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How carbon pricing changes the relative competitiveness of low-carbon baseload generating technologies

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ABSTRACT

There is wide public debate about which electricity generating technologies will best be suited to reduce greenhouse gas emissions (GHG). Sometimes this debate ignores real-world practicalities and leads to over-optimistic conclusions. Here we define and apply a set of fit-for-service criteria to identify technologies capable of supplying baseload electricity and reducing GHGs by amounts and within the timescale set by the Intergovernmental Panel on Climate Change (IPCC). Only five current technologies meet these criteria: coal (both pulverised fuel and integrated gasification combined cycle) with carbon capture and storage (CCS); combined cycle gas turbine with CCS; Generation III nuclear fission; and solar thermal backed by heat storage and gas turbines. To compare costs and performance, we undertook a meta-review of authoritative peer-reviewed studies of levelised cost of electricity (LCOE) and life-cycle GHG emissions for these technologies. Future baseload electricity technology selection will be influenced by the total cost of technology substitution, including carbon pricing, which is synergistically related to both LCOE and emissions. Nuclear energy is the cheapest option and best able to meet the IPCC timetable for GHG abatement. Solar thermal is the most expensive, while CCS will require rapid major advances in technology to meet that timetable.

1. Introduction

The Copenhagen Accord that emerged from the 2009 United Nations Climate Change Conference recognised the scientific view that any increase in global temperature should be kept below 2 °C [1]. According to the International Panel on Climate Change (IPCC) this target would require atmospheric GHG levels to be stabilised below 450 ppm CO_2eq[1] and future emissions to be reduced by 85% below 2000 levels by 2050 [2]. Such reductions call for a switch to low-emission technologies, particularly for electricity generation – a major source of fossil-fuel-derived CO_2.

Economists generally agree that the most effective way to encourage technology switching is to introduce a price on emissions, commonly referred to as a carbon price, that must be paid by the emitter. The options for, and costs of, low-emission technologies are of considerable interest to those tasked with mitigating climate change and there are numerous reviews available. These reviews often start with different premises and arrive at different conclusions. An important cause of these differences is the degree of optimism adopted regarding long-term improvements in emerging technologies and their costs. That is to say, there are differences in the levels of risk that different observers tend to attach to future technology development, including cost projections. While this is understandable, the position taken here is that future energy security is of utmost importance and that minimal reliance should be placed on inherently uncertain projections, especially given the relatively tight timeframes for large-scale emissions reduction, as described above.

Thus, there is a need for an independent, objective analysis of such reviews (a ‘meta-review’ [3]), which is based on a realistic assessment of market needs, current technology performance, and the future prospects of seemingly attractive technologies that are still on the horizon. In this paper, our intention is to fulfil that need. In this assessment of the authoritative technical literature, we explore how the introduction of a price on carbon will impact the relative competitiveness of generating technologies. We take an explicit, transparent but conservative approach to selecting the technologies that can properly be regarded as ‘fit-for-service’ in supplying future low-carbon baseload electricity needs.

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[1] ppm CO_2eq = parts per million of carbon dioxide equivalent.

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1.1. Substantial cuts needed in GHG emissions from electricity generation

Although a decrease in carbon emissions is needed across the whole economy, the energy sector (and electricity in particular) is key to achieving the reduction target by 2050. The energy sector represents 73% of all anthropogenic global emissions, with electricity generation contributing 43% of the energy emissions and 32% of all emissions. Transport is the next largest category at 19% of energy emissions [4]. The electrification of transport to reduce emissions from oil-based products will increase the total demand for low-carbon electricity. Although the efficiency gains this involves may lead to a reduction in total primary energy consumed in the transport sector, it will put further pressure on reducing GHG emissions from electricity generation.

The emission intensity (EI) of electricity plants is the full life-cycle emissions per unit of energy generated, including fuel production and construction and decommissioning of the plant. The average EI of world electricity generation today is around 500 kg CO_2eq/MWh.[2] This figure will need to be below 50 kg CO_2eq/MWh globally by 2050 to meet the IPCC's 85% reduction target [5]. The IPCC indicates that by 2030 the average EI of electricity generation has to be below 300 kg CO_2eq/MWh [6]. These EI targets define the capacity requirements and construction schedule for future low-carbon electricity generating technologies. Future constraints of fossil-fuel supplies may also influence regional technology selection over the next few decades.

1.2. Need to target baseload

Electricity demand is generally categorised into baseload, intermediate load and peak load. In the medium term, baseload demand does not change significantly over time and is defined as the minimum amount of power that an electricity utility or distribution company must always make available to its customers [7]. Intermediate load does vary but is predictable and influenced by time of day such as weekday mornings and evenings. Peak load is much less certain and is often influenced by climatic conditions that change demand for building heating and cooling. Different generators service the three different loads. An efficient mix of generation is one which minimises the total cost of meeting the demand. The shape of the demand profile is a key consideration. For example, a relatively flat demand profile implies a greater role for baseload generation, while a very peaky demand profile implies a greater role for peaking generation [8]. Baseload supply varies between countries and networks but can typically represent 40–60% of peak load but 60–80% of total energy supply. For example, in Australia in 2009 baseload plants provided 60% of the peak load and 76% of total energy [9].

