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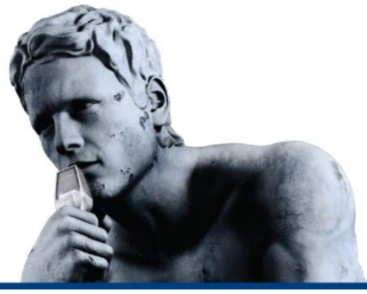

Global Energy update March 2015

Executive Summary

Market consensus has become ever so slightly less negative since the dark days of early January. The general consensus remains that markets are grossly oversupplied, and will remain oversupplied until substantial amounts of current production are forced offline, a process that could take more than 12 months. Our view remains as it was eight weeks ago, and all of the incoming data is on our side. We think the market is setting up for an enormous supply shock through the latter half of 2015 and into 2016, driven by strong demand and shrinking supply. Here we outline the key reasons why we differ from consensus.

As with our original note, we will keep things short. Our view is this: physical crude markets will be on the turn by mid-2015. This will occur as demand strength comes through in response to lower prices. We believe we will have irrefutable evidence of a substantial supply response in both the North American shale plays and the North Sea conventional volumes by mid-year. And as these two forces combine, the net balances shown below will begin to look very different. It will not be plain sailing and investors need to remain cautious for a few weeks yet. There is still the small matter that weakness in physical crude markets is likely to peak around May/June as inventory piles up in the US and in floating storage facilities. But at some point in the not too distant future, equity market players will move from their current extreme bearishness to something less manically depressed. **Equity investors are already recognising the signs of a demand response in the market. But with rising inventories still signalling an oversupplied market, all attention is focused on signs of a supply response, particularly in the epicentre of current oversupply: onshore US. Back in January the default position was "big oil has yet to cut, so there is no supply response". Today, it is "ok, we see cuts in capital spending (capex) coming through so why is supply not falling yet?" We go into more detail below, but the long and the short of our argument is that we believe the window for closing underweight positions is short and crude prices will be substantially higher than they are today come the end of 2015.**

Of course, there are risks to adding exposure to the energy sector here and we would be amiss if we ignored them. There are three key risks at this point. Firstly, oil demand may come up short of expectations if we have an emerging market crisis. Secondly, there is the risk that the Saudis genuinely want a price war and decide to increase production, as opposed to the current strategy of simply talking markets down. And thirdly, if US volumes prove more resilient than we expect despite savage capex cuts, then that would point to prolonged weakness in oil prices.

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Crude market balances in 2015

Figure 1: Oil market supply balances

Energy Aspect	2015 mnbd	Δ
Global Demand	93.5	1.0
OECD Demand	*45.7*	*0.1*
Non-OECD Demand	*47.8*	*1.0*
Non-OPEC Supply	57.3	0.7
Non-OPEC ex-NA	*36.8*	*0.0*
North America	*20.5*	*0.7*
OPEC NGL	*6.5*	*0.1*
Non-OPEC + NGL	63.8	0.8
OPEC to Balance	29.7	0.2

OPEC	2015 mnbd	Δ
Global Demand	92.3	1.2
OECD Demand	*45.7*	*0.0*
Non-OECD Demand	*46.6*	*1.2*
Non-OPEC Supply	57.1	0.9
Non-OPEC ex-NA	*36.4*	*0.0*
North America	*20.7*	*0.9*
OPEC NGL	*6.0*	*0.2*
Non-OPEC + NGL	63.1	1.1
OPEC to Balance	29.2	0.1

US DoE	2015 mnbd	Δ
Global Demand	93.1	1.0
OECD Demand	*46.0*	*0.2*
Non-OECD Demand	*47.2*	*0.8*
Non-OPEC Supply	57.3	0.8
Non-OPEC ex-NA	*35.2*	*-0.1*
North America	*22.0*	*0.9*
OPEC NGL	*6.4*	*0.1*
Non-OPEC + NGL	63.7	0.9
OPEC to Balance	29.4	0.1

IEA	2015 mnbd	Δ
Global Demand	93.4	0.9
OECD Demand	*45.6*	*0.0*
Non-OECD Demand	*47.8*	*1.0*
Non-OPEC Supply	57.4	0.8
Non-OPEC ex-NA	*38.0*	*0.1*
North America	*19.4*	*0.7*
OPEC NGL	*6.6*	*0.2*
Non-OPEC + NGL	64.0	1.0
OPEC to Balance	29.4	0.0

Source: Energy Aspects, Schroders, February 2015.

