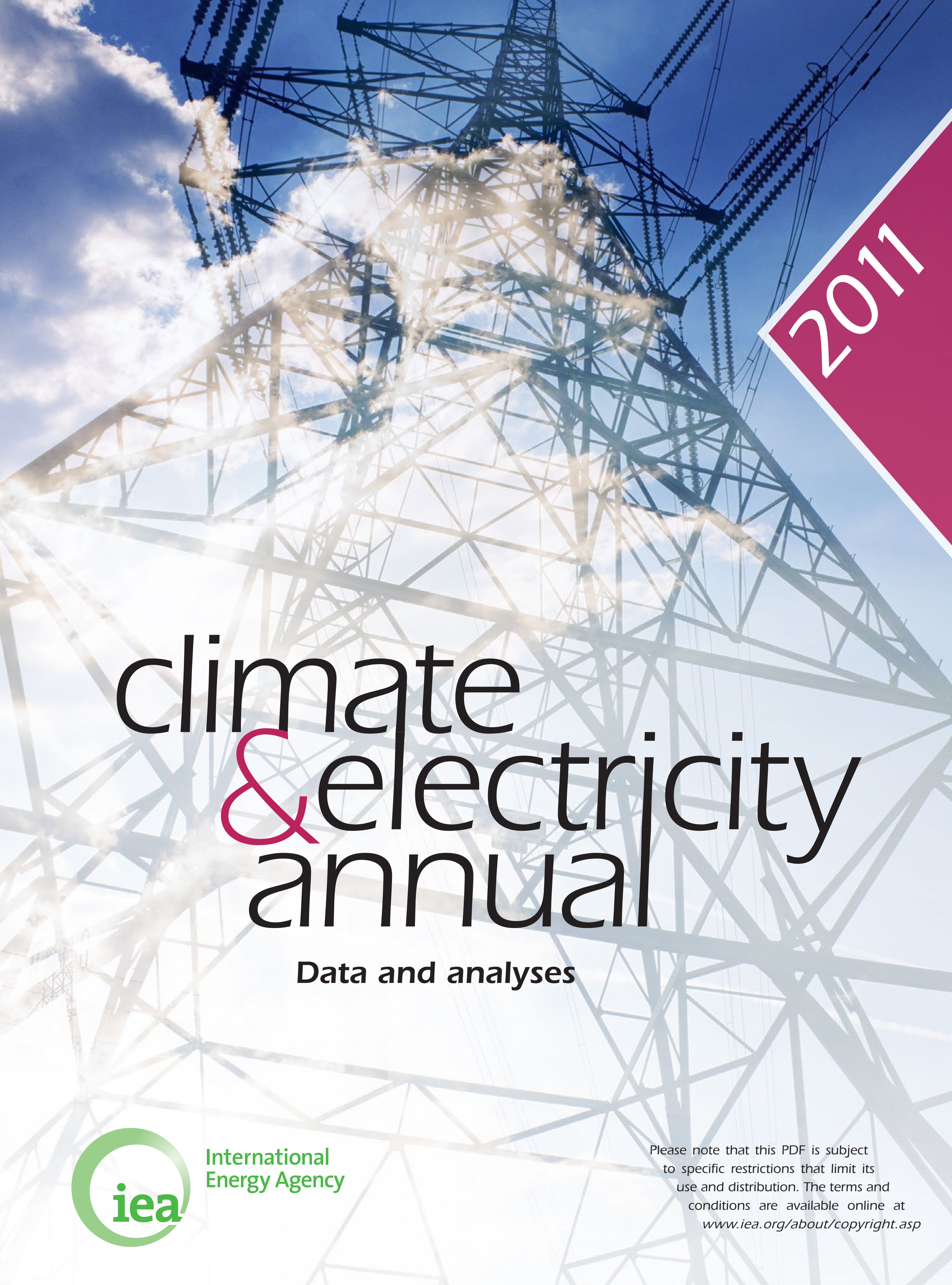

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Electricity use is growing worldwide, providing a range of energy services: lighting, heating and cooling, specific industrial uses, entertainment, information technologies, and mobility. Because its generation remains largely based on fossil fuels, electricity is also the largest and the fastest-growing source of energy-related CO_2 emissions, the primary cause of human-induced climate change. Forecasts from the IEA and others show that "decarbonising" electricity and enhancing end-use efficiency can make major contributions to the fight against climate change.

Global and regional trends on electricity supply and demand indicate the magnitude of the decarbonisation challenge ahead. As climate concerns become an essential component of energy policy-making, the generation and use of electricity will be subject to increasingly strong policy actions by governments to reduce their associated CO_2 emissions. Despite these actions, and despite very rapid growth in renewable energy generation, significant technology and policy challenges remain if this unprecedented essential transition is to be achieved.

The IEA Climate and Electricity Annual 2011 provides an authoritative resource on progress to date in this area, with statistics related to CO_2 and the electricity sector across ten regions of the world. It also presents topical analyses on meeting the challenge of rapidly curbing CO_2 emissions from electricity, from both a policy and technology perspective.

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International Energy Agency

INTERNATIONAL ENERGY AGENCY

The International Energy Agency (IEA), an autonomous agency, was established in November 1974. Its primary mandate was – and is – two-fold: to promote energy security amongst its member countries through collective response to physical disruptions in oil supply, and provide authoritative research and analysis on ways to ensure reliable, affordable and clean energy for its 28 member countries and beyond. The IEA carries out a comprehensive programme of energy co-operation among its member countries, each of which is obliged to hold oil stocks equivalent to 90 days of its net imports. The Agency's aims include the following objectives:

- Secure member countries' access to reliable and ample supplies of all forms of energy; in particular, through maintaining effective emergency response capabilities in case of oil supply disruptions.
- Promote sustainable energy policies that spur economic growth and environmental protection in a global context – particularly in terms of reducing greenhouse-gas emissions that contribute to climate change.
- Improve transparency of international markets through collection and analysis of energy data.
- Support global collaboration on energy technology to secure future energy supplies and mitigate their environmental impact, including through improved energy efficiency and development and deployment of low-carbon technologies.
- Find solutions to global energy challenges through engagement and dialogue with non-member countries, industry, international organisations and other stakeholders.

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Finland
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The European Commission also participates in the work of the IEA.

International Energy Agency

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Foreword

The threat of climate change and the need to curb global greenhouse gas emissions has become a defining factor of energy policy. In spite of the sometimes disappointing pace of international negotiations, and also recent developments in nuclear policy and gas markets which are likely to increase the use of fossil fuels, advances in the development and deployment of renewable energy technologies, smart grids, carbon capture, energy efficiency, and other technologies are encouraging signs on the road to a low-carbon economy.

An effective response to climate change requires policy, technology, business and behavioural changes across all energy producing and consuming activities. Electricity production and its use are emblematic of the climate challenge. On one hand, electricity can effectively meet a growing demand for more efficient services, such as in personal mobility where electric vehicles are set to play an important future role. On the other hand, power generation has been the greatest contributor to the increase in global CO_2 emissions over the past two decades, in spite of the rapid growth of renewable energy sources. Both *World Energy Outlook* and *Energy Technology Perspectives* scenarios show that deep cuts in global CO_2 emissions require the decarbonisation of electricity generation, combined with a growing penetration of electricity in a range of end-uses.

Climate & Electricity Annual 2011: Data and analyses intends to shed light on multiple aspects of this issue, including an objective look at current trends in electricity. These confirm the need for an intense effort to curb the CO_2 intensity of electricity generation. Now is the time for enhanced policy action to drive change. The publication therefore includes individual papers that address current debates, shed light on technology solutions, and pose pressing policy questions about the decarbonisation of power generation. They are based on the latest IEA work across the whole of the electricity sector. It is my hope that this first *Climate & Electricity Annual 2011* will contribute to a better knowledge across both electricity and climate policy communities about the challenges ahead, and to more effective and integrated responses.

The *Climate & Electricity Annual 2011* is published under my authority as Executive Director of the IEA.

Nobuo Tanaka

Executive Director

International Energy Agency

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Introduction

Richard Baron, Climate Change Unit

Electricity is unique when it comes to meeting the climate-change challenge: as the largest and fastest growing source of carbon dioxide (CO_2), it also holds many of the solutions to a more efficient, less carbon-intensive economy. **Climate & Electricity Annual 2011: Data and analyses** ***provides authoritative regional and global data on the evolution of the sector to date and presents original analyses on how policy and technology can address the problem of rising CO_2 emissions associated with the demand for electricity services. With this publication, the IEA seeks to raise the profile of electricity in the climate-change challenge, focus decision makers and the whole range of stakeholders on timely, pressing issues in the electricity sector and encourage the bottom-up actions needed to put the world on a path to a secure and low-carbon energy system.***

Climate, energy and electricity

In Cancún last year, the 192 countries gathered under the United Framework Convention on Climate Change (UNFCCC) agreed to continue the multilateral effort to fight against human-induced climate change. In support of this effort, they also set the environmental goal of keeping the global temperature increase below 2 degrees Celsius (2°C).

With energy-related CO_2 representing the majority of global greenhouse gas emissions, the implications for the energy sector are daunting, as illustrated by the IEA *World Energy Outlook 2010* scenarios. Meeting the emission goals currently pledged by countries under the UNFCCC would still leave the world some 13.7 billion tonnes of CO_2 – or 60% – above the level needed to remain on track with the 2°C goal in 2035 (Figure 1). This path is not sustainable. Much additional investment will need to be directed towards lower-CO_2 technologies, on supply and end-use sides alike. The benefits that society would reap from these measures, beyond avoided climate risks, would be of an equal if not larger magnitude than the cost to the energy sector:

- **Lower exposure to fossil-fuel security risks.** Always high on the international agenda, security is a special concern this year with rising oil prices and turmoil in the Middle East and North Africa.

- **Lower overall energy costs for our economies.** Fuel savings will, in the long term, more than compensate for the capital cost of more efficient and clean technologies.

- **An improved local environment** with lower emissions of SO_2, NOx, and particulate matter from fossil fuels, especially in developing countries. Achieving climate goals could save as many as 750 million life-years, compared to a scenario where no new action is taken to cut CO_2 emissions (IEA, 2010b).

However significant these benefits and the expected impacts of climate change may be, they are still outweighed by business-as-usual energy practices, insufficient policy signals, and the inertia of our energy systems. Yet IEA scenarios show that a rapid transition within the global energy system is both necessary and achievable, even if every passing year increases the cost and reduces the feasibility of reaching a 2°C emissions trajectory.

The IEA low-carbon energy scenarios

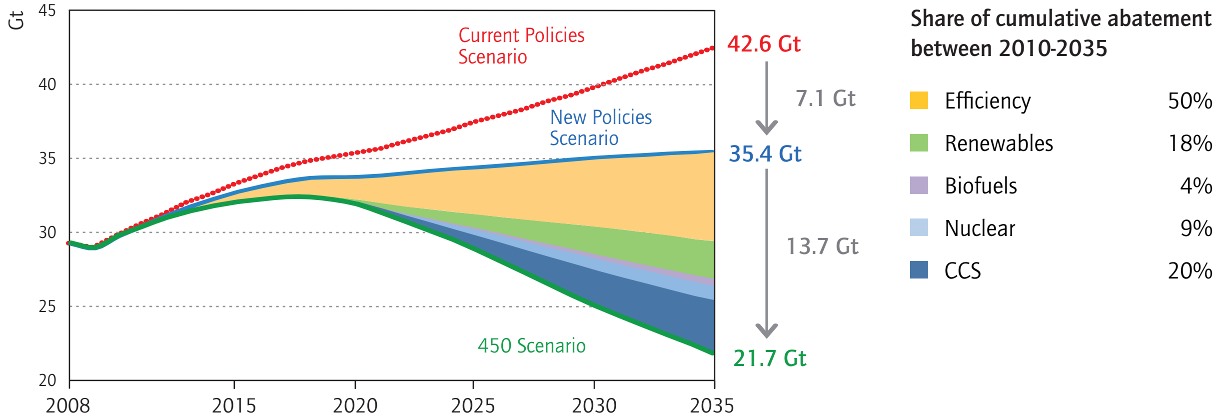
The IEA produces two sets of global energy projections that frame the discussions of much of the analyses in the Climate & Electricity Annual 2011*:*

- *The* World Energy Outlook 2010 *(***WEO 2010***) scenarios to 2035, especially the* **New Policies Scenario***, which provides a realistic view of efforts to date and greenhouse gas emissions reduction goals pledged by countries in the UNFCCC, and the* **450 Scenario***, which indicates policies and technologies needed to remain on track with the 2°C goal (IEA, 2010b).*

- Energy Technology Perspectives 2010 *(***ETP 2010***) extends the time horizon to 2050, with further detail on the technological developments necessary to bring energy-related CO_2 emissions to half their current levels by 2050. This low-carbon scenario, BLUE Map, is complemented by scenario variants focused on the electricity sector: without carbon capture and storage, with a higher contribution of nuclear, a higher contribution of renewables, or a lower discount rate (3%, against 8% to 14% in BLUE Map).*

Figure 1

World energy-related CO_2 emission savings by technology in the IEA *World Energy Outlook 2010* 450 Scenario relative to the New Policies Scenario*



** The 450 Scenario describes an evolution of the global energy systems consistent with the 2°C goal, through limitation of greenhouse gas concentration to around 450 parts per million of CO_2 equivalent. The New Policies Scenario reflects national energy plans and pledges made by countries, including on their future emissions of greenhouse gases.*

Source: IEA, 2010b.

Among all energy activities, the electricity sector, from generation to a myriad of end uses will play a central role in reaching climate-change goals. With 11 gigatonnes (Gt) of CO_2 emitted in 2008, electricity generation is the largest CO_2 source in the energy sector. With a 65% increase since 1990, it is also the fastest growing CO_2 emitter.

Figure 1 shows that much of the solution to rising CO_2 emissions can be found in the electricity sector: end-use efficiency (from fossil-fuel plants to electric appliances), renewable sources of electricity, nuclear and carbon capture and storage – these supply-side solutions alone can bridge 47% of the emissions gap to reach the 450 Scenario of *WEO 2010*. How these technologies will eventually be used hinges on a number of policy assumptions; the response to the recent nuclear accident in Fukushima demonstrates how unexpected events will affect, negatively or positively, global efforts to cut CO_2 emissions from the energy sector. The nuclear accident in Japan will no doubt trigger more analyses on alternative routes to cut CO_2 if some countries decide to lower the contribution of nuclear electricity in the coming years.

Today, the world's appetite for electricity seems endless – even if the year 2009 showed a dip in electricity demand for the first time in decades, largely as a result of the global recession. Electricity provides services of great versatility, often at higher energy efficiency and lower cost than oil products, natural gas or coal: the end-use efficiency gains can be such that they compensate for the losses in transforming fossil fuels into electricity and transmitting it to the consumer.

It meets basic needs, from refrigeration to lighting, and fuels billions of electric devices from computers to new entertainment technologies that were unimaginable two decades ago (IEA, 2009). Electricity could also make significant inroads into the market share of oil in the transportation sector, according to IEA climate-friendly scenarios.

The remarkable consensus among most energy experts and economists on the role of electricity in counteracting human-induced climate change leads to the following assumptions:

- Power generation needs to be "decarbonised" – be produced without net CO_2 emissions – by the second half of this century.
- The simultaneous use of enhanced electricity in all energy services will increase overall energy efficiency, a major contribution to cutting CO_2 emissions.[1]

The required transformation, whether it is measured in new low-carbon generation capacity, in electricity savings on the end-use side, in the number of electric vehicles deployed, or in the hundreds of billions of dollars that must be spent to transform power generation globally, is nothing short of enormous.

1. The International Electricity Partnership, comprising the electricity industries in Australia, Canada, Europe, Japan, Latin America and the United States, stated that "the necessary global reductions can be achieved by 2050 through the simultaneous decarbonisation of electricity and the electrification of the domestic, commercial and transport sectors when combined with significant improvements in energy efficiency" (IEP, 2010).

Unlike what the term suggests, this energy 'revolution' will not happen spontaneously. It requires strong policy signals, new approaches to encourage investments, and ways to put long-term energy goals on the agenda of decision makers for action today.

Three scenarios for a common goal

In March this year, the European Commission released a *Roadmap for Moving to a Competitive Low-Carbon Economy in 2050*, indicating milestones towards cutting its greenhouse gas emissions by 80% to 95% from 1990 levels by 2050 (EC, 2011). The implications for power generation concur with earlier projections, including those in the IEA *ETP 2010*: CO_2 from electricity would be cut by 93% to 99% if the European Union were to achieve an 80% reduction in total greenhouse gas emissions. In the IEA BLUE Map scenario, the whole power generation sector of OECD Europe in 2050 would emit a mere 74 million tonnes of CO_2, equivalent to one-fifth of Germany's power sector emissions in 2008 (EC, 2011).

This official EC report was preceded by two independent scenario analyses: *Power Choices*, a publication by Eurelectric, the European association of the electricity industry (2010), and *Roadmap 2050*, a set of projections authored by the European Climate Foundation (2010). While one can be struck by the unanimity with which these two organisations, along with the IEA, foresee the development of power generation under a carbon constraint (*i.e.* the decarbonisation agenda), differences in the scenarios illustrate some of the strategic choices ahead.

Table 1

Total investments for a decarbonised electricity sector in Europe

Power Choices	Roadmap 2050*	ETP 2010
EUR 3.25 trillion	EUR 2.9 trillion	USD 4 trillion (~EUR 2.8 trillion)

** Scenario with 60% electricity generated from renewable sources.*
Sources: Eurelectric, 2010; European Climate Foundation, 2010; IEA, 2010a.

Power Choices reflects one view on potential future capacity developments in Europe, *e.g.* by assuming the phase-out of nuclear energy in Germany and Belgium. *Roadmap 2050* follows many of the framework assumptions of *WEO 2010*, and envisions three scenarios with 40%, 60% or 80% of total electricity output being supplied by renewables, with much emphasis on the critical role of electricity transmission to smooth the effects of supply variability from the significant wind and solar capacities.[2]

Additional transmission could allow Europe to fully exploit its renewable energy potential: using wind resources when solar output is low, and vice versa, both on an annual or daily basis. In the *Roadmap 2050* scenario with a 60% share of renewables, 102 gigawatts (GW) of additional transmission capacity would be required by 2050 – compared with 2 GW in their baseline scenario. 240 to 325 GW of thermal capacity would be required for balancing and back-up in the same scenario, in contrast with about 200 GW in *Energy Technology Perspectives* and *Power Choices*, largely explained by these scenarios' lower reliance on renewables (55% and 40% respectively).[3] A higher reliance on renewables must be accompanied by increased investment in transmission and extra back-up capacity.

As in many long-term projections, some main assumptions differ: while *Roadmap 2050* and *Power Choices* foresee a sustained growth in power demand, *ETP 2010* BLUE Map scenario projects a rather modest 19% growth in electricity demand between 2007 and 2050, the result of massive efforts in end-use efficiency; under the *ETP 2010* Baseline scenario, electricity demand would grow by 57%, to 4 800 TWh. The difference is also explained by the growth in electricity demand from the transport scenario, driven by different technology assumptions in these three studies. *Roadmap 2050* chooses a high penetration of 'pure' electric vehicles, whereas *ETP 2010* assumes a larger contribution of so-called plug-in hybrid electric vehicles, which also run on fossil fuels. The Eurelectric *Power Choices* scenario also assumes a large penetration of electric vehicles: by 2050, the total electricity demand from transport would be equivalent to half of Europe's electricity output today (Table 2).

Table 2

Final electricity demand in 2050 for Europe under three low-carbon scenarios

	Power Choices	Roadmap 2050*	ETP 2010
Total electricity demand	4 800 TWh	4 900 TWh	3 600 TWh
Electricity demand in transport	1 520 TWh	800 TWh	360 TWh

** Scenario with 60% renewables in the power mix.*
Sources: Eurelectric, 2010; ECF, 2010; IEA, 2010a.

2. *An additional scenario explores the possibility of relying on solar resources in the northern Sahara Desert.*

3. *211 GW of gas in* Energy Technology Perspectives 2010 *(IEA, 2010a) and 200 GW of gas and oil capacity in Power Choices (Eurelectric, 2010).*

Among the numerous policy assumptions underlying these scenarios for a low-carbon electricity system in Europe, the price put on CO_2 emissions plays an important role in directing investments away from traditional fossil-fueled plants. All three low-carbon scenarios are based on the continuation of the EU Emissions Trading System, but policy strategies differ significantly. In *ETP 2010*, the CO_2 price plays a growing role over the years, while subsidies to alternative low-carbon sources (renewables in particular) are important in the first decades. The assumed price of CO_2 reaches USD 175 per tonne (t) of CO_2 (EUR 120/tCO_2) in 2050. *Power Choices* projects a roughly similar carbon price at EUR 100/tCO_2 – skyrocketing to EUR 300 if efficiency policies were to fail. These levels are in sharp contrast with *Roadmap 2050* which assumes a much more modest EUR 20-30/tCO_2 by 2050. By this point in time, the assumed learning effects and economies of scale in renewable electricity supply will have greatly reduced the cost difference with fossil-fuel technologies. A caveat accompanies this result: *A significantly higher CO_2 price may be required to provide incentives for new investments*. In other words, the price of CO_2 may have to rise before it settles at the level that maintains the competitive advantage of new low-carbon sources; otherwise, additional support measures will be needed in the interim (ECF, 2010). *WEO 2010* illustrates the critical and effective role of renewable energy (RE) subsidies in the period to 2035 under its 450 Scenario, but also shows how the rising price of CO_2 would allow governments to greatly reduce these subsidies (IEA, 2010b).

This raises an important policy question on the design of government measures for the massive deployment of not-yet-competitive technologies, and on their articulation, where possible, with a price on CO_2. Further, the competitiveness of low-carbon technologies probably lies in the future organisation of electricity markets, which should be able to provide adequate returns to high-capital investments with low operating costs. At present, the rapidly increasing share of renewable sources (especially wind) creates volatility in some regional electricity markets, which could discourage future investors in power generation.

This brief comparison of *ETP 2010*, *Roadmap 2050* and *Power Choices* scenarios for a low-carbon European electricity system already raises important energy and climate policy issues; more will no doubt arise from the review of other regions' electricity policy frameworks and approaches to sustainability and electricity security.

About the *Climate & Electricity Annual 2011*

First in a series, the IEA *Climate & Electricity Annual 2011* is intended to serve two purposes:

- To publish authoritative statistics on the current evolution of the power sector from the angle of CO_2 emissions and low-carbon generation.
- To draw the attention of decision makers and others engaged in the electricity and climate world to important policy, technology and analytical issues, based on analyses and findings in new IEA work.

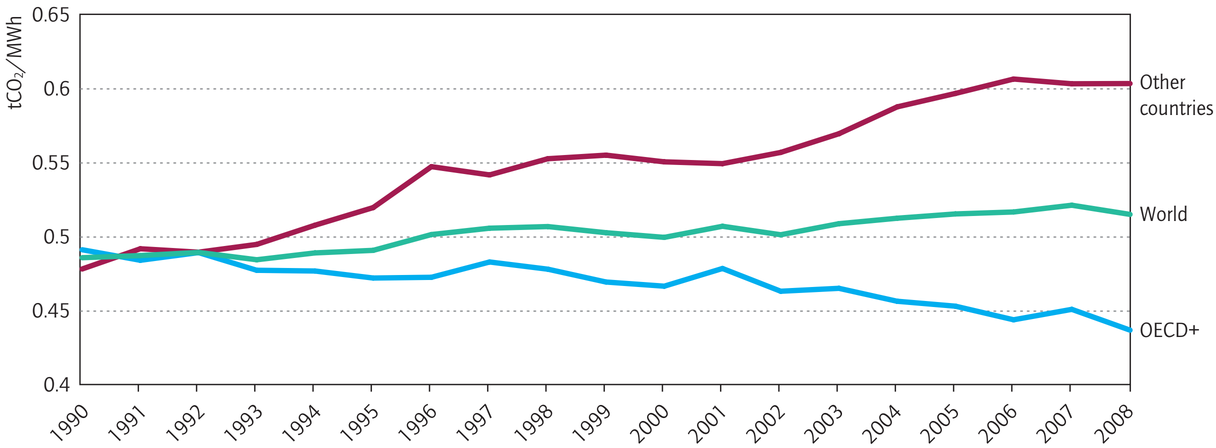
The IEA statistics presented in the Data section are essential to show progress towards a lower CO_2 path—or to sound the alarm on the limited effectiveness of efforts to date. The global trend, until 2008, showed constant increases in electricity demand as well as CO_2 emissions from power generation. The year 2008 represents an anomaly, as the economic recession drove electricity and emissions down in OECD regions and slowed the global growth in electricity demand. As the recession continued in 2009, IEA countries recorded the first decline in electricity consumption in over 50 years, with a 4% drop (IEA Statistics, 2011). But electricity demand grew outside the OECD region, with much coal-based generation capacity driving up CO_2 emissions. Leaving aside a few exceptional years, the amount of CO_2 emitted per megawatt hour of electricity produced has been on an upward trend since 1990 (Figure 2).

Despite these past trends, there is hope for a shift away from this trajectory. The rapid growth in new renewables is particularly promising, even if their total output of 525 terawatt hours (TWh) accounted for only 2.4% of total electricity output in 2008 — hydro generation accounted for another 3 208 TWh. 2009 will, no doubt, show sustained global growth in renewable energy, driven by Chinese investments among others. The data on newly installed, under-construction and planned capacities reveal that changes are on the way in some regions. Yet, other factors continue to raise uncertainty. For example, will the rapid construction of coal-fired power plants witnessed in several countries in recent years continue? Will a postulated "Golden Age" of natural gas in power generation come to pass? How rapidly will carbon capture and storage technologies be developed and become commercially competitive? Will all planned nuclear projects come to fruition? The answers to such questions will have considerable bearing on the pace and cost at which electricity and CO_2 can be decoupled.

To be fair, the inertia of the power sector's capital stock makes last year's output and emissions data only a poor indicator of what may come: a number of new policies and incentives are being implemented to discourage CO_2 emissions from electricity generation, and climate-change mitigation goals are becoming part of energy policy decisions in all regions of the world.

Figure 2

Global evolution of the CO_2 intensity of power generation (1990-2008)



Note: OECD+ includes all OECD member countries as of 2009 and non-OECD European countries (see section on geographical coverage).

Source: IEA statistics, 2011.

In addition to these data, the Analyses part of *Climate & Electricity Annual 2011* edition brings a selection of the latest IEA work, to inform policy and technology debates and to pose important questions on the future decarbonisation of electricity:

- **Electricity market design for decarbonisation** questions whether current electricity markets are the most conducive to investment in low-carbon supply technologies.
- **Funding energy efficiency** discusses the theoretical and practical pros and cons of earmarked environmental taxes versus system-wide public benefit charges to support energy efficiency programmes.
- **Early retirement of coal-fired generation in the transition to low-carbon electricity systems** draws attention to what could become a major policy issue as the world embarks on cutting CO_2 emissions from power generation in the presence of locked-in coal-based capacity.
- **Renewable-energy policy and climate policy interactions** addresses the topical issue of how subsidies to the deployment of renewable electricity hamper or support climate policy goals in the presence of a carbon market.
- **Integrating electric vehicles and plug-in hybrid electric vehicles into the electric grid** details the contribution of EVs and PHEVs to global CO_2 emissions mitigation by 2050, including their impact on electricity-related emissions.
- **Carbon capture in the power sector: from promise to practice** gives an update on this critical CO_2 emissions-mitigation technology, including major demonstration projects, and discusses policy incentives to foster its deployment at scale.
- **Carbon leakage in the European Union's power sector** considers whether the existence of a cap on the EU-27 power generation sector has given competitive advantages to generators in neighbouring countries, at the expense of the European Union's environmental objectives.
- **CO_2 and fuel switching in the power sector** shows how advanced economic analysis provides information on the near-term potential for CO_2 reductions through fuel switching.

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ANALYSES

PART 1

Electricity market design for decarbonisation

Christina Hood, Climate Change Unit

The energy and climate-policy communities are becoming more concerned about the suitability of current wholesale electricity market designs for decarbonisation of the power sector. This discussion is most advanced in the United Kingdom, where the government has announced proposals for significant market reform. Two key issues are under debate: i) whether current market structures are lower risk for fossil fuel plants due to the way electricity market prices track fuel costs; and ii) whether the prospect of zero- or low-price periods in the market – arising from a large penetration of renewable and nuclear energy – is a risk for investors. Delayed investment will raise the cost of decarbonisation, so policies to address risk may be needed as part of a least-cost response. A number of policies are being explored to address these issues.

New challenge for electricity markets

Decarbonisation of the power sector will require a significant change in investment patterns. The IEA 450 Scenario indicates that early decarbonisation of the power sector is necessary to achieve the global goal of stabilising temperature rise to 2°C, as agreed in Cancún (December 2010). In the 450 Scenario, investment in low-carbon generating capacity (renewables, nuclear, and fossil-fuel plants with carbon capture and storage) comprises 55% of total new capacity from now until 2020, and 91% from 2020 to 2035. In OECD countries, the proportion of low-carbon investment is even higher: 70% of new capacity to 2020 and 95% of new capacity from 2020 to 2035 (IEA, 2010).

In countries with liberalised electricity markets, power sector investment decisions are decentralised, and therefore are influenced rather than directed by government policies. Investors will assess the expected costs (plant capital costs, operation and maintenance, fuel and carbon) against anticipated returns from the electricity market and any other support measures. Uncertainties and risks in both costs and returns will also play a significant role in investment decisions (IEA, 2007).

To date, much analysis of power sector decarbonisation has focused primarily on policy interventions to support the development and deployment of low-carbon technologies, to bring down their costs and so reduce the long-term costs of decarbonisation. Now, however, there is a growing focus on risk as well as cost. In particular, there is a question of whether current electricity market designs make low-carbon investment, which typically has high up-front capital costs, riskier than continued investment in fossil-fuel plants. The concern is that this elevated risk could deter investment in low-carbon generation, even where carbon pricing or other policy interventions have made it cost-effective. Delayed investment will raise the cost of decarbonisation (IEA, 2007), so policies that address risk may be needed as part of a least-cost response. Equally, where policies are in place to reduce risks for low-carbon generation, there are concerns about how these affect the rest of the electricity market.

This paper discusses the key concerns identified, and current ideas being proposed to adapt electricity markets to provide better support to capital-intensive generation.

Standard wholesale electricity market design and its risks

In standard wholesale electricity market design, "marginal pricing" determines the spot-market price of electricity. Generators offer capacity into the market at a price sufficient to recover their short-term running costs (including fuel and carbon costs). Capacity is dispatched starting with the lowest-price offer, moving up to more expensive options until demand is met. Under normal conditions, the offer price of the last unit of generation dispatched (the "marginal" unit of generation) sets the market price for electricity, which is paid to all generation dispatched irrespective of their individual offers.[1] In many markets, gas-fired generation generally sets this spot-market clearing price. At times of peak demand, higher-cost generation options are needed, so the market price for electricity is higher. Whenever the spot-market price is higher than a generator's offer price, the generator receives extra revenues (called "infra-marginal rents") that are used to help cover the plant's capital investment costs.

1. In the balancing mechanism of the United Kingdom market, generators are paid based on offer prices, but in this case the market price would still be expected to tend towards the marginal price due to generators adjusting their offers (Baldick, 2009).

At times of exceptional demand or network congestion, market prices can rise well above the short-term running costs of any generator operating. This "scarcity pricing" is a normal component of the market, and is necessary for all generators to recover their capital costs, particularly those that run only at peak times. If prices were prevented from rising sufficiently at peak times, generators would not be able to fully service their capital investments.

One optional market design feature is that of "capacity mechanisms" as an alternative way of ensuring adequate generating capacity to meet peak demand (Joskow, 2008; de Vries, 2008; Batlle and Rodilla, 2010). In some jurisdictions, it is seen as preferable to fund the capital costs of peaking plants though separate payments, rather than through the more volatile prices associated with energy-only markets. Capacity mechanisms can provide greater investment certainty for peak-load investors, but they also require regulators to determine appropriate levels of capacity and payment. Payments can be made to all generators in the system to ensure their availability at peak times, or can be targeted to a smaller subset of plants dedicated to peak use. The value of capacity mechanisms is debated because of the trade-off of greater certainty of prices and remuneration for potentially higher costs due to imperfect regulatory decisions.

In theory, under the marginal pricing market model, all types of plants will recover their operating and capital costs over the long run; and investors obviously would not commit to building a plant unless they foresaw its costs being covered. However, the risks attached to the recovery of capital costs vary considerably. Uncertainty is not new: it is an intrinsic part of the market, but the low-carbon transition adds significant political and policy-related risks that are difficult for investors to accurately assess. Further, in the absence of particular policies (such as feed-in tariffs) to reduce investment risk, current electricity market structures are inherently riskier for low-carbon investment (Grubb and Newberry, 2007).

Risk 1: Investor exposure to uncertainty in fossil fuel and carbon prices

Perhaps surprisingly, nuclear and renewable generators can be more exposed to fuel and carbon price uncertainty than fossil-fuel generators under marginal pricing. A gas-fired combined-cycle plant that often sets the marginal price, for example, will generally recover its operating costs (including fuel and carbon) because the electricity price adjusts to cover these costs. It will also benefit from higher prices during peak periods when more expensive plants set the marginal price, helping it recover its modest capital costs. As long as the gas-fired generator sets the marginal price, its profits are not strongly exposed to fluctuations in the price of gas or carbon.

Conversely, the profitability of a plant that has high capital investment costs but very low short-term running costs (such as a nuclear or solar thermal power station) is more strongly exposed to uncertainty in gas or carbon prices because these set the market price of electricity while the generator's costs remain fixed. The revenue available to cover the high capital costs of these plants is therefore more volatile over time (Figure 1).[2]

Figure 1 shows costs for hypothetical gas and low-carbon plants both running as base-load, compared to average spot prices. Net revenues are roughly equal over the time period, but returns from the low-carbon plant are more volatile.[3]

The exposure of low-carbon generators to the uncertainty of future price paths for both fossil fuels and carbon allowances may encourage continued investment in gas-fired plants, even if low-carbon plants are cost-effective.

Risk 2: Investor exposure to low market prices driven by decarbonisation

With decarbonisation of the power sector, low-carbon plants with high initial capital cost and low running cost (such as nuclear and wind generation) will form a growing proportion of the generating mix. There will increasingly be times when fossil-fuel plants are not needed to meet demand, so these plants will no longer set the electricity price. Instead, the spot-market price at such times will drop to the much lower running costs of the nuclear and renewable generators. Such periods of low, zero, and even negative prices are already being seen in the German and Spanish electricity markets due to the increasing proportion of government-supported wind power.[4]

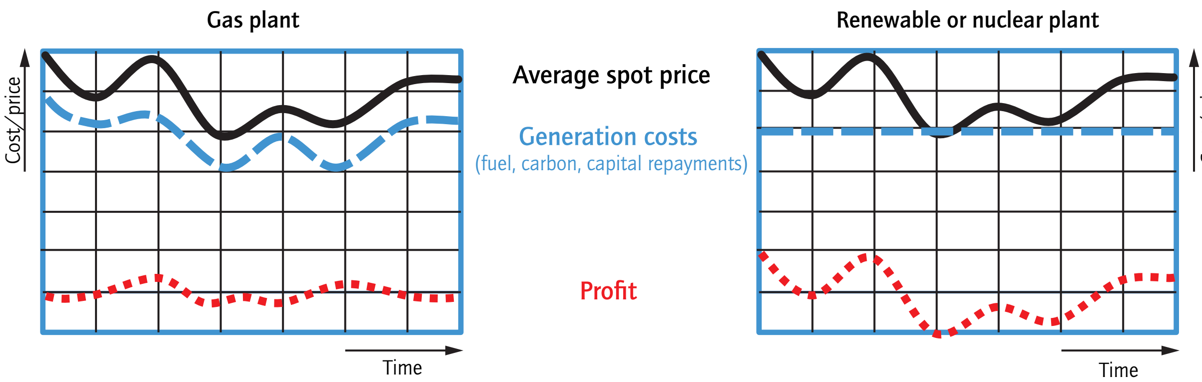
2. This simplistic analysis assumes that generators sell their electricity via the spot market, whereas in many markets the majority of generation will be covered by long-term contracts. The willingness of buyers to enter into long-term purchase agreements will ameliorate this price volatility.

3. The tracking between generation costs and average spot prices is not exact for gas plants, as these do not set the marginal price all the time: at peak periods more expensive plants will set the spot price.