Baseload plants using fossil fuels are typically the primary source of electrical energy in most networks [10] and produce most of the emissions. Intermediate and peaking plants (that are less likely to use fossil fuels) often have much lower EI levels than fossil-fuel baseload plants. Future technology is expected to progressively improve all plant EI levels. Hypothetically, if by 2050, 40% of the energy comes from intermediate and peaking plants (as is typical today), and these plants have a low average EI of 20 kg CO_2eq/MWh (typical for renewable energy plants [11]) then baseload average EI levels will need to be below 70 kg CO_2eq/MWh by 2050 to achieve the target of 50 kg CO_2eq/MWh by 2050 discussed in Section 1.1.

Not all low-carbon generating technologies are suitable for baseload plants. The US Energy Information Administration (EIA) defines baseload plants as facilities that operate almost continuously, generally at annual utilization rates (capacity factors) of 70% or higher [12]. In assessing technologies for costing, we adopt generally accepted selection criteria for technologies that are fit-for-service to provide baseload services (see Section 2.1).

1.3. Need for lowest cost solution

High generation costs obviously lead to high electricity prices and high energy prices tend to have a negative impact on productivity and economic competitiveness. The Commission on Engineering and Technical Systems in a paper titled *Electricity in Economic Growth* [13] stated that:

> "Productivity growth may be ascribed partly to technical change; in many industries technical change also tends to increase the relative share of electricity in the value of output, and in these industries productivity growth is found to be the greater the lower the real price of electricity, and vice versa."

For social and political reasons it is therefore important that electricity costs, inclusive of a carbon price, are kept to a minimum.

Generation costs are a function of the capital cost of the plant, the running costs (operations, maintenance and fuel) and the amount of energy generated over the plant's lifetime (see Section 2.2). Baseload technologies are characterised by high initial capital costs and relatively low running costs [8]. Fossil-fuel dependent baseload plants will be particularly sensitive to future coal and gas prices which are influenced by international supply and demand. Adding a carbon price to the cost of generation increases electricity prices and impacts the competitiveness of various baseload technologies because of their differing EIs. This point is central to the message of this paper.

2. Methods

2.1. Selecting 'Fit-for-Service' (FFS) technologies for low-carbon baseload

We consider only those low-emission technologies that can provide baseload power. We use a set of objective criteria to select candidates from present and proposed technologies commonly mentioned in the context of future power generation (IEA [14], EIA [12]). Each technology is assessed in Table 1 against the following criteria:

Proven	Has the technology been used at commercial scale?
Scalable	Can the technology be built in sufficient quantity to replace significant proportions of existing fossil-fuel generators?
Dispatchable	Can the output be allocated by the system operator to meet the anticipated load?
Fuel supply	Is the energy source reliable and plentiful, even when, as with some kinds of renewable energy, it varies with time?
Load access	Can the generator be installed close to a load centre?
Storage	Does the technology require electricity storage in order to deliver a high capacity factor?
Emission intensity	Is the emission intensity high, moderate or low (as defined in Table 1)?
Capacity factor	Is the capacity factor high, moderate or low (as defined in Table 1)?

[2] kg CO_2eq/MWh = kilograms of carbon dioxide equivalent per megawatt hour (electricity).

Table 1
Assessment of suitability of technologies for baseload using a fit-for-service matrix.

	Proven	Scalable	Dispatchable	Fuel supply	Load access	Storage needed	Emission intensity	Capacity factor	FFS
PF coal	Y	Y	Y	R	G		H	H	
PF Coal/CCS	D	Y	Y	R	G		M	H	Y
IGCC	Y	Y	Y	R	G		H	H	
IGCC/CCS		Y	Y	R	G		M	H	Y
CCGT	Y	Y	Y	R	G		H	H	
CCGT/CCS		Y	Y	R	G		M	H	Y
Nuclear	Y	Y	Y	R	G		L	H	Y
Biomass	Y		Y	R	I		L	H/M	
Hydro	Y		Y	R/VL	I		L	H/M	
Geothermal conventional	Y		Y	R	I		L	H/M	
Geothermal engineered	D	Y	Y	R	P		L	H	Y
Wind	Y	Y		VS	I/P	Y	L	L	
Solar thermal[a]	Y	Y	Y	VL	P		L	H	Y
Solar photovoltaic	Y			VS	G/I	Y	L	L	
Tidal	Y			VL	I	Y	L	L	
Wave	D	Y?		VS	I/P	Y	L	M/L	

Proven: Y = Has been built on commercial scale, D = Built on demonstration/pilot scale. Scalable: Y = Can be built in quantity to replace significant proportion of coal and gas. Dispatchable: Y = Can be allocated to meet anticipated load. Fuel supply: R = Reliable and plentiful, VS = Variable short-term (min), VL = Variable longer-term (h). Load access: G = Can be installed close to any load centre, I = Intermediate – can be installed close to some centres, P = Generally poor access to load centres but often the best location for energy resource access. Storage: Y = Energy storage required to achieve a high capacity factor (see below). Emission intensity: H = >300, M = 100–300, L = <100 kg CO_2eq/MWh. Capacity factor: H = >70%, M = 40–70%, L = <40%.
FFS: Y = Fit-for-service as low-carbon baseload technology to replace conventional fossil-fuel combustion.
[a] Includes sufficient thermal storage and/or gas hybrid integral to plant such that it does not need external storage to have high capacity factor.