Markets are oversupplied today, that much is clear. They have been oversupplied since mid-2014, firstly as reduced US imports created a surplus of crude in the Atlantic basin, and latterly as Libyan volumes through the second half of 2014 exceeded expectations despite civil war conditions. **But the quantum of oversupply is not what you might expect given the scale of price retracement, namely a revised ~1.0mnbd (million barrels per day) through 2014 in a global market of 92mnbd.** A reasonably large portion of this excess was initially absorbed by Chinese strategic inventory building, but as the oversupply crept higher late in the third quarter of 2014 with surging Libyan volumes, inventories began to pile up in commercial storage, pressuring physical markets lower.

As the markets peer into 2015, this oversupply remains in place, and initial forecasts point to things getting worse before they get better. This is predicated on no improvement in demand and further increases in supply from Brazil, Iraq, the Gulf of Mexico and Angola. The key agency forecasts summarised above in Figure 1 are interesting when seen through the lens of marginal change. **Over the past two months, average demand forecasts have improved by around 200kbd (thousands of barrels per day) largely thanks to strength in the US. Similarly, average supply forecasts have fallen by 200kbd on lower assumptions for US and European volumes.** Thus far, that 400kbd swing is not enough to offset the 1mnbd oversupply we had coming into 2015, but the direction of travel points to a tightening market at the margin.

This type of analysis is very static however, giving an impression of certainty that simply does not exist. As an illustration of just how dangerous it is to rely on these balances, the forecasts assume that demand does not change much over the course of 2015 in response to a 50% reduction in crude prices. The forecasts also assume that there will be little or no supply response to sharply lower crude prices during 2015. We vehemently disagree with both assumptions. **We expect demand to respond to lower prices, as it always does. And we expect supply to respond to lower prices, as it always does. It is fashionable to talk about the new normal for oil. We suspect the new normal will look a lot like the old normal. This time is not different. It is just another oil price cycle.**

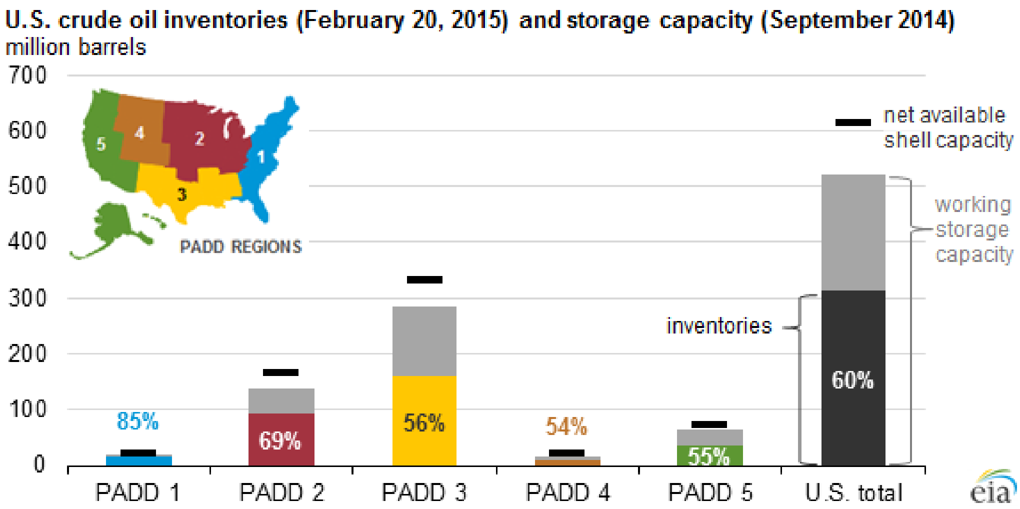
Figure 2: Forecasts for "Call on OPEC" versus 30mnd quota level:

CALL ON OPEC (mnbd)	Q1-15	Q2-15	Q3-15	Q4-15
ENERGY ASPECTS	29.3	28.8	30.1	30.3
US DEPARTMENT OF ENERGY (DOE)	29.5	28.9	29.6	29.5
INTERNATIONAL ENERGY AGENCY (IEA)	28.7	28.4	30.3	30.2
OPEC	27.9	28.1	30.1	30.7
CURRENT OPEC QUOTA	30.0	30.0	30.0	30.0
AVERAGE OVERSUPPLY	-1.2	-1.5	0.0	0.2

Source: Schroders, Energy Aspects, February 2015.

