

# The window for thermal coal investment is closing

Commodities Research

## **The window to invest profitably in new mining capacity is closing**

Earning a return on incremental investment in thermal coal mining and infrastructure capacity is becoming increasingly difficult. In the short term, a sharp deceleration in seaborne demand (we expect average annual growth to decline to 1% in 2013-17 from 7% in 2007-12) has moved the market into oversupply and caused a downward shift in the cost curve; **we downgrade our price forecasts** to US\$83/t in 2014 and US\$85/t in 2015 (down 13% and 11% respectively) and maintain a relatively flat outlook for the rest of our forecast period to 2017.

Mines are long-lived assets with a long payback period, and investment decisions today are sensitive not just to prices and margins today, but also to projections going well into the next decade. We believe that thermal coal's current position atop the fuel mix for global power generation will be gradually eroded by the following structural trends: 1) **environmental regulations** that discourage coal-fired generation, 2) strong competition from **gas and renewable energy** and 3) improvements in **energy efficiency**. The prospect of weaker demand growth (we believe seaborne demand could peak in 2020) and seaborne prices near marginal production costs suggest that most thermal coal growth projects will struggle to earn a positive return for their owners; in our view, this is reflected in the way diversified mining companies are reallocating their capital towards more attractive sectors.

## **Insights from an equipment manufacturer: Alstom interview**

We interview Mr. Wouter van Wersch, President of Alstom Singapore. Equipment manufacturers are directly involved in the decision-making process of power utilities and are thus ideally placed to comment on the future trends in the power sector which accounts for ~80% of global thermal coal demand. The key insights we take away are 1) even when carbon prices are low or non-existent, **the downside risks of future regulation can offset the cost advantage of thermal coal relative to alternative energy sources**, 2) demand for coal-fired generation remains strong in India and southeast Asia but the number of new plants is expected to decline by the end of the decade and 3) the energy sources with the most upside potential include gas and solar power.

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## Executive Summary: Constrained demand will cap investment

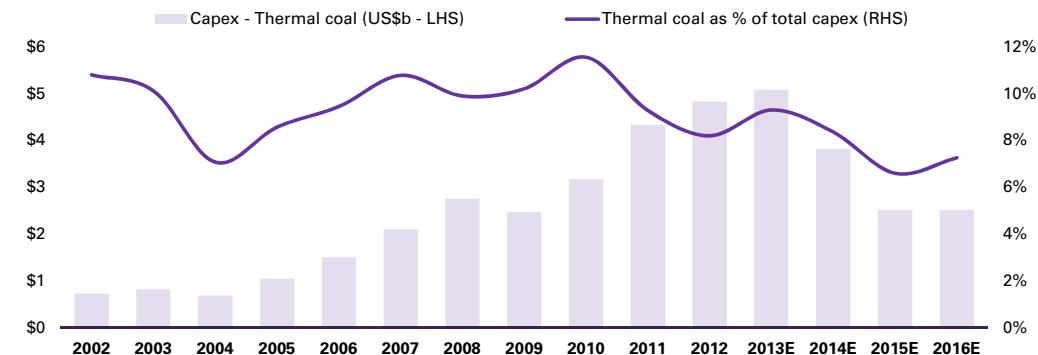
In July 2013 the World Bank announced a new policy to limit financing of coal-fired power plants to rare circumstances where no feasible alternatives are available. A few days later, the US Export-Import Bank declined to participate in the financing of a large coal-fired plant in Vietnam on environmental grounds. Coming on the back of China's first emissions trading program, we believe these events are indicative of a gradually worsening outlook for thermal coal demand, with implications for equity investors in particular.

### The window for profitable investment in coal mining is closing

Thermal coal has enjoyed a long period of strong demand growth but in our view the next 10 years will not be as benign. Coal currently sits comfortably at the top of the global fuel mix with a 36% share of electricity generation, well ahead of gas (23%), hydro (16%) and nuclear energy (13%). In no small part because of China's rapid transition from a mid-sized exporter to the world's largest importer, seaborne demand growth in the period 2007-12 increased to an average annual rate of 7.2%. However, a sharp deceleration in seaborne demand (we expect average annual growth to decline to 1% in 2013-17 from 7% in 2007-12) has moved the market into oversupply and caused a downward shift in the cost curve; we downgrade our price forecasts and expect a narrow price range around US\$85/t FOB Newcastle (vs. US\$95/t previously) for the rest of our forecast period to 2017.

Earning a return on incremental investment in thermal coal mining and infrastructure capacity is becoming increasingly difficult. Mines are long-lived assets with a long payback period, while thermal coal is a geologically abundant resource in an industry with relatively low barriers to entry. As coal demand becomes increasingly constrained, the competition among suppliers is likely to intensify. This change in outlook is reflected in the way diversified mining companies are reallocating their capital towards more attractive sectors. We focus on 4 large diversified miners with a combined share of the seaborne market of approximately 27% in 2013. In contrast to single-commodity miners, they have a range of investment opportunities across their portfolio and the aggregate share of capital allocated by this group to thermal coal should reflect its potential returns relative to other commodities. At its peak in 2006-10, thermal coal absorbed up to 12% of the aggregate growth capital across these companies (Exhibit 1). However, we expect that share to decline in both absolute (down 50% between 2013 and 2016) and relative terms (down to 7% by 2016), according to our estimates.

**Exhibit 1: Thermal coal is attracting a smaller share of mining capex**  
Capital investment in thermal coal by 4 major diversified mining companies



Source: Company data, Goldman Sachs Global ECS Research estimates

## Structural drivers will constrain demand in the long term

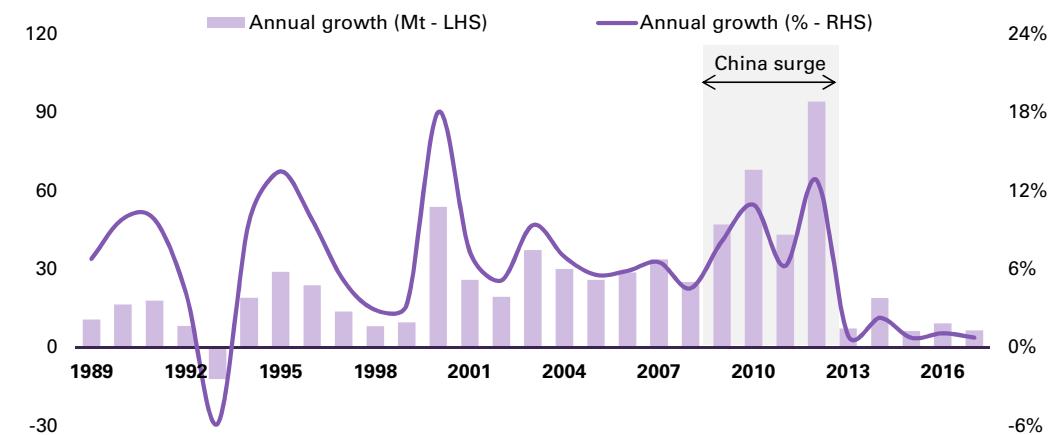
We believe that the following trends will gradually erode coal's dominant position in the long term; in our view, these structural trends are already shaping the power sector and their impact will become increasingly visible.

1. **Environmental regulations** that discourage investment in coal-fired power plants in OECD countries, and to a lesser degree in non-OECD countries as well.
2. Strong competition from **gas and renewable energy**, partly driven by the shale gas revolution on the one hand (with other regions poised to emulate the success of US producers) and the maturing of wind and solar technology on the other hand (for instance in China, Europe and the US).
3. Improvements in **energy efficiency** at the macro level (e.g. lower electricity demand per unit of GDP) and in the power sector (e.g. lower coal burn per unit of electricity) which do not impact directly the share of coal in the mix, but can lead to lower coal consumption relative to business-as-usual scenarios.

In a way, 2013 represents a watershed for the global coal market. On the demand side, we expect the growth rate in the seaborne market to slow down sharply from 7% in 2007-12. On the regulatory front, emissions trading began in California while China launched its first pilot trading scheme. In our view, the start of CO<sub>2</sub> emissions trading in China is a particularly symbolic move coming from an emerging market that is particularly reliant on coal. Meanwhile, far from boosting the seaborne market, the Chinese domestic market is currently acting as a drag on demand growth and thermal coal prices.

We believe the prospects for India and other emerging markets in Asia remain positive, but that is offset by falling consumption in OECD markets and by shrinking import demand from an oversupplied Chinese market. We expect annual seaborne demand growth to moderate toward 1% during our forecast period of 2013-17 (Exhibit 2).

**Exhibit 2: Thermal coal demand to slow down sharply**  
Seaborne thermal coal demand – annual growth



Source: International Energy Agency, Goldman Sachs Global ECS Research

## Oversupply shifts the price range downwards

The price cap and cost support have fully converged this year and we expect prices to be range bound for the duration of our forecast period. The Chinese thermal coal market is well supplied, cost inflation appears to have come to a halt and demand growth has moderated. As a result, the price cap set by China has come down to ~\$85/t for benchmark Newcastle coal. On the supply side, the pressure to improve competitiveness and reduce unit costs, combined with a weaker A\$, has reduced our estimate of cost support to \$85/t (vs. \$90/t previously).

### Cost support and price ceiling converge fully

The price range for seaborne thermal coal prices has been gradually narrowing in recent months, and we believe the price ceiling set by China and the cost support set by seaborne suppliers have finally converged at the US\$85/t level (on a 6,000kcal/kg NAR, FOB Newcastle basis). In practice, spot prices can trade below cost support in an oversupplied market for extended periods of time. On that basis, we expect seaborne thermal coal to trade slightly below cost support in the short term, and to gradually converge towards the US\$85/t level from 2015 onwards (Exhibit 3).

### Exhibit 3: We downgrade our thermal coal price forecasts

Bulk Commodities: Price Forecast Summary nominal US\$/tonne											Long Term 2018 nom \$	
		Q3 2013E	Q4 2013E	Q1 2014E	2012	2013E	2014E	2015E	2016E	2017E		
<b>Thermal Coal</b>												
Spot 6,000 kcal/kg NAR	FOB Newc	\$ 80	\$ 82	\$ 82	\$ 94	\$ 85	\$ 83	\$ 85	\$ 86	\$ 86	\$ 85	
change vs previous		-15%	-14%	-14%		-9%	-13%	-11%	-9%	-9%	-8%	
Atlantic vs Newcastle	note 1	\$ (4)	\$ (4)	\$ (4)	\$ (3)	\$ (5)	\$ (4)	\$ (4)	\$ (4)	\$ (4)	\$ (4)	
Note: 1) Average FOB premium/(discount) in \$/t for RBCT and Colombia sales relative to Newcastle												

Source: Goldman Sachs Global ECS Research

We do not expect a significant demand response to lower coal prices; in an environment of declining coal prices, the cost advantage of coal is bound to increase but this will not necessarily translate into stronger demand, in our view. In some markets such as Japan and South Korea, demand is already capped by the amount of installed coal-fired generation capacity. Meanwhile, demand in Europe is capped by the growing contribution of renewable energy and the absence of growth in power consumption. In other words, we believe the seaborne market will be characterized by ample supply and lacklustre demand in the short to medium term.

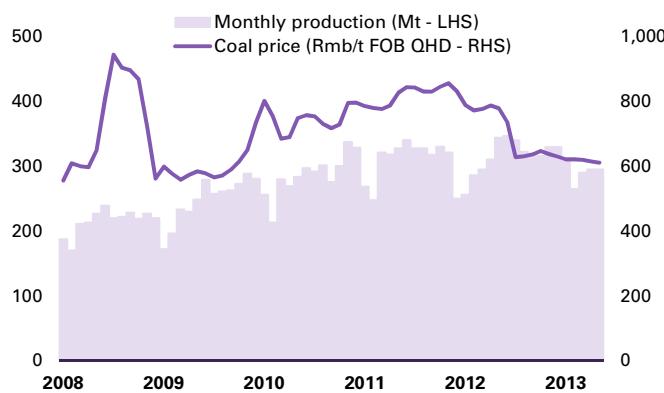
### Chinese supply overtakes demand, limits upside for seaborne prices

The Chinese domestic market has not recovered from the demand shock of 2012, and we now expect a period of oversupply to last until 2015. Several structural changes are behind this shift, in our view. On the demand side, our economists expect GDP growth to slow somewhat to 7.4% in 2013 from 9.3% in 2011. Demand for electricity has underperformed relative to GDP growth, in line with higher energy efficiency and a rebalancing of the economy. Finally, the fuel mix in the Chinese coal sector is gradually becoming more diversified partly on the back of a greater contribution from renewable energy. On the supply side, the Chinese coal sector has benefited from the ongoing consolidation and mechanization of small mines into larger, safer, more competitive operations. As a result,

the Chinese cost curve has shifted downwards, while the shift into oversupply has led to the closure of marginal mines and contributed to the easing of rail transportation bottlenecks.