For a technology to be considered fit-for-service (FFS) as a baseload generator it needs to be scalable, dispatchable without large storage[3] [15] and have a reliable fuel supply, low (L) or moderate (M) emissions intensity and a high capacity factor as defined in Table 1. Load access is considered to be desirable for transmission cost reasons but is not essential to meeting baseload demand.

The technologies that score well enough to meet the FFS criteria are pulverised fuel black coal with carbon capture and storage (PF Coal/CCS), integrated gasification combined cycle coal with CCS (IGCC/CCS), combined cycle gas turbine with CCS (CCGT/CCS), nuclear power, and solar thermal with thermal storage and/or hybrid gas (STE).

Engineered geothermal systems (EGS) could also qualify, but is only at the pilot plant stage of development and furthermore there are inadequate reliable cost data for it. It is therefore excluded from further consideration here.

2.2. Cost literature review of FFS technologies

The literature used to review costs of the five FFS technologies is listed in Table 2. Only work published within the last 10 years is included to ensure relevance. The referenced papers cover several regions and are spread over the decade. Where a report had been updated during the period (IEA [14]), only the most recent is used. All published cost data are converted to US dollars in the base pricing year of the study and then adjusted for the US consumer price index (CPI) to standardise the costs to 2009 US dollars.

The costing literature all report a levelised cost of electricity (LCOE). LCOE is a widely adopted metric for comparing the costs of different power generation technologies. Typically the levelised cost methodology discounts the time series of expenditures to their present values in a specified base year by applying a discount rate and then divides the total discounted expenditures by the total energy production adjusted for its economic time value.

[3] Use of large-scale electricity storage is prohibitively expensive in most networks. There are significant economic issues in deploying storage, stemming from the high capital costs and complexity of operating in liberalized energy markets [15].

The LCOE reflects the constant real wholesale price of electricity that recoups for the investors the overnight capital costs of constructing the plant plus operating, maintenance and fuel costs, taxes, interest and other borrowing expenses. The cost is for the net power supplied to the station busbar where electricity is fed to the grid and does not include transmission costs or utility profit margins.

Discount rates, overnight construction costs, lifetime of the plant, energy generated and fuel costs vary across the literature depending on region of origin and pricing year. These variations account for some of the differences in LCOE values for ostensibly the same technology. For example, technologies that have relatively high construction cost, long lead time and long expected lifetime, such as nuclear power, are particularly sensitive to discount rates.

All the FFS technologies identified in Section 2.1 are evaluated here. For comparison, existing baseload technologies – PF coal, IGCC, and CCGT (all without CCS) – are also included in the evaluation. Costs are collated for both first-of-a-kind (FOAK) and *n*-th build technology for nuclear plants. Nuclear FOAK costs tend to be significantly higher than *n*-th build because of addition costs associated with taking a new design from relatively simple conceptual stages to detailed engineering specifications, and in initial investments in new manufacturing and training capabilities. Costs are often made available for both stages of deployment. FOAK costs were not reported for other technologies in the studies we assessed.

As with engineered geothermal systems, Generation IV nuclear [16] is still in early development stage, with only the Russian BN-600 plant currently under commercial operation [17]. As such, it was not possible to identify sufficient reliable and representative LCOE data. It too was excluded from further consideration.

2.3. GHG emissions literature review of FFS technologies

To assess the impact of carbon pricing on baseload technology selection, it is necessary to go further than simply allocating a moderate or low rating to the emissions intensity. The GHG emissions associated with each technology also need to be quantified. This must be done using a full life-cycle assessment (LCA). LCA accounts for emissions at all stages of the system including the

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Table 2
Levelised cost of electricity (LCOE) literature reviewed, with the FFS technologies covered.

