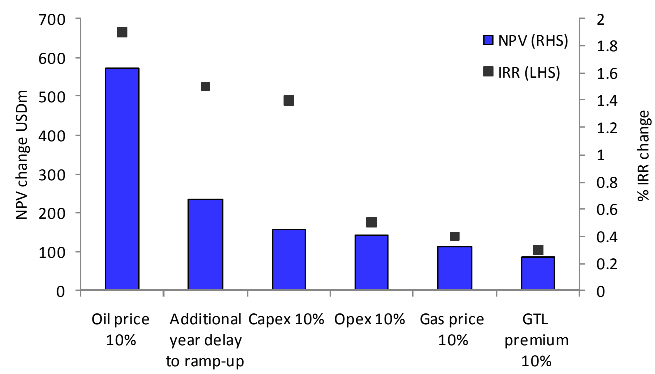
As might be expected for GTL projects, the oil price environment is the most sensitive variable (Figures 28 and 29). We estimate that a 10% movement impacts project NPV by c.US$572m and IRR by 1.9%. Delays to project ramp-up remain a concern and we estimate a potential c.US$270 negative NPV and c.1.5% IRR impact respectively for an additional year delay in reaching operating volume capacity (c.85%).

Figure 28: IRR and NPV sensitivity to key driver, oil



Source: Deutsche Bank

Figure 29: Key variable sensitivities

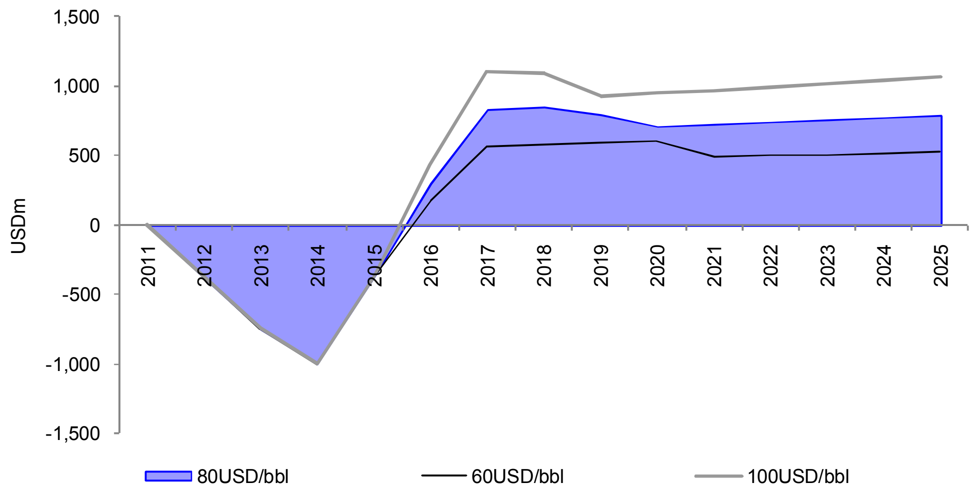


Source: Deutsche Bank

We expect the project to be cash breakeven within four years of commissioning given the strong cash generation potential in an US$80/bbl oil environment (Figure 30).

The project is not expected to significantly impact Sasol's gearing levels as the total financial commitment (33% of c.US$2.5bn) represents only c.15% of Sasol's committed capex at end FY10.

Figure 30: Cash flow forecast for Uzbekistan GTL



Source: Deutsche Bank

Sasol's feedstock hurdle

Sasol's GTL expansion will need to either be based on a partnership with a significant gas resource holder (as is the case with Oryx GTL in Qatar and the potential Uzbekistan project), a significant exploration find or a potential resource acquisition.

GTL is capable of yielding favourable IRRs while diversifying revenues across the majority of the US gas resource.

In this section we identify potential partnerships with resource holders via a global heat map and assess the potential for a gas acquisition focused on the North American market given the recent shale gas influence on gas prices and an active M&A market. Our analysis indicates GTL technology is capable of yielding favourable IRRs while diversifying revenues across the majority of the US gas resource.

Sasol's un-geared balance sheet, coupled with strong expected cash flow generation, allows for various combinations of a significant gas acquisition (3tcf accessibility) and additional attributable GTL (c.50,000bbl/b) capacity, without compromising currently proposed growth projects (China CTL and Uzbekistan GTL).

The GTL heat map: Options supplemented by unconventional gas

With Sasol's GTL technology receiving increased attention from resource holders wishing to diversify revenue streams and monetise stranded gas, we still expect Sasol's GTL technology expansion to be based predominantly on stranded gas reserve partnerships. Potential partnerships with North American Shale gas producers are increasing in probability considering a depressed gas price outlook, below a level required to generate acceptable returns for the existing higher cost producers.

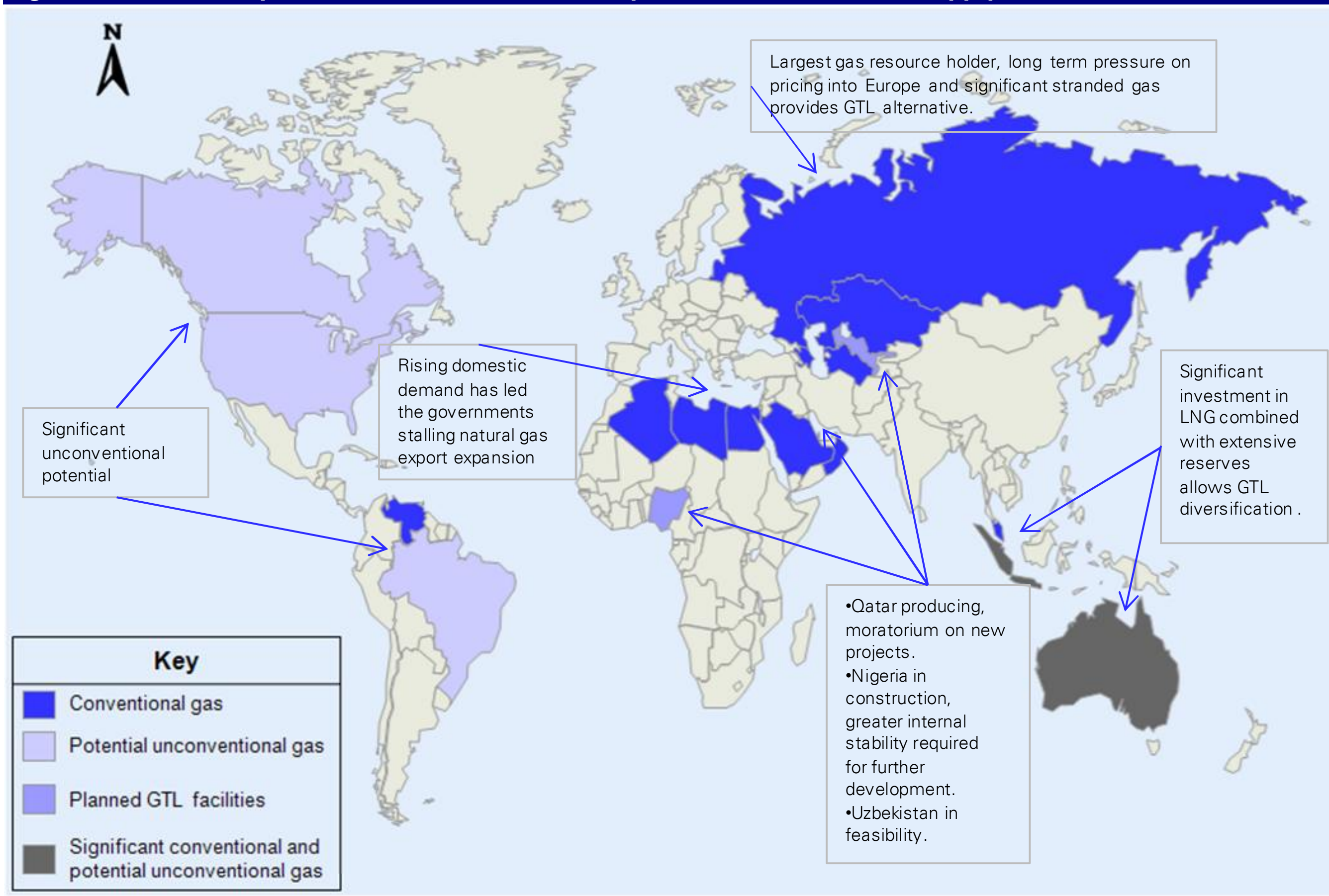
Given the global oversupply of gas with low price elasticity, we forecast a bearish outlook for prices (Appendix B). That said, we have identified potential countries which could be receptive to GTL technology given their vast gas resources.

Criteria used to identify potential countries

- Total conventional reserves above 30Tcf (10x that required for a GTL facility)
- Current reserve lives over 25 years based on production rates
- Net gas exporter, indicating surplus potential supply

The identified regions are not surprising, with Russia, Central Asia, the Middle East, North Africa and South East Asia all identified based on conventional reserves, Figure 31.

Figure 31: Global GTL potential based on reserves and potential unconventional supply



Source: Deutsche Bank

Figure 32: Potential GTL receptive countries based on reserves over 30tcf, current reserve life over 25 years, and status as a net gas exporter

	Reserves (tcf)	Production (bcf/d)	CAGR (99-09) %	Consumption (bcf/d)	CAGR (99-09) %	Years reserves	Export of production %
Algeria	159.1	7.9	-0.50	2.6	2.30	55	67
Australia	108.7	4.1	3.20	2.5	2.40	73	39
Azerbaijan	46.3	1.4	10.50	0.7	3.50	91	50
Egypt	77.3	6.1	14.10	4.1	10.00	35	33
Indonesia	112.5	7	0.30	3.5	1.40	44	50
Kazakhstan	64.4	3.1	13.60	1.9	9.80	57	39
Libya	54.4	1.5	11.80			99	100
Malaysia	84.1	6.1	4.40	3	6.90	38	51
Nigeria	185.4	2.4	15.20			212	100
Oman	34.6	2.4	16.30			39	100
Qatar	895.8	8.6	15.00	2	4.20	285	77
Russia	1567.1	51	-0.20	37.7	1.00	84	26
Saudi Arabia	279.7	7.5	5.3	7.5	5.3	102	0
Turkmenistan	286.2	3.5	5.80	1.9	6.10	224	46
Uzbekistan	59.4	6.2	2.50	4.7	0.20	26	24
Venezuela	200.1	2.7	0.20	2.7	0.80	203	0

Source: Deutsche Bank, BP statistical review

Although Iran, Oman, Saudi Arabia and Qatar host large reserves, we do not anticipate medium term GTL interest

Iran, although a large resource holder, has not been included given its domestic gas shortage. Tightening sanctions also weigh heavily on any potential investment decision.

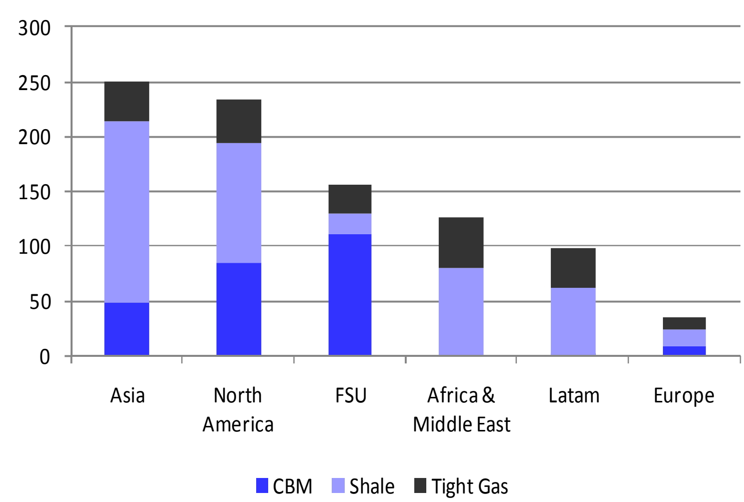
Venezuela, although not a significant exporter of gas, cannot be excluded from the identified regions given its significant reserves. That said, we do not view a potential Saudi Arabian GTL facility as likely in the medium term given OPEC quotas, which govern oil associated gas. We do not anticipate interest in GTL operations from Oman, as concerns have been raised as to the effect significant long-term LNG contracted volumes are expected to have on local supply in the longer term. Russian tax policies and opposition from conventional refineries are the key hindrances to a GTL facility there.

Qatar will host over 80% of global GTL capacity post Shell's Pearl GTL project ramp-up. Given the moratorium in place on new gas projects, we do not see Qatar increasing capacity in the medium term. Refer to pg 44 for additional information on the North Field moratorium.

Unconventional gas adding a new dimension to GTL's potential

Unconventional gas (tight gas, shale gas and coal bed methane) has clearly transformed the supply/demand landscape in the US and the question is now whether a similar contribution can be made in other regions. However, the resource potential of the opportunity in Europe is clearly not of the same absolute magnitude as in the US as illustrated in Figure 33.

Figure 33: Regional distribution of unconventional gas resources (tcm)



Source: Rogner 1997

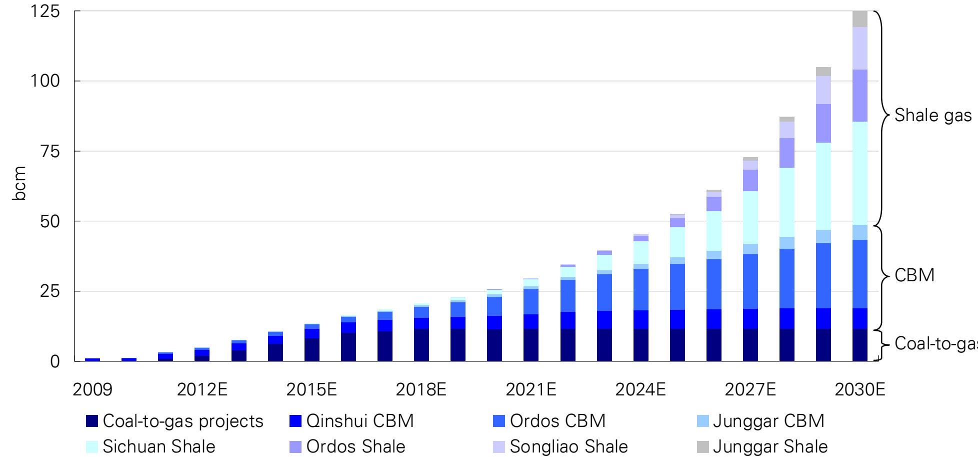
Figure 34: Key additions based on unconventional gas

USA	Significant shale gas and CBM potential
Canada	Significant shale gas potential
Indonesia	Significant CBM potential
Australia	Re-emphasised due to significant CBM potential
Brazil	Natural gas from pre-salt formations could lead to GTL/LNG potential

Source: Deutsche Bank

While there is tremendous potential in CBM and shale gas in China, both have issues that will likely delay meaningful unconventional production until late this decade. Wood Mackenzie estimates that commercial shale production won't commence in China until 2018 and expects unconventional gas production to account for 15% of total domestic output and cover 8% of total domestic demand in 2020. In 2030, those levels may increase to 42% and 26%, respectively. As such, we have not included China in our medium-term potential GTL sites.

Figure 35: China's vast unconventional potential, only medium term



Source: Deutsche Bank, Wood Mackenzie

Balance sheet has R25bn for gas and additional GTL capacity

Management has indicated increased interest in its proprietary GTL technology and renewed interest in a potential gas resource acquisition. Through our analysis of the gas markets, we see potential interest from resource holders and distressed producers seeking to diversify or monetise existing assets. In this section we identify Sasol's ability to respond to the increased demand.