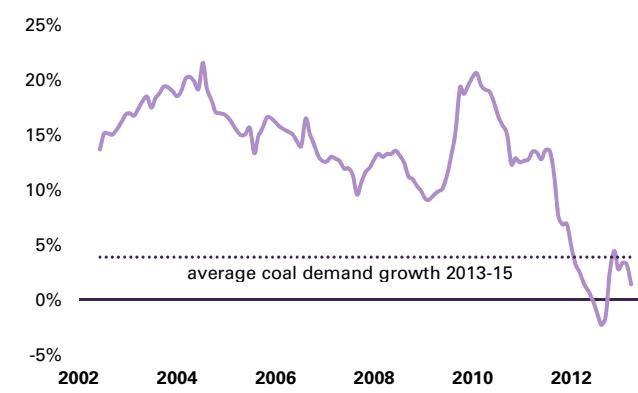
In summary, the domestic outlook has been transformed in a relatively short period of time and we expect Chinese production to keep the market well supplied in spite of lower prices. So far this year, production has been relatively price-insensitive (Exhibit 4) and we argue that thermal coal demand will constrain production for the rest of our forecast period. This is in contrast to the period of 2002-12 when domestic coal production was growing at an average annual rate of 13% but was unable to prevent rising prices and the transition of China to a net importer status. In our view, the subdued demand outlook implies a growth rate of 4% over the period 2013-15 that is less than half the rate of previous years and which the Chinese coal sector will be more than capable of providing (Exhibit 5).

**Exhibit 4: A modest supply response to lower prices**  
Chinese raw coal production and thermal coal prices



Source: SxCoal

**Exhibit 5: A demand-constrained outlook**  
Annual production growth versus expected demand growth



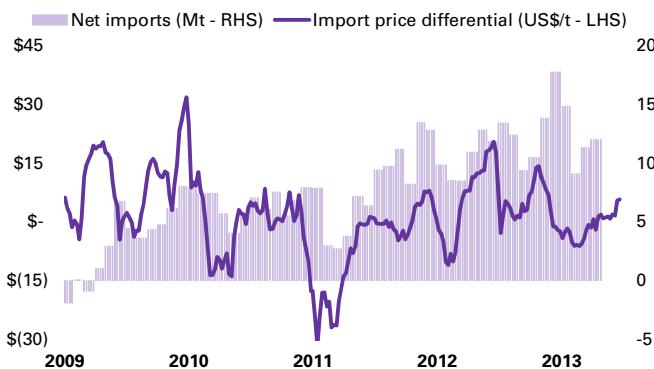
Source: SxCoal, Goldman Sachs Global ECS Research

In the absence of catalysts that may reawaken cost inflation in the Chinese coal industry or lead to a tighter domestic market, the combination of an oversupplied market and a lower cost curve lead us to downgrade our expectations of domestic coal prices. Our China colleagues have recently updated their forecasts (Rmb550/t FOB Qinhuangdao for 5,500kcal/kg coal), which are equivalent to a seaborne price of US\$82/t FOB Newcastle. Given its dual role as the largest consumer in the seaborne market and the marginal buyer, we believe a well-supplied domestic market with a subdued price outlook will effectively cap seaborne prices at US\$85/t FOB Newcastle for the foreseeable future. The price differential between seaborne and domestic coal is currently in favour of higher imports (Exhibit 6). In our view, the decline in seaborne prices has overshot relative to domestic prices, but we expect domestic prices to decline further and the import arbitrage to narrow accordingly.

We also expect import volumes to decline in coming years, as the domestic oversupply continues and policies such as the proposed ban on imports of low-grade coal are implemented (Exhibit 7).

**Exhibit 6: Seaborne coal is competitive into China**

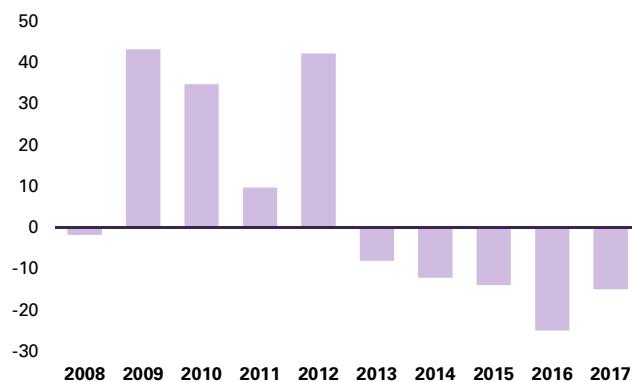
Price differential between Newcastle and Shanxi coal



Source: SxCoal, McCloskey, Goldman Sachs Global ECS Research

**Exhibit 7: China goes from a boost to a drag on demand**

Change in Chinese seaborne thermal coal imports - Mt



Source: McCloskey, Goldman Sachs Global ECS Research estimates

On the other hand, we do not expect China to become a net exporter during our forecast period. A rapid shift from being the largest importer to a net exporter would send seaborne prices crashing and this would make thermal coal exports less attractive from the point of view of Chinese producers. However, there may be times when Chinese coal is sold into East Asian markets if and when the price differential between seaborne and domestic prices widens enough to make it attractive to Chinese producers.

**Gradual productivity gains and a weaker A\$ erode cost support**

The resilience of seaborne suppliers in the face of low prices has prevented mines closures on a larger scale and this has contributed to an extended period of oversupply, in our view. Mining companies are currently focused on increasing efficiency at their operations as a way to increase production volumes and lower unit costs. Meanwhile, weaker commodity currencies are further eroding the cost support for thermal coal. The top quartile of the seaborne cost curve (on a CIF basis, adjusted for calorific value) includes mines from Australia and Indonesia, and local currencies have depreciated by 11% and 2% respectively since the start of the year; our economists expect the A\$ to depreciate by a further 10% over the next 12 months. The cost structure of the coal industry varies by region, and Indonesian mines incur a greater share of their costs in US\$ rather than in local currency. Nonetheless, we believe marginal production costs have decreased moderately on the back of productivity improvements and commodity currency depreciation. On that basis we lower our estimate of cost support to US\$85/t FOB Newcastle (Exhibit 8).

**Exhibit 8: We reset marginal production costs at US\$85/t**

Thermal coal production costs for generic mine types – US\$/t

Region	Indonesia	Indonesia	Indonesia	Australia	Australia
Transport type	Barging	Barging	Barging	Rail	Rail
Overburden	\$ / prime BCM	\$ 3.25	\$ 3.25	\$ 3.25	\$ 4.30
SR	prime BCM / t ROM	12.0	8.0	6.0	7.0
Overburden	\$ / t ROM	\$ 39.00	\$ 26.00	\$ 13.00	\$ 25.80
Mining	\$ / t ROM	\$ 3.00	\$ 3.00	\$ 3.00	\$ 4.75
sub-total	\$ / t ROM	\$ 42.00	\$ 29.00	\$ 16.00	\$ 30.55
Yield	t product / t ROM	100%	100%	80%	70%
CHPP	\$ / t ROM	\$ 1.60	\$ 1.60	\$ 1.60	\$ 4.30
sub-total	\$ / t	\$ 43.60	\$ 30.60	\$ 17.60	\$ 43.56
Sustaining capital	\$ / t	\$ 3.00	\$ 3.00	\$ 3.00	\$ 2.85
Overheads	\$ / t	\$ 3.50	\$ 3.50	\$ 3.50	\$ 3.75
FOR	\$ / t	\$ 50.10	\$ 37.10	\$ 24.10	\$ 50.16
Royalties	\$ / t	\$ 10.80	\$ 9.45	\$ 3.60	\$ 7.38
Loading costs	\$ / t	\$ 4.00	\$ 4.00	\$ 4.00	\$ -
Distance to port	km	50	175	350	150
Transportation rate	\$ / t.km	\$ 0.030	\$ 0.026	\$ 0.026	\$ 0.043
Transportation	\$ / t	\$ 1.50	\$ 4.55	\$ 9.10	\$ 6.45
Port fees	\$ / t	\$ 2.00	\$ 2.00	\$ 2.00	\$ 6.00
FOB	\$ / t	\$ 68	\$ 57	\$ 43	\$ 70
CV - NAR basis	kcal / kg	5,800	4,900	3,800	5,600
Non-CV discount	%	5%	12%	28%	5%
<b>FOB @ 6,000kcal</b>	<b>\$ / t</b>	<b>\$ 74</b>	<b>\$ 79</b>	<b>\$ 94</b>	<b>\$ 79</b>
					<b>\$ 85</b>

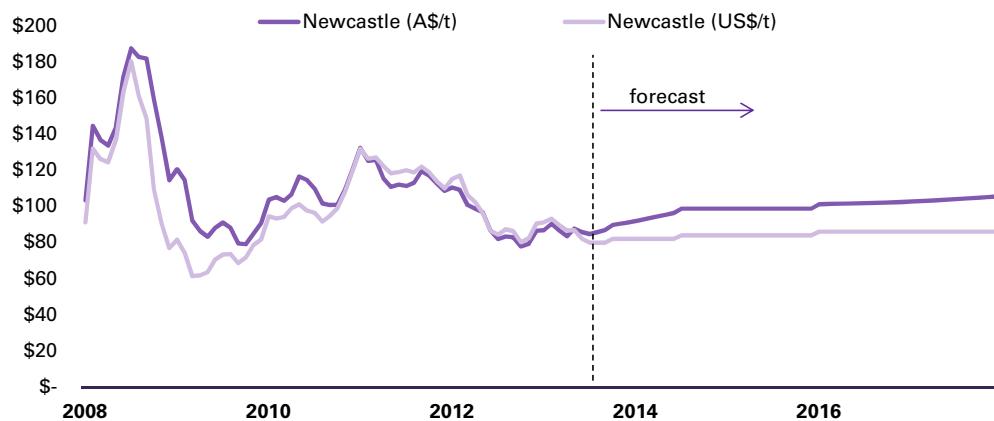
Note: strip ratio (SR) refers to the amount of waste moved per tonne of coal mined; yield at Indonesian mines is ~100% because there is no washing, whereas mines in Australia usually wash their coal to reduce ash and increase calorific content (CV).

Source: Goldman Sachs Global ECS Research

Low prices have put significant pressure on high-cost producers. After several months of uneasy calm, some Australian producers have finally started to announce meaningful production cuts. In June 2013 Peabody and Glencore Xstrata announced 900 staff cuts in aggregate, followed by further layoffs in July; this is roughly equivalent to 10Mtpa of thermal and metallurgical coal production. However, we believe a gradually weakening currency will provide some relief; following the recent depreciation of the A\$, thermal coal prices are flat ytd in local currency terms. Our price forecast implies a modest increase in thermal coal prices for Australian producers, roughly in line with inflation (Exhibit 9).

**Exhibit 9: A lower A\$ will provide some breathing space to Australian producers**

Thermal coal prices (FOB Newcastle, 6,000kcal/kg NAR)



Source: McCloskey, Goldman Sachs Global ECS Research

## Demand has transitioned from high growth to low growth

We believe thermal coal demand growth will slow down in the coming years. The structural drivers behind its current position atop the global fuel mix (namely the exceptional growth in Chinese GDP and its reliance on energy-intensive sectors of the economy) are giving way to a different set of drivers that will undermine further coal demand, in our view. These drivers include a shift towards greater energy efficiency, the increasing pressure of environmental regulation and the prospect of cheap gas and the spread of non-hydro renewable energy. We develop our thesis on each of these structural drivers in subsequent sections of this report. In this section we highlight the implications of slower demand on coal prices, and argue that the potential for profitable investments in new thermal coal mining capacity is becoming increasingly limited.

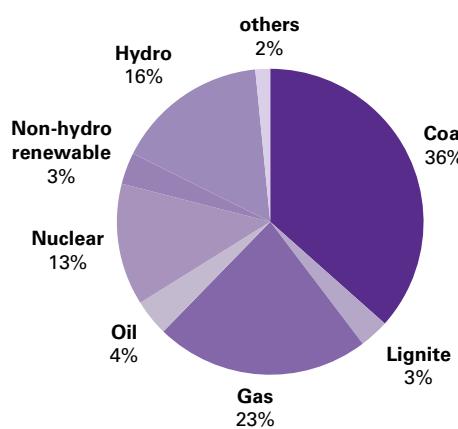
### Coal is the dominant fuel – but growth is concentrated in China

Thermal coal is comfortably at the top of the global fuel mix (Exhibit 10). Relative to other fossil fuels, coal is a widely available resource with low barriers to entry. It is also inexpensive in \$ per unit of energy: at current spot prices (and ignoring the differences in thermal efficiencies in power generation), Newcastle coal is only 27% of the price of contract LNG gas and 21% of the price of Brent oil. This has made it a popular choice in the power sector, with a 36% share of the global fuel mix, well ahead of gas (23%), hydro (16%) and nuclear (13%).