The key market worry for crude traders is still second quarter 2015 seasonal weakness, as the market looks to be around 1.5mnbd off-balance for 90 days during refinery maintenance season as illustrated in Figure 2. It is worth mentioning that this is not much more than seasonal norms, but with current inventory levels quite high and Saudi intentions unclear, this means that up to 135 million barrels of additional inventory will be looking for a home – too much for Cushing, Rotterdam and Singapore to absorb as things stand. There is a fear that the US will run out of storage but a recent report by the US Department of Energy pointed to at least 220 million barrels of storage capacity available in the US, primarily in the core Gulf refining region known as PADD2. **We believe market fears of hitting tank tops are misplaced. To quote the Energy Information Administration (EIA) report, "Simply dividing the total commercial crude inventory by the working capacity can lead to overestimates of storage capacity utilization, because some inventory data include crude oil that is not truly in stored in tankage, such as pipeline fill, lease stocks, or crude oil on ships in transit from Alaska".**

Figure 3: Are we close to maximum storage in the US?



Source: EIA, March 2015.

The supply response is coming, and faster than you think

As crude prices began to sink under the weight of Libyan barrels in October and November 2014, there was a working assumption in boardrooms that OPEC would come to the rescue in late November, and prices would recover back to prior levels. There was no sense of panic or urgency. The OPEC meeting on 27 November changed all that. Crude prices lurched sharply lower, and the first companies to react were the US upstream players, marking 2015 budgets to an assumed price deck of $70 for 2015. Majors and super-majors said little, and where any commentary was forthcoming, it was along the lines of "we are long-term investors and invest through cycle, so we will not respond to temporary movements in price".

With prices continuing to plummet through December and into January 2015, the reaction across the industry changed rapidly. Upstream exploration and production (E&P) companies realised they were now in a battle to survive, with many of them taking two or three hacks at the spending budget to right-size for the rapidly shrinking new price reality. Spending plans have ratcheted down towards maintenance capex levels across the board. And while the majors were slow to react, they too have kicked in with 15-20% capex cuts on average. Figure 4 below summarises the reaction across the energy universe we cover. **It shows an average capex reduction of 40% for the small and mid-sized players, a 17% reaction from the majors, and combining the two gives a 21% reduction in global spending for the industry in 2015.** While 20% does not sound huge relative to 50% lower oil prices, the E&P cuts are focused primarily in the US and give a flavour of the activity reductions being seen across Texas and North Dakota today.

Figure 4: Changes to 2015 capex plan versus 2014 budget and prior indication for 2015