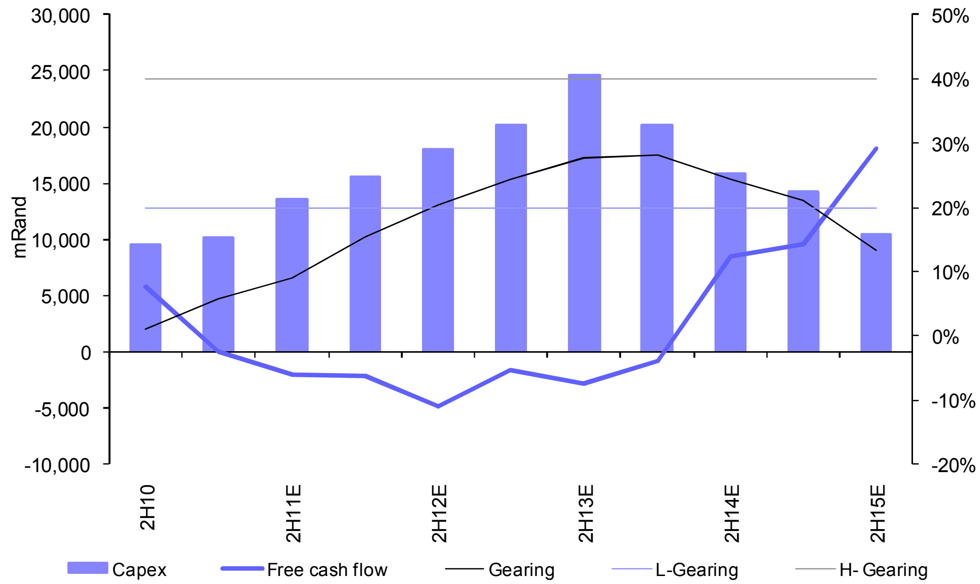
Sasol's balance sheet remains ungeared at 1% as at FY10. We estimate a peak gearing of c.9% in FY12E, resulting from authorised capex and strong cash flow expectations from existing assets. We expect capex of c.R20.7bn and c.R22.5bn in FY11E and FY12E respectively; the major capital projects concluding in FY12E include selected Synfuels expansion (c.R7bn) and the FT Wax expansion project (c.R8.4bn).

Including the capital requirements for China CTL and Uzbekistan GTL.

Comfortable with Sasol's gearing stretched to 50%

In assessing the potential resources available for a gas acquisition or additional project capex, we include the capital requirements for the significant un-committed expansion projects, China CTL and Uzbekistan GTL. We forecast peak gearing of c.28% in FY14E, suggesting c.R15bn available for upstream gas acquisitions while allowing the group to remain within the targeted gearing band of 20-40%. We are comfortable with Sasol's gearing band being temporarily stretched to 50% given the strong cash flow generation on existing assets. As such we estimate a potential c.R25bn is available for the associated gas acquisition or additional capex projects, Figure 36.

Figure 36: Gearing including the proposed China CTL and Uzbekistan GTL



Source: Deutsche Bank

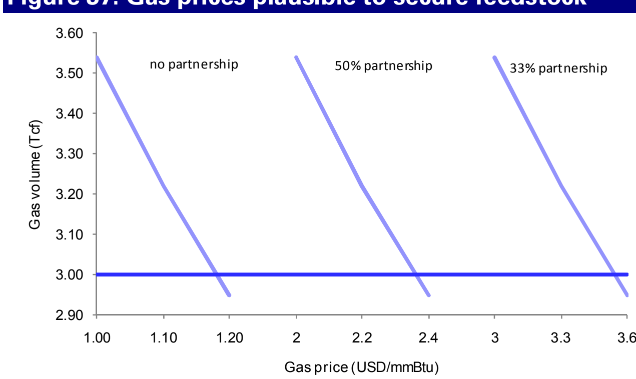
Gas price ranges for 3tcf access assuming balance sheet capacity spend on gas

Sasol would only require access to the reserve

The minimum required gas for a 25 year GTL project, based on Sasol's current GTL operating flow rates (c.32,4kbd), is 3tcf. As Sasol would only require access to the reserve, a partnership is possible in securing the reserve. We estimate, based on the c.R25bn available for a gas acquisition, Sasol could pay up to c.US$1.2/mmBtu. Allowing for a partnership structure similar to the proposed Uzbekistan GTL project, we assess a potential of c.US$3.6/mmBtu, a level similar to current US spot market gas. The broad range does allow Sasol significant opportunities.

During 1H10, US shale gas deals accounted for over US$20bn of acquisition spend, equivalent to around 30% of the global upstream M&A market. These deals, in excess of 35tcfe of shale gas resource changed hands between c.US$0.2/mmBtu and c.US$0.9/mmBtu on a total resource basis, with an average cost of c.US$0.6/mmBtu and c.US$1/mmBtu on a 2P reserve basis(Figures 37 and 38).

Figure 37: Gas prices plausible to secure feedstock



Source: Deutsche Bank

Figure 38: Shale gas resource acquisitions (US$/mcfe)

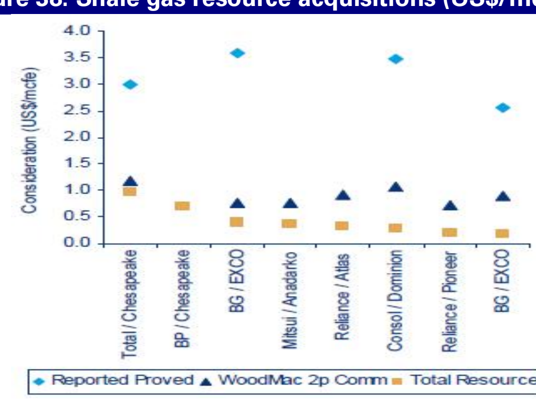


Chart highlights selected key benchmark shale gas deals. Proved reserves for both EXCO deals and the Dominion deal include non-shale gas reserves
Source: Source: Wood Mackenzie M&A Service

We do not expect national resource holders to sell significant gas assets, but rather to continue to provide GTL projects with relatively low cost (we estimate.US$1.2/mmBtu for the

Oryx GTL) or free gas feedstock (as is the case for Shell's Pearl GTL project) as an incentive for technology holders, with a profit sharing structure.

US shale gas focus: key theme in upstream M&A over recent years

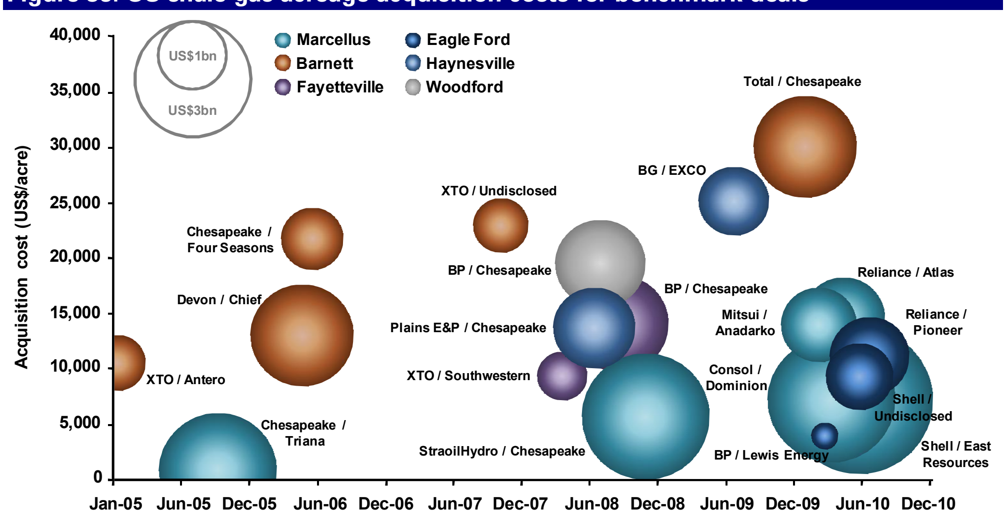
During 1H10, acquisition spend in the sector amounted to US$21bn, equivalent to around one-third of global upstream M&A expenditure. The value of the market has increased with the emergence of shale gas as a world scale source of secure, long-term gas supply. The most attractive plays offer robust economics, good access opportunities and limited above-ground risk.

Marcellus and Eagle Ford in particular

Wood Mackenzie expects activity levels to remain high and while the land-grab is largely over, the corporate landscape across the major resource holding basins – the Marcellus and Eagle Ford in particular – remains fragmented and significant opportunities for intra-play and sector wide consolidation still exist.

During the early stages in the evaluation of a play, deals tend to be priced on acreage costs. As confidence increases in the likely commerciality of the play, so too does the cost of land. Once a play is established, US$/mmBtu metrics based on total resource estimates become increasingly meaningful. Given the relative immaturity of these plays, US$/mmBtu metrics based on proved reserves are not relevant: deals involving assets at an advanced stage of development (only core sections of the Barnett would fit this description) are very unusual, according to Wood Mackenzie.

Figure 39: US shale gas acreage acquisition costs for benchmark deals



Note: Chart highlights key benchmark shale gas deals. Bubble size is proportional to consideration.
Analysis based on total consideration and net acreage associated with unconventional component of the acquired portfolio only.
Source: Wood Mackenzie

Recent benchmark transactions have been priced at US$0.20/mmBtu to US$0.90/mmBtu on a total resource basis, at an average cost of c.US$0.6/mmBtu (Figure 38) and c.US$1/mmBtu on a 2P reserve basis.

Partnership with an existing producer with limited transfer of the resource the most likely entry point

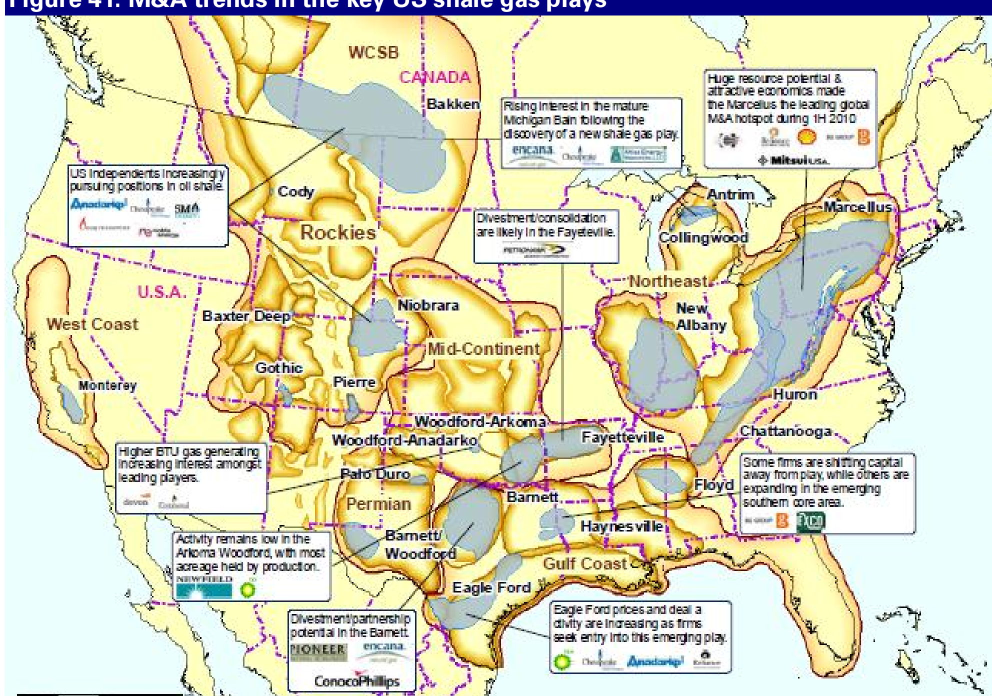
Acquisitions are most likely in the Marcellus, Eagle Ford and potentially Haynesville fields. The breakeven costs of production would also need to be considered. We expect a partnership with an existing marginal producer coupled with limited transfer of the resource to be the most likely entry point for GTL into North America. Regions expected to be receptive to GTL technology are identified in following section.

Figure 40: Degree of corporate consolidation and resource potential

Source: Wood Mackenzie Unconventional gas Service and Upstream service

With the North American large caps and smaller E&Ps holding the largest acreage positions across the majority of plays, there are plenty of buying opportunities in US shale gas. The partnership model will continue to be the preferred route for the majority of sellers. Many companies are actively looking to farm down interests in order to reduce capital commitments: according to Wood Mackenzie, Chesapeake has indicated a potential reduction of its Marcellus position and an Eagle Ford JV; US independent Atlas Energy is seeking a JV partner for its Marcellus position (266,000 acres, largely in south-western Pennsylvania); EOG has announced the disposal of 180,000 acres across the Haynesville, Marcellus and Eagle Ford plays; Encana has indicated its intent to sell interests in periphery gas projects; and PetroHawk is divesting its Fayetteville Shale interests.

Figure 41: M&A trends in the key US shale gas plays



Source: Wood Mackenzie

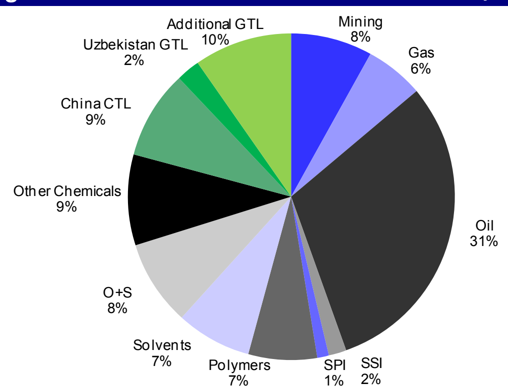
Ability to fund three additional Oryx structured and scale projects

R25bn for additional GTL projects equates to an attributable c.50kbbl/d

Based on Sasol guided capex for the proposed Uzbekistan GTL project, we estimate installed capacity capex of c.US$69.5k/bbl for future GTL projects. Given the potential R25bn available for additional capital projects including China CTL, Uzbekistan GTL, and authorised capex, we estimate c.50kbbl/d of additional attributable GTL production. This volume capacity is expected to be achieved via partnerships with existing gas producers or resource holders. As such, we estimate the balance sheet has the capacity to fund three additional GTL scale facilities on partnership terms similar to Oryx GTL (49%), or an additional four GTL plants with partnership structures similar to the proposed Uzbekistan project (33%) within the next five years.

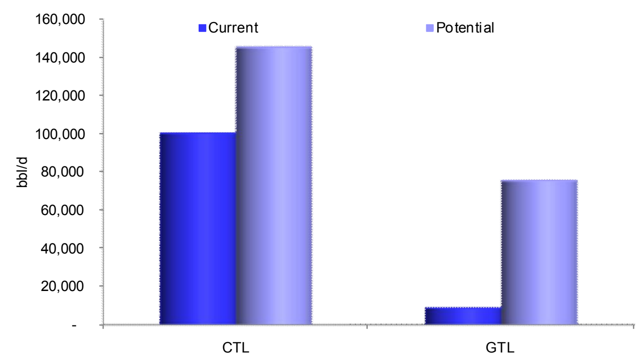
The potential effect on external sales (boe) and additional synthetic fuel production is illustrated in Figures 42 and 43.

Figure 42: Potential external sales volumes (boe)



Source: Deutsche Bank

Figure 43: Expanding Sasol's attributable synthetic fuel



Potential projects include China CTL, Uzbekistan GTL, Oryx ramp-up and Balance sheet capacity for additional GTL facilities

Source: Deutsche Bank

Potential North American GTL: biting at the bit

Sasol could potentially enter into a partnership securing gas feedstocks from marginal producers in exchange for access to the GTL product profit streams, in our view. This partnership would allow the resource holder to:

- benefit from the recent expansion in the US oil-to-gas ratio,
- diversify revenue streams,
- reduce exposure to our view of suppressed US gas prices into the medium term.