These competitive advantages explain the strong increase in global consumption. Over the period 1990-2011, global demand increased by 2.5 billion tonnes, equivalent to an average annual growth rate of 3.0% (Exhibit 11). However, growth was highly concentrated in just 2 countries: China alone accounted for 72% of the global increase in coal burn, while India accounted for an additional 17%. Excluding those 2 countries, global consumption was only growing at an annual rate of 0.7% per year.

**Exhibit 10: Coal is the dominant fuel**

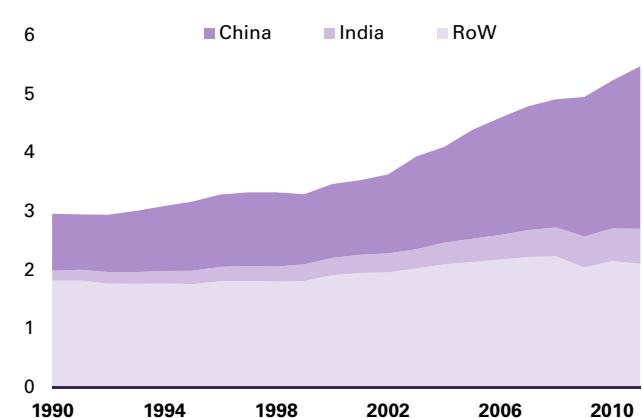
Global fuel mix - 2012



Source: International Energy Agency

**Exhibit 11: China accounts for 72% of global demand growth**

Thermal coal consumption - Gt



Source: International Energy Agency

### Seaborne demand growth to moderate to 1%

We have updated our supply and demand model (Exhibit 12). We expect seaborne imports to grow at an average annual rate of 1% in the period 2013-17, equivalent to 10Mtpa of

incremental demand each year. This represents a slowdown relative to the period 2007-12 when seaborne demand grew at an average rate of 7.2% per annum.

### Exhibit 12: Thermal coal supply & demand

Million tonnes	2008	2009	2010	2011	2012	2013E	2014E	2015E	2016E	2017E
<b>Consumption - energy sector</b>										
US	885	793	830	771	702	770	782	732	706	689
Japan	90	86	90	106	108	109	110	111	112	113
OECD Europe	221	199	205	205	200	198	191	184	177	170
Other	203	205	211	207	209	213	219	224	230	236
<b>OECD total</b>	<b>1,400</b>	<b>1,284</b>	<b>1,336</b>	<b>1,289</b>	<b>1,220</b>	<b>1,290</b>	<b>1,301</b>	<b>1,250</b>	<b>1,224</b>	<b>1,208</b>
China	1,681	1,771	1,886	2,089	2,099	2,236	2,327	2,419	2,513	2,609
India	388	400	409	431	444	461	485	510	538	567
Other	500	459	464	525	534	545	557	570	583	595
<b>non-OECD total</b>	<b>2,569</b>	<b>2,630</b>	<b>2,759</b>	<b>3,045</b>	<b>3,077</b>	<b>3,241</b>	<b>3,369</b>	<b>3,500</b>	<b>3,633</b>	<b>3,771</b>
<b>Total - energy sector</b>	<b>3,968</b>	<b>3,914</b>	<b>4,095</b>	<b>4,334</b>	<b>4,296</b>	<b>4,531</b>	<b>4,670</b>	<b>4,750</b>	<b>4,857</b>	<b>4,979</b>
<b>Consumption - other sectors</b>										
US	46	46	32	61	62	63	63	64	65	65
Japan	37	25	38	15	30	30	30	30	30	30
OECD Europe	57	49	56	58	57	56	56	57	57	58
Other	17	17	19	16	16	17	18	18	18	19
<b>OECD total</b>	<b>157</b>	<b>137</b>	<b>145</b>	<b>150</b>	<b>165</b>	<b>166</b>	<b>168</b>	<b>169</b>	<b>171</b>	<b>172</b>
China	503	608	634	683	779	818	860	904	948	995
India	103	131	144	160	167	175	188	201	216	232
Other	170	158	204	153	157	162	168	174	180	186
<b>non-OECD total</b>	<b>776</b>	<b>897</b>	<b>983</b>	<b>996</b>	<b>1,103</b>	<b>1,155</b>	<b>1,216</b>	<b>1,279</b>	<b>1,344</b>	<b>1,413</b>
<b>Total - other sectors</b>	<b>933</b>	<b>1,034</b>	<b>1,127</b>	<b>1,146</b>	<b>1,268</b>	<b>1,322</b>	<b>1,383</b>	<b>1,448</b>	<b>1,515</b>	<b>1,585</b>
<b>Total demand</b>	<b>4,901</b>	<b>4,947</b>	<b>5,223</b>	<b>5,480</b>	<b>5,564</b>	<b>5,853</b>	<b>6,054</b>	<b>6,198</b>	<b>6,372</b>	<b>6,564</b>
<b>% growth</b>	<b>2.3%</b>	<b>0.9%</b>	<b>5.3%</b>	<b>4.7%</b>	<b>1.5%</b>	<b>4.9%</b>	<b>3.3%</b>	<b>2.3%</b>	<b>2.7%</b>	<b>2.9%</b>
<b>Production</b>										
China	2,229	2,360	2,560	2,831	2,845	2,959	3,092	3,228	3,367	3,509
US	950	875	856	849	794	810	848	823	783	757
India	467	497	499	509	529	551	575	601	628	654
Indonesia	247	289	323	374	402	424	445	461	471	478
Australia	183	210	189	199	214	224	227	231	234	236
South Africa	250	248	252	250	253	255	257	258	259	260
Russia	168	147	179	178	183	189	195	200	204	208
OECD Europe	120	112	108	106	99	93	88	83	79	75
Colombia	72	71	71	80	84	88	91	94	97	100
Other	282	272	281	295	297	298	300	301	303	303
<b>Total Production</b>	<b>4,969</b>	<b>5,081</b>	<b>5,317</b>	<b>5,670</b>	<b>5,699</b>	<b>5,889</b>	<b>6,117</b>	<b>6,280</b>	<b>6,423</b>	<b>6,578</b>
<b>% growth</b>	<b>3.0%</b>	<b>2.2%</b>	<b>4.4%</b>	<b>6.2%</b>	<b>0.5%</b>	<b>3.2%</b>	<b>3.7%</b>	<b>2.6%</b>	<b>2.2%</b>	<b>2.4%</b>
<b>Balancing item</b>										
Stock changes	86	52	11	116	135	36	63	82	51	14
Statistical differences	(19)	82	84	74	-	-	-	-	-	-
<b>Seaborne exports</b>										
Indonesia	196	229	287	315	349	361	367	367	370	370
Australia	125	139	141	148	171	178	183	186	190	194
Russia	74	82	75	82	90	89	87	84	83	82
Colombia	69	63	68	74	80	78	90	94	97	100
South Africa	68	67	70	69	75	74	76	78	79	81
US	18	12	16	31	48	42	36	35	34	33
Other	47	28	23	17	16	15	16	17	17	18
<b>Total seaborne exports</b>	<b>597</b>	<b>621</b>	<b>679</b>	<b>735</b>	<b>829</b>	<b>836</b>	<b>855</b>	<b>861</b>	<b>870</b>	<b>877</b>
<b>Seaborne imports</b>										
Japan	121	107	123	120	133	133	135	136	137	137
China	15	58	92	102	144	136	124	110	85	70
India	38	49	65	86	116	130	145	160	175	190
South Korea	75	81	93	98	97	99	105	106	116	119
Taiwan	65	59	63	66	65	65	69	70	72	74
Other	71	74	77	81	84	88	93	97	102	106
<b>Total Pacific</b>	<b>384</b>	<b>427</b>	<b>514</b>	<b>555</b>	<b>639</b>	<b>651</b>	<b>669</b>	<b>677</b>	<b>686</b>	<b>696</b>
OECD Europe	161	144	130	138	160	151	149	145	144	141
US	29	19	16	10	7	7	6	6	6	6
Other	20	21	22	24	26	28	30	32	34	35
<b>Total Atlantic</b>	<b>210</b>	<b>185</b>	<b>168</b>	<b>172</b>	<b>193</b>	<b>185</b>	<b>185</b>	<b>183</b>	<b>183</b>	<b>182</b>
<b>Total seaborne imports</b>	<b>595</b>	<b>612</b>	<b>682</b>	<b>727</b>	<b>832</b>	<b>836</b>	<b>854</b>	<b>861</b>	<b>869</b>	<b>878</b>
<b>% growth</b>	<b>1.6%</b>	<b>2.9%</b>	<b>10.2%</b>	<b>6.2%</b>	<b>12.6%</b>	<b>0.5%</b>	<b>2.0%</b>	<b>0.9%</b>	<b>0.9%</b>	<b>1.1%</b>
<b>Seaborne surplus/(deficit)</b>	<b>2</b>	<b>8</b>	<b>(2)</b>	<b>9</b>	<b>(3)</b>	<b>0</b>	<b>2</b>	<b>0</b>	<b>1</b>	<b>(2)</b>
<b>Average CV - kcal/kg NAR basis</b>	<b>5,652</b>	<b>5,601</b>	<b>5,538</b>	<b>5,512</b>	<b>5,496</b>	<b>5,462</b>	<b>5,440</b>	<b>5,418</b>	<b>5,395</b>	<b>5,373</b>

Source: International Energy Agency, McCloskey, Goldman Sachs Global ECS Research

## Coal-fired generation is profitable in the short run

The key advantage of thermal coal as an energy source in electricity generation is its low cost. Coal-fired generation benefits from significantly lower fuel costs relative to oil and gas-fired power plants in most markets. Moreover, coal is widely available and the infrastructure to transport and stockpile coal is relatively inexpensive when compared to LNG, for example. These advantages outweigh the higher capital costs of coal-fired plants, the lower efficiency rates and the modest carbon costs (Exhibit 13).

### Exhibit 13: Coal-fired generation is profitable

Indicative costs of electricity for generic coal and gas-fired power plants – US\$ per MWh

		Asia		Europe		US	
		coal	gas	coal	gas	coal	gas
		Newcastle	LNG	API2	pipeline	CAPP	Henry Hub
Fuel price (1)	US\$	\$ 85	\$ 13.00	\$ 82	\$ 10.00	\$ 65	\$ 3.50
Fuel price	US\$/MWh	\$ 12	\$ 44	\$ 12	\$ 34	\$ 9	\$ 12
Power plant efficiency	%	39%	51%	39%	51%	39%	51%
Fuel costs	US\$/MWh	\$ 31	\$ 87	\$ 30	\$ 67	\$ 24	\$ 23
Carbon costs (2)	US\$/MWh	\$ -	\$ -	\$ 5	\$ 2	\$ -	\$ -
Other variable costs (3)	US\$/MWh	\$ 10	\$ 6	\$ 10	\$ 6	\$ 10	\$ 6
<b>Short run cost</b>	US\$/MWh	<b>\$ 41</b>	<b>\$ 93</b>	<b>\$ 46</b>	<b>\$ 75</b>	<b>\$ 34</b>	<b>\$ 29</b>
Capital intensity (4)	US\$ per kW	\$ 2,300	\$ 1,000	\$ 2,300	\$ 1,000	\$ 2,300	\$ 1,000
Capital amortization	US\$/MWh	\$ 33	\$ 19	\$ 33	\$ 19	\$ 33	\$ 19
<b>Long run cost</b>	US\$/MWh	<b>\$ 75</b>	<b>\$ 112</b>	<b>\$ 79</b>	<b>\$ 95</b>	<b>\$ 67</b>	<b>\$ 49</b>

Notes: 1) coal prices in US\$ per metric tonne, gas prices in US\$ per mmBtu 2) carbon costs based on a EUA price of € 4.50/t, 3) variable costs include operations and maintenance costs at the power plant, 4) overnight cost of building new generating capacity, amortized over the plant's lifetime based.

Source: Goldman Sachs Global ECS Research

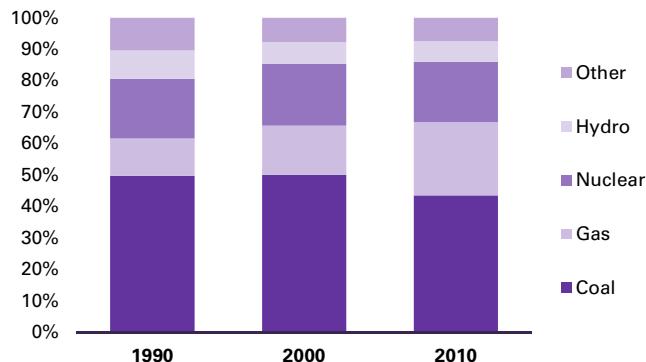
However, the current profitability of coal is not the only factor driving the global fuel mix. For instance, the fleet of newer, more efficient coal-fired plants is profitable in Europe but coal consumption is declining nonetheless; we estimate European thermal coal consumption in 2012 at approximately 270Mt, up 7% yoy but down 10% on 2007 and down 15% on the previous peak of 318Mt in 1996. Moreover, margins today are not necessarily indicative of future investments; power utilities often seek to diversify their asset portfolio, while power plants are long-lived assets and are exposed to expectations of future prices and regulatory changes (please refer to the Alstom interview on page 16 for a discussion of the decision-making process of power utilities).

