Imperial College London

Halving global CO_2 by 2050: technologies and costs

Supporting Annex

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Contents

1 Introduction

This document is intended to supplement our main report, which is available at http://www3.imperial.ac.uk/climatechange/publications/halving-global-CO2-by-2050.

There is still a chance to achieve a reduction in CO_2 emissions that would keep the world broadly on track to limit global warming to around 2 degrees Celsius above pre-industrial levels. Our study outlines how it could be done, by focusing on the technologies which in combination could cut energy and industrial process CO_2 emissions to a 2050 level consistent with a 2^oC temperature rise (which we have interpreted as around 15 Gt/yr by 2050[1]). The approach considers only technologies which either currently exist at commercial scale, or which have been demonstrated at sub-commercial scale but which are still awaiting full-scale deployment.

The subsequent sections provide further information on the end user sectors and energy conversion processes investigated and modelled as part of this study.

[1] This is, of course, dependent on emissions levels before and after 2050, since cumulative emissions (rather than emissions in any given year) affect levels of global warming. For comparison purposes, the IEA's (2012a) Energy Technology Perspectives shows 2050 energy-related CO_2 emissions levels at around 16 $GtCO_2$ in a scenario where there is an approximate 80% chance of limiting global warming to 2^OC.

2 Detailed analysis – power sector

2.1 Low mitigation scenario

The low-mitigation scenario (LMS) forms a baseline against which the costs of higher levels of mitigation can be evaluated. Regional power generation mixes have been largely derived from the IEA Energy Technology Perspectives 2010 report (IEA, 2010a), supplemented by data from a range of local sources and refereed publications where necessary. Mixes of both installed generating capacity and contribution to electricity supply have been estimated, the two being linked by capacity utilisation factors for each type of plant in each region. Where there were discrepancies between the electricity generation required by the sectoral analyses and that in the IEA (2010a) report and supporting documents, the sectoral analysis has been given precedence, but it has been assumed the relative electricity generating mix remained unchanged.

Direct GHG emissions from each plant type are taken from a combination of refereed in-house models and from the literature. Annual global power sector GHG emissions are calculated according to

$$E_{global} = 8766 \sum_{i=1}^{i=10} \sum_{j=1}^{j=n} e_{i,j} f_{i,j} I_{i,j}$$

where

i	=	Region index
j	=	Generation technology index
$e_{i,j}$	=	GHG emissions per unit for technology j in region i (tCO_2e/GWh)
$f_{i,j}$	=	Capacity utilisation factor for technology j in region i
$I_{i,j}$	=	Installed capacity (GW) for technology j in region i.

2.2 Low carbon scenario

For the range of generating technologies and regions, a database of capital costs, operating costs and per unit GHG emissions has been compiled from the literature[2]. The dataset also includes supporting technical information such as expected plant utilisation factors. The spreadsheet representation takes predictions of annual electricity demand from the sectoral analysis and allocates new generating capacity to provide the required carbon abatement at least cost. Initially, any increased electricity demand in the LCS compared to the LMS is fulfilled by 'constructing' new low carbon plant. Subsequently high carbon plant from the LMS are replaced by low carbon plant until an exogenous investment or direct GHG

[2] Graus et al (2008); Hendriks et al (2004); Abellera & Short (2011); Salvadores & Keppler (2010); Koomey & Hultman (2007); The Keystone Center (2007); Ayres et al (2004), PB Power (2004); Energy Information Administration (2009)

Simbolotti, G.(2010); Tolley & Jones (2007); Parsons Brinckerhoff (2011); IEAGHG Zero Emission Platform (2011); Du, Yangbao, and Parsons, John E. (2009); Finkenkrath, M. (2011); Herzog, Rubin, Finkenkrath, Chamberlain, Booras & Li (2011) emissions target is met, selecting plant to provide the minimum GHG abatement cost. The plant allocation/replacement process takes place in TWh 'tranches'. Plant replacement takes place within each region independently until a regional target is met. Finally the calculation outputs the reduction in direct GHG emissions, the corresponding capital investment and the impact on electricity costs.

For fossil fuel and bioenergy based technologies, costs and performance within the database are taken as constants within each region. In other words there is no explicit consideration of where within the region the plant is built and the implications for supporting infrastructure costs, except insofar as the data base figures represent local 'averages'. The technology database includes estimates of upper limits on the total capacity of each technology that could be installed in each region, again taken from the literature[3], and these provide a constraint on how much of each technology can be deployed. These limits represent the capability of each region to build each type of plant. Fuel costs are an exogenous input to the calculation derived from another component of the whole study, to which the sensitivity is investigated. The maximum biomass 'budget' for power generation was 60EJ.

For non-bioenergy renewable technologies, capital and operating costs are again assumed to be constant for each technology in each region. However, as increasing quantities of renewables are installed it is likely in all regions that further developments will take place in locations with poorer resource. The performance, and hence the GHG abatement costs, offered by any renewable installation are crucially dependent on the resource available, and hence it is important that this trend is accounted for in the analysis. To this end a high-level resource assessment has been undertaken for each region to determine (i) how capacity utilisation factors will decline as installed capacity increases and (ii) the maximum capacity that could reasonably installed. Inevitably the level of detail available in the literature across the scale of the regions is limited, a simplified representation with one utilisation factor for each of the four quartiles of capacity up to the maximum. As with the fossil fuel technologies, the total deployment of each technology is constrained by the upper limit identified by the resource assessment.

The calculation methodology is not temporally explicit and as a result, the possible need for electricity storage technologies at relatively high intermittent renewables (primarily wind, solar PV) deployment levels is not directly considered. Intermittency will certainly be a significant factor in future grid operation, but there is currently much controversy over the need for storage and indeed operators may choose to exploit flexible fossil plant or demand management as an alternative means of management. Irrespective of the technical solution adopted there will certainly be a cost associated with intermittency, so to keep the study as general as possible the generation costs for the intermittent renewables technologies considered here have been inflated over those for 'isolated' technologies found in the literature. How grid operators choose to deal with intermittency is beyond the scope of this work, but to a level of approximation the results will remain valid be it through (i) electricity storage (ii) fossil plant flexibility, (iii) demand side flexibility or (iv) installing 'redundant' renewables capacity. The degree to which each individual renewable technology can

[3] Ramana, M.V., (2009); Congressional Budget Office (2008); Stangeland, A. (2007); Carbon Sequestration Leadership Forum (2011); Element Energy (2011)

contribute to regional generation is further constrained to a maximum of 15%, which also limits potential issues from this relatively simple treatment of intermittency. With the levels of global deployment predicted in the base case low carbon scenario these simplified approaches to intermittency are likely to be valid, assuming electricity networks develop effective inter-connections at regional levels.

2.3 Detailed results: power sector

2.3.1 Low mitigation scenario

Results for the power sector low mitigation scenario are shown in Table 1 with respect to installed capacity, and in Table 2 with respect to the contribution to generation of each technology. The corresponding regional emissions factors are provided in Table 3, while Figure 1 summarises the global contribution to generation made by each major technology type.

Perhaps unsurprisingly, given the relative lack of concern about carbon emission in this scenario, there is a heavy dependence on generation from unabated fossil fuels. The contribution made by 'new' renewables is largely in line with current growth rates. Europe, for example, sources a double digit percentage of its electricity from wind, but elsewhere and for all other technologies the regional contributions are less than 10%. The proportion generated from hydropower is similar to 2010. Nuclear power sees an absolute increase in deployment reflecting ambitious programmes in China and elsewhere, but in term of its percentage contribution to world generation remains roughly static.

Table 1: Installed generating capacity (GW) for the LMS.

Tech	Region										
	China	India	OECD Europe	Asia Oceania	N America	L America	E Europe	OD Asia	MENA	SSA	TOTAL
Wind	141	25	240	33	151	47	91	0	10	10	**749**
Solar	53	0	0	29	129	12	0	0	47	47	**317**
Hydro	302	123	252	11	123	242	170	112	58	85	**1478**
Nuclear	107	60	186	35	185	18	115	25	8	4	**743**
Coal	972	402	143	66	640	54	97	148	53	51	**2626**
Gas	282	158	548	333	402	266	198	744	261	250	**3443**
TOTAL	**1857**	**768**	**1369**	**507**	**1631**	**639**	**672**	**1029**	**437**	**448**	**9356**

Table 2: Percentage contribution to generation for the LMS

Technology	Region									
	China	**India**	**OECD Europe**	**Asia Oceania**	**N America**	**L. America**	**E Europe**	**Oth Dev Asia**	**MENA**	**SSA**
Wind	4%	2%	14%	5%	6%	6%	10%	0%	2%	2%
Solar	1%	0%	0%	3%	3%	1%	0%	0%	6%	6%
Hydro	10%	10%	15%	2%	5%	36%	19%	10%	13%	19%
Nuclear	8%	11%	25%	14%	17%	6%	29%	5%	4%	2%
Coal	69%	67%	18%	25%	55%	17%	23%	28%	25%	24%
Gas	8%	11%	28%	51%	14%	34%	19%	57%	50%	48%
TOTAL	**100%**	**100%**	**100%**	**100%**	**100%**	**100%**	**100%**	**100%**	**100%**	**100%**

Table 3: Power sector emissions factors for the LMS

Region	**Power Sector Emissions (teCO2e/GWh)**
China	605
India	621
OECD Europe	255
Asia Oceania	401
North America	515
Latin America	271
Eastern Europe	263
Other Developing Asia	444
Middle East + North Africa	394
Southern & Saharan Africa	377

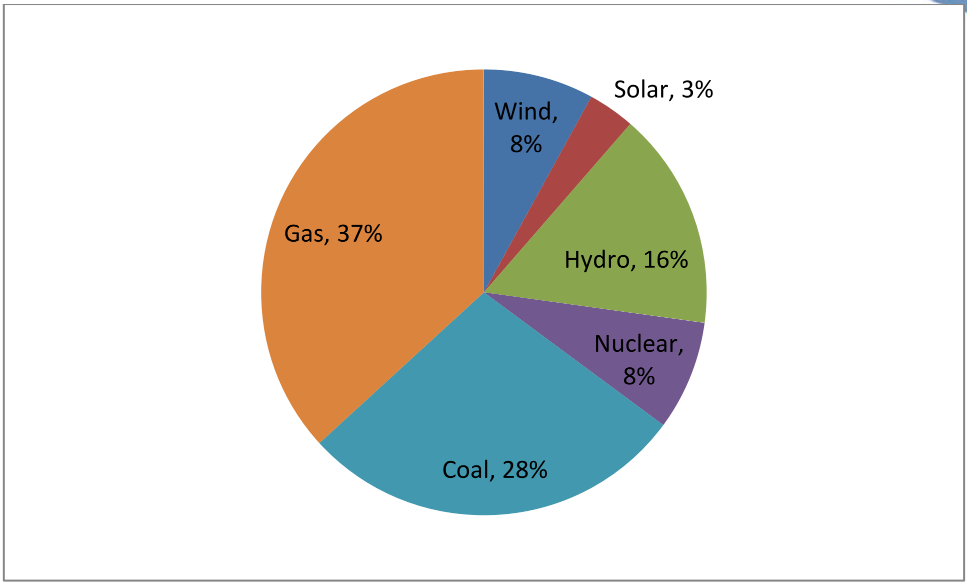

Figure1: Global shares of electricity generation for the LMS.

2.3.2 Low carbon scenario (high fossil fuel prices)

Results for the power sector low carbon scenario, assuming high fossil fuel prices, are shown in Table 4with respect to installed capacity, and in Table 5with respect to the contribution to generation of each technology. The corresponding regional emissions factors are provided in Table 6, while Figure 2 summarises the global contribution to generation made by each major technology type, and Figure 3 shows the breakdown of generation capacity globally.

The weighted average cost increase of electricity over the LMS is 37.3%. The greatest increases are in North America and China, due to their relatively low starting costs. Overall costs in the regions vary from 69.9 $/MWh in Sub-Saharan Africa to 92.8 $/MWh in Latin America, with weighted average cost being 80.4 $/MWh.

The lowest regional carbon intensity of electricity production is Middle East & North Africa with 26.2g/kWh. The highest is China at 139.8kg/MWh, and the weighted global average is 84.5kg/MWh. Total emissions are below the limit of 3100Mt CO_2 per annum at 3095.6Mt, representing a cut from the LMS of 79.9%.

As might be expected, coal-fired and gas-fired power declines in this scenario, losing market share to wind power, solar power, hydroelectricity and nuclear power. The model pushes nuclear power to its upper limit in all regions except OECD Europe. Hydroelectricity also reaches the upper limit in most regions. Gas-fired generation retains 11.7% of the market by generation, of which over 75% is fitted with CCS. Coal falls to less than 13% of total generation, of which one-third has CCS. 3.5Gt CO_2 is separated by CCS plants every year and must be stored or used. 40% of this CO_2 comes from coal CCS plants, 39% from gas CCS plants and 21% from biomass CCS plants.

Intermittent renewables (wind and solar technologies) produce 28.4% of all electricity. They comprise 40% of capacity. Bio-based generation is responsible for 9.6% of generation, some of which may be co-firing with coal. 26.8EJ of biomass is used per annum in power generation in this scenario, and is pushed to its upper limit for all regions except OECD Europe and SSA. Energy from waste, at 7.2% of generation, is almost as large a player in the sector as biomass, but is pushed to its upper limits in all cases except OECD Europe.

Table 4: Installed generating capacity (GW) for the LCS.

Technology	Region										
	China	India	OECD Europe	Asia Oceania	N America	L America	E Europe	OD Asia	MENA	SSA	Total
Wind Onshore	285	200	138	56	196	105	149	118	222	102	1572
Wind Offshore	285	200	138	56	150	0	100	0	0	0	929
Solar	276	206	26	44	214	111	35	104	245	47	1309
Hydro	227	135	189	8	135	266	187	84	64	64	1358
Nuclear	321	90	200	69	232	54	210	74	80	80	1410
BioPower	50	50	167	50	50	20	50	60	50	13	559
BECCS	0	12	0	1	0	21	50	0	35	0	119
Coal	168	59	35	15	125	35	65	43	38	14	597
Gas	50	30	10	15	20	10	10	20	20	10	195
CoalCCS	50	46	10	15	86	10	31	20	20	10	297
GasCCS	111	300	10	15	20	23	61	20	64	10	633
Energy From Waste	80	50	0	30	80	50	50	50	50	60	499

Table 5: Percentage contribution to generation for the LCS

Technology	Region									
	China	India	OECD Europe	Asia Oceania	N America	L America	E Europe	OD Asia	MENA	SSA
Wind Onshore	8%	9%	10%	9%	9%	10%	9%	11%	14%	16%
Wind Offshore	10%	9%	10%	9%	7%	0%	6%	0%	0%	0%
Solar	14%	13%	3%	8%	13%	16%	3%	17%	26%	7%
Hydro	8%	6%	13%	1%	6%	26%	12%	9%	5%	10%
Nuclear	24%	9%	31%	25%	25%	12%	29%	17%	13%	28%
Biomass	4%	5%	24%	17%	5%	4%	6%	13%	8%	4%
BECCS	0%	1%	0%	0%	0%	4%	6%	0%	5%	0%
Coal	12%	6%	5%	5%	13%	7%	8%	9%	6%	5%
Gas	4%	3%	1%	5%	2%	2%	1%	4%	3%	3%
CoalCCS	4%	4%	1%	5%	9%	2%	4%	4%	3%	3%
GasCCS	8%	29%	1%	5%	2%	5%	8%	4%	10%	3%
Energy From Waste	6%	5%	0%	10%	8%	11%	7%	11%	8%	20%
TOTAL	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%

Table 6: Power sector emissions factors for the LCS.

Region	Power Sector Emissions (teCO2e/GWh)	Percentage reduction compared to LMS
China	139.8	76.9%
India	78.9	87.3%
OECD Europe	60.1	76.1%
Asia Oceania	72.9	81.8%
North America	133.5	74.1%
Latin America	36.7	86.4%
Eastern Europe	29.7	88.7%
Other Developing Asia	107.9	75.7%
Middle East + North Africa	26.2	93.3%
Southern & Saharan Africa	58.8	84.4%

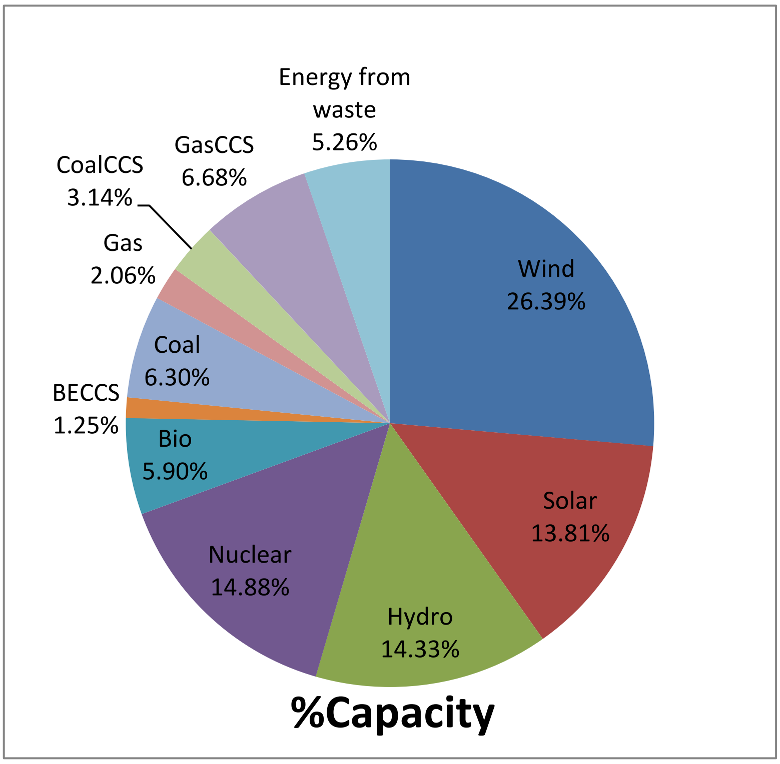

Figure 2: Global generation capacity breakdown for the LCS.

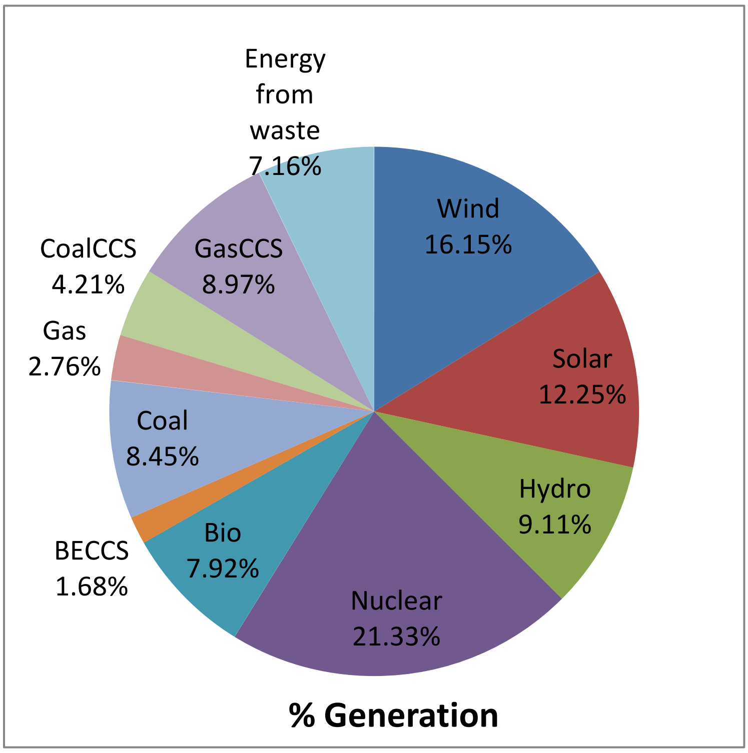

Figure 3: Global contribution to generation breakdown for the LCS.

2.4 Low carbon scenario sensitivities

2.4.1 Reiteration of low carbon scenario base case results (case 1).

Figure 4 shows the regional generation mixes for the base low carbon scenario in a form that aids comparison with the sensitivity studies that follow.

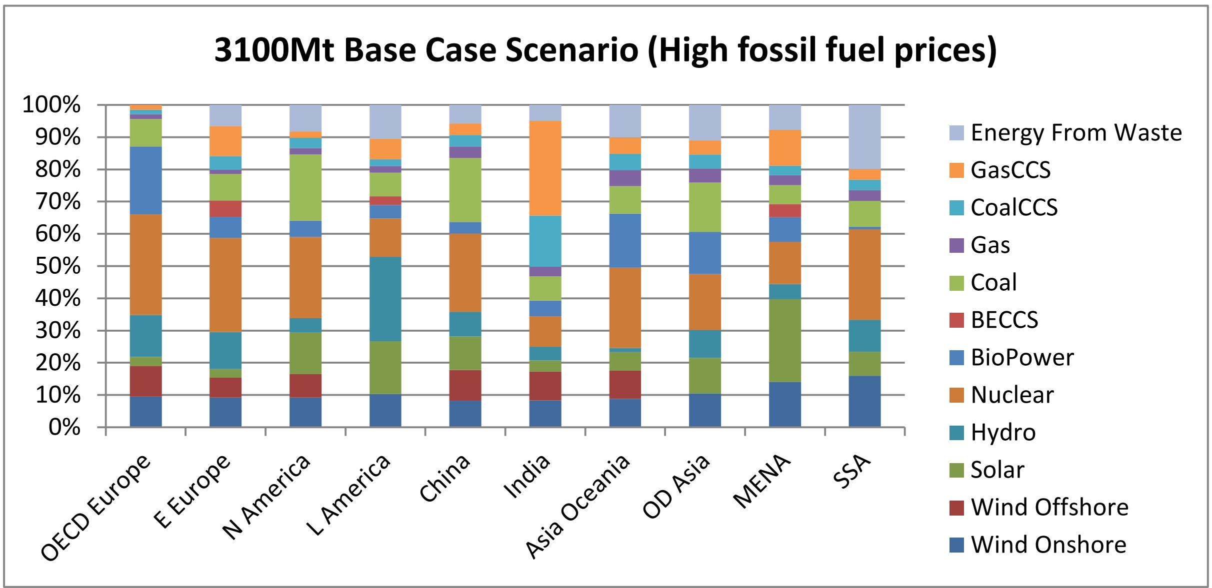

Figure 4: Regional generation mix for the baseline LCS with high fossil fuel prices.

2.4.2 Reduction in fossil fuel costs (case 2)

Reducing the cost of fossil fuels does not change the electricity mix much, as is shown by comparing Figure 6 with Figure 5. Fossil fuels with CCS increase to 13.8% of total generation (from 13.2%) and renewables also remain fairly steady. The cost of generation is 38.4% higher than the low mitigation scenario, assuming low fossil fuel prices in both scenarios (this is how all low fossil fuel price scenarios below are compared, too). The average cost of generation in SSA is 67.8 \$/MWh and 89.6 \$/MWh in Latin America (the cheapest and most expensive regions, respectively, in this scenario). Thus, the price of fossil fuels affects the absolute cost of power generation (now 76.5 \$/MWh) but the percentage increase in cost over the LMS changes very little. Considering the minor differences in generation mix, this is to be expected. Once again, ME & NA has the lowest carbon intensity (26.2kg/MWh) and China the highest at 139.8kg/MWh.

This situation occurs because the costs of fossil fuels, both with and without CCS, are lower than renewables (except for the windiest and sunniest locations) even at high fossil fuel prices. The difference between these two scenarios is because a greater proportion of potential renewable energy projects are below the cost of fossil fuelled CCS generation. Biomass use in power generation is now 26.4EJ. 3.64Gt CO_2 is separated by CCS plants and must be stored or used. 44% of this CO_2 comes from coal CCS plants.

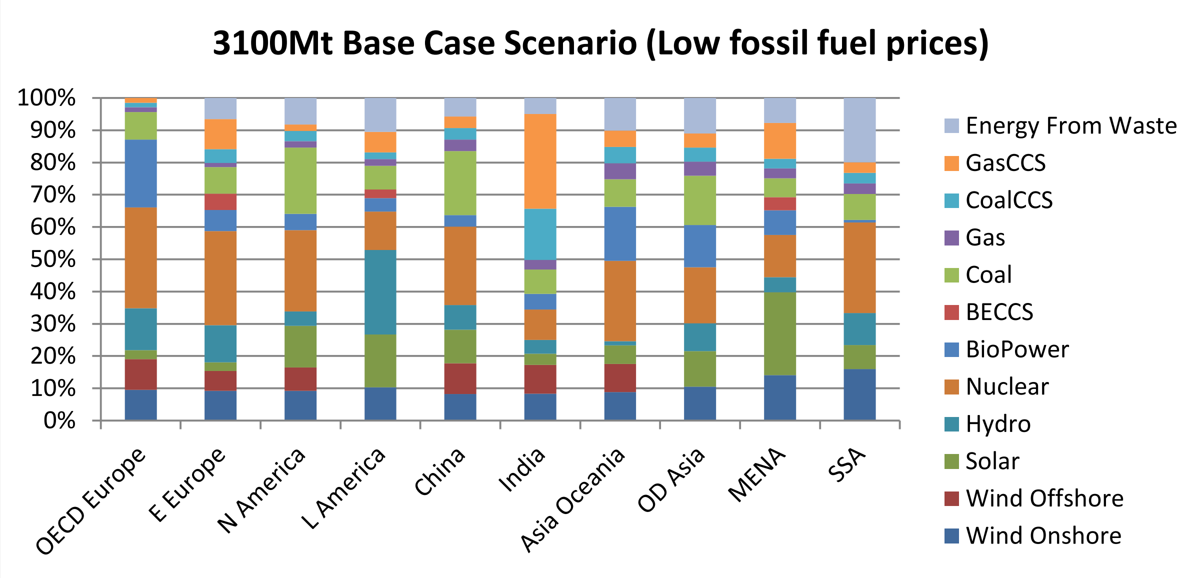

Figure 5: Regional generation mix for the baseline LCS, but with low fossil fuel prices.