4. In these markets, renewable generators receive additional payments based on electricity generated, for example through feed-in tariffs. It can therefore be worthwhile for them to offer generation at a negative market price, distorting efficient price formation. Similarly, some base-load plants (particularly nuclear) would face significant costs to stop generating, so find it more cost-effective to pay the market to take their electricity rather than withdraw their supply and face the higher cost of stopping generation.

Figure 1

Schematic representation of profit variability from electricity generation



With increasing periods of low or zero market prices, the concern has been raised that the loss of infra-marginal rents will make it more difficult for low-carbon generators, whose revenues rely on market prices, to recover their capital costs. While higher peak prices could theoretically compensate for this, the highly uncertain and volatile revenue stream would make these investments riskier and more difficult to finance.

Additionally, it is unclear in this case how much benefit low-carbon generators will derive from carbon-pricing revenue as the system decarbonises. When fossil-fuel plants are setting the market price, all generators receive the carbon cost passed through into the market price for electricity. At times when only low-carbon plants are running, however, the price of electricity falls and there is therefore no carbon-price component to the electricity price. While the carbon price is still useful in making high-emissions generation less competitive, at these times it is no longer providing revenue to help low-carbon generators recover their investment costs. In modelling work for the UK government, Redpoint (2010) found that as the electricity system decarbonises, the effect of a carbon price on electricity prices erodes, weakening its usefulness as a support measure for low-carbon generation over time.

Low-price periods are not only a risk for the economics of low-carbon investment, they also raise significant uncertainty for the expected returns from fossil-fuelled plants. Continued investment in flexible fossil-fuelled plants may well be needed to balance supply and demand in a system with a large share of variable or intermittent renewables (particularly wind), and investors may be reluctant to commit if it is unclear how many hours these plants will run as the system decarbonises.

It should also be remembered that nuclear and renewable generation are not the only low-carbon possibilities under development. If carbon capture and storage technologies are eventually widely adopted, a different market dynamic could unfold because the higher short-term running costs of these plants will set the marginal electricity price and tend to keep market electricity prices higher. The balance of nuclear, renewable and fossil-fuel plants with carbon capture and storage could therefore have a significant impact on electricity market prices – hence on the economic viability of all these investments. Future market designs may therefore need to be robust in all these regimes.

Risk 3: Rising consumer prices

Electricity price rises are politically and publicly contentious, so there is a natural concern that policy changes should not raise consumer prices by more than is necessary. As such, the concern to ensure generators recover the costs of new investment has a corresponding concern that they should not benefit from excessive returns.

In the short to medium term, fossil-fuelled generation will continue to set the electricity market price most of the time as the system decarbonises. For example, modelling for the UK Committee on Climate Change showed that gas generation is still expected to set the market price 85% of the time in 2030, even though it will only be 10% of the generation mix (Redpoint, 2009). The market electricity price will therefore pass through the gas generators' carbon price, which will be paid by consumers on every unit of electricity purchased even though the system will be predominantly renewable. While investors in new plants will need this additional margin to cover their costs, it could result in significant windfalls for those generators with existing low-carbon plants, such as historical nuclear plants (Ellerman, Convery and de Perthuis, 2010; Keppler and Cruciani, 2010).

Under carbon pricing, rising electricity prices are intended to make cleaner generation more profitable; increased infra-marginal rents to some existing generators are a natural result of the marginal pricing market system. Allowing prices to rise to the level needed for marginal investment ensures that investment and consumption decisions are made efficiently and in theory leads to optimal cost-effectiveness. Because opposition to rising electricity prices may stall action on climate change, governments may begin to explore alternative policies to achieve decarbonisation with lower price rises or, alternatively, the recovery of some of the windfall revenue from existing generators (Finon and Romano, 2009). These solutions may involve some loss in overall economic efficiency.

The increase in electricity prices from CO_2 pricing works in the opposite direction to the suppression in prices from the penetration of low-carbon generation discussed as "Risk 2" above (see Philibert in this volume for further discussion). The way in which these effects will interact over time as systems decarbonise will be complex, and warrants further detailed study.

Solutions being explored to improve market arrangements for decarbonisation

The issue of alternative market designs for decarbonisation is only beginning to be considered in academic and policy circles. Among governments, the United Kingdom's recent announcements on market reform provide an example of the market and related policy adjustments being considered (see box below).

Proposals being suggested fit into two broad categories: those that establish a separate market for low-carbon generation, and those that seek to make reforms market-wide so that a high-capital-cost plant is better able to recover its costs.

Separate markets for low-carbon generation

The most commonly proposed method to provide greater certainty for low-carbon investment is to provide separate payments to these generators, outside the main electricity market. These typically build on the support schemes that have already been implemented for renewable energy, and take one of two forms:

- **Feed-in tariffs**, structured either as fixed payments, premium payments on top of the market electricity price, or financial contracts for differences against the market price (Newberry, 2010a; 2010b; Hiroux and Saguan, 2010).
- **Establishing a market for clean energy** by imposing quantity obligations on suppliers. The United Kingdom and Australia have created markets for renewables obligations, and the United States is currently considering extending this approach to a "clean-energy obligation".

In practice, these approaches often overlap. Feed-in tariffs can be restricted to a fixed quantity of generation, with the payment price determined by tender or auction. In this case, they take on some of the properties of a quantity-based obligation. Similarly, renewables obligations have typically been tiered to provide different levels of support to different technologies, acquiring some of the price-based characteristics of a feed-in tariff. The costs and benefits of these types of support schemes are explored in detail in *Deploying Renewables: Principles for Effective Policies* (IEA, 2008).

From the perspective of the wider electricity market, however, these schemes pose a fundamental problem. As the share of low-carbon generation increases, the size and liquidity of the conventional market shrinks. Investors in fossil-fuel plants, which may still be necessary to ensure security of supply, will experience heightened uncertainty over the running hours and electricity prices these plants will realise. The solution generally proposed is to provide supplementary funding for these plants as well, in the form of capacity payments. In this scenario, plants would receive some payment for being available to generate when required for system balancing or meeting peak demand, and receive further payment through the market for actual generation.

Ultimately, if all generation is receiving top-up payments through clean energy contracts, tradable certificates or capacity payments, the significantly broader role of the system regulator will potentially include determining the quantities of various types of generation required for decarbonisation and security of supply, and perhaps also the prices for these. This marks a significant shift away from current market design, where investment decisions are made by market participants based on price expectations – though of course with key cost and risk elements influenced by the regulator.

The implications of market structure for investors' risk will also depend on the degree of aggregation within the industry. While impacts may be significant for individual plants, for large firms with a portfolio of generation the impact is smaller overall (Burtraw and Palmer, 2008).

Market-wide interventions

Given that targeted policy measures to support low-carbon generation may result in system-wide interventions in the long term, it is worth considering whether reforming market-wide structures might be preferable to creating a separate market for low-carbon generation.

As part of early work towards the United Kingdom's market reform proposals, a range of whole-of-market reforms were considered, from enhanced carbon pricing at a minimum through to replacing the market with a central purchaser of electricity at the extreme (Ofgem, 2010; HM Treasury, 2010a).

Carbon pricing is a standard policy tool for improving the economics of low-carbon investment. Tightening emissions caps (and hence raising carbon prices), or moving to carbon taxes for greater certainty, would clearly attract more investment in low-carbon compared to fossil-fuelled plants. As pointed out by Hogan (2010), accurate pricing of the emissions externality allows appropriate decentralised investment decisions to be taken. However, higher and more certain carbon pricing alone will not address all the risks discussed above: low-carbon generators would still have to manage fuel-price uncertainty, and all generators would still face the prospect of low-price periods undermining returns as the system decarbonises. In the United Kingdom analyses, enhanced carbon pricing was seen as a useful step, but insufficient on its own (HM Treasury, 2010a).

Market-wide regulatory standards could also be considered, such as emissions performance requirements that tighten over time. Again, while these would provide support for low-carbon plants, they do not address the market issues of fuel price uncertainty and low-price periods. Regulated approaches are also generally less efficient than carbon pricing, achieving emissions reductions at higher cost (OECD, 2009).

A more comprehensive, though also more speculative, solution would be to attempt to extend capacity mechanisms to cover all generation in the market, rather than only peak-load generation. This could help all generators (low-carbon as well as fossil-fuelled ones needed to balance the system) cover their capital costs. Generators would be paid separately for having capacity available in the market, while the electricity market would cover their running costs when the plant is dispatched. As current capacity mechanisms only address supply security concerns and tend to favour fossil-fuelled capacity, they would need to be restructured to meet the dual objective of supporting low-carbon investment. Detailed proposals for such a mechanism are yet to emerge, but the concept is under discussion (Boot and van Bree, 2010; Gottstein and Schwarz, 2010; KPMG, 2010). Given that existing wholesale markets are already flanked by supplementary markets to provide ancillary services such as spinning reserve, voltage support and frequency regulation, moving to a further supplementary market for capacity would not necessarily be a radical departure.

Finally, there exists the option of retreating from the market model to a system where the regulator contracts for all new generation (a "central purchaser" model). Here, the regulator determines system requirements for new generation in lieu of the competitive price-based investments of market players. This would be a significant departure from fully liberalised market structures, and essentially represent a return to a pre-reform model. While floated in the early UK policy discussions, it was discarded due to the desire to retain the efficiencies delivered by the wholesale market.

Proposals for reform of the United Kingdom electricity market

The UK government is currently consulting on options for reform of its electricity market to better facilitate the decarbonisation of the power sector (DECC, 2010; HM Treasury, 2010b). This is the culmination of work since 2009 by the Committee on Climate Change (CCC, 2009; 2010), the Office of Gas and Electricity Markets (Ofgem, 2010), the UK Treasury (HM Treasury, 2010a) and the Department of Energy and Climate Change.

The package of measures proposed consists of:

- ***Carbon price support.*** *The carbon price from the EU emissions trading system would be supplemented by an alternative tax (the climate-change levy) to guarantee a minimum carbon price in the electricity market.*
- ***Long-term contracts for all low-carbon generators****, structured as contracts-for-difference against the market electricity price. This guarantees returns for low-carbon investors, while maintaining market incentives for efficient operation.*
- ***Targeted capacity payments for flexible plants*** *needed for system balancing and meeting peak demand.*
- ***Emissions performance standards*** *for new fossil-fuelled plants, as a backstop minimum emissions requirement.*

Following consultation, the government intends to issue a white paper in April, so that any changes to the system can be settled quickly to avoid investment uncertainty.

Conclusion

Due to the heightened risk wholesale market structures pose for investors in high-capital-cost, low-running-cost generation, these market structures may not be optimal for decarbonisation. Delays in investment would raise the cost of decarbonisation, so policies to address risk may be needed as part of a least-cost response.

A key question for policymakers will be whether to use targeted measures to ensure capital cost recovery for low-carbon investments, or whether to introduce (or modify) market-wide policies such as capacity payments that cover all generation. Given the early stage of policy development, it is not yet clear which solutions are likely to be best.

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Funding energy efficiency: earmarked environmental taxes versus system public benefit charges?

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Energy efficiency can improve energy security, reduce greenhouse gas (GHG) emissions, promote economic growth and create jobs. However, market failures and other barriers have caused a pattern of underinvestment in energy efficiency, forcing governments to undertake policy interventions. Funding for these policy interventions may come from several sources, including government budgets, earmarked environmental taxes, and charges on network-delivered energy (gas and electricity).

Classical economic theory holds that the government appropriations process is the most efficient way to allocate public funds among competing policy priorities. For this and other reasons the earmarking of environmental taxes to fund energy efficiency has received criticism from economists. In contrast, a different kind of earmarking, namely the funding of energy efficiency with network-delivered energy charges (sometimes called system public benefit charges or wires and pipes charges), has received a more positive support. This paper seeks to understand this differential treatment by examining the fiscal and governance effects, economic efficiency, impacts on equity, and political economy of the two fund-raising systems relative to a default case of funding through government budgets.

Rationale for government intervention in energy efficiency

If energy efficiency is cost-effective, why must governments support energy efficiency investment with public funds? Energy efficiency improvement is often hampered by market, financial, informational, institutional and technical barriers. These barriers exist in all countries, and most energy efficiency policies are aimed at overcoming them. Many governments cite the contributions of energy efficiency to sustainable development and energy security as justification for such policy interventions. Societal or public-good benefits cannot be captured by private parties making energy efficiency investments, thus further justifying government support.

The energy efficiency underinvestment gap due to market failures and other barriers is immense. The IEA estimates that annual investments of USD 300 billion in energy-efficiency improvements are needed globally, in combination with a rising price on CO_2 emissions and support to low-CO_2 supply technologies, to reduce greenhouse gas emissions to a level that would deliver a concentration of 450 parts per million (ppm) (IEA, 2009).

Classical economic theory holds that if energy pricing is right, reflecting externalities resulting from production and consumption, the market should ensure sufficient investment in energy efficiency. Table 1, however, lists market failures related to energy efficiency which cannot be corrected by pricing, and lists the policy interventions used by governments to overcome them. Additional non-pricing policies are needed to close the energy efficiency investment gap (IEA, 2011).

Table 1

Market failures affecting energy efficiency which cannot be addressed with pricing policies

Market failures and other barriers	Intervention policies
Imperfect information	Labelling schemes, education and awareness
Prices set below costs	End-use regulation, subsidies
Principal-agent and split incentive problems	End-use regulation, subsidies, obligations
Behavioural failures	Standards and labelling, regulation, education

The policies listed in Table 1 require government funding to implement. Standards and labelling policies require procedures to determine the technical performance of energy-consuming products through product labelling and testing. Informational and educational programmes to build energy efficiency awareness can be expensive to develop and deliver. Fiscal policies such as subsidies and tax incentives for energy-efficiency investments are an even greater drain on government budgets.

Reliable funding is essential to support government policy interventions in energy efficiency. Governments have options as regards how energy efficiency policy is funded (IEA, 2010). Different mechanisms have advantages and disadvantages, which can be compared along political economy and classical economics axes (Table 2).

This article explores the relative advantages of three funding mechanisms - government budget appropriations, earmarking of energy or environment taxes, and system public benefit charges - to determine whether one has distinct advantages over the others.

Table 2

Attributes and effects to consider when selecting an energy efficiency funding mechanism

Political-economy dimension	
Adequacy and stability	The funding should cover policy implementation costs and be steady and predictable over time
Public acceptance	The funding source should be credible to stakeholders and affected customers and in line with overall EE policies
Classical economics dimension	
Fiscal and governance effects	Funding decisions should be free from political or other influence, have low administrative requirements, and funding levels commensurate with other government spending priorities
Static efficiency	The funding should be raised and spent at least cost, not create market or price distortions or crowd-out other funding
Equity	The funding source should not harm vulnerable groups

System public benefit charges

System public benefit charges (SPBC) are levies placed on network-delivered energy (*e.g.*, gas or electricity) that are earmarked for socially beneficial purposes. These charges are very common in the United States, which has almost two dozen different SPBC programmes. Other countries funding energy efficiency interventions with charges on electricity consumption include the United Kingdom (Energy Savings Trust), Norway (transmission tax), New Zealand (Energy Saver Fund), Jordan, and Brazil (Sovacool, 2010).

An SPBC funding mechanism provides steady and often substantial funding for energy efficiency programmes or other socially beneficial spending. It can be embedded within the regulated tariffs of gas, electricity or water, or even district heating and cooling providers. SPBC funding is especially well suited to long-term market transformation efforts, as it provides a multiyear stream of support. The flexibility of SPBC mechanisms allows the funds to be used for a portfolio of energy efficiency or other interventions across a range of customers.

The collection of the SPBC can be done independently of the policy implementing agency, for political purposes or to avoid conflicts of interest.

In Vermont and New York, for example, the energy utilities serve only as collection agencies, including the SPBC in rates at the direction of the regulator. Revenues flow into a special account administered by a separate statutory authority, also under regulatory oversight.

Another advantage of SPBC schemes is the opportunity to tailor the funding source to programme design and adapt spending to the demand for sectoral programmes; this improves economic efficiency and helps create political acceptance. For example, the Energy Research and Development Authority in New York State (NYSERDA) implements energy-efficiency policies for industrial customers which are funded by their own SPBC contributions. To recoup the funding, the industrial customers must participate in energy-efficiency programmes, *e.g.*, co-finance energy efficiency investments. Table 3 summarises several SPBC schemes in the United States and elsewhere.

Table 3

System public benefit charge examples

Jurisdiction	Public benefit spending as a % of utility revenue	USD/ kWh	Annual revenue (USD million)
Brazil	1%*		80.0
Jordan**			35.0
United States, California±	1.2	0.28	600.0
United States, Massachusetts±	2.4	0.33	246.0
United States, New Jersey±	3.0	0.34	300.0
United States, New York±	1.0	0.06	177.2
United States, Oregon±	1.7	0.19	60.0
United States, Vermont±	3.0	0.33	17.5

** NF/UNEP/World Bank, 2004.*
*** The Jordan Institute, 2010.*
± Energy Programs Consortium, 1999.

Source: IEA, 2010.

SPBC schemes in California, New York, and Massachusetts have successfully created a multiplier effect in overall energy efficiency investment, *i.e.*, the sum of public benefits spending, private investment, and government spending (Nadal and Kushler, 2000). System public benefit charges raise large amounts of funds at only a small cost to the individual customer, with the receipts then disbursed via popular programmes that affected customers can access.

Critics of SPBC schemes argue they are a tax on utility ratepayers that is used to cross-subsidise inefficient rebate programmes beneficial only to a few (Switzer, 2002). However, SPBC schemes have many more proponents than critics. This may be due to the nature of SPBCs: relatively large amounts of funds are raised at only a small cost to the individual customer, with the receipts then disbursed via popular programmes that the affected customers can access themselves. The criticisms raised relate more to how the funds are used than to the collection mechanism itself. There is nonetheless potential for inefficiencies in SPBC schemes, including free-riding, market distortion, rebound effect, technology lock-in, and cost-ineffectiveness (Khawaja, Koss and Hedman, 2001). One may also question whether the monies would not be better collected by governments via an equivalent energy tax, and then used in reducing labour taxes and social charges as per the general recommendation for energy and environmental taxes.

Earmarked energy and environmental taxes

Fiscal policy is a powerful tool used by governments to influence consumer consumption and investment. Fiscal policies can be used to both promote energy conservation and penalise energy consumption. Taxes levied on fuel consumption or emissions from household or economic activity – energy and environmental taxes – adjust the relative prices of energy inputs and emissions output to influence consumers' energy consumption.

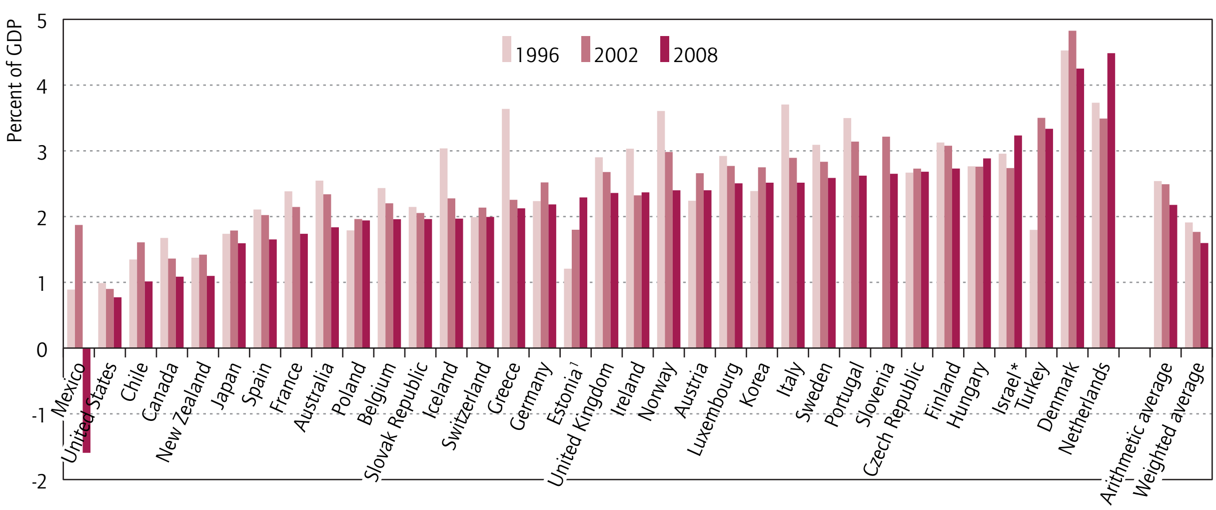
Environmental taxation accounts for an average of around 2% of GDP in OECD member countries, although this share has recently decreased (Figure 1).

How to use the revenues generated by energy or environmental taxes is a separate fiscal policy question. Earmarking is the hypothecation of some or all of the tax revenues for specific purposes, *e.g.*, energy efficiency or technology innovation. Recent reports by the OECD recommend against earmarking, arguing that governments should "use the proceeds [of environmental taxes] to augment general government spending in other areas, maintain spending levels, reduce debt or reduce other taxes" – especially during times of financial crisis (OECD, 2010). In general, the view of classical economists is that earmarking of environmental taxes reduces economic efficiency by creating distortions in the marketplace, as governments place confidence in the wrong technologies or over-invest in some forms of energy efficiency just because the funds are available.

Political economists, however, expect opposition to any new tax, and therefore view the channelling of tax revenues back to affected sectors through earmarking as a way to increase public acceptance of energy taxes. Some schemes, such as the French bonus-malus (*i.e.* feebate-rebate) scheme, build on the political advantages of links between energy consumption and government support.

Figure 1

Revenues from environmentally related taxation as percentage of total tax revenue



Source: OECD (2010) and OECD/EEA database on instruments for environmental policy.

1. Estonia was an accession country to the OECD when these data were drawn together and has not been included in the averages.

** The statistical data for Israel are supplied by and under the responsibility of the relevant Israeli authorities. The use of such data by the OECD is without prejudice to the status of the Golan Heights, East Jerusalem and Israeli settlements in the West Bank under the terms of international law.*

In this self-contained system, tax revenues from over-consumption are redistributed to investment in efficiency.[2]

The creation of a special account for the new tax provides further credibility and institutional justification (Joel, 2008). In the United States, for example, a motorboat gas excise tax is earmarked for conservation of aquatic resources, while revenues from a motor fuels excise tax flow directly to highway construction and maintenance (Muller, 2008). This latter case exemplifies the pitfalls of these kinds of schemes. While the use of fuel excise taxes for highway construction and maintenance increases public acceptance of fuel taxes, they are used in a non-environmental manner which actually counteracts the desired disincentive to road transport.

Despite the protests of classical economists, the earmarking of energy and environmental taxes is a common practice in many countries, at least partly due to the political benefits. According to the OECD, one-third of all environmental and energy taxes in place in 2006 were to some degree earmarked (OECD, 2006a) (Table 4).

A compromise between economic efficiency and political economy might be partial earmarking. This makes sense when energy and environmental tax revenues have large fiscal impacts. One compromise would set an indicative cap for earmarking at levels sufficient to fund desired activities (5-20%) while minimising undue distortive effects or efficiency losses (Andersen, 2010).

2. *See, for example, a recent report on the best practice in fee-bate schemes for transport: www.theicct.org/2010/04/feebate-best-practices/. It should be noted that the French example does not perfectly illustrate the point. This is because the fuel economy level picked as revenue-neutral was set too high, resulting in a net expenditure of public funds on the scheme. A better design would include a mechanism to constantly adjust either the feebate or the rebate, to maintain net public spending (other than administrative) at zero.*

Table 4

Examples of earmarked energy and environmental taxes

Country	Energy/environmental taxes	
	Type of tax	Earmarking
China	Sales tax on engine displacement	None
Korea	Tax on high-consuming or large appliances	Subsidy for low-income EE
Mexico	Tax on oil production	Sustainable Energy Fund
Moldova	Fines for violation of provisions of the Law on Energy Conservation	Energy Conservation Fund
Morocco	Automobile registration	National Energy Savings Fund
Singapore	Road congestion pricing and vehicle downtown access	None
Thailand	Surcharge on gasoline and diesel consumption	Energy Conservation Fund
Tunisia	Duty levied on imported air conditioners	National Energy Savings Fund
United Kingdom	Climate change levy on GHG emissions	Energy supplier obligations
United States	Gasoline tax	State road repairs

Source: IEA, 2010

Arguments against earmarking

Arguments against earmarked taxes can be grouped into three categories: (i) fiscal and governance issues; (ii) distributional impacts and equity; and (iii) economic efficiency (Slama, 2005).

Fiscal and governance issues

There is greater flexibility for finance if all revenues are pooled together. Contrary to good fiscal practice, earmarking removes appropriation choices from the legislature or the government ministry. Some feel that earmarking undermines financial discipline and introduces budgetary rigidity in face of competing needs (Slama, 2005; OECD, 2006b; OECD, 2010). There is also concern that the availability of extra-budgetary funds outside the central treasury may result in spending decisions that are susceptible to political influence or that lack transparency.

The income stream of earmarked taxes is separated from the main budget during the allocation process; this can assure a stable revenue stream for a particular activity, but can also be subject to capture by special interests.

The success of earmarking depends largely on the processes in place for stakeholder representation and pluralistic democracy within the government itself. Another consideration is the amount of revenue generated: if small relative to overall government budgets and appropriate to spending needs after accounting for the distortive effects of other legacy fiscal policies, then the adverse effects inherent in earmarking should be manageable.

Distributional impacts and equity issues

Metcalf (2006) and others point out that an environmental tax resembles a commodity tax. Commodity taxes in general tend to be regressive in an annual income framework. Carbon taxes, gasoline taxes, air pollution taxes, and taxes on electricity also tend to be regressive, depending on how heavily lower-income groups rely on targeted energy uses. The impact of environmental taxes on the social welfare of different groups is dependent upon tax incidence as well as the method of revenue dispersal. The redistribution of revenues to provide "safety nets" to adversely affected groups may mitigate regressive impacts of an energy or environmental tax.

Economic efficiency and market distortion

The main efficiency arguments against earmarking include loss of consumer and producer surplus[3] and increased distortion of labour and other markets. An example of one problem with rebate programmes is the high incidence of free-riding, where people take advantage of a rebate to make an investment they were already planning. The extent of market distortion depends on many factors, including existing distortions and overall fiscal impact of the tax. Uninformed governments or regulators may add to price and market distortion by being ill-placed to choose the energy-efficiency technologies most needing government support.

Comparing system public benefit charges with earmarked environmental taxes

SPBCs resemble earmarked energy and environmental taxes in certain ways and differ in others (Table 5). Although there tends to be less criticism of SPBCs compared to earmarked environmental taxes in the economics literature, SPBCs are arguably a type of hypothecated energy (gas or electricity) tax.

Assuming this, SPBCs should be subject to the same scrutiny regarding distributional impacts and market distortion as environmental taxes. One fundamental difference between SPBCs and earmarked environmental taxes is that SPBC revenues are collected by energy providers from their customers rather than by governments from taxpayers, and thus do not pass through the public finance system. Since SPBCs are levied on one or just a few energy sources, they may create cross-fuel relative price distortions which could in turn produce inefficiencies or allocation effects. A related difference is jurisdiction: setting the charges and overseeing the collection and disbursement of SPBC funds is usually the responsibility of specialised regulators rather than governments. If the regulator is independent and stakeholders are engaged, this may yield better outcomes than specialised government agencies susceptible to vested interests.

SPBC revenues tend to be fully committed to specific programmes and implementing agencies, with the level of the charge corresponding to the desired funding. Quantitative outcome objectives linked to spending may target resources, market transformation, and/or public benefits or social welfare by lowering overall electricity sales, increasing the market share of energy-efficient appliances, or reducing the energy bills of low-income households. Determining funding (and SPBC) levels using a cost-reflective planning scheme should reduce or at least cap market and price distortions.

Another difference between SPBCs and environmental taxes is the scope of activities on which they are levied and spent. SPBCs are levied on delivered energy from gas or electricity networks, whereas environmental taxes can be much broader and can cover any energy-consuming activity and sector. SBPCs tend to be much more rigid in the way that funds are raised and how they are spent, with the revenue generally being channelled to electricity demand-side management programmes or other electricity-saving activities. In contrast, earmarked environmental tax revenues can be recycled back to a wide range of environmental and energy activities. Because SBPCs apparently provide less fiscal flexibility to governments than earmarked environmental taxes do, the arguments against earmarked environmental taxes relating to fiscal and governance issues and economic efficiency apply even more strongly for SPBCs.

In examining the distributional impacts of SPBCs compared to earmarked environmental taxes, it is really only possible to draw situation- or country-specific conclusions. Without knowledge of the energy use of lower-income groups, it is impossible to draw general conclusions on how regressive an SPBC scheme may be compared with earmarked environmental taxes.

3. Consumer surplus is a measure of the welfare that people gain from the consumption of goods and services, or a measure of the benefits they derive from the exchange of goods. In this case since governments might cause distortions to the market through the picking of technology "winners" resulting in unjustified price rises or decreases, consumer welfare might change.

Table 5

Alternative energy efficiency funding mechanisms: comparing SPBCs, earmarked energy taxes and government budgets

Funding source	Collection agency	Disbursement decision-making	Evaluation criteria				
			Classic economics considerations			Political economy considerations	
			Fiscal and governance issues	Equity considerations	Static efficiency	Adequacy and stability	Political acceptance
SPBCs	Energy providers	Regulators & stakeholders	High level of transparency & beneficiary engagement; less flexible collection and disbursement	Disbursement can be targeted to affected segments; potential for regressive impacts	Potential for cross-fuel price distortions; potentially less "waste"	Steady long-term funding can be locked-in	Stakeholders are supportive because of the potential to benefit
Earmarked energy taxes	Govern-ment	Special-purpose agencies	"Special funds" could be abused	Disbursement can be targeted to specific segments; potential for regressive impacts	Depends on size relative to GDP; less distortion between fuel types; least-cost mitigation possible	Steady long-term funding can be locked-in	Stakeholders are supportive because of the potential to benefit
Govern-ment budgets	Govern-ment	Government, but special interest groups may influence	Energy efficiency spending needs rigorous, transparent justification	Subject to mainstream equity considerations but competition from other policy areas may mean energy efficiency not prioritised	More efficient due to flexibility provided by pooling; however, efficiency depends on quality of analysis and decision-making	Funding will be subject to other spending priorities and political preferences	Funding levels will be affected by level of political/ popular support for energy efficiency

For example, in a country that is very road transport-dependent such as the United States, environmental taxes levied on transport fuels will probably be more regressive than SBPCs levied on electricity. Similarly, inhabitants of densely-populated areas or apartment dwellers tend to be less dependent on wood and oil for heating than single-family-housing dwellers, and in this comparison earmarked environmental taxes would be more regressive for the latter group. It is clear, therefore, that there is potential for regressive impact in both SPBCs and earmarked environmental taxes.

Remaining questions

This paper has tried to demonstrate how some criticisms of earmarked environmental taxes may hold for SPBCs as well. More investigation is needed to explore the similarities and differences regarding the two energy efficiency funding mechanisms. The brief discussion above suggests that the greatest potential concern is allocation of SPBC revenues to relatively inefficient activities, whether due to market distortions or political acceptance issues. More research is needed on whether these are real issues and if so how they can be avoided.

One approximate way to prevent overspending and static inefficiency is to set the SPBC charge at a level that will collect the external costs of electricity consumption. The amount of public energy-efficiency investment required in a given jurisdiction might also be estimated by the policy maker to overcome market failures. The SPBC revenue could then be allocated to meet this estimate, rather than tailoring energy-efficiency spending to match the sum of SPBC revenues. If the external costs of electricity have been internalised in electricity prices, it may be argued that any additional funding needed to address market failures should come from the general budget.

The prevalence of market and price distortions resulting from previous fiscal policies makes it difficult to compare the relative static inefficiencies between the three funding mechanisms shown in Table 5. The most powerful arguments for and against SPBCs and earmarked energy taxes will therefore derive from fiscal and governance considerations together with equity implications. In each country, the outcome will depend on the development of governance conditions in the energy sector relative to those for general government.

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Early retirement of coal-fired generation in the transition to low-carbon electricity systems

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Scenarios for decarbonisation of the power sector often involve early retirement of fossil-fuelled electricity generating plants, particularly coal-fired plants that have the highest carbon dioxide (CO_2) emission rates. Including early retirement in the transition raises a number of questions such as who should bear the costs of any stranded assets, and whether additional policies are needed to provide greater certainty about retirement and minimise system-wide costs. If early retirement is deemed unfeasible, even tighter restrictions on new plants may be required to ensure that the emissions reduction from these plants is sufficient to compensate for the higher emissions from existing plants that may remain in operation.

Long-lived capital in power generation

Coal-fired electricity generation contributes a large – and growing – share of global CO_2 emissions. It is responsible for 73% of CO_2 from global power generation and 30% of total global CO_2 emissions from energy. Since 1990, emissions from coal-fired power plants have been growing quickly: at 3.2% annually compared to overall global emissions growth of 1.9%. In this period, the growth in installed coal capacity has been concentrated in non-OECD countries, where capacity has grown by 6.2% per year. In 2008, there were 1 514 gigawatts (GW) of installed coal-fired power plant capacity globally (32% of 2008 total generating capacity), producing 8 273 terawatt hours (TWh) of electricity (41% of total production) and emitting 4.93 gigatonnes (Gt) of CO_2.

The long technical lifetimes of coal-fired plants raises the question of what level of future emissions is already locked in (Davis, Caldeira and Matthews, 2010), and whether the challenge of rapid decarbonisation will require early plant retirement. This paper explores these questions and related policy implications.

Is early retirement a critical element in climate policy scenarios?

Several modelling scenarios include significant early retirement of coal-fired power plants as one of the elements in delivering a climate change mitigation objective. For instance, the *World Energy Outlook 2010* (*WEO 2010*) projects in its 450 Scenario that some 300 GW (or around one-third) of coal plants built between now and 2035 will be retired before the end of their technical lifetime. Around 100 GW will be retired before achieving a commercial return on the capital invested, representing a net loss of around USD 70 billion or 28% of the investment cost (IEA, 2010) (Figure 1).

Early retirement to support climate change mitigation

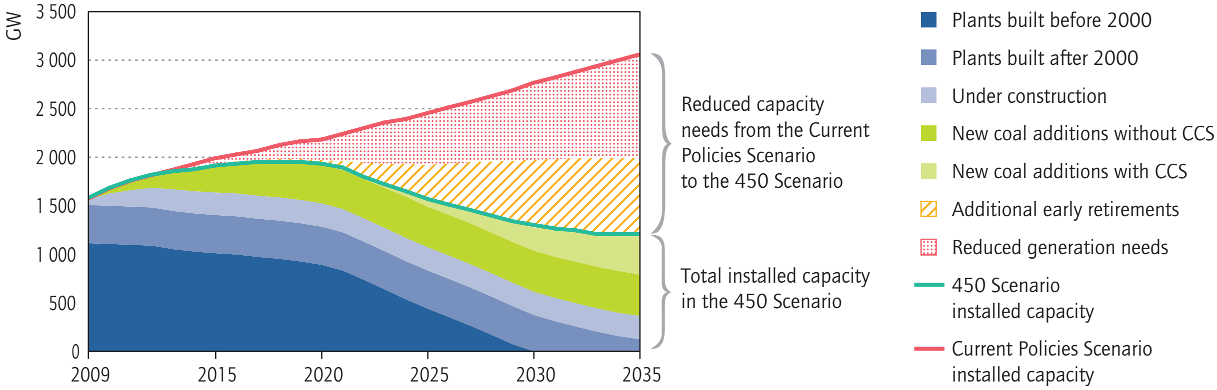
The early retirement of a power plant refers to its closure before the end of its technical lifetime, which is often assumed to be 40 years for a coal-fired plant, although upgrades can allow plants to continue for much longer. This closure can be triggered either by regulation or by economics – i.e. *when the electricity market price is consistently below the plant's short-run marginal cost, the plant cannot cover its operating costs.*

Depending on electricity demand, early retirement may create the need for additional investment in new capacity. In this case, to trigger early retirement through economics, the carbon price has to be such that the short-run marginal costs of an existing coal-fired plant become higher than the long-run marginal costs (including capital costs) of a new lower-carbon plant. This implies that quite high carbon prices may be needed to displace existing capacity before the end of its technical life.