## The share of coal and its momentum varies by region

The share of coal in the fuel mix varies by region as a result of the resource endowment and local fuel prices, as well as government policy. In general terms, the share of coal has been declining in the OECD, with a 7% decline in the US and a 3% decline in Europe over the period 2000-10 (Exhibits 14 and 15). In Europe, the construction of new coal-fired plants continues with approximately 10GW of new capacity to be added in the next 3 years, mainly in Germany and the Netherlands, and partly in response to the early decommissioning of nuclear plants. However, these additions must be set against the retirement of up to 30GW of older power plants that are no longer competitive under tighter emissions regulations, while government policy encourages a shift to cleaner energy sources and, in the case of the US, the energy sector benefits from cheap gas.

**Exhibit 14: The share of coal is falling in the US...**

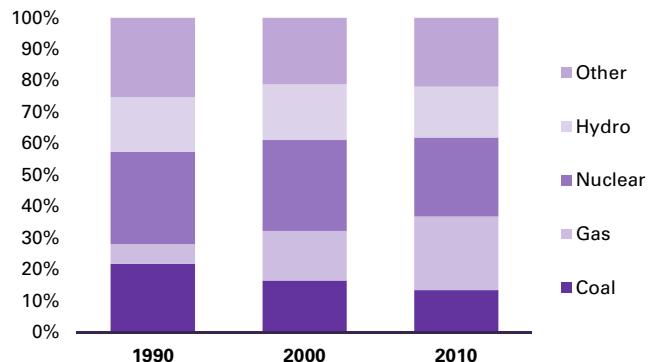
Electricity generation by source - US



Source: International Energy Agency

**Exhibit 15: ... and in Europe**

Electricity generation by source – OECD Europe

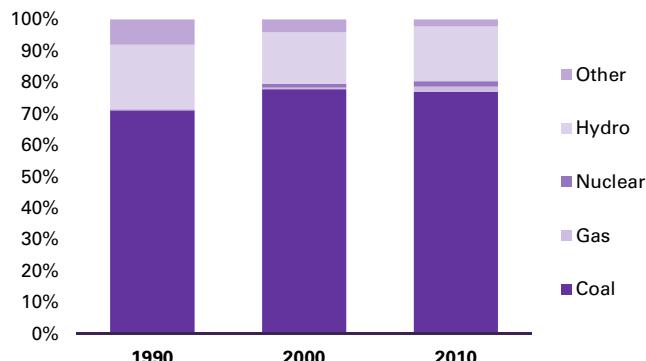


Source: International Energy Agency

Emerging markets on the other hand have followed a different trend to date. In China, the share of coal remains high at 77%, largely unchanged from a decade ago (Exhibit 16). However, the diversification of the fuel mix towards more investment in nuclear and renewable energy in particular may lead to a modest decline in the share of coal in the coming years. Meanwhile, other emerging Asian markets are increasingly reliant on coal; over the period 2000-10 the share of coal increased by 3% to 45% (Exhibit 17).

**Exhibit 16: The share of coal may have peaked in China...**

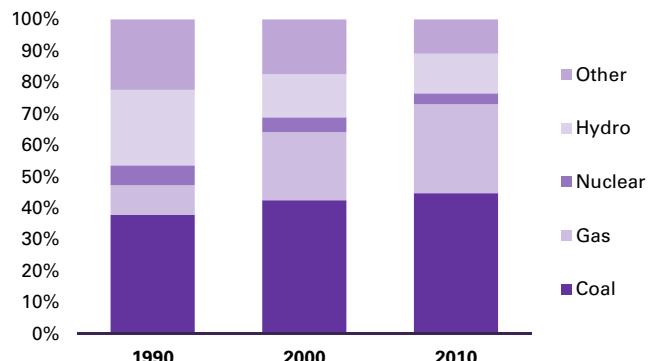
Electricity generation by source - China



Source: International Energy Agency

**Exhibit 17: ... but it continues to grow in Asia ex-China**

Electricity generation by source – emerging Asia ex-China



Source: International Energy Agency

## The viability of growth projects is being eroded

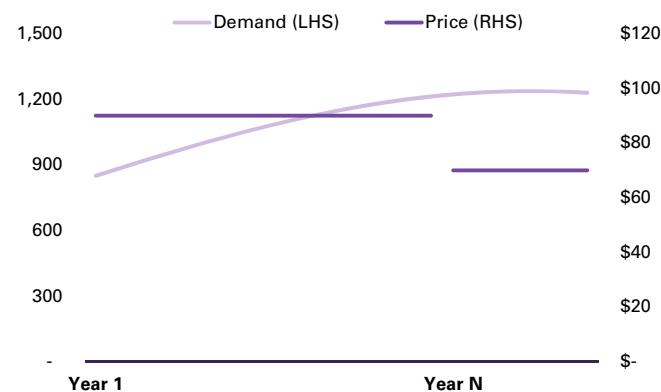
### Slowing demand implies lower prices in the long term

Broadly speaking, demand growth is necessary (but not sufficient) to support high commodity prices. As long as new mining capacity is required by the market, prices will need to be high enough to induce investment. Once markets mature and the supply shortage for a particular commodity disappears, prices will gradually shift downwards to the marginal cost of production (Exhibit 18).

The evolution of copper prices in the 1990s provides a good example of such a transition. In the first half of the decade, copper prices average US\$1.10/lb, a high enough price level to induce a range of greenfield projects. At the same time that new supply started to come online, demand was hit by the Asian crisis and the copper market moved suddenly into surplus. Prices reacted accordingly, falling by approximately 30% to an average of US\$0.80/lb from 1997 onwards (Exhibit 19). In thermal coal terms, the equivalent price levels for induction and marginal cost pricing would be US\$100/t and US\$85/t, respectively.

**Exhibit 18: Slower growth and prices: in theory...**

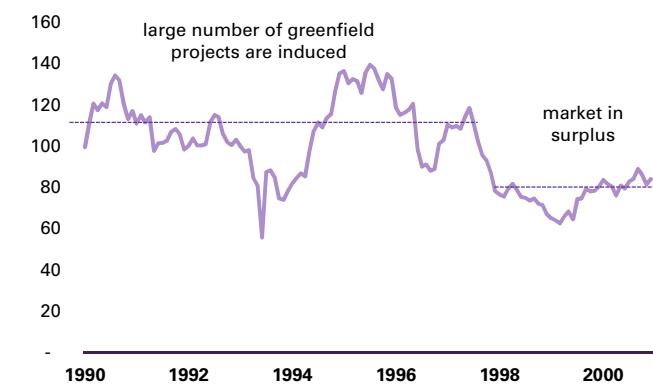
Hypothetical demand growth and price



Source: Goldman Sachs Global ECS Research

**Exhibit 19: ... and in practice: copper 1990-2000**

Historical copper price - US¢/lb



Source: IRESS, Goldman Sachs Global ECS Research

The prospect of maturing demand complicates the investment decision for the thermal coal sector. Mines and the associated rail and port infrastructure are long-lived assets with payback period that often stretch over a decade or more. **We believe that seaborne thermal coal demand could peak in 2020, and this will undermine the profitability of growth projects in the current project pipeline; the window for profitable investment in thermal coal is gradually closing.**

### We downgrade the LT thermal coal price forecast to US\$85/t

We downgrade the long term price for thermal coal to US\$85/t (down 8%), roughly equivalent to US\$75/t in 2013\$. Our previous forecast was based on a hybrid between induction pricing and marginal production costs; we had initially assumed that demand growth would have to be met by new growth projects before demand peaked and prices

fell to marginal production costs. In our view, the outlook has changed and we adjust our forecast to reflect our assessment of long term marginal production costs (Exhibit 20).

#### **Exhibit 20: We reset the long term price to a marginal production cost level**

Methodology behind long term price forecasts – bulk commodities under GS coverage

	Potash	Iron Ore	Metallurgical coal	Thermal Coal
Long term price	inducement price	marginal cost	inducement price	marginal cost
Rationale	Lasting demand growth, high barriers to entry limit the market in surplus from risk of oversupply	Excess capacity will keep 2014+	Geological scarcity and industry concentration	Prospect of peak seaborne demand; excess supply.

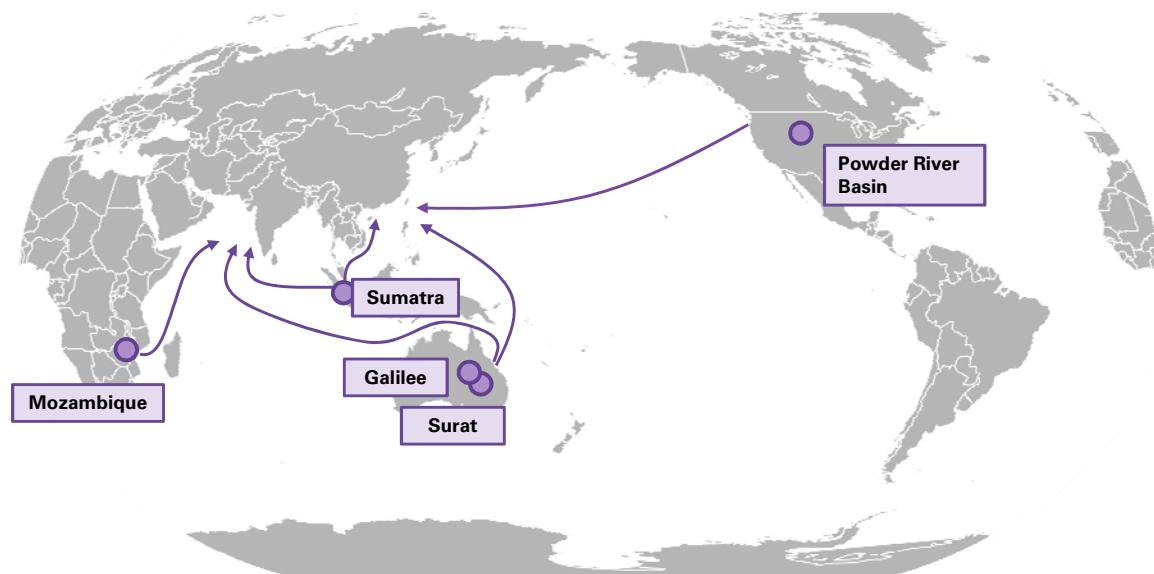
Source: Goldman Sachs Global ECS Research

#### **Demand will be unable to absorb the entire project pipeline**

Thermal coal is not constrained by a lack of geological resources; proven reserves of 861Gt are equivalent to over 100 years of consumption at current rates. The portfolio of growth options for thermal coal exports is correspondingly large. In particular, there are several large scale projects where investment in rail and port infrastructure could unlock large basins that have either remained undeveloped or cut off from the export market (Exhibit 21). The increase in seaborne supply from any of these basins would be in a range between 30Mtpa and 100Mtpa in order to optimize the large capital investment in infrastructure, in our view.

#### **Exhibit 21: Several large scale growth projects will compete in a maturing market**

Selected list of large scale growth projects and key end markets



Source: Goldman Sachs Global ECS Research

In the period 2008-12 when Chinese seaborne demand was increasing at an average rate of 32Mt per year, the market could have absorbed the staged development of new coal basins.

However, in an environment of slowing growth, large scale projects can push the market into oversupply once they are added to the range of brownfield expansions.

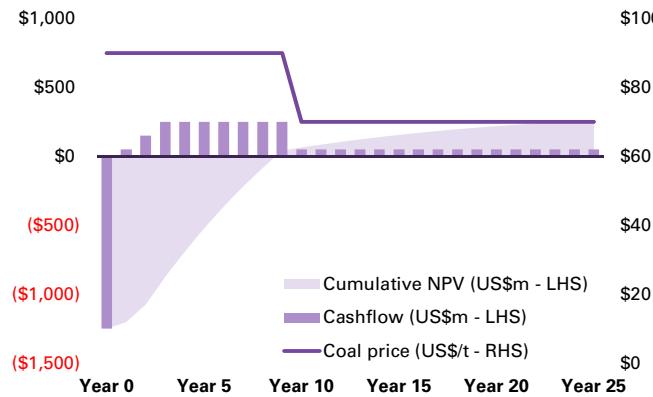
### Cost remains a key differentiating factor – but so is timing

Against a background of lower investment on the one hand and a more challenging demand environment on the other, we expect greater competition for capital among thermal coal growth projects in the years ahead. The projects that deliver positive returns will not only have to be competitive in terms of capital intensity and operating costs; timing will also be crucial, in our view. We illustrate this point by comparing two hypothetical projects with the following characteristics:

- **Production capacity** of 10Mtpa with a 3-year ramp-up period, equivalent to a mid-sized opencast mine.
- **Capital intensity** of US\$125 per tonne of installed capacity, in line with a typical owner-operated opencast mine with modest infrastructure requirements.
- **Production costs** of US\$65/t on an FOB basis, inclusive of sustaining capital, adjusted to a benchmark calorific value of 6,000kcal/kg NAR. This would place the project approximately in the 2<sup>nd</sup> quartile of the current industry cost curve.