2.4.3 Changes in carbon budget for power sector

The sensitivity of the results to the carbon budget available to the power sector is examined in this section.

1700 Mt/year carbon budget, high fossil fuel prices (case 3)

There are small changes in the generation profile at lower emissions levels. Unabated coal (63% of base case), coal with CCS (73%) and unabated biomass (83%) suffer at the expense of gas CCS (121%), biomass with CCS (176%) and hydroelectricity (121%). Total fossil fuel power generation is 22.0%, and renewables reach 53.8%. The electricity cost is 39.4% above the LMS, an increase of 2.8% over the base case. The greatest increases in electricity cost over the LMS are India (91%), China (81%) and North America (64%).

These results show that BECCS is starting to be required in greater amounts, rising from 1.68% of generation to 2.96% (209 GW, 1084 TWh) in an effort to counteract the emissions from unabated coal and gas-fired power stations. Note that BECCS is only used in four regions in the base case, but is present in all regions except for OECD Europe and China when the lower carbon budget is applied.

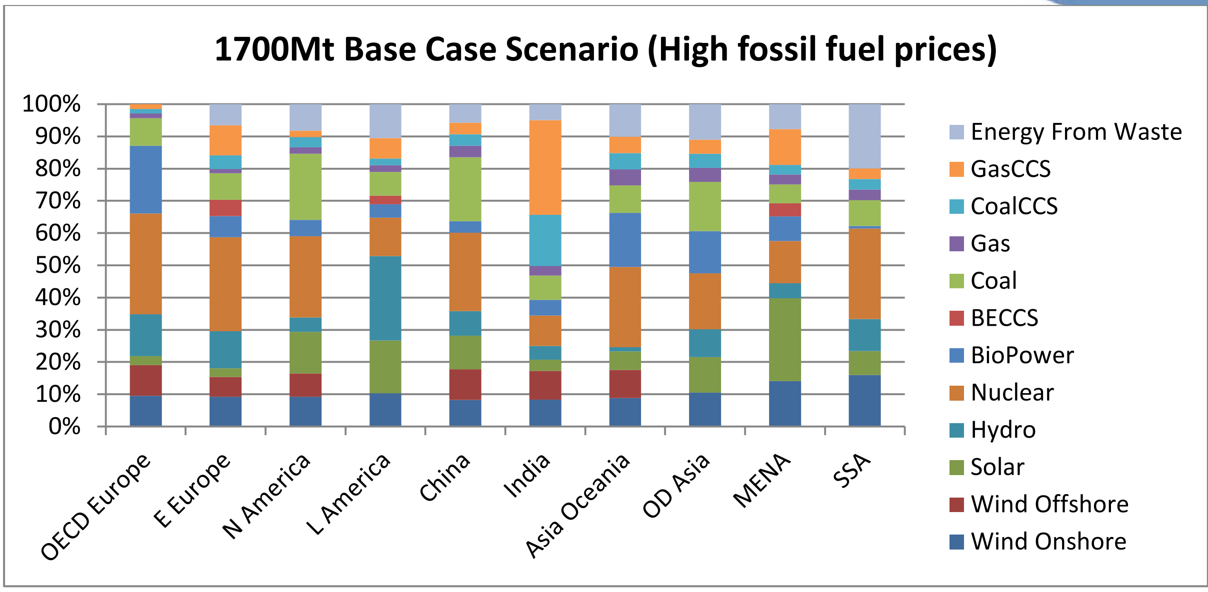

Figure 6: Regional generation mix for the LCS, but with a carbon budget decreased to 1700Mt per year.

1700Mt/year carbon budget, low fossil fuel prices (case 4)

The story here follows predictable trends – it combines the changes seen by reducing the price of fossil fuels (3100Mt, Low prices) with those of decreasing the carbon budget (1700Mt, High Prices). CCS plays a greater role in this scenario than any of the above, at 107.3% of the base case generation (5183 TWh). Despite BECCS losing some market share, gas CCS increases its overall share by 0.23%, rising to 11.1% of generation. The increase in LCOE over LMS is 41.2%.

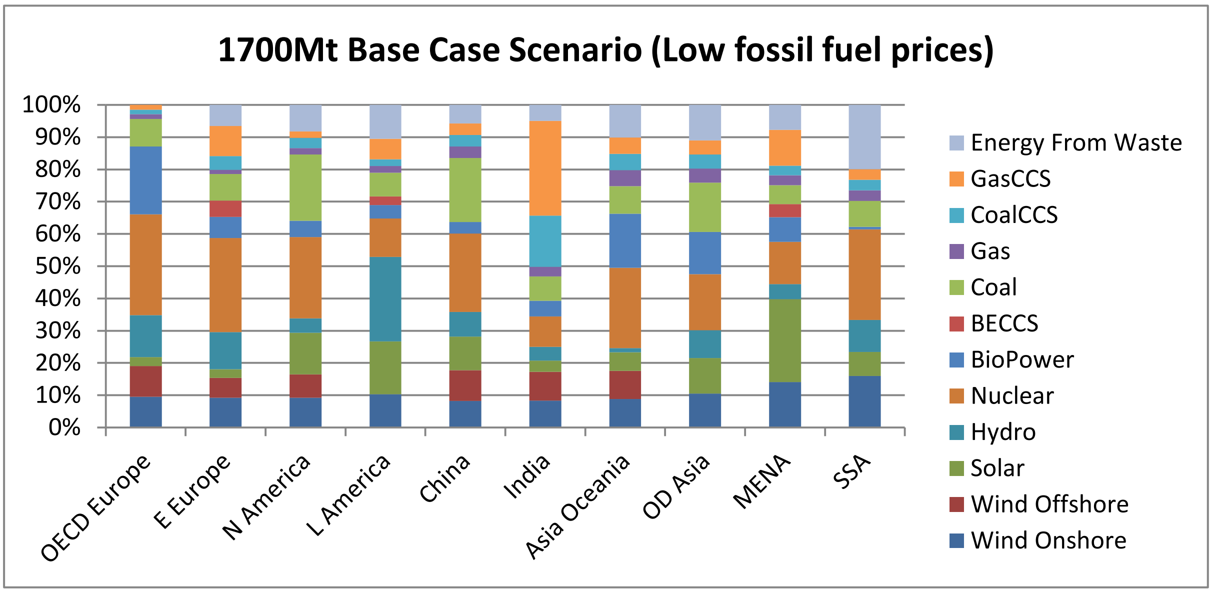

Figure 7: Regional generation mix for the LCS, but with a carbon budget decreased to 2500Mt per year and reduced fossil fuel costs.

4500Mt/year carbon budget, high fossil fuel prices (case 5)

A higher carbon budget favours unabated fossil fuels, something which is evident here. Unabated coal generation replaces other generation methods, increasing by 48% to 884GW/4586TWh. Unabated gas generation is not affected. The biggest loser, percentage-wise, is BECCS, which loses 33% of its generation share (40GW/206TWh). Coal and gas CCS generate 10% and 5% less, respectively. Interestingly, North America's coal CCS generation drops by 77% whilst India's increases by 75%. In absolute terms, solar loses the most (164GW/577TWh, 14%). The global increase in LCOE is 35.4%, to 79.4 \$/MWh.

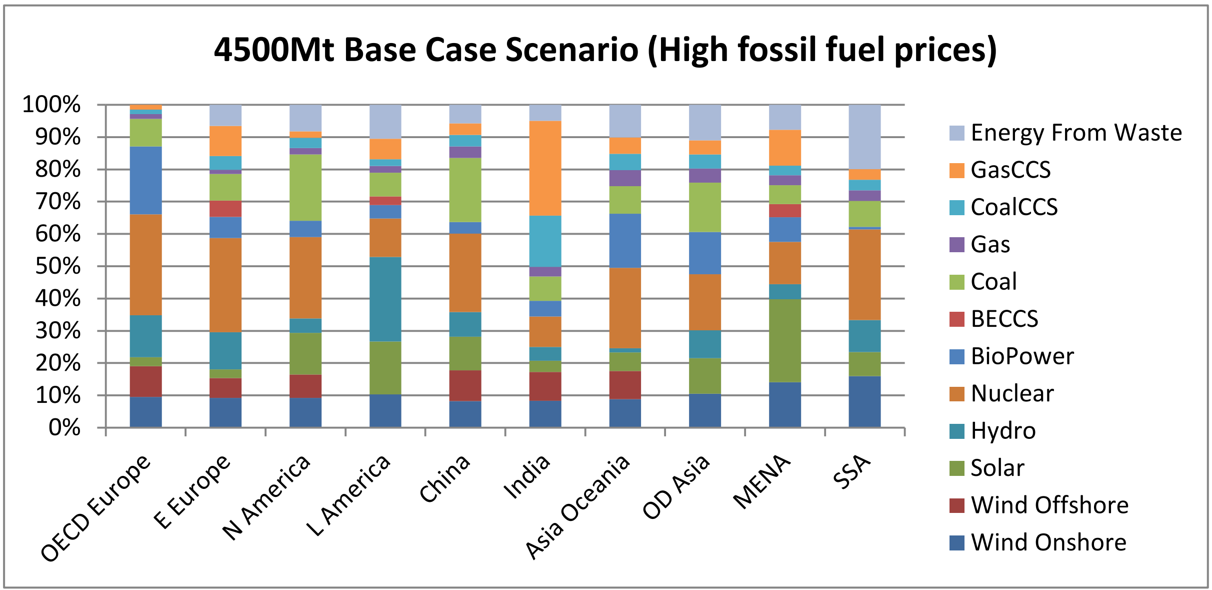

Figure 8: Regional generation mix for the LCS, but with a carbon budget increased to 4500Mt per year.

4500Mt/year carbon budget, low fossil fuel prices (case 6)

The change of fossil fuel prices at this carbon budget has similar consequences. Unabated coal is similar to the previous scenario, but coal CCS also increases, at the expense of more solar (which drops by 21% of its generation) but also hydro in India. There are negligible decreases in wind power in most regions. The increase in LCOE is 35.8% over the LMS, giving a price of 75.1 \$/MWh. In India, coal CCS's share of generation increases by 257% over the LMS, at the expense of solar and hydro.

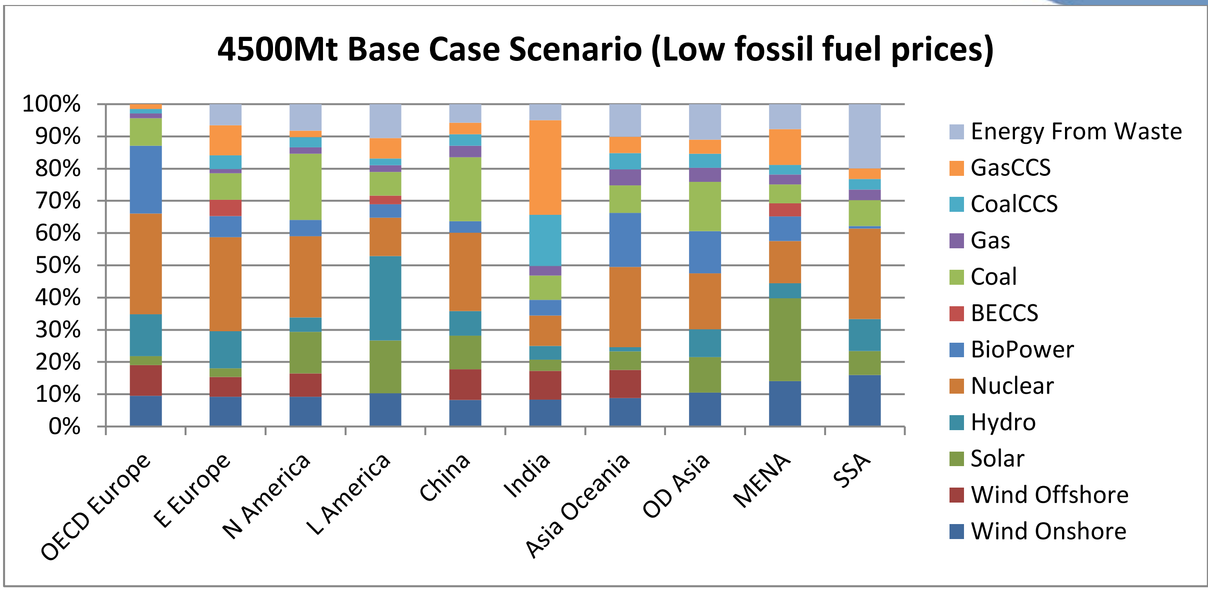

Figure 9: Regional generation mix for the LCS, but with a carbon budget increased to 4500Mt per year and reduced fossil fuel costs.

Conclusions

Unabated coal fired power generation is the most sensitive generation technology to carbon budget, as would be expected by its high carbon intensity. It tends to swap with solar generation and BECCS, but effects are felt in the other CCS generation technologies and even hydroelectricity. Coal CCS is particularly sensitive to fossil fuel prices, especially at higher carbon budgets, with its role increasing with decreasing fossil fuel price as it replaces a mixture of unabated coal and zero-emission technologies with the same aggregate carbon budget.

Sensitivity analysis of LCOE as a function of carbon budget

The carbon budget has a great influence upon the generation profile and thus the cost of electricity. By plotting the LCOE (relative to a base case value) at 28 points with global electricity sector emission targets of between 1100 and 6500 Mt/year at 200Mt/yr intervals, a broadly cubic relationship was observed as shown in figure . The trendline has the equation, where E_{CO_2} is the global CO_2 emission in Gt/yr:

$$LCOE\ (relative) = 0.000176\left(E_{CO_2}\right)^3 - 0.00118\left(E_{CO_2}\right)^2 - 0.00766\left(E_{CO_2}\right) + 1.004$$

The R^2 value for this curve was calculated to be 0.998.

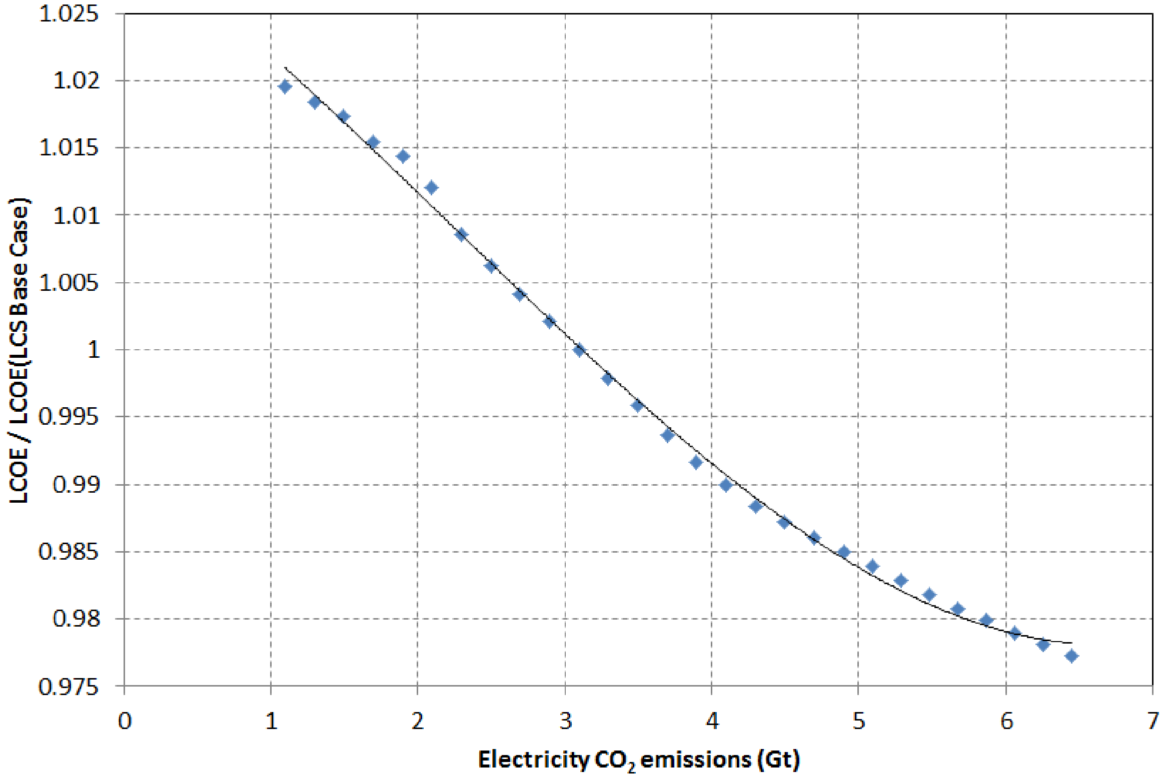

Figure 10: Sensitivity of global LCOE to carbon budget

2.4.4 Biasing the technology data in favour of renewables

General bias in favour of renewables

In these scenarios, the maximum capacity of each renewable power generation technology at each capacity utilisation factor has been increased by 50%. This causes renewable energy production to be significantly cheaper at high penetrations than in the base case. Global generation mixes for both high and low fossil fuel costs are depicted in figure 11 and figure 12 respectively.

High fossil fuel prices (case 7)

At high fossil fuel prices, coal CCS reduces its generation by 32%, gas CCS reduces by 9.5% and BECCS by 3.6%. Unsurprisingly, offshore wind and solar generation increases, by 12% and 7.5%, respectively. Increases are also seen in energy from waste (4%) and unabated coal (2%). The latter increase is taking the portion of the carbon budget that was previously used by CCS. Other changes are minimal. Increase in LCOE over LMS is 35.9%.

Low fossil fuel prices (case 8)

At low fossil fuel prices, coal CCS only reduces by 19% compared with the base case. BECCS reduces by 9.4% compared with the base case. Since the price of biomass is the same in the high and low fossil fuel scenarios, this replacement of one CCS technology with another is quite sensible. Unabated coal and gas generation in this scenario is unchanged from the base case. Energy from waste and offshore wind increase by 4.0% and 12%, respectively, as in the previous case, but solar does not increase as much (only 7.3%). Other changes are minimal. Increase in LCOE over LMS is 37.8%

Conclusions with respect to favouring renewables

In the high fossil fuel price case we see a replacement of fossil fuelled CCS by a mixture of unabated coal and zero-emission technologies. The effective reduction in the cost of generation by wind and solar pushes the mixture to be cheaper than CCS in many regions, up to a certain penetration. This is less pronounced in the low fossil fuel case, because a mixture of coal CCS and zero-emission technologies is less expensive than both the effective mixture of BECCS/coal CCS seen in previous cases and also the unabated coal/zero-emission technology mixture seen in the high fossil fuel case here. Thus, the effective change is a moderate reduction in coal CCS, a significant reduction in BECCS, an increase in renewables and a static unabated coal generation profile.

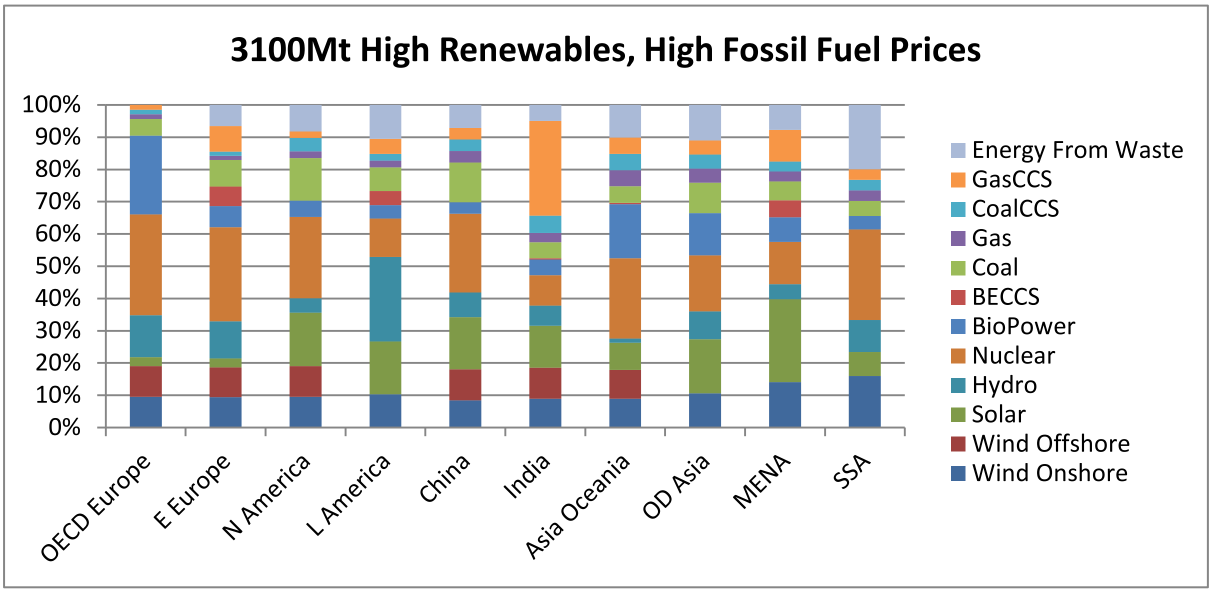

Figure11: Regional generation mix for the LCS, but with the technology data biased in favour of renewable energy.

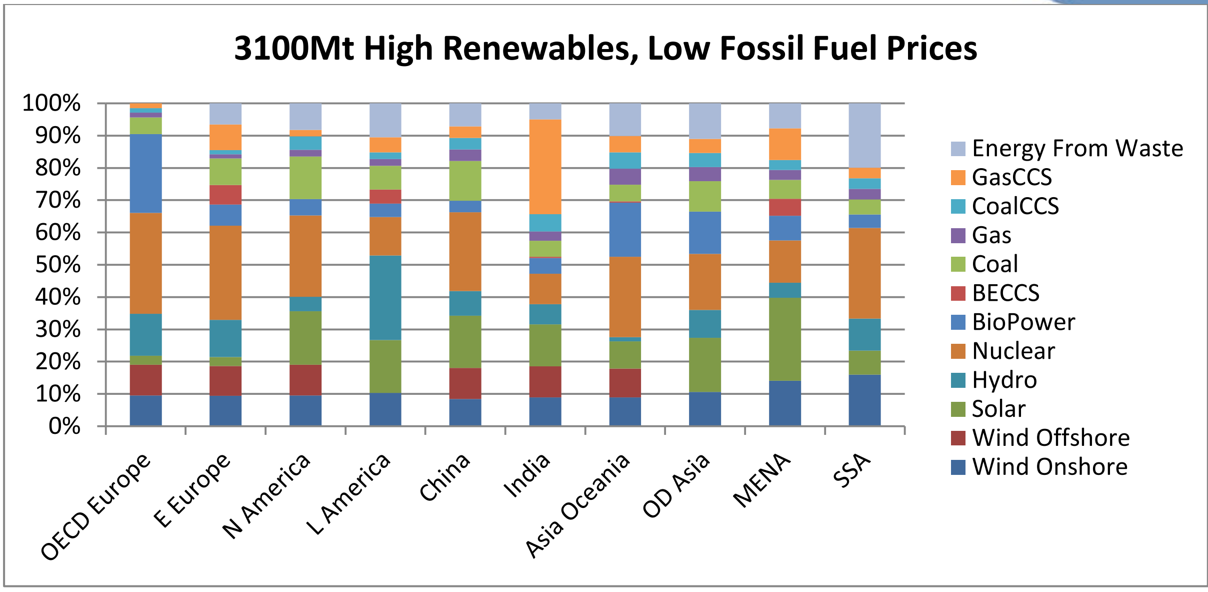

Figure 12: Regional generation mix for the LCS, but with the technology data biased in favour of renewable energy and reduced fossil fuel costs.

2.4.5 Biasing the technology parameters in favour of, and against, CCS (cases 9- 11).

To simulate a CCS friendly world, the build rate and maximum capacity constraints on CCS technologies in the model were increased by 50%. However, as none of the regions reached their maximum CCS uptake level in the base cases, this did not affect the generation mixes. Instead, the effect of reducing the capital cost of all CCS systems by 33% was investigated with the implications for the generation mixes shown in figure 13 for the baseline LCS and in figure 14 for the LCS with reduced fossil fuel prices.

At high fossil fuel cost (case 9), the effect of reducing CCS capital costs is minimal, apart from a slight uptake in coal CCS (381 TWh, up 25%) at the expense of gas CCS (319TWh, down 9.7%), unabated coal (38TWh, down 1.2%) and BECCS (24TWh, down 3.9%). Increase in LCOE is 36.0%.

In the case of reduced fossil fuel costs (case 10), there are significant changes, with coal CCS growing from 1543TWh in the base case to 5087TWh here, a 230% increase. This huge increase occurs mainly in China, which grows to have a coal CCS market share of 32.8% (2401 TWh, 463GW)), compared with 3.6% in the base case. The biggest loser is solar, losing 1388TWh of generation per annum, a decrease of 29% of its base case capacity, followed by offshore wind (700TWh, 30.7% reduction) and unabated coal (466TWh, 15.1%). Gas CCS also loses 10% of its share compared with the base case, meaning that coal CCS accounts for 59% of CCS generation, compared with 28% in the base case and 48% in case 10. Hydroelectricity loses 105TWh in both North America and India. North America also loses 259TWh of unabated biomass power. Increase in LCOE is 36.7%.