Shortening the period of operation leaves the plant owner with "stranded costs" (if the closure occurs before the capital investment costs have been fully recovered) or with a reduction of expected benefits. These factors change the fundamental economics of the project and basis for the original investment decision, which may prompt owners to seek compensation for their losses. If governments were to consider such compensation appropriate, early retirement as an option for transition in the power sector could be substantially more costly.

Figure 1

Global installed coal-fired generation capacity to 2035 in the 450 Scenario relative to the Current Policies Scenario from *WEO 2010*



Source: IEA, 2010.

Note: CCS = carbon capture and storage.

Similarly, analysis by the Energy Information Administration of the American Power Act of 2010 highlights cumulative retirement of between 13% and 83% of current coal-fired power plants in the United States between now and 2035, depending on alternative assumptions on technology availability, international offsets, banking of emission credits and shale gas prices (EIA, 2010).

The Garnaut -25 scenario for Australia's Low Pollution Future also envisages significant early retirement of coal-power plants (Australian Treasurer and Minister for Climate Change and Water, 2008). Analysis of policy options for the UK electricity market reforms to achieve ambitious CO_2 emissions reduction (Redpoint Energy, 2010) also shows cumulative coal plant retirements of between 18 GW and 26 GW by 2030, out of 29.5 GW installed today. By contrast, some modelling scenarios exclude *a priori* early retirement of existing assets. For instance, the European Climate Foundation's *Roadmap 2050* assumes that all plants are retired at the end of their lifetime (40 years for coal plants) (ECF, 2010).

These diverse scenario results are driven by the different assumptions and mechanisms at play in the modelling tools used. First, the emissions pathway considered, particularly its stringency in the first years, determines how many new coal plants are commissioned in the first years and may therefore be retired in later years when more stringent emissions reduction are required. Second, the representation of investment and retirement decisions varies: some models assume foresight of future prices for both fuel and carbon, while others do not. Models assuming that investment decisions are based on average levelised costs also give different investment behaviour than those that factor uncertainties into the equation.

Important end-use efficiency improvements may reduce electricity demand and accelerate the retirement of less efficient plants. An opposite scenario of lower efficiency improvement and higher electricity demand could complicate the retirement issue, as more low-CO_2-emitting plants would need to be financed to meet demand.

The range of modelling assumptions and approaches used means that there is no definitive answer regarding the role that early plant retirement is likely to play in the low-carbon transition. There are, however, certainly indications that it could be a significant issue, and could raise important questions for policy making:

- If early retirements of some plants are necessary, what policy will drive this? Is carbon pricing effective enough, or should alternative policies or some combination of policies be implemented?
- What impact will other environmental regulations have (such as limitations on conventional air pollutants, ash disposal, or water use)?
- As plants' run time is reduced, how will demands of the electricity system for peaking capacity, adequate reserve margins, and locational generation affect plant retirements?
- How should the financing issue be dealt with? Who should bear the cost of early retirements? Should compensation schemes be designed?
- Can alternative policies avoid the need for early retirements?

Past and current experiences with power sector transition

Although the scale of transformation required to decarbonise the power sector is daunting, history provides several examples of rapid transformation in the technology mix of generation.

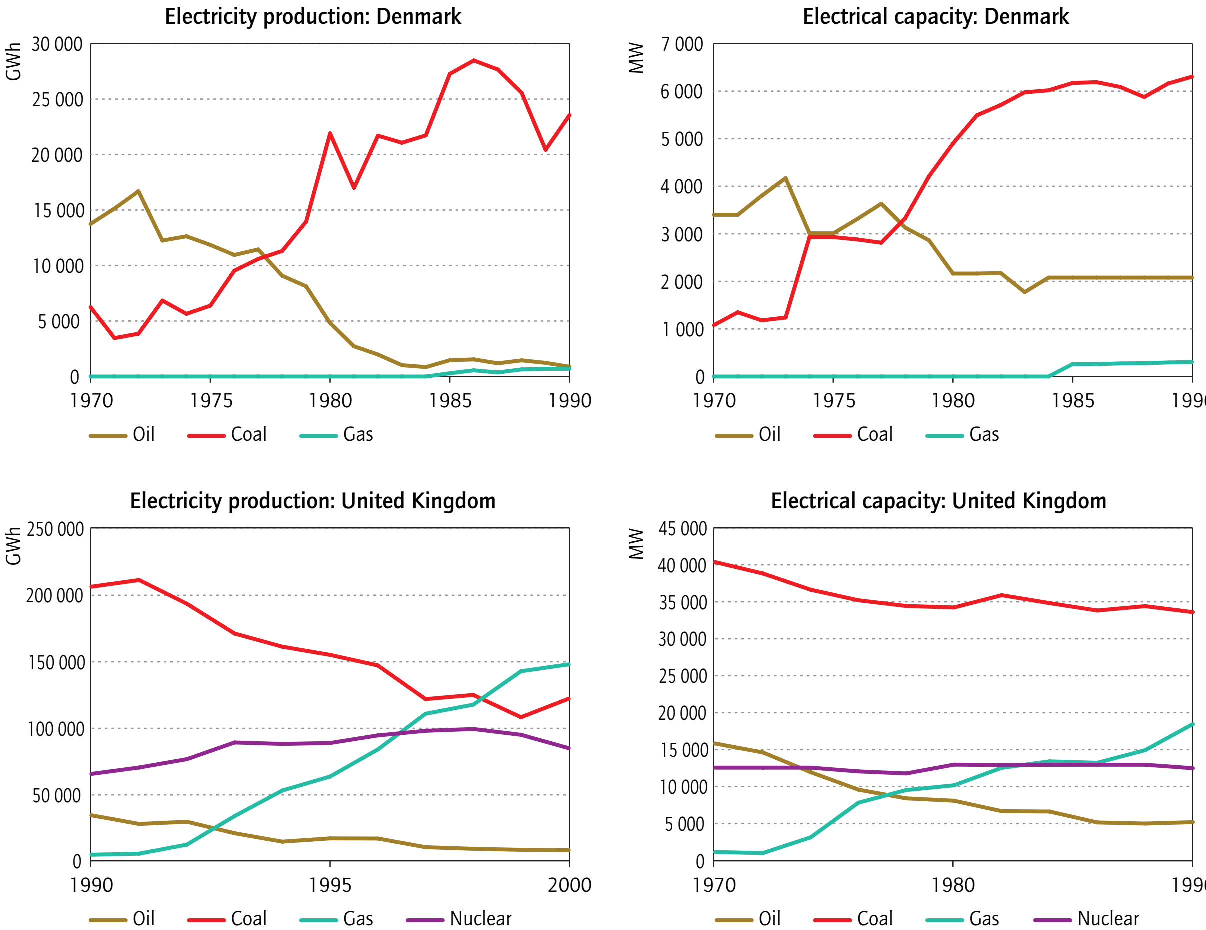
Before the first oil shock in the early 1970s, many electricity generating plants were oil-fired. The sharp increase in oil prices made many of these plants uneconomic, and led to their replacement. In Denmark, for example, electricity production from oil plummeted from 69% in the early 1970s to less than 5% by 1985; it was replaced by coal-fired plants for base-load production (Figure 2). In Sweden and France, the oil shock led to the scaling up of nuclear generation, with oil for base-load generation being phased out by 1985.

Similarly, the 1990s "dash for gas" in the United Kingdom prompted roughly a halving of oil and coal-fired generation in ten years, replaced by the new cheaper gas-fired technology. In each of these cases, the dramatic change in generation shares was not matched by a commensurate change in installed capacity: *e.g*. between 1970 and 1985 in Denmark, generation from oil plants dropped from almost 14 000 gigawatt hours (GWh) to less than 1 500 GWh, while the corresponding installed capacity was reduced by only 40%, from 3 400 megawatts (MW) to 2 000 MW. This indicates that, rather than being completely retired, many of the old plants stayed in service to meet peak demand periods.

These examples demonstrate that it is possible to dramatically change a region's power generation mix over a relatively short period of time. In looking forward to a low-carbon transition, it should be acknowledged that these transitions were pursued in a different context.

Figure 2

Historical electricity production and electrical capacity by fuel in Denmark and the United Kingdom



Source: IEA statistics, 2011.

First, they generally took place under regulated market structures, in which public utilities were able to pass on the cost of stranded plants to their customers or have it borne by taxpayers. In the current environment of wholesale electricity markets the question of who will bear these costs is unclear, as discussed further below.

Second, these transitions were driven by external shocks in generating costs – both fuel and technology costs – which the industry had no choice but to manage. By contrast, the transition to a low-carbon generating mix will be driven largely by policy decisions, and achieved either through carbon pricing or regulation (or some combination). Because government policy can be reversed, or exemptions or compensation granted, this future transition will not offer the same clarity for investors.

Policy-driven retirement of plants is already taking place around the world, in varying contexts. In the United States and Europe, air quality regulations are expected to lead to the retirement of a significant share of aging coal-fired plants (Celebi *et al.*, 2010). The Chinese government aims to close all coal-fired power plants with capacities below 50 MW, and to close power plants up to 100 MW unless they are converted to cogeneration of heat and power (Gupta, Vlasblom and Kroeze, 2001; Cao, Garbaccio and Ho, 2009). This policy targets reduction of sulphur dioxide (SO_2) emissions, but has co-benefits in terms of CO_2 emissions reduction since small power plants generally have lower fuel conversion efficiencies.

Policy issues

Carbon pricing, market structure, investment behaviours and uncertainty

Carbon pricing, either through taxes or emissions trading systems, is a cornerstone policy in climate change mitigation strategies. It can shift a region's electricity generating fleet to a lower-carbon mix in three basic ways:

- **Influencing the dispatch of existing plants**, shifting running hours from coal- to gas-fired generation. This sort of short-run fuel-switching is a significant factor in setting the current European Union Emission Trading Scheme (EU ETS) price of around EUR 15/tCO_2 (Deutsche Bank, 2010).
- **Affecting the relative economics of new plants** installed to meet demand growth or replace retired plants. In the current EU ETS, new gas-fired generation would be favoured over new coal-fired generation at a price of around EUR 25/tCO_2 (Deutsche Bank, 2010).[1]
- **Pushing old, high-emission plants out of the market** when the carbon price increases to the point at which the running costs or short-run marginal costs (fuel, carbon, fixed and variable operations and management) become higher than the costs of new investment (long-run marginal costs, including the cost of capital) in lower-carbon plants.[2] This may involve the retirement of plant before the end of its technical life, and potentially even before it has recovered its capital costs.

Only the third option involves early retirement of plants. Because a new plant has to recover capital costs in addition to running costs, this means that some old, fully-depreciated plants have a profit margin that can accommodate a significant carbon price before they become uneconomic. A modest carbon price could mean that gas (rather than coal) generation is more economic for any new build required to meet demand growth, while a much higher carbon price may be needed to prompt the replacement of existing coal with new gas-fired plants.

Although a simple, levelised cost analysis would imply that a plant be retired as soon as it becomes uneconomic, in reality investment behaviour is more complex. Decisions to retire plants, and to build new plants, are also influenced by uncertainties in future fuel and carbon prices, the role that a particular plant plays in an electricity company's fleet of power stations, and uncertainties in forward climate policies (IEA, 2007).

Electricity market structure and dynamics are also important factors in driving investment decisions. Deregulation of electricity markets, for example, has presumably made affected generators more sensitive to environmental compliance costs than they were in a world of rate-of-return regulation (when such compliance costs could typically be passed on to ratepayers). Another significant uncertainty arises from the structure of current wholesale electricity markets. Decarbonisation is likely to change the nature of price recovery in these markets, with increasingly long periods during which nuclear or wind energy set the market price at low or zero prices, interspersed with very high peak prices (see Hood in this volume for further discussion). This uncertainty around the distribution of future prices raises risk for investors, and poses a further risk to recovery of capital costs (Redpoint Energy, 2009). Investors also perceive significant political risk associated with the possibility governments will not follow through on climate targets or will implement policy that changes electricity markets during the life of their investments.

1. Even in the absence of a carbon price, gas-fired generation may be favoured over coal-fired for new builds for a range of reasons, in particular the inherent flexibility that makes gas-fired a better capital response to uncertain public policy.

2. If there is already surplus generating capacity, plant retirements may instead be prompted by electricity prices being too low to cover generators' costs. In either case, the retirement of plants will change the mix of generation, stimulating a corresponding change of price formation in the market.

All these uncertainties affect investor behaviour. Coupled with the potentially large quantity of underutilised old capacity kept in the system, they could lead to delayed investment in new plants (IEA, 2007). For owners, there is also value in retaining (rather than retiring) a plant to maintain reserve margins, or so that it can be restarted if electricity prices increase, or is available for use during peak periods. Both these effects would be expected to slow the rate of retirement when compared to simple predictions based on levelised costs in a situation of certainty. As a result, a higher carbon price would be needed to achieve the anticipated rate of capital turnover and CO_2 mitigation.

While carbon pricing is clearly a key policy tool, it will no doubt lead to increases in energy prices – which are of concern to consumers and governments.[3] As such, it is reasonable to ask whether supplementing the carbon price with additional decommissioning policies could drive the low-carbon transition at a lower carbon, and therefore lower electricity, price. Moreover, in the absence of a clear forward carbon price, there could be a rationale to supplement the carbon price with other policies as a means of improving plant owners' understanding of retirement and investment needs. In effect, supplementary policies would attempt to correct for the lack of clarity in current forward policy goals for CO_2 reductions (and hence the lack of robust forward price paths for emissions).

As discussed above, because older plants have more fully recovered their capital costs (and may thus require a high carbon price to prompt retirement), governments may wish to consider whether a regulated phase-out of older plants has merits for consumer costs, as long as it is clear that certain plants need to be retired to meet a CO_2 reduction objective. In this case, the carbon price needed could be lower, and allow for reduced electricity costs. The benefits of a lower carbon price would need to be weighed against the potential loss of efficiency (and potentially higher economic cost) of not allowing the carbon pricing to drive the lowest-price actions.

The complex interaction between carbon price and retirement should be carefully considered when suggesting supplementary policies to prompt plant retirement. Electricity prices in the German energy market, for example, are currently low due to an excess of generating capacity arising from, in part, government renewable energy mandates. Forecasts are that more than 20 GW of fossil-fuelled capacity will need to be retired to return margins to sustainable levels (Deutsche Bank, 2011).

3. Under marginal pricing, the same market clearing price is paid to all generators; this price is determined by the most expensive generating plant operating, usually a fossil-fuelled plant. Introducing a carbon price therefore increases the cost of every unit of electricity sold, whether it is of high- or low-carbon origin.

However, because carbon prices are currently low, these retirements are expected to be in older black coal and gas-fired plants, rather than in higher-emitting lignite facilities that have lower fuel costs. If a higher carbon price were present, a different set of plants might be candidates for retirement.

The financing and compensation issue

Early retirement of plants comes at a cost: the question is who will bear it? Modelling exercises assume that owners (and their shareholders) will bear the losses of plants that are made uneconomic by climate policy. Governments need to consider if this is a reasonable expectation.

The recent Australian debate about a previously proposed emissions trading scheme prompted significant discussions around compensation for the losses of brown coal generators, whose profits would have been affected (Australian Department of Climate Change, 2008). The debate reflected a tension between the concern that unforeseen regulatory change might increase the risk profile for new investors (by increasing their borrowing costs and prices for consumers), and the concern that low-carbon investment could be undermined if thermal investors were to be compensated – at a cost to consumers – for lack of appropriate foresight.

When considering the case for compensation, governments should remember that the intent of carbon pricing is to change the relative economics and, therefore, the actual operation of plants: it is expected that there will be winners and losers. Many generating assets will see increased returns as the carbon price increases; if a power company has diverse assets, it may see no impact or even a positive gain overall (Burtraw and Palmer, 2008). Thus, a decision to compensate all losses could easily undermine the purpose of the scheme.

During the deregulation of electricity markets, there was extensive debate over whether and how to compensate utilities for stranded costs (Baumol and Sidak, 1995; Boyd, 1996; Brennan and Boyd, 1996; Kolbe and Tye, 1996; Maloney, McCormick and Sauer, 1997; Beard, Kaserman and Mayo, 2003). Subsequent analyses indicate that compensation outcomes were often decided on a political rather than economic basis. Deregulation in other sectors (*e.g.* telecommunications and airlines) did not necessarily follow the same pattern of compensation. In the case of plant closures caused by climate policy, governments need to be mindful of any precedent this would set. If initial compensation is to be paid, policies should seek to minimise the risk of claims for ongoing compensation.

In the *WEO 2010* 450 Scenario, early closure of plants would lead to USD 70 billion in unrecovered investment costs.

These plants are mainly in OECD countries,[4] and are stranded by the rapid implementation of carbon pricing in this region. Globally, the amount at stake is only a few percent of the projected transition costs; in 2010-35, power-sector investment in the 450 Scenario amounts to USD 11.1 trillion, a net increase of USD 2.4 trillion compared with the Current Policies Scenario. But, at the scale of individual companies, it may represent a significant loss; according to the *WEO 2010* analysis, early retirement represents 28% of the investment costs of the plants retired. This could lead to a situation similar to that seen during early implementation of emission trading systems when worries of competitiveness losses for a few strongly affected industries often justified free permit allocations to the entire industrial sector – at substantial cost to governments.

Alternative policies to avoid the need for early retirement?

To meet an ambitious climate change mitigation target, governments must face the tension between the challenges of stringent short-term action, and the risk that early plant retirement will be needed at a later stage if it becomes necessary to accelerate the emissions reduction rate. Rather than providing direct compensation for early retirement of plants, governments may be tempted to slow policy implementation or provide exemptions to existing generators (thereby increasing the burden on new generators). If existing plants are allowed to run longer, there will clearly need to be a more dramatic reduction in the carbon intensity of new investments to stay within the same emissions budget. This in turn implies a higher carbon price at an earlier date, or equivalent ambitious early action.

If early retirement is to be avoided, there is a short-term policy need to either strengthen and give more certainty in carbon price signals (to trigger more ambitious early action) or potentially to supplement carbon prices with additional policy to guide investments. Since current carbon price signals are weak and uncertain compared to the levels indicated necessary by the models, they are not generally clear enough to guide investor decision making.

There are alternatives to early retirement, including: retrofitting plants with state-of-the-art efficient boilers, turbines, etc., or with carbon capture and storage (CCS) technology; switching from coal to a lower-carbon fuel (such as gas); or using biomass in co-firing. In the United Kingdom, for instance, new fossil-fuel plants are required to make provisions for a future retrofit of CCS, and European investors are required to assess the potential for CCS retrofitting.

Conclusions

The rapid decarbonisation of power generation featured in many climate policy scenarios may require early retirement of many coal-fired plants, shortening their economic life to significantly less than their long technical lifetimes. Policy makers should consider this carefully when planning climate policies.

If early retirement is not seen as politically feasible in the coming decades, there may be a need to enact even tighter policy restrictions on new plants (implying higher carbon prices) in the short term, to compensate for the emissions from existing plants that will continue to operate instead of being retired.

If governments decide that early retirement is an option, they should adequately consider which policies are best to trigger and accompany this action, taking account of factors such as maximising certainty for investors and goverment over the transition period, and promoting flexibility and economically efficient outcomes. Uncertainty creates a bias towards retaining plants for peak periods or re-firing them if electricity prices increase. Moreover, old, fully-depreciated plants have a profit margin that can accommodate a significant carbon price before they become uneconomic. Quite high carbon prices may therefore be needed to displace existing capacity before the end of its technical life. If the related costs for electricity consumers are deemed to be a serious political issue, governments may wish to consider supplementary policies to assist the phase-out of older plants. Finally, goverments will need to decide whether and how to address claims for compensation of "stranded costs" for the firms that would retire plants.

4. Outside the OECD, the model shows rapid expansion, then contraction, of coal-fired capacity in China, but these plants have a shorter payback period so are not generally stranded before their investment costs are recovered.

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Renewable energy policy and climate policy interactions

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This paper explores the relationships between climate policy and renewable energy policy instruments. It shows that, even when CO_2 emissions are appropriately priced, specific incentives for supporting the early deployment of renewable energy technologies are justified by the steep learning curves of nascent technologies. This early investment reduces costs in the longer term and makes renewable energy affordable when it needs to be deployed on a very large scale to fully contribute to climate-change mitigation and energy security. The paper also reveals that both CO_2 prices and the measures to deploy renewable electricity create wealth transfers between electric utilities and their customers, although in opposite directions. This may be important when considering the political economy of the interactions between CO_2 pricing and renewable energy support in the future.

Critiques of renewable energy incentives

Renewable Energy (RE) technologies will play a very important role in reducing greenhouse gas emissions, but they alone will not suffice to keep climate change manageable, *i.e.* in the vicinity of 2°C of global temperature increase. Energy efficiency improvements have been identified as having the largest potential for energy-related carbon dioxide (CO_2) emission cuts. The IEA also includes greater nuclear power deployment, as well as carbon capture and storage (CCS) technologies in its climate-friendly scenarios. The question is often raised: is it necessary or even useful to have two distinct types of policies and objectives, one series for promoting RE technologies, and another one directly addressing GHG emissions? Some economists argue that RE incentives are counterproductive when they interfere with a cap-and-trade policy such as the European Union's Emissions Trading System (EU ETS). By lowering the price of carbon, policies that support RE appear to favour more polluting forms of fossil fuels. More importantly perhaps, it is argued that CO_2 prices single-handedly drive the optimal deployment of low-carbon technologies, including renewables. According to these scholars, specific renewable policies would not only be redundant but also raise the cost of climate-change mitigation.

This paper critically reviews the arguments relating to the interactions between RE and CO_2 policy instruments. It shows that learning should be taken into account when assessing the long-term benefits of achieving reductions that have a high short-term cost but steep learning curve, and which hold the promise of delivering competitive climate-change options later on. Further, the risk that some other mitigation options fall short should motivate policy makers to consider higher-cost options that effectively provide insurance against catastrophic climate change.

This paper also shows that other interactions between RE deployment and climate-change mitigation policies appear through "merit-order" effects on the electricity prices in deregulated markets. These interactions open a whole set of issues relating to the long-term financing of electricity systems, a topic that warrants further research.

The "interaction" argument

In a thought-provoking paper, Böhringer and Rosendahl (2009) claim that "Green Serves the Dirtiest", through a so-called "interaction" effect. RE support policies (quotas in their model – tradeable green certificates or TGC more generally) do, as a first-order effect, reduce the profitability of "black power" (*i.e.* from fossil fuels), and thus reduce the output from all fossil-fuel producers. However, in a country or group of countries like the EU, where an emissions trading system (ETS) covers the CO_2 emissions from electricity production, emission reductions resulting from the deployment of renewables lead to a lower CO_2 price. In essence, they reduce the advantage given to efficient combined cycle gas turbines over coal plants. Emissions are not reduced further by RE incentives, as long as the quantitative cap is set once and maintained, insensitive to CO_2 prices.

The model presented in Bohringer and Rosendahl actually reveals something quite different. When the emission constraint is imposed, power production by lignite power (the "dirtiest technology") decreases by 41% if no additional green quota is in place. However, when a green quota is introduced at 23% of total electricity, output from lignite power plants still decreases, but only by 31%. The "benefit for the dirtiest" is not absolute, but clearly relative – an increase of 17% over the scenario with the ETS alone. Therefore, potential investors in coal plants are still confronted with a negative outlook.

The cost-effectiveness argument

Many believe that the overlapping of CO_2 and RE policy instruments increases the costs of achieving the CO_2 objective. This argument follows a strong logic: the more expensive mitigation achieved through RE displaces reductions that the ETS would achieve at a lower cost. In cases where RE would be driven by the CO_2 price alone and RE incentives were to persist, the additional support only creates windfall profits.

The exact extent of the additional cost of RE support in achieving a given CO_2 objective is difficult to evaluate. It depends on the cost of the promoted RE sources and the amount of CO_2 they avoid, and on the cost of avoiding the same quantities through measures that would have been mobilised, had renewables not been promoted. Electricity generation from renewables is particularly challenging: it requires an assessment of the CO_2 content of the kWh they displace, which depends on the merit order (*i.e.* the last production capacity required to fulfil the demand at every moment). These elements typically differ from one country to the next. This difficulty, however, does not make the point any less valid.[1] The cost-effectiveness argument is often part of the broader argument that climate policies should be technology-neutral, for governments are not good at "picking winners".

Supporting RE incentives

Various arguments can be made in response to the criticism of specific RE incentives when a broader CO_2 policy is in place. This paper considers the following:

▶ Climate change mitigation is only one among many motives behind the promotion of renewables.

▶ Climate change is a long-term issue. It may be optimal to implement higher-cost options together with lower-cost options, if the deployment of the former has the potential to reduce the longer-term costs of mitigation.

*1. A fuller investigation of the short-term effects of these interactions would necessitate assessing the macro-economic effects of CO_2 prices and changes in electricity prices. If RE deployment were required to achieve the short-term CO_2 objectives (*i.e. *if no cheaper options were left out), having a specific RE incentive could help keep the CO_2 and electricity prices lower, and lower their macro-economic effect. As the modelling by Böhringen and Rosendhal suggests, this is probably not the case today. But if their short-term assessment holds in the current context, it may not always hold.*

Other drivers of RE deployment policies

The support to renewables may have various drivers other than climate mitigation. These include 1) a contribution to the reduction of other pollutants and related risks arising from the use of other energy sources; 2) a contribution to increased energy security, reduced dependence on imported fossil fuels; 3) hedging against price volatility and long-term price increase of fossil fuels; 3) and a willingness to develop local employment, sometimes reinforced by the perception of the first mover's advantage.

These arguments are valid. Renewable technology deployment offers many benefits beyond its contribution to climate change mitigation, which need to be assessed and valued. However, they may fall short of justifying the extra cost. For instance, RE may substitute for less costly CO_2 mitigation options that produce similar benefits, or some of them.

With respect to CO_2 emissions from fossil fuel combustion, possible emission reductions can come from energy efficiency improvements, fuel switching to fuels with lower carbon content (usually from coal to natural gas in electricity production), nuclear or renewable, or carbon capture and storage. It is important to consider how these options fare relative to the other objectives possibly attributed to the policies supporting RE deployment.

Energy efficiency improvements contribute as much or perhaps more than RE to all the objectives assigned to RE policies. They reduce other pollution, increase energy security, and often create local jobs (*e.g.* for home insulation).

Fuel switching may or may not contribute to increased energy security, depending on the resources of the country considered, and its relationships to exporting countries. It usually reduces other pollution along with CO_2 emissions – burning natural gas usually entails lower NO_x, SO_x, heavy metals and particulate emissions than burning coal.

Carbon capture and storage increases fuel consumption, and thus does not provide any hedge against price volatility and long-term price increase. It may, nevertheless, increase energy security in a carbon-constrained world for countries with coal resources (or even without, considering a possible diversification in fuels and providers). It captures and stores most atmospheric pollutants as well as CO_2.

Nuclear power does not emit CO_2 and the other pollutants generally associated with fossil-fuel burning. Although nuclear raw fuels must often be imported, their share in the overall cost is much smaller than in the case of fossil fuels, and the diversification of fuels and exporting countries lessens energy security risks.

Another aspect often overlooked in assessing policies with multiple objectives is that other means can often be employed to achieve each objective individually. For example, while it is legitimate to account for the reduction of particulate, SO_x or NO_x emissions when renewable energy substitutes for some fossil-fuel burning, one must also consider other possibilities (and associated costs) to reduce the same emissions. This could be achieved through cleaning the fuel, using low-NO_x burners or end-of-pipe devices such as filters, scrubbers, flue-gas desulphurisation and others.

As a result, the multiplicity of objectives pursued with policy instruments specifically supporting the deployment of RE technologies may fall short of fully justifying them if the analysis remains focused on short-term effects – especially when they displace energy efficiency improvements.

The need for a longer-term perspective

The interactions between RE and CO_2 policy instruments are likely to increase the cost of achieving the CO_2 target set for the relatively short term. However, climate change mitigation extends far beyond the relatively short-term perspective in which CO_2 targets were set.

Climate change is a very long-term issue. The Fourth Assessment report of the Inter-governmental Panel on Climate Change offers emissions ranges for categories of stabilisation scenarios from 2000 to 2100 (IPCC, 2007). Mitigation efforts will need to extend over this entire century and maybe beyond.

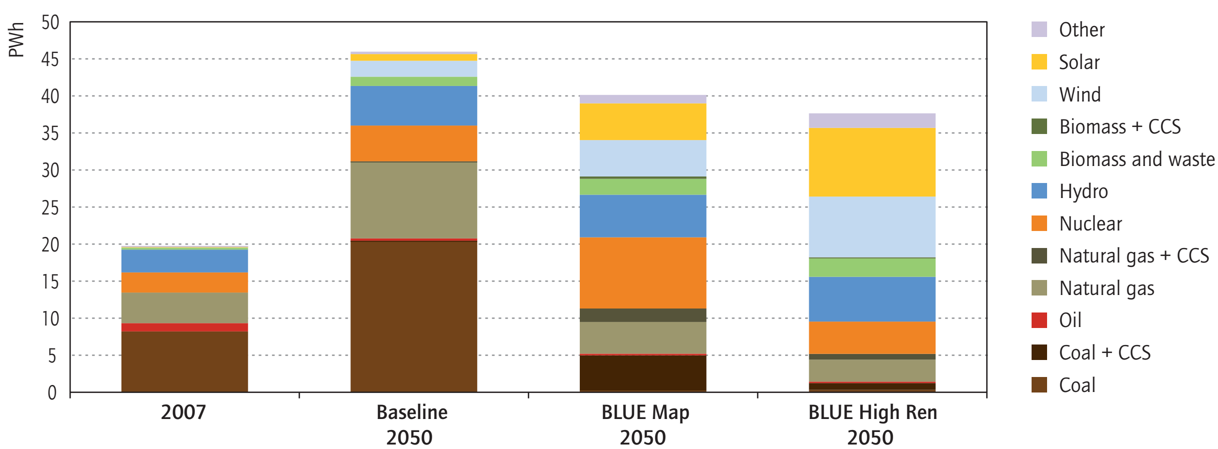
It is widely acknowledged that deep cuts in emissions will require a broad portfolio of mitigation options. The IEA *World Energy Outlook 2010* (IEA, 2010a), suggests that by 2035 energy efficiency improvements above the baseline would provide 47% of the CO_2 emission reductions in the 450 scenario; additional renewable and biofuels 24%; carbon dioxide capture and storage 19%; and additional nuclear power plants 8%.

The IEA *Energy Technology Perspectives 2010* (IEA, 2010b) shows that by 2050 renewable energy sources will provide about half the global electricity (Figure 1). The BLUE Map Scenario charts a path to a reduction in global energy-related CO_2 emissions by 50% from 2005 levels at the lowest possible overall cost. The High Renewable variant of the BLUE Map Scenario suggests that, if nuclear, CCS or energy efficiency improvements were to fall short, or if deeper cuts in CO_2 emissions were warranted, RE sources could provide up to 75% of global electricity by 2050, with an increase in the costs of electricity of about 10%.

The necessary large-scale deployment of low-carbon energy technologies in the coming decades will result from significant cost reductions and a price on CO_2. The costs of deploying CCS technologies or concentrating solar electricity are divided by four from current levels; the cost of photovoltaic (PV) modules by six; and the cost of fuel cells for vehicles by an even greater figure. The costs of associated CO_2 emissions reductions with respect to the baseline scenario can be reduced even more. For example, when renewable energy technologies become fully competitive, the marginal cost of associated emission reductions falls to zero.

Figure 1

Electricity generation by sources in 2007 and 2050 under Baseline, BLUE Map and BLUE High Renewable scenarios



Source: IEA 2010b.

These cost reductions are expected to come, in large part, from an early deployment of these technologies. This is the crux of the longer-term perspective: even if the early deployment of some renewables now has higher costs of immediate emissions reductions than other options, this deployment must be undertaken if the resulting cost reductions are key to future large-scale deployment. The early deployment of RE technologies can be a cost-effective measure for long-term climate-change mitigation, even if it looks too costly when only short-term reductions are considered.

Technical change can be seen as a cyclical process, based on two-way feedback between market experiences and technical developments. Not only are market prospects the most vital stimulant of industry R&D efforts, but more importantly the deployment of technologies in a competitive marketplace is a key source of information on their strengths and weaknesses, critical to orient applied R & D efforts. Market development and technology development go hand in hand.

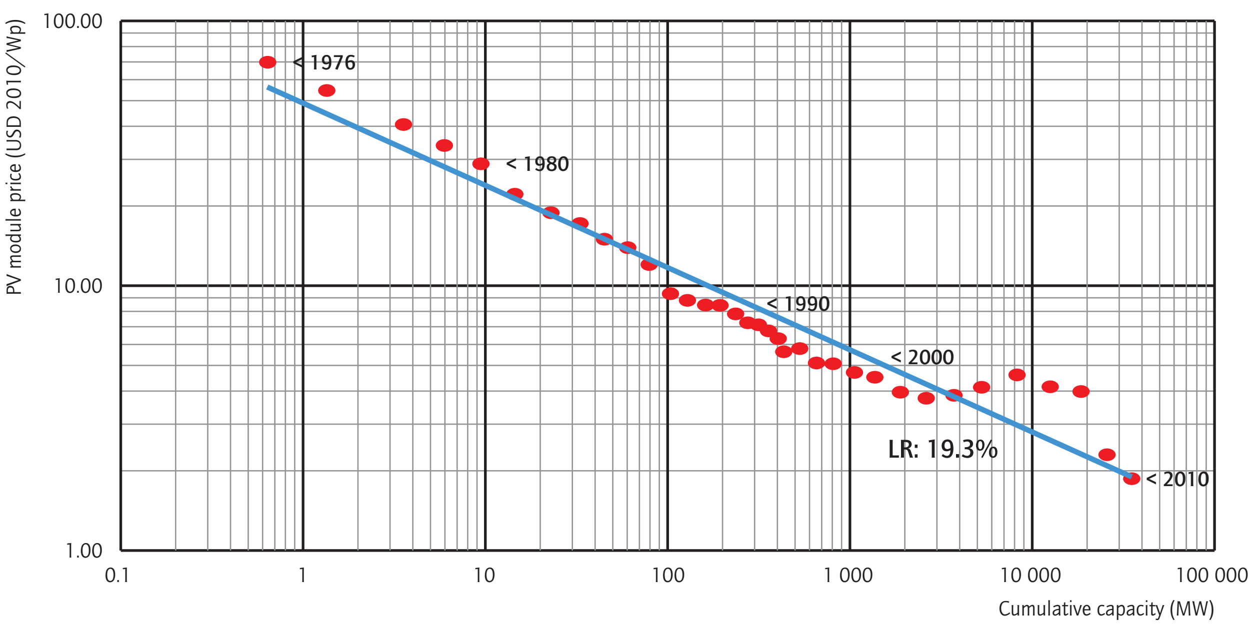
This perspective is borne out by lessons from past technological developments, which reveal that the costs of technologies decrease as total unit volume rises. The metric of such change is the **progress ratio**, defined as the reduction of cost for every doubling of cumulative installed capacity. This ratio has proven roughly constant for most technologies – although it differs significantly from one technology to another. New techniques, although more costly at the outset, may become cost-effective over time if they benefit from sufficient deployment. So-called learning curves illustrate this phenomenon with straight lines on log-log graphs (Figure 2).

Still, it remains difficult to clearly distinguish between the effects of R&D efforts and those arising from market deployment (see Fischer and Newell, 2008; Philibert, 2011). Moreover, the coexistence of increased market shares and decreased costs does not necessarily demonstrate that the former caused the latter. The causality relationship works both ways: when costs decrease, market shares increase.

Some recent studies attempt to shed light on the determinants of cost reduction associated with the learning-curve theory. For example, Nemet (2006) studied the cost reductions of photovoltaics (PV) – whose support policies are perhaps the most controversial. The cost of PV has declined by almost a factor of 100 since 1950, more than any other energy technology in that period. His study focussed on crystalline silicon PV modules and explores the drivers behind technical change in PV by disaggregating historic cost reductions into observable technical factors. He identified three major factors of cost reductions from 1980 to 2001: manufacturing plant size, module efficiency and silicon cost.

Figure 2

PV learning curve



Source: Breyer and Gerlach, 2010.

Originally (Arrow, 1962), learning-by-doing was attributed to "increased workers' productivity" due to experience, other factors remaining constant. Nemet suggests this was a relatively minor factor underlining the drivers of cost reduction. The success of some new entrants was instead due to their capacity to raise capital and take on the risk of large investments. Ten out of the 16 major advances in module efficiency can be traced back to government and university R&D programmes, while the other six were accomplished in companies manufacturing PV cells. Finally, reductions in the cost of purified silicon were a spill-over benefit from manufacturing improvements in the microprocessor industry.