yellow = announced revised number grey = soft guidance	2014 CAPEX US$mn	2015 ORIGINAL CAPEX US$mn	2015 REVISED CAPEX US$mn	%△ NEW/ OLD	%△ 2015/2014
BG Group	-9435	-7750	-6100	-21%	-35%
BP	-23781	-24000	-20000	-17%	-16%
Canadian Natural	-6308	-8600	-6200	-28%	-2%
Canadian Oilsands	-993	-646	-264	-59%	-73%
Cenovus	-2819	-2850	-1850	-35%	-34%
Chevron	-34954	-34954	-31000	-11%	-11%
CNOOC	-19000	-17200	-12000	-30%	-37%
Conoco	-16750	-17000	-11500	-32%	-31%
ENI	-13991	-13500	-12000	-11%	-14%
Exxon	-37764	-37764	-34000	-10%	-10%
Hess	-5800	-5750	-4750	-17%	-18%
Lukoil	-14500	-14000	-12000	-14%	-17%
Marathon Oil	-5485	-5500	-4000	-27%	-27%
MEG Energy	-1200	-1600	-305	-81%	-75%
Occidental	-9305	-8500	-5800	-32%	-38%
Petrobras	-41792	-44000	-32000	-27%	-23%
Petronas	-18431	-17625	-14100	-20%	-24%
Repsol	-5668	-4716	-3516	-25%	-38%
Royal Dutch	-35114	-35114	-33358	-5%	-5%
Statoil	-19834	-19000	-17000	-11%	-14%
Suncor	-6217	-7500	-5400	-28%	-13%
Total	-24762	-24762	-23400	-5%	-5%
CAPEX ASSUMPTIONS - MAJORS	**-355265**	**-353930**	**-292143**	-17%	-18%
Anadarko	-8560	-7860	-5500	-30%	-36%
Apache	-9250	-8700	-3800	-56%	-59%
Approach Resources	-400	-450	-180	-60%	-55%
Athabasca Oil	-550	-432	-242	-44%	-56%
Baytex	-572	-821	-575	-30%	1%
Bellatrix	-455	-530	-300	-43%	-34%
Cabot Oil & Gas	-1480	-1480	-900	-39%	-39%
Callon Petroleum	-254	-270	-200	-26%	-21%
Cimarex	-2045	-2045	-1000	-51%	-51%
Concho Resources	-2600	-3000	-2000	-33%	-23%
Continental Resources	-4800	-5200	-2700	-48%	-44%
Denbury Resources	-1100	-1100	-550	-50%	-50%
Devon Energy	-5785	-5785	-4628	-20%	-20%
Emerald Oil	-406	-400	-80	-80%	-80%
Encana	-2500	-3700	-2800	-24%	12%
Enquest	-970	-1000	-600	-40%	-38%
EOG Resources	-7905	-8500	-5000	-41%	-37%
Gastar Exploration	-214	-257	-171	-33%	-20%
Gran Tierra	-428	-400	-135	-66%	-68%
Goodrich	-318	-325	-175	-46%	-45%
Halcon	-2250	-800	-375	-53%	-83%
Laredo Petroleum	-1050	-1050	-525	-50%	-50%
Legacy	-490	-490	-238	-51%	-51%
Matador Resources	-549	-549	-350	-36%	-36%
Murphy	-3400	-3400	-2300	-32%	-32%
Newfield Exploration	-1950	-1800	-1171	-35%	-40%
Northern Oil & Gas	-435	-435	-140	-68%	-68%
Oasis Petroleum	-1425	-1325	-750	-43%	-47%
Parex	-225	-300	-150	-50%	-33%
Pioneer	-3350	-3350	-1850	-45%	-45%
Premier Oil	-1150	-1000	-600	-40%	-48%
Range Resources	-1442	-1300	-870	-33%	-40%
Sanchez Energy	-832	-1100	-575	-48%	-31%
Ultra Petroleum	-1020	-1440	-500	-65%	-51%
WPX Energy	-1575	-1575	-725	-54%	-54%
CAPEX ASSUMPTIONS - E&P COMPANIES	**-74746**	**-75130**	**-45361**	-40%	-39%
TOTAL (ALL COMPANIES)	-430011	-429061	-337504	-21%	-22%

Source: Schroders, company estimates, February 2015.

US companies are responding the quickest for the simple reason that they are the marginal barrel in a world where the OPEC cartel is out to lunch. As figure 5 below illustrates, Eagle Ford and Bakken volumes make no sense at these prices, and that argument also holds for Permian volumes. **The three great US shale plays, the game changers for US energy independence, are wholly uneconomic at current prices**. Any investors who doubt this statement should take a read of the EOG Resources fourth quarter transcript. The best shale operator in the world, with the lowest cost base, the best acreage and the highest returns, decided to slam the breaks on its drilling program, cutting drilling rigs by 50%. In addition they said “we do not believe that growing oil in a short cycle low oil price environment is the right thing to do”.

Figure 5: Shale economics for new wells do not work here

Oil price deck $/bl	$50	$60	$75	$90
Bakken Economics ATROR				
Tier 1 well	-7%	3%	18%	33%
Tier 2 well	-10%	-2%	10%	22%
Tier 3 well	-10%	-4%	5%	14%
Tier 4 well	-9%	-5%	1%	8%
Eagle Ford Economics ATROR				
Tier 1 well	-8%	6%	26%	46%
Tier 2 well	-7%	2%	16%	30%
Tier 3 well	-3%	0%	5%	10%
Tier 4 well	-8%	-5%	-1%	3%

Source: Energy Aspects, Schroders, December 2015.