The potential partnership would leverage off the producers' specialist gas production experience and Sasol's proprietary GTL technology in an environment where many gas companies are actively looking to farm down gas interests in order to reduce capital commitments.

Mounting pressure on existing players to evaluate and restructure their portfolios

As low gas prices and increasing costs squeeze cash margins, there is mounting pressure on existing players to evaluate and restructure their portfolios. This is currently supporting liquidity in the asset market. Should the difficult environment persist, gas-weighted independents with weak balance sheets and/or hedging positions will appear increasingly distressed. Now, perhaps more than at any time in the recent past, the potential for a GTL partnership exists.

15% IRR in an US$80/bbl oil environment at a purchased real gas price of c.US$4.7/mmBtu

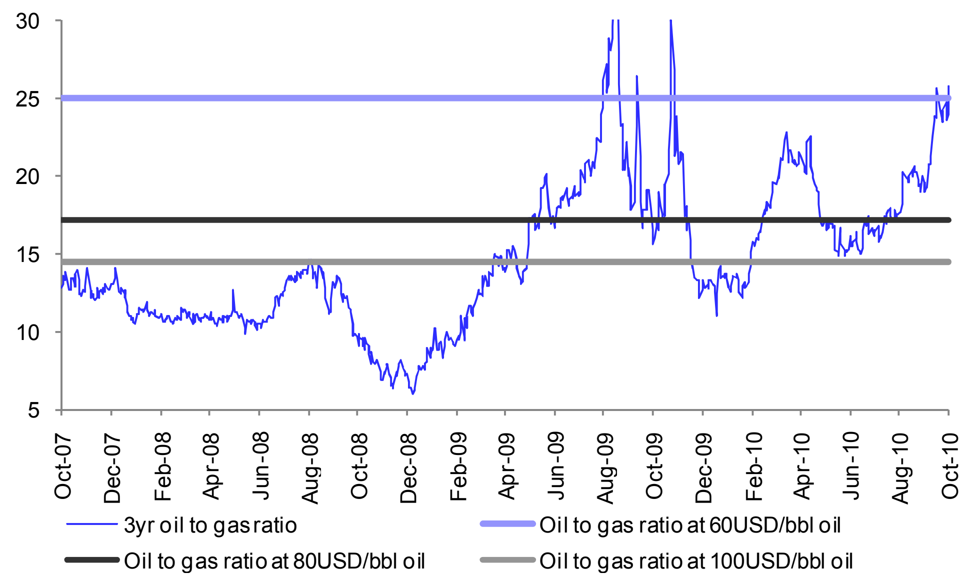
Our analysis suggests a North American GTL facility will return a c.15% IRR in an US$80/bbl oil environment at a purchased real gas price of c.US$4.7/mmBtu, over c.30% above current spot prices (c.US$3.5/mmBtu). As a GTL facility would require gas feedstocks over a 25-year period, gas price visibility is a key determinant in an investment decision. The proposed gas production/GTL facility partnership will aid gas feedstock cost visibility, assumed to increase in line with US inflation.

Partnership allows gas price visibility

The current oil-to-gas ratio (c.25x) could support a GTL facility up to a US$60/bbl oil environment. Deutsche Bank expects the US oil-to-gas ratio to remain higher than 16x into 2015. In a US$100/bbl oil environment, a 15% IRR would be achieved at a c.US$6.6/mmBtu real gas cost, but again, long-term gas price visibility is key.

Deutsche Bank expects the ratio to remain above 16x

Figure 44: Oil–to-gas ratio required for a US GTL facility to yield a 15% IRR

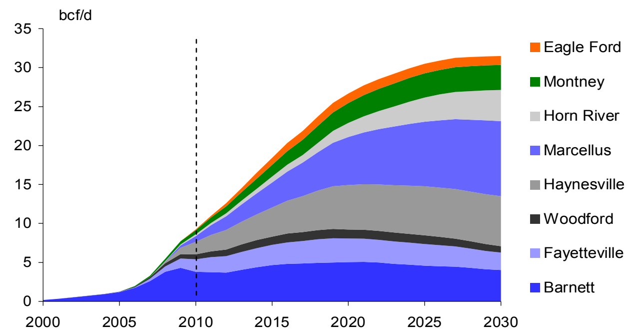


Source: Deutsche Bank, DataStream

Potential offered by unconventional gas

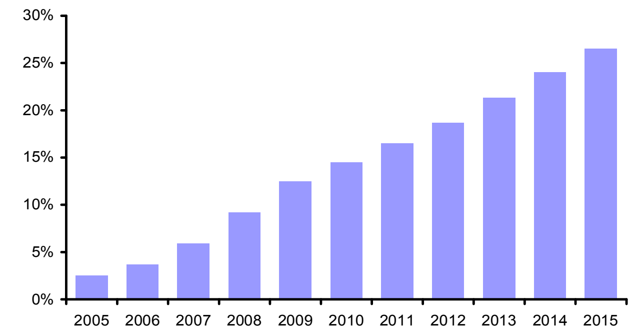
Above and beyond the natural relative abundance of conventional natural gas over oil, the past five years have seen the emergence of an enormous game-changer, whereby aggressive US E&P companies combined two well-established oil and gas technologies, namely horizontal drilling, and hydrofracking, to great effect. The net impact was to unlock vast quantities of trapped gas, previously locked into insufficiently porous rock formations, but which the combined technology opened up. The net result was explosive growth. According to Wood Mackenzie, capex poured into shale gas at a 36% CAGR between 2002 and 2010, versus 3% CAGR for conventional gas. This is an activity-intense theme that requires a sophisticated drilling, service, and support industry, with highly developed infrastructure and markets to justify its economics. The US has all those things. As a result, production is currently concentrated in North America and Eastern Australia. The US is the hot spot, accounting for three-quarters of global unconventional production in 2009.

Figure 45: North America key shales production



Source: Wood Mackenzie, Deutsche Bank, DOE/EIA

Figure 46: US production – shale % of total gas



Source: Wood Mackenzie, Deutsche Bank, DOE/EIA

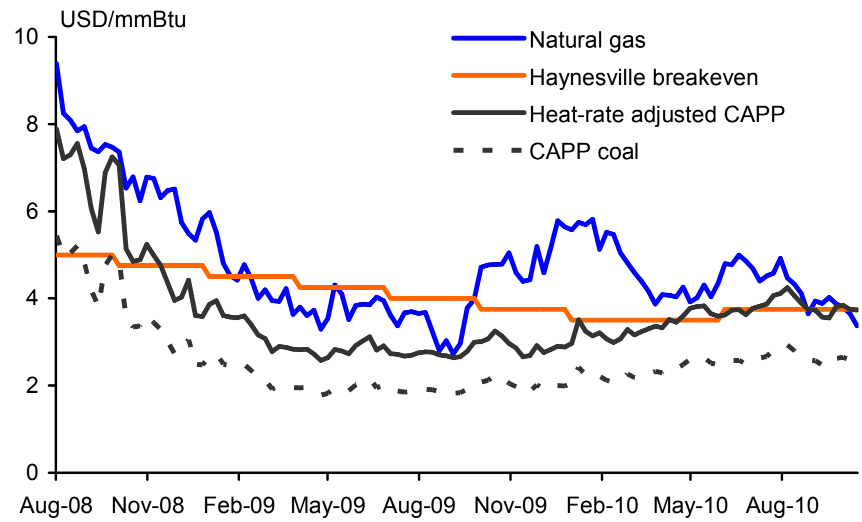
In terms of economics, there is no question that it was the higher prices of the past decade that allowed companies to pursue unconventional gas, which costs more than conventional, because of its more intense activity requirements to offset the dramatic decline rates.

High activity levels continue, despite pressured prices. This is a function of:

- continued aggressive growth targets from companies running a "cash flow" business model,
- drilling to maintain leases,
- hedged companies continuing to have access to greater cash flow than the current price environment would support,
- lower costs,
- NGL/liquids associated with natgas and generating returns (although perversely NGLs then compete with natgas into the petrochemicals sector, and
- perhaps most importantly, the entrance of deep-pocketed major oils into JV arrangements and major acquisitions that we believe are essentially R&D undertakings, rather than returns-led activity.

Should the difficult environment persist, gas-weighted independents with weak balance sheets and/or hedging positions will appear increasingly distressed as illustrated by Figure 47.

Figure 47: Gas prices not supporting existing gas producers, low prices favour GTL



Source: Bloomberg Finance LP, Wood Mackenzie ,Deutsche Bank

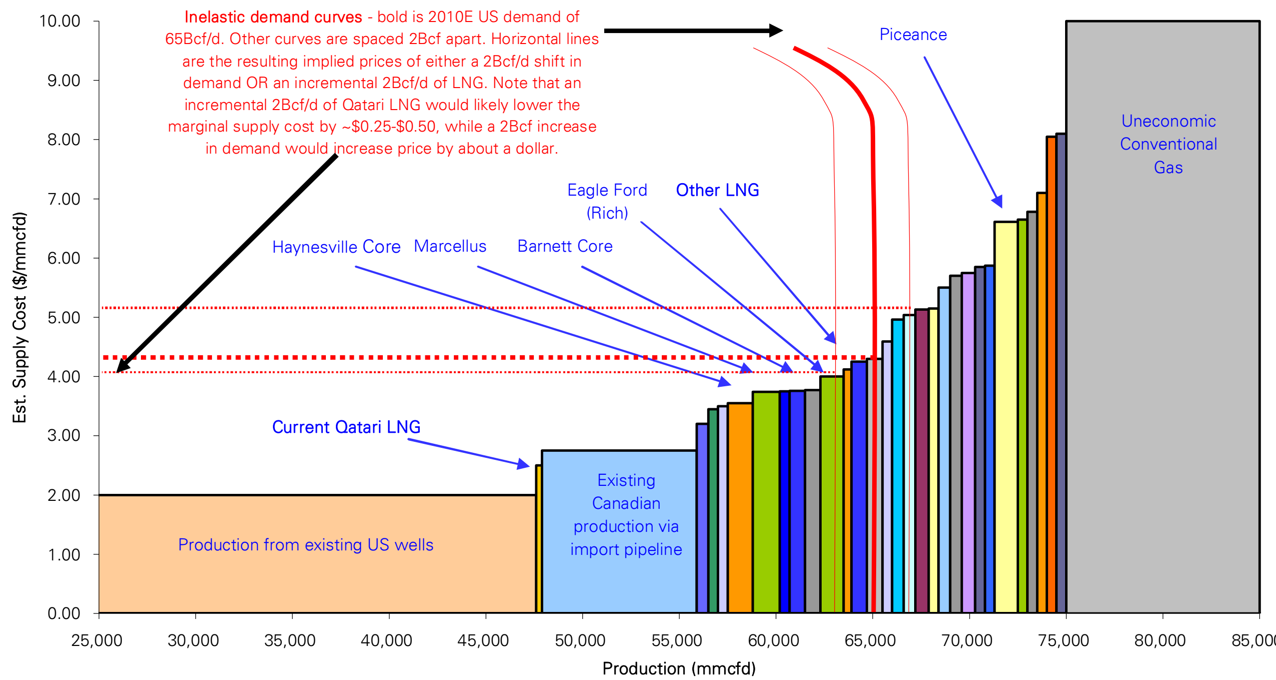
GTL provides an opportunity for marginal gas producers looking to leverage off oil-indexed product streams and reducing their dependence on a continued weak US gas market, in our view (Appendix B).

We ultimately believe that high-cost US unconventional is the marginal global gas producer. There is little question in our mind that the market structure of the US makes it the most competitive in both volume and price globally, and the natural effect of the unconventional gas boom, with the boost in global LNG supply and global gas demand downturn, it is the market that will suffer the most, price-wise.

Pressure from LNG will force many higher-cost marginal natgas producers to cease activity

The fundamental picture in US natgas appears weak, and we believe that the scale of both actual and potential supply is such it is vital that we see more gas demand with the hope of sustaining prices in excess of US$5/mmBtu. We are essentially negative on the outlook for returns and thereby equity values in the space. Our view is that natgas prices will be bound between the marginal cost of supply of around US$6/mmBtu and the point of coal competition on the other, at around US$4.50/mmBtu. We also believe that pressure from LNG will force many higher-cost marginal natgas producers to cease activity, either voluntarily or through bankruptcy. The market clearly underestimates the fact that a global excess of LNG and a massive surge in supply, notably from Qatar but also from others, will force its way into the US market.

Figure 48: Estimated US natural gas supply cost curve – shale gas players are at the margin



Source: Wood MacKenzie, MIT Energy Initiative, ConocoPhillips, CNRL, Upstream, Reuters, Wall Street Journal, Dow Jones, Company data, Deutsche Bank estimates

Value created converting gas into oil indexed products is substantial

North American GTL economics

The value uplift in the end product revenue in its most basic form is illustrated in Figure 49. The additional value created from converting gas into oil-indexed products, given both spot and long-term prices, is substantial. The additional value would be shared between the partners. Additional opex and depreciation charges relate to our assumption of a specific US GTL facility.

Figure 49: GTL product value accretion for potential gas producer partnership

	Gas revenue	GTL product	Value uplift %
Spot commodity	**US$3.5/mmBtu**	**US$80/bbl oil**	
Revenue	35	96	
Opex		11.5	
Depreciation		8	
EBIT	35	76.5	54
Long term commodity	**US$6/mmBtu**	**US$90/bbl oil**	
Revenue	60	108	
Opex		11.5	
Depreciation		8	
EBIT	60	88.5	32

Key assumptions, 10mmBtu is equivalent to 1bbl GTL product, 20% GTL product premium of oil price
Source: Deutsche Bank

The key differences in our assumptions between the Uzbekistan GTL project and a potential US GTL facility are summarised in Figure 50.

Figure 50: Key assumption differences to Uzbekistan GTL

	Uzbekistan GTL	North American GTL	Difference %	Comment
Capex	2,500	2250	-10.0	Uzbekistan landlocked and isolated
Tax %	20	30	50.0	Differences in corporate rates
Inflation %	6	3	-50.0	Uzbekistan is a developing economy
Opex costs	12.5	11	-12.0	Lower product transportation and developed serves industries

Source: Deutsche Bank

Based on our assumptions, we estimate that a US GTL facility would return a 15% IRR for a US$80/bbl oil price and gas price of c.US$4.7/mmBtu (c.US$4.8/mcf).

Figure 51: North American GTL partnership economics based on commodity outlook

Assumption	Value	Unit
Capex	2,250	US$m
Operating capacity	36,000	bbl/d
Capacity utilisation %	85	
First products	Year 5	Year
Stable operation	Year 6	Year
Gas feedstock cost, FY11E	4.5	US$/mmBtu
Production cost	11.0	US$/bbl
Cash production costs	56	US$/bbl
Depreciation	8	US$/bbl
Total costs	64	US$/bbl
Corporate tax rate %	30	Pa
Gas Inflation %	3	Pa
General Inflation %	3	Pa
Oil forecast, FY11E	80	US$/bbl real
GTL product premium	20	%
Project NPV10	1,003	US$bn
Project IRR %	15.5	%
Gas price for 15% IRR	**4.7**	**US$/mmBtu**
Gas price for 15% IRR	**4.8**	**US$/mcf**

Source: Deutsche Bank

Our calculated gas cost for a c.15% IRR is within the major shale gas producing after-tax break-even costs as illustrated in Figure 52. This provides Sasol with significant opportunities within the US shale gas environment.

We estimate that GTL economics are supported in an oil environment ranging from c.US$64/bbl for the Eagle Ford shales to c.US$87/bbl for Antrim. We do not expect short-term GTL activity in these two regions as Eagle Ford offers both limited current production and commercial reserve holdings, while Antrim is estimated to hold relatively low potential recoverable reserves.