Increased deployment has thus been, through various channels, the most important driver of cost reductions. Nemet's analysis supports the policy prescription based on deployment-led cost reductions which is followed in IEA *ETP* projections to 2050. The projections are also based on an analysis of the cost reduction potentials to be mobilised in future learning phases, and milestones towards competitiveness in progressively broader electricity markets (see IEA *Technology Roadmaps*, in particular IEA, 2010c).

Discussion: locking-in, locking-out

The somewhat provocative expression "green serves the dirtiest" designates policies supporting renewable energy deployment as the only culprit of this paradoxical – but relative – advantage given to the most CO_2-emitting fossil fuels. However, the problem, if there is one, arises from the interaction of the two policies. ETS alone would certainly give an advantage to the cleanest fossil fuels. RE policies alone would essentially disadvantage all types of fossil fuel.

The addition of an RE policy to an existing ETS does not lead to additional CO_2 emission reductions from the entities covered by the ETS, as the overall cap remains unchanged. This is not a failure of the RE policy. It is a simple and logical consequence of the very design of the ETS, which is a fixed quantity policy. Things would be different if the policy directly addressing CO_2 emissions were a price policy or a hybrid policy, or if the emission cap were to be set in conjunction with the expected contribution of RE support policies. In the case of a price policy – say, a carbon tax – CO_2 reductions driven by the RE policy could add to the CO_2 reductions driven by the carbon tax, depending on the strength of each. In the case of a hybrid policy, such as an ETS with a price floor, a reduction of the carbon price resulting from the RE policy could lead to additional CO_2 emission reductions, in the event that the carbon price were to fall below the level of the price floor.

The remaining question is whether the short-term, relative advantage given to more CO_2-intensive generation technology could lock-in of such technology, at the expense of efforts to cut emissions.

The feedback process from markets to technical improvements providing increasing returns tends to create "lock-in" and "lock-out" phenomena: it is not (always) because a particular technology is efficient that it is adopted, but (sometimes) because it is adopted that it will become efficient (Arthur, 1989). Technological paths may very much depend on initial conditions. As such, technologies having small short-term advantages may "lock-in" a society into technological choices that may have lesser long-term advantages than technologies that are "locked-out".

How does this apply to the issue of fuel shifting *vs.* renewables? Fossil-fuel technologies have had a very large global market for more than a century. They can still improve, but marginally, while the introduction and deployment of new renewable energy technologies from a very narrow basis holds the possibility of more considerable progress.

It is therefore unlikely that the rather minor advantage given to more CO_2-intensive generation described by Böhringer and Rosendahl (2009) would enhance the lock-in of these fossil fuel technologies. By contrast, RE policy instruments will unlock the potential of renewables.

While this fuel shift in electricity generation does reduce GHG emissions, in climate-friendly scenarios like the 450 Scenario of the *WEO 2010* (IEA, 2010a) the global consumption of natural gas decreases after 2025 while renewable energy production continues to expand. In this scenario, the contribution of renewables to electricity production reaches 14 500 TWh by 2035 (from 3 800 TWh in 2008), the contribution of modern renewables to the production of heat increases from 10% in 2008 to 16%, and the production of biofuels for transportation multiplies sevenfold.

A short-term fuel switch towards natural gas in existing capacities with low capacity factors entails immediate emission reductions; however, providing an incentive to build new gas-fired generating capacities – presumably efficient combined-cycle gas turbines – could make achieving deeper emissions reductions post-2020 more difficult and costly. CCGT plants established this decade would face competitive difficulties post-2020 in the face of tighter emissions targets/caps and higher carbon prices which, ultimately, would favour renewables. Although gas plants can be re-sold and moved, their owners would presumably argue for compensation and/or deferral or softening of post-2020 targets. From this viewpoint, less efficient but cheaper open gas turbines could paradoxically be preferred in that transition for their capability to serve later on, with quite low capacity factors, as back-up capacities for variable renewables.

Other possible forms of lock-in deserve greater consideration, in particular with respect to energy efficiency improvements. Some energy efficiency measures need to be undertaken at a given time – for example, when new plants or buildings are designed and built – or risk costing much more at a later stage. Accepting too large an investment in renewable technologies while neglecting timely energy-efficiency programmes clearly runs the risk of locking in societies' too-high energy consumption patterns, with detrimental long-term implications for both energy security and climate protection.

By the same token, such considerations suggest that climate policies can hardly be technology neutral. Transport infrastructures, city planning and building codes are long-term determinants of future GHG emissions, and require political decisions. As Azar and Sandén (2011) argue, the debate should not be about *whether* climate policies should be technology specific, but *how* technology-specific the policies should be. For example, should one support all renewable electricity technologies indiscriminately, or should one distinguish wind and solar as they take advantage of distinct resources and have different maturity levels? If so, with respect to solar should one distinguish between photovoltaic (PV) and concentrating solar power (CSP) or let the market value the thermal storage capabilities of the latter? Should one give different incentives to roof-mounted PV and ground-mounted PV devices, and/or to multi-crystalline PV and thin-film PV technologies? It is important when addressing these questions to strike the right balance between the chances of maximising the effects of learning investments and the risks of picking the losers instead of the winners, or of preventing useful competition.

Other interaction effects

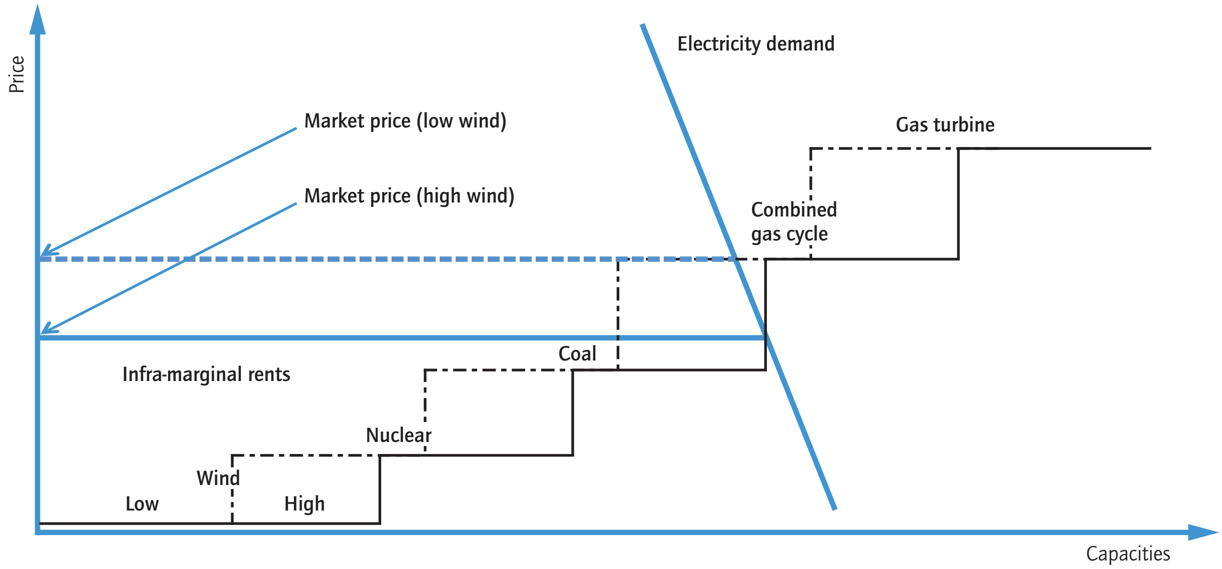
Another possible aspect of the interaction between CO_2 and RE policies seems to have received very little attention so far. It relates to how both policies transfer wealth from utilities to (deregulated) customers or vice versa.

Several studies show, from either theoretical models or observations from existing electricity markets, that the introduction of a large share of RE electricity tends to reduce the electricity price for deregulated customers (for a review, see Pöyry, 2010).

This can best be observed with wind power, which has recently become a significant player in some European countries. At about the same time, their electricity markets underwent deregulation. In deregulated markets, the price is set where supply and demand curves meet. The demand for electricity is relatively inelastic – it does not change much with the price. Typically, the supply is made up of various power technologies: wind, hydro, nuclear, combined heat and power plants, coal and natural gas plants, and gas turbines. In a power market the supply curve is called the "merit order curve" and goes from the least to the most expensive units, taking account only of the marginal variable costs (mostly fuel costs). Utilities bill all kilowatt hours sold on deregulated spot market at the price set by the last and most costly unit. Therefore, they get the benefit of so-called infra-marginal rents.

Figure 3

How wind power influences the power spot price at different times of the day.



The variable marginal cost of wind is very low, and wind power thus enters near the bottom of the supply curve. This shifts the supply curve to the right (Figure 3) and leads, in general, to lower power spot prices. This so-called merit order effect is larger in peak demand times, where the merit-order curve is especially steep. With more wind in the mix, the size of the rents is reduced, for the benefit of deregulated customers and to the detriment of utilities. These rents, however, are used, at least in part, to fund future capital investments, and their shrinking may impede the security of electricity systems.

A few empirical analyses have attempted to estimate this merit-order effect. For example, Sensfuß, Ragwitz and Genoese (2008) calculate that the volume of the merit-order effect would have been EUR 5 billion in 2006 in Germany if the entire electricity demand of a single hour was purchased at the corresponding spot market price. Meanwhile, the cost of incentives for renewables in that same year totalled EUR 5.6 billion.

The same authors estimate the value of the kilowatt hour produced by renewables (*i.e.* the costs avoided by substitution of electricity from other sources) at around EUR 2.5 billion, leaving EUR 3.1 billion as the true extra cost of RE support incentives. Of these, 0.6 billion are directly paid by final consumers, while the remainder EUR 2.5 billion are basically paid by utilities through a decrease of their infra-marginal rents due to the merit order effect. In this way, the merit-order effect transfers wealth from utilities to deregulated customers.

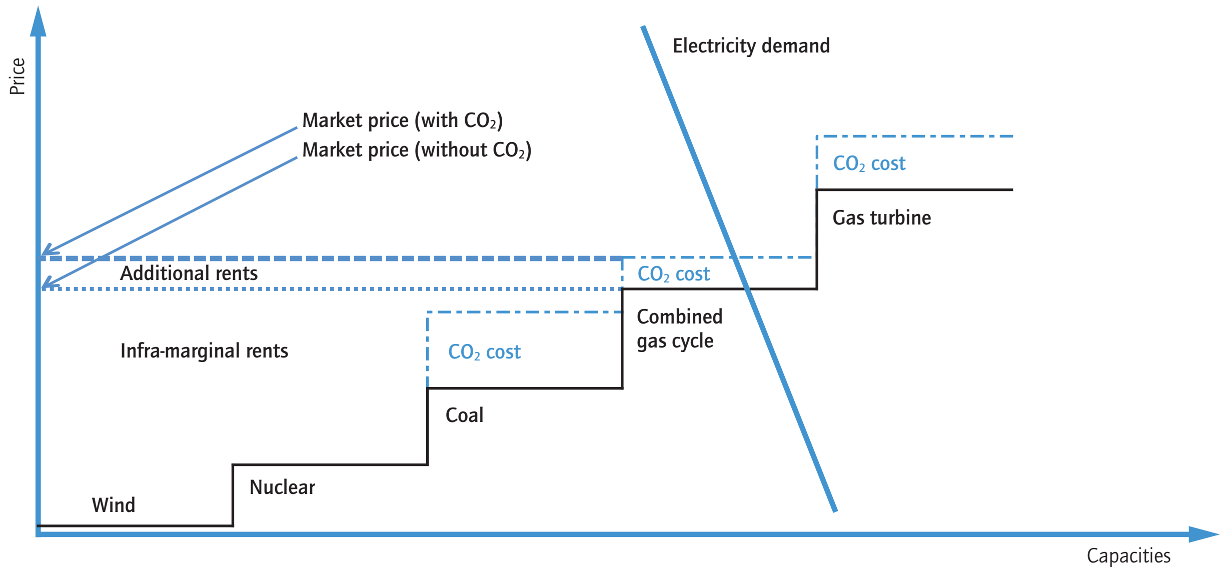
In reality, not all electricity is sold on the spot market in Germany, and bilateral contracts mitigate this result. Furthermore, the lower price paid by deregulated customers does not represent a lower cost for producing electricity. The overall cost of wind remains higher than some of the other generation technologies, even if the gap has considerably narrowed in the last decade. Utilities may ultimately find ways to pass part of these costs to customers.

A more recent study on wind power in Ireland provides even more striking results. Clifford and Clancy (2011), using a detailed model of the all-Island Single Electricity Market, show that the wind generation expected in 2011 will reduce Ireland's wholesale market price of electricity by around EUR 74 million. This is approximately equivalent to the sum of the Public Service Obligation (financing the feed-in tariff for wind) cost, estimated as EUR 50 million, and the increased "constraint" (or balancing) costs incurred due to wind in 2011. The reduction of Ireland's dependence on fossil fuels and the corresponding CO_2 reductions cost nothing in this case, despite the persistence of the support scheme which ensures recovery of the long-term costs of electricity generation from the wind even when the market prices are low.

It has also been shown that the electricity producers and utilities have enjoyed windfall profits from the implementation of the ETS, because the resulting increase in the marginal electricity prices have increased their infra-marginal rents to the detriment of their deregulated customers. This is also an effect of the merit order (Figure 4). Keppler and Cruciani (2010) have estimated these windfall profits for the utility sector as a whole at more than EUR 19 billion for the first phase of the EU ETS, and state that this phenomenon will only be partially mitigated by the auctioning of emission allowances from 2013 on.

Figure 4

Merit order and electricity price increase with CO_2 price



From this perspective, the interaction between RE and CO_2 policy instruments, which work in opposite directions in transferring wealth from utilities to industry customers and vice versa, tend to off-set each other's effects, at least in part.

The quantitative assessment of the impacts of the merit-order effect and other interactions needs further research. This assessment will be crucial to determine the real costs of renewable energy incentives for society.

Conclusion

The juxtaposition of a CO_2 policy instrument of a fixed quantitative form, such as the EU ETS, and of policy instruments specifically promoting the early deployment of RE technologies, may lead to a CO_2 price that is lower than it would have been otherwise. It may also raise the overall costs of achieving the short-term CO_2 reductions of the ETS, as this is attained through some costlier emission reductions driven by RE technology deployment. Meanwhile, both policies entail wealth transfers between utilities and deregulated industry customers that work in opposite directions, thereby off-setting each other's effect.

Looking farther into the future, the prominent role of RE technologies in mitigating climate change becomes more important. Current policies pave the way for making their necessary large-scale deployment affordable, thanks to learning-by-doing processes in the broad sense of the term.

Opponents to RE policies have yet to demonstrate their potential to lock-out the cleaner fossil fuel technologies in the same way that they unlock the RE technologies. The optimal mix of R&D support and early deployment incentives remains difficult to design with great precision, as learning curves are useful tools but not an exact science.

One possible policy recommendation would be to better take into account the potential interactions among policy instruments, in a way that reinforces the effectiveness of both climate and RE instruments.

This examination of the interactions between RE technology deployment and CO_2 emission-reduction policy instruments also reveals important areas for future investigation. The reduction of infra-marginal rents for utilities resulting from the merit-order effect raises issues relating to future investments in new capacities, as well as research relating to the appropriate calculations of true benefits and costs of renewables in complex electric systems. The true cost of the deployment policy for ratepayers is not the simple sum of the incentives, but much less, as renewables progressively reduce the market costs of electricity through the merit-order effect. Finally, how CO_2 prices and RE deployment interact in wealth transfers between various stakeholders, notably electricity customers and utilities, deserves further scrutiny.

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Integrating EVs and PHEVs into the electric grid: long-term projections of electricity demand and CO_2 emissions

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Worldwide CO_2-emissions constraints could stimulate the rapid development of electric vehicles (EVs) and plug-in hybrid electric vehicles (PHEVs) as a much cleaner means of transportation than standard vehicles. This paper provides new findings on this topic based on IEA projections for the year 2050. Questions covered include how much grid-electricity demand the use of PHEVs would create globally and by region, and how PHEV battery electric range affects the percentage of driving on electricity and net CO_2-emission reductions. Although PHEVs, along with EVs, would increase global electricity demand by 2050, the net reduction in CO_2 emissions is clearly positive, owing to vehicle efficiency and avoided gasoline/diesel use.

Electricity in vehicles and climate policy goals

In the IEA BLUE Map scenario, the IEA anticipates great numbers of electric and plug-in hybrid vehicles in use around the world by 2050 (IEA, 2010). This is part of a broader scenario to achieve very low carbon dioxide (CO_2) emissions from transport through improvements in efficiency, alternative fuel use, and changes in travel patterns. Following the BLUE Map scenario, CO_2 emissions from transport by the year 2050 are anticipated to be 5.4 gigatonnes (Gt) of CO_2 lower than if a business-as-usual, or Baseline, scenario is followed. Both pure-electric vehicle (EV) and plug-in hybrid electric vehicle (PHEV) technologies greatly improve efficiency and shift energy demand from petroleum fuels to electricity provided by the grid. The manner in which EVs and PHEVs eventually source electricity from the grid must be better analysed to determine the true CO_2 emissions impact and technological considerations for climate policy.

This paper summarises the results of the *Energy Technology Perspectives 2010* EV/PHEV projections and impacts on electricity use. It extends the *ETP* analysis using a new tool, the "electric and plug-in electric vehicle module" of the IEA Mobility Model (MoMo) (see text box on following page) and addresses a number of questions accompanying the electrification of the light-duty transportation sector:

▶ In the BLUE Map scenario (high PHEV adoption), how much grid electricity demand do PHEVs create over time and in different regions of the world? How does this translate into reductions of CO_2 emissions as a function of the electricity-generating profiles of different regions?

▶ For PHEVs, how does the configuration (*e.g.* the battery's electric range) affect the percentage of driving on electricity, and in turn, the vehicle's electricity demand and CO_2 emissions?

The basics of electric vehicles in climate change mitigation

In 2005, transport accounted for 23% of global energy-related CO_2 emissions (IEA, 2010). It now accounts for more than half the oil used worldwide and nearly 25% of energy-related CO_2 emissions. Petroleum continues to account for about 97% of transport energy use. In order to change, future transport developments must follow a radically different route: this means new types of vehicles and fuels, used in new ways. The IEA BLUE Map scenario envisions a completely different set of propulsion systems and fuel-use patterns in place by 2050. The light-duty vehicle technologies in the BLUE Map scenario include gasoline and diesel hybrids, electric and plug-in hybrid electric vehicles, and fuel-cell vehicles (after 2020). These vehicles account for nearly 100% of sales by 2050, with electric and plug-in hybrid vehicles accounting for more than half. Even by 2020, the BLUE Map includes around 6 million sales per year of EVs and PHEVs; this figure rises to over 100 million per year by 2050.

EVs have only battery-powered motor propulsion, whereas PHEVs are essentially hybrid vehicles containing both an internal combustion engine and electric motor system, with an enlarged battery pack that can be plugged in to recharge. The EV models being introduced today typically have a range of 100-150 kilometres, whereas PHEVs have an electric range of 20-50 kilometres. PHEVs also have the advantage of a liquid-fuel engine capable of long-range travel between refuellings.

A key issue is the impact of the electric travel possible with PHEVs. Since the electric range is short, it may only provide a small share of daily travel, with the liquid-fuel engine providing the rest. The results of a previous study for the United States show that a fairly low-range PHEV (*e.g.* with a range of 32 km or 20 miles) can shift a surprisingly large share of travel to electric – up to 65% of the annual driving distance (Weiller, 2011).

The ***EV/PHEV Module*** *is a new component of the IEA Mobility Model (MoMo), created in order to explore the electricity demand of different EV/PHEV scenarios and assumptions, and the* CO_2 *impacts associated with electrification of LDVs and particular levels of resulting electricity demand. Like the rest of MoMo, the module separates the world into 22 countries and regions. It allows projections of vehicle sales, stocks, travel and energy use to 2050.*

This percentage will depend on the average daily driving distance and the daily variation in this distance. In any case, a PHEV can provide "base-load" driving on electricity and significantly reduce liquid fuel use.

Electric and plug-in hybrid electric vehicles recharging from the grid will instigate increased power generation. Depending on the success of these vehicle types to penetrate the Light-Duty Vehicle (LDV) market, additional generation capacity may be required in the long term. The electricity sector relies on a mix of fuels that may vary each day, as demand peaks at times of high activity, and in the long term as power plants are installed and retired. The time of day at which EVs and PHEVs recharge will have an impact on total CO_2 emissions from these vehicles. This paper presents total emissions from vehicle-charging in a number of scenarios based on the following comparisons:

- Short-range PHEVs versus longer-range PHEVs' dominance of the market (full-EVs do not change in either case, but further work will concentrate on PHEV-EV interdependence).
- Baseline versus BLUE Map electricity-mix evolution.

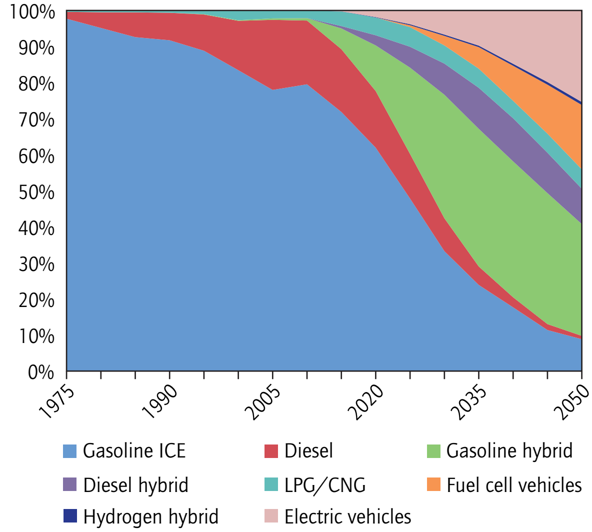
Vehicle shares under a long-term CO_2-emissions constraint

In the *ETP* projections new EV and PHEV models are introduced to the mass market beginning in 2010. From 2015 to 2020, sales per model and the number of existing models increase fairly rapidly as companies move toward full commercialisation, reaching about 7% of all new LDV sales in 2020, 20% by 2030 and over 50% by 2050 (Figure 1).

This fleet is a mix of pure electric vehicles and plug-in hybrid vehicles. PHEVs are further subdivided by electric-driving ranges, with a mix of vehicles able to drive between 20 kilometres and 120 kilometres (PHEV-20 and PHEV-120, respectively). Thirty- and 60-km-range PHEVs (PHEV-30 and PHEV-60) are expected to be the most common intermediate-range standards available on the market. With total plug-in vehicle sales taken from the *ETP 2010* BLUE Map, we explore two scenarios with different shares of PHEV types in the fleet.

Figure 1

Vehicle sales shares under the BLUE Map scenario



Source: IEA 2010.

Under scenario A, **low-range PHEVs** are most successful (Figure 2). In this scenario, 20- and 30-km PHEVs are the only PHEVs sold on the market. This could result from EVs having become particularly economical private vehicles and having taken the market share from longer-range PHEVs. PHEVs in this case are mainly a relatively low-cost electrification option for people who: a) have relatively short daily driving ranges and thus benefit even from the short electric range of PHEVs; and/or b) want some electric range but also plenty of liquid-fuel range for long trips. Such vehicles will enable drivers to reduce gasoline consumption and increase their vehicle efficiency without committing to the all-electric vehicle.

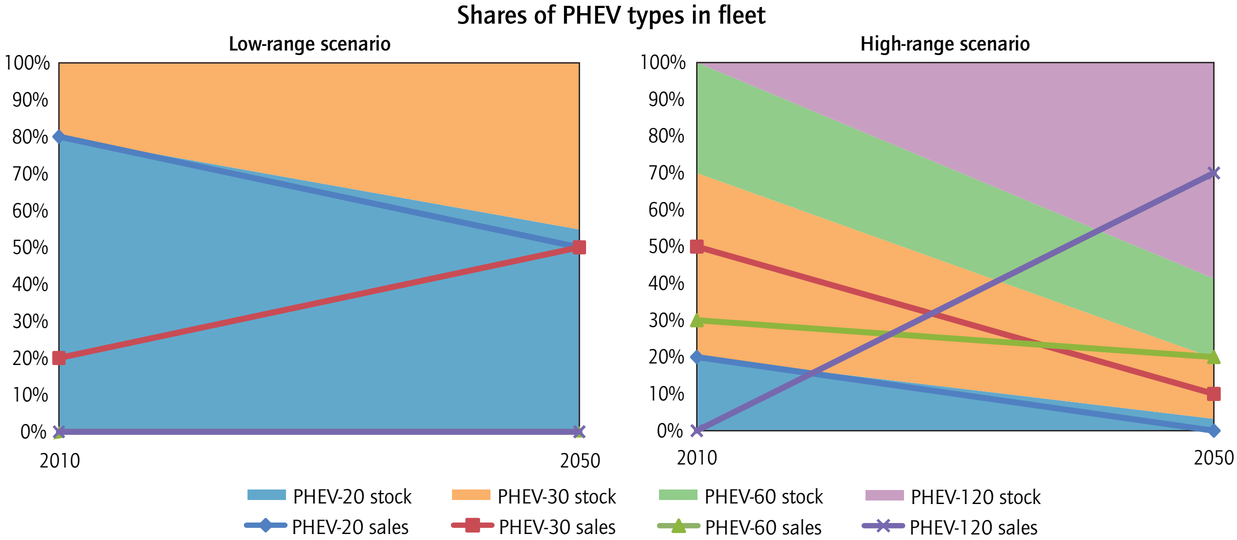
Under Scenario B, **high-range PHEVs** are most successful. This scenario supposes that PHEVs with higher range gain prevalence over low-range PHEVs (those with battery life of 20-30 km). PHEV-120s quickly dominate the market, reaching 70% of sales by 2050, due to their dual advantage of a high share of travel on electricity and reliable unlimited driving range on liquid fuel when the battery is discharged.

The critical role of vehicle driving range

PHEVs' electricity consumption depends on battery size and driving range. The share of distance travelled on grid-provided electricity relative to the total distance travelled, which we call the "utility factor", is used for the evaluation of PHEVs' electricity demand. We obtain the utility factor measures from an analysis of driving statistics from an American travel survey (Weiller, 2011).

Figure 2

Low-range (scenario A) and high-range (scenario B) PHEV scenarios



Weiller's study is based on historical driving patterns of gasoline and diesel vehicles, not EVs or PHEVs. Thus the electric range implied could actually underestimate real electric range if the driving habits of EV and PHEV owners are different from those of the average driver of regular motor vehicles. As well, since American drivers tend to travel much farther than those in many other countries, the estimates used here for electric driving share may be below the actual electric-driving share in countries where average daily driving is less. Further, if public charging stations at workplaces and commercial centres were installed and used in addition to home recharging (not considered here), the percentage of electric driving would become even higher.

Weiller's analysis shows that, starting with vehicles with short battery driving range, increasing battery size is strongly beneficial. A PHEV-10 will travel 30% of its annual distance on electricity, while a PHEV-20 travels around 47% on electricity. But marginal gains decrease with further range increases: an additional doubling to a PHEV with 40 kilometres of range will increase electric travel only by about a third (from 47% to 64%); this simply reflects that the first 40 kilometres of daily driving account for, on average, 64% of total driving in the United States. Thus, using just a night-time charge, these percentages should be achievable.

For fully electric vehicles, three types are assumed in the EV module, with 150, 200 and 400 kilometres of range. Because the share of electric travel of all EV types is 100%, the type of EV does not directly influence electricity demand or CO_2 emissions. EV type would, however, affect driving range and vehicle cost, so could influence driving patterns and market share. Because these aspects are beyond the scope of this paper, the market shares are simply assumed within the definition of the scenarios.

Electricity: fuel mix and CO_2 emissions

Grid-electricity demand is calculated as total electricity charged from the grid in kilowatt hours (kWh), excluding transmission and distribution losses, in a given region. In this calculation, the number of vehicles in stock and average annual distance driven per vehicle (in kilometres) are taken from the MoMo database, which is frequently updated with travel-survey results (IEA, 2009). The annual vehicle distance is assumed to be the same across vehicle categories (cars or light trucks, EVs or PHEVs).

When a PHEV runs in electric mode, it is considered to have the same efficiency, or rate of electric consumption, as a pure EV. Electricity usage per kilometre of travel in the EV module is projected to decrease slightly over time, from around 0.25 kWh/km in 2010 to 0.23 kWh/km in 2050 in the BLUE Map scenario, thanks to improvements in technology. These figures, which depend on the weight and other characteristics of vehicles, are averages for passenger cars (not light-truck electric consumption rates) as found in MoMo. The total kilometres of travel for PHEVs and EVs can thus be translated into annual and daily electricity demand.

As electricity is produced from a mix of sources that have different specific emissions levels, the share of different fuels in the electricity mix determines the CO_2 emissions rate of each unit of electricity produced at a given time.

The energy sources considered in *ETP 2010* which have very low, almost zero emissions are hydro, nuclear, wind, solar, geothermal and tidal. Fossil fuel-based electricity generated from coal is the most CO_2-emissions intensive; oil and gas generation produce intermediate levels of CO_2 emissions. These levels are also affected by the use of carbon capture and storage technologies.

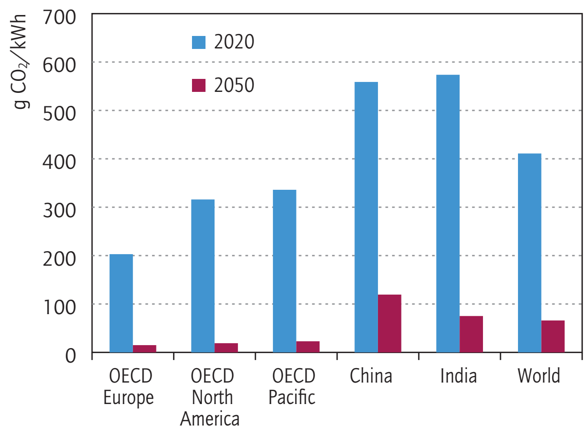
The two scenarios of electricity-sector evolution considered here correspond to the Baseline and BLUE Map scenarios. The BLUE Map scenario forecasts efficiency improvements and a large share of renewable energies in the electricity sector (48%) by 2050 while in the Baseline case, business-as-usual policies lead to a small increase of renewables from 18% of the mix in 2007 to 22% of the mix in 2050 (IEA, 2010). Coal and gas contribute 28% of total electricity generation in 2050 in the BLUE Map scenario, compared with 67% in the Baseline scenario. More than 90% of coal-fired generation stations and one-third of gas-fired facilities are fitted with carbon capture and storage (CCS) in the BLUE Map scenario (IEA, 2010). While the Baseline plan implies that new capacity additions are made without considering environmental consequences, in the BLUE Map scenario they are consistent with a 50% reduction in CO_2 emissions from 2007 to 2050 across all energy sectors.

Total electricity demand from PHEVs jumps from negligible levels in 2020 to 1 398 terawatt hours (TWh) and 2 147 TWh for the two respective PHEV scenarios (low-range and high-range) by 2050, or 54% higher demand in the high-range PHEV scenario than in the low-range (Figure 3). As a percentage of world total electricity demand (40 137 TWh according to the ETP BLUE Map 2050), the low-range PHEV scenario represents a 3% increase in demand and the high-range scenario represents a 5% increase. If EVs were included, world total electricity demand would increase 7%-9% depending on the PHEV scenario.

Although one sees clear differences when looking at CO_2 emissions from electricity generation by region (Figure 4), the emerging picture shows that by 2050 CO_2 intensity will be so low (near or much below 100 grammes/kWh in most regions compared to a world average of about 400 in 2020, and close to 500 today) that increased demand from PHEVs and EVs will result in relatively small increases in CO_2 emissions. In 2020, China and India will have relatively high CO_2 emissions intensities, over 500 g/kWh, but by 2050 they are projected to decrease by 79% and 87% respectively. Shifting to electricity use in vehicles will actually bring about greater CO_2 emissions reductions over time.

Figure 4

Regional CO_2 intensities of electricity



Source: IEA 2010.

Figure 3

Electricity demand under the low- and high-range PHEV scenarios

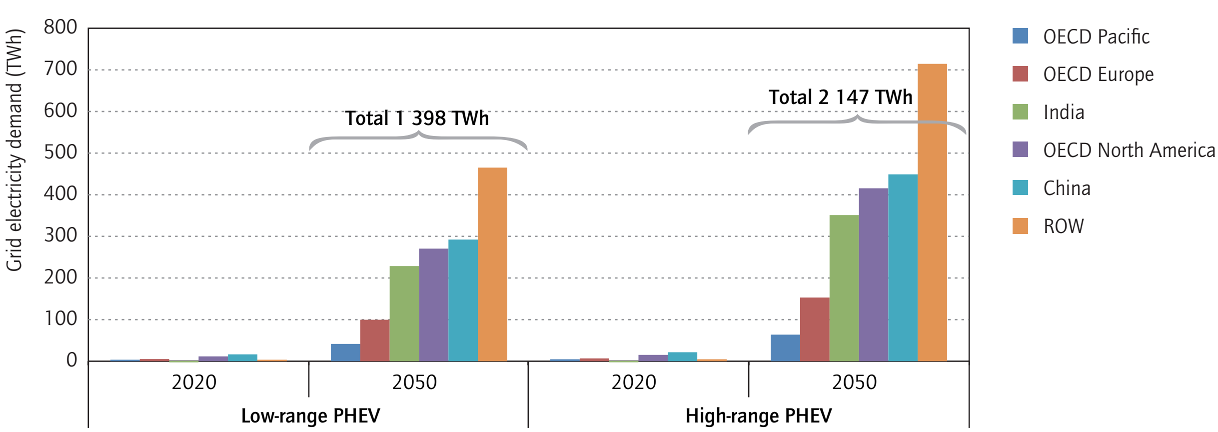
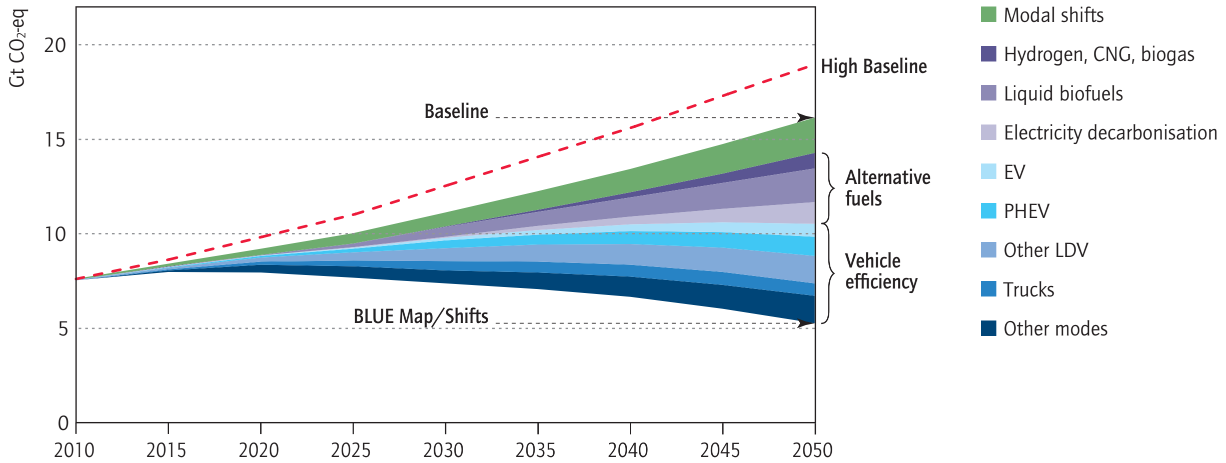


Figure 5

Sources of GHG reduction in the transport sector



Source: IEA 2010.

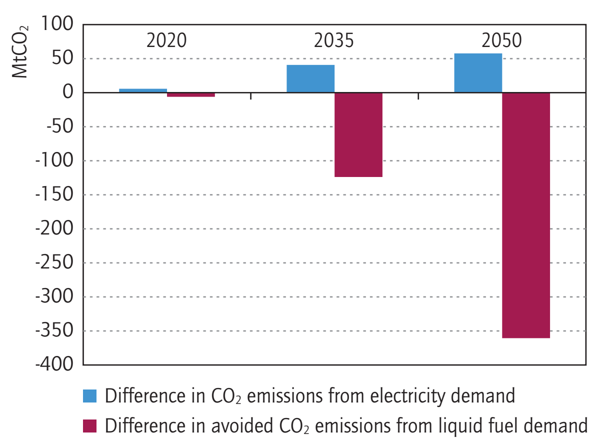
The shift from the Baseline scenario to the BLUE Map scenario, assuming an intermediate PHEV range, already results in a reduction of 2.8 Gt of CO_2 emissions (about 1.6 Gt from efficiency gain and 1.2 Gt from ongoing decarbonisation of electricity – see Figure 5). Of the 1.6-Gt reduction from efficiency, about 1.0 Gt comes from EVs and 0.6 Gt from PHEVs.