Figure 5 really only deals with new well economics, in other words the incentive to spend new dollars. It clearly points to a sharp slowdown in future drilling and production. But might prices also drive some current production out of the industry? In other words, are some fields already losing money every day on a cash basis?

Figure 6 tackles this question at the corporate level. It shows that at $50 per barrel ($50/bl) WTI oil prices, most of the US industry is already in the red zone. On a pure cash cost, the average player needs $36/bl in 2015 to cover all operating costs at the wellhead plus corporate G&A (general and administrative) and interest costs. With prices in the Bakken below $40/bl, current market conditions are clearly critical. When maintenance capex is included as the companies want to do more than just pay the electricity bill every quarter, the average number rises to $54/bl in 2015. These numbers are our own and contain various assumptions, but they are presented in the most consistent way possible. Many market commentators and companies talk about cash costs of ~$30/bl but these are wellhead only – they do not include local basin differentials as costs, nor do they include corporate SG&A (selling, general and administrative expenses) and tax, let alone maintenance capex.

Figure 6: Cash costs for upstream $/bl 2015 (f)

Company	2014 Liquids Volumes	2015 Cash cost breakeven $/boe including SG&A	2015 Cash cost breakeven $/boe including SG&A, tax and maintenance capex
Emerald	4.2	-$40.38	-$68.45
Laredo	15.6	-$40.52	-$61.92
Concho	73.9	-$35.41	-$59.41
Marathon	285.2	-$40.69	-$59.16
Enquest	27.8	-$35.26	-$58.83
Hess	243.0	-$34.70	-$58.32
MEG Energy	69.0	-$45.33	-$58.13
Devon Energy	352.8	-$43.70	-$57.94
Conoco	891.9	-$42.85	-$57.91
Apache	374.6	-$37.17	-$57.88
Sanchez	20.1	-$35.08	-$57.58
Cimarex	73.9	-$42.08	-$57.32
BP	1025.0	-$37.02	-$56.44
Total	1036.2	-$45.41	-$56.00
Newfield	73.3	-$31.35	-$49.35
Anadarko	416.3	-$40.64	-$55.55
Premier Oil	33.8	-$35.11	-$56.80
EOG Resources	369.2	-$35.57	-$53.57
Cenovus	201.1	-$36.25	-$52.71
Matador	8.7	-$34.42	-$52.42
Occidental	563.3	-$37.13	-$52.41
Northern	14.4	-$23.55	-$52.00
Chevron	1724.8	-$32.54	-$50.04
Suncor	541.9	-$28.78	-$49.86
Shell	1486.1	-$29.50	-$53.88
Oasis	40.2	-$27.56	-$49.49
Continental	119.0	-$29.44	-$49.04
Exxon	2082.4	-$34.24	-$47.73
Total / Average	**11788.6**	**-$35.61**	**-$54.22**

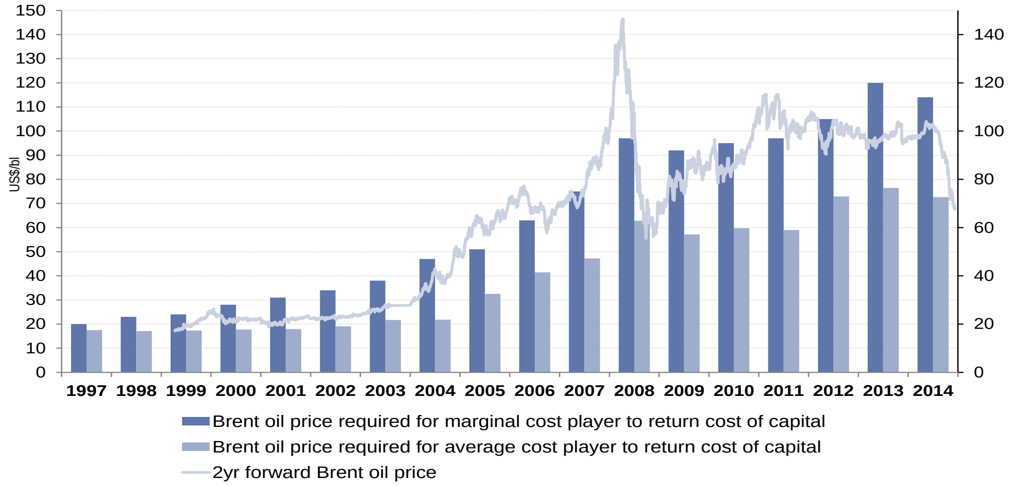
Source: Schroders, company reports, January 2015.
Notes 1: 28 global companies comprising ~12mnbd of daily oil production.
Notes 2: Cash cost calculation includes wellhead opex, transportation, basin differentials, corporate SG&A, corporate net interest payments, corporate tax and any 2015 hedges in place.