The model was also run to model a world in which no CCS is deployed (case 11). In this run, the regional deployment quotas for CCS applied to biomass, coal and gas were set to zero. Deployment constraints on unabated biomass, coal and gas were increased to compensate. This led to a massive take-up in unabated biomass power of an extra 2757 TWh (an increase of 95%), requiring an extra 15.9 EJ of biomass. Solar increases by over 1400 TWh (up 74%). Unabated coal power also reduces (down 16.3%) at the expense of unabated gas-fired power generation (up 147%). Onshore wind increases slightly (up 6%) whilst offshore wind is unchanged.

Unsurprisingly, it seems that solar technologies are the most likely to benefit from a global failure to implement CCS and coal is most likely to lose; however, in this scenario the carbon budget is not reached. 3630 Mt CO_2 is emitted each year from the power sector in this scenario, an 'overspend' of 530 Mt. Of course, a concerted push to implement zero-emission technologies may allow greater rates and extents of penetration than envisaged in this study.

The increase in LCOE over the LMS is 37.3%. This is lower than may be expected. The amount of biomass used in power generation significantly, but this model has a constant cost of biomass fuel, which does not reflect the normal rules of supply and demand.

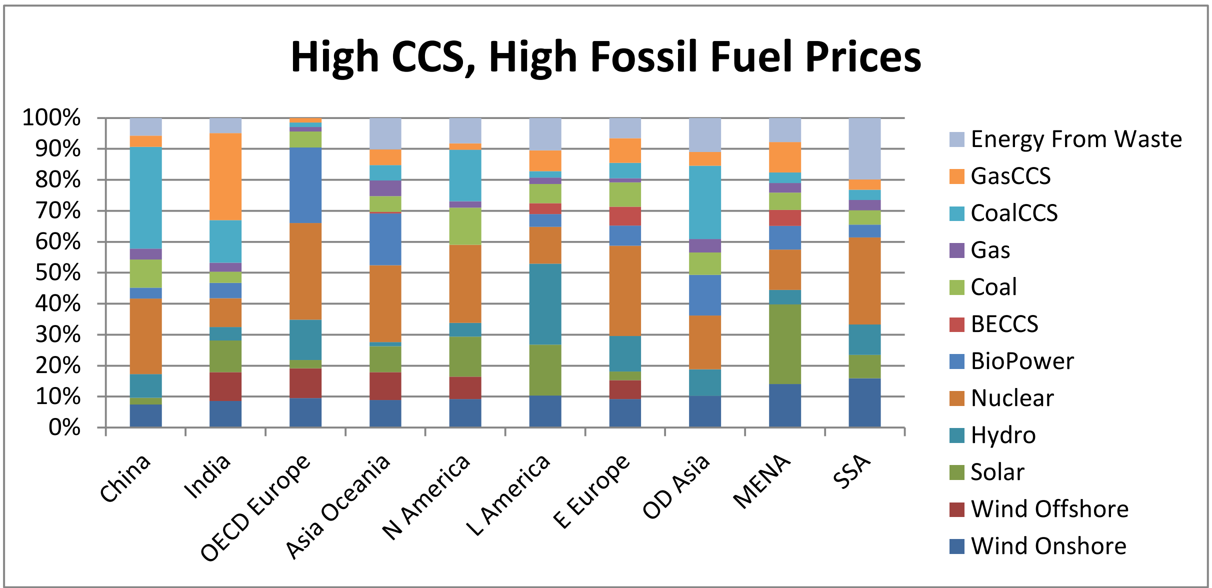

Figure13: Regional generation mix for the LCS, but with the technology data biased in favour of CCS.

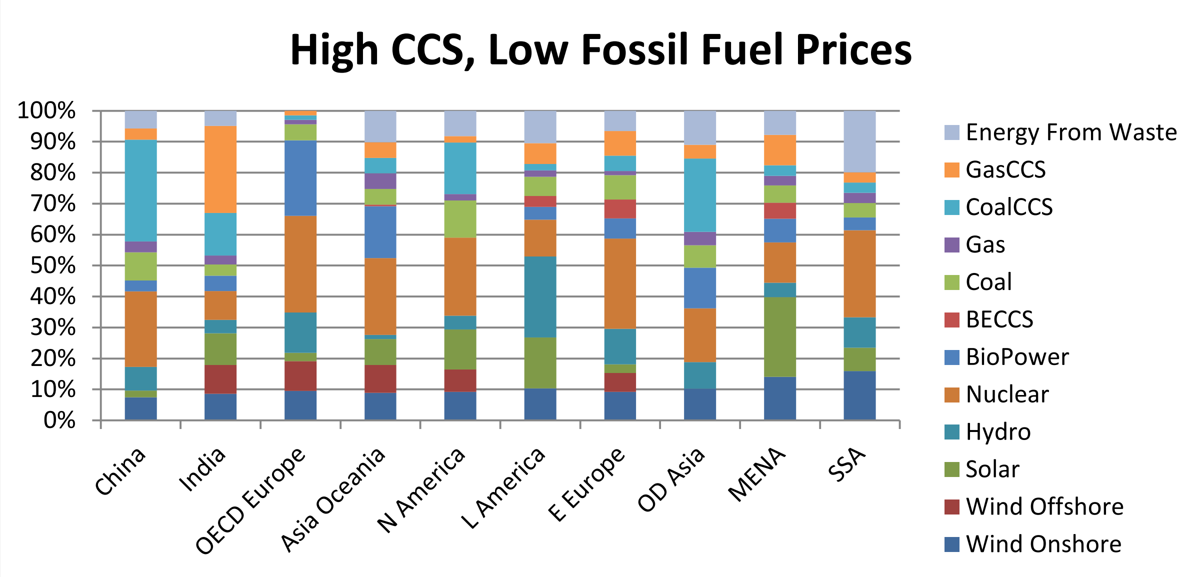

Figure 14: Regional generation mix for the LCS, but with the technology data biased in favour of CCS and reduced fossil fuel costs.

2.4.6 Allowing increased nuclear expansion, and changing nuclear costs

In the base low carbon scenario technology data set, nuclear is a relatively low-cost technology compared to other low-carbon power sources. As a result, the contribution that nuclear makes to the generation mixes described in section 2.2 is limited only by exogenous regional deployment constraints developed using literature estimates. The impact of relaxing these constraints is investigated in this section.

High fossil fuel prices (case 12)

Increasing the maximum capacity of nuclear power in each region in line with the World Nuclear Association's 'High' projections gives a rise in nuclear power generation and capacity of 88%. Sub-Saharan Africa and Eastern Europe do not change their levels of nuclear power generation, but percentage increases in other regions range from 57% in North America (732TWh/132GW) to 249% in Latin America (739TWh/133GW). The largest absolute increase is 1485TWh/268GW in India, closely followed by China with 1372TWh/248GW.

In this scenario, nuclear power accounts for about 40% of all power generation. The biggest losers (in terms of percentage of generation lost compared with case 1) are BECCS (65%), gas CCS (49%), unabated biomass (42%) and solar (33%). In absolute terms, gas CCS and solar lose the most (1600TWh and 1524TWh, respectively). The carbon target is comfortably met, and the increase in LCOE is only 24.8%. This indicates that strategies to increase nuclear power implementation can give cheaper electricity costs.

Low fossil fuel prices (case 13)

With an increase in LCOE of only 26.5% above the LMS, case 14 is the cheapest of any shown so far. Once again, nuclear produces about 40% of all electricity and all technologies are similar relative to case 13.

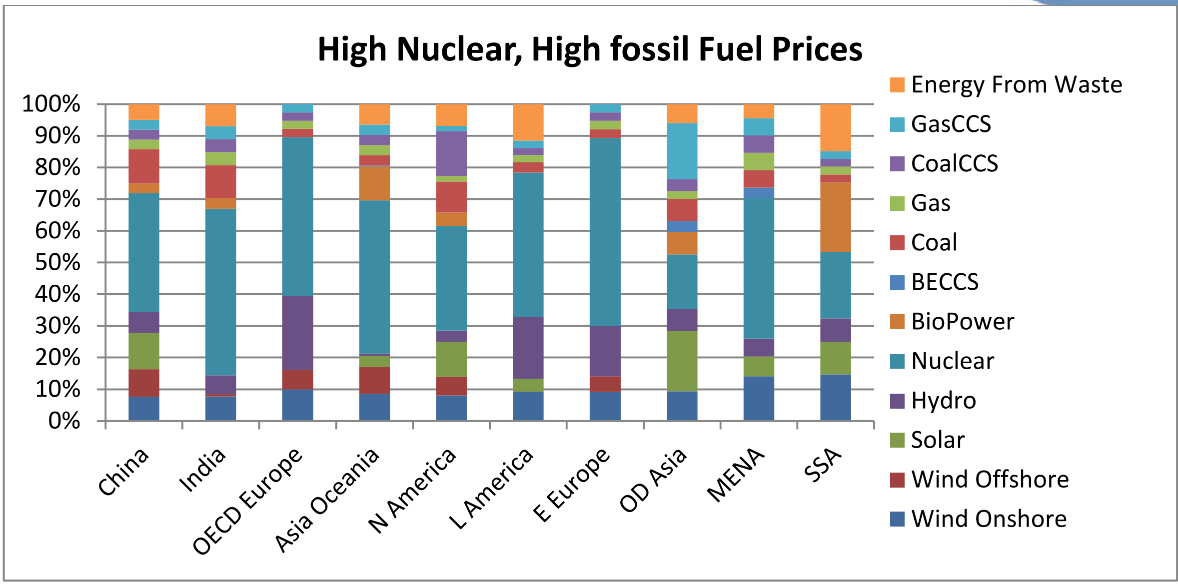

Figure 15: Regional generation mix for the LCS, but with relaxed nuclear deployment constraints.

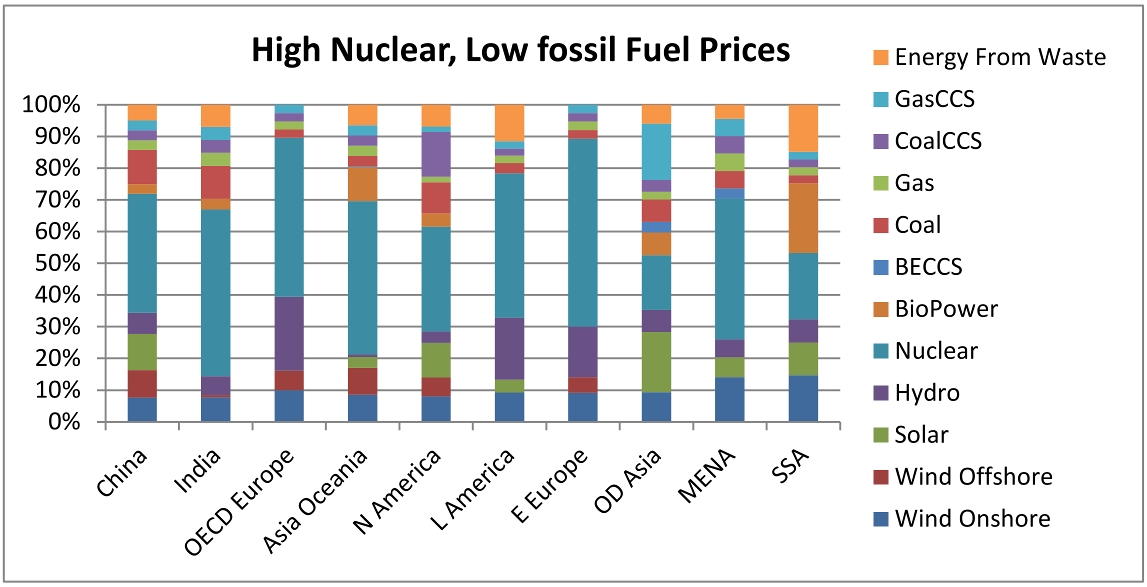

Figure 16: Regional generation mix for the LCS, but with relaxed nuclear deployment constraints and reduced fossil fuel prices.

Sensitivity analysis on nuclear uptake as a function of nuclear CAPEX based on case 1

A sensitivity analysis on the capital cost of nuclear power was also undertaken increasing the base capital cost of nuclear power from 3.25bn $/GW. Various costs, up to 4 times the base case (13bn $/GW), are shown in the graph below along with the implication for global nuclear electricity generation.

The step-wise behaviour of the decreases in deployment with increasing costs is due to the relatively simple nature of the least-cost optimisation model. Once the abatement cost of nuclear exceeds that of an alternative in a region, a whole tranche of nuclear capacity from the base case mix is replaced by that alternative, which produces a ‘step’. The most important region appears to be around 7.5 $bn/GW capacity, where capacity drops from approximately 6600GW to 4600GW very quickly. This step-wise behaviour would not happen in reality, as costs and constraints would vary within each region rather than in the aggregated manner considered here. Yet this sensitivity analysis at least shows the general trend of the relationship and the sensitivity of the generation mix to the relative costs of renewables compared to nuclear power.

At the maximum nuclear capital cost considered, the global average cost of electricity was 98.0 $/MWh. This is significantly higher than case 1’s 80.4 $/MWh. However, because nuclear energy is an important component in the LMS (which is not optimised in a similar manner, but is of fixed generation profile), the cost over an LMS with a nuclear capex of 13 $/GW is only 62.5%.

The increase in capital cost of nuclear capacity is a proxy for several potential cost increases within the nuclear sector, such as: improved safety systems at nuclear facilities; the construction of a small number of fast-breeder reactors to ‘burn’ nuclear waste; construction, operation and maintenance of long-term waste repositories; and uranium extraction and processing.

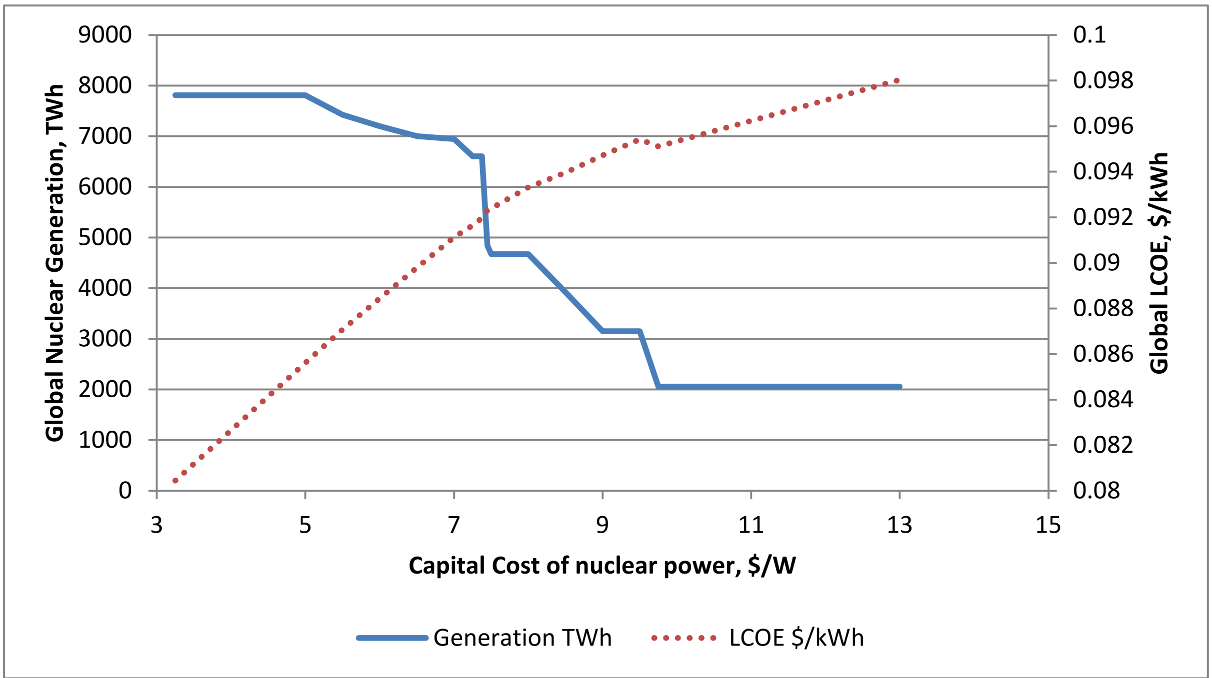

Figure 17: Effect of increased nuclear capital costs on global nuclear generation and LCOE in the LCS.

Nuclear power is an important part of the power generation mix in this study, because it is zero-carbon and low-cost. Even if capital costs are doubled on a global level, about 90% of the base case generation (7000TWh) remains. On a regional level, the sharp drop-offs in nuclear capacity as cost increases shows that the need for nuclear varies in different areas. Public opinion about nuclear power is difficult to characterise on the regional level employed here, and so it is almost impossible to account for the political impact on nuclear deployment.

It should be kept in mind that this study has not directly considered political constraints on nuclear deployment, except insofar as they are taken into account by the WNA and IAEA derived capacity constraints. Public and political attitudes to nuclear fission are evolving rapidly in many countries at the moment, and can differ radically between even neighbouring countries - compare Germany and France for example). In consequence, public opinion about nuclear power is difficult to characterise on the regional analytical level employed here, making it almost impossible to account for the political impact on nuclear deployment. This is a significant limitation as political and social issues may remove nuclear fission entirely from the mix of certain countries by 2050, which will impact on the validity of the fuel mixes provided here. Of course, there will also be social and political constraints on the deployment of other low carbon sources, and nor are these directly accounted for in the study. However such constraints are likely to be more an issue of extent, rather than a go/no go decision. We undertook a “no-nuclear” study which resulted in a global average LCOE of \$93.6/MWhe, an increase of 59.8% on the LMS and an increase of about 16% on the base case LCS value. In the sensitivity analysis above, this LCOE was reached at a capital cost of about 8-8.5 \$/W. Therefore, from a purely economic point of view, including nuclear in the energy mix makes sense until capital costs rise above 8-8.5 \$/W. To put this into context, the capital cost of Flamanville 3, a 1.65GW nuclear power station being built in France, is now estimated at €8.5bn (\$11.1bn)[4]. This is equivalent to 6.7 \$/W. At the level of capital cost, the model gives an LCOE of approximately 90.3 \$/MWh.

2.5 Overall summary

Table 7summarises the full set of low carbon scenario sensitivities examined in the study. Compared to the base case, the range of LCOEs calculated across all the cases extended from an increase of 1.5% (case 3) to a reduction of approximately 30% (case 13). This suggests that the base case considered in the study is relatively conservative, although since most of the sensitivities have involved relaxing constraints it is not surprising that they mostly result in reductions in electricity cost.

Aside from providing a degree of confidence in the calculation method the case studies also highlight the importance of deployment constraints on lower cost technologies. A key observation is that constraints of any form, be they physical, technical or social, on lower cost technologies force reliance on more expensive sources, which in turn pushes up the cost of decarbonisation. Nuclear fission provides an excellent exemplar here, being one of the cheaper low carbon technologies within the analysis. In the base case low carbon scenario study, nuclear fission deployment is constrained to maximum levels derived from those predicted by the World Nuclear Association and the IAEA. Substantially relaxing those constraints produces a reduction in the cost of global decarbonisation – as there is no longer any need to deploy the more expensive technologies. But this is based on the assumed costs of nuclear which are at this stage still uncertain.

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[4] http://www.lemonde.fr/planete/article/2012/12/03/le-cout-de-l-epr-de-flamanville-encore-revu-a-la-hausse_1799417_3244.html

Table 7: Summary of power sector scenario results.

Case number	**Scenario**	**Power Sector Carbon Budget MT/Year**	**Cost of energy increase with respect to LMS**	**Relative cost of energy with respect to LCS Base Case**
1	Base case	3100	37.3%	1.000
3	High fossil prices, Reduced Carbon Budget	1700	39.4%	1.015
5	High fossil prices, Increased Carbon Budget	4500	35.4%	0.987
2	Low fossil prices, Standard Carbon Budget	3100	38.4%	0.951
4	Low fossil prices, Reduced Carbon Budget	2500	41.2%	0.980
6	Low fossil prices, Increased Carbon Budget	4500	35.8%	0.981
7	High Fossil Fuel Prices, High renewables	3100	35.9%	0.990
8	Low Fossil Fuel Prices, High renewables	3100	37.8%	0.995
9	High Fossil Fuel Prices, High CCS	3100	36.0%	0.991
10	Low Fossil Fuel Prices, High CCS	3100	36.7%	0.988
11	High Fossil Fuel Prices, No CCS	3100	37.3%	0.993
12	High Fossil Fuel Prices, High Nuclear	3100	24.8%	0.898
13	Low Fossil Fuel Prices, High Nuclear	3100	26.5%	0.905

3 Detailed analysis – buildings sector

This section describes an analysis of future energy demands and greenhouse gas emissions for the buildings sector in each of our regions. A series of building-level technology and built environment interventions to support decarbonisation were investigated and used to estimate the cost differential between a projected low-mitigation scenario (LMS) and a more ambitious low carbon scenario (LCS), in 2050.

3.1 Current situation and method for projecting energy demand

The global building sector demand for energy was 115 EJ in 2009, an increase of almost 100% from the demand of 57.6 EJ in 1971 (IEA, 2011a) A key question then is what drives this demand for energy? Historically, it would seem that the levels of urbanisation, population, and GDP are good predictors of the demand in the building sector. Historical data is shown in figure 18.

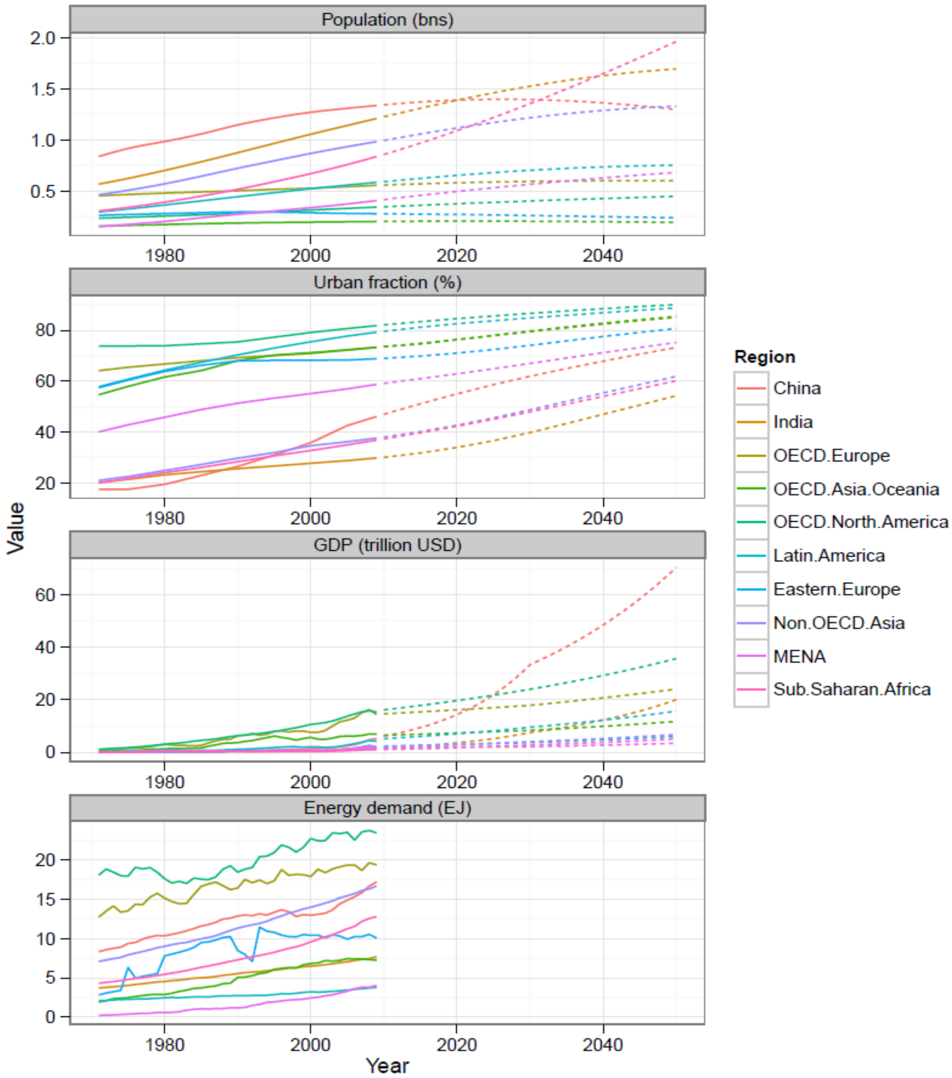

Figure 18. Input data for buildings energy analysis by region. Dashed lines indicate forecast values from UN and World Bank sources

3.2 Projected reference scenario in 2050

A multi-level linear regression to forecast demands by fuel type and region was developed, where the predictors were population, urbanization fraction, and GDP. The 2050 energy demand for the buildings sector was estimated at 199 EJ (+/- 22 EJ) and an associated 12.6 Gt CO_2 in GHG emissions. This compares well with the IEA's Technology Roadmap of 184 EJ and 15.2 Gt CO_2. The regional breakdown is shown in Table 8 (the total energy demand is slightly different from the previous figure due to the use of a separate regression model). The 95% confidence intervals on our 2050 LMS forecasts show that they were consistent with other published estimates.