Source	Region	Year	Nuclear	PF coal with CCS	IGCC with CCS	CCGT with CCS	Solar thermal
NREL [24]	US	2003					Y
MIT [46]	US	2003	Y				
Tarjanne and Luostarinen [47]	Finland	2003	Y				
NREL [48]	US	2004		Y	Y	Y	
UOC [49]	US	2004	Y	Y		Y	
RAE [50]	UK	2004	Y				
San Diego [51]	US	2005					Y
Succar et al. [30]	US	2006			Y		
IPCC [52]	World	2006		Y	Y	Y	
ANSTO [53]	Australia	2006	Y				
MIT [54]	US	2007		Y	Y		
NEEDS [25]	EU	2008					Y
MIT [55]	US	2009	Y				
IEA/NEA [14]	OECD	2010	Y	Y			
EIA [12]	US	2010	Y		Y	Y	Y

fuel life-cycle, plant, construction, operation, infrastructure requirements, and end-of-life processes such as decommissioning and waste disposal. LCA methodologies can involve a process-chain analysis (bottom up), an input/output analysis (top down) or a hybrid approach which uses elements of both [18]. Results of individual studies vary because of different assumptions about lifetime of the plant, plant efficiencies, fuel used, economy-wide EIs, and energy generated by the plant.

Studies were selected that covered the emissions from the technologies identified in Table 2. As with the cost data, only literature produced in the last 10 years is included (see Table 3). Emission intensity data from each study are standardised to kg CO_2eq/MWh.

2.4. External costs not related to GHG emissions

Although not central to the paper's purpose, an assessment was also made of the external costs. The damage attributable to climate change of GHG emissions is one such external cost, or externality, associated with electricity generating technologies. Putting a price on such emissions creates the incentive to switch to technologies with lower emissions. This 'carbon price' represents one of the costs that must be paid by the generator and can properly be included in LCOE calculations. There are other externalities associated with every generating technology that are not connected with climate change or GHG emissions. Such externalities include, for example, costs arising from direct damage to the environment, to human health, to structures and to crops, and from loss of amenity due to noise and visual intrusion [19]. Sophisticated methodologies employing full life-cycle assessments have been developed for putting monetary values on such costs (e.g. [20,21]) but they remain inherently uncertain. In any event, such values cannot be included directly in the LCOE methodology until a generating technology introduces new steps to remove or reduce the source of, or otherwise pay for, a damage cost.

It is nevertheless useful to have a side-by-side comparison between LCOEs and non-GHG external costs because these external costs give some idea of what might need to be spent to avoid or repair damage caused by a technology. The external cost data we use here are taken from a recent summary of the extensive work of the European ExternE and NEEDS (New Energy Externalities Developments for Sustainability) projects [22]. These non-GHG damage costs are site-specific and strictly speaking refer only to Europe where they were derived. These costs are included as an indication only and are not an exhaustive assessment. All costs are converted to US dollars in the base pricing year and then adjusted for the US CPI to bring the costs to 2009 US dollars.

2.5. Uncertainty assessment on costs and GHG emissions

A simple approach to quantifying uncertainty was taken, whereby the values for LCOE and LCA (after standardisation to 2009 US dollars and common energy units) were averaged across all studies listed in Tables 2 and 3, where figures existed for a given technology. The 90% confidence intervals around the mean were then calculated using the 5th and 95th percentiles of 1000 bootstrap iterations of these data [23], with resampling implemented in Program *R* v2.10 (http://www.r-project.org).

Table 3
LCA literature with technologies covered.

Source	Year	Nuclear	PF coal with CCS	IGCC with CCS	CCGT with CCS	Solar thermal
Gagnon et al. [56]	2001	Y				
Meier [57]	2002	Y				
WEC [11]	2004	Y	Y	Y	Y	
Tokimatsu et al. [58]	2004	Y				
NREL [48]	2004		Y		Y	
Audus and Freund [59]	2004			Y		
ExternE-Pol [20]	2005	Y				
Succar et al. [30]	2006			Y		
ISA [60]	2006	Y				
Lechón et al. [61]	2006					Y
IPCC [52]	2006		Y	Y	Y	
Weisser [18]	2007	Y	Y		Y	
MIT [54]	2007		Y	Y		
NEEDS [25]	2008					Y

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Table 4
LCOE study results (2009 US$/MWh).

Study	Year	PF coal without CCS	IGCC without CCS	CCGT without CCS	Nuclear FOAK	Nuclear Est.	PF coal with CCS	IGCC with CCS	CCGT with CCS	Solar thermal
NREL [24]	2003									121
MIT [46]	2003	50		49	80	63				
Tarjanne and Luostarinen [47]	2003	38		43		35				
NREL [48]	2004	49	67	33			85	86	51	
UOC [49]	2004	43		46	82	45	101		73	
RAE [50]	2004	52	66	46		48				
San Diego [51]	2005									124
Succar et al. [30]	2006		50					68		
IPCC [52]	2006	55	56	44			87	74	64	
ANSTO [53]	2006	32		34	53	37				
MIT [54]	2007	52	56				84	71		
NEEDS [25]	2008									169
MIT [55]	2009	64		67	87	68				
IEA/NEA [14]	2010	49		78		79	73			
EIA [12]	2010	97	107	80	116			125	110	246
Median		52	66	52	84	54	86	84	75	165

3. Results

3.1. Electricity cost

Table 4 and Fig. 1 show the standardised LCOE results from each study for the FFS technologies shown in Table 2, as well as existing carbon-intensive baseload technologies pulverised coal, IGCC coal and CCGT. The median and the 90% confidence interval for the LCOE of each baseload technology are illustrated in Fig. 1.