This is not an exhaustive list of companies by any means and could include hundreds of smaller listed and private companies. Arguably our subset shown here gives a false impression of strength as these will be the strongest players in the industry, because small-cap and private players typically have greater exposure to higher cost assets.

Our own conversations and observations also note that the operator of the Athena field in the North Sea recently stated that at $58/bl Brent prices they were losing $30/bl on every barrel produced. Similarly, Repsol have indicated that as part of their takeover due diligence they noted that many of Talisman's North Sea assets have operating expenses (opex) per barrel in the $90/bl range. **The conclusion remains the same. This industry is unsustainable at $50/bl and therefore $50/bl is the wrong price.**

Another way to look at the issue of costs across the industry is to work out where Brent crude prices are trading at relative to where the average oil company earns its cost of capital. We follow much the same approach when setting our normalised oil price of $85/bl in 2019, namely at what price the average company with average costs earn a 15% pre-tax return on capital, equivalent to 11% after-tax returns, a relatively acceptable return above the cost of capital. **The chart below from Goldman Sachs shows that at current prices, the oil price is not only beneath the price required for marginal producers to make their cost of capital, it is also below the price required for *average* cost players to achieve cost of capital returns. This is only the second time in 17 years of data that this has occurred, and highlights how unsustainable the current situation is in a historic context.**

Figure 7: Brent price required for marginal and average cost players to achieve WACC

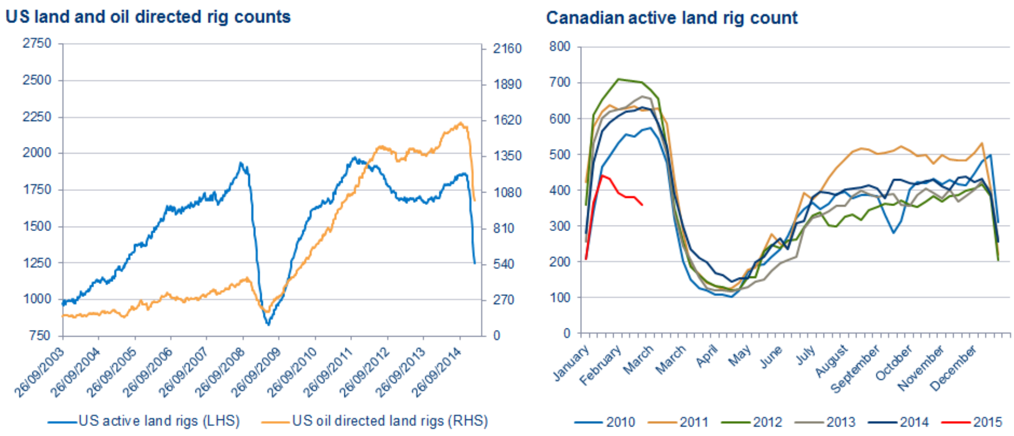


Source: Goldman Sachs, February 2015.

The speed of supply response – USA?

Spending cuts are happening far more quickly and substantially than investors dared to believe only a few weeks ago. The first wave of responses will be felt in North America as rigs are laid down, with expected growth of 1mnbd in 2015 likely to evaporate in the face of current oil prices. Already we have seen 660 rigs dropped since the peak in early December 2014, and at the current rate of rig attrition, we would not be at all surprised to breach 800 by the end of March and 1000 by the end of April. This is from a peak rig level of 1900 reached on 7 December 2014.