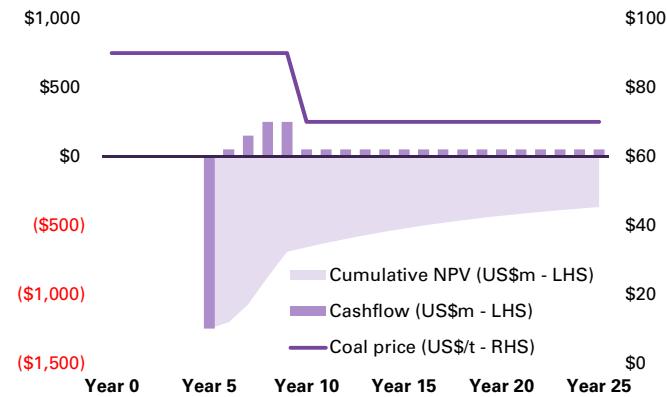
The only difference between the two scenarios is the start-up date relative to the expected price profile for seaborne thermal coal. In the first scenario (Exhibit 22), an advanced project achieves first production in Year 0 and enjoys a period of high prices and the NPV of the project turns positive just prior to the onset of lower prices. In the second scenario (Exhibit 23) less advanced project needs 5 years to secure all relevant permits and complete all design, construction and procurement work, and as a result it only operates for a brief period before the onset of lower coal prices. As a result, the project remains NPV-negative.

**Exhibit 22: Advanced projects make a profit...**  
Cash flows and NPV for a hypothetical 10Mtpa project



Source: Goldman Sachs Global ECS Research

**Exhibit 23: ... while early stage projects miss out**  
Cash flows and NPV for a hypothetical 10Mtpa project



Source: Goldman Sachs Global ECS Research

A mature thermal coal market where prices remain around the level of marginal production costs of US\$85/t (in 2018 \$ terms) will be a challenging environment for growth projects. In the absence of strong demand growth, new brownfield and greenfield expansions will increasingly have to compete on cost against existing mines, in our view. Some undeveloped resources may become Tier 1 assets able to earn a return even under low prices but we argue they will be the exception rather than the rule.

## Insights from an equipment manufacturer: Alstom interview

We interview **Mr. Wouter van Wersch**, Senior VP Sales and Marketing Asia Pacific of Alstom Power and President of Alstom Singapore. Alstom has annual sales of over €20 billion, with 93,500 employees in 100 countries and is active in the power generation sector across the entire energy spectrum, from conventional thermal (coal, gas and oil) to renewable (hydro, wind and solar) and nuclear energy.

Equipment manufacturers are directly involved in the decision-making process of power utilities and are thus ideally placed to comment on the future trends in the power sector which accounts for ~80% of global thermal coal demand. The key insights we take away are 1) **even when carbon prices are low or non-existent, the downside risks of future regulation can offset the cost advantage of thermal coal relative to alternative energy sources**, 2) **demand for coal-fired generation remains strong in India and southeast Asia but the number of new plants is expected to decline by the end of the decade** and 3) **the energy sources with the most upside potential include gas and solar power**.

*The views stated herein are those of the interviewee and do not necessarily reflect those of Goldman Sachs.*

**Christian Lelong:** The profitability of existing power plants is determined by the power tariff and the fuel costs of the day. However, power generation assets can have a lifetime of 40 years or more. What can you tell us about the way in which power companies think about the decision to invest in one energy source over another?

**Wouter van Wersch:** We find that our customers, the power companies, have the objective of building and then operating a generating portfolio that is properly diversified in terms of technology and fuel-mix for their respective markets. Such a strategy results in them managing a power system that is balanced in terms of meeting reliability standards, but also allows them to be sufficiently hedged to achieve satisfactory operating margins, as well as complying with environmental rules and regulations. Therefore, power companies not only will be looking to add generating assets that are the most efficient and lowest-cost, but also to develop a group of plants that best matches a desired risk profile over an extended period. Thanks to its broad portfolio, Alstom can provide the power companies with the optimum solution answering their new power plant requirements, and besides this, we can help them to keep their assets efficient during their lifetime, thanks to our extensive range of optimization services.

**Christian Lelong:** Following the Doha conference, the likelihood of a globally binding agreement appears remote. Instead we are seeing climate change regulation at the national level across both OECD and emerging economies. How sensitive are policy makers in Asia to reducing carbon emissions?

**Wouter van Wersch:** In my view policy makers in Asia are very sensitive about carbon emissions and are considering plans to curb those emissions. However, they must follow a different model than OECD countries. Emerging markets in Asia also must effectively deal with sustained growth in electricity demand, which is not the case in most OECD countries. Therefore, renewable or CO<sub>2</sub>-free energy resources in Asia such as hydro, wind, solar and geothermal, must be developed in tandem with more conventional sources that use fossil fuels. Electricity demand is expanding rapidly in Asia, due to strong economic growth and a need to bring electricity to a large number of people who are without it today. That means there is a pressing need to build large amounts of generating capacity very quickly. While renewable sources, which have a much lower emissions profile, are available and

can contribute to this effort, they have yet to be crafted at the proper scale to meet the urgent need for electric power throughout Asia. Policies to control, or limit carbon emissions will be instituted, but they must be consistent with a model based upon meeting growing demand.

**Christian Lelong:** The current price of CO<sub>2</sub> emission permits in countries that have introduced a carbon price is considered too low to have a material impact on power generation. What assumptions do power utilities make about future carbon prices in their financial models when assessing which type of power plant to build?

**Wouter van Wersch:** When planning to build new generating capacity we have seen that our power company customers definitely consider current and future costs for CO<sub>2</sub> emissions. Those considerations can take two forms. First, whether they plan to only build CO<sub>2</sub>-free sources of power and avoid any and all CO<sub>2</sub> costs in the future, or second, whether they insert a specific cost in economic evaluations to cover CO<sub>2</sub> emissions from the generating asset to be built. As you say, current prices for CO<sub>2</sub> emission credits in regions where such markets are active appear to be too low to influence company decisions. However, concerns over future costs are sufficient to sway a broader, long-term strategy among those same companies. For example, in Europe the levelized cost of building a new coal-fired power plant are more attractive today than building a gas-fired plant (due in part to low CO<sub>2</sub> prices), yet power companies are still more likely to build a gas plant due to concerns over potential costs associated with CO<sub>2</sub> emissions over the long-term.

**Christian Lelong:** Before moving to Asia you spent several years covering the European market. Is there a difference in the way your European clients think about the fuel mix relative to your clients in China, India, Japan and others Asian markets?

**Wouter van Wersch:** Absolutely there is a difference. In Asia there is a much stronger preference to use fossil fuels today, especially coal and natural gas. Both of those fuels are available throughout the region, and when used with highly efficient combustion technologies, become an effective way to add capacity. To better understand the difference, I point back to my earlier response that Asian markets must consider strong growth in power demand when considering fuel mix. In Europe there is no growth today, and since there are mandates to increase renewable energy, plants using fossil fuels generally are not being considered. At the same time, I should note that prior to the 2009 economic slowdown, or when electricity demand was growing in Europe, I sold new coal- and gas-fired power plants to customers in Germany, the Netherlands and the United Kingdom.

**Christian Lelong:** What changes have you noticed in the past few years regarding the fuel mix of new generating capacity in the markets you operate in – has there been a switch from one energy source to another?

**Wouter van Wersch:** Following up on my response to the preceding question, there has been a broad shift away from fossil fuels to renewable sources for new capacity builds. However, any shifts are very sensitive to regional trends. For example, while China has been very active in adding more hydro and wind capacity, coal still is a mainstay, and is now being accompanied by a surge in demand for gas turbines. Once more, power companies in Malaysia, Indonesia and Vietnam that have for years relied heavily upon natural gas and oil, are now turning more to coal to meet rising energy needs. Those trends are likely to shift again in the future, but if I had to bet, I would expect to see an expanding role for generating capacity that uses natural gas. New discoveries of natural gas, especially that involving shale, are changing the business in ways not fully seen as yet.

**Christian Lelong:** And what changes would you expect in the next 5 years in the way that power utilities will allocate their capex spending?

**Wouter van Wersch:** The key to answering your question is the 5 year term. As you mentioned in your first question, power plants can have a 40-year life or more. Therefore, when considering only 5 years, my view is that most power companies are unlikely to be making any major or sudden change to the trends we see today. In growth markets like Asia, we will continue to see capex allocated to support new plant builds and to add emission control equipment. For non-growth markets, especially in Europe, capex likely will go to transmission or distribution projects, aimed at improving delivery and making systems more efficient.

**Christian Lelong:** Regarding energy efficiency and smart grids, what measures are countries implementing and how does it affect the fuel mix?

**Wouter van Wersch:** Your question is very broad, both in terms of geography and the topic itself. Clearly, most countries would like to improve energy efficiency, and using a more effective power distribution system (Smart Grid) is one way to do that. The challenge becomes how to make the actual distribution system more efficient, and to ensure that money spent in this area truly results in a cost saving. Toward that end, customers are likely to be very responsive to receive power in new ways; perhaps through the use of smart meters, but only if it results in lower costs. As distribution systems become more efficient there are likely to be two impacts. First, it should reduce the number of new power plant to be built, by allowing power companies to reduce the amount of capacity needed to be held in reserve to meet peak loads, and second, it should allow for more reliable delivery of renewable sources of electric, which today suffer from intermittency when supplying power to the grid. Developing efficient energy storage systems likely are necessary to fully integrate renewable sources of electric energy.

**Christian Lelong:** Some European countries such as Denmark and Germany have invested heavily in renewable energy, and as the contribution of wind and solar power increases it makes it difficult to balance power supply and demand across the grid. Is there a limit that intermittent renewable such as wind and solar can't exceed without disrupting the electricity grid?

**Wouter van Wersch:** There are two ways I can answer this question. First, is to assess how the increase in wind and solar capacity affects reliability on the European grid, and second how it affects the economics of individual plants and the overall power system. With regard to reliability, grid operators are greatly improving their ability to schedule capacity based upon expected climate conditions affecting the availability of wind and sunshine. However, for scheduling to become even more effective, system operators will need to switch to an intraday dispatching system versus the day-ahead model that mostly is being used today. However, even with improved scheduling, there is a growing need for back-up generating capacity from conventional sources that can be ramped-up and ramped down quickly to account for the intermittency of renewable energy. Second, and with regard to economics, renewable energy is having a major impact on power company decisions to invest in new capacity. Since renewable energy primarily is dispatched first and can have an attractive feed-in tariff, its availability can significantly depress wholesale power prices, which in turn can reduce operating margins, or spreads for conventional power plants (nuclear, coal, gas). As a result, power companies are becoming very reluctant to build new capacity, even if projections show the need for it later in the decade.

**Christian Lelong:** In your view, which energy source (coal, gas, wind, solar, nuclear) has the greatest upside potential in terms of technological innovation over the next 5-10 years? Where are the biggest gains in terms of capital costs and efficiency likely to be made?

**Wouter van Wersch:** In my view all forms of power generation will see technological innovation and advancement over the next 5-10 years. Alstom is committed to making those advancements as we have done in the past. However, if I had to select one from your list, it would be solar. And this choice is based upon solar holding such a small part

of the power supply today, but with a huge opportunity to expand that share in the future. However, one caution with regard to solar is that while advancements and cost reductions are being made to the technology itself, whether it is Solar CSP (Concentrated Solar Power) or Solar PV (photovoltaic), the extent to which it captures a larger share of the power market will depend upon factors related to transmission and delivery. Solar is a much more decentralized source of electricity and its ultimate cost-effectiveness will depend upon how that energy is harnessed and delivered to the system. If those challenges are overcome, in part through more effective means of energy storage, then solar likely is to be the energy source with the greatest upside potential. However, at the same time advancements will be occurring in all other power generation technologies.

**Christian Lelong:** Focusing on thermal coal, where do you see the biggest opportunities and threats for the coal mining sector?