Table 8. Low mitigation scenario demand and emissions for the building sector in 2050

Region	Energy demand (EJ)	GHG Emissions (Gt CO2)
China	33.3	3.1
India	10.5	0.3
OECD Europe	23.2	1.4
OECD Asia Pacific	10.4	1.01
OECD North America	38.0	4.3
Latin America	5.5	0.36
Eastern Europe	8.3	0.35
Non OECD Asia	26.33	1.0
MENA	11.1	0.84
Sub-Saharan Africa	32.2	2.1
Total	199	14.8

3.3 Selection, relative costs and resource constraints for low-carbon technologies

To estimate the potential carbon savings in 2050, we studied the impact of five intervention strategies based on current world-leading standards: reducing residential space heating demand through efficiency measures, introducing ground source heat pumps to the residential sector, fuel switching from fossil fuels to biomass and electricity sources, efficiency improvements in non-heat electrical demands (e.g. lights and appliances), and grid decarbonisation. Using data from the literature, capital and operating costs for each intervention and a selection of the relevant technologies is shown in Table 9. Fuel switching and decarbonisation costs are addressed in the power section of the report.

Table 9. Estimated capital and operating costs of building sector interventions[5,6,7,8].

Measure	Capital cost	Operating cost
External wall insulation	$7,800 per house	-
Superglazing	$4,300 per house	-
Roof insulation	$210 per house	-
Floor insulation	$400 per house	-
Cavity wall insulation	$1,600 per house	-
Residential ground-source heat pumps	$1,600 per kW	$68/kW
Improved lighting	~$1.50-10 per fixture	-
Improved appliances	~$1,000-1,800 per unit	-

The key assumption in estimating the penetration of these measures included a reduction in space heating intensity from 72-191 to 52 kJ/HDD m^2 in the low carbon scenario (see figure 19). It was also assumed that 25% of OECD households would benefit from improved external insulation and 50% of residential heat would switch from fossil fuels to low carbon sources. The mitigation costs by region are shown in figure 20.

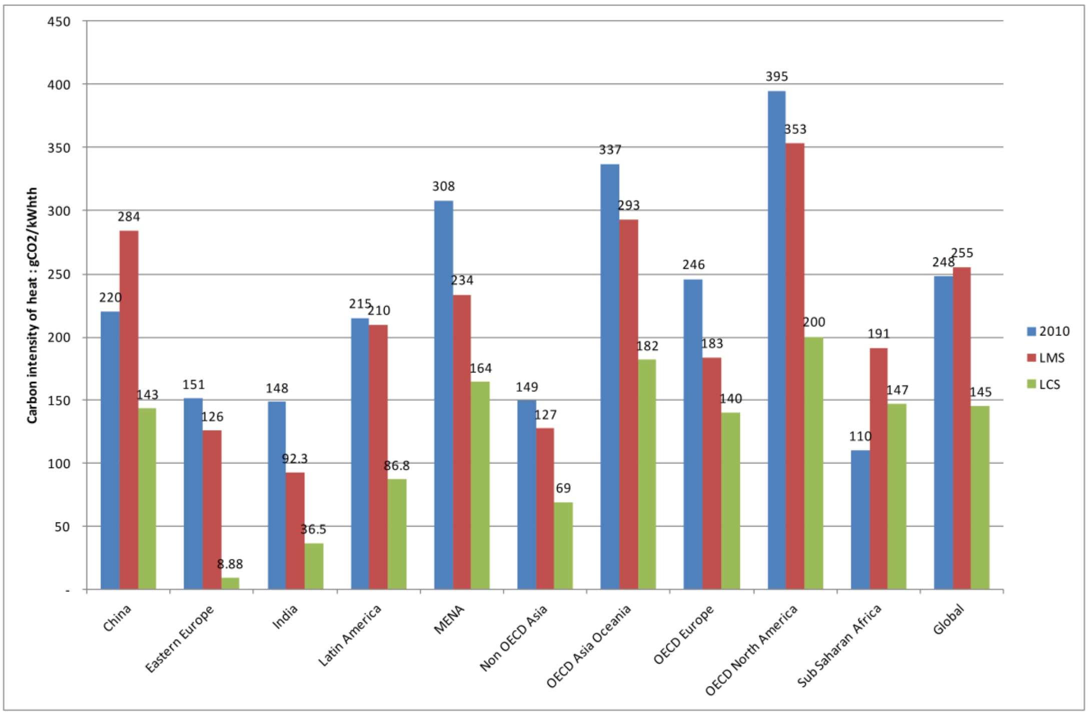

Figure 19. Residential heat emission factors (gCO_2e/kWh_{th}) for different regions

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[5] DECC 2050 calculator, (http://2050-wiki.greenonblack.com/cost_categories/84

[6] CERT 2008 Technical Guidance

[7] Enviros 2006 Carbon abatement options ((http://www.decc.gov.uk/assets/decc/what%20we%20do/supporting%20consumers/saving_energy/analysis/enviros-report.pdf)

[8] P. Liu et al. / Energy Policy 38 (2010) 4224–4231

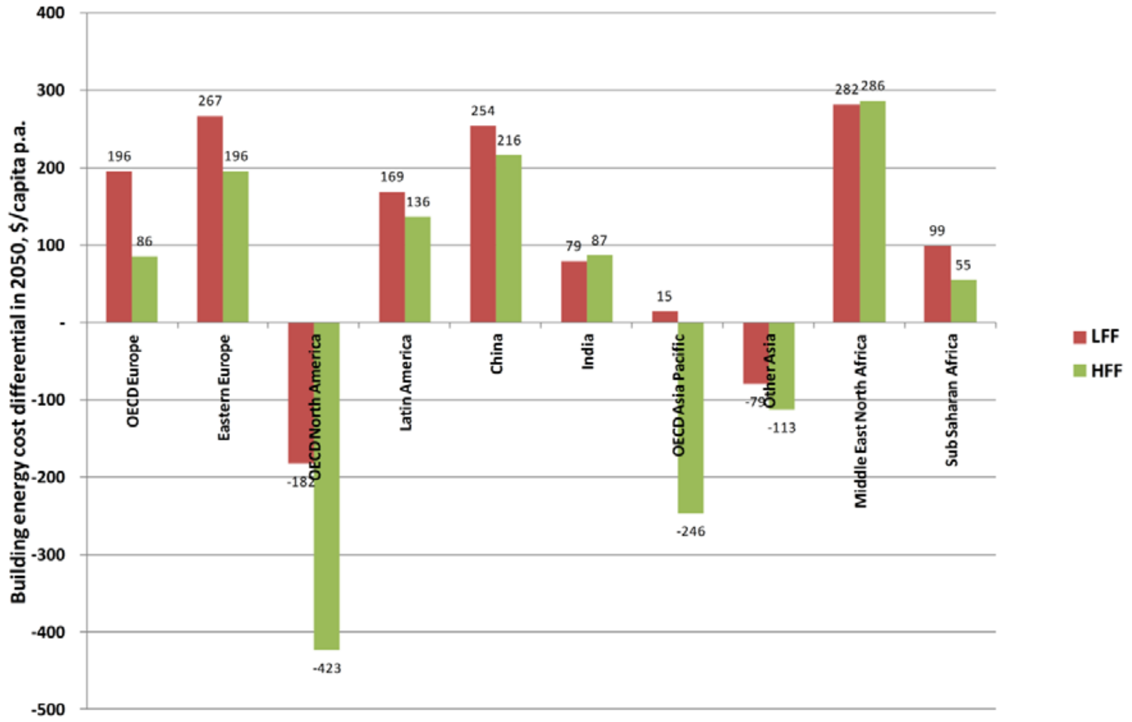


Figure 20. Residential energy mitigation costs for different regions

3.4 Low-carbon scenario in 2050

Table 10shows the projected global savings from each intervention in the low carbon scenario, i.e. savings beyond the projected LMS baseline. The largest changes come from improvements in residential space heating, electricity efficiency of lights and appliances, as well as changes in fuel sourcing (both fuel switching and grid decarbonisation). A rapid acceleration of ground-source heat pump deployment is also beneficial, rising from 0-0.6% global penetration under the LMS to 5-15% under the LCS.

Table 10. Summary of savings in energy demand and greenhouse gas emissions by 2050 for each scenario.

Intervention	Energy demand (EJ)	GHG emissions (Gt CO_2)
Residential space heating intensity	42	2.9
Residential ground source heat pumps	9.5	0.3
Fuel switching	-	0.9
Electrical efficiency	15	1.7
Grid decarbonisation (i.e. reducing the GHG intensity of the power to buildings)	-	5.2
Total savings	66	10.7
LMS overall	199	14.8
LCS overall	133	4.1

These changes result in reductions to household fuel bills (wholesale values only), shown in Table 11. The price of electricity increases in each region as the grid decarbonises; however, given the reduction in overall demand and decreases in electrical demand due to improved electrical efficiency, the overall household fuel bill is decreased.

Table 11. Household fuel bills (wholesale values) by region in the LMS and LCS in 2050, based upon the central emissions high FF scenario.

	LMS fuel bill ($/household)	LCS fuel bill ($/household)
China	405	318
Eastern Europe	574	374
India	218	478
Latin America	327	245
MENA	880	1,605
Non-OECD Asia	700	254
OECD Asia Oceania	1,895	1,071
OECD Europe	1,511	1,069
OECD North America	2,759	1,316
Sub-Saharan Africa	622	503

3.5 Major technical shifts

The energy efficiency and greenhouse emissions improvements seen in the low carbon scenario can be summarized as the result of three major changes:

- A shift away from traditional fossil fuel heating to low carbon sources such as biomass and less carbon intensive electricity.
- Significant improvements to the thermal envelopes of buildings through better glazing and insulation.
- More efficient lighting, cooking, and appliances.

3.6 Major uncertainties

The major sources of uncertainty are thought to lie in the following six inputs for the regional calculations:

- The estimates of fuel demands in the global building sector for the period 1971 – 2009 as obtained from the IEA database;
- The improvement in energy efficiency of future lighting, cooking, and electrical appliances;
- Floor area per capita and useful space heating intensity per heating degree day per floor area;
- Assumed penetration rate of heat pumps; and
- The proportion of fuel switching as a percentage of total fuel use.

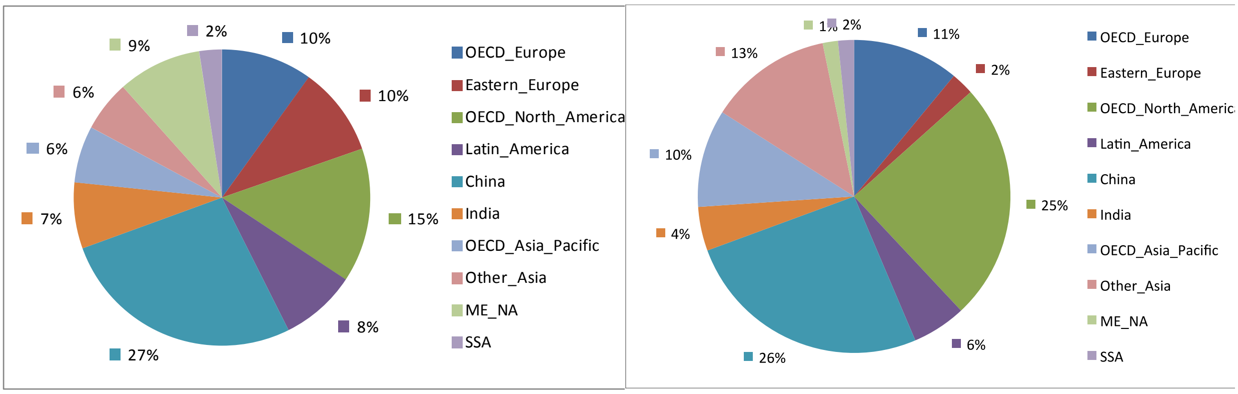
3.7 Overall cost of system transition

Estimating the annualised capital costs and operating costs of five interventions on a per unit basis, it was calculated that the total global cost differential between the low mitigation and low carbon scenarios in 2050 was approximately $974 billion, or $267 per household. However if one assumes that the cost assumptions for improving the efficiency of non-OECD new builds are lower than for OECD retrofits, then the revised estimate is $709 billion or $195 per household.

4 Industry

4.1 Current status

Globally, the total manufacturing value added in 2010 was 10 trillion US$ (PPP) with China and OECD North America making up 51% of this (see figure 21b). This corresponds to a share of around 14% of global GDP. Industrial activity has grown rapidly in recent decades, with the greatest increase occurring in developing countries. This development is reflected in a current energy demand of industry estimated at 102.5 EJ, in which China and OECD North America contribute around 42% of the total (see figure 21a).



(a) Total industrial energy demand in 2010: 102.5 EJ

(b) Total manufacturing value added in 2010:

10 trillion US$ (PPP)

Figure 21(a) Share of global energy demand in the industrial sector by region; (b) Share of global manufacturing value added by region

In most world regions, fossil fuels make up around half of the energy demand as shown in figure 22. The exact mix of fuels depends on regional resources, level of development and the structure of the industrial subsectors. China and India are heavily coal dependent, owing to significant domestic coal reserves in these regions and to the fact that energy-intensive industries such as iron and steel, and cement make up a large share of their industrial activity. By comparison, OECD countries and Eastern Europe rely on a significantly higher portion of gas. In general, electrification in industry is currently less than 27%.

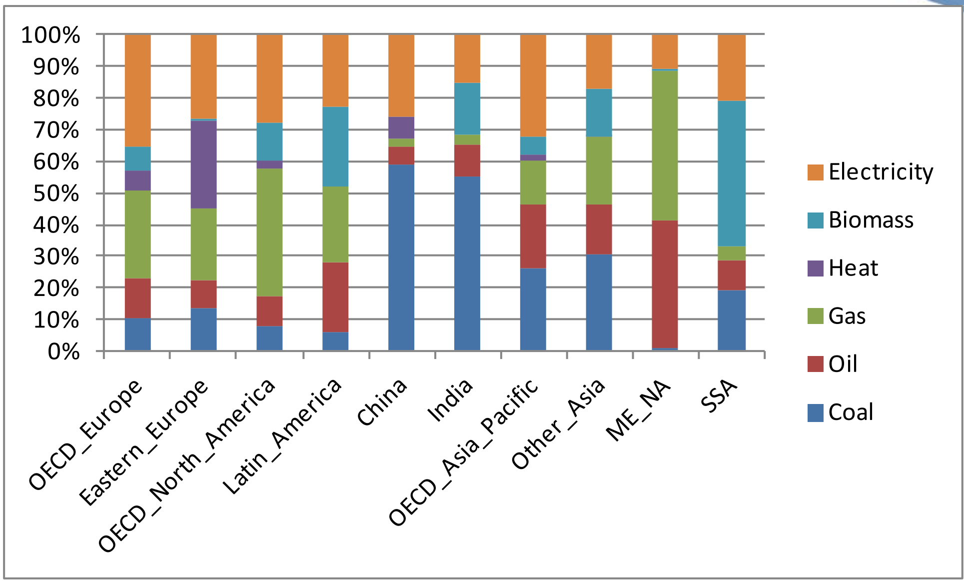
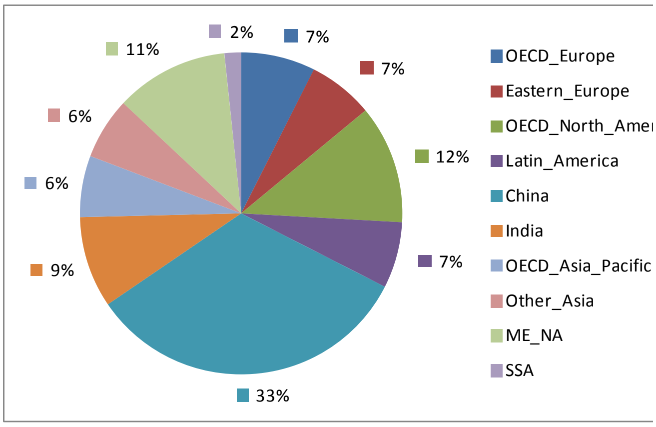
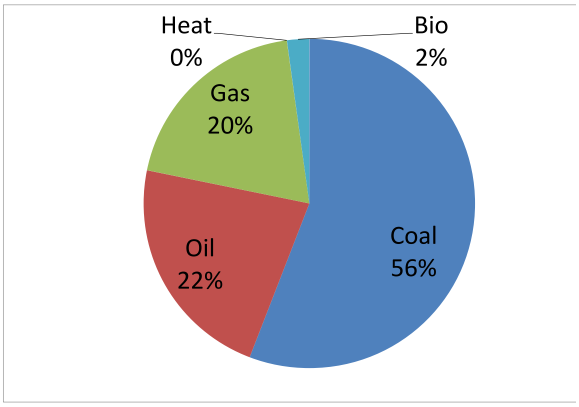


Figure 22: Comparison of current mixes of fuels consumed in industry in different regions





Total CO_2 emissions in 2010: 5.8 $GtCO_2$

Figure 23. Current share of global CO_2 emissions by region and fuel type

In terms of CO_2 emissions, the current global total stands at 5.8 $GtCO_2$ (excluding process emissions from cement and indirect emissions from electricity use). As depicted in Figure 23, China is the largest emitter with 1.9 $GtCO_2$ (33%) followed by OECD North America (12%). It is evident that the future course of fossil fuels use, particularly coal and oil in these regions, holds critical importance for climate change mitigation.

4.2 Modelling methodology

4.2.1 Industrial activity, drivers and projections

The main activity driver for industry used in this model was manufacturing value added. This was determined based on projections of how manufacturing as a share of GDP changes with GDP/capita.

It is generally accepted that as countries develop, certain shifts in economic activity are observed as depicted in Figure 24. In the early stages of development, agricultural activity dominates and industry only makes up a small share of the economy. As a country develops, there is usually a shift away from agriculture towards increased industrial activity, particularly manufacturing. This industrial activity is required to provide the necessary infrastructure to underpin growth and development. At some point, once a region has reached a certain level of development, a second shift is observed and industrial activity is gradually replaced by services. Most developed countries are currently on this trend of decreasing manufacturing activity. It is expected, however, that there is a minimum level of manufacturing activity which is required to sustain growth and maintain infrastructure. It should be noted that this pattern is a generalisation based on the pathway that many currently developed countries have followed; however it is not certain whether it is imperative that countries must follow this route in order to achieve development. However, for the purpose of this model, it was assumed that all regions will follow this trend.

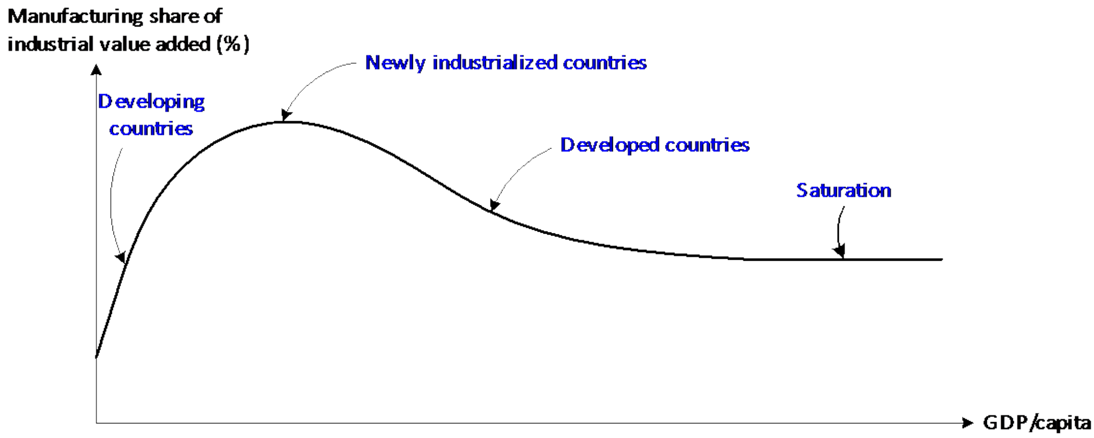


Figure 24. Graphical representation of theoretical changes in manufacturing share with income levels

In this work, we used Weibull probability distribution as an analytical approximation of the curve represented in Figure 24. The Weibull density function is given by:

$$f\,(x;\alpha,\beta) = (\alpha/\beta)(x/\beta)^{\alpha-1}\exp(-x/\beta)^{\alpha}, \quad \text{for } x > 0 \tag{1}$$

where $\alpha > 0$ is the shape parameter and $\beta > 0$ is the scale parameter of the distribution. The Weibull distribution can assume various curves depending on the values of α and β. To model the curve to one that is shown in Figure 24, we have bounded the ranges of α and β according to table 12.

Table 12. Range of values for the Weibull parameters α and β

Region	α	β
Developing regions and newly industrialized regions (India, East EU, Sub Saharan Africa, Latin America, MENA, China)	1 to 3	1 to 5
Developed regions (OECD EU, OECD Pacific, OECD America),	1 to 1.5	1 to 5

We have used a modified 3-parameter Weibull distribution with share of total manufacturing value added as the dependent variable and GDP [in PPP US$] per capita as the independent variable:

$$\mathrm{MVA}_{i,t}^{\mathrm{total}} = \alpha_{i,t}/\beta_{i,t}\left(\left(\mathrm{GDP/capita}\right)_{i,t}/\beta_{i,t}\right)^{\alpha_{i,t}-1}\exp\left(-\left(\mathrm{GDP/capita}\right)_{i,t}/\beta_{i,t}\right)^{\alpha_{i,t}} + c_{i,t}, \forall i \in I, \forall t \in T \qquad (2)$$

Historical data of $\mathrm{MVA}_{i,t}^{\mathrm{total}}$ for each region (i) was plotted against the corresponding regional GDP/capita. Using the built-in "fit" function in the MATLAB software package, regional data was fitted to equation (2) and correspondingly, values of the Weibull parameters $\alpha_{i,t}$ and $\beta_{i,t}$ were determined for each region. Note that we introduce an additional third parameter $c_{i,t} > 0$ to ensure that manufacturing activity does not fall below a certain minimum level. Future $\mathrm{MVA}_{i,t}^{\mathrm{total}}$ values for each region were then determined using these fitted parameters together with future GDP per capita values from World Bank (2009), which were projected based on growth rates. The historical and projected manufacturing value added and its share for each region are shown in Figure 25 and Figure 26.

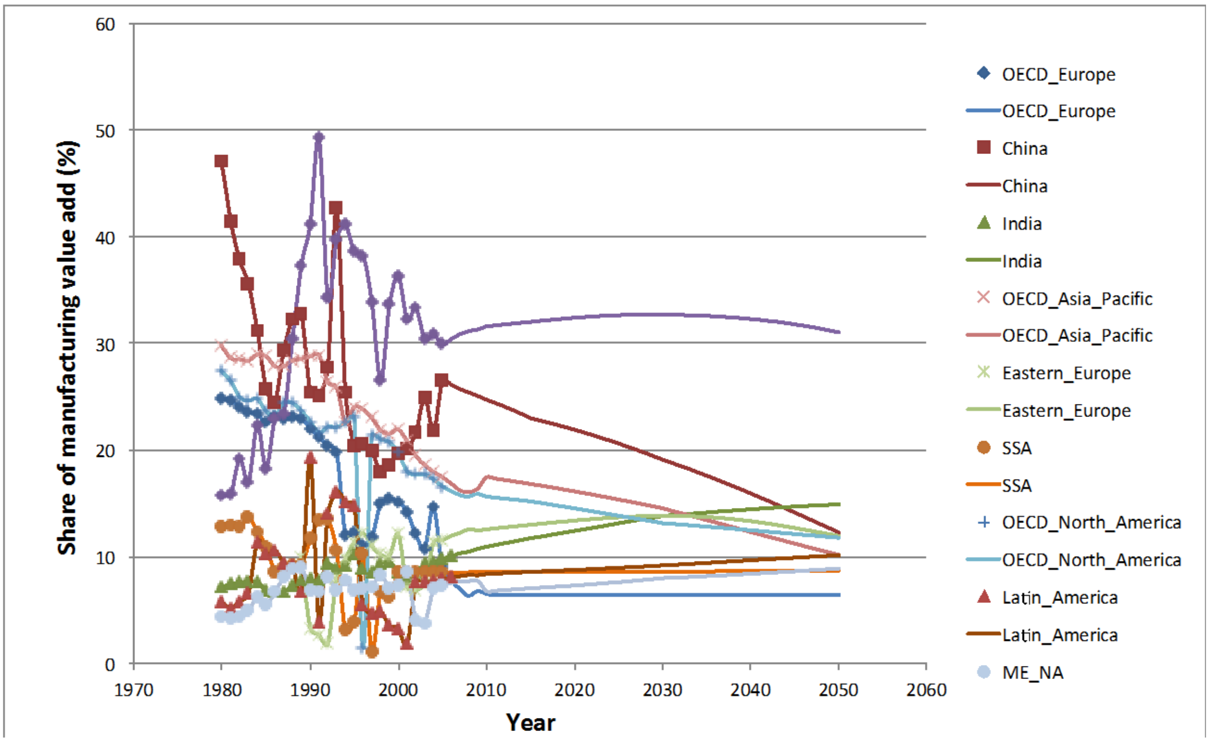


Figure 25. Regional historical and projected share of manufacturing value add

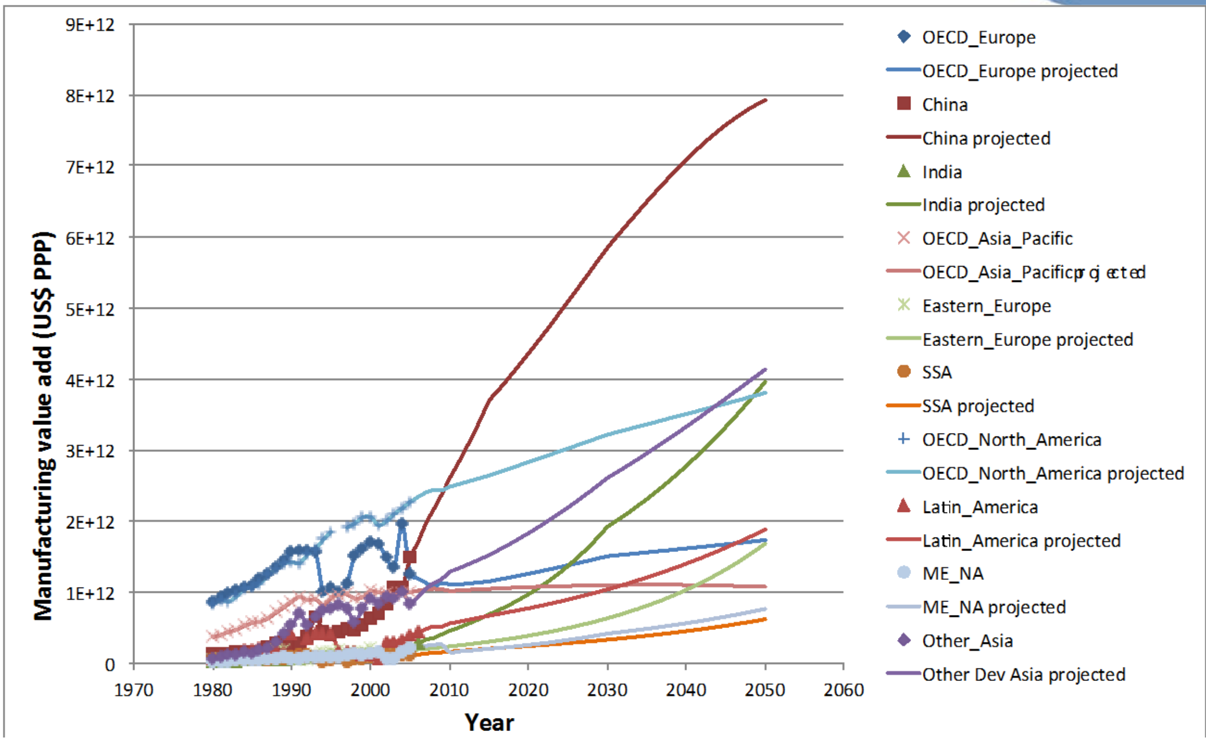


Figure 16: Historical and projected manufacturing value add (in US$ PPP) for each region

4.2.2 Energy efficiency and other low carbon technologies

The annual percentage improvement in energy intensity (where Energy Intensity is in GJ/1000 US$) was based on a study by the Energy Information Administration of the US DoE (EIA, 2007). This study analysed historical trends in energy intensity for different industrial sectors for both a reference case and a high technology scenario. These were taken as the base for the Low Mitigation and Low Carbon scenarios in our study as shown in table 13. Going forward, it was assumed that the share of energy demand for each industrial sector was constant.