The impact on CO_2 emissions of shifting from low electric-driving-range PHEVs (running about 50% of the time on electricity by 2050) to higher-range PHEVs (achieving 80% electric driving by 2050) is shown in Figure 6. The figure shows the difference between the two PHEV scenarios in terms of CO_2 emissions from electricity and the corresponding reduction in CO_2 emissions from liquid fuels, as PHEVs shift toward more electricity use. Though differences are negligible in 2020, by 2035 we see a 40-megatonne (Mt) increase in CO_2 emissions from electricity generation, and a 120-Mt decrease in CO_2 emissions from liquid fuels (primarily gasoline/diesel and some biofuels), for a net emissions decrease of 80-Mt. By 2050 the electricity-related CO_2 emissions increase is about 60 Mt in the high-range PHEV scenario, or 20% higher than in the low-range scenario. However, due to increasingly clean electricity, this 2050 increase is much smaller compared to the cut in liquid fuel CO_2 emissions. The shift to longer-range PHEVs would result in six times the reduction of CO_2 emissions thanks to lower liquid fuel use. Thus, by 2050 the high levels of PHEV use and mostly decarbonised electricity production could result in quite large net CO_2 savings.

To achieve these 2050 reduction goals, production and demand for PHEVs (and EVs) must reach certain minimum levels by 2020 and 2035 so as to spur much larger demand levels by 2050. Overall, the net 300-Mt CO_2 emissions reduction that could be achieved in moving from lower- to higher-range PHEVs adds about 50% to the reductions potentially achieved by PHEVs in the *ETP* Baseline scenario in 2050 (900 Mt as opposed to 600 Mt), and about 11% to total reductions from both PHEVs and EVs from 2.8 Gt to 3.1Gt.

Figure 6

Differences between world electricity-related CO_2 emissions and avoided CO_2 emissions from liquid fuel demand from PHEVs in the two PHEV scenarios



Conclusions

It could be feared that electrifying our vehicle fleet may simply shift CO_2 emissions from the source point (the vehicle) to the generation point (the power plant). Fortunately, the results of the IEA Mobility Model show that widespread vehicle electrification would increase electricity demand by 9% at most and at the same time result in around 1.6 billion tonnes less of CO_2 emissions (or a total of 2.8 billion tonnes less with the decarbonisation of the electricity sector).

The intensity of CO_2 emissions from additional electricity production to meet PHEV and EV demand depends on the generation mix. To reduce emissions-intensive electricity production, it would be prudent to charge the vehicles during off-peak hours, such as during the night, and avoid the two peak times of early morning and early evening. Policies for charging management should therefore encourage night-time charging, but also make it possible to charge at home, at work, and at retail locations.

The emissions-reduction potential of PHEVs and EVs will vary based on the mix of energy sources used in the generation of the electricity they draw upon; the implication is that regions with low CO_2–emitting power production should be the first to introduce PHEVs and EVs. However, because of the inherent improvements in vehicle efficiency and the fact that PHEVs and EVs will become cleaner as power generation becomes cleaner, regions of intensive CO_2 emissions should not neglect the emissions-reduction potential of these vehicles.

Our modelling suggests that while the very large numbers of EVs and PHEVs in the BLUE Map scenario will cut CO_2 emissions substantially by 2050, they will increase global electricity demand by a relatively modest amount, in the range of 7%-9%. Low-range PHEVs could provide a substantial amount of driving on electricity (perhaps around 50% of kilometres travelled), and while higher-range PHEVs will contribute some additional electric driving (bringing the share up to 80%), the effect on electricity demand and CO_2 emissions is likely to be modest. Although PHEVs will retain the option for long-range driving on liquid fuels, they may ultimately compete with pure EVs, since both provide significant reductions in liquid fuel use.

References

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Carbon capture in the power sector: from promise to practice

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The capture and storage of carbon dioxide (CO_2) emissions has significant potential to be part of a least-cost strategy in the global decarbonisation of power generation; it may also be the solution to reducing CO_2 emissions from other large industrial sources. Public and private stakeholders are currently investing in research, development, and demonstration of carbon capture and storage (CCS) projects, with a view to developing a competitive technology during this decade and to provide a large-scale solution to the problem of CO_2 emissions. This paper looks into the current status of CCS technologies, with emphasis on its forthcoming large-scale demonstration in the power sector. It then discusses the incentives and policies required for the success of CCS.

The role of CCS in global climate-change mitigation

Carbon capture and storage (CCS) is a series of technologies and applications which enable the capture of CO_2 from large source points, its transport via pipelines and ships and its safe storage in geological formations such as saline aquifers and depleted oil and gas fields. Capture applications can be implemented as part of electricity production, as well as in various industrial sectors. The technologies involved in CO_2 capture, transportation and storage already exist and are in use in various industries. There are currently five large integrated CCS installations in the world, each of them capturing and storing in the order of 1 megatonne (Mt) of CO_2 per year. None of these five, however, are in the power sector.

A range of technologies will be required to halve current levels of global CO_2 emissions by 2050. In the IEA *Energy Technology Perspectives 2010* BLUE Map Scenario, CCS will contribute around one-fifth of total emissions reductions in 2050, representing some 10 gigatonnes (Gt) of CO_2 captured and stored in 2050, and a total of approximately 140 Gt over the next four decades. While in the power sector there are other options such as renewable and nuclear energy or fuel switching, in other industries such as cement, iron and steel production, CCS is very often the only way to dramatically cut emissions. According to IEA analysis, while coal-fired power production is the single largest sector where carbon capture could be implemented, the importance of CCS in other industrial sectors is likely to increase over time (IEA, 2010). Non-power CCS applications could make up in the order of 50% of the CO_2 captured by 2050. IEA analysis also suggests that without CCS, the total cost of reaching a 450-parts-per-million (ppm) level of CO_2 emissions would be significantly higher. CCS is thus a crucial part of the portfolio of technology solutions for meeting global climate goals (see also Azar *et al.*, 2010 and Edenhofer *et al.*, 2010).

Where is CCS today?

There are currently five large CCS installations globally: at Snøhvit and Sleipner in Norway, in Salah in Algeria, at Rangely in the United States and at Weyburn in Canada. Each of these operations capture and store about 1 Mt of CO_2 per year. Four of the projects capture CO_2 stripped from high-emissions natural gas processing, while one project captures CO_2 from coal-based synthetic natural gas production. Three of these projects store CO_2 in saline formations; the other two store CO_2 in conjunction with enhanced oil recovery.

Large-scale CCS projects do not yet exist in the power sector. Instead, there are numerous smaller-scale pilot projects across the globe, where CO_2 is captured from slipstreams of flue gas. The first large-scale power-sector projects in the hundred-megawatt (MW) range and above are in planning in Europe, North America and China. Many of these projects are currently working to secure sufficient funding and, if successful, could be operational between 2014 and 2016.

Across different regions in the world, post-, pre- and oxy-combustion CO_2 capture are considered options for large-scale demonstration of CCS from power generation. To date, no individual capture route or technology can claim a general competitive advantage over other processes. The status of development in large-scale demonstration is therefore described for all capture routes through the illustration of major flagship projects.

Two examples of large-scale post-combustion CCS demonstrations are the Mountaineer project in the United States and the Porte Tolle project in Italy:

▶ **The Mountaineer project in West Virginia**, operated by American Electric Power, is planning to capture up to 1.5 Mt of CO_2 per year starting in 2015. Chilled ammonia will be used as a post-combustion capture solvent on a 1 300-MW bituminous coal-fired power plant. The separated CO_2 is piped to nearby injection wellheads for storage in a saline formation. The US Department of Energy (US DOE) will share 50% of the project cost, with a limit of up to USD 334 million. The large-scale project is the second phase of a smaller pilot plant's activity, which started in late 2009 on a 20-MW fraction of the power plant's flue gas. This smaller Mountaineer pilot project was the first power-sector project to cover the whole process from capture to storage.

▶ **The Porte Tolle project in Italy** aims at capturing up to 1.5 Mt of CO_2 per year by retrofitting a 660-MW bituminous coal and biomass-fired power plant with amine-based post-combustion capture by 2015. The CO_2 will be transported by pipeline 150 kilometres and stored offshore in a saline aquifer in the northern Adriatic Sea. The project by the Italian utility company ENEL is one of six European projects that secured co-funding from the European Economic Recovery Plan. This project will also be eligible to apply for funding from the European Union Emissions Trading System's NER-300 (New Entrants Reserve-300, described further in this paper).

Pre-combustion capture is planned on a large scale by several consortia, including the GreenGen project in China and the Hydrogen Energy project in the United States:

▶ **The GreenGen project in Tianjin** is under development by the China Huaneng Group, the largest shareholder. Integrated Gasification Combined Cycle (IGCC) technology, primarily based on Chinese technology, is demonstrated at 250 MW in its first step. In a second phase, CCS is planned to be added to the gasification step to capture 1 Mt CO_2 per year and use it for enhanced oil recovery. The project is funded by a variety of sources, including the Chinese Ministry of Science and Technology and the Asian Development Bank. Another possible channel of funding could be the Clean Development Mechanism (CDM) under the Kyoto Protocol, although the recent decision that CCS is eligible as a project activity under CDM is subject to the satisfactory resolution of a number of specified issues, including for example monitoring and verification, the use of modelling and long-term liability (UNFCCC, 2010).

▶ **The Hydrogen Energy California project**, a joint venture between BP and Rio Tinto, plans pre-combustion CO_2 capture from a new 250-MW IGCC plant in Kern County by 2016. The plant would capture and store some 1.8 Mt of CO_2 per year. The gasification plant is designed to run on a blend of bituminous coal and petroleum coke. CO_2 captured from the power plant will be transported 7 kilometres by pipeline to an oil field. The estimated capital cost for the project is USD 2.3 billion, with an expected contribution of USD 308 million by US DOE.

Plans for large-scale oxy-combustion CO_2 capture are illustrated by the Jänschwalde project in Germany and the FutureGen project in the United States:

▶ Based on their existing pilot-scale CO_2 capture experience from the Schwarze Pumpe plant that has been capturing CO_2 since 2008, the utility company Vattenfall plans a large-scale oxy-combustion capture facility in Jänschwalde. In conjunction with a 125 MW post-combustion-capture pilot plant, a 250-MW oxy-combustion capture unit is to be installed by 2015. Up to 1.7 million tonnes of CO_2 per year could be captured and stored in saline aquifers; investment costs are estimated at EUR 1.5 billion. The project is one of six European projects that secured co-funding from the European Economic Recovery Plan. This project will also be eligible to apply for funding from NER-300.

▶ The FutureGen 2.0 project aims at repowering an existing power plant at Meredosia, Illinois, with oxy-combustion for a net power output of 139 MW, which would result in 1.3 million tonnes of CO_2 captured per year. Operation of the full-scale capture process is planned for 2016. CO_2 will be transported by pipeline to a CO_2 storage hub for storage in a saline geologic formation. USD 1 billion in Recovery Act funding has been committed to the project.

Cost: the defining factor

Deploying CCS is presently not economical in power generation. The cumulative cost of capture, transportation and storage of CO_2 is currently too high for any investment to take place without some form of public support, particularly within the power sector. CCS technology is thus faced with the challenge of lowering its costs in the short to medium term. Other challenges include finding, obtaining permits for, and operating storage sites; building the necessary transport infrastructure; ensuring public acceptance of the technology; and establishing relevant policy and regulatory frameworks.

Since CCS from power generation has not yet been demonstrated on a large scale, cost and performance information is limited to estimates from engineering studies and pilot projects.

Based on recent IEA analysis,[1] average cost and performance projections for early commercial CO_2 capture from coal-fired power generation are similar across all capture routes: overnight costs of power plants with CO_2 capture in OECD regions are on average USD 3 800 per kilowatt (kW), or about 74 % above the cost of a pulverised coal-fired power plant without CO_2 capture. Costs of CO_2 avoided are estimated to be about USD 55 per tonne if a pulverised-coal power plant without CO_2 capture is used as a reference. These costs include net efficiency penalties that are significant for all capture routes, reaching 10%-points for post-and oxy-combustion CO_2 capture relative to a pulverised-coal plant without capture, or 8% for pre-combustion CO_2 capture relative to an integrated gasification combined-cycle plant. Based on current technological and economic data, no single technology for CO_2 capture from coal-fired power generation clearly outperforms the available alternative capture routes.

For natural gas combined-cycle power plants, post-combustion CO_2 capture is most often analysed and appears to be the most attractive option for the short term. Costs of CO_2 avoided for such plants are on average USD 80 per tonne if a natural gas combined-cycle reference is used, based on overnight costs of USD 1 700 per kW including CO_2 capture (82% higher than the reference-plant cost without capture), and average net efficiency penalties of 8%.

Costs for transportation and storage of CO_2 have yet to be included in these estimates. These costs are more difficult to generalise, given that they are very site-specific or even unique for every single CCS project. Although a number, albeit small, of large-scale storage operations exist, storage capacities and associated costs still remain subject to significant research in many regions of the world. However, it is widely accepted that capture costs are the most significant expenditures in the CCS chain, and that costs associated with transport and storage are likely to be subsidiary.

Specific costs for pilot plants or new commercial-scale plants can substantially exceed the above-mentioned projections. Even at average CO_2 avoidance costs of USD 55 per tonne of CO_2, or above for recent commercial units, currently available incentive mechanisms or CO_2 prices, where they exist, are still insufficient to stimulate commercial deployment of CCS technology.

1. *Finkenrath, 2011.*

The need for enabling policy framework and incentives

Because of the above considerations, CCS will not be deployed in the power sector without a clear set of policies and financial incentives. If capturing CO_2 was to be profitable solely on market incentives, an average power price of roughly USD 100 per megawatt hour (MWh) would be required. This sum does not take into account the costs of transport and storage, although they are estimated to be a relatively small share of the total CCS cost.

Incentive mechanisms are obviously needed for the successful deployment of CCS both in the short and long term. Other than in the context of climate-change mitigation, CCS will not serve any energy policy goal. This is important to keep in mind when discussing long-term incentive frameworks for CCS. In the short term, incentive mechanisms are required to initiate a number of first-generation plants, or "large-scale demonstration." With low electricity and CO_2 prices, and in the absence of feed-in-type subsidies or other mechanisms, the industry is presently not willing to risk investing in large CCS installations without additional financial incentive. To alleviate some of this first-mover risk, many governments are in the process of putting incentives in place. These are typically "one-off" mechanisms, designed to motivate a small number of large installations for a limited period of time. In most cases, these mechanisms allocate cash funds for additional investment and/or operating costs for 10-15 years. Governments, mostly from OECD countries, have announced public financial support in the amount of USD 25 billion for a number of large-scale demonstration plants (GCCSI, 2011). This funding includes various capital grants, for example the European Union's NER-300 scheme, through which the European Community will make available 300 million emissions allowances from the New Entrants' Reserve under the EU Emissions Trading Directive to finance large-scale demonstration in CCS and innovative renewable energy technologies.

While this development is necessary to get first-mover plants operational, the debate must now address the next phase of projects and long-term incentives. At the basis of this discussion is the recognition that the only driver for CO_2 capture in the vast majority of cases is government willingness to reduce CO_2 emissions, except in some niche areas such as the chemical and food industries and enhanced hydrocarbon recovery.

While incentive mechanisms for renewable energy technologies have often been propelled by government interest in ensuring supply security, directing energy production and transformation away from fossil fuels or building a new industrial sector, the future incentives awarded for CCS will only be driven by the goal of reducing CO_2 emissions. Various mechanisms could be envisaged, coming from either a "market-pull" or a "technology-push" angle. Implementing a robust CO_2 price is a mechanism already in use in a number of regions and countries (Hood, 2010). While CO_2 markets may provide an efficient mechanism from the medium to long term, they have not been effective in the short term in attracting investment in CCS, due to the low and uncertain resulting CO_2 price. This does not necessarily indicate that CO_2 markets do not work: the real problem is over-allocation of CO_2 rights, resulting in low prices, and lack of long-term visibility on reductions. Another option is the imposition of a CO_2 tax to create a reductions incentive by setting a price on carbon emissions, provided the tax is high enough.

Various subsidy schemes could also provide incentives for CCS, at least in the short to medium term. Capital grants and guaranteed loans could be used, as for the first segment of projects (large-scale demonstration), as well as feed-in tariff schemes such as those in use for various renewable energies. Governments would have a range of ways to generate the funds, from direct budget funding to dedicated levies.

Paying subsidies to CCS, or to any CO_2 emissions-mitigation technology, should only be seen as a mid-term solution until CCS technologies become competitive with other low-carbon technologies. Ultimately, installing a mechanism to provide a long-term CO_2 price would be the best way of ensuring that CO_2 reductions in the power sector are achieved at the lowest possible cost. CCS will eventually have to be a competitive technology, surviving alongside other low-carbon technologies within a market framework.

To facilitate discussion and assist governments with policy choices, the IEA is currently launching a study of the various incentive mechanisms that could be used to support CCS. Results will be available in 2011.

In addition to crucial incentive mechanisms, other prerequisite policies are also needed for any deployment of CCS. Legal and regulatory frameworks must be established to ensure the safe employment of CCS and its integrity as an emissions-mitigation technology. Many OECD countries have made significant progress to this end in the past two to three years, with the European Union, the United States, Canada and Australia all well advanced in establishing comprehensive legal and regulatory systems. Progress is now needed in key non-OECD countries that have significant CCS potential, such as China, Indonesia, India and South Africa.

Moving forward

At their 2008 meeting in Japan, G8 leaders recommended that 20 large-scale demonstration projects be launched globally by 2010, with a view to begin "broad deployment" by 2020. While the 2010 goal of 20 projects was clearly not met, the goal of broad deployment by 2020 is still achievable with significant effort from all involved, including government and industry. The IEA CCS Roadmap suggests that such broad deployment should consist of 100 large-scale projects by 2020 if we want CCS to reach its projected emissions reduction potential by the middle of this century (IEA, 2009). The next ten years are crucial to meet this challenge.

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Carbon leakage in the European Union's power sector

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The EU Emissions Trading System (EU ETS) is an essential tool for the European Union to achieve its goal of reducing CO_2 emissions from power generation. The EU ETS encourages fuel-switching away from fossil-based generation, with a cap on CO_2 emissions, eventually resulting in higher electricity prices. The electricity sectors of countries that border on the European Union and do not apply such a policy may gain a competitive advantage and, transmission capacity allowing, gain shares in the European Union's electricity market and trigger so-called carbon leakage. This paper provides an introductory exploration of this issue and indicates how such leakage may be tracked and quantified if it were to become a concern for policy makers.

After heavy industry, now electricity?

Third-phase discussions of the EU emissions trading scheme have created much debate on the issue of so-called carbon leakage. If the cost added to electricity production from CO_2 regulation within the European Union either a) enhances the competitiveness of producers from outside the regulated region by increasing the cost for those inside, or b) causes EU producers to relocate production to outside the European Union, so-called carbon leakage would occur. In both cases, part of the emissions avoided through CO_2 regulation would simply shift elsewhere, undermining the effectiveness of the initial regulation.

The threat of carbon leakage has generally been associated with energy or CO_2-intensive sectors whose products are traded on international markets (Reinaud, 2008). Electricity generation is largely local, with its trade limited by physical transmission capacities; little, if any, attention has been drawn to the issue of carbon leakage in the power sector. There could, of course, be cases of industrial relocation that would lower local electricity demand and related emissions, with higher electricity-related emissions elsewhere: this leakage would be associated with the competitive disadvantage of the industry, and be tracked through changes in trade of this industry's products.

In general, opportunities to trade electricity are well exploited, largely among countries with similar CO_2 regulations. However, recent reports have raised the spectre of European companies installing electricity capacity outside the European Union with the intention of exporting their output back to Europe, hence evading the constraint imposed by the EU Emissions Trading System (EU ETS) (Ames, 2010).

What exactly is carbon leakage?

Carbon leakage is measured as the ratio of emissions increase from a specific sector outside the constrained region (as the result of a policy affecting emissions of that sector in the region), over the emissions reduction in the sector (as a result of that same policy) (Reinaud, 2008). Carbon leakage in the power sector should therefore result from a change in the international trade of electricity to and from a carbon-constrained region after the introduction of CO_2 regulation.

In practice, a generator faced with a carbon constraint would reflect its cost in its prices, therefore enhancing the competitiveness of clean generation sources – what is expected from the regulation – and of those generators that do not face such a constraint. The CO_2 constraint would also lower expected returns on new investments in fossil-fuel-based generation; a decision to replace an old plant may be postponed or cancelled, and electricity imports may be substituted instead. Whenever CO_2 is emitted to generate these electricity imports, carbon leakage would occur.

What EU electricity trade flows tell us at this stage

As a point of reference, the gross electricity trade of all EU-27 countries combined amounted to near 300 terawatt hours (TWh) in 2008, or some 8.9% of the region's total electricity generation. In most years, the European Union also imports electricity from outside countries. In 2008 these imports amounted to 0.5% of total supply, or 16 TWh.[1]

The level of such electricity trade is of course very much dependent on transmission capacity between EU and non-EU neighbouring countries.

1. *In the last decade, net electricity trade varied between net exports of 7 TWh (2004) and net imports of 19 TWh (2000) (IEA Statistics, 2011).*

Any significant change in this percentage can only happen with joint investments in transmission. However, transmission lines are rarely fully used at all times, and there may be opportunities for enhanced electricity trading across the two regions if economic signals were appropriate and excess generation capacity existed.

This analysis first considers net trade flows in electricity between the European Union and neighbouring countries. Carbon leakage occurs either when energy exports are lower from EU to non-EU countries or imports are higher from the latter, due to the additional cost that the CO_2 constraint creates for generators in the European Union. Such observations would also need to take into account the other factors that can affect international electricity trade, including availability of generation capacity (hydro, based on variations in precipitation; nuclear, as a result of maintenance activities), and economic factors such as international fossil-fuel price variations. These factors are not studied in any depth in this analysis.

The statistical method that follows rules out those EU countries that do not border non-EU countries. However, Norway, not an EU country, is included in the group of countries facing a CO_2 cap. In spite of its reliance on CO_2-free hydro power, Norway's integration in the Scandinavian power market exposes its electricity sector to an electricity price which reflects the cost of EU CO_2 allowances faced by generators in Denmark, Finland and Sweden. Electricity trade was observed for the following countries: Albania, Belarus, Macedonia, Russia, Serbia, Switzerland, and Ukraine. Russia and Ukraine are particularly interesting because of the relative importance of their electricity exports to EU countries.

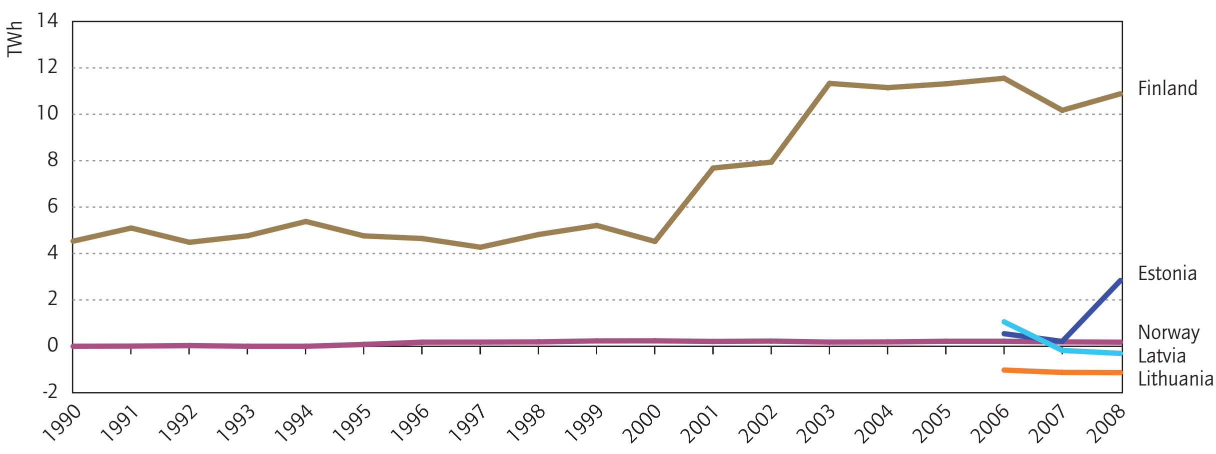
Figure 1 illustrates net electricity trade between CO_2-constrained countries and Russia between 1990 and 2008. The positive value indicates net imports from Russia by the indicated country. Figure 1 shows, for instance, Finland as a net importer from Russia, with amounts growing from around 5 TWh annually up to 2000 and around 11 TWh thereafter.

The increased imports did not begin in 2005. The growing imports seem to follow a general increase in electricity demand over the period, as shown in Figure 2. While there is a net increase in imports in 2005, it is largely due to excess hydro capacity in Norway and Sweden, which crowds out the more expensive coal- and peat-based generation in Finland. If this was accentuated by the price of CO_2, it is a result of the intention of the EU ETS that cleaner generation in the European Union become more competitive than CO_2-intensive sources. Imports from Russia were at roughly the same level between 2003 and 2008, showing no upward adjustment as a result of the CO_2 constraint in Finland.

Figure 1 also shows growing imports of Russian electricity in Estonia in 2007. With only three years of observations (2006-2008), no conclusion can be inferred. In 2007, however, Estonian minister Juhan Parts complained about competitive distortions between Estonian and Russian power generators, as the latter face no restrictions on their emissions of CO_2 and other pollutants (New Europe, 2007); the question is whether the existence of a carbon cost in the price of Estonia's electricity was the defining factor in the competitive advantage of the nearly 3 TWh of Russian electricity sold to Estonia. Only then could carbon leakage be a concern.

Figure 1

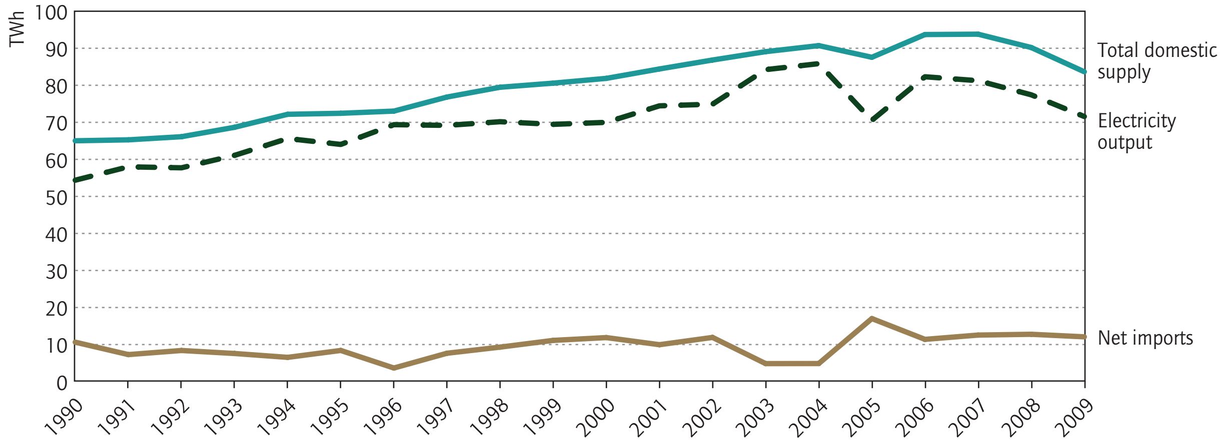
Russia net electricity trade with countries subject to the EU ETS (1990-2008)



Source: ENTSO-E, 2007, 2008, 2009; IEA statistics. Unless otherwise indicated, material in figures derives from IEA data and analysis.

Figure 2

Finland: domestic electricity production (1990-2009)



Source: IEA statistics, 2010.

Note: Total domestic supply = electricity output + net imports.

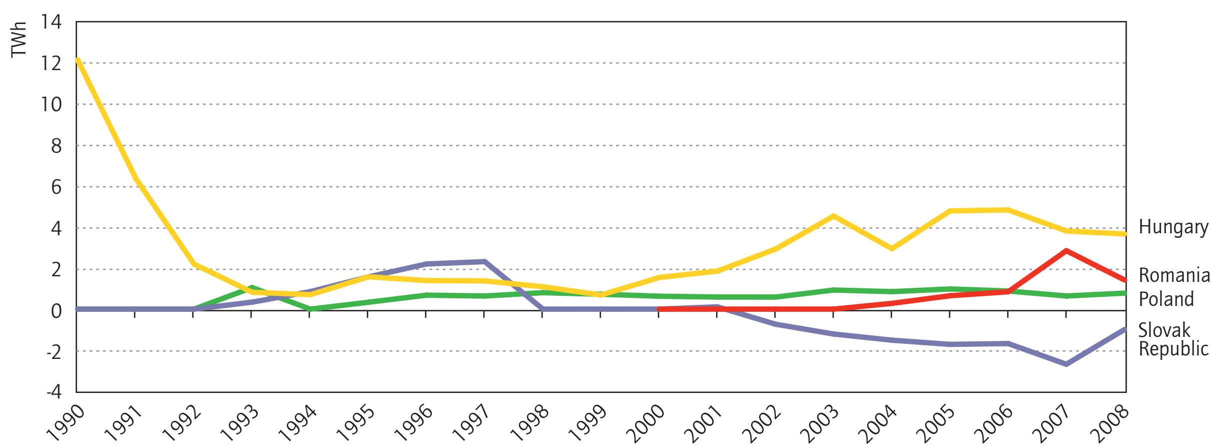
To conclude observations on exports from Russia, Norway continuously imports electricity from Russia, although at a very low level – the electricity transmission line with Russia has a capacity limited to 30 megawatts (MW) (Norwegian Energy Regulator, 2010).

Ukraine is another relatively important exporter of electricity to the European Union. Hungary has imported increasing amounts of electricity from Ukraine since 2000, with a peak in 2005 (Figure 3); such imports are, however, at a much lower level than in 1990. Romania also increased imports from Ukraine in 2005. Poland has been a stable importer from Ukraine since 1993, although of less than 1 TWh annually. Ukraine also imports electricity from the Slovak Republic. As is the case with Russia and Finland, the growing imports of Hungary started much earlier than the introduction of the EU ETS, making it difficult to attribute this evolution to the carbon cost applied to Hungarian power generators.

At this early stage and in the absence of a longer electricity-trading comparison period, it is difficult to estimate how the introduction of the EU ETS affected the changes observed in electricity imports to the European Union from countries without CO_2 constraints on their power-generation emissions. First observations do not support the existence of carbon leakage in the electricity sector.

Figure 3

Ukraine net electricity trade with countries subject to the EU ETS (1990-2008)



Source: IEA statistics, 2010.

How CO_2-intensive is imported electricity?

Trade flows are only one factor in the quantification of carbon leakage. It is equally important to assess the CO_2 content of the imported electricity that may substitute for domestic production. Carbon leakage implies that CO_2 emissions are moved from the constrained region to another region; however, if Italy, for instance, were to increase its imports from Switzerland following the introduction of a cap on Italy's emissions, the near-zero CO_2 content of Switzerland's electricity would make such an exchange free of carbon leakage. Only when the substituted electricity is CO_2-intensive does leakage occur. The following example illustrates this phenomenon:

- Country A emits one million tonnes (t) of CO_2 in the generation of each terawatt hour.
- Country B, not subject to a CO_2 constraint, emits 500 000 tCO_2 in the generation of one terawatt hour.
- Country A reduces its power-generation emissions by 3 megatonnes (Mt) of CO_2. It does so partly through the import of 1 TWh of electricity from Country B, which emits 500 000 tCO_2 more than it would otherwise.
- The observed leakage rate is equal to the ratio of emissions elsewhere to the originally planned emission reductions (500 000 tCO_2 divided by 3 $MtCO_2$, or 17%).

Figure 4 displays the CO_2 intensities of electricity generated in countries that import electricity from both Russia (left) and Ukraine (right), and the imported/exported volumes in 2008. The dotted line in each figure indicates the average CO_2 intensity of the electricity generated in these two countries.

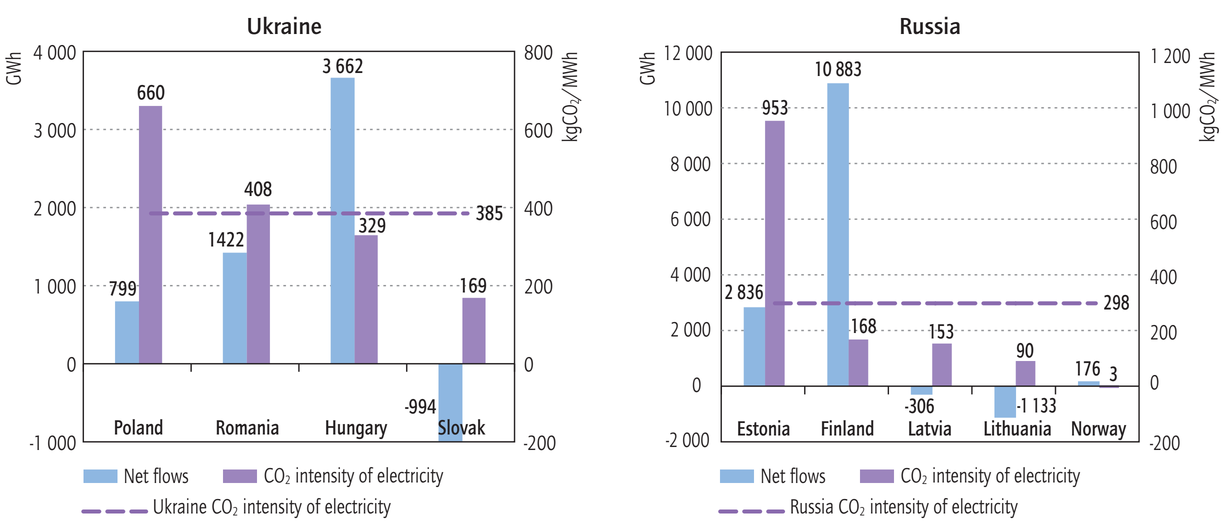
The comparison between Estonia and Finland shows that the latter would record a higher leakage rate resulting from Russian imports, as its CO_2 emissions intensity is somewhat lower than Russia's. The contrast with Estonia would be less dramatic, as its power sector is very CO_2-emissions intensive, with almost one tonne of CO_2 emitted per MWh, against 300 $kgCO_2$ for Russia.

Turning to electricity trade with Ukraine and leaving carbon leakage aside for a moment, the Slovak Republic's exports result in a net improvement in the CO_2 picture, as the emissions intensity of its power generation is considerably lower than that of Ukraine (169 $kgCO_2$ against 385 $kgCO_2$).

In this preliminary exploration, some specific features of electricity trade could not be taken into account, namely the variation in CO_2 emissions of electricity production depending on time of day and season. The above figures are based on the average performance of each country's power sector in a given year, whereas electricity transmission may take place at times when CO_2 emissions are significantly higher or lower than average. If the risk of carbon leakage was serious, a more detailed analysis of the actual CO_2 content of electricity trade would be needed to obtain precise figures for displaced CO_2 emissions.

Figure 4

Ukraine and Russia: net electricity trade with neighbouring countries



Source: IEA statistics, 2010.

Too early to conclude?

This analysis focused on electricity trade flows between the EU member states and neighbouring countries. Although Russia and Ukraine are net exporters to the European Union, this situation predates 2005, the year the EU Emissions Trading System was introduced; observations of other neighbouring countries give a similar picture. The statistics available to the IEA today do not therefore indicate any clear impact of the EU CO_2 caps on electricity trade with neighbouring countries after the introduction of the EU ETS.

This lack of evidence is not surprising at this stage, given the relatively long lead time for the construction of new plants, as well as the relatively low price of EU allowances in the past few years. If there are plans to establish CO_2-intensive power generation outside the European Union, the impact on electricity trade will only be measurable after the plants are operational and suitable transmission capacity is built. While there may be economic incentives to do so – *i.e.*, a significant price differential between EU and non-EU countries – plans to build cross-border transmission capacity would most probably include environmental considerations. At present, existing transmission capacities may act as bottlenecks inhibiting competition with countries under a CO_2 cap. This aspect also needs further research.