**Wouter van Wersch:** This question is outside of my expertise, since I focus on power equipment markets. However, I do have some broad observations. With regard to opportunities, companies that mine and sell thermal coal should see a growing market throughout Asia, especially in India, Indonesia and Vietnam. Given the huge need for new generating capacity in those countries, and the low-cost of coal versus natural gas and oil, we expect to see many more coal-fired power plants built through 2020. The same would apply to coal having a cost advantage over nuclear power in those countries. With regard to threats, the most obvious ones are related to policies aimed at reducing CO<sub>2</sub> emissions, which in turn would increase the economic attractiveness of plants using natural gas or based upon renewable energy. By 2020, the number of coal-fired plants built in Asia is likely to decline. However, I should point out that Alstom has a well-developed and commercially tested system that can capture CO<sub>2</sub> from the stack of a coal-fired plant and sequester those emissions underground. Widespread application of CCS technology would ensure coal's role in the power sector long past 2020.

## Structural trend #1: Environmental regulation

There is a growing momentum of environmental regulation in the power sector (Exhibit 24). From the point of view of coal-fired plants, every new regulation is yet another screw that threatens their long term profitability; every subsequent tightening of existing regulations undermines further the cost advantage of coal relative to other energy sources.

### Exhibit 24: Different ways to influence the fuel mix and reduce demand for coal

Main types of environmental legislation that impact thermal coal demand

Regulation	Description	Impact
CO <sub>2</sub> Emissions Trading Scheme (ETS)	Power utilities must pay the market price for any emissions they generate over their annual allocation.	A price on CO <sub>2</sub> emissions penalises all fossil-fuel plants. Coal-fired plants generate more CO <sub>2</sub> per MWh of output than gas-fired plants (0.9t CO <sub>2</sub> versus 0.4t CO <sub>2</sub> and older, less efficient plants are penalised more than newer plants. However, the current carbon price in Europe and other markets needs to increase significantly in order to incentivise a switch from coal to gas-fired generation.
Carbon tax	Power utilities must pay a fixed price for any emissions they generate.	
CO <sub>2</sub> Emissions Performance Standards (EPS)	An EPS limits the amount of CO <sub>2</sub> that can be emitted per MWh of output.	A mild EPS will force new coal-fired plants to be high efficiency ultra-supercritical plants, while a more stringent EPS will prohibit the construction of new coal-fired plants unless they are fitted with carbon capture.
SO <sub>x</sub> and NO <sub>x</sub> limits	The amount of sulphur and nitrogen emissions can be limited either via an ETS (as in the US) or an EPS (as in Europe).	Power plants often must invest in emissions control equipment such as flue gas desulphurisation (FGD) and selective catalytic converters (SCR), resulting in higher capital costs, lower plant efficiency and higher costs per MWh.
Renewable Energy Targets (RET)	Mandatory targets to achieve a minimum threshold level of electricity from renewable sources.	RETs reduce the amount of future demand for which coal-fired plants can compete, and act as a disincentive to investment in new generating capacity

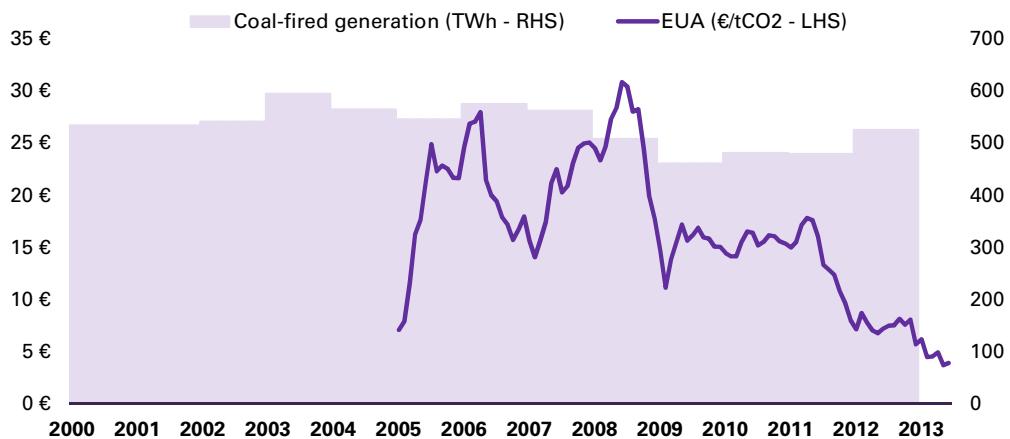
Source: Goldman Sachs Global ECS Research

### Investments in the power sector are sensitive to regulation

In the short term, the impact of regulation has been limited; the profitability of coal-fired plants has not been greatly affected. For instance, countries that have put a price on carbon have not materially changed the relative ranking order of coal versus gas in the fuel mix. However, investment decisions are sensitive not just to current conditions but also to expectations of future prices and regulations. Investment in new coal-fired capacity can be discouraged simply by the risk of new regulations, such as the rules under consideration by the EPA to regulate emissions from coal-fired power plants in the US. While the rules have not been finalized and may not be implemented for years (pending any legal challenges), in the meantime, we think few management teams are likely to submit new coal-fired power plants for approval.

Europe is the world's largest market for seaborne coal, but investments in the European power sector over the past decade have favored gas and renewable energy over coal. The European Trading Scheme (ETS) has arguably had a very modest impact on the competitiveness of existing coal-fired plants relative to gas-fired plants because of the low price of CO<sub>2</sub> permits. However, we note that European coal-fired generation in 2012 was 12% below the 2003 level and 1% below the 2000-12 average and view that as indicative of a gradually declining share of the fuel mix (Exhibit 25). Other regulations such as the Large Combustion Plant Directive (LCPD) set limits on SO<sub>2</sub> and NO<sub>x</sub> emissions that will force the early closure of approximately 30GW of coal-fired capacity in the period to 2015 according to EU data, offsetting the ~10GW of new plants under construction.

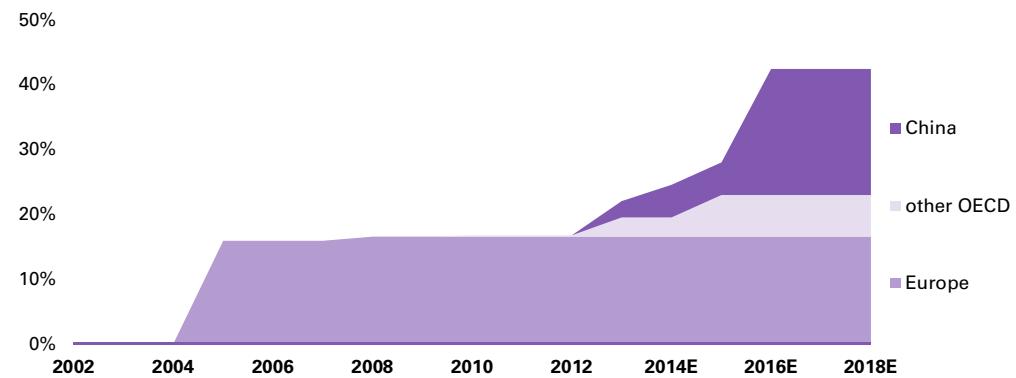
**Exhibit 25: Carbon prices have collapsed but coal-fired generation is 12% below 2003**  
 Coal-fired generation and CO<sub>2</sub> emission allowance (EUA) price in Europe



Source: International Energy Agency, European Environment Agency

In the absence of a globally binding treaty on CO<sub>2</sub> emissions, regulation continues to advance at a national and/or regional level. The number of countries operating an emissions trading scheme exceeds 30, not including regional schemes such as California's. In aggregate, power markets under an ETS account for approximately 20% of global power generation (Exhibit 26). In our view, the launch of emissions trading in Shenzhen, to be followed by six other pilot schemes, sends a particularly strong signal of intent because it is coming from an emerging country with many years of electricity demand growth still to come. If those plans are implemented, the share of global power generation under an ETS would be close to 50%.

**Exhibit 26: Emissions trading schemes cover 20% of global power generation**  
 Global share of power generation under ETS



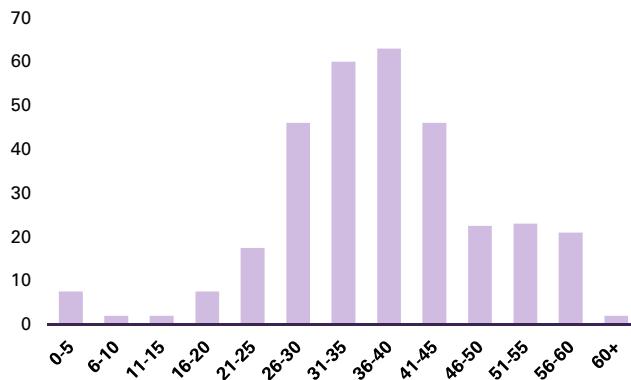
Source: International Energy Agency, Goldman Sachs Global ECS Research

**Retirements will lead to a fall in coal-fired capacity in some markets**

In principle, an average operating life of 40 years implies that new capacity additions equivalent to 2.5% of totaled installed capacity are needed in order to offset the retirement of older plants. On that basis, markets where environmental regulation has contributed to a fall in investment in coal-fired generation in recent years are likely to see a net decrease in capacity. In the case of the US, the average age of coal-fired plants is 35 years and rising

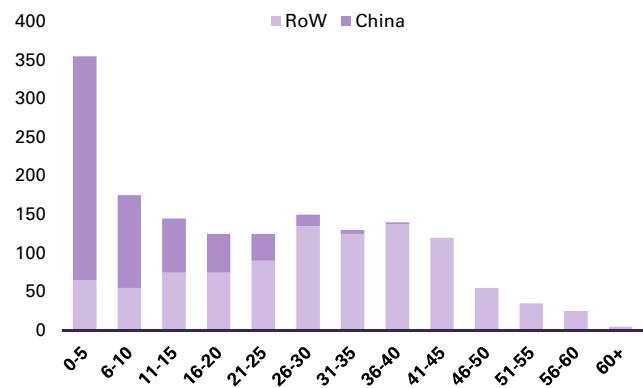
(Exhibit 27). As environmental regulations and competition from alternative energy sources discourages investment in new plants and brings forward the closure of older, less efficient plants, coal-fired capacity is destined to decline. In 2012, 9GW of coal-fired capacity was shut down in the US, equivalent to 3% of total US coal-fired capacity. Across the Atlantic, the European power sector is on a similar trajectory. This trend is obviously not universal, and emerging markets such as China and India have fleets of coal-fired plants that are much younger (Exhibit 28).

**Exhibit 27: A wave of plant retirements is looming...**  
Current age profile of coal-fired plants in the US – GW



Source: International Energy Agency

**Exhibit 28: ... mostly in OECD markets**  
Current age profile of coal-fired plants worldwide – GW



Source: International Energy Agency

Plant retirements do occur in China as part of government efforts to increase efficiency and reduce pollution, but overall capacity is increasing nonetheless. According to the IEA, China's shut down of 85GW of small, inefficient coal-fired plants over the period 2006-11; this is equivalent to the entire installed capacity of the United Kingdom. These efforts to improve power plant efficiency are likely to continue, as per the targets on energy efficiency embedded in the 12<sup>th</sup> Five-Year Plan.

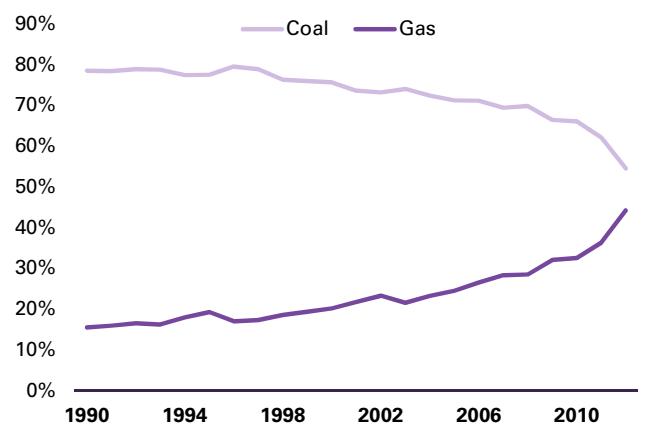
## Structural trend #2: The shift to gas and renewable energy

Shale gas has transformed the outlook for gas-fired generation. Following the example of the US where gas has gained market share in the fuel mix, power utilities in other regions may benefit from cheaper gas supplies in the coming years and will plan their investments accordingly. Meanwhile, non-hydro renewable energy has enjoyed several years of strong growth, and annual investment in new capacity is on a scale similar to investment in fossil-fueled generating capacity. Importantly, the growth in wind and solar energy is now more widely spread between OECD and non-OECD countries. We expect this shift towards gas and renewable energy to continue in the absence of viable technology to deliver low-emissions coal-fired generation at a competitive cost.