Table 13: Annual % improvement in energy intensity for different industrial sectors based on EIA (2007).

	Low Mitigation Scenario	Low Carbon Scenario
Chemicals and petrochemicals	-0.75	-1
Non-ferrous metals	-1.5	-2.5
Machinery and equipment	-1.25	-1.5
Food and tobacco	-0.75	-0.9
Pulp and paper and wood	-0.25	-0.25
Textiles and leather	-1.75	-2
Construction and other	-1.75	-2

More detailed bottom-up sectoral technology models are considered for iron and steel and non-metallic minerals sectors with the main technology parameters summarized in Table 3.

Iron and Steel Sector

Iron and steel production was split into two processes, namely: (1) integrated steel production made up of iron production in a blast furnace (BF) followed by steel production in a basic oxygen furnace (BOF) (referred to as the BF–BOF route), and (2) secondary steel production from scrap in an electric arc furnace (EAF) (referred to as the EAF route). Current physical energy intensity (in GJ/t steel) for each region was calculated based on current figures for production and energy consumption. It was assumed that all regions would approach best available technology by 2050. Where best available technology values of 2.6 GJ/t for the scrap-EAF process and 14.8 GJ/t for the BF-BOF process were assumed based on Worrell (2008, Table 1.1, p. 2).

Non-Metallic Minerals Sector

The non-metallic minerals sector was approximated by assuming it to be made up entirely of cement. Cement production was split into two processes, namely: (a) production in an advanced rotary kiln and (b) production in all other kiln types. It was also assumed that the clinker-to-cement ratio would reduce over time as available from literature (World Business Council for Sustainable Development (WBSCD), 2009; International Energy Agency (IEA), 2009a). As for the iron and steel sectors it was assumed that all regions would approach best available technology by 2050. Here the physical energy intensities assumed were 2 GJ/t for rotary kilns and 6 GJ/t for other kilns as obtained from IEA (2007, p. 151).

Carbon Capture and Storage

It was assumed that no CCS would be applied in the Low-Mitigation scenario. For the Low-Carbon scenario, estimates of the annual amount of CO_2 captured from industry in each region in 2050 were taken from the IEA CCS roadmap targets (IEA, 2009b) by assuming a 60% CCS implementation in industry (out of the regional total projected for industry and upstream; details are as provided in Table 14). These values were subtracted from the total regional CO_2 emissions.

Table 14. Main technology parameters for the detailed sectoral technology models

Region	Iron and Steel		Cement				
	Share of EAF (%)[a]		Share of rotary kilns (%)[b]		Clinker-to-cement ratio[c]		CO_2 captured from CCS (Mt)[d]
	Current	2050	Current	2050	Current	2050	2050
China	9.8	42	45	80	0.77	0.70	455
Eastern EU	70	86	12	40	0.8	0.72	86
India	60.5	84	50	80	0.74	0.72	265
Latin America	71.2	87	82.5	90	0.74	0.72	57
Mid. East & N. Africa	87.4	90	82	90	0.79	0.76	58
Other dev. Asia	37	75	80	85	0.84	0.73	100
OECD America	58.6	84	76.5	100	0.84	0.81	91
OECD Europe	41.9	77	92	100	0.76	0.71	110
OECD Pacific	17.9	57	72	100	0.83	0.72	197
Sub Saharan Africa	10	42	66	80	0.79	0.76	109

Source: [a]World Steel Association (2011), Table 6, p. 22; [b]IEA (2007), p. 151; [c]IEA (2009a) for BLUE low demand scenario; [d]IEA (2009b)

4.2.3 Fuel Mix and CO2 emissions

Data on historical fuel consumption by industrial sector was obtained from IEA (2012a).

For the Low-Mitigation Scenario, the future fuel mix was projected based on a combination of expert opinions and observed trends of historical data reported in the literature. A more complex methodology was employed for the Low Carbon scenario that was based on the current energy service demand for different industrial sectors. These are shown in table 15 below and were assumed to be unchanged in 2050.

Table 15: Percentage share of energy demand by energy service for each industrial sector (Anandarajah et al., 2008)

	Steam	Process heat	Machine drive	Electro-chemical process	Feedstock	Other
Non-ferrous metals	8.1	33.5	2.4	43.6	3.1	9.3
Chem and petrochem	18.0	6.6	16.2	4.6	51.7	2.9
Non-metallic minerals	6.2	79.9	8.2	0	0.7	5.0
Pulp and paper	67.3	8.5	19.1	0	0.05	4.9
Other	31.8	42.9	15.2	0	2.6	7.5

It was assumed that the fuel mix supplying these energy services in 2050 differs by region with regions following one of two types depending on their current fuel dependency: a) Currently largely gas dependent and b) currently largely coal dependent. Details of the fuel mix shifts are given in Table 6. A slightly different approach was taken for the iron and steel sector as here the fuel mix is heavily dependent on the penetration of EAF. The fuel mix was based on the weighted average of the fuel mix for the two different process routes as shown in Table 16.

Table 16: Typical fuel mix for the two major iron and steel production routes

Fuel	Fuel share (%)	
	BF-BOF	Scrap-EAF
Coal	54	7
Oil	0	0
Gas	9	7
Biomass	15	0
Electricity	23	86
Heat	0	0
Total	100	100

Total CO_2 emissions by fuel were estimated by multiplying the sum of the energy demand for each fuel by the associated emission factor ($kgCO_2/GJ$). Note that no carbon capture and storage (CCS) was assumed in the Low-Mitigation scenario. In addition, process emissions from the cement sector were considered by multiplying total cement production by the clinker to cement ratio to determine total clinker production. This in turn was multiplied by the ratio of CO_2 emissions per clinker produced (which is based on the stoichiometry of the calcination reaction and given a fixed value of 0.54).

4.2.4 Abatement cost

The cost of abatement was calculated relative to the Low mitigation scenario. It is the sum of the following costs: 1) The cost of energy efficiency improvements (both fuel savings and investment cost), 2) the cost of fuel switching and 3) the total cost of CCS. i.e.

$$\Delta C^{TOT} = \Delta C^{EE_{fuel}} + \Delta C^{EE_{CAP}} + \Delta C^{FS} + \Delta C^{CCS}$$

The difference in cost between the LMS and the LCS due to fuel savings from energy efficiency improvements ($\Delta C^{EE_{fuel}}$) and fuel switching (ΔC^{FS}) was calculated as follows:

$$\Delta C^{Sub-tot} = \Delta C^{EE_{fuel}} + \Delta C^{FS} = \sum_{i,k} \left(E_{i,k}^{LMS} S_{i,k}^{LMS} P_{i,k}^{LMS} \right) - \sum_{i,k} \left(E_{i,k}^{LCS} S_{i,k}^{LCS} P_{i,k}^{LCS} \right)$$

Where $E_{i,k}$ is the total energy consumption of fuel k in region i, $S_{i,k}$ is the share of fuel k in region i in percentage and $P_{i,k}$ is the price of fuel k in region i.

Similarly, the portion that is attributed to fuel savings from energy efficiency improvements was calculated as follows:

$$\Delta C^{EE_{fuel}} = \sum_{i,k} \left(E_{i,k}^{LMS} S_{i,k}^{LMS} P_{i,k}^{LMS} \right) - \sum_{i,k} \left(E_{i,k}^{LCS} S_{i,k}^{LMS} P_{i,k}^{LMS} \right)$$

Lastly, the cost of switching fuels was calculated:

$$\Delta C^{FS} = \Delta C^{Sub-tot} - \Delta C^{EE}$$

The capital cost associated with energy efficiency improvements was calculated by assuming that only those technologies with a payback time (PB) of less than 5 years were taken up. Thus the total annualised capital cost ($\Delta C^{EE_{CAP}}$), discounted at a rate (r) of 3.5% over a plant lifetime (t) of 25 years was calculated as follows:

$$\Delta C^{EE_{CAP}} = \left[PB \times \Delta C^{EE_{fuel}} \right] \times \frac{(1+r)^t}{(1+r)^t - 1}$$

Lastly, CAPEX and OPEX costs for CCS where calculated based on costs reported for the cement and steel sectors (Kuramouchi et al. 2012). It was assumed that equal shares of CO_2 were captured from these two sectors. Capital costs were annualised and discounted as above.

Table 17: Fuel switching assumptions by energy service demand and sector for the two regional types

Chemical and Petrochemical	Current global mix	Regions currently largely gas dependent	Regions currently largely coal dependent
Steam	11% Coal, 35% Oil, 1% Gas, 53% Heat	20% Oil, 25% biofuels and waste, 25% Electricity, 30% Heat	30% Coal, 25% Biomass and wastes, 15% Electricity, 30% Heat
Process Heat	41% Oil, 59% Gas	35% Oil, 45% Gas, 20% Electricity	45% Coal, 35% Oil, 20% Electricity
Machine	100% Electricity	100% Electricity	100% Electricity
Electrochemical	100% Electricity	100% Electricity	100% Electricity
Feed stock	19% Coal, 10% Oil, 71% Gas	90% Gas, 10% Biomass	50% Coal, 50% Gas
Other	19% Biomass, 81% Electricity	20% Biomass, 80% Electricity	80% Biomass, 20% Electricity

Non-ferrous metals	Current global mix	Regions currently largely gas dependent	Regions currently largely coal dependent
Steam	21% Coal, 18% Oil, 38% Gas, 1% Bio, 22% Heat	70% Gas, 10% Biomass, 20% Heat	50% Coal, 20% Gas, 10% Biomass, 20% Heat
Process Heat	15% Coal, 13% Oil, 72% Gas	10% Coal, 10% Oil, 55% Gas, 25% Electricity	35% Coal, 10% Oil, 30% Gas, 25% Electricity
Machine	100% Electricity	100% Electricity	100% Electricity
Electrochemical	100% Electricity	100% Electricity	100% Electricity
Feed stock	99% Coal, 1% Oil	80% Coal, 20% Gas	80% Coal, 20% Gas
Other	15% Gas, 59% Biomass, 26% Electricity	60% Biomass, 40% Electricity	60% Biomass, 40% Electricity

Non-metallic minerals	Current global mix	Regions currently largely gas dependent	Regions currently largely coal dependent
Steam	35% Oil, 22% Gas, 29% Biomass. 14% Heat	20% Oil, 30% Gas, 10% Biomass and wastes, 40% Heat	20% Coal, 30% Gas, 10% Biomass, 40% Heat

Process Heat	63% Coal, 7% Oil, 27% Gas, 3% Electricity	10% Coal, 35% Gas, 30% Biomass, 25% Electricity	35% Coal, 10% Gas, 30% Biomass, 25% Electricity
Machine	100% Electricity	100% Electricity	100% Electricity
Electrochemical	100% Electricity	100% Electricity	100% Electricity
Feed stock	100% Coal	100% Coal	100% Coal
Other	7% Oil, 25% Gas, 45% Biomass, 23% Electricity	25% Gas, 25% Biomass, 50% Electricity	25% Gas, 25% Biomass, 50% Electricity

Other (Machinery and equipment, Food and tobacco, textiles and leather, construction and other)	Current global mix	Regions currently largely gas dependent	Regions currently largely coal dependent
Steam	13.8% Coal, 17.1% Oil, 3.1% Gas, 44.6% Biomass, 21.4% Heat	10% Gas, 35% Biomass, 40% Electricity, 15% Heat	10% Coal, 35% Biomass, 40% Electricity, 15% Heat
Process Heat	19% Coal, 37.2% Oil, 22.5% Gas, 21.3% Electricity	10% Oil, 10% Gas, 80% Electricity	10% Coal, 10% Oil, 80% Electricity
Machine	100% Electricity	100% Electricity	100% Electricity
Electrochemical	100% Electricity	100% Electricity	100% Electricity
Feed stock	83.5% Coal, 16.5% Oil	80% Coal, 20% Oil	80% Coal, 20% Oil
Other	18.7% Oil, 81.3% Electricity	100% Electricity	100% Electricity

4.3 Industry Scenarios in 2050

4.3.1 Energy Demand and CO_2 Emissions

Figure 27 shows the total projected global industrial energy consumption in 2050 for the LMS and LCS compared to the current level.

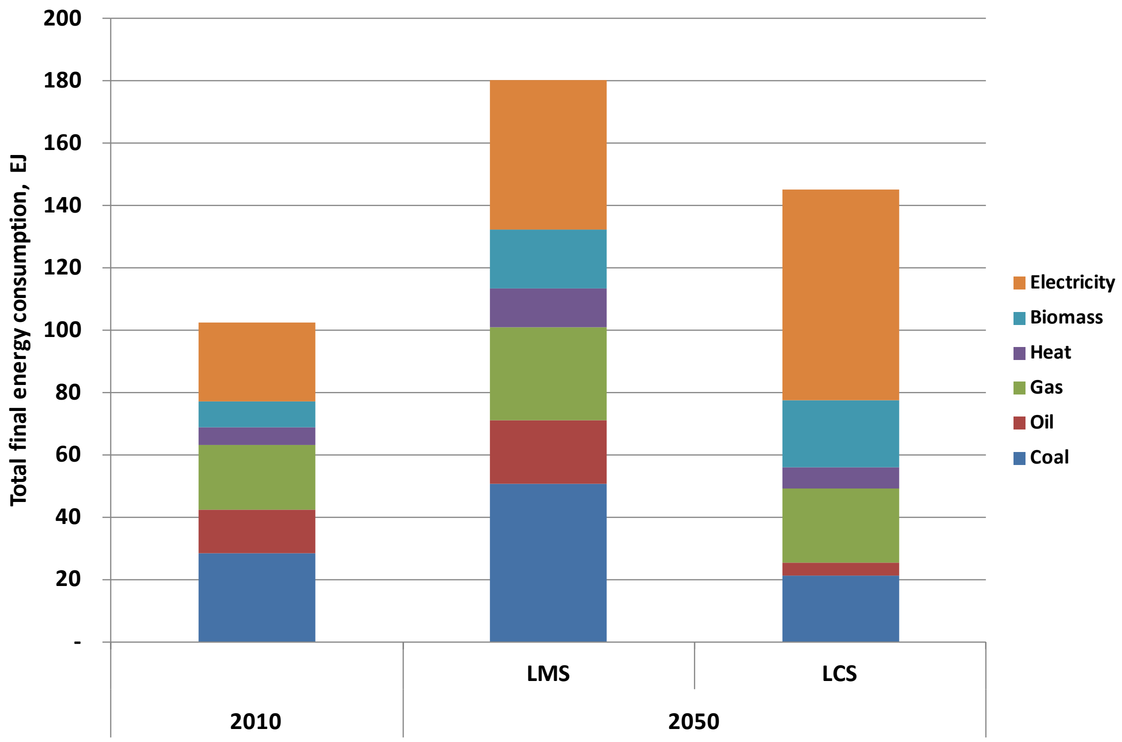


Figure 27. Global industrial energy consumption by fuel for today and in 2050

The LMS scenario projects that global industrial energy demand in 2050 will be about 180 EJ, which is around double of that currently consumed. This compares well with IEA World Energy Outlook 2011 projections of 178 EJ (extrapolated from 2030 projections) (IEA, 2011b). The energy consumption projected for the LCS is 20% lower than the LMS, as a result of increased energy efficiency and adoption of best available technologies in the iron and steel, and cement sectors. Switching away from fossil fuel energy to decarbonised electricity and biomass is an important measure for reducing emissions from industrial processes. It is worth noting that fuel switching in industry does not simply entail purchasing one type fuel instead of another and does not happen overnight. Similarly, the main trend in the LCS is increased electrification and switching away from coal and oil. Electricity demand in the LCS is around 68 EJ compared to 48 EJ in the LMS. Coal demand in the LCS is 21 EJ (15%) compared to 51 EJ (28%) in the LMS. Demand for oil in the LCS is also lower at 4 EJ (3%) compared to 20 EJ (11%) in the LMS. In addition, 60% of industrial energy demand should be met by decarbonised energies, of which 66% is provided by non-fossil fuels (4% heat, 12% biomass, 50% electricity) in the LCS compared to 26% in the LMS.

The LMS projects that global emissions from industry will be 18.4 Gt CO_2 by 2050 (including indirect emissions from electricity use). By contrast, industry is constrained to emit 6.8 Gt CO_2 in the LCS in 2050, thus providing a 73% reduction in emissions. Figure 28 shows that in the LMS, China is the largest emitter at more than double that of the subsequent main emitting regions comprising India, OECD North America, and Non-OECD Asia. However, in the LCS, the emissions are more even. This is largely due to increased decarbonisation of the Chinese power sector compared to India. The large emissions reduction observed in the LCS is primarily due to: (1) energy efficiency through adopting Best Available Technologies (BAT); (2) fuel switching away from coal and oil; (3) decarbonisation of the electricity generation sector and (4) Carbon Capture and Storage (CCS) applied directly to industrial emissions. Around 1.5 GtCO_2 is captured using CCS in this way; this figure is equivalent to 23% of the total emissions in the LCS.

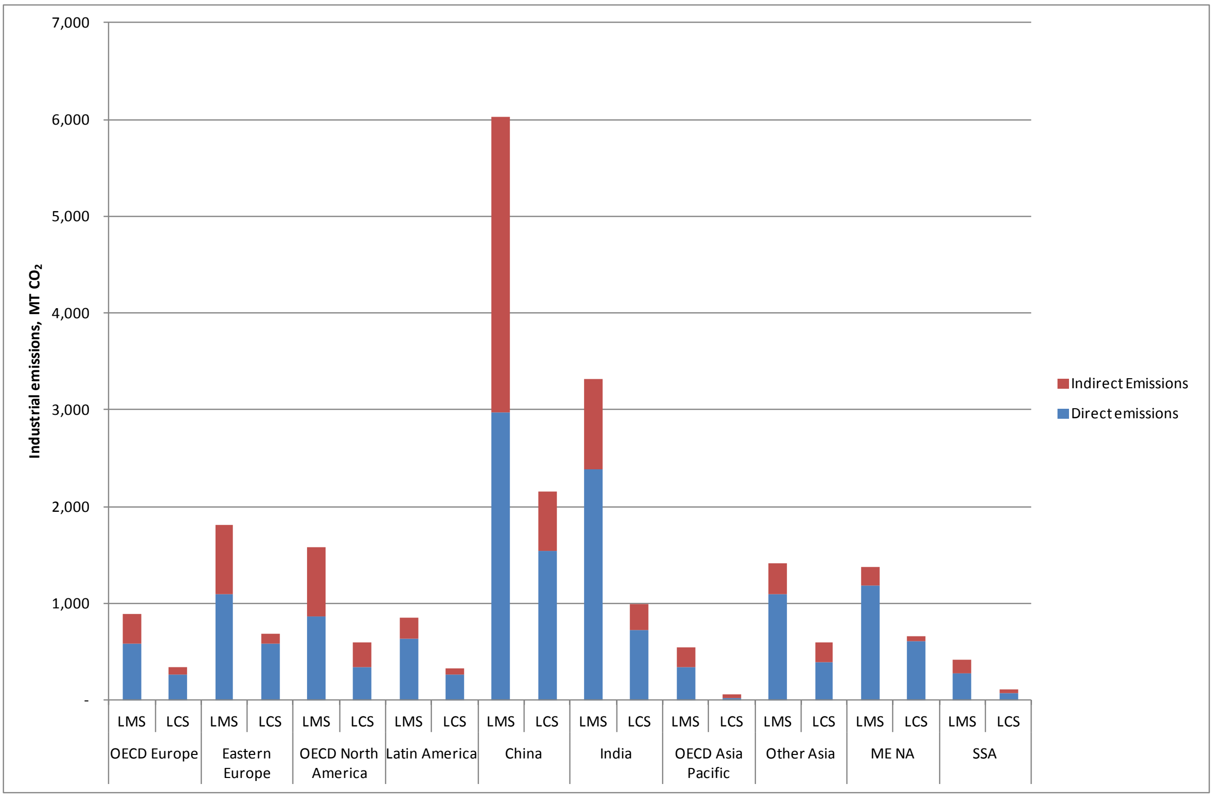


Figure 28. Comparison of the regional CO_2 emissions (direct and indirect) from industry in 2050 for the LMS and LCS. Note that direct includes both emissions arising from the combustion of fuels and process emissions.

4.4 Overall cost of system transition

Figure 29 depicts the total energy costs for industry in the LMS t LCS and for both high and low fossil fuel prices. Three measures contribute to the cost of the transition: 1) the cost of energy efficiency, split into CAPEX and fuel costs, 2) the fuel cost of switching to less carbon intensive fuels and 3) the capital, operational and fuel costs of CCS. This figure shows that the net transition cost for a low-carbon industry in 2050 is estimated at a total of between US$450-750bn. This is equivalent to around 1.6-2.6% of global manufacturing gross value added (GVA). This is a rough indicator of the expected increase in product prices as a result of moving to a low carbon economy.

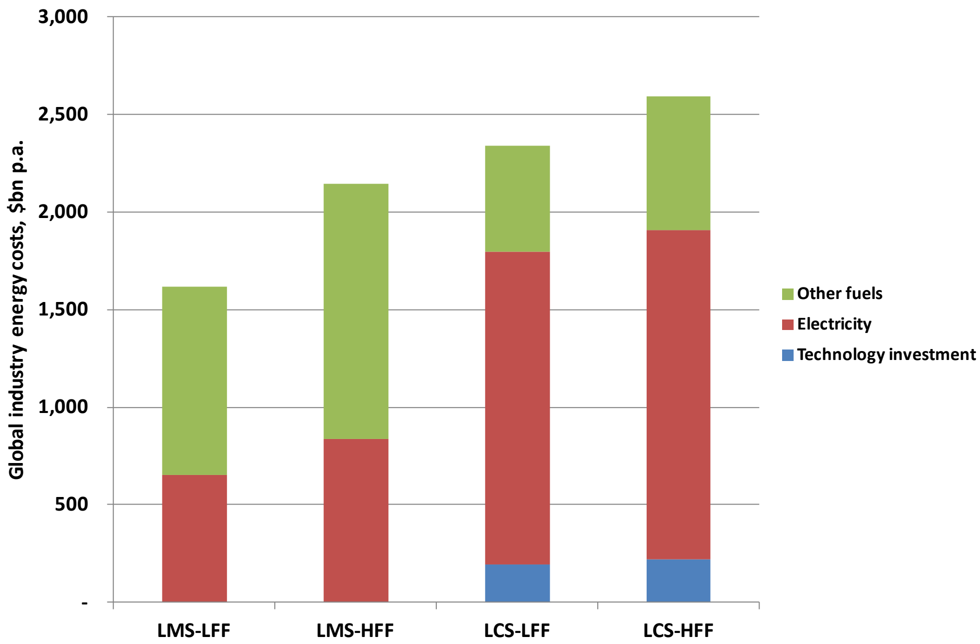


Figure 29: Industrial energy costs for the LCS and LMS in 2050 for both low and high fossil fuel (FF) prices.