Two of the solar thermal studies (NREL [24], NEEDS [25]) suggested that costs for solar thermal electricity would fall over time to the extent that the LCOE could halve by 2020. However, the 2003 NREL report projected LCOEs for 2007 that were all significantly below the actual NEEDS figures for 2008, which underlines the uncertainty in such projections.

There was substantial variation between the studies for all technologies in Table 4, for the reasons discussed in Section 2.2. The cross-study variations are greatest in the newer technologies such as IGCC and solar thermal, where plant experience is relatively low and plant specification is less certain. A similar observation can be made about CCS. Solar thermal costs can vary depending on the solar field size, the amount of thermal storage and gas backup and assumed capacity factor.

3.2. Emission intensity

Table 5 shows the standardised LCA emission intensity results from each study for the FFS technologies shown in Table 3. The median EI (with 90% confidence intervals) for each technology is illustrated in Fig. 2.

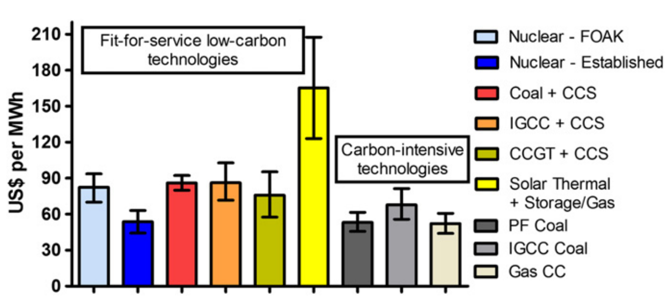

Fig. 1. Levelised cost of electricity (LCOE) for baseload electricity generating technologies. Error bars represent 90% confidence intervals for the mean (bar height).

For comparison with existing baseload technologies, coal plants without CCS have EIs between 762 and 1070 kg CO_2eq/MWh and gas plants without CCS have EIs between 367 and 577 kg CO_2eq/MWh (see Table 5). These results show that CCS can, in principle, reduce coal emissions per unit of energy delivered by approximately 80% and gas emissions by approximately 60%.

All EIs for low-carbon baseload plants are less than 250 kg CO_2eq/MWh. However only nuclear power was able to deliver the 2050 average target EI of less than 70 kg CO_2eq/MWh (see Section 1.2 for explanation). Of the FFS technologies, nuclear has the lowest EI by a factor of about six.

Solar thermal emissions will be lower with greater solar field, more storage and less reliance on gas backup support. Only two of the studies reviewed cover baseload solar thermal and both assume heat storage and gas backup.

3.3. Electricity costs variation with carbon price

Introducing a carbon price increases the LCOE by the carbon price per tonne of CO_2eq multiplied by the EI of the technology expressed in tonnes.[4] Obviously electricity costs will increase with carbon price, which is expected to rise progressively to above $75 per tonne of CO_2eq by 2030 and exceed $150 per tonne of CO_2eq by 2050 as emission reduction targets are tightened [26].

Because of differences in EI, a carbon price affects the cost of each technology differently and changes their relative competitiveness, as illustrated in Fig. 3. Established nuclear technology stays as the lowest cost at any carbon price, and its relative competitiveness vis-à-vis other FFS technologies improves as the carbon price rises. All three CCS technologies are the next most competitive, but their relative competitiveness varies as the carbon price rises, with IGCC becoming the least-cost CCS technology once the carbon price has risen above ~$140 per tonne of CO_2eq.

Solar thermal is currently the most expensive of any of the low-carbon baseload technologies at any carbon price, and would remain more expensive than established nuclear even if its costs could be

[4] A generator will generally pay a carbon cost based on the fuel or 'stack' emissions, not on the full life-cycle emissions which includes other stages such as construction and decommissioning. The emissions cost for these other stages will typically be included in the cost of these stages so will impact the LCOE. For fossil-fuel generators the fuel emissions are a substantial part of the total life-cycle emissions. According to WEC 2004, coal fuel emissions are between 92 and 99% of the total and gas between 81 and 85% [11]. We have used the LCA emission intensity in this calculation.

Table 5
LCA emission intensity study results (kg CO_2eq/MWh).

Study	Year	PF coal without CCS	IGCC without CCS	CCGT without CCS	Nuclear	PF coal with CCS	IGCC with CCS	CCGT with CCS	Solar thermal
Gagnon et al. [56]	2001	960		443	15				
Meier [57]	2002	974		469	18				
WEC [11]	2004	933	795	437	16	247	130	245	
Tokimatsu et al. [58]	2004				13				
NREL [48]	2004	847		499		247		245	
Audus and Freund [59]	2004		763				142		
ExternE-Pol [20]	2005	1070		423	8				
Succar et al. [30]	2006		869				193		
ISA [60]	2006	863		577	60				
Lechón et al. [61]	2006								196
IPCC [52]	2006	762	773	367		112	108	52	
Weisser [18]	2007	1004		543	10	136		136	
MIT [54]	2007	830	832			109	102		
NEEDS [22]	2008								161
Median					20	170	134	169	179

halved (see Section 2.2). STE is still more expensive than PF coal without CCS below a carbon price of $140. Minimising the use of gas in STE plants through larger solar fields and more thermal storage will reduce the impact of carbon price on STE generating costs but increase the capital and maintenance costs. In sum, STE seems unlikely to become cost competitive with nuclear (see Section 4.3).