Figure 8: Rig counts dropping like stones in US and Canada



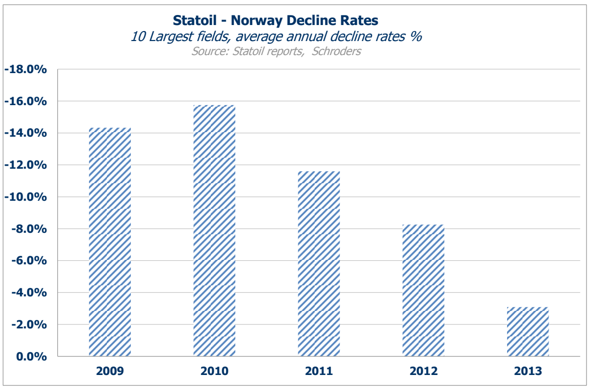
Source: Baker Hughes, February 2015.

Market expectations just a few short weeks ago saw 1mnbd+ of growth coming from US liquids in 2015. As prices have collapsed, expectations had moved towards 300-400 rigs being laid down, allowing growth to continue through the first half of 2015 before slowing sharply in the second half, with an outcome of supply growing by 500kbd across the year. Those expectations are no longer reasonable. If 1000 rigs are dropped, US production will be in steep decline by year-end 2015. Given the high starting point for volumes in 2015 relative to average production in 2014, this still implies some growth year-over-year, but we are talking about 200-300kbd of growth rather than 1mnbd+. And more importantly, given that volumes will be in decline at year-end 2015, it is likely that 2016 volumes will be flat year-over-year. **In sum, that is a combined 1.5-2mnbd of production removed from the system, just from adjustment onshore US. In addition, and importantly for current expectations, we expect the impact of rig lay-ups to be visible well before mid-year (possibly April) as Bakken and perhaps even Eagle Ford volumes drop sharply.**

The speed of supply response – Conventionals/North Sea?

The market is rightly focused on US shale players as the fly-wheel for the industry, where capital can most quickly be deployed and removed in response to price signals. But we should not ignore the speed with which the wider industry will remove capital from conventional production. Yes, they will cut non-core areas such as exploration and seismic as a first step and longer-dated projects will be shelved. But there will also be a substantial withdrawal of capital from maintenance and modification work, the type of work needed to manage decline rates in high decline mature basins. Widespread redundancies at Statoil and service players complaining of a total drought in the North Sea for tie-back and in-fill drilling work, point clearly to an industry cutting back sharply on these short payback projects.

Figure 9: Decline curves and oil prices



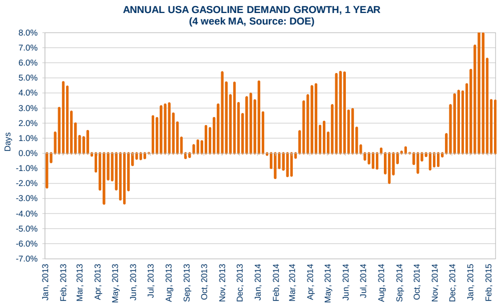
Source: Statoil, Schroders, December 2014.

By way of an example, drilling an infill well at a mature North Sea location will help maintain current production and keep old platforms working, and likely makes nice returns at $100/bl prices**. At $50/bl, such projects make no sense at all and the industry will let the decline curves go for a while in order to balance the books.** We can see strong evidence of this behaviour in the quarterly data-sets provided by Statoil, illustrated here in Figure 9. Decline rates back in 2009 at the previous trough were approaching 16%. As prices recovered, the company dedicated large amounts of cash to stemming decline rates and managing decline in the core portfolio. With oil prices averaging north of $100/bl for three years, they achieved that objective. At current prices and based on evidence from the service providers in Norway we should expect this pattern to reverse quite sharply.

A brief word on demand

Many commentators have said demand will not respond to low oil prices. Many arguments are put forward, from fuel efficiency to demographics to subsidy rollback – the list goes on. In the absence of an emerging market crisis impacting oil demand, there is no reason whatsoever to expect that this time will be different. We already see the first shoots of a demand recovery in the US and China. And with $2 per gallon pump prices across the US it should come as no surprise that large trucks and SUV's like the Escalade are selling like hot-cakes. Fuel efficiency be damned, Escalade sales were up 75% year over year in November. Fill her up!