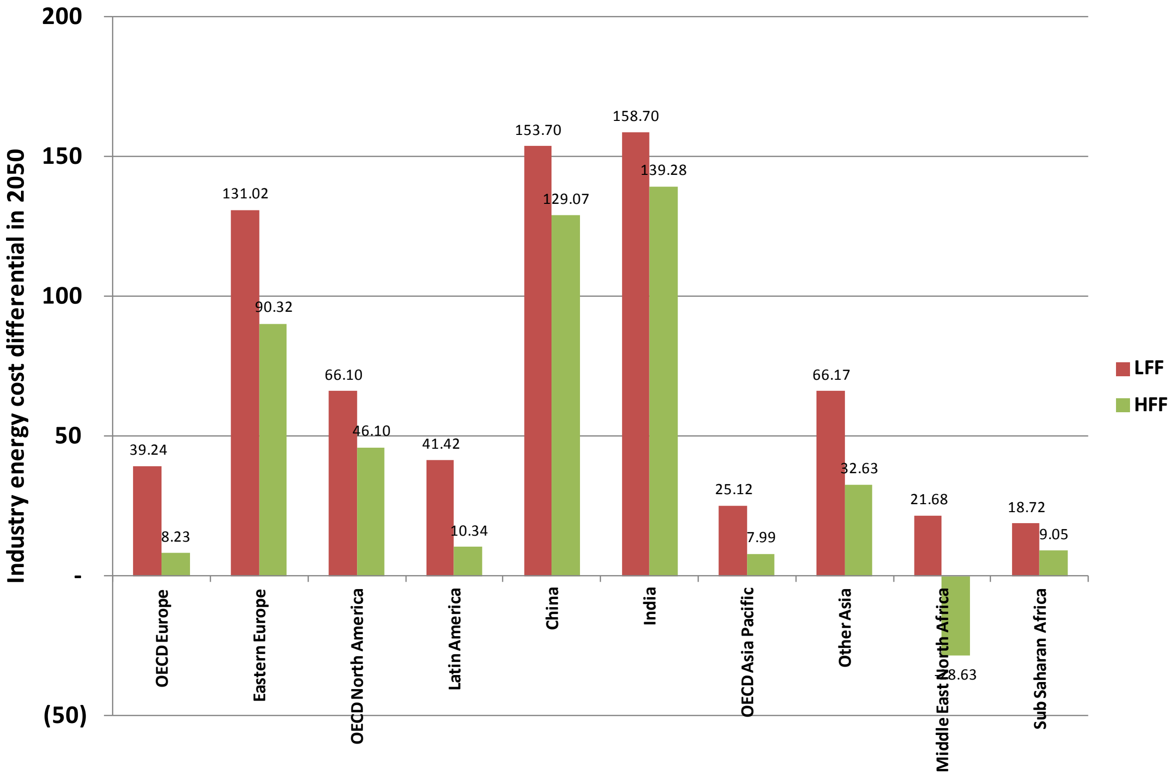


Figure 30: Regional cost delta per capita between the LMS and LCS in 2050 for both low and high fossil fuel prices

4.5 Major technical shifts

The abatement of GHG emissions achieved in the low carbon scenario arises from the following shifts:

- A more aggressive focus on energy efficiency improvements in all industrial sectors. In the iron and steel and cement sectors this is through modifications to the process to reach current best practises.
- Greater electrification in the steel A shift towards more scrap-fed electric arc furnaces
- Reducing the clinker to cement ratio in cement production
- Greater substitution of coal and oil in industry with gas, electricity, biomass/wastes and heat from CHP.

4.6 Major uncertainties

The following inputs are the main sources of uncertainty in this model:

- Projections of future manufacturing value added has a large impact on total industrial energy demand yet this is extremely difficult to predict. Our method of assuming a development pathway is a crude estimate, which appears to provide reasonable estimates. However, this should be confirmed with a more complex economic model.
- The future share of fuels used in industry. Without either a detailed technology-based model or an econometric model based on price elasticity, neither of which was feasible for this project, this is very difficult to model.

4.7 Conclusions for Industry

Industrial growth is a key element for development. It is essential that manufacturing in developing countries can continue to grow, whilst ensuring that CO_2 emissions are mitigated. To attain the transition described in the LCS, a positive cost of less than 3% of the global manufacturing GVA is incurred for industry. However, if industrial emissions remain unchecked, total global industrial energy demand and CO_2 emissions are expected to rise to approximately 181 EJ and 18.3 Gt, respectively, which is more than twice that of current levels. In this regard, energy efficiency has the potential to contribute to more than 40% of total emissions saving between now and 2050. Furthermore, diffusion of energy efficient technologies will be crucial to prevent lock-in of inefficient outdated technologies. In addition, CCS applied directly in industry is an important abatement option, hence collective efforts at a global level are required to realize the viability of its commercial demonstration.

5 Transport

5.1 Introduction

5.1.1 General trends and drivers

According to the IEA's Energy Technology Perspectives 2012 (IEA, 2012a), in 2009, the transport sector accounted for approximately one-fifth of global primary energy use and one-quarter of energy-related CO_2 emissions. It is projected that these shares will stabilize in the coming decades. This raises concerns on resource constraint and energy security, as over 93% of the energy used in transport sector is oil; and more than 50% of oil is consumed in the transport sector.

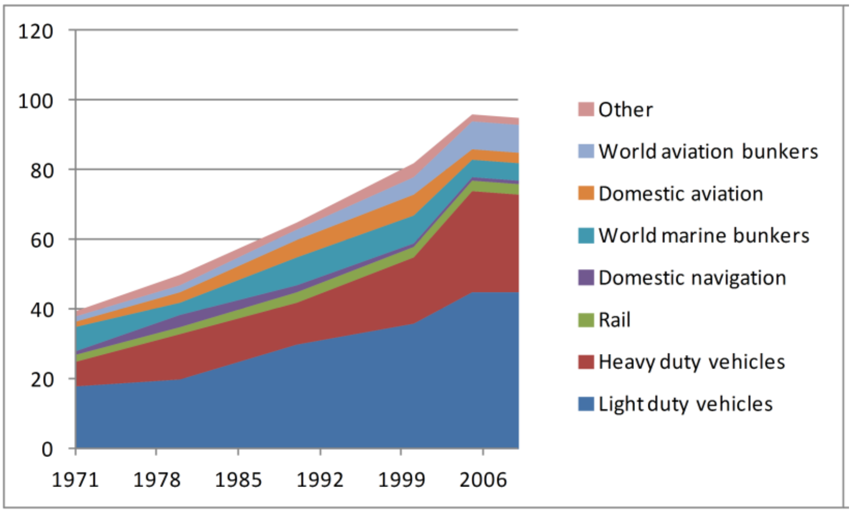


Figure 31: World transport energy use by mode prices

As can be seen from figure 31, the largest share of energy use within the transport sector comes from road vehicles; followed by aviation, which has seen sharp increase in the last decade.

On a regional level, despite the faster rising in transport energy use in non-OECD regions than in the OECD regions, North America and Europe still use the most energy.

5.1.2 Passenger transport

Cars are the dominant mode of transport in OECD countries; they represent 60% to 80% of motorized passenger travel. In non-OECD countries, a much larger variety of motorized passenger travel modes are used. Figure 32 clearly shows that 2,3 –wheelers, rail and buses also make significant contributions to passenger mobility in the non-OECD regions.

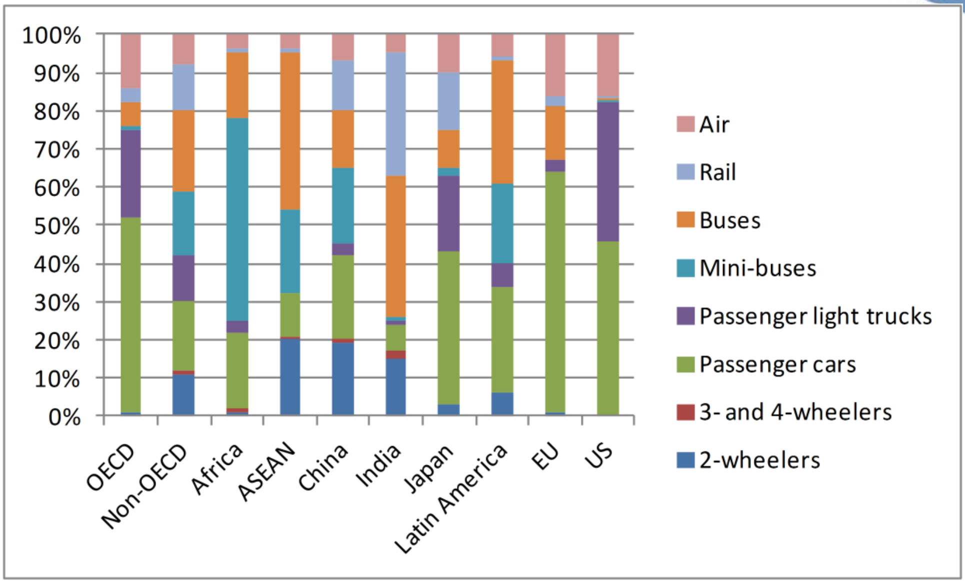


Figure 32. Motorised passenger travel modes, 2009

5.1.3 Freight transport

Freight transport is strongly dependent on economic growth and goods demand. It is therefore expected to increase over time in the globalized world with growing international trade, especially in non-OECD regions.

On a weight basis, rail is still the dominant mode for freight (53% of tkm over land), but consumes far less energy compared to trucks. In 2005, rail freight used about 40 Mtoe (2EJ), less than 10% of that used by trucks, which was responsible for about 500 Mtoe (21 EJ) of energy worldwide.

Huge regional variations can be seen in terms of the rail/trucking split. A common trend is that rail tonnage outstrips truck tonnage mainly in physically large countries and in countries that move large amounts of raw materials such as the United States, Russia, China and Australia (IEA, 2009c).

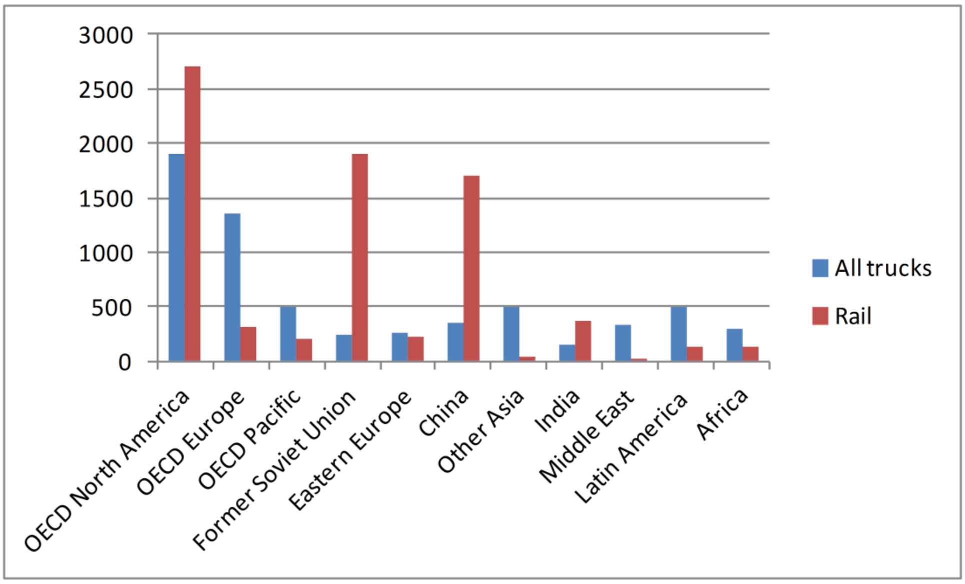


Figure 33. Freight transport by truck and rail, 2005

5.2 Modelling and Analysis Methodology

The transport model developed for this study allows the simulation of energy consumption based on predicted worldwide passenger and freight transport activities, with geographically-explicit results available for all of our ten regions, based on a combination of our GDP-based projections, WEC (2011) and IEA's transport demand projections.

For the case of 2010 each of those regions is characterized by following factors:

- Total passenger kilometres travelled (pkm)
- Distribution of those kilometres on the different means of transport
- Distribution of those kilometres per transport mean on different propulsion types
- Specific consumption factors (per pkm or per tkm) for each region an propulsion type

The study covers road, rail, aviation and maritime transport and for each of those transport means the different available propulsion technologies are taken into account:

Table 18. 2010 transport technologies

Passenger transport		Freight transport	
Road		Road	
- 2/3 wheeler - Cars - Light trucks - Buses	- Petrol - Diesel - Hybrid - Electric - Fuel cell	- Medium Trucks - Heavy Trucks	- Diesel - Hybrid - Electric - Fuel Cell
- Rail	- Diesel - Electric	Rail	- Diesel - Electric
Aviation	- Kerosene	Water	- Diesel

- Borken, J.; Steller, H.; Merétei, T. & Vanhove, F. Global and country inventory of road passenger and freight transportation: fuel consumption and emissions of air pollutants in year 2000 Transportation Research Record: Journal of the Transportation Research Board, Trans Res Board, 2007, 2011, 127-136
- IEA Energy technology perspectives 2010: Scenarios and strategies to 2050, 11 2010
- Calculations based upon national documents and statistics

5.2.1 Activity Level Projections

The development of the activity level projections (resulting in projections of future travel demand) is based upon the IEA's Energy Technology Perspectives 2010 study (IEA, 2010a). The following figures illustrate the future projection of passenger kilometres and tonne-kilometres.

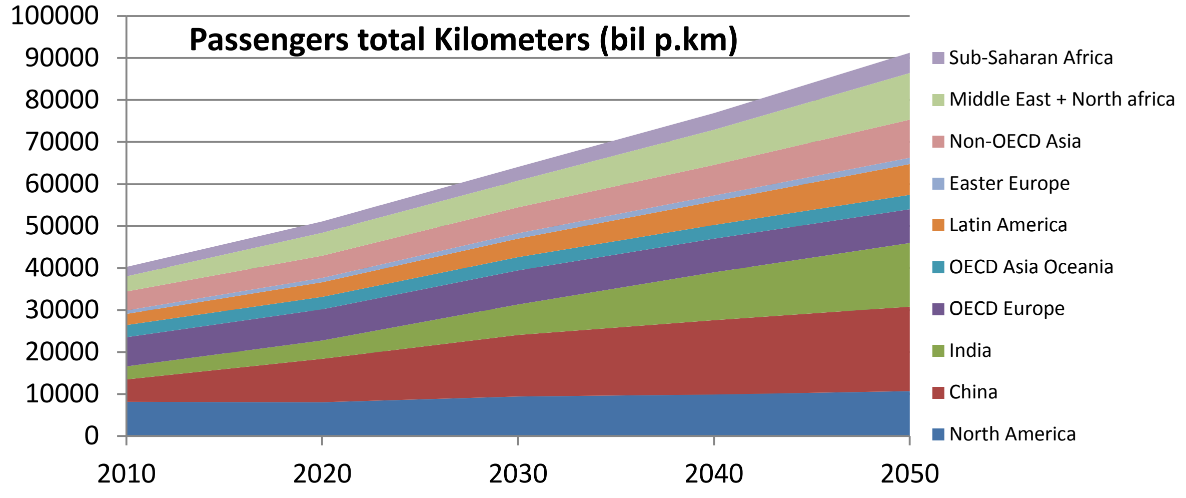


Figure 34. Future passenger-km demand projections by region

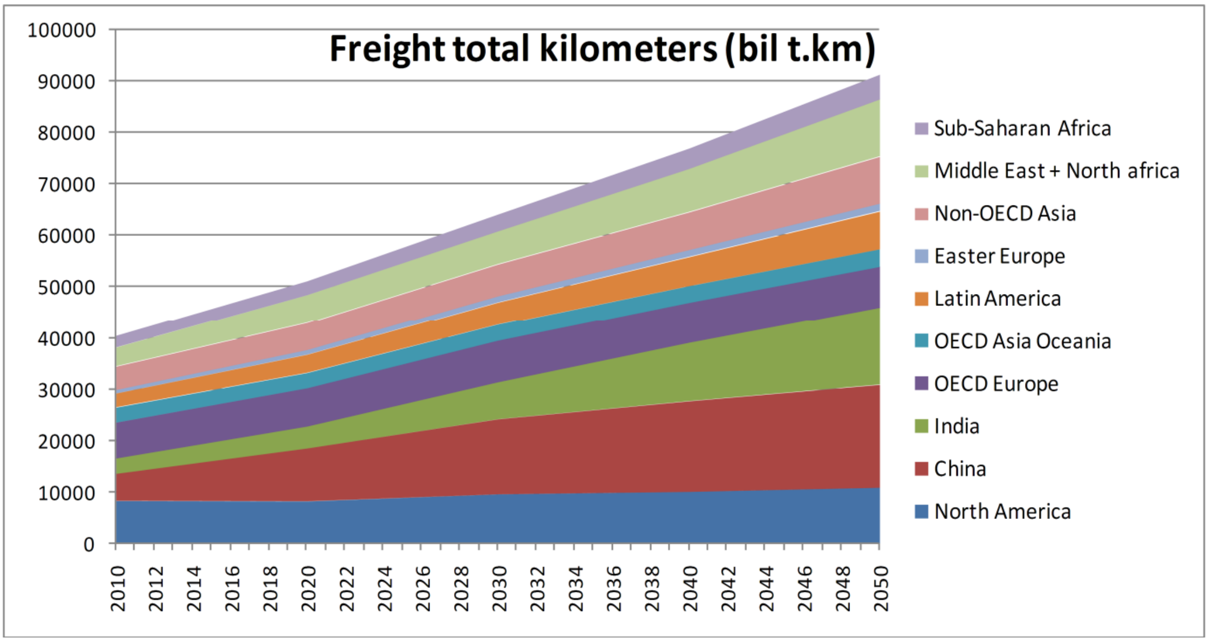


Figure 35. Future tonne-km demand projections by region

5.2.2 Low Mitigation Scenario

Based on these projections, for the creation of the 2050 LMS the following assumptions were made:

- The distribution of the total pkm and tkm among the different transport means and types remains the same as in 2010 (i.e. equivalent mode and technology splits)
- There are anticipated efficiency improvements (i.e 30% for vehicles and 20% for aviation)

This leads to the following 2050 LMS results:

Table 19. LMS transport fuel demand by region

	Vehicles/Rail/Water					Air
2050 LMS	Low mitigation scenario	Low carbon scenario	Low mitigation scenario	Low carbon scenario	Low mitigation scenario	Low carbon scenario
units	[bil liter]	[bil liter]	[bil kWh]	[bil liter]	[bil liter]	[PJ]
OECD North America	723	142	0	0	0.0	5668
China	149	292	239	0	0.0	8664
India	147	344	81	0	0.0	939
OECD Europe	253	132	28	0	0.0	2718
OECD Asia Ocenia	108	41	2	0	0.0	965
Latin America	202	130	1	33	50.6	1849
Easter Europe	45	26	13	0	0.0	371
Non-OECD Asia	200	210	7	0	0.0	800
Middle East + North Africa	578	160	9	0	0.0	2565
Sub-Saharian Africa	101	114	1	0	0.0	746
Sum	1928	1591	380	33	51	25

Table 20. LMS transport CO_2 emissions by fuel type

World LMS 2050					Total Direct GHG	
Gasoline	1928.33	bil liter	61.27	EJ	6.86	GT CO_2
Diesel	1591.35	bil liter	57.43	EJ	6.43	GT CO_2
Electricity	379.66	bil kWh	1.37	EJ	0.24	GT CO_2
Hydrogen	0.00	bil kg	0.00	EJ	0.00	GT CO_2
Biodiesel	32.52	bil liter	1.11	EJ	0.27	GT CO_2
Bio ethanol	50.59	bil liter	1.06	EJ	0.24	GT CO_2
Bio Kerosene	0.00	bil liter	0.00	EJ	0.00	GT CO_2
					16.42	GT CO_2

5.2.3 Low Carbon Scenario results (low FF cost scenario)

The model is created in such a way that for each region and vehicle type and for each year the following factors can be adjusted between 2010 to 2050:

- distribution of propulsion type (e.g. change from petrol to electric) for certain transport means
- total efficiency improvement until 2050 for each propulsion type
- replacement of fossil fuels by bio fuels

In addition to the measures shown above, the use of Biofuels (Bio –based Diesel, Bio ethanol and Bio Jet Fuel) was considered. In total 70% of all liquid fuels (other than kerosene where the figure is 30%)are bio-derived. . For the 2050 LCS, the following assumptions were applied: efficiency improvements of 30% for road, rail, water and 20% for aviation.

This leads to the following results, showing the demands for the various fossil fuels as well as the biofuel vectors.

Table 21. LCS fuel demands by region and vector

	Vehicles/Rail/Water						Air	
2050 LCS	Petrol	Diesel	Electricity	Hydrogen	BioDiesel	Bioethanol	Kerosene	BioKerosene
units	[bil liter]	[bil liter]	[bil kWh]	[bil kg]	[bil liter]	[bil liter]	[PJ]	[PJ]
OECD North America	49	18	552	18	42	114.5	3768	1614.94
China	45	69	473	15	162	104.5	5760	2468.60
India	7	55	287	18	129	16.4	624	267.51
OECD Europe	28	13	215	12	30	65.7	1807	774.38
OECD Asia Ocenia	11	6	120	3	14	25.5	642	275.04
Latin America	17	21	169	12	48	38.8	1229	526.89
Easter Europe	4	4	55	2	9	9.6	246	105.61
Non-OECD Asia	22	48	144	3	112	51.3	532	227.90
Middle East + North Africa	91	34	233	3	78	212.4	1705	730.89
Sub-Saharian Africa	16	26	26	0	61	38.5	496	212.46
Sum	223	294	2273	86	686	677	17	7

Table 22. LCS transport CO_2 emissions by fuel type

LCS 2050					Total Direct GHG	
Petrol	223.27	bil liter	7.09	EJ	0.60	GT CO2
Diesel	293.83	bil liter	10.60	EJ	0.97	GT CO2
Electricity	2272.71	bil kWh	8.18	EJ	0.26	GT CO2
Hydrogen	86.19	bil kg	10.33	EJ	0.24	GT CO2
Kerosene	476.17	bil liter	16.81	EJ	1.46	GT CO2
Biodiesel	685.60	bil liter	23.47	EJ		
Bioethanol	677.26	bil liter	14.17	EJ	1.12	GT CO2
BioKerosene	204.07	bil liter	7.20	EJ		
					4.65	GT CO2

5.3 Cost calculation (central LCS and low fossil fuel prices)

5.3.1 Methodology

A future according to the LCS leads to different costs in comparison to the LMS. In order to simplify this calculation, the following approach has the aim to determine the cost differential between both scenarios. The cost differential arises from two sources of costs:

- Total fuel costs for the various fuels used for transport
- Cost of applied technologies/drive trains, etc.

The cost differential is calculated according to the formula below:

$$\Delta total\ cost = \sum_{LCS} technology\_cost + fuel\_cost - \sum_{LMS} technology\_cost + fuel\_cost$$

$$\sum_{vehice\ types} technology\_cost = \frac{vehicle\_price}{depreciation\_time} * \frac{total\_pkm}{annual\_mileage}$$

The key figures used for these evaluations are below. The lifetime has been scaled to reflect the discount rate used.

Table 23. Data used for transport cost differential

	Average km per year	Lifetime (years)	Investment cost
Passengers			
2/3 wheeler			
Petrol	4000	12	1810
Electric	4000	12	2522
Cars			
Petrol	14000	12	14247
Diesel	14000	12	14247
HEV/PHEV	14000	12	17125
Electric	14000	12	23384
Fuel Cell	14000	12	17983
LTs			
Petrol	16800	12	15672
Diesel	16800	12	15672
HEV/PHEV	16800	12	18838
Electric	16800	12	25722
Fuel Cell	16800	12	19781
Buses	pkm		
Diesel	260800	12	168377
HEV/PHEV	260800	12	179843
CNG/LPG	260800	12	
Electric	260800	12	205706
Fuel Cell	260800	12	187744
Rail			
Diesel	–	–	–
Electric	–	–	–
Air			
Kerosene	–	–	–

*no cost delta for rail and aviation as no changes in technology were decided, technology costs also include average recharging/refuelling infrastructure cost.

	Average km per year	Lifetime (years)	Investment cost
Kerosene	–	–	–
*No cost delta for rail and aviation as no changes in technology were decided, technology costs also include average recharging/ refuelling infrastructure cost.			
Goods			
Medium Trucks	tkm		
Diesel	41600	12	30000
HEV/PHEV	41600	12	32043
Electric	41600	12	36651
Fuel Cell	41600	12	33451
Heavy Trucks	tkm		
Diesel	704000	12	63363
HEV/PHEV	704000	12	67678
Electric	704000	12	77411
Fuel Cell	704000	12	70651
Rail			
Diesel	–	–	–
Electric	–	–	–
Water			
Diesel	–	–	–

*No cost differential for rail and aviation as no material changes in technology were required, technology costs also include average recharging/refuelling infrastructure cost.

Key sources for this data include TERI (TERI, 2009), WEC (WEC, 2011), EC (EC, 2011) and DECC (http://2050-calculator-tool-wiki.decc.gov.uk/pages/59).

For the electrification of the rail tracks following approach has been executed:

- For each region the current amount of track km has been determined (https://www.cia.gov/library/publications/the-world-factbook/rankorder/2121rank.html)
- This study assumes that each km electrified in the LCS (compared to the LMS) incurs a cost of 1 million $ that are depreciated over 25 years.
- Regions such as Europe and China are electrified to 80%, leading to nearly 95% driven electric whereas historically less electrified are electrified to 50% leading to about 70% of driven km electric mode.