3.4. External costs

The external costs not related to GHG emissions are shown in Fig. 4. As already noted, such costs are uncertain, but due to lack of data, no attempt is made here to indicate their confidence limits. External costs for plants with CCS are based on modelling studies rather than real-world experience, adding further uncertainty.

As can be seen from Fig. 4, non-climate external costs are small or negligible compared with LCOEs and would make little if any material difference to total costs if fully internalised. The biggest cost increases, around 20% with these data, would occur with the coal-based CCS technologies. Non-climate impacts do have an influence on public perception of technology acceptance. This is particularly the case for nuclear power, where safety and security issues and long-term waste storage are perceived as significant environmental risks and potentially significant financial costs. The degree to which these costs might increase the small external cost for nuclear illustrated in Fig. 4 is debatable. Nuclear LCOEs already include costs for waste disposal, decommissioning of the plant, and safety regulations [27].

4. Discussion

Electricity generation is widely discussed in the context of reducing GHG emissions. These discussions can involve specific technologies such as renewable energy sources as well as the need for greater efficiency leading to electricity demand reduction. Sometimes these discussions are biased towards a specific solution or are misleading, and can involve over-optimistic assessments of what is possible. We explore some of these issues here.

4.1. Lowest cost and lowest EI both critical in power generation

Electricity costs impact upon productivity growth, so generating costs need to be kept to a minimum (see Section 1.3). As can be seen from the data in Table 4, the more recent studies show increases in LCOE (excluding any carbon price) which exceed the rise in the CPI over the same period. This might suggest an escalation in future electricity prices over and above any increase from carbon pricing. Increasing costs will slow down the deployment of new low-carbon power plants and risk compromising our ability to achieve the 2050 emission reduction target (see Section 1).

Electricity power generation is the largest single contributor to global GHG emissions (see Section 1.1), so reducing emissions from power generation is critical to reducing total world-wide emissions. Emissions from power plants are a product of electricity demand on the plants and average EI of the plants. Reducing plant EI and/or power demand will reduce plant emissions.

4.2. Net world-wide power demand likely to rise

According to the UN, world population is expected to grow by a third, to over 9 billion by 2050, with the largest increases in the developing regions of Africa and Asia [28]. Only Europe is expected to have a reduced population by 2050. Per capita consumption can be expected to grow in most parts of the world but particularly in the developing regions. This will inevitably lead to increases in global energy consumption particularly electricity.

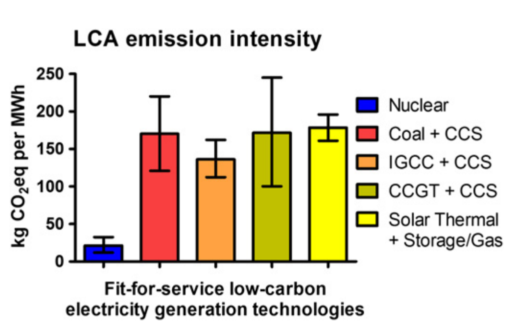

Fig. 2. Emission intensity for fit-for-service baseload electricity generating technologies. Error bars represent 90% confidence intervals for the mean (bar height).

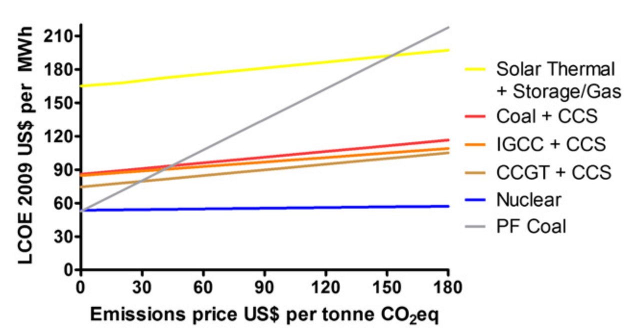

Fig. 3. Impact of carbon pricing on levelised cost of electricity (LCOE) for FFS low-emission baseload technologies.

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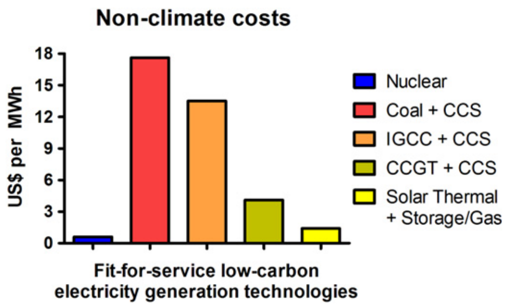

Fig. 4. Non-climate-related costs for FFS low-emission baseload technologies.