Haynesville is a key potential partnership region

We highlight Haynesville as a key potential partnership region with:

- supportive GTL economics (after-tax break-even c.US$4.7/mcf),
- vast potential recoverable reserves (c.160tcf),
- with break-even costs above current spot levels.

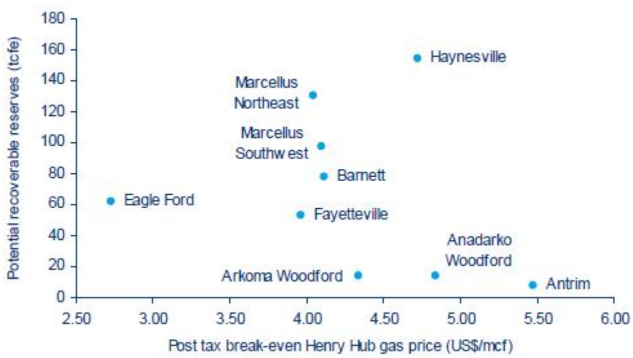
Key players in the region with 2P reserves above 3tcf include Chesapeake, Encana, Shell, and PetroHawk (Figure 54). We estimate Haynesville shales to return the hurdle rate at an oil price of c.US$80/bbl.

Another key region is the Marcellus

Another key region is the Marcellus, which has large potential resources supporting GTL economics in a c.US$75/bbl oil environment. Resource holders with over 3tcf include Chesapeake, Range, Statoil and Shell. Talisman, CONSOL, and Statoil all hold significant acreage in the region.

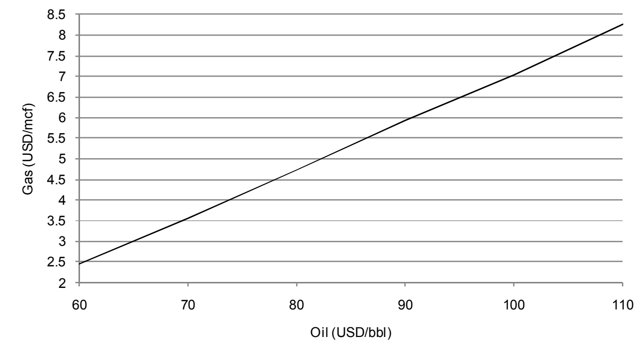
Refer to leading shale after-tax break-evens and potential recoverable resources in Figure 52: and key GTL variables requirements for a c.15% investment hurdle rate in Figure 53. Commercial 2P reserves and net acreage positions are illustrated in Figures 54 and 55.

Figure 52: Leading US shales after-tax break-evens



Source: Wood Mackenzie Unconventional Gas and Upstream service

Figure 53: Oil and gas prices for a 15% IRR



Source: Deutsche Bank

Figure 54: Commercial 2P reserves of key players across the seven main shale plays

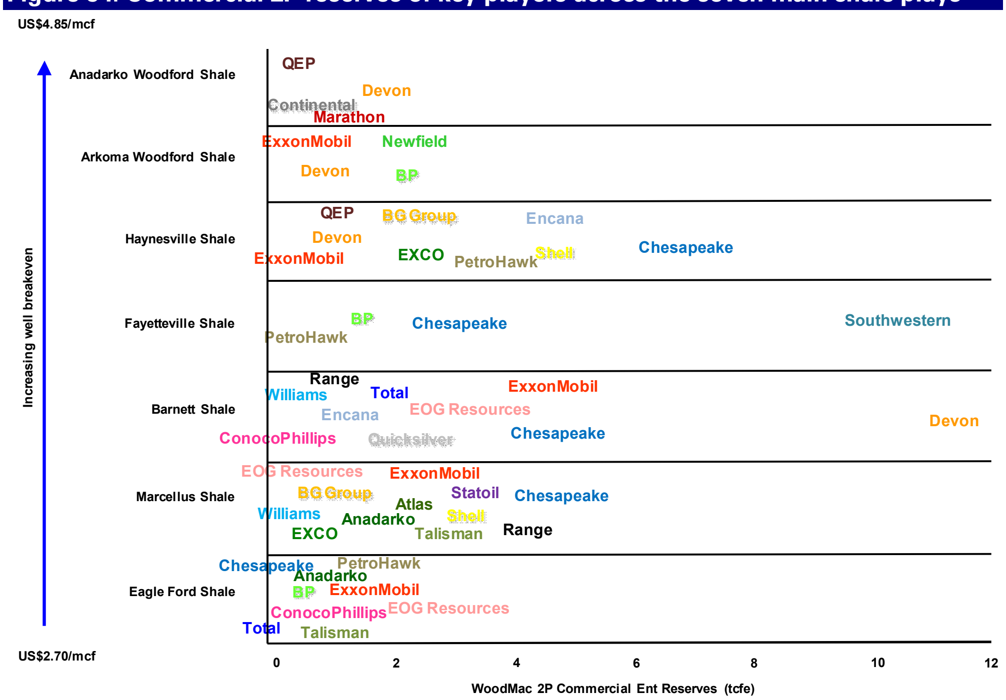
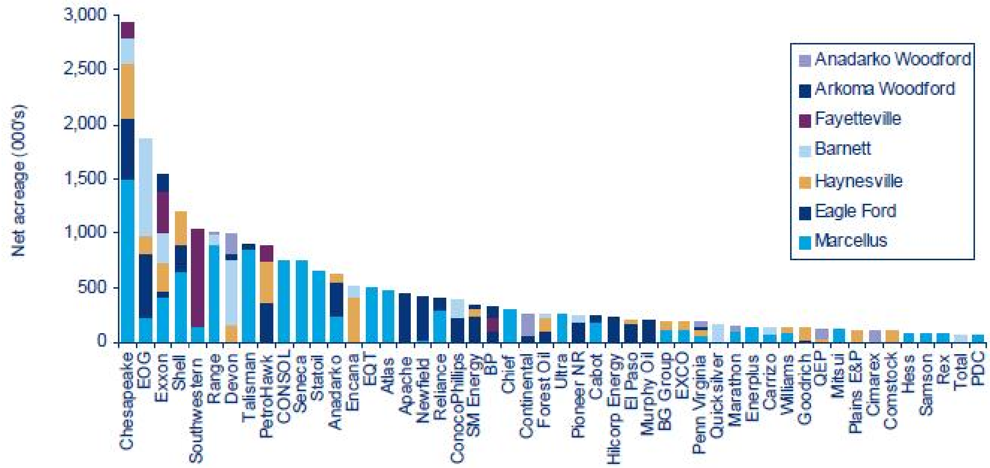


Chart identifies the key corporate positions in the top US shale gas plays. We have excluded the more high cost plays and focused on those with the lowest development breakevens. Furthermore, with commercial reserves of at least 4.7tcfe, each play selected in this analysis is large enough to underpin scaleable development and production growth.

Source: Wood Mackenzie, Deutsche Bank

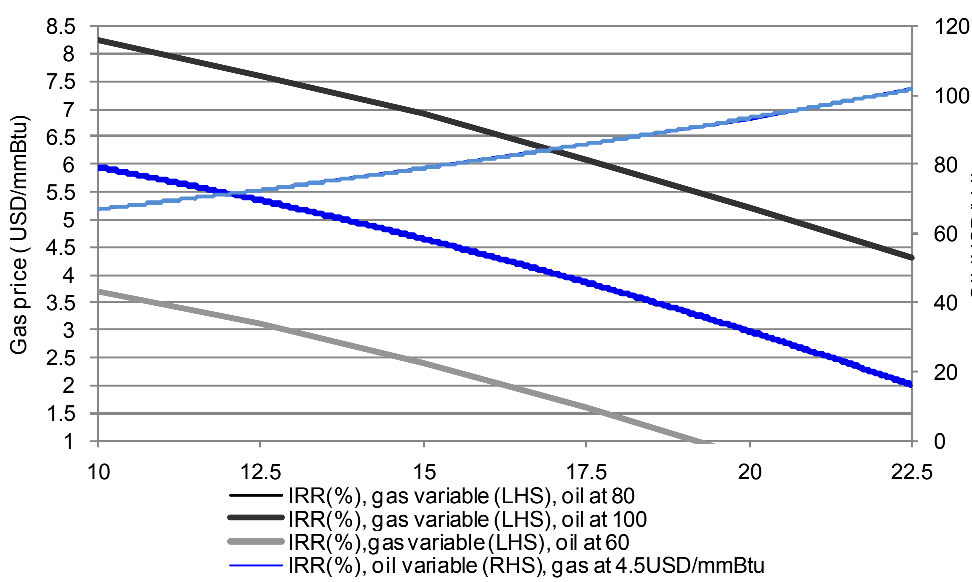
Figure 55: Net acreage position of key players across the seven main shale plays



Source: Wood Mackenzie Upstream service

Given the broad range of regions and gas feedstock costs for a potential partnership, we include a sensitivity table to key variables, oil and gas, to the potential projects IRR (Figure 56). The extent to which GTL technology delivers robust returns is clearly dependent upon the oil price environment; we expect significant interest in GTL technology, given a consensus long-term oil price outlook of higher than c.US$80/bbl.

Figure 56: Oil and gas sensitively to project IRR, altering only one variable

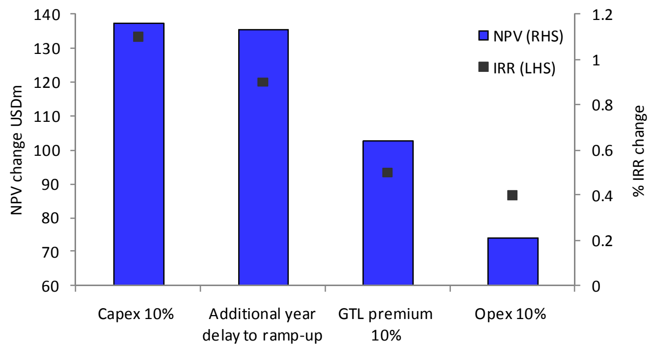


Source: Deutsche Bank

As with Uzbekistan GTL, capex and scheduled plant commissioning are the key variables with a GTL project. Sasol is confident the teething problems experienced in Oryx GTL will not be significant in future projects. The opex sensitivity is muted, given the high relative gas feedstock costs (c.US$45/bbl gas cost, c.80%of cash costs/bbl).

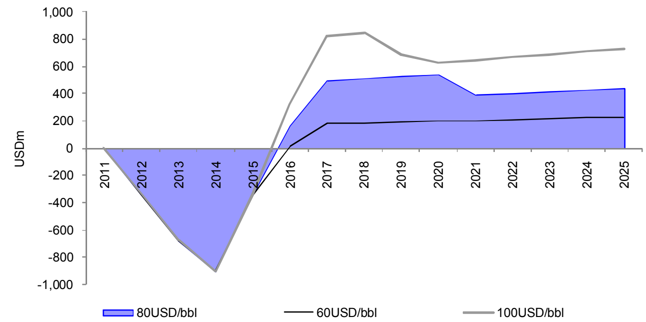
Based on our spot gas forecast in FY11E (US$4.5/mmBtu), we anticipate a GTL project to break-even (return WACC) in a c.US$70/bbl real oil environment. Cash flows and hence potential project IRRs are therefore levered to incremental oil prices above this level, as our estimated total cost is c.US$64/bbl for the forecast spot gas price.

Figure 57: Key variable sensitivities



Source: Deutsche Bank

Figure 58: Cash flows sensitive to oil prices



Source: Deutsche Bank

Risks with shale gas and a US facility

For all the positive factors that make shale gas an attractive investment target, downside risks remain, both across the sector and at the local level. Environmental concerns are the subject of increasing attention at federal level, particularly in the area of hydraulic fracturing. A ban on this process is considered highly unlikely, though the possibility for increased oversight, either through state and federal legislation or new regulations by the US Environmental Protection Agency (EPA), appear likely, according to Wood Mackenzie.

There is also a degree of fiscal risk associated with the US upstream. The US Congress is currently considering proposed changes to the tax code that would eliminate two tax incentives: 1) intangible drilling cost (IDC) expensing and 2) the domestic production activities (section 199) deduction.

A refinery license may be difficult to obtain, given the clear environmental movement in the US. We expect this will be partly offset by the cleaner fuels produced in the GTL process. In addition, a GTL facility would reduce external energy reliance on the US economy. Sasol has the potential to develop a GTL facility adjacent to existing operations.

The potential impact of carbon taxes would add to the operating costs. Given currently traded carbon on a per ton basis, we estimate a potential cost increase of c.US$4/bbl. Current project economics are based on a US$80/bbl oil outlook.

Central Asian focus

Turkmenistan has 8.1tcm of gas reserves or 4.3% of the world's total

Turkmenistan holds one of the richest natural gas reserves in the territory of the former Soviet Union (FSU) and in the world. According to *BP Statistical Review of World Energy,* it reported 8.1tcm at the end of 2009, 4.3% of the world's total. Wood Mackenzie uses 2.9tcm commercial reserves estimate of which 2.5tcm (86%) are concentrated in the Amudarya basin and 0.4tcm (14%) in the South-Caspian basin. The Amudarya basin contains a number a large fields: Dauletabad-Donmez (1.2tcm), South Yolotan (0.4tcm), Yashlar, and a few others. Turkmenistan is placed second equal with Uzbekistan for gas production in the FSU. However, compared with Uzbekistan, the country has far greater potential for future growth.

Pipeline accident reduced Turkmenistan's ability to monetise gas reserves

Yet, a pipeline accident in April 2009 significantly reduced gas deliveries to Russia (from c.42bcma in 2007-08 to the forecast level of less than 10bcm in 2010E) and had a negative impact on Turkmenistan's ability to monetise its vast gas reserve potential. A revised agreement between Russia and Turkmenistan signed in late 2009 stipulates a maximum offtake volume of 30bcma, but it is not clear when this level may be achieved. Note that according to the original 2003 plan, Russia was due to increase gas offtake from Turkmenistan to 70-80bcm beginning in 2009.

However, Turkmenistan started deliveries to China and increased to Iran

Shortly after the 2009 pipeline accident, Turkmenistan's gas reserves monetisation ability was partially restored, as the Central Asian producer agreed to deliver more gas to its southern neighbour Iran (capacity upped from 8bcma to 14-20bcma) and to start deliveries to China. According to *FSU Energy*, exports to China still cannot plug the budget gap in year 2010 at least. Indeed, Russia may only buy 10bcm at US$220/mcm and China 5-6bcm at US$120/mcm. We estimate that in 2008 Gazprom bought c.45bcm at US$160/mcm.