5.3.2 Comparison of cost differentials between LCS and LMS for different scenarios

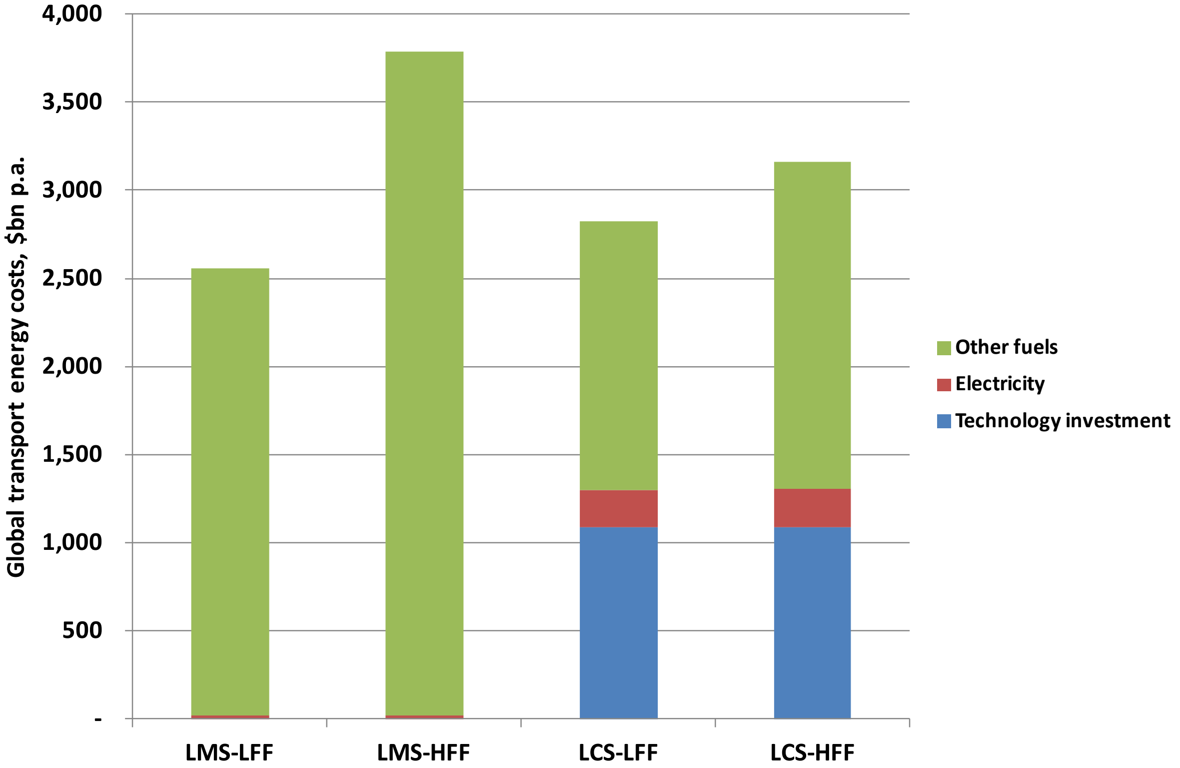


Figure 36. Transport energy cost: LMS and LCS for both low and high fossil fuel prices

The figure above shows the transport costs for the two scenarios (but with the technology cost being a differential between the LMS and LCS; i.e. the additional investment required in the improved propulsion systems or track electrification in the LCS).

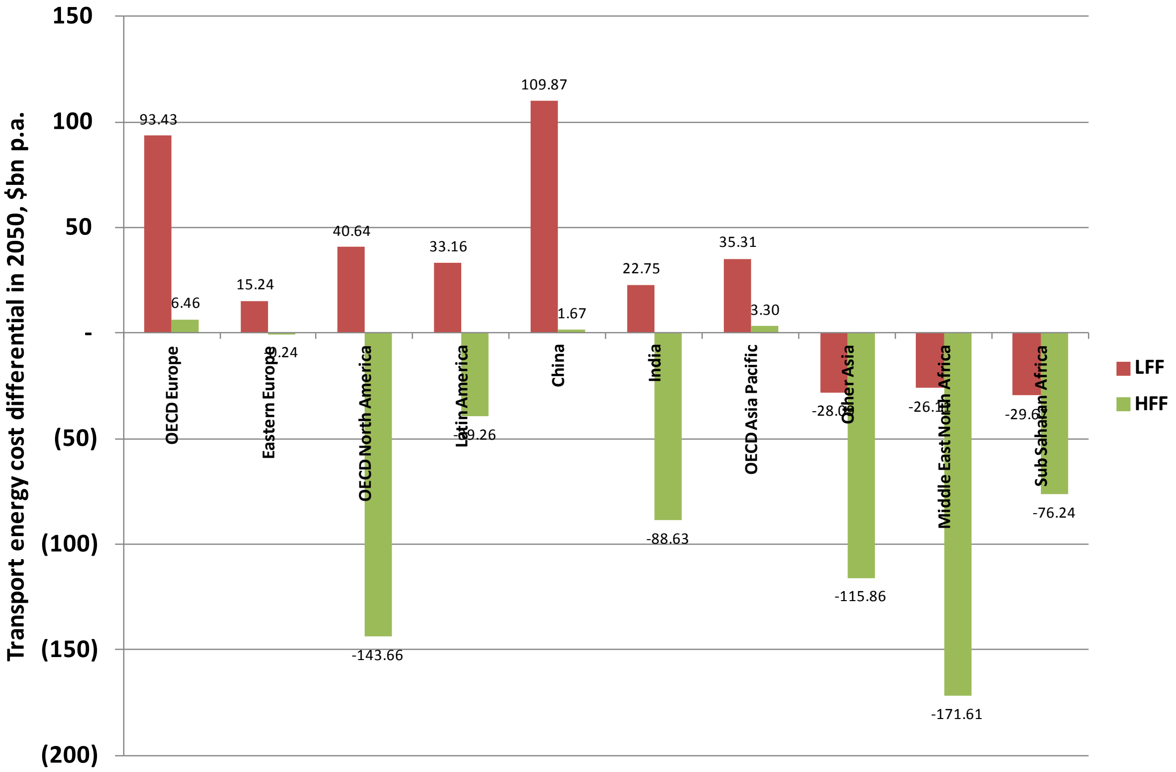


Figure 37. Transport energy cost differentials by region

Overall, the cost differential between the LCS and the LMS ranges between $-620-270bn per annum depending on the fossil fuel price; the transition is effectively cost-neutral.

6 Bioenergy

Bioenergy may make a substantial contribution to reducing fossil fuel dependence and mitigating global warming by 2050. Because of the critical role of bioenergy, in addition to the bioenergy demands projected for each sector in this report (a supply-oriented perspective), an alternative bottom-up model was also developed to estimate bioenergy demand by 2050, based on extrapolating the IEA 2035 scenarios (IEA, 2011a) and applying a set of assumptions about key technology developments and trends. Thus, equations were modelled in order to obtain curves that could fit the available database and be extrapolated to 2050, following both the likely market trends and external thresholds for the bioenergy expansion (e.g. availability of natural resources and technical learning curves). Crop energy yields (i.e. GJ/ha) were estimated for each region and sector, based on biomass efficiencies from reference databases (EC/SETIS, 2012), (Cushion et al, 2010), (MAPA, 2011), (MME, 2011). Thus, it was possible to obtain one estimate of the amount of land necessary to supply the projected bioenergy demand by 2050. We recognise that such estimates are necessarily highly uncertain and controversial, but they give an alternative projection for comparative analysis. The assumptions adopted to estimate the bioenergy emission factors and the bioenergy yields used in the model are described in Appendix 2.

Despite bioenergy being regarded as a renewable energy source which promotes carbon capture through photosynthesis, its carbon balance evaluated through Life Cycle Assessment (LCA) is usually not neutral, due to the use of fossil fuels in its production and transport chains, as well as its potential land use change effects. IEA recently published a report (IEA, 2012c) with a range of current general bioenergy emission factors concerning the use of solid biomass for electricity, co-firing and heating, based on (Cherubini et al, 2009) and (IPCC, 2011). In addition, (AEA, 2011) published emission factors for petrol and diesel for the UK DEFRA and DECC, from which it was possible to estimate, indirectly, the potential emission factors for ethanol and biodiesel by 2050. Assumptions from the carbon balance standards proposed by (EPA, 2012) within the US biofuels policy (currently RFS2) were also considered in these estimates.

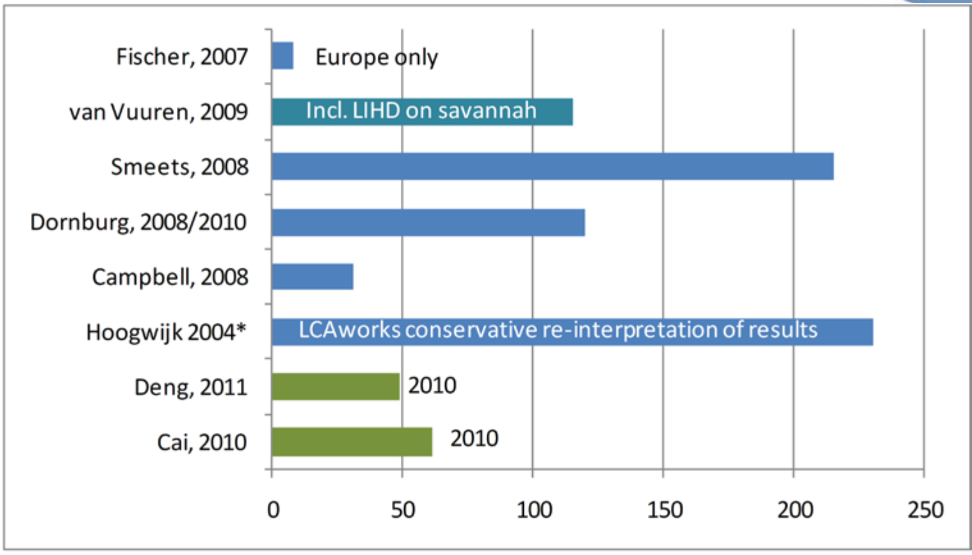
Hence, based on these databases, literature sources and trends, bioenergy emission factors (EF) were estimated for 2050, per region and sector, for both the Low Mitigation Scenario (LMS) and Low Carbon Scenario (LCS). Benefits resulting from a potential increase in the soil carbon from biomass crops or through biochar were also taken in to account in the present model. The carbon intensity of bioenergy chains is expected to decrease over time because of agronomic advancements, more efficient processing, and because the background energy system and industrial processes become less GHG intensive. Table 24 summarises the results obtained for bioenergy demand by 2050, in terms of energy, land use required, and the respective GHG emissions. The proportion of biomass residues follows the IEA 2035 scenarios. The estimated area necessary to meet the projected energy demand in each region described in table 24 would not necessarily be allocated in the same region where estimated, given that some countries (e.g. USA and several European countries) may import substantial amounts of bioenergy in the coming decades as a complementary strategy to their domestic capacity of supply. Bioenergy, including biofuels, is expected to be widely traded as a global commodity, by 2050.

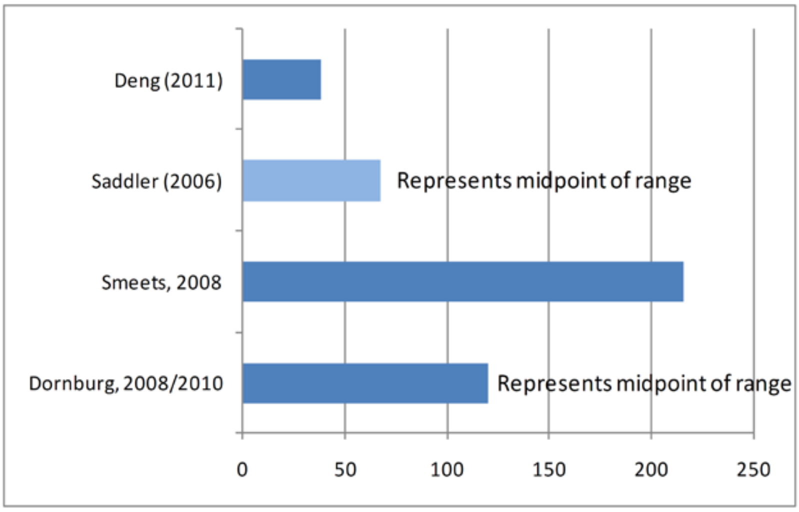
Table 24. Projections of bioenergy demand for all sectors by 2050

	Energy (EJ)		Land use (Mha)		GHG (Mt CO2eq)	
	Low mitigation scenario	Low carbon scenario	Low mitigation scenario	Low carbon scenario	Low mitigation scenario	Low carbon scenario
World	70	115	322	442	1401	2030
OECD Europe	12	20	52	81	256	399
OECD Americas	12	29	74	125	305	538
China	11	23	48	85	235	462
India	10	12	40	43	182	203
Latin America	9	12	41	44	153	174
East Europe	1	2	4	6	13	22
SS Africa	15	15	56	50	240	207
MENA	1	1	4	4	14	14
OECD Pacific	0.1	0.2	1	1	3	5
Other dev Asia	0.1	0.3	0.4	1	2	5

The LCS presents a higher level of GHG emissions than the LMS, given that more biomass and waste would be used in the LCS and, therefore, more fossil fuels would be displaced, which, in contrast, have higher emission factors than bioenergy. The potential GHG savings would depend on the type of fossil fuel displaced in each sector. These carbon savings were not assessed in this alternative scenario, but they were estimated in the sectoral analysis of this report. Emissions from land use change were not included in such projections, due to the large variability and uncertainty of the currently available models and highly complex agricultural dynamics worldwide (M. Akhurst et al, 2011a), Some regions may present positive emissions from land use change, whilst others may have negative emissions from a possible increase of carbon (including below ground biomass) in agricultural soil.

Bioenergy demands estimated by 2050 by this model (e.g. 70 EJ LMS, and 115 EJ LCS, globally) are fairly consistent with the 2050 bioenergy potentials proposed by many other international models. For example, IPCC in its Special Report on Renewable Energy Sources and Climate Change Mitigation (IPCC, 2011), estimates the global bioenergy potential to be between 50 and 1,000 EJ by 2050, and a more likely forecast between 100 and 300EJ. From this potential range, it is expected that between 100 and 150 EJ would be economically viable by 2050, according to (Akhurst et al 2011b), (Slade et al, 2011) and discussions presented by (Woods, 2011). (Akhurst et al, 2011b) summarised the results of various bioenergy models (figure 38), which vary significantly, according to the assumptions adopted in each model. From these estimates it is very likely that bioenergy will provide a substantial contribution to the reduction of fossil fuel dependence GHG emissions.





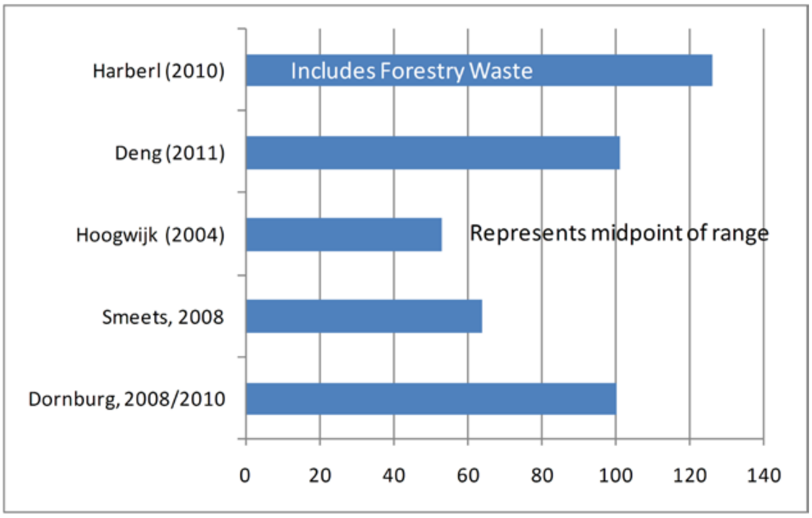


Figure 38. World biomass potential in 2050 in EJ, according to different models (Akhurst et al, 2011b). Top: abandoned land potential; middle: surplus forest products; bottom: residues and wastes.

The results are also consistent with the global technical capacity in terms of land availability, but with some potential impacts on food production, water management, competition for fertilisers etc. The total land required for bioenergy in 2050 (i.e. 322 Mha LMS, and 442 Mha LCS) would be technically possible to be made available without major impacts, although significant land use effects may happen if effective precautionary measures are not implemented. The land use results are consistent with other estimates, for example, IEA estimated in its roadmap for 2050 (IEA, 2010a) that world biofuels demand (i.e. bioethanol, biodiesel, biomethane and biojet) would be approximately 32 EJ, resulting from about 105 Mha, whilst the global estimate in the present model for biofuels in the transport sector would be between 25 EJ (LMS) and 58 EJ (LCS), or 116 Mha and 188 Mha, respectively. The difference between the forecasted land uses in both models is due to the assumptions concerning improvements in bioenergy crop yields by 2050. In our model, bioenergy yields were estimated from 2011 data and their potential improvements by 2050, according to the technical potentials of key biomass sources (e.g. forest plantations, energy grasses, agricultural residues, sugarcane, corn, beet, oilseed crops etc). Further increases in energy yields are assumed in the LCS as a result of additional investments in technology development.

6.1 Food and Fuel Integration

The confluence of energy and food demands, the increasing scarcity of natural resources and the uneven spread of those resources impose an increasing need to find new strategies towards global sustainable development. Energy and food security are strategic issues for any country and they often supersede options to develop economically and environmentally sustainable bioenergy which in turn entail extra effort requiring public policies encompassing global responsibilities. Thus, the challenge is how to promote bioenergy in a symbiotic way with food production and conservation of ecosystems and their services by 2050. Food security and the competition for land and resources between food and fuel has become an overriding global concern in recent past due to perceived continued and increasing demands on agriculture; many papers have been written in this regard (Godray et al, 2010), (Rosillo-Calle & Johnson, 2010), (FAO, 2010), (Lynd & Woods, 2011).

Therefore, new bioenergy-relevant political strategies will be necessary at the local, national and international levels to govern the equitable use of land and the allocation of that land to different productive and non-productive uses. In order to avoid negative impacts on food production, bioenergy should be produced using, for instance, production standards and management regimes/policies designed to ensure best practice and manage trade-offs through policy-established sustainability criteria and other landscape management tools such as agroecological zoning (Strapasson et al, 2012), (Murphy et al, 2011). These policies and standards would need to guide the expansion of bioenergy feedstock production onto favourable areas of land and deliver improved ecosystem services in existing intensively managed land. Moreover, food production could be met by increasing yields in agriculture and livestock, especially in developing countries, through technical improvements and best agronomical practices, for example, no tillage production, crop rotation, biotechnology and livestock intensification (Pacini & Strapasson, 2012). This potential is not restricted to developing countries in tropical regions; it would be also possible in temperate countries, such as Ukraine, Kazakhstan and Pakistan, where land use could be significantly intensified and productivity substantially increased.

As a comparative reference, the global land area is about 13 Gha, which is currently divided into arable 1.5 Gha, pasture 3.5 Gha, forestry 4 Gha, and other 4 Gha (including deserts) (FAO, 2009). Therefore the total land required for bioenergy would be equivalent to 6.4% (LMS) or 8.8% (LCS) of the total world arable and pasture lands (5Gha). Thus, public policies would require further investments in technology transfer in order to increase agricultural yields to meet food and bioenergy, in a symbiotic, integrated way. Sustainable spatial planning tools e.g. agroecological zoning, would also be a key strategy to optimise land use worldwide and mitigate global warming, in association with social and economic policies for bioenergy, including capacity building programmes.

Indirect effects on food prices may occur in some circumstances depending on the scale that bioenergy expansion may occur, on the kind of energy crop and on the producing region. As observed in the 2008 food price crisis, when prices sharply increased worldwide, this escalation was also correlated with a large number of variables, such as: oil price; GDP and per capita income growth rates; trade barriers; US dollar valuation/devaluation; food stock variations; food production subsidies from the developed countries; and migration of investments e.g. to hedge funds. Biofuels can also be one of these variables, but not necessarily. Corn-based ethanol, for instance, had a small impact on such food price, while sugarcane-based ethanol had no effect whatsoever (International Sugar Organisation, 2009). The use of agricultural residues may not significantly influence food prices as well.

6.2 Bioenergy as a development strategy for African countries

Bioenergy may be a strategic option for the international development of poorer regions, when coupled with sustainable public policies and good governance. In Africa, for instance, bioenergy could play a major role in the reduction of GHG emissions, by displacing fossil fuel dependence, and the traditional use of biomass. The exploitation of local biomass for cooking and heating, beyond the resilience capacity of native ecosystems, which could be avoided through the production of sustainable biomass under a renewable process (i.e. modern biomass) and the use or more efficient conversion technologies, for example, ethanol stoves which also have the benefit of reducing indoor air pollution.

Furthermore, crop yield increases in African countries could reduce the need for additional land for food production, as successfully demonstrated by Brazil in the last two decades, where the grain production rose 8.2% a year, but the planted area increased only 1.4% a year (Strapasson et al, 2012). Other developing countries could adopt and adapt this experience from Brazil through technology transfer and capacity-building programmes. In the same direction, (Lynd & Woods, 2011) state that the production of sustainable bioenergy in marginal land in African countries could generate many benefits, such as:

- Employment, and development of marketable skills, for rural communities who have few opportunities for either;
- Introduction of sorely needed agricultural infrastructure and knowhow;
- Improved balance of payments and currency valuation. As economic development proceeds in Africa demand for electricity and fuel will continue to increase sharply; the cost of importing oil imposes an ever-growing burden on Africa's economies and farmers;

- Energy democratization, self-sufficiency and availability for agricultural processing. Restricted access to clean, affordable energy impedes development and food production, amplifies losses in the food supply chain and exacerbates hunger;
- An economically rewarding way to regenerate Africa's vast areas of degraded land;
- A route to advancing agriculture in Africa, largely independent of factors that have made this difficult in the case of food production. North America and Europe export large amounts of food at prices difficult for African farmers to compete with. But these regions do not export biofuels and are unlikely to do so in the future, and exporting heat and electricity is not feasible;
- Lessened conflict, which is widely recognized as both a cause and an effect of hunger and poverty in Africa. Using bioenergy to improve both food security and economic security could help replace a vicious cycle with a virtuous one.

7 Energy Conversion Chains

Our methodology includes the modelling of energy conversion chains for the production of non-power energy vectors (e.g. liquid fuels and hydrogen). We do this to make sure we capture the cost differences between the LMS and LCS accurately and also to quantify the indirect emissions associated with energy conversion processes when associated with end-use sectors. This section explains the methodology that we employ for modelling key energy conversion technologies for a global-wide regional-based CO2 emissions reduction study.

7.1 Introduction

Energy conversion technologies account for production of unconventional synthetic fluid fuels (or synfuels) and hydrogen from primary fossil-based sources consisting of coal, petroleum, and natural gas as well as from biomass, electricity and CO_2. Figure 39 summarizes the model structure that we adopt to represent this sector, which considers not just GHG emissions from the overall synthetic fuel conversion facility, but also emissions from the associated primary resource extraction through ultimate fuel use (Jaramillo, Griffin, & Matthews, 2007), (Jaramillo, Samaras, Wakeley, & Meisterling, 2009), (Kabir & Kumar, 2011), (Marano & Ciferno, 2001), (Spath & Mann, 2001), (DEFRA, 2012).

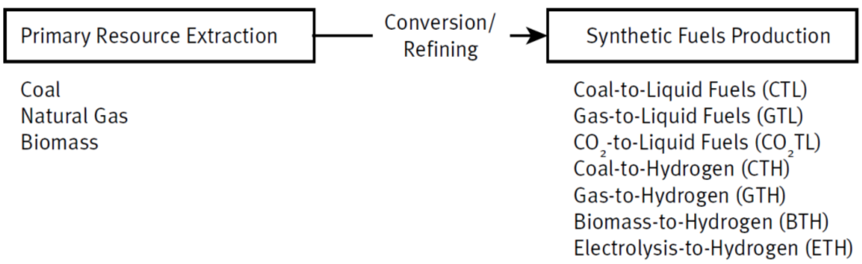


Figure 39. Model structure for energy conversion sector

7.2 Methodology

This section describes the methodology that we adopt for calculating fuel-cycle-wide GHG emissions and the associated costs for developing a technology for CO_2 recycle/utilisation plants that produce electric power and synfuels (Williams & Larson, 2003). It is worth noting that the recycle plants allow the carbon molecule to be utilized twice: once for power generation and another for fuel production. Hence, this approach entails an effective 50% reduction in emissions (unless the CO_2 source is from biomass). Another way to view this is that the power plant emissions are low, but the transport emissions are significant.

There is no unique way of allocating GHG emissions between the fuel and electricity co-products. The approach adopted here is responsive to the need in a climate-constrained world to measure emissions relative to the limits of what is achievable in principle (without violating physical or chemical laws). Because fuel-cycle-wide GHG emissions with a synfuel cannot be less than the CO_2 generated when the synfuel is burned or its carbon content is otherwise released to the atmosphere, whereas emissions from making electricity can in principle be reduced to zero via CO_2 capture and storage, all direct CO_2 emissions associated with synfuel manufacture are allocated to electricity. Hence, the fuel-cycle GHG emission factor GEF^{sf} for a synfuel (as denoted by the superscript "sf"), expressed in kg of CO_2 equivalent per GJ of synfuel produced and used, is made up of four emission components:

1. upstream GHG emissions (UEF^{sf}) involved in resource mining (e.g., coal, natural gas, biomass) and transport to the conversion plant for consumption;
2. downstream emissions (DEF^{sf}) that arise between its production and ultimate conversion.
3. direct CO_2 emissions (PEF^{sf}) from the production process;
4. emissions (C^{sf}) when the synfuel is combusted (or its carbon content is otherwise released to the atmosphere).