The electrification of transport (see Section 1.1) and the manufacture of synthetic fuels over the next few decades will place further demand on electricity supply, particularly in developed countries. The demand for fresh water to supply the growing population using electrodialysis desalination plants will further increase the demand for electricity in many regions.

Efficiency improvement in many areas of electricity use will help to offset some of this increasing demand but it is unlikely to fully compensate for it [6]. In short, there is no prospect that GHG targets can be met by reduced power consumption.

4.3. Greater than 40% use of variable renewable energy (RE) unlikely

Based on the criteria identified in Section 2.1, variable[5] RE sources will not replace significant baseload generating capacity in most parts of the world. In many developed countries, electricity networks assign variable RE sources such as wind and solar with a capacity credit[6] of less than 10% [29], so they are not considered as reliable baseload generators.

The development of large-scale electricity storage systems may be able to increase the capacity credits for variable RE sources by storing energy that would otherwise be surplus to requirements. The stored energy can be released at a future time to meet the electricity demand. Only two large-scale storage systems are currently considered commercial grade: pumped hydro storage (PHS) and compressed air energy storage (CAES). Both these systems require particular geological environments which are not available everywhere and not readily scaled to provide sufficient storage to make a significant contribution to baseload supply at a reasonable cost. A recent study of wind-CAES systems found them not to be cost competitive with IGCC/CCS until the carbon price had reached $100/tonne of carbon eq (equivalent to $367/tonne of CO_2eq) [30]. Such a high carbon price is not expected before 2050 (see Section 3.3).

4.4. Need for sustainable energy

Technologies that rely on energy sources mined from the earth are commonly not considered to be sustainable. This is the case for both coal and gas, as well as the uranium used in current nuclear power plants. Uranium proven reserves are around 5 million tonnes (recoverable at less than $130/kg) and will last 70 years at current use [31]. Current estimates of potentially economic uranium resources exceed 35 million tonnes [32]. Coal proven reserves will last around 120 years and gas proven reserves will last 60 years at today's level of use [33].

There is no clear definition of what constitutes sustainable energy, but it seems likely the current use of fossil fuels and uranium would fail any reasonable test of sustainability. The total resources will almost certainly be significantly greater than the proven reserves but they will still not be sustainable indefinitely.

Both coal- and gas-fired electricity are close to maximum conversion efficiency, so technology improvements are unlikely to significantly extend the life of coal and gas reserves. Uranium conversion, on the other hand, is relatively inefficient with less than one percent of the usable uranium energy actually being converted to electricity. Generation IV reactors (both fast spectrum and thorium-fuelled molten salt designs) will substantially increase this efficiency and are expected to be commercially available long before the depletion of uranium resources. It has been estimated that nuclear fission fuel will in effect be 'inexhaustible' if used in fast nuclear reactors [34].

4.5. Low EI target by 2050 requires nuclear, or else a new technology breakthrough

The EI target of below 50 kg CO_2eq/MWh by 2050 (see Section 1.1) will demand a substantial shift to low-carbon generating technology. Many RE technologies can deliver a low EI, but few can currently make a substantial contribution to the total electricity supply (see Section 4.3). Technology breakthroughs, coupled with substantial price reductions, would be needed to deliver cost-effective large-scale energy storage. This seems unlikely given inherent physical limits (e.g. energy density) of chemical and thermal storage.

The use of carbon capture and storage (CCS) cannot currently address the 2050 EI target with existing capture and sequestration efficiencies. It can address the 2030 target (see Section 1.1), so could provide a transition solution, but it is unlikely to be the major baseload source by 2050 without significant technological breakthroughs.

It may be possible in some countries to address low-carbon baseload requirements by increased use of hydro and conventional geothermal. As noted earlier, these both require specific geological environments that are not available everywhere. Biomass using farmed fuel may also provide some low-carbon baseload but the extensive land resources needed restrict its utility [35].

Solar thermal needs substantial cost reduction for significant adoption. It requires high insolation to be effective (ideal regions are subtropical deserts), and thus often will be located far from load centres, thereby incurring additional transmission costs. Transmission costs for large loads over long distances can be significant [36] and are generally not factored into existing LCOE assessments.[7] Engineered geothermal system costs are difficult to assess given the current immature stage in its technology development. MIT has performed one study that suggests that established commercial wells will still be more expensive than nuclear and require additional transmission costs in most locations [37].

An objective review of the existing authoritative literature demonstrably supports the conclusion that today current generation nuclear power is the only proven baseload technology that can deliver the EI target needed for effective climate change mitigation.

[5] Variable means the energy output varies with time not related to variance in load.

[6] Capacity credit or capacity value is the amount of 'guaranteed' capacity that a generator can contribute to system reliability. This is not to be confused with capacity (or load) factor which is the ratio of the actual energy output from the generator over a year to the output it would produce if it operated non-stop at full capacity.

[7] An exception is the recent EIA report which identified transmission costs [12].