Investment in transmission, especially when electricity decarbonisation will require significant adjustment of power grids, responds primarily to security of supply, and secondarily to the enhancement of economic efficiency through the trading of greater quantities of energy among regions. The example of heavy industry has shown how carbon leakage is a strong argument in negotiating ambitious climate-change goals. The risk that this issue may eventually stand in the way of enhanced security via better transmission should not be minimised. Careful and systematic monitoring of trends in the electricity trade should be undertaken, and should include the factors underlying these trends: the availability of hydro resources, maintenance at large power plants, surge in demand due to extreme weather and changes in relative fuel prices, in addition to the existence of a CO_2 price in the European Union. Furthermore, the magnitude of possible emission leakage should be considered. Because the bulk of the European Union's power generation is in countries without borders to non-EU countries (*i.e.*, France, Germany, Italy, the United Kingdom, etc.), emissions mitigation in these countries is less likely to trigger carbon leakage via electricity trading.

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CO_2 and fuel switching in the power sector: how econometrics can help policy making

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The switching of fuels in power generation is the topic of much analysis in the field of climate policy. Fuel switching, especially from coal to gas, is an effective short- to medium-term measure used to abate carbon dioxide (CO_2) emissions in electrity generation. The extent of its potential remains uncertain to policy makers. Econometrics based on market data can reveal the possible magnitude of fuel switching as a result of price changes, including those induced by a price on CO_2 emissions. The method discussed here, and illustrated for the United States and Spain, can help to establish realistic short-term CO_2 emissions reduction goals in competititive electricity markets.

The role of fuel switching in lowering CO_2 emissions from electricity production

The decarbonisation of the power sector requires the implementation of regulatory measures and changes in business strategies. Setting the envisaged energy revolution in motion requires, among other things, a carbon-pricing policy to discourage the use of CO_2-emissions-intensive fuels and generation technologies (IEA, 2010).[1] The third phase of the European Union Emissions Trading Scheme (EU ETS) starting in 2013, together with the possible emergence of new carbon market mechanisms and carbon taxes (*e.g.*, in Australia, Chile, some Chinese provinces, Japan, Korea, Mexico, New Zealand, and some US states), could trigger significant changes in the operation of electricity generators. In the short term, switching across fossil fuels, from coal or oil to gas in particular, may be an important transition measure to lower CO_2 emissions from electricity generation.

Fuel switching in thermal power plants has been identified as one of the main CO_2 emissions-mitigation options in the short term, and deserves careful assessment when designing policy. The extent to which reductions can be expected in the near future from coal-to-gas switching, for instance, is useful information for policy makers who set the overall cap on emissions.[2]

In the presence of a price on CO_2 emissions, fuel switching will be the first-business response to reduce operating costs and CO_2 emissions. It will also contribute to the reduction of other local pollutants (*e.g.* particulate matter), thus reconciling both utilities' interests and environmental concerns. For these reasons, understanding and characterising fuel-switching behaviour is crucial. Arguably, these mechanisms can be best observed in competitive electricity markets, where generators are meant to optimise operations to minimise cost.

This paper investigates the prospects for market-based power-fuel switching, looking at historical fuel use and price data and using relevant statistical methods (see Hicks, 1932; McFadden, 1963; and Morishima, 1967). The econometric methodology, described in full after the Conclusions, measures the responsiveness of fuel use in electricity generation to changes in international coal, gas and oil markets – in economics terms, it estimates fuel price "elasticities" of fuel demand. These estimates can then be used to forecast degrees of fuel switching in electricity generation. Although it is applied here to the power sector, the method can be used for other sectors where fuels can be substituted.

While the examples given below are mainly for illustration, they are based on real data and preliminary conclusions on fuel switching can be derived for the United States and Spain. The examples of these two countries are used in different ways: there is comprehensive data for the US electricity sector, which permits testing of the methodology; there is, however, no CO_2 pricing applied across the United States. Spain, by contrast, is part of the European Emissions Trading System and the analysis can be used to demonstrate the possible fuel-switching effect of a CO_2 price variation.

1. Dedicated incentives or price and research and development (R&D) mechanisms to support the deployment of low-carbon technologies (including fossil-fuel plants with CCS, nuclear plants and renewables-based electricity) need be implemented in parallel.

*2. Fuel switching is meant here as substitution of fuels which is done using existing generation capacity, and is different from long-term, gradual changes of capacity and generation mix (*e.g.*, phasing out oil-fired capacity and generation).*

The relationship between fuel cost and fuel use

In order to identify the role of fuel switching among emissions-mitigation mechanisms, and the relationship between fuel switching and carbon prices, we introduce a proven method of quantification.

Since emission costs are added to fuel and other costs in calculating the price of generating a unit of electricity, the question of how carbon price affects fuel use can be answered through an investigation of how relative generation costs, based on different fuels, influence short-run switching between them. An estimate of this relationship allows us to forecast fuel switching driven by a change in carbon price:

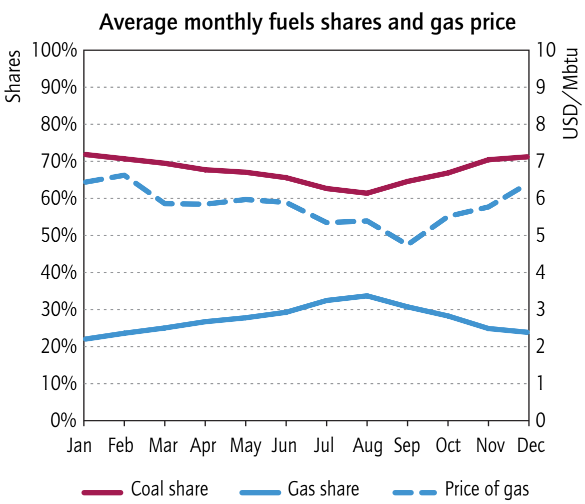
Change in CO_2 price → changes in fuel generation costs → changes in fuel inputs (fuel switching)

The first calculation of the sequence is easily done using standard emission factors for each fuel and the carbon price observed on the market for EU allowances. The second calculation, which requires knowing the relationship between fuel costs and fuel use, is provided by the model we describe below.

The switching between coal and natural gas in the US power sector provides us with an illustration of how fuel use is affected by relative fuel prices. Although there is currently no carbon price in place at the federal level in the United States, the core of our analysis is an estimation of changes in fuel use in response to price changes.

Figure 1

Relationship between relative prices of coal and gas and their shares in thermal generation, United States



Source: IEA statistics.

Notes: the shares are percentages of total generation from combustible fuels (gas and coal) and add up to roughly 95% each month, the rest being generation from oil and combustible renewables; the averages are for years 2003-2009 excepting 2005 and 2008, which show extreme fluctuations.

Figure 1 shows a clear correlation between short-term seasonal changes in fuel prices and fuel choice (note that the coal price does not demonstrate great seasonal fluctuation; the seasonal nature of natural gas fluctuations, however, creates seasonal variation in the price of coal relative to gas). These data, coupled with the fact that the US power sector has been partly liberalised, indicate a possible link between relative fuel shares and underlying fuel prices; for the purpose of policy making the important question is the *magnitude* of such a relationship. The model and measures used here are described in the Methodology section; they essentially rely on the notion of cross-price elasticity: that is, a percentage change in demand of one fuel divided by the percentage change in price of another, alternative fuel.

Empirical estimates: The United States and Spain

The US Energy Information Administration (EIA) provides monthly generation and fuel-cost data separately for utilities and independent power producers (IPPs), showing significant differences in capacity and generation mixes for each and allowing separate estimates. Table 1 shows results for utilities only.

Table 1

Cross-price elasticities in US utilities

Demand of \ Price of	Coal	Gas	Oil
Coal		0.19	
Gas	0.17		0.22
Oil		0.66	

Note: A 50% increase in the price of gas would trigger a 9.5% (0.19 x 50%) increase in demand for coal, and a 33% increase in demand for oil (0.66 x 50%). Likewise, a 50% increase in the price of coal would increase gas demand by 8.5% (0.17 x 50%).

The results in Table 1 suggest significant potential for fuel substitution in the US power sector. To demonstrate the scale of the estimated price-driven fuel switching, let us consider past gas price movements: the average monthly percentage change was about 11% over the period 2003-2009 (excluding "crisis" years 2005 and 2008, when it was much higher), but for many months it was in the range of 20%-45%. From our estimates, a 20%-45% increase in gas price leads to approximately a 4%-9% increase in utilities' use of coal. Note that elasticities depend on the current share of fuels, in terms of price and quantity, in the generation mix (see Methodology for details).

The above results demonstrate that the introduction of a carbon price in the United States would lead to some fuel switching. The degree of this switching can be estimated based on the latest share of fuels in the mix, current fuel prices, carbon and fuel price projections, and the estimates from the model above. This approach is illustrated below with data from Spain, considering changes in all fuel prices: a price on CO_2 would increase the price of coal the most, with the price of gas being affected the least.

Spain provides a picture that differs from the United States in two respects: first, the generation side of the market is entirely liberalised in Spain; second, continental Spain only uses coal and gas, allowing the analysis to focus on the cross-elasticities of two, rather than three, fuels. In the United States, the majority of states are either not active in, or have suspended, the restructuring process,[3] whereas in Spain's wholesale market the majority of the electricity generated from fossil fuels is sold at or linked (through bilatereal contracts) to the prices set by the electricity pool.[4] Elasticity estimation results for Spain are shown in Table 2.

Table 2

Spain's peninsular cross-price elasticities

Demand of \ Price of	Coal	Gas
Coal		0.30
Gas	0.22	

To elaborate the approach further, Table 3 gives two examples of model-output applications to predict fuel switching triggered by a change in the CO_2 price, with different starting points for coal and gas prices (low coal price/high gas price and vice versa). The price of CO_2 in both cases increases from EUR 15 to EUR 30 per tonne (t) of CO_2, a realistic increase observed in the past (although over a long period). Policy makers with an interest in such predictions could base them on their own observations of coal, gas, and expected CO_2 price changes. Table 3 follows a variation of the calculation steps described in the previous section:

Fixed fuel prices → change in CO_2 price → changes in fuel costs → changes in fuel inputs

3. www.eia.doe.gov/cneaf/electricity/page/restructuring/restructure_elect.html

4. Combined heat and power (CHP) plants are treated under "special regime"status and are dispatched first, but only 16% of electricity is generated in CHP plants (IEA data for 2008).

The simulated policy change assumes a EUR 15 /tCO_2 increase, assuming other fuel prices are fixed – the CO_2 price change could also come from a change in fundamentals. Using CO_2 emission factors for coal and gas, the extra CO_2 cost is added to the net fuel costs (columns 5 and 6). The gas price is much lower in Example 2, which amplifies the effect of a CO_2 price rise on gas cost compared to Example 1 (14% versus 8%); the same argument applies to coal, but the price is higher in Example 2. These combinations of fuel prices result in a larger difference between cost increases for coal and gas in Example 1 (35% and 8%), which understandably leads to more fuel switching than in Example 2 (since switching is triggered by changes in relative costs). To summarise, fuel prices are a significant factor in switching from coal to gas, but the effect of a change in CO_2 price diminishes when the price of coal grows relative to gas.

Table 3

Projected effect of hypothetical CO_2 price incease on use of coal and gas in Spain

	Example 1	Example 2
Coal price USD/ton	61	92
Gas price USD/MBtu	11.4	6.3
Change in CO_2 price EUR/tCO_2	15 → 30	15 → 30
Change in coal cost	35%	26%
Change in gas cost	8%	14%
Change in coal use	-6.1%	-3.8%
Change in gas use	+4.9%	+1.6%

Table 3 alone does not indicate the net effect of the simulated changes on CO_2 emissions: it would obviously depend on the the level of coal and gas consumption to which the percentage changes apply. What appears to be small percentage changes could be significant in absolute terms. In reality, data on consumption levels would be readily available to make accurate predictions of electricity market responses to changes in CO_2 prices.

Conclusions

The methodology used in this paper estimates the extent of decarbonisation that can be achieved in accord with cost-minimisation objectives of power-plant operators. It illustrates the potential of individual countries to tap into power systems' fuel-switching capabilities, leading to a further reduction in CO_2 emissions. The two preliminary examples demonstrate the flexibility with which US utilities respond to fuel price changes, an indication that a price on CO_2 would trigger some fuel substitution and lower CO_2 emissions in electricity generation in the near future. The Spanish market, largely liberalised and facing emission caps imposed by the EU ETS, displays cross-price elasticities of a higher value, indicating an even more responsive generation sector. A thorough comparison with the United States would require further analysis.

The framework presented could support further climate-policy analyses. It could, for instance, be combined with new-capacity investment behaviour under uncertainty: to what extent would fuel switching offer a viable 'wait-and-see' approach when the future of climate policy is uncertain and new-capacity investments carry a high risk (see Blyth *et al.*, 2007)? The connection between inter-fossil fuels substitution and increased competition from alternative fuels such as renewables can also be further analysed using this tool. More generally, this estimation method reveals one of the core relationships in electricity markets: the linking of fuel cost and fuel use. As such, it could guide many decisions on climate policy design.

Methodology

A detailed derivation of equations for interfuel substitution models is outside the scope of this paper, so here we only provide key formulae and ideas. The model is essentially based on estimating the power sector's aggregate "variable cost functions". "Variable" refers to the exclusion of fixed costs of generation, and "cost function" refers to a functional relationship between inputs, such as fuel prices, capacity, amount generated and the cost, after optimisation of costs. Thus, the estimates seek to identify the optimised allocation of fuel inputs in the electricity sector.

The cost function is estimated by first assuming a very generic form called translog, and then estimating its parameters from observed data. The translog cost function takes the form of the following "cost share equation" after applying a lemma and a few transformations:

$$S_i = \alpha_i + \beta_{iq}\log Q + \beta_{ik}\log K + \alpha_{i1}\log P_1 + \alpha_{i2}\log P_2 + \alpha_{i3}\log P_3 \quad (1)$$

where S_j are fuel cost shares in the total combustible fuels cost; index i=1,2,3 refers to coal, gas and oil; α_i is intercept; Q is electricity generated from fossil fuels; K is generation capacity; P_1 are fuel prices; and β_{iq}, β_{ik} and α_{ij} are regression parameters (Söderholm, 1999). Formula (1) consists of three equations, one for each fuel; for each fuel equation we have observations over a period of time. The equations are estimated by adding an error term and applying "seemingly unrelated regression" because the equations are linked (*e.g.* the sum of shares is one). After the regression parameters are estimated, one can apply known formulae for calculating elasticities.

One important aspect of the methodology is that elasticity changes as cost shares of fuels change with time. The significance of this characteristic is twofold: a high elasticity, such as in the case of the oil-gas elasticity in the US example above, can be due to a low cost share of a fuel in the generation mix; secondly, when one projects a policy effect on fuel switching, one needs to have some assumptions for future cost shares (thus, fuel mix and fuel prices) because they will determine future elasticities. In other words, the underlying estimate of the cost function can be assumed to stay the same, but changing cost shares will affect elasticities and therefore the size of response to carbon prices.

As to values of elascticity, one of the common measures of relationship between the price of one fuel and demand for another fuel is "cross-price elasticity". The simplified definition of cross-price elasticity is:

η_x, elasticity of demand of fuel X to the price of fuel Y = [% change in demand of fuel X] / [% change in price of fuel Y]

There is a large body of academic literature on the theoretical and practical aspects of estimating cross-price and other elasticities of substitutable input factors in various sectors of the economy (see Frondel, 2004). For this study we used the flexible translog cost function and excluded the capital-investments variable in order to get short- to medium-term estimates.

Cross-price elasticity is defined for changes in the price of only one fuel (and changes in the use of another fuel). However, since carbon dioxide is emitted by both coal and gas, changes in the price of CO_2 simultaneously affect costs of coal and gas generation. We therefore need to use another measure of substitution, and one of the classic definitions, the "behavioural" elasticity of substitution (Frondel, 2004), suits the purpose:

σ, elasticity of substitution between fuels X and Y = [% change in *relative* demand] / [% change in *relative* price].

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DATA

PART 2

World

OECD North America

OECD Pacific

Europe

Africa

Latin America

Middle East

Former Soviet Union

Asia (excluding China and India)

China

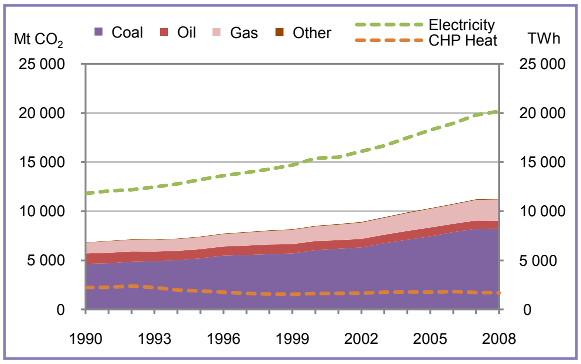
India

Geographical coverage

World

Figure 1

CO_2 emissions by fuel in electricity generation



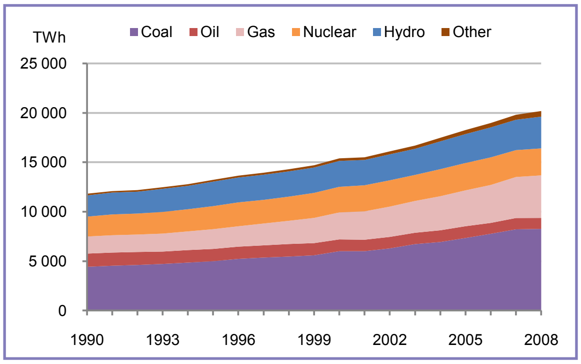
Source: IEA, 2010.

Notes: Emissions from electricity only and CHP plants, total electricity output, heat output from CHP plants.
Coal includes peat. Other includes non-renewable waste.

• Largest source of emissions (2008)		73% (Coal)
• Fastest growth over the last decade		56.8% (Gas)
• Slowest growth over the last decade		-17.2% (Oil)
• Emissions (annual rate):	1998-2008	3.4%
	1990-1998	2.1%

Figure 2

Generation mix in power sector



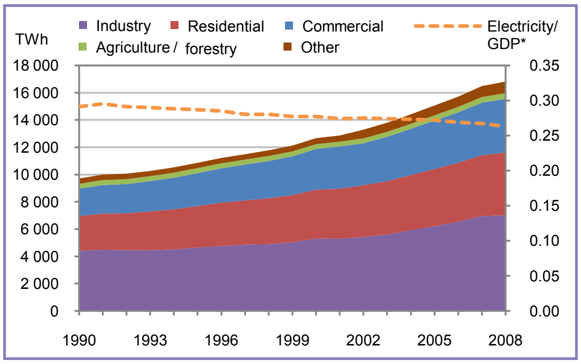
Source: IEA, 2010.

Notes: Coal includes peat. Other includes geothermal, solar, wind, biofuels and waste, etc.

• Largest source of supply (2008)		40.9% (Coal)
• Fastest growth over the last decade		165.4% (Other)
• Slowest growth over the last decade		-12.5% (Oil)
• Growth (annual rate):	1998-2008	3.5%
	1990-1998	2.4%

Figure 3

Electricity use by sector and per unit of GDP



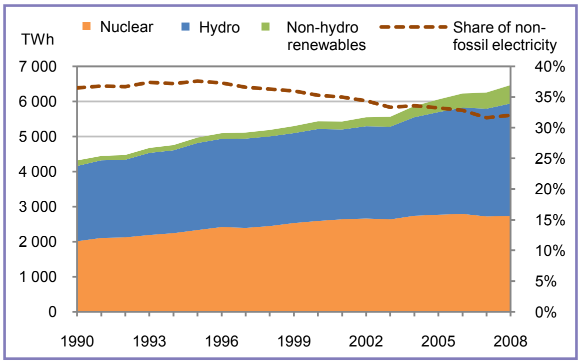
Source: IEA, 2010.

** Electricity/GDP measured in kWh per 2000 USD PPP.*

• Largest sector of consumption (2008)		41.7% (Industry)
• Fastest growth over the last decade		105.4% (Other)
• Slowest growth over the last decade		14.3% (Agriculture/forestry)
• Final electricity growth (annual rate):	1998-2008	3.6%
	1990-1998	2.4%
• Final electricity intensity (annual rate, 1990-2008)		-0.6%

Figure 4

Electricity generation by non-fossil fuels



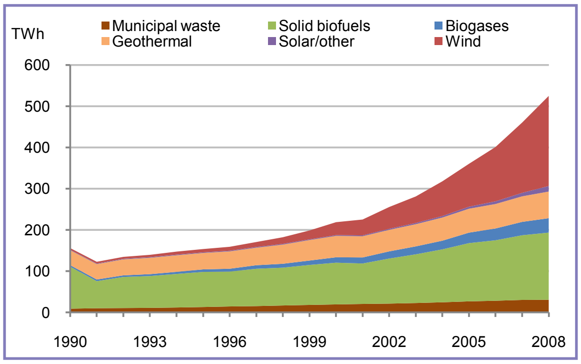
Source: IEA, 2010.

Note: Non-hydro renewables includes geothermal, solar, wind, biofuels and renewable municipal waste.

• Share of non-fossil sources in total electricity (2008)		32%
• Largest source (2008)		49.6% (Hydro)
• TWh growth (annual rate):	1998-2008	3.1%
	1990-1998	2.2%

Figure 5

Electricity from renewables (excluding hydro)



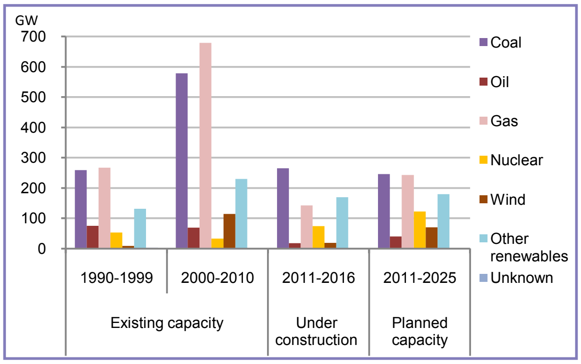
Source: IEA, 2010.

Notes: Biogases includes small quantities of liquid biofuels. Municipal waste only includes the renewable portion of waste.

• Largest source excluding hydro (2008)		41.6% (Wind)
• Largest growth over the last decade		202.4 TWh (Wind)
• Growth (annual rate):	1998-2008	11.2%
	1990-1998	2%

Figure 6

New capacity by installation date



Source: Platts, 2010.

Notes: Other renewables includes bioenergy, biogas, geothermal, hydro, solar photovoltaics and solar thermal.

• Largest additions in 1990-2010	37.8% (Gas)
• Largest additions under construction	38.5% (Coal)
• Largest additions planned	27.2% (Coal)

Key features in electricity and CO_2: world

▶ Total electricity (and heat[1]) output grew by 56% between 1990 and 2008, with a marked reduction in growth in the year 2008 (1.5% against 3.3% over the previous decade).

▶ OECD North America, Europe and China account for 60.5% of global power output in 2008. These three regions also account for 61.6% of electricity-related CO_2 emissions in that year, with China as the first emitter.

▶ China recorded the fastest growth, at 11.3% per annum between 1998 and 2008, followed by the Middle East region, with 6.5%. Other regions with fast growing electricity-related CO_2 emissions include India and the rest of Asia, driven by economic growth and reliance on coal and gas in electricity generation.

▶ The CO_2 emissions intensity of electricity and heat generation has grown by 6% since 1990, to 0.5 tonnes of CO_2 emitted per megawatt-hour produced (tCO_2/MWh). Global CO_2 emissions from combined electricity and heat production grew by 64.9% over the same period.

▶ The share of electricity produced from non-fossil fuels has been decreasing slowly since 1995, in spite of growth in nuclear, hydro, and other renewables in the electricity mix.

▶ Non-hydro renewables are the fastest growing source of electricity; coal dominates global output with 41% of the total. Gas has gained market shares over oil, which supplied only 5.5% of the global production of electricity in 2008.

▶ Industry is the largest consumer of electricity, with about 42% of total final consumption in 2008, against 45% in 1990. Its share has been increasing again since 2003 as the result of industrial growth in Asia.

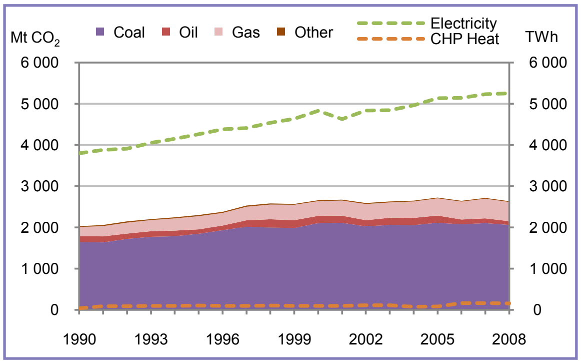
▶ Wind capacity witnessed extraordinary growth in the last couple of decades, with 114 GW installed in 2000-2010 compared to 9 GW in the previous decade. Wind power generation has become the largest non-hydro renewable source since 2007, ahead of biofuels. Coal and gas have nonetheless largely dominated capacity additions since 1990.

1. In this report, heat refers to the output of combined electricity and heat plants.

OECD North America

Figure 1

CO_2 emissions by fuel in electricity generation



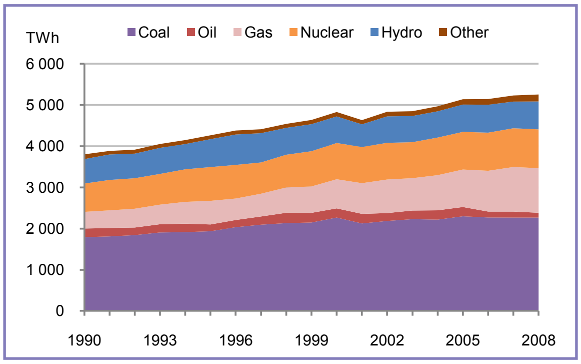
Source: IEA, 2010.

Notes: Emissions from electricity only and CHP plants, total electricity output, heat output from CHP plants.
Coal includes peat. Other includes non-renewable waste.

• Largest source of emissions (2008)		78.1% (Coal)
• Fastest growth over the last decade		30.5% (Gas)
• Slowest growth over the last decade		-54.7% (Oil)
• Emissions (annual rate):	1998-2008	0.2%
	1990-1998	3.1%

Figure 2

Generation mix in power sector



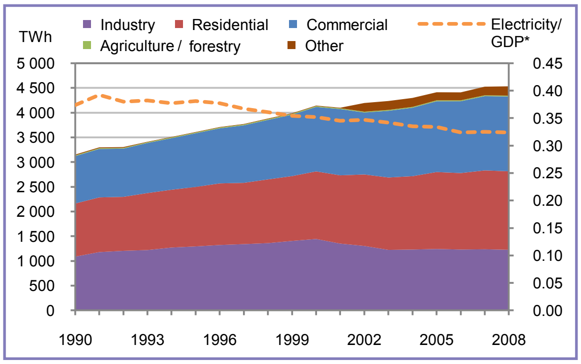
Source: IEA, 2010.

Notes: Coal includes peat. Other includes geothermal, solar, wind, biofuels and waste, etc.

• Largest source of supply (2008)		43.1% (Coal)
• Fastest growth over the last decade		76.2% (Other)
• Slowest growth over the last decade		-53.5% (Oil)
• Growth (annual rate):	1998-2008	1.5%
	1990-1998	2.2%

Figure 3

Electricity use by sector and per unit of GDP



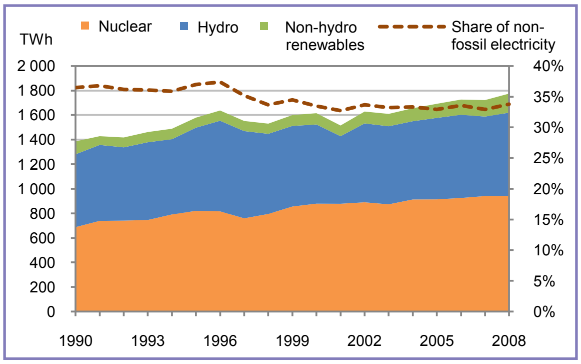
Source: IEA, 2010.

** Electricity/GDP measured in kWh per 2000 USD PPP.*

• Largest sector of consumption (2008)		35% (Residential)
• Fastest growth over the last decade		1690.5% (Other)
• Slowest growth over the last decade		-9.9% (Industry)
• Final electricity growth (annual rate):	1998-2008	1.6%
	1990-1998	2.6%
• Final electricity intensity (annual rate, 1990-2008)		-0.8%

Figure 4

Electricity generation by non-fossil fuels



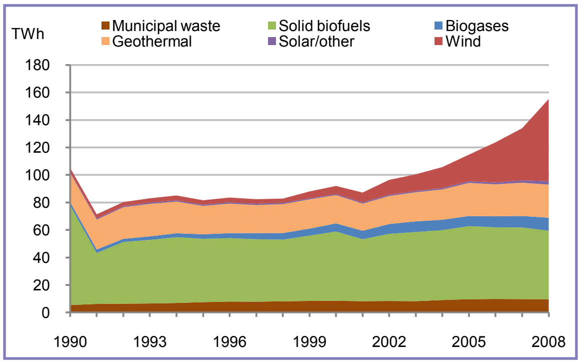
Source: IEA, 2010.

Note: Non-hydro renewables includes geothermal, solar, wind, biofuels and renewable municipal waste.

• Share of non-fossil sources in total electricity (2008)		33.8%
• Largest source (2008)		53% (Nuclear)
• TWh growth (annual rate):	1998-2008	1.2%
	1990-1998	0.6%

Figure 5

Electricity from renewables (excluding hydro)



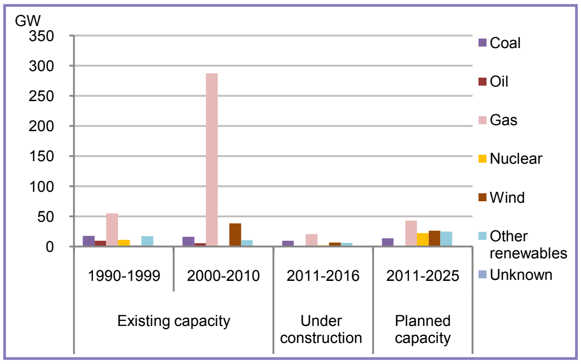
Source: IEA, 2010.

Notes: Biogases includes small quantities of liquid biofuels. Municipal waste only includes the renewable portion of waste.

• Largest source excluding hydro (2008)		38.5% (Wind)
• Largest growth over the last decade		56.7 TWh (Wind)
• Growth (annual rate):	1998-2008	6.5%
	1990-1998	-2.9%

Figure 6

New capacity by installation date



Source: Platts, 2010.

Notes: Other renewables includes bioenergy, biogas, geothermal, hydro, solar photovoltaics and solar thermal.

• Largest additions in 1990-2010	72.5% (Gas)
• Largest additions under construction	44.8% (Gas)
• Largest additions planned	32.4% (Gas)

Key features in electricity and CO_2: OECD North America

▶ Electricity output has grown at an average 1.5% per annum in the last decade, at a slower rate than the GDP.

▶ Electricity-related CO_2 emissions have grown by 0.5% annually between 1998 and 2007, and dropped near 3% to 2.6 $GtCO_2$ in 2008, partly as a result of the recession. North American CO_2 emissions from energy still account for 23% of global emissions from this sector, second after China.

▶ Coal still contributes the largest share of electricity generation in 2008, at 43%. Gas-based power has been growing most rapidly over the last decade, alongside new renewables; they respectively account for 20.6% and 3.2% of the total output in 2008. The CO_2 intensity of power generation has been decreasing accordingly over the past decade by 12%, to 0.49 tCO_2/MWh in 2008

▶ The decrease of the electricity of GDP intensity across the period indicates effects from enhanced end-use efficiency as well as a decreasing share of manufacturing and industry in GDP, particularly in the United States.

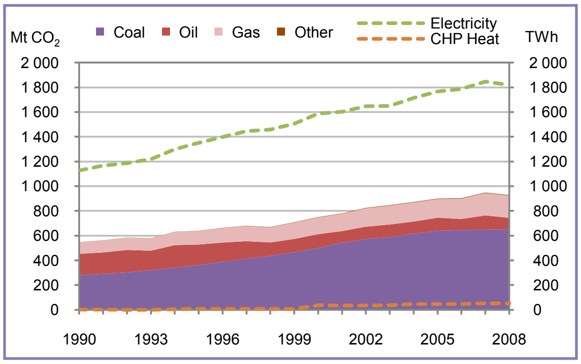
▶ In the United States, the share of non-fossil-fuel electricity accounted for 34% of the total. Policies in support of renewables as well as loan guarantees for nuclear – pending discussions after the Fukushima accident – ought to increase this share in the near future.

▶ Investments in new capacity over the last two decades indicate the dominance of gas (73% of the total) at the expense of coal, and a very rapid growth in wind capacity.

OECD Pacific

Figure 1

CO_2 emissions by fuel in electricity generation



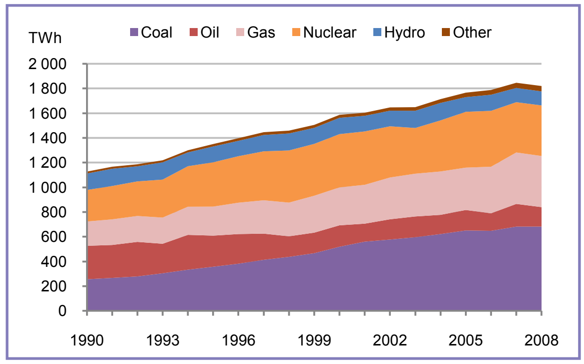
Source: IEA, 2010.

Notes: Emissions from electricity only and CHP plants, total electricity output, heat output from CHP plants.
Coal includes peat. Other includes non-renewable waste.

• Largest source of emissions (2008)		70.2% (Coal)
• Fastest growth over the last decade		82.8% (Other)
• Slowest growth over the last decade		-14.5% (Oil)
• Emissions (annual rate):	1998-2008	3.3%
	1990-1998	2.6%

Figure 2

Generation mix in power sector



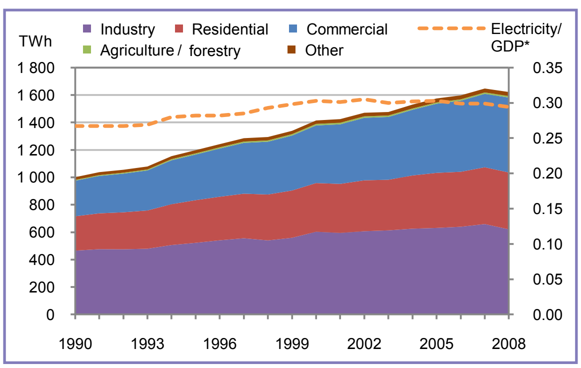
Source: IEA, 2010.

Notes: Coal includes peat. Other includes geothermal, solar, wind, biofuels and waste, etc.

• Largest source of supply (2008)		37.5% (Coal)
• Fastest growth over the last decade		90.3% (Other)
• Slowest growth over the last decade		-17.4% (Hydro)
• Growth (annual rate):	1998-2008	2.2%
	1990-1998	3.3%

Figure 3

Electricity use by sector and per unit of GDP



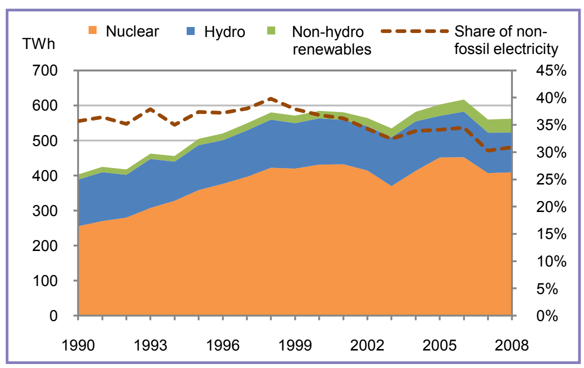
Source: IEA, 2010.