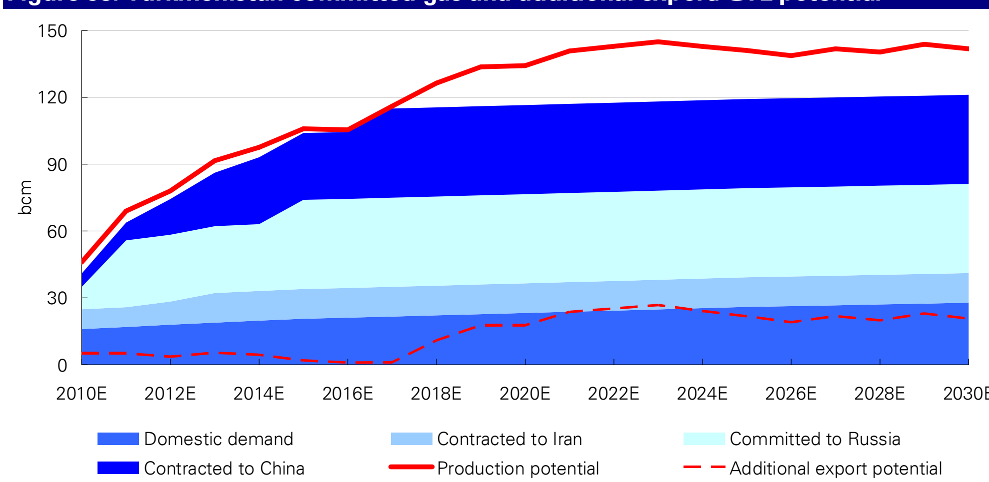
The China-bound pipeline was inaugurated in December 2009

The 1,833km Trans-Asia pipeline to the border with China (total length including West-East 2 pipeline segment in China is 7,000km) was inaugurated on December 2009. It provides Turkmenistan with an ability to deliver 5-6bcm in 2010, 8-16bcma in 2011-2012, 25-30bcma in 2013-2016, and may be expanded to a potential 40bcma starting from 2016-17. The pipeline's projected capacity has been increased only recently from 30bcma to 40bcma on Turkmenistan's request. As the pipeline crosses the territories of Kazakhstan and Uzbekistan, those countries may potentially join gas suppliers to China. That, however, is subject to their ability to expand production, satisfy local demand, and meet existing commitments to supply gas to Russia.

Turkmenistan's export potential is 25+bcma above existing commitments

Wood Mackenzie estimates that based on existing reserves (predominantly Dauletabad-Donmez and South Yolotan fields), Turkmenistan is capable of producing up to 145bcma of natural gas compared to just 66bcm in 2008 and 36bcm in 2009. However, this is based on the assumption that all three phases of South Yolotan are on-stream. Note that Wood Mackenzie currently models only Phase 1 as commercial reserves, while additional reserves are modelled as technical for the Phase 2 and 3 developments. The country's commitments to Russia stand at 30bcma (but Wood Mackenzie assumes they may grow to 40bcma by 2015), to China 40bcma and to Iran 14bcma. In the event Turkmenistan realises its production potential, it could potentially increase exports by more than 25bcma above the existing commitments, Figure 59.

Figure 59: Turkmenistan committed gas and additional export/GTL potential



Source: Wood Mackenzie

Central Asia's export potential is 40bcma at peak

A similar analysis for the entire region suggests that Turkmenistan accounts for most of Central Asian export potential, which is around 40bcma total at peak (Figure 60). The balance is equally split between Uzbekistan and Kazakhstan:

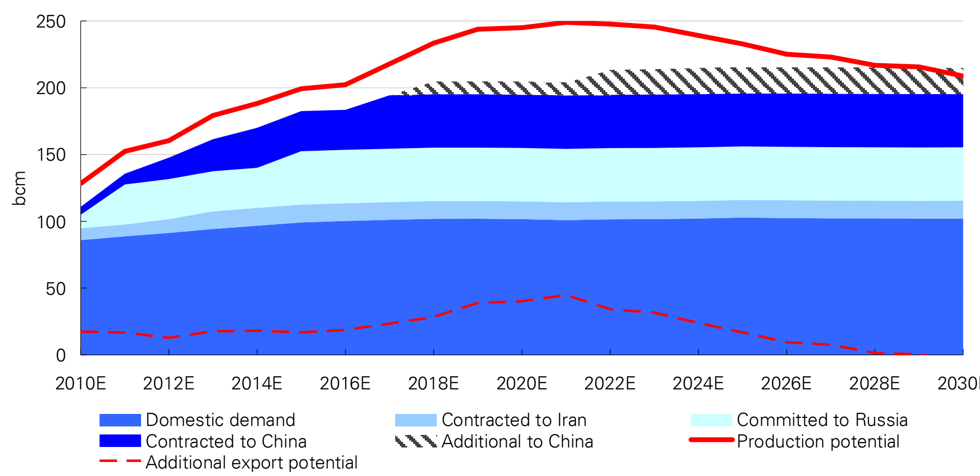
- Uzbekistan has production comparable to Turkmenistan but much greater local demand: 50bcma versus 16bcma, respectively, in 2010E. As the country's main gas fields reduce output, PSA projects operated by foreign companies are likely to offset that production decline. In particular, we expect the largest of those projects, LUKoil's Kandym-Khauzak-Shady, to produce 10bcma in 2017E, complemented by the Gissar project with 2.5bcma in 2017E. In June 2010, Uzbekistan signed an agreement with China to potentially supply 10bcma of natural gas, but details of that agreement are unknown.

- Kazakhstan's future gas production depends on the successful development of the Caspian projects (Tengiz, Karachaganak and Kashagan—associated gas production), but the probability of exports to China is small, in our view, due to difficult logistics. That said, the government of Kazakhstan is currently planning a gas pipeline to the east of the country that may be potentially linked to the Trans-Asia China-bound pipeline.

Turkmenistan may be able to supply a total volume of 60bcma to China

As a result, on top of the existing commitments by Turkmenistan to supply 40bcma to China, another 20bcma may bring the total to 60bcma of future deliveries. This upside can be provided solely by Turkmenistan based on its existing reserves, but contributions from other Central Asian states are possible. The region's gas export potential yet again highlights the necessity for Russia to accelerate its talks with China and strike a supply deal as soon as possible before additional commitments are extended by Turkmenistan, Uzbekistan, and Kazakhstan.

Figure 60: Central Asia committed gas and additional export/GTL potential



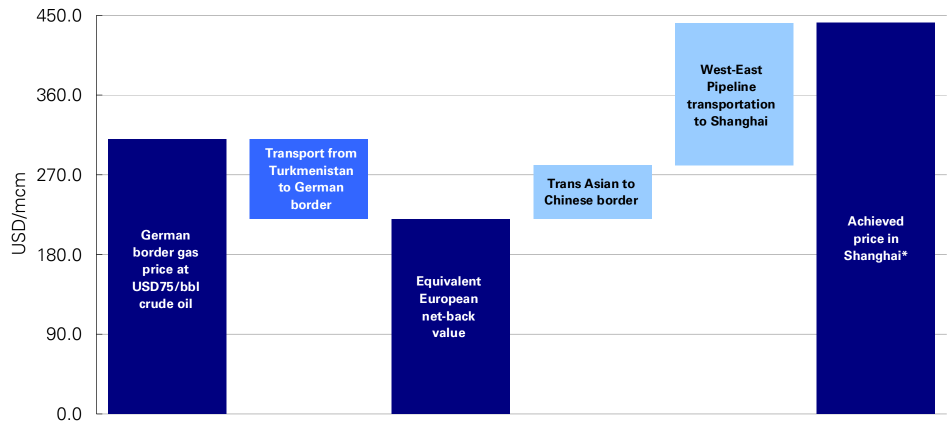
Source: Wood Mackenzie

Monetising volumes

Wood Mackenzie believes that Turkmenistan is selling to China at European net-back parity price

Wood Mackenzie believes that gas sales to China generate to Turkmenistan net-back price parity with European deliveries (c.US$220/mcm at crude oil price level of US$75/bbl and gas price at German border of US$310/mcm). Even though Turkmenistan does not sell directly to Europe, we understand that the contract with Gazprom signed in late 2008 gave it the export net-back parity price (note that Gazprom has never disclosed the price level). We believe that for this particular reason Gazprom decided to significantly scale down its imports from Turkmenistan starting from 2010 compared to the original agreement.

Figure 61: Turkmen contract price in Shanghai

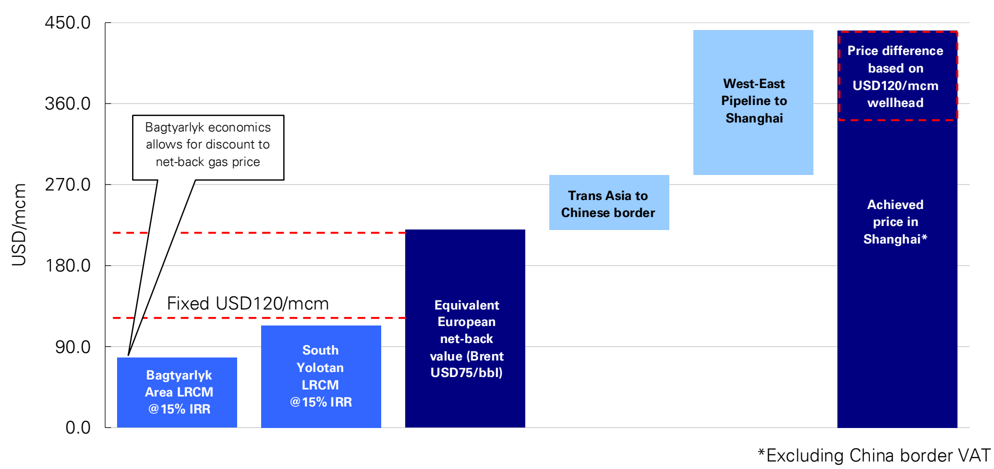


Source: Wood Mackenzie

However, China may be paying a much lower fixed price to Turkmenistan

An *FSU Energy* report suggests, however, that China could be paying much less for Turkmen gas. Apparently, CNPC pays a fixed price of just US$120/mcm at wellhead. This price level was agreed in June 2009, when Turkmenistan received a US$4bn loan from the China Development Bank. The price applies until Turkmenistan pays the loan back. *FSU Energy* notes that the deal was struck after Russia stopped imports from Turkmenistan, leaving the Central Asian producer essentially no choice but to accept the low gas price offer.

Figure 62: Turkmenistan upstream economics



Source: Wood Mackenzie, FSU Energy, Deutsche Bank estimates

GTL potential

Monetisation options are currently limited to the export of natural gas due to the landlocked nature of the region. GTL could potentially offer an attractive alternative and diversification, given the infrastructure constraint and high relative costs associated with transportation of gas over great distances.

Sasol is currently conducting feasibility studies for a c.36kbd GTL facility in Uzbekistan, refer to pg 19 for project economics. We expect an investment decision in 2011, with the region expected to remain a key GTL expansion target going forward.

Although basic economics support the sale of gas at European net back or similar oil-indexed contract prices, (Figure 63), we believe the limited additional contract volumes available support diversification even at these price levels. As suggested by FSU Energy, the region is prepared to accept significant discounts to net back prices to secure foreign investment. We believe the discount could be further increased should an equity partnership be accepted as with the 33% equity stake of Uzbekneftegaz in the proposed Uzbekistan GTL project. We estimate that at a gas price of US$1.5/mmBtu, the Uzbekistan GTL offers Sasol and Petronas a c.21% IRR, with Uzbekistan expected to achieve a c.25% IRR through the additional tax benefit.

The expected value uplift offered by GTL to the Bagtyarlyk (c.61%) and South Yolotan (c.47%) projects including a 15% IRR for gas costs, suggests additional investment in resource development supports GTL economics.

Figure 63: GTL product value accretion at US$80/bbl

	Gas price (US$/mcm)	Gas price (US$/mmBtu)	
European net back oil at 75US$/bbl	220	7.9	
European net back oil at US$80/bbl	234	8.4	
FSU Energy expected sales into China - fixed	120	4.32	
Net back profit per barrel			
Net back price parity with European deliveries at US$80/bbl oil	**Gas sales**	**GTL project**	**GTL value uplift %**
Revenue	84	96	
Production	0	12.5	
Depreciation	0	9	
Profit	**84**	**74.5**	**-13**
FSU Energy expected sales into China			
Revenue	43.2	96	
Production	0	12.5	
Depreciation	0	9	
Profit	**43.2**	**74.5**	**42**
Potential extraction costs including 15% IRR			
Bagtyarlyk	**28.8**	**74.5**	**61**
South Yolotan	**39.6**	**74.5**	**47**

**Key assumptions, 10mmBtu is equivalent to 1bbl GTL product, 20% GTL product premium of oil price.*
Source: Deutsche Bank

Figure 64: Existing and proposed Caspian gas export infrastructure

Source: Wood Mackenzie

Russian focus

Russia, through Gazprom, is the largest natural gas producer in the world. However, in a global context, it has always been viewed as a regional player operating in the Russian domestic and European export markets. The global financial crisis has seriously undermined Gazprom's position in Europe: in 2009, gas output fell sharply by 16% and gas exports by 11% yoy. We believe that sluggish European demand will continue to impose growth limitations on Gazprom. Diversification, which has been part of Gazprom's agenda for some time, may take a more concrete form, as Russia and China plan to sign a preliminary gas deal toward the end of 2010. Gazprom expects the final deal to close in the middle of next year.

On the supply side, the diversification of gas should not only allow Gazprom to reduce its exposure to Europe but should also provide an opportunity for the Russian gas monopoly to monetise reserves with no alternative market.

The European gas market is showing signs of recovery, which has been reflected in spot price levels. The gap with oil-linked contract prices has fallen from more than 50% a year ago to just 20-25% currently. This indicates that the gas market is becoming balanced, reducing pressure on Gazprom from its European gas customers to sell more gas at lower spot market prices. We note that Gazprom's spot price sales this year are likely to be less than 5% and we remain bullish on Gazprom as a supplier of conventional gas. Gazprom's strategy is to be aggressive on oil-indexed pricing and probably be willing to accept lower market share as they expect the European gas market to recover in 2013. Once oil-indexation is lost, it may prove difficult to reinstate.

Relative cost of Russian LNG supply

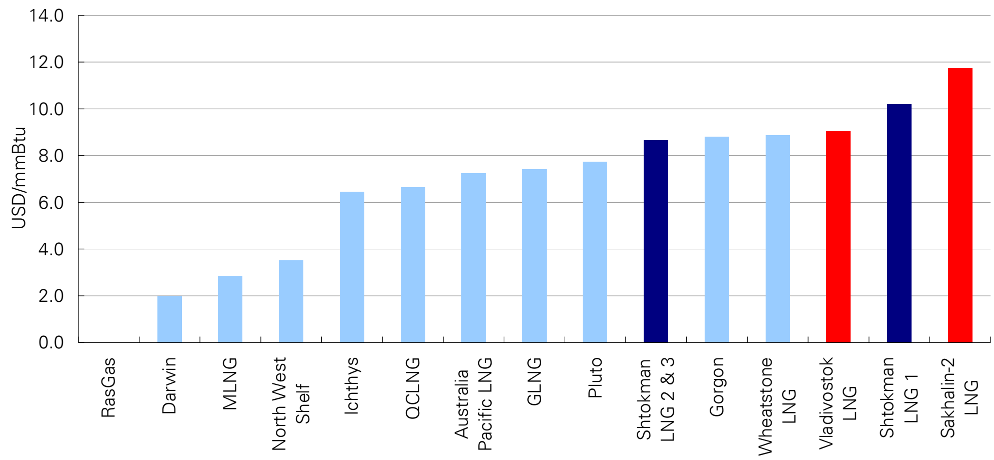
LNG competitiveness reduces as oil prices rise. This may potentially lead to the introduction of S-curves into future LNG supply contracts to enable greater competition. Wood Mackenzie believes the Pacific market appears to offer more favourable potential as a means of monetising Russia's eastern gas resources. This is due to the assumption that LNG prices in Asia are likely to retain at a premium over the rest of the world through the medium term and that Russia's gas resources in the region are located in relative proximity to the established Asian LNG markets. Hence, the economics of an expansion at Sakhalin-2 or a new facility at Vladivostok appear more compelling than western LNG projects. Gazprom will have to make a key decision about east Russia is if it is willing to prioritise LNG over pipeline exports. We believe the company has decided in favour of the latter.