### Shale gas has benefited the US first, other countries to follow

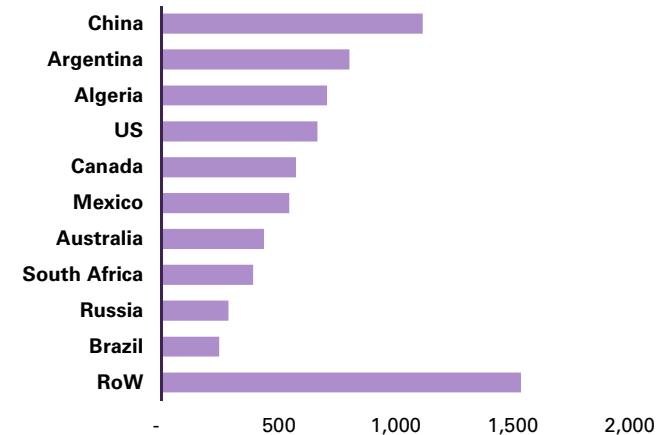
The impact of cheap gas on the US power sector has been dramatic. The share of gas in power generation has increased in recent years and is now near parity with coal (Exhibit 29). In the process, the share of coal has declined and while it remains the largest energy source in the US power sector, its share has declined and we expect that trend to continue. Outside the US, shale gas reserves are significant (Exhibit 30). Admittedly, the conversion of technically recoverable resources to large scale gas production is a process that will take years. For instance, the technology developed to extract US shale gas may have to be adapted to local conditions via trial and error, while the scarcity of water supply may constrain production in some areas. Nevertheless, the International Energy Agency speaks of a "golden age for gas" and we believe that gas will play a larger role in the future global mix than was expected before the onset of shale gas.

**Exhibit 29: Gas has approached parity with coal in the US**  
Share of fossil-fueled power generation in the US



Source: Energy Information Administration

**Exhibit 30: Shale gas reserves are widely spread**  
Current technically recoverable shale gas resources – Tcf



Source: Energy Information Administration

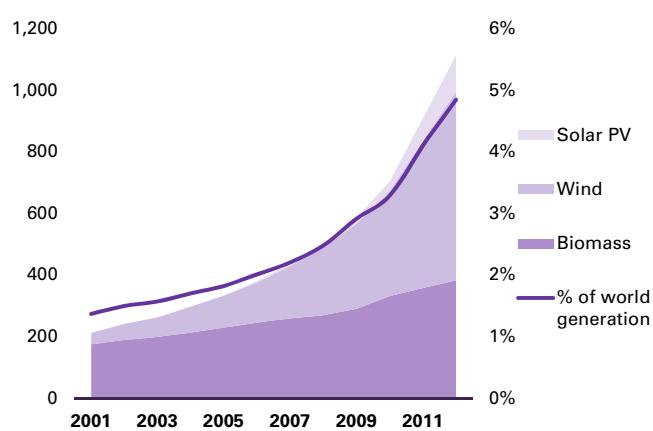
### Non-hydro renewable energy is growing strongly

The growth in non-hydro renewable energy has been remarkable. According to the International Energy Agency, polar photovoltaic (PV) generation reached 65TWh in 2011 (up 100% yoy), and approximately 30GW of new capacity was installed in 2012. Onshore wind power is now considered a mature technology that can sometimes compete without

subsidies against conventional energy sources in some markets. Offshore wind power on the other hand still faces challenges, but there are several large projects in the pipeline. Overall, the IEA recently stated that renewable energy is on track in terms of electricity generation and level of capital investment. Non-hydro renewable energy is on track to exceed 5% of global electricity generation (Exhibit 31).

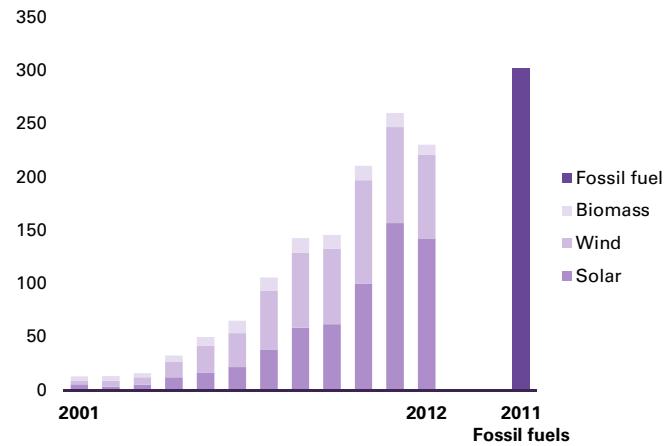
Global investment in the main non-hydro renewable sources (solar, wind and biomass) has grown at an average annual rate of 27% per annum over the period 2001-12 (Exhibit 32). In other words, non-hydro renewable energy now attracts investments in excess of US\$200 billion, on a similar scale to global investment in conventional fossil fuel plants.

**Exhibit 31: Strong growth from a small base**  
Power generation from selected non-hydro sources - TWh



Source: International Energy Agency

**Exhibit 32: Investment levels in excess of US\$200 billion**  
Global investment in generating capacity – US\$ billion



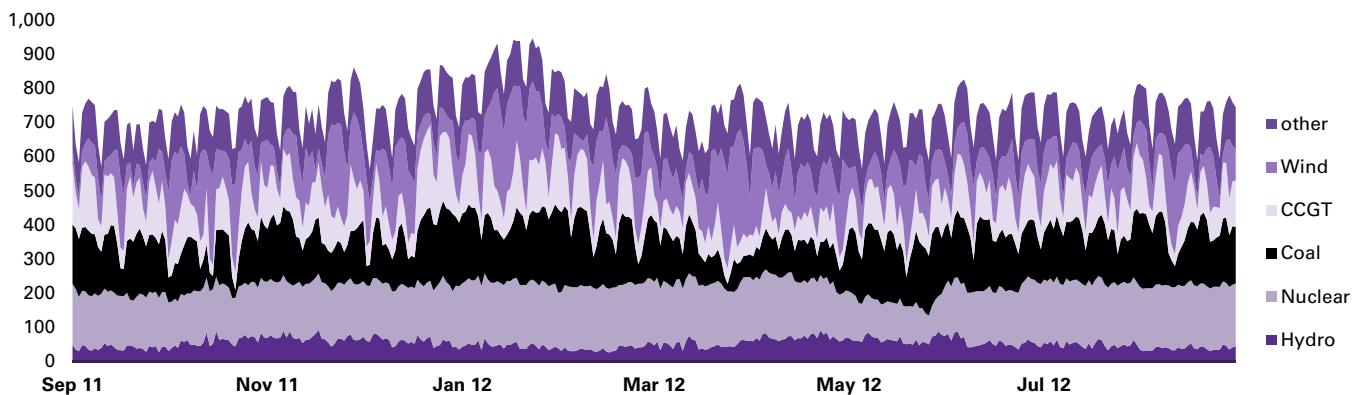
Source: International Energy Agency

A growing contribution from non-hydro renewable energy can impact conventional power plants in different ways. First, assuming the output of hydro and nuclear plants remains unchanged, the impact of rising generation from wind and solar plants has to be offset by a lower average load among fossil-fuel plants. Second, rising generation from solar plants in particular (whose output often coincides with the time of peak power demand) can result in lower peak power tariffs, undermining the profitability of many conventional power plants.

Spain is a good example of how intermittent renewable energy coexists in practice with conventional energy sources because of its diverse energy mix and relatively high contribution from wind power (Exhibit 33). Daily power output statistics show the variability of wind power on a day-to-day basis, while solar power output varies during the day as well as on a seasonal basis. Nevertheless, the Spanish grid operator has been able to manage successfully the intermittency of solar and wind power, partly by leveraging the spare capacity of gas and coal-fired plants. Over a 12-month period to September 2012, wind power contributed roughly 17% of total Spanish power generation and is on track to match and even exceed the share of coal (20%) in coming years. Daily wind output varied significantly between 20 and 320GWh (Exhibit 34). In order to balance the grid, daily generation from gas and coal-fired plants was negatively correlated with wind power output, and the profile of coal-fired plants on aggregate was that of a mid-merit energy source rather than the traditional base load profile its cost competitiveness would imply (Exhibit 35).

**Exhibit 33: A diversified fuel mix: a year in the life of the Spanish power grid**

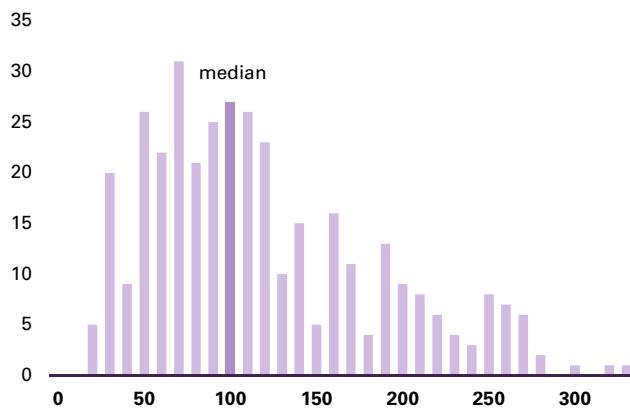
Spanish daily power generation by source - GWh



Source: Red Eléctrica de España

**Exhibit 34: Rising output from renewable sources...**

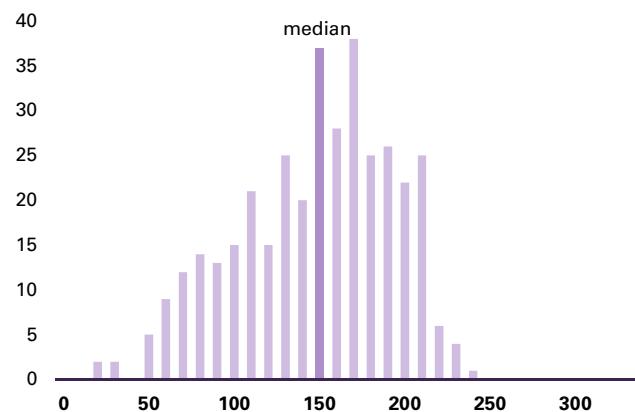
Spanish wind power - # of days per level of output (in GWh) over a 12 month period to September 2012



Source: Red Eléctrica de España, Goldman Sachs Global ECS Research

**Exhibit 35: ... reduces the load on conventional plants**

Spanish coal power - # of days per level of output (in GWh) over a 12 month period to September 2012



Source: Red Eléctrica de España, Goldman Sachs Global ECS Research

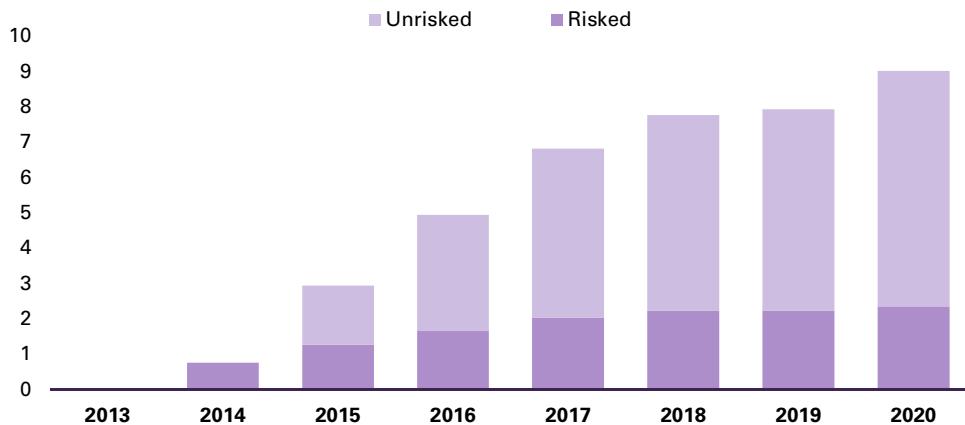
**CCS has not delivered yet a viable solution for coal-fired plants**

In contrast with technological developments in the non-hydro renewable sector, efforts to deploy carbon capture and storage (CCS) in the power generation sector have failed to gather momentum. In 2003 the US government launched FutureGen, a flagship US\$1 billion program to develop the world's first commercial scale CCS plant. Across the Atlantic, the European Commission announced in 2006 its commitment to develop 12 large scale CCS projects by 2015. Meanwhile, the Australian coal industry launched an initiative to raise A\$1 billion over 10 years for investment into CCS projects. As of 2013, none of these initiatives has led to the successful development of a commercial scale coal-fired plant equipped with CCS.

According to the Global CCS Institute, there are several dozen CCS projects around the world. If all these projects were built, they would lead to approximately 9GW of generating capacity by 2020 (Exhibit 36). However, if a probability rating is applied to the project

pipeline according to the project stage the resulting risked capacity is only 2.3GW, equivalent to just 0.04% of global generating capacity.