** Electricity/GDP measured in kWh per 2000 USD PPP.*

• Largest sector of consumption (2008)		38.3% (Industry)
• Fastest growth over the last decade		42% (Commercial)
• Slowest growth over the last decade		15% (Industry)
• Final electricity growth (annual rate):	1998-2008	2.3%
	1990-1998	3.3%
• Final electricity intensity (annual rate, 1990-2008)		0.5%

Figure 4

Electricity generation by non-fossil fuels



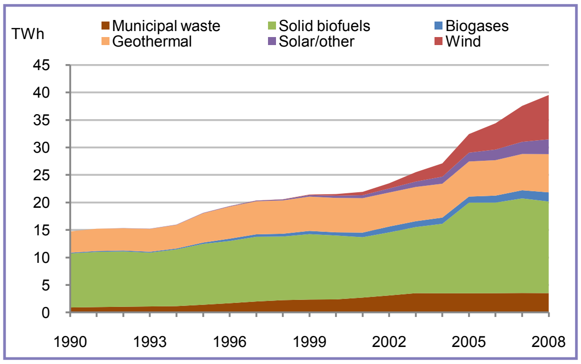
Source: IEA, 2010.

Note: Non-hydro renewables includes geothermal, solar, wind, biofuels and renewable municipal waste.

• Share of non-fossil sources in total electricity (2008)		30.9%
• Largest source (2008)		72.8% (Nuclear)
• TWh growth (annual rate):	1998-2008	-0.7%
	1990-1998	1%

Figure 5

Electricity from renewables (excluding hydro)



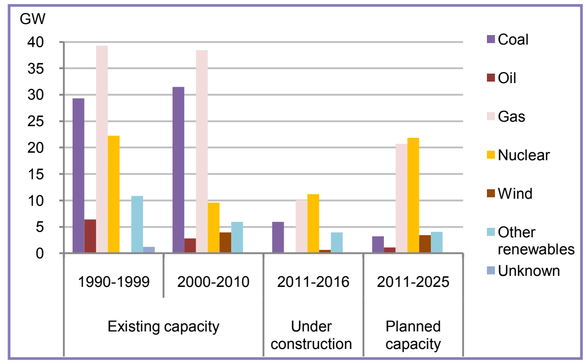
Source: IEA, 2010.

Notes: Biogases includes small quantities of liquid biofuels. Municipal waste only includes the renewable portion of waste.

• Largest source excluding hydro (2008)		42.1% (Solid biofuels)
• Largest growth over the last decade		8 TWh (Wind)
• Growth (annual rate):	1998-2008	6.7%
	1990-1998	4.3%

Figure 6

New capacity by installation date



Source: Platts, 2010.

Notes: Other renewables includes bioenergy, biogas, geothermal, hydro, solar photovoltaics and solar thermal.

• Largest additions in 1990-2010	38.5% (Gas)
• Largest additions under construction	35.2% (Nuclear)
• Largest additions planned	40.2% (Nuclear)

Key features in electricity and CO_2: OECD Pacific

▶ Electricity-related CO_2 emissions have increased by 3.3% annually over the last decade, against 2.6% in the 1990-1998 period. The CO_2 intensity of power generation has been stable since 2002 at 0.5 tCO_2/MWh.

▶ The relatively balanced fuel mix in power generation hides striking country-by-country differences, with Australia relying mostly on coal; Japan using a diversified mix, reflecting resource constraints; and Korea showing a rapid uptake of coal and increasing nuclear generation following electricity demand that more than quadrupled since 1990.

▶ The intensity of final electricity use per GDP has grown by 0.5% annually since 1990, although it has been relatively stable over the last decade. Final electricity use has grown by 62% since 1990, in spite of a 1.6% drop in 2008 as a result of the recession.

▶ CO_2 from electricity accounts for 44.6% of the region's total CO_2 emissions, higher than in Europe or OECD North America.

▶ The share of non-fossil fuel generation has declined since 1990, from 36% to 31% in 2008. Among OECD regions, the growth in non-hydro renewables has been the lowest in OECD Pacific, from 15 to 40 TWh between 1990 and 2008. Wind recorded the fastest growth in the 1998-2008 decade.

▶ Japan accounts for half of the region's CO_2 emissions from electricity. The Fukushima accident will most probably increase the CO_2 intensity of power generation in Japan in the coming years.

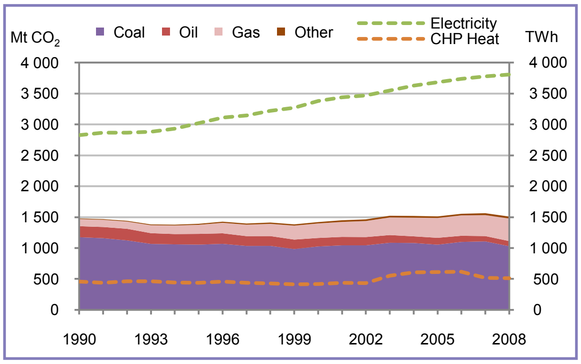
▶ Australia and Korea face some uncertainty, with ongoing political processes to introduce emission trading schemes. Japan has stepped back for now from a national emissions trading system and was considering a carbon taxation program.

▶ Nuclear is projected to represent the largest additions in capacity in this region.

Europe

Figure 1

CO_2 emissions by fuel in electricity generation



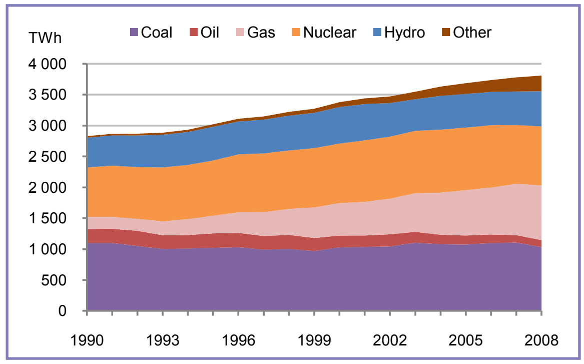
Source: IEA, 2010.

Notes: Emissions from electricity only and CHP plants, total electricity output, heat output from CHP plants.
Coal includes peat. Other includes non-renewable waste.

• Largest source of emissions (2008)		68.2% (Coal)
• Fastest growth over the last decade		84.5% (Gas)
• Slowest growth over the last decade		-47.3% (Oil)
• Emissions (annual rate):	1998-2008	0.7%
	1990-1998	-0.6%

Figure 2

Generation mix in power sector



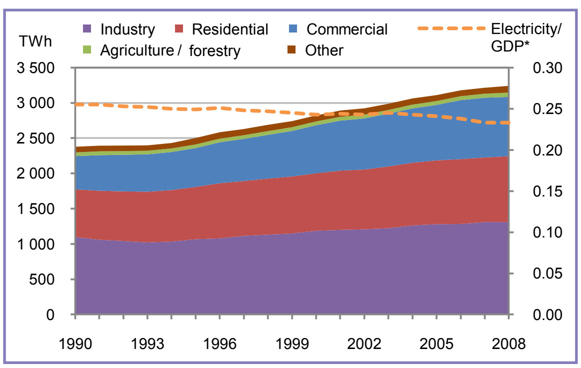
Source: IEA, 2010.

Notes: Coal includes peat. Other includes geothermal, solar, wind, biofuels and waste, etc.

• Largest source of supply (2008)		27.1% (Coal)
• Fastest growth over the last decade		311.8% (Other)
• Slowest growth over the last decade		-49.2% (Oil)
• Growth (annual rate):	1998-2008	1.7%
	1990-1998	1.6%

Figure 3

Electricity use by sector and per unit of GDP



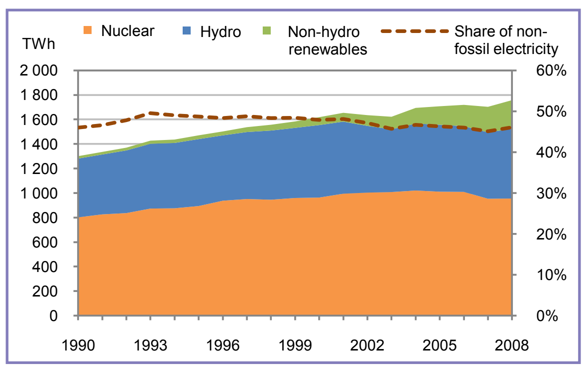
Source: IEA, 2010.

** Electricity/GDP measured in kWh per 2000 USD PPP.*

• Largest sector of consumption (2008)		40.4% (Industry)
• Fastest growth over the last decade		35.6% (Commercial)
• Slowest growth over the last decade		7% (Other)
• Final electricity growth (annual rate):	1998-2008	1.9%
	1990-1998	1.5%
• Final electricity intensity (annual rate, 1990-2008)		-0.5%

Figure 4

Electricity generation by non-fossil fuels



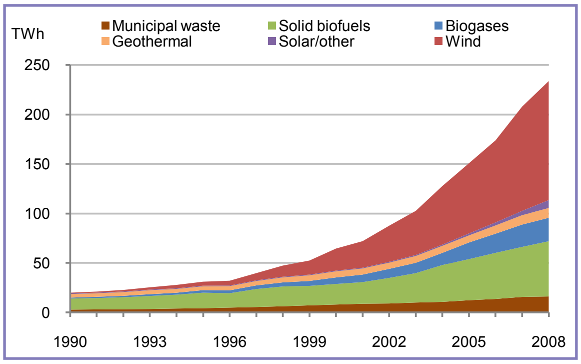
Source: IEA, 2010.

Note: Non-hydro renewables includes geothermal, solar, wind, biofuels and renewable municipal waste.

• Share of non-fossil sources in total electricity (2008)		46.1%
• Largest source (2008)		54.3% (Nuclear)
• TWh growth (annual rate):	1998-2008	2.5%
	1990-1998	2.4%

Figure 5

Electricity from renewables (excluding hydro)



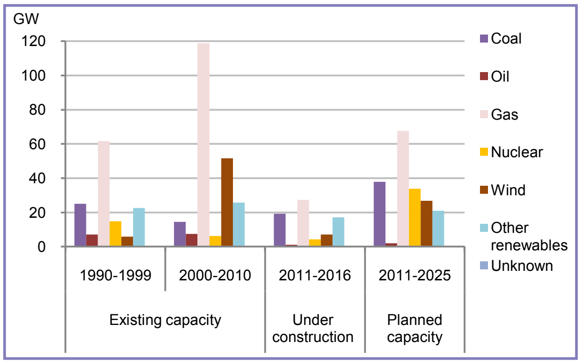
Source: IEA, 2010.

Notes: Biogases includes small quantities of liquid biofuels. Municipal waste only includes the renewable portion of waste.

• Largest source excluding hydro (2008)		51.4% (Wind)
• Largest growth over the last decade		108.9 TWh (Wind)
• Growth (annual rate):	1998-2008	17.3%
	1990-1998	11.4%

Figure 6

New capacity by installation date



Source: Platts, 2010.

Notes: Other renewables includes bioenergy, biogas, geothermal, hydro, solar photovoltaics and solar thermal.

• Largest additions in 1990-2010	49.9% (Gas)
• Largest additions under construction	35.8% (Gas)
• Largest additions planned	35.8% (Gas)

Key features in electricity and CO_2: Europe

▶ Total electricity output has increased at an annual rate of 1.7% over the last decade, while CO_2 emissions have remained relatively stable. The emission intensity has decreased from 0.39 to 0.35 tCO_2/MWh.

▶ The largest source of CO_2 emissions are coal power plants. Germany, the United Kingdom, Poland and Italy, account for 54% of total European emissions from electricity. Electricity is the main CO_2 source in the EU emissions trading system. Power generation generally emits above its allocated CO_2 cap and is the main buyer on the carbon market.

▶ The largest source of electricity is still coal at 27.1% of total output, against 39% in 1990. The European generation mix is characterised by a large share of nuclear (25.1%), and a rapidly increasing share of gas (up 10 percentage points from 1998 to 2008), as well as non-hydro renewables.

▶ Non-hydro renewables have recorded a spectacular 17.3% per annum growth over the 1998-2008 decade, with their share in total output increasing from 1.9% in 1998 to 6.7% in 2008, thanks to strong policy support measures.

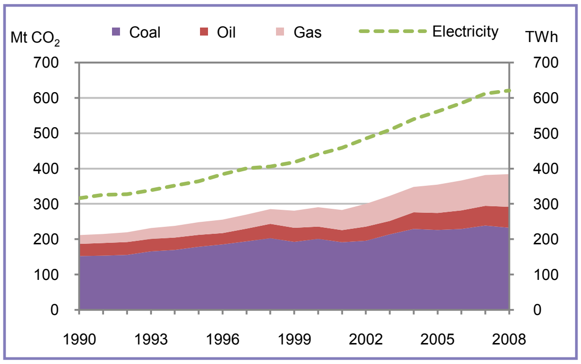
▶ Wind dominates non-hydro renewable generation with 51.4%. Germany and Spain concentrate a large share of Europe's wind-based electricity with 40.6 TWh in Germany (34% of total European wind power) and 32.2 TWh in Spain (27%). Denmark wind power, 6% of the European total, amounts to 20% of the country's power generation.

▶ Europe shows a mixed portfolio of technologies for new capacity to be installed post-2010.

Africa

Figure 1

CO_2 emissions by fuel in electricity generation



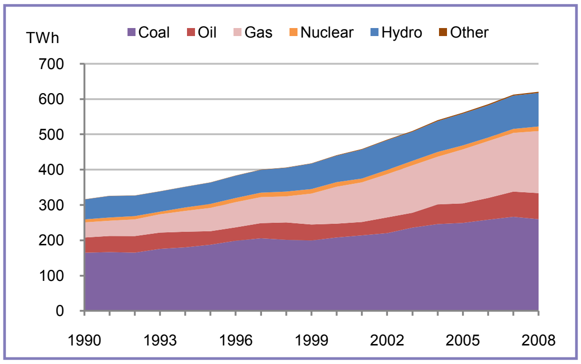
Source: IEA, 2010.

Notes: Emissions from electricity only and CHP plants, total electricity output. Coal includes peat.

• Largest source of emissions (2008)		60.5% (Coal)
• Fastest growth over the last decade		121.2% (Gas)
• Slowest growth over the last decade		14.6% (Coal)
• Emissions (annual rate):	1998-2008	3%
	1990-1998	3.8%

Figure 2

Generation mix in power sector



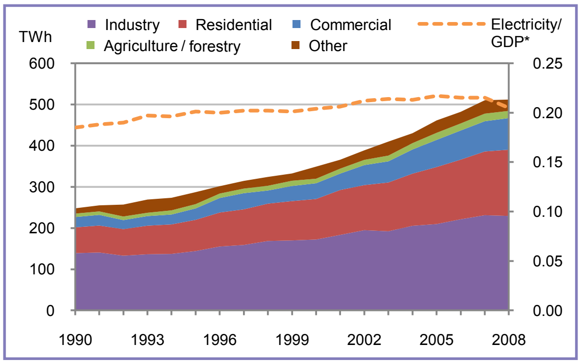
Source: IEA, 2010.

Notes: Coal includes peat. Other includes geothermal, solar, wind, biofuels and waste, etc.

• Largest source of supply (2008)		41.9% (Coal)
• Fastest growth over the last decade		255.3% (Other)
• Slowest growth over the last decade		-4.4% (Nuclear)
• Growth (annual rate):	1998-2008	4.3%
	1990-1998	3.2%

Figure 3

Electricity use by sector and per unit of GDP



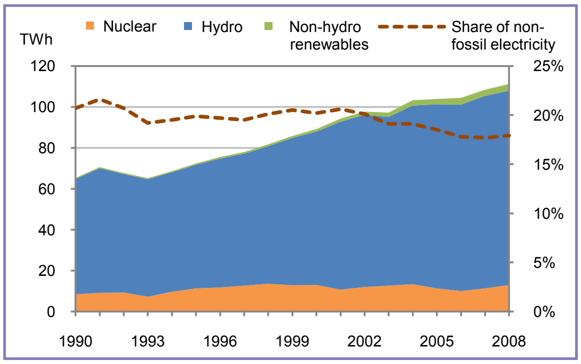
Source: IEA, 2010.

** Electricity/GDP measured in kWh per 2000 USD PPP.*

• Largest sector of consumption (2008)		44.8% (Industry)
• Fastest growth over the last decade		141.4% (Commercial)
• Slowest growth over the last decade		27.8% (Other)
• Final electricity growth (annual rate):	1998-2008	4.7%
	1990-1998	3.4%
• Final electricity intensity (annual rate, 1990-2008)		0.6%

Figure 4

Electricity generation by non-fossil fuels



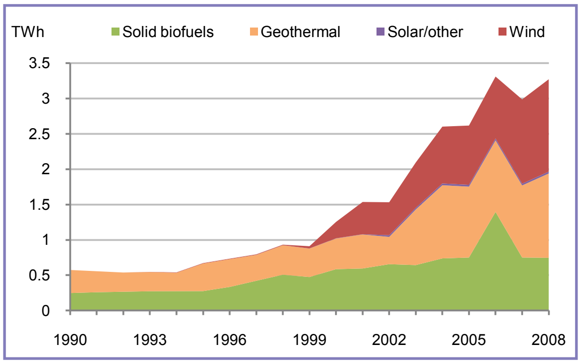
Source: IEA, 2010.

Note: Non-hydro renewables includes geothermal, solar, wind, biofuels and renewable municipal waste.

• Share of non-fossil sources in total electricity (2008)		17.9%
• Largest source (2008)		85.4% (Hydro)
• TWh growth (annual rate):	1998-2008	2.8%
	1990-1998	1.6%

Figure 5

Electricity from renewables (excluding hydro)

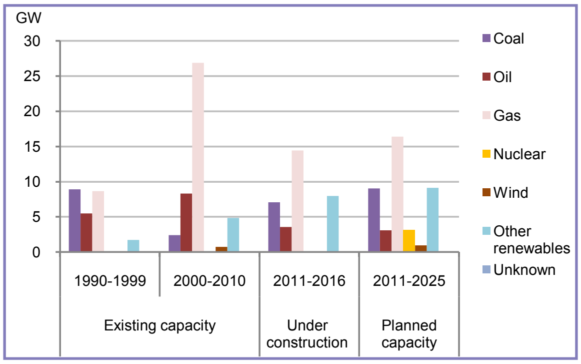


Source: IEA, 2010.

- Largest source excluding hydro (2008) 39.9% (Wind)
- Largest growth over the last decade 1.3 TWh (Wind)
- Growth (annual rate): 1998-2008 13.4%
  1990-1998 6.2%

Figure 6

New capacity by installation date



Source: Platts, 2010.

Notes: Other renewables includes bioenergy, biogas, geothermal, hydro, solar photovoltaics and solar thermal.

- Largest additions in 1990-2010 52.2% (Gas)
- Largest additions under construction 43.6% (Gas)
- Largest additions planned 39.2% (Gas)

Key features in electricity and CO_2: Africa

▶ Total electricity output (TWh) has increased by over 50% over the period 1998-2008, leading to an increase in emissions of 35% over the same period.

▶ The emissions intensity has fallen from 0.70 tCO_2/MWh in 1998 to 0.62 tCO_2/MWh in 2008 as a result of a falling share of coal (from 50% to 42%) mainly being replaced by gas (growing from 18% to 28%) in generation.

▶ Total regional CO_2 emissions in the electricity sector are dominated by a few main emitting countries, with South Africa, Egypt, Libya and Algeria representing over 80% of the total in 2008. Overall emissions from the electricity sector in Africa remain small at 384 $MtCO_2$, representing only 3.4% of total global emissions from electricity.

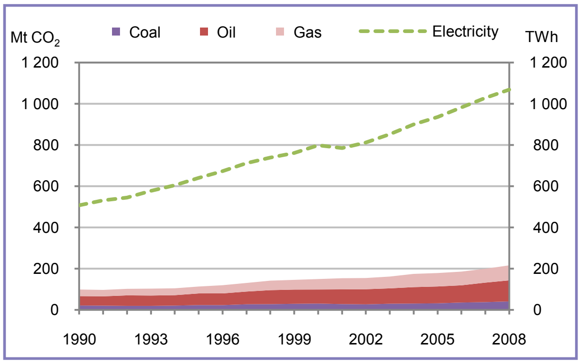
▶ Final electricity use grew most quickly in the commercial and residential sectors from 1998 to 2008, their share growing from 10% to 15%, and 28% to 31%, respectively. This indicates modest progress in access to electricity in Africa. Average final electricity consumption per capita amounted to 0.5 MWh, against 5.4 MWh in Europe.

▶ Excluding hydro power, which is the dominant non-fossil fuel, the main renewable energy technology in 2008 is wind, ahead of geothermal and solid biofuels. However, total output in 2008 from these renewable energy technologies remains low, with 3.3 TWh, or less than 1% of total output.

▶ Much new capacity in hydro is either under construction or planned for the next two decades, although the majority of additions will be fossil-fuel based (gas, coal and oil).

Latin America

Figure 1
CO_2 emissions by fuel in electricity generation

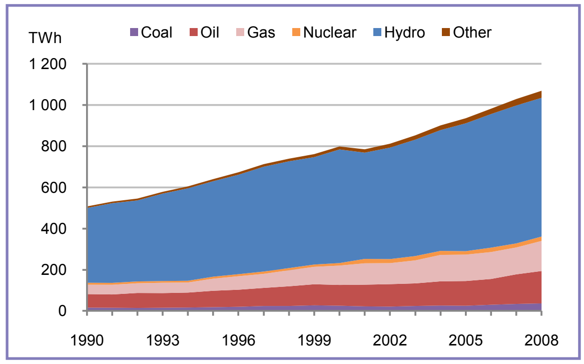


Source: IEA, 2010.

Notes: Emissions from electricity only and CHP plants, total electricity output, heat output from CHP plants.
Coal includes peat.

• Largest source of emissions (2008)		47.4% (Oil)
• Fastest growth over the last decade		57.9% (Gas)
• Slowest growth over the last decade		48.5% (Coal)
• Emissions (annual rate):	1998-2008	4.3%
	1990-1998	4.6%

Figure 2
Generation mix in power sector

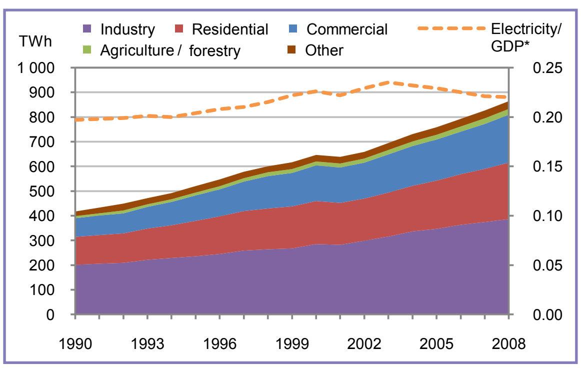


Source: IEA, 2010.

Notes: Coal includes peat. Other includes geothermal, solar, wind, biofuels and waste, etc.

• Largest source of supply (2008)		63% (Hydro)
• Fastest growth over the last decade		170.1% (Other)
• Slowest growth over the last decade		29.9% (Hydro)
• Growth (annual rate):	1998-2008	3.8%
	1990-1998	4.8%

Figure 3
Electricity use by sector and per unit of GDP

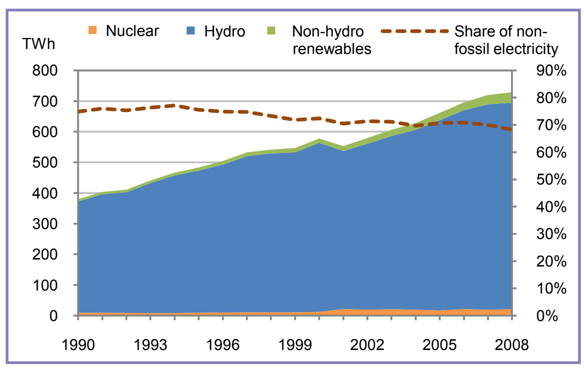


Source: IEA, 2010.

** Electricity/GDP measured in kWh per 2000 USD PPP.*

• Largest sector of consumption (2008)		44.7% (Industry)
• Fastest growth over the last decade		51% (Agriculture/forestry)
• Slowest growth over the last decade		30.2% (Other)
• Final electricity growth (annual rate):	1998-2008	3.7%
	1990-1998	4.7%
• Final electricity intensity (annual rate, 1990-2008)		0.6%

Figure 4
Electricity generation by non-fossil fuels



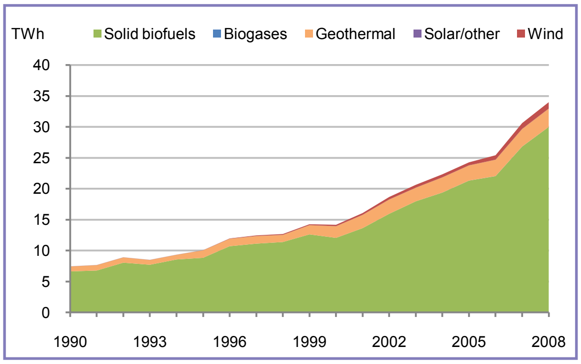
Source: IEA, 2010.

Note: Non-hydro renewables includes geothermal, solar, wind, biofuels and renewable municipal waste.

• Share of non-fossil sources in total electricity (2008)		68.2%
• Largest source (2008)		92.4% (Hydro)
• TWh growth (annual rate):	1998-2008	2.5%
	1990-1998	3.9%

Figure 5

Electricity from renewables (excluding hydro)



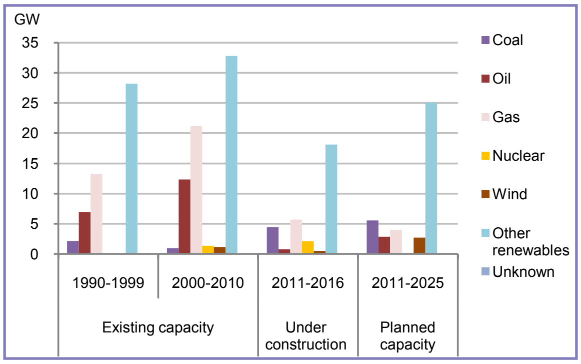
Source: IEA, 2010.

Notes: Biogases includes small quantities of liquid biofuels.

• Largest source excluding hydro (2008)		88.2% (Solid biofuels)
• Largest growth over the last decade		18.6 TWh (Solid biofuels)
• Growth (annual rate):	1998-2008	10.4%
	1990-1998	6.9%

Figure 6

New capacity by installation date



Source: Platts, 2010.

Notes: Other renewables includes bioenergy, biogas, geothermal, hydro, solar photovoltaics and solar thermal.

• Largest additions in 1990-2010	50.6% (Other renewables)
• Largest additions under construction	57.2% (Other renewables)
• Largest additions planned	62.3% (Other renewables)

Key features in electricity and CO_2: Latin America

► With hydro power accounting for 63% of Latin America's electricity generation, the sector boasts an extremely low level of CO_2 emissions, at 216 $MtCO_2$ in 2008.

► Growth in hydro electricity generation remains steady and the contribution of non-hydro renewables has grown quickly over the last decade, driven largely by an increase of 18.6 TWh in power generation from solid biofuels. Geothermal energy is also playing an increasing role, having more than tripled between 1990 and 2008.

► Despite these advances and a contribution from nuclear to the mix, the CO_2 intensity of power generation is at its highest in 2008, albeit at the lowest level of all regions considered in this report (0.2 tCO_2/MWh in 2008).

► While oil is Latin America's largest source of CO_2 emissions in power generation (47.4% of the total in 2008), all three fossil fuels have followed a similar growth pattern since 1998, with gas leading the way at 58% growth.

► The region shows great diversity in its electricity-emission profiles, with Brazil and Colombia benefitting from vast hydro resources, while Argentina and Chile rely on imported fossil fuels for the growth in power generation.

► The electricity intensity of GDP is higher in 2008 than 1990 in Latin America, although the growth trend seems to have reversed since 2003.

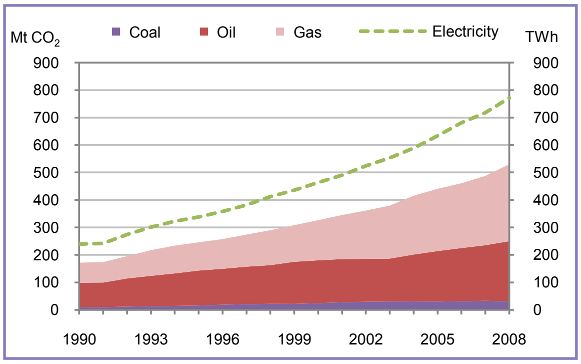
► Solid biofuels dominate the contribution of non-hydro renewables to electricity output, with about 30 TWh in 2008.

► Latin America has added much gas and oil capacity in the last two decades. Hydro still represents the largest capacity additions, a trend that will increase in the future.

Middle East

Figure 1

CO_2 emissions by fuel in electricity generation



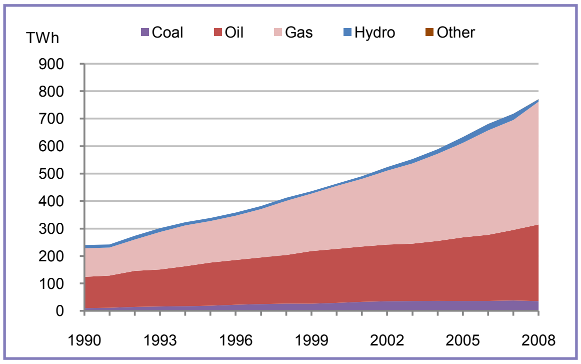
Source: IEA, 2010.

Notes: Emissions from electricity only and CHP plants, total electricity output. Coal includes peat.

• Largest source of emissions (2008)		52.8% (Gas)
• Fastest growth over the last decade		120% (Gas)
• Slowest growth over the last decade		40% (Coal)
• Emissions (annual rate):	1998-2008	6.2%
	1990-1998	6.8%

Figure 2

Generation mix in power sector



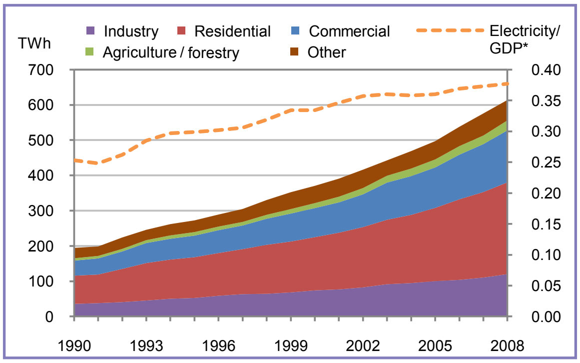
Source: IEA, 2010.

Notes: Coal includes peat. Other includes geothermal, solar, wind, biofuels and waste, etc.

• Largest source of supply (2008)		58% (Gas)
• Fastest growth over the last decade		14 466.7% (Other)
• Slowest growth over the last decade		-20.3% (Hydro)
• Growth (annual rate):	1998-2008	6.5%
	1990-1998	7%

Figure 3

Electricity use by sector and per unit of GDP



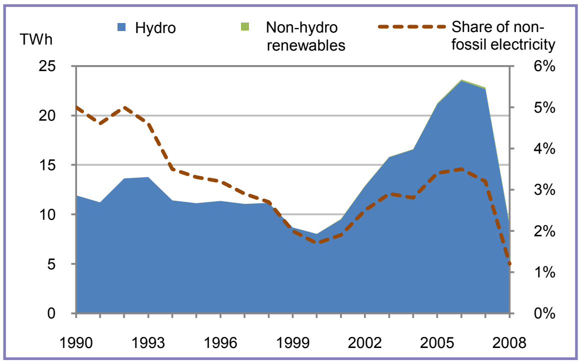
Source: IEA, 2010.

** Electricity/GDP measured in kWh per 2000 USD PPP.*

• Largest sector of consumption (2008)		42.4% (Residential)
• Fastest growth over the last decade		152.9% (Agriculture/forestry)
• Slowest growth over the last decade		38.1% (Other)
• Final electricity growth (annual rate):	1998-2008	6.4%
	1990-1998	6.9%
• Final electricity intensity (annual rate, 1990-2008)		2.2%

Figure 4

Electricity generation by non-fossil fuels



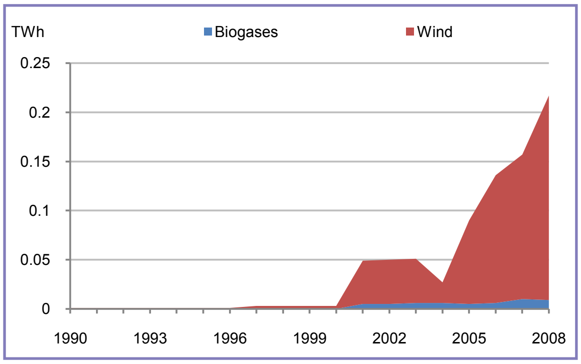
Source: IEA, 2010.

Note: Non-hydro renewables includes geothermal, solar, wind, biofuels and renewable municipal waste.

• Share of non-fossil sources in total electricity (2008)		1.2%
• Largest source (2008)		97.6% (Hydro)
• TWh growth (annual rate):	1998-2008	-2.9%
	1990-1998	-2.5%

Figure 5

Electricity from renewables (excluding hydro)



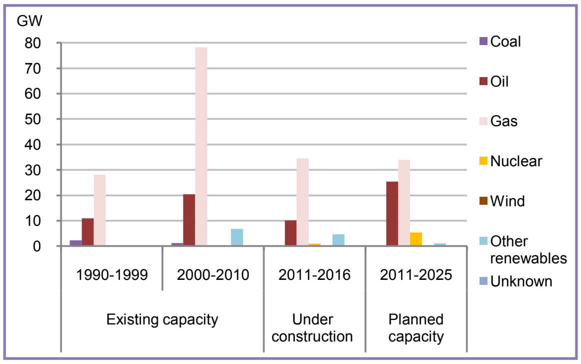
Source: IEA, 2010.

Notes: Biogases includes small quantities of liquid biofuels.

• Largest source excluding hydro (2008)		95.9% (Wind)
• Largest growth over the last decade		0.2 TWh (Wind)
• Growth (annual rate):	1998-2008	53.4%
	1990-1998	14.7%

Figure 6

New capacity by installation date



Source: Platts, 2010.

Notes: Other renewables includes bioenergy, biogas, geothermal, hydro, solar photovoltaics and solar thermal.

• Largest additions in 1990-2010	71.7% (Gas)
• Largest additions under construction	68.7% (Gas)
• Largest additions planned	51.4% (Gas)

Key features in electricity and CO_2: Middle East

▶ The Middle East region recorded an 87% growth in electricity output over the 1998-2008 decade. Total CO_2 emissions have followed a similar trend, growing by 83% over the same period. The CO_2 intensity of power generation fell by 2% over the period, to 0.69 tCO_2/MWh in 2008.

▶ CO_2 emissions from power generation are fairly concentrated in this region with the two largest emitters, Saudi Arabia and Iran, representing about 53% of total emissions.

▶ Gas represents the largest source of electricity supply. Electricity from gas grew more than fourfold between 1990 and 2008. The second largest supply source is fuel oil with 36% of total supply in 2008 – a very high share compared to the global average of 5.5%.

▶ With 42% of the total final electricity use, the residential sector remains the largest consumer of electricity. It represents a high percentage of overall consumption compared to the global average of 27.4%.

▶ Given the abundant energy reserves located in this region, energy prices have been low in most of the region. Energy efficiency has not been a high priority, but a policy shift can now be seen in several countries including Saudi Arabia, with the creation of a National Energy Efficiency Programme, and Israel, with a 20% reduction in energy consumption by 2020.

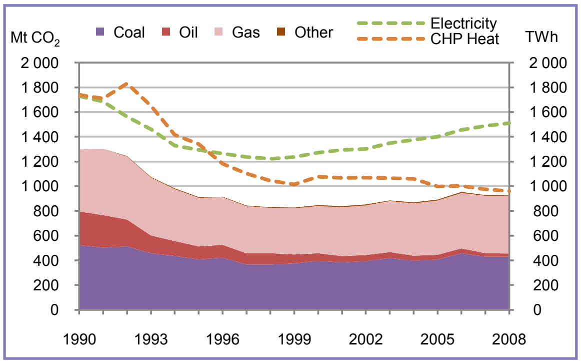
▶ The share of non-fossil fuel, essentially only hydro power, in overall electricity generation has fallen markedly from 2007 to 2008 and represented only about 1% of total output in 2008. However, the drop from 2007 to 2008 was mainly a result of severe drought that adversely affected Iran's hydroelectric production.