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4.6. Review needed of nuclear regulations

For historical reasons, the building of new nuclear power stations is a heavily regulated process which extends construction time and increases costs. This is especially the case in the EU and North America. The nuclear industry is moving to plant pre-fabrication to address some of these issues, but long delays in licensing still slow down construction [38,39]. Finance for new nuclear installations often demands a higher interest rate than for fossil-fuel plants. High interest rates can have a significant impact on the LCOE (see Section 2.2). The LCOE is approximately doubled when the required interest rate is doubled [40]. A level playing field is required where equal financial assistance is provided to all technologies to allow them to compete on their merits and not be handicapped by community biases that are not supported by objective analysis (see Section 3.4).

There is a need to address the social and political issues that disadvantage nuclear power. The British government announced in late 2009 that it would approve the building of 10 new nuclear plants as well as speeding up planning decisions on new energy projects aimed at cutting decisions to one year [41].

4.7. Some recent examples of nuclear costs

Nuclear power is being most actively pursued today in China (23 reactors currently under construction), India (4), South Korea (6) and Russia (8) [31]. In terms of forward projections through to 2020, China plans to expand its nuclear generation capacity to 70 GW (up from 8.6 GW in 2010), South Korea to 27.3 GW (up from 17.7 GW), and Russia from 43.3 GW (up from 23.2 GW). Looking further ahead, India's stated goal is 63 GW by 2032 and 500 GW by 2060 [42], whilst China's 2030 target is 200 GW, with at least 750 GW by 2050 [17]. These nations are heavily focused on rapidly overcoming FOAK costs and establishing standardised designs based around modular construction and passive safety principles. By contrast, the country with the most installed nuclear power – the United States, with over 100 commercial reactors – has announced loan guarantees to support new plants, but has not yet started construction of any Generation III reactors.

It is therefore in the rapidly developing Asian countries that current real-world costs can be most reliably established. The two leading reactor designs now being built in China are the indigenous CPR-1000 and the Westinghouse AP-1000. Reported capital costs are in the range of $1296–$1790/kW [43]. Korea has focused attention on its APR-1400 design, with domestic overnight costs of $2333/kW [44]. A recent contract for $20.4 billion has been signed with Korean consortium KEPCO to build four APR-1400 reactors in the United Arab Emirates, at a turnkey cost of $3643/kW. This price is notable considering that it is offered under near-FOAK conditions, because these will be the UAE's first nuclear plants.

5. Conclusions

To address the cause of anthropogenic climate change, we must aim to uncouple energy production from greenhouse gas emissions [45]; this requires using only low-carbon technologies for baseload electricity generation. Here we have shown how a systematic approach can be used to identify and qualify potential technologies that are able to supply fit-for-service electricity in sufficient quantities to replace existing fossil-fuel plants (Table 1). There is an abundance of authoritative energy literature on the costs and emission intensities of each of the qualifying technologies (Tables 2 and 3); these are the focal studies of this meta-review (see Section 2.5). We have also assessed the impact of carbon pricing on the relative costs of the qualified technologies to see how cost competitiveness changes with the anticipated progressive increase in carbon price (Fig. 3).

Our meta-review of the authoritative energy literature shows that the technology options for replacing fossil fuels, based on proven performance and reliable cost projections, are much more limited than is popularly perceived. An objective analysis of these data shows nuclear power to be the standout solution for low-emissions baseload electricity, in terms of cost and ability to meet the timetable for GHG abatement. Further, nuclear power's relative competitiveness increases as the carbon price rises.

Of the other candidate technologies, solar thermal is, by comparison, the least competitive, and there is no clear evidence that its costs will compete with nuclear, even in the long term. Further, depending on CCS technologies delivering the desired emissions outcome by 2050 is a risky strategy at this stage of their development. Renewable energy technologies are unlikely to be able to supply the majority of electricity for most regions at reasonable cost, particularly in the urgent timeframe required for effective climate change mitigation.

Appendix. Nomenclature

Abbreviation	
CAES	Compressed air energy storage
CCGT	Combined cycle gas turbine
CCS	Carbon capture and storage
CO_2	Carbon dioxide
CO_2eq	Carbon dioxide equivalent
CPI	Consumer price index
EGS	Engineered geothermal systems
EI	Emission intensity
EIA	The U.S. Energy Information Administration
EU	European Union
FFS	Fit-for-service
FOAK	First-of-a-kind
GHG	Greenhouse gas emissions
GW	Gigawatt
IEA	International Energy Agency
IGCC	Integrated gasification combined cycle
IPCC	Intergovernmental Panel on Climate Change
LCA	Life-cycle assessment
LCOE	Levelised cost of electricity
MIT	Massachusetts Institute of Technology
MWh	Megawatt hour
NEEDS	New Energy Externalities Developments for Sustainability
NREL	The U.S. National Renewable Energy Laboratory
PF Coal	Pulverised fuel black coal
PHS	Pumped hydro storage
STE	Solar thermal electricity
UAE	United Arab Emirates

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