Figure 10: US Gasoline Demand Growth 1yr %



Source: Department of Energy, February 2015.

Figure 11: Fuel efficiency, US style

Conclusion

Crude markets have been in turmoil for three months now as the Saudis appear to have relinquished their role as swing producers. The market is searching for a level that will both incentivise near-term storage economics and longer-term reinvestment levels. At current prices and forward curve structures, the market has achieved the former, but not the latter. There are three key risks to our recovery scenario at this point.

Firstly, oil demand may come up short of expectations if we have an emerging market crisis, with the combined impact of lower oil prices and a stronger US dollar increasing risks in this regard. We do not have much to add here other than to point out that stress lines today appear to be running through major oil producers such as Venezuela, Russia, Nigeria and Iran.

Secondly, there is the risk that the Saudis genuinely want a price war. At this stage the Saudis have done nothing but talk. Their actions in the market remain normal and are not indicative of any market share seeking behaviour. If the Saudis decide to actually increase production and drive prices down for a sustained period, as opposed to the current strategy of talking markets down, then that would be a significant change to expectations. We note that the Saudis have around ~$750 billion worth of reserves today and that holding oil prices at the current levels will cost them approximately $150 billion per year.

And thirdly, if US volumes prove more resilient than we expect despite savage capex cuts, then that would point to prolonged weakness in oil prices. Producers might be expected to prioritise the best wells with the highest productivity and oilfield service pricing will undoubtedly fall sharply. But we believe that the first order of business for the industry today is to save the balance sheet, reduce drilling activity sharply, wait for lower costs and then reconsider activity levels once they have guaranteed survival. The behaviour of industry leader EOG Resources is entirely in keeping with our thought process. For poorer quality players, the constraint will be financing both on the way down and in the recovery phase. We do not believe any management teams are looking to drill through the weakness at this stage.

Our view for 2015 is as follows. Market participants want to see signs of demand growth and supply restraint before taking a position in either crude markets or the related equities. The first significant moves have already come with fourth quarter (2014) earnings, as capex cuts have been far deeper than investors expected. Two months ago we forecast that the industry overall would see capex down 15-20% for majors on average, down 30-40% on average for E&P companies, for an industry wide capex reduction in the region of 25%. We are almost exactly on track today. We have reset all our oil service company models to reflect this outlook for revenues.

The physical manifestation of these capex reductions on supply should become visible relatively quickly with Bakken volumes and North Sea volumes falling short of expectations, and we anticipate the first concrete signs of supply restraint to appear in April as we come out of the winter slowdown in North Dakota. All the while, inventories will likely be climbing as the refinery maintenance season begins midway through the first quarter and runs through to May, so physical markets will remain weak during the period. It is therefore unlikely that spot crude markets will show any signs of strength until later in the second quarter and into the third, as prices will be dictated by daily balances and storage availability. **Nevertheless, futures markets should begin to grind higher before spot prices move if signs of both demand growth and supply restraint come through as we expect. Equity markets should move ahead of the futures markets, climbing a classic wall of worry. Those investors wise enough or lucky enough to have been substantially underweight the sector through the last 12 months should think very seriously about closing that position today given equity valuations are now back to early 2009 levels**.

Figure 12: Schroders price deck assumptions – 2019

	2013	2014	2015F	2016F	2017F	2017F	2019Fn
Schroders Brent ($/bl)	108.8	99.0	62.6	70.2	73.0	79.0	85.0
Brent Forward	108.8	99.0	62.6	70.2	73.0	75.0	77.3
Schroders WTI ($/bl)	97.7	93.2	53.9	62.2	65.0	71.1	75.0
WTI Forward	97.7	93.2	53.9	62.2	65.0	66.9	68.6
Schroders Henry Hub Gas ($/mcf)	3.70	4.40	2.90	3.20	3.50	4.25	5.00
Henry Hub Forward	3.70	4.40	2.90	3.20	3.50	3.60	3.70

Source: Schroders March 2nd 2015, Schroders assumptions for oil at 100% of forward strip to 2017, fading to 2019 normalised year.

John Coyle/Mark Lacey – March 2015