On a global basis, Russian LNG is the most expensive in the world

Figure 65 shows the cost of supply for three Russian LNG projects—Sakhalin-2 (operating), Shtokman (planned) and Vladivostok (planned)—compared with other global LNG projects. According to Wood Mackenzie, they are less competitive than other projects globally as they require a FOB price of US$8.7-11.8/mmBtu (US$240-326/mcm) to break even. On a global basis, this makes Russian LNG—both existing and planned—the most expensive in the world. We believe this is also a favorable argument for natural gas deliveries from the region of East Siberia by pipeline.

GTL is potentially an attractive alternative to relatively expensive gas pipeline transportation and the regions' position on the LNG cost curve, Figure 65. However, tax policies regarding oil products could limit a potential project.

Figure 65: LNG FOB break-even prices discounted at 12% from 1 January 2010*



** Cost of supply for the Sakhalin-2 LNG and Shtokman LNG projects was calculated by Wood Mackenzie on an integrated project basis. LNG costs for the Vladivostok LNG project were modelled separately for the upstream, pipeline and LNG plant components.*
Source: Wood Mackenzie

North Field moratorium – additional GTL capacity delayed

Discovered in 1971, the North Field giant field is estimated to contain some 900tcf of proven gas reserves, or around 9.4% of the world's proven total, making Qatar the third largest holder of natural gas reserves after Russia (1,529tcf) and Iran, much of whose 1,046tcf natural gas reserve base is also located in that part of the North Field that extends across its maritime border and is known as South Pars (see Figure 67). Starting with the development of its first LNG facility, Qatar Gas, which commenced production in 1996, has enlisted the help of a select number of international oil companies not the least being Exxon, Total, and Shell, as it has sought to monetize its resource potential not the least through the establishment of a leading position in the export markets for LNG (Figure 66). Following the completion of the Qatar 4 facility, Qatar will have LNG supply capacity of c.78mtpa or 27% of the world's total.

The North Field will host over 80% of global GTL capacity following Shell's Pearl GTL project ramp-up, resulting from one of the lowest gas production costs globally combined with established distribution networks, relative proximity to the product markets, and a foreign-investor-friendly environment.

Figure 66: Qatar – the project line up to date – monetising some 150tcf of gas over 25 years

LNG project	IOC*	Gas reserves tcf	Liquid reserves mb	Capacity (mtpa)	Start up	Gas/GTL project	IOC	Gas reserve tcf	Liquid reserves mb	Start up
Qatargas	XOM 10%, TOT 10%	9.257	193	9.7	1996	NF Alpha	n/a	4.130	166	1991
Qatargas 2	XOM 24%, TOT 8%	22.064	804	15.6	2009	Dolphin	TOT/OXY 24.5%	18.250	1744	2007
Qatargas 3	COP 30%	11.368	398	7.8	2010	Al Khaleej	XOM 100%	16.334	1246	2005
Qatargas 4	RDS 30%	11.151	390	7.8	2011	Barzan	XOM 10%	13.323	1226	2014
Rasgas	XOM 25%	7.676	307	6.6	1999	Oryx GTL	Sasol 49%	3.000	n/a	2007
Rasgas II	XOM 30%	19.362	678	14.1	2004	Pearl GTL	RDS 100%	15.000	521	2011
Rasgas 3	XOM 30%	21.963	769	15.8	2009					

**Qatar Petroleum major shareholder in all projects excluding IOC interest*
Source: Deutsche Bank

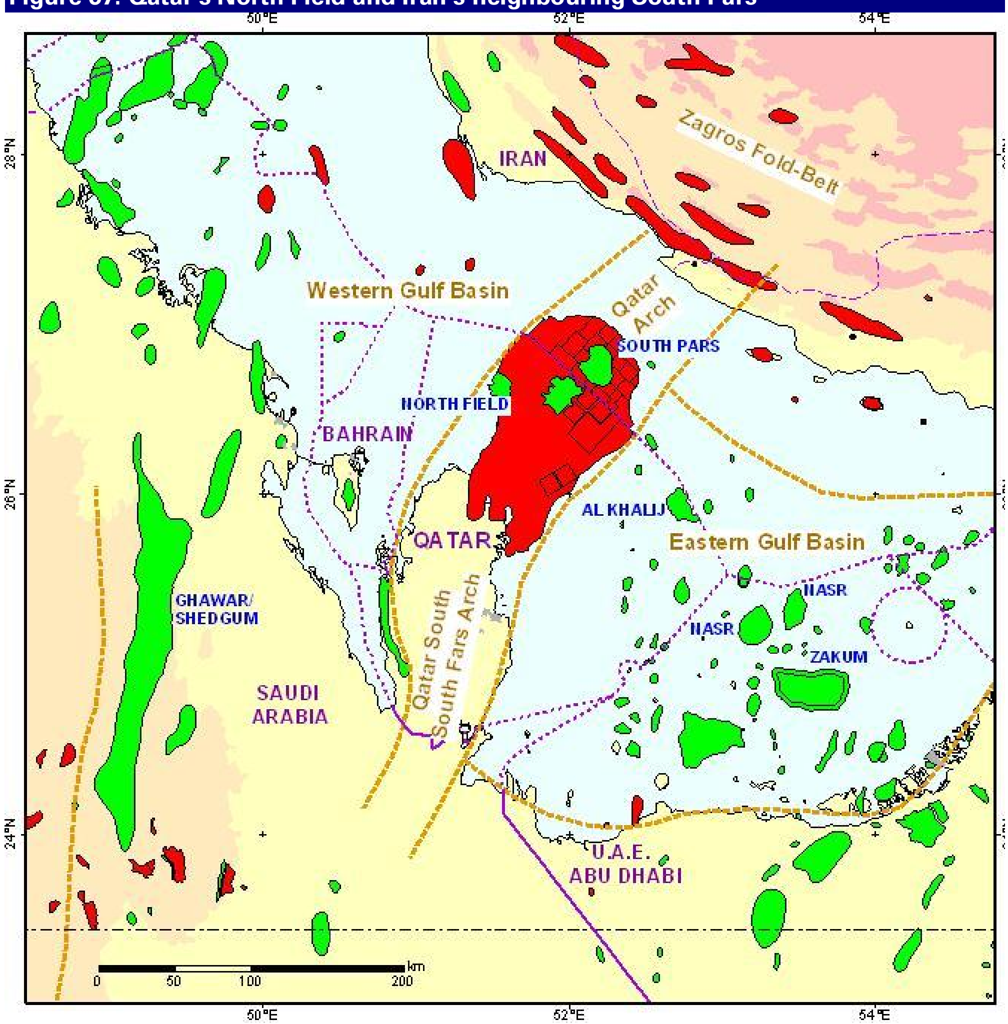
Given the concerns raised relating to declining rates and potential longer-term damage to the North Field, a moratorium on future projects has been implemented. We expect the moratorium to be effective until around 2015, following the ramp-up of the Barzan project. Sasol's gas contract allows for the original nameplate production capacity to be reached

(34,000bbl/d). As such, Sasol could increase production in Oryx from the current reduced nameplate capacity of 32,400bbl/d.

Given the wave of new LNG coming on-stream both globally and from the North Field, we expect GTL projects to resume following the end of the moratorium, as Qatar seeks to diversify end product price risk into a net long global LNG market expected to 2020, in our view. Supporting this view is the expected continuation of oil-to-gas price de-linkage in both the US and European markets, favouring GTL technology, coupled with continued robust operating performances (c.60% EBIT margin FY11E) from Oryx GTL.

As the Qataris are heavily invested in GTL from a global perspective, the success of Pearl GTL is vital for additional expansion. Should the project disappoint, additional gas will most likely be utilised for LNG debottlenecking over additional GTL capacity. Shell could potentially benefit most from further GTL expansion as there is an area designated for a third train in the Pearl project.

Figure 67: Qatar's North Field and Iran's neighbouring South Pars



Source: Deutsche Bank

Appendix A: Gas-to-liquids

Definition

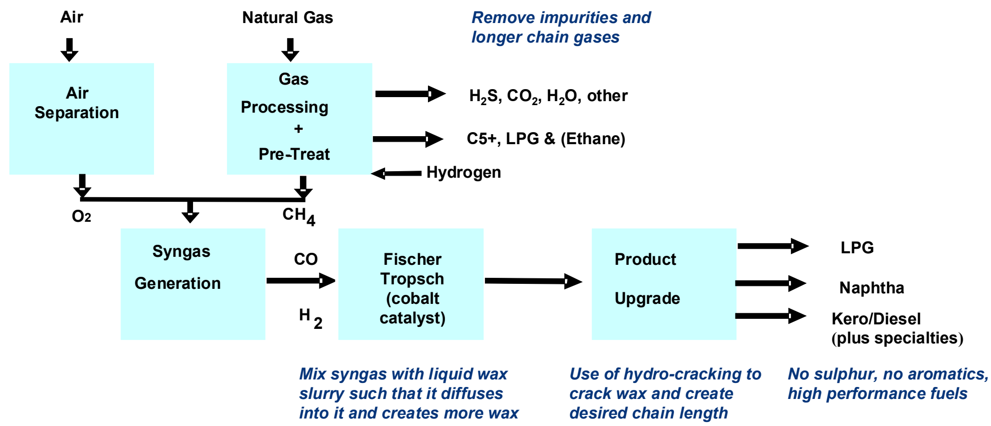
GTL technology represents a means of converting natural gas into liquids. Energy and capital-intensive, the process offers the potential to convert large reserves of stranded gas to higher value, high purity, synthetic liquids namely diesel, naphtha, and lubricant-based oils that can be transported to consuming markets. According to a catalytic chemical reaction called the FT process, the chemical process at its most basic represents the addition of single carbon molecules to create carbon chains, the lengths of which can, to some extent, be determined by altering the conditions through the conversion process. Because of the very high associated costs, GTL is unlikely to prove economic at oil prices of less than US$40/bbl. However, at high oil prices the process creates far greater value than the main alternative for gas monetisation, LNG. Only two companies—Sasol and Shell—currently have the technology proven to work on a commercial scale.

Background

In the 1920s, two German scientists, Franz Fischer and Hans Tropsch, sought to discover an alternative source of liquid fuels in petroleum-poor but coal-rich Germany. They discovered that by combining carbon monoxide with hydrogen (collectively entitled syngas) in the presence of either an iron or cobalt catalyst at high pressures and temperatures, they could create longer chain, liquid, carbon molecules (synthetic petroleum), which could be used as fuel. Moreover, the fuel produced contained no sulphur, aromatics, or other impurities all of which enhanced engine performance. For countries in need of transport fuels but lacking in access to crude oil, their process became an important alternative source of supply. Indeed, by the time of World War II, Germany was producing over 125kbbl/d of synthetic fuels from 25 plants. Similarly, the process was used by South Africa to meet its energy needs during its isolation under Apartheid, with the South African energy company, Sasol, becoming the global leader in the commercial application of FT technology for the production of high-quality diesel fuels, albeit predominantly using coal as a source of carbon.

Today GTL represents the potential for those countries with substantial, low-cost or stranded gas resources to monetise their gas and diversify their sources of revenue by producing high-value transport fuels and lubricants rather than LNG or other low value-added base chemicals such as methanol.

Figure 68: The GTL process –straightforward addition chemistry removes the need for a refinery but very commercially and technologically challenging

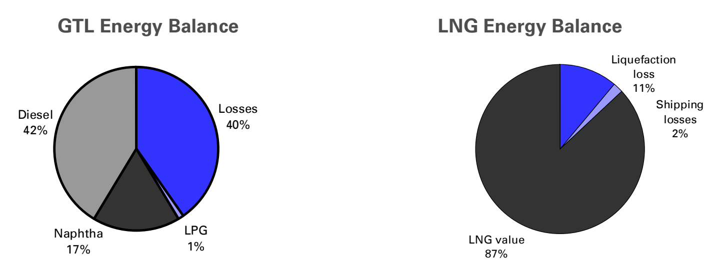


Source: Deutsche Bank

Energy intensity

GTL is a very energy-intensive process. Overall, around 40% of the energy value of the natural gas used in the process is lost, with extensive associated production of carbon dioxide. For example, Shell's Pearl GTL facility is expected to require 1.4bcf/d of gas or the oil equivalent of 240kboe/d to create 140kb/d of oil products. This contrasts with the production and shipping of LNG, the major alternative for stranded gas, which results in energy usage of a far less material 13% during the liquefaction process and through 'boil-off' during shipping to its final destination, and an oil refinery's consumption of around 7% of its crude oil feedstock.

Figure 69: About 40% of the gas entering the GTL process is consumed within it relative to only 13% for LNG



› **A GTL plant incurs:**

- **Carbon losses of around 30%, due to the extensive production of carbon dioxide and water. Optimal carbon efficiency of ~75 % may be achieved (depending upon slate)**
- **Energy losses of over 40%, which is primarily associated with the production of synthesis gas, which is energy intensive. The process "looses" significant energy in its generation of water, a major by-product. Optimal energy efficiency of ~65 % could be achieved**

Source: Deutsche Bank

Selected extracts from Global Gas: Battlefield Analysis, published 13 September 2010

Appendix B: Global gas outlook

Industry factors/drivers

1. **Too much gas: global glut**
2. **Russia in Gas OPEC is the Saudi of global gas – holding back production to maintain price**
3. **Still a major challenge for Russia to maintain prices as global LNG supply rises over next year**

There is a **global gas supply glut**, with around 10bcf/d spare capacity – even after demand has been strong on cold winter and hot summer globally. Worryingly for gas prices, we show in this note that gas demand is not price elastic to low prices; with no CO2 legislative change at the margin, demand is dependent on weather and GDP. Slow global growth and less extreme weather could present a demand issue in 2011.

Prices would be even lower if not for the actions of Gas OPEC members, the world's biggest pipeline and LNG gas exporters Russia and Qatar, as they withhold production. We believe that Russia's Gazprom is now the equivalent of Saudi Arabia for oil prices. Current policy is to maintain oil-indexed prices of around US$8/mmBtu for its gas, and hold back excess supply. This policy has attracted LNG to Europe and left US LNG import capacity 85% empty, holding up US gas prices.

Qatar's volume growth will likely drive **a major growth in gas supply over the coming year, whereas US and European demand may well fall** on more normal weather which has been highly supportive of demand in 2010. Gazprom will need to hold back supply to maintain prices globally. By contrast Asia demand races ahead and buyers continue to be happy to pay oil-indexed prices.