Hence, the lifecycle emissions can be calculated as:

$$GEF^{sf} = UEF^{sf} + DEF^{sf} + PEF^{sf} + C^{sf}$$

It is typical to assume DEF^{sf} to be negligible.

To illustrate the methodology, we consider a specific conversion example of CO_2-to-methanol fuels production, as illustrated in Figure 40, with the stoichiometric balance given by:

$$CO_2 + 3H_2 = CH_3OH + H_2O$$

Note that this CO_2-based synthetic fuel production process assumes carbon capture but not its storage.

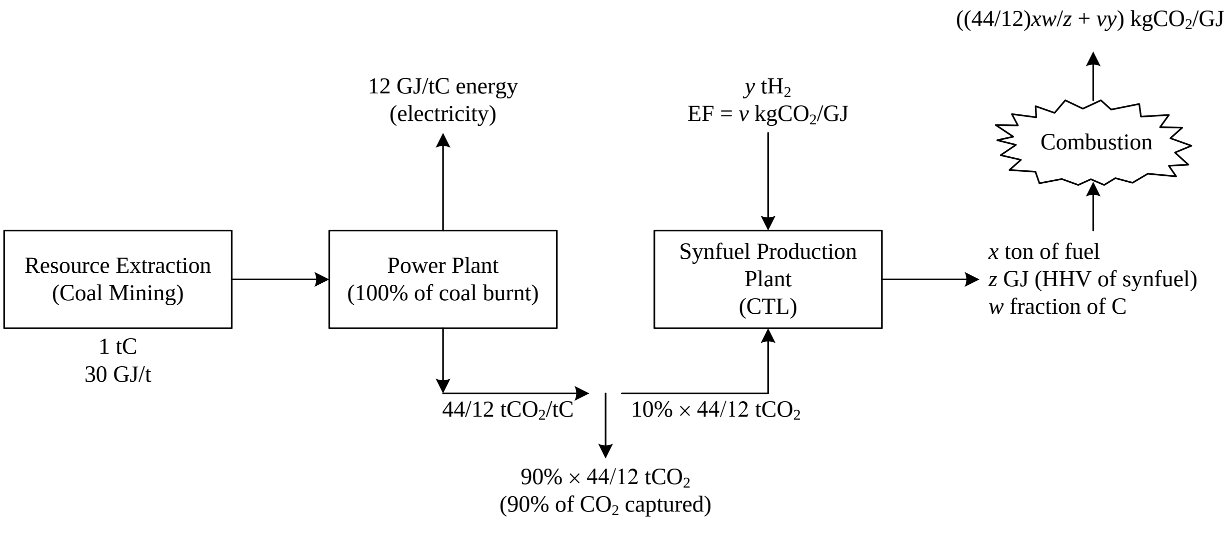


Figure 2. Schematic diagram for CO_2-to-methanol production (note: EF is emission factor, HHV is high heating value)

For every ton of coal combusted in a power plant, the upstream GHG emissions is given by the ratio of the molar mass of CO_2 to the molar mass of carbon:

$$UEF^{sf} = (44\ tCO_2)/(12\ tC)$$

Considering installation of a carbon capture (CC) plant with a CO_2 emissions capture rate of α (in percentage) from the power plant, the amount of CO_2 fed into a synfuel production facility is:

$$u = \alpha(44\ tCO_2/12\ tC)$$

This procedure allocates the decarbonisation credit to the power system (or the industrial system for that matter) where the CC plant is fitted.

In the methanol (MeOH) synthesis process, a stoichiometric amount of the raw material hydrogen is consumed (9.9t H_2 based on a ratio of 1 mol CO_2 to 3 mol H_2 according to reaction (2)). The associated emissions are calculated as:

$$\mathrm{PEF}^{sf} = y \times \mathrm{EF}_{H2}$$

where EF_{H2} is taken to be the emission factor for the conversion process of natural gas to hydrogen (94.8 $kgCO_2$/GJ).

For combustion of methanol, the direct CO_2 emissions are given by:

$$C^{sf} = Mw/F^{sf}$$

where F^{sf} = synfuel energy output as given by the high heating value (HHV) of methanol (226 GJ); M is the stoichiometric amount (in mass) of methanol produced 3.3 ton of methanol); and w is the fraction of carbon in methanol as given by molar mass of carbon per molar mass of methanol:

$$w = (12\ \text{g/mol MeOH})/(32\ \text{g/mol MeOH})$$

Finally, the lifecycle GHG emission factor is given by:

$$GEF^{sf} = (44\ tCO_2)/(12\ tC)(\ Mw/F^{sf}) + yEF_{H2}$$

This modelling approach is applied to each pathway considered for synthetic fluid fuels production. The emission factors (EF) and costs are obtained based on a combination of literature values and expert judgment as reported in Table 20 and Table 21, respectively.

Table 1. Emission factors (EF) for unconventional synthetic fuels production (abbreviations are as explained in Figure 39)

Pathway	EF	Low carbon scenario
Liquid synfuels		
CTL in LMS	266.6	Stoichiometric reaction: $C + 2H_2O \rightarrow CO_2 + 2H_2$
CTL + CCS (90%) in LCS	181.4	CO_2 emissions capture rate = 90%
GTL in LMS	150.9	Stoichiometric reaction: $C + 2H_2O \rightarrow CO_2 + 2H_2$
GTL + CCS (90%) in LCS	100.4	CO_2 emissions capture rate = 90%
CO2TL in LMS	97.0	Stoichiometric reaction for methanol synthesis: $CO_2 + 3H_2 \rightarrow CH_3OH + H_2O$
Hydrogen-based synfuels		
CTH in LMS	266.6	Stoichiometric reaction: $C + 2H_2O \rightarrow CO_2 + 2H_2$
CTH + CCS (90%) in LCS	181.4	CO_2 emissions capture rate = 90%
GTH in LMS	150.9	Stoichiometric reaction: $CH_4 + 2H_2O \rightarrow CO_2 + 4H_2$
GTH + CCS (90%) in LCS	100.4	CO_2 emissions capture rate = 90%
BTH in LMS	31.9	Stoichiometric reaction: $CH_2O + H_2O \rightarrow CO_2 + 2H_2$
BTH + CCS (80%) in LCS	−61.9	CO_2 emissions capture rate = 80%
ETH in LMS	0	No carbon penalty for source of water

Table 2. Costs of unconventional synthetic fluid fuels production (Jaramillo P. G., 2008), (Konda, Shah, & Brandon, 2011), (Kramer, Huijsmansb, & Austgen, 2006)

Pathway	Low Price (US$/GJ)*	High Price (US$/GJ)*	Basis/Assumption
CTL in LMS	15.46	17.18	B1.1. Levelized cost = US$0.40 per liter of synfuels produced B1.2. Energy content of: gasoline = 31 MJ/L, diesel = 36 MJ/L B1.3. Production share of synfuels; 50% gasoline, 50% diesel
CTL + CCS (90%) in LCS	18.15	19.87	B2.1. Levelized cost = US$0.49 per liter of synfuels produced B2.2. (similar to B1.1 and B1.2)
GTL in LMS	27.79	30.63	B3.1. Levelized cost = US$0.61 per liter of synfuels produced B3.2. (similar to B1.1 and B1.2)
GTL + CCS (90%) in LCS	28.69	31.53	B4.1. Levelized cost = US$0.64 per liter of synfuels produced B4.2. (similar to B1.1 and B1.2)
CO_2TL in LMS	46.96	46.96	B5.1. Material costs of synfuels based on stoichiometry = US$30/t$CO_2$ B5.2. Material costs of synfuels is 50% of total material costs (per GJ) B5.3. Total material costs is 50% of non-material costs B5.4. Hydrogen cost = US$3/kg H_2 B5.5. 12% of CO_2 entering synfuels plant is biogenic (consistent with 12% limit on biomass conversion to power in the overall study), hence EF is reduced by 12% Note: A range of 25-60 US$/GJ is considered for conducting sensitivity analysis
Scaled price according to share	LMS: 21.62 LCS: 31.27	LMS: 31.27 LCS: 32.79	
Hydrogen-based fuels			
CTH in LMS	23.45	25.17	Comparable to GTH with relatively lower capital cost but higher raw material cost
CTH + CCS (90%) in LCS	26.97	28.95	15% higher than CTH
GTH in LMS	30.58	33.42	B6.1. HHV of hydrogen = 142,182 J/g B6.2. (similar to B5.4)
GTH + CCS (90%) in LCS	35.16	38.43	15% higher than CTH
BTH in LMS	36.69	40.11	20% higher than GTH
BTH + CCS (80%) in LCS	42.20	46.12	15% higher than CTH
ETH in LMS	26.57	26.57	Total costs = EUR3/kg of H_2 produced
Scaled price according to share	LMS: 30.58 LCS: 33.42	LMS: 38.68 LCS: 42.28	
*Applies to both LMS and LCS			

7.3 Concluding Remarks

This section presents a methodology for modelling energy conversion technologies involving various transformation processes to produce liquid fuels and hydrogen in a CO_2 emissions reduction study. It may be worth noting that a plausible future pathway is to consider converting CO_2 emissions from the cement industry to fuel due to the good quality of CO_2 and relatively easy logistics.

APPENDIX 1. Fossil Fuel Price Scenarios

Our future (2050) fossil fuel prices are defined for two scenarios: high and low. The rationale for the exact values is described below.

Oil: DECC (2011) estimate a value of $75/bbl by 2030, based on the long run marginal cost curve for oil in 2008 (from IEA estimates), and an assumption of no/weak economic growth (or at least no oil demand growth) to 2030. In our view this is somewhat unrealistic, and as demand increases strongly, the LRMC will increase as cheaper production sites are dried out. DECC's central and high estimates are $130/bbl and $170/bbl for 2030. The IEA (2011a) price forecasts are between $92/bbl (450 ppm scenario) and $135/bbl (current policies scenario) for 2035. We believe a fair estimate that the LRMC in 2030 could be $100/bbl, and in 2050 $130/bbl. So we have fixed on a 2050 low estimate of $100/bbl and a high of $150/bbl.

Coal: DECC's (2011) LRMC for coal is $80/tonne currently, not deemed to rise in the Low scenario to 2030, but to rise to $110/tonne in the central and $155/tonne in the high scenarios. In IEA (2011a), the range is $116/tonne to $182/tonne by 2035. For 2050 we have assumed $100/tonne for the low value and $150/tonne for the high value. We are assuming there is not much coal monopoly power in the same way as there is for oil.

Gas: DECC's (2011) low gas price most closely reflects LRMC which is 45p/therm (or about $0.7/therm) in 2030. The central and high estimates are $1/therm and $1.5/therm in 2030. IEA (2011a) has $1-1.3/therm in 2035. Of course anything could happen with shale gas, but we would doubt there will be a long-term collapse in global prices, and therefore settle for $1/therm in 2050 (low) and $1.3/therm (high).

APPENDIX 2. Biomass energy yields, emission factors and costs

Bioenergy Yields

	Land use efficiency (current yields)	Region	Reference
Raw Biomass			
Grass for bioenergy	5-15 toe/ha	Developed countries (less in high altitudes)	[1]
Short-Rotation Coppice (SRC)	4-7 toe/ha	–	[1]
Forest plantation (Eucalyptus, Acacia, Pine and Poplar)	2-6 toe/ha	Africa, East Asia, Oceania and South Asia	[1]
Forest plantation	2-10 toe/ha	south east Asia and Latin America	[1]
Forest plantation	until 18 toe/ha	Brazil	[1]
Agricultural residues	0.3-1.2 toe/MT of crop production	Europe, North America and Southeast Asia	[1]
Wood residues	0.2-0.4 toe/m3 of wood production	Europe, North America and Southeast Asia	[1]
Grain residues	1-4 toe/ha	–	[1]
Sugarcane residues	12 toe/ha	–	[1]
Biofuels			
Bioethanol from cereals	1.0-1.5 toe/ha	EU	[2]
Bioethanol from sugarbeet	3-4 toe/ha	EU	[2]
Bioethanol from corn	1.5 toe/ha	USA	[2]
Bioethanol from sugarcane	3.7 toe/ha	Brazil	Estimated based on [3] and [4]
Biodiesel from oilseed crops	0.8-1.2 toe/ha	EU	[2]
Oil palm	3.8-4.0 toe/ha	–	[2]
Firewood: energy equivalence for power generation	1 m3 firewood = 0.310 toe = 3.61 MWh	–	[4]

[1] World Bank (2010). Bioenergy Development. Technical Report.
[2] EC/SETIS (2012). Biofuels for the Transport Sector. Website.
[3] MAPA (2011). Anuario Estatistico da Agroenergia. Brasilia, Brazil.
[4] MME (2011). Balanco Energetico Nacional: Ano base 2010. Brasilia, Brazil.

Bioenergy Emission Factors

Liquid Fuels			
Fuel	**EF**	**Unit**	**Comments**
Petrol	66.56	Mt eq CO_2/EJ	Source: AEA (2011)
Ethanol (LCA)	26.62	Mt eq CO_2/EJ	Assumption: 60% GHG emissions savings in 2050 compared to petrol in 2011
Diesel	69.41	Mt eq CO_2/EJ	Source: AEA (2011)
Biodiesel (LCA)	41.65	Mt eq CO_2/EJ	Assumption (2050): 40% GHG emissions savings compared to diesel (LCA) in 2011
Solid biomass			
End use	**EF**	**Unit**	**Comments**
Electricity (LCA)	20 – 40	g CO_2 eq/MJ	Approx. EF based on Cherubini et al (2009) and IPCC (2011), both apud IEA (2012)
Co-firing (LCA)	0 – 30	g CO_2 eq/MJ	Approx. EF based on Cherubini et al (2009) and IPCC (2011), both apud IEA (2012)
Heating (LCA)	5 – 20	g CO_2 eq/MJ	Approx. EF based on Cherubini et al (2009) and IPCC (2011), both apud IEA (2012)

Note 1: In a UK based study for 2050, it has been considered for the whole chain bioenergy emission factor of 20-50 gCO_2/kWh (average across heat, power and fuel). As a comparison, in 2009, on average 1 MJ in the world power generation sector (primary energy) generated approximately 0.732 kWh (secondary energy). Thus, the range of 20-40 gCO_2/MJ (IEA, 2012) adopted for electricity in solid biomass, for example, would be equivalent to 27.3 – 55.6 gCO_2/kWh. However some improvements are expected by 2050 and, therefore, the estimates described below are also consistent to such UK based study.

Note 2: the units Mt eq CO_2/EJ and g CO_2 eq/MJ are equivalents.

Bioenergy Emission Factors (EF) estimated per sector and region by 2050:

World	LMS	LCS	Unit	Assumptions
Power generation	25.00	20.00	Mt eq CO2/EJ	LMS: Estimated based on a likely mix of electricity and co-firing technologies, with slightly lower emissions in 2050 than the current average of EF. LCS: additional improvements (20%) expected in technical changes, system integrations and negative soil carbon balance in relation to LMS. The use of agricultural residues may be intensified as well. Biochar may also happen in some regions.
Industry	14.60	11.68	Mt eq CO2/EJ	LMS: 80% of the total biomass would be used for heating and 20% for electricity in 2050 and the emissions would be slightly lower than the current average. LCS: additional improvements (20%) expected in technical changes, system integrations and negative soil carbon balance in relation to LMS.
Transport (biofuels)	31.88	25.51	Mt eq CO2/EJ	LMS: 65% of the total biofuels would be used for displacing petrol (gasoline) and 35% for diesel in 2050. The LMS EF is based on 60% of GHG emission saving ethanol vs petrol and 40% biodiesel vs diesel as an average in 2050. LCS: additional improvements (20%) expected in technical changes, system integrations, negative soil carbon balance and with partial carbon capture from the fermentation tanks, in relation to LMS. Biojetfuel is expected to have a similar emission to biodiesel, representing a share of the keronsene market in the aviation sector.
Building	12.00	9.60	Mt eq CO2/EJ	LMS: all biomass would be used for heating by 2050 and the emissions would be slightly lower than the current average. LCS: additional improvements (20%) expected in technical changes, system integrations and negative soil carbon balance in relation to LMS.

OECD Europe	LMS	LCS	Unit	Assumptions
Power generation	22.50	18.00	Mt eq CO2/EJ	Idem world assumptions, but OECD Europe tends to have about 10% higher energy efficiency in thermopowers regarding global average.
Industry	13.14	10.51	Mt eq CO2/EJ	Idem world assumptions, but, OECD Europe tends to have about 10% higher energy efficiency in industrial uses regarding global average.
Transport (biofuels)	37.14	29.71	Mt eq CO2/EJ	Idem world assumptions, but with different biofuels share: 30% ethanol and 70% biodiesel in 2050, given that EU tends to keep focusing on diesel displacement.
Building	10.80	8.64	Mt eq CO2/EJ	Idem world assumptions, but 10% more efficient than global average due to the use of better energy standards and technologies.

OECD Americas	LMS	LCS	Unit	Assumptions
Power generation	22.50	18.00	Mt eq CO2/EJ	Idem OECD Europe assumptions.
Industry	13.14	10.51	Mt eq CO2/EJ	Idem OECD Europe assumptions.
Transport (biofuels)	28.13	22.50	Mt eq CO2/EJ	Idem world assumptions, but with different biofuels share: 90% ethanol and 10% biodiesel in 2050, mainly because USA tends to keep focusing on gasoline displacement through corn-based ethanol. Second generation ethanol could contribute to improve carbon balance in the LCS, by using switchgrass and other crops as well.
Building	10.80	8.64	Mt eq CO2/EJ	Idem OECD Europe assumptions.

China	LMS	LCS	Unit	Assumptions
Power generation	25.00	20.00	Mt eq CO2/EJ	Idem world assumptions.
Industry	14.60	11.68	Mt eq CO2/EJ	Idem world assumptions.
Transport (biofuels)	31.88	25.51	Mt eq CO2/EJ	Idem world assumptions. China recently halted the production of grain-based ethanol, but future technologies (e.g. 2nd generation biofuels) and imports (e.g. palm-based biodiesel) may increase in the comming years.
Building	12.00	9.60	Mt eq CO2/EJ	Idem world assumptions.

India	LMS	LCS	Unit	Assumptions
Power generation	25.00	20.00	Mt eq CO2/EJ	Idem world assumptions.
Industry	14.60	11.68	Mt eq CO2/EJ	Idem world assumptions.
Transport (biofuels)	29.63	23.70	Mt eq CO2/EJ	Idem world assumptions, but with different biofuels share: 80% ethanol and 20% biodiesel in 2050. India may increase the use of sugarcane to produce ethanol. Jatropha curcas may also become competitive in the coming decades in India, as other biodiesel crops.
Building	12.00	9.60	Mt eq CO2/EJ	Mean value. All biomass would be used for heating ends in the building sector.

Latin America	LMS	LCS	Unit	Assumptions
Power generation	20.00	16.00	Mt eq CO2/EJ	Idem world assumptions, but some significant bioenergy producing countries in LA (e.g. Brazil and Argentina) tend to have a more efficient biomass production (e.g. eucaliptus, pine, sucargane bagasse, elephant grass) than worldwide average, due to tropical climate and technologies. Thus about 20% of higher energy efficiency would be expected in comparison to global standards.
Industry	11.68	9.34	Mt eq CO2/EJ	Idem world assumptions. However, LA tends to have about 20% higher energy efficiency in industrial uses regarding global average, because some countries, specially Brazil which is highly representative in biomass production in LA, would keep using efficient crops (e.g. eucaliptus, pine and sugarcane bagasse) in key industrial sectors (e.g. sugar and ethanol, pulp and cellulosis, mine and steel industries), with further technical improvents. Other LA countries may follow this tendence as well.
Transport (biofuels)	23.70	18.96	Mt eq CO2/EJ	Idem world assumptions, but with different biofuels share: 80% ethanol and 20% biodiesel in 2050. In LA key biofuels producing countries (e.g. Brazil, Argentina, Colombia and Caribbean countries) would keep using bioenergy crops with higher efficiency standards than global average, for example, sugarcane. Therefore, the transport EF are expected to be 20% lower than worldwide.
Building	10.80	8.64	Mt eq CO2/EJ	Idem world assumptions, but 10% more efficient than global average due to the use of more efficient energy crops and technologies than globally.
East Europe	**LMS**	**LCS**	**Unit**	**Assumptions**
Power generation	25.00	20.00	Mt eq CO2/EJ	Idem world assumptions.
Industry	14.60	11.68	Mt eq CO2/EJ	Idem world assumptions.
Transport (biofuels)	37.14	29.71	Mt eq CO2/EJ	Idem world assumptions, but with different biofuels share: 30% ethanol and 70% biodiesel by 2050, given that East Europe tends to keep focusing on diesel displacement, as the OECD European countries.
Building	10.80	8.64	Mt eq CO2/EJ	Idem world assumptions.

Sub Saharian Africa	LMS	LCS	Unit	Assumptions
Power generation	27.50	22.00	Mt eq CO2/EJ	Idem world assumptions, but technoly improvements may happen a bit slower than world average. Therefore a 10% higher EF would be expected regarding global standards.
Industry	16.06	12.85	Mt eq CO2/EJ	Idem world assumptions, but with 10% higher EF due to industrial learning curve.
Transport (biofuels)	29.63	23.70	Mt eq CO2/EJ	Idem world assumptions, but with different biofuels share: 80% ethanol and 20% biodiesel by 2050. Sugarcane-based ethanol tends to expand in countries such as Mozambique, Tanzania, Sudan, Ghana and Angola. Biodiesel from Jatropha and palm trees may also expand in some SSA countries with tropical climate.
Building	14.40	11.52	Mt eq CO2/EJ	Idem world assumptions, but with 20% higher EF than worldwide, because limitations on technology access. In addition, traditional biomass may be still substantially used in 2050, specially for cooking.

MENA	LMS	LCS	Unit	Assumptions
Power generation	25.00	20.00	Mt eq CO2/EJ	Idem world assumptions.
Industry	14.60	11.68	Mt eq CO2/EJ	Idem world assumptions.
Transport (biofuels)	31.88	25.51	Mt eq CO2/EJ	Idem world assumptions.
Building	12.00	9.60	Mt eq CO2/EJ	Idem world assumptions.
Note: In general, no major production of bioenergy is expected from MENA countries in the comming decades, due to climate conditions and focus on other energy sources (e.g. oil and natural gas).				

OECD Pacific	LMS	LCS	Unit	Assumptions
Power generation	22.50	18.00	Mt eq CO2/EJ	Idem world assumptions. Technical improvements and energy efficiency standards may lead to a 10% lower EF than worldwide.
Industry	13.14	10.51	Mt eq CO2/EJ	Idem world assumptions. Technical improvements and energy efficiency standards may lead to a 10% lower EF than worldwide.
Transport (biofuels)	31.88	25.51	Mt eq CO2/EJ	Idem world assumptions. South Korea and Japan may increase imports of ethanol from Brazil and other countries, as well as palm-oil-based biodiesel from Indonesia and Malasia for example, in the comming decades, with minor domestic productions. Australia may increase the domestic production of sugarcane-based ethanol, but new areas for sugarcane expansion are quite limited. New Zealand may increase domestic biodiesel production (e.g. animal fat from livestock production, and oil crops) and biofuels imports.
Building	10.80	8.64	Mt eq CO2/EJ	Idem world assumptions. Technical improvements and energy efficiency standards may lead to a 10% lower EF than worldwide.
Note: Japan and Korea may focus on imports with high efficiency standards (e.g. certification schemes), whilst Australia and New Zealand could increase domestic bioenergy production in an efficient manner too.				

Other dev Asia	LMS	LCS	Unit	Assumptions
Power generation	25.00	20.00	Mt eq CO_2/EJ	Idem world assumptions.
Industry	14.60	11.68	Mt eq CO_2/EJ	Idem world assumptions.
Transport (biofuels)	35.64	28.51	Mt eq CO_2/EJ	Idem world assumptions. Some countries may focus on ethanol production from sugarcane (e.g. Vietnam), whilst others would probably focus on oil-palm-based biodiesel (e.g. Indonesia and Malasia). Both crops present high bioenergy performances and significant potentials for technical improvements, but some deforestation (although only in some areas) are forecasted to happen as a result of such biofuels expansion and, therefore, no higher EF would be expected than globally. Palm oil is the currently main vegetable oil produced worldwide and these countries are its main global producers. Thus, ethanol and biodiesel are forecasted to share 40% and 60%, respectively, of the biofuels market.
Building	12.00	9.60	Mt eq CO_2/EJ	Idem world assumptions.

Estimated costs of bioenergy in 2050 (USD 2010 basis)

The following costs were estimated through market analysis and involve the whole production chain, including the energy conversion costs, but without adding an internal carbon price:

- **Average production cost of liquid biofuels: U$ 11.83 / GJ.**
- **Cost for solid biomass (odt, oven dry tonne; any type of biomass): U$ 7.22 / GJ**. Value estimated from U$ 130 / odt of raw biomass. Energy conversion factor 18 GJ/t;
- **Cost for biofuels (mean value for all liquid fuels): U$ 11.83 / GJ**. Estimation based on U$ 390 / t of biofuel. Mean energy conversion factor: 1 tonne of liquid biofuel = 32.97 GJ; which was estimated based on an average of both ethanol and biodiesel mean heating values.

Conversion factor: 1.00 boe = 5.73 GJ.

For simple estimates, CAPEX and OPEX for biomass-based power generation were considered equivalent to those for a coal power plant, except for the raw material cost i.e. coal *versus* biomass.

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