**Exhibit 36: CCS is on track to deliver just 2.3GW of installed capacity by 2020**  
Generating capacity fitted with CCS in the power sector - GW

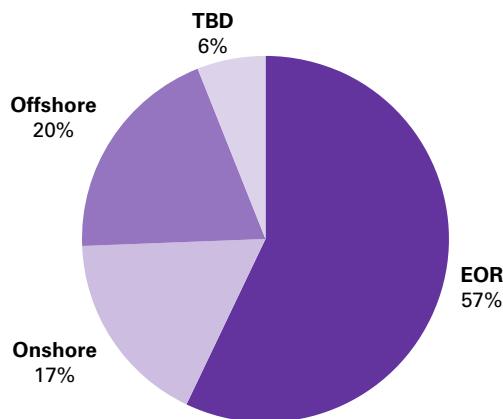


Source: Global CCS Institute, Goldman Sachs Global ECS Research

Enhanced Oil Recovery (EOR) has emerged as a potential niche application for CCS. The use of a CO<sub>2</sub> stream in oil production not only addresses the need for a storage site, but it also improves the economics of a CCS project. The share of EOR as a storage solution among the list of projects tracked by the GCCSI is over 50% (Exhibit 37). However, EOR projects usually do not have the same requirements to ensure that CO<sub>2</sub> remains trapped underground, an important distinction relative to traditional CCS projects.

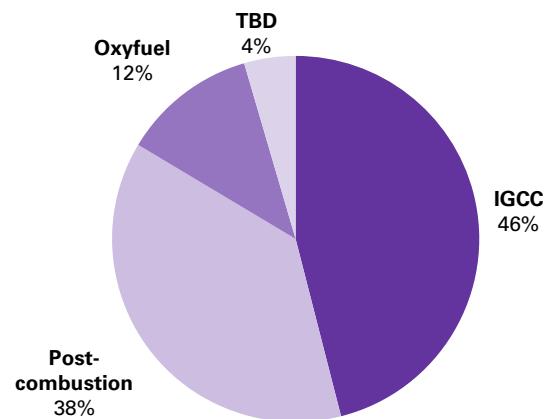
The absence of a clear winner among the competing technologies for CO<sub>2</sub> capture is another hurdle (Exhibit 38). For instance, FutureGen was initially designed as an IGCC project, but in its current incarnation it has become an oxy-fuel project. In the absence of large-scale demonstration plants, it is difficult to determine which among these technologies will provide the most competitive platform for future CCS deployments.

**Exhibit 37: CCS may become a niche EOR application**  
Current CCS project pipeline by CO<sub>2</sub> storage type



Source: Global CCS Institute

**Exhibit 38: A winning CCS technology has yet to emerge**  
Current CCS project pipeline by CO<sub>2</sub> capture technology



Source: Global CCS Institute

According to a range of studies quoted by the Congressional Budget Office (CBO), electricity generation at CCS plants is expected to be approximately 75% more expensive than for coal-fired plants without CCS. In the same report<sup>1</sup>, the CBO states:

*"The Department [of Energy, or DOE]'s analysts believe that the current technology for capturing CO<sub>2</sub> could never meet DOE's goal of reducing the cost of CCS-generated electricity. Consequently, DOE has been seeking to develop next-generation CCS equipment and processes that would capture CO<sub>2</sub> more quickly and more completely but use less energy than today's technology does."*

CCS projects other hurdles besides the challenge to develop technology at lower cost. First, the liabilities related to the transportation and storage of CO<sub>2</sub> need to be addressed; will the power utility continue to have title on the CO<sub>2</sub> and be responsible for monitoring the storage site for decades? Second, the risks of a potential CO<sub>2</sub> leak (whether real or imaginary) may lead to opposition from local communities.

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<sup>1</sup> Federal Efforts to Reduce the Cost of Capturing and Storing Carbon Dioxide, Congressional Budget Office, 2012

## Structural trend #3: Energy efficiency

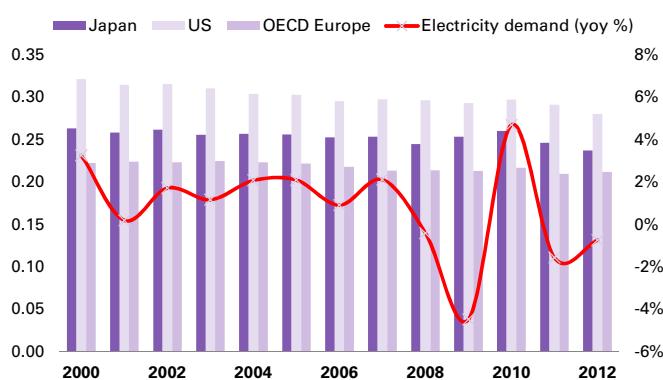
Improvements in energy efficiency at the macro level (e.g. lower electricity demand per unit of GDP) can impact coal-fired generation disproportionately in markets where other energy sources (e.g. nuclear, renewable energy) take precedence in the merit order.

Meanwhile, higher energy efficiency in the power sector (e.g. lower coal burn per unit of electricity) does not impact the share of coal in the mix, but it does lead to lower coal consumption.

### Electricity demand growth will moderate as efficiency improves

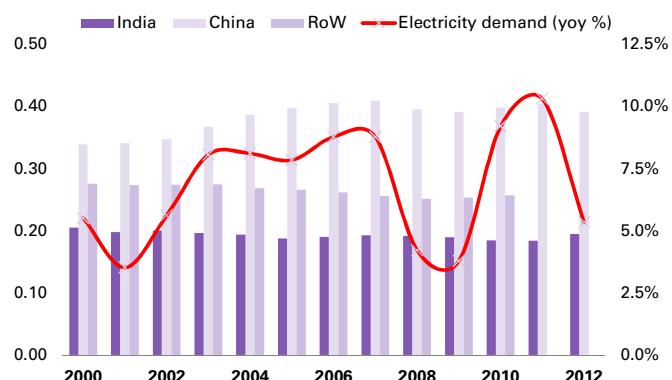
There is a sharp contrast between developed and emerging markets in terms of energy efficiency. In the OECD, the electricity intensity of the economy is relatively low: the US, Japan and Europe consume between 0.21 KWh and 0.28 KWh to create US\$1 of GDP (measured on a PPP basis in constant US\$). Non-OECD markets such as China on the other hand can be more power intensive (Exhibits 39 and 40). However, a common trend across regions is the search for better efficiency.

**Exhibit 39: High efficiency and low demand growth**  
Electricity intensity (KWh per US\$ of GDP) - OECD



Source: IEA, Goldman Sachs Global ECS Research

**Exhibit 40: ... versus low efficiency and high demand**  
Electricity intensity (KWh per US\$ of GDP) – non-OECD



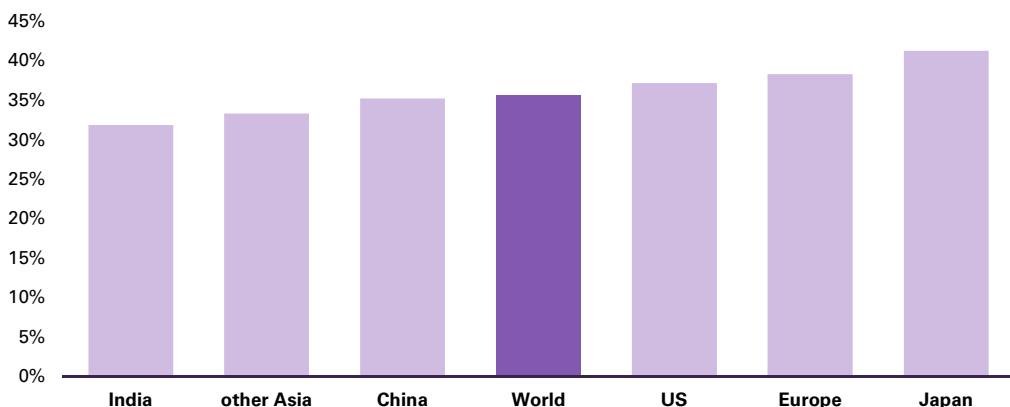
Source: IEA, Goldman Sachs Global ECS Research

Governments around the world are trying to encourage energy efficiency gains. In 2013 the US government announced a goal to double energy productivity by 2030. In Europe, the Energy Efficiency Directive aims to improve efficiency by 20% by 2020, although progress to date has been disappointing; electricity intensity has decreased by just 5% since 2000.

### Improving power plant efficiency rates will lead to lower coal use

Annual investment in coal-fired generating capacity has averaged around US\$80 billion over the period 2006-10. Even though more advanced plant designs are available, older, less efficient designs still account for the bulk of installed capacity. According to the IEA, subcritical power plants account for 72% of current coal-fired capacity of 1,833GW, far ahead of supercritical (21%) and ultra-supercritical (7%) plants. On a regional basis, OECD countries tend to have more efficient power plants than emerging markets (Exhibit 41). We estimate the world average efficiency rate of coal-fired plants at 36%, well below Japan (41%) but ahead of India (32%).

**Exhibit 41: Emerging markets lag behind in power plant efficiency**  
 Average efficiency of coal-fired power plants – 2010 data

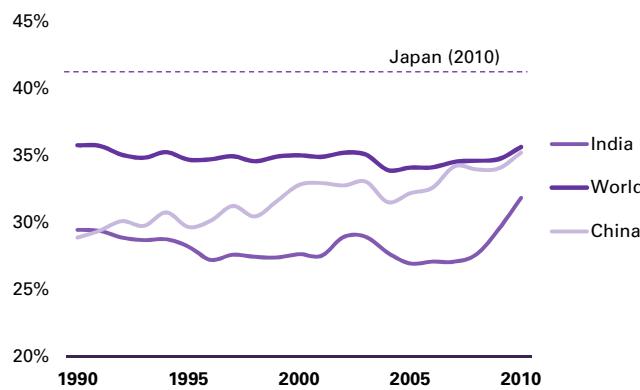


Source: International Energy Agency, Goldman Sachs Global ECS Research

The construction of newer plants in China and India has lifted the average efficiency rates in those countries; as a result, China is now close to the world average (Exhibit 42).

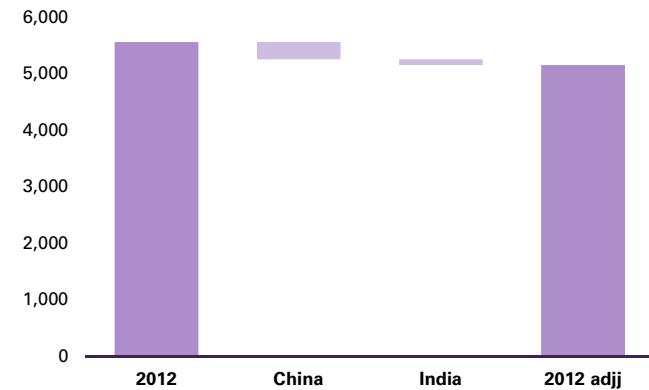
However, there is room for further improvements. If the average efficiency of coal-fired power plants in China and India were already on a par with the efficiency of Japan, thermal coal demand would be reduced by over 400Mt, equivalent to 7% of global demand in 2012 (Exhibit 43).

**Exhibit 42: China and India still lag in efficiency**  
 Average efficiency of coal-fired power plants



Source: International Energy Agency, Goldman Sachs Global ECS Research

**Exhibit 43: Efficiency gains could reduce demand by 7%**  
 Impact on global demand from higher power plant efficiency



Source: Goldman Sachs Global ECS Research

## Risks to our view

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We highlight a set of risks with the potential to undermine our forward view of the thermal coal market.

- **A catastrophic weather event:** Climate change has been displaced by other issues as a top concern. However, public opinion could swing as a result of a weather event such as an ice-free summer at the North Pole, a particularly destructive hurricane season in North America or a weather disruption that materially impacts agricultural output. Under such a scenario, governments may be forced to respond with drastically tighter environmental regulations that would further erode the long term demand for coal.
- **Gas prices:** The rise of unconventional gas has significantly improved its competitiveness in the US against coal and other energy sources. Other markets have not yet experienced the same degree of success in increasing production and lowering prices. However, if future exploration in Europe and China in particular point towards a world of cheap gas beyond the US (i.e. via cheaper LNG), in our view the rate of investment in coal-fired plants is likely to slow down.
- **China and India:** Global coal demand growth has been supported by China and India over the past decade. Their aggregate demand currently accounts for 32% of the seaborne market; the macroeconomic outlook, the potential rebalancing of the Chinese economy away from energy intensive sectors towards light industry and services, and the future direction of energy policy will continue to shape the outlook for thermal coal demand and prices.
- **Technological innovation:** Future investments in the power sector will be affected by the way technological innovation drives further reduction in costs (in US\$ per MW of installed capacity) and increases in efficiency. The long term prospects for thermal coal would improve if CCS is eventually deployed on a cost competitive basis without the support of EOR. For non-hydro renewables, onshore wind is considered a mature technology, but offshore wind and in particular solar PV still have further upside.

# Disclosure Appendix

## Reg AC

We, Christian Lelong, Jeffrey Currie, Samantha Dart and Philipp Koenig, hereby certify that all of the views expressed in this report accurately reflect our personal views, which have not been influenced by considerations of the firm's business or client relationships.

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