▶ Oil and gas dominate plans for new capacity; non-fossil fuel capacity accounts for only 10%, with some hydro under construction and nuclear planned in Abu Dhabi

Former Soviet Union

Figure 1

CO_2 emissions by fuel in electricity generation



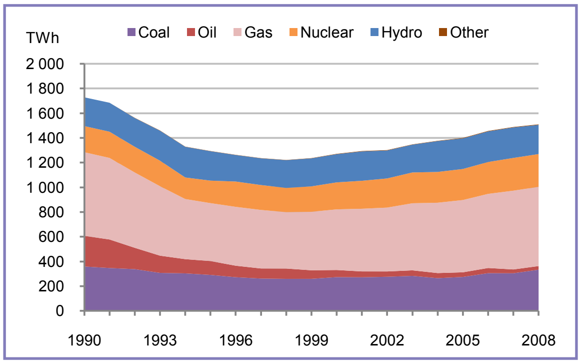
Source: IEA, 2010.

Notes: Emissions from electricity only and CHP plants, total electricity output, heat output from CHP plants.
Coal includes peat. Other includes non-renewable waste.

- Largest source of emissions (2008) 50% (Gas)
- Fastest growth over the last decade 44.5% (Other)
- Slowest growth over the last decade -72.4% (Oil)
- Emissions (annual rate): 1998-2008 1.1%
  1990-1998 -5.4%

Figure 2

Generation mix in power sector



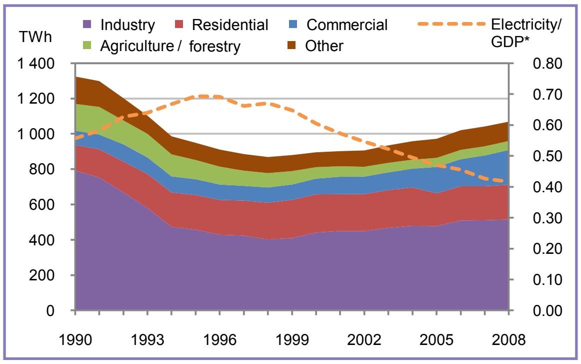
Source: IEA, 2010.

Notes: Coal includes peat. Other includes geothermal, solar, wind, biofuels and waste, etc.

- Largest source of supply (2008) 42.5% (Gas)
- Fastest growth over the last decade 138.3% (Other)
- Slowest growth over the last decade -65.1% (Oil)
- Growth (annual rate): 1998-2008 2.1%
  1990-1998 -4.2%

Figure 3

Electricity use by sector and per unit of GDP



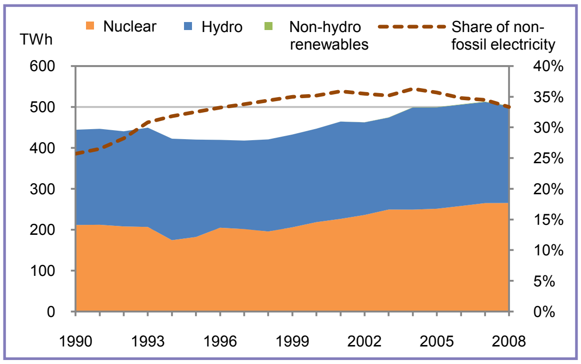
Source: IEA, 2010.

** Electricity/GDP measured in kWh per 2000 USD PPP.*

- Largest sector of consumption (2008) 48.2% (Industry)
- Fastest growth over the last decade 127.3% (Commercial)
- Slowest growth over the last decade -37.3% (Agriculture/forestry)
- Final electricity growth (annual rate): 1998-2008 2.1%
  1990-1998 -5.1%
- Final electricity intensity (annual rate, 1990-2008) -1.6%

Figure 4

Electricity generation by non-fossil fuels



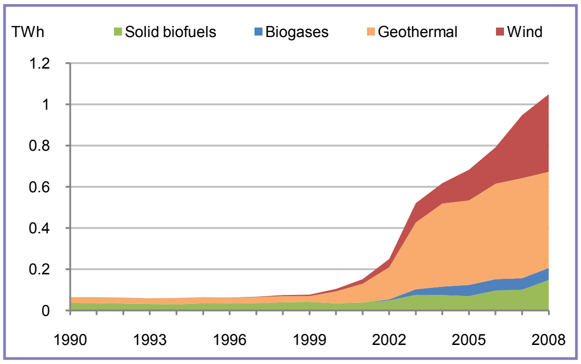
Source: IEA, 2010.

Note: Non-hydro renewables includes geothermal, solar, wind, biofuels and renewable municipal waste.

- Share of non-fossil sources in total electricity (2008) 33.3%
- Largest source (2008) 52.8% (Nuclear)
- TWh growth (annual rate): 1998-2008 0.4%
  1990-1998 0%

Figure 5

Electricity from renewables (excluding hydro)



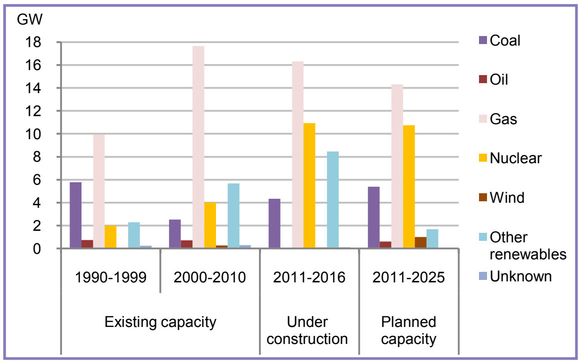
Source: IEA, 2010.

Notes: Biogases includes small quantities of liquid biofuels.

- Largest source excluding hydro (2008) 44.5% (Geothermal)
- Largest growth over the last decade 0.4 TWh (Geothermal)
- Growth (annual rate): 1998-2008 30.2%
  1990-1998 1.8%

Figure 6

New capacity by installation date



Source: Platts, 2010.

Notes: Other renewables includes bioenergy, biogas, geothermal, hydro, solar photovoltaics and solar thermal.

- Largest additions in 1990-2010 52.8% (Gas)
- Largest additions under construction 40.5% (Gas)
- Largest additions planned 42.4% (Gas)

Key features in electricity and CO_2: Former Soviet Union

▶ Total output in electricity and heat from cogeneration plants slightly increased over the last decade (0.9% annual growth), after a significant decrease between 1990 and 1998 following the fall of the Soviet Union and resulting economic recession.

▶ CO_2 emissions from power generation increased slightly over the last decade, remaining 29% below the 1990 level. The CO_2 intensity of power generation has remained stable over 1998-2008, at around 0.37 tCO_2/MWh, a relatively low level due to the important share of CHP plants, which are more efficient than electricity-only plants.

▶ The fuel mix in electricity generation is characterised by a large share of gas (42.5%).

▶ The data for the region is dominated by Russia, which represents 73% of total electricity and heat from CHP output, and 66% of total emissions.

▶ The electricity intensity of GDP has significantly decreased over the last decade from 0.67 to 0.42 kWh/USD, but remains the highest among regions in this report.

▶ Industry remains the largest consumer (48.2% of total final electricity use). The commercial sector's consumption increased rapidly, from 10% of electricity use in 1998 to 18.4% in 2008.

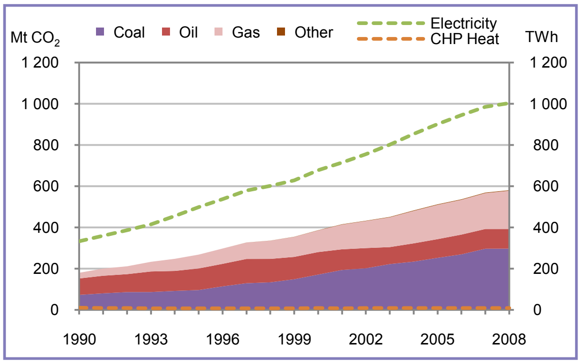
▶ The share of non-fossil generation has remained relatively stable over the last decade, around 34%. Nuclear and hydro account for 53% and 47% of non-fossil generation, respectively. Total output from non-hydro renewables is negligible, less than 0.1% of total electricity generation, even though it experienced rapid growth during the last decade (30.2% per annum).

▶ Gas, nuclear, hydro and coal to a lesser extent (with 13%) account for the vast majority of projected new capacity.

Asia *(excluding China and India)*

Figure 1

CO_2 emissions by fuel in electricity generation



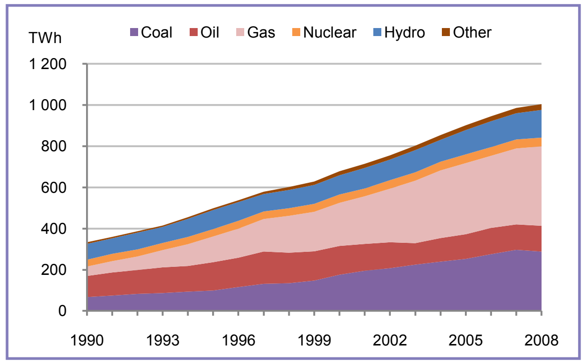
Source: IEA, 2010.

Notes: Emissions from electricity only and CHP plants, total electricity output, heat output from CHP plants.
Coal includes peat. Other includes non-renewable waste.

- Largest source of emissions (2008) 51.1% (Coal)
- Fastest growth over the last decade 452.6% (Other)
- Slowest growth over the last decade -16% (Oil)
- Emissions (annual rate): 1998-2008 5.6%
  1990-1998 8.1%

Figure 2

Generation mix in power sector



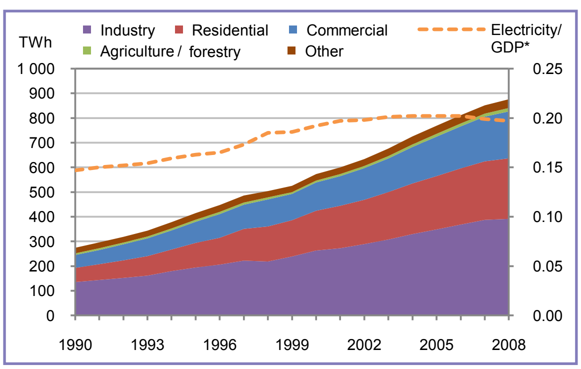
Source: IEA, 2010.

Notes: Coal includes peat. Other includes geothermal, solar, wind, biofuels and waste, etc.

- Largest source of supply (2008) 38.4% (Gas)
- Fastest growth over the last decade 115.8% (Gas)
- Slowest growth over the last decade -15.6% (Oil)
- Growth (annual rate): 1998-2008 5.3%
  1990-1998 7.7%

Figure 3

Electricity use by sector and per unit of GDP



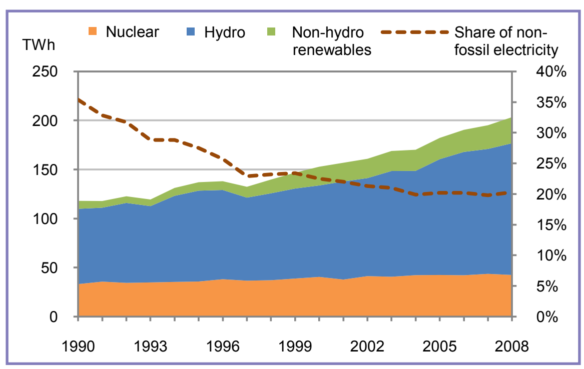
Source: IEA, 2010.

** Electricity/GDP measured in kWh per 2000 USD PPP.*

- Largest sector of consumption (2008) 44.7% (Industry)
- Fastest growth over the last decade 79% (Industry)
- Slowest growth over the last decade 38.8% (Other)
- Final electricity growth (annual rate): 1998-2008 5.7%
  1990-1998 7.9%
- Final electricity intensity (annual rate, 1990-2008) 1.6%

Figure 4

Electricity generation by non-fossil fuels



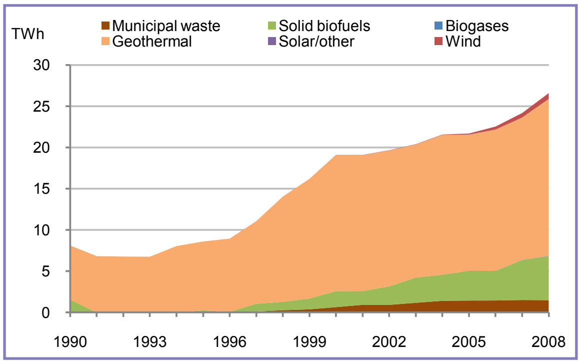
Source: IEA, 2010.

Note: Non-hydro renewables includes geothermal, solar, wind, biofuels and renewable municipal waste.

- Share of non-fossil sources in total electricity (2008) 20.3%
- Largest source (2008) 66.1% (Hydro)
- TWh growth (annual rate): 1998-2008 3.7%
  1990-1998 0.6%

Figure 5

Electricity from renewables (excluding hydro)



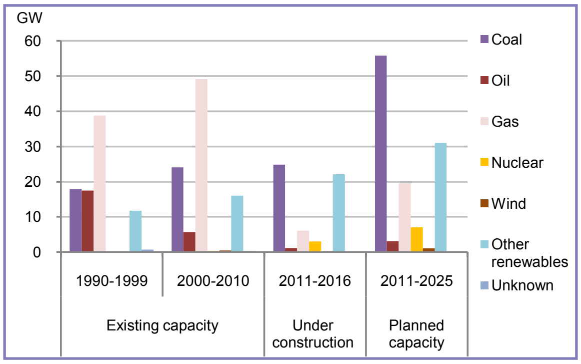
Source: IEA, 2010.

Notes: Biogases includes small quantities of liquid biofuels. Municipal waste only includes the renewable portion of waste.

• Largest source excluding hydro (2008)		71.5% (Geothermal)
• Largest growth over the last decade		6.3 TWh (Geothermal)
• Growth (annual rate):	1998-2008	6.6%
	1990-1998	7.1%

Figure 6

New capacity by installation date



Source: Platts, 2010.

Notes: Other renewables includes bioenergy, biogas, geothermal, hydro, solar photovoltaics and solar thermal.

• Largest additions in 1990-2010	48.1% (Gas)
• Largest additions under construction	43.1% (Coal)
• Largest additions planned	47.4% (Coal)

Key features in electricity and CO_2: Asia (excluding China and India)

▶ There has been steady growth in total electricity generation (TWh), although the rate of growth has slowed slightly from 7.7% per annum in 1990-98 to 5.3% in the decade to 2008.

▶ This growth has largely been met with new gas (12.6% annual increase since 1990) and coal (8.4% annual increase since 1990) generation. Together, these moved from 33.9% of supply in 1990 to 67.1% in 2008, triggering a decline in the share of generation from non-fossil fuels, from 35.4% in 1990 to 20.3% in 2008.

▶ Total CO_2 emissions have risen alongside the increase in coal and gas generation, more than tripling since 1990. The emissions intensity of the overall supply has only changed slightly, moving from 0.52 tCO_2/MWh in 1990 to 0.57 tCO_2/MWh in 2008, with more efficient gas-based generation offsetting the high CO_2 intensity of coal.

▶ Demand growth is evenly spread between the industrial, commercial and residential sectors. Since the Asian financial crisis of 1998-99, demand in each of these sectors has grown very steadily, averaging around 6% per annum between 1998 and 2008.

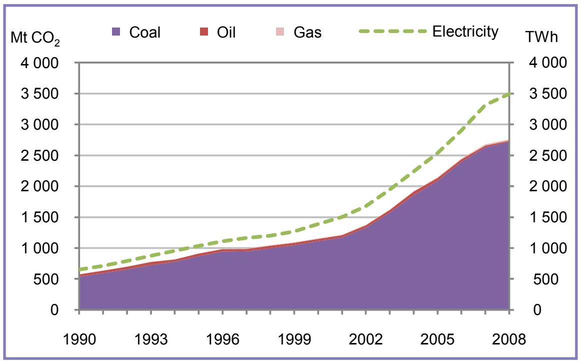
▶ Non-fossil generation is predominantly from hydro (13.4% of supply in 2008) and nuclear (4.2% in 2008). Geothermal plants in Indonesia and the Philippines contribute 1.9% to total generation. Geothermal generation is expected to increase rapidly, with Indonesia planning construction of a further 43 plants by 2014, and new plants also planned in the Philippines.

▶ Fossil-based capacity accounted for 84% of capacity additions from 1990-2010. Although hydro is expected to account for a growing share of supply in the next two decades, coal presently leads new capacity projects.

China

Figure 1

CO_2 emissions by fuel in electricity generation



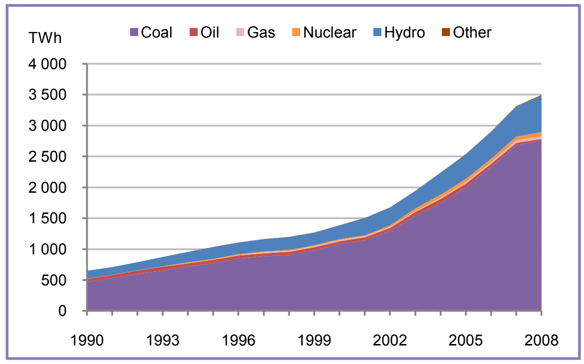
Source: IEA, 2010.

Notes: Emissions from electricity only and CHP plants, total electricity output. Coal includes peat.

• Largest source of emissions (2008)		98.6% (Coal)
• Fastest growth over the last decade		173.1% (Coal)
• Slowest growth over the last decade		-55.9% (Oil)
• Emissions (annual rate):	1998-2008	10.2%
	1990-1998	7.7%

Figure 2

Generation mix in power sector



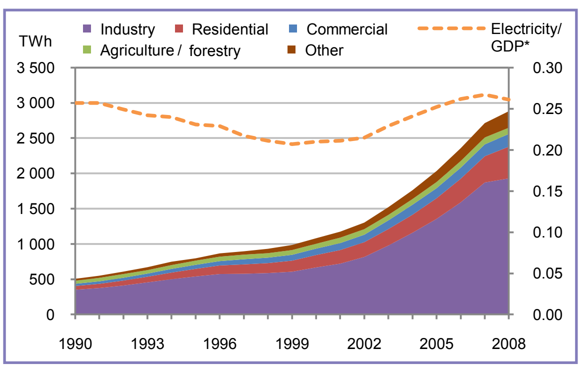
Source: IEA, 2010.

Notes: Coal includes peat. Other includes geothermal, solar, wind, biofuels and waste, etc.

• Largest source of supply (2008)		78.9% (Coal)
• Fastest growth over the last decade		467.5% (Other)
• Slowest growth over the last decade		-55% (Oil)
• Growth (annual rate):	1998-2008	11.3%
	1990-1998	7.9%

Figure 3

Electricity use by sector and per unit of GDP



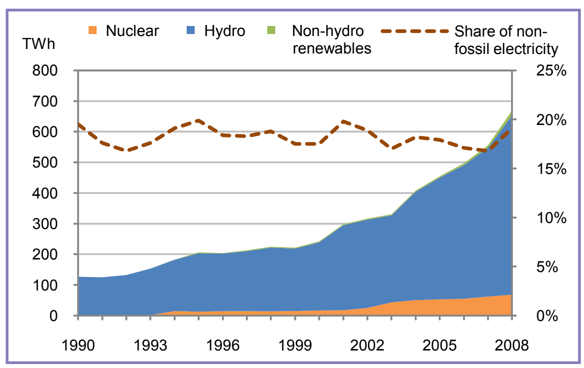
Source: IEA, 2010.

** Electricity/GDP measured in kWh per 2000 USD PPP.*

• Largest sector of consumption (2008)		66.9% (Industry)
• Fastest growth over the last decade		274.8% (Other)
• Slowest growth over the last decade		39.8% (Agriculture/forestry)
• Final electricity growth (annual rate):	1998-2008	12%
	1990-1998	7.9%
• Final electricity intensity (annual rate, 1990-2008)		0.1%

Figure 4

Electricity generation by non-fossil fuels



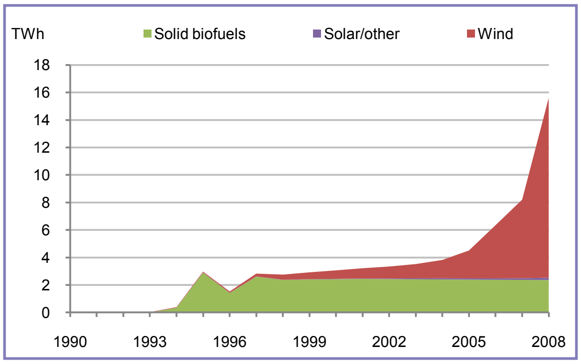
Source: IEA, 2010.

Note: Non-hydro renewables includes geothermal, solar, wind, biofuels and renewable municipal waste.

• Share of non-fossil sources in total electricity (2008)		19.1%
• Largest source (2008)		87.4% (Hydro)
• TWh growth (annual rate):	1998-2008	10.4%
	1990-1998	5.8%

Figure 5

Electricity from renewables (excluding hydro)

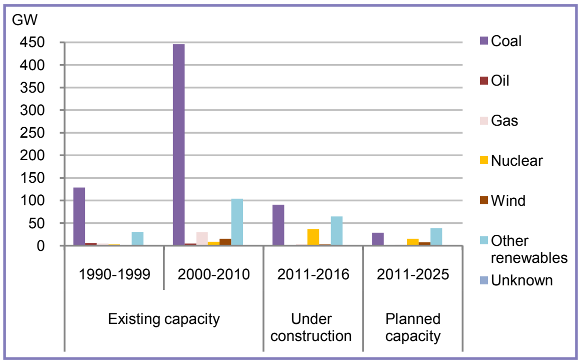


Source: IEA, 2010.

• Largest source excluding hydro (2008)		83.8% (Wind)
• Largest growth over the last decade		12.7 TWh (Wind)
• Growth (annual rate):	1998-2008	19%
	1990-1998	126.3%

Figure 6

New capacity by installation date



Source: Platts, 2010.

Notes: Other renewables includes bioenergy, biogas, geothermal, hydro, solar photovoltaics and solar thermal.

• Largest additions in 1990-2010	73.7% (Coal)
• Largest additions under construction	46% (Coal)
• Largest additions planned	42.8% (Other renewables)

Key features in electricity and CO_2: China

▶ China's electricity generation growth averaged 11.3% per annum over the decade to 2008, and a record 14.6% between 2002 and 2007. Total demand is projected to grow 12% in 2011 alone, to 4 700 TWh according to the China Electricity Council (Interfax, 2011).[1]

▶ Coal dominates, at 78.9% of generation in 2008. The next largest share is hydro (16.7%) with nuclear playing a minor role at present (2.0%). The contribution of oil and gas-based generation remains small (respectively 0.7% and 1.2% in 2008), while all other sources deliver only 0.5%. China has ambitious nuclear and renewable plans for the coming decade but these will displace coal only slowly.

▶ Electricity-related CO_2 emissions rose 10.2% per annum in 1998-2008. While the shares of fossil-based and non-fossil-based generation remained relatively stable, the emissions intensity of coal generation has improved, leading to a decrease in overall electricity emissions intensity from 0.89 tCO_2/MWh in 1990 to 0.79 tCO_2/MWh in 2008.

▶ Electricity use is dominated by industry (66.9% of demand in 2008). Industrial demand grew 18% per annum during the five years 2002 to 2007. While industrial demand growth slowed in 2008 due to the global recession, there was a strong increase in residential demand (+20.8% in 2008).

▶ Non-hydro renewables have grown quickly in percentage terms, triggered by government support policies. Investment in wind generation is accelerating rapidly, more than doubling in one year from 2007 to 2008, with an additional 7.4 TWh of generation. China reported 41.8 GW of installed wind capacity in 2010.

▶ China added an enormous 450 GW of coal capacity in the last decade, and 117 GW in renewables (86% hydro, 12% wind and 2% of others). According to Platts, 36 GW of nuclear are now under construction, with an additional 15 GW planned by 2025. China's goal is 86 GW of nuclear capacity by 2020 (China Daily, 2011).[2]

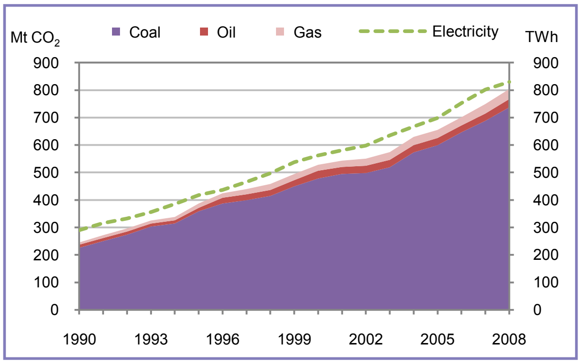
1. "China's power consumption to grow by 12 pct in 2011 – CEC". February 10, 2011.

2. China Daily (2011): "Nuclear Power Sector Target 'too aggressive', says expert". www.chinadaily.com.cn/bizchina/2011-02/09/content_11967140.htm

India

Figure 1

CO_2 emissions by fuel in electricity generation



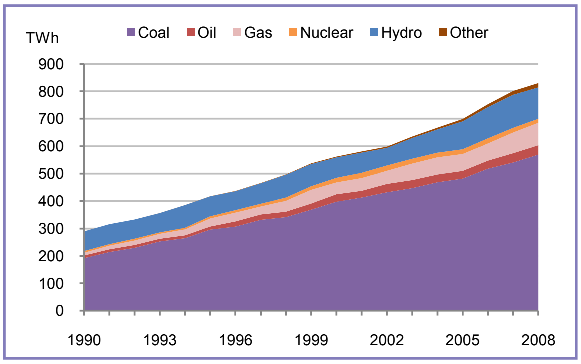
Source: IEA, 2010.

Notes: Emissions from electricity only and CHP plants, total electricity output. Coal includes peat.

• Largest source of emissions (2008)		91.7% (Coal)
• Fastest growth over the last decade		77.7% (Coal)
• Slowest growth over the last decade		39.4% (Oil)
• Emissions (annual rate):	1998-2008	5.8%
	1990-1998	8.1%

Figure 2

Generation mix in power sector



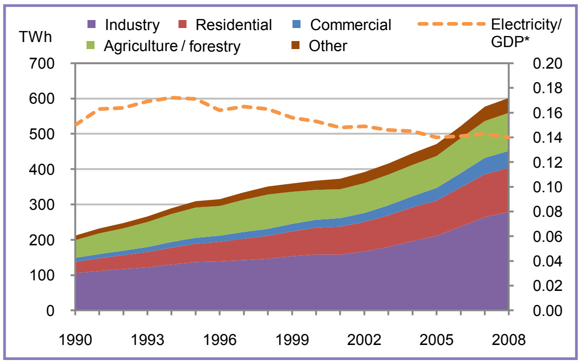
Source: IEA, 2010.

Notes: Coal includes peat. Other includes geothermal, solar, wind, biofuels and waste, etc.

• Largest source of supply (2008)		68.6% (Coal)
• Fastest growth over the last decade		1 288.6% (Other)
• Slowest growth over the last decade		23.4% (Nuclear)
• Growth (annual rate):	1998-2008	5.3%
	1990-1998	7%

Figure 3

Electricity use by sector and per unit of GDP



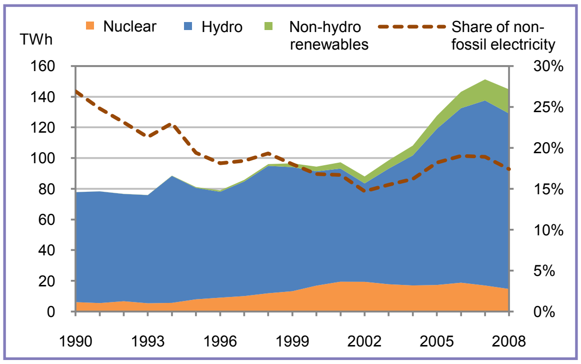
Source: IEA, 2010.

** Electricity/GDP measured in kWh per 2000 USD PPP.*

• Largest sector of consumption (2008)		46.4% (Industry)
• Fastest growth over the last decade		142.7% (Commercial)
• Slowest growth over the last decade		10.9% (Agriculture/forestry)
• Final electricity growth (annual rate):	1998-2008	5.5%
	1990-1998	6.5%
• Final electricity intensity (annual rate, 1990-2008)		-0.4%

Figure 4

Electricity generation by non-fossil fuels



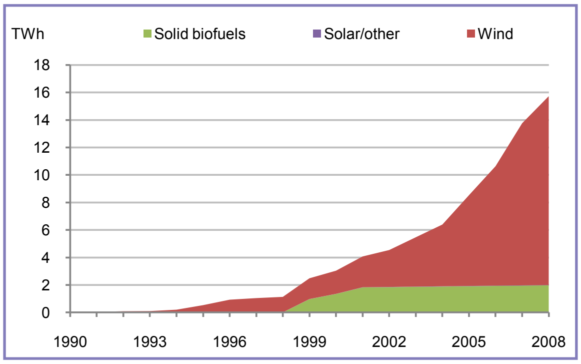
Source: IEA, 2010.

Note: Non-hydro renewables includes geothermal, solar, wind, biofuels and renewable municipal waste.

• Share of non-fossil sources in total electricity (2008)		17.4%
• Largest source (2008)		79% (Hydro)
• TWh growth (annual rate):	1998-2008	3.6%
	1990-1998	0.6%

Figure 5

Electricity from renewables (excluding hydro)

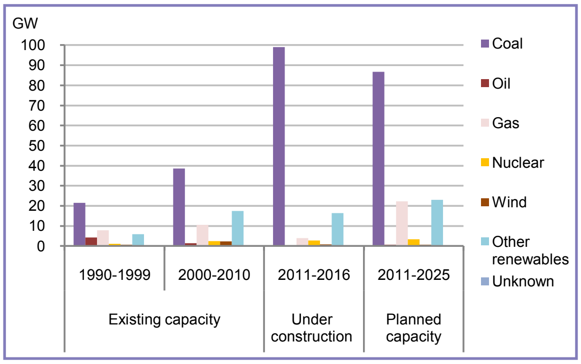


Source: IEA, 2010.

• Largest source excluding hydro (2008)		87.3% (Wind)
• Largest growth over the last decade		12.6 TWh (Wind)
• Growth (annual rate):	1998-2008	30.1%
	1990-1998	56.2%

Figure 6

New capacity by installation date



Source: Platts, 2010.

Notes: Other renewables includes bioenergy, biogas, geothermal, hydro, solar photovoltaics and solar thermal.

• Largest additions in 1990-2010	52.8% (Coal)
• Largest additions under construction	80.3% (Coal)
• Largest additions planned	63.6% (Coal)

Key features in electricity and CO_2: India

▶ Energy and especially electricity access is a permanent challenge for India.

▶ India relies on coal for over 68% of its electricity generation. CO_2 emissions have therefore increased in tandem with electricity demand. In 2008, emissions stood at more than three times their 1990 level.

▶ The CO_2 intensity of power generation has increased over the 1990-2008 period, from 0.85 to 0.97 tCO_2/MWh.

▶ The industry sector accounts for 46.4% of electricity use in India, although the commercial sector shows the strongest growth, ahead of the residential sector. India has introduced measures to enhance efficiency in industry, such as the Energy Conservation Act of 2001 and the more recent "Perform, Achieve and Trade" policy. Building codes are in place since 2006.

▶ Hydro is India's major renewable resource in electricity, with 13.8% of the total output. The National Action Plan on Climate Change identifies hydro, wind and solar as priorities for development.

▶ Non-hydro renewables are by far the fastest growing source of electricity, primarily spurred by wind generation, with targeted government assistance since 2002.

▶ India's solar energy potential has not been exploited yet. The country is planning for 20 GW of solar capacity by 2020, starting with 1 000 MW in 2013 under its National Solar Mission.

▶ These developments, as well as wind capacity additions, are not yet fully reflected in the capacity data collected by Platts.

Geographical coverage

- **OECD North America** comprises Canada, Mexico and the United States.

- **Europe includes: OECD Europe**, *i.e.* comprises Austria, Belgium, Czech Republic, Denmark, Finland, France, Germany, Greece, Hungary, Iceland, Ireland, Italy, Luxembourg, Netherlands, Norway, Poland, Portugal, Slovak Republic, Spain, Sweden, Switzerland, Turkey and the United Kingdom and non-OECD Europe, *i.e.* Albania, Bosnia and Herzegovina, Bulgaria, Croatia, Cyprus[1], Gibraltar, Former Yugoslav Republic of Macedonia (FYROM), Malta, Romania, Serbia[2] and Slovenia.

- **OECD Pacific** comprises Australia, Japan, Korea and New Zealand.

- **Africa** includes Algeria, Angola, Benin, Botswana, Cameroon, Congo, Democratic Republic of Congo, Côte d'Ivoire, Egypt, Eritrea, Ethiopia, Gabon, Ghana, Kenya, Libyan Arab Jamahiriya, Morocco, Mozambique, Namibia, Nigeria, Senegal, South Africa, Sudan, United Republic of Tanzania, Togo, Tunisia, Zambia, Zimbabwe and Other Africa. Other Africa includes Burkina Faso, Burundi, Cape Verde, Central African Republic, Chad, Comoros, Djibouti, Equatorial Guinea, Gambia, Guinea, Guinea-Bissau, Lesotho, Liberia, Madagascar, Malawi, Mali, Mauritania, Mauritius, Niger, Reunion, Rwanda, Sao Tome and Principe, Seychelles, Sierra Leone, Somalia, Swaziland, Uganda and Western Sahara.

- **Latin America** includes Argentina, Bolivia, Brazil, Chile[3], Colombia, Costa Rica, Cuba, Dominican Republic, Ecuador, El Salvador, Guatemala, Haiti, Honduras, Jamaica, Netherlands Antilles, Nicaragua, Panama, Paraguay, Peru, Trinidad and Tobago, Uruguay, Venezuela and Other Latin America. Other Latin America includes Antigua and Barbuda, Aruba, Bahamas, Barbados, Belize, Bermuda, British Virgin Islands, Cayman Islands, Dominica, Falkland Islands, French Guyana, Grenada, Guadeloupe, Guyana, Martinique, Montserrat, Puerto Rico, St. Kitts and Nevis, Saint Lucia, Saint Pierre et Miquelon, St. Vincent and the Grenadines, Suriname, and Turks and Caicos Islands.

- **Asia** includes Bangladesh, Brunei Darussalam, Cambodia, Chinese Taipei, Indonesia, DPR of Korea, Malaysia, Mongolia, Myanmar, Nepal, Pakistan, Philippines, Singapore, Sri Lanka, Thailand, Vietnam and Other Asia. Other Asia includes Afghanistan, Bhutan, Cook Islands, East Timor, Fiji, French Polynesia, Kiribati, Laos, Macau, Maldives, New Caledonia, Palau, Papua New Guinea, Samoa, Solomon Islands, Tonga and Vanuatu.

- **India** is India.

- **China** includes the People's Republic of China and Hong Kong (China).

- **Former Soviet Union** includes Armenia, Azerbaijan, Belarus, Estonia, Georgia, Kazakhstan, Kyrgyzstan, Latvia, Lithuania, Republic of Moldova, Russian Federation, Tajikistan, Turkmenistan, Ukraine and Uzbekistan.

- **Middle East** includes Bahrain, Islamic Republic of Iran, Iraq, Israel[4], Jordan, Kuwait, Lebanon, Oman, Qatar, Saudi Arabia, Syrian Arab Republic, United Arab Emirates and Yemen.

1. Footnote by Turkey: The information in this document with reference to "Cyprus" relates to the southern part of the island. There is no single authority representing both Turkish and Greek Cypriot people on the Island. Turkey recognizes the Turkish Republic of Northern Cyprus (TRNC). Until a lasting and equitable solution is found within the context of United Nations, Turkey shall preserve its position concerning the "Cyprus" issue. Footnote by all the European Union Member States of the OECD and the European Commission:The Republic of Cyprus is recognised by all members of the United Nations with the exception of Turkey. The information in this report relates to the area under the effective control of the Government of the Republic of Cyprus.

2. Data for Serbia include Montenegro until 2004 and Kosovo until 1999.

3. Chile became a member country of the OECD with effect from 7 May 2010. Since the preparation of the annual statistics publications was well on its way at that stage, data for Chile have not been included in OECD totals for the 2010 edition and will continue to be included in Latin America with the OECD non-member countries. The IEA Secretariat will work closely with the Chilean Administration, especially on the consistency of the time series, for incorporating Chile into OECD totals in the 2011 edition.

4. The statistical data for Israel are supplied by and under the responsibility of the relevant Israeli authorities. The use of such data by the OECD is without prejudice to the status of the Golan Heights, East Jerusalem and Israeli settlements in the West Bank under the terms of international law.

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