Key thinking

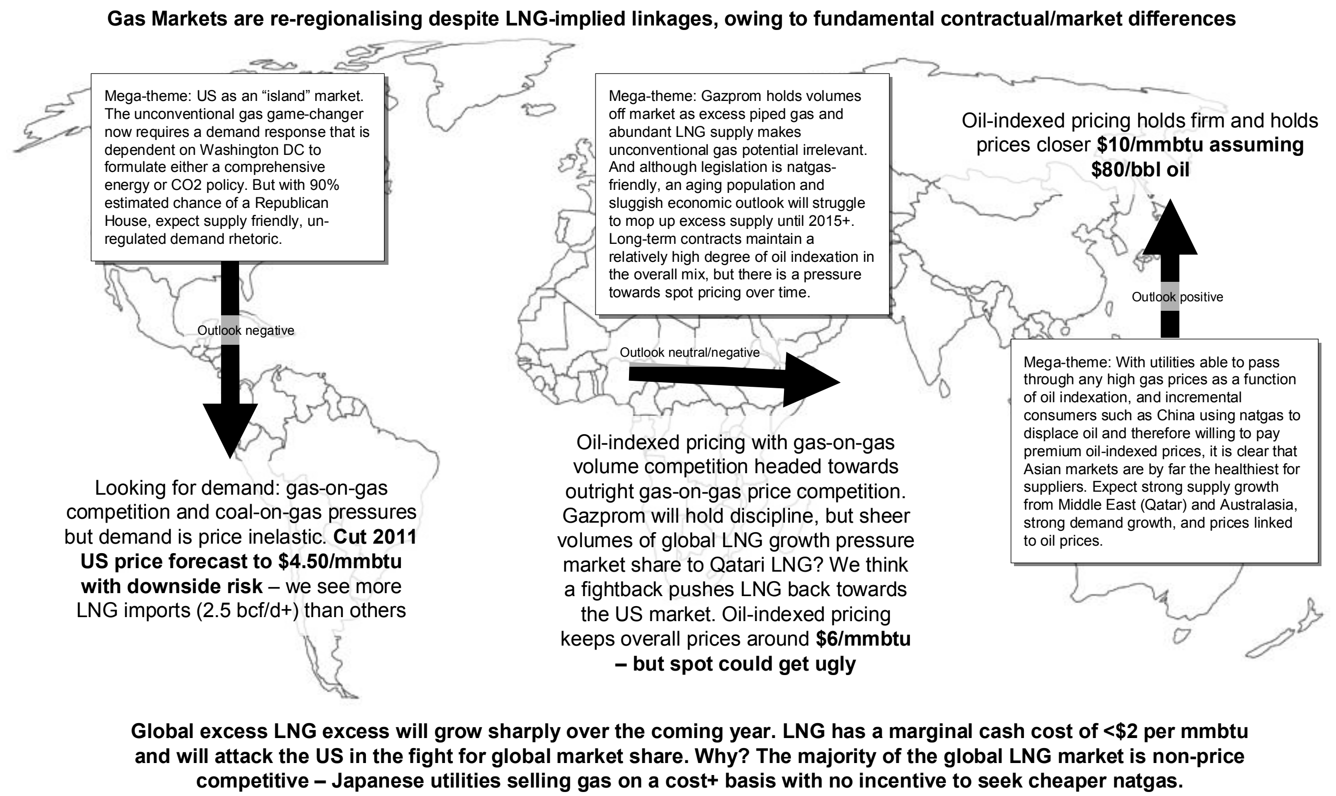
1. **Cutting US gas price forecast on weak outlook**
2. **Europe over-supplied too**
3. **Asia looks good – strong demand and oil indexed prices**

We believe the market is under-estimating the growth in incremental LNG supply that Qatar will supply over the coming year, doubling US LNG imports to 2.6bcf/d into a market we expect to remain over-supplied, as production holds up. **We are cutting our US natural gas price forecast to a below-strip US$4.50 for 2011** and US$5.25 for 2012, and see little market tightness over the next two years.

Given that CO2 legislation is already in place, **Europe** also looks fully supplied through 2015, and only in the post 2015 timeframe does the market look tight, basically because of declining supply rather than any great demand growth potential from these mature, high tax, aging economies. **The huge question here is for how long Gazprom is willing to hold back supply and maintain prices, losing market share to LNG.** Gazprom is arguably now in the position that Saudi found itself in 1986 – lose market share or allow lower prices.

Asia is the bright spot, and we expect strong demand and monopoly buyers to pay around 2x US and European gas prices. Key attractions: growth in Chinese demand and Australian supply.

Figure 70: Too much natgas supply and not enough demand, with low price elasticity of both = fundamentally bearish outlook for prices



Source: Deutsche Bank

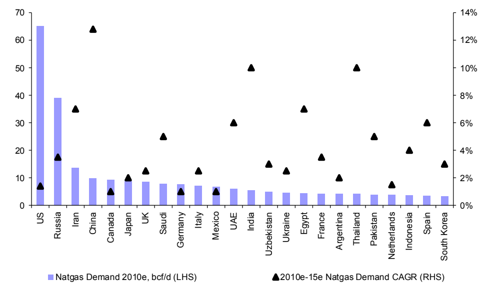
Global natural gas demand

The bad news: there is a demand problem related to the plummet in global gas consumption of some 6bcf/d in 2009 (-2%), which has now led to a 3.0bcf/d glut in excess supply estimated in 2010, with Gazprom scaling back an earlier production 2010 forecast by 9.7bcm (0.94bcf/d). In this note we show that gas demand is price inelastic – in the short and medium term. That is the problem.

The good news: longer term global natural gas consumption rises by a robust 3.6% annually over the period 2010-15 in our forecasts – from 300bcf/d to over 350bcf/d. As with oil demand patterns, Asia and the Middle East are set to be the largest gainers. We expect Asia to generate a 7.6% growth in demand from 2010-15, driven by the world's fourth-largest gas consumer, China (including Hong Kong) (+14.9% CAGR) as it continues to urbanise, industrialise, and adopt centrally-planned, national policies to promote clean fuels. Asian growth should also be driven by India and Thailand, but most bullishly by former gas exporters turning to imports, notably Indonesia and Malaysia. At the margin, this is a key additional driver for Asian volume tightness and price strength.

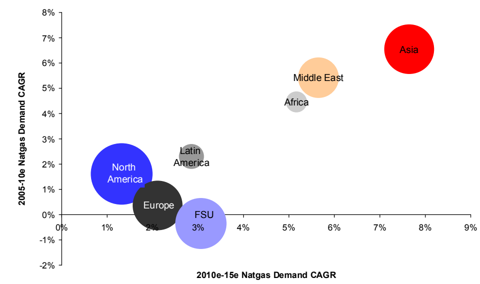
In India demand growth is largely supply-led, as the rising domestic natural gas supply from Reliance's Krishna-Godavari Basin is also replacing fuel oil demand (down 10% year to date) and naphtha (down 15% year to date) for power and fertilizer production.

Figure 71: Natgas demand by country



Source: Deutsche Bank

Figure 72: Natgas demand by region



Source: Deutsche Bank

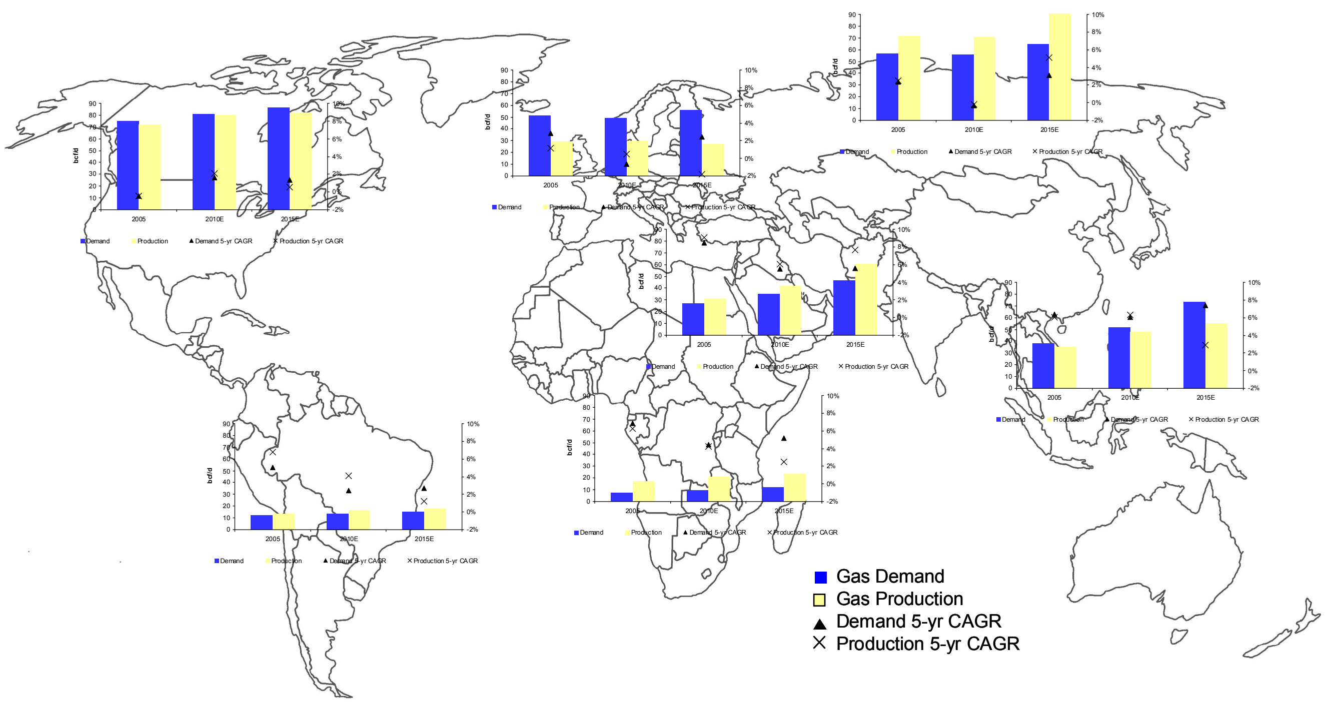
Gas demand is expected to grow 5.6% during 2010-15 in the Middle East, where natgas is underdeveloped, mispriced, and abundant. From a global gas perspective, this is neutral, as we expect most of the gas developments to meet local demand. Overall these countries have failed to develop their natgas resource and left their economies burning expensive oil to meet electricity shortages. Governments have totally failed to exploit their massive gas resources, missed exporting low-cost and abundant gas, with the major exception of tiny Qatar, Oman, and Yemen. Population and GDP growth remains strong. Iran, Saudi, and the UAE will continue to be the top growth drivers and overall consumers, but their exploitation of natgas relative to its potential for their economies has been poor. On balance, Middle East demand growth will equal supply growth and be global gas-neutral.

Among the major consumers, demand is driven by GDP (long term by population growth as a proxy). Weather is hugely important. But a major shift towards natgas as a core fuel has lagged supply growth, and we are convinced that global gas demand is basically price insensitive. More bad news for gas.

Among sectors: although the industrial sector currently consumes more natural gas than any other end-use sector, the growth driver of consumption is clearly electricity generation. The biggest marginal uncertainty in this regard is the US, the largest market with the biggest potential for further growth, should the 50% of power that comes from coal-firing be forced at greater pace towards more carbon-friendly fuels such as natgas. But legislation is required, in our view, to prompt switching from coal-fired power. We believe that abundant US gas supply and weak gas demand puts the onus on low enough pricing to encourage demand. In the absence of legislation, that is in competition with coal. Oversupply is large enough to make oil linkage irrelevant—everything that can switch to natgas already has, as the price relationship in calorific terms is overwhelmingly in favour of gas.

By contrast in Europe, the high relative penetration of natgas, not least as a function of EU energy legislation, makes the outlook for demand far more dependent on GDP growth, which itself will be muted by low population growth, the overall maturity of the economies, and high government deficits. We forecast just 2.1% of demand growth for the period 2010-2015 with expected real Euroland GDP growth of just c.1% in 2010 and 2011 (Deutsche Bank forecast), or 1.9% EU GDP CAGR across 2010-15 (IMF).

Figure 73: Global natural gas supply and demand



Source: Deutsche Bank

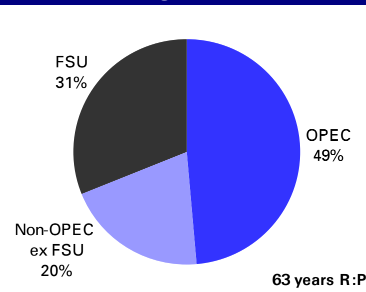
Global natural gas supply

Fundamentally natural gas is more abundant than oil, with a greater resource base across a greater geographic spread; notably some 51% of natgas reserves are non-OPEC, compared with oil's 23%.

Russia dominates global natgas reserves holdings, followed by the Middle Eastern players of which only Qatar has emerged as a natgas exporter, a situation we expect to continue; Middle Eastern gas developments will broadly be to support local demand. Even dominant export growth player Qatar has a moratorium on future developments, once we are past the major phase of growth that is now reaching fruition there. As such, Qatar sits on the largest single gas field in the world, the North Field (also known as South Pars to Iranians).

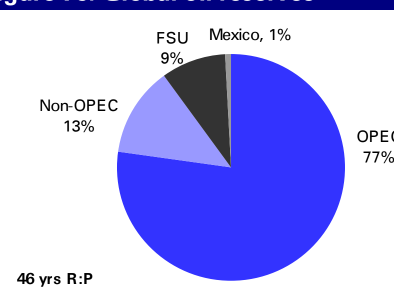
The US is notably high on the list of reserves holders and has an even more impressive reserve when unconventional resource is taken into consideration.

Figure 74: Global gas reserves



Source: Deutsche Bank

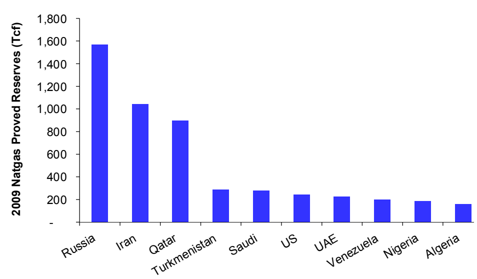
Figure 75: Global oil reserves



Source: Deutsche Bank

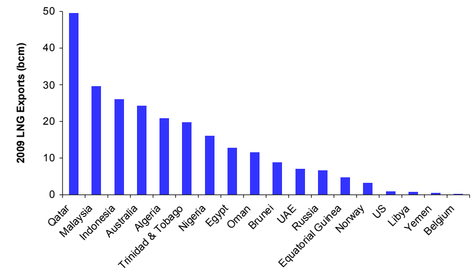
As outlined, we expect strong growth from the Middle East and FSU. These two regions are expected to see the largest production growth between 2010 and 2015. Again, Qatar is the standout growth player, with Turkmenistan, Australia, Brazil, and Saudi also notable.

Figure 76: Top 10 natgas reserves holders



Source: Deutsche Bank

Figure 77: LNG exports



Source: Deutsche Bank

Iran, the largest natgas producer and proved reserves holder in the Middle East, is set to grow production by over 4% annually 2010-2015, in our forecast, despite sanctions, but this will all be consumed locally and, as such, is neutral for the global gas balance—whatever it can develop itself, it will use itself. Number one LNG exporter Qatar, after an extensive summer maintenance plan for seven LNG trains (Qatargas and Rasgas), or 41mmtpa (5.4bcf/d) from April to the middle of July, it is set to drive a c.16% production CAGR in the next five years by leveraging its enormous natgas reserves and low upstream production costs. In 2009, Qatar was the fourth largest gas exporter (6.6bcf/d, 8% of global exports), behind Russia, Norway and Canada, and by far the dominant player in global LNG.

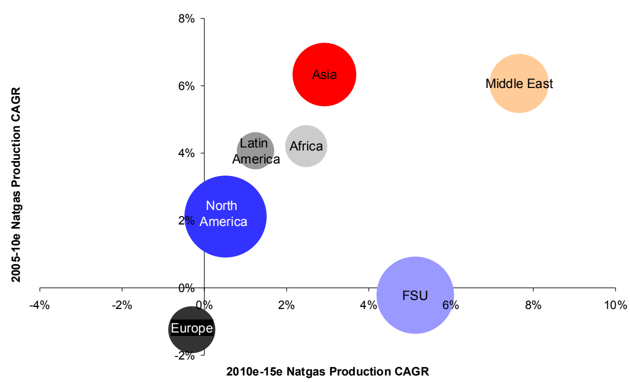
As highlighted, Saudi Arabia and the UAE are also expected to show material growth. Although natgas produced domestically will be used domestically, there is no implicit oil demand impact, basically because the countries are energy short, particularly regarding electricity supply, and all developments, as with Iran, are incremental to overall energy use, rather than substitution; they are neutral for the global gas balance.

Production growth in the FSU will be driven by Turkmenistan (+19.3% CAGR over 2010-15), the world's fourth-largest proved natgas reserves holder, as it comes off a low base following an accident that shut the major CAC (Central Asia-Center) gas pipeline system for a significant portion of 2009. The CAC pipelines run from Turkmenistan to Russia via Uzbekistan and Kazakhstan.

In corporate terms, especially given Gazprom's status as a private company, the interest of gas supply is that it is dominated by private companies, in total contrast to global oil.

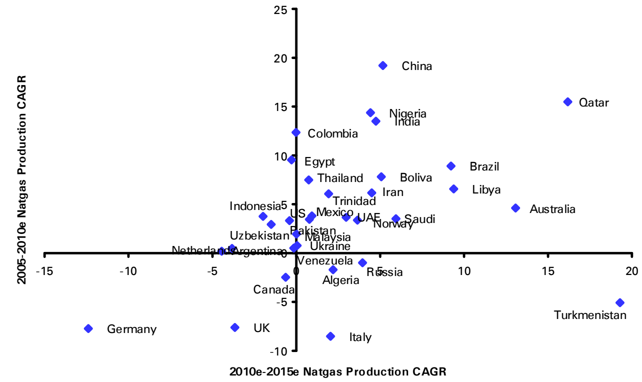
The list of reserves holders in global gas appears similar to oil, with clear over-weights from Qatar, Russia, and Turkmenistan as being notable.

Figure 78: Natgas production by region



Source: Deutsche Bank

Figure 79: Natgas production by country



Source: Deutsche Bank

By contrast the list of global gas producers clearly shows that governments have proven to be even less aggressive and successful in developing natgas as they have been in oil, with super-majors enjoying a disproportionate market share. The good news for the super major oils is that Gazprom and Qatar have acted to reduce supply into the market over the past year, through shut-ins, project development slowdowns, and extended maintenance. The concern is that we now see major growth from Qatar/ExxonMobil, and increasing frustration from Gazprom over its lost market share.

Global gas: price conclusions

In many ways the current hierarchy of global pricing is what would be expected in a market where Gazprom has held back supply and US inventories threatened to hit very high levels. The Asian market, as such, will primarily be driven by oil prices and remain the premium global market. The only major challenge to suppliers in Asia is the "back door price cut," in which buyers sign contracts in exchange for equity stakes in LNG supply projects, therefore enjoying the impressive returns on offers to producers, in exchange for maintaining high-end user prices. Most major contract signings in Asia now include an equity component, underlining that headline prices may well remain high, and spot markets very limited, but that Asian utilities may still be acting entirely in their own interests, simply by moving upstream.

There is also increasing risk to the European supply from the rate of decline and aging infrastructure in the North Sea, which is leading to a risk premium being baked into markets. The contango is incentivising steadily rising storage in Europe to mitigate winter and supply deliverability concerns.

German stocks are now at record levels, and more interesting, and of concern for Gazprom, are also increasingly being met by a knock-on effect of UK LNG imports, re-exported to the Netherlands, and eventually making their way to German inventory. Again, the key question for global gas markets is for how long Gazprom will tolerate this.

Either way, for now European gas prices are at a premium and are keeping LNG volumes headed to Europe, rather than flooding the US. Whether that situation can persist remains to be seen, as European gas buyers paying a premium for long-term contracted oil-indexed gas must surely begin to expect a heavily discounted spot price to balance their weighted average cost of gas over time.

We believe that Asia clearly remains the best-priced market going forward. In the debate between the US and Europe, overall European prices will clearly be higher because of more long-term oil indexed contracts, but in the battle between spot prices, we believe that it will be a tough battle with weather and relative economic strength being the key deciders, alongside, once again, the huge issue of how aggressive Gazprom intends to be on market share and retention of oil-indexed pricing.

In no scenario do we see very high spot natgas prices, in either market, for at least two years; over the longer term we would favour the US market as being more in need of lower carbon fuels, more subject to high decline rate supply, and having better demography, as the more attractive market for long-term spot prices. As outlined in this report, Europe appears fully supplied through 2015 with relatively low risk, price-insensitive supply. That view is not reflected in current futures strips, which clearly discount a return to full market control for Gazprom and a continued overhang of excess supply for US markets.

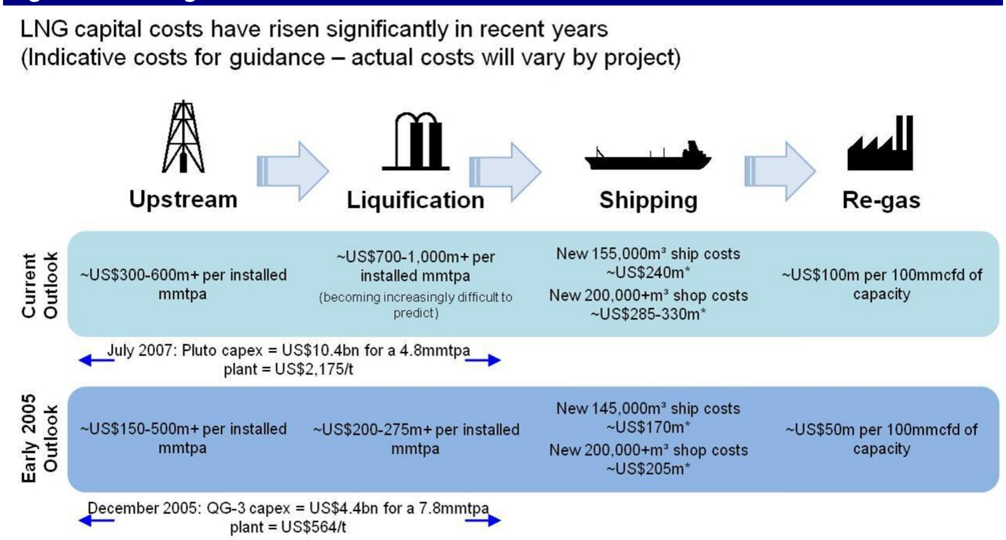
Appendix C: Key economic differences between GTL and LNG

Expanding assumptions

LNG average capex not dissimilar to GTL

LNG technology has not escaped the escalation in capex cost associated with GTL. In December 2005, QG-3 LNG capex was estimated at US$564/t compared with Pluto LNG's expected capex of US$2,175/t in July 2007 (c.US$80,000/boe capacity). In comparison Oryx GTL was constructed in 2007 at c.US$34,000/boe capacity. New capacity in a commercial plant with significant output is expensive with Shell's Pearl GTL plant expected to cost c.US$75,000/bbl of capacity. Sasol is guiding to new GTL facilities capex being approximately equivalent to Pearl GTL on a boe basis. We have allowed for the lowest cost producer (Qatar) LNG capex costs based on guidance for Qatargas 4 (7.8mtpa, c.US$6.1bn).

Figure 80: Rising LNG costs

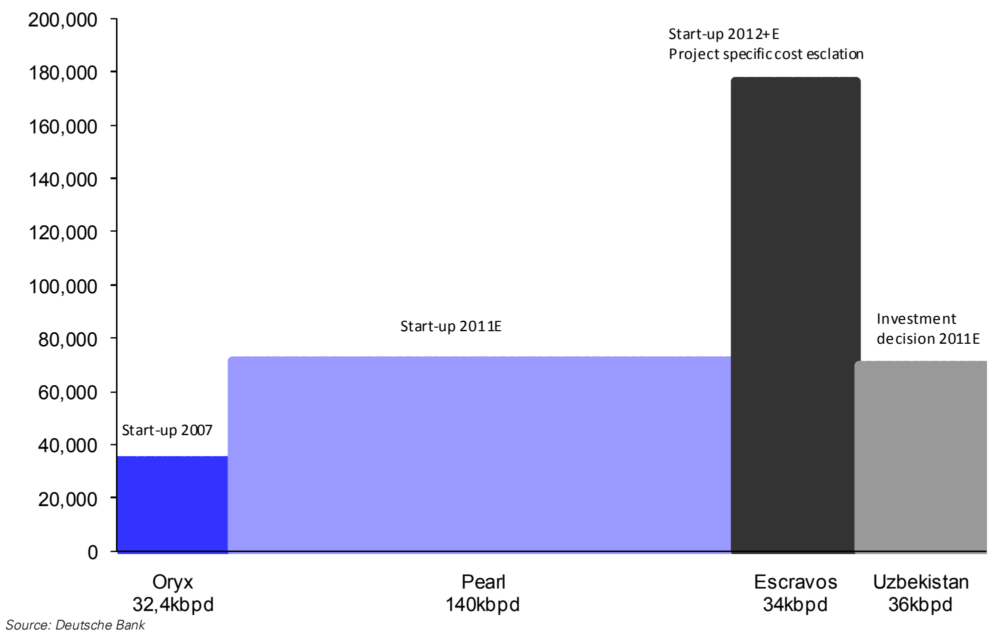


** Delivered cost is approximately 10% higher*
Source: Wood Mackenzie, Deutsche Bank

GTL capital costs limited by reactor economics

The capital costs associated with constructing GTL facilities remain substantial. In part this reflects the inability of companies to find benefit from improved reactor economics. Given the extremely exothermic and challenging conditions under which these operate, increasing reactor capacity has proven very difficult. Consequently, projects operate in batch mode, each unit having a capacity of around 8kb/d using Shell's 'fixed bed' technology or 17kb/d using Sasol's slurry process (but which produces a lower value end product slate). Future capital economics are potentially enhanced by using the steam generated through cooling water to run a combined cycle gas turbine plant.

Figure 81: Capex costs for GTL technology on an installed capacity basis

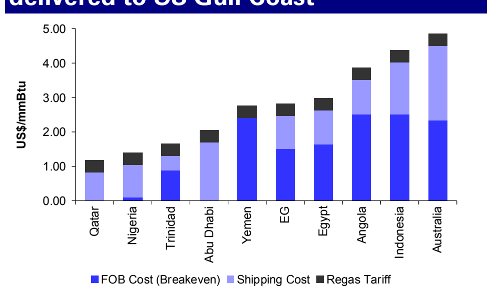


Source: Deutsche Bank

Opex in LNG

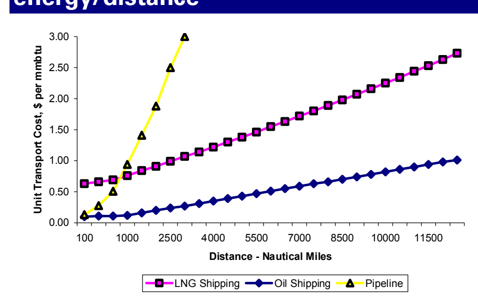
In the longer term, LNG projects have relatively low decline rates and have enormous sunk capex costs, but just c.US$1.50/mmBtu of cash costs making this some of the cheapest gas available in the world at the margin. We have assumed cash costs for low-cost producers of US$0.25/mmBtu with the global average producer tending towards US$1.5/mmBtu. Transportation costs of LNG, although higher than crude oil, are significantly lower than pipeline gas. We have assumed transportation and re-gas costs to total US$1.5/mmBtu for LNG.

Figure 82: Cash cost stack for LNG delivered to US Gulf Coast



Source: Wood Mackenzie, Deutsche Bank

Figure 83: Natgas vs. oil transport by energy/distance



Source: Wood Mackenzie, Deutsche Bank

Opex in GTL

Based on disclosed financial results of Sasol's Oryx GTL facility, we assume opex inclusive of transportation costs to be US$14/bbl with a GTL facility operating at nameplate production capacity. The key components of the cost include staff costs and catalyst expenses.

LNG product pricing

North American LNG is generally sold at posted prices into key hubs, most gas in Europe and Asia has traditionally been sold under long-term contracts indexed to oil.

GTL product pricing

GTL products are assumed to be able to attract a 20% premium over the ruling oil price. This level includes both the conventional refining margin, weighted to the GTL product slate (predominantly higher value diesel and naphtha) and a superior GTL product premium. Low sulphur diesel has averaged a 20% premium over WTI oil prices in the US over the last five-year period.

Appendix 1

Important Disclosures

Additional information available upon request

Disclosure checklist			
Company	**Ticker**	**Recent price***	**Disclosure**
Sasol	SOLJ.J	325.48 (ZAR) 4 Nov 10	1,3,7,8,14,15

*Prices are sourced from local exchanges via Reuters, Bloomberg and other vendors. Data is sourced from Deutsche Bank and subject companies.

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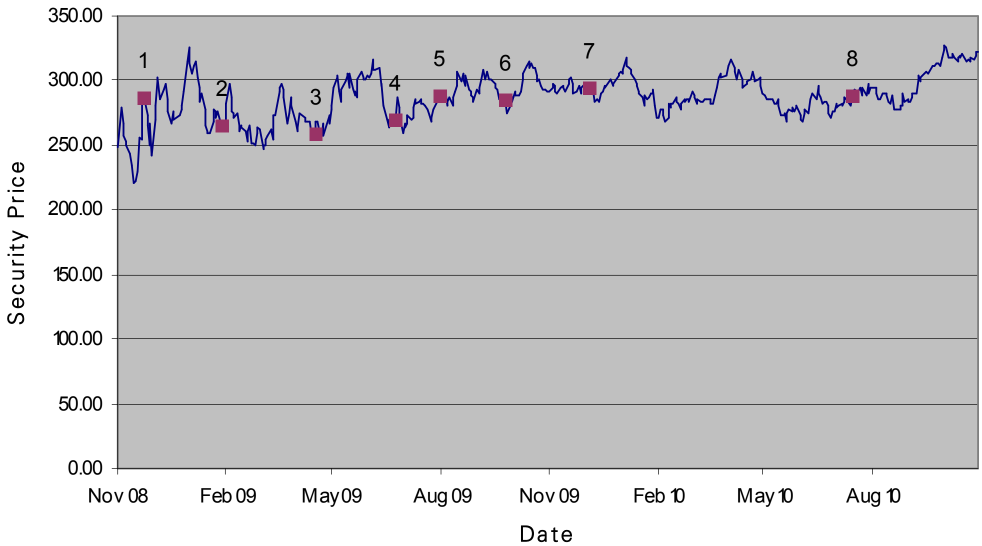
Historical recommendations and target price: Sasol (SOLJ.J)

(as of 11/4/2010)



Previous Recommendations

Strong Buy
Buy
Market Perform
Underperform
Not Rated
Suspended Rating

Current Recommendations

Buy
Hold
Sell
Not Rated
Suspended Rating

*New Recommendation Structure as of September 9, 2002

1.	28/11/2008:	No Recommendation, Target Price Change ZAR0.00	5.	6/8/2009:	Buy, Target Price Change ZAR410.00
2.	2/2/2009:	Buy, Target Price Change ZAR415.00	6.	1/10/2009:	Buy, Target Price Change ZAR370.00
3.	22/4/2009:	Buy, Target Price Change ZAR430.00	7.	10/12/2009:	Buy, Target Price Change ZAR360.00
4.	30/6/2009:	Buy, Target Price Change ZAR440.00	8.	21/7/2010:	Buy, Target Price Change ZAR380.00

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1. Newly issued research recommendations and target prices always supersede previously published research.
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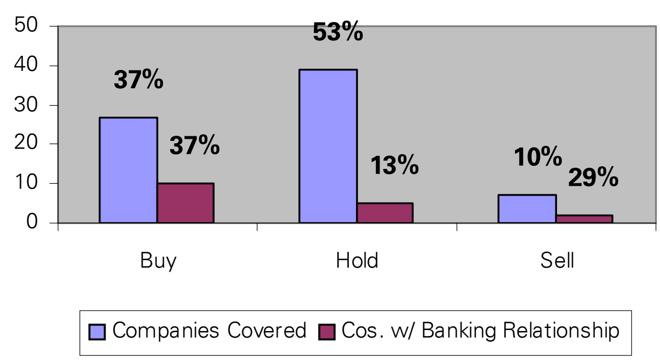

GEMs South African Universe

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